Bundesnetzagentur Bundeskartellamt

Monitoring report 2019 -
Key findings and summary

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A Key findings

Generation

The market power of the largest conventional electricity producers (electricity not eligible for payments under the Renewable Energy Sources Act – EEG) has decreased significantly over the last few years. In 2018, 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 was 73.9%, compared to 75.5% in the previous year.

With respect to the German conventional generating capacity generally available for use in the market for the first-time sale of electricity, the share of the five largest suppliers was 60.8% and thus also significantly below the previous year's level of 64.9%.

Germany's total net electricity generation declined from 601.4 TWh in 2017 to 592.3 TWh in 2018 due to a decrease in gross electricity consumption. After a substantial rise of 24.6 TWh in generation from renewable energy sources in 2017, there was a smaller increase of 6.0 TWh in 2018 to a total of 210.8 TWh. Electricity generation from renewable energy sources accounted for 37% of gross electricity consumption.

The year 2018 saw a further expansion of renewable energy capacity, although growth was slightly smaller than in the previous year. At the end of 2018, installed renewable capacity had increased year-on-year by approximately 6.6 GW. The total generating capacity was at 221.6 GW in 2018, compared to 215.6 GW in 2017, with 103.3 GW of non-renewable and 118.2 GW of renewable capacity.

The growth in renewable energy capacity of 6.6 GW (sum of renewable energy installations with and without payments under the EEG) is due in particular to the greater increase in solar installations (+2.9%) compared to the previous years. Onshore and offshore wind power capacity also continued to grow. However, at 2.3 GW the net expansion of onshore wind power capacity more than halved compared to 4.9 GW a year earlier.

Total renewable electricity generation increased year-on-year by 6.0 TWh or 2.9% to 210.8 TWh, mainly accounted for by a 15.2% year-on-year increase in the amount of electricity generated through solar. Compared to 2017, onshore wind generation increased by 2.4 TWh or 2.8% in 2018. Offshore wind generation was also up, showing an increase of 1.8 TWh or 10.1%. The warm temperatures in 2018 led to a drop in electricity generated from run-of-river hydroelectric plants by 2.0 TWh or 11.7% and from hydro storage plants by 0.8 TWh or 37.3%. Payments to renewable installation operators under the EEG averaged 13.2 ct/kWh in 2018.

Despite the increase in electricity generation from installations receiving EEG payments, the total amount of payments under the EEG decreased for the first time in 2018 compared to previous years falling by 1.3% to €25.7bn. The decrease is due in particular to the comparatively high electricity prices in 2018, which affect the level of the payments. Directly marketed installations do not receive the full amount via the EEG surcharge, but only the difference, if any, to the market price.

Redispatching and feed-in management

The need for redispatching measures continued to be at a high level in 2018, but the volume decreased compared to 2017. In 2018, total reductions in feed-in amounted to 7,919 GWh, increases in feed-in from operational plants totalled 6,956 GWh and the use of reserve power plants accounted for 654 GWh. Overall, a total of 15,529 GWh of reductions and increases in feed-in was requested. Redispatching measures were taken on 354 days. The reductions in feed-in from power plants as a result of redispatching measures thus corresponded to 2.1% of the total non-renewable generation fed into the grid. Costs for redispatching measures with operational and grid reserve power plants amounted to approximately €803m in 2018.

At around 5,403 GWh, feed-in management measures in 2018 almost remained at the 2017 level. Compared with 2017, when feed-in management measures totalled 5.518 GWh, this corresponds to a decrease in the amount of energy curtailed of approximately 115 GWh. The total estimated compensation payments claimed by installation operators and notified to the Bundesnetzagentur amounted to approximately €635.4m in 2018, slightly up on the previous year's level of €609.9m.

Electricity network charges

After average network charges for household customers had fallen for the first time again in 2018, there was an increase of 0.4% to 7.22 ct/kWh in 2019. As from 2019, cost components from the network charges are part of the offshore network surcharge. The costs for network users nationwide based on the sum of the network charges and the offshore network surcharge increased by just under 6% from 7.23 ct/kWh (7.19 ct/kWh plus 0.037 ct/kWh offshore liability surcharge) in 2018 to 7.64 ct/kWh (7.22 ct/kWh plus 0.416 ct/kWh offshore network surcharge) in 2019.

Wholesale electricity markets

The spot market was characterised by various developments. The volumes of day-ahead trading on EPEX SPOT and on EXAA showed a year-on-year decrease, while the volume of intraday trading rose by some 12.5% compared to the previous year.

Volumes in futures trading recorded a growth of approximately 11% year-on-year. Moreover, in 2018 the Phelix-DE future almost entirely replaced the Phelix-DE/AT future. Phelix-DE trading volumes were at 1,058 TWh and Phelix-DE/AT at 27 TWh, compared to 196 TWh and 786 TWh in 2017 respectively. Volumes traded via broker platforms also increased. The volume of OTC clearing of Phelix-DE futures on EEX rose significantly to 1,053 TWh in 2018, now equalling the volume traded on the exchange.

Wholesale electricity prices averaged across 2018 were again considerably higher. Spot market prices (for the combined German-Austrian market area until 30 September 2018) were up about 22% year-on-year, and futures (for the market area Germany/Luxembourg) were quoted approximately 33% higher for the following year.

Retail electricity markets

Retail market developments in 2018 stagnated in many areas. Rising prices on the wholesale markets are now also affecting final customers.

As in previous years, the Bundeskartellamt assumes that there is no longer any single dominant undertaking in either of the two largest electricity retail markets. The cumulative market share of the four largest undertakings showed a further year-on-year decrease, down to around 24.4% in the national market for supplying interval-metered customers, and down to 31.3% in the national market for non-interval-metered customers on special contracts.

The supplier switching rate for non-household customers has been fairly constant since 2009. The volume-based switching rate for customers with an annual consumption of more than 10 MWh stood at 12.3% in 2018, compared to 13.0% in 2017. The share of electricity consumed by household customers served by a supplier other than their local default supplier is stable at 31%. At 4.7m, the number of household customers who switched their electricity supplier also remained unchanged. The number of undertakings operating in the market largely remained the same, giving household customers a choice between an average of 124 different suppliers.

The average total price (excluding VAT and possible reductions) for industrial customers with an annual consumption of 24 GWh was 15.98 ct/kWh on 1 April 2019, up 0.68 ct/kWh on the previous year. The average total price (excluding VAT) for commercial customers with an annual consumption of 50 MWh was 22.22 ct/kWh in April 2019, representing an increase on the previous year of 0.66 ct/kWh. This increase in prices for industrial as well as commercial customers is mainly accounted for by the price components controlled by the supplier.

The average price for household customers as at 1 April 2019 was 30.85 ct/kWh, and thus for the first time exceeded 30 ct/kWh. This average value is calculated by weighting the individual prices across all contract models according to consumption for an annual consumption of between 2,500 kWh and 5,000 kWh, producing a reliable average for the electricity price for household customers. As at 1 April 2019, the price component controlled by the supplier (energy procurement, supply and margin) accounted for about 7.6 ct/kWh or 25% of the total price, thus showing a further year-on-year increase. The average network charge and the meter operation charges add up to 7.22 ct/kWh in 2019, which is just under 24% of the total price. At 6.41 ct/kWh, the EEG surcharge fell again, now accounting for about 21% of the total price.

Electric heating

Electric heating prices were higher than in 2018. The arithmetic mean of the gross total price for night storage heating as at 1 April 2019 was 21.92 ct/kWh, up on the previous year's level of 21.08 ct/kWh. The arithmetic mean of the total price for heat pump electricity was 22.50 ct/kWh, up on the previous year’s figure of 21.71 ct/kWh. In general, prices for heat pump electricity are higher than for night storage heating.

There has been a steady increase in switching activity among electric heating customers, albeit at a low level, following many years with hardly any customers switching. This increase in the switching rate indicates a higher degree of competition. Yet at the same time, the switching rates are still far below those for household electricity and non-household customers. The volume-based supplier switching rate for 2018 was around 4%. There is a steady increase in the share of electricity provided for heating purposes and in the number of electric heating meter points served by a supplier other than the local default supplier, now standing at around 13%. This figure was still at around 9% in 2016.

Electricity imports and exports

Germany's electricity exports decreased slightly for the first time in 2018 compared to the previous year. Cross-border trade volumes for electricity amounted to 85.3 TWh in 2018, down from 90 TWh in 2017. With an export balance of 51.3 TWh, Germany is one of Europe's large exporters of electricity. The export surplus corresponded to €2,099m. Despite a decrease in the volume, there was an increase in the export surplus in monetary terms, up from €1,725m in 2017.

Gas imports and exports

The volume of gas imported into Germany rose by some 83 TWh or around 5% from 1,676 TWh in 2017 to 1,760 TWh in 2018. The year 2018 also saw an increase in gas exports, from 770.4 TWh in 2017 to 849.1 TWh in 2018, up approximately 105.6 TWh or 14% on the previous year.

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

Gas supply interruptions

In 2018, the average interruption in supply per connected final consumer was 0.48 minutes per year, which is a value that clearly reflects the high level of supply quality of the German gas network.

Market area conversion

The conversion of German L-gas networks to H-gas began in 2015 with the smaller network operators and has since been in progress as planned with the larger network operators such as Westnetz, EWE Netz and wesernetz Bremen. The highest annual figure of around 550,000 converted appliances will be reached in the coming years.

Gas storage facilities

The market for the operation of underground natural gas storage facilities is still relatively highly concentrated, although concentration has eased over the past few years. The aggregate market share of the three largest storage facility operators stood at around 67.1% at the end of 2018, representing a slight decrease on the previous year.

On 31 December 2018, the total maximum usable volume of working gas in underground storage facilities was 280.02 TWh. Of this, 134.12 TWh was accounted for by cavern storage, 123.89 TWh by pore storage and 22.01 TWh by other storage facilities. As at 1 November 2019 the storage level of gas storage facilities was at over 99%.

Wholesale natural gas markets

Overall, the liquidity of the wholesale natural gas markets declined in 2018. Although the volume traded on the stock exchange increased by a total of around 13% (spot market: +26%, futures market: -33%), bilateral wholesale trading via broker platforms, which accounts for a much larger share, experienced a decrease in volume of around 14%.

As in the previous year, wholesale gas prices in 2018 showed some considerable increases. The various price indices (EGIX, cross-border prices, as calculated by the Federal Office for Economic Affairs and Export Control (BAFA)) show a year-on-year increase of between 13% and 28%. A fully reliable year-on-year comparison for the European Gas Spot Index (EGSI) introduced in September 2017 will be available next year.

Retail gas markets

The level of concentration in the two largest gas retail markets continues to be well below the statutory thresholds for presuming market dominance. In 2018, cumulative sales for the four largest companies to customers with a standard load profile (SLP) were about 86 TWh and around 138 TWh for interval-metered customers. The aggregate market share of the four largest companies (CR4) in 2018 was around 23% for SLP customers, and thus the same as in the previous year, and about 31% for interval-metered customers, compared to 30% in 2017.

The retail gas markets are continuing to develop positively. Over 1.5m household customers switched gas supplier in 2018; yet the overall number of customers switching gas supplier recorded a slight decline. What is noticeable though is that a growing number of household customers immediately choose an alternative supplier rather than the default supplier when moving home or moving into new builds.

The total consumption affected by supplier switches in 2018 was 89.5 TWh, corresponding to a year-on-year increase of 1.5 TWh or about 2%. The switching rate for non-household customers was 9.0%, representing an increase of around 0.9 percentage points compared to the previous year.

At approximately 0.6m, the total number of customers changing contract continued to develop positively in 2018. Overall, the percentage of household customers supplied by the local default supplier on a default contract continues to decline, standing at 18% in 2018. In addition, there was another significant increase in the number of undertakings operating in the market. Today, household customers can choose between an average of more than 100 different suppliers. At the same time, the number of gas disconnections has again fallen. In 2018, a total of nearly 33,000 customers were disconnected, representing a year-on-year decrease of just over 17%.

The gas prices for non-household (industrial and commercial) customers as at 1 April 2019 showed year-on-year increases. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 GWh ("industrial customer") was 2.86 ct/kWh, and thus 0.04 ct/kWh or around 1.4% higher than the previous year's figure. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 MWh ("commercial customer") was 4.55 ct/kWh, and thus 0.15 ct/kWh or around 3.4% higher than a year earlier.

After several years of decreases the gas prices for household customers again recorded a year-on-year increase as at 1 April 2019. The volume-weighted average across all groups of household customers with an average consumption of 23,250 kWh was up 4.4% or 0.27 ct/kWh at 6.34 ct/kWh (including VAT). The main reasons for the rise in gas prices are the increases in gas procurement costs (6%) and network charges (4%).

B Developments in the electricity markets

1. Summary

1.1 Generation and security of supply

At 592.3 TWh, Germany's net electricity generation in 2018 was lower than the 2017 level (601.4 TWh). One particular reason for the reduction in the level of net electricity generation is the decrease in gross electricity consumption. The decline in the overall level of net electricity generation was accompanied by a decrease in generation from non-renewable energy sources (-15.1 TWh or -3.8%). The largest decrease here was in net electricity generation from natural gas power plants at -8.3 TWh (-11.4%). There was a reduction of 3.1 TWh (-3.7%) in electricity generation from black coal plants. Lignite power plants generated 1.6 TWh less electricity (-1.2%).

After a large rise in generation from renewable energy sources in 2017, there was a smaller increase of 2.9% in 2018 to a total of 210.8 TWh (2017: 204.8 TWh). Electricity generated from renewables accounted for 37% of gross electricity consumption in 2018[1].

Installed generating capacity was characterised in 2018 by a further increase in renewable capacity. Overall, renewable capacity increased by 6.6 GW, compared to an increase of 7.4 GW[2] between 2016 and 2017. The largest increases here in 2018 were in solar photovoltaic (+2.9 GW), onshore wind (+2.3 GW) and offshore wind (+1.0 GW). Non-renewable generating capacity (nuclear, lignite, black coal, natural gas, mineral oil products, pumped storage and other non-renewable energy sources) decreased by 0.7 GW in 2018. Total (net) installed generating capacity increased to 221.6 GW at the end of 2018, with 103.3 GW of non-renewable and 118.2 GW of renewable capacity. The non-renewable generating capacity includes power stations operational in the market and power stations outside the market (eg standby lignite and grid reserve power stations).

The installed capacity of systems eligible for payments under the Renewable Energy Sources Act (EEG) in Germany stood at 114.1 GW at the end of 2018 (2017: 107.5 GW). This represents an increase of around 6.6 GW (6.1%). A total of 195.4 TWh of electricity from renewable energy installations received payments under the EEG in 2018. Electricity generation from installations eligible for EEG payments thus increased by 4.2%. Despite the increase in the amount of electricity generated by installations receiving EEG payments, payments in 2018 fell for the first time compared to previous years. The total amount of payments decreased by 1.3% to €25.7bn. The decrease is due in particular to the comparatively high electricity prices in 2018, which affect the level of the payments. Directly marketed installations do not receive the full amount via the EEG surcharge, but only the difference, if any, to the market price. In 2018, renewable installation operators received an average of 13.2 ct/kWh under the EEG[3].

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[1] If the share of renewables in generation is taken to be more than 40%, it usually relates to the definition of consumption as "grid load" (for example on the SMARD website).

[2] The 2017 figure from the 2018 monitoring has been updated.

[3] 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.

1.2 Cross-border trading

Electricity exports again exceeded imports in 2018. The volume of cross-border trading increased slightly by 2%.

Germany's electricity exports decreased slightly for the first time in 2018 compared to the previous year. Cross-border trade volumes for electricity amounted to 91.57 TWh in 2018 (2017: 90 TWh). With an export balance of 52.46 TWh Germany is one of Europe's large exporters of electricity. The export surplus corresponded to €2,125m. Despite a decrease in the volume, there was an increase in the export surplus in monetary terms (2017: €1,725m).

1.3 Networks

1.3.1 Network expansion

The projects currently listed in the Power Grid Expansion Act (EnLAG) (as at the first quarter of 2019) comprise lines with a total length of about 1,800 km. A further 20 km are in the spatial planning procedure and around 550 km are in or about to start the planning approval procedure (as at the first quarter of 2019). Overall, around 1,200 km have been approved, of which approximately 800 km – or about 45% of the total – have been completed. So far, none of the underground cable pilot lines have been put into full operation. Operational testing is in progress for the first 380 kV underground cable pilot project in Raesfeld.

The projects listed in the Federal Requirements Plan Act (BBPlG) comprise lines with a total length of about 5,900 km (as at the first quarter of 2019). According to the network development plan, around 3,050 km of these lines will serve to reinforce the system. The total length of the lines in Germany will be largely determined by the route of the north-south corridors and will become apparent in the course of the procedure. Approximately 3,600 km fall under the responsibility of the Bundesnetzagentur. As at the first quarter of 2019, approximately 2,700 km of these lines are in the federal sectoral planning procedure, around 200 km are about to start the planning approval procedure and about 30 km are in the planning approval procedure. Approximately 2,200 km of the total fall under the responsibility of the federal state authorities. As at the first quarter of 2019, around 50 km of these lines are in the spatial planning procedure and 1,100 km are in or about to start the planning approval procedure. A further 100 km or so have already been approved in the procedures carried out by the Federal Maritime and Hydrographic Agency (BSH).

1.3.2 Investments

In 2018, investments in and expenditure on network infrastructure by the network operators amounted to around €9,830m (2017: €9,727m) (both values under commercial law[4]). This comprised €6,464m of investments and expenditure by the distribution system operators (DSOs) and €3,366m by the four

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

transmission system operators (TSOs). The TSOs' investments increased slightly from €2,707m in 2017 to €2,954m in 2018. The DSOs' investments also increased slightly from €3,501m in 2017 to €3,938m in 2018. The investment figures back to 2008 have been corrected to include the TSOs' offshore investments.

1.3.3 Network and system security

Redispatching measures serve to maintain network and system security. In 2018, total reductions in feed-in amounted to 7,919 GWh and increases in feed-in from operational power plants amounted to 6,956 GWh. The need for redispatching was thus still at a high level but was 24% lower compared to 2017 (2017: 20,439 GWh).

In 2017, in particular the unusual load flows in the first quarter that were due to various factors had led to a high need for redispatching measures. In the fourth quarter of 2017, the strain on the networks was already beginning to ease due to the commissioning of the "Thuringia power bridge". From the third quarter of 2018, however, there was another increase in redispatched volumes; one particular reason was the introduction at the end of April 2018 of the MinRAM process for flow-based capacity calculation in the CWE region. This methodology involves taking account of a standard minimum capacity of 20% per line in the capacity calculation. This increases the need for redispatching measures and is only partly compensated by the congestion management scheme (bidding zone split) introduced at the border with Austria as from 1 October 2018.

There was a correspondingly small decrease in the costs. An initial estimate by the TSOs puts the costs for the operational power stations at around €351.5m plus about €36.0m for countertrading measures (in total €387.5m). These costs are around 8% lower than the total costs in 2017 (2017: €420.6m).

In 2018, the grid reserve was used on 166 days to provide a total of around 904 GWh of energy. The initial estimate by the TSOs put the costs of using the grid reserve at €85.2m, representing a decrease of 54% (2017: €183.9m). The main reason for this is that no plants outside Germany were contracted for the grid reserve for winter 2018/2019. The costs for reserving the plant capacity plus other costs not dependent on the use of the grid reserve amounted to around €330.3m.

The amount of energy curtailed as a result of feed-in management measures, that is the curtailing of installations receiving payments under the EEG or the Combined Heat and Power Act (KWKG), was again high in 2018, totalling 5,403 GWh. This represents a slight decrease of 2% compared to the previous year (2017: 5,518 GWh). The amount of energy curtailed thus corresponded to 2.8% of the total amount of energy generated by renewable energy installations eligible for payments under the EEG (including direct marketing) (2017: 2.9%). The amount of compensation paid to installation operators in 2018 was about €719m, up around €145m on 2017 (2017: €574m). The total estimated claims from installation operators, however, increased slightly in 2018 to €635m. The discrepancy between the figures is due to the fact that the compensation paid in 2018 does not reflect the amounts payable for the curtailments actually made in 2018. The compensation paid in 2018 may include amounts for curtailments in previous years, and claims from 2018 may not be reflected properly, as the billing period does not correspond to the period when the curtailments were made.

In 2018, as in previous years, feed-in management measures primarily involved onshore wind power plants, which accounted for 72% of the total amount of curtailed energy (2017: 81%). Offshore wind power plants, which were first affected by feed-in management measures in 2015, accounted for around 25% (about

1,356 GW) of the total amount of curtailed energy in 2018, representing another increase (2017: 15% or around 826 GW).

The main reason for the continuing high level of feed-in management measures in 2018 was the curtailment of offshore wind power plants in addition to the wind situation and the growth of renewable capacity. Given the increased need for feed-in management measures and assuming that there will be a further steady increase in renewables, the measures required for network optimisation, reinforcement and expansion must be implemented without delay. This applies to the networks in and around Dörpen in the Emsland region and, in the case of feed-in management measures, in particular to the substation level between high voltage and extra-high voltage in Schleswig-Holstein.

In 2018, a total of five DSOs took adjustment measures. The measures to adjust electricity feed-in totalled around 8.3 GWh.

In total, the costs for network and system security amounted to about €1,438.4m in 2018. This represents a decrease of around €72.3m (-4.8%) compared to the previous year (2017: €1,510.7m).

1.3.4 Network charges

The volume-weighted network charges (including meter operation charges) for household customers for 2019 rose by 0.4% (+3 ct/kWh).

- Household customers, annual consumption 2,500 kWh to 5,000 kWh: volume-weighted 7.22 ct/kWh

As from 2019, the offshore liability surcharge and cost components from the network charges are part of the offshore network surcharge. The costs for network users nationwide based on the sum of the network charges and the offshore network surcharge increased by just under 6% from 7.23 ct/kWh (7.19 ct/kWh plus 0.037 ct/kWh offshore liability surcharge) in 2018 to 7.64 ct/kWh (7.22 ct/kWh plus 0.416 ct/kWh offshore network surcharge) in 2019.

With respect to non-household customers, the arithmetic mean charges for commercial customers are slightly higher than the previous year's level.[5] The network charges (including meter operation charges) for commercial customers increased by 1% to around 6.31 ct/kWh (2017: 6.27 ct/kWh). By contrast, the network charges (including meter operation charges) for industrial customers fell by approximately 1% to around 2.33 ct/kWh (2017: 2.36 ct/kWh). The charges as at 1 April 2019 for the selected consumption groups were as follows:

- Commercial customers, annual consumption 50 MWh: arithmetic mean 6.31 ct/kWh

- Industrial customers, annual consumption 24 GWh, without a reduction under section 19(2) of the Electricity Network Charges Ordinance (StromNEV): arithmetic mean 2.33 ct/kWh

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

There are large regional differences in the network charges. A comparison of the network charges in Germany for the three consumption groups, based on all the DSOs' published price lists (charges excluding meter operation), shows the following: the network charges for household customers range from 1.78 ct/kWh to 25.38 ct/kWh; the range of network charges for commercial customers is similar to that for household customers, with charges ranging from 0.19 ct/kWh to 24.63 ct/kWh; the network charges for industrial customers (without possible reductions) range from around 1.16 ct/kWh to 7.77 ct/kWh.

1.4 System services

The net costs for system services decreased in 2018 to around €1,881.39m (2017: €1,983.1m). A large part of the costs were accounted for by the costs of reserving and using grid reserve power plants at around €415.5m (2017: €480.0m), national and cross-border redispatching at just under €351.5m (2017: €391.6m) and the estimated claims for compensation for feed-in management measures at €635.4m (2017: €609.9m). Other large costs incurred were for procuring primary, secondary and tertiary control reserves at €123.3m (2017: €145.5m) and for energy to compensate for losses at about €273.2m (2017: €280.4m). The structure of the costs for system services in 2018 was only slightly different to that in 2017.

1.5 Wholesale

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

The liquidity of the wholesale electricity markets was characterised by various developments in 2018. There was a slight decrease in the overall volume of trading in the spot market. Trading volumes in the day-ahead market decreased, while those in the intraday market increased. Another key development in wholesale electricity trading was the introduction of congestion management at the border between Germany and Austria on 1 October 2018, which effectively divided the combined German-Austrian market area (bidding zone split)[6].

Various developments were seen on the spot market. The volume of day-ahead trading on EPEX SPOT in 2018 was 224.6 TWh, around 3.7% lower compared to the previous year (233.2 TWh). The volume of day-ahead trading on EXAA was also lower, with a decrease of about 13.9% to around 7.2 TWh. By contrast, the volume of intraday trading rose to 52.8 TWh, corresponding to an increase of around 5.8 TWh or about 12.5% compared to the previous year.

Futures trading recorded small increases in volumes. The Phelix-DE future almost entirely replaced the Phelix-DE/AT future in 2018. Volumes traded via broker platforms also recorded increases[7]. The volume of

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

[7] The volume reported to the Bundeskartellamt is smaller compared to the previous year, but one large broker did not report data; taking the broker's volume in the previous year, there are also slight increases.

OTC clearing of Phelix-DE futures on EEX rose considerably to 1,053 TWh in 2018, now equalling the volume traded on the exchange.

Alongside trading on the exchange, OTC clearing on the exchange has a special function in bilateral wholesale trading. The volume of OTC clearing of Phelix futures on EEX in 2018 was 1,053 TWh, compared to 905 TWh in the previous year. As OTC clearing has the effect of (subsequent) equalisation with futures traded on the exchange, it makes sense to also look at the development of the OTC clearing volume in the context of the on-exchange futures trading volume.

Wholesale electricity prices averaged across 2018 were again considerably higher. Spot market prices (for the combined German-Austrian market area up until 30 September 2018) were up about 22% year-on-year, and futures (for the market area Germany/Luxembourg) were quoted approximately 33% higher for the following year.

Futures prices rose considerably during the course of 2018. One reason was the closure or removal from the market of power stations. On 27 December 2018, the Phelix-DE peak year-ahead future stood at €66.26/MWh, representing an increase of around 43% compared to the beginning of the year. The Phelix-DE base year future also rose to €54.44/MWh, corresponding to an increase of around 48% compared to the start of the year.

1.6 Retail

1.6.1 Contract structure and competition

In the retail market, there was no further increase in the number of electricity suppliers available to consumers. In 2018, final consumers could choose on average between 143 suppliers in each network area (not taking account of corporate groups). The average number of suppliers for household customers was 132.

The number of household customers switching supplier has increased steadily since 2006. The number stagnated for the first time in 2017 and remained at the same high level of around 4.7m in 2018 (2017: 4.7m). The supplier switching rate – based on the total number of household customers – is thus again 10.2% (2017: 10.2%[8]). In addition, around 2.6m household customers switched energy supply contracts with the same supplier. The switching rate for non-household customers – with an annual consumption of more than 10 MWh – based on consumption volumes was 12.3% (2017: 13.0%).

In 2018, a relative majority of 42% of household customers' consumption was supplied under non-default contracts with local default suppliers (2017: 41%). The percentage of household customers' consumption supplied under default contracts stood at 27% (2017: 28%). This represents only a slight decrease in the percentage of consumption supplied under default contracts, unlike in previous years. The percentage of household customers' consumption provided by a supplier other than the local default supplier is stable at around 31% (2017: 31%), having previously increased continuously. Overall, around 69% of household

[8] The supplier switching rate for 2017 has been corrected.

customers' consumption is still supplied 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.

1.6.2 Disconnections

There was a decrease in 2018 in the number of electricity customers whose supply was disconnected. The number of disconnections actually carried out by the network operators in 2018 was 296,370, representing a decrease of 10% compared to the previous year (2017: 330,098). The number of disconnection notices issued by suppliers to household customers is very much higher. The number of notices issued in 2018 was approximately 4.9m, of which about 1m were passed on to the relevant network operator with a request for disconnection (2017: 4.8m notices and 1.1m requests).

1.6.3 Price level

Varying developments were recorded for electricity prices for non-household customers as at 1 April 2019 compared to the previous year. The average total price (excluding VAT and possible reductions) for industrial customers with an annual consumption of 24 GWh was 15.98 ct/kWh, up 0.68 ct/kWh on the previous year; the increase is mainly accounted for by the price components controlled by the supplier. There was also a year-on-year increase in the total price (excluding VAT) for commercial customers with an annual consumption of 50 MWh, up around 0.66 ct/kWh to 22.22 ct/kWh. This rise is mainly due to the increase in the price component controlled by the supplier. Overall, this price component makes up around 26% (2017: 24%) of the total price; on average about 74% of the total price comprises costs that the supplier cannot control, with in particular the EEG surcharge and the network charge accounting for a large part of these costs.

Data was collected from the suppliers operating in Germany on the prices for household customers as at 1 April 2019. The average price (including VAT) increased to 30.85 ct/kWh (2018: 29.88 ct/kWh). This average is calculated by weighting the individual prices across all contract models for an annual consumption of 2,500 kWh to 5,000 kWh according to consumption volumes to obtain a reliable average for the electricity price for household customers.

In 2019, the price component controlled by the supplier (energy procurement, supply and margin) accounts for around 24.7% of the total electricity price and has thus increased as in the previous year. This increase can be related in particular to the increasing wholesale prices in 2018. These higher prices are slowly being passed on to the household customers. The network charge in 2019 remains broadly unchanged on the previous year and thus still at a high level. The EEG surcharge has decreased by 6% but still makes up around 21% of the total price. Together with the reduction in the KWKG surcharge and the section 19 StromNEV surcharge, this is dampening increases in prices in 2019.

Compared to 2018, the average price for household customers on default contracts with an annual consumption of 2,500 kWh to 5,000 kWh increased by around 1.5% to 31.94 ct/kWh (2018: 31.47 ct/kWh). The average price for customers on a non-default contract with their default supplier is 30.46 ct/kWh (2018: 29.63 ct/kWh). The price for customers on a contract with a supplier other than their local default supplier has increased by around 5.8% and is now also 30.46 ct/kWh (2018: 28.80 ct/kWh).

As a rule, customers on default contracts can make savings by switching contract (-1.48 ct/kWh) and switching supplier (-1.48 ct/kWh)[9]. Household customers with an annual consumption of 3,500 kWh could consequently cut their energy costs by around €52 per year. Special bonuses offered by suppliers, including one-off bonus payments, are an added incentive for customers to switch. One-off bonus payments for customers switching to non-default contracts with their local default supplier average €55, and those for customers switching to a non-default supplier €64.

1.6.4 Surcharges

The network operators estimated that they would pass on nearly €26.14bn in surcharges to network users in 2019. In order of volume, this total comprises the EEG surcharge (€22.59bn), the section 19 StromNEV surcharge (€0.91bn), the KWKG surcharge (€1.05bn), the new offshore network surcharge (€1.56bn) and the interruptible loads surcharge (€0.02bn). The EEG charge thus continues to make up the largest part (over 86%) of total surcharges.

1.6.5 Electric heating

According to the suppliers' data, the arithmetic mean of the total gross price (including VAT) for night storage heating as at 1 April 2019 was 21.92 ct/kWh and thus higher than the previous year's level of 21.08 ct/kWh. The arithmetic mean of the total gross price for heat pump electricity was 22.50 ct/kWh and thus also higher than the previous year's level of 21.71 ct/kWh. Here, too, the rise is mainly due to the increase in the price component controlled by the supplier.

There has been a steady increase in switching activity among electric heating customers, albeit at a low level, following many years with hardly any customers switching. This increase in the switching rate indicates a higher degree of competition. Yet at the same time, the switching rates are still far below those for household electricity and non-household customers. The volume-related supplier switching rate for 2018 was again around 4%. However, there is a steady increase in the share of electricity provided for heating purposes and electric heating meter points provided by a supplier other than the local default supplier, now standing at around 13%.

1.7 Digitisation of metering

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

Since the beginning of 2017, the first modern metering systems have been available in the market and have been installed by the first metering operators on a large scale. It was still not possible to start the rollout of smart metering systems in 2018, since only one smart meter gateway certified by the Federal Office for

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

Information Security (BSI) was available in the market at the end of 2018. However, in light of the statutory requirements set out in the MsbG and advances in metering technology, a large-scale rollout of modern metering equipment and smart metering systems is expected in the coming years.

C Developments in the gas markets

2. Summary

2.1 Production, imports and exports, and storage

In 2018, natural gas production in Germany fell by 1bn m^3 to 6.2bn m^3 of gas (with calorific adjustment[10]) (2017: 7.2bn m^3). This corresponds to a decrease of 13.3% compared to 2017. The decline in production is chiefly due to the increasing exhaustion of the large deposits and the resulting natural decline in output. The reserves-to-production ratio of proven and probable natural gas reserves, calculated on the basis of the previous year's production and reserves, was 8.0 years as at 1 January 2019, the same as in the previous year.

The total volume of natural gas imported into Germany in 2018 was 1,760 TWh. Based on the previous year's figure of 1,676 TWh, imports to Germany increased by 83 TWh or just over 5%. Imports from Norway dropped by just over 11%, while imports from Russia through the Nord Stream pipeline rose by 14.9%.

In 2018, Germany exported a total of 849.1 TWh of natural gas. Based on the previous year's figure of 743.5 TWh, exports increased by 105.6 TWh, corresponding to a rise of 14%. Around 48% (2017: 50%) of the natural gas exported by Germany went to Czechia, with exports to the country up 10% on the previous year. There was a clear increase in exports to Luxembourg (+67.1%) and the Netherlands (+54.2%) and a clear decrease in exports to Poland (-25.9%) and Austria (-8.9%).

The total maximum usable volume of working gas in underground storage facilities as at 31 December 2018 was 280.02 TWh. Of this, 134.12 TWh was accounted for by cavern storage, 123.89 TWh by pore storage and 22.01 TWh by other storage facilities.

The volume of short-term (up to 1 October 2018) freely bookable working gas declined slightly again, as did the capacities still bookable for 2020. There was another increase in the volume of long-term bookable working gas from 2021. Overall, customers are tending towards shorter-term bookings in the storage market.

Owing to the mild winter 2018/2019, the storage level at natural gas storage facilities in Germany at the beginning of the storage year 2019/20 still stood at over 50%. Due to the good supply of gas and low prices in the gas markets, the storage facilities were filled to a very good level during the summer half-year. On 1 November 2019, the total storage level stood at over 99%.

The market for the operation of underground natural gas storage facilities is still highly concentrated, although concentration has eased over the past few years. The aggregate market share of the three largest

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[10] Gas volumes with calorific adjustment are amounts measured in a manner that is commercially relevant. Calorific adjustment is used because natural gas is not sold according to its volume, but according to its energy content (9.7692 kWh/m^3). In contrast, gas without calorific adjustment has a natural calorific value that may vary depending on the location of the deposit (in Germany this figure varies from 2 kWh/m^3 to 12 kWh/m^3).

storage facility operators stood at around 67.1% at the end of 2018, representing a slight decrease compared to the previous year (68.2%).

2.2 Networks

2.2.1 Network expansion

On 20 December 2018, the Bundesnetzagentur decided on the gas network development plan (NDP) 2018-2028 submitted by the transmission system operators (TSOs). The NDP, which is binding for the TSOs, comprises a total of 156 measures with an investment volume of about €7bn. The measures involve the construction of new transmission lines with a total length of 1,364 km and 499 MW of additional compressor capacity over the next ten years. The TSOs incorporated the necessary changes and published the binding gas NDP 2018-2028 on time. The majority of the network expansion measures in the NDP result from the conversion from L-gas to H-gas in Germany that is to be completed by 2030 and from the connection of planned new power stations.

The TSOs' publication of the scenario framework for the gas NDP 2020-2030 marked the start of the next NDP cycle in June 2019. The scenario framework sets out the input parameters for the next gas NDP: planning assumptions for capacity for a time frame of ten years, for example resulting from future capacity requirements in downstream distribution networks and from the planned connection of new gas power stations, gas storage facilities or LNG facilities to the transmission network.

2.2.2 Investments

In 2018, investments in and expenditure on network infrastructure by the 16 German TSOs amounted to €1.45bn (2017: €970m) (both values under commercial law)[11]. Total investments of €1.65bn are planned for 2019, corresponding to an increase of 13% compared to 2018. This relatively high fluctuation is due to investments in large-scale, one-off projects.

In the 2019 monitoring, 600 gas distribution system operators (DSOs) reported total network infrastructure investments in 2018 of €1,273m (2017: €1,031m) in new builds, upgrades and expansion (€798m (2017: €623m)) and in maintenance and renewal (€475m (2017: €408m)). For 2019, a total investment of €1,371m is foreseen.

Service and maintenance expenses, based on the data provided by the DSOs, totalled €1,078m in 2018 (2017: €1,084m). For 2019, service and maintenance expenses amounting to €1,116m are foreseen.

2.2.3 Supply interruptions

As in previous years, the Bundesnetzagentur conducted a comprehensive survey of all gas supply interruptions throughout the Federal Republic of Germany. The system average interruption duration index (SAIDI) determined from the results of this survey reflects the average duration of supply interruptions

[11] 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).

experienced by a customer over a period of one year and was 0.48 minutes per year in 2018 (2017: 0.99 minutes per year).

2.2.4 Network charges

The average network charge (including metering and meter operation charges) for household customers independent of the type of supply contract is currently around 1.56 ct/kWh and thus just over 3% higher than in the previous year.

2.2.5 Network balance

The total quantity of gas supplied by general supply networks in Germany fell slightly in 2018 by 13.6 TWh to 928.1 TWh (2017: 941.7 TWh[12]), representing a year-on-year decrease of just over 1.4%. The quantity of gas supplied to household customers (as defined in section 3 para 22 of the Energy Industry Act (EnWG)) rose by just over 1.3% to 275.2 TWh (2017: 278.8 TWh). Gas supplies to gas-fired power stations with a nominal capacity of at least 10 MW fell, after several years of increases. Gas supplies in 2018 totalled 87.8 TWh (2017: 98.1 TWh), just over 10% lower than in 2017.

With regard to gas transmission networks, the quantity of gas procured directly on the market by large final consumers (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 72.57 TWh, equivalent to just over 42% of the total quantity of gas supplied by the TSOs. With regard to gas distribution networks, the quantity of gas procured without a conventional supplier contract amounted to around 40 TWh, corresponding to a share of just over 5% of the DSOs' total gas supplies.

2.2.6 Market area conversion

The conversion of German L-gas networks to H-gas began in 2015 with the smaller network operators and has since been in progress as planned with the larger network operators such as Westnetz, EWE Netz and wesernetz Bremen. The highest annual figure of around 550,000 converted appliances will be reached in the coming years.

2.3 Wholesale

Liquid wholesale markets are vital to ensure well-functioning markets along the entire value chain in the natural gas sector, from the procurement of natural gas through to supplying end customers. The greater the variety of options for companies to procure gas for both the short and long term at the wholesale level, the less they are tied to one supplier long-term. Market players can choose from a wide range of competing trading partners and maintain a diversified portfolio of short and long-term contracts. Liquid wholesale markets thus facilitate market entry for new providers and ultimately promote competition for final consumers. The Bundeskartellamt now defines the wholesale market for natural gas as a national market and no longer defines markets based on their respective network or market area.

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[12] The DSOs' gas supplies figure for 2017 was adjusted to 758.4 TWh following the submission of a data correction. The total quantity of gas supplied by TSOs and DSOs in 2017 therefore amounted to 941.7 TWh.

Overall, the liquidity of the wholesale natural gas markets decreased in 2018. While there was an increase of around 13% in the total volume traded on the exchange in 2018, there was a decrease of about 14% in the volume of bilateral wholesale trading via broker platforms, which accounts for a much larger share.

The volume traded on the spot market rose in 2018 by 26% to around 391 TWh (2017: 309 TWh). As in previous years, the focus of spot trading for both market areas in 2018 was on day-ahead contracts (NCG: 132.9 TWh (2017: 115.8 TWh); GASPOOL: 102.8 TWh (2017: 69.3 TWh)). The futures trading volume fell from around 86 TWh in 2017 to about 58 TWh in 2018, corresponding to a decrease of some 33%.

In 2018, broker platforms reported having brokered natural gas transactions for delivery to Germany for an amount totalling 2,289 TWh (2017: 2,672 TWh), representing a decrease of around 14%. Of this, 858 TWh was for contracts with delivery in 2018 and a delivery time of at least one week.

As in the previous year, wholesale gas prices in 2018 showed some considerable increases. The various price indices (EGIX, cross-border prices, as calculated by the Federal Office for Economic Affairs and Export Control (BAFA)) show a year-on-year increase of between 13% and 28%. A fully reliable year-on-year comparison for the European Gas Spot Index (EGSI) introduced in September 2017 will not be possible until next year.

2.4 Retail

2.4.1 Contract structure and competition

An overall analysis of how household customers were supplied in 2018 in terms of volume shows that half of them (50%) were supplied by the local default supplier under a non-default contract and were supplied with 124.7 TWh of gas (2017: 51%/126.4 TWh).

Only 18% of household customers had a default supply contract in 2018 and were supplied with 45.3 TWh of gas (2017: 19%/47.3 TWh). The percentage of household customers who had a contract with a supplier other than the local default supplier once again increased and was 32% for a total of 79.1 TWh of gas (2017: 30%/75.5 TWh)[13]. 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 25.7% of the total volume delivered to these customers was supplied under a contract with the default supplier on non-default terms (2017: 29%) and about 74.2% was supplied under a contract with a legal entity other than the default supplier (2017: 71%). These figures show that default supply is of only minor significance in the acquisition of interval-metered customers in the gas sector.

The total number of customers switching contract in 2018 was 0.6m; the volume of gas delivered to these customers was approximately 13.4 TWh. The volume-based switching rate was therefore 5.4%.

The number of household customers who switched gas supplier fell slightly again by just under 1% year-on-year to 1.2m (down 7,256 supplier switches). There was a clear rise of nearly 6% in the number of household customers who immediately chose an alternative supplier rather than the default supplier when moving

[13] The total volume of gas supplied to household customers reported by gas suppliers of 249.1 TWh differs from the amount reported by gas DSOs (275.2 TWh) because the market coverage of the network operator survey is higher.

home. In 2018, there was an increase in the overall switching rate for household customers due to the rise in the number of customers who switched when moving home. When looking at 12.9m household customers (according to DSO figures), the resulting overall numbers-based supplier switching rate for household customers is 11.5%.

The total consumption affected by supplier switches in 2018 was 89.5 TWh, corresponding to a year-on-year increase of 1.5 TWh or about 2%. The switching rate for non-household customers was 9.0%, representing an increase of around 0.9 percentage points compared to the previous year.

The levels of concentration in the two largest gas retail markets continue to be well below the statutory thresholds for presuming market dominance. In 2018, cumulative sales for the four largest companies to customers with a standard load profile (SLP) were about 86 TWh (2017: 87 TWh) and around 138 TWh (2017: 138 TWh) for interval-metered customers. The aggregate market share of the four largest companies (CR4) in 2018 was around 23% for SLP customers, and thus the same as in the previous year, and about 31% for interval-metered customers (2017: 30%).

Since market liberalisation and the creation of a legal basis for a well-functioning supplier switch, there has been a steady positive development in the number of active gas suppliers for all final consumers in the different network areas. This positive trend continued in 2018. In 2018, more than 50 gas suppliers were operating in 94% of the network areas. Final consumers in over 62% of network areas had a choice of more than 100 gas suppliers. If viewed separately, the trend for household customers is similarly positive. In nearly 89% of network areas, household customers have a choice of 50 or more gas suppliers. More than 100 gas suppliers are operating in 45% of network areas.

2.4.2 Gas disconnections

The number of disconnections actually carried out by the network operators in 2018 was 33,145, representing a decrease of 17% compared to the previous year (2017: 40,048). This corresponds to 0.2% of gas connections based on all market locations of final consumers.

According to the gas suppliers' data, a disconnection notice is issued when a customer is on average around €120 in arrears. A total of 1.2m disconnection notices were issued to household customers, of which around 0.2m or 17% were passed on to the relevant network operator with a request for disconnection. The suppliers' data shows that a total of around 3% of the notices actually resulted in the customer being disconnected.

The gas suppliers stated that in some 26,731 cases they had disconnected customers with default contracts. This corresponds to 0.2% of household customers on default contracts. According to the suppliers' data, customers with non-default contracts were disconnected in about 11,940 cases, corresponding to 0.1% of non-default customers. The gas suppliers stated that around 10% of disconnections were repeated disconnections of the same customer.

2.4.3 Price level

The volume-weighted gas price for household customers across all contract categories as at 1 April 2019 was 6.34 ct/kWh, representing the first increase in three years. The price increased by around 4.4%. With respect to the individual price components, the largest increases were in energy procurement, supply and margin (+5.7%) and network charges (+4.2%).

The volume-weighted gas price for customers on a default contract as at 1 April 2019 was 7.28 ct/kWh (2018: 6.64 ct/kWh), corresponding to an increase of around 10% compared to the previous year. The volume-weighted gas price for customers on a non-default contract with the default supplier was 6.44 ct/kWh (2018: 6.06 ct/kWh), equivalent to a year-on-year increase of about 6%. The volume-weighted gas price for customers on a contract with a supplier other than the local default supplier was 6.22 ct/kWh (2018: 5.71 ct/kWh), representing an increase of around 9% compared to the previous year.

The average household customer with a gas consumption of 23,250 kWh could save an average of €195 a year as at 1 April 2019 by changing contract. The average potential saving for the year through changing supplier was €245.

The price component "energy procurement, supply and margin" for default supply customers was 3.74 ct/kWh as at 1 April 2019 (2018: 3.29 ct/kWh). This represents an increase of around 14%. The gas procurement costs in the price for customers supplied under a non-default contract with the default supplier increased by around 10% from 3.01 ct/kWh to 3.30 ct/kWh. The gas procurements costs for customers supplied under a contract with a supplier other than the local default supplier increased by around 14% to 3.02 ct/kWh (2018: 2.66 ct/kWh).

Special bonuses offered by gas suppliers, including one-off bonus payments, are an added incentive for customers to switch. These one-off payments amount to an average of €75 to €80.

The gas prices for non-household (industrial and commercial) customers as at 1 April 2019 showed year-on-year increases. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 GWh ("industrial customer") was 2.86 ct/kWh and thus 0.04 ct/kWh or around 1.4% higher than the previous year's figure. The part of the total price controlled by the supplier increased by 0.07 ct/kWh and thus to nearly 70%. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 MW/h ("commercial customer") was 4.55 ct/kWh and thus 0.15 ct/kWh or around 3.4% higher than the previous year's figure. The part of the total price controlled by the supplier also increased by 0.15 ct/kWh and thus to nearly 60%.

The prices paid by household and non-household customers in Germany in the second half of 2018 were below the EU average. The net gas price in Germany in the annual consumption range of 27.8 GWh to 278 GWh was 2.65 ct/kWh, which was at the lower end of the scale. The EU average was 2.81 ct/kWh. On an EU average, the net price is subject to about 8% (0.22 ct/kWh) of non-refundable taxes and levies. In this regard, Germany's figure of about 15% (0.40 ct/kWh) is higher than average. Compared with the gas prices for industrial customers, there are relatively large differences between the gas prices for household customers across the EU. The gas price for household customers in Germany was 6.08 ct/kWh and thus around 2% below the EU average (6.20 ct/kWh). Taxes and levies amounted to an average of 1.57 ct/kWh in Germany. The EU average was 1.68 ct/kWh.

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