Bundesnetzagentur Bundeskartellamt

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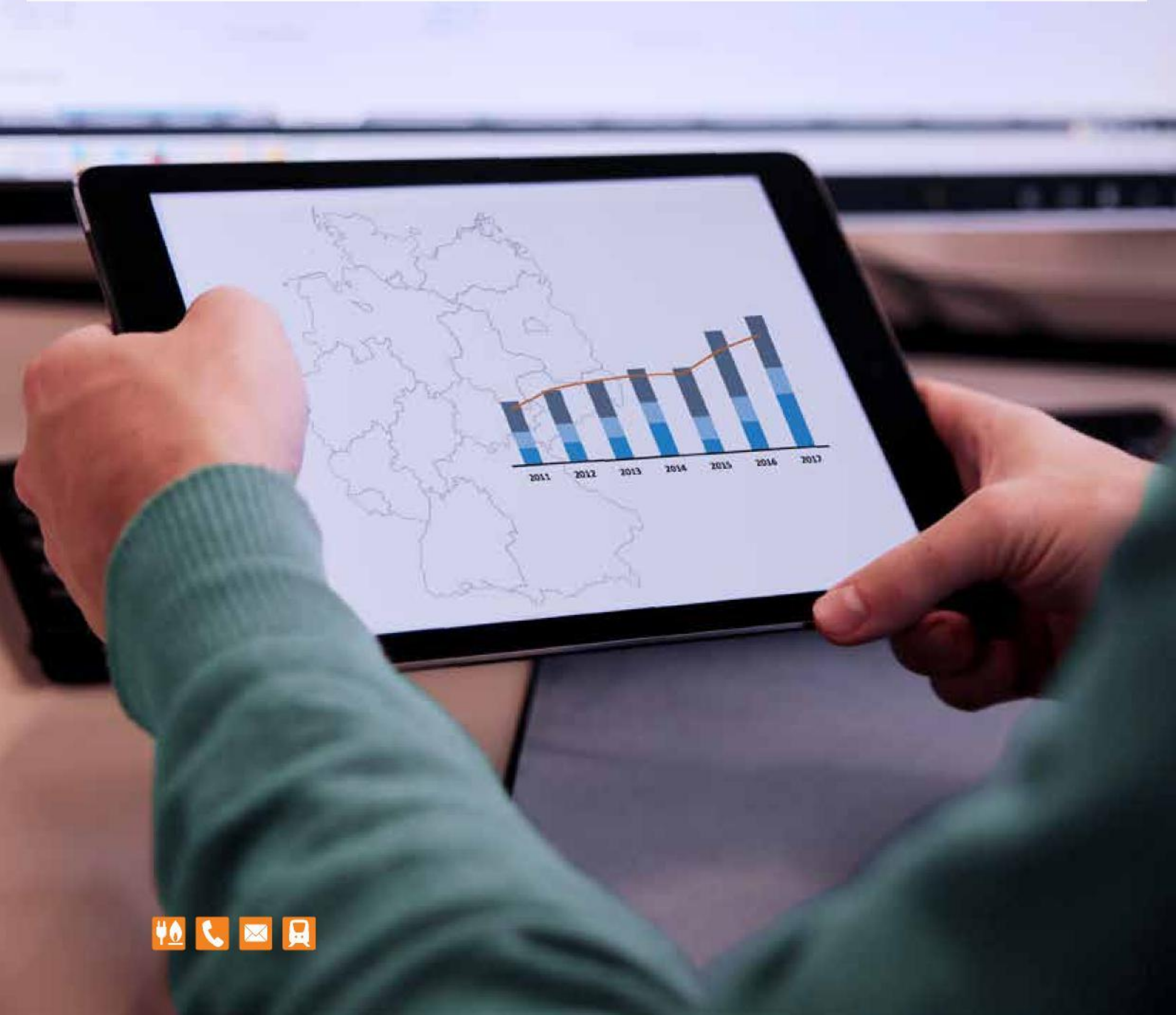
Report

Monitoring report 2017 - key findings



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Key findings

Electricity generation

Germany's net electricity generation increased in 2016 to 600.3 TWh, up 6.0 TWh on the 2015 level of 594.3 TWh. There was a marked year-on-year increase of 37.7% in the amount of electricity generated by natural gas-fired power plants, following several years of declining production, with generation at more or less the same level as in 2012. Generation from virtually all the other non-renewable sources was down on 2015.

The generation landscape was characterised in 2016 by further growth in installed renewable energy capacity. At the end of 2016, renewable capacity had increased year-on-year by 6.7 GW. Altogether, total generating capacity rose from 204.9 GW in 2015 to 212.0 GW in 2016, with 107.5 GW of non-renewable and 104.5 GW of renewable capacity.

The market power of the largest conventional electricity producers (electricity not eligible for payments under the Renewable Energy Sources Act – EEG) has decreased significantly over the last few years. There was a further decline in market concentration in 2016, with the cumulative market share of the then four largest electricity producers in the German-Austrian market having already decreased in the period between 2010 and 2015 from 72.8% to 69.2%. The most recent decline is mainly due to the sale of Vattenfall's lignite activities to LEAG and the associated shifts in market shares: the cumulative market share of 69.4% for 2016 is now spread between five large, independent undertakings. The cumulative market share of the five largest undertakings in only the German market for the first-time sale of electricity – to be considered in light of the plan to split the joint bidding zone – is 76.5%, compared to the four largest undertakings' share of 76.2% in 2015. This indicates a decline in market concentration in this market area as well.

Electricity supply interruptions

In 2016, the average interruption in supply per connected final consumer was 12.80 minutes and thus below the ten-year average from 2006 to 2015 of 15.87 minutes. The quality of supply thus remained at a consistently high level in 2016.

Development of renewable energy generation

The growth in renewable energy capacity of 6.7 GW is due in particular to the continued expansion of onshore wind capacity. Onshore wind recorded a year-on-year increase of 4.2 GW, solar energy 1.5 GW, and offshore wind 0.8 GW.

Onshore wind generation was down by 6.5% on 2015 despite the continued increase in capacity, on account of the relatively low wind levels in 2016. The amount of electricity generated through solar also fell slightly, down 2.1% on a year earlier. There was an increase in offshore wind generation of 3.9 TWh or 48.1%. Total renewable electricity generation thus remained broadly unchanged for the first time ever, up by just 0.2%. Renewable electricity generation was equivalent to 31.2% of gross electricity consumption in 2016. Payments to renewable installation operators under the Renewable Energy Sources Act averaged in 2016 at 15.1 ct/kWh.

Competitive auctions have now been introduced to determine the level of payments for new renewable capacity, and a total of 13 auctions have been held (nine for solar photovoltaic installations, two for onshore wind energy, one for offshore wind projects, and one for biomass plants).

Redispatch and feed-in management

In 2016, reductions in feed-in comprised 6,256 GWh and increases 5,219 GWh, amounting to a total volume of 11,475 GWh, compared to 15,436 GWh in 2015. The reductions in feed-in as a result of redispatch measures corresponded to 1.5% of total non-renewable generation, down from 1.9% in the previous year.

The amount of renewable energy curtailed as a result of feed-in management measures also decreased, down from 4,722 GWh in 2015 to 3,743 GWh in 2016. The sum total of compensation payments made in 2016 – for curtailments in 2016 and previous years – was around €643m, compared to €315m in 2015. Claims for compensation for 2016 are estimated at €373m, compared to €478m a year earlier.

A main factor for the decrease in redispatch and feed-in management measures was the relatively low wind levels in 2016. Overall, an analysis of the annual figures does not indicate any general trend in these measures.

Electricity network charges

The charges for household customers showed an increase, having been broadly stable in the period between 2013 and 2015. The average network charges rose from 1 April 2016 to 1 April 2017 by around 9% to 7.30 ct/kWh. There was also an increase in the network charges for non-household customers: the charges for commercial customers rose by almost 6% to 6.19 ct/kWh, while those for industrial customers with an annual energy consumption of 24 GWh increased by a good 10% to 2.26 ct/kWh.

Wholesale electricity markets

The liquidity of the wholesale electricity markets in 2016 reached its highest level since monitoring began. Volumes in on-exchange futures trading and volumes traded via broker platforms increased significantly, while spot market trading volumes declined.

Average wholesale prices declined further in 2016. The average base price on EPEX SPOT fell by about 8% to €28.98/MWh and thus to its lowest level since 2007. With an average of €26.58/MWh, the Phelix base year future was down by around 14% on the previous year, with a marked low in mid-February 2016 and an increase in the price at year-end. In response to the planned split of the German-Austrian price zone, EEX launched trading in separate power futures for the two countries.

Retail electricity markets

The Bundeskartellamt assumes that there is no longer any single dominant undertaking in either of the two largest electricity retail markets. The cumulative market shares of the four largest undertakings showed a further year-on-year decrease, down to around 28% in the national market for supplying interval-metered customers and 34% in the national market for non-interval-metered customers on special contracts.

The retail markets are continuing to develop very positively. More than 4.6m household customers switched supplier in 2016. This is the highest figure since the start of liberalisation. In addition, almost 2.4m household customers switched tariffs with the same supplier. There was also another increase in the number of undertakings operating in the market. Household customers can choose between an average of 112 different suppliers. At the same time, there was a decrease in the number of customers whose electricity supply was disconnected. In 2016, a total of about 328,000 customers were disconnected, representing a year-on-year decrease of around 31,000.

The supplier switching rate for non-household customers has been fairly constant since 2009. The rate for non-household customers with an annual consumption of more than 10 MWh stood at 12.7% in 2016, compared to 12.6% in 2015.

The average total price (excluding VAT and possible reductions) for industrial customers with an annual consumption of 24 GWh was 14.90 ct/kWh, up 0.69 ct/kWh on the previous year; the increase is mainly accounted for by the network charges and statutory surcharges. The average total price (excluding VAT) for commercial customers with an annual consumption of 50 MWh in April 2017 was 21.70 ct/kWh, representing an increase on the previous year of 0.50 ct/kWh. This rise is largely due to the increase in both the surcharges and the network charges.

The average electricity price for household customers as at 1 April 2017 was broadly unchanged from the previous year. Despite a rise in the network charges and renewable energy surcharge, a decrease of almost 13% in the energy price components prevented a further increase in the overall price. This can be explained by, amongst other things, the increase in the number of customers switching supplier and the continued fall in wholesale prices since 2011. The volume-weighted average across all groups of household customers with an annual consumption of between 2,500 kWh and 5,000 kWh was broadly unchanged from 2016, up only very slightly by 0.06 ct/kWh to 29.86 ct/kWh (including VAT). Taxes, levies, network charges and surcharges make up around 78% of the total price in Germany.

Electric heating

Electric heating prices were slightly higher than in 2016. The arithmetic mean of the gross total price for night storage heating customers as at 1 April 2017 was 20.94 ct/kWh (including VAT), slightly up on the previous year's level of 20.59 ct/kWh. The arithmetic mean of the total price for heat pump customers was 21.65 ct/kWh (including VAT), around 0.7 ct/kWh higher than the price for night storage heating customers and broadly unchanged from the previous year.

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. The increase in the switching rate indicates a higher degree of competition. Yet at the same time, the switching rates for electric heating customers are still far below those for household electricity and non-household customers. The supplier switching rate for 2016 was around 4%.

Electricity imports and exports

Germany's electricity exports again exceeded its imports in 2016. Whilst total cross-border traded volumes fell from 84.9 TWh in 2015 to 78.1 TWh, there was another small increase in the German export balance from 51.0 TWh in 2015 to 51.9 TWh in 2016.

Gas imports and exports

Gas imports and exports were higher than in 2015. The volume of gas imported into Germany rose by some 89 TWh or around 6% to 1,626 TWh from 1,537 TWh. Gas exports also increased, from 746.3 TWh in 2015 to 770 TWh in 2016, equivalent to a rise of about 24 TWh or 3%.

The main sources of gas imports for Germany remain Russia (Nord Stream, 28%), Norway (19%) and the Netherlands (16%). Exports primarily went to Czechia (46%), the Netherlands (18%) and Switzerland (12%).

Gas supply interruptions

In 2016, the average interruption in supply per connected final consumer was 1.03 minutes per year. The level of gas supply reliability remained at 99.999%.

Market area conversion

The conversion of German L-gas networks to supply H-gas started well in 2015 with the Schneverdingen conversion. This success continued in 2016 in the networks of Stadtwerke Böhmetal, Hilter, Rees, Nienburg/Weser, Gasversorgung Grafschaft Hoya, Gelsenwasser Energienetze (Isselburg, Landesbergen-Brokeloh), Stadtnetze Neustadt am Rübenberge, Achim and some parts of the wesernetz in Bremen. Approximately 114,000 appliances will have been adapted by the end of 2017.

The probable, planned costs of market area conversion were €5.5m for the NetConnect Germany market area in 2016. For the GASPOOL market area, the planned costs amounted to about €18m for 2016.

Gas storage facilities

The market for the operation of underground natural gas storage facilities is still relatively highly concentrated, although less so than in the previous year. The cumulative market share at the end of 2016 of the three largest storage facility operators was down considerably to 68.2% (2015: 73.3%).

The storage year started with rather subdued levels of injections, with one reason being natural gas prices during the period. On 1 October 2017, at the beginning of the 2017/2018 gas year, the total storage level of German storage facilities was around 85% (2016: 95%). The high storage level of the previous year, which had been driven by prices, was not repeated, with a level of over 92% on 1 November 2017.

Wholesale natural gas markets

Overall, the liquidity of the wholesale natural gas markets increased significantly in 2016. There was once again a rise, of about 17%, in volumes of bilateral wholesale trading via broker platforms. On-exchange gas trading volumes were actually up 69%.

2016, the year under review, was again marked by significantly lower wholesale gas prices. The various price indices showed a year-on-year decrease of between 25% and 31%.

Retail gas markets

The levels of concentration in the two largest gas retail markets are well below the statutory thresholds for presuming market dominance. The Monitoring Report 2017 deals with the market concentration of the four largest companies in the retail gas market for the first time, rather than the three largest as in the year before, because there is now another provider with a notable market share. The cumulative market share of the four largest companies in 2016 was around 25% for standard load profile (SLP) customers and about 28% for interval-metered customers. A decline in market concentration may therefore be identified in both areas, since the four largest companies now have a slightly higher market share of SLP customers than the three largest companies had the year before and around the same share of interval-metered customers.

The retail gas market continues to develop very positively. Over 1.5m household customers changed their gas supplier in 2016, equivalent to a notable increase of about 34% over 2015. This is the highest level since the gas market was liberalised. The volume-based switching rate among non-household customers was just over 11% in 2016 (2015: nearly 12%). There were also around 780,000 changes of contract in the year. The diversity of suppliers on the market increased again as well, with household customers being able to choose between an average of 90 different suppliers. At the same time, the number of gas disconnections reduced. In 2016, a total of about 40,000 disconnections were reported, which was down about 5,000 on the figure from 2015.

The noticeable downward trend in consumer gas prices continued. There was a further decrease in the prices paid by industrial customers. The average overall price (excluding VAT) was 0.08 ct/kWh lower at 2.69 ct/kWh, slightly lower (around 3%) than the previous year's figure of 2.77 ct/kWh. The average gas price for an annual consumption of 116 GWh was therefore the lowest ever since the first data on gas prices (as at 1 April 2008) was collected for monitoring reports.

There was also a considerable decrease in the prices paid by commercial customers. The arithmetic mean of the overall price (excluding VAT) of 4.50 ct/kWh is 0.27 ct/kWh or around 5% lower than last year's average price.

Gas prices for household customers as at 1 April 2017 showed a year-on-year decrease. The main reason for this was the significant drop in procurement costs, reflected in the price component "energy procurement, supply and margin". The volume-weighted average across all groups of household customers with average consumption was up 6% or 0.40 ct/kWh to 6.15 ct/kWh (including VAT). Taxes, levies and network charges make up around 50% of the total gas price in Germany.

A Developments in the electricity markets

1. Summary

1.1 Generation and security of supply

Germany's net electricity generation in 2016 was up 6.0 TWh on 2015 to 600.3 TWh. Generation from non-renewable energy sources increased by 5.6 TWh. There was a significant year-on-year change in generation by natural gas-fired power plants: the amount of electricity generated increased considerably by 18.2 TWh or 37.7% for the first time following several years of declining production and reached the level recorded in 2012. By contrast, generation from virtually all the other non-renewable sources decreased. Nuclear generation was down 6.8 TWh or 8.0% on 2015. Generation by hard coal-fired power plants was down 2.7 TWh or 2.6%. Generation by lignite-fired plants was 2.1 TWh or 1.5% lower.

The market power of the largest electricity producers has decreased significantly over the last few years. In 2010, the cumulative market share of the then four largest electricity producers in the market for the first-time sale of electricity (electricity not eligible for payments under the Renewable Energy Sources Act) in the German-Austrian market area stood at 72.8%, while in 2015 it was just 69.2%. Against the backdrop of the changes among the undertakings in 2016 and the associated shifts in market shares, due in particular to the sale of Vattenfall's lignite activities to LEAG, an analysis of electricity generation and the first-time sale of electricity must now include five – instead of previously four – electricity producers. The cumulative market share of these five largest producers in the market for the first-time sale of electricity in 2016 amounted to 69.4%. Overall, the degree of market concentration is lower since the cumulative market share is now spread between five large, independent undertakings. The cumulative market share of the five largest undertakings in only the German market for the first-time sale of electricity – to be considered in light of the plan to split the joint bidding zone – is 76.5%, compared to the four largest undertakings' share of 76.2% in 2015. This indicates a decline in market concentration in this market area as well.

Several factors besides lower market concentration are leading to a downward trend in market power. In particular, more of the demand for electricity is now covered by renewable energy sources, and the cumulative market share of the largest producers as regards renewable electricity is considerably smaller than that regarding conventional electricity. In addition, the closure of the remaining nuclear power plants by 2022 will lead to changes in the market structure.

Renewable electricity generation was equivalent to 31.2% of gross electricity consumption in 2016, around the same as the 2015 level of 31.4%. Unlike in previous years, net generation from renewables showed only a slight increase of 0.4 TWh or 0.2%. Onshore wind generation fell by 4.6 TWh or 6.5% despite the continued increase in wind generation capacity, on account of the relatively low wind levels in 2016. The amount of electricity generated through solar also fell slightly, down 0.7 TWh on 2015. The largest increase was offshore wind at 3.9 TWh or 48.1%. This is mainly due to the fact that numerous installations were put into operation during 2015, and 2016 was their first whole year of generation, with approximately 2,930 hours.

The generation landscape was characterised in 2016 by a further increase in installed renewable energy capacity. Altogether, growth in renewable capacity amounted to 6.7 GW, compared to 7.5 GW in 2015. Onshore wind and solar energy recorded the highest increases in generating capacity with 4.2 GW and 1.5 GW respectively. Non-renewable generating capacity (nuclear, lignite, hard coal, natural gas, mineral oil products, pumped storage and other non-renewable energy sources) increased slightly in 2016 by 0.4 GW. This is largely due to new natural gas-fired power stations being put into operation. Total (net) installed generating capacity thus increased to 212.0 GW at the end of 2016, with 107.5 GW of non-renewable and 104.5 GW of renewable capacity.

The total installed capacity of installations eligible for payments under the Renewable Energy Sources Act in Germany stood at 99.7 GW at the end of 2016, compared to 92.9 GW a year earlier. This represents an increase of around 6.7 GW or 7.2%. A total of 161.5 TWh of electricity from renewable energy installations received payments in 2016, compared to 161.8 TWh in 2015. This slight fall was the first decrease in renewable electricity generation since 2003. Despite the small decrease, payments under the Renewable Energy Sources Act were broadly stable at €24.3bn, up 0.4% on 2015. This can be explained by the fact that the level of payment varies for the different sources of energy. Energy sources eligible on average for lower payments fed in less in 2016 than in 2015, while energy sources eligible on average for higher payments fed in more than in the previous year. In 2016, the average paid to installation operators under the Renewable Energy Sources Act was 15.1 ct/kWh[1]. Unlike previous years, 2016 was the first year in which the majority of the payments – 52% – were made to installation operators eligible for market premiums.

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

The auctions for solar photovoltaic installations have so far been marked by a high level of competition. The average volume-weighted award price fell in each successive auction from 9.17 ct/kWh to under 5 ct/kWh. The two auctions held for onshore wind energy (together comprising a total volume of 1,800 MW) were also significantly oversubscribed. Citizens' energy companies showed a strong presence in these first two auctions, accounting for more than 90% of the successful bids in each case. The average volume-weighted award price fell from 5.71 ct/kWh in the first auction to 4.28 ct/kWh in the second. In the auction held in April 2017 for offshore wind farm projects, four bids for projects with a total capacity of 1,490 MW were accepted. The prices awarded ranged from 0.00 ct/kWh to 6.00 ct/kWh. In the auction for biomass plants, all the bids submitted together comprised a volume of 40,912 kW, which was considerably lower than the volume available of 122,446 kW. The average volume-weighted award price was 14.30 ct/kWh. In the first joint auction for ground-mounted solar photovoltaic systems in Germany and Denmark, all of the successful bids were for Danish projects.

In 2016, the average interruption in supply per connected final consumer was 12.80 minutes and thus below the ten-year average from 2006 to 2015 of 15.87 minutes. The quality of supply thus remained at a consistently high level in 2016.

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

1.2 Cross-border trading

Electricity exports again exceeded imports in 2016. Despite the overall decrease in trading volumes, Germany forms the hub for electricity exchange in Europe and plays a key role within the central interconnected system. The average available transmission capacity to and from Germany's neighbouring countries was largely stable in 2016.

Total cross-border traded volumes fell from 84.9 TWh in 2015 to 78.1 TWh in 2016, a decrease of 8%. This reflects a decline of 22.6% in imports from 16.9 TWh in 2015 to 13.1 TWh, while exports also fell 4.4% from 68 TWh in 2015 to 65 TWh. Overall, there was a small increase of 1.6% in the German export balance from 51.0 TWh in 2015 to 51.9 TWh in 2016.

1.3 Networks

1.3.1 Grid expansion

Based on the third quarterly report for 2017, 1,000 km of the total of about 1,800 km of power lines listed in the Power Grid Expansion Act (EnLAG) have been approved, with around 750 km of these – about 40% of the total – completed. A further 600 km or so of lines are at the regional planning and planning approval stage. The transmission system operators (TSOs) anticipate that some 80% of the line kilometres listed in the Act will be completed by 2020. So far, none of the underground cable pilot lines have been put into full operation. Operational testing is in progress for the first 380 kV underground cable pilot project in Raesfeld.

Alongside monitoring the projects in the Power Grid Expansion Act, the Bundesnetzagentur publishes quarterly updates on the status of the expansion projects listed in the Federal Requirements Plan Act (BBPlG). These projects currently comprise lines with a total length of some 5,900 km. At the third quarter of 2017, around 450 km had been approved and about 150 km of these completed. A further 2,400 km or so of lines are at the federal sectoral planning stage with the Bundesnetzagentur and around 600 km are at the regional planning and planning approval stage with the federal state authorities.

1.3.2 Investments

In 2016, investments in and expenditure on network infrastructure by the four German TSOs amounted to €2,439m, compared to €2,358m in 2015 (both values under commercial law[2]). Investments in new builds, upgrades and expansion projects fell slightly from €1,672m in 2015 to €1,636m in 2016. The investments and expenditure incurred by the distribution system operators (DSOs) rose from €6,845m in 2015 to €7,157m in 2016. There was a further increase in the number of DSOs carrying out measures to enhance, reinforce or expand their networks as at 1 April 2017.

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[2] 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.

1.3.3 Network and system security and system stability

The redispatch measures taken by the TSOs serve to maintain network and system security. A measure can be any action taken to ease restrictions on a network element. The reductions in feed-in as a result of redispatch measures corresponded to 1.5% of total non-renewable generation, down from 1.9% in the previous year. In 2016, reductions in feed-in comprised 6,256 GWh and increases 5,219 GWh, amounting to a total volume of 11,475 GWh, compared to 15,436 GWh in 2015.

Overall, redispatch measures amounted to 13,339 hours, representing a decrease from 15,811 hours in 2015. Since all measures taken to ease restrictions in the network and thus measures taken in parallel are recorded, the sum of the hours in which measures were taken cannot be put in relation to the total number of 8,760 hours in a year. In 2016, redispatch measures were taken by the operators on a total of 329 days.

This represents a decrease of around a quarter compared to 2015, although the volume remains high compared to the years preceding 2015. The TSOs put the costs of system services for redispatch measures in 2016 at around €220m. As in the previous years, the measures primarily concerned the TenneT and 50Hertz control areas, with the line between Remptendorf and Redwitz, the area around the line from Vierraden to Krajnik in Poland, and the Brunsbüttel area (north of Hamburg) the most affected.

The amount of renewable energy curtailed as a result of feed-in management measures also decreased from 4,722 GWh in 2015 to 3,743 GWh in 2016. This corresponds to 2.3% of the total amount of renewable energy generated, compared to 2.9% in 2015. The sum total of compensation payments increased significantly from €315m in 2015 to €643m in 2016. In total, claims for compensation from installation operators for 2016 are estimated at €373m. The discrepancy between the figures is due to the fact that the compensation paid in 2016 does not reflect the compensation for energy curtailments in 2016 but includes compensation paid for curtailments in previous years.

In 2016, as in the previous years, feed-in management measures primarily involved wind power plants, accounting for 94.4% of the total amount of curtailed energy, up from 87.3% in 2015. Solar was the second leading energy type affected in 2016 by curtailments, with a share of almost 5%.

In 2016, a total of four DSOs and one TSO took non-renewable energy adjustment measures for which no compensation is paid. The measures taken to adjust electricity feed-in and offtake totalled around 14.4 GWh.

In total, the costs for network and system security[3] fell by about €243m from €1,133m in 2015 to around €890m in 2016. This is primarily due to the reduction in the number of network and system security measures taken in 2016, which was in turn due to the weather.

In 2016, the grid reserve was used on 108 days to provide an average capacity of 552 MW and a total of around 1,209 GWh of energy.

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

1.3.4 Network charges

There was a significant increase in the network charges (including billing, metering and meter operation charges) for household customers. The charges for non-household customers were also up on a year earlier. The network charges (including billing, metering and meter operation charges) for commercial customers increased by almost 6% or 0.34 ct/kWh and those for industrial customers by a good 10% or 0.20 ct/kWh. The charges as at 1 April 2017 for the three consumption groups were as follows:

-household customers (default tariffs), annual consumption 2,500-5,000 kWh: 7.30 ct/kWh;

-commercial customers, annual consumption 50 MWh: 6.19 ct/kWh;

-industrial customers, annual consumption 24 GWh, without a reduction under section 19(2) of the Electricity Network Charges Ordinance (StromNEV): 2.26 ct/kWh.

There are large regional differences in the network charges. A comparison of the network charges in Germany for the three consumption groups, based on all the TSOs' published price lists (charges including billing but excluding metering and meter operation), shows the following: the network charges for household customers range from just over 3 ct/kWh to 11.7 ct/kWh; the range of network charges for commercial customers is similar to that for household customers, with charges ranging from 2.8 ct/kWh and 10.4 ct/kWh; and the network charges for industrial customers range from around 1 ct/kWh to 6.6 ct/kWh.

1.4 System services

The net costs for system services in a broader sense[4] fell by €339m from €1,800m in 2015[5] to €1,461m in 2016. These figures for the first time also include the estimated claims from installation operators for compensation for feed-in management measures as costs for system services in a broader sense. A large part of the total costs is accounted for by the costs of reserving and using grid reserve power plants at around €285m (2015: €219m), national and cross-border redispatch at just under €220m (2015: €412m), reserving primary, secondary and tertiary balancing capacity at €198m (2015: €316m), energy to compensate for losses at about €305m (2015: €277m), and the estimated claims from installation operators for compensation for feed-in management measures in 2016 at around €373m (2015: €478m).

The structure of the system service costs changed in 2016 from 2015. The total net costs for balancing fell again, this time by €118m. One reason for this fall is the further slight decrease in the volume of the three types of balancing reserve. The costs for energy to compensate for losses in 2016 were up around €27m on 2015. One of the reasons for this increase was that additional energy was needed at short notice to compensate for energy lost in transport.

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

[4] TSOs' system services and TSOs' and DSOs' feed-in management measures.

[5] This figure has been adjusted to include the estimated claims from installation operators for compensation for feed-in management measures taken by the TSOs and DSOs.

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.

Overall, the liquidity of the wholesale electricity markets in 2016 reached its highest level since monitoring began. Volumes in on-exchange futures trading and volumes traded via broker platforms increased significantly, while spot market trading volumes declined. The volume of day-ahead trading on EPEX SPOT in 2016 was around 235 TWh, significantly down on the previous year's volume of 264 TWh. By contrast, the volume of intraday trading rose, with a substantial increase of around 3 TWh or 9% to 41 TWh. The volume of day-ahead trading on EXAA remained stable at around 8 TWh in 2016. The on-exchange trading volumes of Phelix futures increased significantly again, following considerable growth in the previous years: volumes rose in 2016 by 56% from 937 TWh to over 1,466 TWh.

Average spot market prices declined further in 2016. The Phelix day base average on EPEX SPOT fell by about 8% from €31.63/MWh in 2015 to €28.98/MWh and thus to its lowest level since 2007. At €32.01/MWh, the Phelix day peak was also nearly 9% below the previous year's level of €35.06/MWh. The gap between the Phelix day base and the Phelix day peak was €3.03/MWh in 2016 and thus again down on the previous year. As a result, the average Phelix day peak in 2016 was just 10% higher than the Phelix day base (compared to 21% in 2008).

The annual averages of the Phelix future prices fell again compared to a year earlier, despite an increase in the price at the end of the year. With an average of €26.58/MWh in 2016, the Phelix base year future was down by €4.40/MWh or around 14% on the previous year's average of €30.97/MWh, with a marked low in mid-February 2016 and an increase in the price at year-end. The price of the Phelix peak front year future averaged €33.51/MWh over the year. This was €5.55/MWh or around 14% down on the previous year's average of €39.06/MWh. Compared to the historic high of 2008, the base and peak front year future prices have continued their downward trend.

In response to the planned split of the German-Austrian price zone, EEX launched trading in separate power futures for the two countries. EEX launched Phelix-DE futures for the German market area in April 2017 and separate Phelix-AT futures for the Austrian market area on 26 June 2017. It also introduced trading in options on Phelix-DE futures.

1.6 Retail

There was another increase in the number of electricity suppliers available to retail customers. In 2016, final consumers could choose between an average of 130 suppliers in each network area (not taking account of corporate groups). The average number of suppliers for household customers was 112.

The number of household customers switching supplier has increased significantly since 2006. The number of switches reached a new high of about 4.6m in 2016, up by around 595,000 on the previous year's figure of 4m. In addition, almost 2.4m household customers switched tariffs with the same supplier. In 2016, a relative majority of household customers – 40.9% compared to 43.1% in 2015 – were on non-default tariffs with their regional default supplier. The percentage of household customers on default tariffs stood at 30.6%, representing another year-on-year decrease from 32.1% in 2015. 28.6% of all household customers are now served by a supplier other than their regional default supplier, compared to 24.9% in 2015. There was a corresponding increase in the percentage of customers who no longer have a contract with their default supplier. Overall, around 71.5% of all households are served by their default supplier (on either default or other tariffs). Thus the strong position held by default suppliers in their respective service areas weakened again in 2016.

By contrast, default suppliers play a relatively small role in serving non-household customers. Around 70% of the total amount of electricity delivered to interval-metered customers in 2016 was supplied by a legal entity other than the regional default supplier, while only about 30% was supplied on non-default tariffs by the default supplier. Less than 1% of all interval-metered customers are on standard tariffs with their default supplier. The supplier switching rate for non-household customers in 2016 was about 13%, the highest since monitoring began in 2006.

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 in the national market for supplying interval-metered customers decreased further, down three percentage points on 2015 to 28%. The cumulative share in the national market for supplying non-interval-metered customers on special contracts[6] (above all household customers, excluding electric heating customers) stood at 34%, down two percentage points on a year earlier. These figures are clearly below the statutory thresholds for the presumption of market dominance (section 18(4) and (6) of the Competition Act – GWB).

There was a slight decrease in 2016 in the number of electricity customers whose supply was disconnected. The number of household customers whose supply was disconnected by the network operator at the regional default supplier's request fell by 13,000 to 318,469. For the first time, the DSOs were also asked to provide the number of customers not with their regional default supplier whose supply they had disconnected, and reported around 12,000 disconnections. According to the suppliers, a total of about 328,000 customers across all tariffs (default and non-default) were disconnected in 2016, representing a decrease of some 31,000. Suppliers issued around 6.6m disconnection notices to household customers. Of these, about 1.2m were subsequently passed on to the relevant network operator with a request for disconnection. These figures are based on data provided by 770 DSOs and 962 suppliers. Data was again collected on the use – at the default suppliers' request – of prepay systems such as pay-as-you-go meters using cash or smart cards. In total, around 20,200 prepay systems were installed in 2016.

Electricity prices for non-household customers as at 1 April 2017 showed a year-on-year increase. The individual price for industrial customers depends to a large extent on special statutory regulations enabling certain price components to be reduced. These regulations aim primarily to lower prices for electricity-intensive undertakings. There was a minimal decrease in the arithmetic mean of the price component that is controlled by the supplier for customers with an annual consumption of 24 GWh ("industrial customers") and not eligible for any statutory reductions, falling from 3.48 ct/kWh to 3.41 ct/kWh, down by 0.07 ct/kWh compared to the previous year's decrease of 0.71 ct/kWh. By contrast, there was an increase in the surcharges. These totalled 7.08 ct/kWh – with the renewable energy surcharge alone at 6.88 ct/kWh – and were thus 0.58 ct/kWh up on a year earlier. The average net network charge was 2.23 ct/kWh, up by around 10% on the previous year's level of 2.03 ct/kWh. The average total

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[6] The term "special contract" appears in section 1(4) of the Electricity and Gas Concession Fees Ordinance (KAV). The term continues to be of importance in calculating concession fees and has already been the subject of abuse proceedings and sector inquiries (electric heating). The terms default (and fallback) supply and "special contract" are relevant to market definition under competition law and will continue to be used because they are defined in law.

price (excluding VAT and possible reductions) was 14.90 ct/kWh, up 0.69 ct/kWh on the previous year; the increase is mainly accounted for by the network charges and statutory surcharges.

The average total price (excluding VAT) for non-household customers with an annual consumption of 50 MWh ("commercial customers") in April 2017 was 21.70 ct/kWh, representing an increase on the previous year of 0.50 ct/kWh. This rise is largely due to the increase in both the renewable energy surcharge and the network charges. This is also reflected in the shares of these price components in the total price. The renewable energy surcharge now accounts for 32% of the total price, compared to 30% a year earlier, while the net network charge accounts for 27% compared to 26% in the previous year. As a result, the price components not controlled by the supplier (network charges, metering, surcharges, electricity tax and concession fees) now amount to around 78% of the total price for commercial customers, compared to 76% a year earlier.

In 2017, data was collected from the suppliers operating in Germany on the prices for household customers. As in the previous year, there was a small increase in the prices. As at 1 April 2017, the average price for household customers on default tariffs with an annual consumption of between 2,500 kWh and 5,000 kWh had risen slightly by around 1% from 30.63 ct/kWh in 2016 to 30.94 ct/kWh (including VAT). Prices for the other two customer groups – those on other tariffs with their default supplier and those with another supplier – also increased slightly. Electricity prices for customers on other tariffs with their default supplier and with an annual consumption of between 2,500 kWh and 5,000 kWh averaged 29.61 ct/kWh and for customers with another supplier 29.12 ct/kWh. The volume-weighted average across all three groups for an annual consumption of between 2,500 kWh and 5,000 kWh was 29.86 ct/kWh (including VAT). This figure is calculated by weighting the individual prices for the three groups according to their consumption, producing a reliable average for the electricity price for household customers. There were further increases in particular in the renewable energy surcharge and the net network charge. The price components not controlled by the supplier (taxes, levies, surcharges and network charges) amount to about 78%. The competitive component of the electricity price found in "energy procurement, supply and margin" accounts for around 22% of the average total price.

As at 1 April 2017, there was another decrease in this price component, falling by around 13% or 0.93 ct/kWh from 7.35 ct/kWh to 6.42 ct/kWh and leading to a dampening effect on overall prices. This further decrease across all household customer tariff categories could be related in particular to the continued low level of wholesale prices and the increase in the number of customers switching supplier.

As a rule, customers on default tariffs can make savings by switching tariff and even more by switching supplier, saving up to 1.34 ct/kWh and 1.82 ct/kWh[7] respectively. Household customers with an annual consumption of 3,500 kWh could consequently cut their energy costs by around €47 or €64 per year. Special bonuses offered by suppliers, including one-off bonus payments, are an added incentive for customers to switch. One-off bonus payments for customers switching to special tariffs with their regional default supplier average at €50, and those for customers switching to a non-default supplier at €62.

According to Eurostat, there are large differences throughout Europe in the price of electricity for household customers. At 29.77 ct/kWh, Germany has the second highest price after Denmark of the 28 EU

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

Member States[8]. German prices are about 45% higher than the European average of 20.54 ct/kWh. Germany's comparatively high price is due according to Eurostat to its higher proportion of surcharges, taxes and levies.

Eurostat publishes price data for non-household customers in seven different consumption bands. The statistics show that the price of electricity for instance for industrial customers with an annual consumption of between 20 GWh and 70 GWh varies considerably between the different European countries. The net price in Germany excluding taxes and levies is 5.28 ct/kWh, nearly 1 ct/kWh below the European average of 6.25 ct/kWh; non-recoverable surcharges, taxes and levies average at 4.37 ct/kWh, nearly twice the European average of 2.25 ct/kWh. The total net price for Germany of 9.65 ct/kWh is higher than the average in Europe of 8.50 ct/kWh.

There has been a continued increase in the low-level switching activity of electric heating customers, following many years with hardly any customers switching. The DSOs have reported a steady increase in the number of customers switching supplier. In the reporting year, around 91,350 electric heating meter points with a total electricity consumption of around 583 GWh changed supplier. This was the equivalent of 4.4% of meter points and 4.2% of consumption, compared to 2.8% and 2.7% a year earlier. This higher switching rate indicates a higher degree of competition. The last two years have seen an increase in transparency for end customers and in the services offered by national electric heating suppliers. Consumers can now find locally available suppliers more easily, for instance by using internet portals, looking in consumer magazines or obtaining information from the consumer advice centres. Yet at the same time, the switching rates for electric heating customers are still far below those for household electricity and non-household customers.

Electric heating prices were broadly unchanged from the previous year. The arithmetic mean of the gross total price for night storage heating customers as at 1 April 2017 was 20.94 ct/kWh (including VAT), slightly up on the previous year's level of 20.59 ct/kWh. The arithmetic mean of the total price for heat pump customers was 21.65 ct/kWh (including VAT), around 0.7 ct/kWh higher than the price for night storage heating customers and broadly unchanged from the previous year.

1.7 Digital metering

The Metering Act (MsbG), a key element of the Energy Transition Digitisation Act, sets out new rules for meters and metering in Germany, making the rollout of modern metering equipment and smart metering systems mandatory throughout the country. The monitoring survey was adapted to take account of the introduction of the new technology. In 2016, there were no smart metering systems available in the market, thus the condition for the Federal Office for Information Security (BSI) to determine technical availability – market availability of systems from at least three independent manufacturers – was not met. Nor was any modern metering equipment available in the market in 2016. Whilst the beginning of 2017 saw the first modern metering equipment being installed by various network and meter operators, the rollout of smart metering systems is no longer expected to begin before year-end, since no BSI-certified smart meter gateways are yet available in the market. The BSI has therefore not yet been able to determine technical availability in accordance with section 30 of the Metering Act; this first requires the availability of

[8] The European comparison is based on prices calculated by Eurostat. The price for household customers therefore differs from the volume-weighted price given in this report.

systems from at least three independent manufacturers and would then mark the start of the mandatory rollout of smart metering systems.

However, in light of the statutory requirements set out in the Metering Act and advances in metering technology, a large-scale rollout of modern metering equipment and smart metering systems is expected in the coming years.

B Developments in the gas markets

1. Summary

1.1 Production, imports and exports, and storage

In 2016, natural gas production in Germany fell by 0.7bn m³ to 7.8bn m³ of gas (with calorific adjustment).[9] This corresponds to a decline of 8.1% compared to the previous year. The decline in production is chiefly due to the increasing exhaustion of the large deposits and the resulting natural decline in output. The reserves-to-production ratio of proven and probable natural gas reserves, calculated on the basis of the previous year's production and reserves, was 8.1 years as at 1 January 2017 (2016: 8 years).

The total volume of natural gas imported into Germany in 2016 was 1,626 TWh. Compared to the previous year's figure of 1,537 TWh, imports to Germany rose significantly by 89 TWh or about 6%. Imports from Norway dropped around 9%, while imports from Russia through the Nord Stream pipeline rose by 12.5%.

In 2016, the total volume of natural gas exported by Germany was 770.4 TWh. Compared to the previous year's figure of 746.3 TWh, exports from Germany rose by 3.2% to 24.2 TWh. About 46% of the natural gas exported by Germany went to Czechia although exports to the country were down 7.4% on the previous year. Exports to the Netherlands (+58.2%) and France (+24.7%) rose sharply, while there was a clear decrease in exports to Switzerland (-6.8%) and Austria (-10.9%).

The total maximum usable volume of working gas in underground storage facilities as at 31 December 2016 was 25.3bn Nm³. About half of this was accounted for by cavern storage facilities and the other half by pore storage facilities. The volume of short-term (up to 1 October 2017) freely bookable working gas declined slightly, as did the capacities bookable for 2018. The volume of long-term bookable working gas from 2019 remained stable. Compared to previous years, the volume of long-term working gas that can be booked five years in advance increased again.

The storage year started with rather subdued levels of injections, with one reason certainly being natural gas prices during the period. Prices for supply in winter 2017/18 were in some cases lower than spot market prices, so many traders preferred futures over buying and injecting gas.

On 1 October 2017, at the beginning of the 2017/2018 gas year, the total storage level of German storage facilities was around 85% (2016: 95%). The high storage level of the previous year, which had been driven by prices, was not repeated, with a level of over 92% on 1 November 2017.

The market for the operation of underground natural gas storage facilities is relatively highly concentrated but less so than in the previous year. The cumulative market share at the end of 2016 of the three largest storage facility operators dropped markedly to 68.2% (previous year: 73.3%). This decline is largely due to

[9] Gas volumes with calorific adjustment are amounts measured in a manner that is commercially relevant. Calorific adjustment is used because natural gas is not sold according to its volume, but according to its energy content (9.7692 kWh/m³). In contrast, gas without calorific adjustment has a natural calorific value that may vary depending on the location of the deposit (in Germany this figure varies between 2 and 12 kWh/m³).

the deconcentration in the storage market resulting from the takeover of VNG AG by EnBW AG during 2016. In the previous year, VNG AG had still been owned by EWE AG.

1.2 Networks

The first draft of the gas network development plan (NDP) 2016-2026 was presented to the Bundesnetzagentur by the transmission system operators (TSOs) on time on 1 April 2016. The TSOs submitted the second draft of the gas NDP 2016-2026 to the Bundesnetzagentur on 5 April 2017. It became necessary to draw up a second draft following a complaint procedure concerning the scenario framework underlying the gas NDP 2016-2016, which had been confirmed by the Bundesnetzagentur on 11 December 2015.

Taking the results of the consultation into account, the Bundesnetzagentur issued a request for modification to the TSOs on 26 July 2017 and as a result, 42 new measures have been added compared to the gas NDP 2015. These new measures mostly involve the market area conversion from low-calorific L-gas to high-calorific H-gas, the connection of new gas power stations and the diversion of gas from the planned Nord Stream expansion. With the request for modification, the Bundesnetzagentur confirmed 112 of the measures submitted by the TSOs, with an investment volume of approximately €3.9bn. The confirmed measures include an 822.6 km pipeline extension and a compressor expansion of 429 MW.

Five measures related to the Nord Stream expansion will not be included in the gas NDP 2016-2026 until the approvals for its construction have been obtained. The inclusion of these measures would bring the investment volume for the gas NDP 2016-2026 to €4.4bn. In addition, three measures had to be taken out of the gas NDP 2016-2026 as they were not yet detailed enough for the Bundesnetzagentur to assess and approve them. Two further measures are no longer necessary since the planning they are based on has been updated, according to the TSOs.

In 2016, investments in and expenditure on network infrastructure by the 16 German TSOs amounted to €753.2m (2015: €861.4m) (both values under commercial law)[10].

Total investments of €1.132bn are planned for 2017, corresponding to a year-on-year increase of 76%. This relatively high fluctuation is due to investments in large-scale, one-off projects. Investments and expenditure of distribution system operators (DSOs) amounted to €2,131m in 2016 (2015: €2,315m).

As in previous years, the Bundesnetzagentur conducted a comprehensive survey of all gas supply interruptions throughout the Federal Republic of Germany. The System Average Interruption Duration Index (SAIDI) determined from the results of this survey reflects the average duration of supply disruptions experienced by a customer over a period of one year and was 1.03 minutes in 2016 (2015. 1.699 minutes per year).

[10] 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.

The average volume-weighted network charge, including metering and meter operation charges, for household customers on default tariffs in consumption band II was 1.50 ct/kWh on 1 April 2017, remaining stable from the previous year.

Compared to 2015, the total quantity of gas supplied by general supply networks in Germany increased in 2016 by 75.6 TWh or nearly 9% to 941.3 TWh. The quantity of gas supplied to household customers (as defined in section 3 para 22 of the Energy Industry Act (EnWG)) rose by about 8% to 275.6 TWh. Reversing the trend of recent years, gas supplied to gas-fired power stations with a nominal capacity of at least 10 MW rose sharply to 94 TWh in 2016, 38% higher than in 2015 (68.2 TWh).

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) – ie not using the classic route via a supplier, and instead approaching the network operator as a shipper (paying the transport charges themselves) – amounted to 87.5 TWh, equivalent to nearly 48% of the total quantity of gas supplied by the TSOs. With regard to gas distribution networks, the amount of gas procured without a conventional supplier contract amounted to 58.1 TWh, corresponding to a share of approximately 7.7% of the total supplied by the DSOs.

The conversion of German L-gas networks to supply H-gas started well in 2015 with the Schneverdingen conversion. This success continued in 2016 in the networks of Stadtwerke Böhmetal, Hilter, Rees, Nienburg/Weser, Gasversorgung Grafschaft Hoya, Gelsenwasser Energienetze (Isselburg, Landesbergen-Brokeloh), Stadtnetze Neustadt am Rübenberge, Achim and some parts of the wesernetz in Bremen. Approximately 114,000 appliances will have been adapted by the end of 2017.

The probable, planned costs of market area conversion were €5.5m for the NetConnect Germany (NCG) market area in 2016, while for the GASPOOL market area they amounted to about €18m. Both figures are purely projected costs from the network operators, without differences from previous years being included.

1.3 Wholesale

Liquid wholesale markets are vital to ensuring well-functioning markets along the entire value-added chain in the natural gas sector, from the procurement of natural gas all the way to supplying final customers. The greater the variety of options for companies to procure gas for both the short and long term at the wholesale level, the less they are tied to a single supplier long-term. The Bundeskartellamt now defines the wholesale market for natural gas as a national market and no longer defines markets based on their respective network area.

The volume traded on the spot market rose again in 2016 to about 295 TWh (2015: about 195 TWh). As in previous years, the focus of spot trading for both market areas in 2016 was on day-ahead contracts (NCG: 128.5 TWh, 2015: 76.8 TWh; GASPOOL: 51.1 TWh, 2015: 42.6 TWh). The futures trading volume rose from about 97 TWh in 2015 to about 130 TWh in 2016, corresponding to an around 34% increase. In 2016, natural gas transactions brokered by the broker platforms surveyed with Germany as the place of delivery amounted to a total of 3,120 TWh (2015: 2,652 TWh), of which 1,252 TWh was for contracts with delivery in 2016 (delivery time of at least one week).

The year 2016, much like the previous year, was marked by falling wholesale gas prices.[11] The annual average daily reference prices calculated by EEX fell by around 29% (2015: 6%), while the cross-border price, as calculated by the Federal Office for Economic Affairs and Export Control (BAFA), decreased on average by 25% (2015: 13%). The changes in the BAFA cross-border price over the course of 2016 indicates a correlation with exchange prices for natural gas.

1.4 Retail

An overall analysis of how household customers were supplied in 2016 in terms of volume shows that the majority of them (53%) were supplied by the local default supplier under a non-default contract (2015: 54%) and were delivered 128.3 TWh of gas (2015: 122.4 TWh). Nearly 22% of household customers had a default supply contract (2015: 24%) and were supplied with 52.8 TWh of gas (2015: 53.3 TWh). The percentage of household customers who have a contract with a supplier other than the local default supplier once again increased and now stands at 25.6% (2015: 22%) for 62.4 TWh of gas (2015: 50.8 TWh), making supply by the local default supplier under a default contract the least popular form of supply.

The gas sold to non-household customers is mainly to interval-metered customers. About 29% of the total volume delivered to these customers was supplied under a contract with the default supplier on non-default terms and some 71% under a contract with a legal entity other than the default supplier, which is the same distribution as in the previous year. The figures show that default supply is of only minor significance in the acquisition of non-household customers in the gas sector.

The total number of household customers changing contract was 780,000. The volume of gas these customers were delivered was approximately 16 TWh. The resulting numbers-based and volume-based switching rates are 6.5% and 6.6% respectively. The slightly higher volume-based switching rate is an indication that it is high-consumption household customers who tend to change contracts in order to gain cost advantages.

The number of household customers who switched supplier rose significantly yet again, by around 36% (+333,117 supplier switches) to 1,258,312 (2015: 925,195). There was also a clear rise of about 25% to 264,954 in the number of household customers who immediately chose an alternative supplier rather than the default supplier when moving home (+52,655 household customers). When looking at 12.4m household customers (according to DSO figures) the resulting number-based household customer switching rate comes out to 12.3% (2015: 9.2%).

The total volume of gas supplied to customers who switched supplier (including those switching when moving home) increased in 2016 by 11.6 TWh or 45% to 37.2 TWh. Considering the increase in gas supplied to household customers by network operators in 2016, the volume-based switching rate rose to 13.5% (2015: 10.1%). The volume-based supplier switching rate (13.5%) is still above the numbers-based rate (12.3%) because high-consumption household customers exhibit more intensive switching behaviour. At around 24,500 kWh, the calculated annual consumption of an average gas customer that switched supplier is above the national average of approx 20,000 kWh.

[11] Influencing factors include the world market prices for oil and LNG, weather and temperatures, the renegotiation of long-term supply contracts on the European gas market, increasing trade at European gas trading points and gas storage capacities.

There was a strong rise in the switching rates among non-household customers between 2006 and 2010. Since then the switching rate has remained more or less constant. A total of 103 TWh of gas consumed was affected by supplier switches, a rise of 11 TWh or 12% over the previous year.

The Monitoring Report 2017 deals with the concentration ratio (CR) of the four largest companies in the retail gas market for the first time, rather than the three largest as in the year before, because there is now another provider with a notable market share. The cumulative sales for the four largest companies to customers with standard load profile (SLP) was about 94 TWh in 2016, of which about 79 TWh came from special contracts. Cumulative sales to interval-metered customers were about 126 TWh. The cumulative market share of the four largest companies in 2016 was around 25% for SLP customers (2015 CR3: 22%) and about 28% for interval-metered customers (2015 CR3: 29%). These two market shares remain well below the statutory thresholds for presuming market dominance. A decline in market concentration may therefore be identified in both areas, since the four largest companies now have a slightly higher market share of SLP customers than the three largest companies had the year before and around the same share of interval-metered customers.

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 2016 as well. Consumers had more than 50 gas suppliers to choose from in nearly 90% of network areas. Final consumers in over 46% of network areas had a choice of more than 100 suppliers. It is clear that developments are similarly positive when focusing particularly on household customers. In 79% of network areas, household customers had a choice of 50 or more suppliers. In 30% of network areas, customers had a choice of more than 100 gas suppliers. On average, final consumers in Germany can choose between 105 suppliers in their network area; household customers can, on average, choose between 90 suppliers (these figures do not take account of corporate groups).

As at 1 April 2017 retail prices for gas fell again compared to a year earlier (1 April 2016).

The average price for household customers across all three contract categories (ie default supply contract, non-default contract with the default supplier, and contract with a supplier other than the local default supplier) decreased by about 6% to 6.15 ct/kWh (including VAT) as at 1 April 2017 (1 April 2016: 6.54 ct/kWh).

The gas price for default supply dropped 3.7% to 6.73 ct/kWh (including VAT) as at 1 April 2017. The gas price for special contracts with the default supplier fell by 4.7% and was 6.07 ct/kWh (including VAT) on 1 April 2017. Gas prices under a contract with a supplier other than the regional default supplier decreased markedly, by 11% to 5.78 ct/kWh (including VAT) as at 1 April 2017, reaching the lowest level since the first survey as at 1 April 2008.

A look at the household customer gas prices over the past eleven years (2006-2017) shows that default supply constitutes the most expensive contract category for gas customers. During the period under review, the gas price for customers under a default contract fluctuated between 6.14 ct/kWh in 2006 and 7.20 ct/kWh in 2014. The price paid by default supply customers has increased by just under 10% over the past ten years up to 1 April 2017.

The gas price for customers supplied under a special contract with the default supplier (after change of contract) fluctuated between 6.25 ct/kWh and 6.07 ct/kWh between 2007 and 2017. Overall, the gas price for customers with a special contract with the default supplier (after change of contract) has fallen by almost 3% over the last ten years.

The price customers paid for gas under a supplier other than the regional default supplier (after change of supplier) fluctuated between 6.41 ct/kWh and 5.78 ct/kWh between 2008 and 2017. Overall, the gas price for customers in this category has fallen significantly over the past nine years, by nearly 10%, and reached a historic low as at 1 April 2017. This type of contract is the most affordable supply contract for customers with average consumption (band II).

When considering a longer period of time, it becomes clear that customers with a special contract with their default supplier and customers with a supplier other than the regional default supplier have been able to rely on stable gas prices that have seen further clear drops this year. The difference between the most expensive and the most affordable contract for an average customer (band II) was 0.49 ct/kWh in 2008. By contrast, it was 0.95 ct/kWh in 2017. The incentive to switch from default supply to a more affordable contract therefore increased in the review period.

With regard to the main component of the gas price for household customers in band II, which is the price component that can be controlled by the supplier: "energy procurement, supply and margin", it is notable that this price component for customers with a supplier other than the regional default supplier hit the lowest point since the survey was started at 2.7 ct/kWh. Moreover, the price component "energy procurement, supply and margin" for default supply customers was 3.35 ct/kWh on 1 April 2017, 6.4% lower than in the first survey in 2007. There was an even greater drop in this component for customers with a non-default contract with their default supplier (3.01 ct/kWh).

Customers on default tariffs can make savings by switching tariff or supplier. The average household customer with gas consumption of 23,250 kWh could save an average of €153 a year as at 1 April 2017 by changing contract. The average potential saving for the year from changing supplier was €221.

In addition, special bonuses offered by gas suppliers, including one-off bonus payments, are an added incentive for customers to switch supplier. Such one-off bonuses average €65 for customers on non-default terms in a contract with the default supplier and €75 for customers under contract with a supplier other than the local default supplier.

Gas prices for non-household (industrial/commercial) customers fell again. The average overall price (excluding VAT) for an annual consumption of 116 GW/h ("industrial customer") was 0.08 ct/kWh lower at 2.69 ct/kWh, slightly lower (around 3%) than the previous year's figure of 2.77 ct/kWh. The average gas price was therefore the lowest ever since the first data on gas prices (as at 1 April 2008) was collected for monitoring reports. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 MWh ("commercial customer") of 4.50 ct/kWh is 0.27 ct/kWh or around 5% lower than last year's price. Components of the overall price that are not under the control of the supplier (in particular, network charges and levies) both remained more or less stable compared to the previous year.

The number of disconnections carried out by DSOs on behalf of the regional default supplier fell to 38,576, which represents a drop of nearly 12% year-on-year or around 5,000 disconnections. Additionally, 1,260 gas disconnections were carried out on behalf of suppliers other than the regional default supplier.

In 2016, gas DSOs restored supply to around 30,633 customers whom they had previously disconnected on behalf of the default supplier. The decline in restored meter points, of about 5,300 meter points compared to the year before, is largely due to the general decrease in gas disconnections. Supply was also restored to about 1,486 meter points on behalf of gas suppliers other than the regional default supplier.

Compared to the previous year, the number of disconnection notices issued by all gas suppliers (1,845,550) remained almost steady (-0.1%). Compared to 2015, the number of disconnection orders fell by 4.3% to 272,135. Around 14% of the 1.8m disconnection notices issues by gas suppliers (both default and non-default) resulted in a disconnection subsequently being ordered from the DSO in 2016.

According to the gas suppliers, 39,004 disconnection orders (for customers on a default contract or a non-default contract with the default supplier) ended with a disconnection carried out by the network operator responsible, equivalent to a decline of around 4,000 disconnections on the year before. A comparison of the number of disconnection notices issued with the number of disconnections actually carried out makes it clear that about 2.1% of the notices issued actually resulted in a disconnection being carried out by the DSO. Additionally, gas suppliers indicated that they disconnected customers with a default contract 26,707 times. The disconnection rate with respect to the total number of customers under a default contract was on average less than one percent (0.8%). Customers outside of default supply (non-default customers) were disconnected 12,297 times. The disconnection rate for non-default customers was 0.2%.

German household customers paid slightly more than the European average for gas, while non-household customers paid significantly more. The net gas price in the consumption range 27.8 to 278 GWh/year ("industrial customer") is 2.64 ct/kWh, which is at the upper end of the scale. The EU average is 2.40 ct/kWh. On average, approximately 10% of the net price in Europe (0.24 ct/kWh) is made up of non-recoverable taxes and levies, whereas in Germany it is higher at about 15% (0.40 ct/kWh). Unlike in the industrial customer sector, there are major differences in gas prices for household customers across Europe. The gas price level for household customers in Germany (6.42 ct/kWh) is only slightly above the EU average (6.36 ct/kWh).

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