Monitoring report 2022

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)

Bundesnetzagentur Bundeskartellamt

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German Energy Industry Act (EnWG) 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 (GWB) 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 2022, some 6,500 undertakings overall supplied data to the two authorities. Thus the degree of coverage in each market segment, as reflected by the level of response, was well over 95% and in many areas it reached 100%. Any discrepancies between this and other data are the result of different data sources, definitions and survey periods.

Foreword

The German energy markets are currently highly dynamic in the wake of Russia's attack on Ukraine. Electricity and gas consumers, as well as businesses, in Germany are feeling the strain of higher energy costs. The gas supply is a focus of both the authorities' work and public attention. The global economic upturn following the restrictions of the coronavirus pandemic and the related rising demand for energy led to significant price rises on the energy markets in 2021. The Monitoring Report 2022 describes, documents and analyses the developments of 2021, the year before the turning point in the energy sector caused by the Russian invasion of Ukraine. Where sufficiently reliable information was already available, developments in 2022 have been included as well.

The joint monitoring carried out in continued close and effective cooperation by the Bundesnetzagentur and the Bundeskartellamt aims to inform consumers, create transparency in the market and provide an analysis of developments in competition. The Bundeskartellamt focuses on the competitive aspects of the electricity and gas value added chains, including supply to non-household customers, while the Bundesnetzagentur directs its attention towards the areas of network expansion, generation, evaluating security of supply, and delivery to household customers.

A major development of 2021 was the departure of many conventional electricity generating installations from the market in the course of the coal phase-out. Numerous coal-fired plants that were intended to be shut down actually returned to the electricity market in 2022 amidst the tense situation on the energy markets. They will contribute fully to stabilising the electricity supply in this and the next heating season. In addition, the legislators have decided to extend the life of the three remaining nuclear power plants until 15 April 2023 in the interests of security of supply.

Germany's net electricity generation was 551.3 TWh in 2021, higher than in 2020 but still lower than the pre-pandemic level of 2019. Conventional electricity generation rose about 11.6% in 2021 despite there being fewer conventional plants on the grid and the ongoing expansion of renewable generation. One reason for this increase is that conventional energy sources had to make up for reduced generation from renewables due to relatively low levels of wind and sun. There was a particular increase in the net electricity generation of hard coal and lignite power plants, whereas generation by natural gas power stations was already in decline in 2021. Generation from renewable energy decreased by around 7.2%. The share of renewables in gross electricity consumption, which had hit a record high of 45% in 2020, fell back to 40%.

The phase-out of coal and nuclear power for generating electricity has increased the importance of the remaining conventional plants to meet electricity demand. As a result, market concentration in conventional electricity generation and the first-time sale of electricity saw an increase in 2021 from 65.3% to 66.5% with respect to the market shares of producers.

In the more detailed analyses in the market power report 2021 on the competitive conditions in the electricity generation market, the Bundeskartellamt also identified a corresponding intensification in market power for 2021. For the first time in over ten years, the results of the pivotal analysis (indispensability) indicated a dominant position in the market held by RWE. There was also an increase in 2021 in the importance of the power plant capacity operated by LEAG and EnBW for meeting Germany's demand for electricity as well as in the significance of electricity imports and thus foreign power plant capacity.

The reduction in the supply of gas due to the Ukraine war in 2022 therefore coincided with a lower level of supply in the market for the first-time sale of electricity. Other special circumstances further exacerbated this restriction in supply in the course of the year. As a result, it was virtually impossible to use less expensive power plants to replace electricity generated by gas-fired power plants, which was marked by considerably higher marginal costs, especially at times of peak demand. The legislators' plans, already implemented in some cases, for coal-fired plants to return to the market and to extend the life of coal and nuclear plants should counteract these developments and prevent a deterioration of the situation. However, it is not yet possible to fully assess the actual effects of these measures on market shares and the degree to which individual providers are indispensable in terms of meeting the demand for electricity. Further analyses are therefore being undertaken.

The second half of 2021 already saw considerable price increases in the energy markets. Electricity and gas wholesale prices have multiplied again since February 2022 and are still very volatile and remain at a high level despite having dropped somewhat. Wholesale electricity prices largely track gas prices because gas-fired power plants set the price in German wholesale electricity trading during most hours of trading. Although the planned extension in the operation of coal and nuclear power plants is likely to bring down prices, nevertheless it can be assumed that they will remain high.

The combined market shares of the four largest electricity and gas suppliers for interval-metered and standard load profile customers in the retail markets were below the statutory thresholds for presuming market dominance in 2021, as in previous years. In light of this, the current assumption is that there is no single dominant undertaking in these markets.

The sharp rise in electricity and gas wholesale prices starting in the third quarter of 2021 was already reflected in retail price trends up to 1 April 2022. These increases are accounted for by the price components controlled by the supplier, in particular energy procurement costs. Moreover, prices as at 1 April 2022 for household customers with their local default supplier (on a default or non-default contract) were lower than the prices with suppliers that were not the local default supplier for the first time. Lawmakers have mitigated the price rises by bringing forward the end to the surcharge under the Renewable Energy Sources Act (EEG) to 1 July 2022 and cutting VAT on gas to 7% from 1 October 2022.

Electricity network tariffs rose again in 2022. The negative trend could not be stopped despite government stabilisation measures such as the exclusion of the offshore connection costs from the network tariffs and a further reduction in the avoided network tariffs under the Network Tariffs Modernisation Act (NEMoG). Rising costs for grid expansion, projected high costs for system security measures and increasing costs for the procurement of loss energy due to higher electricity prices on the exchange will cause network tariffs to rise again in 2023. The TSOs' revenue caps are expected to remain the same in 2023 due to financing from the "brake" on electricity prices.

The total volume of network congestion management measures was considerably higher in 2021 than the year before. The costs for congestion management measures are provisionally put at around €2.3bn and are thus also significantly higher (2020: approximately €1.4bn).

After the number of household electricity customers switching supplier reached a record high of around 5.4mn in 2020, customers switching "voluntarily" fell to 4.8mn in 2021. In the gas sector, too, the number of switches fell in 2021, from 1.6mn to about 1.3mn. Numerous insolvencies and market withdrawals by suppliers were registered in the second half of 2021. A number of suppliers stopped supplying customers or became insolvent as a result of the increase in wholesale prices. These included one larger gas and electricity supplier as well as several smaller suppliers. Electricity and gas customers may have been put off changing to a new supplier because of the lack of alternatives in terms of price.

The gas imports situation has intensified as a result of the reduction in supply and the end to deliveries from Russia since the beginning of the war of aggression against Ukraine in February 2022. In 2021 1,458 TWh of natural gas was imported to Germany, with the most important source countries being Russia and Norway. In 2022, however, there was a fundamental shift. Gas flows through the Nord Stream 1 pipeline were suspended indefinitely in early September 2022, supposedly for technical reasons. The certification procedure for Nord Stream 2 was halted in February 2022 as geostrategic developments came to a head. The attacks on the Nord Stream 1 and 2 pipelines and the destruction of three of their lines made transporting gas from Russia via this route technically impossible as well. Importers have been forced to procure gas at high cost to make up for the lack of gas from Russia. The halt to supplies from Russia was counterbalanced by an increase in imports from Norway and via the pipeline networks in the Netherlands, Belgium and, more recently, France. Additional gas supplies through an increase in liquefied natural gas imports via the planned floating LNG terminals (floating storage and regasification units – FSRUs) on the North and Baltic Sea coasts are anticipated for the end of 2022/beginning of 2023.

The entry into force of the Gas Storage Act at the end of April 2022 and the introduction of statutory requirements for storage levels served to ensure that security of gas supply in Germany will be maintained. The target storage level of 85% for 1 October 2022 was already reached by mid-September. By November 2022, storage facilities were over 99% full.

The Bundesnetzagentur and the Bundeskartellamt will continue to pay close attention to the highly dynamic developments on the electricity and gas markets in Germany and will play a role in shaping this process within their areas of activity.

Klaus Müller
President of the
Bundesnetzagentur für Elektrizität, Gas,
Telekommunikation, Post und Eisenbahnen

Andreas Mundt
President of the Bundeskartellamt

Key findings

Impact of the Ukraine war on the electricity and gas markets

Russia's invasion of Ukraine and the ongoing war have left a profound mark on Germany's energy markets. The situation in many areas changed dramatically in 2022. The systematic and comprehensive monitoring surveys always relate to the previous calendar year, however, and so the Monitoring Report 2022 relates to the situation in 2021, since definitive figures checked for plausibility and quality are only available for 2021. In cases where sufficiently reliable information for 2022 was already available, the information has been taken into account above all in the key findings in order to present the further course of developments in 2022.

The second half of 2021 already saw considerable price increases in the energy markets as a result of the global economic recovery following the restrictions of the coronavirus pandemic. The situation in the energy markets has intensified since the invasion of Ukraine in February 2022. Prices in the wholesale markets for electricity and gas have once again multiplied; they are very volatile at this high level and particularly dependent on the diverse developments relating to the Ukraine crisis. The higher prices are mainly due to the increase in prices for natural gas, which in turn is due to the reduction in the natural gas supply. Russia first reduced and then completely halted gas supplies to Europe via the Nord Stream 1 pipeline. Use of the Nord Stream 2 pipeline has not been approved, nor is it an alternative for the energy industry in light of the current crisis. As things now stand, use of the Nord Stream 1 pipeline is completely impossible and use of the Nord Stream 2 pipeline partially impossible because of sabotage. Importers have been forced to procure gas at high cost to make up for the lack of gas from Russia. Additional gas supplies through an increase in liquefied natural gas (LNG) imports via the planned floating LNG terminals (floating storage and regasification units – FSRUs) on the North and Baltic Sea coasts are anticipated for the end of 2022/beginning of 2023. The tense supply situation and the sharp rise in prices in the gas sector are also affecting the electricity sector, since in Germany the electricity generated by natural gas power stations determines the wholesale price for electricity in many hours of trading (merit order principle). The price explosion in wholesale electricity and gas trading is also leading to extreme price increases and, in the short term at least, to a considerable dampening of competition among suppliers both for household and for commercial and industrial customers.

Electricity generation

Market concentration in electricity generation and the first-time sale of electricity (not entitled to payment under the Renewable Energy Sources Act – EEG) saw an increase in 2021 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 67% in 2021, compared to 65.3% in 2020. By contrast, the share of the five largest suppliers in Germany's conventional generating capacity at the end of 2021 was 53.0% and thus below the previous year's level of 56.7%. The reason for this is the implementation of the nuclear and coal phase-out, which involves a significant amount of conventional generating capacity, including plants operated by the five largest suppliers, exiting the market. This reduction in capacity in the market has reinforced the importance of the remaining conventional capacity, which is reflected among other things in the increase in the amount of energy generated by the larger providers with an overall smaller conventional power plant fleet.

In the more detailed analyses in the market power report 2021 on the competitive conditions in the electricity generation market, the Bundeskartellamt identified a corresponding intensification in market power for 2021. For the first time in over ten years, the results of the pivotal analysis (residual supply index) indicated a dominant position in the market held by RWE. The number of hours in the year in which the power plants operated by RWE were indispensable to meet the demand for electricity was significantly higher than the 5% statutory threshold for presuming dominance. The analyses also showed an increase in 2021 in the importance of the power plant capacity operated by LEAG and EnBW for meeting Germany's demand for electricity as well as in the importance of electricity imports and thus foreign power plant capacity.

The reduction in the supply of gas due to the Ukraine war in 2022 therefore coincided with an already comparatively lower level of supply in the market for the first-time sale of electricity. This restriction in supply was exacerbated further in the course of the year by other special circumstances such as the relatively low level of production by French atomic energy plants. As a result, it was virtually impossible to use less expensive power plants to substitute electricity generation by gas-fired power plants, which was marked by considerably higher marginal costs, especially at times of peak demand. The legislators' plans, already implemented in some cases, for coal-fired plants to return to the market and to extend the life of nuclear plants should structurally counteract these developments and a deterioration of the situation. However, it is not yet possible to fully assess the actual effects of these measures on market shares and the degree to which individual providers are indispensable in terms of meeting the demand for electricity, and therefore further analyses are being conducted.

At 551.3 terawatt hours (TWh), Germany's net electricity generation in 2021 was 3.3% higher than the 2020 level. Conventional power plants recorded an increase in electricity generation of around 11.6%. There was a steep rise particularly in electricity generation by coal-fired power plants. Generation from renewable energy sources fell by 17 TWh compared with the previous year. This was mainly because there was less wind and sun. The share of renewables in gross electricity consumption was around 40%.

In 2021, net electricity generation not receiving support under the EEG was 35.9 TWh higher than in the previous year and amounted to 347.9 TWh.

The total installed generating capacity stood at 238.4 gigawatts (GW) at the end of 2021 (2020: 236.3 GW).[1] This comprised 99.8 GW of non-renewable and 138.6 GW of renewable capacity. In the renewable energy sector, there was an increase in capacity of 7.5 GW in 2021. 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 return of hard coal and lignite power plants to the market this year under the Maintenance of Substitute Power Stations Act is of course not reflected in the monitoring report's figures for the market conditions in 2021.

The growth in renewable energy capacity of 7.5 GW (sum of renewable energy installations with and without payments under the EEG) is due in particular to the larger increase in solar capacity (+5.7 GW). The net growth in onshore wind was 1.6 GW, the same as the previous year.

[1] The 2020 figure from the 2021 monitoring has been updated.

The development of generation volumes and the energy mix in 2022 are not covered by this report.

Redispatching and feed-in management

Overall, the volume of network congestion management measures was considerably greater in 2021 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 €2.3bn and are thus also considerably higher (2020: €1.4bn).

Electricity network tariffs

Average network tariffs for household customers were considerably higher in 2022 at 8.12 cents per kilowatt hour (ct/kWh). With respect to non-household customers, the arithmetic mean tariffs for commercial customers increased by around 3% to 6.85 ct/kWh and increased considerably for industrial customers by around 11% to 2.96 ct/kWh.

Wholesale electricity markets

The trading volume and liquidity of the wholesale electricity markets remained at a high level in 2021, although the trading volume of the coupled day-ahead 12 o'clock auctions was lower than in the previous year at around 218.7 TWh (2020: 231.2 TWh). Volumes of on-exchange futures trading increased. In 2021, the on-exchange trading volume for Phelix-DE futures stood at 1,450 TWh, an increase of around 2.4% compared to the previous year. Volumes traded off-exchange via broker platforms also recorded growth. The volume of over-the-counter (OTC) clearing of Phelix-DE futures on the European Energy Exchange (EEX) rose by about 4% to 1,750 TWh in 2021, around 20% above the volume traded directly on the exchange.

The second half of 2021 already saw considerable price increases in the energy markets. The spot market Phelix Day Base average for 2021 was about €97.12 per megawatt hour (MWh), compared with an average of €30.46/MWh in the previous year, representing an increase of around 218%. There was also a large increase in the average prices for year-ahead futures. The average for Phelix Base Year Futures in 2021, traded for 2022, was €88.42/MWh, compared with the previous year's average of €40.17/MWh, traded for 2021, which represents an increase of around 120%. The average for Phelix Peak Year Futures in 2021 was €107.23/MWh. This corresponds to an increase of around 119% compared to the previous year's average (€49.04/MWh).

A look at the prices for futures in the course of 2021 shows a continual increase up until the end of the year. While the average price for futures in the previous five years and at the beginning of 2021 was around €50/MWh, on 22 December 2021 prices for Phelix Base Year Futures peaked at €324.50/MWh and for Phelix Peak Year Futures at as much as €410/MWh.

Prices in wholesale electricity trading have once again multiplied since the beginning of the invasion of Ukraine in February 2022. The prices are also extremely volatile at this very high level. By the end of August, prices for Phelix Base Year Futures had trebled to a peak of around €1,000/MWh, while prices for Phelix Peak Year Futures had quadrupled to around €1,500/MWh. Since then – and in particular since the final halt to direct Russian gas supplies to Germany – prices have halved. At the beginning of October, year-ahead prices stood at around €450/MWh (base) and €600/MWh (peak). The trend in wholesale electricity prices largely mirrors that in gas prices. This is because gas-fired power plants set the price in German wholesale electricity trading during most hours of trading (merit order principle). The situation also deteriorated mid-year because of extremely low water levels on the Rhine and consequent problems in supplying hard coal-fired power plants in the south of Germany.

The trend in prices is now also being exacerbated by numerous nuclear power plant outages in France due to maintenance work and by the need to meet the demand for electricity using generation technologies that have higher marginal costs. The planned extension in the operation of a number of coal and nuclear power plants in Germany should help to bring down prices, although it will still be gas-fired power plants that will frequently set the prices for electricity when demand is high.

Retail electricity markets

As in previous years, the Bundeskartellamt assumes for 2021 that there is currently no single dominant undertaking in the largest electricity retail markets. The combined market share of the four largest undertakings in 2021 was around 25.8% (2020: 28.5%) in the national market for supplying interval-metered customers and 36.1% (2020: 42.8%) in the national market for non-interval-metered customers on non-default contracts. The joint market share of the four biggest providers in 2021 is still well below the threshold for presuming market dominance.

With respect to supplier switching rates, the 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 10.7% in 2021 (2020: 11.6%). The percentage of household customers' consumption provided by a supplier other than the local default supplier was around 39% (2020: 38%). The number of household customers switching electricity supplier fell to around 4.8mn (2020: 5.4mn). It must be noted, however, that these figures include customers who switched because of their supplier becoming insolvent or stopping their supply to customers, in particular because of the large increase in procurement prices. In 2021 at least, 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 147 different suppliers in 2021 (2020: 142).

The major distortions in the market due to, among other things, the war in Ukraine also had a negative impact in the course of 2022 on both the market structure and the ability and willingness of electricity retail customers to switch supplier. As well as suppliers exiting the market, for example because of insolvency, changes in the business models of some suppliers, such as smaller or local electricity suppliers no longer operating nationwide, have reduced supplier diversity and, consequently, customers' switching options. It is not yet possible to put a figure on the effect of these developments over the year. Nor is it yet clear to what extent the current deterioration in the market environment will prove to have a sustainable structural effect or merely be a temporary phenomenon of the extreme price volatility.

The large increase in prices in wholesale electricity trading was already reflected in the trend in retail prices up to 1 April 2022, which is the date for reporting prices in the energy monitoring survey. 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 2022 was about 22.51 ct/kWh, up 5.57 ct/kWh on the average for April 2021. This represents an increase of nearly 33%. The average total price (excluding VAT) for commercial customers with an annual consumption of 50 MWh in April 2022 was 25.65 ct/kWh, up 2.42 ct/kWh on the previous year and corresponding to an increase of about 10.4%. These increases are accounted for by the price components controlled by the supplier, and in particular energy procurement costs, in view of the significant rise in wholesale prices for electricity up to 1 April 2022. More recent developments since 1 April 2022 are not yet included.

The picture is similar with prices for the supply of electricity to household customers as at 1 April in 2021 and 2022. The average price for household customers rose considerably from 32.63 ct/kWh on 1 April 2021 to 36.06 ct/kWh on 1 April 2022, corresponding to an increase of around 10.5%. 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.

As with industrial and commercial customers, the rise in retail prices as at 1 April 2022 is due to the increase in the price component controlled by the supplier (energy procurement, supply and margin). While the electricity price component not controlled by the supplier (taxes, levies, network tariffs) was down 1.51 ct/kWh on the previous year overall, the component controlled by the supplier was up 4.65 ct/kWh. This rise is largely due to the trend in wholesale prices for electricity procured at short notice, with prices in April 2022 around 390% up on the previous year. The overall increase in energy procurement costs is comparatively small because only about 10% of electricity is procured at short notice (one quarter, one month and one day in advance).

The price component controlled by the supplier (energy procurement, supply and margin) accounted for about 13.54 ct/kWh (38% of the total electricity price) as at 1 April 2022 and had thus increased considerably, as with industrial and commercial customers. The average network tariff and the meter operation charge added up to 8.12 ct/kWh in 2022, around 23% of the total price. The EEG surcharge (3.72 ct/kWh) accounted for around 10.3% of the total price (2021: 20%).

In addition, for the first time, prices as at 1 April 2022 for household customers with their local default supplier (on a default or non-default contract) were lower than the prices with suppliers that were not the local default supplier. In previous years there had already been a noticeable convergence of the prices of non-default contracts with the default supplier and with suppliers other than the local default supplier. For the first time, prices in 2021 for household customers on a non-default (but not default) contract with their local default supplier were below the average prices of suppliers that were not the local default supplier. This phenomenon is presumably also due to the large increase in wholesale prices and the suppliers' procurement strategies. Suppliers also operating as a local default supplier are mostly able to procure electricity well in advance because they can plan better, which is why the short-term increase in wholesale prices has not had an immediate effect on their retail prices. By contrast, other suppliers not operating as a local default supplier have been procuring their electricity at much shorter notice. This can have a more immediate effect on the level of these suppliers' retail prices than with suppliers procuring electricity further in advance.

The rise in wholesale prices for electricity had a further disruptive effect on the supply of electricity to retail customers in the second half of 2021 and at the beginning of 2022. A number of suppliers stopped supplying customers or became insolvent as a result of the increase in wholesale prices. These included notably one larger electricity supplier as well as several smaller ones. The suppliers' customers were automatically transferred to their default supplier without their energy supply being disrupted. This above-average increase in customer numbers prompted several default suppliers to introduce different general prices for existing and new customers. One particular reason for doing this was that the energy they had to procure at short notice for their new customers was considerably more expensive than the energy procured further in advance for their existing customers.

The legal admissibility of this "price split" was subsequently the subject of court proceedings. The legislators responded with an amendment of the Energy Industry Act (EnWG) in July 2022 to prohibit suppliers from having different general prices for existing and new customers on default contracts. However, the general prices for customers automatically transferred to their local default supplier (fallback supply) are allowed to be higher than those for customers (including household customers) on default contracts and can also be changed on the first and the fifteenth of each month.

It is not yet clear how far the upheavals caused by the current crisis will have a sustainable effect on the market structure or how far the measures already taken or discussed will have an impact.

There was only a slight increase in 2021 in the number of customers whose electricity supply was disconnected. In 2021, a total of 234,926 customers were disconnected, representing a year-on-year increase of around 2% (2020: 230,015). The slight rise in the number of disconnections in 2021 is partly due to disconnections carried over from 2020. There was a clear drop in the number of disconnections in 2020 owing to the right to withhold performance set out in Article 240 section 1 of the Introductory Act to the Civil Code (EGBGB), which applied during part of the coronavirus pandemic. In addition, a large proportion of the suppliers had voluntarily decided not to disconnect their customers.

In 2021, around half of the suppliers surveyed by the Bundesnetzagentur again voluntarily decided not to disconnect customers. Suppliers often accommodated customers by offering them special or individual payment arrangements. The trend in the number of electricity customers disconnected since 2017 shows that the number of disconnections does not necessarily correlate with the increase in prices.

The Bundesnetzagentur collects statistics on the number of customers disconnected for the previous calendar year and therefore no figures for 2022 are yet available.

Heating electricity

Overall, the volume of electricity supplied for heating in 2021 was higher than in the previous year. According to the volumes reported by the suppliers, just under 1.98mn market locations were supplied with about 14.3 TWh of electricity for heating purposes. Around 38.8% of the total volume of electricity for heating in 2021 was supplied by non-default suppliers (2020: 37.3%). However, the large rise in the percentage of heating electricity supplied by non-default suppliers between 2019 and 2020 was due to one unique circumstance (the sale of E.ON's heating electricity business to LichtBlick SE as one of the conditions for clearance of the merger between E.ON and innogy under competition law).

The supplier switching rate in the heating electricity segment based on the number of market locations was lower than in the previous year. The switching rate for 2021 was around 4.6% by volume and around 5.4% by market location. The present extreme increases in electricity prices, partly due to the war in Ukraine, are also having a significant negative impact as described above on supplier diversity and the willingness and ability for customers to switch supplier in this special, but increasingly important retail segment. As with the supply of electricity to household customers, it is not yet clear how the situation will develop or how far the deterioration in the competitive environment will have a sustainable structural effect.

The heating electricity segment is also characterised by considerable price increases. The total gross price for night storage heating was 25.55 ct/kWh as at 1 April 2022 and thus higher than the previous year's level of 23.93 ct/kWh. The average total gross price for heat pump electricity was 25.07 ct/kWh and thus also higher than the previous year's average of 23.80 ct/kWh. The increase is mainly due to the part of the price controlled by the supplier, in particular for energy procurement. 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 2021. Germany's electricity exports were up in 2021 compared to a year earlier. Cross-border trade volumes for electricity amounted to 93 TWh in 2021 (2020: 83 TWh). The 2021 export balance was 14 TWh, making the export surplus worth €775mn.

As stated in the Bundeskartellamt's 2021 market power report, the German electricity market has been dependent on imports to meet the country's demand via the market – in other words without reserve power plants – in individual instances for a number of years and is now increasingly dependent in certain hours of the year.

The ability of foreign power plants to provide these imports has been limited in particular as a result of the technical outages of numerous French atomic energy plants because of maintenance work. At the same time, power plant closures in Germany have led to a further reduction in supply. This was one of the factors prompting the Federal Ministry for Economic Affairs and Climate Action (BMWK) to initiate the second grid stress test. Overall, there was an increase in electricity exports from Germany in 2022.

Gas imports and exports

The total volume of natural gas imported into Germany in 2021 was 1,458 TWh. Imports to Germany were thus down by 24 TWh or around 2% from the previous year's figure of 1,482 TWh.[2] The main sources of gas imports to Germany in 2021 were Russia and Norway. However, the Netherlands, as an established and liquid European producer, trading hub and point of arrival for LNG shipments with connections to natural gas fields in Norway and the United Kingdom, was also a significant source of imports for Germany.

The total volume of gas imported into Germany in the period from January to October 2022 was 1,161.1 TWh. This represents a decrease of 52.1 TWh compared with the previous year's figure (for January to October 2021) of 1,213.2 TWh.

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[2] The figures for 2020 have been adjusted for this report in line with the latest calculation methodology and are therefore not comparable with those in the Monitoring Report 2021. For the first time, the export volumes at the Brandov cross-border interconnection point were deducted to avoid the transit volumes – the volumes imported via the Nord Stream 1 pipeline and the Greifswald cross-border interconnection point – being counted twice at the Waidhaus cross-border interconnection point.

The gas imports situation has intensified as a result of the reduction in supply and the volumes from Russia since the beginning of the war of aggression against Ukraine in February 2022. According to the Bundesnetzagentur's daily status reports on the supply of gas in Germany, gas flows from Russia to Germany were last at the normal level of around 1,800 GWh/day on 10 May 2022. The halting of Russian gas deliveries to Poland and Bulgaria has so far had no impact on the security of supply in Germany. Following Russia's imposition of sanctions on Gazprom Germania and almost all the company's subsidiaries, the volumes of gas flowing through Ukraine to Waidhaus in Germany were more than 25% down on the previous day because of the reduction in transit flows.

On 14 June 2022, gas flows from the Nord Stream 1 pipeline were at about 60% of maximum capacity, but were down to 40% the following day. As from 11 July 2022, gas flows were at zero percent because of planned maintenance work on the Nord Stream 1 pipeline scheduled until 21 July 2022. Gas flows through Nord Stream 1 resumed on 22 July 2022 and were at about 40% of maximum capacity. On 27 July 2022, there was another, announced reduction in gas flows from Nord Stream 1 to around 20% of maximum capacity.

These reduced gas flows through the Nord Stream 1 pipeline were then suspended indefinitely on 2 September 2022, allegedly for technical reasons. On 26 September 2022, a sudden drop in pressure first in Nord Stream 2's pipe A and then in both Nord Stream 1 pipes was identified. The damage to the Nord Stream 1 and 2 pipelines did not have any effect on the gas supply. No gas had been delivered through Nord Stream 1 since the beginning of September anyway, and Nord Stream 2 had never been put into operation. Gas importers were forced and able to find alternative sources of gas to make up for the lack of Russian supplies, but at a high cost. The reductions in supplies from Russia were counteracted by an increase in imports from Norway and via the pipeline networks in the Netherlands, Belgium and, more recently, France. The overall situation with gas imports is not expected to improve in the short term; the operation of the LNG terminals (FSRUs) and a subsequent increase in natural gas imports with LNG promise to ease the situation, but not until 2023.

Gas supply disruptions

In 2021, the average interruption in supply per connected final customer was 2.18 minutes (2020: 1.09 minutes in the year). This figure of around two minutes is slightly above the long-term average. Despite the increase, this figure shows that the German gas network still has a high quality of supply. The increase in the average interruption duration was mainly due to third-party damage caused to gas pipes during construction work.

Market area conversion

The year 2021 was marked by the disastrous flooding in July that led to the loss of more than one hundred lives and huge damage to property. The flooding also affected areas in which market area conversion work was in progress. The market area conversion was still affected by the coronavirus pandemic in early 2022. As in the previous year, people working from home and travelling less actually facilitated the conversion process. Almost all network operators and companies carrying out adjustments reported that it was easier to make contact with customers for the conversions. The market area conversion was overshadowed by the war in Ukraine, which created uncertainty among many customers regarding the conversion to H-gas. This uncertainty was resolved with the help of transparent information from the network operators and companies carrying out the adjustments. The market area conversion is consequently on schedule and making good progress.

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 66.9% at the end of 2021, representing a slight decrease compared to the previous year (67.2%).

Germany's gas storage facilities are key to the supply of gas in particular in the winter months. The total maximum usable volume of working gas in underground storage facilities as at 31 December 2021 was 278.51 TWh. Of this, 137.02 TWh was accounted for by cavern storage, 119.90 TWh by pore storage and 21.59 TWh by other storage facilities.

The entry into force of the Gas Storage Act on 30 April 2022 and the introduction of statutory requirements for storage levels serve to increase security in the supply of gas in Germany. The target storage level of 85% for 1 October 2022 was already reached in mid-September 2022. Storage levels on 2 November 2022, the editorial deadline for the monitoring report, stood at 99.19%.

Gas network tariffs

The average network tariff for household customers was 1.62 ct/kWh in 2022 and thus around 2% higher than in the previous year. For commercial customers, the average network tariff in 2022 was 1.25 ct/kWh, slightly lower than in the previous year (2021: 1.28 ct/kWh). For industrial customers, there was a significant increase of just over 37% to 0.44 ct/kWh (2021: 0.32 ct/kWh).

Wholesale natural gas markets

Following a large decrease in the demand for natural gas in 2020 during – and presumably due to – the coronavirus pandemic, there was an increase again in 2021 as a result of the global economic recovery. The volumes traded on the exchange increased by around 36% for the spot market and around 41% for the futures market, both well over 2019 levels. There was also another significant rise in the wholesale prices for gas. The non-weighted annual average of the European Gas Index (EGIX), which is taken as the reference price for the medium-term procurement market, increased year-on-year by around 403% and overtook the border price calculated by the Federal Office for Economic Affairs and Export Control (BAFA), which rose year-on-year by around 116%.

It should be noted that this report covers developments in prices and volumes in 2021; the developments in 2022 are not included in the figures. However, the situation in the wholesale gas markets has also intensified further since the invasion of Ukraine in February 2022. Prices have doubled again, in particular since mid-2022, and are very volatile at this high level. This development is due to the fundamental factors described in connection with gas imports.

Retail gas markets

The levels of concentration in 2021 in the two largest gas retail markets for standard load profile (SLP) and interval-metered customers were still well below the statutory thresholds for presuming market dominance. In 2021, the cumulative sales of the four largest companies to SLP customers were about 102.7 TWh, while to interval-metered customers they were around 123.9 TWh. The aggregate market share of the four largest companies (CR4) in 2021 was around 26% for SLP customers (the same as in the previous year) and just 24% for interval-metered customers (2020: 28%).

The total consumption amount of non-household customers affected by supplier switches in 2021 was 107.6 TWh, corresponding to a clear year-on-year increase of 27 TWh from 2020 levels. The switching rate for non-household customers increased to more than 10% again (2020: 7.3%).

The total number of supplier switches by household customers fell in 2021 by just over 0.5% to around 1.64mn. Around 1.3mn of these household customers changed by cancelling their previous supply contract (voluntary switching). It should be noted that the total number of switches for 2021 does not include "involuntary" switching by customers whose contracts were cancelled by their suppliers, including insolvent suppliers, who were no longer able to supply their customers because of the increase in prices. The number of "involuntary" supplier switches amounted to around 345,200. The overall numbers-based supplier switching rate for household customers, based on a total number of household customers of 12.8mn as reported by the gas distribution system operators (DSOs) and excluding insolvency-related "involuntary" switches, was 12.8% (2020: 12.9%). Possible reasons for the decrease in the number of customers switching supplier include the increases in gas prices beginning in the third quarter of 2021. Customers may have been reluctant to switch to a new gas supplier because of the lack of alternatives in terms of price.

There was a significant decrease of around 30% in 2021 in the number and volume of contract switches with the same suppliers. The volume-based contract switching rate was down to 3.1% from 4.8%. As with supplier switching, the underlying reasons include the increases in gas prices beginning in the third quarter of 2021. Household customers kept their existing contracts because of the general developments in prices and because of the lack of alternatives. In 2021, at least, the number of undertakings operating in the market was the same as in 2020. Household customers could choose on average from among 113 different suppliers in 2021.

As in the retail electricity market, there were major distortions in the retail market for gas during 2022 due to, among other things, the war in Ukraine. In addition to suppliers exiting the market because of insolvency, for instance, some suppliers are currently changing their business models, with smaller or local gas suppliers no longer operating nationwide in supplying customers under non-default contracts. This means that customers have had considerably fewer options for new contracts, at least for some of the time. Here, too, it is not yet possible to put an exact figure on the effect of this development over the year. Nor is it yet clear whether the current negative developments in the market structure and the ability and willingness of customers to switch supplier will prove to have a sustainable structural effect.

The volume-weighted gas price for household customers across all contract categories increased to 9.88 ct/kWh as at 1 April 2022. In the price across all contract categories, the largest price component "energy procurement, supply and margin", which makes up around 45%, rose by over 86% from 2.95 ct/kWh to 5.5 ct/kWh.

The volume-weighted gas price for customers on a default contract as at 1 April 2022 was 9.51 ct/kWh (2021: 7.45 ct/kWh), corresponding to an increase of around 28% compared to the previous year.
On 1 April 2022, the volume-weighted price for customers under a non-default contract with the default supplier was 9.02 ct/kWh, an increase of about 37% compared to 2021 (6.58 ct/kWh).

On 1 April 2022, the volume-weighted price for a contract with a supplier other than the local default supplier was 10.95 ct/kWh, an increase of just over 71% compared to the previous year (2021: 6.41 ct/kWh). No distinction is made in the price survey between existing and new contracts. The prices are averages that may not reflect the prices applicable to new contracts because of price guarantees attached to existing contracts.

The gas prices for non-household (industrial and commercial) customers as at 1 April 2022 showed substantial year-on-year increases as a result of the effects of the war in Ukraine. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 GWh ("industrial customer") was 6.76 ct/kWh, 3.81 ct/kWh or around 129% 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 7.19 ct/kWh on the reporting date, an increase of 2.45 ct/kWh or around 52% year-on-year. Because the monitoring is based on a specific date, 1 April 2022, developments that occurred after this time are not included.

In addition, for the first time, gas prices as at 1 April 2022 for household customers with their local default supplier (on a default or non-default contract) were also lower than the prices of suppliers that were not the local default supplier. This phenomenon is presumably also due to the large increase in wholesale prices and the gas suppliers' procurement strategies. Suppliers also operating as a local default supplier are mostly able to procure gas well in advance because they can plan better, which is why the short-term increase in wholesale prices has not had an immediate effect on their retail prices.

By contrast, other suppliers not operating as a local default supplier more often procure their gas at much shorter notice. This can have a more immediate effect on the level of these suppliers' retail prices than with suppliers procuring gas further in advance.

The rise in wholesale prices for gas had a further disruptive effect on the supply of gas to retail customers in the second half of 2021 and at the beginning of 2022. A number of suppliers stopped supplying customers or became insolvent as a result of the increase in wholesale prices. These suppliers included notably one larger gas supplier as well as several smaller suppliers. The suppliers' customers were automatically transferred to their default supplier without their energy supply being disrupted. This above-average increase in customer numbers prompted several suppliers to introduce different general prices for existing and new customers. One particular reason for doing this was that the energy they had to procure at short notice for their new customers was considerably more expensive than the energy procured further in advance for their existing customers.

The legal admissibility of this "price split" was subsequently the subject of court proceedings. The legislators responded with an amendment of the EnWG in July 2022 to prohibit suppliers from having different general prices for existing and new customers on default contracts. However, the general prices for customers automatically transferred to their local default supplier (fallback supply) are allowed to be higher than those for customers (including household customers) on default contracts and can also be changed on the first and the fifteenth of each month.

It is not yet clear how far the upheavals caused by the current crisis will have a sustainable effect on the structure of the gas market as well or how far the measures already taken or discussed will have an impact.

The number of disconnections carried out by the network operators in 2021 was 26,905, representing an increase of about 12% compared to the previous year (2020: 23,991). The increase in the number of disconnections in 2021, especially among gas customers, is partly due to disconnections carried over from 2020. There was a clear drop in the number of disconnections in 2020 owing to the right to withhold performance set out in Article 240 section 1 EGBGB, which applied during part of the coronavirus pandemic. In addition, a large proportion of the suppliers had voluntarily decided not to disconnect their customers.

In 2021, around half of the suppliers surveyed by the Bundesnetzagentur again voluntarily decided not to disconnect customers. Suppliers often accommodated customers by offering them special or individual payment arrangements.

The Bundesnetzagentur collects statistics on the number of customers disconnected for the previous calendar year and therefore no figures for 2022 are yet available. Based on the figures currently available, the number of gas disconnections correlates even less than electricity disconnections with the increase in prices.

Table of contents

I Electricity market

Developments in the electricity markets

1. Summary

Russia's invasion of Ukraine has left a profound mark not only on the gas markets but also on the electricity markets. The Bundesnetzagentur and the Bundeskartellamt have made an effort to incorporate any provisional but reliable figures available into the monitoring report. The Monitoring Report 2022 essentially relates to the situation in 2021, however, since definitive figures checked for plausibility and quality are only available for 2021. Any validated figures for 2022 have been explicitly included; otherwise, the figures for 2021 are also valid in the sense that they indicate the longer-term developments as well. The Bundeskartellamt will present the development of market concentration in 2022 in its forthcoming report on the competitive conditions in the field of electricity generation ("market power report").

1.1 Generation

At 551.3 TWh, Germany's net electricity generation in 2021 was higher than the 2020 level (533.9 TWh) but still lower than the 2019 level. Generation from non-renewable energy sources increased by 34.4 TWh or 11.6% despite the withdrawal of a number of power plants from the market as a result of the phase-out of coal. One reason for this is that the conventional energy sources were mostly needed to make up for the lack of renewable generation when there was little wind or sun. There was a particularly large increase in net electricity generation from coal-fired power plants: 11.1 TWh more was generated in hard coal-fired power plants (+27.6%) and 19.3 TWh more in lignite-fired power plants (+23.1%). Against the trend of the last few years (with the exception of 2018), natural gas power stations produced less electricity (-4.3 TWh or -5.2%).

There was a 7.2% decrease in generation from renewable energy sources to 219.7 TWh. The share of renewable electricity as a proportion of gross electricity consumption in 2021 was 40%.[3]

Installed generating capacity was characterised by a further increase in renewable capacity in 2021. Overall, renewable capacity growth amounted to 7.5 GW. The year-on-year increase in 2020 was 6.7 GW.[4] The largest increases in 2021 were in solar photovoltaic (+5.7 GW) and onshore wind (+1.6 GW). Non-renewable generating capacity (nuclear, lignite, hard coal, natural gas, mineral oil products, pumped storage and other sources) decreased by 5.4 GW. Total (net) installed generating capacity thus increased to 238.4 GW at the end of 2021, with 99.8 GW of non-renewable and 138.6 GW of renewable capacity. The non-renewable generating capacity includes power stations operational in the market and those outside the market (for example power plants in the grid reserve or that have been shut down temporarily).

The installed capacity of installations eligible for payments under the EEG in Germany stood at 134.2 GW at the end of 2021 (2020: 126.7 GW). This represents an increase of 7.5 GW (+5.9%). A total of 203.4 TWh of electricity from renewable energy installations received payments under the EEG in 2021. Electricity generation from installations eligible for EEG payments thus decreased by 8.4%. EEG payments were

[3] If the share of renewables generation is taken to be about 42.8% or more, it usually relates to the definition of consumption as the "grid load" (for example on the SMARD website).

[4] The 2020 figure from the 2021 monitoring has been updated.

down 34% to €19.7bn. In 2021, renewable installation operators thus received an average of 9.7 ct/kWh under the EEG.[5] The solar expansion target of 63 GW for 2022 as set out in the EEG 2021 was achieved as early as mid-2022, and the onshore wind expansion target of 57 GW will be met by the end of the year.

1.2 Cross-border trading

Electricity exports again exceeded imports in 2021. Germany's electricity exports were up in 2021 compared to a year earlier. Cross-border trade volumes for electricity amounted to 93 TWh in 2021 (2020: 83 TWh). Germany is still one of Europe's biggest electricity exporters. The 2021 export balance was 14 TWh, making the export surplus worth €775mn.

1.3 Networks

1.3.1 Network expansion

The projects listed in the Power Grid Expansion Act (EnLAG) (as at the second quarter of 2022) comprise lines with a total length of about 1,821 km. Around 8 km are currently in the spatial planning procedure and around 205 km are in or about to start the planning approval procedure. A total of 360 km have been approved and are under or about to start construction, and 1,248 km have been completed. The projects listed in the Federal Requirements Plan Act (BBPlG) (as at the second quarter of 2022) comprise lines with a total length of about 10,413 km. The projects designated as crossing federal state or national borders, which fall under the responsibility of the Bundesnetzagentur, account for around 6,425 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 2022, some 2,662 km of the total were ready to start the planning approval procedure. Around 394 km are in the spatial planning or federal sectoral planning procedure, and 5,815 km are in or about to start the planning approval or notification procedure. A total of 656 km have been approved and are under or about to start construction, and 886 km have been completed. Additionally, 218 km are being carried out in procedures by the Federal Maritime and Hydrographic Agency (BSH).

1.3.2 Investments

In 2021, investments in and expenditure on network infrastructure by the network operators amounted to around €13,556mn (2020: €12,332mn) (both figures under commercial law).[6] This comprised €8,395mn of investments and expenditure by the DSOs and €5,161mn by the four German transmission system operators (TSOs). Investments by the TSOs in 2021 were up by around 21% on the previous year (2020: €3,862mn, 2021: €4,677mn). Investments by the DSOs decreased slightly (2020: €4,838mn, 2021: €4,835mn).

1.3.3 Congestion management

The total volume of network congestion management measures was considerably higher in 2021 than the year before. The costs for congestion management measures (feed-in management, redispatching including

[5] 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.

[6] 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).

countertrading, and grid reserve provision and use) are provisionally put at around €2.3bn and are thus also considerably higher (2020: €1.4bn).

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 2021 to about 21,546 GWh (10,804 GWh of reductions and 10,742 GWh of increases). The total volume of requested reductions and increases in feed-in from power plants in 2021 was therefore higher than in 2020 (16,795 GWh). In particular, the volume of electricity-related measures was higher than in the previous year. There was a further increase in 2021 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 €396.7mn (2020: €134.1mn).

The costs for redispatching measures using operational and grid reserve power plants and for countertrading measures are provisionally put at around €1,236mn in 2021 and are thus about 260% higher than the previous year's level (2020: €474.7mn). The increase in the costs for redispatching measures using operational and grid reserve power plants is largely accounted for by the fourth quarter of 2021. The large increase in the volume of the measures was due firstly to problems with transporting coal because of low river levels and secondly to the big increase in wholesale prices.

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 around €243mn in 2021 and are thus higher than in the previous year (2020: €196mn). The costs of using the grid reserve amounted to around €249mn, considerably more than in the previous year (2020: €100mn).

Feed-in management measures: in absolute terms, the volume of curtailments from electricity from renewable sources as part of feed-in management measures was 5,818 GWh in 2021, around 5% lower than in the same period of the preceding year (2020: 6,146 GWh). The decline was probably due to network expansion projects successively going into operation.

Onshore wind is the most-curtailed energy source, making up around 59% of energy curtailed, followed by offshore wind now with 36%. Installations in Lower Saxony are curtailed the most (45%), followed by those in Schleswig-Holstein (32%). Although around 63% of curtailments were in the distribution system, around 73% 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 €807mn in 2021 (2020: €761mn). This rise, which amounts to about 6%, was caused by the greater curtailment of offshore wind turbines. Compensation payments are covered by final customers via the network tariffs 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 tariffs

There was a clear increase in the volume-weighted network tariffs (including meter operation charges) for household customers for 2022 (+0.6 ct/kWh). The weighted average for household customers with an annual consumption of 2,500 to 5,000 kWh was 8.12 ct/kWh. With respect to non-household customers, the arithmetic mean tariffs for commercial and industrial customers are higher than the previous year's levels. The network tariffs (including meter operation charges) for commercial customers increased by around 3% to 6.85 ct/kWh (2021: 6.64 ct/kWh). The network tariffs (including meter operation charges) for industrial customers increased by around 11% to 2.96 ct/kWh (2021: 2.67 ct/kWh). These increases confirm the information provided last year by the DSOs under the Bundesnetzagentur's responsibility about the provisional network tariffs for 2022. According to that information, average network tariffs in Germany were set to increase noticeably in 2022. 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.

1.4 Costs for system services

The net costs for system services, which are passed on to final customers, were considerably higher in 2021 than in 2020 at around €3,437.3mn (2020: €2,102.7mn). Major costs were the costs for congestion management at around €2,285.4mn (2020: €1,432.2mn), contracting frequency containment reserves (FCR), automatic frequency restoration reserves (aFRR) and manual frequency restoration reserves (mFRR) at a total of €568.6mn (2020: €152.4mn), and loss energy at €458.4mn (2020: 450.5mn).

The increase in the costs for congestion management is due firstly to the large increase in the volume of the measures owing to problems with transporting coal because of low river levels and secondly to the big increase in wholesale prices. The latter also had an impact on the costs for contracting reserves.

1.5 Wholesale

The trading volume and liquidity of the wholesale electricity markets remained at a high level in 2021, although there was a year-on-year decrease in the trading volume of the coupled day-ahead 12 o'clock auctions to around 218.7 TWh (2020: 231.2 TWh).

Volumes of on-exchange futures trading increased. In 2021, the on-exchange trading volume for Phelix-DE futures stood at 1,450 TWh, an increase of around 2.4% compared to the previous year. Volumes traded off-exchange via broker platforms also recorded growth. The volume of OTC clearing of Phelix-DE futures on the EEX rose by about 4% to 1,750 TWh in 2021, around 20% above the volume traded directly on the exchange.

The situation in the energy markets has intensified since the beginning of the war in Ukraine in February 2022. Prices in the wholesale markets for electricity and gas have risen considerably again and are very volatile. The second half of 2021 already saw considerable price increases in the energy markets. The spot market Phelix Day Base average for 2021 was about €97.12/MWh, compared with an average of €30.46/MWh in the previous year, representing an increase of around 218%. There was also a large increase in the average prices for year-ahead futures. The average for Phelix Base Year Futures in 2021, traded for 2022, was €88.42/MWh, compared with the previous year's average of €40.17/MWh, traded for 2021, which represents an increase of around 120%. The average for Phelix Peak Year Futures in 2021 was €107.23/MWh. This corresponds to an increase of around 119% compared to the previous year's average (€49.04/MWh).

A look at the prices for futures in the course of 2021 shows a continual increase up until the end of the year. On 22 December 2021, prices for Phelix Base Year Futures peaked at €324.50/MWh and for Phelix Peak Year Futures at as much as €410/MWh.

1.6 Retail

1.6.1 Contract structure and competition

As in previous years, the Bundeskartellamt assumes that there is currently no single dominant undertaking in the largest electricity retail markets and that the four biggest providers are still well below the threshold for presuming market dominance. The combined market share of the current four largest undertakings was around 25.8% (2020: 28.5%) in the national market for supplying interval-metered customers and 36.1% (2020: 42.8%) in the national market for non-interval-metered customers on non-default contracts.

The number of electricity suppliers from which retail customers can choose increased slightly. In 2021, final customers could choose between an average of 167 suppliers in each network area (not taking account of corporate groups), compared to 162 suppliers in 2020. The average number of suppliers for household customers in Germany was 147 (2020: 142).

As in 2020, a relative majority of 37% of household customers' consumption was supplied on non-default contracts with local default suppliers. The volume-weighted percentage of household customers' consumption supplied under default contracts stood at around 24% (2020: 26%) and was thus about the same as in the previous year. The percentage of household customers' consumption provided by a supplier other than the local default supplier is around 39% (2020: 38%). Overall, about 61% 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 remains broadly unchanged.

There was a decrease in the number of supplier switches in 2021 to almost 4.8mn. The switching rate based on the total number of household customers was 9.7% and thus just over one percentage point lower than in the previous year (2020: 10.9%). It should be noted that the 2021 figure does not include switches because of insolvencies or (involuntary) switches because of suppliers cancelling contracts (the number including these switches is around 5.7mn). In addition, about 1.5mn household customers changed energy supply contract with the same supplier. The supplier switching rate for non-household customers – with an annual consumption of more than 10 MWh – based on consumption volumes was 10.7% (2020: 11.6%).

1.6.2 Disconnections

The number of disconnections actually carried out by the network operators was 234,926, representing an increase of 2% compared to the previous year (2020: 230,015). The number of disconnection notices issued by suppliers to household customers was very much higher, although it was lower than the year before. The number of notices issued was approximately 4mn, of which about 740,000 were passed on to the relevant network operator with a request for disconnection (2020: 4.2m notices and 696,000 requests). The amendment of the Electricity Default Supply Ordinance in December 2021 introduced stricter conditions for disconnecting customers on default contracts.

1.6.3 Price level

The average total price (excluding VAT and possible reductions) for industrial customers with an annual consumption of 24 GWh as at 1 April 2022 was about 22.51 ct/kWh, up 5.57 ct/kWh on the average for April 2021. The average total price (excluding VAT) for commercial customers with an annual consumption of 50 MWh in April 2022 was 25.65 ct/kWh, up 2.42 ct/kWh on the previous year. The increase in these prices is mainly due to the price components controlled by the suppliers, which include the rising energy procurement costs. Because the monitoring is based on a specific date, 1 April 2022, developments that occurred after this time are not included.

Data was collected from the suppliers operating in Germany on the prices for household customers as at 1 April 2022. The average price (including VAT) increased significantly to 36.06 ct/kWh (2021: 32.63 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.

The electricity price is made up of a component controlled by the supplier (energy procurement, supply and margin) and a component not controlled by the supplier (levies, taxes, etc). While the component not controlled by the supplier accounted for 62% in 2022 and was thus smaller than in the previous year (2021: 74%), the component controlled by the supplier accounted for about 38% and was therefore considerably larger (2021: 26%). This contributed significantly to the rise in the retail price. The underlying cause is the large increase in wholesale prices, which has an effect in particular on the energy volumes procured by suppliers at short notice. The network tariff in 2022 was also higher than in the previous year and thus still at a high level. The EEG surcharge (3.72 ct/kWh) accounted for only around 10% of the total price. It should be noted that the prices relate to a specific reporting date and do not take account of the early discontinuation of the EEG surcharge on 1 July 2022. If the EEG surcharge had been discontinued before the reporting date, 1 April 2022, and assuming that prices include the full EEG surcharge, the average price (including VAT) would be 31.64 ct/kWh.

Compared to 2021, the average price for household customers on default contracts with an annual consumption of 2,500 kWh to 5,000 kWh increased to 35.70 ct/kWh (2021: 33.80 ct/kWh). The average price for customers on a non-default contract with their default supplier was 34.86 ct/kWh (2021: 31.89 ct/kWh). In 2022, as in the previous year, prices with the default supplier were lower than prices with suppliers that were not the local default supplier. For the first time, prices for both types of contract with the local default supplier (default and non-default contracts) were lower than those for non-default contracts with suppliers that were not the local default supplier. The price for customers on a contract with a supplier other than their local default supplier increased by around 14% to 37.22 ct/kWh (2021: 32.70 ct/kWh). This is presumably due to the suppliers' different procurement strategies. While default suppliers tend to have longer-term procurement strategies, suppliers not operating as a default supplier presumably usually procure their energy at shorter notice. This is also reflected in the number of insolvencies and supply contract cancellations among suppliers not operating as a local default supplier.

1.6.4 Surcharges

The network operators estimated that they would pass on around €17.2bn in surcharges to network users in 2022. This total comprises the EEG surcharge (€12.96bn), the offshore network surcharge (€1.48bn), the section 19 Electricity Network Charges Ordinance (StromNEV) surcharge (€1.22bn), the Combined Heat and Power Act (KWKG) surcharge (€1.49bn) and the interruptible loads surcharge (€0.014bn). The sum to be refinanced through the EEG surcharge therefore still makes up the largest share (about 75%) out of all the surcharges, although it is already considerably lower than in the previous year (2021: €22.28bn). The federal government assistance of €3.25bn that was planned for 2022 as a means of capping the EEG surcharge (assistance in 2021: €10.8bn) is not required because of the high exchange prices for electricity.

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. The government decided to reduce the surcharge to 0 ct/kWh as from 1 July 2022 in order to quickly reduce the burden on electricity customers from the significant rise in energy prices. The coalition agreement had originally set the date of 1 January 2023 for the EEG surcharge to be discontinued.

1.6.5 Heating electricity

Overall, the volume of electricity supplied for heating was higher than in the previous year. According to the volumes reported by the suppliers, just under 1.98mn market locations were supplied with about 14.3 TWh of electricity for heating purposes. The supplier switching rate in the heating electricity segment based on the number of market locations was lower than in the previous year. The switching rate for 2021 was around 4.6% by volume and around 5.4% by market location.

The total gross price for night storage heating was 25.55 ct/kWh as at 1 April 2022 and thus higher than the previous year's level of 23.93 ct/kWh. The average total gross price for heat pump electricity was 25.07 ct/kWh and thus also higher than the previous year's average of 23.80 ct/kWh. The increase is mainly due to the part of the price controlled by the supplier, in particular for energy procurement. Here, too, developments that occurred after the monitoring date are not covered in this report.

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 with an interface capable of connecting to a communication unit (smart meter gateway). 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, that is 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 this requirement is not met, the meter operators are required to initiate a process to transfer their default metering 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. Following 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 with effect from 24 February 2020. By February 2020, several default meter operators and another company had started legal action against the BSI's general administrative order determining the technical feasibility of the installation of smart metering systems. In an application for an interim injunction, the Higher Administrative Court (OVG) in Münster initially ruled in favour of the complainant. Adjustments have been made to the MsbG to remove the resulting legal uncertainties. The law introducing these amendments 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. In addition, the Gateway Standardisation committee was set up within the Federal Ministry for Economic Affairs and Energy (BMWi) and was consulted regarding the expanded Technical Directive BSI-TR-03109-1 v1.1 of 23 September 2021. The Technical Directive was subsequently approved by the BMWi and published by the BSI. The Technical Directive focuses on the interoperability certification of smart meter gateways.
On 20 May 2022, the BSI revoked its market statement of 7 February 2020, which had been viewed as likely unlawful in the proceedings for interim measures, with retrospective effect. In its administrative order under section 19(6) MsbG, the BSI stated that smart meter gateways already certified could still be used safely and BSI-compliant systems could still be installed voluntarily. An objection was filed against the BSI's revocation of its market statement.

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 the year 2021. Total electricity supply was 603.0 TWh, comprising a net total of electricity generated of 551.3 TWh (including 9.0 TWh from pumped storage) and cross-border flows[7] from abroad amounting to 51.7 TWh. Total electricity consumption was 608.2 TWh, including 467.0 TWh for final consumers (13.2 TWh of which was for pumped storage stations) from the general supply networks. The amount of energy consumed by pumped storage stations is 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 42.7 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

[7] The physical flows, and not the trade flows, are decisive for the network balance. Trade flows (70.8 TWh of exports and 51.7 TWh of imports) are different from physical flows in the interconnected alternating current system.

reported to the Bundesnetzagentur. Distribution and transmission losses amounted to 27.7 TWh and physical flows to other countries 70.8 TWh. The sum of the individual entries for demand is around 608.2 TWh. The difference between this and the total supply of 603.0 TWh is 5.2 TWh or 0.9%. Supply and demand from the monitoring survey are therefore almost balanced. The difference of 5.2 TWh is due to the complex structure of the data survey involving a large number of different market players.

Electricity: network balance 2021

	TSOs	DSOs	Total 2021	Total 2020
Total net nominal generating capacity as at 31 December 2021 (GW)			**238.4**	**236.3**
Facilities using non-renewable energy sources			99.8	105.2
Facilities using renewable energy sources			138.6	131.1
Generation facilities eligible for payments under the Renewable Energy Sources Act			134.2	126.7
Total net generation (including electricity not fed into general supply networks (TWh)			**551.3**	**533.9**
Facilities using non-renewable energy sources			331.6	297.2
Pumped storage			9.0	10.2
Facilities using renewable energy sources			219.7	236.7
Generation facilities eligible for payments under the Renewable Energy Sources Act			203.4	222.0
Net amount of electricity not fed into general supply networks (TWh)[1]			42.7	34.4
Losses (TWh)	**9.9**	**17.8**	**27.7**	**27.2**
Extra-high voltage	8.2	<0,1	8.2	8.1
High voltage (including EHV/HV)	1.7	3.3	5.1	4.9
Medium voltage (including HV/MV)		5.8	5.8	5.7
Low voltage (including MV/LV)		8.8	8.8	8.6
Cross-border flows (physical flows (TWh)				
Imports			**70.8**	**65.4**
Exports			**51.7**	**47.6**
Consumption (TWh)[2]	**25.5**	**428.3**	**467.0**	**455.6**
Industrial, commercial and other non-household customers	25.5	299.5	325.0	318.5
Household customers		128.8	128.8	125.7
Pumped storage			13.2	11.4

[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: 2021 network balance based on data from TSOs, DSOs and power plant operators

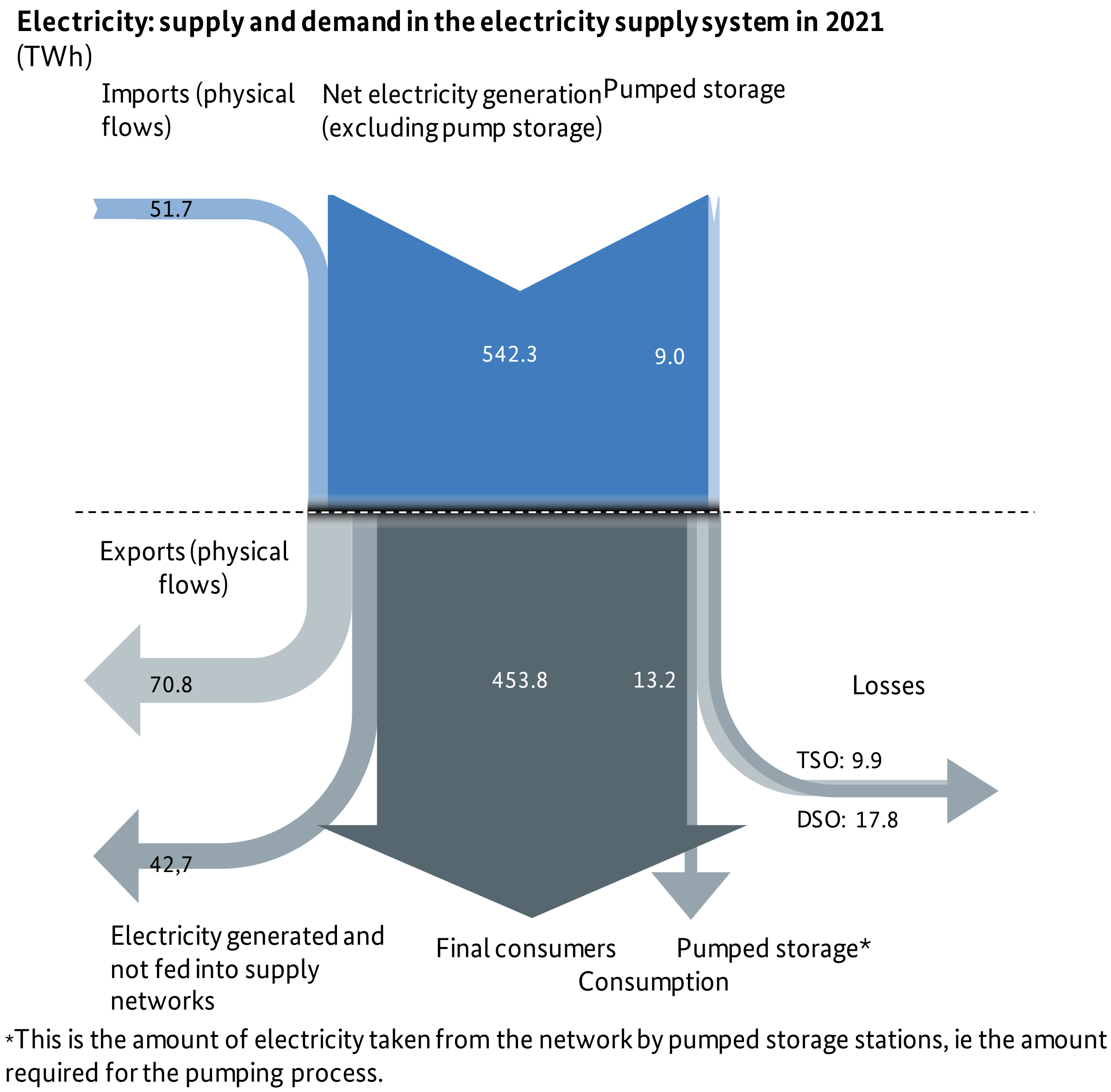

Figure 1: Supply and demand in the electricity supply system in 2021

2.2 Electricity consumption

For 2021 a gross electricity consumption reported for the monitoring survey of 557.3 TWh can be derived from the network balance presented in 2.1. This gross consumption comprises the sum of gross electricity generation from renewable (220.8 TWh) and non-renewable (355.6 TWh) energy sources and cross-border flows into Germany (51.7 TWh) less the cross-border flows out of Germany (70.8 TWh).[8] Gross generation is higher than net generation because it includes power station internal consumption. Generation from renewable energy sources thus accounted for around 40% of gross electricity consumption in 2021.

[8] The actual figure is higher, because only power station internal consumption and electricity volumes from self-generation plants with an installed capacity of 10 MW per location 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	122.0	122.0	27%
10 MWh/year - 2 GWh/year	0.1	117.4	117.5	26%
> 2 GWh/year	25.4	188.9	214.3	47%
Total 2021	**25.5**	**428.3**	**453.9**	**100%**
Total 2020	26.1	418.1	444.2	

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	25.5	266.1	291.6	64%
Standard load profile customers		162.2	162.2	36%
Household customers within the meaning of section 3 para 22 EnWG		128.8	128.8	28%
Total 2021	**25.5**	**428.3**	**453.8**	**100%**
Total 2020	26.1	418.1	444.2	

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 2021 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 428.3 TWh and from the TSOs' networks 25.5 TWh.

Table 3 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 2021. 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 2,612 kWh in 2021, according to data from DSOs.[9] The highest household customer consumption was in the band between 2,500 kWh and 5,000 kWh and totalled about 44.6 TWh, according to data from electricity suppliers. The average consumption for this representative case was about 3,449 kWh, and the total number of market locations around 12.9mn.

2.3 Network structure data

The electricity TSOs and 812 DSOs took part in the Monitoring Report 2022 data survey.[10] As at 2 November 2022, a total of 865 electricity DSOs were registered with the Bundesnetzagentur.

Electricity: TSOs and DSOs in Germany

	2017	2018	2019	2020	2021	2022
TSOs with responsibility for control areas	4	4	4	4	4	4
Total DSOs	878	890	883	879	873	865
DSOs with fewer than 100,000 connected customers	797	809	803	799	791	782
DSOs with fewer than 30,000 connected customers	625	614	645	678	674	664

Table 4: Number of TSOs and DSOs in Germany: 2016 to 2022

The following table shows the network structure figures "circuit length" and "market locations" for the TSOs and DSOs. Since 2018 the market location has been 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 locations. 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.

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

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

Electricity: network structure figures 2021

	TSOs*	DSOs	Total
Network operators (number)	8*	867	867
Total circuit length (thousand km)	37.2	1,896.9	1,934.1
Extra-high voltage	37.0	0.2	37.2
High voltage	0.2	95.0	95.2
Total final consumers (market locations) (thousand)		527.1	527.1
Low voltage		1,274.6	1,274.6
Total final consumers (market locations) (thousand)	0.4	52,261.1	52,261.6
Industrial, commercial and other non-household customers	0.4	2,964.3	2,964.7
Household customers		49,296.9	49,296.9
Annual peak load (GW)			81.4

* Figures include offshore holding companies and Baltic Cable AB.

Table 5: 2021 network structure figures based on data from TSOs and DSOs

The circuit length at TSO level was 37,200 km in 2021. The total number of market locations of final consumers in the TSOs' networks was 414. 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 2021 was around 1.90mn km. As shown in the following figure, the majority of the DSOs included in the data analysis (610 or 75%) have networks with a short to medium circuit length (lines and cables) of up to 1,000 km. These DSOs serve 7.4mn or 14% of all market locations in Germany. A total of 202 DSOs have networks with a total circuit length of more than 1,000 km. These network operators supply 44.9mn market locations, about 86% of the total. The annual peak load is the highest sum value of electrical capacity occurring at one time in a calendar year from all connected consumers in the general supply network including line losses; it shows the maximum capacity that the energy supply network must be able to supply. In 2021 the annual peak load occurred on 30 November between 11.45am and 12.00pm and measured 81.37 GW; the 2020 annual peak load occurred on 3 December between 5.45pm and 6.00pm and measured 78.71 GW.

Electricity: market locations by federal state at DSO level 2021
(millions)

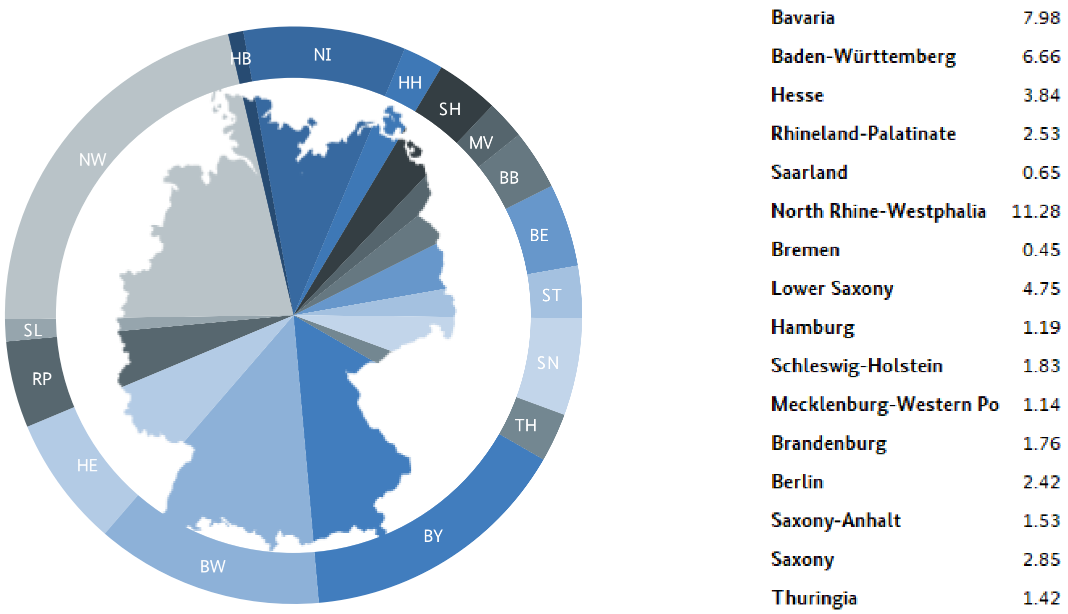

Figure 2: Market locations by federal state at DSO level based on data from DSOs

Electricity: market locations by federal state at TSO level 2021
(number)

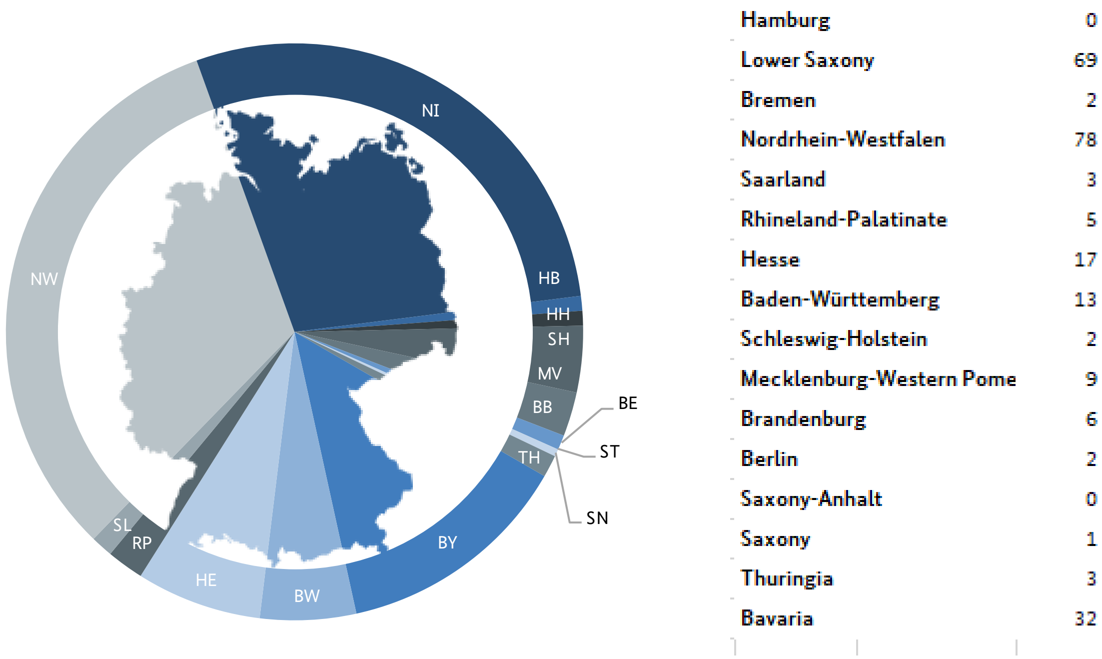

Figure 3: Market locations by federal state at TSO level based on data from TSOs

Electricity: DSOs by circuit length in 2021
(number and percentage)

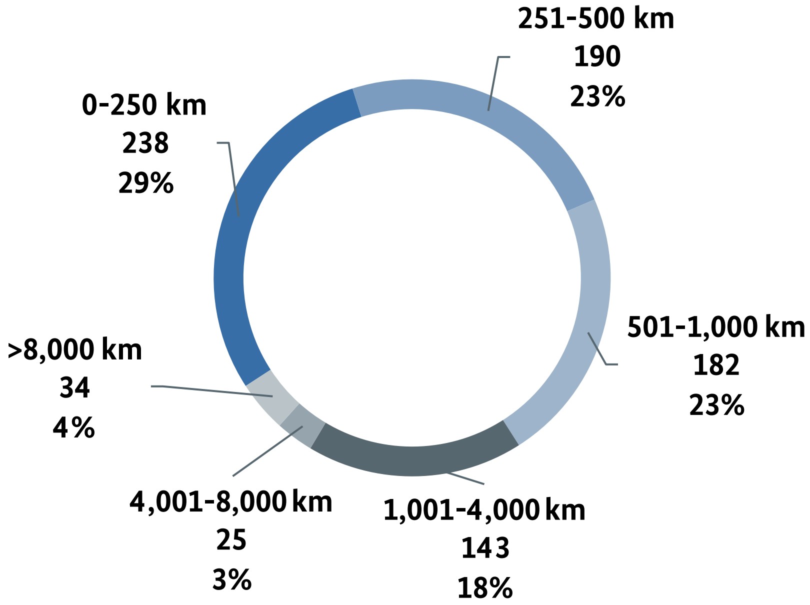

Figure 4: Number and percentage of DSOs by circuit length based on data from DSOs

Electricity: DSOs by number of market locations supplied in 2021 (number and percentage)

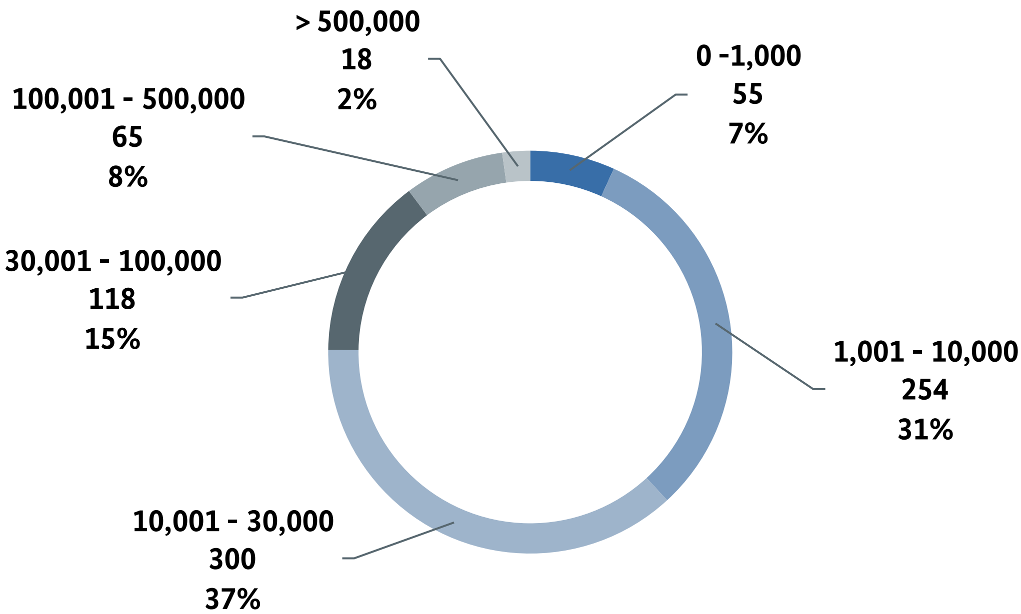

Figure 5: DSOs by number of market locations supplied based on data from DSOs

The number of market locations of final consumers in the DSOs' network areas was around 52.3mn, of which about 49.3mn were for household customers as defined in section 3 para 22 of the Energy Industry Act (EnWG). Around 385,552 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% (39.4mn) 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. Instead this report will be based on indicators which are less complex to identify.

An extensive market power analysis is provided in the third report on competitive conditions in the electricity generation sector ("2021 Market Power Report"), which the Bundeskartellamt published on 17 February 2022 in accordance with Section 53 of the German Competition Act, GWB. Such an analysis will also be included in the upcoming market power report. 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 point in time the amount of electricity generated 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 2021 Market Power Report (period analysed: October 2020 to the end of September 2021) have shown that for the first time in around ten years, RWE's power plants were once again pivotal in a significant number of hours during the reporting period, i.e. they were indispensable for meeting the electricity demand. In the context of general market shortages caused by the phase-out of coal powered plants, the lower feed-in volumes of renewable energies and the increased demand due to the relaxation of Covid restrictions, the number of hours in which RWE's power plants were indispensable increased. In the reporting period – that is before the further reduction of electricity generation capacities using coal and nuclear power, which have meanwhile been implemented, and the effects of the war in Ukraine – the percentage of hours in which the electricity demand could no longer be met without RWE significantly exceeded the threshold for the presumption of market dominance for the first time in more than ten years. The analyses have moreover shown that the importance of power plant capacities provided by LEAG and EnBW for meeting the electricity demand in Germany in 2021 also increased. However, the percentage of hours covered by these two companies in 2021 was still clearly below the threshold for the presumption of market dominance. The importance of power plants outside Germany for meeting the electricity demand also increased in the reporting period.

For the purposes of this report the identification of possible market power is based on the degree of market concentration, which in turn is determined by the players' market share distribution 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.[11]

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, 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 (in the following referred to as CR5)). In this context it has to be noted that the CR5 companies differ significantly in terms of their size. As shown in the tables below, RWE clearly is the leading supplier among the five largest providers both in terms of electricity volumes generated and electricity capacities available.

The analysis of end customer supply is based on the four suppliers with the highest sales volumes, which 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[12] 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 sale of electricity.

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 relating to 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).

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

[12] For more details see Bundeskartellamt, case summary B8-28/19, available at: https://www.bundeskartellamt.de/SharedDocs/Entscheidung/EN/Fallberichte/Fusionskontrolle/2019/B8-28-19.pdf?__blob=publicationFile&v=2 (retrieved on 1 September 2022)

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 as a 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.[13]

In its case practice the Bundeskartellamt has recently applied the following criteria for the calculation of market shares[14]:

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.[15] 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.[16]

In geographical terms, the Bundeskartellamt defines the market as a joint market for Germany and Luxembourg.[17] Data on electricity generation were collected from the five largest companies as defined above. In terms of the first-time sale of electricity, these were RWE, LEAG, EnBW, E.ON and Vattenfall. 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.

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[13] Cf. Bundeskartellamt, Competitive conditions in the electricity generation market (Market Power Report) 2021, published on 17 February 2022, pp. 12 ff.

[14] 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.

[15] Cf. Bundeskartellamt, 2021 Market Power Report, pp. 35 f.

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

[17] Cf. Bundeskartellamt, 2021 Market Power Report, pp. 24 ff.

The results of the survey on volumes of electricity generated in 2021 are shown in the table below. Data from the previous year are shown for comparison.

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

Germany 2020			Germany 2021		
Company	**TWh**	**Share**	**Company**	**TWh**	**Share**
RWE	67.8	25.3%	RWE	77.1	26.1%
LEAG	39.9	14.9%	LEAG	46.4	15.7%
EnBW	26.6	9.9%	EnBW	33.8	11.4%
E.ON	25.7	9.6%	E.ON	27.5	9.2%
Vattenfall	15.0	5.6%	Vattenfall	13.3	4.5%
CR 5	175.0	**65.3%**	**CR 5**	198.0	**67.0%**
Other companies	92.8	34.7%	Other companies	97.5	33.0%
Total net electricity generation	267.8	100%	Total net electricity generation	295.5	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 companies with the highest sales volumes on the market for the first-time sale of electricity in the German market area including Luxembourg was 67% in 2021. In 2020 their market share was 65.3%. The total net electricity generation which was not entitled to payments under the EEG increased from 267.8 TWh to altogether 295.5 TWh compared to the previous year. After the sharp drop in demand caused by the measures to fight the Covid-19 pandemic in 2020, the demand for electricity has again reached the level of the previous years. Compared to the previous year, RWE's market share increased from 25.3% to 26.1%. The market shares of LEAG and EnBW also increased, while the market shares of E.ON and Vattenfall decreased. The aggregated market share of the five largest companies increased while the market volume also rose at the same time. This means that this group was able to expand its offer immensely.

Electricity generation from renewable energies entitled to payments under the EEG decreased in 2021 to around 203.4 TWh (around 221.9 TWh in the previous year) due to fewer volumes of wind and solar energy fed into the grid.

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

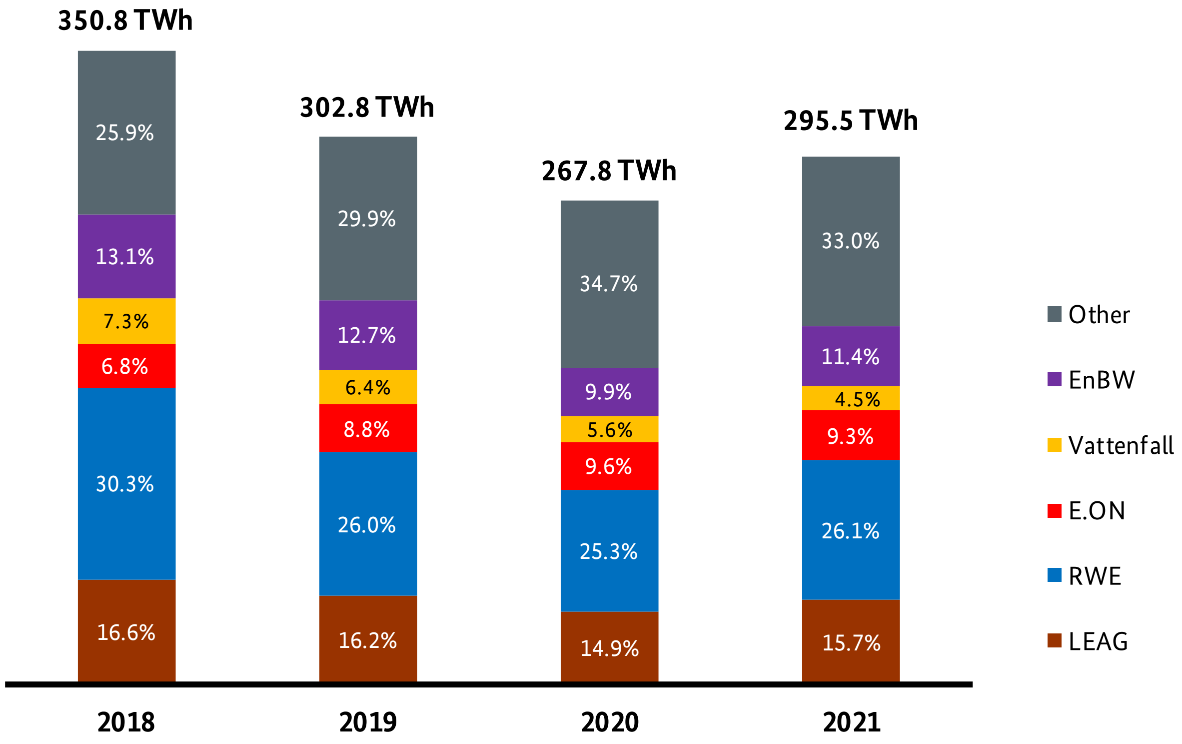

Figure 6: Shares of the five largest companies on the market for the first-time sale of electricity in the German market area

The total amount of non-EEG electricity generation capacities of around 86.9 GW available in Germany as at the reference date 31 December 2021 decreased year-on-year by around 5.7 GW – mainly due to the removal of further generation capacities from the market. It has to be noted, however, that since the reference date 31 December 2021 and the subsequent geopolitical developments in 2022 as well as the energy crisis, capacities have been and still are supposed to be made available to the market, which is not yet reflected in the current figures. The five largest suppliers' share of the German non-EEG subsidised generation capacities generally available for use on the market for the first-time sale of electricity was 53% in 2021, down from 56.7% in the previous year. Despite this smaller conventional power plant fleet of the large providers, their share of the generation volume increased as shown above. This illustrates the increasing importance of the remaining conventional capacities for meeting the electricity demand. It has to be noted, however, 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.

Electricity: Generation capacities of the five largest electricity producers

Germany 31 December 2020			Germany 31 December 2021		
Company	**GW**	**Share**	**Company**	**GW**	**Share**
RWE	20.4	22.0%	RWE	18.2	21.0%
EnBW	9.6	10.4%	EnBW	9.7	11.2%
LEAG	7.8	8.4%	LEAG	8.0	9.2%
Vattenfall	7.5	8.1%	Vattenfall	4.9	5.6%
Uniper	7.3	7.9%	Uniper	5.3	6.1%
CR 5	52.6	**56.7%**	**CR 5**	46.0	**53.0%**
Other companies	40.0	43.3%	Other companies	40.9	47.0%
Total capacity	92.6	100%	Total capacity	86.9	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 2021 with a CR5 of 67%. The power plant shut-downs in 2021 also tightened the market on the supply side and thus increased the competitive weight of the remaining conventional capacities. The legislators' current plans, which partly have already been implemented, to recommission and extend the life of coal-fired plants and nuclear plants are likely to structurally counteract these developments in the current year.

This monitoring report contains information on the market shares of EEG electricity volumes of the five producers mentioned above 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 figures for the entire EEG subsidised electricity volume. In terms of the EEG subsidised generation volume (same companies as with regard to the generation volume in the market for the first-time sale of electricity, i.e. excluding Uniper) the share of the five largest companies in the German market area was around 6.4% in 2021. In the previous year it was still around 5.5%. 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 2021, the same figure as in the previous year.

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 the market for the supply of electricity to metered load profile customers as a national market. 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)[18].

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 than the local default supplier".[19] 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 1,411 electricity providers (legal entities) (2020: 1,413 electricity providers).

Based on the information provided by suppliers, in 2021 around 246.6 TWh of electricity were sold to metered load profile customers and around 159.0 TWh of electricity to standard load profile customers; 14.3 TWh of the total sales to standard load profile customers consisted of heating electricity. Of the remaining 144.7 TWh sales to standard load profile customers without electric heating, 30.7 TWh went to standard load profile customers with default supply contracts, i.e. around 21%; the remaining 113.9 TWh went to standard load

[18] Cf. Bundeskartellamt, decision of 30 November 2009, B8-107/09, Integra/Thüga, paras. 32 ff., most recently, decision of 30 September 2022, B8-134/21 RheinEnergie/Westenergie/rhenag, paras. 143 ff., 335 ff.

[19] 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 fall-back) supply" and "special contract" are appropriate for the purpose of market definitions under competition law and will continue to be used because they are legally defined.

profile customers with special contracts, i.e. around 79%. By comparison: In 2020, 213.6 TWh were sold to metered load profile customers and 133.8 TWh to standard load profile customers, which are significantly lower volumes. Around 11.2 TWh of the sales to standard load profile customers consisted of heating electricity; 25.1 TWh went to standard load profile customers with default supply contracts and 97.4 TWh to standard load profile customers with special contracts. The significant increase in 2021 is likely to have been primarily caused by the increase in demand due to the relaxation of Covid restrictions.

Supply volumes by electricity suppliers

	2020 in TWh	2021 in TWh
metered load profile (RLM)	213.6	246.6
SLP	159.0	133.8
of which heating electricity	11.2	14.3
of which SLP default supply	25.1	30.7
of which SLP special contracts	97.4	113.9

Table 8: Volumes of electricity provided by suppliers according to markets as defined by the Bundeskartellamt[20]

Based on the data provided by the individual companies, it was determined which sales volumes were attributed to the four companies with the highest sales volumes in each market segment. The aggregate sales volumes were attributed to the four 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 the percentage shares provided, 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 percentages provided therefore merely approximate the actual market shares.

When comparing the figures to those of the previous year, it is to be noted that there were some shifts in the retail markets. For example, the market shares changed and, as a consequence, the ranking of the large providers supplying electricity to metered load profile customers also changed, resulting in the fact that the current CR4 companies are only partly identical with those in the previous year.

[20] The discrepancy between these figures and those in table 3 in the network overview can be explained by the fact that the figures in the network overview were provided by the TSOs and DSOs. This table, however, only takes account of the data provided by electricity providers.

In 2021 the four companies with the highest sales volumes (currently: E.ON, RWE, EWE and – which is new – GETEC) sold a total of around 63.7 TWh on the German market for the **supply of electricity to metered load profile customers**. Their aggregated market share thus amounted to 25.8%. A comparison with the previous year is possible only to a limited extent since N-Ergie was still one of the four companies with the highest sales volumes at the time. In the previous year, the companies still sold as much as 60.8 TWh, which was equivalent to a share of 28.5%. 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 2021 the cumulative sales of the four companies with the highest sales volumes (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 41.2 TWh – a decrease from 41.7 TWh sold by the same companies in the previous year. The CR4 value on this market thus amounted to approx. 36.1% in 2021 (2020: 42.8%). This development shows that the share of supply volumes provided by the four largest electricity providers slightly decreased contrary to the general market trend (significant increase in supply volumes). This CR4 value 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 companies with the highest sales volumes[21] (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 12.9 TWh of the total default supply volume of around 30.7 TWh. The share of the CR4 companies was therefore around 42%. In 2020 the sales of these providers to standard load profile customers with default contracts still amounted to around 13.2 TWh.

With regard to the supply of standard load profile customers with **heating electricity** the default suppliers usually have a paramount market position in the local geographic markets. In a hypothetical – and contrary to the Bundeskartellamt's usual market definition – national analysis, the cumulative sales of the companies with the highest sales volumes (here E.ON, EnBW, Vattenfall and Lichtblick) on the German market amounted to around 7.8 TWh. The total volume of heating electricity sold in 2021 was around 14.3 TWh. The four largest companies therefore accounted for around 54.7% (2020: 58.8%) of the volumes supplied.

The shares of 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 determined in this way do not correspond to the Bundeskartellamt's definitions of a product market and a geographic market but are nonetheless indicative of the size of the shares of the companies with the highest sales volumes in a national analysis involving all standard load profile customers. The volume of electricity supplied by the four companies with the highest sales volumes to all standard load profile customers

[21] 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.

(currently: E.ON, EnBW, Vattenfall and EWE) was around 60.2 TWh of a total of 159.0 TWh. This is equivalent to an aggregate share of around 37.9%. In 2020 the volume supplied by the CR4 companies was still 60.8 TWh and their share of the total volume supplied was 45.5%. The share in relation to all standard load profile customers is thus slightly 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 companies with the highest sales volumes – 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).

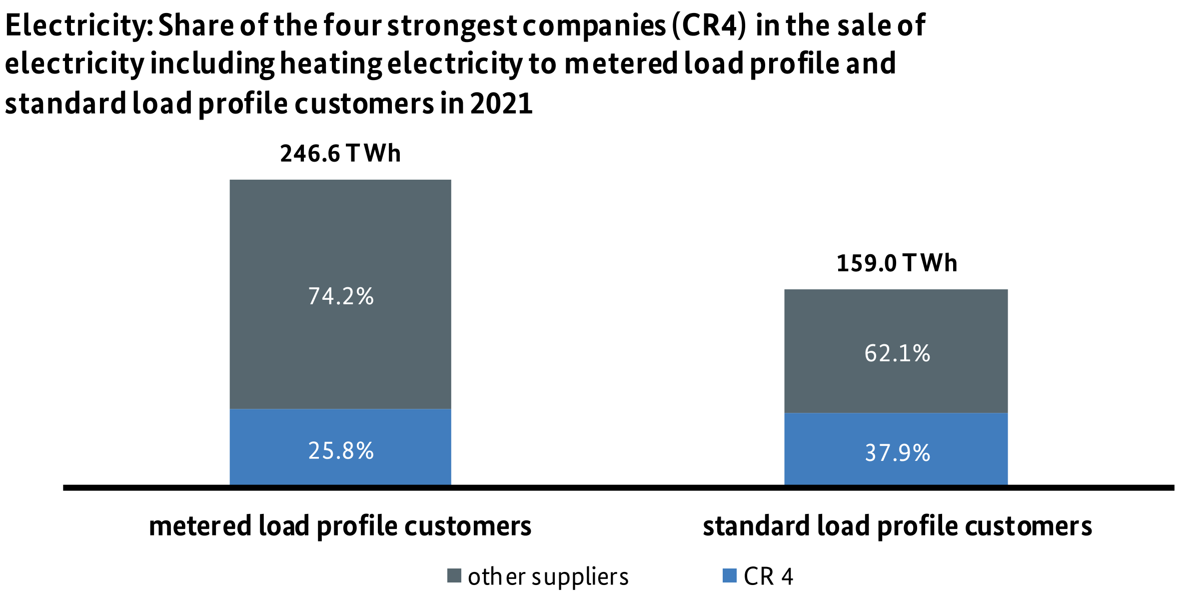

Figure 7: Shares of the four companies with the highest sales volumes (CR4) in the sale of electricity to end customers in 2021

4. Consumer advice and protection

In addition to finding information through the general channels, customers can in particular turn to the Bundesnetzagentur's energy consumer advice service for help with issues relating to the obligations of energy suppliers, network operators and meter operators. The energy consumer advice service also provides information about customer complaint and dispute resolution options.

In Germany, 48.1mn household customers are connected to the electricity grid and 12.8mn to the gas network. In 2021, about 4.8mn electricity customers and about 1.64mn gas customers switched supplier.

In the period up to 30 September 2022, the Bundesnetzagentur received a total of 21,374 telephone, email, online and postal queries and complaints (compared with 14,807 in the same period in 2021). This represents a year-on-year increase of just over 40%.

The energy consumer advice service received nearly 6,573 telephone calls from consumers, 11,195 emails and 3,611 postal and online submissions (as at 30 September 2022). An increasing number of consumers are especially using the online form, with online submissions making up just under 7% of all queries and complaints in 2021 but 13% in 2022.

These figures do not include complaints made in writing or by telephone about unsolicited marketing calls for electricity or gas supply contracts. The total number of these complaints in the first half of 2022 was 8,338.

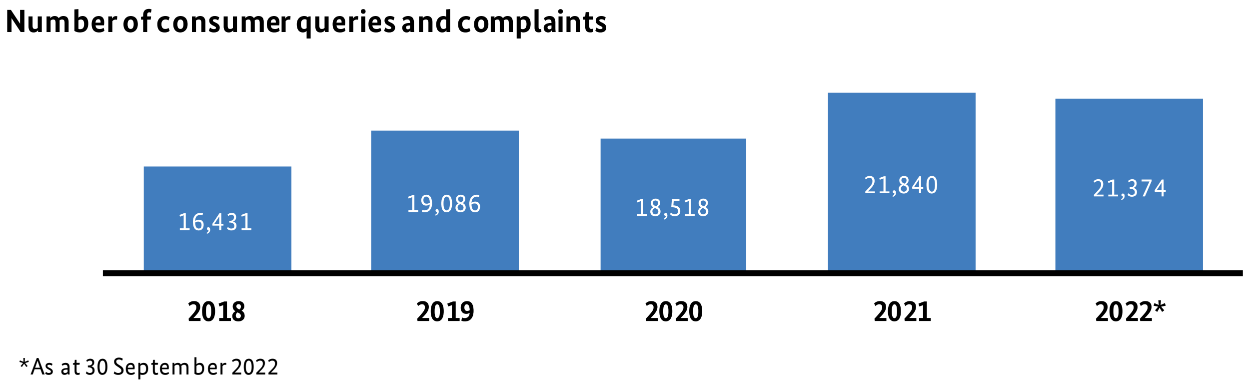

Figure 8: Number of consumer queries and complaints from 2018 to 2022

Main subject of queries and complaints

In the period up to 30 September 2022, 61% of the queries and complaints received were about electricity. As in previous years, the majority were about contracts (concluding contracts, contractual terms and conditions, and rules for terminating contracts) and consumers' bills. There were hardly any queries from consumers about the reduction in the EEG surcharge to 0 ct/kWh with effect from 1 July 2022. Customers will be able to see exactly what effect the reduction has when they receive their next annual bills, so there may well be more queries then.

There was a noticeable increase in 2022 in the number of queries and complaints about gas issues, which made up 18% of the total received (2021: 12%). One reason is the general rise in gas procurement prices. Another reason is the effect on consumers of the tense gas supply situation in Germany because of the war in Ukraine.

These political developments have increased awareness and interest among consumers with regard to increases in prices and advance payments. The main topic of interest was general contractual and billing issues (as with electricity). An increasing number of consumers also sought information about the arrangements for default and fallback supply.

The remaining queries (21%) 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.

The legislators responded to the rise in procurement prices in autumn and winter 2021 and to the subsequent exit of suppliers from the market with the "Easter Package". Energy suppliers must now announce their ending of activities three months in advance and must inform their household customers accordingly. The legislators also put in place new rules for setting and changing general prices for customers on default and fallback supply contracts.

Up-to-date consumer information and further information on the topics mentioned here are available on the internet at www.bnetza.de/verbraucherservice-energie (in German).

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.[22] 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 10f 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 2021, seven facilities injected hydrogen and two facilities injected synthetically produced methane (both figures as at 31 December 2021). With 3.5mn kWh of hydrogen and 0.1mn kWh of synthetically produced methane, however, these forms of injection accounted for only 0.035% of the total amount of biogas injected in 2021. 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 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.

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[22] The term "defossilisation", in contrast to the more common term "decarbonisation", makes a clearer distinction between the use of carbon compounds and their origin. A large number of (for example industrial) processes depend on the use of carbon. Defossilisation still "allows" this use, provided that no fossil carbon is used.

The scenarios approved in the electricity scenario framework 2023-2037/2045 assume electrolysis capacities of 26 GW (A 2037), 28 GW (B 2037) and 40 GW (C 2037) and 50 GW (A 2045), 55 GW (B 2045) and 80 GW (C 2045); no figures are given for how much of the hydrogen produced by electrolysis would subsequently be used to produce methane. The NDP 2023-2037/2045 must take account of these assumptions.

5.2 Electric vehicles

The Charging Station Ordinance, which entered into force in March 2016, requires charging infrastructure operators to notify the Bundesnetzagentur of the charging points they put into or take out of operation. Operators must in particular provide details of the technical capacity of the charging infrastructure they operate. All publicly accessible high-power recharging points and all normal-power recharging points that have been taken into operation since the LSV entered into force are subject to the notification requirement. Charging points not subject to the requirement can also be notified voluntarily.

The LSV was amended with effect from 1 January 2022 (Second Ordinance amending the Charging Station Ordinance of 2 November 2021; Federal Law Gazette I page 4788). One of the main changes affects payment options for users charging their vehicles on an ad hoc basis. In future, users must at least be able to make contactless payments with standard credit and debit cards. New charging points must also have an interface that can be used to transmit location information and dynamic data. The Bundesnetzagentur was notified of a total of 34,476 charging stations with 66,132 recharging points by 1 July 2022, of which 55,549 charging points had a power less than or equal to 22 kW (normal-power recharging points) and 10,583 were high-power recharging points (see https://www.bnetza.de/ladeinfrastruktur).[23] In 2021, the number of charging stations increased by 8,179 and the number of charging points by 15,581. According to the Kraftfahrt-Bundesamt 1,440,574 externally rechargeable passenger vehicles were registered in Germany as at 1 July 2022, of which 756,517 were fully electric vehicles and 684,057 plug-in hybrids.

5.3 Electrical heat generation

As in the past, almost all of today's so-called controllable loads, in particular heat pumps or night storage heating systems, are for electrical heat generation. The network operators surveyed levy a reduced network tariff for 1,813,007 controllable loads. This represents a year-on-year increase of 36,242 loads (see I.C.7.2). There has been a large decrease in the number of night storage heating systems but an increase in the number of heat pumps.

It should be noted that the total number of heat pumps and other types of electric heating systems may differ considerably from the above number of controllable loads with an agreement under section 14a EnWG. A large increase in the number of heat pumps is expected in light of the political objectives. The aim of the declaration of intent agreed at the heat pump summit is to create the necessary conditions to enable up to 500,000 heat pumps a year to be installed from 2024.

[23] Bundesnetzagentur (2022), Charging infrastructure in figures (as at 1 July 2022)

B Generation

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

1.1 Net electricity generation in 2021

Net annual electricity generation since 2015 can be broken down into individual energy sources.[24] Section I.B.2 "Development of renewable energies" contains a detailed analysis of the annual amount of energy supplied by installations eligible for payments under the Renewable Energy Sources Act (EEG) and its development. Renewable energies are therefore only shown in aggregated form in the following figure and table.

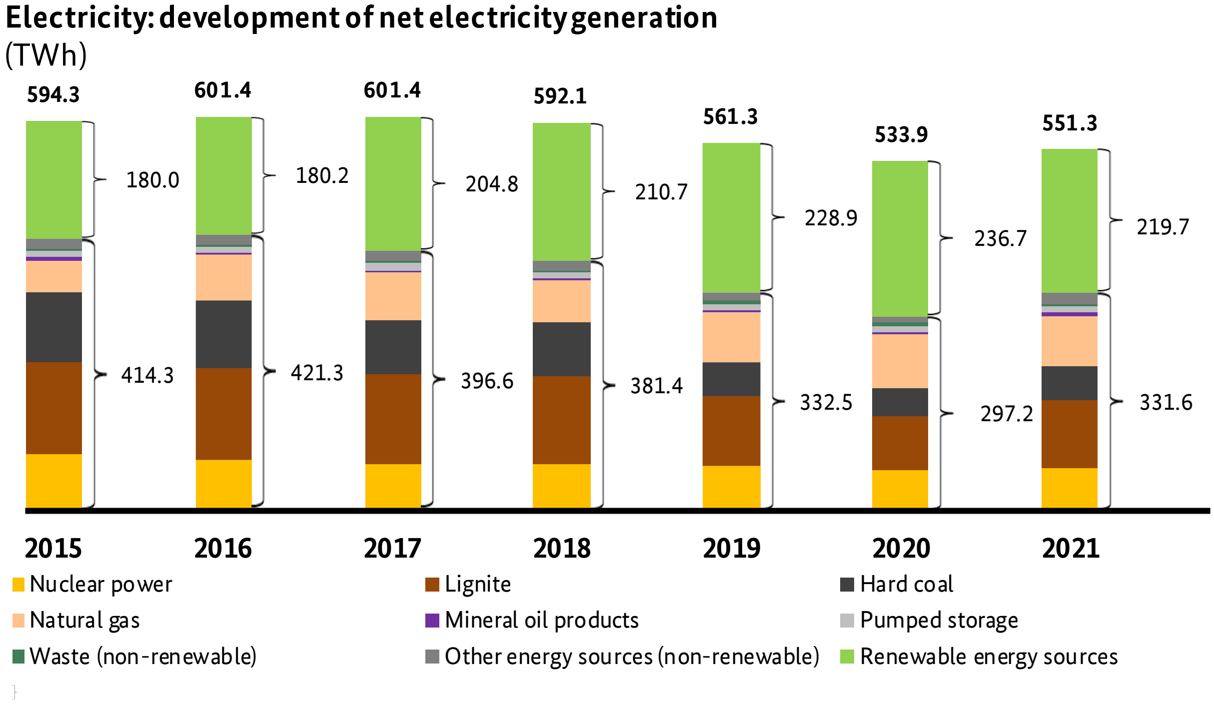

Figure 9: Net electricity generation since 2015

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

Electrcity: development of net electricity generation
(TWh)

	2015	2016	2017	2018	2019	2020	2021
Nuclear power	85.1	78.3	70.5	70.4	69.5	61.8	65.4
Lignite	142.5	139.9	137.5	135.9	104.2	83.5	102.8
Hard coal	106.1	103.3	83.5	80.3	53.4	40.2	51.3
Natural gas	48.7	68.0	72.7	64.4	75.5	82.1	77.8
Mineral oil products	4.3	3.9	3.5	3.5	3.1	4.5	4.8
Pumped storage	10.1	9.9	10.2	9.2	9.8	10.2	9.0
Waste (non-renewable)	4.2	4.3	4.3	4.2	4.1	4.0	4.0
Other energy sources (non-renewable)	13.4	13.6	14.3	13.6	12.9	10.9	16.5
Total of non-renewable energy sources	414.3	421.3	396.6	381.4	332.5	297.2	331.6
Renewable energy sources	180.0	180.2	204.7	210.7	228.9	236.7	219.7
Total	594.3	601.4	601.3	592.1	561.3	533.9	551.3

Table 9: Net electricity generation since 2015

Unlike in 2020, there was a slight increase again in total net electricity generation in 2021, though it was still below the level from 2019. Generation from nuclear power, lignite and hard coal saw particularly sharp increases compared with 2020. Electricity generation from natural gas fell and there was a slight increase in generation from mineral oil. In spite of increased installed capacity, electricity generation from renewable sources saw a decline due to weather with relatively low levels of wind and sun.

The main reason behind the increase in total electricity generation in 2021 was that economic output was partially recovering[25], and that is associated with higher electricity consumption compared with the previous year.

Electricity generation from hard coal and lignite increased by around 27.6% and 23.1% respectively, despite the statutory closure of Niederaußem D on 31 December 2020 in accordance with the Act to Reduce and End

[25] See https://www.destatis.de/DE/Presse/Pressemitteilungen/2022/01/PD22_020_811.html

Coal-Fired Power Generation (KVBG), the KVBG coal bans from the first and second tendering rounds that took effect on 8 July 2021 and on 8 December 2021 respectively and also in spite of the increase in prices for CO_2 certificates. One explanation for this is that, as described below, coal power stations had to substitute for other energy sources.

Electricity generation from natural gas decreased by around 5.2%, mainly because natural gas prices have increased significantly since autumn 2021. Another relevant reason for the increase in electricity generation from coal is the decrease in electricity generation from renewable sources, in particular from wind power. Winds in the first few months of 2021 were much calmer than the year before and, in spite of increased capacity, there was no way to catch up with wind generation levels from 2020. Additionally, 2021 was not particularly sunny. Even though there was a large increase in the number of new PV installations, electricity generation only reached the 2020 level. For further information on electricity generation from renewables under the EEG see "Development of renewable energies".

Mineral oil power stations generated around 6.6% more electricity and generation from the last six remaining nuclear power plants saw moderate growth of around 5.8%.

For the reasons mentioned above, generation from renewable energy sources dropped to contribute around 40% of gross electricity consumption in 2021 (see "Electricity consumption").
The following figure shows the sources of energy for net electricity generation in 2021 in percent.

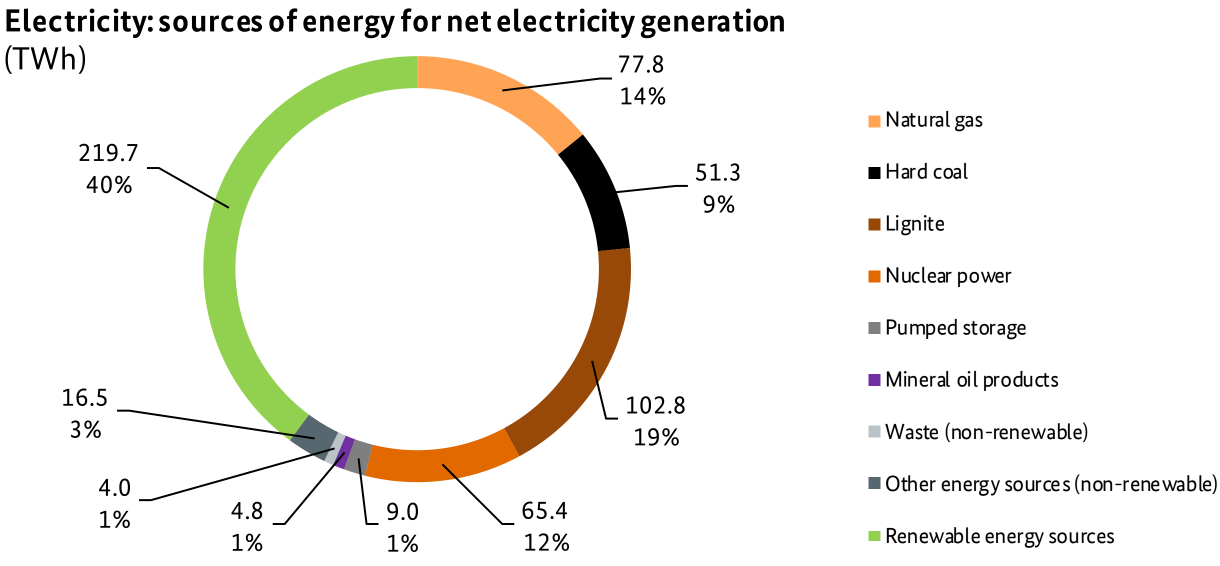

Figure 10: Sources of energy for net electricity generation in 2021

1.2 CO_2 emissions from electricity generation in 2021

The Bundesnetzagentur asked operators of power generation units with a net rated capacity of at least 10 MW (per location) to supply data on CO_2 emissions from electricity generation in 2021.[26] For CHP plants, operators

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

only had to supply data on the share of CO_2 emissions attributable to electricity generation. The results of the survey of power plant operators are provided in the table below.

Electricity: CO_2 emissions from electricity generation
(million tonnes)

	CO_2-Emissionen			Change on
	2019	2020	2021	2020
Lignite	117.0	94.2	115.3	21.0
Hard coal	47.9	36.3	45.6	9.3
Natural gas	26.3	30.0	28.0	-2.0
Mineral oil products	1.3	3.1	3.7	0.6
Waste	8.0	7.2	7.8	0.7
Other energy sources	17.2	12.3	12.0	-0.3
Total	217.8	183.1	212.4	29.3

Table 10: CO_2 emissions from electricity generation

The increase in net electricity generation is reflected in higher CO_2 emissions from power generation (up by 29.3mn tonnes of CO_2). The reasons for the increase in power generation are explained in I.B.1.1. Power plant operators reported that lignite-fired power plants emitted 115.3mn tonnes of CO_2 emissions, which accounted for over half of all CO_2 emissions from electricity generation (54.6%). Hard coal-fired power plants emitted 9.3mn tonnes of CO_2 more than in the previous year. Less electricity generation from natural gas power stations reduced CO_2 emissions by 2mn tonnes. The remaining CO_2 emissions originated, as shown in the table above, from mineral oil-fired power plants, waste-to-energy plants and other energy sources.

1.3 Installed electricity generation capacity in Germany in 2021

The change in total (net) installed generation capacity since 2015 is shown below in Figure 11 and Table 11 (including power plants that are not currently operating in the electricity market but that are, for example, grid reserve power stations or are temporarily shut down)[27].

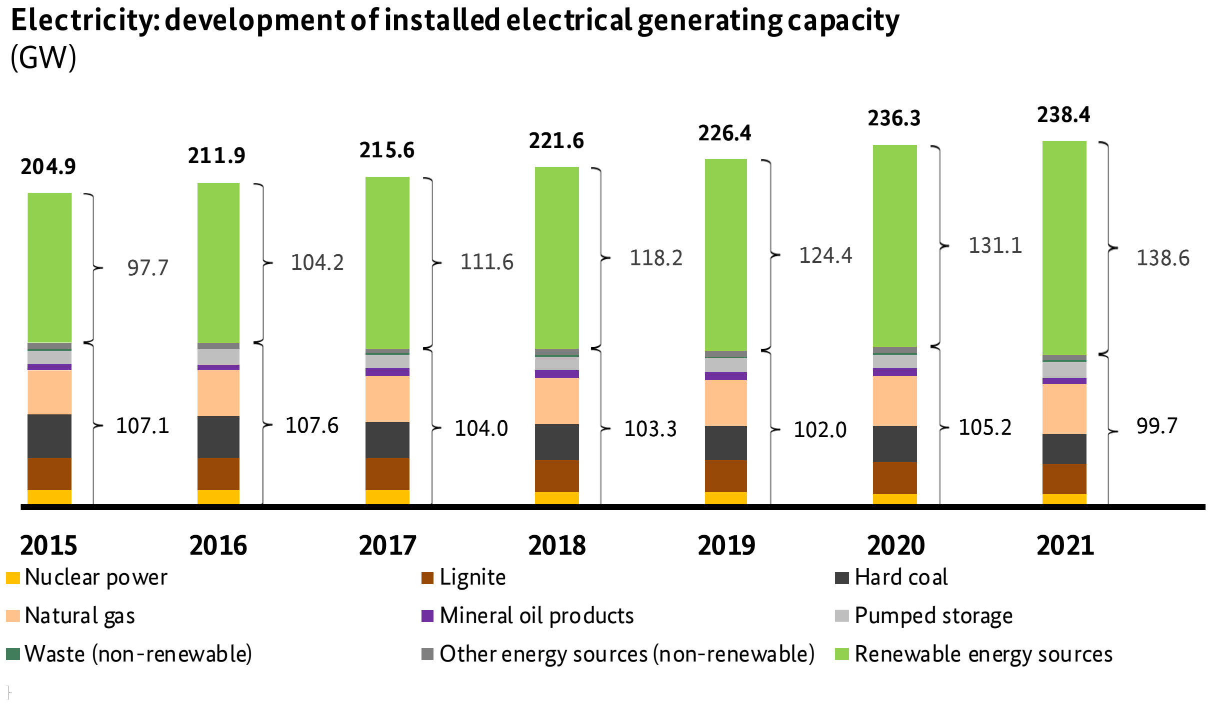

Figure 11: Development of installed generation capacity since 2015

Due to the new system of using the master data from the core energy market data register (MaStR), making a comparison with monitoring report figures older than 2020 is only possible to a limited extent.

Installed net generation capacity from renewable energy has increased by 7.5 GW.

The decrease in generation from conventional energy sources is mainly due to the closure of lignite and hard coal-fired power plants in accordance with the KVBG and other closures of individual plants.

Total generation capacity in 2021 was therefore 238.4 GW. This comprises 99.8 GW from non-renewables and 138.6 GW from renewables.

[27] As from the 2021 monitoring, power plant operators are not asked to provide capacity data where such data must be entered in the core energy market data register (MaStR). This means that the evaluations since 2021 are based on capacity data taken from the MaStR and may differ from data in earlier monitoring reports.

Electricity: development of installed electrical generation capacity
(GW)

	2015	2016	2017	2018	2019	2020	2021
Nuclear power	10.8	10.8	10.8	9.5	9.5	8.1	8.1
Lignite	21.4	21.3	21.1	20.9	20.9	20.9	19.9
Hard coal	28.7	27.4	24.0	23.8	22.7	23.7	19.1
Natural gas	28.4	29.7	29.8	30.1	30.1	32.5	32.8
Mineral oil products	4.2	4.6	4.4	4.4	4.4	4.9	4.8
Pumped storage	9.4	9.5	9.5	9.8	9.8	9.7	9.7
Waste (non-renewable)	0.9	0.9	0.9	0.9	0.9	1.0	1.0
Other energy sources (non-renewable)	3.4	3.5	3.5	3.5	3.7	4.4	4.4
Total of non-renewable energy sources	107.1	107.6	104.0	103.1	102.0	105.2	99.8
Renewable energy sources	97.7	104.2	111.6	118.2	124.4	131.1	138.6
Total	204.9	211.8	215.6	221.3	226.4	236.3	238.4
Renewables' share of total electricity generation	**48%**	**49%**	**52%**	**53%**	**55%**	**55%**	**58%**

Table 11: Development of installed generation capacity since 2015

The increase in capacity in 2021 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 72.1 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.

1.4 Current power plant capacity in Germany

On 2 November 2022, total (net) installed generating capacity amounted to 239.0 GW. Of this amount, 95.8 GW was sourced from non-renewables and 143.2 GW from renewables (as at 30 June 2022). Subsequent power plant closures and also plants being put into operation reduced non-renewable capacities compared to capacity levels on 31 December 2021 by around 3.9 GW. The main reason for this is the closures of the three nuclear power plants Grohnde, Brokdorf and Gundremmingen C as well as the lignite block closures Neurath B, Weisweiler E and Niederaußem C, which each went into effect on 31 December 2021. A detailed breakdown of the development of the installed capacity by each renewable energy source can be found in section I.B.2 "Development of renewable energies".

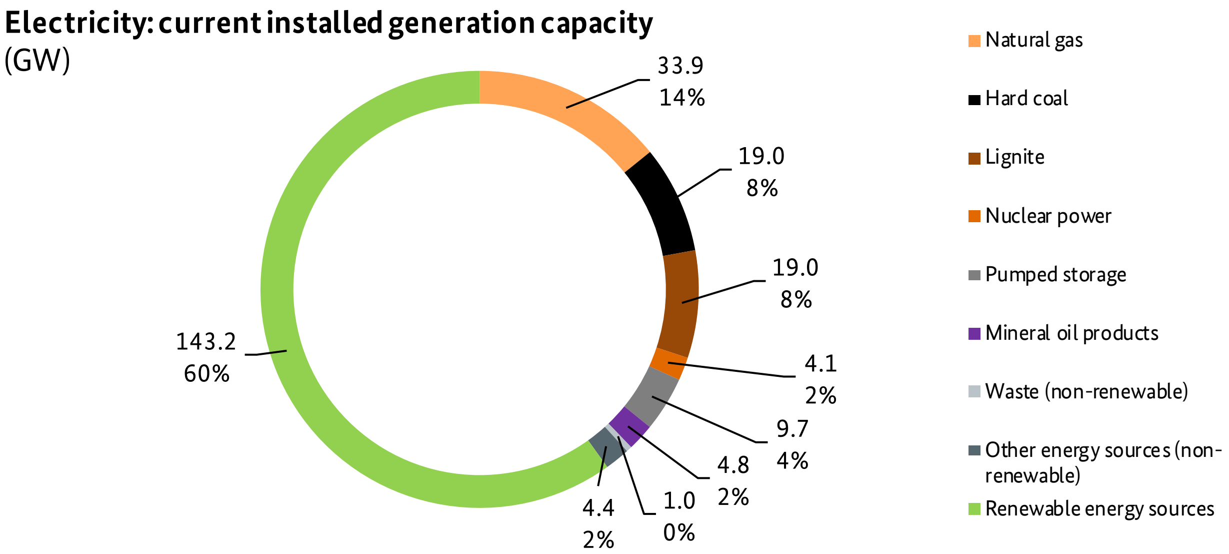

Figure 12: Current installed electrical generating capacity as at 2 November 2022

Electricity: power plant capacity that has exited the market since 2016

Year		2016	2017	2018	2019	2020	2021	2022[1]	Total
Power plant capacity that has exited the market (MW)		2,039	4,610	2,861	3,947	375	10,244	478	22,668*
of which final closure[2]	Capacity (MW)	1,687	2,764	1,767	1,753	78	538	184	8,771
	Average age in years at that time	36	41	34	35	33	34	26	34
New capacity on security standby[3]	Capacity (MW)	352	562	1,094	792	0	0	0	2,800
	Average age in years at that time	31	49	41	39	-	-	-	41
Closures under the Nuclear Phase-Out Amendment Act[4]	Capacity (MW)	0	1,284	0	1,402	0	4,058	0	6,744
	Average age in years at that time	-	33	-	34	-	36	-	35
Marketing and operation bans and closures	Capacity (MW)	0	0	0	0	297	5,648	294	6,239
	Average age in years at that time	-	-	-	-	52	36	50	37

[1] Preliminary values, including statutory capacity up to 2 November 2022

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

[3] The power plants on standby were to be permanantly closed after four years and had already exited the electricity market as of the year shown. The power plants that were placed on standby in 2016 and 2017 have been closed. The power plants that were placed on standby in 2018 and 2019 have been placed on supply reserve and may not be closed before 31 March 2024. They have been placed back on the market on a temporary basis until 30 June 2023.

(4) The closure dates of the 19th amendment to the Atomic Energy Act have been taken into account (Bundestag resolution from 11 November 2022; Bundesrat resolution from 25 November 2022).

* The capacity of the power plants that were added to security standby in 2018 and 2019 has not been added to the total capacity removed from the market. This capacity (1,886 MW) is currently in the supply reserve in accordance with section 50d EnWG. These plants are currently on the electricity market because of the Supply Reserve Access Ordinance (VersResAbV).

Table 12: Power plant capacity that has exited the market since 2016

Electricity: power plant capacity kept on standby outside the electricity market since 2016

Year		2016	2017	2018	2019	2020	2021	2022[1]	Gesamt*
Capacity kept on standby (MW)		1,717	2,272	0	0	1,481	1,565	4,006	12,752
of which temporary closure[2]	Capacity (MW)	29	40	0	0	0	0	0	1,767
	Average age in years at that time	49	25	-	-	-	-	-	37
of which grid reserve in accordance with section 13b EnWG[3]	Capacity (MW)	1,688	2,232	0	0	425	0	0	4,358
	Average age in years at that time	29	38	-	-	38	-	-	31
of which capacity reserve in accordance with section 13e EnWG	Capacity (MW)	-	-	-	-	1,056	0	30	1,086
	Average age in years at that time	-	-	-	-	37	-	47	37
of which supply reserve in accordance with section 50d EnWG[4]	Capacity (MW)	-	-	-	-	-	-	1,886	1,886
	Average age in years at that time	-	-	-	-	-	-	40	40
of which grid reserve in accordance with section 26 KVBG[5]	Capacity (MW)	0	0	0	0	0	1,565	2,090	3,655
	Average age in years at that time	-	-	-	-	-	34	47	45

[1] Preliminary values, including statutory capacity up to 2 November 2022

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

[3] Some plants returned to the market from the grid reserve, and under section 50a(1) EnWG in conjunction with the Electricity Supply Expansion Ordinance (StaaV) plants may return to the market temporarily until 31 March 2024 under the condition that they do not generate electricity from natural gas.

[4] The plants from section 13g(1) EnWG were transferred to the supply reserve on 1 October 2022 in accordance with section 50d EnWG and must be closed by the end of 31 March 2024. Electricity network operators with plants in the supply reserve excercised their right afforded by the Supply Reserve Access Ordinance to bring plants back to the electricity market. This participation in the electricity market is permitted on a temporary basiss until 30 June 2023.

[5] Section 52(2) KVBG prohibits plants participating in the third and fourth tendering rounds with a coal ban until 31 October 2022 and 22 May 2023 respectively are prohibited from permanently closing before 31 March 2024. These plants are automatically placed in the grid rserve as from the coal ban date (section 50a(4) sentences 1 and 2 EnWG). Such plants may return to the market temporarily as long as the alert level of the gas emergency plan is in place and StaaV is in effect. Nearly all operators from the third tendering round have already excercised their right to return to the market temporarily.

*Status as at 2 November 2022 (includes capacities before 2016)

Table 13: Power plant capacity kept on standby outside the electricity market since 2016

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, 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 per location are shown. The Bundesnetzagentur records detailed data on smaller installations with a capacity of less than 10 MW that are not eligible for payments under the EEG in aggregated form and therefore cannot allocate this capacity (totalling 6.9 GW) to specific federal states.

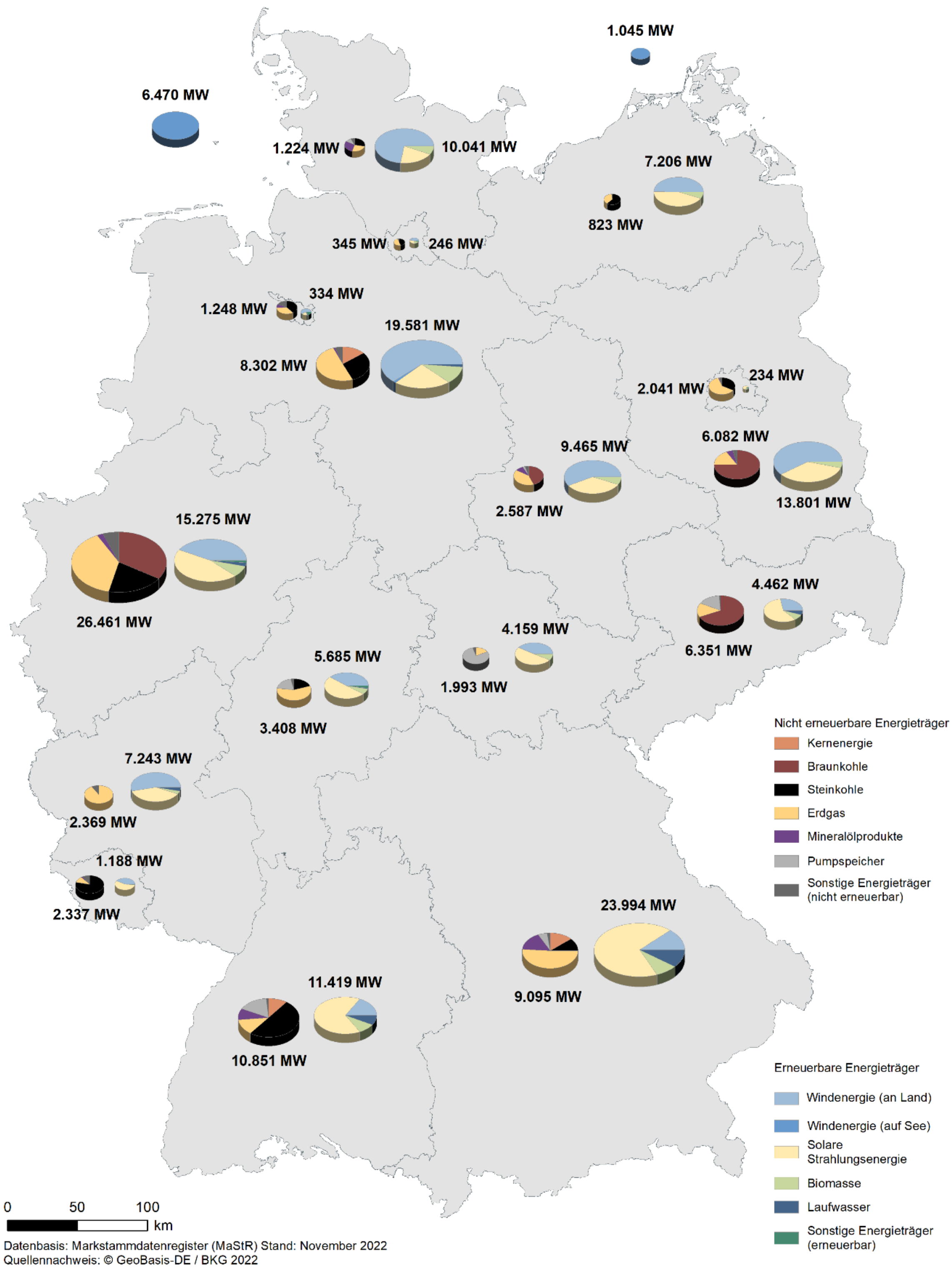

Figure 13: Generating capacity by energy source in each federal state

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	Nicht erneuerbare Energieträger							Erneuerbare Energieträger						
	Lignite	Hard coal	Natural gas	Nuclear power	Pumped storage	Mineral oil products	Other	Biomass	Run-of-river hydro	Offshore wind	Onshore wind	Solar	Other	Total
BW	0	5,477	1,218	1,310	1,876	779	191	981	746	0	1,759	7,889	44	**22,270**
BY	0	857	4,655	1,410	586	1,369	219	1,968	2,019	0	2,581	17,274	152	**33,089**
BE	0	653	1,267	0	0	34	87	44	0	0	17	156	18	**2,276**
BB	4,572	0	931	0	0	334	245	508	5	0	8,004	5,206	79	**19,883**
HB	0	469	459	0	0	86	234	14	10	0	198	57	56	**1,582**
HH	0	154	171	0	0	0	20	45	0	0	119	71	12	**591**
HE	34	687	1,881	0	645	25	136	316	63	0	2,318	2,876	112	**9,093**
MV	0	514	294	0	0	0	14	410	3	48	3,550	3,185	9	**8,028**
NI	19	2,166	4,153	1,336	0	119	509	1,909	265	224	11,789	5,335	60	**27,884**
NW	8,508	5,867	9,450	0	162	638	1,836	1,104	301	0	6,678	6,975	217	**41,736**
RP	0	0	2,121	0	0	11	237	202	231	0	3,836	2,924	51	**9,612**
SL	0	1,825	226	0	0	35	252	11	12	0	510	641	14	**3,525**
SN	4,403	0	760	0	1,085	17	87	318	212	0	1,259	2,665	8	**10,813**
ST	1,113	0	1,029	0	80	229	136	528	29	0	5,300	3,515	93	**12,053**
SH	0	342	333	0	119	332	97	623	5	0	7,227	2,159	28	**11,265**
TH	0	0	373	0	1,509	0	111	306	36	0	1,750	2,061	6	**6,152**
North Sea	0	0	0	0	0	0	0	0	0	6,470	0	0	0	**6,470**
Baltic Sea	0	0	0	0	0	0	0	0	0	1,045	0	0	0	**1,045**
Total	**18,648**	**19,011**	**29,321**	**4,056**	**6,061**	**4,009**	**4,410**	**9,285**	**3,935**	**7,787**	**56,893**	**62,989**	**958**	**227,363**

No detailed data is available for non-EEG installations with a capacity of less than 10 MW; the total capacity of these installations (6,929 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 (4,410 MW).

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

Table 14: Generating capacity by energy source and federal state

1.6 Bivalence

Bivalence or bivalent operation of a power plant/electricity generating unit refers to electricity generating units that can be operated using the turbine's main energy source or a second energy source. Operation of the unit using the second energy source typically reduces the turbine's capacity by as much as 55% compared with operation using the main energy source. Due to geopolitical changes in Europe and the shortage of raw materials associated with those changes, as well as the already high prices of raw materials, it is becoming increasingly important to be able to switch between energy sources that operate a power station in an emergency.

The energy sources that generally come into consideration for bivalent operation are natural gas, hard coal, lignite, waste, biomass, mineral oil and others. For better visual presentation and protection of trade and business secrets, only summarised data for natural gas, lignite and hard coal are shown in the chart below; the remaining data fall under "other". The chart depicts bivalent operation capacity in relation to the net rated capacity of individual electricity generating units.

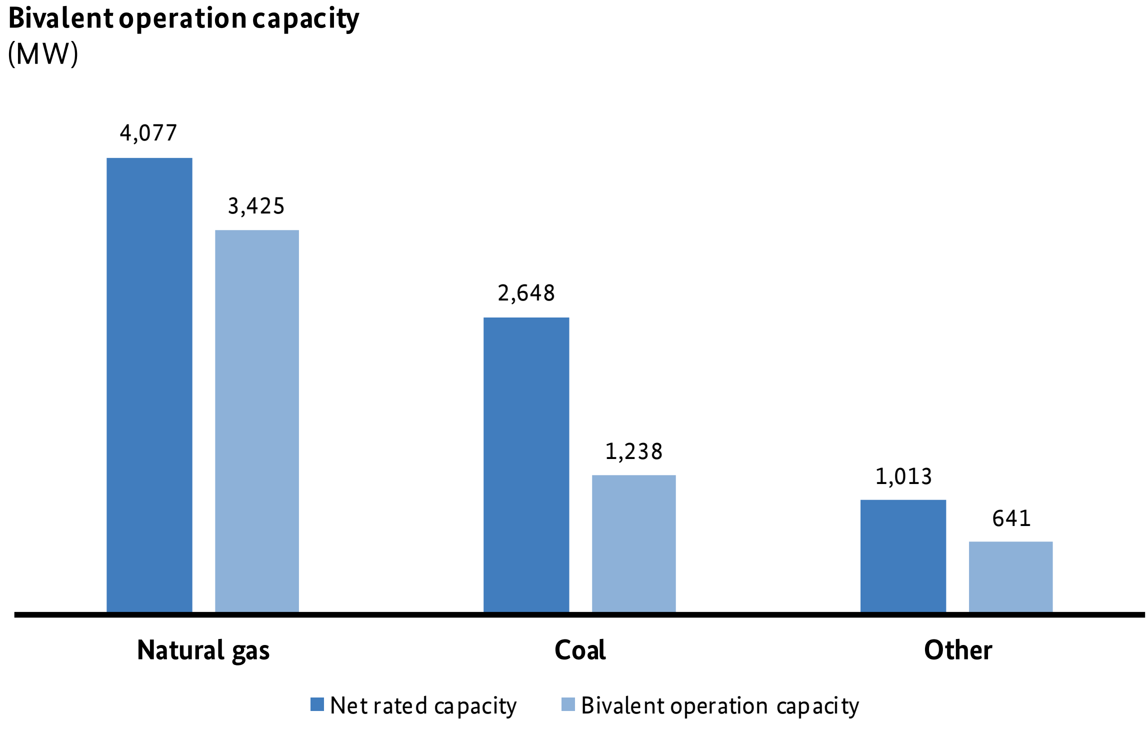

Figure 14: Bivalent operation capacity

The chart clearly shows that natural gas and coal-fired power plants are the most suitable energy sources for bivalent operation. Power stations with bivalent operation capability only comprise a small portion of total installed capacity. Around 13% (4.1 GW) of total installed natural gas capacity can be operated bivalently and can generate 3.4 GW of power in bivalent operation.

Around 7% (2.6 GW) of total installed capacity for generating electricity from coal can be operated bivalently and can generate 1.2 GW of power in bivalent operation. Around 5% (1.0 GW) of the other energy sources can be operated bivalently and can generate 0.6 GW of power in bivalent operation. Geographically, southern Germany[28] has 4.1 GW of installed capacity (2.6 GW if using second energy sources). Northern Germany has 3.6 GW of installed capacity (2.7 GW if using second energy sources).

Bivalent operation capacity broken down by second energy source
(GW)

Energy sources in bivalent operation

Main energy source	Waste	Natural gas	Heating oil	Extra light heating oil	Heavy heating oil	Other mineral oil products	Other	Hard coal	Total
Natural gas	0.0	0.0	12.1	3,203.3	70.0	0.0	15.5	25.8	3,326.7
Coal	11.5	412.1	0.0	65.9	748.5	0.0	0.0	0.0	1,238.0
Other	0.0	60.0	0.0	410.8	0.0	0.0	142.6	0.0	613.4
Total	11.5	472.1	12.1	3,679.9	818.5	0.0	158.1	25.8	5,178.1

Table 15: Bivalent operation capacity broken down by second energy source

Table 15 shows bivalent operation capacity with a breakdown of second energy sources substituting for main energy sources. The table also shows the original energy sources.

Questions about whether a power plant can be modified for bivalent operation were also asked in the 2022 monitoring survey. Here as well, the share of potentially modifiable electricity generating plants that would not need an update to their existing permit under the Federal Immission Control Act is fairly small (around 8% and totalling 574 MW).

[28] The following federal states fall under southern Germany: Baden-Württemberg, Bavaria, Hesse, Rhineland-Palatinate and Saarland

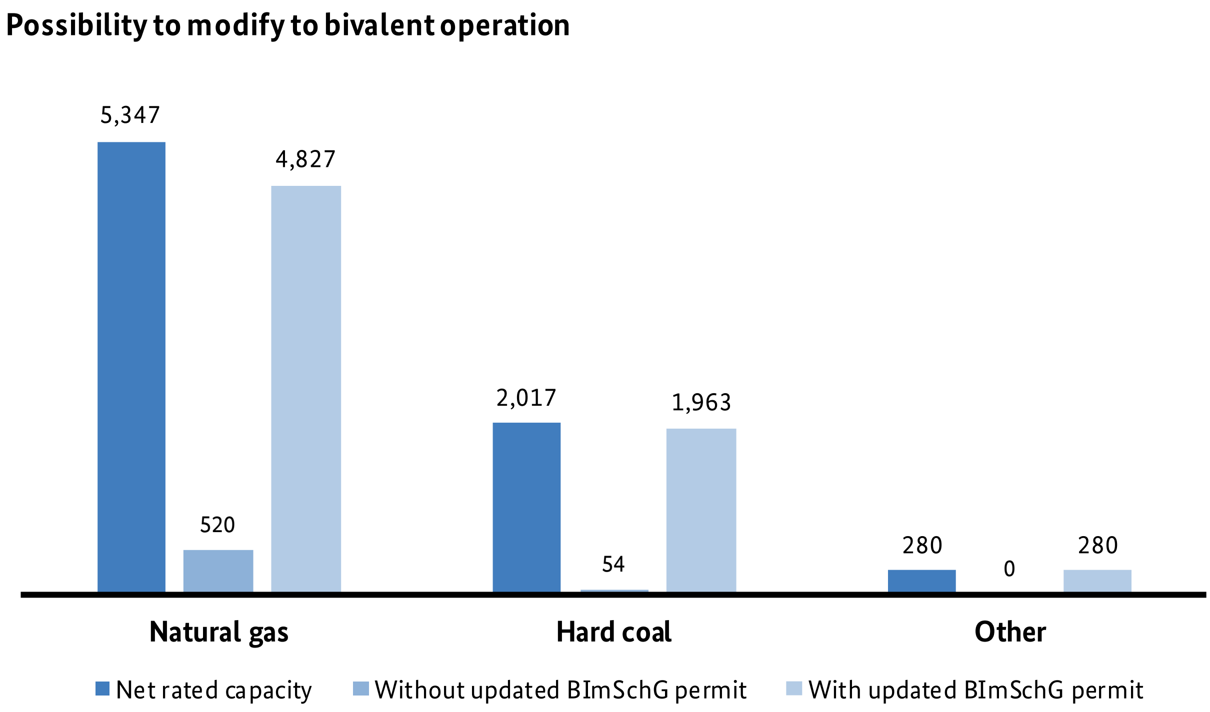

Figure 15: Modification to bivalent operation

Nearly all power plants require an updated BImSchG permit when they are modified to use a different energy source, which explains why operators indicated long time periods for the modification. In half of the cases, the modification would take longer than 24 months.

The natural gas power plants that are classed as important for the system are particularly important for bivalent operation.[29] Section 13f(2) of the Energy Industry Act (EnWG) contains certain obligations that these power plants provide bivalent operation. Data related to this are as follows: installed natural gas plant capacity that is classed as important for the system is 10.3 GW, which is 32% of Germany's total installed natural gas plant capacity. The essential natural gas plants already have a bivalent operation capacity of 1.4 GW. Bivalent operation of these plants would add another 1.3 GW (89% of the bivalently operable electricity generating units). Modification for bivalent operation is possible for another 2.6 GW of the plants, whereas 4.9 GW cannot be modified. The Bundesnetzagentur has no information as to why these plants cannot be modified for bivalent operation or if doing so would be unreasonable for the plant operators.

[29] Section 13f EnWG specifies the rights and obligations of natural gas plants that are important for the system. The transmission system operator (TSO) can request a gas-fired power plant to be classed as important for the system. To qualify as essential, the gas-fired power plant must have a net rated capacity of more than 50 MW and the TSO must explain that the power plant is necessary for grid security. A current list of natural gas plants designated as important for the system in accordance with section 13f EnWG is available at https://www.bundesnetzagentur.de/DE/Fachthemen/ElektrizitaetundGas/Versorgungssicherheit/Erzeugungskapazitaeten/Systemrelevante_KW/start.html

1.7 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 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. Storage facilities are therefore generally considered final consumers of the electrical energy they receive from the grid (BGH ruling 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 tariffs and levies are payable for the use of all electricity withdrawn from the grid, supplied or last consumed by electricity storage facilities. However, for various reasons electricity storage facilities are subject to numerous special rules that drastically reduce the payment of tariffs and levies.

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, temporarily exempt these stations completely from network tariffs. In 2019, exemptions for storage facilities or pumped storage stations under section 118 EnWG amounted to around €275.5mn. In addition, pumped storage stations that are not completely exempt from network tariffs under section 118 EnWG may agree an individual network tariff under section 19(4) and an additional discount for grid flexibility under section 19(2) sentence 1 of the Electricity Network Tariffs Ordinance (StromNEV).

Section 18 StromNEV also requires distribution system operators to pay out "avoided network tariffs" 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 for 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 tariffs. It is possible for electricity storage facilities in the electricity distribution network to receive avoided network tariffs that exceed the cost of the network tariffs.

All storage facilities must be registered in the Bundesnetzagentur's core energy market data register (MaStR) regardless of size. There are 452,564 storage facilities registered in the market data register (as at 1 September 2022). The Bundesnetzagentur has monitoring information on storage facilities with a capacity of at least 10 MW per location. This currently covers pumped storage stations and battery-storage systems. Notification of battery-storage systems with a net rated capacity of at least 10 MW per location was made for the 2022 monitoring. These systems have a total net rated capacity of 798 MW. 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 that nonetheless feed electricity directly into the German public supply network were also notified in the 2022 monitoring. Pumped storage stations in the Federal Republic of Germany currently have a total capacity of 6,063 MW, and pumped storage stations outside of Germany feed 3,625 MW of electricity into Germany's supply network. The amount of electricity consumed through the pumping process (the uphill pumping of water) in 2021 was 13.2 TWh. In return, pumped storage power stations generated 9.0 TWh of electricity in 2021 that was then fed into Germany's public supply network.

1.8 Power plants outside of the electricity market

The total generation capacity of 95.4 GW from non-renewables (as at 2 November 2021) can be divided into power plants operating within the electricity market (88.1 GW) and power plants operating outside of the electricity market (7.3 GW). Within these two categories, the following subsets can be classified with regard to power plant status:

- 88.1 GW: power plant capacity within the electricity market:
  - of which 81.2 GW: plant capacity in operation;

  - of which 2.9 GW: temporary return from the grid reserve to the electricity market. On the basis of section 50a(4) EnWG in conjunction with the Electricity Supply Expansion Ordinance grid reserve power plants (with the exception of natural gas plants) can resume participation in the electricity market on a temporary basis until 31 March 2024. However, this is only allowed when the alert and emergency levels of the Emergency Plan for Gas have been declared by the Federal Ministry for Economic Affairs and Climate Action Several operators have taken up this opportunity.

  - of which 2.1 GW: plants from the third tendering round under the coal phase-out law (KVBG) that would have been banned from coal-fired operation as of 31 October 2022 were placed in the grid reserve from 1 November 2022 to 31 March 2024 on the basis of the rules of section 50a(4) EnWG. The StaaV allows those power plants to participate in the electricity market until 31 March 2024. However, this is only allowed when the alert and emergency levels of the Emergency Plan for Gas have been declared by the Federal Ministry for Economic Affairs and Climate Action (BMWK). Nearly all operators with a successful bid have exercised their right to a temporary return to the electricity market.

  - of which 1.9 GW: plant capacity in the supply reserve in accordance with section 50d EnWG.[30] These are temporarily in the electricity market until 30 June 2023 on the basis of the Supply Reserve Access Ordinance In accordance with section 13g EnWG, the lignite-fired power plants listed in the table below were transferred to security standby status until 30 September 2022. These plants remained on standby for a period of four years, during which the plants were not permitted to produce electricity other than for security standby purposes. After the four-year period, the plants had to be shut down permanently. A return to the electricity market was not permitted.

As a contingency for a supply shortage on the gas and electricity market, the power plants on security standby were transferred under section 50d EnWG to the supply reserve in accordance with section 13g EnWG from 1 October 2022 until no later than 31 March 2024. The Federal Ministry for Economic Affairs and Climate

[30] The costs for these power plants were between €250mn and €300mn in 2021. More detailed information is unobtainable as the operators of these facilities classify this information as operating and business secrets.

Action's Supply Reserve Access Ordinance allows the power stations in the supply reserve to participate temporarily in the electricity market when the alert and emergency levels of the Emergency Plan for Gas are in effect. The time window for this participation is from 1 October 2022 until 30 June 2023. All operators with power stations in the supply reserve have exercised their right to a temporary return to the electricity market.

Lignite-fired power plants in the supply reserve in accordance with section 50d EnWG

Name of power plant	Net nominal capacity in MW	Entry into lignite security standby status	Entry into the supply reserve	Temporary return to market under the Supply Reserve Access Ordninance	Final closure on
Niederaußem F	299	1 October 2018	1 October 2022	October 2022 until 30 June 2023	31 March 2024
Niederaußem E	295	1 October 2018	1 October 2022	October 2022 until 30 June 2023	31 March 2024
Jänschwalde F	500	1 October 2018	1 October 2022	October 2022 until 30 June 2023	31 March 2024
Jänschwalde E	500	1 October 2019	1 October 2022	October 2022 until 30 June 2023	31 March 2024
Neurath C	292	1 October 2019	1 October 2022	October 2022 until 30 June 2023	31 March 2024

Table 16: Lignite-fired power plants in the supply reserve in accordance with section 50d EnWG

- 7.3 GW: plant capacity outside of the electricity market:
    - of which 4.4 GW: power plants that are important for the system under the EnWG in the grid reserve

A power plant is deemed important for the system when its permanent closure would, with sufficient probability, lead to a not inconsiderable threat to or disruption of the security or reliability of the electricity supply system and this threat or disruption cannot be removed by other appropriate measures. A power plant in the grid reserve that is important for the system (see also I.C.5.2.6 "Deployment of grid reserve power plants") is a station that must remain in operation for supply security reasons even though the operator wishes to shut it down (temporarily or permanently) or the coal-fired operation ban under the KVBG requires the operator to shut it down.

Of the power plants designated as important for the system, 1.4 GW use natural gas, 1.4 GW use hard coal and 1.6 GW use mineral oil products.

- Of this amount, 1.8 GW: temporarily closed power plants in accordance with the EnWG

The EnWG distinguishes between temporary and permanent closure. A power plant is defined as temporarily closed if the operator is able to put it back into operation again within 12 months. A power plant is defined as permanently shut down if restoring its operational readiness could not be done within 12 months.

The temporarily closed plants that are not in the grid reserve use natural gas (1.6 GW) and mineral oil products (0.2 GW).

- Of this amount 1.1 GW: capacity reserve in accordance with section 13e EnWG

Power plants are kept in the capacity reserve to help maintain balance of the system in extraordinary and unforeseeable situations (see also I.D.1). These are natural gas-fired power plants.

The following figure shows the location of power plants operating outside of the electricity market.

Power plants outside the electricity market

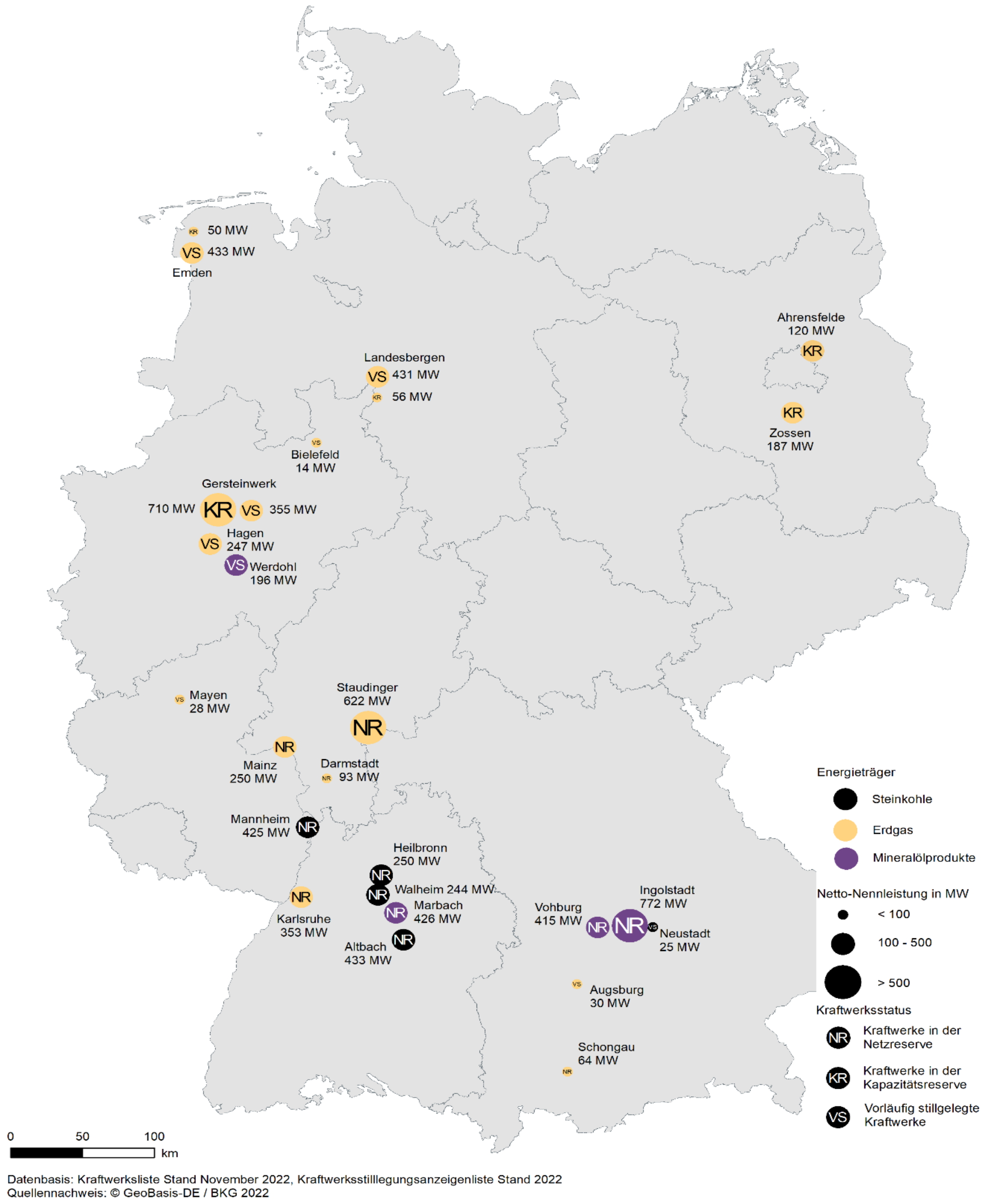

Figure 16: Power plants outside of the electricity market

1.9 Future development of non-renewable energy sources

1.9.1 Projected power plant construction

In addition to information on existing power plants, the Bundesnetzagentur also requests information in the monitoring survey on the future development of power plant capacity. The following section first examines the construction of new power plants. Section 1.9.3 complements the assessment of the future development of the generation system by including power plant closures. The analysis of the future power plant fleet 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 per location up to the year 2025. In such cases, the probability of projects being implemented is considered to be sufficiently high.

Generation capacity totalling 3,286 MW is currently in trial operation or under construction and will likely be completed in the next four years (Figure 17). The power plants projects in Germany relate to natural gas (2,779 MW), mineral oil products (300 MW), other energy sources (73 MW), pumped storage (16 MW) and battery storage (118 MW).

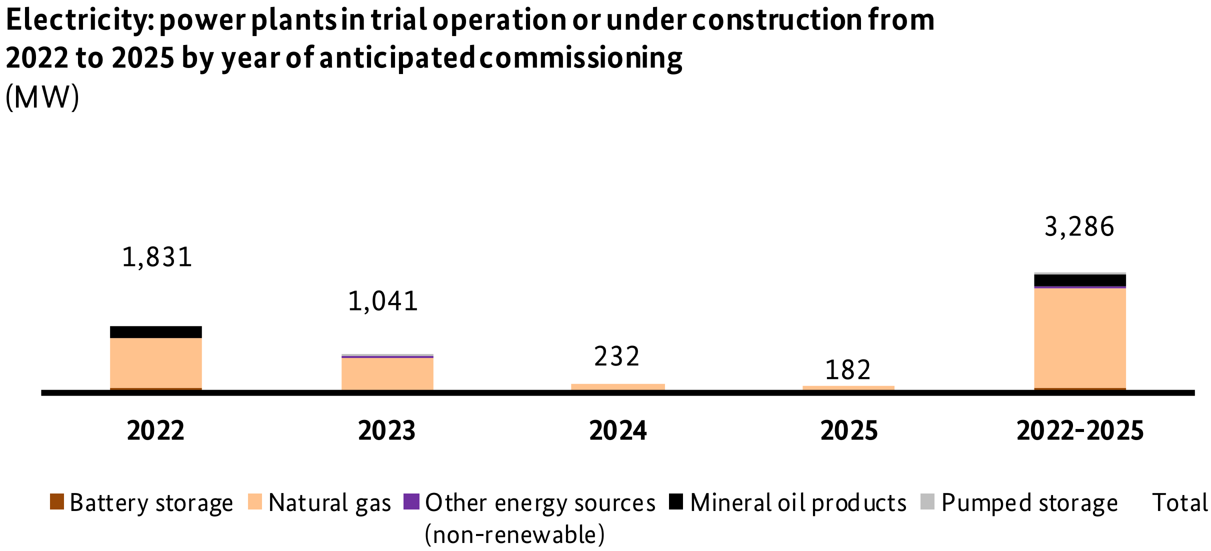

Figure 17: Power plants in trial operation or under construction 2022 - 2025

1.9.2 Tendering procedures and statutory reduction to end the production of electricity from coal

Following the results shown in the Monitoring Report 2021 of the first three tendering rounds of the coal phase-out, the Bundesnetzagentur completed three more tendering rounds in this reporting period to reduce coal-fired electricity generation in hard coal-fired power plants and small lignite-fired power plants in accordance with the KVBG.

The tender volume of the fourth bidding round with a bid deadline of 1 October 2021 for the target year 2023 was 433.016 MW and the maximum price permitted by law was €116,000 per MW of net nominal capacity. The fourth tendering round was oversubscribed. Three of the bids for termination of coal power generation were successful, with a total net nominal capacity of 532.514 MW being awarded. The successful bids were for between €75,000 and €116,000 per MW of net nominal capacity. The tendering results were published on the Bundesnetzagentur website on 15 December 2021.

Plants with successful bids in the tendering round that ended on 1 October 2021

Name of bidder	Name of the installation	Location	Awarded bid volume (MW)
Pfeifer & Langen GmbH & Co. KG	HKW Euskirchen	Euskirchen	14.164
Pfeifer & Langen GmbH & Co. KG	HKW Könnern - Block 1	Könnern	8.350
Uniper Kraftwerke GmbH	Kraftwerk Staudinger Block 5	Großkrotzenburg	510.000
		Total	532.514

Table 17: Overview of plants with successful bids in the tendering round that ended on 1 October 2021

Every plant operator whose bid was successful gains entitlement to payment of the hard coal award once the award is final. The hard coal award is calculated by multiplying the respective bid value by the bid quantity. The payment becomes due from the effective date of the coal-fired operation ban. The ban on coal-fired operation at the plants that bid successfully in the fourth round was initially set to come into effect on 22 May 2023.

However, in light of the current gas supply situation, closure of the plants with successful bids in the third and fourth tendering rounds has been postponed until 31 March 2024 on the basis of the Act on the Maintenance of Substitute Power Stations (section 50a EnWG). Plants that are scheduled for closure, regardless of whether or not they are essential for the system, will be placed in the grid reserve and kept ready for operation. On the basis of the Electricity Supply Expansion Ordinance (StaaV), these plants are also allowed to participate in the electricity market until 31 March 2024 when the alert and emergency levels of the Emergency Plan for Gas are in effect. These changes do not affect the due date of payment of the hard coal award.

The fifth tendering round ended on 1 March 2022 and its results were published on the Bundesnetzagentur website on 20 May 2022. In this round for a total of 1,222.886 MW, six bids with a net nominal capacity of 1,015.604 MW were awarded a tender. As from 27 May 2024 coal may no longer be burned in these plants.

Plants with successful bids in the tendering round that ended on 1 March 2022

Name of bidder	Name of the installation	Location	Awarded bid volume (MW)
Pfeifer & Langen GmbH & Co. KG	HKW Könnern - Block 2	Könnern	19.670
Grosskraftwerk Mannheim AG	DSA 6,7,8 - Block 8	Mannheim	435.000
EnBW Energie Baden-Württemberg AG	RDK 7	Karlsruhe	517.000
Koehler Greiz GmbH & Co. KG	Braunkohlestaub - Heizkraftwerk Greiz	Greiz	1.488
Südzucker AG	KWK Anlage Ochsenfurt - Steinkohleblock	Ochsenfurt	16.474
Basell Polyolefine GmbH	Kraftwerk Wesseling - Block 2	Wesseling	25.972
		Total	1,015.604

Table 18: Overview of plants with successful bids in the tendering round that ended on 1 March 2022

The prices of the bids awarded a tender ranged from €0 per MW to €107,000 per MW, with each successful bidder being paid the individual price that they bid. The plants bidding the maximum price were awarded a tender. The average volume-weighted price of the bids awarded a tender was around €45,000 per MW.

Because the fifth tendering round was undersubscribed by around 207 MW, statutory reduction had to be ordered for the Scholven B power plant (net nominal capacity of 345 MW) in order to achieve reduction goals in 2024. The Scholven B power plant thereby has no entitlement to payment of the hard coal award.

The bid deadline of the sixth tendering round was 1 August 2022 and its results were published on 14 October 2022. The maximum bidding price fell again in the sixth tendering round and reached €98,000 per MW. The tender volume was 698.882 MW. One bid for a total capacity of 472 MW was awarded a tender. The winning bid received an award of the maximum price allowed by law for this tendering round. As from 21 February 2025 coal may no longer be burned in this plant. Until then it can remain active in the electricity market.

Plants with successful bids in the tendering round that ended on 1 August 2022

Name of bidder	Name of installation	Location	Awarded bid volume (MW)
Onyx Kraftwerk Zolling GmbH & Co. KGaA	Onyx Steinkohlekraftwerk Zolling – Block 5	Zolling	472.000

Table 19: Overview of plants with successful bids in the tendering round that ended on 1 August 2022.

With regard to the tender volume that was not awarded, the Bundesnetzagentur ordered the statutory reduction of the Heizkraftwerk West der Volkswagen AG in accordance with section 20(3) KVBG. The order to close this plant, which has a net rated capacity of 277 MW, results in an over-achievement of the tender volume.

Tendering procedures

Tendering procedure end date	Maximum bidding price (€/MW net nominal capacity)	Tender volume (MW)	Total awarded bid volume (MW)	Effective date of the coal-fired operation ban (year / date)
1 September 2020	165,000	4,000	4,787.676	2021 / 8 July 2021
4 January 2021	155,000	1,500	1,514.000	2021 / 8 December 2021
30 April 2021	155,000	2,481	2,132.682	previously 2022 / 31 October 2022 but invalid until 31 March 2024 under section 50a(4) EnWG
1 October 2021	116,000	433	532.514	previously 2023 / 22 May 2023 but invalid until 31 March 2024 under section 50a(4) EnWG
1 March 2022	107,000	1,223	1,015.604	2024 / 27 May 2024
1 August 2022	98,000	699	472.000	2025 / 21 February 2025
1 June 2023	89,000	still open		2026

Table 20: Tendering procedures

The total awarded bid volume of the first six tendering rounds was 10,454 MW. The hard coal awards amount to around €730mn, which equates to an average of around €70,000 per MW.

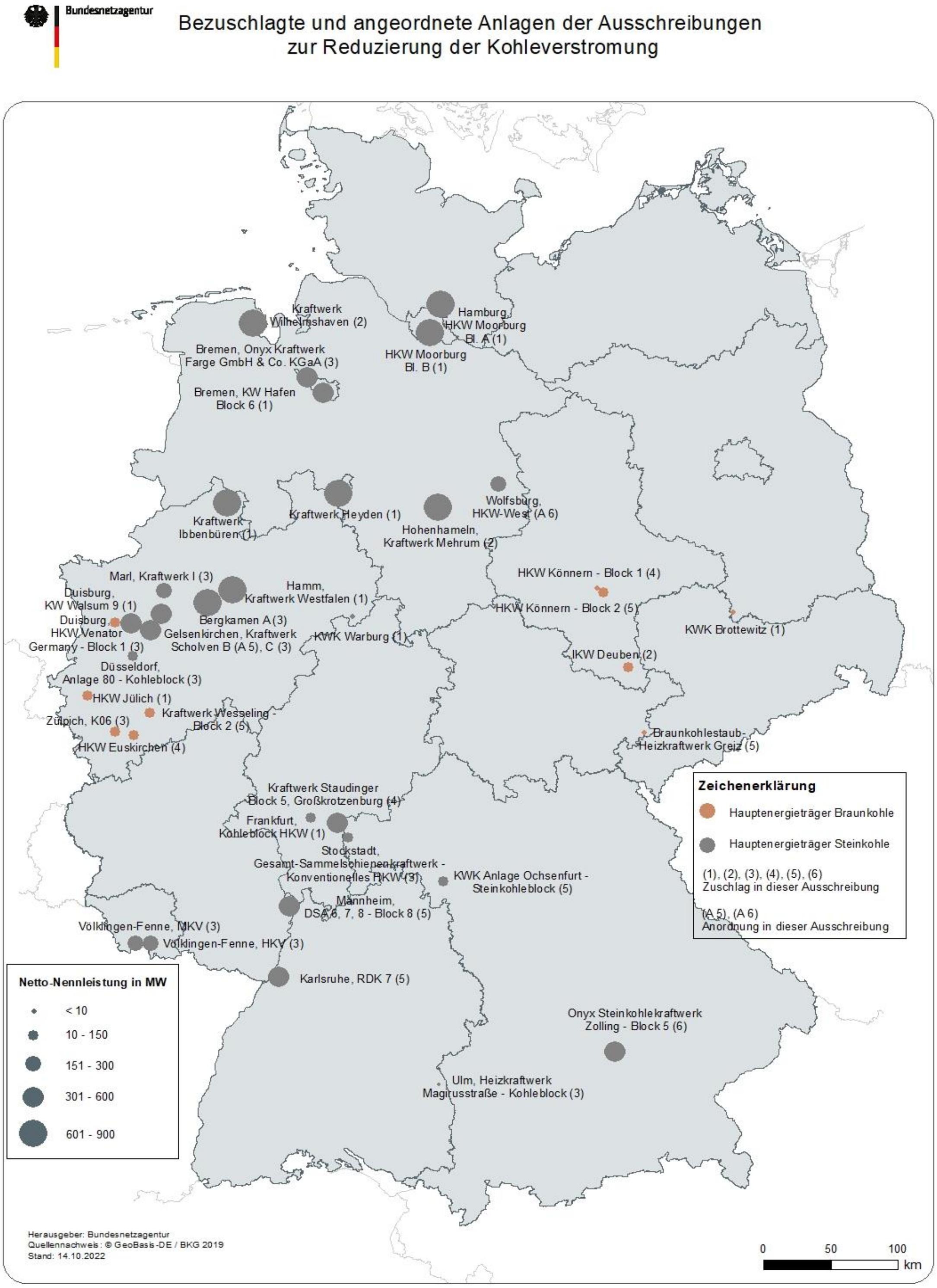

Figure 18: Plants of the first to sixth tendering rounds that had successful bids or were ordered to close

1.9.3 Expected power plant closures

The data shown in section I.B.1.9.2 on the voluntary termination of coal-fired power generation and the capacity reduction path for lignite-fired power plants under the KVBG will result in around 6.4 GW of coal-fired power plant capacity being shut down in the years ahead. In addition to the closure of coal-fired power plants in connection with the coal exit, more power stations will be closed by 2025. These will be:

- the nuclear power plants that are to be decommissioned as required by law (4.1 GW);
- lignite-fired power plants that are closed (1.9 GW) after completion of their time in the supply reserve (see Table 16);
- closures after return from the grid reserve to the market (2.9 GW).

The following table provides an overview of the power plant capacity that is expected to be withdrawn from the market by 2025.

Power plant capacity expected to be withdrawn from the market 2022 - 2025 (MW)

	2022	2023	2024	2025	2022 - 2025
Coal phase-out under KVBG	**120**	**-**	**5,237**	**1,070**	**6,427**
of which legally stipulated capacity reduction path for lignite-fired power plants (1)	120		1,211	321	1,652
of which auction for hard coal-fired power plants and lignite-fired power plants			4,026	749	4,775
third auction round*			2,133		2,133
fourth auction round*			533		533
fifth auction round			1.361 (2)		1,361
sixth auction round				749 (3)	749
Closure after completion of time in supply reserve in accordance with section 50d EnWG	**-**	**-**	**1,886**	**-**	**1,886**
Nuclear power plants under section 7(1a) AtG (4)	**-**	**4,056**	**-**	**-**	**4,056**
Closures after return from the grid reserve to the market (5)	**-**	**-**	**1,565**	**1,382**	**2,947**
Total	**120**	**4,056**	**8,688**	**2,452**	**15,316**

* On the basis of the Act on the Maintenance of Substitute Power Stations (section 50a EnWG), closure of the plants with successful bids in the third and fourth tendering rounds is postponed until 31 March 2024 if further operation is technically and legally possible. Regardless of whether or not they are essential for the system, plants that are scheduled for closure will be placed in the grid reserve and kept ready for operation

(1) Capacities listed for the KVBG reduction path include the political agreement between the BMWK, power plant operator RWE and the federal state of North Rhine-Westphalia. A legal basis had not yet been established at the time this report went to press.

(2) Awarded bid volume 1,015.6 MW and statutory reduction 345 MW

(3) Awarded bid volume 472 MW and statutory reduction 277 MW

(4) The closure dates in the draft version of the BMUV's 19th revision of the Atomic Energy Act from 19 October 2022 were taken into account.

(5) Power plants that were in the grid reserve but temporarily returned to the electricity market on the basis of section 50a EnWG

Table 21: Power plant capacity expected to be withdrawn from the market 2022 - 2025

In Germany as a whole, 15,316 MW of capacity is expected to be withdrawn from the market by 2025. This exceeds the planned increase of 3,286 MW in conventional power plant capacity by 12,030 MW.

Ending coal-fired electricity generation at a plant does not necessarily mean that 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 and some have already done so.

Locations with an expected increase in or withdrawal of generation capacity by 2025

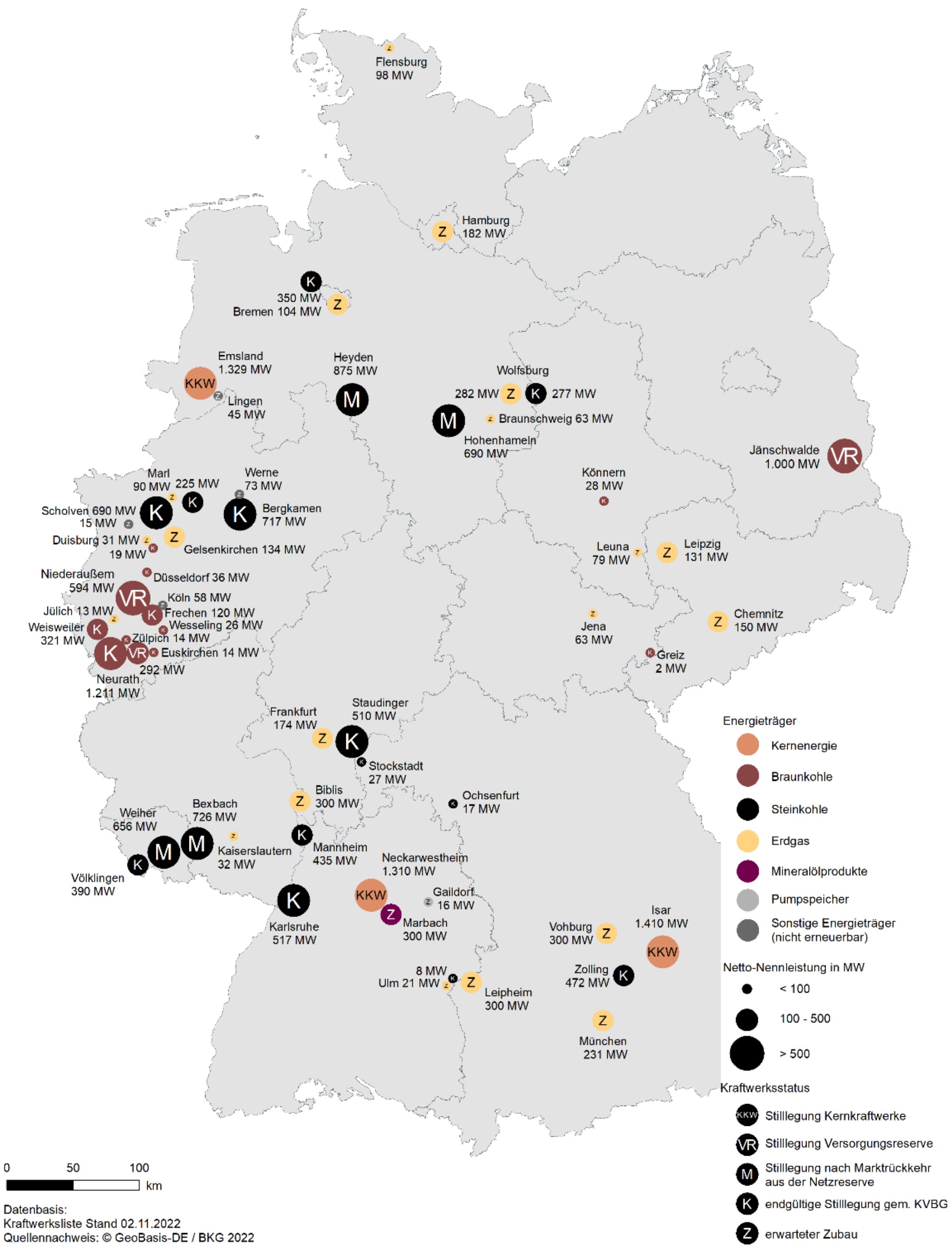

Figure 19: Locations with an expected increase in or withdrawal of generation capacity by 2025

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 in the course of 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 361 MW can thus be expected by 2025 and will come from natural gas power plants (211 MW), mineral oil-fired power plants (116 MW) and other energy sources (34 MW).

The capacity of power plants scheduled for closure by the year 2025 therefore totals 15,677 MW.

Consequently, the overall national anticipated balance of the increase and decrease of power generation capacity by 2025 is 12,391 MW.

1.10 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 of the Combined Heat and Power Act (KWKG). CHP payments are only paid on electricity fed into the general supply network to plant operators that 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 systems on 1 June 2018. There are two auctions every year for both procedures.

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

1.10.1 CHP plant capacity with a minimum capacity of 10 MW

The evaluations presented in this section include CHP-capable power generation units in Germany 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 CHP plants that does not have to be entered in the core energy market data register (eg useful heat generation).

The installed capacity of these CHP installations is shown in MW in Figure 20. The installed electrical capacity and the useful heat capacity of CHP installations are shown separately.

Electricity: installed electrical and thermal capacity of CHP installations with a minimum capacity of 10 MW (MW)

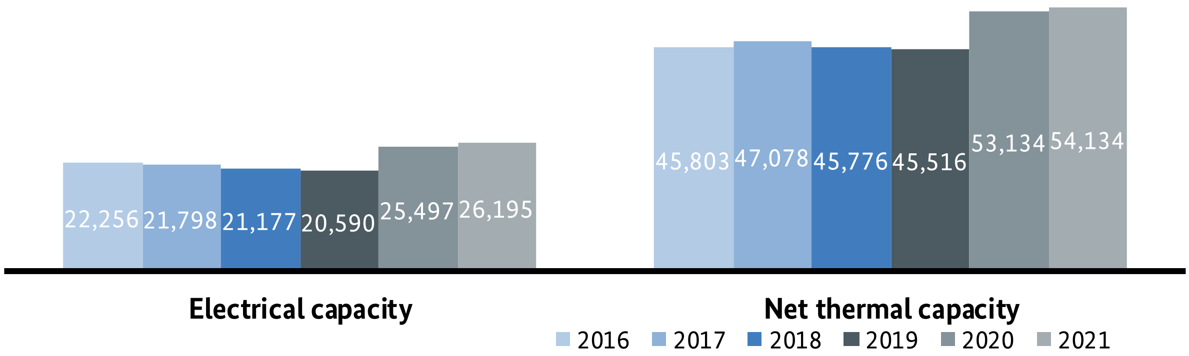

Figure 20: Installed electrical and useful heat capacity of CHP installations with a minimum capacity of 10 MW per location

The installed (electrical and useful heat) capacity is sourced as set out in the table below. The table clearly shows the predominant use of natural gas and hard coal in CHP power plants. There are also numerous smaller CHP power plants in Germany, particularly in the field of natural gas, with an installed net rated capacity of less than 10 MW per location.

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	
	2020	2021	2020	2021
Waste	1,185	1,203	4,007	4,022
Biomass	1,002	1,002	3,626	3,626
Lignite	1,700	1,700	4,817	4,817
Natural gas	13,077	13,758	23,192	24,167
Other	1,749	1,748	4,986	4,987
Hard coal	6,784	6,784	12,515	12,515
Total	25,497	26,195	53,143	54,134

Table 22: Installed electrical and useful heat capacity of CHP power plants by energy source with a minimum capacity of 10 MW (MW)

The figure below shows the electrical and thermal energy generated since 2017.

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

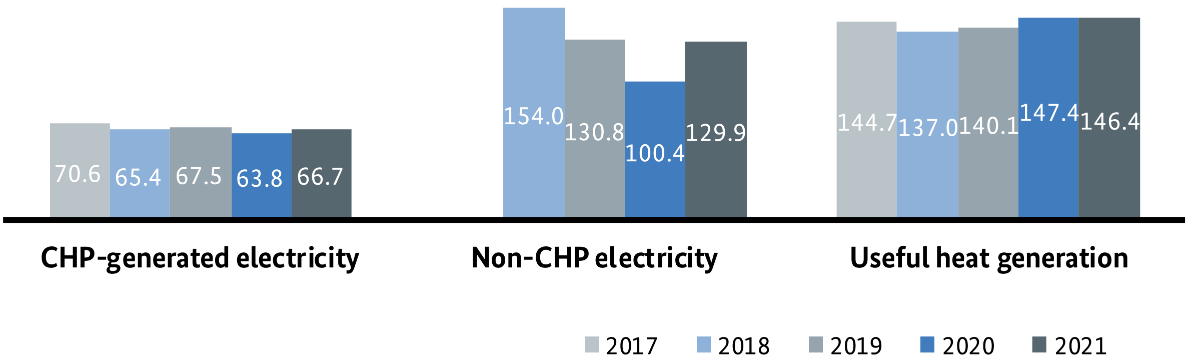

Figure 21: Electrical and thermal energy produced by CHP installations with a minimum capacity of 10 MW

The CHP plants on which this evaluation is based produced 146.4 TWh of useful heat and 66.7 TWh of electricity in 2021. CHP plants produced around 2.9 TWh more electricity compared to 2020 (increase of 4.4%) and generated slightly less (around 1 TW) useful heat in 2021 compared to 2020 (decrease of 0.7%). Non-CHP electricity generation increased by 29.5 TWh (up 23%) compared to 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 increase in non-CHP electricity primarily results from the energy sources lignite (61%) and hard coal (24%). This means that overall non-CHP electricity generation was in line with the increase in electricity generation from non-renewable sources.

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

	CHP-generated electricity		Non-CHP electricity		Useful heat generation	
	2020	2021	2020	2021	2020	2021
Waste	2.9	1.6	2.3	2.4	12.0	10.1
Biomass	2.4	3.1	1.7	1.6	9.0	10.5
Lignite	2.4	3.2	54.8	79.2	11.6	12.6
Natural gas	43.8	45.9	14.2	10.6	67.9	67.9
Other	3.5	2.8	7.0	5.4	24.0	19.1
Hard coal	8.8	10.1	20.4	30.7	22.9	26.2
Total	63.8	66.7	100.4	129.9	147.4	146.4

Table 23: Electrical and thermal energy produced by CHP installations with a minimum capacity of 10 MW

The most important energy sources for the generation of CHP electricity and useful heat are natural gas and hard coal (see Table 23). Natural gas is a particularly important energy source for electricity generated by CHP plants through heat extraction and accounted for around 67% of total generation in 2021. For useful heat, around 46% is generated from natural gas and around 18% from hard coal.

1.10.2 CHP plants newly registered in the core energy market data register in 2021

Since 1 July 2017, under the Core Energy Market Data Register Ordinance CHP plants must be registered in the core energy market data register. 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 2021, 4,966 CHP power generation units with a total net nominal capacity of 1,004 MW were newly registered. The significantly smaller increase in capacity compared to the previous year (2020: 2,389 MW) is mainly due to the fact that net nominal capacity of 1,052 MW from the Datteln 4 hard coal-fired power plant went into operation in 2020. There was also a general decrease, however, in newly registered net nominal capacity in nearly all capacity classes of at least 36% compared with the previous year. Newly installed capacity in the capacity class up to 50 kW was an exception and remained unchanged at 50 MW.

Most commissioned units in CHP plants run on natural gas (4,374) followed by plants that run on biomass (364). These energy sources are used by more than 95% of the units in CHP plants and account for nearly 90% of net nominal capacity. Year on year the net nominal capacity of natural gas fell by 2% and of biomass by 63%.

Electricity: CHP plants newly registered in 2021

Month	Net rated 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 24: Commissioning of power generation units in CHP plants

Electricity: commissioning by energy source in 2021

Capacity class	Net rated capacity in MW	Number
Other gases	8	143
Biomass	154	364
Pressure from gas lines	0.03	2
Natural gas	750	4,374
Mine gas	0.1	1
Sewage sludge	5	8
Mineral oil products	1	59
Non-biogenic waste	32	1
Solar thermal	0.01	2
Heat	55	12
Total	**1,004**	**4,966**

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

Table 25: Commissioning by energy source

Electricity: commissioning by capacity class in 2021

Capacity class	Net rated capacity in MW	Number
≤ 50 kW	50	4,308
50 kW - 250 kW	37	282
250 kW - 1 MW	150	271
1 MW - 10 MW	28	84
> 10 MW	560	21
Total	**1,004**	**4,966**

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

Table 26: Commissioning by capacity class

Electricity: commissioning by federal state in 2021

Federal state	Net rated capacity	Number
Baden-Württemberg	181	975
Bavaria	221	910
Berlin	7	117
Brandenburg	67	130
Bremen	0.4	17
Hamburg	1	61
Hesse	115	356
Mecklenburg-Western Pomerania	13	44
Lower Saxony	181	569
North Rhine-Westphalia	96	891
Rhineland-Palatinate	23	234
Saarland	24	34
Saxony	43	194
Saxony-Anhalt	5	92
Schleswig-Holstein	17	230
Thuringia	10	112
Total	**1,004**	**4,966**

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

Table 27: Commissioning by federal state

The capacity class up to 50 kW had the highest number of newly commissioned units (4,308). This accounted for more than 87% of all newly commissioned plants. The capacity class of more than 10 MW had the largest net nominal capacity (560 MW), which accounted for around 56% of new capacity. Baden-Württemberg had the largest number of newly commissioned plants (975), followed by Bavaria (910) and North Rhine-Westphalia (891). The largest amount of net nominal capacity was installed in Bavaria (221 MW).

1.10.3 CHP auctions

Auctions to determine the level of financial support for CHP electricity were also held in 2021. The electrical capacity of the CHP plants ranges from more than 0.5 MW to 50 MW. Innovative CHP systems with an electrical capacity of more than 1 MW and up to 10 MW can participate in the auctions. The highest bid amount for CHP plants was 7.0 ct/kWh and 12 ct/kWh for innovative CHP systems. Bids are accepted on the basis of the rate specified in the respective bid ("pay as bid"). The tables below show the outcomes of previous auctions.

Electricity: auction results for CHP systems

Auction end date	3 June 2019	2 Dec 2019	2 June 2020	1 Dec 2020	1 June 2021	1 Dec 2021	1 June 2022
CHP systems							
Auction volume in MW	51 MW	80 MW	75 MW	75 MW	59 MW	76 MW	84 MW
Number of bids	13 (87 MW)	13 (58 MW)	22 (71 MW)	22 (71 MW)	16 (112 MW)	18 (131 MW)	23 (140 MW)
Number of awards	4 (46 MW)	12 (53 MW)	21 (69 MW)	21 (69 MW)	13 (58 MW)	3 (76 MW)	17 (79 MW)
Excluded bids	0	3 (8 MW)	1 (2 MW)	1 (2 MW)	1 (0,8 MW)	2 (7 MW)	2 (32 MW)
Average award price*	3.95 ct/kWh	5.12 ct/kWh	6.22 ct/kWh	6.22 ct/kWh	5.64 ct/kWh	6.11 ct/kWh	5.87 ct/kWh
Innovative CHP systems							
Auction volume in MW	30 MW	25 MW	29 MW	28 MW	26 MW	26 MW	25 MW
Number of bids	5 (22 MW)	10 (43 MW)	13 (44 MW)	12 (31 MW)	9 (29 MW)	7 (21 MW)	5 (20 MW)
Number of awards	5 (22 MW)	5 (20 MW)	8 (26 MW)	10 (27 MW)	7 (25 MW)	5 (17 MW)	5 (20 MW)
Excluded bids	0	1 (9 MW)	1 (2 MW)	2 (4 MW)	1 (1,6 MW)	2 (4 MW)	0
Average award price*	11.17 ct/kWh	10.25 ct/kWh	10.22 ct/kWh	10.80 ct/kWh	11.57 ct/kWh	11.37 ct/kWh	11.74 ct/kWh

*volume weighted

Table 28: CHP auctions

2. Development of renewable energies

An essential cornerstone of the clean 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, ie 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 (79%) of renewable electricity generated in Germany in 2021 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 138.6 GW of capacity installed at the end of 2021, 134.2 GW was eligible for EEG payments. This section therefore examines renewable energies eligible for payments in more detail.

The 4.4 GW of renewable energy capacity not eligible for payments is primarily accounted for by the energy sources hydropower (3.3 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 16.3 TWh of electricity was generated from non-eligible renewable sources in 2021. The majority of that energy was generated in hydropower plants (run-of-river and dammed water) in an amount of 12.2 TWh and in waste-fired power plants totalling 4.0 TWh.

The key figures presented in this section are collected by the Bundesnetzagentur to fulfil its supervising function in the nationwide EEG equalisation mechanism. To this end, selected data is provided on an annual basis from the year-end EEG accounts of TSOs (by 31 July), energy utilities and DSOs (by 31 May). The Bundesnetzagentur's core energy market data register has been used since July 2017 as an additional source of information to evaluate the installed capacity of EEG installations.

In the publication "EEG in Numbers 2021", 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.[31]

2.1.1 Installed capacity[32]

As at 31 December 2021, the total installed capacity of installations eligible for payments in accordance with the EEG was approximately 134.2 GW. A total of around 7.5 GW of additional capacity entitled to payments under the EEG was installed in 2021, representing an increase of around 5.9%.

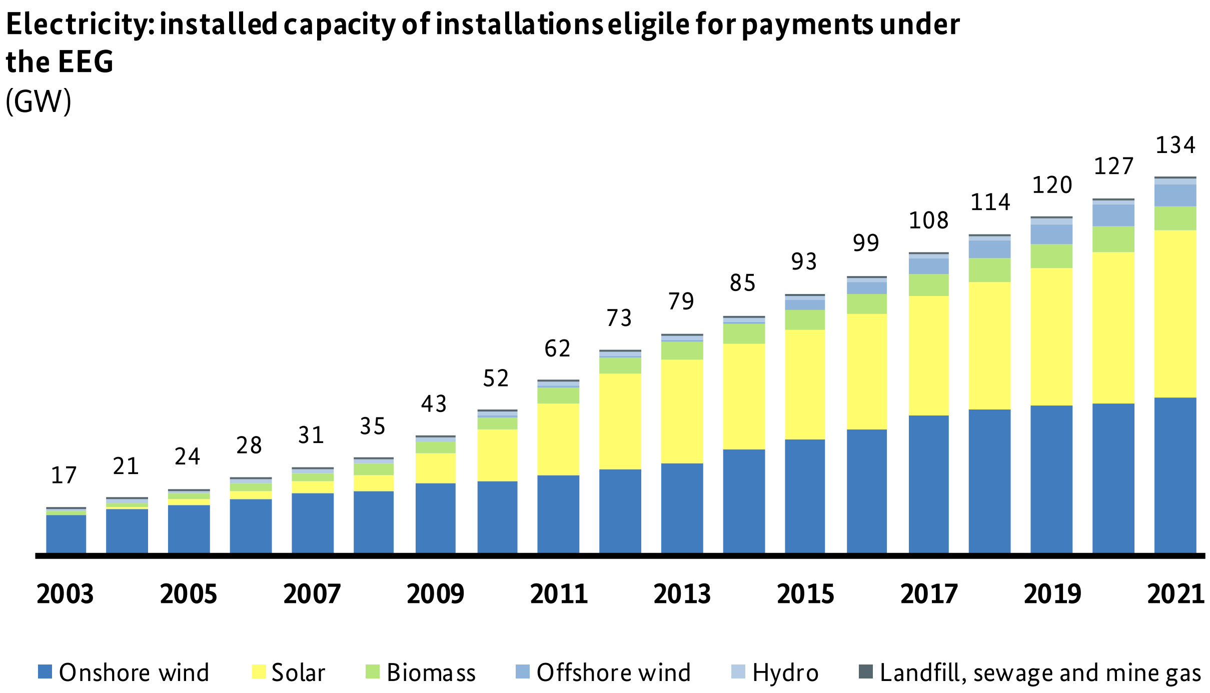

Figure 22: Installed capacity of installations eligible for payments under the EEG up to 2021

Solar capacity rose sharply again in 2021. Some 5.7 GW of new capacity was installed in 2021, compared to an average of 2.9 GW annually over the previous five years. Onshore wind continues to expand as well, whereas offshore wind saw no capacity expansion in 2021. After reaching a low in 2019, there was again a small increase of 1.6 GW in net new capacity from onshore wind power plants in 2021 (2020: 1.2 GW, 2019: 0.9 GW, 2018: 2.2 GW). The 0.1 GW expansion in biomass installations was considerably lower than in the previous year (2020: 0.4 GW).

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

[32] Renewable energy source installed capacity figures for 2020 are still subject to change and have not been finalised by AGEE-Stat.

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

	Total 31 December 2020	Total 31 December 2021	Increase / decrease in 2021	Increase / decrease compared to 2020
	in MW	in MW	in MW	in Prozent
Hydro	1,624.5	1,627.0	2.5	0.2%
Gases[1]	376.5	374.0	-2.5	-0.7%
Biomass	8,748.4	8,884.6	136.2	1.6%
Geothermal	47.1	54.1	7.0	14.9%
Onshore wind	54,413.8	56,045.5	1,631.8	3.0%
Offshore wind	7,786.8	7,786.8	0.0	0.0%
Solar	53,720.7	59,422.9	5,702.2	10.6%
Total	126,717.8	134,194.9	7,477.1	5.9%

[1] Landfill, sewage and mine gas

Table 29: Installed capacity of installations eligible for payments under the EEG by energy source (as at 31 December)

Some 232,272 new facilities were installed in 2021. Solar installations accounted for around 99.8% of the new installations, onshore wind installations for around 0.1% and the remainder is shared among other technologies. For 2021, the figures as of 30 June 2022 indicate a trend of steady expansion. For geothermal energy it should be noted that the significant increase in the number of installations results from a method of data collection that differs from the core energy market data register.

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

	2016	2017	2018	2019	2020	2021	Jun 22
Hydro	7,041	7,138	7,172	7,192	7,243	7,261	7,276
Gases[1]	612	600	593	567	566	566	568
Biomass	14,186	14,271	14,496	14,535	14,699	14,821	14,898
Geothermal	10	9	10	11	11	20	22
Onshore wind	26,057	27,406	28,131	28,310	28,579	28,818	28,948
Offshore wind	945	1,167	1,307	1,467	1,499	1,499	1,499
Solar	1,622,405	1,686,993	1,760,396	1,863,684	2,047,963	2,279,847	2,434,361
Total	1,671,256	1,737,584	1,812,105	1,915,766	2,100,560	2,332,832	2,487,572

[1] Landfill, sewage and mine gas

Table 30: Changes in the installed capacity of installations eligible for payments under the EEG

Electricity: growth rates of installations by energy source

	Total 31 December 2020	Total 31 December 2021	Increase / decrease in 2021	Increase / decrease compared to 2020
	Number	Number	Number	in %
Hydro	7,243	7,261	18	0.2%
Gases[1]	566	566	0	0.0%
Biomass	14,699	14,821	122	0.8%
Geothermal	11	20	9	81.8%
Onshore wind	28,579	28,818	239	0.8%
Offshore wind	1,499	1,499	0	0.0%
Solar	2,047,963	2,279,847	231,884	11.3%
Total	2,100,560	2,332,832	232,272	11.1%

[1] Landfill, sewage and mine gas

Table 31: Growth rates of installations eligible for payments under the EEG by energy source (on 31 December)

2.1.2 Development corridors

The EEG 2017 defined 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 2040. These development corridors were adjusted in the revised versions of the EEG 2023 and the Offshore Wind Energy Act 2023 (WindSeeG). These goals are summarised in the following table.

Electricity: overview of development corridors

<table>
<tr><th></th><th>Onshore wind</th><th>Offshore wind</th><th>Solar</th><th>Biomass</th></tr>
<tr><td>EEG 2017</td><td>2.8 GW gross expansion for 2017 to 2019;
2.9 GW Brutto-Zubau ab 2020</td><td>20 GW expansion in 2030</td><td>2.5 GW gross expansion per year</td><td>150 MW gross expansion for 2017 to 2019
200 MW gross expansion for 2020 to 2022</td></tr>
<tr><td>EEG 2021</td><td>57 GW in 2022
62 GW in 2024
65 GW in 2026
68 GW in 2028
71 GW in 2030</td><td>20 GW in 2030
40 GW in 2040</td><td>63 GW in 2022
73 GW in 2024
83 GW in 2026
95 GW in 2028
100 GW in 2030</td><td rowspan="2">8.4 GW in 2030</td></tr>
<tr><td>EEG 2023</td><td>69 GW in 2024
84 GW in 2026
99 GW in 2028
115 GW in 2030
157 GW in 2035
160 GW in 2040</td><td>30 GW in 2030
40 GW in 2035
70 GW in 2045</td><td>88 GW in 2024
128 GW in 2026
172 GW in 2028
215 GW in 2030
309 GW in 2035
400 GW in 2040</td></tr>
</table>

Table 32: Overview of development corridors

The following charts show the annual expansion of the four technologies compared to the expansion targets defined in the EEG. With around 848 MW of newly installed capacity in the first half of 2022, a total of 56.9 GW of onshore wind power is now installed. In the last half year, the most wind power plants were commissioned in Schleswig-Holstein (233 MW), North Rhine-Westphalia (177 MW) and Brandenburg (144 MW).

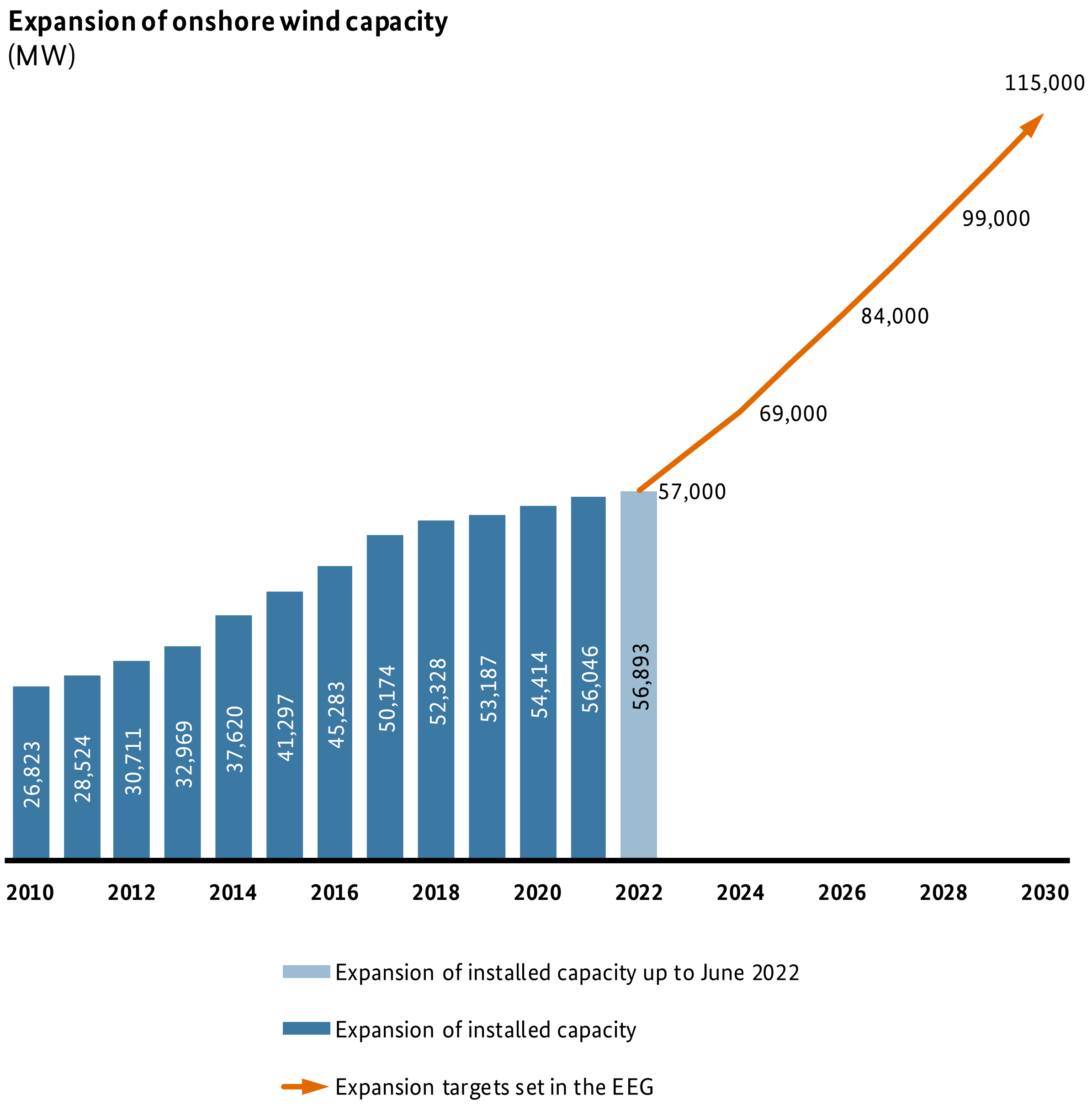

Figure 23: Expansion targets for onshore wind

Newly installed solar capacity in the first half of 2022 was 3.6 GW. A total of 2.4mn solar installations with 63 GW capacity are in operation in Germany. The most solar power newly installed in the past half year was in Bavaria (1,051 MW), Brandenburg (582 MW) and North Rhine-Westphalia (398 MW).

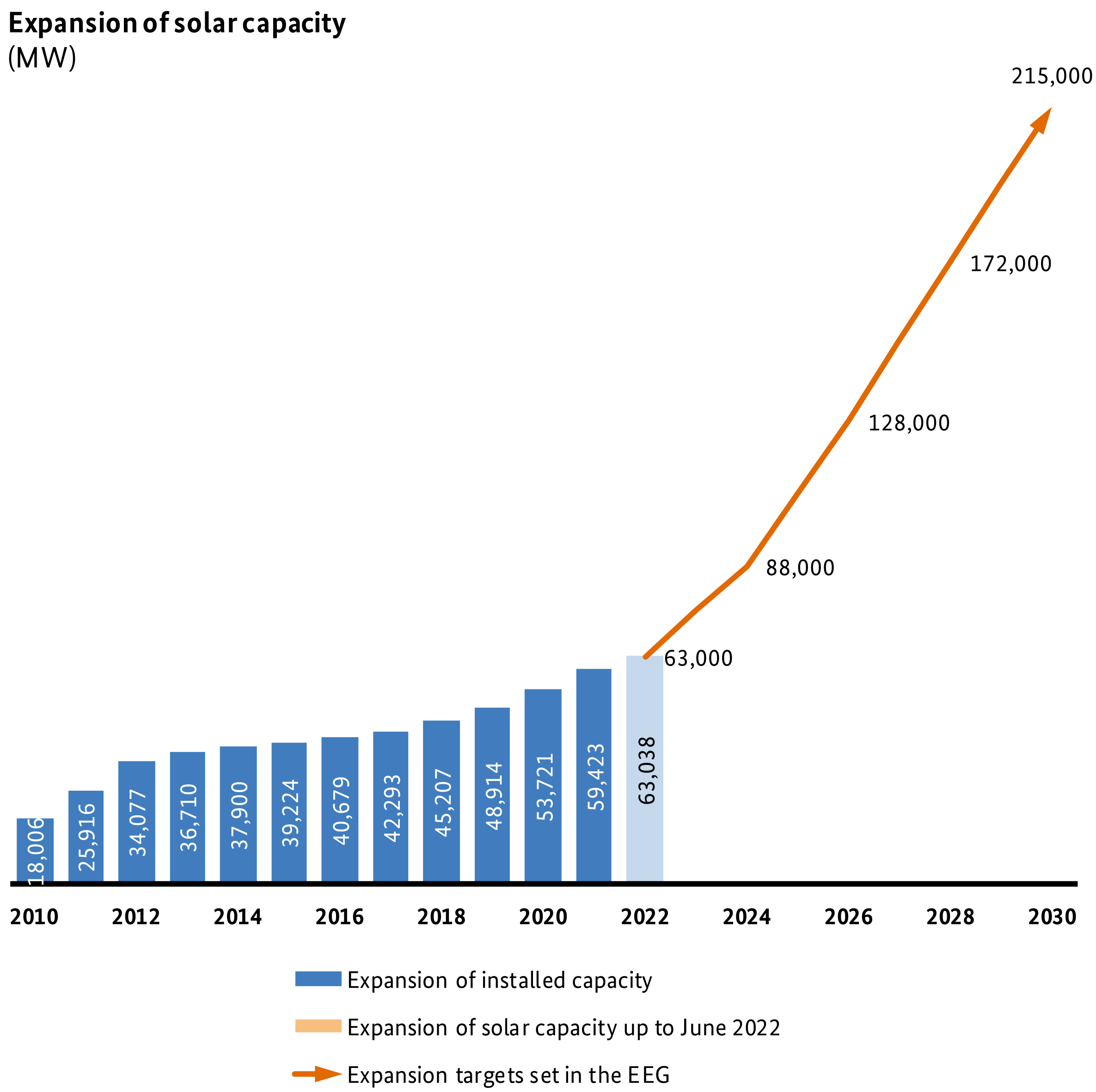

Figure 24: Solar capacity expansion targets

Newly installed biomass capacity was at a relatively low level of 41 MW in the first half of 2022. A total of 8.9 GW biomass capacity receives EEG payments, of which 8.4 GW will be retained under the expansion targets in the EEG 2021 until 2030.

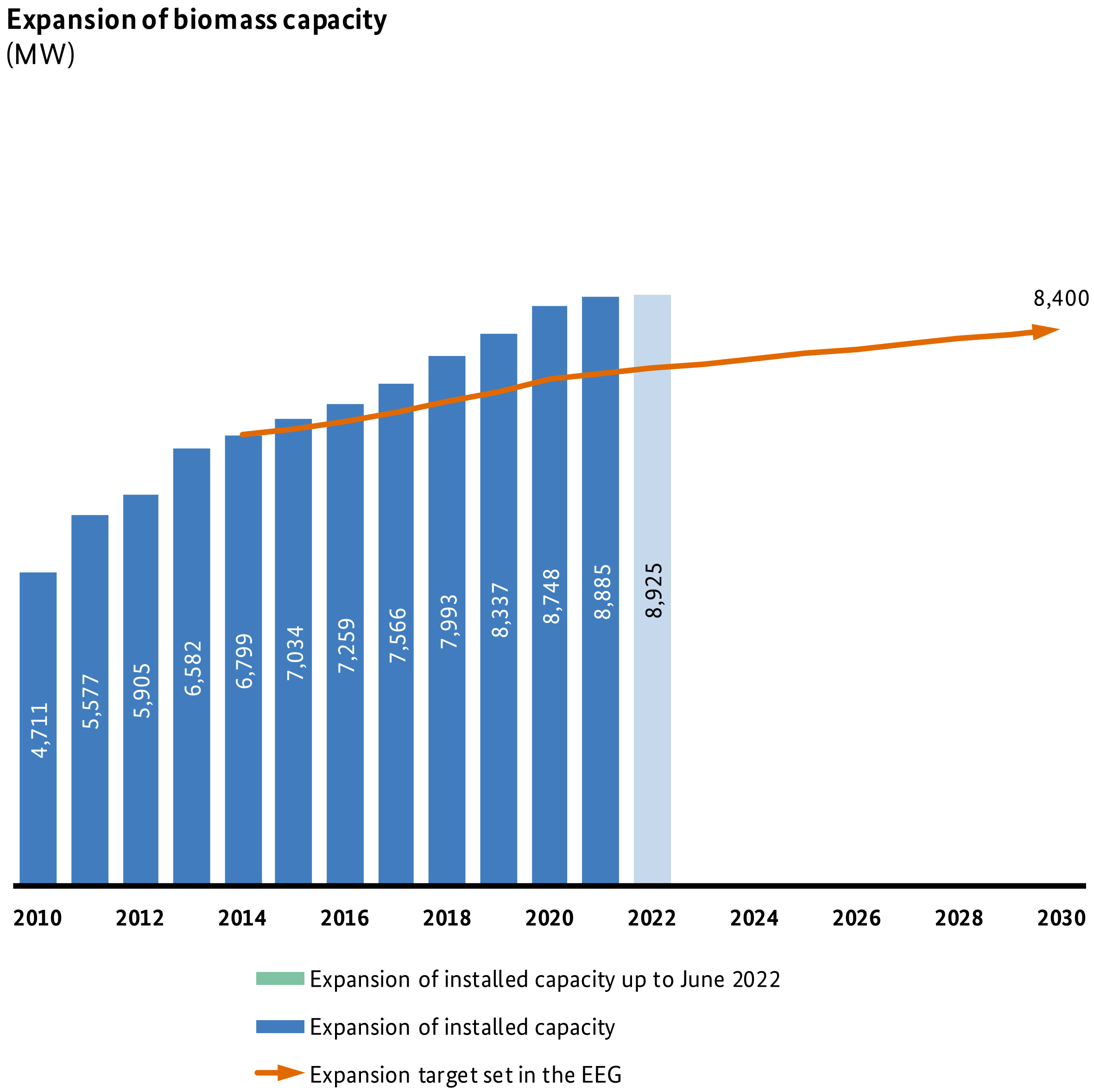

Figure 25: Biomass capacity expansion targets

Offshore wind energy capacity expansion has been stagnant since July 2020.

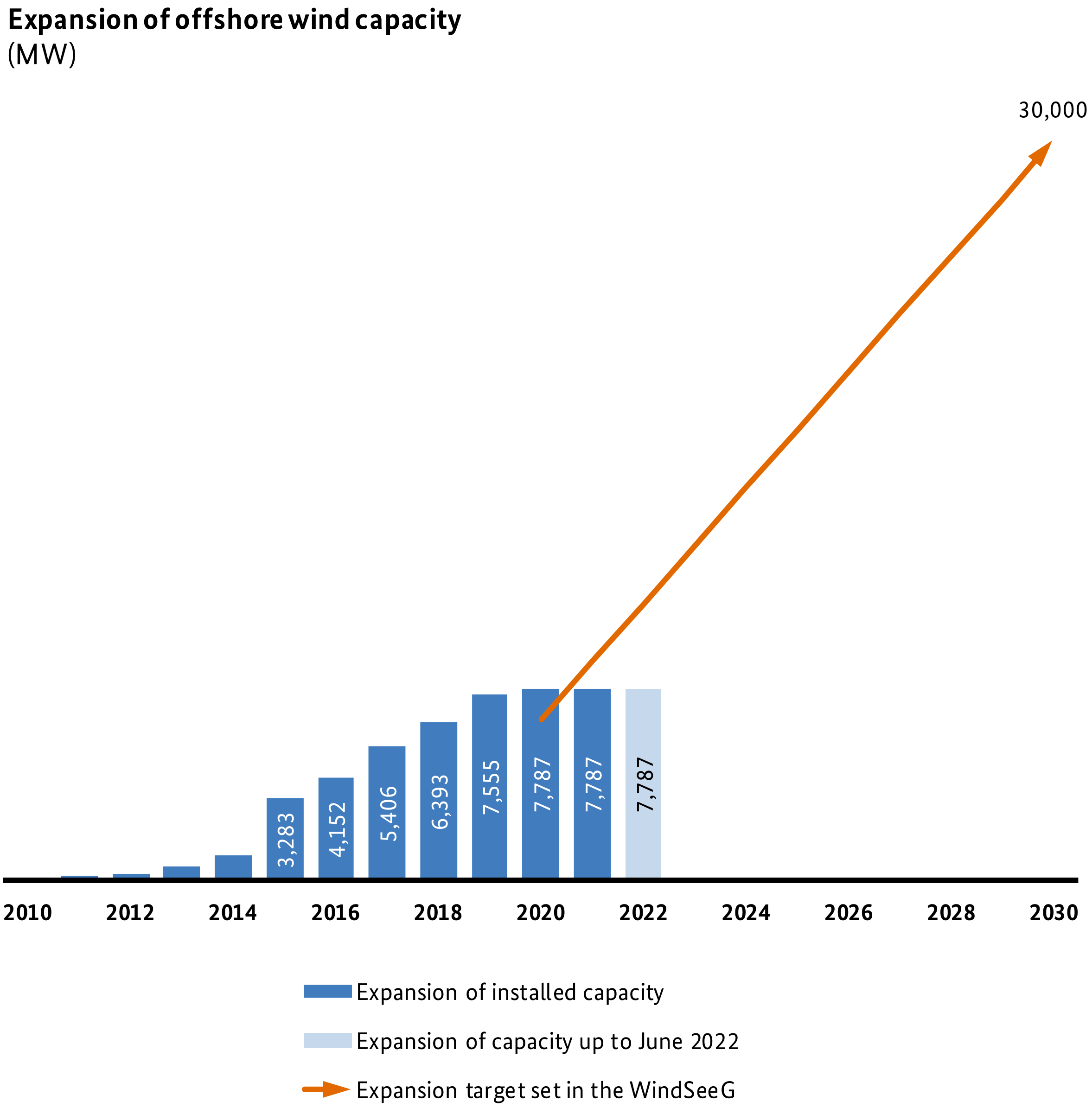

Figure 26: Offshore wind capacity expansion targets

2.1.3 Annual feed-in of electricity

In 2021 the total annual feed-in of electricity from installations eligible for payments under the EEG was 203.4 TWh. Total annual electricity feed-in has decreased by 8.4% compared to the previous year (2020: 222.0 TWh). At 88.5 TWh or 43.5%, the largest share of this electricity was generated by onshore wind installations, followed by solar installations with 44.3 TWh (21.8%) and biomass installations with 40.0 TWh (19.7%).

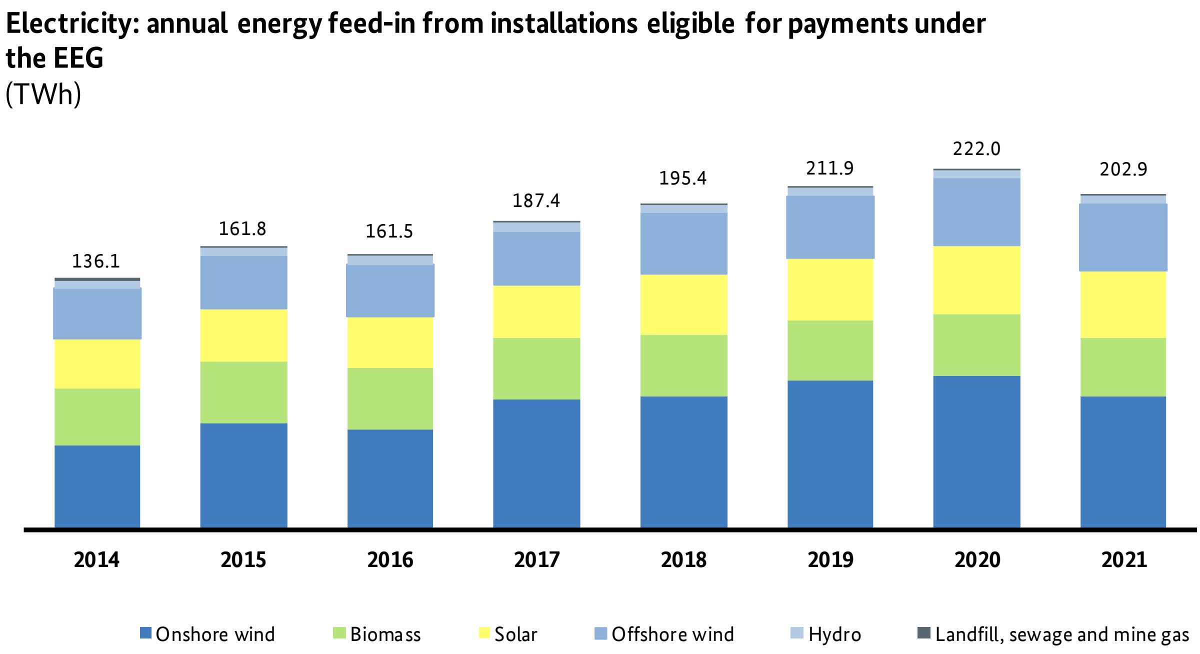

Figure 27: Changes in annual feed-in of electricity from installations eligible for payments under the EEG

There was a slight decrease of 1.7% in annual feed-in from solar installations. The stagnation of the amount of feed-in from solar installations in spite of the steady expansion of capacity is a result of the relatively little sunshine in the summer months of 2021.[33]

The significant decline in the amount of feed-in from onshore and offshore wind (each down 10%) is due to the fact that there was little wind in 2021 (see Figure 25).

The significant decline in the amount of feed-in from gas facilities is only partially due to the closures in this sector (see Table 25).

Unlike other energy sources, feed-in from hydropower saw an increase in 2021, rising from 5.0 TWh in 2020 to 5.6 TWh in 2021 (up 10.8%). This trend is due to the amount of precipitation being slightly above average in 2021 and the fact that there were several heavy rainfall events.34 Large amounts of precipitation were measured particularly in Bavaria and Baden-Württemberg, where numerous hydropower plants are installed because of the high altitude location on the edge of the Alps and the Black Forest.

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[33] Source: data from the DWD's publication (in German), "Das Strahlungsjahr 2021" at https://www.dwd.de/DE/leistungen/solarenergie/solarenergie.html;jsessionid=202DF6C959DA3A98FAA70C9CE3A1B71D.live11042?nn=16102.

[34] Source: DWD press release at https://www.dwd.de/DE/presse/pressemitteilungen/DE/2021/20211230_deutschlandwetter_jahr2021_news.html#:~:text=Im%20Jahr%202021%20fielen%20rund,(791%20l%2Fm%C2%B2%20).

Electricity: annual feed-in of electricity from EEG installations eligible for payments by energy source

	Total 31 December 2020	Total 31 December 2021	Increase / decrease compared to 2020
	in GWh	in GWh	in %
Hydro	5,048	5,592	10.8%
Gases[1]	1,089	765	-29.8%
Biomass	40,948	40,016	-2.3%
Geothermal	197	210	6.6%
Onshore wind	102,741	88,502	-13.9%
Offshore wind	26,903	24,015	-10.7%
Solar	45,030	44,252	-1.7%
Total	221,956	203,352	-8.4%

[1] Landfill, sewage and mine gas

Table 33: Annual feed-in of electricity from installations eligible for payments under the EEG by energy source (on 31 December)

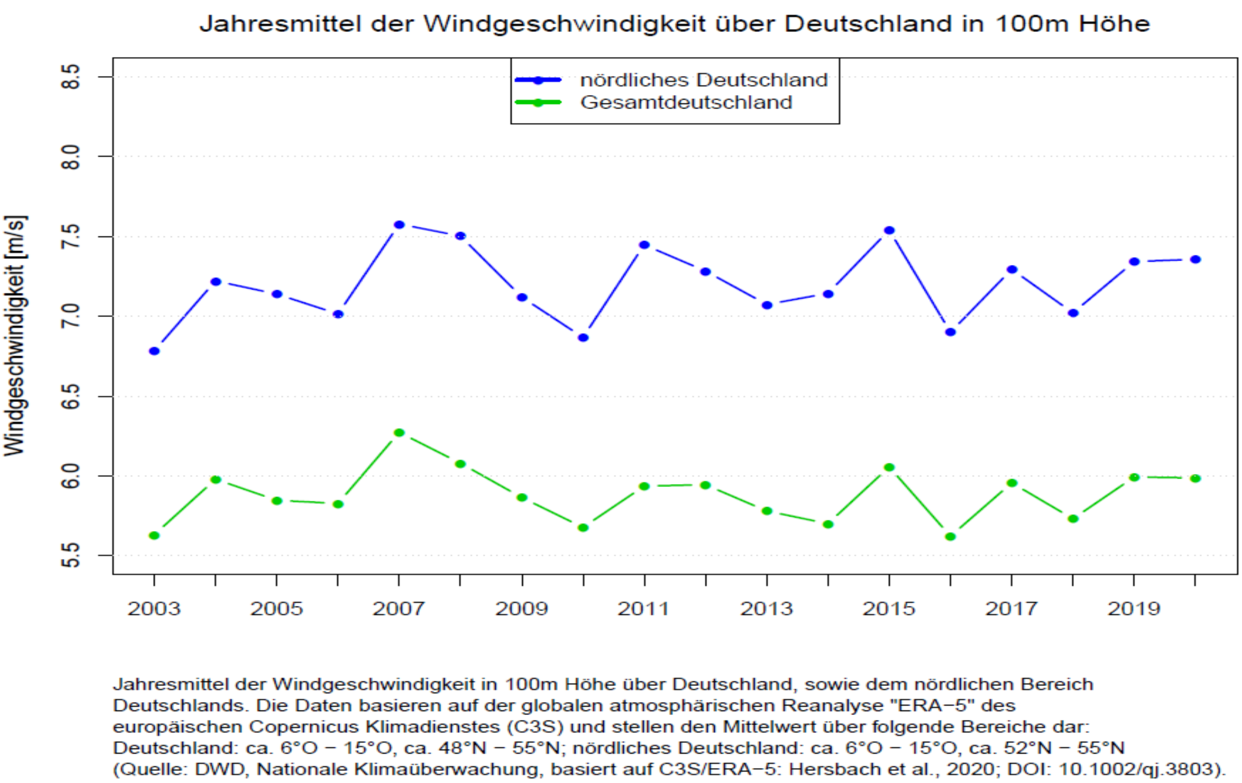

Figure 28: Annual average wind speed at 100 m elevation for all of Germany as well as for northern Germany

Maximum feed-in from wind power and solar installations

The maximum feed-in from wind power and solar installations increased only very slightly compared with previous years. In 2021, the maximum feed-in from wind power installations and solar installations of 71.8 GW was recorded on 5 May 2021 between 1pm and 2pm. The feed-in peak was comprised of 70.4% from wind power plants and 29.6% from solar installations. On this day, wind installations fed up to 50.6 GW into the grid. This coincided with a level of feed-in from solar installations (21.3 GW) that was particularly high for the time of year.

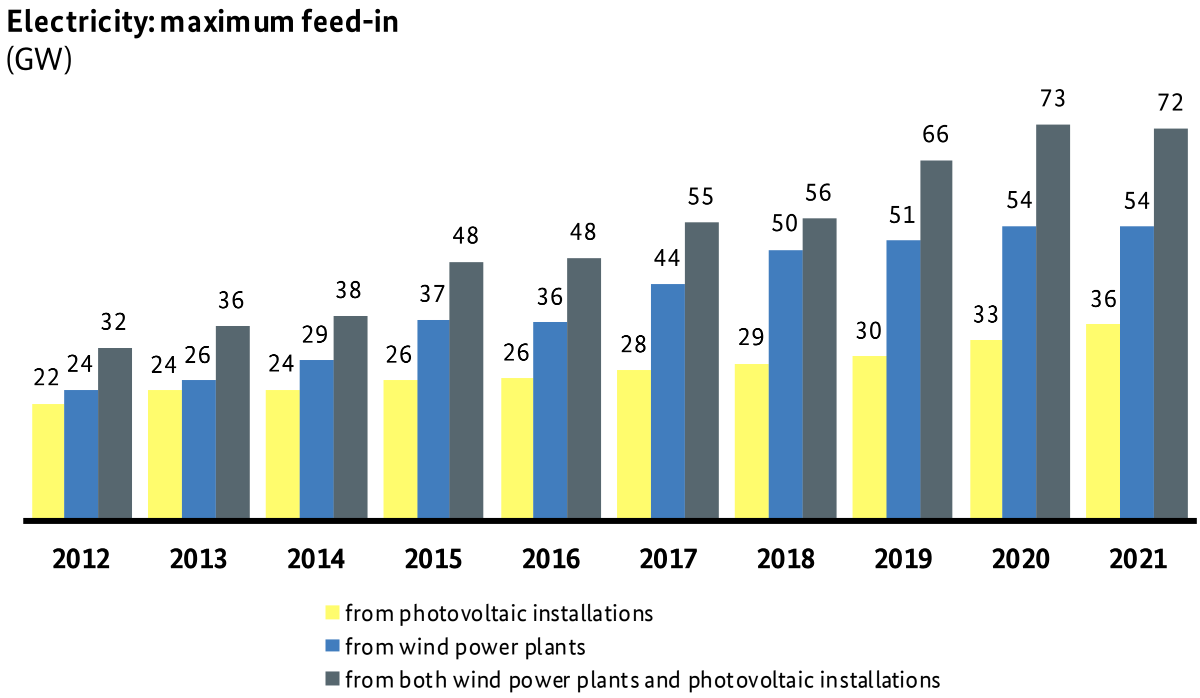

Figure 29: Maximum feed-in

The year's maximum feed-in exclusively from solar installations (36.3 GW) occurred on 27 April 2021 between 1pm and 2pm. Wind installations (onshore and offshore combined) had their highest feed-in levels of the year between the end of November and the beginning of December 2021. The peak level (54.1 GW), due in particular to the low pressure areas "Christian" and "Daniel" in quick succession, was reached on 1 December 2021 between 8pm and 9pm.[35] There were numerous feed-in peaks over the course of the year caused by various low pressure areas that in some cases led to high feed-in levels for several days.

[35] Source: data from the DWD's 2021 annual report at https://www.dwd.de/DE/presse/publikationen/jahresberichte_node.html.

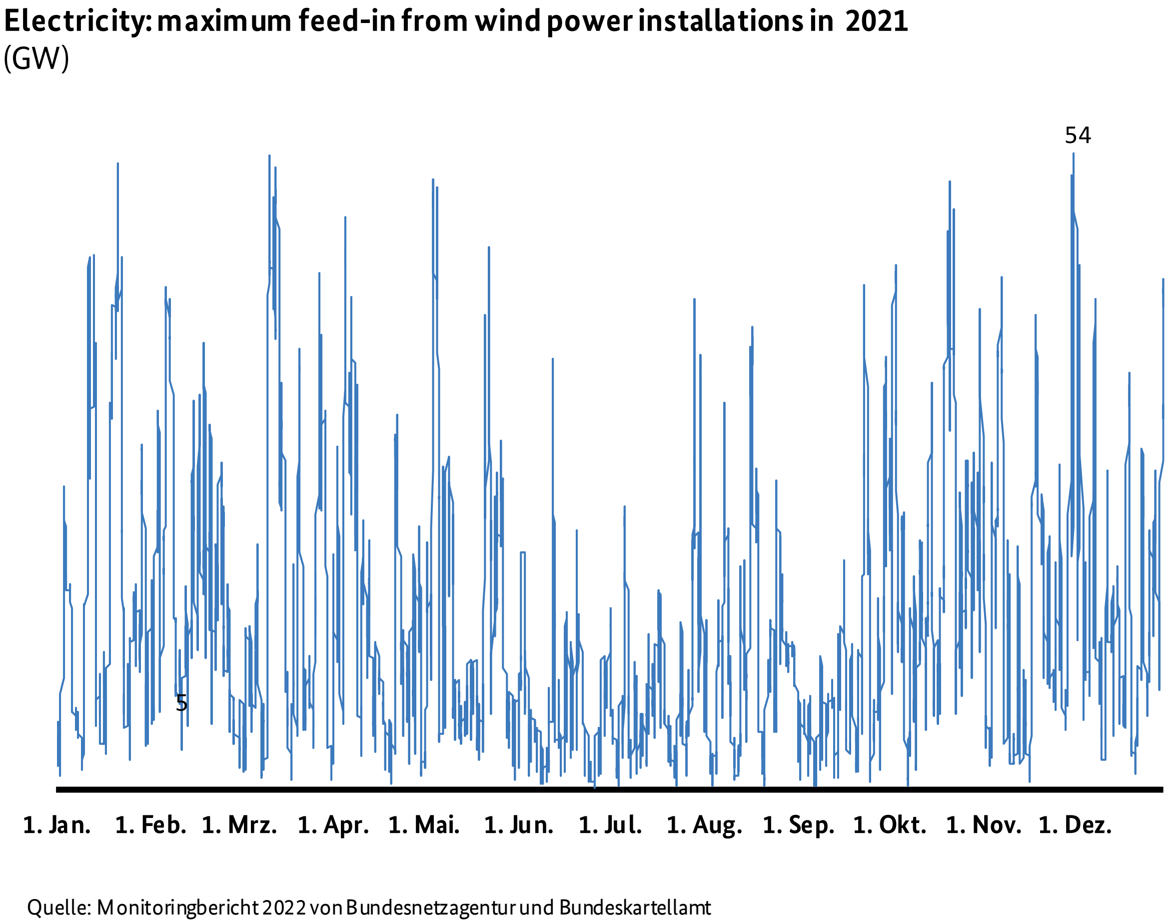

Figure 30: Maximum feed-in from wind power installations in 2021

2.1.4 Forms of selling

Under the EEG 2012, installation operators were able for the first time to choose between 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 revenue) or another form of direct selling (sale of EEG electricity without claiming any other EEG payments). Subsequent amendments to the EEG all stipulate direct selling and the market premium as standard forms of selling. Only installations with a capacity of up to 100 kW can still opt for feed-in tariffs or payment of a landlord-to-tenant electricity premium. Another form of direct selling, ie selling without receiving payment under the EEG, also remains possible.

In 2021, 79% of annual energy feed-in was remunerated under the EEG in the form of the market premium. This was the case for 100% of offshore wind power plants and for well over 90% of both onshore wind power and geothermal energy. At 36% (2020: 34%), the proportion of electricity from solar installations receiving a market premium is still relatively low but growing continually.

For the first time, the proportion of other direct selling rose to more than 2% in 2021. Particularly noticeable was the increased share of direct selling from gas installations as well as from wind, solar and hydropower installations. For wind and hydropower this is because of the installations that, after 20 years of receiving support, are no longer eligible to receive payments under the EEG. By contrast, the solar power installations were either new or the installations opted out of EEG funding.

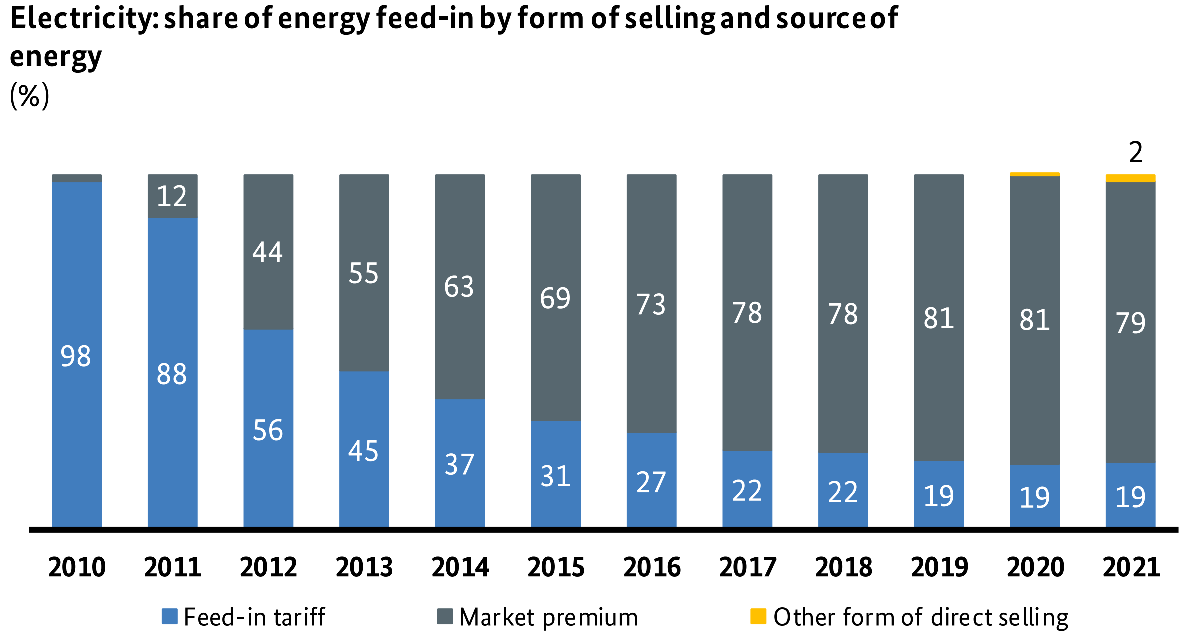

Figure 31: Forms of selling energy feed-in

Electricity: energy feed-in by form of selling and source of energy in 2021

	all in GWh	Feed-in tariff		Market premium		Other form of direct selling	
		in GWh	Share in %	in GWh	Share in %	in GWh	Share in %
Hydro	5,592	2,060	37%	3,281	59%	251	4%
Gases[1]	765	91	12%	582	76%	91	12%
Biomass	39,525	5,576	14%	33,858	86%	582	1%
Geothermal	210	9	5%	201	95%	-	0%
Onshore wind	88,502	2,680	3%	83,055	94%	2,767	3%
Offshore wind	24,015	-	0%	24,015	100%	-	0%
Solar	44,252	27,881	63%	15,714	36%	656	1%
Total	**202,861**	**38,298**	**19%**	**160,706**	**79%**	**4,348**	**2%**

[1] Landfill, sewage and mine gas

Table 34: Energy feed-in by form of selling and source of energy

2.2 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 2021 a total of €19.7bn 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). The installation operators who market their electricity themselves normally receive payment for this electricity at values that are set in the EEG. This market premium covers the share that the installation operators were not able to earn through sales up to the value to be applied.

Payments overall were 34.1% lower in 2021 than in the previous year. This was mainly due to the high electricity prices in 2021 (see A 1.5). In some cases the installation operators were able to make revenue from their electricity even beyond the value to be applied, which strongly reduced the share that had to be paid as the market premium by the network operators. Whereas 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%), that figure was down to 8.2% in 2021. Solar installations (€9.9bn) and biomass plants (€4.8bn) accounted for significant shares of these payments.

Electricity: payments by energy source

	Total 31 December 2020 (€ mn)	Total 31 December 2021 (€ mn)	Increase / decrease compared to 2020 (%)
Hydro	386	302	-21.8%
Gases[1]	51	12	-76.5%
Biomass[2]	6,984	4,788	-31.4%
Geothermal	43	32	-25.9%
Onshore wind	6,674	2,334	-65.0%
Offshore wind	4,246	2,259	-46.8%
Solar	11,456	9,926	-13.4%
Total	29,841	19,652	-34.1%

[1] Landfill, sewage and mine gas

[2] Including support for flexibility

Table 35: Payments under the EEG by energy source (as at 31 December)

The individual energy sources also show a clear decrease in payments for energy sources that are mostly sold directly (onshore and offshore wind). By contrast, energy sources that generally still receive the feed-in tariff (solar) saw a smaller decrease in payments.

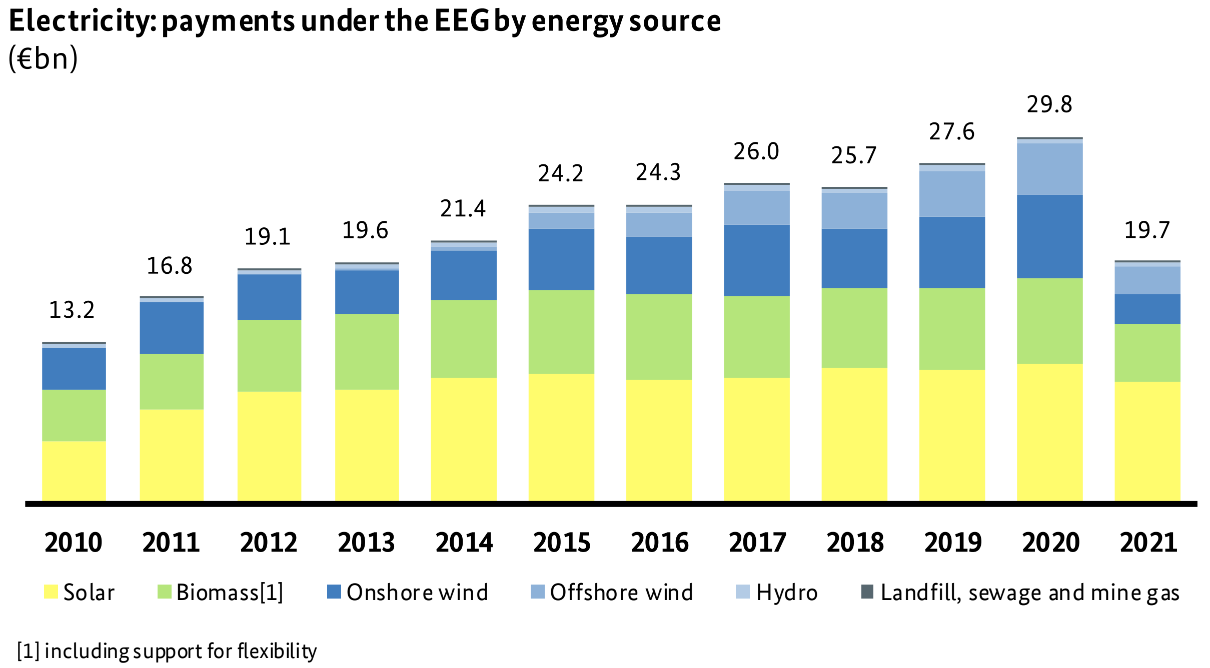

Figure 32: Changes in payments under the EEG by energy source

Renewable energy operators received an average of 9.7 ct/kWh in payments under the EEG[36] in 2021. This decline was also mainly due to the high electricity prices mentioned above.

In addition, it must be taken into account that payments for the different energy sources vary significantly. For example, operators of solar installations received an average of 22.4 ct/kWh in 2021, while operators of onshore wind installations received an average of 2.6 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.

[36] 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.

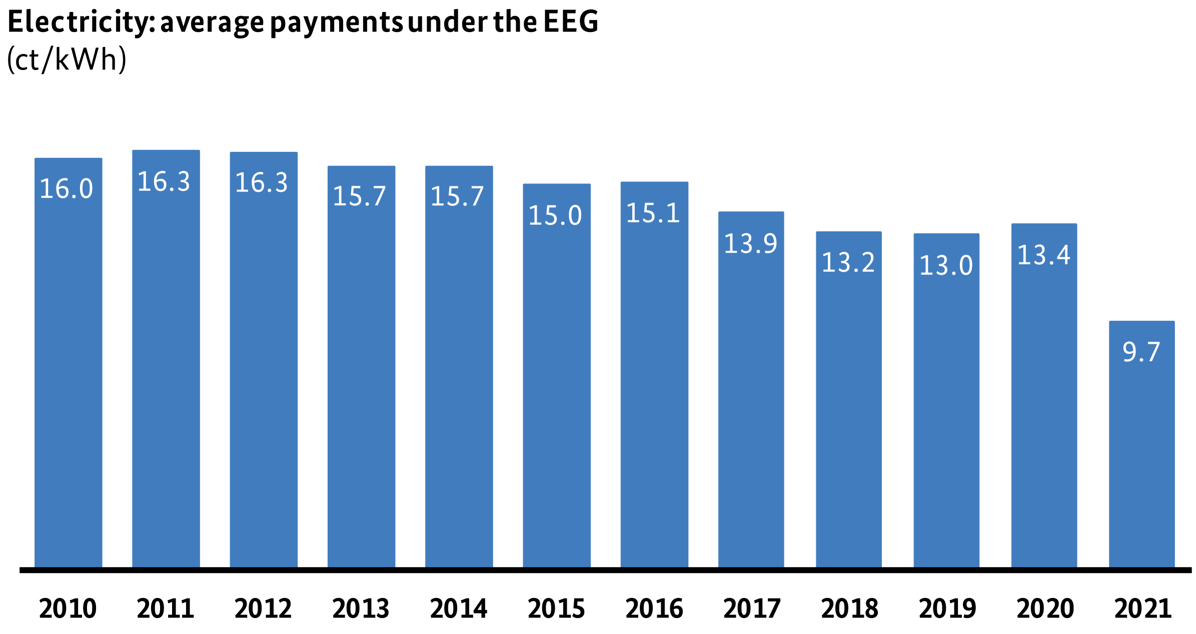

Figure 33: Changes in average payments under the EEG

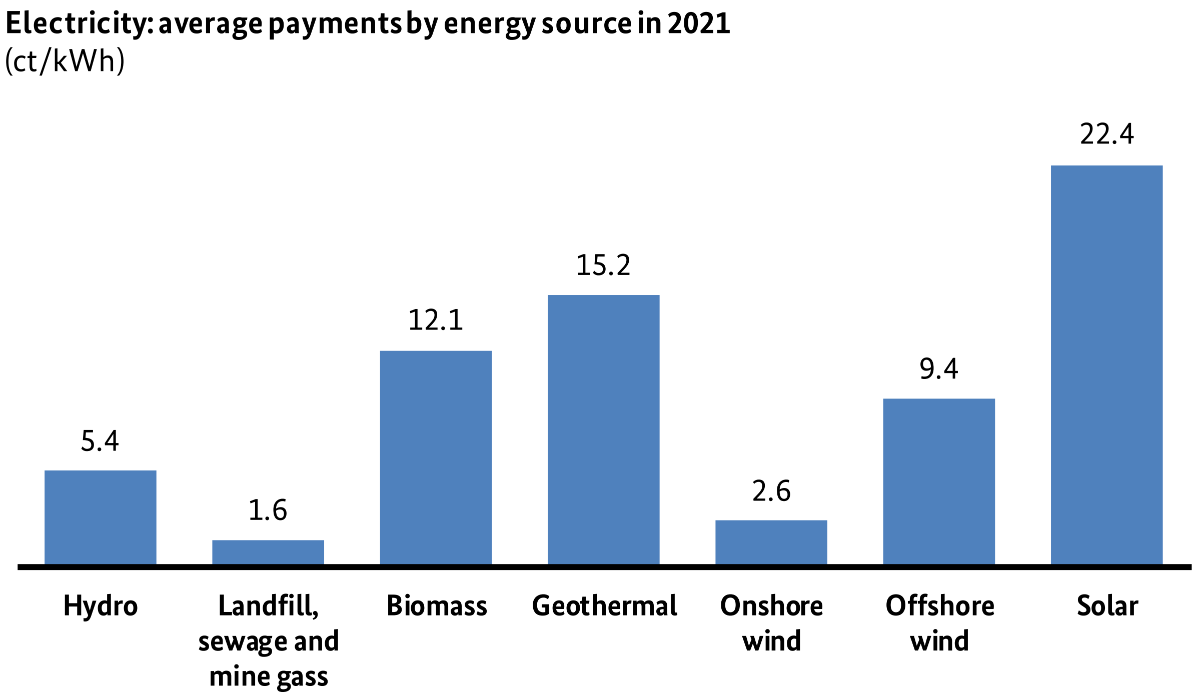

Figure 34: Average payments by energy source

2.2.1 The EEG surcharge

From 2008 to 2022, payments under the EEG were mostly refinanced through the EEG surcharge.

The EEG surcharge for the first half of 2022 was 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 federal government assistance, which will be financed from revenues derived from the national CO_2 price. A new provision in the EEG set the EEG surcharge to zero for the second half of 2022. As from 2023 there will no longer be an EEG surcharge.

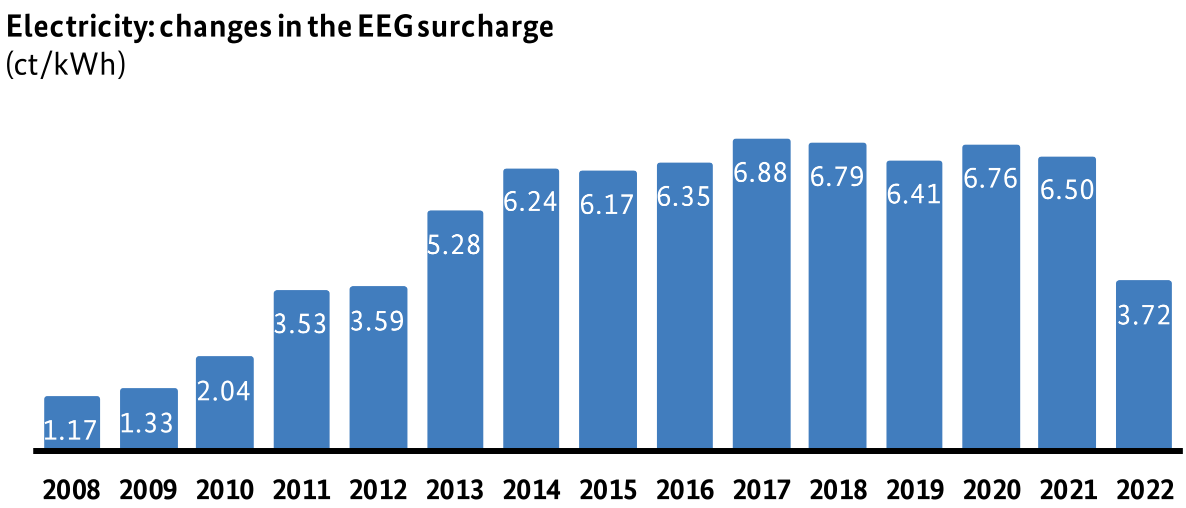

Figure 35: The EEG surcharge

2.3 Auctions

Operators of new onshore wind, offshore wind, solar and biomass plants only receive EEG payments if they have successfully participated in an auction.

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 EEG 2021 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 30 auction rounds in the January 2021 to October 2022 period with the following results:

Electricity: technology-specific auctions for solar and onshore wind installations 2021 - 2022

Technology	Auction end date	Award price (ct/kWh)*
Solar (1st segment)	01.03.2021	5.03
	01.06.2021	5.00
	01.11.2021	5.00
	01.03.2022	5.19
	01.06.2022	5.51
Solar (2nd segment)	01.06.2021	6.88
	01.12.2021	7.43
	01.04.2022	8.53
	01.08.2022	8.84
Onshore wind	01.02.2021	6.00
	01.05.2021	5.91
	01.09.2021	5.79
	01.02.2022	5.76
	01.05.2022	5.85
	01.09.2022	5.84

*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 2021 and 2022 for solar and onshore wind installations with sliding premium

Electricity: other auctions in 2021 - 2022 with sliding market premiums

Technology	Auction end date	Award price (ct/kWh)*
Biomass	1 March 2021	17.02
	1 September 2021	17.48
	1 March 2021	15.75
	1 September 2021	17.48
Biomethane	1 December 2021	17.84
	1 October 2022	18.71

*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 2021 and 2022 for biomass and biomethane installations with sliding premium

Electricity: other auctions in 2021 - 2022 with fixed market premium

Technology	Auction end date	Award price (ct/kWh)*
CHP	1 June 2021	5.64
	1 December 2021	6.11
	1 June 2022	5.87
Innovative CHP systems	1 June 2021	11.57
	1 December 2021	11.37
	1 June 2022	11.74
Innovation auction: system combinations	1 April 2021	4.29
	1 August 2021	4.55
	1 April 2022	5.42

* 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 2021 and 2022 for CHP plants, innovative CHP systems and combinations of installations with a fixed market premium.

The figures in Table 32 and Table 33 are not comparable with Table 34 because both Table 32 and Table 33 feature a sliding premium with a deduction of potential revenue on the power exchange, while the figures in Table 34 show fixed premiums that are paid to the installation operator in addition to other revenue.

2.3.1 Solar installation auctions

Following the pilot auction for ground-mounted installations in the years 2015 to 2016, auctions have been held for all ground-mounted solar installations with an installed capacity of more than 750 kW 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, Lower Saxony, Rhineland-Palatinate and Saxony-Anhalt). Three auction rounds were held in 2021 for 1,637 MW. A total of 331 solar projects (bids) with a volume of 1,645 MW were awarded a tender.

In 2022, 3,434 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 for 1,779 MW were awarded to 310 solar projects. In June 2022 the auction volume was undersubscribed for the first time since the introduction of solar energy auctions. The main reason could be that the auction volume was nearly doubled (2021: 1,637 MW; 2022: 3,434 MW).

As of 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. The award value remained around the five-cent mark in the first auctions of 2021, too (5.03 ct/kWh in March and 5.00 ct/kWh in June and November). In the first half of 2022, the average volume-weighted award prices rose again slightly and were at 5.19 ct/kWh (March 2022) and 5.51 ct/kWh (June 2022). The next auction round will take place in November 2022.

Electricity: solar auctions, first segment 2021

	March	June	November
Volume auctioned (MW)	617	510	510
Submitted bids	288	242	232
Submitted bid volume (MW)	1504	1130	986
Winning bids*	103	95	133
Volume awarded (MW)*	620	513	512
Excluded bids	6	11	10
Volume of excluded bids (MW)	38	36	32
Highest permissible bid (ct/kWh)	5.90	5.90	5.90
Average volume-weighted award price (ct/kWh)	5.03	5.00	5.00
Lowest bid (awarded) (ct/kWh)	4.69	4.69	4.57
Highest bid (awarded) (ct/kWh)	5.18	5.09	5.20

*Prior to receipt of the second security deposit.

Table 39: Solar auctions, first segment 2021

Electricity: solar auctions, first segment 2022

	March	June	November
Volume auctioned (MW)	1108	1126	1200*
Submitted bids	209	116	not available
Submitted bid volume (MW)	1116	714	not available
Winning bids*	201	109	not available
Volume awarded (MW)*	1084	696	not available
Excluded bids	8	6	not available
Volume of excluded bids (MW)	32	17	not available
Highest permissible bid (ct/kWh)	5.57	5.70	not available
Average volume-weighted award price (ct/kWh)	5.19	5.51	not available
Lowest bid (awarded) (ct/kWh)	4.05	4.87	not available
Highest bid (awarded) (ct/kWh)	5.55	5.69	not available

*The actual auction volume can change due to legal provisions.

Table 40: Solar auctions, first segment 2022

The deadlines for the implementation of awards are between 18 and 24 months. From the previous 33 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 12 solar photovoltaic auction rounds under the EEG and the Cross-Border Renewable Energy Ordinance have expired. These all have high rates of implementation, 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 relatively large solar projects. As a result of the Covid-19 pandemic, the implementation periods for all tenders awarded prior to 1 March 2020 whose implementation periods had not yet expired when the change went into effect, have been extended by six months. Thus the implementation periods for all other auction rounds as from December 2019 have not yet expired.

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

Auction end date	Implementation status in %	Commissioning period (exclusion deadline)	Basis of auction
15 April 2015	99	06 May 2017	FFAV
01 August 2015	90	20 August 2017	FFAV
1 December 2015	92	18 December 2017	FFAV
01 April 2016	100	18 April 2018	FFAV
01 August 2016	96	12 August 2018	FFAV
01 December 2016	73	15 December 2018	FFAV
01 November 2016	99	05 December 2018	GEEV
01 February 2017	99	15 February 2019	EEG
01 June 2017	97	21 June 2019	EEG
01 October 2017	35	23 October 2019	EEG
01 February 2018	44	27 February 2020	EEG
01 June 2018	83	21 December 2020	EEG
01 October 2018	55	26 April 2021	EEG
01 February 2019	91	22 Otober 2021	EEG
01 March 2019	94	06 December 2021	EEG
01 June 2019	93	28 February 2022	EEG
01 October 2019	83	27 June 2022	EEG
01 December 2019	89	22 September 2022	EEG

Table 41: Implementation rates for solar auctions, first segment

Figure 36 shows that over 50% of the bids awarded for solar photovoltaic auctions in 2021 and 2022 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.

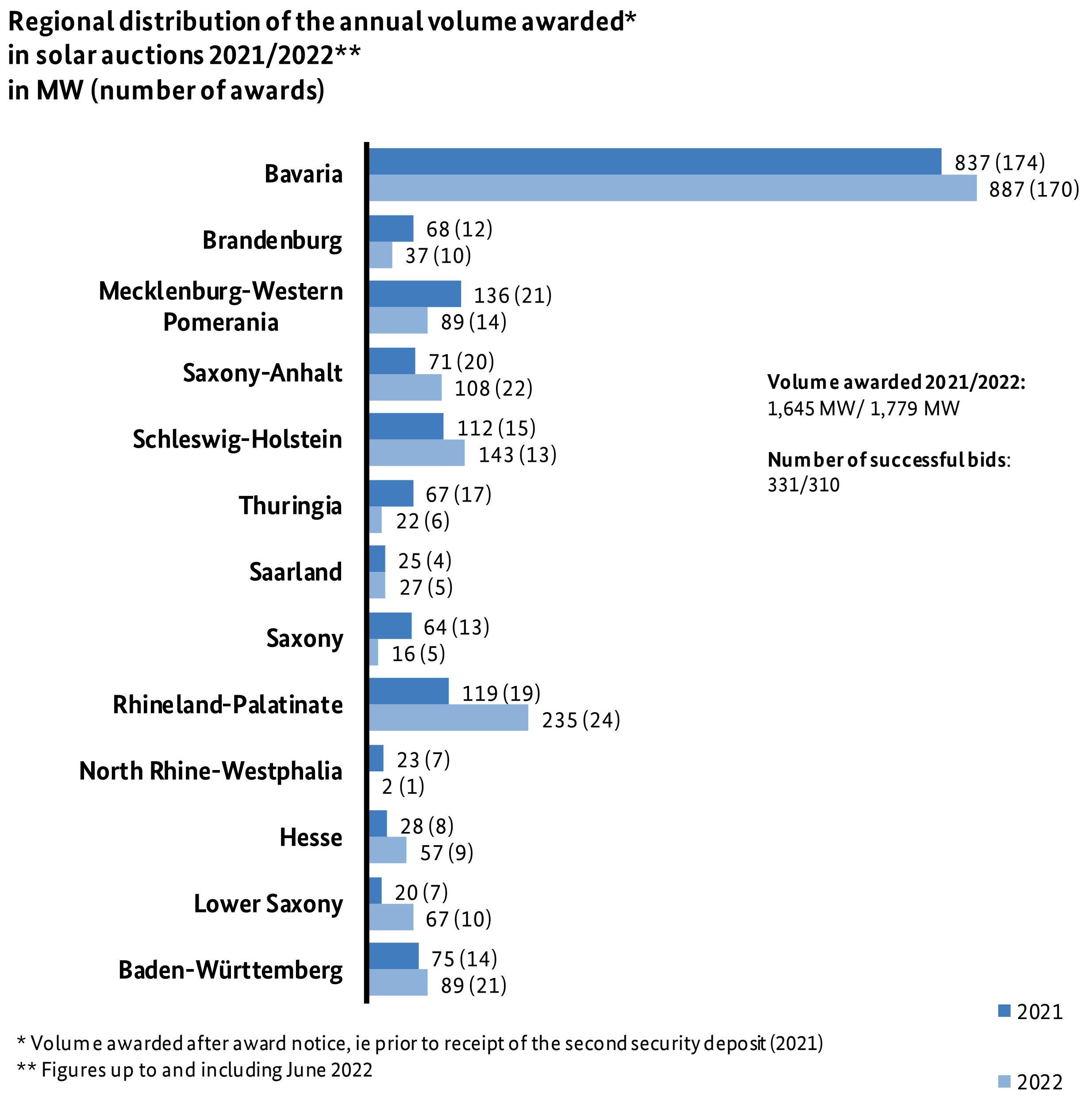

Figure 36: Regional distribution of the annual volume awarded in EEG ground-mounted PV auctions 2021/2022

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 2021, auctions were held for 4,235 MW in three different auction rounds. Two of the three rounds in 2021 were undersubscribed. A volume of just 3,295 MW was awarded and the targeted development corridor was not reached. Only the last round in September was slightly oversubscribed (Table 42). In 2022, auctions were held for 5,158 MW in four different auction rounds. The first auction of 2022, in February, was slightly oversubscribed and was followed by two significantly undersubscribed rounds in May and September (Table 39). There will be an additional round in December with an auction volume of 1,190 MW.

Electricity: onshore wind auctions 2021

	February	May	September
Volume auctioned (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
Volume of excluded bids (MW)	27	51	34
Highest permissible bid (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 42: Onshore wind auctions 2021

Electricity: onshore wind auctions 2022

	February	May	September	December*
Volume auctioned (MW)	1,328	1,320	1,320	1,190
Submitted bids	147	116	87	not available
Submitted bid volume (MW)	1,356	947	773	not available
Winning bids*	141	114	87	not available
Volume awarded (MW)*	1,332	931	773	not available
Excluded bids	6	2	0	not available
Volume of excluded bids (MW)	24	16	0	not available
Highest permissible bid (ct/kWh)	5.88	5.88	5.88	5.88
Average volume-weighted award price (ct/kWh)	5.76	5.85	5.84	not available
Lowest bid (awarded) (ct/kWh)	4.77	5.44	5.76	not available
Highest bid (awarded) (ct/kWh)	5.88	5.88	5.88	not available

The actual auction volume can change due to legal provisions.

Table 43: Onshore wind auctions 2022

The deadlines for the implementation of awards are between 24 and 54 months. From the previous 26 rounds, the implementation periods for 11 rounds have expired. Generally these rounds have had high rates of implementation since 2018. Exceptions are clearly visible in the 2017 auction rounds because at that time it was possible for citizen cooperatives to participate without a BImSchG permit and thus projects not as far along in their planning participated (Table 41). As a result of the Covid-19 pandemic, the implementation periods for all tenders awarded prior to 1 March 2020 whose implementation periods had not yet expired when the change went into effect have been extended by six months. Thus the implementation periods for all other auction rounds as from December 2019 have not yet expired.

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

Auction end date	Implementation rate in %	Implementation period deadline
01 May 2017	32	26 May 2022
01 August 2017	6	22 August 2022
01 November 2017	1	29 November 2022
01 February 2018	62	01 March 2021
01 May 2018	82	25 May 2021
01 August 2018	93	24 August 2021
01 October 2018	81	26 October 2021
01 February 2019	91	23 August 2021
01 May 2019	86	22 November 2021
01 August 2019	97	16 February 2022
01 September 2019	95	19 September 2022

Table 44: Implementation rates for wind auctions

From a regional perspective, 74% of the volume awarded in wind energy auctions in 2021 was concentrated in the four federal states of Schleswig-Holstein (26%), Lower Saxony (17%), North Rhine-Westphalia (17%) and Brandenburg (14%). In 2022 as well, 76% of the volume awarded remained concentrated in these federal states: Schleswig-Holstein (22%), Lower Saxony (23%), North Rhine-Westphalia (20%) and Brandenburg (11%).

Electricity: distribution of bids and awards for onshore wind energy per federal state 2021 - 2022*

	Number of bids		Capacity bids in kW		Number of awards		Awarded capacity in kW	
Federal state	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**
Baden-Württ.	5	6	58,200	53,960	4	6	54,000	53,960
Bavaria	8	3	68,000	20,800	6	3	51,400	20,800
Brandenburg	63	37	531,060	330,100	50	37	459,110	330,100
Bremen	1	0	3,600	0	1	0	3,600	0
Hesse	16	12	206,480	206,840	15	12	171,980	206,840
Meckl.-WP	13	11	157,200	95,100	13	11	157,200	95,100
Lower Saxony	52	72	593,800	711,540	49	72	574,400	711,540
N. Rhine-W.	109	67	707,740	615,399	90	63	553,290	599,899
Rhineland-P.	21	7	157,800	66,600	20	7	152,200	66,600
Saarland	2	4	17,850	28,760	1	4	3,450	28,760
Saxony	10	10	48,400	51,400	5	10	23,300	51,400
Saxony-Anhalt	12	25	136,100	143,850	11	25	123,500	143,850
Schl.-Holstein	107	87	895,300	687,250	100	83	869,850	662,450
Thuringia	19	9	122,500	64,400	17	9	98,500	64,400
Total	**438**	**350**	**3,704,030**	**3,075,999**	**382**	**342**	**3,295,780**	**3,035,699**

*Auction rounds in February, May and September 2022

Table 45: Distribution of bids and awards per federal state

2.3.3 Other auctions (offshore wind, biomass, innovation auctions, second segment solar installations and biomethane)

Offshore wind auctions

Another tendering round (after the auction last year for offshore wind) with a bid deadline of 1 September 2022 was for a site that had been subject to a preliminary assessment by the Federal Maritime and Hydrographic Agency (BSH). The assessment, which was commissioned by the Bundesnetzagentur, included the building ground and the marine environment. The awards include the right to grid connection – financed by electricity consumers through the offshore network surcharge – and the possibility to operate the offshore wind farm for 25 years. The successful bidders also receive the right to apply for planning approval from the BSH to construct an offshore wind farm on the site.

The auction for a total volume of 980 MW was for (pre-assessed) site N-7.2 in the North Sea. The offshore wind farm is expected to go into operation in 2027.

Several bids were placed on the N-7.2 site, and the successful bidder was RWE Renewables Offshore HoldCo Four GmbH with an award price of 0 ct/kWh. Vattenfall Atlantis 1 and Global Tech 2 Offshore Wind GmbH has a right of subrogation because it had once planned an offshore wind farm there. These project developers exercised their right to take part in the award by the 15 September 2022 deadline.

The next offshore wind energy auctions take place under the revised Offshore Wind Energy Act (WindSeeG, which enters into force on 1 January 2023) on 1 June 2023 and 1 August 2023. To meet the increased expansion targets of no less than 30 GW by 2030, the new WindSeeG provides for a significant increase in auction volumes, which the Bundesnetzagentur will award using a newly designed auction process as from 2023. Under the new process auctions will be held for sites that have and have not been pre-assessed by the BSH. In 2023 and 2024 alone, sites with around 16 GW of capacity will be auctioned.

Electricity: offshore wind auctions; auctions ending 1 September 2021 & 2022

	2021			2022
Site	N-3.7	N-3.8	O-1.3	N-7.2
Volume put up for auction (MW)	225	433	300	980
Volume awarded (MW)	225	433	300	225
Highest permissible bid (ct/kWh)	7.30	7.30	7.30	6.40
Award price (ct/kWh)	0.00	0.00	0.00	0.00
Lottery	No	Yes	Yes	No
Right of subrogation	No	Yes	Yes	Yes
Offshore transmission link	NOR-3-3	NOR-3-3	OST-1-4	NOR-7-2

Table 46: Tendering procedures for offshore wind

Biomass auctions

The Bundesnetzagentur has held 10 auction rounds since the auction procedure was introduced for biomass installations in 2017. Two auction rounds are held each year. Since 2021, rounds have been held in March and September and roughly 600 MW are auctioned each year. The auction volume is reduced or increased using the statutory adjustment mechanism. A total of 575 MW were auctioned 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 their remaining eligibility for payments under the EEG is less than eight years.

So far all auction rounds have been significantly oversubscribed since the introduction of auctions for biomass installations. This trend continued in 2021 and 2022. The volume-weighted average for all winning bids was 17.25 ct/kWh in 2021 and 15.75 ct/kWh in 2022. The average winning bid for new installations was 15.59 ct/kWh in 2021 and 15.66 ct/kWh in 2022. On average, bids for existing installations with installed capacity exceeding 150 kW were awarded at 18.75 ct/kWh in 2021 and 16.83 ct/kWh in 2022. Bids for existing installations with installed capacity equal to or less than 150 kW were, on average, awarded at 18.07 ct/kWh in 2021 and 18.50 ct/kWh in 2022. Regardless of the actual award value, the value to be applied for existing installations is limited to the average in the three years preceding the auction.

Electricity: biomass auctions in 2021

	1 March 2021			1 September 2021		
	New installations ≥ 150 kW	**Existing installations ≤ 150 kW**	**Existing installations > 150 kW**	**New installations ≥ 150 kW**	**Existing installations ≤ 150 kW**	**Existing installations > 150 kW**
Volume put up for auction (MW)	300			275		
Submitted bids	7	8	45	7	10	83
Bid volume submitted (MW)	14	0.6	29	21	0.9	65
Winning bids	5	5	28	7	7	59
Volume awarded (MW)	12	0.5	21	21	0.6	48
Excluded bids	0	2	6	0	0	6
Volume of excluded bids (MW)	0	0.09	3	0	0	4.7
Highest permissible bid (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

Electricity: biomass auctions 2022

	1 March 2022			1 September 2022		
	New installations ≥ 150 kW	Existing installations ≤ 150 kW	Existing installations > 150 kW	New installations ≥ 150 kW	Existing installations ≤ 150 kW	Existing installations > 150 kW
Volume put up for auction (MW)		275			300	
Submitted bids	5	8	63	12	1	87
Bid volume submitted (MW)	15	0.8	66	23	0.05	78
Winning bids	5	7	45	7	1	61
Volume awarded (MW)	15	0.7	53	19	0.05	59
Excluded bids	0	1	0	3	0	8
Volume of excluded bids (MW)	0	0.05	0	2.3	0	6
Highest permissible bid (ct/kWh)	16.24	18.22	18.22	16.24	18.22	18.22
Average volume-weighted award price (ct/kWh)	15.09	18.79	18.09	15.54	17.90	17.84

Table 48: Biomass auctions in 2022

The deadlines for the implementation of awards are between 24 and 30 months. From the previous 10 rounds, the implementation period for three rounds have expired. These rounds have had consistently high rates of implementation (see Table 49). As a result of the Covid-19 pandemic, the implementation periods for all tenders awarded prior to 1 March 2020 whose implementation periods had not yet expired when the change went into effect have been extended by six months. Thus the implementation periods for all other auction rounds as from April 2019 have not yet expired.

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

Auction end date	Implementation rate in %	Implementation period deadline
01 September 2017	90	25 September 2019
01 September 2018	93	27 September 2021
01 April 2019	93	25 April 2022

Table 49: Implementation rates for biomass auctions

Innovation auctions for individual installations (onshore wind, solar, biomass) or combinations of installations

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 auction procedure, bids could either be submitted for a single renewable technology (onshore wind, biomass or 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 installation 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 an endogenous volume limit in the absence of competition (undersubscription of 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 citizen cooperatives do not apply to onshore wind installations.

Since 2021, only system combinations may take part in innovation auctions. A total of 250 MW was auctioned in April 2021. With a bid volume of 509 MW the auction was significantly oversubscribed. A total of 18 bids for a capacity of 258 MW were awarded a tender. The average award price in this round was 4.29 ct/kWh. A total of 250 MW was also auctioned in August 2021. The submitted bid quantity was just under 250 MW and thus the legally stipulated volume limit was 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.

A total of 397 MW was auctioned in April 2022. A total of 45 bids with a volume of 435 MW were received, which means that this round was also oversubscribed. The average volume-weighted award (5.42 ct/kWh) was slightly higher than in the previous year. The next auction round will take place in December 2022. In this round for the first time, bids could be submitted for installation combinations with special solar installations, which are installations on bodies of water, farmland or parking areas so as to enable dual use of those areas. Bids for combinations with special solar installations were given priority in this round. There were 13 such bids comprising a volume of 22 MW and all the bids were successful. They included 12 awards covering 21 MW on farmland and one award covering 1 MW on a parking area.

Electricity: auctions for innovative installation concepts in 2021

	April	August
Volume put up for auction (MW)	250	250
Submitted bids	43	23
Bid volume submitted (MW)	509	250
Winning bids	18	16
Volume awarded (MW)	258	156
Excluded bids	1	6
Volume of excluded bids (MW)	3	67
Highest permissible bid (ct/kWh)	7.50	7.50
Average volume-weighted award price (ct/kWh)	4.29	4.55
Lowest bid (awarded) (ct/kWh)	3.33	3.99
Highest bid (awarded) (ct/kWh)	4.88	5.48

Table 50: Auctions for innovative installation concepts 2021

Electricity: auctions for innovative installation concepts in2022

	April	Dezember
Volume put up for auction (MW)	397	250
Submitted bids	45	not available
Bid volume submitted (MW)	435	not available
Winning bids	43	not available
Volume awarded (MW)	403	not available
Excluded bids	0	not available
Volume of excluded bids (MW)	0	not available
Highest permissible bid (ct/kWh)	7.43	7.50
Average volume-weighted award price (ct/kWh)	5.42	not available
Lowest bid (awarded) (ct/kWh)	3.95	not available
Highest bid (awarded) (ct/kWh)	7.43	not available

Table 51: Auctions for innovative installation concepts 2022

Solar auctions, second segment

The EEG 2021 introduced solar auctions for second segment solar installations. Bidders wishing 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 these auctions. Both auctions in 2021 had an auction volume of 150 MW and were oversubscribed. The auction in June had a bid volume of 213 MW and the December auction had a bid volume of 154 MW. The volume-weighted average winning bid was 6.88 ct/kWh in June and 7.43 ct/kWh in December; the highest bid in these rounds was for 9.00 ct/kWh. A total of 767 MW was auctioned in April 2022. The volume of the bids submitted was 212 MW, which means that this round was significantly undersubscribed. The average award price in this round was 8.52 ct/kWh and thus significantly higher.

The next auction round took place in August, again with an auction volume of 767 MW. The submitted bid quantity increased slightly to 214 MW, although this did nothing to change the fact that the auction was significantly undersubscribed. The average award price increased to 8.84 ct/kWh and thus continued to approach the highest permissible bid of 8.91 ct/kWh.

Electricity: auctions for photovoltaic installations, second segment 2021

	June	December
Volume put up for auction (MW)	150	150
Submitted bids	168	209
Bid volume submitted (MW)	213	154
Winning bids	114	136
Volume awarded (MW)	153	204
Excluded bids	15	38
Volume of excluded bids (MW)	21	49
Highest permissible bid (ct/kWh)	9.00	9.00
Average volume-weighted award price (ct/kWh)	6.88	7.43
Lowest bid (awarded) (ct/kWh)	5.35	5.70
Highest bid (awarded) (ct/kWh)	7.89	8.28

Table 52: Solar auctions, second segment 2021

Electricity: auctions for photovoltaic installations, second segment 2022

	April	August	December
Volume put up for auction (MW)	767	767	767*
Submitted bids	171	115	not available
Bid volume submitted (MW)	212	214	not available
Winning bids	163	107	not available
Volume awarded (MW)	204	202	not available
Excluded bids	8	8	not available
Volume of excluded bids (MW)	8	12	not available
Highest permissible bid (ct/kWh)	8.91	8.91	8.91
Average volume-weighted award price (ct/kWh)	8.53	8.84	not available
Lowest bid (awarded) (ct/kWh)	7.00	8.20	not available
Highest bid (awarded) (ct/kWh)	8.91	8.91	not available

*The actual auction volume can change due to legal provisions.

Table 53: Solar auctions, second segment 2022

Awards must be implemented within 12 months. From the previous four solar auctions for the second segment, the implementation period for one round has expired. The result of this round reflects a rate of implementation of 73% (Table 54).

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

Auction end date	Implementation rate in %	Implementation period deadline
01 June 2021	73	22 July 2022

Table 54: Implementation rates for solar auctions, second segment

Biomethane installation auctions

Since 2021 the Bundesnetzagentur has been conducting auctions for biomethane installations with a capacity of 150 kW or more. The auction procedures for biomethane are generally similar to those for biomass, except that existing installations are excluded from participating in a biomethane auction.

In the first auction round in December 2021 bids could also be submitted for projects that were not yet approved as well as for projects in the north. Bids were submitted for a total capacity of 148 MW. The volume to be auctioned was 150 MW, which means that this auction was slightly undersubscribed. The volume-weighted average winning bid was 17.84 ct/kWh; the highest permissible bid was 19.00 ct/kWh. Unlike in the first round in December 2021, only bids on approved projects could be submitted in the October 2022 round. The auction volume was 152 MW and only two bids with a total quantity of 3.5 MW were submitted. The main reason for the low level of participation could have to do with the fact that in 2023 the highest permissible bid will be increased to 19.31 ct/kWh, which can be calculated to guarantee an increase in revenue of half a cent per kWh.

Electricity: auctions for biomethane plants 2021-2022

	December 2021	October 2022
Volume put up for auction (MW)	150	150
Submitted bids	21	2
Bid volume submitted (MW)	148	3.5
Winning bids	21	2
Volume awarded (MW)	148	3.5
Excluded bids	0	0
Volume of excluded bids (MW)	0	0
Highest permissible bid (ct/kWh)	19.00	18.81
Average volume-weighted award price (ct/kWh)	17.84	no data*
Lowest bid (awarded) (ct/kWh)	16.88	no data*
Highest bid (awarded) (ct/kWh)	18.98	no data*

*The exact figures are not listed so that inferences about the bidder cannot be made.

Table 55: Biomethane installation auctions 2021-2022

Joint auction procedure for wind and solar installations

From 2018 to 2020 the Bundesnetzagentur held six technologically neutral (joint) auctions, two each year for solar and onshore wind installations. As the Joint Auctions Ordinance (GemAV) is no longer in force as from 1 January 2021, no more joint auction rounds will take place.

The deadlines for the implementation of awards are between 24 and 30 months. From the six joint auction rounds, the implementation periods for four rounds have expired. These rounds have had consistently high rates of implementation (see Table 50). As a result of the Covid-19 pandemic, the implementation periods for all tenders awarded prior to 1 March 2020 whose implementation periods had not yet expired when the change went into effect, have been extended by six months. Thus the implementation periods for all other auction rounds as from October 2019 have not yet expired.

Electricity: implementation rates for joint solar and onshore wind installation auctions with expired implementation periods

Auction end date	Implementation rate in %	Implementation period deadline
01 April 2018	79	20 April 2020
01 November 2018	73	26 May 2021
01 April 2019	77	27 December 2021
01 November 2019	92	02 August 2022

Table 56: Implementation rates for joint solar and onshore wind installation auctions

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 includes the projects from the Federal Requirements Plan Act (BBPlG) and the Power Grid Expansion Act (EnLAG). It also covers the status of the planned and implemented measures to optimise the network.

The Bundesnetzagentur publishes the updates on its website at www.netzausbau.de/vorhaben.

As at the second quarter of 2022, 101 projects were listed in the BBPlG and the EnLAG: 23 projects had already been completed and another 13 had been at least fully approved; 46 projects were still at the approval stage; and 19 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 30 June 2022 was some 12,234 km:

- around 2,662 km were about to start the approval procedure;
- around 402 km were in the federal sectoral/spatial planning procedure;
- around 6,020 km were in or about to start the planning approval or notification procedure;
- 1,016 km had been approved/were under construction; and
- 2,134 km had been completed.

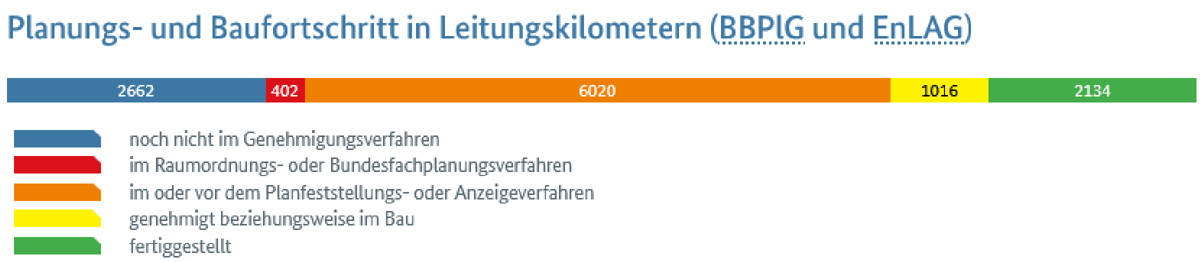

Figure 37: Progress in planning and construction (BBPlG and EnLAG)

1.1 Monitoring of EnLAG projects

The EnLAG listed 22 expansion projects as at the second quarter of 2022. 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 2022 was some 1,821 km:

- around 8 km were in the spatial planning procedure;
- around 205 km were in or about to start the planning approval procedure;
- 360 km had been approved/were under construction; and
- 1,248 km had been completed.

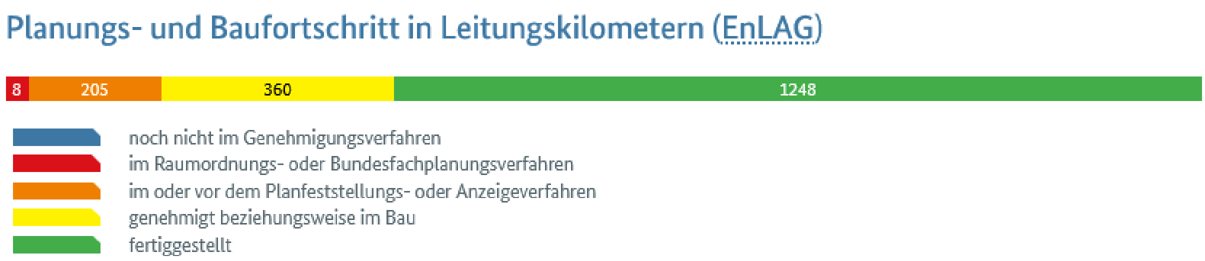

Figure 38: Progress in planning and construction (EnLAG)

The following map shows the status of the EnLAG projects in the second quarter of 2022.

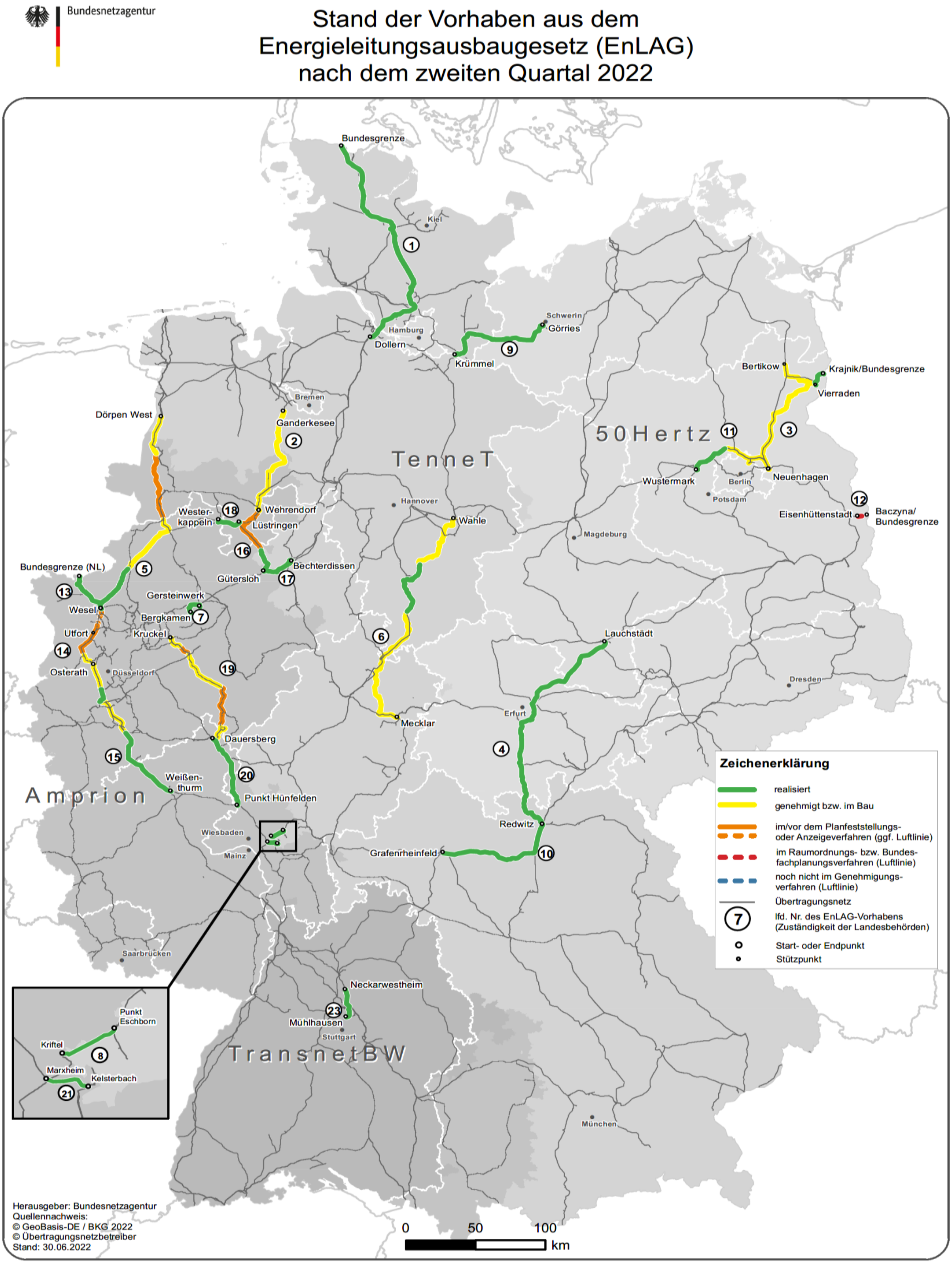

Figure 39: Status of EnLAG projects

1.2 Monitoring of BBPlG projects

The revised BBPlG entered into force on 29 July 2022. The new Federal Requirements Plan (the annex to the BBPlG) includes 19 new projects. Project 37 BBPlG was deleted. The total number of projects in the BBPlG has therefore increased from 79 to 97.

A total of 18 of the 97 expansion projects in the current Federal Requirements Plan are designated as pilot projects for low-loss transmission over long distances (HVDC transmission). A total of 13 DC projects are earmarked for priority underground cabling and ten AC projects for possible partial undergrounding. In addition, one project is a pilot project using high-temperature superconductors. A total of 36 projects and four 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 under the Bundesnetzagentur's responsibility as at the second quarter of 2022 was around 6,425 km. This 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 3,770 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 30 June 2022 was some 10,413 km:

- around 2,662 km were about to start the approval procedure;
- around 394 km were in the federal sectoral/spatial planning procedure;
- around 5,815 km were in or about to start the planning approval or notification procedure;
- 656 km had been approved/were under construction; and
- 886 km had been completed.

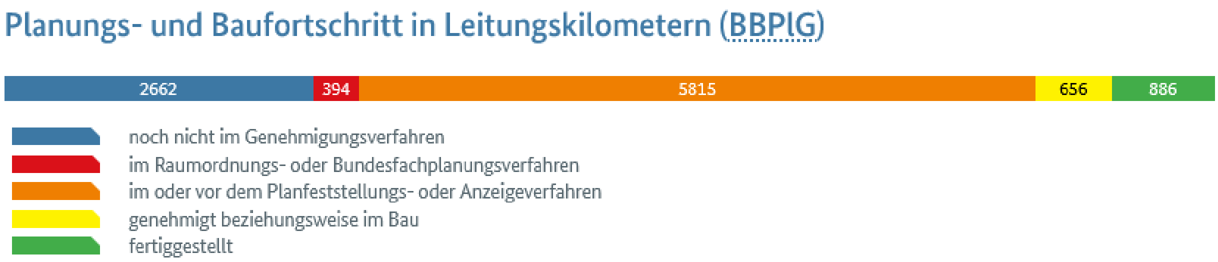

Figure 40: Progress in planning and construction (BBPlG)

The following map shows the status of the BBPlG projects in the second quarter of 2022.

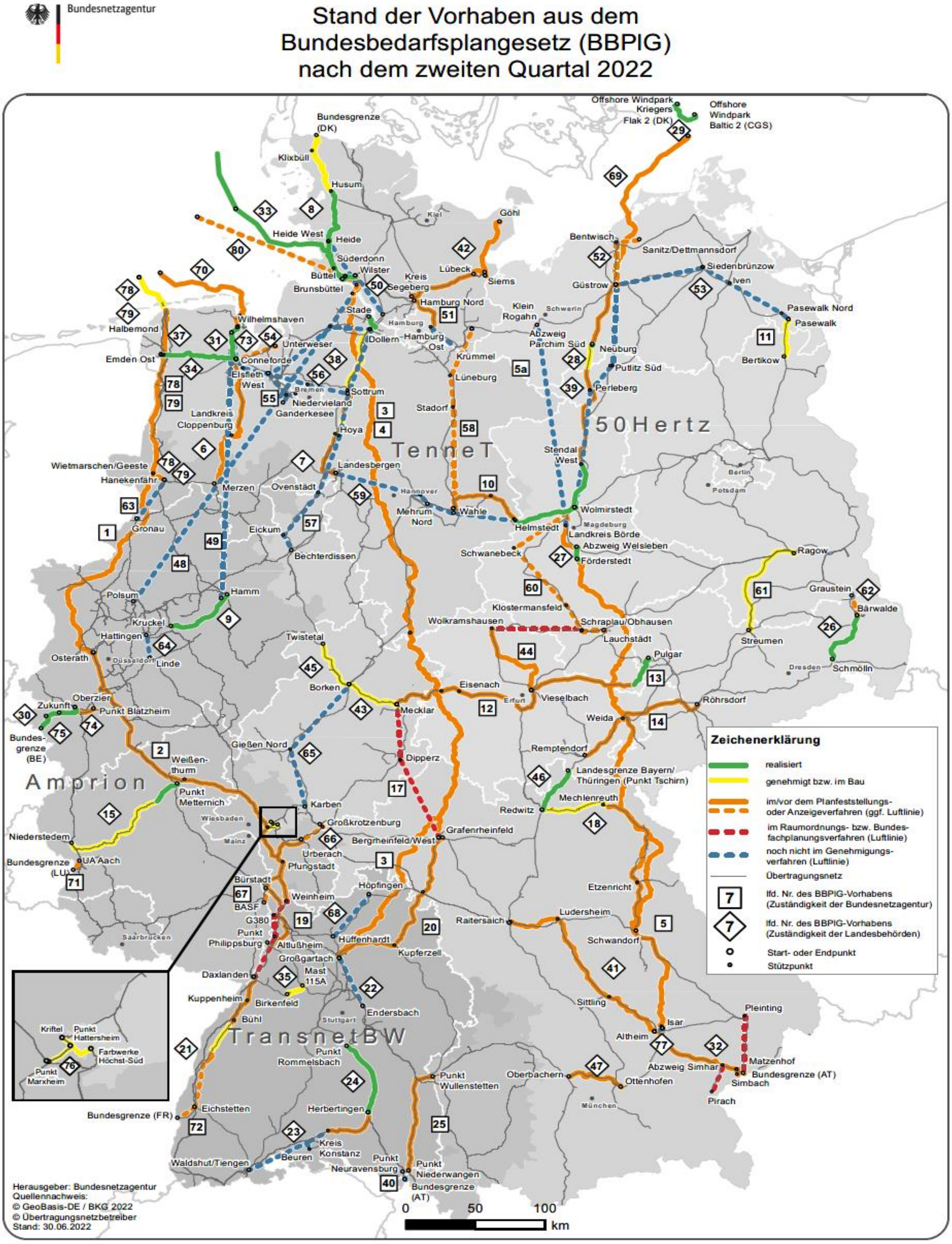

Figure 41: Status of BBPlG projects

1.3 Electricity network development plan status

The Bundesnetzagentur confirmed the Electricity Network Development Plan 2021-2035 (NDP 2021-2035) on 14 January 2022 and published it online at www.netzausbau.de. There is a need for additional measures covering just over 1,000 km of transmission routes compared with the BBPlG of 2021. Around 900 km of these are new-build measures within Germany (of which about 700 km are HVDC systems), while the rest are reinforcements of the existing networks. The NDP also includes optimisation measures such as dynamic line monitoring and innovative technical solutions. As well as the Federal Requirements Plan projects, the Bundesnetzagentur confirmed a total of 28 new measures concerning lines, including two additional HVDC transmission corridors by 2040. One of these corridors will run from Schleswig-Holstein to Mecklenburg-Western Pomerania, while the other will go from Lower Saxony to Hesse. A ten-week public participation process took place before the process of establishing requirements. The Bundesnetzagentur received nearly 300 responses from public agencies and private individuals.

Electricity: kilometre overview

	Second draft	Confirmed	Not confirmed	Federal Requirements Plan (for comparison)
AC new builds	500 km	450 km	50 km	200 km
DC new builds	2,150 km	2,150 km	0 km	1,450 km
DC interconnectors	250 km	250 km	0 km	250 km
AC interconnectors	50 km	50 km	0 km	0 km
AC reinforcements	3,700 km	3,450 km	250 km	2,800 km
				Now in start network 5,250 km
Total	**6,650 km**	**6,350 km**	**300 km**	**9,900 km**

Table 57: Kilometre overview

The use of multi-terminal converters for HVDC transmission was examined for the first time in the NDP 2021–2035. The use of such converters, rather than individual point-to-point structures, can reduce the number of converters needed and thus also save costs. On the basis of the TSOs' proposals to prepare certain HVDC connections to be more closely meshed in the future using the multi-terminals, the Bundesnetzagentur has worked out an overall solution that it judges to be logical and confirmed the relevant projects. This will make the future grid expansion more efficient and create opportunity for innovation in network technology and operations.

Offshore

The NDP 2021-2035 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. The NDP takes full account of the expansion of offshore wind energy – 20 GW by 2030 and up to 40 GW by 2040 – decided on by the federal government. These offshore wind farms will require eleven transmission links in the North Sea and Baltic Sea by 2040, in addition to those already planned. The links will ensure that the wind farms can be integrated into the German transmission system and the electricity they generate can be transported onwards.

Reactive power

The NDP 2021-2035 includes a new budget for the implementation of reactive power compensation for each TSO, which was confirmed as part of the process of identifying reactive power requirements; the budget replaces and does not supplement the budget in the NDP 2019-2030. In addition, in line with a "no regrets" test, efficient reactive power management and increasingly decentralised approaches, it is assumed that the DSOs' requirements are met by the DSOs themselves using the equipment and operating resources connected to their networks and not centrally by the TSOs. This reduces the compensation requirements for the transmission networks and increases the requirements for the distribution networks. Although the examination of the compensation requirements was less restrictive, the requirements confirmed are lower than those put forward; one reason for this is that the requirements for the distribution networks were not taken into account.

Inertia

The NDP 2021-2035 is the first NDP to include the TSOs' inertia requirements. The TSOs' reasons for their requirements are based on the restriction of the frequency gradients in the case of a system split. The overall solution encompasses TSOs' assets and new requirements for renewables, gas power plants and storage facilities (revision of the technical connection rules and network code on requirements for grid connection of generators). The basic problem and methodology are clear, but there are still many questions to clarify regarding the details. The confirmation of the requirements makes it possible to take first steps such as equipment planning and development with manufacturers, while the smaller volume confirmed is in line with a "no regrets" approach.

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 to increase the utilisation of the transmission system. The first example is flow management, which involves using special network operating resources to actively control flows in order to specifically relieve overloaded network elements without increasing the overall transmission capacity of the network. The second example is the grid booster pilot facilities confirmed in the NDP 2021-2035. The innovative scheme is designed to increase the level of utilisation of the transmission network. Reactive network operations management can help to keep costs of redispatching measures down. The long-term aim is to site the loads and energy sources at places in the transmission network where they can relieve large parts of the network and therefore make it possible for the network to be operated closer to the limits of its capacity (permanent admissible load). The third example is dynamic line monitoring. This involves measuring the weather conditions at a line and dynamically adjusting the maximum allowable operating temperature of the line. The last example is the use of high-temperature superconductors to increase network capacity.

Optimisation measures

The planned and current load flow management measures include the use of phase shifting transformers and series compensators. The planned network optimisation measures also include grid boosters.

The greater the flow of active power on a line, the greater the phase angle difference. The AC voltage reaches its maximum at one end of a line a couple of milliseconds later than at the other end. If it were exactly in phase, the differential voltage between the two ends would be zero. There would be no voltage drop over the line and therefore no current or power would flow along the line. It is possible to influence this phase angle and therefore the utilisation of the line. This is exactly what a phase shifting transformer can do. A phase shifting transformer has an excitation winding in addition to low-voltage and high-voltage windings (copper coils within the transformer). This third winding can be used to influence the difference between the phase angles at the beginning and end of a line to a certain extent. If the difference between these phase angles is decreased, less power can flow through the transformer. If the difference is increased, more power can flow.

Phase shifting transformers are currently used in particular on cross-border lines to prevent unwanted loop flows through neighbouring countries.

Series compensators are also stationary secondary equipment. They are located at certain points of a line to minimise reactive power flows on the circuits. They reduce the voltage drop at the end of a line by balancing out the voltage along the line. This can increase the transmission capacity of long extra-high voltage lines with a high level of utilisation by reducing the lines' reactance.

The measures confirmed in the NDP 2021-2035 include grid booster pilot facilities. The innovative scheme is designed to increase the level of utilisation of the transmission network. Reactive network operations management can help to keep costs of redispatching measures down. In contrast to the traditional preventive interpretation of the n-1 criterion, which does not allow the transmission network to be overloaded after the occurrence of a contingency, reactive operational management approaches such as the grid booster scheme allow the network to be overloaded for a brief period if a fault occurs. The n-1 security criterion is met reactively using equipment that can be activated quickly, enabling a higher level of utilisation during normal operation (n-0). The aim is to resolve the overloading using controllable loads in front of the congestion and energy sources (such as batteries) behind the congestion. The long-term aim is to site the loads and energy sources at places in the transmission network where they can relieve large parts of the network and therefore make it possible for the network to be operated closer to the limits of its capacity (permanent admissible load).

Dynamic line monitoring

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 (ampacity) of a conductor to be increased in certain situations, for instance when the ambient temperature is very low.

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 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).

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. These include power station lines, interconnectors, industrial/customer-owned lines, overhead lines with partial undergrounding, underground cabling sections, transformer lines, and circuits with regional and therefore limited transport tasks that are not earmarked for dynamic line monitoring. Dynamic line monitoring is not intended for circuits with high-temperature superconductors or high-current cabling, either. The operators regularly review when and where dynamic line monitoring makes sense, taking into account network planning processes and operational experience. If a review indicates that the use of dynamic line monitoring is necessary on additional circuits, an order of priority is established for the introduction of dynamic line monitoring based on the whole portfolio.

The operation of overhead line circuits using dynamic line monitoring also needs to take account of adjacent or intersecting pipes. More specifically, the impact of the use of dynamic line monitoring on these pipes needs to be analysed. If the impact is too great, remedial measures need to be taken, requiring close cooperation with the partners concerned.

The degree to which dynamic line monitoring can be implemented also depends on the availability of service providers and approval procedures. The charts below show the current and planned implementation of dynamic line monitoring by the TSOs. The charts do not take into account the latest amendment to section 43f EnWG and the consequent large reduction in the use of dynamic line monitoring.

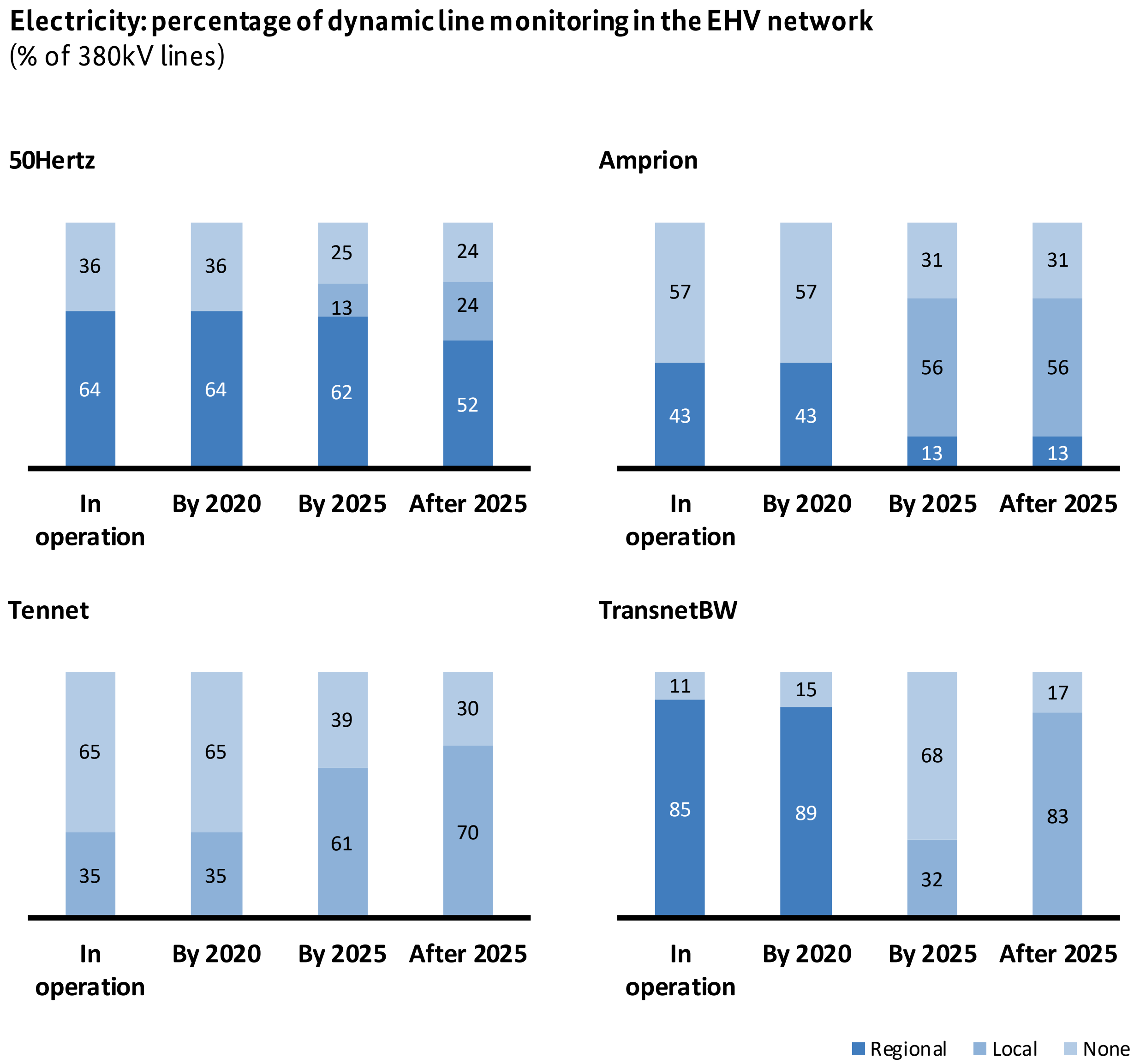

Figure 42: Percentage of dynamic line monitoring in the EHV network (380 kV)

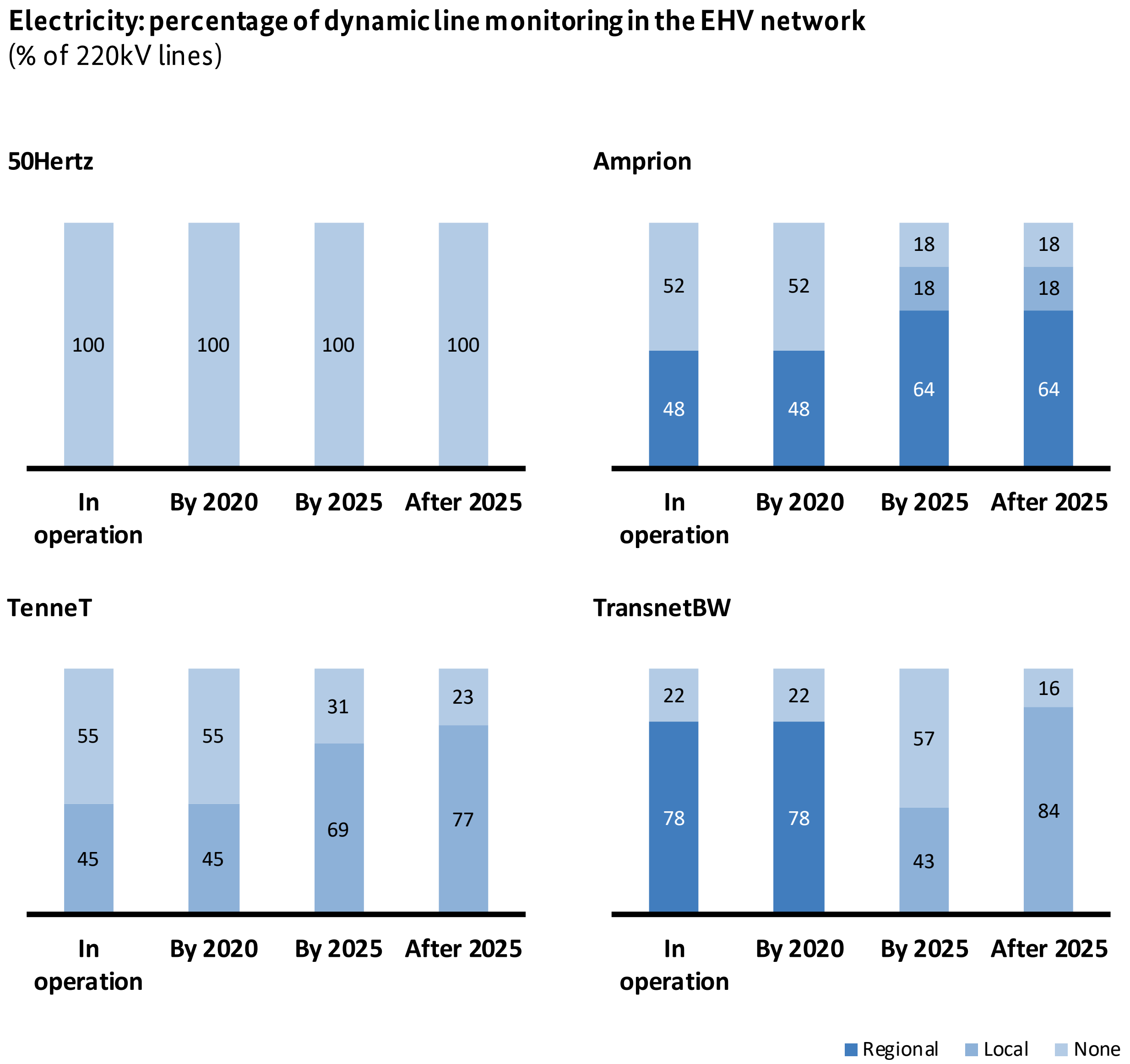

Figure 43: Percentage of dynamic line monitoring in the EHV network (220 kV)

High-temperature superconductors

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.

There are various types of high-temperature superconductors. The conventional thermal-resistant aluminium conductors already in use today have a maximum operating temperature of 150°C. The more electricity a line carries, the higher the temperature and so the bigger the sag. It is therefore not always possible to simply replace existing cables with thermal-resistant aluminium conductors. Additional pylons may also be necessary.

High-temperature low-sag conductors can operate at temperatures up to 210°C. These conductors have a smaller sag than other conductors because of their special core material. Additional pylons may therefore not be necessary.

Another option is the use of high-current cables. These cables have a larger conductor cross-section and therefore a higher permanent ampacity (3,600 A to 4,000 A). The advantages of high-current cables compared to high-temperature superconductors are lower network losses and lower noise levels. High-current cables are generally the first choice when new lines are constructed for technical and economic reasons, as the investment costs are lower. It is not always possible to simply replace or supplement existing cables with high-current cables without new pylons because of the structural design of the existing pylons. However, if installing high-temperature superconductors would make it necessary to replace pylons because of the individual circumstances, it may make sense to install high-current cabling instead of replacing existing cables with high-temperature superconductors.

This report does not cover the use of high-current cabling.

2. Distribution system expansion

2.1 Optimisation, 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 for this was created in 2021 with section 14d of the revised EnWG.

A total of 812 DSOs (841 in the previous year) provided information about the measures they had taken to optimise their networks. A total of 624 companies reported network optimisation measures. The chart below shows the measures implemented by the DSOs to optimise and reinforce their networks.

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

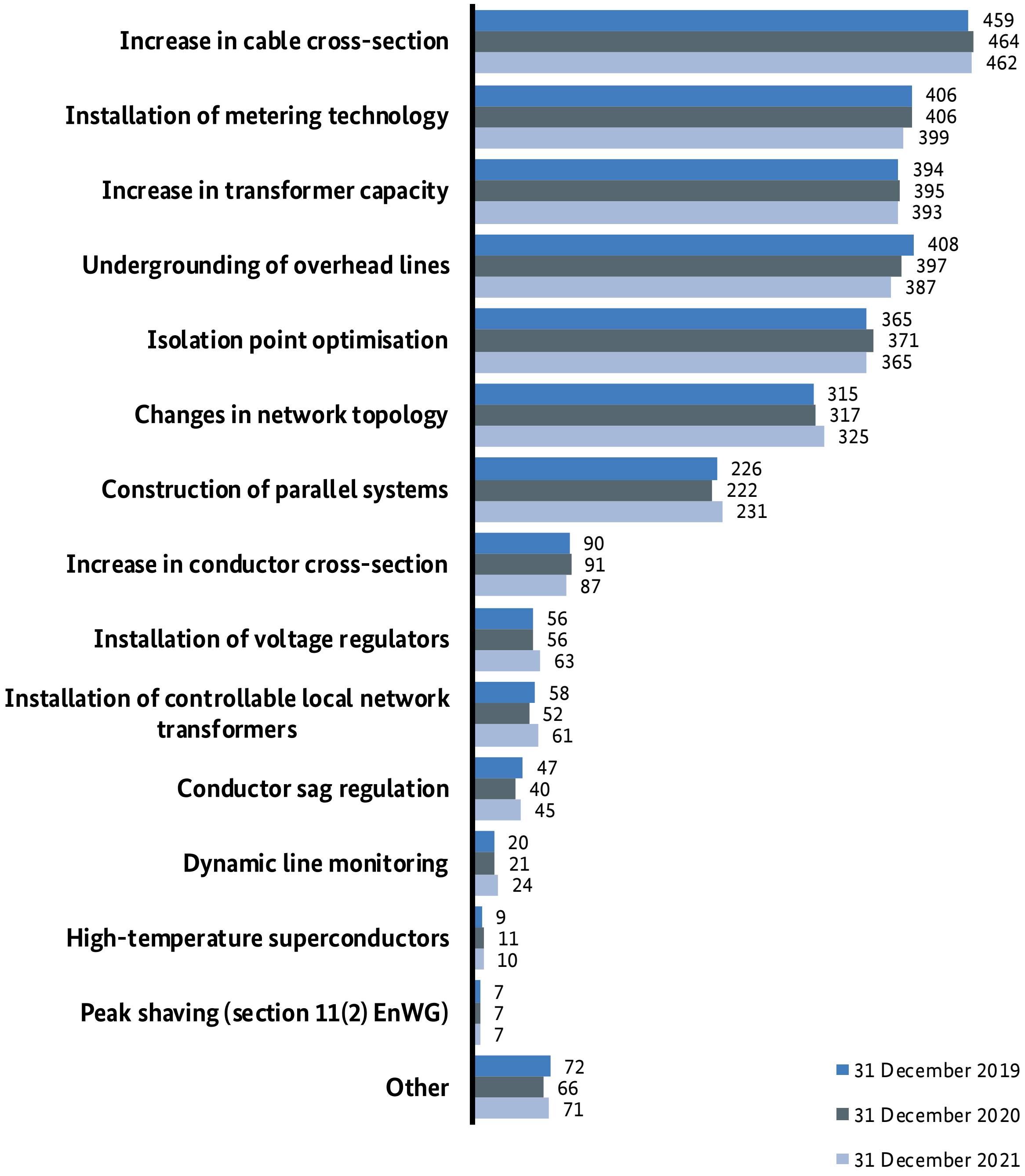

Figure 44: Overview of optimisation and reinforcement measures

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 in order to be able to assess the DSOs' future grid expansion requirements. In 2022, the information was collected pursuant to section 14(2) in conjunction with section 14d EnWG (old version).[37] As a result of the revision of the EnWG in July 2021, the number of DSOs from whom information was requested increased from 58 to 82.

The information reported by the DSOs on the status of their networks and their expansion plans was current as at 31 December 2021. The information on expansion plans provided by the DSOs in 2022 covers the whole of Germany's HV level about 79.60% of the total circuit length at MV level.

The lower the voltage level (from HV down to LV), the shorter the timescales in network expansion planning. This means that the DSOs do not usually make long-term expansion plans for the lower network levels. Any necessary expansion measures at these levels are implemented within a short-term timescale. Since the 2021 survey, the DSOs have therefore been able 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 approach enables a better assessment of the expected investment requirements for the lower network levels in the next ten years.

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. Any measures reported as such by the DSOs have been excluded from the figures.

[37] In the version valid from July 2021 to July 2022

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

	Total expected expansion up to 2032	Expansion based on measures plan	Expansion based on generalised 10-year plans for lower network levels
HV	10.66 Mrd. Euro	10.66 Mrd. Euro	--
HV/MV	3.10 Mrd. Euro	3.10 Mrd. Euro	--
MV	13.01 Mrd. Euro	2.02 Mrd. Euro	10.99 Mrd. Euro
MV/LV	5.43 Mrd. Euro	0.07 Mrd. Euro	5.36 Mrd. Euro
LV	9.93 Mrd. Euro	0.44 Mrd. Euro	9.49 Mrd. Euro
Other	0.14 Mrd. Euro	0.14 Mrd. Euro	--
Total	**42.27 Mrd. Euro**	**16.42 Mrd. Euro**	**25.84 Mrd. Euro**

Table 58: Electricity: expansion at distribution level designed to increase transmission capacity (€bn)[38]

The 82 DSOs reported 3,337 individual measures. Around 32% of the 3,337 individual measures reported are under construction, 25% are at the planning stage, and 43% are "envisaged". The reinforcement, optimisation, new build and replacement[39] measures cover a total length of 92,872 kilometres.[40]

The increase in the number of DSOs from whom information was requested (as a result of the revision of the EnWG in July 2021) means that it is not possible to make a direct comparison with the total expansion investment figure of €27.61bn published in last year's report. A total of 24 additional DSOs were included in the survey and one DSO that previously took part was no longer included.[41] The total planned investment volume of the DSOs that participated in last year's survey increased by €12.38bn. The number of individual measures of these 58 DSOs increased by 827. In addition, the expected costs for a large number of "old measures" were adjusted in the course of the more detailed project planning, for instance because of expected price increases or changes in the project scope.[42]

[38] The "Other" network level category comprises projects relating to the whole network and projects not primarily attributable to one specific network level.

[39] Only replacement measures designed to increase transmission capacity

[40] Overhead lines and underground cables

[41] DB Energie GmbH is no longer included in the survey.

[42] "Old measures" refer to measures reported in the survey in 2021 or earlier.

It is possible to compare the expected HV expansion investment volume for 58 DSOs that participated in the surveys from 2019 (reporting for 2018) to 2022 (reporting for 2021). The total expected volume for these DSOs increased considerably by €3.62bn compared with the previous year.

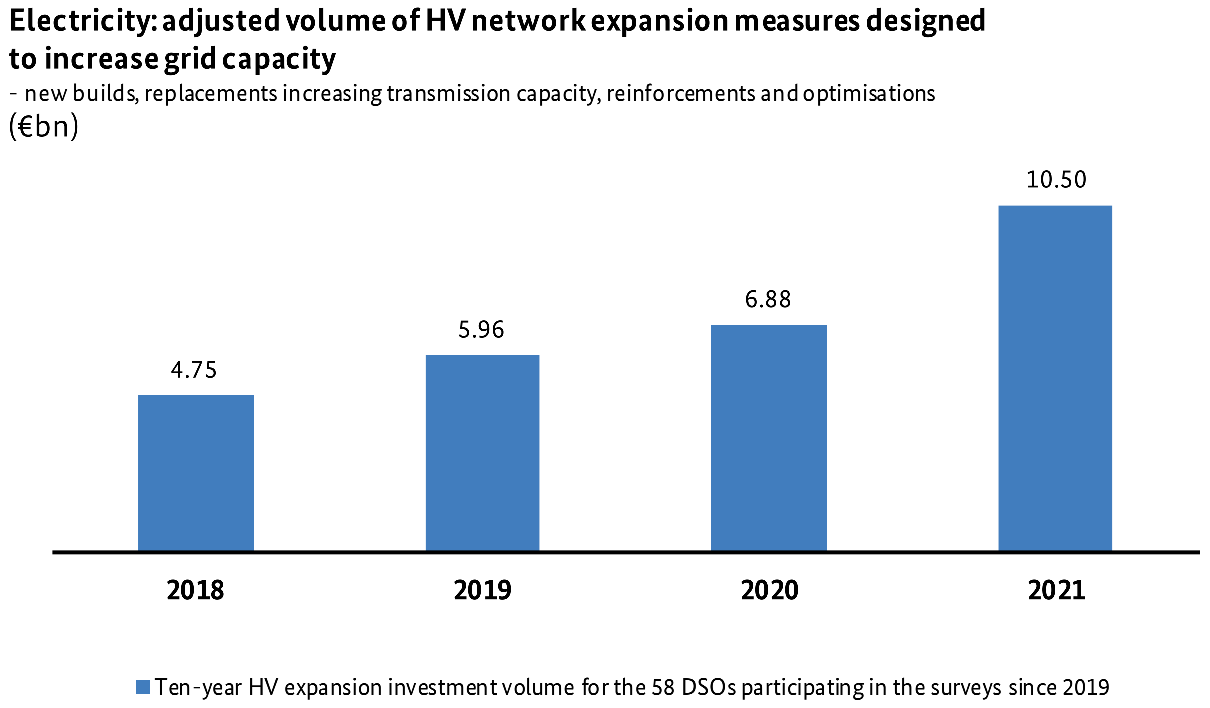

Figure 45: Electricity: adjusted volume of HV network expansion measures designed to increase grid capacity (€bn)

The 82 DSOs surveyed reported a total of 1,214 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 €100mn. A total of 11 of the 19 DSOs listed have an expected investment volume for the next ten years exceeding €250mn.

Electricity: volume of HV network expansion measures designed to increase transmission capacity
- new builds, replacements increasing transmission capacity, reinforcements and optimisations
(€mn)

HV network operator	Expected HV expansion investment (€mn)
Avacon Netz GmbH	1,955.6
E.DIS Netz GmbH	1,833.6
Bayernwerk Netz GmbH	831.0
Westnetz GmbH	810.4
Schleswig-Holstein Netz AG	573.8
Stromnetz Berlin GmbH	526.3
Stromnetz Hamburg GmbH	418.1
NRM Netzdienste Rhein-Main GmbH	354.9
WEMAG Netz GmbH	352.7
Netze BW GmbH	348.9
Rheinische NETZGesellschaft mbH	326.5
N-ERGIE Netz GmbH	225.3
Mitteldeutsche Netzgesellschaft Strom mbH	212.7
Syna GmbH	201.4
LEW Verteilnetz GmbH	200.0
SachsenNetze HS.HD GmbH	197.4
TEN Thüringer Energienetze GmbH & Co. KG	167.5
SWM Infrastruktur GmbH & Co. KG	162.2
Energienetze Offenbach GmbH	103.4

Table 59: Electricity: volume of HV network expansion measures designed to increase transmission capacity (€mn)

3. Investments

For the purposes of the monitoring survey, investments are defined as the gross additions to fixed assets capitalised in 2021 and the value of new fixed assets newly rented and hired in 2021. Expenditure arises from the combination of all technical or administrative measures taken during the life cycle of an asset to maintain or restore working order so that the asset can perform the function required.

The following figures are the values under commercial law derived from the TSOs' and DSOs' balance sheets. The values under commercial law do not correspond to the implicit values included in the operators' revenue caps in accordance with the provisions of the Incentive Regulation Ordinance (ARegV).

3.1 TSOs' investments and expenditure

In 2021, investments in and expenditure on network infrastructure by the four German TSOs amounted to approximately €5,161mn, up about 22% on the previous year (2020: €4,244mn). The difference between actual investments and expenditure in 2021 and the figure of €5,309mn forecast for 2021 in the 2020 monitoring survey is about €148mn. The TSOs thus realised 97% of their planned investments and expenditure. The individual categories for network infrastructure investments and expenditure are shown in the table below:

Electricity: TSOs' network infrastructure investments and expenditure

	2020	2021
Investments (€mn)	**3,862**	**4,677**
New build, upgrade and expansion projects other than for cross-border connections	2,930	3,761
New build, upgrade and expansion projects for cross-border connections	506	327
Maintenance and renewal excluding cross-border connections	424	555
Maintenance and renewal of cross-border connections	3	34
Expenditure (€mn)	**382**	**484**
Expenditure excluding cross-border connections	376	476
Expenditure on cross-border connections	6	8
Total	**4,244**	**5,161**

Table 60: TSOs' network infrastructure investments and expenditure

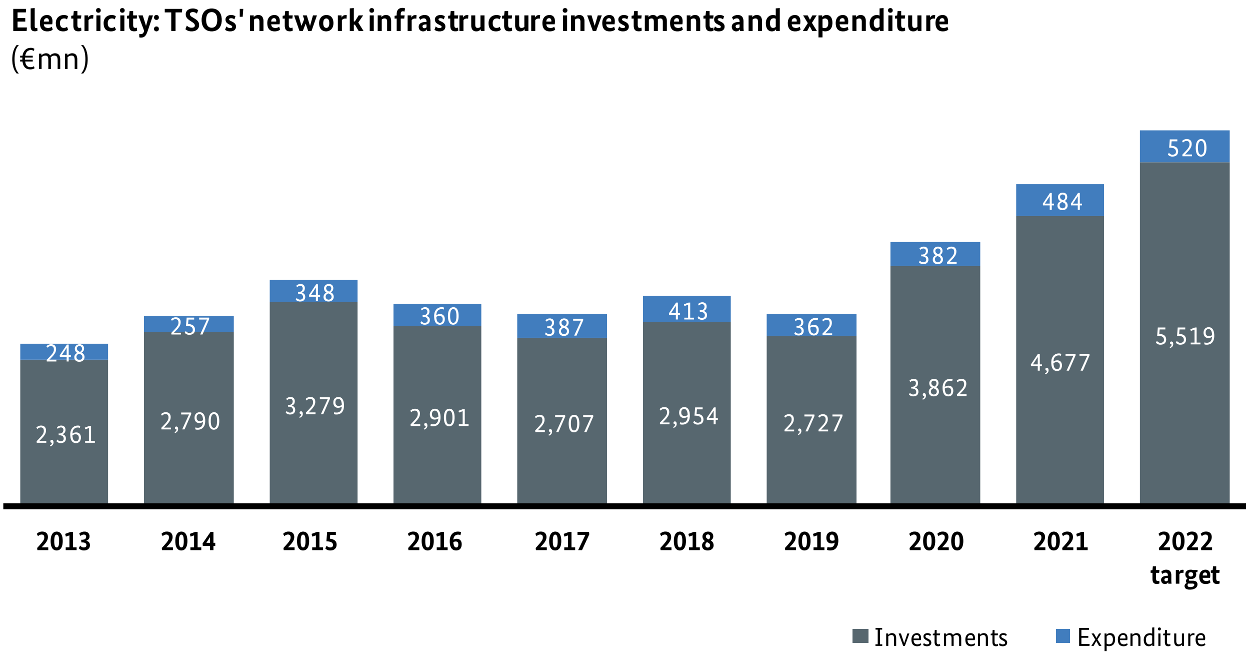

Figure 46: TSOs' network infrastructure investments and expenditure (including cross-border connections)

Total investments of around €5,519mn and total expenditure of €520mn are currently planned for 2022. The planned total for investments and expenditure of about €6,039mn 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 DSOs' investments and expenditure

In 2021, investments in and expenditure on network infrastructure by the 808 DSOs that provided data in the monitoring survey amounted to around €8,395mn, up about 4% on the previous year (2020: €8,088mn). Investments and expenditure for metering systems amounted to around €734mn in 2021 (2020: €371mn). Detailed information on investments in metering systems can be found in H.7. The planned total for investments and expenditure in 2022 is €9,291mn.

The chart below shows the figures for investments, expenditure and combined investments and expenditure since 2013 and the planned figures for 2022. The two noticeable peaks of investment in 2016 and 2021 are likely to be related to the incentive regulation. Both years were used as base years that were decisive for the revenue that the DSOs were allowed to attain in the subsequent years. There was therefore an incentive to bring investments forward or postpone them for the base years. One possible reason for the high planned figures for investments for the year following the base year 2021 is that the revenue cap with the base year 2021 is adjusted during a period using the capex mark-up. The network operators therefore no longer need to shift all investments to a base year.

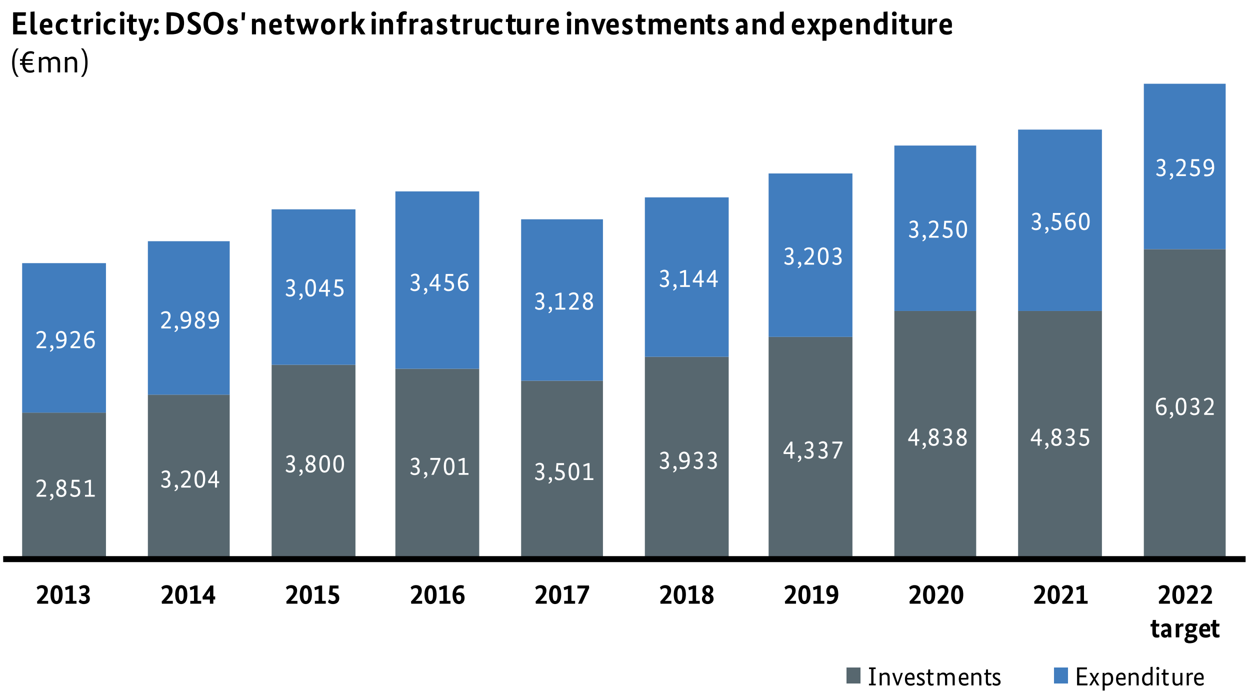

Figure 47: DSOs' network infrastructure investments and expenditure

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 91 of the DSOs are in the top category with investments exceeding €10mn per network area. These 11% of the DSOs, however, make 86% of the investments. The chart below shows investment categories by the total number of DSOs and the investment and expenditure amounts.

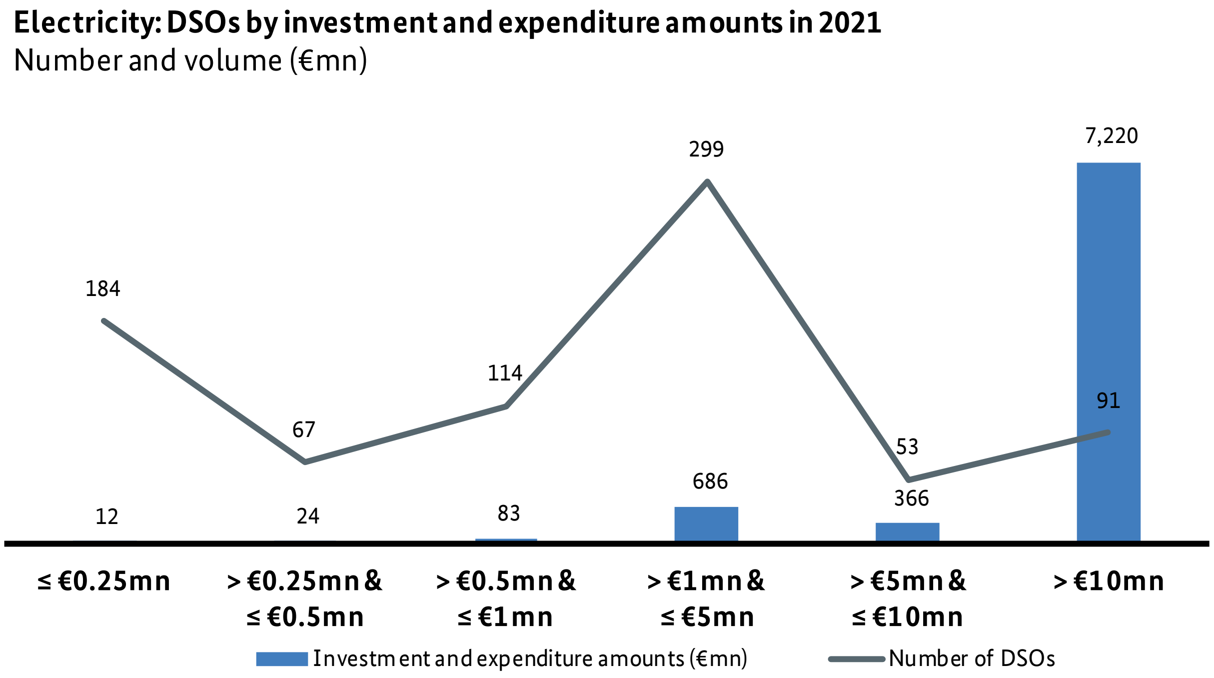

Figure 48: DSOs by investment and expenditure amounts

3.3 Investments and incentive regulation

The ARegV gives network operators the opportunity to budget for expansion and restructuring investment costs in the network tariffs over and above the level approved in the revenue caps. Based on section 23 ARegV (investment measures), upon application from the TSOs the Bundesnetzagentur grants approval for individual projects if the prerequisites stated in the ARegV have been met. In accordance with section 35(4) sentence 1 ARegV (transitional provision), the last date for applications from TSOs was 31 March 2022.

By way of exception, section 35(4) sentence 2 para 1 ARegV allows applications for an extension of the approval period for investment measures valid until the end of the third regulatory period (31 December 2023) to be made by 30 June 2023 for an extension at the most until the end of the fourth regulatory period (31 December 2028). In addition, section 35(4) sentence 2 para 2 allows applications to be made for an amendment of an approval while the approval is valid and at the most until the end of the fourth regulatory period (31 December 2028).

Once approval has been given, TSOs may adjust their revenue caps by the operating and capital expenditure associated with their project immediately in the year in which the costs are incurred. The costs budgeted are checked by the Bundesnetzagentur in an ex-post control.

3.3.1 Expansion investments by TSOs

As of 31 March 2022, 79 applications for approval of an investment measure had been submitted by the TSOs to the competent ruling chamber. Costs of acquisition and production of about €19.5bn are linked to these investment measures. Compared to 2021, the number of applications submitted by the TSOs more than doubled. This is mainly due to the fact that last year the TSOs did not submit applications for projects requiring prior confirmation in the electricity NDP. The applications for the NDP projects were submitted following confirmation of the NDP this year. There was also a significant increase in the costs compared to 2021, although most of the costs are accounted for by two HVDC transmission system projects confirmed for the first time in the NDP.

3.3.2 Capex mark-up and monitoring of the adjustment of capital expenditure

The Bundesnetzagentur introduced the capex mark-up for electricity distribution networks 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 capitalisation.

These adjusted revenue caps cover all network costs plus a return on equity, which companies may pass on to consumers through the network tariffs. The capex mark-up already includes a pre-financing element as the companies can factor in planned investments. By 30 June 2022, 164 applications for capex mark-up approvals for 2023 had been received (99 under the Bundesnetzagentur's own responsibility and 65 for the regulatory authorities of the federal states of Schleswig-Holstein and Brandenburg).

By 30 June 2022, the Bundesnetzagentur had approved capex mark-ups for distribution network expansion amounting to around €5.0bn for the years 2019 to 2022. This corresponds to past or planned investments totalling some €20.4bn. 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.

Approval of the incentive regulation account balance for 2020 includes reconciling the forecasted and actual 2020 capex mark-up. This makes it clear whether or not the network operators have followed through completely with their planned investments. The Bundesnetzagentur approved capex mark-ups totalling around €1.09mn for 2020. The cost examination of actual expenditure showed an actual capex mark-up of around €1.14mn.

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 chart below shows the regulatory rates of return on equity allowed under the ARegV or through actual determinations.

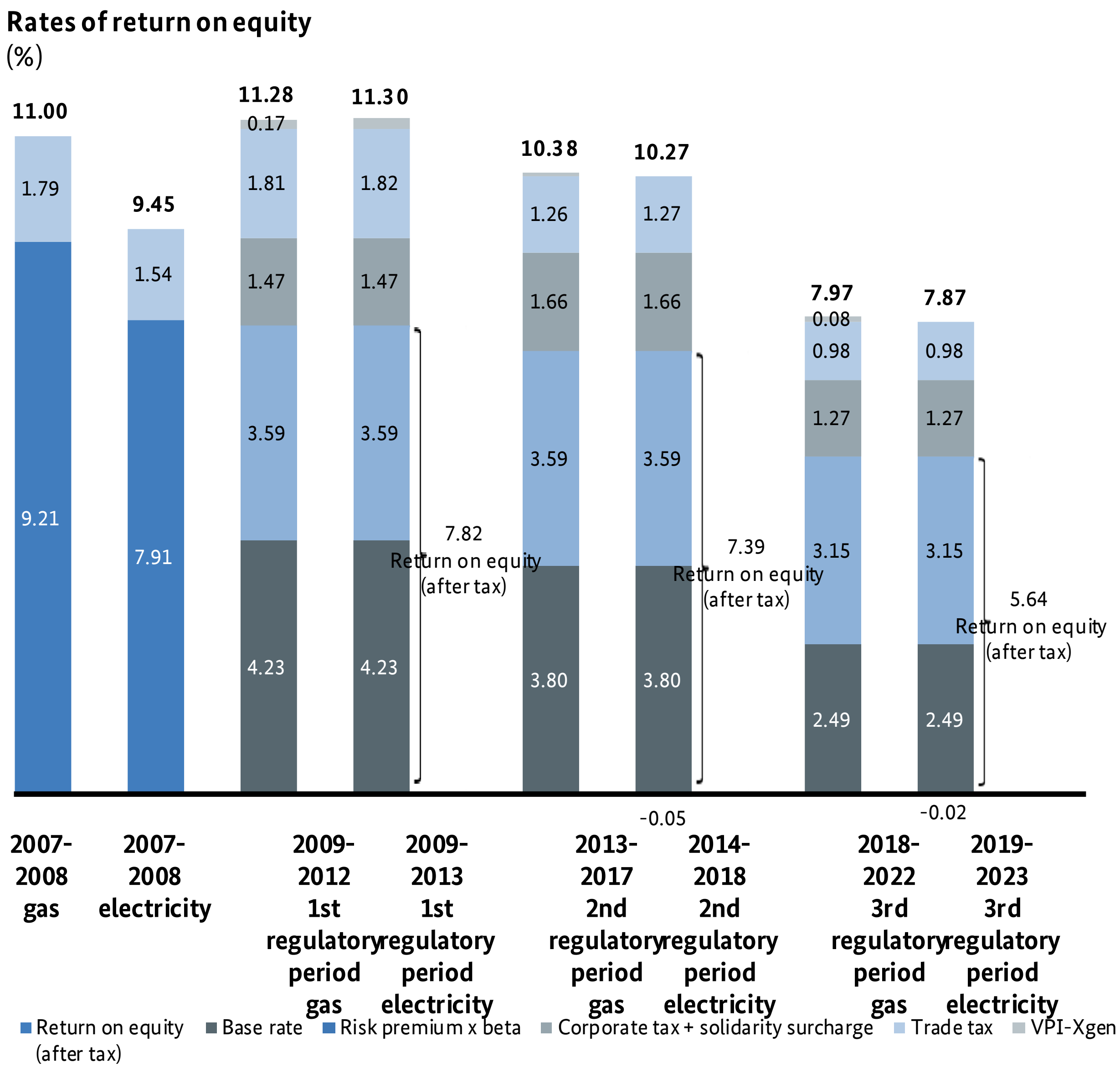

Figure 49: Rates of return on equity

The chart below compares these changes in the return on equity with a presumed annual result that would have been achieved if the input parameters had been calculated (ex post) for each individual year. The figures show the rate of return on equity (comprising the base rate and the risk premium) and the regulatory allowed corporate tax, trade tax and indexation (VPI-Xgen).

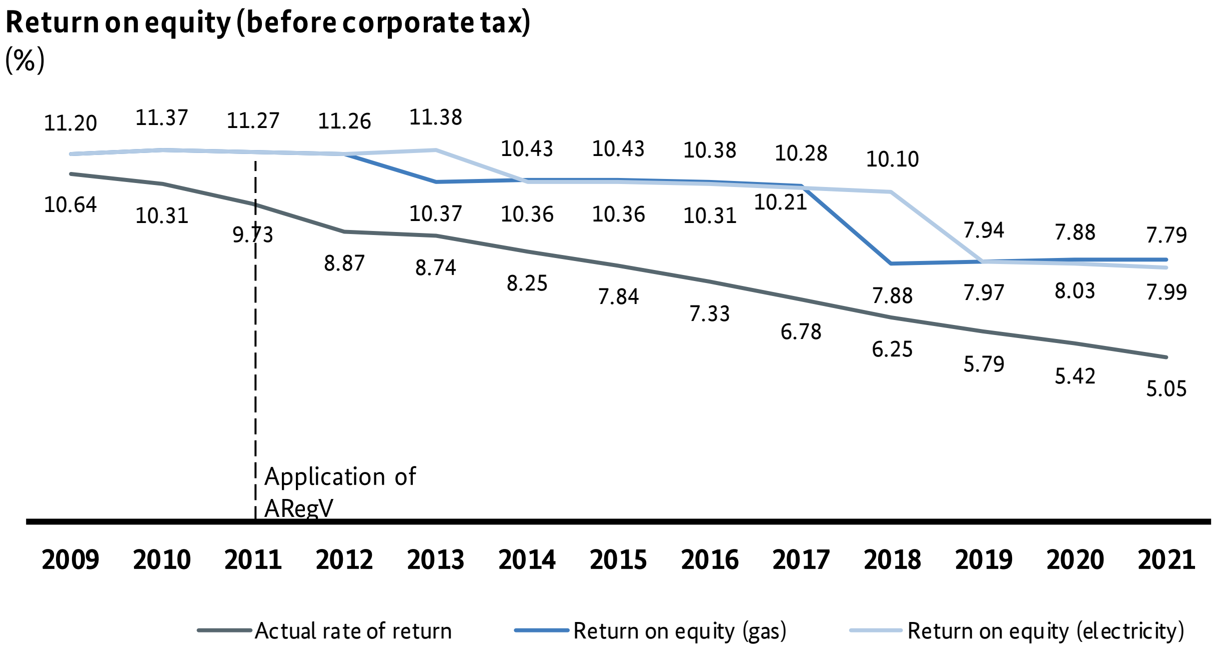

Figure 50: Return on equity (before corporate tax)

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) StromNEV/GasNEV and referred to as the "equity II interest rate". The chart below shows the equity II interest rates actually applied during cost examination, the annual results under StromNEV/GasNEV (10-year average) and the development of the rates by year.

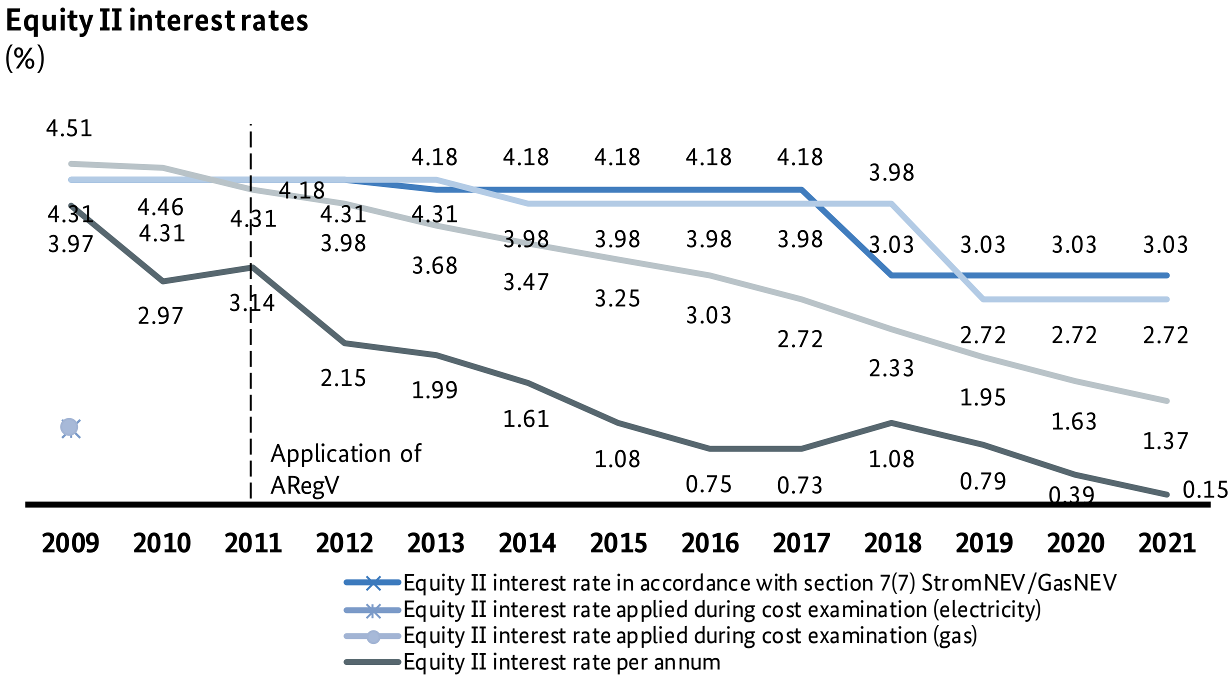

Figure 51: Equity II interest rates

3.4.3 Rate of interest 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. The interest rate on borrowings that may generally be taken into account for the electricity and gas networks is shown in the chart below, listed by normal incentive regulatory regime (budget principle) and investment measure regime. 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.

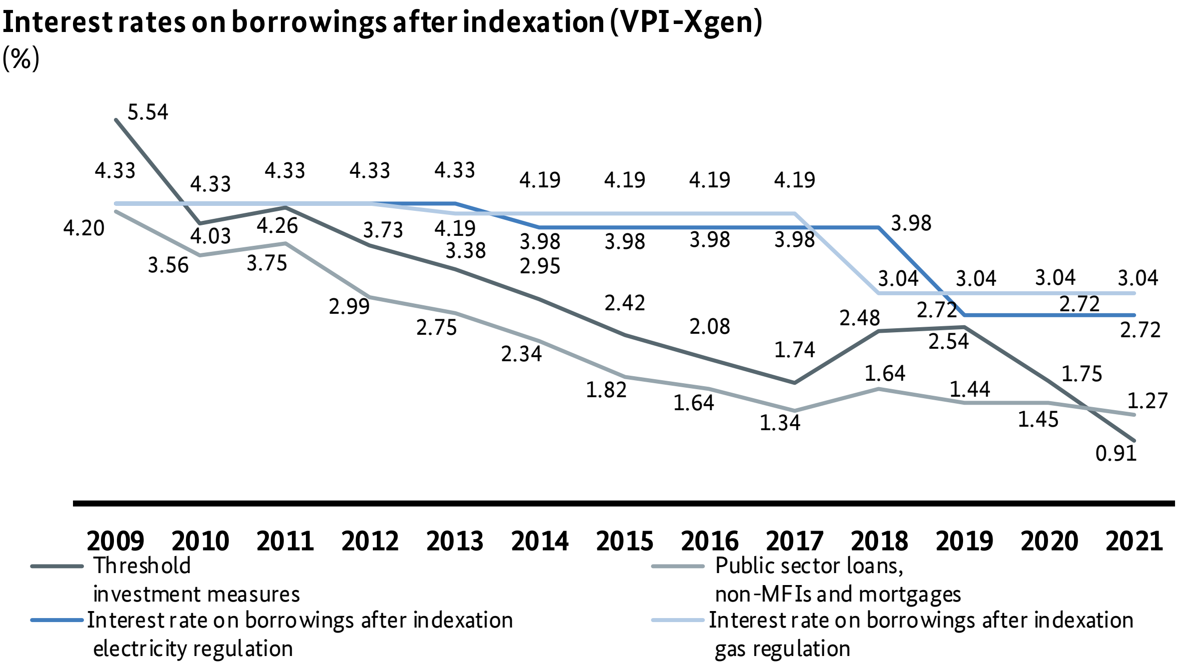

Figure 52: Interest rates on borrowings after indexation (VPI-Xgen)

4. Electricity supply disruptions

The System Average Interruption Duration Index ($\text{SAIDI}_{\text{EnWG}}$) is the average length of supply interruption experienced per connected final customer in a year at the low-voltage and medium-voltage levels, and is calculated from the reports of network operators about the interruptions that occurred in their network areas. The $\text{SAIDI}_{\text{EnWG}}$ for 2021 is 12.7 minutes.

Operators of energy supply networks are required under section 52 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. Furthermore, the network operator must provide information on the measures to be taken to avoid supply interruptions in the future.

The System Average Interruption Duration Index value ($\text{SAIDI}_{\text{EnWG}}$[43]) does not take into account planned interruptions or those that occur owing to force majeure, such as the disastrous flooding in the Ahr valley.

[43] The System Average Interruption Duration Index $\text{SAIDI}_{\text{EnWG}}$ differs from the $\text{SAIDI}_{\text{ARegV}}$ index calculated for each individual company for the quality management pursuant to the ARegV.

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 2021, 850 operators reported 166,733 interruptions in supply for 857 networks for the calculation of the $SAIDI_{EnWG}$. This is an increase of 4,509 compared with 2020.

The figure of 12.7 minutes per connected final customer for the low-voltage and medium-voltage levels is below the average from 2011 to 2020 (13.63 minutes per year). The security of supply thus remained at a high level in 2021.

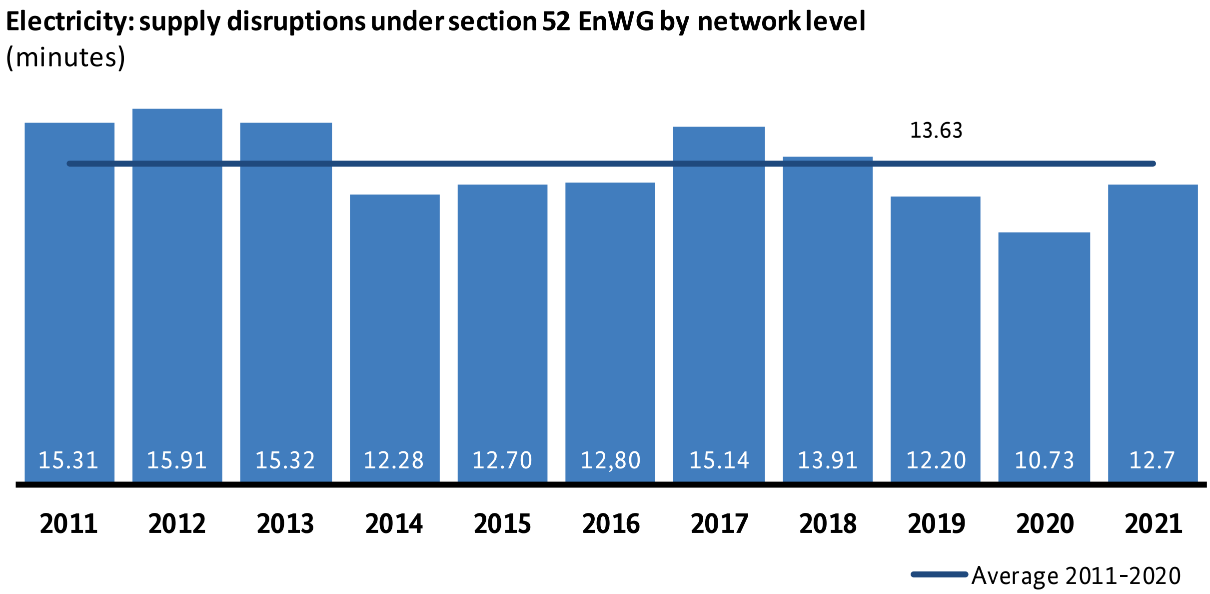

Figure 53: $SAIDI_{EnWG}$ from 2011 to 2021

The increase in the average interruption duration is mainly due to an increase in interruptions at the medium-voltage level of 1.7 minutes to 10.3 minutes. There was also an increase of 0.3 minutes to 2.4 minutes at the low-voltage level. There was an increase in 2021 in the effects of the causes of interruptions used to calculate the $SAIDI_{EnWG}$ at both the low-voltage and the medium-voltage levels. For example, there was a large increase in "atmospheric effects" at the low-voltage level compared with the previous year. These effects include thunder, storms, ice, hail and snow.

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 2021.

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 but was not initially fully implemented. Balancing can lead to costs and revenues (for example due to imbalance payments) for the balance responsible party.

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. The revised Grid Expansion Acceleration Act (NABEG 2.0) changed the rules for redispatching and feed-in management with effect from 1 October 2021. However, the switch to "Redispatch 2.0" was delayed because of operational difficulties and so balancing for redispatching with renewable energy (feed-in management) was only initially implemented in exceptional cases. This report is therefore based on the previous survey method. In cases where network operators had already implemented balancing in the fourth quarter of 2021, the costs are included in the costs for positive redispatching.

5.1 Overall development in 2021

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 19% higher in 2021 than the year before. The costs for congestion management (feed-in management, redispatching including countertrading, and grid reserve use) are provisionally put at around €2.3bn and are thus also higher (2020: €1.4bn). The increase in the volume and costs is mainly due to the unavailability of power stations, repair work at a substation in the fourth quarter of 2021, and the large increase in wholesale prices in the second half of 2021. In the long term, grid expansion will bring down the costs for congestion management measures again.

Electricity: congestion management measures under section 13 EnWG in 2021

	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 with section 3(1) sentence 3 KWKG	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): **21,546 GWh**	Curtailed energy of installations remunerated under EEG (TSOs and DSOs): **5,818 GWh**	Curtailed volume from adjustment measures (TSOs and DSOs): **20.4 GWh**
Estimated costs in reporting period	Preliminary cost estimate for redispatching, countertrading, and use and contracting of grid reserve power plants: **€1,478.6mn**	Preliminary estimated claims for compensation from installation operators under section 15 EEG (TSOs and DSOs): **€807.1mn**	No entitlement to compensation for installation operators for adjustment measures under section 13(2) EnWG

Table 61: Congestion management measures under section 13 EnWG in 2021

Electricity: congestion management measures

		2019	2020	2021
Redispatching				
Total volume[1] of operational plants	GWh	13,323	16,561	20,405
Cost estimate[2] for redispatching	€mn	227	240	590
Cost estimate for countertrading	€mn	64	135	397
Grid reserve power plants				
Volume[3]	GWh	430	635	1,280
Cost estimate for activation	€mn	82	100	249
Capacity[4]	MW	6,598	6,596	5,670
Annual costs of holding in reserve[5]	€mn	197	196	243
Feed-in management				
Volume of curtailed energy[6]	GWh	6,482	6,146	5,818
Estimated compensation	€mn	710	761	807
Feed-in adjustments				
Volume	GWh	9	16	20

[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 62: overview of congestion management measures

5.2 Development of redispatching in 2021

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.

The chart below shows that the majority of the redispatching measures were taken by the TSOs. Out of the around 268 GWh at DSO level, about 41 GWh is accounted for by DSOs' own measures and 227 GWh by support measures requested by a total of 24 DSOs. The following figures, tables and descriptions therefore relate to redispatching by the TSOs, as presented in the Bundesnetzagentur's quarterly reports.

Electricity: redispatching measures by network level in 2021
(GWh)

Figure 54: redispatching measures by network level in 2021

The table below shows a breakdown of the redispatching measures taken in 2021.

Redispatching within the meaning of section 13(1) EnWG in 2021
(GWh)

	2021	2020
Total	21,546	16,795
Breakdown into reductions/increases	21,546	16,795
Reductions	10,742	8,522
Increases	10,804	8,273
Operational power plants	9,787	7,891
Grid reserve power plants (without test runs/test starts)	1,017	382
Breakdown by type of measure	21,546	16,795
Individual overloading measures	11,539	11,561
4-TSO measures	10,007	5,235
Breakdown by reason for measure	21,546	16,795
Voltage-related	1,009	2,926
Electricity-related	20,537	13,869
Breakdown by geography	21,546	16,795
Non-cross-border	4,864	7,837
Cross-border	16,682	8,958
Countertrading	8,550	5,671

Table 63: Redispatching within the meaning of section 13(1) EnWG in 2021

The reductions and increases in feed-in from conventional operational and grid reserve power plants requested as part of the redispatching process amounted in 2021 to about 21,546 GWh (10,742 GWh of reductions and 10,804 GWh of increases). The total volume of requested reductions and increases in feed-in from power plants was therefore higher than in 2020 (16,795 GWh).

This increase is mainly accounted for by the fourth quarter of 2021, when there were problems with transporting coal because of low river levels, which restricted the operational readiness of several power plants in southern Germany. Generation by these plants was consequently replaced by electricity generated in Switzerland and, in some cases, Italy as well as by gas-fired power plants. The unavailability of power plants in the south also led to a general increase in the volume of electricity needed from the north. The increase in the amount of electricity that needed to be transported in turn led to a greater need for redispatching. In addition, heavy rain in July 2021 caused damage to a substation. The necessary repair work and deactivation of power lines in November and December 2021 put a considerable strain on the transmission network in south-west Germany.

The costs for redispatching measures using operational and grid reserve power plants and for countertrading measures are provisionally put at around €1,236.2mn in 2021 and are thus considerably higher than the previous year's level (2020: €474.7mn). This increase is due to the large increase in the volume of the measures as well as to the big increase in wholesale prices. This increase in wholesale prices had an effect on the costs of on-exchange countertrading and the costs for positive redispatching.

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 5,002 GWh was curtailed and 5,006 GWh increased on the basis of advance measures by the four TSOs (10,007 GWh overall). These measures make up 46% 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 IC5.2.2.

5.2.2 Individual overloading measures

The volume of reductions in feed-in through individual overloading measures in the whole of 2021 amounted to around 5,740 GWh. Increases in feed-in for balancing were around 5,797 GWh. The total volume of these redispatching measures was thus approximately 11,539 GWh, which is about the same as in the previous year.

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 the tables below 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, which shows the location of the critical network elements from the tables (at least 48 hours of overload per line).

Electricity: electricity-related redispatching on the most heavily affected network elements in 2021

No	Network element	Control area[1]	Duration (hours)	Volume of feed-in reductions (GWh)	Volume of feed-in increases (GWh)
1	Kontek (DK - Zealand island)	50Hertz	1959	39	39
2	Dollern-Sottrum	TenneT	1219	932	934
3	Landesbergen - Ovenstädt circuit	TenneT	355	387	387
4	Altheim (Altheim-Sittling, Altheim-Simbach-Sankt Peter (AT))	TenneT	334	103	103
5	Dörpen (Dörpen-Niederlangen-Meppen-Hanekenfähr)	TenneT/ Amprion	216	81	81
6	Voslapp transformer	TenneT	171	56	52
7	Mecklar - Dipperz	TenneT	170	58	58
8	Bürstadt-Lambsheim	Amprion	152	43	56
9	Ovenstädt-Bechterdissen (Ovenstädt-Eickum-Bechterdissen)	TenneT	143	76	76
10	Daxlanden area (Daxlanden-Maximiliansau-Goldgrund, Daxlanden-Weingarten)	TransnetBW/ Amprion	130	40	41

Table 64: Electricity-related redispatching on the most heavily affected network elements in 2021

Electricity: electricity-related redispatching on the most heavily affected network elements in 2021

No	Network element	Control area[1]	Duration (hours)	Volume of feed-in reductions (GWh)	Volume of feed-in increases (GWh)
11	Landesbergen (Landesbergen-Wechold-Sottrum)	TenneT	128	152	150
12	Ensdorf-Vigy line	Amprion	126	46	46
13	Borken/Gießen	TenneT	85	25	25
14	Dipperz - Großkrotzenburg	TenneT	84	23	23
15	Bergshausen - Borken circuit	TenneT	77	43	43
16	Sechtem (Sechtem-Paffendorf-Oberzier)	Amprion	68	28	21
17	Vöhringen-Dellmensingen line	Amprion	48	11	11
18	Frixheim south line (Rommerskirchen-St. Peter)	Amprion	48	6	6
19	Borken - Waldeck - Twistetal circuit	TenneT	48	19	19

Table 65: Continuation of the table showing electricity-related redispatching on the most heavily affected network elements in 2021

Electricity: duration of electricity-related redispatching measures in cases of individual overloading of the most heavily affected network elements in 2021

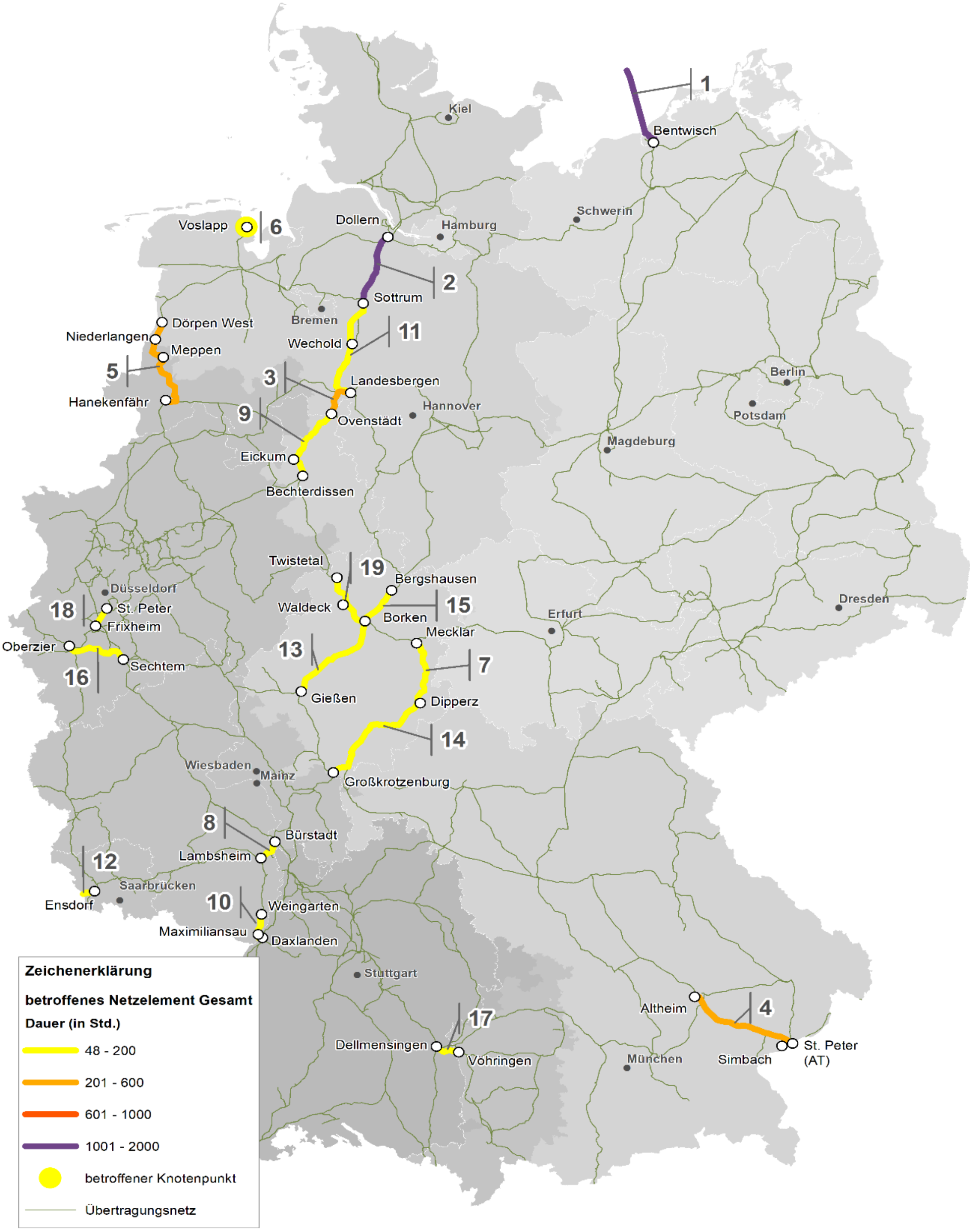

Figure 55: Duration of electricity-related redispatching measures in cases of individual overloading of the most heavily affected network elements in 2021

Voltage-related individual overloading measures

In addition to electricity-related redispatching, the TSOs reported voltage-related redispatching measures with a total volume of around 1,009 GWh in 2021. Voltage-related measures are balanced by countertrades on the exchange.[44] The need for voltage-related redispatching measures was smaller than in the previous year (2020: 2,926 GWh). 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.

The table below shows the duration and volume of the measures required in the individual control and network areas.

Electricity: voltage-related redispatching in 2021[1]

Network area	Duration (hours)	Volume (GWh)
TenneT control area	**2140**	**796**
Ovenstädt-Bechterdissen-Borken network area	1100	463
Oberbayern network area	806	252
Dipperz - Großkrotzenburg	184	81
Mehrum-Grohnde-Borken	41	0
Lehrte-Helmstedt-Krümmel network area	09	0
TransnetBW control area	**302**	**90**
Mittlerer Neckar, Obere Rheinschiene	302	90
50Hertz control area	**154**	**121**
Central region	54	25
Southern region	52	56
Eastern region	48	35
Southern region (Thuringia); central region (Berlin)	00	5
Amprion control area	**05**	**3**
Westfalen - Uentrop	05	3

[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 66: Voltage-related redispatching in 2021

[44] 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 2021, a total volume of 15,323 GWh (6,053 GWh of reductions and 9,271 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.

The chart below 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 cross-border or voltage-related redispatching. In a number of cases, the TSO does not know what type of fuel the power plant uses, and these are also put down as "unknown".

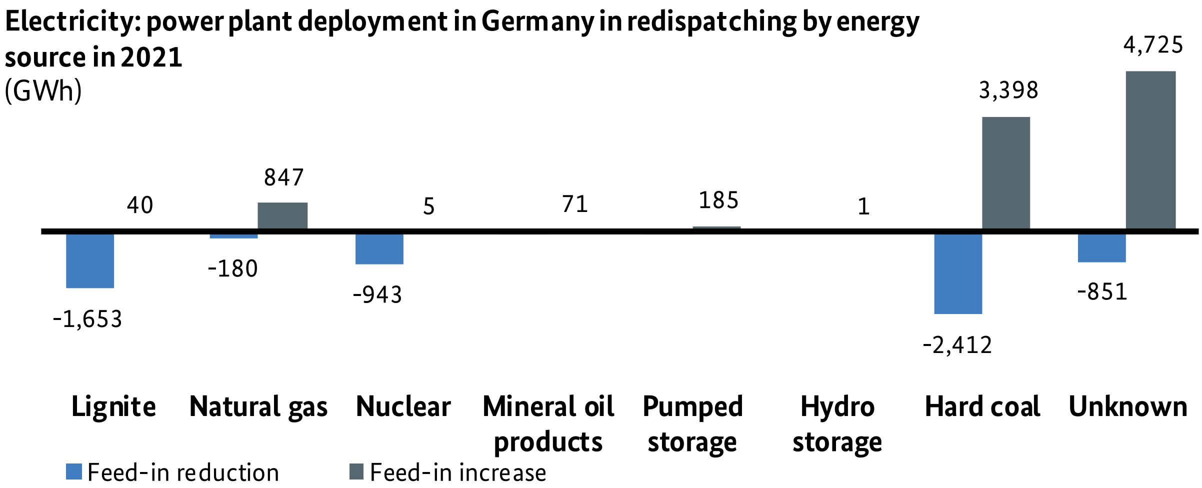

Figure 56: Power plant deployment in redispatching by energy source in 2021

The table below shows power plant deployment across the individual federal states.

Power plant reductions and increases as requested by German TSOs in 2021 (GWh)

Federal state	Reduction	Increase
Baden-Württemberg	Up to 50 GWh	> 1,000 GWh
Bavaria	Up to 250 GWh	Up to 500 GWh
Berlin	0 GWh	Up to 10 GWh
Brandenburg	Up to 1,000 GWh	Up to 10 GWh
Bremen	Up to 500 GWh	0 GWh
Hamburg	0 GWh	Up to 100 GWh
Hesse	Up to 100 GWh	Up to 250 GWh
Mecklenburg-Western Pomerania	Up to 100 GWh	Up to 10 GWh
Lower Saxony	> 1,000 GWh	Up to 250 GWh
North Rhine-Westphalia	Up to 1,000 GWh	Up to 1,000 GWh
Rhineland-Palatinate	Up to 50 GWh	Up to 100 GWh
Saarland	0 GWh	Up to 500 GWh
Saxony	Up to 500 GWh	Up to 50 GWh
Saxony-Anhalt	Up to 10 GWh	Up to 10 GWh
Schleswig-Holstein	Up to 1,000 GWh	0 GWh
Thuringia	Up to 10 GWh	Up to 10 GWh
Not attributable*	Up to 1,000 GWh	> 1,000 GWh

*The redispatching volume procured on the exchange cannot be attributed to a specific federal state

Table 67: Power plant reductions and increases as requested by German TSOs in 2021 (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.

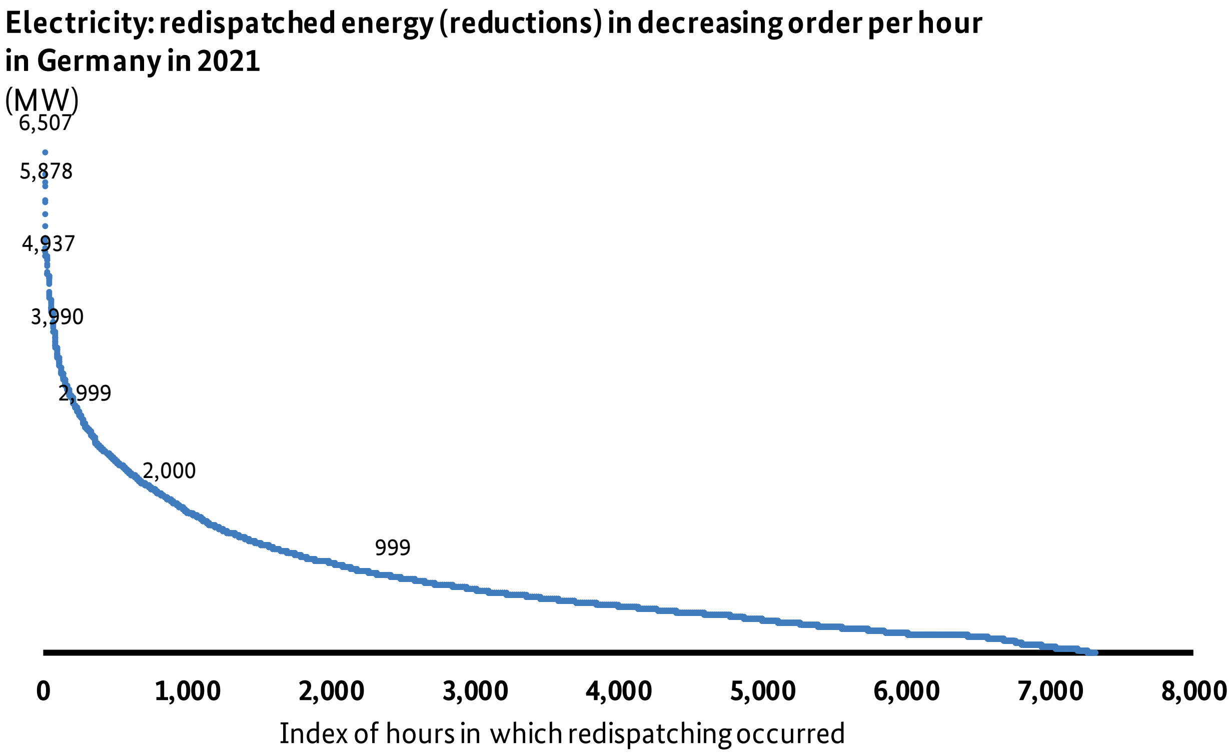

Figure 57: Redispatched energy (reductions) in decreasing order per hour in Germany in 2021

In 2021, the largest required reduction was 6,856.75 MW. The volume of redispatched energy was higher than 5,000 MW in 25 individual hours. No redispatching measures were carried out in 3,754 hours.

5.2.5 Countertrading

Countertrading, which forms part of the individual overloading measures, made up about 8,550 GWh of the total redispatching volume in the whole of 2021. This represents an increase of more than 50% compared with the previous year (2020: 5,671 GWh). Countertrading incurred costs of around €397mn, which is nearly three times as much as in the previous year (2020: €134mn). The large increase in costs is due not only to the increase in the volume but also particularly to the general increase in market prices in the second half of the year.

The increase is mainly due to compliance with the requirements of the European Regulation on the internal market for electricity ((EU) 2019/943) and to a commitment made in antitrust proceedings by TenneT TSO GmbH to make a further incremental increase in the minimum trading capacity at the border between western Denmark and Germany in line with the generally applicable minimum requirements. The commitment requires expansion measures to increase the minimum trading capacity. The reinforcement of the west coast line with effect from 1 October 2020 means that an additional 96 MW of minimum trading capacity will be made available each year (up to 2026). As a result, the minimum trading capacity was increased in 2021 to 1,396 MW. Further changes to the minimum trading capacity are planned in view of future grid expansion measures (such as the west coast line).

5.2.6 Deployment of grid reserve capacity

In 2021, the grid reserve was used on 217 days to provide a total of around 1,280 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 €249mn. The preliminary costs of holding them in reserve plus other costs not dependent on their deployment amounted to €243mn.

The table below 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 2021

	Number of days	Average deployment (MW)	Maximum volume of use (MW)	Total (MWh)
January	18	299	1,390	91,735
February	11	150	820	23,113
March	9	263	710	27,150
April	19	355	1,365	121,773
May	9	116	329	14,241
June	14	147	450	27,839
July	24	212	902	80,541
August	15	154	610	30,796
September	21	207	550	61,033
October	20	362	1,190	141,839
November	27	443	1,404	256,170
December	30	569	2,265	403,915
Total	**217**			**1,280,143**

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

Table 68: Summary of grid reserve deployment in 2021

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 2013.

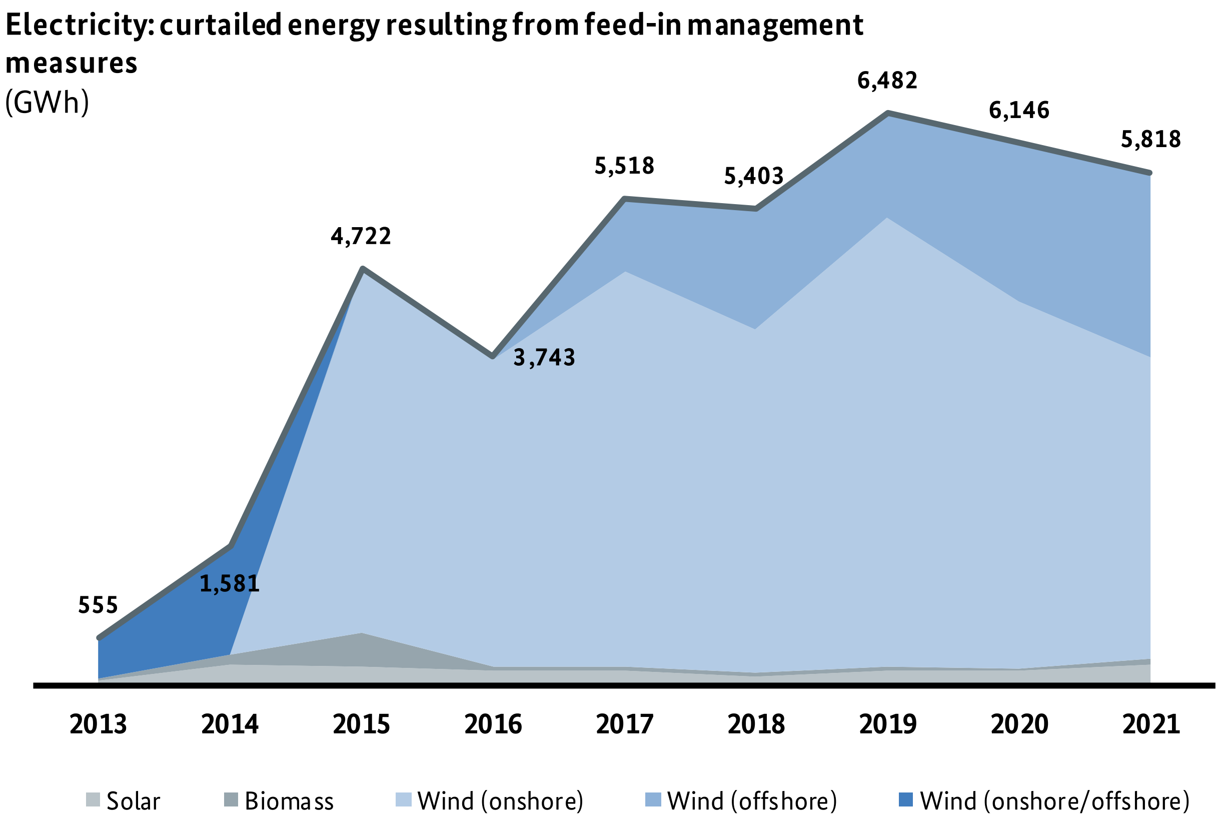

Figure 58: Curtailed energy resulting from feed-in management measures

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

	2013	2014	2015	2016	2017	2018	2019	2020	2021
Wind	480.3	1,221.5	4,124.9	3,530.1	5,287.2	5,246.9	6,272.5	5,942.2	5,817.6
Wind (onshore)			4,110.6	3,498.0	4,461.2	3,890.5	5,084.8	4,145.0	3,408.3
Wind (offshore)			14.3	32.0	826.0	1,356.3	1,187.6	1,797.3	2,095.0
Solar	65.5	245.2	227.7	184.1	163.1	116.5	177.6	164.8	237.3
Biomass	8.8	112.1	364.4	26.5	61.1	35.7	30.2	34.9	72.4
Other	0.2	1.8	21.1	2.6	6.6	3.6	2.3	4.1	4.5
Total	**554.8**	**1,580.6**	**4,722.3**	**3,743.2**	**5,518.0**	**5,402.7**	**6,482.5**	**6,146.0**	**5,817.6**

Table 69: 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 6,146 GWh in 2020 to 5,817 GWh. The decline was probably due to the network expansion projects in Schleswig-Holstein successively going into operation.[45]

The amount of energy curtailed as a result of feed-in management measures corresponds to 2.7% of the total amount of electricity generated by installations eligible for payments under the EEG (including direct selling) (2020: 2.8%).[46] Thus around 97% of the renewable energy marketed in 2021 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.[47]

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

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

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

[47] https://www.bundesnetzagentur.de/systemstudie (in German)

Electricity: curtailed energy resulting from feed-in management measures by energy source in 2021

Energy source	Curtailed energy (GWh)	Percentage of total (%)
Wind (onshore)	3,408.33	58.6
Wind (offshore)	2,095.05	36.0
Solar	237.35	4.1
Biomass, including biogas	72.37	1.2
CHP electricity	2.74	< 0,1
Run-of-river	0.96	< 0,1
Other	0.77	< 0,1
Landfill, sewage and mine gas	0.04	< 0,1
Total	**5,817.62**	**100**

Table 70: Curtailed energy resulting from feed-in management measures by energy source in 2021

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 2021. Overall, restrictions in the transmission networks accounted for around 73% of the energy curtailed, although installations connected to transmission networks accounted for only around 37% of the energy curtailed and compensated. The remaining amount – approximately 63% – was accounted for by installations connected to distribution networks.

Electricity: network levels of curtailments and causes of feed-in management measures in 2021

	Curtailed energy (GWh)	Percentage of total curtailed energy (%)
Measures taken by TSOs (cause in transmission network)	**2,165**	**37**
Measures taken by DSOs	**3,653**	**63**
DSOs' own measures (cause in distribution network)	1,588	27
DSOs' support measures (cause in transmission network)	2,065	35
Total feed-in management measures	**5,818**	**100**

Table 71: Network levels of curtailments and causes of feed-in management measures in 2021

Over the past few years, there has been a continual increase in the proportion of curtailments from feed-in management measures with causes in the distribution network. The chart below shows the proportions over time.

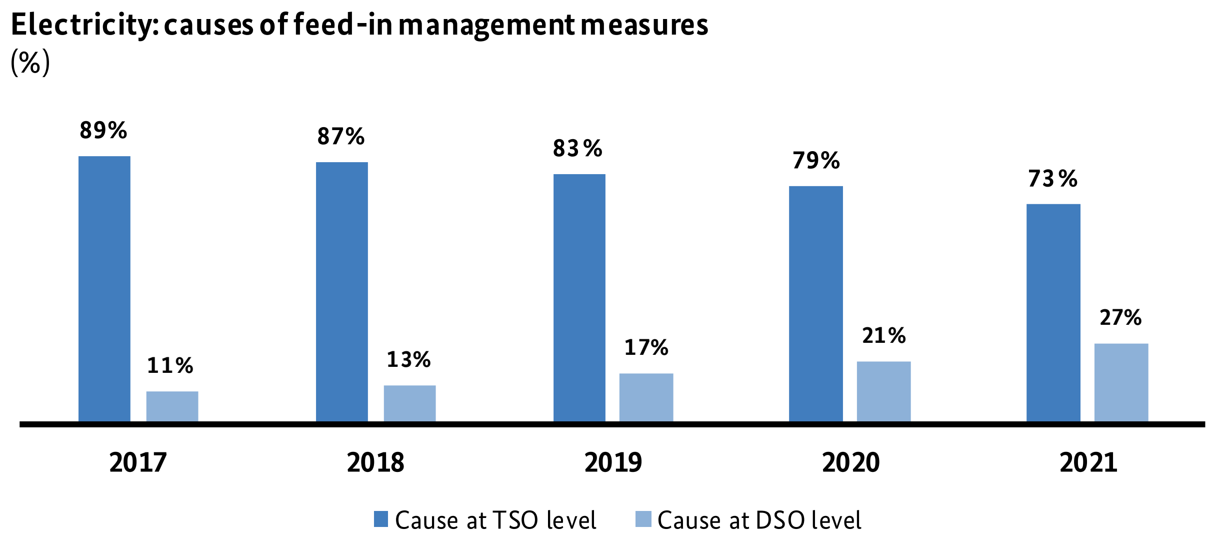

Figure 59: Causes of feed-in management measures

Although many regions in Germany now require feed-in management measures, around 77% of curtailed energy from such measures occurs in the federal states of Lower Saxony and Schleswig-Holstein, with Lower Saxony being particularly affected (about 45%).

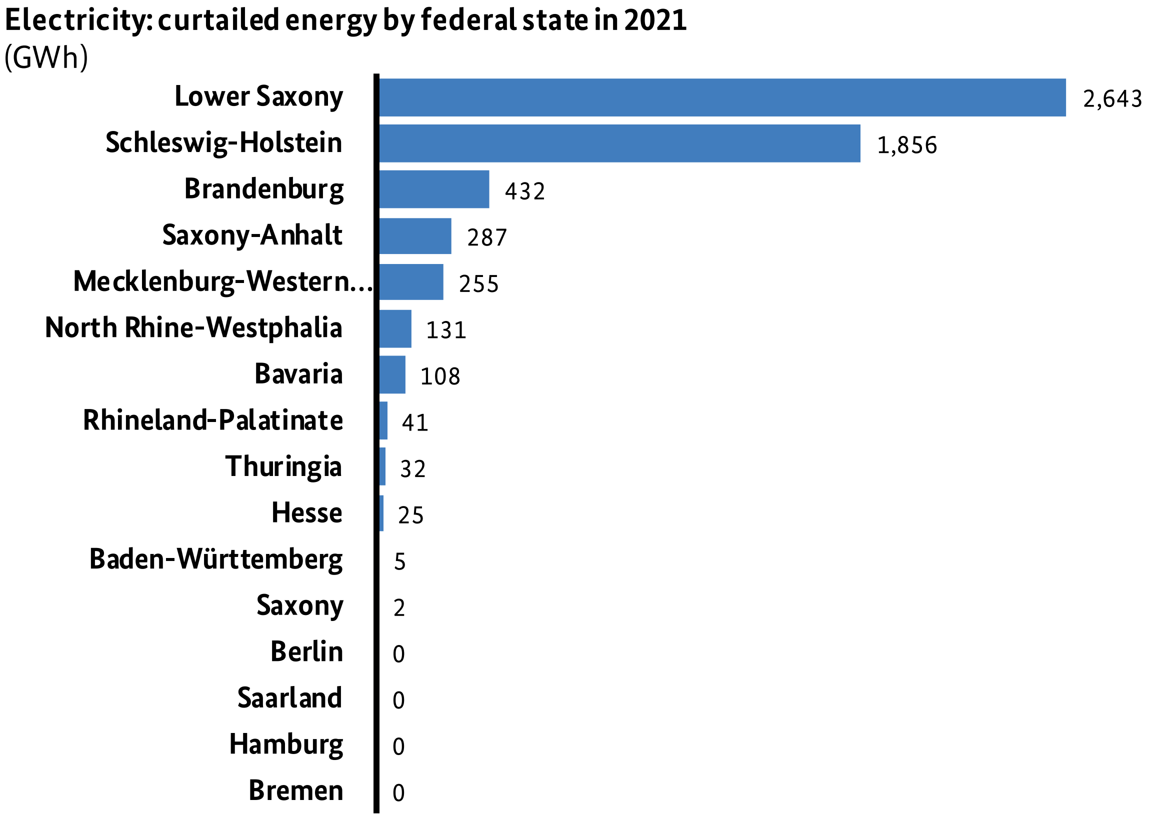

Figure 60: Curtailed energy by federal state in 2021

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.[48]

The amount of compensation paid in 2021 was about €774mn, down around €145mn on 2020 (2020: €919mn). Around 2.1% (€16.4mn) comprises compensation for feed-in management measures taken because of restrictions caused by remedial or maintenance measures. Most of the compensation paid in 2021 came under the EEG payments, with about €33,000 coming under the CHP payments. The costs of the compensation paid to the installation operators are borne by the network tariffs paid by final customers, adding an average of around €14.83 per final customer in 2021 (2020: €17.67; 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 2012 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 2021 therefore does not reflect the actual amounts payable for the curtailments in 2021. The compensation paid in 2021 also includes amounts payable for curtailments in previous years.

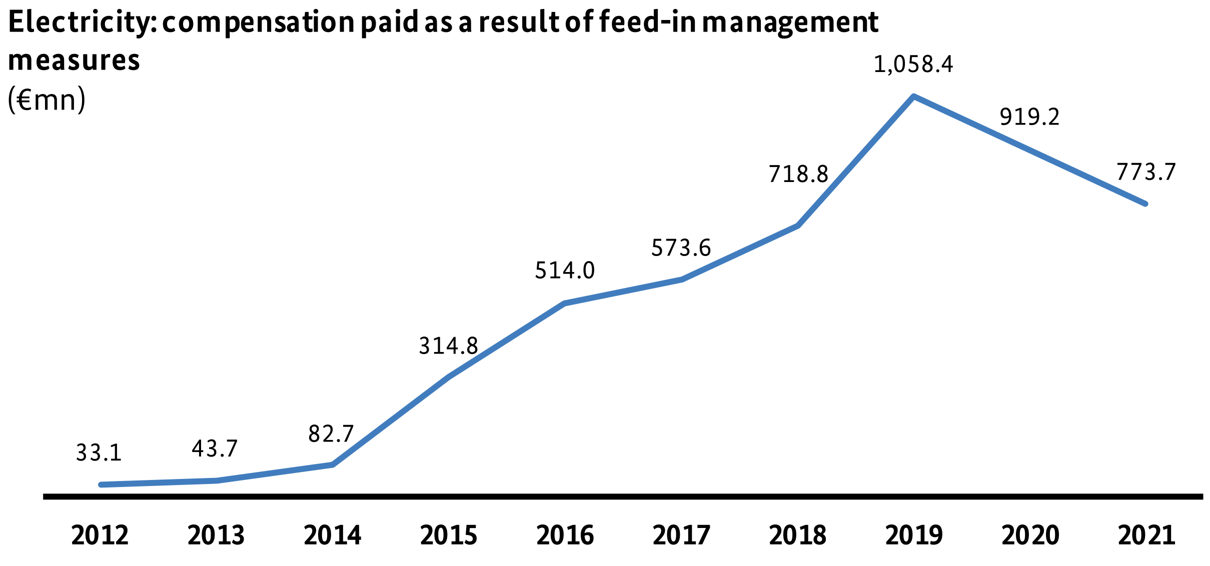

Figure 61: Compensation paid as a result of feed-in management measures

[48] 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.

The claims for compensation from installation operators in 2021, based on the network operators' monthly estimates, amounted to around €807mn, some €46mn higher than in 2020.[49] This rise, which amounts to about 6%, was caused by the greater curtailment of offshore wind turbines.

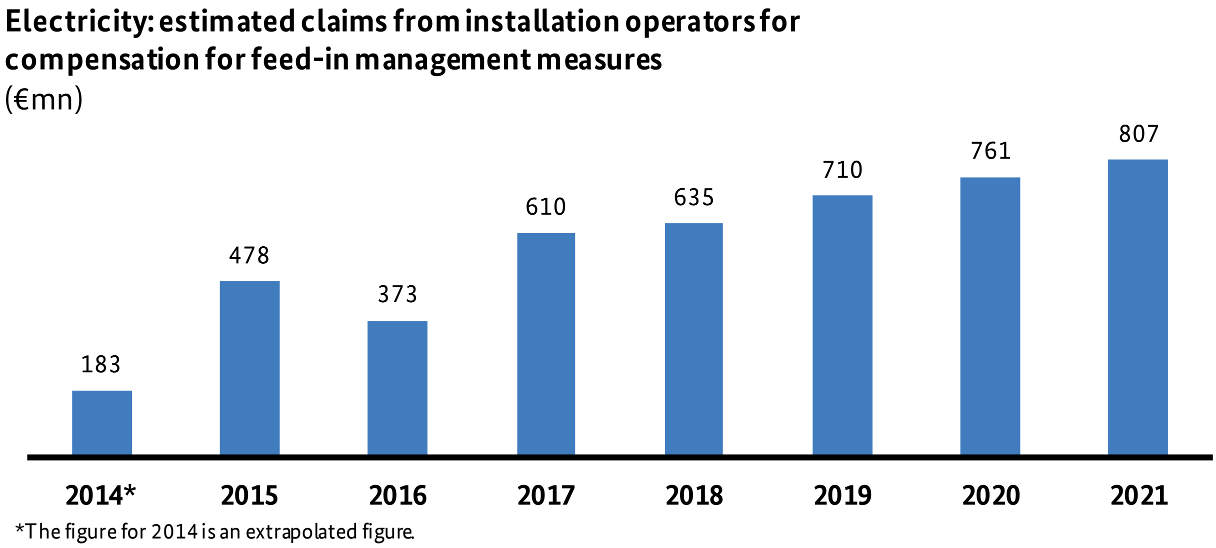

Figure 62: Estimated claims from installation operators for compensation for feed-in management measures

In 2021, the network operators paid a total of around €774mn in compensation to the installation operators. Approximately €451mn was compensation for curtailments actually occurring in 2021, while the remaining amount of around €323mn was compensation for curtailments in previous years. This means that some 56% of the claims from installation operators for compensation for curtailments in 2021, as estimated by the network operators, have already been settled. At the time of the survey, around 44% (€356mn) of the estimated compensation claims had not yet been settled; this will have a knock-on effect on the amount of compensation paid in subsequent years. The table below shows the detailed figures for the network operators' estimates of compensation claims and the actual compensation paid.

[49] See the Bundesnetzagentur's quarterly reports available at https://www.bundesnetzagentur.de/systemstudie (in German).

Electricity: compensation claims and payments by measures taken and causes of feed-in management measures according to network operators' reports in 2021

	Estimated claims for compensation from installation operators (€mn) (for measures in 2021)		Total compensation paid (€mn) (in 2021)		Compensation for measures in previous years (€mn)
Measures taken and compensation paid by TSOs (cause in transmission network)	**419**	**52%**	**348**	**45%**	**144**
Measures taken and compensation paid by DSOs	**388**	**48%**	**426**	**55%**	**179**
DSOs' own measures (cause in distribution network)	178	22.1%	179	23.1%	83
DSOs' support measures (cause in transmission network)	211	26.1%	247	31.9%	97
Total feed-in management measures	**807**	**100%**	**774**	**100%**	**323**

Table 72: Compensation claims and payments by measures taken and causes of feed-in management measures according to network operators' reports in 2021

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 2021, a total of six DSOs took adjustment measures. Brandenburg accounted for the majority of the adjustment measures with some 73%, followed by Saxony-Anhalt with about 16% and Thuringia with around 11%. The table below shows a breakdown by energy source.

Electricity: feed-in and offtake adjustments by energy source in 2021

Energy source	Adjustments under section 13(2) (GWh)	Percentage of total (%)
Waste (non-biodegradable)	19.57	89%
Natural gas	2.44	11%
Other energy sources (non-renewable)	0.01	0%
Total	**22.02**	**100%**

Table 73: Feed-in and offtake adjustments by energy source in 2021

6. Network tariffs

Network tariffs 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 (such as expansion and system security measures) are passed on to final customers through the network tariffs.

Network tariffs made up around 23% of the electricity price in 2022 for household customers with an annual consumption of between 2,500 kWh and 5,000 kWh. Following a levelling out in 2021, the network tariffs for household customers increased considerably in 2022 to an average of 8.12 ct/kWh (2021: 7.52 ct/kWh).

The level of network tariffs 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 very generously sized 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 congestion 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 tariffs

Network tariffs are levied by the TSOs and DSOs and make up part of the retail price for electricity (see also IG.4). Network tariffs 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 tariffs 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 tariffs. There are three steps in the process of setting network tariffs 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 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 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.[50] 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 tariffs (see IC6.4) or for the use of upstream network levels; costs for redispatch and feed-in management (see IC5.1 and IC5.3). For TSOs, there is an array of costs for means to ensure security of supply and grid expansion, in particular costs for investment measures pursuant to section 23 ARegV (see IC3.3), costs for redispatching with grid reserve power plants (see IC5.1) and costs of procuring balancing reserves (see ID).

- The consumer price index, which reflects general inflation.

- The capex mark-up (see IC3.3.2), 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

[50] 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%.

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[51], 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 tariffs

The network tariffs 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 transformation 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 transformation 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 pricing 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 tariffs. The difference between the costs allocated to the network level and the expected network tariff 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 tariffs on their websites on 15 October each year for the following calendar year and then publish their final tariffs on 1 January of the year in which the tariffs

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[51] BGH ruling of 11 December 2018 - EnVR 21/18

take effect. They are not allowed to make any changes to the published network tariffs in the course of the year. Operators must demonstrate to the regulatory authority that their published network tariffs 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 tariffs. 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 tariffs.

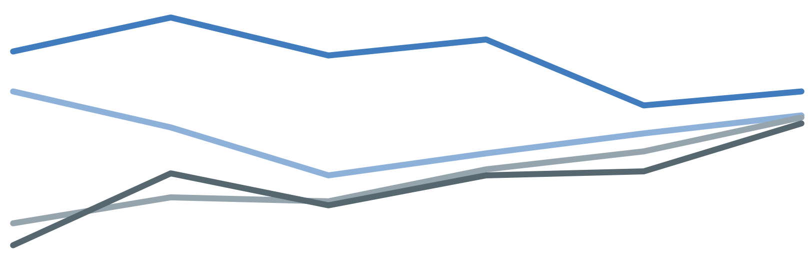
Other surcharges that form components of the final customer price are detailed in IG4.3.

6.2 Development of network tariffs in Germany

6.2.1 Development of network tariffs at TSO level

The following chart shows the four TSOs' network tariffs from 2017 to 2022 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 tariff reduction of 75% pursuant to section 19(2) StromNEV.

Electricity: TSOs' network tariffs
(ct/kWh)



	2017	2018	2019	2020	2021	2022
TenneT	0.64	0.70	0.63	0.66	0.54	0.56
50Hertz	0.56	0.50	0.41	0.45	0.48	0.52
TransnetBW	0.32	0.37	0.36	0.42	0.45	0.52
Amprion	0.28	0.41	0.35	0.41	0.42	0.50

TenneT 50Hertz TransnetBW Amprion

Figure 63: TSOs' network tariffs

Network tariff 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 tariffs throughout Germany. This process will be completed in 2023 with a uniform network tariff for the extra-high voltage and extra-high voltage/high voltage transformation levels. The level of each revenue cap is, in turn, determined primarily by the grid expansion costs, as well as by the costs for redispatching (including previous feed-in management), and also by the costs for power plant reserves and balancing/loss energy. The network tariff increases at the beginning of the 2016-2021 period are due in particular to rising grid expansion costs and cost increases for the grid reserve, but also due to rising costs for redispatching and feed-in management measures. The decrease in the network tariff in the 50Hertz control area in 2018 was, however, largely due to the costs saved for redispatching and the (then) feed-in management measures through the commissioning of the "Thuringia power bridge". The main reason for the decrease in the network tariffs in all four control areas in 2019 was the implementation of the Network Tariffs Modernisation Act (NEMoG), on the basis of which in 2019 the offshore connection costs were removed from the transmission network tariffs for the first time and transferred to the new offshore network surcharge. If the network costs in 2018 and 2019 were presented in such a way that the offshore cost items are comparable, the decreases in the tariffs in 2019 compared with 2018 would be much smaller; in the TransnetBW control area there would even be an increase in network tariffs for the sample customer.[52]

The increase in transmission network tariffs in 2020 is largely the result of a revenue cap increase for 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 2018/2019. The increase in the Amprion, 50Hertz and TransnetBW control areas is a result of the ongoing process to gradually harmonise transmission network tariffs in Germany. Only the TenneT control area saw a decrease in transmission network tariffs 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 tariffs in Germany, which already led to a distribution of 60% of revenue caps Germany-wide in 2021. Although Amprion's revenue cap is also decreasing, the transmission network tariff harmonisation process leads to transmission network tariff increases for it. Overall, other factors offset the effect of the lower revenue cap and the transmission network tariffs increase slightly. In 2021, 50Hertz was able to benefit for the first time from the gradual harmonisation of the transmission network tariffs in Germany, but this was more than outweighed 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 tariffs associated with the harmonisation of network tariffs that is gradually being implemented throughout Germany.

In 2022, the network tariffs for the example industrial customer increased in all control areas, with the largest increase in the Amprion control area. One particular reason for the increase in network tariffs is the increase in the revenue caps for the individual TSOs, which in some cases was also large. The only slight decrease in 2022 was in the revenue cap for 50Hertz, as a result of a large reduction in redispatching costs and a negative regulatory account balance. The increase in the aggregate revenue cap for the four TSOs is mainly due to the continued increase in grid expansion costs and the rise in the costs for balancing and loss energy

[52] For a breakdown of the offshore network surcharge and an analysis of the comparability of the network tariffs with and without a surcharge see also the Monitoring Report 2019 IC.6.3.1.

and the grid reserve. The influencing factors here include the large increases in electricity prices on the power exchange, fuel prices and carbon prices. In 2021, customers in the TenneT and 50Hertz control areas benefited for the first time from the gradual harmonisation of the TSOs' network tariffs in Germany; in 2022, once again only network users in the TenneT control area benefited from the present distribution of 80% of the TSOs' tariffs Germany-wide.

In 2023, the TSOs' revenue caps are expected to remain the same due to financing through the brake on electricity prices. The last stage of the national harmonisation of the TSOs' network tariffs and changes in the planned volumes lead to changes in the network tariffs in the single-digit percentage range (a decrease in TenneT's tariffs and increases in the other TSOs' tariffs).

6.2.2 Development of average network tariffs

The analysis of average network tariffs 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 tariffs for customers in specific consumption groups and different contract categories.[53] The consumption groups are as follows:

Household customers: as from 2016, the network tariffs 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 tariffs 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 tariff for each consumption group. The network tariff 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 tariffs 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 tariffs. Various factors have influenced the rise in network tariffs 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 avoided network tariffs, while at the same time there was an increased need for redispatching and feed-in management measures. Finally, the growth in renewable installations made further grid expansion necessary. All of these factors pushed up network costs. A turning point occurred in 2018 when the volume-weighted average network tariff fell by around 2% from 2017. The main reason for the drop was the effect of the NEMoG bringing down costs for avoided network tariffs. Despite the exclusion of the offshore connection

[53] Net network tariffs do not include VAT.

costs from the network tariffs and a further reduction in the avoided network tariffs under the NEMoG, this trend did not continue for reasons including increasing grid expansion costs and projected high costs for system security measures. The national average network tariff for household customers increased in 2022 from 7.52 ct/kWh to 8.12 ct/kWh (+8%), and is thus at a high level. This confirms the information provided last year by the DSOs under the Bundesnetzagentur's responsibility about the provisional network tariffs for 2022. According to that information, average network tariffs in Germany were set to increase noticeably in 2022. Reasons include higher upstream network costs in the control areas of 50Hertz, 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.

Electricity: average volume-weighted network tariffs (including meter operation) for household customers
(ct/kWh)

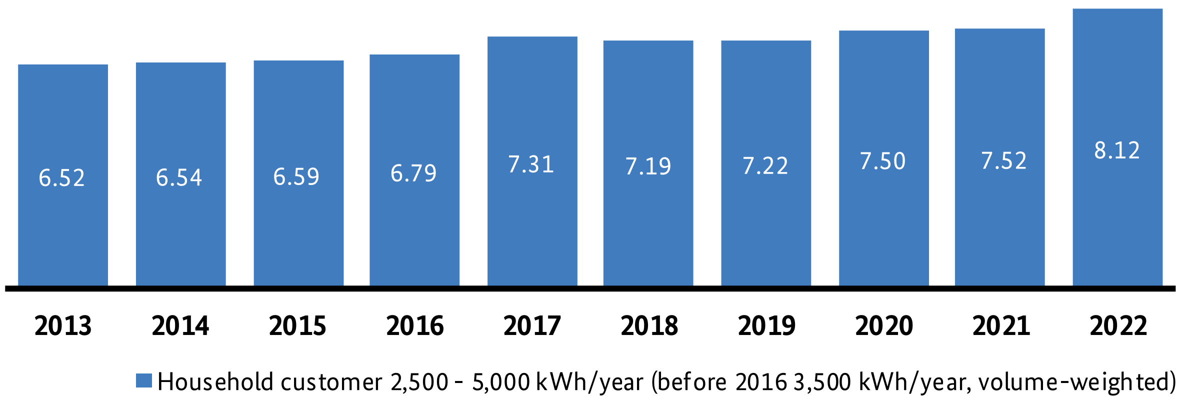


Figure 64: Average volume-weighted network tariffs for household customers from 2013 to 2022

According to information from DSOs under the Bundesnetzagentur's responsibility about the provisional network tariffs for 2023, average network tariffs in Germany will increase noticeably. Reasons include rising congestion management costs for several DSOs, investments in the networks, and increasing costs for the procurement of loss energy due to higher electricity prices on the exchange. A number of DSOs also expect a decrease in volumes because of energy-saving measures.

For non-household customers the arithmetic mean tariffs for 2022 are higher than the previous year's level. With regard to consumption by commercial customers, network tariffs rose by around 3% (+0.21 ct/kWh) to 6.85 ct/kWh. The arithmetic mean tariff for consumption by industrial customers increased by around 11% (+0.29 ct/kWh) to 2.96 ct/kWh.

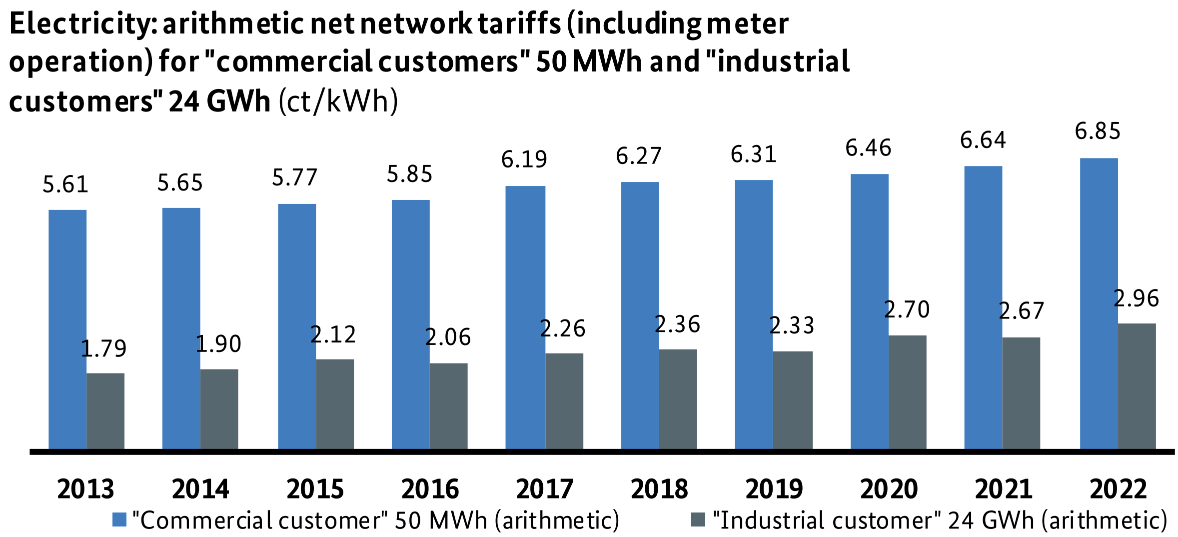


Figure 65: Arithmetic net network tariffs (including meter operation) for "commercial customers" (50 MWh) and "industrial customers" (24 GWh)

6.2.3 Standing charges

For non-interval metered customers, the network tariffs 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 non-interval metered customers in Germany (see chart below). However, the table below shows a nationwide trend towards introducing or increasing standing charges in recent years. The maximum standing charge in 2022 remained at the previous year's level (2021: €105 per year).

Electricity: standing charges in 2022

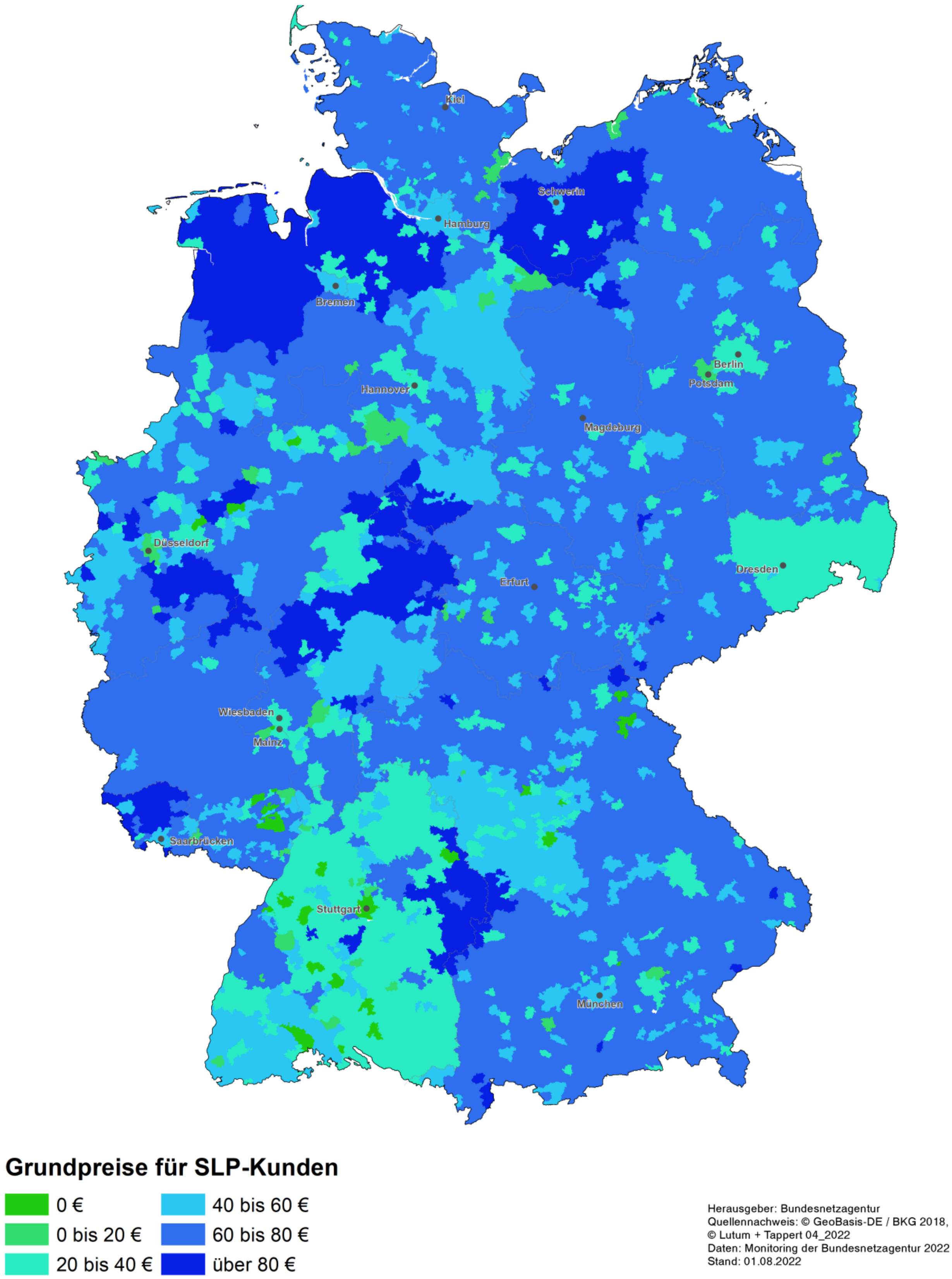


Figure 66: Network operators' standing charges per year for non-interval metered customers

Electricity: standing charges
(€/year)

	2017	2018	2019	2020	2021	2022
Average standing charge	35	37	40	52[2]	57[2]	58[2]
Maximum standing charge	95	100	105	105	105	105
Minimum standing charge [1]	6	4	7	8	8	9
DSOs without standing charge (number)	46	36	42	40	31	30

[1] Minimum standing charge levied by DSOs with standing charges.
[2] The standing charges for 2020, 2021 and 2022 were weighted using the DSOs' delivery volumes. The unweighted averages were €42 per year for 2020, €45 per year for 2021 and €47 per year for 2022.

Table 74: 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 tariffs

There are large regional differences in the network tariffs. To compare network tariffs across Germany, the monitoring report collects information from the DSOs about the current network tariffs in their network areas. This information can then be compiled relating to the three consumption groups of household, commercial and industrial customers (see IC6.2). Section 21(3) EnWG requires all network operators to publish the network tariffs applicable in their networks on their websites. The information relating to each DSO's unit and capacity charges was used to calculate the network tariffs (in cents per kilowatt hour) applicable for 2022. 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 tariffs more clearly. The network tariffs 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 tariffs in each federal state was also created: the individual network tariffs were weighted with the relevant consumption quantity to obtain the average network tariff in each federal state.[54]

[54] 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 non-interval metered final customers excluding household customers; industrial customer = consumption quantity of interval-metered final customers. The quantities for DSOs operating in more than one federal state were weighted using the relevant market location distribution.

Results of the monitoring survey show that the DSOs' network tariffs for household customers range from 3.48 ct/kWh to 20.15 ct/kWh. The following tables and maps show the network tariffs in the federal states and individual network areas.

Electricity: net network tariffs for household customers in Germany in 2022
(ct/kWh)

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks included
Schleswig-Holstein	9.79	6.00	11.94	41
Hamburg	9.11	6.03	11.94	4
Brandenburg	8.95	3.90	14.64	34
Mecklenburg-Western Pomeran	8.71	4.95	10.42	19
Saarland	8.25	5.63	20.15	18
Baden-Württemberg**	7.84	5.22	18.67	125
Rhineland-Palatinate	7.69	5.55	13.05	52
Saxony-Anhalt	7.60	5.60	10.00	33
Thuringia	7.55	5.66	9.30	38
Hesse	7.53	5.58	11.04	58
Saxony	7.45	5.52	10.79	39
North Rhine-Westphalia	7.37	3.48	11.43	107
Lower Saxony	7.24	5.05	11.88	73
Bavaria	6.95	3.64	12.22	228
Berlin	6.49	6.03	17.80	7
Bremen	5.85	5.83	9.39	8

* 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 75: Net network tariffs for household customers in Germany[55] in 2022

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

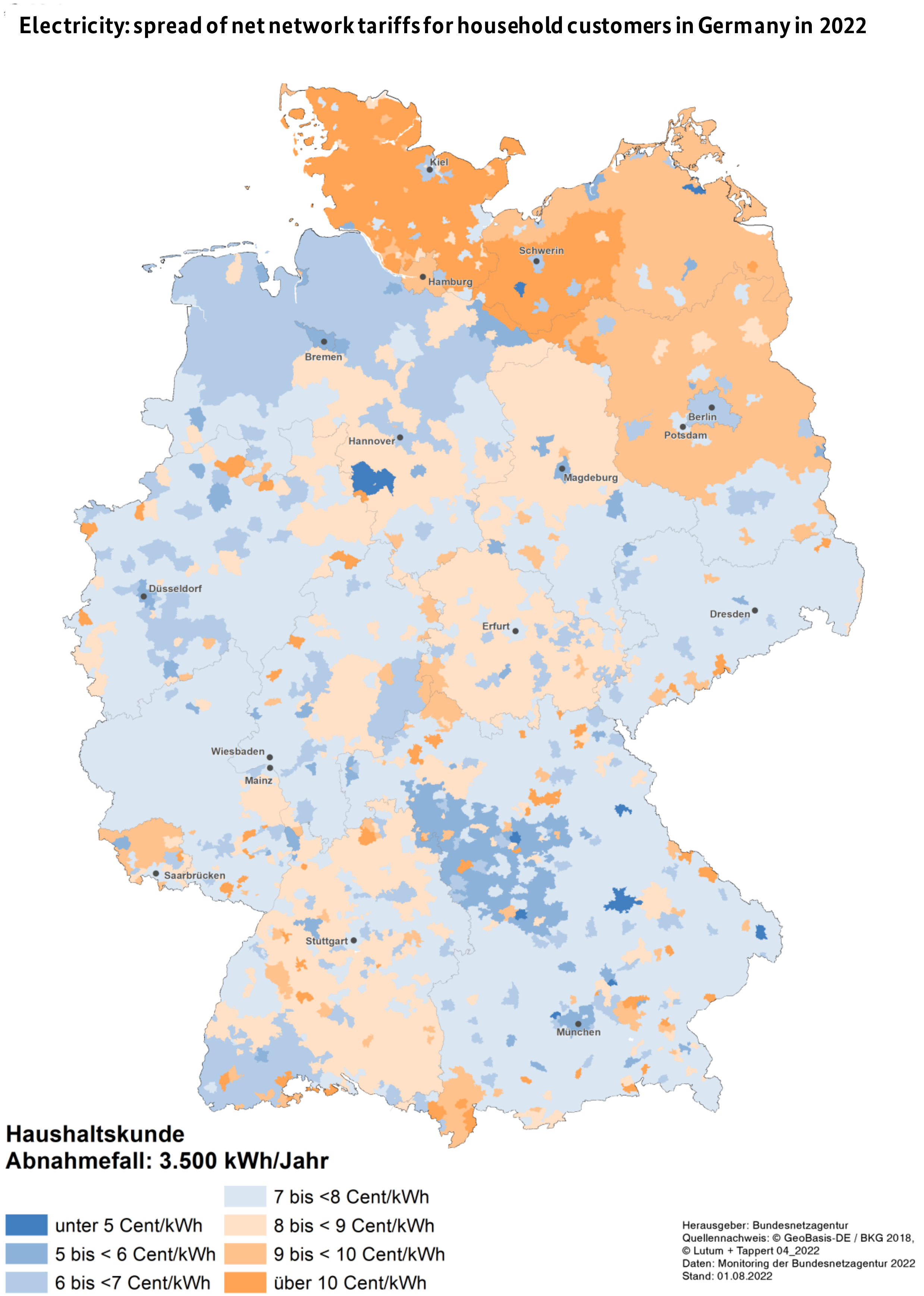


Figure 67: Spread of net network tariffs for household customers in Germany in 2022

The spread of network tariffs for the 50 MWh annual consumption group (commercial customers) is similar to that for household customers, with tariffs ranging from 2.31 ct/kWh to 18.88 ct/kWh. Overall, however, tariffs are lower than for household customers.

Electricity: net network tariffs for commercial customers in Germany in 2022
(ct/kWh)

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks included
Saarland	7.61	4.17	18.88	18
Hamburg	7.50	4.37	10.00	4
Brandenburg	7.17	3.63	14.64	34
Baden-Württemberg**	6.90	4.23	17.40	125
Mecklenburg-Western Pomeran	6.85	3.69	9.06	19
Schleswig-Holstein	6.75	4.67	10.07	41
Saxony	6.33	4.04	9.41	39
Rhineland-Palatinate	6.26	4.16	11.72	52
Thuringia	6.00	3.90	8.03	38
Hesse	5.92	3.89	9.98	58
Saxony-Anhalt	5.87	4.18	8.87	33
North Rhine-Westphalia	5.63	3.48	10.14	107
Berlin	5.63	4.97	16.87	7
Lower Saxony	5.31	3.77	11.08	73
Bavaria	5.28	2.31	11.10	228
Bremen	4.58	4.37	8.75	8

* 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 76: Net network tariffs for commercial customers (annual consumption 50 MWh) in Germany in 2022

Electricity: spread of net network tariffs for commercial customers in Germany in 2022

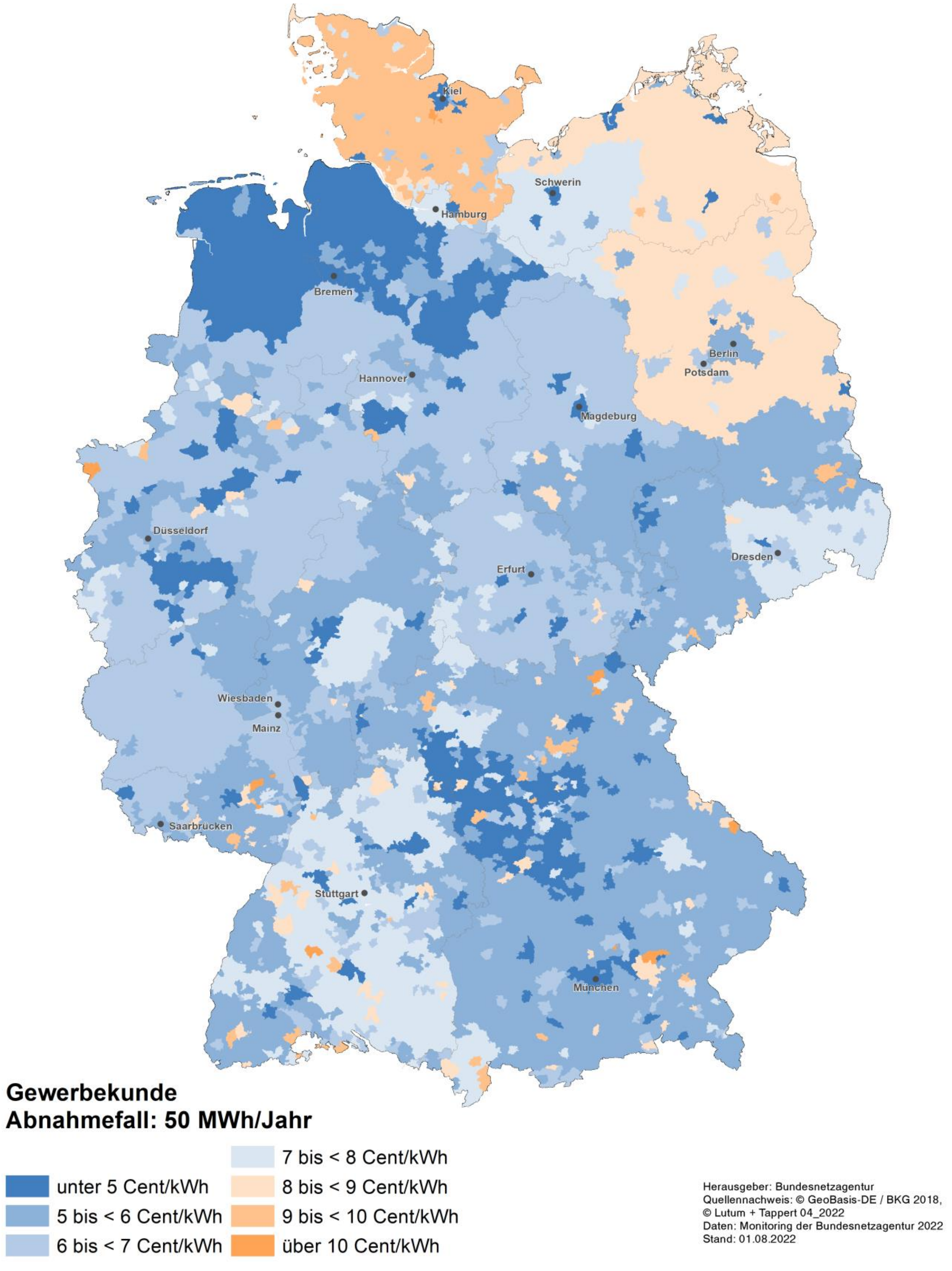


Figure 68: Spread of net network tariffs for commercial customers (annual consumption 50 MWh) in Germany in 2022

The spread of network tariffs for the 24 GWh annual consumption group (industrial customers) is different. The volume-weighted average network tariffs are higher in Schleswig-Holstein, Mecklenburg-Western Pomerania and Brandenburg than elsewhere in the country. The lowest average network tariffs are in Saarland. The network tariffs for industrial customers range from 0.74 ct/kWh to 5.73 ct/kWh. These tariffs do not take account of possible reductions through individual network tariffs pursuant to section 19(2) StromNEV. In some cases, the tariffs for industrial customers entitled to individual network tariffs may be lower.

Electricity: net network tariffs for industrial customers in Germany in 2022
(ct/kWh)

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks included
Schleswig-Holstein	3.35	1.15	4.76	41
Mecklenburg-Western Pomeran	3.35	1.69	4.43	19
Brandenburg	3.34	1.08	4.43	34
Hesse	3.12	1.74	4.48	59
Hamburg	3.09	2.52	4.01	4
Saxony	2.97	2.06	4.31	39
Saxony-Anhalt	2.97	1.52	4.23	32
Thuringia	2.90	2.09	4.20	36
Baden-Württemberg	2.82	1.64	4.91	124
Berlin	2.72	2.38	3.91	6
Lower Saxony	2.70	1.51	4.83	73
Rhineland-Palatinate	2.69	1.92	5.66	52
North Rhine-Westphalia	2.58	1.51	4.78	109
Bremen	2.56	2.28	3.36	8
Bavaria	2.48	0.74	5.73	219
Saarland	2.41	1.76	5.54	18

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

Table 77: Net network tariffs for industrial customers (annual consumption 24 GWh) in Germany[56] in 2022

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

Electricity: spread of net network tariffs for industrial customers in Germany in 2022

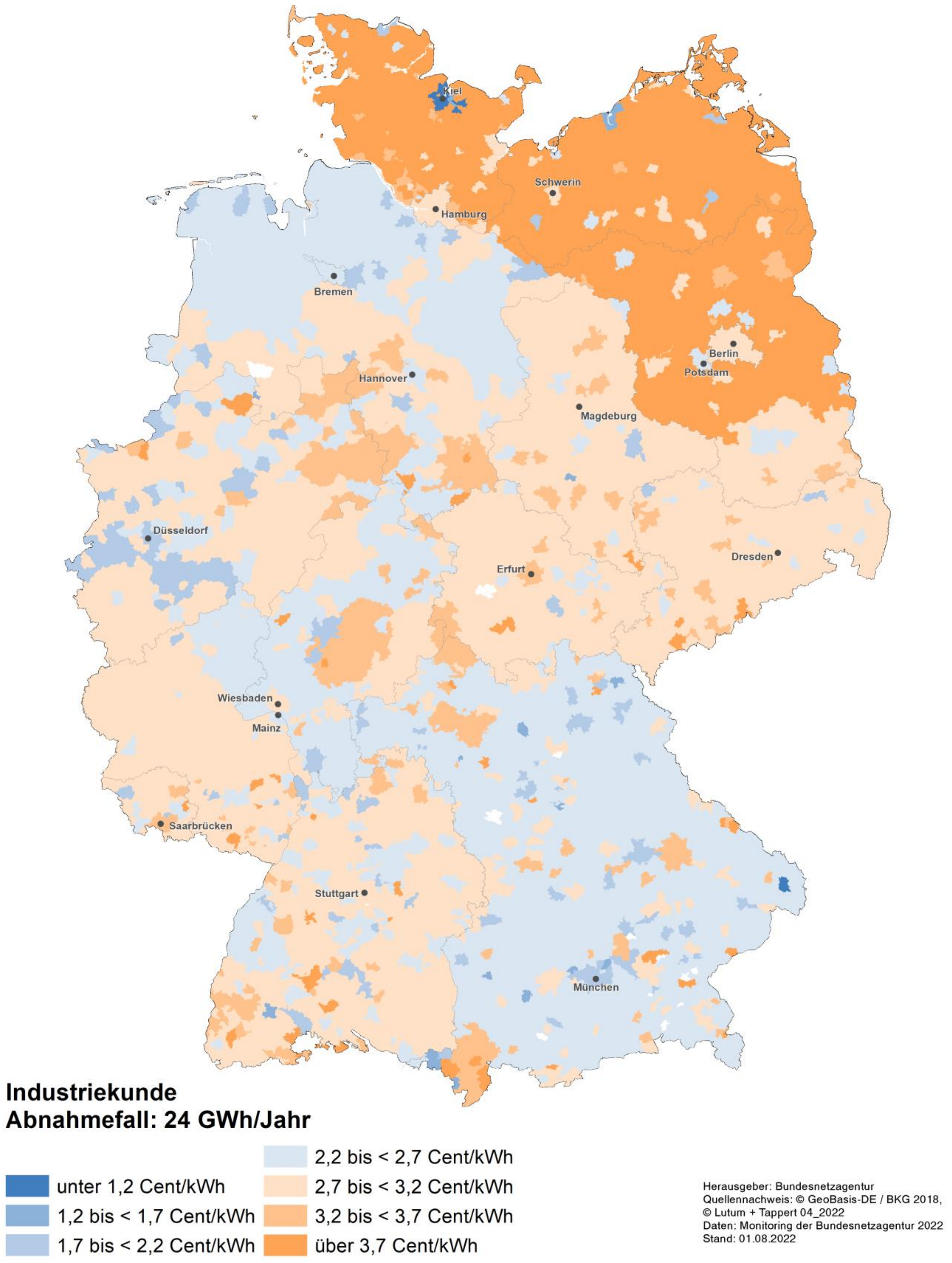


Figure 69: Spread of net network tariffs for industrial customers (annual consumption 24 GWh) in Germany in 2022

The regional differences in network tariffs are due to a complex range of factors.[57] 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 integrating renewables, including feed-in management measures, have also become a factor contributing to differences in network tariffs. 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 tariffs. Increases in the TSOs' tariffs – 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 Tariffs Modernisation Act (NEMoG). The tariffs at transmission network level are to be gradually harmonised as from 2019. Uniform national tariffs 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 tariffs

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 tariff avoided by feeding in less electricity at an upstream network or transformation 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 tariffs. In 2017 the NEMoG entered into force.[58] Among other things, it adjusted the group of recipients and the amount of the avoided network tariffs.

In accordance with the legislation, new, non-volatile facilities will be excluded from the payment of avoided network tariffs. The non-volatile facilities put into operation before 1 January 2023 will remain subject to the provision indefinitely.

Continuing payment of avoided network tariffs to operators of non-volatile facilities will therefore still cause an uneven burden on network users in individual network areas.

The information below refers to avoided network tariffs 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

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

[58] Network Tariffs Modernisation Act of 17 July 2017, Federal Law Gazette I page 2503; Bundestag printed paper 18/11528 of 15 March 2017 contains the federal government's draft legislation and reasoning, the Bundesrat's response and the federal government's counter-response.

avoided network tariffs paid was continually on the rise and reached its peak in 2017 at €2.5bn.[59] The NEMoG had the effect of reducing the amount of avoided network tariffs paid in 2018 to €1.3bn. In 2019, payments for avoided network tariffs fell to €1.2bn. The discontinuation of payments for volatile generation facilities meant that avoided network tariffs fell to below the €1bn mark for the first time in 2020, totalling €985mn.[60] The projected avoided network tariffs total €1,066mn for 2021 and €1,026mn for 2022.[61]

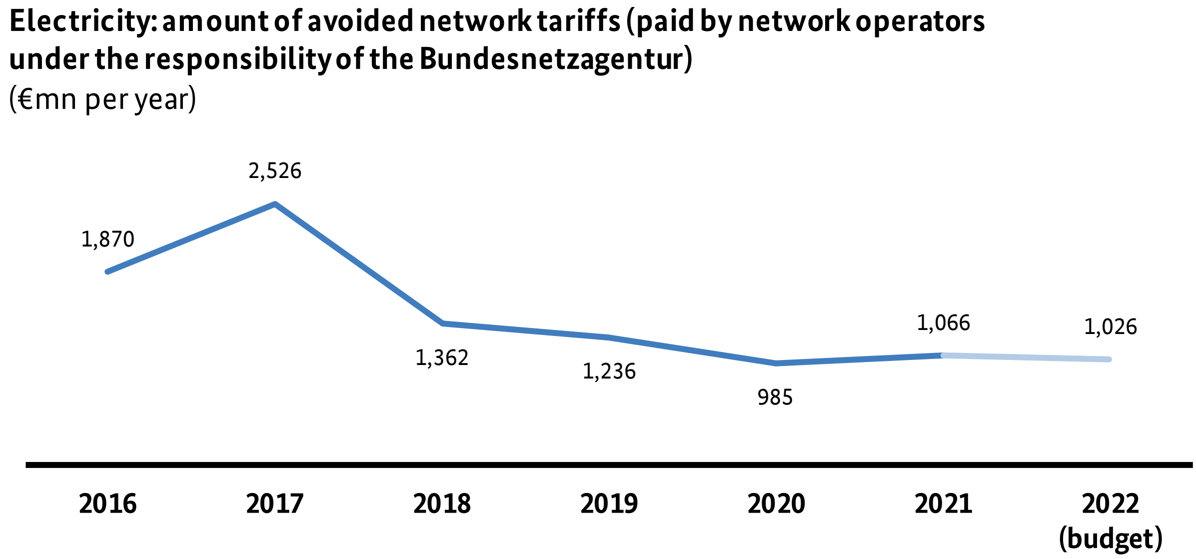


Figure 70: Amount of avoided network tariffs (paid by network operators under the responsibility of the Bundesnetzagentur)[62]

Effect of the payment of avoided network tariffs in general

The concept of avoided network tariffs is based on the assumption that distributed feed-in would reduce consumption from, and thus use of, the upstream network, thereby saving network infrastructure costs.[63] The introduction of the principle of avoided network tariffs was based on the assumption that electricity flows from the highest to the lowest voltage level. The assumption that distributed feed-in would lead to a reduction in grid expansion measures in the medium to long term originated around the turn of the millennium and is, at least now, unfounded.

[59] These figures each relate to the network operators under the responsibility of the Bundesnetzagentur. The avoided network tariffs 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.

[60] 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:
https://www.bundesnetzagentur.de/SharedDocs/Downloads/EN/Areas/ElectricityGas/CollectionCompanySpecificData/Monitoring/MonitoringReport2020.pdf?__blob=publicationFile&v=2, page 171 et seq.[60]

[61] The actual figure for 2021 is not available to the Bundesnetzagentur until 31 December 2022.

[62] 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.

[63] See most recently, for example, the statement in Bundestag printed paper 18/11528 of 15 March 2017, page 12.

The network is generally dimensioned so that the peak load of the year can be met solely by drawing electricity from the upstream transmission network. This is for good reason: so as to avoid structural interests in congestion with regard to the upstream network and not to hinder the future participation of loads in the European electricity market through congestion. It also serves to safeguard security of supply.

The reduction of the remuneration to be paid to upstream operators as a result of distributed feed-in should therefore 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.

Further information and explanations about avoided network tariffs can be found in the Monitoring Report 2020.[64]

6.5 Transfer of electricity networks

Section 26(2) to (5) 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 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) to (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 2021, the Bundesnetzagentur had received 17 applications for electricity network transfers in 2021.

[64] https://www.bundesnetzagentur.de/SharedDocs/Downloads/EN/Areas/ElectricityGas/CollectionCompanySpecificData/Monitoring/MonitoringReport2020.pdf?__blob=publicationFile&v=2, pages 171-179.

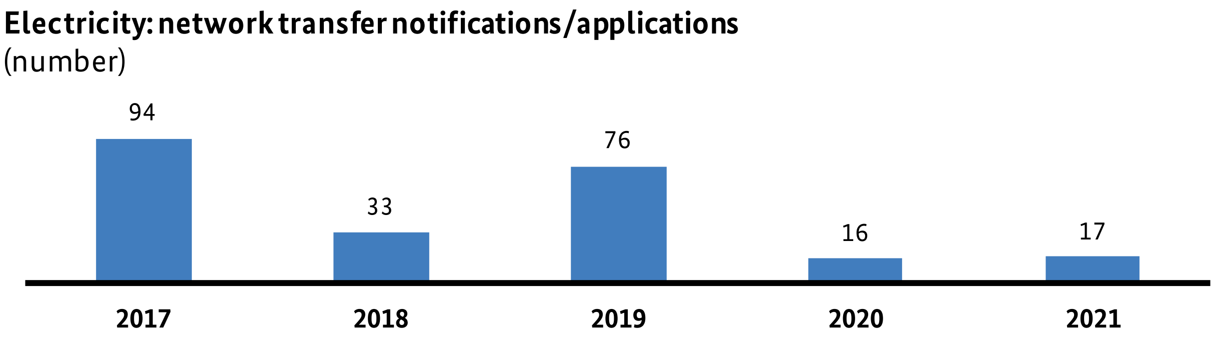


Figure 71: Network transfer notifications/applications

The chart below shows the value of the network assets transferred.

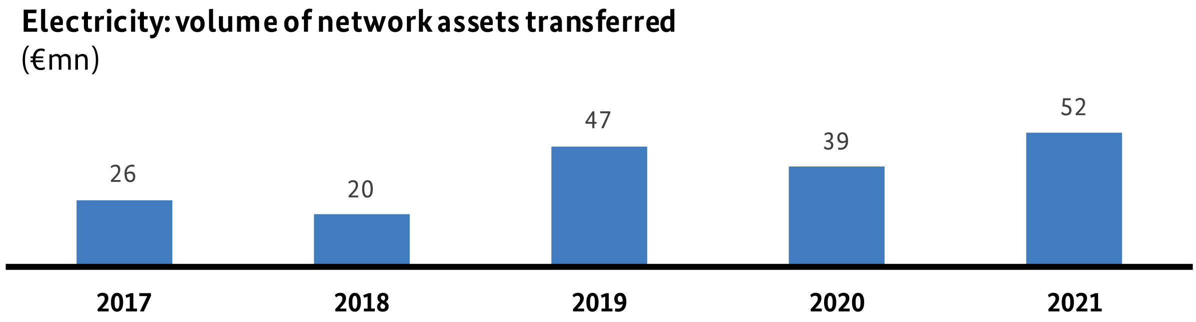


Figure 72: Value of network assets transferred

In 2021, Ruling Chamber 8 took decisions on 51 electricity network transfers, including network transfers from previous years.

6.6 Individual network tariffs – StromNEV section 19(2)

Individual network tariffs are granted as a reduction on the general network tariff to network users meeting certain defined criteria. Section 19(2) StromNEV therefore essentially grants privileges to final customers 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 even and permanent consumption patterns. The criteria for determining these individual network tariffs 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 tariffs was replaced by a notification procedure as a result of the provisions effective from 1 January 2014 on appropriate arrangements for setting individual network tariffs under section 19(2) StromNEV (ruling BK4-13-739 of 11 December 2013). Individual network tariffs 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 customers are able to notify agreements with network operators for individual network tariffs as provided for by section 19(2) StromNEV by 30 September of each year. After the end of each billing period, the final customers are required to provide the regulatory authority responsible with proof of compliance with the criteria for appropriately setting individual network tariffs.

The first notifications for individual network tariffs under the Bundesnetzagentur's responsibility were registered and settled for 2014. The number of final customers actually granted individual network tariffs rose continually up to 2021.

Individual network tariffs 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 tariffs for the company in question.

6.6.1 Atypical network users – section 19(2) sentence 1 StromNEV

In 2021, a total of 7,108 notifications for individual network tariffs for atypical network users were registered with the Bundesnetzagentur (see the table below).

In the 2022 notification period, the Bundesnetzagentur received 510 further notifications for individual network tariffs in connection with atypical network users, with the volume of reductions granted amounting to €15.7mn. As these notifications include a considerable number of new notifications relating to existing individual network tariff agreements, it is not currently possible to determine the effect on the total volume of reductions.

Electricity: notifications for individual network tariffs for atypical network users

	2016	2017	2018	2019 [1]	2020 [2]	2021 [2]	New in 2022
Number of individual network tariff agreements	3,375	5,210	5,341	5,692	6,478	7,108	510
Total energy (TWh)	25.8	27.9	32.1	31.6	33.6	35.8	1.7
Total reductions (€mn)	310.8	271.8	262.7	253.7	275.4	296.0	15.6

[1] Figures are based on acquired consumption data.

[2] Figures for 2020 and 2021 are based on forecasts from the notifications submitted and are therefore classed as estimates; final figures for 2022 are not yet available.

Table 78: Notifications for individual network tariffs for atypical network users

6.6.2 Permanent loads – section 19(2) sentence 2 StromNEV

The total volume of reductions in network tariffs granted to electricity-intensive network users in 2021 was considerably higher at around €801mn, although the number of notifications for reductions for these users was significantly lower. In 2021, reductions were granted for a total of 513 offtake points for final customers such as large businesses or industrial enterprises with particularly energy-intensive production processes. The total volume of reductions was thus €203.8mn higher than in 2020. In the 2022 notification period, the Bundesnetzagentur received 65 further notifications for individual network tariffs in connection with electricity-intensive network users, with the volume of reductions granted amounting to €228.7mn. As these notifications include a considerable number of new notifications relating to existing individual network tariff agreements, it is not currently possible to determine the effect on the total volume of reductions.

Electricity: notifications for individual network tariffs for electricity-intensive network users

	2016	2017	2018	2019 [1]	2020 [2]	2021 [2]	New in 2022
Number of individual network tariff agreements	317	345	378	362	432	513	65
Total energy (TWh)	45.2	47.3	48.3	46.9	52.9	69.7	19.5
Total reductions (€mn)	388.4	523.8	556.9	515.8	597.3	801.1	228.7

[1] Figures are based on acquired consumption data.

[2] Figures for 2020 and 2021 are based on forecasts from the notifications submitted and are therefore classed as estimates; final figures for 2022 are not yet available.

Table 79: Notifications for individual network tariffs for electricity-intensive network users

Electricity: breakdown of total volume of reductions for electricity-intensive network users by network level category
(€mn)

	2016	2017	2018	2019 [1]	2020 [2]	2021 [2]	New in 2022
Transmission network	79.0	117.9	155.5	132.0	133.8	233.9	90.7
Regional network	168.0	225.8	213.9	176.5	209.6	268.9	89.7
Distribution network	141.0	180.1	187.5	207.3	253.9	298.3	48.2
Total	388.0	523.8	556.9	515.8	597.3	801.1	228.6

[1] Figures are based on acquired consumption data.

[2] Figures for 2020 and 2021 are based on forecasts from the notifications submitted and are therefore classed as estimates; final figures for 2022 are not yet available.

Table 80: Breakdown of total volume of reductions for electricity-intensive network users by network level category (€mn)

Electricity: breakdown of total final consumption for electricity-intensive network users by network level category
(TWh)

	2016	2017	2018	2019 [1]	2020 [2]	2021 [2]	New in 2022
Transmission network	13.0	13.5	13.9	13.1	13.3	22.7	8.1
Regional network	19.0	18.2	18.5	17.0	19.7	24.1	8.2
Distribution network	13.0	12.9	15.9	16.8	19.9	22.9	3.2
Total	45.2	44.6	48.3	46.9	52.9	69.7	19.5

[1] Figures are based on acquired consumption data.

[2] Figures for 2020 and 2021 are based on forecasts from the notifications submitted and are therefore classed as estimates; final figures for 2022 are not yet available.

Table 81: Breakdown of total final consumption for electricity-intensive network users by network level category (TWh)

The final figures for 2022 will not be available until completion of the checks on notifications and receipt of the actual billing data as required from the final customers concerned.

7. Electric vehicles/charging stations and load control

7.1 Electric vehicles/charging stations

The federal government's target is for there to be 15 million electric vehicles (vehicles solely operated with electricity) on Germany's roads by 2030. 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 when vehicles are being charged, especially 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 equipment to be notified to the network operator. In addition, the operation of charging equipment 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 operator or connection owner and the time needed for these measures.

According to the network operators' information, a total of 300,738 recharging points had been notified as connected to the network in accordance with section 19(2) NAV as of 31 December 2021.[65] This figure includes both public recharging points and 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.[66] In view of the large number of electric vehicles registered in 2021 alone (325,460 fully electric vehicles and 286,404 plug-in hybrids), it can be assumed that more recharging points, in particular private recharging points, were

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[65] A recharging point is defined in section 2 para 2 of the Charging Station Ordinance (LSV) as equipment that is suitable and intended for charging or for charging and discharging electric vehicles and that is capable of charging or discharging 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.

[66] According to section 2 para 5 LSV, a recharging point is accessible to the public if 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, unless the operator has restricted use to an individually defined group of persons by a clearly visible mark or sign at or in the immediate vicinity of the recharging point; the group of persons cannot be defined solely by the fact that use of the recharging point is made conditional on registration.

connected than are known to the network operators.[67] In the 2020 report on the status and expansion of the distribution networks, 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 equipment 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.

The most common measures proposed to connection owners to remedy the reasons for not being able to connect equipment were:

- modernising and upgrading the building connection;
- installing a new building connection;
- installing load management/restricting the charging capacity;
- recommending smaller-scale charging equipment; 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.

The Act relating to immediate action to accelerate the deployment of renewable energy and further action in the electricity sector of 20 July 2022 assigned new tasks and powers to the Bundesnetzagentur under section 14a EnWG to promote and strengthen the grid integration of controllable loads, the most prominent example being electromobility (or rather charging equipment), but only with effect from 1 January 2023.

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[67] Federal Motor Transport Authority (KBA) (2022), vehicle registrations, stock of motor vehicles and trailers by federal state, vehicle category and selected characteristics, 1 January 2021 and 1 January 2022, last accessed on 29 August 2022 at https://www.kba.de/DE/Statistik/Fahrzeuge/Bestand/Vierteljaehrlicher_Bestand/viertelj%C3%A4hrlicher_bestand_node.html (in German).

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 Member State 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 online at https://www.bundesnetzagentur.de/ladeinfrastruktur (in German).

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 introduced more uniform requirements, including for ad hoc recharging, in November 2021. Operators of recharging points taken into operation after 1 July 2023 are required to enable payment at least using standard debit and credit cards. 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 34,476 charging stations with 66,132 recharging points by 1 July 2022, of which 55,549 recharging points had a power less than or equal to 22 kW (normal-power recharging points) and 10,583 were high-power recharging points. A total of 8,179 of these charging stations and 15,581 of these recharging points were taken into operation in 2021.

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	Electric vehicles* per recharging point
Baden-Württemberg	5,963	11,571	1,655	22
Bavaria	6,959	13,109	1,975	21
Berlin	1,055	1,989	241	22
Brandenburg	735	1,409	284	21
Bremen	248	483	56	18
Hamburg	919	1,829	242	20
Hesse	2,684	5,225	733	27
Mecklenburg-Western Pomerania	414	812	160	16
Lower Saxony	3,724	7,094	1,240	20
North Rhine-Westphalia	6,242	11,770	1,672	30
Rhineland-Palatinate	1,312	2,499	636	28
Saarland	265	534	75	31
Saxony	1,369	2,685	500	14
Saxony-Anhalt	588	1,139	292	16
Schleswig-Holstein	1,379	2,695	472	19
Thuringia	620	1,289	350	17

*Fully electric vehicles and plug-in hybrids as at 1 July 2022

Table 82: Notified charging infrastructure by federal state (as at July 2022)

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 (German web page).

The Bundesnetzagentur published its first monthly "Charging infrastructure in figures" in March 2022. The Excel tables provide comprehensive data on Germany's charging infrastructure, with a comparison of the most recent monthly figures as well as an overview since 2017. The tables provide figures on normal and high-power recharging points, charging capacities and plug types in Germany as well as on recharging points and charging capacities in each federal state and recharging points in each district and town not affiliated with a district. The data are available online at https://www.bundesnetzagentur.de/DE/Fachthemen/ElektrizitaetundGas/E-Mobilitaet/start.html (in German).

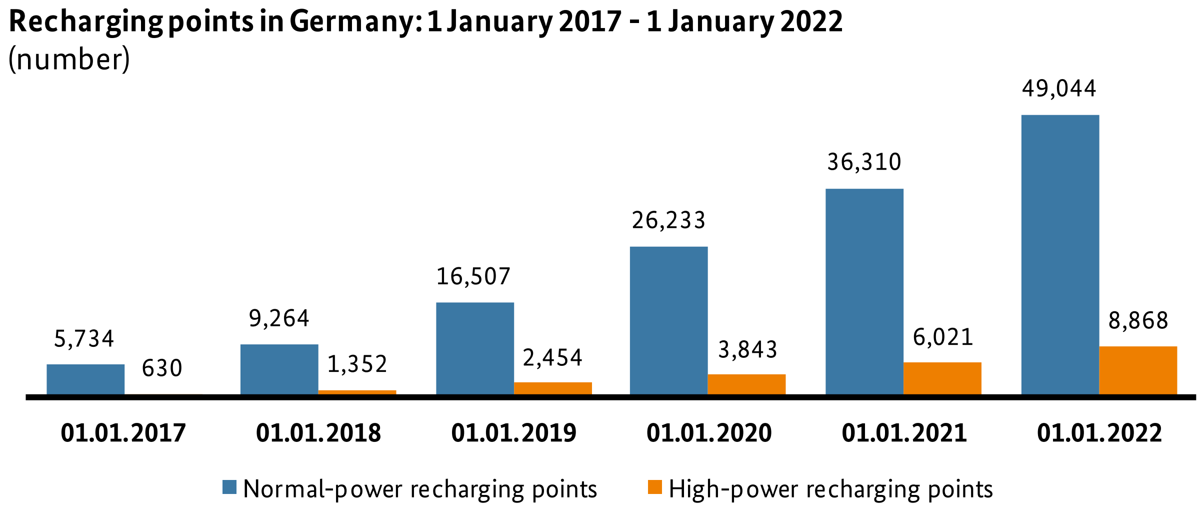
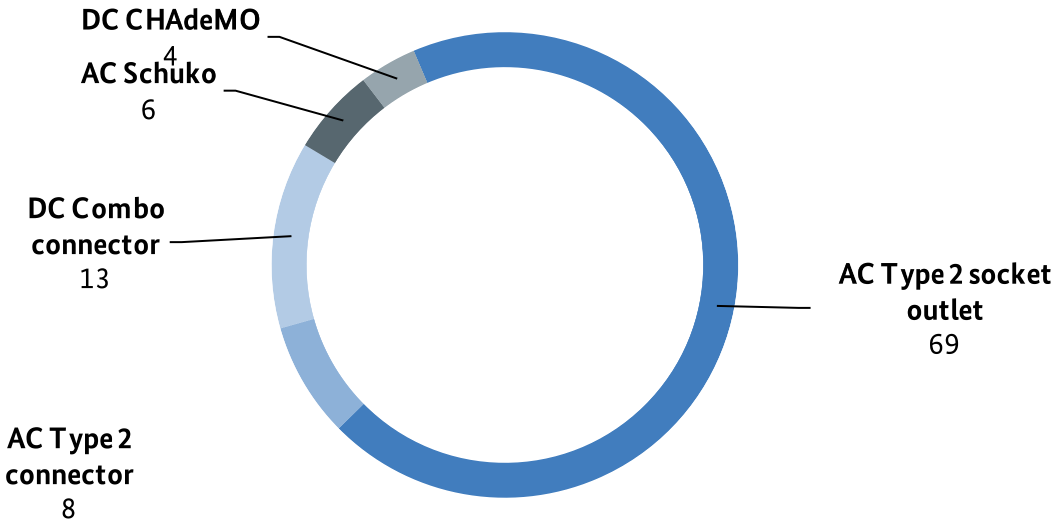


Figure 73: Recharging points in Germany

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 chart 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 2022

Figure 74: Breakdown of charging plugs by type in Germany

The charging capacities of the recharging points are distributed as shown in Figure 75. 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 also being installed.

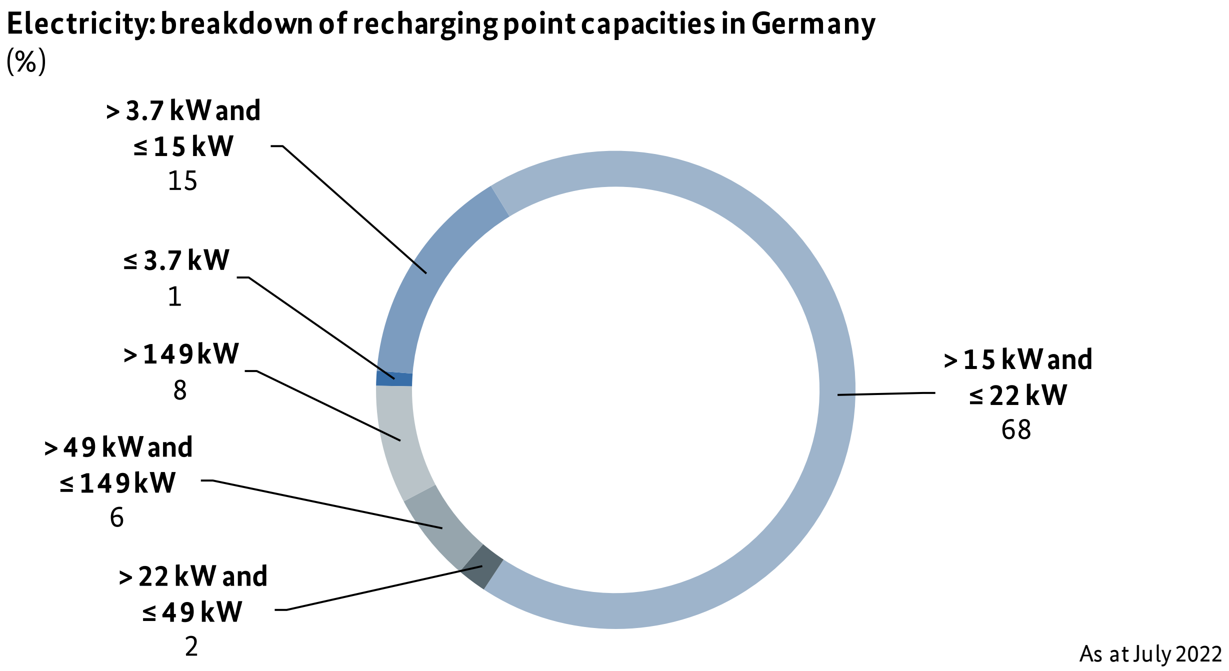


Figure 75: Breakdown of recharging point capacities in Germany

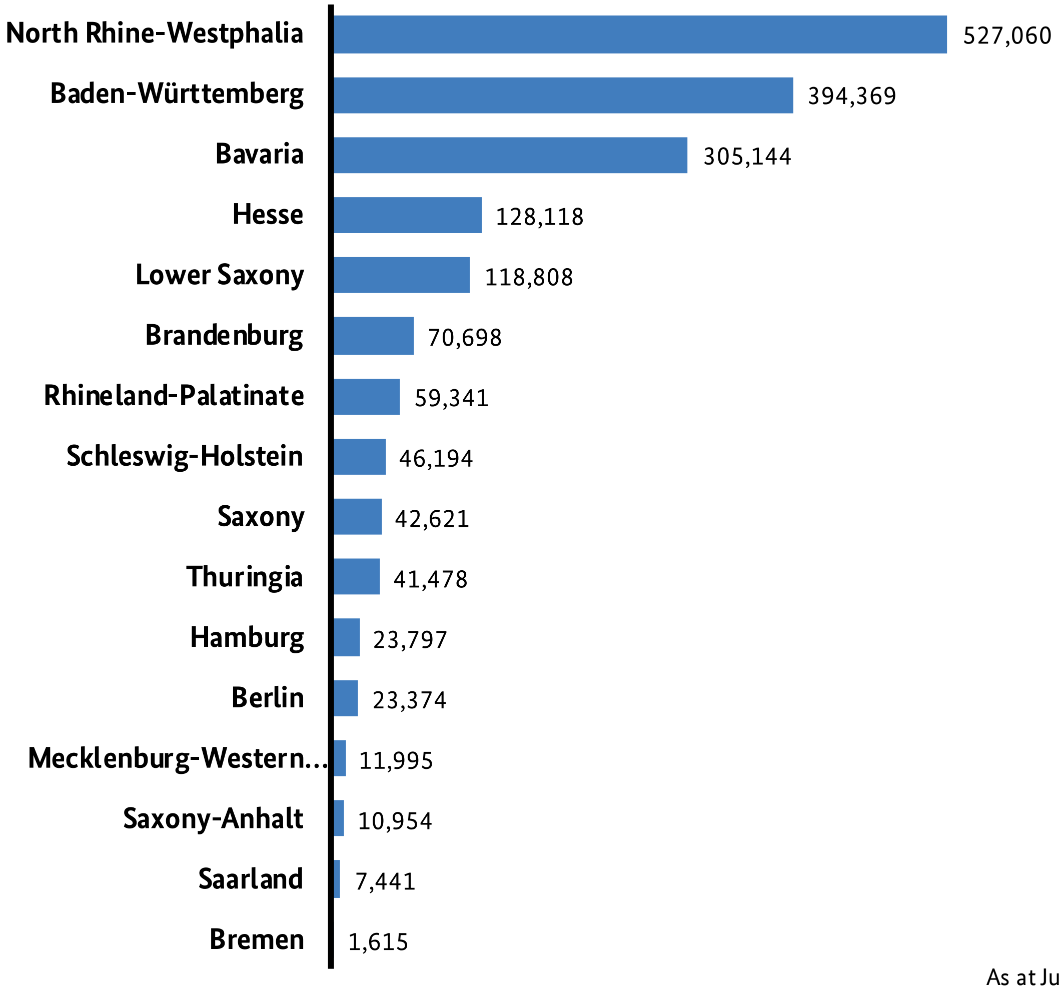
Since 2018, the Bundesnetzagentur has been working together with the PTB and now also records the public keys for the notified recharging points. The user can enter the verification key on the metering equipment into verification software provided by the e-mobility provider. With this software, the user 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.

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 the Monitoring Report 2021, 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 tariff. 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)

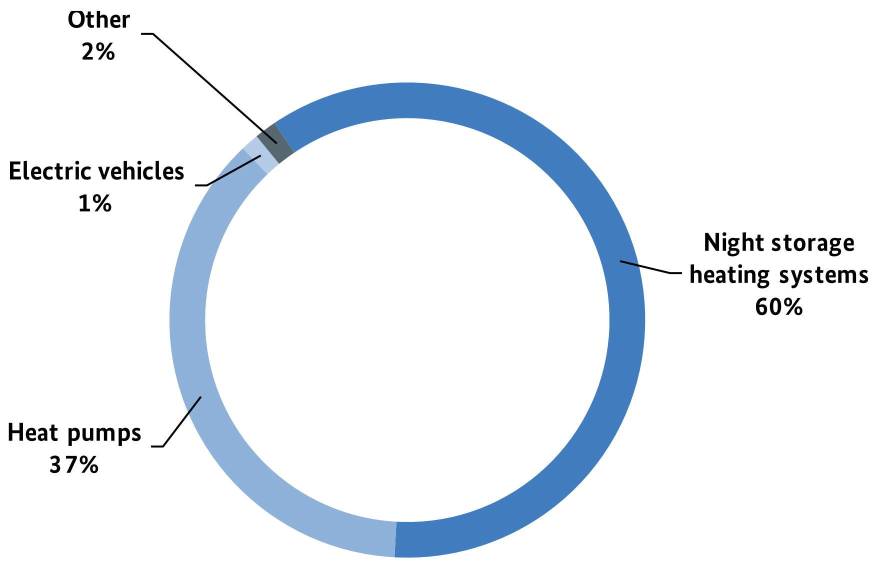


As at July 2022

Figure 76: Market locations with load control by federal state

A total of 675 out of the 809 network operators surveyed stated that they took advantage of the provision and charged reduced network tariffs for a total of 1,813,007 market locations with load control. This represents a year-on-year increase of 36,242 loads. The regional distribution is shown in the chart above. As in previous years, the chart shows a high concentration in Baden-Württemberg, Bavaria and North Rhine-Westphalia, with two thirds 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
(%)



As at July 2022

Figure 77: Breakdown of market locations with reduced network tariffs by load type

It is still the case that almost all the market locations with load control are for heating systems (see above chart), and direct electric heating also accounts for most of the "Other" loads, with only a few sprinkler or street lighting systems also counted in this category. The changes in the shares seen in previous years have continued. For example, the share of night storage heating systems is down by more than three percentage points, while the share of heat pumps is up by three and a half percentage points. The share of electric vehicle charging infrastructure is now 1.23% (previous year: 0.71%).

The average reduction in the network tariff given by network operators in return for load control is about 57%, which corresponds to an average discount of 3.84 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 about 85% of the general network tariff, while the lowest is just 3%. 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 over 55% of the network operators use ripple control, while only just over 1% use the more modern remote control technology. Between 4% and 8% 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 electric vehicles is very different. Ripple control accounts for only about a third, remote control technology here again accounts for only around 4%, but only just over 16% of network operators use time switching. What is striking, however, is that about 40% of the network operators use no control technology at all for electric vehicles, even though the vehicles benefit from section 14a network tariffs. The chart below shows a more detailed breakdown of the control technologies used.

Electricity: load control technology
(%)

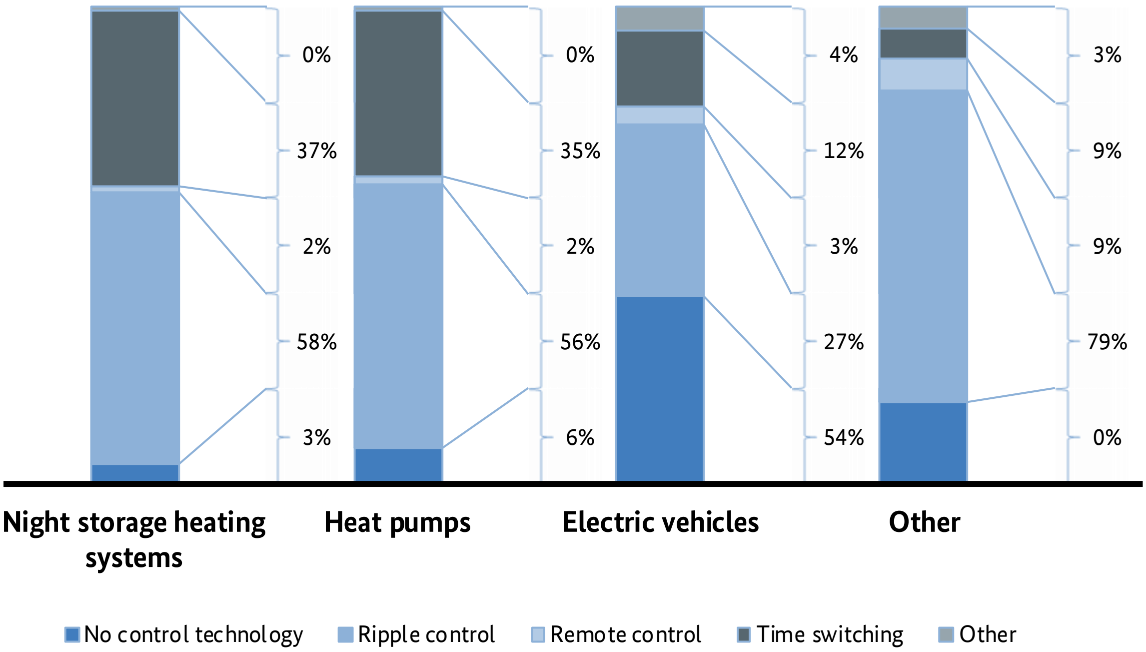


Figure 78: Load control technology

As far as a move to more modern technology is concerned, there has hardly been a 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 change a pre-set control profile if necessary to ensure network stability and carry out ad hoc control actions not within a profile.

8. Differential balancing groups

Section 12(3) of the Electricity Network Access Ordinance (StromNZV) requires electricity DSOs to implement a "differential balancing group". A differential balancing group comprises the differences between the consumption of all non-interval metered (standard load profile – SLP) final customers and actual consumption. These can be differences in the load pattern and/or in the consumption quantity of the non-interval metered customers. The differences in quantity are registered when the non-interval metered customers' energy meters are read on a rolling schedule. The differences in load pattern are determined by subtracting the interval-metered consumption from the total consumption. The actual load pattern determined for non-interval metered customers has a degree of inaccuracy with respect to quantifying loss energy.

The requirement to implement a differential balancing group does not apply to DSOs with fewer than 100,000 customers connected directly or indirectly to their distribution networks.

It is only necessary to balance a differential balancing group if synthetic load profiling is used. In the case of synthetic load profiling, the load profiles are defined in accordance with section 12(2) sentences 1 and 2 StromNZV. The DSOs communicate the profiles to the suppliers. The electricity is supplied and charged for in accordance with these profiles.

Any differences between the SLPs and the actual patterns are balanced within the differential balancing group. Changes in consumption in the winter mean that there is a risk of these differences becoming much larger. A differential balancing group managed by a DSO is balanced through electricity trading, which could lead to a significant rise in costs because of higher prices on the exchange.

If analytical load profiling is used, it is not necessary to balance a differential balancing group because the profile deviations can be determined for each customer group on a daily basis and passed on in full to the suppliers' balancing groups.

The 2022 monitoring survey showed that about 15% of the DSOs surveyed use analytical load profiling and do not therefore need to implement differential balancing. The remaining 85% of the DSOs use synthetic load profiling. About 49% of these DSOs stated that they are required to implement a differential balancing group, while the remaining 51% are not subject to the requirement.

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 three different qualities 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 directly 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 IC5. Interruptible loads under the Interruptible Loads Ordinance (AbLaV) and the provision of the capacity reserve are also part of the range of tasks.

1. Costs for system services

The net costs for the system services that are **recovered through the network tariffs** amounted to around €3,437.3mn in 2021 (2020: €2,102.7mn).[68] Major costs in 2021 were the costs for congestion management, contracting FCR, aFRR and mFRR, and loss energy.

The costs for network management amounted to around €2,285.4mn (2020: €1,432.2mn) and comprise the estimated claims for compensation for feed-in management measures at €807.1mn (2020: €761.2mn), national and cross-border redispatching at €590.2mn (2020: €240.1mn), reserving and using grid reserve power plants at around €491.4mn (2020: €296.3mn), and countertrading at €396.7mn (2020: €134.7mn). The increase in the costs for congestion management is due firstly to the large increase in the volume of the measures and secondly to the big increase in wholesale prices. This increase in wholesale prices also had an effect on the costs of on-exchange countertrading and the costs for positive redispatching. The large increase in the volume of the congestion management measures was due to problems with transporting coal because of low river levels, which restricted the operational readiness of several power plants in southern Germany. More information on congestion management can be found separately in IC5.

Loss energy is the energy required to compensate for the energy lost during transport in the network. The costs for loss energy are therefore the costs of procuring this energy. The costs for loss energy amounted to €458.4mn in 2021 (2020: €450.5mn), representing an increase of about 2%. The relatively small increase compared with other major costs is due to the fact that most of the energy needed to compensate for network losses was procured well in advance before the rise in wholesale prices and so relatively low prices were secured.

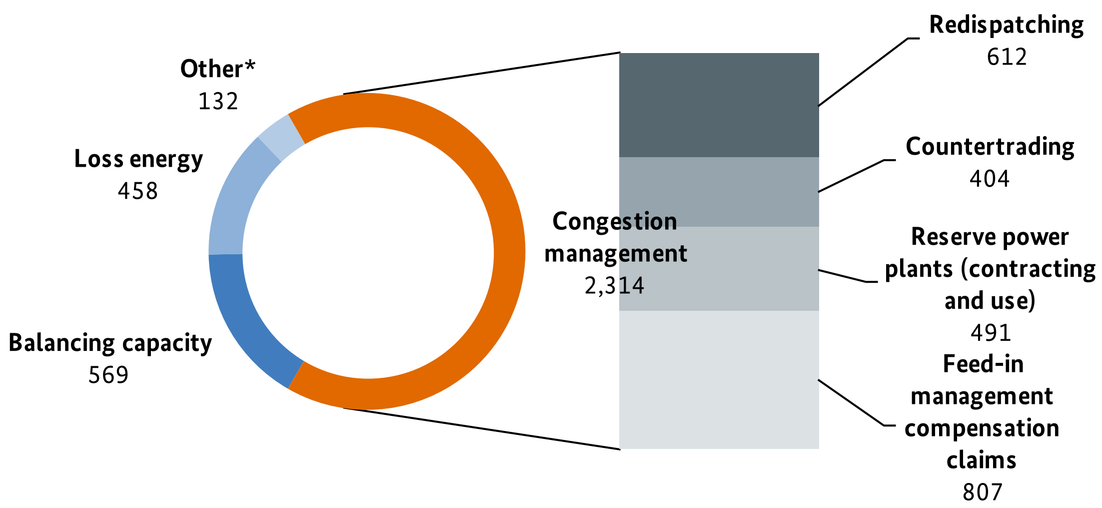
The TSOs procure different qualities of balancing capacity – FCR, aFRR and mFRR – to balance electricity generation and consumption with the aim of maintaining the frequency of the European interconnected grid at 50 Hz. In 2021, the costs for FCR (€86.2mn), aFRR (€393.0mn) and mFRR (€89.4mn) amounted to €568.6mn

[68] The costs for loss energy for 2020 were corrected.

(2020: €152.4mn). As the day-ahead and intraday markets are seen to be lead markets for the balancing capacity markets and have a strong influence on the prices for balancing services, the increase in the costs for contracting the capacity is probably mainly due to the general developments in the electricity market. In light of the fact that balancing service providers could also market their capacity on the day-ahead and intraday markets, the revenues lost by not marketing their capacity on these markets are priced into the contracting costs. The rise in prices on the electricity exchange in 2021 resulted in an increase in the revenues lost by the balancing service providers by not marketing their capacity on the day-ahead and intraday markets and consequently in an increase in the contracting costs.

The chart below shows a breakdown of the above-mentioned costs for 2021:

Electricity: breakdown of the costs for system services and for congestion management measures in 2021
(€mn)



*Other: reactive power, black start capability, interruptibleloads under AblaV

Figure 79: Breakdown of the costs for system services and for congestion management measures in 2021

The chart below shows the development in the costs for system services from 2017 to 2021:

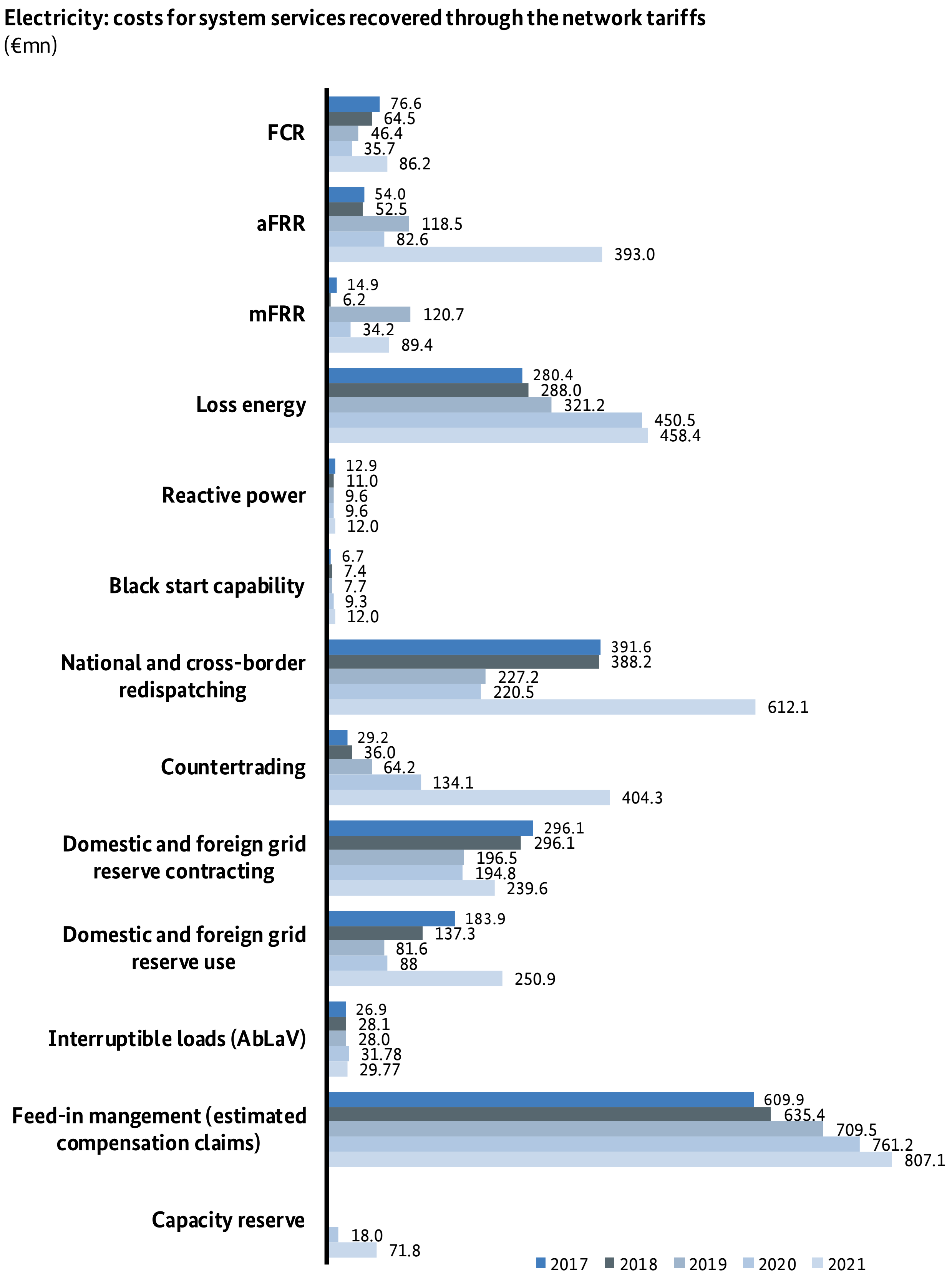


Figure 80: Costs for system services recovered through the network tariffs

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. In 2021, the capacity reserve was made up of eight generation plants with a total capacity of 1,086 MW that are remunerated with a price of €68,000/(MW*year) determined in a competitive award process. The provisional costs for keeping the plants in the capacity reserve in 2021 amount to €71.8mn.

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 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.

The costs for system services also include the costs for converting power plants to rotating phase shifters. Power plants operating as rotating phase shifters do not feed electricity into the grid but stabilise the grid by providing reactive power. The aim of the coal phase-out – to reduce greenhouse gas emissions – is met because the converted power plants stop generating electricity from coal. The hard coal-fired power plant Westfalen E has been classed as systemically important for providing reactive power to maintain voltage stability and is being converted to a rotating phase shifter. The converted power plant is due to start operation in 2022.

2. Balancing services

Since the introduction of the balancing energy market on 2 November 2020 (first delivery day: 3 November 2020) there have been 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 can be delivered by all pre-qualified providers 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 currently released by the TSOs and can be marketed elsewhere. The TSOs have proposed that all balancing energy bids submitted by balancing service providers should be transmitted to the European platforms for the exchange of balancing energy – PICASSO (aFRR) and MARI (mFRR). A decision on the proposal will be made in the course of the year.

The product validity periods in the balancing energy market were initially the same as in the balancing capacity market (six products with a validity period of four hours each). The product validity periods were changed to 15 minutes, with a gate closure time of 25 minutes before the start of each product validity period, when the PICASSO and MARI platforms went live in June 2022 and October 2022 respectively.

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.[69] 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

[69] Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing, Article 2 point (3)

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.[70]

- 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; they can also be activated directly outside the 15-minute schedule.

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

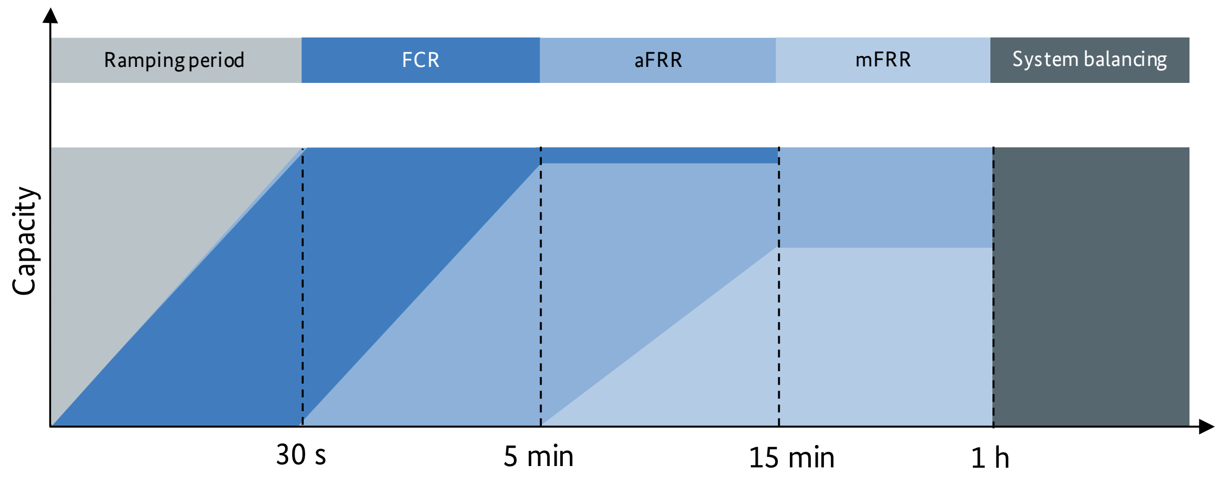


Figure 81: Order and time frame for the use of balancing services

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, there will be too little power in the system and 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 need more energy to be fed into the system and/or less energy to be consumed at short notice. 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 need negative balancing services in the form of electricity consumers withdrawing more electricity from the system and/or electricity generators feeding less electricity

[70] 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.

into the system at short notice. The TSOs procure both positive and negative balancing 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 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. The International Grid Control Cooperation (IGCC) enabled cooperation with Denmark, the Netherlands, Switzerland, Czechia, Belgium, Austria, France, Croatia and Slovenia with the aim of avoiding the inefficient use of balancing services; this cooperation was carried over into the imbalance netting platform under Article 22 of Regulation (EU) 2017/2195 in 2021. 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. However, the national and cross-border imbalance netting is reflected by the decrease in the activated volumes of aFRR and, indirectly, mFRR.

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[71], aFRR[72] and mFRR and in line with European rules and decisions.

The tendering for the procurement of aFRR and mFRR was, however, redesigned following the entry into force of new European provisions.[73] The new provisions required 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. Previously, balancing energy could only be delivered by providers successfully bidding in the capacity market; now, balancing energy can be delivered by all pre-qualified providers independent of participation in the capacity market.

[71]Tendering in accordance with the decisions of 13 December 2018 (BK6-18-006) and 18 May 2022 (BK6-21-366). See I.D.3.1.

[72] 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).

[73] 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

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 volatile 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 intermittent 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 as well. In addition, new rules were introduced on the minimum bid volumes and safeguards for both aFRR and mFRR. These framework conditions also initially applied in the balancing energy market. The product validity periods in the balancing energy market were changed to 15 minutes, with a gate closure time of 25 minutes before the start of each product validity period, when the European platforms for the exchange of balancing energy – PICASSO (aFRR) and MARI (mFRR) – went live. The balancing energy market is designed to make it easier for flexible generators to participate in the balancing markets. 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 up-to-date tendering conditions. By 28 January 2022, the number of pre-qualified balancing service providers stood at 30 for FCR (2021: 29), 34 for aFRR (2021: 35) and 34 for mFRR (2021: 38). The number of pre-qualified providers for FCR has therefore increased slightly, while there has been a slight decrease in the number of pre-qualified providers for aFRR and for mFRR.

Procurement of FCR

FCR procurement needs are determined jointly by the central European TSOs within ENTSO-E and are based on the simultaneous failure of the two largest power plant blocks within the Continental Europe Synchronous Area. The total amount – currently 3,000 MW – is divided proportionally between the participating TSOs in the various countries within this area; the proportions are recalculated each year based on both the previous year's electricity feed-in and the load. The chart below 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 and 2021. The volume of FCR tendered in Germany in 2021 amounted to 562 MW. As there has been an overall decrease in generation in Germany in the past few years compared with other countries in the Continental Europe Synchronous Area, Germany's share in FCR has also decreased, as has its share in feed-in and load in continental Europe.

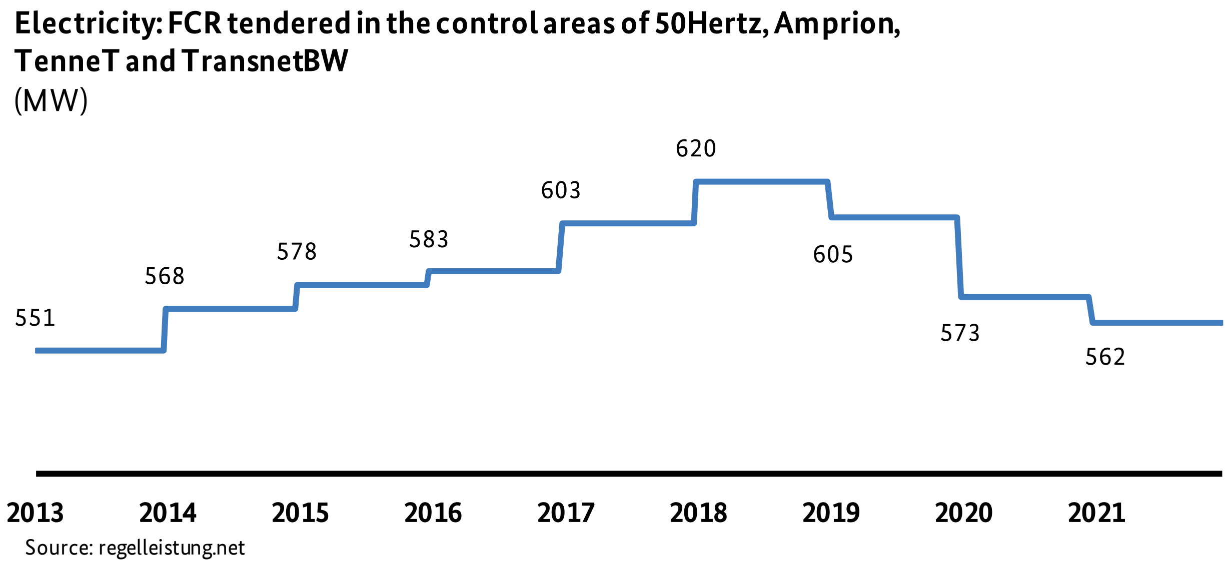


Figure 82: FCR tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

Procurement of aFRR

The chart below shows that in 2021 there was a slight decrease in the average volume of both positive and negative aFRR tendered. The average volume of positive aFRR tendered was 2,092 MW (2020: 2,101 MW) and the average volume of negative aFRR tendered was 1,972 MW (2020: 2,022 MW).

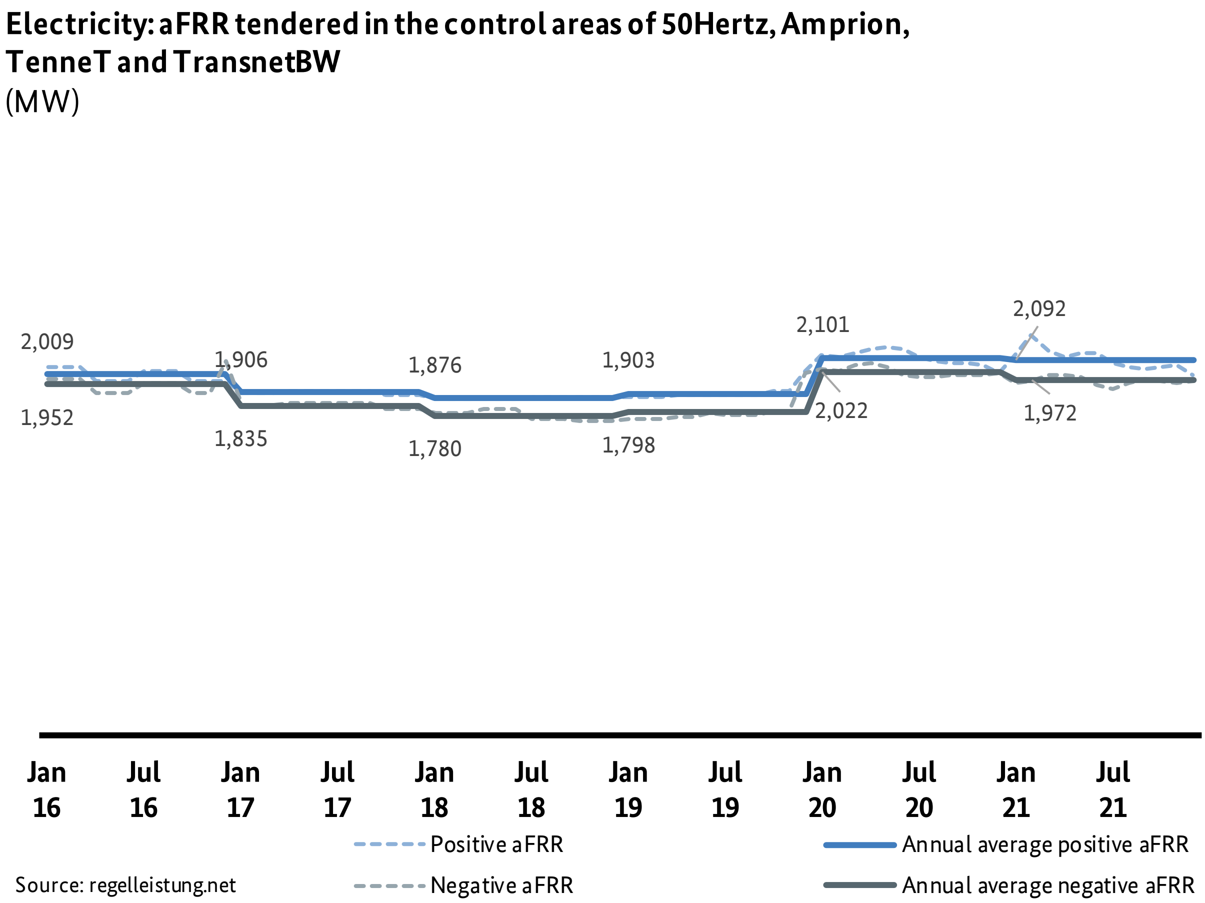


Figure 83: aFRR tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

The table below shows that the ranges between the minimum and maximum amounts for both positive and negative aFRR were again 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)	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
	2021	1,618	2,669
aFRR (negative)	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
	2021	1,671	2,530

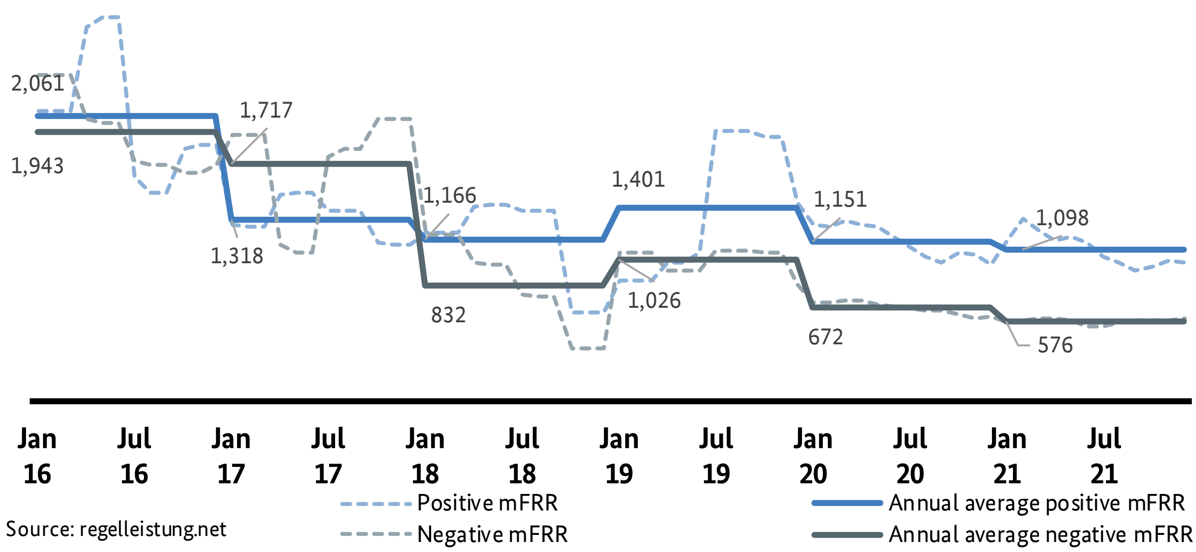
Source: regelleistung.net

Table 83: Range of aFRR tendered by the TSOs

Procurement of mFRR

There was another decrease in 2021 in the average volume of both positive and negative mFRR tendered, with an average volume of positive mFRR of 1,098 MW and of negative mFRR of 576 MW.

Electricity: mFRR tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW
(MW)



Source: regelleistung.net

Figure 84: 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)	2016	1,504	2,779
	2017	1,131	1,850
	2018	641	1,419
	2019	874	1,952
	2020	337	1,406
	2021	339	1,740
mFRR (negative)	2016	1,654	2,353
	2017	1,072	2,048
	2018	375	1,199
	2019	644	1,094
	2020	276	809
	2021	339	809

Source: regelleistung.net

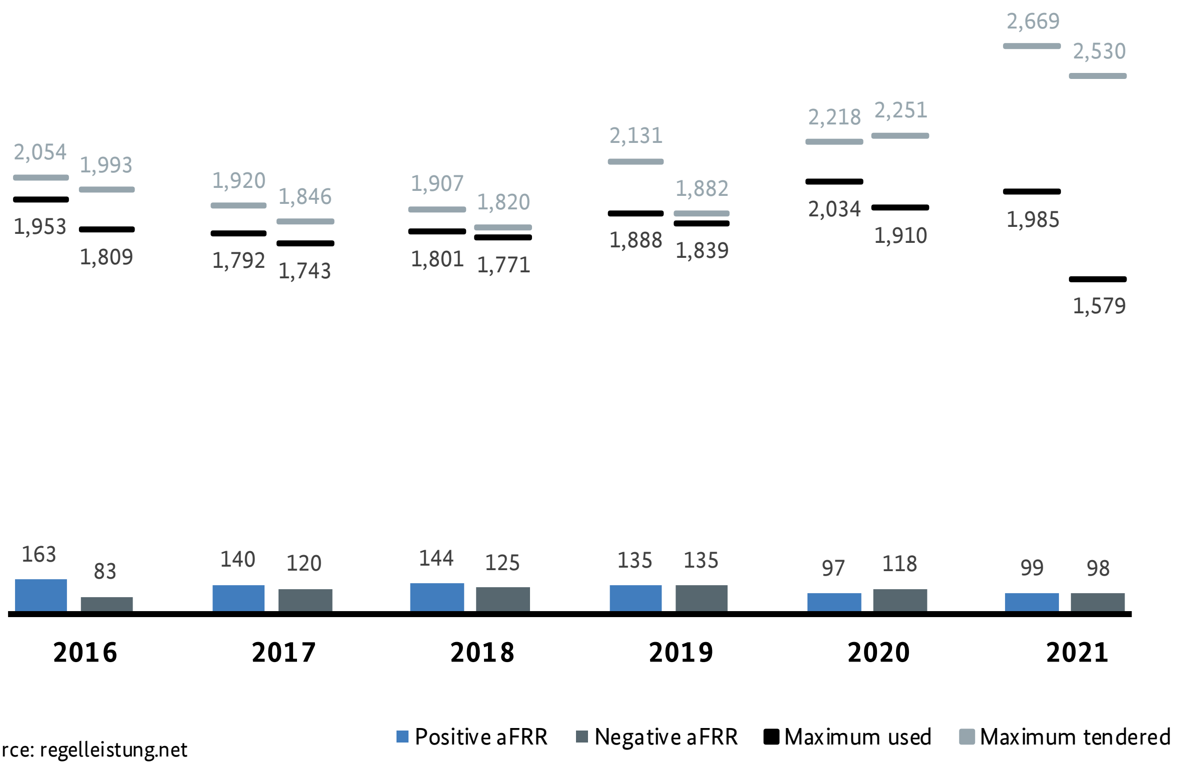
Table 84: Range of mFRR tendered by the TSOs

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 a 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.

The chart below shows that in 2021 there was a slight increase in the average volume of positive aFRR used at 99 MW (2020: 97 MW) and a decrease in the average volume of negative aFRR used at 98 MW (2020: 118 MW). By contrast, the highest volume of both positive and negative aFRR activated was lower 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)



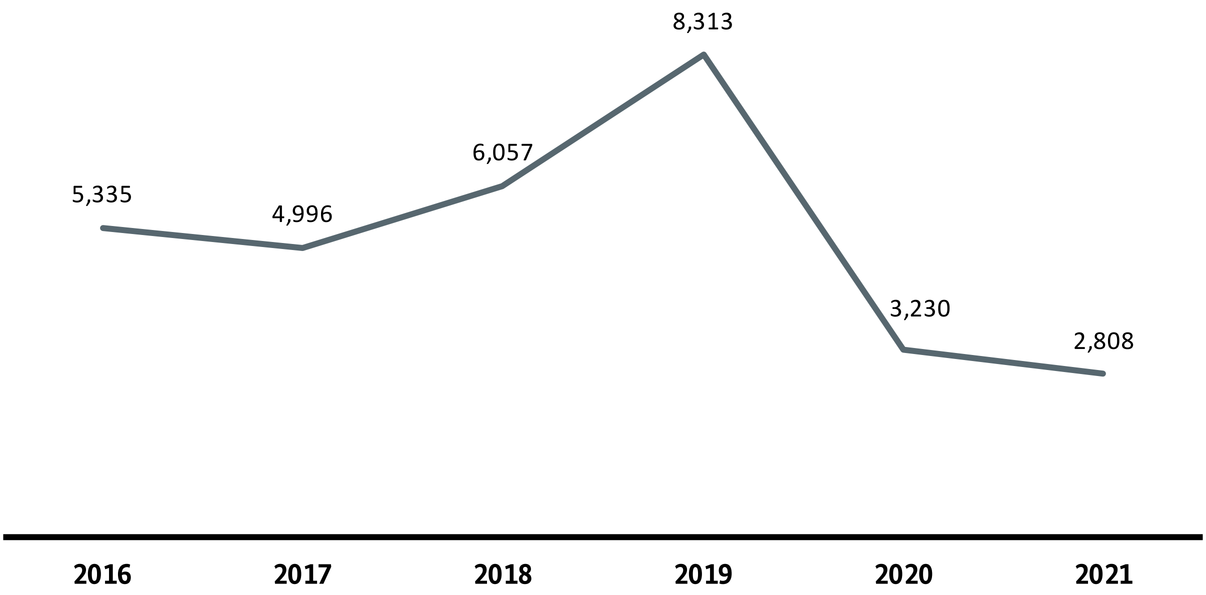
Source: regelleistung.net

Figure 85: Average volume of aFRR used, including aFRR drawn and delivered under online netting in the national grid control cooperation (MW)

In 2021, the total amount of positive aFRR activated was around 0.9 TWh (2020: 0.8 TWh), and the total amount of negative aFRR activated was 0.8 TWh (2020: 1.0 TWh). On average in 2021, just under 1% of the average volume of positive and negative aFRR tendered was used.

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.[74]

Electricity: frequency of use of mFRR
(number of requests)



Source: regelleistung.net

Figure 86: Frequency of use of mFRR

At 2,808, the total number of requests for mFRR in 2021 was lower than the previous year's figure of 3,230. Overall, there were 1,192 requests for negative mFRR in 2021 (2020: 974) and 1,616 requests for positive mFRR (2020: 2,256).[75]

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[74] https://www.smard.de

[75] The number of requests for aFRR is not illustrated separately because it is requested in nearly every quarter hour.

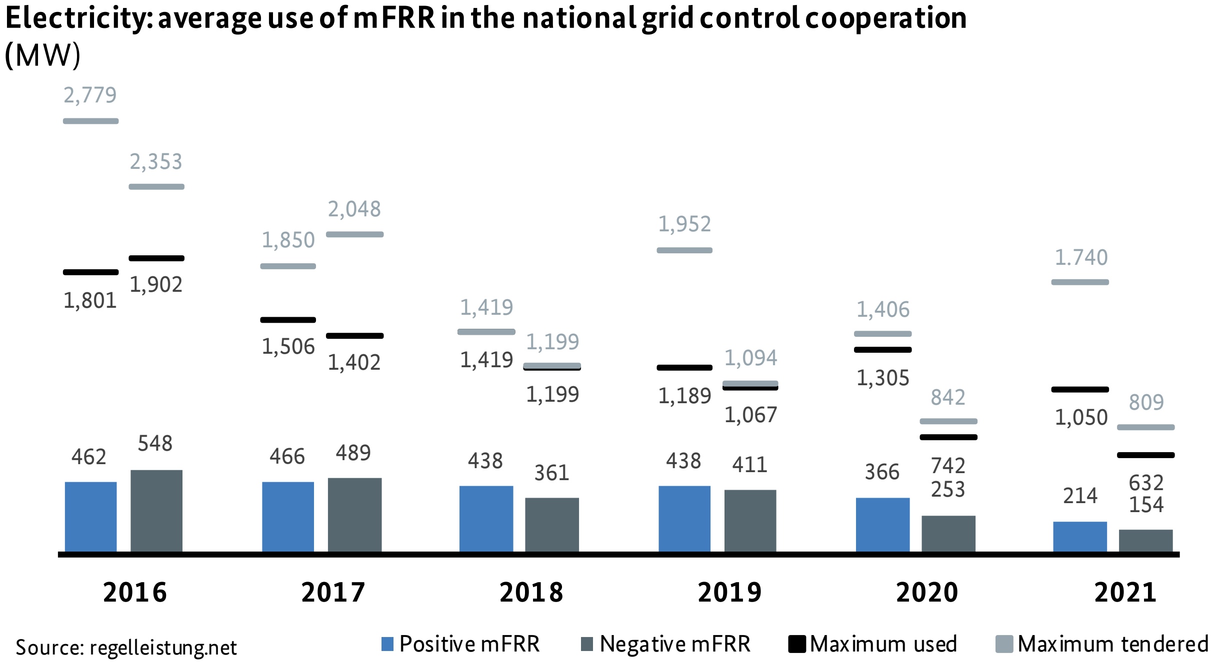

Figure 87: Average use of mFRR in the national grid control cooperation (MW)

In the quarter hours in which mFRR were requested, on average 5% of the positive mFRR tendered and 6% of the negative mFRR tendered were used. There was a decrease in the average volume of positive mFRR used from 366 MW in 2020 to 214 MW in 2021. At 154 MW, the average volume of negative mFRR used in 2021 was considerably lower than in the previous year (2020: 253 MW).

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 2021 each amounted to less than 1% of the average volumes tendered.

The chart below illustrates the average use of aFRR and mFRR in each calendar week from 2016 to 2021. 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 package of measures designed to improve the upholding of balancing group commitments that the Bundesnetzagentur drew up in response to the major imbalances in the transmission system in June 2019 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.[76]

[76] See decisions of 11 December 2019 (BK6-19-212, BK6-19-217 and BK6-10-218).

There were consequently 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.

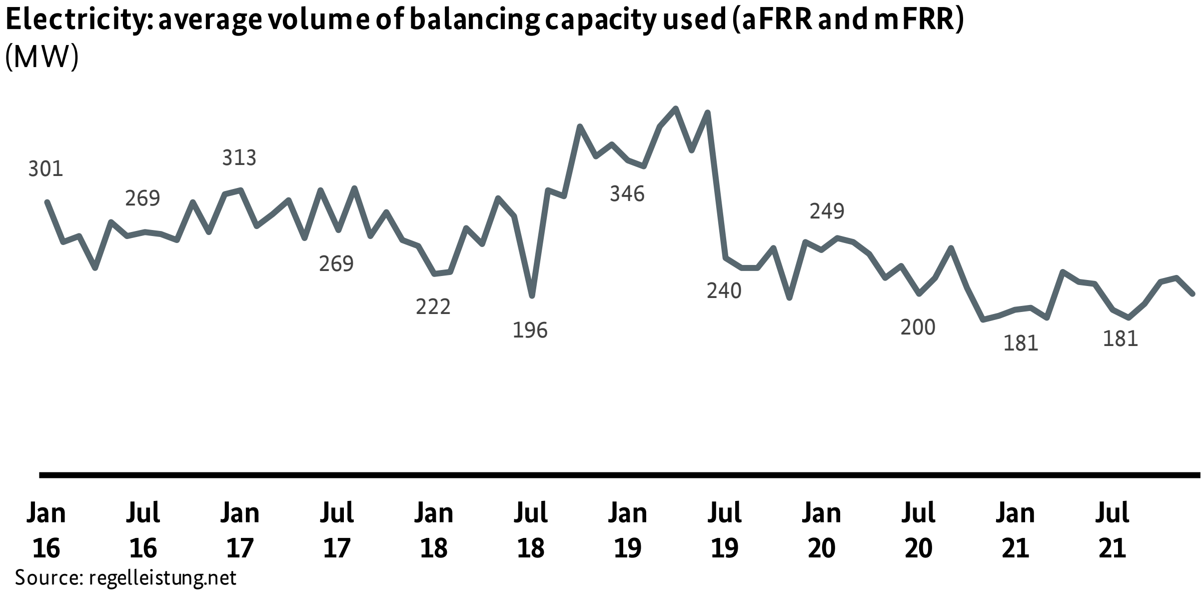

Figure 88: Average volume of balancing capacity used (aFRR and mFRR) (MW)

2.3 Imbalance prices

While the costs for contracting balancing capacity are included in the network tariffs 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. In 2021, the costs for contracting balancing capacity amounted to €568.6mn (2020: €152.4mn). The increase in the costs for contracting the capacity is mainly due to the general developments in the electricity market. Further information on contracting balancing capacity can be found in ID1. 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. 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; this used to be based on the costs and revenues from using aFRR and mFRR, but as from mid-2022 is based on prices; 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.[77] 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.[78] 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:

Electricity: maximum imbalance prices

Year	Uniform single imbalance price (€/MWh)
2016	1,212.80
2017	24,455.05
2018	2,013.51
2019	2,865.11
2020	15,859.10
2021	3,804.59

Source: regelleistung.net

Table 85: Maximum imbalance prices

The price calculation rules for module 1 and the related rules for the imbalance price system were changed in 2022 because of the need for the calculation of the imbalance price to follow European rules when the German TSOs joined the PICASSO and MARI platforms for the exchange of balancing energy.[79] Instead of the previous "cost-based" calculation described above, the European rules envisage a "price-based" calculation of the imbalance price based on the cross-border marginal prices formed on the abovementioned platforms for the main activation direction of the respective TSO in the relevant quarter hour. In order to limit unwanted developments in the form of high balancing energy prices when the European platforms went live, as well as the consequences for the imbalance price, ACER approved a proposal from the European TSOs to lower the

[77] See decision of 11 May 2020 (BK6-19-552) https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK6-GZ/2019/BK6-19-552/Beschluss/BK6-19-552_Beschluss.html.

[78] 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.

[79] See decision of 28 April 2022 (BK6-21-192) https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK6-GZ/2021/BK6-21-192/BK6-21-192_beschluss.html?nn=411978.

upper price limit for balancing energy for a transitional period to €15,000/MWh.[80] The occurrence of high imbalance prices as a result of an unwanted development in the balancing energy prices would have meant enormous financial risks for the balance responsible parties even with small and unavoidable imbalances. In 2021, 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: positive balancing capacity is used and balancing service providers reduce consumption or increase feed-in) was considerably higher than in the previous year at €198.69/MWh (up €96.71/MWh). The average volume-weighted imbalance price in the case of a negative control area imbalance (long portfolio: negative balancing capacity is used and balancing service providers increase consumption or reduce feed-in) was €16.77/MWh and thus positive for the first time. This development is also due to the general increase in prices on the wholesale markets for electricity beginning in 2021. While the prices usually bid – and later activated – for negative balancing energy sometimes mean that payments are made by the balancing service providers to the TSOs (in particular because of savings in fuel costs), prices for negative balancing energy also increased in 2021, with the result that the average volume-weighted imbalance price was positive.

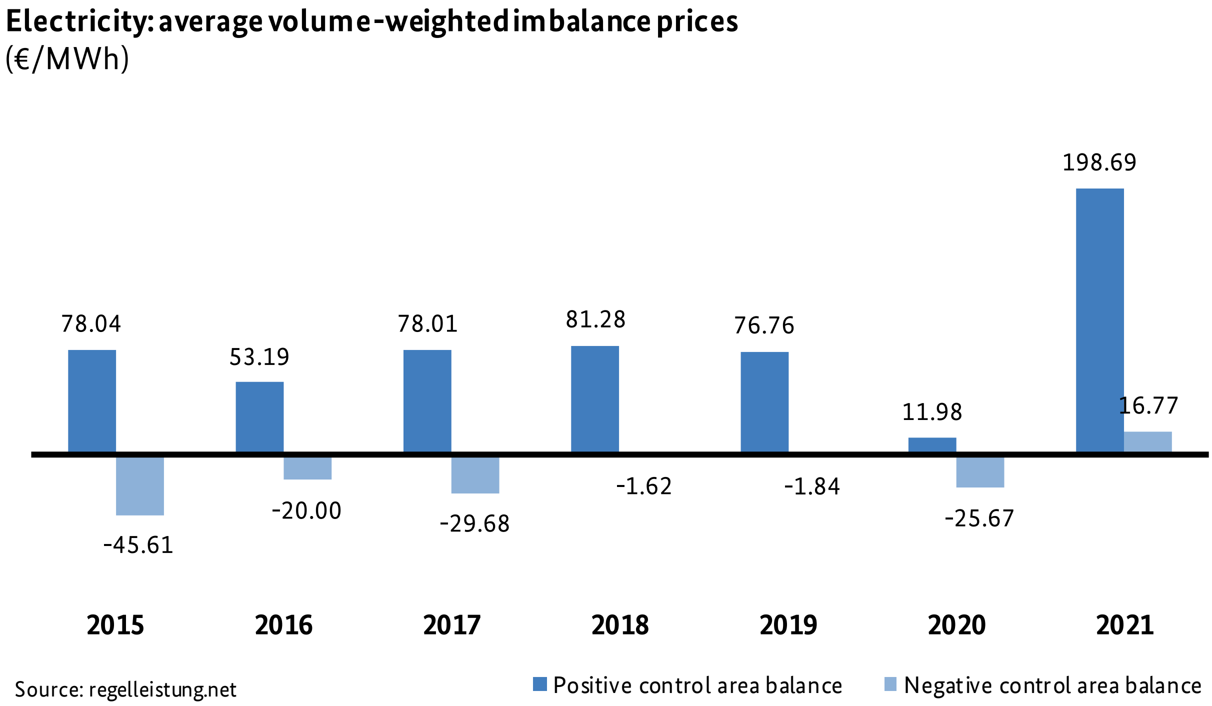

Figure 89: Average volume-weighted imbalance prices

[80] See ACER Decision No 03/2022 of 25 February 2022 on the amendment to the methodology for pricing balancing energy and cross-zonal capacity used for the exchange of balancing energy or operating the imbalance netting process.

3. European developments in the field of electricity balancing services

3.1 International FCR cooperation

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.

Electricity: total volume of FCR tendered in the control areas of the German TSOs, Swissgrid (CH), TenneT (NL), APG (AT), ELIA (BE) and RTE (FR) (MW)

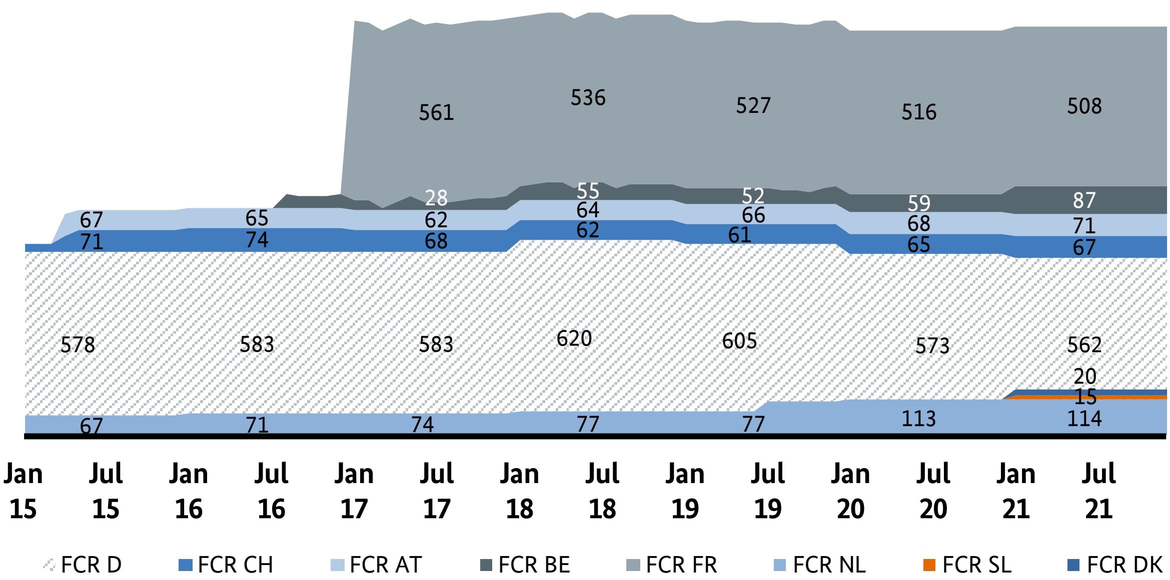

Figure 90: Total volume of FCR tendered in the control areas of the German TSOs, Swissgrid (CH), TenneT (NL), APG (AT), ELIA (BE) and RTE (FR)

The proportion of the volume of more than 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 and consumption 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 and consumption.

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, BK6-21-366).

Last year, the TSOs in Denmark (energinet.dk) and Slovenia (ELES) joined the cooperation scheme. The TSO in Czechia (CEPS) is expected to join in 2023 to procure all of its required FCR through the cooperation scheme.

3.2 Go-live for the 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.

The platforms were established by the European TSOs on the basis of the approval from ACER. The PICASSO platform (pursuant to Article 21 of Regulation (EU) 2017/2195), which went live in June 2022, serves the exchange of balancing energy from aFRR and the MARI platform (pursuant to Article 20 of Regulation (EU) 2017/2195), which went live in October 2022, the exchange of balancing energy from mFRR. The German TSOs are among the first to use both platforms. The other European TSOs will join the platforms successively up to 2024.

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 expiry of the ordinance with effect from 1 July 2022 did not have any effect on the procurement and use of interruptible loads during the reporting period. The TSOs held 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 2021. The chart shows that over the whole period the capacity contracted for immediate interruption was still well below the total interruptible load capacity tendered of 1,500 MW.

The highest total amount of capacity contracted for fast interruption in the reporting period was up to 863 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 capacity contracted for fast interruption exceeded the volume of 750 MW in 46 auctions.

By contrast, the highest total amount of capacity contracted for immediate interruption in 2021 was only 517 MW. This does not represent an increase compared with the previous year (519 MW). In addition, the highest total amount of capacity contracted for immediate interruption was again well below the maximum possible of 750 MW.

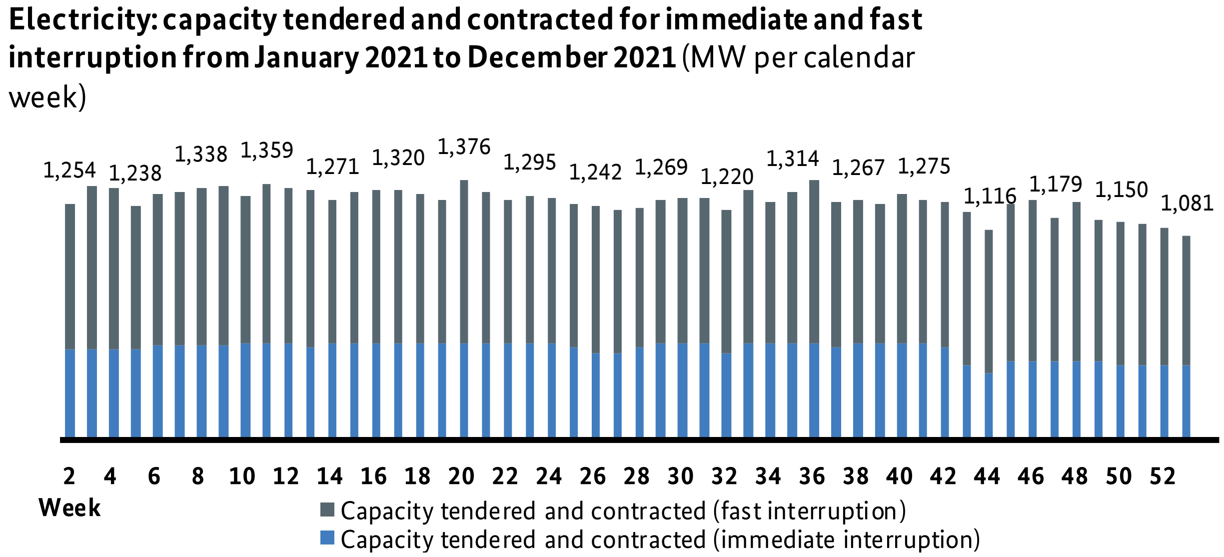

Figure 91: Capacity tendered and contracted for immediate and fast interruption from January 2021 to December 2021 (MW)

4.2 Pre-qualified capacity

Nine loads with a total interruptible capacity of 797 MW were pre-qualified as immediately interruptible loads in 2021. In addition, 49 loads pursuant to section 2 para 11 AbLaV with a total interruptible capacity of 1,726 MW were pre-qualified as quickly interruptible loads in 2021. No consortia pursuant to section 2 para 12 AbLaV pre-qualified as interruptible loads. 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 2021, interruptible loads were used comparably with the use of balancing capacity to balance the system on four days. The highest interruptible load capacity of 891 MW was requested on 14 August 2021. The interruptible loads were used to balance the system at the same time as positive mFRR. Interruptible loads were not used in 2021 for redispatching purposes.

The contracted immediately interruptible loads were registered on time as not available for 11,442 hours, thus 376,470 MWh of interruptible energy was not available from the immediately interruptible loads. By contrast, the quickly interruptible loads were registered as not available in 2021 for 35,403 hours, thus 632,892 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 2021 were again lower at €1,080,183 (2020: €1,200,460; 2019: €2,933,093; 2018: €952,774), reflecting the decrease in the use of interruptible loads compared with the previous year. There was also a slight decrease in the capacity-based costs for contracting the interruptible loads at€29,765,393 (2020: €30,124,235; 2019: €28,013,447; 2018: €26,770,491). The TSOs' transaction costs for implementing the AbLaV fell in 2021 to €205,150 (2020: €454,000; 2019: €306,112; 2018: €355,023). The total costs for interruptible loads therefore amounted to €31,050,727 in 2021 (2020: €31,778,695; 2019: €31,252,653; 2018: €28,078,289).

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 extended the applicability of the arrangement to plants outside the network expansion area. The 2022 version of the EnWG provides for a new tendering procedure beginning in 2023 for 2030.

Under the previous 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 abovementioned TSOs started to offer relevant contracts to plant operators in 2018. Since then, six contracts have been concluded in the 50Hertz control area. The potential redispatch load of the plants under contract amounts to around 202 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 ongoing development of the European internal market for electricity is integrating electricity markets even more closely, which facilitates cross-border trade and ensures the secure, cost-efficient and sustainable supply of electricity.

The Bundesnetzagentur cooperates with the other regulatory authorities in Europe (National Regulatory Authorities – NRAs) and the European Union 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. Germany and Luxembourg constitute a common bidding zone with uniform prices. Electricity is traded within the bidding zone free of congestion (ie without capacity restrictions) from the generator to the consumer. So that this works, physical congestion is rectified within a bidding zone either through redispatching measures and network expansion or congestion is taken into account when calculating cross-border capacity. However, the European regulatory framework, with its provisions for rising minimum capacities, is placing more and more constraints on how much leeway is allowed when calculating capacity, which is increasing pressure on network expansion and redispatching measures.

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 marginal pricing, whereby the last winning 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 delivery 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, meaning 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 factor in 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.

All the countries of the European Union are now completely coupled in the SDAC (Single Day-ahead Coupling).

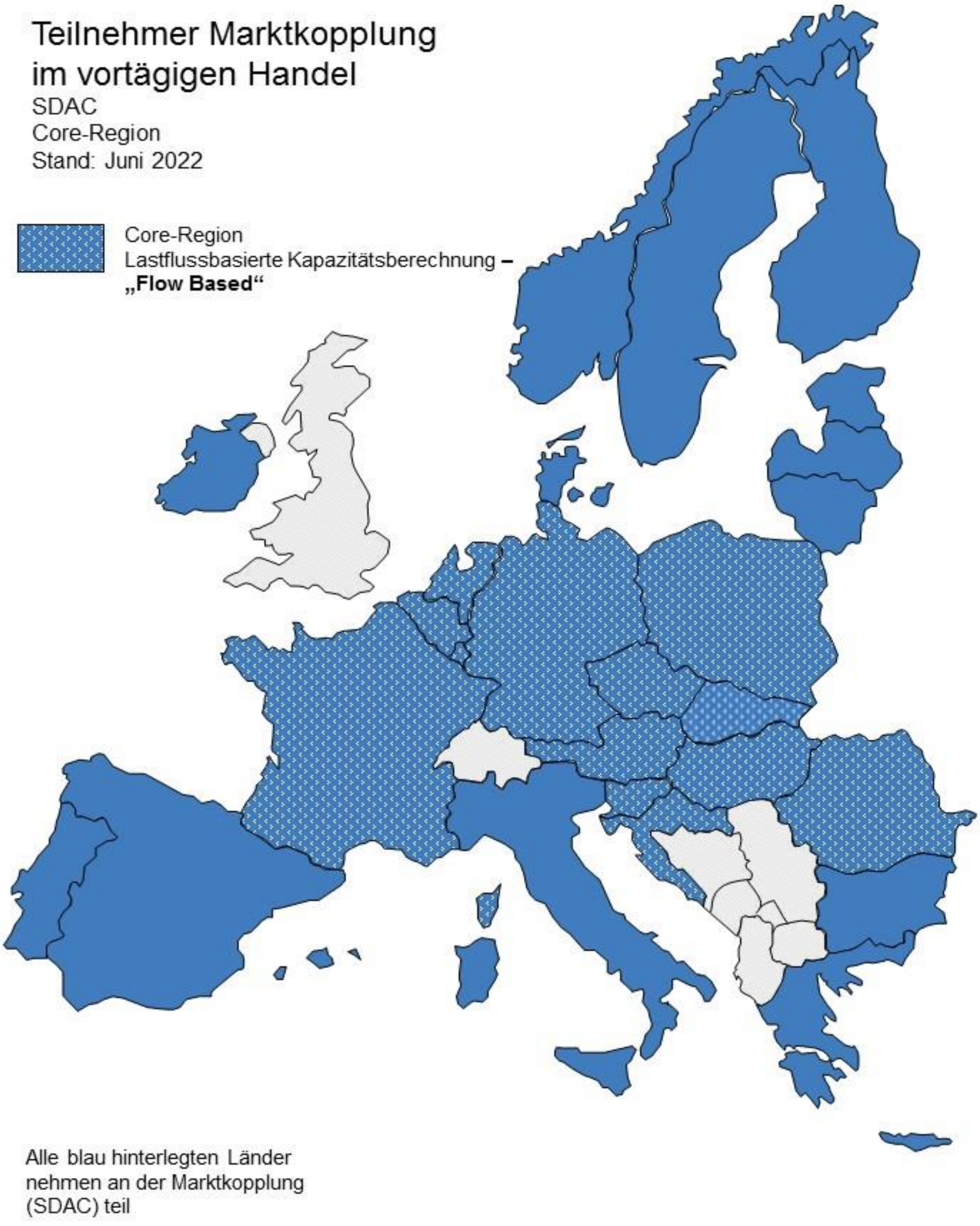

Figure 92: Participants in market coupling in day-ahead trading in 2022

The aim of market coupling is the efficient use of available day-ahead and intraday transmission capacity between the participating countries. The SDAC 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 at a border 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 calculates the transmission capacity algorithmically. A grid model and the trading results are used to achieve a capacity allocation that maximises welfare. This calculation method not only takes account of a single bidding zone border but also of all the flows of electricity in the area including the 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 method. In June 2022 the flow-based market coupling of the Core region for day-ahead trading was launched.

The region encompasses the bidding zone borders between a total of 13 countries in Central Western and Eastern Europe: Belgium, Germany, France, Croatia, Luxembourg, the Netherlands, Austria, Poland, Romania, Slovenia, Slovakia, Czechia and Hungary. The introduction of the flow-based market coupling in the Core region marked the successful passing of a major milestone for European market coupling and the achievement of a major objective of Commission Regulation (EU) 2015/1222. More efficient determination of the cross-border exchanges and the actual flows gives market participants even better trading opportunities because it balances supply and demand and the transmission capacity available for safe operation. The approach will also serve to more strongly integrate renewables in the internal electricity market in the coming years. By June 2023 flow-based capacity calculation is to be expanded in the Core region to include intraday trading.

3. Average available transmission capacity

The average 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 methods were applied for the two procedures presented in I.E.2.

Net Transfer Capacity (NTC)

For this report, the average available transmission 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 transmission 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.

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 the tables below.

Electricity: import capacity

Border	2019	2020		2021	
			Change compared to previous year		Change compared to previous year
NTC					
CH → DE	3,491.04	3,707.67	6	3,628.99	-2
CZ → DE	1,416.35	1,420.55	0	1,375.81	-3
DK → DE	1,782.23	1,900.75	7	2,644.19	39
NO → DE *		23.50		668.70	2,746
PL → DE	1,249.22	1,414.65	13	1,376.12	-3
SE → DE	533.56	516.23	-3	548.29	6
Flow-based					
AT → DE	5,080.67	5,028.24	-1	4,945.28	-2
BE → DE		571.59		922.15	61
FR → DE	3,748.00	4,810.14	28	5,298.74	10
NL → DE	3,246.32	3,560.67	10	4,110.64	15

* Commissioned near the end of 2020. Source: TSO, ENTSO-E

Table 86: Overview of the development of import capacities

Electricity: export capacity

Border	2019	2020		2021	
			Change compared to previous year		Change compared to previous year
NTC					
DE → CH	1,342.98	1,263.67	-6	1,346.61	7
DE → CZ	1,348.30	1,050.24	-22	1,054.81	0
DE → DK	1,965.43	2,180.85	11	2,931.48	34
DE → NO *		35.30		1,134.26	3,113
DE → PL	904.03	1,042.28	15	1,054.81	1
DE → SE	248.55	321.57	29	462.40	44
Flow-based					
DE → AT	4,984.73	4,864.04	-2	4,987.86	3
DE → BE		571.59		922.18	61
DE → FR	5,488.41	5,820.48	6	6,102.20	5
DE → NL	3,301.61	3,016.47	-9	3,205.74	6

* Commissioned near the end of 2020. Source: TSO, ENTSO-E

Table 87: Overview of development of export capacities

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, a minimum remaining available margin of 20% was applied in the CWE region for flow-based market coupling, which continues to be applied in the Core region as well. 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). Year on year declines in capacity may also be due to outages and maintenance work. Electricity trading capacity at the border of Denmark West and Germany is largely subject to special rules (see I.C.5.2.5 "Countertrading").

Figure 93 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
in GW

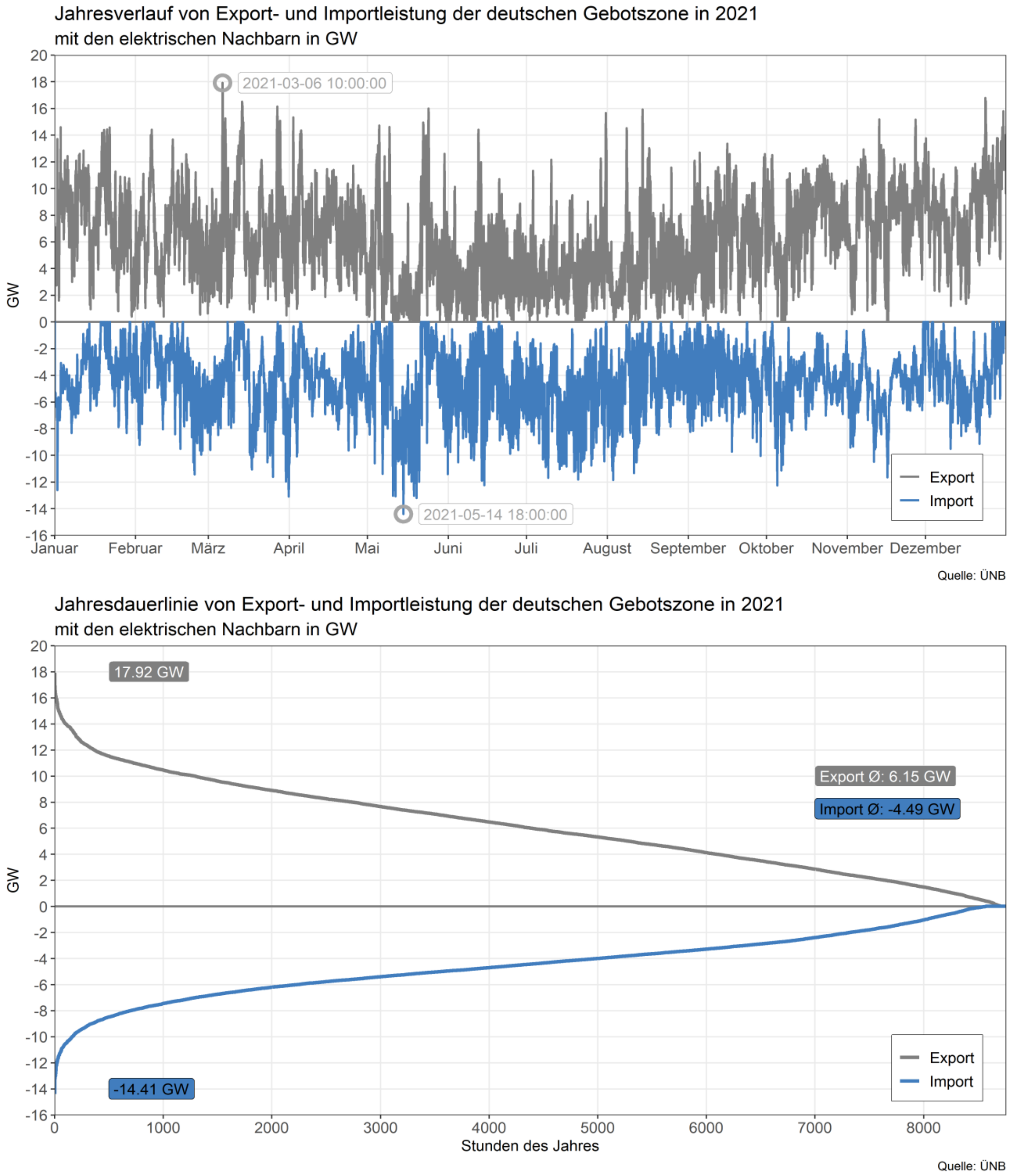

Figure 93: Export and import capacity

4. Cross-border flows and realised trade flows

The physical flows measured at bidding zone borders are related to the realised exchange schedules, or trade flows. Ideally, the balance of physical flows and trade flows should be nearly identical overall. However, this is often not the case owing to unscheduled flows (loop and transit flows, see section I.E.5), 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 94). This is unavoidable in a highly meshed network with large bidding zones.

Electricity: exchange schedules (cross-border electricity trade) and physical flows (in TWh)

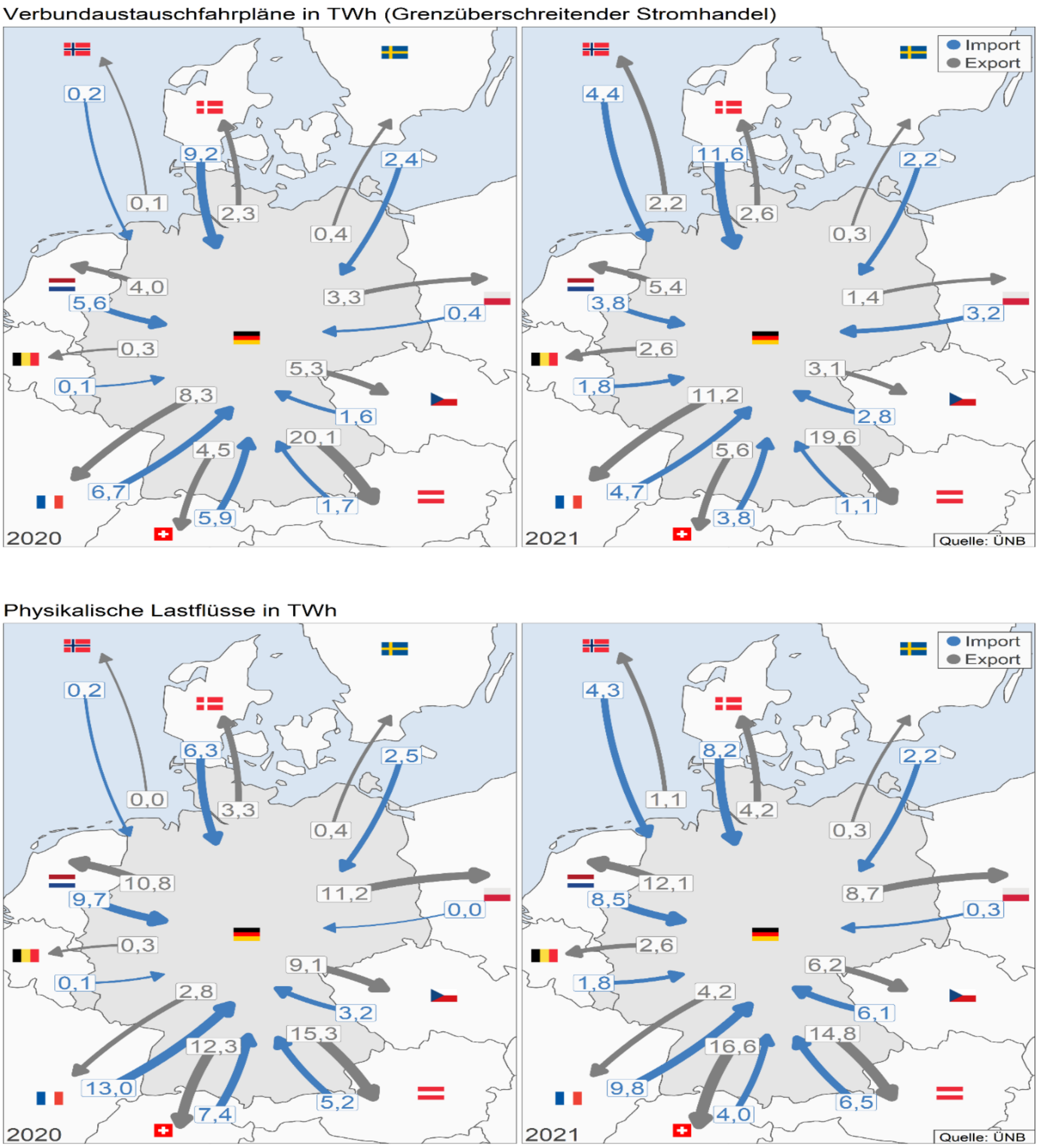

Figure 94: Exchange schedules and physical flows

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 94 shows the realised exchange schedules and the physical flows at Germany's borders in 2020 and 2021, whereas the tables below show the summarised values.

Electricity: comparison of the balance of cross-border eletricity flows
(TWh)

	Actual physical flows in 2020	Binding exchange schedules in 2020	Actual physical flows in 2021	Binding exchange schedules in 2021
Imports	47.6	33.7	51.7	39.3
Exports	65.4	48.6	70.8	53.8
Balance	17.8	14.8	19.1	14.5

Source: TSOs

Table 88: Comparison of the balance of cross-border flows

Electricity: comparison of imports from cross-border flows
(TWh)

	Actual physical flows in 2020	Exchange schedules in 2020	Actual physical flows in 2021	Exchange schedules in 2021
AT → DE	5.2	1.7	6.5	1.1
BE → DE	0.1	0.1	1.8	1.8
CH → DE	7.4	5.9	4.0	3.8
CZ → DE	3.2	1.6	6.1	2.8
DK → DE	6.3	9.2	8.2	11.6
FR → DE	13.0	6.7	9.8	4.7
NL → DE	9.7	5.6	8.5	3.8
NO → DE	0.2	0.2	4.3	4.4
PL → DE	0.0	0.4	0.3	3.2
SE → DE	2.5	2.4	2.2	2.2

Source: TSOs

Table 89: Comparison of imports from cross-border flows

Electricity: comparison of exports from cross-border flows
(TWh)

	Actual physical flow in 2020	Exchange schedules in 2020	Actual physical flows in 2021	Exchange schedules in 2021
DE → AT	15.3	20.1	14.8	19.6
DE → BE	0.3	0.3	2.6	2.6
DE → CH	12.3	4.5	16.6	5.6
DE → CZ	9.1	5.3	6.2	3.1
DE → DK	3.3	2.3	4.2	2.6
DE → FR	2.8	8.3	4.2	11.2
DE → NL	10.8	4.0	12.1	5.4
DE → NO	0.0	0.1	1.1	2.2
DE → PL	11.2	3.3	8.7	1.4
DE → SE	0.4	0.4	0.3	0.3

Source: TSOs

Table 90: Comparison of exports from cross-border flows

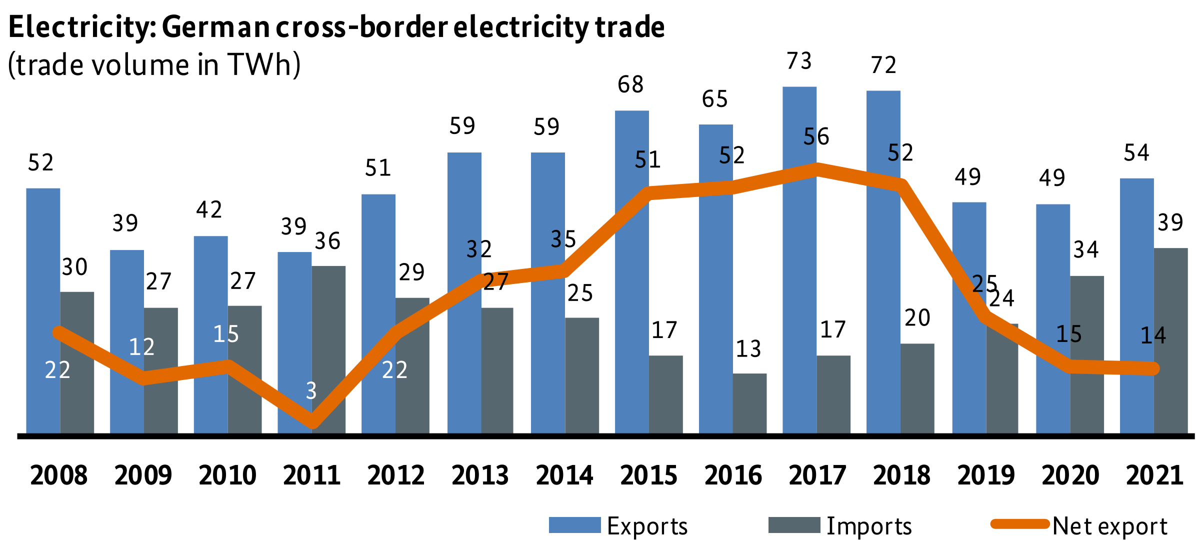

Figure 95: German cross-border electricity trade

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

	2020		2021	
	(TWh)	Trade in €mn	(TWh)	Trade in €mn
Imports	33.71	1,112.08	39.34	4,180.06
Exports	48.55	1,324.78	53.83	4,955.32
Balance	14.84	212.71	14.50	775.26
Export revenue €/MWh		27.28		92.05
Import costs in €/MWh		32.99		106.26

Source: TSOs, ENTSO-E

Table 91: Monetary development of cross-zonal electricity trade (trade flows)

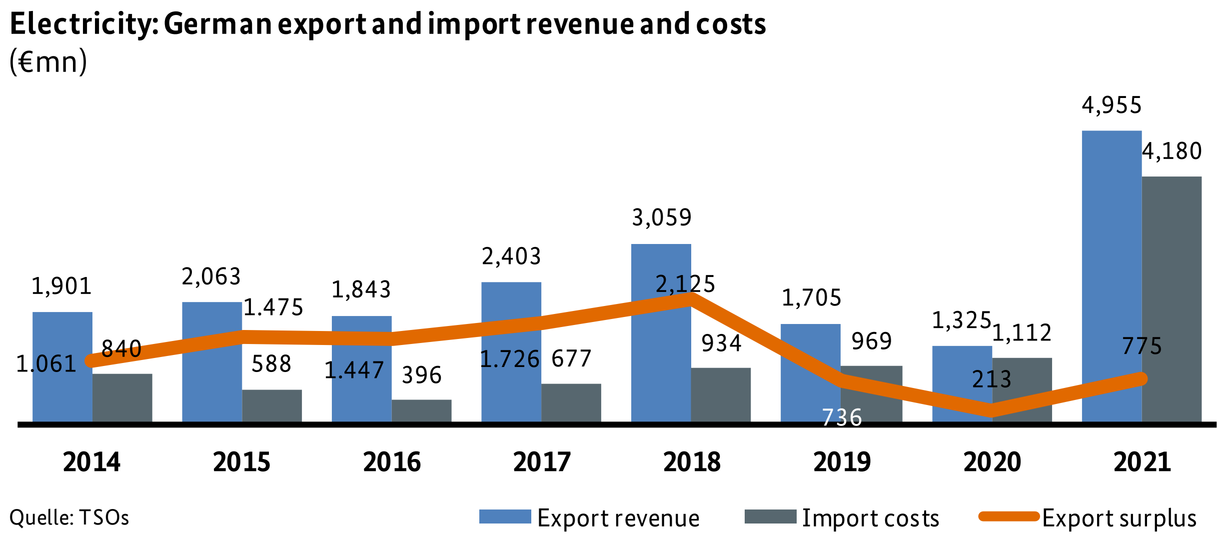

Figure 96: German export and import revenues and costs

Changes in cross-border trading volumes between Germany and its neighbouring countries reflect changes in the price differences. The reasons for these differences depend on a wide range of factors that have a direct influence on the merit order and therefore especially 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 whenever the physical load flow differs from the amount of electricity sold. There are two forms of unscheduled flows. The first form (called a transit) is when electricity is transported from one bidding zone to another, passing through a bidding zone that is not involved in the commercial transaction. The second form (called a loop flow) is when electricity from one bidding zone passes through a bidding zone that is not involved in the commercial transaction and returns 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 calculated for each border as the difference between physical flow and realised exchange schedules, showing annual aggregate figures after deducting the export surplus from the physical exports.

The following example demonstrates how unscheduled flows are calculated. In 2021, Germany imported (trade) 3.8 TWh from and exported 5.4 TWh to the Netherlands. This is equal to an export surplus (trade) of 1.6 TWh. At the same time, 8.5 TWh flowed physically from the Netherlands to Germany. By contrast, 12.1 TWh flowed from Germany to the Netherlands. This is equal to an export surplus (physical) of 3.6 TWh. This means that on balance (physical minus trade) 1.9 TWh of electricity (deviations possible due to rounding) flowed from Germany to the Netherlands and was not traded between the two countries.

The following map shows the unscheduled flows arising from the difference between net physical and trade flows from the Germany/Luxembourg market area to its neighbouring countries and vice versa.

Electricity: unscheduled flows
(TWh)

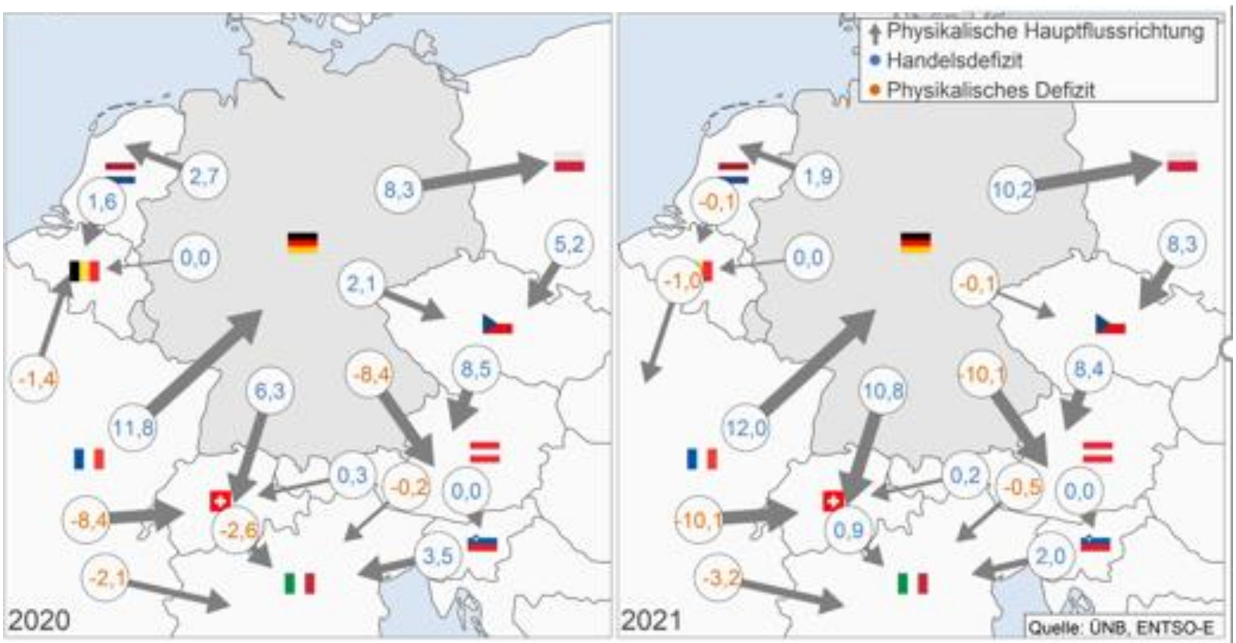

Figure 97: Unscheduled flows

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 2021, for example, the net physical flow from France to Switzerland was 10.1 TWh less than the volume of trade.

The numbers 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, trade in electricity 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 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 is to 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 transit flows. ACER reports to the European Commission each year on the implementation of the ITC mechanism as required in point 1.4 of Part A of the Annex to Commission Regulation (EU) No 838/2010. According to provisional ACER[81] calculations, the ITC fund for 2021 comprised a record volume of approximately €364.5mn (€264.5mn for the costs of lost energy and €100mn for provision of transport infrastructure). For the ITC year 2021, the four German TSOs with responsibility for control areas received compensation for lost energy and the provision of infrastructure totalling €30.18mn and in return were required to pay contributions of €0.39mn. On balance this means the German TSOs received a net sum of €29.79mn as compensation payments from the ITC mechanism, which is more than a fourfold increase in revenue from the ITC fund compared to the previous year. The changes in the amount of compensation paid from the ITC fund are shown in Figure 98.

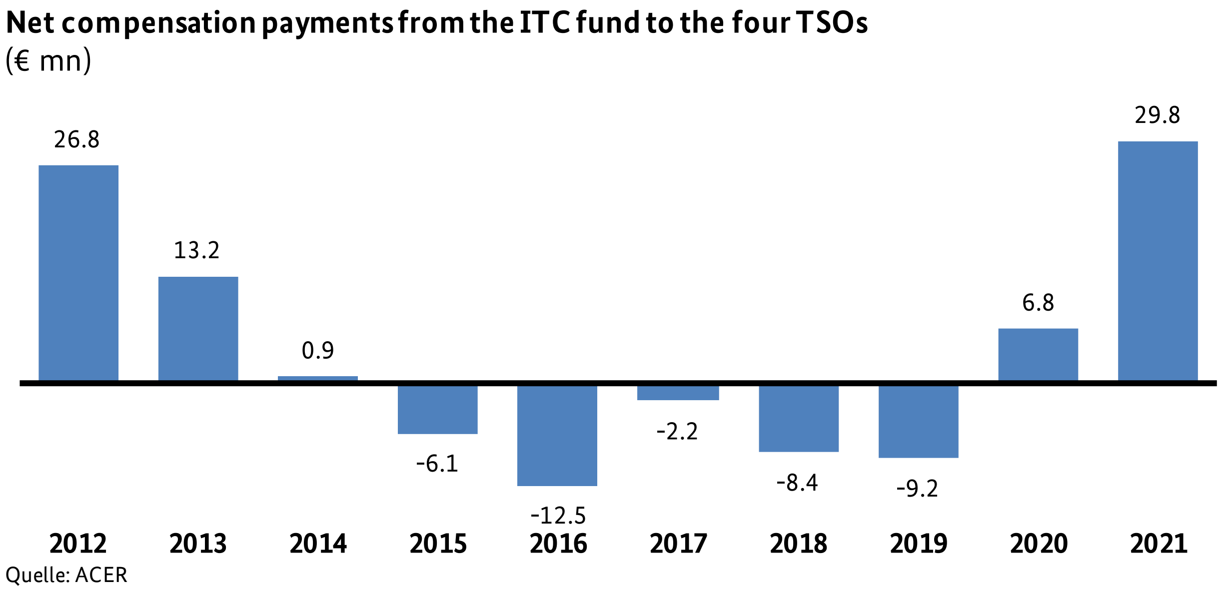

Figure 98: Net compensation payments from the ITC fund to the four TSOs

The cause of the strong reduction in deposits with increased payments from the ITC fund can be found in the interplay of numerous interdependent influencing factors inside and outside of Germany. However, generally

81 The final figures for 2021 will be published in the ACER ITC Monitoring Report towards the end of 2022. https://www.acer.europa.eu/electricity/infrastructure/inter-tso-compensation-monitoring

there was a significant increase in transits, which led to high revenue from transit-related losses and thus to the high overall revenue.

7. Current developments in the European electricity sector

7.1 Minimum trading capacity and national action plan

Regulation (EU) 2019/943 on the internal electricity market requires Member States to make at least 70% of their transmission capacity available for cross-border electricity trade. Just in time for the new regulation to come into force, the federal government presented its bidding zone action plan[82], which enables this minimum trading capacity to be reached in stages by 31 December 2025. In late 2019 the Bundesnetzagentur worked with the TSOs to develop principles for calculating and reporting the starting point of the linear trajectory of minimum trading capacities and published them on its website. The TSOs then calculated and published the starting points so that the corresponding capacities could be made available for cross-border trading from 1 January 2020. The Bundesnetzagentur has been monitoring compliance with the minimum amounts since then.

On 17 June 2022 the Bundesnetzagentur approved the report of the five TSOs (50 Hertz Transmission GmbH, Amprion GmbH, Baltic Cable AB, Tennet TSO GmbH, TransnetBW GmbH) on the available cross-border capacity for 2021 under Article 15(4) of Regulation (EU) 2019/943[83]. 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 2023.

7.2 Regional coordination centres

The regional coordination centres (RCCs) for Central Europe – emerging from the existing regional security coordinators TSCNET and Coreso – went into operation on 1 July 2022. In January 2021 the Bundesnetzagentur and the other regulatory authorities affected in the Central Europe system operation region had first approved the provisions on the establishment of the RCCs and in July 2022 approved an amended version of the provisions (on the basis of changes to the system operation regions approved by ACER). The monitoring of the implementation of the new RCC tasks, which include risk-preparedness, emergency and restoration, training and certification, calculation of required capacity and sizing of reserve capacity, and procurement of balancing capacity, is now done on a continual basis by the regulatory authorities of Central Europe.

[82] https://www.bmwi.de/Redaktion/DE/Downloads/A/aktionsplan-gebotszone.html

[83] https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/HandelundVertrieb/EuropMarktkopplung/start.html

7.3 Establishment of the European entity for distribution system operators (EU DSO Entity)

Article 52 et seq of Commission Regulation (EU) 2019/943 stipulate the establishment of the EU DSO Entity, in which DSOs have the right to cooperate at European 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.[84] Currently around 300 DSOs from Germany are members.

7.4 Short term adequacy assessment

Seasonal adequacy assessments are conducted by ENTSO-E separately for the summer and winter months (ENTSO-E Summer and Winter Outlooks). These are performed using the methodology in Article 8 of 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 an hourly resolution. The main result is the "weekly LOLP (weekly Loss of Load Probability) as a measure of the level of security of supply, plus the EENS (Expected Energy Not Served).

The current Summer Outlook 2022[85] has identified practically no risks to security of supply because risks associated with a gas shortage are only relevant to winter.

Owing to the provisions of Article 9(2) of Regulation (EU) 2019/941, the ENTSO-E Winter Outlook 2022/2023 should be completed by no later than 1 December 2022. The Winter Outlook will provide information on the current risks from reduced availability of gas.

7.5 Implementation and enhancement of European network codes and guidelines

Further progress was made in 2021 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.[86]

Capacity management

TSOs and nominated electricity market operators work with NRAs and ACER to implement Commission Regulation (EU) 2015/1222 (CACM Regulation) on 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

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[84] https://www.eudsoentity.eu

[85] https://www.entsoe.eu/outlooks/seasonal/

[86] The Bundesnetzagentur's related method approvals have been published at https://www.bundesnetzagentur.de/DE/Fachthemen/ElektrizitaetundGas/HandelundVertrieb/EuropElektrBinnenmarkt/start.html

coupling algorithms[87], the relevant products[88] and the necessary back-up measures[89], the times at which intraday trading opens and closes[90] and the fallback procedures for capacity allocation.[91] These rules are the foundation for the European internal market for electricity. After the cross-border intraday solution (XBID) went live in 2018 and a second implementation wave followed in 2019, Italy joined the system in 2021 so that now most of the European Union is coupled in intraday trading.[92]

In 2021 ACER (with involvement by the Bundesnetzagentur and the other European regulatory authorities) proposed changes to the CACM Regulation that result in part from the amended version of the 2019 regulation on the internal market for electricity. The European Commission is expected to complete a revision of these proposed changes at the end of 2022. Legislative passage of the new CACM Regulation and its entry into force should take place in 2023.

For the German market, the capacity calculation method for the Capacity Calculation Region (CCR) Core is also particularly relevant (see section IE2).

In February 2019 ACER adopted a decision on the proposal submitted by the CCR Core TSOs and thereby determined the region's capacity calculation method for day-ahead and intraday trading of electricity. The Bundesnetzagentur brought an action for annulment against ACER's decision before the European General Court). The Bundesnetzagentur's main criticism of the decision is its establishment of a mechanism by means of which potentially fewer and fewer network elements may be considered trade-sensitive. The mechanism causes the assumption during capacity calculation that these network elements can transmit electricity without limitations. The Bundesnetzagentur is of the opinion that this endangers system security and leads to avoidable additional costs for the network users. Oral proceedings took place on 17 November 2021 and on 7 September 2022 the court announced its verdict to uphold the Bundesnetzagentur's action. ACER is now required to adopt a new decision that complies with the law. In the meantime the capacity calculation method will remain applicable until the old decision is repealed and a new decision is adopted.

Another Bundesnetzagentur action is still pending before the EGC against the decision by the ACER Board of Appeal from 28 May 2021 in which the ACER decision of 30 November 2020 on the cost sharing methodology

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[87] https://extranet.acer.europa.eu//Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2004-2020%20on%20Algorithm%20methodology.pdf

[88] https://extranet.acer.europa.eu//Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2037-2020%20on%20the%20DA%20Products.pdf

[89] 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

[90] 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

[91] For the Core region:
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 Hansa region:
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

[92] Slovakia and Greece are still missing but are expected to join at the end of 2022.

for redispatching and countertrading was confirmed. The main points of criticism of the ACER Decision were the extension of the cost sharing methodology to practically all network elements of the transmission network and the priority penalisation of loop flows over internal flows. This disproportionately burdens network users in Germany's large bidding zone with costs. The European legal framework does acknowledge that TSOs have to bear the cost burden for disproportionately high loop flows, but it also sees a certain proportion of loop flows as inherent to the system and therefore tolerable. ACER's Decision does not take this into account and is thus in breach of EU law. In these proceedings before the EGC a hearing may take place.

ACER decided in April 2021 to allocate the bidding zone border managed by the TSO Baltic Cable AB between Germany/Luxembourg and Sweden 4 to the CCR Hansa.[93] The Bundesnetzagentur has been working together with the TSOs and the other NRAs of the capacity calculation region to integrate Baltic Cable AB into the CCR Hansa's methodologies. This process is expected to be completed in 2023.

The rules on forward capacity allocation in Regulation (EU) 2016/1719 (FCA Regulation) are also being implemented. In November 2021 ACER decided the method for calculating long-term capacities for the CCR Core.[94] In 2021 the Bundesnetzagentur and the other NRAs in the CCR Hansa approved a change to the calculation methodology for long-term capacities that had been approved in 2019 in order to take account of the decision of the European Commission on the priority feed-in of wind energy (and secondary market-based interconnector use) of the Kriegers Flak combined grid solution (KF CGS) project.[95]

In 2022 work was initiated to revise the FCA Regulation with the goal of designing the futures market so that prices are secured for long-term electricity trading more effectively and efficiently.

System operation

Part of Regulation (EU) 2017/1485 deals with European harmonisation in the area of system operation. Implementation will require TSOs to develop and to adjust as needed various methods and procedures, which will also involve participation/approval by the relevant regulatory authorities. On the regional and European level for 2021/2022 this included changes in the joint determination of load frequency control blocks in the Continental Europe Synchronous Area through the removal of Denmark West from the TenneT (Germany) control area and the specification of a minimum delivery period (between 15 and 30 minutes) for frequency containment reserves with limited energy storage, which is to be discussed on the basis of two studies conducted by the TSOs and approved by the end of 2022.

Regulation (EU) 2017/2196 on electricity emergency and restoration also concerns system operation. Certain procedures (in particular an action plan for grid restoration with a focus on extending the minimum availability of communication not affected by a blackout) were developed and discussed in 2021/2022 and are expected to be revised and approved by the Bundesnetzagentur by the end of 2022.

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[93] http://acer.europa.eu/sites/default/files/documents/Individual%20Decisions_annex/ACER%20Decision%2004-2021%20on%20the%20CCR%20-%20Annex%20I_0.pdf

[94] http://acer.europa.eu/sites/default/files/documents/Individual%20Decisions_annex/ACER%20Decision%2014-2021%20on%20the%20Core%20LT%20CCM%20-%20Annex%20I_0.pdf

[95] https://ec.europa.eu/energy/sites/ener/files/documents/2020_kriegers_flak_decision_de.pdf (11/11/2020)

F Wholesale

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 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 of the wholesale electricity markets are still at a high level, although the trading volume of the coupled day-ahead 12 o'clock auction was lower than in the previous year at around 218.7 TWh (231.2 TWh in the previous year). The trading volume on the intraday market rose again to 74.1 TWh, representing an increase of around 5.6 TWh or approx. 8% on the previous year.

On-exchange futures trading volumes increased. In 2021, the on-exchange trading volume for Phelix-DE futures stood at 1,450 TWh, an increase of around 2.4% compared to the previous year. The off-exchange volumes traded via broker platforms also increased. The volume of OTC clearing of Phelix-DE futures on the EEX exchange rose by about 4% to 1,750 TWh in 2021, around 20% above the volume traded directly on the exchange.

The situation in the energy markets has intensified since the beginning of Russia's war of aggression against Ukraine in February 2022. Prices in the wholesale markets for electricity and gas have risen considerably again and are very volatile. The second half of 2021 already saw considerable price increases in the energy markets. The spot market Phelix Day Base average for 2021 was about 97.12 euros/MWh, compared to an average of 30.46 euros/MWh in the previous year, representing an increase of around 218%. There was also a large increase in the average prices for year-ahead futures. The average price for Phelix Base Year Futures in 2021, traded to be supplied in 2022, was 88.42 euros/MWh, which represents an increase of around 120% compared to the previous year's average of 40.17 euros/MWh, supplied in 2021. The average price for Phelix Peak Year Futures was 107.23 euros/MWh in 2021. This corresponds to an increase of around 119% compared to the previous year's average (49.04 euros/MWh).

A look at the prices for futures in the course of 2021 shows a continuous increase up until the end of the year. On 22 December 2021, prices for Phelix Base Year Futures peaked at 324.50 euros/MWh and for Phelix Peak Year Futures at as much as 410 euros/MWh.

1. On-exchange wholesale trading

The analysis 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, Nord Pool and EXAA supply electricity products on the spot markets. These exchanges once again took part in the collection of energy monitoring data this year.

The total number of participants admitted to the respective electricity exchanges in the Germany/Luxembourg market area has developed differently over the last few years. The number of participants active in futures trading on the EEX exchange has constantly increased in recent years. However, with 291 participants active as at the reference date 31 December 2021, the number of participants has dropped compared to the previous year (2020: 336 participants). There was little change in the number of participants active in the spot market. There was a slight increase in the number of participants in the EPEX SPOT market to 203 (2020: 197 participants); the number of participants admitted to the EXAA exchange fell to 56 compared to the previous year. The number of participants on the Nord Pool exchange was 52 (compared to 50 participants in the previous year).

Electricity: Development of number of registered trading participants on EEX, EPEX SPOT, EXAA and Nord Pool

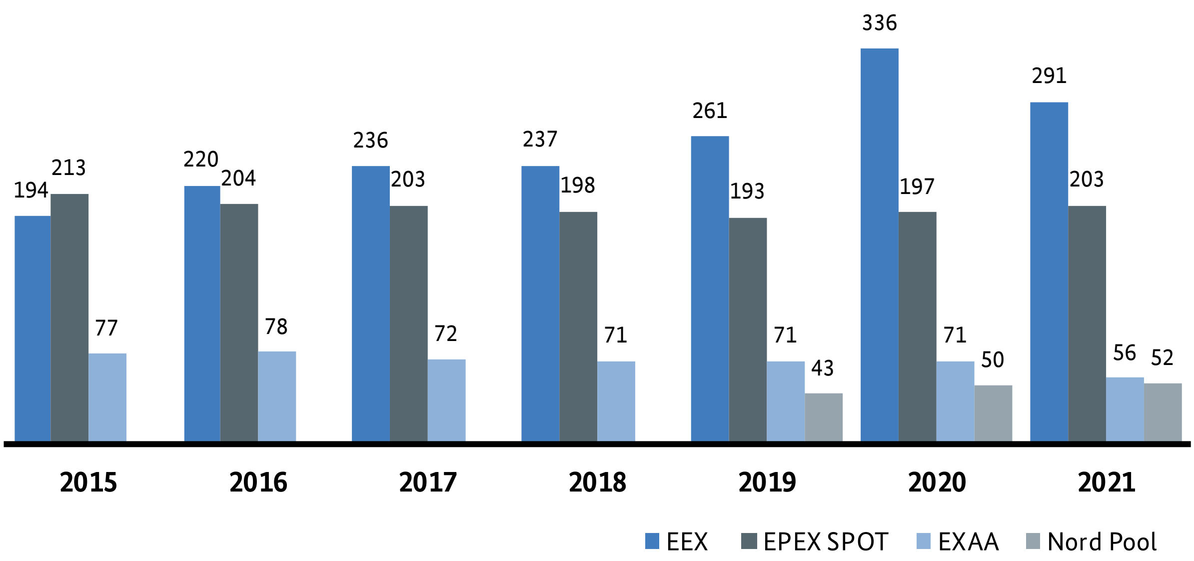

Figure 99: Development of the number of registered electricity trading participants on the exchanges

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 the EEX exchange 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 traded for the current day (intraday). The spot markets examined here, EPEX SPOT, Nord Pool and EXAA, offer day-ahead trading. EPEX SPOT and Nord Pool also offer continuous intraday trading. 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).

Developments in day-ahead trading

Since 2 July 2019 day-ahead trading is possible across all bidding zones of the western Europe region (and therefore also in the German bidding zone) within the framework of single day-ahead coupling (SDAC) based on Commission Regulation (EU) 2015/1222 of 24 July 2015 (CACM Regulation). Based on this market participants can access the noon auction for the Germany/Luxembourg market area via each of the three admitted exchanges named above[96] (NEMO – Nominated Electricity Market Operator). In this auction, a single day-ahead price (SDAC price) is calculated for each bidding zone by a central auction algorithm based on all the orders placed in time, taking into account the available capacities of the interconnectors. The SDAC price determined in this way is the binding auction price for every electricity exchange within a bidding zone; it is therefore irrelevant at which electricity exchange market participants conduct their trading.

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 coupled day-ahead auction. Bids for the complete or partial physical fulfilment of futures traded on EEX (futures positions) may also be submitted.

In addition to the SDAC auction, EXAA currently offers another earlier, independent and non-coupled day-ahead auction at 10:15 am for the Germany/Luxembourg market area. The earlier auction time on the EXAA exchange at 10:15 am provides a first relevant price signal for traders for the remainder of the trading day.

[96] Nasdaq Oslo ASA is also admitted for day-ahead trading but is not yet operating, source: https://www.nemo-committee.eu/designated-NEMOs.pdf (retrieved on 1 September 2022)

Developments in intraday trading

Since 13 June 2018 the bidding zone Germany/Luxembourg has been coupled with 14 other European markets (Austria, Belgium, Denmark, Estonia, Finland, France, Latvia, Lithuania, Luxembourg, Norway, the Netherlands, Portugal, Spain, Sweden) within the framework of the single intraday coupling (SIDC). The following countries joined in November 2020: Bulgaria, Croatia, the Czech Republic, Hungary, Poland, Romania and Slovenia. Italy joined in September 2021. Via the cross-zonal intraday market, market participants are given access to the entire European market liquidity, irrespective of the exchange on which they trade. In the German bidding zone, both Nord Pool and EPEX SPOT provide access to cross-zonal intraday trading. [97] Continuous intraday trading on EPEX SPOT and Nord Pool involves single hours, 15-minute periods and standardised or user-defined blocks. In all bidding zones, continuous cross-zonal intraday trading begins at 3.00 pm on the previous day and ends 60 minutes before supply. Electricity contracts for the German control areas can be traded on EPEX SPOT up to 30 minutes before commencement of supply (coupled within the SIDC framework only up to 60 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 the time of supply on Nord Pool.[98] As cross-border capacities in the DE/LU bidding zone are not made available until around 10 pm, it is only possible to trade across control zones on the basis of the electricity exchanges' coupled markets in "shared order books".

EPEX SPOT still offers the intraday auction for quarter hourly offers for the Germany/Luxembourg market area at 3 pm on the previous day.

The so-called shared order books (SOB) are essential for SIDC. Under the CACM Regulation all NEMOs active within SIDC are obliged to submit orders received from their market participants to the SOB immediately upon 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 obligation that NEMOs have to submit their orders to the SOB ends at the intraday cross-zonal gate closure time 60 minutes prior to the commencement of supply since this is the time at which cross-border trading closes and no more cross-border capacities are available.

Intraday trading within the Germany/Luxembourg bidding zone continues until the actual commencement of supply. This means that it is just as necessary for all NEMOs in the Germany/Luxembourg bidding zone to access intraday orders in the last 60 minutes. Against this background the EU Commission initiated a formal investigation proceeding (KOM AT.40700) to examine whether EPEX SPOT could have restricted competition on the intraday markets. By removing the orders from the SOB in the last 60 minutes, EPEX SPOT may have

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[97] For further information please see BNetzA, decisions BK6-18-098 and BK6-16-017 (preceding decision for the DE/AT/LU bidding zone), available in German at: https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK6-GZ/2018/BK6-18-098/BK6-18-098_beschluss_vom_04_10_2018.html?nn=872010

[98] ACER 2018: Acer adopts a decision on intraday cross-zonal gate opening and closure time, available at: https://documents.acer.europa.eu/Media/News/Pages/ACER-adopts-a-decision-on-intraday-cross-zonal-gate-opening-and-closure-time.aspx dated 7 May 2018 (retrieved on 1 September 2022)

taken measures which had the effect of excluding exchanges competing with EPEX SPOT from the market or significantly impeding their access to the market.[99]

The CACM Regulation is currently being amended. ACER suggests that the sharing of the books be extended to the entire period of intraday trading and not only when cross-border capacities are available.

1.1.1 Trading volumes

The trading volume of the coupled day-ahead noon auction amounted to approx. 218.7 TWh in 2021. 180.8 TWh were traded on EPEX SPOT, 22.8 TWh on Nord Pool and 15.1 TWh on EXAA. The volume of the independent 10:15 am day-ahead auction on EXAA for the German bidding zone amounted to around 2.33 TWh in 2021 (3.31 TWh in the previous year).

The volume of the intraday trading on EPEX SPOT increased again to 69.93 TWh (around 7.64 TWh in the intraday auction and 62.28 TWh in continuous intraday trading). With regard to the total intraday volume this represents an increase of around 6.3 TWh or around 10% compared to 2020. The volume of continuous intraday trading on Nord Pool in the DE/LU bidding zone amounted to around 4.25 TWh in 2021, a slight decrease on the previous year (4.89 TWh).[100]

[99] See the EU Commission's press release, available at https://ec.europa.eu/commission/presscorner/detail/en/ip_21_1523

[100] The presentation of trading volumes was adjusted from 2020 onwards to reflect the participation of several electricity exchanges in the coupled day-ahead auction. 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 coupled 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 in previous years already represent the average number of purchase and sales orders fulfilled on each electricity exchange throughout the year.

Electricity: Development of spot market volumes on EPEX SPOT, Nord Pool and EXAA
in TWh

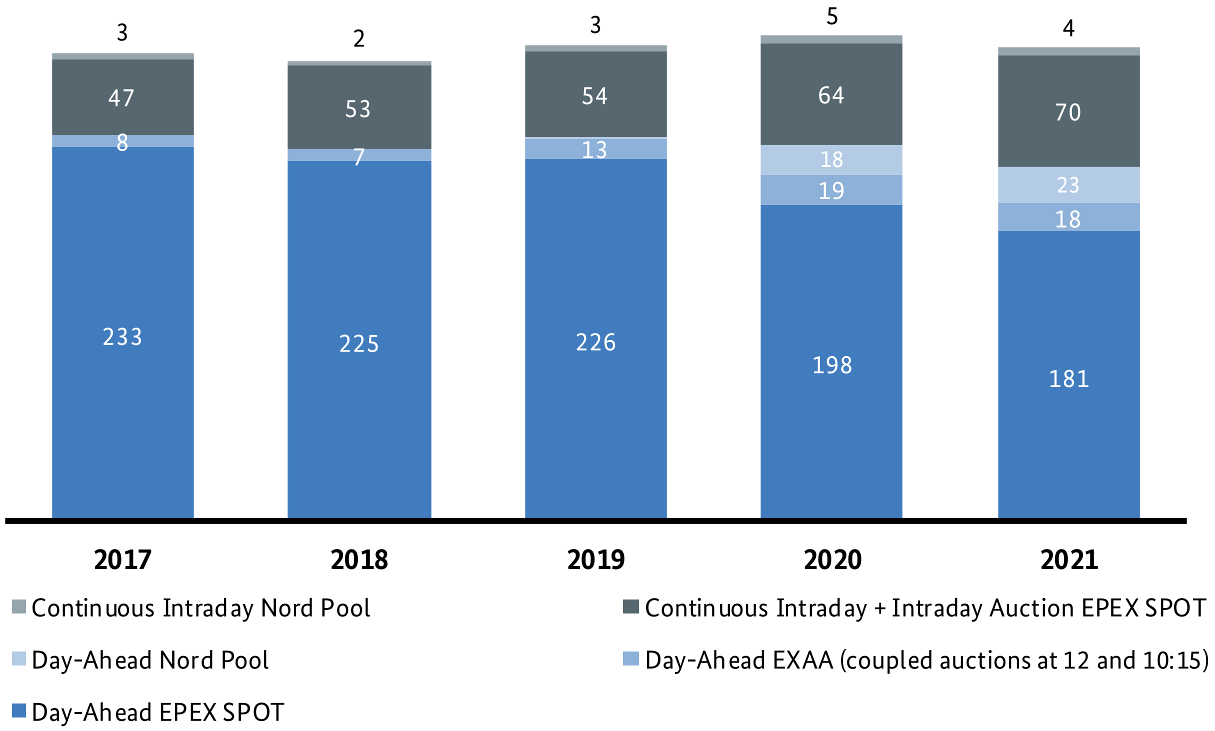

Figure 100: Development of spot market volumes on EPEX SPOT, Nord Pool and EXAA

1.1.2 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 the coupled day-ahead auction of a specific day, and the Phelix day peak is the arithmetic mean of hours 9 to 20, i.e. 8 am to 8 pm.

The average spot market prices increased sharply in 2021 – especially in the second half of the year the increases were considerable as shown in figure 97. The average spot market price for the Phelix day base for 2021 was around 97.12 euros/MWh compared to an average of 30.46 euros/MWh in the previous year. This represents an increase of 218%. The Phelix day peak DE average for 2021 was approx.105.09 euros/MWh, compared to an average of 32.74 euros/MWh in the previous year, this is also an increase of around 220%.

Electricity: Development of average spot market prices on EPEX SPOT in euros/MWh

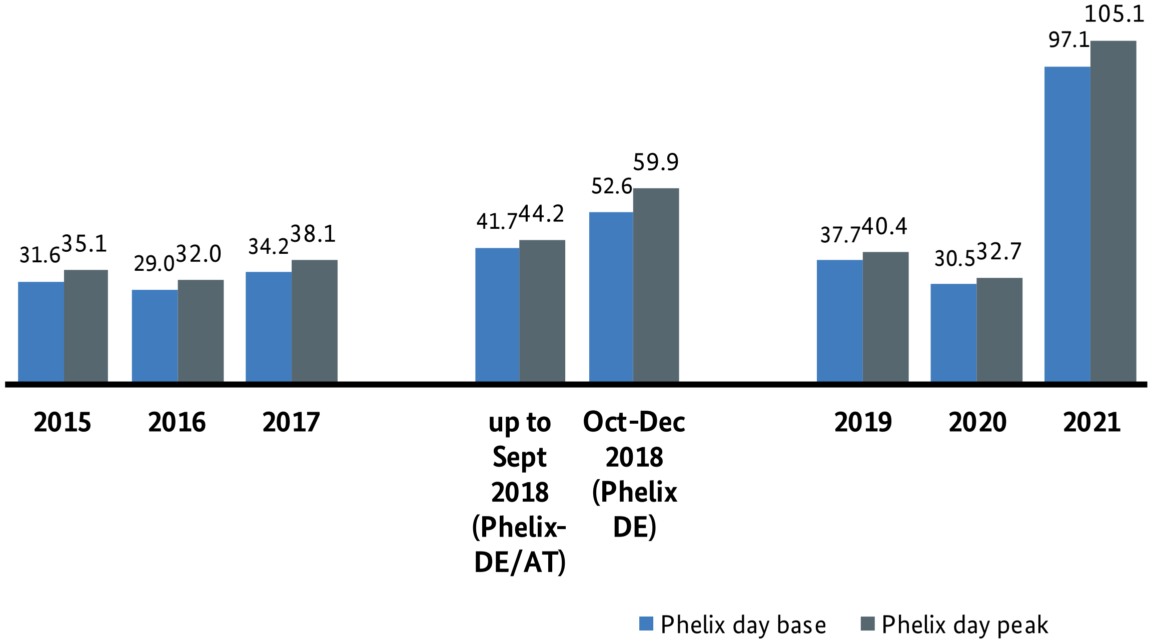

Figure 101: Development of the average spot market prices of the coupled auction

1.1.3 Price dispersion

As in previous years the prices of the coupled day-ahead auction exhibit considerable dispersion. The following figure shows the development of spot market prices over the year, using the Phelix day base as an example. Daily average prices typically have a weekly profile with lower prices at the weekend.

Electricity: Price development of Phelix day base in 2021
in euros/MWh

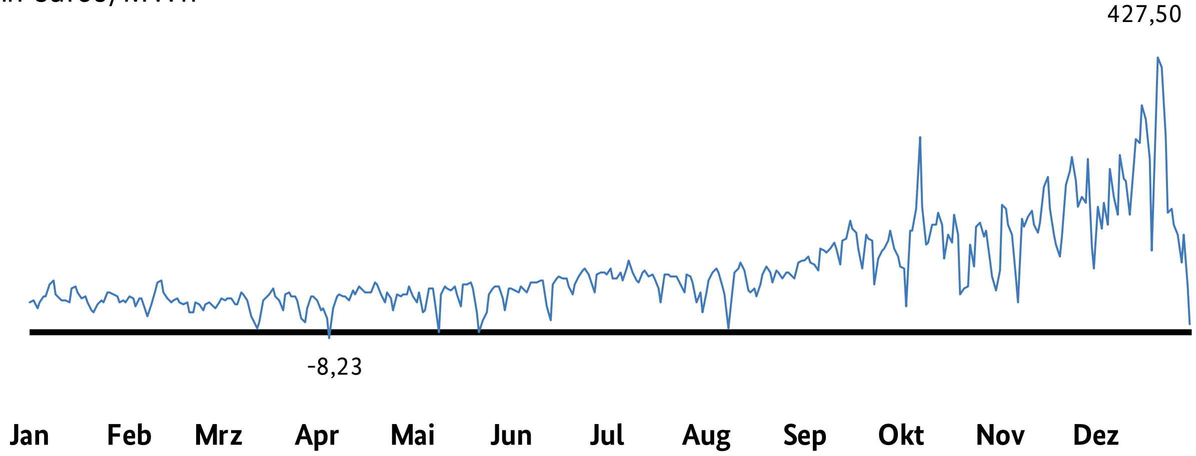

Figure 102: Development of the Phelix day base in 2021

There were numerous positive and negative extreme values in the Phelix base and peak prices in the coupled auction in 2021. The range of the middle 80% of the graded Phelix day base values rose in 2021 to 144.54 euros/MWh. In 2020 the difference amounted to only 32.54 euros/MWh. The corresponding peak range of the middle 80% also rose significantly from 40.81 euros/MWh in 2020 to 172.78 euros/MWh in 2021.

Negative values were reached in the Phelix day base prices on two days in 2021, and even on six days in the case of the Phelix day peak.[101] The Phelix day base reached its lowest value of -8.23 euros/MWh on 5 May 2021. The Phelix day peak registered its lowest value of -19.56 euros/MWh on 22 May 2021. In the previous year the minimum day base value was -26.13 euros/MWh and the minimum day peak was -45.64 euros/MWh. The development of prices must be seen against the background of the market shortages in generation capacities as well as the increase in demand due to the relaxation of Covid restrictions and the lower feed-in volumes of renewable energy.

The maximum values of both indices increased compared to the previous year. In 2021 the highest Phelix day base value was 427.50 euros/MWh, or around 427% above the previous year's value of 75.03 euros/MWh. The maximum day base price was reached on 21 December 2021. The highest Phelix day peak value in 2021 was 510.51 euros/MWh, an increase of around 400% compared to 103.79 euros/MWh in 2020.

Electricity: Price ranges of Phelix day base and Phelix day peak
in euros/MWh

	Middle 80%	Range of middle 80%	Extreme values	Range of extreme values
	10 to 90% of graded values		Min – Max	
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
Base 2021	40,26 - 184,81	144.54	-8,23 – 427,5	435.73
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
Peak 2021	38,73 - 211,50	172.78	-19,56 – 510,52	530.08

Table 92: Price ranges of the Phelix day base and Phelix day peak between 2019 and 2021

[101] 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.

1.2 Futures markets

Futures with standardised maturities can only be traded on EEX for the Germany/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 in the futures market, excluding OTC clearing.

1.2.1 Trading volumes

The on-exchange trading volume of Phelix DE futures was 1,451 TWh in 2021, a year-on-year increase of around 2.4%.

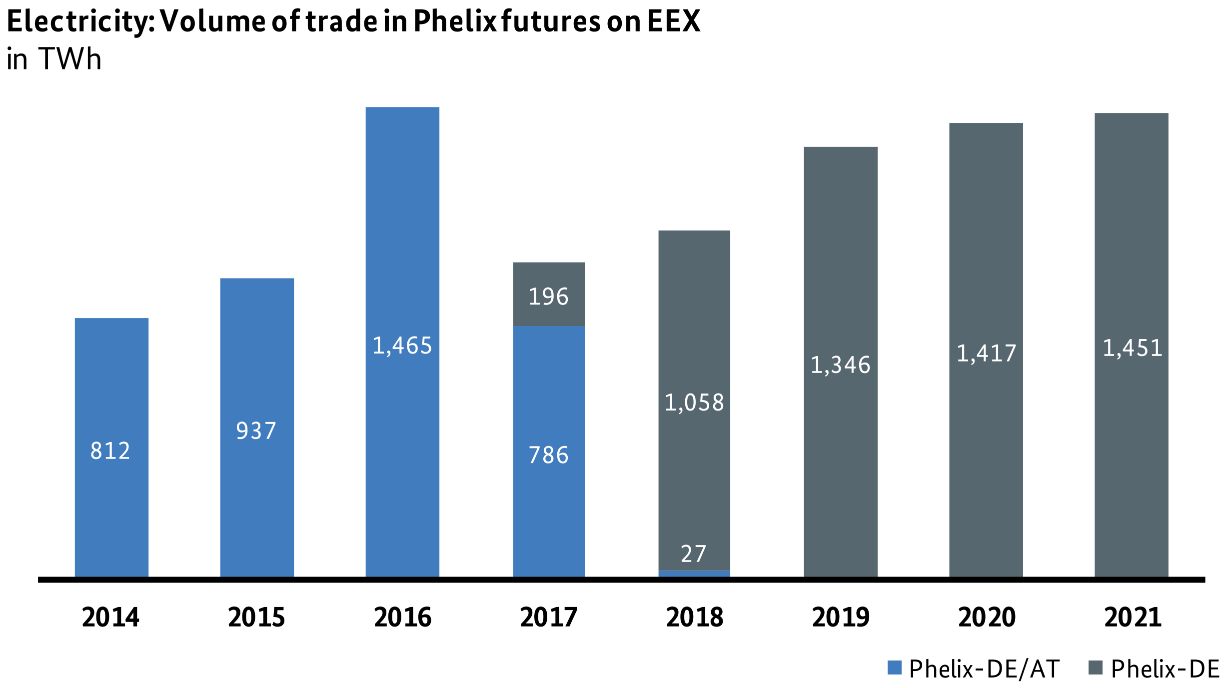

Figure 103: Trading volumes of Phelix DE/AT and Phelix DE futures on EEX

Exchange trading in Phelix DE futures in 2021 predominantly focused on contracts for the year ahead (2022 as the fulfilment year) with approx. 54% of the total trading volume, i.e. 780 TWh. Trading for 2021 made up the second largest share with approx. 26%, i.e. a total of 382 TWh. The total volume traded for 2023 and the following years increased. Trading for the third subsequent year (i.e. 2024) increased to around 217 TWh. Volumes for the fourth subsequent year and later also increased from 51 TWh to 72 TWh.

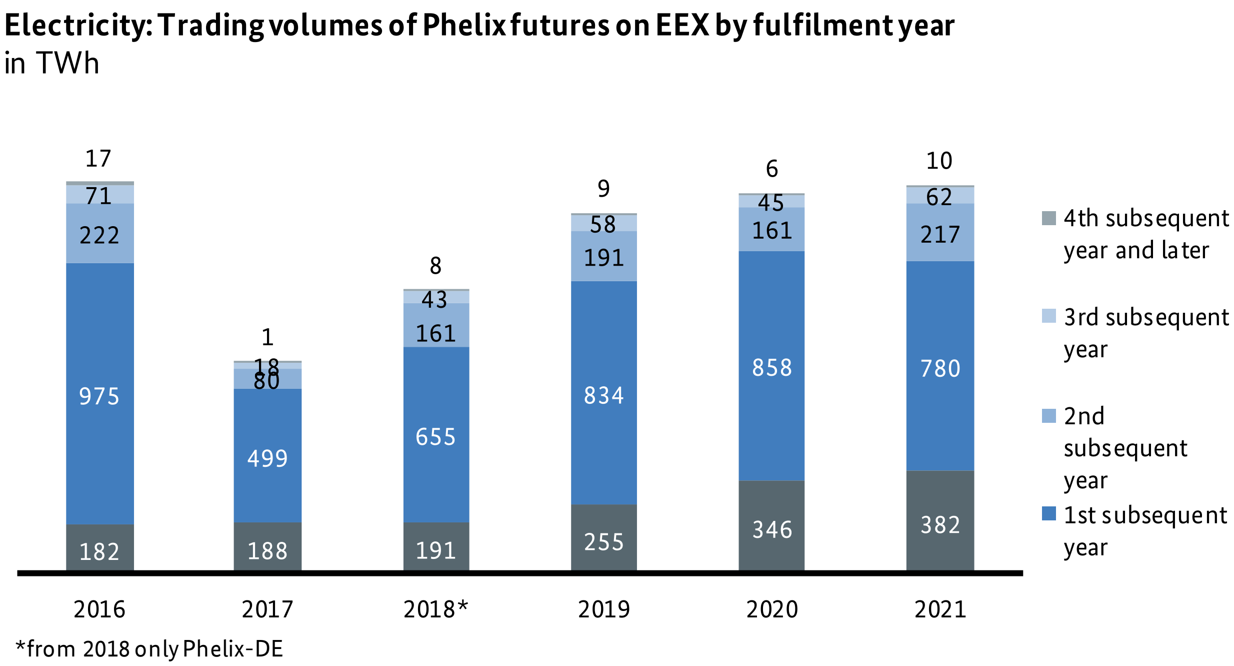

Figure 104: Trading volumes of Phelix DE/AT futures and from 2018 of Phelix DE by fulfilment year

1.2.2 Price level

The futures prices increased sharply over the course of 2021 – especially in the second half of the year. The futures prices increased sharply due to gas shortages and other market shortages in generation capacities as well as the increase in demand due to the relaxation of Covid restrictions and the lower feed-in volumes of renewable energy. In addition, the reduced gas supplies and the failure to fill the gas storage facilities also caused prices to rise. At the beginning of 2021, the Phelix DE peak year ahead future was quoted at 61.00 euros/MWh and at the end of December 2021 at 290.00 euros/MWh, i.e. representing an increase of approx. 375% over the year. The Phelix DE base year future also increased over the year from 50.92 euros/MWh to 219.88 euros/MWh. This represents an increase of around 332% since the beginning of the year.

Electricity: Price development of Phelix front year futures in 2021
in euros/MWh

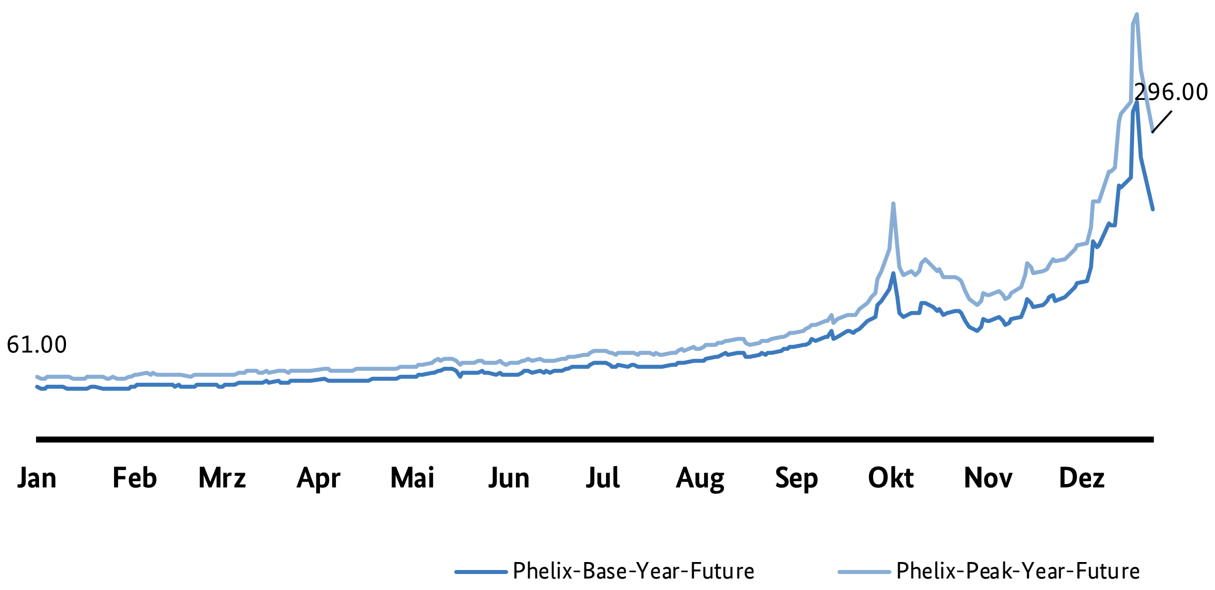

Figure 105: Price development of Phelix DE front year futures in 2021

An annual average can be calculated on the basis of the Phelix DE futures prices recorded on the EEX exchange on individual trading days. This average would correspond to the average electricity purchase price or electricity sales price of a market player if the player bought or sold the electricity not at short notice but in the preceding year.

The annual averages of the Phelix DE futures prices increased sharply year-on-year. With an annual average of 88.42 euros/MWh, the Phelix base year future fell by 40.17 euros/MWh, a decrease of approximately 120%. The price of the Phelix peak front year futures averaged at 107.23 euros/MWh over the year. This corresponds to an increase of around 119% compared to the previous year's average (49.04 euros/MWh).

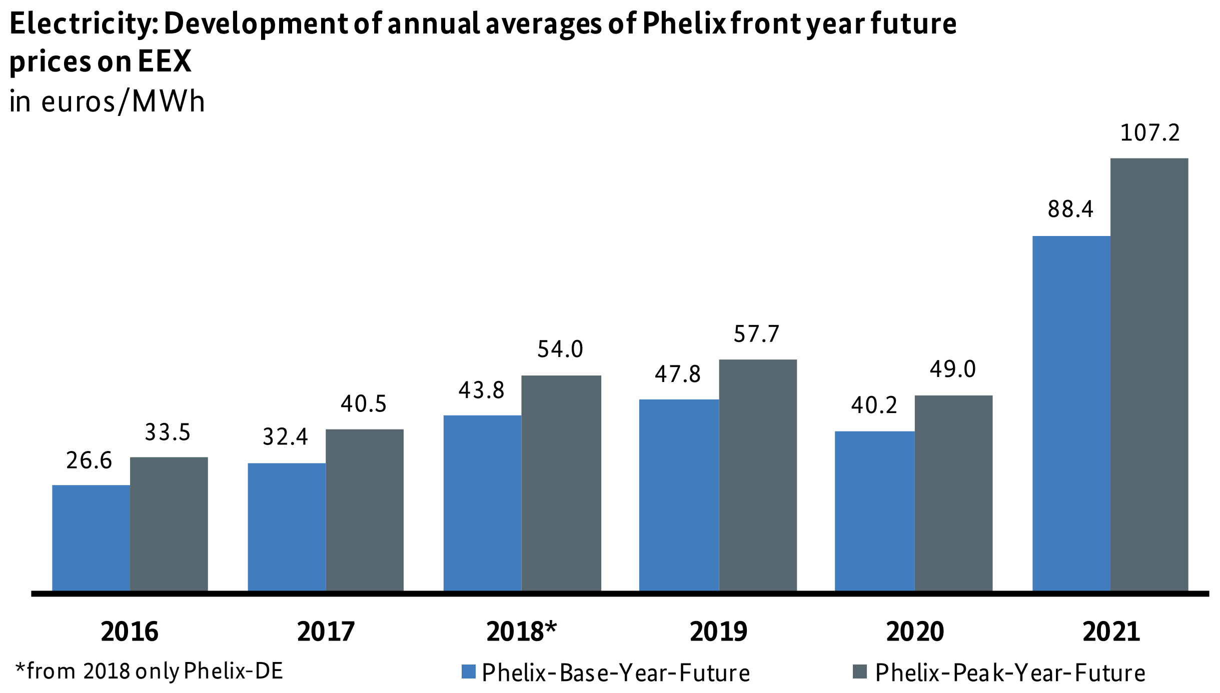

Figure 106: Development of the annual averages of the Phelix DE front year futures prices on EEX

The annual average price difference between base and peak products was 18.81 euros/MWh. In 2020 the difference still amounted to 8.87 euros/MWh. The peak price was therefore around 21% 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: The market makers' share of the purchase volume was thus approx. 0.141%. On the sales side the volume was 0.135%.

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 in total accounted for about 0.24% and 0.32% respectively of purchases and sales in 2021.

1.3.2 Share of transmission system operators

In accordance with the Renewable Energy Sources Ordinance (EEV)[102], 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. 23% in 2021; in the previous year it was 19%. 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 42 TWh in 2021; in 2020 this value was around 41 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 3% 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.[103]

The share of the five purchasers with the highest turnover of the trading volume in the coupled day-ahead auction rose from 39% in 2020 to 42% in 2021. The corresponding share on the seller side also increased compared to the previous year. The cumulative share of the five sellers with the highest turnover was approximately 37% in 2021. This was 30% in the previous year.

[102] More information on the EEV available in German at: https://www.gesetze-im-internet.de/ausglmechv_2015/BJNR014610015.html (retrieved on 1 September 2022)

[103] Generally speaking, company groups only have one participant registration.

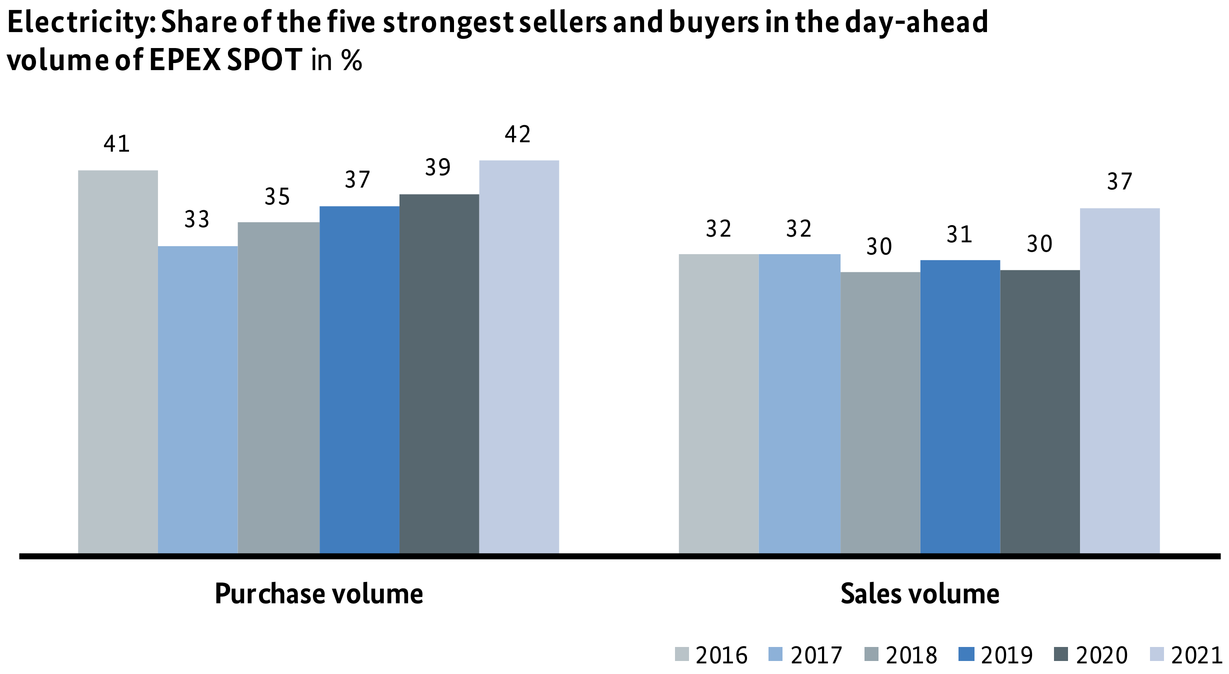

Figure 107: Share of the five sellers and buyers with the highest turnover of the day-ahead volume on EPEX SPOT

The share of the five buyers of Phelix DE futures with the highest turnover on EEX (excluding OTC clearing) fell from around 28.3% in 2020 to 25.2% in 2021. The share of the five sellers with the highest turnover fell from around 29.1% in 2020 to 26.6% in 2021.

2. Off-exchange wholesale trading

Off-exchange 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 2021 different broker platforms were once again surveyed with regard to off-exchange wholesale trading (see sections below). Data on OTC clearing on EEX were also collected.

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.

Ten brokers (eleven in the previous year) 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 3,512 TWh in 2021 compared to 5,702 TWh in 2020. Contracts for the year 2022 (first year following the publication of the report) continue to make up the main focus of electricity transactions brokered on broker platforms with 45%, followed by the activities for the current year 2021 with 38%. Short-term transactions with a fulfilment period of less than one week generated only small volumes.

Further considerations regarding the trading volume can be based on data from the London Energy Brokers' Association (LEBA), which, however, does not include all broker platforms surveyed. The volume of trading transactions brokered by LEBA members decreased. The trading volume for "German power" brokered by LEBA members fell from 5.368 TWh in 2020 to 4,345 TWh in 2021, or by around 19%.[104]

Electricity: Volume of electricity traded via broker platforms in 2021 by fulfilment period

Fulfilment period	Volumes traded in TWh	Share
Intraday	5	0%
Day ahead	72	2%
less than 1 week	40	1%
over 1 week	1,327	38%
1st subsequent year	1,585	45%
2nd subsequent year	366	10%
3rd subsequent year	117	3%
4th subsequent year	9	0%
Total	**3,521**	**100%**

Table 93: Volume of electricity traded via broker platforms in 2021 by fulfilment period

[104] See London Energy Brokers' Association, Monthly Volume Report.

2.2 OTC Clearing

Alongside on-exchange trading, on-exchange OTC clearing plays 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. with regard to futures, that has to be deposited with the clearing bank.

By registering on the exchanges, the contracting parties ensure that their contract is subsequently treated as a transaction originating on the exchange, i.e. both parties are put in a position as if 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 1,740 TWh in 2021. The volume was still 1,668 TWh in 2020. Since OTC clearing is used to "retrospectively" treat contracts as 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. Compared to the previous year, the volume increased, both in OTC and on-exchange trading. It is worthy of note that the volume of OTC clearing since 2019 increased more than the volume of normal exchange trading.

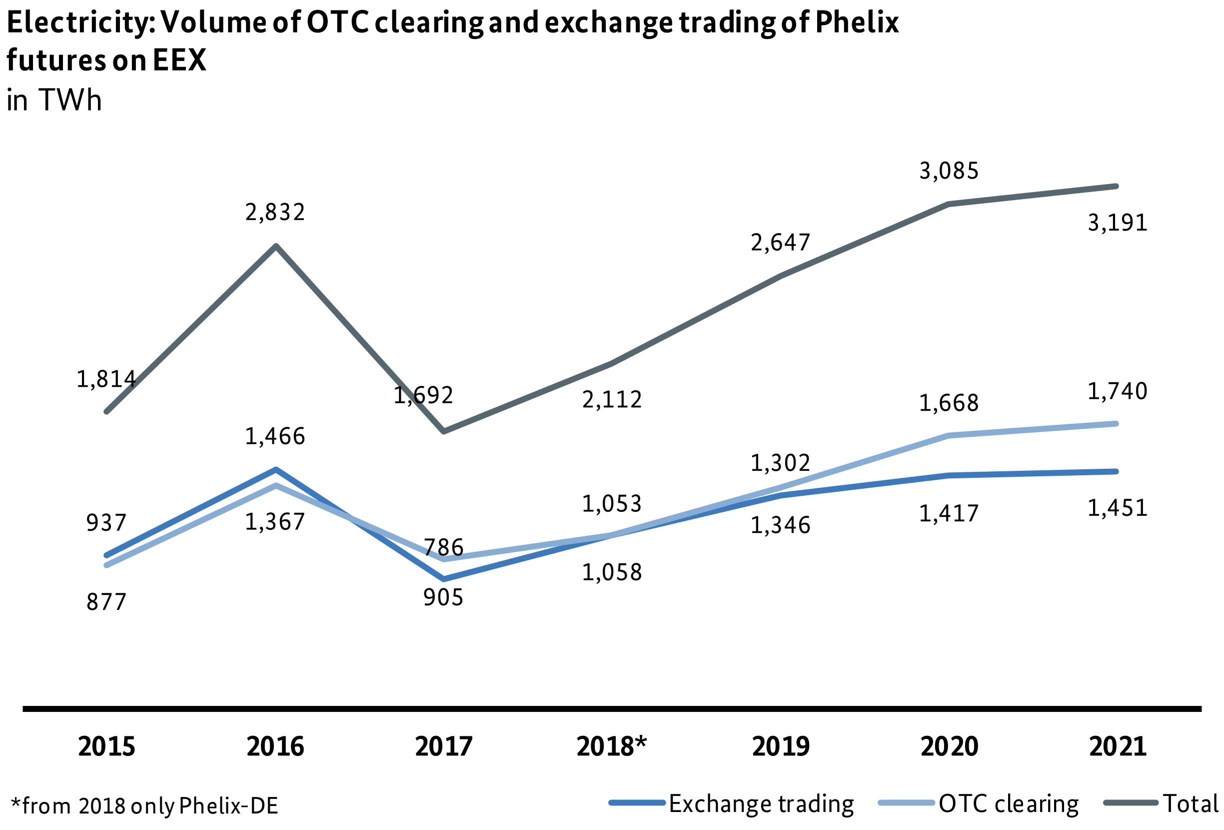

Figure 108: Volume of OTC clearing and exchange trading of Phelix DE futures

If the additional data provided by LEBA are included in the assessment, the volume for "German power" registered by LEBA members for clearing was approx. 1,566 TWh in 2021, which is equivalent to a share of about 36% of the total OTC contracts brokered by LEBA members. Here the volume registered for clearing also increased, accounting for approx. 29% of the total volume in 2020.[105]

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 2021. However, there are Phelix options which are agreed off-exchange and cleared on EEX. In 2021 Phelix options agreed off-exchange and cleared OTC accounted for 94 TWh on EEX. This corresponds to a share of 5,4%. The OTC clearing volume for options in 2021 rose by approx. 19% compared to the previous year.

The distribution of the volumes registered on EEX for OTC clearing across the various fulfilment periods in 2021 only marginally changed compared to the previous year. While in 2020 approx. 54% consisted of contracts for the year ahead (2022), this figure fell to 52% in 2021 or 551 TWh. Around 32%, or 898 TWh, of the OTC clearing volume is for the year 2021. The share for the year after next increased to 222 TWh, or by around 13%. Later fulfilment periods made up only a small share.

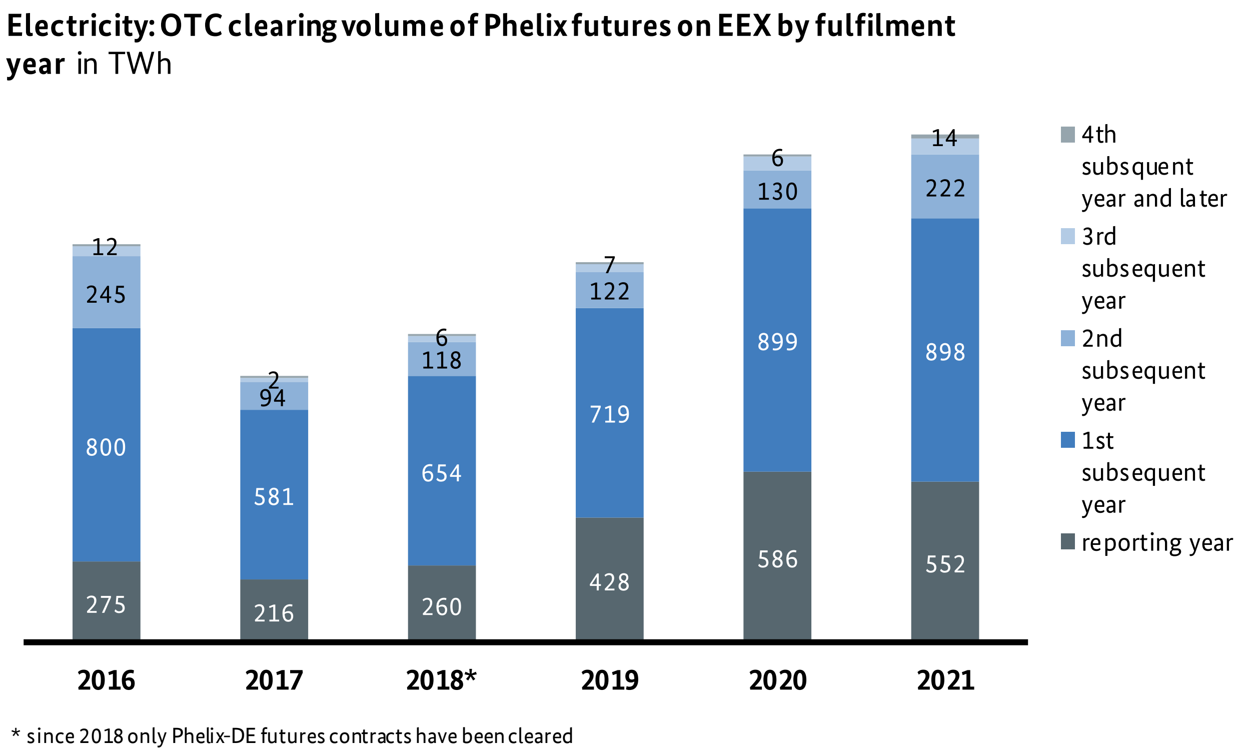

Figure 109: OTC clearing volume of Phelix futures on EEX by fulfilment year

[105] Cf. https://www.lebaltd.com/monthly-volume-reports/ (retrieved on 1 September 2022).

G Retail

1. Supplier structure and number of providers

In total, at least 1,423 companies were operating as electricity suppliers in Germany in the year 2021. Suppliers are considered to be individual legal entities without taking company affiliations or links into account.

Around 52.2mn market locations of final consumers were recorded in the monitoring survey. As the following figure shows, of 1,357 suppliers, approximately 84% serve fewer than 30,000 market locations. This amounts to just under 8.1mn market locations in this category (around 16% of all market locations). Around 6% of all suppliers serve over 100,000 market locations. In absolute terms, these 6% serve 37mn market locations, or around 71% of all customers, the same figure as in the previous year. These 88 large suppliers serve the majority of market locations in Germany. This means that 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 2021
not taking company affiliations into account

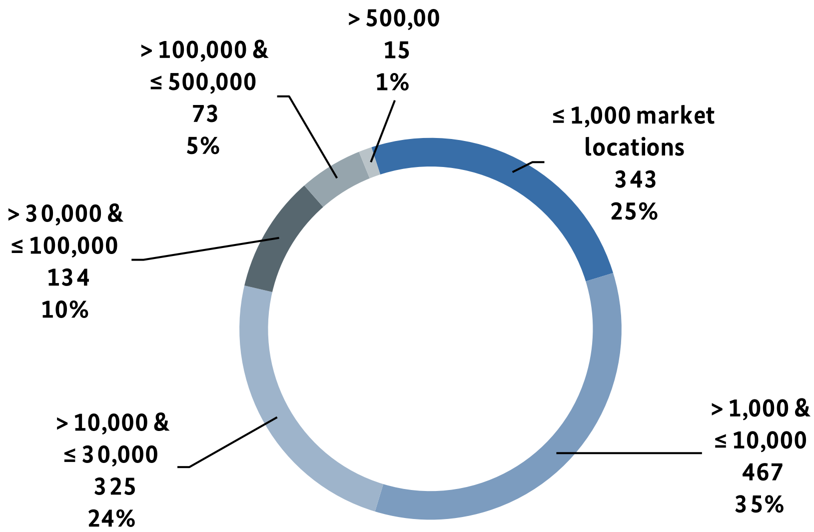

Figure 110: Number of suppliers by number of market locations supplied

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 1,250 suppliers shows that nearly half of them only operate regionally. 108 suppliers, or around 9%, supply customers in more than 500 network areas (see following chart). 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: 205 suppliers have concluded contracts in all 16 federal states. On a national average, a supplier has customers in 100 network areas (2020: 99 network areas).

Electricity: number and share of suppliers serving customers in the given number of network areas in 2021
not taking company affiliations into account

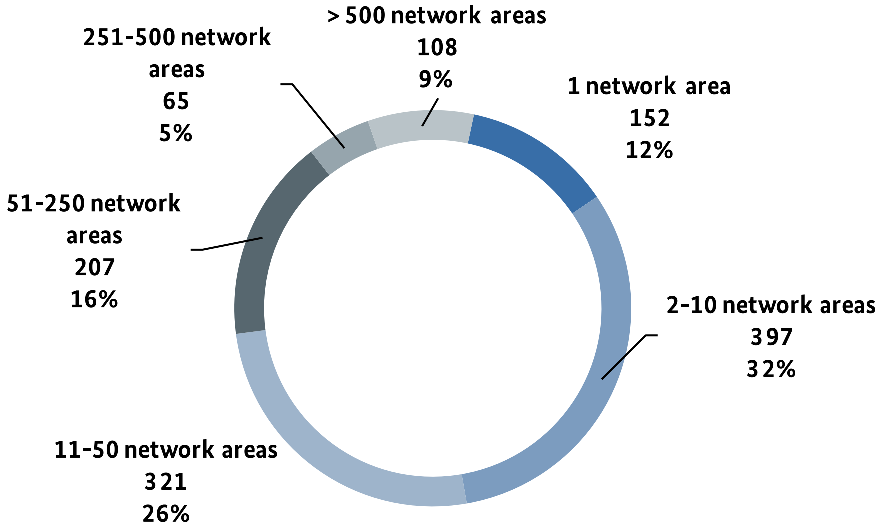

Figure 111: Number of suppliers by number of network areas supplied

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 812 distribution system operators on the number of suppliers that supply consumers in each network area produced the following results (see figure below): in 2021 more than 50 suppliers operated in 90% of all network areas (722 network areas). In 2008, this figure was 50% of the network areas (362 network areas). Today more than 100 suppliers operate in around 77% of the network areas, whereas in 2014 it was only around 50%. On average, final consumers in Germany were able to choose between 167 suppliers in 2021 (2020: 162), while household customers were able to choose between 147 suppliers (2020: 142).

Electricity: breakdown of network areas by number of suppliers operating
in %, not taking company affiliations into account

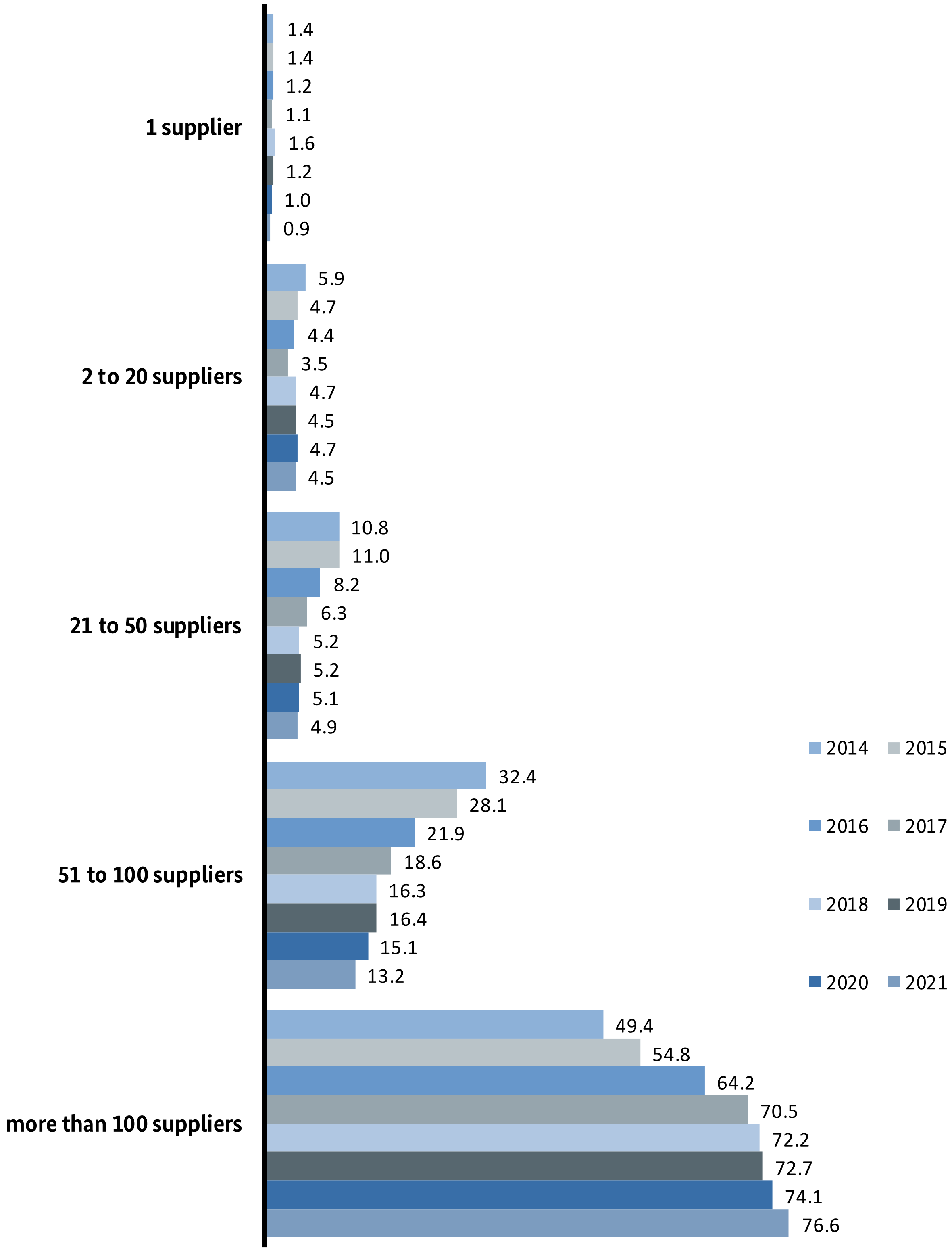

Figure 112: Breakdown of network areas by number of suppliers operating

2. Contract structure and supplier switching

37% of household customers are on non-default contracts with the regional default supplier. Approximately 24% of household customers are on default contracts. 39% of household customers have a contract with a supplier other than the local default supplier.

Overall, 61% of the consumption volume of all households are procured from the default supplier. The position of default suppliers in their respective service areas thus remains strong.

Approximately 4.8 million household customers switched supplier in 2021. It should be noted that the 2021 figure does not include switches because of insolvencies or (involuntary) switches because of suppliers cancelling contracts (the number including these switches is around 5.7 million)

In the fourth quarter of 2021 procurement prices in Germany rose sharply. As a consequence a number of suppliers stopped supplying customers or became insolvent. These suppliers included notably one larger electricity supplier as well as one larger gas supplier. The suppliers' customers were automatically transferred to their default supplier without their energy supply being disrupted. This above-average increase in customer numbers prompted several default suppliers to introduce different general prices for existing and new customers. One particular reason for doing this was that the energy they had to procure at short notice for their new customers was considerably more expensive than the energy procured further in advance for their existing customers. The legal admissibility of this split was subsequently the subject of court proceedings.

The legislators responded with an amendment of the EnWG in July 2022 to prohibit suppliers from having different general prices for existing and new customers on default contracts. However, the general prices for customers automatically transferred to their local default supplier (fallback supply) are allowed to be higher than those for customers (including household customers) on default contracts and can also be adjusted on the first and the fifteenth of each month.

Consumers are advised to check their contract status (default contracts etc.) and their current supplier's current prices and compare them with the prices of other electricity providers.

Important indicators for the intensity of competition are switching rates and switching processes. Data on supplier switches are gathered through indicators reflecting the actual switching behaviour to the best possible extent. In this context, supplier switch is the process of allocating a final consumer's market location to a new supplier. Final consumers moving into or out of a location are not considered as switching suppliers. In this analysis it must be noted that the change of supplier question refers to a change in the supplying legal entity. Pursuant to this definition, a "supplier switch" can also occur if supply contracts are transferred from one corporate group to another or if the former supplier is insolvent or terminates the supply contract. This is why the actual extent to which customers switched suppliers may deviate from the figures established in the survey. In addition to supplier switches, the monitoring report also analyses the household customers' choice of supplier upon moving house if they choose a supplier other than the default supplier. Supplier switches within the same corporation are referred to as contract changes.

Data on contract structures and supplier switching are collected by the network operators (transmission system operators and distribution system operators) and suppliers for various customer groups to calculate the indicators. Final consumers can be grouped, according 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 grouped into household, commercial and industrial customers. Household customers are defined in the German Energy Act (EnWG) according to mostly qualitative characteristics.[106] Non-household customers are referred to in the monitoring report as commercial and industrial customers. There is so far no recognised definition of commercial customers[107] 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 2021 was approximately 405.6 TWh. In the previous year, this figure was 347.3 TWh. In 2021, around 290.9 TWh of this amount was supplied to interval-metered customers and 144.7 TWh to SLP customers (including 14.3 TWh of electricity for thermal night storage heating and heat pumps). The majority of SLP customers are household consumers.

In the monitoring survey the volumes of electricity sold to various final consumer groups were broken down into the following categories:

- default supply contract,
- non-default contract with the default supplier,
- contract with a supplier other than the local default supplier.

For the purpose of this analysis, the default contract category also includes fallback supply (Section 38 EnWG) and doubtful cases.[108] Supply outside the framework of a default contract is either designated as a non-default contract or is defined specifically as a "non-default contract with the default 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

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[106] 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 or commercial purposes not exceeding an annual consumption of 10,000 kilowatt hours.

[107] 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.

[108] 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".

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 another company affiliated with the default supplier falls under the category "contract with another supplier". It is also possible that further ambiguities may arise, for example if the local default supplier changes. In these cases no automatic contract change takes place (Section 36(3) EnWG).

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[109], the majority are industrial or other high-consumption non-household customers.

In the reporting year 2021, approximately 1,411 electricity suppliers (individual legal entities) provided data on the meter points supplied and on the consumption of interval-metered customers (1,413 in the previous year). The 1,411 electricity suppliers include many affiliated companies, so that the number of suppliers does not equal the number of competitors.

The companies supplied just under 246.6 TWh of electricity to the approximately 376,086 meter points of interval-metered customers in 2021 (approx. 213.3 TWH was supplied to 368,586 meter points in the previous year). 99.9% of this was supplied under contracts outside of default supply[110]. It is unusual but not impossible for interval-metered customers to be supplied under default or fallback supply contracts. A total of 0.29 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% of the total electricity for interval-metered customers was supplied under a special contract with the default supplier (divided between around 38.1% of all interval meter points). Approximately 75.9% of the total electricity was supplied under a contract with a legal entity other than the local default supplier (divided between approximately 60.7% of all meter points). In the previous year, 24.4% of the volume was sold under special contracts with the default supplier and 75.5% 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.

[109] In accordance with Section 12 of the Electricity Network Access Ordinance (StromNZV), interval metering is generally required if annual consumption exceeds 100 MWh.

[110] 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.

Electricity: Contract structure for interval-metered customers in 2021
Volume and distribution

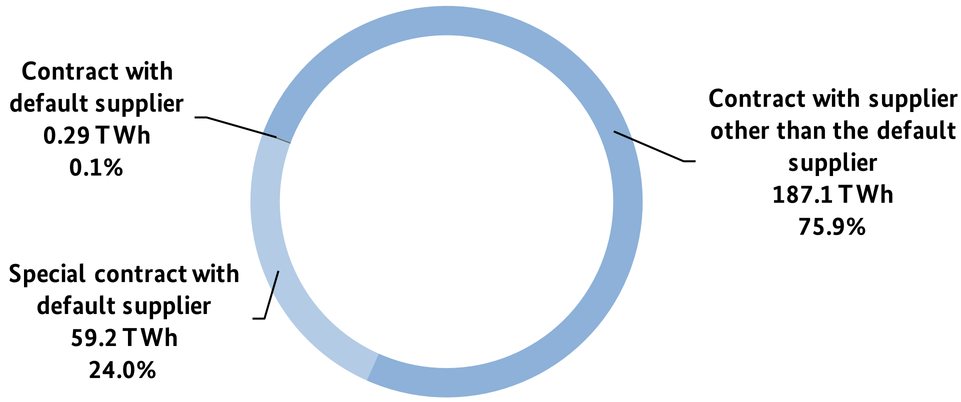

Figure 113: Contract structure for interval-metered customers in 2021

2.1.2 Switching supplier

Data on the supplier switching rates among different customer groups in 2021 and the consumption volumes attributed to these customers were 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:

Electricity: Supplier switching by consumption category in 2021

Consumption category	Number of meter points with supplier switching	Share of all meter points in consumption category	Consumption volume at meter points with switching in TWh	Share of consumption volume in consumption category
>10 MWh/year – 2 GWh/year	210,407	10.0%	14.0	12.0%
> 2 GWh/year	2,398	13.4%	22.1	10.0%
Total non-household customers	**212,805**	**10.0%**	**36.1**	**10.7%**

Table 94: Supplier switching by consumption category in 2021

The volume-based switching rate for the categories with a consumption exceeding 10 MWh/year was 10.7% in 2021. The switching rate in the previous year was 11.6%. Switching rates in the non-household customer category have remained more or less stable for several years. 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.

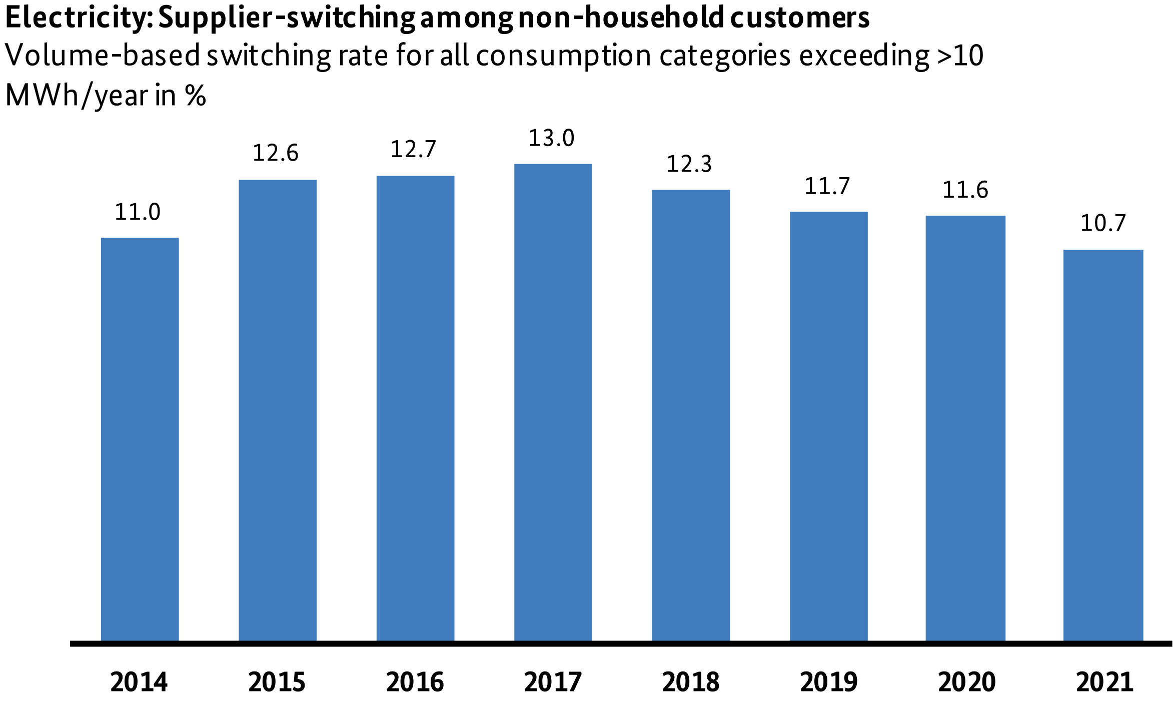

Figure 114: Supplier switching among non-household customers

2.1 Household customers

2.1.1 Contract structure

The data from the monitoring report shows that in 2021 the category "non-default contract with the default supplier" accounted for around 37% of electricity consumption by household customers (2020: 37%). The percentage of household customers with a standard default supply contract is 24% of electricity consumption (2020: 25%). The percentage of consumption provided under a contract with a company other than their local default supplier was 39% (2020: 38%). Overall, 61% of all household consumption is still provided by the default supplier (2020: 62%). Despite a steady decline in recent years, the position of the default suppliers in their respective service areas remains strong.

Data was collected for the first time on the contract duration of electricity customers in the various tariffs with suppliers operating in Germany, allowing conclusions to be drawn on this. Contracts ending in 2021 were examined.

Electricity: average contract duration of household customers

Household customers (outside default supply)	Average length of time (months)
in the default supply network areas	38
outside the default supply network areas with a monthly contract	34
outside the default supply network areas with a 12-month contract	27
outside the default supply network areas with a 24-month contract	33

Table 95: Average contract duration of household customers

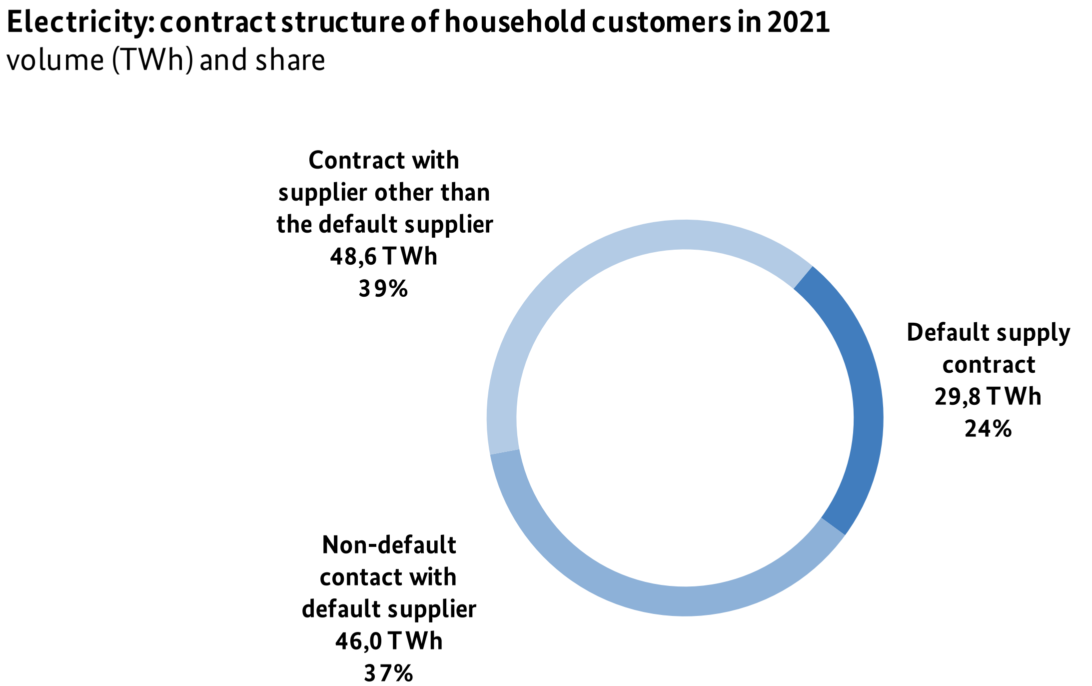

Figure 115: Contract structure of household customers in 2021

2.1.2 Switch of contract

The following table depicts contract switches within a company carried out at the customer's request. The total number of contract switches was around 1.53mn, which is below the previous year's level (2020: 1.83mn contract switches). The corresponding volume of electricity involved in the contract switches amounted to approximately 3.7 TWh (2020: 5.3 TWh). This results in a number and volume-based contract switching rate of 3.1% and 3.3% respectively. The number of switches within a company is thus slightly lower than last year's figure, whereas the volume of electricity involved in contract switches declined significantly, by approximately 1.5 TWh.

Electricity: contract switches by household customers in 2021

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	3.7 TWh	3.1%	1.53 Mio.	3.3%

Table 96: Contract switches by household customers (based on survey of electricity suppliers)

2.1.3 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 2021 the total number of household customers switching supplier amounted to 4.76mn in total, which is around 615,000 lower than the previous year's level of 5.4mn. It should be noted that in the analysis of monitoring data for 2021, the special effect caused by insolvencies and (involuntary) switching due to contract terminations by suppliers who could not continue supply due to increased prices was taken into account. Based on the previous year's data from 38 companies, the Bundesnetzagentur estimates the affected customers to amount to about 950,000, and this number was deducted from the total number of (voluntary) supplier switches.

For a few small suppliers who terminated their customers' electricity supply, the Bundesnetzagentur does not have information on the number of customers affected. Because of the resulting degree of uncertainty, the values are thus not directly comparable with previous years' figures.

In 2021 the overall supplier switching rate was approximately 9.7% for household customers and has thus decreased (2020: 10.9%; 2019: 9.9%). These switches entail an electricity volume of about 16.6 TWh, which is around 0.4 TWh higher than the previous year's figure (2020: 16.6 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. The electricity volumes that these figures are based on do not allow the special effect of insolvencies and (involuntary) switches due to contract terminations to be deducted from the total number of active (voluntary) supplier switches. The following figure shows the increasing trend in the rate of supplier switches since 2012.

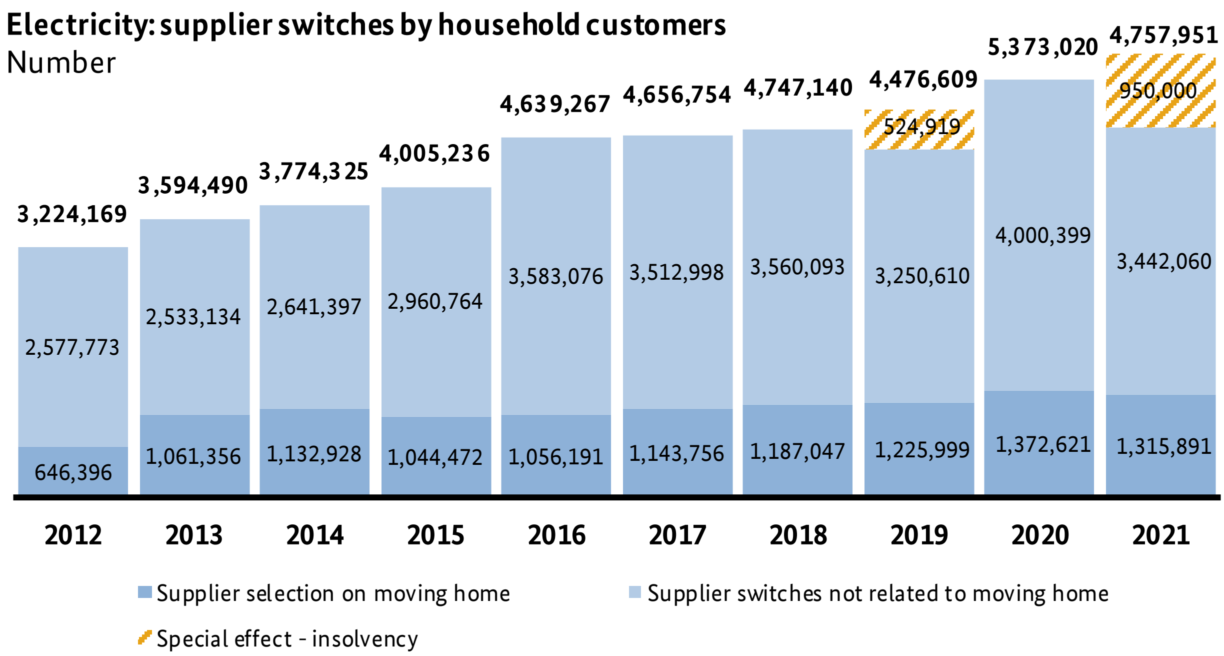

Figure 116: Supplier switches by household electricity customers[111]

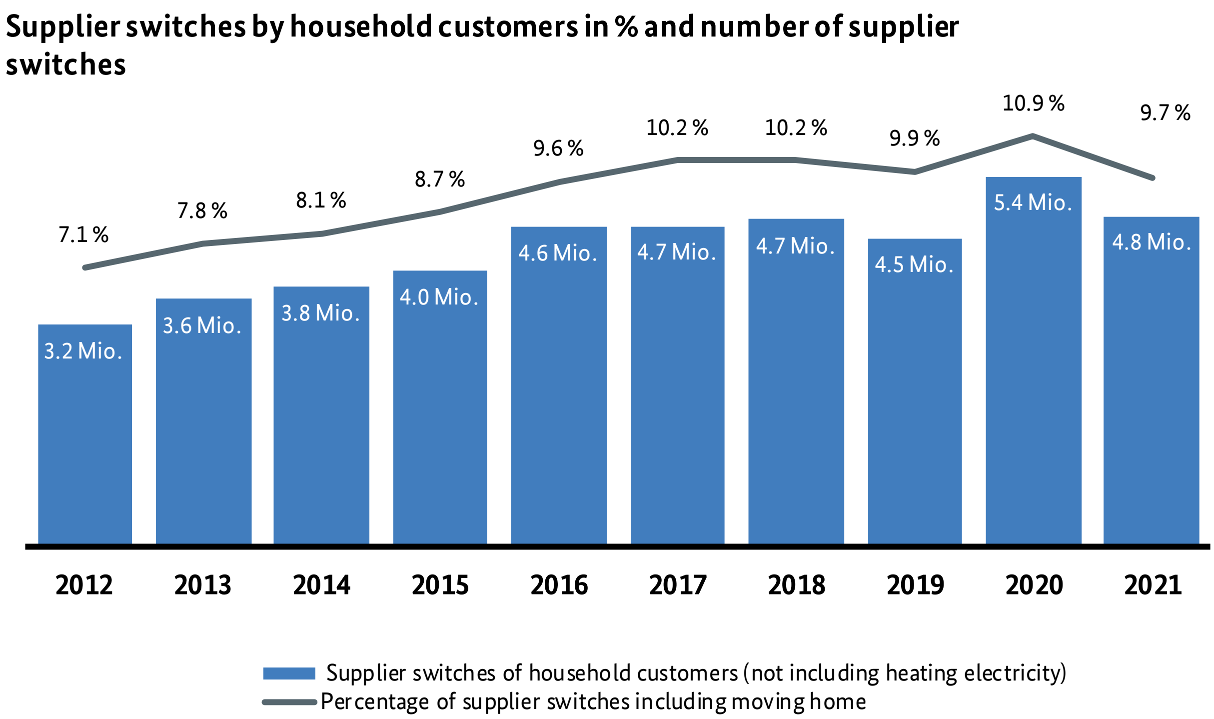

Figure 117: Supplier switches by household electricity customers

[111] 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

A joint view of the contract and supplier switches in 2021 makes it possible to determine the number of household customers who undertook a change in their energy supply contract. Around 6.3mn switches were made in total.

3. Disconnections, cash/smart card 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. With this disconnection notice, the customer must be informed about possibilities for avoiding disconnection.

Disconnection (interruption) of supply is carried out at the earliest four weeks after the disconnection notice. Under default supply, the date of actual disconnection must be announced to the customer eight working days in advance; with this announcement at the latest, the customer must be offered an arrangement to prevent disconnection that includes an instalment payment option and the possibility of a continued supply on an advance payment basis.

Under a default supply contract, it is only possible to disconnect a customer who is twice the monthly instalment in arrears and the sum owed is more than €100. If no monthly instalments are arranged, the arrears in payment must amount to at least one sixth of the estimated annual amount. A disconnection may not be disproportionate; in particular, it may not cause a risk to life or limb of those affected.

The supplier may charge the customer for issuing notices, disconnecting supply and 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 December 2021, more stringent prerequisites for carrying out disconnections under default supply were imposed. The prerequisites outlined above reflect the new legal situation.

3.1 Disconnections of supply

In 2021, 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 234,926, which is 2% higher than the previous year's figure (2020: 230,015). Based on the total number of market locations, the disconnection rate was 0.45%. Due to the right to refuse performance temporarily introduced during the coronavirus pandemic (Article 240 section 1 of the Introductory Act to the Civil Code EGBGB) there was a sharp decline in the number of disconnections carried out in 2020. In addition, a majority of suppliers also decided not to carry out disconnections of their customers. In 2021, too, around half of the electricity and gas suppliers questioned by the Bundesnetzagentur announced that they chose to forgo carrying out disconnections of supply. In many cases, electricity suppliers also agreed to special or individual payment terms with their customers in order to reach customer-friendly solutions.

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 twice the monthly instalments (alternatively one sixth of the annual amount), at least €100, after proportionality has been verified, and after the appropriate notice has been given. Non-default suppliers stipulate the regulations governing failure to fulfil payment obligations in their contracts.

The following figure shows how often during 2021 suppliers issued notices threatening disconnections of supply due to failure to fulfil payment obligations, how often they issued disconnection requests, and how often those disconnections were carried out.

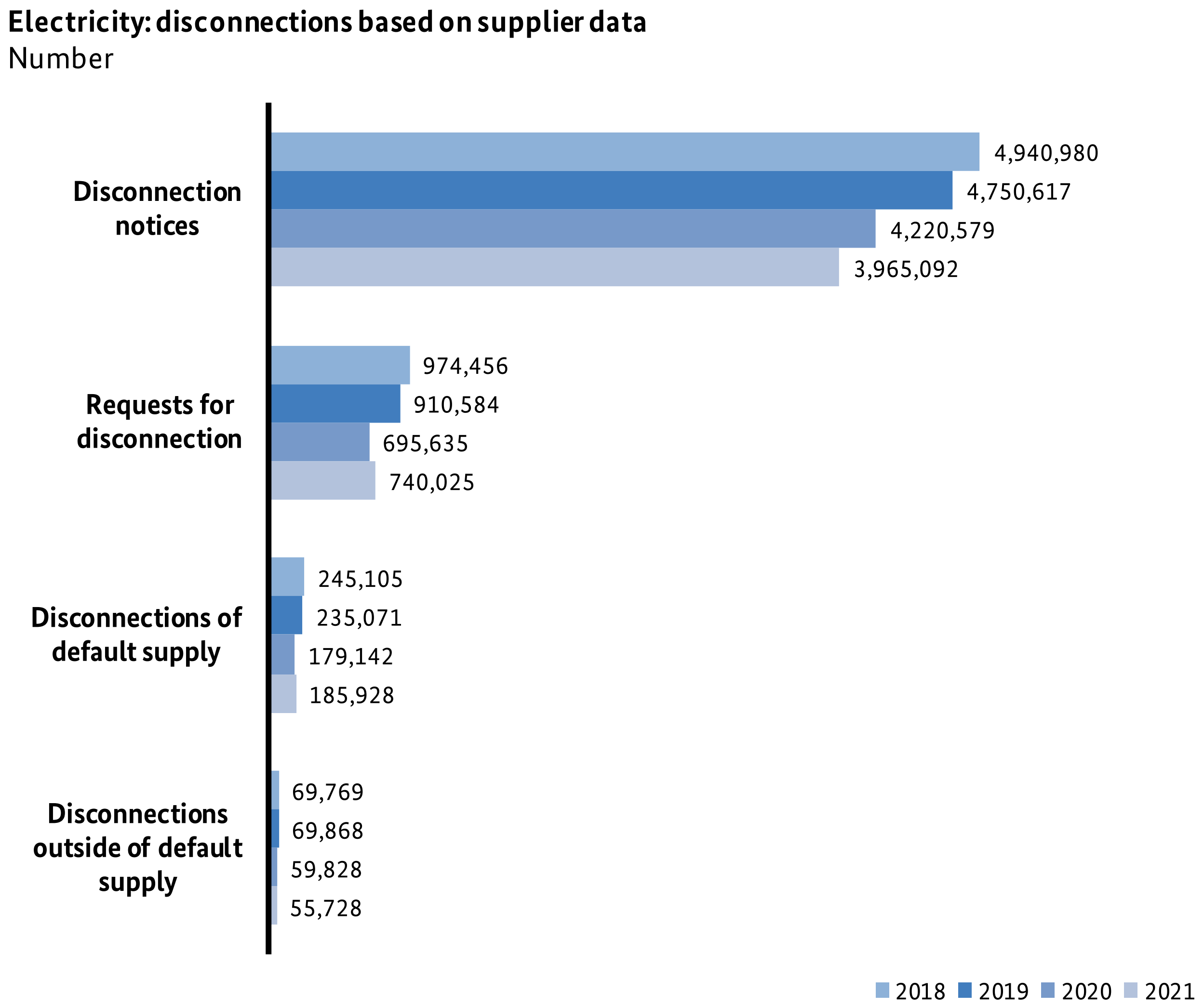

Figure 118: Disconnection notices, requests for disconnection and disconnections, within and outside of default supply, based on survey of suppliers

According to the data provided by suppliers, disconnection notices were sent out when, on average, a customer was €125 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 their 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),[112] with the actual fee ranging between €0.07 and €150. Suppliers who did not carry out a flat rate calculation charged their customers an average of €48 (including VAT), with the actual fee ranging between €0.07 and €199. For reconnection, electricity suppliers using the flat rate model

[112] Suppliers' own costs, not including costs incurred with the commissioned network operator.

charged their customers an average of approximately €48 (including VAT), with the actual fee ranging between €0.07 and €145, while suppliers who did not use the flat rate model charged an average of €50 (including VAT), with the actual charges ranging between €0.07 and €125. Suppliers charged household customers an average of €2.74 for issuing a reminder because of arrears in payment.

The following figure shows how often DSOs carried out a disconnection of supply in 2021. A total of 234,926 disconnections and 216,883 reconnections were carried out in 2021.

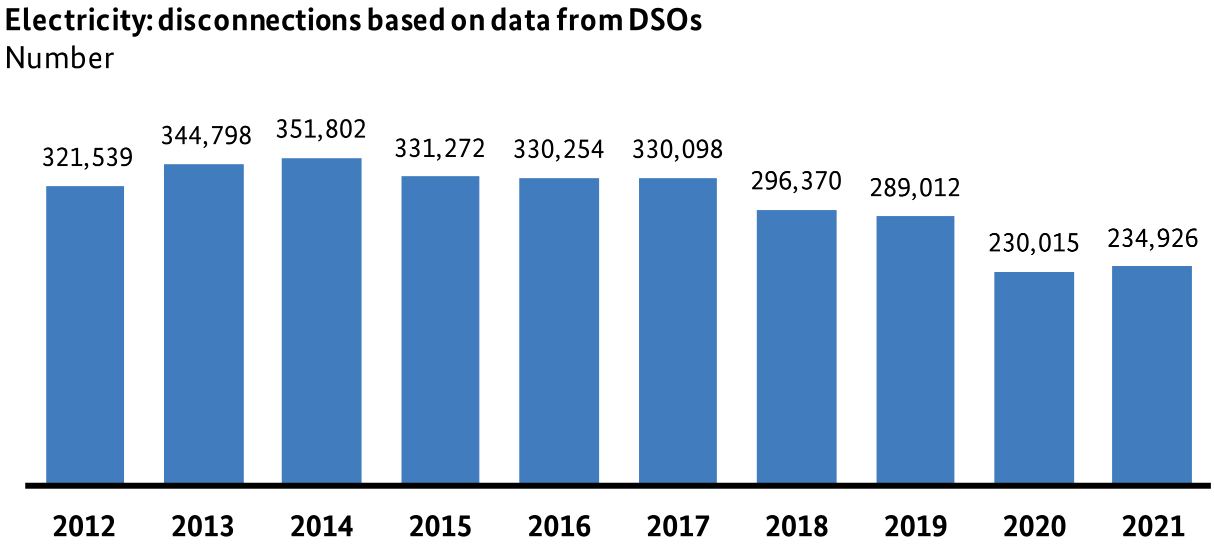

Figure 119: Disconnections based on data from DSOs[113]

In 2021 for the first time, suppliers provided data on the breakdown of disconnections by quarter, thus giving an overview of seasonal differences. It should be noted that, given the need for the debt to be a certain amount and the deadlines for disconnection notices and orders, the disconnection process always takes some time. A majority of disconnections were carried out during the third quarter. Suppliers were not asked the reasons for this. In general, the detrimental impact of disconnections on consumers is much greater in the darker winter season than in the summer. The following figure provides an overview of the breakdown of the disconnections (since not all DSOs submitted data, the total sums deviate from the figures above).

[113] 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.

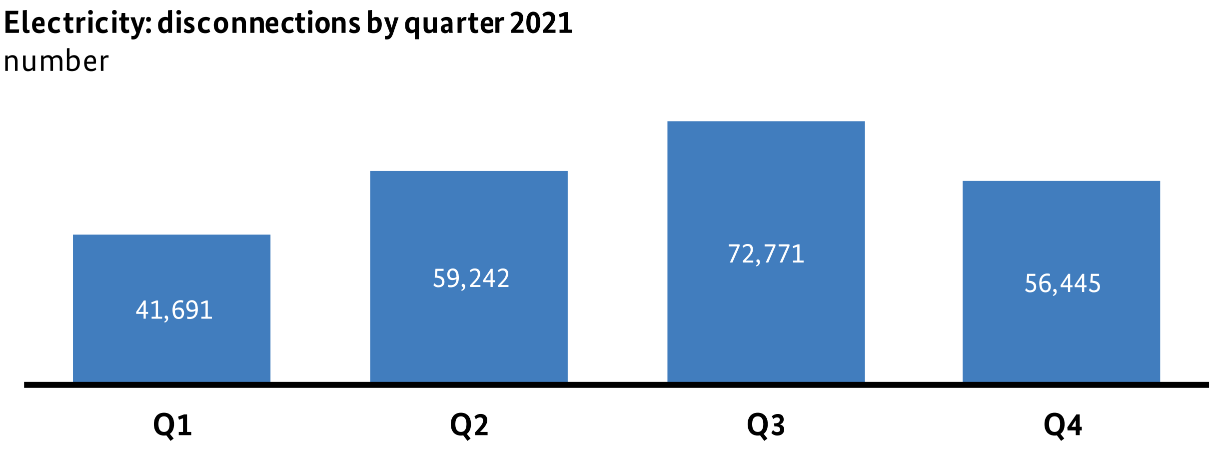

Figure 120: Breakdown of disconnections by quarter 2021

The following table shows the distribution of disconnections broken down by federal state, sorted by percentage of disconnections at market locations in the respective federal state.

Electricity: number of disconnections by federal state in 2021 (DSO data)

	Number of disconnections (within and outside of default supply)	Percentage of market locations of final consumers in the federal state
Bremen	4,039	0.90
Saxony-Anhalt	10,872	0.71
North Rhine-Westphalia	79,240	0.70
Hamburg	6,836	0.58
Berlin	12,192	0.50
Hesse	18,773	0.49
Saxony	13,539	0.48
Mecklenburg-Western Pomerania	5,237	0.46
Thuringia	6,303	0.44
Rhineland-Palatinate	10,027	0.40
Schleswig-Holstein	6,975	0.38
Saarland	2,397	0.37
Lower Saxony	15,367	0.32
Brandenburg	5,463	0.31
Bavaria	21,341	0.27
Baden-Württemberg	16,325	0.25

Table 97: Number of disconnections by federal state in 2021

The network operators charged the electricity suppliers an average fee of €54 (excluding VAT) for disconnecting a supply, with the actual costs charged ranging between around €12 and €280. The amount charged for reinstating supply to household customers was between €15 and €175, with an average fee of €58 (excluding VAT).

The average length of time between an actual disconnection and a reconnection was 16 days (for reasons of clarity, this figure only includes cases in which disconnection and reconnection were carried out in 2021). 13,824 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 disconnection notices and requests, in recent years very few suppliers actually terminated services with their customers. In 2021, however, there was a new development caused by the sharp increase in energy prices during the second half of the year. Due to extremely high wholesale prices and a procurement strategy that seems to be geared solely towards short-term purchases, a small number of suppliers were not able to continue supplying their customers with electricity and terminated their contracts with them. The reason thus does not lie with the customers (as a result of their failure to pay, for example), but rather with the procurement strategy of the respective suppliers.

In 2021, suppliers (default and non-default suppliers) terminated a total of nearly 180,658 contracts with their customers for reasons such as non-payment (2020: approximately 173,627). Of these, 90% (169,985) took place outside default supply contracts. The average customer arrears upon a termination of the energy supply contract was €184. A smaller proportion of terminations, 10% or 18,673, were of default supply contracts. 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 unreasonable.

In addition there are the terminations by suppliers who were unable to continue supply due to price increases. Based on the previous year's data from 38 companies, the Bundesnetzagentur estimates this number to be around 950,000 customers.[114]

3.3 Cash meters and smart card meters

In the 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 meters. Over the course of 2021, such prepayment systems were installed at about 19,670 household customers' points of consumption. Of these, 70% were allocated to default suppliers. This corresponds to 0.04% of all market locations of household customers in Germany. In just under 2,800 cases, a cash meter or smart card meter was newly installed in the 2021 calendar year, with about 2,500 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 41a(1) EnWG). In 2021, around 6% of suppliers offered load-based tariffs, while some 57% of suppliers offered time-of-use tariffs.

About ten suppliers (2020: 2 suppliers; 2019: 2 suppliers; 2018: 1 supplier) so far offer tariffs with dynamic pricing that reflect the price on the day-ahead market in intervals; this requires the installation of a corresponding meter.

A dynamic electricity tariff is, analogous to the fixed electricity tariff, made up of a monthly base price and a kilowatt-hour price. While the monthly base price covers the fixed costs for the electricity connection and the meter, the kilowatt-hour price is made up of the energy procurement and supply costs and the margin, network tariffs and various taxes, fees and surcharges (see chapter IG4.2.1). The particular feature of the dynamic tariff is that the energy procurement costs contained in the kilowatt-hour price are coupled with the price on the exchange, which is calculated hourly at the Central European spot market, the European Power Exchange (EPEX Spot), for each hour of the following day. This allows the short-term fluctuations in the

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[114] For a few smaller suppliers, the Bundesnetzagentur does not have customer figures.

electricity price to be passed on to the electricity customers, which can adjust their consumption accordingly. The prerequisite for a dynamic electricity tariff is a smart metering system.

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 133,460 meter locations of customers with standard load profiles (0.25%) were equipped with smart metering systems certified by the Federal Office for Information Security (BSI) in the reporting year 2021, no accurate conclusions can be made regarding the development of dynamic tariffs.

In 2021, 126 companies (13% of the total) 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 46%. Among companies with 10,000 to 200,000 market locations, primarily municipal utility companies offer bundled tariffs.

Overall, 33% 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 by volume to household customers, 67% offer an online tariff. Separate tariffs that include energy saving incentives are currently offered by around 6% of companies.

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 2021

Product category	Frequency
Natural gas	71
Hardware	14
Telecommunications, internet	30
Water	8
Solar/tenants' electricity	40
Other	28
Total	**191**

Electricity: size of companies offering bundled tariffs in 2021

Number of meter points	Proportion
1 < 1,000	1%
1000 < 10,000	6%
10,000 < 30,000	14%
30,000 < 100,000	20%
100,000 < 500,000	29%
< 500,000	46%
Total	**10%**

Table 98: 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 2021, also required suppliers to offer final consumers monthly, quarterly or semi-annual billing. In 2021, 161 suppliers stated that they carry out monthly, quarterly or semi-annual billing for some 100,771 household customers. The average charge (including VAT) for each additional billing was approximately €7 with customer reading and approximately €9 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 procurement and supply costs and the margin, the main components are the network tariffs, 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 2022 for various consumption levels. The standard case for household customers is in the 2,500 kWh 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, including network tariffs, concession fees and meter operation charges. Furthermore, the national 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 the offshore network under section 17f EnWG and interruptible loads. After deducting these transitory items from the overall price, the amount remaining is the amount controlled by the supplier, which includes the energy procurement and supply costs and the margin.

Both with regard to the overall price and the individual price components, the suppliers provided their "average" price for the consumption category of household consumers for each of the three different contract types (see below).[115]

For household customers, companies were asked to provide data on the price components for the consumption band of 2,500 kWh to 5,000 kWh for the following three different contract types:

- default supply contract,

[115] If a company cannot calculate an average price due to the many different tariffs they offer, one representative tariff is chosen.

– 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 for the consumption level. To better illustrate any long-term trends, a comparison is made in each case with the previous year's figures. When comparing the figures as at 1 April 2022 and 1 April 2021, 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 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 17 f. 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 were 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 192 suppliers (197 in the previous year). These data were 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 2022 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	1.60 - 4.05	2.94
Messung, Messstellenbetrieb	0.00 - 0.02	0.02
Konzessionsabgabe	0.05 - 0.11	0.14
EEG-Umlage		3.72
weitere Umlagen[1]		0.87
Stromsteuer		2.05
Vom Lieferanten beeinflussbarer Preisbestandteil (Restbetrag)	4.53 - 25.69	12.77
Gesamtpreis (ohne Umsatzsteuer)	**13.60 - 35.03**	**22.51**

[1] Umlage nach KWKG (0,378 ct/kWh), Umlage nach § 19 StromNEV (0,066 ct/kWh), Umlage nach § 18 AbLaV (0,003 ct/kWh), Offshore-Netzumlage (0,419 ct/kWh)

Table 99: Price level for the 24 GWh/year consumption category without reductions on 1 April 2022

The arithmetic mean of the price component controllable by the supplier increased from 4.20 ct/kWH in the previous year to 12.77 ct/kWh in 2022. The surcharges totalled 4.59 ct/kWh (the EEG surcharge amounted to 3.72 ct/kWh and the other surcharges category to 0.87 ct/kWh). The arithmetic mean of the net network charge increased to 2.94 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.[116] The average overall

[116] 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.

price (excluding VAT and excluding possible reductions) of 22.51 ct/kWh was 5.57 ct/kWh higher than the arithmetic mean of the figures collected in the previous year (16.94 ct/kWh), i.e. around 32% 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 category defined in this way, cost items outside the supplier's control accounted for a total of 9.74 ct/kWh. 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 17 f. EnWG. There are different eligibility requirements for the various possible reductions. During monitoring, no data were 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 10 ct/kWh to below 1 ct/kWh.

The EEG surcharge offers the greatest scope for possible reductions. It can be reduced 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.[117] 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 17 f EnWG offer significantly less scope for a reduction of the overall price in quantitative terms. No monitoring data were collected on the actual extent to which industrial customers make use of each of the possible reductions. It should be noted that the prices relate to a specific reporting date and do not take account of the early discontinuation of the EEG surcharge on 1 July 2022. As a result, the monitoring data cannot be used to draw conclusions on the "correct" average price for industrial customers.

Electricity: Possible reductions for the 24 GWh/year consumption category

Price survey on 1 April 2022	**Estimated charge**	**Possible reduction**	Remaining balance
EEG surcharge	3.72	-3.51	0.21
Electricity tax	2.05	-2.05	0.00
Net network charge	2.94	-2.35	0.59
Other surcharges	0.87	-0.73	0.13
Concession fee	0.14	-0.14	0.00
Total	**9.73**	**-8.79**	**0.94**

[117] 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.

Table 100: Possible reductions for the 24 GWh/year consumption category on 1 April 2022

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, 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 2022. Data were 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 905 suppliers (940 in the previous year). This data were 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 2022 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	4.48 - 9.01	6.54	25%
Messstellenbetrieb	0.02 - 0.94	0.31	1%
Konzessionsabgabe	0.11 - 1.59	0.77	3%
EEG-Umlage		3.72	15%
weitere Umlagen[1]		1.24	5%
Stromsteuer		2.05	8%
Vom Lieferanten beeinflussbarer Preisbestandteil (Restbetrag)	5.96 - 19.41	11.03	43%
Netto-Gesamtpreis	**20.21 - 34.04**	**25.65**	**100%**

[1] Umlage nach KWKG (0,378 ct/kWh), Umlage nach § 19 StromNEV (0,066 ct/kWh), Umlage nach § 18 AbLaV (0,003 ct/kWh), Offshore-Netzumlage (0,419 ct/kWh)

Table 101: Price level for the 50 MWh/year consumption category on 1 April 2022

The remaining balance that can be controlled by the supplier increased again as at the 1 April 2022 reference date. While this value was at 6.16 ct/kWh on the reference date in 2021, it rose to 11.03 ct/kWh this year – an increase of 4.87 ct/kWh or 80%.

The EEG surcharge fell from 6.50 ct/kWh in the previous year to 3.72 ct/kWh. Because the monitoring is based on a specific date, 1 April 2022, developments that occurred after this time are not included. The other surcharges rose from 1.09 ct/kWh in April 2021 to 1.24 ct/kWh in April 2022. The average net network charge also rose from 6.34 ct/kWh in the previous year to 6.54 ct/kWh. As the spread of net network charges is very high, the arithmetic mean does not necessarily represent the actual development. 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.

The average overall price (excluding VAT) rose by 2.42 ct/kWh from 23.23 ct/kWh in the previous year to 25.65 ct/kWh as at 1 April 2022, which is an increase of around 10%. 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 43% of the overall price, whereby an average of about 57% of the overall price relates to cost items outside the supplier's control.

4.2 Household customers

In this section, retail prices and individual price components for household customers of suppliers of electricity to final consumers in Germany are presented as volume-weighted averages. The consumption band from 2,500 kWh to 5,000 kWh per year for low-voltage supply (0.4 kV) was examined and set out in tabular form for the three different types of contract.

The volume-weighted average price across all types of contract for household customers was looked at in the representative consumption band from 2,500 kWh to 5,000 kWh per year (band III). It is important to note that the average network tariff listed for each type of contract is calculated using the figures provided by the suppliers, who in turn provide the network tariffs averaged over all the networks they supply. This results in a different network tariff for each of the three contract types.

4.2.1 Volume-weighted price across all contract categories for household customers (band III)

In the following tables and figures, the volume-weighted overall price across all contract categories in the middle consumption category[118] is examined. A single, volume-weighted 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 contract with the default supplier; 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 2022 was 36.06 ct/kWh, which is a significant increase from the previous year (2021: 32.63 ct/kWh). The increase of the retail price as at 1 April 2022 is mainly due to the increase of the price component "energy procurement". Energy procurement costs are significantly influenced by the wholesale electricity price. The prices on the wholesale electricity markets increased significantly in 2022, in particular for short-term electricity purchases. A more detailed analysis of the procurement costs of the suppliers is provided below.

[118] Eurostat customer category: Band III (DC): annual electricity consumption from 2,500 kWh to 5.000 kWh

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 2022 (ct/kWh)

Price component	Volume-weighted average across all types of contract (ct/kWh)	Percentage of total price
Supply and margin	4.27	11.8
Energy procurement	9.27	25.7
Net network tariff	7.76	21.5
Meter operation charge	0.36	1.0
Concession fee	1.64	4.5
EEG surcharge	3.72	10.3
KWKG surcharge	0.38	1.0
Section 19 StromNEV surcharge	0.44	1.2
Section 18 AbLaV surcharge	0.00	0.0
Offshore network surcharge	0.42	1.2
Electricity tax	2.05	5.7
VAT	5.75	16.0
Total	**36.06**	**100.0**

Table 102: Average volume-weighted price for household customers in consumption band III across all types of contract as at 1 April 2022

The table above provides a detailed breakdown of the individual price components of the average volume-weighted price. The change relative to the previous year is shown in the following table.

Electricity: change in volume-weighted price level for household customers across all types of contract from 1 April 2021 to 1 April 2022 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	%
Supply and margin	4.27	4.95	57.6
Energy procurement	9.27		
Net network tariff	7.76	0.59	8.2
Meter operation charge	0.36	0.02	6.5
Concession fee	1.64	-0.03	-1.8
EEG surcharge	3.72	-2.78	-42.7
KWKG surcharge	0.38	0.13	51.2
Section 19 StromNEV surcharge	0.44	0.01	1.6
Section 18 AbLaV surcharge	0.00	-0.01	-70.0
Offshore network surcharge	0.42	0.02	4.8
Electricity tax	2.05	0.00	0.0
VAT	5.75	0.54	10.5
Total	**36.06**	**4.02**	**10.5**

Table 103: Change in volume-weighted price level for household customers across all types of contract from 1 April 2021 to 1 April 2022 (consumption band between 2,500 kWh and 5,000 kWh per year)

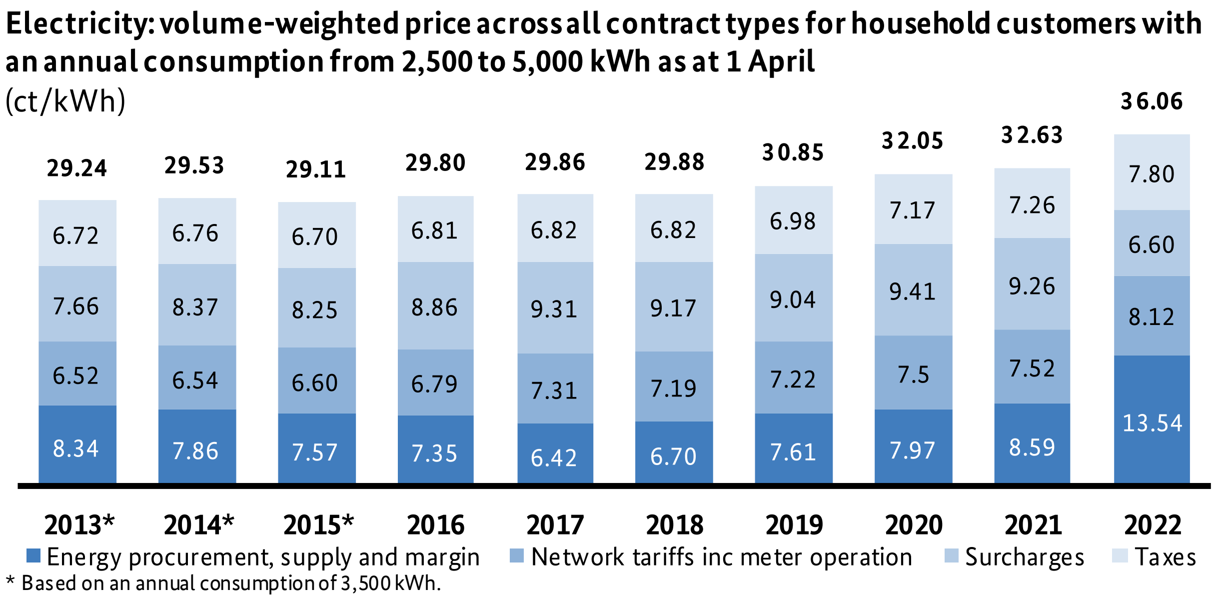


Figure 121: Development of the electricity price for household customers, volume-weighted across all types of contract

The development of the average price for household customers is depicted in the figure above. The following section examines the price components in more detail. The following figure shows the breakdown of the individual price components of the volume-weighted electricity price for household customers.

Electricity: breakdown of retail price for household customers with an annual consumption from 2,500 to 5,000 kWh as at 1 April 2022 (volume-weighted across all types of contract, band III, Eurostat: DC) (%)

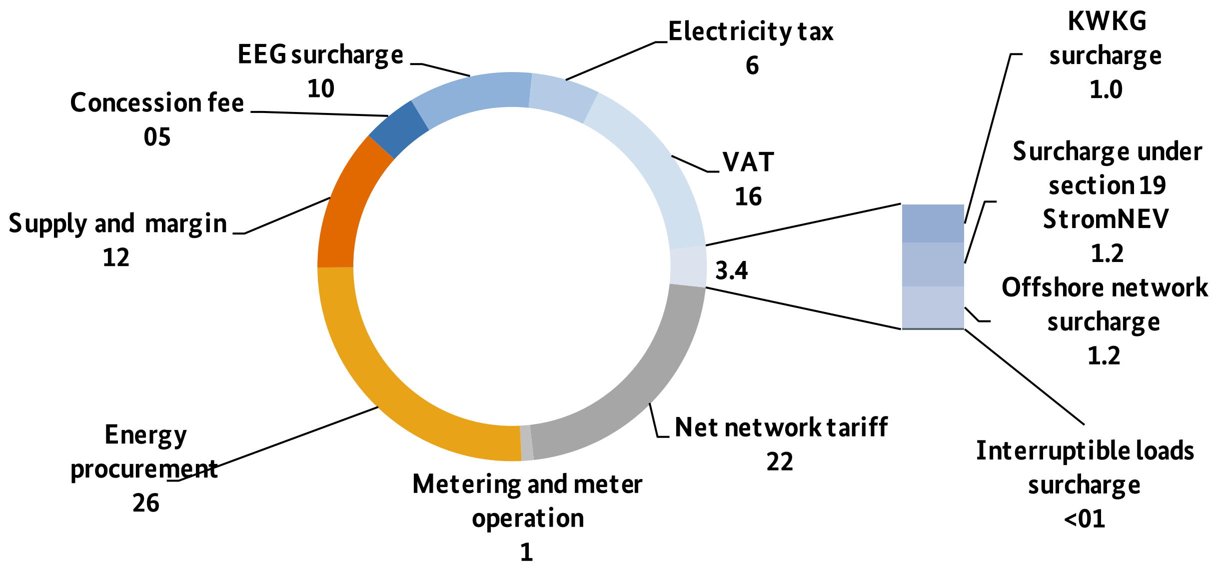


Figure 122: Breakdown of the retail price level for household customers in consumption band III as at 1 April 2022 (volume-weighted average across all contracts)[119]

First, a look at the network tariffs[120] shows a relatively sharp increase until 2017, following successive decreases in the period up to 2011. In 2022, a significant increase in the average network tariff is again noticeable. The network tariff thus continues to be high.

[119] 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.

[120] Net network tariff includes charges for meter operations.

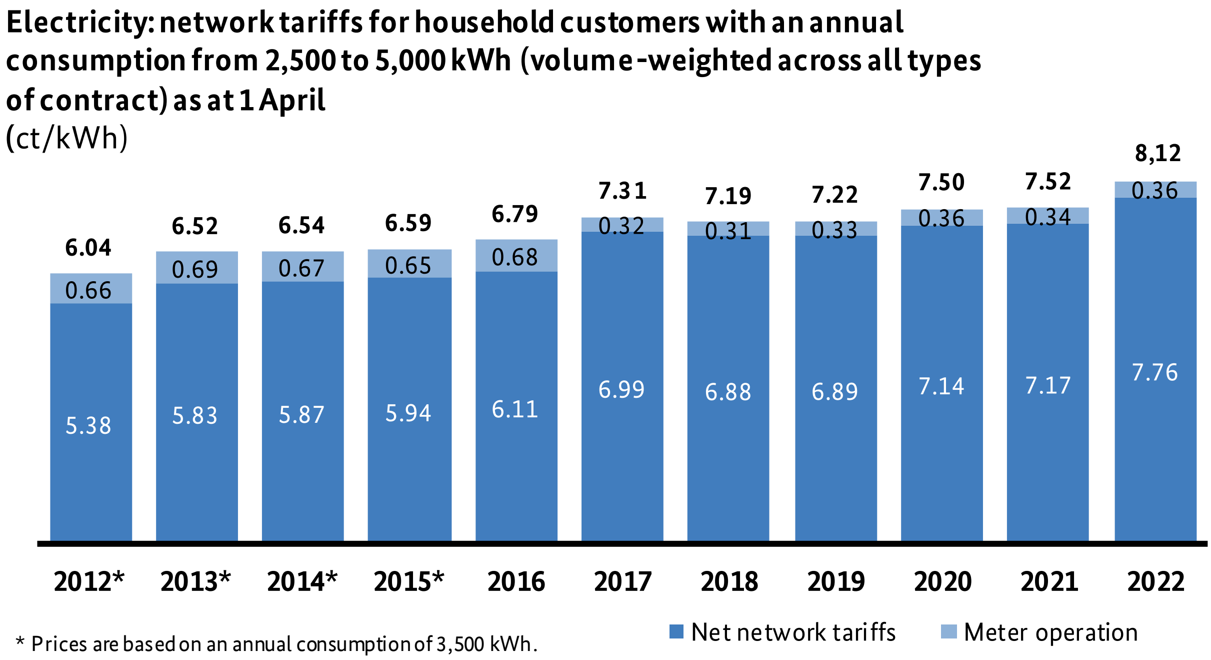


Figure 123: Development of network tariffs for household customers, including tariffs for meter operation

In 2022 there have been noticeable decreases in the other taxes and levies. These include in particular the renewable energy surcharge (EEG surcharge) (see section 4.3 "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 each year for the following calendar year. The Bundesnetzagentur ensures that the surcharge has been determined properly. The renewable energy surcharge for 2022 is 3.7 ct/kWh and is thus below the previous year's level. In order to provide quick relief to electricity customers from the sharp increase in electricity prices, the German government decided to lower the surcharge to 0 ct/kWh as of 1 July 2022. The coalition agreement had originally provided for the elimination of the renewable energy surcharge on 1 January 2023.

The price component of "energy procurement, supply and margin" (see figure 121) remained largely stable in the period from 2009 to 2013. While this supplier-controlled price component had fallen steadily since 2014, in 2022 it increased by around 70% (+5.57 ct/kWh) to 13.54 ct/kWh (2021: 8.59 ct/kWh).

In 2022 there was an additional splitting of the price components for energy procurement, supply and margin, which allowed for a separate analysis of the price for energy procurement. About 68% of the combined price component is made up of the cost of energy procurement. Since this information is included in the 2022 survey for the first time, a comparison with previous years is not possible. Over the course of the next years a more detailed analysis of the energy procurement costs will become possible.

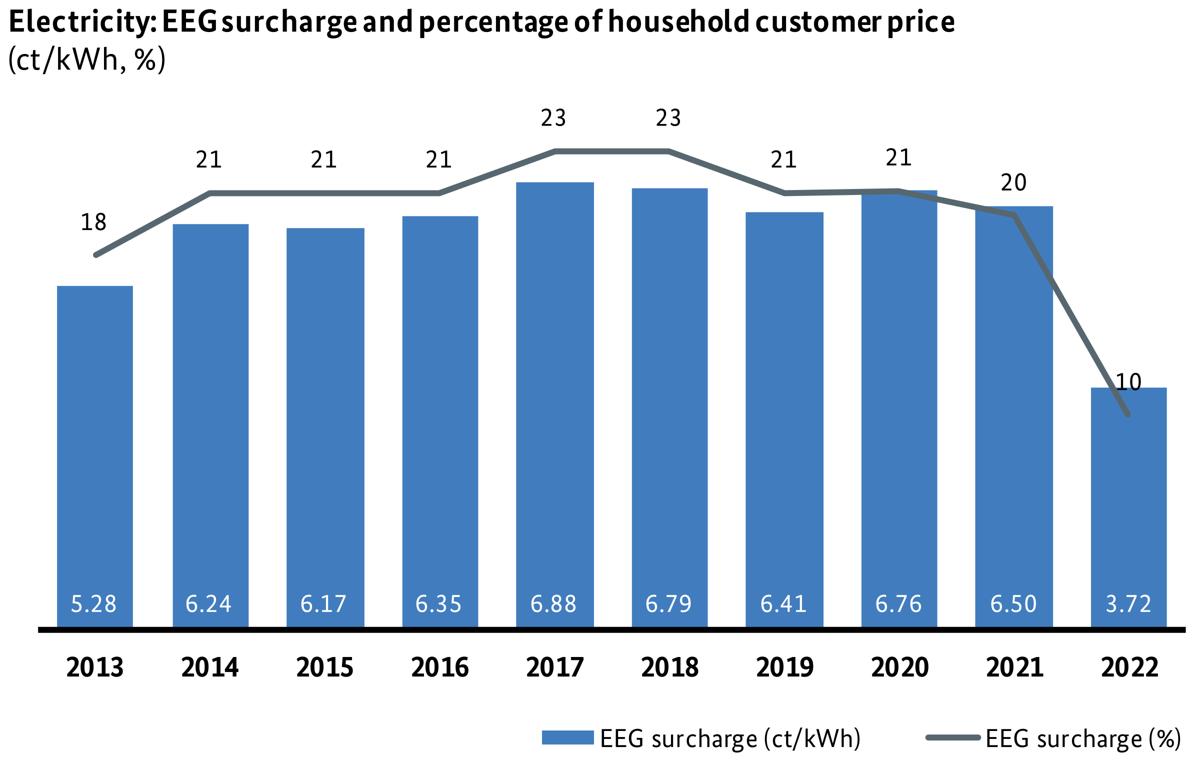


Figure 124: Renewable energy surcharge and percentage of household customer price

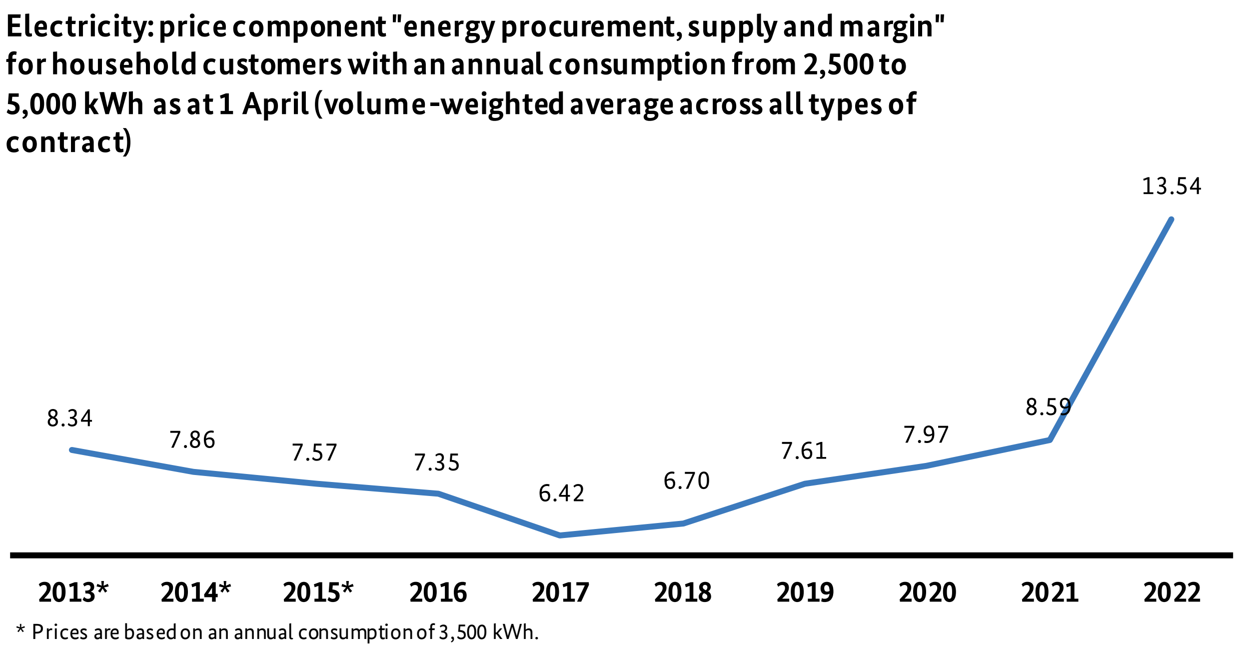


Figure 125: Change over time in the price component for “energy and supply and the margin” for household customers

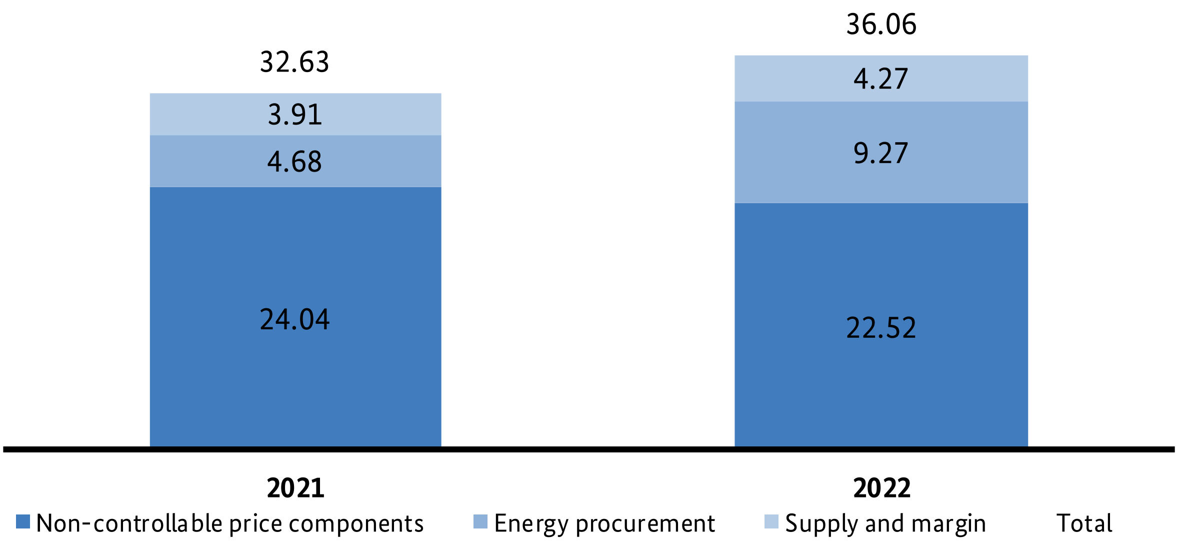
4.2.2 Relationship between household and wholesale prices

In accordance with Directive (EU) 2019/944, the Bundesnetzagentur monitors the relationship between household and wholesale prices. This requirement was transposed into national law in section 35 EnWG. The resulting data, first collected for the Monitoring Report 2022, now allows for a more detailed analysis of the procurement costs of electricity suppliers operating in Germany.

The increase in the retail price as at 1 April 2022 is due to the increase in the share of the electricity price that can be controlled by the supplier (energy procurement, supply and margin). While the non-controllable share of the electricity price (levies, surcharges, network tariffs) has decreased by 1.51 ct/kWh in comparison to the previous year, the controllable part of the electricity price has increased by 5.57 ct/kWh. For the first time, energy procurement costs are now shown separately. As at 1 April 2022 they amounted to 9.27 ct/kWh, which is around 68% of the controllable share of the electricity price.

In order to draw a conclusion about how much electricity procurement costs have increased in comparison to the previous year, an estimate of the energy procurement costs as at 1 April 2021 is provided. This estimate is based on historical wholesale prices, which have been weighted with the average figures from the procurement strategy as provided by electricity suppliers for the first time this year. According to this calculation, the estimated energy procurement costs amounted to 4.68 ct/kWh as at 1 April 2021. The comparison of the years 2021 and 2022 thus shows that energy procurement costs have doubled. This increase is largely due to the development of the wholesale prices of short-term electricity purchases, which in the month of April 2022 increased by around 390% compared to the previous year. The reason for the proportionately lower increase in the energy procurement costs included in the household customer price is that only approximately 10% of electricity in this sector is purchased on a short-term basis (one quarter, one month or one day in advance). An estimated 90% of the electricity volume purchased for the year 2021 was purchased on a long-term basis (three, two or one year in advance).

Electricity: development of price components in 2021 and 2022
(ct/kWh)



*Energy procurement costs and supply estimated for 2021

Figure 126: Development of price components 2021/2022

4.2.3 Household customer prices for the consumption band from 2,500 kWh to 5,000 kWh (Eurostat band III (DC))

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 supplier. The following section examines the prices for the consumption band of household customers.

It is important to note that the average network tariff given for each type of contract is calculated using the figures provided by the suppliers, who in turn provide the network tariffs averaged over all the networks they supply. This results in a different network tariff for each of the three types of supply. There is considerable heterogeneity in both the supplier structure and the contract structure of customers supplied in the large number of network areas. For example, suppliers can mainly supply electricity to customers in network areas with particularly high or particularly low network tariffs, 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 tariffs. In a single network area, the network tariff 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 tariff.

The volume-weighted prices were calculated using the prices as at 1 April 2022 and the consumption volumes for 2021. The survey only asked about the consumption band from 2,500 kWh to 5,000 kWh, representing the average household customer in Germany, to reduce the effort required for the participating companies.

Consumption band from 2,500 kWh to 5,000 kWh (Eurostat band III (DC))

Band III covers the majority of typical household customers in Germany. It 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 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 III; 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
Supply and margin	5.42	3.96	3.93
Energy procurement	7.74	8.80	10.42
Net network tariff	7.78	7.50	7.95
Meter operation charge	0.37	0.37	0.35
Concession fee	1.68	1.65	1.61
EEG surcharge	3.72	3.72	3.72
KWKG surcharge	0.38	0.38	0.38
Section 19 StromNEV surcharge	0.44	0.44	0.44
Section 18 AbLaV surcharge	0.00	0.00	0.00
Offshore network surcharge	0.42	0.42	0.42
Electricity tax	2.05	2.05	2.05
VAT	5.70	5.56	5.94
Total	**35.70**	**34.86**	**37.22**

Table 104: Average volume-weighted price per type of contract for household customers in consumption band III as at 1 April 2022

In previous years there has been a noticeable convergence of the prices of non-default contracts with the default supplier and with suppliers other than the local default supplier. Last year for the first time, the price of electricity under a non-default contract with the default supplier was lower than the price for electricity supply with a supplier that is not the local default supplier. For the first time across the different contract types, the prices for default electricity supply are now lower than the price for electricity supply with a supplier that is not the local default supplier. This is likely due to the sharp increase in wholesale prices and the procurement strategies of the suppliers. Because suppliers that also serve as default suppliers are usually able to plan and make long-term purchases, their retail prices are not immediately affected by short-term increases in the wholesale price. Suppliers competing for customers using generous bonuses and low prices often purchase energy on a much more short-term basis, which has a more immediate effect on retail prices than a longer-term procurement strategy.

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 the local default supplier (usually after changing supplier) – makes it clear that a contract with a supplier other than the local supplier was the most expensive type of supply for customers with an annual consumption of between 2,500 kWh and 5,000 kWh in 2022. At the same time, a direct comparison is only possible to a limited extent. While the average consumption in 2021 for customers on default tariffs with the default supplier was around 1,955 kWh, the average for customers on non-default tariffs with the default supplier and customers who had switched from their default supplier was around 47% higher, at around 2,875 kWh.

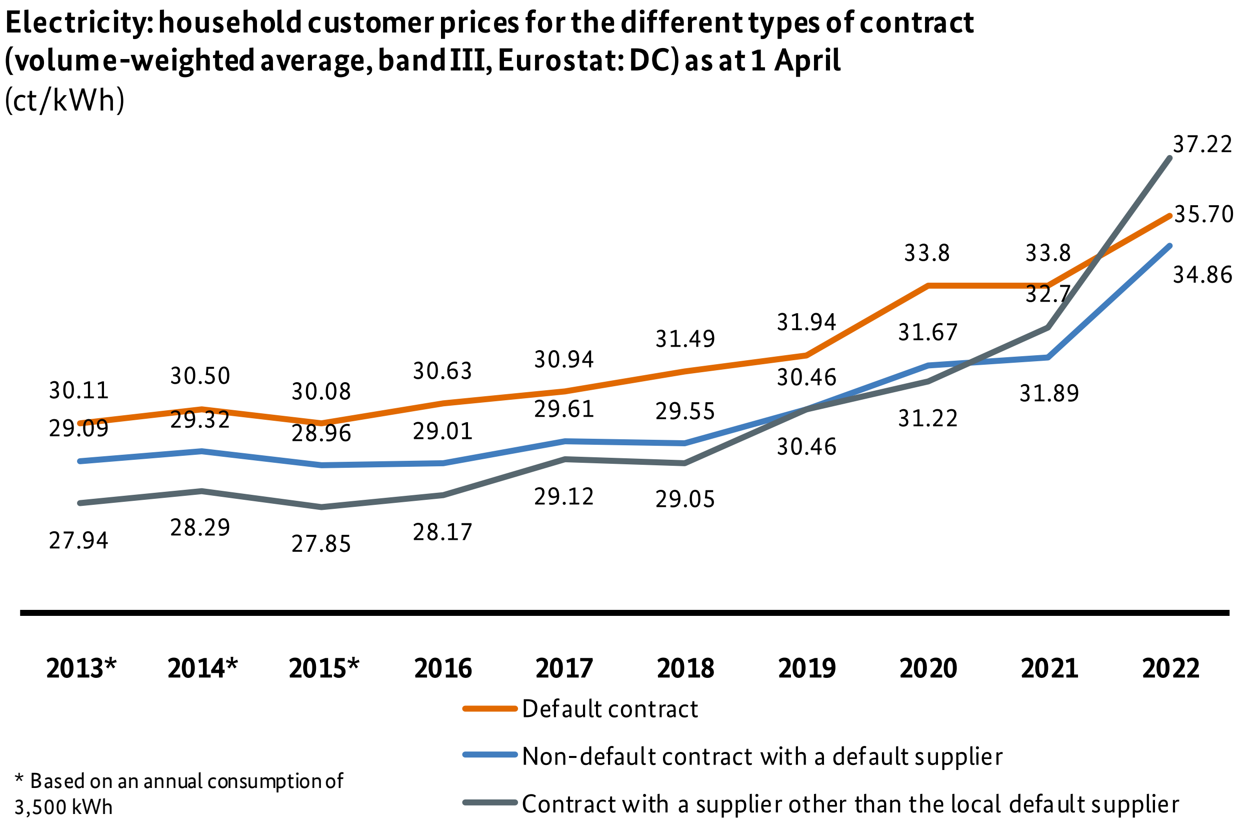


Figure 127: Household customer prices for the different types of contract (volume-weighted average, band III, Eurostat: DC)

A comparison of the average prices for the three types of tariffs shows that from 2013, default supply was the most expensive option for household customers until this year. For the first time, a contract with a supplier that is not the local default supplier is now the most expensive type of electricity supply. Prices for customers on non-default contracts with the default supplier were cheaper every year in the period under observation than for those on default tariffs. However, since 2013 the prices for non-default contracts with the default supplier and contracts with a supplier that is not the local default supplier have been converging more and more.

Considering the changed price structure of default suppliers and non-default suppliers, consumers have all the more reason to compare prices and obtain an offer from their local default supplier. As at 1 April 2022 a household customer with an annual consumption of 3,500 kWh can thus achieve savings in energy costs of around €83 per year with a non-default contract with their local default supplier.

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.

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

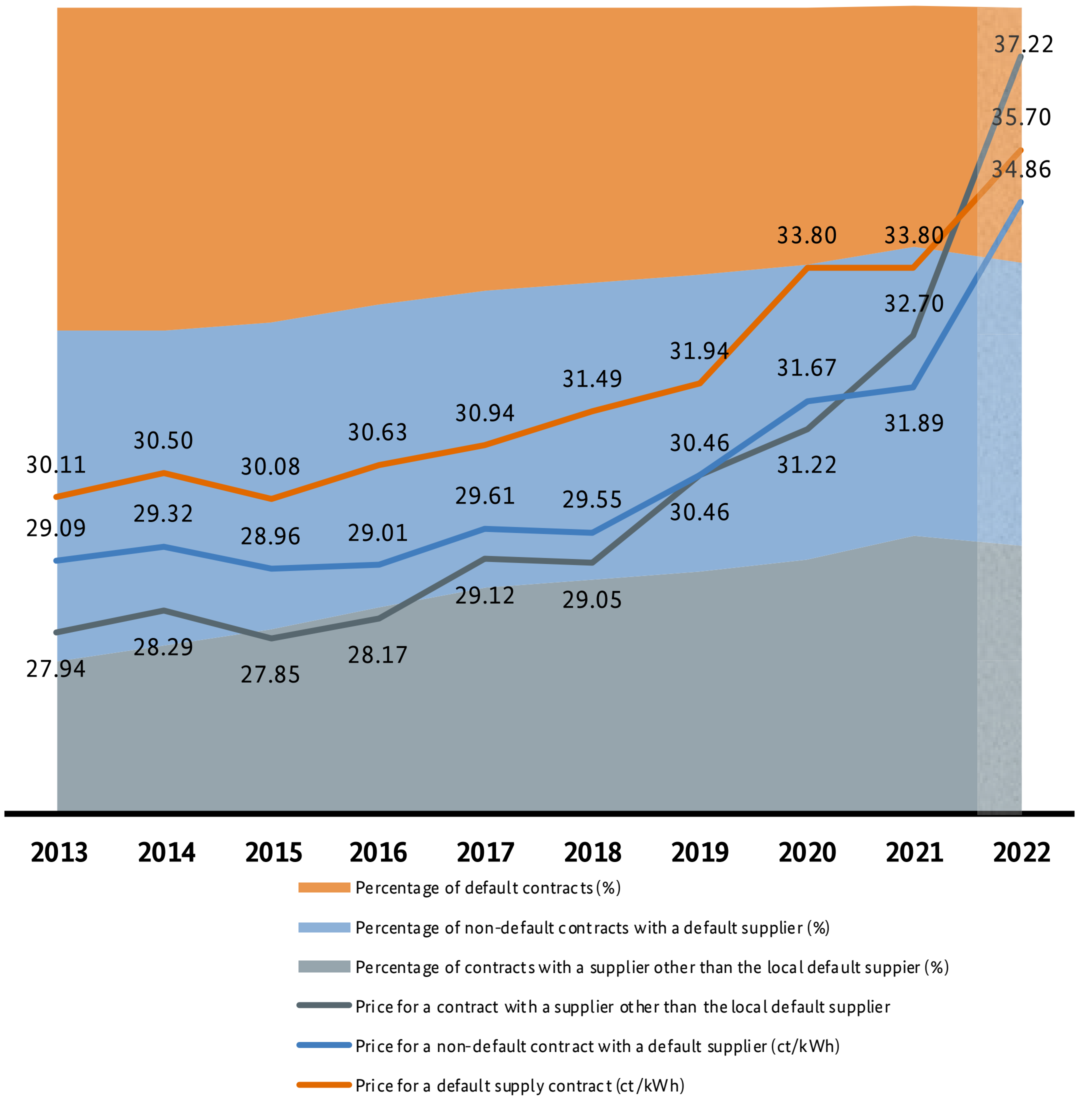


Figure 128: Household customer prices for electricity and percentage for the different types of contract

At 13.16 ct/kWh, the price component that can be controlled by the supplier, including energy procurement and supply, was nearly 8% lower for customers on default tariffs than for customers who had switched from their default supplier; the average price for the latter group was 14.36 ct/kWh. Customers on non-default contracts with their local default supplier paid an average of 12.76 ct/kWh (2021: 8.12 ct/kWh) for energy procurement, supply and margin, and thus around 3% less than customers on default tariffs. Any direct comparison of these figures must take into account further differences between the customer groups other than their different consumption levels. For instance, default contracts have shorter notice periods and on average a 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.

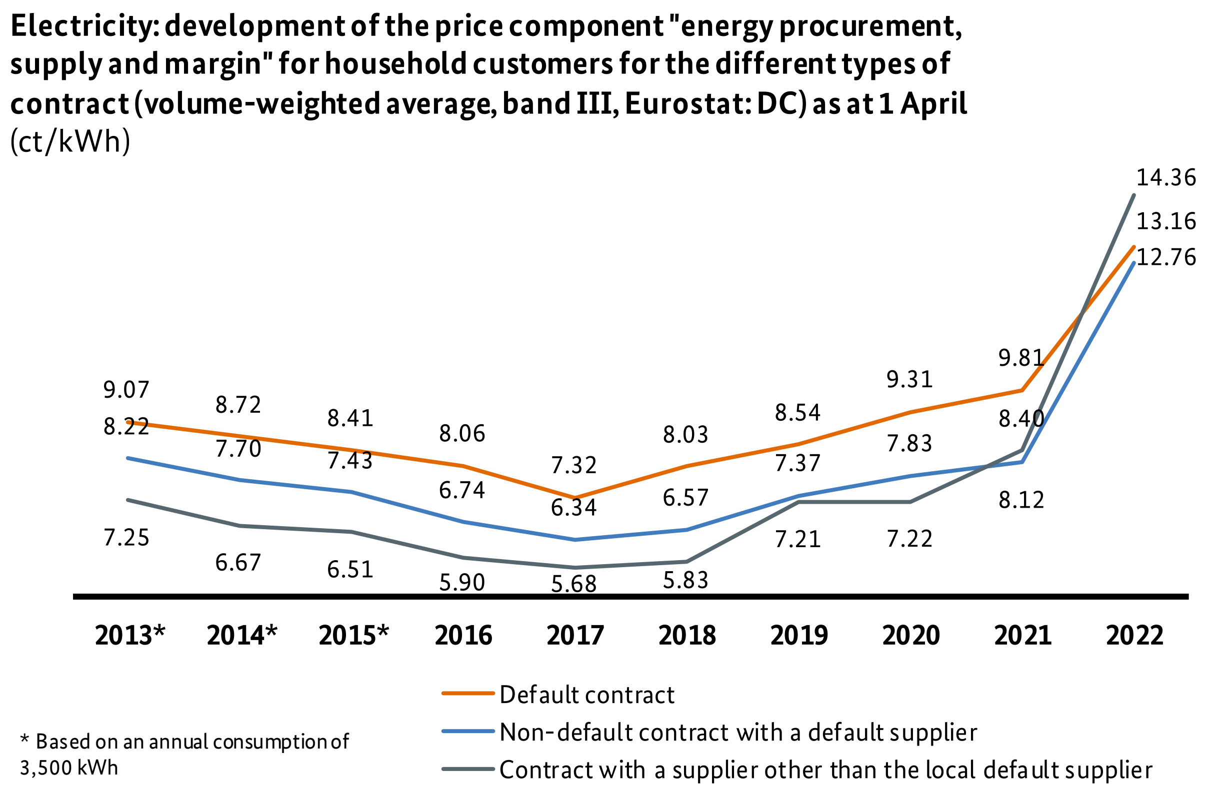


Figure 129: Development of the price component “energy and supply costs and margin” for household customers

Special bonuses and schemes

Non-default supply contracts can have a range of further features that suppliers use to compete for customers in addition to the overall price. 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	
	No. of tariffs	**Average scope**
Minimum contract period	275	10 months
Price stability	270	12 months
Advance payment	54	10 months
One-off bonus payment	86	€ 56
Free kilowatt hours	6	190 kWh
Deposit	4	-
Other bonuses and special arrangements	78	-

Table 105: Special bonuses and schemes for household customers with a non-default contract with their default supplier

Electricity: special bonuses and schemes for household customers

	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**
Minimum contract period	196	10 months	325	11 months	193	16 months
Price stability	167	11 months	299	11 months	184	19 months
Advance payment	20	10 months	36	11 months	18	12 months
One-off bonus payment	37	€ 51	112	€ 59	61	€ 65
Free kilowatt hours	5	208 kWh	6	190 kWh	4	97 kWh
Deposit	1	-	2	-	2	-
Other bonuses and special arrangements	40	-	73	-	48	-

Table 106: Special bonuses and schemes for household customers with a non-default supplier

4.3 Surcharges

In the electricity sector, surcharges still account for a significant share of the electricity price.

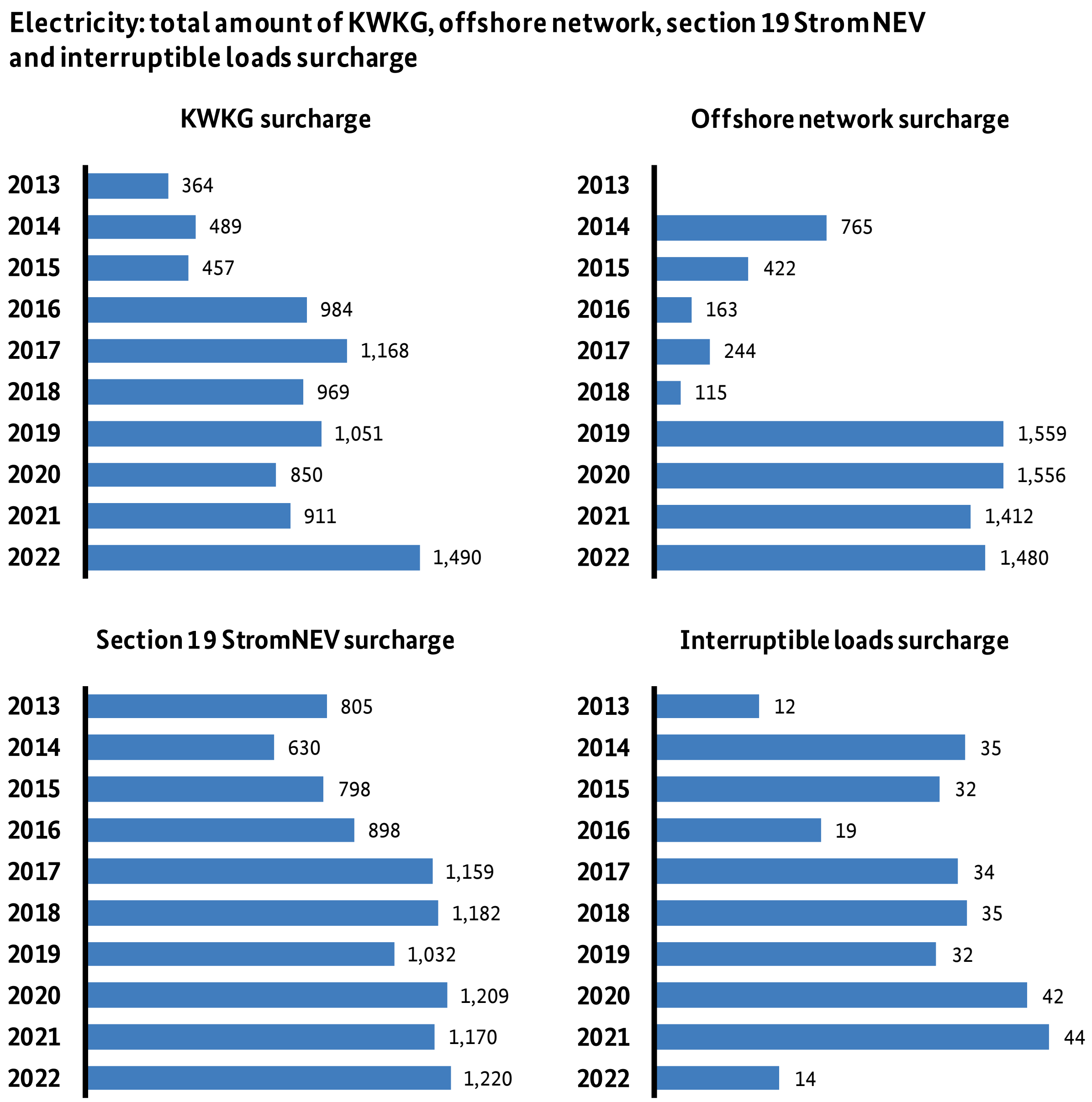


Figure 130: Total amount of KWKG, offshore network, section 19 StromNEV and interruptible loads surcharges

EEG surcharge

Under section 60(1) EEG, transmission system operators are entitled and obliged to demand from electricity suppliers that supply 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 (EEV).

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) EEV and section 6 of the Renewable Energy Sources Implementing Ordinance (EEAV).

The surcharge is determined and announced by 31 October of each year for the following calendar year by the transmission system operators.

As of 1 July 2022, the EEG surcharge is no longer being charged. In the future, the federal government will, in principle, cover any possible costs relating to the EEG. As a result, refinancing through the electricity price will no longer take place. It must be noted, however, that revenues generated by the marketing of renewable energy currently exceed costs, which would have brought the current EEG surcharge to 0.00 ct/kWh in any case.

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 31 October of each year for the following calendar year by the TSOs.

Offshore network surcharge

Under section 17f EnWG, network operators are entitled to pass on the costs for compensation payments to final consumers in the form of a surcharge on network tariffs. In addition, as of 2019 , the offshore network surcharge also includes the costs of installing and operating the offshore transmission links.

The offshore network surcharge is determined and announced by 15 October of each year (as of 2023 by 25 October) 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 Tariffs Ordinance (StromNEV), final consumers can request an individual network tariff as provided for by section 19(2) StromNEV. TSOs are obliged to reimburse downstream DSOs for revenues lost as a result of individual network tariffs. TSOs must balance these payments as well as their own lost revenue among themselves. The lost revenue is thus passed on to all final consumers as a pro-rata surcharge on the network tariffs.

The revenue from the surcharge under section 19 StromNEV is used to cover lost network tariff proceeds brought on by reductions of the network tariff.

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 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. Heating electricity

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 – were once again collected from suppliers and distribution system operators (DSOs).

Overall, the volume of electricity supplied for heating was higher than in the previous year. According to the volumes reported by around 1,000 heating electricity suppliers, about 14.3 TWh of heating electricity was supplied to customers at just under 1.98 million meter points. This corresponds to an average supply of just under 7,210 kWh per meter point. The previous year's figure was just under 6,256 kWh per meter point, with a total volume of 11.2 TWh supplied to 1.79 million meter points.

According to the data provided by the suppliers, just under 9.4 TWh was supplied for night storage heating at 1.2 million night storage meter points. The volume of electricity supplied to approximately 782.000 meter points for heat pumps amounted to just over 4.95 TWh. Night storage heating accounts for the largest share of consumption (around 65.4% in terms of volume and 60.7% in terms of meter points). The share of heat pumps compared to night storage heating has constantly increased over the years. Compared to the previous year, the number of meter points supplied rose by just under 40%. This is also reflected by the shares of the two consumption systems in the overall volumes sold and in the meter points supplied with heating electricity. In 2021 the share of heat pumps accounted for as much as 39.3% of meter points and 34.6% in terms of volume. In the previous year it accounted for 31.2% of meter points and 28.5% in terms of volume. Almost all heating electricity suppliers serve both night storage customers and heat pump customers.

Overview of heating electricity volumes supplied

	2021			2020		
	Night storage heaters	Heat pumps	Total	Night storage heaters	Heat pumps	Total
Volume in TWh	9.4	5.0	14.3	8.0	3.2	11.2
Number of meter points in millions	1.2	0.78	2.0	1.23	0.55	1.79
Percentage of total volume	65.4	34.6	100	71.5	28.5	100
Percentage of total meter points	60.7	39.3	100	68.8	31.2	100
Average per meter point in kWh	7,210			6,256		

Table 107: Overview: Volume of heating electricity supplied

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 correspond to the results of the supplier survey. According to the data provided by 809 DSOs (839 in the previous year), a total of 13.89 TWh of heating electricity was supplied to just under 2.07 million meter points (night storage heating and heat pumps) in 2021. 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.[121]

[121] Cf. Bundeskartellamt, Heizstrom – Überblick und Verfahren, September 2010, pp. 9 – 10.

Electricity: Percentage of total heating electricity supplied by a supplier other than the regional default supplier

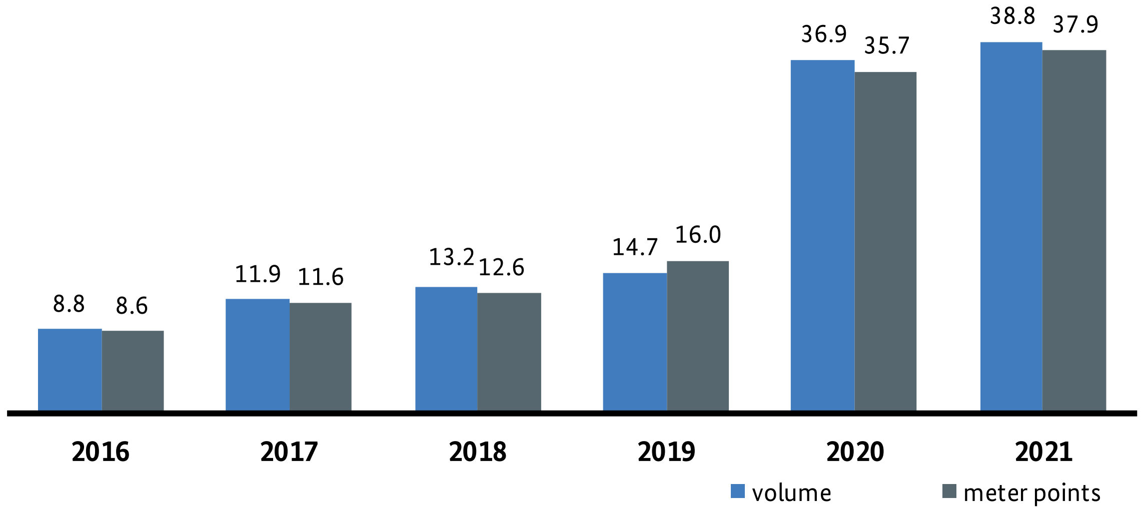


Figure 131: Percentage of heating electricity volume and meter points supplied by a supplier other than the regional default supplier

The share of heating electricity supplied in 2021 by a legal entity other than the regional default supplier slightly rose compared to the previous year. Around 38.8% of the total volume of electricity for heating in 2021 was accounted for by suppliers other than the default supplier (2020: 37.3%). The number of heating electricity meter points not served by the default supplier also slightly increased from 35.7% to 37.9%. The large rise in the percentage of heating electricity supplied by non-default suppliers between 2019 and 2020 is due to the aftereffects of the E.ON/innogy merger. The merger had only been cleared subject to commitments, among other reasons due to competition problems in the heating electricity sector. [122] E.ON's heating electricity business was subsequently sold to Lichtblick SE. Irrespective of the obligations imposed by the Commission, Innogy SE's heating electricity business was hived off to a new E.ON subsidiary, Deine Wärmeenergie GmbH & Co. KG, after the takeover by E.ON. The two companies still jointly account for a high percentage of the volumes supplied by non-default suppliers.

According to the data provided by the DSOs, there was a decrease in supplier switching rates based on the number of meter points supplied in the heating electricity sector compared to the previous year. The figures of the previous year, however, also took into account the transfer of customers from E.ON to Lichtblick described above as a special effect. Compared to further previous years the 2021 supplier switching rate is even lower than in 2019. In 2021 a change of supplier took place at about 110,983 heating electricity meter points. These meter points accounted for about 640.5 GWh of heating electricity in 2021. This represents a switching rate of 4.6% in terms of volume and 5.4% in terms of meter points. In the previous year, due to the special effect, there was a change of supplier at just under 310,526 meter points, accounting for a volume of around

[122] European Commission, case M.8870 E.ON/Innogy.

1,520 GWh. This corresponds to a switching rate of 12% in terms of consumption volume and of 14.8% in terms of meter points.

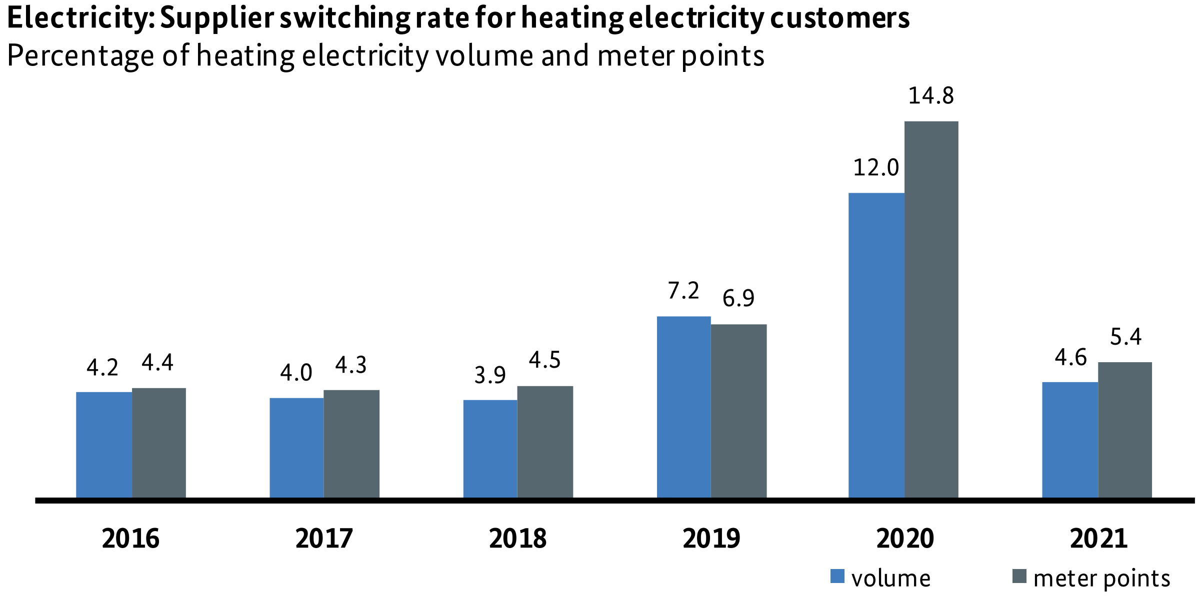


Figure 132: Supplier switching rate for heating electricity customers

539 of the 730 DSOs that provided data on heating electricity volumes also reported figures on supplier switching. These 539 DSOs represent around 95% of the heating electricity volume and meter points of all 730 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.[123] 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 10.7%.

5.2 Price level

Price data were collected on night storage tariffs and heat pump tariffs as at 1 April 2022. 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 night storage heating provided by 877 suppliers (866 in the previous year) and the price data for heat pumps provided by 868 suppliers (901 in the previous year).

According to the data provided by the suppliers, the arithmetic mean of the total gross price for night storage heating was 25.07 ct/kWh (including VAT) on 1 April 2022, which is above the previous year's level of 23.39 ct/kWh. The arithmetic mean of the total gross price for heat pump electricity was 25.55 ct/kWh, which is also up on the previous year's level of 23.80 ct/kWh.

[123] 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.

Electricity: Price level on 1 April 2021 for night storage heating with a consumption of 7,500 kWh/year

	Spread between 10 and 90% of suppliers in ct/kWh	**Arithmetic mean** in ct/kWh	**Share of total price**
Price components outside supplier's control			
Net network charge	1,52 - 4,64	3.12	12%
Metering	0,12 - 0,47	0.33	1%
Concession fee	0,11 - 0,98	0.39	2%
EEG surcharge		3.72	15%
Other surcharges [1]		1.24	5%
Electricity tax		2.05	8%
VAT	3,35 - 4,75	4.02	16%
Price component which can be controlled by supplier (remaining balance)	7,00 - 13,83	10.21	41%
Total price (incl. VAT)	**20,97 - 29,72**	**25.07**	**100%**

[1] KWKG (0.378 ct/kWh), Section 19(2) StromNEV (0.437 ct/kWh), surcharge under Section 18 AbLaV (0.003 ct/kWh), offshore network surcharge (0.419 ct/kWh)

Table 108: Price level on 1 April 2022 for night storage heating with a consumption of 7,500 kWh/year

The remaining balance controlled by the supplier, which includes energy and supply costs and the margin, was 10.21 ct/kWh for night storage heating and thus rose by around 61% above the 2021 level of 6.35 ct/kWh. The trend over the last years shows that the price component for heating electricity that can be controlled by the supplier has risen steadily.

The remaining balance that can be controlled by the supplier also increased in the heat pump sector to 10.48 ct/kWh as at 1 April 2022, compared to 6.58 ct/kWh in the previous year, i.e. by around 60%. The price component which can be controlled by the supplier makes up about 41% of the total price for night storage heating and heat pumps. About 59% of the price for night storage heating and for heat pumps consists of taxes, surcharges and concession fees. Compared to the previous year, the total of all fixed surcharges rose slightly from 1.09 ct/kWh to 1.24 ct/kWh. The Bundeskartellamt has set the concession fee at 0.11 ct/kWh because heating electricity is supplied under special contracts.[124] 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.

Electricity: Price level at 1 April 2022 for heat pumps with a consumption of 7,500 kWh/year

	Spread between 10 and 90% of suppliers in ct/kWh	**Arithmetic mean** in ct/kWh	**Share of total price**
Price components outside the supplier's control			
Net network charge	1,55 - 5,41 - 4,80	3.25	13%
Metering	0,12 - 0,48	0.33	1%
Concession fee	0,11 - 1,32	0.40	2%
EEG surcharge		3.72	15%
Other surcharges [1]		1.24	5%
Electricity tax		2.05	8%
VAT	3,45 - 4,78	4.08	16%
Price components which can be controlled by supplier (remaining balance)	7,16 - 13,99	10.48	41%
Total price (incl. VAT)	**21,63 - 29,96**	**25.55**	**100%**

[1] KWKG (0.378 ct/kWh), Section 19(2) StromNEV (0.437 ct/kWh), surcharge under Section 18 AbLaV (0.003 ct/kWh), offshore network surcharge (0.419 ct/kWh)

Table 109: Price level at 1 April 2022 for heat pumps with a consumption of 7,500 kWh/year

124 Cf. Bundeskartellamt, Heizstrom – Überblick und Verfahren, September 2010, pp. 9 – 10.

5. Green electricity segment

In the 2022 survey, information was also collected from suppliers on 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 2021 and the share of green electricity in the total amount of electricity supplied in 2021 are presented below.

Electricity: green electricity supplied to household customers and other final consumers in 2021

Category		Total electricity supplied	Total green electricity supplied	Share of green electricity in total volume and market locations (%)
Household customers	TWh	124.2	46.4	37.4%
	Market locations (thousand)	48,135	16,572	34.4%
Other final consumers	TWh	286.3	43.8	15.3%
	Market locations (thousand)	4,026	916	22.8%
Total	TWh	410.4	90.2	22.0%
	Market locations (thousand)	52,162	17,489	33.5%

Table 110: Green electricity supplied to household customers and other final consumers in 2021

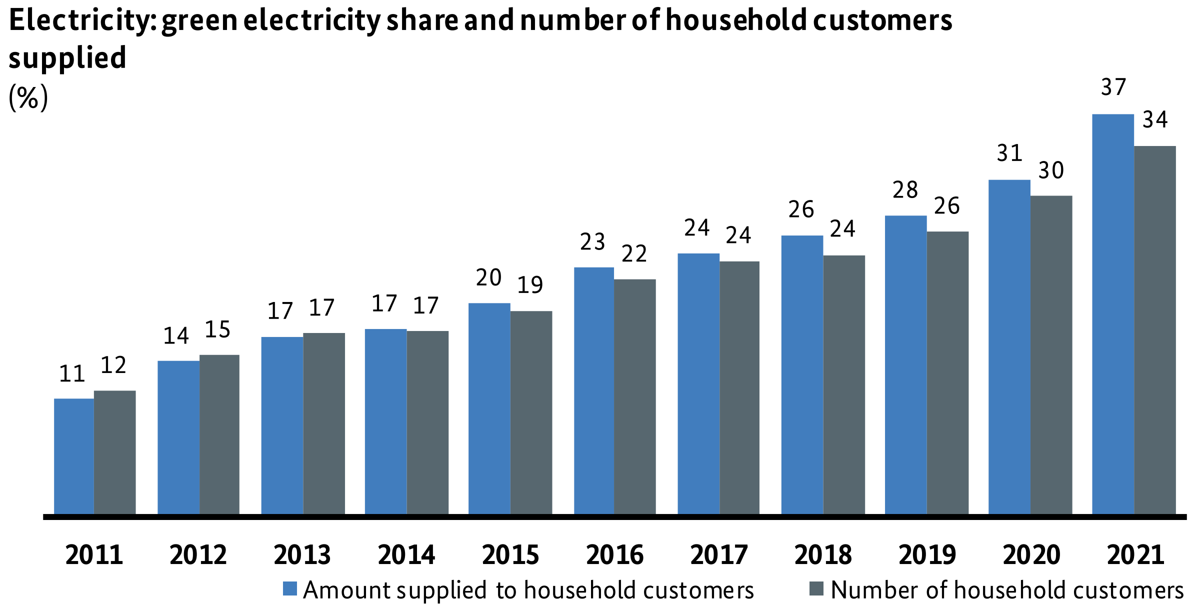


Figure 133: Green electricity share and number of household customers supplied

There was a further increase in the share of green electricity supplied to household customers in 2021. The number of household customers supplied with green electricity increased by a total of more than 2.3mn market locations. The share of green electricity in total consumption rose by around 6%. The number of household customers supplied with green electricity is now at around 16.6mn market locations. The average length of time that electricity customers stayed with a green electricity tariff was around 30 months.[125]

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 2021. The price for green electricity is 37.83 ct/kWh as at 1 April 2022 (2021: 32.54 ct/kWh) and has thus increased by nearly 16%.

[125] First-time collection of this data. Average figures from data provided by 171 suppliers offering green electricity contracts that ended in 2021.

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 2021 to 1 April 2022 (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	%
Supply and margin	3.69	6.33	76.1
Energy procurement	10.95		
Net network tariff	7.94	0.67	9.2
Meter operation charge	0.56	0.07	14.3
Concession fee	1.65	0.01	0.7
EEG surcharge	3.72	-2.78	-42.7
KWKG surcharge	0.38	0.12	48.8
Section 19 StromNEV surcharge	0.44	0.01	1.2
Section 18 AbLaV surcharge	0.00	-0.01	-66.7
Offshore network surcharge	0.42	0.02	6.1
Electricity tax	2.05	0.00	0.0
VAT	6.04	0.84	16.3
Total	**37.83**	**5.29**	**16.3**

Table 111: Average volume-weighted prices and change relative to 1 April 2021 for green electricity supplied to household customers in consumption band III as at 1 April 2022

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 2022
(%)

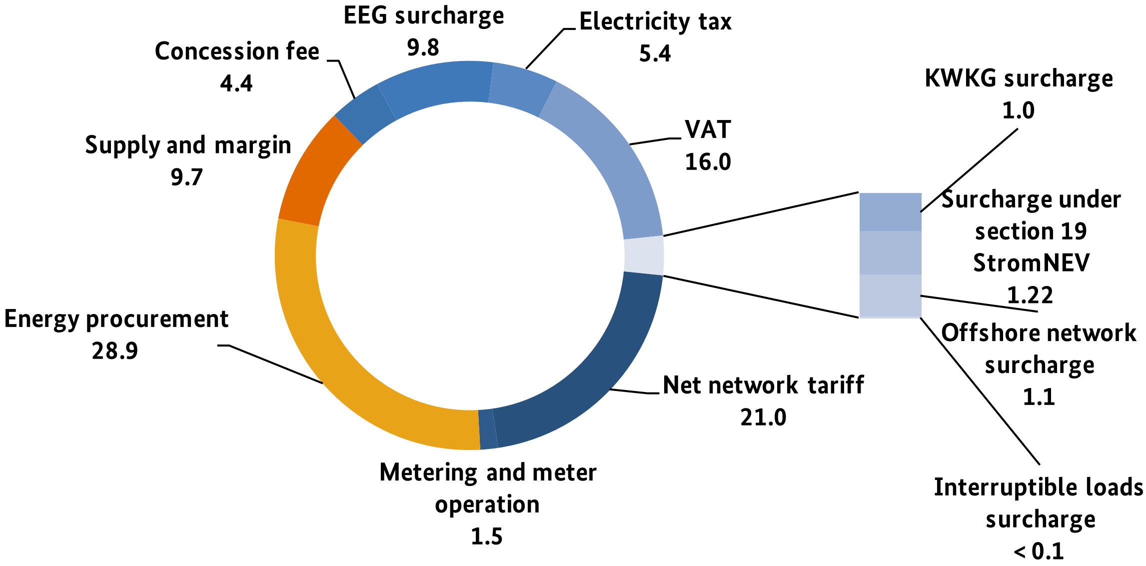


Figure 134: Breakdown of the retail price level for green electricity for household customers in consumption band III as at 1 April 2022[126]

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 the 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.

126 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 2022	Household customers (green electricity)	
	Number of tariffs	Average scope
Minimum contract period	374	11 months
Price stability	321	14 months
Prepayment	43	11 months
One-off bonus payment	109	€ 56
Free kilowatt hours	7	120 kWh
Deposit	5	-
Other bonuses and special arrangements	92	-

Table 112: 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 duration, 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"). For the second six-month period Eurostat also publishes a breakdown of the adjusted price into network costs and the remaining balance controlled by the supplier ("energy and supply"), which includes electricity procurement costs, supply costs and the margin. Eurostat does not collect the data itself but relies on data from national bodies, for Germany on data provided by the Federal Statistical Office.[127] 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. 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.

[127] 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 these the price data were collected by the German Association of Energy and Water Industries on behalf of the Federal Ministry for Economic Affairs and Climate Action. This change naturally also brought about changes in the survey method, 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.

7.1 Non-household customers

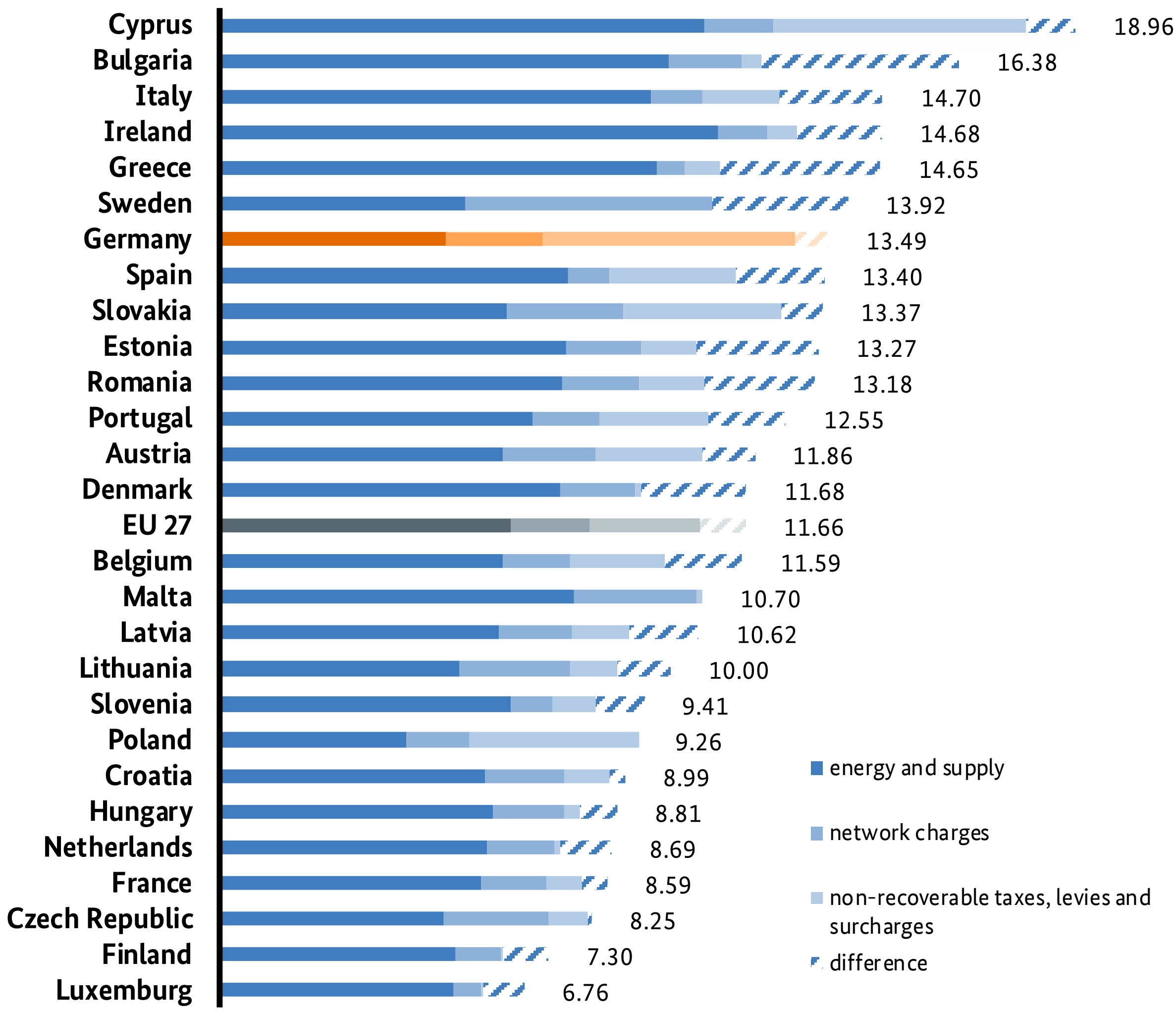
Eurostat publishes price statistics for seven different consumer groups in the non-household sector that differ according to annual consumption ("consumption bands"). The following section describes the 20 GWh/year to 70 GWh/year consumption band as an example. The 24 GWh/year category ("industrial customers"), for which specific price data are collected during monitoring, falls into this consumption band.

The customer group with an annual consumption of 20 GWh to 70 GWh mainly consists of industrial customers. These customers can usually deduct national VAT. For this reason, the total price has been adjusted for VAT for the purpose of an EU-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 IG4.1).

According to the Eurostat data, there are significant differences in the price of electricity for industrial customers across the EU. Cyprus has the highest net price at 18.96 ct/kWh, while Luxembourg has the lowest, at 6.76 ct/kWh. The EU average is 11.66 ct/kWh. 2.43 ct/kWh of this average price consists of non-recoverable taxes, levies and surcharges, 1.75 ct/kWh is made up of network charges and 6.45 ct/kWh of the remaining balance controlled by the supplier for energy and supply. At 13.49 ct/kWh, the net price in Germany is around 15% above the EU average. The German net price consists of 2.12 ct/kWh network charges, 5.02 ct/kWh "energy and supply" and 5.63 ct/kWh non-recoverable taxes, levies and surcharges. The answer to the question as to whether the net price paid by industrial customers in the 20 GWh/year to 70 GWh/year consumption band in Germany is higher or lower than the EU 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 average amount of possible reductions claimed. The documents published by Eurostat, however, do not list the relevant assumptions concerning the prices paid by industrial customers in Germany. The figure relating to the average amount of non-recoverable surcharges, taxes and levies in the 20 GWh/year to 70 GWh/year consumption band in Germany is 5.63 ct/kWh and therefore more than twice as much as the EU average of 2.43 ct/kWh.

Comparison of European electricity prices in second half of 2021 for non-household customers with an annual consumption between 20 GWh and 70 GWh
in ct/kWh ; without recoverable taxes, levies and surcharges



Source: Eurostat
Note: For some countries a difference (hatched) is shown. This is because the individual price components are only retrieved once per year whereas Eurostat collects data every six months.

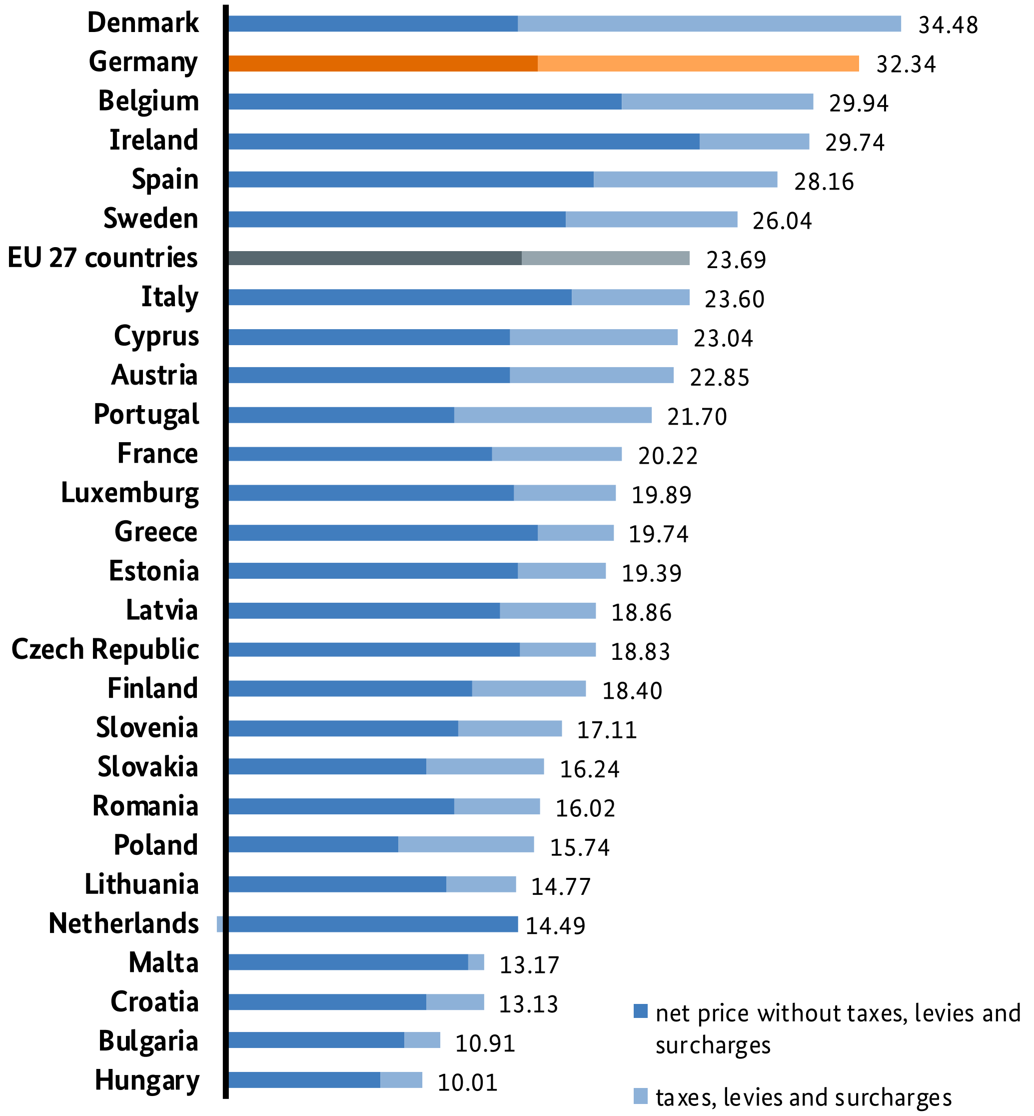
Figure 135: Comparison of EU electricity prices in the second half of 2021 for non-household customers with an annual consumption between 20 GWh and 70 GWh

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 the EU. Based on the calculation method used by the Federal Statistical Office, Germany has, at 32.34 ct/kWh, the second highest price among the now 27 EU Member States. Only the price in Denmark is higher. Prices in Germany are about 37% higher than the EU average of 23.69 ct/kWh. The high electricity price paid in Germany compared to other Member States is due to a higher proportion of surcharges, taxes and levies. In the EU, 8.54 ct/kWh on average consist of surcharges, taxes and levies, whereas in Germany these components account for more than 91% as much, at 16.38 ct/kWh. By contrast, at 14.85 ct/kWh, the German net price adjusted for all taxes, surcharges and levies in Germany is on an equal par with the EU average of 15.15 ct/kWh.

Comparison of European electricity prices in second half of 2021 for household customers with an annual consumption between 2,500 kWh and 5,000 kWh
in ct/kWh ; incl. VAT



Source: Eurostat

Figure 136: Comparison of EU electricity prices in the second half of 2021 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. 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. Proceedings were initiated against two default meter operators for not complying with this legal requirement. 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 could 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, several default meter operators, predominantly municipal utility companies, and another company had started legal action against the BSI's general administrative order determining the technical feasibility of the installation of smart metering systems. In an application for an interim injunction (case reference no 21 B 1162/20), the Higher Administrative Court (OVG) in Münster initially ruled in favour of the complainant. Adjustments were 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. In addition, the Gateway Standardisation committee was set up within the Federal Ministry for Economic Affairs and Energy (BMWi) and was consulted regarding the expanded Technical Directive BSI-TR-03109-1 v1.1 of 23 September 2021. The Technical Directive was subsequently approved by the BMWi and published by the BSI. The Technical Directive focuses on the interoperability certification of smart meter gateways.

On 20 May 2022, the BSI revoked its market statement of 7 February 2020, which had been viewed as likely unlawful in the proceedings for interim measures, with retrospective effect. In its administrative order under section 19(6) MsbG, the BSI stated that smart meter gateways already certified can still be used safely and BSI-compliant systems can still be installed voluntarily. An objection was filed to the BSI's revocation of its market statement.

2. The network operator as the default meter operator and independent meter operators

There were 840 companies operating a total of 53,013,016 meter locations[128] who responded to the questions about electricity metering for the monitoring survey in 2021. 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 (EnWG) must obtain approval from the Bundesnetzagentur under section 4 MsbG.

The 634 meter operators for conventional meter operation and 773 meter operators for meter operation of modern metering equipment and smart metering systems had the following roles in 2021 (multiple answers allowed):

Electricity: meter operator roles within the meaning of the Metering Act in 2021

	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	634	773
Network operator as non-default meter operator offering meter services on the market	41	39
Supplier acting as meter operator	52	46
Third-party, independent meter operator	32	16

Table 113: Meter operator roles within the meaning of the Metering Act according to data provided by electricity meter operators

This overview shows that the role of meter operator is only rarely performed by suppliers or third-party independent meter operators. In the case of modern metering equipment and smart metering systems, in

[128] The term "meter location" corresponds to the term "meter" within the meaning of section 2 para 11 MsbG. 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.

particular, the joint roles of network operator and metering operator dominate, with only 16 companies (around 2% of all meter operators) acting as third-party independent meter operators.

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 MsbG. A competing third party can be responsible instead of the default meter operator. Independent operators take on the activity of metering operations in the 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.

The total number of meter locations is broken down by federal state as shown in Table 114. The table shows that the German state of North Rhine-Westphalia has the highest number of meter locations - more than 11mn.

Electricity: number of meter locations by federal state in 2021

	Meter locations - consumption and feed-in
Baden-Württemberg	6,794,313
Bavaria	8,235,833
Berlin	2,421,497
Brandenburg	1,739,844
Bremen	449,012
Hamburg	1,186,481
Hesse	3,918,826
Mecklenburg-Western Pomerania	1,173,267
Lower Saxony	4,773,459
North Rhine-Westphalia	11,317,227
Rhineland-Palatinate	2,618,317
Saarland	672,675
Saxony	2,883,794
Saxony-Anhalt	1,597,952
Schleswig-Holstein	1,815,886
Thuringia	1,414,633

Table 114: Number of meter locations by federal state

3. Roll-out of smart metering systems and modern metering equipment

Under the Metering Act, meters with an average annual electricity consumption of over 6,000 kWh must be included in the rollout of smart metering systems. Around 5.2mn 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 MsbG. With nearly 2.1mn 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.

Compared with last year there was an increase of almost 105,000 to the number of meter locations now equipped with mandatory smart meters (around 130,400) in the >6,000 kWh consumption and the >7 kW generation groups. Additionally, consumers of less than 6,000 kWh annually and producers of less than 7 kW annually have opted to have around 27,500 smart metering systems installed.

As in previous years, there was also a rise in installed modern metering equipment. Whereas there were only around 9.5mn meter locations with modern metering equipment in the 2020 reporting year, that figure had already reached around 13.6mn in the 2021 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 2021	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				
> 6,000 kWh & ≤ 10,000 kWh	2,063,024	150,699	533,465	48,456
> 10,000 kWh & ≤ 20,000 kWh	1,008,656	81,966	242,313	45,432
> 20,000 kWh & ≤ 50,000 kWh	506,887	59,567	105,145	25,213
> 50,000 kWh & ≤ 100,000 kWh	152,259	39,503	19,659	4,184
> 100,000 kWh	252,439	121,186	6,290	128
Consumer devices in accordance with section 14a EnWG	1,206,337	103,350	267,905	6,537
of which meter locations at charging points for electric vehicles	19,203	1,406	9,692	13
Installed capacity at plant operators in accordance with section 2(1) MsbG				
> 7 kW & ≤ 15 kW	839,060	76,008	274,121	158
> 15 kW & ≤ 30 kW	391,578	35,971	97,221	185
> 30 kW & ≤ 100 kW	206,557	37,483	32,156	60
> 100 kW	564,660	87,451	2,677	15

Table 115: Mandatory installation within the meaning of section 29 in conjunction with sections 31 and 32 MsbG

For final consumers with annual consumption of 6,000 kWh or less, section 29 in conjunction with section 31 of the Metering Act gives the default meter operator the right to choose whether to install smart metering systems (referred to as an optional installation) or just to install modern metering equipment. Meter operators reported approximately 46.5mn 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

	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	23,584,414	1,737,334	6,562,381	8,218
> 2,000 kWh & ≤ 3,000 kWh	9,714,482	682,958	2,445,465	4,340
> 3,000 kWh & ≤ 4,000 kWh	6,502,334	403,660	1,574,137	1,757
> 4,000 kWh & ≤ 6,000 kWh	6,722,666	329,092	1,211,630	10,029
Installed capacity at plant operators in accordance with section 2 para 1 MsbG				
> 1 kW & ≤ 7 kW	710,930	64,533	212,347	3,287

Table 116: Voluntary installation within the meaning of section 29 in conjunction with sections 31 and 32 MsbG

In response to the question in the monitoring survey as to whether the default meter operator is planning on equipping meter locations of final consumers whose annual consumption is below 6,000 kWh with a smart metering system, 86 companies responded with "Yes" and 378 responded with "No". 311 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 27 July 2022, the BSI had certified 45 companies as gateway administrators.[129] The stringent security requirements make gateway administration a business sector where service providers are likely to continue to specialise in the future, rather than meter operators 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.

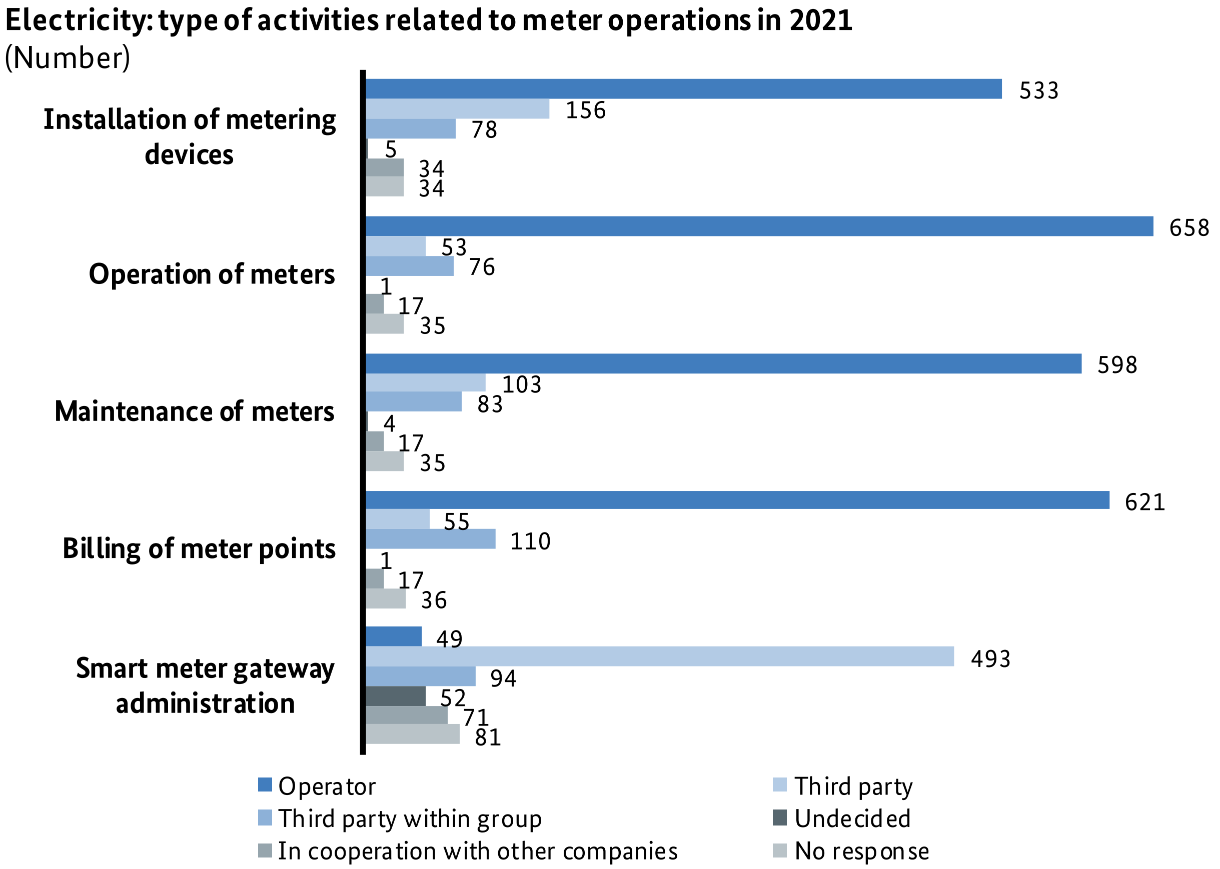


Figure 137: Type of activities related to metering operations

The Metering Act only regulates the nationwide rollout of modern metering equipment and smart metering systems for electricity. New gas meters can only be legally installed if they can be securely connected with a smart meter gateway. If meters have a smart meter gateway, default meter operators are obliged to connect it if it is technically possible to do so.

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 3% and 7% of the total number of the companies offering metering operations. Only for the gas sector is the number somewhat higher (around 12%), with 96 providers (see figure below).

[129] https://www.bsi.bund.de/DE/Themen/Unternehmen-und-Organisationen/Standards-und-Zertifizierung/Smart-metering/Administration-und-Betrieb/Zertifikate25Msbg/zertifikate25MsbG_node.html

Electricity: additional metering operations for other sectors using the smart meter gateway in 2021
(Number)

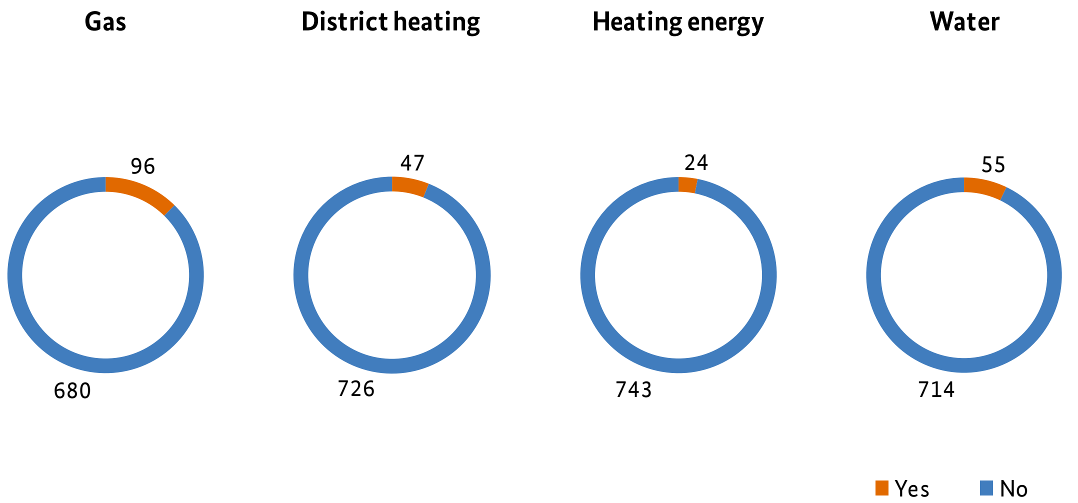


Figure 138: Additional metering operations for other sectors using the smart meter gateway

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) MsbG. 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 IG3.3), 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. The following figure shows the evaluation of additional services.

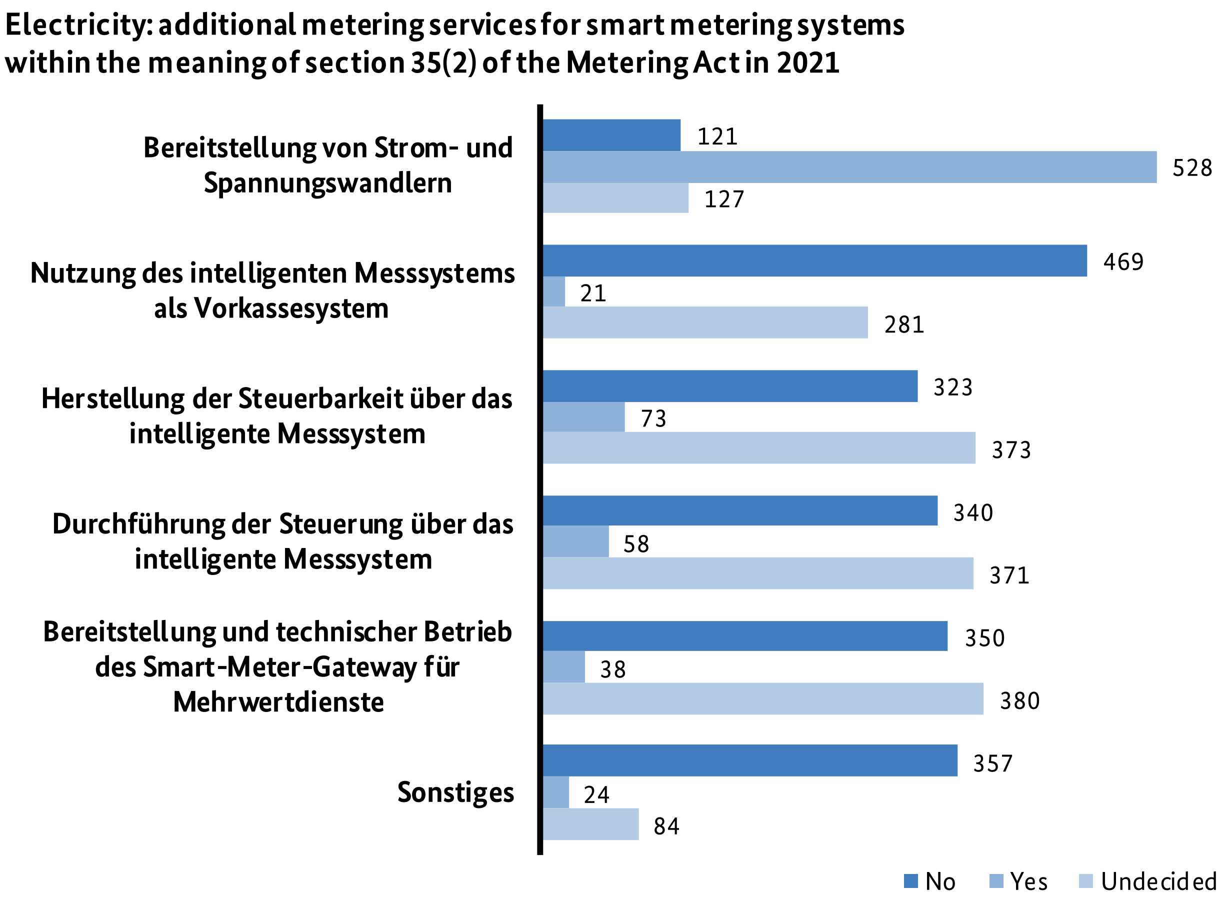


Figure 139: Additional services for smart metering systems

A large majority (81%) of meter operators do not sell products that combine electricity supply and meter operation.

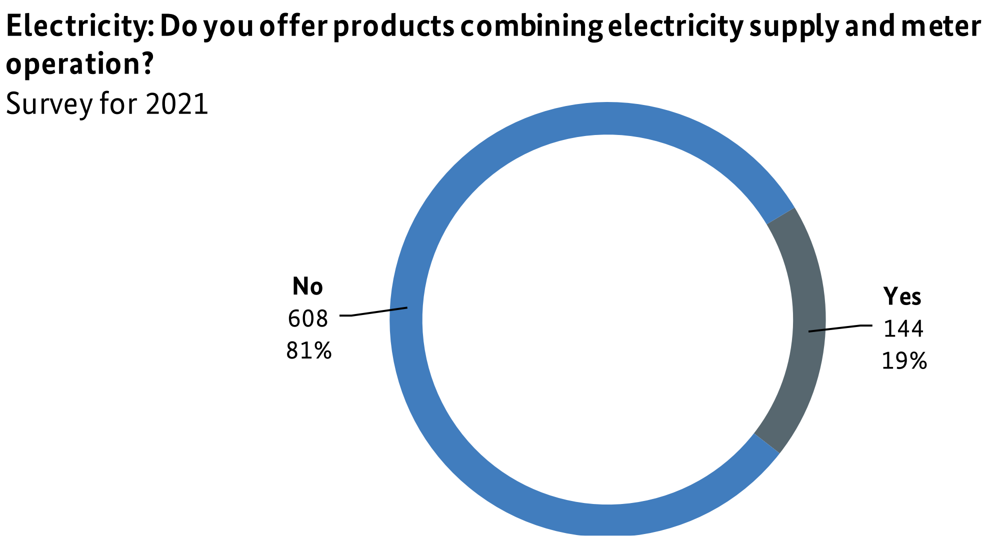


Figure 140: Combined products for electricity supply and meter operation

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, increased slightly, from 68 meter operations in 2020 to 74 in 2021 (see graph below).

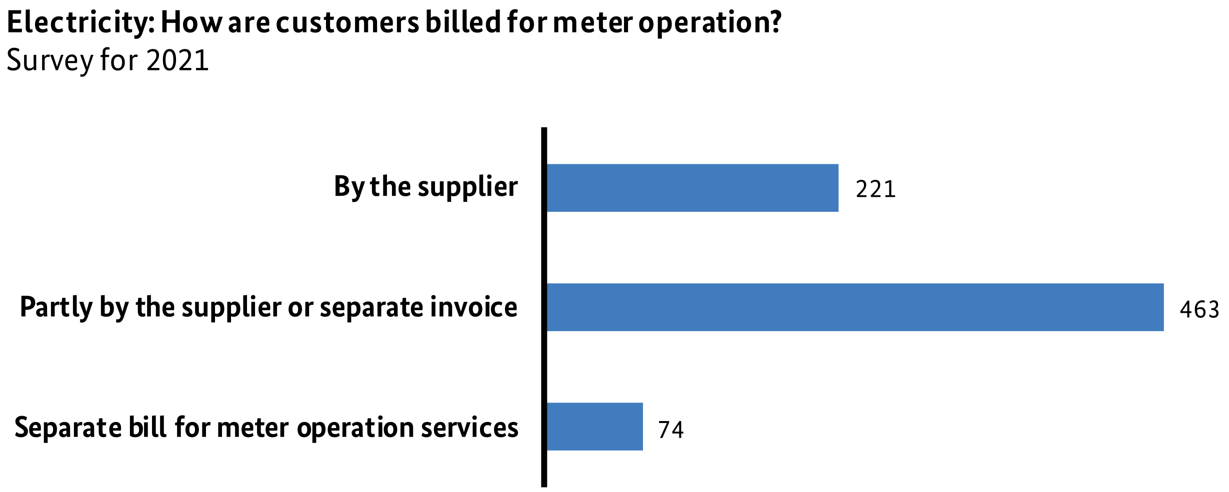


Figure 141: Billing the connection user/owner for meter operation

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 2020	Meter locations in 2021
Electromechanical metering systems (with current transformers and three-phrase meters based on the Ferraris principle)	33,709,940	30,180,731
of which are two-tariff and multiple-tariff meters (Ferraris principle)	2,045,361	1,843,208
Electronic meter device (basic meter not connected to a communication network) in accordance with section 2 para 15 MsbG	7,097,436	6,497,685
Modern measuring device (not connected to a communication network) in accordance with section 2 para 15 MsbG	9,637,122	13,813,899
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)	401,896	361,839
Smart metering systems in accordance with section 2 para 7 MsbG	27,599	133,460

Table 117: Meter technology employed for standard load profile (SLP) customers

In 2021 there was again a clear 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 3.6mn meter locations. There has been another small drop in the use of two-tariff and multiple-tariff meters to just around 1.8mn. The number of electronic meters has also declined over the previous year so that there are currently about 6.5mn meter locations where these types of meters are used. These declines are due to the availability of modern metering equipment and the requirement to have it installed. There was therefore again a sharp increase in 2021 in the number of modern metering devices that comply with section 2 para 15 MsbG and are not connected to a communications network. Modern metering equipment is now in use at about 13.6mn meter locations, which means that overall around 29% 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 had actually fulfilled the 10% quota by the deadline. For last year's monitoring survey 102 companies reported that they did not meet the quota by 30 June 2020. The Bundesnetzagentur approached the companies concerned and clarified the matter. One key obstacle the companies cited to reaching the 10% quota was the coronavirus situation. In nearly all cases the quota was fulfilled shortly thereafter and the implementation target was thus met. The Bundesnetzagentur had to launch supervisory proceedings against just two of the companies concerned.

There was a decrease in the number of meter systems as defined under section 2 para 13 MsbG that are not smart metering systems, which are now installed at only around 360,000 SLP customer meter locations. By contrast, the number of smart metering systems consisting of modern metering equipment and a smart meter gateway, which are already installed at more than 133,000 meter locations, increased fivefold compared with the previous year.

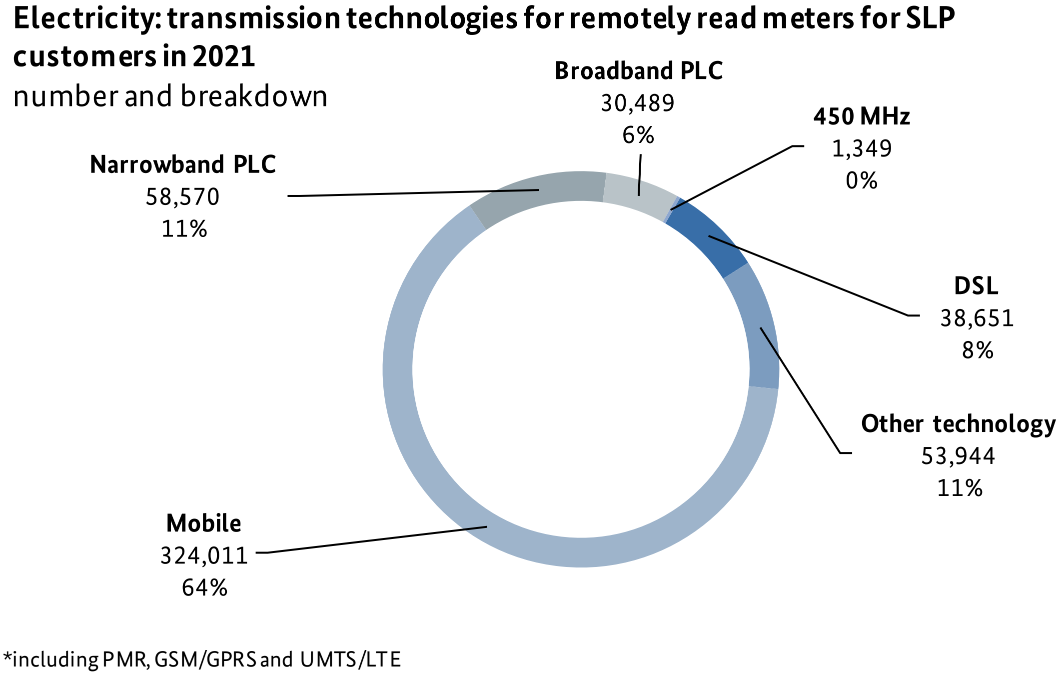


Figure 142: Transmission technologies for remotely read meters for SLP customers

As the chart above shows, only about 507,000 of the nearly 50mn 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 35,000 meter locations compared to the previous year. PLC transmission technology, broadband and narrowband, is now being used in just 17.5% of cases. Transmissions via broadband (DSL) have declined by around seven percentage points, thus reducing its overall share to 6%, whereas transmission via mobile communication is used in 64% of cases.

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 815,000 meter locations. Interval-metered customers are solely non-residential customers from the industry and business sector.

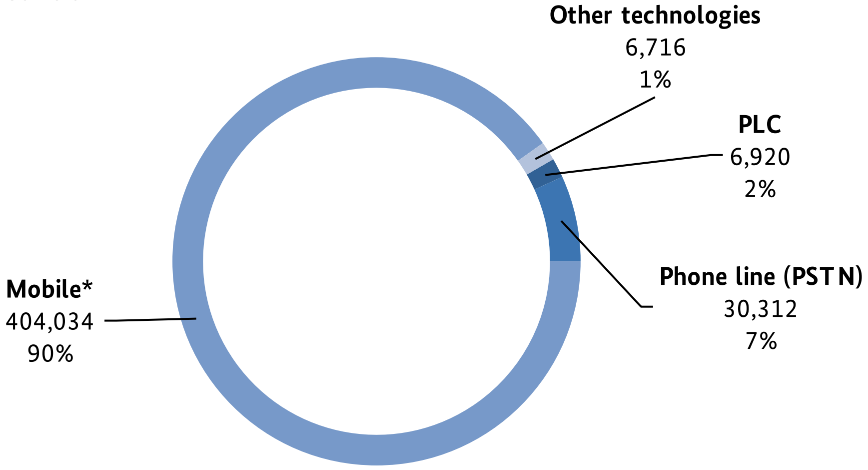
Electricity: meter technology employed for interval-metered customers

Requirement	Meter locations 2021
Metering equipment in the interval-metered segment (> 100,000 kWh/year)	406,518
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)	369,460
Optional installations of BSI-certified smart metering systems	27,977
Other	11,887

Table 118: Meter technology employed for interval-metered customers

The following diagram shows the number and breakdown of transmission technologies used.

Electricity: transmission technology for remotely read meters for interval-metered customers in 2021
number and breakdown



*including PMR, GSM/GPRS and UMTS/LTE

Figure 143: Transmission technologies for remotely read meters for interval-metered customers

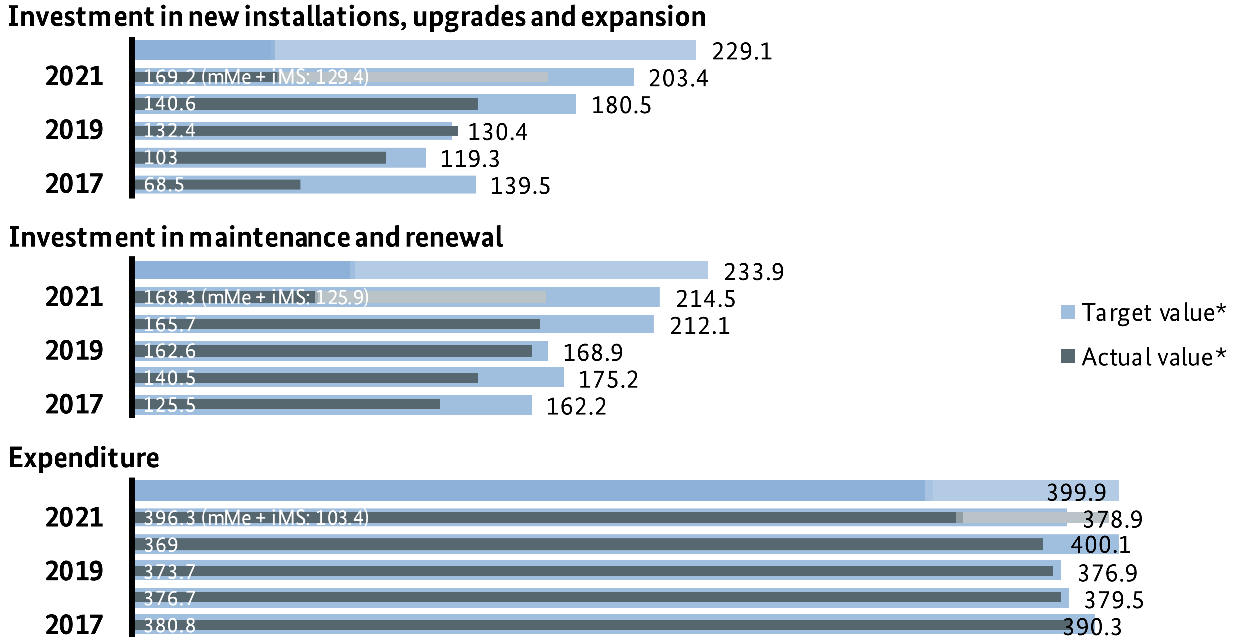
There were some changes in the transmission technology landscape for interval-metered customers compared with 2020. Remote meter readings transmitted via mobile communication increased slightly from

86% to 88%. Similar to 2020, 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. The technology of 450 MHz transmission is currently being used by 180 interval-metered customers, although its share of the technologies used remains small thus far (0.04%).

7. Metering investment and expenditure

Total investment and expenditure on metering was up about €58mn to around €734mn in 2021, leaving expenditures around €34.2mn below the planned investment amounts. Investment in new installations, upgrades and expansion made in 2021 lagged around 17% behind projected figures for the year. Investments in maintenance and renewal were around 9% below what was planned. The volume of expenditure, by contrast, was around 5% above the projected values. At a total of €837mn, this year's forecast figures are higher than projections from the prior year. Of the €734mn invested in 2021, investment in smart metering systems and modern metering equipment was around €359mn, which is around a €62mn increase over the previous year. This share is projected to rise significantly again to about €471mn in 2022.

Electricity: metering investment and expenditure
(€ million)



* With the change in the reporting procedure the actual values as from 2019 and the target values as from 2020 for investments and expenditure are surveyed proportionately 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 144: Metering investment and expenditure

8. Regulatory costs for metering

Under section 7(2) MsbG 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 tariffs, 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 BSI's withdrawal of its market statement will likely delay the rollout of smart metering system again in 2022.

The difference between the actual costs of meter operation 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 to 2020 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. The chart below shows the amount of costs removed from the network operators' revenue caps and the remaining costs for network operators after meters have been replaced.

Regulatory costs for modern metering equipment and smart metering systems
(€mn)

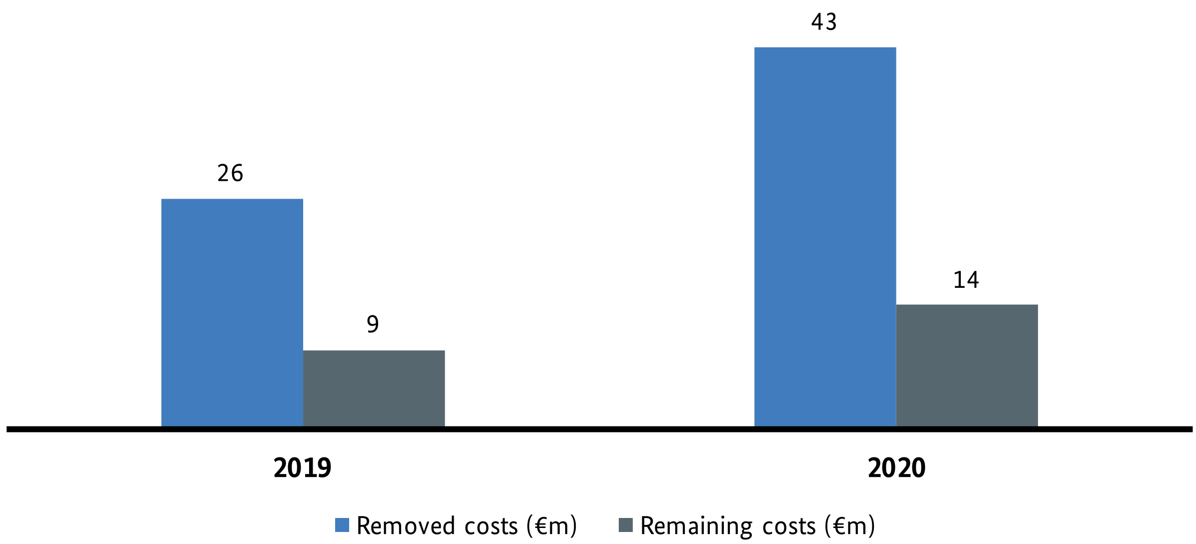


Figure 145: Regulatory costs for modern metering equipment and smart metering systems.

II Gas market

A Developments in the gas markets

The monitoring reports published by the Bundesnetzagentur and the Bundeskartellamt always relate to the previous calendar year because reliable and firm figures are available for that year. With regard to the situation in the gas markets, the year presented in this report – 2021 – is the last year before the turning point in 2022. The situation changed dramatically in 2022 in the wake of Russia's invasion of Ukraine. The Bundesnetzagentur and the Bundeskartellamt have made an effort to incorporate any relatively reliable figures available into the monitoring report. The editorial deadline was 2 November 2022. The Bundesnetzagentur and the Bundeskartellamt have refrained from explicitly pointing out in each individual case that the situation has since changed and is now radically different to that in 2021. In this respect, we assume that readers will naturally keep this fact in mind.

1. Gas supply situation

1.1 Imports

The total volume of natural gas imported into Germany in 2021 was 1,458 TWh. Imports to Germany were thus down by 216 TWh from the previous year's figure of 1,674 TWh. The main sources of gas imports to Germany in 2021 were Russia and Norway. However, the Netherlands, as an established and liquid European producer, trading hub and point of arrival for LNG shipments with connections to natural gas fields in Norway and the United Kingdom, was also a significant source of imports for Germany.

According to the Bundesnetzagentur's daily status reports on the supply of gas in Germany, gas flows from Russia to Germany were last at the normal level of around 1,800 GWh/day on 10 May 2022. The halting of Russian gas deliveries to Poland and Bulgaria has so far had no impact on the security of supply in Germany. Following Russia's imposition of sanctions on Gazprom Germania and almost all the company's subsidiaries, the volumes of gas flowing through Ukraine to Waidhaus in Germany were more than 25% down on the previous day as a result of the reduction in transit flows. On 14 June 2022, gas flows from the Nord Stream 1 pipeline were at about 60% of maximum capacity, but were reduced to 40% the following day. As from 11 July 2022, gas flows were at zero percent because of planned maintenance work on the Nord Stream 1 pipeline scheduled until 21 July 2022. Gas flows through Nord Stream 1 resumed on 22 July 2022 and were at about 40% of maximum capacity. On 27 July 2022, there was another, announced reduction in gas flows from Nord Stream 1 to around 20% of maximum capacity. These reduced gas flows through the Nord Stream 1 pipeline were then suspended indefinitely on 2 September 2022, reportedly for technical reasons. On 26 September 2022, a sudden drop in pressure first in Nord Stream 2's pipe A and then in both Nord Stream 1 pipes was identified. The damage to the Nord Stream 1 and 2 pipelines has not had any effect on the gas supply. No gas had been delivered through Nord Stream 1 since the beginning of September anyway, and Nord Stream 2 had never been put into operation.

The total volume of gas imported into Germany in the period from January to October 2022 was 1,161.1 TWh. This represents a decrease of 52.1 TWh compared with the previous year's figure (for January to October 2021) of 1,213.2 TWh.

1.2 Production

In 2021, natural gas production in Germany amounted to 5.1bn m³ of gas (with calorific adjustment).[130] This is about the same as in the previous year.[131] The reserves-to-production ratio of proven and probable natural gas reserves of 42bn m was 7.4 years as at 1 January 2022. In 2021, natural gas production in Germany covered about 5% of the country's demand; 95% of the annual demand therefore had to be met with imports from countries including Russia, Norway and the Netherlands.[132]

1.3 Gas storage facilities

Germany's gas storage facilities are key to the supply of gas in particular in the winter months. The total maximum usable volume of working gas in underground storage facilities as at 31 December 2021 was 278.51 TWh. Of this, 137.02 TWh was accounted for by cavern storage, 119.90 TWh by pore storage and 21.59 TWh by other storage facilities.

The entry into force of the Gas Storage Act on 30 April 2022 and the introduction of statutory requirements for storage levels serve to further increase security in the supply of gas in Germany. The original storage level targets were 80% on 1 October, 90% on 1 November and 40% on 1 February of each year. These levels were raised again by a ministerial ordinance on 29 July 2022. The targets for 1 October and 1 November were increased to 85% and 95% respectively, while the target for 1 February was left at 40%.

The target storage level of 85% for 1 October 2022 was already reached in mid-September 2022. Storage levels on 2 November 2022, the editorial deadline for the monitoring report, stood at 99.19%.

The market for the operation of underground natural gas storage facilities was still highly concentrated in the year under review. The cumulative market share of the three largest storage facility operators stood at around 66.9% at the end of 2021, representing a slight decrease compared to the previous year (67.2%).

1.4 Consumption

In 2021, approximately 188.7 TWh of gas was delivered to final customers from the TSO network (2020: 199.5 TWh). The volume of gas delivered from the TSO network was thus about 5.5% less than the level of the previous year. Total gas supplies from the network of the DSOs amounted to 810.2 TWh in 2021, up by around 70 TWh or just over 9% compared to the previous year (2020: 741.6 TWh). The quantity of gas supplied in 2021 to household customers as defined in section 3 para 22 EnWG was up by more than 11% at about 300.8 TWh (2020: 270.3 TWh). A simplified comparison between the supply and use of natural gas in 2021 in Germany is shown below.

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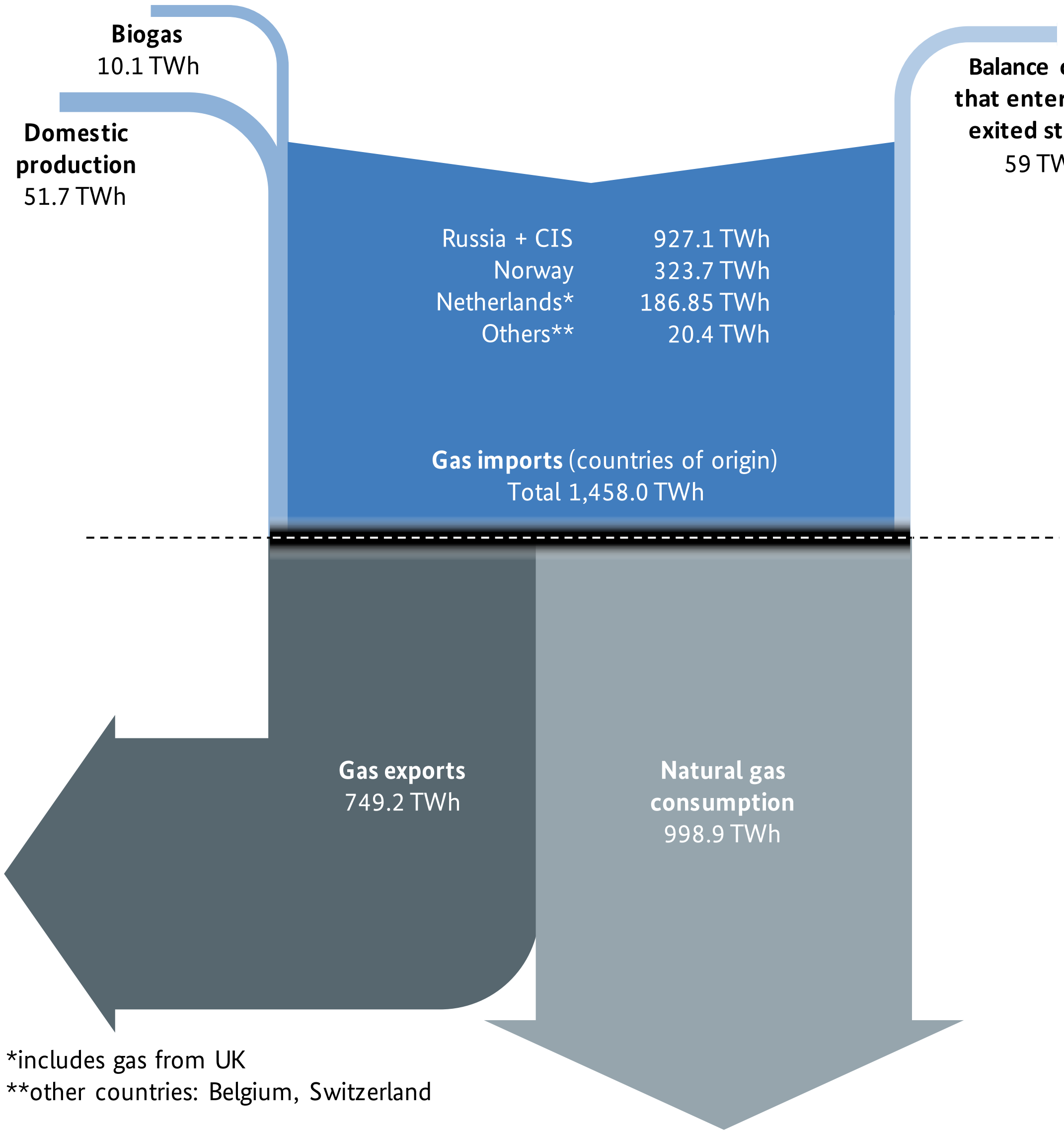
[130] Calorific adjustment is used because natural gas is not sold according to its volume but according to its energy content (9.7692 kWh/m³). In contrast, gas without calorific adjustment has a natural calorific value that may vary depending on the location of the deposit (in Germany this figure varies between 2 and 12 kWh/m³).

[131] Source: Annual report "Erdöl- und Erdgasreserven in der Bundesrepublik Deutschland am 1. Januar 2022" [Crude Oil and Natural Gas Reserves in the Federal Republic of Germany as at 1 January 2022]; State Authority for Mining, Energy and Geology (LBEG), Lower Saxony.

[132] See previous footnote.

Gas: gas available and gas use in the supply network in 2021
(TWh)



*includes gas from UK
**other countries: Belgium, Switzerland

Figure 146: Gas available and gas use in Germany in 2021

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 1,578 TWh in 2021. Of this, 51.7 TWh came from domestic sources, while 1,458 TWh was imported.[133]

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[133] The import figure for 2020 has been adjusted for this report in line with the latest calculation methodology and is therefore not comparable with the figure in the Monitoring Report 2021. For the first time, the export volumes at the Brandov cross-border

In 2021, the annual storage balance – the difference between the gas that entered and exited storage in a year – was +59 TWh. The storage balance was positive, which means that overall more gas was withdrawn from storage than was injected into it. Moreover, 9.7 TWh of biogas upgraded to natural gas quality was fed into the German natural gas system in 2021.

In 2021, just over 51% (749.2 TWh) of the gas was exported and transported to neighbouring countries in Europe. Final customers used 998.9 TWh of gas in Germany (2020: 941.1 TWh).

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 2021.

Gas: offtake volumes in 2021 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%	365.0	45.1%
> 300 MWh/year ≤ 10,000 MWh/year	0.5	0.3%	136.4	16.8%
> 10,000 MWh/year ≤ 100,000 MWh/year	5.7	3.0%	108.1	13.3%
> 100,000 MWh/year	138.6	73.4%	141.9	17.5%
Gas power plants ≥ 10 MW net nominal capacity	43.9	23.3%	58.8	7.3%
Total	188.7	100%	810.2	100%

Table 119: Gas offtake volumes in 2021 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 2021. Once again, gas TSOs and DSOs were asked in the 2022 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, that is 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 79.3 TWh (2020: 73.7 TWh), equivalent to about 42% of the total quantity of gas delivered by TSOs to final

interconnection point were deducted to avoid the transit volumes – the volumes imported via the Nord Stream 1 pipeline and the Greifswald cross-border interconnection point – being counted twice at the Waidhaus cross-border interconnection point.

customers. As regards gas distribution systems, the amount of gas procured without a conventional supplier contract amounted to 45.9 TWh (2020: 41.4 TWh), corresponding to a share of just over 6% of the DSOs' total gas supplies.

The difference between the 2021 offtake volumes of the system operators, 998.9 TWh (2020: 941.1 TWh), and the gas delivered by gas suppliers, 908.9 TWh (2020: 853 TWh), includes the amount of gas procured directly on the market without using a supplier as well as survey-related variations.[134]

Gas: total offtake volumes in 2021 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	365.0	36.5%	349.2	38.4%
> 300 MWh/year ≤ 10,000 MWh/year	136.9	13.7%	122.8	13.5%
> 10,000 MWh/year ≤ 100,000 MWh/year	113.8	11.4%	100.6	11.1%
> 100,000 MWh/year	280.5	28.1%	268.7	29.6%
Gas power plants ≥ 10 MW net nominal capacity	102.7	10.3%	67.7	7.4%
Total	998.9	100.0%	909.0	100.0%

Table 120: Total gas offtake volumes in 2021, according to the survey of gas TSOs and DSOs and total volumes of gas delivered according to the gas supplier survey

The total quantity of gas supplied by general supply networks in Germany rose in 2021 by about 57.8 TWh or just over 6% year-on-year to 998.9 TWh. The quantity of gas supplied to household customers as defined in section 3 para 22 EnWG rose by just over 11% to 300.8 TWh (2020: 270.3 TWh). Gas supplies to gas-fired power stations with a nominal capacity of at least 10 MW decreased by about 4.9% to 102.7 TWh (2020: 108 TWh). The quantity of gas supplied to SLP and interval-metered customers in 2021 as reported by the system operators was 992.4 TWh. Based on the reported volumes of gas sold to SLP and interval-metered customers, about 572.7 TWh went to interval-metered customers and about 419.7 TWh to SLP customers. The majority of

[134] Variations in data quality and response frequency mean that the difference between the figures from the system operators and the gas suppliers (90 TWh) is lower than the figure calculated for gas procured directly on the market (125.2 TWh).

SLP customers are household customers. In 2021, household customers within the meaning of section 3 para 22 EnWG were supplied with around 300.8 TWh, according to the DSOs' figures.[135]

The following chart shows the use of gas by economic sector in 2021. The data from the monitoring survey are set against the consumption data of final customers with a technical connection capacity of 10 MWh/h or more in the Trading Hub Europe market area. These customers were divided into three categories: goods production, energy supply, and other sectors.

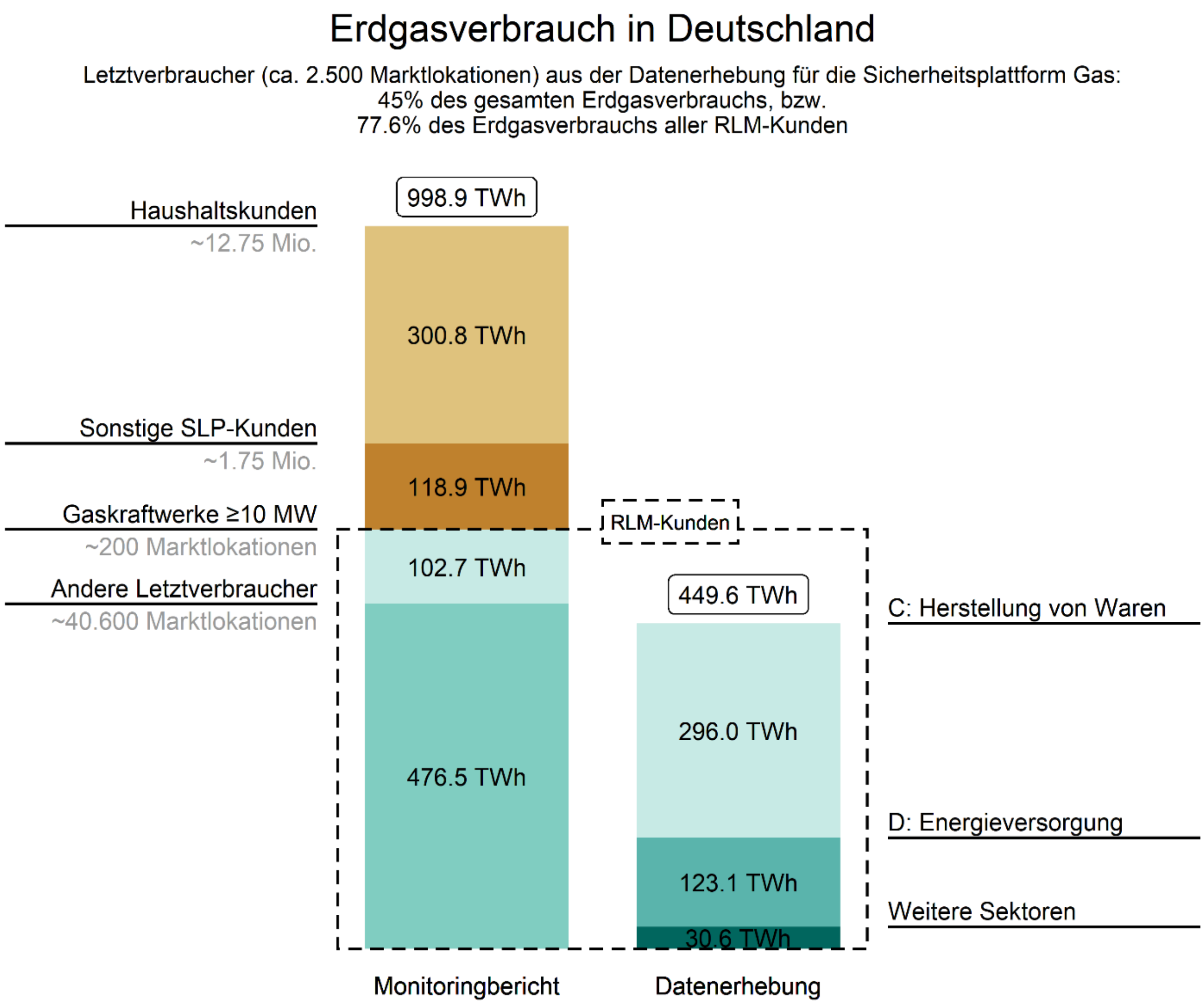

Figure 147: Natural gas consumption in Germany in 2021 by sector

[135] Variations in the system operators' data quality and response frequency mean that there is a difference of about 6.5 TWh between the gas offtake volume based on Eurostat categories and that based on the distinction between SLP and interval-metered customers.

2. Summary

2.1 Networks

2.1.1 Network expansion

For the first time, hydrogen projects were considered and determined as part of the Gas Network Development Plan (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.

The Bundesnetzagentur confirmed the scenario framework for the Gas NDP 2022-2032 with changes on 20 January 2022. The draft NDP was originally due to be submitted to the Bundesnetzagentur on 1 July 2022. The original timetable changed because of the geopolitical situation and the political objectives for the construction of LNG facilities in Germany. The Bundesnetzagentur and the TSOs agreed to deviate from the normal NDP process and to publish the NDP in two parts because the substitution of Russian gas imports has necessitated further network calculations in the TSOs' network planning process and the results are not yet available.

2.1.2 Investments

In 2021, the 16 German gas TSOs invested a total of €679mn (2020: €995mn) in network infrastructure. Of this, €420mn (2020: €638mn) was accounted for by investments in new builds, upgrades and expansion projects and €259mn (2020: €357mn) by investments in network infrastructure maintenance and renewal.

Across all TSOs, expenditure on maintenance and repair of network infrastructure amounted to €358mn in 2021 (2020: €402mn), with expenditure lower than that in the previous year but within the usual range of fluctuation. The TSOs' planned expenditure for 2022 is €385mn.

The 600 gas DSOs reported total network infrastructure investments in 2021 of €1,736mn (2020: €1,674mn) in new builds, upgrades and expansion (€1,101mn (2020: €1,044mn)) and in maintenance and renewal (€635mn (2020: €631mn)). For 2022, the projected total investment is €1,732mn.

Service and maintenance expenses, based on the data provided by the DSOs, totalled €1,204mn in 2021 (2020: €1,365mn). The projected expenditure on maintenance and repair for 2022 is €1,189mn.

2.1.3 Supply interruptions

In 2021, the average interruption in supply per connected final customer was 2.18 minutes, twice that in the previous year (2020: 1.09 minutes in the year). The figure is also higher than the long-term average of 1.54 minutes in the year. The increase in the average interruption duration was mainly due to third-party damage caused to gas pipes during construction work. The figure nevertheless shows that the German gas network has a high quality of supply.

2.1.4 Network tariffs

As of 1 April 2022, the average volume-weighted network tariff including the charges for metering and meter operation for household customers (volume-weighted across all contract categories) was 1.62 ct/kWh (2021: 1.59 ct/kWh), a slight increase of around 2% compared to the previous year.

For commercial customers, the average network tariff in 2022 was 1.25 ct/kWh, slightly lower than in the previous year (2021: 1.28 ct/kWh). For industrial customers, there was a significant increase of just over 37% to 0.44 ct/kWh (2021: 0.32 ct/kWh).

2.1.5 Transport

The total quantity of gas supplied by general supply networks in Germany rose in 2021 by about 57.8 TWh or just over 6% year-on-year to 998.9 TWh. The quantity of gas supplied to household customers as defined in section 3 para 22 EnWG rose by just over 11% to 300.8 TWh (2020: 270.3 TWh). Gas supplies to gas-fired power stations with a nominal capacity of at least 10 MW decreased by about 4.9% to 102.7 TWh (2020: 108 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 79.3 TWh (2020: 73.7 TWh), equivalent to about 42% of the total quantity of gas supplied by the TSOs to final consumers. As regards gas distribution systems, the amount of gas procured without a conventional supplier contract amounted to 45.91 TWh (2020: 41.1 TWh), corresponding to a share of just over 6% of the DSOs' total gas supplies.

2.1.6 Market area conversion

The year 2021 was marked by the disastrous flooding in July that led to the loss of more than one hundred lives and huge damage to property. The flooding also affected areas in which market area conversion work was in progress. The market area conversion was still affected by the coronavirus pandemic in early 2022. As in the previous year, people working from home and travelling less actually facilitated the conversion process. Almost all network operators and companies carrying out adjustments reported that it was easier to make contact with customers for the conversions. The market area conversion was overshadowed by the war in Ukraine, which created uncertainty among many customers regarding the conversion to H-gas. This uncertainty was resolved with the help of transparent information from the network operators and companies carrying out the adjustments. The market area conversion is consequently on schedule and making good progress.

2.1.7 Wholesale

Following a decrease in the demand for energy in 2020 because of the coronavirus pandemic, there was an increase in demand again in 2021 due to the global economic recovery. The total volume traded on the EEX Group energy exchange, which is the exchange relevant for natural gas trading in Germany, increased by around 37% or 178 TWh compared with 2010.

The volume traded on the spot market was about 582 TWh in 2021 (2020: about 429 TWh), which corresponds to an increase of around 36%. The focus of spot trading in 2021 for the NCG and GASPOOL market areas and for the THE market area, which was formed by merging these two market areas in October 2021, was on day-ahead contracts, with a total volume of 373.2 TWh (NCG: 149.2 TWh; GASPOOL: 110.2 TWh, THE: 113.8 TWh).

The futures trading volume rose from around 58 TWh in 2020 to about 82 TWh in 2021, corresponding to an increase of some 41%.

The nine broker platforms surveyed reported a total volume of off-exchange wholesale gas transactions for delivery to Germany of 2,392 TWh in 2021 (2020: 2,898 TWh). This represents a decrease of around 17% compared to the previous year. Of this, 862 TWh was for contracts with delivery in 2021 and a delivery time of at least one week, 793 TWh was for transactions with delivery in 2022, and 616 TWh was for delivery in 2023 or later.

Wholesale gas prices in 2021 were also considerably higher than in previous years. The respective price indices (EGIX and the BAFA border price) show an increase of around 403% (EGIX) and around 116% (BAFA border price) from the arithmetic mean of the year before. The European Gas Spot Index (EGSI) also increased significantly year-on-year. The average EGSI for the new THE market area was €90.94/MWh in October 2021 and had risen to €115.05/MWh by December 2021. This represents an increase from December 2020 of around 624% for the former NCG market area and 611% for the former GASPOOL market area.

2.2 Retail

2.2.1 Contract structure and competition

An overall analysis of how household customers were supplied in 2021 in terms of volume shows that nearly half of them (48%) were supplied by the local default supplier under a non-default contract, receiving 131.7 TWh of gas.

Only 16% of household customers still had a default supply contract in 2021 and these were supplied with 44.6 TWh of gas. The percentage of household customers who had a contract with a supplier other than the local default supplier increased again to 36% for a total of 98.2 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 (as in the previous year) and about 77.1% was supplied under a contract with a legal entity other than the default supplier (2020: 77.2%). These figures show that default supply is still of minor significance in the acquisition of interval-metered customers in the gas sector.

The total number of customers changing contract in 2021 was 0.54mn. The volume of gas these customers were delivered was approximately 8.5 TWh. The volume-based switching rate was therefore 3.1%.

The total number of supplier switches by household customers fell in 2021 by just over 0.5% to around 1.64mn. Around 1.3mn of these household customers changed by cancelling their previous supply contract (voluntary switching). It should be noted that the total number of switches for 2021 does not include "involuntary" switching by customers whose contracts were cancelled by their suppliers, including insolvent suppliers, who were no longer able to supply their customers because of the increase in prices. The number of "involuntary" supplier switches amounted to around 345,200. Possible reasons for the decrease in the number of customers switching supplier include the increases in gas prices beginning in the third quarter of 2021.

Customers may have been reluctant to switch to a new gas supplier because of the lack of alternatives in terms of price.

The total consumption amount of non-household customers affected by supplier switches in 2021 was 107.6 TWh, corresponding to a year-on-year increase of 27 TWh. The switching rate for non-household customers rose to 10.2% (2020: 7.3%).

The level of concentration in the two largest gas retail markets for SLP and interval-metered customers is still well below the statutory thresholds for presuming market dominance. In 2021, the cumulative sales of the four largest companies to SLP customers were about 102.7 TWh, while to interval-metered customers they were around 123.9 TWh. The aggregate market share of the four largest companies (CR4) in 2021 was again 26% for SLP customers (the same as in the previous year) and 24% for interval-metered customers (2020: 28%).

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 2021 as well.

On average, final consumers in Germany can choose between 135 suppliers in their network area; household customers can, on average, choose between 113 suppliers (these figures do not take account of corporate groups).

2.2.2 Gas disconnections

The number of disconnections actually carried out by the network operators in 2021 was 26,905, representing an increase of about 12% compared to the previous year (2020: 23,991). The increase in the number of disconnections in 2021, especially among gas customers, is partly due to disconnections carried over from 2020. There was a clear drop in the number of disconnections in 2020 owing to the right to withhold performance set out in Article 240 section 1 EGBGB, which applied during part of the coronavirus pandemic. In addition, a large proportion of the suppliers had voluntarily decided not to disconnect their customers. In 2021, around half of the suppliers surveyed by the Bundesnetzagentur again voluntarily decided not to disconnect customers. Suppliers often accommodated customers by offering them special or individual payment arrangements.

According to the gas suppliers' data, a disconnection notice is issued when a customer is on average around €120 in arrears. Just over a million disconnection notices were issued to household customers in total, of which around 174,000, or 17%, were passed on to the relevant network operator with a request for disconnection. The suppliers' data show that a total of around 3% of the connections issued with a disconnection notice were actually disconnected. Around 53% of the customers disconnected in 2021 were on default contracts and 47% were outside of default supply. The gas suppliers stated that around 10% of disconnections were the same customers being disconnected more than once.

2.2.3 Price level

The volume-weighted gas price for household customers across all contract categories rose about 48% year-on-year from 6.68 ct/kWh to 9.88 ct/kWh. The current survey method does not make a distinction between prices for existing and new customers. There was a considerable increase in the gas prices for new customers, especially from the third quarter of 2021 onwards, while existing customers were still able to benefit from their cheaper prices. The survey method and widening gap between prices for existing and new customers mean that the average calculated is lower than would be expected based on current trends.

In the price across all contract categories, the largest price component "energy procurement, supply and margin", which makes up around 45%, rose by over 86% from 2.95 ct/kWh to 5.5 ct/kWh. This figure is also lower than would be expected based on current trends because of the survey method described above.

The volume-weighted gas price for customers on a default contract as at 1 April 2022 was 9.51 ct/kWh (2021: 7.45 ct/kWh), corresponding to an increase of around 28% compared to the previous year.[136]

On 1 April 2022, the volume-weighted price for customers under a non-default contract with the default supplier was 9.02 ct/kWh, an increase of about 37% compared to 2021 (6.58 ct/kWh).

On 1 April 2022, the volume-weighted price for a contract with a supplier other than the local default supplier was 10.95 ct/kWh, an increase of just over 71% compared to the previous year (2021: 6.41 ct/kWh).

The gas prices for non-household (industrial and commercial) customers as at 1 April 2022 showed substantial year-on-year increases as a result of the effects of the war in Ukraine. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 GWh ("industrial customer") was 6.76 ct/kWh, 3.81 ct/kWh or around 129% higher than the previous year's figure. The proportion of the total price (about 77.1%) controlled by the supplier was 5.21 ct/kWh, up by 3.67 ct/kWh. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 MWh ("commercial customer") was 7.19 ct/kWh on the reporting date, an increase of 2.45 ct/kWh or around 52% year-on-year. The proportion of the total price (about 65.1%) controlled by the supplier was 4.69 ct/kWh, up by 2.28 ct/kWh. The prices paid by non-household customers in Germany in the annual consumption range of 27.8 GWh to 278 GWh was 3.85 ct/kWh in the second half of 2021, about 0.32 cents below the EU average of 4.17 ct/kWh. On an EU average, the net price is subject to about 7% (0.36 ct/kWh) of non-refundable taxes and levies. In this regard, Germany's figure of about 17% (0.65 ct/kWh) is again 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 6.92 ct/kWh and thus around 11.5% below the EU average (7.82 ct/kWh). Taxes and levies amounted to an average of 2.18 ct/kWh in Germany, which is relatively close to the EU average of 2.36 ct/kWh.

3. Network structure data

All 16 TSOs took part in the Monitoring Report 2022 data survey. As at 31 December 2021, the length of pipelines in the transmission system was about 42,500 km and included around 3,500 exit points for delivery to final consumers, redistributors or downstream networks including the points at which gas can be taken off for delivery to storage facilities, hubs and conditioning or conversion plants. The number of registered final customer market locations in the transmission system was 512. As at 2 November 2022, a total of 702 gas DSOs

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

were registered with the Bundesnetzagentur, 675 (just over 96%) of whom took part in the 2022 monitoring survey. As at 31 December 2021, the total length of pipelines in the gas distribution system including house connections was around 529,000 km and included about 11.3mn 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 2021, there were 14.6mn 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 12.8mn.

Gas: number of gas network operators in Germany registered with the Bundesnetzagentur

	2017	2018	2019	2020	2021	2022
TSOs	16	16	16	16	16	16
DSOs	717	718	708	703	703	702
DSOs with fewer than 100,000 connected customers	692	693	683	682	676	674
DSOs with fewer than 15,000 connected customers*	548	547	536	534	534	532

*Based on data from gas DSOs.

Table 121: Number of gas network operators in Germany registered with the Bundesnetzagentur as at 2 November 2022

The majority of gas DSOs (585 operators) have short to medium length systems of up to 1,000 km, and 90 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
(number and share)

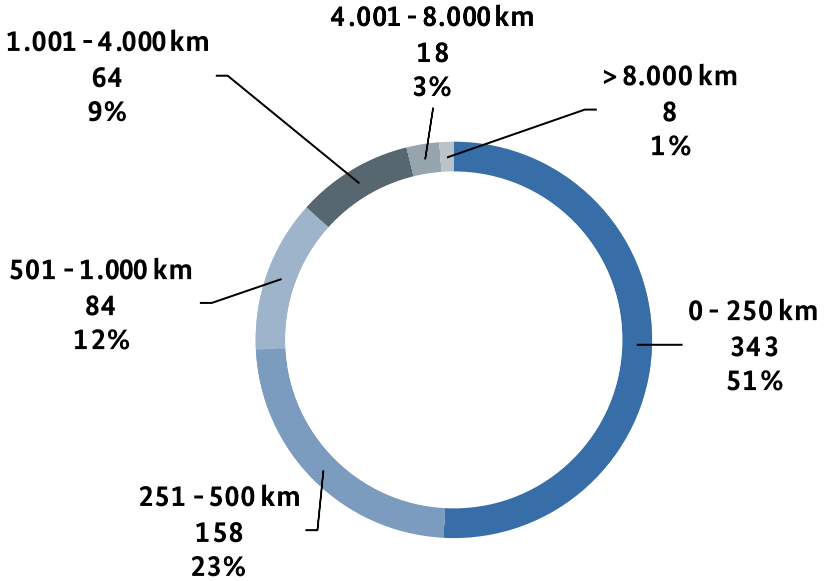

Figure 148: DSOs by gas pipeline network length as stated in the DSO survey as at 31 December 2021

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 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.

Gas: 2021 network structure figures

	TSOs	DSOs	Total number of TSOs and DSOs
Network operators (number)	**16**	**650**	**666**
Network length (thousand km)	**42.4**	**529.0**	**571.4**
≤ 0.1 bar	0.0	189.8	189.8
> 0.1 – 1 bar	0.0	264.0	264.0
> 1 – 5 bar	0.1	27.2	27.3
> 5 – 16 bar	2.8	27.2	30.0
> 16 bar	39.5	20.8	60.3
Total exit points (thousand)	**3.5**	**11,253.4**	**11,256.9**
≤ 0.1 bar	0.0	6,152.9	6,152.9
> 0.1 – 1 bar	0.0	4,882.6	4,882.6
> 1 – 5 bar	0.1	206.3	206.4
> 5 – 16 bar	1.2	9.3	10.5
> 16 bar	2.2	2.3	4.5
Market locations of final customers (thousand)	0.5	14,571.3	14,571.8
Industrial and commercial customers and other non-household customers	0.5	1,820.7	1,821.2
Household customers	0.0	12,750.6	12,750.6

Table 122: 2021 network structure figures according to the TSO and DSO survey (data from 650 of the total 703 DSOs) as at 31 December 2021

Gas: market locations by federal state at DSO level in 2021
(number in millions)

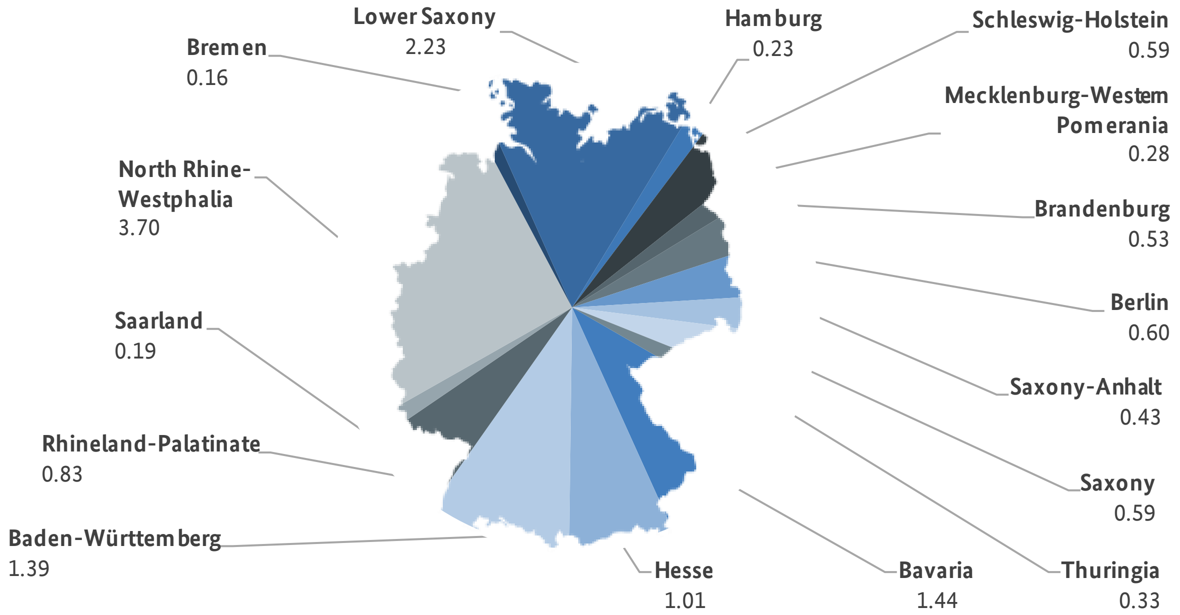

Figure 149: Market locations by federal state at DSO level as stated in the DSO survey as at 31 December 2021

Gas: market locations by federal state at TSO level in 2021
(number)

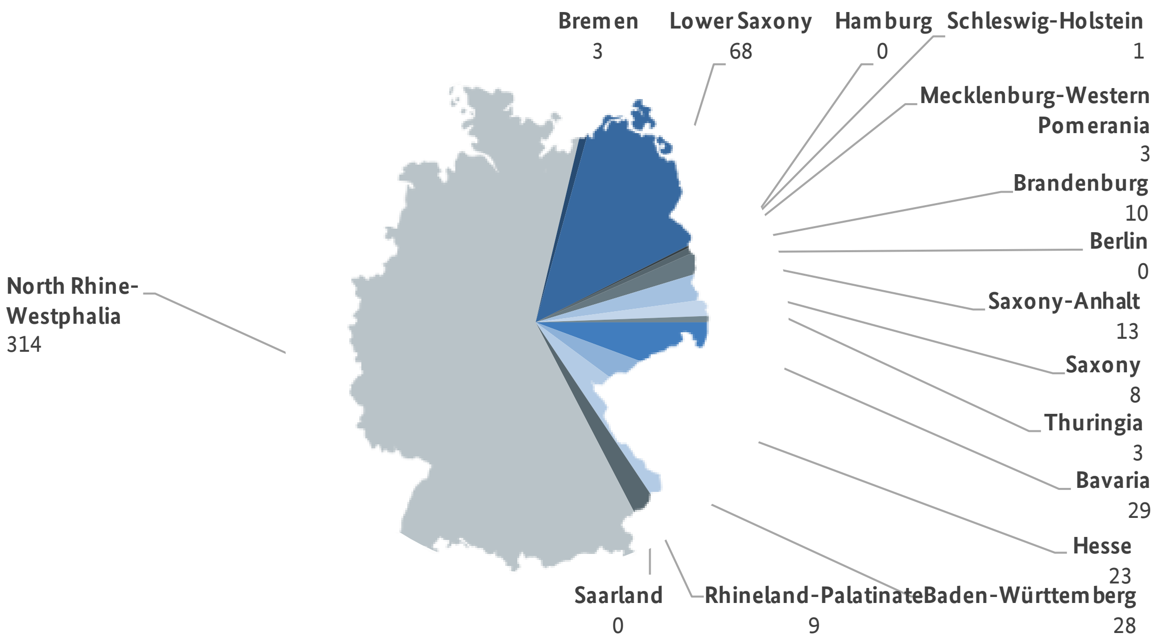

Figure 150: Market locations by federal state at TSO level as stated in the TSO survey as at 31 December 2021

Structure of the gas retail market

The structure of the gas retail market remained for the most part unchanged. There are a total of around 6,200 entry points to the gas distribution networks, of which 231 are for emergency entry only. A look at the number of market locations served by the DSOs shows that only 29 DSOs supply more than 100,000 each (2020: 28). Out of a total of 14.6mn market locations supplied by the DSOs in Germany, some 47% (6.9mn), accounting for just over 48% (385.6 TWh) of the total gas supplies, are served by DSOs that supply more than 100,000 customers. The majority (around 54%) of DSOs active in Germany supply between 1,000 and 10,000 gas customers.

Gas: DSOs by number of market locations supplied in 2021
(number and share)

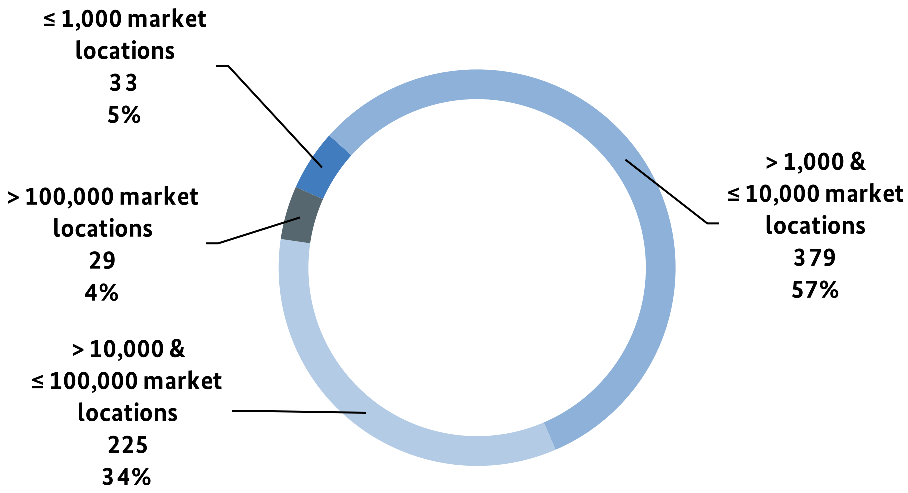

Figure 151: DSOs by number of market locations supplied (data from the gas DSO survey) as at 31 December 2021

4. 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.

4.1 Underground natural gas storage facilities

In its decisional 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.[137] 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.[138] The Haidach and 7Fields storage facilities in Austria are fully included in the following assessment to illustrate the concentration in the market for the operation of underground natural gas storage facilities. Data from 23 legal entities were collected. The Bundeskartellamt calculates the market shares in this market on the basis of storage capacities (maximum usable working gas volume).[139] Companies were attributed to a group according to the dominance method.

The market for the operation of underground natural gas storage facilities is still 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 291.3 TWh on 31 December 2021 (290.2 TWh in the previous year). On 31 December 2021, the aggregate working gas volume of the three companies with the largest storage capacities amounted to approx. 195 TWh (195.2 TWh in the previous year). The CR3 value was around 66.9% and was only slightly lower than in the previous year (CR3 value: 67.2%).

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[137] 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.

[138] Cf. COMP/M.6910 – Gazprom/Wintershall of 3 December 2013, paras. 30 ff.

[139] Cf. Bundeskartellamt, decision of 23 October 2014, B8-69/14 – EWE/VNG, paras. 236 ff.

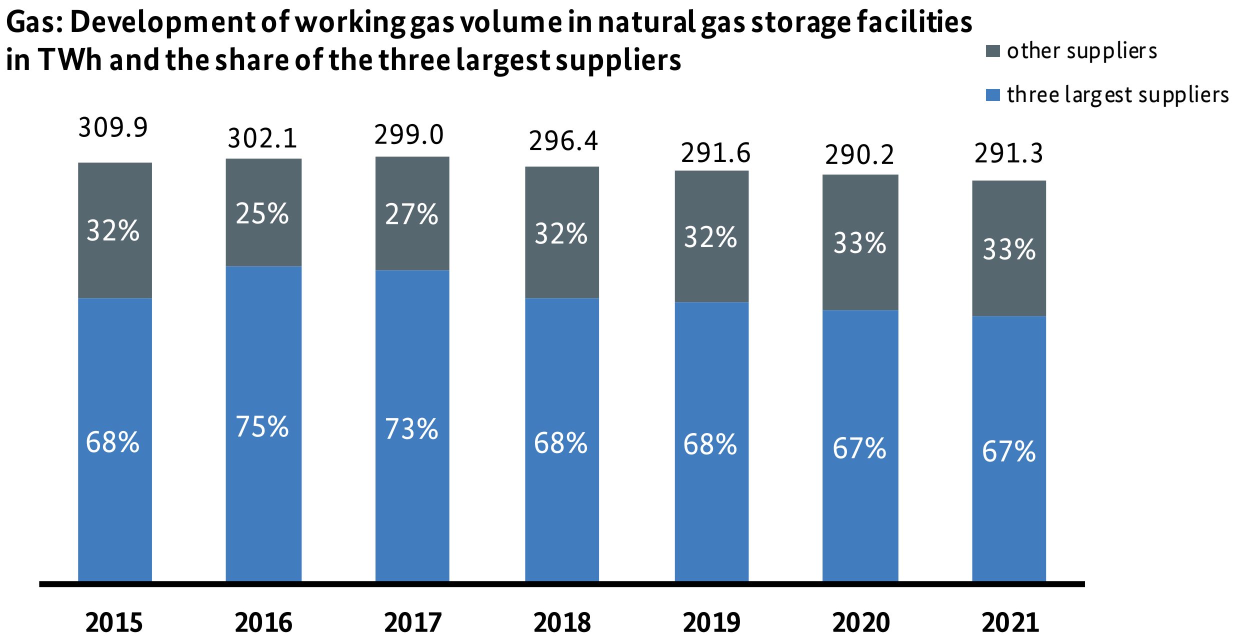

Figure 152: Development of the working gas volume of natural gas storage facilities and the share of volume of the three largest suppliers

4.2 Gas retail markets

On the gas retail markets the Bundeskartellamt differentiates between metered load profile 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 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 on the basis of special contracts as national markets (see section IA3.2). 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.[140]

In energy monitoring the sales volumes of the individual suppliers (legal entities) are collected as national total values[141]. 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 963 gas suppliers (legal entities) (952 in the previous year). In 2021 these companies sold a total of 402.7 TWh of gas to standard load profile customers in Germany (2020: 356 TWh) and 508.3 TWh of gas to metered load profile customers (2020: 493.5 TWh). Of the total volume of sales to standard load profile customers in 2021,

[140] Cf. Bundeskartellamt, decision of 23 December 2014, B8-69/14 – EWE/VNG, paras. 129-214.

[141] 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.

special contracts accounted for approx. 349 TWh (2020: 307.5 TWh) and default supply contracts for 53.7 TWh (2020: 48.5 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 homogeneous and ongoing calculation basis (cf. methodological notes in section IA3).

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 102.7 TWh in 2021, of which approx. 90.4 TWh were accounted for by special contracts. Cumulative sales to metered load profile customers were around 123.9 TWh. The aggregate market share of the four strongest companies in 2021 was 26% for standard load profile customers (CR4: 26% in the previous year) and 24% for metered load profile customers (CR4: 28% in the previous year). Both market shares continue to be significantly below the statutory thresholds for the presumption of market dominance (Section 18(6) GWB). The market concentration in relation to the four strongest companies decreased by 4% in the reporting year only with regard to the gas supply to metered load profile customers. It did not change in relation to standard load profile customers.[142]

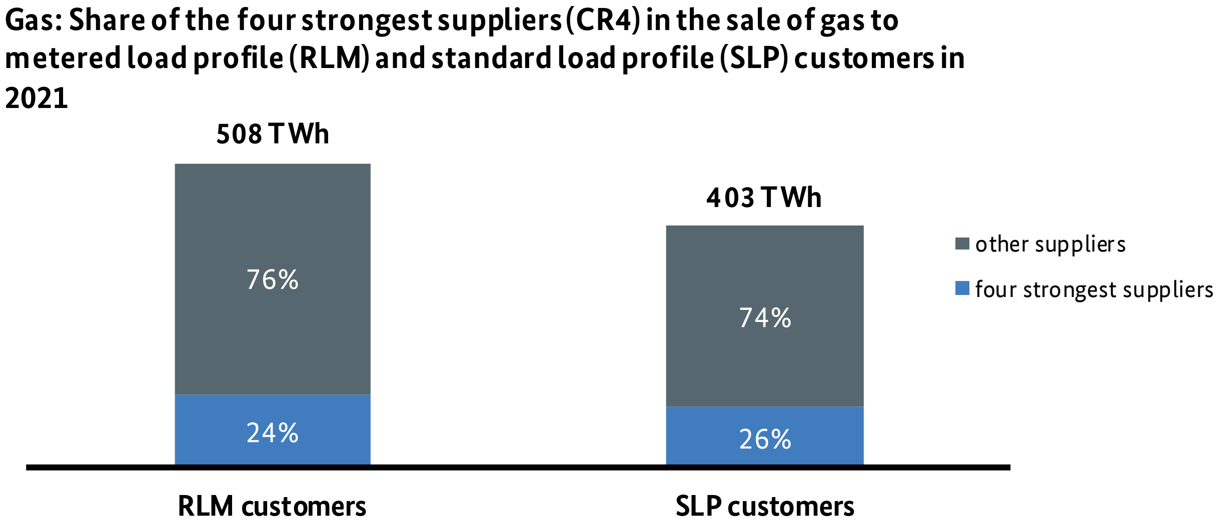

Figure 153: Share of the four strongest suppliers (CR4) in the sale of gas to metered load profile customers and standard load profile customers in 2021

[142] 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 entire market. The percentages consequently merely approximate the actual values.

B Gas supplies

1. Production of natural gas in Germany

In 2021, natural gas production in Germany amounted to 5.1bn m³ of gas (with calorific adjustment).[143] This is about the same as in the previous year.[144]

The reserves-to-production ratio of proven and probable natural gas reserves was 7.4 years as at 1 January 2022. 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.[145]

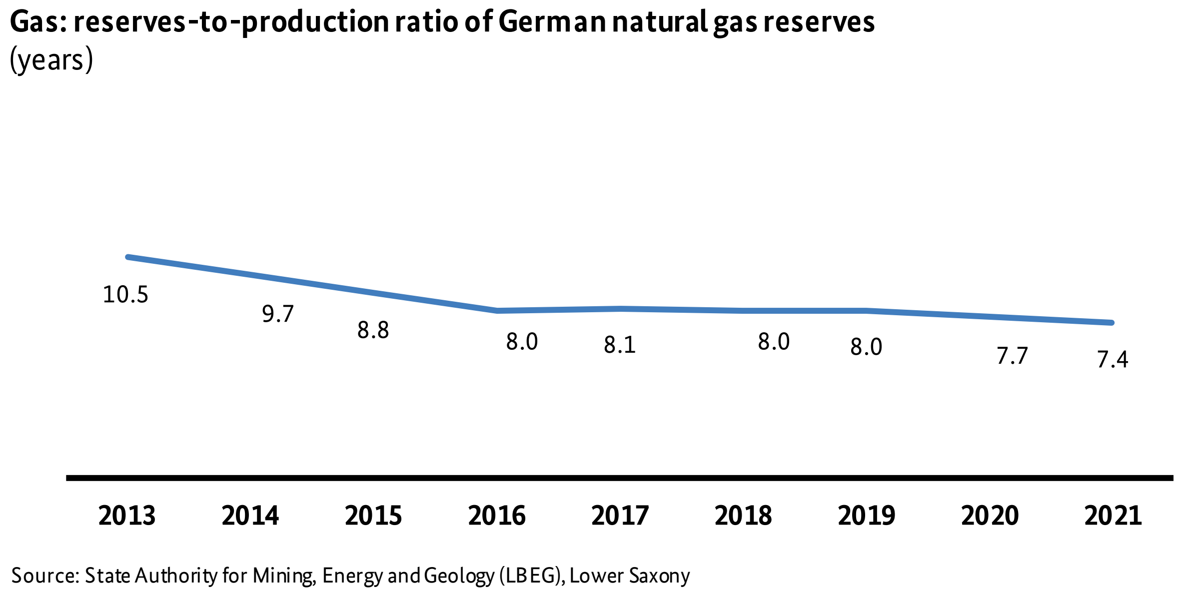

Figure 154: Reserves-to-production ratio of German natural gas reserves since 2012

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143 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).

144 Source: Annual report "Erdöl- und Erdgasreserven in der Bundesrepublik Deutschland am 1. Januar 2022" [Crude Oil and Natural Gas Reserves in the Federal Republic of Germany as at 1 January 2022]; State Authority for Mining, Energy and Geology (LBEG), Lower Saxony.

145 See previous footnote.

2. Natural gas imports and exports

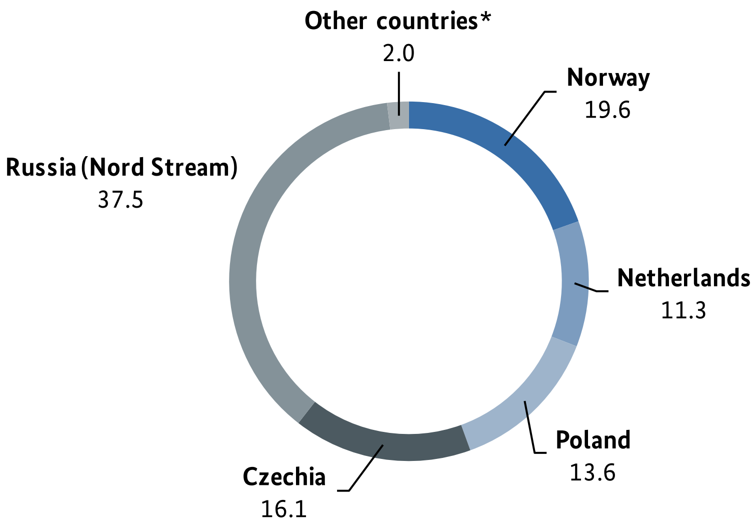
The monitoring report bases its assessment of imports and exports on the physical gas flows that enter and exit Germany at cross-border interconnection points, reported daily by the TSOs to the Bundesnetzagentur. It is possible that, because of the infrastructure in place, recorded import and export 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). For the first time, the export volumes at the Brandov cross-border interconnection point were deducted to avoid the transit volumes – the volumes imported via the Nord Stream 1 pipeline and the Greifswald cross-border interconnection point – being counted twice at the Waidhaus cross-border interconnection point.

The total volume of natural gas imported into Germany in 2021 was 1,458 TWh. Imports to Germany were thus down by 24 TWh or around 2% from the previous year's figure of 1,482 TWh.

The main sources of gas imports to Germany in 2021 were Russia and Norway. However, the Netherlands, as an established and liquid European producer, trading hub and point of arrival for LNG shipments with connections to natural gas fields in Norway and the United Kingdom, is also a significant source of imports for Germany. Improved integration of national markets and more efficient management of cross-border capacities have eased trading and provided further alternatives for gas traders.

The charts below provide an overview of the volumes of gas that were imported, divided into transfer countries and source countries.

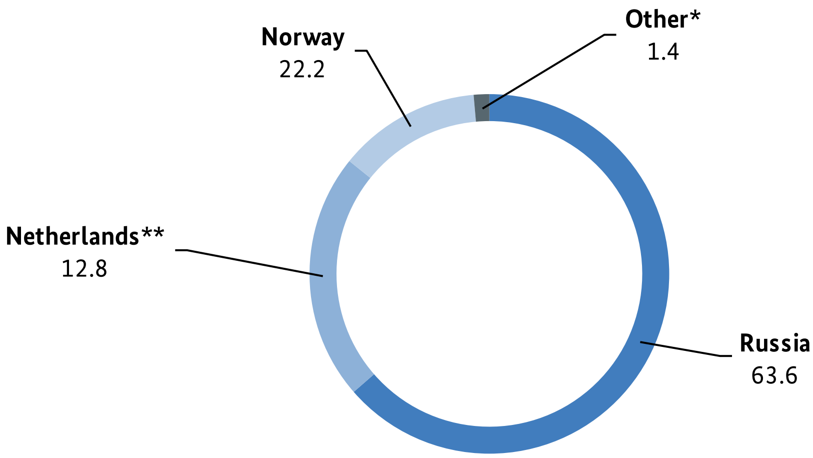
Gas: volumes imported to Germany (physical flows) in 2021 - broken down by transfer country
(%)



* Other countries: Belgium, Denmark, Austria, Switzerland

Figure 155: Gas volumes imported to Germany in 2021 by transfer country

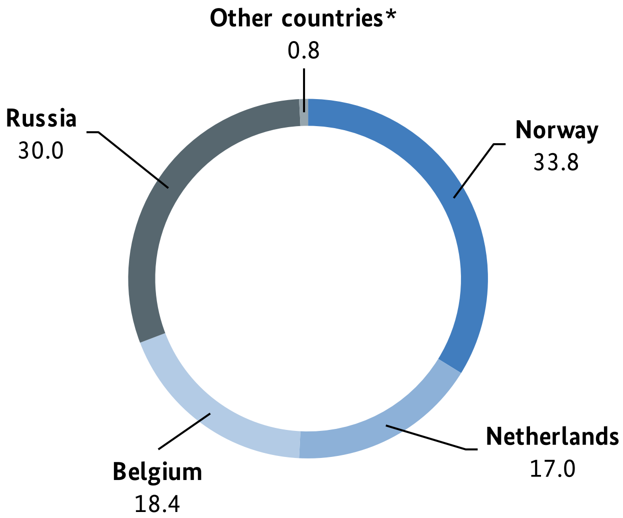
Gas: volumes imported to Germany (physical flows) in 2021 - broken down by source country
(%)



* Other countries: Belgium, Switzerland
** includes gas from UK

Figure 156: Gas volumes imported to Germany in 2021 by source country

Gas: volumes imported to Germany (physical flows) from January to October 2022 - broken down by source country
(%)

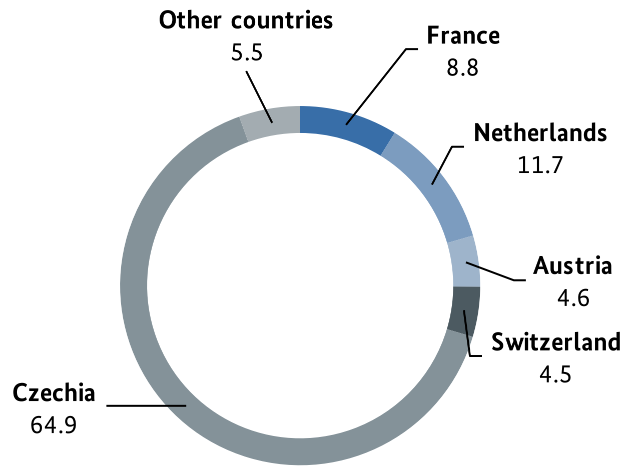


* Other countries: Denmark, Switzerland, France

Figure 157: Gas volumes imported to Germany in the period from January to October 2022 by source country

In 2021, the total volume of natural gas exported by Germany was 749 TWh. Based on the previous year's figure of 814 TWh, exports from Germany fell by 65 TWh. When looking at the destination countries, the focus here is on the countries that Germany exports to at their respective cross-border interconnection point.

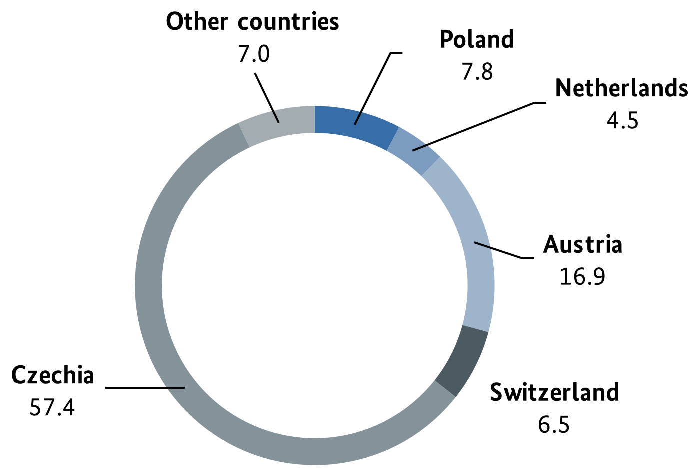
Gas: volumes exported from Germany (physical flows) in 2021 - broken down by importing country
(%)



* Other countries: Belgium, Denmark, Luxembourg, Poland

Figure 158: Gas volumes exported from Germany in 2021 by importing country

Gas: volumes exported from Germany (physical flows) from January to October 2022 - broken down by importing country
(%)



* Other countres: Belgium, Denmark, Luxembourg, France

Figure 159: Gas volumes exported from Germany in the period from January to October 2022 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 transferring to Germany, giving a picture of the changes that took place over the years.

Gas: changes in imports (physical flows)

Transfer country	Imports 2021 (TWh)	Imports 2020 (TWh)	Year-on-year change (TWh)	Year-on-year change (%)
Russia (Nord Stream)	425.2	429.8	-4.6	-1.1
Poland	224.3	263.4	-39.1	-14.8
Norway	323.7	349.1	-25.4	-7.3
Netherlands	186.9	194.3	-7.4	-3.8
Czechia	265.8	228.6	37.2	16.3
Austria	11.8	7.8	4.0	51.3
Belgium	19.8	9.6	10.2	106.3
Denmark	0.0	0.0	0.0	0.0
Total	1,458.0	1,482.6	-24.6	-1.7

Table 123: Changes in gas imports between 2021 and 2020[146]

Gas: changes in imports (physical flows) from January to October 2021/2022 by source country

Source country	Imports 2022 (TWh)	Imports 2021 (TWh)	Year-on-year change (TWh)	Year-on-year change (%)
Russia	348.6	798.0	-449.4	-56.3
Norway	392.5	252.8	139.7	55.3
Netherlands	196.8	147.9	48.9	33.1
Belgium	213.6	14.3	199.3	1393.7
Switzerland	9.6	0.3	9.3	3100.0
Denmark	0.0	0.0	0.0	0.0
Total	1,161.1	1,213.3	-52.2	-4.3

Table 124: Changes in gas imports in the period from January to October 2021 and 2022

[146] The figures for 2020 have been adjusted for this report in line with the latest calculation methodology and are therefore not comparable with those in the Monitoring Report 2021. For the first time, the export volumes at the Brandov cross-border interconnection point were deducted to avoid the transit volumes – the volumes imported via the Nord Stream 1 pipeline and the Greifswald cross-border interconnection point – being counted twice at the Waidhaus cross-border interconnection point.

Gas: changes in exports (physical flows)

Importing country	Exports 2021 (TWh)	Exports 2020 (TWh)	Year-on-year change (TWh)	Year-on-year change (%)
Czechia	486.5	464.0	22.5	4.9
Netherlands	87.7	131.3	-43.6	-33.2
Switzerland	33.6	61.3	-27.7	-45.2
Austria	34.2	68.4	-34.2	-50.0
France	66.1	44.3	21.8	49.1
Belgium	5.5	7.1	-1.6	-22.6
Poland	7.0	8.2	-1.2	-15.1
Luxembourg	1.8	1.8	0.0	0.8
Denmark	26.7	27.6	-0.9	-3.3
Total	749.2	814.1	-65.0	-8.0

Table 125: Changes in gas exports between 2021 and 2020

Gas: changes in exports (physical flows) from January to October by importing country

Importing country	Exports 2022 (TWh)	Export 2021 (TWh)	Year-on-year change (TWh)	Year-on-year change (%)
Czechia	273.0	420.6	-147.6	-35.1
Netherlands	21.5	73.8	-52.3	-70.9
Switzerland	30.8	25.0	5.8	23.2
Austria	80.4	30.1	50.3	167.1
France	13.4	55.3	-41.9	-75.8
Belgium	0.0	5.5	-5.5	-100.0
Poland	37.0	4.5	32.5	722.2
Luxembourg	0.0	1.6	-1.6	-100.0
Denmark	19.8	21.3	-1.5	-7.0
Total	426.6	637.7	-211.1	-33.1

Table 126: Changes in gas exports in the period from January to October 2021 and 2022

Gas volumes imported to Germany (physical flows) from January to October 2022 by transfer country (TWh and %)

	Russia (Nord Stream)		Norway		Netherlands		Belgium		Czechia		Other	
	TWh	%	TWh	%	TWh	%	TWh	%	TWh	%	TWh	%
January	34.0	26.8	40.9	29.8	20.9	14.2	10.8	13.7	20.1	15.8	0.2	0.1
February	32.5	27.2	36.9	31.0	17.2	14.4	14.4	12.1	18.1	15.2	0.2	0.2
March	35.2	26.6	38.6	29.2	18.3	13.9	16.4	12.4	20.2	15.3	3.5	2.6
April	35.5	25.1	41.2	29.2	20.0	14.2	23.9	16.9	19.9	14.1	0.6	0.5
May	37.1	29.2	34.4	27.1	15.2	11.9	23.3	18.3	16.2	12.8	0.8	0.7
June	44.9	34.4	34.2	26.1	14.5	11.1	24.4	18.6	12.0	9.3	0.9	0.7
July	17.3	15.9	40.9	37.6	15.8	14.4	30.7	28.1	4.3	4.0	0.0	0.0
August	14.5	13.5	42.7	39.8	12.7	11.8	32.2	30.1	4.2	3.9	0.9	0.9
September	0.0	0.0	37.4	46.0	15.1	18.6	24.6	30.3	0.0	0.0	3.1	3.8
October	0.0	0.0	45.1	47.1	22.2	23.2	25.3	26.4	0.0	0.0	2.5	2.6

Table 127: Gas volumes imported to Germany in the period from January to October 2022

Gas volumes imported to Germany (physical flows) from January to October 2022 by source country (TWh and %)

	Russia		Norway		Netherlands		Belgium		Other	
	TWh	%	TWh	%	TWh	%	TWh	%	TWh	%
January	54.1	42.7	40.9	29.8	20.9	14.2	10.8	13.7	0.2	0.1
February	50.8	42.6	36.9	31.0	17.2	14.4	14.4	12.1	0.2	0.2
March	58.1	44.0	38.6	29.2	18.3	13.9	16.4	12.4	3.5	2.6
April	55.5	39.3	41.2	29.2	20.0	14.2	23.9	16.9	0.6	0.5
May	53.4	42.0	34.4	27.1	15.2	11.9	23.3	18.3	0.8	0.7
June	56.9	43.5	34.2	26.1	14.5	11.2	24.4	18.8	0.9	0.7
July	21.6	19.9	40.9	37.6	15.8	14.4	30.7	28.1	0.0	0.0
August	18.7	17.5	42.7	39.8	12.7	11.8	32.2	30.1	0.9	0.9
September	0.0	0.0	37.4	46.0	15.1	18.6	24.6	30.3	4.0	5.0
October	0.0	0.0	45.1	47.1	22.2	23.2	25.3	26.4	3.2	3.3

Table 128: Gas volumes imported to Germany in the period from January to October 2022 by source country

Gas volumes exported from Germany (physical flows) from January to October 2022 (TWh and %)

	Czechia		Poland		Austria		Switzerland		Netherlands		France	
	TWh	%	TWh	%	TWh	%	TWh	%	TWh	%	TWh	%
January	36.0	57.2	7.1	11.3	7.0	11.1	6.1	9.7	2.7	4.3	1.7	2.7
February	32.3	61.7	1.9	3.6	7.4	14.1	4.9	9.3	1.9	3.6	2.7	5.2
March	40.1	67.0	1.6	2.7	7.7	12.8	1.8	3.0	4.4	7.4	2.6	4.3
April	39.0	64.2	5.2	8.5	8.6	14.1	2.2	3.6	2.0	3.2	1.6	2.7
May	38.5	59.6	7.3	11.3	9.6	14.9	3.0	4.7	1.7	2.6	1.1	1.6
June	32.0	60.8	2.8	5.4	9.3	17.7	2.6	4.8	1.7	3.2	1.7	3.2
July	19.0	42.2	3.0	6.7	9.5	21.2	8.4	18.7	2.1	4.7	1.2	2.7
August	14.3	50.1	3.5	12.2	7.3	25.6	0.0	0.0	1.5	5.4	0.7	2.4
September	9.3	44.6	2.2	10.6	6.2	29.6	0.0	0.0	2.4	11.7	0.0	0.0
October	12.6	43.9	2.4	8.2	7.8	27.2	1.8	6.4	1.2	4.1	0.1	0.2

Table 129: Gas volumes exported from Germany in the period from January to October 2022

Gas: imports to and exports from Germany from January to October 2022
(TWh)

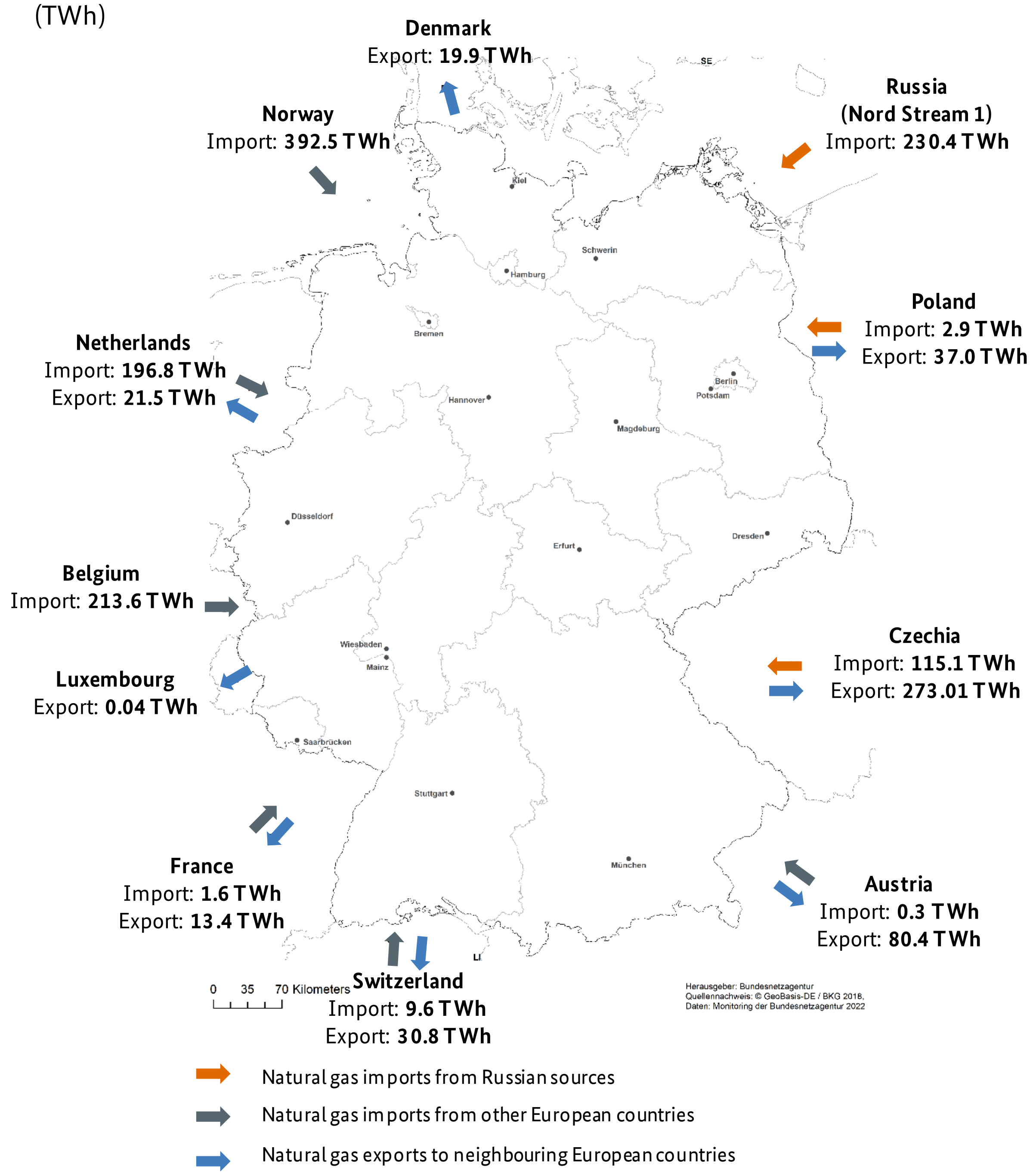


Figure 160: Gas flows to and from Germany in the period from January to October 2022

Nord Stream 2 certification procedure

On 16 November 2021, the Bundesnetzagentur temporarily halted the certification of the Nord Stream 2 pipeline on grounds of the unbundling requirements of an independent transmission operator. On 22 February 2022 the Federal Ministry for Economic Affairs and Climate Action (BMWK) withdrew from the Bundesnetzagentur the existing report analysing the security of supply, which brought the certification of Nord Stream 2 to an end.

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 2022 this charge amounted to €0.7335 kWh/h/a. In 2023 it will increase to €0.7547 kWh/h/a due to the increase in the number of appliances to be converted and the expected drop in the level of exit capacity likely to be booked or ordered in all networks in the country. 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**Fehler! Textmarke nicht definiert.** to high-calorific H-gas**Fehler! Textmarke nicht definiert.** coordinated by the TSOs, is a central issue for the 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 after 1 October 2029. The resulting scarcity of L-gas resources means that L-gas will largely disappear from the German gas market by 2030. This is why the companies responsible, namely the TSOs and affected DSOs, are taking the necessary steps to prevent the declining availability of L-gas from adversely affecting the security of supply. The new natural gas supply structure will affect more than four million household, commercial and industrial customers with an estimated 4.9mn 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 successfully 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 2022 and 2026, about 4,300 conversions will be carried out for interval-metered customers and about 2.1mn for standard load profile (SLP) customers.

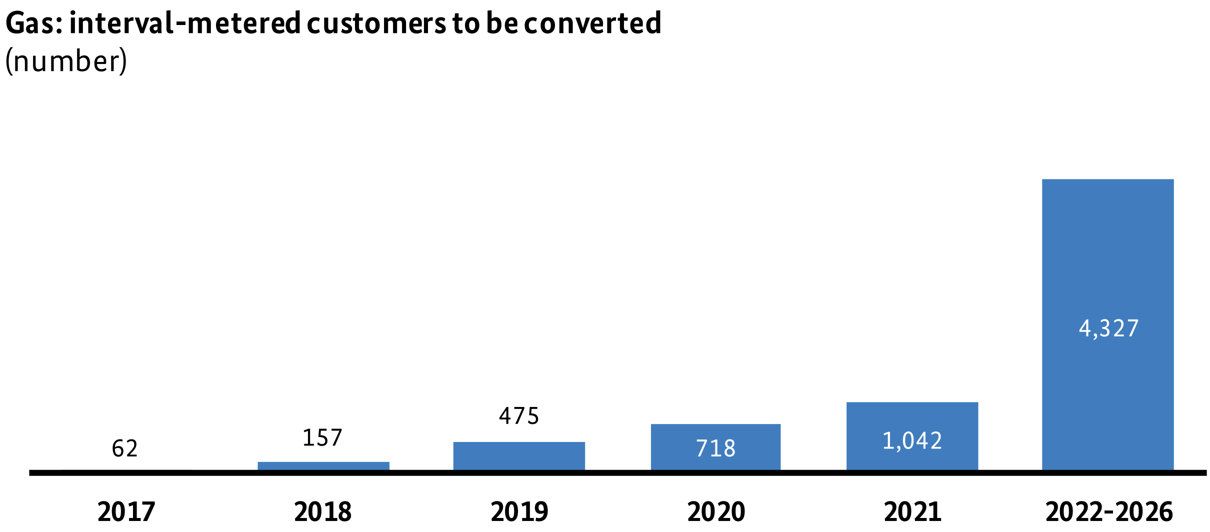


Figure 161: Interval-metered customers to be converted

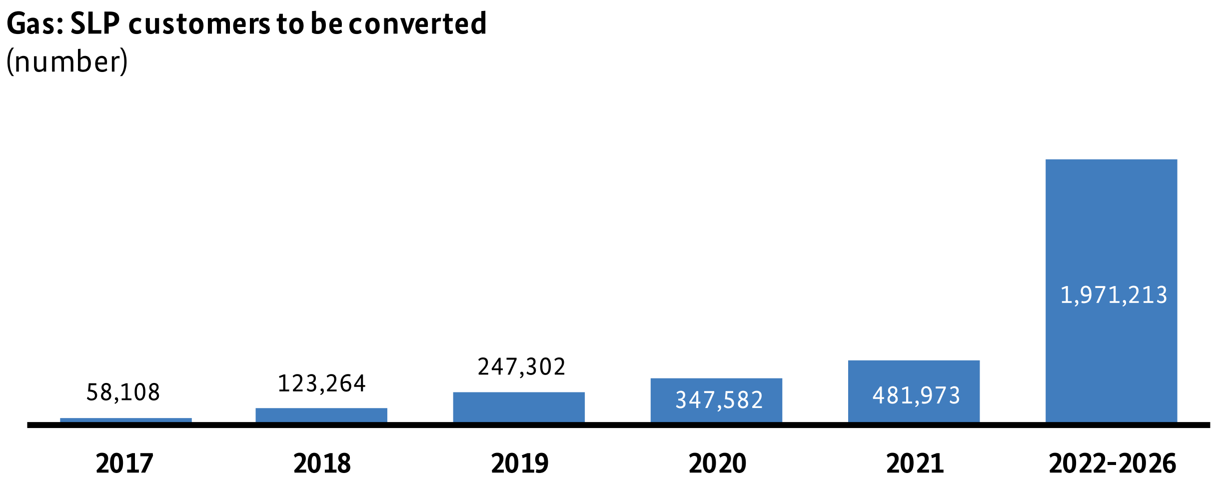


Figure 162: SLP customers to be converted

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 the appliances are inspected one more time to monitor quality. Just a few years ago, only one or two companies provided such services. After the market area conversion became official, an increasingly competitive market began developing that currently counts 43 active companies, up from 40 a year ago. There continued to be a high response rate to the calls for bids from the network operators to carry out this work in 2021.

Gas: bids and awards for task packages for the market area conversion

Task packages	Bids			Awards		
	2019	2020	2021	2019	2020	2021
Appliance registration	7.3	9.4	8.5	3.3	3.6	3.4
Monitoring registration process	4.0	5.3	5.0	1.0	1.1	1.0
Conversion and adjustments	7.3	9.2	8.4	3.3	3.5	3.3
Inspection of conversions and adjustments	4.5	5.6	5.0	1.0	1.1	1.0
Project management	3.8	4.3	4.0	1.0	1.0	1.0

Table 130: Bids and awards for task packages for the market area conversion

From a total of 37 network operators, 565,410 appliances were registered in 2021, of which 257,696 were condensing boilers (45.6%) and 63,909 self-adaptive appliances (11.3%). The proportion of condensing boilers had been 43.2% in 2020 and that of self-adaptive appliances 10.7%. During the reporting period, 481,989 appliances were adapted for SLP customers and 1,069 for interval-metered customers. A total of 8,146 appliances that were to be adapted could not be, a proportion of 1.7% (2020: 2.6%).

A total of 2,281 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 (2020: 1,866). There was a decrease in the number of customers making use of the reimbursement granted under the Gas Appliance Reimbursement Ordinance (GasGKErstV), 241 compared to 287 the year before.

The year 2021 was marked by the disastrous flooding in July that led to the loss of more than one hundred lives and huge damage to property. The flooding also affected areas in which market area conversion work was in progress. The market area conversion was still affected by the coronavirus pandemic in early 2022. As in the previous year, people working from home and travelling less actually facilitated the conversion process. Almost all network operators and companies carrying out adjustments reported that it was easier to make contact with customers for the conversions. The market area conversion was overshadowed by the war in Ukraine, which created uncertainty among many customers regarding the conversion to H-gas. This uncertainty was resolved with the help of transparent information from the network operators and companies carrying out the adjustments. The market area conversion is consequently on schedule and making good progress.

4. Biogas (including synthesis gas)

As at 31 December 2021, key biogas injection figures within the meaning of section 3 para 10f EnWG were as follows:

Gas: biogas injection 2021 key figures

	Injection, contractually agreed (mn kWh/h)	Injection (mn kWh/a)	Number of plants
Biomethane	2.482	9,724.0	210
Hydrogen produced by water electrolysis provided that the electricity used to perform electrolysis is mainly and verifiably derived from renewable energy sources[1]	0.004	3.5	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	0.1	2
Other (gas from biomass, landfill gas, sewage treatment plant gas and mine gas)	0.021	414.0	14
Total	2.548	10,141.5	233

[1] within the meaning of Directive 2009/28/EC (OJ L 140 of 5 June 2009, page 16)

Table 131: Biogas injection key figures for 2021

The costs for biogas passed on by gas network operators to all network users amounted to about €192mn in 2021. That was the equivalent of about €0.0191 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 natural gas storage facilities

Twenty-four companies operating and marketing a total of 34 underground natural gas storage facilities took part in the 2022 monitoring survey. On 31 December 2021 the maximum usable working gas volume in the storage facilities was 278.51 TWh.147 Of this, 137.02 TWh was accounted for by cavern storage, 119.90 TWh by pore storage and 21.59 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 (255.07 TWh, compared to 23.44 TWh for L-gas).

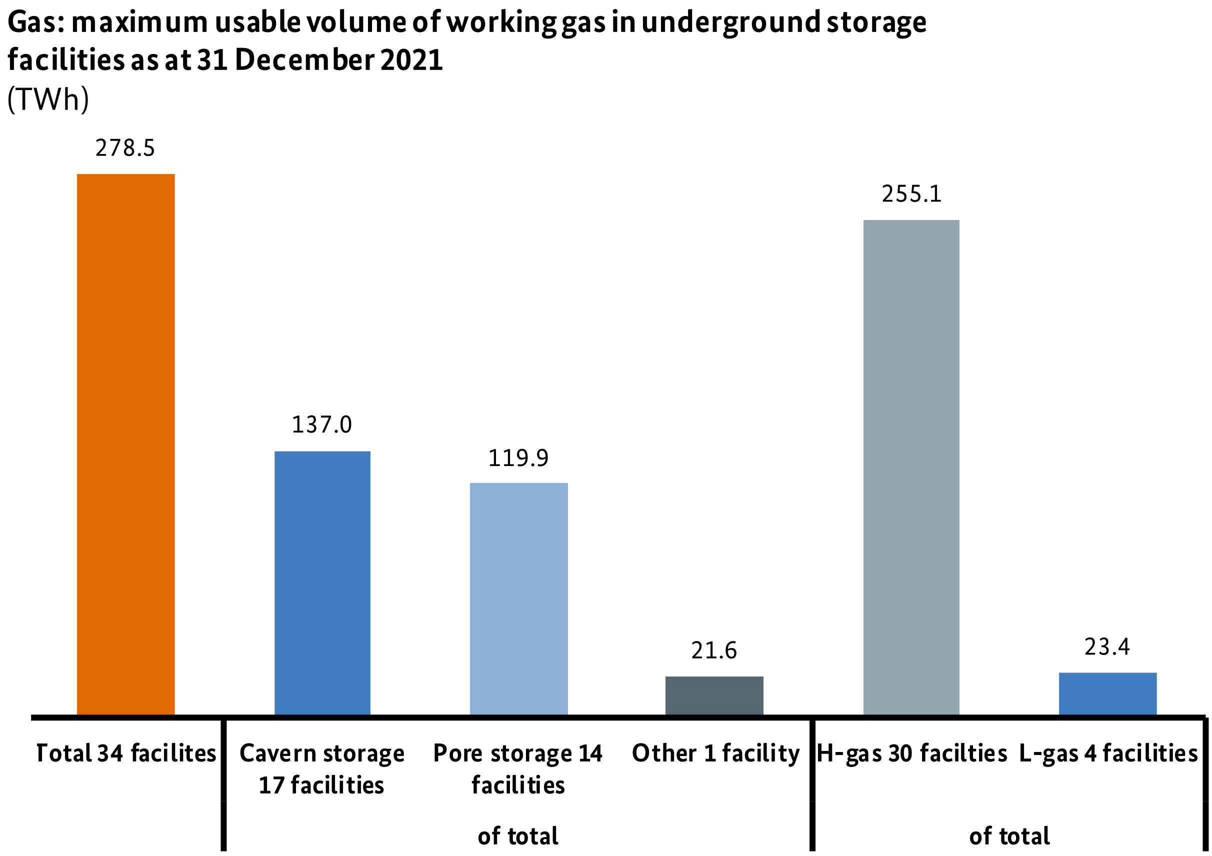


Figure 163: Maximum usable volume of working gas in underground natural gas storage facilities as at 31 December 2021

[147] 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.

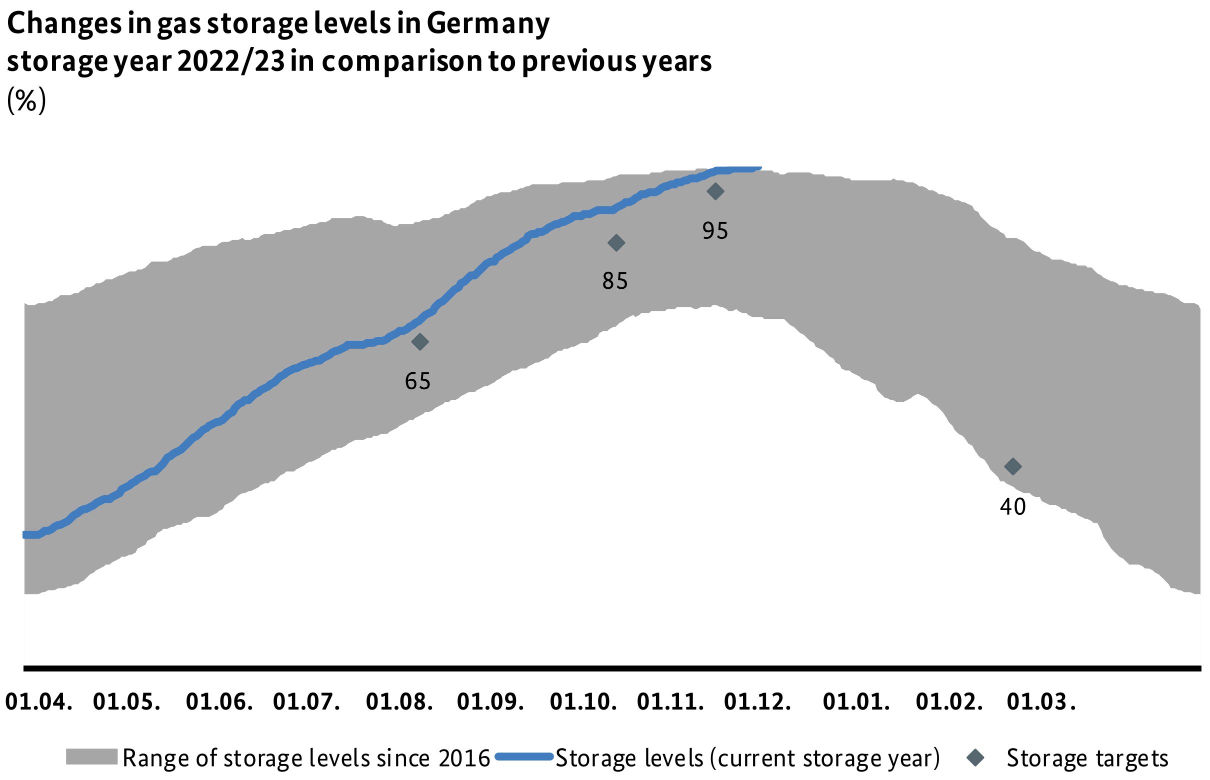


Figure 164: Changes in gas storage inventory levels in Germany – as at 20 November 2022

5.2 Use of underground storage facilities – customer trends

Of the 24 storage facility operators, 22 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 60% of storage volume (around 166.7 TWh) of the 22 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 156.3 TWh in total). According to the data provided by 24 companies, the average number of storage customers in 2021 was 6.1 (2020: 6.5). 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 customers	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	8	7	9	8	10	11	9	10	11	9	11
2	2	3	3	4	2	2	2	4	2	3	2
3 - 9	6	7	7	5	4	6	6	4	6	4	4
10 - 15	1	2	2	3	3	1	3	4	3	3	2
16 - 20	1	1	2	1	1	2	3	2	1	2	1
> 20	1	1	1	2	2	2	0	0	1	2	4

Table 132: Changes in the number of customers per storage facility operator over the years

5.3 Capacity trends

The following chart shows the volume of bookable, available working gas in underground natural gas storage as at 31 December 2021 compared to the previous years.

Gas: changes in the freely bookable working capacity, as offered on 31 December, in the subsequent periods from 2017 to 2021
in TWh

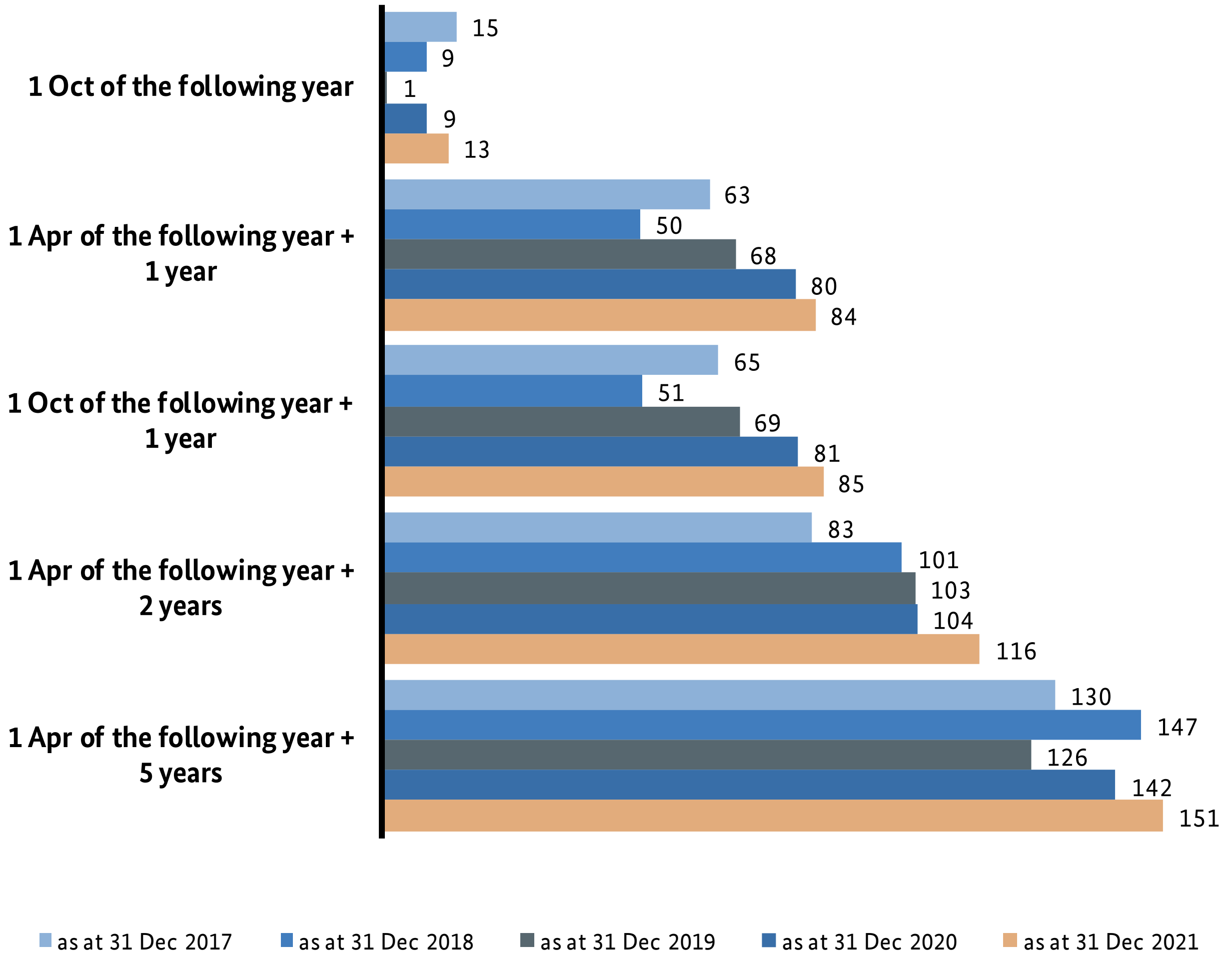


Figure 165: Changes in the freely bookable working gas capacity in the subsequent periods

The freely bookable working gas volume rose in all periods under review in 2021.

C Networks

1. Network expansion – 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 measures 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. The Gas NDP identifies pipelines that can be removed from the natural gas network and can be considered for conversion to hydrogen. Section 113b EnWG also permits the construction of new natural gas infrastructure on a small scale.

The Bundesnetzagentur confirmed the scenario framework for the Gas Network Development Plan 2022-2032, with amendments, on 20 January 2022. The draft Network Development Plan was originally meant to be submitted to the Bundesnetzagentur on 1 July 2022. Due to the Russian invasion of Ukraine, the subsequent suspension of Russian gas deliveries to Germany and the policy objective of constructing LNG facilities in Germany, the original schedule was changed. The Bundesnetzagentur and the TSOs agreed to deviate from the usual NDP process and to publish the Network Development Plan in two parts because the substitution of Russian gas imports gave rise to further network calculations within the TSOs' network development planning, the results of which have not yet been determined. The consultation document produced following the interim status is being presented by the TSOs for consultation with the public and the market. The draft document for the Gas NDP 2022-2032 will then be published after the comments have been taken into account. The Bundesnetzagentur can subsequently request changes to the draft in the request for amendment.

The interim status of the Gas NDP 2022-2032 is based on the conditions on the entry and exit side before the outbreak of the war in Ukraine. Furthermore, the interim status already includes LNG security of supply variants in order to take account of the diversification of supply sources via new LNG facilities to be built and the partial replacement of quantities of natural gas from Russia. The forthcoming consultation document on the Gas NDP 2022-2032 includes further security of supply variants ("LNGplus") that are geared towards completely replacing Russian natural gas.

The results of the baseline variant and the security of supply variants range from 870–961 km of new pipelines and 194–251 MW of compressor capacity as a consequence of additional construction or necessary reversal in order to increase the flexibility of potential transport routes so that natural gas can also be transported in the opposite direction to the main direction of flow if the need arises. The planned costs associated with the development of the various scenarios amount to €3.9–4.6bn in total by the end of 2032. In contrast with the description from previous years, the total investments do not include any "start network measures". Start network measures are defined as measures whose implementation is so far advanced that changes to the project are no longer reasonably possible. These measures are therefore not a result of network modelling. Of the total investment costs, roughly €2bn is attributable to network expansion measures from previous network development plans (not including LNG), €1.5–2.4bn to measures for transporting LNG volumes via the transmission networks, and €0.4bn to new network expansion measures from the submitted Gas Network Development Plan 2022-2032.

The interim status of the Gas NDP 2022-2032 also includes a hydrogen variant. The demand reports from the market survey have risen significantly in comparison with the last NDP. The TSOs were able to conclude a Memorandum of Understanding with more than 250 project sponsors for transport demand of 165 TWh.

For the first time the hydrogen variant was also modelled with other potential hydrogen network operators, as well as the TSOs. For 2027 this results in three relatively large regional subnetworks in the north, north-west and east, which together have a pipeline length of up to 3,000 km. For the modelling year 2032 there is a contiguous German hydrogen network with a pipeline length of up to 8,500 km (of which pipelines to be converted account for up to 5,900 km and newly constructed pipelines up to 2,900 km). The networks presented for the modelling years are based on Memoranda of Understanding concluded between TSOs and project developers, pipeline reports (TSOs and third parties) and the previous results of the Gas NDP 2020-2030; consequently the routes are suitable.

Due to the dynamic state of the gas market, it is not possible at the present time for the TSOs to give a final assessment of which pipelines actually need to be built or converted. Accordingly, it was therefore not possible either to identify any natural gas reinforcing measures in the course of planned conversion, as had been the case in the previous Gas NDP 2020-2030. The specified total costs of €8-10bn by the end of 2032 must thus also be considered merely indicative.

All measures envisaged in the Gas NDP 2020-2030 continue to be necessary for the development of the hydrogen network and remain unchanged.

Umsetzungsstand der Grüngasvariante 2030

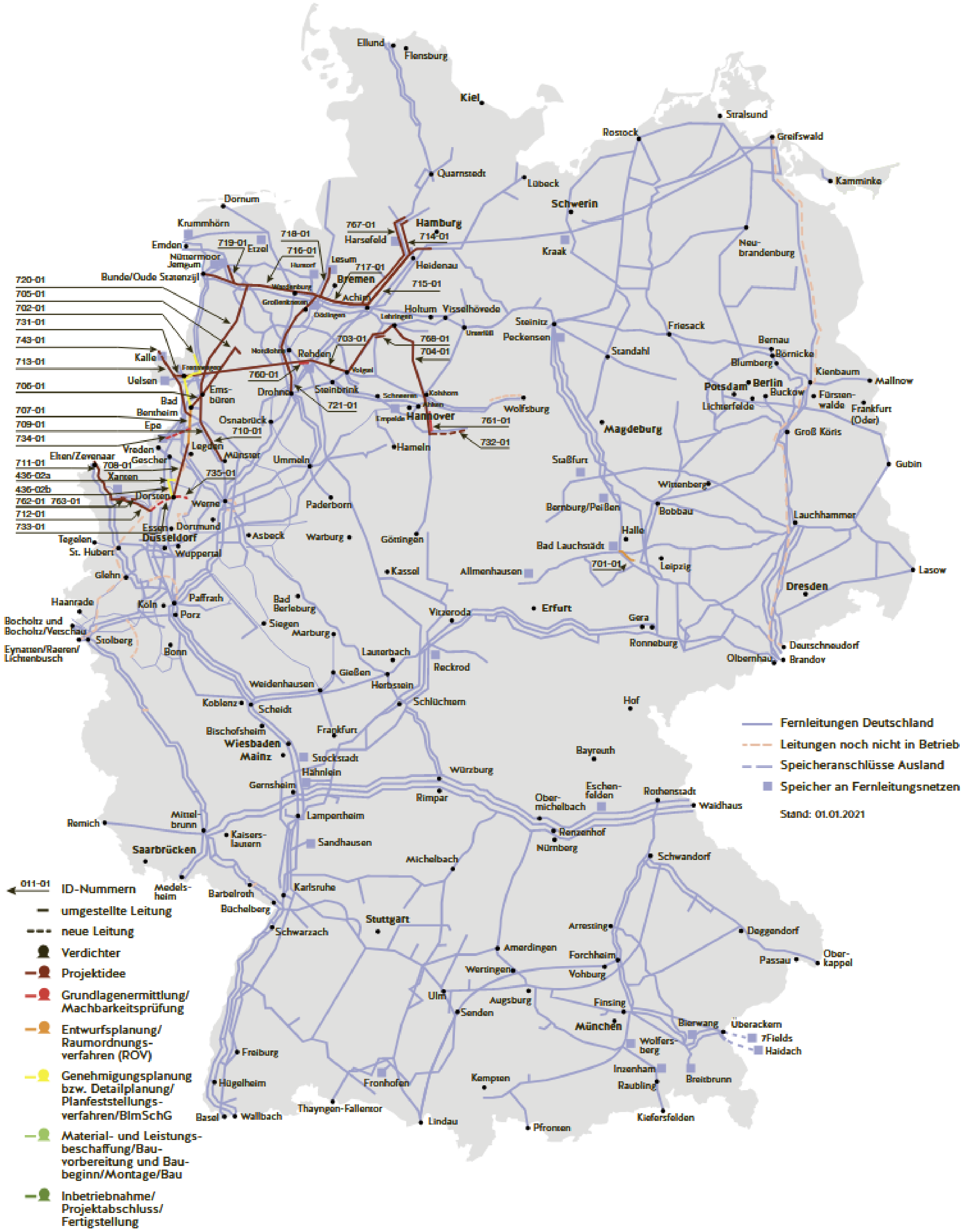


Figure 166: Implementation status of the hydrogen measures for the Gas Network Development Plan 2020-2030

2. Investments

Investments as defined in the monitoring survey are considered to be gross additions to fixed assets capitalised in 2021 and the value of new fixed assets newly rented and hired in 2021. 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 Gas Network Tariffs Ordinance and Incentive Regulation Ordinance (GasNEV and ARegV).

2.1 Investments and expenditure by TSOs

In 2021 the 16 German TSOs invested a total of €679mn (2020: €995mn) in network infrastructure. Of this total, €420mn (2020: €638mn) was investment in new installations, expansion and extension and €259mn (2020: €357mn) investment in maintenance and renewal of network infrastructure. The investments planned for 2022 amount to a total of €659mn, as a result of which the investment level would remain at an almost constant level with a slight decline of 3%. The relatively large fluctuations in investment expenditure in network infrastructure in the past were a consequence of capital-intensive investment in a few individual large-scale projects. Across all TSOs, expenditure on maintenance and repair of network infrastructure amounted to €358mn in 2021 (2020: €402mn). This figure is therefore below the total amount of expenditure from the previous year but within the usual fluctuation range. For 2022 the transmission system operators expect planned expenditure to amount to €385mn. The overall total for investments and expenditure in 2021 across all TSOs was approximately €1.04bn (2020: €1.40bn). The chart below shows investments and expenditure both separately and as a sum total since 2013, as well as the planned figures for 2022.

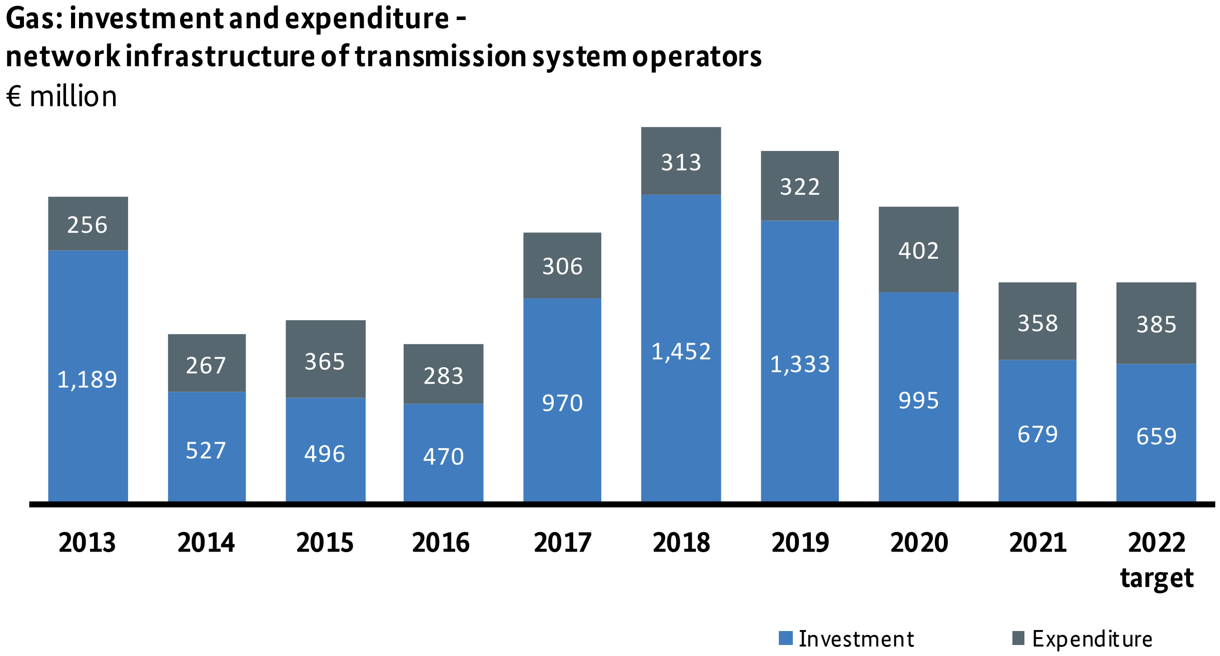


Figure 167: Investments in and expenditure on network infrastructure by TSOs

2.2 Investments in and expenditure on network infrastructure by gas DSOs

In the course of data collection for the Monitoring Report 2022, more than 600 of the surveyed gas DSOs declared investment in new installations, expansions and extensions (€1,101mn compared to €1,044mn in 2020) and maintenance and repair (€635mn compared to €631mn in 2020) of network infrastructure, totalling €1,736mn compared to €1,674mn in 2020. The projected total investment for 2022 is €1,732mn. According to the gas DSOs' reports, expenditure on maintenance and repair in 2021 was €1,204mn (2020: €1,365mn). The projected expenditure on maintenance and repair for 2022 is €1,189mn.

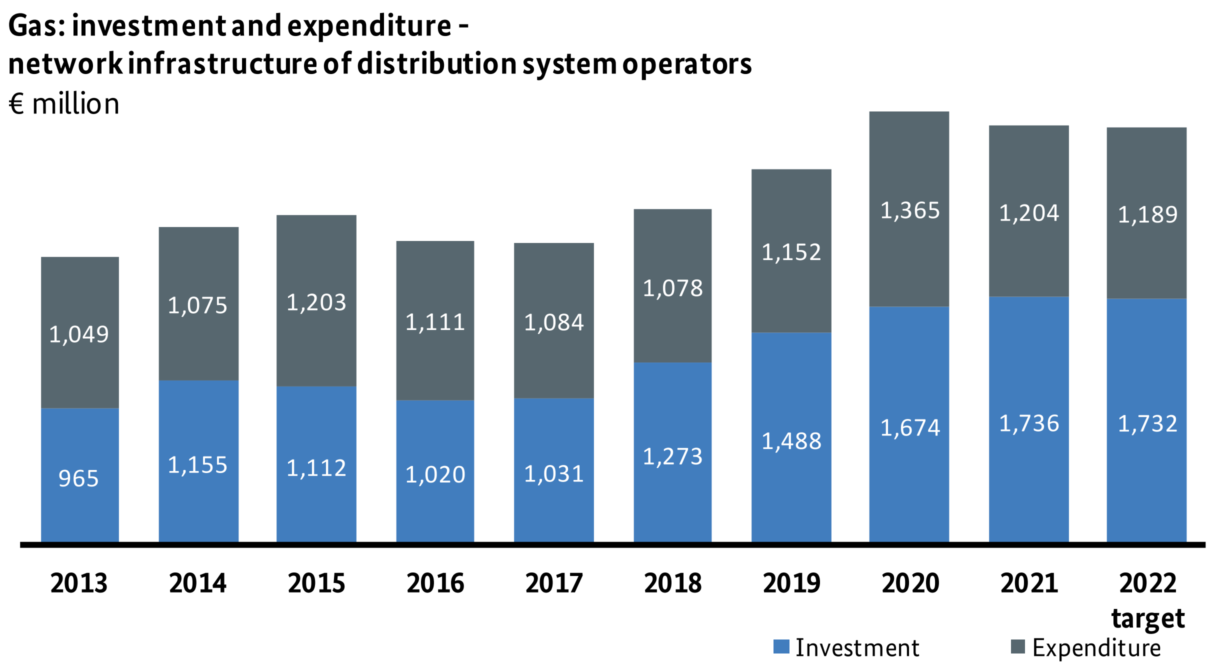


Figure 168: Progression of investments in and expenditure on network infrastructure by gas DSOs over time

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 160 of the surveyed gas DSOs reported investments of between €1mn and €5mn, 68 gas DSOs made investments totalling more than €5mn. Of the surveyed gas DSOs, 251 reported total expenditures in the bracket between €100,001 and €500,000, while 50 gas DSOs reported expenditures totalling more than €5mn.

Gas: DSOs broken down according to level of investment in 2021
Number and %

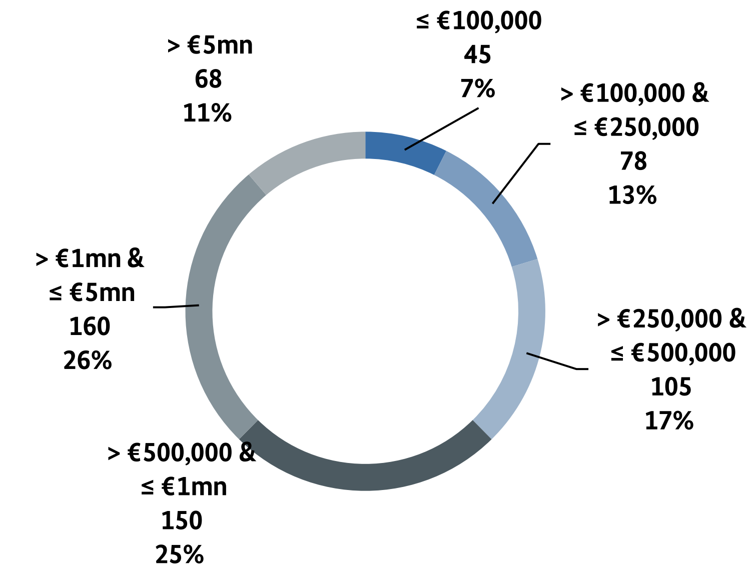


Figure 169: Distribution of gas DSOs according to level of investment in 2021

Gas: DSOs broken down according to level of expenditure in 2021
Number and %

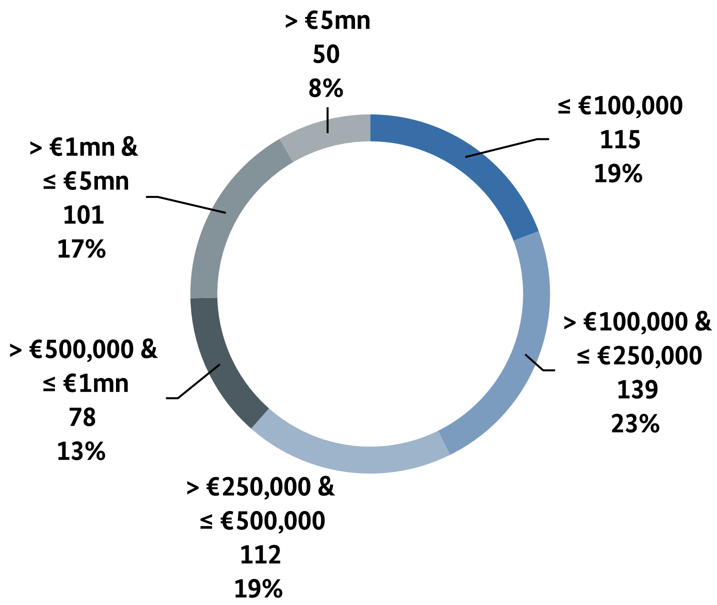


Figure 170: Distribution of gas DSOs according to level of expenditure in 2021

2.3 Investments and incentive-based regulation

2.3.1 Investment in network expansion by the TSOs

The Incentive Regulation Ordinance (ARegV) offers network operators an opportunity to budget for costs for expansion and restructuring investment in the network tariffs over and above the level in the approved revenue caps, on the basis of section 23 ARegV. Upon application from transmission system operators, the

Bundesnetzagentur granted approval for individual projects if the prerequisites stated in the Ordinance were met. The new provisions of the ARegV brought an end to this refinancing possibility for new investments, expiring on 31 July 2021 in accordance with section 35(3) sentence 1 ARegV. Accordingly, transmission system operators were able to place new applications for investment measures for the last time up until that date.

In derogation of this, for investment measures with a time limit of the end of the third regulatory period (31 December 2022) provision was made that applications for an extension of the approval period in accordance with section 35(3) sentence 2 para 1 ARegV were to be submitted no later than 30 June 2022 and a time limit of no later than the end of the fourth regulatory period (31 December 2027) can be set. Over and above this, in accordance with section 35(3) sentence 2 para 2 ARegV it is possible to submit applications to change the granted approval during the period of validity of the respective approval – at the latest up until the end of the fourth regulatory period (31 December 2027).

Once approval has been granted, the transmission system operators may adjust their revenue cap by the capital and operating costs 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.

In summary, the refinancing instrument of investment measures according to section 23 ARegV for expansion and restructuring investment in transmission networks will no longer be available as of the end of the fourth regulatory period on 31 December 2027.

2.3.2 Capex mark-up for TSOs and DSOs

The new instrument of capital expenditure adjustment (capex true-up) is being introduced for transmission system operators as of the start of the fourth regulatory period (1 January 2023). It has already been implemented for the gas distribution networks since the start of the third regulatory period. The capex true-up comprises the possible annual application for a capex mark-up and the corresponding annual capex deduction. As a result of the amendment of the ARegV (section 35 ARegV), the previous instrument of the investment measure is replaced by the annual capex true-up.

Since 2022, the transmission system operators have been able to place an application for a capex mark-up. It allows network operators to apply every year for an adjustment to the approved calendar-year revenue cap with respect to new investments that have previously not been taken into account. This includes both investments that have already been made and planned investments. The transmission system operators applied for capex mark-up totalling €113mn for 2023, and the distribution system operators applied for a total of €256mn. 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.

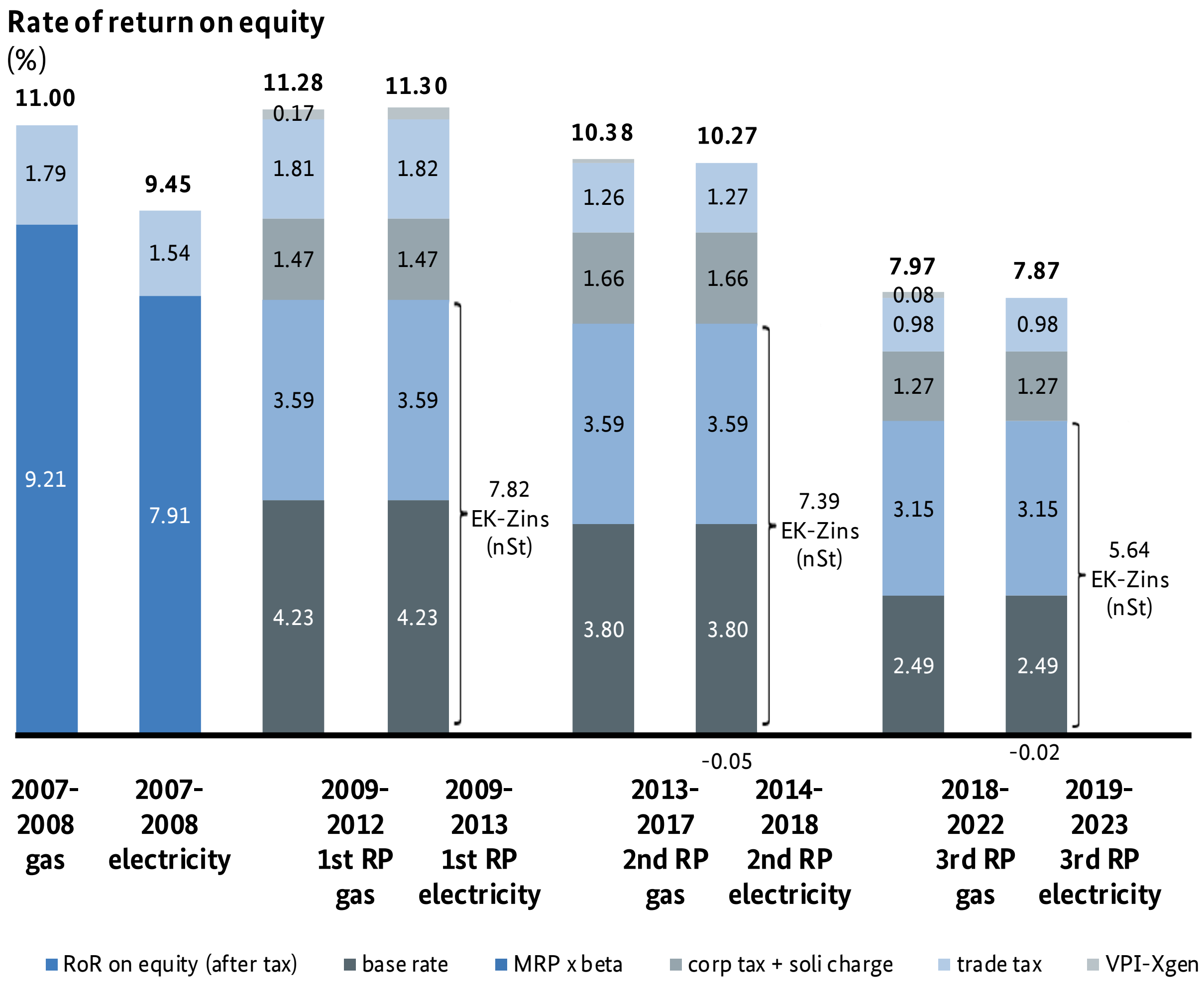


Figure 171: Rate of return on equity

The second chart (Return on equity (before corporate tax)) compares these changes in the return on equity with a presumed annual result that would have been achieved if the input parameters had been calculated (ex post) for each individual year. The figures show the rate of return on equity (comprising the base rate and the risk premium) and the regulatory allowed corporate tax, trade tax and indexation (VPI-Xgen).

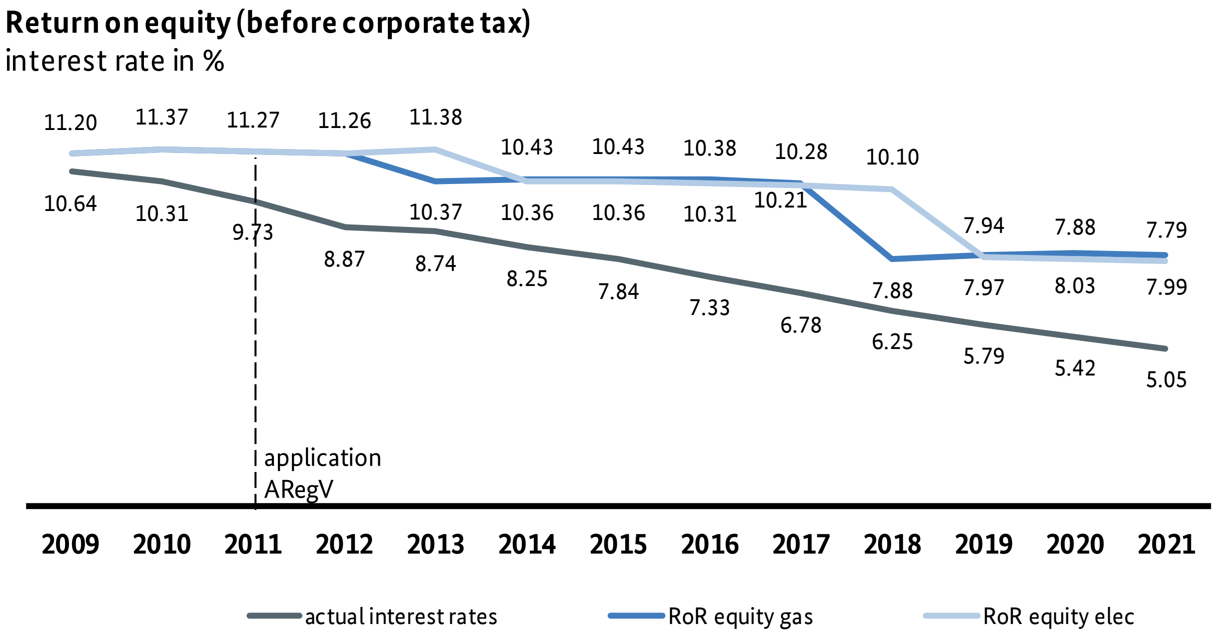


Figure 172: Return on equity (before corporate tax)

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. However, if the level of equity capital exceeds 40%, regulatory provisions apply the thesis that it is no longer worthwhile as it 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(7) StromNEV or GasNEV (averaging over 10 years) (rate of return on equity EKII). The figure below (Equity II interest rates) shows the equity II interest rates actually applied during cost examination, the annual results under StromNEV/GasNEV (10-year average) and the development of rates by year.

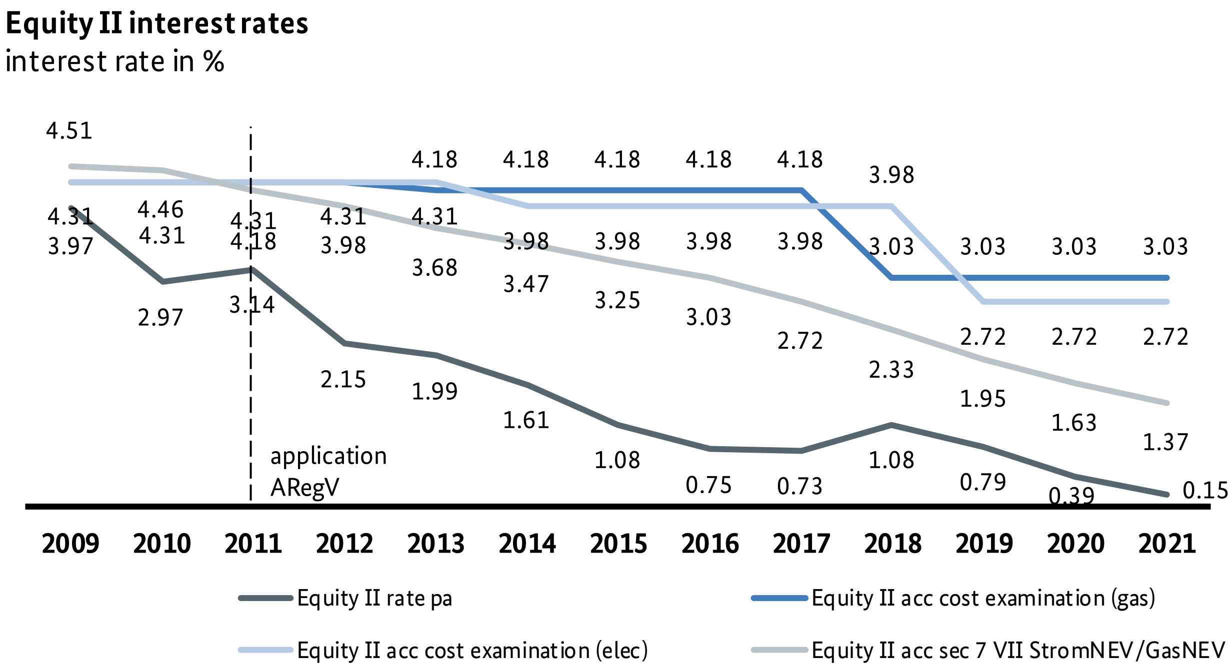


Figure 173: Equity II interest rates

2.4.3 Rate of return on borrowed capital

Within the scope of the various regulatory systems, 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. The figure below (Rate of return on borrowed capital after indexation (VPI-Xgen)) shows the levels of the rate of return on borrowed capital – shown separately under a normal incentive regulation system (budget principle) or under an investment measures system – that can be taken into account in principle for the electricity and gas networks as set out above. 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.

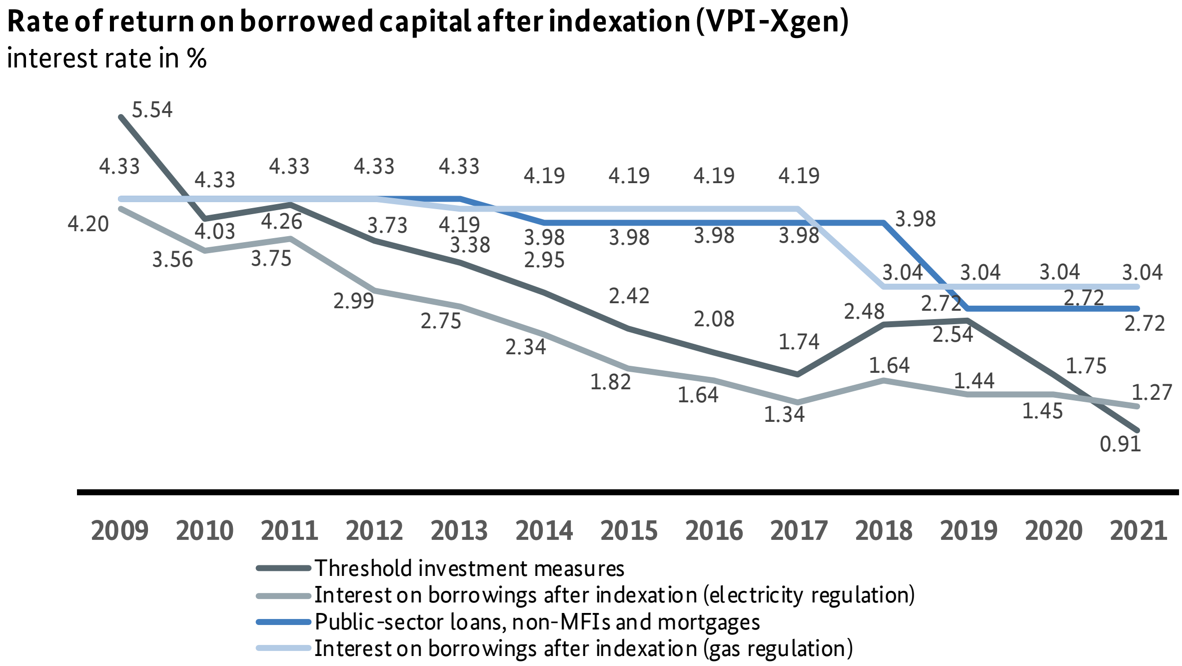


Figure 174: Rate of return on borrowed capital after indexation (VPI-Xgen)

3. Capacity offer and marketing

3.1 Availability of entry and exit capacities

As in previous years, for the 2020/2021 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 interconnection points to storage facilities, power stations and final customers. The tariff 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 tariffs. In addition, the electricity network tariff 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 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. Since 1 October 2021 it has no longer been 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.

In the 2020/2021 gas year the total firm entry capacity offered across both market areas was 543.0 GWh/h, an increase of 1.6 GWh/h compared to the previous year. The offer of firm and freely allocable capacity (FZK) amounted to 129.6 GWh/h, corresponding to about 44.8% of the total entry capacity offered in the GASPOOL market area. In the NCG market area the FZK offered was 112.4 GWh/h, corresponding to a share of 40.1% of the total capacity offered. The total volume of entry capacity offered in the NCG market area equates to around 45.6% of the total entry capacity offered across both market areas. The remaining and larger share of 54.4% is attributed to the GASPOOL market area.

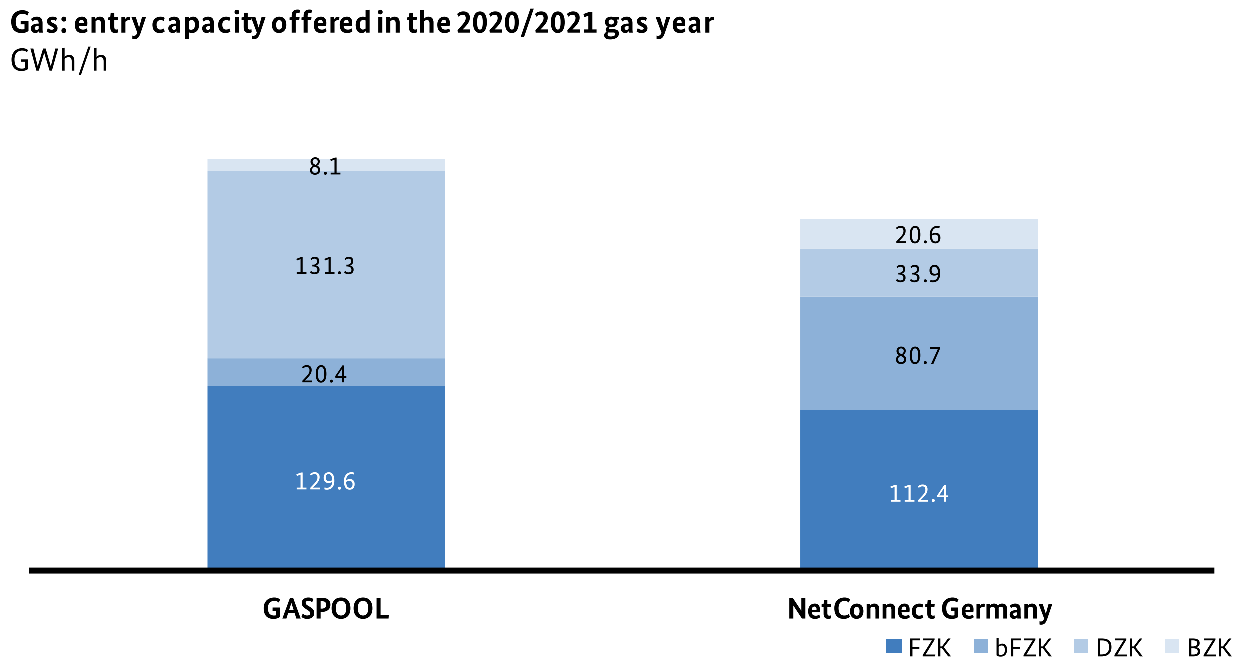


Figure 175: Entry capacity offered

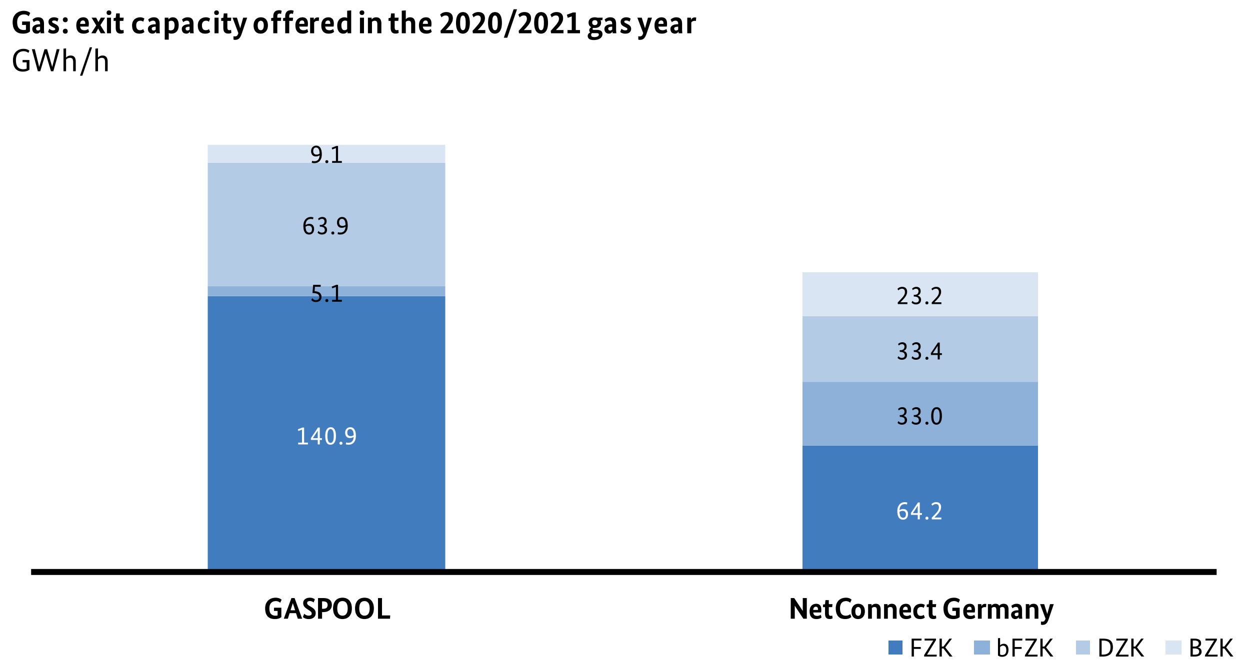


Figure 176: Exit capacity offered

In the 2020/2021 gas year the total firm exit capacity offered across both market areas was 372.8 GWh/h, a slight decrease of 1.0% 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.

As described above, the capacities for distribution networks and therefore the majority of final consumers 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 2021, the total capacity booked with TSOs by downstream DSOs was 182 GWh/h. This is roughly 49% of the bookable exit capacity offered in the 2020/21 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.

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.

Gas: booking of entry capacity according to product duration and market area in the 2020/2021 gas year
GWh/h

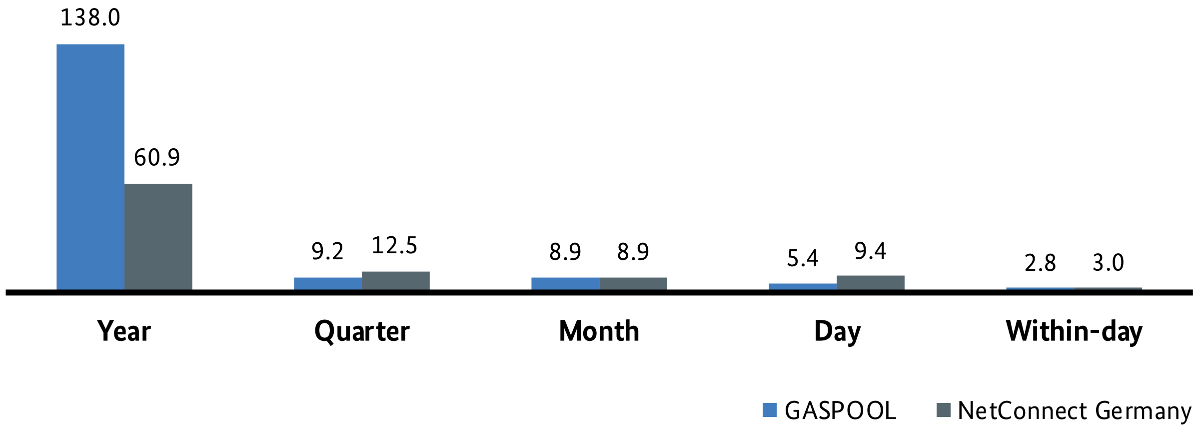


Figure 177: Booking of entry capacity according to product duration and market area

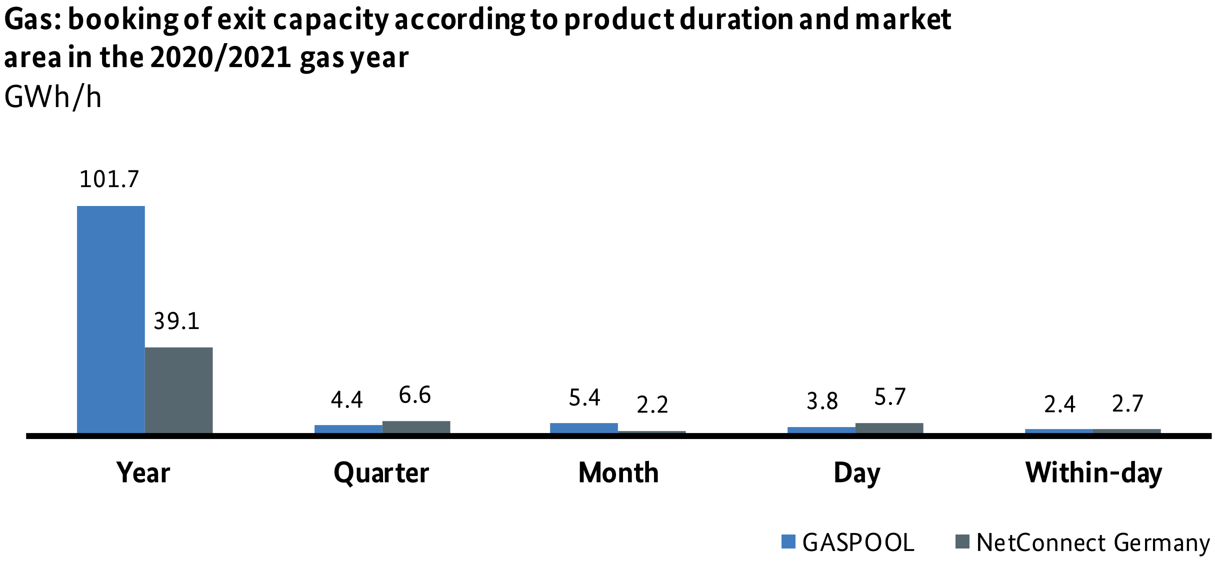


Figure 178: Booking of exit capacity according to product duration and market area

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 2020/2021 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. This correlation was already apparent in the charts of the corresponding capacity offers. Consequently the total volume of entry capacity booked was 259.0 GWh/h, significantly exceeding the exit capacity booked, which amounted to a total of 174.0 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. After the total amount for yearly capacity bookings declined in the previous reporting period, a shift from quarterly bookings towards yearly bookings can be observed in the 2020/2021 gas year, especially in the GASPOOL market area. The capacity volume booked on a long-term basis in the GASPOOL market area, with a total of 239.7 GWh/h (previous year: 211.1 GWh/h) of yearly capacity marketed and 13.6 GWh/(previous year: 51.7 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 100.0 GWh/h (previous year: 121.8 GWh/h) and 19.1 GWh/h (previous year: 22.0 GWh/h) respectively. In comparison with the previous year, a moderate increase continues to be seen in bookings of shorter-term capacity products, above all daily and within-day products, 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 (CAM NC) entered into force.

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 (2020: 1,882 TWh). In contrast, nominated quantities at exit points were considerably lower, totalling 905 TWh (2020: 1,000 TWh).

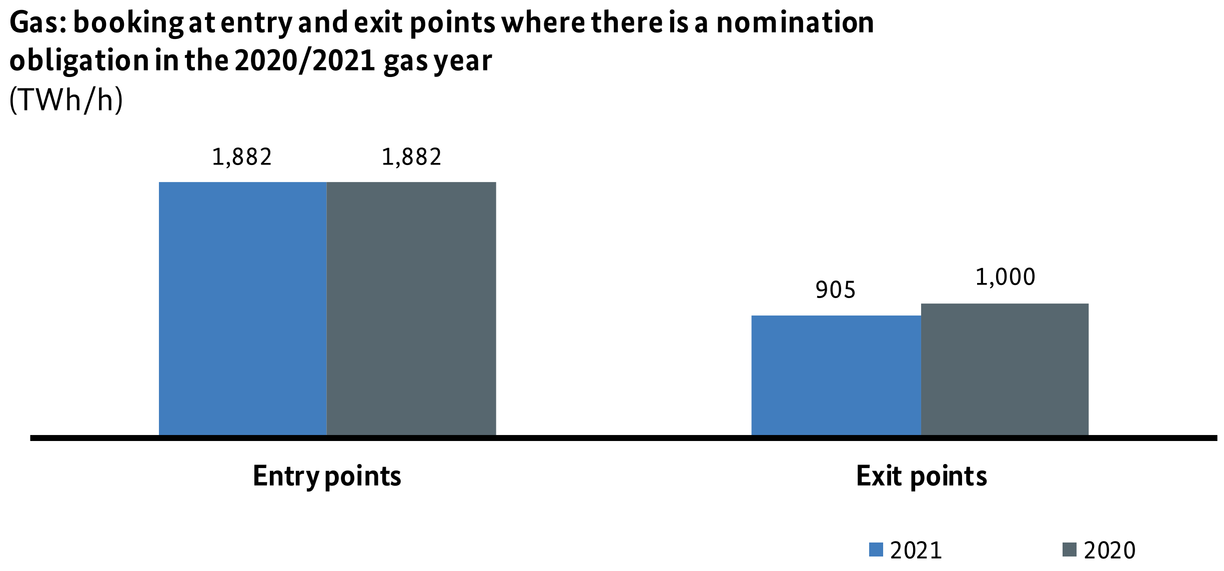


Figure 179: Booking at entry and exit points where there is a nomination obligation in the 2020/2021 gas year

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 exit points to final consumers. For the sake of clarification, the booking relates to the acquisition of transport capacities, ie capacity indicated in TWh/h, which corresponds to TW. The nomination, on the other hand, relates to planned transport within a certain period of time, therefore indication of a quantity in MWh or GWh. For example, the use of 10 MW of transport capacity for a period of 24h results in a nominated quantity of 240 MWh.

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 2021, a total of 248 capacity contracts with a duration of at least one month were terminated. This is a significant increase compared to the previous year, when 39 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.

Gas: termination of capacity contracts by type of entry/exit point in the 2021 calendar year

Number/%

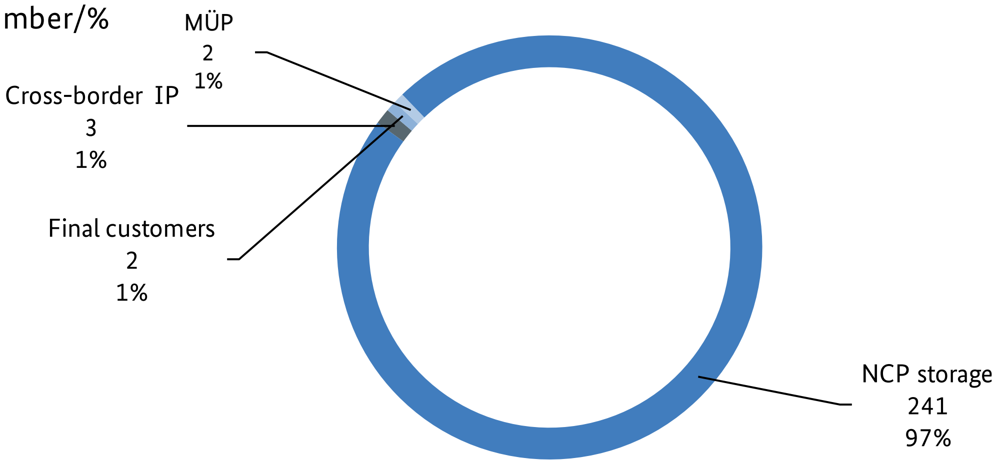


Figure 180: Termination of capacity contracts by type of entry/exit point

A total of 248 capacity contracts were terminated, of which three were contracts at cross-border interconnection points. A further 241 capacity contracts were terminated at storage facility connection points, and two at gas production connection points. Once again no capacity contracts were terminated at exit points to final customers, as in the previous year when no contracts were terminated at those points either.

Differentiating terminated capacity contracts according to product type shows that most of them, namely 129, were terminated FZK capacity contracts. In contrast to the previous year, five interruptible capacity contracts were terminated.

Gas: termination of capacity contracts by product type in the 2021 calendar year
Number and %

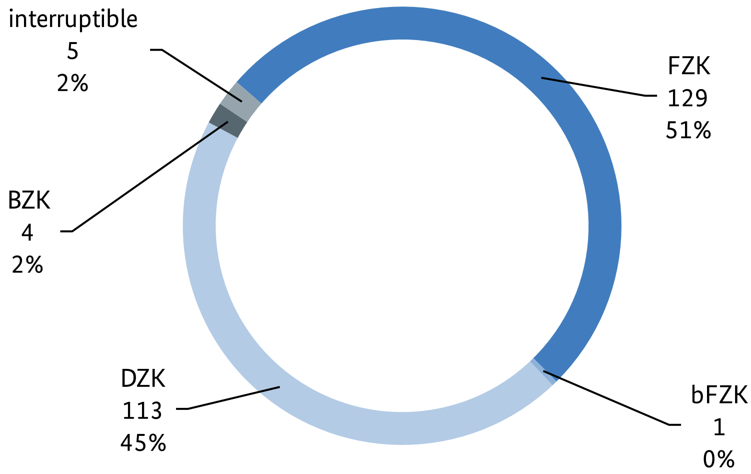


Figure 181: Termination of capacity contracts by product type

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 2021 calendar year.

In 2021, 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 1,119 GWh (2020: 726 GWh). 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.

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 2021 calendar year the volume of gas to be exported from the German NCG market area to Switzerland was 0.5 GWh. The initially (re-)nominated volumes at the exit points from Belgium to Germany accounted for the largest proportion of the total interrupted volume, amounting to 483.3 GWh.

The key reason for the different figures is the relative share in the marketing of interruptible compared to firm capacity at the individual cross-border interconnection points. Interruptions are naturally higher at cross-border interconnection points where a relatively high proportion of interruptible capacity gas been marketed compared to firm capacity.

Gas: interruptions in the 2021 calendar year

Interruption volume (GWh)

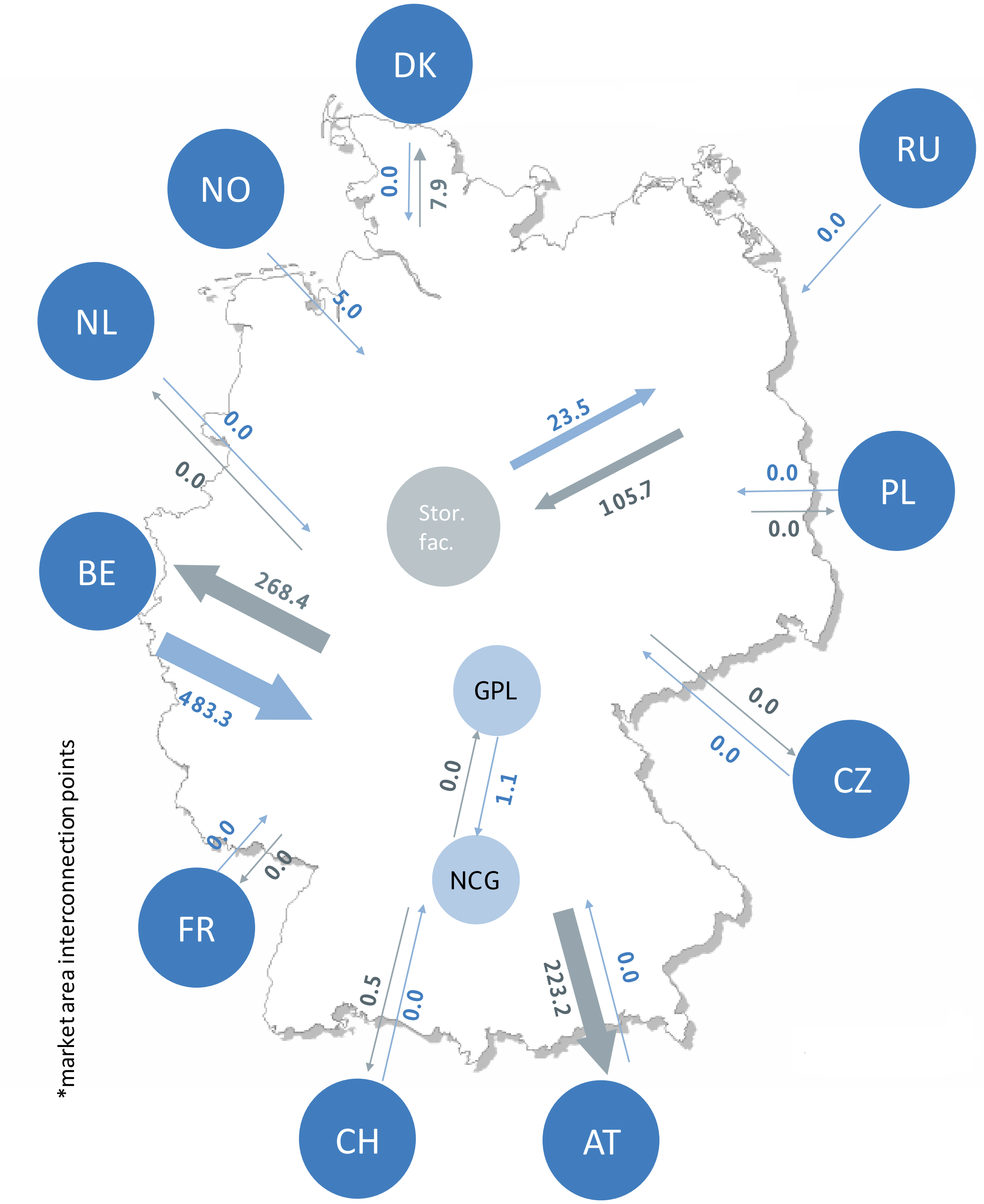


Figure 182: Interruption volumes according to region

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 tariff 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 2021 calendar year for the two market areas NCG and GASPOOL respectively.

Gas: capacities agreed between TSOs and DSOs in 2021
GWh/h

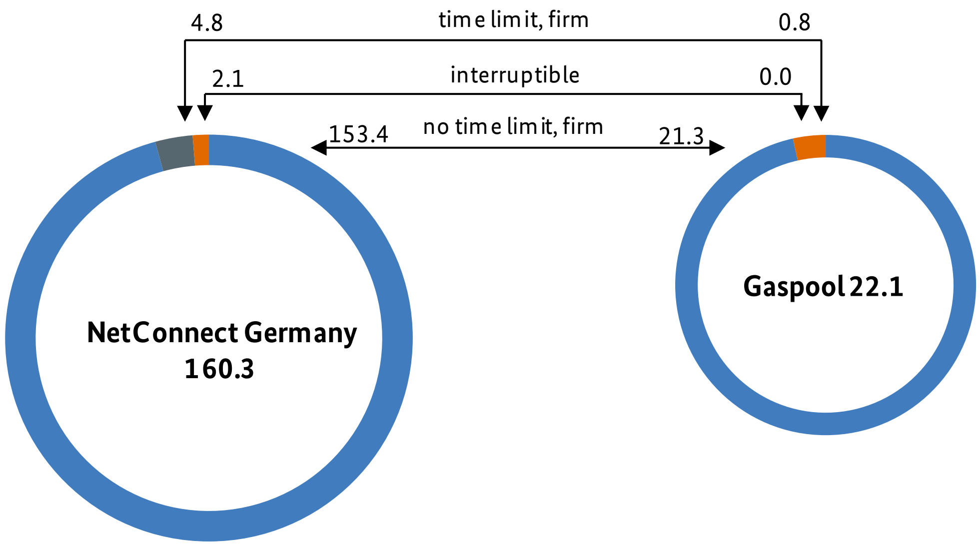


Figure 183: Capacities agreed between TSOs and DSOs

In the 2021 calendar year, the volume of internal bookings in the two market areas fell from a total of 271.2 GWh/h to 182.22 GWh/h compared to the previous year. This relates solely to 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 182 GWh/h (rounded) was agreed between TSOs and downstream network operators. The majority of this capacity, 160 GWh/h, was agreed in the NCG market area, and the remainder, 22 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 96.9% in the previous year to 97% in the 2021 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 shifting 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.

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 2021 the SAIDI was 2.18 minutes, and therefore higher than the long-standing average of 1.5 minutes.

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 average interruption duration per final customer over the course of the year (SAIDI).

Only unplanned interruptions caused by the following factors are included in the calculations:

- third-party intervention
- disturbances in the network operator's area
- ripple effects from other networks
- other disturbances

Gas: SAIDI result for 2021

Pressure level	Specific SAIDI	Notes
≤ 100mbar	2.16 min/year	Household/small consumers
> 100mbar	0.02 min/year	Major consumers, gas power plants
> 100mbar	0.32 min/year	Downstream network operators (not part of SAIDI)
across all levels	2.18 min/year	SAIDI across all final customers

Table 133: Supply disruptions in 2021

The Bundesnetzagentur has calculated the SAIDI figures for gas network operators in Germany since 2006. The trend over time since 2011 is shown in the figure below.

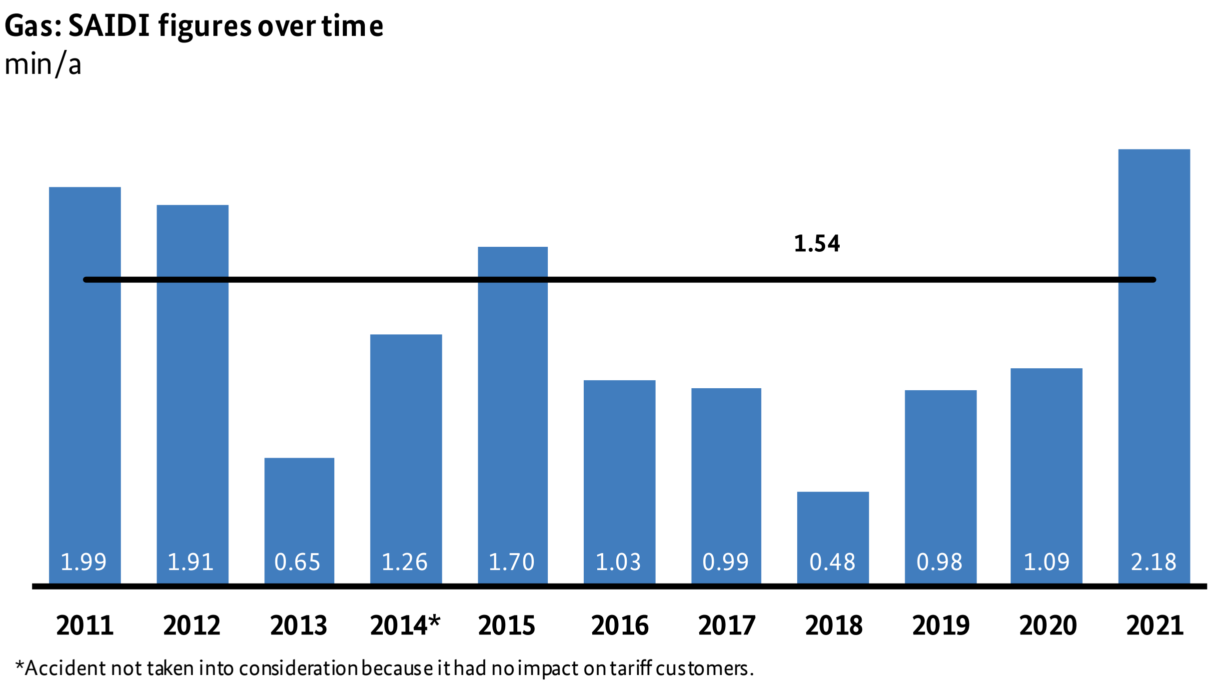


Figure 184: SAIDI gas figures for the period from 2011 to 2021

5. Network tariffs

The network tariffs are the means of spreading the costs of operation, maintenance and expansion of networks among all network users, ie also consumers.

Network tariffs account for a substantial share (around 15%) of the total gas price.

For an average household customer, the average network tariff irrespective of the type of supply and including charges for metering and meter operation is currently around 1.62 ct/kWh, an increase of slightly more than 2%.

5.1 Calculation of network tariffs for gas

Network tariffs are imposed by the TSOs and DSOs and form part of the retail price (see also section IIF4). The network tariffs are the means of spreading the costs of operation, maintenance and expansion of networks among all network users. The network operator's tariffs 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 tariffs 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, consumer price index, individual 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 tariff system is used to share the revenues allowed for the respective network operators among the network users.

The network tariffs 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 tariffs as prescribed by section 13 GasNEV are the norm. These apply in the case of TSOs and those DSOs that have capacity tariffs. Since 1 January 2020 the provisions of Regulation (EU) 2017/460 (TAR NC), in which harmonised requirements for the tariff structure are laid down Europe-wide, apply to the TSOs. The network tariff system for gas networks at the level of TSOs and of DSOs that have capacity tariffs differs significantly from the system for electricity networks, which currently has neither entry tariffs nor capacity tariffs. 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 tariff 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 tariffs in Germany

The figure below shows the development of the average volume-weighted net gas network tariffs for three consumption categories in ct/kWh from 1 April 2007 to 1 April 2022. The charges for metering and meter operation have been added to the network tariffs shown in the figure below. Since 1 January 2017 the charge for accounting forms part of the network tariffs 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 tariffs 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 tariffs 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 2022, the average volume-weighted network tariff including the charges for metering and meter operation (volume-weighted across all contract categories) for household customers was 1.62 ct/kWh (2021: 1.59 ct/kWh), only a slight increase of around 2% compared to the previous year. For commercial customers, as of 1 April 2022 the arithmetic mean of the network tariff including the charges for metering and meter operation was 1.25 ct/kWh (2021: 1.28 ct/kWh). For industrial customers, as of 1 April 2022 the arithmetic mean of the network tariff including the charges for metering and meter operation increased significantly to 0.44 ct/kWh (2021: 0.32 cg/kWh), an increase of just over 13.5%.

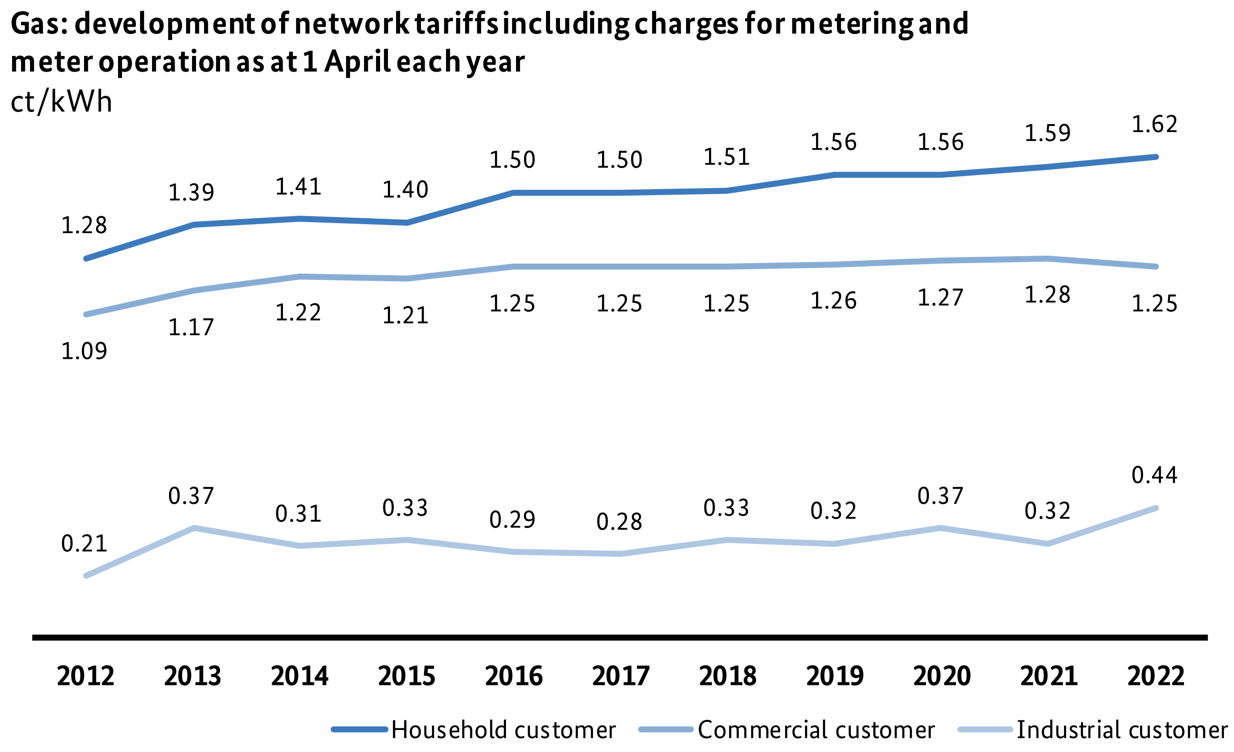


Figure 185: Development of network tariffs for gas (including charges for metering and meter operation) according to the survey of gas suppliers

For the Germany-wide market area Trading Hub Europe (THE), as of 30 May 2022 the transmission system operators initially indicated definitive entry and exit tariffs for firm, freely allocable annual capacity for 2023 of €4.82 kWh/h/a (2022: €3.51 kWh/h/a). This corresponds to a rise of around 37.3%.

However, the transmission system operators applied for an adjustment to the previously indicated entry and exit tariffs as of 1 January 2023. The reasons for this include a steep rise in fuel gas costs and changes in the marketable capacities. Ruling Chamber 9 approved the adjustment in principle. The final level of the TSOs' entry and exit tariffs had not yet been established at the time this report was going to press.

The distribution network tariffs for 2023 provisionally reported on 15 October show a significant increase across all customer groups. The figures are based on a random sample of network operators under the responsibility of the Bundesnetzagentur. No firm statements on the precise extent of the increase can be made at the time of going to press. The distribution system operators' tariffs may therefore still need to be adjusted if an adjustment is made to the transmission system operators' tariffs. Furthermore it is conceivable that DSOs will make adjustments to the tariff calculation, in particular to the volume forecasts, in light of prevailing uncertainties.

5.3 Regional distribution of network tariffs

There is regional variation in the level of network tariffs. For household, commercial and industrial customers the network tariffs in Saxony-Anhalt, Mecklenburg-Western Pomerania and Saarland are at the upper end of the Germany-wide range.

Gas: net network tariffs for household customers in Germany for 2022
ct/kWh

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks considered
Saxony-Anhalt	1.83	1.12	2.56	26
Mecklenburg-Western P.	1.72	1.07	2.55	21
Bremen	1.71	1.65	1.78	2
Saarland	1.65	1.05	2.14	16
Thuringia	1.63	1.05	2.23	25
Saxony	1.63	1.07	2.40	35
Baden-Württemberg	1.62	0.95	3.27	86
Brandenburg	1.59	0.86	2.31	23
Rhineland-Palatinate	1.56	0.90	2.28	31
Bavaria	1.53	0.76	3.41	91
North Rhine-Westphalia	1.49	0.74	2.47	114
Hesse	1.45	1.09	1.81	40
Schleswig-Holstein	1.41	0.98	2.19	34
Hamburg	1.38	1.38	1.38	1
Berlin	1.31	1.31	1.31	1
Lower Saxony	1.30	0.48	2.11	60

* The gas offtake volume of the network operators in the respective network areas was used as the basis for weighting.

Table 134: Distribution of gas network tariffs for the "household customer" consumption category in Germany, as at 1 January 2022

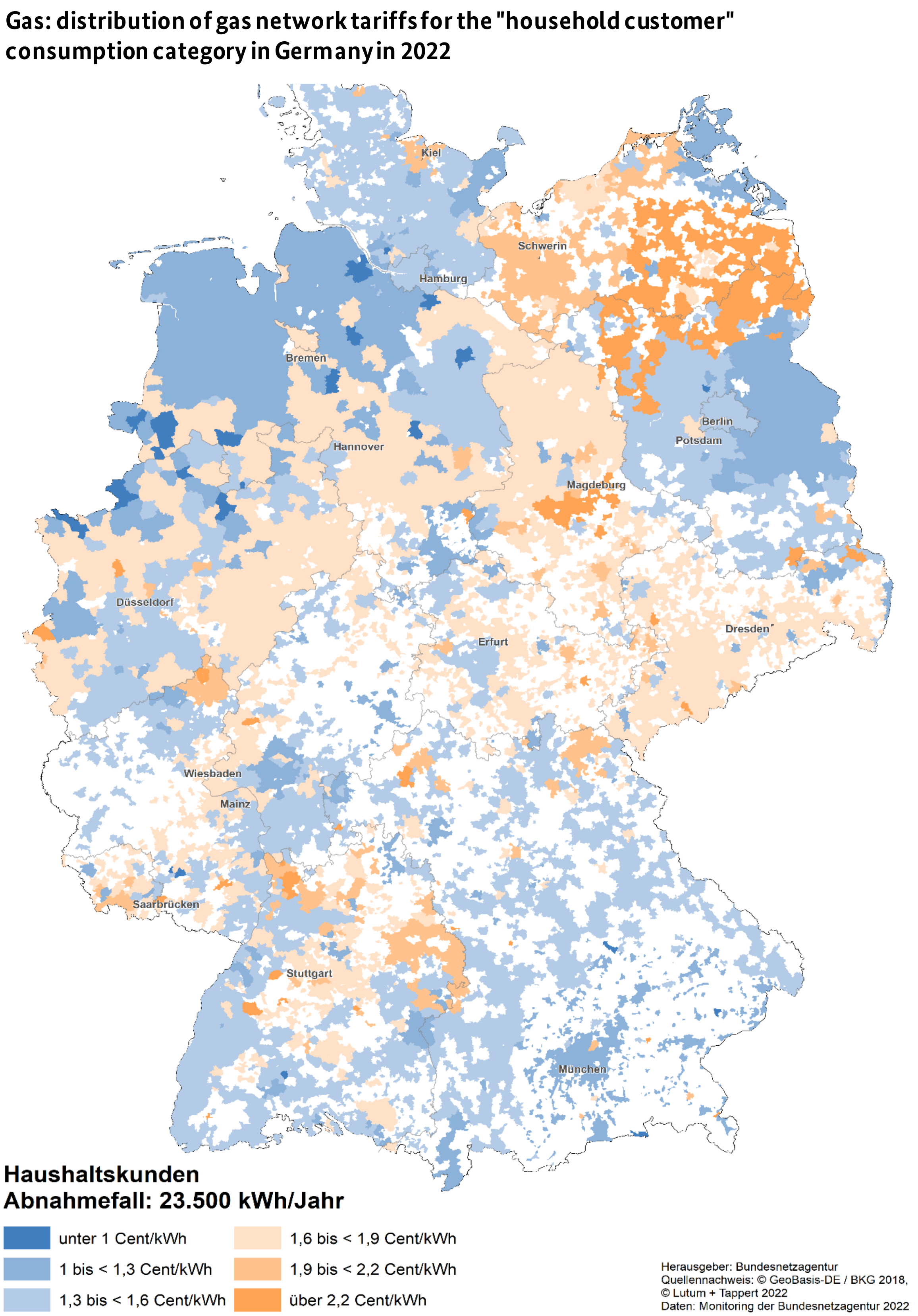


Figure 186: Distribution of gas network tariffs for the "household customer" consumption category, as at 1 January 2022

Gas: net network tariffs for commercial customers in Germany for 2022
ct/kWh

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks considered
Saxony-Anhalt	1.57	1.06	2.05	28
Mecklenburg-Western P.	1.45	0.89	2.18	21
Thuringia	1.42	0.97	1.90	25
Saarland	1.40	0.77	1.91	16
Brandenburg	1.40	0.75	2.94	23
Baden-Württemberg	1.38	0.76	2.53	101
Saxony	1.37	0.78	1.99	35
Rhineland-Palatinate	1.35	0.84	1.97	31
Bavaria	1.30	0.78	2.92	91
Bremen	1.23	1.23	1.23	2
Hesse	1.21	0.90	1.56	40
North Rhine-Westphalia	1.20	0.42	2.20	113
Hamburg	1.17	1.17	1.17	1
Schleswig-Holstein	1.15	0.31	1.67	34
Lower Saxony	1.14	0.47	1.97	58
Berlin	1.12	1.12	1.12	1

* The number of meter points belonging to the operators in the respective network areas was used as the basis for weighting.

Table 135: Distribution of gas network tariffs for the "commercial customer" consumption category in Germany, as at 1 January 2022

Gas: distribution of gas network tariffs for the "commercial customer" consumption category in Germany in 2022 (116 MWh/year)

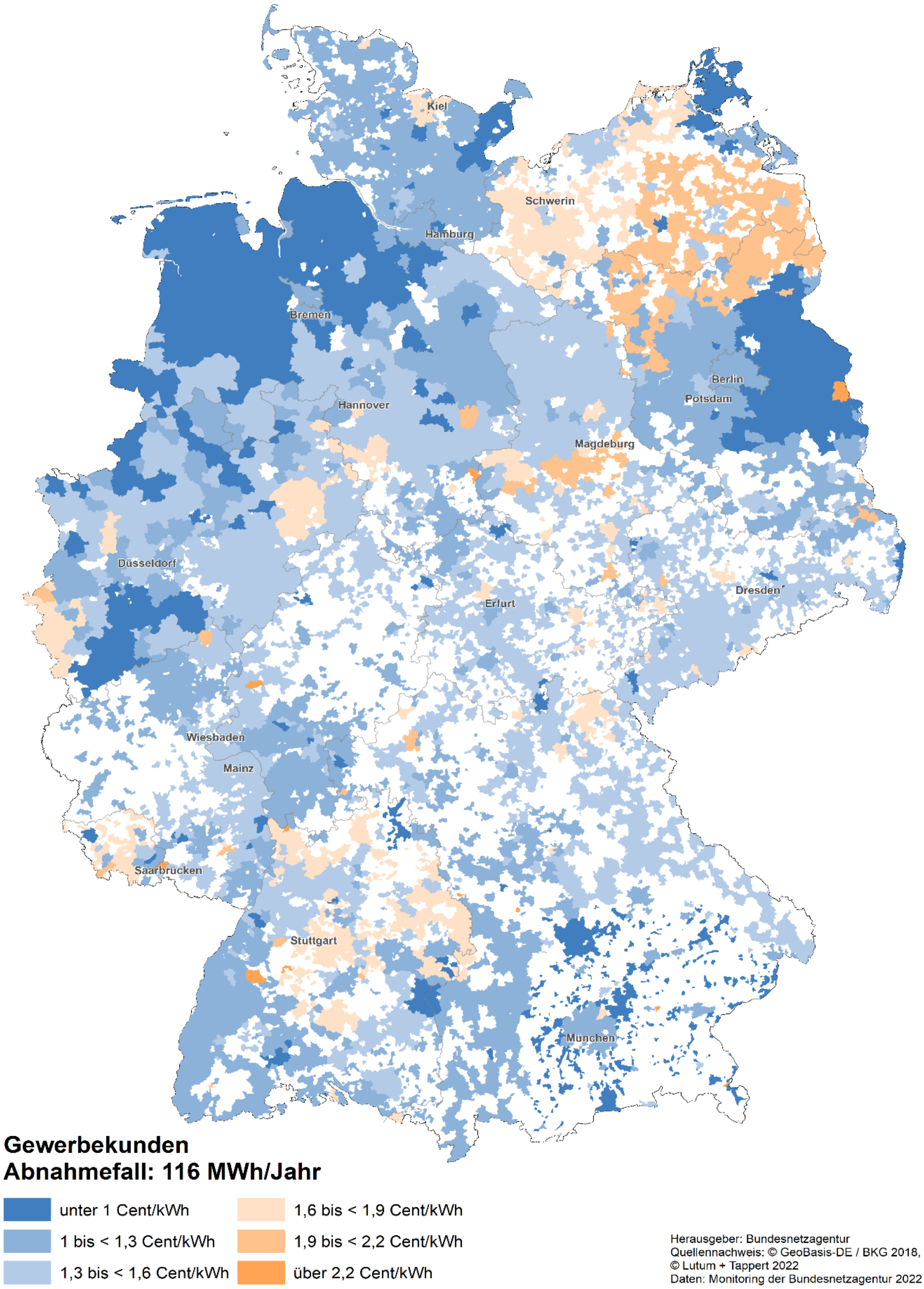


Figure 187: Distribution of gas network tariffs for the "commercial customer" consumption category in Germany, as at 1 January 2022

Gas: net network tariffs for industrial customers in Germany for 2022
ct/kWh

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks considered
Mecklenburg-Western P.	0.52	0.28	0.92	8
Saarland	0.47	0.29	0.67	5
Saxony-Anhalt	0.40	0.22	1.00	8
Thuringia	0.39	0.23	0.61	11
Rhineland-Palatinate	0.36	0.27	0.48	12
Baden-Württemberg	0.36	0.15	0.58	32
Berlin	0.33	0.33	0.33	1
Lower Saxony	0.32	0.20	0.61	18
Hesse	0.32	0.05	0.52	17
Bavaria	0.32	0.17	0.58	24
Brandenburg	0.32	0.22	0.45	8
Schleswig-Holstein	0.31	0.15	0.45	7
Northrhine-Westphalia	0.31	0.16	0.59	40
Saxony	0.30	0.21	0.46	9
Bremen	0.25	0.21	0.28	2
Hamburg	0.25	0.25	0.25	1

* The quantity of gas supplied by the operators in the respective network areas was used as the basis for weighting.

Table 136: Distribution of gas network tariffs for the "industrial customer" consumption category in Germany, as at 1 January 2022

Gas: distribution of gas network tariffs for the "industrial customer" consumption category in Germany in 2022 (consumption 116 GWh/year)

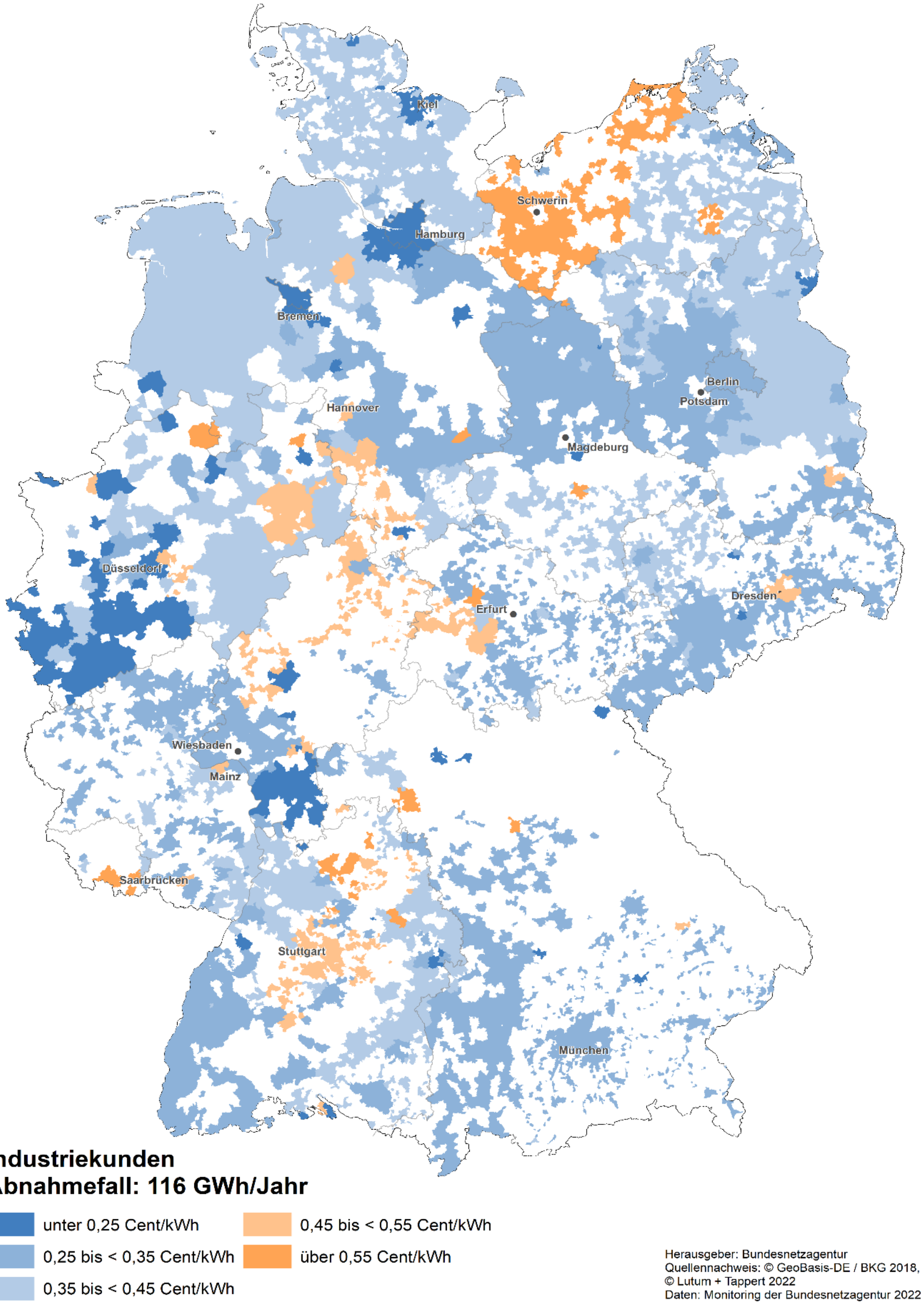


Figure 188: Distribution of gas network tariffs for the "industrial customer" consumption category in Germany, as at 1 January 2022

The reasons for the regional differences in network tariffs 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 tariffs. More recently built networks have higher residual values, which increases specific capital costs and in turn leads to higher tariffs. As a result of their greater depreciation, older networks have lower residual values and therefore lower capital costs, thus in turn leading to lower tariffs. However, with advancing age, networks incur higher costs for maintenance and repair, which have a corrective effect that tends to equalise the tariffs.

5.4 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

Ruling Chamber 9 is currently carrying out the cost examination to determine the base level for gas supply network operators for the fourth regulatory period.

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.

In the year prior to this, the Bundesnetzagentur started to use the data as the initial basis for determining the base level for gas supply network operators and to conduct efficiency benchmarking. Almost all network operators under the standard procedure have already been sent the notifications about the base level.

A final decision on the revenue caps for the fourth regulatory period is due to be taken in the coming months.

5.5 Determination proceedings for calculation of tariffs by transmission system operators "MARGIT 2023"

Ruling Chamber 9 has completed the proceedings concerning the determination of the level of multipliers, of discounts for interruptible capacities, of discounts at LNG terminals and of seasonal factors.

The MARGIT 2023 determination proceedings specify certain calculation factors that affect the calculation of tariffs by transmission system operators in the 2023 calendar year. These calculation factors include, in particular, price mark-ups, referred to as multipliers, for non-yearly capacity products and discounts for interruptible capacity products. The basis for these proceedings is provided by the European network code on harmonised transmission tariff structures.

In light of the dynamic geopolitical events, Ruling Chamber 9 extended the draft determination to include discounts at entry points from LNG facilities. The changes with respect to the most recently issued determination (MARGIT 2022) result in particular from the updated calculation of the discounts for interruptible capacity products and the discount of 40% at entry points from LNG facilities for yearly and quarterly capacity products in the interest of greater security of supply, introduced for the first time from 2023 onwards. The percentage is based on the network tariff level (not the level of discount) set by the neighbouring countries the Netherlands and France.

5.6 Determination of imputed useful lives of natural gas pipeline structures "KANU

Ruling Chamber 9 launched the proceedings concerning the determination of imputed useful lives of natural gas pipeline structures and launched the consultation on the draft determination on 13 July 2022.

Insofar as it relates to imputed useful lives for new facilities, the draft determination serves to create a regulatory framework for the German federal government's policy objectives for reducing greenhouse gas emissions. The planned determination provides, among other things, that LNG facilities can be written down within a manageable time frame. No imputed useful lives are specified for LNG facilities in the existing legal framework, and are introduced for the first time by the determination. In addition, network operators are to be able to write down connection lines for LNG facilities more quickly than before and generate revenue again through the network tariffs.

Furthermore, the draft determination opens up the option of adapting the imputed useful lives of natural gas transport network infrastructures to the federal government's climate targets. On the other hand, it includes no provisions on whether and to what extent the use of the natural gas networks will indeed be discontinued or the extent to which it may be possible to continue to use the networks for other purposes.

The draft determination was made available to all participating actors for consultation.

6. Merger of market areas

The joint German market area Trading Hub Europe (THE) began work on 1 October 2021, thereby replacing the two former market areas Gaspool and NetConnect Germany. As THE GmbH had already been established as the new market area manager on 1 June 2021, the TSOs ensured that the operational merger process to form a new company ran smoothly and thus also laid the foundations for the successful launch of the new market area. Thanks in no small part to the close dialogue between all market participants, it proved possible to meet the substantive and operational challenges of a merger of this nature in advance, in a transparent manner and with a focus on results. The Bundesnetzagentur supported the process from the regulatory standpoint, particularly with regard to the growing transport options resulting from the geographical enlargement of the market area.

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 area 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,[148] (MOL 1 exchange-traded, MOL 2 also exchange-traded but taking account of network aspects- geographical location and gas quality, MOL 4 tender procedure).[149]

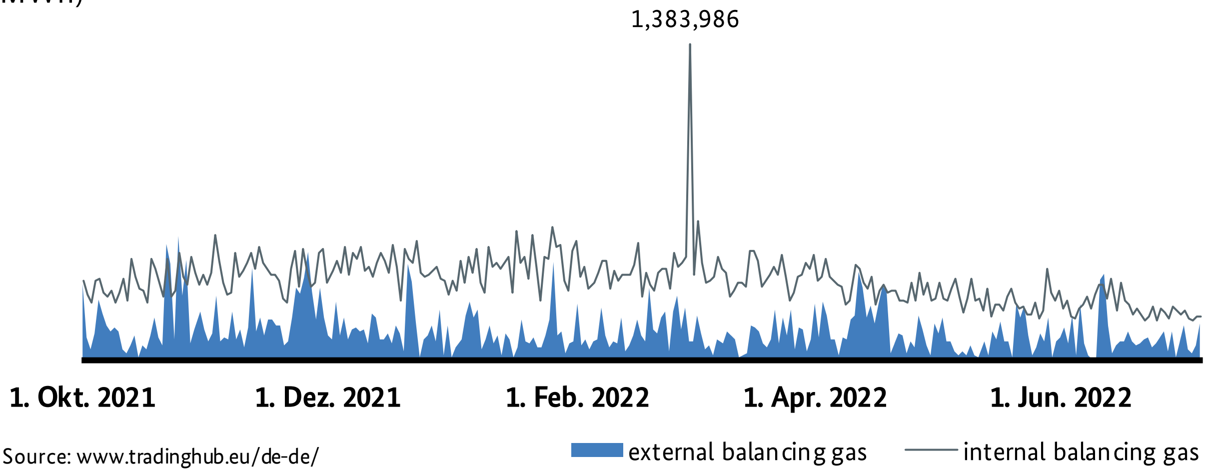
Because in winter months there are greater fluctuations regarding short and long portfolios, there is an increase in the share of external balancing gas during this period.

On 1 October 2021 the single German market area Trading Hub Europe (THE) launched, replacing the previous two market areas NetConnect Germany (NCG) and GASPOOL. The charts below thus refer to this single market area. The earlier data on NCG and GASPOOL may be found in previous monitoring reports or on THE's website, www.tradinghub.eu/de-de/.

[148] 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

149 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 for Trading Hub Europe.

Gas: balancing gas use in Trading Hub Europe
(MWh)



Source: www.tradinghub.eu/de-de/

Figure 189: Balancing gas use from 1 October 2021 in the Trading Hub Europe market area, as at July 2022

The purchase prices for balancing gas depicted below are calculated as an average of the daily balancing gas prices.

The charts show that the demand for external balancing gas is covered by products from MOL rank 1 and, in particular, 2.[150]

As purchasing is mainly exchange-traded, the purchase prices are on the same level as general market prices.

[150] 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 for Trading Hub Europe.

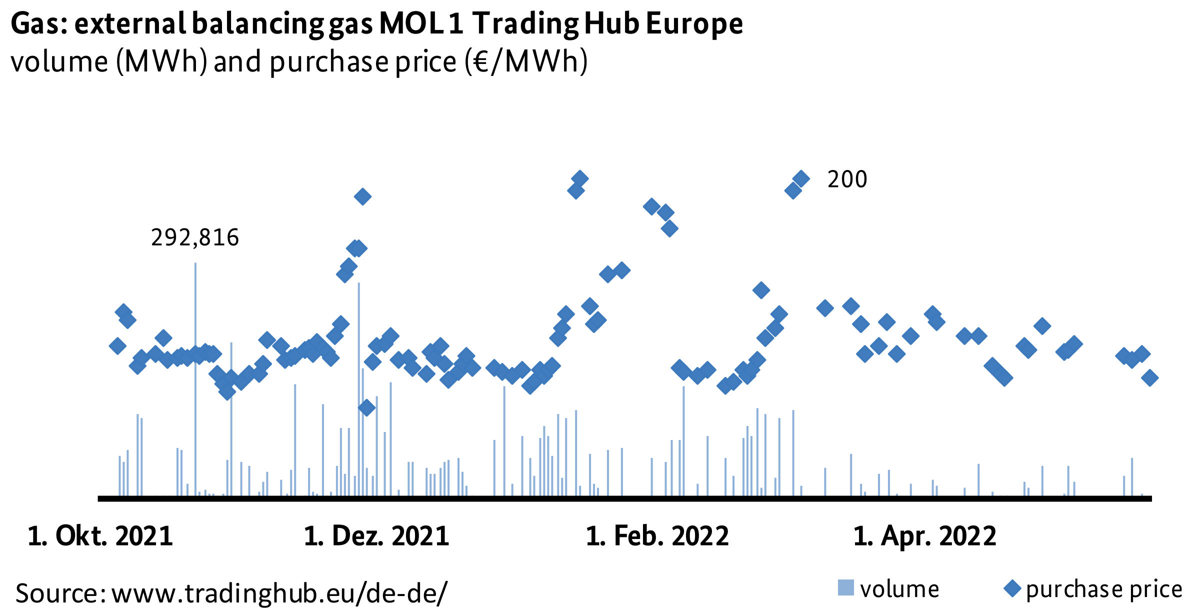


Figure 190: External balancing gas purchase prices and volumes from 1 October 2021 for MOL 1 in the Trading Hub Europe market area, as at July 2022

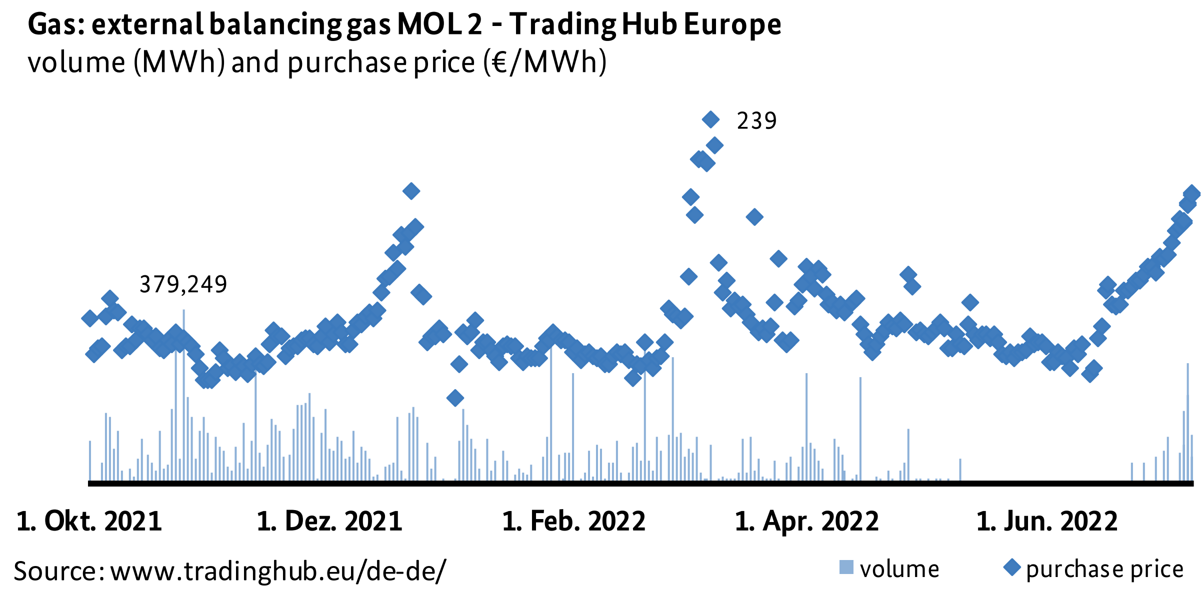


Figure 191: External balancing gas purchase prices and volumes from 1 October 2021 for MOL 2 in the Trading Hub Europe market area, as at July 2022

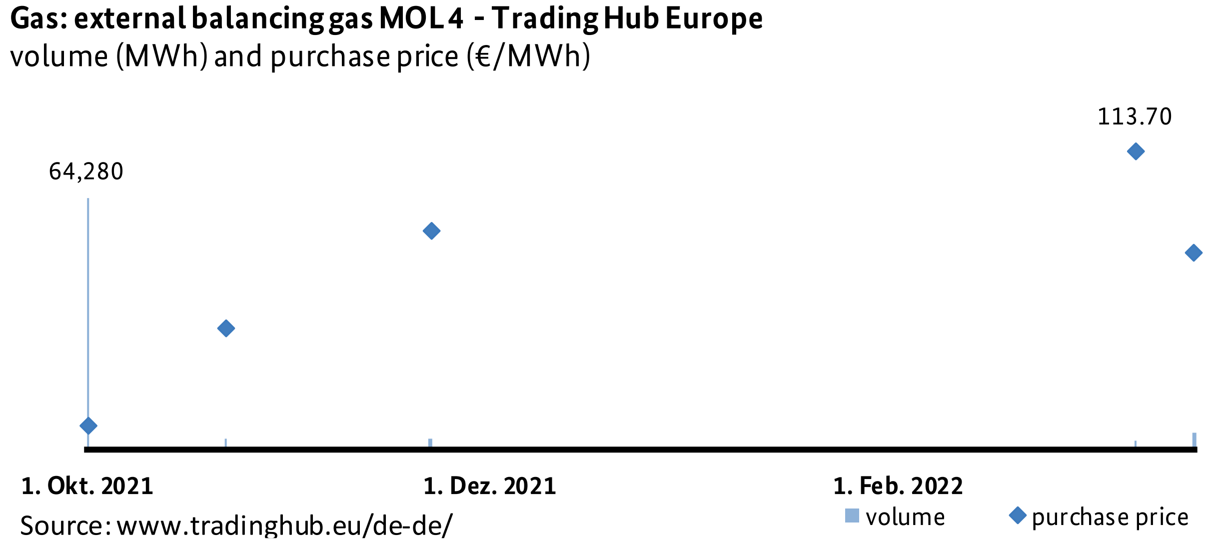


Figure 192: External balancing gas purchase prices and volumes from 1 October 2021 for MOL 4 in the Trading Hub Europe market area, as at July 2022

1.2 Imbalance gas

The term imbalance gas refers to the difference between entry and exit quantities within a balancing group at the end of the balancing period. It comes about through deviations between the amount of gas actually consumed and the forecast consumption volume. For this quantity of gas the balance responsible party 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 figure below shows the development of the imbalance prices.

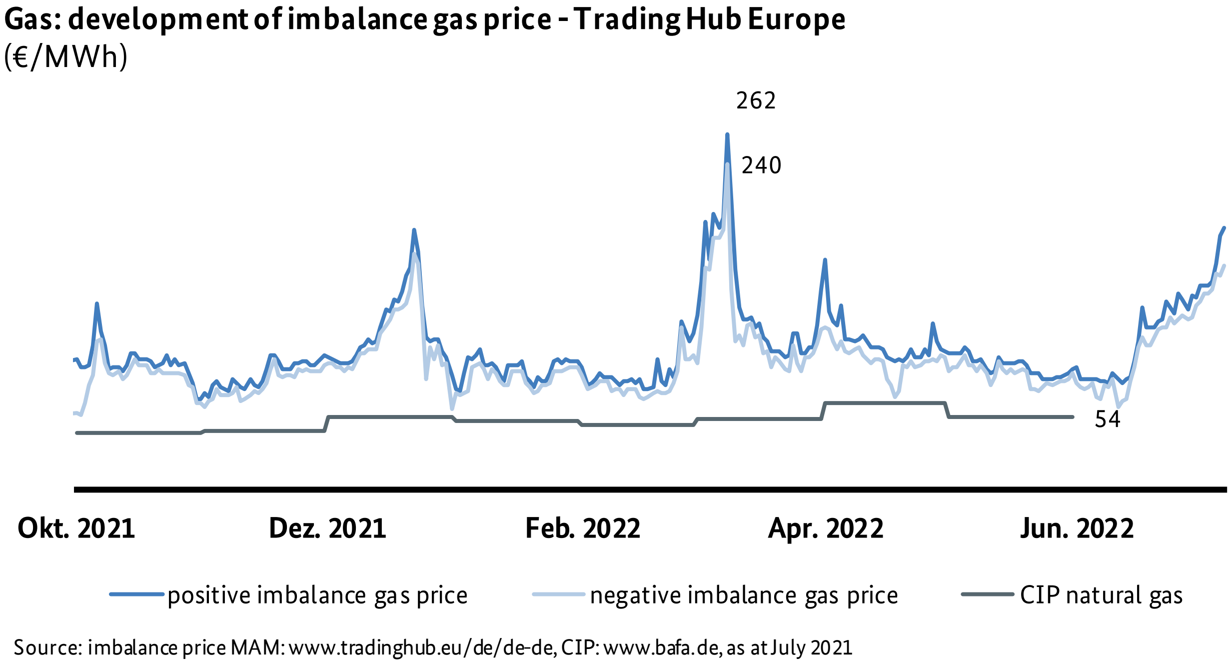


Figure 193: Development of Trading Hub Europe imbalance prices since 1 October 2021, as at July 2022

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 balance responsible parties. 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 balance responsible parties.

There are two separate neutrality charge accounts, for exit points connecting users with either standard load profiles (SLPs) or interval metering. If the costs are forecast to exceed revenues, the market area manager levies a neutrality charge from the respective balance responsible parties. As of 1 October 2016, the neutrality charges (for SLPs and interval metering) each apply for one year.

Since the launch of the single German market area THE, there has only been one neutrality charge for balancing for SLPs and one for interval metering, instead of the previous two for the two former market areas, NCG and GASPOOL. For the period of validity from 1 October 2021 to September 2022, a neutrality charge of €0/MWh will be levied for SLP customers and €0/MWh for customers with interval metering in the THE market area.[151]

[151] The neutrality charges applicable from 1 October 2021 were published by the market area manager at https://www.tradinghub.eu/de six weeks before the start of the contribution period.

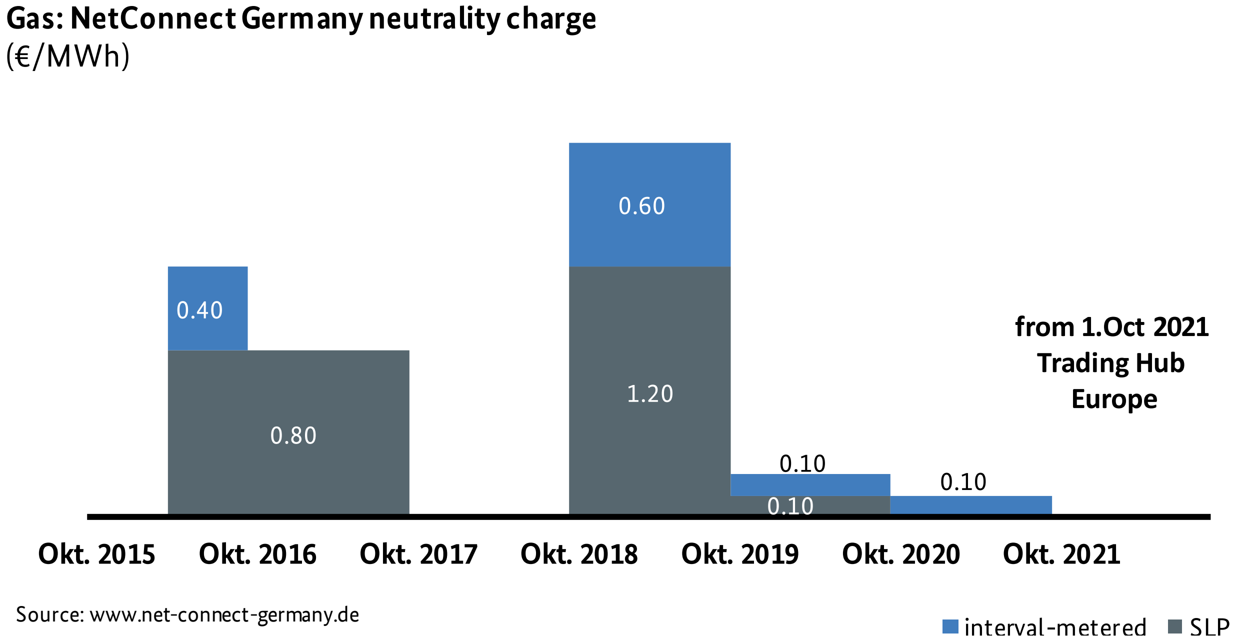


Figure 194: Neutrality charge in the NetConnect Germany market area, as at July 2021

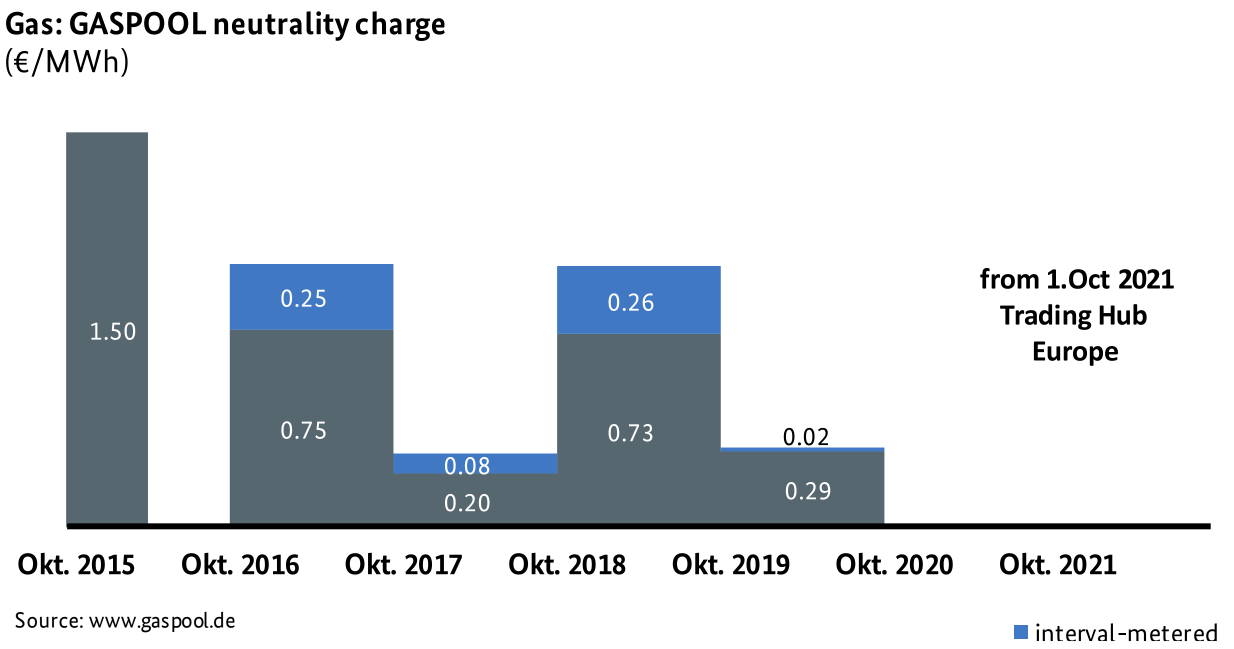


Figure 195: Neutrality charge in the GASPOOL market area, as at July 2021

3. Standard load profiles

Network operators use standard load profiles (SLPs) to allocate offtake quantities of final consumers, especially household and small business customers. They are used by 97.9% of network operators (2020: 97.3%). Customers with an installed capacity of at least 500 kW or annual consumption of at least 1.5mn kWh must generally be interval-metered. The opportunity to deviate from this limit was taken by 4% of network operators (2020: 3.4%), of which 25.9% stated that they reduced the limit for network-related reasons. The previous year, the figure was 26.1%. In 51.9% of cases (2020: 56.5%), the limits were agreed individually with shippers. According to the information provided, 57.1% of these agreed limits (2020: 53.9%) 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 2021, the synthetic SLPs were used by 85.9% of operators (2020: 85.8%); analytical profiles were used by 14.1% of operators, compared to 14.2% in 2020. 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 96.4%. This figure, too, remains almost unchanged from the previous year (96.2%). 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, 46.2% of network operators said they were, compared to 48.5% in 2020. As in the previous years, two to three profiles were generally used for household customers, whereas seven profiles were used on average for business customers (2020: eight).

Of network operators using the analytical profiles, 77.5% of them used the two-day delay method (2020: 71.4%), with 24.7% (2020: 24.1%) stating they apply an optimisation procedure to minimise the two-day delay. Whatever method was used, only 2.5% of operators made adjustments to the load profiles owing to large deviations from forecasts, compared to 2.3% in 2020. These adjustments consisted of applying correction factors (47%), changing coefficients (11.8%) or other measures (41.2%).

The network operator's network account balances all gas injected into a network against the allocated offtake quantities to final customers and transfers from the network to downstream networks, storage facilities, adjacent market areas and foreign networks. The market area managers settle these network accounts in the case of a short or long portfolio. The network accounts of 37.3% of network operators were settled due to short portfolios in at least one month (no data from the network operator: 18.7%). In the previous year, the figure was 48.7% (no data: 18.3%). The average among the network operators that provided data was 1.2 months (2020: 1.7 months). The average across all network operators was 1.0 months (2020: 1.4 months).[152] The network accounts of 57.2% of all network operators were settled due to long portfolios in at least one month (no data: 18.7%). In the previous year, the figure was 54.9% (no data: 15.8%). The average among the network operators that provided data was 6.7 months (2020: 6.4 months). The average across all network operators was 5.4 months (2020: 5.2 months).[153] According to 65.5% of network operators, they had waived the credit from the settling of long portfolios (2020: 64.0%).

[152] Due to a change in the calculation method, the values for average short portfolios from the previous reporting year were adjusted and cannot therefore be directly compared with the Monitoring Report 2020.

[153] Due to a change in the calculation method, the values for average long portfolios from the previous reporting year were adjusted and cannot therefore be directly compared with the Monitoring Report 2020.

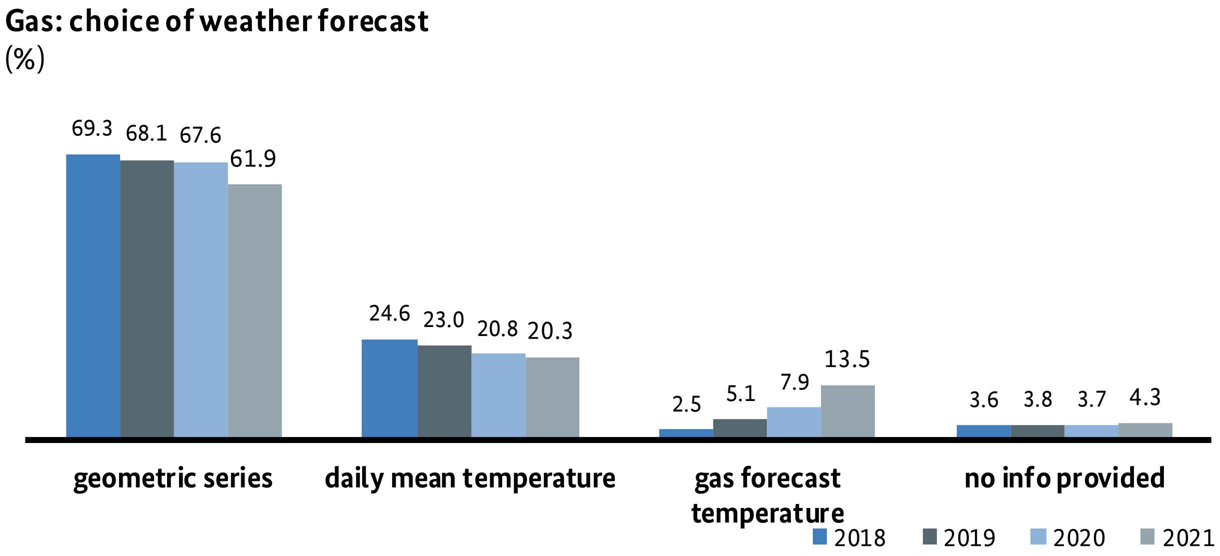


Figure 196: Choice of weather forecast

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 of the forecast. The use of the gas forecast temperature was also included in the survey for the fourth time in the year under review, with 13.5% of network operators stating they used it. This percentage is, again, higher than the previous year (7.9%).

E Wholesale

It has now become clearer than ever that liquid wholesale markets are vital to the 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 is a national market and therefore no longer defines it within the limits of networks or market areas. Natural gas wholesale trading for the futures market is done to a large extent via off-exchange broker platforms. The volume of on-exchange gas wholesale trading, of the European Energy Exchange AG and its subsidiaries (in the following referred to collectively as EEX), for example, increased significantly in 2021, which is due to the rise in demand on the global markets after the first year of the COVID-19 pandemic.[154] In addition to EEX there are other gas exchanges, such as the CME Group, ICE and Nasdaq, which are to be included in monitoring activities in the energy sector in the coming years.

The situation in the energy markets has intensified since the beginning of Russia's war of aggression against Ukraine in February 2022, which violates international law. Prices in the wholesale markets for electricity and gas have again risen considerably and are very volatile. The second half of 2021 already saw considerable price increases in the energy markets. The non-weighted annual average of the European Gas Index (EGIX), which is taken as the reference price for the medium-term procurement market, increased by around 403% compared to 2020 and for the first time overtook the border price calculated by the Federal Office for Economic Affairs and Export Control (BAFA), which in 2021 rose by around 116% on the previous year.

1. On-exchange wholesale trading

EEX operates 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) as well as spread product trading. All types of contracts were equally tradable for the two German market areas NetConnect Germany (NCG) and GASPOOL until 30 September 2021. As a result of the merging of these two market areas on 1 October 2021, these now form a single market area for Germany under the name Trading Hub Europe (THE).

On the spot market, trading in natural gas is possible 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

[154] EEX Group financial results for 2021, press briefing, p. 13

contracts (for high calorific gas or low calorific gas) are also tradable. Futures contracts for specific months, quarters, seasons (summer/winter) and years can be traded. 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.

In addition, in the second half of 2017 EEX introduced the new European spot market index "European Gas Spot Index" (EGSI) to enable market participants to better mirror short-term price developments in their contracts. This index is drawn up for the gas markets Germany (Trading Hub Europe, THE), the Netherlands (TTF), France (TRF), Austria (CEGH VTP), Denmark (ETF) and Belgium (ZTP). A total volume of 3,033 TWh was traded on the EEX Group's European gas markets in 2021 (2020: 2,379 TWh). The spot market accounted for 1,847 TWh (2020: 1,411 TWh); a total volume of 1,186 TWh was traded on the futures market (2020: 968 TWh).[155] Following a sharp decline in demand for natural gas in 2020 due to the COVID-19 pandemic, the energy demand increased again in 2021 as a result of the global economic recovery. EEX's total volume on both submarkets increased by approximately 27.5% on the previous year. The entire trading volume, including "cleared" volumes, relating to the two German market areas GASPOOL and NCG until September 2021 and realised in the common market area "Trading Hub Europe" (THE) as of October 2021, amounted to approximately 664 TWh in 2021, an increase of around 37% on the previous year's figure of 486 TWh. The on-exchange volume traded on the spot market also increased in 2021 and was around 582 TWh (2020: around 429 TWh). In 2021 – as in previous years– the majority of spot market transactions for all market areas focused on day-ahead contracts. The trading volume of futures contracts rose from about 58 TWh in 2020 to around 82 TWh, corresponding to an increase of around 41%.

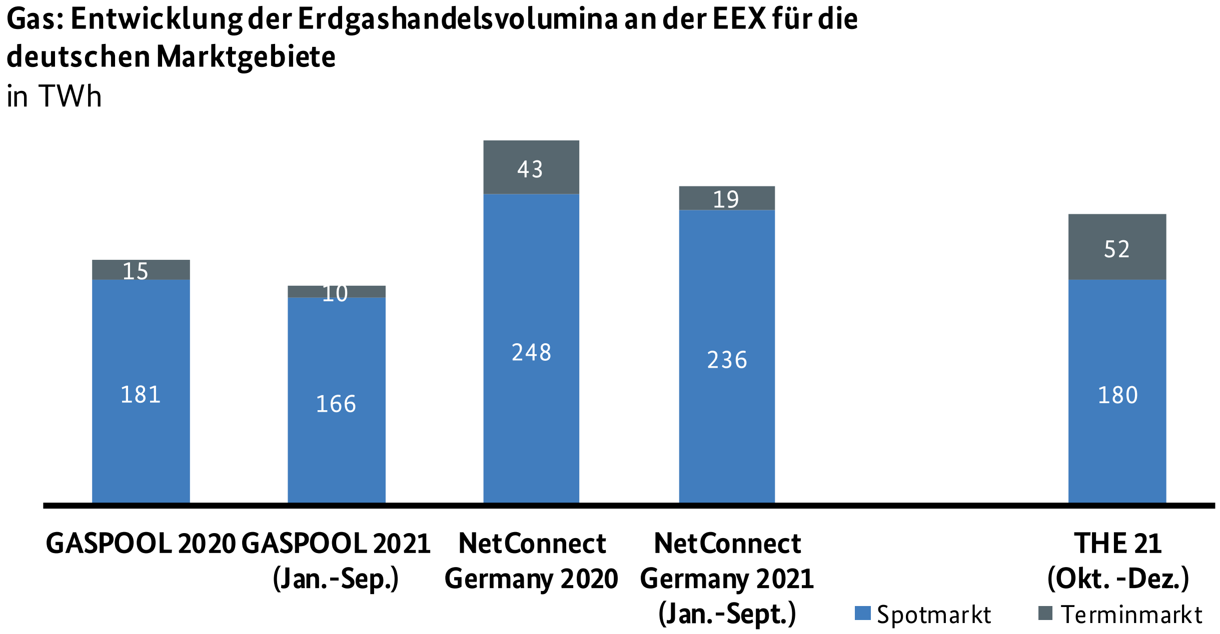


Figure 197: Development of natural gas trading volumes on EEX for the German market areas

[155] EEX Group annual report/financial results for 2020, press briefing, p. 13

On 31 December 2021 the total number of participants trading on the EEX exchange was 158. The annual average number of active[156] participants on the spot market per trading day was 83 for THE contracts. The average number of active participants on the futures market per trading day was merely five participants for the THE market area. 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 on-exchange trading 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.

Nine broker platforms (ten 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 2021 with Germany as the supply area comprised a total volume of 2,392 TWh (2,898 TWh brokered by ten platforms in the previous year) of which 862 TWh were for contracts to be fulfilled in 2021 with a fulfilment period of at least one week. The year-on-year decrease of around 17% in the total volume brokered is likely to also result from the lower number of brokers participating in the data survey for 2021.

[156] Participants are considered to be active on a trading day if at least one of their bids has been fulfilled.

Gas: Natural gas trading via nine broker platforms in 2021 by fulfilment period
in TWh

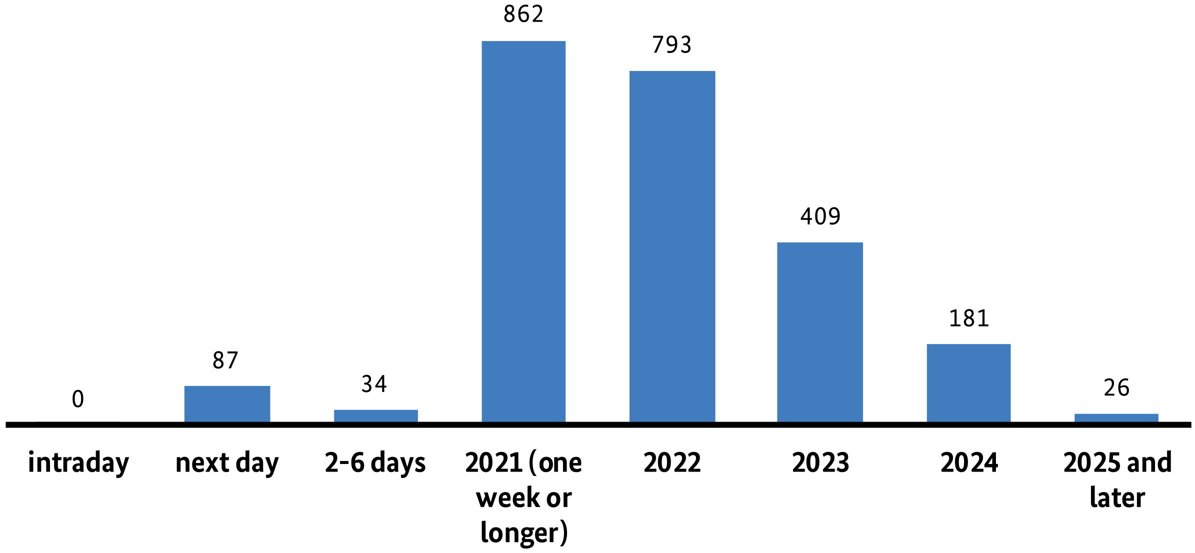


Figure 198: Natural gas trading for the German market areas via nine broker platforms in 2021 by fulfilment period

With regard to the survey of the nine brokers for the 2021 energy monitoring, short-term transactions on the spot market with a fulfilment period of less than one week only accounted for around 5% (previous year: 7%) of the transactions brokered by the nine broker platforms whereas 95% were futures contracts. Transactions for the current year make up the majority of brokered natural gas trading, followed by the deliveries for the subsequent year. While natural gas traded in 2021 (including spot trading) made up only 41% (47% in the previous year) of the total trading volume, the share of natural gas traded in 2022 was around 33% (29% in the previous year). Transactions with supply dates in 2023 and later amounted to around 26% (24% in the previous year).

A decline in the gas trading volume in 2021 is also shown in the data relating to brokered natural gas trading published by the London Energy Brokers' Association (LEBA). Seven of the nine broker platforms that provided data on which the following analysis was based are members of LEBA. All the LEBA-affiliated broker platforms accounted for a total of 2,465 TWh for the German market areas in 2021 (2,841 TWh in the previous year), which corresponds to a decrease of around 15% compared to the previous year.

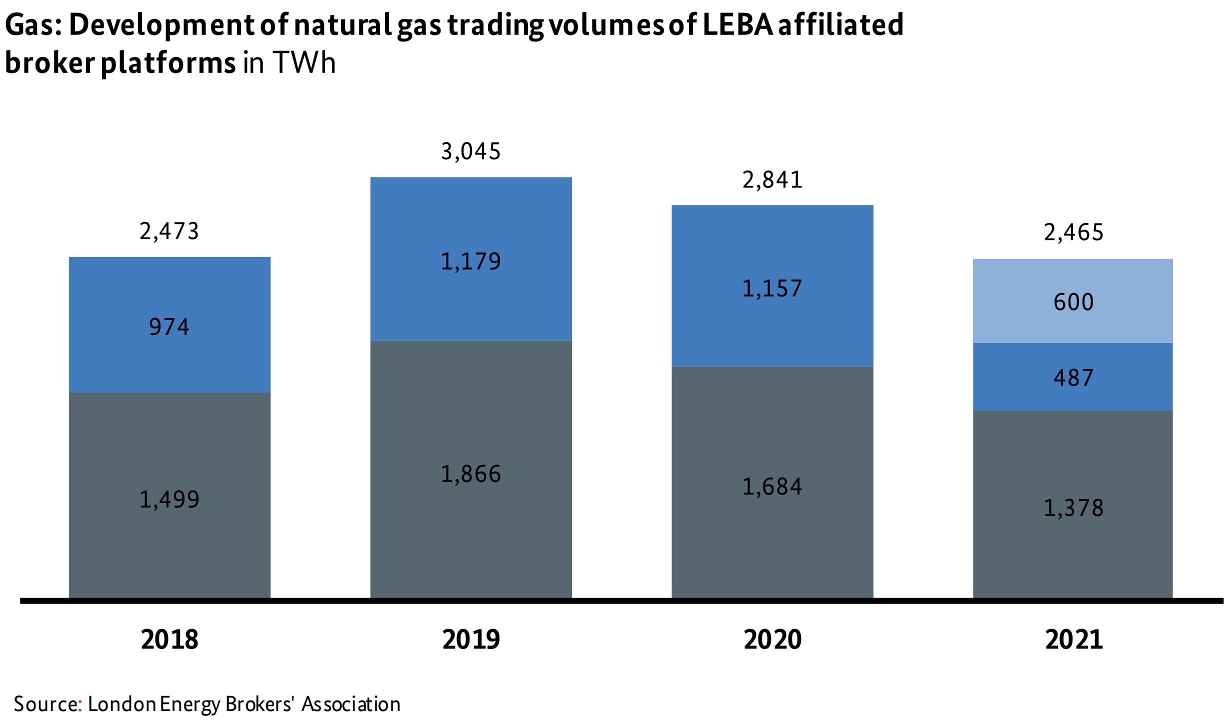


Figure 199: Development of natural gas trading volumes of LEBA-affiliated broker platforms for the German market areas

2.2 Nomination volumes at virtual trading points

The nominated volumes at the German virtual trading points (VTPs) are also key indicators of the liquidity of 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 case of exchange transactions. 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 market area managers, NCG and GASPOOL (data until September 2021), and THE (data as of October 2021) took part in this year's collection of gas wholesale trading data. The gas volumes nominated at the VTPs increased only slightly from a total of 3,806 TWh in the previous year to 3,807 TWh in 2021. Around 35% (1,342 TWh) of the gas volumes were nominated at the GASPOOL VTP, around 39% (1,498 TWh from January to September 2021) at the NCG VTP and around 25% (967 TWh from October to December 2021) at the THE VTP. Almost 91% of the nomination volume consisted of high calorific gas, the remaining 9% of low calorific gas.

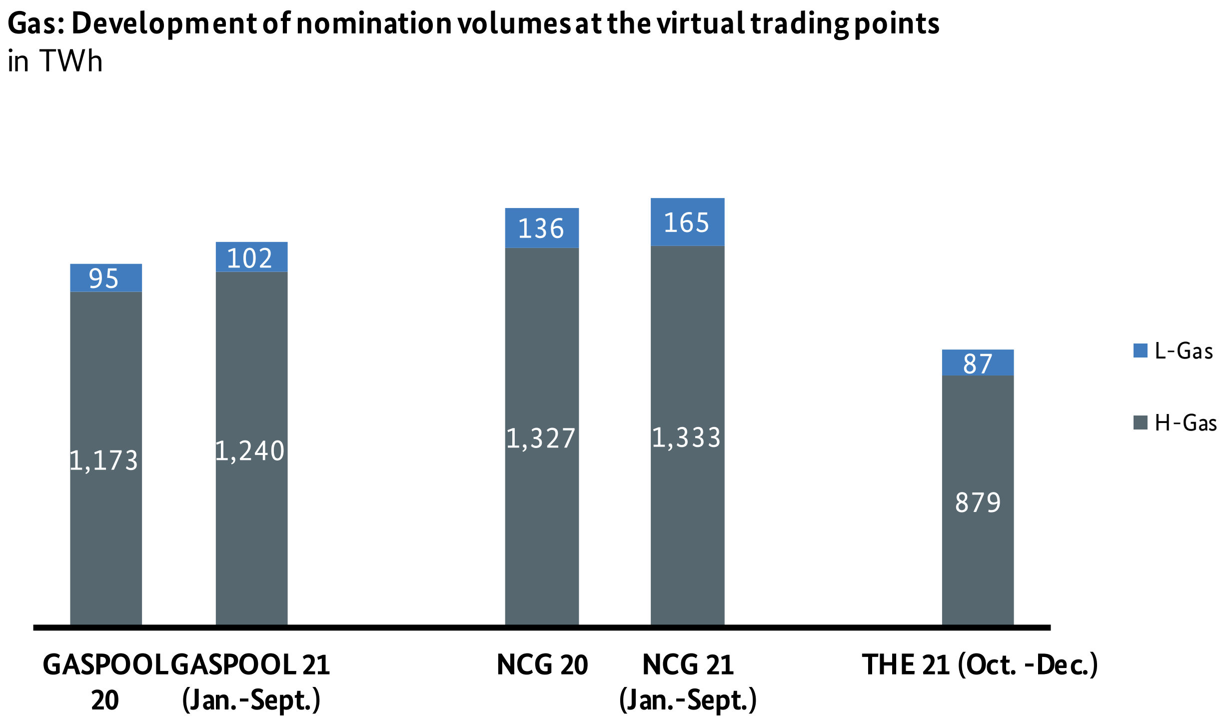


Figure 200: Development of nomination volumes at the German virtual trading points

A comparison with the previous year shows the development of the volumes nominated by NCG and GASPOOL from October to December 2020 and the volumes nominated by THE from October to September 2021.

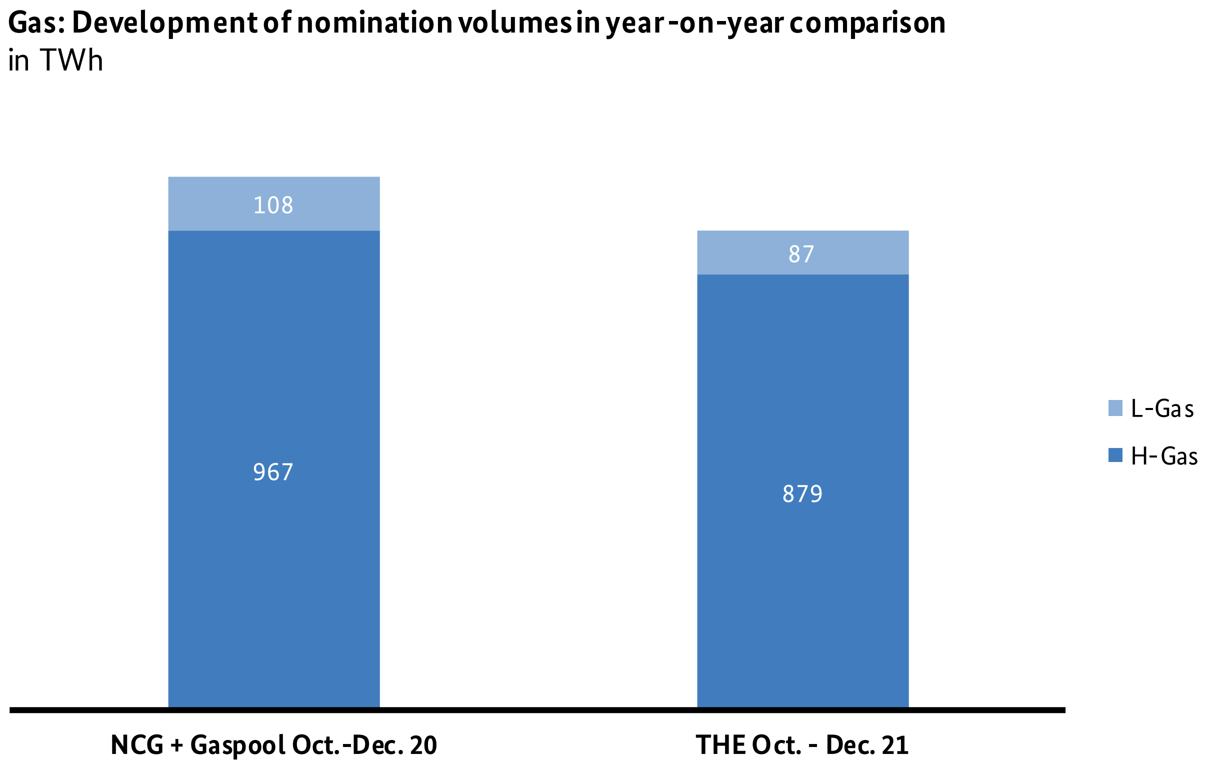


Figure 201: Year-on-year development of nomination volumes in TWh

As in previous years, the monthly nomination volumes reflect seasonal differences. The (aggregated) monthly volume nominated at VTPs peaked at 254 TWh between July and September 2021. The lowest nomination volume was around 232 TWh in June 2021; the annual peak of 440 TWh was reached in January 2021.

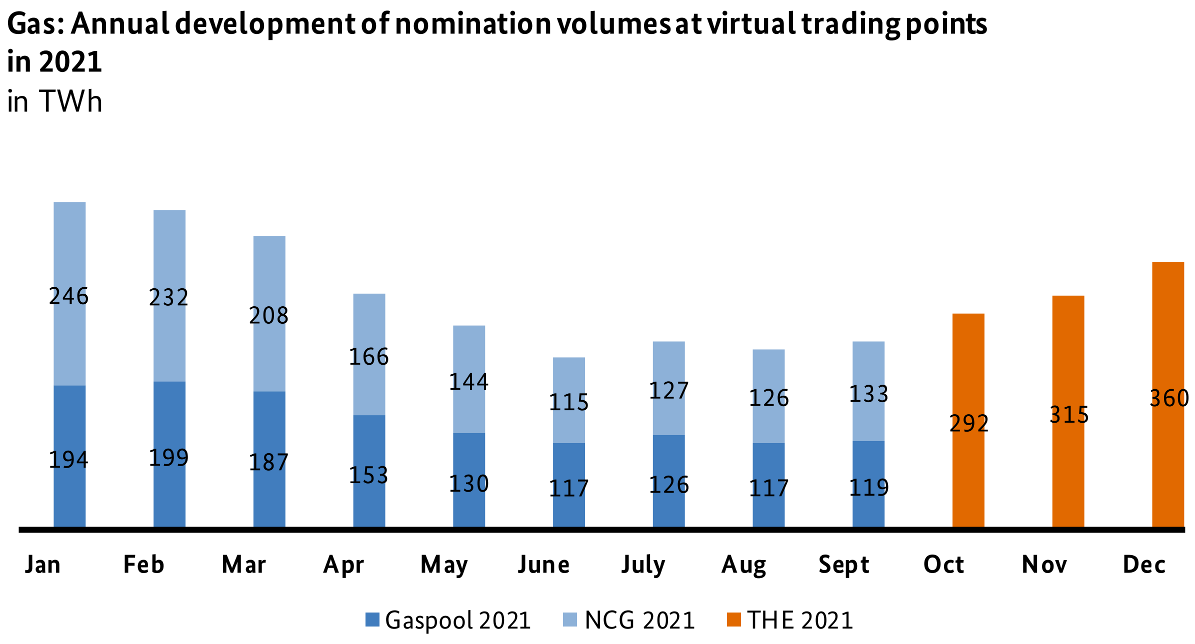


Figure 202: Annual development of nomination volumes at virtual trading points in 2021

The number of active trading participants in 2021, i.e. companies that carried out at least one nomination in the relevant month, developed as follows: The number of active trading participants in the NCG market area rose from 341 to 345 for high calorific gas whereas the number of active trading participants for low calorific gas was 176 (179 in the previous year). The number of active participants in the GASPOOL market area increased from 279 to 284 for high calorific gas. With regard to low calorific gas the number of active participants in the GASPOOL market area also increased again from 139 to 142. The average number of active participants in the THE market area amounted to 424 for high calorific gas, and 197 for low calorific gas.

3. Wholesale prices

As an important exchange for natural gas trading in Germany EEX publishes several price indices as a bases for reference prices for gas contracts with different procurement periods. The EGSI 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 time frame of approximately one month. The price for the procurement of natural gas based on long-term supply contracts can, on the other hand, be estimated based on the BAFA border price for natural gas (see figure 206).

The EGSI has replaced the daily reference price as a short-term price index and 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.

Until September 2021 the (unweighted) annual average EGSI amounted to 30.29 euros/MWh for the NCG market area and 30.33 euros/MWh for the GASPOOL market area. In 2020 the comparative figures for the daily reference price were 9.58 euros/MWh for the NCG market area and 9.71 euros/MWh for the GASPOOL market area, which corresponds to an increase of about 316% for the NCG market area and an increase of about 312% for the GASPOOL market area in 2021. In the course of 2021 the EGSI fluctuated between the monthly average figures of 17.69 euros/MWh (in February 2021) and 62.85 euros/MWh (in September 2021) in both market areas. The sharp rise of the EGSI in the second half of the year already indicates the subsequent price development in 2022, which is not yet presented in this report.

Gas: EGS Index (EGSI) in 2021 for the NCG and Gaspool market areas
in euros/MWh

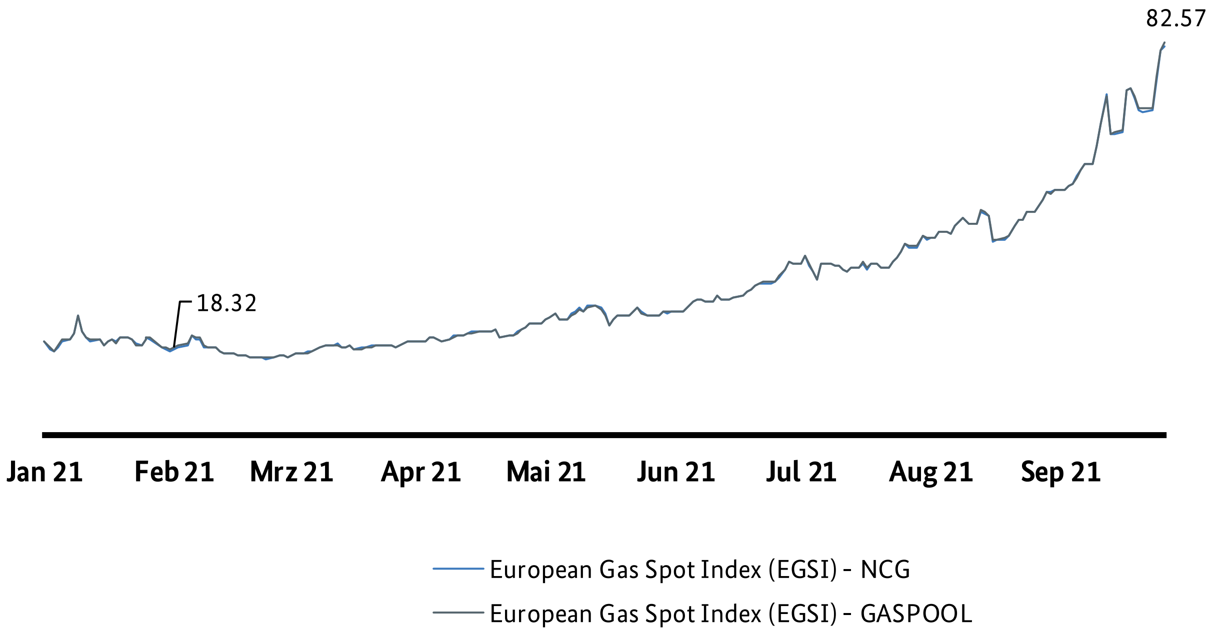


Figure 203: EEX-EGSI in 2021 (until September 2021)

The EGSI for the new THE market area was 90.94 euros/MWh in October 2021 and rose to 115.05 euros/MWh by December 2021, which compared to the EGSI in December 2020 represents a price increase of around 624% for the former NCG market area and 611% for the former GASPOOL market area.

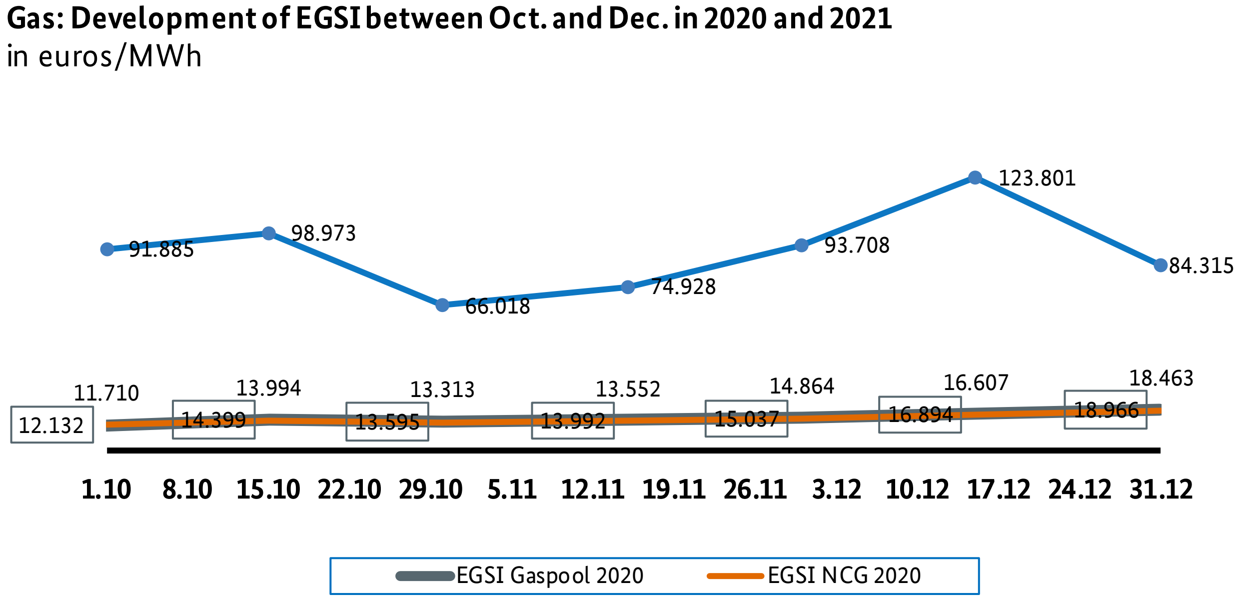


Figure 204: Year-on-year comparison of the EGSI development

The deviations between the EGSI for the NCG and GASPOOL market areas were only marginal in 2021. There were price differences of 3% or less on only six trading days (2020: on 15 trading days). On 218 of 226 exchange trading days[157] (2020: 171 of 249 exchange trading days) the difference was no more than 1%.

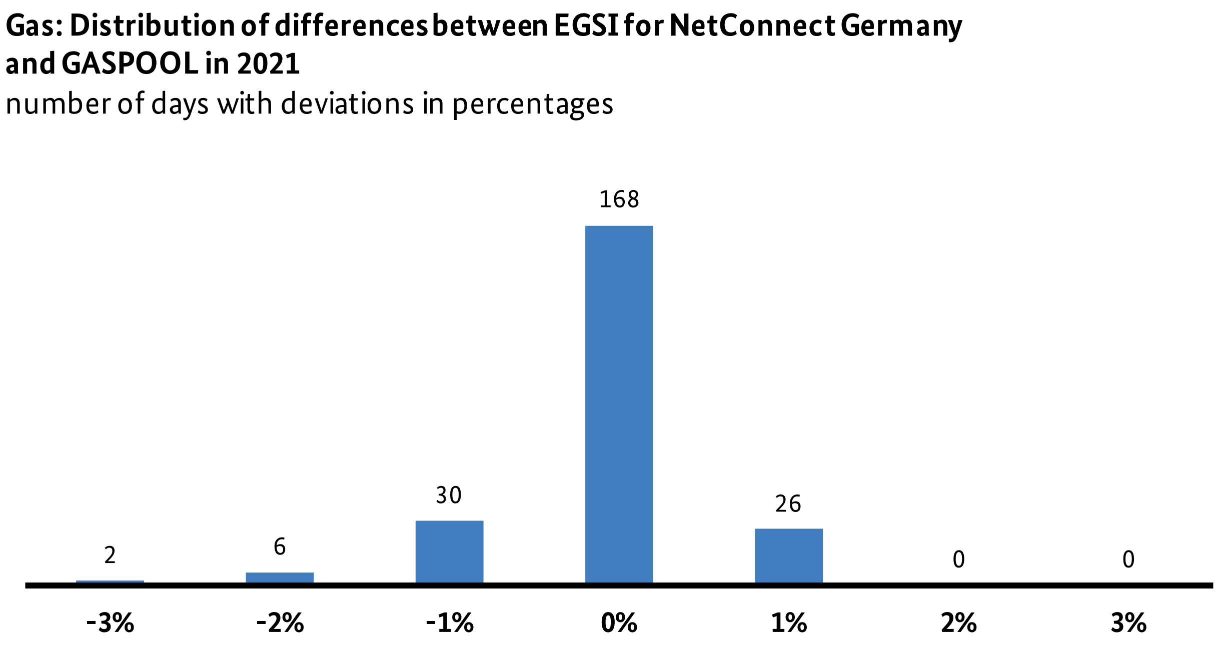


Figure 205: Distribution of the differences between the EGSI for GASPOOL and NCG in 2021

[157] Exchange trading days until 30 September 2021. After this date the market areas were merged.

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 in the market areas[158]. In 2021 the EGIX Germany ranged between 16.03 euros/MWh in January and 94.05 euros/MWh in November. The arithmetic mean of the twelve monthly figures was 38.64 euros/MWh, an increase of around 403% compared to the previous year's figure of 9.59 euros/MWh.

The border price for each month is calculated by the Federal Office for Economic Affairs and Export Control (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 import quantities included in the calculation of the border price are mainly based on import agreements; spot volumes, however, are not comprehensively reflected in the imports and exports.[159] The (unweighted) average of the monthly BAFA border prices was 26.02 euros/MWh in 2021, up by 115.6% from the 2020 figure of 12.07 euros/MWh.

Gas: Entwicklung des BAFA-Grenzübergangspreises und des EGIX Deutschland
in Euro/MWh

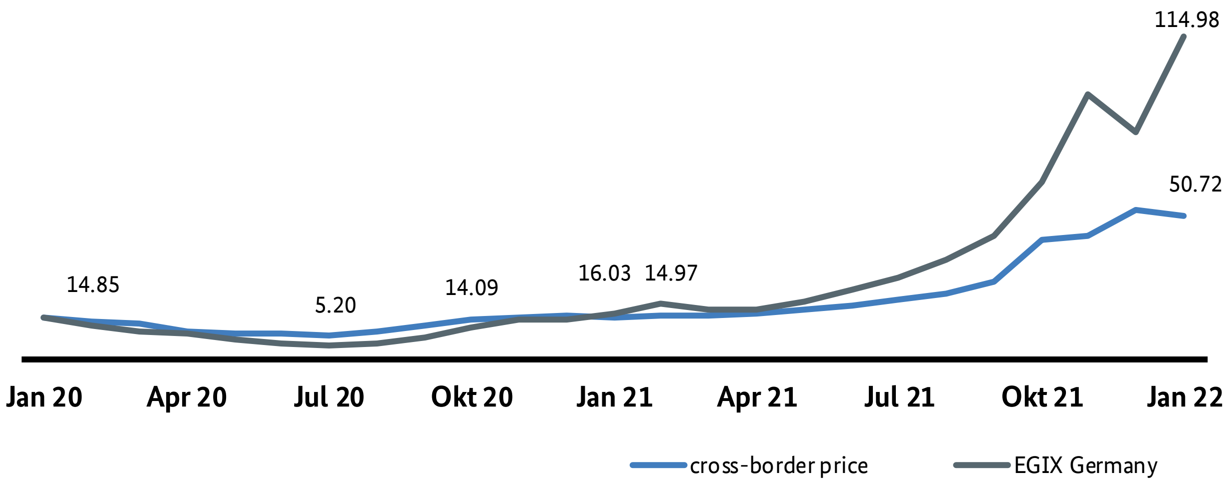


Figure 206: Development of the BAFA border price and the EGIX Germany between January 2020 and January 2022

The development in 2021 shows that the EGIX increased more significantly than the average BAFA border price.

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[158] For a detailed calculation of the values https://www.eex.com/fileadmin/EEX/Downloads/Trading/Indices/20220801_EEX_Gas_Reference_Price_EGIX_01.pdf (retrieved on 17 August 2022).

[159] See https://www.bafa.de/DE/Energie/Rohstoffe/Erdgasstatistik/erdgas_node.html (retrieved on 17 August 2021).

F Retail

1. Supplier structure and number of providers

A total of 1,019 gas suppliers took part in the 2022 monitoring survey. 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

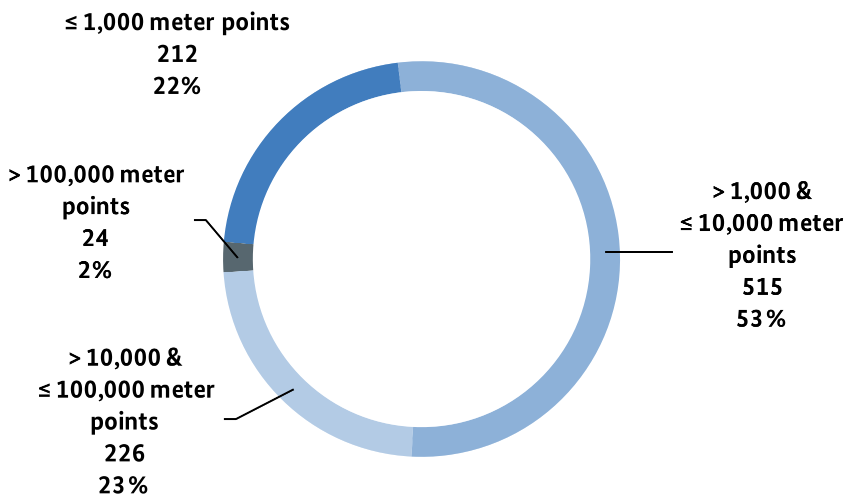


Figure 207: Gas suppliers by number of market locations supplied (number and percentage) – as at 31 December 2021

One indicator of the degree of choice for gas customers is the number of suppliers in each network area. In the 2022 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 into account . 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 2021 as well.

On average, final consumers in Germany can choose between 135 suppliers in their network area; household customers can, on average, choose between 113 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))
(%, without taking account of company affiliations)

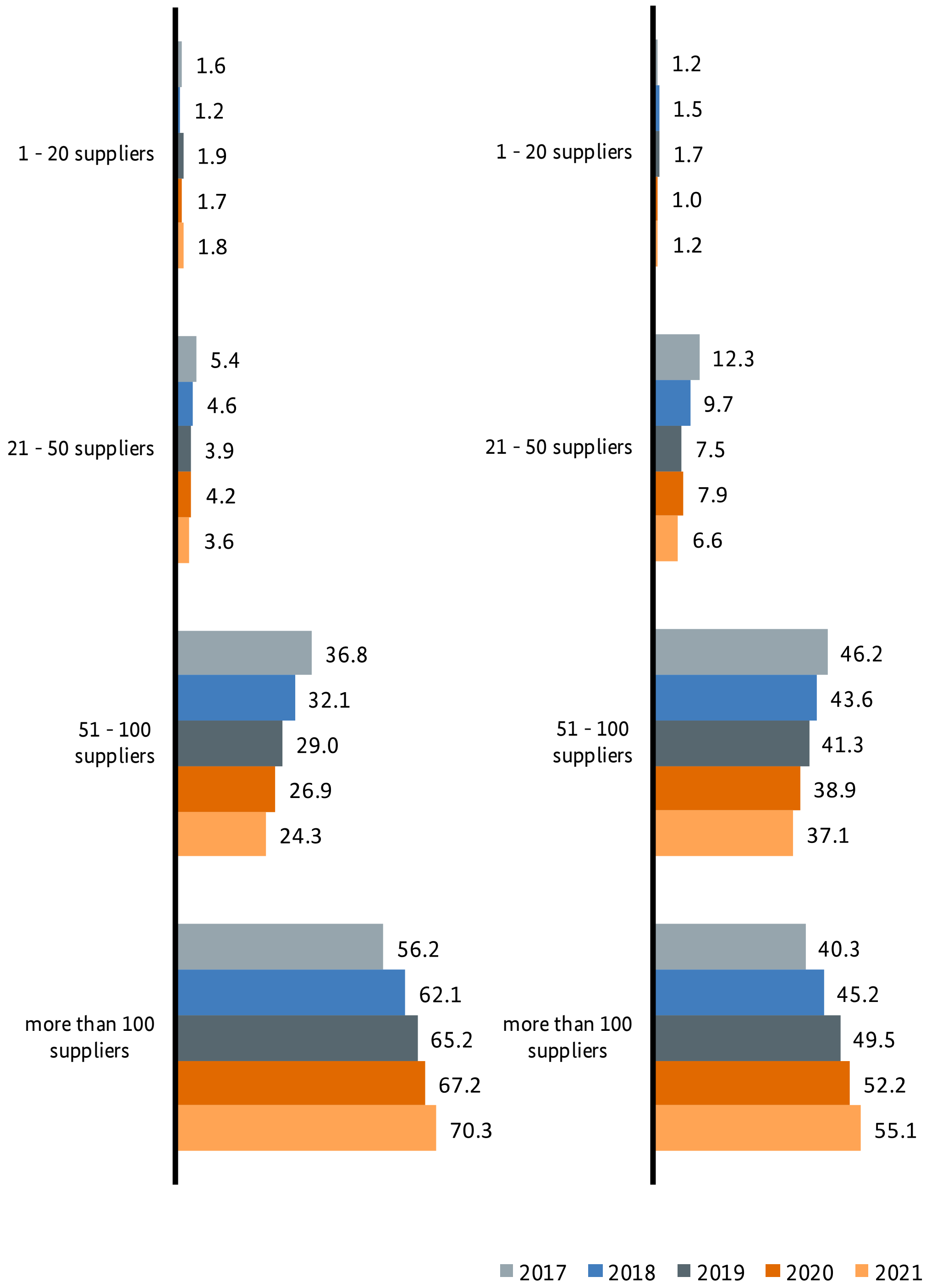


Figure 208: Breakdown of network areas by number of suppliers operating according to the survey of gas DSOs as at 31 December 2021

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 65 gas suppliers (6%) fulfil this criterion and are regarded as suppliers that are active nationwide.

Gas: number and percentage of suppliers supplying customers in the number of network areas shown
figures do not take account of company affiliations

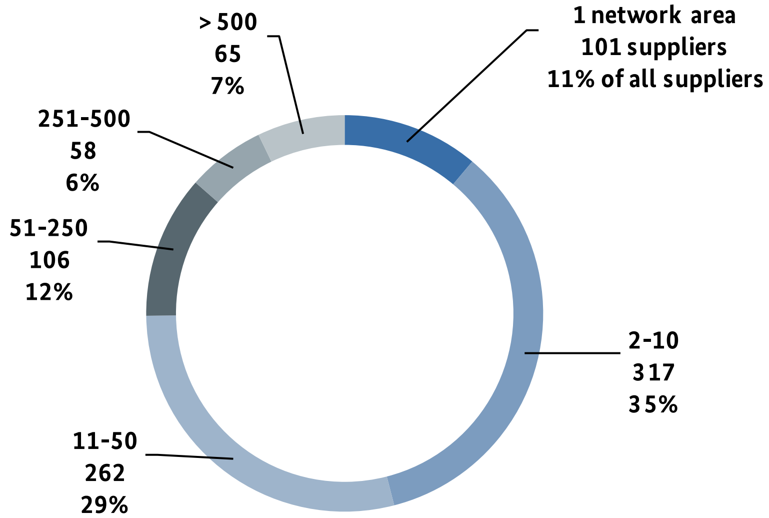


Figure 209: Gas suppliers by number of network areas supplied (number and percentage) according to the survey of gas suppliers as at 31 December 2021

2. Contract structure and supplier switching

In 2021, about 41% of Germany's 12.8mn household customers had a non-default contract with the local default supplier. About 24% had a default contract with their default supplier. Around 35% of household customers had a gas supply contract with a supplier that is not the local default one.

The proportion of default contracts has been falling for years, while the proportion of contracts with a supplier other than the local default supplier has been rising continually.

Nearly two million household customers switched gas supplier in 2021. People moving house or moving into new homes, in particular, were more and more likely to turn directly to a supplier that is not the local default one.

In the fourth quarter of 2021, procurement prices in Germany rose sharply, leading some suppliers to cease business and, in some cases, to become insolvent. These included one larger gas and one larger electricity supplier as well as several smaller suppliers. The suppliers' customers were automatically transferred to their default supplier without their energy supply being disrupted. This above-average increase in customer numbers prompted several suppliers to introduce different general prices for existing and new customers. One particular reason for doing this was that the energy they had to procure at short notice for their new customers was considerably more expensive than the energy procured further in advance for their existing customers. The legal admissibility of this "price split" was subsequently the subject of court proceedings.

The legislators responded with an amendment of the Energy Industry Act (EnWG) in July 2022 to prohibit suppliers from having different general prices for existing and new customers on default contracts. However, the general prices for customers automatically transferred to their local default supplier (fallback supply) are allowed to be higher than those for customers (including household customers) on default contracts and can also be changed on the first and the fifteenth of each month.

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.

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.[160] 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 interval-metered and SLP customers in 2021 was 911 TWh (2020: 853 TWh). Based on the reported volumes of gas sold to SLP and interval-metered customers, about 508.3 TWh went to interval-metered customers and about 402.7 TWh to SLP customers, compared to 493.5 TWh and 356 TWh respectively in the previous year.[161] The majority of SLP customers are household customers. In 2021 household customers within the meaning of section 3 para 22 EnWG were supplied with around 273 TWh (2020: 245 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.[162] Supply outside the framework of a default contract is either designated as a non-default contract or is defined specifically ("non-default contract with the default supplier" or "contract with a supplier other than the local default supplier"). This is also known as a special contract *sui generis* between the supplier and the customer (cf section 1(4) 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".[163] Gas suppliers were also asked

[160] 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.

[161] The difference between the amount of 911 TWh (total of interval-metered and SLP volumes) and the total volume of 909 TWh is due to different data from the suppliers surveyed.

[162] 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".

[163] It is also possible that further ambiguities may arise, for example if the local default supplier changes.

how many household customers have switched or changed their energy supply contract in the 2021 calendar year (change of contract).

Data were also collected from the TSOs and DSOs on the number of customers in different groups switching supplier in 2021. 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 a high demand for energy.[164] 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 2021, 932 gas suppliers (separate legal entities) provided information on meter points and on the volumes supplied to interval-metered customers (2020: 922). The 922 gas suppliers include a number of affiliated companies, so that the number of suppliers is not equal to the number of independent competitors.

Overall these suppliers sold over 508.3 TWh of gas to interval-metered customers via more than 42,160 meter points in 2021. Over 99% of this volume was supplied under non-default contracts with the default supplier[165] (116.1 TWh) and under contracts with suppliers other than the local default supplier (392 TWh). It is unusual but not impossible for interval-metered customers to be supplied under default or fall-back supply contracts. Around 0.25 TWh of gas was supplied to interval-metered customers with a default or fall-back supply contract. This corresponds to about 0.05% of the total volume supplied to such customers.

About 22.8% of the total volume supplied to metered load profile customers was as in the previous year sold under contracts with the default supplier outside the default supply and about 77.1% (77.2% in 2020) under

[164] In accordance with Section 24 of the Gas Network Access Ordinance (GasNZV), interval metering is generally required for customers with a hourly consumption rate exceeding 500 KW or an annual consumption of 1.5 GWh.

[165] In accordance with Section 36 EnWG, default supply relates only to household customers. In the following, the term default supply used in connection with non-household customers refers to “fall-back supply”.

supply contracts with a legal entity other than the default supplier. The figures show that being a default supplier is of only minor importance for the acquisition of interval-metered gas customers.

Figure 210: Contract structure for interval-metered customers in 2021

2.1.2 Supplier switching

Data on the supplier switching rates (as defined for monitoring, see above) of different customer groups in 2021 were collected in the transmission system operator and distribution system operator 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:

Gas: Lieferantenwechsel nach Verbrauchskategorien im Jahr 2021

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	1,972,831	14.5%	46.7 TWh	13.6%
≥ 0,3 GWh/Jahr < 10 GWh/Jahr	16,879	12.5%	15.6 TWh	13.2%
≥ 10 GWh/Jahr < 100 GWh/Jahr	875	21.7%	13.3 TWh	13.1%
≥ 100 GWh/Jahr	88	15.5%	27.8 TWh	10.2%
Gaskraftwerke	7	3.5%	4.2 TWh	3.9%
Gesamt	**1.992.882**		**107.6 TWh**	

Table 137: Supplier switching by consumption category in 2021

The total number of meter points with a change of supplier in 2021 increased from 1,547,014 in 2020 to 1,992,882 in 2021 (+28.8%). The total gas volume affected by supplier switching also rose significantly to 107.6 TWh (80.6 TWh in the previous year, +33.5%). This change suggests that more large industrial enterprises also switched supplier in the reporting year.

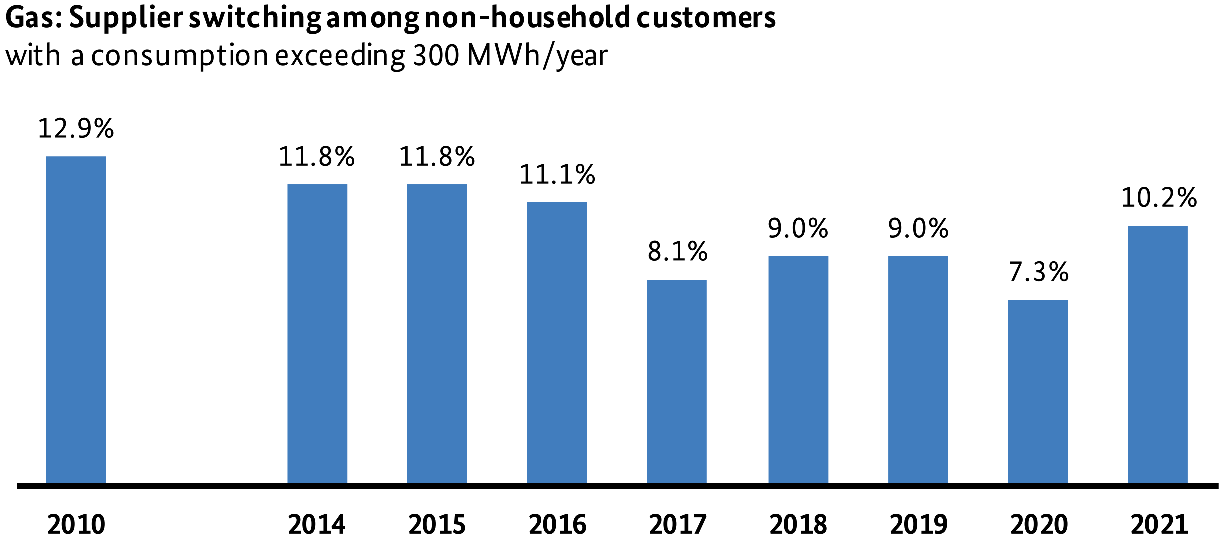


Figure 211: Supplier switching among non-household customers

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 rose again to 10.2% in 2021.

2.2 Household customers

2.2.1 Contract structure

In the data survey for the Monitoring Report 2022, the survey of quantities of gas supplied to household customers was carried out using the representative Eurostat band II (D2) with an annual consumption from 20 gigajoules (GJ) (5,556 kWh) to 200 GJ (55,556 kWh). The average gas consumption for a household customer in Germany of 20,000 kWh is covered by this consumption category, based on the Eurostat system..

An overall analysis of how household customers were supplied shows that the situation was stable although the share of default supply fell again after a slight rise the year before.

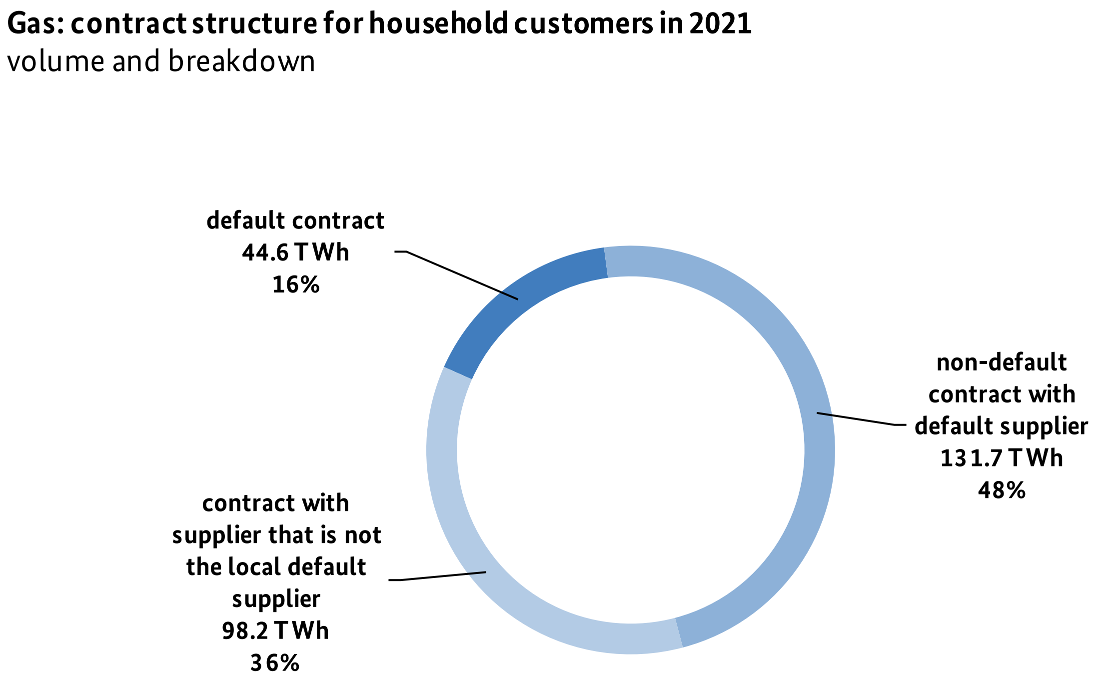


Figure 212: Contract structure for household customers (volume of gas delivered) according to survey of gas suppliers as at 31 December 2021

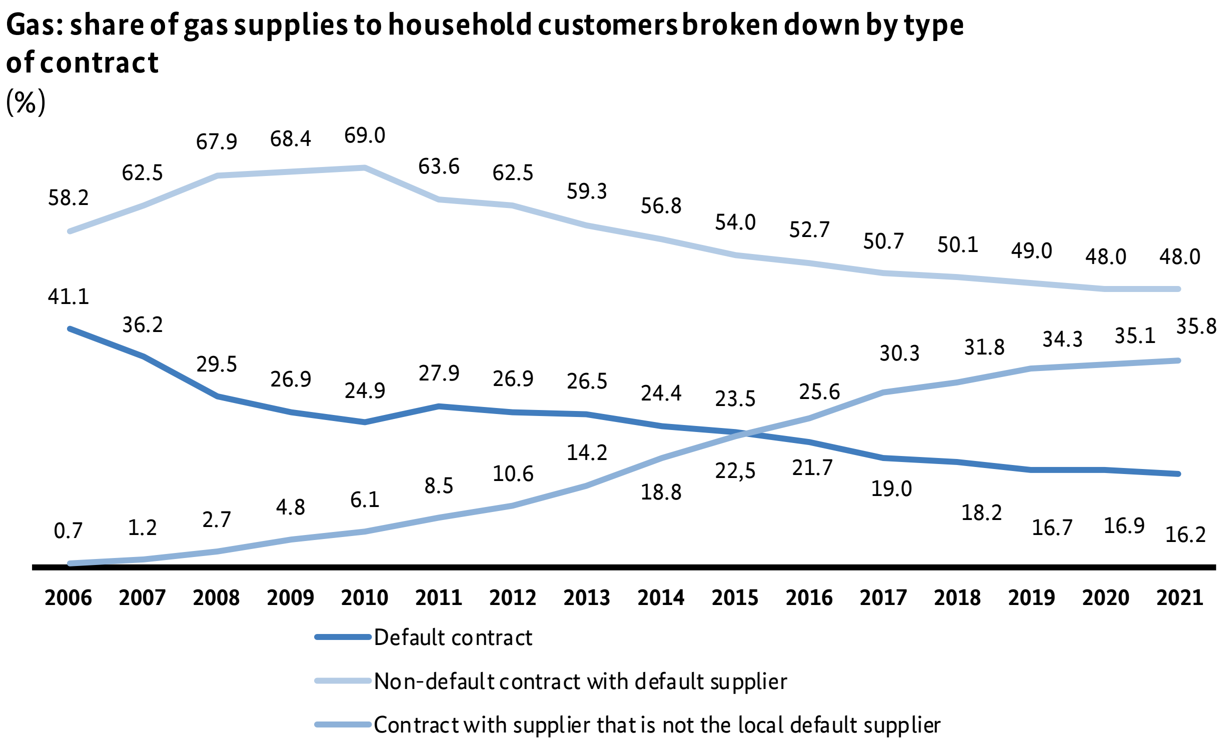


Figure 213: Share of gas supplies to household customers broken down by type of contract according to survey of gas suppliers as at 31 December 2021

The volumes of gas supplied to household customers were examined for a typical household customer example (Eurostat band II, D3) to enable a more in-depth analysis of how household customers were supplied.

Gas: contract structure of household customers (volume and distribution) in consumption band II, D3

Contract type	Band II with consumption of ≥ 5,556 kWh (20 GJ) and < 55,556 kWh (200 GJ)			
	2020		2021	
	Volume (TWh)	Distribution (%)	Volume (TWh)	Distribution (%)
Default contract	31.2	17.8	32.9	16.9
Non-default contract with default supplier	85.8	49.1	93.5	48.1
Contract with a supplier other than the local default supplier	57.9	33.1	67.8	34.9
Total	174.9	100.0	194.2	100.0

Table 138: Contract structure for household customers (volume) for a typical household customer example (Eurostat band II, D3) as at 31 December 2021

When focusing on the number of household customers supplied in 2021, it becomes clear that a relative majority of 41% of them had a non-default contract with the local default supplier.

Gas: contract structure for household customers in 2021
number in millions and percentage

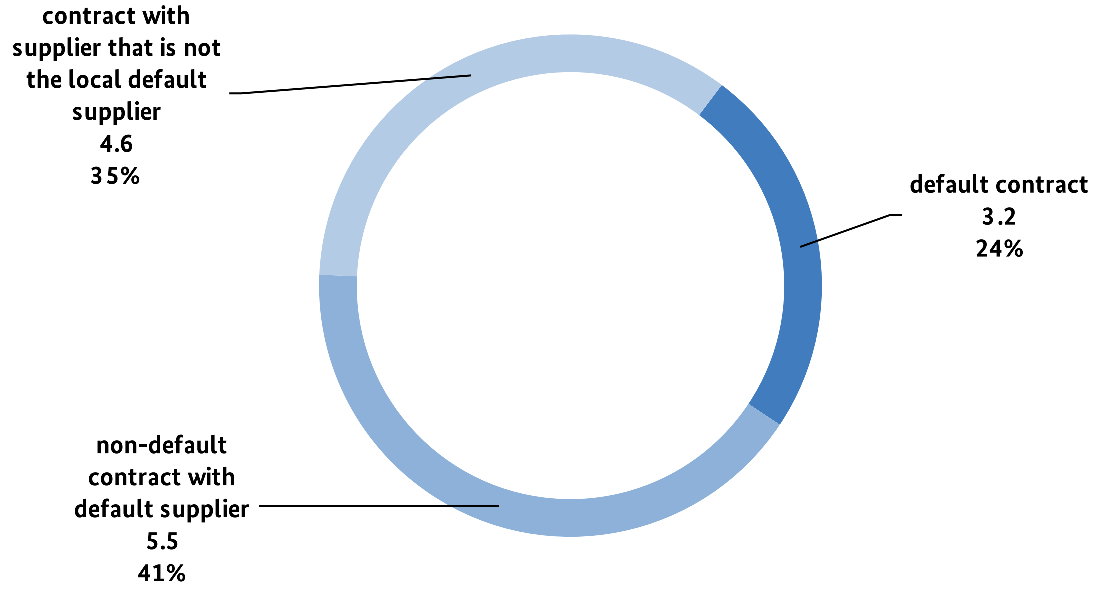


Figure 214: Contract structure for household customers (number of customers supplied) according to survey of gas suppliers as at 31 December 2021

The number of household customers supplied was examined for a typical household customer example (Eurostat band II, D3) to enable a more in-depth analysis of how household customers were supplied.

Gas: contract structure of household customers (number and distribution) in consumption band II, D3

Contract type	Band II with consumption of ≥ 5,556 kWh (20 GJ) and < 55,556 kWh (200 GJ)			
	2020		2021	
	Number (mn)	Distribution (%)	Number (mn)	Distribution (%)
Default contract	1.8	19.6	1.8	18.9
Non-default contract with default supplier	4.3	46.7	4.3	45.3
Contract with a supplier other than the local default supplier	3.1	33.7	3.4	35.8
Total	9.2	100.0	9.5	100.0

Table 139: Contract structure for household customers (number) for a typical household customer example (Eurostat band II, D3) as at 31 December 2021

2.2.2 Change of contract

Gas suppliers were asked about household customers that changed contract at their own request in 2021.[166] There was a significant decrease of around 30% in 2021 in the number and volume of contract switches. The volume-based switching rate was down to 3.1% in 2021 from 4.8%. This could have been due to the gas price rises that started in the third quarter of 2021. Household customers may have kept their existing contracts because of the general developments in prices and the lack of alternatives.

[166] Adjustments to the contract that result from changes to the general terms and conditions, expiring tariffs or customers moving to an affiliated company within the group do not apply here.

Gas: household customers that changed their contracts

Category	Subsequent consumption in 2021 (TWh)	Share of total consumption (273.1 TWh) (%)	Number of contracts changed in 2021	Share of all household customers (13.3mn) (%)
Household customers that changed their contract with their existing supplier	8.5	3.1	0.54 Mio.	4.1

Table 140: Gas household customers that changed their contracts in 2021 according to survey of gas 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. The total number of supplier switches by household customers fell in 2021 by just over 0.5% to around 1.64mn. Around 1.3mn of these household customers changed by cancelling their previous supply contract (voluntary switching). It should be noted that the total number of switches for 2021 does not include "involuntary" switching by customers whose contracts were cancelled by their suppliers, including insolvent suppliers, who were no longer able to supply their customers because of the increase in prices. The number of "involuntary" supplier switches amounted to around 345,200. Possible reasons for the decrease in the number of customers switching supplier include the increases in gas prices beginning in the third quarter of 2021. Customers may have been reluctant to switch to a new gas supplier because of the lack of alternatives in terms of price.

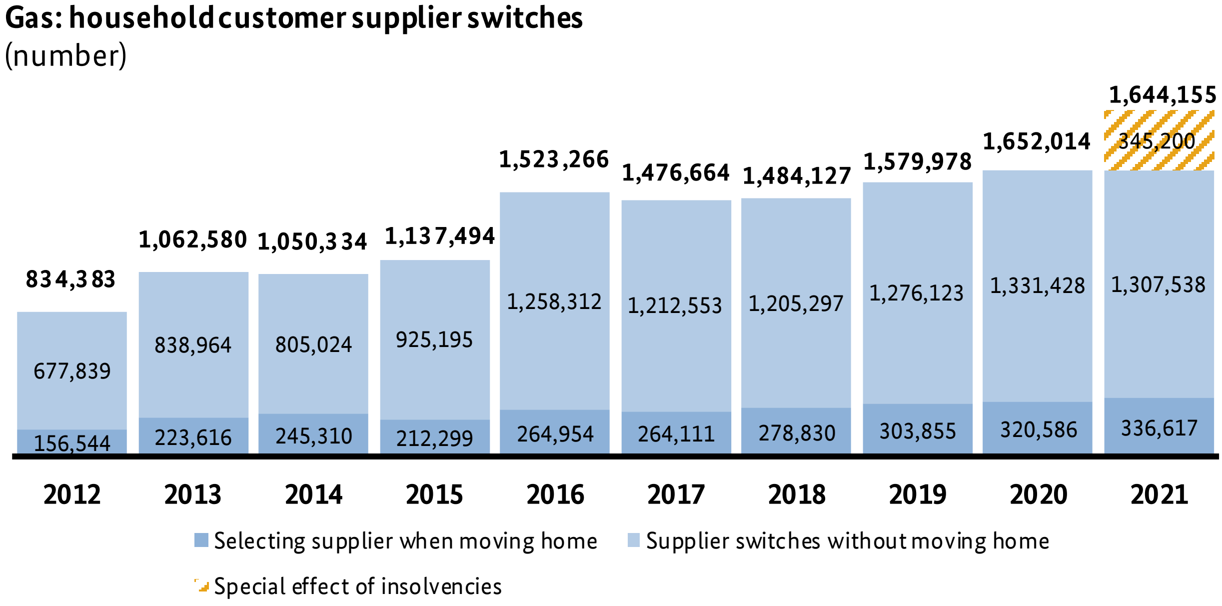


Figure 215: Household customer supplier switches according to survey of gas DSOs

The overall numbers-based supplier switching rate for household customers, based on a total number of household customers of 12.8mn as reported by the DSOs and excluding insolvency-related "involuntary" switches, was 12.8% (2020: 12.9%). The following figure shows the numbers-based switching rates since 2009:

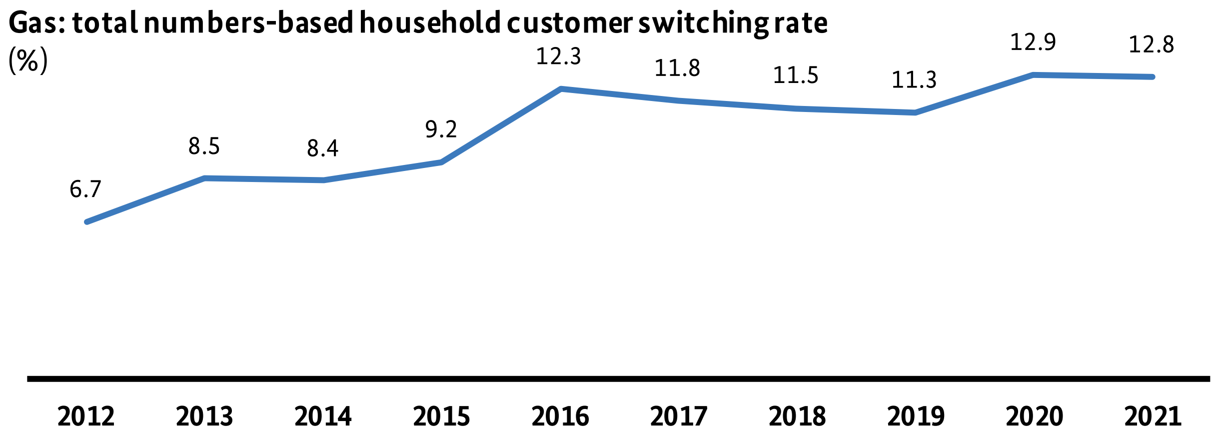


Figure 216: Total numbers-based household customer switching rate according to survey of gas DSOs

3. Gas supply disconnections and contract terminations, cash/smart card meters and non-annual billing

Around 27,000 gas customers were affected by disconnections in 2021.

Customers owing money to their supplier are sent a reminder with a fee, together with or followed by a disconnection notice. The disconnection notice must also include information for the customer about how to avoid being disconnected.

The gas supply cannot actually be disconnected (interrupted) until at least four weeks after a disconnection notice has been issued. For customers on default supply, the specific disconnection date has to be provided eight working days in advance and, at the latest with this announcement, options to prevent disconnection must also be offered, including repayments by instalment and a continued supply on a prepayment basis.

The gas sector has now been brought into line with the electricity sector with the introduction of a lower limit for debt that can lead to the supply being disconnected. Under a default supply contract, the interruption of supply may only be carried out if the customer is two monthly payments and €100 or more in arrears. If no monthly instalment has been agreed, the customer must be at least one sixth of the projected annual amount in arrears. A disconnection may not be disproportionate; in particular, it may not cause a risk to life or limb of those affected.

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 their consumption pattern to change can avoid large back payments by changing their instalment payments. By changing tariff or supplier, consumers can lower their energy costs. Advice about energy costs is available from consumer advice centres, amongst others.

The conditions for disconnecting customers on default supply were tightened up in December 2021. The conditions shown here reflect the new legal situation.

3.1 Disconnections and terminations

In 2021, 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. Disconnections were recorded on a quarterly basis for the first time.

The number of disconnections actually carried out by the network operators in 2021 was 26,905, representing an increase of about 12% compared to the previous year (2020: 23,991). The increase in the number of disconnections in 2021, especially among gas customers, is partly due to disconnections carried over from 2020. There was a clear drop in the number of disconnections in 2020 owing to the right to withhold performance set out in Article 240 section 1 EGBGB, which applied during part of the coronavirus pandemic. In addition, a large proportion of the suppliers had voluntarily decided not to disconnect their customers. In 2021, around half of the suppliers surveyed by the Bundesnetzagentur again voluntarily decided not to disconnect customers. Suppliers often accommodated customers by offering them special or individual payment arrangements.

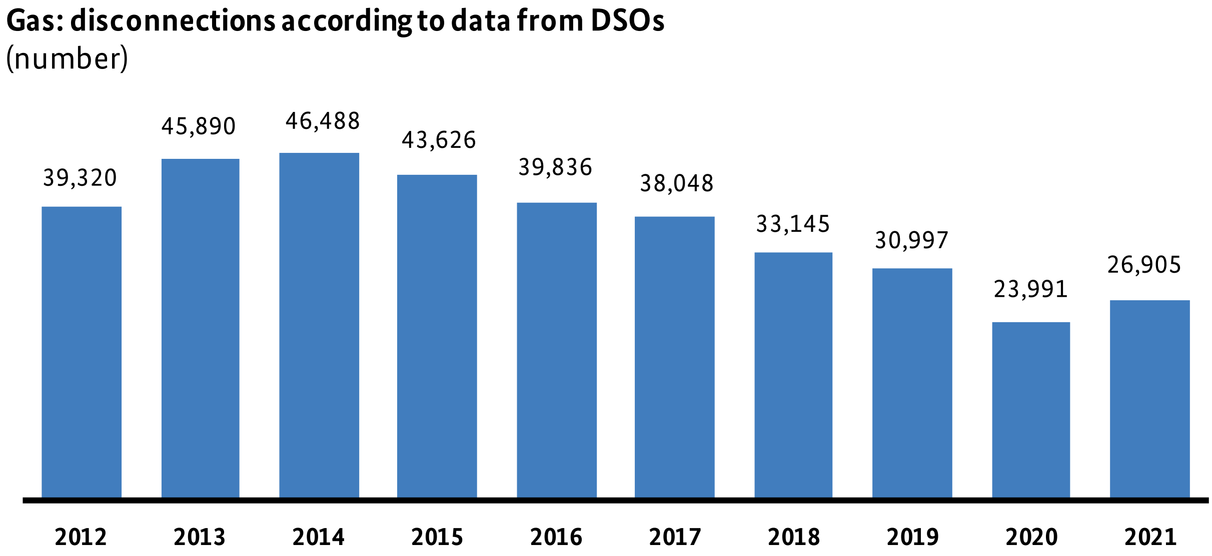


Figure 217: Gas disconnections according to DSOs, from 2013 to 2021

The chart below shows how often suppliers issued disconnection notices to customers that had failed to meet payment obligations in 2021 and how often they requested the network operator responsible to disconnect supplies or carried out the disconnection. There was a rise of about 7.6% in disconnection requests from gas suppliers. This, too, is likely to have been partly due to requests carried over from 2020.

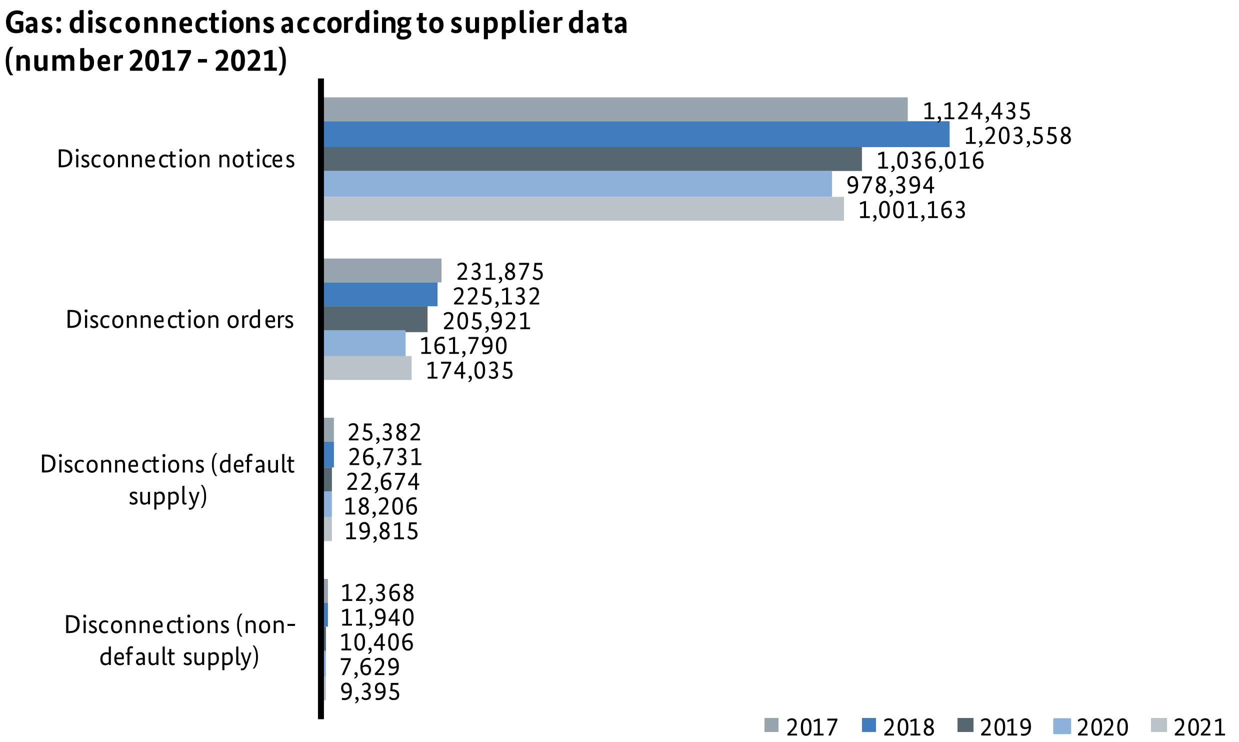


Figure 218: Disconnection notices, disconnection orders and disconnections for gas within and outside default supply, according to data from suppliers

In December 2021, the rules for default supply were changed to the effect that the interruption of supply may only be carried out if the customer is two monthly payments and €100 or more in arrears. If no monthly instalment has been agreed, the customer must be at least one sixth of the projected annual amount in arrears. 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 €3.50 to €210. Suppliers not applying the general calculation charged customers an average of about €50 (including VAT), although the charge also 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 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.

Disconnections were recorded on a quarterly basis for the first time in 2021, providing an overview of seasonal trends. It should be noted that, given the need for the debt to be a certain amount and the deadlines for disconnection notices and orders, the disconnection process always takes some time. The majority of disconnections were carried out in the third quarter, although no reasons were recorded. Generally speaking, consumers are much more severely affected by being disconnected in the winter than in the summer. The chart below shows how disconnections were spread over the year.[167]

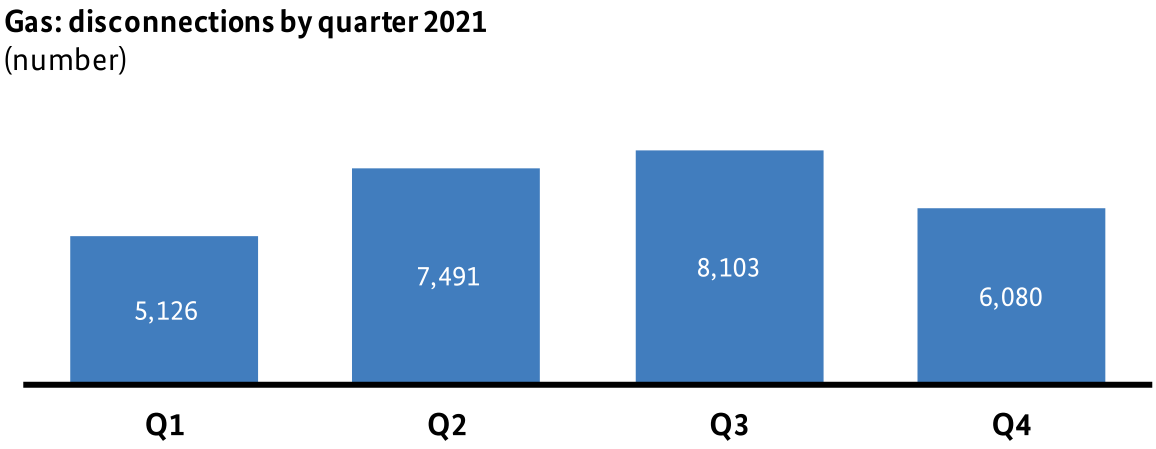


Figure 219: Gas disconnections in each quarter of 2021

The following table shows the distribution of disconnections carried out by DSOs broken down by federal state:

[167] The small difference between the sum of the disconnections reported for each quarter (26,800) and the total number of disconnections reported by the DSOs (26,905) is due to statistical differences.

Gas: number of disconnections in 2021 by federal state according to data from DSOs

	Number of disconnections (default/non-default supply)	Share of market locations of final customers in Germany (%)
North Rhine-Westphalia	12,613	0.34
Berlin	1,470	0.25
Hesse	2,108	0.21
Baden-Württemberg	2,682	0.19
Rhineland Palatinate	1,364	0.16
Saxony-Anhalt	628	0.15
Thuringia	437	0.13
Lower Saxony	2,847	0.13
Bavaria	1,578	0.11
Saxony	530	0.09
Brandenburg	460	0.09
Mecklenburg-Western Pomerania	244	0.09
Schleswig-Holstein	473	0.08
Saarland	145	0.08
Hamburg	144	0.06
Bremen	16	0.01
Germany total	**27,739**	0.19

Table 141: Gas disconnections by federal state in 2021, according to data from DSOs[168]

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 36 days (for reasons of clarity, this figure only includes cases in which both disconnection and reconnection took place in 2021). Around 2,700 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 equipment that could not be reconnected for safety reasons. Despite issuing

[168] The small difference between the sum of the disconnections reported for each federal state (27,739) and the total number of disconnections reported by the DSOs (26,905) is due to statistical differences.

disconnection notices and orders, only a small number of gas suppliers actually terminate supply contracts with their customers. Moreover, the termination of a default supply contract is only permitted under stringent conditions. There must be no obligation to provide basic services or the requirements to disconnect gas supply must have been met repeatedly and the customer must have been warned of contract termination because of late payment. In 2021, gas suppliers (default suppliers and their competitors) terminated their contractual relationship with a total of 41,363 gas customers (2020: 45,462) 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 €185 in 2021, although this figure ranged from €5 to €5,000.

3.2 Cash meters and smart card meters

Gas meter operators and gas suppliers answered questions on prepayment systems, as per section 14 GasGVV, such as cash meters or smart card meters. According to 39 suppliers, a total of 931 household customers had cash or smart card meters, or comparable prepayment systems, in 2021 compared to 1,008 in 2020. There were 96 new installations of prepay systems and 144 existing ones were removed in 2021. 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 €130, with the costs charged ranging from €7.50 to €238. The average kilowatt-hour rate for gas billed using a prepayment meter was 10.14 ct/kWh and ranged from around 5 ct/kWh to 29 ct/kWh.

3.3 Non-annual billing

The new section 40(1) EnWG (section 40(3) EnWG in the old version) 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 2021

	No of requests	Average charge for reach additional bill for customers reading their own meters (range)	Average charge for reach additional bill for customers not reading their own meters (range)
Total other forms of billing for household customers	6,455	€15.40 (€2 - €210)	€19.50 (€1.50 - €210)
of which monthly	3,905		
of which quarterly	547		
of which semi-annual	1,997		

Table 142: Non-annual billing for gas household customers in 2021 according to gas supplier survey

4. Price level

The gas prices for household customers across all types of supply as at 1 April 2022 were considerably higher compared with the previous year and averaged 9.88 ct/kWh. General price developments starting in the third quarter of 2021 and the war in Ukraine were major contributors to the price rises.

Suppliers of gas to final customers in Germany were asked the retail prices their companies charged on 1 April 2022 for various consumption levels. Household customers come under Eurostat band II (D3) with consumption from 20 gigajoules (GJ) (5,556 kWh) to 200 GJ (55,556 kWh). Furthermore, as in previous years, the consumption levels of 116 MWh (= 417.6 GJ for "commercial customers") and 116 GWh (= 417,600 GJ for "industrial customers") were analysed.

Suppliers were asked to give the overall price in cents per kilowatt hour (ct/kWh) and to include the non-variable price components such as the service price, base price and transfer or internal price. Suppliers were also asked to provide a breakdown of the price components that they cannot control, including in particular network tariffs[169], 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, distribution costs and the supplier's margin. The suppliers were asked to provide their "average" overall prices and price components for each of the consumption levels. The two indirect charges, the biogas neutrality charge and the market area conversion charge, are not shown separately in gas bills and are included in the network tariffs. Trading Hub Europe's current gas balancing neutrality charge is €0.0/MWh for the period from 1 October 2022 to 30 September 2022, so it is not shown here.

The gas storage neutrality charge of 0.059 ct/kWh (net) will be part of the gas price from 1 November 2022. The amount of this charge will be regularly reviewed and can be adjusted. At the same time, VAT on gas and district heating will be cut from 19% to 7% from 1 October 2022. The reduction is to be in place until March 2024.

In respect of the consumption of household customers (band II), suppliers were asked to provide data on the price components for three different contract types:

– default contract,

[169] Since 1 January 2017, the component "charge for billing" has been part of the network tariffs and is no longer reported separately.

– non-default contract with the default supplier, and

– 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 2022 and 1 April 2021, 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 87 and 757 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 and nomination 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 were 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 87 suppliers (94 in the previous year).

Gas: Preisniveau am 1. April 2022 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	0.16 - 1.18	0.44	6.5%
Messung, Messstellenbetrieb	0.00 - 0.012	0.004	0.1%
Konzessionsabgabe[1]	0.00	0.00	0.0%
CO_2-Abgabe	0.5461	0.5461	8.1%
Gassteuer	0.55	0.55	8.1%
Vom Lieferanten beeinflussbarer Preisbestandteil (Restbetrag)	1.38 - 11.28	5.21	77.1%
Gesamtpreis (ohne Umsatzsteuer)	2.62 - 12.76	6.76	

[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 143: Price level for the 116 GWh/year consumption category on 1 April 2022

These data were 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 GWh ("industrial customer") is 6.76 ct/kWh and has thus more than doubled compared to the previous year (2021: 2.95 ct/kWh). The price increase is due to the effects of the war in Ukraine and the raw material shortage caused by Russia. An average 7% 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 in the amount of 0.5461 euros, which had to be paid for the first time in 2021, are other cost items outside the supplier's control. Together they account for 16.2% of the average overall price (excluding VAT). Around 77% (2021: 52.1%) of the price is made up of price components that can be controlled by suppliers (gas procurement costs, supply costs and the margin). The share of the price components that cannot be controlled by suppliers is much higher than in the case of household customers or non-household customers with low consumption (see below).

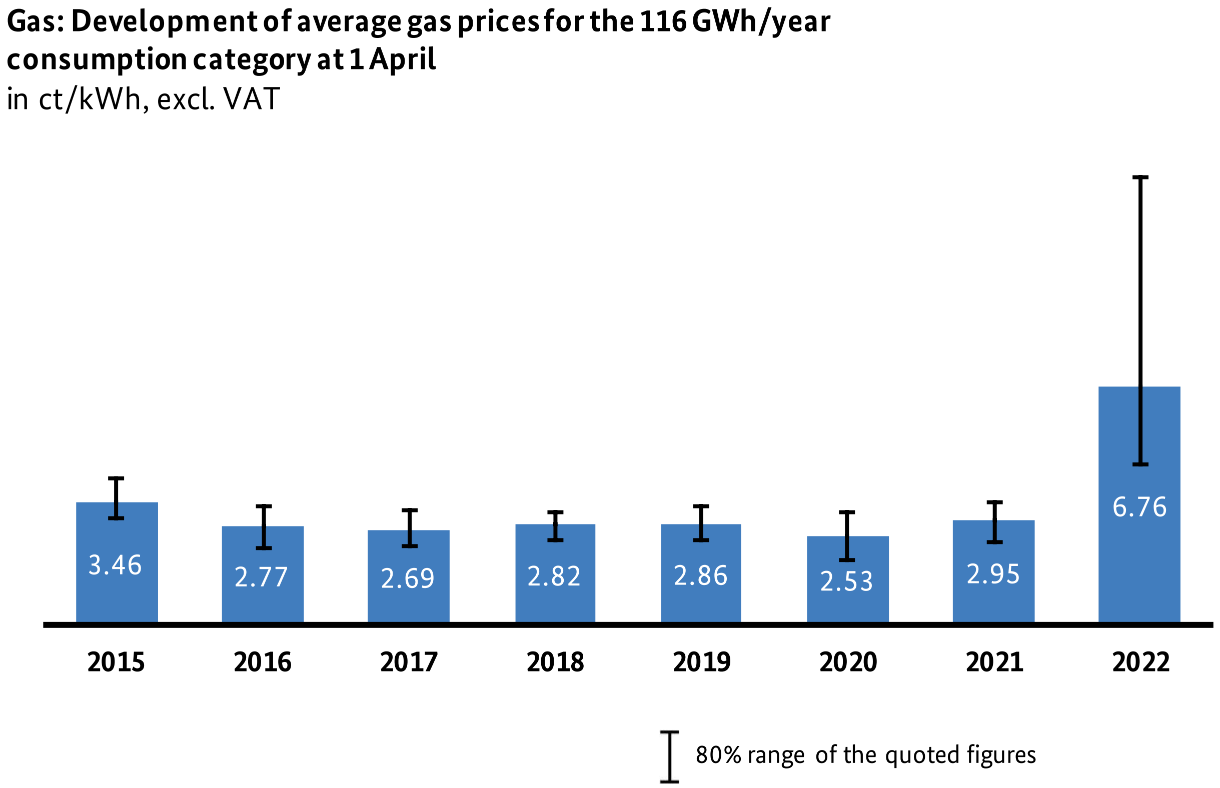


Figure 220: Development of average gas prices for the 116 GWh/year consumption category

116 MWh/year consumption category ("commercial customers")

The non-household customer category based on an annual consumption of 116 MWh includes 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 2022. Data were 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 757 suppliers (777 in the previous year).

Gas: Price level for the 116 GWh/year consumption category on 1 April 2022

	Spread between 10 and 90% of figures provided by suppliers in ct/kWh	**Arithmetic mean** in ct/kWh	**Share of total price**
Price components outside the supplier's control			
Net network charge	0,92 - 1,65	1.25	17.4%
Metering, meter operation	0,01 - 0,09	0.05	0.7%
Concession fee[1]	0,03 - 0,03	0.05	0.7%
CO_2 surcharge	0.5461	0.5461	7.6%
Gas tax	0.55	0.55	7.7%
Price components which can be controlled by the supplier (remaining balance)	2,07 - 9,74	4.69	65.1%
Total price (excl. VAT)	4,55 - 12,28	7.19	

[1] 62 of the 757 suppliers quoted a concession fee of more than 0.03 ct/kWh. These were suppliers with low supply volumes. A concession fee exceeding 0.03 ct/kWh is plausible in the supply of non-household customers in default supply (cf. Section 2(2) no. 2 b KAV).

Table 144: Price level: Price level for the 116 MWh/year consumption category on 1 April 2022

As in the case with industrial customers, these data were used to calculate the arithmetic mean 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 35% (2021: 49%) 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 carbon tax). Around 65% (2021: 51%) relates to price elements that provide scope for entrepreneurial decisions. The arithmetic mean of the overall price of 7.19 ct/kWh (excluding VAT) is 2.45 ct/kWh higher than the previous year's figure. The average net amount of the price components outside the supplier's control rose to 2.44 ct/kWh, 0.11 ct/kWh higher than in the previous year, mainly due to the 0.10 ct/kWh increase in the carbon tax rate. The remaining balance that can be controlled by suppliers, rose by 2.28 ct/kWh (from 2.41 ct/kWh on 1 April 2021 to 4.69 ct/kWh on 1 April 2022) or by about 94.1%. With regard to the 116 MWh/year consumption level the cost increase is also due to the effects of the war in Ukraine and the raw material shortage caused by Russia.

Gas: Development of average gas prices for the 116 MWh/year consumption category at 1 April
in ct/kWh, excl. VAT

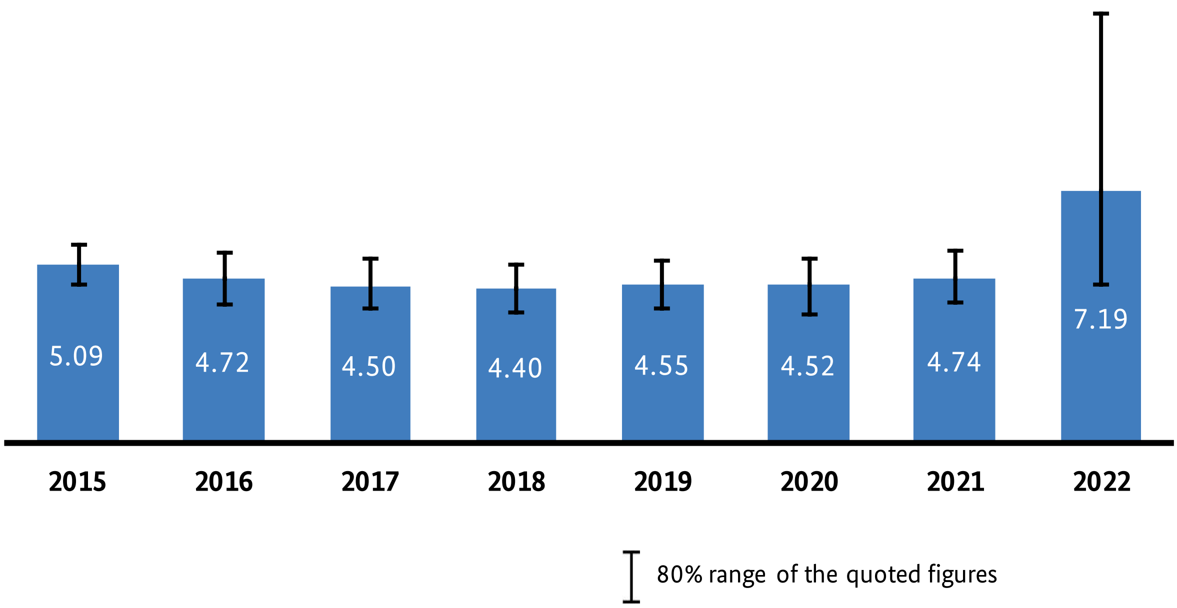


Figure 221: Development of average gas prices for the 116 MWh/year consumption category

4.2 Household customers

The survey of household customer prices was carried out using the Eurostat band II (D2) with an annual consumption from 20 gigajoules (GJ) (5,556 kWh) to 200 GJ (55,556 kWh). The total quantities of gas that were delivered by each supplier as at 31 December 2021 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 tariffs listed for each type of contract category are calculated using figures provided by the suppliers, which in turn are the tariffs averaged over all the networks supplied. This results in a different network tariff for each of the three types of supply contract. The carbon levy rose to 0.5461 ct/kWh on 1 January 2022.

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[170], 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 2022.

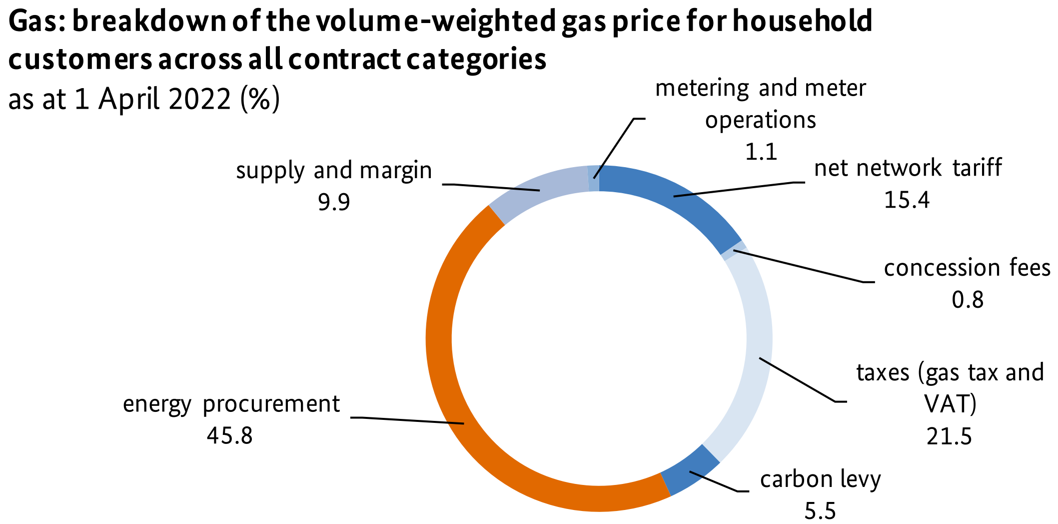


Figure 222: Breakdown of the volume-weighted gas price across all contract categories for household customers according to the gas supplier survey

[170] Eurostat customer category: 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 as at 1 April 2022 (ct/kWh)

Price component	Volume-weighted average across all tariffs (ct/kWh)	Share of total price (%)
Network tariff including upstream network costs	1.52	15.4%
Metering tariff	0.03	0.3%
Meter operations tariff	0.08	0.8%
Concession fees	0.07	0.7%
Carbon levy	0.5461	5.5%
Current gas tax	0.55	5.6%
VAT	1.58	16.0%
Energy procurement	4.53	45.9%
Supply and margin	0.97	9.8%
Total	**9.88**	**100.0%**

Table 145: Average volume-weighted price across all contract categories for household customers according to the gas supplier survey

Gas: development of the volume-weighted gas price for household customers across all contract categories as at 1 April of the respective year
(ct/kWh)

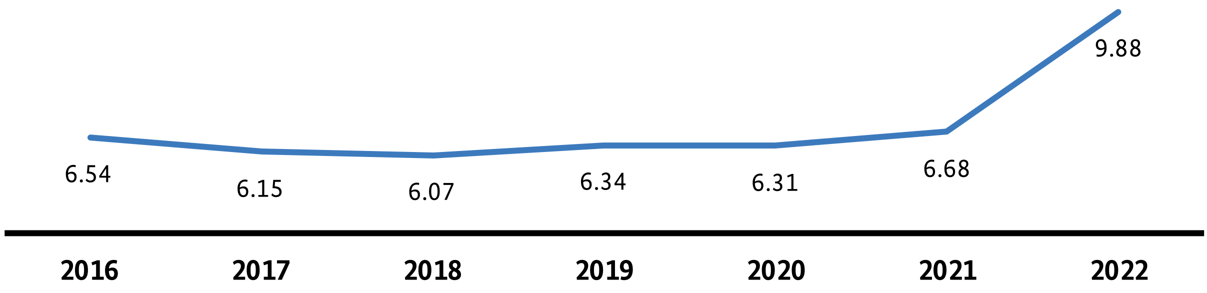


Figure 223: Volume-weighted gas price across all contract categories for household customers according to the gas supplier survey

The volume-weighted gas price for household customers across all contract categories rose about 48% year-on-year from 6.68 ct/kWh to 9.88 ct/kWh. The current survey method does not make a distinction between prices for existing and new customers. There was a considerable increase in the gas prices for new customers, especially from the third quarter of 2021 onwards, while existing customers were still able to benefit from their cheaper prices. The survey method and widening gap between prices for existing and new customers mean that the average calculated is lower than would be expected based on current trends.

4.2.2 Household customer prices broken down by contract category

Gas: average volume-weighted price for household customers per contract category as at 1 April 2022 (ct/kWh)

Price component	Default contract	Non-default contract with default supplier	Contract with supplier other than local default supplier
Net network tariff including upstream network costs	1.54	1.52	1.50
Metering tariff	0.02	0.02	0.05
Meter operations tariff	0.09	0.07	0.08
Concession fees	0.26	0.03	0.03
Carbon levy	0.5461	0.5461	0.5461
Current gas tax	0.55	0.55	0.55
VAT	1.52	1.45	1.76
Energy procurement	3.71	3.80	5.63
Supply and margin	1.27	1.03	0.80
Total	**9.51**	**9.02**	**10.95**

Table 146: Average volume-weighted prices for household customers by contract category according to the gas supplier survey

Supply under a default contract

The volume-weighted gas price in the default supply category was 9.51 ct/kWh as at 1 April 2022 (2021: 7.45 ct/kWh).

Gas: development of gas prices for household customers on a default contract as at 1 April of the respective year
(ct/kWh)

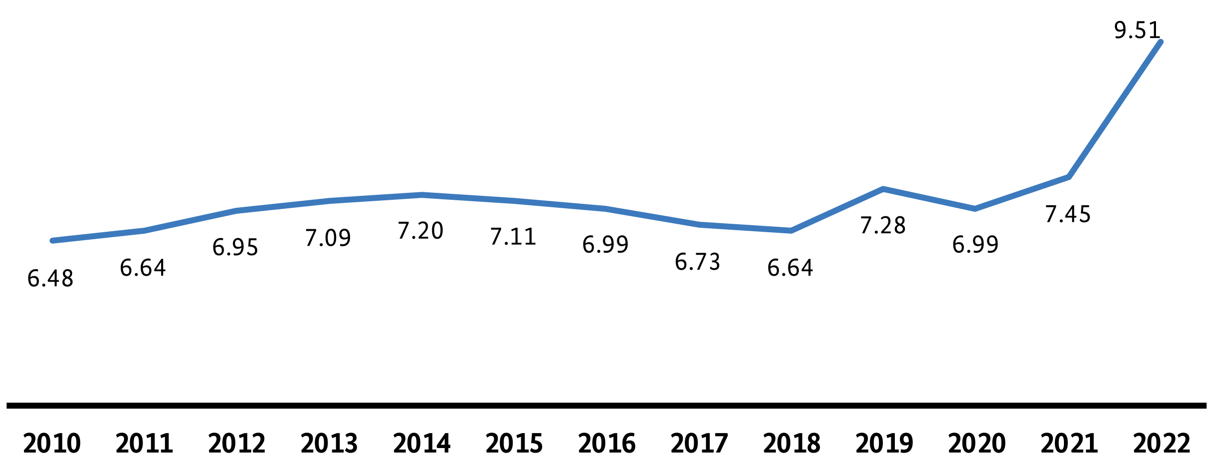


Figure 224: Gas prices for household customers under a default contract (volume-weighted averages) according to the gas supplier survey

Supply by the default supplier under a non-default contract

On 1 April 2022, the volume-weighted gas price for customers under a non-default contract with the default supplier was 9.02 ct/kWh (2021: 6.58 ct/kWh).

Gas: development of gas prices for household customers on a non-default contract with the default supplier as at 1 April of the respective year
(ct/kWh)

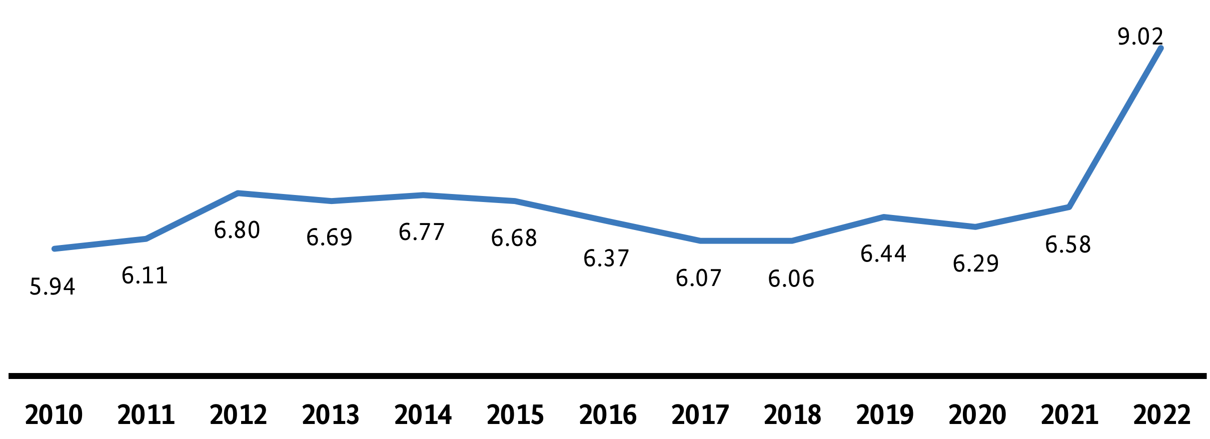


Figure 225: Gas prices for household customers under a non-default contract with the default supplier (volume-weighted averages) according to the gas supplier survey

Supply under a contract with a supplier other than the local default supplier

On 1 April 2022, the volume-weighted price for a contract with a supplier other than the local default supplier was 10.95 ct/kWh (2021: 6.41 ct/kWh).

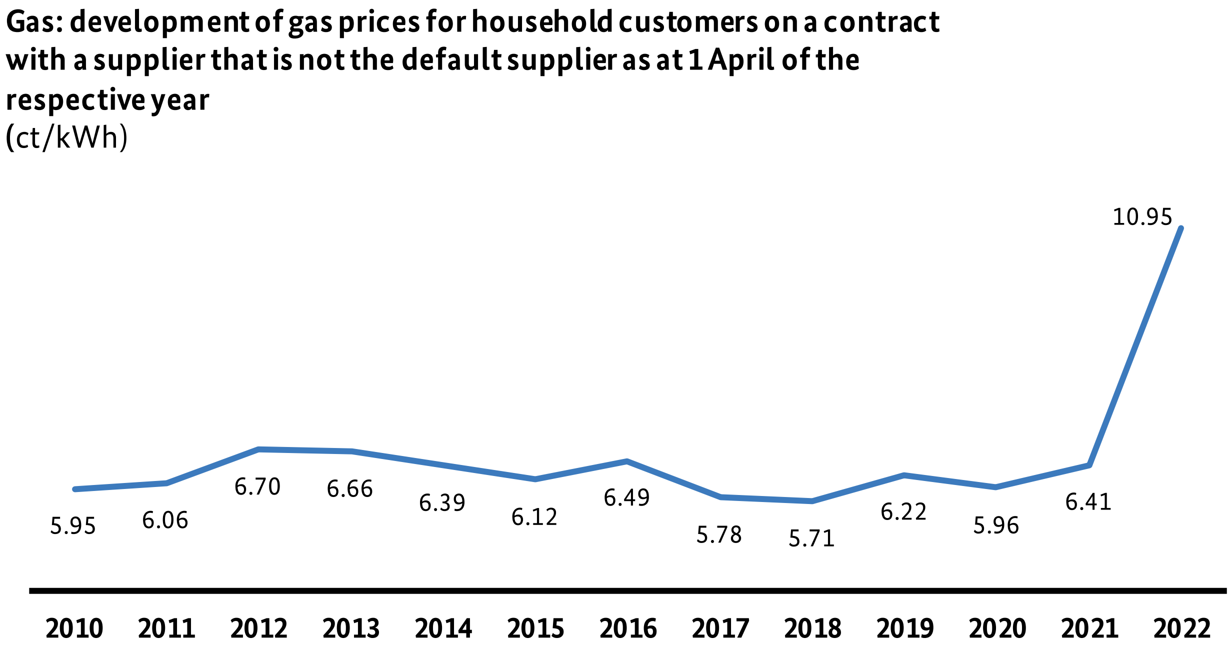


Figure 226: Gas prices for household customers under a contract with a supplier other than the local default supplier (volume-weighted averages) according to the gas supplier survey

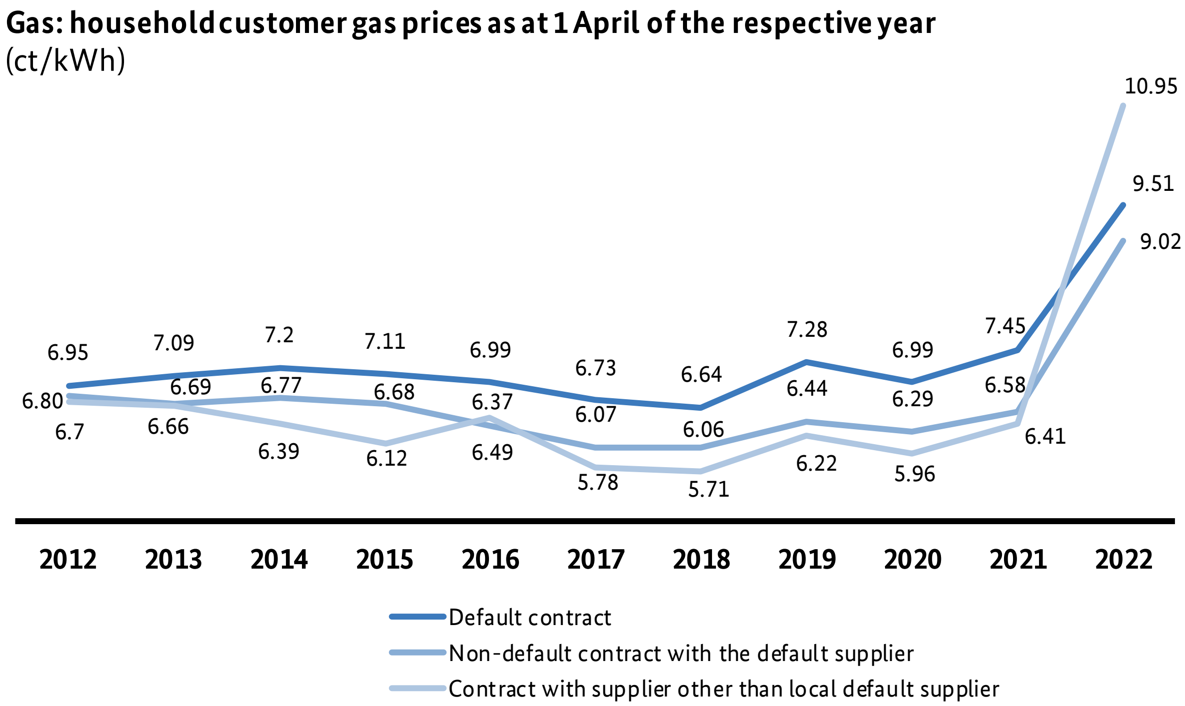


Figure 227: Gas prices for household customers according to the gas supplier survey

The analysis of energy procurement costs reflects the situation on 1 April 2022. In order to continue the time series, the energy procurement costs, distribution costs and margin were aggregated for this representation. As prices on the procurement markets have been extremely dynamic, this evaluation should be regarded as a snapshot. It should also be noted that existing and new customer contracts are taken into account in the averaging of results from the survey, so the currently rising procurement prices are likely to be even higher. The biggest rises in gas procurement costs may be seen in the tariffs of the competitors of the default suppliers, primarily because of their underlying short and medium-term procurement strategy. The cost increases were more modest for default suppliers as they tend to have a longer-term buying strategy.

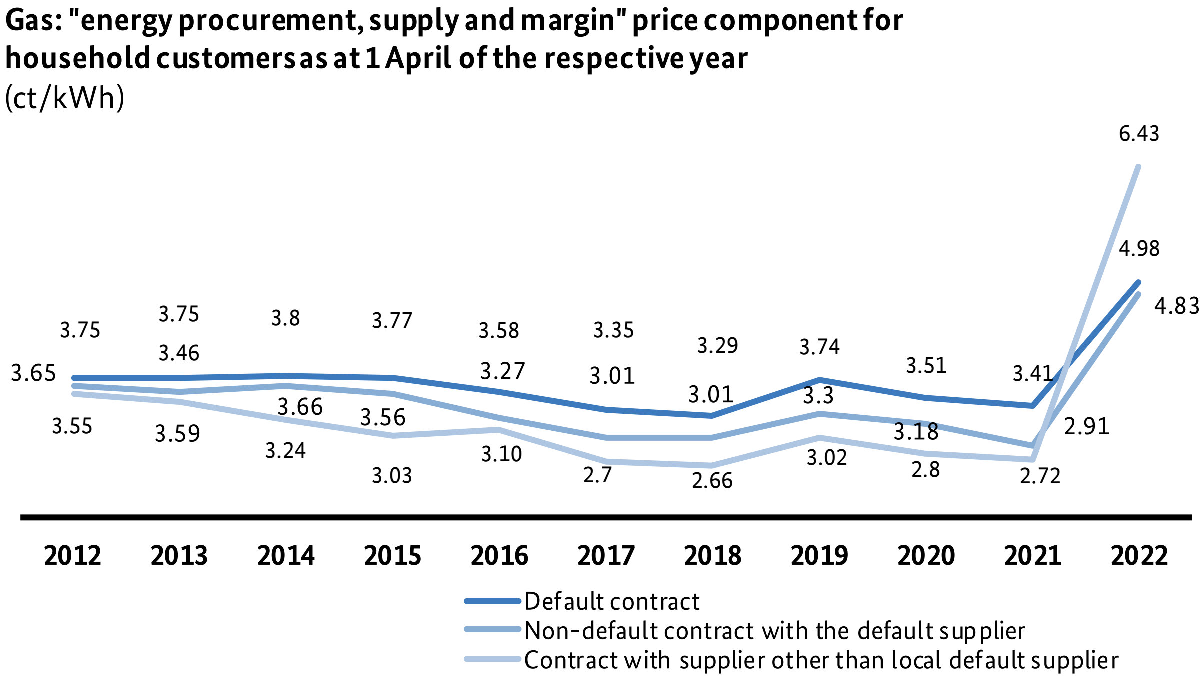


Figure 228: "Energy procurement, supply and margin" price component for household customers according to the gas supplier survey

Special bonuses and schemes

The analysis here is based on data for 1 April 2022. 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. It may already be observed that some companies are not offering special bonuses as a result of the price changes up to 1 April 2022.

Gas: special bonuses and schemes for household customers

As at 1 April 2022	Household customers			
	Non-default contract with default supplier		Contract with supplier other than local default supplier	
	No tariffs reported by surveyed companies	Average length/amount	No tariffs reported by surveyed companies	Average length/amount
Minimum contract period	339	12 months	191	12 months
Price stability	245	14 months	261	11 months
Pre-payment	50	10 months	31	9 months
One-off bonus payment	96	€ 50	114	€ 70
Free kilowatt hours	4	600 kWh	4	1200 kWh
Deposit	4	-	4	-
Other bonuses	52	-	42	-
Other special arrangements	30	-	28	-

Table 147: 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.[171] 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) 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.

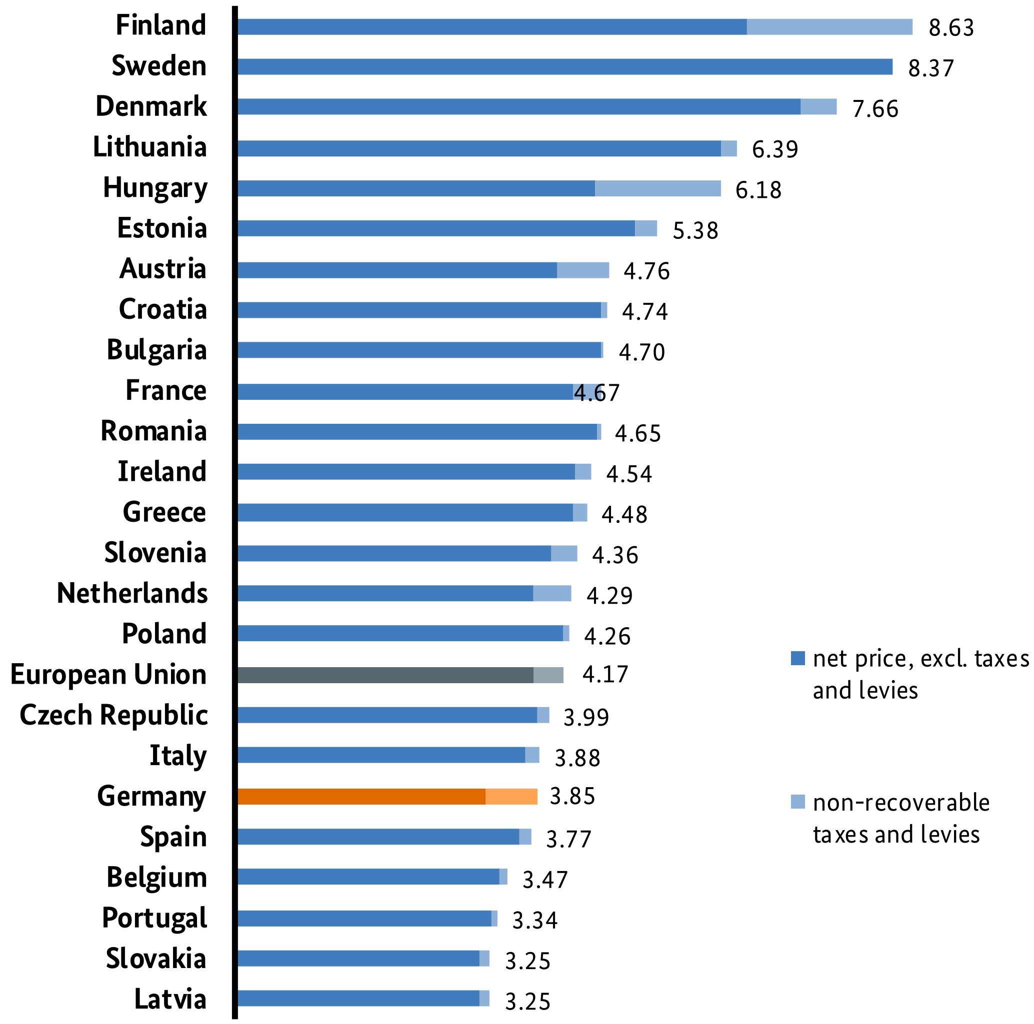
5.1 Non-household customers

Eurostat publishes price statistics for six different consumption groups in the non-household customer sector that differ according to annual consumption (“consumption bands”). The following describes the 27.8 to 278

[171] 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.

GWh/year consumption category (equivalent to 100,000 GJ to 1,000,000 GJ) as an example of one of these consumption bands. The 116 GWh/year consumption category ("industrial customers"), for which specific price data are collected during monitoring, falls into this consumption range.

Comparison of European gas prices in second half of 2021 for non-household customers with an annual consumption between 27.8 GWh and 278 GWh
in ct/kWh; without recoverable taxes and levies



Source: Eurostat

Figure 229: Comparison of EU gas prices in the second half of 2021 for non-household customers with an annual consumption between 27.8 GWh and 278 GWh[172]

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 circumstances which can typically be recovered by this customer group. These components have also been

[172] The Eurostat comparison does not include prices in Luxembourg, Malta and Cyprus. The price for Romania is an estimate.

deducted from the gross price in accordance with the Eurostat classification.[173] Most Member States impose additional taxes and levies that are not recoverable (e.g. carbon tax, gas tax and concession fee in Germany in 2021).

Across Europe, prices for non-household customers varied to a much lesser extent than those for household customers. According to prices published by Eurostat, the volume-weighted[174] average EU price for non-household customers with an annual consumption between 27.8 GWh and 278 GWh in the second half of 2021 was 4.17 ct/kWh. The net gas price paid by German non-household customers in the second half of 2021 in this consumption category was 3.85 ct/kWh, i.e. approximately 39% more than in the second half of 2020 (2.34 ct/kWh). This increase is due, in part, to the introduction of the carbon tax, which was introduced in Germany for the first time in 2021. Nevertheless, when comparing prices across Europe the German net gas price paid by non-household customers in the second half of 2021 was in the lower third. In a European comparison, taxes and levies imposed by Member States for gas consumption vary to a large extent. Non-recoverable taxes and levies amounted to an average of approx. 7% (0.36 ct/kWh) of the net price in the EU. The figure of about 17% (0.65 ct/kWh) for Germany in 2021 is above average in this respect, also due to the introduced carbon tax.

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 usually 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 the EU. Household customers in Sweden paid around 267% more for natural gas than customers in Germany and more than five or even six times as much as customers in Lithuania, Croatia and Hungary, the countries with the lowest gas prices. According to prices published by Eurostat, the volume-weighted average EU price[175] for household customers in the second half of 2021 was 7.82 ct/kWh. The gas price paid by household customers in Germany was 6.92 ct/kWh. The price paid by German consumers of natural gas per kilowatt hour was therefore 11.5% less than the EU average price despite the introduction of the carbon tax. 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 6.5% of the price in Greece, they made up about 70% of the price in the Netherlands. Germany's figure of about 37.5% again matched the European average in this respect. Around 2.18 ct/kWh of the overall price in Germany consisted of taxes and levies; the volume-weighted EU average was 2.36 ct/kWh (about 35%).

[173] 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 18 July 2022).

[174] For details on the calculation method of the EU aggregates see para. 18.1: https://ec.europa.eu/eurostat/cache/metadata/en/nrg_pc_202_esms.htm#stat_process1554804191624 (retrieved on 18 July 2022)

[175] See above.

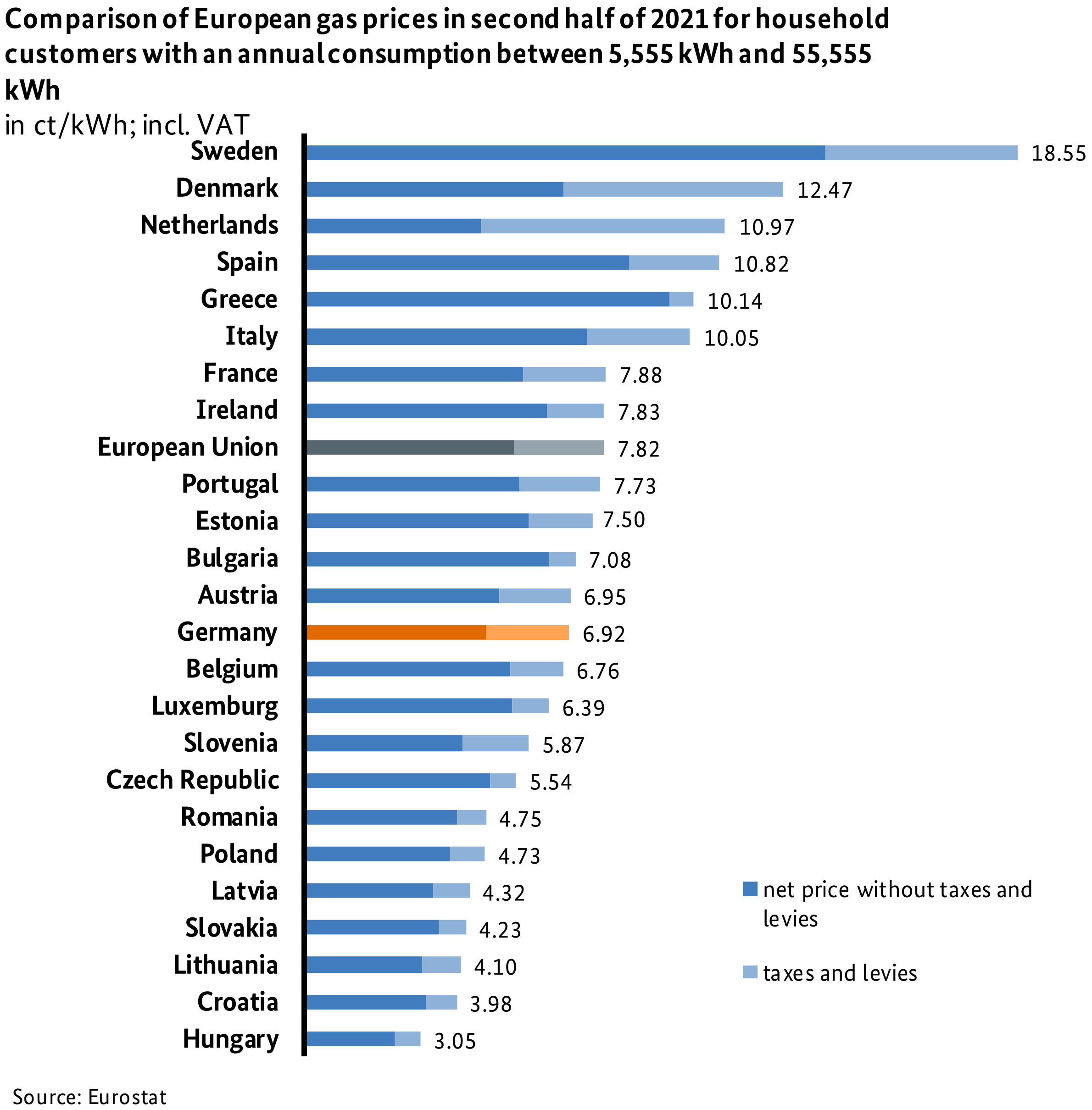


Figure 230: Comparison of EU gas prices in the second half of 2021 for household customers with an annual consumption between 5,555 kWh and 55,555 kWh.[176].

[176] 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 669 companies. This paints the following picture for 2021 with regard to the distribution of market roles:

Gas: meter operator roles

Function	2021
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)	659
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	13
Independent third party that provides metering services	8

Table 148: Distribution of network operator roles according to data provided by gas meter operators as at 31 December 2021

The table below shows the total reported meter locations broken down by federal state.

Gas: number of meter locations by federal state in 2021

Federal state	Number
Baden-Württemberg	1,449,267
Bavaria	1,386,425
Berlin	620,399
Brandenburg	552,619
Bremen	185,699
Hamburg	259,979
Hesse	1,018,608
Mecklenburg-Western Pomerania	306,235
Lower Saxony	2,175,795
North Rhine-Westphalia	3,714,443
Rhineland-Palatinate	859,433
Saarland	233,599
Saxony	600,970
Saxony-Anhalt	464,871
Schleswig-Holstein	586,443
Thuringia	393,306

Table 149: Number of meter locations by federal state in 2021

2. Metering technology used for household customers

As at 31 December 2021, approximately 7.4 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 2021

Types of metering equipment used by meter operators for SLP customers	No. Of meter points by meter size		
	G1.6 bis G6	G10 to G25	G40+
Diaphragm gas meters with mechanical counter	4,851,090	164,615	19,002
Diaphragm gas meters with mechanical counter and pulse output	8,009,047	254,934	25,688
Diaphragm gas meters with mechanical counter and manufacturer-specific output (eg Cyble, Absolute ENCODER)	886,112	29,020	5,236
Diaphragm gas meters with electronic counter	2,986	159	173
Ultrasonic gas meters	4,479	1	133
Load/interval meters as for interval-metered customers	131	221	3,182
Other mechanical gas meters	8,286	2,628	28,725
Other electronic gas meters	1,475	11	356
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	7,093,944	224,616	34,689
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	367,594	18,590	4,174

Table 150: Breakdown of metering equipment used by SLP customers as at 31 December 2021, according to meter size

The overwhelming majority of meters use pulse generators as their communication technology.

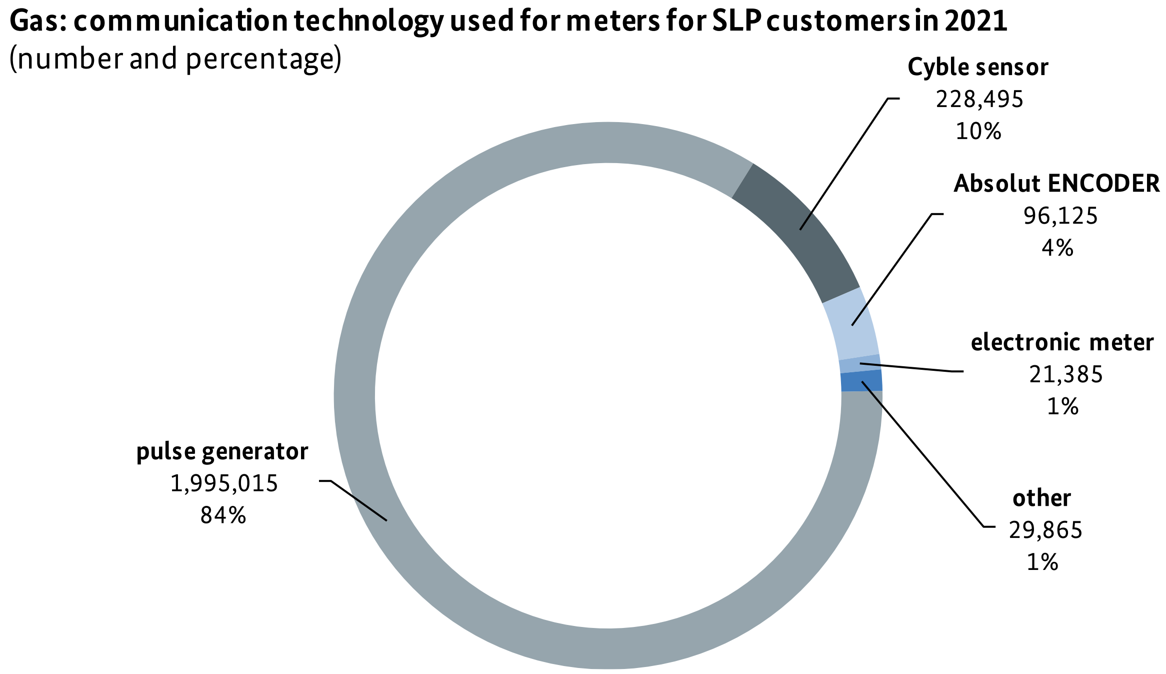


Figure 231: Communication technology used for meters for SLP customers – as at 31 December 2021

3. Metering technology used for interval-metered customers

The distribution of metering technology employed for interval-metered customers in 2021 is as follows:

Gas: metering technologies used for interval-metered customers in 2021

Function	No. of meter locations
Transmitting meter with a pulse output/encoder meter + a recording device/data storage	15,110
Transmitting meter with a pulse output/encoder meter + gas volume converter	10,231
Transmitting meter with a pulse output/encoder meter + combustion value quantity converter	277
Transmitting meter with a pulse output/encoder meter + gas volume converter + recording device/data storage	16,155
Transmitting meter with a pulse output/encoder meter + temperature volume converter + recording device/data storage	842
Transmitting meter with a pulse output/encoder meter + smart meter gateway	1
Other	117

Table 151: Breakdown of metering technologies used for interval-metered customers – as at 31 December 2021

Gas: communication link-up systems used for interval-metered customers in 2021
(number and percentage)

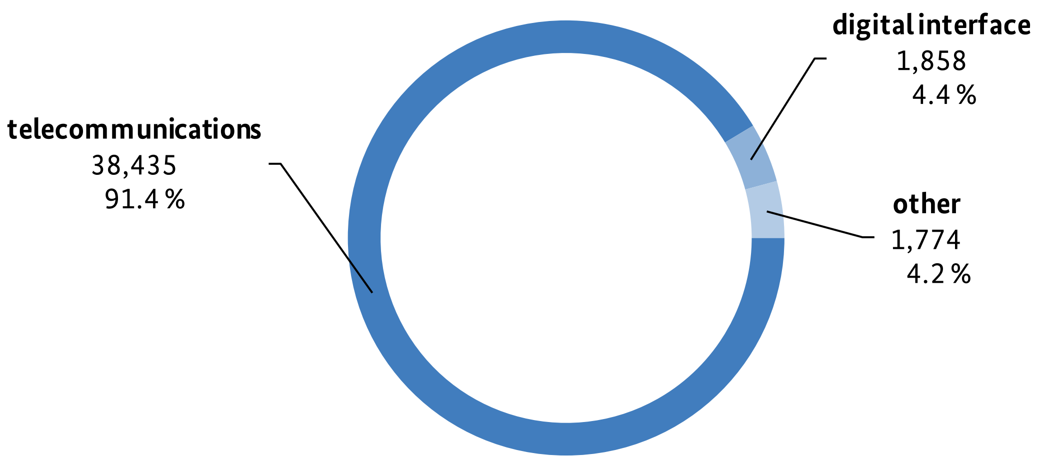


Figure 232: Number and percentage of communication link-up systems used for interval-metered customers – as at 31 December 2021

The metering technology used by interval-metered customers transmits data almost exclusively via telecommunication systems (91.4%). 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 4.4% 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 669 gas meter operators.

Gas: metering investment and expenditure
(€m)

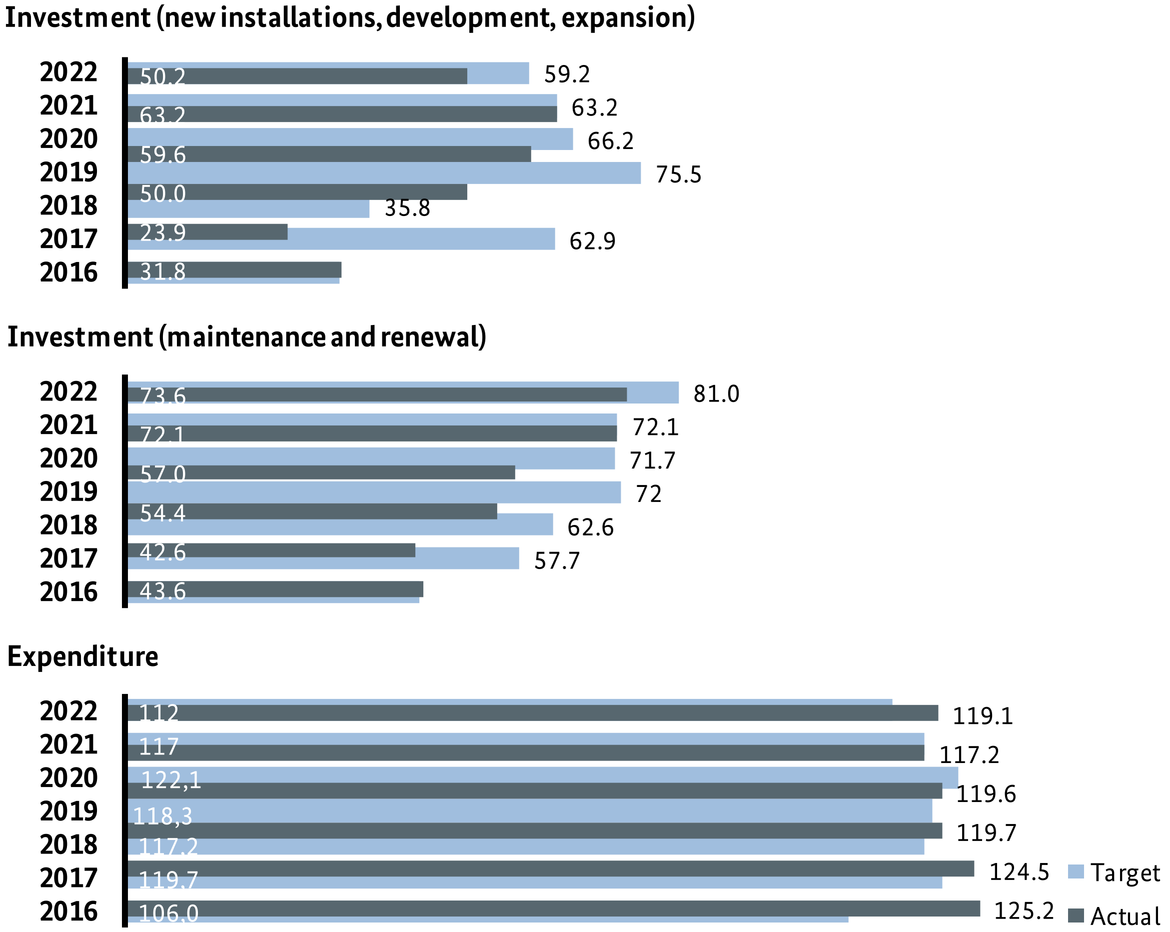


Figure 233: Metering investment and expenditure

III General topics

A Market Transparency Unit for Wholesale Electricity and Gas Markets[177]

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

Since the first wave of registrations when the requirement to register came into force in 2015, the total number of registrations has increased steadily by an average of 200 market participants per year.

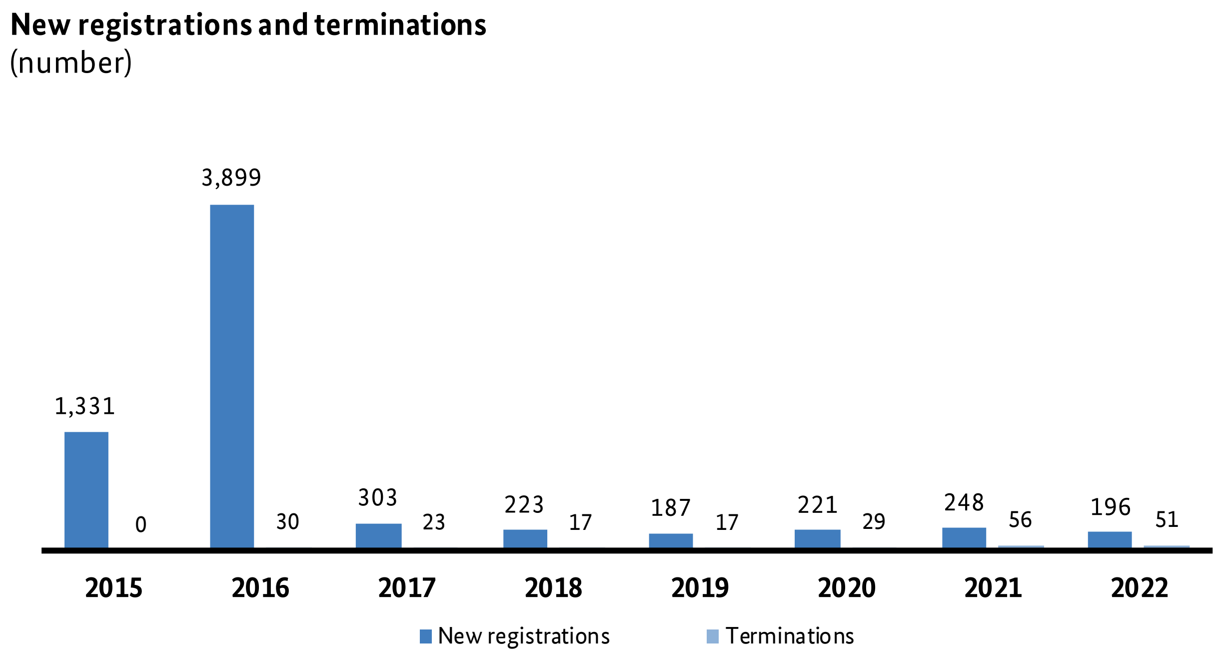


Figure 234: New registrations and terminations in Germany per year

In 2021, the registered market participants were requested to bring their information on the place of publication of their potential inside information into line with ACER's stricter requirements. This led to an increase in the number of terminations as from 2021.

[177] Also constitutes the activity report of the Market Transparency Unit under section 47h(2) of the German Competition Act (GWB).

At present, 5,028 market participants are registered in Germany. A total of 15,788 market participants are currently registered in the Centralised European Register of Energy Market Participants (CEREMP).

ACER 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 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 chart below shows the number of reports transmitted in the relevant period.

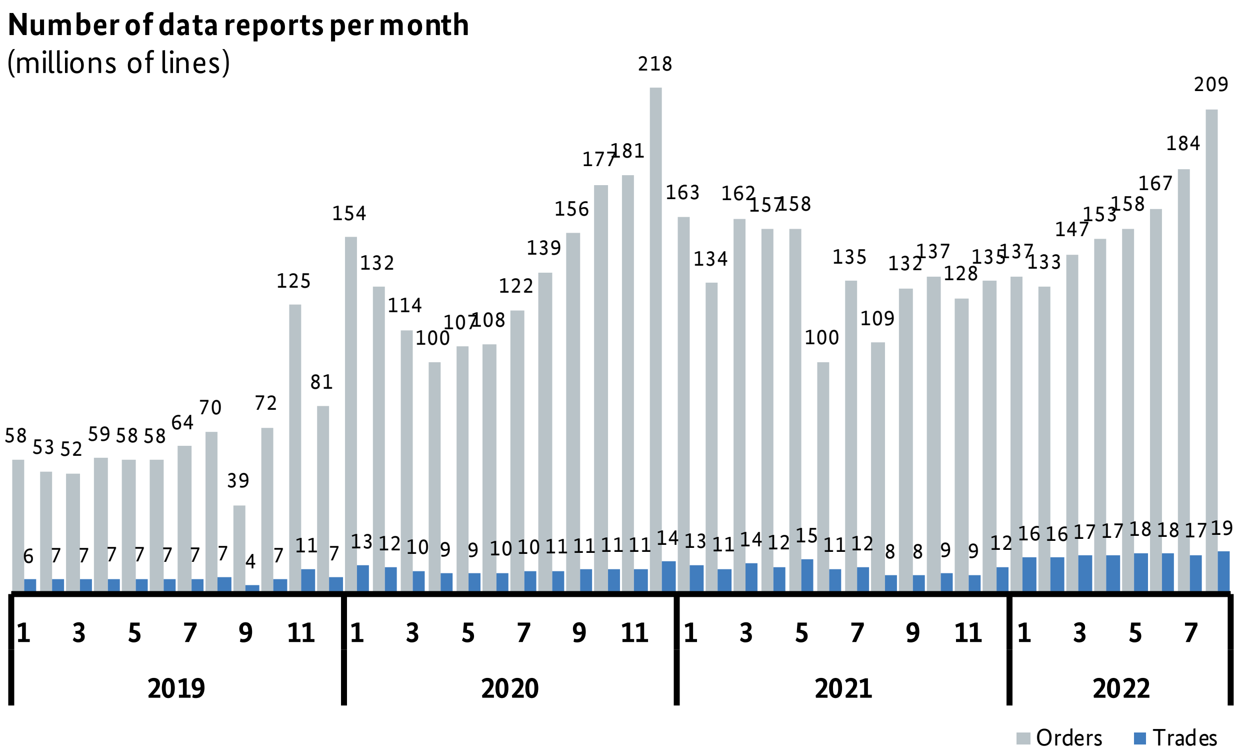


Figure 235: Number of data reports on orders and trades received per month by the Market Transparency Unit[178]

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 or transaction 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. Since

[178] 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.

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 2019 (2022: average of 144mn per month; 2021: 138mn per month; 2020: 142mn per month; 2019: 66mn per month). There has also been a continuous increase in the number of reports on trades concluded (2022: average of 15mn per month; 2021: 11mn per month; 2020: 11mn per month; 2019: 7m 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 market places 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)

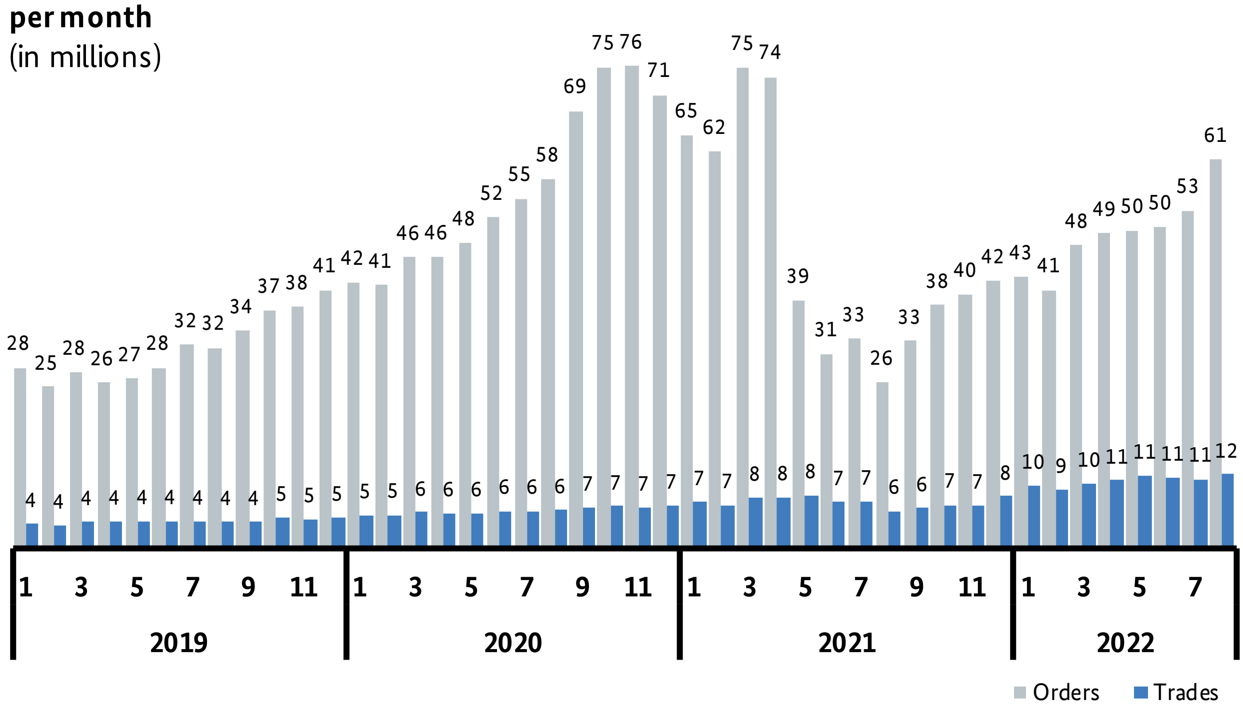


Figure 236: Number of unique trade and order identification numbers (IDs) reported by market participants per month

The following diagram shows a breakdown of the data reported in the period from December 2017 to August 2022 into the categories exchange trading, trades via broker platforms, and bilateral contracts.

Breakdown of the data reports on trades and orders from December 2017 to August 2022 (%)

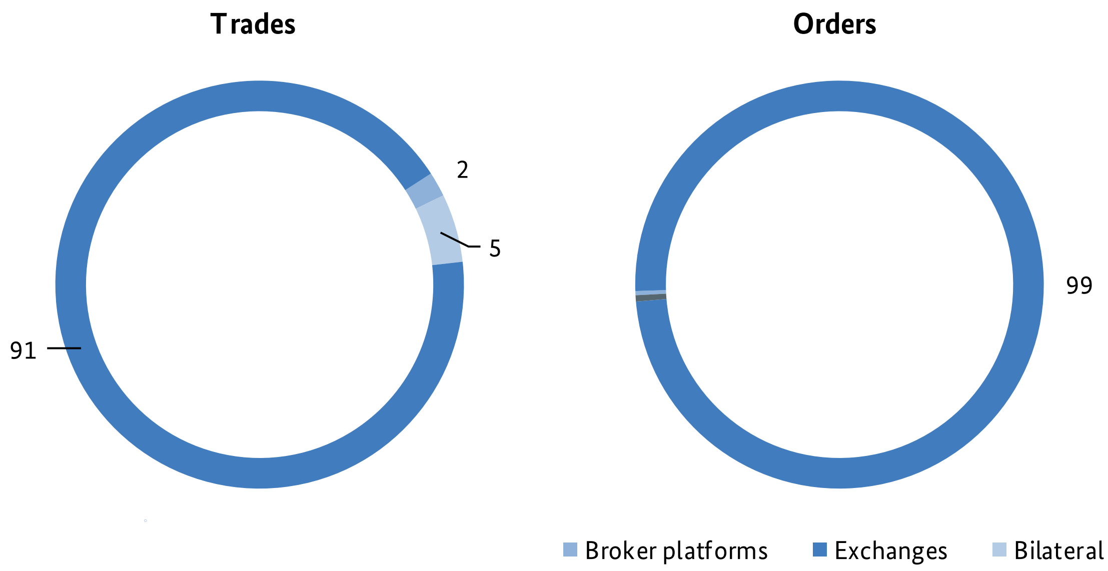


Figure 237: Reports on trades and orders by market place (%)[179]

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.

[179] The individual percentages may not add up to 100% because of rounding and reports that cannot be placed in a specific category.

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[180] 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.

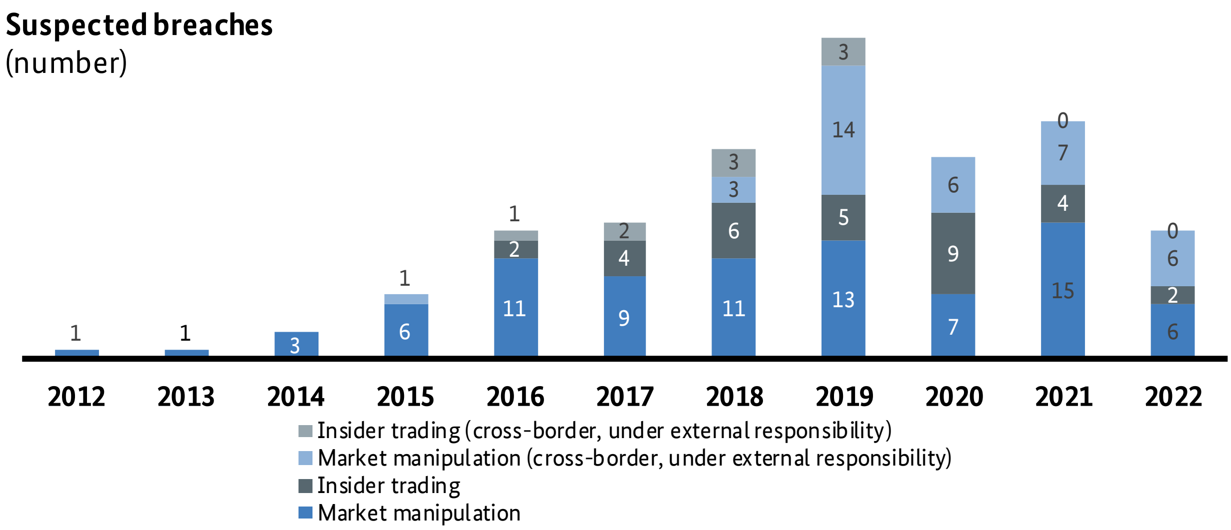


Figure 238: Suspected breaches, 2012 to 2022

The initial increase in the number of suspected breaches did not necessarily mean that there had been an increase in the number of actual breaches. Rather, it can be assumed that it just took time for the new regulations in REMIT to become established and to be taken into account by market participants and at energy exchanges and other market places. 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.

Cross-border cases

[180] Agency for the Cooperation of Energy Regulators

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.

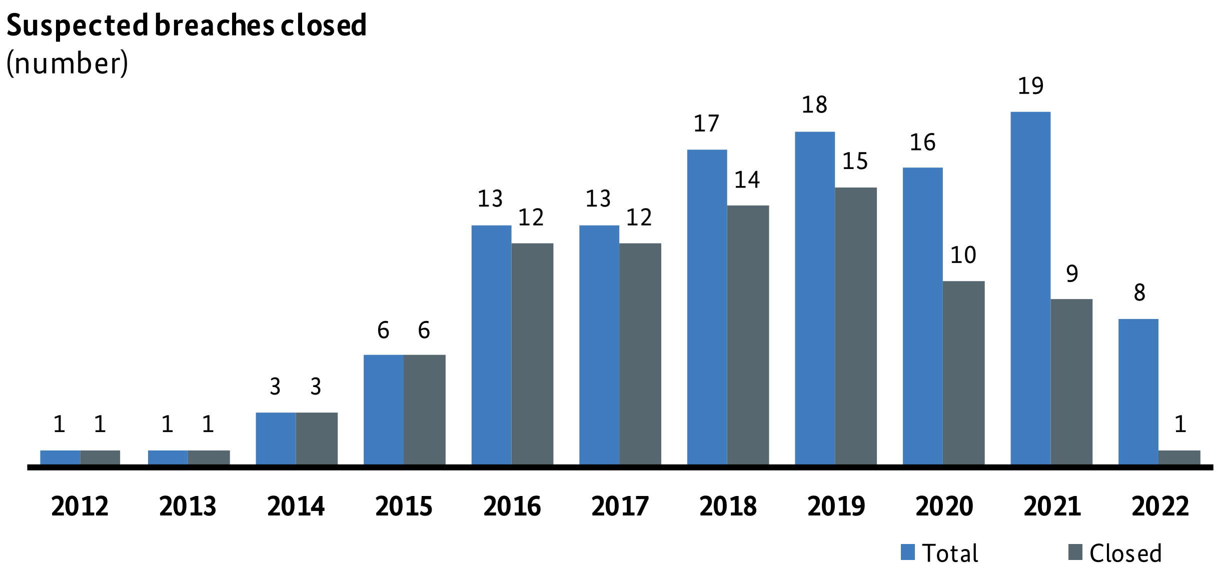


Figure 239: Suspected breaches closed, 2012 to 2022[181]

Suspected breaches identified by ACER

As part of its market monitoring responsibilities under REMIT, ACER has been examining all trading data EU-wide for irregularities using a specially designed monitoring system and particular parameters since early 2018. ACER is uniquely placed to carry out this task since it has an overview of electricity and gas trading both across borders and across market places. It complements the monitoring activities of the market places and the national regulatory authorities. ACER regularly sends the results of its analyses – known as alerts – to the relevant national regulatory authorities. These alerts initially show anomalies flagged up from the data

[181] The figures shown as the total are the total number of cases processed internally.

available to ACER, such as outliers from certain defined ranges. The alerts may lead to suspected breaches. ACER first carries out a preliminary initial assessment (PIA), involving a more detailed analysis of the data and its own assessment of whether there are grounds to suspect a breach. The PIA is then forwarded to the energy regulator(s) responsible for further processing. A total of 16 of the suspected breaches reported to the Bundesnetzagentur came from ACER as PIAs, and nine of them are/were being processed under the lead responsibility of the Bundesnetzagentur.

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 to electricity generating installations even if no financial support is claimed and if the installation does not feed any electricity into the grid.

The chart below shows that the majority of registrations in 2020 were for units of installations that were put into operation before the end of January 2019. The large number of registrations made in December 2020 and January 2021 is due to the deadline of 31 January 2021 for registering any installations already in operation at the end of January 2019.

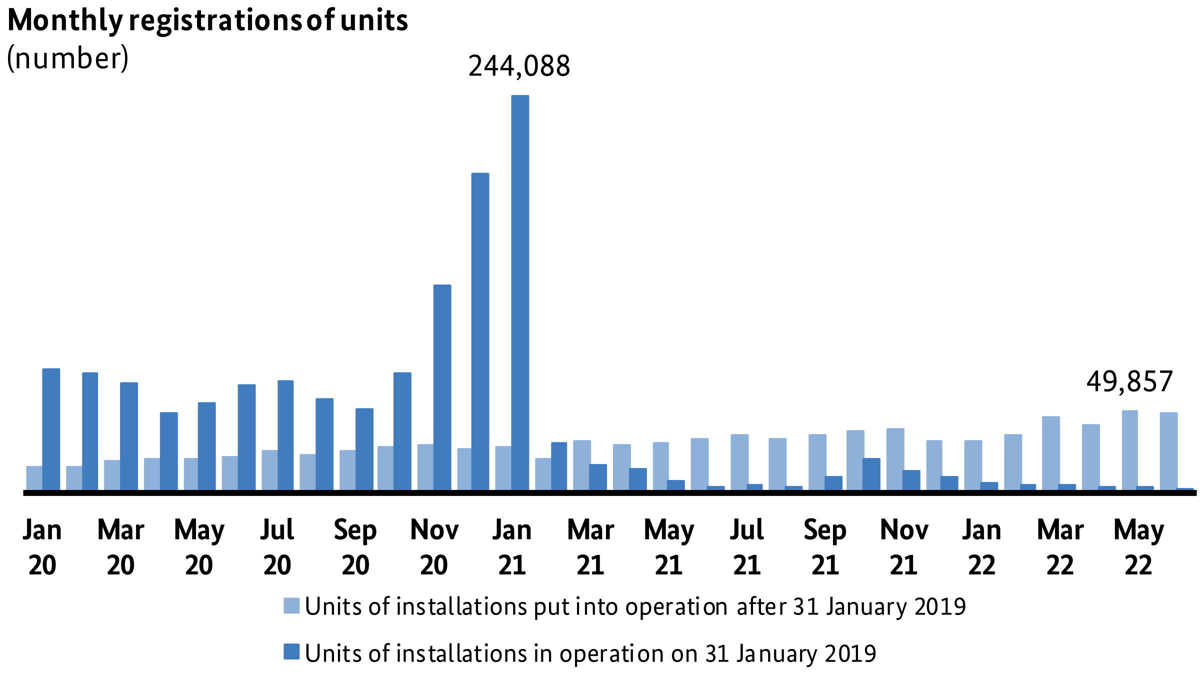


Figure 240: Monthly registrations of units

The majority of registrations since March 2021 are for units of new installations. There has been a steady increase in the number of registered units of new installations. While the average number of units registered each month in 2020 was 22,000, the monthly average in 2021 was 32,000 and in the first six months of 2022 even 42,000. This increase reflects above all the overall growth in solar capacity.

The table below shows that the majority of registrations have been for solar installations, which include large-scale ground-mounted solar PV systems as well as rooftop and balcony installations. The table below shows a breakdown of the units registered as at 10 July 2022 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.

Number of registered units in the core energy market data register
As at 10 July 2022

Unit type	Total	In operation	Planned	Permanently closed down	Temporarily closed down
Electricity generating unit	**3,002,929**	**2,967,778**	**26,045**	**8,056**	**1,050**
Solar	2,430,820	2,411,762	15,110	3,367	581
Storage	428,383	419,232	8,097	968	86
Combustion without biomass[1]	79,443	76,119	612	2,501	211
Wind	33,290	30,657	1,935	669	29
Biomass	21,453	20,630	240	468	115
Hydro	8,565	8,470	31	39	25
Other[2]	546	512	8	23	3
Other renewables[3]	423	393	12	18	0
Nuclear	6	3	0	3	0
Electricity consumption unit	**362**	**292**	**68**	**2**	**0**
Gas generating unit	**309**	**299**	**8**	**0**	**2**
Gas storage	55	54	0	0	1
Biomethane	223	215	8	0	0
Fossil natural gas extraction	21	20	0	0	1
Other generation	10	10	0	0	0
Gas consumption unit	**770**	**739**	**20**	**10**	**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 152: 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 in the case of units with an installed capacity less than 30 kW. 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 and 420 in June 2021 to the current number of 750.

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 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.

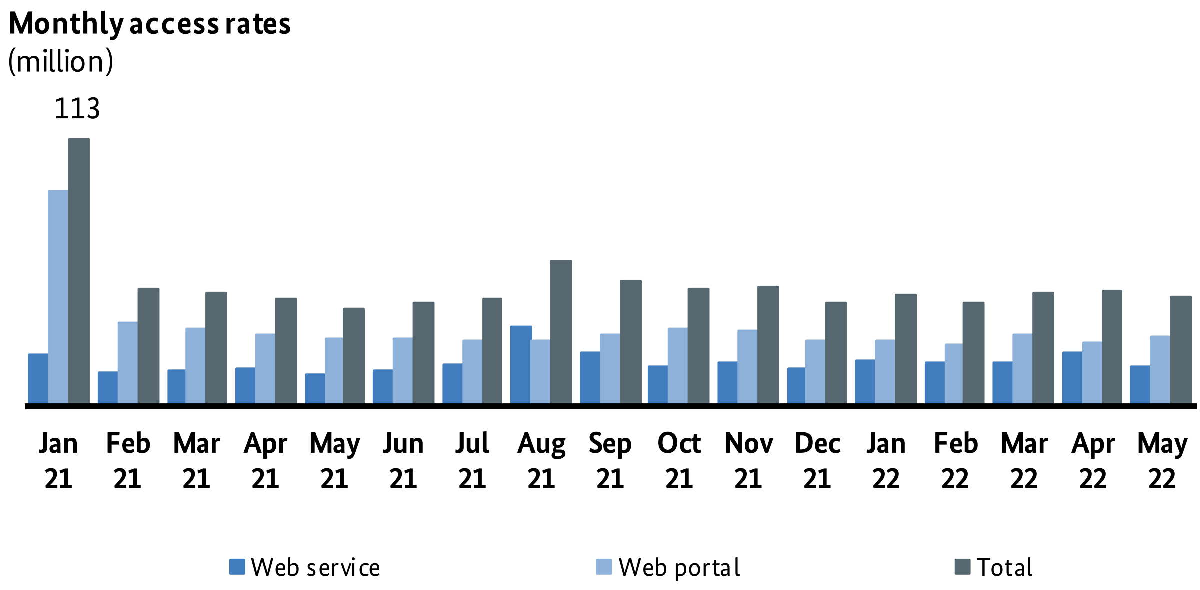


Figure 241: Monthly access rates

2.1 Quality management

The following subsections set out the 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.

2.1.1 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 2022: 76.7% of the checks had been completed (1 July 2021: 68.7%); 8.5% had not been started; 12.0% had been referred to and were still with the installation operator; and 2.5% had been referred back from the installation operator to the network operator.

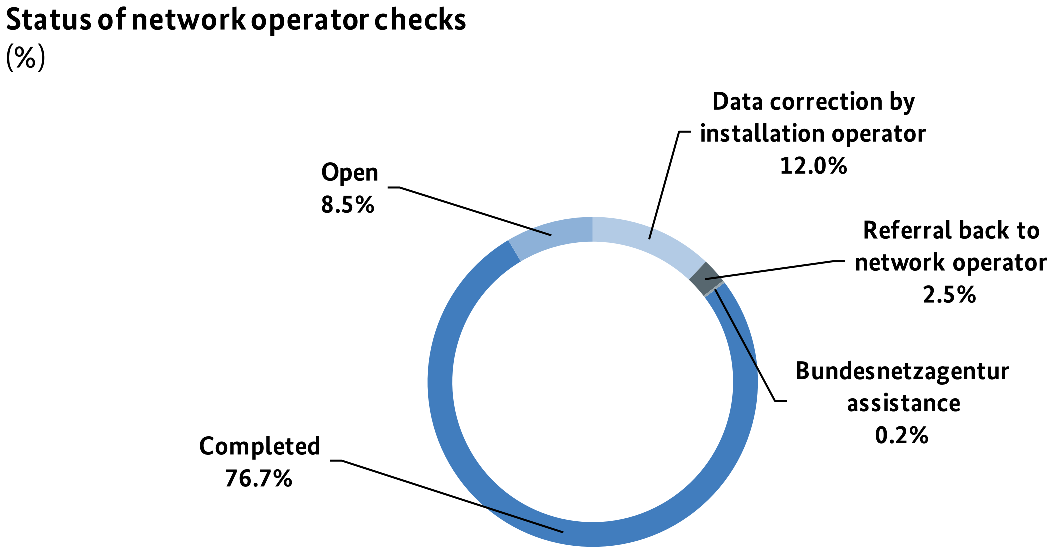


Figure 242: Status of network operator checks

2.1.2 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, even after a unit/installation has been closed down, to make it possible for historical data analyses to be made. The data are not deleted, but the links to the installation operator are removed when a unit/installation is closed down.

Unit/installation data are therefore only deleted if an error has occurred. 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 1,500 requests for data deletion and about 650 reports about incorrect data from network operators each month.

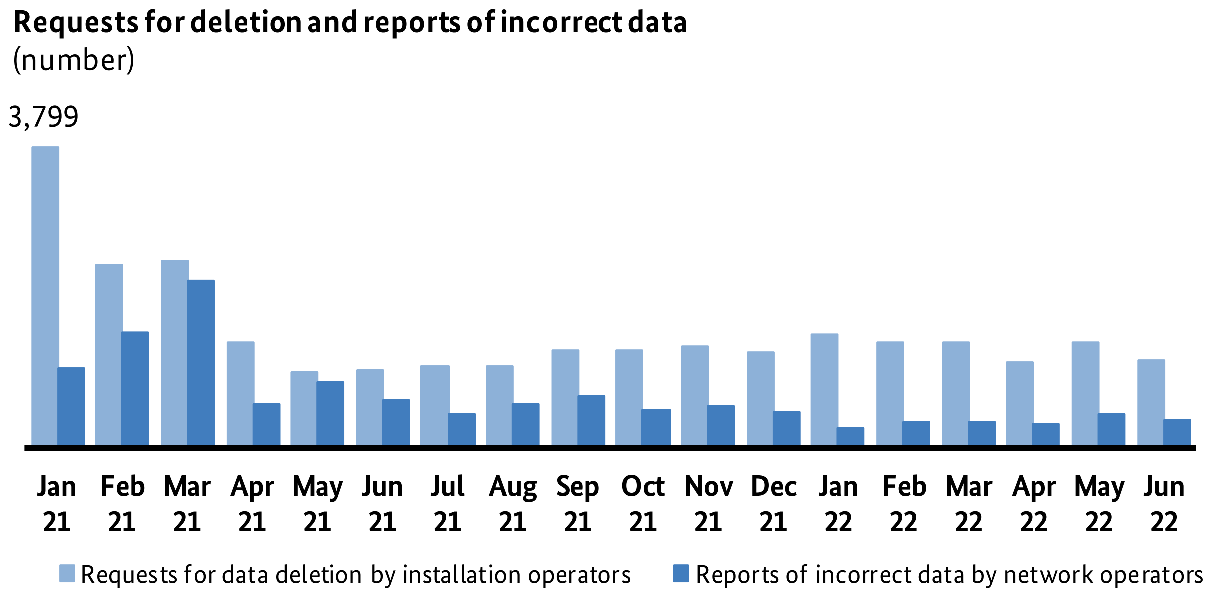


Figure 243: Requests for data deletion and reports of incorrect data

2.1.3 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 focus of the checks in 2021 and in the first six months of 2022 was on the following:

- errors in capacity data;
- site data and geographical coordinates for wind units;
- all data for units on the Bundesnetzagentur's power plant list (units with a net rated capacity exceeding 10 MW).

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 130 times each month.

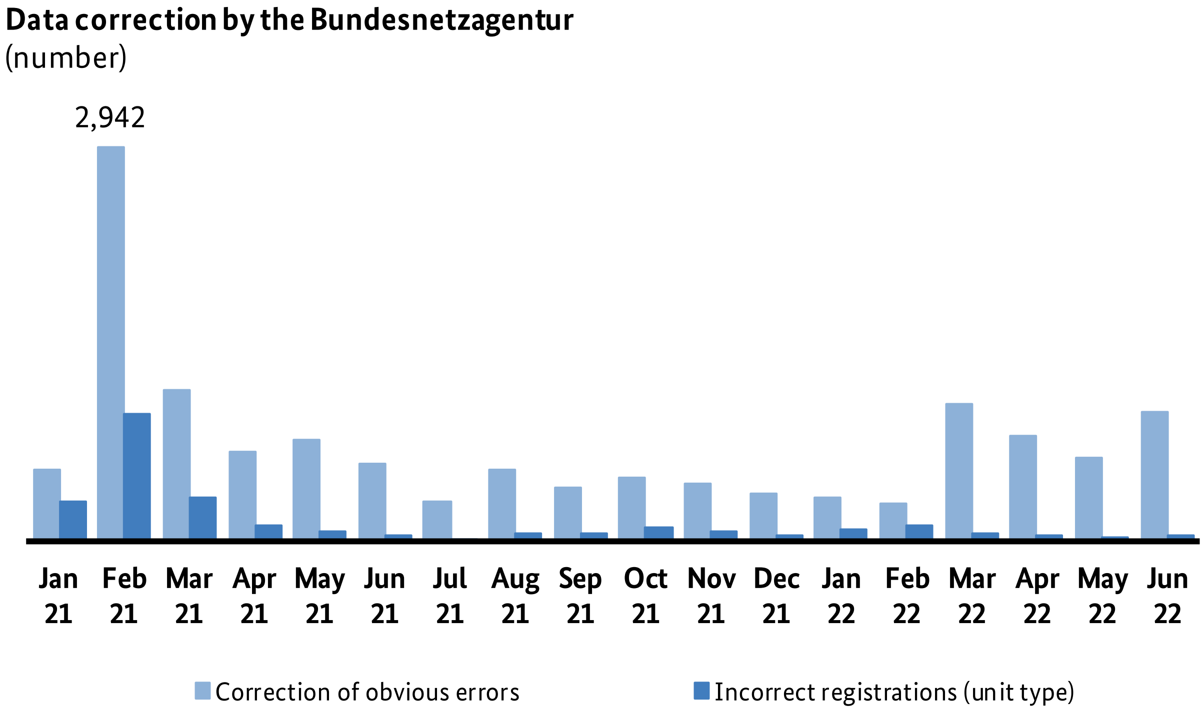


Figure 244: Data correction by the Bundesnetzagentur

2.2 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. In most cases, these changes can be registered by the old and new operators themselves using the register's information and templates and without involving the Bundesnetzagentur. However, the Bundesnetzagentur's help is needed 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 number of changes in operator registered in 2021 was 25,868 (2020: 14,337), and the monthly average was 2,150. In the first six months of 2022, the average number of changes registered each month had increased to 2,500. 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. In the case of installations receiving financial support, it is expected that network operators will increasingly base payments on the data in the register. This also means that a change in operator is more likely to be registered as required.

The chart below shows a particularly high number of registrations in January. It is not currently possible to identify the reason for this noticeable peak.

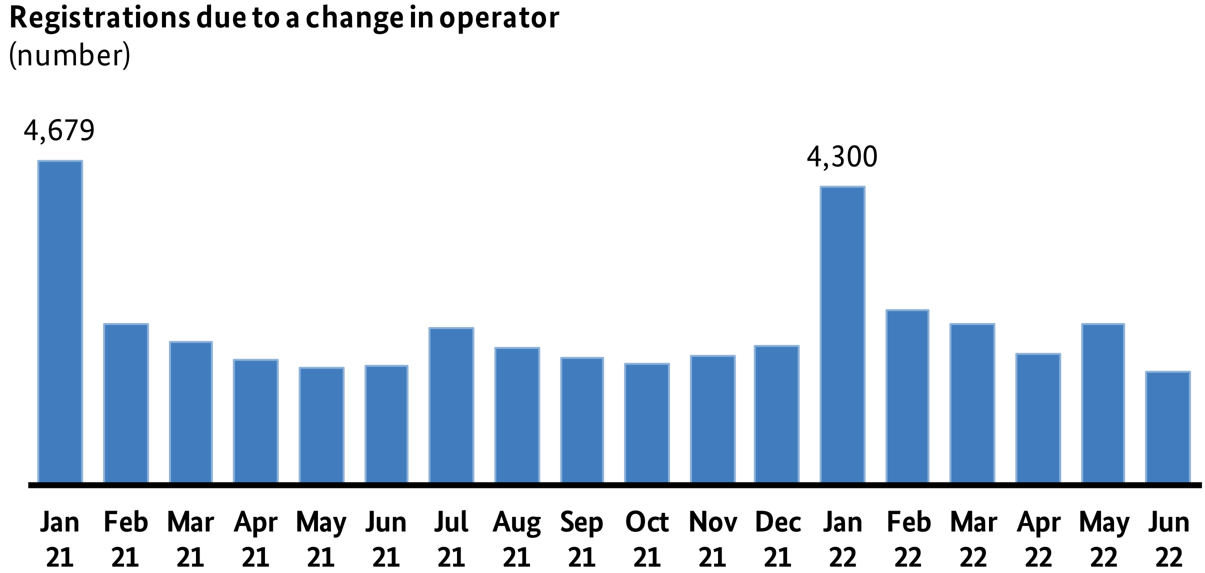


Figure 245: Registrations due to change in operator

3. Use of digital technology in the energy sector

The energy sector is undergoing significant change as a result of the digital transformation and energy transition. The use of digital technology is the foundation and key to success for the energy industry and a sustainable energy transition designed for the long term.

In the past few years, major technological progress has been made particularly in the field of artificial intelligence and blockchain technology. While AI is already seen as a key technology and one of the main drivers behind digitisation and the development of (semi-)autonomous systems, blockchain technology potentially offers much more than the creation and administration of cryptocurrencies because any process that can be represented digitally can essentially be implemented using a blockchain.

To gain an overview of the current importance of AI and blockchain technology in the energy sector, the companies participating in the monitoring survey were also asked to provide information about the use of these two technologies.

The two technologies are defined as follows:

Artificial intelligence (AI) refers to systems that display intelligent behaviour by analysing their environment and taking actions – with some degree of autonomy – to achieve specific goals (European Commission, 2021).

A blockchain is a register where digital transactions are stored in chronologically ordered data blocks (block), in a way that is transparent for all participants, and are unalterably chained to one another (chain) (Bundesnetzagentur, 2021).

3.1 Artificial intelligence (AI)

A total of 3,447 companies took part in the additional survey on AI; the table below shows the market roles of these companies.

Market roles of the companies surveyed
(number)

Market role	Sample size
Electricity TSO	7
Electricity DSO	544
Electricity supplier	970
Electricity meter operator	561
Generator	236
Gas storage facility	21
Gas TSO	15
Gas supplier	630
Gas DSO	463

Table 153: Market roles of the companies participating in the survey on the use of AI

About 16% of the companies surveyed stated that they already use AI. On average, they have been using AI since 2019. A total of 3% of the companies surveyed stated that they plan to use AI. On average, they plan to begin using it in 2023. The remaining 81% of the companies surveyed stated that they neither use nor plan to use AI.

Looking at the companies' market roles, it is striking that it is mainly the electricity and gas transmission system operators (TSOs) that already use AI technology. The most common use of AI by electricity TSOs is for forecasts, forward-looking maintenance and repair, and operation and process optimisation. Gas TSOs increasingly implement AI-based security measures, while the use of AI for forward-looking maintenance and repair is still at the planning stage.

This partly confirms the trend already observed that larger companies are using or planning to use AI more than smaller companies.[182]

[182] Source: Federal Ministry for Economic Affairs and Climate Action (BMWK): Den digitalen Wandel gestalten. Mittelstand digitalisieren: www.bmwk.de/Redaktion/DE/Dossier/digitalisierung.html, accessed on 5 August 2022.

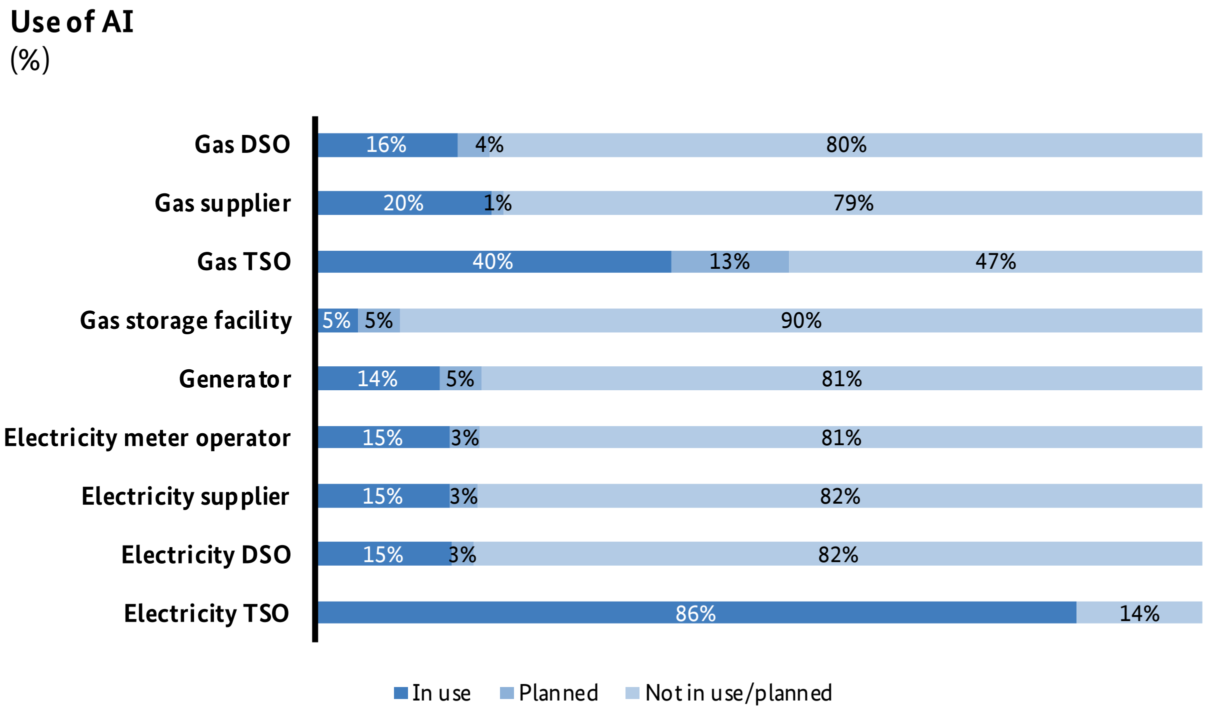


Figure 246: Use of AI by market role

For data quality reasons, the evaluation of the information on the added value and challenges in using AI only included the information provided by the 663 companies already using or planning to use AI. As the evaluation is an overall assessment across all market roles, the results for individual market roles may differ considerably from the overall results.

The added value was rated on a scale of 1 ("no added value") to 4 ("significant added value") for the following categories:

- efficiency gains
- automation
- complexity management
- ecological sustainability
- cost reduction.

Each company could rate the added value for each category separately.

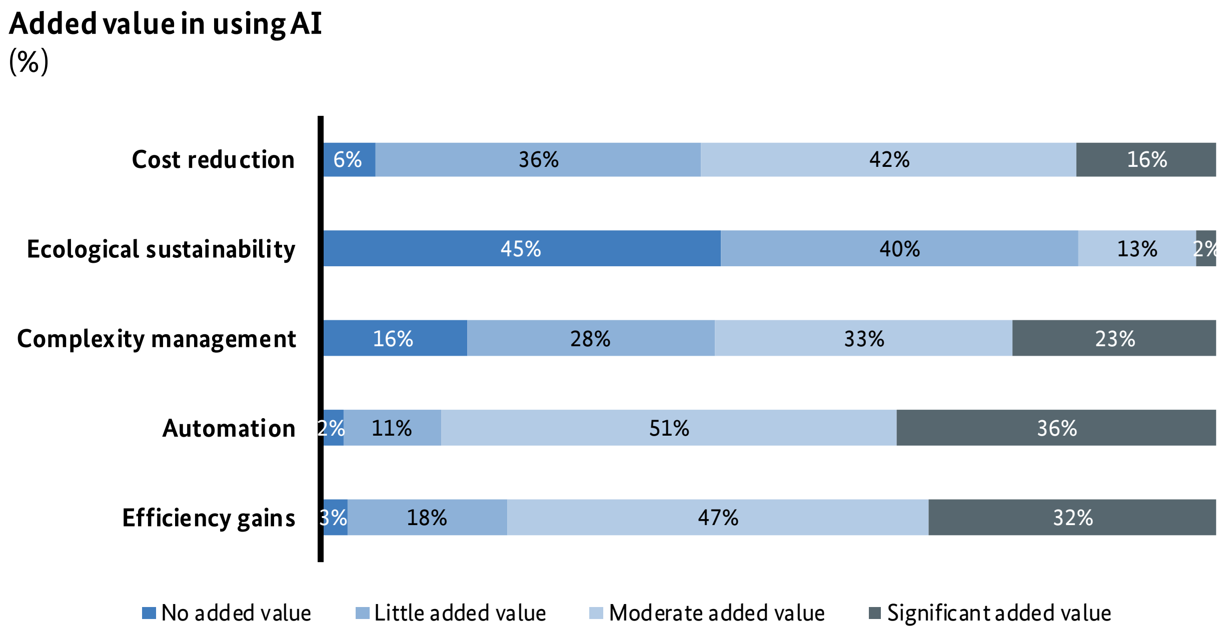


Figure 247: Added value in using AI

Figure 247 shows that the companies surveyed see AI as offering most added value in automation and efficiency gains and least added value in economic sustainability.

The challenges in using AI were assessed in the following categories:

- economic (skills gap, development costs, etc)
- technical (hardware, software, data availability, etc)
- legal/regulatory (data protection regulations, energy legislation, etc).

As with the added value, the companies surveyed could rate the challenges on a scale of 1 ("no challenges") to 4 ("significant challenges"). Each company could rate the challenges for each category separately. Figure 248 shows the results.

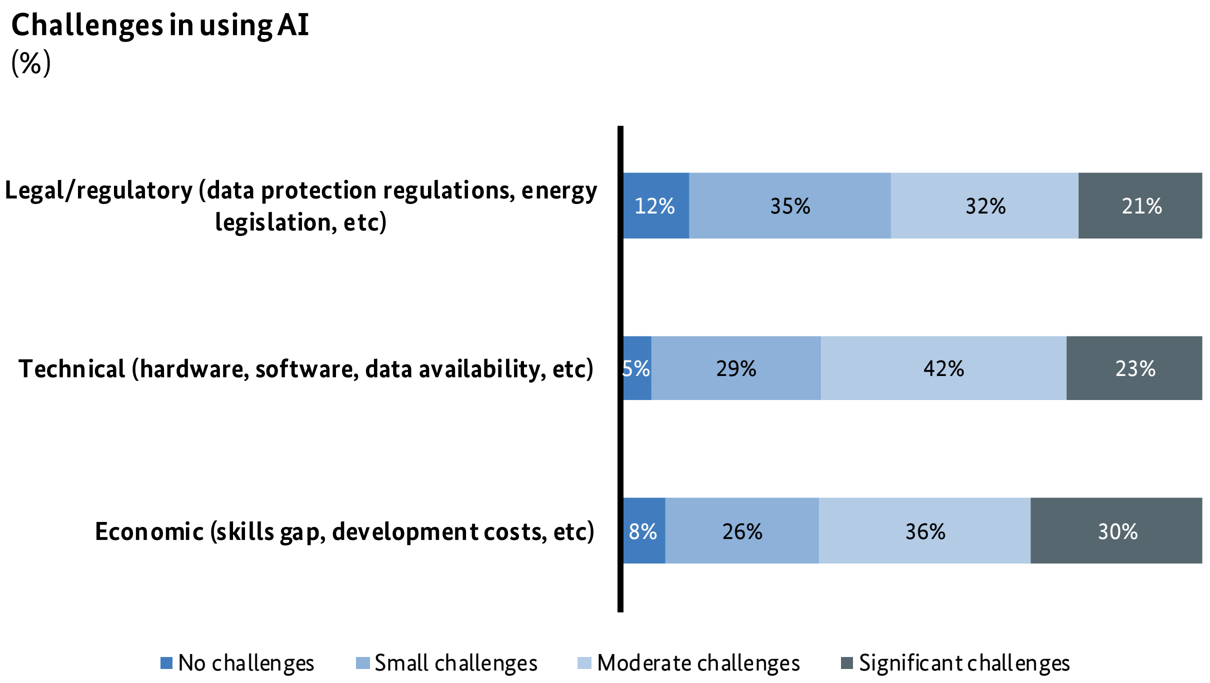


Figure 248: Challenges in using AI

The chart shows that the companies surveyed do not generally see AI as presenting greater challenges in any one particular category, although a small majority of companies see economic challenges as significant, followed by technical challenges.

3.2 Blockchain

A total of 3,212 companies took part in the additional survey on blockchain technology. The table below shows the market roles of these companies.

Market roles of the companies surveyed
(number)

Market role	Sample size
Electricity TSO	7
Electricity DSO	507
Electricity supplier	909
Electricity meter operator	528
Generator	203
Gas storage facility	19
Gas TSO	14
Gas DSO	429
Gas supplier	596

Table 154: Market roles of the companies participating in the survey on the use of blockchain technology

Out of the 3,212 companies, 2% stated that they already use or plan to use blockchain technology. Figure 249 shows the market roles of the companies using, planning to use and neither using nor planning to use blockchain technology.

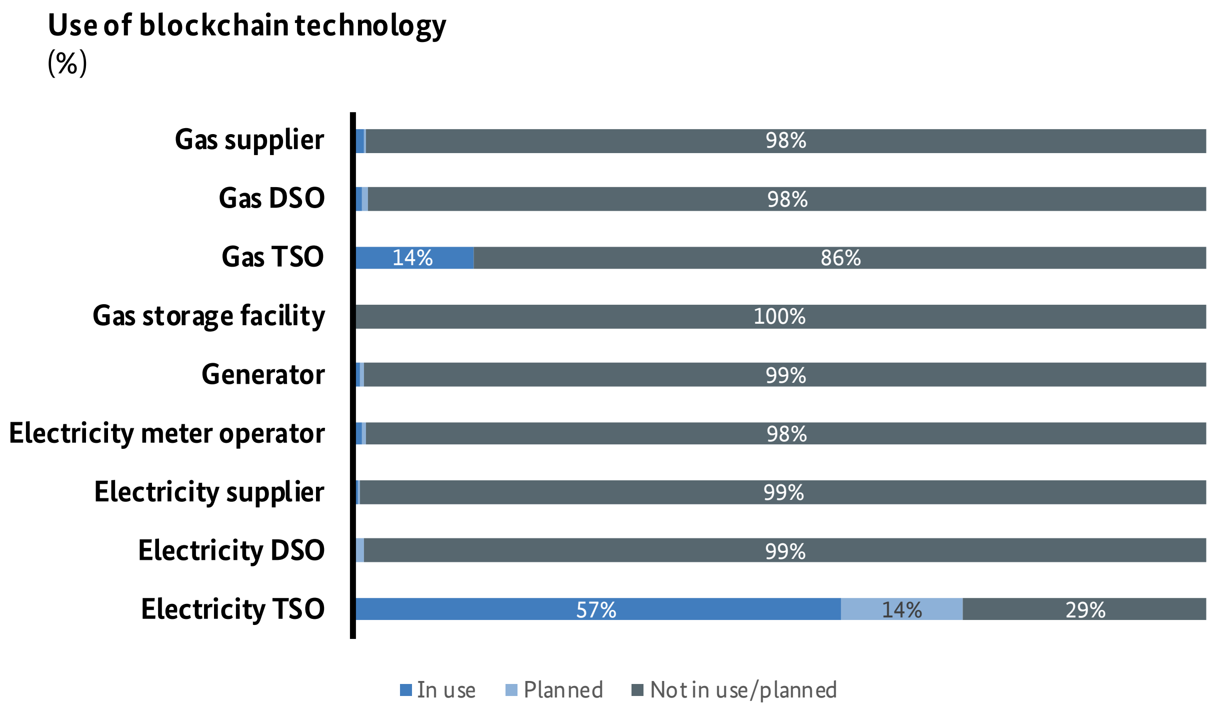


Figure 249: Use of blockchain technology by market role

For data quality reasons, the evaluation of the information on the added value and challenges in using blockchain technology only included the information provided by the 52 companies already using or planning to use the technology. The responses to the additional survey on the use of blockchain technology indicate no higher market penetration of the technology at present with respect to the market roles assessed. This means that blockchain technology generally remains a niche technology. The only indication of higher market penetration is among electricity TSOs. On average, they have been using blockchain technology since 2018. The use of blockchain technology is being tested in particular for interconnecting, controlling and using distributed units for congestion management. The use of the technology for billing tariffs and surcharges is at the planning stage. Only several large companies, mainly electricity and gas TSOs, stated in the survey that they already use or plan to use blockchain technology.

Figure 250 illustrates the added value in using blockchain technology as seen by the companies. The companies were asked to rate the added value for the following categories based on the characteristics and associated potential advantages of the technology:

- resilience
- traceability

- cost reduction
- automation of work processes
- data security
- transparency.

The potential added value was rated on an ascending scale: 1 "no added value", 2 "little added value", 3 "moderate added value", 4 "significant added value". Each company could rate the added value for each category separately.

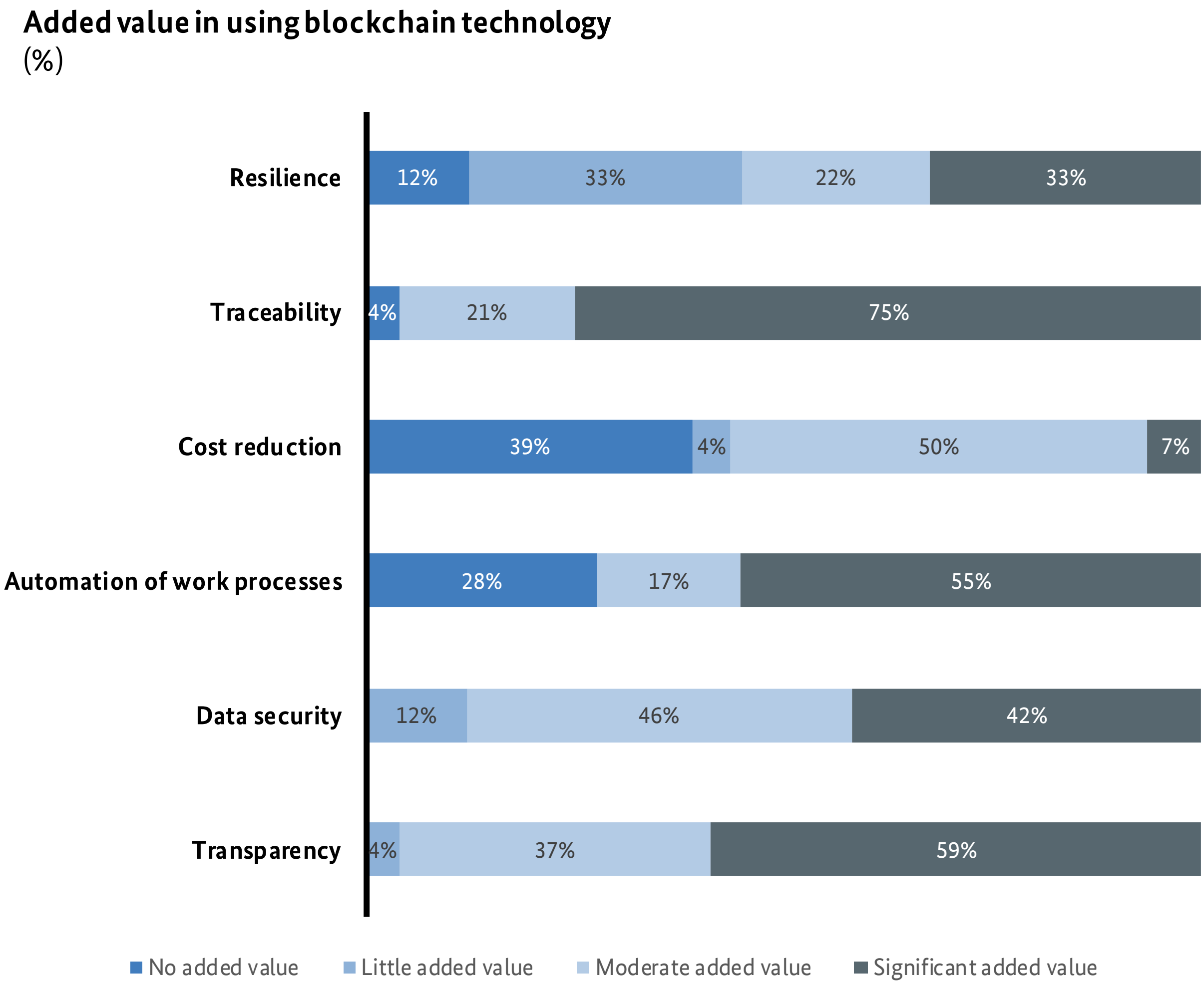


Figure 250: Added value in using blockchain technology

An overall assessment across all market roles shows that the companies see most added value in traceability and the complementary goals of transparency and data security and least added value in cost reduction. The companies also see a low level of added value in resilience. It can be presumed here that the systems in the energy sector already offer a high degree of resilience anyway and therefore achieving resilience with blockchain technology is seen as less important.

It should be noted that the results are affected by the higher use of blockchain technology by electricity and gas TSOs, as shown in Figure 249, and may not be generally applicable.

Figure 251 shows the greatest challenges in using blockchain technology as seen by the companies. The potential challenges for companies were assessed in the following categories:

- economic (skills gap, development costs, etc)
- technical (hardware, software, data availability, etc)
- legal/regulatory (data protection regulations, energy legislation, etc).

The potential challenges were rated on an ascending scale: 1 "no challenges", 2 "small challenges", 3 "moderate challenges", 4 "significant challenges". Each company could rate the challenges for each category separately.

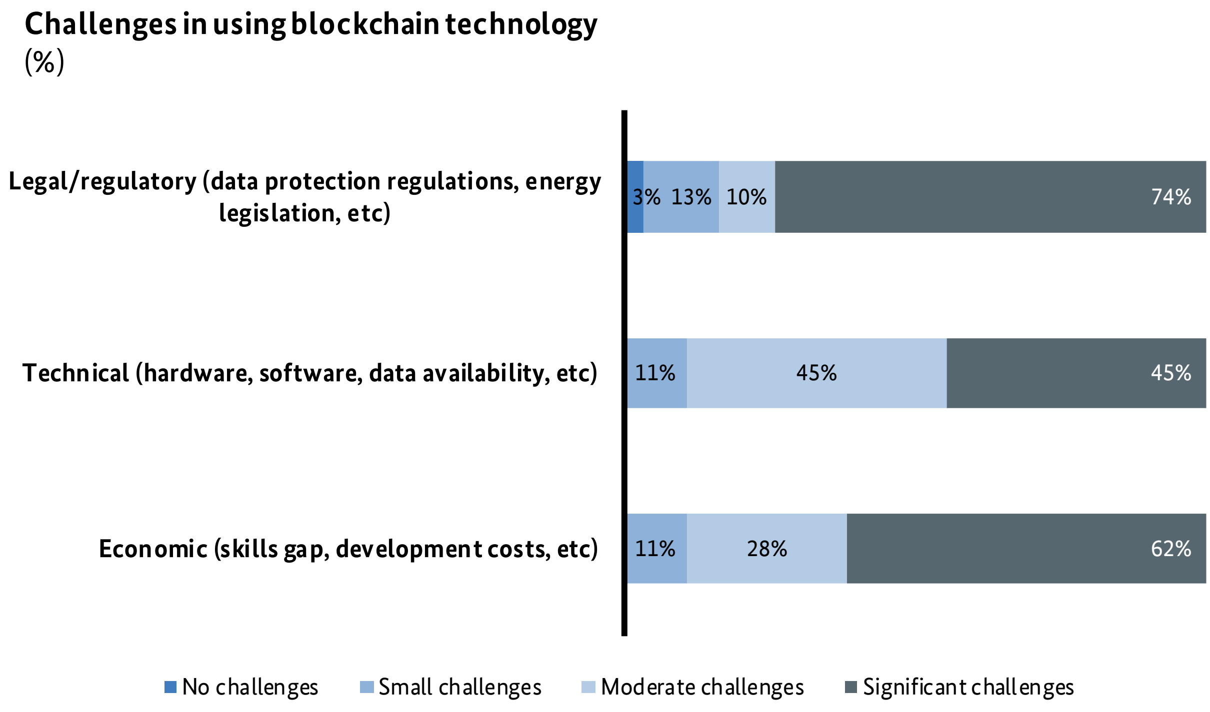


Figure 251: Challenges in using blockchain technology

The greater challenges in planning and using blockchain technology are generally seen to be legal/regulatory and economic challenges. It should again be noted that the results shown may not be representative for all market roles because the majority of the companies included are electricity and gas TSOs.

C Selected activities of the Bundeskartellamt

1. Overview of merger control proceeding B8-134/21 RheinEnergie/Westenergie/rhenag

In the reporting period the Bundeskartellamt closely examined a merger planned by Westenergie AG, a company based in Essen which belongs to the E.ON group, aPRIVEnd RheinEnergie AG based in Cologne. The project is to create a strategic connection between the two companies and essentially includes three parts:

- First, RheinEnergie and Westenergie will bring their participations in municipal utilities in the Cologne area under joint control in the rhenag joint venture. More specifically, RheinEnergie will transfer its shares in AggerEnergie, GVG Rhein-Erft, Stromnetz Bornheim, Stadtwerke Lohmar, Stadtwerke Sankt Augustin, evd Dormagen, Stadtwerke Pulheim and Stadtwerke Troisdorf to rhenag and acquire joint control of rhenag. Westenergie will maintain joint control of rhenag, which continues to hold shares in particular in Rhein-Sieg Netzgesellschaft, Westerwald-Netz, Energieversorgung Niederkassel, Gemeindewerke Windeck, Stadtwerke Siegburg, Hennef (Sieg) Netz and e-regio Euskirchen. In addition, Westenergie will transfer further shares in e-regio Euskirchen and also shares held in EWR Remscheid, Stadtwerke Haan, Stadtwerke Ratingen, Stadtwerke Langenfeld and BEW Netze Wipperfürth to rhenag.

- Second, Westenergie, and thus E.ON, will increase its participation in RheinEnergie to almost 25% and as a result will for the first time also gain a material competitive influence on RheinEnergie.

- The third part of the planned transaction, namely RheinEnergie's acquisition of the 20% share in the municipal utility company Stadtwerke Duisburg previously held by Westenergie, has already been examined and cleared separately.

The project affects almost all stages of the energy sector's value added chain, in particular heating electricity, electromobility, distribution network concessions and operation, metering services, energy contracting as well as further retail markets for the supply of electricity and gas. The project's geographic focus is on Cologne and the greater Cologne area.

Heating electricity

According to the Bundeskartellamt's investigations, competition concerns mainly arose with regard to heating electricity. In its general decisional practice, which has recently been reviewed and confirmed, the Bundeskartellamt defines a separate product market for the supply of heating electricity to end customers. The supply of electricity for electrical night storage heating and heat pumps is assumed to represent one market; in geographic terms the heating electricity markets are defined as local markets according to the geographic scope of the default supply or network areas and based on the recently reviewed and confirmed decisional practice. Although the liberalisation of the energy markets took place a long time ago, the Bundeskartellamt's investigations have shown that the default suppliers have outstanding and structurally secured positions in the local markets affected. Due to the elimination of competition from the E.ON group the project would have strengthened the dominant position of RheinEnergie and further RheinEnergie group companies in ten local markets in the greater Cologne area. At the same time the project strengthens the E.ON group's dominant position in two markets where competition is eliminated by RheinEnergie's participation in rhenag.

Electromobility

Competition problems have also been identified in the operation of charging points for electric vehicles. For the operation of publicly accessible charging infrastructure the Bundeskartellamt for the first time defined separate relevant product markets and in terms of charging capacity differentiated between normal-power charging points (up to and including 22 kW) and high-power charging points (exceeding 22kW). As to the latter charging points the authority also differentiated between those located "on motorways" and "off motorways". In geographic terms the relevant product markets for the operation of publicly accessible charging station infrastructure are to be defined as local or regional markets. Based on these market definitions the Bundeskartellamt identified a total of seven market areas for the operation of publicly accessible normal-power charging points within the cities of Bergheim, Cologne and Sankt Augustin as markets where the requirements for prohibition are fulfilled due to competition concerns raised by the concentration. However, this concerns only a few very narrowly defined local areas currently still generating marginal revenues. This market will also develop very dynamically in the future. Furthermore, the Bundeskartellamt considered the definition of separate product markets for the supply of charging options by charging cards ("EMP market") and the sale of charging electricity to consumers ("charging electricity market"). The authority also considered separate markets for white-label services in the area of charging infrastructure and for the charging infrastructure retail sector. The exact definitions of the respective product and geographic markets could ultimately be left open as they were not relevant for the decision.

Other markets affected

Based on the Bundeskartellamt's investigations, all other markets affected have not been considered to raise competition concerns under merger control rules. The authority closely examined the areas of distribution network concessions and operation as well as meter operation.

A restriction of the bidding competition for concessions in the greater Cologne area can be expected as probably only one of the parties (instead of previously two or more) will be participating in future. However, the Bundeskartellamt's investigations have shown that the parties' competitive scope of action can still be expected to be sufficiently controlled by regulating the award of concessions and network operations. Countervailing market power is also exercised by the municipalities which organise the tender procedures for concessions. In view of the increasing trend towards remunicipalisation these entities and their own energy suppliers and network operators play an increasingly important role. Finally, in view of the fact that the next concession award procedures are still in the (in some cases very) distant future, it could not be ascertained with sufficient certainty on the basis of the criteria available under merger control law that the strategic connection will actually result in negative competitive effects which fulfil the conditions for a prohibition pursuant to Section 36(1) of the German Competition Act (GWB).

In the area of metering services the Bundeskartellamt defined further markets after it had previously only differentiated between metering and submetering services. As to metering, a differentiation is now made between the offers of default meter operators and competing third-party operators while it could be left open whether these markets should be further divided according to the meter's load profile or according to the metering system used. In geographic terms, default meter operation is defined as a local market, i.e. network-based, while meter operation by competing third parties is likely to be defined as a national or at least supra-regional market. The Bundeskartellamt has also considered defining several product markets for white label services in the metering sector. In geographic terms such white label services for metering would probably have to be defined as a nationwide market. A final market definition could be left open. Irrespective of the specific market definitions, the project was not expected to significantly impede effective competition in any of the areas examined.

Clearance subject to remedies

The concentration project could be cleared in second phase proceedings following changes to the merger plans. The Bundeskartellamt's clearance is subject to the condition precedent that RheinEnergie sells a large part of its heating electricity business to a single acquirer as the company's dominant position in the heating electricity sector in and around Cologne would otherwise be strengthened. The parties' commitment includes selling 20% of RheinEnergie's special contracts in the company's core business area of Cologne and Bornheim as well as all special contracts for heating electricity in RheinEnergie's other default supply areas (Frechen, Hürth, Pulheim, Langenfeld, Wachtberg and Rösrath, among other areas), a total of more than 6,000 contracts. Overall, after possible customer objections have been considered, the company is to sell at least 5,000 heating electricity contracts. By creating a strong competitive force which can act as a counterweight to the dominant default supplier, the commitment will clearly improve the competition situation in RheinEnergie's default supply areas.

The commitment does not address the other local heating electricity markets where the requirements for prohibition are fulfilled and which cover the supply areas of the municipal utilities in which RheinEnergie and Westenergie have participations or of their subsidiaries, because no customer contracts will be sold in these areas. Furthermore, the commitment does not address the markets in the area of charging infrastructure where the requirements for prohibition are fulfilled. In the heating electricity sector the improvements to competition achieved by the very significant extent to which the negative effects of the concentration are compensated and the creation of a strong counterweight to the default supplier's market power in the heating electricity markets addressed outweigh the fact that competition from the E.ON group will be eliminated both in terms of quantity and quality in the remaining markets where the requirements for prohibition are fulfilled. Overall, RheinEnergie loses significantly more heating electricity customers than it gains by intensifying its cooperation with E.ON. At the same time, the improvements also outweigh the negative effects on competition in the markets for normal-power charging points where the requirements for prohibition are fulfilled as revenues in these narrow local market areas are low. For these reasons the project was cleared pursuant to the balancing clause under Section 36(1) sentence 2 no. 1 GWB.

Lists

List of authorship

Joint texts

Key findings

Electricity markets summary (I.A.1)

Introduction to Retail: Contract structure and supplier switching (I.G.2)

Introduction to Retail: Price level (I.G.4)

Gas markets summary (II.A.1)

Introduction to Retail: Contract structure and supplier switching (II.F.2)

Introduction to Retail: Price level (II.F.4)

Market Transparency Unit for Wholesale Electricity and Gas Markets (III.A)

(Text passages in these four sections authored as listed below)

Authorship of the Bundesnetzagentur

I	Electricity market
A	Developments in the electricity markets (the following sections only)
2.	Network overview
4.	Consumer advice and protection
B	Generation
C	Networks
D	System services
E	Cross-border trading and European integration
G	Retail (the following sections only)
1.	Supplier structure and number of providers
2.2	Contract structure and supplier switching, household customers

3. Disconnections, cash/smart card readers, tariffs and contract terminations

4.2 Price level, household customers

6. Green electricity segment

H Metering

II Gas market

A Developments in the gas markets (the following sections only)

2. Network overview

B Gas supplies

C Networks

D Balancing

F Retail (the following sections only)

1. Supplier structure and number of providers

2.2 Contract structure and supplier switching, household customers

3. Gas supply disconnections and contract terminations, cash/smart card meters and non-annual billing

4.2 Price level, household customers

G Metering

III General topics

A Market Transparency Unit for Wholesale Electricity and Gas Markets

B Selected activities of the Bundesnetzagentur

Authorship of the Bundeskartellamt

I Electricity market

A Developments in the electricity markets (the following sections only)

3. Market concentration

F Wholesale market

G Retail

2.1 Contract structure and supplier switching, non-household customers

4.1 Price level, non-household customers

5. Heating electricity

7. Comparison of European electricity prices

II Gas market

A Developments in the gas markets (the following sections only)

3 Market concentration

E Wholesale market

F Retail (the following sections only)

2.1 Contract structure and supplier switching, non-household customers

4.1 Price level, non-household customers

5. Comparison of European gas prices

III General topics

C Selected activities of the Bundeskartellamt

Figures

Tables

List of abbreviations

Abbreviation	Definition
AC	alternating current
ACER	European Union Agency for the Cooperation of Energy Regulators
BAFA	Federal Office for Economic Affairs and Export Control
bFZK	conditionally firm, freely allocable capacity
BGH	Federal Court of Justice
BZK	capacity with limited allocability
CAM NC	European Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems
capex	capital expenditure
CAPM	capital asset pricing model
CEPS	TSO in Czechia
CEREMP	Centralised European Register of Energy Market Participants
CHP	Combined heat and power
ct/kWh	cents per kilowatt hour
DC	direct current
DSO	distribution system operator
DZK	firm, dynamically allocable capacity
EGIX	European Gas Index
EGSI	European Gas Spot Index
EHV	extra high voltage
EPEX	European Power Exchange
FZK	firm, freely allocable capacity
Gas NDP	Gas Network Development Plan
GasGKErstV	Gas Appliance Reimbursement Ordinance
GasGVV	Gas Default Supply Ordinance
GasNEV	Gas Network Tariffs Ordinance
GemAV	Joint Auctions Ordinance
GJ	gigajoules
GWB	German Competition Act
HVDC	high voltage direct current
ID	identification number
InnAusV	Innovation Auction Ordinance
ITC	inter-TSO compensation
KASPAR	capacity product standardisation
KAV	Electricity and Gas Concession Fees Ordinance
kV	kilovolt

KVBG	Act to Reduce and End Coal-Fired Power Generation
LBEG	State Authority for Mining, Energy and Geology
LNG	liquefied natural gas
MaStR	core energy market data register
MOL	merit order list
NABEG 2.0	Grid Expansion Acceleration Act
NCG	NetConnect Germany
NDP	Network Development Plan
NEMoG	Network Tariffs Modernisation Act
NRA	National Regulatory Authority
PIA	preliminary initial assessment
PICASSO (aFRR)/ MARI (mFRR)	European platforms for the exchange of balancing energy
power-to-gas	the use of synthetically produced gas
power-to-heat	generation of heat from electricity
PV	photovoltaic
RAB	regulatory asset base
REMIT	Regulation (EU) No 1227/2011 on wholesale energy market integrity and transparency
SAIDI	System Average Interruption Duration Index
SDAC	Single Day-ahead Coupling
uFZK	interruptible, freely allocable capacity
VAT	Valued Added Tax
VPI-Xgen	indexation
WindSeeG	Offshore Wind Energy Act

Glossary

The definitions pursuant to section 3 of the Energy Industry Act (EnWG), section 2 of the Electricity Network Access Ordinance (StromNZV), section 2 of the Gas Network Access Ordinance (GasNZV), section 2 of the Electricity Network Tariffs Ordinance (StromNEV), section 2 of the Gas Network Tariffs Ordinance (GasNEV), section 3 of the Renewable Energy Sources Act (EEG) and section 2 of the Combined Heat and Power Act (KWKG) apply. In addition the following definitions apply:

Term	Definition
Adjustment measures	Section 13(2) EnWG entitles and obliges TSOs to adjust all electricity feed-in, transit and offtake or to demand such adjustment (adjustment measures) where a threat or disruption to the security or reliability of the electricity supply system cannot be removed or cannot be removed in a timely manner by network-related or market-related measures as referred to in section 13(1) EnWG. Where DSOs are responsible for the security and reliability of the electricity supply in their networks, they too are entitled and obliged under section 14(1) EnWG to take adjustment measures as referred to in section 13(2) EnWG. Furthermore, section 14(1c) EnWG requires DSOs to support the TSOs' measures as required by the TSOs with the DSOs' own measures (support measures). Curtailing feed-in from renewable energy installations under section 13(2) EnWG may also be necessary in situations other than those covered by the feed-in management provisions if the threat to the system is caused not by congestion but by another security problem. Adjustments pursuant to section 13(2) EnWG constitute emergency measures and as such are without compensation.
Affiliated undertakings within the meaning of section 15 AktG	As set out in the German Stock Corporation Act: legally independent companies that in relation to each other are subsidiary and parent company (section 16), controlled and controlling companies (section 17), members of a group (section 18), undertakings with cross-shareholdings (section 19) or parties to a company agreement (sections 291 and 292).
Annual peak load (final consumers)	Peak load, expressed in kilowatt (kW), as metered in 15 minute readings, in the course of a year.
Annual usage period (final consumers)	The annual usage period 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 period in days = annual consumption divided by maximum daily amount). The usage period in hours indicates the number of hours required to withdraw the annual consumption volume by taking off the maximum hourly amount (usage period 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 activation 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 each balancing group in 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 withdrawal points that serves the purpose of minimising deviations between feed-in and withdrawal 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 flows, which represent the actual cross-border flow of electricity, exchange schedules reflect the commercial cross-border exchange of electricity. Physical 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 facilities	Artificial hollows in salt domes created by drilling and solution mining. These facilities 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.
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 from a specific generating unit 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	Amount of electricity delivered by electricity network operators to final consumers.

Conventional meter operation	Conventional meter operation includes all metering systems that are not modern metering equipment or smart metering systems (eg Ferraris meters, electronic household meters, EDL21, EDL40, 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 trading	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 consumers.
Dominance method	Simplified group accounting method for the purposes of evaluating market concentration. It focuses solely on whether one shareholder holds at least 50% of the shares in a company. If a single shareholder holds more than 50% of a company’s shares, that company’s sales will be fully attributed to that shareholder. If two shareholders each hold 50% of a company’s shares, they will each be attributed 50% of the sales. 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).
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.
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 TSOs to ensure that the network and system is operated securely (see Bundesnetzagentur decision BK6-13-200).

Energy price components	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 that 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.
Expenditure	Expenditure consists of the combination of all technical or administrative measures taken during the life cycle of an asset to maintain or restore working order so that the asset can perform the function required (expenditure on replacement and maintenance).
Fallback supplier	The default supplier is the fallback supplier (see section 38 EnWG).
Fallback supply	Energy received by final customers from the general supply system at low voltage or low pressure and not allocable to a particular delivery or a particular supply contract (see section 38 EnWG).

Feed-in management	This is a special measure regulated by law to increase network security relating to renewable energy, mine gas and combined heat and power (CHP) installations. Priority is to be given to feeding in and transporting the electricity generated by these installations (section 11(1) and (5) EEG and section 4(1) and (4) 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 curtailment measures for conventional installations have been exhausted. The expansion obligations of the operators responsible 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 curtailed energy and heat as provided for in section 15(1) EEG. The costs of compensation must be borne by the operator in whose network the cause for the feed-in management measure is located. The operator to whose network the installation with curtailed feed-in is connected is obliged to pay the compensation to the operator of the installation with curtailed feed-in. If the cause lay with another operator, that operator is held responsible and is required to reimburse the costs of compensation to the operator to whose network the installation is connected.
Flow Based Allocation (FBA)	Flow based allocation of capacity. Starting from the planned commercial flows (trades), the capacity available for cross-border electricity trading is determined and allocated on the basis of the actual flows in the network. FBA thus makes it possible to allocate transmission capacity in line with the actual market situation as reflected by the bids.
Futures	Contractual obligation to buy (futures buyer) or deliver (futures seller) a specified amount of, for example, electricity, gas or emission rights at a fixed price in a defined future period (period of delivery). Futures contracts are settled either physically or financially.
Futures market	Market for trading futures and derivatives. It differs from the spot market in that obligation and settlement do not take place at the same time.
Green electricity tariff	Tariff for electricity 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 reserve capacity	Grid reserve capacity is a price element for customers with their own generation or network operator 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.
Grid/network connection	*electricity* Pursuant to section 5 of the Low Voltage 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 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.
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).
Heating electricity	Heating electricity is the electricity supplied to operate controllable loads for the purposes of room heating. Controllable loads essentially comprise overnight storage heaters and electric heat pumps.
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.
Interval metering	Measurement of the power used by final consumers in a defined period. Interval 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 interval metering.
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 tariffs 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 tariffs 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, version in force until 31 December 2022)
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 consumers and transfer gas to other balancing groups.
Market coupling	A process for efficient congestion management between different market areas involving several power exchanges. Market coupling improves the use of scarce transmission capacities by taking into account the energy prices in the coupled

	markets. It involves day-ahead allocation of cross-border transmission capacities and energy auctions on the power exchanges being carried out at the same time based on the prices on the exchanges. For this reason, reference is also made here to implicit capacity auctions.
Market location	Energy is generated or consumed in a market location. The market location is connected to the network by means of at least one line. The market location is a connecting point for supply and balancing.
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 books 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	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.
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 tariffs	*electricity* Electricity network tariff, from 1 January 2017 including billing tariff, not including tariffs for meter operations, VAT, concession fees, surcharges payable under the EEG and KWKG and other surcharges. *gas* Gas network tariff, from 1 January 2017 including billing tariff, not including tariffs 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 tariffs to network operators. However, it is also permissible for final customers to use the network, in which case, the final customer pays the network tariffs to the network operator.
Network area	Entire area over which the network and transformation 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, known as network losses, 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 non-CHP 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 non-CHP electricity generation. The net non-CHP electricity generated by a generating installation is the gross non-CHP generation less the non-CHP 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 1.01325 bar, corresponds to the volume of one cubic metre.
Offtake volume	Amount of gas taken off by gas network operators.
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 facilities	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".
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 rectify at short notice 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 an instrument set out in 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 general supply network receive a payment from network operators that has been set under the EEG or determined through auctions. The funds required are passed on to electricity consumers by the renewable energy surcharge. All non-privileged electricity consumers pay the renewable energy surcharge as part of the electricity price. The TSOs calculate the surcharge. They are required to determine and publish the surcharge for the following calendar year by 15 October each year. The network operators publish this online at www.netztransparenz.de. The Bundesnetzagentur ensures that 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 facility operator	In this context the term refers to a storage facility operator in the commercial sense. It does not refer to the technical operator, but rather to the company 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.
Tariff for meter operations	Tariff for meter installation, operation and maintenance. In accordance with section 17(7) sentence 1 StromNEV, in the electricity sector only a "tariff for meter operations" may be shown from 1 January 2017. This includes the metering tariff.
Tariff for metering	In the gas sector, the tariff for reading the meter, reading out and passing on the meter data to the authorised party (section 15(7) sentence 1 GasNEV).
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 consumer)	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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