Bundesnetzagentur Bundeskartellamt

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Report
Monitoring report 2014

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in accordance with section 63(3) i. c. w. section 35 EnWG
and section 48(3) i. c. w. section 53(3) GWB
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Bundesnetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen

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Foreword

This Monitoring Report documents and analyses the developments in the electricity and gas markets in Germany. The Bundeskartellamt (Federal Cartel Authority) and the Bundesnetzagentur (Federal Network Agency for Electricity, Gas, Telecommunications, Post and Railway) have continued to work closely together in collecting the data for the year and in preparing the report. Whereas the Bundeskartellamt places its focus on the competition aspects of the electricity and gas value-added chain, the Bundesnetzagentur's main emphasis is on the grid and network areas, the security of supply and the situation as regards supply to household customers. There has been an increase since last year in the market coverage and validity of the data collected, made possible by the active participation of the energy undertakings. The analysis of this data shows the market developments comprehensively and in full detail.

The Energiewende continues to make rapid progress with a nuclear exit and a further rise in the proportion of renewable energy sources. The network expansion needed for this is still not managing to keep pace with the changes in the power generation landscape. By the third quarter of 2014, just 23 per cent of the total kilometres of power lines planned under the Power Grid Expansion Act had been completed. Originally the aim was to complete the majority of the expansion projects before the end of 2015. In 2013 the network operators had to take increased steps to safeguard network and system stability, such that the unused energy resulting from feed-in management measures rose by 44 per cent in comparison with 2012. Conventional electricity generation revealed a continued growth in electricity production from coal-fired power plants whereas the amount of electricity produced from gas-fired power plants continued to fall.

From a competition perspective, the electricity markets continue to develop favourably; a reduction in market concentration and a downwards trend in market power have been noted in the area of electricity generation. The high liquidity on the electricity wholesale markets plays a decisive role in competition. There are a significant number of suppliers on the main electricity retail markets, which is reflected in the fall in market concentration. Household customers are increasingly taking advantage of being able to freely select their electricity supplier. The amendment to the Renewable Energy Sources Act (EEG) has also introduced elements of competition in the field of renewable energy sources. However, market integration of renewable energy sources remains a core task.

The surcharges system, driven by the changes in the electricity generation land-scape, increasingly makes up a greater proportion of the electricity price. In contrast to previous years, however, the considerable rise in the EEG surcharge this year did not result in further price increases for the majority of electricity consumers. This is due to the competitive structure of the retail markets and the fall in wholesale prices.

Natural gas import figures showed another year on year increase, with a marked rise in direct imports from Russia via the Baltic Sea pipeline. Exports in the year under review also increased, strengthening Germany's position as a natural gas transit country within Europe. Germany remains dependent on natural gas imports owing to its low level of domestic production. Gas supply reliability has been boosted, firstly by new natural gas storage facilities being opened and, secondly, by storage levels at existing facilities in Germany reaching near maximum at some 97 per cent at the beginning of the withdrawal period in early November 2014.

Competitive conditions in the natural gas markets also improved, with the convergence of wholesale markets and an increase in their liquidity. The supplier switching rate for business and industrial customers at just fewer than 13 per cent now matches switching rates in the electricity sector. The growing number of active gas suppliers and hence greater choice of provider are encouraging more household customers to switch as well. Special contract customers can now also benefit from strong competition in the national market.

Germany's electricity and gas markets are characterised by dynamic development driven by the restructuring of electricity supply and constant improvements in competitive conditions. The Bundesnetzagentur and the Bundeskartellamt will continue to follow and shape this process of development within their areas of activity.

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A Developments in the electricity markets

1. Key findings

1.1 Generation/Security of supply

In 2013, the year under review, power generation was characterised by further capacity growth in renewables. Of these, special mention must be made of the growth in solar energy and onshore wind capacity, which grew by 3.3 GW and 2.9 GW respectively. Altogether, growth in generating facilities using renewable energy sources amounted to 6.7 GW and in facilities using non-renewable resources to 1.6 GW. The total (net) installed generating capacity thus rose to 188.1 GW as of 31 December 2013, of which 105.0 GW was accounted for by non-renewable energy sources and 83.1 GW by renewable energy sources.

Non-renewable electricity generation in 2013 was characterised by a further increase in the production of electricity from coal and a continued decrease in the volume produced using natural gas. The volume generated using brown coal increased by 7.2 TWh or 5.1 per cent and using hard coal by 6.0 TWh or 5.6 per cent. In contrast, there was a decrease in the volume of electricity generated using natural gas of 8.3 TWh or 12.4 per cent and of nuclear power of 2.1 TWh or 2.2 per cent. Altogether, net non-renewable electricity generation rose in 2013 by 5.4 TWh or 1.2 per cent to 444.5 TWh.

The aggregate market share of the four largest undertakings in conventional electricity generation in Germany and Austria in terms of sales was approximately 67 per cent in 2013. This represents a noticeable decline in market concentration of six percentage points when compared with the year 2010. Besides the decline in the shares of the largest undertakings in conventional generating capacity, several additional factors are causing a downwards trend in market power. At present, more electricity generating capacity exists throughout Germany and Europe than is necessary to cover demand. Improved use of the available import capacity as a consequence of progressive market coupling can lead to constraints on the room to manoeuvre on the primary sales market for electricity. Moreover, a growing proportion of electricity demand is being covered by input from renewable energy sources.

Net non-renewable electricity generation rose in 2013 by 8.2 TWh or 5.9 per cent to 146.3 TWh. The biggest growth was in electricity generation by solar power, which rose by 3.5 TWh (up 13.3 per cent). Altogether the net total volume of electricity generated in 2013 was 590.8 TWh, which was13.6 TWh or 2.4 per cent more than in 2012.

The total installed capacity of installations in Germany eligible for payments under the Renewable Energy Sources Act (EEG) was approximately 78.4 GW on 31 December 2013 (31 December 2012: around 71.7 GW). This represents an increase in the installed capacity of all installations eligible for EEG payments in 2013 of some 6.7 GW. Under the EEG, 125,693 GWh electricity from renewable energy installations was subsidised. The EEG payments and market and flexibility bonuses for this electricity paid by the transmission system operators (TSOs) to the operators of renewable energy installations totalled €19,637m. This represents a rise of 6.2 per cent in the total volume of EEG-remunerated electricity and of 2.7 per cent in total payments by the TSOs compared with the previous year.

As a rule, the transmission system is subject to its greatest pressure during the winter months when high grid loads and strong winds with subsequent high input from wind power plants frequently appear together. The TSOs require a sufficient level of redispatch potential through secured power plant capacity in southern Germany and in southern European regions to maintain secure operation of the grid in such critical circumstances. In the 2013/14 winter the need for reserve capacity, ie plants that only operate at the request of the TSOs, to ensure security of supply was 2.5 GW. There was, however, no need to deploy these reserve power plants last winter. The reserve capacity needed for the 2014/15 winter is 3.1 GW. Some 2.2 GW will be covered by German reserve power plants, the remaining 0.9 GW by power plants in Austria and Italy. The main reserve power plants are those in southern Germany that have been marked for closure but have been designated system-relevant by the TSOs and Bundesnetzagentur and thus are maintained operational and accessible for the TSOs. The Bundesnetzagentur has so far recognised nine power generation units with a net nominal output of 1,660.4 MW as being system-relevant under section 13a(2) of the German Energy Act (EnWG). Due to the planned phasing out of the Grafenrheinfeld nuclear power plant, additional reserve power plant capacity of 0.5 GW in excess of the 3.1 GW of demand already established for the 2014/15 winter will be required in the first quarter of 2015.

The average interruption duration determined in the low and medium voltage range fell from 15.91 minutes (2012) to 15.32 minutes (2013). The quality of supply thus maintained a constant high level throughout 2013. A decisive factor in this improvement in quality of supply in 2013 from 2012 was the considerable decline in disruptions caused by third parties.

1.2 Networks

The monitoring survey for the Power Grid Expansion Act (EnLAG) revealed the following in the third quarter of 2014: A mere 438 km of the total 1,887 km of lines planned (some 23 per cent) have been completed. The TSOs estimate that some 40 per cent of lines should be completed by 2016. So far none of the underground cable pilot lines have been put into operation.

The Onshore Network Development Plan 2023 was approved by the Bundesnetzagentur at the end of 2013. The projects confirmed comprise some 2,800 km of lines that will be reinforced or optimised and around 2,650 km of new lines. In the Offshore Network Development Plan 2023 four of six grid connection lines in the North Sea and all four of the grid connection lines proposed in the Baltic Sea were likewise approved.

In 2013, investments in and expenditure on network infrastructure by the four German TSOs amounted to approximately €1,135m (2012: €1,152m). At the same time investments in new builds, upgrades and expansion projects rose from €967m (2012) to €1,087m (2013). In contrast, investments and expenditure incurred by the distribution system operators (DSOs) fell once again from €6,005m (2012) to €5,778m (2013). The number of DSOs carrying out optimisation, reinforcement or expansion measures in their networks increased once more in 2013.

In 2013, the TSOs took redispatch measures to manage current and voltage situations pursuant to section 13(1) of the Energy Act (EnWG) – adjusting feed-in from generating facilities to ensure security of supply and of the network – over a total of 7,965 hours, an increase of 11 per cent compared with 2012 (7,160 hours). In total, redispatch intervention measures were carried out on 232 days in 2013. These measures comprised a total volume of 4,390 GWh (2012: 4,690 GWh). Consequently, the redispatch share of all generation by installations eligible for payments under the Renewable Energy Sources Act (EEG) reached 0.95 per cent. The TSOs gave their computed basic costs of system support services for national redispatch in 2013 as being €132.6m. As in the previous years, this involved primarily the TenneT and 50Hertz control areas. The transmission lines around the Lehrte substation and the transmission line between the Remptendorf and Redwitz substations bore the largest loads.

In 2013, none of the TSOs carried out any adaptation measures under section 13(2) EnWG. Nevertheless, four DSOs took adaptation measures for 4,393 hours spread over 346 days, of which 340 hours over 45 days involved conventional installations and 4,053 hours over 261 days renewable energy installations. The measures for conventional installations comprised a total volume of 1,467 MWh. For renewable energy installations the total volume of reduced feed-in was 12,813 MWh. In addition, four DSOs took support measures under section 13 subsections 2 and 2a and section 14 subsection 1c EnWG at the instigation of a TSO. In doing so, this caused a reduction in electricity feed-in of about 142 MWh over four hours on one day and a maximum fall in output of 3.4 MW.

The amount of unused energy caused by feed-in management measures (FMM) as per section 11 EEG (2012) rose markedly in 2013 by 44 per cent to 555 GWh. This brings the proportion of unused energy as measured by total energy produced by installations eligible for payments under the EEG to 0.44 per cent. The sum total of compensation payments likewise increased to approximately €43.7m (2012: €33.1m). As in previous years, in 2013 feed-in management measures were applied primarily to wind power plants, which accounted for 86.6 per cent of the total volume of unused energy (2012: 93.2 per cent). The share of solar installations affected has risen sharply and in 2013 reached 11.8 per cent (2012: 4.2 per cent). For some 30 per cent of measures the reason for the restriction lay with the transmission network, whereas the remaining 70 per cent of feed-in management intervention measures could be attributed to network congestion in the distribution grid. Every region in Germany has since been affected by feed-in management measures although 95 per cent of total unused energy is accounted for by the northern regional states.

Network tariffs for household, industrial and business customers have stabilised. The tariffs for these three customer groups, based on specific offtakes, resulted in the following prices as at 1 April 2014:

- household customers (default supply), consumption 3,500 kWh/year: 6.47 ct/kWh
- business customers, consumption 50 MWh/year: 5.65 ct/kWh
- industrial customers, consumption 24 GWh/year: 1.90 ct/kWh

The net costs of the TSOs' system support services rose by €72m from €1,009m in 2012 to €1,081m in 2013. A large part of the total costs is made up by the costs for keeping reserves of system balancing power – €594m (2012: €417m) – and for energy to compensate for grid losses – €333m (2012: €354m). The cost structure of the system support services changed once again in 2013 from that of 2012. There was a rise of €177m in the total costs for system balancing energy, most notably because of the higher costs for secondary balancing energy (rise of €86m) and for minute reserve power (rise of €89m). In contrast, there was a fall in the costs for reactive power of €35m and energy to cover grid losses of €21m. A decrease of €52m was also shown in the costs declared by TSOs for national and cross-border redispatch.

As in previous years, Germany was once again the hub for electricity exchange within the central European interconnected system. The average available transmission capacity declined slightly in 2013. The import and export capacity decreased by 2.79 per cent to 21,137 MW in 2013. Greater changes arose in export capacity: whilst capacity at the Polish and Czech border fell by 16.68 per cent and at the Swedish border by 16.84 per cent, capacity at the border to Switzerland rose by 7.71 per cent. As regards import capacity, changes were most noticeable at the Polish and Czech border and the Danish border, where it fell by 5.47 per cent and 10.61 per cent respectively and at the Swedish border where it rose 5.39 per cent.

Traded volumes in electricity exchange across Germany's network borders grew once again by 8.4 per cent from 79.7 TWh in 2012 to 86.4 TWh in 2013. At the same time the net export surplus of traded electricity rose sharply from 21.7 TWh in 2012 to 32.5 TWh in 2013. In 2011, this figure was only 3.0 TWh. Overall, the traded export volume stood at approximately €2,198m and the import volume at about €1,053m. Average export revenues were €36.98 per MWh, whereas import costs averaged €39.07 per MWh.

1.3 Wholesale

In 2013 the electricity wholesale markets were marked once again by high liquidity. Well-functioning wholesale markets are fundamental to competition in the electricity sector. Spot and futures markets are crucial for meeting suppliers' short and longer term electricity requirements. Adequate liquidity with sufficient volume on both the supply and demand sides improves opportunities for new suppliers to enter the market. Alongside the bilateral, over-the-counter wholesale trade, power exchanges play a key role. They create a reliable trading forum and at the same time provide important price signals for market participants in other electricity sectors.

On the EPEX and the EXAA power exchange spot markets, the volume of day-ahead auctions was the same as the previous year. The EPEX SPOT registered an increase in volume in intraday trading. The sales volumes of the TSOs, which use the power exchanges primarily to market EEG-regulated electricity, once again fell in a year-on-year comparison. The percentage of electricity sold by the TSOs on the EPEX SPOT has fallen from 38 per cent in 2011 to 23 per cent in 2013. This is a result of the increase in the volume of renewable electricity sold directly. At mid-year, the average prices on the spot markets showed a year-on-year decrease of around 11 per cent. Although the average daily price dispersion was greater in a year-on-year comparison.

Clear growth in volume was recorded on the futures market and the EEX OTC clearing of 50 per cent and 23 per cent respectively. Prices for electricity futures fell again in 2013 and reached their lowest level of the last seven years. At €39.08 per MWh in mid-2013, the Phelix Base Year Future fell just over 20 per cent from the previous year. The Phelix Peak Year Future price reached €49.67 per MWh at mid-year and was therefore some 18 per cent less than the previous year's figure.

The trading volume in the off-exchange wholesale sector is several times higher than that on the exchange as far as futures trading is concerned. Broker platforms play a large role in this. Futures contracts totalling more than 5,900 TWh were brokered in 2013, of which more than 3,200 TWh were accounted for by contracts for 2014.

Most recently, power exchanges have developed and introduced new forms of spot trading. Since September 2014 the EXAA day-ahead auction allows trading in quarter hours. The EPEX SPOT announced it would introduce an additional day-ahead auction for quarter hours in December 2014. Extending trading opportunities to include 15-minute contracts is especially due to a rise in the feed-in of renewable energy and the duty of balancing group managers to balance the power budget by quarter hours.

1.4 Retail

The number of electricity suppliers from whom retail customers can choose increased slightly again. In 2013, final consumers could choose between an average of 97 suppliers in each network area (not taking account of groups of affiliated companies). The average number of suppliers for household customers was 80.

The supplier switching rate for business and industrial customers in 2013 was about 12 per cent. The switching rate for business and industrial customers has remained steady since 2006. By contrast, the number of household customers switching supplier has increased significantly since 2006. The data collected shows an increase in the number of household customers switching supplier from just over 3.2 million in 2012 to approximately 3.6 million in 2013. This increase is due to a higher number of customers choosing a supplier other than the local default supplier when moving home. In contrast, the number of household customers switching supplier when not moving home was the same as the previous year at just over 2.5 million if those customers are excluded who switched automatically (in the first instance to the fall-back supplier) on account of a large supplier becoming insolvent in 2013.

A relative majority of household customers (45 per cent) have a special contract with their local default supplier (2012: 43 per cent), while 34 percent still have a standard contract with their default supplier (2012: 37 per cent) and 21 per cent are served by a company other than the default supplier (2012: 20 per cent). The overall strong position that default suppliers continue to hold in their service areas for household customers weakened further in the year under review. By contrast, default suppliers played a relatively small role in serving business and industrial customers: some 66 per cent of the total volume of electricity delivered to interval metered customers in 2013 was supplied by a legal entity other than the local default supplier while only around 34 per cent was supplied under a special contract with the default supplier; less than 1 per cent of all interval metered customers have a standard contract with their default supplier.

There is no high concentration on the electricity consumer markets defined by the Cartel Office as national markets. The aggregate market share of the four largest undertakings (CR4) in the market for supplying interval metered customers was some 34 per cent. Also, given the high liquidity in the electricity wholesale markets, it can be assumed that there is no longer any single dominant supplier on this market. The aggregate market share of the four largest undertakings in the national market for supplying special contract standard load profile (SLP) customers - primarily household customers - was around 42 per cent.

The number of disconnections of supply to household customers with a standard contract with their default supplier increased by about 23,000 compared with the previous year. Overall, suppliers issued nearly seven million threats of disconnection to household customers with standard contracts. Of these, 1.5 million were subsequently passed on to the relevant network operator for disconnection. Ultimately only 344,798 disconnections were carried out.

Electricity prices for industrial and business customers as of 1 April 2014 remained more or less at the previous year's level despite a sharp rise in the surcharge payable under the EEG. The average price as of 1 April 2014 for industrial customers that cannot claim any discounts and that have an annual consumption of 24 GWh was around 15 ct/kWh (excluding VAT), of which 10.5 ct/kWh was accounted for by surcharges, taxes, network tariffs and levies. The rise in the EEG surcharge from 5.28 ct/kWh to 6.24 ct/kWh was compensated by a reduction in the price component that can be controlled by the supplier. An electricity price of 15 ct/kWh for industrial customers is higher than the European average. Insofar as consumers meet the conditions for the statutory compensation scheme, in individual cases the state-controlled surcharges, taxes, network tariffs and levies may decrease from 10.5 ct/kWh to about 1 ct/kWh. This would then result in electricity prices for industrial customers that are lower than the European average. The average price of electricity for business customers with an annual consumption of 50 MWh was around 22 ct/kWh (excluding VAT), more or less the same as in the previous year. For these customers the considerable rise in the EEG surcharge has also been compensated by a similarly high reduction in the price component that can be controlled by the supplier (electricity procurement, supply, other costs, margins).

The steep price rises in recent years for household customers have slowed in the year under review. As of 1 April 2014, the average price for household customers with a standard default supply contract and annual consumption of 3,500 kWh had increased by 1.3 per cent to 30.50 ct/kWh (including VAT) in a year-on-year comparison. Prices for the two remaining customer groups – those with a special contract with their default supplier or a special contract with a third-party supplier (supplier switch) – also increased slightly. Electricity prices for a special contract with a default supplier and annual consumption of 3,500 kWh averaged 29.32 ct/kWh and for a special contract with a different supplier were 28.29 ct/kWh. The volume-weighted average across all three price categories was 29.53 ct/kWh (including VAT) as of 1 April 2014. In a European comparison only Denmark had higher electricity prices than Germany. Germany's high electricity prices are caused by a heavy burden of surcharges, taxes and levies. Once again, an increase in the state-controlled price components can be noted. Essentially this has been caused by an increase in the EEG surcharge to 6.24 ct/kWh. The surcharge now accounts for 21 per cent of the average total price. This brings the total share of the state-controlled price components (taxes, levies, surcharges and network tariffs) to about 73 per cent. The competitive component of the electricity price found in "energy procurement, supply, other costs and the margin" still comprises only about 27 per cent of the average total price.

As of 1 April 2014, there was a reduction in the "energy procurement, supply, other costs and margin" component of the price, leading to a subdued effect on total prices. For the first time since 2010 this component has fallen in all price categories for household customers. This decrease could be due to the reduction in wholesale prices.

As a rule, consumers can save additional costs from a standard default supply contract by switching contract and even more by switching supplier. Special bonuses offered by suppliers are an added incentive for costumers to switch supplier.

The green electricity sector is once again recording growth. In 2013, green electricity accounted for 10.6 per cent of the total volume of electricity from suppliers, while some 17 per cent of all final customers purchased green electricity.

The rate of customers changing supplier for heating currents is still very low. The proportion of household customers with a supplier other than the local default supplier was 2 per cent in 2013, although the general framework for more competition in the supply of heat current customers has been in place for quite a while. Last year internet portals added to the range of information they provide to include night storage heating and heat pumps. It has yet to be seen whether this increased transparency will give a boost to competition. Heating current prices are more or less the same as for last year. The price of electricity as of 1 April 2014 for night storage customers with an annual consumption of 7,500 MWh was around 20.6 ct/kWh on average. These customers also saw the increased EEG surcharge compensated by a reduction in the price component controlled by the supplier (energy procurement, supply, other costs and the margin).

2. Market overview

Network structure figures for 2013

	TSOs	DSOs	Total
Network operators (number)	4	804	808
Total circuit length (km)	34,855	1,763,083	1,797,938
Extra high voltage	34,631	348	34,979
High voltage	224	96,084	96,308
Medium voltage	0	509,866	509,866
Low voltage	0	1,156,785	1,156,785
Total final customers (metering points)	664	49,934,777	49,935,441
Industrial and business customers		3,829,740	3,829,740
Household customers		46,105,037	46,105,037

Table 1: Network structure figures for 2013

DSOs split by circuit length (%)

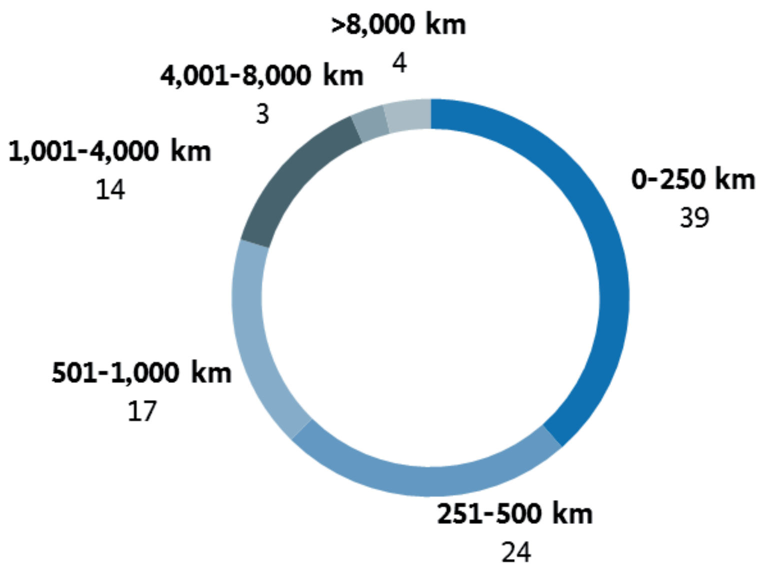

Figure 1: DSOs split by circuit length

Market and network balance 2013

	TSOs	DSOs	Total
Total net nominal capacity of generation facilities (GW) (as of 31 December 2013)			188.1
Facilities using non-renewable energy sources			105.0
Facilities using renewable energy sources			83.1
Facilities eligible for EEG payments			78.4
Total net output (TWh) (including output not fed into general supply networks) in 2013			590.8
Facilities using non-renewable energy sources			444.5
Facilities using renewable energy sources			146.3
Facilities eligible for EEG payments			125.7
Net output not fed into general supply networks (TWh) in 2013[1]			24.7
Network losses (TWh)	6.3	19.9[2]	26.2
Extra high voltage	5.0	0	
High voltage (including EHV/HV)	1.3	3.3	
Medium voltage (including HV/MV)	0	6.9	
Low voltage (including MV/LV)	0	9.7	
Cross-border trading (TWh) (implemented exchange schedules)			86.4
Imports			26.9
Exports			59.4
Offtake (TWh)[3]	41.0	469.6	510.6[3]
Industrial and business customers	30.7	342.2	372.9
Household customers	0	126.1	126.1
Pumped storage	10.3	1.3	11.6

[1] Captive use by industrial, business and private users; excluding electricity fed into Deutsche Bahn AG's traction network

[2] Corrected figure for DSOs' network losses in 2012: 17.9 TWh (not 17.2 TWh as originally published)

[3] Including offtake for Deutsche Bahn AG's traction network

Table 2: Market and network balance for 2013

The market and network balance provides an overview of supply and demand in the German electricity grid in the year under review. The supply volume of 617.7 TWh comprises a total net output of 590.8 TWh and imports totalling 26.9 TWh. On the demand side, the total offtake from general supply networks of 510.6 TWh comprises 499.0 TWh for final customers and 11.6 TWh for pumped storage. The net output not fed into general supply networks (captive use by industrial, business and private users) amounted to 24.7 TWh. Network losses totalled 26.2 TWh and exports 59.4 TWh. The individual volumes on the demand side amount to a total of 620.9 TWh. The difference between this and the total supply volume (617.7 TWh) is 3.2 TWh or 0.5 per cent.

Supply and demand in the German electricity grid in 2013
(TWh)

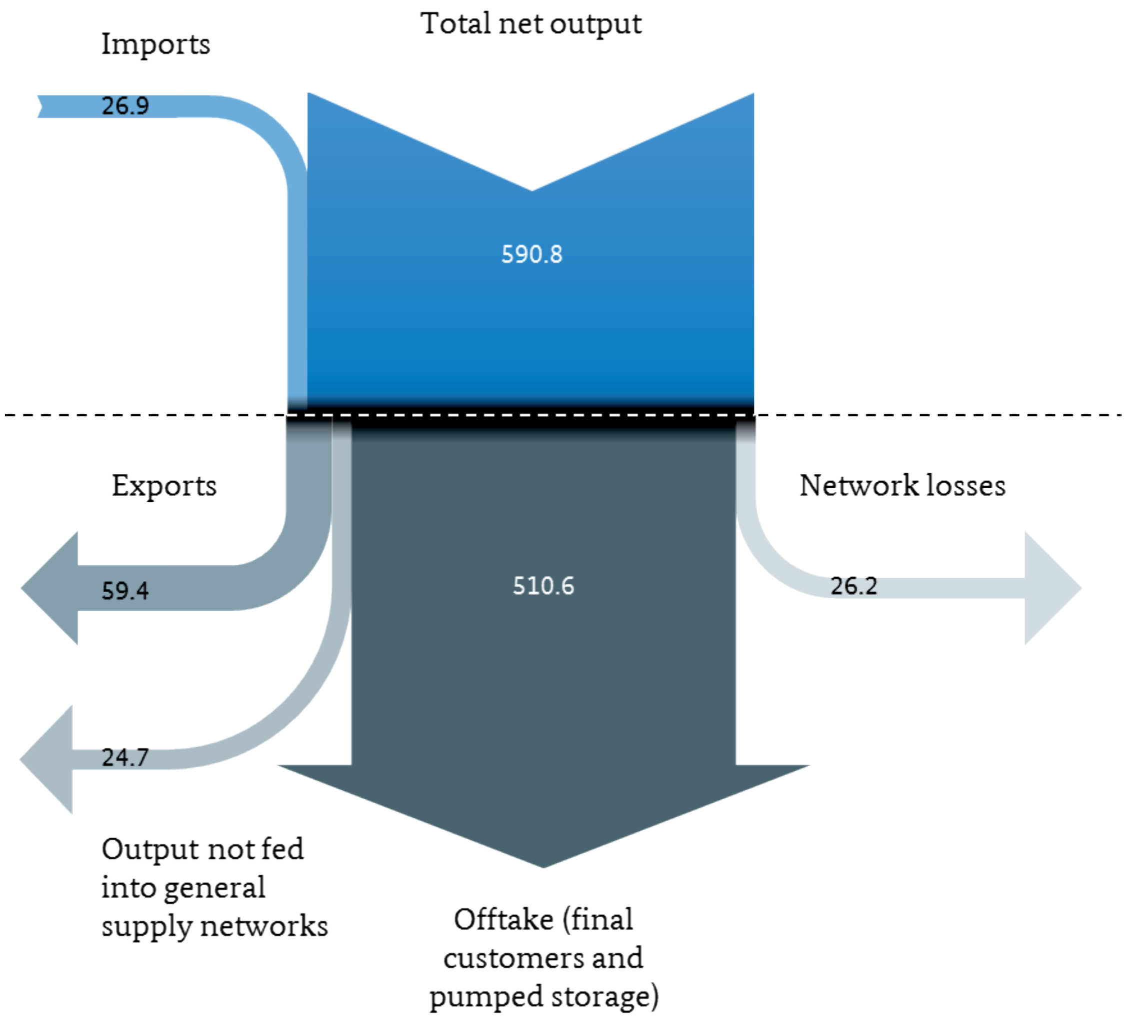

Figure 2: Supply and demand in the German electricity grid in 2013

The four German TSOs took part in the Bundesnetzagentur's 2014 monitoring survey. The TSOs' total circuit length (underground and overhead lines) amounted to 34,855 km as of 31 December 2013 (see Table 1 on page 18). The total number of metering points in the four TSOs' network areas – excluding "virtual" metering points as defined in the Metering Code 2006 – was 664, including 546 metering points for interval-metered customers. The offtake of the 155 final customers connected to the TSOs' networks totalled 30.7 TWh as of 31 December 2013, representing a year on year decrease of around 2 TWh.

As of 14 July 2014 a total of 884 DSOs were registered with the Bundesnetzagentur, 804 of whom took part in the 2014 survey. The offtake in 2013 of the 49,281,588 final customers connected to the DSOs' networks totalled 468.3 TWh, which is more or less the same as in the previous year.

The DSOs' total circuit length (underground and overhead lines) at all network levels amounted to 1,763,083 km as of 31 December 2013. The total number of metering points supplied in the DSOs' network areas was 49,934,777, including 354,044 metering points for interval-metered customers and a total of 46,105,037 metering points for household customers as defined in section 3 para 22 EnWG.

Number of TSOs and DSOs in Germany

	2006	2007	2008	2009	2010	2011	2012	2013	2014
TSOs	4	4	4	4	4	4	4	4	4
Total DSOs	876	877	855	862	866	869	883	883	884
DSOs with fewer than 100,000 connected customers	799	799	779	787	790	793	807	812	812

Table 3: Number of TSOs and DSOs in Germany from 2006 to 2014

The majority of DSOs (641 or 79.7 per cent) have networks with a short to medium circuit length (underground and overhead lines) up to 1,000 km. 163 DSOs have networks with a total circuit length exceeding 1,000 km. Figure 1 on page 18 shows a breakdown of DSOs according to circuit length.

The following table shows the electricity offtake volume of final customers in the network areas of the participating TSOs and DSOs and the delivery volume of the participating suppliers for 2013. It also shows the percentage share of the individual categories in the overall offtake and delivery volumes for final customers. The differences between the offtake and delivery volumes are due to the fact that the suppliers' market coverage, in particular for industrial and business customers, is slightly smaller than the operators' market coverage.

Final customers' offtake volumes and suppliers' delivery volumes split by customer category

Category	Electricity offtake TSOs/DSOs (TWh)	Share of total	Volume delivered by suppliers	Share of total
		(%)	(TWh)	(%)
≤10 MWh/year	126.1	0.253	124.1	0.272
>10 MWh/year ≤2 GWh/year	133.8	0.268	117.9	0.259
>2 GWh/year	239.1	0.479	213.8	0.469
Total	499	100	455.8	100

Table 4: Final customers' offtake volumes and suppliers' delivery volumes split by customer category according to data provided by TSOs, DSOs and suppliers

The total offtake volume from general supply networks in 2013 was 2.7 TWh or 0.5 per cent lower than in the previous year. Although the number of large industrial customers with an annual consumption of >2 GWh is relatively small, these customers accounted for 47.9 per cent of the total offtake volume in Germany, a year on year decrease of 1.4 per cent. Smaller industrial and business customers with an annual consumption of >10 MWh and ≤2 GWh accounted for 26.8 per cent of the total offtake in 2013, about the same as in the previous year. The largest customer group in terms of numbers, comprising customers with an annual consumption of ≤10 MWh and mainly household customers, accounted for around 25.3 per cent of the total volume in 2013, 0.5 per cent more than in the previous year.

The retail market remains characterised by a strongly regional structure; there were no significant changes, with differences compared to 2012 being single figure percentages. As in the previous year, more than three quarters of the DSOs surveyed supply up to 30,000 metering points. Around 10 per cent of all DSOs supply more than 100,000 metering points but at the same time account for 345 TWh or some 75 per cent of the total offtake volume and around 77 per cent (38.3m) of all metering points.

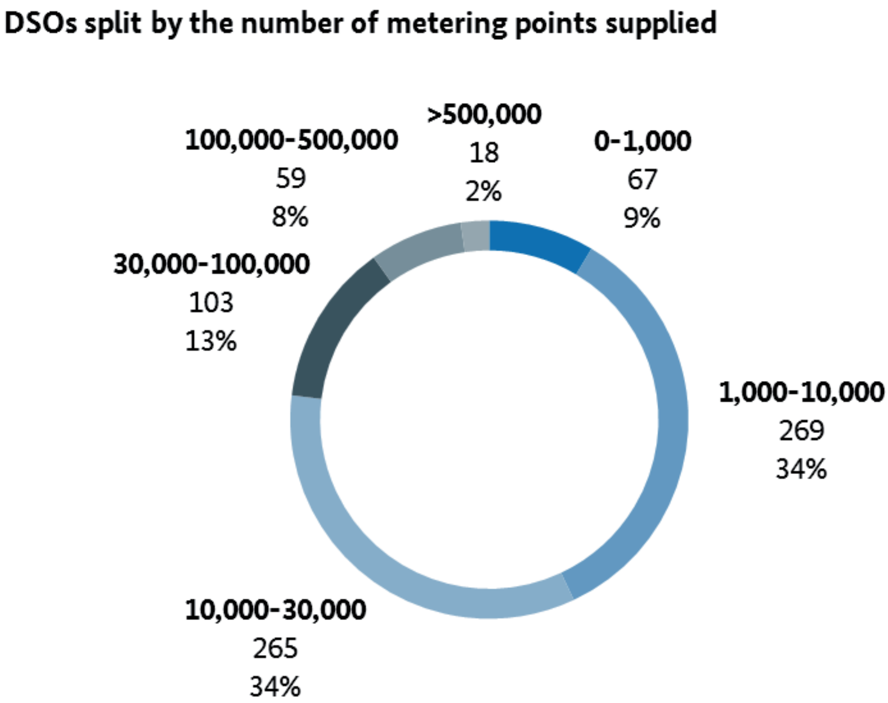

Figure 3: DSOs split by the number of metering points supplied

3. Market concentration

The degree of market concentration is a good indicator of the intensity of competition in the respective market. Market shares are generally a useful reference point for estimating market power because they represent (for the period of reference) the extent to which demand in the relevant market was actually satisfied by a company[1]. For the purpose of energy monitoring, however, an extensive analysis of market power is not required. Such an analysis would include a residual supply analysis with regard to electricity generation[2].

There are typically two ways to represent market share distribution (which is tantamount to market concentration): one is the Herfindahl-Hirschman-Index (sum of the squared market shares of all competitors in a market) and the other is the sum of the market shares of the three, four or five competitors with the largest shares in the market ("concentration ratios", CR3 - CR4 - CR5). The larger the market share covered by only a few competitors, the higher the market concentration. In view of the (historically evolved) structure of the electricity markets, the following analysis uses the market shares of the four strongest suppliers as a point of reference to measure market concentration.

The report examines the market concentration on the economically significant market for the first-time sale of electricity (generation of electricity for further resale) and on the two largest retail markets for electricity (sales to end consumers). The market shares on the retail markets are estimated with the help of the so-called

[1] Cf. Bundeskartellamt, Guidance on substantive merger control, para. 25.

[2] Cf. Bundeskartellamt, Sector Inquiry Electricity Generation and Wholesale Markets, 2011.

"dominance method". The market shares on the market for the first-time sale of electricity are calculated on the basis of competition law principles, which renders more accurate results (the following box explains the differences between the two calculation methods).

Calculation of (group) market shares under competition law vs. calculation of market shares with the "dominance method"

For the calculation of market shares (or rather the sum of the market shares of the strongest suppliers) one first has to define which companies (legal persons) are to be considered as affiliated companies (and consequently as a corporate group). This step is necessary because it has to be assumed that there is no (substantial) competition between the individual companies of a group.

Competition law uses the concept of "affiliated companies" (Section 36 (2) GWB). The concept focuses on whether there is a control relationship between companies. The turnover or sales quantities of each controlled company are fully attributed to the company group, the sales quantities of a company that is not controlled are not added to the company group's sales quantities (not even in parts). A typical example of a control relationship is a scenario where the majority of the voting rights in an affiliated company are held by another company. There are also other, less typical forms of control, for example through personal links between the companies or an agreement to confer control. If several companies act together in such a way that they can jointly exercise a controlling influence over another company, each of them is regarded as controlling. Investigating and assessing which companies belong to a certain group under these principles can sometimes be rather time-consuming.

For this reason, in energy monitoring group membership is predominantly assessed by applying the considerably simpler "dominance method". This method exclusively focuses on whether one shareholder holds at least 50 per cent of the shares in a company. If a shareholder holds more than 50 per cent of the shares in a company, that company's sales quantities are fully attributed to the shareholder. If two shareholders each hold 50 per cent of the shares in a company, they each are attributed with 50 per cent of the sales quantities. Where there is only one shareholder holding 50 per cent of the shares while all other shareholders hold shares of under 50 per cent, half of the sales quantities are attributed to the largest shareholder; the other half is not attributed to any of the remaining shareholders. If all shareholders hold shares of below 50 per cent, the sales quantities of the company are not attributed to any of them (in this case the company is a "controlling company" itself).

In the case of majority participations, usually both calculation methods render the same results. However, a controlling relationship can also occur under a minority participation. Such a case would not be covered by the dominance method. A calculation of market shares under the dominance method therefore tends to render results where the market shares of the strongest company groups are too low. This applies in particular if there are strong joint ventures active in the market.

3.1 Electricity generation

The Bundeskartellamt defines one relevant product market for the first-time sale of electricity (first level of supply)[3].

The market only covers electricity which is generated according to supply and demand. Electricity which is subject to the fixed remuneration system under the Renewable Energy Sources Act (EEG) and electricity whose remuneration is subject to optional direct marketing do not belong to this market. In the case of drawing rights, the corresponding amounts or capacities are attributed to the owner of the drawing rights provided he decides on the use and output of the power plant and bears the risks and rewards of marketing the electricity[4]. Only those volumes of electricity will be considered that are fed into the general supply grid.

[3] Cf. Bundeskartellamt, decision of 08/12/2011, file reference B8-94/11, RWE/Stadtwerke Unna, para. 22 ff.

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

In other words traction current and electricity for own consumption (which is not fed into the grid) do not belong to the market for the first-time sale of electricity. The Bundeskartellamt defines the geographic market as a joint market for Germany and Austria. The main reasons for this definition are that there are no network bottlenecks at the interconnections between the two countries and that there is a common price zone for German-Austrian electricity wholesale trading. These conditions do not exist in any other neighbouring country of Germany[5].

For this year's Monitoring Report, data on the electricity capacities and volumes generated by the four strongest companies (EnBW, E.ON, RWE and Vattenfall) was additionally collected. Data on the overall market was derived from a survey of producers undertaken as part of the energy monitoring activities. In addition, the Austrian energy regulator E-Control has provided aggregate data for Austria. The market definition applied to the market for the first-time sale of electricity leads to different results in the calculation of market shares than the "dominance method" has rendered in previous years. Differences exist in particular because the calculation under the dominance method did not include electricity purchase rights and electricity generated in Austria. The values calculated for 2013 are therefore not directly comparable to the values of previous years which were calculated on the basis of the dominance method. However, the values obtained in a Bundeskartellamt merger control proceeding in 2010 can alternatively be used for a comparison with the 2013 values[6]. The survey produced the following results:

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

[6] Cf. Bundeskartellamt, decision of 8 December 2011, file reference B8-94/11, RWE/Stadtwerke Unna, para. 42.

Electricity volumes generated by the four largest German electricity producers in 2010 and 2013 based on the definition of the market for the first-time sale of electricity

	Germany + Austria 2010		Germany + Austria 2013		Germany 2010		Germany 2013	
	GWh	**Share**	**GWh**	**Share**	**GWh**	**Share**	**GWh**	**Share**
RWE	163,700	31%	138,900	29%	160,600	36%	135,500	32%
E.ON	82,900	16%	51,700	11%	82,700	18%	51,300	12%
Vattenfall	73,500	14%	77,100	16%	73,500	16%	77,100	18%
EnBW	60,000	12%	50,600	11%	59,900	13%	50,600	12%
CR 4		**73%**		**67%**		**84%**		**74%**
Other companies	141,300	27%	157,400	33%	73,700	16%	113,400	26%
Total net electricity generation	521,500	100%	475,600	100%	450,400	100%	427,800	100%

Data are rounded. Data for 2010: Bundeskartellamt, decision of 08.12.2011, file reference B8-94/11, RWE/Stadtwerke Unna, para. 42. Data for 2013: Survey for the purpose of the Monitoring Report. Data on E.ON only include power plants with a nominal capacity of 10 MW or more. Data on EnBW include electricity which is directly marketed under the EEG.

Table 5: Electricity volumes generated by the four largest German electricity producers in 2010 and 2013 based on the definition of the market for the first-time sale of electricity

The aggregate market share of the four strongest companies (CR 4) on the market for the first-time sale of electricity amounted to 67 per cent in 2013. This corresponds to a decrease of 6 per cent compared to 2010. In particular the increased feed-in of electricity under the EEG has led to a decrease in conventional market volumes of 9 per cent for the same period. Correspondingly, the electricity volume generated by the four strongest companies has decreased by a total of 16 per cent.

The decrease in market concentration is largely a consequence of E.ON's loss of market shares. The volume of electricity generated by E.ON fell by 38 per cent, significantly more than the 9 per cent fall in overall market volume. Of the four strongest companies only Vattenfall was able to achieve market share increases between 2010 and 2013. When assessing the data of the individual companies one has to bear in mind that the indicated volumes of generated electricity (and, consequently, the indicated market shares) are slightly overstated in the case of EnBW and slightly understated in the case of E.ON. The data on EnBW also contain quantities that are directly marketed and subject to compensation under the EEG (which usually do not belong to the market for the first-time sale of electricity), while the data an E.ON do not contain generation volumes or capacities of power plants with a nominal capacity of below 10 MW.

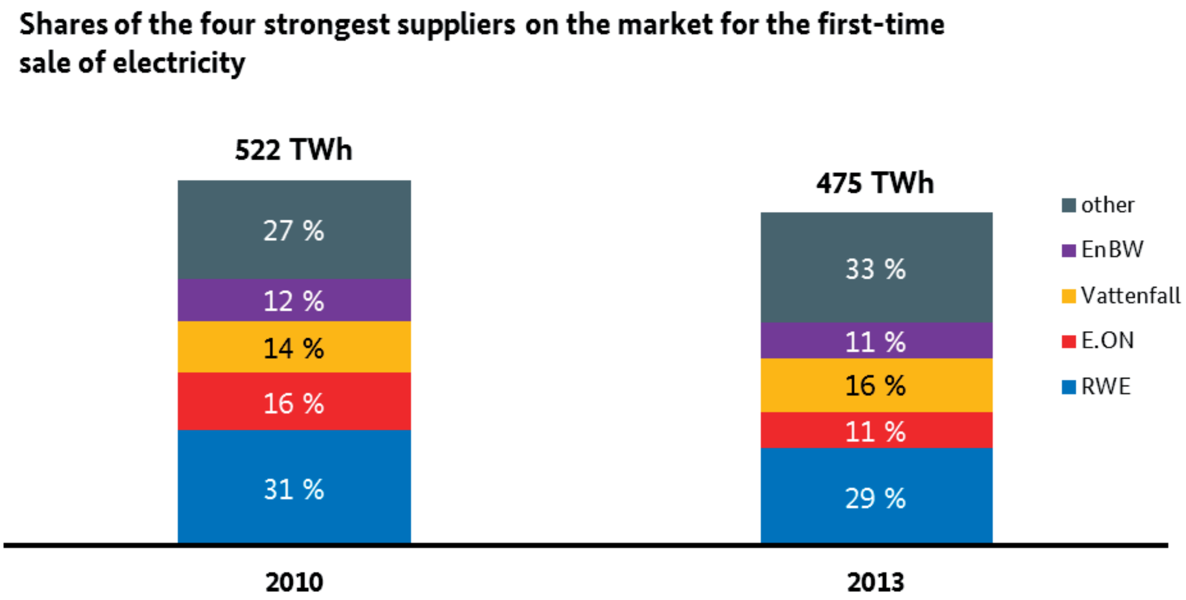

Figure 4: Shares of the four strongest suppliers on the market for the first-time sale of electricity in 2010 and 2013

The decline in market shares of the four strongest electricity producers is also reflected in the power plant capacities. The companies' share of Germany-wide generation capacities (without EEG capacities and without capacities not connected to the general supply grid) fell from 77 per cent in 2010 to 68 per cent in 2013. The four electricity companies have only low capacities in Austria. Including generation capacities in Austria, their share of overall capacity in 2013 amounted to around 59 per cent. As is the case with the generation volumes, the reduction in shares is principally due to E.ON's sunk capacity. Almost 7 per cent of the 9 per cent decline in the Germany-wide share of the four companies is attributed to E.ON.

Generation capacities of the four largest German electricity producers in 2010 and 2013 based on the definition of the market for the first-time sale of electricity

	Germany 2010		Germany 2013		Germany + Austria 2013	
	MW	**Share**	**MW**	**Share**	**MW**	**Share**
RWE	33,900	31%	30,500	29%	31,700	26%
E.ON	19,800	18%	11,700	11%	11,900	10%
Vattenfall	16,700	15%	15,800	15%	15,800	13%
EnBW	14,100	13%	12,200	12%	12,200	10%
CR 4		**77%**		**68%**		**59%**
Other companies	25,500	23%	33,600	32%	50,100	41%
Total net nominal generation capacity	109,900	100%	103,900	100%	121,600	100%

Data are rounded. Data for 2010: Bundeskartellamt, decision of 8.12.2011, RWE/Stadtwerke Unna, para. 42. Data for 2013: Survey for the purpose of the Monitoring Report. Data on E.ON only includes plants with a nominal capacity of 10 MW or more.

Table 6: Generation capacities of the four largest German electricity producers in 2010 and 2013 based on the definition of the market for the first-time sale of electricity

The market shares of the four strongest electricity producers established in the data survey indicate a major decline in market concentration on the market for the first-time sale of electricity in comparison to 2010. Nonetheless with a CR4 concentration ratio of 67 per cent, the market is still highly concentrated. Apart from the decline in market shares, other factors have led to a downward trend in market power. Currently there are more generation capacities Germany-wide and European-wide than are required to cover demand. Improved possibilities for importing electricity as a consequence of increased market coupling (see section I.F.) can help to limit the companies' scope of action on the market for the first-time sale of electricity. In addition, an increased share of the demand for electricity is covered with the feed-in of renewable energy. These additional aspects are not reflected in the market shares illustrated but would be taken into consideration in an extensive analysis of market power - in particular in a residual supply analysis.

3.2 Electricity retail markets

In the electricity retail markets the Bundeskartellamt differentiates between customers with metered load profiles and customers with standard load profiles. Metered load profile customers are customers whose electricity consumption is determined on the basis of a recording load profile measurement. These are generally industrial or large-scale commercial customers. Standard load profile customers are consumers with relatively low levels of consumption. These are usually household customers and smaller commercial customers. In the case of these customers a standard load profile is assumed based on the distribution of their electricity consumption over specific time intervals. In recent cases the Bundeskartellamt has defined a Germany-wide market for the supply of metered load profile customers with electricity as well as a Germany-wide market for the supply of standard load profile customers with electricity on the basis of special contracts. The supply of standard load profile customers with basic supply contracts constitutes a separate product market which in the most recent cases has been defined according to the respective network area[7].

In energy monitoring the sales volumes of the individual suppliers (legal persons) are collected as national total values. In the data survey a differentiation is made in sales to standard load profile customers between basic supply and supply on the basis of a special contract. The following analysis is based on data provided by around 1,160 electricity providers (legal persons). In the reporting year 2013 these companies sold Germany-wide a total of approx. 281 TWh of electricity to metered load profile customers, 120 TWh to standard load profile customers with special contracts and 48 TWh to standard load profile customers with basic supply contracts.

Based on the data provided by the individual companies it was determined which sales volumes are attributed to the four strongest companies. The aggregate sales volumes were attributed to the four strongest companies with the help of the "dominance method" according to the rules illustrated above. This method provides sufficiently exact results for the purposes of this analysis. In interpreting the percentage shares it should be borne in mind that the monitoring survey of the electricity suppliers does not cover the entire market. The percentage shares therefore only approximately reflect the actual market shares.

In 2013 the four strongest companies sold a total of approx. 95 TWh on the market for the supply of electricity to metered load profile customers. The aggregate market share of the four companies (CR 4) accordingly amounts to around 34 percent on the Germany-wide metered load profile customer market. This value is clearly below the statutory thresholds for the presumption of a dominant position (Section 18 (4 and 6) GWB). Also in view of the fact that meanwhile there is a high level of liquidity on the electricity wholesale markets (see section I.G on page 108ff) it can be assumed that there is now no dominant supplier on the market for the supply of metered load profile customers.

In 2013 the total sales of the four strongest companies on the market for the supply of standard load profile customers with special contracts amounted to approx. 50 TWh. The aggregated market share of the four companies (CR 4) on this market therefore amounts to around 42 per cent. On the basis of the monitoring data also the shares of sales to all standard load profile customers, i.e. including special contract and basic supply customers, can be calculated. However, the total values thus determined do not correspond with the Bundeskartellamt's market definition. They only represent the size of the shares of the strongest companies in the Germany-wide sale of electricity to all standard load profile customers. This calculation based on the supply of electricity to all standard load profile customers does not produce a different result: The volume of electricity supplied by the four strongest companies amounts to approx. 72 TWh, which corresponds to a CR 4 of 43 per cent.

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

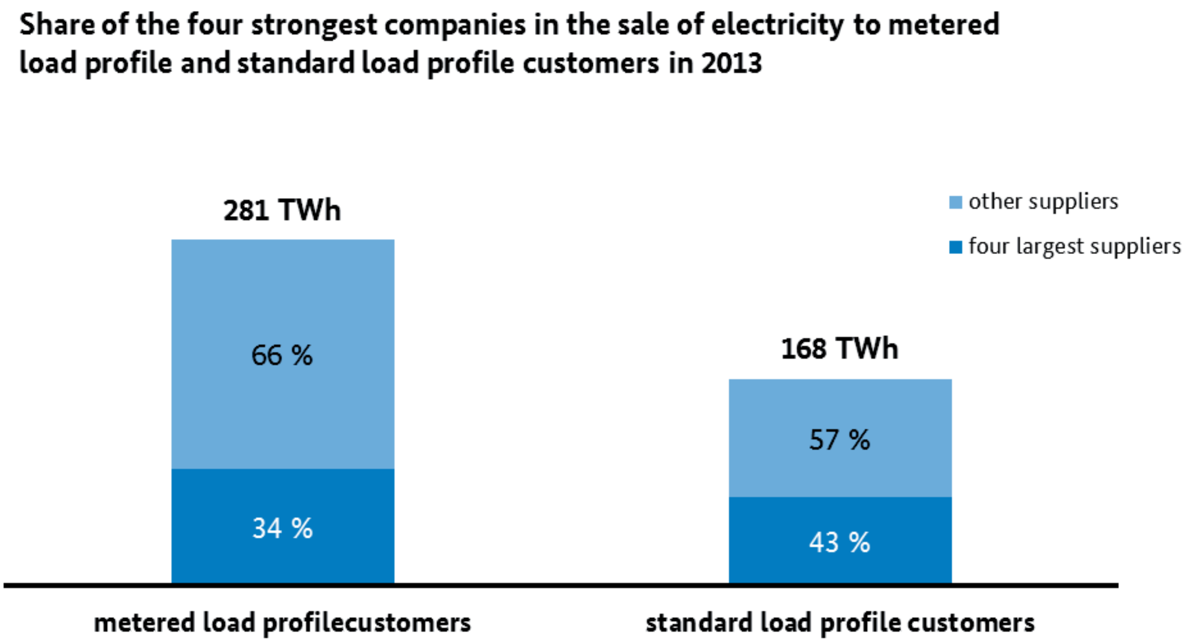

Figure 5: Share of the four strongest companies in the sale of electricity to metered load profile and standard load profile customers in 2013

B Generation and security of supply

1. Generation

1.1 Existing capacity and structure of the generation sector

In 2013, the year under review, power generation was characterised by further growth in renewables. Solar energy grew by 3.3 GW and onshore wind capacity by 2.9 GW. There was also a marked increase in natural gas and hard coal capacity, which rose by 1.0 GW and 0.8 GW respectively. Altogether, growth in generating facilities using renewable energy sources amounted to 6.7 GW and in facilities using non-renewable resources 1.6 GW. The total (net) installed generation capacity thus rose by 8.4 GW from 179.7 GW (31 December 2012) to 188.1 GW (31 December 2013)[8]. As of 31 December 2013, non-renewable and renewable energy sources accounted for a total of 105.0 GW and 83.1 GW respectively.

[8] Capacities (pumped storage, hydropower) feeding into the German grid from Austria, Luxembourg and Switzerland are also included in the figures.

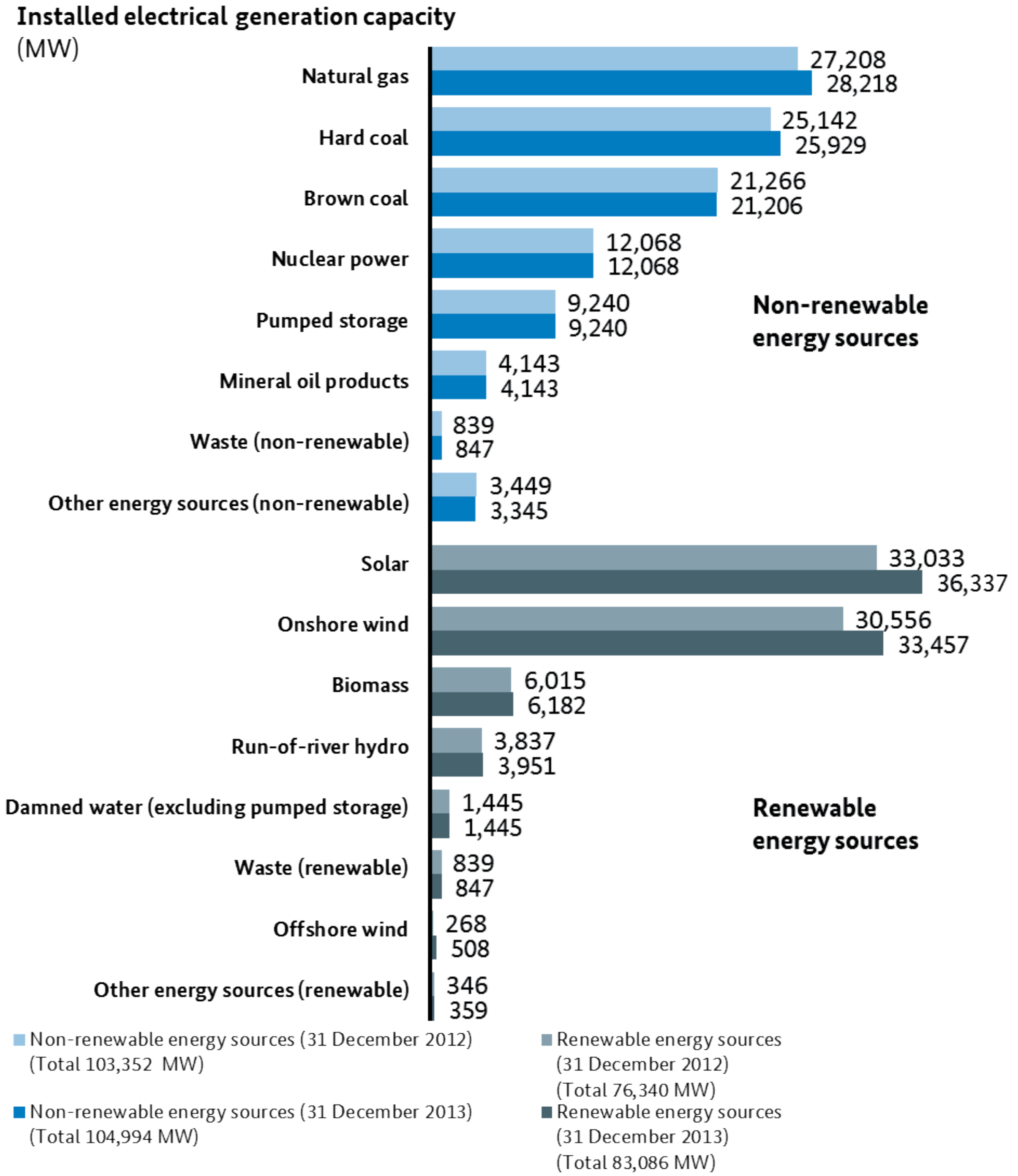

Figure 6: Installed electrical generation capacity (net nominal capacity)
(Correct as of 31 December 2012/31 December 2013)

According to the figures from October 2014 and August 2014 (solar), non-renewable and renewable energy sources accounted for a total of 107.1 GW and 87.0 GW respectively. The growth in non-renewable energy since 31 December 2013 is a result of the increase of 1.9 GW in hard coal capacity. In regard to renewables, solar capacity grew by 1.8 GW and onshore wind by 1.6 GW.

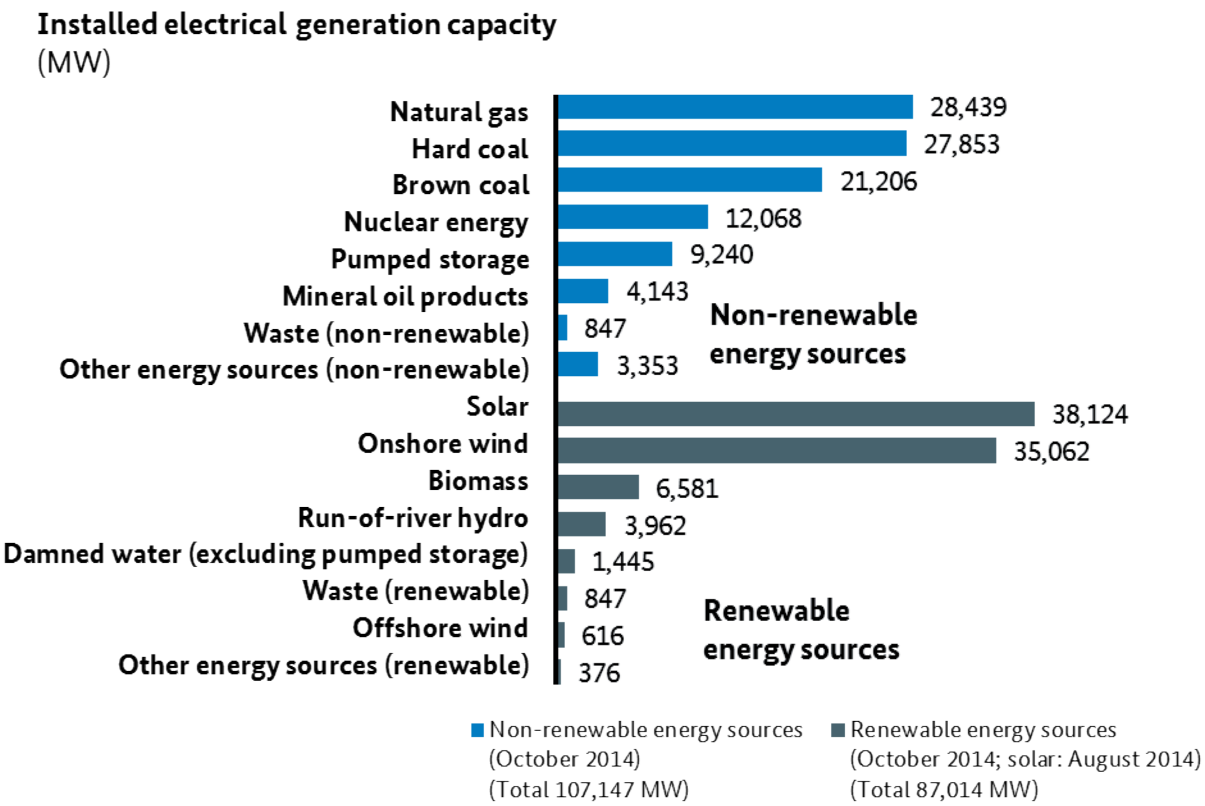

Figure 7: Installed electrical generation capacity (net nominal capacity)
(Correct as of October 2014 and August 2014 (solar))

The following figure shows the location of the installed generation capacity using renewable and non-renewable energy sources in each federal state (excluding capacities feeding into the German grid from Austria, Luxembourg and Switzerland).

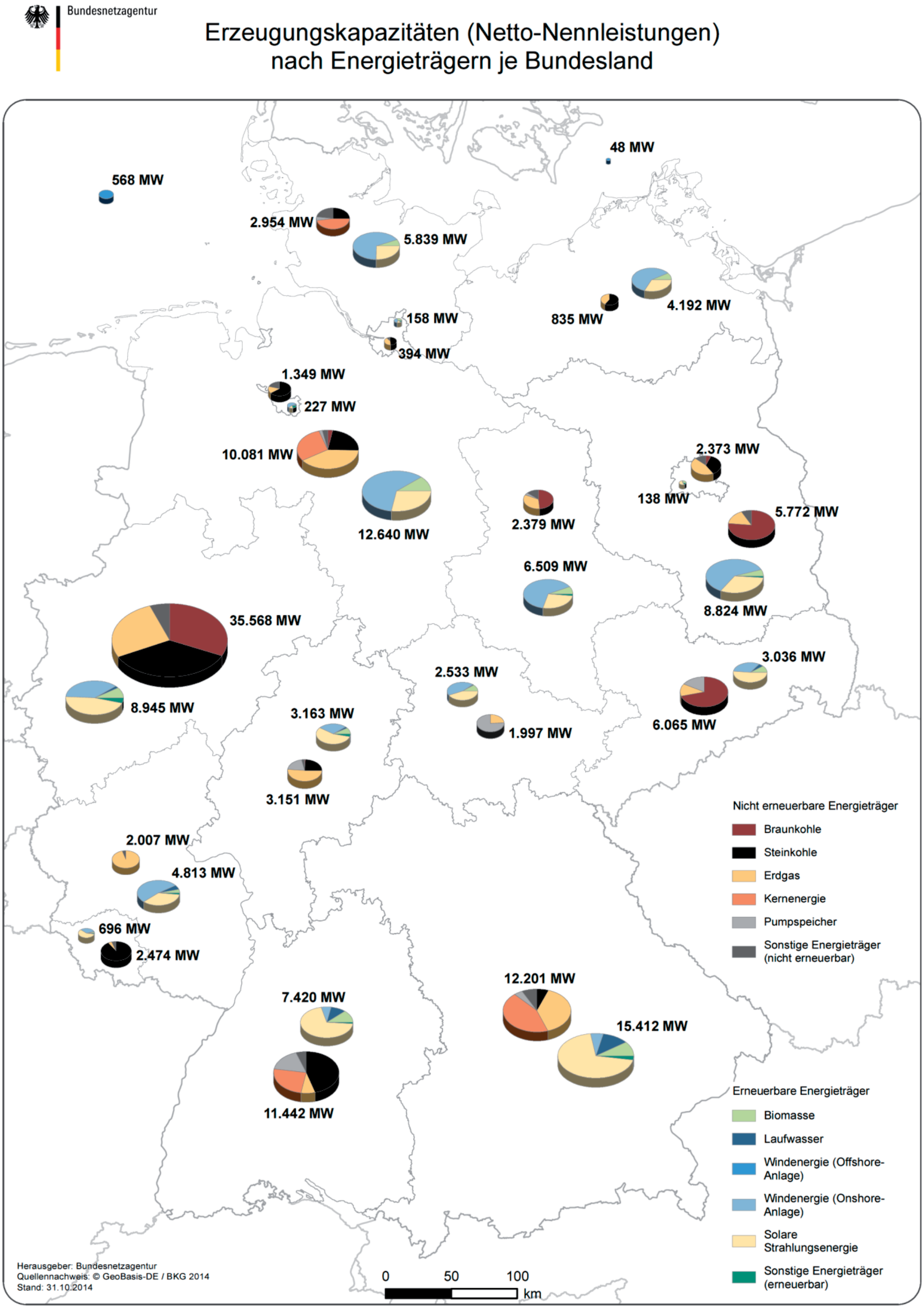

Figure 8: Generation capacity (net nominal capacity) by energy source in each federal state (Correct as of October 2014 and August 2014 (solar))

The total generation capacity of 107.1 GW using non-renewable energy sources (as of October 2014) can be divided between the power plants as follows:

- 99.8 GW: power plants in operation;

- 1.5 GW: power plants temporarily not in operation (eg owing to repairs following damage) or with restricted operation;

- 2.2 GW: reserve power plants, ie plants operated only at the TSOs' request to ensure security of supply;

- 3.6 GW: power plants temporarily closed.

The majority of the plants temporarily closed are natural gas power plants: 3.0 GW of the total capacity of 3.6 GW is accounted for by gas-fired plants. The reserve power plant capacity comprises 1.4 GW of natural gas, 0.4 GW of mineral oil product and 0.4 GW of hard coal plant capacity. The following figure shows the location of Germany's reserve power plants and the plants temporarily closed.

An additional 2.1 GW of plant was temporarily mothballed in summer 2014; these plants are closed during the summer season and fired up again afterwards. The majority of this plant capacity – 1.7 GW of the total of 2.1 GW – is accounted for by gas-fired power plants.

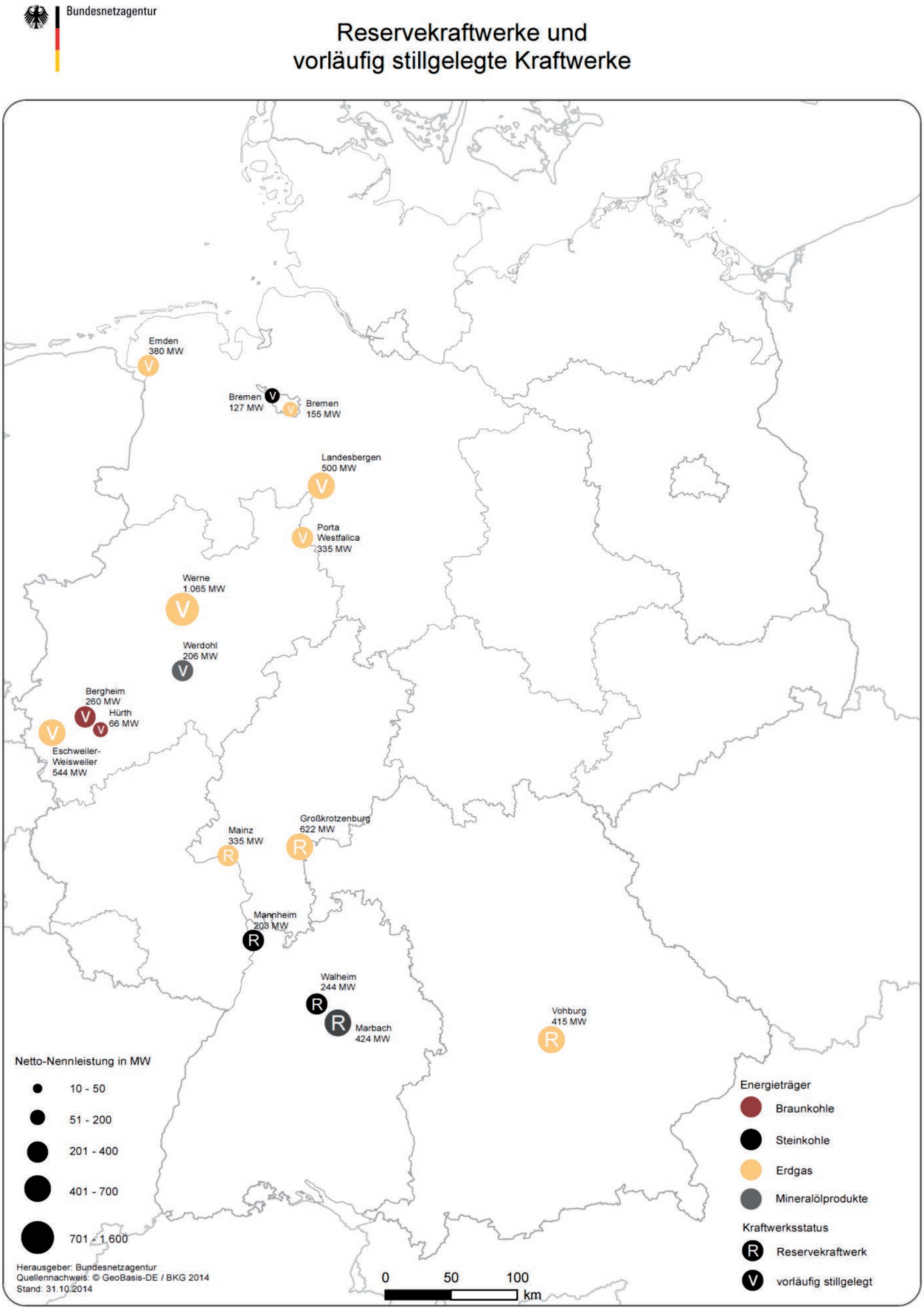

Figure 9: Reserve power plants and plants temporarily closed (net nominal capacity)
(Correct as of October 2014)

Non-renewable electricity generation in 2013 was characterised by a further increase in the production of electricity from coal and a continued decrease in the volume produced using natural gas. The volume generated using brown coal increased by 7.2 TWh and using hard coal by 6.0 TWh. By contrast, there was a decrease in the volume of electricity produced using natural gas and nuclear power of 8.3 TWh and 2.1 TWh respectively. Altogether, non-renewable electricity generation increased by 5.4 TWh from 439.1 TWh in 2012 to 444.5 TWh in 2013.

The volume of electricity produced from renewable energy sources increased by 8.2 TWh from 138.1 TWh in 2012 to 146.3 TWh in 2013. The biggest growth was in electricity generation by solar power, which rose by 3.5 TWh.

The net total volume of electricity generated in 2013 was 590.8 TWh, 13.6 TWh more than the total of 577.2 TWh generated in 2012.

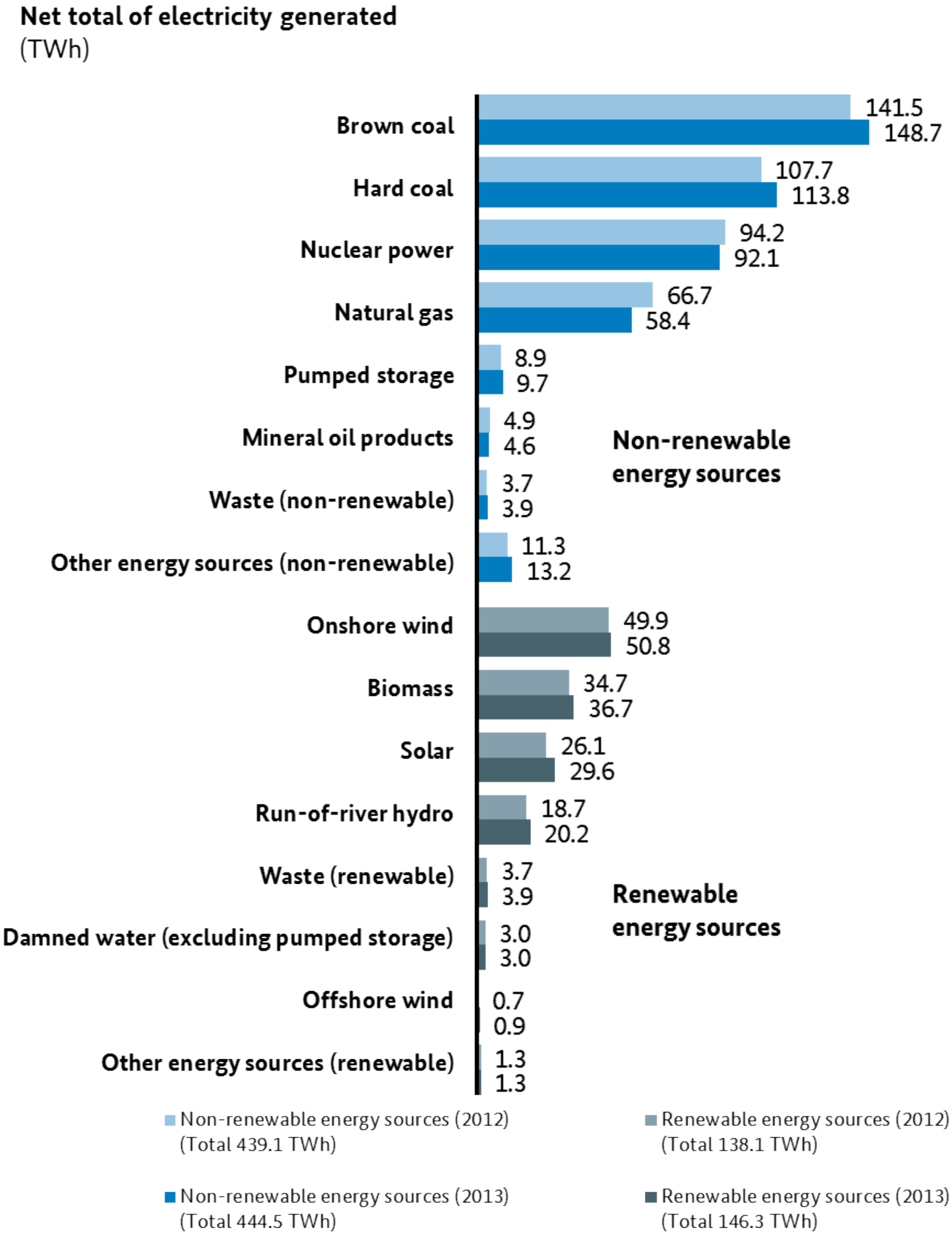

Figure 10: Net total of electricity generated in 2012 and 2013

1.2 Expected growth and decline in generation capacity

The following analysis of the development of non-volatile energy sources (ie excluding solar, hydro and wind) that are of importance to the security of supply takes account of generating facilities currently under construction only. The analysis takes account of the companies' final closure plans and takes as a starting point for 2014 the plant capacity as of 31 October 2014[9].

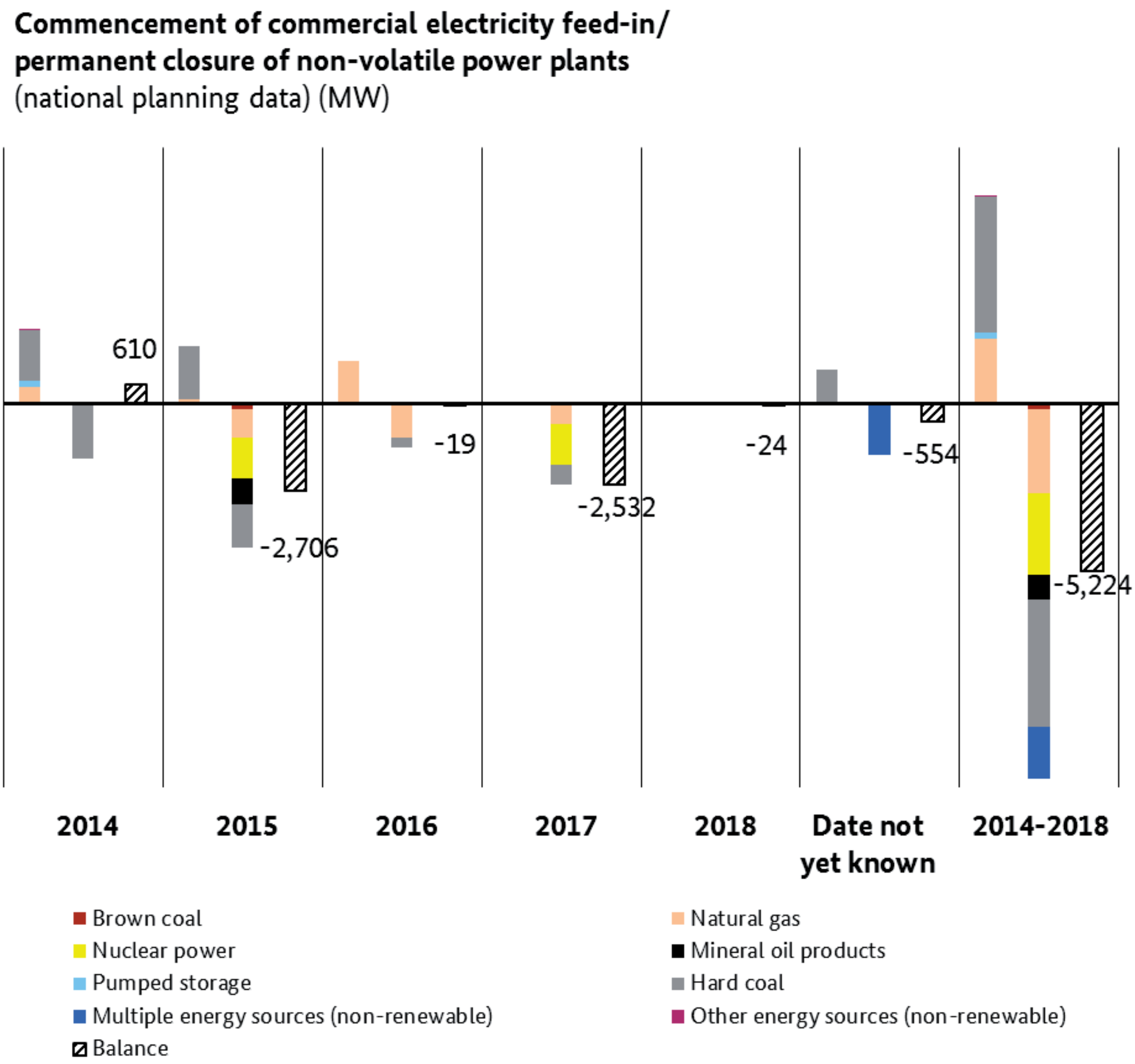

Figure 11: ommencement of commercial electricity feed-in/permanent closure of non-volatile power plants (national planning data for net nominal capacity for 2014-2018)
(Correct as of 31 October 2014)

Non-volatile generation capacity totalling 6,523 MW is currently under construction across the country and will likely be completed by 2016 (it is not yet known when the Datteln 4 hard-coal fired power plant will start generation). By contrast, the power plant operators plan to permanently close plant comprising 11,747 MW (including 6,835 MW in southern Germany) by 2018. As of 31 October 2014, however, the operators had formally notified the Bundesnetzagentur in accordance with section 13a of the Energy Act (EnWG) of the

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[9] Five plants with a total capacity of 668 MW were marked for final closure in early July 2014. The facilities were designated by the TSOs as systemically relevant as defined by section 13a EnWG and the designations were approved by the Bundesnetzagentur. These facilities are included in the 2.2 GW of reserve plant capacity in I.B.1.1 and are therefore not taken into account in the following analysis.

planned final closure of facilities with a total capacity of only 6,875 MW (including 3,869 MW in southern Germany). Facilities may only be shut down after formal notification to the Bundesnetzagentur and after a certain period of time, usually twelve months. Should the operators give formal notification of the remaining facilities they plan to close, this could result in a negative balance as of 31 December 2018 of -5,224 MW nationwide and -5,717 MW in southern Germany. Moreover, it should be noted that four facilities in southern Germany with a total capacity of 992 MW that were scheduled for closure from November 2014 onwards have been rated by the TSOs as systemically relevant as defined by section 13a EnWG; these ratings have been approved by the Bundesnetzagentur, hence the facilities will not be shut down as planned, reducing the negative balance by 992 MW.

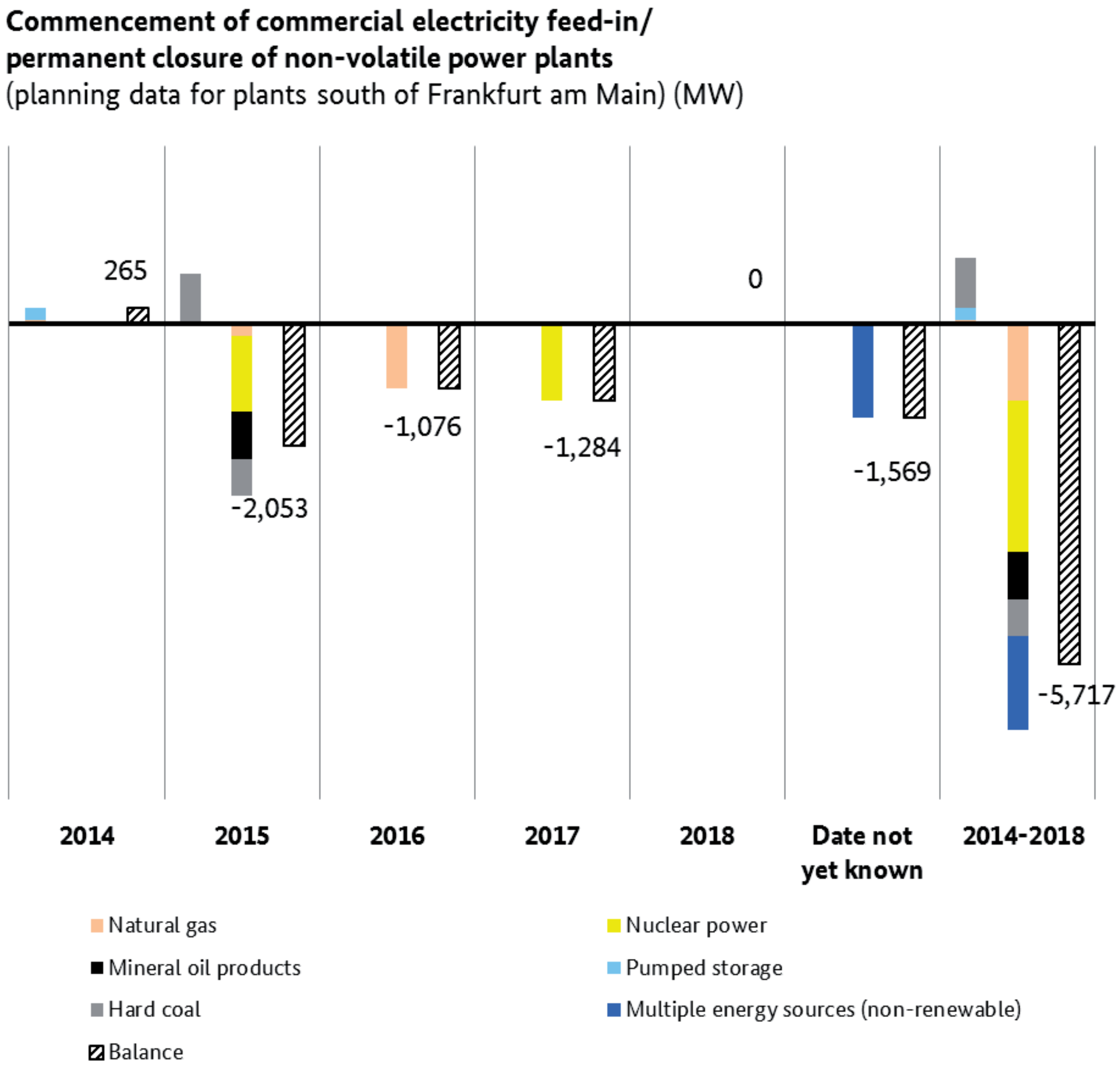

Figure 12: Commencement of commercial electricity feed-in/permanent closure of non-volatile power plants (planning data for net nominal capacity for plants in and south of Frankfurt am Main for 2014-2018) (Correct as of 31 October 2014)

The following figure shows the location of the non-volatile power plants under construction in Germany and those marked by the operators for final closure (information correct as of October 2014). Plants that are marked for closure and for which the information is confidential have not been individually specified but have been grouped together as either north or south of Frankfurt am Main.

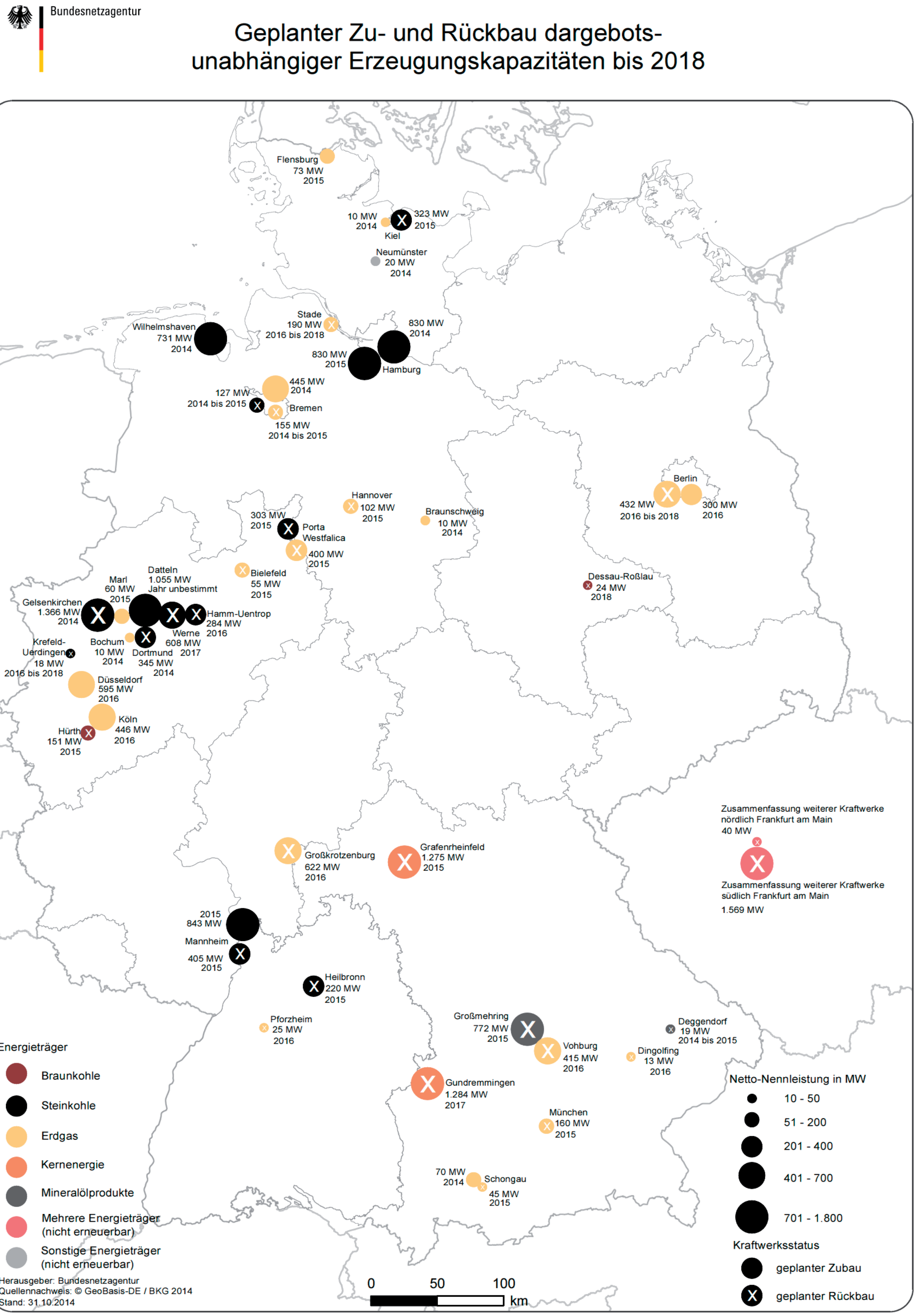

Figure 13: Planned increase and decrease in non-volatile generation capacity up to 2018 (net nominal capacity) (Correct as of October 2014)

1.3 Electricity generation eligible for payments under the Renewable Energy Sources Act (EEG)

The total installed capacity of installations in Germany eligible for payments under the EEG as of 31 December 2013 was approximately 78.4 GW (31 December 2012: around 71.7 GW). This represents an increase in 2013 in the installed capacity of all installations eligible for EEG payments of some 6.7 GW, corresponding to a relative growth of around 9 per cent in one year.

The installed EEG capacity figures are taken from the Bundesnetzagentur's power plant list as published on the internet[10].

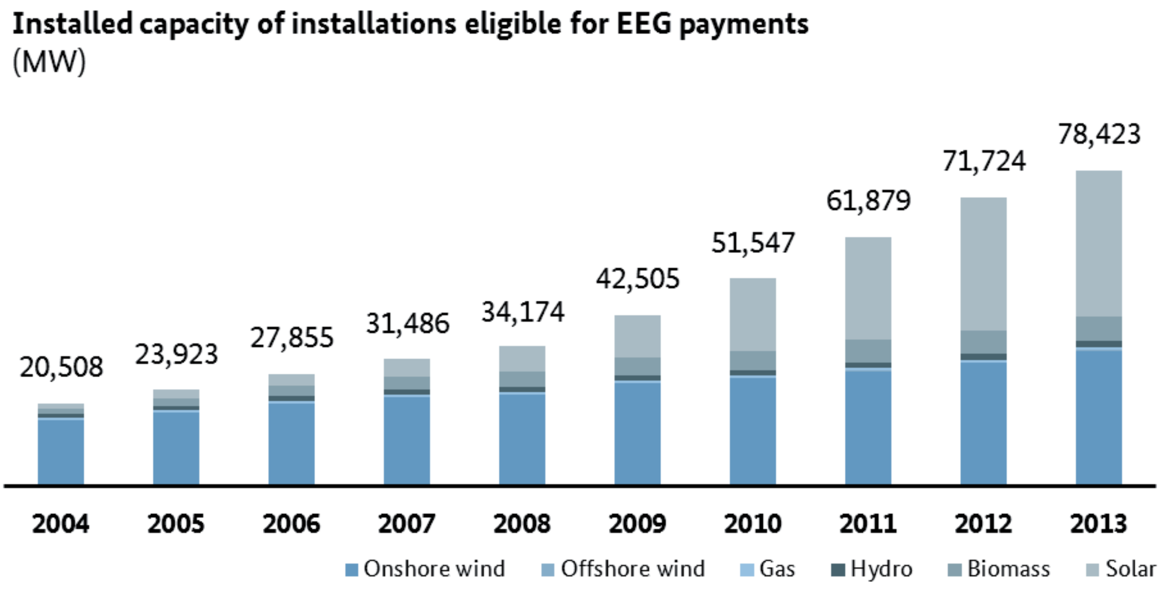

Figure 14: Installed capacity of installations eligible for EEG payments from 2004 to 2013

[10] Bundesnetzagentur List of Power Plants
http://www.bundesnetzagentur.de/cln_1411/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Versorgungssicherheit/Erzeugungskapazitaeten/Kraftwerksliste/kraftwerksliste-node.html

Installed capacity of installations eligible for EEG payments by energy source

	Total as of 31 December 2013	Total as of 31 December 2012	Increase/decrease compared to 2012
	(MW)	(MW)	(%)
Hydropower	1,487	1,411	5.4
Gas[1]	551	551	0.0
Biomass	6,052	5,885	2.8
Geothermal	31	19	63.2
Onshore wind	33,457	30,556	9.5
Offshore wind	508	268	89.6
Solar	36,337	33,033	10.0
Total	78,423	71,724	9.3

[1] Landfill, sewage and mine gas

Table 7: Installed capacity of installations eligible for EEG payments by energy source (as of 31 December 2013/31 December 2012)

In 2013, the year under review, there was another increase in the installed capacity of solar installations, albeit smaller than between 2010 and 2012. Facilities with a total capacity of approximately 3.3 GW were newly installed (2012: approximately 7.6 GW), which amounts to an increase of around 10.0 per cent for solar installations in 2013. The installed capacity of onshore wind plants increased by approximately 2.9 GW in 2013, corresponding to a growth rate of 9.5 per cent. The increase in the capacity of offshore wind facilities was around 240 MW, representing a growth rate of 89.6 per cent.

The energy produced from renewables and fed into the public electricity supply system is eligible for payments from the DSOs; the rates determined in the EEG vary according to the energy source. Payments are made in the year the installations become operational and for the subsequent 20 years. The rate paid remains the same during the whole period. The following table contains absolute figures and the change relative to 2012. The figures are taken from the TSOs' certified annual financial statements.

Total energy feed-in remunerated under the EEG and minimum amount paid to installation operators in 2013 by energy source

Energy source		Total 2013	Change compared to 2012 (%)
Hydropower	GWh	3,007.0	10.4
	€m	302.7	11.9
Gas[1]	GWh	19,551.7	-19.7
	€m	4,059.2	-16.7
Biomass	GWh	528.9	-8.6
	€m	37.9	-9.4
Geothermal	GWh	68.2	168.8
	€m	16.1	190.8
Onshore wind	GWh	7,514.1	-47.5
	€m	687.5	-47.6
Offshore wind	GWh	0.0	-100.0
	€m	0.0	-100.0
Solar	GWh	25,258.7	3.7
	€m	8,587.4 [2]	-3.6
Total	GWh	55,928.6	-15.8
	€m	13,690.8	-11.2

[1] Landfill, sewage and mine gas

[2] Including payments for solar electricity used by the installation owners themselves under section 33(2) EEG 2009. In 2013 a total of some €111m was paid for 821 GWh. The bonus scheme for solar electricity used by the installation owners themselves was discontinued as from 1 April 2012 as a result of new regulations for renewable energy and was excluded from the EEG. Solar installations
eligible before the scheme was discontinued will still receive the bonus for the whole 20-year period.

Table 8: Total energy feed-in remunerated under the EEG and minimum amount paid to installation operators in 2013 by energy source

In 2013, the total annual energy feed-in from installations receiving fixed EEG payments was 55,929 GWh (2012: 66,434 GWh); the minimum amount paid to the installation operators totalled €13,691m (2012: €15,416m). The downward trend does not mean that the volume of electricity generated and fed in by EEG installations was lower: in fact it increased by 6.2 per cent to a total of 124,872 GWh. Rather, the decrease is due to the switch from fixed EEG payments to direct selling (see below).

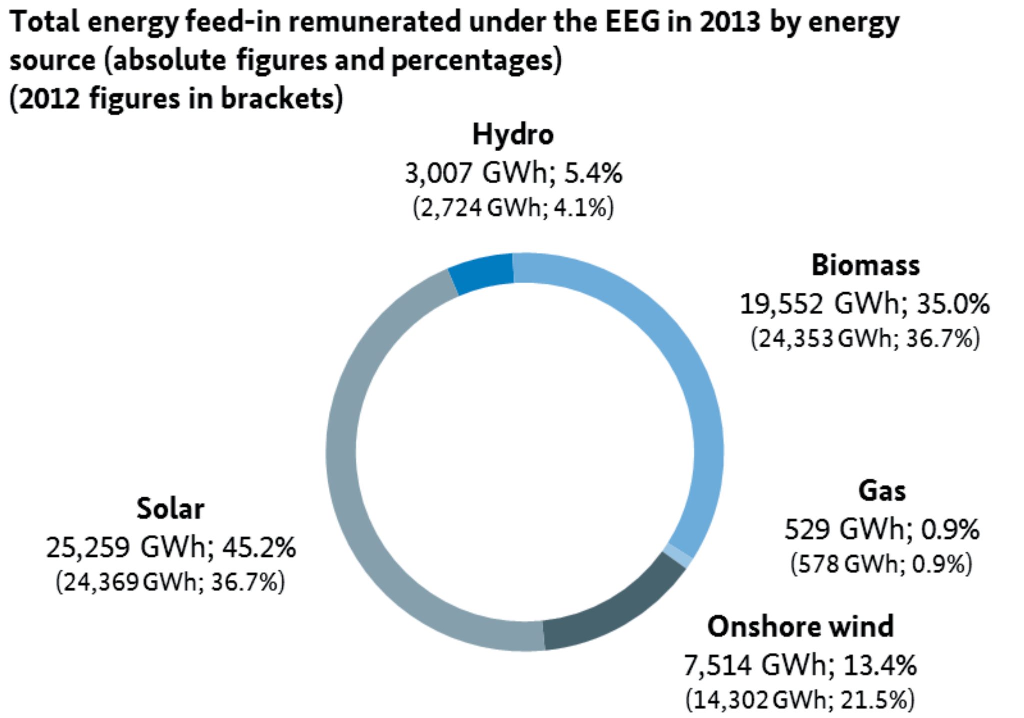

Figure 15: Total energy feed-in remunerated under the EEG in 2013 by energy source (absolute figures and percentages) (2012 figures in brackets) Geothermal energy is not included on account of its small share

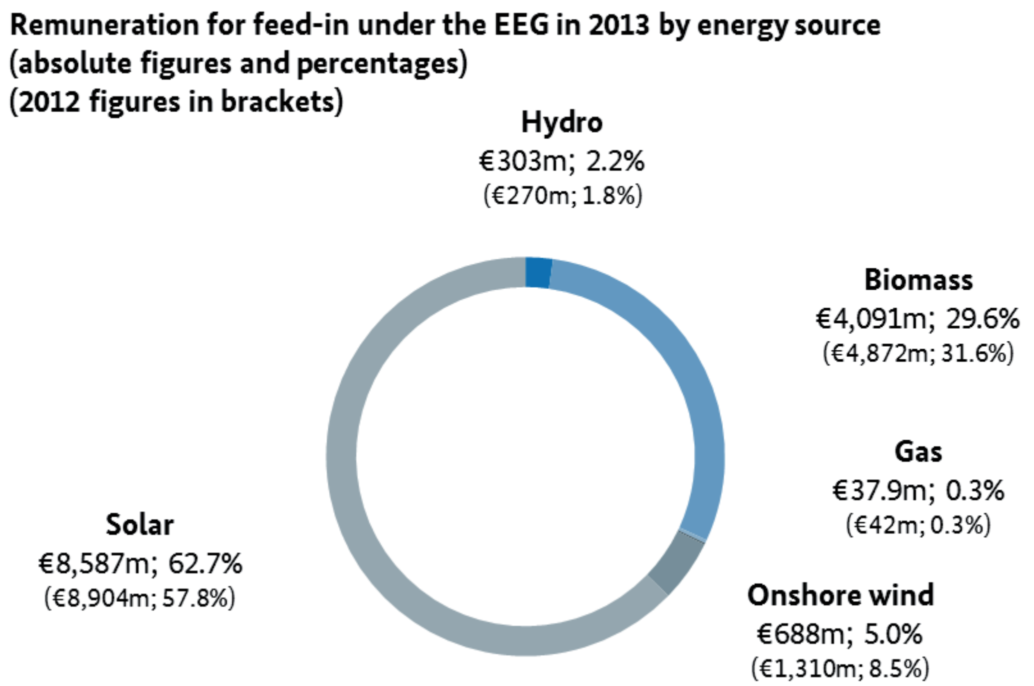

Figure 16: Remuneration for feed-in under the EEG in 2013 by energy source (absolute figures and percentages) (2012 figures in brackets) Geothermal energy is not included on account of its small share.

Solar energy continued to account for the largest share of EEG payments with 63 per cent and the largest share of annual energy feed-in at 25,259 GWh. Fixed EEG payments fell, however, from €8,856m in 2012 to €8,587m. This is due to the switch to direct selling for solar energy. There was relatively strong growth in geothermal capacity in 2013, although the share of the total annual energy feed-in remained small at 0.1 per cent.

1.4 Direct selling of electricity generated from renewable energy sources

As an alternative to the system of fixed EEG remuneration, installation operators also have the option of selling the electricity they generate on their own (direct selling). Between 2009 and 2011 the operators were slow to take up this option. In 2012, the share of the total volume of renewable energy sold directly rose to 43 per cent, with a further increase in 2013 to 55 per cent. 100 per cent of electricity from offshore wind and 85 per cent from onshore wind installations were sold directly.

Electricity from installations with fixed EEG remuneration and for direct selling in 2013

	Total (GWh)	Fixed EEG remuneration (GWh)	Direct selling (GWh)	Volume sold directly as a percentage of total volume (%)
Hydropower	6,265	3,007	3,258	52.0
Gas[1]	1,776	529	1,247	70.2
Biomass	36,258	19,552	16,707	46.1
Geothermal	80	68	12	14.6
Onshore wind	50,803	7,514	43,289	85.2
Offshore wind	905	0	905	100.0
Solar	28,785	25,259	3,526	12.3
Total	124,872	55,929	68,943	55.2

[1] Landfill, sewage and mine gas

Table 9: Electricity from installations with fixed EEG remuneration and for direct selling in 2013

Installation operators were able to choose between three different forms as provided for by section 33b EEG 2012: direct selling to claim a market premium, to claim a reduction in the EEG surcharge, or other direct selling. The dominant energy source in the area of direct selling in 2013 was onshore wind power, with a share of 63 per cent. The share accounted for by biomass increased further from 19 per cent in 2012 to 24 per cent.

Volume of electricity sold directly under section 33b EEG 2012 in 2013

Energy source	Market premium (GWh)	Green electricity privilege (GWh)	Other direct selling (GWh)	Total volume sold directly (GWh)	Share of total volume sold directly (%)
Hydropower	2,440.0	755.6	62.1	3,257.7	4.7
Gas[1]	272.8	960.8	13.4	1,247.0	1.8
Biomass	16,644.4	62.1	0.2	16,706.7	24.2
Geothermal	11.6	0.0	0.0	11.6	<0,1
Onshore wind	41,844.5	1,259.5	184.6	43,288.6	62.8
Offshore wind	904.8	0.0	0.0	904.8	1.3
Solar	3,525.5	0.0	0.9	3,526.4	5.1
Total	65,643.7	3,038.0	261.2	68,942.8	100

[1] Landfill, sewage and mine gas

Table 10: Volume of electricity sold directly under section 33b EEG (2012) in 2013

The increase in the volume of electricity sold directly is due to the large number of installation operators opting for direct selling to claim a market premium. The market premiums paid to operators in 2013 totalled some €5,919.3m. Onshore wind and biomass accounted for the largest shares, with €2,827m (47.7 per cent) and €2,089m (35.2 per cent) respectively. The flexibility premiums paid in 2013 for biogas plants totalled €3.3m. Thus, the total paid in market and flexibility premiums in 2013 was €5,922.6m. The volumes sold directly to claim the green electricity privilege or through other forms of direct selling remained at a low level.

The share of electricity sold directly will continue to grow in the future. While the 2012 EEG legislation introduced direct selling as an additional, voluntary option, the 2014 regulations lay down the procedure as standard for all new installations above a certain capacity.

2. Security of supply

2.1 Measures to ensure security of supply

Reserve power plants

As a rule, the transmission system is subject to its greatest pressure during the winter months when high grid loads and strong winds with subsequent high input from wind power plants frequently appear together. Low temperatures and darker evenings contribute to relatively high loads. High wind infeed in northern Germany coinciding with unplanned plant outages in the south of the country place a considerable strain on the power lines. Should this result in excessive flows on the transmission lines and the technical limits being exceeded, those parts of the system that are overloaded would automatically switch off to avoid damage to the lines concerned. If one part shut down, the electricity would flow through the remaining parts of the system, in turn causing further parts to overload and automatically switch off. This would ultimately result in disruptions or interruptions to electricity supply.

To prevent such risks to the security of electricity supply from arising in the first place, the TSOs, in consultation with the Bundesnetzagentur, once more took appropriate precautionary measures last winter. To avoid overloading when demand and wind infeed are high, TSOs instruct certain power plants to adjust their input of electricity so as to only produce such flows in the grid that do not overload certain sections of the lines. This measure, known as "redispatch", involves a TSO instructing the power plants north of the overloaded sections to reduce their feed-in and those south of the overloaded sections to increase their feed-in to the same extent.

While there is a surplus of plant capacity in northern Germany, there is a deficit in secured capacity south of the critical sections of the grid, ie where feed-in needs to be increased as part of the redispatch measure. In particularly critical grid situations there is not enough plant capacity in southern Germany for the TSOs to implement redispatch measures. In light of this, the TSOs have, since winter 2011/2012, had to contract reserve capacity from plants in neighbouring countries to the south of Germany.

A particularly critical grid usage scenario is used to determine how much reserve plant is required. The scenario simulates the situation that would arise if different events that are particularly crucial to network security coincided. These events include strong winds in northern Germany and a correspondingly high wind infeed coinciding with a peak load in Germany and its direct neighbours. The scenario also assumes a series of unplanned power plant outages in southern Germany. The TSOs require a sufficient level of redispatch potential to maintain secure operation of the grid in such critical circumstances.

The TSOs and the Bundesnetzagentur have confirmed that a total reserve capacity of around 3,091 MW is needed for winter 2014/2015. Due to E.ON Kernkraft GmbH's planned phasing out of the Grafenrheinfeld nuclear power plant, additional reserve power plant capacity of 545 MW in excess of the 3,091 MW of demand already established for the 2014/15 winter will be required in the first quarter of 2015. The reserve capacity required for 2015/2016 – with the Grafenrheinfeld nuclear power plant going offline by the end of 2015 – amounts to 6,000 MW. In the 2017-2018 period, which will be marked by the shutdown of Gundremmingen B by 31 December 2017, the required reserve capacity will increase to 7,000 MW.

The main reserve power plants will be those in Germany which have been marked for closure but which have been designated systemically relevant by the TSOs and the Bundesnetzagentur and will thus remain on standby for use by the TSOs. The TSOs invited expressions of interest in accordance with section 4 of the Reserve Power Plant Ordinance (ResKV) for the remaining reserve capacity required in all three periods concerned. In this process, power plant operators are called on to submit offers to the TSOs regarding the use of their facilities as reserve power plants. The offers submitted comprised considerably more capacity than would actually have been required as reserve. After coordinating details with the Bundesnetzagentur, the TSOs sign contracts with power plant operators covering the three periods of time concerned. In return for payment, the power plant operators are obliged to keep their plants operational for the duration of the contract and to feed electricity into the grid when instructed to do so by the TSO. The offers selected were those that fulfilled the criteria of technical effectiveness, technical availability and cost efficiency to the highest degree. Of great practical significance here are the foreign power plant operators, especially those from Austria, France and Italy, as without their plants it would be impossible to meet the reserve capacity requirements.

Last winter (2013/14) passed by without any situation arising that actually required reserve power plants to be used. The TSOs decide on the use of the reserve power plants on the basis of a forecast prepared on the previous day. The forecast itself is primarily based on assumptions on the expected weather conditions (wind infeed), load and plant availability.

The costs for domestic (section 13a EnWG) and foreign (section 5 ResKV) contracted reserve power plants for the 2013/14 winter amounted to €41m.

For the 2014/15 winter, the costs for domestic and foreign contracted reserve power plants amount to €78m. This amount would increase by the costs of the power fed in should reserve capacity actually be called upon from these power plants.

Avoiding power plant closures

On 20 December 2012 the Energy Act (EnWG) was supplemented by the new section 13a, requiring power plant operators to give notification of planned closures at least twelve months in advance. The plants concerned may not be shut down in the twelve months following notification. If the TSO responsible does not consider a plant to be systemically relevant, the operator may close the plant. Power plants rated by the Bundesnetzagentur at the TSOs' request as systemically relevant may not be shut down even after the twelve-month period. In this case, the plant is held as reserve for use when necessary by the TSO responsible to stabilise the system. The reserve plant operator is reimbursed the costs of keeping the plant on standby and generating electricity. The Bundesnetzagentur has received a total of 48 effective closure notifications (planned temporary and final closures) from plant operators (as of 12 November 2014). The plants to be closed together have a net nominal capacity of 12,814.9 MW.

Of the 48 facilities marked for closure, a total of 16 plants with a net nominal capacity of 4,763.5 MW have been notified for temporary closure to the Bundesnetzagentur in accordance with section 13a(1) EnWG. Facilities that are only to be closed temporarily are, by their legal definition in section 13a(1) third sentence EnWG, to be made operational and ready for redispatch procedures as instructed by the TSOs. In accordance with the legal regulations, no assessment is made by the Bundesnetzagentur to determine if a plant notified for "only" temporary closure is systemically relevant. Rather, only the TSOs' assessment of system relevance is decisive in this respect.

The Bundesnetzagentur is empowered on the basis of section 13a(2) EnWG to verify whether or not and to what extent facilities notified for final closure have been rightly designated as systemically relevant by the TSO responsible. Altogether 32 facilities with a total net nominal capacity of 8,051.4 MW have been notified for final closure. The TSOs have already rated eleven of these facilities, with a total net nominal capacity of 2,697.4 MW, as systemically relevant within the meaning of section 13a(2) EnWG. The TSOs have also designated 15 facilities, with a total net nominal capacity of 3,459 MW, as not systemically relevant within the meaning of section 13a(2) EnWG. The remaining six facilities, which have a total net nominal capacity of 1,895 MW, have not yet been rated. The Bundesnetzagentur has so far recognised nine facilities with a net nominal capacity of 1,660.4 MW as being system relevant under section 13a(2) EnWG.

The future shape of the electricity market

Future electricity markets must be designed so as to meet the three intrinsically linked energy policy aims of supply security, economic efficiency and environmental sustainability. The dynamic growth in renewables, nuclear power plant closures and the relocation of generation capacity present a significant challenge to balancing these aims.

From the Bundesnetzagentur's perspective, we need to take a close look to see whether and to what extent today's energy only market can guarantee supply security in the long term, that is create economic incentives to ensure the availability of sufficient capacity. The increasing number of plant closure notifications is indicative of a market shake-out to eliminate current surplus capacity, which is a normal market reaction. However, it is questionable whether operation of conventional plants will still be economically viable once the surplus capacity has been eliminated. It is for this very reason that the possibility of introducing a capacity allocation mechanism must be looked at. To be able to guarantee supply security in the transitional period as well, the Bundesnetzagentur would prefer to supplement the market for system balancing energy with a new product, namely standby capacity.

Irrespective of whether or not a capacity allocation mechanism is introduced, the existing balancing group system should be optimised to provide further incentives for an adequately secured balancing group. This would enable potential to be developed without any negative consequences.

2.2 Duties to report supply disruptions under section 52 EnWG

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

868 network operators reported some 179,000 interruptions in supply for 878 networks in 2013 for the calculation of the system average interruption duration index (SAIDI) for final consumers. The figure of 15.32 minutes calculated for the low and medium voltage levels is lower than the previous year's figure of 15.91 minutes and slightly higher than the 15.31 minutes for 2011, but is still considerably lower than the average of 16.92 minutes calculated for the preceding six years from 2006 to 2012. The quality of supply thus maintained a constant high level throughout 2013.

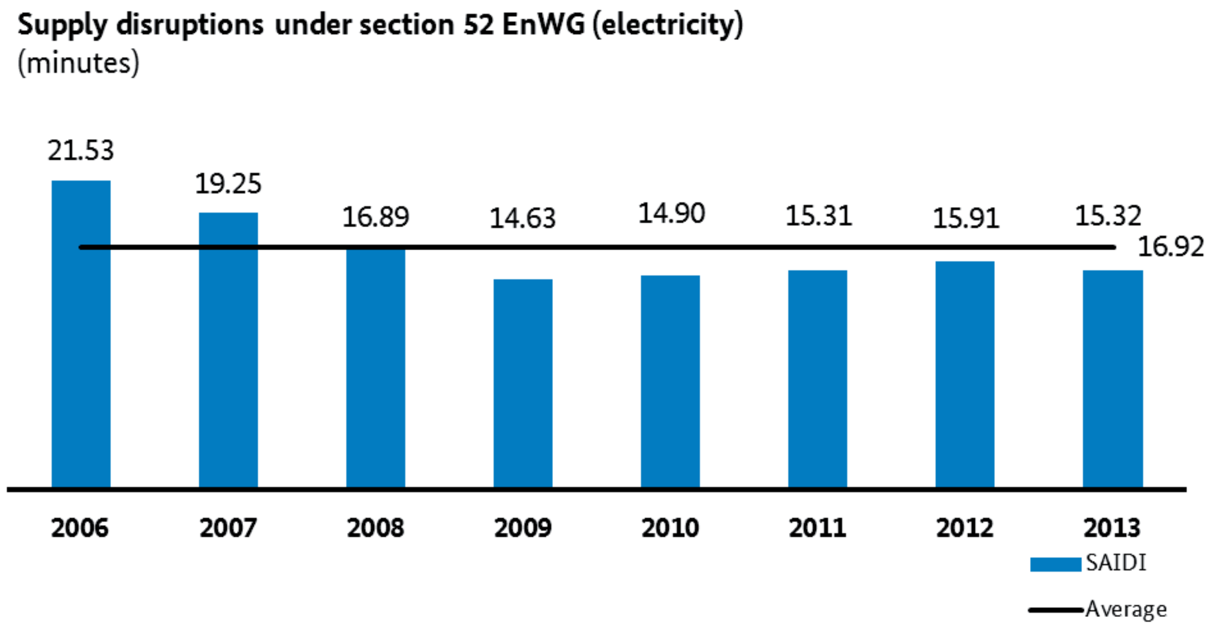

Figure 17: Supply disruptions under section 52 EnWG (electricity)

The slight decrease in the average interruption duration is mainly due to a decrease of 30 seconds from 13.35 minutes to 12.85 minutes at the medium voltage level. At the low voltage level, on the other hand, the average interruption duration decreased by only six seconds from 2.57 minutes to 2.47 minutes.

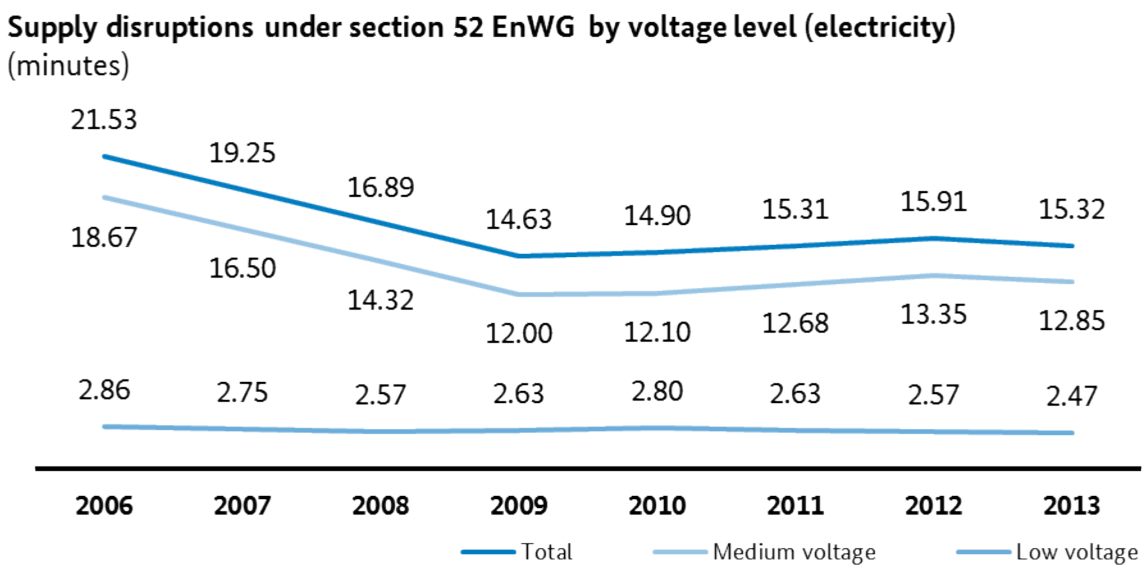

Figure 18: Supply disruptions under section 52 EnWG by voltage level (electricity)

A decisive factor in this improvement in quality of supply in 2013 from 2012 was the considerable decline in disruptions caused by third parties. Disruptions caused by third-party intervention are interruptions in supply resulting from people, animals, trees, diggers, cranes, vehicles or flying objects, for instance, touching or approaching live electrical components, as far as the disruption can be attributed to a third party. At the medium voltage level, by contrast, there was an increase for the third consecutive year in disruptions caused by ripple effects from other networks. Disruptions caused by ripple effects are defined by the Bundesnetzagentur as supply interruptions in a network caused by a disturbance in an upstream or downstream network or at the end customer's facility or by an interruption in supply at power plants feeding in electricity. There are however no grounds to believe that the Energiewende and the associated increase in decentralised power generation had a significant effect on the quality of energy supply in 2013.

The SAIDI value does not take into account planned interruptions, nor those which occur owing to force majeure, for instance natural disasters. Only unplanned interruptions caused by atmospheric effects, third-party intervention, ripple effects from other networks or other disturbances in the network operator's area are included in the calculations.

C Networks / Network expansion / Investments / Network tariffs

1. Networks / Network expansion / Investments

1.1 Status of network expansion

Progress on power line projects arising from the Power Grid Expansion Act 2009

The purpose of the Power Grid Expansion Act (EnLAG), which was passed in 2009, is to speed up the installation of extra-high voltage lines for expanded transmission networks.

The current amendment to this legislation specifies 23 projects which require urgent implementation in order to meet energy requirements.

The four German transmission system operators (TSOs), TenneT, 50Hertz, Amprion and TransnetBW, are responsible for planning, establishing and operating these projects. The relevant federal state authorities are responsible for conducting the applicable spatial planning and planning approval procedures for construction of a total of 1,876 new path kilometres. The current state of construction and planning work, as detailed in quarterly reports produced by the TSOs, is documented by the Bundesnetzagentur on its website www.netzausbau.de.

Current status

Of the total 1,887 kilometres of lines which are required – taking into account the third quarterly report for 2014 - 438 kilometres have so far been constructed. Around 50 per cent of the path kilometres built so far are 380 kV lines; all others are 220 kV lines or the section is being completed. The TSOs expect around 40 per cent of the kilometres of line provided for by the Power Grid Expansion Act (EnLAG) to be completed by 2016. To date, none of the projects with pilot routes for underground cables has gone into operation. In the first quarter of 2014, TSO Amprion obtained planning approval for the first 380-kV underground cable pilot project in Raesfeld and construction work was launched on an approximately 3.5-kilometre underground cable section.

The following map shows the current expansion status of EnLAG procedures up to the third quarter of 2014:

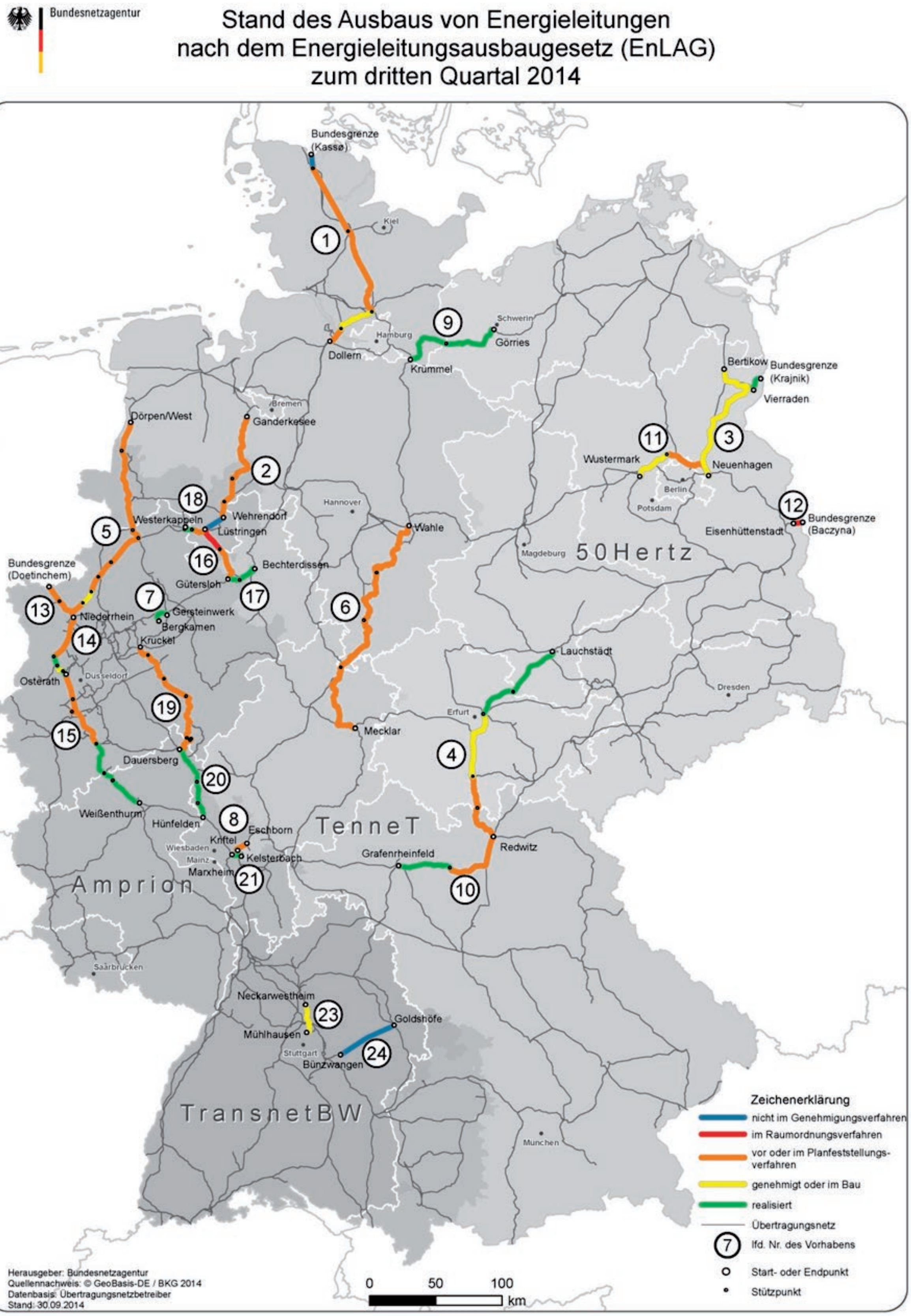

Figure 19: Progress on expanding power lines under the Power Grid Expansion Act (EnLAG) by the third quarter of 2014

1.2 Network development plan / O-NDP / Federal requirements plan - Electricity

Grid expansion

The amendment of the Energy Act (EnWG) in 2011 created a new procedure for the expansion of the extra-high voltage network. Since 2012 the four German transmission TSOs have been required to produce annual network development plans which detail all the effective measures for improving the grid to meet demand and for reinforcing and expanding the onshore grid which will be necessary in the next ten to twenty years to ensure continued operation of the network. In addition to their onshore network development plans, TSOs have also been required since 2013 to produce offshore expansion plans (offshore network development plans) for the connection of off-shore wind facilities.

Network development plans are produced every year and this allows them to take account of new economic and technological developments and changes from a very early stage.

Both network development plans are consulted by TSOs and the Bundesnetzagentur and are then examined and subsequently confirmed by the Bundesnetzagentur. The confirmed network development plans are submitted to the federal government in the form of a draft Federal Requirements Plan Act by the Bundesnetzagentur at least every three years. The federal requirements plan adopted by the legislator endorses the energy economy's urgent need for the projects specified in the plan.

Scenario Framework

Both network development plans are based on the scenario framework which is produced once a year by the TSOs in compliance with section 12a EnWG and which is subject to the approval of the Bundesnetzagentur. The scenario framework presents different development pathways (scenarios) to describe the probable development of electricity generating capacity and consumption in ten and twenty years' time.

The first two scenario frameworks were approved by the Bundesnetzagentur at the end of 2011 and 2012 and the third scenario framework in August 2013.

The Bundesnetzagentur held a consultation on the fourth scenario framework in the period 12 May to 23 June 2014. This framework should be approved by the end of the year 2014 and will incorporate the changes in the regulatory framework for electricity introduced by the amendment to the Renewable Energy Sources Act (EEG).

2022 Onshore electricity network development plan

The Bundesnetzagentur endorsed the first network development plan at the end of November 2012. This was preceded by a consultation process which continued over several weeks as well as a number of information events throughout Germany. The Bundesnetzagentur endorsed 51 of a total of 74 measures proposed by TSOs. The 2012 network development plan covers a total of around 2,800 km of new routes and around 2,900 km of optimisation and reinforcement measures.

Federal Requirements Plan

The Bundesnetzagentur has submitted the endorsed 2012 network development plan to the Federal Government to be used as a draft basis of the first Federal Requirements Plan Act. This came into effect in July 2013 and includes all the 51 nation-wide measures in the network development plan which involves

36 projects. The specific routes and precise starting and end points of the measures are determined in subsequent planning steps. These take particular account of spatial/geographic issues, environmental concerns, regulations on distances from residential areas, etc.

2023 Onshore electricity network development plan

The Bundesnetzagentur endorsed the 2023 onshore electricity network development plan on 19 December 2013. 56 of the 90 reinforcement and grid expansion measures detailed in the draft network development plan were endorsed. Apart from a few exceptions the measures confirmed in the 2022 network development plan have again proved to be eligible for endorsement. The confirmed 2023 network development plan covers around 2,800km of measures to optimise and reinforce existing routes (compare Federal Requirements Plan Act: 2,700km) and approximately 2,650km of new build projects (compared with 2,300km in the Federal Requirements Plan).

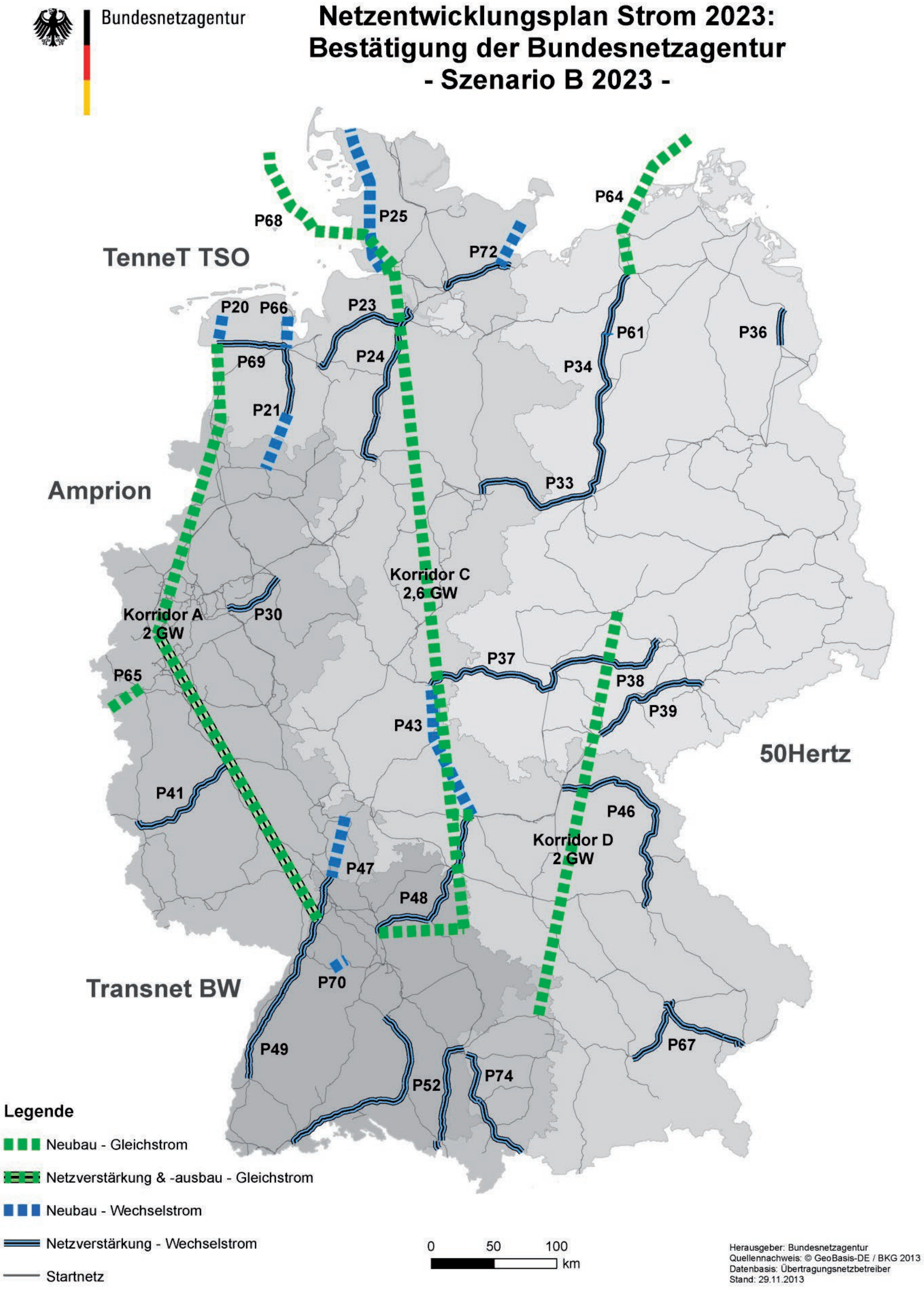

Figure 20: The 2013 Network Development Plan (November 2013)

2023 Offshore network development plan

The Bundesnetzagentur also confirmed the 2023 offshore network development plan on 19 December 2013. In response to the new regulatory framework for electricity to which the new German government is committed in its Coalition Agreement (which also entails decelerating the pace of offshore expansion) the Bundesnetzagentur has now decided to incorporate the specifications of the scenario framework for the 2024 network development plans in its endorsement of the 2023 offshore network development as this reflects the new policy framework more accurately than the 2023 scenario framework. Consequently, only four of the six grid connection lines in the North Sea have been confirmed. In contrast, all four of the grid connection lines in the Baltic Sea were eligible for endorsement.

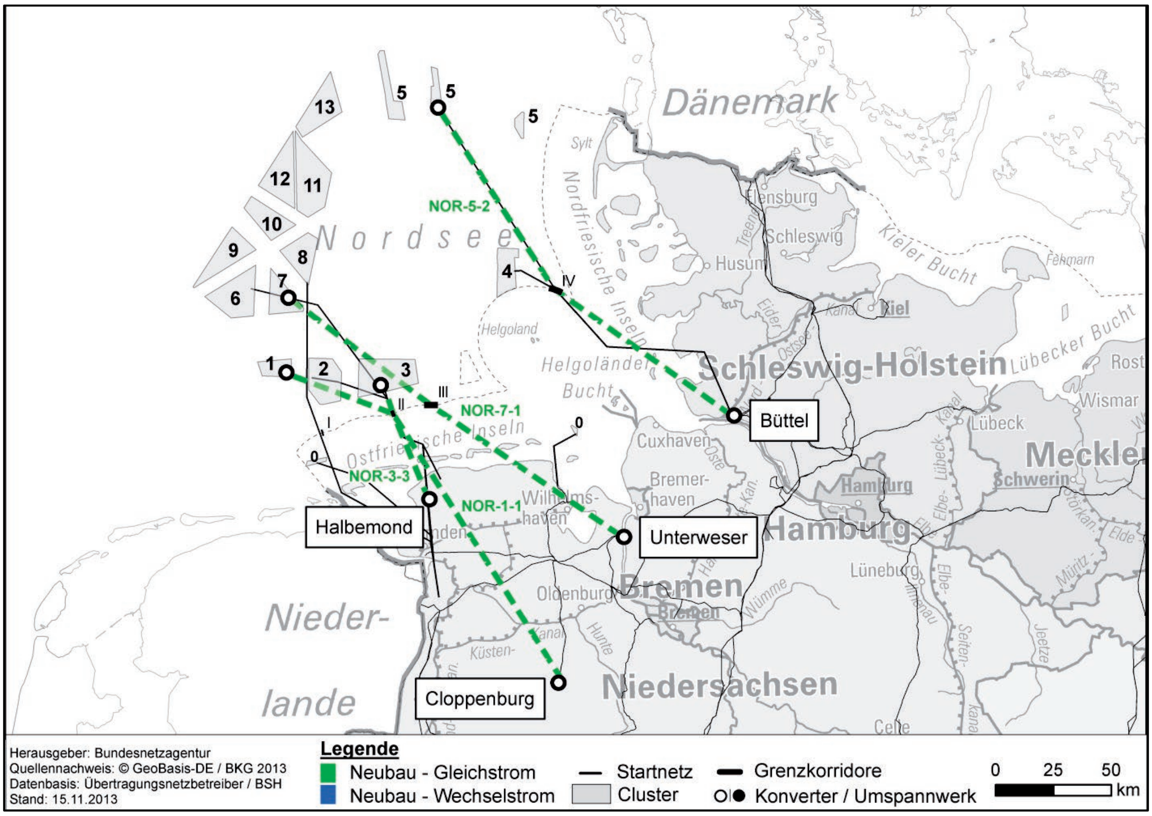

Figure 21: Grid connection lines confirmed in the 2013 offshore network development plan; North Sea

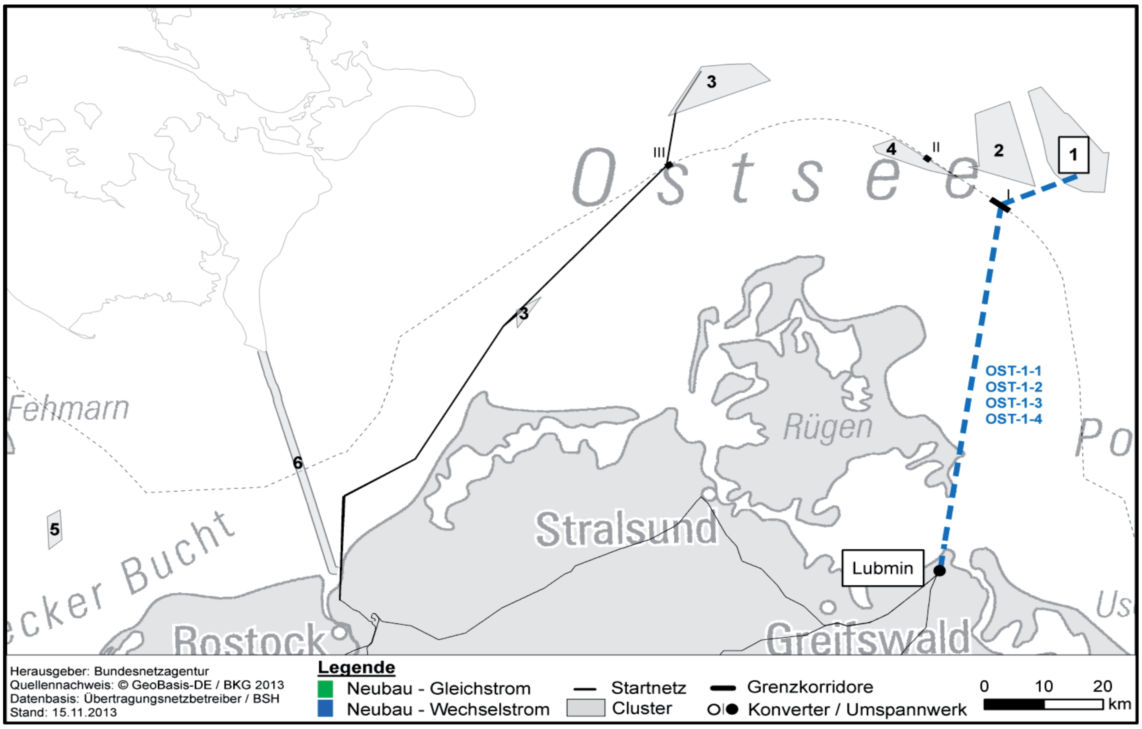

Figure 22: Grid connection lines confirmed in the 2013 offshore network development plan; Baltic Sea

2024 Onshore electricity network development plan

The transmission system operators published the first draft of the 2024 electricity network development plan on 16 April 2014 and put out the plan for consultation on 28 May 2014. They then submitted the revised draft plan to the Bundesnetzagentur for evaluation on 4 November 2014. The analyses and calculations undertaken by the transmission system operators for the 2024 network development plan do not differ significantly from previous expansion planning. All the scenarios confirm a high level of demand for north-south transmissions. Most of the projects in the federal requirements plan will be retained. However, as the revised draft network development plan does include some important changes to the first draft (including a new form of regionalisation and changes in grid connection points), the Bundesnetzagentur will now carefully evaluate the draft and open consultation procedures as soon as it has concluded its evaluation.

2024 Offshore electricity network development plan

Between 16 April and 28 May 2014, the transmission system operators also put out the draft 2024 offshore network development plan for consultation and submitted the revised draft to the Bundesnetzagentur on 4 November 2014 for evaluation.

For the North Sea, the plan includes three applications by the transmission system operators for grid connection lines in scenario A 2024 and four grid connection lines in scenario B 2024. For the Baltic Sea, the TSOs are applying for one grid connection line in scenario A 2024 and three grid connection lines in scenario B 2024. The Bundesnetzagentur will now carefully evaluate the revised draft offshore network development plan and thereafter open consultation procedures.

Sensitivity Report 2014

In order to meet the objective of incorporating the changed regulatory framework for electricity arising from the Coalition Agreement of the new German government in the NDP process at the earliest possible stage (particularly those elements of the new framework which concern the newly defined renewable energy expansion corridor, slower offshore expansion and feed-in management to reduce the load on grids from new onshore plants), the Bundesnetzagentur requested the transmission system operators to produce evaluative "sensitivity reports" on the impact of the changed regulatory framework on the need for grid expansion in parallel to the regular NDP process. The transmission system operators submitted the results of these initial analyses in April 2014. In the view of the TSOs the changed framework conditions will simply spread the need for grid expansion measures over a longer period of time.

Current status of federal sectoral planning

The Federal Requirements Plan Act (BBPIG), which is based on the confirmed 2022 network development plan, came into effect in July 2013. The federal requirements plan identifies 36 projects which are required for the energy industry in Germany and which are absolutely necessary to ensure that the grid remains secure and stable. 16 of these projects which cross state or national borders within the meaning of the Grid Expansion Acceleration Act are the responsibility of the Bundesnetzagentur. The Bundesnetzagentur will also carry out federal sectoral planning and go through the subsequent planning approval procedure.

The Bundesnetzagentur is well organised and prepared for the federal sectoral planning procedures which lie ahead and, with the aim of fostering close and fruitful cooperation with the federal states, has deliberately sought discussion with representatives of the spatial planning authorities in the federal states.

Federal sectoral planning is the first step in specifying the actual spatial implications of projects. Part of the federal sectoral planning process involves defining strips of land, which can be up to 1,000 metres wide, which will become the route corridors along which power lines will later run. One central feature and cornerstone of grid expansion is the high voltage direct current (HVDC) corridors. These lines must be completed as a matter of urgency, in part owing to the shutdown of nuclear power plants and their length of several hundred kilometres.

The first federal sectoral planning application for project no. 11 in the Federal Requirements Plan Act was received by the Bundesnetzagentur in August. This was for the planned extra-high voltage line from Bertikow in Brandenburg to Pasewalk in Mecklenburg-Vorpommern.

Formal procedures were opened following evaluation of the documents by the Bundesnetzagentur. The application documents were published on the Bundesnetzagentur's website at www.netzausbau.de/vorhaben11. The website also includes further information on the procedure in addition to the application documents as well as on applicable legislative framework.

The Bundesnetzagentur held a public scoping conference in Torgelow on 24 September 2014 to which it invited project developers, the public agencies concerned and associations. Interested members of the public were also able to participate. The object and scope of the federal sectoral planning of the route corridors were discussed as part of the scoping conference (section 7 NABEG). Discussion focused in particular on the extent to which the route corridors for which application has been made meet, or can be made to meet, the regional planning requirements of the federal states affected. The amount of information and the level of detail to be included in the environmental report under section 14g UVPG were also discussed.

Further applications for federal sectoral planning are expected to be made in the next few months.

The Bundesnetzagentur will continue to provide information about grid expansion and open up relating discussions to the general public. The Bundesnetzagentur provides information about the procedure and explains its role as an approval authority at local events and meetings. Dialogue and information events (eg scientific dialogues) which have proven useful in the past will be continued and expanded on. In this connection an initial dialogue with the public was launched in June 2014. This one-day event included intensive and constructive discussion with representatives from civic action groups of ways and means of fostering participation. Nationwide information events will be planned to accompany the consultation procedure on the 2024 network development plan and the 2024 environmental report.

Project monitoring under the Federal Requirements Plan Act

The Bundesnetzagentur monitors the federal requirements plan procedure. The data for the federal requirements plan is surveyed on a quarterly basis in parallel to the EnLAG and includes the status of procedures, in their legal order, as well as planned completion dates and section lengths. The progress made on these expansion projects is shown at www.netzausbau.de.

1.3 Network connection of offshore wind farms

The contract to supply a grid connection to the DolWin 3 project was awarded in the reporting year 2013. In April 2014 TenneT placed an order for the BorWin 3 grid connection. No contract has yet been awarded for BorWin 4. Under the stipulations laid down in the position paper on network connection obligations published in October 2009 by the Bundesnetzagentur in accordance with section 17(2a) of the Energy Act (EnWG) – which is specified in more detail in the annex dated January 2011 – a call to tender should have been issued and awards made for this collective connection for the DolWin cluster.

In December 2012 new legislation came into force aimed at solving the problems building network connections encountered by TSOs which are required to establish such connections. The "change in system" involves both rules on compensation payments in the event of delays in the construction of network connections and also transfers to the Bundesnetzagentur the authority to allocate and transfer connection capacities. The Bundesnetzagentur thereafter initiated corresponding procedures to assist establishing a general framework for the allocation and transfer of connection capacities and the treatment of compensation payments. In anticipation of the changes to the EnWG which are expected to take effect on 1 August 2014 the Bundesnetzagentur launched early talks with the offshore industry to discuss the necessary changes to the planned draft rules. Shortly thereafter, on 13 August 2014, the Bundesnetzagentur established new procedures for the allocation and transfer of offshore connection capacity. On this basis the Bundesnetzagentur's 6th Ruling Chamber initiated a procedure on 27 August 2014 for the allocation of grid connection capacity for offshore wind farms and, on 23 October 2014, admitted a total of eight applications for the allocation procedure for a total capacity of 1,826.6 MW. The capacity allocation procedure is only expected to be completed in 2015.

Within the framework of continuing discussions, the Bundesnetzagentur remains in regular contact with all the parties involved in order to assist with issues relating to the linking up of wind farms to the grid.

By 1 November 2014 a total of 27 applications had been submitted to the Bundesnetzagentur for the approval of investments in the connection of OWFs with a total volume of €222bn, of which 21 applications with a volume of €15.6bn have already been approved.

1.4 Investments in transmission networks (incl. cross-border connections)

In 2013 the four German TSOs together spent approximately €1,335m (2012: €1,152m) on investment in and expenditure on network infrastructure. Included in this spending is investments in and expenditure on cross-border connections amounting to approximately €16m (2012: €22m). Actual expenditure on network infrastructure deviated by €95m from the planning values reported in 2012 (planning values for 2013: approximately €1,240m). This difference is due in part to the investments in new build/extension/expansion category in which the actual value for 2013 of €880m deviates by €36m from the planned value for 2013 of €844m. The TSOs also invested around €90m more than planned in the investments in maintenance and renewal category in 2013. In contrast, just about €37m, or around €26m less than the €63m originally planned by the TSOs, was invested in new build/extension/expansion in cross-border connections. The planning values for 2014 reveal a further increase in investments, including in particular in the new build/extension/expansion category.

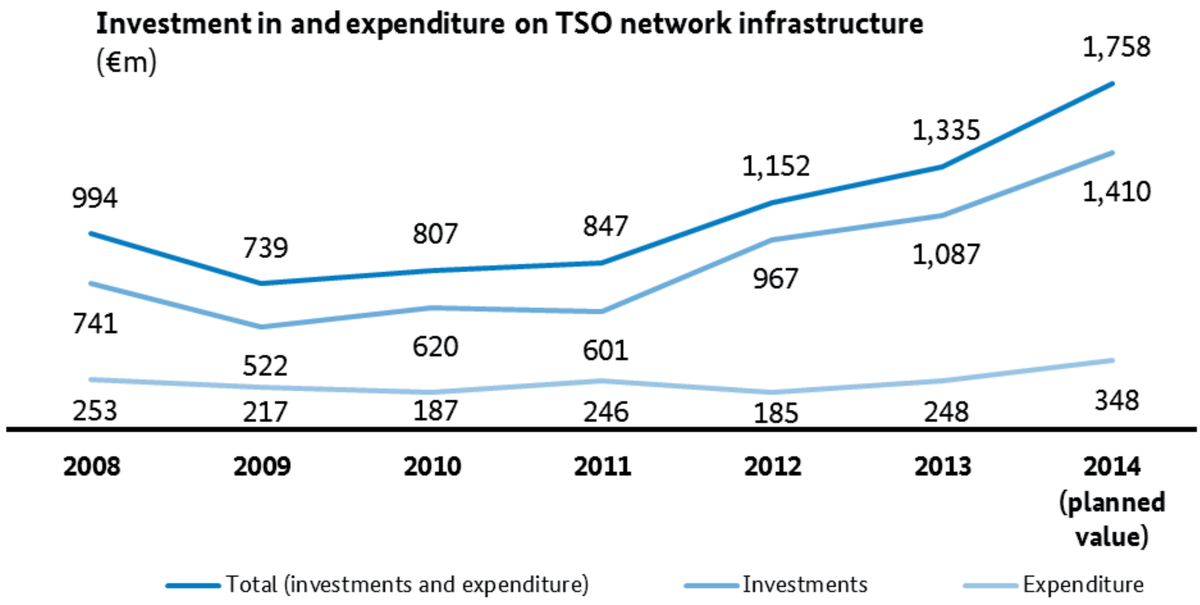

Figure 23: Investments in and expenditure on TSO network infrastructure since 2008 (including cross-border connections)

1.5 Investments and expenditure by electricity distribution system operators

Investments in and expenditure on network infrastructure by 789 DSOs totalled approximately €5,778m in 2013 (2012: €6,005m). This figure includes investments in and expenditure on metering/control devices and communication infrastructure amounting to approximately €463m (2012: €356m). The target volume of investment in distribution networks of €3,025m planned by distribution system operators (DSOs) for 2013 was undershot by €157m: actual investment amounted to €2,851m. On the other hand, spending with a planned volume of investment of €2,908m was exceeded by €18m and amounted to €2,926m. Overall, with a delta of €155m, total DSO spending on the network infrastructure is below the planning values for 2013 of €5,933m.

For the coming year of 2014, the DSOs have planned for a growing volume of investment for in the distribution networks for new installations, extension, expansion, maintenance and renewal of approximately 5 per cent and falling costs for spending of approximately 10 per cent.

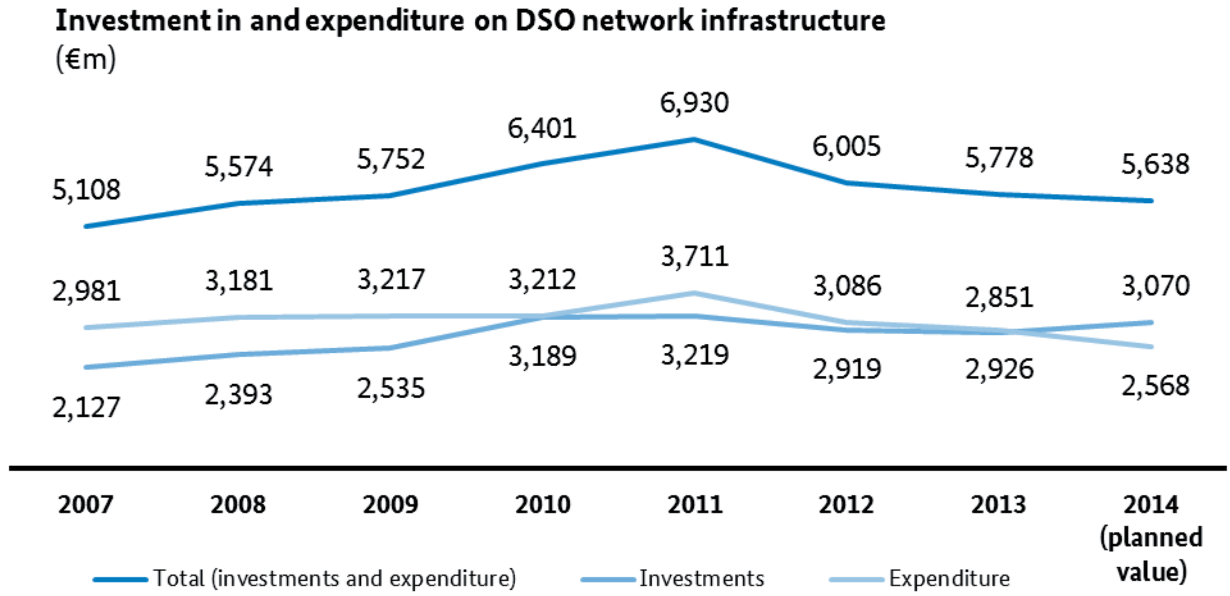

Figure 24: Investments in and expenditure on network infrastructure (including metering/control devices and communication infrastructure) by DSOs

The level of DSO investment depends on circuit lengths, the number of metering points served as well as other individual structure parameters, including geographical circumstances. As a rule, DSOs tend to invest more the longer their circuits are. Most DSOs (572) are in the €0 to €100,000 investment category. In contrast, only 14 companies have peak investments of over €5m per network area. The following diagram shows the various categories of investment as percentages of total investment:

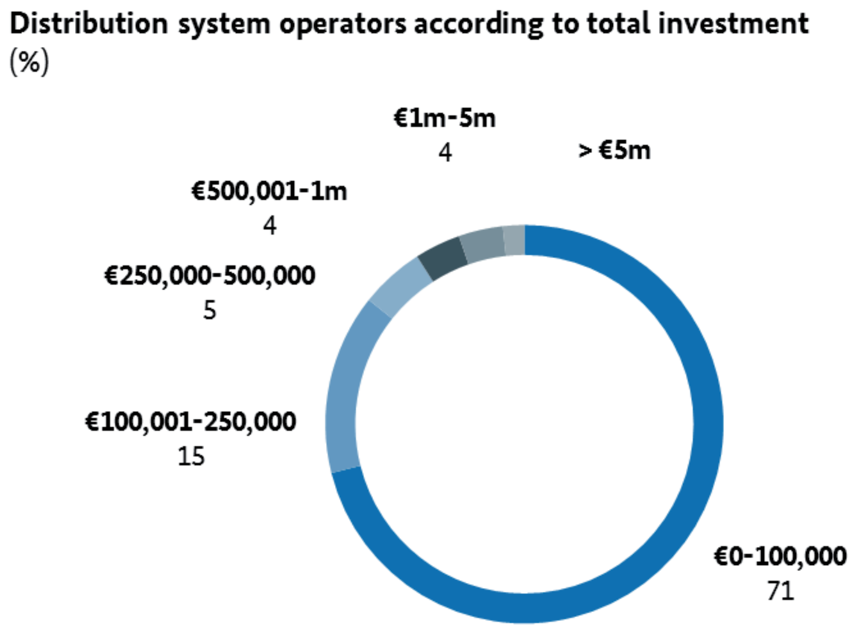

Figure 25: Electricity distribution system operators according to total investment

In contrast to investments, DSOs with medium and small electricity networks appear to have relatively higher expenditure. While 305 DSOs report expenditure of between €0 and €100,000, there are also around 70 companies in the highest category with spending of over €5m. This means that a different percentage of expenditure is made in the various spending categories than in the investment category referred to previously. In 2013, for example, 72 per cent of DSOs spent at least €100,000 on their networks:

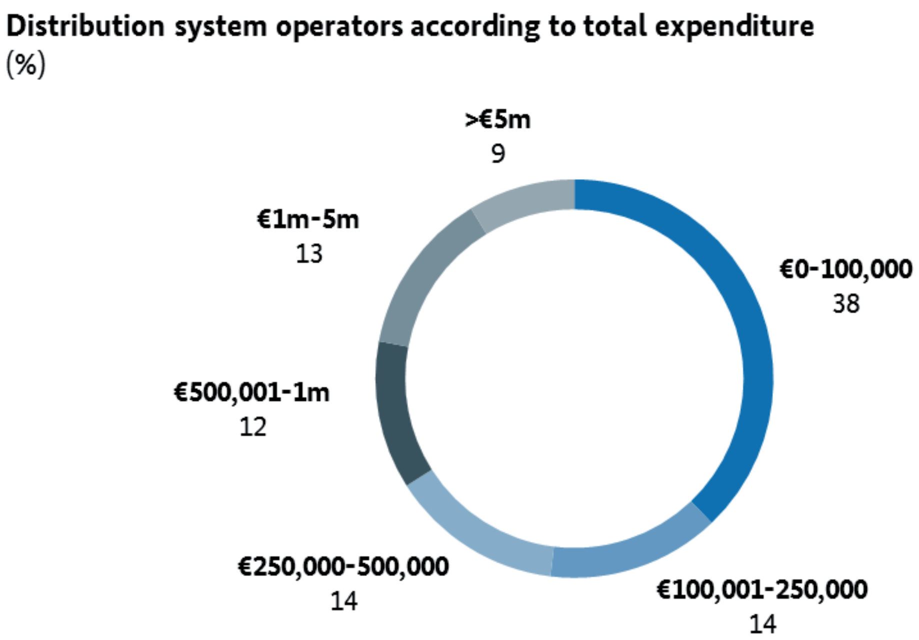

Figure 26: Distribution system operators according to total expenditure

1.6 Measures for the optimisation, reinforcement and expansion of the distribution system

The DSOs are obliged under section 11(1) EnWG and section 9(1) EEG to optimise, reinforce and expand their networks to reflect the state of the art without undue delay, in order to ensure the uptake, transmission, and distribution of electricity. The strong expansion of generation installations based on renewable energies, coupled with the legal obligation to connect and purchase regardless of network capacity, represents a considerable challenge for DSOs. Alongside conventional expansion measures, system operators are primarily responding to these challenges by developing increasingly smart grids which will allow them to adapt to changing requirements over time. The way forward and the measures adopted may differ considerably from one system operator to the next. Given the highly heterogeneous nature of grids in Germany, future energy developments mean that each DSO will have to adopt its own strategy for achieving efficient grid operations. It is actually quite useful in this context that so many networks are in any case due for modernisation. In many cases it will therefore be possible to convert grids by investing the returns from existing systems (intelligent restructuring) without any associated increases in network costs.

As of 1 April 2014 a total of 817 (1 April 2013: 806) DSOs had provided information about the extent to which they had taken action to optimise, reinforce and expand their networks. More measures to optimise and expand networks have been taken than in the previous year. There was a slight decline, on the other hand, in the number of network reinforcement measures taken.

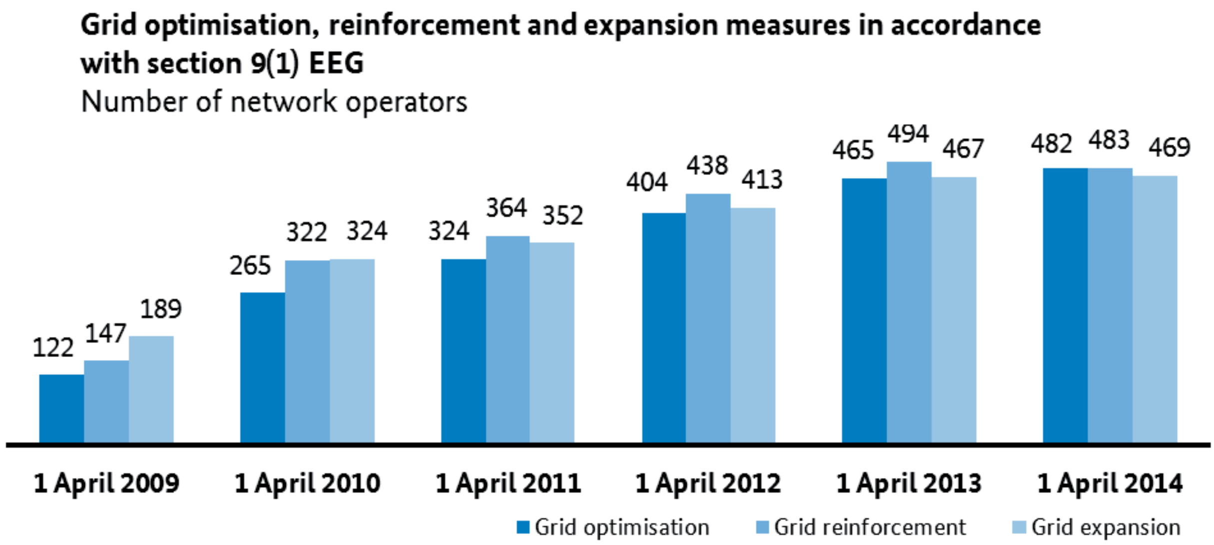

Figure 27: Grid optimisation, reinforcement and expansion measures in accordance with section 9(1) EEG

The following grid optimisation and reinforcement measures are being implemented by the DSOs.

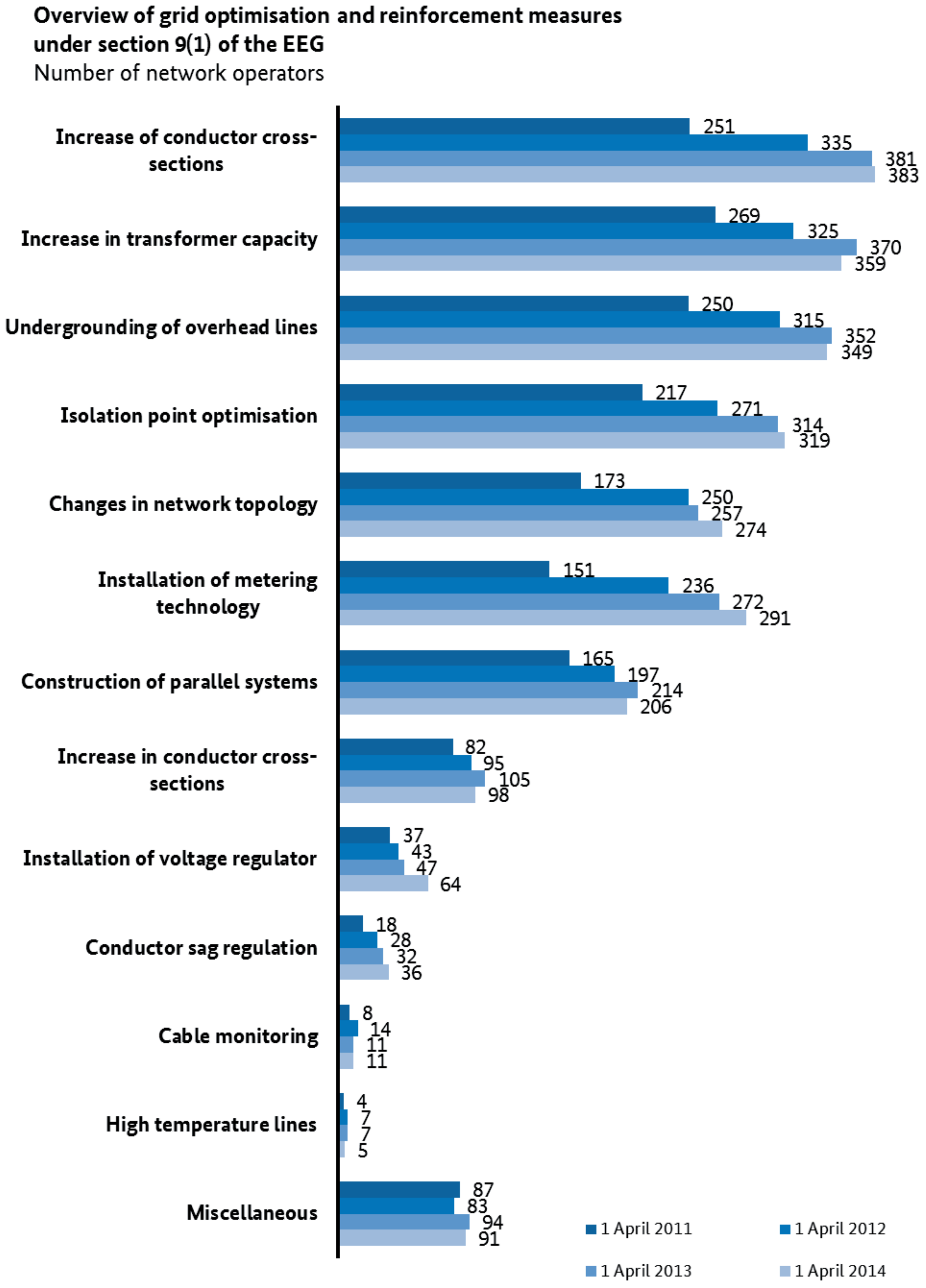

Figure 28: Overview of grid optimisation and reinforcement measures under section 9(1) EEG

In particular, more has been done than last year to modify network topologies and to integrate metering technology and voltage regulators. Somewhat less has been done than last year to increase transformer capacity, to build parallel systems or increase conductor cross sections. Other measures were taken in much the same frequency as was the case in the previous year.

1.7 Operators' systems responsibility for transmission systems with measures under section 13(1) EnWG in calendar years 2012 and 2013

In accordance with section 13(1) EnWG, the TSOs are both authorised and required to adopt network and market-related measures to remedy any threat to or malfunction in the electricity supply network. Insofar as DSOs are responsible for the security and reliability of the electricity supply in their networks, these too are both authorised and required to implement such measures as set out in section 14(1) EnWG.

Network-related measures, in particular with regard to network switches, are implemented by the TSOs practically every day of the year. To a large extent, market-related measures take the form of congestion management measures. A fundamental distinction must be made here between redispatch and countertrade: Redispatch refers to intervention in the market-based roadmaps of generating units for the shifting of power plant feed-ins to prevent line overloading (preventive redispatch) or to rectify line overloading (curative redispatch). Electricity-related redispatch is used to avoid or rectify at short notice congestion affecting power lines and transformer stations. The aim of voltage-related redispatch, on the other hand, is to maintain voltage in the affected network area by providing additional reactive power. Redispatch measures can be applied either internally within control areas or across control areas. By reducing feed-in from one or more power stations while simultaneously increasing the feed-in from one or more other power stations (in the balance areas or other areas which are to be balanced), it is possible to keep the overall energy feed-in at a constant level.

Countertrading, in contrast, is a preventive or corrective reciprocal commercial transaction undertaken across control areas at the TSO's initiative in order to prevent or eliminate short-term congestion.

As part of the data survey under section 13(5) EnWG (congestion evaluation) the German TSOs provide the Bundesnetzagentur detailed data on a monthly basis about any redispatch measures taken. The following evaluation is based on the data notified in 2012 and 2013.

Calendar year 2012

In the calendar year 2012 networks came under pressure in the following areas in particular (in the table below) so that TSOs were required to take redispatch measures to prevent an infringement of the (n-1) criterion:

Electricity-related redispatch measures on the most strongly affected network elements in 2012

Affected network element	Control area	Duration (hours)	Redispatch interventions (GWh)[1]
Remptendorf - Redwitz	50Hertz/ TenneT	1,857	1,291
Lehrte area (Lehrte-Mehrum, -Godenau, -Göttingen)	TenneT	1,080	97
Wolmirstedt – Helmstedt	50Hertz	470	207
Pulgar-Vieselbach	50Hertz	346	161
Conneforde area (Conneforde-Dollern-Sottrum)	TenneT	196	44
Vierraden - Krajnik (PL)	50Hertz	138	34
Wahle area (Wahle-Hattorf, Wahle-Helmstedt, Algermissen)	TenneT	127	20
Hamburg-Flensburg area (Hamburg Nord-Audorf-Kassö (DK))	TenneT	117	11
Rommerskirchen-Weissenthurm	Amprion	106	21
Zolling area (Zolling, Freising-Nord, Unterschleißheim)	TenneT	68	5

[1] The volume of redispatch measures for the individual network elements is presented and broken down by the number of measures carried out. The number of balancing counter trades performed (increase in input capacity of power plants) is not taken into account. This breakdown determines the extent to which the network elements were physically overloaded and the work needed to remove the overload by reducing the feed-in from power plants.

Table 11: Electricity-related redispatch measures on the most strongly affected network elements in 2012 as notified by TSOs

As in previous years the situation along the Remptendorf (50Hertz control area) – Redwitz (TenneT control area) line was marked by above-average demand for redispatch measures. This was followed by the area around the Lehrte transformer station in the TenneT control area and, thirdly, by the power line between the Wolmirstedt and Helmstedt transformer stations in the 50Hertz control area.

The remaining measures covered a total period of 2,655 hours (2,389 hours of which for voltage-related redispatch) so that redispatch measures totalling 7,160 hours had to be carried out in the German transmission network in 2012.

Calendar year 2013 (year under review)

In the period from 1 January 2013 to 31 December 2013 the Bundesnetzagentur was notified of 7,965 hours of electricity and voltage-related redispatch measures. This is equal to an increase of 11 per cent compared with the previous year. Overall, interventions of this kind were required on 232 days in 2013. The number of activities corresponded with an overall volume of 2,278 GWh. This is a fall of 11 per cent compared with last year. A total of 2,112 GWh balancing counter trades were performed. As a result, a total of around 4,390 GWh of redispatch interventions (measures taken and counter trades performed) were undertaken in 2013. The corresponding volume for 2012 amounted in total to 4,690 GWh. Redispatch thus accounted for 0.95 per cent of total generation from installations not eligible for payment in accordance with the EEG. The TSOs reported current outlay costs for national redispatch in 2013, estimated for system services, at €132.6m[11]. Most of these redispatch measures were taken in the TenneT and 50Hertz control areas. Precise details are provided by the following table:

Redispatch measures in 2013

<table>
<tr><th>Network area</th><th>Duration (hours)</th><th>Volume of interventions (GWh)</th><th>Current outlay costs for national redispatch[11] (€ million)</th></tr>
<tr><td>TenneT control area</td><td>5,392</td><td>984</td><td rowspan="4">132.6</td></tr>
<tr><td>50Hertz control area</td><td>2,417</td><td>1,257</td></tr>
<tr><td>Transnet BW control area</td><td>108</td><td>26</td></tr>
<tr><td>Amprion control area</td><td>47</td><td>11</td></tr>
</table>

Table 12: Redispatch measures in 2013

Most redispatch measures carried out in 2013 were electricity related. In total, measures lasting a total of 6,406 hours and with a volume of 2,065 GWh were instigated. Of these, 6,147 hours (96 per cent) related to the following network elements:

[11] For more information refer to System services on p. 80

Electricity-related redispatch measures on the most strongly affected network elements in 2013

Affected network element	Control area	Duration (hours)	Number of measures carried out (GWh)
Lehrte area (Lehrte-Mehrum, -Godenau, -Göttingen)	TenneT	2,102	256
Remptendorf - Redwitz	50Hertz/ TenneT	1,581	923
Mecklar area (Mecklar-Borken, Mecklar-Dipperz)	TenneT	629	367
Conneforde area (Conneforde-Dollern-Sottrum-Wechold-Diele)	TenneT	607	87
Bärwalde-Schmölln	50Hertz	359	142
Vierraden - Krajnik (PL)	50Hertz	346	142
Hamburg-Flensburg area (Hamburg Nord-Audorf-Kassö (DK))	TenneT	247	7
St. Peter area (Altheim - Simbach - St. Peter, Altheim-Sittling, Pleitning-St. Peter)	TenneT	130	25
Brunsbüttel-50 Hertz zone (Hamburg Nord)	TenneT	80	25
Grafenrheinfeld-Kupferzell	Transnet BW	66	18

Table 13: Electricity-related redispatch measures on the most strongly affected network elements in 2013 as notified by TSOs

The Remptendorf-Redwitz power line and the area around the Lehrte-Mehrum power line, which accounted for 32.8 per cent and 24.7 per cent of all electricity-related redispatch interventions, were particularly affected. In addition, the TSOs took a further total of 259 hours of action on network elements where in each case fewer than 50 hours were spent on each power line.

The following map assigns the especially critical network elements (number of hours per power line > 50) in the table above to their geographical location:

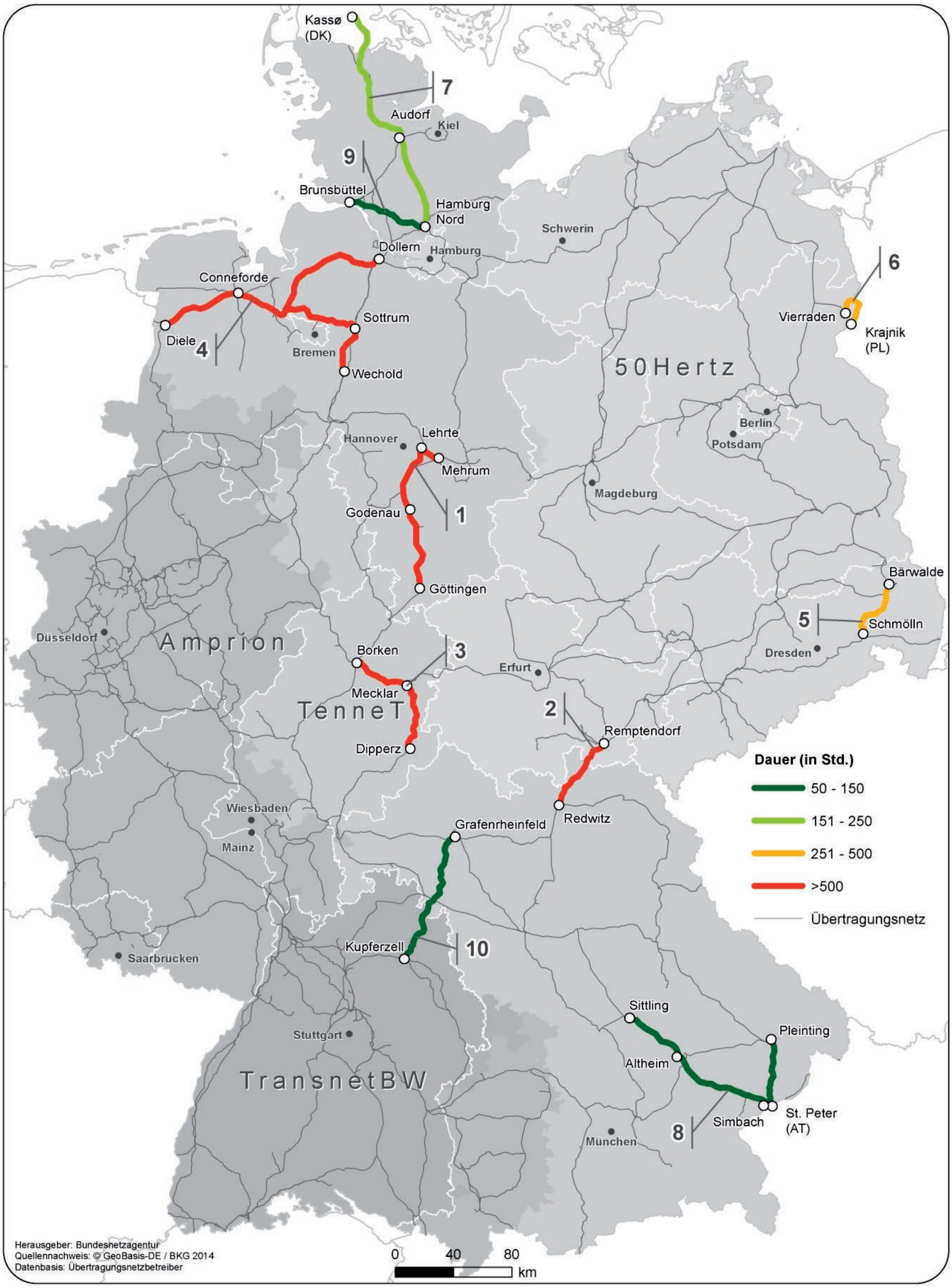

Figure 29: Electricity-related redispatch measures on the most strongly affected network elements in 2012 as notified by TSOs

In addition to electricity-related redispatch measures a total of 1,559 hours of voltage-related redispatch measures were also notified, the overwhelming majority of which for TenneT. The total volume of interventions amounted to 213 GWh. The northern network area of the TenneT control area, which accounted for over 46 per cent of the hours was most strongly affected.

Voltage-related redispatch measures on the most strongly affected network elements in 2013

Network area	Duration (hours)	Volume (GWh)
TenneT control area: Network area north	723	64
TenneT control area: Network area south	464	96
TenneT control area: Network area central	348	49

Table 14: Voltage-related redispatch measures on the most strongly affected network elements in 2013 as notified by TSOs

In addition a total of 24 hours of voltage support measures, equivalent to a total volume of four GWh, were also taken in the control areas of 50Hertz and Amprion.

Development from calendar year 2012 to calendar year 2013

There was a further strong increase between 2013 and 2012 in the duration of intervention on the line between the Lehrte and Mehrum transformer stations and the neighbouring transformer stations. The number of these notified hours of redispatch measures has almost doubled. The number of activities corresponded with an overall volume of 189 GWh. This development underlines the need to strengthen and reinforce the grid around Mehrum[12]. In contrast, there was a reduction in the frequency of interventions in the Remptendorf-Redwitz power line for the first time. This is equal to a reduction of 276 hours with the volume of actual measures taken falling by 368 GWh. Nonetheless, the Remptendorf-Redwitz power line is still one of the elements of the grid which is taking most strain. This situation is only expected to improve with the completion of the Thüringia Power Bridge (EnLAG no. 4). Increases also took place in the areas around the Conneforde and Mecklar transformer stations and on the Vierraden-Krajnik and Bärwalde-Schmölln power lines. Measures to strengthen and reinforce the grid were also adopted here.

In addition to the developments on the network elements described here there were substantial reductions in the number of redispatch interventions during the reporting period for 2013 on other previously heavily congested network elements. There has been an especially large reduction in measures on the Wolmirstedt-Helmstedt power lines and in Pulgar-Vieselbach. The high level of redispatch required on the Pulgar-Vieselbach power line in 2012 was due to weather-related damage.

The detailed changes in electricity-related redispatch interventions on the most highly affected network elements in the German transmission network are shown in the following table.

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[12] NDP measure M205: 380-kV switchgear and 380/220-kV interconnection coupler in Mehrum

Changes in electricity and voltage-related redispatch measures on the most highly affected network elements, 2012-2013

Affected network element	Control area	2013 (duration in hours)	Absolute change in duration in hours compared with previous year
Lehrte area (Lehrte-Mehrum, Lehrte-Godenau, Lehrte-Göttingen)	TenneT	2,102	1,022
Remptendorf – Redwitz	50Hertz/TenneT	1,581	-276
Mecklar area (Mecklar-Borken, Mecklar-Dipperz)	TenneT	629	568
Conneforde area (Conneforde-Dollern-Sottrum-Wechold-Diele)	TenneT	607	295
Vierraden-Krajnik (PL)	50Hertz	346	208
Bärwalde-Schmölln	50Hertz	359	350
Wolmirstedt – Helmstedt	50Hertz	48	-422
Pulgar-Vieselbach	50Hertz	0	-346

Table 15: Changes in electricity-related redispatch measures on the most highly affected network elements, 2012-2013

The duration and scope of electricity-related redispatch measures fell in the calendar year 2013. All in all, the overall duration of measures was reduced by 832 hours. The number of voltage support measures fell significantly by 391 GWh. The reduction in voltage-related redispatch interventions, particularly in terms of the work involved in such interventions, explains why the overall reduction in the duration of redispatch (voltage and electricity related) increased compared across the whole of 2012 and 2013 while the actual volume of measures taken fell.

The table clearly shows that in the calendar year 2013 it was primarily the 50Hertz and TenneT control areas which came under particularly strong pressure at certain times. Despite this, the German TSOs had the instruments which allowed them to control the situation at all times. In the view of the TSOs and the Bundesnetzagentur the need for redispatch measures is unlikely to decline in the near future. In this connection it is significant that the Irsching 4 and 5 power generation units continue to be available to provide electricity and voltage-related redispatch. TenneT and the power plant operators have agreed that, on the basis of a Bundesnetzagentur ruling, Irsching 4 and 5 should also be assured annual service remuneration based on the relationship at any one time between market-driven generation by the power stations or network-driven generation as a proportion of total generation.

1.8 Operators' systems responsibility for electricity transmission networks with measures under section 13(2) EnWG

In accordance with section 13(2) EnWG, transmission system operators are authorised and obliged to adapt the feed-in, transportation and take-up of electricity or demand that such adaptations be made (adaptation measures) in cases where a threat or malfunction affecting the security or reliability of the electricity supply system cannot be eliminated or cannot be eliminated in good time by network and market-related measures in accordance with section 13(1) EnWG.

Insofar as electricity distribution system operators are responsible for the security and reliability of the electricity supply in their networks, such distribution system operators are also both authorised and obliged under section 14(1) EnWG to implement adaptation measures as set out in section 13(2) EnWG. Furthermore, section 14(1c) EnWG requires distribution system operators to support the measures taken by the transmission system operators by implementing their own measures as instructed by the latter (supporting measures).

In the year under review 2013, four DSOs undertook adaptation measures for a total of 4,394 hours spread over 346 days in accordance with section 13(2) EnWG. 340 hours of these adaptation measures taken on 45 days affected conventional installations and 4,053 hours taken on 261 days affected EEG installations. Electricity feed-in from conventional installations was lowered by a maximum power of 89 MW and total energy of 1,467 MWh and EEG installations were reduced by a maximum power of 195 MW and total energy of 12,813 MWh.

Four DSOs also took supporting measures at the instigation of a TSO under sections 13(2), (2a) and 14(1c) EnWG. In this context electricity feed-in was lowered over a period of 4 hours on one day by a maximum of 33.4 MW and total energy of around 142 MWh.

1.9 Feed-in management measures under section 11 and hardship rules under section 12 EEG

Feed-in management (FMM) is a specially regulated network security measure for renewable energy, mine gas and cogeneration installations. The climate-friendly electricity produced from these installations is fed into and transported on the grid with priority (section 8(1) and (4) EEG, section 4(1) and (4) sentence 2 of the Combined Heat and Power Act, KWKG). Under specific conditions the system operator responsible can also scale back priority feed-in from these installations temporarily if the network capacities are not sufficient to transport the total amount of electricity generated (section 13(2), 2a sentence 3 EnWG and sections 11 and 12 EEG (2012), for CHP plants also with section 4(1) sentence 2 KWKG). In particular restrictions on priority feed for conventional producers must first have been exhausted. At the same time, system operators who are responsible for congestion are also subject to grid expansion duties.

The operator of the scaled back installation is entitled to compensation for the unused energy and heat under section 12(1) EEG (2012). The compensation costs are borne by the system operator in whose network the cause of the feed-in management measures is located. If the network access carrier pays compensation to the installation operator on the basis of the carrier's joint liability even though a different system operator may actually have been responsible, the responsible system operator must repay the compensation costs to the network access carrier.

According to the monitoring survey, the following use was made of feed-in management in 2013:

Unused energy subject to section 11 EEG (2012) and compensation payments under section 12 EEG (2012) in 2013

	Unused energy under section 14 EEG in kWh		Compensation payments under section 15 EEG in €	
Feed-in management, total	554,834,272	100%	43,734,974	100%
Feed-in management with cause in the transmission system	164,611,235	30%	16,101,409	37%
Implementation and compensation by the TSO	11,612,500	2%	569,560	1%
Instructions to DSOs and compensation by the TSOs	152,998,735	28%	15,531,849	36%
Feed-in management with cause in the distribution system	390,223,037	70%	27,633,566	63%
Implementation and compensation in the same distribution system	271,672,467	49%	14,262,671	33%
Implementation in downstream distribution system and compensation in upstream distribution systems	118,550,570	21%	13,370,895	31%

Table 16: Unused energy under section 11 EEG (2012) and compensation payments under section 12 EEG (2012) in the year 2013

The volume of unused energy (555 GWh) resulting from feed-in management measures under section 11 EEG, is 44 per cent higher than in 2012 (385 GWh). In 2013, unused energy arising from FMM was equal to 0.44 per cent of the total volume of net power from generation facilities which are eligible for payment under the EEG (including direct marketing).

Some 30 per cent of the unused energy resulting from FMM was due to grid congestion in transmission systems. Only 2 per cent (11.6 GWh) of unused energy was also scaled back from facilities which are directly connected to transmission systems. The remaining 98 per cent is due to the scaling back of renewable energy installations at the DSO level. The reason for these scale backs in the distribution networks may be previous instructions issued by the TSO (28 per cent) or the upstream system operator (21 per cent), or congestion in the restricting DSO's network (49 per cent).

Total compensation payments also rose by around €43.7m (2012: €33.1m) or 32 per cent. Compensation payments are taken from the network tariffs paid by final consumers and lead to an average increase in costs of 89 cents per final consumer.

These total compensation payments do not, however, account for the total costs of unused energy in 2013 as compensation has not yet been demanded by the plant operator or paid for 27 per cent of unused energy.

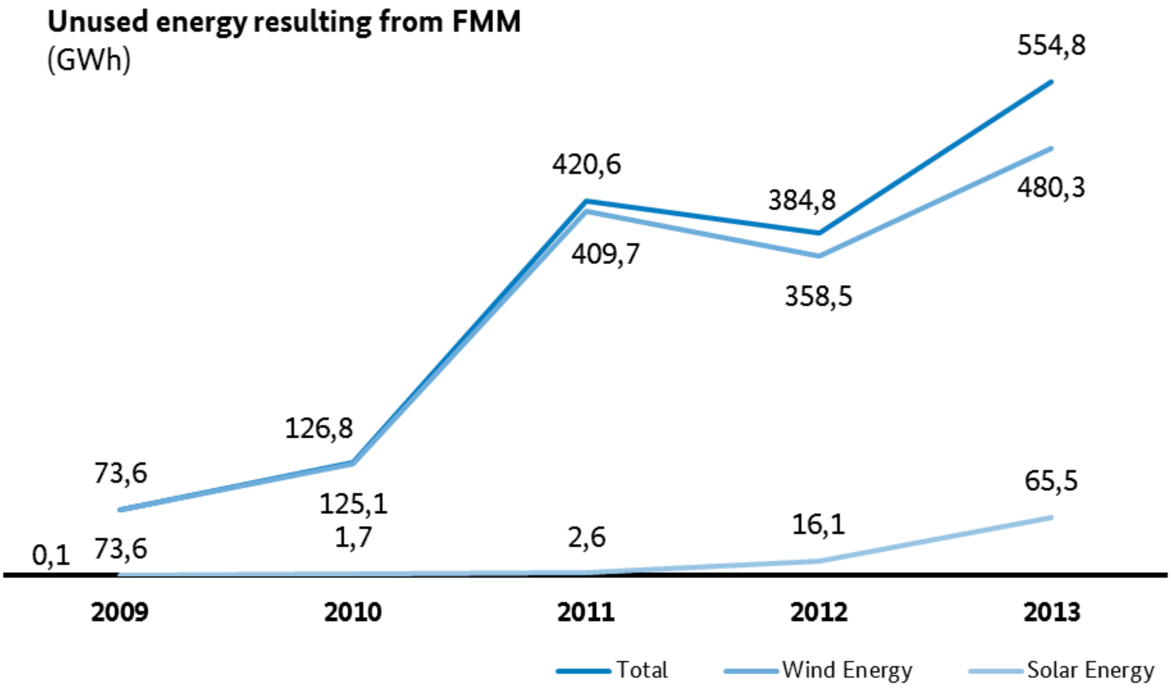

Figure 30: Unused energy resulting from FMM

As in previous years wind power plants accounted for 86.6 per cent of total unused energy and were thus again most affected by FMM (2012: 93.2 per cent). The number of PV installations affected has also risen compared to the previous year (4.2 per cent) and now accounts for 11.8 per cent of unused energy.

Unused energy resulting from FMM according to sources of energy

Energy source	Unused energy (incl. heat) in kWh	Share (%)
Wind power	480,291,260	86.6
Solar Energy	65,502,817	11.8
Biomass	8,805,830	1.6
Gases	29,160	<0.1
Water	91,020	<0.1
Geothermal energy	0	0
Installation under KWKG	114,185	<0.1
Total	554,834,272	100

Table 17: Composition of unused energy resulting from FMM according to sources of energy

In the year 2013 a total of two TSOs and 17 DSOs took feed-in management measures. All the regions of Germany are now affected by such measures. Nonetheless, 95 per cent of unused energy is the result of FMM in the northern federal states, where Brandenburg and Schleswig-Holstein are particularly affected.

Number of network operators in various regional states which undertook FMM in 2013

Land	Number of DSOs that carried out FMM in 2013
Lower Saxony	3
Bavaria	3
Saxony-Anhalt	2
North Rhine Westphalia	2
Schleswig-Holstein	2
Brandenburg	1
Mecklenburg-Vorpommern	1
Hesse	1
Bremen	1
Rhineland-Palatinate	1
Total	17

Table 18: Number of system operators in various regional states which undertook FMM in 2013

2. Network tariffs

2.1 Development of network tariffs

The following chart shows the development of average, volume-weighted[13] network tariffs for three purchase cases in ct/kWh from 1 April 2006 to 1 April 2014, whereby the year 2006 varies owing to the special effects linked to the introduction of regulation in this year. The charges for billing, metering and meter operations are included in the values as shown. The values shown are based on data provided by electricity suppliers which shows considerable spread. The data collection systems used have also varied on numerous occasions over the course of time. The networks charges shown are based on the following purchase cases:

- Household customers: Households with annual consumption of 3,500 kWh/year, low-voltage supply

- Business customers: Annual consumption of 50 MWh/a, annual peak load of 50 kW and annual usage time of 1,000 hours, low-voltage supply (0.4 kV)
  (where the load profile of industrial customers is not measured the value was stated on the basis of delivery without load profile measurement.)

[13] For the key date 1 April 2014 the network tariff values for industrial and business customers were calculated arithmetically.

– Industrial customers: Annual consumption of 24 GWh/year, annual peak load of 4,000 kW and annual usage time of 6,000 hours, medium-voltage supply (10 or 20 kV). No account is taken of surcharges and exemptions under section 19 StromNEV.

No account is taken of surcharges and exemptions under section 19 StromNEV.

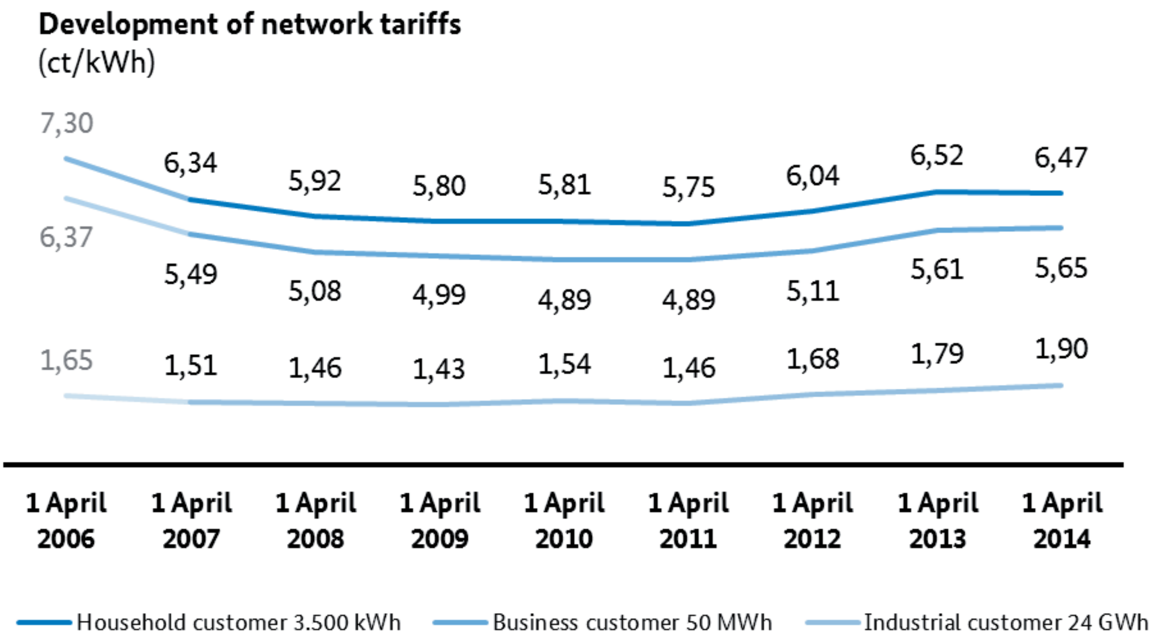

Figure 31: Development of volume-weighted prices for three purchase cases[14] up to 2014

Average, volume-weighted network tariffs in the period 1 April 2013 to 1 April 2014 for household customers (low voltage), business customers (low voltage, load measured) and industrial customers (medium voltage) remained relatively stable.

The regulation of electricity transmission and distribution charges was introduced in 2005 with the intention of reducing monopoly returns and network operation inefficiencies. After initial reductions in network costs and the resulting charges, these then rose again last year by almost 8 per cent for household customers, by almost 10 per cent for business customers and by 6.5 per cent for industrial customers. Prices are currently stabilising once again.

Network regulation nonetheless makes an important contribution to curbing price increases on electricity markets. Electricity prices have risen substantially since 2007, particularly as a result of the EEG surcharge. As network tariffs remained relatively stable during this same period, the overall share of the total electricity

[14] 2006 was marked by special effects arising from the introduction of regulation which initially resulted in excessive network tariffs being disclosed by companies. It was only once regulation began to take effect and network tariffs were reduced that costs which had been erroneously allocated to network tariffs could be assigned to the price components to which they belong under the principle of causation. The increases in price components other than network tariffs which took effect after regulation began, particularly in "supply", were consequently partly a result of reductions in network tariffs. 2006 is therefore of only limited use as a reference year for a time series comparison.

price paid by industrial customers, commercial customers and household customers contributed by network tariffs has fallen. Network tariffs as a share of the total electricity price paid by household customers fell slightly, according to data collected in 2014, and compared to 2013 now account for around 21 per cent of the price.

2.2 Determining the quality element of DSO electricity for the second regulation period

There is a risk in a system of incentive regulation that system operators will achieve potential cost savings and hence comply with the required cap at least partly by not carrying out measures to maintain or improve quality of supply. This can result in a deterioration in the quality of supply. In order to prevent this happening, the EnWG and the Incentives Regulation on Energy Supply Networks (ARegV) both provide for quality regulation.

The Q element was defined for a period of two years in the framework of the introduction of quality regulation on 1 January 2012. For this reason, a new Q element was calculated for the start of the second regulation period.

This was calculated in line with the basic elements of the basic variants of quality regulation introduced in the first regulation period with the aim of guaranteeing a stable and predictable regulatory framework.

The equality regulation covers both the low-voltage and medium voltage grids which take part in regular incentive regulation procedures. The key figures for 184 electricity distribution networks were used to determine the reference values for low and medium voltage. The level of quality elements calculated at the end of 2013 is contingent on the reliability of the relevant network in the years 2010 to 2012. System operators whose networks have provided good standards of supply in recent years compared to other network operators have their revenue caps raised for the years 2014 to 2016. Network operators which offer a comparatively poor quality must, in contrast, expect their revenue caps to be reduced. The quality elements calculated for 2016 will impact revenues for the remaining two years of the regulatory period (2017 and 2018).

The amounts by which revenue caps are raised or reduced are also influenced by the economic costs of supply outages and the number of final consumers supplied. Structural differences between the individual network areas are shown using load density as a parameter. The load density is calculated based on the quotient of all simultaneous offtake and the area of the system operator.

The system aims to achieve revenue neutrality. Revenue neutrality means that the totality of all bonuses and penalties are offset across all system operators.

In order to limit the maximum impact on revenue caps which a system operator could obtain from the quality element, penalties are capped at ± 2 per cent on the relevant revenue cap.

Out of a total of 184 system operators, 133 companies will have an amount added (bonus) and 51 an amount deducted (penalty). In comparison, in the first regulation period 143 companies received a bonus and 59 a penalty. The highest amount added is approximately €4.2m and the highest amount deducted approximately €3.9m. Both the highest bonus and the highest penalty were slightly lower than in the first regulatory period.

2.3 Performance of electricity DSO efficiency benchmarking for the second regulatory period

Nationwide efficiency benchmarking was carried out for the second time in 2013 on 179 electricity DSOs as part of the Bundesnetzagentur's regulatory procedure for companies falling within the responsibility of the federal states and the national authorities. The individual efficiency values for system operators arising from this benchmarking exercise form the basis for the calculation of individual revenue caps for the second regulatory period from 1 January 2014 through to 31 December 2018.

In the context of the efficiency benchmarking, the supply duties of system operators were considered in relation to the individual costs of operators to determine the relative cost efficiency of particular system operators compared to all their competitors. The multifaceted and complex supply tasks of DSOs were mapped using various structural parameters, such as the number of exit and metering points, the length of cable or overhead lines, annual peak load, the area supplied or decentralised installed power generation. The findings of previous cost assessments were used to determine the cost basis of each system operator.

The network operators and associations were consulted on the methodological procedures to be adopted and the selection of parameters at a presentation provided by the commissioned consortium of consultants (Swiss Economics and Sumicid) and the Bundesnetzagentur. This consultation and other forums at which information was shared with the participating business circles, as well as numerous opportunities for comment, ultimately allowed the industry to be involved in the efficiency benchmarking exercise.

The individual efficiency levels of the DSOs were communicated to the responsible department of Ruling Chamber 8 and to the responsible regulatory authorities of the federal states and considered by these during the process of determining revenue caps.

The system operators covered were found to have a preliminary unweighted efficiency value of 94.7 per cent. Compared to the first regulatory period, relative efficiency has thus risen by 2.5 percentage points. The differentials between individual efficiency values have also narrowed by 1.0 percentage points, which means that the efficiency of electricity DSOs has converged in the first five years of incentive regulation, as was intended.

The total of 700 transmission operators involved in the simplified procedure (DSOs with fewer than 30,000 customers who have not registered for the normal procedure) were found, on the basis of efficiency values for the first regulation period, to have an estimated efficiency value of 96.1 per cent.

D System services

Guaranteeing system stability is one of the TSOs' core tasks and is performed using system services. System services include contracting and using the three kinds of balancing power, namely primary and secondary control and minute reserves. Other system services are the provision of energy to cover grid losses, the provision of reactive power and black start capability, and national and cross border redispatch and countertrading.

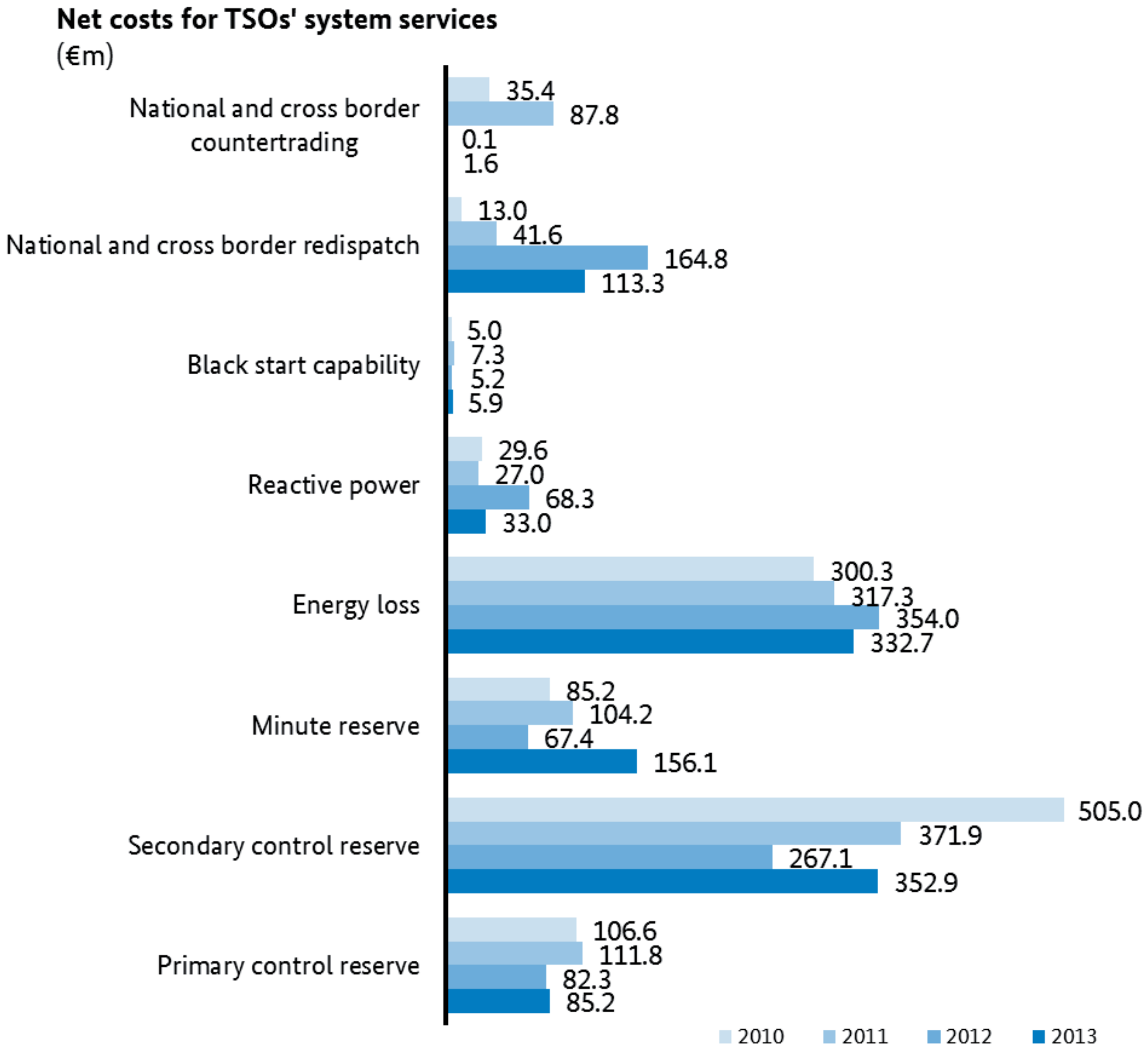

Figure 32: Net costs (outlay costs minus cost-reducing revenues) for German TSOs' system services from 2010 to 2013

The total outlay costs for system services increased from €1,077m in 2012 to €1,127m in 2013 while the cost-reducing revenues decreased from €68m to €46m. As a result, there was an increase in the net costs from €1,009m in 2012 to €1,081m in 2013. A large part of the costs is accounted for by the costs for primary and secondary control and minute reserves – totalling €594m compared to €417m in 2012 – and for energy to compensate for grid losses – at €333m compared to €354m in 2012.

The structure of the costs for system services also changed. There was an increase of €177m in the total net costs for balancing power, most notably because of the higher costs for secondary control and minute reserves (up €86m and €89m respectively). In contrast, the costs for reactive power and energy to cover grid losses fell by €35m and €21m respectively. There was also a decrease of €52m in the net costs for national and cross border redispatch; according to the TSOs this was primarily due to a decrease in the volume of redispatched power in 2013[15].

Breakdown of net costs (outlay costs minus cost-reducing revenues) for German TSOs' system services in 2013
(€m)

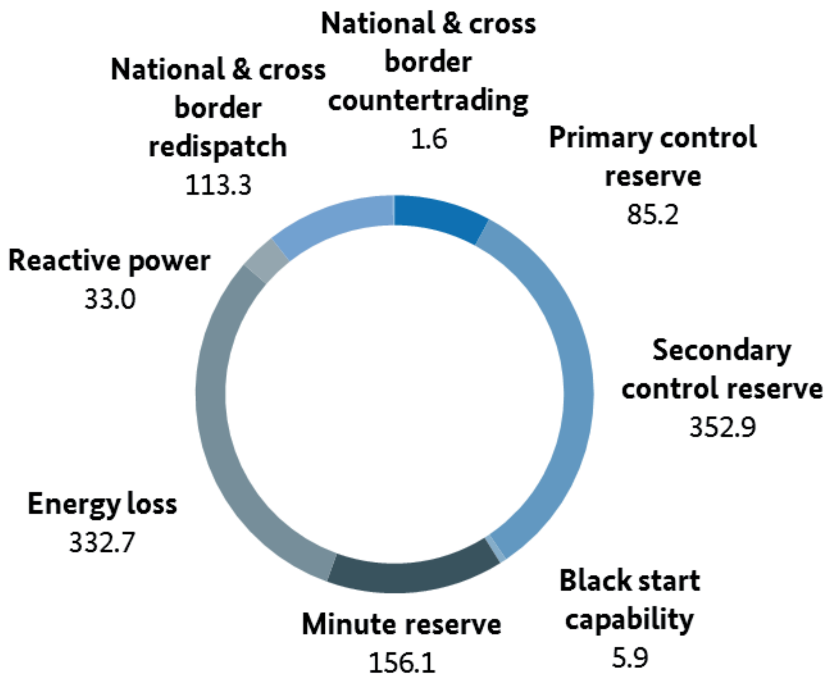

Figure 33: Breakdown of net costs (outlay costs minus cost-reducing revenues) for German TSOs' system services in 2013

1. Balancing energy

The TSOs contract and use balancing reserves and energy to balance offtake and feed-in within the transmission system and ensure the security of electricity supply. They procure balancing services in national tendering procedures in accordance with the Bundesnetzagentur's determinations issued in 2011 (BK6-10-097/098/099). While the costs for contracting reserve capacity are included in the network usage

[15] See I.C.1.7 "Operators' systems responsibility for transmission systems with measures under section 13(1) EnWG in calendar years 2012 and 2013" on page 68

tariffs, the actual energy used is compensated for in the form of portfolio balancing energy by the balancing group managers (dealers, suppliers) causing the imbalances[16].

A grid control cooperation scheme, covering the control areas of all four German TSOs (50Hertz, Amprion, TenneT and TransnetBW), was completed when Amprion joined in 2010 as directed by the Bundesnetzagentur. The scheme's modular structure prevents inefficient use of secondary control and minute reserves and dimensions the reserve requirements for all four control areas together. The scheme also creates a single nationwide market for secondary and minute reserves and optimises the cost of using balancing power for the whole of Germany. The imbalances in the individual control areas are netted so that only what remains has to be compensated for using balancing energy. Inefficient use is almost completely eliminated and the level of balancing power that has to be kept in reserve is reduced, as seen in the lower levels of secondary control and minute reserves tendered and actually used.

One of the aims of the determinations issued by the Bundesnetzagentur in 2011 on reducing minimum bid volumes, shortening tendering periods, pooling and providing collateral for investments in the primary and secondary control and minute reserve markets is to encourage new suppliers to enter the market and to further open the balancing markets for other technologies, eg for interruptible consumption or for storage facilities.

[16] See I.D.4 "Portfolio balancing energy" on page 92.

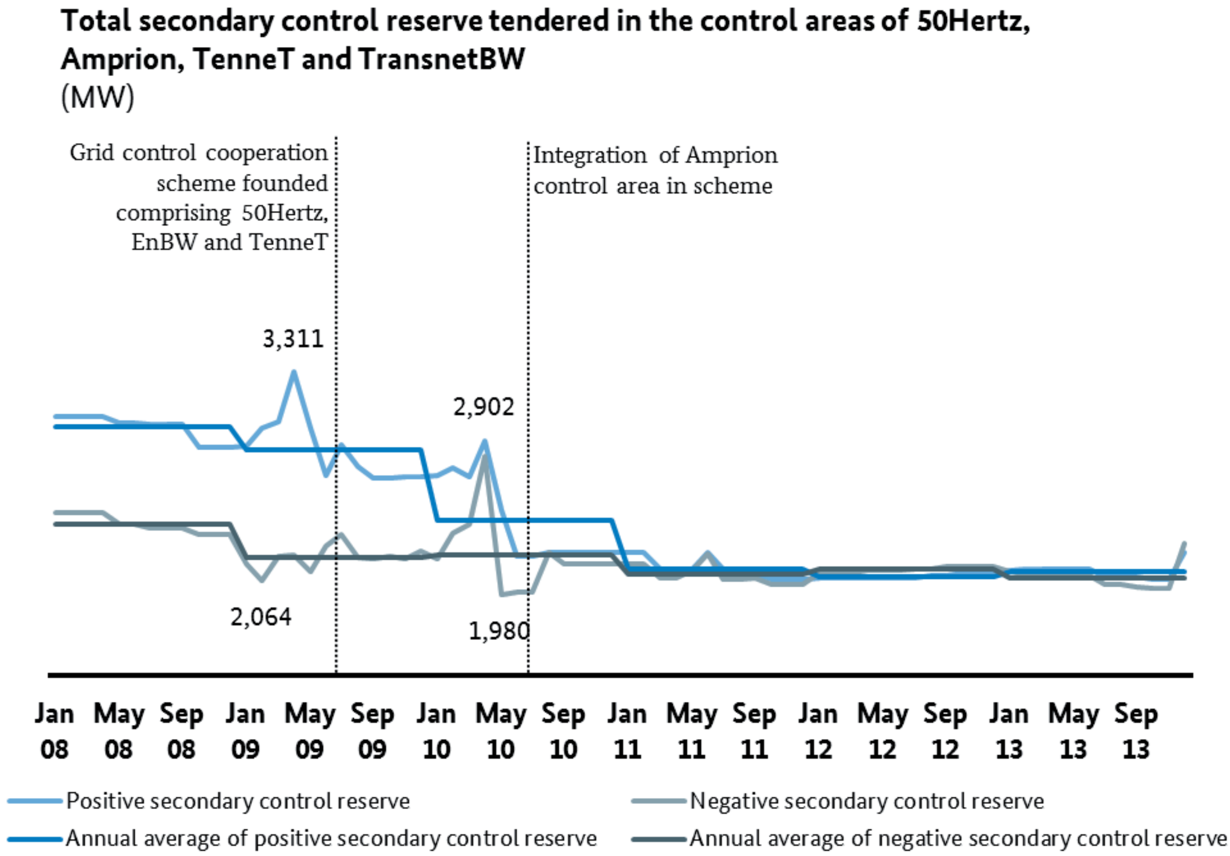

Figure 34: Total secondary control reserve tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

The average secondary control reserve tendered in 2013 was more or less the same as in 2011. The average negative secondary control reserve tendered fell from 2,133 MW in 2012 to 2,081 MW while the positive secondary control reserve rose slightly from 2,091 MW to 2,122 MW.

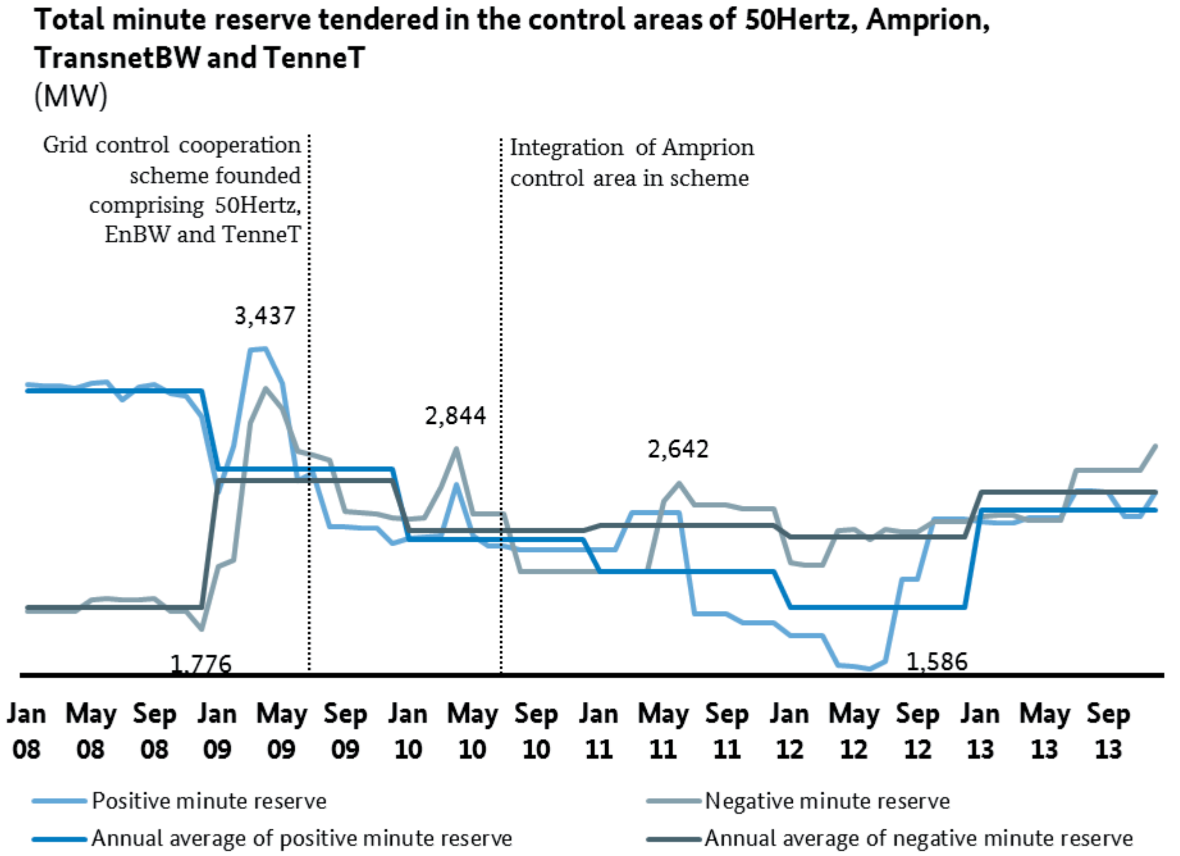

Figure 35: Total minute reserve tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

The picture is less uniform when it comes to the provision of minute reserve. While there was a continued decline in the average positive minute reserve tendered from 2,309 MW to 1,907 MW between 2010 and 2012, the average in 2013 was 2,483 MW. Following a substantial increase in the demand for positive minute reserve from a historic low in May 2012, demand stabilised in the first half of 2013 at just above 2,400 MW. The second half of 2013 was marked by volatility and an overall increase in average levels, with the average positive minute reserve tendered reaching 2,592 MW at the end of the year. There was a year on year increase in the share of negative minute reserve contracted, with an average negative minute reserve tendered in 2013 of 2,591 MW. Overall, the change in the positive and negative minute reserve capacity tendered within the twelve-month period is considerably more volatile than for secondary control reserve. This is partly due to changes in generating patterns and the growing number of renewable energy installations in Germany. The range of the reserve capacity tendered in 2013 can be seen in the table below.

Reserve capacity tendered by TSOs in 2012 and 2013 (MW)

		Primary control reserve		Secondary control reserve				Minute reserve			
				Positive		Negative		Positive		Negative	
		2012	2013	2012	2013	2012	2013	2012	2013	2012	2013
Reserve capacity tendered (MW)	from	567	551	2,081	2,073	2,114	2,018	1,552	2,406	2,158	2,413
	to	567	551	2,109	2,473	2,149	2,418	2,426	2,947	2,491	3,220

Source: www.regelleistung.net

Table 19: Reserve capacity tendered by the TSOs in 2012 and 2013

The demand for primary control reserve fell from 567 MW in 2012 to 551 MW in 2013. There was a year on year increase in the maximum positive and negative secondary control and minute reserve capacity tendered.

The German TSOs are seeking, in consultation with the Bundesnetzagentur and foreign TSOs and regulators, to harmonise the primary control reserve markets across the borders. Swissgrid joined the German TSOs' primary control reserve tendering scheme as the fifth TSO on 12 March 2012. An initial capacity of 25 MW of Switzerland's primary reserve requirements is tendered in line with the German regulations, with Swissgrid acting as the connecting TSO for Swiss providers. The tendering procedure is open to current German and prequalified Swiss providers. TenneT TSO BV in the Netherlands joined the joint tendering scheme as the sixth TSO on 7 January 2014. Here, an initial capacity of 35 MW of the Netherlands' primary reserve requirements is tendered in line with the German regulations, with TenneT TSO BV acting as the connecting TSO for providers in the Netherlands. The tendering procedure is open to current German providers and prequalified providers from the Netherlands. If the procedure proves successful, the Bundesnetzagentur and ACM, the regulatory authority in the Netherlands, may agree in the medium term on joint tendering for all of the Netherlands' primary reserve requirements. The German TSOs are also considering joint primary reserve tendering with other countries. The grid control cooperation scheme and the determinations issued by the Bundesnetzagentur are helping to increase the potential for competition by enlarging the market area, creating a national market for secondary control and minute reserve and aligning the conditions for tendering. By 12 November 2014 the number of prequalified secondary and minute reserve providers had risen to 27 (compared to 15 in 2010 and 20 in 2013) and 40 (compared to 35 in 2010 and 36 in 2013) respectively. The number of primary reserve providers increased from 14 in 2013 to 21. The growing number of balancing service providers shows how attractive this market is. In particular the possibility for one single provider to pool several small installations into one virtual power plant has had a positive effect on competition.

2. Use of secondary control reserve

As Figure 34 shows, the secondary control reserve contracted between 2011 and 2013 remained at a similarly low level. There was another decrease in the volume of secondary control reserve used compared to 2012.

The volume of energy used for positive secondary control in 2013 was some 1.5 TWh (compared to 1.6 TWh in 2010 and 2.1 TWh in 2012) and that for negative secondary control was 2.3 TWh (compared to 4.5 TWh in 2010 and 2.7 TWh in 2012). The total volume of energy for secondary control hence decreased from 4.8 TWh in 2012 to 3.8 TWh in 2013, with a slight shift towards negative power.

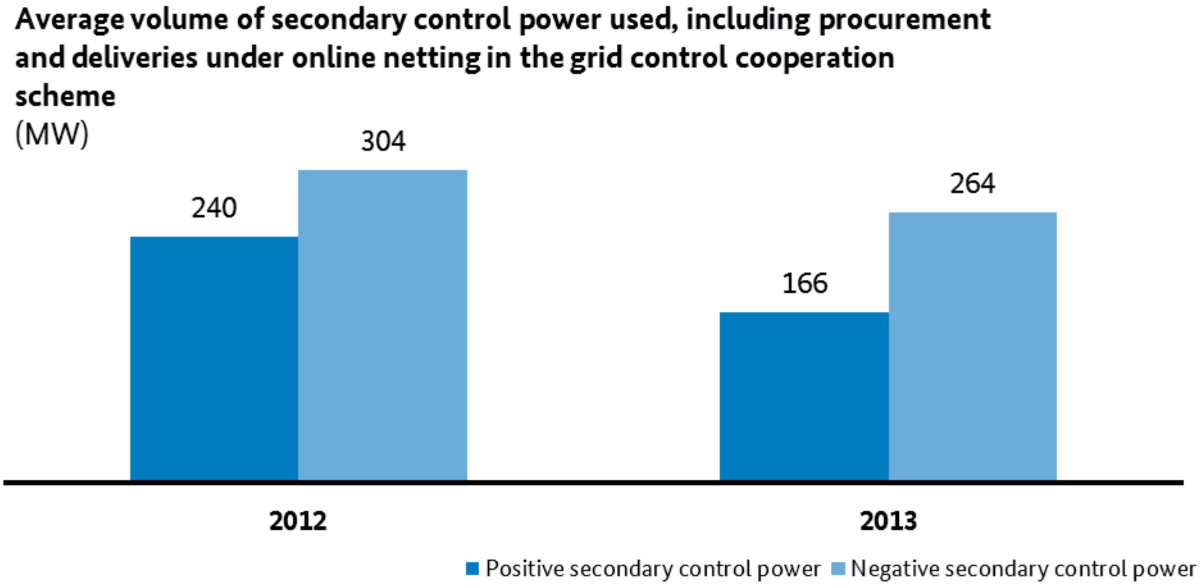

Figure 36: Average volume of secondary control power used, including procurement and deliveries under online netting in the grid control cooperation scheme

3. Use of minute reserve

The total number of dispatch instructions for minute reserve in 2013 was 12,481, representing a year on year decrease of a good 62 per cent (see figure below). This is due in particular to the decrease in the use of positive minute reserve. Overall, there were 4,294 dispatch instructions for positive minute reserve in 2013 (compared to 9,914 in 2012) and 8,187 instructions for negative minute reserve (compared to 10,319 in 2012).

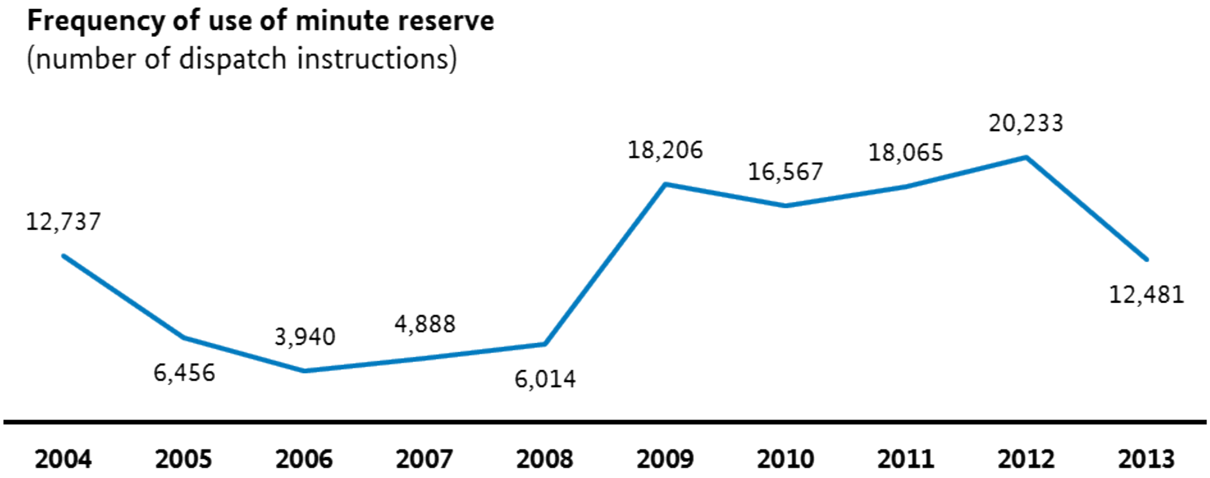

Figure 37: Frequency of use of minute reserve

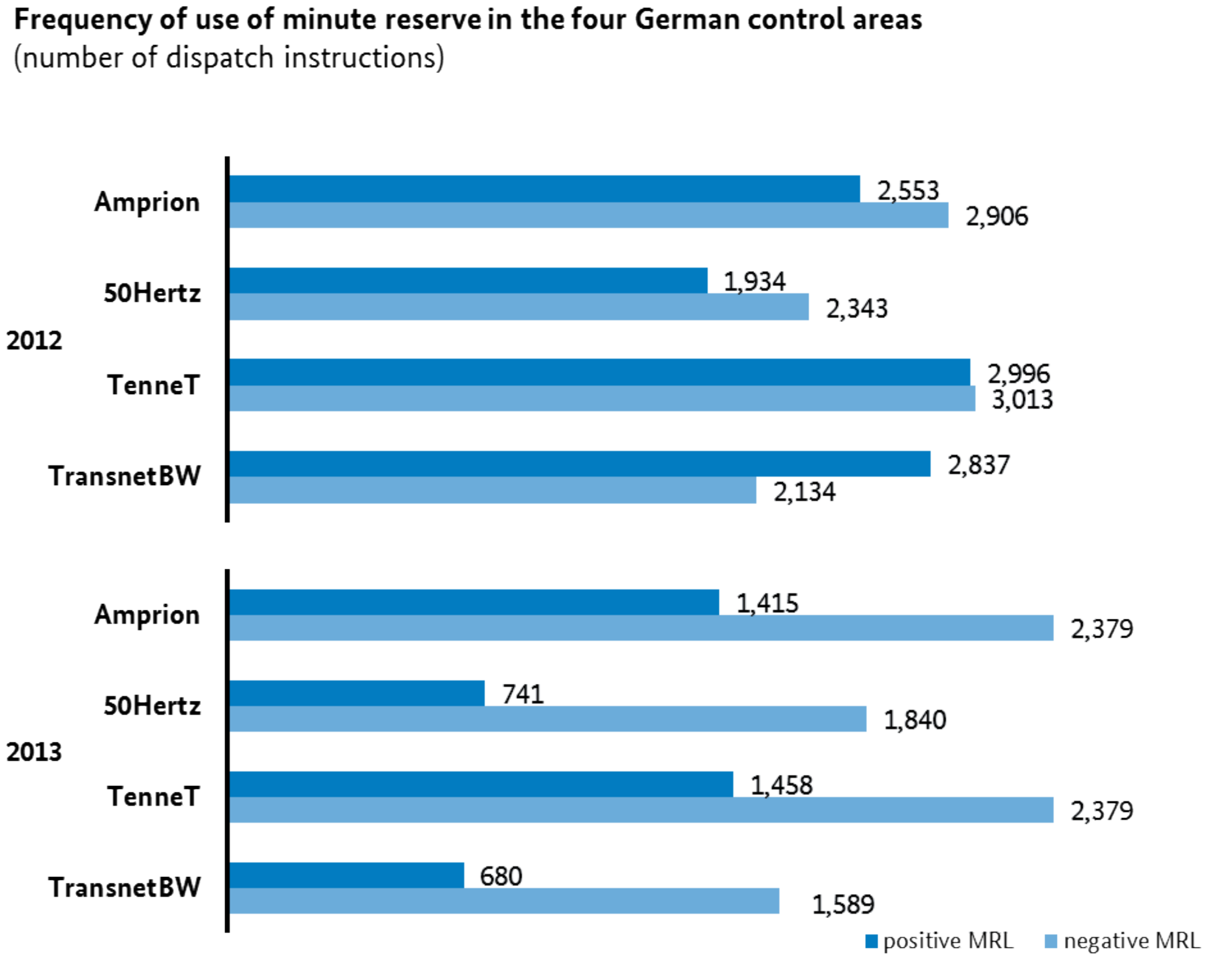

Figure 38: Frequency of use of minute reserve in the four German control areas in 2012 and 2013

There was another decrease in the average positive minute reserve dispatched from 215 MW in 2012 to approximately 201 MW in 2013. Likewise, there was a decrease in the average negative minute reserve dispatched from 233 MW in 2012 to some 215 MW in 2013.

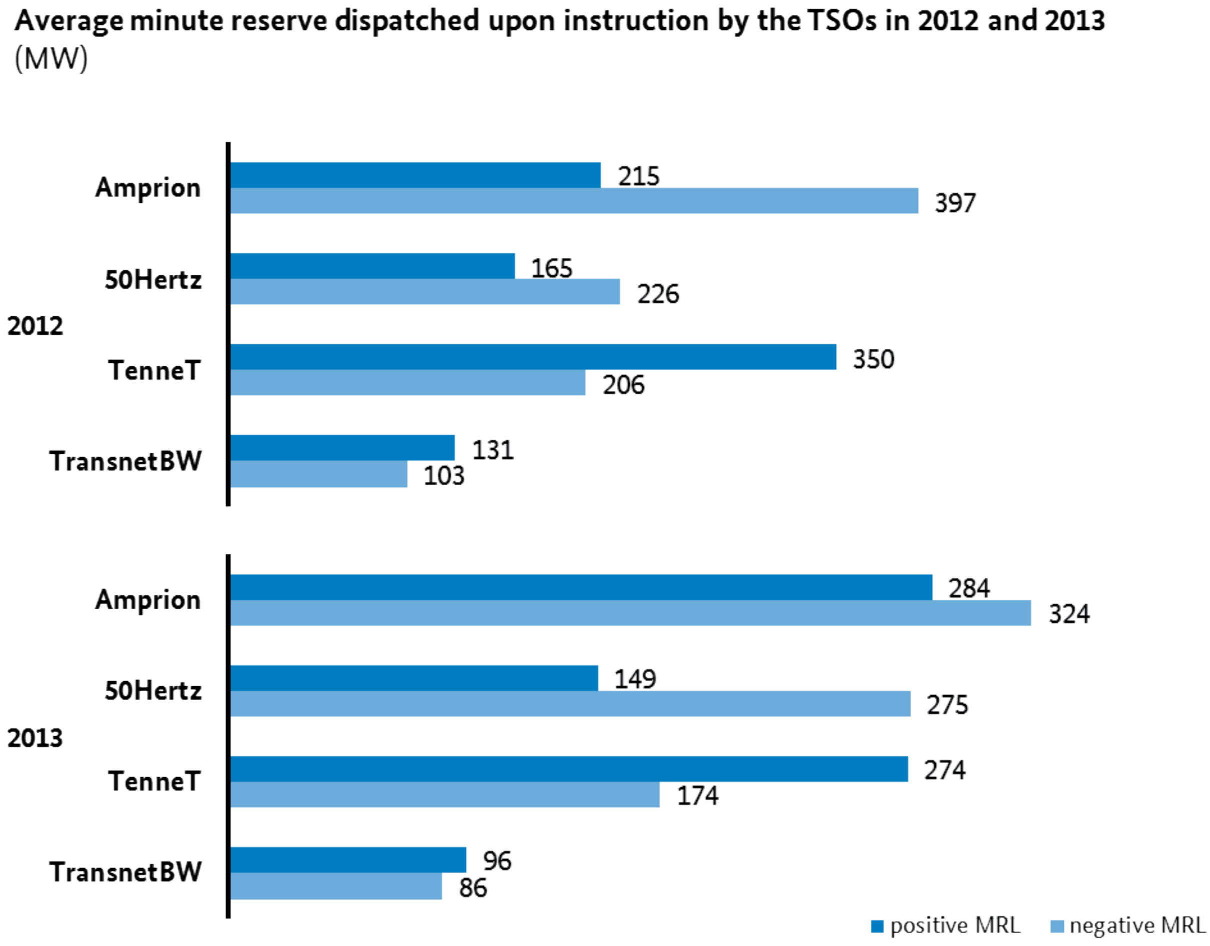

Figure 39: Average minute reserve dispatched upon instruction by the TSOs in 2012 and 2013

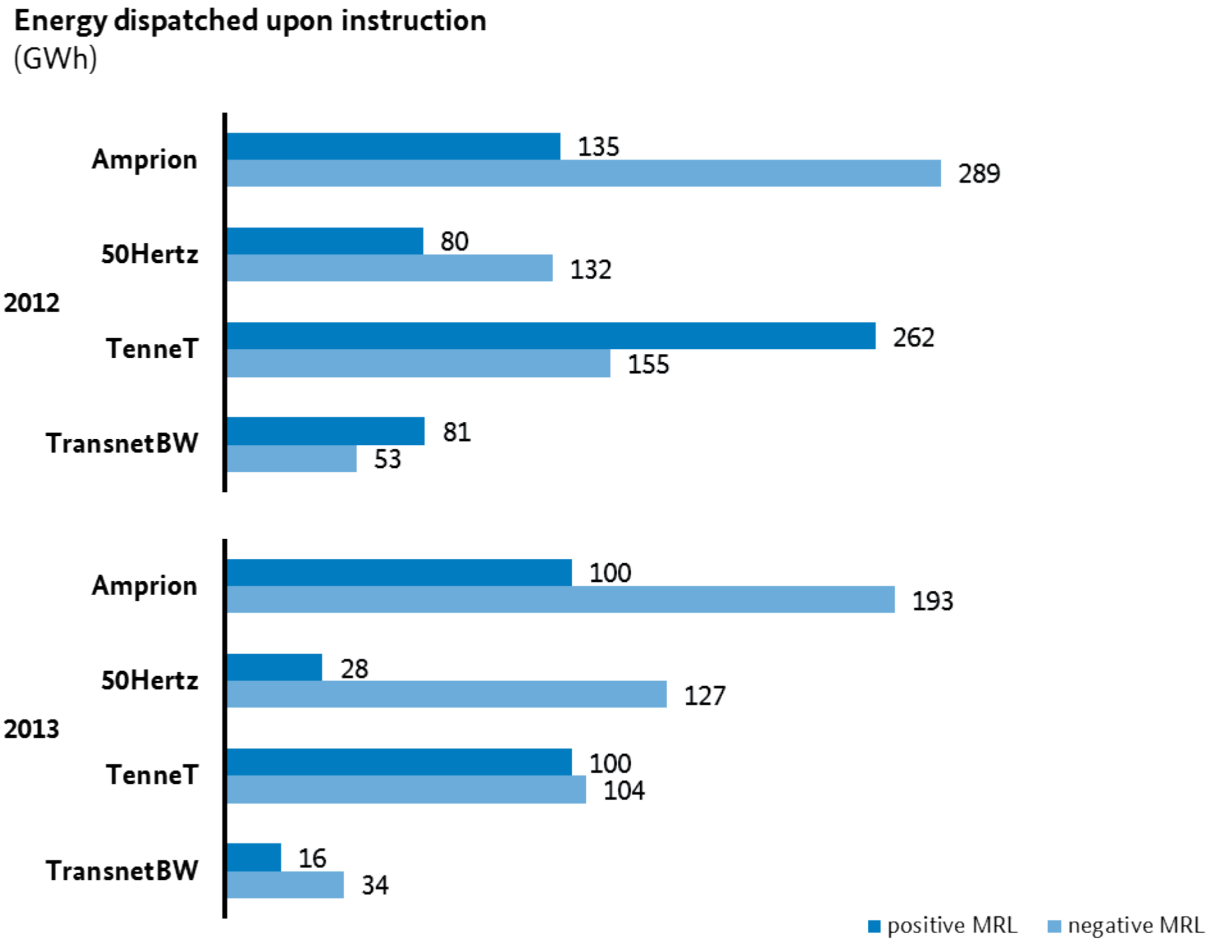

Figure 40: Energy dispatched upon instruction in 2012 and 2013

In 2013, a total of 244 GWh was used for positive minute reserve and 458 GWh for negative minute reserve, compared to 558 GWh and 629 GWh respectively in 2012. This reverses the trend seen in 2012 of a shift away from negative to positive minute reserve.

The figure below shows the average use of balancing energy in each calendar month. It also shows a mean for each period (a change in the grid control cooperation scheme (eg setting up, Amprion joining) marks the beginning of a period). The figure shows the savings potential of the scheme in terms of balancing energy.

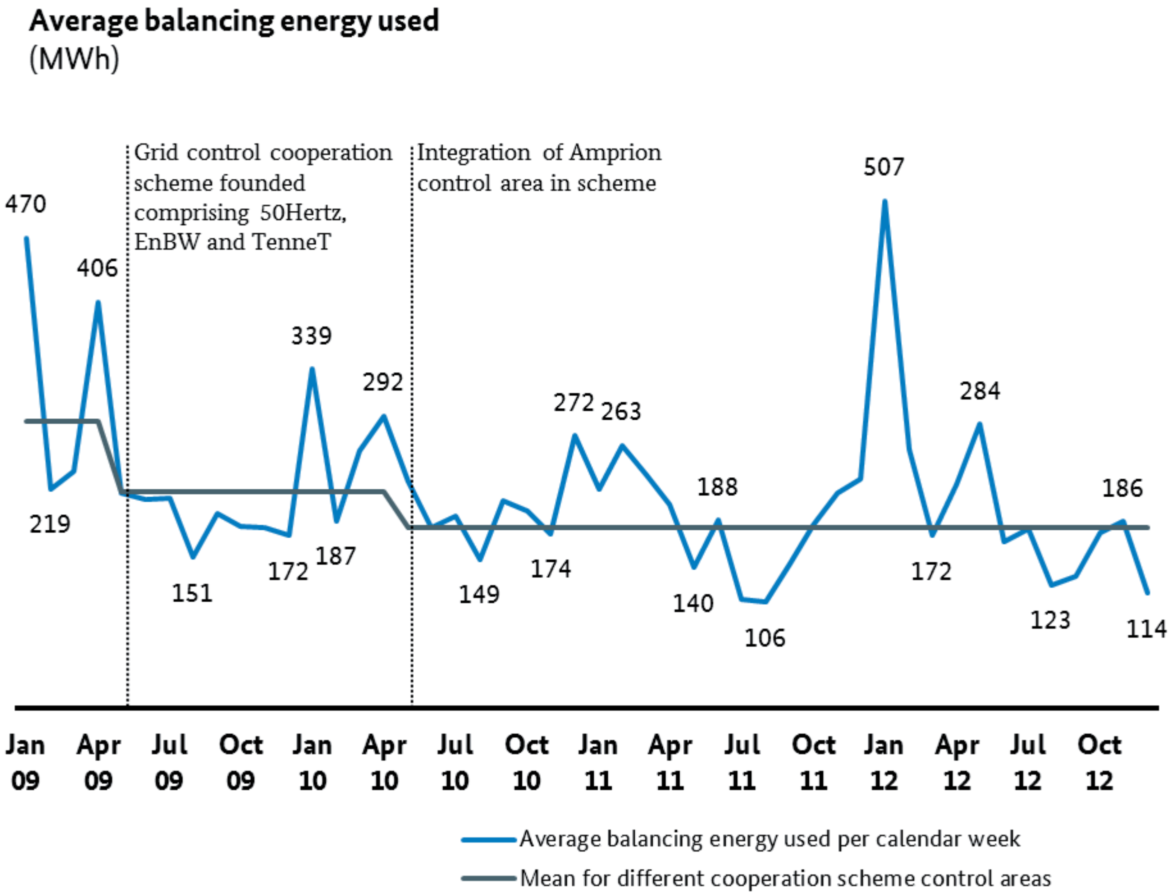

Figure 41: Average balancing energy used

4. Portfolio balancing energy

The regulations laid down by the Bundesnetzagentur reforming the portfolio balancing energy price system came into effect on 1 December 2012. The aim is to provide better incentives for the proper management of balancing groups with a view to preventing system-relevant imbalances such as occurred in February 2012.

The maximum portfolio balancing energy price within the grid control cooperation scheme rose in 2013 to €1,608.20/MWh.

Maximum portfolio balancing energy prices

Year	Grid control cooperation scheme (€/MWh)
2010	600.90
2011	551.60
2012	1,501.20
2013	1,608.20

Table 20: Maximum portfolio balancing energy prices from 2010 to 2013

Under the cooperation scheme, the average 15-minute price for portfolio balancing energy in 2013 in the case of a positive control area balance (short portfolio) was some €84.36/MWh, and in the case of a negative balance (long portfolio) around -€8.43/MWh. There was a clear year on year decrease in the average price for portfolio balancing energy.

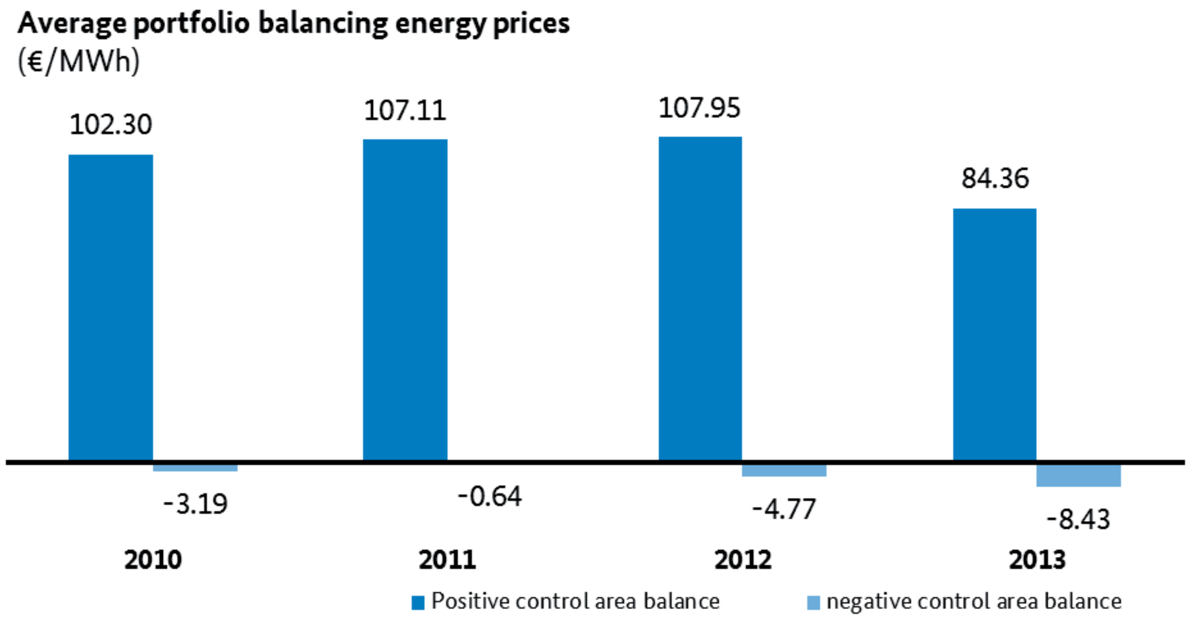

Figure 42: Average portfolio balancing energy prices from 2010 to 2013

The following diagram shows the frequency distribution of portfolio balancing energy prices in the grid control cooperation scheme in 2012 and 2013. In the case of a negative control area balance there is an accumulation of prices around €0/MWh in both years. In the case of a positive control area balance there was also a greater frequency of prices in 2013 between €50/MWh and €100/MWh.

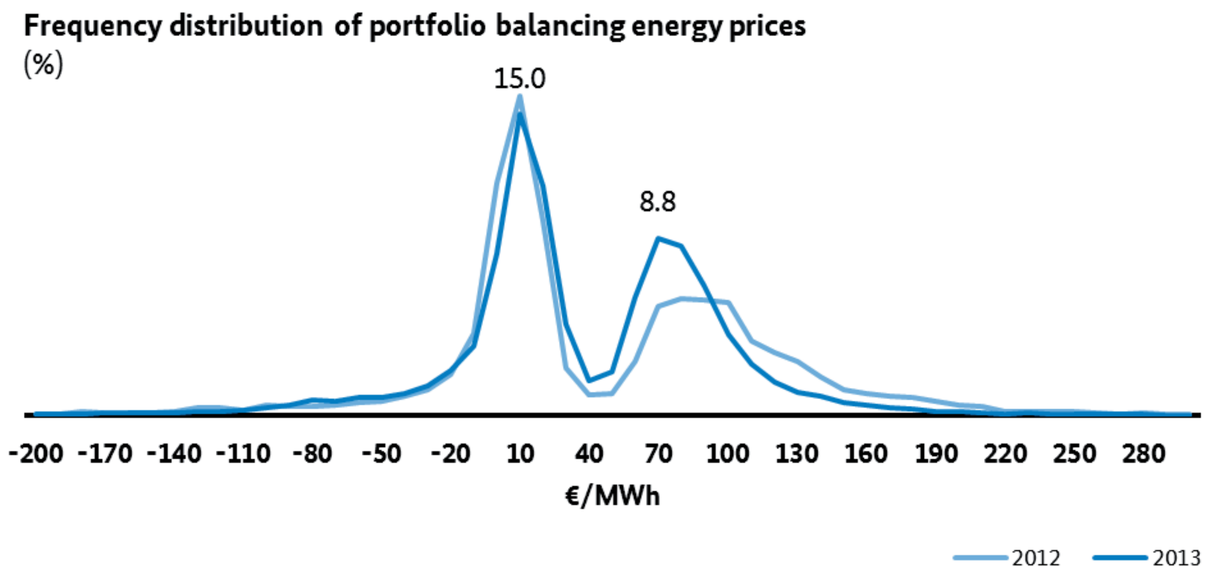

Figure 43: Frequency distribution of portfolio balancing energy prices in 2012 and 2013

5. Intraday trading

Section 5(1) StromNZV allows schedule notifications – in which balancing group managers notify TSOs about planned electricity supply and commercial transactions in the period from the day following submission until the next working day (based on quarter-hour figures) – to be submitted up to 14:30 on a given day. Schedules can also be modified during the day, enabling balancing group managers to respond to short-term changes in supply and demand. The following diagram shows the number and volume of intraday changes to schedules in 2013.

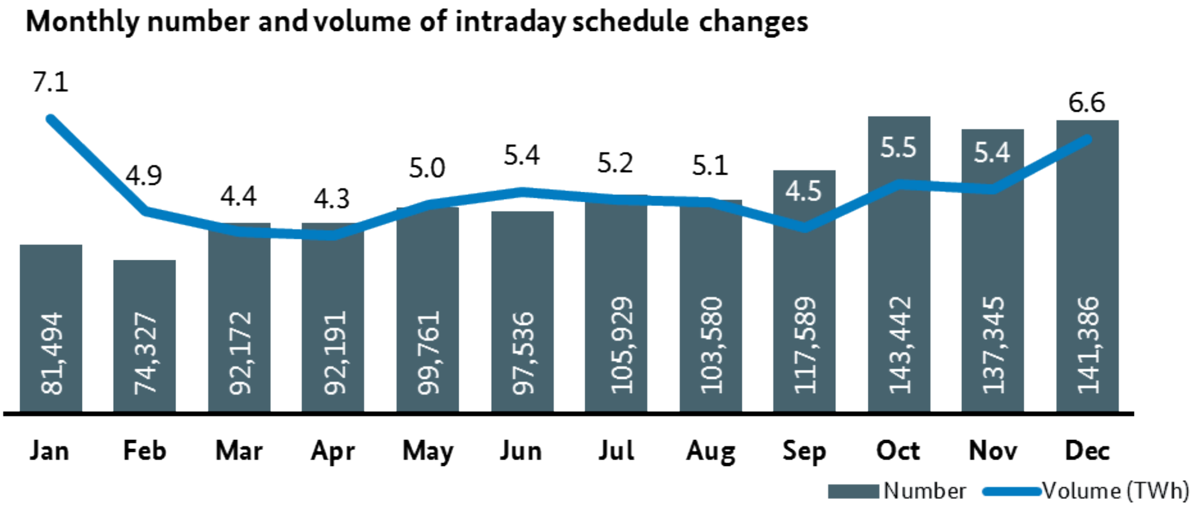

Figure 44: Monthly number and volume of intraday schedule changes in 2013

One reason for the repeated increase in both the number and volume of intraday schedule changes is the increase in the fluctuating feed-in from renewables which frequently needs to be balanced out during the day through intraday trading. In 2013, a total number of 1,286,752 schedule changes accounted for a total volume of 75.5 TWh, compared to 676,902 changes and 63.4 TWh in 2012. On average, 107,000 schedule changes were made each month in 2013, the highest monthly number being 143,442 in October and the lowest 74,327 in February.

6. International expansion of grid control cooperation

The modular grid control scheme of cooperation among the four German TSOs has been fully active in all respects since mid-2010. No more potential for yet more efficient use of balancing energy in Germany can currently be seen.

The modular structure makes a phased expansion of the grid control cooperation scheme to neighbouring foreign control areas possible. The German TSOs have been seeking to push the expansion of Module 1 (Avoidance of action leading to inefficient use of secondary control reserve) since 2011. The International Grid Control Cooperation (IGCC) enables the imbalances and hence the demand for secondary control power in the participating control areas to be automatically registered and physically netted: TSOs with a surplus of energy in their control areas provide power to those with a shortage. No cross border transmission capacity needs to be reserved for this exchange of energy: the maximum amount of balancing energy that can be exchanged across the border corresponds to the remaining capacity available after the close of trading in the intraday market.

Extending the grid control cooperation scheme to other countries enables optimum use of secondary control reserve, leading to a reduction in the amount of minute reserve required without interfering with national framework conditions. The optimisation potential can be realised relatively easily through incorporation in the system. The optimisation system is managed and operated for all participants at TransnetBW's main control centre in Wendlingen.

Cooperation to avoid inefficient use of secondary reserve is carried out with the following countries: Denmark (since October 2011), the Netherlands (since February 2012), Switzerland (since March 2012), the Czech Republic (since June 2012), Belgium (since October 2012) and Austria (since April 2014). Talks and preparations to enable further countries to participate in the scheme are in progress.

7. Network Code on Electricity Balancing[17]

In December 2012 the European Commission requested ENTSO E to develop a network code in line with ACER's Framework Guidelines on Electricity Balancing. In December 2013, after over one year's work with the continuous participation of stakeholders, ENTSO E delivered the Network Code on Electricity Balancing (NC EB) to ACER for its reasoned opinion.

The aim of the Network Code is to integrate the balancing markets in Europe which are currently organised on a largely national basis. Harmonising the balancing products and rules will facilitate the cross border exchange of balancing energy within Europe and promote competition between balancing service providers. One particular aim is to facilitate the inclusion of load management and renewable energy sources in the balancing market. The Network Code enables TSOs to make more efficient use of available resources, thus reducing the costs of contracting reserves and using balancing energy, and at the same time strengthens operational security in Europe.

The Bundesnetzagentur will play an active role in ACER's assessment of the Network Code. If the Network Code meets the requirements of the Framework Guidelines, ACER will recommend that it be adopted by the European Commission as a Regulation via comitology.

[17] See also "Electricity Balancing Network Code
" on page 287.

E Cross-border trading, cross-border interconnectors

Germany has an important role to play in the European interconnected system as a result of its special geographical position in central Europe. As in the previous years, Germany was once again the hub of the exchange of electricity within the central interconnected system. The average available transfer capacity to neighbouring countries changed only slightly in 2013. Capacity showed a year-on-year decrease of 2.79 per cent to 21,137 MW (import and export capacities) in contrast to 2012 when there was an increase of 1.9 per cent.

Cross-border traded volumes rose by 8.4 per cent from 79.7 TWh in 2012 to 86.4 TWh in 2013. The German export balance increased from 21.7 TWh in 2012 to 32.5 TWh in 2013, which corresponds to a rise of 49.9 per cent.

Average available transmission capacity

The availability of transmission capacities between the countries in Europe is of key importance to the internal electricity market. The average available transmission capacities were determined using the TSOs' annual average hourly net transfer capacity (NTC) values, where available. Gaps were filled using average NTC values calculated using ENTSO-E formulae[18].

[18] Care was taken to ensure that border values were determined using data from the same source. Only a limited comparison can be made of individual country capacities, however, as the NTC values transmitted on an hourly basis by the TSOs may deviate from the average values calculated using ENTSO-E formulae, owing to the use of different calculation methods. Details of the NTC calculation methods used by ENTSO-E and the German TSOs can be found at https://www.entsoe.eu/publications/market-reports/ntc-values/Pages/default.aspx.

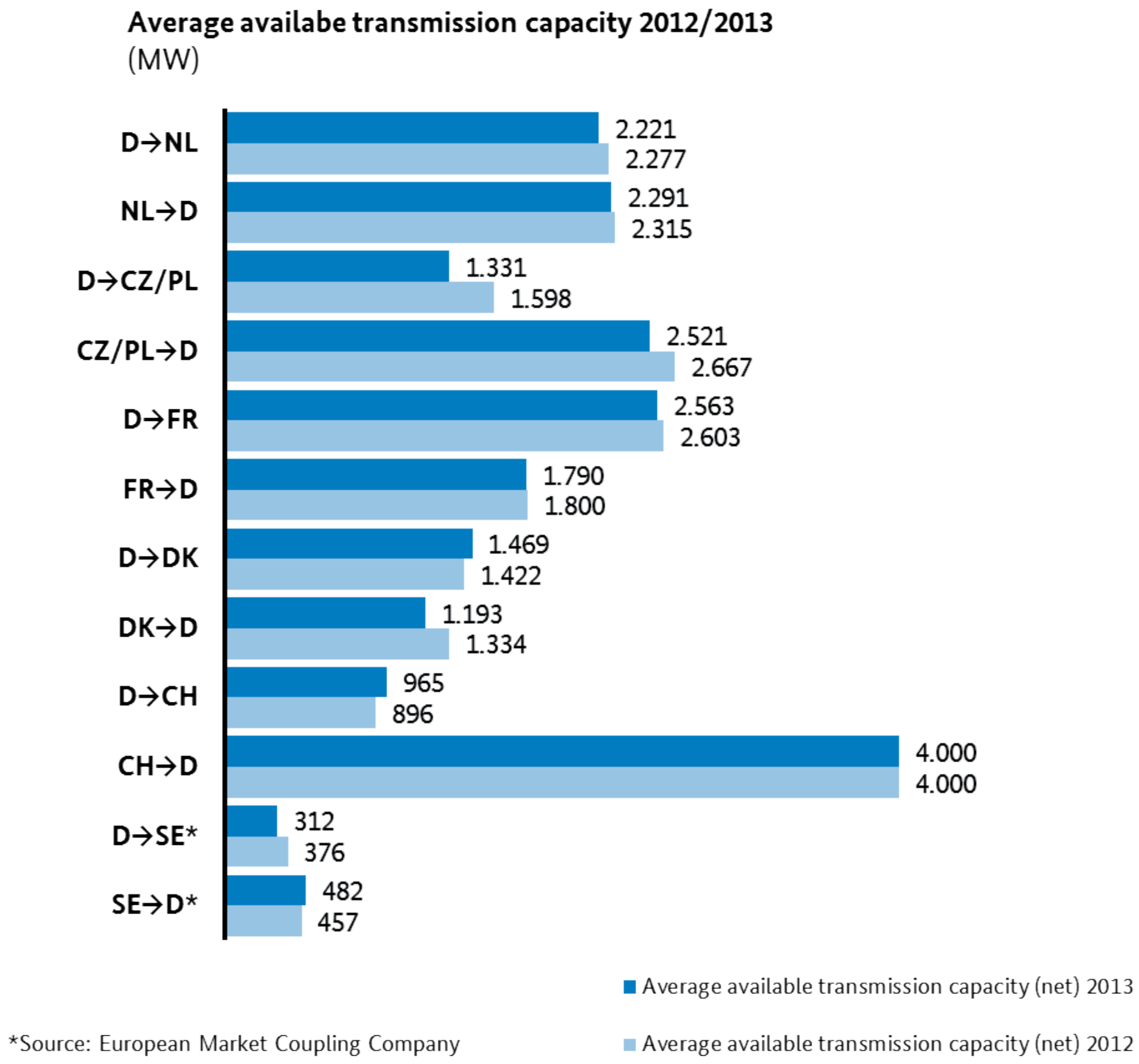

Figure 45: Monthly number and volume of intraday schedule changes in 2013

A change in import capacity was most noticeable at the Polish and Czech border and the Danish border, where import capacity fell by 5.47 per cent and 10.61 per cent, respectively, whereas the Swedish border recorded an increase of 5.39 per cent in import capacity. Some significant changes in export capacity were also noted: whilst capacity at the Polish and Czech border fell by 16.68 per cent and at the Swedish border by 16.84 per cent, capacity at the border to Switzerland rose by 7.71 per cent. These changes in capacity, which were considerable in part, were due to faults in the undersea cable to Sweden and to the transmission system operators' (TSO) modifications so as to achieve the best possible exchange of electricity with other countries yet having regard to system reliability. Average available transmission capacity over all German cross-border interconnectors fell by 2.79 per cent from a total of 21,336 MW in 2012 to 21,137 MW (import and export capacities) in 2013. All the figures are summarised in the table below.

Import capacity

	Average available transmission capacity (net value) in 2012 (MW)	Average available transmission capacity (net value) in 2013 (MW)	Change (%)
NL → D	2,314.83	2,291.11	-1.0
CZ/PL → D	2,667.21	2,521.25	-5.5
FR → D	1,800.00	1,790.46	-0.5
DK → D	1,334.16	1,192.55	-10.6
CH → D	4,000.00	4,000.00	0.0
SE → D	457.00	481.65	5.4
Total	12,573.19	12,277.01	-2.4

Table 21: Import capacity trend from 2012 to 2013

Export capacity

	Average available transmission capacity (net value) in 2012 (MW)	Average available transmission capacity (net value) in 2013 (MW)	Change (%)
D → NL	2,276.65	2,220.70	-2.5
D → CZ/PL	1,597.87	1,331.32	-16.7
D → FR	2,603.07	2,562.95	-1.5
D → DK	1,422.47	1,468.68	3.3
D → CH	895.63	964.72	7.7
D → SE	375.72	312.45	-16.8
Total	9,171.42	8,860.81	-3.4

Table 22: Export capacity trend from 2012 to 2013

1. Cross-border load flows and implemented exchange schedules

The exchange schedules implemented are decisive in assessing the net balance of electricity imports and exports at each external border and at all of Germany's borders as a whole.

These exchange schedules reflect net excess generation, or demand shortage, which arise according to the rules of the market[19]. The following diagram shows the exchange schedules implemented at Germany's borders in 2013.

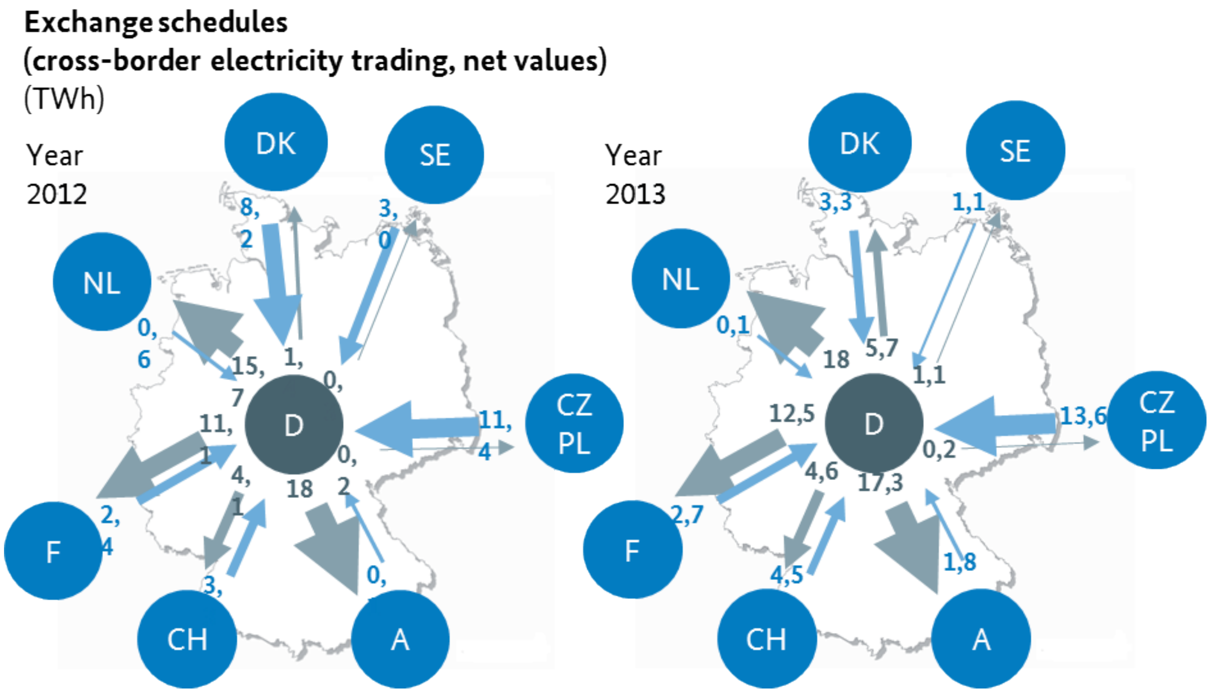

Figure 46: Exchange schedules (cross-border electricity trading)

The rise in exports in 2013 is linked to the increase in electricity generated by renewable sources and to falling prices on the German power exchange. In 2013, the average EPEX day-ahead spot price shrank to just €37.78 per megawatt hour, whereas in 2012 the average price was €42.60. All the figures are summarised in the tables below.

[19] The aim is for electricity to be traded from low-price to high-price countries via the cross-border interconnectors.

Imports in TWh

	Actual physical load flow in 2012	Binding exchange schedules in 2012	Actual physical load flows in 2013	Binding exchange schedules in 2013
NL → D	0.7	0.6	0.3	0.1
CZ/PL → D	8.6	11.4	9.9	13.6
FR → D	13.2	2.4	11.8	2.7
DK → D	8.2	8.2	3.2	3.3
CH → D	3.1	3.3	3.7	4.5
AT → D	6.8	0.1	5.7	1.8
SE → D	2.9	3.0	1.1	1.1

Table 23: Comparison of imports from cross-border flows

Exports in TWh

	Actual physical load flow in 2012	Binding exchange schedules in 2012	Actual physical load flows in 2013	Binding exchange schedules in 2013
D → NL	22.6	15.7	24.6	18.0
D → CZ/PL	8.7	0.2	7.9	0.2
D → FR	0.8	11.1	1.2	12.5
D → DK	1.5	1.4	5.8	5.7
D → CH	12.7	4.1	11.7	4.6
D → AT	15.9	18.0	14.4	17.3
D → SE	0.3	0.3	1.0	1.1

Table 24: Comparison of exports from cross-border flows

Balance in TWh

	Actual phsyical load flow in 2012	Binding exchange schedules in 2012	Actual physical load flows in 2013	Binding exchange schedules in 2013
Import	43.5	29.0	35.8	26.9
Export	62.4	50.7	66.5	59.4
Balance	18.8	21.7	30.7	32.5

Table 25: Comparison of the balance of cross-border flows

Monetary trend in cross-border electricity trading

	2012		2013	
	in TWh	Trade volume in €	in TWh	Trade volume in €
Export	50.69	2,106,176,769.68	59.44	2,197,629,995.34
Import	28.99	1,274,129,231.47	26.95	1,052,899,357.22
Balance	21.70	832,047,538.20	32.49	1,144,730,638.12
Export revenues in €/MWh		41.55		36.98
Import costs in €/MWh		43.95		39.07

Table 26: Monetary trends in cross-border exchanges in electricity

Changes in cross-border trading volumes between Germany and its neighbouring countries in particular reflect changes in the price differences. The reasons for these differences depend on a wide range of factors that have a direct influence on the merit order and therefore especially on wholesale prices in the individual countries. This means that changes in trading volumes are not determined solely by the German market, but also reflect shifts in supply and demand in each neighbouring country. Factors such as temperature and season have a direct effect on demand. The direct influencing factors on supply are weather phenomena. For example, the occurrence of unexpected fog patches or snow cover may cause actual photovoltaic generation to differ from that forecast and this then has a direct influence on electricity prices. Further influencing factors are the poor economic climate and consequent decrease in electricity consumption, as are fuel costs on the world market.

The actual physical load flows shown in the following diagram deviate from the exchange schedules for each border[20].

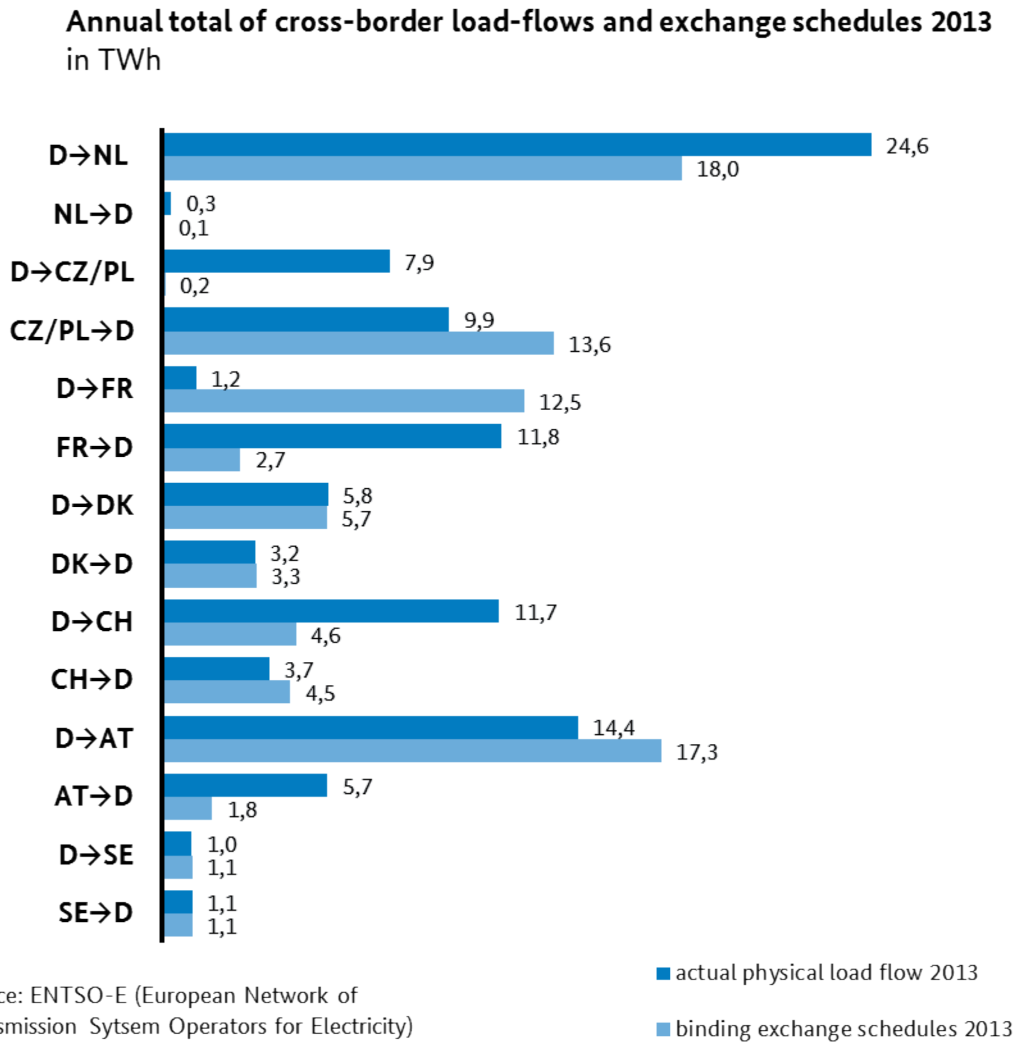

Figure 47: Physical cross-border load flows

2. Revenue from compensation payments for cross-border load flows

Under Article 1 of Commission Regulation (EU) No 838/2010 the TSOs receive inter-TSO compensation (ITC) for costs incurred as a result of hosting cross-border flows of electricity (transit flows) on their networks. ENTSO E set up an ITC fund for the purpose of compensating the TSOs. The fund is to cover the costs of losses incurred on national transmission systems as a result of hosting cross-border flows as well as the costs of making infrastructure available to host these flows.

[20] While the total net export balance for implemented exchange schedules and actual physical flows – with the exception of transmission losses – across all German cross-border interconnectors is identical, the values at each border generally differ as actual flows follow the purely physical path of least resistance and, on account of the interconnected transmission systems, can deviate from implemented exchange schedules and go indirectly from regions with high generation capacities via third countries (eg from France via Germany/Switzerland to Italy).

Every year ACER publishes a Report to the European Commission on the implementation of the ITC mechanism in accordance with point 1.4 in Part A of the Annex to Commission Regulation No 838/2010.

As per the ACER report, the latest figures for 2013 are as follows:

The four German TSOs received compensation in 2013 of €41.97m for energy loss and for making infrastructure available and, in return, made contributions of €27.76m. On balance this represents an amount of €13.21m (2012: €26.8m), which the German TSOs received net as compensation payments from the ITC mechanism.

F European integration

1. Market coupling of European electricity wholesale markets

The creation of a European internal market in electricity is a declared aim of the European Union. Under point 3.2. of Annex I to Regulation (EC) No 714/2009 this aim should be implemented progressively in individual European regions. The work begun in November 2010 on coupling the day-ahead electricity markets for central western Europe continued strongly in 2013 for North Western Europe ("NWE" – Benelux, France, Germany, Great Britain and Scandinavia). The NWE day-ahead price coupling project was successfully launched in February 2014. Other regions are expected to follow and gradually join the NWE region. The first other region to be coupled was South Western Europe ("SWE" - France, Portugal and Spain) in May 2014. This means that three-quarters of European power exchanges have now been successfully coupled.

The objective of market coupling is the efficient use of day-ahead available transmission capacities between participating countries. This reduces the loss of social welfare that may result from congestion between the countries. This method consequently brings about an alignment of prices on the participating national day-ahead markets. Indeed, price convergence, as an indicator of the efficient use of interconnector capacities, is significantly higher in coupled than in uncoupled regions.

At the European level, ACER has tasked the Bundesnetzagentur with managing the project to implement market coupling throughout Europe. With this aim in mind, the Bundesnetzagentur has drawn up an implementation plan for ACER which details specific milestones.

2. Flow-based capacity allocation

The Framework Guidelines on Capacity Allocation and Congestion Management for Electricity drawn up by ACER define flow-based market coupling as the target model for short-term capacity management in Central Europe. One of the cornerstones of this is flow-based capacity calculation. This involves already taking account of the physical flows that specific commercial transactions are expected to generate in the capacity calculations and then determining the remaining available transmission capacities according to efficiency criteria and system security aspects. This guarantees greater system security and the improved use of transmission capacities.

Following the successful introduction of market coupling in Central Western Europe (CWE region) in autumn 2010, work began on the implementation of the flow-based capacity calculation method. In 2013 the project partners held a public consultation to give all market players affected by the flow-based capacity allocation method an opportunity to share their technical expertise and clarify any ambiguities. The outcome of this was subsequently taken into account when implementing the flow-based market coupling. It is planned to launch the flow-based capacity calculation method in the CWE region on 31 March 2015.

In addition to the CWE region, work is currently being undertaken in Central Eastern Europe (CEE region) to introduce the flow-based capacity calculation method, which is expected to be launched in 2016. Subsequently the two regions will be linked together.

For further development it is essential that the work in the two regions is well-coordinated at an early stage to ensure that the flow-based capacity calculation methods in each region will be compatible. The focus here will be on identifying common standards in both regions, drawing up a common timetable for implementing these standards, accompanying the cross-regional harmonisation process and producing a final report following successful market coupling.

3. Network Code on Capacity Allocation and Congestion Management[21]

Network Code on long-term capacity allocation

With the aim of accelerating the integration of national electricity markets across Europe, Regulation (EC) No 714/2009 provides for the development in the first instance of framework guidelines on cross-border congestion management, amongst other things, by the regulators within ACER. The next step is for ENTSO E, the European association of transmission system operators, to draw up network codes in line with these framework guidelines.

The regulators began their work on the Framework Guidelines on Capacity Allocation and Congestion Management for Electricity at the end of 2009 and completed it in summer 2011. The Framework Guidelines set the fundamental course for the future organisation of the internal electricity market in Europe. Specifically, they set out principles for congestion management methods for forward, day-ahead and intraday capacity allocation. They also specify the abstract method to be used to calculate cross-border electricity transmission capacities.

Financial transmission rights are envisaged for forward capacity allocation, together with a single platform at European level for secondary trading with long-term transmission rights. Day-ahead capacity trading is to take place implicitly, ie at the same time as commercial electricity trading, via a single price coupling algorithm. Intraday trading should also be implicit, using a calculation algorithm based on a first come, first served principle. Intraday available capacity is to be traded via a single platform and linked to the exchanges' order books.

A flow-based capacity calculation method is to be introduced that determines cross-border transmission capacity on the basis of commercial transactions and neighbouring cross-border interconnectors. In parallel to this, the Regional Initiatives established in the electricity sector have launched various projects to implement the models in the Framework Guidelines. Some of these projects build on others begun in the regions before 2010.

The regulatory approval procedures are to be amended so that the powers of approval also cover the methodologies and the regulatory authorities have the general power to request amendments. As regards intraday auctions, provision should be made in the Network Code to enable regional auctions in addition to continuous cross-border trading in the daily process. The Code should define clear and consistent deadlines for the key trading time frames to provide a common timetable for trading.

[21] See also "Network Code on Capacity Allocation and Congestion Management (CACM)" on page 284

In 2013 ACER submitted the Network Code on Capacity Allocation and Congestion Management (CACM) to the European Commission for agreement. In December of that year, the Electricity Cross-Border Committee of the European Commission started the committee procedure for final conciliation and adoption. So far discussions have been held on the basis of an informal text as the Commission has not prepared its own official draft. Adoption should take place in 2014 following a majority decision. The Bundesnetzagentur is assisting and advising the Federal Ministry of Economics and Technology, which represents the Federal Republic on the Electricity Cross-Border Committee, throughout this part of the procedure.

A separate network code has been developed for forward capacity allocation. Upon completion of the public consultation process, the final version of the Network Code was delivered to ACER in October 2013. In its reasoned opinion ACER commenced by pointing out material deviations still existing in the Network Code from the proposed Framework Guidelines to ENTSO-E and requesting swift implementation. A revision of the Code will take until 2014.

The question of redefining the current bidding zones is one that is coming increasingly to the fore in discussions at European level about the future design of the electricity market. The procedure laid down in the CACM Network Code is therefore already being followed on an informal basis as part of the early implementation of the Code.

ENTSO E's current draft provides for a joint assessment of the bidding zone configuration by the TSOs, the national regulatory authorities and ACER every three years once the Network Code is in force.

The assessment process is divided into four procedural steps: First of all the TSOs are to submit a technical report which examines their current bidding zone configuration from a network perspective. At the same time, in cooperation with the national regulatory authorities, ACER will draw up a market report that examines the distribution of market power and market liquidity in the current bidding zones. Based on the results of these two reports, the national regulatory authorities will decide whether an evaluation of the bidding zone configuration is to be carried out, in which case the TSOs will examine the bidding zone configuration. The evaluation gives priority to criteria relating to network security, market efficiency and the stability of the bidding zones.

As part of this evaluation, the TSOs are to propose alternative bidding zone configurations to be assessed in a public consultation of the stakeholders. The consultation can result in a proposal to maintain or to amend the existing configuration. The proposal put forward as a result of the assessment is to be implemented within twelve months of the decision to carry out the evaluation.

ACER and the national regulatory authorities will jointly decide on the next course of action based on an evaluation of the current assessment of the bidding zone configuration, in due accordance with the criteria laid down in the draft CACM Network Code.

Germany welcomes this process, which enables much-discussed issues to be examined for the first time in a structured procedure within a European perspective.

4. Network load in adjacent countries

On account of the laws of physics and the consequent fact that electricity flows through the lines of least resistance, electricity does not always flow in the direction traded. Rather electricity flows in part through the lines of neighbouring countries. The resulting loop and transit flows constitute a natural phenomenon in interconnected networks, hence each country can be the cause as well as the recipient of such flows.

In the case of northern Germany, these unplanned electricity flows occur particularly in generation situations with high wind power feed-in. Flows from the north to the south of Germany, and trade flows between Germany and Austria, may therefore sometimes follow a path via Poland and the Czech Republic or via the Netherlands, Belgium and France. One timely solution to the problem of loop flows is the deployment of virtual or physical phase-shifting transformers (PSTs). Physical PSTs (pPSTs) can be used to restrict the flow of electricity on a line like a valve. The use of pPSTs has already produced good results in the CWE region in physically restricting the transit flows through Belgium. Their use, however, will place an even greater strain on the German networks, in particular on flows from north to south. The deployment of virtual PSTs (vPSTs) comprises a contractual agreement between two or more TSOs defining a maximum limit for cross-border electricity flows, to be adhered to by means of redispatching. The use of a vPST between Germany and Poland in a pilot phase from 8 January to 30 April 2013 showed that this can successfully counter loop and transit flows until the installation and commissioning of a pPST. In light of this, 50Hertz Transmission GmbH, a German TSO, and PSE S.A., a Polish TSO, agreed to introduce the operational phase of the vPST, which has now been in operation since 18 March 2014. The German share of the costs are being shared by 50Hertz Transmission GmbH and TenneT TSO, GmbH, both German TSOs, and by APG, an Austrian TSO. The first pPSTs are expected to be installed at the end of 2015/beginning of 2016 on the German-Polish border. Alongside this, 50Hertz Transmission GmbH has entered into an agreement with CEPS, a Czech TSO, for the installation and coordinated operation of pPSTs on the German-Czech border by the end of 2016. One issue that is at least partly related to restricting ring flows is the configuration of bidding zones. In this connection, the current bidding zone configuration and possible alternatives are being assessed as part of the early implementation of the CACM Guideline. At the present time the scenarios to be evaluated by the ENTSO-E are being identified and the calculation criteria established. ACER and the national regulatory authorities are involved both in this phase of the procedure and in the further course of action.

G The wholesale market

Functioning wholesale markets are vital to competition in the electricity industry. Spot markets, on which volumes of electricity which are needed, or not needed, in the near future can be bought or sold, and futures markets, which amongst other things facilitate the hedging of price risks in the medium and long term, equally take on a major role. Sufficient liquidity, that is an adequate volume on the supply and demand sides, improves the scope for market entry for new suppliers. Market players are given the opportunity to diversify their selection of trading partners and products, as well as forms and procedures of trading. In addition to bilateral wholesale trading (known as “OTC” or over-the-counter trading), central importance attaches to electricity exchanges. Such exchanges create a reliable trading place, at the same time as also providing major price signals for market players in other areas of the electricity industry.

The liquidity of the electricity wholesale markets remained stable at a high level in 2013. Volume growth can be observed in on-exchange forward trading. Average electricity wholesale prices fell in 2013. Average spot market prices on EPEX SPOT fell by roughly eleven percent year-on-year, whilst average futures were quoted roughly 20 percent lower for the following year on EEX.

1. On-exchange wholesale trading

As in previous years under report, the observation of on-exchange electricity trading relates to the market area of Germany and Austria and to the exchanges in Leipzig (EEX), Paris (EPEX SPOT) and Vienna (EXAA). The exchanges have once more participated this year in the data collection in energy monitoring. Since Germany and Austria constitute one single supply area, the individual types of electricity contract (“products”) are traded on all three exchanges at exchange prices (“one price zone”) which are uniform for both countries[22]. European Energy Exchange AG (EEX) offers electricity products in forward trading, whilst EPEX SPOT SE and Energy Exchange Austria/EXAA Abwicklungsstelle für Energieprodukte AG (EXAA) supply electricity products in the spot market area[23].

The exchanges have become established as major trading places. The number of participants authorised at the exchanges for electricity trading in the Germany/Austria market area has been at a stable level for several years.

[22] The intraday product on EPEX SPOT is offered separately for Austria and Germany.

[23] There are company affiliations between EEX and EPEX SPOT. In particular, EPEX SPOT SE is owned equally by EEX AG and Powernext SA, which are currently being restructured in the course of a merger project. EEX is to become the indirect majority shareholder of EPEX SPOT via Powernext SA as per 1 January 2015.

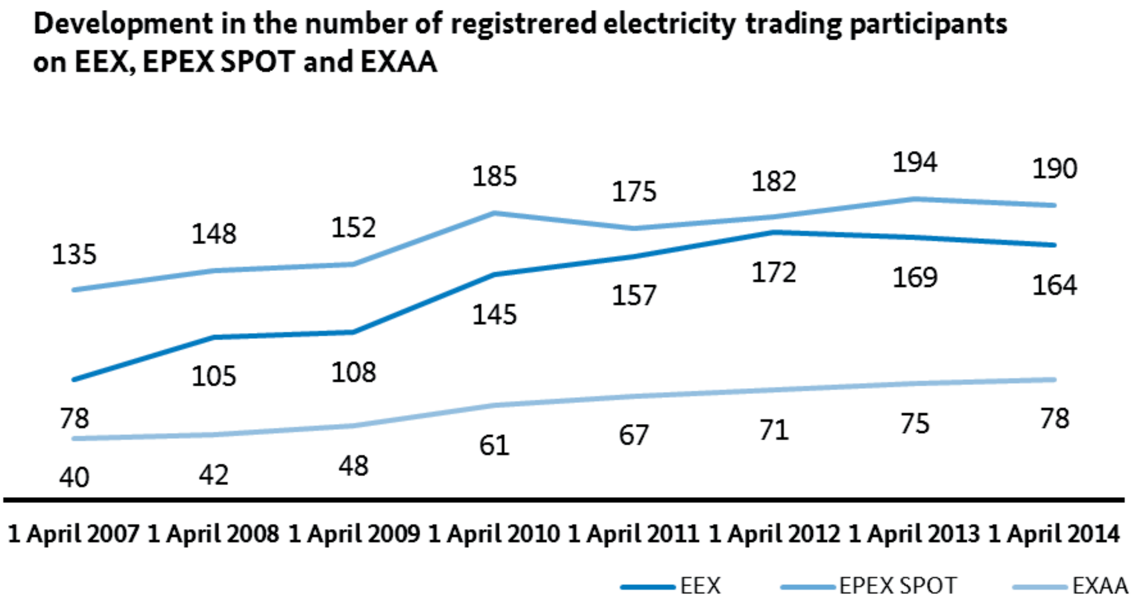

Figure 48: Development in the number of registrered electricity trading participants on EEX, EPEX SPOT and EXAA

Not every company operating at wholesale level needs to have its own access to the exchange in order to take up the possibilities offered by the exchange. In fact, companies can also take up services offered by brokers that are registered on the exchanges. Larger groups frequently combine their trading activities in a group company which has the appropriate exchange registration. The following spectrum of participants emerges according to the categories by which EPEX SPOT and EEX classify their exchange participants.

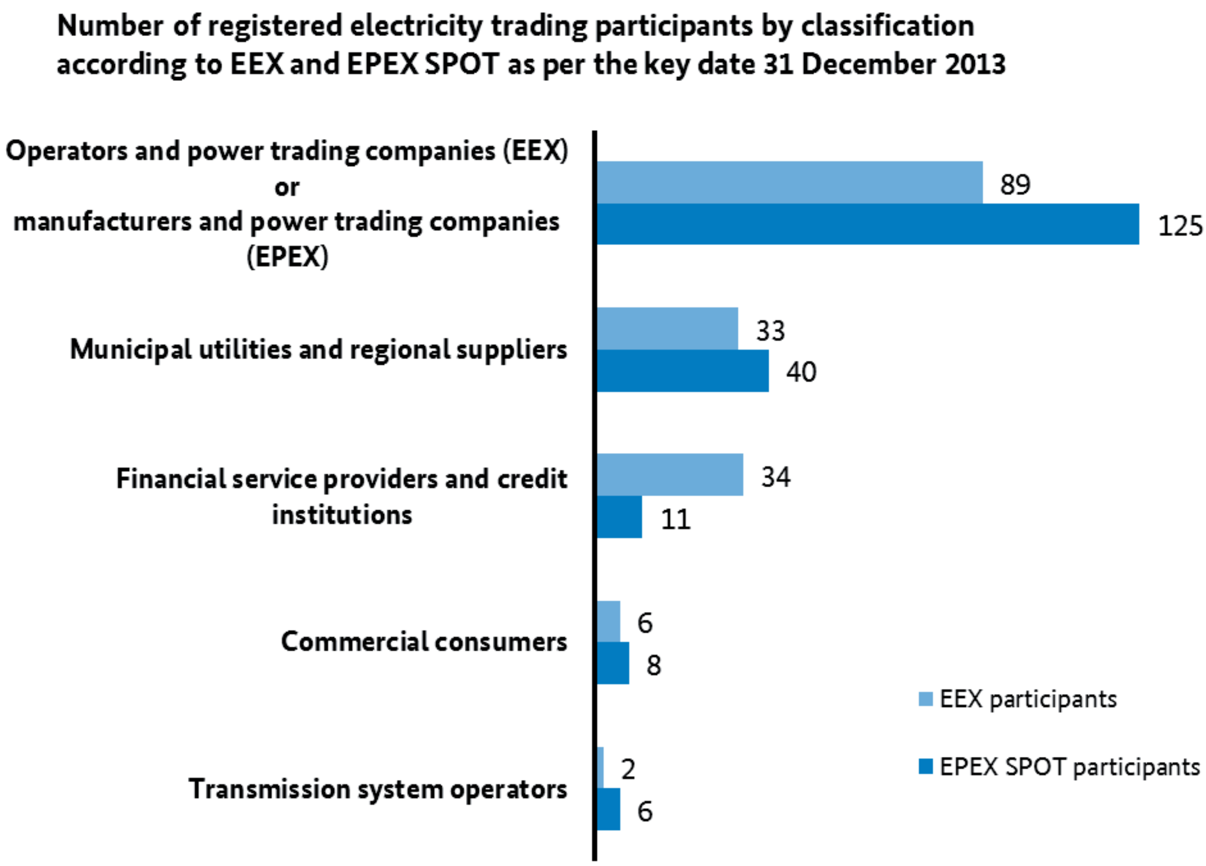

Figure 49: Number of registered electricity trading participants by classification according to EEX and EPEX SPOT as per the key date 31 December 2013

Forward trading and spot trading perform different but largely complementary functions. Whilst on the spot market the focus is on the physical fulfilment of the electricity supply contract (supply within a balance group), futures are largely performed financially. Financial performance means that no supply of electricity ultimately takes place between the contracting partners as per the agreed performance date, but a cash compensation is provided for the difference between the pre-agreed futures price and the spot market price. The on-exchange spot markets (section I.G.1.1) and the futures markets (I.G.1.2) are presented separately below.

1.1 Spot markets

Electricity is traded on the on-exchange spot markets on the previous day (day-ahead auction), and with shorter lead times (intraday). Whilst the spot market at EXAA only includes day-ahead trading, EPEX SPOT furthermore also offers continuous intraday trading. The contracts can be physically fulfilled (supply of electricity) on on-exchange spot markets in both the Austrian control area (APG) and in the German control areas (50Hertz, Amprion, TenneT, TransnetBW).

The day-ahead auction on EPEX SPOT takes place at 12 a.m. every day. Auctions at EXAA are concentrated on five days per week, the time of the auction (10:12-10:15 a.m.) being earlier than on EPEX SPOT. In addition to individual hours and standardised blocks, a self-selected combination of individual hours (user-defined blocks) can also be traded in the day-ahead auction of EPEX SPOT. Furthermore, bids for complete or partly physical fulfilment of futures traded on EEX (futures positions) can be submitted. In the day-ahead auction of EXAA, in addition to individual hours and blocks, it has also been possible since September 2014 to trade quarters of an hour. EPEX SPOT has announced the introduction of a separate day-ahead auction for quarter-of-an-hour contracts at 3 p.m. daily from 9 December 2014 onwards. The expansion of the trading opportunities to include quarter-of-an-hour contracts particularly allows for the increased feed-in of electricity from supply-dependent (regenerative) sources and the obligation of those responsible for the balance group[24] to equalise the performance balance per quarter of an hour.

In addition to individual hours, continuous intraday trading at EPEX SPOT concerns standardised or user-defined blocks. Trading with 15-minute contracts has also been possible for the German control areas since December 2011. Electricity contracts can be traded for the German control areas up to 45 minutes before commencement of supply and for the Austrian control areas up to 75 minutes before commencement of supply. Unlike with day-ahead auctions, continuous intraday trading is not designed as a clearing price auction.

Trading volumes

The volume of day ahead trading on EPEX SPOT was 245.6 TWh in the year under report 2013, which corresponds to the previous year's level. The volume of intraday trading increased once more after the stagnation in 2012, namely to 19.6 TWh (0.4 TWh of which was accounted for by the supply area Austria). The volume of the day ahead market on EXAA fell to 7.8 TWh in the year under report 2013, which corresponds to the level of 2011.

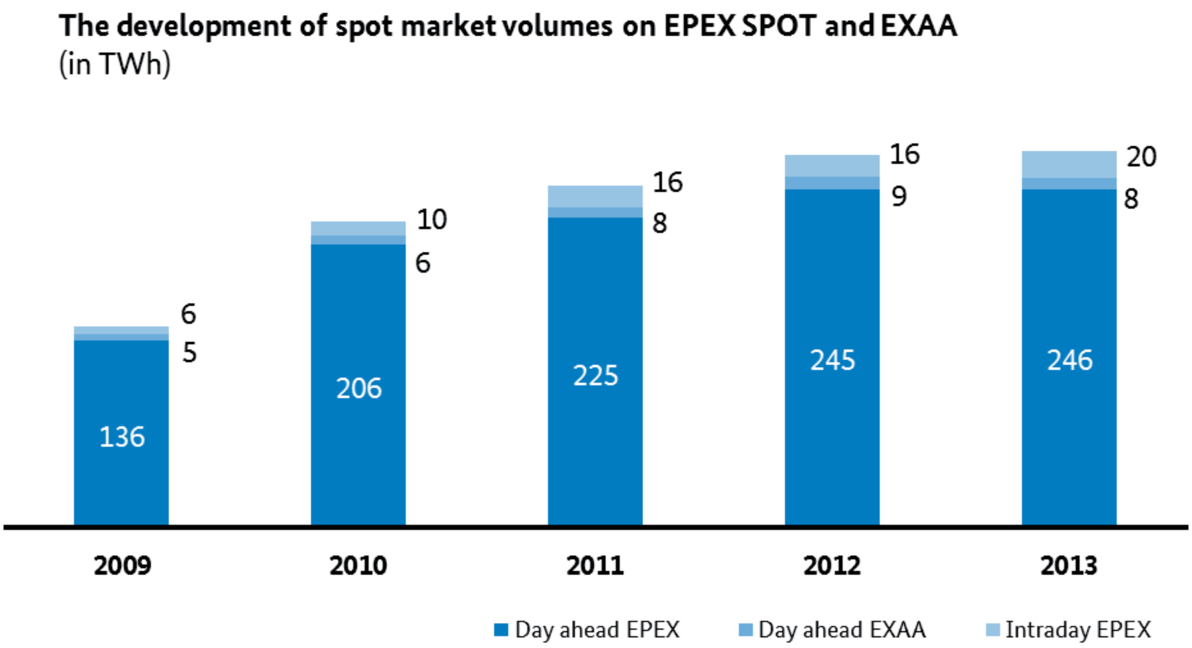

Figure 50: The development of spot market volumes on EPEX SPOT and EXAA in the period 2009-2013

[24] See on this also: Bundesnetzagentur, position paper of 16 September 2013 concerning the obligations incumbent on the parties responsible for the balance group in accordance with Section 4 (2) of the Electricity Grid Access Ordinance (*StromNZV*) and No. 5.2 of the Standard Balance Group Contract (*Standardbilanzkreisvertrag*) (*Positionspapier zur Wahrnehmung der Pflichten nach § 4 Abs. 2 StromNZV und Ziffer 5.2. des Standardbilanzkreisvertrages durch die Bilanzkreisverantwortlichen*)

Number of active participants

No major changes can also be reported when it comes to the number of participants who are active on both exchanges.

A participant registered on EPEX SPOT is regarded as "active" on the trading day if the participant implemented at least one bid (purchase or sale). An average of 156 participants (in 2012: 150 participants), and hence roughly 82 percent of all registered participants, are active per trading day. The average number of active buyers (122 in 2013 and 117 in 2012) and sellers (118 in 2013 and 110 in 2012) rose slightly year-on-year. The number of net buyers per trading day (balance towards: "purchase") is roughly at the previous year's level, with 81 participants in 2013 (83 in 2012). The number of net sellers (balance towards "sale") rose again, that is by more than 10 percent, reaching 75 (68 in 2012).

A participant registered on EXAA is regarded as "active" if at least one bid (purchase or sale) has been implemented, related to each supply day[25]. An average of roughly 39 participants, and hence once more roughly half of all registered participants, were active per supply day. Two-thirds of all participants in EXAA (52) have trading accounts in the German control areas. An average of almost twenty participants per trading day implemented bids in the German control areas.

Price dependence of the bids

Bids in day-ahead auctions on EPEX SPOT and EXAA can be submitted on a price-dependent or price-independent basis. Unlike a price-dependent bid (limit order), in a price-independent bid (market order), the participant does not set fixed price-volume combinations. Price independence means that the volume is to be bought or sold regardless of a price limit.

Price-independent bids continue to make up a large share of EPEX SPOT, both on the buyer side and on the seller side. 72 percent of the purchase bids in the year under report 2013 were price-independent. This corresponds to the ratio in recent years (2011: 73 percent; 2012: 70 percent). The proportion of price-independent bids among the sale bids that were implemented fell year-on-year, that is from 83 percent in 2012 (2011: 82 percent) to 72 percent in 2013.

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[25] The different approach – supply day instead of trading day – is intended to facilitate an equal view of the values of the two spot market places despite the different trading conditions (auctions days, auction time). Because of further differences between EPEX SPOT and EXAA, this is however only possible to a limited degree.

Price dependence of the bids implemented in EPEX SPOT's hour auctions

	Sale bids implemented in 2013		Purchase bids implemented in 2013	
	Volume in TWh	Share in percent	Volume in TWh	Share in percent
Price-independent bids	175.91	71.6	178.00	72.5
of which by transmission system operators	54.9		0.45	
of which physically-implemented Phelix futures	33.96		62.63	
of which others	87.05		114.92	
Price-dependent bids (incl. blocks and market tying contracts)	69.66	28.4%	67.57	27.5%
Total	245.57	100%	245.57	100%

Table 27: Price dependence of the bids implemented in EPEX SPOT's hour auctions in 2013

The marketing of renewable energy (EEG) volumes by transmission system operators, which took place almost completely price-independent (97.5 percent; 2012: 99.6 percent), plays a major role on the seller side. Having said that, the volume in this regard fell from almost 70 TWh to 55 TWh. The volume of bids on EPEX SPOT for the physical fulfilment of Phelix futures fell on by 20 TWh the seller side and by 14 TWh on the buyer side.

Both on the buyers' and on the seller side, the share of price-dependent bids plus the market coupling contracts[26] (imports and exports) was roughly 28 percent in 2013. The volume of limited bids fell slightly on the buyer side (by 6 TWh), whilst it increased considerably on the seller side (by 30 TWh).

The bids implemented on EXAA are spread by price dependence in an opposite relationship. More than 70 percent of the bids on EXAA are contingent on price conditions (purchase: 74.2 percent or 5.8 TWh; sale: 70.3 percent or 5.5 TWh).

[26] See also section I.F "European integration" from page 105ff

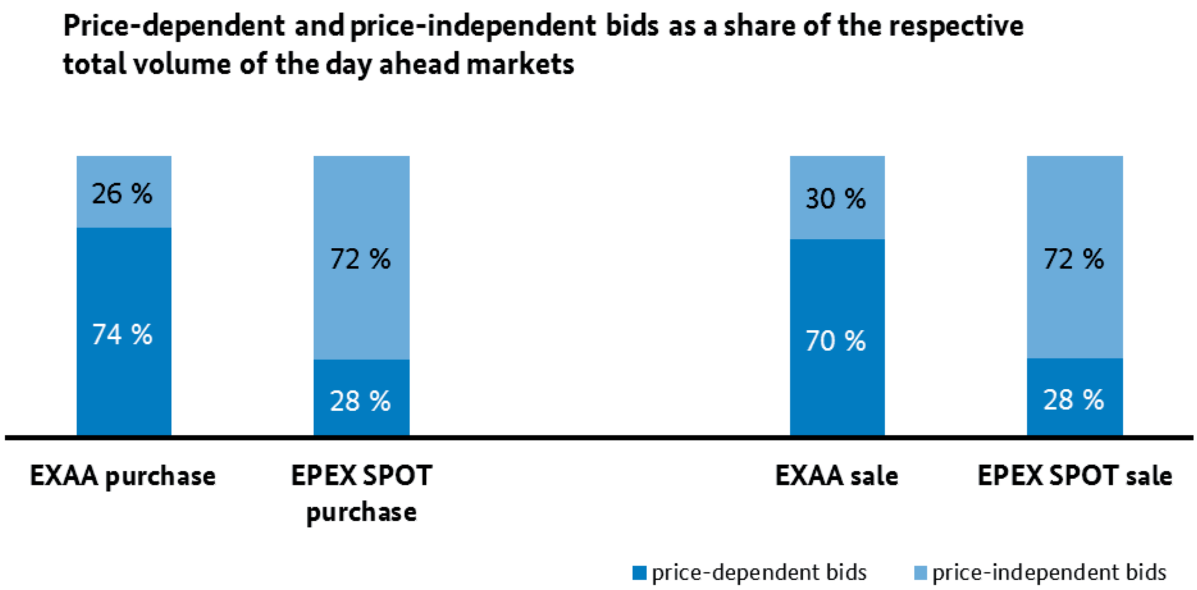

Figure 51: Price dependence of the implemented bids in the hour auctions of EPEX SPOT and EXAA in 2013

Price level

The price index that is most common for the spot market for the market area Germany/Austria is the Phelix ("Physical Electricity Index"), published by EEX/EPEX SPOT. The Phelix day base is the arithmetic mean of the 24 individual hour prices of a day, whilst the Phelix day peak is the arithmetic mean of the hours from 9 to 20 (e.g. 8 a.m.-8 p.m.). EXAA publishes the bEXAbase and the bEXApeak, which relate to the corresponding individual hours (for the same market area).

The average spot market prices fell once more in 2013. The average of the Phelix day base fell from 42.60 Euro/MWh to 37.78 Euro/MWh, that is by roughly eleven percent. The average price in 2013 hence roughly corresponds to the level of 2009. At a value of 43.13 Euro/MWh, the Phelix day peak was also roughly eleven percent below the previous year's level.

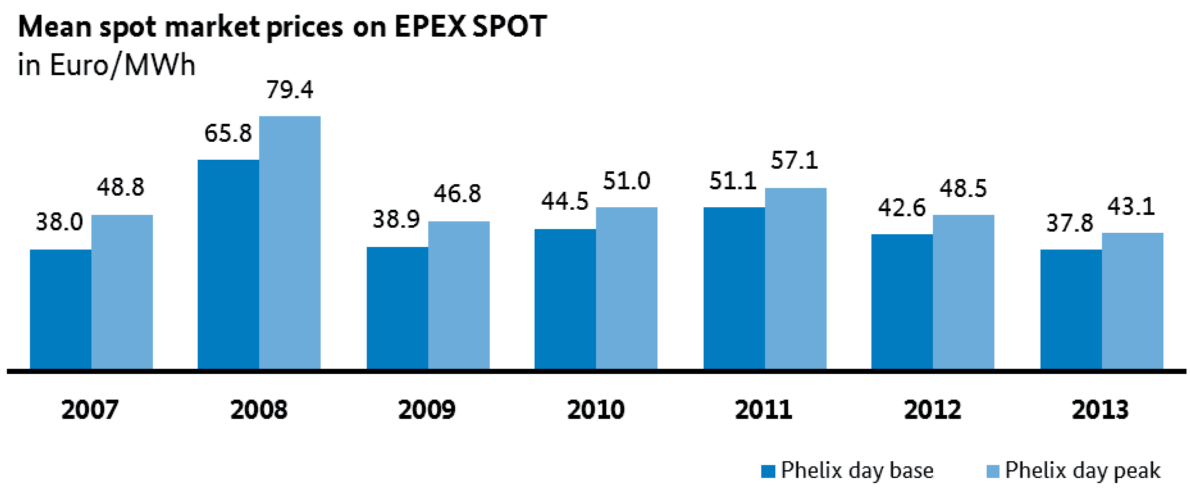

Figure 52: Mean spot market prices on EPEX SPOT 2007 to 2013

The bEXA and Phelix indices available for 2013 are close together, as was the case in previous years. Unlike in previous years, however, higher electricity prices emerged in the day-ahead auction on EPEX SPOT (Phelix), averaged over 2013, than on EXAA (bEXA).

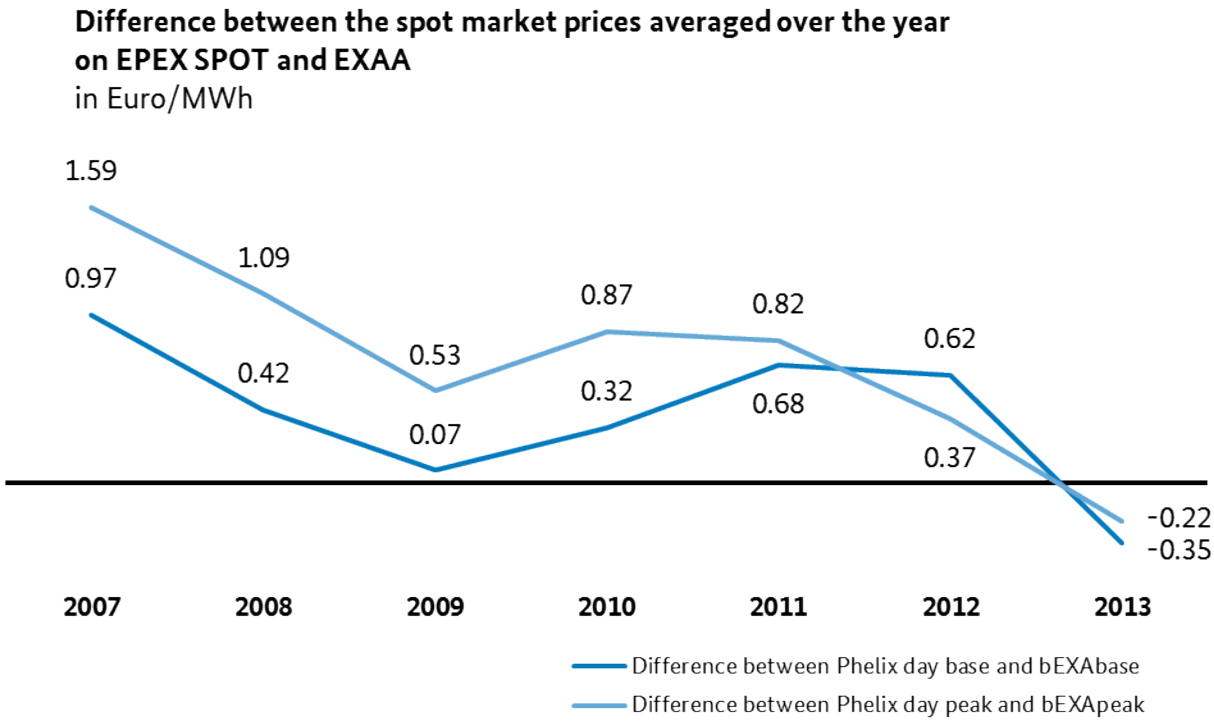

Figure 53: Difference between the spot market prices averaged over the year on EPEX SPOT and EXAA 2007 to 2013

Price spread

As in the previous years, the spot market prices averaged over a day demonstrate a considerable spread. Figure 54 shows the development in spot market prices over the year, taking the example of the Phelix day base. The prices averaged over a day typically have a weekly profile with lower prices at the weekend. Further, a tendency towards lower prices is observed in the summer months than in the winter months. The bEXAbase, which is not shown in the figure, follows the same pattern.

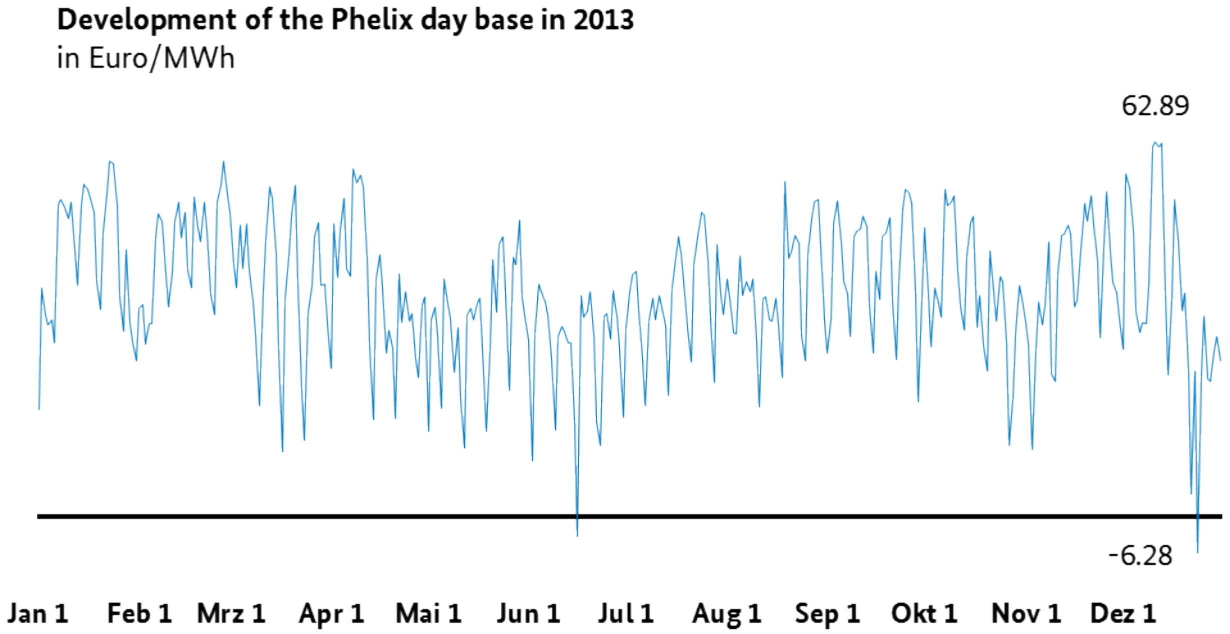

Figure 54: Development of the Phelix day base in 2013

When observing various price ranges, an increase in the spread is seen year-on-year in the base and peak prices on EPEX SPOT. The range of the mid-50 percent of the graded Phelix day base values was 11.56 Euro/MWh in 2012, and rose to 15.65 Euro/MWh in 2013, that is by 4.09 Euro/MWh or by roughly 35 percent[27]. In the same way, a considerable widening of the ranges (from 5.33 to 6.94 Euro/MWh, or by roughly 23 percent to 36 percent) can be observed for the range of the mid-80 percent of the graded values and for the corresponding peak ranges. Solely the difference between the maximum and minimum is less prominent in 2013 than in 2012. There were two negative values in the Phelix day base in 2013 (on 16 June and on 24 December, the latter corresponding to the minimum of all values).

It can be observed all in all that the spot market prices averaged over a day are at a lower average level, but within a broader range.

[27] 2013: upper limit 46.88 Euro/MWh – lower limit 31.23 Euro/MWh = range 15.65 Euro/MWh.
2012: upper limit 49.21 Euro/MWh – lower limit 37.65 Euro/MWh = range 11.56 Euro/MWh.

Price ranges of the Phelix day base and of the Phelix day peak in 2012 and 2013

	mid-50 percent Range of 25 to 75 percent of the graded values in Euro/MWh	**mid-80 percent** Range of 10 to 90 percent of the graded values in Euro/MWh	**extreme values** Lowest and highest value in Euro/MWh
Phelix day base 2012	37.65 – 49.21	29.82 – 52.82	56.87 – 98.98
Phelix day base 2013	31.23 – 46.88	23.66 – 52.81	6.28 - 62.89
Phelix day peak 2012	41.38 – 56.03	30.33 – 60.91	10.94 – 129.94
Phelix day peak 2013	34.44 – 54.42	24.76 – 62.28	-18.99 - 80.50

Table 28: Price ranges of the Phelix day base and of the Phelix day peak in 2012 and 2013

A similar development can be observed on EXAA. Whilst all upper and lower limits of the range of the bEXAbase and of the bEXApeak fell year-on-year, the range for the medium 50 percent and 80 percent of the values increased. The respective lower range limit fell more rapidly than the upper range limit.

Price ranges of the bEXAbase and of the bEXApeak in 2012 and 2013

	mid-50 perent Range of 25 to 75 percent of the graded values in Euro/MWh	**mid-80 percent** Range of 10 to 90 percent of the graded values in Euro/MWh	**extreme values** Lowest and highest value in Euro/MWh
bEXAbase 2012	37.75 – 48.74	29.24 – 53.03	5.07 – 85.66
bEXAbase 2013	30.75 – 46.56	23.80 – 51.33	1.10 – 60.62
bEXApeak 2012	41.72 – 55.90	29.06 – 62.02	10.01 – 108.00
bEXApeak 2013	34.25 – 54.51	23.14 – 61.73	4.80 – 76.40

Table 29: Price ranges of the bEXAbase and of the bEXApeak in 2012 and 2013

1.2 Futures markets

Futures can be traded on EEX for the Germany/Austria market area with standardised maturities where the subject-matter of the contract is the Phelix (base value). Options may also be traded for specific Phelix futures as a matter of principle. As in the previous year, however, there were no corresponding transactions on EEX. The next section is based solely on the on-exchange transaction volumes without OTC clearing (see section I.G.2.3 on OTC clearing).

Trading volume

The trading volumes of Phelix futures on the exchanges increased (2012: 445 TWh) by roughly 50 percent year-on-year, reaching 669 TWh. The number of active participants on the futures market of EEX (not including OTC clearing) averaged 48 per trading day in 2013.

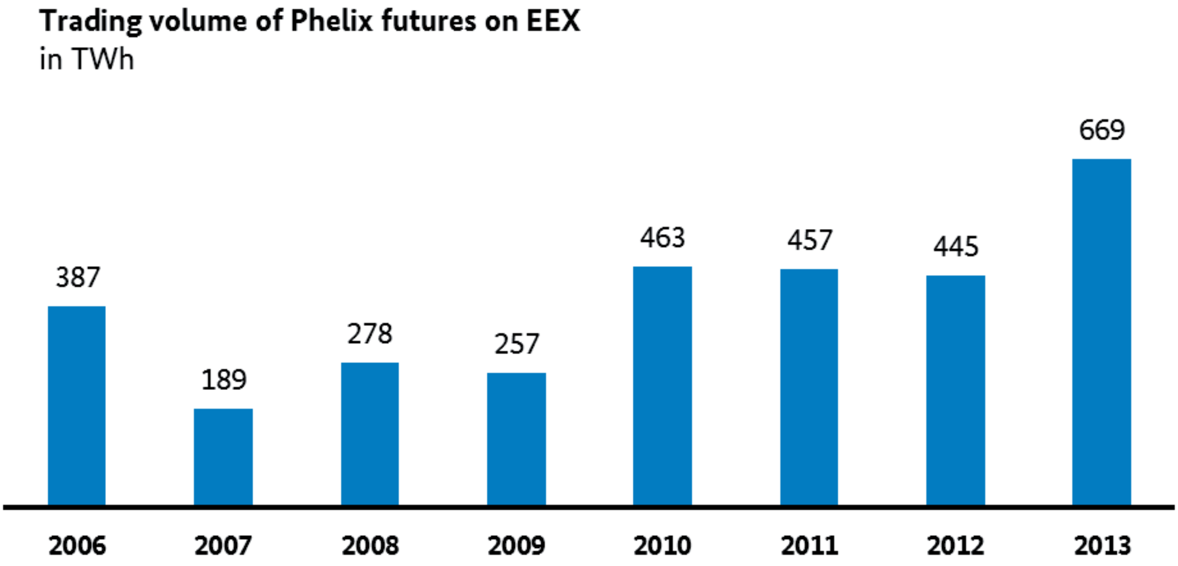

Figure 55: Trading volume of Phelix futures on EEX 2006 to 2013

The on-exchange market volume of futures increased considerably, not only in total, but also for each individual supply year. Forward trading in 2013 once more focussed on contracts with the following year (2014) as the fulfilment year (roughly 54 percent of the total trading volume). For the year under report (2013), at approx. 17 percent roughly as much was traded as for the 2nd following year (2015). Trading for 2016 (8.5 percent) and for the further years (2.6 percent) however fell.

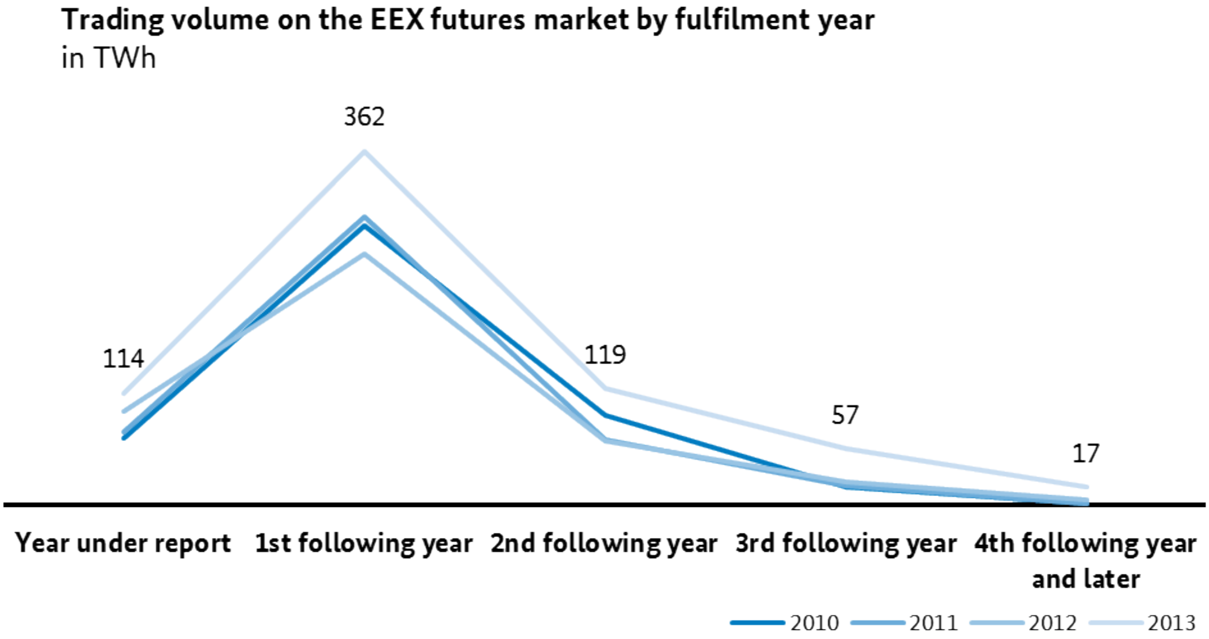

Figure 56: Trading volume on the futures market of EEX by fulfilment year – Comparison 2010 to 2013[28]

Price level

The two most important futures traded on EEX in terms of volume for the Germany/Austria market area are the Phelix year futures base and peak. Whilst the baseload future relates to a constant and continuous delivery rate (every hour, every day), the peakload future is based on the hours from 8:00 a.m. to 8:00 p.m. for the days Monday to Friday.

The prices for year futures fell considerably over the year under report 2013. The Phelix base year future 2014 was quoted at 45.26 Euro/MWh at the beginning of the year (at the same time, this was the highest level over the year), and it closed at 37.30 Euro/MWh at the end of the year. The Phelix peak year future 2014 fell from 57.01 Euro/MWh at the beginning of the year to 48.63 Euro/MWh at the end of the year. The price differences between Phelix base year future 2014 and Phelix peak year future 2014 ranged between 9.93 Euro/MWh and 11.75 Euro/MWh, and were therefore within a range of 1.82 Euro/MWh.

[28] The values stated in the figure relate to 2013. The course of the curve between two data points only serves to make these and their ratio to one another visible.

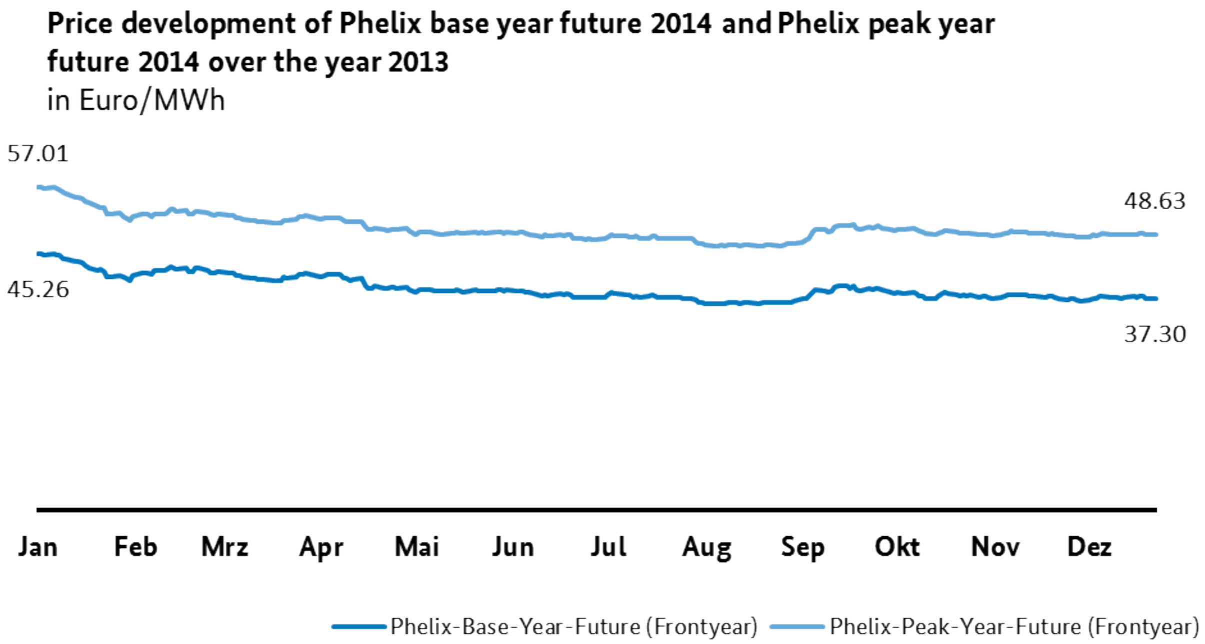

Figure 57: Price development of Phelix base year future 2014 and Phelix peak year future 2014 over the year 2013

An annual average can be calculated from the prices of EEX front year futures on the individual trading days. This average would correspond to the average electricity purchase price (or electricity sales price) of a market player if the latter buys (or sells) the electricity not at short notice, but proportionally in the previous year.

The annual averages of the Phelix front year future prices fell once more year-on-year, and reached their lowest level in the seven-year observation period. At 39.08 Euro/MWh averaged over 2013, the Phelix base year future fell year-on-year (2012: 49.30 Euro/MWh) by 10.22 Euro/MWh, and hence by a good 20 percent. With the Phelix Peak front year future, the price averaged 49.67 Euro/MWh over the year. The year-on-year reduction (2012: 60.86 Euro/MWh) is 11.19 Euro/MWh, and hence a good 18 percent.

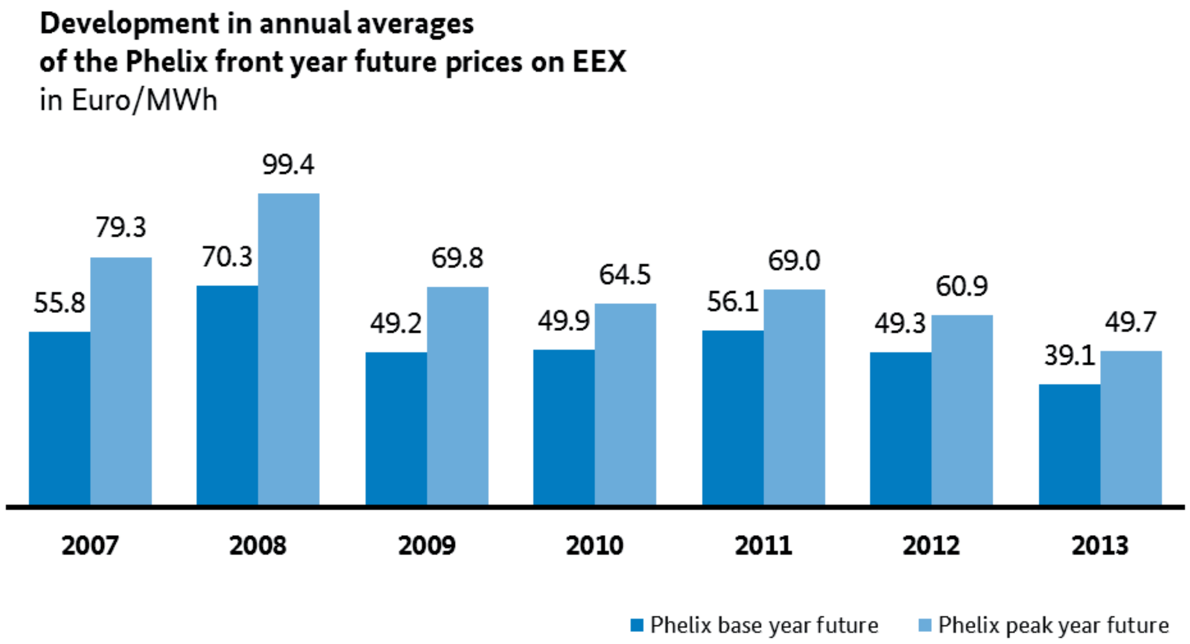

Figure 58: Development in annual averages of the Phelix front year future prices on EEX from 2007 to 2013

Once again, the price difference between the base and peak products was less pronounced in 2013 than was the case prior to 2010. Whilst the peak price was more than 40 percent higher than the base price in the period 2007-2009, since 2010 this difference has only been between 22 and 29 percent. When taken in absolute terms, the difference fell year-on-year from 11.56 Euro/MWh (2012) to 10.59 Euro/MWh (2013), which – observed relative to the respective base price – corresponds to an increase in the peak/base difference from 23.5 percent to roughly 27 percent.

1.3 Shares of various exchange participants in the trading volume

Share of market makers

An exchange participant who has undertaken at the same time to publish binding purchase and sales prices (quotations) is referred to as a market maker. A market maker serves to increase the liquidity of the market place. The specific conditions are regulated between the market maker and the exchange in “market maker agreements”, which contain amongst other things arrangements on quotation times, quotation period, minimum number of contracts and maximum spread.

E.ON Global Commodities SE, EDF Trading Limited, RWE Supply & Trading GmbH and Vattenfall Energy Trading GmbH were consistently active during the period under report as market makers on the futures market of EEX for Phelix futures. All four companies had already been similarly active in the previous year. The cumulated share of the four market makers in the purchase volume of Phelix futures increased from 20.2 percent (2012) to 30.5 percent (2013), and the corresponding share in the sales volume rose from 28.4 percent (2012) to 31.8 percent (2013).

Three market makers were active on the day ahead market of EXAA in the period under report. The cumulated share of market makers in the purchase volume of the day-ahead auction in 2013 was 3.6 percent, accounting for 5.2 percent of the sales volume.

Share of the transmission system operators

In accordance with the Equalisation Mechanism Ordinance (*Ausgleichsmechanismusverordnung*), the transmission system operators are obliged to sell the renewable (EEG) energy volumes passed on in accordance with the fixed fee for the feed-in of electricity under the Renewable Energy Sources Act (*EEG*) to the transmission system operators on the spot market of an electricity exchange. For this reason, a large share of the spot market volume is accounted for on the seller side by the transmission system operators.

A further fall in the share accounted for by transmission system operators in the spot market volume can be observed in the year under report 2013. The share of the transmission system operators in the EPEX SPOT day ahead sales volume was 23 percent in 2013, whilst this value had been as high as 28 percent in 2012 and 38 percent in 2011.

This marked reduction is caused by the fact that an increasing number of renewable energy plant operators opted for direct marketing. This led to a fall in the take–up of the fee for the feed-in of electricity under the Renewable Energy Sources Act despite increased total renewable (EEG) energy volumes, so that the total volume to be marketed by the transmission system operators fell accordingly[29].

On the buyer side, only a very small spot market volume is accounted for by the transmission system operators. The latter only implement a small number of transactions on the futures markets too.

Share accounted for by the participants with the highest turnover

The observation of the trading volume accounted for by the participants with the highest turnover provides an impression of the degree to which exchange trading is concentrated. In addition to the large electricity producers, financial institutions and transmission system operators on the spot market are among the participants in the futures market with the highest turnover. In order to compare the values over time, it should be pointed out that the composition of the respective (e.g. five) participants with the highest turnover can change over the years, so that the cumulated turnover share does not necessarily relate to the same companies. Furthermore, no group view is carried out here, i.e. the turnover of a group is not aggregated if a group has several participant registrations[30].

The share of the five sellers with the highest turnover on the day ahead trading volume of EPEX SPOT fell markedly once again, from 49 percent to 39 percent, in the year under report. This is particularly caused by the fall in sales volumes of the transmission system operators. By contrast, no major change can be found on the buyer side in the year under report. The cumulated share of the five buyers with the highest turnover was roughly 40 percent in 2013.

[29] See for details on this section I.B.1.3 from page 43 and I.B.1.4 from page 47

[30] Groups only have one participants' registration as a rule.

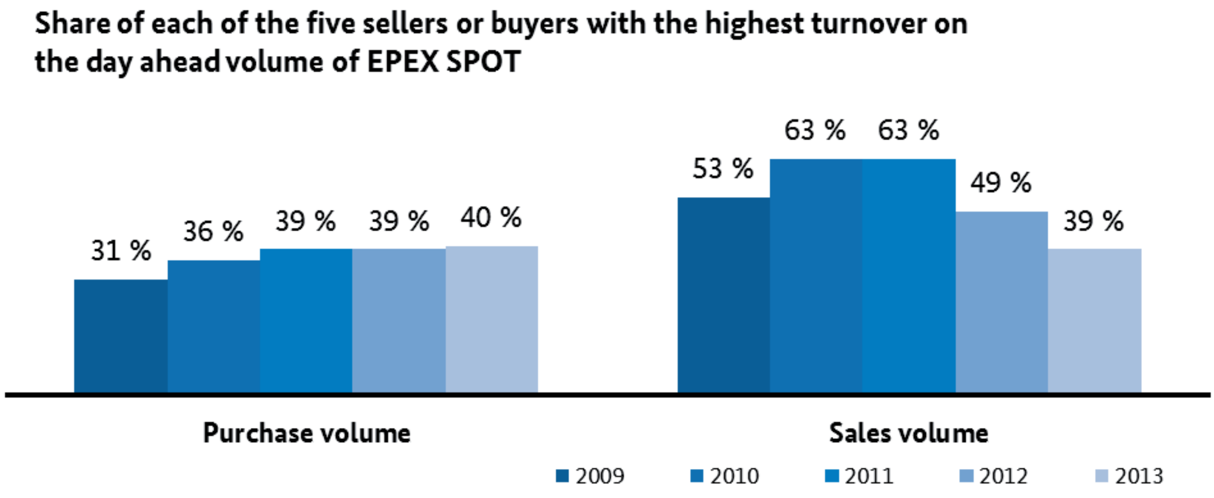

Figure 59: Share of each of the five sellers or buyers with the highest turnover on the day ahead volume of EPEX SPOT in the period 2009 to 2013

If the volumes of the hour auction of EPEX SPOT for the purchase and sales sides are observed on an aggregated basis, roughly 142 TWh are accounted for in 2013 by transactions where the five participants with the highest turnover appeared either as buyers or as sellers. This value – with the same total volume of day-ahead auctions – was still roughly 172 TWh in the previous year 2012. The share of the participants with the highest turnover has therefore also fallen with this aggregated observation method. If the cumulated share of these five participants is averaged over the respective purchase and sales volumes, a medium share of 29 percent emerges (as against 35 percent in comparison with the previous year).

On EXAA as a further exchange for day-ahead auctions, the share of participants with the highest turnover is the same as the previous year's level. The shares of the three participants with the highest turnover were 23 percent in 2013 (2012: 22 percent), averaged over the sales or purchase volume. If one expands to the five participants with the highest turnover, a share of 32 percent emerges in 2013 (2012: 33 percent).

On EEX, the share both of the five buyers of Phelix futures with the highest turnover (not including OTC clearing), and those of the five sellers with the highest turnover, is approximately 40 percent. This roughly corresponds to the values of the two previous years. It should be taken into account here that the trading volume on the futures market has increased by roughly 50 percent, i.e. the volume accounted for by the buyers or sellers with the highest turnover has increased equally considerably.

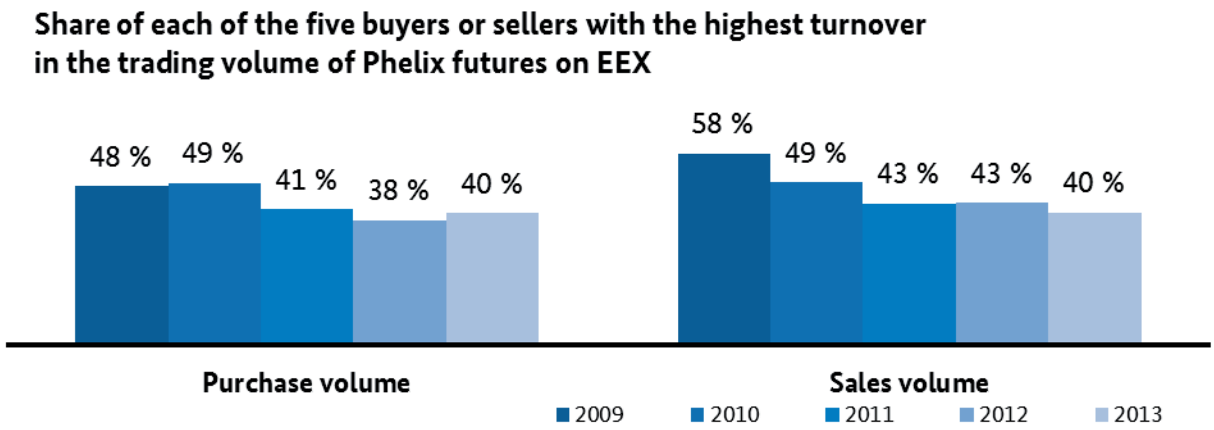

Figure 60: Share of each of the five buyers or sellers with the highest turnover in the trading volume of Phelix futures on EEX

Spread of the trading volume by exchange participant classification

The electricity exchanges assign each of the participants registered with them to a group of participants. The transaction volume accounted for by these groups of participants is not shown below separately by purchase and sale, but only by the shares averaged for purchase and sale in each case. The shares in the spot market volume are represented related to the transaction volume, reduced by market tying contracts (imports and exports).

Averaged shares of the groups of EPEX SPOT and EEX participants in sales and purchase volume 2013

	EPEX SPOT	EEX
Supra-regional suppliers and energy trading companies (EEX) / electricity producers and energy trading companies (EPEX SPOT)	64%	63%
Financial service providers and credit institutions	11%	29%
Transmission system operators	15%	< 1%
Municipal utilities and regional suppliers	9%	5%
Commercial consumers	1%	3%

Table 30: Averaged shares of the groups of EPEX SPOT and EEX participants in sales and purchase volume 2013

2. Bilateral wholesale trading

The particular feature of bilateral wholesale trading ("OTC trading", "over-the-counter") is that the contracting partners are known to one another (or become known to one another at the latest on concluding the transaction), and that the parties can arrange the contractual details flexibly and individually. The surveys carried out in energy monitoring for OTC trading aim to record the amount, structure and development of bilateral trading volumes. Unlike exchange trading, however, it is not possible to portray the complete bilateral wholesale volume since there are neither clearly delimitable marketplaces outside the exchanges, nor is there a fixed model of types of contract.

Brokers play a major role at bilateral wholesale level. They act as intermediaries between buyers and sellers and combine information on the supply and demand of electricity trading transactions. The connection between interested parties on the supply and demand sides is formalised on electronic broker platforms, hence increasing the chance for two parties to reach an agreement.

A specific role is played by on-exchange "OTC clearing". OTC trading can be registered with the exchange, so that the parties' trading risk is hedged. OTC clearing forms an interface between on-exchange and non-exchange electricity wholesale trading.

A survey of the individual participants in OTC trading was once more carried out in the year under report for the area of bilateral wholesale trading (cf. section I.G.2.1 from page 125) and with various broker platforms (cf. section I.G.2.2 from page 127). Moreover, data on OTC clearing on EEX were requested (cf. section I.G.2.3 from page 128). On the basis of these three surveys, a stable, high level of liquidity can be ascertained for the year under report 2013 in bilateral electricity wholesale trading.

2.1 Survey among wholesalers

Data provided by companies on their trading activities (apart from on the exchanges) in 2013 were collected in this year's monitoring. As had been the case in the previous year, the collection was carried out at the level of the individual companies, and incorporated both purchases and sales. Regardless of whether the companies may have only acted as buyers, or only as sellers, they are referred to below as "wholesalers".

In distinction to retail, electricity wholesale is understood within this survey as constituting all electricity supply contracts and electricity trading transactions with own-name physical or financial fulfilment in which the buyer does not consume the electricity volumes in question itself, and which does not concern any system services. Only non-exchange transactions were to be stated – including transactions via broker platforms – with Germany as the supply area.

According to this definition, contracts between two companies within a group are also "wholesale" transactions as a matter of principle. Since such intra-group transactions are not based on a mutual selection process as a rule, the companies were asked in this year's survey (for the first time) to show the share of intra-group transactions separately. In the overall view of the individual details, the share stated as intra-group may be "too small"[31].

683 companies (previous year: 590) provided information for the year under report 2013 on their wholesale electricity transactions outside the exchanges. Even if the participation of the companies in the survey increased year-on-year, not all trading participants and volumes can be covered with this survey. In particular, it can be presumed that some (volume-)relevant companies which have their registered offices abroad do not take part in the survey. Moreover, some electricity suppliers did not provide information on the volumes that they purchased in bilateral trading[32]. For these reasons, one can presume a higher bilaterally-traded electricity volume than emerges from the detailed information that has been collected. This assessment is confirmed by the fact that, as in the previous years, the trading volumes calculated on the broker platforms (cf. section I.G.2.2) from page 127 are much larger than the wholesale volumes collected from the individual participants[33].

The results of the evaluation of the volume data provided by the 683 companies on the wholesale transactions concluded in 2013 were as follows.

[31] Many medium-sized wholesalers have group structures, and only stated "extra-group" volumes in the survey. This statement is plausible according to definitions at the level of each individual company in the survey. The frequency with which exclusively "extra-group" volumes were stated was however surprising.

[32] This statement is also plausible according to definitions that were made in the survey at the level of each individual company. The frequency with which exclusively "extra-group" volumes were stated was however surprising. (see also preceding footnote)

[33] By definition, the trading volumes collected in the wholesaler survey include those via broker platforms. On the other hand, the survey of broker platforms does not make a distinction according to wholesale level vs. end consumption. Nonetheless, with a constantly high level of coverage of both surveys, one could anticipate that higher total volumes would tend to emerge in the wholesaler survey than in the broker platform survey.

Volume of the electricity wholesale contracts concluded on a non-exchange basis in 2013 according to the wholesaler survey

Fulfilment period	Non-exchange wholesale electricity trading volumes in TWh		of which intra-group in TWh	
	Purchase	Sale	Purchase	Sale
Intraday	29	23	4	9
Day-ahead	258	141	153	77
2-6 days	44	42	7	5
2013, min. 7 days	899	772	207	98
2014	1,995	2,027	279	357
2015	689	700	192	248
2016	333	358	120	160
2017 and later	83	65	46	30
Total	**4,330**	**4,128**	**1,008**	**984**

Table 31: Volume of the electricity wholesale contracts concluded on a non-exchange basis in 2013 according to the wholesaler survey

The totals shown in the table are much larger than the corresponding values of the previous year's survey. Because of the increased participation in the survey, and of changes in the questions, the values for 2013 are however not directly comparable with the previous year's figures.

The spread of the bilateral trading volume over the various fulfilment periods corresponds roughly to the perception of on-exchange trading: Almost half of the wholesale transactions are accounted for by the following year. Only one-quarter is accounted for by subsequent years (year after next and years following on from that). Trading for the ongoing year accounts for a good quarter of the volume. Day ahead contracts are dominant with short-notice trading transactions.

In order to simplify the questionnaire that is sent to wholesalers, a number of differentiations in the information on trading volumes were omitted this year. Instead, amongst other things qualitative questions were asked as to the use of broker platforms. 72 wholesalers stated that they used broker platforms for futures transactions, and 68 wholesalers said that they did so for spot transactions. The companies not only stated in general terms that there was a broad spectrum of service-providers. Rather, they pointed to several individual service-providers which they used for this. It can be concluded from these statements that the companies are seeking not only to simplify their trading processes by using brokers, but furthermore that they would also like to diversify or optimise them.

2.2 Broker platforms

Because of the boundaries imposed on the direct surveying of trading participants, operators of broker platforms are also asked to answer questions regarding the monitoring of the contracts that they have brokered. Brokers play a major role in bilateral electricity wholesale trading. Many brokers provide an electronic platform to support their intermediary business.

A total of eleven brokers took part in this year's data collection on wholesale trade (previous year: six), ten of whom brokered electricity trading transactions with Germany as a supply area in the year under report. The volume that they supplied totalled 5,930 TWh in 2013. In comparison to the values collected in the previous year – with a total of six broker platforms – this would correspond to an increase by up to 20 percent. The larger volume could however also be caused exclusively by the expansion of the survey group.

When comparing this total volume with the values of the wholesaler survey, it should be taken into account that the broker survey does not distinguish according to use, i.e. the volume information is based on a volume which is probably small, but which cannot be quantified in greater detail, including contracts with (industrial) end customers. On the other hand, it can be presumed for the contracts brokered by brokers that all of these are non-intra-group transactions.

Also when it comes to the transactions brokered by broker platforms, contracts for the following year form the clear focus of electricity trading (55 percent), followed by the activities for the current year (27 percent). Only small volumes are accounted for by short-term transactions with a fulfilment period of less than one week.

Volume of electricity trading via ten broker platforms in 2013 by fulfilment period

Fulfilment period	Volumes traded in TWh	Share in percent
Intraday	0	0%
Day ahead	48	1%
2-6 days	121	2%
2013, min. 7 days	1,611	27%
2014	3,263	55%
2015	646	11%
2016	225	4%
2017 and later	15	0%
Total	**5,930**	**100%**

Table 32: Volume of electricity trading via ten broker platforms in 2013 by fulfilment period

2.3 OTC clearing

On-exchange "OTC clearing" performs a specific function for bilateral wholesale trading. The exchange or its clearing house is the trading participant for the contracting partner in such trading, so that the exchange bears the counterparty default risk. The default risk can be reduced or secured in bilateral trading by various measures, but it cannot be eliminated altogether.

Using clearing for OTC transactions, the counterpart risk is transferred to the exchange or its clearing house. By registering on the exchanges, the contracting partners ensure that their contract is subsequently traded as a transaction which came about on the exchange, i.e. both parties act as if they had each bought or sold a corresponding futures market product on the exchange. OTC clearing is hence an interface between on-exchange and non-exchange electricity wholesale trading.

EEX, or its clearing house European Commodity Clearing AG (ECC), facilitates OTC clearing[34] for all futures market products which are also approved on EEX for exchange trading.

The volume of OTC clearing of Phelix futures on EEX increased from 466 TWh in 2012 to 575 TWh in 2013. Since OTC clearing leads to (retroactive) balancing with futures concluded on the exchange, the development of the OTC clearing volume is to be placed within the context of the on-exchange futures market volume. If one observes the total volumes of on-exchange forward trading and OTC, the added volume is relatively constant in the long term, and has averaged roughly 1,100 TWh since 2006. However, a shift of the volume away from OTC clearing to futures concluded on the exchanges has been observed since 2008[35]. Both the volume of futures traded on the exchanges, and the volume of OTC clearing, increased for the first time in the year under report 2013. Another new feature is the fact that the exchange volume exceeded the OTC volume.

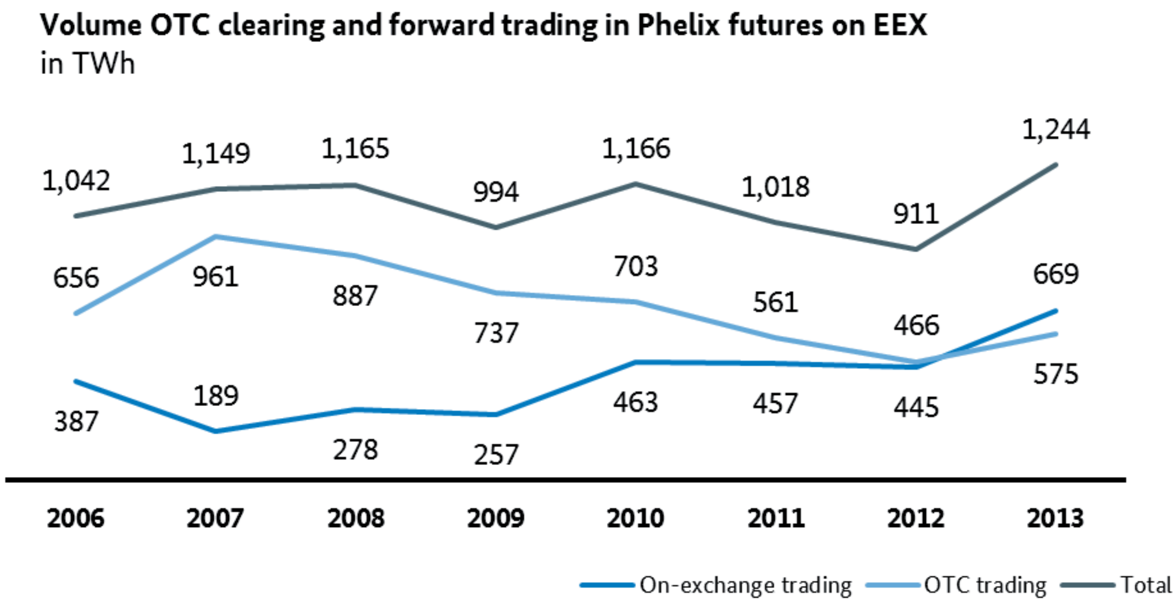

Figure 61: Volume OTC clearing and forward trading in Phelix futures on EEX in the period 2006 to 2013

Changes in the volume of OTC clearing do not necessarily imply corresponding changes in the total OTC trading volume. According to the London Energy Brokers´ Association (LEBA), the share of cleared contracts fluctuates over time. The volume registered by the LEBA members (not only on EEX) for clearing for "German Power" was 534 TWh in 2013 according to the LEBA, corresponding to a total share of roughly 10 percent of

[34] The term "trade registration" is used for OTC clearing in EEX's more recent terminology.

[35] This may have been aided amongst other things by the fact that EEX changed the transaction fees for OTC clearing in 2008.

the total OTC contracts brokered by LEBA members. By contrast, the values in question were approx. 7 percent (377 TWh) in 2012, and approx. 9 percent (730 TWh) in 2011[36].

Phelix options do not play a role in exchange trading on EEX (that is there were no such transactions in the year under report – in common with the previous year). By contrast, practical significance attaches to the OTC clearing of non-exchange Phelix options agreed. In the year under report 2013, Phelix options accounted for a share of 37 TWh in OTC clearing, i.e. 538 TWh of the OTC clearing were accounted for by Phelix futures. The volume of OTC clearing of options corresponds in absolute terms to roughly the volume of the previous year (2012: 38 TWh), the share of the total volume in OTC clearing however fell from 8.2 percent in 2012 to 6.5 percent in 2013.

The distribution of the volumes registered in 2013 on EEX for OTC clearing over the various fulfilment periods shows a similar structure as in the previous years. More than half of the volume (52 percent) was accounted for by contracts for the next year (2014). Roughly 29 percent concerned the year under report itself. The year after next (trading for 2015) accounted for roughly 14 percent. Subsequent fulfilment periods only accounted for a small share.

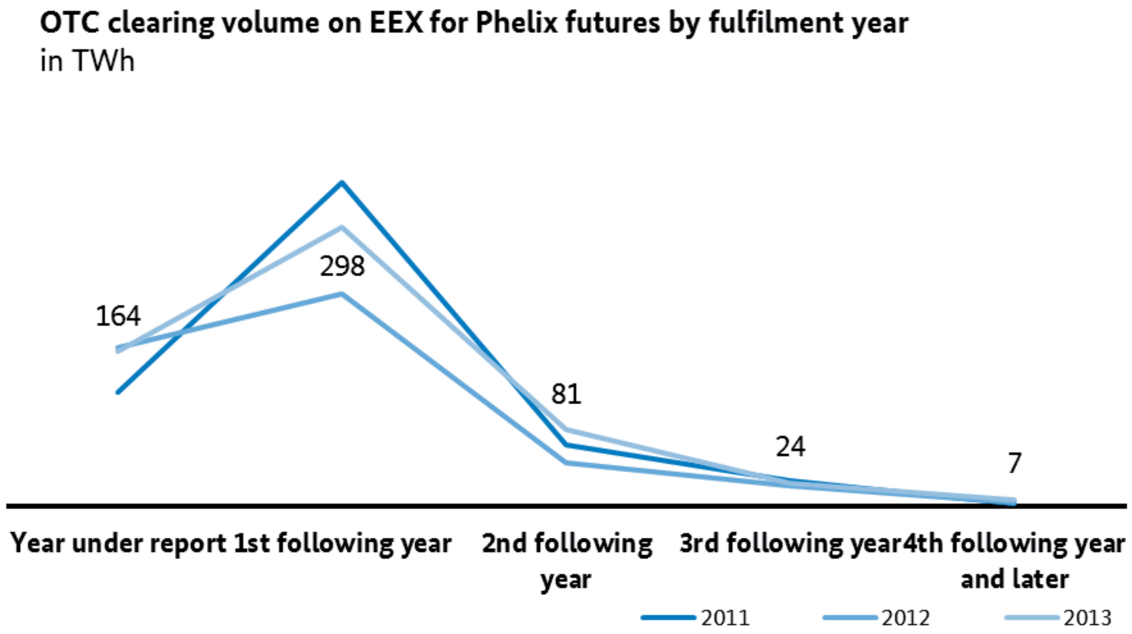

Figure 62: OTC clearing volume on EEX for Phelix futures by fulfilment year in comparison 2011 to 2013

EPEX SPOT offers OTC clearing for intraday contracts. The practical significance of this supply remains very small, however. The volume for which this accounted in 2013 was only 0.04 TWh.

[36] cf. http://www.leba.org.uk/pages/index.cfm?page_id=59, retrieved on 22 August 2014. The total volume of “German Power” brokered by the LEBA members was 7,879 TWh (2011), 5,395 TWh (2012) and 5,301 TWh (2013).

H Retail trade

1. Supplier structure and number of providers

When looking at the retail market in the electricity sector it is interesting to consider how the supply-side of the market is structured and how many suppliers are active in the market. An evaluation of the data from 1,012 suppliers on the metering points supplied by them illustrates that, in absolute figures, the majority of suppliers serve relatively few metering points. The analysis was based on figures notified by suppliers acting as separate legal entities without taking account of their membership of a corporate group or any other corporate links. Approximately 80 per cent of all of the companies taking part in the monitoring activities belong to the group of suppliers that supply fewer than 30,000 metering points. When considering the grand total of nearly 6.5 million metering points, this only makes up 14 per cent of all registered metering points[37]. Some 8.1 per cent of all suppliers account for over 100,000 metering points. This group, however, covers approximately 35.1 million metering points and therefore about 73 per cent of all of the metering points registered by the suppliers. Accordingly, the majority of companies active on the supply side have a customer base that is made up of a relatively small number of metering points. In contrast, around 80 large suppliers (separate legal entities) serve the majority of metering points in absolute terms.

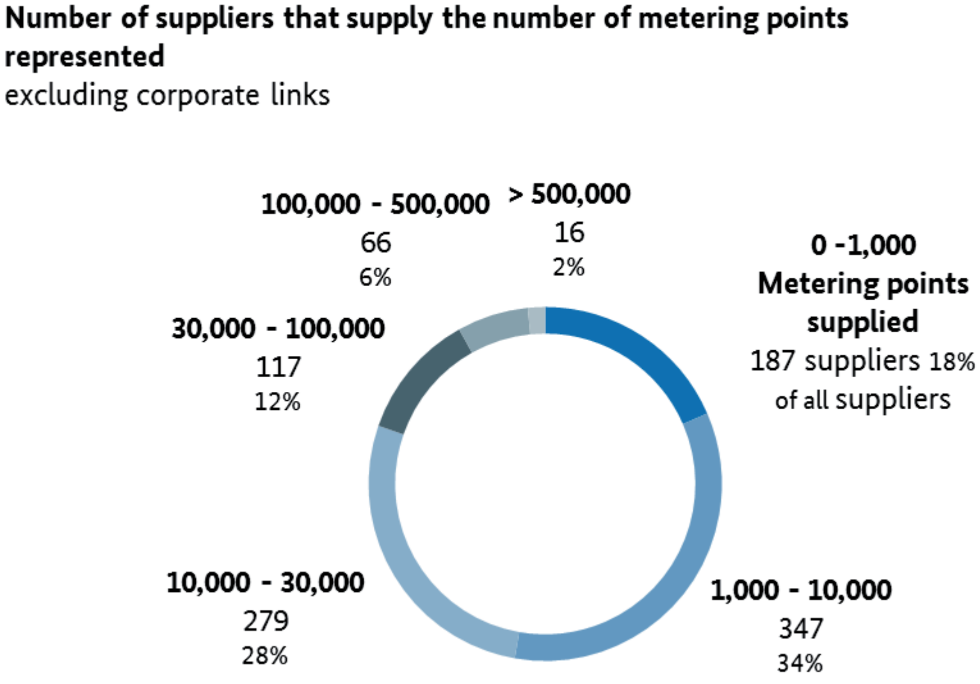

Figure 63: Number of suppliers for metering points[38]

[37] In total, suppliers reported 47.9 million metering points for final consumers.

[38] Figures may not sum exactly owing to rounding.

The potential for electricity customers to choose between a large number of suppliers (separate legal entities) improved again in comparison with the preceding year (2012). An analysis of the figures provided by 791 distribution system operators on the number of suppliers serving consumers connected in the relevant network area produced the following results: More than 50 suppliers were active in almost 80 per cent of all network areas in 2013. In 2007, this figure only applied to just under one quarter of the network areas. More than 100 suppliers are now active in around 40 per cent of network areas compared with 33 per cent of areas last year. On average, a final consumer in Germany can choose between 97 (2012: 88) suppliers in their network area. Household customers can choose between 80 suppliers (2012: 72). A large number of suppliers does not, however, automatically translate into a high level of competition. Many default suppliers offer tariffs in several network areas without acquiring a significant number of customers outside their own default supply areas.

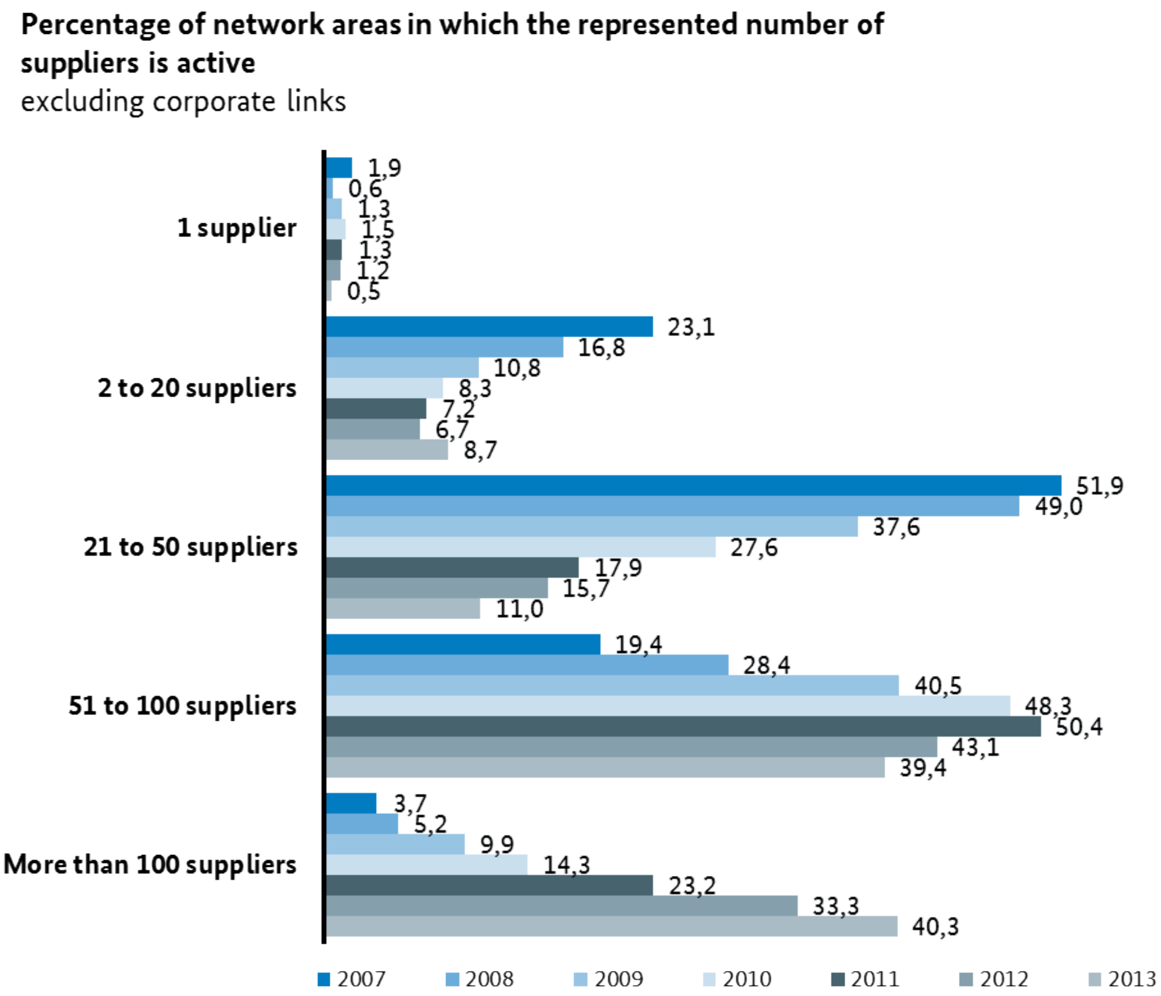

Figure 64: Percentage of network areas in which the represented number of suppliers is active

Suppliers were also asked about the number of network areas in which they serve final consumers with electricity. An evaluation of the data notified by 900 suppliers shows that the overwhelming majority of individual legal entities are only active at a regional level. Some 58 per cent of suppliers serve a maximum of ten network areas and 16 per cent just a single area. Of companies, 21 per cent are active in 11-50 network areas, 12 per cent in 51-250 network areas. Around 5 per cent of suppliers (separate legal entities) supply customers in more than 500 network areas. This value can be assumed to be roughly equal to the number of suppliers active nationwide. On average in Germany, suppliers served around 71 network areas.

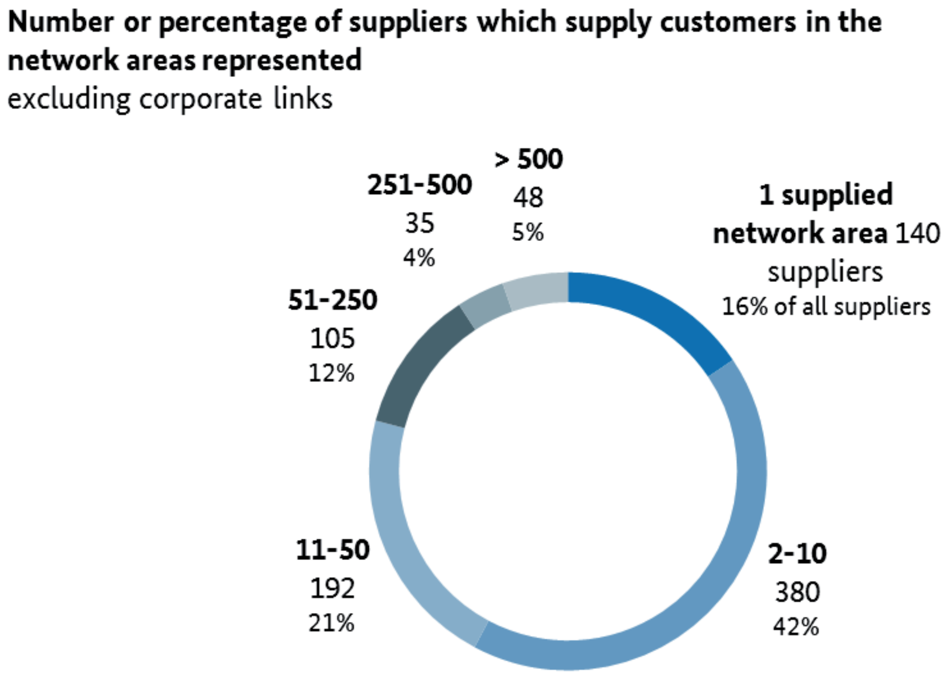

Figure 65: Number of suppliers according to network areas served by them[39]

2. Contract structure and supplier switching

Rates of switching and switch processes are key indicators of competitive developments. There are many problems associated with the collection of such indicators, however. As a result, these surveys must be restricted to data which correspond as closely as possible to actual switching behaviour.

For monitoring purposes, data on contract structures and supplier switching are collected using questionnaires 2 and 3 (Market role of transmission and distribution system operators) and questionnaire 4 (Market role of suppliers) differentiated according to various customer groups.

Final electricity consumers are split into load profile measured (interval-metered) customers or customers without registered load profiles according to how consumption is recorded. The distribution of consumption over time for customers without registered load profiles is estimated using a standard load profile (SLP customers).

In addition, final electricity consumers can also be subdivided into domestic, commercial and industrial customers. The group of household customers is defined in EnWG according to qualitative attributes[40]. Non-

[39] Figures may not sum exactly owing to rounding.

[40] Under section 3 para EnWG, household customers are final consumers who predominantly purchase energy for their own household use or whose annual consumption for professional, agricultural or commercial purposes does not exceed 10,000 kWh.

household customers are referred to in the Monitoring Report as commercial and industrial customers. As yet, there is no widely accepted general definition of commercial customers[41] or industrial customers. These two customer groups are not sharply distinguished for the purpose of the energy Monitoring Report either.

According to questionnaire 4, the volume of electricity provided by suppliers to all final consumers in the year 2013 was around 450 TWh[42]. Of this volume, around 281 TWh was supplied to RLM customers and 168 TWh to SLP customers. SLP customers are predominantly household customers. Around 127 TWh was supplied to the group of household customers in the year 2013.

In the framework of monitoring, data is collected on the volumes of electricity supplied to different final consumer groups according to the three contract categories "default supply contract", "Special contract with the default supplier" and "Special contract with a supplier other than the default supplier". For the purposes of this evaluation, the default supply contract category includes substitute energy supplies (section 38 EnWG) and any other doubtful cases[43]. Supplies which are not subject to a default supply contract are referred to as a special contract. The evaluation under these three categories allows conclusions to be drawn about the significance of default supplies and default supplier status since the energy market was liberalised. The corresponding figures should not, however, be interpreted directly as "accumulated net switching figures since liberalisation". It is particularly important to note in this context that, with regard to the contractual partner, monitoring focuses on legal entities, which means that a special contract with a different company in the default supplier's corporate group will be assigned to the category "Special contract with a supplier other than the default supplier"[44].

What is more, the number of supplier switches in 2013 has also been determined for various customer groups in questionnaires 2 and 3 (transmission and distribution system operators). In this context, a “supplier switch” is a process in which a final consumer's meter is assigned to a new supplier, although customers moving into and out of a property are not regarded as supplier switches[45]. It is also important to take into account in this evaluation that the monitoring survey looked into switches between supplying legal entities. According to this definition, the restructuring of supply contracts within a single corporate group to a different member of that group can also lead to a “supplier switch” in the same way as the insolvency of the previous supplier or termination by the supplier ("involuntary" supplier switch). The actual scale of the change made by customers to a competitor is therefore lower than the supplier switch figures suggest. On the other hand, it is not possible to tell from this figure whether the supplier has reduced prices, for example, or implemented other improvements to discourage customers from switching.

[41] The category "commercial customers" also, as a rule, covers customers in the group of self-employed professionals, in agriculture, services and public administration.

[42] Differences between the total amount of electricity supplied to final consumers of 456 TWh and 449 TWh (total volumes provided by suppliers according to the final consumer categories in Table 4 on page 22 and the total amount of electricity supplied to SLP and RLM customers) can be explained by marginal differences in the completion of the relevant questions in questionnaire 4.

[43] Alongside household customers, final consumers receiving substitute energy supplies are usually covered by the default supply tariff, section 38 EnWG. For monitoring purposes, the "default supply" category is also used for cases which are difficult to assign.

[44] Lack of clarity can also arise, for example, if there is a change in the local default supplier.

[45] If, when a customer moves into a property, the supplier is not the locally responsible default supplier, this is counted as a supplier switch. Transfers of supply contracts when concessions change hands are not treated as supplier switches.

2.1 RLM, business and industrial customers

Contract structure

The energy consumed by interval-metered (RLM) customers is recorded at short intervals ("load profile"). RLM customers consume higher volumes of energy[46]. RLM customers are industrial customers and (high-volume) business customers[47].

In the 2013 reporting period, around 925 electricity suppliers (separate legal entities) provided data on metering points and offtake volumes for RLM customers (supplied in Germany). Of these 925 electricity suppliers, many are members of corporate groups so this figure is not identical to that of the number of competitors. Nonetheless, there is a broad diversity of suppliers to RLM customers.

Overall, in 2013, these companies supplied RLM customers at a total of around 342,000 metering points with a good 281 TWh of electricity. Some 99 per cent of deliveries were made on the basis of special contracts. A situation in which RLM customers are supplied within the framework of default or substitute supply is atypical, but not to be excluded. Around 0.6 TWh of electricity was supplied to RLM customers within the framework of default or substitute supply; this is equivalent to around 0.2 per cent of the total volume supplied to RLM customers.

Of the total volume of supplies to RLM customers, around 34 per cent was provided under special contracts with the default supply (spread among some 53 per cent of all metering points) and around 66 per cent under supply contracts with a legal entity other than the locally responsible default supplier (spread among some 45 per cent of all metering points). These figures show that default supply status is still of very little practical significance for RLM customers.

[46] According to section 12 StromNZV, an RLM is usually required to have annual consumption of 100 MWh upwards.

[47] The consumption of business customers who use less electricity is currently recorded in the form of a standard load profile (SLP).

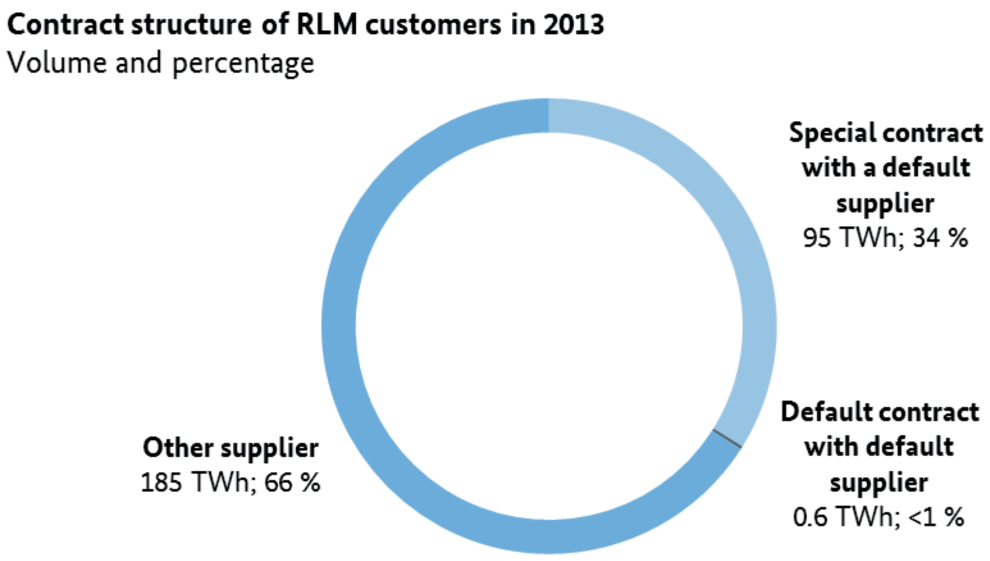

Figure 66: Contract structure for RLM customers, 2013

Supplier switch

The number of supplier switches in 2013 was determined for various customer groups in questionnaires 2 and 3 (transmission and distribution system operators). This does not relate to the customer groups explained above (SLP/RLM customers, commercial and industrial customers), but to various consumption categories. The consumption category of over 2 GWh/year typically refers to industrial customers, whereas the consumption category of 10 MWh/year to 2 GWh/year usually includes commercial customers and (low-volume) industrial customers. As outlined above, a supplier switch is defined as a change in the supplying legal entity, which is not always the same as a change of provider. The survey results were as follows:

Supplier switches in each customer category

Final consumer category	Number of metering points changing the supplying legal entity in 2013	Percentage of all metering points in this category	Offtake volume of metering points where the supplier changed in 2013	Percentage of total offtake volume in this category in 2013
> 2 GWh/year	2,959	15.9%	26.3 TWh	11.0%
10 MWh/year – 2 GWh/year	241,406	10.0%	18.7 TWh	14.0%
<10 MWh/year	3,281,882	6.9%	9.8 TWh	7.8%

Table 33: Supplier switch in each consumer category, 2013

Across both consumption categories of over 10 MWh/year, the volume-based change rate in 2013 was around 12.1 per cent. Compared with last year, this is equal to an increase of 0.8 percentage points. This change is consonant with the fluctuations in previous years. Considered over a longer period of time, the rates of change among industrial and business customers have remained fairly constant since 2006. The current monitoring survey did not investigate the proportion of industrial and business customers who have changed suppliers repeatedly, once or not at all. The supplier switch rates in the consumption categories of 10 MWh/year and over continue to be substantially higher than the switch rates of consumers using less than 10 MWh/year.

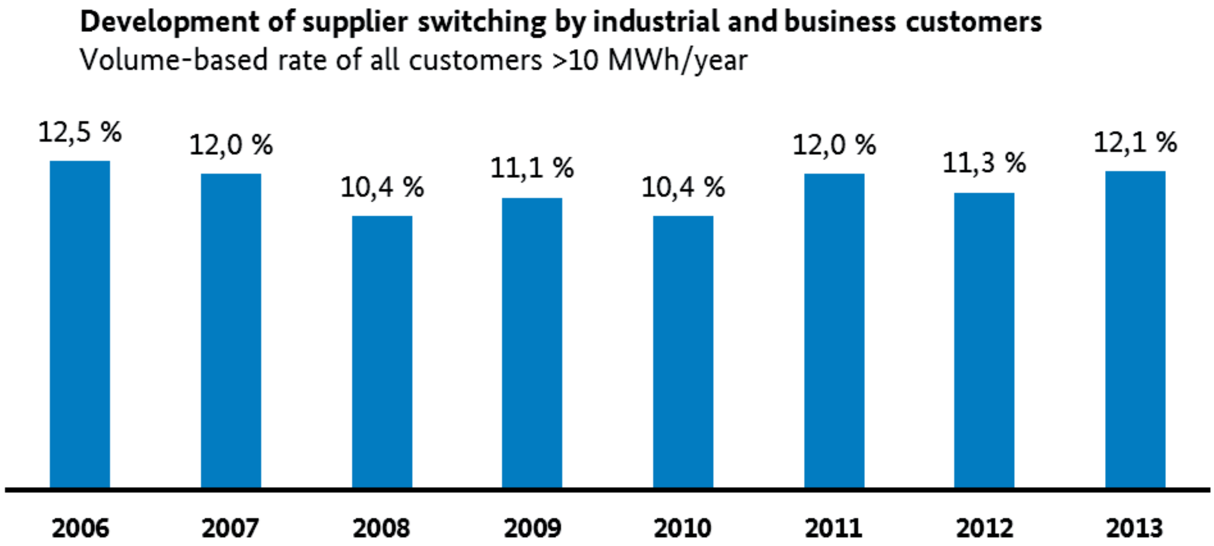

Figure 67: Development of supplier switch rates for industrial and business customers, 2006 to 2013

2.2 Household customers

Contract structure

The 2014 Monitoring data on volumes supplies to household customers shows that, in 2013, a relative majority of 45 per cent of household customers had a special contract with a local default supplier. Some 34.1 per cent of household customers have a classic default supply contract. The share of customers being served by their default supplier has thus dropped once again since last year (2012: 36.7 per cent). Around 21 per cent of all household customers are now supplied by an enterprise other than the default supplier. The share of customers who no longer have contracts with their default suppliers has gone up slightly. 79 per cent of households are supplied by their default suppliers (either receiving default supply services or under a special contract). This means that the continuing strong position of default suppliers in their own service areas weakened somewhat further during the year under review.

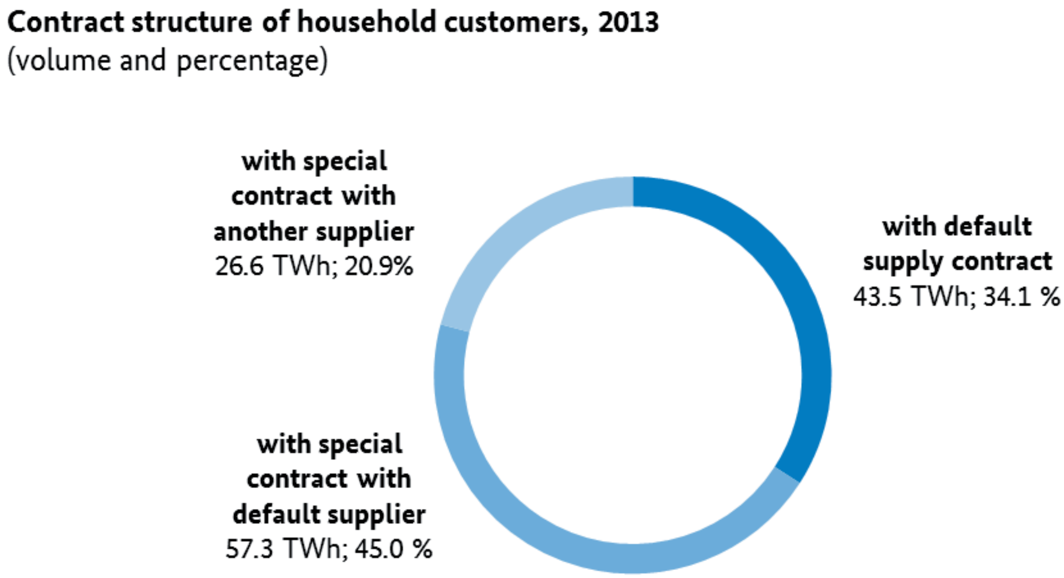

Figure 68: Contract structure for household customers

A standard load profile (SLP) is applied to simplify recording of consumption by customers whose offtake over time is not recorded. SLPs are only used for customers who withdraw up to a maximum of 100 MWh/year from the electricity distribution network (section 12, Strom NZV). SLP customers are for the most part household customers, but may also include non-household customers whose energy consumption is relatively low. The figures for metering points and delivery volumes for around 1,000 individual companies show that SLP (standard load profile) customers consume a total of around 168 TWh supplied power with 47.8m SLP metering points. Of this, approximately 127 TWh, or around 75 per cent was accounted for by household customers.

Of a total volume supplied to SLP customers, 48 TWh (around 29 per cent) was supplied under default supply contracts, 82 TWh (almost 49 per cent) under special contracts with the default supplier and 38 TWh (about 23 per cent) under special contracts with another legal entity.

Higher-consumption SLP customers are much more likely to have a special contract than SLP customers that consume less. The median annual consumption per metering point for customers receiving default supplies is just under 2,400 kWh/year; the corresponding figure for customers with special contracts is over 4,000 kWh/year.

Among the approximately 1,000 suppliers (individual company level) with figures on metering points and volumes for SLP customers 751 have the status of default suppliers. Most of these suppliers have only relatively low customer figures: 632 of these default suppliers supply fewer than 50,000 SLP metering points and 310 of these fewer than 10,000 SLP metering points.

Supplier switch

In order to determine the number of household customers changing supplier the DSOs were asked to provide figures on the volume and number of changes at metering points and the choice of supplier following changes of residence in their network area. Compared with 2012, the total number of supplier switches by household customers (including customers moving home) rose from 3.2 million to 3.6 million. Above all, this development reflects the higher number of switches taking place when customers move to a new location. In contrast, the number of changes of supplier not associated with a change of residence has remained stable compared to last year, even taking into account the special impact of an insolvency of one of the major suppliers.

In unadjusted terms, the number of changes of household customers, not including moving home, has gone up from around 450,000 to about 3,033,000. As was the case in 2011 however, these figures are influenced by a special factor related to the monitoring survey itself, which leaves considerable uncertainty about the actual decisions taken by customers to change supplier.

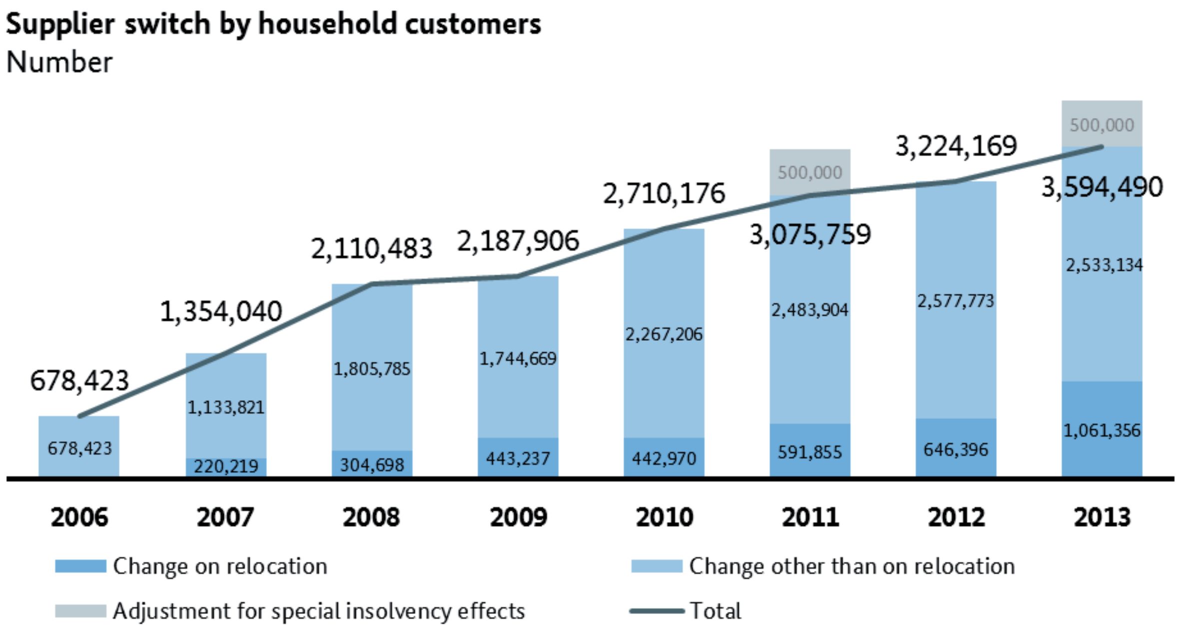

Figure 69: Number of supplier switches by household customers

In early 2013 a major electricity supplier again filed for insolvency. The customers affected by this insolvency initially fell back on a substitute supplier and thereafter, if they had not subsequently made a switch, transferred to the standard services provided by their local default supplier. As in a similar case of insolvency in 2011, an estimated figure of 500,000 customers was affected (also taking the numbers provided by the 2012 Monitoring Report into account). By definition, such an atypical procedure is recorded as a switch, despite the fact that it is not based on a customer's decision to change. It is therefore appropriate to remove the estimated proportion of "switches automatically brought on" by the insolvency.

After adjusting the switching figures for 2013 by removing the 500,000 switches brought on by the insolvency, a clearer picture of the increasing number of switches apart from moving home emerges. If the special impact of insolvencies in 2011 and 2013 is neutralised, the number of supplier switches by household customers apart from moving home has remained practically constant since 2011. A total of around 2,533,000 switches for 2013 were recorded in this way, equal to a share of around 5.5 per cent of all household customers. The volume relating to adjusted changes is around 8.4 TWh.

It remains to be seen whether in the area of household customers – as in the case of industrial and business customers a stable change rate (excluding customers moving home) has now been established. This detailed development, taking into account the special effect of insolvencies in 2011 and 2103, is shown in the following table:

Supplier switches by household customers

Change since previous year	Adjustment [1] for special insolvency effects		Without adjusting for special insolvency effects	
	Absolute	(%)	Absolute	(%)
2008-2009	-61,117	-9.1	-61,117	-9.1
2009-2010	522,538	30	522,538	30
2010-2011	216,698	9.6	716,698	31.6
2011-2012	93,869	3.8	-406,131	-13.6
2012-2013	-44,639	-1.7	455,361	17.8

[1] 500,000 changes were deducted from the adjusted switching figures for 2011 and 2013.

Table 34: Changes in supplier switching figures for household customers (excluding customers moving home, with and without adjustment for special insolvency effects)

In addition to the change in the figures for switches by household customers (excluding moving home) shown, the number of household customers that directly chose an alternative supplier, rather than the default one, when moving into new premises increased by more than 400,000. In the year under review this number was about 1,061,000 household customers. The number of notified supplier switches upon moving home rose by 0.9 TWh to a total of 2.4 TWh compared with the previous year.

Number of supplier switches made by household customers adjusted for insolvencies, including changes from moving home

Category	2013: Supplier switches in TWh	Percentage of total offtake volume (126.1 TWh)	2013: Number of supplier switches	Percentage of total household customers
Household customers who switched supplier but did not move home	8.4	6.7	2,533,134	5.5
Household customers who switched to a supplier other than the default supplier when moving home	2.4	1.9	1,061,356	2.3
Total	10.8	8.6	3,594,490	7.8

Table 35: Number of supplier switches made by household customers adjusted for insolvencies, including changes resulting from moving home[48]

An analysis of the household customer supplier switches adjusted for insolvencies combined with those moving home gives a total of 3.6 million switches for 2013, with a total volume of 10.8 TWh. This corresponds to a volume- and quantity-based switching rate of 8.6 and 7.8 per cent respectively. The volume-based rate was therefore again slightly above the quantity-based rate. The conclusion can be reached that a household customer's high level of electricity consumption positively influences the decision to switch. The average volume of electricity consumed by a household customer that made a switch was approximately 3,200 kWh in 2013. In contrast to this, customers that were supplied by a default supplier consumed on average only approximately 2,300 kWh.

3. Disconnection notices and disconnections, tariffs and terminations

3.1 Disconnections

In the 2013 reporting period the Bundesnetzagentur performed surveys of tariffs on offer for the third time and asked network operators and electricity suppliers about threatened disconnections, disconnection orders as well as the number of actual disconnections under section 19(2) StromGVV and the associated costs.

[48] Figures may not sum exactly owing to rounding.

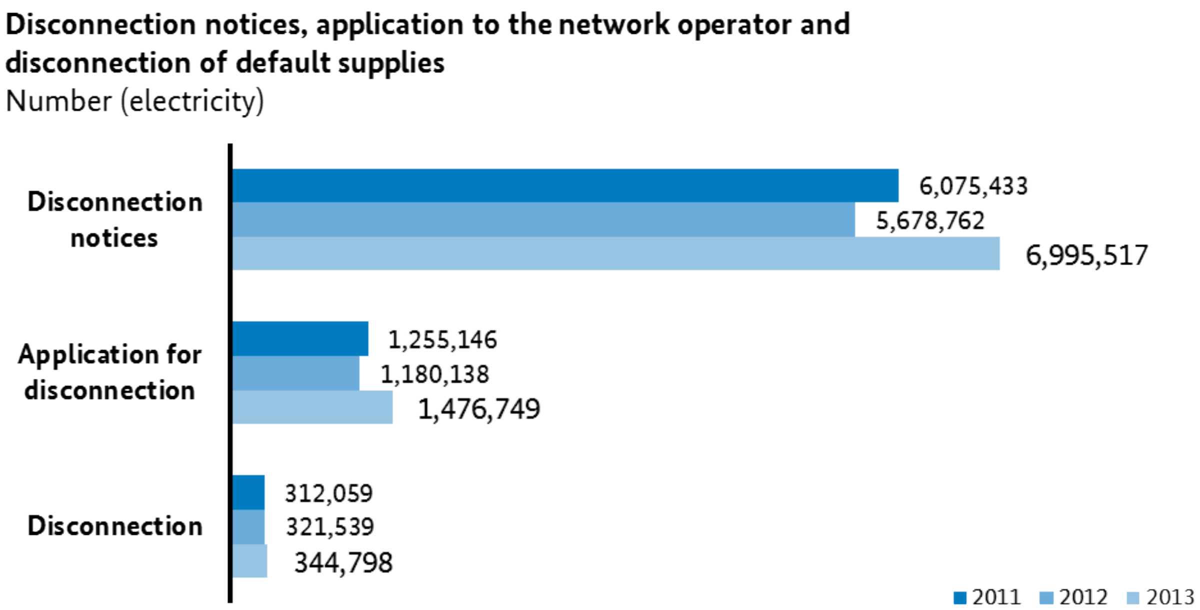

Figure 70: Disconnection notices, application to the network operator and disconnection of electricity supplies[49]

The StromGVV entitles default suppliers to disconnect supplies to customers, particularly for non-payment where arrears have mounted to at least €100 and after a corresponding reminder has been given. The number of actual disconnections has risen slightly since the previous year to 344,798. In total, just over 23,000 more metering points were disconnected than last year. This outcome is based on figures provided by the distribution system operators who ultimately disconnect supplies on behalf of the supplier. Measured against the total number of all the metering points at the distribution system level covered by the monitoring in Germany, the market coverage ratio for this question was around 98.5 per cent.

At the same time, suppliers were asked how often in 2013 they had issued disconnection notices warning customers in arrears that they may be disconnected or had applied to the responsible network operator for supplies to be disconnected. Companies stated that they had issued almost seven million disconnection notices to household customers. According to the data provided by companies, disconnection notices threatening to cut a customer off are issued when the statutory requirements of section 19 StromGVV are met and when, on average, a customer is €105 in arrears. However, of the almost seven million disconnection notices issued, only around 1.5 million resulted in electricity being cut off by the responsible network operator.

Ultimately, network operators actually disconnected 344,798 household customers. Overall the relationship between threatened disconnections, disconnection orders and actual disconnections reported in the 2013 Monitoring report improved somewhat. Of the almost seven million threatened disconnections, around 21 per cent escalated to a disconnection order. Almost 5 per cent of the approximately seven million threatened disconnections actually led to the system operator cutting off supplies.

[49] It is important to note with regard to the data for 2011 that some suppliers were only able to provide estimated figures for disconnection notices and applications to the network operator .

On average, network operators charged their customers €48 for cutting off supplies, whereby actual charges varied between €13 and €168.

3.2 Tariffs and terminations

Under section 40(5) EnWG suppliers of electricity must offer final consumers load-based or peak/off-peak tariffs in particular, if this is technically and economically feasible. During the 2013 reporting period only around 10 per cent of suppliers offered load-based tariffs. Around 76 per cent of suppliers offer peak/off-peak tariffs[50] and another 14 per cent or so other tariffs as well.

Under section 40(3) EnWG suppliers are also required to offer final consumers monthly, quarterly or half-yearly settlement. Demand from final customers for these forms of billing was still negligible in 2013, however. A total of 3,595 inquiries from customers about mid-year billing were reported by 132 companies.

Despite the relatively high number of reported disconnection notices and applications for disconnections, very few suppliers actually stop doing business with their customers. In 2013, suppliers terminated contracts with about 141,000 customers. The average arrears per customer when contracts were terminated was around €169.

Disconnections are usually only carried out with customers who receive default supplies. These contracts can only be terminated if very specific conditions are met. Supplies may be cut off when a duty to provide default supplies does not exist or the conditions for disconnection have been met repeatedly. Disconnections and the threat of disconnection are rare with customers with special contracts as termination is a simpler and less expensive option for the supplier.

4. Price level

For the purposes of the Monitoring report suppliers who provide final customers with electricity in the Federal Republic of Germany were also asked about the retail prices charged by their companies on 1 April for three purchase cases. These three purchase cases are based on annual consumption of 3,500 kWh, 50 MWh and 24 GWh. These consumption figures are for a household customer, a commercial customer and an industrial customer respectively.

Suppliers were asked to state the total price in ct/kWh taking account of price components which are not related to consumption (service price, base price and prices for metering and billing etc.). Each of the price components was also to be broken down in detail into elements that cannot be influenced by the supplier, including for example network tariffs, concession fees and charges for billing, metering and meter operations. The total price also had to take account of (stipulated) surcharges under EEG, KWKG, section 19 StromNEV and for offshore liability. After deducting "transitory items" from the total price, the residual amount which can be influenced by the supplier is made up, in particular, of energy procurement and supply costs, miscellaneous costs and the margin.

Suppliers were asked to state their "average" price for each of the three consumer cases, both for the total price and for the price components. Several companies pointed out in their responses that, owing to their

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[50] These include, in particular, tariffs for heating current and heat pump electricity.

supralocal activities or custom-tailored price arrangements, they were not able to provide such average figures.

The separate price components for three different types of contract were ascertained for the smallest purchase case of 3,500 kWh/year ("household customer"): default supply contract, special contract with the default supplier and special contract with a supplier other than the default supplier (cf also section I.H.4.2 “Household customers" from page 149).

The evaluation of information provided by suppliers is shown in the following according to customer category or purchase case. All the results are shown alongside figures for the previous year in order to shed light on long-term development trends. When comparing the figures for 1 April 2014 and 1 April 2013 it is important to bear in mind that changes in calculated average values usually fall below the margin of error associated with the data collection system (and changes made to it). It is therefore often not possible to make statistically significant statements on whether prices had risen and fallen on 1 April 2013. It is also important to note that the informants providing price data have changed since last year: On the one hand, price questions were previously only directed at suppliers who were default suppliers in at least one network area, whereas this year's monitoring survey included all suppliers active in the Federal Republic of Germany. On the other, price questions for the purchase cases 50 MWh/year and 24 GWh/year were only intended to be completed by suppliers who have at least one customer with electricity requirements falling within the relevant purchase case.

4.1 Business and industrial customers

Customer category 24 GWh/year ("Industrial customer")

Industrial customers are all interval-metered customers (RLM customers). According to the information provided by suppliers, the diversity of possible contractual arrangements plays a significant role for this group of customers. Suppliers do not define any tariff groups for customers that consume 24 GWh/year, but instead offer customised service. This means that there are customers who procure all their supplies from a single source as well as customers for whom the negotiated offtake volume (on the scale relevant in this context) makes up just part of its procurement portfolio. Supplier prices are often indexed to wholesale prices. In the survey, several suppliers stated that their contract models require customers to settle network tariffs with the network operator themselves. These contract models can, in extreme cases, go so far that, in economic terms, the "supplier" only offers the customer a balancing group management service. This means that, for the largest consumers, the distinctions between retail and electricity wholesale are blurred.

The compensation scheme for large electricity-consuming enterprises has a substantial impact on the individual price paid by an industrial customer. The scale of price components that cannot be influenced by the supplier and the corresponding impacts on individual prices vary according to the maximum level of exemption available to a company in the 24 GWh/year purchase case category. The price question was framed under the assumption that none of these compensation measures are relevant to the customer. This means that suppliers were asked to ignore the special compensation measures for electricity-intensive companies and rail operators under sections 40 to 44 EEG (prior to amendment) and the provisions of section 19(2) StromNEV, section 9(7) sentence 3 KWKG and section 17f EnWG.

The customer category for an industrial customer is defined as annual consumption of 24 GWh and 6,000 hours annual usage time (4,000 kW annual peak load; medium voltage supplies of 10 or 20 kV). This year's survey only addressed suppliers who have at least one customer that uses between 10 GWh and 50 GWh a year. These customer attributes means that only a limited circle of suppliers are considered. Data was obtained from 208 suppliers (previous year: 206) for the following price evaluations for the purchase case. More than half of these 208 suppliers had fewer than ten customers who consumed over 24 GWh/year.

This data was used to calculate the (arithmetical) average total price and the individual price components. The spread of data for each price component was also evaluated in the form of ranges. The lower range limit relates to the 10th percentile and the upper limit to the 90th percentile. This means that the middle 80 per cent of values provided by suppliers lie within the stated range. The results of the evaluation were as follows.

Price level of customer category 24 GWh/year without possible reductions on 1 April 2014

	Spread between 10 and 90% of supplier information sorted by size in ct/kWh	**Average** (arithmetical) in ct/kWh
Price components that cannot be influenced by the supplier		
Net network tariff	1,12 - 2,61	1.86
Charge for billing, metering and metering operatons	0,00 - 0,04	0.04
Concession fee	0,11 – 0,11	0,12 [1]
Surcharge under EEG	6.24	6.24
Other Surcharges [2]	0.19	0.19
Electricity tax	2.05	2.05
Price components that can be influenced by the supplier (residual amount)	3,57 – 5,85	4.61
Total price (without value-added tax)	13,53 – 16,70	15.11

[1] More than 80% of the supplier provided a concession fee of 0,11 ct/kWh. As some of the supplier provided a significantly higher value, the arithmetical average is above the 0,11 ct/kWh.

[2] KWKG (0,055 ct/kWh), section 19(2) StromNEV (0,066 ct/kWh), offshore liability (0,058 ct/kWh) and interruptible loads (0,009 ct/kWh).

Table 36: Price level on 1 April 2014 for the 24 GWh/year customer category without compensation

The average total price (excluding VAT and without any reduction options) of 15.11 ct/kWh is 0.07 ct/kWh under the arithmetic mean of the values arrived at in the preceding year. This marginal difference is below the survey accuracy threshold. The relative price elements shifted, however: While the EEG surcharge has risen from 5.28 ct/kWh to 6.24 ct/kWh, the arithmetic mean of the residual amount which can be influenced by the supplier has dropped from 5.43 ct/kWh to 4.61 ct/kWh[51]. The remaining price components are at about the same level as last year.

By definition these prices imply that an (industrial) customer that consumes 24 GWh/year is not eligible for any exemptions at all. In a customer category defined in this way a total of 10.50 ct/kWh, ie around 70 per cent, is deducted from the cost positions that cannot be influenced by suppliers. If, on the other hand, electricity consumers are able to meet the requirements stipulated in the applicable regulations and statutes, reductions are made in the network tariffs, in electricity tax and the surcharges under EEG, KWKG, section 19 StromNEV and for offshore liability. If all these reduction possibilities are met, the price component that cannot be influenced by the supplier, of over 10 ct/kWh in certain cases, can be reduced to around 1 ct/kWh.

Under the amendment of 1 April 2014 the EEG surcharge could be reduced for this customer category by up to 91.5 per cent (section 41(3) EEG prior to amendment). Under section 19(2) sentence 1 StromNEV the net network tariff can be reduced by up to 80 per cent. Under section 9a StromStG the electricity tax can be remitted, reimbursed or refunded. In relation to the total price, quantitatively less significant exemption options apply to the concession fee under section 2(4) sentence 1 KAV and other surcharges. The energy monitoring survey does not examine the extent to which specific reduction options are actually used by industrial customers. In this respect as well, the monitoring data cannot be used to make statements about "the" average price for industrial customers.

Possible price reductions of customer category 24 GWh/year on 1 April 2014

	Supposed or ascertained value in price query in ct/kWh	Possible reduction down to in ct/kWh
Surcharge under EEG	6.24	0.53
Electricity tax	2.05	0.00
Net network tariff	1.86	0.37
other surcharges	0.19	0.10
Concession fee	0.12	0.00
Total	**10.50**	**1.00**

Table 37: Possible exemptions for the 24 GWh/year customer category on 1 April 2014

Customer category 50 GWh/year ("Commercial customer")

The customer category for a commercial customer is defined as annual consumption of 50 MWh and 1,000 hours annual usage time (50 kW annual peak load; low-voltage supplies of 0.4 kV). This annual consumption is fourteen times that of the 3,500 kWh customer category ("household customer") and 1/2000 of the 24 GWh customer category ("industrial customer"). As this represents relatively moderate consumption,

[51] The spread of data referred to above must be taken into account when comparing these averages.

individual contract arrangements play a significantly smaller role than is the case for the "industrial customer" customer category. Suppliers were asked to provide plausible estimates, based on the conditions applying on 1 April 2014, for the amount charged to their customers with a purchase structure comparable to the stated customer category. The relevant suppliers were those who were already serving customers with a load profile on a comparatively similar scale, ie those with annual requirements of between 10 MWh and 100 MWh. This customer category relates to consumption below the threshold of 100 MWh above which the system operator is required to apply interval metering. It is therefore possible to assume that, in this selected customer category, consumption will often be recorded using a standard load profile.

For the following price evaluations for the customer category data was obtained from 763 suppliers (previous year: 641 suppliers). This data was used to calculate the (arithmetical) average total price and the individual price components. The spread of data for each price component was also evaluated in the form of ranges within which the value stated by the median 80 per cent of suppliers fell. The results of the evaluation were as follows.

Price level of customer category 50 MWh/year on 1 April 2014

	Spread between 10 and 90% of supplier information sorted by size in ct/kWh	**Average** (arithmetical) in ct/kWh	**Percentage of total price**[1]
Price components that cannot be influenced by the supplier			
Net network tariff	4,09 – 6,75	5.35	24%
Charge for billing, metering and metering operatons	0,04 – 1,14	0.30	1%
Concession fee	0,11 – 1,59	1.00	5%
Surcharge under EEG	6.24	6.24	29%
Other Surcharges[2]	0.53	0.53	2%
Electricity tax	2.05	2.05	9%
Price components that can be influenced by the supplier (residual amount)	4,77 – 8,23	6.39	29%
Total price (without value-added tax)	19,43 – 24,02	21.86	

[1] Totals may deviate slightly owing to rounding differences.

[2] KWKG (0,178 ct/kWh), section 19(2) StromNEV (0,092 ct/kWh), offshore liability (0,250 ct/kWh) and interruptible loads (0,009 ct/kWh).

Table 38: Price level on 1 April 2014 for the 50 GWh/year customer category

On average, around 71 per cent of the total price for this customer category was for cost positions that cannot be influenced by suppliers (network tariffs, surcharges and electricity tax, concession fees). Only around 29 per cent (previous year: 33 per cent) relate to price elements which allow scope for business decisions to be taken.

The average total price (excluding VAT) of 21.86 ct/kWh is 0.11 ct/kWh under the arithmetic mean of the values arrived at in the preceding year (21.97 ct/kWh). This marginal difference is below the survey accuracy threshold. However, compared with the previous year, there are significant differences in two price components: While the EEG surcharge has risen from 5.28 ct/kWh to 6.24 ct/kWh, the arithmetic mean of the residual amount which can be influenced by the supplier has dropped from 7.29 ct/kWh to 6.39 ct/kWh[52]. The remaining price components are at about the same level as last year.

4.2 Household customers

In the following, consumer prices for household customers are considered as volume-weighted averages for a typical customer category (household with annual consumption of 3,500 kWh/year, low-voltage supply (0.4 kV)) for the relevant contracts. This produces evaluations for the average price for default supply services, for a special contract with a default supplier and for a contract with a supplier other than the local default supplier ("supplier switch"). A volume-weighted total price across all tariff categories is also determined.

The consistent and substantial increase in prices which has taken place in recent years was not repeated this year. Compared with 2013, the rate of price increases slowed down for all consumer groups – default supply services, special contract with default supplier, special contract with a third supplier.

Information was provided by 664 companies for the 2014 Monitoring report on tariffs and volumes for the default supply service category. Based on the reported data a volume-weighted average price of 30.50 ct/kWh was determined for 1 April 2014[53]. This means that, on the key date of 1 April 2013, the price for customers receiving default supply services had risen by 1.3 per cent or 0.39 ct/kWh compared with the previous year. This is the lowest increase in prices since 2006. Within a period of eight years the price has risen by 11.61 ct/kWh from an original price of 18.89 ct/kWh. This corresponds to an increase of around 61 per cent. The detailed development of volume-weighted average prices for default supply services is shown in the following diagram.

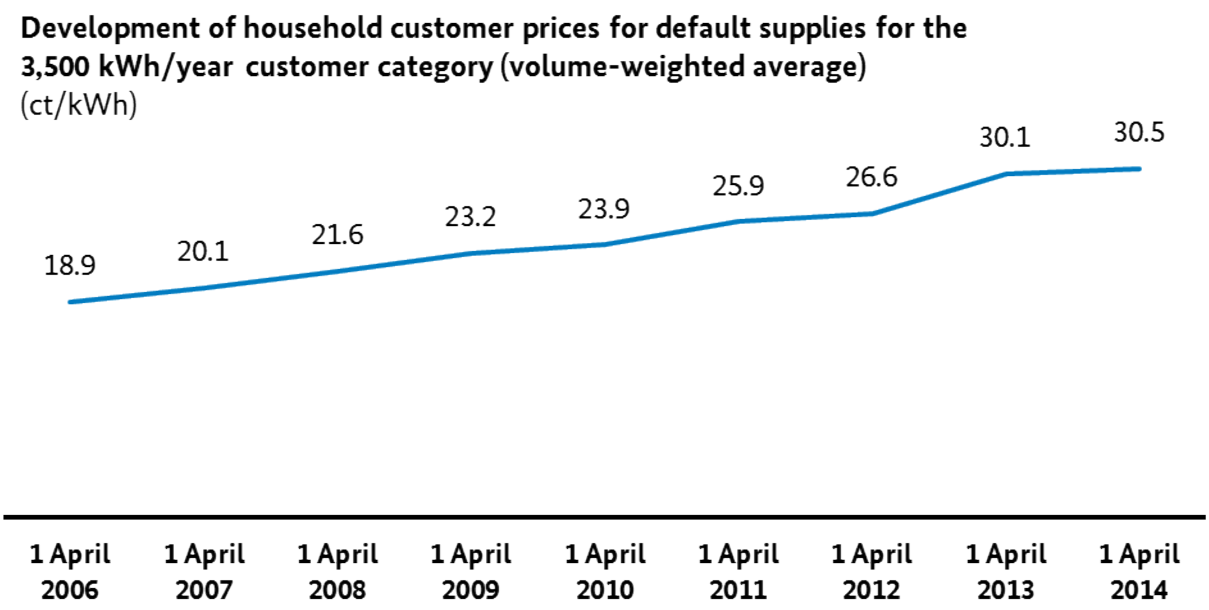

Figure 71: Development of household customer prices for default supplies for the 3,500 kWh/year customer category (volume-weighted average)

[52] The spread of data referred to above must be taken into account when comparing these averages.

[53] The arithmetical mean value is around 0.42 ct/kWh below the volume-weighted result.

635 suppliers provided information on tariffs and volumes for the "special contract with a default supplier" contract category. Based on the reported data a volume-weighted average price of 29.32 ct/kWh was determined for 1 April 2014[54]. This means that the price for customers who changed to special contracts with default suppliers is just 1 per cent or 0.23 ct/kWh higher than in 2013. This is also the smallest price increase in this tariff category since the survey was launched in 2007. Within seven years the price has risen by 9.38 ct/kWh. This is equal to an increase of 47 per cent. The development of volume-weighted average prices for a special contract with a default supplier is shown in the following diagram.

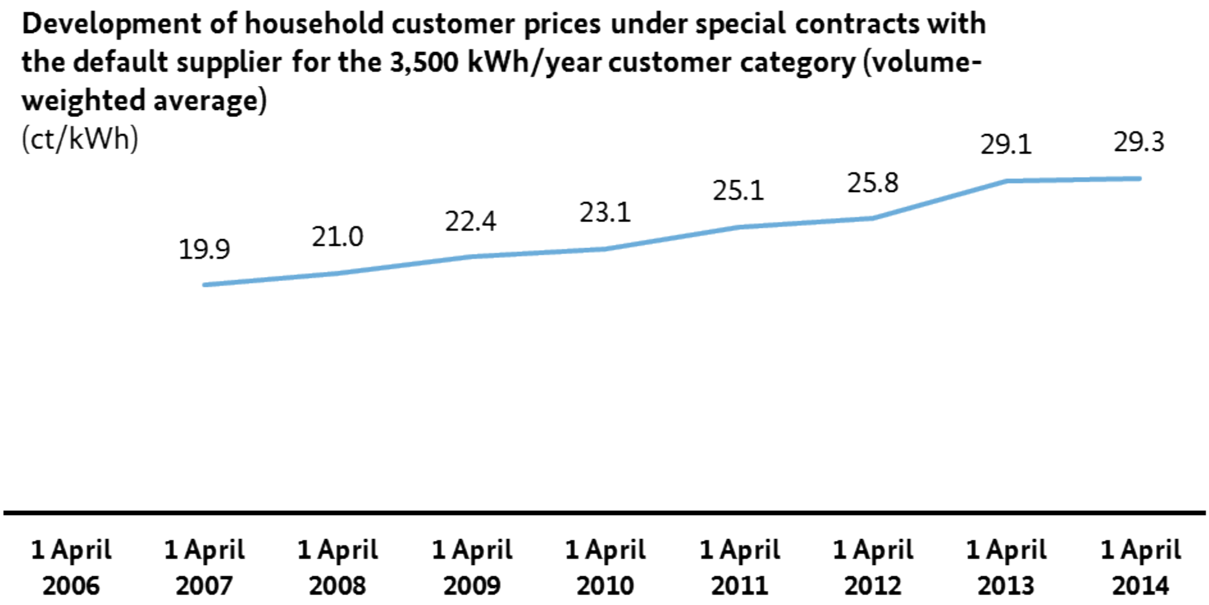

Figure 72: Development of household customer prices for annual consumption under a special contract with a default supplier of 3,500 kWh from 2007 to 2014 (volume-weighted average)

In the category of special contracts with suppliers other than the local default supplier ("supplier switch" category) 638 companies provided information on prices and volumes. Based on the reported data a volume-weighted average price of 28.29 ct/kWh was determined for 1 April 2014[55]. This means that the price for customers who have a special contract with a supplier who is not the local default supplier is a good 1 per cent or 0.35 ct/kWh higher than last year. In percentage terms, this (with 2012, when prices rose even less) is one of the smallest increases in prices since the survey began in 2008. Within six years the price has thus risen by 7.43 ct/kWh. This is equal to an increase of 36 per cent. The detailed development of volume-weighted average prices for a change of supplier is shown in the following diagram.

[54] The arithmetical mean value is around 0.49 ct/kWh below the volume-weighted result.

[55] The arithmetical mean value is around 0.28ct/kWh above the volume-weighted result.

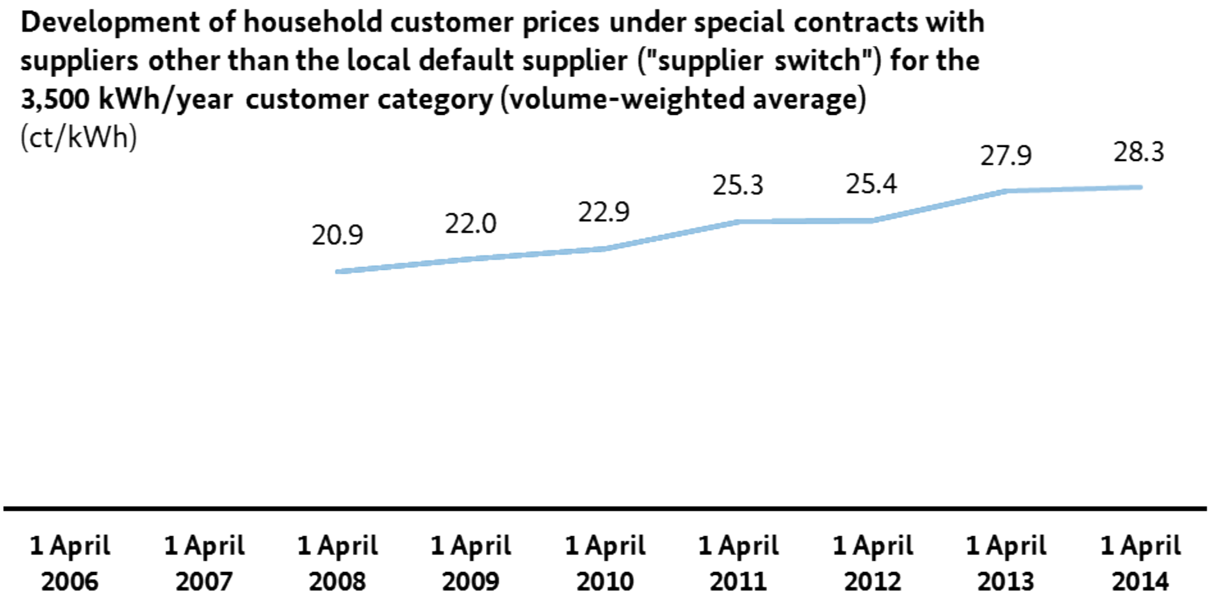

Figure 73: Development of household customer prices for annual consumption under a special contract with a supplier other than the local default supplier ("supplier switch") of 3,500 kWh from 2008 to 2014 (volume-weighted average)

Direct comparison of the three tariff categories - default supply services, special contract with the default supplier (change of contract) and special contract with another supplier (supplier switch) - shows that default supply services for annual consumption of 3,500 kWh continue to be the most expensive form of service. Nonetheless, direct comparisons are very difficult to make as customers served by default suppliers consume significantly less electricity than customers with special contracts. While customers served by default suppliers used an average of 2,350 kWh in 2013, customers with special contracts used an average of 40 per cent more, or around 3.290 kWh.

Household customers can continue to pay lower prices if they revise their contracts or change supplier, whereby changing supplier is usually the more cost effective alternative. A comparison of the average values for the three categories since 2008 reveals that the annual default supply of 3,500 kWh is consistently the most expensive category of electricity supply for household customers. Over the monitored period, a special contract with a default supplier category is in all cases cheaper than default supply every year. Considered over the entire period the supplier switch category is also, on average, cheaper than default supply services. In six of the seven years monitored the average price in the supplier switch category was – more or less clearly – below that for the special contract with default supplier category.

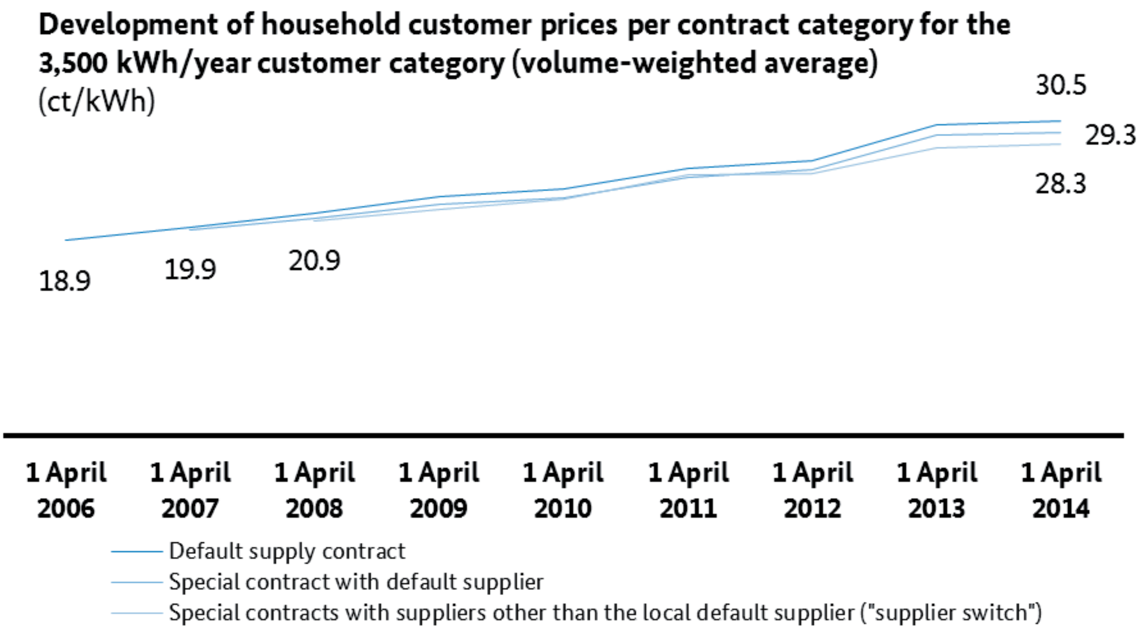

Figure 74: Development of household customer prices per contract category 2006 to 2014 (volume-weighted average per tariff)

The survey of default suppliers to household customers also recorded the overall price and individual price components. As certain components of the price are mandated by law (surcharges, electricity tax) or are regulated for the network area (net network tariff), a key price variable in comparisons between default supply services and special contracts with a default supplier is the component of the price which can be influenced by the supplier ("energy procurement and supply"). In this context information obtained from almost 664 (default supply services) and 638 (change of tariff) suppliers was evaluated. These figures have been integrated in the following diagram.

On 1 April 2014 the average volume-weighted price for the supplier change tariff category was 2.21 ct/kWh or 8 per cent below the price for default supply services. If, in contrast, the unweighted average prices are compared, the difference is just 1.51 ct/kWh or 5 per cent. The difference between default supply services and a change of contract (volume weighted) is 1.18 ct/kWh or a difference of 4 per cent. The volume-weighted difference between a change of contract and a change of supplier is 1.03 ct/kWh or 4 per cent. The price differences between the contract categories are due, in particular, to the differences in the price component elements which can be influenced by suppliers (including energy procurement and supply).

The price component which can be influenced by suppliers providing default supplies, which includes the costs of energy procurement and supply, for annual consumption of 3,500 kWh on 1 April 2014 is 8.72 ct/kWh or 31 per cent above the average in the change of supplier category for which an average volume-weighted value of 6.67 ct/kWh has been calculated from the data. In 2013, there was still a difference of 25 per cent between the two categories. An average of 7.70 ct/kWh is cited as the price component for energy procurement, supply, other costs and margin for special contracts with the local default supplier. The relevant price component in this category is thus just under 12 per cent below that for standard default supplies.

An indirect comparison of these values – which takes more than various consumption values into account – must also consider the differences between the three customer groups. Default supply contracts, for example, have shorter termination periods and, on average, a higher risk of non-payment. Risk costs such as these are also included in the price component which can be influenced by the supplier. And, finally, account must also be taken of the inaccuracies inherent in the survey and evaluation method used. A detailed overview of this development is provided in the following diagram.

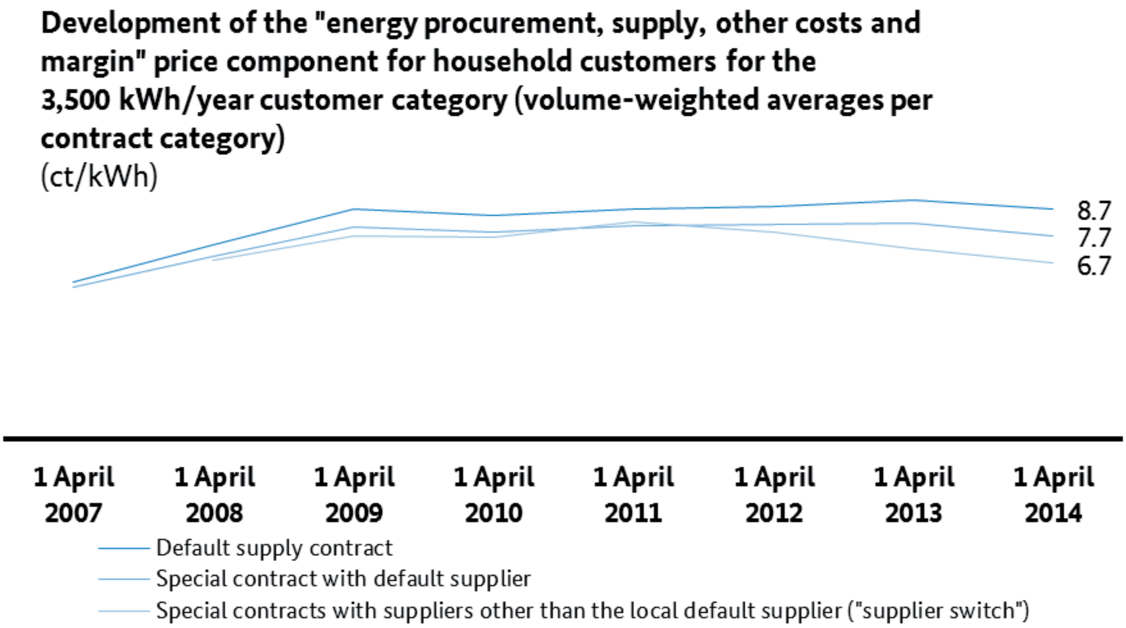

Figure 75: Development of the "energy procurement, supply, other costs and margin" price component for household customers with annual consumption of 3,500 kWh 2007 to 2014 (volume-weighted averages per contract category)

A comparison of the price component which can be influenced by the supplier ("energy procurement, supply, other costs and margin") in the three contract categories illustrates that, since 2011, this element of the price has fallen in the change of supplier category. For the first time since 2010 the price components which can be influenced by suppliers have again fallen in both types of contractual arrangement with default suppliers.

In addition to the costs of procurement and supply, the electricity prices paid by household customers are composed of network tariffs, surcharges, taxes and levies. Each of the components of the price in various contract categories are shown in the following table.

Average retail price for household customers per contract category with 3,500 kWh/year consumption

Household customers (volume-weighted) 1 April 2014 (ct/kWh)	Default supply contract	Special contract with default supplier	Special contract with other supplier
Net network tariff	5.81	5.87	5.96
Charge for billing	0.33	0.33	0.36
Charge for metering	0.09	0.09	0.12
Charge for metering operations	0.24	0.24	0.26
Energy procurement, supply, other costs and margin	8.72	7.70	6.67
Concession fee	1.62	1.59	1.59
Surcharge under EEG	6.24	6.24	6.24
Surcharge under KWKG	0.18	0.18	0.18
Surcharge under section 19 StromNEV	0.09	0.09	0.09
Surcharge for offshore liability	0.25	0.25	0.25
Surcharge for interruptible loads	0.01	0.01	0.01
Electricity tax	2.05	2.05	2.05
Valued-added tax	4.87	4.68	4.52
Total	30.50	29.32	28.29

Table 39: Average retail price for household customers with an annual consumption of 3,500 kWh per contract category on 1 April 2014

Special contracts may have a number of other features, in addition to the overall price, which are used by suppliers to compete for customers. These features may offer greater security to customers (e.g. guaranteed stable prices) or to suppliers (e.g. advance payment, minimum contract term), which is then compensated for between the contracting parties elsewhere (overall price).

Suppliers have been specifically surveyed on such elements. Minimum contract terms or price stability guarantees are especially common. On average the commitment periods for special contracts are ten months. Price stability is offered over an average period of 14 months under special contracts.

The following table provides an overview of the various special bonuses and special arrangements which are offered by electricity suppliers:

Special bonuses and arrangements for household customers

Dienstag, 1. April 2014	Household customers			
	Special contract with default supplier		Special contract with other supplier	
	Number of tariffs	Average scope	Number of tariffs	Average scope
Minimum contract term	344	10 months	390	10 months
Price stability	288	14 months	334	14 months
Advance payment	67	11 months	42	11 months
One-off bonus payment	80	€ 48	136	€ 53
Deposit	4	-	1	-
Other bonuses and special arrangements	41	-	36	-

Table 40: Special bonuses and arrangements for household customers in 2013

The variety of (variously combinable) price forming elements makes it very difficult to compare tariffs, the diversity of which is relevant for competitive purposes. A single average price is shown in the following as an indicator for all household customers consuming 3,500 kWh/year. For this purpose a volume-weighted average is calculated across all tariff categories by weighting the single prices of the three contract categories with their respective volume of electricity delivered. The average price on 1 April 2014 was 29.53 ct/kWh. In detail the price is composed of the following elements.

Average volume-weighted retail price level for all household customers with 3,500 kWh/year consumption across all contract categories

Household customers (volume-weighted) 1 April 2014 (ct/kWh)	Volume-weighted average price across all tariffs (ct/kWh)	Share of total (%)
Net network tariff	5.87	19.9
Charge for billing	0.34	1.1
Charge for metering	0.09	0.3
Charge for metering operations	0.24	0.8
Energy procurement, supply, other costs and margin	7.86	26.6
Concession fee	1.60	5.4
Surcharge under EEG	6.24	21.1
Surcharge under KWKG	0.18	0.6
Surcharge under section 19 StromNEV	0.09	0.3
Surcharge for offshore liability	0.25	0.8
Surcharge for interruptible loads	0.01	0.0
Electricity tax	2.05	6.9
Valued-added tax	4.71	16.0
Total	29.53	100

Table 41: Average volume-weighted retail price level for all contract categories for household customers consuming 3,500 kWh/year on 1 April 2014

The different percentage components of the price are shown in the following.

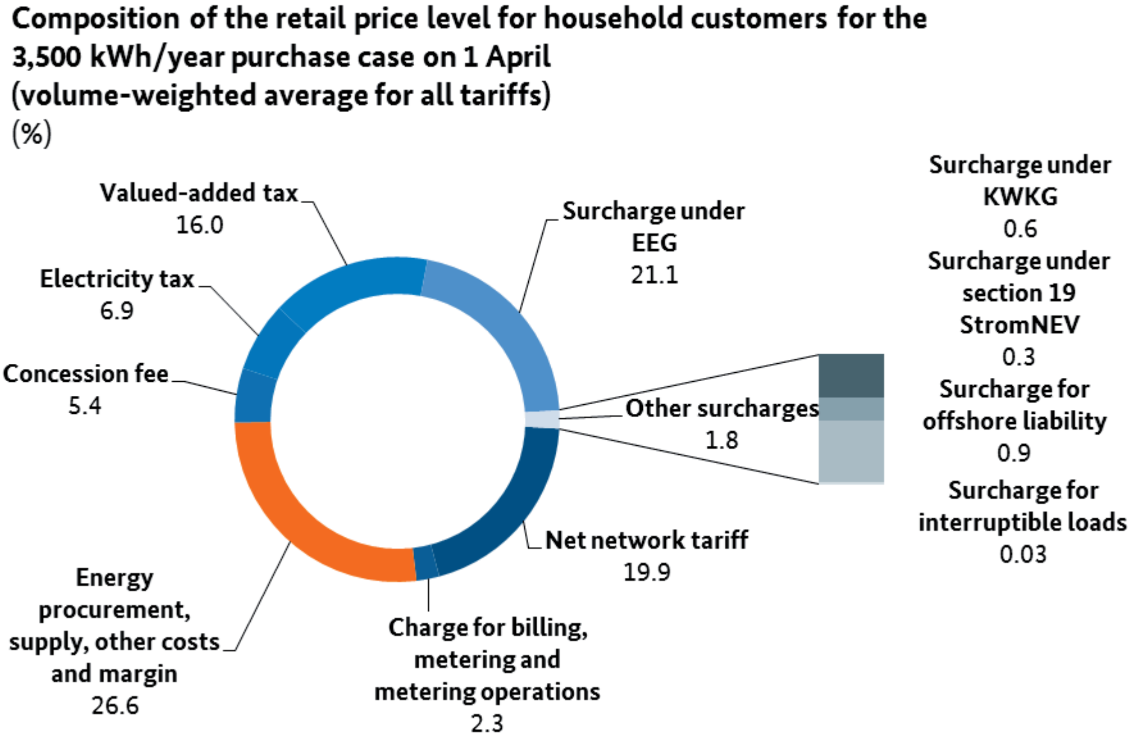

Figure 76: Composition of the retail price level (volume-weighted average for all tariffs) for household customers consuming 3,500 kWh/year on 1 April 2014[56]

The net network tariff accounts for 20 per cent of the total electricity price for household customers. Charges for billing, metering and metering operations account for 2.3 per cent of the overall price. Energy procurement accounts and supply accounts for 26.6 per cent. Taxes (electricity and VAT) add up to a share of 22.9 per cent and total levies (surcharges under the EEG, KWK-G, section 19 StromNEV and offshore liability as well as loads which can be shut down and concession charge) to around 28.4 per cent. At 21 per cent, the EEG surcharge makes up the largest share. Total taxes and levies make up almost 51 per cent of the average electricity price paid by household customers.

The change in volume-weighted electricity prices for all tariffs from 1 April 2013 to 1 April 2014 for an offtake volume of 3,500 kWh/year is shown in the following. The electricity price rose slightly by 1 per cent (+0.29 ct/kWh) and is now just above the price for the year 2013. This minor increase is largely due to the price component that can be influenced by suppliers falling by 0.48 ct/kWh and the surcharge under section 19 StromNEV by 0.24 ct/kWh; consequently these compensate to some extent for higher surcharges (EEG and KWKG).

[56] The component shown in orange is the share which can be influenced by the supplier.

Change in the volume-weighted price level for all contract categories from 1 April 2013 to 1 April 2014 for household customers with 3,500 kWh/year consumption

	Volume-weighted average across all tariffs (ct/kWh)	Change relative to level of price component	
		(ct/kWh)	(%)
Net network tariff	5.87	0.04	1
Charge for billing	0.34	-0.01	-4
Charge for metering	0.09	0.00	4
Charge for metering operations	0.24	-0.01	-3
Energy procurement, supply, other costs and margin	7.86	-0.48	-6
Concession fee	1.60	-0.07	-4
Surcharge under EEG	6.24	0.96	18
Surcharge under KWKG	0.18	0.05	37
Surcharge under section 19 StromNEV	0.09	-0.24	-72
Surcharge for offshore liability	0.25	0.00	0
Surcharge for interruptible loads	0.01	0.01	
Electricity tax	2.05	0.00	0
Valued-added tax	4.71	0.05	1
Total	29.53	0.29	1

Table 42: Development of the volume-weighted price level for household customers for all tariffs

The development of the key price components for the volume-weighted electricity price for household customers consuming 3,500 kWh/year is shown below. However, first consideration is given to network tariffs. After a period during which these charges fell consistently up to 2011, network charges[57] again went up slightly in 2014 by 0.3 per cent (+0.02 ct/kWh) compared with the previous year. Network tariffs have fallen by 0.20 ct/kWh or 3 per cent over a period of seven reporting periods. This analysis encompasses network tariffs excluding surcharges under section 19 StromNEV of 0.09 ct/kWh[58].

Compared to 2013, network tariff components for billing, metering and metering operations have fallen by 0.02 ct/kWh. Since 2009, these price components have fallen by a total of 0.18 per cent. In percentage terms, the charges for billing, metering and metering operations in the year 2014 accounted for approximately 10 per cent of network charges and net network tariffs for approximately 90 per cent of network charges.

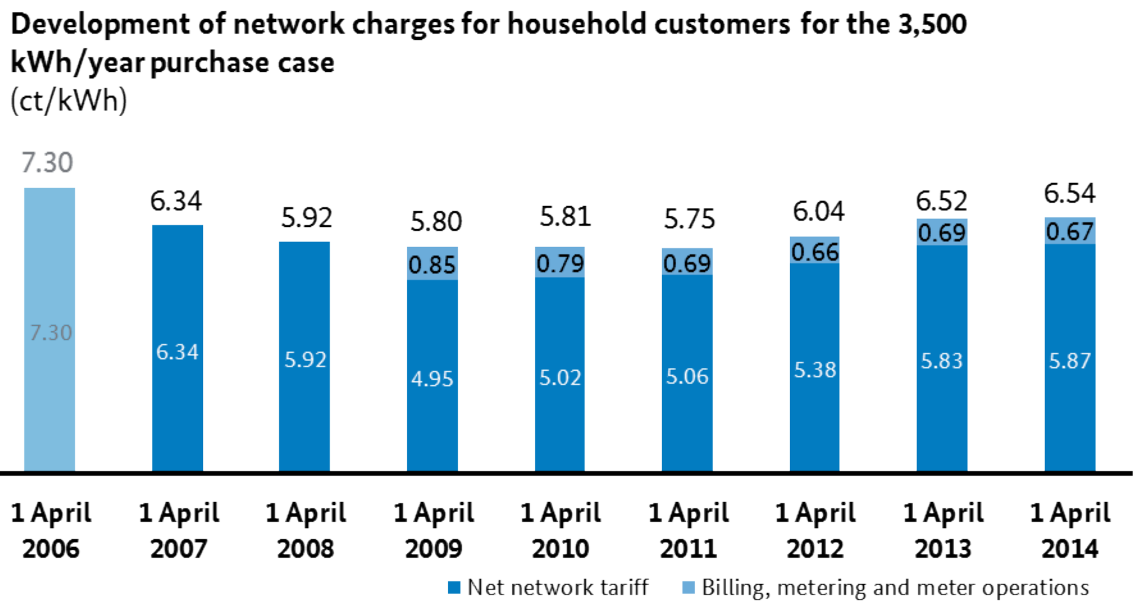

Figure 77: Development of network charges for household customers consuming 3,500 kWh, 2006[59] to 2014[60]

The chart below provides an overview of the remaining price components of volume-weighted consumer prices in all tariff categories. The share of the electricity price made up of surcharges, taxes and levies has constantly risen. Substantial increases have taken place over the last two years, in particular. The price component for energy procurement, supply, other costs and margin remained largely relatively stable in the period 2009 to 2013, while these components rose from 2007 to 2009. A decrease was only apparent in the

[57] Net network tariff, including charges for billing, metering and metering operations

[58] The surcharge under section 19 StromNEV continued to be taken into account in the network tariffs for 2011 and has been treated separately since 2012.

[59] 2006 was marked by special effects arising from the introduction of regulation which initially resulted in excessive network tariffs being disclosed by companies. It was only once regulation began to take effect and network tariffs were reduced that costs which had been erroneously allocated to network tariffs could be assigned to the price components to which they belong under the principle of causation. The increases in price components other than network tariffs which took effect after regulation began, particularly in "supply", were consequently partly a result of reductions in network tariffs. 2006 is therefore of only limited use as a reference year for a time series comparison.

[60] The price elements "billing, metering and metering operations" were not recorded separately in the period 2006 to 2008 and are therefore not included in the net network tariffs.

period between 1 April 2013 and 1 April 2014. This fall was due in particular to lower wholesale prices (cf section I.G from page 108). This fall is apparent in all categories of contract[61].

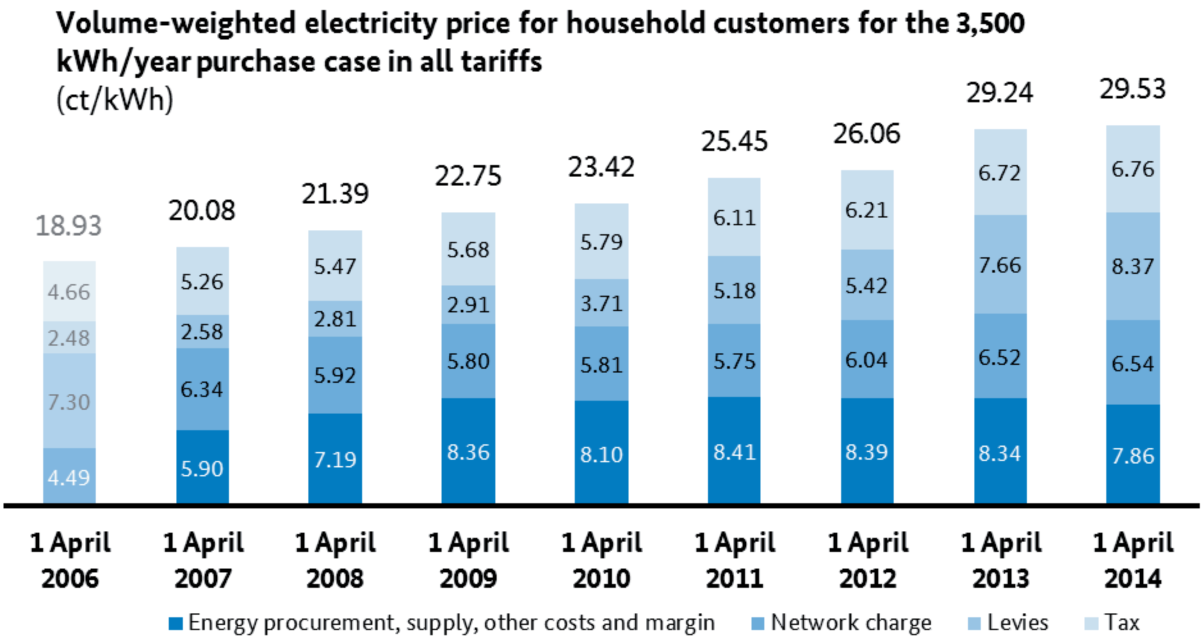

Figure 78: Volume-weighted electricity price for household customers consuming 3,500 kWh in all tariffs, 2006[62] to 2014[63]

The EEG surcharge makes up a particularly large share of increases in levies. The EEG surcharge is used to balance out the EEG costs incurred by TSOs (in particular the remuneration payments to installation operators) and EEG energy sales by TSOs on the spot market. The surcharge level is announced every year by the TSO on 15 October for the following calendar year. The Bundesnetzagentur monitors the calculation of the surcharge to ensure that it is correct. The EEG surcharge for 2014 went up to 6.24 ct/kWh. This largely reflects the substantial increase in remuneration payments for EEG installations. More EEG-supported capacity was also projected to be installed in 2014. The more electricity is produced from regenerative installations and paid for under the EEG provisions, the higher the surcharge will go up. The disproportionately strong increase in the EEG surcharge has resulted in it accounting for an ever greater share of the price of electricity. This is now over 21 per cent of the total volume-weighted price for household customers for all tariff categories. In 2010, the EEG surcharge was still 2.05 ct/kWh and made up a share of 8.8 per cent of the total price. The following figure shows in detail how the surcharge has increased.

[61] Cf Figure 75 page 154

[62] 2006 was marked by special effects arising from the introduction of regulation which initially resulted in excessive network tariffs being disclosed by companies. It was only once regulation began to take effect and network tariffs were reduced that costs which had been erroneously allocated to network tariffs could be assigned to the price components to which they belong under the principle of causation. The increases in price components other than network tariffs which took effect after regulation began, particularly in "supply", were consequently partly a result of reductions in network tariffs. 2006 is therefore of only limited use as a reference year for a time series comparison.

[63] Figures may not sum exactly owing to rounding.

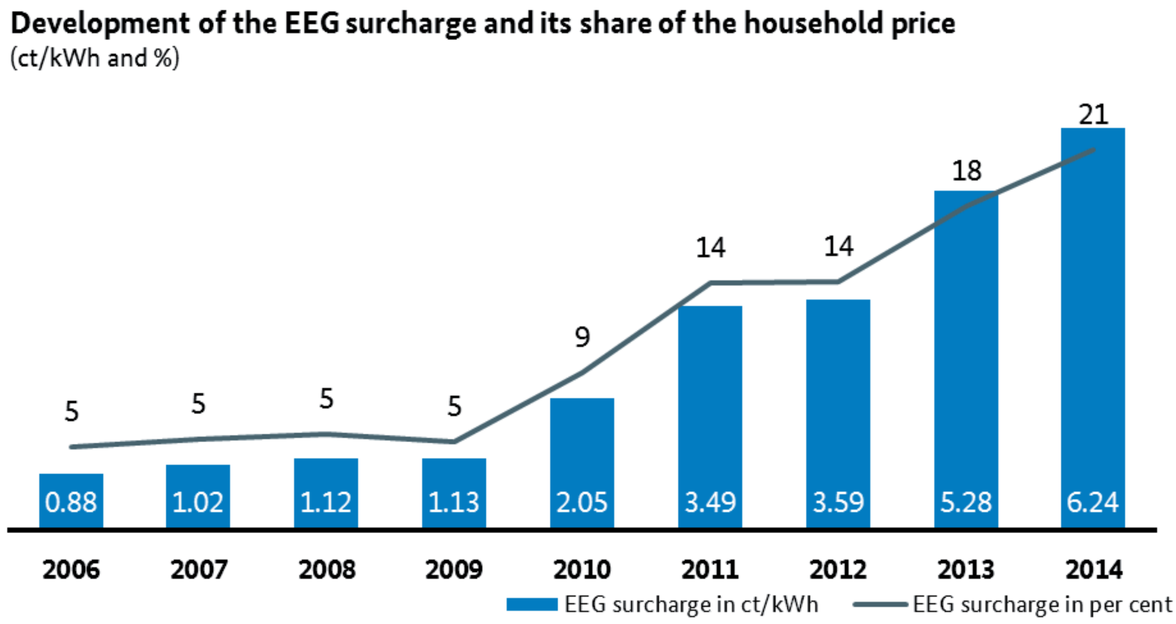

Figure 79: Development of EEG surcharge and its share of household customer prices from 2006 to 2014 (volume-weighted averages for all tariffs)

The development of the energy procurement, supply, other costs and margin price components for the years 2006 to 2014 are outlined in the following[64]. While the price component which can be influenced by the supplier was still 8.34 ct/kWh, and thus 28.5 per cent of the volume-weighted total price last year, this year it has fallen by 0.48 ct/kWh to 7.86 ct/kWh or 27 per cent of the volume-weighted total electricity price for all tariffs. The share of the total price which is amenable to business decisions by the supplier has again fallen. For the first time since 2008 the price has again dropped below 8 ct/kWh compensating for permanently rising, state-determined price components and helping to keep electricity prices at the same stable level. The following diagram shows each of the price components for energy procurement, supply, other costs and margin for the years 2006 to 2014.

[64] Owing to a change in the survey questions given to suppliers since 2014 the price components for energy procurement and supply are no longer shown separately.

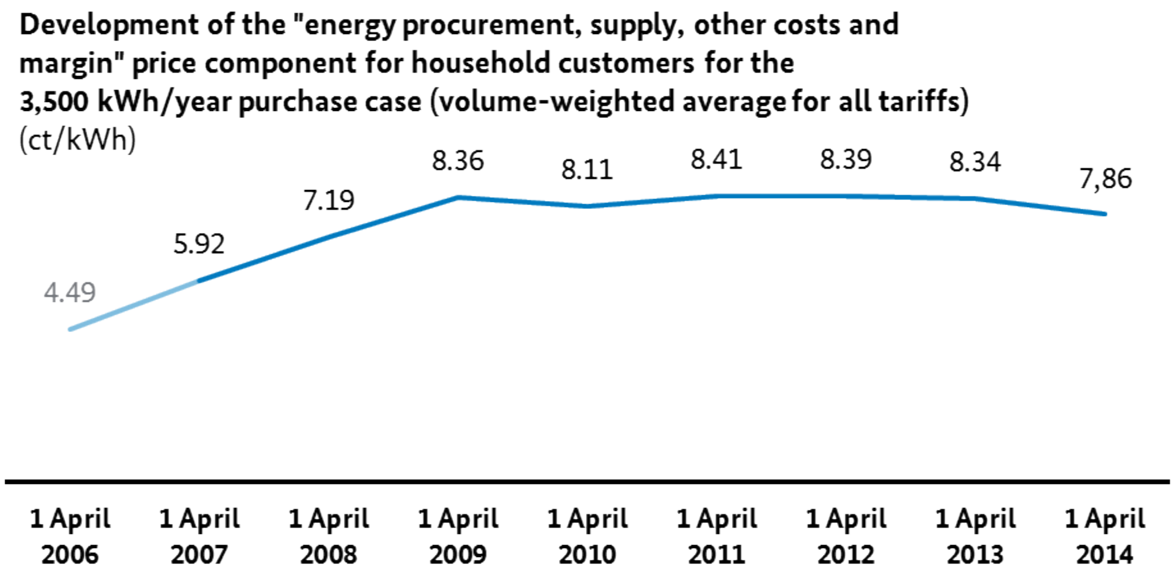

Figure 80: Development of the "energy procurement, supply, other costs and margin" price component for household customers with an annual consumption of 3,500 kWh 2006[65] to 2014[66] (volume-weighted average for all tariffs)

5. Heat current

The data on delivery volume and supplied metering points surveyed for interruptible consumer equipment covered both night storage heaters and heat pumps. Price surveys, in contrast, only covered night storage heaters.

The following is based on information from 777 suppliers (previous year: 742). In the reporting year 2013 they supplied a total of around 2.0 million metering points with around 15.7 TWh of electricity. This corresponds on average to the supply of almost 7,800 kWh/year per metering point.

Night storage heaters are supplied by 757 suppliers and heat pumps by 718 providers (number of supplying legal entities in each case). Most of the companies which provide heating current (698) supply both night storage heaters and heat pumps[67]. A volume of electricity of around 13.2 TWh was used for night storage heaters. On average, around 8,000 kWh/year was supplied at the 1.6 million metering points. This contrasts with a delivery volume to heat pumps of around 2.5 TWh to around 360,000 metering points, averaging

[65] 2006 was marked by special effects arising from the introduction of regulation which initially resulted in excessive network tariffs being disclosed by companies. It was only once regulation began to take effect and network tariffs were reduced that costs which had been erroneously allocated to network tariffs could be assigned to the price components to which they belong under the principle of causation. The increases in price components other than network tariffs which took effect after regulation began, particularly in "supply", were consequently partly a result of reductions in network tariffs. 2006 is therefore of only limited use as a reference year for a time series comparison.

[66] Data on energy procurement for 2012 was obtained from suppliers. The data for the period 2006 to 2011 was calculated from surveyed procurement volumes and EEX prices. However, given the change of method a degree of caution must be exercised when comparing data for 2012 with data for previous years.

[67] 59 suppliers had no heat pump customers at all; 20 suppliers had no night storage heater customers.

6,800 kWh/year (rounded). Night storage heaters account for the largest share of consumption (rounded to 82 per cent of metering points and 84 per cent of the delivery volume). Heat pumps continue to play a comparatively minor role despite an increase of 2 per cent points since last year (rounded to 18 per cent of metering points and 16 per cent of delivery volume).

Almost 98 per cent of interruptible consumer equipment (making no distinction between night storage heating or heat pumps) was supplied by the local default supplier. At over 2 per cent, the number of customers (based on metering points or volume delivered) who have a supplier other than the local default supplier in is still as low as it was last year. 60 non-default suppliers provide electricity for night storage heaters (heat pumps: 43 suppliers); another six (night storage heaters) and nine (heat pumps) suppliers are default suppliers but are not active outside their local area in relation to interruptible consumer equipment.

The 22 highest-volume suppliers (individual companies) delivered a total (not differentiated according to type of consumer equipment) of a good 75 per cent of the total volume of electricity supplied to interruptible consumer equipment.[68].

The analysis of prices for night storage heaters is based on the evaluation of information provided by 694 suppliers[69]. The analysis assumed a "customer with a tariff for the running of a night storage heater which uses 7,500 kWh/year"; the price level was for the reporting date of 1 April 2014. Bearing in mind this consumption profile, it is reasonable to assume that these types of customer are primarily private consumers.

Accordingly, the total price (arithmetic mean including VAT) was 20.6 ct/kWh and, as such, was roughly the same as last year. The substantial rise in prices for heating current up to the reporting date last year (from 17.6 ct/kWh to 20.3 ct/kWh) did not continue into 2014.

The following is an overview of the averages for the total price and for individual price components. Ranges are also stated in each case and reflect the assessment of the spread of data examined. The lower range limit relates to the 10th percentile and the upper limit to the 90th percentile. This means that the middle 80 per cent of values provided by suppliers lie within the stated range

[68] Despite the reduction in the number of suppliers supplying around 75 per cent of interrupted consumer equipment (30 suppliers covered around 77 per cent of the volume consumed by interruptible consumer equipment), there are no grounds for assuming a trend towards greater concentration. The drop in the number of individual companies affected is largely due to internal corporate restructuring.

[69] 581 suppliers participated last year. However, the survey was restricted to suppliers who were default suppliers in at least one network area. This year the survey covered all suppliers.

Price level of customer category night stroage heater with 7.500 kWh/year on 1 April 2014

Price components	Spread of dimension-sorted values		Average (arith-metical) in ct/kWh	Percentage of total price
	from 10% in ct/kWh	to 90% in ct/kWh		
Price components that cannot be influenced by the supplier				
Net network tariff	1.50	3.36	2.43	12%
Charge for billing, metering and metering operatons	0.25	0.67	0.40	2%
Concession fee	0.11	1.05	0.45	2%
Surcharge under EEG	6.24	6.24	6.24	30%
Other Surcharges[2]	0.53	0.53	0.53	3%
Electricity tax	2.05	2.05	2.05	10%
Value-added tax	2.92	3.72	3.29	16%
Price components that can be influenced by the supplier (residual amount)	3.42	7.19	5.24	25%
Total price (without value-added tax)	18.27	23.28	20.62	100%

[1] KWKG (0,178 ct/kWh), section 19(2) StromNEV (0,092 ct/kWh), offshore liability (0,250 ct/kWh) and interruptible loads (0,009 ct/kWh)

Table 43: Price level on 1 April 2014 for the 7,500 GWh/year night storage heater purchase case

On specific price components:

According to the suppliers, the network charges are largely below the values for SLP customers in the area of general-purpose electricity, the estimated average difference is 3.5 ct/kWh.

The concession fee for customers on special electricity contracts within the meaning of section 2(3) number 1 KAV is a general 0.11ct/kWh. As mixed billing is one possibility when supplies are consumed outside of the cheaper periods (two-tariff electricity metres; use of peak and off-peak tariffs) the average for the concession fee deviates from this value[70].

Compared to last year, total fixed surcharges have risen by 0.78 ct/kWh. This increase is largely due to the hike in the EEG surcharge from 5.28 ct/kWh to 6.24 ct/kWh.

The residual amount which can be influenced by the supplier, which alongside the margin also includes the costs of procurement, supply and other costs, fell in contrast by approximately 0.56 ct/kWh compared to last year.

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[70] One of the reasons for this could also be incorrect entries which cannot be distinguished from the permissible mixed values.

The residual amount which can be influenced by the supplier makes up just about 25 per cent of the total price, including VAT. Taxes and levies account for around 59 per cent of the total price. The following diagram shows the share of the average total price made up of each separate price component:

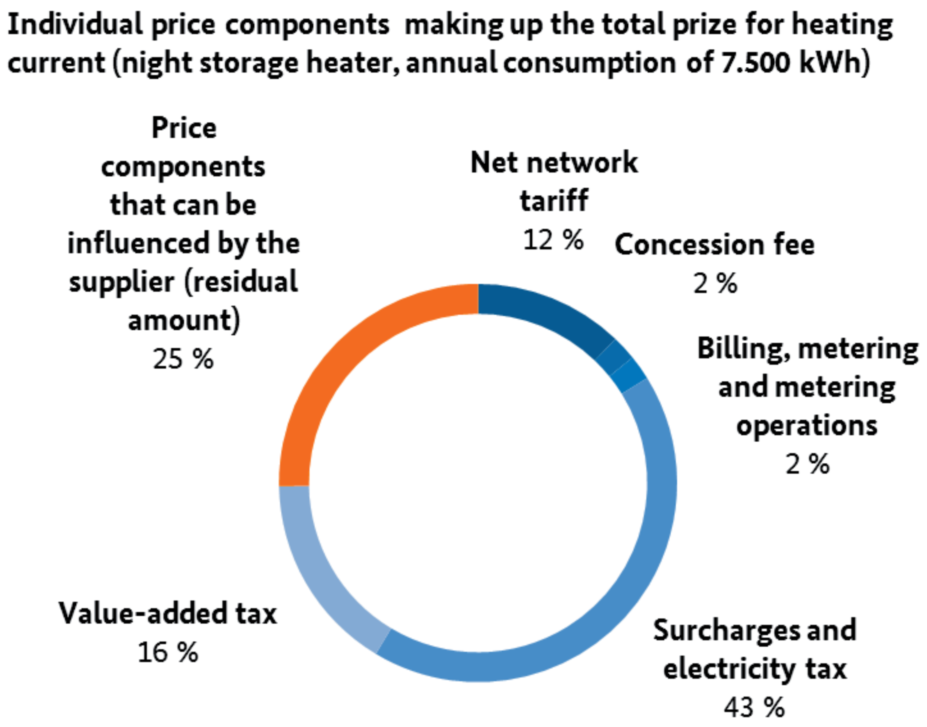

Figure 81: The individual price components making up the total price for heating current (night storage)

The proportion of heating current customers with a supplier other than the local default supplier is still very low, at just 2 per cent. Nonetheless, the conditions for more competition in supplies to interruptible consumer equipment are in place. This is partly due to the assurances given by the major suppliers to open markets in the context of the heating current procedure instigated by the Federal Cartel Office. There are, in particular, no technical or legal barriers to supplying customers in other suppliers' service areas. Customers can easily change electricity provider if heating current is recorded by a meter which is not used to record household electricity.

To date, a change of supplier has been associated with relatively high search costs for the customer with regard to whether and which companies in the customer's network area offer services for interruptible consumer equipment in competition with established competitors. Since last year internet portals have expanded the consumer advice information they provide and now provide support in the field of night storage heaters and heat pumps. This will improve transparency and enliven competition. It remains to be seen how tangible the impact of this will be. If the switching rate remains at its currently low level, this might be a reason – for example, owing to a lack of standardised load profiles – to examine the issue in more depth.

6. Green electricity segment

The suppliers participating in the 2014 monitoring survey provided information about the volume of green electricity delivered to final customers. The trend of previous years continued with an increase both in the number of final customers supplied with green electricity and in the volume delivered. In 2013, a total of 48.29 TWh of green electricity was supplied to 8.12 million metering points. This was an increase in volume of 3.69 TWh and over 850,000 more metering points supplied. The volume of green electricity now accounts for 10 per cent of the total volume of electricity supplied, 0.6 percentage points higher than in 2012. A detailed breakdown of the volume of green electricity delivered to final customers in 2013 is given in the following table

Green electricity supplied to household customers and other final customers

Category		Total electricity offtake	Total green electricity supplied	Green electricity volume delivered and metering points (%)
Household customers	TWh	124.1	20.8	16.7
	Number of metering points	43,968,870	7,447,754	17.0
Other final customers	TWh	331.9	27.5	8.3
	Number of metering points	4,125,176	673,225	16.3
Total	TWh	456.1	48.3	10.6
	Number of metering points	48,093,883	8,120,979	17.0

Table 44: Green electricity supplied to household customers and other final customers in 2013

16.7 per cent of the total volume of electricity delivered to household customers was green electricity, equal to an increase of 2 percentage points compared to last year. The available figures again show that, relatively speaking, green electricity customers continue to use slightly less electricity than other household customers, as illustrated below.

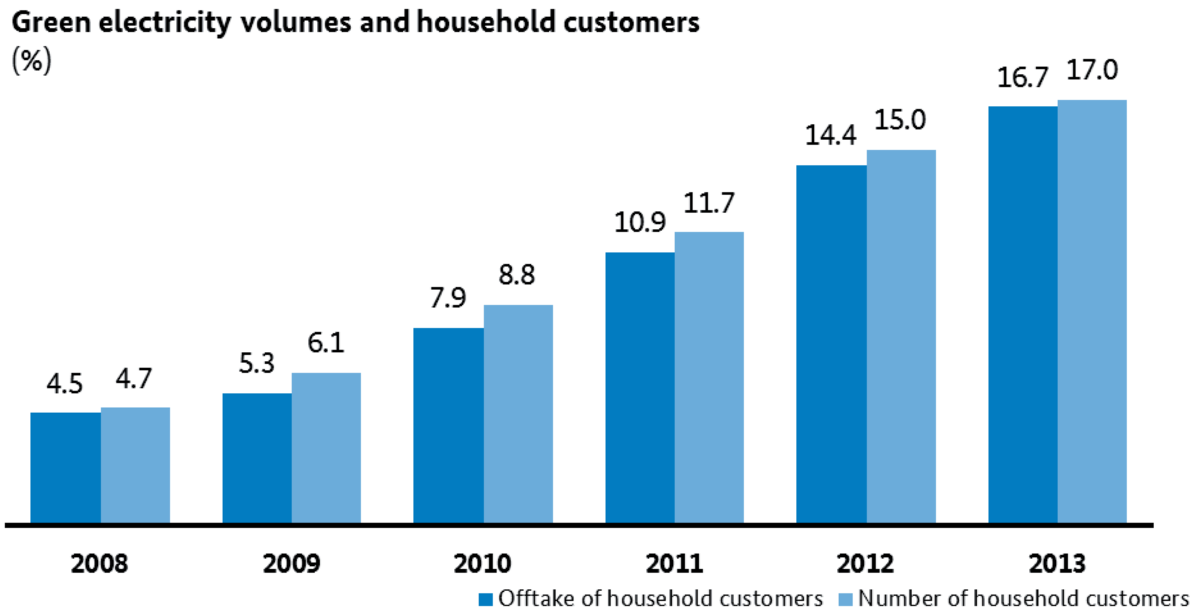

Figure 82: Green electricity volumes and household customers

The change in the monitoring survey methodology meant that it was possible for the first time in 2014 to show the individual price components for household customers receiving 3,500 kWh green electricity a year in detailed form as volume-weighted individual price components. The information supplied by 636 companies about tariffs and volumes in the 2014 monitoring survey is based on the following evaluation. The following table shows the price components for a typical green electricity purchase case (household with annual consumption of 3,500 kWh/year, low-voltage supply (0.4 kV)).

Average volume-weighted retail price for green electricity for household customers with 3,500 kWh/year consumption

Household customers (green electricity) 1 April 2014	Volume-weighted average (ct/kWh)	Share of total (%)
Net network tariff	5.81	20.5
Charge for billing	0.31	1.1
Charge for metering	0.10	0.4
Charge for metering operations	0.22	0.8
Energy procurement, supply, other costs and margin	6.85	24.1
Concession fee	1.68	5.9
Surcharge under EEG	6.24	22.0
Surcharge under KWKG	0.18	0.6
Surcharge under section 19 StromNEV	0.09	0.3
Surcharge for offshore liability	0.25	0.9
Surcharge for interruptible loads	0.01	0.0
Electricity tax	2.05	7.2
Valued-added tax	4.62	16.2
Total	28.41	100

Table 45: Average volume-weighted retail price for household customers receiving green electricity in 2014 with annual consumption of 3,500 kWh

Based on the individual price components shown, the volume-weighted total price for households in Germany with an annual consumption of 3,500 kWh is 28.41 ct/kWh. This means that the price for green electricity is 1.34 ct/kWh or 5 per cent below the volume-weighted total price across all tariff categories.

The different percentage components of the price are shown in the following.

Composition of individual price components for green electricity supplied to household customers; prices as at 1 April 2014
(%)

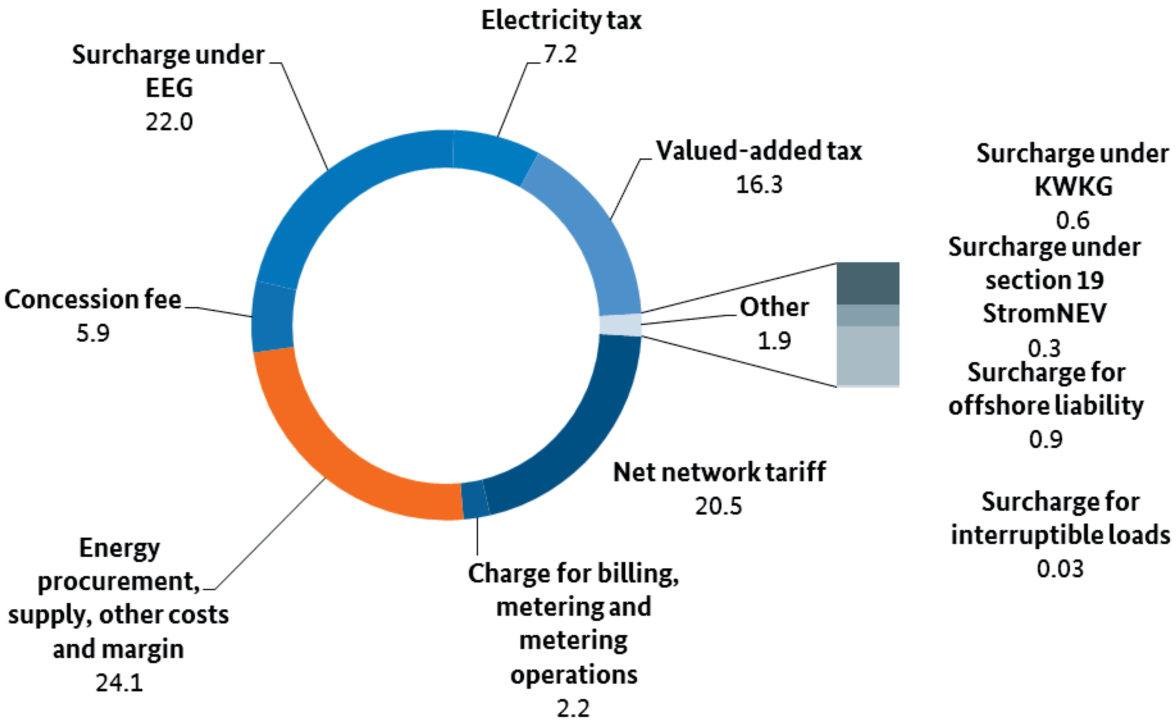

Figure 83: Composition of individual price components for green electricity supplied to household customers with a consumption of 3,500 kWh; prices as at 1 April 2014

Energy procurement, supply, other costs and margin makes up the largest block of individual price components and accounts for around 24 per cent of the total price. The downwards trend of recent years has in fact accelerated in the last year. A reduction of 8.27 ct/kWh on 1 April 2013 to 6.85 ct/kWh on 1 April 2014 can be calculated from the data. This is equal to a reduction in the price component of 1.42 ct/kWh or 17 percentage points.

As was also the case for supplies for conventional electricity, suppliers of green electricity offer a series of special bonuses and arrangements for household customers which have a downward impact on prices. The most frequently applied of these are the definition of a minimum contract term or guaranteed price stability. In relation to last year the number of tariffs offering a minimum contract period, price stability and one-off bonus payments went up by almost 20 per cent. On the other hand, tariffs advance payments are offered in approximately 60 per cent fewer cases. Tariffs with deposits are seldom offered, in fact by only two suppliers.

Special bonuses and arrangements on 1 April 2014

	Household customers (green electricity)	
	Number of tariffs	Average scope
Minimum contract term	387	10 months
Price stability	305	13 months
Advance payment	41	12 months
One-off bonus payment	80	€ 48
Deposit	2	-
Other bonuses and special arrangements	102	-

Table 46: Special bonuses and arrangements for household customers (green electricity tariff) in 2014

7. Comparison of European electricity prices

Eurostat[71] regularly publishes the final customer energy prices paid on average by defined consumer groups in individual EU Member States.

Statistics cover entire blocks of price components:

Taxes and levies[72];

Network costs;

Energy and supply

The broader picture also includes the data on electricity published by Eurostat for the second half of 2013[73]. Averages have only been made for comparisons between Germany (other individual countries) and the "EU average" based on the number of countries shown (own calculation; no weighting).

Household customers

For household customers Eurostat considers the purchase case "annual consumption between 2,500 kWh and 5,000 kWh"[74]. This is shown in the following:

[71] Eurostat, the statistical office of the European Union, draws on data provided by authorities designated by the Member States. Stipulations concerning collection, analysis etc are geared to achieving comparability.

[72] In Germany this includes concession fees.

[73] No average is formed with the first six-month period. Where changes are made during the year, the data for the second six months are approximated closer to the current situation.

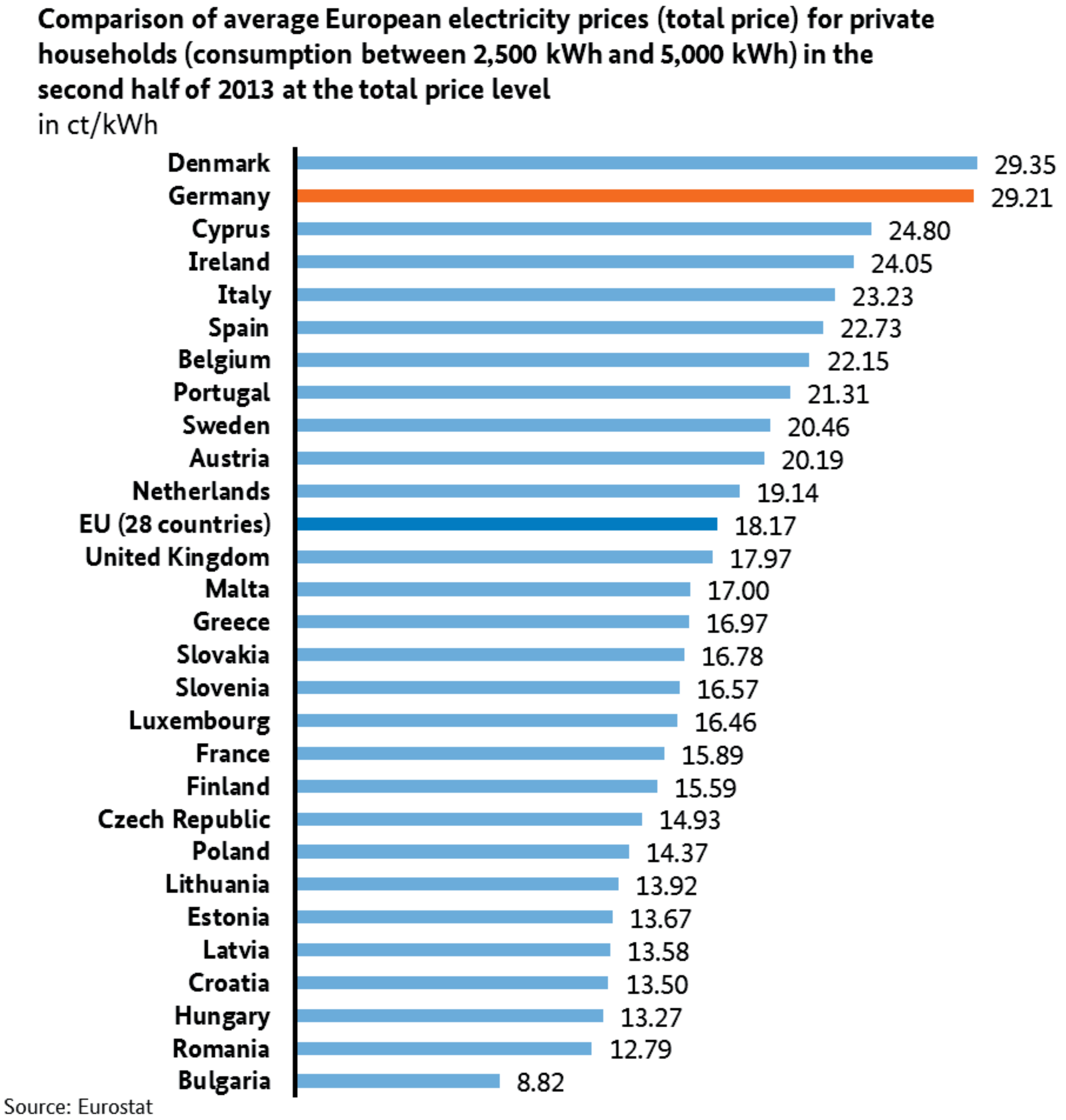

Figure 84: Comparison of average European electricity prices (total price) for private households (consumption between 2,500 kWh and 5,000 kWh) in the second half of 2013 at the total price level

Household customers in Germany pay the second highest overall price in all the EU Member States. At an average of 29.21 ct/kWh this total price is 60 per cent higher than the average for all 28 EU Member States of 18.17 ct/kWh.

[74] Alongside this "Group DC" there are other categories in the household customer segment; these can be accessed at http://epp.eurostat.ec.europa.eu/portal/page/portal/energy/data/database. The case selected here also includes the purchase case for which price data was independently surveyed in the monitoring survey.

However, not all price components are included equally. Eurostat distinguishes between "network costs", "taxes and levies" and a block referred to as "energy and supply" which includes all the other price components. In Germany this is equal to the part of the total price which can be influenced by suppliers[75].

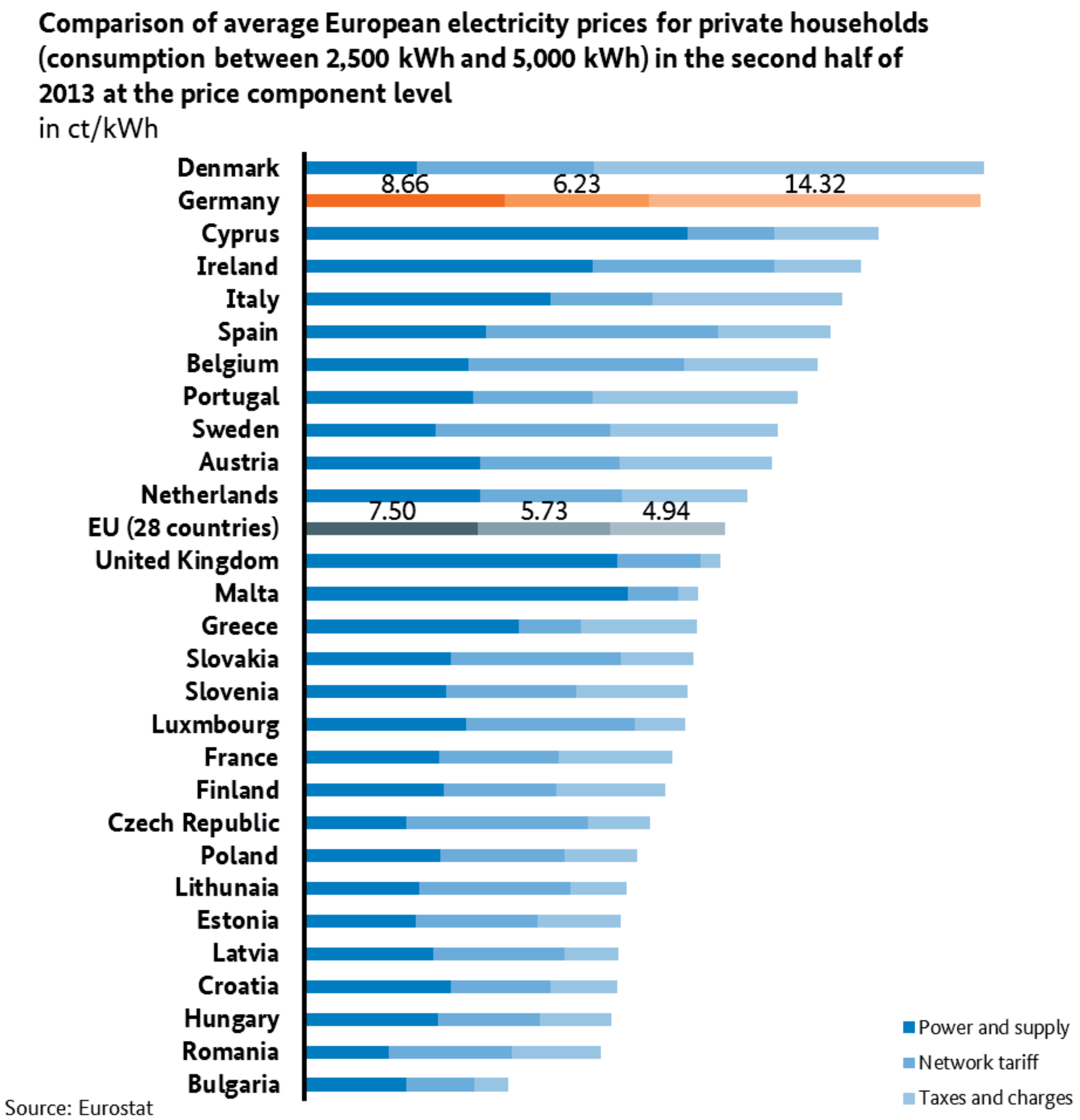

Figure 85: Comparison of average European electricity prices for private households (consumption between 2,500 kWh and 5,000 kWh) in the second half of 2013 at the price component level

With regard to the "energy and supply" price block, at 8.66 ct/kWh Germany is around 15.5 per cent above the average for the EU Member States of 7.50 ct/kWh. At 6.23 ct/kWh network costs in Germany exceed the EU average of 5.73 ct/kWh by 8.8 per cent. The difference between Germany and the EU average for taxes and

[75] Refer to "energy procurement, supply, other costs and margin (residual amount)" in the section on I.H.4.2 "Price level Household customers" from page 150

levies is over 9 ct/kWh; the share of 14.32 ct/kWh of the total price in Germany is almost three times as high as the European average of 4.94 ct/kWh.

Considered over the period[76] of the last five years, electricity prices for household customers (all price components) are higher than the EU average[77], as the following diagram shows:

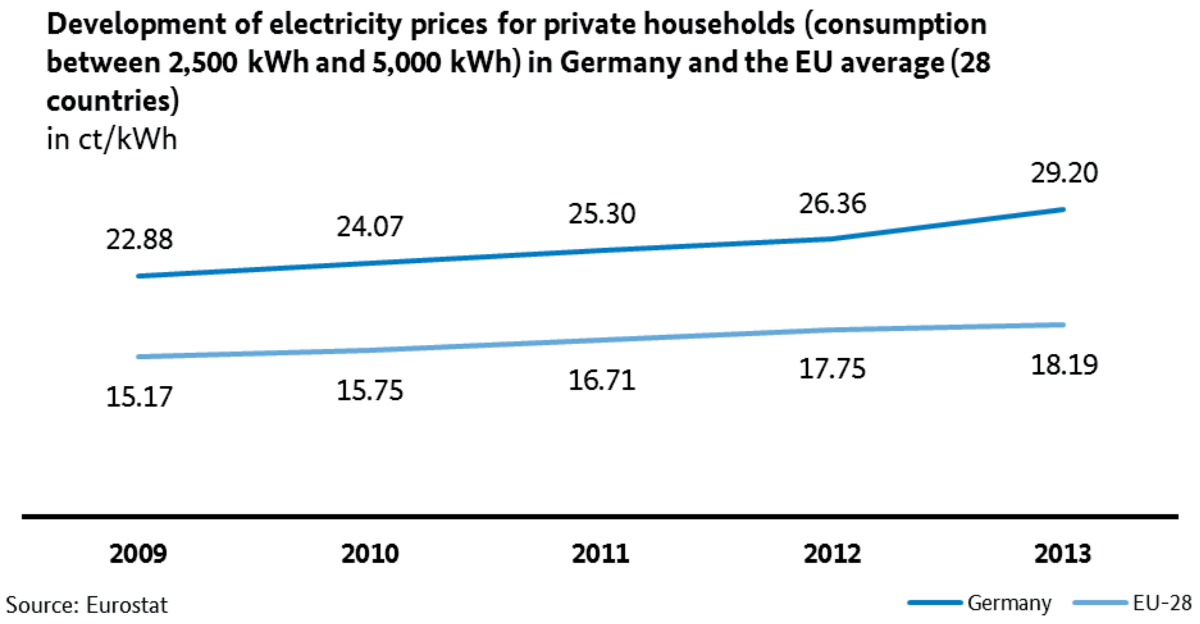

Figure 86: Development of electricity prices for private households (consumption between 2,500 kWh and 5,000 kWh) in Germany and the EU average (28 countries) from 2009 to 2013

The difference rose from 7.71 ct/kWh in 2009 to 8.61 ct/kWh in 2012; in 2013 a further increase of 2.41 ct/kWh brought the price up to 11.01 kWh.

Industrial customers

As well as household customers, Eurostat also looks at various purchase cases for offtake volumes not relating to private consumption. Of these purchase cases, which are recorded as "industrial customers", examples are provided[78], as in last year's Monitoring Report, of customer categories for annual consumption of "between 2,000 MWh and 20,000 MWh". The total price including all price components, ie plus national VAT, is shown. These are then compared with the figures after deducting VAT alone[79]. This takes account of the

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[76] The comparison over time is based on the annual average (mean taken from the figures for both six monthly periods).

[77] The data for Croatia have also been included in the calculation for the period prior to that country's accession to the EU in 2013 in order to enhance comparability.

[78] Alongside this "Group ID" other categories in the "industrial customers" category can be accessed athttp://epp.eurostat.ec.europa.eu/portal/page/portal/energy/data/database. For comparison: The "industrial customer case", for which no separate data was collected in the monitoring survey, is based on an annual consumption volume of 24,000 MWh.

[79] See "Rates of VAT in the Member States of the European Union" on 1 July 2014, available at http://ec.europa.eu/taxation_customs/resources/documents/taxation/vat/how_vat_works/rates/vat_rates_de.pdf. Alternative rates are stated for Belgium and France for which the lower rate is taken in each case.

circumstances that the customers considered are all able to deduct this component of the price[80]. Finally, the relationships between the „taxes and levies“ and „energy and supply plus network costs“ price blocks are shown.

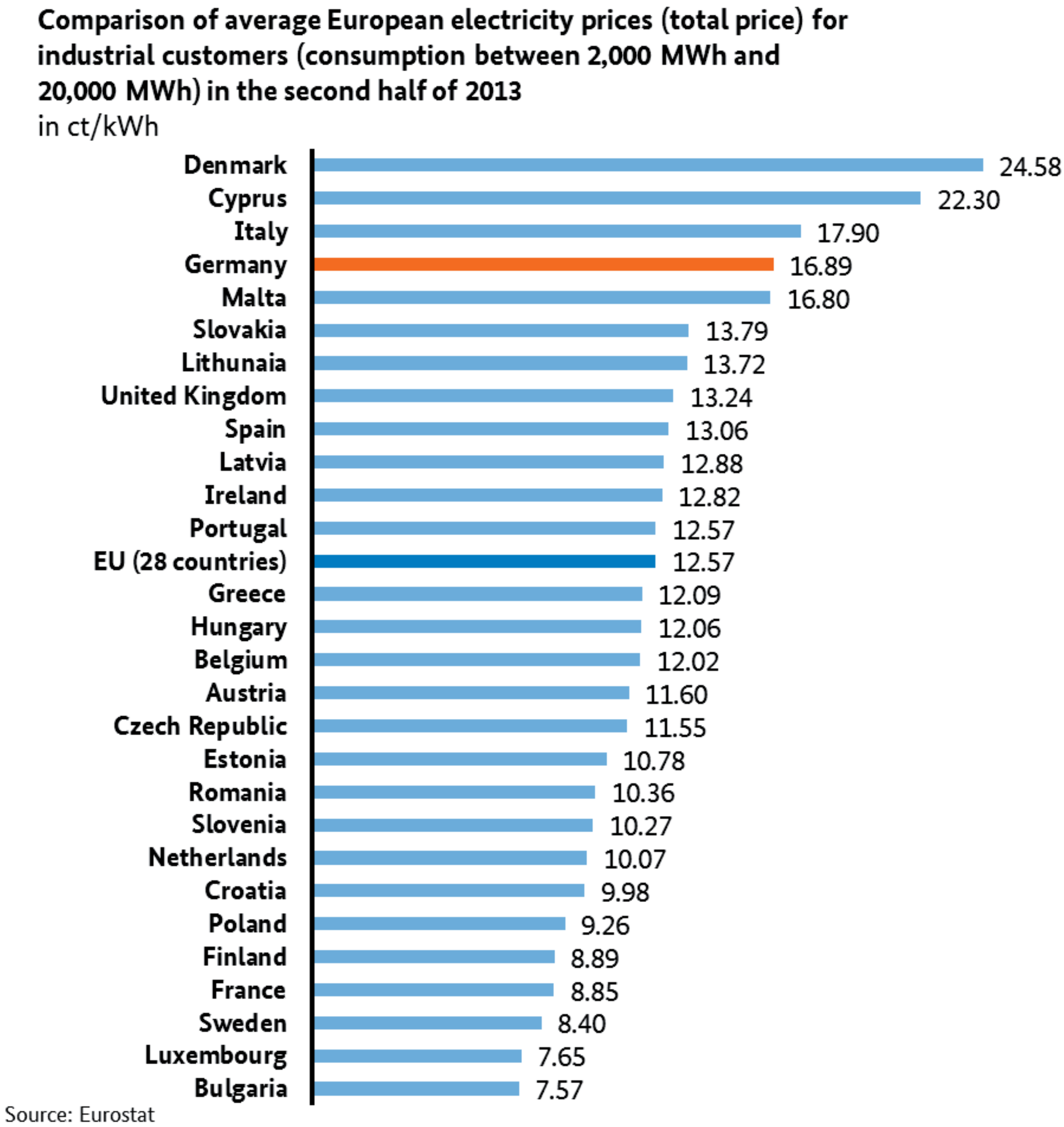

Figure 87: Comparison of average European electricity prices (total price) for industrial customers (consumption between 2,000 MWh and 20,000 MWh) in the second half of 2013

If VAT is also included, this results in a broad range from 17.01 ct/kWh for the lowest figure (7.57 ct/kWh in Bulgaria) and the highest figure (24.58 ct/kWh in Denmark). In Germany the figure is 16.89 ct/kWh or 4.32 ct/kWh (34.4 per cent) above the EU average of 12.57 ct/kWh.

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[80] The total price "excluding VAT and reimbursable taxes and levies" (Eurostat category) is not provided. Where further deductions are possible in addition to VAT at the national level, these only apply to the affected consumer group.

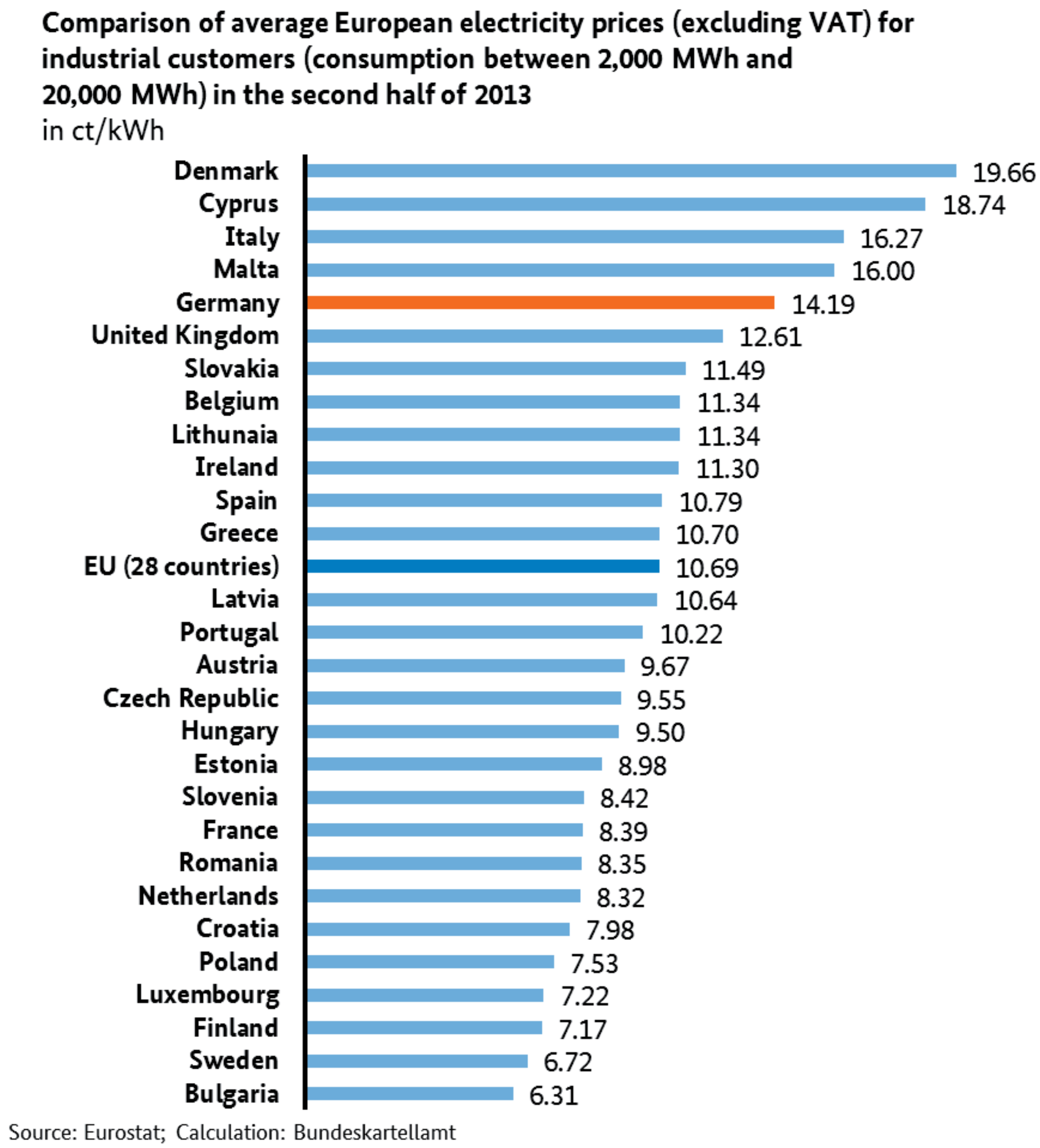

Figure 88: Comparison of average European electricity prices (excluding VAT) for industrial customers (consumption between 2,000 MWh and 20,000 MWh) in the second half of 2013[81]

The rates of VAT for electricity vary from 5 per cent (Malta and the United Kingdom) and 27 per cent (Hungary). The values at the extreme are 13.36 ct/kWh apart. At 14.19 ct/kWh Germany still lies above the EU average of 10.69 ct/kWh. The difference, however, is just 3.5 ct/kWh or 32.7 per cent.

Those are relevant differences in the distribution for the groups of price components (network costs, taxes and levies[82] as well as energy and supply).

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[81] Refer to "Rates of VAT in the Member States of the European Union" on 1 July 2014, available at http://ec.europa.eu/taxation_customs/resources/documents/taxation/vat/how_vat_works/rates/vat_rates_de.pdf. Alternative rates are stated for France for which the lower rate is taken.

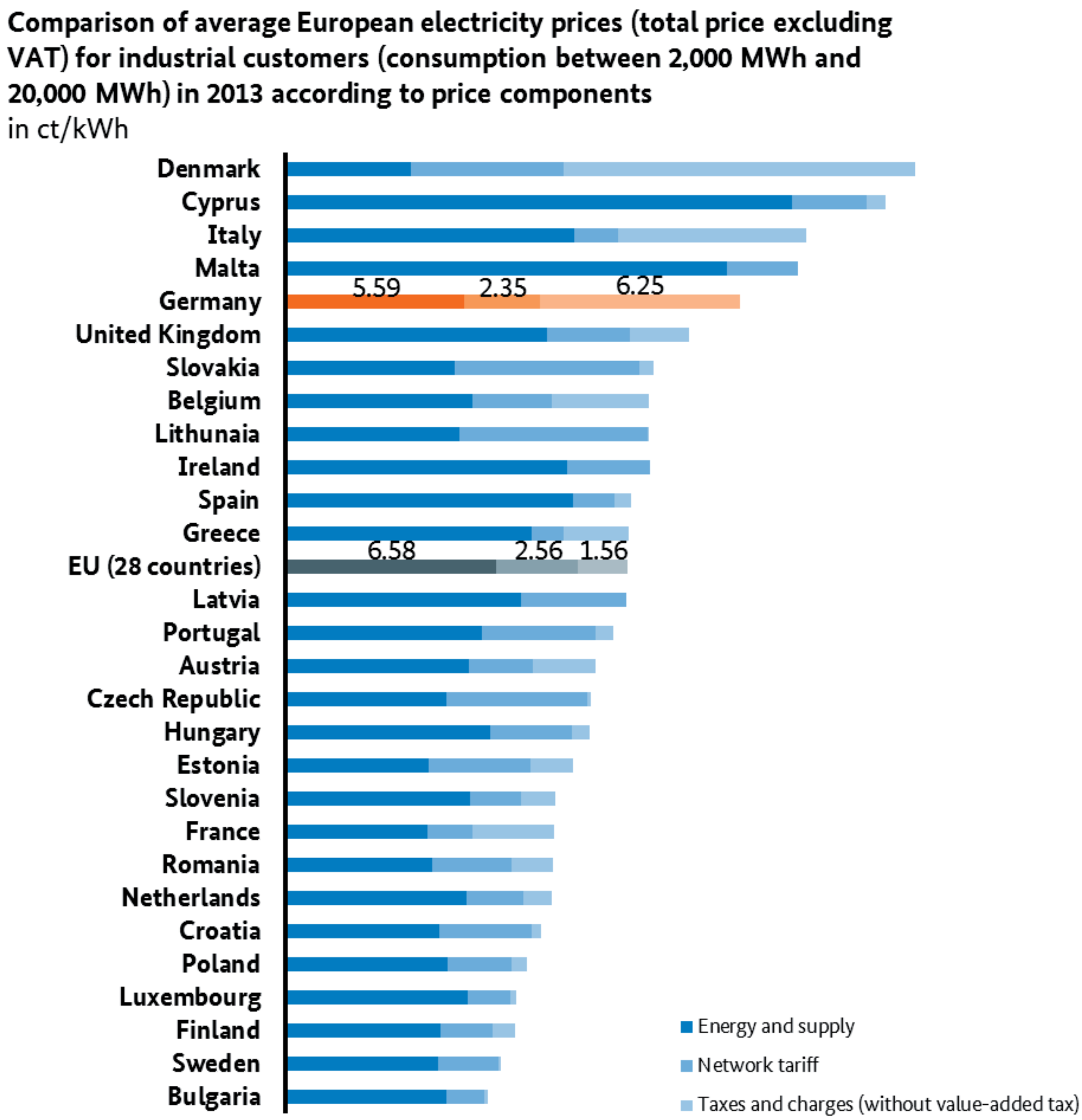

Figure 89: Comparison of average European electricity prices (total price excluding VAT) for industrial customers (consumption between 2,000 MWh and 20,000 MWh) in 2013 according to price components

These are arranged (as in the previous diagram) according to the total price (adjusted for VAT). Among the first five countries, Cyprus, Malta and Italian also have the highest figures for "energy and supply" (between 9.02 and 15.8 ct/kWh). Lithuania (5.87 ct/kWh) and Slovakia (5.76 ct/kWh) lead the field and are among the first nine countries. Denmark has the third highest network costs (4.74 ct/kWh), although its status as the country with the highest electricity price is due to its top ranking for "taxes and levies". At 10.99 ct/kWh this

[82] Eurostat shows the "taxes and levies" share as a separate price block which has already been adjusted for VAT and reimbursable taxes and levies. In this case, "taxes and levies" are shown as the difference between the total price excluding VAT and the total of network costs and energy and supply. "Taxes and levies" in this sense may also include elements which may be deducted to some extent for consumers in the specific purchase case group.

amount is substantially higher than the second highest figure of 6.25 ct/kWh (Germany followed by Italy at 5.87 ct/kWh).

The average total price for Member States of 10.69 ct/kWh is distributed as 61.5 per cent (6.58 ct/kWh) for energy and supply, 24.0 per cent for network costs (2.56 ct/kWh) and 14.6 per cent of all taxes and levies (1.56 ct/kWh).

Each of the four countries with the highest prices has notably above average figures in two areas. Germany is in position five. While in Germany the figure of 5.59 ct/kWh for "energy and supply" is 15 per cent and the figure of 2.53 ct/kWh for "network costs" is 8.3 per cent below the EU average, "taxes and levies" in Germany are almost four times the European average.

I Metering

In the 2014 survey, 734 companies responded to the questions about metering. Data was collected from network operators providing metering services under their primary responsibility and from independent meter operators.

Network operators providing metering services and independent meter operators

598 network operators stated that they provide metering services to customers under their primary responsibility. 109 network operators stated that they provide metering services to customers outside their primary responsibility. 20 companies are suppliers that also provide metering services to their customers; three of these companies also provide metering services to customers whom they do not supply.
22 companies are independent meter operators providing metering services to customers for whom they are neither the network operator nor the supplier.

Requirements under section 21b ff of the Energy Act (EnWG)

New requirements for smart metering systems and rules as to when smart meters are mandatory were introduced in 2011. The following table shows the number of metering points for which a smart meter is mandatory under section 21c EnWG:

Metering points requiring smart meters under section 21c EnWG

Requirement	Metering points
a) buildings which have been newly connected to the energy supply network or which have undergone major renovation	356,671
b) final customers with an annual consumption exceeding 6,000 kWh	4,534,986
c) operators of new installations with an installed capacity exceeding 7 kW that are subject to the provisions of the Renewable Energy Sources Act (EEG) or the Combined Heat and Power Act (KWKG)	230,230

Table 47: Metering points requiring smart meters under section 21c EnWG

There was only a slight year on year increase in the number of metering points in categories a) and b). In contrast, there was an increase of 94,054 in the number of smart meters required for new installations subject to the provisions of the Renewable Energy Sources Act (EEG) or the Combined Heat and Power Act (KWKG).

Meter technology for domestic customers (standard load profile (SLP) customers)

The majority of the domestic meters used for SLP customers are still Ferraris meters. A total of 44.5m such meters are in use, of which 3m (around 7 per cent) are two-tariff or multiple-tariff meters. 269,464 meters for SLP customers were read remotely using the following transmission technologies:

Transmission technologies for remotely read meters for SLP customers
(number and breakdown)

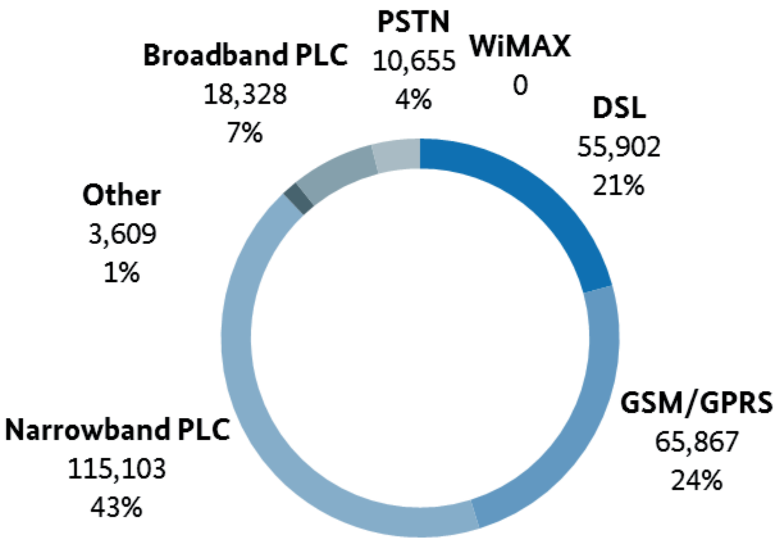

Figure 90: Transmission technologies for remotely read meters for SLP customers

Meter technology used for interval-metered customers

According to the figures provided by 789 DSOs, there were 354,044 metering points for interval-metered industrial and business customers. The meter data was transmitted using the following technologies:

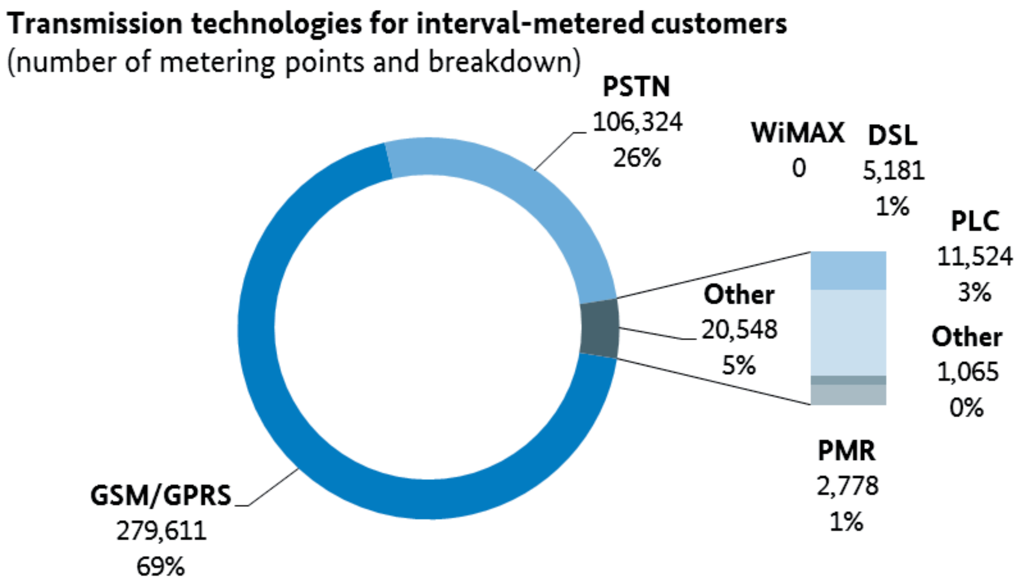

Figure 91: Transmission technologies for interval-metered customers

Investments and expenditure for metering

While there was a year on year decrease in the investments for metering systems, expenditure remained at about the same level.

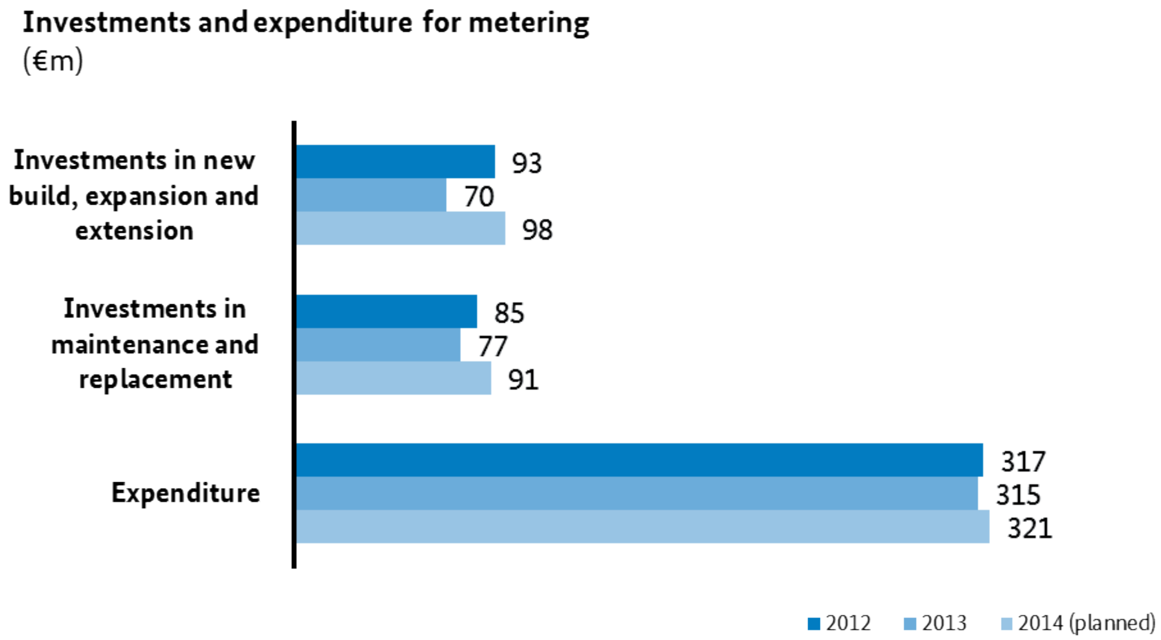

Figure 92: Investments and expenditure for metering

II Gas markets

A Developments in the gas markets

1. Key findings

More than 10 per cent of Germany's gas consumption is covered by domestic production. In 2013, the year under review, natural gas production in Germany fell by 1.0bn m3 to 9.7bn m3. This represents a year on year decrease of 9.3 per cent. The steady decline in natural gas reserves in Germany and in production is chiefly due to the increasing exhaustion and dilution of existing deposits. 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 9.7 years as of 1 January 2014; this represents a decrease of almost one year compared to the ratio as of 1 January 2013.

The volume of gas imported into Germany rose by some 243 TWh or 18.8 per cent from 1,535 TWh in 2012 to 1,778 TWh in 2013. The main sources of imports remain the Commonwealth of Independent States (CIS: Armenia, Azerbaijan, Belarus, Kazakhstan, Kyrgyzstan, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine, Uzbekistan), the Netherlands and Norway.

The volume of gas exported increased by some 8.8 per cent from 667.3 TWh in 2012 to 725.8 TWh in 2013, the main recipients being the Czech Republic, France, the Netherlands and Switzerland.

As regards the reliability of gas supply, the system average interruption duration index (SAIDI) for 2013 was around 0.6 minutes. This means an average supply interruption of just below one minute per consumer in Germany in 2013. This again shows a high level of gas supply reliability, with the average duration lower than the multi-annual average of two minutes.

The total maximum usable volume of working gas in underground storage facilities was 25.45bn Nm^3. Of this, 12.86bn Nm^3 was accounted for by cavern storage and 12.59bn Nm^3 by pore storage facilities. There was another slight decrease in the volume of short term (up to 1 October 2014) freely bookable working gas while the volume of longer term freely bookable working gas increased again. This is due to the expiry of long term storage contracts and the conclusion of short to medium term contracts.

The storage level of natural gas storage facilities on 1 November 2014 at the beginning of the withdrawal period was near maximum at around 97 per cent; the storage level on 1 November 2013 stood at just under 90 per cent.

The level of concentration in the market for the operation of underground natural gas storage facilities has fallen, but is still relatively high. The cumulative share of the three largest operators (CR3) on 31 December 2013 was some 68 per cent, representing a decrease of five percentage points within three years. The fall in the level of concentration is due to a number of new storage facilities being opened.

The investment volume of the gas transmission system operators (TSOs) for the 27 binding network expansion measures laid down in the Network Development Plan 2013 amounted to approximately €2,200m. The measures comprise new lines with a total length of 522 km and additional compressor capacity of 344 MW in the period up to 2023.

There was a reduction of 5.1 per cent in the expenditure incurred by the gas distribution system operators (DSOs) in 2013 compared to 2012, while investments increased by 11.9 per cent.

There was a further increase in the liquidity of the wholesale natural gas markets in 2013, with significant growth in both exchange and bilateral trading. The trading volume on the EEX rose by 36 per cent while the nominated volume at the two virtual trading points, Gaspool and NCG, increased by some 20 per cent. In terms of percentage, growth in trading on broker platforms was even stronger. However, the liquidity of the wholesale natural gas markets is still considerably lower than that of the wholesale electricity markets.

Overall, wholesale prices for natural gas were comparable to those of the previous year. While average gas import prices (border prices according to BAFA) fell from around €29.0/MWh in 2012 to €27.6/MWh in 2013, the average gas price on the EEX spot market rose from approximately €25.2/MWh to €27.2/MWh. It can be assumed that the importance to pricing of the link between gas and oil prices continued to decline in the period under review.

The volume of gas delivered by the gas suppliers taking part in the survey to consumers (including gas-fired power plants) in 2013 amounted to 867.6 TWh, 6.4 per cent more than in 2012. Of this, 481 TWh was delivered to interval metered customers and 387 TWh to standard load profile (SLP) customers. The volume of gas delivered by gas suppliers to private households amounted to 245.5 TWh, 7.3 per cent more than in the previous year. The volume of gas delivered to gas-fired power plants fell by 14 per cent within twelve months from 94.5 TWh in 2012 to 81.2 TWh in 2013. Gas network operators in Germany reported a total output volume of 928.58 TWh in 2013, including a volume of 282.96 TWh for private households. The gas network operators recorded a total of 13.98m metering points as of 31 December 2013, including some 12.45m metering points for household customers as defined in section 3 para 22 of the Energy Act (EnWG).

The trend towards greater choice of provider strengthened in the year under review. In over 90 per cent of the network areas consumers can choose from 31 or more gas suppliers (without taking company group affiliations into account). In almost 70 per cent of the networks consumers even have a choice of more than 50 suppliers. Less than 5 per cent of the network areas have 20 or fewer suppliers.

The supplier switching rate for business and industrial customers in 2013 was just under 13 per cent. The rate has remained stable since 2010, following considerable increases in the period from 2006 to 2010. By contrast, the switching rate for household customers has risen. According to the gas network operators, the volume of gas affected by household customers switching supplier in 2013 (including those switching when moving home) was 27.3 TWh. This represents a clear increase of 7 TWh or 35 per cent compared to the previous year and corresponds to 9.6 per cent of the total volume supplied. The network operators reported a total of 1,062,580 switches by household customers (including those switching when moving home) in 2013. This represents a year on year increase of some 228,197 or 27 per cent and corresponds to 8.53 per cent of all households supplied.

A closer look at how household customers were supplied in 2013 shows the following: almost 14 per cent of all household customers were served by an undertaking other than their default supplier; just under 60 per cent of household customers had a special contract with their default supplier; and more than 26 per cent of the volume of gas delivered to household customers was supplied under a standard contract with a default supplier. By contrast, default suppliers played a relatively small role in serving business and industrial customers: some 68 per cent of the total volume of gas delivered to interval metered customers in 2013 was supplied by a legal entity other than the local default supplier, while only around 32 per cent was supplied under a special contract with the default supplier; less than 1 per cent of all interval metered customers have a standard contract with their default supplier.

The market shares of the largest providers in those retail markets now defined by the Bundeskartellamt as national markets are well below the thresholds laid down in law for assuming market dominance. The aggregate market share of the three largest undertakings (CR3) in the national market for supplying interval metered customers was some 33 per cent. The aggregate market share of the three largest undertakings in the national market for supplying special contract SLP customers was only around 22 per cent.

Overall, there were no significant changes in the consumer prices for gas compared to the previous year, although prices fell for customers with higher consumption. The average price as of 1 April 2014 for industrial customers with an annual consumption of 116 GWh was around 3.6 ct/kWh (excluding VAT), representing a year on year decrease of some 9 per cent. The difference is due to a reduction in the price component that can be controlled by the supplier. The average price as of 1 April 2014 for business customers with an annual consumption of 116 MWh was around 5.2 ct/kWh (excluding VAT), more or less the same as in the previous year.

Overall, gas prices for household customers remained stable in the year up to 1 April 2014. Prices for customers with an annual consumption of 23,269 kWh rose slightly for customers in two of the three defined contract categories and fell slightly for those in the third category:

- The volume weighted price (including VAT) for customers with an annual consumption of 23,269 kWh and a standard contract with their default supplier rose from 7.09 ct/kWh to 7.20 ct/kWh, representing a year on year increase of 1.6 per cent.

- The volume weighted average price for customers with a special contract with their default supplier rose again, from 6.69 ct/kWh on 1 April 2013 to 6.77 ct/kWh on 1 April 2014; this is an increase of 1.2 per cent.

- The volume weighted average price (including VAT) for customers served by an undertaking other than their default supplier fell from 6.66 ct/kWh to 6.39 ct/kWh on 1 April 2014; this represents a decrease of almost 4 per cent compared to the previous year.

A comparison with the gas prices across Europe shows that household customers in Germany continue to pay average prices.

2. Market overview

Volume of gas delivered by TSOs and DSOs for each consumer category

	TSOs (kWh)	DSOs (kWh)	Total (kWh)
≤300 MWh/year	3,180,876	343,421,038,322	343,727,879,480
>300 MWh/year ≤10,000 MWh/year	578,797,748	130,340,106,005	130,918,903,753
>10,000 MWh/year ≤100,000 MWh/year	6,688,074,179	90,817,059,636	97,505,133,815
>100,000 MWh/year	148,330,465,208	119,956,314,954	268,286,780,162
Gas power plants	33,555,696,050	54,584,370,238	88,140,066,288
Total	189,156,214,061	739,118,889,155	928,578,763,498

Table 48: Volume of gas delivered by TSOs and DSOs for each consumer category

Network operators were asked about the total length of their networks, as well as the length subdivided according to pressure ranges (nominal test pressure in bar). The findings were as follows:

Network structure figures for 2013

	TSOs	DSOs	Total
Number of operators	17	711	728
Pressure range (km)	37,880	485,413	523,293
≤0.1 bar	0	159,611	159,611
>0.1–1 bar	1	231,623	231,624
>1 bar	37,879	92,853	130,732
Final customers (metering points)	593	13,978,744	13,979,337
Industrial and business customers	537	1,524,537	1,525,074
Household customers	0	12,453,223	12,453,223
Gas power plants	56	984	1,040

Table 49: Total length of networks according to pressure range

There is a total of 5,877 entry points to all gas networks, of which 208 entry points are for emergency entry only. 76 per cent of the companies responding can access upstream network operators at several interconnection points, 23 per cent cannot and 1 per cent provided no relevant information.

The DSOs were asked if in 2013 they had either placed an internal order with an upstream network operator under section 8 of the cooperation agreement or notified the required capacity in accordance with section 13 of the cooperation agreement. 93 per cent of the DSOs had done so, 4 per cent had not and 3 per cent provided no relevant information. Those DSOs who had done so were also asked whether their internal orders had been reduced by the upstream network operator; this was the case for almost 18 per cent. Of these, 77 per cent were offered interruptible capacities for internal booking as an alternative. 5 per cent of the DSOs exceeded their internal bookings or notified capacity in 2013, considerably less than in the previous year (52 per cent).

Only 20 per cent of the companies provided specific figures concerning the potential for concluding disconnection contracts with customers. 50 per cent of the companies see no potential for disconnection contracts while 30 per cent did not respond to the question. Almost 95 per cent of the companies publish no relevant information.

The following figure shows the number of exit points from 2007 to 2013:

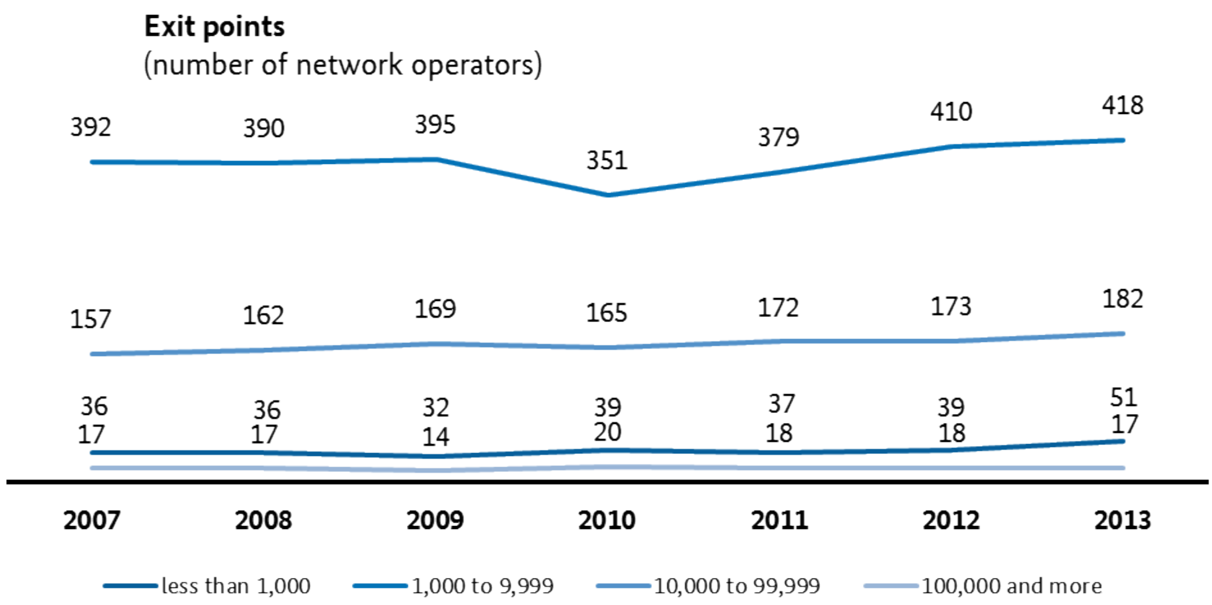

Figure 93: Number of exit points

The majority of DSOs (586 or 88.4 per cent) have networks with a short to medium length up to 1,000 km. 77 DSOs have networks with a total length exceeding 1,000 km. The following figure shows a breakdown of DSOs according to network length:

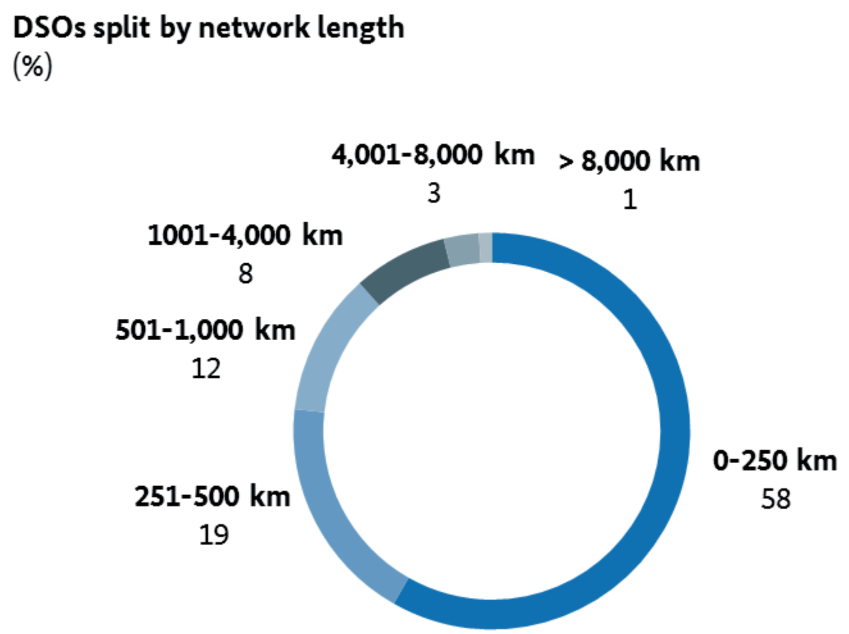

Figure 94: DSOs split by network length

3. Market concentration

The degree of market concentration is a good indicator of the intensity of competition. Market shares are a useful reference point for estimating market power because they represent (for the period of reference) the extent to which demand in the relevant market was actually satisfied by one company[83]. There are typically two ways to represent the market share distribution, i.e. the market concentration: One is the Herfindahl-Hirschman-Index (sum of the squared market shares of all competitors in a market) and the other is the sum of the market shares of the three, four or five competitors with the largest market shares ("concentration ratios", CR3 - CR4 - CR5). The larger the market share covered by only a few competitors, the higher the market concentration.

The following text explains the CR3 values (i.e. the sum of the market shares of the three strongest suppliers) for the market for natural gas storage facilities and for the two largest retail markets for natural gas. Due to the actual market structure in the sectors of natural gas storage facilities and natural gas retail, the CR3 value is more relevant here than CR4 or CR5.

Natural gas storage facilities

In its decision-making practice the Bundeskartellamt defines a relevant product market for the operation of underground gas storage facilities which include both porous rock and cavern storage facilities[84]. In geographic terms the Bundeskartellamt has defined this market as a national market. It has also considered the suggestion made by the Bundesnetzagentur to include the "Haidach“ and "7Fields“ storage facilities

[83] Cf. Bundeskartellamt, Guidance document on substantive merger control, para. 25.

[84] Cf. Bundeskartellamt, decision of 23 October 2014, B8-69/14 – EWE/VNG, para. 215 ff.

located in Austria[85]. These two storage facilities located near the Austrian-German border are connected directly or indirectly to the German gas networks. The European Commission recently considered this alternative market definition as well as some further alternatives – and ultimately left open the detailed market definition[86]. For the purposes of illustrating the concentration in the market for the operation of underground natural gas storage facilities, the Haidach and 7Fields storage facilities located in Austria will be included in the following assessment. The Bundeskartellamt assesses the market shares in this market on the basis of storage capacities (maximum working gas volume)[87].

This year's survey based on the questionnaire "Underground natural gas storage facility operators" achieved 100 per cent coverage, i.e. the data on working gas volumes were available for all storage facilities at the reference date 31 December 2013. A total of 24 legal persons were surveyed. With one exception the attribution of companies to a group was carried out on the basis of the dominance method (cf. the methodological notes in section I.A.3, p. 23): At the reference date 31 December 2013, Wingas was a joint venture between BASF and Gazprom. According to the merger project that was cleared by the European Commission in December 2013, BASF is to withdraw from Wingas and/or its gas storage operations[88]. The total storage capacities have therefore been attributed to Gazprom. Due to this "correction" it is expected that the resulting CR3 value will be largely identical with the value resulting from the system of attribution under competition law.

On 31 December 2013, the maximum working gas volume of the German underground natural gas storage facilities, including Haidach and 7Fields, amounted to approx. 27.2 billion m^3. At the reference date 31 December 2010 the maximum volume amounted to approx. 22.5 billion m^3. On 31 December 2010, the aggregate working gas volume of the three companies with the largest storage capacities amounted to approx. 16.4 billion m^3, and approx. 18.5 billion m^3 on 31 December 2013. The CR3 value thus decreased from approx. 73 per cent to approx. 68 per cent. The increased market volume and decrease in concentration are due to the fact that some new storage facilities have become operational. However, the market is still characterised by a relatively high level of concentration.

[85] Cf. Bundeskartellamt, decision of 31 January 2012, B8-116/11 – Gazprom/VNG, para. 208 ff.

[86] Cf. COMP/M.6910 – Gazprom/Wintershall of 3. December 2013, para. 30 ff.

[87] Cf. Bundeskartellamt, decision of 23. October 2014, B8-69/14 – EWE/VNG, para. 236 ff.

[88] Cf. COMP/M.6910 – Gazprom/Wintershall of 3. December 2013.

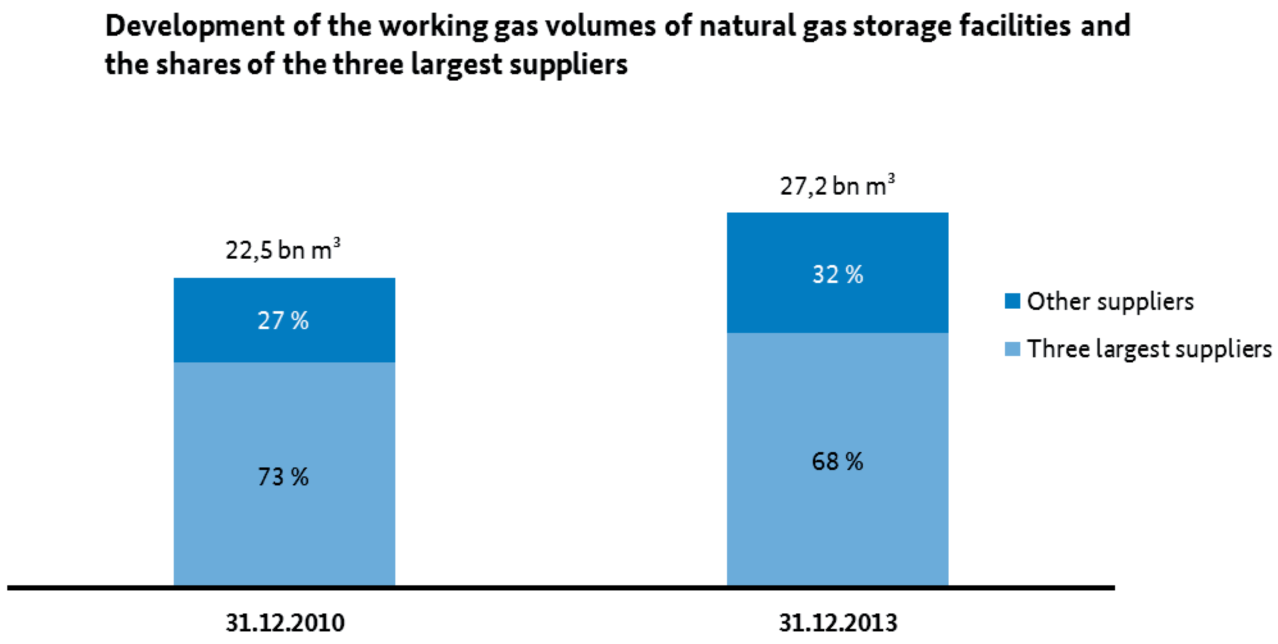

Figure 95: Development of the maximum working gas volumes of natural gas storage facilities and the shares of the three largest suppliers

Supply to customers with metered load profiles and standard load profiles

On the gas retail markets the Bundeskartellamt differentiates between customers with metered load profiles and those with standard load profiles. Customers whose consumption is measured on the basis of metered load profiles are mainly large industrial or commercial customers as well as gas power stations. Gas consumption by customers with standard load profiles involves relatively low volumes. These are generally household customers and smaller commercial customers. A standard load profile is assumed for the distribution of their gas consumption over specific time intervals. The Bundeskartellamt currently defines the market for the supply of gas to customers with metered load profiles and the market for the supply of gas to customers with standard load profiles on the basis of special contracts as national markets. The supply of gas to standard load profile customers in the basic supply sector is a separate product market which is still defined according to the respective network area[89].

In the energy monitoring process the suppliers' sales are recorded as cumulative values throughout Germany at the level of the individual companies (legal persons). In the survey a differentiation is made between basic supply to standard load profile customers and supply on the basis of special contracts. The following evaluation is based on the data of approx. 780 gas suppliers (legal persons). In 2013, these companies sold a total of approx. 387 TWh of gas to standard load profile customers in Germany and approx. 481 TWh of gas to customers with metered load profiles. In accordance with the Bundeskartellamt's practice of market definition, sales to customers with metered load profiles – also include sales to gas power stations. Of the total volume of sales to standard load profile customers, special contracts accounted for 310 TWh and basic supply contracts accounted for 77 TWh.

[89] Cf. Bundeskartellamt, decision of 23 October 2014, B8-69/14 – EWE/VNG, para. 129-214.

The attribution of sales volumes to the company groups was carried out on the basis of the dominance method which provides sufficiently accurate results for the purposes of this report (cf. methodological notes in section I.A.3, p. 23). This attribution process also took into account the intended sale by BASF of the retail business segment of Wingas/Wintershall to Gazprom[90]. Therefore, the sales volumes of the respective companies were aggregated and treated as one single group of companies.

Most of the companies (about 590 of the 780 companies) were under municipal ownership, either majority owned or at least 50 per cent owned[91]. About 204 TWh of gas supplied to standard load profile customers and about 147 TWh of gas supplied to customers with metered load profiles were accounted for by companies in which one single municipality held at least 50 per cent of the shares. In the case of customers with standard load profiles, the total cumulative sales of the three strongest companies amounted to approx. 84 TWh in 2013, 68 TWh of which were accounted for by special contracts. In the case of customers with metered load profiles, sales amounted to approx. 161 TWh. Two companies are among the three largest suppliers of gas to standard load profile customers and among the three largest suppliers of customers with metered load profiles. In 2013, the aggregated market share of the three strongest companies (CR3) thus amounts to about 22 per cent for standard load profile customers with special contracts, and about 33 per cent for customers with metered load profiles. These market shares are clearly below the statutory threshold for the presumption of market dominance (§18 GWB).

For the standard load profile sector an alternative calculation was made to determine the CR3 value for the supply of gas to all standard load profile customers (i.e. including basic supply customers). A CR3 value of about 22 per cent also applies for the total number of standard load profile customers (throughout Germany). With regard to the percentage shares provided it should be noted that in the sector of gas suppliers, the monitoring survey does not cover the whole market. The percentage shares are thus merely approximate to the actual values.

[90] Cf. COMP/M.6910 – Gazprom/Wintershall of 3 December 2013.

[91] In this context, companies in which several municipalities held cumulative shares of more than 50 per cent, but where each individual municipality held a share of less than 50 per cent, have not been counted as "municipal suppliers".

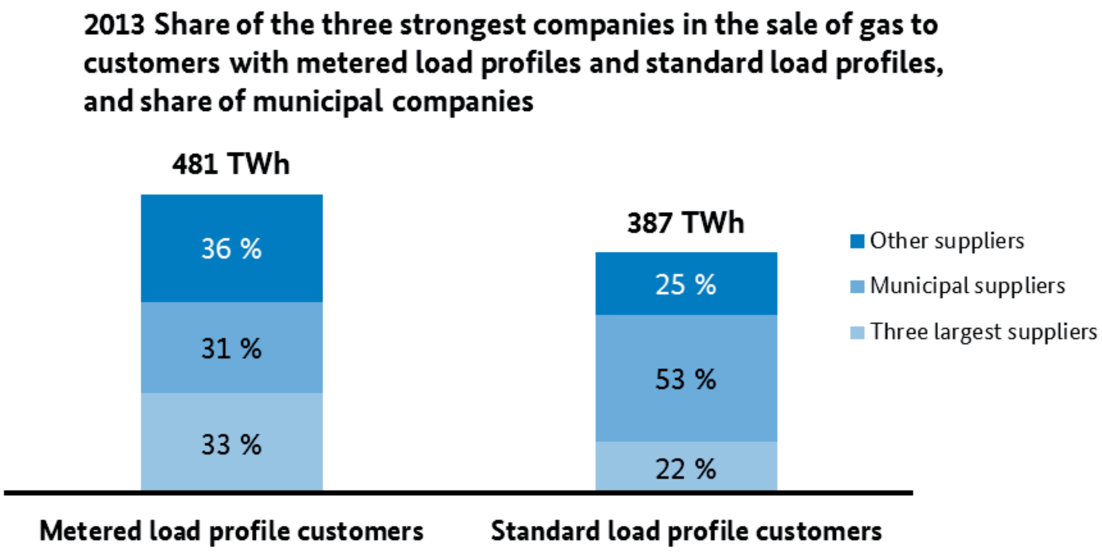

Figure 96: Share of the three strongest companies in the sale of gas to customers with metered load profiles and standard load profiles, and share of companies in which a municipality is the majority shareholder

B Production of natural gas in Germany and imports and exports/security of supply

1. Production of natural gas in Germany and imports/exports

1.1 Production of natural gas in Germany

In 2013, the year under review, natural gas production in Germany fell by 1.0bn m3 to 9.7bn m3. This represents a year on year decrease of 9.3 per cent. The continual decline in natural gas reserves and production is chiefly due to the increasing exhaustion and dilution of existing deposits. 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 9.7 years as of 1 January 2014; this represents a decrease of almost one year compared to the previous year. The reserves-to-production ratio does not take account of the natural decline in output from deposits and should therefore not be seen as a forecast, but rather as a snapshot and guide. (Source: Landesamt für Bergbau, Energie und Geologie (LBEG).)

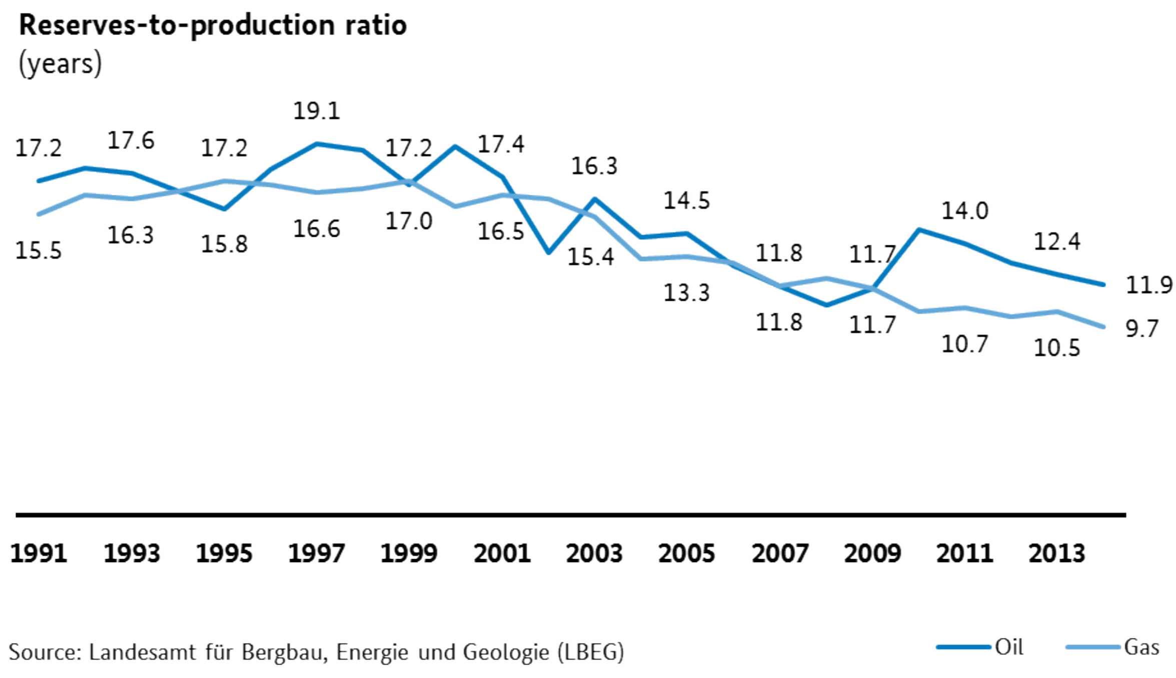

Figure 97: Reserves-to-production ratio of German oil and gas reserves since 1991

1.2 Imports and exports

The volume of gas imported into Germany rose by some 243 TWh or 18.8 per cent from 1,535 TWh in 2012 to 1,778 TWh in 2013.

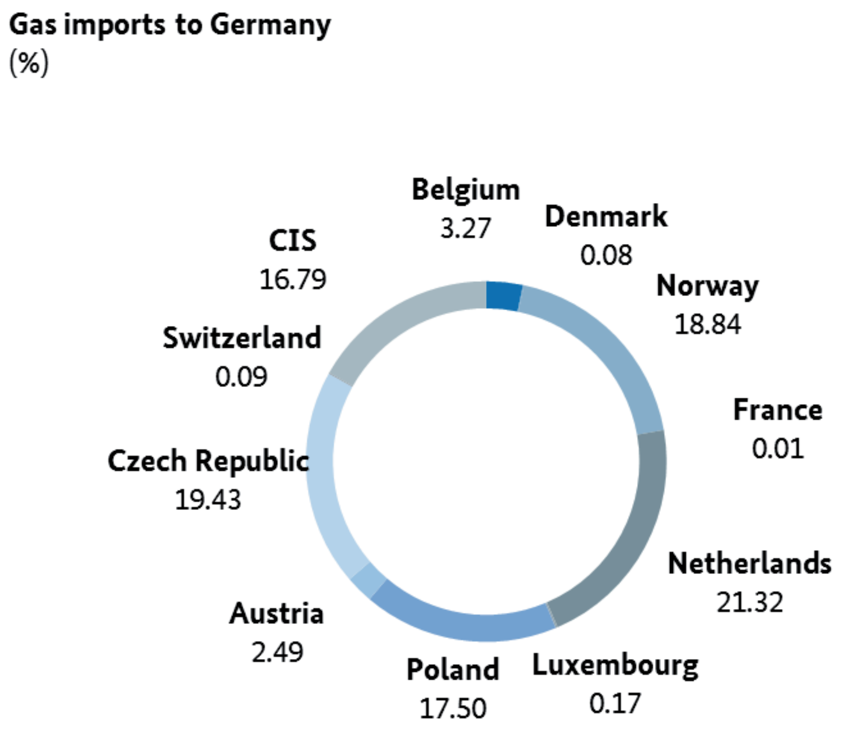

Figure 98: Countries exporting gas to Germany in 2013

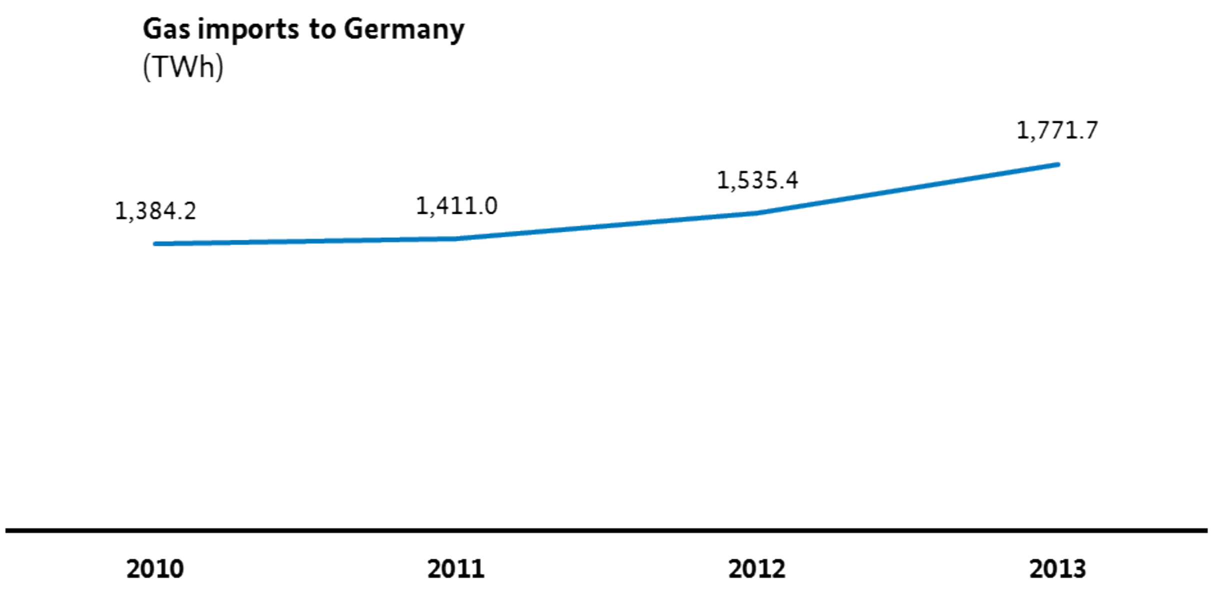

Figure 99: Gas imports

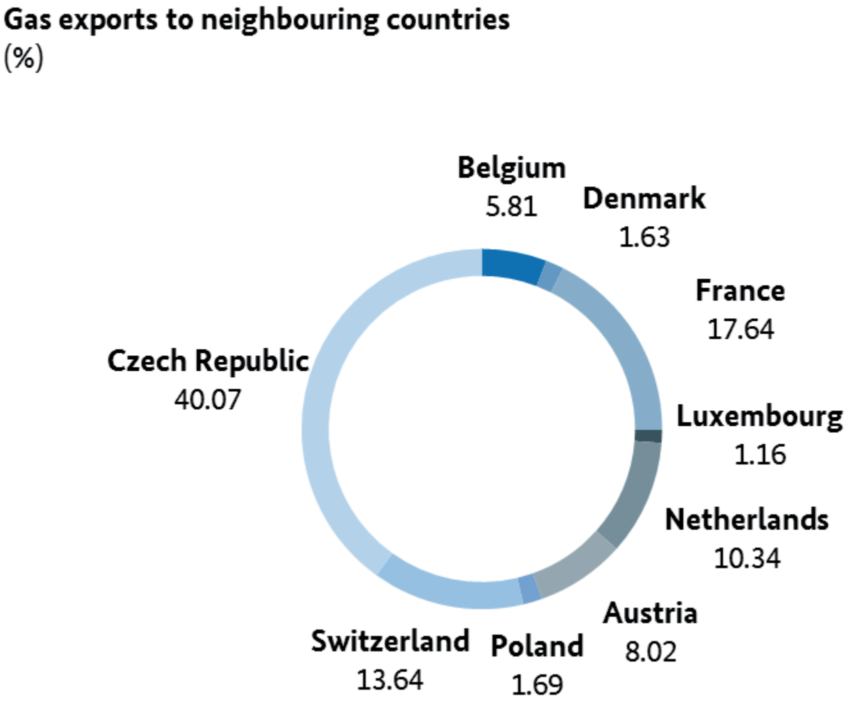

Figure 100: Neighbouring countries importing gas from Germany in 2013

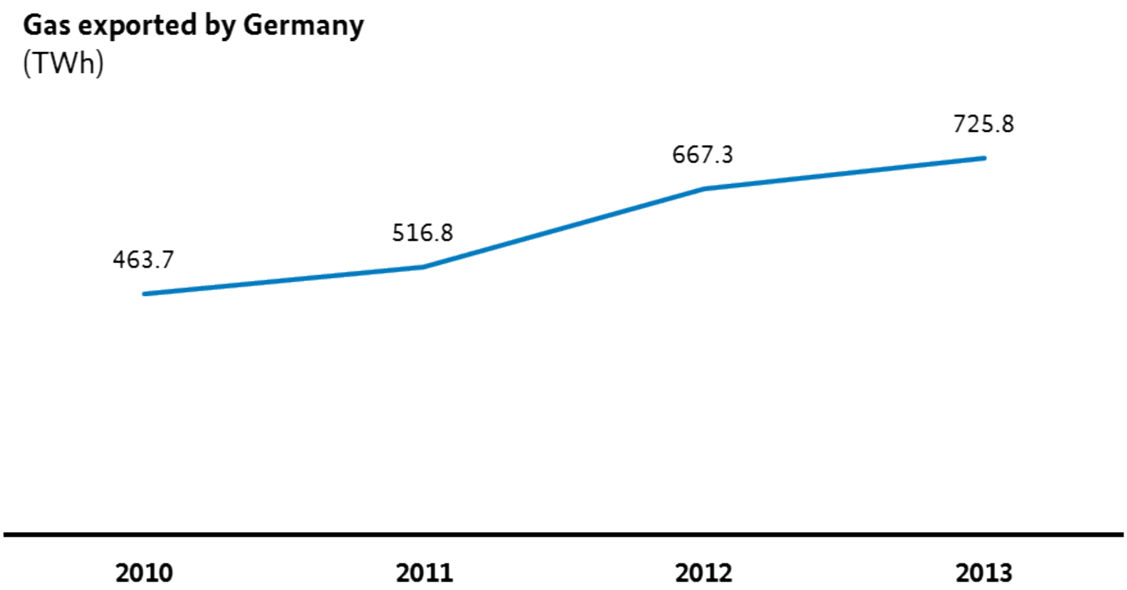

Figure 101: Gas exported by Germany

The main sources of gas imports remain the Commonwealth of Independent States (CIS) and Norway. However, the Netherlands, as an established and liquid trading hub in Europe and point of arrival for liquefied natural gas supplies with connections to natural gas fields in Norway and the United Kingdom, is also a significant source of imports for Germany. Improved integration of national markets and more efficient management of cross-border capacities has eased trading and provided further alternatives for gas traders.

The second full operational year of the Nord Stream pipeline under the Baltic Sea again led to an increase of gas imports from the CIS. Some 56 per cent of all gas imports came from the CIS.

Gas exports also increased, with a rise of 8.8 per cent from 667.3 TWh in 2012 to 725.8 TWh in 2013.

There were some significant changes in the volumes exported by Germany to the individual countries. There was another increase in exports to the Czech Republic: 40.7 per cent of Germany's total gas exports went to the Czech Republic, compared to 20.3 per cent in 2011 and 32.4 per cent in 2012. This can partly be accounted for by the operation of the Nord Stream and OPAL pipelines since 2011. While there was a smaller increase of around 21.7 per cent in the volume exported to France, there was a year on year increase of 71 per cent in exports to Denmark. Export volumes to the other countries remained at more or less the same level but accounted for a lower percentage of total exports owing to the considerable increase in the overall volume exported.

2. Security of supply

The Bundesnetzagentur again conducted a comprehensive survey of all gas supply interruptions throughout the Federal Republic of Germany. Section 52 of the Energy Act (EnWG) requires gas network operators to report all interruptions in supply to the Bundesnetzagentur by 30 April of each year. The Bundesnetzagentur uses the data reported to calculate the System Average Interruption Duration Index (SAIDI), which gives the average interruption duration per consumer in one year. Planned interruptions to supply or force majeure interruptions, such as those caused by natural disasters, are not taken into account. The figure reflects only unplanned interruptions to supply caused by third-party intervention, disturbances from other networks or other disruptions that the operator is answerable for.

In 2013 the SAIDI figure stood at around 0.6 minutes, which means that gas supplies in Germany were interrupted for less than one minute per consumer on average. This again shows a high level of gas supply reliability, with the average duration lower than the multi-annual average of two minutes.

The comprehensive survey of supply interruptions in all gas networks in Germany registered in the Bundesnetzagentur's energy database (around 720) produced the following results:

SAIDI results for 2013

Pressure range	SAIDI	Notes
≤100 mbar	0.57 min/a	Household and small consumers
>100 mbar	0.07 min/a	Major consumers
>100 mbar	0.01 min/a	Downstream network operators
All pressure ranges	0.64 min/a	SAIDI for all final consumers

Table 50: SAIDI results for 2013

The Bundesnetzagentur has calculated the SAIDI figures for gas network operators since 2006, as shown below:

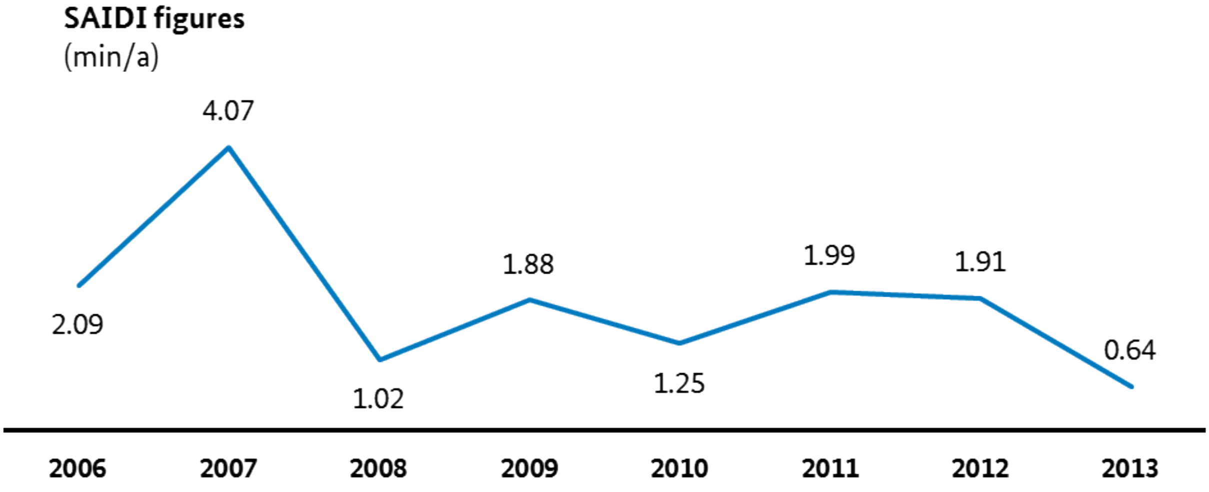

Figure 102: SAIDI figures from 2006 to 2013

C Networks / Investments / Network tariffs

1. Networks / Investments

1.1 Gas Network Development Plan 2012 to 2014

The Gas Network Development Plan, to be published on an annual basis as provided for in section 15a of the EnWG, includes measures for needs-oriented optimisation, reinforcement and expansion of the network, which will be necessary in the next decade to ensure security of supply. The content of the Gas Network Development Plan focuses on the one hand on expansion issues arising due to the connection of new gas power plants – there is particular overlap here with the electricity market – and gas storage facilities, while on the other hand looking at further connections between the German transmission network and those in neighbouring European countries and the capacity needs in the downstream networks.

The Gas Network Development Plan 2013 was presented to the Bundesnetzagentur by the TSOs within the specified period on 1 April 2013. The document was then submitted for comprehensive consultation by the Bundesnetzagentur[92]. Taking the results of the consultation into account, the Bundesnetzagentur formulated a modification request addressed to the TSOs on 18 December 2013.

In this modification request, the TSOs were instructed to reincorporate five measures from the Gas Network Development Plan 2013 into the current plan, as these were no longer included in the 2013 draft. Additionally, they were obliged to adjust the dimensioning of several measures. There has been no significant change in the need for expansion of the gas network compared to the previous year. With this procedure, however, the Bundesnetzagentur has ensured the required degree of continuity in the planning and expansion of the gas transmission networks.

The measures contained in the Gas Network Development Plan 2013 are necessary in particular for the north to south transport of gas. In addition, they contribute to relieving the critical situation of the gas supply faced by distribution system operators in southern Germany. For the first time, the Gas Network Development Plan 2013 also addresses the decreasing supply of L-gas, in particular in the Netherlands, and specifies concrete network areas for the switch to H-gas supply.

The total investment volume for the 27 binding network expansion measures specified in the Gas Network Development Plan 2013 is approximately €2,200m. By 2023, the measures translate into line construction of a total length of 522km and additional compressor capacity of 344 MW[93].

The Gas Network Development Plan 2013 became binding on the TSOs with the announcement of the modification request. The revised Gas Network Development Plan 2013, taking into account the modification request of the Bundesnetzagentur, has been published on the website of the TSOs[94] on 18 March 2014.

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[92] The statements made as part of the consultation process have been published on the website of the Bundesnetzagentur (http://www.bundesnetzagentur.de/cln_1412/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/NetzentwicklungundSmartGrid/Gas/NEP_Gas2013/netzentwicklungsplan_Gas2013-node.html)

[93] See Network Development Plan 2013 from 18 March 2014, Network Expansion Measures as per Modification Request, p. 169 ff.

On 1 April 2014, the TSOs presented the Bundesnetzagentur with the Gas Network Development Plan 2014. For the most part, the measures included in the Gas Network Development Plan 2013 that the Bundesnetzagentur specified as binding are continued in the Gas Network Development Plan 2014. In addition to those measures, the view to 2024 contains additional necessary expansion measures that result primarily from the need for conversion from L- to H-gas, the consideration of the increased need for H-gas and an increased need for gas storage capacity. Another reason for individual measures is the increased need for capacity in the distribution network in southern Germany.

The draft Network Development Plan 2014 contains two different modelling variations that are only marginally different in terms of network expansion measures and expansion costs (€2.9m vs. €3.1m investment costs until 2024). This deviation is based on the consideration of unequal amounts for the capacity requirements of downstream distribution system operators.

The draft Network Development Plan that was selected from these variants – a combination of the two modelling results – translates into a required line construction of 760km and an increased compressor capacity of 358 MW over the next 10 years. The corresponding investment volume is €3.1m[95]. The document was made available by the Bundesnetzagentur for consultation up to 6 June 2014. An evaluation of the consultation results in the drafting of any modification requests had not been completed at the time of the editorial deadline of the Monitoring Report.

[94] http://www.fnb-gas.de/de/netzentwicklungsplan/nep-2013/nep-2013.html

[95] See draft of the Network Development Plan 2014 (http://www.fnb-gas.de/de/netzentwicklungsplan/nep-2014/nep-2014.html)

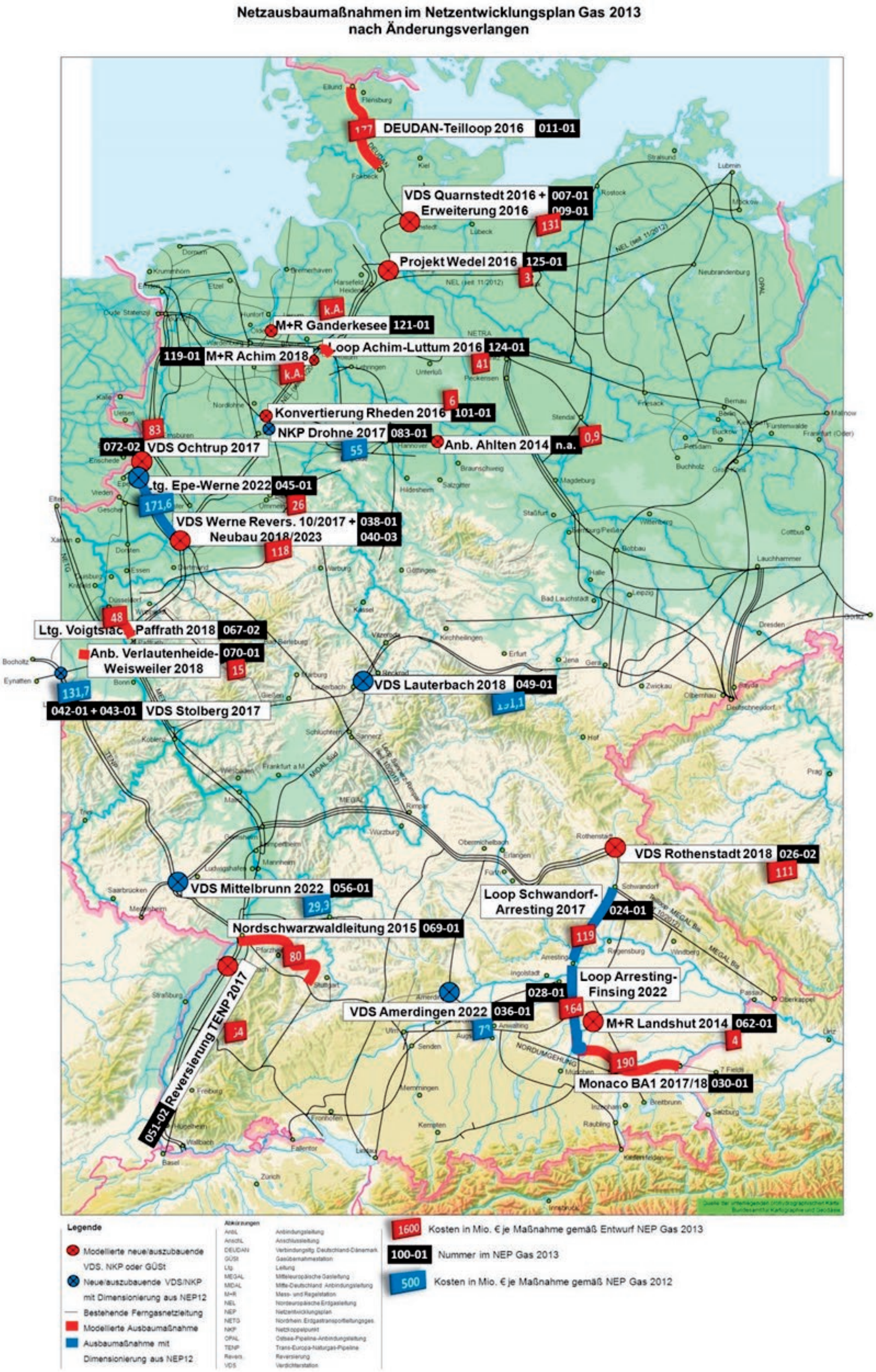

Figure 103: Network expansion measures in the Gas Network Development Plan 2013 as per modification request

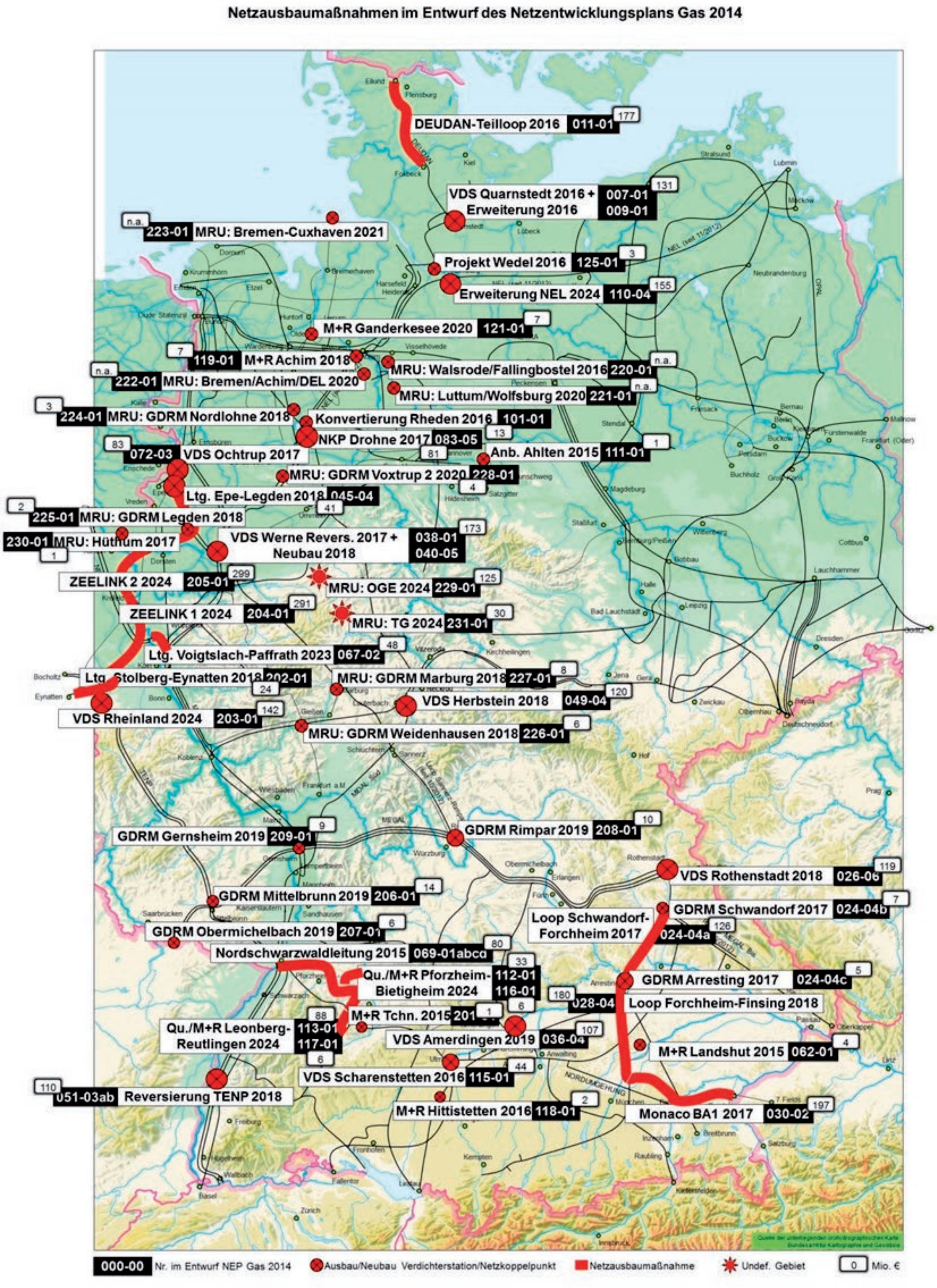

Figure 104: Network expansion measures in the Gas Network Development Plan 2013

1.2 Capacity offer and marketing

As in the previous reporting year 2012, the questions asked dealt with the booking, use, availability and booking preference for transport capacity in 2013. Distinctions were again made between the various capacity products offered on the market.

Shippers were asked about their preference for different capacity products. They were asked to state on a scale from 1 (for very important) to 4 (unimportant) whether in addition to firm and freely allocable capacity (FZK) only interruptible capacity products should be offered or whether, in contrast, other firm capacity products should be offered in addition to FZK and interruptible capacity. In contrast to the past two years' reports, less than half (49 per cent) of all shippers preferred the two-product variant, (see gas year 2010/11: 55 to 45 per cent and gas year 2011/12: 60 to 40 per cent in favour of the two-product variant). The absolute figures of shippers surveyed are shown inside the column in the diagram.

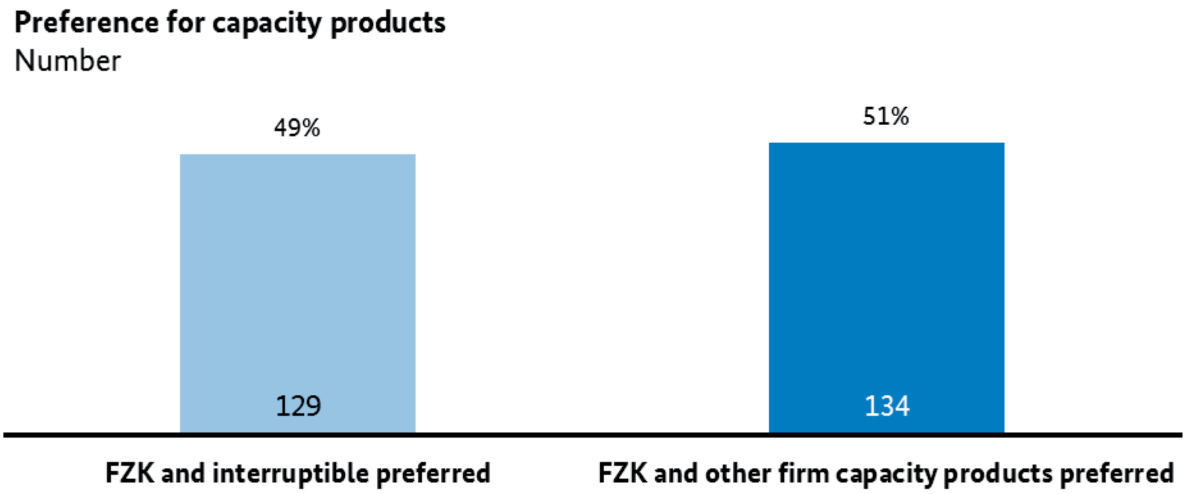

Figure 105: Preference for FZK capacity model and interruptible vs. FZK, interruptible and other firm products

Shippers were also asked whether load flow commitments should be entered into so as to safeguard FZK in large market areas or whether other capacity products should be offered instead of FZK (eg conditionally firm FKZ (bFZK) or dynamically allocable capacities (DZK)). LFZ are contractual agreements between a transmission system operator (TSO) and a third party (usually a shipper or a storage user) regarding the provision or restriction, upon the request of the TSO, of a specific gas flow at an entry or exit point or zone within the network. They can be offered by third parties which have either entry or exit points in their portfolio and are prepared, against payment by the network operator, to adapt the original free use of their capacities, when necessary, to the TSOs' requirements.

A majority of the shippers surveyed (58 per cent) were in favour of using load flow commitments.42 per cent preferred the alternative, ie the offer of other capacity products.

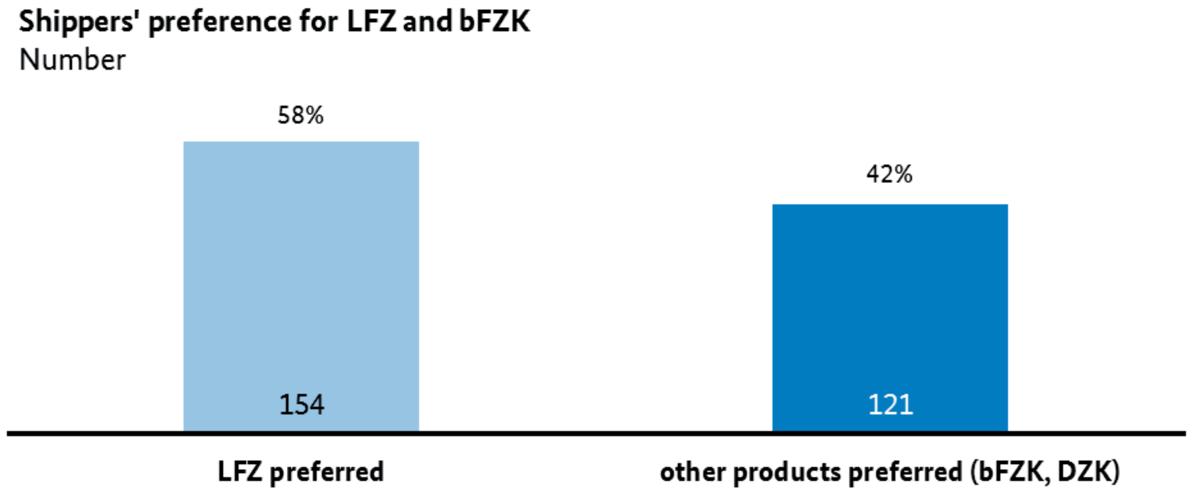

Figure 106: Preference for FZK safeguarding through load flow commitments vs. preference for other products as alternative to FZK

1.3 Offer of entry and exit capacities

In the 2012/13 gas year there were market area specific changes in the supply of entry and exit capacities. While the entry capacity in both market areas NetConnect Germany and Gaspool increased by 0.7m kWh/h, the exit capacity decreased significantly by 84m kWh/h. These figures do not take interruptible capacity and internal orders into account, but refer instead to the median offer of firm capacity at cross-border and market area interconnection points and also at points of interconnection with storage facilities, power stations and final consumers.

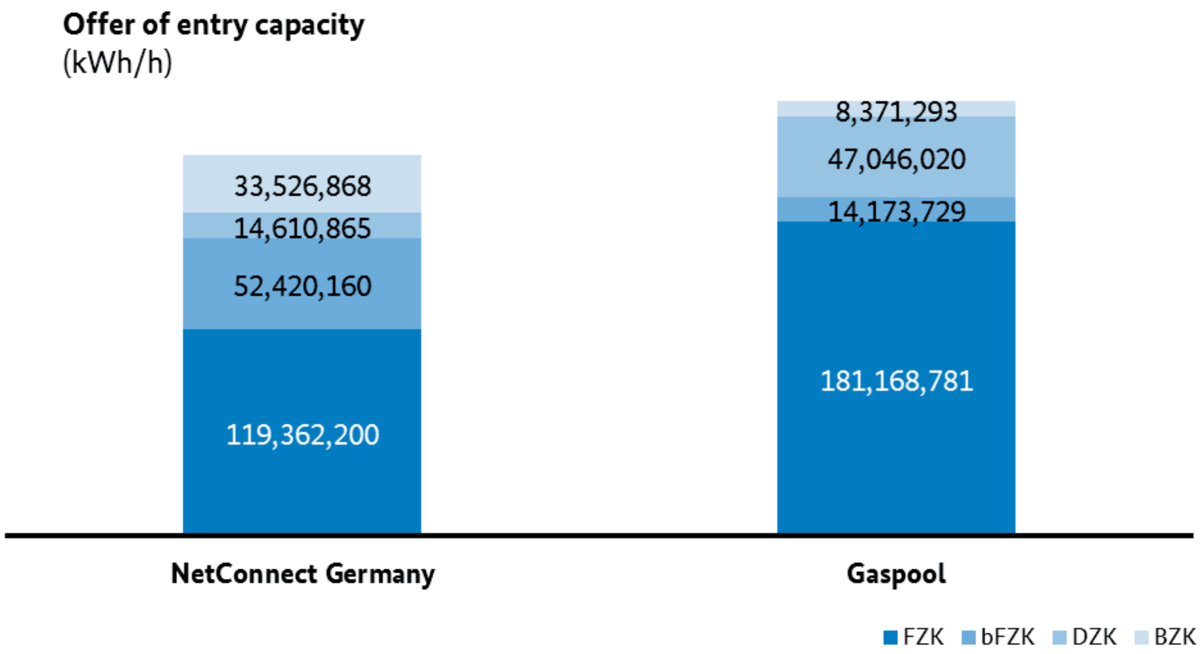

Figure 107: Offer of entry capacity in the market areas of NetConnect Germany and Gaspool

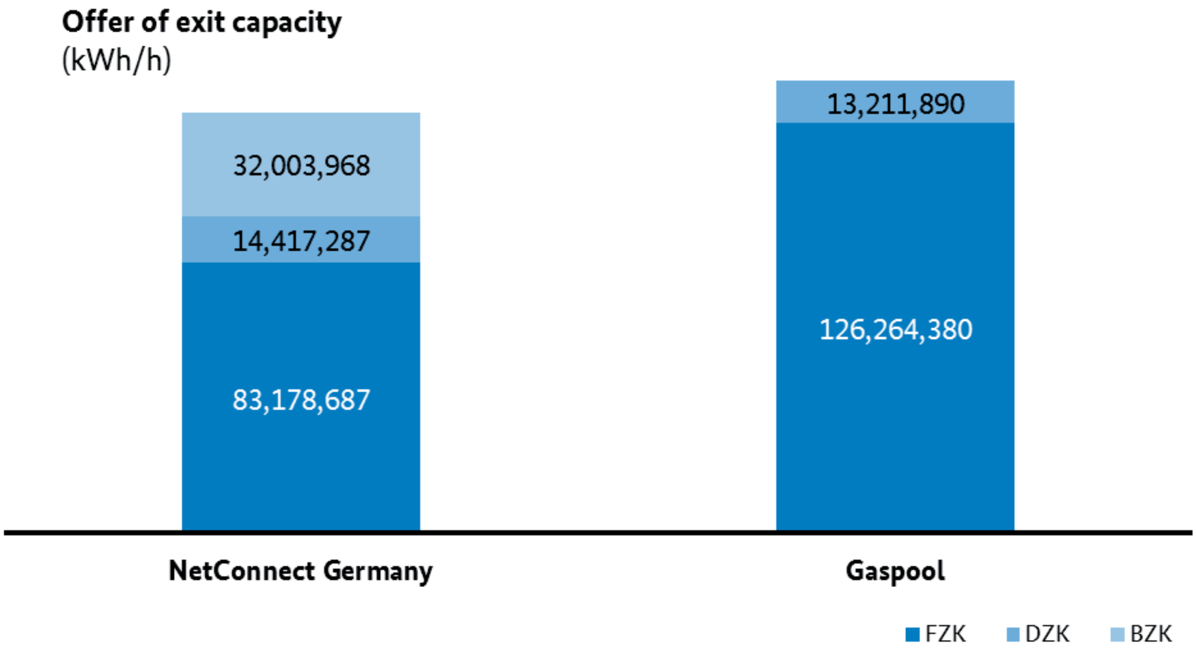

Figure 108: Offer of exit capacity in the market areas of NetConnect Germany and Gaspool

1.4 Capacity

During the reporting period, a total of 88 long-term capacity contracts were terminated. The following kinds of capacity were affected: 70x FZK, 11x bFZK, 3x interruptible and 2x generally interruptible FZK (uFZK). Contracts were terminated in particular at cross-border points, the peak being reached at a capacity of 2,841m kWh/h and a median contract term of four years. The ratio of terminated entry to exit capacities is 2 to 1.

The following factors may have brought about terminations of capacity contracts:

- Successful capacity and congestion management measures make it possible to procure capacity at short notice;
- the influence of the contract term on tariffs (surcharges for short-term capacities) has been abolished;
- shippers have found that the contractual congestion situations of the past have been dissipated by the congestion management mechanisms laid down by KARLA Gas and that sufficient capacity is available in the short term. Thus they can dispense with the hoarding of capacity, for which powerful incentives existed in the past;
- shippers attach little importance to gaining a favourable position in the queue for interruptible capacity since there is little actual interruption and a lack of extreme over-booking.

The changing booking situation offers the TSOs both opportunities and risks. On the one hand the fact that the capacity bookings by the shippers are tied more closely to physical transport requirements enables them to align their offer of capacity more precisely to market needs. Capacity can be shifted from points of low demand to points where it is high, provided this is hydraulically possible without having to carry out further network expansion measures. On the other hand there is the challenge posed by the TSOs' commercial liquidity problems. When it is more difficult to forecast booking patterns it becomes harder to set specific tariffs and plan revenue flows.

1.5 Capacity offer; interruptible capacity

Interruptible gas capacity is, as a rule, less expensive than firm capacity. It does however involve the risk that the desired gas transport may not be possible.

Overall, bookings of interruptible capacity decreased significantly compared to the previous year. In the current reporting period, the sum of bookings is 108m kWh/h on the entry side and 135m kWh/h on the exit side, which in total amounts to a decline of 62 per cent.

The total share of interruptible bookings, based on the median booking volume, was 42 per cent on the entry side and 9 per cent on the exit side. This means a significant year-on-year decline in the relative share of booked interruptible exit capacity (23 per cent).

Eleven of the 64 gas wholesalers and suppliers working under interruptible capacity contracts stated that they had in fact experienced interruption in the 2012/13 gas year. As in recent reporting years there was a very uneven distribution of both the number and the length of the interruptions among the various wholesalers and suppliers. Apart from the average duration of interruption in hours (as shown by the column height), the diagram below shows the absolute number of interruptions experienced by the wholesalers and suppliers in the particular gas year (different colours for different years on the horizontal axis). The average interruption duration is longer than generally in previous years: 28 hours as against 26 in the year before. There was a significant year-on-year overall decrease in the total length of interruption for all affected companies (from 8,648 hours in 2011/12 to 1,975 hours in 2012/13). The same applies for the absolute number of affected companies (a decrease from 19 in 2011/12 to 11 in 2012/13).

Total interruption duration and number of interruptions per wholesaler or supplier

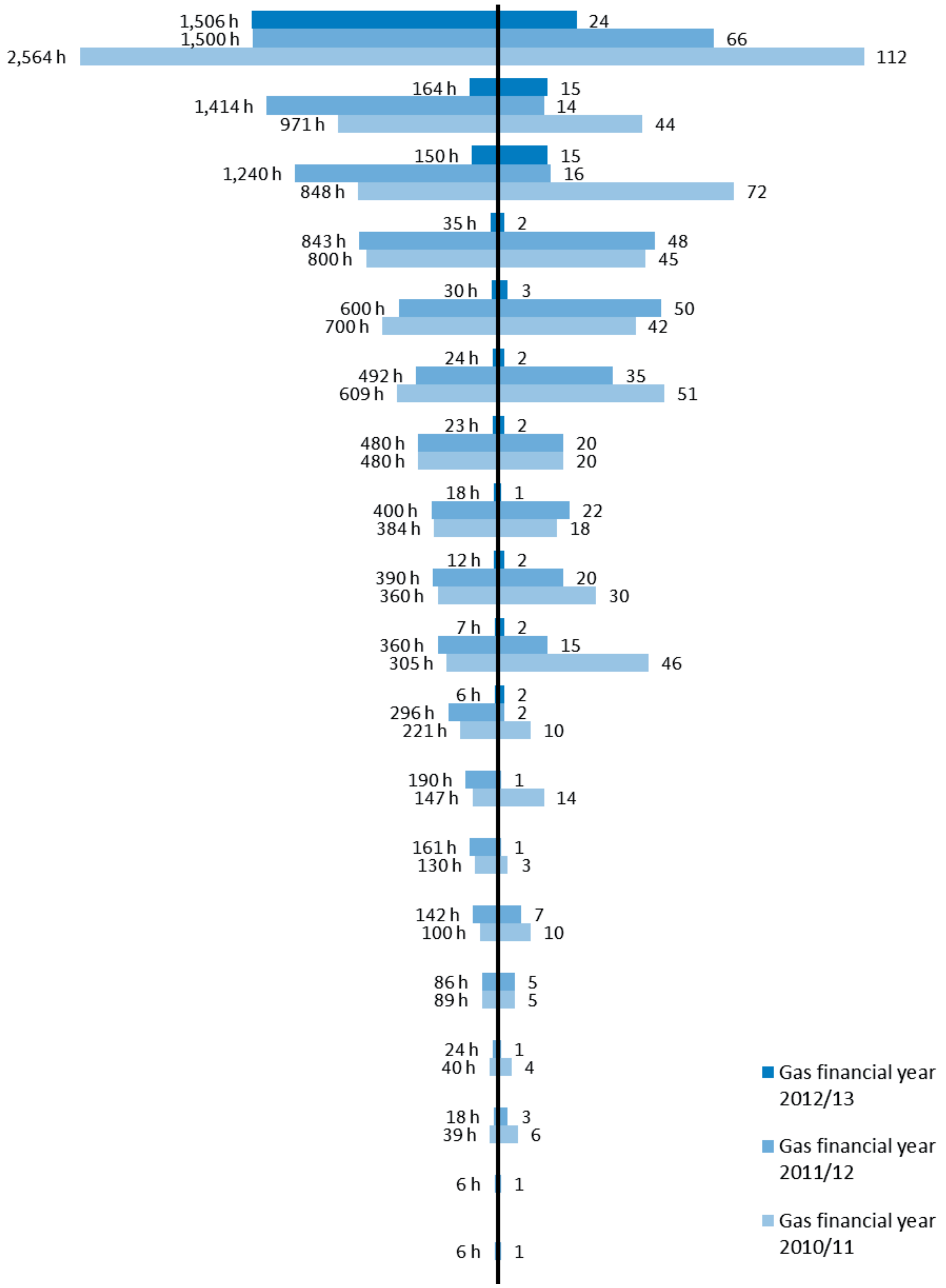

Figure 109: Number of interruptions and average interruption duration per company for the gas year 2009/10 and 2010/11, 2011/12, 2012/13

The diagram can be elucidated by a brief explanation of a single example: The company with the second highest interruption duration (column 1, gas year 2012/13) experienced a total of one interruption lasting 18 hours. Another company (column 6 for gas year 2012/13) was interrupted much more frequently (15 interruptions), on average however for just 11 hours in each case. As a result, the total interruption duration for this company is 164 hours, significantly higher than for the first company with 18 hours.

Similarly, network operators were surveyed on the duration of interruption and interrupted volume of both interruptible and firm capacity products in relation to the initial nomination or alternatively the last figure renominated by the shipper before the interruption was made known. In the 2012/13 gas year, the volume of gas that was not transported through all entry and exit points was 2bn kWh, compared with 1.3bn kWh in the previous reporting period. Of that amount, the interruption of firm capacity made up the majority (59.5 per cent) of the interruptions. The conspicuously high number of interruptions of firm capacities was caused largely by unforeseen technical problems. Through the interruption of interruptible capacity, a total of 835m kWh of the nominated volume was not transported (compared to 1.3bn kWh in the previous year). In relation to the total volume transported in the gas year under review (2,749bn kWh), only 0.08 per cent of the nominated gas volume was actually interrupted.

The following map lays out the regional distribution of interruptions. The direction of the arrows shows in what direction transmission was interrupted. In this context it is important to note that the width of each arrow grows in proportion to the share of the volume interrupted in relation to total interruptions.

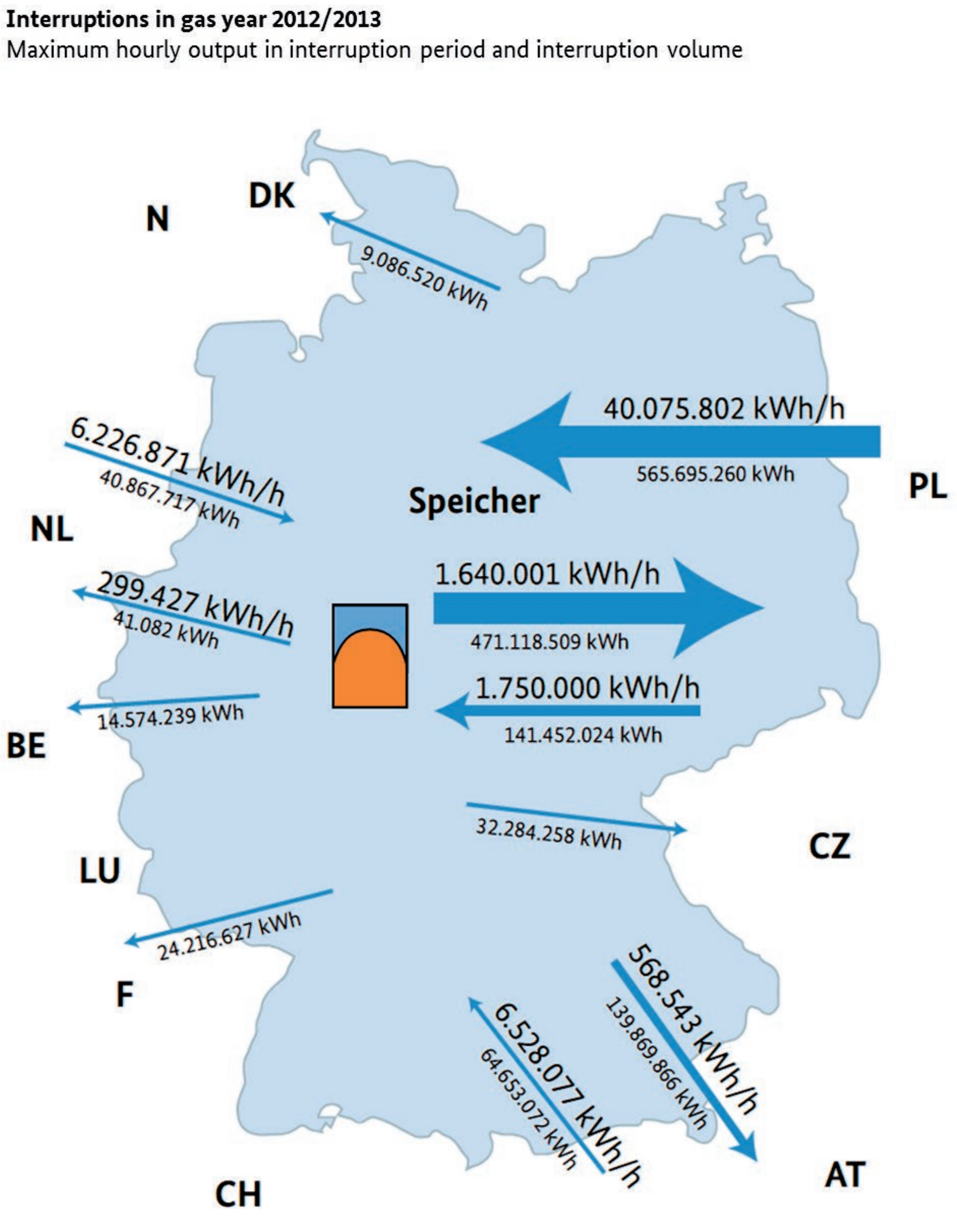

Figure 110: Regional overview of interruption capacity and gas volumes

In contrast to the previous reporting period there were no interruptions of supply to final consumers. In the last report, there was still a small volume of 0.08 per cent of the total interrupted volume that affected final consumers. The share of the total interrupted volume at the market area interconnection points was only

0.35 per cent; during the previous reporting period there were no interruptions at the market area interconnection points.

1.6 Contractual disconnection agreements

This year for the second time, network operators were asked about any disconnection contracts they had concluded with their customers. The background is that an amendment to section 14(b) of the energy act (EnWG) had enabled them to enter into such contracts on condition and for as long as the contracts served the purpose of averting congestion in the upstream network. In addition, the regulatory authority of Baden-Württemberg, as a reaction to the tense supply situation of February 2012, granted the network operators a similar possibility within its area of responsibility. A total of 9.8 per cent of network operators made use of this possibility.

In this context, the average number of disconnection contracts per network operator was 3.2 (2012: 3.9). The highest number of disconnection agreements for one network operator was 19. As a rule, these agreements have a limited term of one year and offer the customer a tariff reduction of a maximum of 86 per cent (average cut: 21.2 per cent). In the previous year the figures were still at a maximum of 80 per cent and an average of 48 per cent. The possibility of a disconnection was actually utilised in only 16.4 per cent of the contracts entered into. In the previous year, that figure was still at 67 per cent.

1.7 Investment in and expenditure on infrastructure by gas DSOs

In the year 2013, there was a total of €2,014m (2012: €1,967m) in investment in an expenditure on network infrastructure. The DSOs' forecasted investment volume in the distribution networks amounting to €895m for the year 2013 was exceeded by €70m, bringing it to a total actual investment volume of €965m. By contrast, actual expenditures fell slightly short (by €38m) of the forecasted expenditures of €1,085m, bringing that figure to €1,049m. In total, the amount of DSOs' expenditures for network infrastructure was €34m higher than the 2013 forecast of €1,980m. The DSOs' forecasts for the coming year 2014 indicate a 14 per cent increase in investment volume in new installations, expansion, extension, sustainment and renewal and an 18 per cent increase in expenditures.

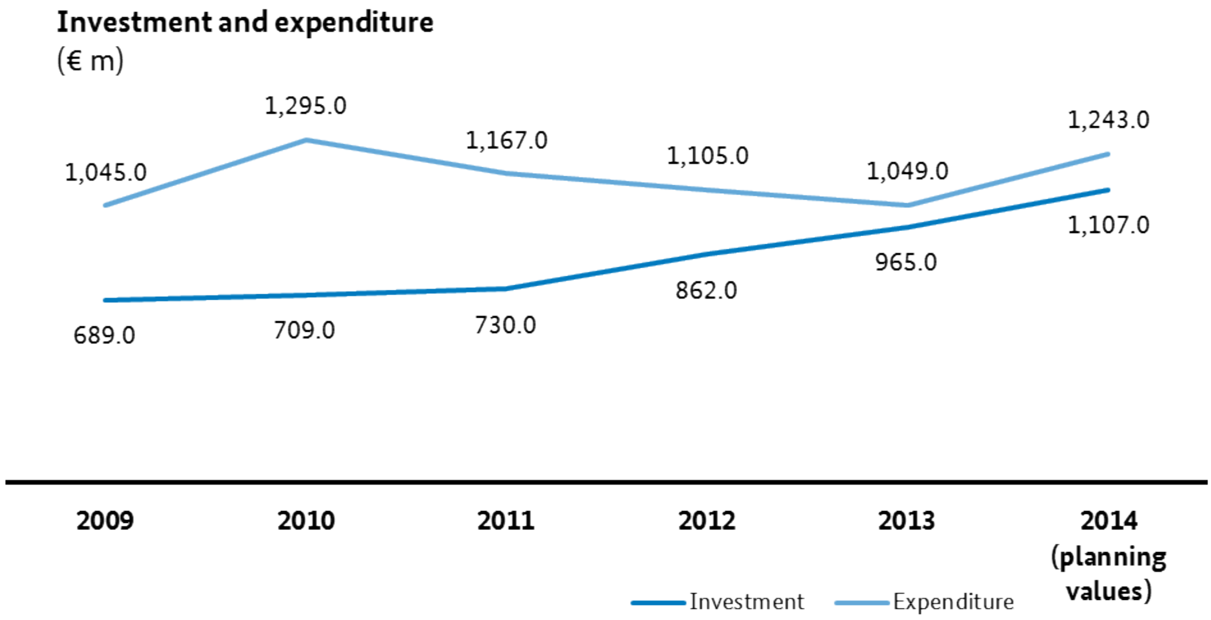

Figure 111: Investment in and expenditure on network infrastructure by gas DSOs

The amount of investment made by the DSO is dependent on the length of the gas network, the number of metering points serviced as well as on other individual structural parameters, including, in particular, geographical conditions. The tendency is for DSOs to make higher investments with increasing lengths of the gas network. In the investment category of €0 100,000, there are 122 DSOs (18 per cent). Only eight percent of companies, by contrast, showed a peak investment over €5m per network area. The following illustrations show the share of the total investment volume for different investment categories.

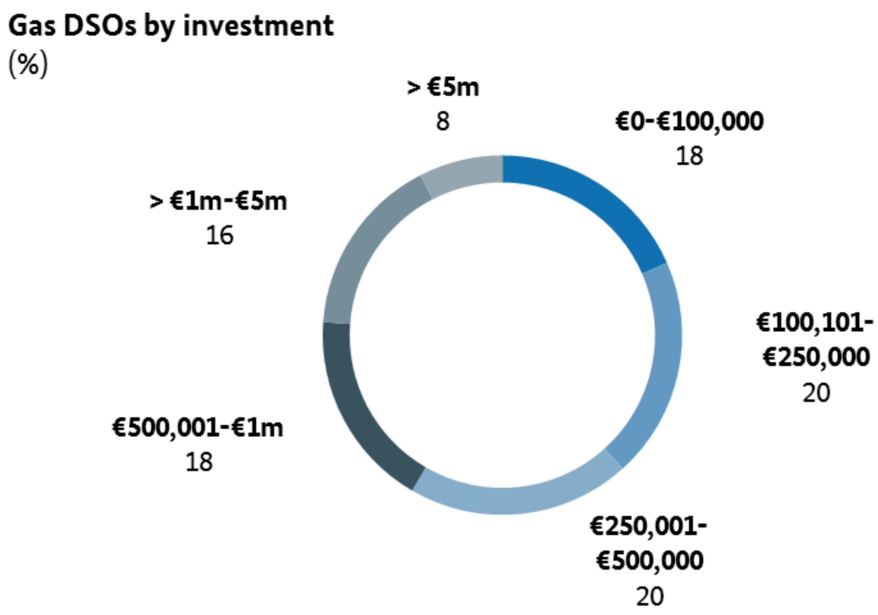

Figure 112: Gas distribution network operators by investment volume

The shares of expenditure made by the gas DSOs according to volume category show a similar distribution as investments. There are 152 companies in the range of €0 to €100,000, while there are 51 companies in the top category with expenditure exceeding €5m.

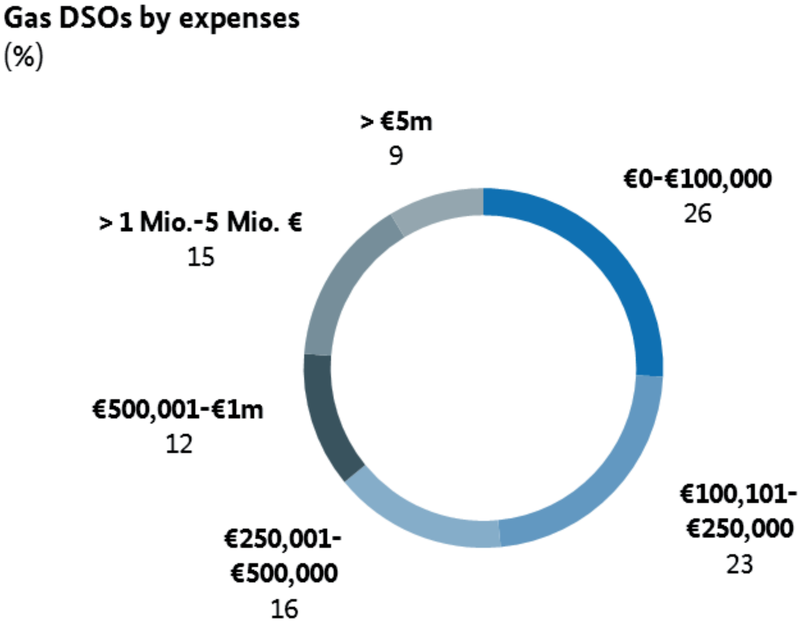

Figure 113: Gas distribution network operators by expenditure amounts

2. Network tariffs

2.1 Network tariff share in overall gas price between 2007 and 2013

The following figure shows the share of the average volume-weighted net gas network tariff, including upstream network costs and charges for billing, metering and metering operations, in the overall gas price as of 1 April between 2007 and 2013.

While in the area of household customers, the absolute amount of network tariffs is in decline for all types of supply, there was a marginal decline in the share of the total gas price for default supply tariffs as well as tariffs for change of contract. Among the tariffs for change of supplier, the share of network tariffs of the overall gas price increased to a new peak, due to a decrease in the share of the price component energy procurement and supply.

In the category of business and industrial customers as well, there was a slight increase in the share of the average volume-weighted net network tariff in the total gas price.

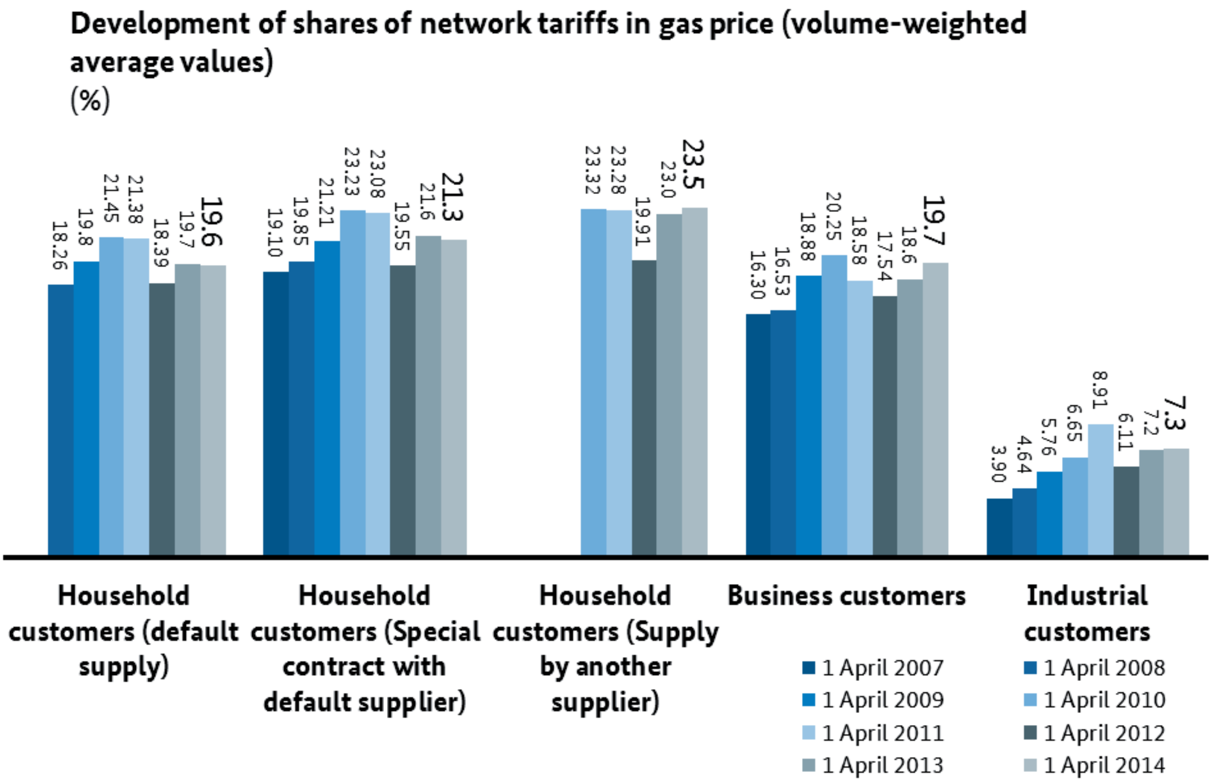

Figure 114: Development of the shares of network tariffs in the gas price

2.2 Expansion factor as per section 10 ARegV

A lasting change in supply services allowed DSOs to apply once again for an expansion factor for their investments in this area. This factor ensures that costs for these investments resulting from a lasting change in the operator's supply services during the regulatory period are taken into account when determining the revenue. A lasting change in supply services is deemed to have occurred if the parameters cited in section 10(2) sentence 2 of the Incentive Regulation Ordinance (ARegV) change on a permanent basis and to a significant extent. In 2013, a total of 30 applications for expansion factors were made.

2.3 Incentive regulation account as per section 5 ARegV

The difference between revenue allowed under section 4 ARegV and revenue potentially generated by operators in light of the development of actual consumption volumes is entered annually in an incentive regulation account. Section 28 para 2 ARegV requires operators to submit the data needed to keep the incentive regulation account to the regulatory authority in each instance by 30 June of the following calendar year. The regulatory authorities use the data to determine the differences to be entered in the incentive regulation account. In the final year of the regulatory period the balance of the account is established for the past calendar years in accordance with section 5(4) ARegV. The balance in the account is cleared by additions or deductions spread evenly over the following regulatory period; these carry interest as stated in section 5(2) sentence 3 ARegV.

2.4 Network interconnection points under section 26(2) ARegV

In 2013, a total of 19 applications concerning network transfer, merging and splitting in the gas sector were submitted under section 26(2) ARegV to the Bundesnetzagentur. The network operators state in their applications which percentage of the revenues is to be assigned to the part of the network being transferred and which percentage to the remaining part. The Bundesnetzagentur must ensure in particular that the total of both parts of the revenue does not exceed the revenue cap already set as a whole.

2.5 Revenue caps gas

On 1 January 2013, the second gas regulatory period began for gas distribution network operators and transmission system operators. The regulatory period lasts five years.

After in 2012 the base level for determining the revenue caps was established under section 6(1) ARegV, in 2013 the determination of revenue caps began for 104 companies in simplified proceedings, for 75 gas DSOs in standard proceedings and for 12 gas transmission system operators.

In this context, the Bundesnetzagentur reviewed and finalised the amounts to be added and deducted from the revenue caps for the second regulatory period to balance the gas incentive regulation account. The procedures in federal jurisdiction and in the official delegation of powers were completed in summer 2014.

2.6 Horizontal cost allocation

One result of the two-contract model is that, in contrast to the earlier contract path model, capacities within a market area are no longer booked by the shipper, and no tariffs are charged for this. Gas transmission system operators only conduct internal bookings of network interconnection points within a market area. TSOs thus perform a service for each other without receiving a service in return. Capacity bookings and gas transports at such network interconnection points within a market area are thus free of charge, despite the fact that the TSOs' networks incur necessary operating costs to varying amounts. This fact, however, has so far not been taken into account in the calculation of charges. Costs are not allocated at these network interconnection points, even though they come about there. According to the scheme of the two-contract model, the calculation of tariffs is also distorted at the "margins" of the market area, which puts out imprecise price signals. This can result in disincentives within the German capacity market.

During the course of the second regulatory period, the 9th Ruling Chamber recognised the danger of wrong price signals that is contained in the network tariffs, and in 2013 initiated a requirements proceeding in order to appropriately address the problem described. Within the framework of formal consultations, it became clear that some of the gas transmission system operators welcome the objective of the Ruling Chamber 9. Despite this positive sign, the requirements proceeding has currently been suspended, as there are similar efforts currently being pursued at EU level as well with the Framework Guideline Tariffs and the Network Code Tariff. The Bundesnetzagentur is actively supporting this EU development.

2.7 Determination of load flow commitments as volatile cost shares according to section 11(5) ARegV (KOLA)

On 20 December 2012, the Ruling Chamber issued a preliminary order on the determination of costs for load flow commitments (LFZ) as volatile cost shares according to section 11(5) ARegV. Based on this preliminary ruling, costs for load flow commitments since 1 January 2013 were recognised as volatile cost shares within the meaning of section 11(5) ARegV. Furthermore, as of 1 January 2013, transmission system operators who are subject to incentive regulation are obliged to take into consideration the “Specifications for the procurement of load flow commitments” that are laid out in the annex to the preliminary order when procuring load flow commitments.

At the moment, however, this is only a preliminary order that was necessary in the short term to ensure the required legal certainty for network operators and users. Questions regarding the relation of load flow commitments and balancing energy and an efficient procurement of load flow commitments were so far not addressed in the preliminary order.

Based on the preliminary order, the Ruling Chamber drafted the final determination, while affected economic stakeholders and consumers were given the opportunity to comment.

The comments submitted demonstrated that topics which had, in the context of hearings on the preliminary order, been fiercely debated were not of relevance in practice. In particular the ratio of load flow commitments to balancing energy and other incentives for an efficient procurement of load flow commitments do not require further regulations. As a result, it was possible to retain the majority of the provisions of the preliminary order within the framework of the final determination. The costs of load flow commitments continue to be recognised as volatile cost shares according to section 11(5) ARegV. When procuring load flow commitments, gas transmission system operators who are subject to the application of incentive regulation are obliged to take into consideration the “Specifications for the procurement of load flow commitments” that are laid out in the annex to the order. As of 15 May 2014, the Ruling Chamber adopted the final KOLA determination.

D Balancing

1. Development of system and portfolio balancing energy contribution

The market area managers are authorized to levy a system and portfolio balancing energy contribution if the forecasted costs for the next contribution period exceed forecasted revenues. The principle of revenue and cost neutrality applies.

The continuous development of the markets and the increasing liquidity of institutionalized exchanges contributed to the procurement of system balancing energy at market-based prices. This development was positively influenced by, amongst other things, the implementation of the market area managers' so-called "target model for system balancing energy". This prioritizes the procurement of system balancing energy by market area managers in the form of standardised short-term capacity products at virtual trading points.

The continuous optimisation of the procurement of system balancing energy has led to a further decrease in the system and portfolio balancing energy contribution during the period under review. During the contribution period from October 2013 to March 2014, contribution in both market areas were set at 0 ct/MWh.

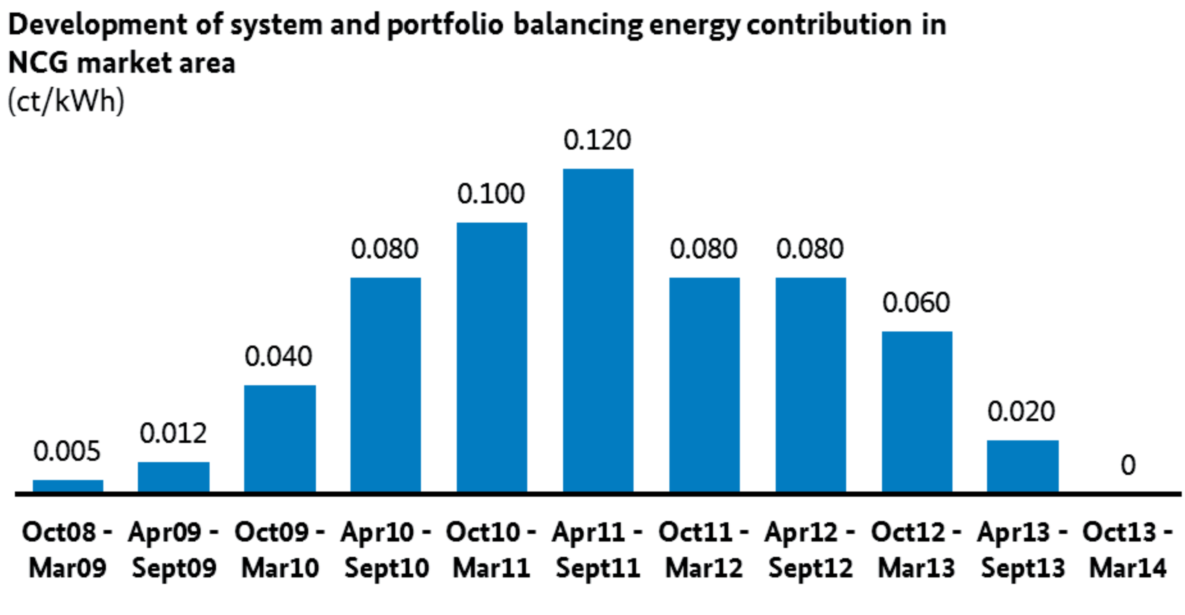

Figure 115: Development of system and portfolio balancing energy contribution in the NCG market area

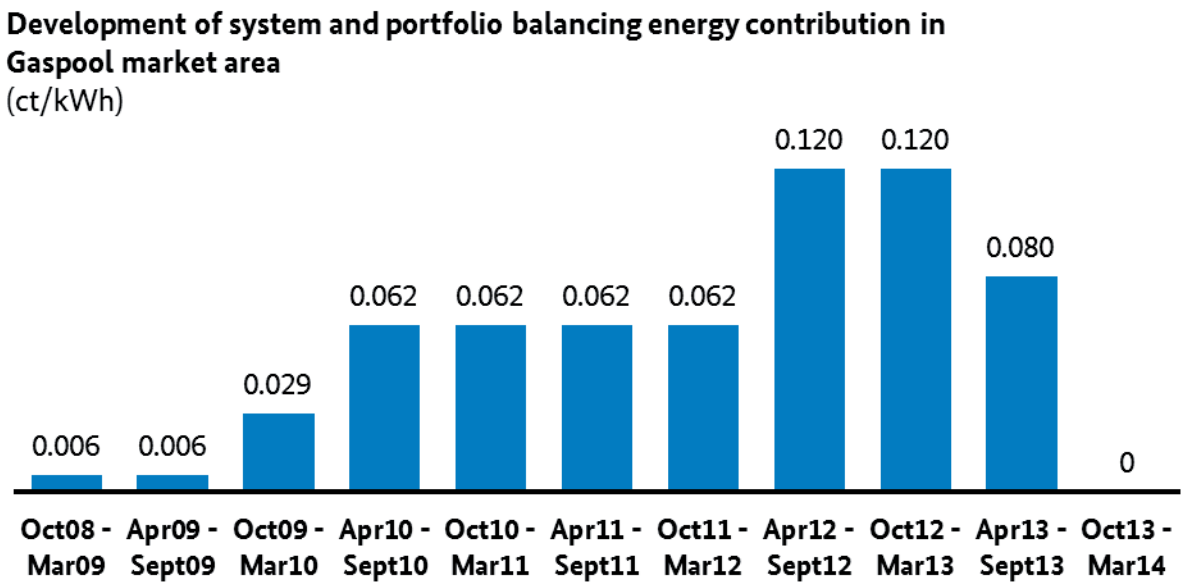

Figure 116: Development of system and portfolio balancing energy contribution in the Gaspool market area

The following section describes the groups of final consumers with interval metering (*registrierende Leistungsmessung - RLM*) and outlines which effect the contribution for system and portfolio balancing energy has for shippers on the decision to allocate a particular customer group.

2. Final consumer groups with interval metering and group switching

The GABi Gas balancing system categorises final consumers according to their offtake and reserve capacity and allocates them into different groups. These include, on the one hand, standard load profile (SLP) customers who are, for the most part, household and small business customers. On the other hand, there is the group of high-volume interval-metered industrial consumers, which in turn is divided into high-volume customers with and without a daily flat supply (RLMmT and RLMoT). The allocation of these high-volume customer groups is principally based on the respective reserve or offtake capacity, for which a threshold of 300 MW/h has been set. High-volume customers with a reserve capacity of more than 300 MWh/h are allocated to the consumer group RLMoT and vice versa, although the balancing group manager (Bilanzkreisverantwortlicher - BKV) can decide, at the request of the shipper, (Transportkunde - TK) to switch groups, provided that he does not see the risk of an unacceptable degradation of system stability and reject the request of a planned switch. In addition to the groups mentioned above, there are also interval-metered exit points with the possibility of a substitute nomination procedure, for example in the form of an online flow control.

In the survey on the gas year 2012/2013, 366 balancing group managers provided information about the groups to which their interval-metered customers were allocated. The information provided shows that the reduction of the system and portfolio balancing energy contribution in the NCG market area to 0.02 ct/kWh provided balancing group managers/shippers with a significant incentive to switch from the RLMoT to the RLMmT group. The advantage of the RLMmT group, in addition to the ex-post allocation of output volumes to a daily flat supply, lies in the higher hourly balancing group deviation tolerance of 15 per cent (compared to 2 per cent for RLMoT/interval metering without a daily flat supply). In the GASPOOL market area, there is no incentive for switching groups to interval metering with a daily flat supply, even though here the reduction of the contribution was just as high as in the NCG market area. At a contribution level of 0.08 ct/kWh, there is a marginal trend toward the RLMoT (interval metering without daily flat supply) group.

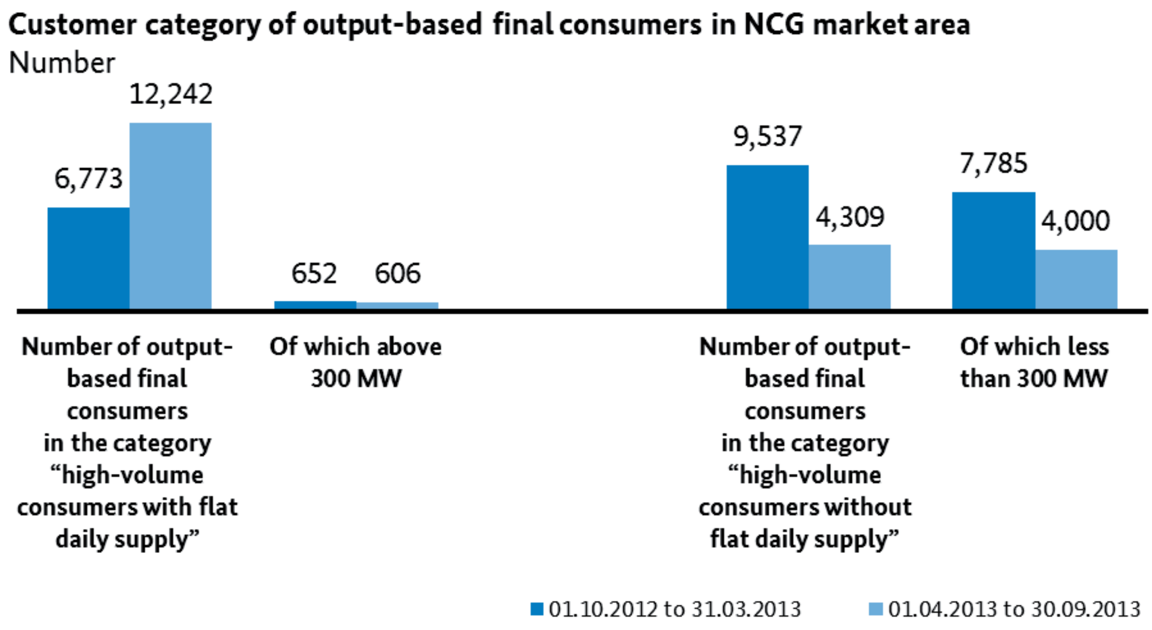

Figure 117: Customer group allocation of output-based final customers in the Gaspool market area

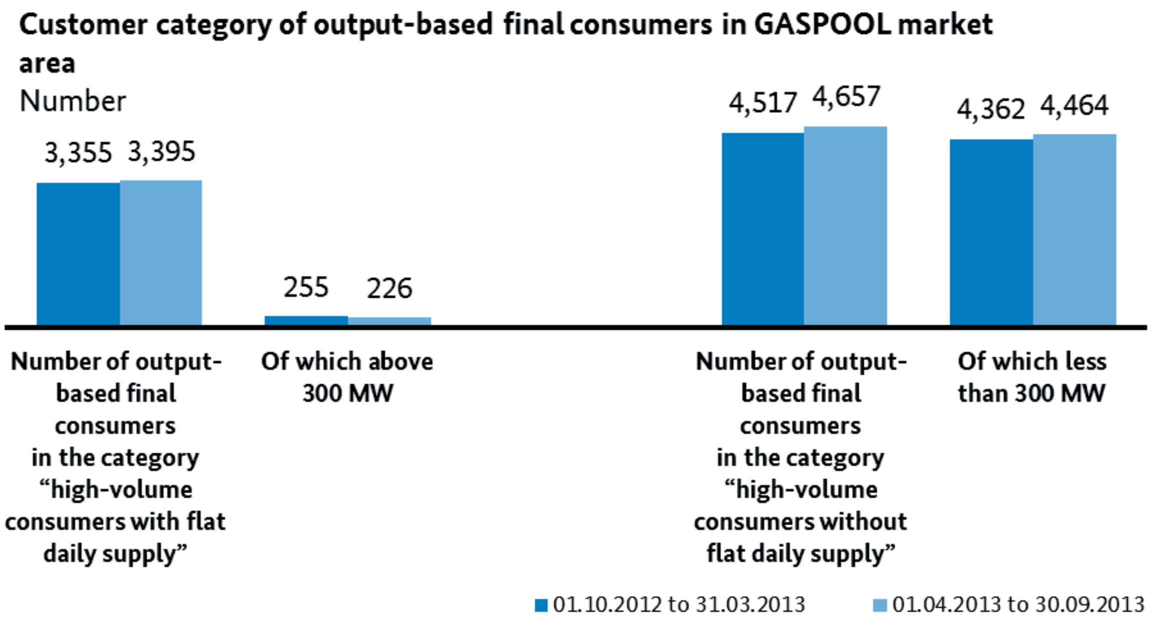

Figure 118: Customer group allocation of output-based final consumers in the Gaspool market area

The avoidance of the system and portfolio balancing energy contribution is evident from the diagram depicting the Gaspool market area. During the period under review, well over 90 per cent of final consumers in the group of interval-metered customers without a daily flat supply have a capacity lower than 300 MWh/h and are therefore not in the group corresponding to their capacity. The costs of the system and portfolio balancing energy contribution are hence borne by a smaller number of final customers.

In general, the balancing group manager or shipper can decide, independently of the reserve capacity, to switch groups, as long as the market area manager does not see an associated risk to the safe and efficient operation of the gas network. In this case, the market area manager is authorised to reject the request for a planned switch. In the gas year 2012/13, one out of a total of 8,984 notices was rejected on technical grounds. The number of requested switches is particularly high in the second half of the gas year, as the system and portfolio balancing energy contribution in the subsequent period was reduced to zero in both market areas.

E System balancing energy

1. Standard load profiles

Operators can use two types of standard load profile (SLP): analytical profiles, which in general terms are based on the previous day's consumption at the time of estimation, and synthetic profiles, which rely on statistically calculated values. In 2013, synthetic profiles were used by 87.8 per cent of operators; analytical profiles were used by 12.2 per cent, compared with 10.4 per cent in 2012.

The significance of standard load profiles is evident in the fact that nearly all exit operators (97.3 per cent) used them when delivering to household or small business customers. The synthetic profiles of the Technical University of Munich (TU München), used in the versions of 2002 and 2005, dominate with a market coverage of 94.4 per cent. This figure remains virtually unchanged compared with 2012 (95.2 per cent).

The TU München offers a range of different profiles which reflect the offtake behaviour of various customer groups. 48 per cent of the operators stated that all available profiles were applied, compared with 50.7 per cent in 2012. The responses to the follow-up question as to how many profiles were actually used indicated that two profiles were generally used for household customers, as in the previous year, while an average of seven profiles was used for business customers, again the same as in 2012.

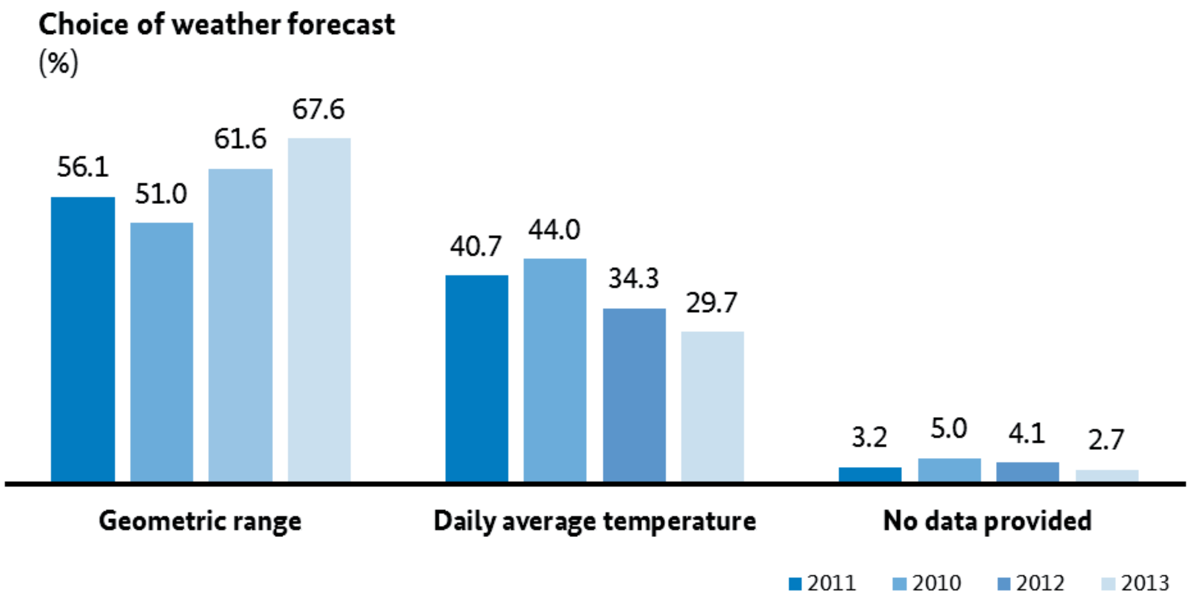

Figure 119: Choice of weather forecast

Standard load profiles, as forecasts, are naturally marked by inaccuracies. The average deviation between allocation and actual offtake on a daily basis was 4.6 per cent, lower than in 2012 (5.1 per cent). The average maximum deviation on one day was 56.4 per cent, higher than in the previous year (45.7 per cent). These maximum fluctuations occur in isolated cases only, but are cause for concern as they can each result in increased system balancing energy. It is must be borne in mind, however, that these figures may not be representative as only 62.1 per cent of the operators provided any relevant data, compared to 57.9 per cent in the previous year, and it could be assumed that operators with a comparatively high forecast quality tended to respond.

22.6 per cent of operators made fixed adjustments to the load profiles owing to the deviations; this represents another increase compared to the previous year (18.1 per cent).

2. Billing for higher and lower volumes

Various procedures are available to the operators for billing SLP customers for higher or lower volumes. A trend towards fixed-date procedures has already been observed in recent years, as can be seen in Figure 120.

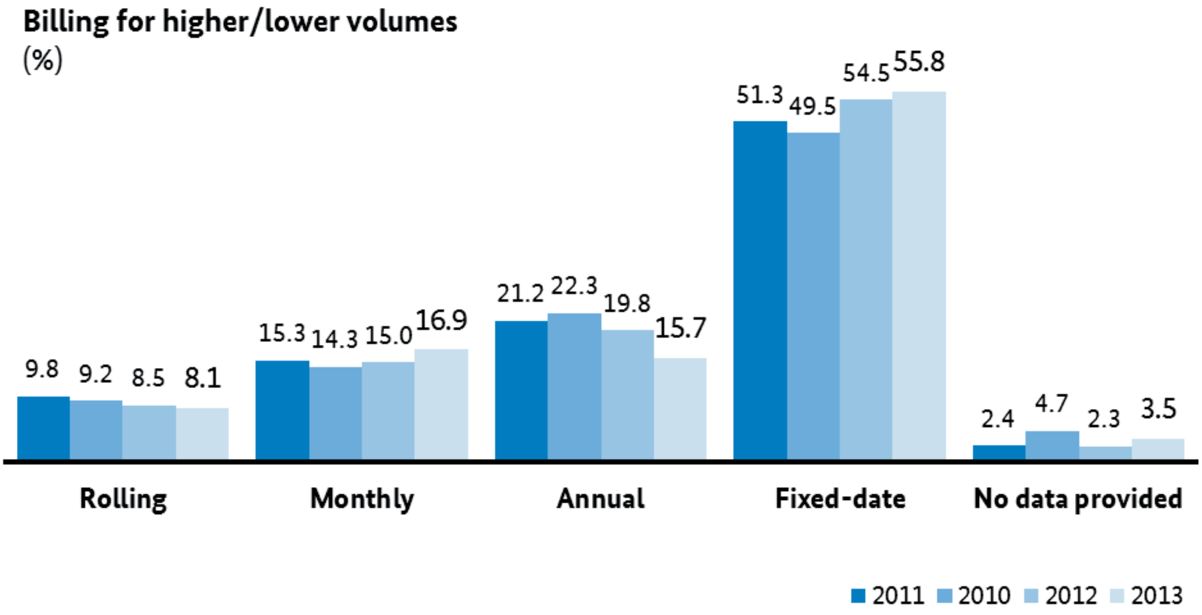

Figure 120: Billing for higher/lower volumes

F The wholesale market

Liquid wholesale markets are vital to ensure well-functioning markets along the entire added-value chain in the natural gas sector, from the procurement of natural gas through to supplying end customers. The more varied the possibilities for the short- and long-term procurement of gas at wholesale level are, the less companies depend on tying themselves to a single supplier in the long term. The options open to market players to select from a large number of trading partners and to hold a diversified portfolio of short- and long-term trading contracts are expanded. Liquid wholesale markets hence make it easier to enter the market, and promote competition for end customers.

The liquidity of the natural gas wholesale markets increased once more in 2013. Major increases can be observed, both at exchange and at bilateral wholesale level. The liquidity of the natural gas wholesale markets nonetheless continues to lag far behind the electricity wholesale markets.

Viewed as a whole, wholesale prices for natural gas are within the range of the previous year's levels. Whilst average gas import prices (BAFA cross-border prices) fell from roughly 29 Euro/MWh to 27.5 Euro/MWh year-on-year, an average price increase from roughly 25 Euro/MWh to 27 Euro/MWh was observed on EEX' spot market. It can be presumed that the significance of oil prices for pricing continued to decrease in the period under report.

1. On-exchange wholesale trading

The exchange that is relevant for German natural gas trading is operated by the European Energy Exchange AG (EEX) and its subsidiary European Gas Exchange GmbH (EGEX). EEX and its subsidiaries have once more taken part in this year's data collection within monitoring. The trading place of EEX includes short- and long-term trading transactions (spot market and futures market). All types of contract are equally tradable in both of the German market areas – NetConnect Germany (NCG) and Gaspool.

Natural gas trading for the current gas supply day is possible on the spot market with a lead time of three hours (within-day contract/intraday product), for one or two days in advance (day contract) and for the following weekend (weekend contract), that is continuously ("24/7 trading"). The minimum contract size is one MW, so that smaller volumes of natural gas can also be procured or sold at short notice. An innovation in the year under report is the introduction of quality-specific contracts (high calorific gas or low calorific gas) as per October 2013.

The futures market serves to ensure the long-term procurement of gas, as well as to optimise portfolios, and to hedge against price and volume risks. Futures are tradable on EEX for specific months, quarters, seasons (summer/winter) and years.

A major new development in the period under report 2013 is the establishment and launching of "PEGAS" on 29 May 2013. PEGAS is a cooperation between EEX and the French Powernext SA. This cooperation has in particular made it easier for participants to also gain access to the respective other exchange. It aims to enhance on-exchange gas trading and to increase liquidity on the markets concerned.

The entire trading volume related to the German market areas on EEX was roughly 90 TWh in 2013, which corresponds to an increase of roughly 24 TWh, or 36 percent, in comparison to the previous year's value of 66 TWh. A heterogeneous picture however emerges if one takes a look at the individual contract types.

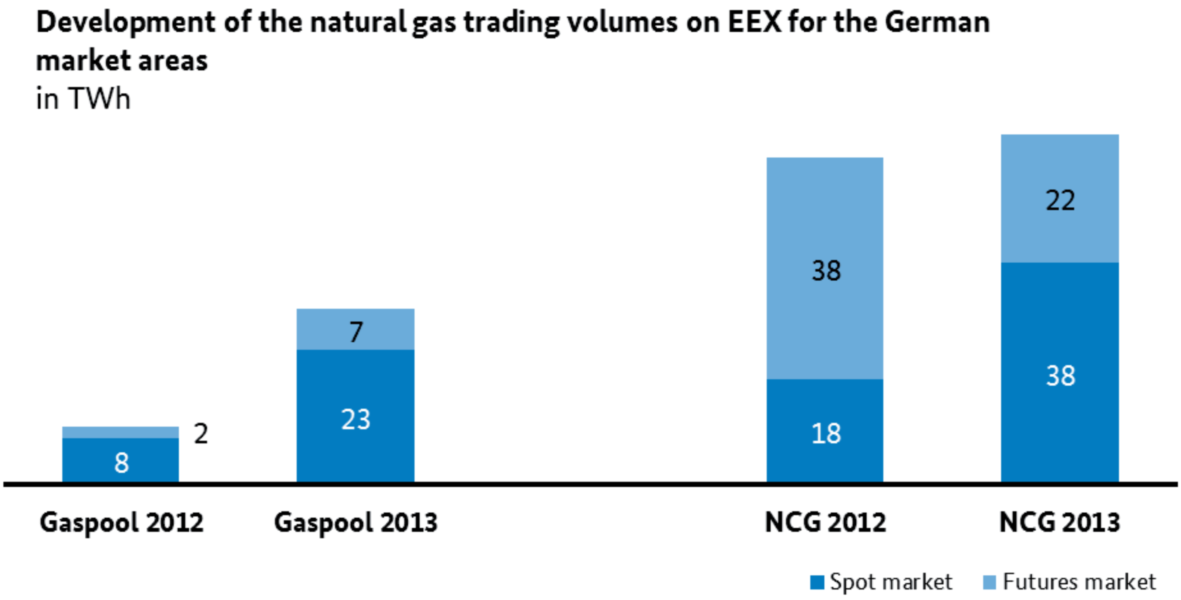

Figure 121: Development of the natural gas trading volumes on EEX for the German market areas

The spot market shows a highly-positive tendency. The volumes traded on the spot market have more than doubled in both market areas, and were roughly 61 TWh in 2013. As in the previous year, the focus with both market areas was on day contracts (NCG: 19.1 TWh; Gaspool: 15.7 TWh). A total increase of roughly 130 percent can be observed with regard to these contracts.

By contrast, the – already limited – volume of futures traded on EXX fell in 2013. The trading volume fell from 40 TWh to 29 TWh, corresponding to a reduction by approx. 27 percent. Whilst the trading volumes for the Gaspool market area increased by approx. 5 TWh, the volume for the NCG market area fell by 16 TWh.

The focus of on-exchange trading in the spot area is also reflected in the number of active participants per trading day[96]. The number of active participants for NCG contracts per trading day on the spot market averaged over the year was roughly 40, and was approximately 33 for Gaspool contracts. By contrast, the number of active participants per trading day for both market areas on the futures market was between 3 and 4. It should be taken into account when comparing these numbers that, by virtue of its term, a futures contract aims to achieve a higher volume than a spot contract does.

2. Bilateral wholesale trading

By far the largest share of wholesale trading in natural gas is transacted bilaterally, that is outside the exchanges ("over-the-counter" – OTC). Bilateral trading offers the advantage that it can be carried out at short

[96] A participant is considered to be active on a trading day if at least one of its bids has been implemented.

notice and flexibly, i.e. in particular without having to have recourse to a limited set of contracts. A significant role is played in OTC trading by brokerage via broker platforms.

Broker platforms

Brokers act as intermediaries between buyers and sellers, and combine information on the demand and supply of short- and long-term natural gas trading products. Taking up the services of a broker can reduce the search costs and make it easier to effect larger transactions. At the same time, as a matter of principle it makes a broader risk spread possible. Finally, brokers offer as a service to have the trading transaction which they have brokered registered for clearing on the exchange, so that the parties' trading risk is hedged[97]. The bringing together of interested parties on the supply and demand sides is formalised on electronic broker platforms, and the chance is increased that two parties will come together.

A total of eleven broker platforms took part in this year's data collection on wholesale trading. Seven of these platforms brokered natural gas trading transactions in 2013 with the supply area Germany (NCG or Gaspool).

The natural gas trading transactions brokered by these seven broker platforms in 2013 with the supply area Germany account for a total volume of 2,576 TWh, 1,519 TWh of which were accounted for by contracts with fulfilment in 2013. In comparison to the values that were collected in the previous year – with a total of four broker platforms –, this corresponds to an increase of roughly 80 and 60 percent, respectively.

Short-term transactions with a fulfilment period of less than one week account for roughly 18 percent of the trading brokered by these broker platforms. The transactions for the ongoing year unambiguously form the focus of natural gas trading, followed by the activities for the following year. Whilst the natural gas traded in and for 2013 (including spot trading) constituted as much as 59 percent of the total volume, and as much as 30.5 percent are traded for the following year (2014), transactions with delivery dates in 2015 and later account for a share of 10.5 percent. This structure roughly corresponds to the previous year's result.

[97] OTC clearing on EEX in natural gas only has very slight practical significance so far. In 2013, OTC clearing included a volume of 0.34 TWh of natural gas contracts.

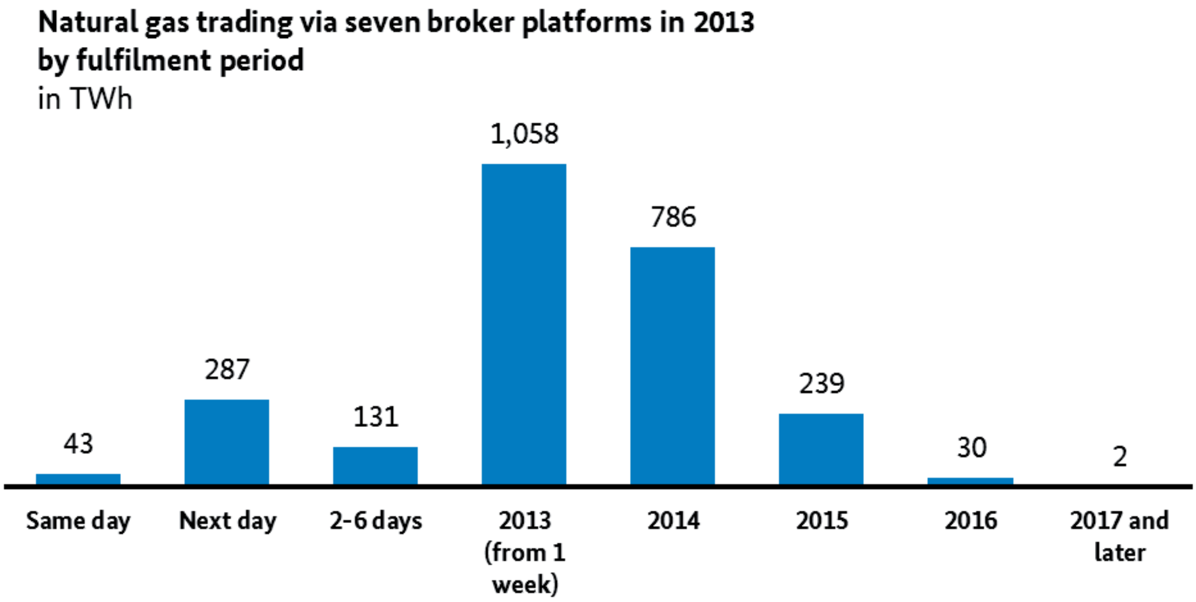

Figure 122: Natural gas trading via seven broker platforms in 2013 by fulfilment period

The increase in volume is confirmed by the figures published by the London Energy Brokers' Association (LEBA) on brokered natural gas trading for the market areas NCG and Gaspool[98]. Four of the seven broker platforms are members of the LEBA, the information provided by which forms the basis for the above evaluation. Also according to the figures published by the LEBA, a considerable increase can be observed for 2013, as in the previous years. A total of 2,213 TWh is accounted for on the corresponding broker platforms in 2013 for both German market areas. This corresponds to an increase of 44 percent vis-à-vis the previous year's volume of 1,538 TWh.

[98] cf. http://www.leba.org.uk/pages/index.cfm?page_id=59&title=leba_data_notifications

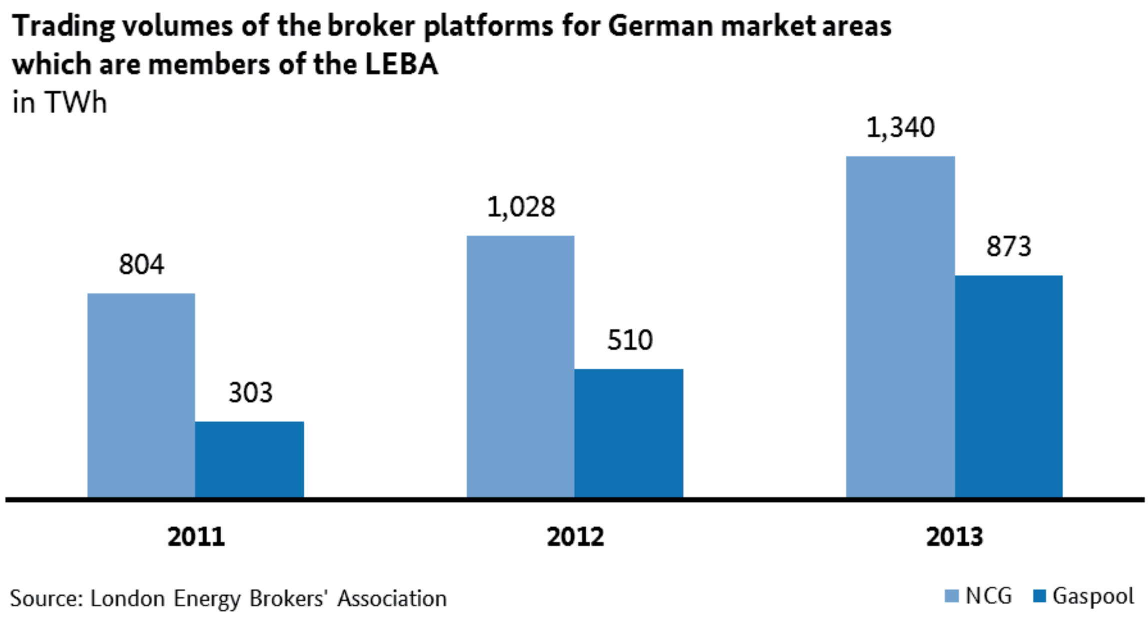

Figure 123: Development in trading volumes of the broker platforms for German market areas which are members of the LEBA between 2011 and 2013

Nomination volumes at the Virtual Trading Points

Significant indicators of the liquidity of the wholesale natural gas markets are also the nomination volumes on the two German Virtual Trading Points NetConnect Germany GmbH & Co. KG (NCG) and GASPOOL Balancing Services GmbH (Gaspool). Via the Virtual Trading Points (VP), parties responsible for balance groups can transfer gas volumes between balance groups via nominations. Wholesale transactions with physical fulfilment are reflected in corresponding balance group transfers as a rule, so that an increase in wholesale transactions leads to a corresponding increase in the nomination volumes[99].

A significant increase in the nomination volumes has been observed at the Virtual Trading Points since the consolidation of the German market areas. This trend from the previous years also continued in the year under report.

The two parties responsible for market areas, namely NCG and Gaspool, once more participated in this year's data survey on gas wholesale trading. The gas volumes nominated on the VPs of both market areas increased once more in 2013. The increase from a total of 2,459 TWh to 2,948 TWh corresponds to growth of roughly 20 percent. The Gaspool VP accounts for roughly 43 percent of the nomination volume in 2013, and the NCG VP accounts for 57 percent. Almost 90 percent of the nomination volume is accounted for by high calorific gas.

An increase in the nominated volume was observed year-on-year with each of the two gas qualities (high calorific gas and low calorific gas), both on NCG's VP and on Gaspool's VP. The nomination volume increased

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[99] Conversely, however, not all nomination volumes are necessarily tied to a transaction on the wholesale markets since nominations can also be in-group balance group transfer trading.

by 15 percent at NCG and by 28 percent at Gaspool. The total nominated high calorific gas volume increased by roughly 18 percent, and that of nominated low calorific gas volume by 37 percent.

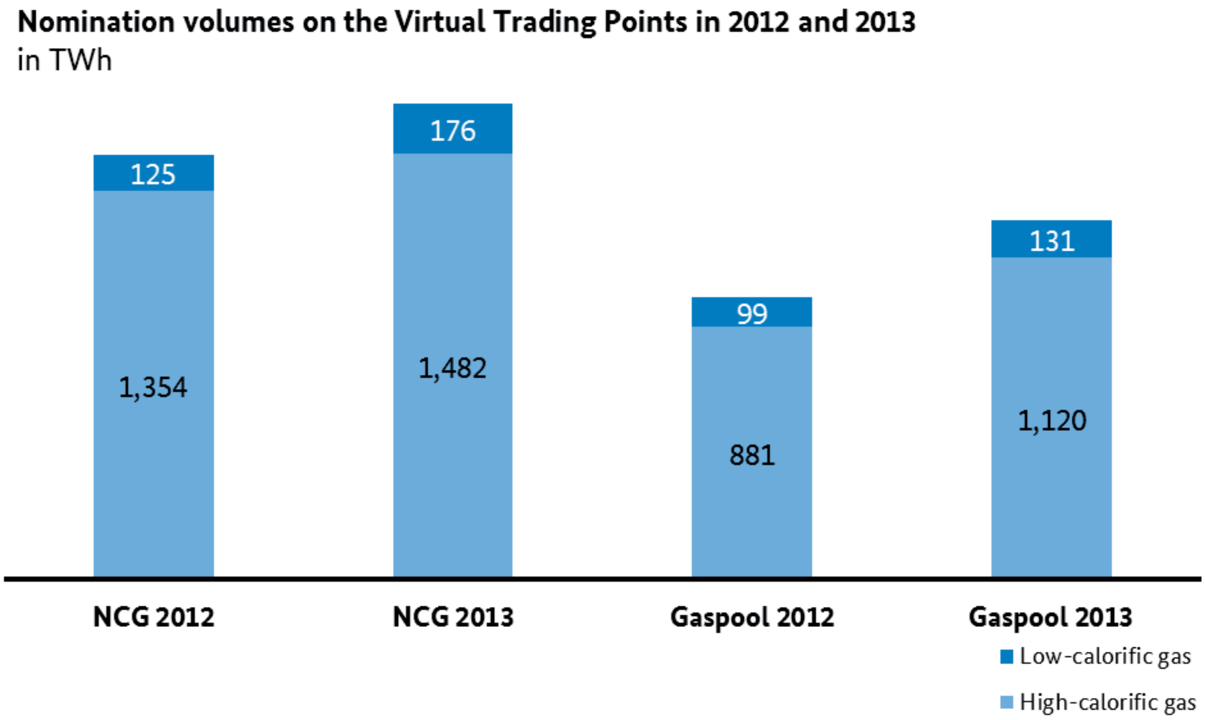

Figure 124: Nomination volumes on the VPs in 2012 and 2013

As in the previous years, seasonal differences are shown in the monthly nomination volumes. In the months May to August 2013, the (added) monthly nomination volume of both VPs was a maximum of 200 TWh, and was more than 270 TWh in the winter months in each case. The peak value for the year was reached in March 2013, at roughly 322 TWh. With the exception of December, the nomination volume increased in each case as against the same month of the previous year. The greatest increase was accounted for by March, when there was an increase of a good 45 percent.

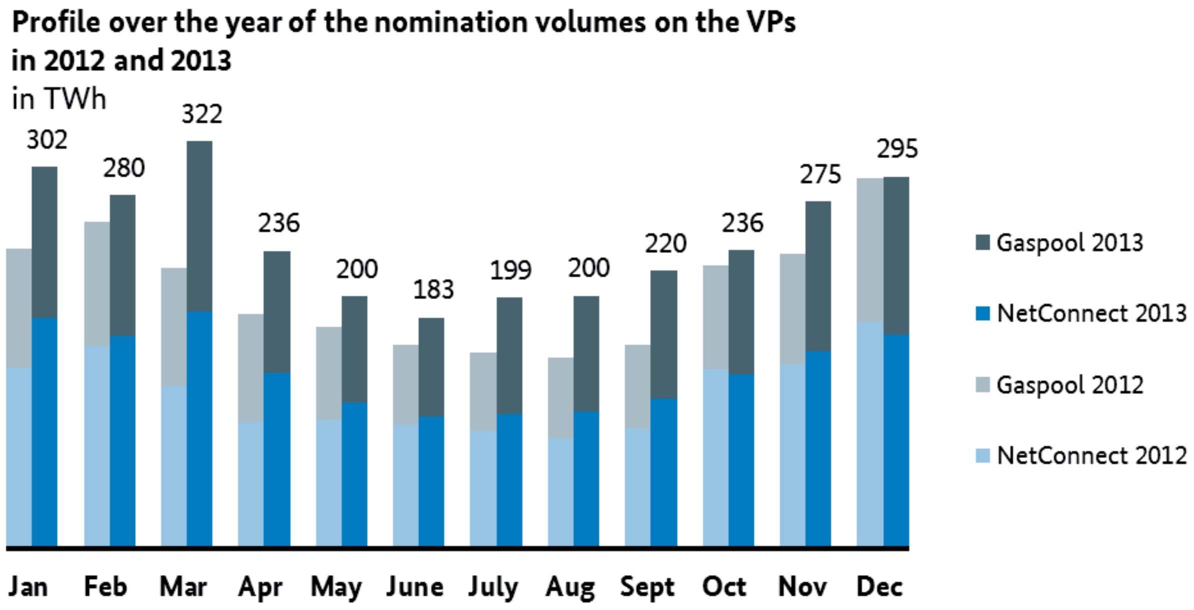

Figure 125: Profile over the year of the nomination volumes on the VPs in 2012 and 2013

The number of active trading participants, that is of companies which carried out at least one nomination in the respective month, increased once more in both market areas in 2013. The number of active participants for high calorific gas in the Gaspool market area, averaged over the year, increased year-on-year from 277 to 311 (and thus by 12 percent) and for low calorific gas from 120 to 149 (by 24 percent). The number of active trading participants for high calorific gas in the NCG market area increased from 257 to 291 (by 13 percent) and for low calorific gas from 117 to 145 (by 24 percent).

3. Wholesale prices

On the on-exchange spot market, EEX calculates daily reference prices for the Gaspool and NCG market areas by depicting the volume-weighted average of the prices over all trading transactions for gas supply days on the last trading day prior to physical fulfilment[100]. The daily reference prices are published by EEX at 10:00 a.m. CET on the respective supply day. They are an indicator of the price level of the spot market trading transactions.

The daily reference price averaged 27.16 Euro/MWh for both market areas in 2013. In the previous year, these values were 25.19 Euro/MWh (NCG) and 25.11 Euro/MWh (Gaspool), respectively. Over 2013, the daily reference prices fluctuated between 25.14 Euro/MWh and 39.51 Euro/MWh. The maximum values of close to 40 Euro/MWh occurred in connection with a cold period at the end of March 2013.

[100] For details of the calculation method see www.bafa.de/bafa/de/energie/erdgas/publikationen/energie_erdgas_ermittlung_preis.pdf (retrieved on 18 August 2014).

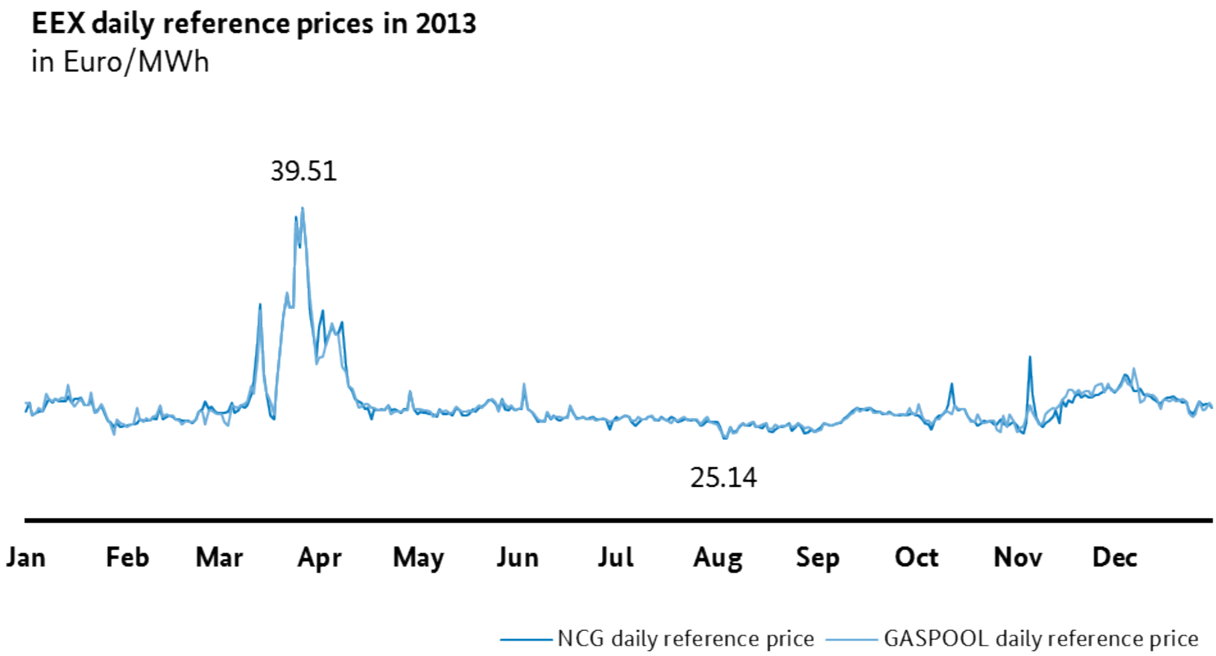

Figure 126: EEX daily reference prices in 2013

The price level on the on-exchange spot market shows the average costs of the short-term procurement of natural gas. The price of natural gas procurement on the basis of long-term supply contracts, by contrast, can be read approximately by the cross-border price for natural gas. The cross-border price is calculated for each month by the Federal Office for Economic Affairs and Export Control (BAFA). In order to do this, the BAFA evaluates available documents on natural gas received from Russian, Dutch, Norwegian, Danish and UK mining areas[101].

Primarily the import volumes agreed in import contracts are shown here. Older import contracts were as a rule based on a price agreement which is linked to the oil price. This has been the case less and less frequently in recent years in new contracts and within contract adjustments[102]. Price indices such as the daily reference price of EEX make it possible to index long-term contracts to spot market prices. It can therefore be presumed that the cross-border price calculated by the BAFA is also gradually becoming decoupled from the price of oil.

The monthly cross-border prices for natural gas ranged between 23.71 Euro/MWh and 29.84 Euro/MWh from 2011 to 2013. The average monthly cross-border price for 2013 was 27.56 Euro/MWh, whilst this value had been as high as 29.00 Euro/MWh in 2012. A considerable difference was indicated in 2012 between the cross-border price and the average daily reference price (roughly 29 vs. 25 Euro/MWh). By contrast, the two indices were at roughly the same level in 2013.

The European Gas Index Germany (EGIX), published by EEX, also provides a monthly reference price for the futures market. It is based on the trading transactions on the on-exchange futures market which are

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[101] See for details www.bafa.de/bafa/de/energie/erdgas/publikationen/energie_erdgas_ermittlung_preis.pdf; retrieved on 19 August 2014.

[102] cf. e.g. RWE AG, *Geschäftsbericht 2013*, p. 93; E.ON SE, *Geschäftsbericht 2012*, p. 15.

concluded in the respectively current front monthly contracts of the NCG and Gaspool market areas[103]. In 2013, EGIX Germany was between 25.93 Euro/MWh (September) and 27.70 Euro/MWh (December). The twelve monthly values averaged 26.76 Euro/MWh.

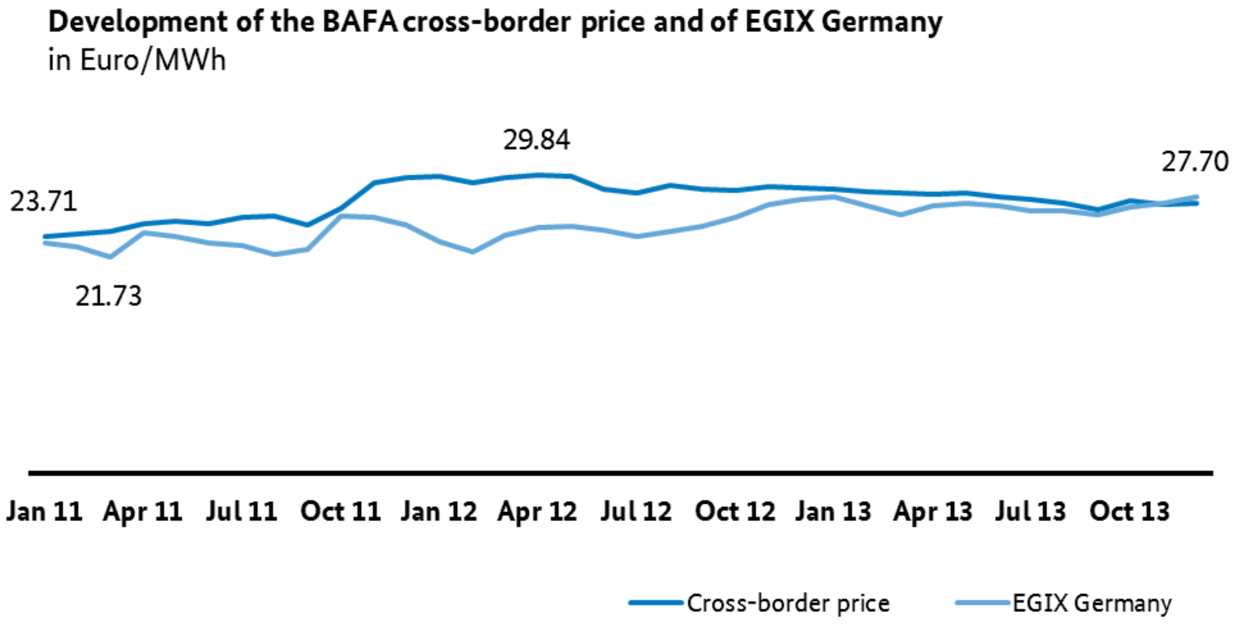

Figure 127: Development of the BAFA cross-border price and of EGIX Germany in the period 2011 to 2013

[103] On the calculation of the values in detail www.eex.com/blob/68596/836d03126059d5115fb61134fe8f9993/2014-02-06---beschreibung-egix-pdf-data.pdf (retrieved on 19 August 2014).

G Retail

1. Market coverage

The high level of market coverage reached in the previous year could be maintained in 2014 across all the market areas. The following information provides a brief overview of the market coverage, while certain sections include statements that go beyond the database used.

Transmission system operators

All 17 transmission system operators (TSOs) took part in the 2014 data survey, producing a market coverage in this area of 100 per cent.

Distribution system operators

The number of participating distribution system operators (DSOs) remained at the same high level as in the 2013 survey, when taking concentrations between undertakings and new companies into account. A total of 663 companies submitted data (compared to 674 in 2013), representing a market coverage in this area of over 95 per cent.

Wholesalers and suppliers

There was a particular increase in the number of wholesalers and suppliers providing data for the 2014 survey. 825 wholesalers and suppliers submitted data (compared to 792 in 2013), also representing a market coverage in this area of over 95 per cent.

Importers and exporters

39 importers and exporters submitted data for the 2014 survey (compared to 38 in 2013), corresponding to a market coverage of almost 100 per cent.

Storage facility operators

24 storage facility operators provided data for the 2014 survey (compared to 28 in 2013), producing a market coverage of 100 per cent, similar to the previous year's high level.

2. Delivery and output volumes

2.1 Delivery volumes of gas suppliers

The volume of gas delivered by the gas suppliers taking part in the survey to final consumers (including gas-fired power plants) in 2013 amounted to 867.6 TWh, 6.4 per cent more than in 2012. The volume of gas delivered to private households amounted to 245.5 TWh, 7.3 per cent more than in the previous year. The volume of gas delivered to gas-fired power plants fell by 14 per cent within twelve months from 94.5 TWh in 2012 to 81.2 TWh in 2013.

Based on the total volume of gas delivered in Germany in 2013 of 956 TWh as calculated by the Working Group on Energy Balances (AGEB), the market coverage for wholesalers and suppliers in the survey was some 91 per cent[104]. As of 31 December 2013, the suppliers in Germany delivered gas to approximately 13.5m final consumers, including nearly 11.2m household customers as defined by section 3 para 22 of the Energy Act (EnWG).

The following table shows the volumes delivered by suppliers to each consumer category in 2012 and 2013, according to the data provided in the survey[105].

Volume of gas delivered to final consumers in 2012 and 2013, broken down by category of consumer

<table>
<tr><th rowspan="2">Category</th><th colspan="2">2012</th><th colspan="2">2013</th></tr>
<tr><th>Volumes delivered (TWh)</th><th>Share of total (%)</th><th>Volumes delivered (TWh)</th><th>Share of total (%)</th></tr>
<tr><td>≤ 300 MWh/year</td><td>303.54</td><td>37.23</td><td>334.35</td><td>39.92</td></tr>
<tr><td>> 300 MWh/year
≤ 10,000 MWh/year</td><td rowspan="2">200.57</td><td rowspan="2">24.6</td><td>115.79</td><td>13.83</td></tr>
<tr><td>> 10,000 MWh/year
≤ 100,000 MWh/year</td><td>79.32</td><td>9.47</td></tr>
<tr><td>> 100,000 MWh/year</td><td>216.76</td><td>26.58</td><td>226.82</td><td>27.08</td></tr>
<tr><td>Gas power plants</td><td>94.52</td><td>11.59</td><td>81.22</td><td>9.7</td></tr>
<tr><td>Total</td><td>815.39</td><td>100</td><td>867.63</td><td>100</td></tr>
</table>

Table 51: Volume of gas delivered to final consumers in 2012 and 2013 according to the survey of gas wholesalers and suppliers, broken down by category of consumer

Here, the Bundeskartellamt differentiates between two types of final consumer: standard load profile (SLP) customers and interval-metered customers. The companies participating in the survey supplied a total of

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104 See AGEB's annual report for 2013.

105 The total sum of the individual categories only amounts to 837.5 TWh because some of the data provided by the companies was incomplete. Data for 2012 is only available for the joint category ">300 MWh/year ≤100,000 MWh/year".

approximately 13.6m SLP customers and over 40,000 interval-metered customers[106]. The total volume of gas delivered to SLP customers was around 387 TWh and to interval-metered customers some 481 TWh.

2.2 Output volumes of gas network operators

Gas network operators in Germany reported an output volume of 928.59 TWh in 2013. The volume of gas delivered to private households was 282.96 TWh. The gas network operators recorded a total of 13.98m metering points as of 31 December 2013, including around 12.45m metering points for household customers as defined by section 3 para 22 EnWG.

Gas output volumes in 2012 and 2013 broken down by final consumer category, according to survey of gas TSOs and DSOs

<table>
<tr><th rowspan="2">Category</th><th colspan="2">2012</th><th colspan="2">2013</th></tr>
<tr><th>Volumes delivered by TSOs and DSOs (TWh)</th><th>Share of total (%)</th><th>Volumes delivered by TSOs and DSOs (TWh)</th><th>Share of total (%)</th></tr>
<tr><td>≤ 300 MWh/year</td><td>308.08</td><td>33.8</td><td>343.73</td><td>37.0</td></tr>
<tr><td>> 300 MWh/year
≤ 10,000 MWh/year</td><td rowspan="2">198.04</td><td rowspan="2">21.7</td><td>130.92</td><td>14.1</td></tr>
<tr><td>> 10,000 MWh/year
≤ 100,000 MWh/year</td><td>97.51</td><td>10.5</td></tr>
<tr><td>> 100,000 MWh/year</td><td>274.98</td><td>30.1</td><td>268.29</td><td>28.9</td></tr>
<tr><td>Gas power plants</td><td>131.33</td><td>14.4</td><td>88.14</td><td>9.5</td></tr>
<tr><td>Total</td><td>912.43</td><td>100</td><td>928.59</td><td>100</td></tr>
</table>

Table 52: Gas output volumes in 2012 and 2013 broken down by final consumer category, according to the survey of gas TSOs and DSOs[107]

[106] One metering point does not necessarily account for one customer. Multi-metering is to be expected especially with interval-metered customers (industrial customers and high-consumption business customers). The number of metering points therefore only offers a guide to the actual number of customers.

[107] Data for 2012 is only available for the joint category ">300 MWh/year ≤100,000 MWh/year".

Number of gas metering points in 2013 broken down by final consumer category, according to survey of gas TSOs and DSOs

Category	Number of metering points served by DSOs	Number of metering points served by TSOs	Total
≤ 300 MWh/year	13,820,154	60	13,820,214
> 300 MWh/year ≤ 10,000 MWh/year	153,497	148	153,645
> 10,000 MWh/year ≤ 100,000 MWh/year	3,638	175	3,813
> 100,000 MWh/year	471	154	625
Gas power plants	984	56	1,040
Total	13,978,744	593	13,979,337

Table 53: Number of gas metering points in 2013 broken down by final consumer category, according to the survey of gas TSOs and DSOs

3. Default supply

In the 2014 survey, the gas suppliers were asked to provide data on the volumes of gas delivered to final consumers within and outside of default supply. The following table shows the share accounted for by default supply of the total volume of gas delivered to each customer category. The volume of gas supplied to household customers as defined by section 3 para 22 EnWG in 2013 amounted to 245.5 TWh, including 65.1 TWh under default supply.

The share accounted for by default supply of the total volume supplied to household customers thus decreased slightly from 26.9 per cent to 26.5 per cent. The volume of gas supplied to "other final consumers", which comprises all final consumers other than household customers (business and industrial customers) amounted to 574.1 TWh, including 11.6 TWh or 2 per cent under default supply.

Overall, default supply accounted for 76.7 TWh or 9.4 per cent of the total output volume reported of 819.6 TWh[108], which is more or less the same as in previous years.

7.9 per cent of the total volume of gas delivered to all final consumers was supplied to household customers under default supply. 1.4 per cent of the volume delivered to final consumers was supplied under default supply to final consumers other than household customers as defined by section 3 para 22 EnWG. The

[108] The total volume of 819.6 TWh differs from the total delivery volume of 867.6 TWh given above because some gas suppliers did not fully answer the question on default supply.

remaining 90.6 per cent of the volume delivered to final consumers was supplied outside of default supply contracts.

Volumes delivered by default suppliers to final consumers broken down by customer category

Category	Year under review	Total volume delivered (TWh)	Default supply volume (TWh)	Share of volume delivered per category (%)
Household custome	2007	199.6	72.3	36.2
	2008	236.0	69.6	29.5
	2009	228.0	61.2	26.9
	2010	273.9	68.3	24.9
	2011	211.0	58.7	27.8
	2012	228.7	61.6	26.9
	2013	245.5	65.1	26.5
Other final consumers	2007	638.4	20.9	3.3
	2008	669.1	17.5	2.6
	2009	615.7	16.4	2.7
	2010	602.7	13.9	2.3
	2011	549.2	12.8	2.3
	2012	566.1	12.7	2.2
	2013	574.1	11.6	2.0
Total	2007	838.0	93.2	11.1
	2008	905.2	87.1	9.6
	2009	843.7	77.6	9.2
	2010	876.6	82.1	9.4
	2011	760.2	71.5	9.4
	2012	794.8	74.2	9.3
	2013	819.6	76.7	9.4

Table 54: Volumes delivered by default suppliers to final consumers from 2007 to 2013 broken down by customer category

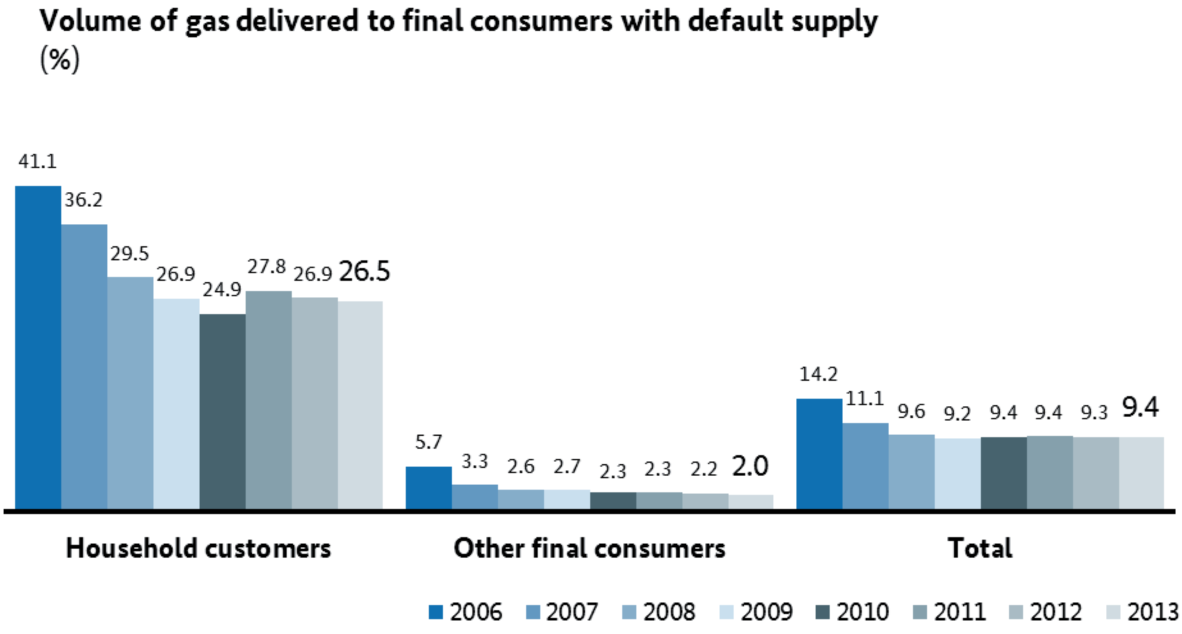

Figure 128: Volumes of gas delivered under default supply to final consumers from 2006 to 2013 according to the survey of gas wholesalers and suppliers

Some 19.9 per cent of the total volume of 387 TWh of natural gas delivered to SLP customers was provided under default supply, representing a slight decrease compared to the previous year's figure (approx. 20.9 per cent).

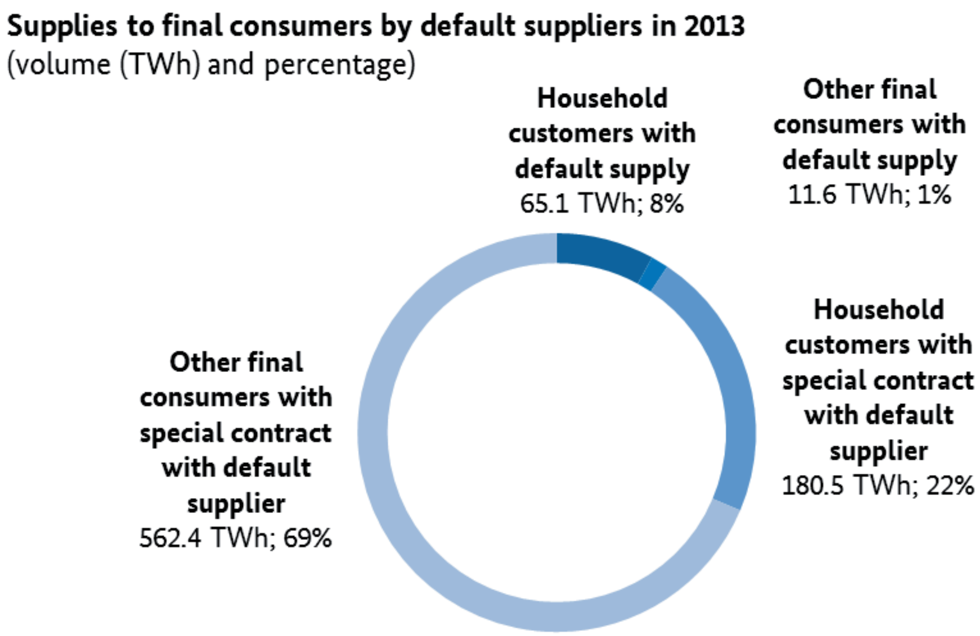

Figure 129: Supplies to final consumers by default suppliers in 2013 according to the survey of gas wholesalers and suppliers

The following diagram shows the number of household customers and other final consumers served with and without default supply. Around 4.1m household customers (metering points), or 30.1 per cent of all final consumers, are served under default supply. Some 7.2m household customers, or 53.1 per cent of all final consumers, are served outside of default supply.

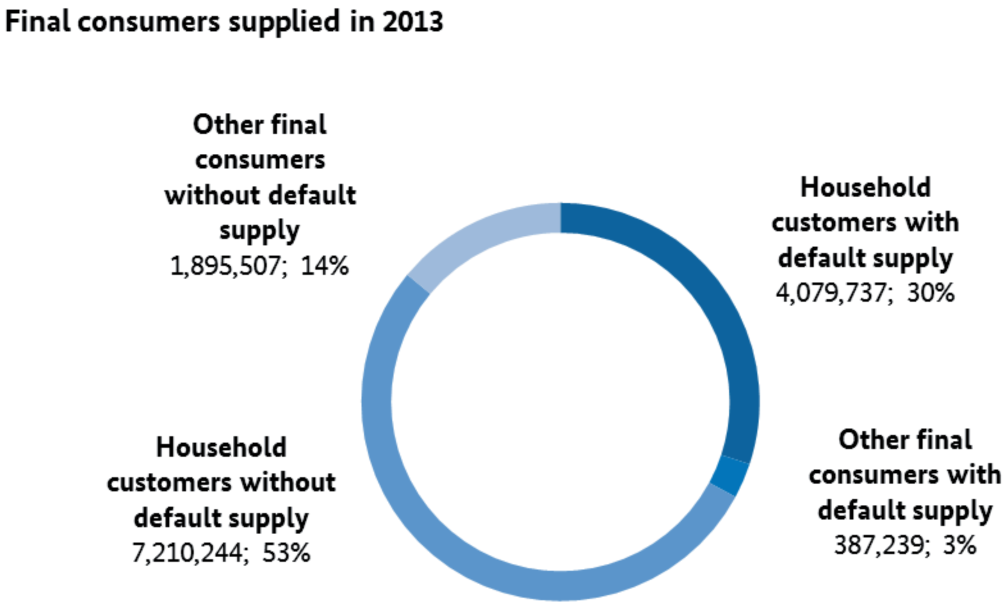

Figure 130: Number of final consumers served within and outside of default supply in 2013

4. Supplier structure and number of providers

772 sets of data were provided for the following evaluation of the structure of the gas supplier sector. The figure below shows that in absolute terms most suppliers serve only a small number of metering points. For the purposes of evaluating the data, the information provided by the suppliers was considered as reports from individual legal entities without taking into account possible company affiliations or links.

68 per cent of all 527 gas suppliers serve a maximum of 10,000 metering points. These gas suppliers serve a total of some 1.9m metering points, which is 14 per cent of all reported metering points in Germany. Only 4 per cent of the companies (28 legal entities) supply more than 100,000 metering points. These companies, however, serve a total of 5.9m metering points, which is around 44 per cent of all reported metering points in Germany.

Most gas suppliers in Germany have a relatively small number of customers, whereas in absolute terms the few large gas suppliers serve the majority of metering points.

One indicator of well-functioning competition between gas suppliers, and thus of a greater degree of choice for gas customers, is the number of gas suppliers available per network area. In the 2014 survey, the gas network operators were asked to report on the number of suppliers serving at least one final consumer in their networks.

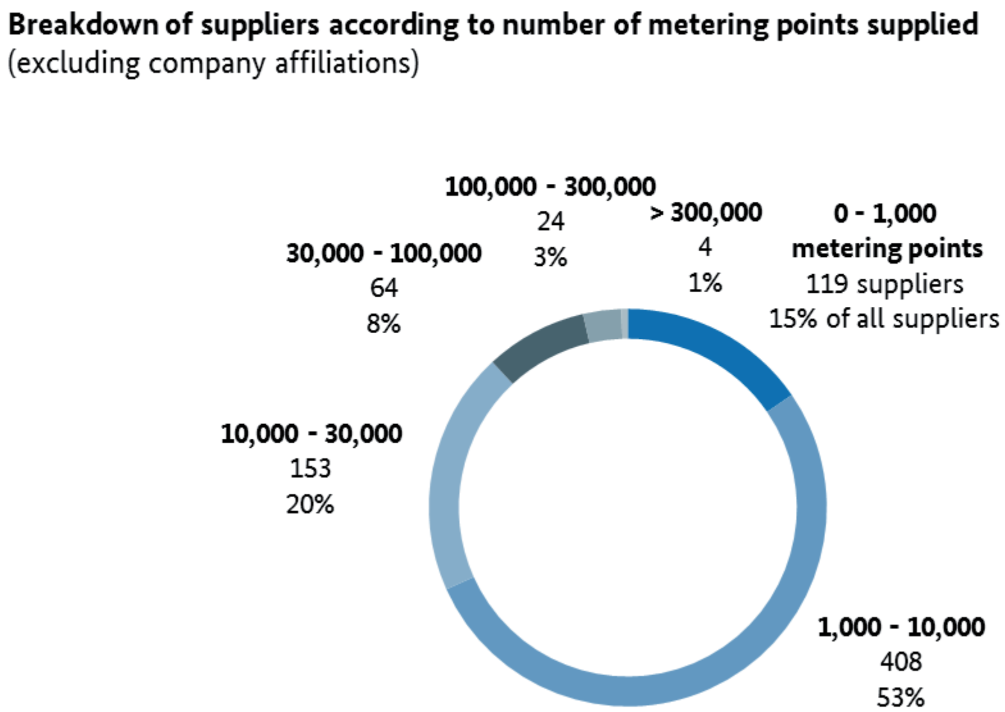

Figure 131: Breakdown of suppliers according to the number of metering points supplied (excluding company affiliations)

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 gas suppliers active in the various network areas since 2006. In 2013, the year under review, the trend towards more diversity has continued. In over 90 per cent of the network areas final customers can choose from 31 or more gas suppliers. In almost 70 per cent of the networks consumers even have a choice of more than 50 suppliers. Less than 5 per cent of the network areas have 20 or fewer suppliers.

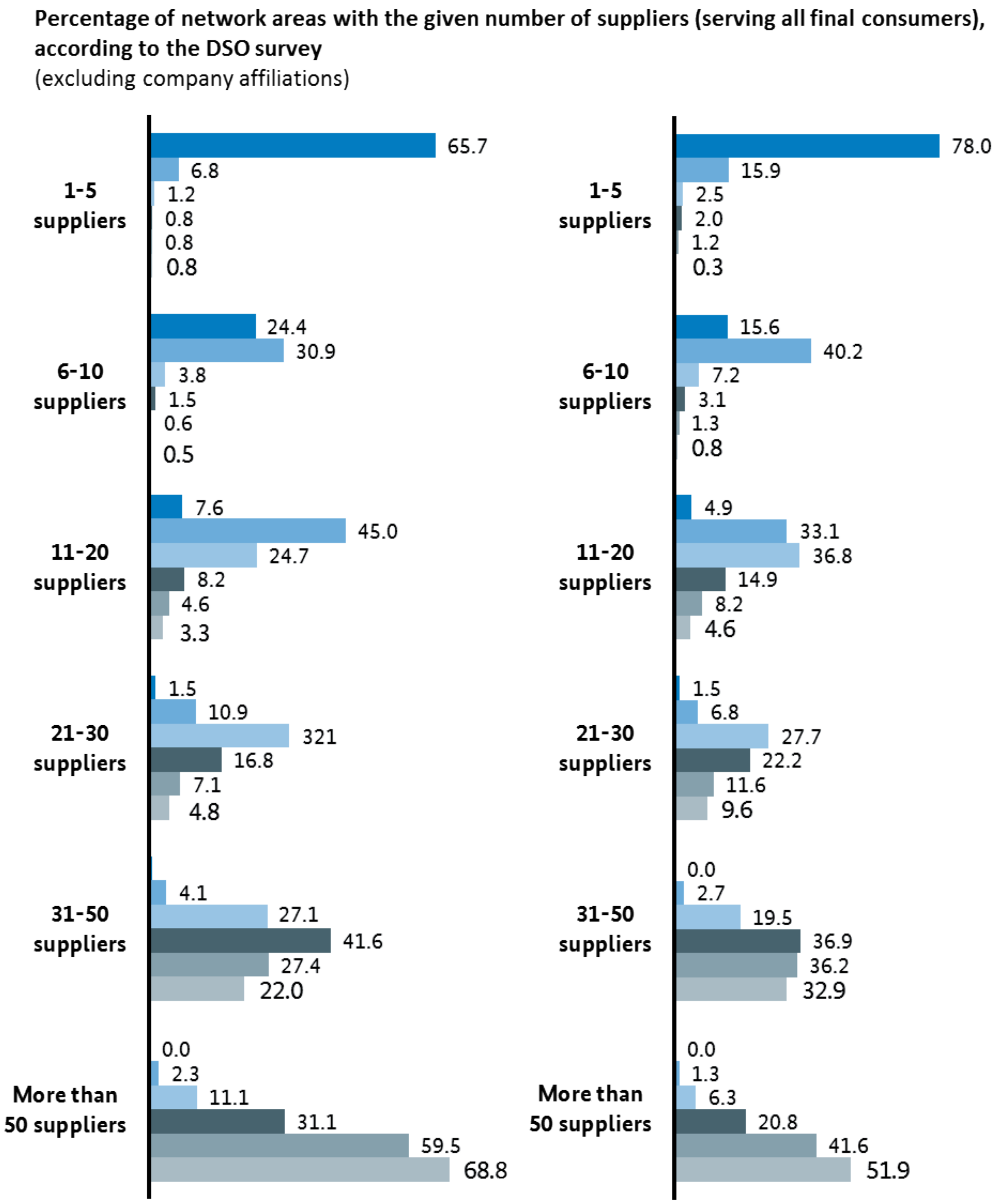

Figure 132: Percentage of network areas with the given number of suppliers (serving all final consumers and household customers) from 2008 to 2013 according to the survey of gas DSOs (excluding company affiliations)

The situation when looking at household customers only is similar: in just fewer than 85 per cent of the network areas final customers can choose from 31 or more gas suppliers; and in almost 52 per cent of the networks consumers even have a choice of more than 50 suppliers.

5. Contract structure and supplier switching

Switching rates and processes are important indicators of the development of competition. A survey of such indicators is linked to various difficulties, however, meaning that data collection would have to be limited to data that best reflected actual switching behaviour.

In the survey, data on contract structures and supplier switching is collected through questionnaires relating to each specific customer group to be completed by the TSOs, DSOs and suppliers.

Final consumers can be grouped according to their metering profile into customers with and without interval metering. For customers without interval metering, consumption over a certain period of time is estimated using a standard load profile (SLP).

Final consumers can also be divided into household, business and industrial customers. Household customers are defined in the Energy Act (EnWG) through qualitative characteristics[109]. Non-household customers are termed business and industrial customers. There is no generally recognised definition for either business customers or industrial customers. A clear distinction between these two customer groups is therefore not made in the survey or report.

The total volume of gas delivered by suppliers to all final consumers in 2013, as reported in questionnaire 9, amounted to around 868 TWh, with about 481 TWh supplied to interval-metered customers and 387 TWh to SLP customers. The majority of SLP customers are household customers. In 2013 around 245.5 TWh of gas was delivered to household customers.

Data was collected in the survey on the volumes of gas delivered to final consumers grouped as having one of three types of contract: "default supply contract", "special contract with the default supplier" and "special contract with an alternative supplier". In the survey, "default supply contracts" also include supply from fall-back suppliers (section 38 EnWG) and cases of doubt[110]. Supply outside the framework of a default supply contract is designated as a "special contract". The analysis of these three categories provides conclusions on the extent to which the importance and role of default supply have diminished since the liberalisation of the energy market. The figures should however not be interpreted directly as "cumulative net switching figures since liberalisation". It is especially important to note here that the specific legal entity is taken to be the contracting party, hence a special contract with a company affiliated with the default supplier is seen as a "special contract with an alternative supplier"[111].

Data was also collected from the TSOs and DSOs on the number of customers in each group switching supplier in 2013. Switching supplier is taken to mean the process where a final consumer's metering point

[109] Section 3 para 22 EnWG defines household customers as final consumers who purchase energy primarily for their own household consumption or for their own consumption for professional, agricultural or business purposes not exceeding an annual consumption of 10,000 kilowatt hours.

[110] In addition to household customers, final consumers served by a fallback supplier (section 38 EnWG) are usually included under "default supply". Suppliers were asked to include cases that could not be clearly categorised in "default supply".

[111] Further ambiguities may arise for instance if the local default supplier changes.

(meter) is served by a new supplier. It does not include switches when customers move home[112]. A switch is taken to be a change in the legal entity supplying gas, hence the term includes cases where a supply contract is transferred from one company to another within the same group and also where a customer switches "involuntarily" because the supplier becomes insolvent or terminates the supply contract. The actual number of customers switching to a competitor is therefore lower than the number of "supplier switches" registered. On the other hand, the figure does not show whether or not a supplier lowered prices or made other improvements, for example, to prevent customers from switching.

5.1 Interval-metered, business and industrial customers

Contract structure

Offtake for interval-metered customers is recorded at short intervals ("load profile"). Interval-metered customers are characterised by high consumption and/or energy requirements[113] and are all industrial or (high consumption) business customers[114].

In 2013 around 690 gas suppliers (separate legal entities) provided information on the metering points served and offtake volumes for interval-metered customers in Germany. The 690 gas suppliers include many affiliated companies, hence the number of suppliers is not equal to the actual number of competitors. At the same time, however, it can be said that there are a considerable number of suppliers serving interval-metered customers.

In 2013, these suppliers delivered more than 481 TWh of gas to interval-metered customers through a total of over 40,600 metering points. Over 99 per cent of this volume was supplied under a special contract. It is not usual, but not impossible, for interval-metered customers to be supplied under default supply or fall-back supply. Around 0.7 TWh of gas was supplied to interval-metered customers under default or fall-back supply. This is about 0.1 per cent of the total volume supplied to interval-metered customers. About 32 per cent of the total volume delivered to interval-metered customers was supplied under a special contract with the default supplier and some 68 per cent under a contract with a legal entity other than the default supplier[115]. These figures show that in practice default supply is of only minor significance for interval-metered gas customers.

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[112] Cases where contracts are transferred because of a concession being awarded to a different supplier are not counted as supplier switches.

[113] In accordance with section 24 of the Gas Network Access Ordinance (GasNZV) interval metering is generally required for a maximum hourly offtake capacity above 500 KW and a maximum annual offtake above 1.5 GWh.

[114] Standard profiles are used for some business customers with a lower consumption.

[115] Some suppliers did not include the volumes delivered to gas-fired power plants in the volumes for interval-metered customers. The volumes shown in the figure total 457 TWh (147 TWh under contracts with the default supplier and 310 TWh under contracts with another legal entity) and not the full volume actually delivered to interval-metered customers.

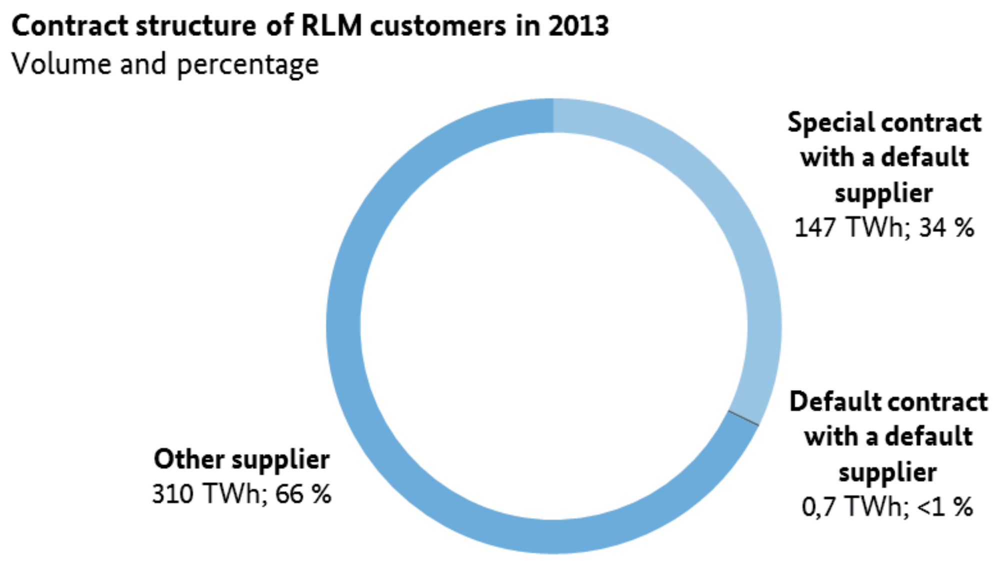

Figure 133: Contract structure for interval-metered customers in 2013

Supplier switching

Data was collected in questionnaires 7 and 8 (TSOs and DSOs) on the level of supplier switching in different customer categories in 2013. Different consumption categories were used instead of the above-mentioned customer groups (SLP/interval-metered customers, business and industrial customers). As stated above, a supplier switch is defined as a change in the legal entity supplying gas and does not necessarily involve a change in provider. The survey produced the following results:

Supplier switching according to consumer category

Category	Number of metering points with a change in 2013 in the legal person supplying gas	Percentage of all metering points for category	Offtake volume in 2013 for metering points with a change of supplier in 2013	Percentage of total offtake volume for category in 2013
< 0.3 GWh/year	1,184,057	8.6%	31.4 TWh	9.1%
0.3 GWh/year - 10 GWh/year	32,747	21.3%	19.9 TWh	15.2%
10 GWh/year - 100 GWh/year	907	23.8%	15.9 TWh	16.3%
> 100 GWh/year	121	19.4%	31.6 TWh	11.8%
Gas power plants	50	4.8%	6.7 TWh	7.6%

Table 55: Supplier switching in 2013 by consumer category

The volume-based switching rate in 2013 for all four categories with a consumption of or above 0.3 GWh/year (including gas-fired power plants) was about 12.7 per cent. This represents an increase of 0.5 per cent compared to the previous year. There was a strong rise in the switching rates among industrial and business customers between 2006 and 2010. Since then the switching rate has remained more or less constant. The survey does not determine which percentage of industrial and business customers have switched supplier once, more than once or not at all over a period of several years.

Development of supplier switching by industrial and business customers
Volume-based rate of all customers >10 MWh/year

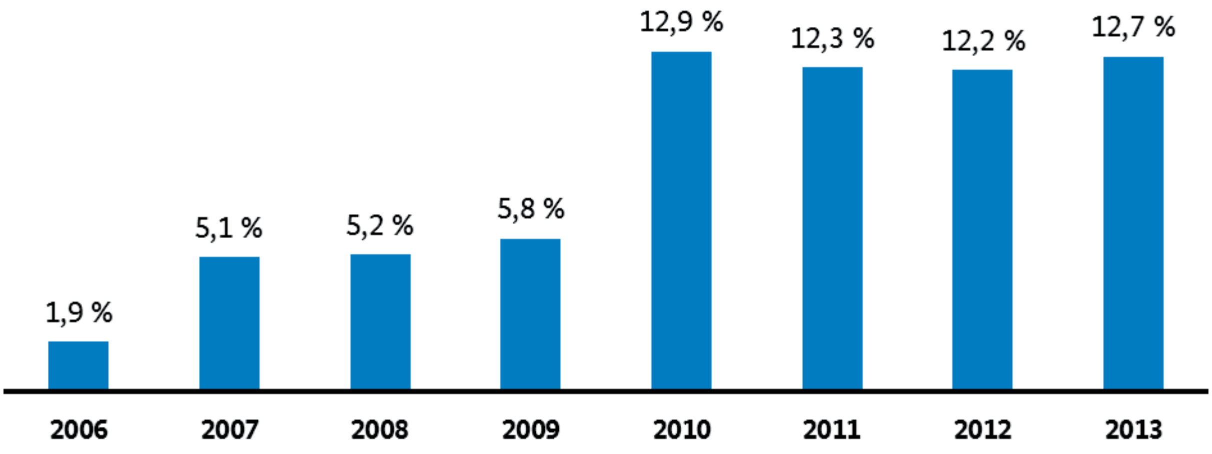

Figure 134: Supplier switching by industrial and business customers from 2006 to 2013

5.2 Household customers

Contract structure

A closer look at how household customers were supplied in 2013 in terms of volume shows the following: 26.5 per cent of the volume of gas delivered to household customers was supplied under a standard contract with a default supplier; 59.6 per cent of household customers had a special contract with their default supplier; and 13.9 per cent of all household customers were served by an undertaking other than their default supplier.

Household customer contracts
Volume and percentage
(correct as of 31 December 2013)

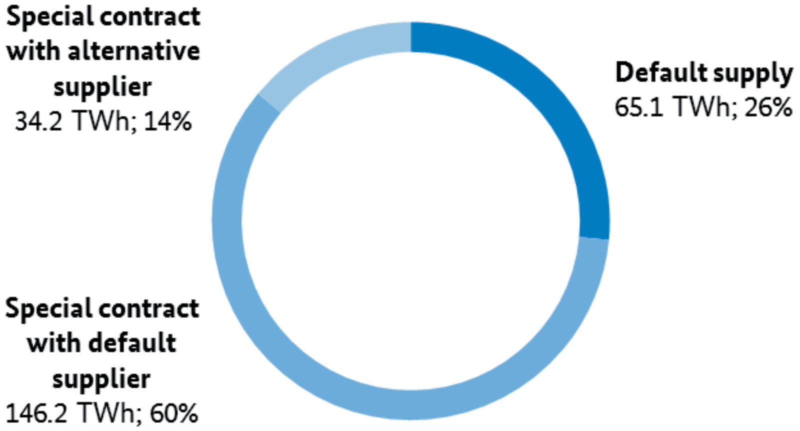

Figure 135: Household customer contracts according to the survey of wholesalers and suppliers (correct as of December 2013)

A standard load profile (SLP), which is a simplified method of metering, is used for customers whose fluctuation in offtake is not registered at certain intervals. An SLP is generally used only for those gas customers with a maximum annual offtake of 1.5 GWh and a maximum hourly offtake capacity of 500 kWh (section 24 GasNZV). SLP customers comprise primarily household customers but also non-household customers with a relatively low consumption.

760 individual companies provided information on metering points and delivery volumes for SLP customers. Approximately 387 TWh of gas was delivered to 13.6m metering points. This roughly corresponds to the previous year's figures. The total volume comprises about 245 TWh (63 per cent) for household customers and some 142 TWh (37 per cent) to non-household SLP customers.

77 TWh (20 per cent) was supplied under standard default supply contracts, 230 TWh (59 per cent) under special contracts with the default supplier and 80 TWh (21 per cent) under special contracts with another legal entity.

Higher consumption SLP customers are much more likely to have a special contract than those with a lower consumption. The average (median) annual consumption of default supply customers was just over 17,000 kWh and of special contract customers just over 35,000 kWh.

592 of the 760 or so suppliers (individual companies) providing data on metering points and volumes for SLP customers were active as default suppliers. Most of the default suppliers have only a small customer base: 517 serve fewer than 30,000 metering points for SLP customers, including 378 serving fewer than 10,000 metering points.

Supplier switching

According to the gas network operators, the volume of gas affected by household customers switching supplier in 2013 (including those switching when moving home) was 27.3 TWh. This represents a clear increase of 7 TWh, or 35 per cent, compared to the previous year. Based on the total volume of 283 TWh delivered to household customers as reported by the network operators, the volume-based switching rate for household customers is 9.65 per cent.

An analysis of switching by household customers as defined by section 3 para 22 EnWG based on the data provided by the network operators gives the following picture. A total of 1,062,580 household customers switched gas supplier in 2013, including those switching when moving home; that is some 228,197 more than in 2012, representing an increase of 27 per cent. A total of 223,616 household customers chose a supplier other than the local default supplier directly after moving; this is an increase of 43 per cent. This shows that a growing number of customers are taking the opportunity when moving to switch to a less expensive supplier for their new home. Based on the total of 12,453,223 household customers as reported by the network operators, the switching rate for household customers in terms of numbers was 8.53 per cent.

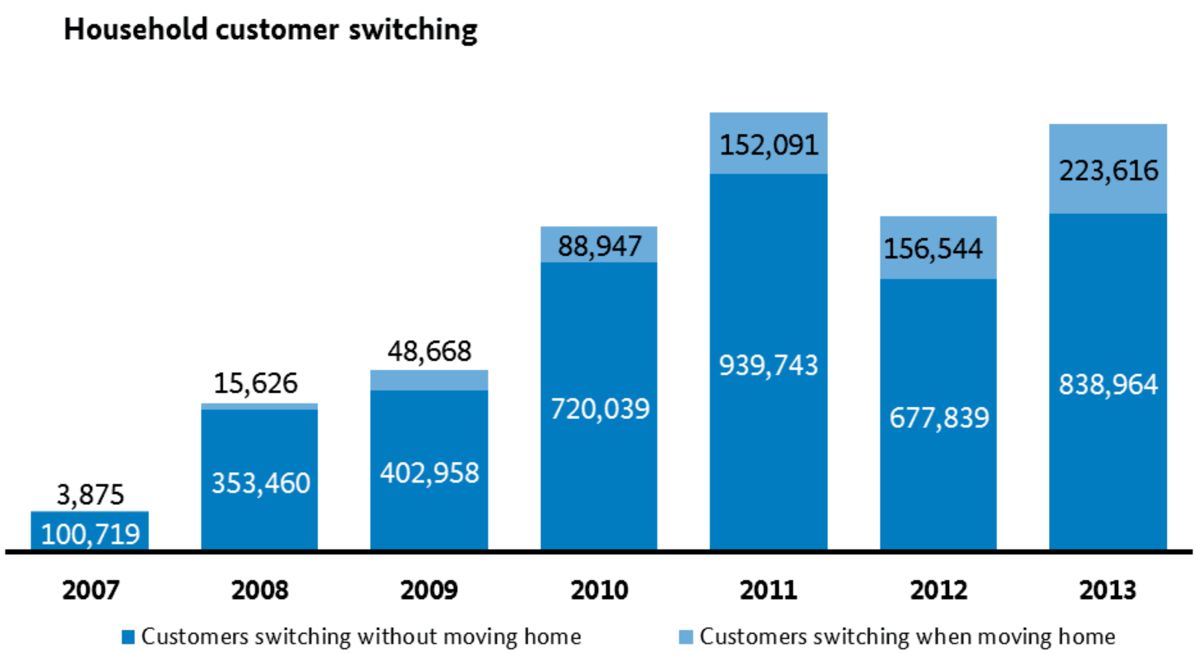

Figure 136: Household customer switching from 2006 to 2013

6. Disconnection notices, disconnections, tariffs and terminations

6.1 Disconnection of supply

In 2013, the Bundesnetzagentur for the third time carried out surveys of the tariffs offered and asked network operators and gas suppliers about disconnection notices and requests (to the DSOs) as well as the number of actual disconnections under section 19(2) of the Gas Default Supply Ordinance (GasGVV) and the associated costs.

Section 19(2) GasGVV entitles default suppliers to disconnect supplies to customers in particular upon failure to fulfil payment obligations and after appropriate notice has been given. While there was a year-on-year decrease in the number of disconnection notices and requests, there was a slight increase of around 6,500 in the number of disconnections actually carried out. The number of disconnections is based on information from the DSOs, who ultimately carry out the disconnections on behalf of the suppliers. Based on the total number of metering points served by the DSOs in Germany, the market coverage rate here was about 97.4 per cent.

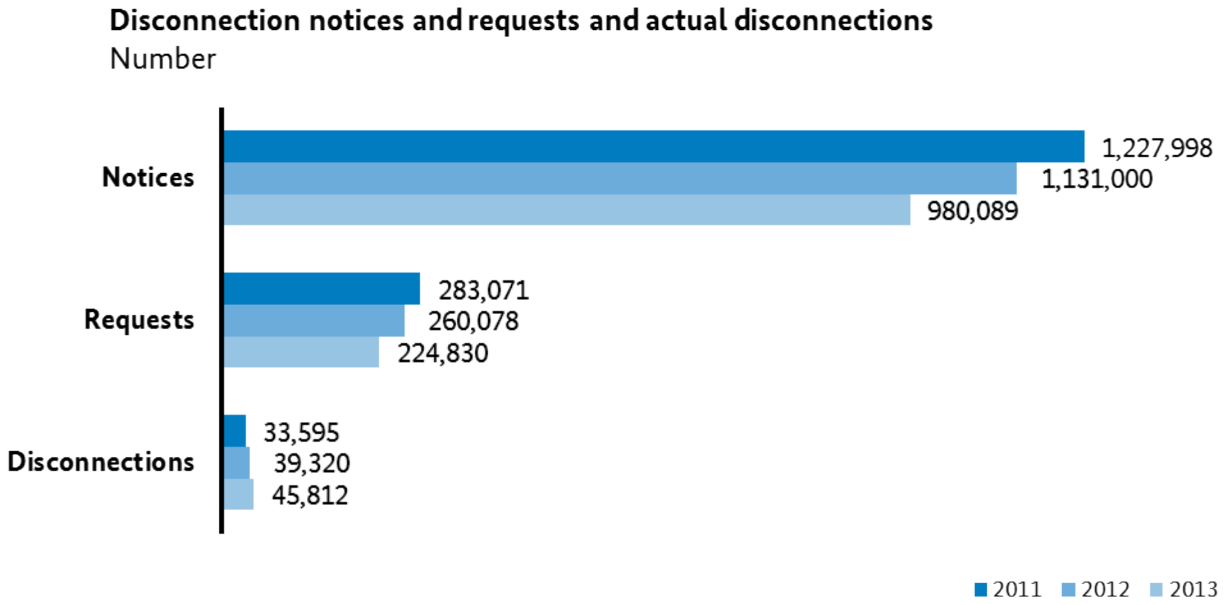

Figure 137: Disconnection notices and requests and disconnections[116]

The Ordinance does not specify a minimum level of arrears for supply disconnection. The average level of arrears was about €115. The average charge paid by suppliers to DSOs for disconnecting customers was around €53, with the actual costs charged ranging from €13 to €200. The average charge for reconnecting customers was about €58, with actual charges at between €19 and €200.

Suppliers charged their customers an average of around €46 for disconnecting supply, with the actual charges ranging from €2 to €200, excluding the DSOs' costs.

[116] In respect of the data for 2011 it is important to note that some of the suppliers could only provide estimates of the number of disconnection notices and requests.

6.2 Tariffs and terminations of contract

Section 40(3) EnWG requires suppliers to offer final consumers monthly, quarterly or half yearly bills. There is, however, little demand from gas customers for such bills, probably because of the large seasonal fluctuations in household customers' gas consumption.

Non-annual billing

	Number of requests	Number of bills	Average charge per additional bill with customer reading (range of charges) (€)	Average charge per additional bill without customer reading (range of charges) (€)
Non-annual billing for household customers	13,278	15,996	13.91 (0.00 - 113.00)	19.44 (2.37 - 557.75)
Monthly	964	715		
Quarterly	155	135		
Half yearly	925	849		

Table 56: Non-annual billing

Only few gas suppliers terminate service with their customers. In 2013, suppliers issued a total of some 44,000 termination notices to customers. The average level of customer arrears here was about €130, with the highest amount being €1,000.

As in the past, the vast majority of contract terminations were carried out by just a few, young inter-regional companies, while regional providers rarely or never terminated service with their customers.

Only default suppliers have customers disconnected on a regular basis. Default suppliers may only terminate contracts with customers on strict conditions: no basic supply obligation may apply or the conditions for disconnection must have been met repeatedly. Disconnections and disconnection notices for customers under special contract are rare since it is easier and less expensive for the supplier to terminate the contract.

7. Price level

In the survey, suppliers delivering gas to final consumers in Germany were asked to provide data on their company's retail prices as of 1 April 2014 for three consumption levels: 23 MWh (household customers), 116 MWh (lower consumption business customers) and 116 GWh (industrial customers).

Suppliers were asked to give the overall price in cents per kilowatt hour (ct/kWh) including the non-variable price components such as the service price, base price and transfer or internal price. Suppliers were also asked to provide a breakdown of the non-controllable price components including in particular network tariffs, concession fees and charges for billing, metering and meter operations. After deducting these components from the overall price, the amount remaining is the amount controlled by the supplier which comprises above all gas procurement, supply, other costs and the supplier's margin.

The suppliers were asked to provide their "average" overall prices and price components for each of the three consumption levels. Several companies drew attention to the fact that they were unable to provide average figures on account of their inter-regional activity and/or customer-specific pricing.

Companies were asked to provide data on the price components for the lowest consumption level of about 23 MWh/year (household customer) for three different contract types: default supply contract, special contract with the default supplier, and special contract with an alternative supplier (see II.G.5 on page 240ff).

The findings are set out separately for each consumption level and are compared with the previous year's results to indicate any long-term trends. In respect of the comparison between the figures for 1 April 2014 and 1 April 2013, it should be noted that differences in the calculated averages are lower than the range of error for the survey's methodology. Hence it is not always possible to provide a statistically significant statement as to whether or not there was a year-on-year price increase or decrease. In addition, it should be noted that a different group of suppliers was asked to provide data: this year all suppliers operating in Germany were asked instead of only suppliers active as default suppliers in at least one network area. In the case of the prices for the two higher consumption levels (116 GWh/year and 116 MWh/year), however, this year only suppliers serving at least one customer with the relevant consumption was asked to provide data.

7.1 Business and industrial customers

116 GWh/year ("industrial customers")

All industrial customers are interval-metered customers. The wide scope for customer-specific contracts plays a large role for this customer group. In general, suppliers do not have any specific tariffs for such high consumption customers but instead tailor pricing to individual customers, who include those receiving the full range of services as well as those whose negotiated offtake is only part of their procurement portfolio. In the case of customers with the highest consumption, there are natural crossovers between retail and wholesale trading, with retail prices often being indexed to wholesale prices. Several suppliers stated in the survey that their contracts provided for the customers themselves to be responsible for paying the operators' network tariffs. Such contracts may go so far that in economic terms the "supplier" only provides balancing group and nomination management services to the customer.

The industrial customer was taken to have an annual consumption of 116 GWh and an annual usage period of 250 days (4,000 hours). This year only those suppliers with at least one customer with an annual consumption of between 50 GWh and 200 GWh were asked to provide data. This limits the suppliers to a small group. The following analysis is based on data from 96 suppliers (compared to 134 in 2013). More than half of the 96 suppliers had fewer than ten customers with an annual consumption above 100 GWh.

The data was used to calculate the arithmetic mean of the overall price and the individual price components. The distribution of the figures for each price component was also analysed using ranges. The 10th percentile represents the lower limit and the 90th percentile the upper limit of each range, with 80 per cent of the figures provided by the suppliers therefore within the range. The analysis produced the following results:

Price level of customer with an annual consumption of 116 GWh (correct as of 1 April 2014)

	80 % of the values are the range of (in ct/kWh)	Average (arithmetical) in ct/kWh	Percentage of total price
Price components that cannotbe influenced by the supplier			
Net network tariff	0,14 – 0,43	0.30	8%
Charge for billing, metering and metering operations	0,00 – 0,03	0.01	0%
Concession fee	0.00	0,00 [1]	0%
Gas tax	0.55	0.55	15%
Price components that can be influenced by the supplier (residual amount)	2,43 – 3,15	2.73	76%
Total price (without value-added tax)	3,24 – 4,06	3.59	

[1] Under section 2(5) para 1 Electricity and Gas Concession Fees Ordinance (KAV), concession fees for special contract customers are only incurred for the first 5 GWh (0.03 ct/kWh). In cases of 116 GWh consumption, this results in an average (rounded up) 0.00 ct/kWh.

Table 57: Price for customers with an annual consumption of 116 GWh (correct as of 1 April 2014)

On average, the network tariff, concession fees and metering charges account for less than 10 per cent of the overall price for industrial customers (116 GWh/year). This is considerably lower than for household and business customers. Accordingly the components that can be controlled by the supplier (gas procurement and supply, other costs and the margin) account for a much larger share of the overall price at 76 per cent.

The average overall price (excluding VAT) of 3.59 ct/kWh is 0.35 ct/kWh or 9 per cent lower than last year's average price. The difference is due to a reduction in the price components that can be controlled by the supplier. It is important to remember the survey inaccuracy and the change in the group of suppliers providing data (see above) when comparing this year's with last year's figures.

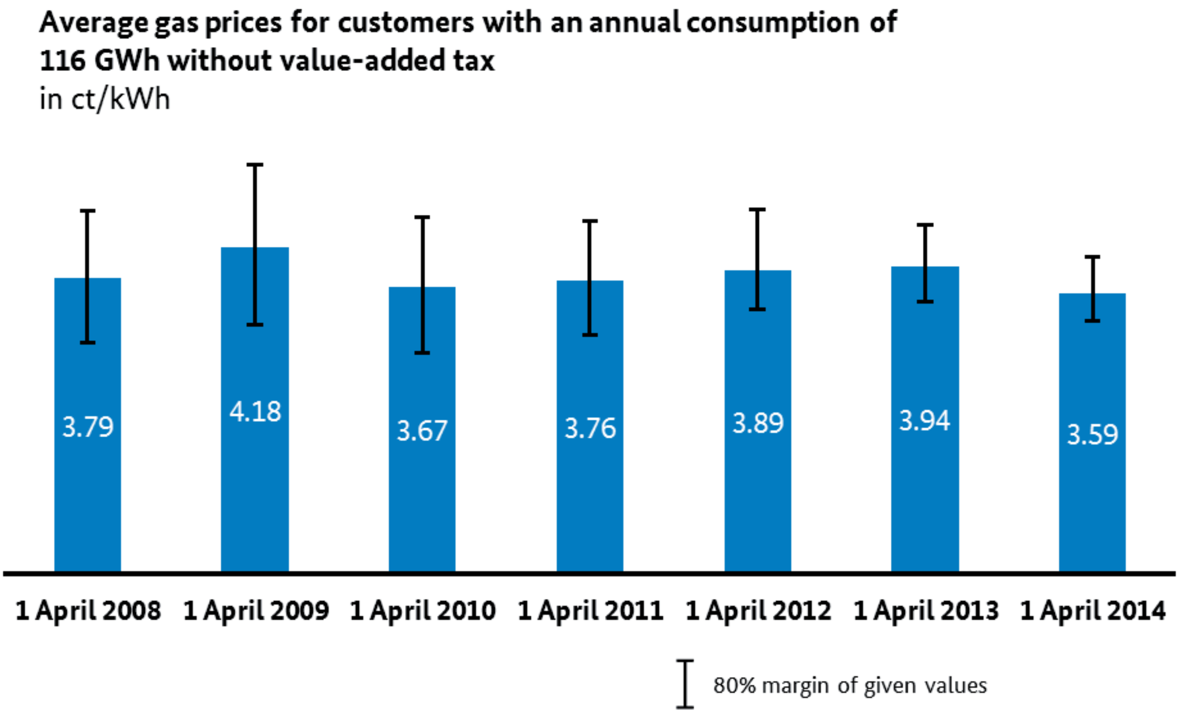

Figure 138: Average gas prices for customers with an annual consumption of 116 GWh

116 MWh/year ("business customers")

The business customer was taken to have an annual consumption of 116 MWh and no specific annual usage period. This annual consumption is five times higher than for a household customer (23 MWh) and a thousandth of that of an industrial customer (116 GWh) and represents a business customer with a relatively low consumption. Given the moderate level of consumption, options for individual contracts play a considerably smaller role than with industrial customers. Suppliers were asked to provide plausible estimates based on their conditions applicable on 1 April 2014 of prices for customers with a similar consumption. Suppliers serving customers with a comparable consumption, ie an annual gas consumption of between 50 MWh and 200 MWh, were asked to provide data. Since this consumption level is well below the 1.5 GWh threshold above which operators are required to use interval metering, it can be assumed that a standard load profile (SLP) is generally used for such customers.

The following analysis is based on data from 582 suppliers (compared to 491 in 2013). The data was used to calculate the arithmetic mean of the overall price and the individual price components. The distribution of the figures for each price component was also analysed using ranges, with 80 per cent of the figures provided by the suppliers within the range. The analysis produced the following results:

Price for customers with an annual consumption of 116 MWh (correct as of 1 April 2014)

	80 % of the values are the range of (in ct/kWh)	Average (arithmetical) in ct/kWh	Percentage of total price
Price components that cannot be influenced by the supplier			
Net network tariff	0,83 – 1,55	1.16	22%
Charge for billing, metering and metering operations	0,02 – 0,11	0.06	1%
Concession fee	0,03 – 0,03	0,04 [1]	1%
Gas tax	0.55	0.55	11%
Price components that can be influenced by the supplier (residual amount)	2,94 – 3,94	3.40	65%
Total price (without value-added tax)	4,68 – 5,76	5.20	

[1] 38 of 582 suppliers replied a concession fee value over 0.03 ct/kWh. These are suppliers with rather low offtake volumes. A concession fee of above 0.03 ct/kWh for business costumers is also conceivable if the delivery is realised under a default supply contract (see § 2 sect.2 Nr. 2b KAV).

Table 58: Price for customers with an annual consumption of 116 MWh (correct as of 1 April 2014)

On average, non-controllable price components (network tariff, gas tax and concession fees) account for 35 per cent of the overall price while components that can be influenced by the supplier's company decisions account for 65 per cent.

The average overall price (excluding VAT) of 5.20 ct/kWh is only slightly lower (0.10 ct/kWh) than last year's average price. The absolute level of the non-controllable price components is the same as in the previous year, hence the change is due to the remaining components.

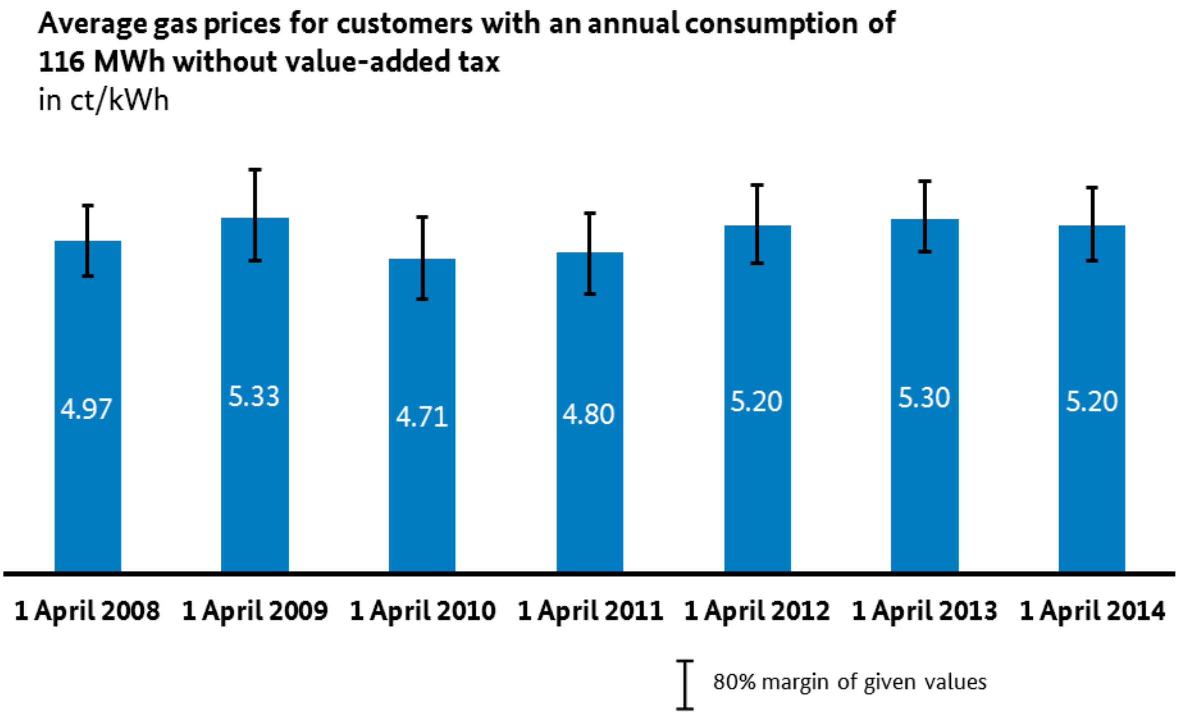

Figure 139: Average gas prices for customers with an annual consumption of 116 MWh

7.2 Household customers

Overall, gas prices for household customers with an annual consumption of 23,269 kWh as of 1 April 2014 remained stable compared to the previous year[117]. There was a slight increase in both the weighted and unweighted average prices for two of the three categories. The volume-weighted prices for default supply customers and customers with a special contract with their default supplier were the highest since 2008. By contrast, the price as of 1 April 2014 for customers served by an alternative supplier was slightly lower than the highest recorded price of 1 April 2013.

The volume-weighted price for household customers with a standard contract with their default supplier increased from 7.09 ct/kWh in 2013 to 7.20 ct/kWh; this represents an increase of 1.6 per cent. The average net network tariff (including upstream network costs) rose from 1.27 ct/kWh to 1.29 ct/kWh. The share in the overall price rose accordingly to approximately 18 per cent.

[117] The annual consumption of 23,269 kWh is based on Eurostat's standard household consumer in band D3.

Average retail price for default supply household customers with an annual consumption of 23,269 kWh

Correct as of 1 April 2014	Arithmetic mean (ct/kWh)	Share of total (%)	Volume-weighted average (ct/kWh)	Share of total (%)
Average net network tariff including upstream costs	1.38	18.7	1.29	17.9
Average charge for billing	0.06	0.8	0.05	0.7
Average charge for metering	0.02	0.3	0.02	0.3
Average charge for meter operations	0.06	0.8	0.05	0.7
Average concession fees	0.25	3.4	0.26	3.6
Current gas tax	0.55	7.4	0.55	7.6
Average VAT	1.18	16.0	1.18	16.4
Average price component for energy procurement and supply, other costs and margin	3.89	52.6	3.80	52.8
Total	7.39	100	7.2	100

Table 59: Average retail price for default supply household customers with an annual consumption of 23,269 kWh according to the survey of gas wholesalers and suppliers (correct as of 1 April 2014)

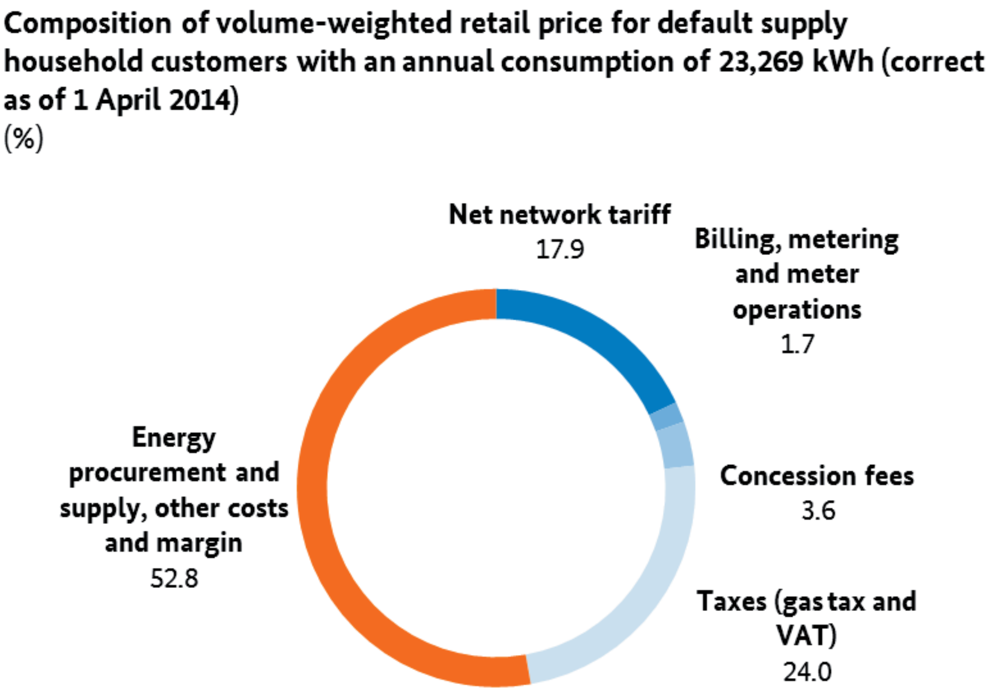

Figure 140: Composition of volume-weighted gas retail price for default supply household customers with an annual consumption of 23,269 kWh according to the survey of gas wholesalers and suppliers (correct as of 1 April 2014)

The volume-weighted average price for customers with a special contract with their local default supplier rose again, from 6.69 ct/kWh on 1 April 2013 to 6.77 ct/kWh on 1 April 2014; this represents another small increase of 1.2 per cent. The price component for energy procurement and supply, other costs and the margin rose again from 3.59 ct/kWh to 3.66 ct/kWh. The average net network tariff (including upstream network costs) in this category decreased very slightly from 1.32 ct/kWh to 1.31 ct/kWh and accounted for 19.4 per cent of the overall price compared to 19.7 per cent in 2013.

Average retail price for household customers with a special default supplier contract and an annual consumption of 23,269 kWh

Correct as of 1 April 2014	Arithmetic mean (ct/kWh)	Share of total (%)	Volume-weighted average (ct/kWh)	Share of total (%)
Average net network tariff including upstream costs	1.39	20.5	1.31	19.4
Average charge for billing	0.06	0.9	0.06	0.9
Average charge for metering	0.02	0.3	0.02	0.3
Average charge for meter operations	0.06	0.9	0.05	0.7
Average concession fees	0.05	0.7	0.04	0.6
Current gas tax	0.55	8.1	0.55	8.1
Average VAT	1.08	15.9	1.08	16.0
Average price component for energy procurement and supply, other costs and margin	3.58	52.7	3.66	54.1
Total	6.79	100	6.77	100

Table 60: Average retail price for household customers with a special default supplier contract and an annual consumption of 23,269 kWh according to the survey of gas wholesalers and suppliers
(correct as of 1 April 2014)

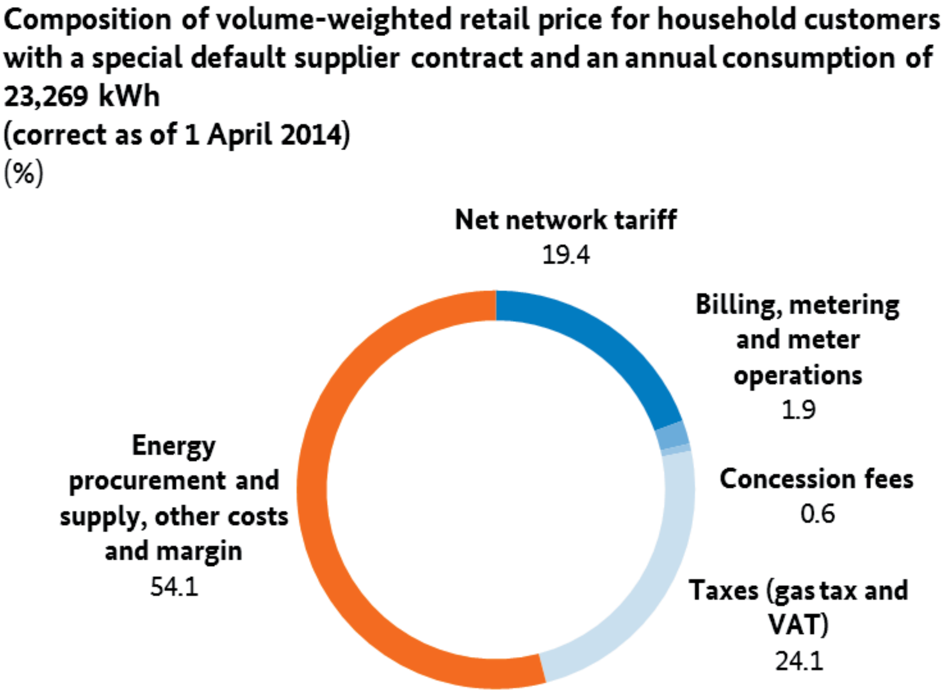

Figure 141: Composition of volume-weighted gas retail price for household customers with a special default supplier contract and an annual consumption of 23,269 kWh (correct as of 1 April 2014)

The average price for customers served by a supplier other than their default supplier decreased to 6.39 ct/kWh. Following an increase to 6.66 ct/kWh in 2013, this represents a year-on-year decrease of 4 per cent in the volume-weighted price. As with the price for customers with a special default supplier contract, there are two opposing developments behind the decrease in the volume-weighted price for customers with an alternative supplier: an increase in the average net network tariff (including upstream network costs) and a decrease in the price component controlled by the supplier. The price component for gas procurement and supply, other costs and the margin accounted for just fewer than 51 per cent of the overall price as of 1 April 2014 compared to around 52 per cent in 2013.

Average retail price for household customers served by an alternative supplier and with an annual consumption of 23,269 kWh

Correct as of 1 April 2014	Arithmetic mean (ct/kWh)	Share of total (%)	Volume-weighted average (ct/kWh)	Share of total (%)
Average net network tariff including upstream costs	1.42	21.3	1.34	21.0
Average charge for billing	0.06	0.9	0.06	0.9
Average charge for metering	0.03	0.5	0.04	0.6
Average charge for meter operations	0.06	0.9	0.06	0.9
Average concession fees	0.05	0.8	0.03	0.5
Current gas tax	0.55	8.2	0.55	8.6
Average VAT	1.06	15.9	1.07	16.7
Average price component for energy procurement and supply, other costs and margin	3.45	51.7	3.24	50.7
Total	6.68	100	6.39	100

Table 61: Average retail price for household customers served by an alternative supplier and with an annual consumption of 23,269 kWh according to the survey of gas wholesalers and suppliers
(correct as of 1 April 2014)

Composition of volume-weighted retail price for household customers served by an alternative supplier and with an annual consumption of 23,269 kWh (correct as of 1 April 2014) (%)

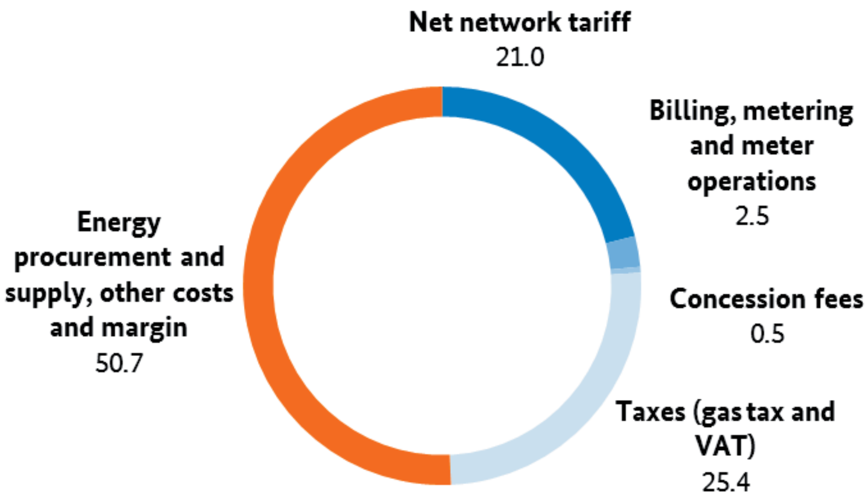

Figure 142: Composition of volume-weighted gas retail price for household customers served under special rates by an alternative supplier and with an annual consumption of 23,269 kWh (correct as of 1 April 2014)

In the year under review, there was another slight increase in the difference between the prices for customers with a standard contract and those with a special contract with their local default supplier for an annual consumption of 23,269 kWh. There is therefore still an incentive for customers with this level of consumption to switch to a special contract. A look at the prices over several years shows an upward trend in both default supplier groups.

A look at the development of the price component for energy procurement and supply, other costs and the margin shows a tendency to stagnate (default supply customers) or fall (special contract customers) (see Figure 144).

The controllable price component accounts for more or less the same share of the overall price in all customer categories: around 53 per cent for default supply customers, 54 per cent for customers with a special contract with their default supplier and about 51 per cent for customers served by an alternative supplier[118].

118 Based on unweighted averages.

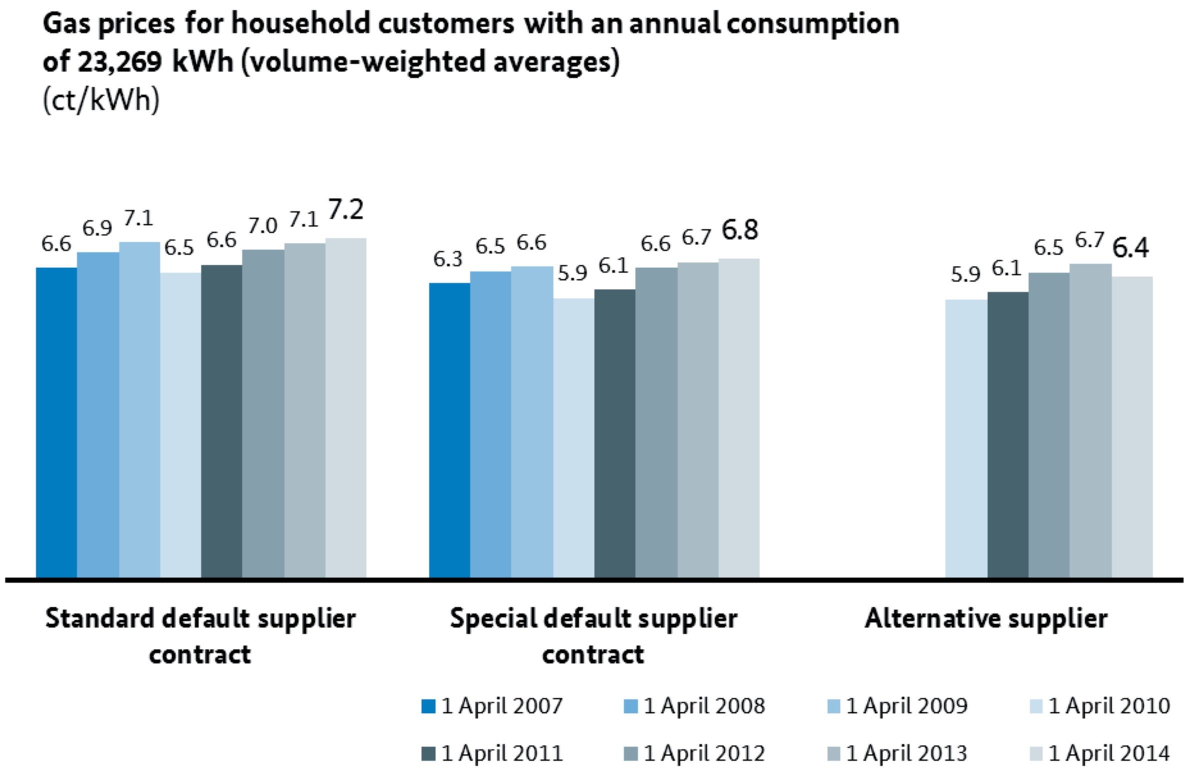

Figure 143: Volume-weighted gas prices for household customers with an annual consumption of 23,269 kWh from 2006 to 2014

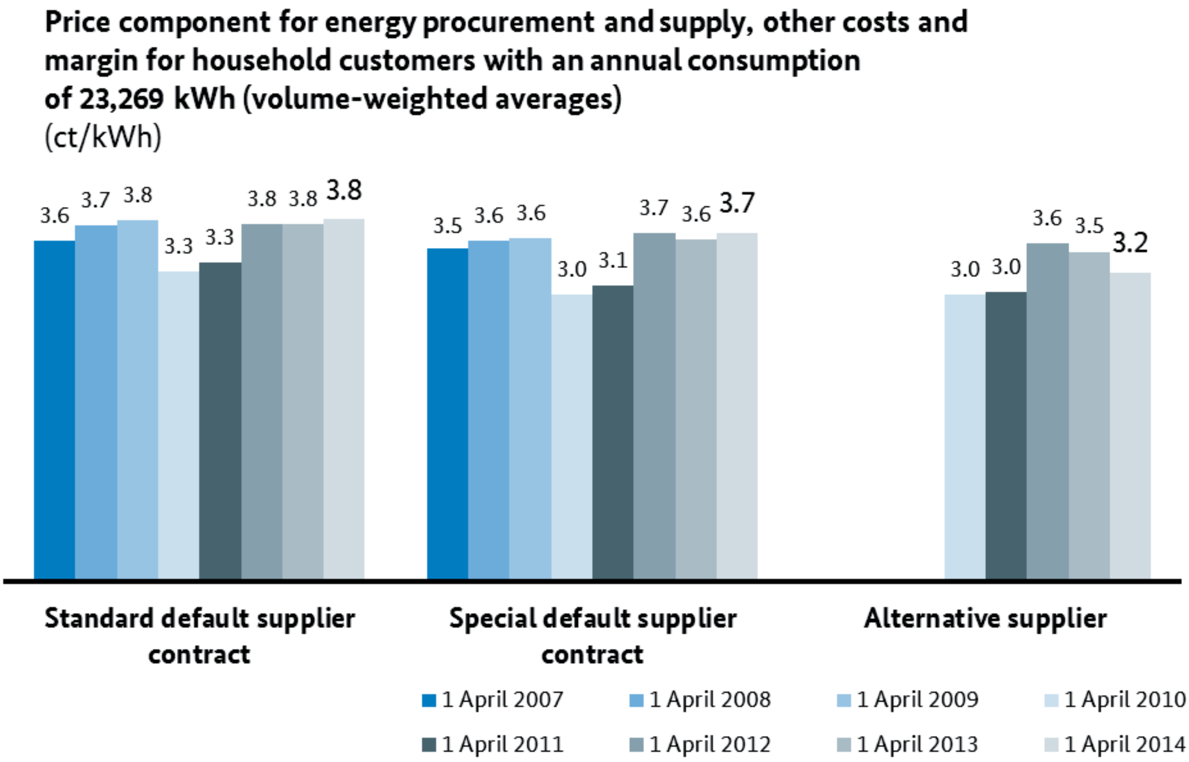

Figure 144: Price component for energy procurement and supply, other costs and the margin for household customers with an annual consumption of 23,269 kWh from 2006 to 2014

8. Comparison of European gas prices

Eurostat[119] publishes regular statistics on the average energy prices for different consumer groups within the European Union and in other European countries.

The prices are analysed in various forms:

– overall price (without any deductions);

– price excluding VAT and refundable taxes and levies;

– price excluding all taxes and levies[120].

The following analysis is based on the data published by Eurostat for the second half of 2013[121].

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[119] Eurostat, the statistical office of the European Union, uses data from sources specified by the Member States. Rules on data collection and analysis, etc aim to ensure the comparability of the findings.

[120] These include the concession fees in Germany.

[121] There are no averages covering the first half of 2013. The data for the second half of the year gives a more accurate picture of the current situation owing to changes over the year. Eurostat's data for household consumers covers 25 EU Member States (no data is available for Cyprus, Finland or Malta) and the data for industrial consumers covers 26 EU Member States (no data is available for Cyprus or Malta).

Household consumers

Eurostat's data relates to domestic consumers in band D2 with an annual consumption of between 20 GJ and 200 GJ[122]:

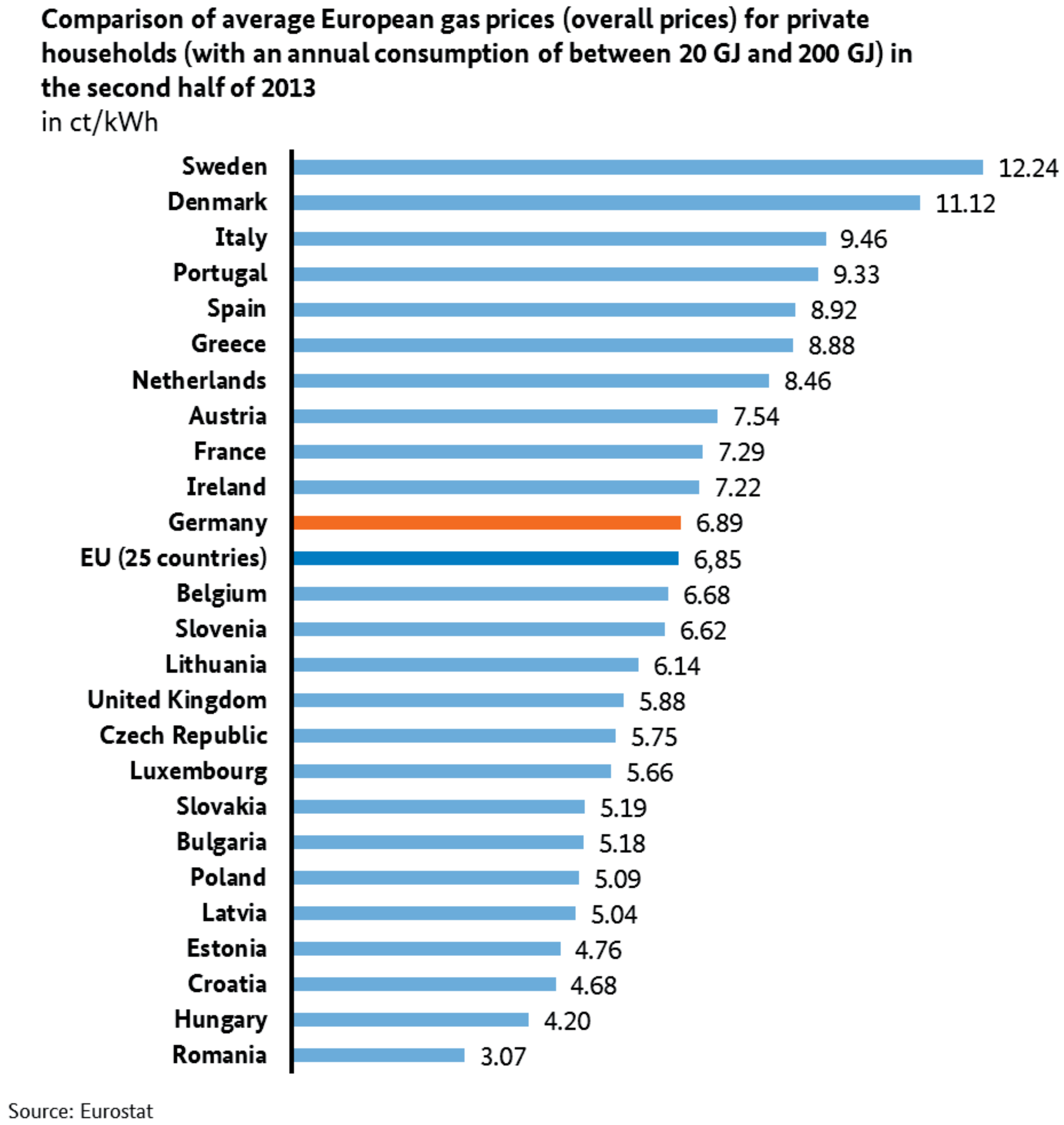

Figure 145: Comparison of average[123] European gas prices (overall prices) for private households (with an annual consumption of between 20 GJ and 200 GJ) in the second half of 2013

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[122] Information on other household consumer bands is available at http://epp.eurostat.ec.europa.eu/portal/page/portal/energy/data/database. The D2 group with an annual consumption of between 20 GJ and 200 GJ covers the consumption assumed for the monitoring survey's price analysis.
1 gigajoule corresponds to 278 kWh (after rounding); 20 GJ to 200 GJ therefore corresponds to 5,556 kWh to 55,556 kWh.

The price paid by German household customers is close to the average price for the EU Member States covered. Average overall prices vary by up to 9 ct/kWh, with the lowest in Romania at 3.07 ct/kWh and the highest in Sweden at 12.24 ct/kWh.

The share of the individual price components in the overall price also varies between the countries. Eurostat publishes data on the share accounted for by taxes and levies. The following figure shows the overall prices divided into "energy and supply[124] and network costs" and "taxes and levies".

[123] Eurostat's data covers 25 EU Member States (no data is available for Cyprus, Finland or Malta).

[124] This corresponds to the controllable price component in Germany, ie the component that can be influenced by the supplier's decisions; see II.G.7 "Price level" for energy procurement and supply, other costs and margin.

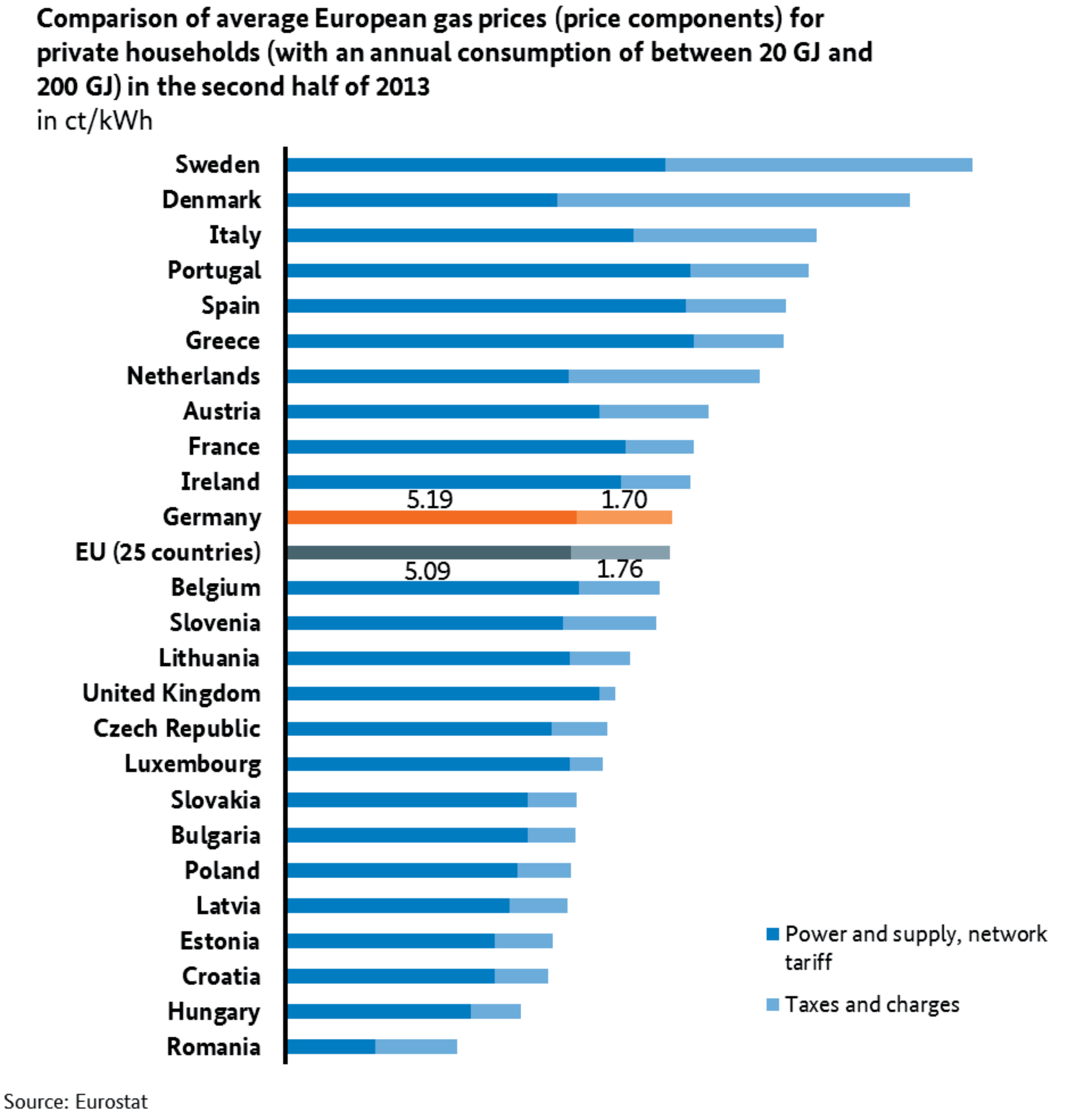

Figure 146: Comparison of average[125] European gas prices (price components) for private households (with an annual consumption of between 20 GJ and 200 GJ) in the second half of 2013

Taxes and levies account for between 4.8 per cent (United Kingdom with an overall price just below average) and 56.4 per cent (Denmark with the second highest overall price) of the overall price.

A comparison[126] of the prices over the past five years shows that the difference between gas prices (including all price components) for household customers in Germany and the EU average[127] was less than 1 ct/kWh.

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[125] Eurostat's data covers 25 EU Member States (no data is available for Cyprus, Finland or Malta).

[126] The comparison is based on the average price for each year, ie the average of both sets of half-yearly data.

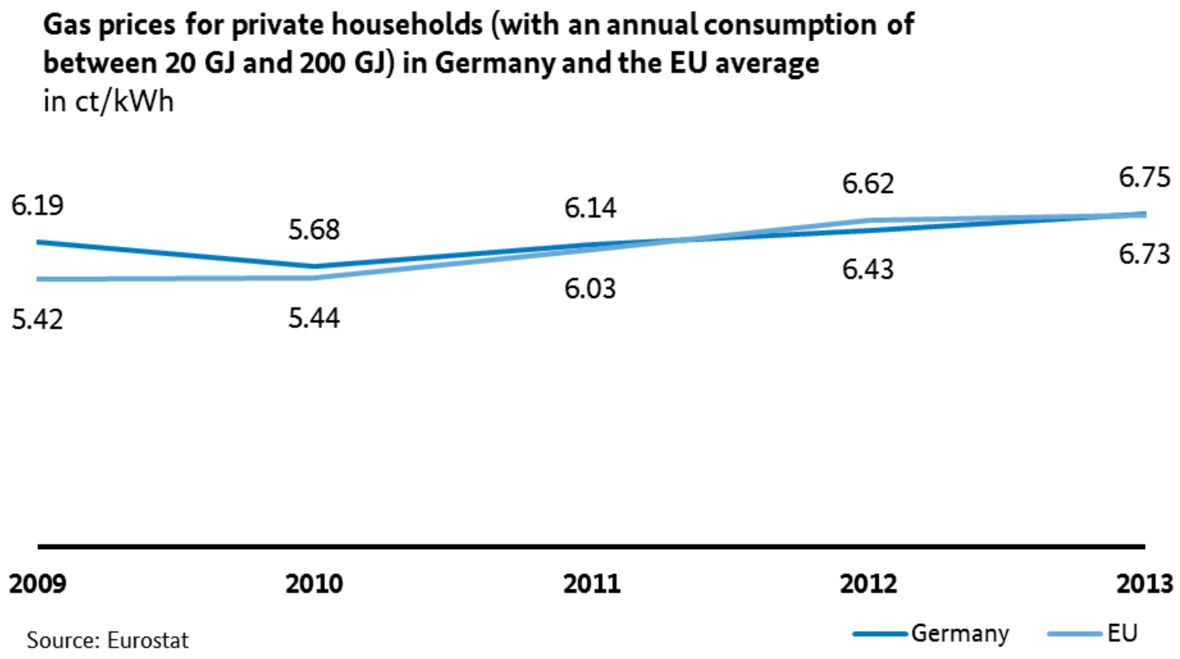

Figure 147: Gas prices for private households (with an annual consumption of between 20 GJ and 200 GJ) in Germany and the EU average from 2009 to 2013

There is now only a very marginal difference between the prices (0.02 ct/kWh for 2013).

Industrial consumers

Eurostat also publishes data on prices for consumers with a higher consumption than private households. These include industrial consumers in band I3[128] with an annual consumption of between 10,000 GJ and 100,000 GJ. A first comparison is made of the overall prices with all price components, ie including the VAT applicable in each country. A second comparison is made of the prices excluding VAT[129] only. This takes account of the fact that the VAT is generally deductible for these customers[130]. Finally, a comparison is made of the "taxes and levies" and "energy and supply and network costs" components.

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[127] Figures for Croatia prior to its membership in the EU in 2013 were also included to improve the comparability of the data. Since no comprehensive data was available for Greece up to 2012, the averages from 2009 to 2012 are based on 24 countries while the average for 2013 is based on 25 countries.

[128] Information on other industrial consumer bands is available at http://epp.eurostat.ec.europa.eu/portal/page/portal/energy/data/database. By comparison, the annual consumption assumed for industrial and business customers in the monitoring survey is 418,600 GJ (418.6 TJ).

[129] See "VAT Rates Applied in the Member States of the European Union", 1 July 2014, available at http://ec.europa.eu/taxation_customs/resources/documents/taxation/vat/how_vat_works/rates/vat_rates_en.pdf. The reduced rates applicable in Belgium and France are assumed here.

[130] An overview of the price excluding VAT and refundable taxes and levies (as published by Eurostat) is not included here. Where components other than the VAT are deductible in certain countries, the deductions generally apply to only some of the consumers in the group.

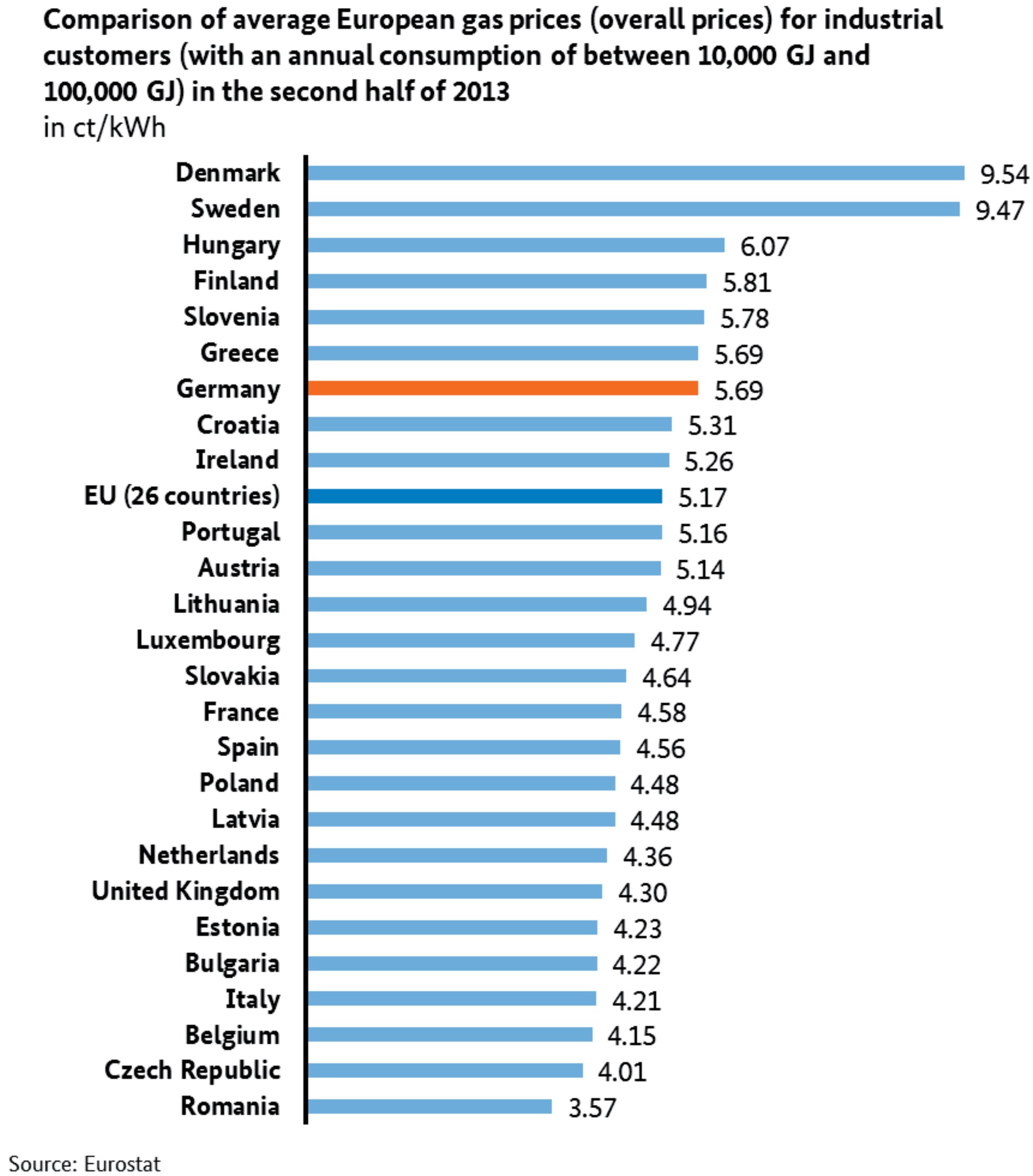

Figure 148: Comparison of average[131] European gas prices (overall prices) for industrial customers (with an annual consumption of between 10,000 GJ and 100,000 GJ) in the second half of 2013

Prices including VAT vary by about 6 ct/kWh, with the lowest in Romania at 3.57 ct/kWh and the highest in Denmark at 9.54 ct/kWh. The price in Germany at 5.69 ct/kWh is 0.52 ct/kWh or 10.0 per cent higher than the EU average of 5.17 ct/kWh.

[131] Eurostat's data covers 26 EU Member States (no data is available for Cyprus or Malta).

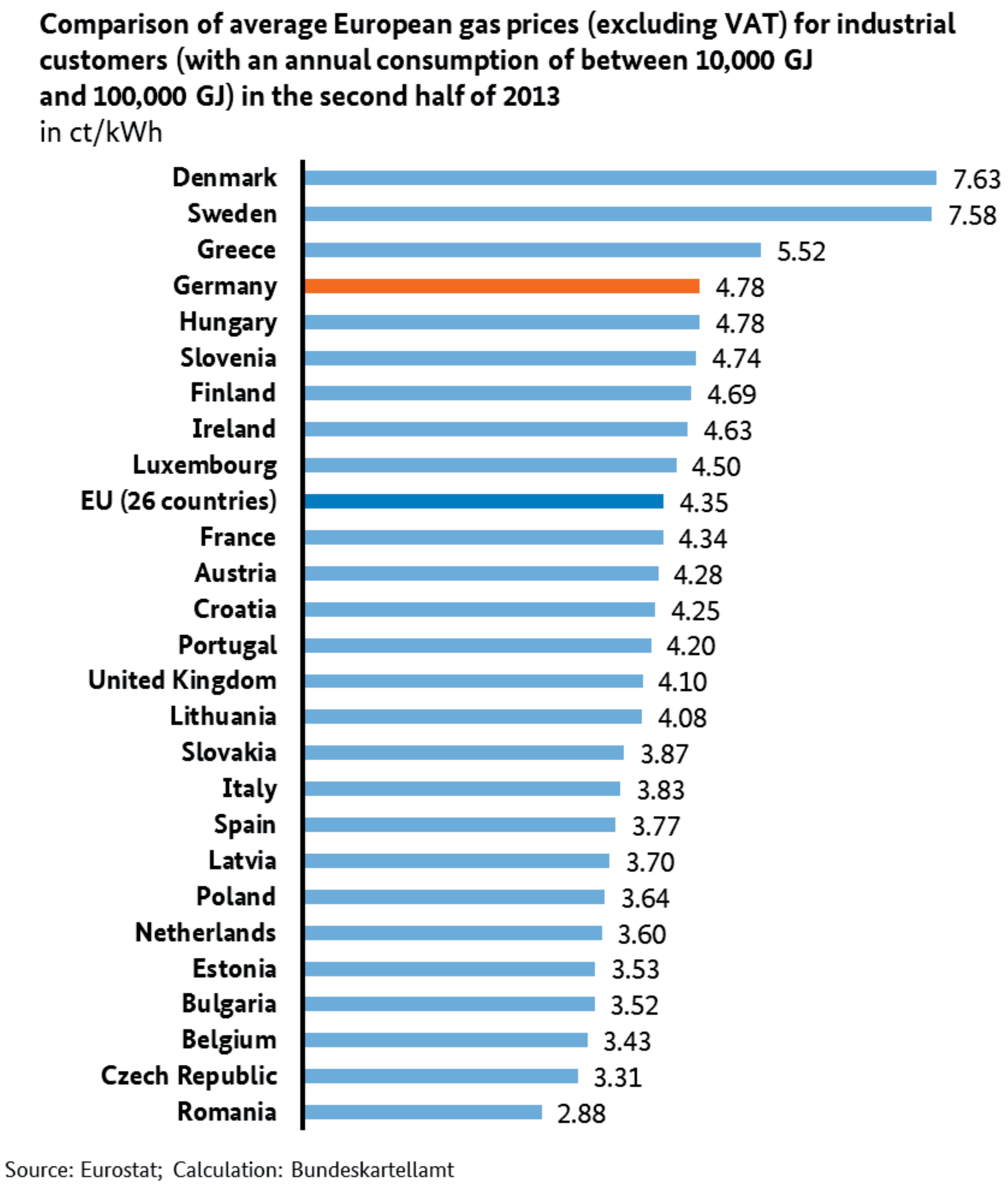

Figure 149: Comparison of average European gas prices (excluding VAT) for industrial customers (with an annual consumption of between 10,000 GJ and 100,000 GJ) in the second half of 2013

VAT rates for natural gas range from 3 per cent (in Greece) to 27 per cent (in Hungary). The difference between the highest and lowest prices excluding VAT is 4.75 ct/kWh. The price excluding VAT in Germany at 4.78 ct/kWh is still 0.43 ct/kWh or 9.9 per cent higher than the EU average of 4.35 ct/kWh.

A comparison of the shares accounted for by taxes and levies and by energy and supply and network costs also shows significant differences.

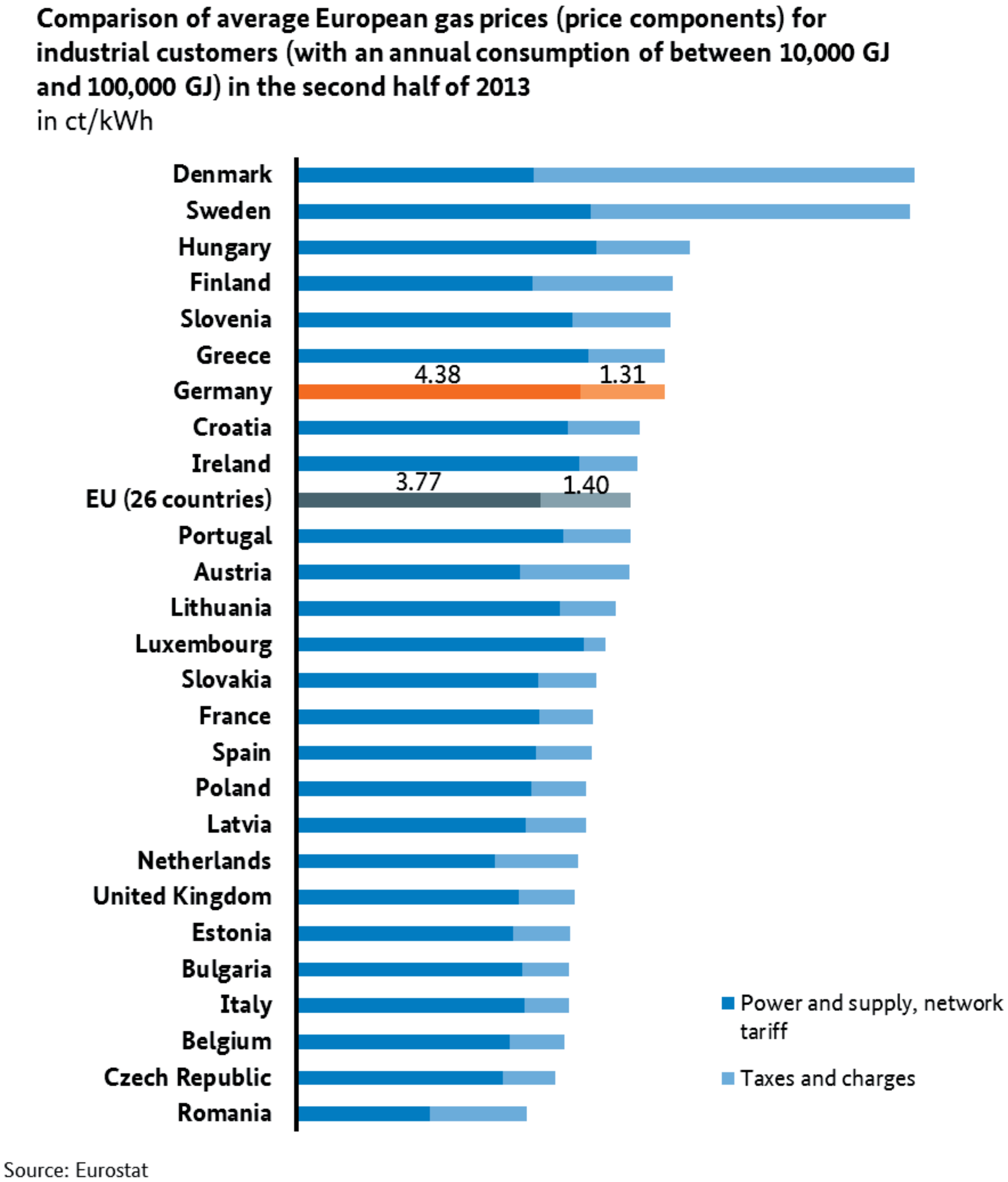

Figure 150: Comparison of average European gas prices (price components) for industrial customers (with an annual consumption of between 10,000 GJ and 100,000 GJ) in the second half of 2013

In Germany taxes and levies account for about 23 per cent (and energy and supply and network costs for around 77 per cent) of the overall price, which is close to the EU average. Taxes and levies in the individual countries account for between 7 per cent (Luxembourg with an overall price of 4.77 ct/kWh, just below the average) and 62 per cent (Denmark with the highest overall price at 9.54 ct/kWh).

Excluding the countries with the highest and lowest prices (Denmark and Sweden with by far the highest prices and Romania with the lowest price), the difference between the prices in the remaining 23 countries and the average of these countries is between 2 per cent and 25 per cent.

H Storage facilities

1. Access to underground storage facilities

All 24 companies operating and marketing a total of 41 underground natural gas storage facilities took part in the 2014 monitoring survey. The total maximum usable volume of working gas in these storage facilities was 25.45bn Nm³. Of this, 12.86bn Nm³ was accounted for by cavern storage and 12.59bn Nm³ by pore storage facilities. Reflecting the structure of the German natural gas market, the largest part of the storage facilities, by far, is designed for the storage of H-gas (23.16bn Nm³ compared to 2.29bn Nm³ for L-gas).

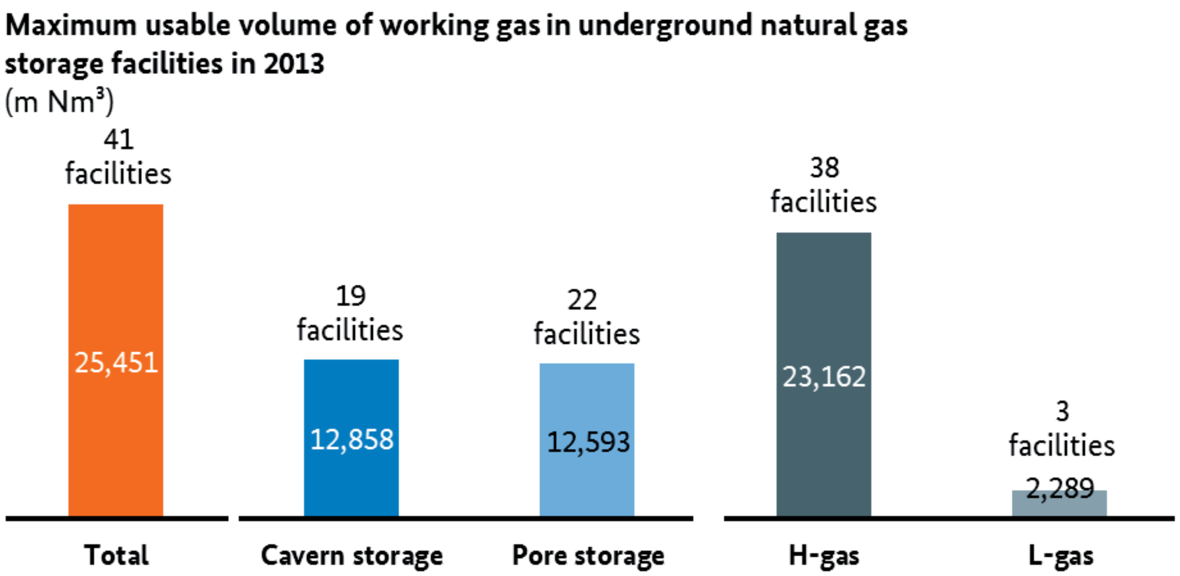

Figure 151: Maximum usable volume of working gas in underground natural gas storage facilities in 2013

2. Use of underground storage facilities for production operations

In 2013, less than one percent of the maximum usable volume of working gas in underground natural gas storage facilities was used for production operations in two storage facilities. After deducting the working gas volume used for production operations, the total working gas volume accessible to third parties in 2013 was 25.20bn Nm³ (compared to 23.37bn Nm³ in 2012), the injection capacity was 14.46m Nm³/h and the withdrawal capacity 15.38m Nm³/h.

3. Use of underground storage facilities by third parties – customer trends

According to the companies' data, the average number of storage customers in 2013 was 5.3, compared to 4.2 in 2009, 4.4 in 2010, 5.0 in 2011 and 5.4 in 2012. The following chart shows the trend in the number of customers per storage facility operator since 2009:

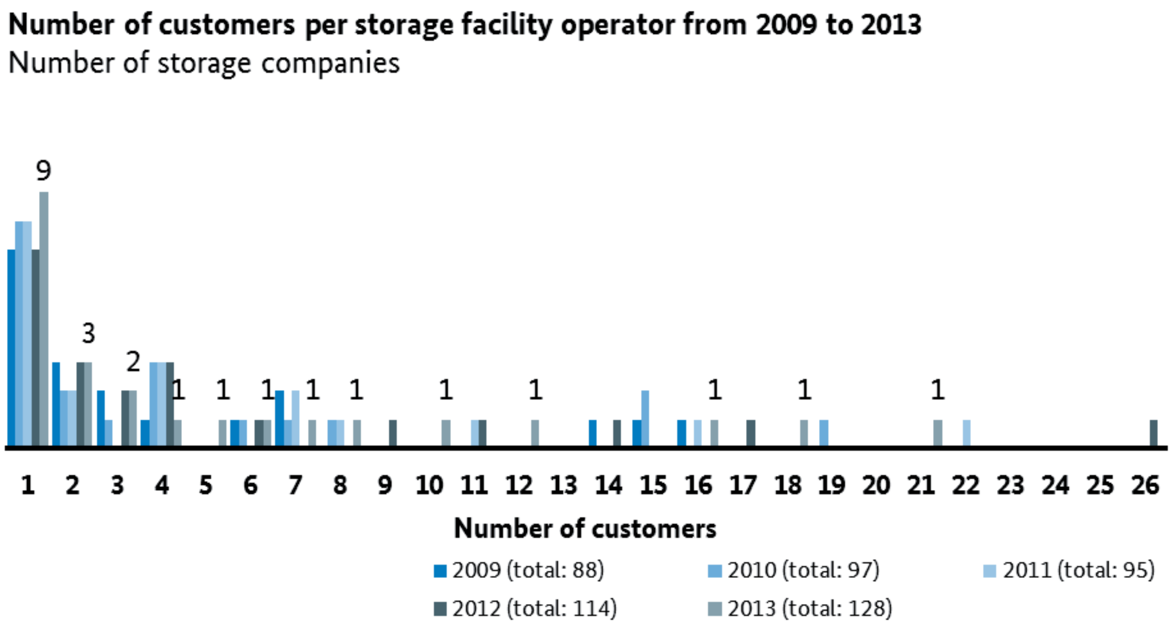

Figure 152: Number of customers per storage facility operator from 2009 to 2013

The number of storage customers increased from 114 in 2012 to 128 in 2013. The survey again showed, however, that one third of the storage companies have only one customer. The storage company with the most customers had up to 21 customers in the year under review.

4. Capacity trends

The following chart shows the free working gas volumes in underground natural gas storage as of 31 December 2013 compared to the previous years.

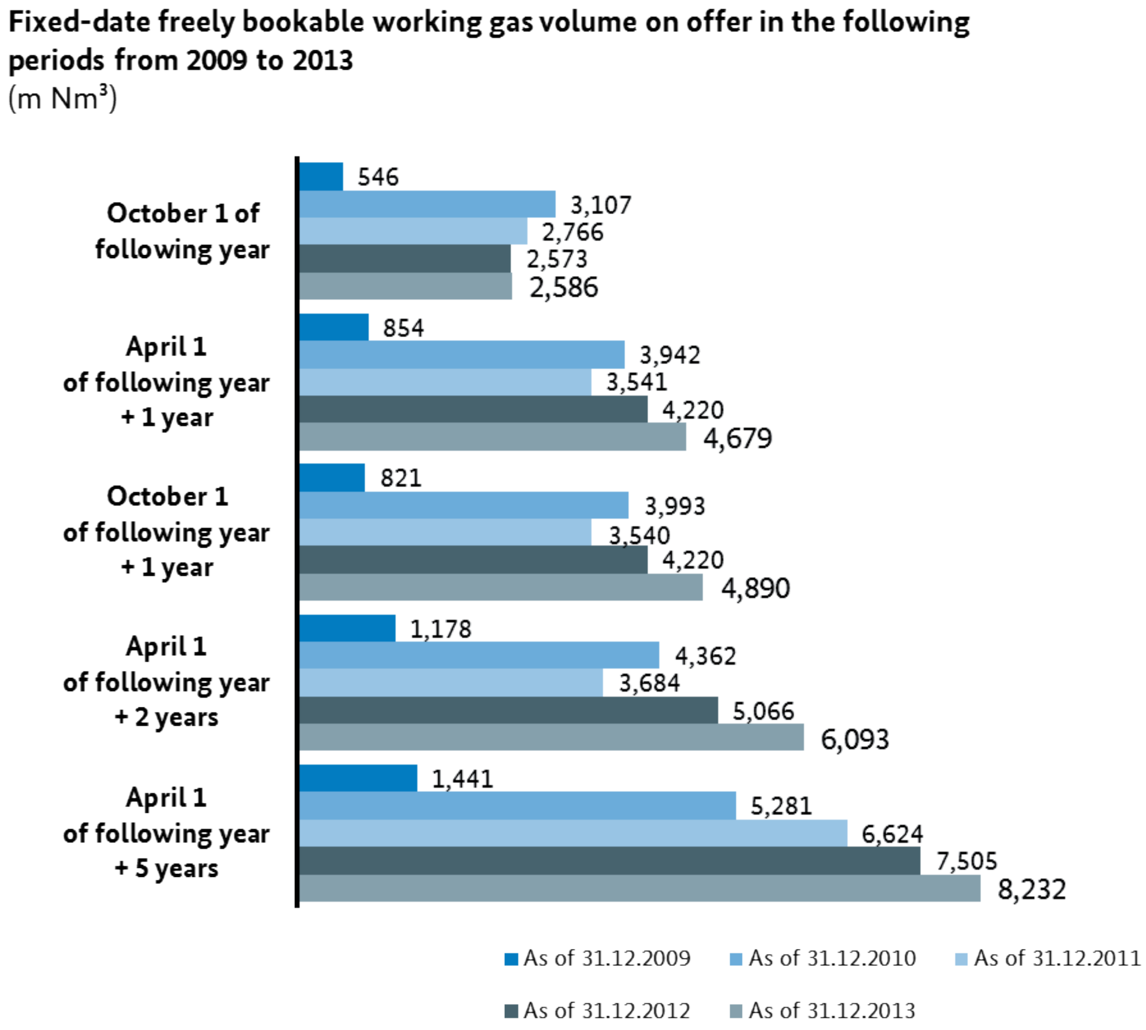

Figure 153: Fixed-date freely bookable working gas volume on offer in the following periods from 2009 to 2013

There was another slight decrease in the volume of short-term (up to 1 October 2014) freely bookable working gas while the volume of longer-term bookable working gas increased again. Here, too, there is a clear shift in the market towards shorter-term bookings.

I Metering

Since the full liberalisation of electricity and gas metering activities gas customers have been free to choose their provider for meter operations and metering services. If a customer does not switch to another provider, the network operator is responsible by law for providing these services.

634 companies operating a total of almost 13.7m meters responded to the questions about gas metering.

In the following section a distinction is made between distribution system operators acting as meter operator for their own systems and those providing (metering) services in the market. A further distinction is made between suppliers undertaking meter operator activities and independent meter operators. The following table shows in which capacity meter operators are present in the market:

Meter operator function

Function	Number
System operator acting as meter operator within the meaning of section 21b(1) EnWG	625
System operator acting as meter operator within the meaning of section 21b(2) EnWG, providing (metering) services in the market	9
Supplier with meter operator activities	5
Independent meter operator	1

Table 62: Meter operator function

The number of interval meters increased considerably from 51,944 in 2012 to 74,945. The number of metering points fitted by the meter operator with metering equipment within the meaning of section 21f EnWG and capable of connection to metering systems as defined in section 21d EnWG was nearly 871,000, or just 6 per cent of all metering equipment installed.

The following table shows the types of metering equipment used by the meter operators for standard load profile (SLP) customers:

Metering equipment for SLP customers

Metering equipment used by the meter operators for SLP customers	Number of metering points according to meter size		
	G1.6 bis G6	G10 bis G25	ab G40
Diaphragm gas meter with mechanical counter	8,799,944	285,586	36,941
Diaphragm gas meter with mechanical counter and pulse output	4,375,647	139,868	14,651
Diaphragm gas meter with electronic counter	8,896	209	852
Interval meters as for interval-metered customers	60	249	3,598
Other mechanical gas meters	11,037	2,380	25,055
Other electronic gas meters	3,741	7	1,427
Total number of meters within the meaning of section 21f EnWG (revised)	38,084	43,779	4,157
Total number of meters that can be upgraded within the meaning of section 21f EnWG (revised)	871,077	1,631	512

Table 63: Metering equipment for SLP customers

The following figure shows the technologies used to connect metering equipment to systems as defined in section 21d EnWG.

A total of 106,944 such meters were in use for SLP customers:

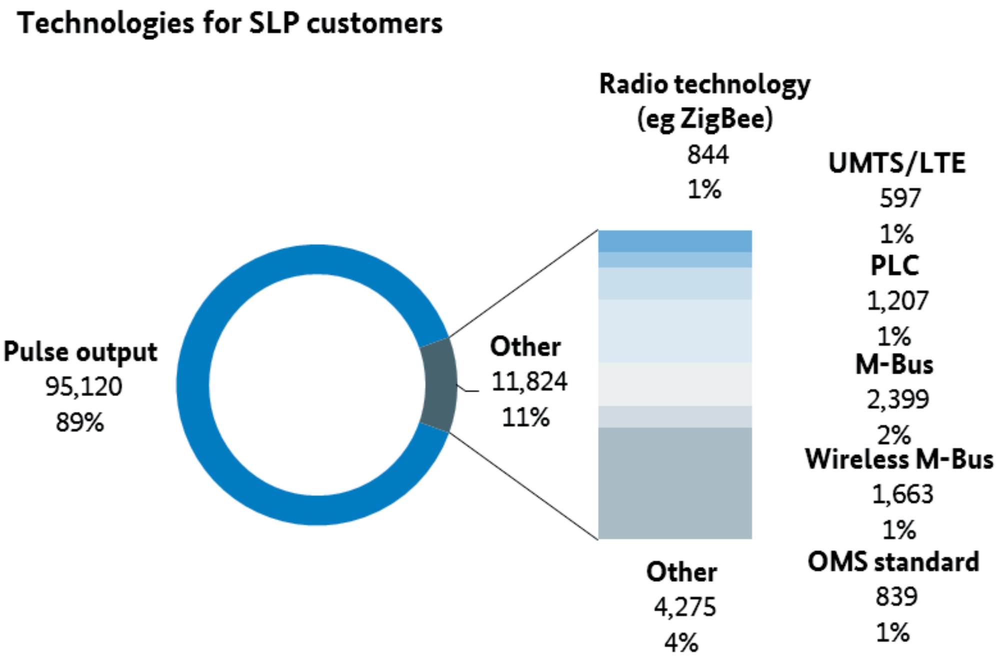

Figure 154: Technologies for SLP customers

The meter operators were also asked which type of meter they used for interval-metered customers. The following table shows the number of metering points fitted with each type of meter.

Metering equipment for interval-metered customers

	Number of metering points
Transmitting meter with pulse output/encoder meter and recording device/data storage	15,004
Transmitting meter with pulse output/encoder meter and volume corrector	8,797
Transmitting meter with pulse output/encoder meter and volume corrector and recording device/data storage	14,262
Other	122

Table 64: Metering equipment for SLP customers

The following figure shows the technologies used to connect interval-metered customers' meters (36,516 metering points) to metering systems.

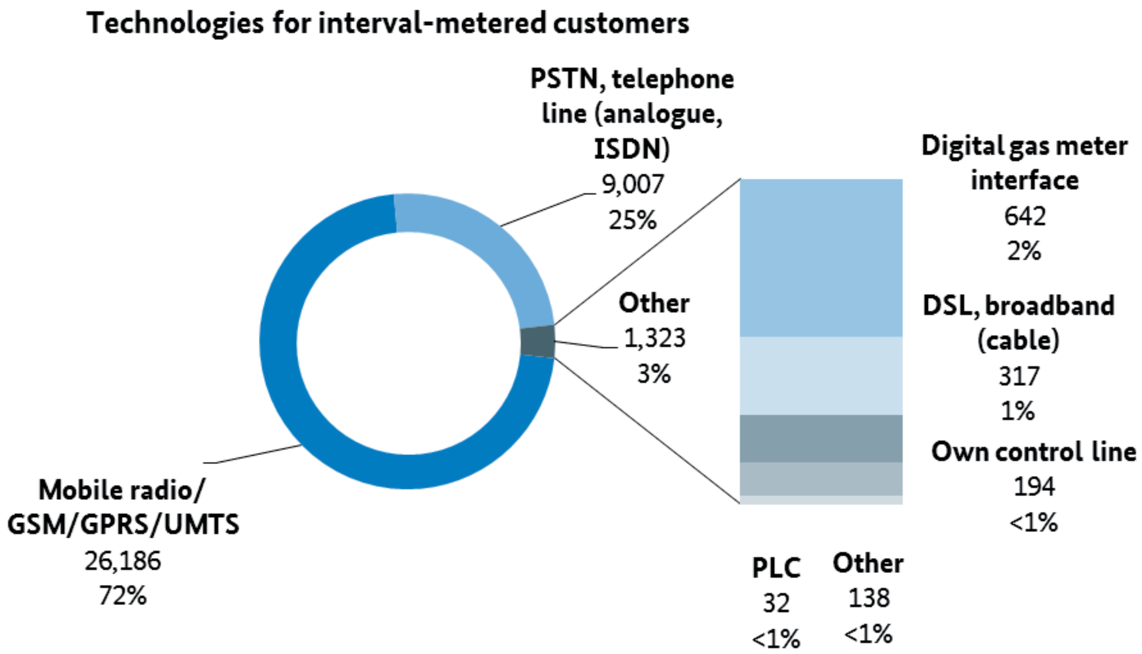

Figure 155: Technologies for interval-metered customers

III General topics

A Market Transparency Unit for Wholesale Electricity and Gas Markets

The Market Transparency Unit (MTU) based at the Bundesnetzagentur is tasked with ensuring fair pricing in the wholesale energy markets. The Unit also acts as the national market monitoring body under Regulation (EU) No 1227/2011 on wholesale energy market integrity and transparency (REMIT). Its tasks are carried out jointly by the Bundesnetzagentur and the Bundeskartellamt on the basis of a cooperation agreement requiring the approval of the German Federal Ministry for Economic Affairs and Energy (BMWi). Establishment of the Unit was provided for by new legislative provisions (sections 47a ff) incorporated into the German Restraints of Competition Act (GWB) in December 2012.

The tasks performed jointly by the Bundesnetzagentur and the Bundeskartellamt within the Unit and the other tasks carried out by the Bundesnetzagentur under REMIT are coordinated by a task force in the Bundesnetzagentur's energy regulation department.

Joint market monitoring

One particular task undertaken jointly by the Bundesnetzagentur and the Bundeskartellamt within the Market Transparency Unit is to collect data relating to the German gas and electricity wholesale markets and to analyse the data for possible breaches of the law. Irregularities and suspicions are referred to the enforcement authorities responsible, these being the Bundesnetzagentur for breaches of REMIT, the Bundeskartellamt for competition law offences, the Federal Financial Supervisory Authority (BaFin) for breaches of the German Securities Trading Act (WpHG), and the Saxon State Ministry of Economic Affairs, Labour and Transport for offences against the German Stock Exchange Act (BörsG).

Data will be collected primarily at European level, with transaction (trading) and fundamental data being reported to the Agency for the Cooperation of Energy Regulators (ACER) as provided for by REMIT. The European Commission's Implementing Regulation stipulates the exact data to be provided, the data formats and the reporting channels. Staff from the Bundesnetzagentur contributes within ACER to the activities of the working group advising the European Commission in drawing up these regulations. The Implementing Regulation is currently expected to be published in winter 2014, with ACER collecting the first data nine months after the Regulation enters into force.

ACER and the national regulatory authorities within the EU have signed a memorandum of understanding regulating access by the national regulatory authorities and market monitoring bodies to the data required for market monitoring and hence allowing the Market Transparency Unit to use such data.

The Federal Ministry for Economic Affairs and Energy plans to issue an ordinance for the Market Transparency Unit in accordance with section 47f of the Restraints of Competition Act, taking due consideration of the requirements laid down in the Implementing Regulation. This ordinance will enable the Unit to stipulate its own requirements. The scope of the reporting obligations and the requirements that can be defined by the Unit itself is laid down in the Restraints of Competition Act. The Unit may specify requirements for transaction and fundamental data that is not collected by ACER and passed on to the Unit.

The Unit is expected to define requirements for both electricity and gas balancing energy data and for selected electricity generation data.

The Market Transparency Unit will examine the data and information it receives for indications of breaches of Articles 3 and 5 of REMIT, sections 1, 19, 20 or 29 of the Restraints of Competition Act, Articles 101 or 102 of the Treaty on the Functioning of the European Union, the Securities Trading Act and the Stock Exchange Act. Any indications are referred immediately to the authorities responsible for pursuing these suspected offences.

The exact procedures followed are optimised by the Market Transparency Unit in agreement with the authorities in question to ensure full and effective cooperation. The Unit also consults with the Federal Financial Supervisory Authority and the market surveillance office of the European Energy Exchange (EEX).

An extensive computer-based trade monitoring system is needed to collect and analyse the data. The Bundesnetzagentur and the Bundeskartellamt are currently working together on acquiring and implementing the required system.

REMIT market monitoring

ACER's task under REMIT is to monitor the wholesale energy markets to identify and prevent trading based on inside information and market manipulation.

The Bundesnetzagentur is heavily involved in shaping market monitoring in Europe under REMIT. It chairs the ACER Monitoring, Integrity and Transparency Working Group and the ACER Wholesale Market Surveillance Task Force where all issues relating to REMIT are discussed by representatives of the European regulatory authorities and ACER. It also chairs the ACER REMIT IT Management and Governance Task Force which coordinates the installation of the required IT systems at ACER and the European regulatory authorities.

The Market Transparency Unit acts as the national market monitoring body which monitors the wholesale energy markets under REMIT in cooperation with ACER and the other national regulatory authorities. The basic framework and procedures for cooperation have been developed at European level.

Market monitoring under antitrust law

The Market Transparency Unit is also responsible for detecting indications of breaches of certain antitrust rules. It forwards the relevant information to the 8th Decision Division at the Bundeskartellamt, thus aiding the Division in its supervision of the wholesale gas and electricity markets. The Unit also provides the Bundeskartellamt with data for merger control proceedings and sector inquiries.

A cooperation agreement lays down the foundation for the Bundesnetzagentur and the Bundeskartellamt to work jointly within the Market Transparency Unit, covering aspects such as staffing, task allocation and coordinated data collection and exchange. Basic procedures were developed jointly as part of the work to establish the Unit. For instance, tasks relating to antitrust rules are assigned to the Bundeskartellamt staff within the Unit. Procedures to detect irregularities in respect of antitrust law are to be drawn up by the Bundeskartellamt's 8th Decision Division in close cooperation with the Unit.

In its Special Report on grid-based energy published in 2007 the Monopolies Commission called for continuous monitoring of the energy markets (para 211). This was substantiated by the Bundeskartellamt's findings from its sector inquiry into electricity generation and wholesale markets published in early 2011. Through the subsequent legislative processes, market monitoring under antitrust law was consolidated with market monitoring under REMIT in one independent body – the Market Transparency Unit – thus accommodating overlapping data requirements and the close relation between some of the prohibitions monitored. The fundamental pricing mechanisms have since become increasingly more complex on account of the Energiewende (Monopolies Commission, Special Report 65 "Energy 2013", para 167ff).

In light of the rapidly changing conditions in today's electricity market as a result for instance of the advancing Energiewende and the exit from nuclear power, the Market Transparency Unit will initially focus its antitrust monitoring activities on investigations to feed into the Bundeskartellamt's analysis of market power. Here, the pivotal analysis methodology first used in the Bundeskartellamt's sector inquiry into electricity generation and wholesale markets is to be elaborated and used to identify those electricity generating companies whose capacity is actually essential for a significant amount of hours during the year to meet the demand for electricity.

In 2013 antitrust monitoring activities centred on the work on drafting the REMIT Implementing Regulation and coordinating activities with those of the Bundesnetzagentur under section 12(4) of the German Energy Act (EnWG) within the framework of the energy information network. This close coordination aims to avoid contradictory data requirements and thus additional work for the market participants. At the same time existing data sources were identified in close cooperation with the trade associations, the gas and electricity transmission system operators and the market area managers. Another focus of activities was on the technical work in planning the computer-based system required for the determination of market power under section 18 of the Restraints of Competition Act and Article 102 of the Treaty on the Functioning of the European Union.

B Selected activities Bundesnetzagentur

1. REMIT tasks

1.1 Registration of market participants under REMIT

Market participants are to register with the Bundesnetzagentur. Pursuant to article 9(2) REMIT, registration should start at the latest within three months of adoption of the implementing act. ACER has provided a web-based registration platform CEREMP (Centralised European Register for Energy Market Participants) for the national regulatory authorities to register market participants. The Bundesnetzagentur, market participants and professional associations have all taken part in testing the platform in Germany.

The Bundesnetzagentur provides registration information on its website for market participants whose headquarters are in Germany[132]. Market participants whose headquarters are not in the European Union, or who are not resident there, must register in a Member State in which they are active.

1.2 Market participants' reporting and publication obligations

Pursuant to REMIT, market participants must publish inside information on the enterprise or its production facilities, effectively and timely. The Bundesnetzagentur has published a fact sheet on how to present this information[133]. The Bundesnetzagentur monitors the information published and checks as necessary whether this complies with the regulations and whether the market participants make correct use of exemptions to the ban on insider trading and the publication requirement.

The use of exemptions is subject to a reporting obligation to ACER and to the Bundesnetzagentur. The report can be submitted via the report form on the ACER website, which guarantees that the report will be forwarded to the competent regulatory authority.

The Bundesnetzagentur receives reports on the use of the exemption regulation. In the event of any peculiarities, the reports are checked for completeness and correctness. The Bundesnetzagentur has published a fact sheet on its website on the use of exemptions for the publication obligation and the prohibition on insider trading. The fact sheet provides market participants with information and explanatory comments on the statutory provisions.

1.3 Insider trading and market manipulation

Pursuant to article 3 REMIT, insider trading is prohibited on the energy trading market, as is market manipulation pursuant to article 5 REMIT. Pursuant to section 56 para 4 EnWG (Energy Industry Act), it is incumbent upon the Bundesnetzagentur to monitor compliance with REMIT and to pursue violations. Depending on the gravity of a violation, it may be considered an administrative offence, which will be

[132] http://www.bundesnetzagentur.de/cln_1412/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/HandelundVertrieb/MTS+REMIT/Registrierung/Registrierung-node.htm

[133] http://www.bundesnetzagentur.de/cln_1422/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/HandelundVertrieb/MTS+REMIT/Dokumente/Dokumente-node.html

sanctioned by the Bundesnetzagentur, or a criminal act, which will be prosecuted by the public prosecutor's office. Owing to the European context, the Bundesnetzagentur is working with other national regulatory authorities to develop responsibilities and efficient prosecution policies.

Information received from third parties about possible violations of the REMIT regulations also plays a decisive role in preventing insider trading and market manipulation. In this connection it is planned to set up an anonymous information system.

In addition, the Bundesnetzagentur pursues reports of suspicious transactions as per article 15 REMIT from persons professionally arranging transactions in wholesale energy products (eg energy brokers or energy exchanges). Such reports together with continuous analysis of the data collected are an important resource for uncovering insider trading and market manipulation.

2. Bundesnetzagentur cooperation with the Agency for the Cooperation of Energy Regulators (ACER)

The Agency for the Cooperation of Energy Regulators (ACER) was established in 2010 to support the authorities charged with regulatory tasks in the Member States to fulfil these at the Community level and to coordinate their efforts where necessary. From the start the Bundesnetzagentur has played an active role on the agency's committees, in particular on the Regulatory Council and in working groups, in order to press ahead with pertinent European solutions wherever cross-border trade demands it.

2.1 Drawing up Framework Guidelines and Network Codes

In May 2013 the European Council reaffirmed the fixed objectives of completing the internal energy market by 2014 and called for the effective and consistent implementation of the Third Energy Package, as well as swifter adoption and implementation of Network Codes.

National regulatory authorities, market participants, the European Commission and the Member States are drafting the Network Codes in a multi-stage process. Taking the ACER Framework Guidelines as a basis, the European professional associations of gas and electricity transmission system operators (ENTSO-E for electricity and ENTSOG for gas) are drawing up the Network Codes, which will enter into force following a committee procedure initiated by the European Commission with the participation of the Member States.

The Bundesnetzagentur has contributed actively to the agency working groups responsible for preparing the Framework Guidelines and the comments on the Network Codes, and is assisting the Federal Ministry for Economic Affairs and Energy (BMWi) in the ongoing committee procedures.

The European Commission has recently carried out a legal re-evaluation of the requirements for the Network Codes. According to this, the Network Code instrument would require an exhaustive rule avoiding references to any subsequent acts of transposition (contrary to the Commission Guidelines as per article 18 of the Electricity Regulation 714/2009/EU or article 23 of the Gas Regulation 715/2009/EU). Whereas the Commission Guidelines could contain such references, according to the Commission. Therefore, should the Network Codes refer to the subsequent joint adoption of implementation rules by the transmission system operators (TSOs), these rules must be transposed into guidelines according to the Commission. In this respect the regulatory authorities take the view that the participation rights of the agency, such as the right to initiate action to change the rules affected at a later date, must be safeguarded.

Gas network codes

Network Code on Capacity Allocation Mechanisms (CAM) in the gas transmission system

The CAM Network Code was created to correct the lack of non-discriminatory and transparent access to the gas infrastructure for all market participants. Essentially the network code is intended to ensure that the capacity on each side of a cross-border interconnection point can be offered in a bundled manner and thus make it possible for traders to carry out cross-border trade without any restrictions.

The network code is based on non-binding Framework Guidelines that were published by ACER on 3 August 2011 taking account of the Commission's annual priority categories. ENTSOG was then commissioned to develop the appropriate network code. A draft was presented by ENTSOG on 6 March 2012. ACER then gave its comments on 4 October 2012, at which point the draft was amended. Finally, ACER makes a recommendation to the Commission to approve the network code by committee procedure and to adopt it as a regulation. The CAM Network Code was adopted on 15 April 2013 and published as Regulation (EU) 984/2013 on 15 October 2013. The regulation enters into force as of 1 November 2015.

Gas Balancing Network Code in the gas transmission system (BAL NC)

The BAL NC serves to harmonise the fragmented gas markets and remove inefficient balancing systems in order to facilitate arbitrage transactions and develop a European wholesale market. Therefore there is a need for market-driven balancing arrangements. The BAL NC is based on non-binding framework guidelines, which were adopted by ACER on 18 October 2011. From these ENTSOG designed a corresponding network code and submitted a draft on 26 October 2012. On 25 March 2013 ACER presented its opinion and recommended that the European Commission approved the BAL NC and adopted it as a regulation. The BAL NC was published as Commission Regulation (EU) No 312/2014 on 25 March 2014. The Regulation enters into force on 1 October 2015 or 1 October 2016.

Network Code on Interoperability and data exchange in the gas transmission systems (Interoperability - INT)

With respect to the European gas infrastructure it has been determined that complete integration of the natural gas internal market is being hindered by the absence of common standards and a lack of uniform rules for data exchange. Common operational and technical provisions and communication rules are viewed as prerequisites for a functioning European transmission system. This premise also forms the basis of the non-binding Framework Guidelines that were published by ACER on 26 July 2012. ENTSOG was commissioned to develop an appropriate network code. A draft was submitted by ENTSOG on 10 September 2013. On 7 January 2014, ACER issued an opinion that amended the draft. ACER then recommended to the European Commission that the INT NC be approved by committee procedure and adopted as a regulation. The committee procedure is on-going.

Guidelines to prevent congestion in the European gas transmission pipelines (Congestion Management Procedures - CMP)

The frequent occurrence of contractual congestion prevents (new) market participants from gaining access to gas transmission systems despite the physical availability of the capacity.

To remove these obstacles and complete the internal market, guidelines have been drawn up to prevent congestion in the European gas transmission pipelines, which essentially promote efficient handling of capacity and increase the amount of capacity available. Based on decision 2012/490/EU of the European

Commission of 24 August 2012 on amending Annex 1 to Regulation (EC) No 715/2009 on conditions for access to the natural gas transmission networks, these new provisions apply to congestion management as of 1 October 2013.

Framework Guideline for the calculation of tariffs for transmission services (Tariff Framework Guideline)

Market participants in the European gas market are often subject to a large number of inconsistent tariffs that frequently do not reflect costs adequately. Therefore a framework guideline has been drawn up that is intended to ensure both cost-reflective, non-discriminatory access for each market participant and competition. Moreover, the guideline aims to encourage the efficient use of the gas transmission system and appropriate investment in it.

The Framework Guideline was produced by ACER on 29 November 2013. In December 2013 the European Commission asked ACER to draft a network code by the end of 2014.

Amendment to the Network Code on Gas Capacity Allocation (Incremental Capacity)

Although the CAM NC prescribes Community rules for the uniform auction of existing capacity at cross-border interconnection points, it does not contain any provisions for – where necessary – new capacity to be created at cross-border interconnection points or for incremental capacity. This is the capacity that is in demand at existing cross-border interconnection points and that exceeds the technically available capacity. Therefore there is a need to set harmonised, market-based approaches to determining new capacity and incremental capacity.

ACER produced a corresponding framework guideline on 2 December 2013. ENTSOG was then requested to draft a network code based on this guideline by the end of 2014.

Electricity network codes

The integration of markets necessitates the creation of technical minimum standards. In particular, this involves the introduction of common network connection conditions, balancing times, control criteria and settlement rules. These will reduce barriers to trade and market entry and drive integration.

The EU Third Internal Energy Market Package has set far-reaching requirements on the development of such standards and places an obligation on the European transmission system operators (TSOs) and on ACER to develop and implement such standards. Accordingly, within ENTSO-E their European organisation, the TSOs started to draft a new standard set of rules in 2012 for network usage - the electricity network codes.

Network Code on Capacity Allocation and Congestion Management (CACM) [134]

The CACM Network Code will be the first electricity network code to be adopted. It determines the rules for cross-border trade and in this connection the cooperation between the TSOs and power exchanges, as well as between the regulatory authorities and ACER. These include capacity calculation, allocation in day ahead and intraday capacity and the design of bidding zones in which electricity can be traded free of congestion.

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[134] See also I.F.3 "Network Code on Capacity Allocation and Congestion Management" on page 113

To achieve the network code objectives as quickly as possible, implementation has already commenced of individual requirements on a voluntary basis. Of special mention in this connection is the successful launch of market coupling in north-western Europe. This is the most highly developed project, which will be given a legal footing by the CACM Network Code.

Electricity Balancing Network Code[135]

The use of electricity balancing by TSOs ensures that the electricity offered at any given time meets the demand for electricity. The electricity balancing markets have taken on a key role in security of supply, most especially because of the growth of electricity generated from renewable sources that suffers disruption to availability.

The aim of the Electricity Balancing Network Code is to integrate the balancing markets in Europe which are currently organised on a largely national basis. Harmonising the balancing products and rules will facilitate the cross border exchange of balancing energy within Europe and promote competition between balancing service providers. One particular aim is to facilitate the inclusion of load management and renewable energy sources in the balancing market. The Network Code therefore enables TSOs to make more efficient use of available resources, thus reducing the costs and reinforcing the security of supply.

Forward Capacity Allocation Network Code (FCA)

The FCA Network Code plays a key role in hedging electricity business with our European neighbours. It opens up the opportunity for market participants when they conclude an agreement to reserve the circuit capacity necessary for cross-border electricity exchange for up to one year before the delivery date, thus giving them the fundamental security of being protected against price changes for electricity transport.

The network code provides all market participants with a reliable, uniform set of rules that specifies the prerequisites for participating in the futures market, explains the potential trading products and their design, shows settlement and liability scenarios and creates a basis for a standard auction platform and harmonised auction rules.

Network codes for the network connection (Requirements for Generators, Demand Connection Code, High Voltage Direct Current Connections)

Clearly essential in achieving a European internal market for electricity is to establish the most standardised network connection conditions possible for those market participants that connect their facilities to the transmission system. These market players include operators of generating facilities, of HVDC cables, of major electricity consumption units (such as energy-intensive industrial enterprises) and distribution network operators.

It is not always easy in these cases to find a balance between the interests of those players entitled to a connection and those players obliged to guarantee a connection. However, with the assistance of ENTSO-E, and through the involvement and consultation of market participants and their organisations, it has been ensured that the amount of investment required to update facilities to meet the new, standardised network connection conditions has been limited to the amount necessary for network integrity.

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[135] See also I.D.7 "Network Code on Electricity Balancing" on page 95

2.2 Energy infrastructure package

Regulation (EU) 347/2013 entered into force in May 2013 as a revised version of the TEN-E Regulation on guidelines for trans-European energy infrastructure. In October 2013 the European Commission accepted the Union list of projects of common interest. This list totals 248 projects in the fields of electricity, gas and oil infrastructure to which the objectives of the Regulation will be applied. The list became legally binding on 10 January 2014 as the Commission Delegated Regulation (EU) 1391/2013. It contains 20 projects in the electricity sector, five in the gas sector and two in the oil sector relating directly to Germany.

In line with the Regulation's requirements, on 31 July 2013 the Bundesnetzagentur reported the methods and criteria for the assessment of investment in the electricity and gas infrastructures. This data forms the basis for drawing up best practice procedures and recommendations for incentives to be set by ACER. On 30 March 2014 the Bundesnetzagentur published within the prescribed period its methods and criteria used to assess investments in electricity and gas infrastructure projects and the higher risks assumed.

The Bundesnetzagentur worked closely on an ACER Recommendation of 26 September 2013 to interpret the requirements of Article 12 of the TEN-E Regulation on a decision on cross-border allocation of investment costs.

In 2013 the Bundesnetzagentur dealt with three applications for cost allocation for projects of common interest. The Bundesnetzagentur reached a decision on these applications within the prescribed period and according to the application.

Since the designation of the Bundesnetzagentur as a "one-stop shop" for the approval procedure for projects of common interest on 15 November 2013, synergies with the Grid Expansion Acceleration Act and the Planning Approval Responsibilities Ordinance have been made use of and expertise combined. This should serve to further speed up the approval procedure.

3. Bundesnetzagentur participation in the Council of European Energy Regulators (CEER)

Since 2005 the Bundesnetzagentur has been a member of the independent Council of European Energy Regulators (CEER). Since ACER was established in 2011, CEER has concentrated on issues that do not fall under the remit of ACER. These include consumer protection, regulatory aspects of retail markets, the promotion of renewable energy sources, the future of the internal market and international cooperation. In addition, CEER supports the work of ACER in many areas.

3.1 European developments in consumer protection

Through its participation in the CEER Customer Retail Market Working Group (CRM WG), in 2013 the Bundesnetzagentur once again actively assisted in drafting pioneering guidelines in consumer rights. In this regard the interaction with the European Commission, an exchange of views within the working groups set up to deal with these issues and the London Forum, where the essential guidelines are adopted in the area of consumer rights, are gaining in importance.

The "2020 Vision for Europe's energy customers" developed by CEER in 2012 was driven ahead last year by integrating more interest groups. The focus of the second consumer conference organised by CEER was the implementation of the specific aims by that date. These are based on four key principles that characterise the relationship between the energy sector and its groups of customers:

1. securing a reliable energy supply,
2. safeguarding an affordable energy supply,
3. achieving simplicity and transparency in offers and invoices,
4. strengthening consumer protection and competence to act.

To strengthen contact between regulators and consumer organisations, CEER in close cooperation with BEUC, the European umbrella organisation of consumer organisations, analysed the current working relations at national level for the first time. This status report dated 1 January 2013 provides an overview of whether, how and which specific issues the two sides exchange information on. It showed that cooperation took place mostly on a voluntary basis on various issues and to varying extents. Nevertheless the representatives of both parties wished to have even greater collaboration in areas such as the systematic exchange of data and in strategic and political issues.

To ensure that consumers are well-informed, under EU law they must be afforded clear information on energy costs, their rate of consumption, comprehensible contracts, transparent prices and energy efficiency systems. CEER took this as a basis for a status report to examine the extent to which specific information on energy costs, energy sources and energy efficiency systems is accessible for the consumers and which information is decisive in the choice of a supplier. The findings showed that much of the relevant information is already accessible although there are differences between regulatory authorities regarding the type and extent of information. In general, regulatory authorities provide more comprehensive information on cost-related aspects than on energy sources. In some countries there are other sources of information besides the regulatory authorities such as providers, consumer organisations or the relevant ministries. In addition, energy efficiency systems are frequently well-established yet seldom fall under the jurisdiction of the regulators rather they fall under that of the ministry responsible.

As part of the Third Internal Market Package intelligent measuring systems are to be introduced where a rollout has been positively evaluated by the respective Member State in a cost-benefit estimate. In this respect, in 2013 CEER reviewed status reports to check compliance with its guidelines on smart meters as at 1 January 2013. Although the technical standards varied greatly throughout Europe, the findings showed that the Member States had already implemented them as far as possible or planned to introduce them in the next two years.

Under the requirements of the Third Internal Market Package, ACER has to draw up a report every year on the status of the energy markets. The report is drafted jointly with CEER, although the Bundesnetzagentur also contributed especially on the issue of consumer complaints ("ACER/CEER Market Monitoring Report"). The aim of the report is to identify weaknesses on the retail markets and to organise these more efficiently in the future.

3.2 The Bundesnetzagentur's international work

The Bundesnetzagentur has been working long-term through the International Strategy Group (ISG) on coordinating a dialogue with strategically important energy partners. The work involves an exchange of information on regulatory practices with regulatory authorities and their regional mergers. Examples of an in-depth exchange of views with external energy partners include once again the relations with the Federal Tariff Service (the Russian regulatory authority) and to the states in the "Eastern Partnership Platform" of the EU Commission (Armenia, Azerbaijan, Belarus, Georgia, Moldavia, Ukraine).

After regulatory issues had been a priority under the G20 Russian presidency, the Russian G8 chair then followed on from this with similar objectives. The focus was placed on regulatory aspects that ensure the long-term reliability of critical infrastructure. Following the events in the Ukraine, however, this intention could not be met.

Beyond this, existing relations with the International Energy Agency (IEA) were strengthened. In this respect the Bundesnetzagentur contributed to establishing a regular exchange of information at the working level to facilitate the dissemination of expert knowledge. In addition, the IEA set up an advisory committee on issues of security of supply for electricity, which encourages regulators, amongst others, to actively join in the work.

Furthermore, on 19 November 2013 and for the first time, CEER organised a round table, together with the Association of Mediterranean Energy Regulators for Electricity and Gas (MEDREG), at which representatives from regulatory authorities, industry and financial institutions discussed the challenges faced by the energy markets and incentives for investment in infrastructure in the Mediterranean region. They also exchanged views on challenges in connection with the market integration of renewable energy sources. Both sides agreed to extend the bilateral cooperation and to work on technical projects for the exchange of knowledge and best practices in the CEER and MEDREG working groups.

4. Investment measures/Incentive regulation

The Ordinance concerning Incentive Regulation for the Energy Supply Networks (ARegV) offers network operators an opportunity to budget for costs for expansion and restructuring investment beyond the authorised revenue cap of network tariffs. Based on section 23 ARegV, the Bundesnetzagentur issues approval upon application for individual projects insofar as the prerequisites stated in the Ordinance have been met.

Since the amendment to section 23 ARegV in spring 2012, approval of the project is given on the merits of the investment. Once the approval has been issued, the network operator may adjust his revenue cap by the costs of capital and of operation connected to the project immediately in the year the costs are incurred. The costs budgeted are checked by the Bundesnetzagentur in an ex-post control.

In 2013 some 401 applications for investment projects were submitted to the competent Ruling Chamber. Costs of acquisition and production of about €20.2bn are related to these investment measures. Some 362 applications concern the electricity sector totalling approximately €19bn. Of these, the four TSOs accounted for 84 applications worth about €17.5bn and the distribution system operators (DSOs) accounted for 278 applications worth €1.5bn. Gas network operators submitted 39 applications in total with a volume of about €1.2bn. Compared to 2012, both the number and the investment amount of the applications have risen. In 2012 there were 123 applications with a total investment volume of approximately €15.2bn.

An amendment to an ordinance in August 2013 affected the 110 kV level. A new paragraph 7 was added to Section 23 ARegV to increase the possibilities for approval of investment measures for DSOs at the high voltage level. In the past such investments were generally covered by the expansion factor pursuant to section 10 ARegV. By making this change the issuer of the ordinance wanted to accommodate the DSOs' need for investment at the high voltage level where a greater number of transport tasks would have to be assumed because of the expansion of facilities in the renewable energy sector.

5. Withdrawal of the determinations on pooling (settlement at several points of offtake with synchronous supply) in derogation from section 17(8) StromNEV (Electricity Network Charges Ordinance) effective as of 1 January 2014

On 22 August 2013 the Ordinance on the Change of Ordinances in the field of Energy Legislation of 14 August 2013 (Federal Law Gazette I page 3250) entered into force. This provides for a new provision on pooling in section 17(2a) StromNEV. This was one of the reasons why on 6 November 2013 pursuant to sections 48 ff VwVfG the Bundesnetzagentur initiated several proceedings on the withdrawal of determinations on pooling in derogation from section 17(8) StromNEV (file number BK8-11-015).

The market participants had the opportunity until 6 December 2013 to submit their comments on the first draft of the withdrawal decisions. The comments focused particularly on the considerable difficulties that could arise in the event of reversal. The pending appeal proceedings were terminated by mutual agreement. A modified hearing of 7 May 2014 that provided for a withdrawal from 1 January 2014 took account of these circumstances. The market participants had an opportunity to comment on the amended draft.

Due to the expiration of a delegation of powers agreement with the state of Lower Saxony as of 31 December 2013, the withdrawal proceedings will now continue with the Lower Saxony regulatory chamber under file number BK8-11-0919.

6. Reserve capacity / Reserve Power Plants

Since 27 June 2013 the Reserve Power Plant Ordinance (ResKV) has governed the acquisition of reserve capacity. This gives TSOs an opportunity to keep reserve capacity available within the scope of security of supply and reliability.

The Bundesnetzagentur is charged with checking the power plant output requirements for reserve capacity determined by the TSOs. The requirements for the 2013/2014 winter for both the cold weather scenario and the wind scenario were about 2.5 GW. Under the extensions of contract pursuant to section 1(3) ResKV the following list of power plants was secured for winter 2013/2014:

Power plants for reserve capacity for winter 2013/2014 under the contract extensions

Power plant operator	Capacity (MW)
Germany	
E.ON	1,037
Grosskraftwerk Mannheim AG	200
Austria	
Energieversorgung Niederösterreich AG	785
Total	2,022

Table 65: Power plants for reserve capacity for winter 2013/2014 under the contract extensions

A voluntary commitment was reached with the TSOs for standby capacity that makes it possible to allocate costs over the revenue caps of the TSOs. This allowed the costs of reserve power plants due to a contract extension to be implemented in the corresponding revenue caps of the TSOs.

In addition to this, as part of an expression of interest procedure pursuant to section 3 ResKV further capacity from Italy (183 MW) and Austria (183 MW) was secured to cover the remaining requirements. The negotiations with the power plant operators that followed on from the expression of interest procedures were led by the TSOs. The payments fixed in the contracts will be allocated above the revenue caps of the TSOs concerned.

In total the TSOs' revenue caps for 2014 contain a moderate amount in the tens of millions for the power plant reserve capacity and will be allocated to the network tariffs. The costs of any use of the reserve power plants in winter 2013/2014 would be recognised in summer 2014 and would be allocated to the revenue cap of the corresponding TSO in 2015 taking into account a specific interest rate in line with an incentive regulation account. However in the winter months 2013/2014 the reserve power plants were not used.

7. System support services

The Bundesnetzagentur in 2014 set the TSOs an incentive model for system services (control power, energy loss, redispatch). This applied to the entire second incentive regulation scheme period and provided a continuation of the essential key aspects of the model effective in the first period. With the aid of the model set out in the determination, and on the basis of the energy amounts and price trends forecast annually for the following year, a reference value is set up, which is included in the TSOs' revenue caps as the predicted cost. Based on a subsequent comparison of the predicted costs and the actual costs, it can seen whether the reference value is undercut or exceeded. If the difference is below the target value, the TSOs must refund the difference to the network user with a two-year delay, however, they may keep a bonus. If the target value is exceeded, they are refunded the difference but must pay a penalty, which in turn is credited to the network users. This creates an incentive for the TSOs to set up efficient system services so as to keep any negative impacts on the network tariffs to a minimum.

C Selected activities of the Bundeskartellamt

The most important case in the authority's merger control practice in 2014 involved an in-depth examination of the EWE / VNG merger project, in the context of which the authority changed its definition of the gas markets. With regard to the prohibition of anti-competitive agreements, the Bundeskartellamt initiated a proceeding against an agreement which aimed to restrict electricity generation at the Irsching 4 and Irsching 5 power plants. The focus of the authority's control of abusive practices lay in several proceedings concerning the award of concessions for electricity and gas networks and in the examination of prices for district heating of seven district heating suppliers. As regards the area of competition advocacy, the Bundeskartellamt has warned in particular of the risks to competition of an over-hasty introduction of a capacity market.

1. Merger control

In October 2014, following an in-depth examination, the Bundeskartellamt cleared plans by EWE AG to increase its share in VNG – Verbundnetz Gas AG to a majority stake and to acquire sole control of the company. In the course of the proceedings the Bundeskartellamt took into consideration new developments in the gas markets and changed its definition of these markets which, in some cases, had been applied for decades.

Generally speaking there has been a shift in market power away from the German gas transmission companies to foreign gas producers, above all Gazprom and Statoil, which are also becoming increasingly active as traders on the downstream levels. The differentiation that had so far been made between the supply of gas to supraregional gas transmission companies (1st level) and regional gas transmission companies (2nd level) has therefore been abandoned. Both levels of the market are now classified as one single gas wholesale level (for H-gas and L-gas), including traders. The geographic wholesale market for natural gas is defined as a national market and its definition will no longer be based on the network or market area. This also applies to the downstream market for the supply of gas to regional and local distributors, in particular municipal utilities.

On the end customer markets the Bundeskartellamt differentiates between a market for the supply of gas to load profile end customers (in particular industrial customers) and standard load profile customers (mainly household customers). The market for the supply of gas to industrial customers (metered load profile) will also no longer be defined on the basis of the network or market area, but as a national market. As regards the supply of gas to household customers, the Bundeskartellamt, in line with its practice in the electricity sector, now differentiates between basic supply household customers and special contract customers. The markets for special contract household customers are defined as nationwide. However, the geographic market for the supply of gas to basic supply household customers will still be defined on the basis of the network. Under this definition each basic supplier has a monopoly position in its region.

In many municipalities the current concession contracts for the operation of electricity and gas networks are about to expire. A large number of notifications of merger projects during the reporting period concerned the establishment of joint network operation or network ownership companies and lease models which occurred either in connection with the application for a concession or as a consequence of the implementation of an award decision. Merger projects of this kind usually do not raise any concerns because they do not significantly impede effective competition on the markets affected by the merger. Instead one monopolist replaces another without any further strengthening of the dominant position. With the outcome of its examination of such a merger project the Bundeskartellamt does not take a position on whether the procedure conducted by the municipality to award a new undertaking the rights of way complied with relevant competition law provisions (§§ 1, 19, 20 Act against Restraints of Competition (GWB), Art. 102 Treaty on the Functioning of the European Union (TFEU), in conjunction with §§ 1, 46 Energy Industry Act (EnWG)). In the letter of clearance which the Bundeskartellamt sends to the notifying undertakings attention is generally drawn to this limited scope of the examination under merger control.

In October 2014 the Bundeskartellamt cleared plans to convert a temporary minority participation of RWE Deutschland AG (RWE) in Dortmunder Energie- und Wasserversorgung GmbH (DEW 21) into a permanent one. Once the project is implemented RWE will have a permanent holding of 39.9 per cent of the shares in DEW 21 whilst 60.0 per cent will fall to the municipal utility Stadtwerke Dortmund and 0.1 per cent to the City of Dortmund. There was no evidence that the merger would significantly impede effective competition in the markets affected. The turnover achieved by DEW 21 on the national electricity retail markets represents a market share of less than 0.5 per cent. There are no market share additions on the market for the first-time sale of conventional electricity: DEW 21 is not active in this area and the electricity generating capacities of STEAG, in which DEW 21 has an indirect minority shareholding, are not attributable to DEW 21 under merger control. Also under the general aspect of a possible acquisition strategy by RWE, the merger will not have any lasting negative effects on the market. The major electricity companies are no longer pursuing a strategy of acquiring participations in a large number of municipal utilities. In view of the general developments in the market it also no longer seems plausible that the companies could successfully pursue a customer foreclosure strategy by acquiring participations in municipal utilities.

2. Prohibition of anti-competitive agreements

The Bundeskartellamt has initiated proceedings under Art. 101 TFEU against an agreement which is aimed at restricting electricity generation at the Irsching 4 and Irsching 5 power plants. The proceedings concern the specific arrangements for remuneration payments contained in the redispatch contracts for the Irsching 4 and Irsching 5 power plants.

Both contracts relate to the Federal Network Agency's decision BK8 12 019 of 30 October 2012 in which it set criteria for determining an adequate remuneration for redispatch measures. The basic idea behind these criteria is to reimburse the costs of redispatch measures (variable costs) while the costs of maintaining capacity (fixed costs) are generally not reimbursed. Redispatching must not lead to additional profits for the power plant operators because this could otherwise lead to market distortion, system destabilization and unnecessarily high costs. However, if the resdispatch measures account for more than 10 per cent of the feed-in quantities of the previous year of a production plant, the transmission system operator may pay the power plant operator remuneration for maintaining capacity. The redispatch contracts for the two power plants mentioned above are the first to specify this remuneration possibility as foreseen in clause 5 of the BK8 12 019 decision.

It was agreed between TenneT and the power plant operators that the remuneration charges be calculated based on the proportion of market-driven generation by the power stations or network-driven generation to total generation (cf. Monitoring Report 2013, p. 61). The remuneration payable by TenneT for the maintenance of capacity is calculated according to the following formula: Fee = XX million euros x (quantity fed-in as a redispatch measure within the calendar year / total quantity fed-in within the calendar year). The remuneration system provides an incentive to limit the amount of electricity generated by the power plant. The payments to the power plant operators increase the less the power plants are used on the "regular" production markets i.e. outside the area of redispatch measures. Under the contracts the power plant operators undertake to continue a "market-driven operation of Irsching 4 and 5" as previously done. The Bundeskartellamt is examining whether the remuneration system is compatible with Art. 101 TFEU. The proceeding is being conducted in close cooperation with the Bundesnetzagentur.

Several appeals against the BK8-12-019 Bundesnetzagentur decision are pending before the Oberlandesgericht Düsseldorf (Higher Regional Court Düsseldorf). In these proceedings the Bundeskartellamt has issued amicus curiae opinions in accordance with § 90 GWB, Art. 15 Regulation 1/2003 which deal with operative provision 5 of the decision.

3. Control of abusive practices of dominant companies

Award of concessions for electricity and gas networks

In respect of the abuse of a dominant position by municipalities in the award of rights of way under § 46 of the EnWG, two decisions of the Bundesgerichtshof (Federal Court of Justice; (BGH, decision of 17 December 2013, KZR 65/12 - Heiligenhafen and KZR 66/12-Berkenthin) have led to more legal security in key issues and confirmed the Bundeskartellamt's position in its prohibition decision against the district town of Mettmann (cf. Monitoring Report 2013, p. 277). According to the decision, it is inadmissible for a municipality to assign rights of way inhouse in preference of its own utilities, municipal undertakings and holding companies without a tender procedure. According to the court, the requirement to conduct a non-discriminatory award procedure and the prohibition of an inhouse award did not infringe upon the guarantee of self-government of a municipality under Art. 28 (2) of the Basic Law. The Bundesgerichtshof has also made it clear that the award decision should be made according to appropriate criteria, which can be divided into two categories: (1) Criteria relevant to the aims of § 1 EnWG and (2) criteria relevant to the purpose of the concession contract, i.e. an admissible economically efficient utilisation of the rights of way. As regards the relation of the categories of criteria to one another, priority must be given to those criteria pertinent to the objectives of § 1 EnWG (§ 46 (3) sentence 5 EnWG). Where the award procedure violates the relevant provisions, this will result in the concession contract being declared void in accordance with § 134 German Civil Code. For the first time the Bundesgerichtshof has set an obligation for the unsuccessful applicants to object (in analogy to section 101a GWB) if the municipality informs them in writing beforehand about the intended award.

The court's decision of 3 June 2014 (EnVR 10/13) brought further clarification on network transfer and regulatory follow-up questions after conclusion of the award procedure. The court decided that co-generation plants also have to be transferred, that this does not constitute a violation of Art. 14 of the Basic Law and that the Bundesnetzagentur has the discretion to take up the matter. If the Bundesnetzagentur does take up a case, it also has to examine the validity of the concession contract.

Upon a complaint by the defeated concession holder, the Bundeskartellamt has initiated a proceeding against the municipality of Titisee-Neustadt on suspicion of abusing its dominant position by awarding rights of way to a municipal holding company. The municipality of Titisee-Neustadt has been given the right to be heard. The proceeding is still pending.

At the request of the authorities conducting the award procedures of the capital of Baden-Württemberg, Stuttgart, the Freie und Hansestadt Hamburg (Free and Hanseatic City of Hamburg) and the Federal State of Berlin, the Bundeskartellamt has been consulted in the respective concession procedures for the award of rights of way in Stuttgart, Hamburg and Berlin. These consultations already began in 2012. Talks on data disclosure, award procedures and award criteria, also partly on the drafting of concession contracts, have been held at the premises of the Bundeskartellamt. The Bundeskartellamt informed the authorities of its preliminary assessment without examining all issues in a final and binding way because the consultations were not part of the abuse proceedings.

Upon complaints by unsuccessful bidders, the Bundeskartellamt initiated a proceeding against the City of Stuttgart in April 2014 and against the Federal State of Berlin in July 2014 on suspicion of abusing their dominant positions in the award of rights of way. The proceeding against the City of Stuttgart could be terminated in June 2014 after an examination of the evaluation documents revealed that there had been no violation of §§ 19, 20 GWB. Although the evaluation was not without error, this did not affect the selection outcome.

With its commitment decision concerning Cölbe municipality, the Bundeskartellamt has made it clear that secret competition is to be protected in procedures for the selection by a municipality of a new rights of way holder. This applies first and foremost to the relations between the bidders. If the municipality itself participates in the competition for the award of the concession with a municipal undertaking, a company operated by the municipality or a municipal holding company, it is faced with certain challenges. According to the rationale of § 16 VgV (Ordinance on the Award of Public Contracts) the municipality has to ensure that the municipal bidder receives no competition-relevant information about the bids of other bidders and the award procedure. This requires a strict separation in terms of staff and organisation of the award procedure from the participation of the municipality as a bidder in the competition.

District heating prices

The proceedings instituted in spring 2013 by the Bundeskartellamt against seven district heating suppliers on suspicion of their charging excessive prices are still ongoing. The investigations focus on more than 30 different heating supply areas throughout Germany. The starting basis of the proceedings was the outcome of the sector inquiry into the district heating sector which was concluded in August 2012. In order to follow up the initial suspicion of excessive pricing the Bundeskartellamt first collected data for the years 2010 to 2012 both from the companies concerned and eight potential comparable companies. Before the data could be analysed, extensive data examination and further enquiries to the companies concerned were necessary to attain reliable results.

In accordance with case-law in the area of district heating the Bundeskartellamt usually assumes that the local provider holds a dominant position. According to the case-law of the Oberlandesgericht Düsseldorf the supply of district heating is the "ideal-typical" monopoly market. Although it is true that before deciding on a heating system customers can choose between different supply channels (provided they are available, may be used and there is no obligation to procure district heating), once they have opted for district heating they are bound to this kind of heating system in the long term.

The different levels of district heating supply, i.e. generation, network and distribution, are normally integrated in one company. In addition, district heating suppliers often supply several different areas with district heating, whereby tariffs can vary from one area to another. Also in the case of the companies against which the Bundeskartellamt has instituted proceedings, excessively high revenues have not been generated in all of their supply areas. Furthermore, high revenues can also be justifiable - e.g. due to different generation and network structures which result in cost differences. Another aspect to consider is the fact that district heating which is generated together with electricity in co-generation plants is a by-product. This raises certain questions on the allocation of costs which have gained even more relevance in view of sinking electricity wholesale prices.

If connection to and use of the municipal district heating system is compulsory in a certain district or there is a similar obligation under private law to use district heating, the district heating provider has a legally protected monopoly position. The Bundeskartellamt views such mandatory connection with criticism. It further weakens competition between the different heating systems because it not only prevents customers from changing to another system but even limits the selection of a heating system from the onset. Instead an increase in competition between the different systems would be desirable since this could limit the scope for pricing in the district heating sector.

4. Competition advocacy

In the debate about a new market design in the German electricity sector the Bundeskartellamt strongly advocates competitive structures.

It is appreciated that in the reform of the Renewable Energy Sources Act (EEG) more focus has been placed on competition mechanisms in promoting renewable energies. With the mandatory direct marketing of electricity from new plants and the invitation to tender for grant funding, market-based elements have now been introduced into the amendment. With the introduction of direct marketing, producers of electricity from renewable energies are obliged to take on responsibility for the marketing of the electricity they generate. Tenders ensure that the support levels are determined by the market in future. It is expected that this will help to promote a more cost-effective support of renewable energies. However, in the Bundeskartellamt's opinion more endeavours could have been undertaken to introduce competition to the amendment by e.g. including existing installations in the direct marketing scheme.

It takes a critical view of demands to introduce capacity markets as a next step after the reform of the EEG. The electricity market is currently characterised by considerable overcapacities. Sinking prices, unprofitable power plants and shutdowns are therefore a normal market reaction. Such a process ensures a necessary consolidation of the market and leads to the adjustment of capacities to demand. This is not only reasonable from a microeconomic viewpoint but also efficient in macroeconomic terms because the maintenance of unnecessary means of production causes unnecessary costs. On the conclusion of such an adjustment process prices can also be expected in the wholesale markets which ensure the profitable operation of conventional power plants and enable new investments where necessary. In the Bundeskartellamt's view, therefore, one cannot deduce from the current market situation that the market is not functioning properly and that security of supply is at risk.

In addition, the maintenance of reliable capacity is already rewarded in the current market system. The electricity price already comprises a capacity-based component because the supplier undertakes to supply the electricity it has sold at a specific point in time. Should shortages occur, the electricity price acts as an incentive to build up and hold capacities.

The Bundeskartellamt is also sceptical about the introduction of capacity markets because all the possible models are highly complex and therefore pose a considerable threat of regulatory failure. Moreover, the introduction of a capacity market is difficult to reconcile with the completion of the European internal market. National capacity markets would further distort competition. There is the danger that this would trigger a subsidy race and power plants would only be built where the highest capacity payments can be expected.

A capacity market can also have unfavourable effects on market structures. A market for reliable electricity capacities is likely to be much narrower than the current market for electricity supply. The reason for this is among other things the fact that renewable energies and foreign suppliers are hardly likely to play a role in this market. This could lead to the high market power of suppliers of guaranteed capacity which would be further strengthened by certain characteristics of some of the models currently under discussion. For example there is a strong likelihood of considerable information asymmetries between buyers and suppliers of guaranteed capacity on decentralised capacity markets. At the same time, price elasticity on the demand side is likely to be extremely low. Should there actually be an increase in market power on the supply side, this poses the risk of abusive practices in the form of strategic behaviour to the detriment of consumers. Monitoring capacity withholding practices on a capacity market would be extremely complex and – if feasible at all – would require a high level of bureaucracy.

In the light of this the Bundeskartellamt does not advocate the introduction of capacity markets at this point in time. Should concerns about guaranteeing security of supply be too great, milder means are available. One of these is the strategic reserve, which is comparably flexible and low-cost and can be introduced at short notice. Only if such a solution proves insufficient should a capacity market be introduced as a last resort.

In connection with the award of rights of way for electricity and gas networks the Bundeskartellamt observes with concern political endeavours to afford municipal undertakings privileges in competition with private enterprises. As already mentioned, under the current legal situation the preference of municipal companies and inhouse awards without a tender procedure are inadmissible (cf. Section III.C.3.). However, there are political initiatives which wish to change the existing legal situation in favour of the municipalities. In Nordrhein-Westfalen (North Rhine-Westphalia) a working group has formed under the auspices of the Ministry for Economic Affairs, Energy and Industry of the Federal State of Nordrhein-Westfalen as the land competition authority to amend the rules and requirements for procedures for the award of concessions for electricity and gas networks in accordance with § 46 EnWG. The Bundeskartellamt has also participated in this working group and offered its criticism on reform proposals wherever necessary. In competition law terms the discussions about the extent to which the award decision should be based on the objectives of § 1 EnWG and the admissibility of the inhouse award are of particular significance. There is the danger that an amendment might prevent a level playing field for private and municipal network operators in the award of concessions. This is of particular concern because network operation is a natural monopoly and "competition for the market" is the only kind of competition which exists in this area. Further topics of discussion within the working group were the extent of data disclosure under § 46 (2) sentence 4 EnWG, the calculation of the appropriate remuneration, a possible obligation to object and the introduction of a preclusion for such objections.

D Unbundling

Activities for monitoring compliance with the unbundling requirements focused in the period under review on the certification process for gas and electricity transmission system operators (TSOs) introduced in 2012. In respect of the monitoring of compliance with the legal requirements on the unbundling of corporate communication and branding between operators and distributing companies the chief focus was on the procedures to implement these requirements. Both have their origin in the European Union's Third Energy Package adopted in 2009 and were transposed into German law in 2011 by way of an amendment of the German Energy Act (EnWG).

1. Certification

Certification is a procedure carried out by the regulatory authority under which TSOs are required to demonstrate proof of compliance with unbundling and organisational requirements in one of three forms, or models, outlined below:

- the full ownership unbundled TSO (section 8 EnWG),
- the independent transmission operator (section 10ff EnWG), and
- the independent system operator (section 9 EnWG).

Certification as a **full ownership unbundled** TSO requires ownership of the transmission assets. Measures must be taken to guarantee that control and rights relating to production, generation or supply are restricted, the requirements on appointing board members are met and sufficient financial, technical and human resources are available.

An **independent transmission operator** must perform the tasks of a transmission operator independently and must also be assigned specific responsibility for a number of other tasks. An independent transmission operator must have the necessary financial, technical, physical and human resources and must have ownership of the necessary assets. The provision of services to the vertically integrated energy company is allowed under certain conditions only. Any possibility of confusion with the vertically integrated company must be ruled out. Finally, the transmission operator may not share IT systems and equipment or offices and business premises with the vertically integrated company, and separate accounting is required.

In 2013 the Bundesnetzagentur completed the certification proceedings opened in 2012, monitored compliance with the conditions attached to the certifications, and also opened and completed new proceedings.

Certification has been granted to the following transmission system operators[136]:

[136] Correct as of 14 July 2014

Transmission system operators with certification

Transmission system operator	Sector	Unbundling model
Amprion GmbH	Electricit	Independent transmission operator
50Hertz Transmission GmbH		Full ownership unbundled transmission system operator
TenneT Offshore 1. Beteiligungsgesellschaft mbH		Full ownership unbundled transmission system operator
TransnetBW GmbH		Independent transmission operator
bayernets GmbH	Gas	Independent transmission operator
Fluxys Deutschland GmbH		Full ownership unbundled transmission system operator
Fluxys TENP GmbH		Full ownership unbundled transmission system operator
GASCADE Gastransport GmbH		Independent transmission operator
Gastransport Nord GmbH		Independent transmission operator
Gasunie Deutschland Transport Services GmbH		Full ownership unbundled transmission system operator
Gasunie Ostseeanbindungsleitung GmbH		Full ownership unbundled transmission system operator
GRTgaz Deutschland GmbH		Independent transmission operator
jordgas Transport GmbH		Independent transmission operator
NEL Gastransport GmbH		Independent transmission operator
Nowega GmbH		Independent transmission operator
ONTRAS - VNG Gastransport GmbH		Independent transmission operator
Open Grid Europe GmbH		Independent transmission operator
terranets bw GmbH		Independent transmission operator
Thyssengas GmbH		Independent transmission operator

Table 66: Transmission system operators in Germany with certification

Corporate communication and branding

A basic change for distribution system operators (DSOs) in the new Energy Act arises from the obligation to provide differentiated communication and branding in respect of integrated distribution and sales activities. In 2011 already, 76 per cent of the operators reported to the Bundesnetzagentur that they had begun their implementations. On 16 July 2012 an interpretation guide was published on this. The Bundesnetzagentur's monitoring activities revealed that many companies have yet to comply with the legal requirements. For instance half of the obligated operators do not yet have unique branding, a basic requirement for a communication system that is in conformity with the unbundling requirements. To push through the requirements, proceedings were initiated to supervise the compliance of 36 DSOs with the obligation to unbundle corporate communication and branding between operators and distributing companies. Some of the DSOs took measures to implement unique branding in conformity with the unbundling requirements, and the proceedings for 24 companies were consequently discontinued.

The proceedings commenced in 2013 concern in particular the companies shown in the Annex on page 306 which do not provide adequate differentiation between network operations and sales and distribution in their branding.

To date two prohibition orders have been issued:

Ruling Chamber 7 ruled on 9 May 2014 in the proceedings against SWM Infrastruktur GmbH (BK7 13 119) that the company's branding was in breach of the requirements on the unbundling of corporate communications and branding set out in section 7a(6) EnWG. SWM Infrastruktur GmbH was therefore prohibited from using the "SW/M" trademark in communications on the internet, in standard contracts and in business mail.

Ruling Chamber 7 ruled on 30 June 2014 in the proceedings against enercity Netzgesellschaft mbH (BK7 13 121) that the company's branding was in breach of the requirements on the unbundling of corporate communications and branding set out in section 7a(6) EnWG. Enercity Netzgesellschaft mbH was therefore prohibited from using the "enercity Netz" trademark in its current form in communications on the internet, in standard contracts and in business mail.

Updated information on the proceedings is published on the Bundesnetzagentur's website on the pages of Ruling Chambers 6 and 7, the bodies leading the proceedings.

Developments in the operator landscape

In the past few years several thousand concession contracts for gas and electricity networks have expired, with more due to expire in the near future. The municipalities give notice of expiry at least two years in advance. The number of expiry notices published therefore serves as an indicator of the number of new concessions to be awarded. Although the number is falling, it is set to remain high over the next few years.

In 2013 a total of 525 notices of expiring rights of way were published by the municipalities in the electronic Federal Gazette (under "section 46 EnWG") compared to 731 in 2012.

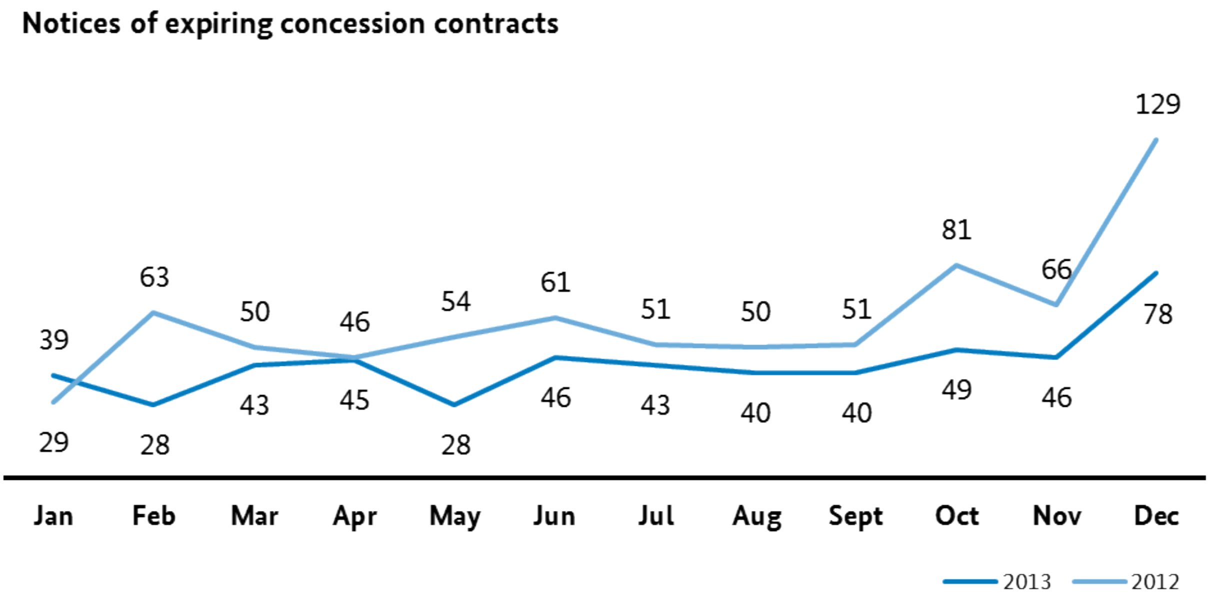

Figure 156: Notices of expiring concession contracts

Should more than one company apply when a new concession contract is to be granted or an existing contract extended, municipalities must publish their award decision together with the main reasons underlying the decision. 234 such notices were published in the electronic Federal Gazette in 2013 compared to 286 in 2012.

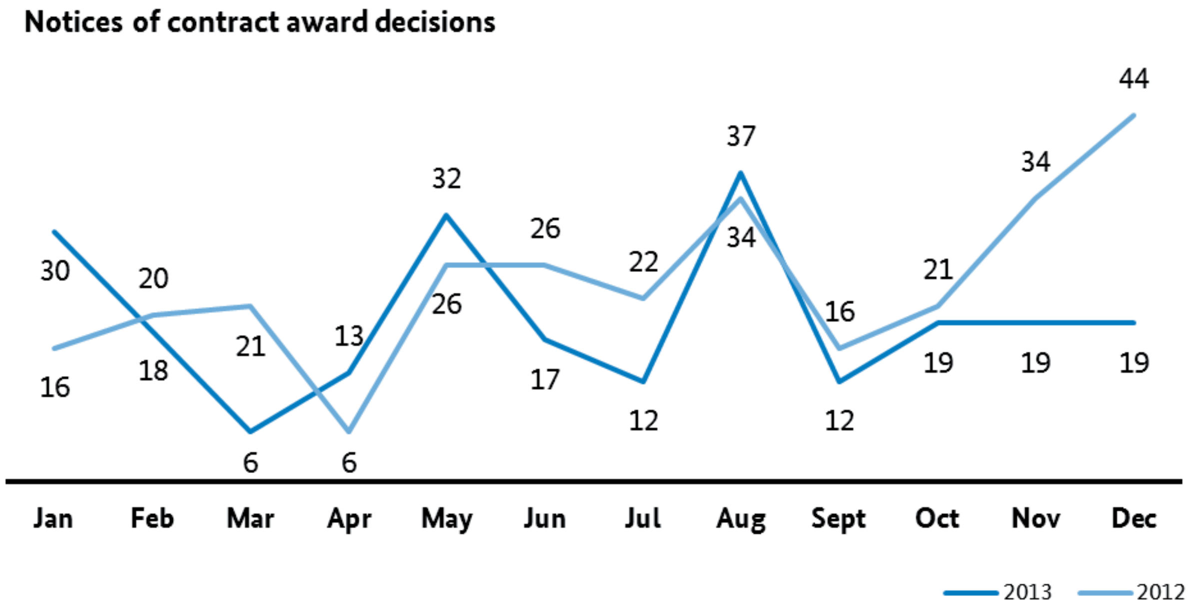

Figure 157: Notices of contract award decisions

It is important to remember that one notice may relate to more than one area; for instance, the 234 notices published in 2013 covered a total of 290 concessions.

At the same time throughout 2013 the municipalities continued their activities aimed at strengthening their role in the operation of energy supply networks. Nevertheless, no significant increase in the number of operators can be seen; rather, the number has remained relatively stable at a high level for several years. No other European country has a comparable number of operators.

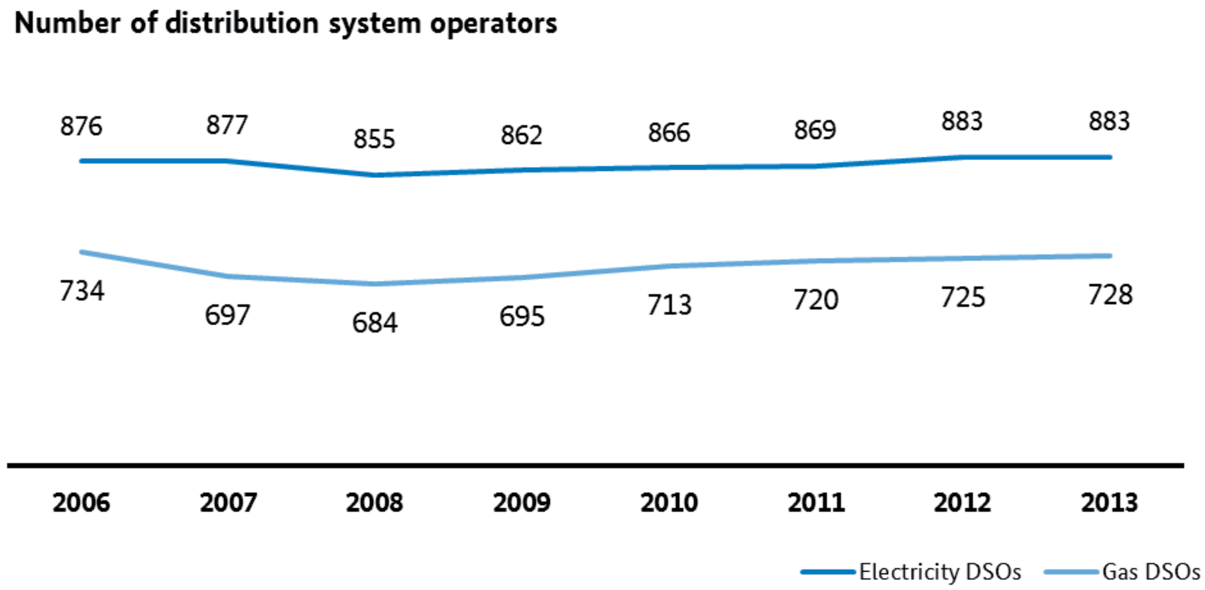

Figure 158: Distribution system operators from 2006 to 2013

E Consumer protection and consumer service

As the central information point for energy consumers, the Bundesnetzagentur advises private energy consumers of the current legal situation, their rights as domestic customers and the dispute resolution option.

In 2013 the Energy Consumer Service received a total of around 17,500 telephone and written queries and complaints, with some 12,000 on electricity, 1,200 on gas and about 4,300 on general issues.

As in previous years, the majority of queries and complaints on gas and electricity were questions about contracts and billing and complaints about the quality of service delivered in particular by suppliers. The bulk of these queries and complaints concerned the same few companies. Complaints were made in particular about differences in interpreting the terms and conditions of bonus payments or contract termination, incorrect billing, and delays in receiving credit balances and bonuses.

There were also a large number of queries and complaints about continuity of supply as provided for by section 38 of the German Energy Act (EnWG) in the event that a consumer's electricity or gas supplier has, for example, failed to pay the network charges and no longer has the required access to the low voltage or low pressure network. In such cases, continuity of supply is guaranteed by the relevant network connection provisions which require the network operator to transfer the customers affected to their local default supplier.

This happened in 2013 most notably to FlexStrom and Care-Energy[137] customers.

In April 2013 the FlexStrom group of companies requested the opening of insolvency proceedings. A number of network operators subsequently terminated their access agreements with the FlexStrom companies. FlexStrom customers were concerned in particular about the reliability and scope of the service delivered by the supplier to whom they were to be transferred, their obligations to pay the new supplier, prepayments made to the insolvent company, and their contractual and legal options in relation to the company and the insolvency practitioner. Since consumers making prepayments bear part of the risk of corporate insolvency, they must at worst expect to lose the money paid in advance.

In the summer and autumn of 2013 one of the Care-Energy group's companies was refused network access by several operators, who had informed the Bundesnetzagentur in advance of their intention to refuse access. Care-Energy had the legality of the operators' action examined in expedited proceedings, with varying outcomes. Many consumers were consequently worried about the current status of their contracts and of deliveries. Here again, they were concerned about the reliability of the substitute service and their contractual rights in relation to their supplier and the network operator as well as the legal position in respect of network usage and the Bundesnetzagentur's responsibilities.

In June 2013 the Bundesnetzagentur had fined the managing director of the Care-Energy group €40,000 for breaching the company's obligation to notify the Bundesnetzagentur of its supply of energy to household

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[137] Care-Energy is a retail brand marketed by Care-Energy Holding GmbH, which operated until 2014 as mk-group Holding GmbH.

customers. The company itself refers to its business model as contracting, which involves supplying useful energy in the form of "light, power, heat and cold" to consumers, and argued that as a pure energy service provider, it was not subject to the obligations imposed on suppliers by the Energy Act. The Bundesnetzagentur however regards the company's business model as a classic case of selling electricity to household customers. As the company filed an objection to the fine, the case was referred to the Chief Public Prosecutor in Düsseldorf. In October 2014, in the subsequent proceedings before the Higher Regional Court in Düsseldorf, the managing director of the Care-Energy group withdrew the objection and paid the fine. It is now clear that the Care-Energy supply concept is subject in all respects to the requirements of the Energy Act, and the company must now provide the Bundesnetzagentur with the necessary notification of its supply to household customers.

A large number of the complaints about switching supplier received by the Energy Consumer Service concerned network operator Westnetz GmbH, part of the RWE group. As far as the Bundesnetzagentur is aware, IT restructuring within the company was the main cause of the problems with customers switching supplier and market communication.

The amendments to German energy law made in August 2011 entitle private consumers with contractual or billing problems to have a complaints procedure carried out with their company instead of taking their case to court. If the company does not provide a remedy within a period of four weeks, energy consumers can then turn to the Energy Dispute Resolution Panel for redress.

Since November 2011 the Energy Dispute Resolution Panel has been responsible for mediating between consumers with complaints about contracts or the quality of a company's service and their energy utility, metering operator or metering service provider. In 2013 the Panel received 9,600 requests for redress. The Panel publishes its conciliatory proposals and an annual report of its activities on its website at www.schlichtungsstelle-energie.de. As a rule, the dispute resolution procedure is free of charge for the consumers. The conciliatory proposal is not binding, however, so that both consumers and companies still have the option of going to court.

Appendix

Appendix 1: Brands without adequate differentiation between network operations and sales and distribution

badenova AG & Co. KG

badenova Netz GmbH

Stadtwerke Düsseldorf AG

Stadtwerke Düsseldorf Netz GmbH

Energie- und Wasserversorgung Bonn/Rhein-Sieg GmbH

SWB Energie Netze GmbH

ENSO Energie Sachsen Ost AG

ENSO Netz GmbH

Stadtwerke Wismar

Stadtwerke Wismar Netz GmbH

SWU Energie GmbH (Ulm)

SWU Netze GmbH

Stadtwerke Bad Langensalza GmbH

Stadtwerke Bad Langensalza NETZ GmbH

Stadtwerke Lübeck GmbH

Stadtwerke Lübeck Netz GmbH

Energie Werk Mittelbaden AG & Co. KG

Energie Werk Mittelbaden Netzbetriebsgesellschaft mbH

N-ERGIE AG

N-ERGIE Netz GmbH

SWE Stadtwerke Erfurt GmbH

SWE Netz GmbH

Stadtwerke Karlsruhe GmbH

Stadtwerke Karlsruhe Netze GmbH

Stadtwerke Gotha GmbH

Stadtwerke Gotha Netz GmbH

Stadtwerke Arnstadt GmbH

Stadtwerke Arnstadt Netz GmbH

evo Energieversorgung Oberhausen AG

evo Energie-Netz GmbH

WEMAG AG

WEMAG Netz GmbH

ESWE Versorgungs AG

ESWE Netz GmbH

Stadtwerke Münster GmbH

Stadtwerke Münster Netzgesellschaft mbH

Energieversorgung Mittelrhein AG

EVM Netz GmbH

LSW Landestadtwerke GmbH & Co. KG

LSW Netz GmbH

Energieversorgung Nordhausen GmbH

Energieversorgung Nordhausen Netz GmbH

Stadtwerke Aachen AG

STAWAG Netz GmbH

Stadtwerke München GmbH

SWM Infrastruktur GmbH /
SWM Infrastruktur Region GmbH

Städtische Werke Magdeburg GmbH und Co. KG

SWM Netze GmbH

Energiedienst AG (Rheinfelden in Baden)

Energiedienst Netze GmbH

DREWAG - Stadtwerke Dresden GmbH

DREWAG Netz GmbH

ovag ENERGIE AG

Ovag Netz AG

Stadtwerke Augsburg Energie GmbH

Stadtwerke Augsburg Netze GmbH

Stadtwerke Husum GmbH

Stadtwerke Husum Netz GmbH

Städtische Werke AG Kassel

Städtische Werke Netz + Service GmbH

Stadtwerke Bochum GmbH

Stadtwerke Bochum Netz GmbH

Stadtwerke Hannover AG

enercity Netzgesellschaft mbH

Dortmunder Energie- und Wasserversorgung GmbH DEW 21

Dortmunder Energie und Wasserversorgung – Netz GmbH

Stadtwerke Frankfurt (Oder) GmbH

Stadtwerke Frankfurt (Oder) Netzgesellschaft mbH

Energis GmbH (Saarbrücken)

Energis Netzgesellschaft mbH

Stadtwerke Bielefeld GmbH	Stadtwerke Bielefeld Netz GmbH
Stadtwerke Bielefeld	Stadtwerke Bielefeld Netz

Table 67: Brands without adequate differentiation between network operations and sales and distribution

Lists

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List of abbreviations

Term	Definition
a	Year
ACER	Agency for Cooperation for European Regulators
AEUV	Vertrag über die Arbeitsweise der Europäischen Union
TFEU	Treaty on the Functioning of the European Union
AGV	Arbeitsgasvolumen bzw. Arbeitsgasvolumina (von Gasspeichern) working gas volume(s) (of gas storage facilities)
AktG	Aktiengesetz German Stock Corporation Act
ARegV	Incentive Regulation Ordinance
ASIDI	Average System Interruption Duration Index
ATC	Available Transfer Capacity
AusglMechAV	Ausführungsverordnung zur Ausgleichsmechanismusverordnung Ordinance on the Implementation of the Ordinance on the Further Development of the Nationwide Equalisation Scheme
AusglMechV	Ausgleichsmechanismusverordnung Ordinance on the Further Development of the Nationwide Equalisation Scheme
Art.	Article
BAFA	Bundesamt für Wirtschaft und Ausfuhrkontrolle Federal Office of Economics and Export Control
BDEW	German Association of Energy and Water Industries

BFZK	Capacity with conditional firmness and allocable
BGBl.	Bundesgesetzblatt Federal Law Gazette
BGH	Bundesgerichtshof Federal Court of Justice
BilMOG	Bilanzrechtsmodernisierungsgesetz Act to Modernise Accounting Law (AMAL)
BImSchG	Bundes-Immissionsschutzgesetz Federal Immission Control Act
BKV	Balancing group manager
BMWi	Federal Ministry for Economic Affairs and Energy
bn	Billion
CAO	Coordinated Auction Office
CASC-CWE	Capacity Allocation Service Company for the Central West-European Electricity Market
CEE	Central East Europe
CEER	Council of European Energy Regulators
CEN	European Committee for Standardization
CENELEC	European Committee for Electrotechnical Standardization
CEPS	Czech transmission system operator
CHP	Combined Heat and Power
CSE	Central South Europe
CWE	Central West Europe

DEA	Data Envelopment Analysis
DIN	Deutsches Institut für Normung e.V. German Institute for Standardization [www.din.de]
DSL	Digital Subscriber Line
DSfG	Digitale Schnittstelle für Gasmessgeräte digital interface for gas meters
DZK	Dynamically allocable capacity
EC	European Community
ECC	European Commodity Clearing AG
EDIFACT	(United Nations) Electronic Data Interchange For Administration, Commerce and Transport
EEG	Renewable Energy Sources Act
EEX	European Energy Exchange AG
EHV	Extra High Voltage
EICOM	Swiss Federal Electricity Commission
EMCC	European Market Coupling Company GmbH
EnBW TNG	Energieversorgung Baden Württemberg Transportnetze AG
EnLAG	Power Grid Expansion Act
ENTSO-E	European Network of Transmission System Operators for Electricity
EnWG	Energy Act
EPEX SPOT	European Power Exchange
ERGEG	European Regulators Group for Electricity and Gas
Eurostat	Statistical Office of the European Communities

ETSI	European Telecommunications Standards Institute
EVU	Energieversorgungsunternehmen energy utility
EXAA	Energy Exchange Austria
FBA	Flow Based Allocation
FCFS	First come first serve
FMM	Feed-in Management Measure
FNB	Gas transmission system operator
FTP	File Transfer Protocol
FZK	Freely allocable entry-exit capacity
GABi Gas	Portfolio and system balancing energy regime
GasNEV	Gas Network Charges Ordinance
GasNZV	Gas Network Access Ordinance
GeLi Gas	Business processes for change of gas supplier [MT]
GPKE	Business processes for supplying customers with electricity [MT]
GPRS	General Packet Radio Service
GSM	Global System for Mobile Communications
GW	Gigawatt
GWB	Gesetz gegen Wettbewerbsbeschränkungen Act against Restraints of Competition
GWh	Gigawatt hour
GWJ	Gas year
h	Hour

HGÜ	Hochspannungs-Gleichstrom-Übertragung high voltage direct current (HVDC) transmission
HTWK	Hochschule für Technik, Wirtschaft und Kultur Leipzig University of Applied Sciences
HV	High Voltage
ITC	Inter-TSO-Compensation
ITO	Independent Transport Operator
KARLA	Capacity arrangements and auctions in the gas sector
KAV	Konzessionsabgabenverordnung Concession Fees Ordinance
km	Kilometre
KoV IV	Cooperation agreement IV
KraftNAV	Kraftwerks-Netzanschlussverordnung Power Plant Grid Connection Ordinance
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt hour
kWh/h	Kilowatt hour per hour
KWKG	Kraft-Wärme-Kopplungsgesetz Combined Heat and Power Act
LFZ	Load flow commitments
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas

LV	Low Voltage
m²	Cubic metre
m³/h	cubic metre per hour
(Wireless) M-Bus	(Wireless) Meter-Bus
MessZV	Messzugangsverordnung Meter Access Ordinance
m	Million
MüT	Marktgebietsüberschreitende Netzkoppelpunkte Interconnection points between market areas
MR	Minute Reserve
MRL	Minute Reserve Power
MUC	Multi Utility Controller
MV	Medium Voltage
MW	Megawatt
MWh	Megawatt hour
MWh/km²	Megawatt hour per square kilometre
NABEG	Grid Expansion Acceleration Act
NAV	Niederspannungsanschlussverordnung Low-Voltage Connection Ordinance
NaWaRo	Nachwachsende Rohstoffe renewable resources
NBP	National Balancing Point
NCG	NetConnect Germany

NDAV	Niederdruckanschlussverordnung Low Pressure Connection Ordinance
NE	Northern Europe
neg.	Negative
NEL	Nordeuropäische-Erdgas-Leitung North European natural gas pipeline
NKP	Netzkoppelpunkte Interconnection points
Nm^3	Normalised cubic metre
Nm^3/h	Normalised cubic metre per hour
NRV	Grid control cooperation
NTC	Net Transfer Capacity
OFC	Online Flow Control
OGE	Open Grid Europe
OLG	Oberlandesgericht Higher regional court
OMS	Open Metering System
OPAL	Ostsee-Pipeline-Anbindungsleitung Gas pipeline in the Baltic Sea
OTC	Over the counter
OWF	Offshore Wind Farm
PLC	Powerline Carrier / Powerline Communication
PSA	Pressure swing adsorption

PSTN	Public Switched Telephone Network
pos.	Positive
PRL	Primärregelleistung Primary control power
PRS	General Packet Radio Service
REMIT	Regulation on wholesale Energy Market Integrity and Transparency
reBAP	Uniform portfolio balancing energy price across control areas
RLM	Load metering
RLMmT	Load metering with daily flat supply
RLMoT	Load metering without a daily flat supply
RLMNEV	Load metering with substitute nomination procedures
RSI	Residual Supply Index
SAIDI	System Average Interruption Duration Index
SBL	Secondary Balancing Power
SFA	Stochastic Frontier Analysis
SLP	Standard load profile
StromNEV	Electricity Network Charges Ordinance
StromNZV	Electricity Network Access Ordinance
TGL	Tauern gas pipeline
tps	transpower Stromübertragungs GmbH
TRM	Transmission Reliability Margin
TSO	Transmission System Operator
TTC	Total Transfer Capacity

TTF	Title Transfer Facility
TU	Technical University
TWh	Terawatt hour
TWh/h	Terawatt hour per hour
ÜTS	Übertagespeicher Above ground storage facilities
ÜNB	Übertragungsnetzbetreiber Transmission System Operator
UGS	Underground storage facility
UMTS	Universal Mobile Telecommunications System
VAN	Value added network
VNB TSO	Verteilernetzbetreiber Transmission System Operator
VNG	Verbundnetz Gas AG
VP	Virtual trading point
WEG	Wirtschaftsverband Erdöl- und Erdgasgewinnung e. V.
Zigbee	Industry standard for radio network technology

Glossary

In addition to the definitions given in section 3 EnWG, section 2 StromNZV, section 2 GasNZV, section 2 StromNEV, section 2 GasNEV, section 3 EEG and section 3 KWKG, the following definitions and the Bundesnetzagentur's guidelines on electricity network operators' internet publication obligations (Leitfaden für die Internet-Veröffentlichungspflichten der Stromnetzbetreiber) apply:

Term	Definition
Access	*Electricity* Includes all the equipment that is the property of the supplier and that is used for one customer only. *Gas* The network connection joins the general supply network with the customer's gas facilities from the supply pipeline to the internal pipes on the premises. It comprises the connecting pipe, any shut-off device outside the building, insulator, main shut-off device and any in-house pressure regulator. The provisions on connection to the network are still applicable to the pressure regulator when it is installed after the end of the network connection but located within the customer's system.
Actual energy consumption	For indicating the actual consumption of gas it would seem appropriate to state the volume at measurement conditions in m^3 instead of the number of kWh.
Affiliated undertakings within the meaning of section 15 AktG	Legally independent companies that in relation to each other are subsidiary and parent company (section 16 AktG), controlled and controlling companies (section 17 AktG), members of a group (section 18 AktG), undertakings with cross-shareholdings (section 19 AktG) or parties to a company agreement (sections 291, 292 AktG).
Annual peak load (final consumer)	Peak load, expressed in kilowatt (kW), as metered in 15 minute readings, in the course of a year.[6)]
Annual usage time (final consumers)	Annual usage time defines the regularity of the consumer's offtake of electrical energy from the network during a year. The longer the time, the more evenly consumption is distributed over the 8,760 hours of the year (8,784 in a leap year). The time gives the number of hours the consumer needs to reach his annual consumption if he constantly uses the power corresponding to his annual peak load (annual usage time = annual consumption divided by annual peak load).[6)]
Balancing group network operator	A network operator covering the whole market area or a third party enabling a balancing group to be established and with whom a balancing group contract is concluded.

Balancing Zone	Within a balancing zone all entry and exit points can be allocated to a specific balancing group. In the gas sector a balancing zone corresponds to the market area. This means that all entry and exit points in all networks or network segments that are part of the particular market area belong to a balancing group (cf section 3 para 10b EnWG).
Binding exchange schedules	Unlike physical load flows, which represent the actual cross-border flow of electricity, exchange schedules reflect the commercial cross-border exchange of electricity. Physical load flows and commercial exchange schedules do not necessarily have to match (eg due to loop flows).
Black start capability	Ability of a generating unit (power plant) to start up independently of power supplies from the electricity network. As a first step to restore supply, this is particularly important in the event of a disruption causing the network to break down. Additionally, a "stand-alone capability" is required with a steady supply voltage and capable of bearing loads without any significant voltage and frequency fluctuations.
Cavern storage facility	Artificial hollows in salt domes created by drilling and solution mining. In comparison to pore storage facilities, these often have higher injection and withdrawal capacities and a lower cushion gas requirement but are also smaller in volume.
Certified technical management of safety	A network operator's technical safety management that has been certified by an independent external body and is subject to regular reviews.
Change of contract	A customer's change to a new tariff with the same energy supplier.
Charge for billing	Charge for settling network use and forecasting annual consumption in accordance with section13(1) StromNZV.
Charge for metering	Charge for reading the meter, reading out and passing on the meter data to the authorised party.
Charge for meter operations	Charge for meter installation, operation and maintenance.
Churn rate	The ratio of the volume of traded to physically transported gas; indicates the liquidity of an energy exchange or other trading platform.
Clearing	The physical and financial fulfilment of spot and futures transactions. Offsetting and settlement of claims and liabilities arising from spot and futures transactions. In the spot market "clearing" refers particularly to the settlement and entering of collateral and the daily settlement of gains and losses, the entering of collateral and

	the drawing up of the final account on the last trading day.[4)]
Completion of/Start of operation	The time at which gas supply could begin (gas pipeline under pressure up to the shut-off valve).
Continuous capacity	Maximum capacity at which a generation, transmission or consumption facility can be operated for a sustained period without impairing its service life (operating life) or safety, provided it is operated as intended. N.B. Continuous capacity may be subject to seasonal variations (eg as a result of cooling water conditions.[2)]
Day-ahead trade	Trading market for energy supplied the next day.[4)]
Default supplier	The gas and electricity company providing default supply in a network area as provided for by section 36(1) EnWG.
Default supply	Energy supply by the default supplier to household customers on the basis of general terms and conditions and general prices (cf section 36 EnWG).
Delivery volumes	Amounts of gas delivered by gas suppliers to final consumers.
Denial of network access	A network operator's negative reply or revised contract offer after receiving a formal request for network access.
Dominance method	This allocates the volumes supplied by a controlled (consolidated) undertaking to the particular controlling undertaking. Allocation is made as to 100 per cent. For joint ventures with a 50/50 equity interest, allocation is made accordingly. Equity interests below 50 per cent are disregarded.[3)]
Downstream distributor	Regional and local gas distribution network operator (not an exporter)
EEG surcharge	Pursuant to the AusglMechV, as of 1 January 2010 electricity utility companies must pay an EEG surcharge to the transmission system operators for every kilowatt hour of electricity supplied to a final customer. These payments cover the difference between the transmission system operators' income and expenditure in implementing the EEG in accordance with section 3(3) and (4) AusglMechV and section 6 AusglMechAV. The TSOs are required pursuant to section 3(2) AusglMechV to determine and publish the EEG surcharge for the following calendar year by 15 October each year.

EEX / EPEX Spot	European Energy Exchange / European Power Exchange. The EEX operates marketplaces for trading electricity, natural gas, $CO2$ emission rights and coal. EEX holds a 50 per cent equity investment in the Paris-based EPEX Spot which operates the power spot markets for Germany, France, Austria and Switzerland (see www.eex.com/de).
Electrical power used by the plant	Electrical power a generating unit requires to operate its auxiliary and ancillary facilities (eg for water treatment, water supply to steam generators, fresh air and fuel supply, flue gas cleaning), plus the power losses of step-up transformers (generator transformers). There are two types of internally used electrical power: the electrical power required to operate a generating unit's auxiliary and ancillary facilities during operating hours and the electrical power required to operate its auxiliary and ancillary facilities outside operating hours.[2)]
Energy to cover power losses	The energy required for the compensation of technical power losses.
Entry-exit system	Gas booking system in which the shipper signs only one entry and exit contract, even if the transport is distributed among several TSOs.
Entry point	A point at which gas can be transferred to the network or subnetwork of a system operator, including transfers from storage, gas production facilities, hubs, or blending and conversion plants.
Exit point	The point at which gas can leave an operator's network for delivery to final customers, downstream networks (own and/or other) or redistributors, plus the points at which gas can be taken off for delivery to storage facilities, hubs and conditioning or conversion plants.
Expenditure on maintenance	Expenditure on any technical, administrative or management measure taken to maintain or restore working order to an asset during its life cycle so that it can perform its required function.
Explicit auction	In an explicit auction available capacity is allocated to market participants submitting the highest bids (cf ETSO: An Overview of Current Cross-border Congestion Management Methods in Europe, May 2006).
FBA	Flow Based Allocation of capacity Starting from the planned commercial flows (trades), the capacity available for cross-border electricity trading is determined and allocated on the basis of the actual flows in the network. FBA thus makes it possible to allocate transmission capacity in line with the actual market situation as reflected by the bids.

FCFS	The first to request capacity will be served first, obtaining as much capacity as requested, as far as possible. First come first served/First committed first served.
Fractional ownership	Line sections whose capacity is shared by two or more network operators (by ownership or similar) and which can therefore be used only partially by each network operator.
Futures	Contractual obligation to buy (futures buyer) or deliver (futures seller) a specified amount of, for example, electricity, gas or emission rights at a fixed price in a defined future period (period of delivery). Futures contracts are settled either physically or financially.[4)]
Futures market	Market for trading futures and derivatives. It differs from the spot market in that obligation and settlement do not take place at the same time.
Green electricity tariff	Tariff for electricity which, on account of green electricity labelling or other marking, is shown to have been produced with a high share/high promotion of efficient or regenerative production technologies and which is offered/traded at a separate tariff. The tariff for default supply also comes under this category if, on the whole, it applies to electricity produced with a high share of efficient or regenerative production technologies. Not included is the share of electricity generated from renewable sources that is sold at prices other than those for electricity produced with a high share/high promotion of efficient or regenerative production technologies.
Gross capacity	Delivered power to the generator terminals Hydro power: In turbine operation, gross capacity is measured at the generator's terminals. In a pumped storage station, net capacity is measured at the terminals of the (motor) generator if the facility is operated as a motor. Gross capacity is equal to net capacity plus the electrical power used by the plant, including power lost by the plant's transformers but not the power consumed in the process of generation and the power required for the phase shifter.[2)]
Gross electricity generation	Electrical energy produced by a generating unit, measured at the generator's terminals.[2)]
H-gas	A second-family gas with a higher amount of methane (87 to 99 volume percent) and thus a lower volume percentage of nitrogen and carbon dioxide. It has a medium calorific value of 11.5 kWh/m^3 and a Wobbe index of 12.8 kWh/m^3 to 15.7 kWh/m^3.
Hub	An important physical node in the gas network where different pipelines, networks and other gas infrastructures come together and where gas is traded.

Implicit auction	See market coupling
Intermediate network operator	A network operator downstream from one operator, for instance a market area-wide gas transmission system operator, and usually also upstream from a distribution system operator.
Intraday trading	On the EEX, transactions involving gas and electricity contracts for supply on the same or following day (see www.eex.com/de).
Investments	Investments are considered to be gross additions to fixed assets capitalised in the year under review and the value of new fixed assets newly rented in the year under review. Gross additions also include leased goods capitalised by the lessee. The gross additions must be notified without deductible input VAT. The value of internally generated assets as capitalised in the fixed asset account (production costs) is to be included. Notification is also required of assets under construction (work begun for operational purposes, as far as capitalised). If a special "assets under construction" summary account is kept, notification should be made only of the gross additions without the holdings shown in the account at the beginning of the year under review. Payments on account should be included only if the parts of assets under construction for which they were made have been settled and if they have been capitalised. Not included are the acquisition of holdings, securities etc. (financial assets), the acquisition of concessions, patents, licences etc. and the acquisition of entire undertakings or businesses and the acquisition of rental equipment formerly used in the undertaking, additions to fixed assets in branch offices or specialist units in other countries and financing charges for investments.[5)]
Length of circuit	System length (the three phases L1+L2+L3 together) of cables at the network levels LV, MV, HV and EHV (example: If L1 = 1km, L2 = 1km and L3 = 1km, then the length of the circuit = 1km). In the case of different phase lengths, the average length in kilometres is to be determined. The number of cables used per phase is irrelevant for the length of circuit. However, cables leased by, or otherwise made available to the network operator, should be included to the extent they are operated by the network operator. Planned cables, cables under construction or let on lease, and decommissioned cables are not included. Lines in fractional ownership should be included with their full number of kilometres to determine the network length. The circuit length at the low voltage network level should include service lines but not the lines of street lighting systems. Lines of more than 36 kV that have a transport function and are subject to a high voltage tariff may be considered at the high voltage level.
L-gas (low calorific gas)	A second-family gas with a lower amount of methane (80 to 87 volume percent) and higher volume percentages of nitrogen and carbon dioxide. It has a medium calorific value of 9.77 kWh/m^3 and a Wobbe index from 10.5 kWh/m^3 to 13.0

	kWh/m³.
Load-metered customer	Final customers with an annual electricity offtake exceeding 100,000 kWh, or with a gas offtake exceeding 1.5m kWh per year or more than 500 kWh per hour.
Load-metered final customers	Measurement of the power used by final consumers in a defined period. Load metering is used to establish a load profile showing a final customer's consumption over a defined period. A distinction is made between customers with and customers without load metering.
Market area	*Electricity* Several points of supply (TSOs) are combined in one market area if there is no congestion between these TSOs' networks. The auction prices of hour contracts for the same hour of supply but for different points of supply (TSOs) are the same if they belong to the same market area.[4)] *Gas* A gas market area refers to a consolidation of networks at the same or downstream level in which shippers can freely allocate booked capacity, deliver gas to final consumers and provide gas to other balancing groups.
Market area network operator	The gas transmission system operator operating the top-level pipeline network in a market area. This can also be several network operators jointly covering a market area.
Market coupling	A process for efficient congestion management between different market areas involving several power exchanges. Market coupling improves the use of scarce transmission capacities by taking into account the energy prices in the coupled markets. It involves day-ahead allocation of cross-border transmission capacities and energy auctions on the power exchanges being carried out at the same time based on the prices on the exchanges. For this reason, reference is also made here to implicit capacity auctions.
Market maker	Trading participant who, for a minimum period of time during a trading day, has both a buy and a sell quote in his order book at the same time. Market makers ensure basic liquidity.[4)]
Market splitting	Same procedure as market coupling but involving only one electricity exchange.
Master data	Company data for the successful processing of business transactions. These include contract data such as a customer's name, address and meter number.
Matching/Mismatching	Comparing nominations in a balancing group. Entry/exit in balance = matching; imbalances = mismatching

Maximum capacity	Capacity at which a generating unit can be operated for a sustained period under normal conditions. It is limited by the weakest part of the plant, determined by measurement and converted to the levels applicable under normal conditions. In the case of a long-term change (eg changes in individual units, changes as a result of ageing), maximum capacity needs to be redetermined. It may deviate from the rated capacity by +/- Δ P. Short downtimes of individual parts of the plant do not result in reduced maximum capacity.[2)]
Maximum usable volume of working gas	The total storage volume less the cushion gas required.
Metering point	Point in the grid at which the flow of energy, or the amount of gas transported, is recorded for billing purposes.
Metering service	Metering the energy supplied in accordance with verification regulations and processing the metered data for billing purposes.
Minimum capacity	The minimum capacity of a generating unit is the minimum level of power that must be maintained in continuous operation for specific plant or operational requirements.[2)]
m:n nomination procedure	The m:n nomination procedure facilitates schedule nominations to any corresponding balancing group. For cross-border transactions it is therefore no longer necessary for the balancing groups on each side of the border to be managed by the same company (1:1 nomination). With this procedure it is now possible to nominate transactions between non-neighbouring countries, as may be the case in flow-based capacity allocation procedures.
Natural gas reserves	Secure reserves: in known deposits based on reservoir engineering or geological findings that can be extracted with a high degree of certainty under current economic and technical conditions (90 per cent probability). Probable reserves: a probability level of 50 per cent.
Net capacity	The power a generating unit delivers to the supply system (transmission and distribution networks, consumers) at the high-voltage side of the transformer. It corresponds to the gross capacity less the power consumed by the unit in the process of generation, even if this is not supplied by the generating unit itself but by a different source.[2)]
Net electricity generation	A generating unit's gross electricity generation less the energy consumed in the process of generation. Unless otherwise indicated, the net electricity output relates to the reference period.[2)]

Net network tariffs	*Electricity* Electricity network tariff excluding billing, metering and meter operation charges. *Gas* Gas network tariff excluding billing, metering and meter operation charges.
Netting	Netting (by the TSOs), as far as technically possible, of the capacity requirements of power flows in opposite directions on a congested cross-border interconnection line in order to use this line to its maximum capacity (cf Art. 6(5) s.1 EC Regulation 1228/2003).
Net Transfer Capacity (NTC)	Total transfer capacity less the transmission reliability margin (cf Transmission Code 2003)
Network area	Entire area over which the network and substation levels of a network operator extend.
Network level	Areas of power supply networks in which electrical energy is transmitted or distributed at extra high, high, medium or low voltage (section 2 para 6 StromNEV) low voltage ≤ 1 kV medium voltage > 1 kV and ≤ 72.5 kV high voltage > 72.5 kV and ≤ 125 kV extra-high voltage > 125 kV
Network losses	The energy lost in the transmission and distribution system is the difference between the electrical energy physically delivered to the system and the energy drawn from the system within the same period.[2)]
Network number	On assignment of a registration number, network operators are automatically given the network number 1. Upon request, the Bundesnetzagentur will assign additional network numbers for additional network segments.
Nomination	Shippers' duty to notify the network operator, by 2pm at the latest, of their intended use of the latter's entry and exit capacity for each hour of the following day.
Offtake load	The correct sum of all offtakes by downstream network areas (+) and reverse flows from downstream network areas (-) via transformers and lines that are directly connected with downstream network areas. This corresponds to the vertical grid load less the final consumers' offtake. Horizontal load flows and grid losses are not taken into account.
Offtake volume	The gas network operators' offtake gas quantities.

OMS standard	Selection of options chosen by the OMS Group from the European Standard 13757-x. This open metering system specification standardises communication in consumption metering.
Open season procedures	Procedures for identifying market demand for capacity in a new or expanded gas infrastructure. Data is also collected on the conclusion of binding capacity agreements. With its Guidelines for Good Practice on Open Season Procedures (GGPOS), ERGEG has drawn up guidelines for transparent and non-discriminatory open season procedures for the first time.
Operating time	Length of time during which a plant or part thereof converts or transmits energy. The operating time begins with the connection of the plant, or part thereof, to the network and ends with its disconnection. It does not include start-up and shut-down times of generation plant without any usable energy output.[2)]
OTC clearing facility	Bilateral exchange of over-the-counter trades and joint entry of these trades in the EEX system, provided the trades are admitted for entry and entered in compliance with the provisions.[7)]
OTC trading	Over-the counter or off-exchange trade.
Own consumption	Electrical energy consumed in the auxiliary and ancillary facilities of a generating unit (eg a power plant unit or power plant) for water treatment, water supply to steam generators, fresh air and fuel supply and flue gas cleaning, but excluding the energy consumed in the process of generation. A power plant's own consumption also includes step-up transformer (generator transformer) losses but not, however, the power consumed by auxiliary and ancillary facilities that are not electrically operated; this is covered by the power plant's total heat consumption. A power plant's own consumption during the reference period comprises two elements: own consumption for operations during operating hours and own consumption during idle hours. The latter is not taken into account in the net calculation.[2)]
Peak load	Load profile for constant electricity supply or consumption over a period of 12 hours from 8am to 8pm every day of a delivery period.[4)]
Phelix (Physical Electricity Index)	The Phelix Day Base is the calculated average of the hourly auction prices for hours 1-24 every calendar day of the year on the EPEX Spot SE market for the market area of Germany/Austria. The Phelix Peakload Index is based on the hourly prices during peak load hours (8am to 8pm) (cf www.eex.com/de).
Physical network congestion	A situation in which demand for supply exceeds the technical capacity at a given point in time.

Pore storage facility	Storage facilities where the natural gas is housed within the pores of suitable rock formations. These are often large in volume but, in comparison to cavern storage, have lower entry and exit capacity and greater cushion gas requirements.
Portfolio balancing energy	Difference between entry and exit quantities established by the balancing group network operator for the market area at the end of each balancing period and settled with the balancing group managers.
Power plant status	*Reserve power plants*: power plants that are operated only at the TSOs' request to ensure security of supply. *Exceptional cases:* power plants temporarily not in operation (eg owing to repairs following damage) or with restricted operation. *Seasonal mothballing:* power plants that are closed during the summer season and fired up again afterwards.
Rated capacity	Maximum capacity at which a plant can be operated for a sustained period under rated conditions at the time of handover. Capacity changes are only permitted in conjunction with major modifications of the rated conditions and structural alterations at the plant. Until the exact rated capacity has been determined, the value ordered in the supply contract should be indicated. If it is unclear whether the value ordered complies with the actual permit and operating conditions expected, a preliminary average rated capacity is to be determined and applied until definitive measurement results are available. The average is to be fixed in such a way that higher or lower production levels, over a normal year, will be offset (eg on account of the cooling water temperature curve). The definitive rated capacity of a power plant unit is determined when the plant has been handed over, usually when the acceptance measurement results are available. It should be noted that the rated conditions apply to an annual average, ie that seasonal changes (for example in the cooling water and air inlet temperature) and internal electrical and steam-side requirements balance out, and that exemplary conditions used in the acceptance test, eg special closed circuit switching, must be converted to normal operating conditions. The rated capacity, unlike the maximum capacity, may not be adjusted to a temporary change in capacity. The rated capacity may not be changed in the case of a reduction in capacity as a result of, or to prevent, damage, nor may it be reduced on account of ageing, deterioration or pollution. Capacity changes require: • additional investment with a view to increasing the plant's capacity, eg retrofitting to enhance efficiency; • the decommissioning or removal of parts of the plant, accepting a loss of capacity; • operation of the plant outside the design range stipulated in the supply contracts on a permanent basis, ie for the rest of its life, for external reasons, or • a restriction of capacity, imposed by statutory regulations or orders of public authorities without there being a technical fault in the plant, until the end of its operating life.[2)]

Pro rata	The quota allocated to a party requesting goods in short supply is determined by calculating the respective share of total demand and subsequently allocating this percentage as a share of the available supply.
Provision	The former supplier provides a customer with energy on behalf of the new supplier; the latter buys the energy from the former supplier in order to sell it to his customer. For this purpose, the competitor signs a provision contract with the former supplier.
Pulse output	Mechanical counter with a permanent magnet in the counter rotation. May be modified by a synchronising pulse generator (reed contact). Pulse output also includes what is known as a "cyble counter".
Rated thermal capacity	Maximum capacity at which a plant can be operated for a sustained period and ordered in the supply agreement. If the rated capacity cannot be established from the order documents, the average capacity that can be reached under normal conditions needs to be determined once for a new plant. Net rated thermal capacity corresponds to gross rated thermal capacity less the thermal output used for thermal processes in the plant itself.
Redispatching	Adjustment of power plant dispatch to the requirements of the network if this is congested or congestion is threatening. As trade transactions remain unaffected by such intervention, the TSOs may take the costs involved into account in their calculation of network tariffs.
Reference period	Total uninterrupted reporting period (calendar period, eg day, month, quarter, year).[2)]
Reference power	The reference power is the correct sum of all withdrawals from upstream grid areas (+) and reverse feed-in to upstream grid areas (-) via directly connected transformers and lines to upstream grid areas. For this purpose horizontal load flows and grid losses are not taken into account.
Registration number for network operators	The eight-digit registration number is assigned by the Bundesnetzagentur as a code identifying the undertaking and categorising it according to field of activity; the number for network operators begins with 1000 (electricity) or 1200 (gas) and comprises four additional digits (eg 10005678 or 12005679).
Registration number for suppliers	The eight-digit registration number is assigned by the Bundesnetzagentur as a code identifying the undertaking and categorising it according to field of activity; the number for suppliers begins with 2000 and comprises four additional digits (eg 20001234).
Rucksack principle	Subject to the conditions referred to in section 42 GasNZV, a new supplier may insist that the capacity required to supply a final consumer is transferred to him

	from the former supplier.
Shift factor	The shift factor cos φ is the cosine of the phase angle between the sine oscillations of voltage and current. It also represents the ratio between active and apparent power and indicates the extent to which reactive power is used. A distinction is made between capacitive and inductive reactive power. If the sinus oscillations of the current move faster than those of voltage, the reactive power is called capacitive, while in the opposite case it is called inductive.
Spot market	Market where transactions are handled immediately.
Standard cubic metre	Section 2 subpara 11 GasNZV defines a standard cubic metre as the quantity of gas which, free of water vapour and at a temperature of 0°Celsius and an absolute pressure of 1.01325 bar, corresponds to the volume of one cubic metre.
Standard load profile customer (SLP)	*Electricity* Section 12 StromNZV defines standard load profile customers as final customers with an annual offtake up to 100,000 kWh (electricity) for whom no load profile needs to be recorded by the DSO. (Any deviation to the specific offtake limit may be determined in exceptional cases by the DSOs.) *Gas* Section 24 GasNZV defines standard load profile customers as final customers with a maximum annual offtake of 1.5m kWh or a maximum hourly offtake of 500 kWh (gas) for whom no load profile needs to be recorded by the DSO. (Any variations above or below these specific withdrawal and offtake capacity limits may be determined by the DSOs.)
Storage facility operator	In this context the term refers to a storage facility operator in the commercial sense. It does not refer to the technical operator but rather to the company which sells the storage capacities and appears as a market participant.
Standard supplier	The default supplier (cf section 38 EnWG).
Standard supply	Energy received by final customers from the general supply system at low voltage or low pressure and not allocable to a particular delivery or a particular supply contract (cf section 38 EnWG).
Supplier switch	This process describes the interaction between market partners in cases in which a customer at a metering station wishes to change from their current supplier to a different one. In principle this does not include cases of moving home. A switch of supplier when moving home need only be recorded if the customer chooses a supplier other than the default supplier within the meaning of section 36(2) EnWG directly at the time of moving in. Nor are supply contracts transferred as a result of a change of supply rights regarded as a switch of supplier.

System balancing energy	Energy procured by the balancing group manager and used to guarantee the stability of the networks in the particular market area.
Transformation level	Areas in power supply networks in which electrical energy is transformed from extra high to high voltage, high to medium voltage and medium to low voltage (section 2 para 7 StromNEV). An additional transformation within one of the separate network levels (eg within the medium voltage level) is part of that network level.
Two-contract model	Procedure for handling the transport of gas within a balancing zone (market area) with two contracts with the shippers: one contract for input into the market area and one for output to final consumers in that market area or to a bookable exit point at the market area border.
Unbundled storage services	Products for which the volume of working gas, feed-in and offtake capacity are sold separately.
Underground storage facilities	These are notably pore, cavern and aquifer storage facilities.
Usage time (final consumers)	Number of days that would be required to withdraw the annual consumption volume by taking off the maximum daily amount (usage time in days = annual consumption divided by maximum daily amount). Usage time in hours indicates the number of hours required to withdraw the annual consumption volume by taking off the maximum hourly amount (usage time in hours = annual consumption divided by maximum hourly amount). (cf. Eurostat)[1)]
Vertical network load	The correct sum of all transfers from the transmission network over directly connected transformers and lines to distribution networks and final customers.
Virtual point (VP) (also called virtual trading point)	The VP is used as a reference point for settlement in order to represent the gas trading and gas transport transactions within the two-contract model. When gas is injected into a market area, it is available at the VP of that market area and can be traded there as deemed necessary.
Working gas	Gas actually available for withdrawal from a gas storage facility. The formula is: storage volume – cushion gas (volume not available for use) = working gas.
Yesterday trading	The purchase and sale of schedules on the working day following the delivery day. This reduces deviations from forecast and lessens the system balancing energy requirement through retroactively improving forecast quality. Trading takes place at the EEX market clearing price.

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