Bundesnetzagentur

Bundeskartellamt

Monitoringreport 2013

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1. Key findings

1.1 Generation/Security of supply

In 2012, the year under review, there was again strong growth in renewable energy generating facilities, mainly driven by the expansion of solar energy by 7.6 GW. This expansion slowed down considerably in 2013, with an increase of 2.5 GW in solar power from January to August 2013. There was also significant growth in 2012 in onshore wind and brown coal capacity, which increased by 1.5 GW and 1.4 GW respectively. The total (net) installed generating capacity rose by 10.3 GW from 168.0 GW (31 December 2011) to 178.3 GW (31 December 2012), with 102.6 GW conventional and 75.6 GW renewable capacity.

While non-renewable electricity generation decreased in 2012 by 8.1 TWh from 445.8 TWh (2011) to 437.7 TWh, the volume of electricity produced from renewable energy sources increased by 19.1 TWh from 119.8 TWh (2011) to 138.9 TWh (2012). Non-renewable electricity generation in 2012 was marked by an expansion in the production of electricity from coal (brown coal +7.2 TWh, hard coal +4.7 TWh). In contrast, there was a decrease in the production of electricity using natural gas (-11.4 TWh) and nuclear power (-8.2 TWh). The increase in renewable energy generation was mainly due to the growth in solar and biomass power.

The total installed capacity of installations in Germany eligible for payments under the Renewable Energy Sources Act (EEG) was approximately 71.0 GW on 31 December 2012 (31 December 2011: around 61.7 GW). This represents an increase in the installed capacity of all installations eligible for EEG payments in 2012 of some 9.4 GW. In 2012, the total volume of electricity remunerated under the EEG was 118,330 GWh, including electricity sold directly as well as solar electricity used by the installation owners themselves, for which a bonus was paid. The EEG payments and market and flexibility bonuses for this electricity totalled €19,118m. This represents a rise of 15 percent in the total volume of EEG-remunerated electricity and of 14 percent in total payments, compared with the previous year.

In October 2013, non-volatile generating plants with a total capacity of 10,898 MW were under construction in Germany, with completion scheduled in or before 2016. At the same time, cutbacks in capacity of up to 9,941 MW are planned by 2018, resulting in a positive balance of 957 MW across the country as of 31 December 2018.

In the south of Germany, plants with a capacity of 1,978 MW (as of October 2013) are currently under construction and due to be completed by 2015. On the basis of the current construction projects, no further growth in non-volatile capacity is expected in the subsequent period from 2016 to 2018. According to the companies' data, it is planned to cut back capacity in the south by up to 7,395 MW between 2013 and 2018, leading to a potential negative balance of up to 5,417 MW.

In the interest of maintaining security of supply, the transmission system operators (TSOs) again secured sufficient reserve capacity (some 2,600 MW) for winter 2012/2013 to safeguard supply in particularly critical situations. Despite the long cold period in winter 2012/2013, the situation in the transmission system was less tense than in the previous winter of 2011/2012. The only instance in which the reserve plants were called upon was on 28 January 2013 for the following day.

The average interruption duration determined in the low and medium voltage range rose from 15.31 minutes (2011) to 15.91 minutes (2012). This was due to a large increase in interruptions resulting from third-party intervention and other disruptions in the medium voltage sector. The idea that the increase in decentralised power generation had a significant effect on the quality of energy supply can be ruled out for 2012.

1.2 Networks

The monitoring survey revealed delays in the majority of the transmission lines planned as part of the grid expansion under the Power Grid Expansion Act (EnLAG) in the third quarter of 2013. Just 268 km of the total 1,855 km of lines planned (some 15 percent) had been completed. The majority of the expansion projects were originally due for completion before the end of 2015, but only around 50 percent can realistically be expected to be finished by 2016.

According to the TSOs slight progress has been achieved in some projects by the end of 2013, for example at the “Thuringia Electricity Bridge”, at an interconnector to Poland or at a segment between North Rhine-Westphalia and Rhineland-Palatinate. However, the affected sections, respectively the whole projects, are still under construction.

In 2012, total investments in and expenditure on network infrastructure by the four German TSOs amounted to approximately €1,152m (2011: €847m). This increase is primarily a result of the cost of investments in new builds, upgrades and expansion projects, which rose from €470m (2011) to €864m (2012). In contrast, investments and expenditure incurred by the distribution system operators (DSOs) fell from €6,930m (2011) to €6,005m (2012). The number of DSOs carrying out optimisation, reinforcement or expansion measures in their networks again increased in 2012.

In 2012, 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 and storage facilities to ensure security of supply – over a total of 7,160 hours, an increase of 42.3 percent compared with 2011 (5,030 hours). The measures in 2012 comprised a total volume of 2,566 GWh and primarily concerned the control areas of TenneT and 50Hertz.

Two TSOs also took adaptation measures in accordance with section 13(2) of the EnWG for a total of twelve hours on four days, reducing feed-in by a maximum capacity of 4,805 MW and a total of 15,594 MWh of electrical energy. In addition, seven DSOs took adaptation measures under section 13(2) of the EnWG for 1,649 hours spread over 254 days. Here, feed-in was reduced by a maximum capacity of 87 MW and a total of approximately 5,935 MWh of electrical energy. Support measures taken by 13 DSOs in accordance with sections 13(2) and 14(1a) of the EnWG for a total of twelve hours on four days resulted in a reduction in feed-in by a maximum capacity of 326 MW and a total of approximately 4,535 MWh of electrical energy.

The volume of unused energy as a result of feed-in management measures pursuant to section 11 of the EEG fell by 8.5 percent to 385 GWh compared with 2011 (421 GWh) In addition to individual network expansion measures, the generally favourable weather conditions (no extreme feed-in levels from photovoltaic and wind power systems simultaneously) in 2012 contributed to the decrease in the volume of unused energy resulting from feed-in management measures. As in previous years, feed-in management measures were applied primarily to wind power plants, which accounted for 93.2 percent of the total volume of unused energy (2011: 97.4 percent). Solar power systems accounted for 4.2 percent in 2012, seven times as much as in 2011 (0.6 percent). The sum total of compensation payments was virtually unchanged at approximately €33.1m (2011: €33.5m) despite the decrease in the volume of unused energy owing to more reduction in feed-in from solar installations.

The revenue caps for the TSOs increased from 2012 to 2013 by around 7.81 percent. One significant reason for this is the increase in costs arising from investment measures. Higher expansion investments led to an increase of 15.3 percent from 2012 to 2013 in the revenue caps for the DSOs. These revenue caps provide the basis for calculating the tariffs of the different network areas. There was an overall rise in the network tariffs for household, industrial and business customers. The tariffs for these three customer groups, based on specific offtakes, increased between 1 April 2012 and 1 April 2013 as follows:

- Household customers: 6.52 ct/kWh (+0.48 ct/kWh)
- Business customers: 5.61 ct/kWh (+0.50 ct/kWh)
- Industrial customers: 1.79 ct/kWh (+0.11 ct/kWh)

The costs of the TSOs' system support services fell by €60m from €1,069m in 2011 to €1,009m in 2012. A large part of the total costs is made up by the costs for keeping reserves of system balancing power – €417m (2011: €588m) – and for energy to compensate for grid losses – €354m (2011: €317m). The cost structure of the system support services was not the same in 2012 as in 2011. The costs for system balancing energy fell by €171m, most notably because of the lower costs for secondary regulation (-€105m), while there was an increase in the costs for reactive power (+€41m) and energy to cover grid losses (+€37m).

As in the previous years, Germany was once again the hub of the exchange of electricity within the central interconnected system. The average available transmission capacity remained more or less unchanged in 2012. Capacity showed a year-on-year increase of 1.9 percent to 21,735 MW (import and export capacities) in contrast to 2011, when there was a decrease of 7.1 percent. Changes took place in particular at the border between Germany and the Czech Republic and Poland, where export and import capacity increased by 40 percent and 14.4 percent respectively. Import capacity at the border with France decreased by 14.8 percent, with exports more or less constant (+0.4 percent). At the border with Switzerland, export capacity fell by 16.9 percent, while import capacity rose just slightly (+0.8 percent).

Cross-border traded volumes grew by 7.7 percent from 74 TWh in 2011 to 79.7 TWh in 2012, with Germany's net electricity exports increasing sevenfold from 3.0 TWh in 2011 to 21.7 TWh in 2012.

1.3 Wholesale

Well-functioning wholesale markets are key to competition in the electricity sector. Spot and futures markets are crucial for meeting the suppliers' short and longer term electricity requirements. Indicative of liquidity, which is necessary for the markets to function properly, are the number of market players and the trading volumes.

Overall, the number of active participants in the institutionalised exchanges in the year under review was around the same as in the previous year. In addition, the particular function fulfilled by market makers is to raise the liquidity of the markets.

The trading volume on the EPEX SPOT day-ahead market showed a total year-on-year increase of some nine percent. The share of the TSOs' price-independent bids, which the TSOs use primarily to market EEG-regulated electricity, was smaller than in the previous year. This is a result of the increase in the volume of renewable electricity sold directly. There was also a rise in the trading volume on the EXAA day-ahead spot market. The average prices on the spot markets showed a year-on-year decrease of around 15 percent (peak) and 17 percent (base).

On the EEX futures market, the volume of direct exchange trading fell slightly while the volume of OTC clearing (excluding options) showed a stronger decrease. The annual average prices for standard products (front-year futures) fell, with the difference between base prices (€49.30/MWh compared to €56.08/MWh in 2011) and peak prices (€60.86/MWh compared to €69.03/MWh in 2011) becoming smaller.

The trading volume in the bilateral – ie off-exchange – wholesale sector is several times higher than that on the exchange, at least as far as futures trading is concerned. A large number of participants active in short-term and futures trading also act as suppliers for final customers. Many of these market participants restrict their activities on the futures market to buying the electricity needed to supply their final customers. Broker platforms play a key role for wholesale trading participants who do not supply final customers.

The energy exchanges have recently developed and introduced several new products that can directly or indirectly promote the integration of electricity (demonstrably) generated from renewable energy sources.

1.4 Retail

The number of electricity suppliers from whom retail customers can choose again increased slightly. In 2012, final customers could choose between an average of 88 suppliers in each network area. The average number of suppliers for household customers was 72.

The data collected shows a decrease in the number of customers switching supplier compared with 2011. 2.8m final customers switched supplier in 2012, including 206,000 industrial and business customers. The apparent decrease in the number of household customers switching supplier constitutes a slight increase if the customers who switched automatically (in the first instance to the fallback supplier) on account of a large supplier becoming insolvent in 2011 are excluded from the figure for that year. The increase in supplier switches is smaller compared with previous years. 7.8 percent of household customers, 11.2 percent of business customers and 11.1 percent of industrial customers switched supplier.

A relative majority – 43.2 percent – of household customers have a special contract with their local default supplier, while 36.7 percent still have a standard contract with their default supplier and one fifth are served by a company other than the default supplier. The overall strong position that default suppliers continue to have in their service areas weakened slightly in the year under review. The situation with industrial and business customers is different: only 2.1 percent of these customers have a standard contract with their default supplier; 39.3 percent have a special contract with their local default supplier, and 58.6 percent are served by a company other than the default supplier.

The number of interruptions in supply to household customers with a standard contract with their default supplier increased slightly to 321,539 compared with the previous year. The relation determined in the last monitoring report between threatened supply interruptions, interruption requests and actual interruptions was confirmed this year.

There was a clear increase in retail prices in the year under review. The total price for business customers rose by an average of 11.9 percent to 26.74 ct/kWh. The total price for industrial customers showed a slightly smaller rise than in other customer segments, with an average increase of 8.8 percent to 17.17 ct/kWh. The largest increases affected prices for household customers. As of 1 April 2013, the average price for household customers with a standard default supply contract had increased by 13.2 percent to 30.11 ct/kWh compared with 2012. This was the largest increase in seven years. Prices for the other customers – those with a special contract with their default supplier or a special contract with a third-party supplier (supplier switch) – also increased. The average electricity prices after contract switching and supplier switching were 29.09 ct/kWh and 27.94 ct/kWh respectively. The volume-weighted average for 2013 across all three prices was 29.38 ct/kWh. The prices increases are mainly due to the increase in price components determined by the state[1]. The

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1.1 [1] See I.H.4.1 „Business and industrial customers

The following section examines the development of retail prices for industrial and business customers. The depictions of the retail price level for industrial customers are based on the following purchase case:

- 24 GWh/year annual consumption
- 4,000 kW annual peak load and 6,000 hours annual usage time
- Medium voltage supplies (10 or 20 kV).

The suppliers reporting on industrial customer prices were asked to provide plausible estimates, based on the conditions applicable as of 1 April 2013 for the amount charged to their company's customers with a purchase structure comparable to the stated purchase case. The evaluation of information provided by 206 companies (volume-weighted average: tariffs and volumes) produced the results shown in the following table:

Table 29: Average retail price level (fixed and variable price components) on 1 April 2013 for industrial customers according to survey of wholesalers and suppliers

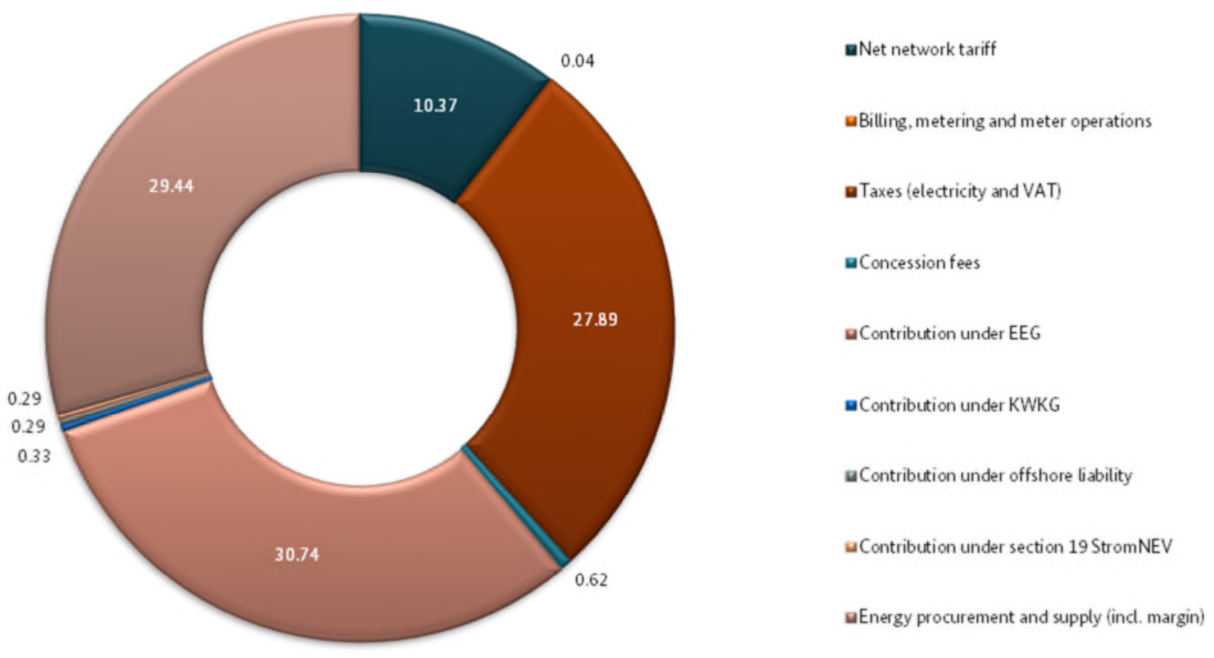
Industrial customers (volume weighted) 1 April 2013	Price component ct/kWh	Share of total price in percent
Net network tariff	1.78	10.37
Charge for billing	0.002	0.012
Charge for metering	0.002	0.012
Charge for meter operations	0.003	0.017
Concession fees	0.11	0.62
Surcharge under EEG	5.28	30.74
Surcharge under section 19 StromNEV	0.05	0.29

Surcharge under KWKG	0.06	0.33
Surcharge for offshore liability	0.05	0.29
Tax (electricity and VAT)	4.79	27.89
Energy procurement and supply (incl. margin)	5.05	29.44
Total	17.17	100

The average volume-weighted total price for industrial customers in Germany is at 17.17 ct/kWh. The arithmetically determined price level, which is not shown here, is approximately 0.9 ct/kWh above the volume-weighted price level. Depicted here for the first time is the newly introduced surcharge for offshore liability, which is being charged since 1 January 2013.

The following figure shows the share of the individual price components in percent:

Figure 69: Retail price composition for industrial customers on 1 April 2013, in percent



As the diagram shows, the net network tariff accounts for a share of 10.4 percent of the entire electricity price for industrial customers. Charges for billing, metering and meter operations account for only 0.04 percent of the total price. The competitive price component “energy procurement and supply” accounts for 29.4 percent of the total electricity price for industrial customers. Taxes (electricity and value-added tax) account for 27.9 percent and the sum of all levies (surcharges under the EEG, KWKG, section 19 StromNEV and for offshore liability as well as concession fee) amounts to approximately 32.3 percent. The EEG surcharge, at 30.7 percent, accounts for the biggest share by far. In other words, taxes and levies make up nearly 60 percent of the electricity price charged to industrial customers. However, it must be noted that the monitoring survey, in order to enable the greatest possible degree of uniformity in survey results, expressly does not take into account the special compensation scheme for electricity-intensive companies. As this issue is of considerable general interest, the following section provides a brief exemplary calculation of the maximum possible benefits for an electricity-intensive company in the category of the purchase case of 24 GWh/year.

Assuming that such a company can fulfill all prerequisites for compensation measures provided for in the relevant ordinances and laws, this leads to reductions in the net network tariff, as well as in the surcharges under the EEG, KWKG, section 19 StromNEV and in the surcharge for offshore liability. A further assumption is an exemption from the concession fee, which is possible according to section 2(4) sentence 1 KAV. The maximum possibilities of reductions for a typified electricity-intensive company with an offtake volume of 24 GWh are listed in the following table, together with the other, non-reduced price components:

Table 30: Components of the price paid by industrial customers (24 GWh), taking into account the maximum possibilities of reduction

Industrial customers (volume weighted) 1 April 2013	Price component ct/kWh	Share of total price in percent
Net network tariff	0.36	3.78
Charge for billing	0.002	0.02
Charge for metering	0.002	0.02
Charge for meter operations	0.003	0.03
Concession fee	0.00	0.00
Surcharge under the EEG	0.45	4.72
Surcharge under section 19 StromNEV	0.03	0.31
Surcharge under the KWKG	0.03	0.31
Surcharge for offshore liability	0.03	0.31
Tax (electricity and VAT)	3.57	37.47
Energy procurement and supply (incl. margin)	5.05	53.01
Total	9.53	100

The resulting average total price is an exemplary value of 9.53 ct/kWh. The maximum reduced price is thus nearly 50 percent lower than the price without any possibility of reductions. Of particular significance in this context are the compensation measures in respect of the EEG surcharge, as these bring about a drastic reduction of the charge from 4.83 ct/kWh to 0.45 ct/kWh. The surcharges payable under the KWKG, section 19 StromNEV and for offshore liability are reduced by approximately half. With regard to the net network tariff, the assumed case was a maximum possible reduction of 80 percent pursuant to section 19(2) sentence 1 StromNEV. With regard to the tax burden it must be noted that there are also exemption and reimbursement possibilities for the electricity tax of 2.05 ct/kWh (cf. section 9a StromStG), which since they must take place ex-post are not given any further explanation here.

In addition to providing information on industrial customers, suppliers were also asked to provide information on prices for business customers. Retail prices shown are based on the purchase case:

- 50 MWh/year annual consumption,
- 50 kW annual peak load and 1,000 hours annual usage time,
- Low-voltage supply (0.4 kV) (where the load profile of business customers is not measured, the value was stated on the basis of delivery without load metering).

Table 31: Average retail price level (fixed and variable price components) on 1 April 2013 for business customers according to survey of wholesalers and suppliers

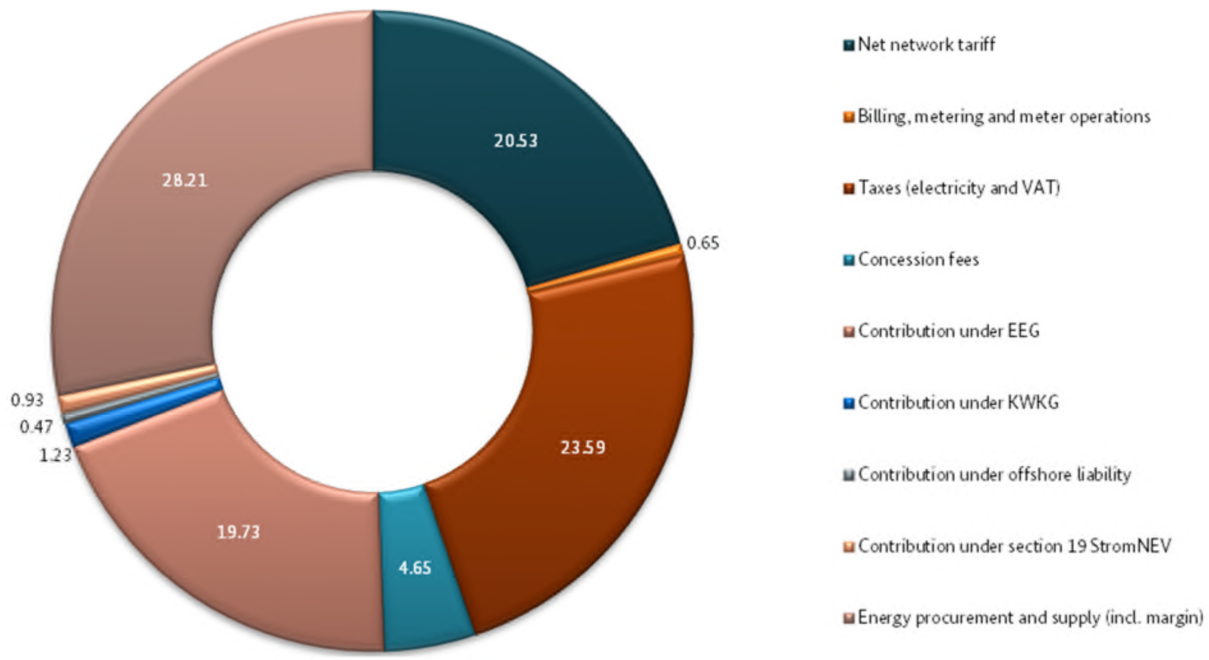
Business customers (volume weighted) 1 April 2013	Price component ct/kWh	Share of total price in percent
Net network tariff	5.49	20.53
Charge for billing	0.08	0.28
Charge for metering	0.04	0.14
Charge for meter operations	0.06	0.23
Concession fee	1.24	4.65
Surcharge under the EEG	5.28	19.73
Surcharge under the KWKG	0.13	0.47
Surcharge under section 19 StromNEV	0.33	1.23
Surcharge for offshore liability	0.25	0.93
Tax (electricity and VAT)	6.31	23.59
Energy procurement and supply (incl. margin)	7.54	28.21
Total	26.74	100

641 companies provided information on tariffs and volumes for the category of business customers. This produced the results shown in Table 31.

The average, volume-weighted total price for business customers in Germany thus amounts to 26.74 ct/kWh. The arithmetically averaged price level, which is not shown here, is approximately 0.6 ct/kWh below the volume-weighted price level.

The following figure shows the percentage share of the individual price components.

Figure 70: Retail price composition for business customers on 1 April 2013, in percent



The analysis shows that the net network tariff accounts for a share of 20.5 percent of the entire electricity price for business customers. This share is approximately twice as high as that for industrial customers. Charges for billing, metering and meter operations account for 0.6 percent of the total price. The competitive price component "energy procurement and supply" accounts for 28.2 percent of the total electricity price for business customers. This is comparable to the share for industrial customers. Taxes (electricity and value-added tax) account for 23.6 percent, which is approximately four percent below the share for industrial final consumers. The sum of all levies (surcharges under the EEG, KWKG, section 19 StromNEV and for offshore liability as well as concession fee) amounts to approximately 27 percent for business customers. That is approximately five percent below the share for industrial customers. The EEG surcharge, at 19.7 percent, accounts for the biggest share of levies to business customers by far. That figure is significantly lower than that for industrial consumers. In total, taxes and levies make up around half of the price charged to business customers.

The figures clearly show that a large portion of retail prices for industrial and business customers are accounted for by the state-controlled price components such as taxes and levies, as well as by network charges. The competitive portion in both customer segments now makes up less than a third of the retail price. This shift is due in part to the significant price increase that has taken place in particular in the area of levies. A detailed depiction of this development can be found below.

Table 32: Change in electricity price: 1 April 2013 to 1 April 2012 (absolute and in percent)

Volume-weighted average	Industrial customer		Business customer	
	ct/kWh	percentage	ct/kWh	percentage
Net network tariff	0.11	6.6	0.54	10.9
Charge for billing	0	0	0.01	7.8
Charge for metering	0	0	0.01	24.3
Charge for meter operations	0	0	-0.01	-11.6
Concession fee	0	0	0.05	4.5
Surcharge under the EEG	1.69	47.0	1.69	47.0
Surcharge under the KWKG	0.02	40.0	0.13	640.0
Surcharge under section 19 StromNEV	0	0	0.18	119.3
Surcharge for offshore liability	0.05	-	0.25	-
Tax (electricity and VAT)	0.18	3.8	0.32	5.3
Energy procurement and supply (incl. margin)	-0.66	-11.5	-0.31	-3.9
Total	1.39	8.8	2.85	11.9

Compared with the previous year, cutoff date 1 April 2012, the average (volume-weighted) retail prices for industrial and business customers increased by 8.8 and 11.9 percent respectively. Table 32 shows the change in ct/kWh in the volume-weighted average of the individual price components as well as in the total electricity price for industrial and business customers between 1 April 2012 and 1 April 2013. It also shows the percentage change of the relevant price components.

Compared to the previous year (cutoff date 1 April 2012) and in relation to the volume-weighted average of price components for industrial and business customers, there has been a price increase in surcharges, network tariffs (including billing, metering and meter operations) as well as in taxes. The increase in the EEG surcharge is particularly significant. The surcharge for offshore liability is depicted for the first time. For business customers, there is also a marginal increase in the charges for metering and in the concession fee, while the charges for meter operations have decreased negligibly. The increase in all taxes and levies as well as in network tariffs for industrial customers amounted to 2.04 ct/kWh, while for business customers it was as high as 3.16 ct/kWh.

These significant increases were cushioned by another reduction in the price component "energy procurement and supply". Compared to the previous year, the share for industrial customers has fallen by 0.66 ct/kWh, and for business customers by 0.31 ct/kWh. Since 2011, the price component for energy procurement and supply has thus decreased for industrial customers by a total of 1.15 ct/kWh and for business customers by 0.4 ct/kWh. This is most likely due in large part to lower wholesale prices. The fact that these price reductions are passed on to final customers in the industrial consumer sector to a greater extent than is the case in increase in the EEG surcharge to 5.28 ct/kWh had a considerable effect on retail prices. This surcharge now accounts for 18 percent of the average total price.

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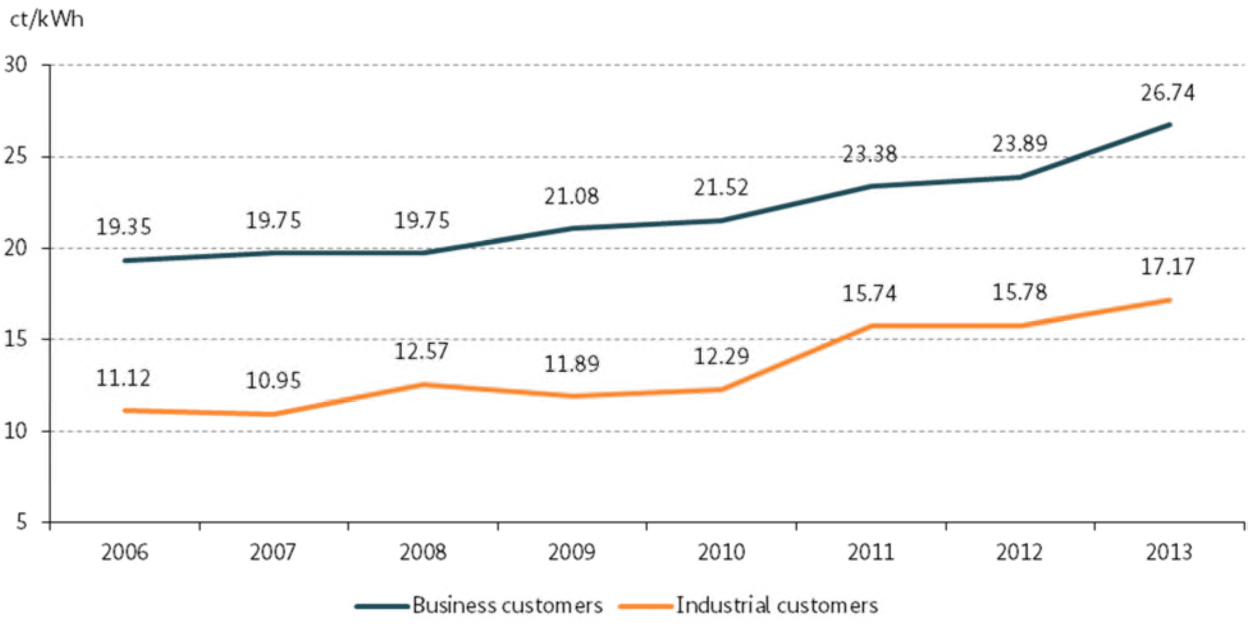
the business consumer sector is largely due to differing procurement strategies. Suppliers' procurement portfolios have a much more short-term orientation for industrial customers than for other customer groups. These mechanisms have also been confirmed in the analyses of previous monitoring reports.

Compared with the previous year, the total price for industrial customers has increased significantly, by 1.39 ct/kWh. For business customers, there was an even more dramatic increase in the total price, by 2.85 ct/kWh. This is the greatest price increase within the course of one year since the beginning of monitoring activities in 2006. Since that point in time, the price for business customers has increased from an average of 19.35 ct/kWh to 26.74 ct/kWh. This amounts to an increase of 38.2 percent or 7.34 ct/kWh. During the same time period, the prices for industrial customers have also increased significantly, from 11.12 ct/kWh in the year 2006 to 17.17 ct/kWh in 2013. The increase in this customer segment thus amounts to 54.4 percent or 6.05 ct/kWh. However, it must be noted that the price survey for industrial customers in past years has also not taken into account the special compensation scheme.

A detailed depiction of the price curves for industrial and business customers can be seen in the following figure.

Figure 71: Development of prices for industrial and business customers from 2006 to 2013



Household customers" beginning in page 131 for details of retail prices and individual price components.

The data collected shows a decrease in the "energy procurement and supply" component of the price for industrial and business customers and that the fall in wholesale prices was passed on to the final customers. In the case of household customers, there was a decrease in the "energy procurement and supply" component of the price for customers switching supplier only. Consumers can cut costs by switching contract and even more by switching supplier. Special bonuses offered by suppliers are an added incentive for final customers to switch supplier.

In 2012, 98 percent of final customers of electricity for interruptible consumer equipment were served by their regional default supplier. There are, however, competitors who are active in more than one region. Up until now, switching supplier has involved relatively high costs for the customers in looking for a new supplier. This situation, which is unsatisfactory to the customers, may change on account of the increased availability of information – from Internet portals to consumer advice services – that has been evident this year.

Further growth is expected in the green electricity segment. In 2012, green electricity accounted for ten percent of the total volume of electricity supplied, while some 15 percent of all final customers purchased green electricity.

2. Market overview

Table 1: Network structure figures 2012

Network structure figures 2012	TSOs	DSOs	Total
Network operators (number)	4	806	810
Total circuit length (km)	34,841	1,753,290	1,788,131
Extra high voltage	34,780	490	35,270
High voltage	61	95,364	95,425
Medium voltage	0	507,953	507,953
Low voltage	0	1,149,973	1,149,973
Total transmission route length (km)	17,961		
Extra high voltage	17,454		
High voltage	507		
Total final customers (metering points)	649	48,769,032	48,769,681
Industrial and business customers	509	3,046,244	3,046,753
Household customers	140	45,722,788	45,722,928

Table 2: Number of electricity network operators in Germany from 2006 to 2013

	2006	2007	2008	2009	2010	2011	2012	2013
TSOs	4	4	4	4	4	4	4	4
Total DSOs	876	877	855	862	866	869	883	888
DSOs with fewer than 100,000 connected customers	799	799	779	787	790	793	807	812

Table 3: Market and network balance for 2012[2]

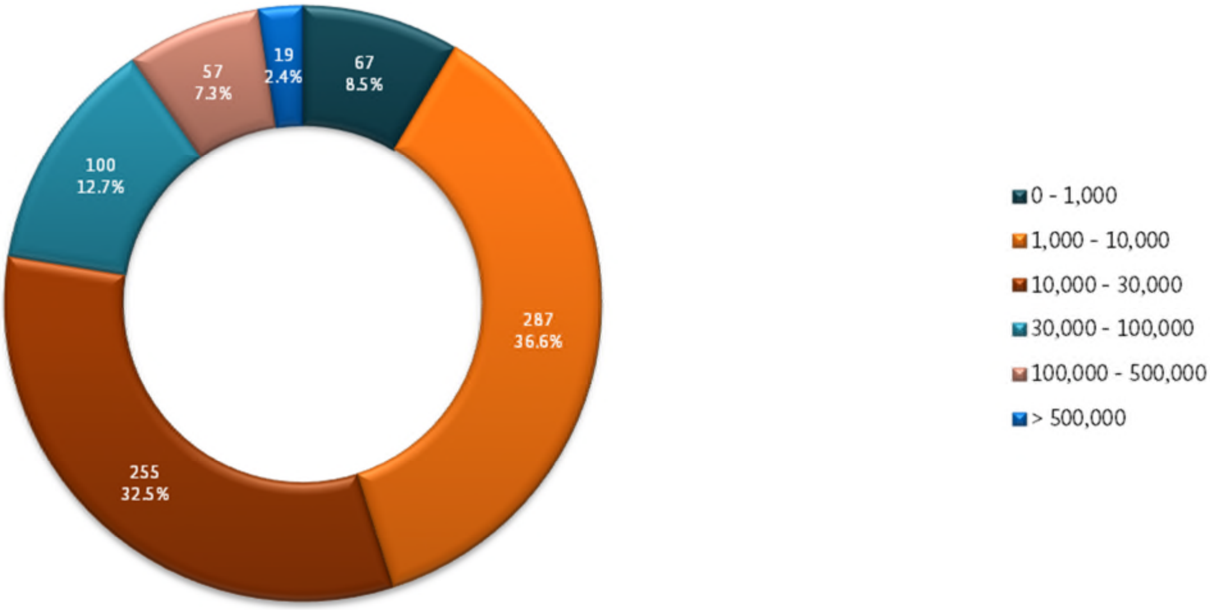
Market and network balance 2012	TSOs	DSOs	Total
Total net nominal capacity of generation facilities (GW) (as of 31 December 2012)			178.3
Facilities using non-renewable energy sources			102.6
Facilities using renewable energy sources			75.6
Facilities eligible for EEG payments			71.0
Total net output (TWh, including output not fed into general supply networks) in 2012			576.6
Facilities using non-renewable energy sources			437.7
Facilities using renewable energy sources			138.9
Facilities eligible for EEG payments			118.3
Net output not fed into general supply networks (TWh) in 2012			32.8
Network losses (TWh)	6.2	17.2	23.4
Extra high voltage	4.9	0	4.9
High voltage (including EHV/HV)	1.3	2.8	4.1
Medium voltage (including HV/MV)	0	5.4	5.4
Low voltage (including MV/LV)	0	9	9
Cross-border trading (TWh) (implemented exchange schedules)			79.7
Imports			29
Exports			50.7
Offtake (TWh)	42.1	469.9	512
Industrial and business customers	32.9	344.3	377.2
Household customers	0	124.5	124.5
Pumped storage	9.2	1.1	10.3

In absolute terms, the retail market in the electricity sector remains characterised by a strongly regional structure. More than three quarters of all DSOs in Germany supply fewer than 30,000 metering points. DSOs supplying 1,000 to 10,000 metering points make up the largest group with 37 percent. Nine percent of all DSOs supply more than 100,000 metering points but at the same time account for 347 TWh, or some 70 percent, of

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

the total electricity offtake volume and more than 77 percent[3] of all metering points. This shows that the majority of DSOs in Germany are small companies supplying a small number of metering points and with a relatively small share in electricity offtake while a small number of large DSOs, in terms of metering points and volume, account for the largest shares.

Figure 1: Breakdown of DSOs according to the number of metering points supplied



The four German TSOs took part in the Bundesnetzagentur's 2013 monitoring survey. As of 31 December 2012, the TSOs' total circuit length (cables and overhead power lines) amounted to 34,780 km at extra high voltage level and 61 km at high voltage level. The total number of metering points in the four TSOs' network areas, excluding so-called virtual metering points as defined in the Metering Code 2006, was 649. These included 509 metering points for load-metered customers. The total offtake volume of the 649 final customers connected (as of 31 December 2012) to the TSOs' networks was 32.9 TWh.

As of 16 September 2013 a total of 888 DSOs were registered with the Bundesnetzagentur, 806 of whom took part in the 2013 monitoring survey. The offtake of these DSOs' final customers totalled 468.8 TWh.

The overall circuit length (cables and overhead power lines) of the DSOs taking part in the 2013 survey amounted to 1,753,290 km as of 31 December 2012. A total of 48,769,681 metering points were supplied at all network levels. The total number of metering points in the DSOs' network areas, excluding so-called virtual metering points as defined in the Metering Code 2006, was 48,769,032. These included 419,921 metering points for load-metered customers. The total number of metering points for household customers as defined in section 3 para 22 of the EnWG was 45,722,788.

[3] In absolute figures: approximately 37.7m metering points

1,065 electricity wholesalers and suppliers took part in the Bundesnetzagentur's 2013 monitoring activities. Of these, 53 companies are active as wholesalers only, not supplying final customers, 895 as suppliers, and 117 as suppliers and wholesalers. The suppliers' delivery volume to final customers in 2012 totalled 448.2 TWh.

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 2012. It also shows the share, in percentage terms, of the individual categories in the overall offtake and delivery volume for final customers.

The total electricity offtake volume in Germany increased in 2012 by 7.2 TWh, or 1.4 percent, compared with 2011. Although the number of large industrial customers is small, these customers accounted for 48.3 percent of the total offtake volume in Germany, a year-on-year increase of 0.5 percent. Smaller industrial and business customers had a share of 26.9 percent of the total offtake, representing a slight increase of 0.1 percent. Household customers, who make up the largest customer group in terms of numbers, accounted for around 24.8 percent of the total volume, 0.6 percent less than in the previous year.

Table 4: Total sum of final customers' offtake volumes split by customer category according to data supplied by DSOs and TSOs[4]

Category	Electricity offtake TSOs/DSOs (TWh)	Share of total amount (percent)	Volume delivered by suppliers (TWh)	Share of total amount (percent)
≤10 MWh/year	124.5	24.8	125.8	28.1
>10 MWh/year ≤2 GWh/year	134.8	26.9	109.3	24.4
>2 GWh/year	242.4	48.3	213.0	47.5
Total amount	501.7	100	448.2	100

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

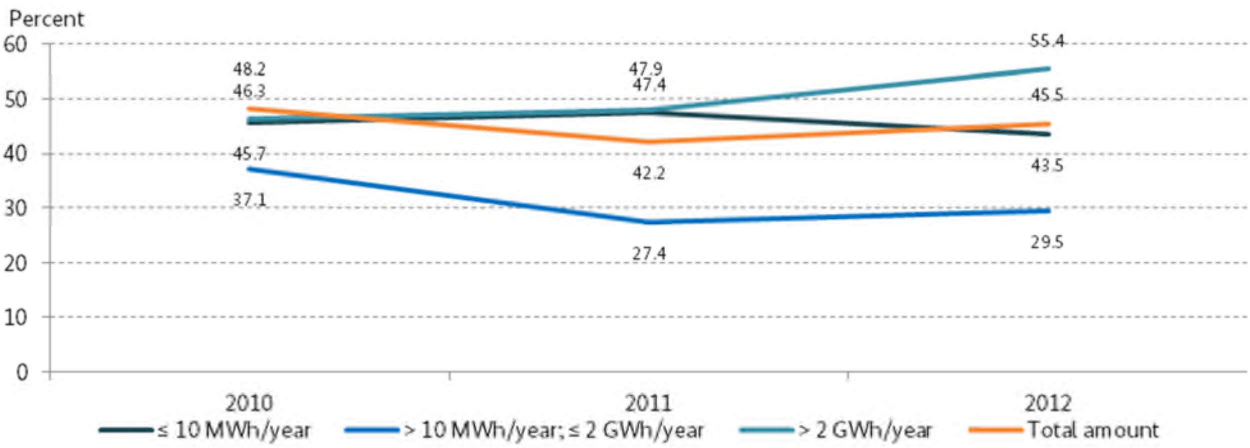
Shares of the major companies (dominance method)

In 2012, the total volume of electricity delivered to final customers in Germany by the four largest suppliers, using the dominance method, was 228.1 TWh. This is some 45.5 percent of the total electricity offtake from general supply networks of 501.7 TWh, and an increase of approximately three percentage points compared with 2011. The four largest suppliers reported a decrease in the volume for household customers (≤10 MWh/year) against an increase in the volumes and shares for industrial and business customers (>10 MWh/year), and in particular for industrial customers (>2 GWh/year). The dominance method involves allocating the delivery volumes of the dominated (consolidated) companies to the dominant company (based on the shareholding status at the time of reporting). The shares of the four largest companies in the individual sectors of the electricity market examined are shown below.

Table 5: Shares of the four largest companies in the individual sectors of the electricity market 2011-2012

Category	Electricity offtake DSOs/TSOs (TWh)		Volume supplied by the four largest companies (TWh)		Share of total amount (percent)	
Year	2011	2012	2011	2012	2011	2012
≤10 MWh/year	125.6	124.5	59.5	54.1	47.4	43.5
>10 MWh/year ≤2 GWh/year	132.7	134.8	36.3	39.8	27.4	29.5
>2 GWh/year	236.2	242.4	113.1	134.2	47.9	55.4
Total amount	494.5	501.7	208.9	228.1	42.2	45.5

Figure 2: Shares of the four largest companies in the individual sectors of the electricity market



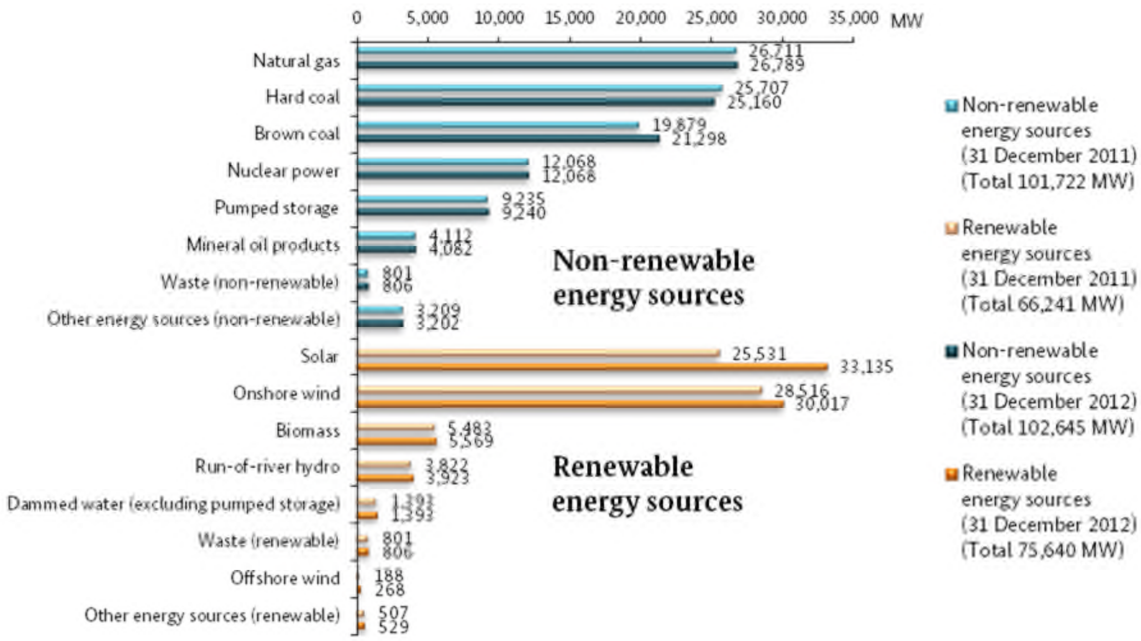
B Generation/Security of supply

1. Generation

1.1 Existing capacity and structure of the generation sector

In 2012, the year under review, power generation was again characterised by strong growth in renewables, mainly driven by the expansion of solar energy by 7.6 GW. There was also a significant increase in onshore wind and brown coal capacity, which grew by 1.5 GW and 1.4 GW respectively. Altogether, growth in generating facilities using renewable energy sources amounted to 9.4 GW and in facilities using non-renewable resources 0.9 GW. The total (net) installed generation capacity thus rose by 10.3 GW from 168.0 GW (31 December 2011) to 178.3 GW (31 December 2012)[5].

Figure 3: Installed electrical generation capacity (net nominal capacity as of 31 December 2011/31 December 2012)

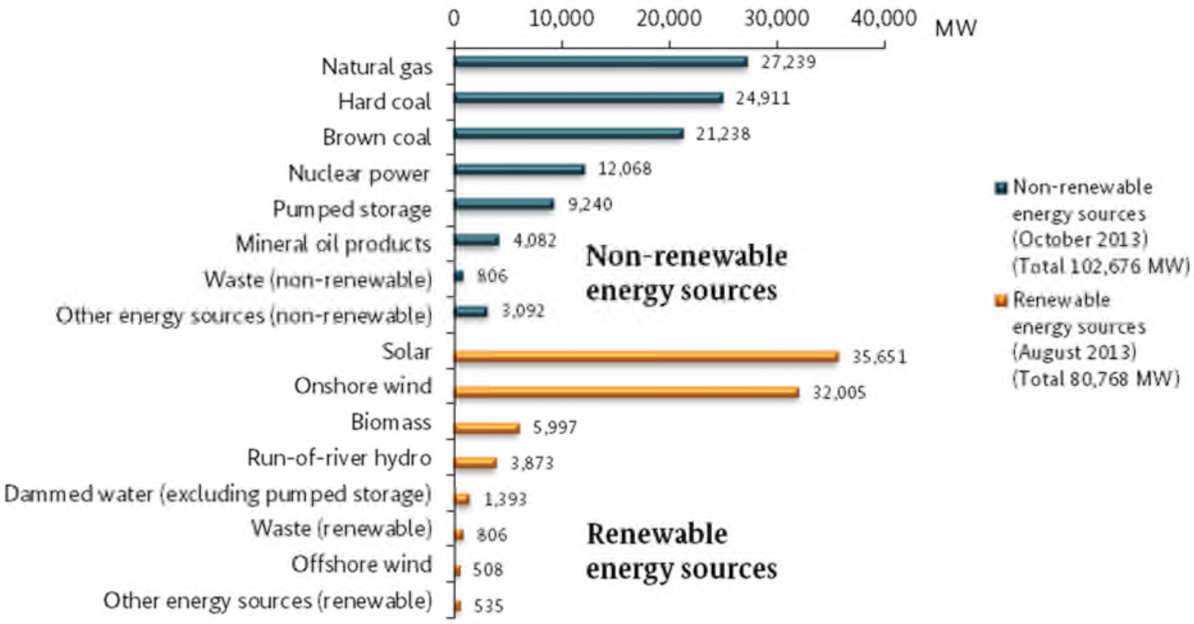


According to the figures from October 2013 (non-EEG) and August 2013 (EEG), non-renewable and renewable energy sources accounted for a total of 102.7 GW and 80.8 GW respectively. The continued growth in renewa-

[5] The generation capacity figures for the first time also include facilities <10 MW not eligible for EEG payments, which altogether account for approximately 3.5 GW. Generating facilities using more than one energy source are included in the figures for the main energy source. Capacities (pumped storage, hydropower) feeding into the German grid from Austria, France, Luxembourg and Switzerland are also included in the figures.

ble energy is a result of the increase of 2.5 GW in solar energy compared with 31 December 2012, indicating a considerably slower growth rate than in 2012. There was also a rise of 2.0 GW in onshore wind capacity.

Figure 4: Installed electrical generation capacity (net nominal capacity as of October 2013 (non-EEG) and August 2013 (EEG))



Non-renewable electricity generation in 2012 was marked by an expansion in the production of electricity from coal: the volume generated using brown coal increased by 7.2 TWh and using hard coal by 4.7 TWh. In contrast, there was a decrease in the volume of electricity produced using natural gas and nuclear power of 11.4 TWh and 8.2 TWh respectively. Altogether, non-renewable electricity generation decreased in 2012 by 8.1 TWh from 445.8 TWh (2011) to 437.7 TWh[6].

By contrast, the volume of electricity produced from renewable energy sources increased by 19.1 TWh from 119.8 TWh (2011) to 138.9 TWh (2012). This was mainly due to the growth in solar (+6.5 TWh) and biomass (+6.3 TWh) power. There was also an increase of 3.4 TWh in run-of-river hydroelectricity.

The net total volume of electricity generated in 2012 was 576.6 TWh, 11.0 TWh more than the total of 565.6 TWh generated in 2011.

[6] The total volume of electricity generated by facilities <10 MW not eligible for EEG payments is available for 2012 only: 7.3 TWh. This was also taken as the volume for 2011 to enable a comparison of the overall figures for 2012 and 2011.

Figure 5: Net total of electricity generated in 2011 and 2012

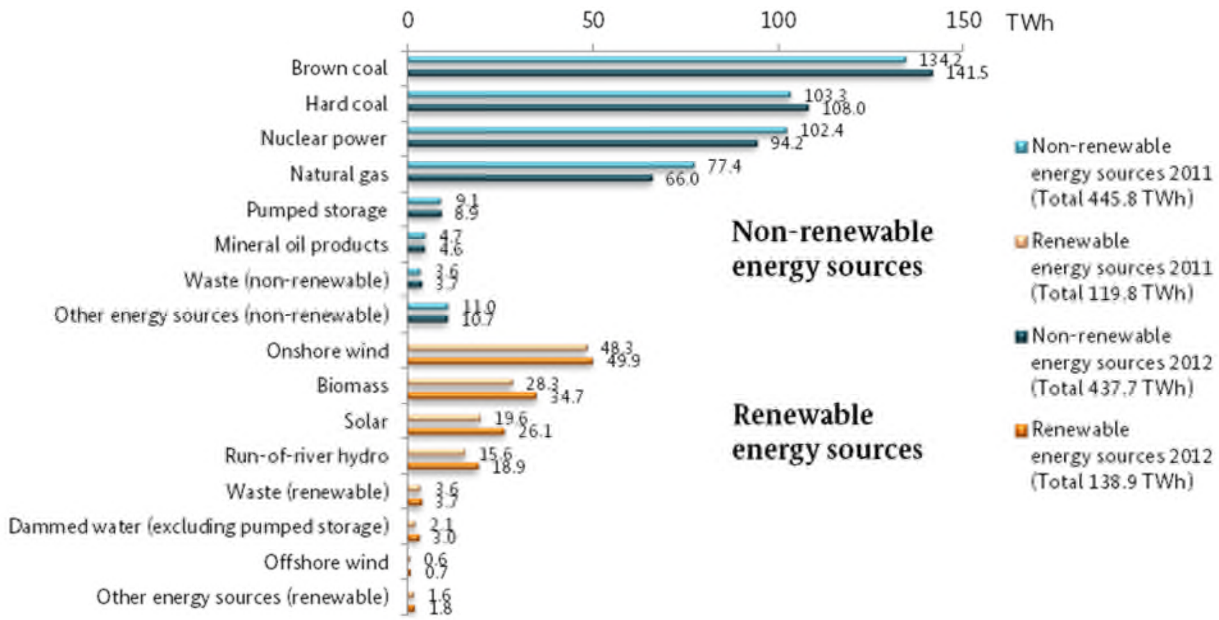
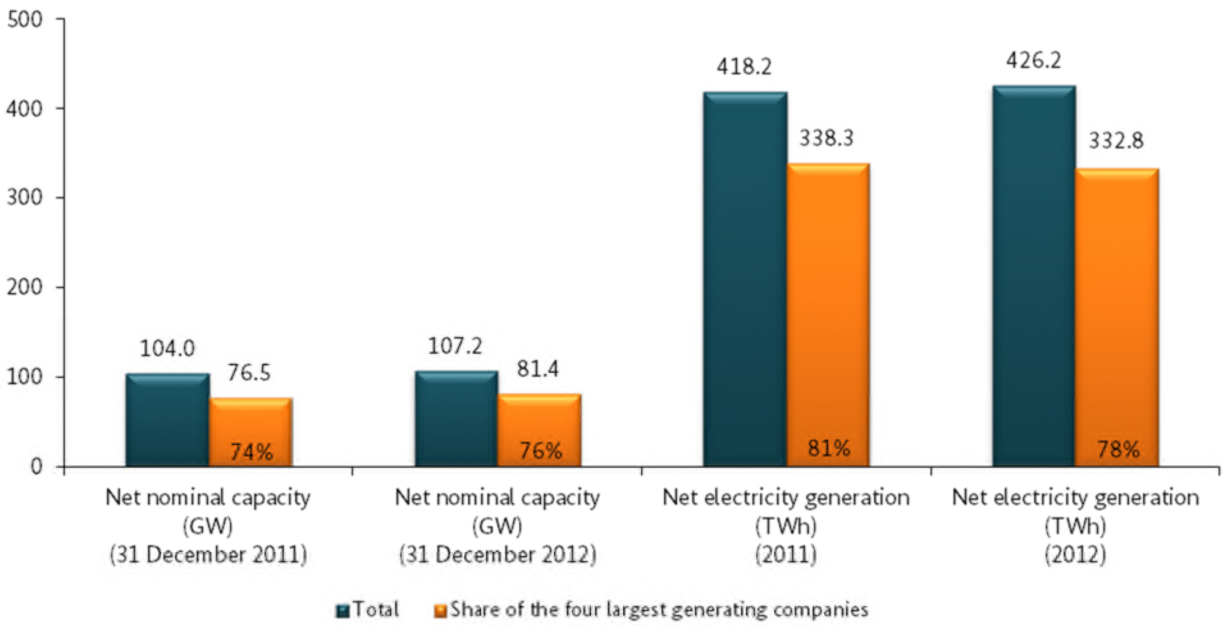


Figure 6: Generation capacity not eligible for EEG payments and electricity fed into the general supply networks, with shares of the four largest generating companies



As of 31 December 2012, the installed generation capacity totalled 178.3 GW, of which 71.0 GW was eligible for EEG payments and 107.2 GW not eligible. The share of the four largest generating companies, calculated using the dominance method, in terms of the capacity not eligible for EEG payments was approximately 76 percent

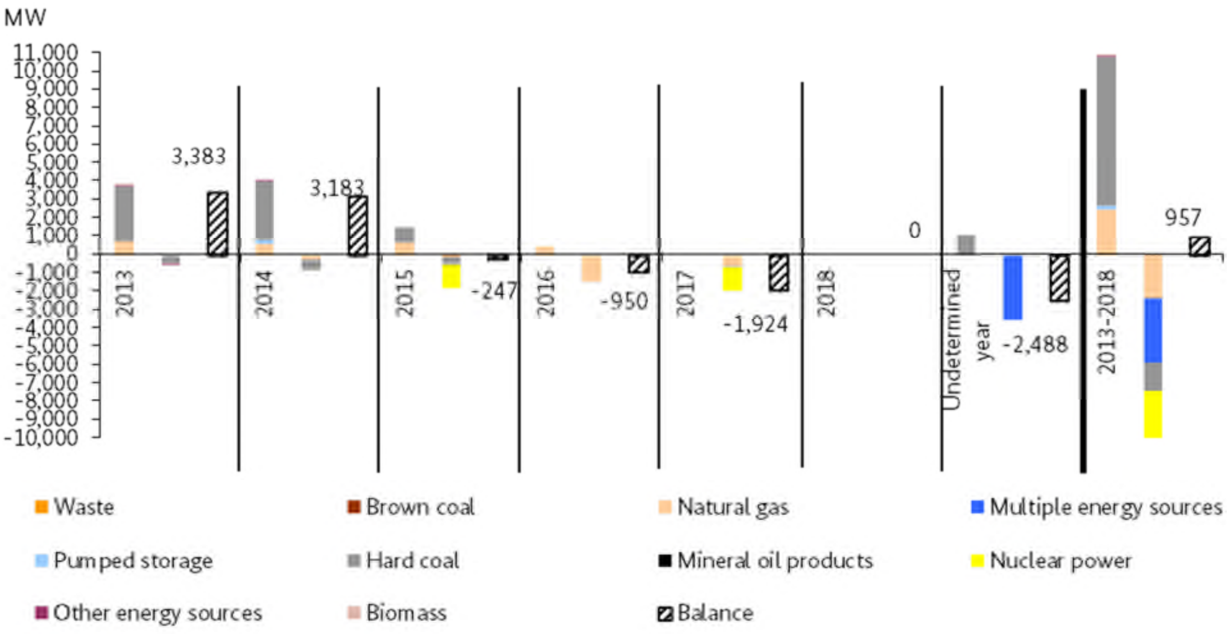
(81.4 GW) as of 31 December 2012. This represents a year-on-year increase of two percentage points in the market-based generation sector.

The total volume of electricity generated in 2012 (576.6 TWh) comprised 118.3 TWh eligible and 458.3 TWh not eligible for EEG payments. 426.2 TWh of the 458.3 TWh not eligible for EEG payments was fed into the general supply networks. The share of the four largest generating companies here was approximately 78 percent (332.8 TWh), which represents a decrease of three percentage points in the market-driven generation sector compared with 2011.

1.2 Expected growth and decline in generation capacity

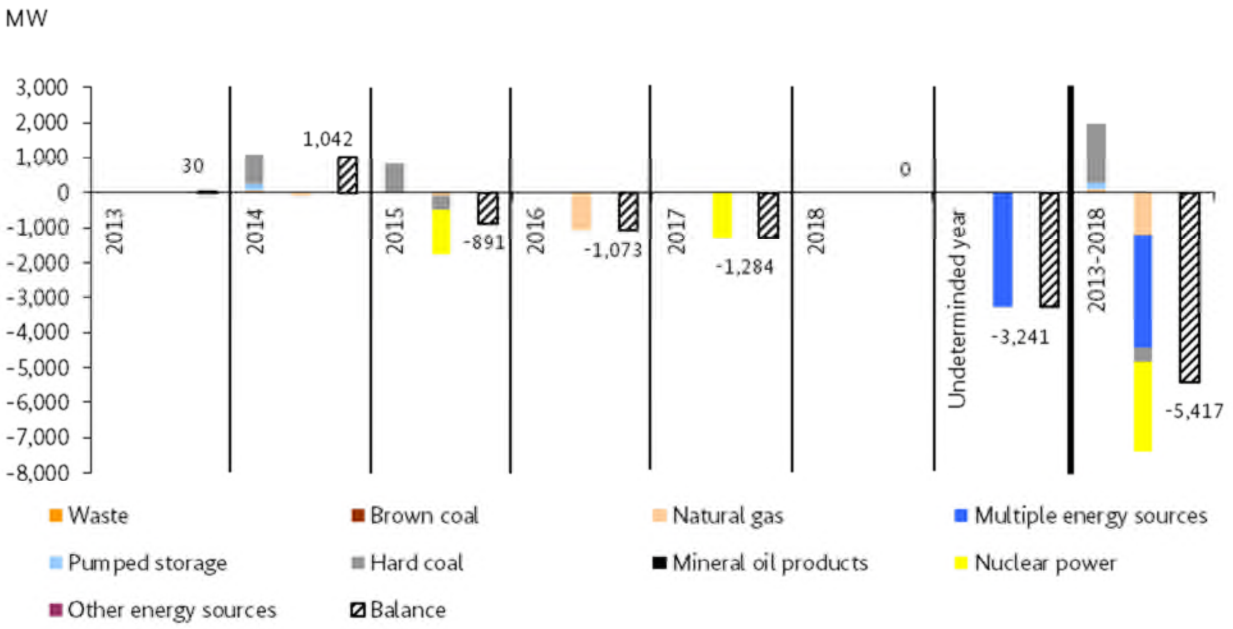
The following section on the development of non-volatile energy sources (ie excluding solar, hydro and wind) that are of importance to the security of supply only takes account of generating facilities currently under construction.

Figure 7: Commencement of commercial electricity feed-in/permanent shutdown of non-volatile power plants (2013-2018 nationwide planning data for net nominal capacity, as of October 2013)



Generating facilities based on non-volatile energy sources with a total capacity of 10,898 MW are currently under construction in Germany, with completion scheduled in or before 2016. At the same time, cutbacks in capacity of up to 9,941 MW are planned by 2018, resulting in a positive balance of 957 MW across the country as of 31 December 2018.

Figure 8: Commencement of commercial electricity feed-in/permanent shutdown of non-volatile power plants (2013-2018 planning data for net nominal capacity for power plants in and to the south of Frankfurt am Main, as of October 2013)



In the south of Germany, facilities with a capacity of 1,978 MW (as of October 2013) are currently under construction, with completion due by 2015. On the basis of the current construction projects, no further growth in non-volatile capacity is expected in the subsequent period from 2016 to 2018. According to the companies' information, it is planned to cut back capacity in the south by up to 7,395 MW between 2013 and 2018, resulting in a potential negative balance of up to 5,417 MW.

1.3 Electricity generation eligible for payments under the EEG

The total installed capacity of installations in Germany eligible for payments under the EEG was approximately 71.0 GW on 31 December 2012 (31 December 2011: around 61.7 GW). This represents an increase in the installed capacity of all installations eligible for EEG payments in 2012 of some 9.4 GW, corresponding to a relative growth of around 15 percent in one year.

The installed EEG capacity figures are taken from the Bundesnetzagentur's power plant list as published on the Internet[7].

[7] Bundesnetzagentur List of Power Plants http://www.bundesnetzagentur.de/cln_1912/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Versorgungssicherheit/Erzeugungskapazitaeten/Kraftwerksliste/kraftwerksliste-node.html

Figure 9: Installed capacity of installations eligible for EEG payments, 2004-2012

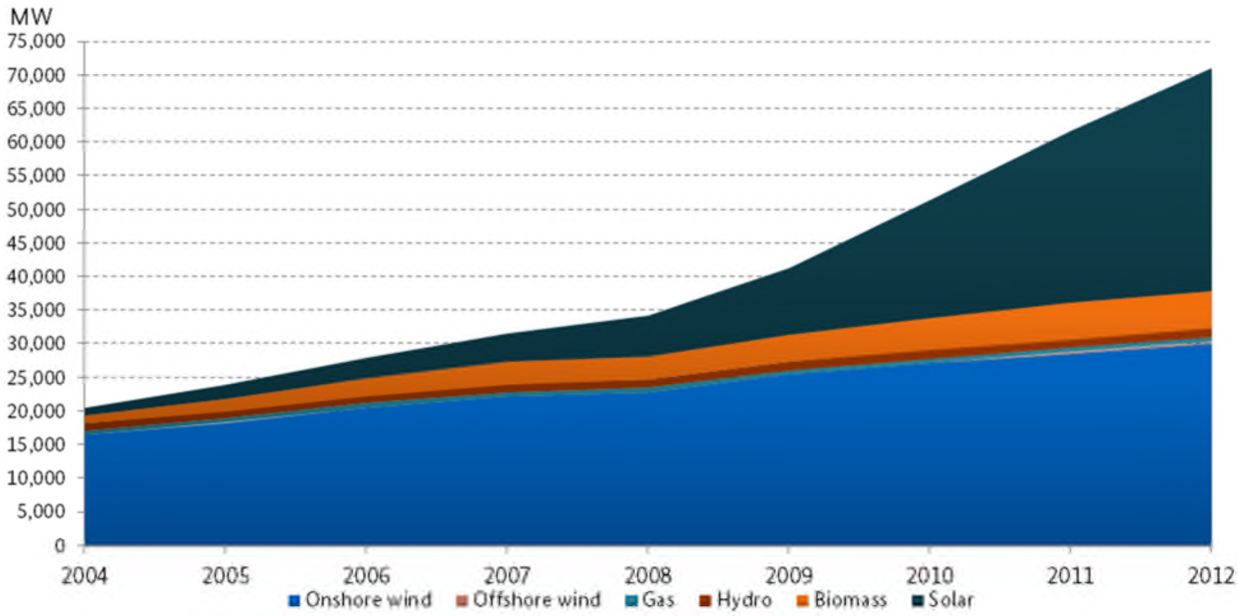


Table 6: Installed capacity of installations eligible for EEG payments by energy source (as of 31 December 2012/31 December 2011)

	Total in 2012 (MW)	**Total in 2011 (MW)**	**Increase/decrease compared to 2011 (%)**
Hydropower	1,529	1,428	7.1
Gas	606	595	1.8
Biomass	5,469	5,384	1.6
Geothermal	12	8	50.0
Onshore wind	30,017	28,516	5.3
Offshore wind	268	188	42.6
Solar	33,135	25,531	29.8
Total	71,036	61,650	15.2

In 2012 there was another sharp increase in the installed capacity of solar installations. Systems with a total capacity of approximately 7.6 GW were newly installed (2011: approximately 4 GW), which amounts to an increase of around 29.8 percent for solar installations in 2012. The installed capacity of onshore wind plants increased by approximately 1.5 GW in 2012, corresponding to a growth rate of 5.3 percent. The increase in the capacity of offshore wind facilities was around 80 MW, representing a growth rate of 42.6 percent.

The energy produced from renewables and fed into the public electricity grid 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 2011. The figures are taken from the TSOs' certified annual financial statements.

Table 7: Total energy feed-in remunerated under the EEG and minimum amount paid to installation operators by energy source in 2012

Energy source	Total 2012		Change compared to 2011 (%)
Hydropower	GWh	2,724	13.7
	€m	270	17.1
Gas[8]	GWh	578	18.7
	€m	42	16.1
Biomass	GWh	24,353	4.2
	€m	4,872	8.8
Geothermal	GWh	25	33.5
	€m	6	38.4
Onshore wind	GWh	14,302	-68.2
	€m	1,310	-68.5
Offshore wind	GWh	82	-85.6
	€m	12	-0.9
Solar	GWh	24,369	26.0
	€m	8,904[9]	14.6
Total	GWh	66,434	-27.2
	€m	15,416	-8.0

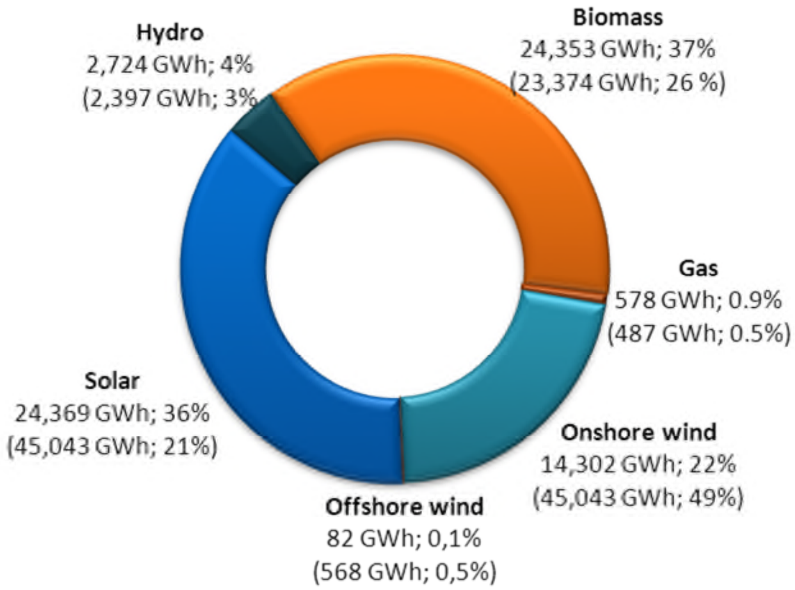
In 2012, the total annual energy feed-in from installations receiving fixed EEG payments was 66,434 GWh (2011: 91,227 GWh); the minimum amount paid to the installation operators totalled €15,416m (2011:

[8] Sewage, landfill and mine gas

[9] Including payments for solar electricity used by the installation owners themselves under section 33(2) of the EEG 2009. In 2012, a total of some €102m was paid for 734 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 electricity and was excluded from the EEG 2012. Solar installations eligible before the scheme was discontinued will still receive the bonus for the whole 20 year period.

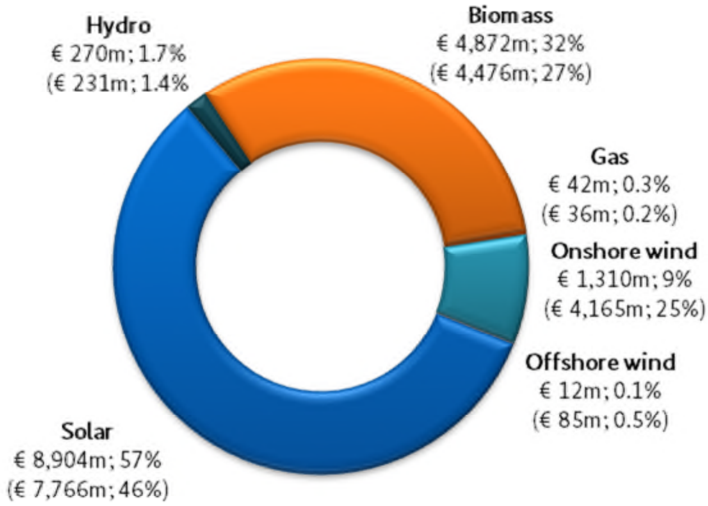
€16,763m). This does not mean that the volume of electricity generated and fed in by EEG installations was lower. Rather, the decrease is due to the switch from fixed EEG payments to direct selling: while there was a year-on-year decrease of 27 percent in the total volume of electricity fed in by installations receiving fixed EEG payments and a decrease of around eight percent in total payments, there was a marked increase in 2012 in the volumes sold directly, in particular in the case of wind electricity (see section below).

Figure 10: Total energy feed-in remunerated under the EEG in 2012 by energy source, absolute and proportional (2011 figures in brackets). Geothermal energy was not included on account of its small share.



The sharp increase in the installed capacity of solar installations in 2012, as described above, resulted in another substantial increase in both the annual energy feed-in, with an absolute value of 24,369 GWh (2011: 19,339 GWh), and the amount of remuneration paid, with an absolute value of €8,904m (2011: €7,766m). Direct selling played only a secondary role for solar energy. Solar energy accounted for by far the largest share of EEG payments, with 57 percent.

Figure 11: Remuneration for feed-in under the EEG in 2012 by energy source, absolute and proportional (2011 figures in brackets). Geothermal energy was not included on account of its small share[10].



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. Between 2009 and 2011 the operators were slow to take up this option. In 2012, installation operators were able to choose between three different forms as provided for by section 33b of the EEG: direct selling to claim a market premium, to claim a reduction in the EEG surcharge, or other direct selling. The total volume of renewable energy sold directly increased more than fourfold to around 51,163 GWh (2011: 11,650 GWh). This means that in 2012 slightly more than 43 percent of the total volume of renewable energy was sold directly. The dominant energy source in the area of direct selling in 2012 was onshore wind power, with a share of almost 70 percent. Biomass again also accounted for a significant share (19 percent).

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

Table 8: Volume of electricity sold directly under section 33b of the EEG in 2012[11]

Energy source	Market premium (GWh)	Green electricity privilege (GWh)	Other direct selling (GWh)	Total volume of electricity sold directly (GWh)	Share of total volume sold directly (%)
Hydropower	1,880	569	244	2,693	5.26
Landfill, sewage and mine gas	139	1,049	2	1,191	2.33
Biomass	9,891	74	2	9,967	19.48
Geothermal	0	0	0	0	0.00
Onshore wind	34,315	1,169	163	35,647	69.67
Offshore wind	640	0	0	640	1.25
Solar	1,025	0	1	1,025	2.00
Total	47,890	2,861	411	51,163	100

The increase in the volume of electricity sold directly is due to the large number of installation operators claiming a market premium. The market premiums paid to operators in 2012 totalled some €3,701.6m. Onshore wind and biomass accounted for the largest shares, with €2,314.9m (62.5 percent) and around €969.9m (26.2 percent) respectively. The flexibility premiums paid in 2012 for biogas plants totalled approximately €0.6m. Thus, the total paid in market and flexibility premiums in 2012 was €3,702.2m. The conditions for claiming the green electricity privilege were tightened considerably in 2012, with the result that this form of marketing played only a minor role in contrast to 2011. Other direct selling played an insignificant part.

2. Security of Supply

2.1 Measures to ensure security of supply

Reserve power plants

The transmission system is typically under greatest pressure during the winter period when low temperatures and shorter days lead to relatively high peaks in load. High wind infeed in northern Germany coinciding with power plant outages in the south of the country place a considerable strain on the power lines. If technical

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

capabilities are exceeded, parts of the system may be damaged or destroyed, resulting in disruptions to the 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.

The most significant measure in winter 2012/2013 was to again secure sufficient reserve capacity. In this case, contracts are concluded with power plant operators allowing the TSOs to use the plants for redispatching to relieve the network. A TSO can then require a plant operator to control the input of electricity from a plant to produce certain flows in the grid which prevent congestion on certain sections of the lines. Reserve power plants may be used exclusively by the TSOs to manage the network, their use being secondary to that of other available plants.

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 correspondingly high wind infeed coinciding with – unplanned – plant outages in the south, and failure of an extra high voltage line during a period of peak demand. The TSOs concluded that a reserve of some 2,500 MW was needed to maintain secure operation of the grid in such circumstances.

The TSOs were able to secure reserve plant with a total capacity of around 2,600 MW to meet this requirement. As a result, block 2 of the Mainz-Wiesbaden power plant (335 MW) and block 3 of the large-scale Mannheim plant (200 MW) in Germany were contracted for reserve, as in winter 2011/2012. In Austria, the EVN AG (785 MW) and Verbund AG (152 MW) power plants were made available to the TSOs as reserve. The Irsching 3 (415 MW) and Staudinger 4 (622 MW) plants, having been withdrawn from the market by the operators, were also placed under contract to provide the capacity required by the TSOs.

Despite the long cold period in winter 2012/2013, the situation in the transmission system was less tense than in the previous winter of 2011/2012 when reserve power plants were needed for a prolonged period, in particular following an interruption to the gas supply to a number of power plants in southern Germany. The only instance in which the reserve plants were called upon was on 28 January 2013 for the following day. A high wind infeed forecast had given reason to believe that lines, particularly those on the north-south routes, could become overloaded. The reserve plants could be taken offline again on 30 January 2013 after wind output had reached its peak.

The transmission system was then critically overloaded on 25 and 26 March 2013 when four power plants in the south experienced outages at the same time as substantial amounts of electricity were being exported from Germany to Austria. As a consequence, the scope for redispatching in TenneT's control area was considerably restricted. Deployment of the reserve plants could have helped to ease the strain on the lines, but this could not be foreseen on the basis of the information available on the previous day. When it became clear that the plants were required to stabilise the network, it would have been too late to relieve the critical situation because the plants have a lead time of several hours. This shows the need for further measures to minimise the time required by reserve plants between being called upon and reaching output.

In September 2013 the Bundesnetzagentur confirmed the reserve requirement of 2,540 MW for winter 2013/2014, as determined by the TSOs in a system analysis, and published the details in a report. This constituted the initial step in an annual process carried out for the first time under the new Reserve Power Plant Ordinance for securing conventional plant capacity to manage critical situations in the transmission system. The TSOs immediately launched a newly introduced call for expressions of interest from operators of decommissioned power plants wishing to put forward their plants as reserve capacity. The call is also open to operators in other countries wishing to offer their plants for use to maintain the stability of the transmission system in Germany.

Avoiding power plant closures

On 20 December 2012 the Energy Act 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 30 effective closure notifications (as of 20 November 2013).

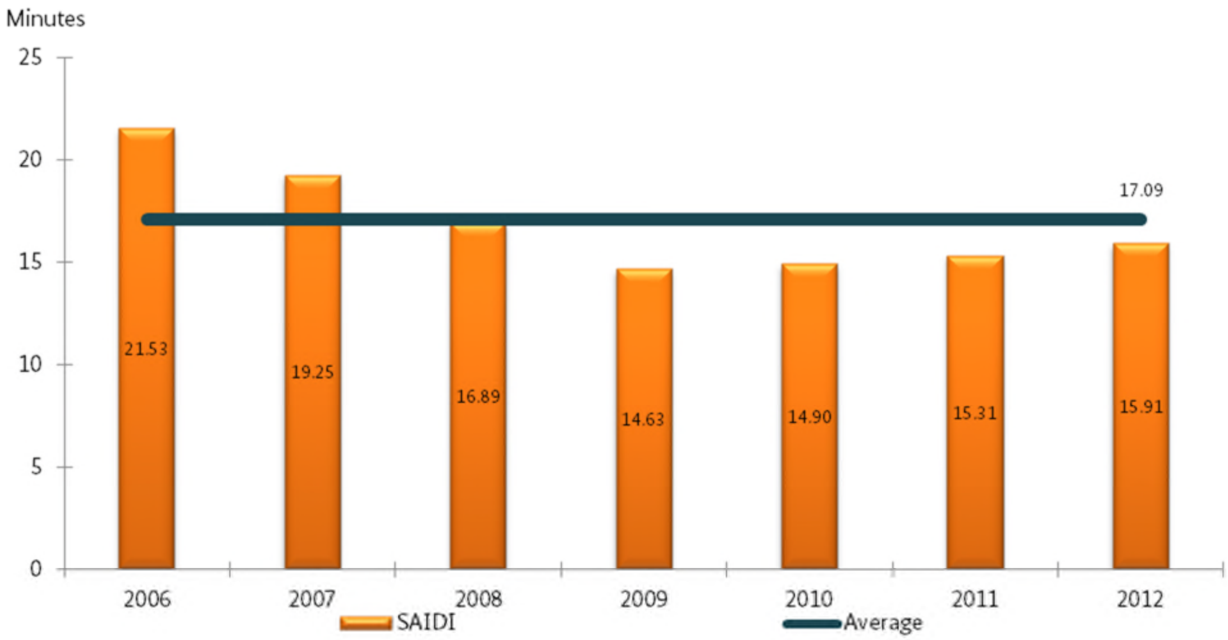
To date, five plants in southern Germany have been rated by the TSO as systemically relevant. The Bundesnetzagentur will most likely confirm these ratings soon. A number of other notifications are still being assessed by the TSOs. There have already been many cases in which the TSOs, having assessed the notifications, have concluded that a plant is not systemically relevant.

2.2 Duties to report supply disruptions under section 52 EnWG

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

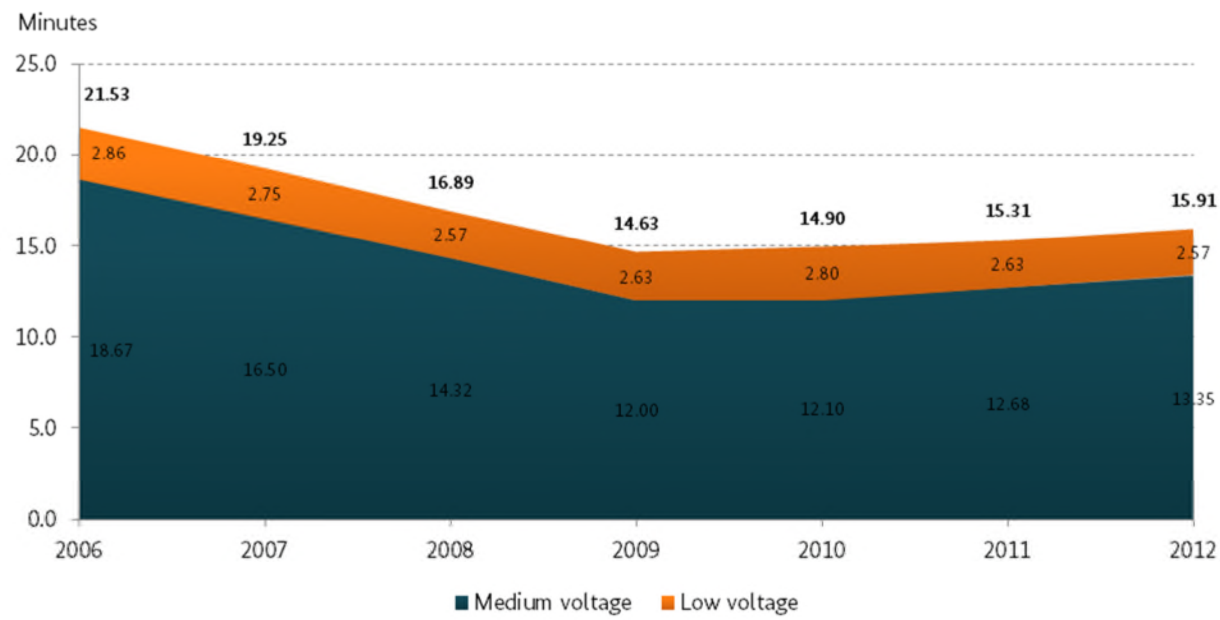
866 network operators reported approximately 191,000 interruptions in supply for 883 networks in 2012 for the calculation of the system average interruption duration index (SAIDI) for final consumers. The figure of 15.91 minutes calculated for the low and medium voltage levels is higher than the previous years' figures of 15.31 minutes for 2011 and 14.90 minutes for 2010, but is still considerably lower than the average of 17.09 minutes calculated for the period between 2006 and 2011.

Figure 12: Supply disruptions under section 52 EnWG (electricity)



The slight increase in the average interruption duration is again solely attributed to the increase of 40.2 seconds, from 12.68 minutes to 13.35 minutes, at the medium voltage level. At the low voltage level, on the other hand, the average interruption duration decreased by 3.6 seconds from 2.63 minutes to 2.57 minutes.

Figure 13: Supply disruptions under section 52 EnWG by voltage level (electricity)[12]



At the medium voltage level there was a large increase for the second consecutive year in disruptions caused by ripple effects from other networks and by third-party intervention. 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. Disruptions caused by third-party intervention are interruptions in supply resulting from people, animals, trees, diggers, cranes, vehicles, flying objects, etc touching or approaching live electrical components, as far as the disruption can be attributed to a third party. The idea that the energy policy turnaround and the associated increase in decentralised power generation had a significant effect on the quality of energy supply in 2012 can therefore be ruled out.

The increase in disruptions resulting from ripple effects and third-party intervention stands in contrast to a moderate decline in disruptions at the low and medium voltage levels caused by atmospheric effects such as lightning strikes.

The SAIDI value does not take into account scheduled interruptions, nor those caused by force majeure, for example by 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.

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

C Networks / Network expansion / Investments / Network tariffs

1. Networks / Network expansion / Investments

1.1 Status of network expansion

Progress on power line projects specified in 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 legislation specifies 23 projects which require urgent implementation in order to meet energy requirements and to secure future supplies in Germany, a growing share of which will be met from renewable energy sources.

These expansion projects involve constructing 1,855 km of new routes. The regional states are responsible for carrying out this construction work. The planning, approval and implementation stages will be documented on a quarterly basis as part of the monitoring undertaken by the Bundesnetzagentur. Monitoring will be based on data provided by transmission system operators (TSOs). The latest EnLAG monitoring findings are available on the internet at www.netzausbau.de.

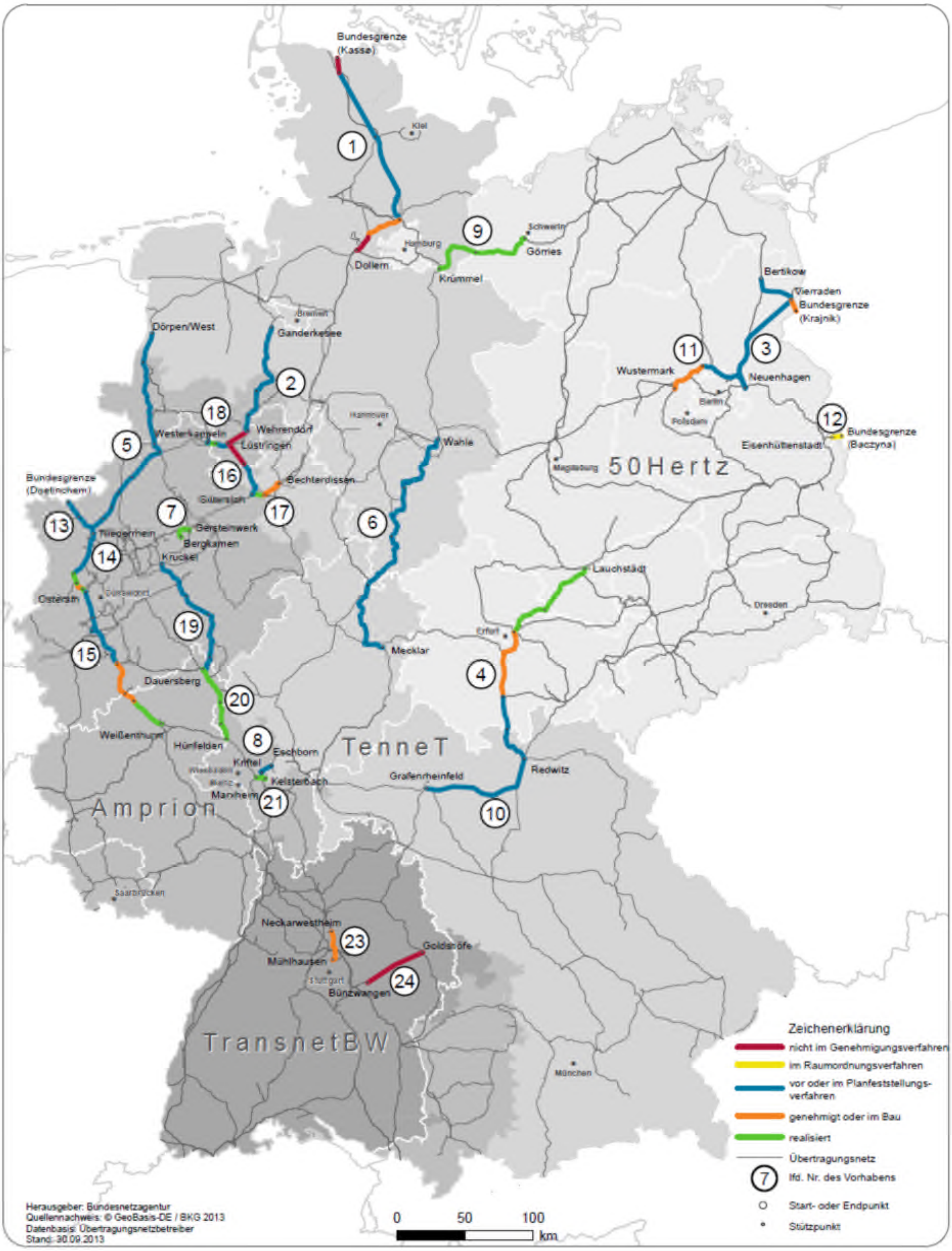
The Network Development Plan for 2012 reclassified Project 22 - Weier-Villingen in Baden-Württemberg - as no longer necessary. The project was removed from the Power Grid Expansion Act during the legislative procedure for the Federal Requirements Plan Act (which came into effect on 27 July 2013) and further planning has therefore now stopped.

Current status

The monitoring results for the third quarter of 2013 show that commissioning of a large proportion of the planned power lines will be delayed. According to information provided by transmission system operators only 268 km (or around 15 percent) of a total of 1,855 km of EnLAG power lines had been built by 30 September. Originally the aim was to have completed most of the EnLAG projects by 2015. However, realistic estimates suggest that in fact this target will only be 50 percent reached by 2016.

The map in Figure 14 shows the status of each of the projects in the third quarter:

Figure 14: Status of the expansion of power lines after the Power Grid Expansion Act (EnLAG) for the third quarter of 2013



Transmission system operators reported in late 2013 that modest progress had been made on the construction of several projects, such as the Thuringia power line (Project 4), on an interconnector towards Poland (Project 3) and a section of the line between North Rhine-Westphalia and Rhineland-Palatinate (Project 15). However, none of the relevant sections or overall projects have as yet been completed.

Other positive developments of note are the recent granting of planning approval for Project 11 (the section between west Birkenwerder (mast 189) and Neuenhagen) and the opening of planning approval procedures for the construction of the Thüringer Strombrücke (Thuringian power bridge).

Progress on power line projects specified in the Federal Requirements Plan Act

Thanks to planning and approval procedures which were ongoing at the time the law was enacted, progress has also begun to be made on power line projects in the Federal Requirements Plan Act. Initial construction work has been undertaken, for example, on the power line sections Bärwalde-Schmölln and Abzweig Welsleben–Förderstedt.

1.2 Network Development Plan / 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 TSOs have been required to produce annual network development plans which detail all the effective optimisation, reinforcement and expansion measures which will be necessary in the next ten to twenty years to ensure continued operation of the onshore part of the grid. In addition to their onshore network development plans TSOs have also been required since 2013 to produce offshore expansion plans (offshore network development plans).

Because network development plans are produced every year it is possible to integrate new economic and technological developments and changes very early on.

Both network development plans are issued for public consultation by TSOs and the Bundesnetzagentur, reviewed by the Bundesnetzagentur and subsequently endorsed. At least every three years the endorsed network development plans are passed on to the Federal Government by the Bundesnetzagentur as a draft Federal Requirements Plan Act. The federal requirements plan passed by the legislator endorses the urgent need for the projects specified in the plan.

Scenario framework

Both network development plans are based on the scenario frameworks which, under section 12a EnWG, must also be produced by the TSOs and endorsed by the Bundesnetzagentur every year. These frameworks draw on various development pathways (scenarios) to forecast, in particular, projected generation capacities and the amount of electricity which will be used in the next ten to twenty years.

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

Electricity Network Development Plan 2012 - Onshore

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

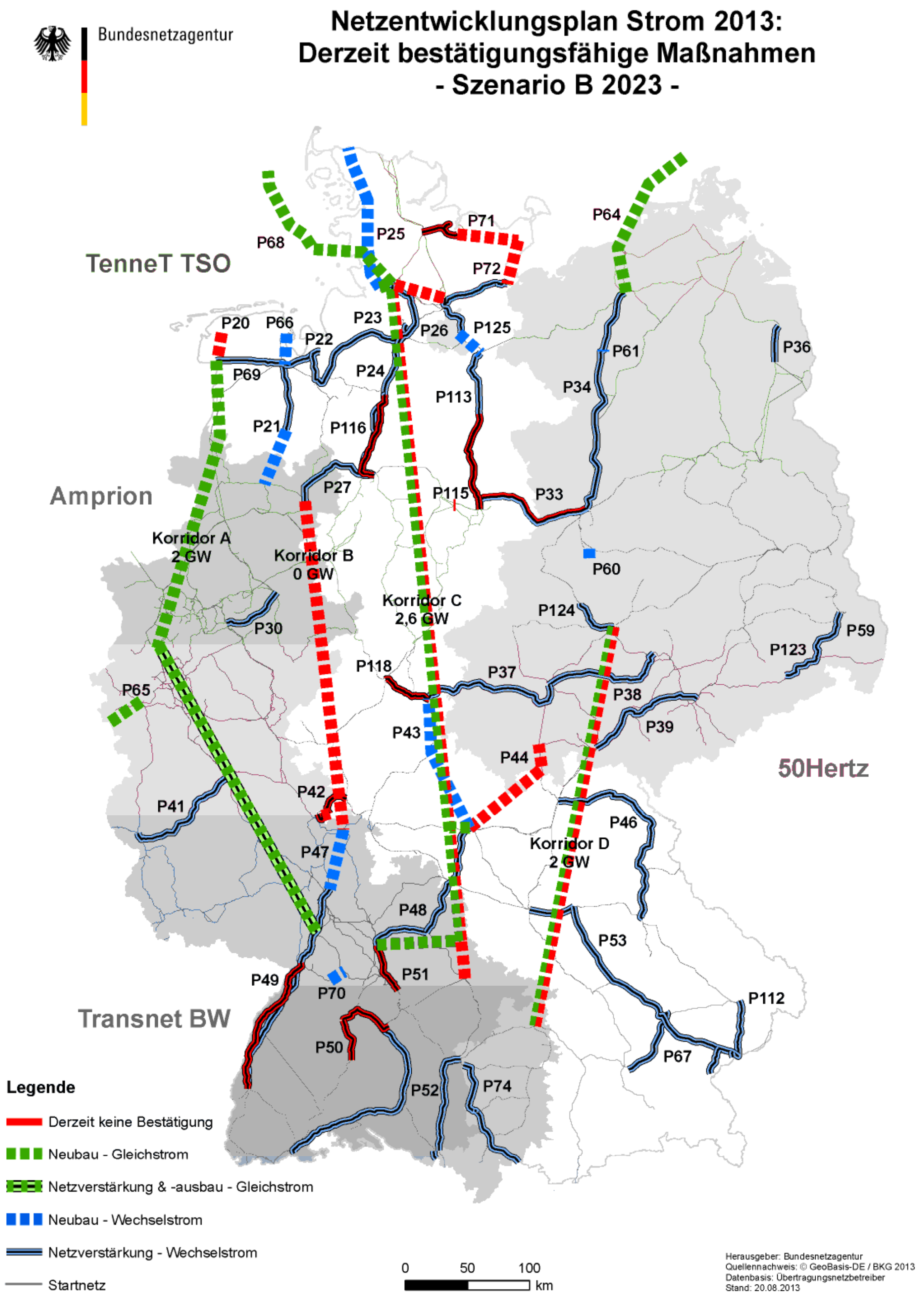
The Bundesnetzagentur has submitted the endorsed 2012 network development plan to the Federal Government to be used as a draft basis of the first Federal Requirements Plan Act. This came into effect in July 2013 and includes all the 51 measures endorsed throughout the country, which comprise 36 projects. 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.

Electricity Network Development Plan 2013 - Onshore

The TSOs published and consulted on the draft network development plan for 2013 in March 2013. The revised draft was submitted to the Bundesnetzagentur in July 2013. The Bundesnetzagentur reviewed the draft and issued it for consultation again in September 2013. At the outset of the consultation the Bundesnetzagentur found that 70 of the total of 90 grid expansion and network reinforcement measures appeared to be capable of endorsement. The review by the Bundesnetzagentur has not yet been completed, however. As a result, the scope of the measures to be confirmed could change during the course of the consultation. Compared to the network development plan for 2012 the TSOs have made applications for 21 new measures. These relate exclusively to network reinforcements in the three-phase electrical grid.

What is more the Bundesnetzagentur also again ran nationwide information events on the draft network development plan and the offshore network development plan for 2013. The Bundesnetzagentur intends to approve the Onshore Network Development Plan for 2013 by the end of the year.

Figure 15: The current review status of the network development plan 2013 (September 2013)



Offshore Network Development Plan 2013

In parallel to the publication of the onshore network development plan the TSOs also published the first draft offshore network development plan in March 2013. This plan details all the measures which will be required in the next ten to twenty years to optimise, reinforce and expand grid connection lines from offshore wind farms. TSOs, in whose control areas there are plans to build connection lines from offshore wind farms, will be required to establish and operate the connection from the point of interconnection on the transformer platform of an offshore wind park through to the grid connection point in the transmission network. In June 2103 the Bundesnetzagentur also received the revised draft of the offshore network development plan from the TSOs for review. The offshore network development plan is consulted on in parallel with the onshore network development plan. At the outset of the consultation the Bundesnetzagentur found that the grid connection lines proposed by the TSOs were capable of endorsement. The interpretation and application of the statutory criteria for the staggering of connection lines over time also appear to be fundamentally appropriate. The Bundesnetzagentur is continuing to review the offshore network development plan with the onshore network development plan during the consultation. Approval of the offshore network development plan is also planned for the end of 2013.

Figure 16: The current review status of the offshore network development plan 2013; North Sea

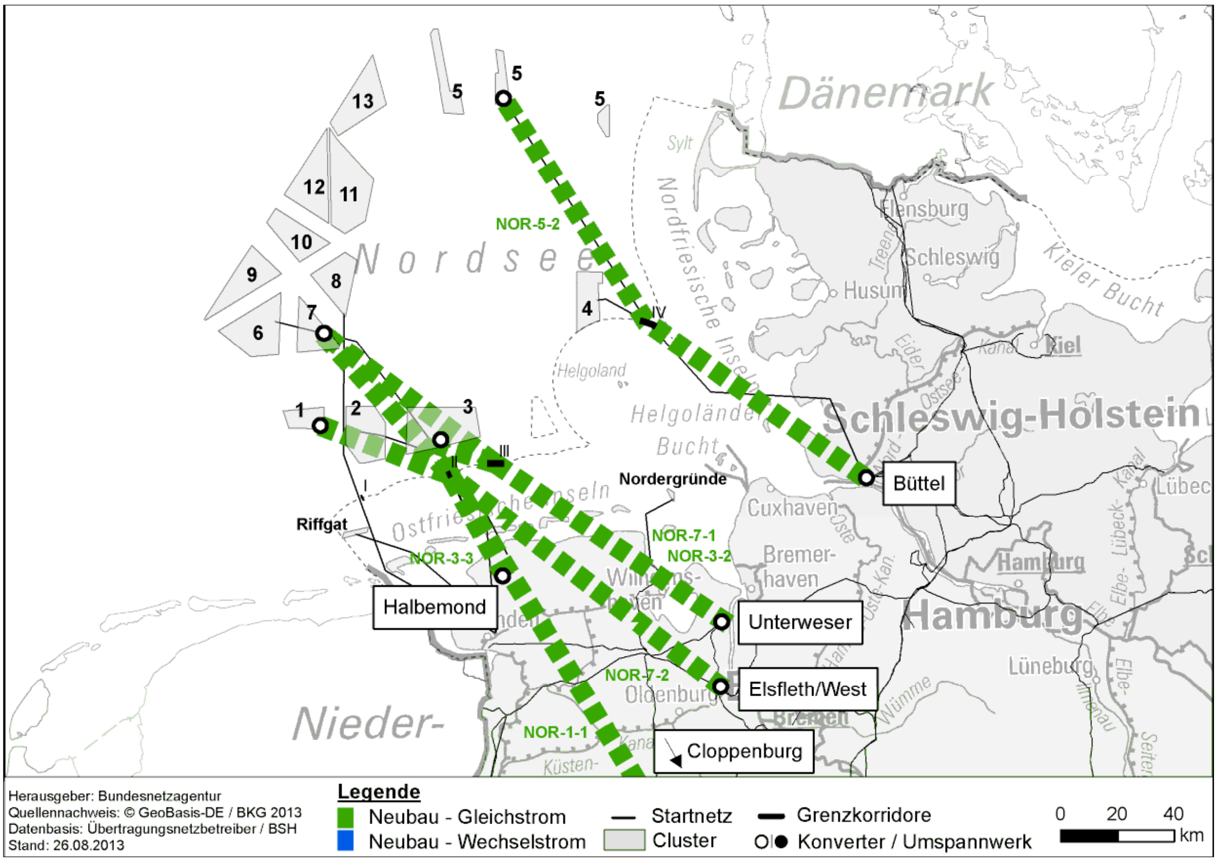


Figure 17: The current review status of the offshore network development plan 2013; Baltic Sea

Environmental Report

The Bundesnetzagentur reviews the network development plan and submits the strategic environmental assessment for the Federal Requirements Plan every year. In line with section 14g of the Environmental Impact Assessment Act (UVPG), the environmental report, which documents the findings of the strategic environmental assessment, determines, describes and evaluates the substantial environmental impact which implementation of the plan is expected to have.

The environmental report is made up of a general section on the impact of very high voltage lines on protected goods under the Environmental Impact Assessment Act (UVPG) and a presentation of the potential significant impacts on the environment during the key period of study.

The Bundesnetzagentur drew up its strategic environmental assessment for the Federal Requirements Plan for the first time in 2012. The underlying method has been positively received by the public authorities involved and the general public and will consequently be largely retained this year. The 2013 environmental report also meets public demand for a broader review of alternatives. Project-related alternatives are also reviewed in the report in addition to scenarios A 2023 and C 2023.

This year's environmental report is much more comprehensive than last year's as it covers coastal areas from the Baltic through to the North Sea. The Bundesnetzagentur has not only considered onshore projects (electricity network development plan 2013 (NEP 2013)), but also, and for the first time, projects in the offshore network development plan (O-NEP 2013). An alternative review will also be performed for coastal areas. This will involve considering alternative connection arrangements. The possibility of using direct current transmissions is also being reviewed as an alternative technology to the AC connection envisaged for the Baltic in the offshore network development plan.

The strategic environmental assessment will begin by defining the assessment framework (scoping). This year the Bundesnetzagentur exchanged views in writing with public authorities and environmental organisations. The scope of the assessment takes account of this participation and the outcome has been slightly modified. The sensitivity of biosphere reserve buffer zones has been upgraded.

Public authorities and the general public are also involved in the assessment of the environmental report and the draft confirmation of the network development plan and the offshore network development plan. Last year the Bundesnetzagentur received over 3,300 comments which were included in its assessment. Consultations on the environmental report and the network development plan 2013 were launched on 13 September 2013. Public authorities will be able to submit comments until 25 October 2013. The public concerned had the opportunity to respond to the draft network development plans and the environmental report by 8 November 2013.

Status of legislative procedure on the Federal Requirements Plan Act

The first Federal Requirements Plan Act came into effect on 27 July 2013 on the basis of the network development plan 2012, which had been confirmed by the Bundesnetzagentur, and the related environmental report. This created the legal framework enabling the Bundesnetzagentur to perform federal sectoral planning for projects spanning regional state and national borders. Regional impact assessments, which were previously carried out by the regional states, have now been superseded as a planning instrument by federal sectoral planning which defines binding route corridors for projects spanning regional state and national borders. 16 of the 36 projects in the Federal Requirements Plan fall within the area of responsibility of the Bundesnetzagentur. In particular these include large high voltage direct current transmission corridors (HVDC corridors):

- Corridor A: Emden/Borßum – Osterath and Osterath – Philipsburg,
- Corridor C: Brunsbüttel – Großgartach and Wilster – Grafenrheinfeld,
- Corridor D: Lauchstädt – Meitingen.

The Planning Approval Responsibilities Ordinance also came into effect at the same time as the Federal Requirements Plan Act. In addition to federal sectoral planning this will also assign responsibility for planning approval procedures for projects spanning federal and national borders to the Bundesnetzagentur. In order to further accelerate expansion of the grid, responsibility for planning and approval procedures for these projects will be held by a single body.

Federal sectoral planning

The Bundesnetzagentur is well prepared - as regards organisation and expertise - for the forthcoming federal sectoral planning procedures in which, at the request of TSOs, 500m to 1,000m route corridors will be defined which will have an acceptable land use impact and are environmentally compatible. In this context the focus will be on HVDC corridors in particular, as the central pillars of the Federal Requirements Plan.

Under section 6(1) of the Grid Expansion Acceleration Act (NABEG) federal sectoral planning begins with an application by the TSOs in the capacity as project owners. A common understanding of the federal sectoral planning methods used has been arrived at with the TSOs based on the guidelines published last year by the Bundesnetzagentur and the specimen layout for the application under section 6 NABEG. The specimen application produced by the TSOs provides the framework for the content and methodological approach to the forthcoming applications for federal sectoral planning. Part I of the draft, which is published on the website of the transmission system operators www.netzentwicklungsplan.de outlines the application procedure under section 6 NABEG. Work is currently underway on part II of the specimen application, which focuses in particular on the framework for the assessment of land use impact and environmental compatibility.

The Federal Sectoral Planning Advisory Council provided for by section 32 NABEG was established on 21 June 2012 to clarify certain fundamental issues. This body consists of representatives from the regional states and relevant federal ministries as well as their subordinate authorities. The Federal Sectoral Planning Advisory Council is a forum for the exchange of information and primarily plays a consultative function.

Outlook

The Bundesnetzagentur assumes that the project owners will submit their first applications for federal sectoral planning by late 2013 / early 2014.

1.3 Network connection of offshore wind farms

No new network connections for offshore wind farms (OWP) were commissioned in 2012. 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 a collective connection in the DolWin cluster and two other collective connections for the BorWin cluster.

In December 2012 new legislation came into force which is intended to solve 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 the corresponding determination procedures to assist establishing a general framework for the allocation and transfer of connection capacities and the treatment of compensation payments.

In January 2013 TenneT awarded the DolWin 3 power line. The BorWin 3 and 4 collective connections have still not been awarded.

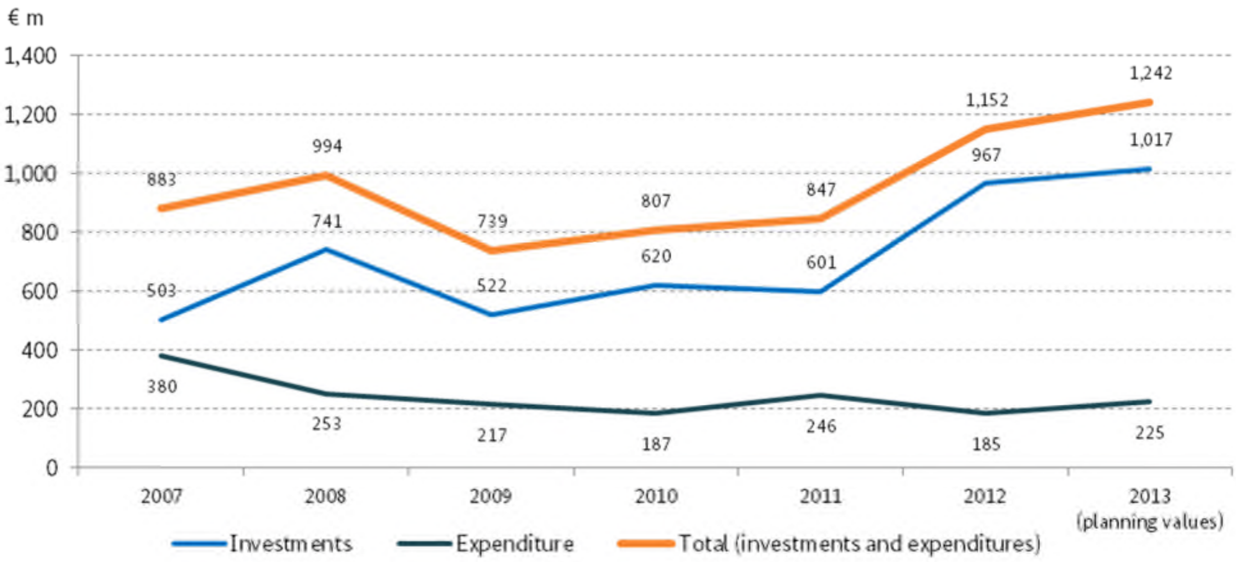
Within the framework of continuing discussions, the Bundesnetzagentur remains in regular contact with all the parties involved in order to assist with issues relating to the linking up of wind farms to the grid.

By the end of 2012 a total of 25 applications had been made to the Bundesnetzagentur for the approval of investments in the connection of OWFs with a total volume of €20.5bn, of which 17 applications with a volume of €10bn have already been approved.

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

In 2012 the four German TSOs together spent approximately €1,152m (2011: €847m) on investment in and expenditure on network infrastructure. This also included investments in and expenditure on cross-border connections amounting to approximately €22m (2011: €13m). Actual expenditure on network infrastructure deviated by €200m from the planning values notified in 2011 (planning values for 2012: approximately €952m). The cause of this delta is basically the category of investments in build/extension/expansion which, at €864m in 2012, was €282m higher than the planned value of €582m.

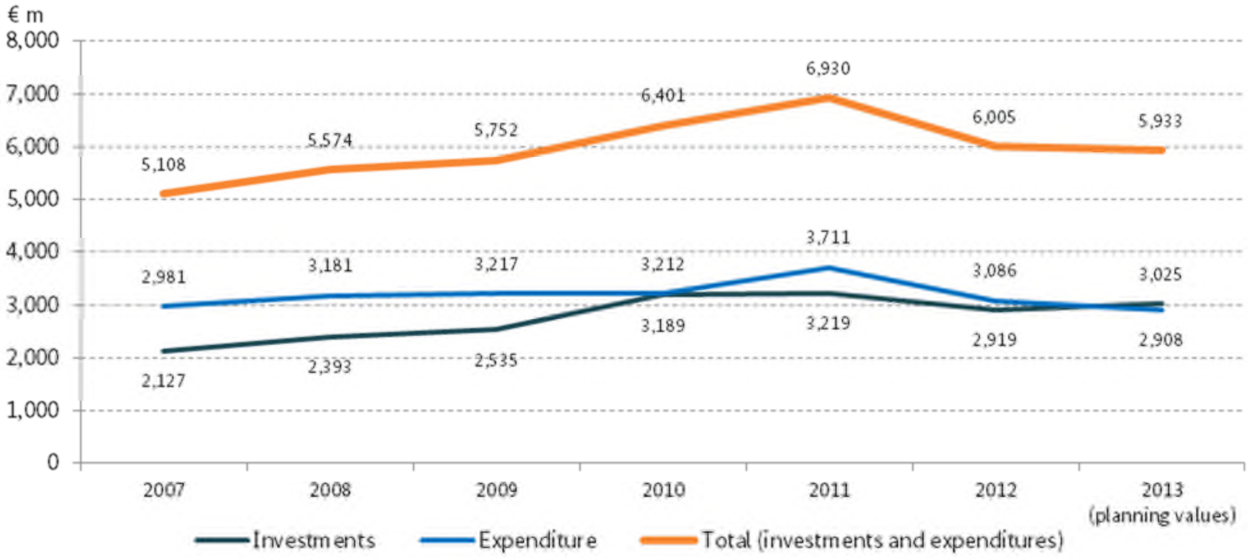
Figure 18: Investment in and expenditure on TSO network infrastructure since 2007 (including cross-border connections)



1.5 Investments in distribution networks

Investments in and expenditure on network infrastructure by 806 DSOs totalled approximately €6,005m in 2012 (2011: €6,930m). This figure includes investments in and expenditure on metering/control devices and communication infrastructure amounting to approximately €356m (2011: €462b). Overall, with a delta of €283m, total DSO spending on the network infrastructure is below the planning values for 2012 of €6,288m.

Figure 19: Investments in and expenditure on network infrastructure (including metering/control devices and communication infrastructure) by DSOs[13]



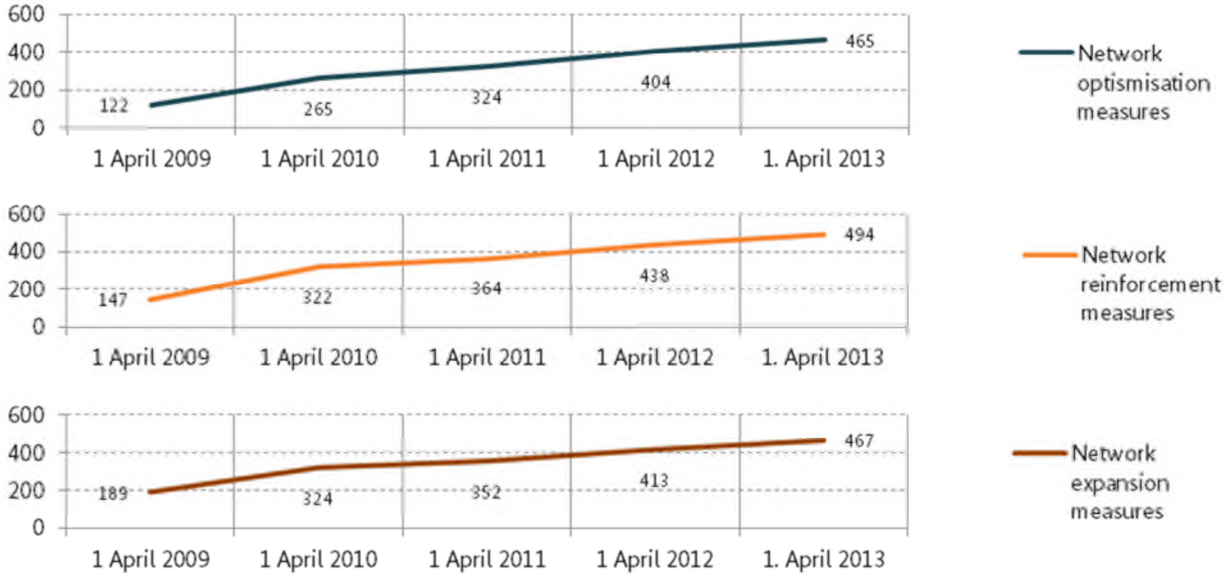
1.6 Measures for the optimisation, reinforcement and expansion of the distribution system

The DSOs are obliged under section 11(1) of the EnWG and section 9(1) of the 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 to DSOs. Alongside conventional expansion measures, network 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 network operator to the next. Given the highly heterogeneous nature of grids in Germany each DSO must adopt its own strategy for achieving efficient grid operations in the energy future. It is actually quite helpful 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 2013 a total of 806 (1 April 2012: 735) DSOs had provided information about the extent to which they had taken action to optimise, reinforce and expand their networks. Compared with previous years the number of corresponding DSOs has again gone up.

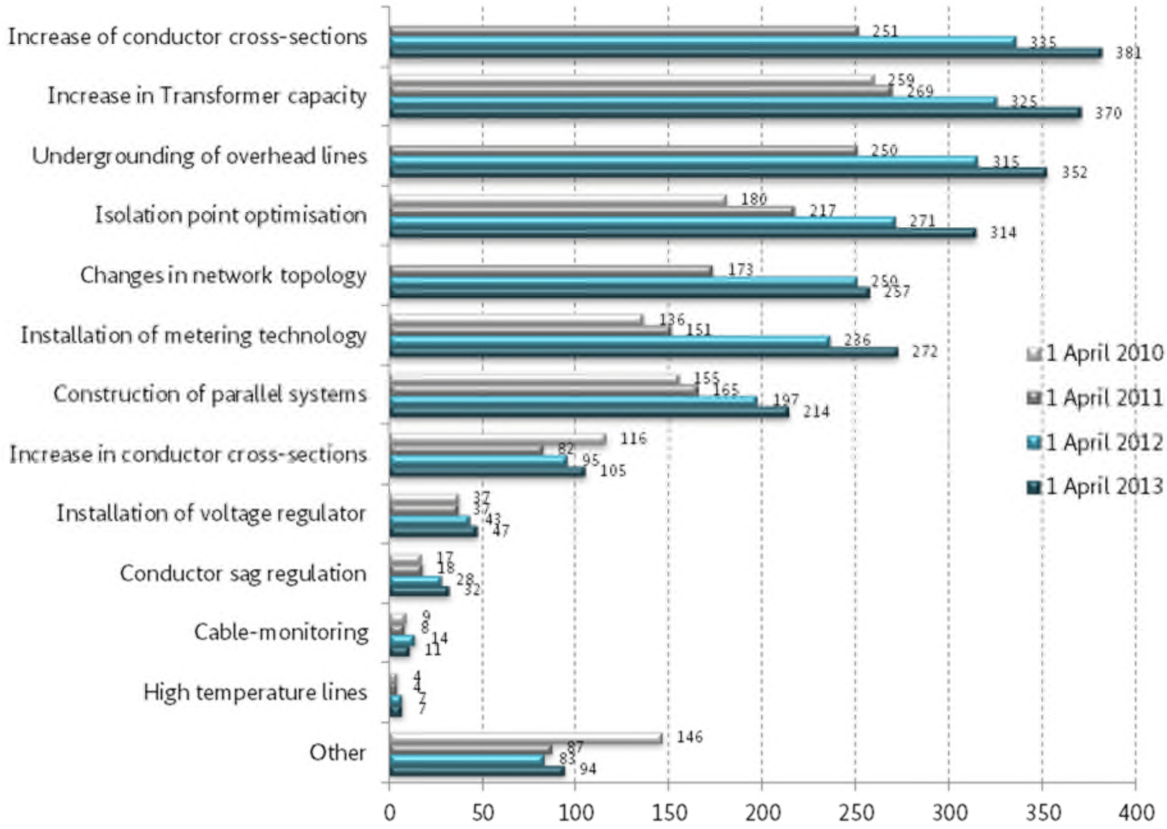
[13] The data for 2011 provided in the Monitoring Report 2012 has been adjusted based on new information.

Figure 20: Network optimisation, reinforcement and expansion measures in accordance with section 9(1) of the EEG.



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

Figure 21: Overview of network optimisation and reinforcement measures applied under section 9(1) of the EEG



"Cable monitoring" is the only measure to have been scaled down since last year. All the other measures have been stepped up. There was a significant increase, for example, in measures to "increase the cross section of cables", "to underground overhead lines", "to increase transformer capacity", "to optimise cut-off points" and "to integrate measuring technology".

1.7 Operators' systems responsibility for transmission systems with measures under section 13(1) EnWG in calendar years 2011 and 2012

In accordance with section 13(1) EnWG, the TSOs are both authorised and obliged to remedy any threat to or malfunction in the electricity supply network through the adoption of network and market-related measures. Insofar as DSOs are responsible for the security and reliability of the electricity supply in their networks, these too are both authorised and obliged 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, the market-related measures take the form of congestion management measures. There is a fundamental distinction which must be made between redispatch and countertrade: Redispatch refers to intervention in the market-based schedules 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 2011 and 2012.

Calendar year 2011

In the calendar year 2011 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:

Table 9: Redispatch measures on the most strongly affected network elements in 2011 as notified by TSOs

Affected network element	Number of hours
Redwitz– Remptendorf power line	1,727
Kriegenbrunn-Raitersaich-Irsching area	727
Lehrte-Mehrum area	576
Conneforde area	401
Sottrum-Borken area (mainly: Ovenstädt,-Twistetal)	319
Flensburg-Hamburg area	281
Helmstedt - Wolmirstedt power line	272
Vierraden-Krajnik area	250

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 TenneT control area in the area between the Kriegenbrunn, Raitersaich and Irsching transformer stations and, in third place, the power line between the Lehrte and Mehrum transformer stations.

The remaining measures covered a total period of 447 hours so that redispatch measures totalling 5,030 hours had to be carried out in the German transmission network in 2011.

Calender year 2012 (year under review)

In the period from 1 January 2012 to 31 December 2012 the Bundesnetzagentur was notified of 7,160 hours of electricity and voltage-related redispatch measures. This is equal to an increase of 42.3 percent compared with the previous year. These measures entailed an overall volume of 2,566 GWh. Most of these redispatch measures were taken in the TenneT and 50Hertz control areas. Precise details are provided by the following table:

Table 10: Redispatch measures in each control area in 2012 as notified by the TSOs

Network area	Duration in hours	Volume in GWh
TenneT control area	4,157	822
50Hertz control area	2,841	1,714
Amprion control area	162	30
TransnetBW control area	0	0

Most redispatch measures carried out in 2012 were electricity related. In total, measures lasting a total of 4,769 hours and with a volume of 1,962 GWh were instigated. Of these, 4,505 hours (94.5 percent) related to the following network elements:

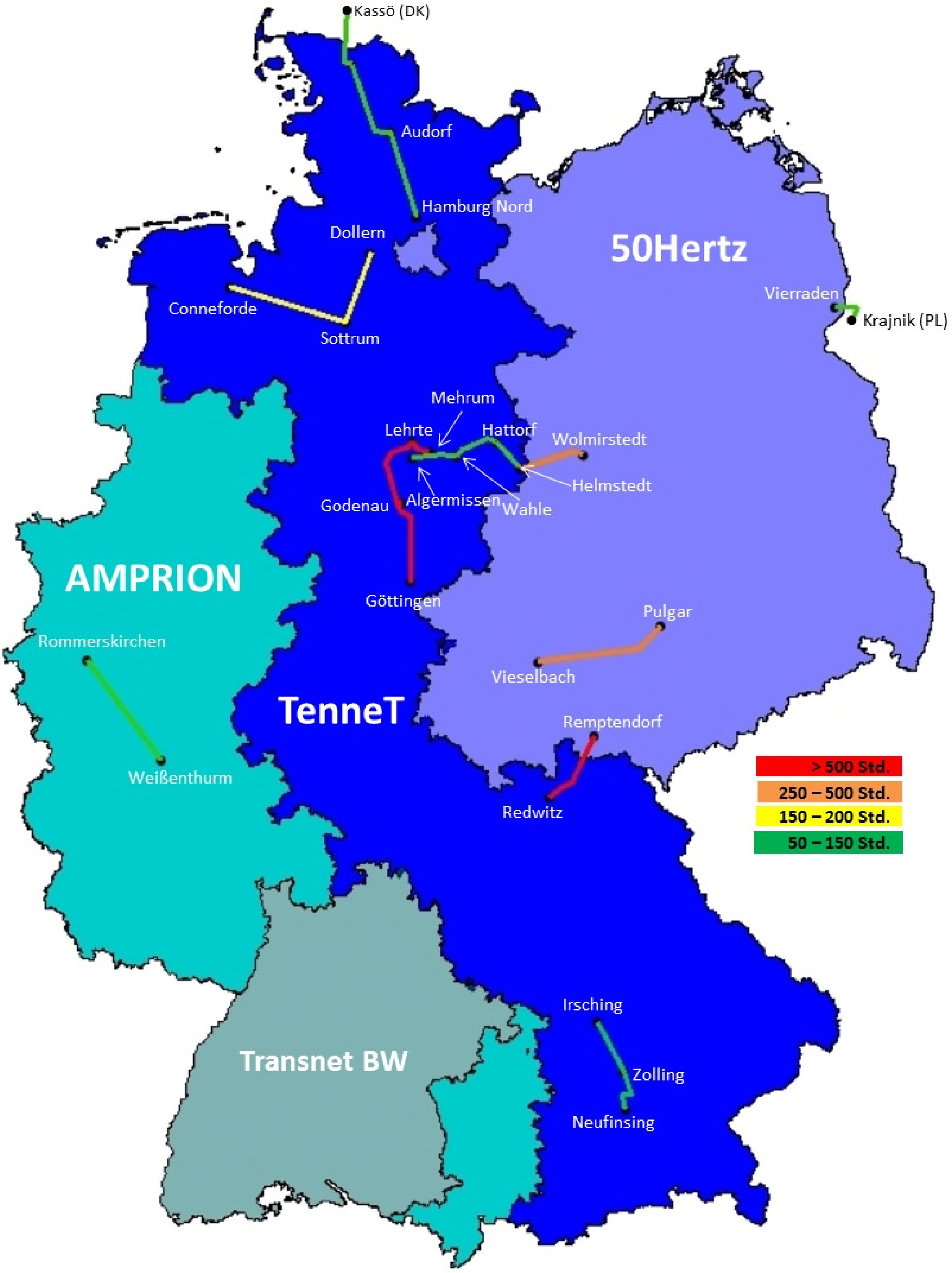
Table 11: Electricity-related redispatch measures on the most strongly affected network elements in 2012 as notified by TSOs

Affected network element	Control area	Duration in hrs.	Volume in GWh
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

The Remptendorf-Redwitz power line and the area around the Lehrte-Mehrum power line, which accounted for 38.7 percent and 22.5 percent of all electricity-related redispatch interventions, were particularly affected. In addition, the TSOs took a further total of 264 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 22: Electricity-related redispatch measures on the most strongly affected network elements in 2012 as notified by TSOs. Source: Own graph based on BNetzA GIS



In addition to electricity-related redispatch measures a total of 2,371 hours of voltage-related redispatch measures were also notified for the TenneT control area in 2012, the overwhelming majority of which were preventive in nature. The total volume of interventions amounted to 599 GWh. The southern network area of the TenneT control area, which accounted for over 61 percent of the hours and almost 60 percent of the volume, was most strongly affected.

Table 12: Electricity-related redispatch measures on the most strongly affected network elements in 2012 as notified by TSOs.

Network area	Duration in hrs.	Volume in GWh
TenneT control area: Network area south	1,456	385
Of which Kriegenbrunn- Raitersaich- Irsching-Grafenrheinfeld area	274	65
TenneT control area: Network area north	504	131
Of which Conneforde-Dollern-Sottrum area	116	28
TenneT control area: Network area central	411	83
Of which Sottrum-Borken area (mainly: Ovenstädt-Twistetal)	268	48

In addition a total of 18 hours of voltage support measures, equivalent to a total volume of five GWh, were taken in the control area of 50Hertz.

Development from calendar year 2011 to calender year 2012

In 2012 there was a further increase in the frequency of interventions in the Remptendorf-Redwitz power line compared to 2011. This increase amounted to 130 hours, or 7.5 percent. However, it is also important to bear in mind that the current figures for the winter half-year 2012/2013 show a significant reduction in demands on the line. There was a strong increase in the duration of intervention on the power 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. There was also an increase on the Wolmirstedt-Helmstedt power line. 346 hours of redispatch measures were notified for the first time on the Pulgar-Vieselbach power line in the 50Hertz control area, which was to do with weather-related damage.

Alongside the increases on the network elements described here there were substantial reductions in the number of redispatch interventions during the reporting period for 2012 on other previously heavily congested network elements. There has been an especially large reduction in measures in the area around the Kriegenbrunn transformer station: 453 hours fewer in 2012 than the year before. In 2011 the area around Kriegenbrunn had the second most affected network elements in the German transmission network. The reason for this, according to network operator TenneT, was construction work on the transformer station in

2011[14]. Redispatch measures were also of shorter duration in the areas of Hamburg-Flensburg, Conneforde and on grid elements between Sottrum and Borken. This is partly to do with reduced feed-in from wind in 2012.

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

Table 13: Changes in electricity and voltage-related redispatch measures on the most highly affected network elements, 2011-2012

Affected network element	2012: Duration in hours	Absolute change in duration in hours compared with previous year	Percentage change in duration in hours compared with previous year
Remptendorf - Redwitz	1,857	130	7.5
Lehrte area (Lehrte-Mehrum, Lehrte-Godenau, Lehrte-Göttingen)	1,080	504	87.5
Wolmirstedt – Helmstedt	470	198	72.8
Pulgar-Vieselbach	346	346	-
Conneforde area (Conneforde-Dollern-Sottrum)	312	-89	-22.2
Kriegenbrunn-Irsching-Raitersaich-Grafenrheinfeld area	274	-453	-62.3
Sottrum-Borken area (mainly: Ovenstädt-Twistetal)	268	-51	-16.0
Hamburg-Flensburg area (Hamburg Nord-Audorf-Kassö (DK))	117	-164	-58.4

This table clearly shows that in the calendar year 2012 it was mainly the 50Hertz and TenneT control areas which came under particularly strong pressure at certain times. The tense network situation for TenneT is particularly striking. Nonetheless 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 for purposes of electricity and voltage-related redispatch. TenneT and the

[14] According to TenneT construction work was undertaken in 2011 on the transformer station in Kriegenbrunn as part of the complete renovation of the 110kV system. This work inevitably resulted in temporary non-availability of TTG operational equipment. In order to fend off the threat of overburdening other operating equipment (in particular the DK 9 transformer) in Kriegenbrunn there was consequently additional need for redispatch interventions in 2011.

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 between market-driven generation by the power stations or network-driven generation as a proportion of total generation.

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

In accordance with section 13(2) of the EnWG, TSOs 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) of the EnWG.

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

In 2012, two TSOs undertook adaptation measures for a total of twelve hours spread over four days in accordance with section 13(2) of the EnWG. This resulted in a reduction of electricity feed-in by a maximum capacity of 4,805 MW and total electrical energy of 15,594 MWh. In addition, seven DSOs undertook adaptation measures for 1,649 hours spread over 254 days in accordance with section 13(2) of the EnWG. Electricity feed-in was reduced by a maximum capacity of 87 MW and total energy of 5,935 MWh.

Supporting measures provided by thirteen DSOs under section 13(2) and section 14(1a) of the EnWG led to a reduction over a period of twelve hours on four days in electricity feed-in of 326 MW and of total energy of approximately 1,670 MWh from conventional power plants and approximately 2,865 MWh from renewable energy, mine gas and cogeneration installations.

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 must be 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 network operator responsible can 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 in conjunction with sections 11 and 12 EEG, for CHP plants also with section 4(1) sentence 2 KWKG). In particular, restrictions on feed-in for conventional producers must first have been exhausted. At the same time network 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. The compensation costs are borne by the network operator in whose network the cause of the feed-in management measures is located. If the local network operator pays compensation to the installation operator on the basis of his joint liability even though a different network operator may actually have been responsible, the responsible network operator must repay the compensation costs to the local network operator.

According to the monitoring survey, the following use was made of feed-in management in 2012:

Table 14: Feed-in management measures (FMM) under sections 11 and 12 of the EEG in 2012

	Unused energy under section 11 EEG in kWh		**Compensation payments under section 12 EEG in kWh**	
Total 2012	384,787,772.45	100 percent	33,099,279.87	100 percent
Share compensated by network operator to whose network the installations were connected	82,375,775.82	21 percent	7,341,112.55	22 percent
Share compensated by the upstream network operator whose network caused the requirement for FMM	256,817,401.63	67 percent	25,758,167.32	78 percent
Share as yet uncompensated	45,594,595.00	12 percent		

The volume of unused energy (385 GWh) resulting from feed-in management measures under section 11 EEG, is 8.5 percent lower than in 2011 (421 GWh). In this context a mere two percent (8.1 GWh) of unused energy was due to scaling back of installations which were directly connected to the 50Hertz and TenneT transmission networks. The remaining 98 percent are 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 or the upstream network operator, or congestion in the restricting DSO's network.

Figure 23: Unused energy resulting from FMM in GWh

In addition to individual measures undertaken by the network operators to expand their networks the overall positive weather conditions (with no coincidence of extreme feed-in from photovoltaic systems and wind power) in 2012 also played a role in the lower volume of unused energy resulting from feed-in management. As far as the substantial increase in FMM in 2011 is concerned, however, it is also important to bear in mind that by late 2010 one of the four TSOs had in practice declared measures under section 13(2) EnWG in conjunction with section 11 EEG as measures under section 13(2) EnWG. The correct assignment of these measures in 2011 was an important factor in the substantial increase in FMM between 2010 and 2011.

As in previous years wind power plants were again most affected by FMM, accounting for 93.2 percent of total unused energy (2011: 97.4 per cent). In 2012 the share of PV installations was 4.2 percent, representing a sevenfold increase on 2011 (0.6 percent). The proportion of unused energy under section 11 EEG from biomass installations also doubled in 2012 (2011: 1.4 per cent).

Table 15: Breakdown of unused energy resulting from FMM according to sources of energy

Energy source	Unused energy (incl. heat) in kWh	Share in percent
Wind Energy	358,450,447	93.155
Solar Energy	16,057,791	4.173
Biomass	9,431,194	2.451
Gases	45,620	0.012
Water	303,636	0.079
Geothermal energy	0	0
Installation under KWKG	499,084	0.130
Total	384,787,772	100

In 2012 FMM were reported by a total of two TSOs and 17 DSOs. As in 2011 it was mainly operators with network areas in northern Germany which were affected and, for the first time in 2012, operators with network areas in Bavaria and Baden-Württemberg.

Table 16: Number of network operators in the various German states, which have carried out FMM in 2012

Land	Number of DSOs which carried out FMM in 2012
Saxony-Anhalt	3
Lower Saxony	3
Bavaria	2
Brandenburg	2
North Rhine-Westphalia	2
Schleswig-Holstein	2
Mecklenburg-Vorpommern	1
Hesse	1
Baden-Württemberg	1
Total	17

Unused energy resulting from FMM amounted to just 0.33 percent of overall feed-in from EEG installations (including volumes sold directly) in 2012 (2011: 0.41 percent). In relation to total wind infeed under the EEG, the share was 0.71 percent (2011: 0.89 percent).

At €33.1 million (2011: €33.5 million), total compensation payments remained all but constant despite the reduction in unused energy. This is due to the increased scaling back of PV installations which, compared to wind power plants, have a higher feed-in tariff and consequently attract higher FMM compensation under the EEG.

Just 22 percent of compensation payments were made by the network operator to whose network the restricted installation was directly connected. 78 percent of compensation payments in contrast were made by the upstream network operators whose network was the cause of the FMM.

2. Network tariffs

2.1 Revenue caps in incentive regulation

On 1 January 2009, the Bundesnetzagentur set revenue caps determining how much revenue a network operator can generate in a calendar year. On 1 January 2013, for the fourth time since the introduction of incentive regulation, the operators were able to independently adjust the revenue caps and network tariffs in accordance with the Incentive Regulation Ordinance (ARegV) and the Electricity Network Charges Ordinance (StromNEV) and taking into consideration the altered retail price index and the changes in the cost shares that cannot be controlled on a lasting basis.

The Bundesnetzagentur examines the adjustments made by the operators by comparing them with the permitted revenue, so that any unjustified adjustments can be re-credited with interest in future to the network users via the incentive regulation account. Significant driving factors in the increase in the revenue caps are the rise in costs from investment measures and special influencing factors associated with the Energiewende. Growth in renewables and the expansion of infrastructure, in particular, make heavy investments in the transmission networks necessary. The adjustments made led to an increase of around 7.81 percent in the revenue caps for the TSOs between 2012 and 2013.

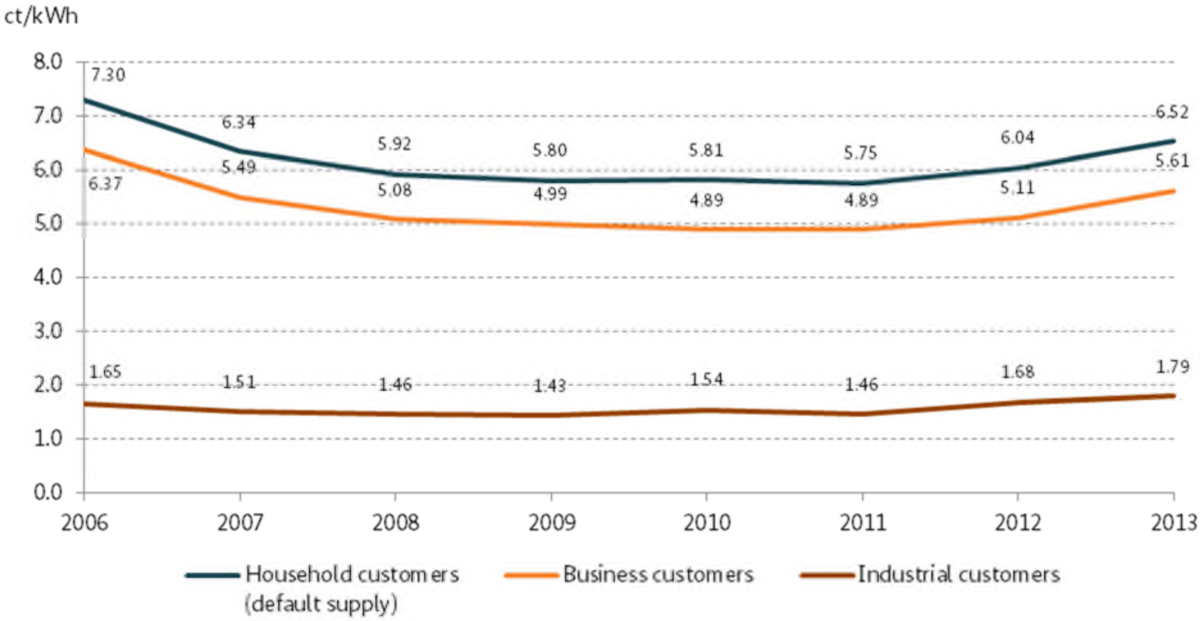
The DSOs may reapply each year for an expansion factor for their investments in this area if there is a lasting change in their supply services. In 2012, 82 approved applications for an expansion factor resulted in an increase in the revenue caps. In addition, 54 expansion factors already approved in 2011 were still applicable in 2012. A total of 113 applications for expansion factors had been received as of 30 June 2013. The higher expansion investments lead to an increase in the revenue caps.

There was an increase of 15.3 percent in the revenue caps for the DSOs between 2012 and 2013. These revenue caps provide the basis for calculating the tariffs of the different network areas. There was an overall rise in the network tariffs for household, industrial and business customers.

2.2 Network tariffs

The following figure shows the average volume-weighted net network tariffs (ct/kWh), including charges for billing, metering and metering operations, by customer category[15] between 1 April 2006 and 1 April 2013.

Figure 24: Network tariffs between 2006 and 2013 (volume-weighted averages)



There was a clear increase in the average volume-weighted network tariffs for household customers (low voltage), business customers (low voltage, interval metering) and industrial customers (medium voltage) between 1 April 2012 and 1 April 2013. The graph shows that the average network tariffs for household and business customers fell by around 0.78 ct/kWh and 0.76 ct/kWh respectively between 2006 and the end of the period under review, while those for industrial customers increased overall by approximately 0.14 ct/kWh.

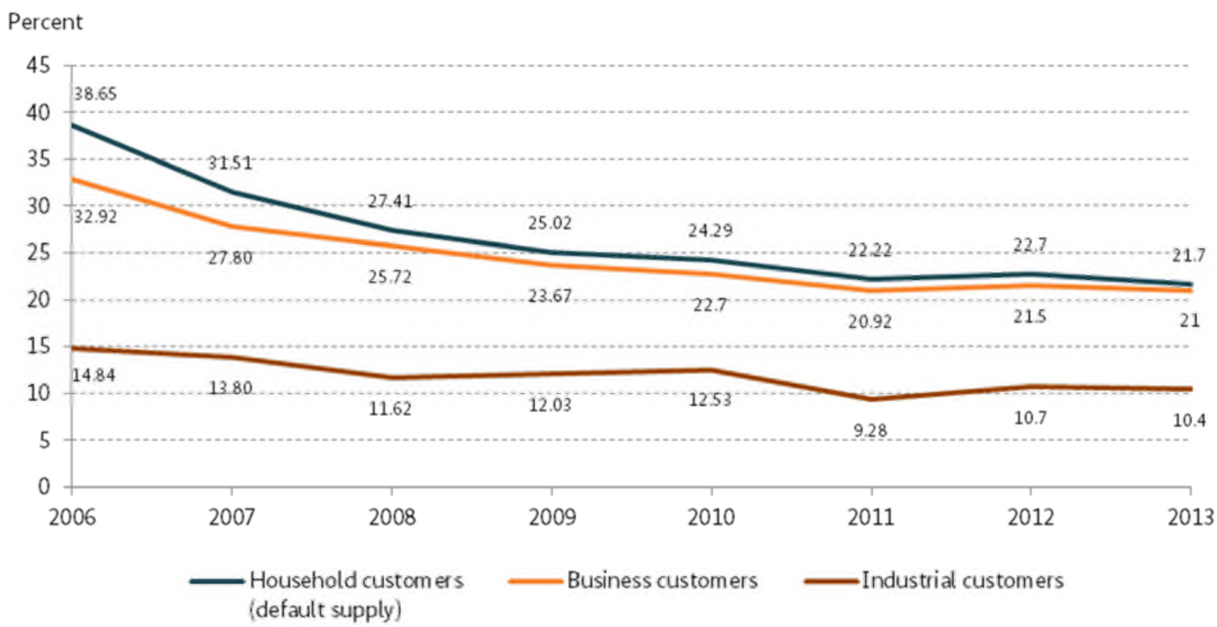
The regulation of network usage tariffs in the electricity sector was introduced in 2005 with a focus on reducing existing monopoly profits and inefficiencies in network operations. Network tariffs had stabilised in recent years following initial significant reductions in network costs and the subsequent tariffs; considerable

[15] The network tariffs are shown for the following categories:
• Household customers: annual consumption 3,500 kWh, low voltage supply
• Business customers: annual consumption 50 MWh, annual peak load 50 kW, annual usage 1,000 hours, low voltage supply (0.4 kV) (Figures for non-interval metered business customers were based on supply without interval metering.)
• Industrial customers: annual consumption 24 GWh, annual peak load 4,000 kW, annual usage 6,000 hours, medium voltage supply (10 kV or 20 kV)
• The contribution charge under section 19 StromNEV is not taken into account here, but leads to a further increase in the tariffs for household customers.

increases are now to be expected. The increase in the network tariffs can be traced back to a number of factors, not least to investments in network expansion.

Nevertheless, network regulation makes a key contribution towards dampening the rise in prices in the electricity markets. Decreases in the network tariffs can, however, only partially offset increases in the price components for energy procurement and supply, taxes and other state-introduced price components, hence there has been only a moderating effect on the rising electricity prices.

Figure 25: Share of network tariff in overall electricity price between 2006 and 2013 (volume-weighted averages)



The share of the network tariffs in the overall electricity price for industrial, business and household customers decreased as a whole over the entire period between 2006 and 2013. It also showed a year-on-year decrease from 2012 to 2013.

Overall it can be seen that – as in 2012 – the ongoing expansion of the transmission and distribution networks as a result of the *Energiewende* triggered significant costs and thus rises in tariffs in connection with the adjustment of the revenue cap for 2013. In contrast, the efficiency and cost reduction potential offered by incentive regulation only had a minor dampening effect. The aim is standardised and transparent network tariff regulation guaranteeing target-oriented and also cost-effective development of the energy system. This can lead to increasing tariffs and thus have a corresponding effect on the electricity price. This rise must, however, be limited to the minimum necessary.

2.3 Cost examination

The second regulatory period for electricity DSOs and TSOs will begin on 1 January 2014 and will last for five years.

In 2012, the Bundesnetzagentur began its cost examination in accordance with the StromNEV provisions to determine the base level for the revenue cap. The examination is based on data for the 2011 business year, which the operators were required to submit by 30 June 2012. The Bundesnetzagentur examines the costs of 105 operators under its core remit. In addition, it carries out the cost examination for 173 other operators by administrative agreement. This is done through an official delegation of powers on behalf of the states of Berlin, Brandenburg, Bremen, Lower Saxony, Mecklenburg-Western Pomerania, Schleswig-Holstein and Thuringia.

Operators with less than 30,000 customers connected directly or indirectly to their distribution systems were able to apply to take part in simplified proceedings by 30 June 2012. A total of 168 operators whose costs were to be examined made use of this option.

The necessary operating costs were determined as part of the cost examination. According to the principles of determining network costs, current outlay and calculated costs of network operation are to be recognised only in so far as they are in line with the costs of an efficient and structurally comparable operator. The main focus of the examination was on determining the imputed depreciation, return on equity and taxes, minus cost-reducing revenue and income, as well as examining the current outlay costs.

While the cost examination was still in progress, changes were made to the legal framework; these included amendments to the StromNEV, which were taken into account in calculating the necessary operating costs. The changes affect the index series for the tangible fixed assets and the return on equity in cases where the equity ratio as defined in section 6 StromNEV is exceeded.

The reforms mean that, from 2015 onwards, additional costs incurred by operators for research and development can also be taken into account in the revenue caps (cf section 25a ARegV).

The Bundesnetzagentur will set the revenue caps for the operators following the cost examination.

2.4 Treatment of transmission loss costs in the second regulatory period

The Bundesnetzagentur has issued a decision on determining the volatile cost shares according to section 11(5) ARegV for the costs of procuring transmission loss for the second regulatory period, as provided for by section 29(1) EnWG in conjunction with section 32(1) para 4a ARegV. The main elements of the voluntary commitments for transmission loss from 2010 remain in place. Here, the allowed transmission loss costs in each calendar year are derived from the product of the reference price and the allowed volume. Differences between the actual annual procurement costs and the allowed costs are kept as a bonus or paid as a penalty by the DSOs, as the case may be.

In addition, the Bundesnetzagentur introduced a further option to the voluntary commitments enabling transmission loss costs to be recognised on the basis of a fixed price of €54/MWh and the volume of the base year 2006 for the whole of the second regulatory period. 28 operators made use of this option.

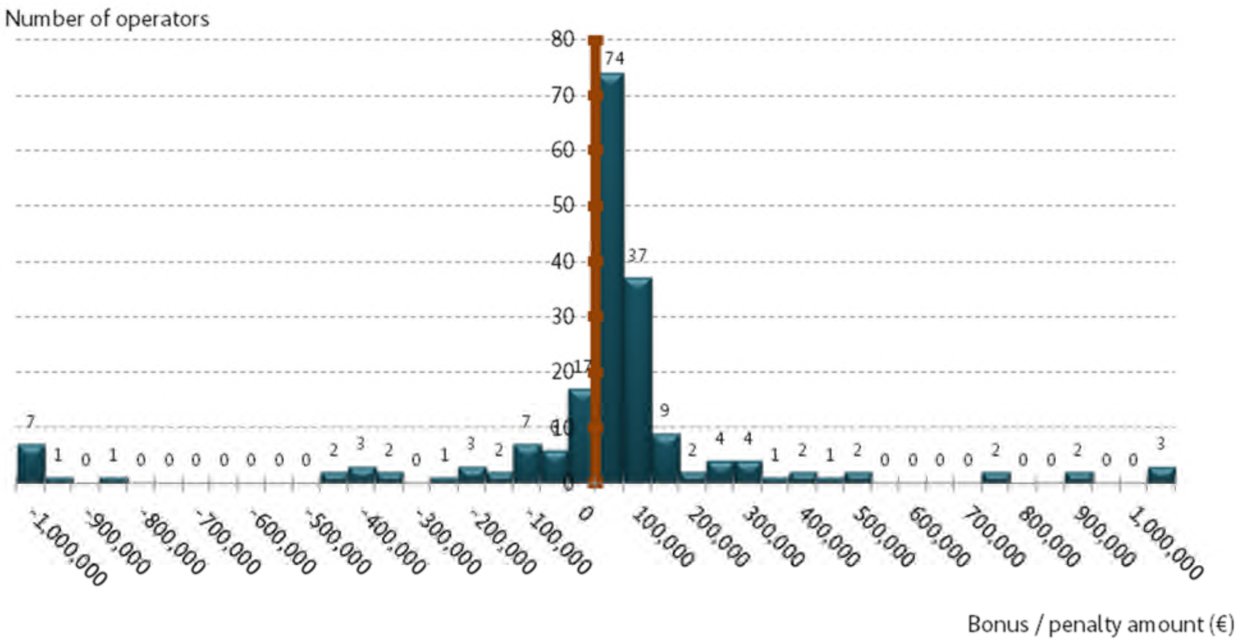
2.5 Start of quality regulation on 1 January 2012

Incentive regulation harbours the risk that operators will comply with the applicable revenue caps by not investing in their networks or not carrying out other measures to maintain or improve quality of supply, in order to save costs. This could lead to a deterioration in the quality of supply. To counteract this, the ARegV provides for the introduction of quality regulation through a quality element that is part of the formula for the revenue cap. As a result, operators whose network has had above-average quality levels in past years will have an amount added to the cap, while operators whose networks have comparatively poor quality levels will have amounts deducted (bonus/penalty system).

The Bundesnetzagentur developed a concept detailing the quality element for electricity network reliability in 2010. The concept includes a basic variant of quality regulation for network reliability, which was introduced on 1 January 2012. The quality element was set for two years and used in the revenue caps for 2012 and 2013.

In the first regulatory period, the quality element for 2012 and 2013 produced a bonus for 143 operators and a penalty for 59 operators. The bonus and penalty amounts for the individual operators ranged from approximately -€4m to approximately €4m.

Figure 26: Bonus and penalty amounts for individual operators



A second quality element based on the concept of the basic variant is to be calculated for the start of the second regulatory period (2014-2018). The quality elements to be calculated will apply in the revenue caps for the first three years of the second regulatory period, ie 2014, 2015 and 2016. The quality element will be calculated using data from 2010, 2011 and 2012.

The variant currently used is based on a report on the design and integration of a quality element for electricity network reliability in the revenue cap[16] commissioned by the Bundesnetzagentur from a consortium of consultants comprising Consentec Consulting für Energiewirtschaft GmbH, Forschungsgemeinschaft für Elektrische Anlagen und Stromwirtschaft e. V.(FGH) and Frontier Economics Limited. In order to calculate the quality element, the basic variant uses the SAIDI (system average interruption duration index) for the low voltage level and the ASIDI (average system interruption duration index) for the medium voltage level to indicate interruption duration. All interruptions lasting longer than three minutes are included in the calculations. The SAIDI and ASIDI indices are based on the interruptions to supply notified by the operators under section 52 EnWG. Reference figures are derived from the indices, with load density as a parameter to replicate structural differences between the individual network areas. If an operator's individual SAIDI/ASIDI value deviates from the calculated reference value, the operator receives a bonus or penalty on the permitted revenue cap by means of an incentive factor.

It must be stressed that the reference values are not targets set by the authorities for the individual operators regarding the level of network reliability to be achieved. Rather, every operator must perform integrated cost and revenue optimisation, taking into consideration the incentive factor. This will optimise quality levels for the economy as a whole in the long term.

The quality incentive system is to take national data into account. The basic variant is used for all low and medium voltage networks of operators participating in the national efficiency benchmarking procedure under sections 12–14 ARegV. Networks of operators participating in the simplified procedure under section 24 ARegV are therefore not included, in accordance with section 24(3). The basic variant excludes high and extra high voltage networks from the quality element, as no reliable quality regulation can be carried out in this area with the figures currently available.

2.6 Status of efficiency benchmarking for electricity DSOs for the second regulatory period

The second regulatory period for the DSOs begins on 1 January 2014. The Bundesnetzagentur is to carry out national efficiency benchmarking for the DSOs in accordance with section 12(1) ARegV. The Bundesnetzagentur was assisted in determining the efficiency levels by a consortium of consultants comprising Swiss Economics and Sumicid. The required structural and cost data from the base year 2011 for the 185 operators participating in the standard procedure were submitted to the Bundesnetzagentur and the regulatory authorities of the federal states and checked for plausibility. On 12 July 2013, representatives of the business circles concerned and consumers were consulted on the methods and the parameters presented for the electricity DSOs' efficiency benchmarking, in accordance with sections 12(1) and 13(3) ARegV. The efficiency levels were calculated after evaluation of the responses. The individual efficiency levels are due to be available in good time to enable the operators to determine the individual network tariffs to apply as from 1 January 2014. A general efficiency level of 96.14 percent is applicable to operators participating in the simplified procedure under section 24(2) ARegV.

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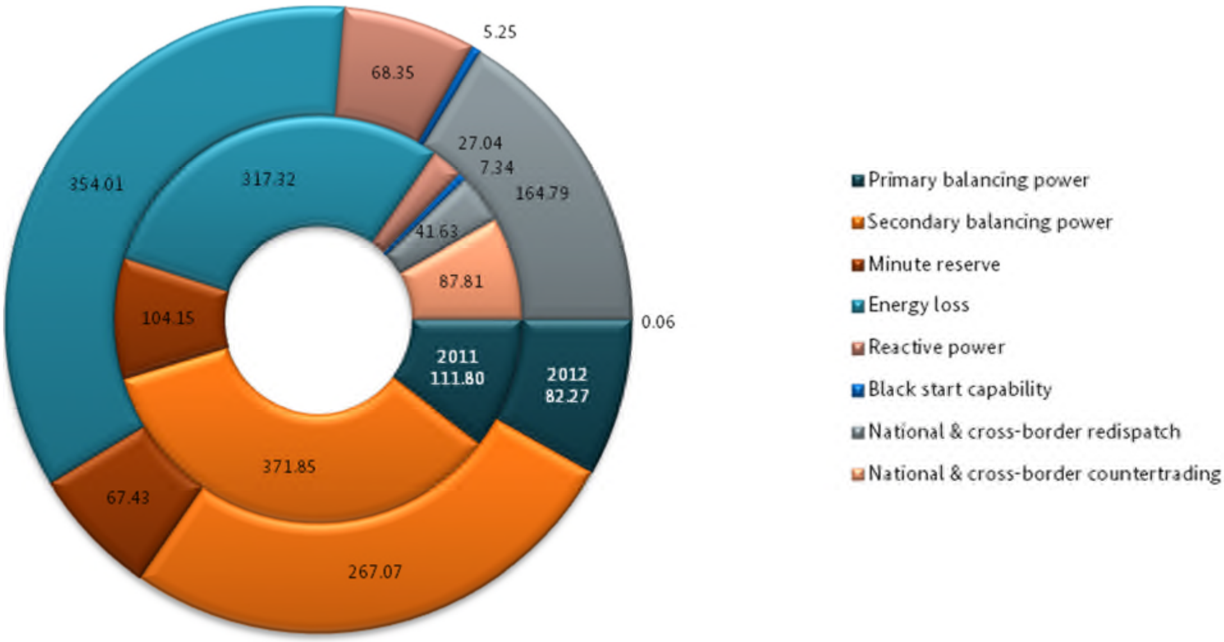
[16] Available on the Bundesnetzagentur's website at http://www.bundesnetzagentur.de/cln_1911/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Netzentgelte/Strom/Qualitaetselement/1Regulierungsperiode/1regulierungsperiode-node.html.

D System support services

System support services are core tasks for the transmission system operators (TSOs). They include keeping and using the three kinds of system balancing power, that is to say primary balancing power, secondary balancing power and minute reserve. Other system support services are the provision of energy to compensate for transmission losses, the provision of reactive power and black start capability, and national and cross-border redispatch and countertrading.

Figure 27: Total costs of German TSOs' system support services in 2011 and 2012 (€m)



There was a fall in the total costs of system support services in 2012 to €1,077m (2011: €1,135m). The cost-reducing revenues totalled €68m (2011: €66m). As a result, the costs of the system support services fell to €1,009m (2011: €1,069m). A large part of the total costs is made up by the costs for keeping reserves of system balancing power – €417m (2011: €588m) – and for energy to compensate for grid losses – €354m (2011: €317m).

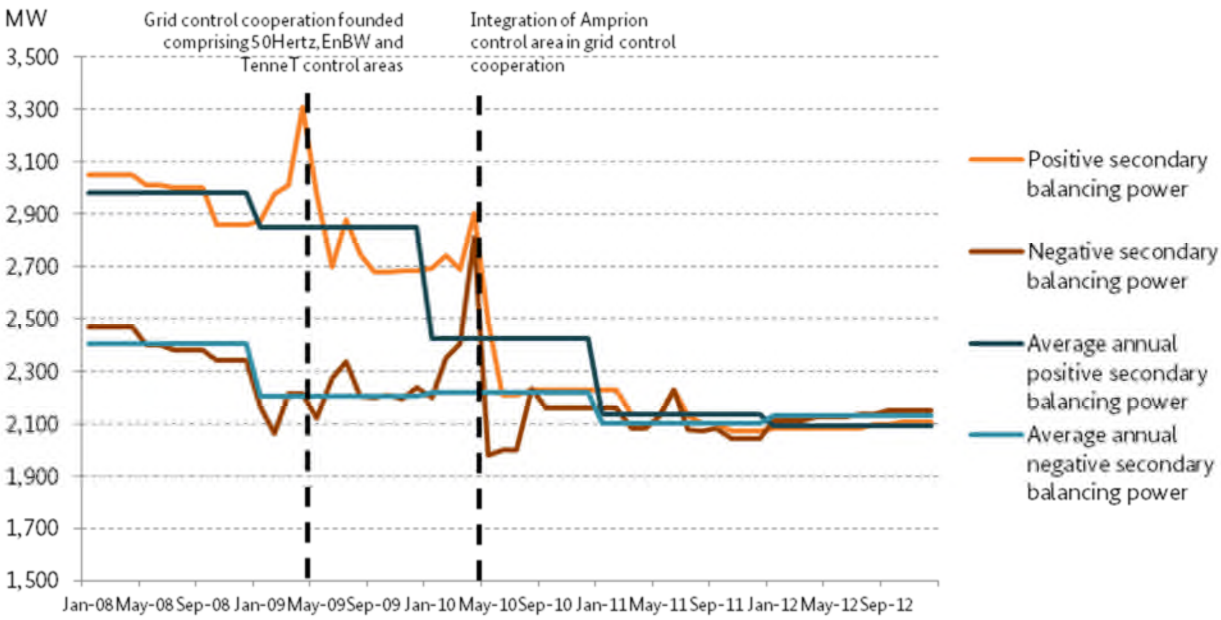
The cost structure of the system support services was not the same in 2012 as in 2011. There was a drop of €171m in the total costs for system balancing energy, most notably because of the decrease of €105m in the costs for secondary reserve. By contrast, there was an increase in the costs for reactive power (+€41m) and energy to cover grid losses (+€37m).

1. System balancing energy

A cooperation scheme for grid control, covering the control areas of all four German TSOs (50Hertz, EnBW TNG, TenneT TSO, Amprion), was completed when Amprion joined in 2010. Its modular structure prevents inefficient use of secondary and minute reserve, dimensions the reserve requirements for all four control areas together, creates a single nationwide market for secondary and minute reserve 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 balanced by the use of this energy. Inefficient use is almost completely eliminated and the level of balancing power that has to be kept is reduced, as seen in the lower levels of secondary and minute reserve tendered for and actually used.

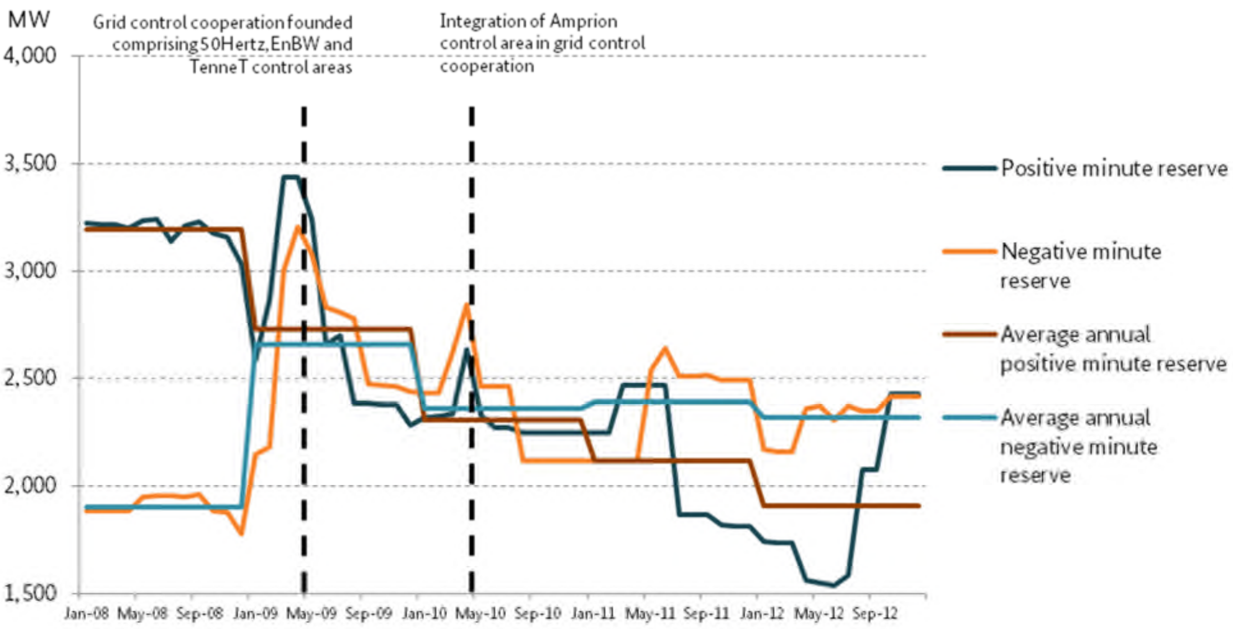
One of the aims of the determinations issued by the Bundesnetzagentur in 2011 on reducing minimum bid volumes, tendering periods and timeslices on the primary, secondary and minute reserve market is to encourage new suppliers to enter the market and to further open the system balancing energy market for other technologies, eg for interruptible consumption, for storage facilities, etc.

Figure 28: Total secondary balancing power tendered for in the control areas of 50Hertz, Amprion, TransnetBW and TenneT



The above figure shows the effect of introducing grid control cooperation: the average volume of secondary balancing power tendered for in the periods between May of one year and April of the next was more or less the same as in the comparable period in 2011. Compared with 2011, the average level of positive secondary balancing power tendered for fell to 2,091 MW (2011: 2,139 MW) and negative secondary balancing power rose slightly to 2,133 MW (2011: 2,102 MW).

Figure 29: Total minute reserve power tendered for in the control areas of 50Hertz, Amprion, TransnetBW and TenneT



The picture is less uniform when it comes to the provision of minute reserve. There was a continued decline in the average volume of positive minute reserve tendered for from 2,309 MW to 1,907 MW between 2010 and 2012. The demand for positive minute reserve rose during 2012 from a historic low in May to reach the level of early 2011. The share of negative minute reserve kept was consistently low as in the previous year. The change in the volumes tendered for within the twelve-month period is considerably more volatile in the case of the two minute reserve power products compared with the secondary balancing power products. To some extent, this is accounted for by the changed generating patterns and the growing number of generating installations for renewables in Germany. It is also accounted for by surpluses that often occur in the control area at the end of the year as a result of the dimensioning method used later reappearing in the dimensioning of the balancing power kept.

The efficiency-increasing potential of grid control cooperation is currently seen to have been exhausted in Germany. Yet the modular structure of the scheme makes it possible to extend it to neighbouring control areas in other countries, something the German TSOs are looking to do. The framework conditions for the system balancing energy markets in Europe still differ from one another, and so not all the modules are applicable straightaway. What can be implemented in the short term, however, is the first module, which prevents inefficient use of reserves. At the borders subject to congestion management, offsetting the use of system balancing energy is limited to the transmission capacities not used by the market. There is no booking of capacity for an exchange of system balancing energy. Nor does the planned cooperation with foreign TSOs have any effect on the level of balancing power procured jointly by the German TSOs.

The ranges of the volumes tendered for in 2012 can be seen in the table below.

Table 17: Overview of the system balancing power tendered for by the TSOs in 2012 (MW); source: www.regelleistung.net

	Primary	Secondary		Minute reserve	
	pos/neg	pos	neg	pos	neg
Volume tendered for (MW)	567-592	2,081-2,109	2,114-2,149	1,536-2,426	2,158-2,413

The requirements of primary balancing power at 567-592 MW were lower than in 2011 (612-624 MW).

The German TSOs and the Swiss TSO Swissgrid are seeking, in consultation with the Bundesnetzagentur and the Swiss regulatory authority, the Eidgenössische Elektrizitätskommission ElCom, to harmonise both markets for primary balancing power. Since 12 March 2011, the beginning of the first harmonisation stage, Swissgrid has issued calls for tender for 25 MW of Switzerland's requirements for coverage by German primary balancing reserve suppliers. There is no limit on coverage of the German requirements from Switzerland. But there are technical limits on account of the rules in the Operation Handbook of the Union for the Co-ordination of Transmission of Electricity (UCTE). Swissgrid is taking part, with this 25 MW for joint tendering, as the fifth TSO in the German tenders in line with the German regulations and is the connecting TSO for the Swiss suppliers.

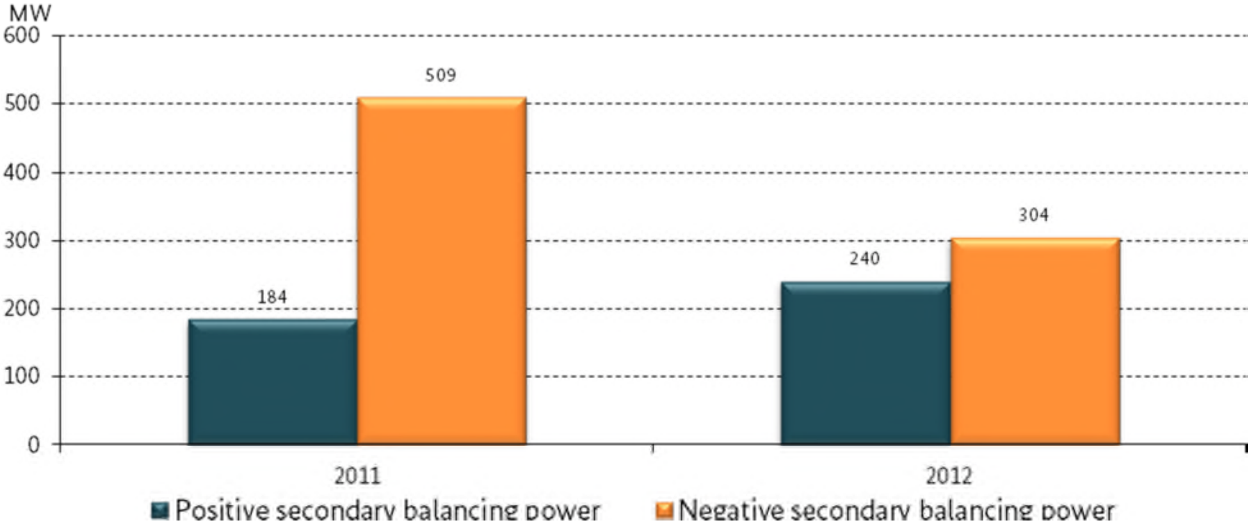
Grid control cooperation and the determinations issued by the Bundesnetzagentur are contributing to greater competitive potential as a result of enlarging the market area by creating a nationwide market for secondary balancing power and for minute reserve and amending the tender specifications. Thus the number of prequalified suppliers of system balancing energy had risen to 20 for secondary reserve (2010: 15) and to 36 for minute reserve (2010: 35) by 25 June 2013. The number of primary reserve suppliers at 14 was the same as in the previous year.

2. Use of secondary balancing power

Use of secondary balancing power dipped in 2012 compared to 2011. As the figure above shows, the secondary reserve procured in 2011 and 2012 remained at a similarly low level.

For the year 2012 the total volume of energy used was some 2.1 TWh (2010: 1.6 TWh) for positive and 2.7 TWh (2010: 4.5 TWh) for negative secondary balancing power. A shift towards positive secondary balancing power can be observed with a slightly lower overall volume of energy, compared to 2011.

Figure 30: Average use of secondary balancing power including procurement and deliveries under online off-setting in the grid control cooperation



3. Use of minute reserve

With a total of 20,233 release requests, the frequency with which minute reserve was used in 2012 increased year-on-year by a good ten percent, as shown in the table below. This is primarily due to the increase in the use of positive minute reserve, analagous to secondary balancing power.

Figure 31: Minute reserve frequency of use

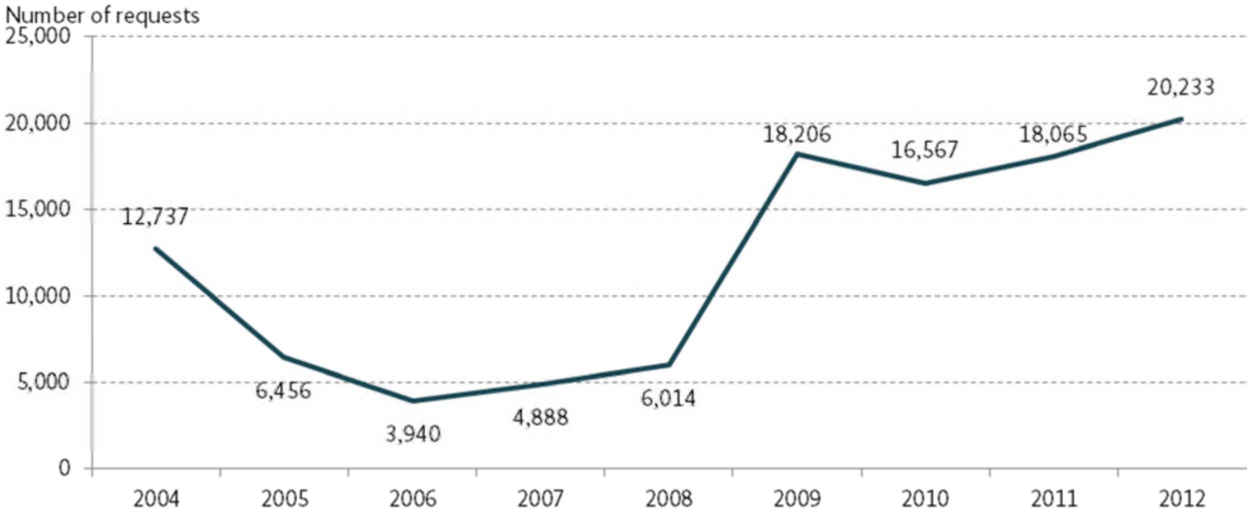
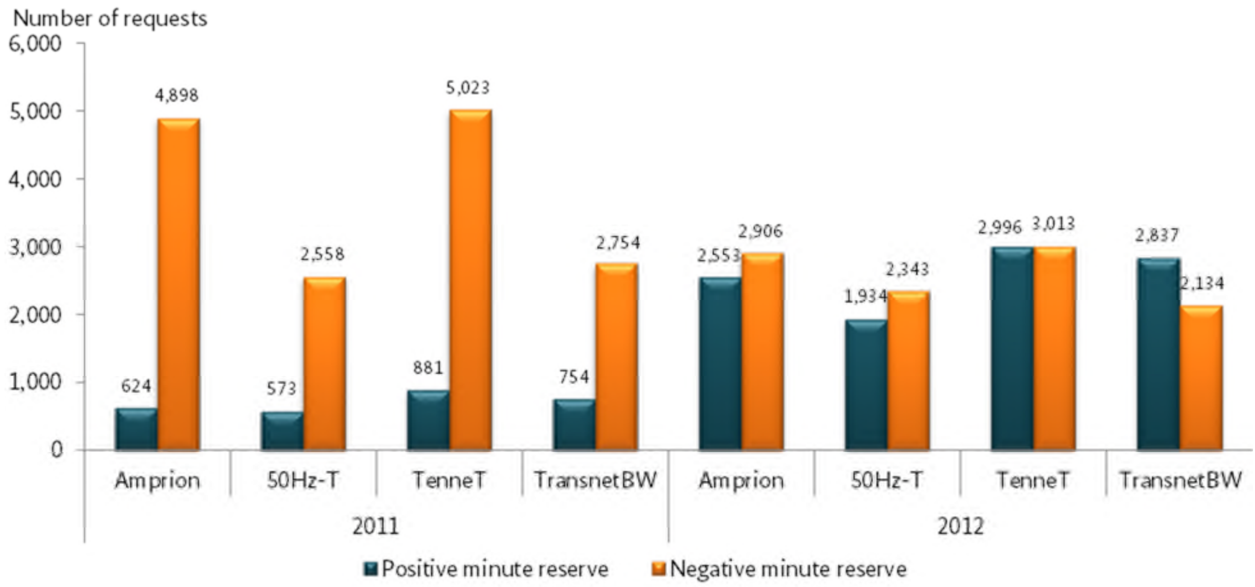


Figure 32: Minute reserve frequency of use in the four German control areas in 2011 and 2012



The average power in a release request, approximately 215 MW, was lower for positive minute reserve than in 2011 (227 MW). With around 233 MW for negative minute reserve in 2012 the average volume of power requested decreased again compared to 2011 (302 MW).

Figure 33: Average volumes of minute reserve requested by the TSOs in 2011 and 2012

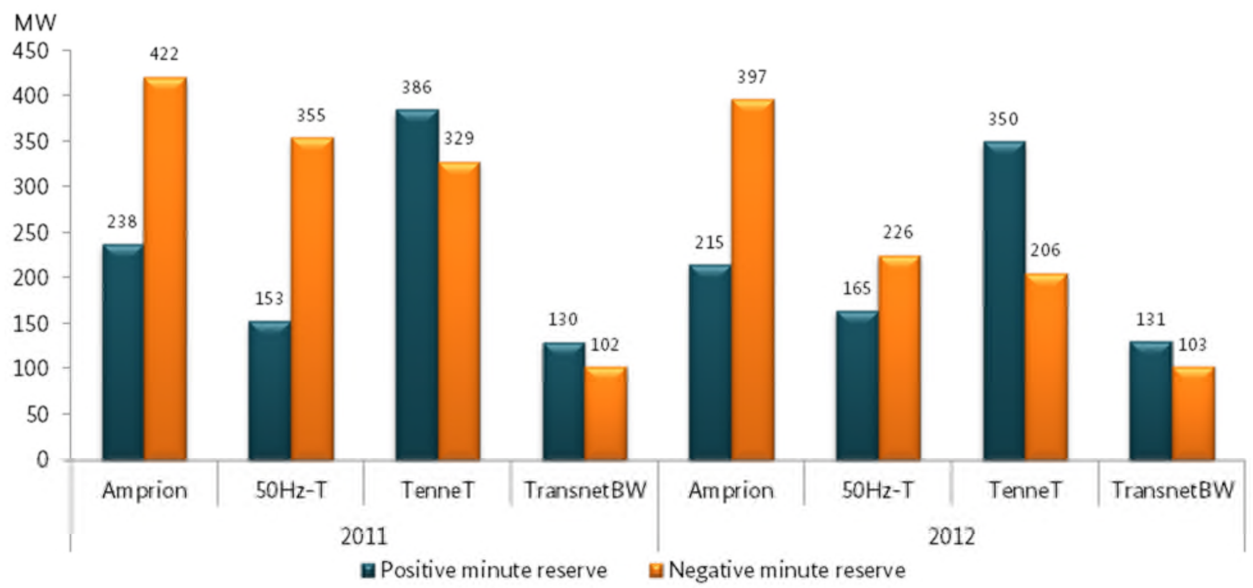
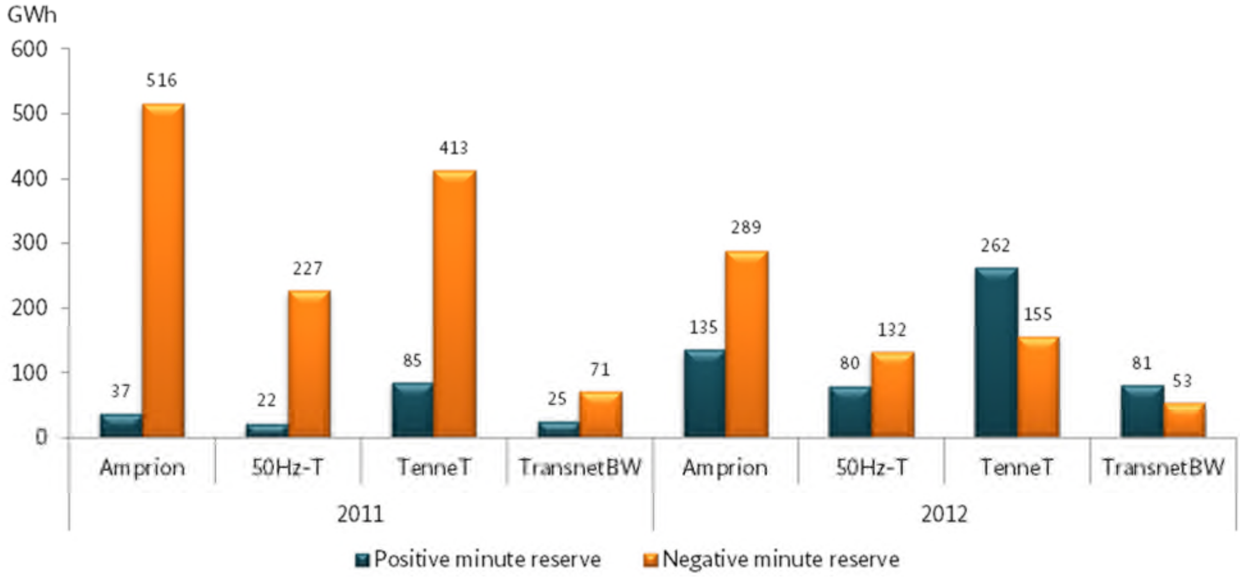
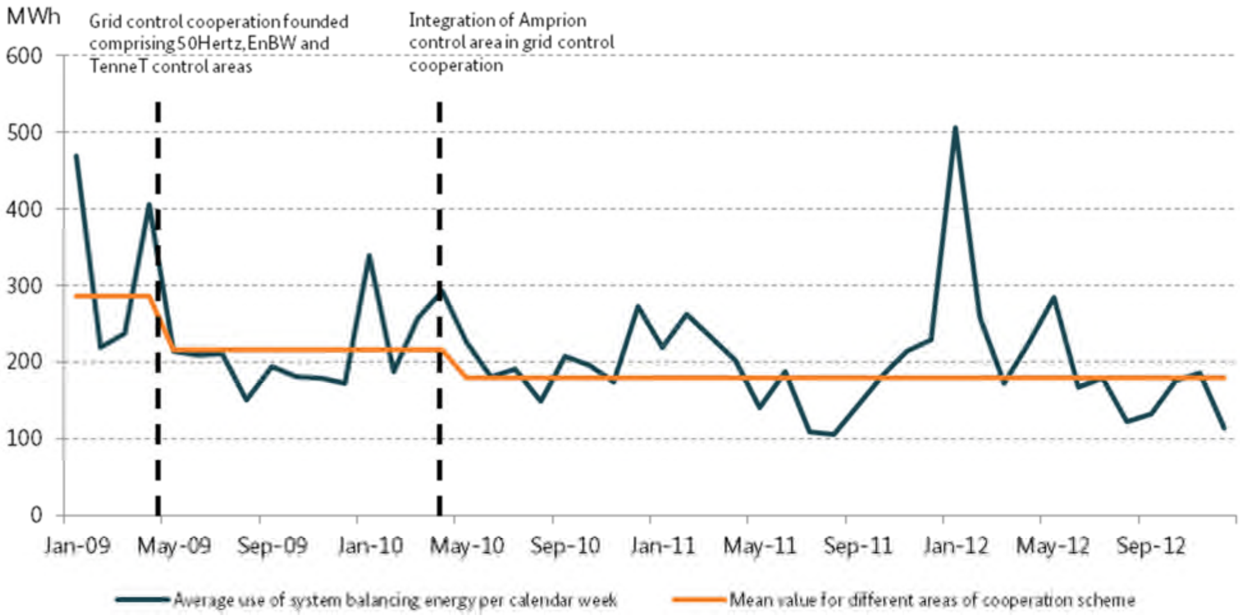


Figure 34: Energy volumes requested in 2011 and 2012 (GWh)



Thus altogether 558 GWh (2011: 168 GWh) was used in 2012 for positive minute reserve, and 629 GWh (2011: 1,226 GWh) for negative minute reserve. As with secondary balancing power, a shift away from negative to positive minute reserve was observed.

Figure 35: Average system balancing power used (MWh)



The figure below shows the average use of system balancing energy for each calendar month. It also shows a period mean. A period always begins with a change in grid control cooperation (eg setting up, Amprion joining). This indicates the savings potential of the scheme in relation to the system energy.

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.

There was a significant increase in the maximum portfolio balancing energy price within the grid control cooperation scheme compared with 2011.

Table 18: Maximum portfolio balancing energy prices 2010-2012

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

Under the cooperation scheme, the average 15-minute price for portfolio balancing energy in 2012, in the case of a positive control area balance (short portfolio), was approximately €107.95/MWh, and in the case of a negative balance (long portfolio), approximately €4.77/MWh. A slight year-on-year increase in the average price for portfolio balancing energy was identified in 2012. The average weighted price in 2012 with a positive control area balance was €130.53/MWh, and €14.54/MWh with a negative balance (cf Figure 37).

Figure 36: Average portfolio balancing energy prices 2010-2012

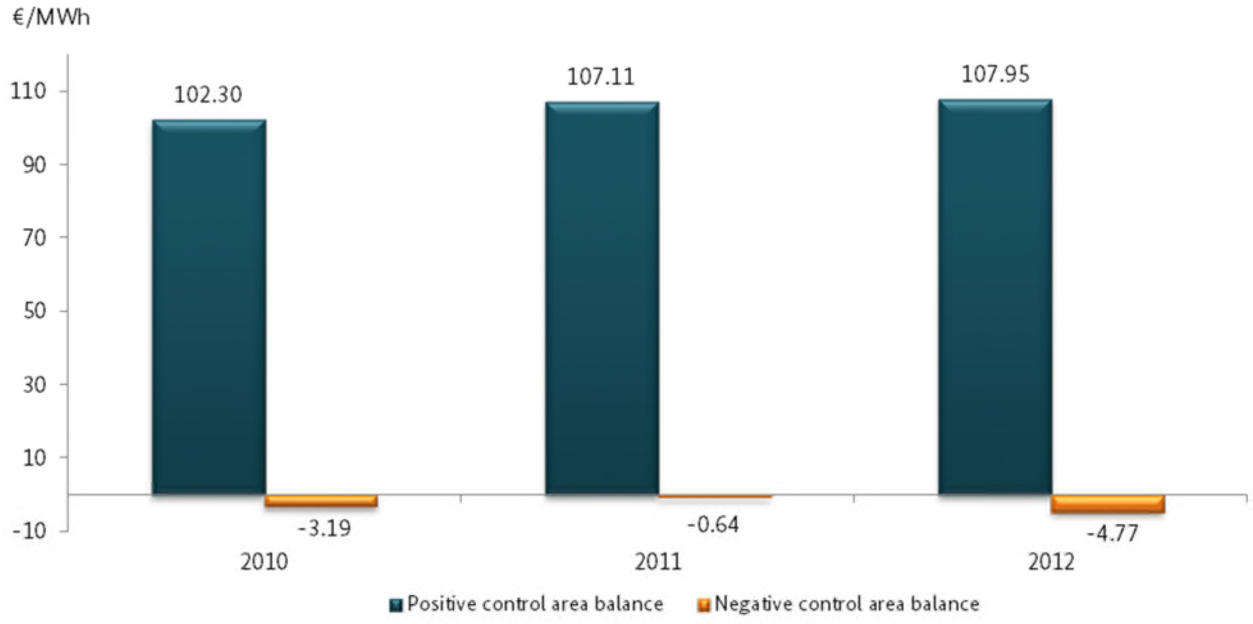
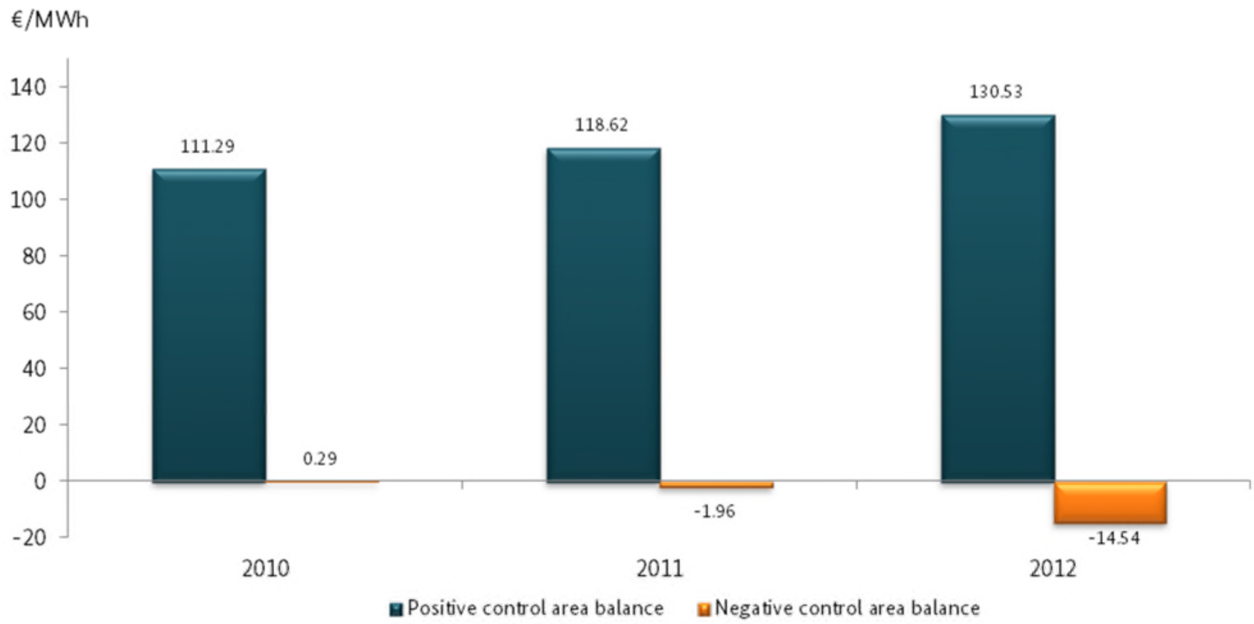
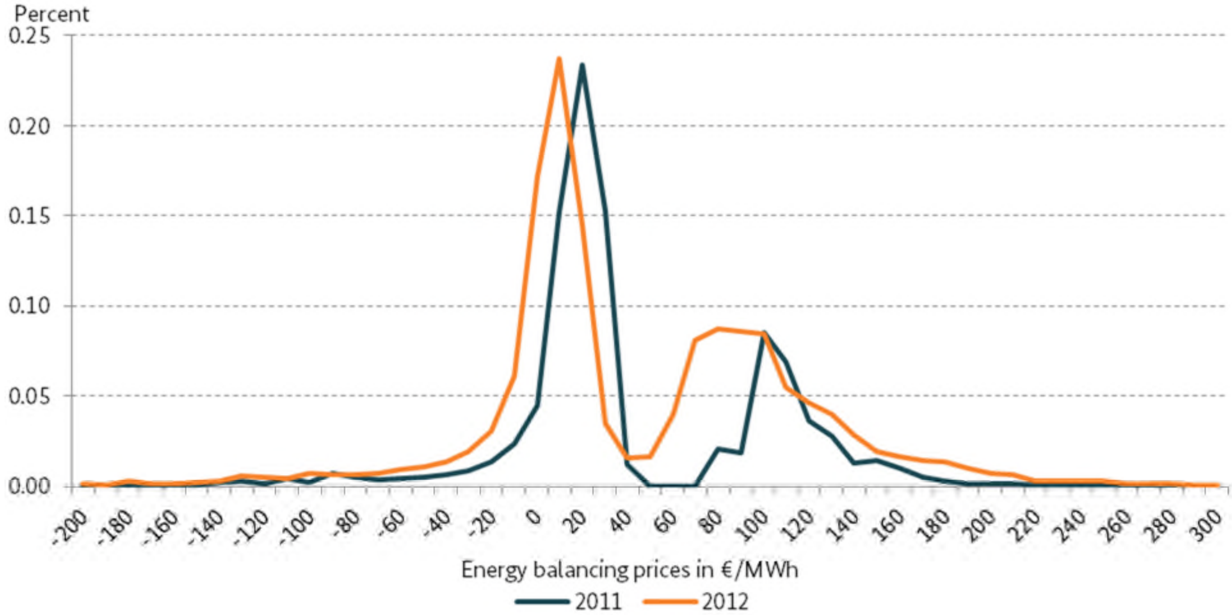


Figure 37: Average volume-weighted portfolio balancing energy prices 2010-2012



The following diagram shows the frequency distribution of the prices for portfolio balancing energy in grid cooperation control. With the negative control area balance there is an accumulation of the prices around €0/MWh. This effect was stronger in 2012 than in 2011.

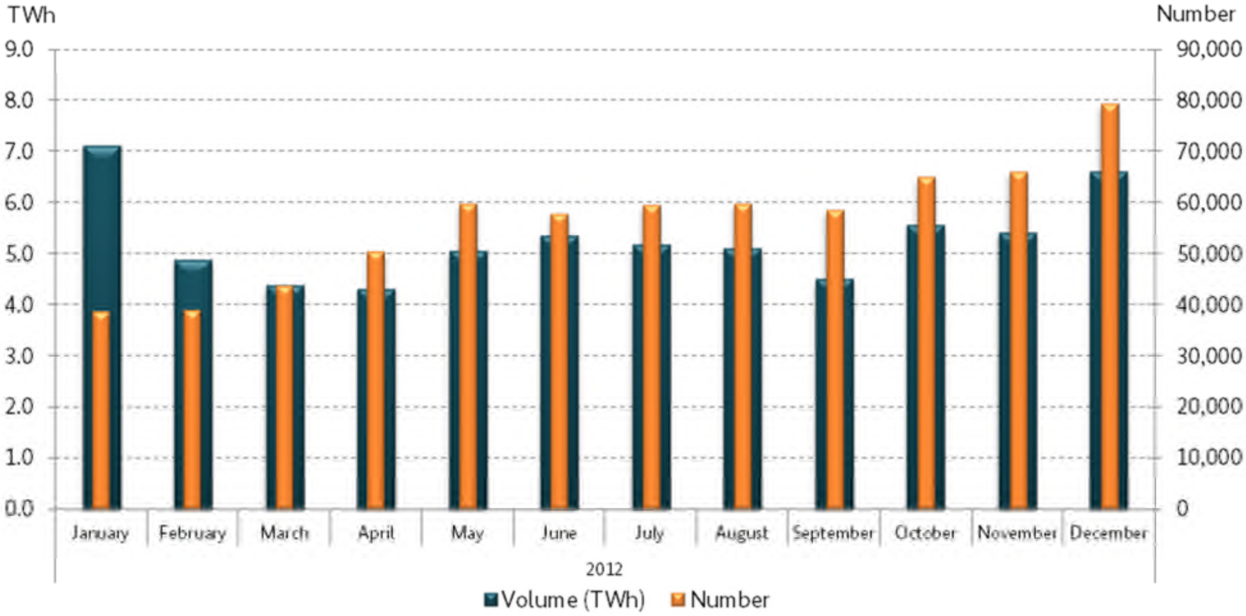
Figure 38: Frequency distribution of portfolio energy balancing prices in 2011 and 2012 in percentages



5. Intraday trading

Section 5(1) of the Electricity Network Access Ordinance allows schedule notifications, in which balancing group managers notify TSOs about planned electricity supply and commercial transactions for a given day (based on quarter-hour figures), up to 14:30 on the day before. In order to enable balancing group managers to respond to short-term changes in the supply and demand situation, schedules can be modified during the day as well. The following diagram shows the number and volume of intraday changes to schedules in 2012.

Figure 39: Monthly number and volume of intraday schedule changes



The increase (in both number and volume) of intraday schedule changes can be partly explained by the increase in the intermittent input of renewable energies which makes it necessary to balance this out during the day by means of intraday trading. In 2012, a total number of 676,902 schedule changes (2011: 363,281) accounted for a total volume of 63.4 TWh (2011: 64.8 TWh). On average, 56,400 schedule changes were made each month, the largest monthly number being 79,238 and the lowest 38,629.

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 system balancing energy in Germany can currently be seen.

However, the modular structure makes a phased expansion of grid control cooperation to neighbouring foreign control areas possible. And in 2011 and 2012, the TSOs indeed sought to push the expansion of Module 1 (Avoidance of action leading to inefficient use of reserve power). As merely the imbalances in the control areas are offset at this stage in line with the transmission capacity remaining after the participants' trades, no changes to the national framework conditions are required. The optimisation potential can be realised relatively easily through incorporation in the system. The optimisation system is managed in TransnetBW's main control centre in Wendlingen and operated for all the participants from there.

Cooperation to avoid inefficient use of reserves 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) and Belgium (since October 2012). The next step is to include Austria in the cooperation scheme.

7. Framework guidelines on Electricity Balancing

In January 2012 the European Commission officially mandated ACER with drawing up these Framework Guidelines. The Bundesnetzagentur is making a major contribution to this within ACER. The Framework Guidelines will concretise the areas named in Article 8(6)(h) and (j) of Regulation (EC) No 714/2009. They will set rules for trading related to technical and operational provision of network access services and system balancing, and balancing rules including network-related power reserve rules. The Framework Guidelines aim to ensure security of supply, to strengthen competition in the system balancing energy markets, to enable the inclusion of load management and renewables in the system balancing energy markets and to promote cross-border exchanges of system balancing energy. All Framework Guidelines must contribute to non-discrimination, to real competition and to the efficient working of the market. To this end the balancing energy Framework Guidelines aim to achieve, to the necessary degree, the integration, the coordination and the harmonisation of the national system balancing energy regimes.

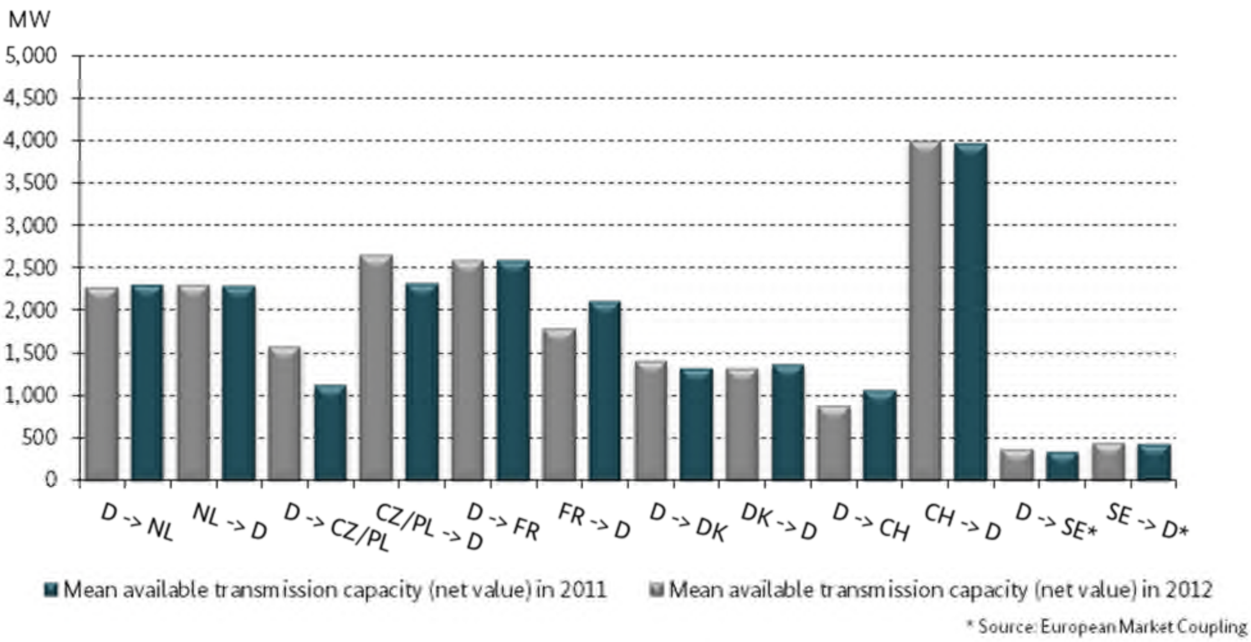
ACER submitted the Framework Guidelines to the European Commission in September 2012. The European Network of Transmission System Operators for Electricity, ENTSO-E, was then called upon to draw up network codes in accordance with the Framework Guidelines.

E Cross-border trading, cross-border interconnectors

1. 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[17].

Figure 40: Average available transmission capacity



The results show that in 2012, the year under review, Germany continued to play a central role in the exchange of electricity within the central European system. Changes took place in particular at the borders between Germany and the Czech Republic and Poland, France and Switzerland. Export capacity at the border with the Czech Republic and Poland increased by a total of 40 percent while import capacity rose by 14.4 percent. Average available import capacity at the border with France decreased by 14.8 percent, with ex-

[17] 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/.

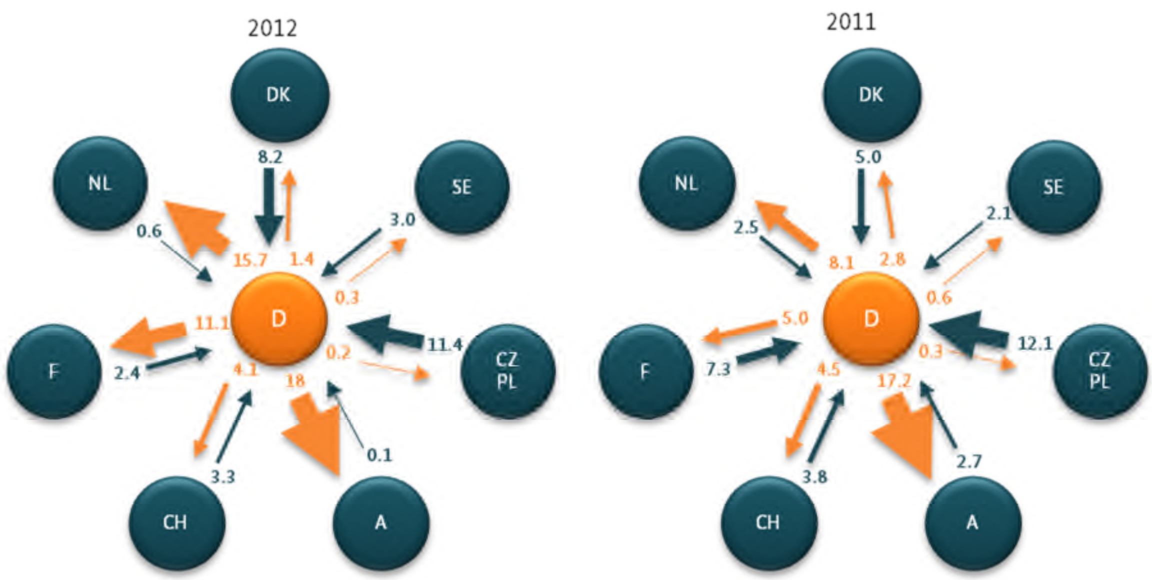
ports more or less constant (+0.4 percent). At the border with Switzerland export capacity fell by 16.9 percent and import capacity rose just slightly (+0.8 percent). There was a 6.3 percent increase in export capacity at the border between Germany and Denmark, accompanied by a 3.2 percent decrease in import capacity. Export and import capacities at the German-Swedish border increased by 6.8 percent and 2.5 percent respectively. At the border with the Netherlands, export capacity fell by 1.5 percent while import capacity showed a one percent rise. Average available transmission capacity over all German cross-border interconnectors increased by 1.9 percent from a total of 21,336 MW in 2011 to 21,735 MW (import and export capacities) in 2012.

2. 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 excess generation, or demand shortage, and hence follow the rules of the market[18]. The following diagram shows the exchange schedules implemented at Germany's borders in 2012.

Figure 41: Exchange schedules (TWh) (cross-border electricity trading)



Cross-border traded volumes rose from 74 TWh in 2011 to 79.7 TWh in 2012. Of this, 50.7 TWh was exported and 29 TWh imported. This means that in 2012, as in previous years, Germany was a net exporter, with a surplus of some 21.7 TWh, 18.7 TWh more than in 2011.

In 2012, net exports to the Netherlands rose by 7.6 TWh and those to France even doubled with an increase of 6.1 TWh. Exports to the other neighbouring countries remained largely unchanged, however, with the ex-

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

ception of Sweden; here, net exports halved, with a decrease of 0.3 TWh. From Germany's perspective, the main electricity customers in 2012, on balance, were Austria, followed by the Netherlands and France.

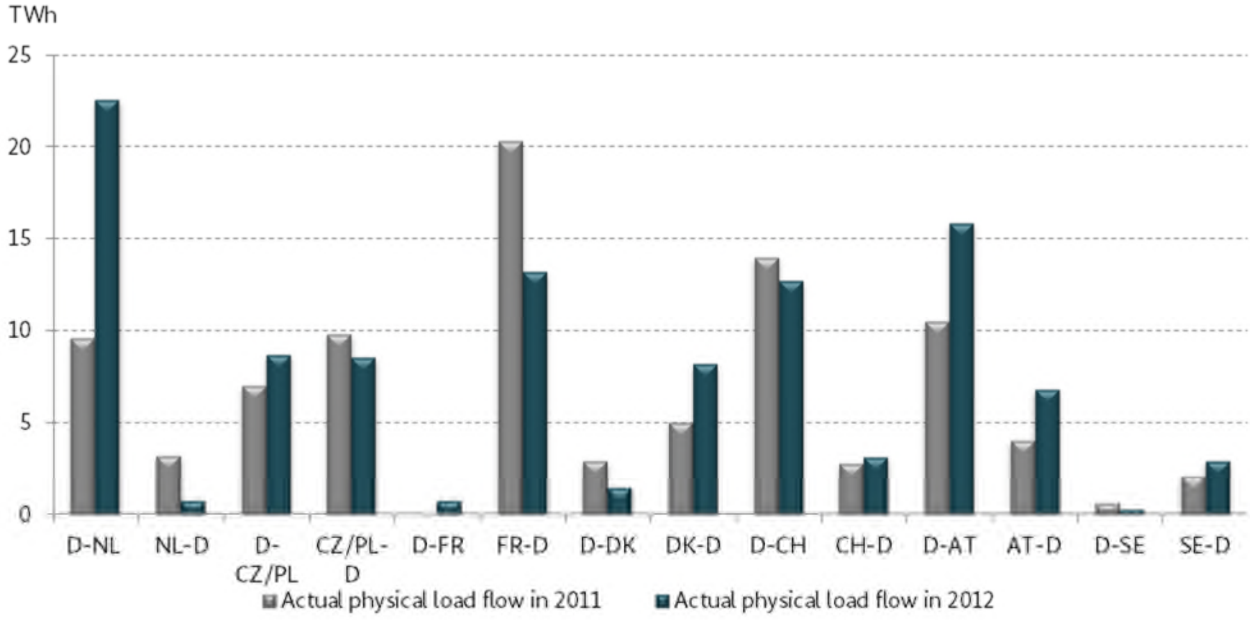
The rise in exports in 2012 is linked to the increase in electricity generated by renewable sources, notably from wind and solar power.

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 thus 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 poor economic climate and consequent decrease in electricity consumption also directly affected electricity prices, as did the fuel costs that are determined on the world market.

The actual physical load flows shown in the following diagram deviate from the exchange schedules for each border[19].

[19] 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).

Figure 42: Physical cross-border load flows (Source: ENTSO E – European Network of Transmission System Operators for Electricity)



3. 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. The ITC mechanism was introduced on 3 March 2011. 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.

The number of TSOs participating in the ITC mechanism remained unchanged at 34 in 2012. The ITC fund amounted in 2011 to a total compensation of €225m, with €100m to cover the costs of providing infrastructure and €125m to cover the costs of hosting transit flows. In 2012, the amount set aside for hosting cross-border flows rose to €179m, on account of an increase both in the volume of transit flows and in the average value of losses. As a result, the ITC fund in 2012 totalled €279m. This increase lies within the scope of the total increase in the fund's volume.

In 2012 the four German TSOs received a total compensation from the ITC fund of €26.8m (2011: €22.06m).

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 in North West Europe (NWE – Benelux, France, Germany, Great Britain and Scandinavia) was continued in 2012, with realisation planned for November 2013. The other regions will then gradually join the NEW region.

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 resulting from congestion between the countries. The method consequently brings about an alignment of prices on the 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. Full price convergence[20] between the Czech Republic, Hungary and Slovakia, for instance, jumped from eleven to 82 percent following market coupling in 2012.

At European level, ACER has tasked the Bundesnetzagentur with managing the project for implementing market coupling throughout Europe by 2014. 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. One of the cornerstones for this is flow-based capacity calculation. This involves already taking into account 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 West Europe (CWE) in autumn 2010, work began on the rapid implementation of the flow-based method. In 2012 it was decided to hold a public consultation to give all market players affected by the flow-based capacity allocation method the opportunity to present their own views and raise any ambiguities. The consultation and evaluation of the responses are set to take place in 2013. The flow-based method is due to be implemented in the CWE region after market coupling in the NWE region, where it will then also be introduced.

Alongside the introduction of the flow-based method in the CWE region, the possibility of implementing the method is currently also under discussion in Central East Europe (CEE), with the aim of accelerating integration of the CEE region with the CWE and NWE regions. In this context, ACER has drawn up a cross-regional roadmap for the introduction of the flow-based capacity calculation method in the CEE region. The objective

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[20] The calculations assume full price convergence up to a price difference of €1/MWh.

is for the method to be implemented throughout the CEE region in 2014. With this aim in mind, the TSOs in the CEE region have established a high-level working group to draw up an implementation timetable for introducing the flow-based capacity calculation method and to ensure joint coordination.

Later on, a Central-East-West Europe load-flow working group is to take on overarching tasks with a view to enabling coupling of the NWE and CEE regions. 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.

In addition, the TSOs in the Czech Republic, Hungary and Slovakia in the CEE region joined forces on 12 September 2012 to form a trilateral market where the NTC calculation method is used. It is, however, advantageous for the participating countries in the CEE region to use the same capacity calculation method to ultimately achieve the aim of creating a common European electricity market. Various working groups in the CEE region – the Regional Initiatives – are therefore currently working on a joint solution.

3. Network Code on Capacity Allocation and Congestion Management

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.

Since 2010, against the background of the Community-wide focus of the Framework Guidelines, the boundaries of the Regional Initiatives have been increasingly overstepped and interregional cooperation has been initiated. Of particular interest here is the introduction of volume-based market coupling between the CWE region[21] and the northern countries[22].

In September 2012 ENTSO-E submitted the Network Code on Capacity Allocation and Congestion Management (CACM) to ACER for comment. ACER basically approved the Network Code but proposed a number of amendments to improve specific areas that do not fully comply with the Framework Guidelines. In particular, deadlines for essential methodologies and terms and conditions are to be incorporated with the aim of completing the internal electricity market by the end of 2014.

In addition, the Network Code should provide a more detailed description of the capacity calculation process as well as clear requirements for redispatching. Since ACER's required harmonisation of redispatch pricing is not in line with the Framework Guidelines, the Bundesnetzagentur does not agree with ACER in this case.

The regulatory approval procedures are to be amended so that the approval competences also cover the methodologies and the regulatory authorities have the general competence to request amendments. As regards intraday auctions, the Network Code should be revised 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. The Network Code provides for reimbursement of the market price difference in case of force majeure. The Framework Guidelines, however, explicitly state that only the auction price should be reimbursed in such cases; ACER therefore believes that the Code needs to be amended accordingly, and the Bundesnetzagentur expressly supports this view.

A separate network code is being developed for forward capacity allocation.

According to ENSTO-E the code is in its final drafting stage, with the public consultation process completed and the final version due to be delivered to ACER in October 2013.

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, in anticipation of its entry into force.

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 two years once the Network Code is in force.

The process also requires the TSOs to submit a technical report to the regulatory authorities as the basis for an evaluation by the authorities and ACER of the market structure, and in particular the current bidding zone configuration. The evaluation gives priority to criteria relating to network security, market efficiency and the stability of the bidding zones.

[21] Benelux, France and Germany

[22] Denmark, Finland, Norway and Sweden

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 launch a review.

ACER and the national regulatory authorities will jointly decide on the further course of action based on an evaluation of the individual votes of the participants in 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. Here, it seems desirable and – in light of the grid expansion goals – realistic to maintain the congestion-free German-Austrian wholesale market.

4. Network load in adjacent countries

On account of the laws of physics and the consequent fact that electricity flows through lines with the least resistance, electricity does not always flow in the direction traded. 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 electricity flows are particularly marked in generation situations with high wind power feed-in. Flows from the north to the south of Germany 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, would 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 results of the pilot use of a vPST in Poland between 8 January and 30 April 2013 are currently being analysed. At the same time, 50Hertz Transmission GmbH is negotiating with the Czech Republic and Poland about the use of pPSTs, with installation expected in 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 Network Code.

G Wholesale

1. General

Well-functioning wholesale markets are of key importance for competition in the electricity sector. Spot markets, where electricity can be bought and sold at short notice, and futures markets, which also allow for a medium and long-term hedging of price risks, are particularly significant for electricity wholesale trading. The energy exchanges send important price signals to market participants, also in other areas of the electricity wholesale trade[23]. One precondition for effective wholesale markets is sufficient liquidity, i.e. sufficient quantities on the supply and demand side.

Basis of the survey

For this monitoring report, the trading data of 583 wholesalers for the year 2012 have been analysed. Several broker platforms have also been included in the survey. The energy exchanges relevant for supplies into the four German control areas[24] and the Austrian control area[25] have also contributed data for the report.

Types of electricity wholesale trading

There are two types of electricity wholesale trading, exchange trading and off-exchange[26] trading.

OTC clearing has its own significance as an interface. Off-exchange wholesale electricity trading can take two forms: bilateral trading in the strict sense (which denotes direct trade between a seller and a buyer[27], provided the latter does not buy as a final customer) and bilateral trading between companies via broker platforms[28]. Under certain conditions, an off-exchange contract can be cleared at the exchange and thus subsequently be registered as an exchange transaction. These two types of off-exchange trading are complemented by exchange trading in the strict sense (i.e. bringing together supply and demand through an exchange).

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[23] The prices at the energy exchanges indicate amongst other things the effects of electricity that is marketed under the German Renewable Energy Sources Act (EEG) on the wholesale markets.

[24] 50Hertz Transmission GmbH, Amprion GmbH, TransnetBW GmbH, TenneT TSO GmbH.

[25] Austrian Power Grid (APG); APG is a 100 percent subsidiary of Verbund AG.

[26] Over-the-counter (OTC) trading

[27] Seller and buyer can also be associated companies. System services are not included.

[28] Wholesale electricity trading involves various supporting or brokering services. This report will focus on trading volumes rather than on how individual services are provided. Data from broker platforms, however, can be quite useful as they allow for conclusions on trading volumes.

Structure of the survey

When assessing the electricity wholesale trade, there are aspects other than the type of trading that also need to be considered. The monitoring report generally focuses on Germany as the place of delivery[29]. For both types of trading (on and off exchange) a differentiation is made between short-term trading (spot market) and long-term trading (futures market). On the spot markets, contract settlement is usually physical (supply to the balancing group), on the futures market financial. A special aspect that has been considered is whether buyer and seller have used a broker platform to initiate their transaction. Another significant aspect is the question as to what extent off-exchange transactions can, with the help of OTC clearing, be equated with on-exchange transactions.

Table 19: Structure of data acquisition (electricity wholesale)

Type of trading	**Futures market**	**Spot market**
Over the counter (OTC)	defined as transactions with a settlement period of at least one week	defined as transactions with a settlement period of less than one week
bilateral transactions in the strict sense bilateral transactions on broker platforms	Settlement in the year of contract conclusion Settlement in the year(s) following contract conclusion	Intraday and day-after Day-ahead Other contracts
OTC Clearing (interface)	Conditions according to specifications of the exchange	Conditions according to specifications of the exchange
bilateral transactions in the strict sense bilateral transactions on broker platforms	in principle possible for the products in question	possible for intraday (EPEX SPOT)
Exchange		
EEX / EPEX SPOT	Phelix futures Options on Phelix futures	Intraday Day-ahead
EXAA	_	Day-ahead

[29] The data collected for exchange futures trading and exchange day-ahead trading relate to Germany/Austria as the place of delivery.

2. Exchange wholesale trading

2.1 Introduction

As in previous years, this report on exchange electricity trading focuses on the exchanges in Leipzig, Paris and Vienna[30]:

The European Energy Exchange (EEX), Leipzig, offers electricity products for futures trading; the EPEX SPOT[31], Paris, offers electricity products for spot market trading. Both exchanges are connected via their operating companies[32]. The Energy Exchange Austria (EXAA), Vienna, conducts spot market auctions[33]. All three exchanges trade uniform products[34] at uniform prices for the delivery zones Germany and Austria.

The exchanges have become important trading venues. The number of trading participants admitted to them (which are not necessarily active participants) has almost constantly increased in the past six years. The number of participants active on the EEX futures market has more than doubled since 2007. The EXAA spot market shows a comparable increase in participants and the number of registered participants active on the EPEX SPOT market has increased by about 50 percent in the same period. However, this does not indicate a radical change in the level of participants. One also needs to bear in mind that interconnected companies, for example, pool their purchase and sales activities within the company group. Subsidiaries are supplied by their parent companies. In addition, companies also make use of (other) opportunities of brokered trade (purchasing syndicates; brokers).

[30] Other market places can also be of relevance for electricity wholesale trading in Germany, such as the ELBAS intraday trading platform of Nord Pool Spot (Lysaker, Norway). Conversely, the EEX and EPEX SPOT exchanges (which have been used as reference for this report) also offer electricity products for places of delivery other than Germany/Austria. This will not be considered in this report's analysis

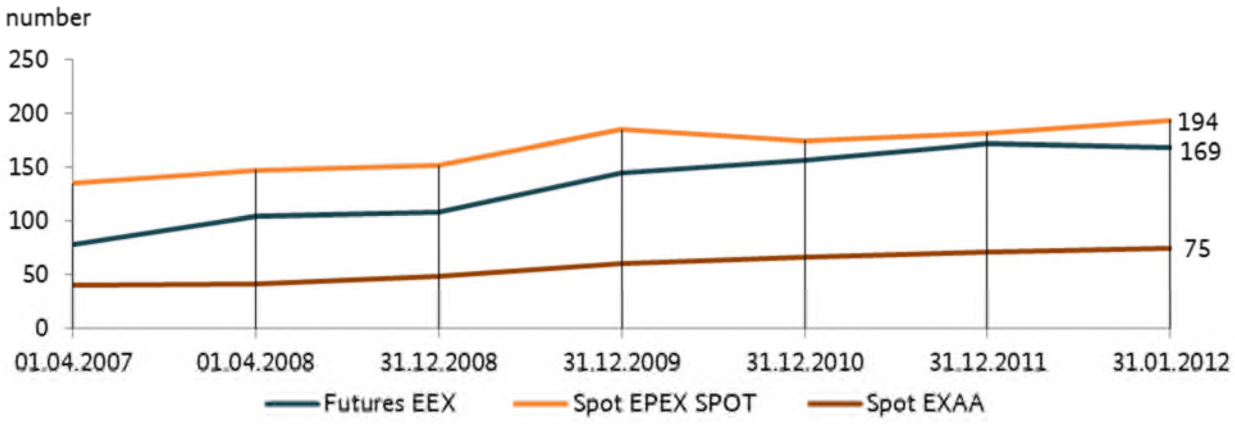
[31] Comparisons with previous years will refer to "EPEX SPOT", and will not differentiate between the EEX Power Spot (previous Leipzig spot market of EEX) and the EPEX SPOT.

[32] The EEX is an institution under public law within the meaning of Section 2 (1) BörsG (Stock Exchange Act). Its operating company within the meaning of Section 5 BörsG is the European Energy Exchange AG (EEX AG), or rather its 80 percent subsidiary EEX Power Derivatives GmbH, via which all electricity futures are traded. The remaining 20 percent in EEX Power Derivatives GmbH are held by the French Powernext SA. The operating company of EPEX SPOT is EPEX SPOT SE which is owned in equal proportion by EEX AG and Powernext SA.

[33] The EXAA has twelve shareholders. The largest shareholders with around 35 percent and 25 percent are APCS Power Clearing and Settlement AG and Wiener Börse AG (WBAG). The other shareholders are predominantly companies from the energy sector with shares of about 3 percent.

[34] The intraday product traded at the EPEX SPOT is offered separately for Austria and Germany.

Figure 43: Number of registered participants on the exchanges until reference date[35] 31.12.2012

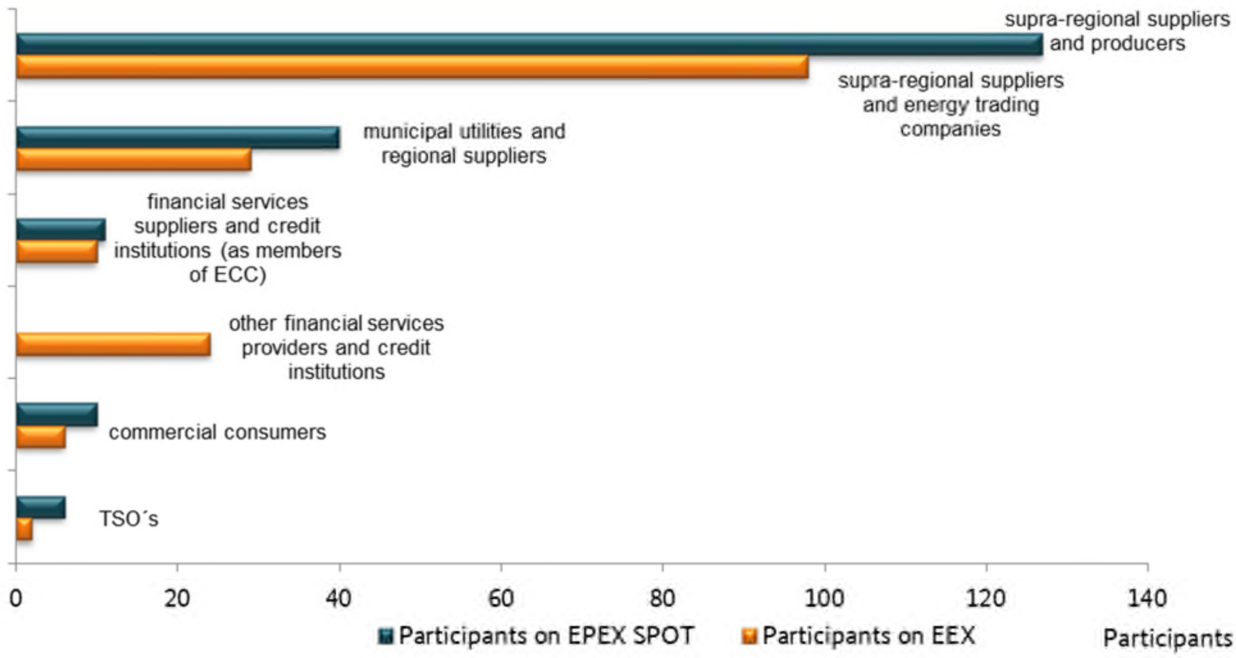


The following graph shows the representation of participant categories at the EPEX SPOT and EEX[36]:

[35] The graph depicts the situation at the respective reference date. The curve progression between two reference dates does not reflect developments within the course of that respective year.

[36] It has not been examined to what extent there are overlaps between the individual categories.

Figure 44: Registered participants on EPEX SPOT and EPEX at reference date 31.12.2012 (according to categories)



2.2 Spot markets EPEX SPOT and EXAA

Standard products traded on the EPEX SPOT are designed for two different trading processes, namely the day-ahead auction and the continuous intraday market (both trading forms are possible for supplies to all German and the Austrian[37] control areas). Day-ahead auctions can be used to trade individual hours and standardised blocks, as well as specific combinations of individual hours (user-defined blocks[38]). Market coupling contracts (MCC)[39] are also traded in the daily auctions. Also, it is possible to submit a bid for a complete or partial settlement of futures positions with futures contracts that are traded at the EEX. Individual hours and (standard or user-defined) blocks can also be traded in intraday trading.

The EXAA offers trading of individual hours and standardised blocks in day-ahead auctions. Physical settlement is effected into the Austrian control area or into one of the German control areas. In December 2012 a new quality variant for electricity was introduced under the name "GreenPower", in which the physical supply of electricity is coupled with a specific guarantee of origin.

[37] The Austrian intraday market was only launched in October 2012; therefore, data have only been collected for supplies to the four German control areas.

[38] With the deviation from standards their advantage is also forfeited; a matching becomes less likely.

[39] In the German control areas, MCC are possible to and from France and to the Netherlands.

The day-ahead market for Germany/Austria

Active participants

EPEX SPOT conducts auctions throughout the whole year on each trading day at noon. A registered participant is considered "active" on a trading day if at least one bid (sale or purchase) has been executed in his name. On average, 150 participants (in 2011: 146 participants) were active per trading day, which equals around 78 percent of all registered participants. The average number of active buyers (117 compared to 123 in 2011) and sellers (110 compared to 105 in 2011) has also remained at the level of the previous year. The number of net buyers per trading day (balance in favour of "purchases") fell from 89 in 2011 to 83 in 2012 (decrease of 7 percent). In contrast, the number of net sellers (balance in favour of "sales") rose by 21 percent to 68 (from 56 in 2011).

At the EXAA auctions take place five days a week as of 10:12 a.m., which is earlier than at the EPEX SPOT. A registered participant is considered "active" if at least one bid (sale or purchase) has been executed in his name on a delivery day[40]. On average, 37 participants (or 50 percent) of all registered participants were active per trading day; in the case of on average 20 participants per trading day, bids were executed into the German control areas.

Traded volumes

In the reporting year, volumes traded on the day-ahead market of the EPEX SPOT and EXAA continued to increase. The rate of increase at the EPEX SPOT amounted to around 9 percent, which is the same as in the previous reporting year. The EXAA registered an increase of about 24 percent (compared to around 18 percent in the previous year).

[40] The different point of reference - delivery day instead of trading day - is used to allow for a comparative assessment of data from the two spot markets, despite their differing trade conditions (auction days, times of auctions). However, this is only possible to a certain extent, also (but not exclusively) due to the substantially different number of registered participants on EPEX SPOT and EXAA.

Figure 45: Day-ahead trading volumes at the EPEX SPOT from 2009 to 2012[41]

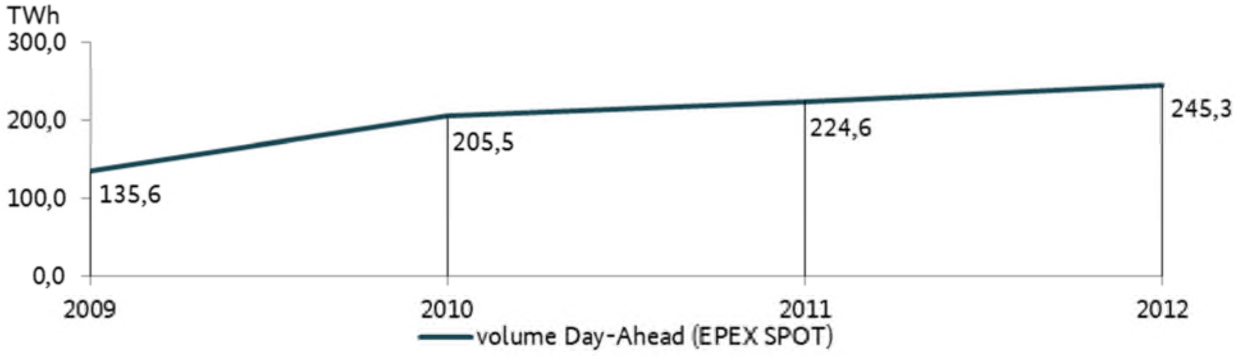
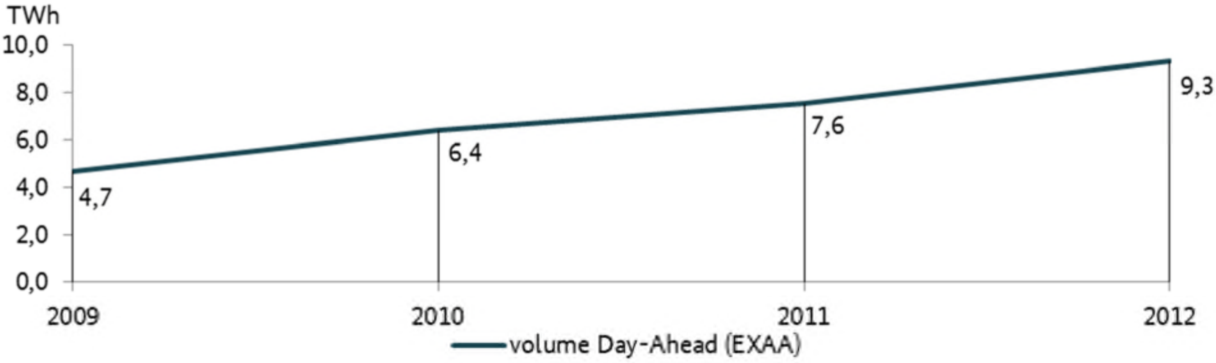


Figure 46: Day-ahead trading volumes at the EXAA from 2009 to 2012[41]



Purchases for the German control areas account for 61.4 percent of the aggregated purchase volume of the EXAA; deliveries from the German control areas account for 59.9 percent of the aggregated sales volume.

A significant share of the electricity traded at the EPEX SPOT was again traded on the basis of price-independent bids, both on the seller and the buyer side. The gap between the proportion of price-independent bids in the overall purchase volume (decrease to 70 percent compared to 73 percent in 2011) and their proportion in the overall sales volume (increase to 83 percent compared to 82 percent in 2011) has increased from close to 9 percent in the previous year to a good 13 percent (higher proportion in the sales segment).

Price-independent bids can be placed in the single hour auctions. Other than in the case of price-dependent bids, participants here do not decide on a fixed price/quantity combination. Price independence on the demand side signifies that buyers aim to satisfy their demand irrespective of a price limit. Price independence on the sales side signifies that the quantities are to be sold irrespective of the price. More than 25 percent of all

[41] The graph depicts the situation at the end of the years indicated. The curve progression between two reference dates does not reflect developments within the course of that respective year.

price-independent bids are bids for the settlement of EEX financial futures products (Phelix Futures). On the sales side, the marketing of electricity regulated under the EEG (Renewable Energy Sources Act) via TSOs is even more important: also in 2012, almost all (99.6 percent) of these sales were price-independent. This is shown in more detail in the table below:

Table 20: Purchase volume on the day-ahead market of the EPEX SPOT in 2012[42]

Executed purchase bids on the day-ahead market of the EPEX SPOT in 2012	Volume in TWh	Percentage of total
Price-independent bids	171.60	70.0
Of which via TSOs	0.05	0.0
Of which physically settled Phelix Futures	48.48	28.3
Other	123.07	71.7
Price-dependent bids	41.47	16.9
Blocks	8.09	3.3
Imports (MCC)	24.10	9.8
Total	245.27	100.0

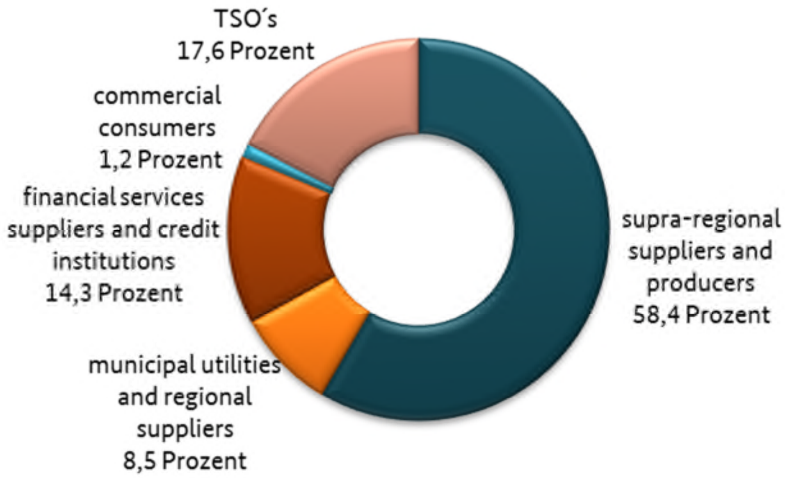
Table 21: Sales volume on the day-ahead market of the EPEX SPOT in 2012

Executed sales bids on the day-ahead market of the EPEX SPOT in 2012	Volume in TWh	Percentage of total
Price-independent bids	204.53	83.4
Of which via TSOs	69.28	33.9
Of which physically settled Phelix Futures	52.52	25.7
Other	82.73	40.4
Price-dependent bids	29.78	12.1
Blocks	10.07	4.1
Exports (MCC)	0.88	0.4
Total	245.27	100

The (aggregated) total purchase and sales volumes at the EPEX SPOT in the reporting year 2012 are broken down among the different categories of participants as follows[43]:

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

Figure 47: Shares of total sales and purchase volumes at the EPEX in 2012 according to participant category



Supra-regional suppliers and producers account for a larger share than all other categories taken together. The (non-brokered) activities of municipal utilities and regional suppliers amounted to less than 10 percent, which is less than the share of the financial service providers and credit institutions. The relevance of TSOs is owed almost exclusively to their share in the overall sales volume. A small proportion is accounted for by companies that use the exchange to satisfy their in-house energy requirements.

Price level[44]

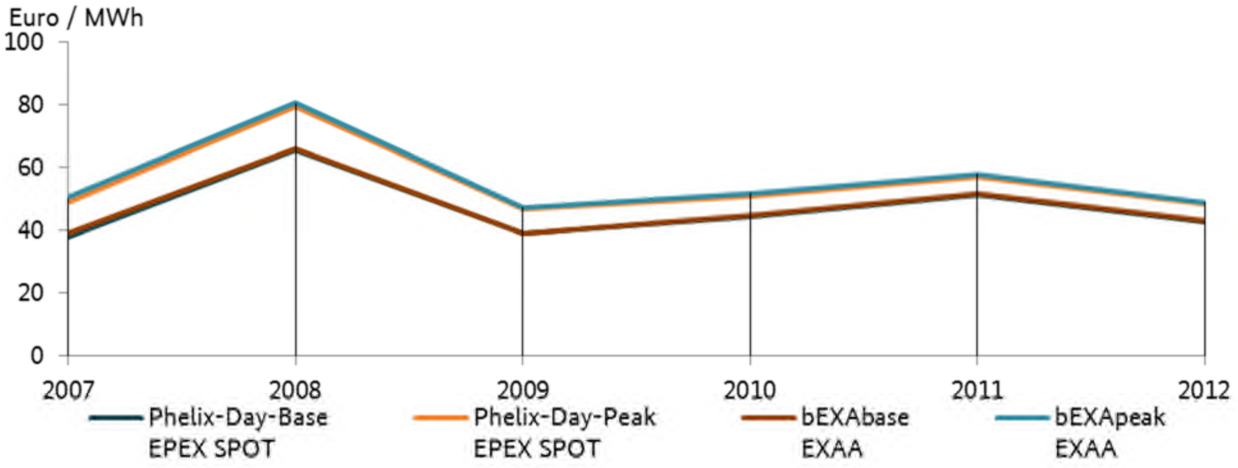
The average prices of day-ahead products on the spot market exchanges EPEX SPOT and EXAA remain very similar to each other with slightly higher EXAA values[45]: In 2012, the arithmetic average of the Phelix Day Base (EPEX SPOT) amounted to 42.60 ct/MWh compared to 43.22 ct/MWh for bEXAbase (EXAA). On average, the Phelix Day Peak price (EPEX SPOT) was 48.51 ct/MWh, the bEXApeak price (EXAA) 48.88 ct/MWh.

[43] The values indicated already include the shares in the intraday market of the EPEX SPOT. They give no indication of how one category's proportion of the purchase volume relates to its proportion of the sales volume.

[44] The following values are monitored: The Phelix Day Base price published by the EEX / EPEX SPOT is the average price of the hours 1 to 24 in the market area Germany/Austria; the Phelix Day Peak index covers a section of these, i.e. hours 9 to 20. The EXAA publishes bEXAbase and bEXApeak which refer to the relevant single hours (in the same market area).

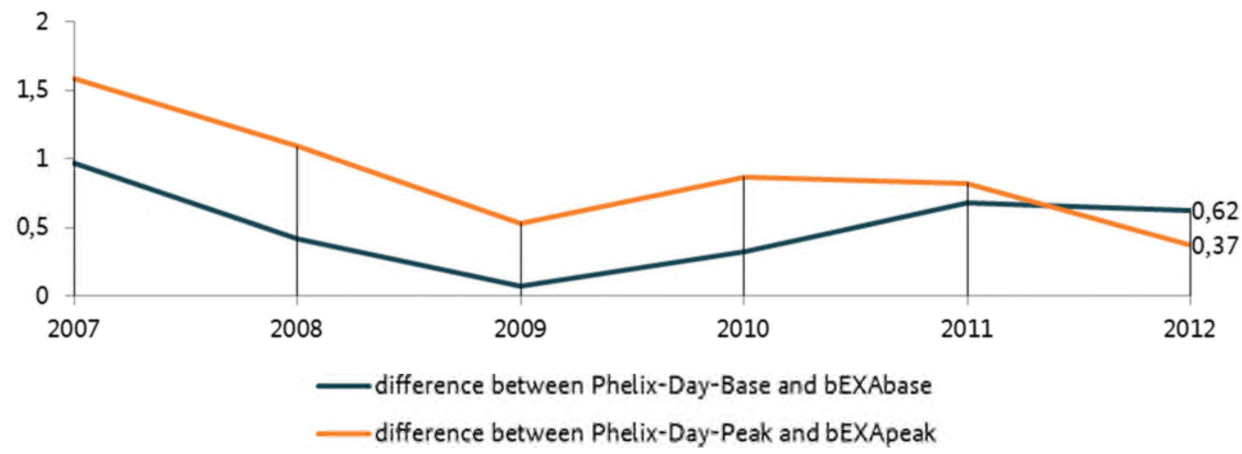
[45] The EXAA's auction takes place about two hours before the start of the auction on the EPEX SPOT.

Figure 48: Day-ahead auctions - development of arithmetic averages at the EPEX SPOT and EXAA 2007 - 2012[46]



The differences between the EPEX SPOT and EXAA values in the base and peak sectors have remained unchanged over several years. While in 2011 the difference between the base products increased and remained at a similar level in 2012, the difference between peak products had already slightly decreased in 2011; in 2012, the peak values only differed by 0.37 ct/MWh on average, which shows a remarkable further decrease in difference.

Figure 49: Day-ahead auctions - differences between the arithmetic averages at the EPEX SPOT and EXAA 2007 - 2012[46]

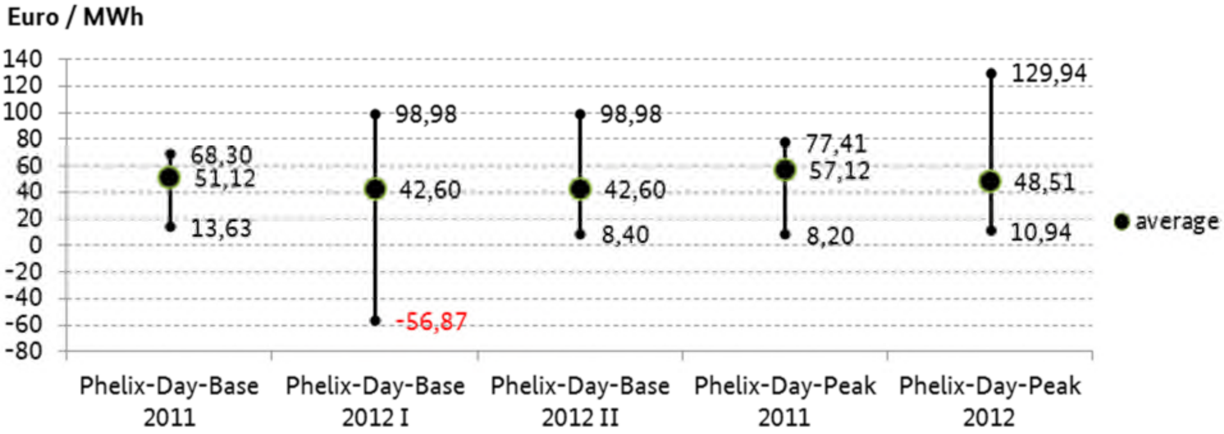


[46] The curve between the two data points merely serves to make them visible and show their relationship to one another.

In contrast to previous years, the annual average prices did not increase during the reporting period, but fell by 15 to 17 percent in comparison with 2011.

An examination of the price spread at the EPEX SPOT (span between minimum value and maximum value) reveals a considerable increase over the previous year:

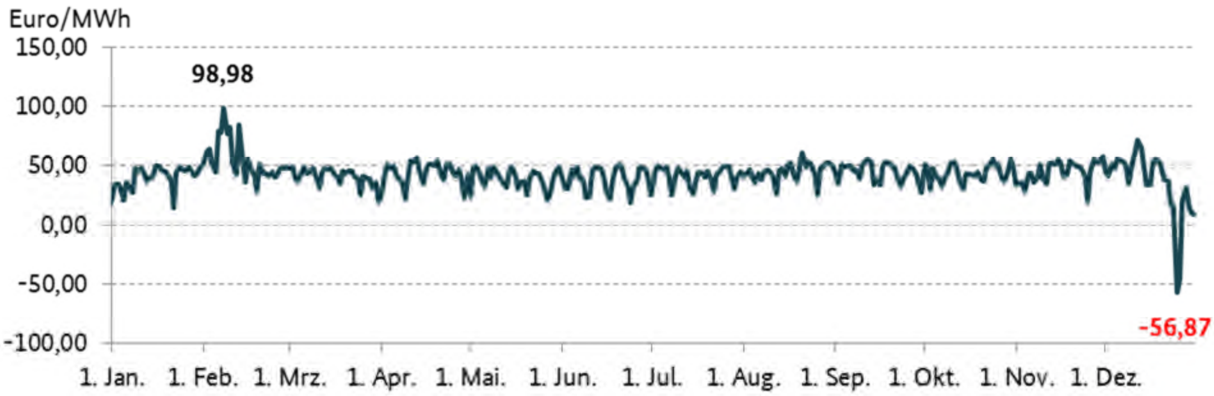
Figure 50: EPEX SPOT: Price spreads between 2011 and 2012



A remarkable change is the considerable increase in maximum values (base, peak). In December 2012 the Phelix Day Base reached negative values on two occasions (Phelix Day Base 2012 I). If these are left out (not discounted), there is still a slight decrease in the minimum value (Phelix Day Base 2012 II). The Phelix Day Peak shows a slight increase in the minimum value.

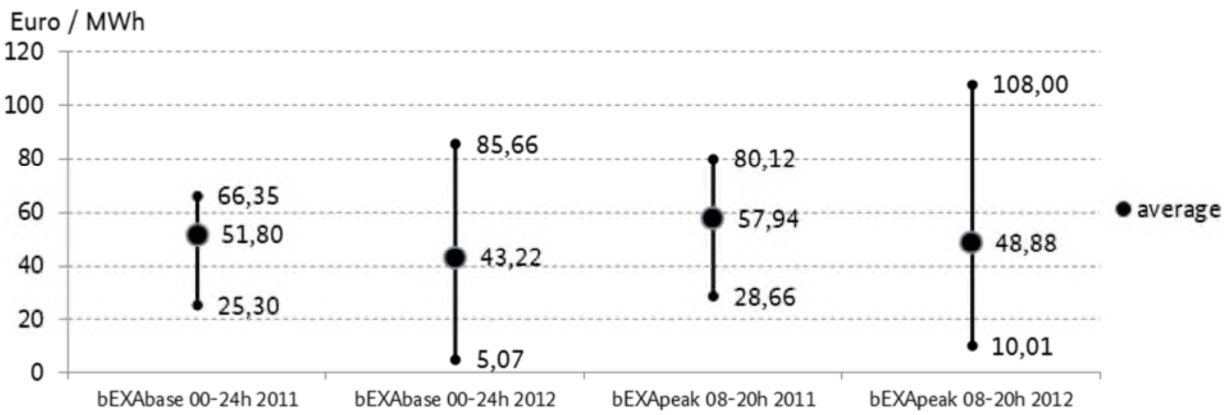
In total, prices in the spot market segment under review are on average lower, but move within a significantly wider range with considerably higher maximum values. Annual overview of the Phelix Day Base development:

Figure 51: Development of Phelix Day Base in 2012; Source: EEX; own diagram



At the EXAA (bEAXbase, bEXApeak), the price spreads also significantly increased with a falling arithmetic average. The maximum values rose considerably (Base: 29 percent; Peak: 35 percent), and the minimum values decreased to a relevant extent (Base: 80 percent; Peak: 65 percent).

Figure 52: EXAA: Price spreads between 2011 and 2012



The intraday market at the EPEX SPOT

In continuous intraday exchange trading for deliveries on the same or next day, volumes can be traded up to 45 minutes before the start of delivery, which closes the gap between day-ahead trading and electricity generation / the start of delivery. Since the introduction of intraday trading in 2006 the annual trading volumes have risen continuously[47]. In the 2012 reporting period a stagnation can be observed for the first time with a volume of some 15.5 TWh compared with 15.6 TWh in 2011.

2.3 EEX futures market

In Germany / Austria Phelix Futures can be traded with different standardized delivery periods. In 2012 Day Futures and Weekend Futures were launched to supplement the existing futures product range. Furthermore, options are available for specific Phelix Futures. However, in 2012 these products, which are defined by their exercise periods, did not play any significant role outside the OTC clearing system.

Overview of participants and volumes

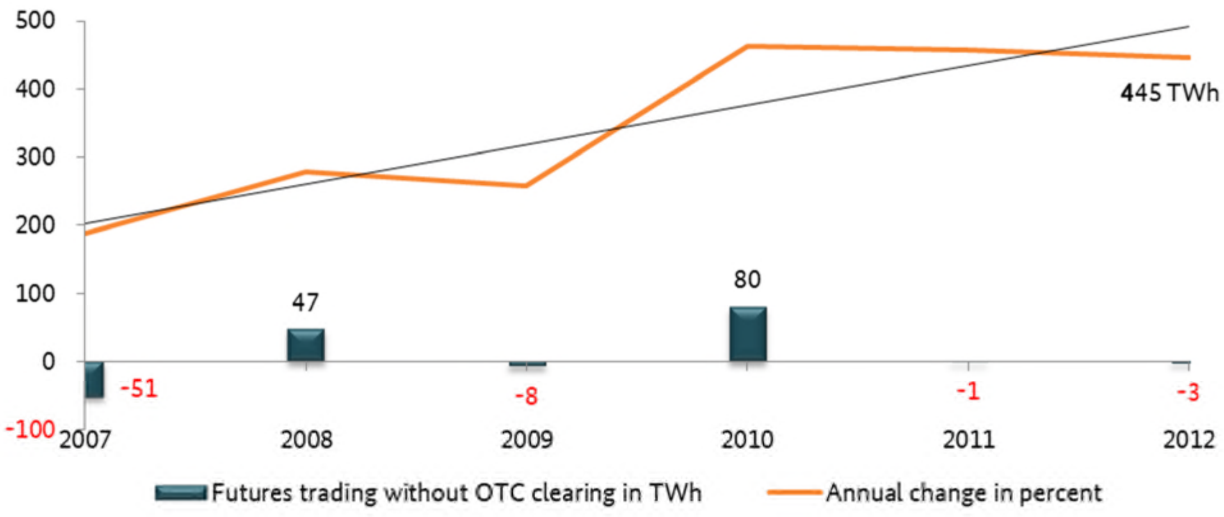
In 2012, the average number of active participants in the futures market per trading day was 48.0 (43.4 in the previous year)[48]. As the precondition for counting a participant on a certain day is the execution of at least one bid, the increase in this area does not indicate whether participants submitted more bids. At any rate, the relevant number of bids could be matched. This may be due to an increase in bids, but could also be due to better interrelation between bids or bids being submitted with fewer restrictions.

This does not provide any indication of the actual trading volumes either. There was a slight decrease in trading volumes for the second consecutive year:

[47] As of 2010, quantities resulting from OTC clearing are not included; on OTC clearing cf. "OTC clearing at the exchange".

[48] OTC clearing (excluding options) included.

Figure 53: Trading volumes on the EEX futures market from 2007 to 2012[49]

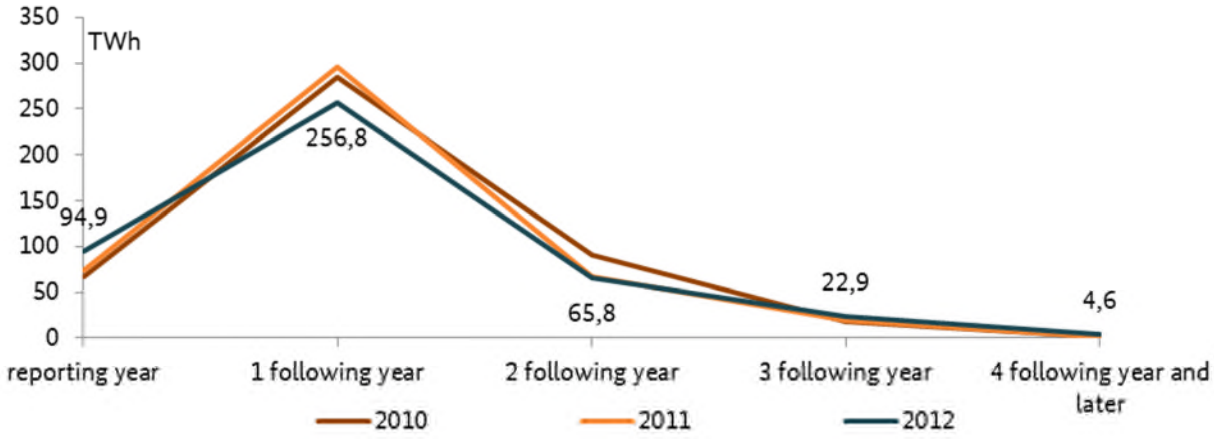


An analysis of the futures transactions concluded solely on the exchange in 2012 and of the dates of delivery indicated in the contracts shows a slight but remarkable shift over the previous years 2010 and 2011[50].

[49] The curve between the two data points merely serves to make them visible and show their relationship to one another.

[50] A comparison with further previous years is not possible because of changes in the data survey.

Figure 54: Futures trading on the EEX according to year of settlement – Comparison 2010 to 2012[51]



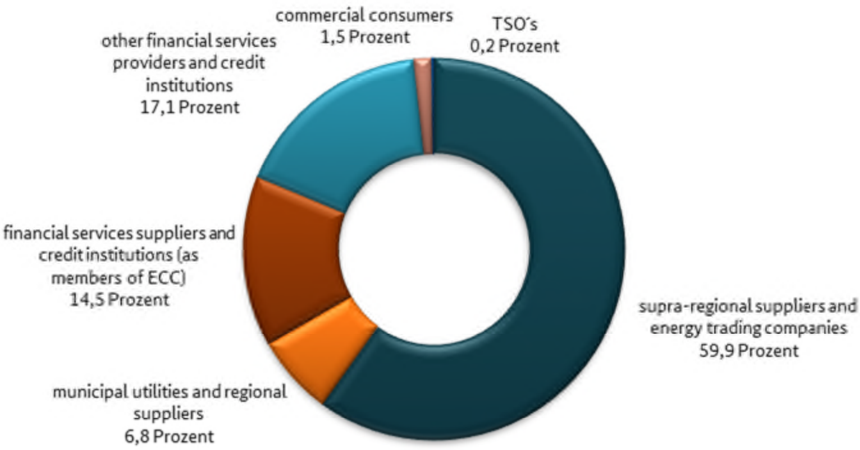
Trading continues to focus particularly on contracts which have the following year as the year of settlement (i.e. 2013 for the year under review). However, the resulting peak decreased by approx. 13 percent compared to the previous year 2011. On the other hand, the volume that was to be supplied during the year under review increased by just under 28 percent. The general emphasis on short settlement periods that do not extend beyond the following year has thus tended to become stronger.

In 2012 the (aggregated) total purchase and sales volumes at the EEX were accounted for by the different categories of participants as follows[52]:

[51] The 2012 values are indicated in the figure. The following applies to all graph lines: The curve between the two data points merely serves to make them visible and show their relationship to one another.

[52] This gives no indication of how one category's proportion of the purchase volume relates to its proportion of the sales volume.

Figure 55: Shares of total sales and purchase volumes at the EEX in 2012 according to participant category



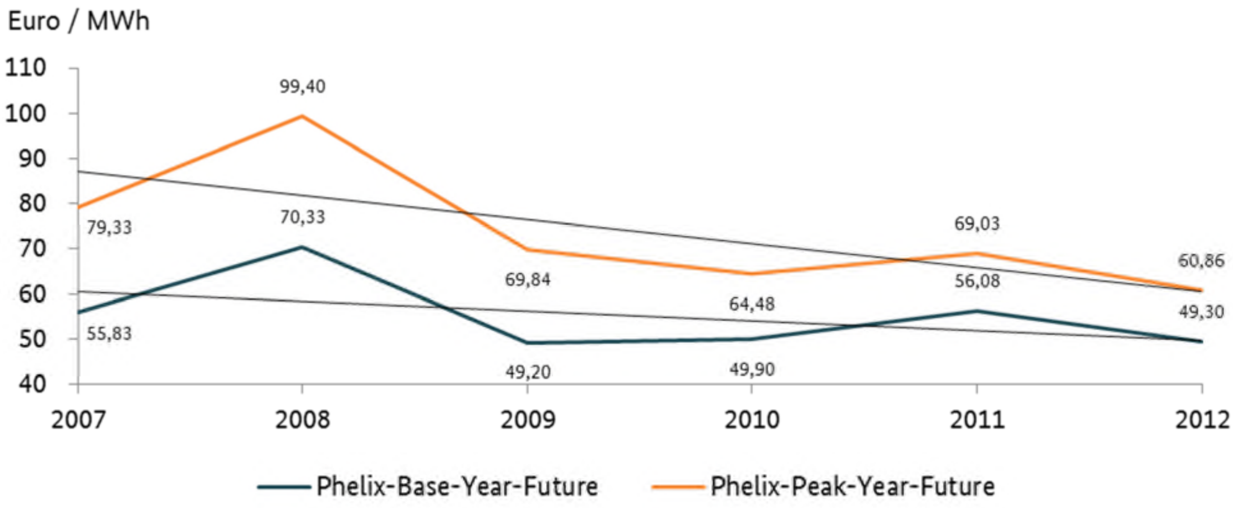
Also in the futures market, the supra-regional suppliers and energy trading companies had a larger share than all other groups added together. Municipal utilities and regional suppliers accounted for a share of almost 7 percent and thus held a lower share than in the spot market. With a share of 31.6 percent the activities of all financial service providers and credit institutions accounted for almost one third of the total volume. In the futures market the TSOs only play a very minor role. Their share was even smaller than the share accounted for by final customers that were active at the exchange.

Price levels

Last year's monitoring report showed that the arithmetic averages for Phelix futures (base/peak[53]; based on all ascertainable prices for the front year) had generally fallen over the past 5 years, although in the 2011 reporting period there was a certain increase. This trend has continued.

[53] The difference lies in the load profile: A base load future traded on the EEX is based on a constant and continuous supply rate (all hours, all days), a peak load future, on the other hand, is based on a constant but time-limited rate of supply (from 08:00 to 20:00 hours, only Mondays to Fridays).

Figure 56: Phelix front year products - development of arithmetic averages on the EEX from 2007 to 2012[54]

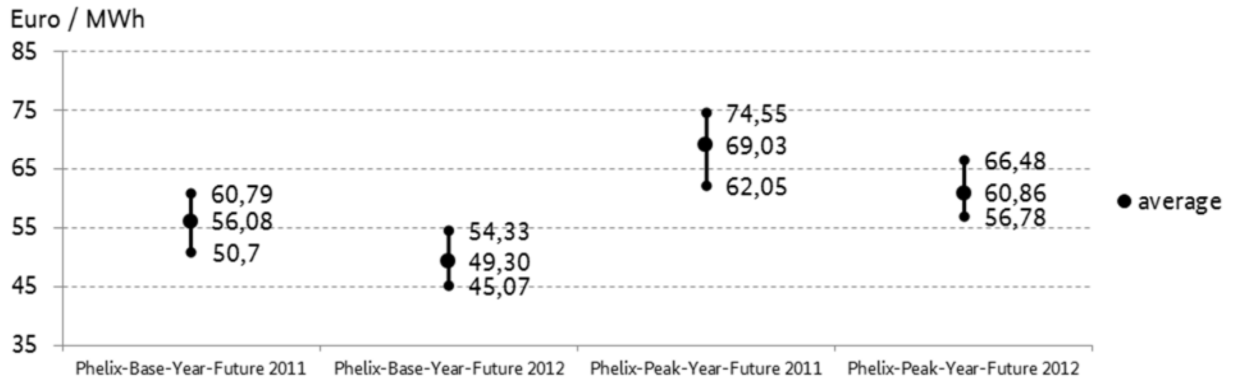


In addition, the increases in 2011 are balanced out (in the base area: 49.30 Euro/MWh in 2012 compared with 49.90 Euro/MWh in 2010) or overcompensated (in the peak area: 60.86 Euro/MWh in 2012 compared with 64.48 Euro/MWh in 2010). This represents a change of around 12 percent (base, peak) in 2012 compared with 2011.

In the reporting year 2012 the prices of the base and peak product have converged to the point where on average their price difference is 11.56 Euros/MWh.

[54] Representation of Phelix averages: The curve between the two data points only serves to make them visible and show their relationship to one another.

Figure 57: Phelix front year products - price spreads between 2011 and 2012



Compared to the previous year, the price spread (span between minimum value and maximum value) for the Phelix Peak Year Future decreased further (from 12.50 Euros to 9.70 Euros). In the base area the price spread increased lightly in 2011 compared with 2010; this increase was more than compensated for by a decrease in price spread in 2012 (from 10.09 Euros to 9.26 Euros). The price spread in the case of the front year future (base or peak) is therefore under 10 Euros.

Annual overview of the development of the front year future (base):

Figure 58: Phelix Base Year Future (Front year) in 2012; Source: EEX; own representation

2.4 OTC clearing at the exchange

Apart from exchange trading there is also "over the counter trading" which does not have to take place on the exchange (OTC trading, bilateral trading, see below). OTC clearing is an interface between on-exchange transactions and off-exchange OTC trading. It allows parties of an (off-exchange) OTC contract to subsequently subject it to the rules of the exchange and thus to combine the benefits of both forms of trade.

A special feature of OTC trading is that the trading partners are known to one another; if an intermediary (e.g. a broker) is involved, the identity of the partners becomes known, at the latest on conclusion of the transaction. In line with the principle of freedom of contract, the parties have full flexibility in the formulation of their agreement. Trading on the exchange, on the other hand, is anonymous; here a standardisation of the products is necessary in order to bring together supply and demand. As the exchange itself becomes the contractual partner of the trading parties, there is no counterparty risk. In bilateral trading, apart from exercising prudence in selecting the contractual partner, this risk can be reduced but not completely eliminated by protective agreements. By using the clearing facility for OTC transactions, a special service provided by the exchange, this counterparty risk can be shifted to the exchange. The specific conditions are set by the exchange. EEX Power Derivatives GmbH enables clearing for all registered futures products. At the EPEX SPOT this is also possible for intraday trading. European Commodity Clearing AG (ECC), Leipzig, is responsible for the actual clearing service.

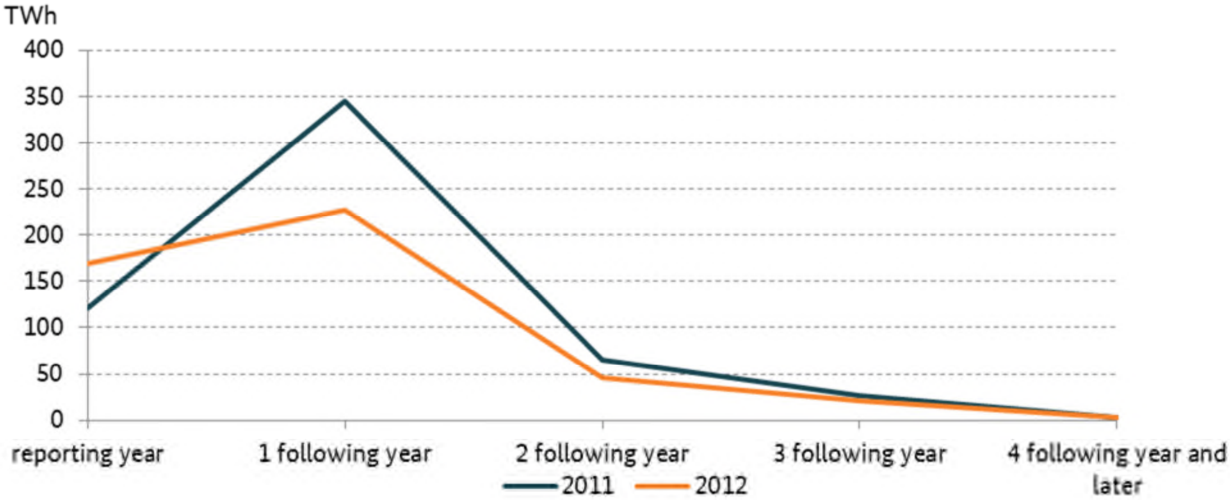
The contract is initially concluded off-exchange as a bilateral trading transaction, in some cases with the assistance of a broker. With the conclusion of a clearing transaction the contractual partners ensure that their contract will be treated in the same way as an exchange transaction.

If the areas of exchange trading and OTC clearing are taken as a whole from 2007 to 2012, the total volume of trade is found to be highly stable. Whereas the volume of OTC clearing decreases after an initial growth phase, the volume of direct exchange trading increases after an initial decline.

Registered participants on the exchange generally also make use of the OTC clearing of spot transactions (only for intraday) or futures contracts; 14 (of 127) of the producers and trading companies registered on the EPEX SPOT and five (of 40) of the municipal utilities and regional providers registered on the EPEX SPOT did not make use of the OTC clearing for intraday contracts.

Whereas the share of direct exchange futures contracts remained relatively stable in 2012 (decline of around 12 TWh, i.e. 2.6 per cent), the OTC futures transactions registered for clearing in the reporting year covered supply volumes of around 95 TWh less than in 2011. This corresponds to a decline of almost 17 per cent.

Figure 59: OTC clearing of futures transactions[55] in 2011 and 2012[56]



A similar development to that in direct on-exchange transactions can be observed: Whereas there is an increase in trading activities for the current year (by around 48 TWh or 39 per cent), there is a decline in the volume of trade for later years (between 22 and 34 per cent), whereby the segment "trade for the following year" clearly loses in significance by 118 TWh (34 per cent). Unlike in direct exchange trading, in the off-exchange realm, options are not only traded but also cleared OTC. It is noticeable that in spite of a considerable decline in total volume, the sub-section concerning options has increased from 31.5 TWh in 2011 to 38.1 TWh.

The decline in volume in the OTC clearing of futures transactions (place of delivery of electricity: Germany) can also be observed elsewhere. Major broker platforms are organised within the London Energy Brokers´ Association (LEBA) for trade with "German Power". According to the data published by the association[57] OTC clearing for "German Power“ declined from 730 TWh to 377 TWh (a good 48 percent)[58]. Where evaluable individual data is available from the broker platforms providing these total values, the trend for the reporting

[55] Futures (forwards) and options.

[56] The curve between the two data points merely serves to make them visible and show their relationship to one another.

[57] http://www.leba.org.uk/assets/LEBA%20December%202012%20volume%20report1.pdf

[58] The volume indicated here is not in its entirety a partial amount of the volume from OTC contracts which were cleared on the ECC. OTC clearing of transactions by the members of the LEBA association also takes place to a smaller, unquantifiable extent on other exchanges. Conversely, part of the above-quoted OTC clearing volumes in futures transactions are not attributable to these specific broker platforms as other broker platforms are also active. Finally, a portion of the volume is registered for clearing by the partners of the OTC transaction themselves.

period 2012 is also noticeable here i.e. there is a decline in trading volume for the following year, which nevertheless remains a main area of trade, in favour of the reporting year itself, i.e. more short-term contracts.

Finally, in "OTC clearing" it should be noted that the clearing volume for intraday contracts has fallen from 0.295 TWh to 0.189 TWh.

3. Bilateral Wholesale

A complete picture of bilateral wholesale electricity trading[59] (place of delivery: Germany) cannot be derived on the basis of the data collected. This is essentially because not all the relevant companies, especially if they are registered abroad, can be included in the survey. In addition, the many possibilities which market participants can choose from to design their products and methods of transaction processing can lead to classification problems in the survey.

For off-exchange transactions there are neither clearly defined market places nor a fixed catalogue of types of contract. There are standardised types but there is no strict requirement to adhere to set forms which define the contract in detail as is the case on the exchanges.

Despite this freedom of contract design, a basic classification is also made in bilateral trading into longer-term futures transactions and short-term spot market transactions. In order to obtain an idea of the extent of the volume of off-exchange trade, the survey addressed to wholesalers differentiates transactions in terms of time periods. Contracts with a time-frame of at least one week are defined as futures transactions and those with a settlement period of less than one week are defined as spot transactions. The wholesalers are also asked whether they use broker platforms[60].

Participants

The statements are based on information provided by 590 companies which stated that they were active in wholesale trading in the reporting year 2012.

522 of these are also active as suppliers (sale of electricity to final consumers), 411 were basic suppliers (in one or several network areas). If the activities of the 522 companies are differentiated according to futures and spot market trading, the result is as follows:

Nearly all these companies, i.e. 512, concluded futures transactions (334 of them did not conclude any spot transactions). Around half of them (258) were active in futures trading exclusively as buyers, 221 of them were basic suppliers. Five companies indicated that they only concluded forward sales. A good 40 companies (less than 10 per cent) indicated that they used a broker platform.

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[59] In the survey market participants are questioned about "all electricity trading transactions with physical or financial settlement concluded in one's own name and on one's own account as well as about all electricity supply contracts with physical settlement (delivery of electricity) between companies" (with the exception of system services and deliveries to final consumers).

[60] There is at least some comparative data on this aspect. The data about trade on broker platforms are an indication (but nothing more) of the extent of overall off-exchange wholesale trading.

Among the companies surveyed, the number which were active in off-exchange spot market trading was considerably lower, i.e. 186. Of these, only eight were not simultaneously active in futures trading. Most of the wholesalers which are also active as suppliers of electricity to final consumers (180) were buyers, but at the same time also active as sellers (172). More than half of them (135) simultaneously supplied at least one basic supply area. 35 of 186 companies (almost 20 per cent) reported that they used a broker platform.

Nearly all the companies active only as wholesalers (67 of 68) concluded futures transactions. Of these, 58 were active both as buyers and sellers. Around half of the companies exclusively active as wholesalers also used broker platforms.

In spot trading participation by the companies exclusively active as wholesalers was a little lower (52 of 68). Practically all of these companies were active as buyers and sellers. The proportion of users of broker platforms in the spot market (around 60 per cent) was slightly higher than in the futures market.

Where broker platforms were generally used in off-exchange wholesale trading, the position of those organised in LEBA[61] can be assumed to be strong. However, the wholesalers have also named a larger number of other intermediaries which assist them in spot and futures trading. The importance of these other service providers cannot be clearly estimated on the basis of the surveyed data but could in total be of relevance.

Volumes traded off-exchange

As in last year's report, the following table shows the volumes according to segment and total amounts as based on the findings of the survey, with the express indication that the actual extent of trading in the reporting year 2012 exceeded the values shown[62]. From findings gained from the survey, two different types of shortages can be expected. Apart from the fact already mentioned that a number of wholesalers registered abroad were not reached, a larger number of suppliers which are (almost) exclusively active in wholesale to procure their required supply volume, did not provide any information other than that on sales quantities[63]. A larger amount of electricity can therefore be assumed to have been traded, the extent of which however cannot yet be quantified by the survey.

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[61] London Energy Brokers' Association, see: www.leba.org.uk.

[62] Please refer to the comments at the beginning of the chapter.

[63] In the case of the group of (missing) suppliers, this could be estimated from the volume of retail sales, whereby any auto-production would have to be deducted. The survey, however, focuses on the differentiation between transactions according to settlement periods. A mere projection of the volumes for procurement would not be sufficient to illustrate this.

Table 22: Volumes recorded in the bilateral futures market 2012 (Settlement period of one week or more)[64]

Contracts in the reporting year 2012	Volumes in TWh
Contracts without broker platforms[65] without OTC clearing of which for	1,546.0
Settlement year 2012	372.8
Settlement year 2013	580.8
Settlement year 2014	318.8
Settlement year 2015	208.5
Settlement year 2016 and later	64.9
Contracts via broker platforms[66] without OTC clearing	4,829.0
only contracts with OTC clearing[67] (all)	411.0
Total	6,786.0

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

[65] In the individual segments there have been differing total amounts on sales and purchases based on the data provided by the wholesalers. This can be explained by the fact that the survey of companies is not fully comprehensive . For every purchase there has to be a sale which can be attributed to the same category and form of initiation (without or with a broker platform); the respective quantities of bilateral purchase and sale have to correspond with one another. If there is a deviation between the total purchase and sales volumes, the deficit between the smaller value and the overall value can be added to the overall transaction. The larger value is always taken as a reference.

[66] The initial value is based on the data of six broker platforms. 2 percent was deducted for possible trading by commercial consumers because such transactions are not the subject of the survey. On the basis of the findings of the survey, it can be assumed that trading takes place on a number of other broker platforms. This underlines the importance of this form of contract initiation.

[67] The initial value in this case is based on the data provided by the EEX on OTC clearing, whereby OTC clearing was used for 466.0 TWh in OTC trading (Phelix Futures and Options). Firstly, a tenth was deducted for the trade in the Austrian control area (the estimation is in line with the population figures); 2 further percent were deducted for possible trading by commercial consumers; according to information gained from the survey, the share of commercial consumers in the trading of futures (without OTC clearing) accounts for less than 2 per cent.

Table 23: Volumes recorded in bilateral short-term trading 2012 (settlement period of less than a week)[68]

Contracts in the reporting year 2102	Volumes in TWh
Contracts without broker platforms without OTC clearing of which	241.0
Intraday[69] and day-after	15.4
Day ahead	101.4
other contracts settlement period < one week	124.3
Contracts via broker platforms without OTC clearing[70]	102.2
only contracts with OTC clearing[71] (all)	0.2
Total	343.4

Overview of participants and volumes

The data collected on minimum turnovers above suggests that the off-exchange electricity market is liquid. A good example for this is the futures trading for 2013, i.e. for the year following the survey year of 2012. The information provided by a relevant share of the active broker platforms, which has been verified by external sources, substantiates a trade volume of approx. 2,840 TWh for this segment. With the ascertained approx. 580 TWh which (as a minimum quantity) have been traded without broker platforms, this sum amounts to 3,420 TWh, which is around seven times the approx. 500 TWh which are currently required annually as an electricity volume for Germany. This does not take into account that a portion of the requirement to be procured by the suppliers originates from the auto-production of the respective supplier.

Total trading activities are distributed over a large number of participants. However, shares in the provision of liquidity are not equally distributed. Looking at the example "futures trading in 2012 for the settlement year

68 Figures may not sum exactly owing to rounding.

69 The survey showed that in some cases the companies recorded their contracts with different time periods (i.e. quantities were registered as intraday contracts although according to the definition of the survey a day-ahead transaction would have been the appropriate answer). However, possible differences in categorisation do not alter the reliably established total volume from contracts with short-term settlement.

70 The initial value is the data of six broker platforms. 2 per cent were deducted for possible trading by commercial consumers because such transactions are not the subject of examination of the survey.

71 The initial value is based on data derived from the EEX on OTC clearing. Here again 2 per cent was deducted for possible trading by commercial consumers; according to the information gained from the survey, the share of commercial consumer participation in spot transactions (without OTC clearing) is less than 2 per cent.

2013“, based on the data provided by the wholesalers themselves on the (minimum) 580 TWh[72] traded without broker platforms, the following picture emerges:

For 478 buyers there are 248 sellers, whereby all sellers are also active as buyers:

On the buyers' side less than 20 participants account for 70 per cent of the turnover. A larger portion of this group of participants also fulfils a market role as supplier (some of them as basic suppliers).

On the sellers' side a comparable number of participants account for 85 per cent of the turnover. The number of companies which are also active as suppliers is smaller.

Although in other segments of the futures market the picture is not identical (other settlement periods; inclusion of broker platforms or OTC clearing), the group of buyers surveyed still accounts for 50 per cent of the total purchase volume (values without projection). In the case of the group of sellers surveyed, these still account for 70 per cent of the total sales volume (compared to 85 per cent for the section indicated above) (values without extrapolation). The off-exchange trade can therefore be generally assumed to be highly concentrated.

4. Additional aspects of exchange trading

Market makers on the EEX futures market

The term market maker is used to describe a participant on the exchange who has undertaken to simultaneously publish binding purchase and sale prices (quotations). The function of the market maker raises the liquidity of the market[73].

In the period under review the companies RWE Supply & Trading GmbH, Vattenfall Energy Trading GmbH and E.ON Energy Trading SE were active as market makers on the EEX Phelix Futures market. All three companies were already active in this function in the previous years. In November 2012 EDF Trading Limited entered the market as a further market maker.

The aggregate share of the market makers of the Phelix Futures purchase volume fell from 27 per cent (2011) to 20.2 percent (2012), their share of the sales volume fell from 31.5 per cent (2011) to 28.4 per cent (2012).

The market making activities mentioned do not give any indication of the extent of further exchange trading activities of the companies (i.e. other than in their role as market makers or under the rules applicable to market makers).

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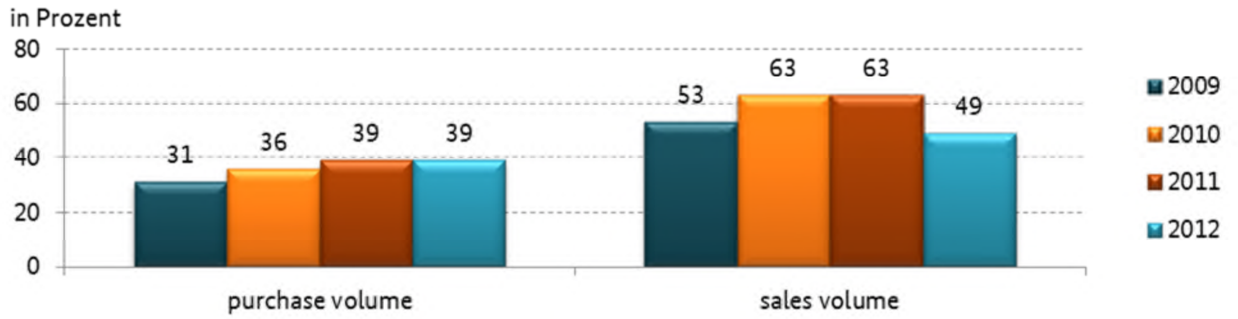
[72] The amount of 580 TWh is based on sales data. On the purchase side, the total quantity of electricity bought, based on the data obtained, was approx. 560 TWh. In consideration of the fact that each purchase must correspond to a sale, the purchase volume has been projected to 580 TWh. The following detailed analyses of the purchase side are, however, based on the original volume of 560 TWh.

[73] The specific (varying) conditions are regulated between the exchange and market makers in market maker agreements (quotation times, quotation duration, minimum number of contracts, maximal spread etc.)

Share of high turnover companies at the exchanges

Focusing on the companies with the highest turnover[74] on an exchange gives an indication of the extent to which trading is concentrated. The following figure differentiates between purchase and sales volumes. In order to illustrate a development over time, the companies' share of the trading (in percent) over the last four years under review is shown:

Figure 60: Share of the five companies with the highest turnover of day-ahead volumes on the EPEX SPOT



If the purchase and sales volumes are jointly considered, the share of the five companies with the highest turnover in 2012 is 35 per cent (compared with 42 per cent in the previous year). Based on the absolute overall turnover (purchase plus sale) this means that in 2012 the five companies with the highest turnover accounted for 171.7 TWh of the turnover and all other companies accounted for 318.8 TWh; in 2011 on the other hand, the five companies with the highest turnover accounted for 188.7 TWh and all other companies accounted for 260.5 TWh. The difference in absolute turnover between the five companies with the highest turnover and all others more than doubled from 71.9 TWh to 147.2 TWh. The day-ahead turnover at the exchange increased by around 40 TWh. It may seem reasonable to suppose that the five companies with the highest turnover in 2011 had no share of this. However, this cannot be confirmed because there is no indication as to whether the five companies in 2011 were identical with those in 2012. However, the following is certain: The reduction in overall concentration can be explained by a reduction in concentration in sales. The relevant position of the TSOs in terms of overall turnover[75] can be explained by their share of the sales volume[76] which can be derived from the role they play in marketing electricity from renewable energies. Here a shift has occurred: In the marketing of electricity from energy plants eligible for remuneration under the Renewable Energy Sources Act (EEG), direct marketing by the producers has increased not only in absolute terms but also in proportion to the use of

[74] No statement is given as to whether or not the composition of the group of high-turnover companies has varied or remained constant over the years or in the areas of trade under review.

[75] see Figure 47 on page 98: Shares of total sales and purchase volumes at the EPEX in 2012 according to participant category

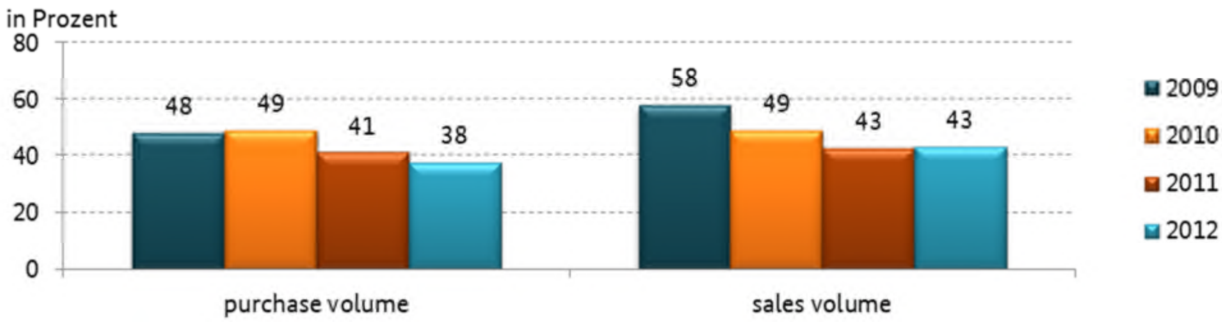
[76] See Table 20: Purchase volume on the day-ahead market of the EPEX SPOT in 2012 and Table 21: Sales volume on the day-ahead market of the EPEX SPOT in 2012.

EEG feed-in tariffs[77]. The increased self-marketing of electricity from energy plants eligible for feed-in tariffs thus lessons the concentration on the spot markets.

Concentration at the EXAA as another exchange for day-ahead auctions has also diminished again. Whilst in the previous years the shares of the three companies with the highest turnover of the purchase volume fell from 38 per cent (2010) to 32 per cent (2011) and their respective share of the sales volume fell from 29 per cent to 24 per cent, their share of the total volume in 2012 was only 22 per cent. If the scope is extended to the group of five companies with the highest turnover, the share of the total volume in 2012 is 33 per cent.

An evaluation of the spot market produced the following results:

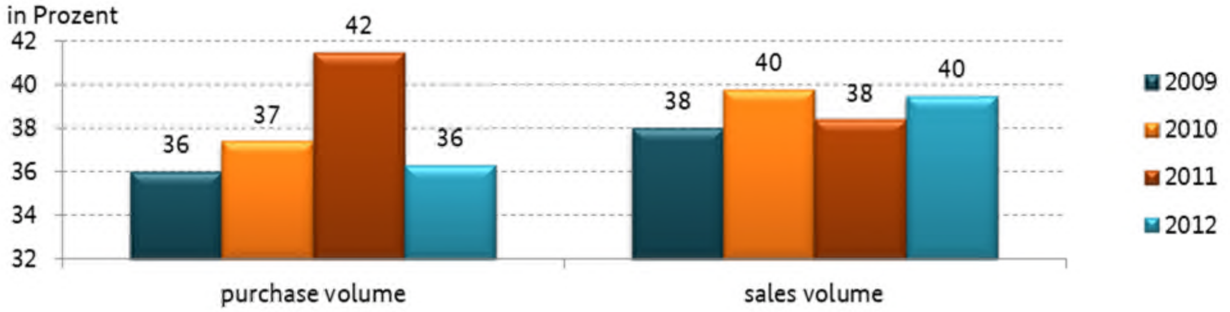
Figure 61: Individual share of the five companies with the highest turnover in the futures market of the EEX (without OTC clearing)



Concentration on the buyer side is weakening; this generally also applies to the seller side even if concentration in 2012 rose slightly compared to the previous year.

[77] See **Fehler! Verweisquelle konnte nicht gefunden werden. Fehler! Verweisquelle konnte nicht gefunden werden.** on page **Fehler! Textmarke nicht definiert.** and **Fehler! Verweisquelle konnte nicht gefunden werden. Fehler! Verweisquelle konnte nicht gefunden werden.** on page **Fehler! Textmarke nicht definiert.**.

Figure 62: Individual shares of the five companies[78] with the highest turnover of the futures market of the EEX (incl. OTC clearing).



As regards sales volumes, concentration has remained at approximately the same level over the years (fluctuations of less than 2 per cent). The same applies to the buyer side with the exception of 2011; in 2011 the concentration was 6 (5) per cent higher than in 2012 (2010).

Developments in the competitive exchange-based electricity market due to renewable energies

There is a relevant demand among final customers for electricity which comes from verified renewable energies[79]. Although no differentiation can be made on the origin of the electricity, the final customer influences behaviour on the production side with his demand decision. Certificates of origin therefore play an important role in the marketing of green electricity products to final customers. With such a certificate the supplier can verify from which sources the electricity which he procures and feeds into the network originates.

In the summer of 2013 the EEX started trade with specific certificates of origin. It reacted to the needs of companies at all levels of trade since proof of origin from renewable sources is a price-relevant feature.

The physical procurement of quantities of electricity from renewable energies which are approved for marketing to the final consumer as green electricity, is usually done off exchange. In December 2012 the EXAA introduced a green electricity product for trading in its day-ahead auction. This electricity is generally generated in power plants for renewable energies specially authorised for this type of trading at the exchange (green electricity in contrast to grey electricity). Buyers acquire a guarantee of origin when they purchase the electricity. The delivery of electricity (feed-in into the network) occurs on the day following the transaction. Unmarketed green electricity can be marketed in the auction for grey electricity within a time lag of a few minutes. To avoid multiple sales, strict requirements (also of a technical nature) will have to be posed on the regulatory system.

[78] The initial volume per year and group (purchase/sale) also includes the initial volumes from the previous figure (futures market without OCT clearing). It does not indicate whether a company with the highest turnover in the "without OTC clearing" segment also belongs to the companies with the highest turnover in the segment where the volumes from OTC clearing have been included (see footnote 75).

[79] See following chapter Retail / Green electricity segment

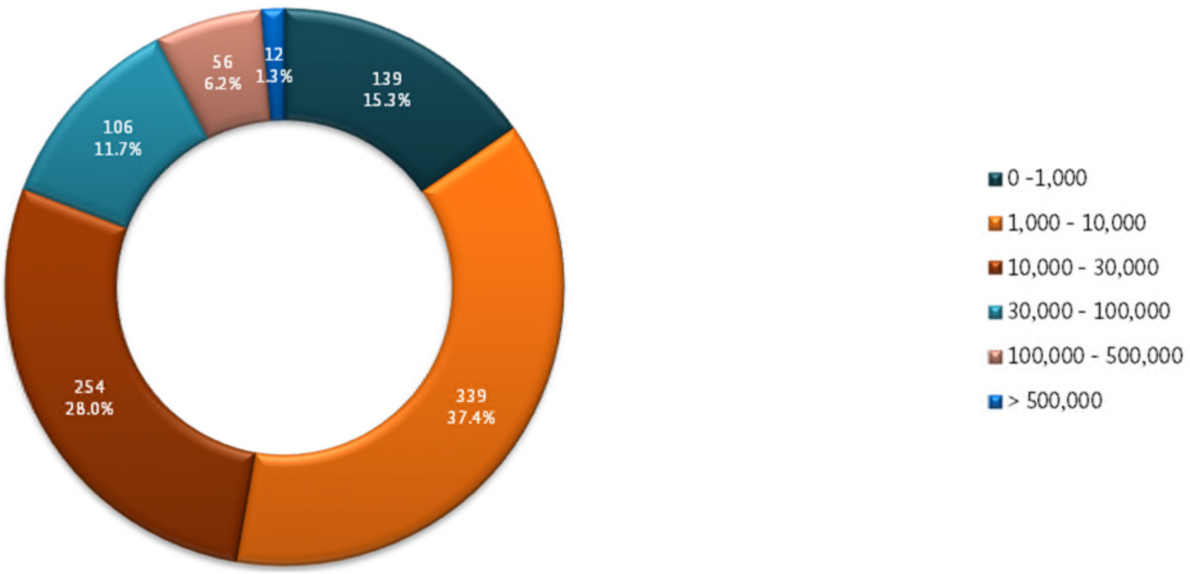
In December 2011 the EPEX SPOT introduced the trading of 15 minute contracts for the German intraday market. As electricity from renewable energy sources is subject to strong volatility, making a reliable prognosis of actual feed-in volumes of electricity from renewable sources becomes more challenging. The 15 minute contracts offered by the EPEX SPOT make it possible to react at even shorter notice to changes and can therefore help to improve the integration of renewable energies into the market.

H Retail

1. Market structure and number of providers

When looking at the retail market in the electricity sector it is noteworthy to consider how the market of the suppliers is structured and how many suppliers are active in the market. An evaluation of the data from 906 suppliers on the metering points supplied by them illustrates that, in absolute figures, the majority of suppliers serve relatively few metering points. When taking account of the group holdings of the four largest suppliers using the dominance method, approximately 80 percent of all of the companies taking part in the monitoring activities belong to the group of companies that supply fewer than 30,000 metering points. When considering the grand total of nearly 6 million metering points, this only makes up some 13 percent of all registered metering points[80]. 7.5 percent of all suppliers account for over 100,000 metering points. This group, however, covers 35.8 million metering points and therefore some 75 percent of all of the metering points registered by the suppliers. Accordingly, the majority of companies active on the supplier side have a customer base that is made up of a relatively small number of metering points. In contrast, a few large suppliers serve the majority of metering points in absolute terms.

Figure 63: Number and percentage of suppliers for metering points[81]

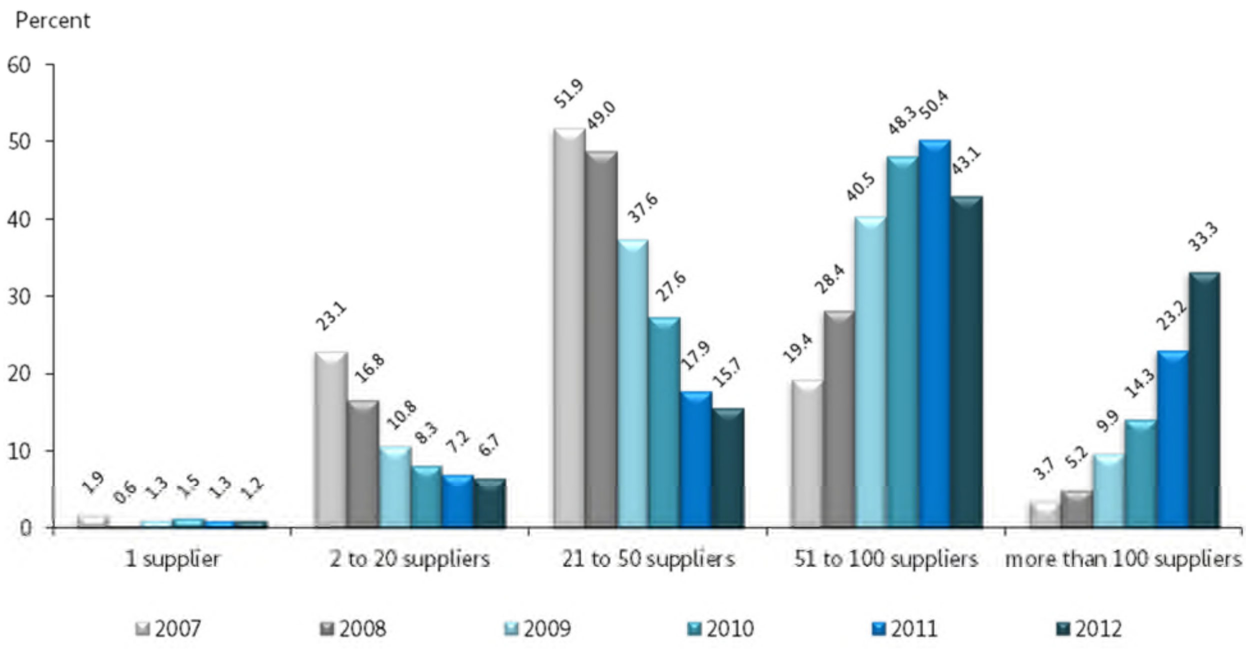


[80] In total, the suppliers reported 47.8 million metering points for final consumers.

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

The potential for electricity customers to choose between a large number of suppliers improved again in comparison to the preceding year (2011). In 2012, more than 50 providers were active in more than three quarters of all network areas. In 2007, this figure only applied to just under one quarter of the network areas. On average, a final consumer in Germany can choose between 88 (2011: 80) suppliers in their network area. Household customers can choose between 72 suppliers (2011: 65). 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 in these areas.

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



2. Contract structure and supplier switching

2.1 Supllier switching

The TSOs and DSOs were surveyed on the volume and number of switches at the metering points in their network areas to investigate the number of supplier switches. The supplier switch results are given as absolute total values for the three final consumer categories. Typical household customers are placed in the 10 MWh/year category, smaller industrial and business customers in the > 10 MWh/year ≤ 2 GWh/year category and industrial customers in the > 2 GWh/year category. These values taken from the questionnaire are presented in the tables below.

Table 24: Volume of supplier switches in each customer category in 2012

Final consumer category	2012: TSO and DSO offtake volumes (TWh)	2012: Supplier switches (TWh)	2012: Supplier switch share of total offtake (%)
≤ 10 MWh/year	124.5	9.7	7.8
> 10 MWh/year ≤ 2 GWh/year	134.8	15.6	11.6
> 2 GWh/year	242.4	27	11.1
Total	501.7	52.3	10.4

Table 25: Number of supplier switches in each customer category in 2012

Final consumer category	2012: Number of DSO and TSO final consumers	2012: Number of supplier switches	2012: Supplier switch share of number of final consumers (%)
≤ 10 MWh/year	46,221,649	2,617,745	5.7
> 10 MWh/year ≤ 2 GWh/year	2,474,295	204,092	8.2
> 2 GWh/year	18,707	2,743	14.7
Total	48,714,651	2,824,580	5.8

The data collected shows a decrease in the number of customers that switched their supplier compared with the previous year. The volume of electricity accounted for by all of the switches amounts to 52.3 TWh in the year under review. This is 3.7 TWh less than that reported in 2011 and corresponds to a decrease of 6.7 percent. A total of 2,824,580 final consumers switched suppliers. Of those switches, 206,835 are attributed to industrial and business customers, a decrease of 12,437 compared to 2011. A total of 2,617,745 switches were registered in the final consumer category ≤ 10 MWh/year for 2012[82].

The volume and quantity-based supplier switching rates in the consumer categories with electricity offtakes greater than 10 MWh/year are considerably higher than the rates for final consumers with lower electricity offtakes. This might be partially due to the fact that high-volume final consumers generally have a higher price sensitivity than low-volume customers translates into a higher readiness to change suppliers on the part of high-volume final consumers. At the same time, it should be considered that just one large industrial customer switching their supplier significantly affects the share. The volume and quantity-based switching rates

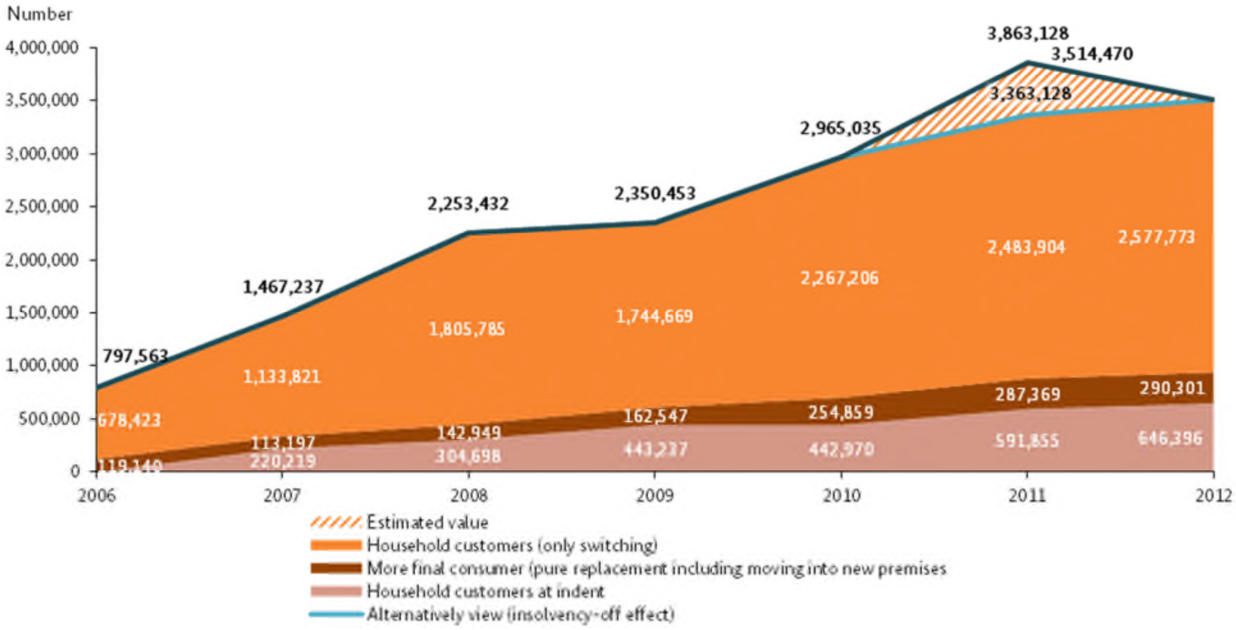
[82] Owing to a change in data evaluation methods, the quantity-based results of the "≤ 10 MWh/year" category cannot be compared directly with those of the previous year. Moreover, the data requires adjustment prior to a closer investigation of the switching behaviour, see Figure 65 on page 122.

are at 11.1 and 14.7 percent respectively. This shows that the rates in this area hardly changed compared to the previous year (2011). The moderation of the switching rate for industrial and business customers can therefore be attributed to the decline in the "> 10 MWh/year; ≤ 2 GWh/year" consumption category. The volume and quantity-based switching rates decreased by 1.4 and 0.7 percent respectively for this category.

Based on the data collected, the volume-based supplier switching rate decreased by 0.9 percent compared to 2011 values and is now at 10.4 percent for all customer groups. The quantity-based supplier switching rate for all final consumers is 5.8 percent.

The decrease in the number of supplier switches by final consumers, based on the data collected, is above all the result of a clear decrease in switches in the area of household customers. This value, however, is influenced by the special effect caused by the questionnaire that gives a distorted picture of the actual decision-making behaviour of the customers in respect to switching.

Figure 65: Final customers who switched suppliers (incl. moving into new premises)



Customers affected by the insolvency of a major discount supplier in 2011 were, after falling back to the substitute supplier and had they not subsequently made a switch, transferred to the standard services with their local default supplier. An estimated figure of 500,000 customers applies here (when also taking the numbers provided by the 2011 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 deciding to make the switch. It is therefore appropriate to remove the estimated portion of "switches automatically brought on" by the insolvency.

After adjusting the figures from 2011 by removing the 500,000 switches brought on by the insolvency, a clearer picture of the decreasing number of switches is painted. The number of supplier switches rose again in 2012 in comparison to 2011, even if the growth rate clearly shrank with respect to the two preceding years. An increase of 30 percent supplier switches was attributed between 2009 and 2010 to household customers (discounting household customers moving into new premises). The figure for the increase between 2011 and 2012 was only 3.8 percent. Compared to this, a decrease of 9.1 percent in the number of household customer switches was actually recorded in the 2008-2009 annual period. The detailed development that takes into account the special effect of the insolvency can be seen in the following table:

Table 26: Supplier switches figures for household customers (with and without adjustment for the insolvency special effect)

	Adjustment83 for insolvency special effect		Without adjustment for insolvency special effect	
Change compared to previous year	**In absolute terms**	**As a percentage**	**In absolute terms**	**As a percentage**
2008-2009	-61,117	-9.1	-61,117	-9.1
2009-2010	+522,538	+30.0	+522,538	+30.0
2010-2011	+216,698	+9.6	+716,698	+31.6
2011-2012	+93,869	+3.8	-406,131	-13.6

With the growth rate decrease, the question arises whether, in the area of household customers, a certain level of saturation has set in with respect to customers willing to switch.

In addition to the development of the figures for household customers as presented, 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 50,000. 646,000 such household customers were recorded for 2012. The offtake volumes recorded for the moves increased only insignificantly by 0.06 TWh compared to the previous year.

[83] 500,000 switches were removed in the adjusted analysis of the number of switches in 2011.

Table 27: Household customer supplier switches including customers moving in[84]

Category	2012: Supplier switches (TWh)	Share of total offtake (124.5 TWh) (%)	2012: Supplier switches Number	Share of total household customers85 (%)
Household customers choosing a different supplier than the default supplier without changing residence	8.7	7.0	2,577,773	5.7
Household customers choosing a different supplier than the default supplier upon changing residence	1.5	1.2	646,596	1.4
Total	10.2	8.2	3,224,369	7.1

An analysis of the household customer supplier switches combined with those changing their residence gives a total of 3.2 million switches for 2012, with a total volume of 10.2 TWh. This corresponds to a volume- and quantity-based switching rate of 8.2 and 7.1 percent respectively. The volume-based rate was therefore slightly above the quantity-based rate. The conclusion can be reached that a household customer's high level of electricity consumption positively influences their decision to switch. The average volume of electricity consumed by a household customer that made a switch was approximately 3,200 kWh in 2012. In contrast to this, customers that were supplied by a default supplier consumed on average only approximately 2,500 kWh.

The number of industrial and business customer switches, including those brought on by any form of move, was at almost 290,000 in 2012 and therefore on a par with the 2011 level.

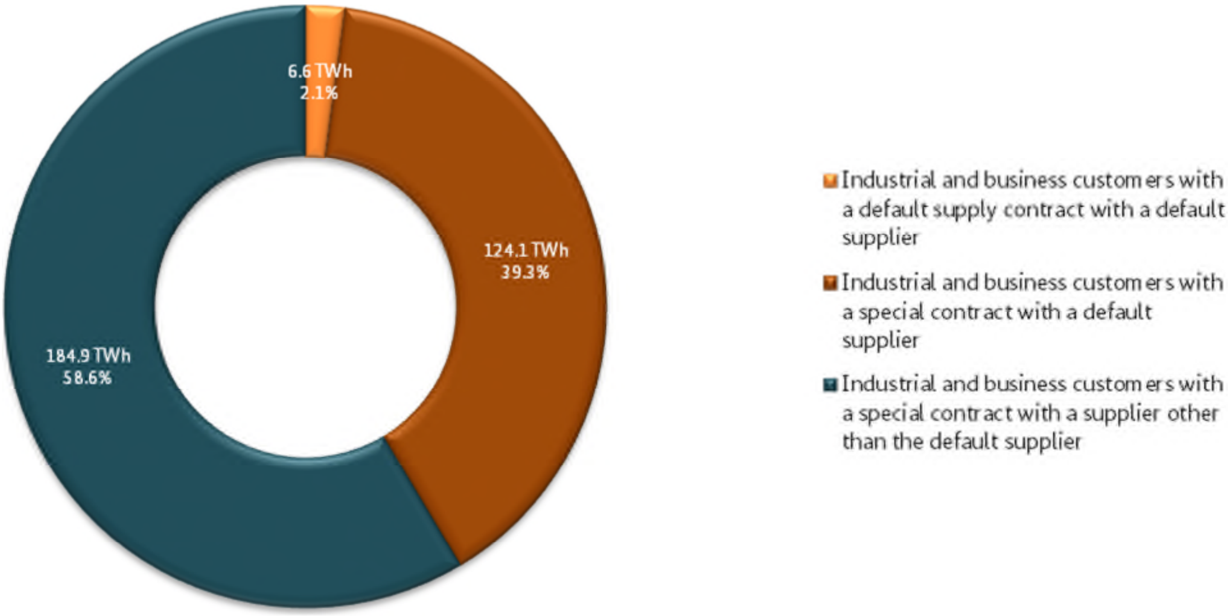
2.2 Contract structure of industrial and business customers

In addition to the supplier switching rates, the contract structure of final consumers is of relevance to competition. Data from 957 electricity suppliers was assessed for the following analysis on industrial, business and household customers. The diagram below shows the existing contract structure for industrial and business customers in 2012, the year under review.

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

[85] The total number of household customers is 45,259,096.

Figure 66: Contract structure of industrial and business customers, as of 2012



As of 31 December 2012, only around 2.1 percent of the industrial and business customers are supplied under[86] standard terms. These customers are almost exclusively smaller business customers. Larger business and industrial customers are predominantly supplied on the basis of other contracts. Around 39.3 percent of the business and industrial customers have a special contract with the default supplier of their network area. Most of the business and industrial customers are served by an alternative supplier and not a supplier other than the default one. This applied to approx. 58.6 percent of the customers being supplied in 2012.

Interval-metered (RLM) customers

Interval metering is used with high-volume consumers, that is larger business customers as well as industrial customers. Customers that consume a volume of electricity starting at 100,000 kWh/year are targeted for the monitoring survey.

In respect of RLM customers, data is available from a total of 870 suppliers[87] who presented information on metering points and volumes supplied to final consumers. With regards to the information, suppliers distinguished between default supply, special contracts with customers from the default supply area of the supplier concerned and special contracts with other customers (from the default supply area of another supplier).

[86] In cases were assignment was unclear (eg with respect to substitute supply)the suppliers were asked to register volumes and metering points under the default supply category. This also provides an explanation for the share, that cannot be defined more precisely, of such customers with the default supplier that are not household customers.

[87] For comparison: Data from 758 companies could be evaluated in this area in the 2012 monitoring report.

A situation in which RLM customers are supplied within the framework of default supply is atypical, but not to be excluded. Around 100 suppliers have indicated that they supply RLM customers within the framework of default supply. This implies that only around 4,200 metering points with a good 0.7 TWh are being supplied. This is just over 1 percent of the metering points in in this category and less than half a percent of the volume delivered. Additionally, the values are to be considered with a constraint: In cases where assignment was unclear with regard to the categories indicated (ie substitute supply) the suppliers were asked to register metering points and volumes under "default supply"[88].

RLM customers generally conclude special contracts whereby they have the freedom of choosing a supplier. The supplier could be the local default supplier or a different one.

Around 700 suppliers supply RLM customers in their default supply area within the framework of a special contract. Out of these suppliers, around 280 are active only locally (inside their default supply area) while the remaining 420 are also active in other areas. About 140 further suppliers that supply RLM customers do not have a default supplier status in any area[89].

The RLM customer suppliers that are not default suppliers in any region[90] provided around 81 TWh to just under 46,000 metering points in 2012. These suppliers accounted for 15 percent of all of the recorded metering points and nearly 30 percent of all recorded volumes delivered in the RLM area. This metering points-to-volumes delivered ratio points out that location-independent suppliers tend to supply high-volume customers.

The suppliers that supply RLM customers only within their default supply area with special contracts provided these customers with less than 6 TWh (around 2 percent of the delivery volume determined) to just under 12,000 metering points (just under four percent of all of the reported metering points). On average, that is less than 0.5 GWh/year per metering point. This means that the companies supplied are generally (larger) business customers rather than industrial customers.

Suppliers that were active both locally (within their default supply area) and beyond local boundaries supplied local RLM customers (in their default supply area) on the basis of a special contract with just over 90 TWh to less than 170,000 metering points. This makes up approximately 33 percent of the noted volumes delivered and corresponds to close to 55 percent of all of the noted metering points supplied in the RLM area. In contrast, the same supplier group provided 74,000 metering points (around 24 percent of all metering points in the RLM area) inter-regionally with over 92 TWh (which corresponds to around 34 percent of the entire volume delivered). Local and inter-regional shares of RLM customers vary in relation to total volumes and the

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88 This specification was also made in the standard profile area. However, the values there are so high that the special cases recorded (or rather included) can probably be neglected, although their share cannot be assessed more closely.

89 According to the information they provided, few suppliers provide only default supply services to RLM customers. See previous footnote.

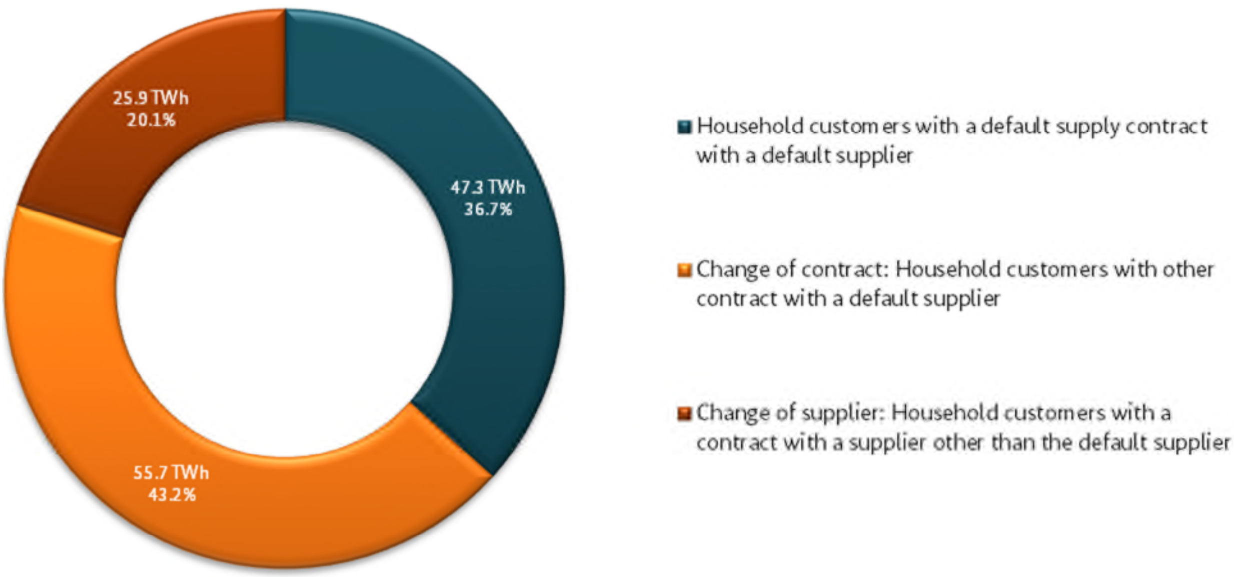
90 Since the default supplier status is tied to the number of supplied household customers, a supplier can may be a default supplier (and supply an adequate number of household customers in a network area) while serving RLM customers only on an inter-regional basis. The existence of such cases cannot not be assumed based on the survey, however.

total number of metering points. The ratio of total volumes and total number of metering points differs for local and non-local RLM customers. As far as the local share is concerned, the ratio was 0.5 GWh per metering point per year, corresponding more or less to the ratio of suppliers that were exclusively active in the RLM area locally. Special-contract RLM customers with small volumes are overall more likely to be with a local default supplier. RLM customers with higher volumes are more likely to be with a supplier that is not the local default supplier (regardless of whether or not this supplier is the default supplier in another area).

The average annual volume delivered to a special-contract RLM customer by an exclusively inter-regionally active supplier is close to 1.8 GWh, compared to just under 1.3 GWh delivered to a customer in the same situation by a supplier that also serves RLM customers in a default supply area. Noteworthy is the fact that some high-consuming industrial customers also use the exchange as a way of purchasing electricity.

2.3 Contractual structure for household customers

Figure 67: Change of supplier and contract by household customers, 2012



The Monitoring data 2013 on supplies to household customers shows that, in 2012, a relative majority of 43.2 percent of household customers had entered into a special contract with a local default supplier. 36.7 percent of household customers obtained standard supplies of electricity in the most expensive categories. A fifth of all households are supplied by an enterprise other than the default supplier. The share of customers who no longer have contracts with their default suppliers reached a new record. However, 80 percent of households continue to be 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 weakened somewhat during the year under review.

The survey results show that the share of the four biggest electricity undertakings is around 44 percent within their own supply areas and around 36 percent outside their own supply areas. These undertakings continue to have a strong market position, particularly in their own network areas.

Table 28: Share of supplies to household customers provided by the four biggest electricity suppliers in 2012

Supply to household customers	Volume delivered in TWh	Volumes delivered by the four biggest companies in TWh	Share of volume deliverd in percent
In network areas where they are default suppliers	103.0	45.3	44
outside network areas where they are default suppliers	25.9	9.4	36
Total	128.9	54.7	42

SLP customers

A standard load profile (SLP) is applied to simplify recording of consumption by customers for whom interval load data is not subject to registered load profile measurement (RLM). This is (only ever) the case for customers who withdraw up to a maximum of 100,000 kWh from the electricity distribution network (section 12, Strom NZV). These are predominantly household and business customers[91].

Data for SLP customers is available from a total of 939 suppliers[92] and provides information about supplied metering points and volumes supplied to final customers. The survey differentiated between default supply services, special contracts with customers in the relevant default supply area and special contracts with other customers (outside their own default supply area).

Deliveries to SLP customers receiving default supply services are made exclusively on the terms and conditions which apply to public supply (default supply services), i.e. not subject to agreed special conditions. The default supplier is the electricity supplier which supplies the most household customers in a public power supply network. This is determined by network operators on a regular basis for a three year period (section 36(2) EnWG). Whether or not a default supplier is able to retain this status in the next period depends on whether most household customers continue to be supplied by it (who receive public supplies or have a special contract).

According to information provided by suppliers, SLP customers who receive default supply services have an electricity offtake of 52.9 TWh from around 20 million metering points. Depending on the metering point in each case, an average of around 2,600 kWh/year is supplied. This average value covers a broad range of differ-

[91] Under section 12(2) para 5 StromNZV etc, standard load profiles must also be established for interruptible consumer equipment; on interruptible consumer equipment see also page 154 f.

[92] For comparison: Data from 809 companies in this field was obtained and evaluated for the 2012 Monitoring.

ent consumption cases (up to consumption of 100,000 kWh/year). The corresponding average figure last year (almost identical) was 2,620 kWh.

Around 730 suppliers reported supplying customers receiving default supply services; fewer than four percent of these suppliers only supply this customer group. The vast majority of these default suppliers (almost 700) supply SLP customers in their own default supply area under the terms of a special contract. From this group of companies almost 80 percent also supply SLP customers outside their own default supply areas. Conversely, only around two percent of default suppliers have special contracts with customers wholly outside their default supply areas.

The participating suppliers (only default suppliers in this case) supplied 82.7 TWh of electricity to around 18.5 million SLP customers under special contracts in the reporting year 2012. Depending on the metering point an average of around 4,500 kWh/year is supplied (the equivalent value last year was around 4,600 kWh/year). That is a significantly higher average value than determined for supplies to SLP customers receiving default supply services.

On average 60 percent of the volume of electricity supplied to SLP customers in any particular default supply area (according to supply volume) is taken up by customers on special contracts and 40 percent by customers receiving default supply services. However, in reality, these suppliers actually had customers in every possible constellation, from recipients of default supply services through to customers with special contracts in their default supply area (SLP customers according to supply volume). Based on metering points rather than supply volumes the figures shift to a good 52 percent for default supply services and 48 percent for special contracts. There is also a similar spread on the supplier side as regards shares of SLP customers receiving default supply services or on special contracts. From a different perspective the figures again illustrate that SLP customers with higher annual consumption are more likely to have a special contract with their suppliers.

According to information provided by suppliers, in the reporting year 2012 around 36.2 TWh of electricity, distributed to 8.8 million metering points, was supplied to SLP customers who had a special contract with a supplier which was not the local default supplier. On average almost 4,100 kWh/year was supplied to SLP customers in this segment. The equivalent figure for last year was around 4,500 kWh/year. The indicator (average volume per metering point based on the contract status of the SLP customer) for supplies to SLP customers with special contracts with a default supplier or with a special contract with another supplier are relatively similar. In contrast, the indicator for default supply services is significantly lower.

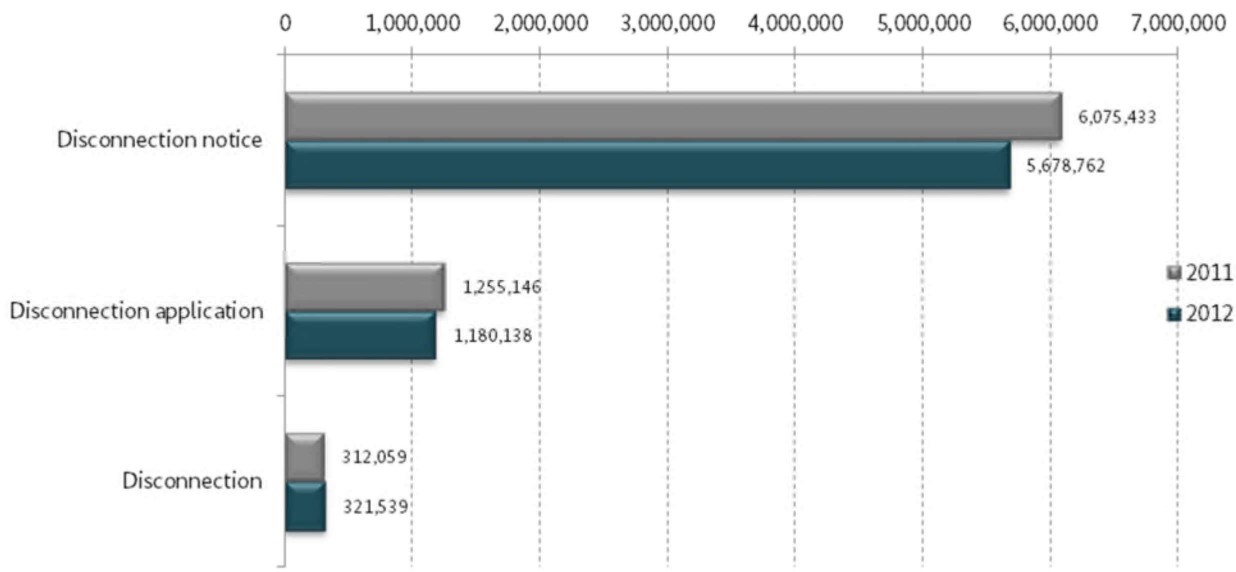
Almost a quarter of suppliers do not have the status of default supplier in any area and consequently supplies SLP customers exclusively in other undertakings' default supply areas. These suppliers provided a good 70 percent of electricity volumes which overall was supplied to SLP customers with special contracts who had not concluded a special contract with a default service supplier. The remaining 30 percent or so was accounted for by default suppliers which were active in other default supply areas.

3. Disconnection notices and disconnections, tariffs and terminations

3.1 Disconnections

In the year under review 2012 the Bundesnetzagentur performed surveys of tariffs on offer for the second 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) of the Electricity Default Supply Ordinance (StromGVV) and the associated costs.

Figure 68: Disconnection notices, application to the network operator and disconnection of electricity supplies



The StromGVV entitles default suppliers to disconnect supplies to customers, particularly for non-payment where arrears have mounted to at least 100 euros and after a corresponding reminder has been given. The number of actual disconnections has gone up slightly compared to last year. Some companies were not able to provide exact figures, but did disclose estimated figures. Overall the relationship between threatened disconnections, disconnection orders and actual disconnections reported in the 2012 Monitoring report is confirmed.

Electricity network operators were asked at how many metering points they had disconnected or reconnected supplies during the reporting year 2012 at the request of a supplier. Network operators reported a total of 321,539 disconnections.

At the same time, network operators and suppliers were asked how often in 2012 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 5.7 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 114 euros in arrears. However, of the 5.7 million disconnection notices issued, only around 1.2 million resulted in electricity being cut off by the responsible network operator. Ultimately, network operators actually disconnected 321,539 household customers. On average, suppliers charged their customers 31 euros for cutting off supplies, whereby actual charges varied between 0 euros and 155 euros.

3.2 Tariffs and terminations

Under section 40(5) EnWG suppliers of electricity must offer final customers load-based or peak/off-peak tariffs in particular, if this is technically and economically feasible. During the reporting year 2012 only around 11 percent of suppliers offered load-based tariffs. Around 81 percent of suppliers offer peak/off-peak tariffs and another 17 percent or so other tariffs as well.

Under section 40(3) EnWG suppliers are also required to offer final customers monthly, quarterly or half-yearly settlement. Demand from final customers for these forms of billing is still negligible, however. 136 companies reported a total of 3,480 inquiries from customers about mid-year billing.

Despite the relatively high number of reported disconnection notices and applications for disconnections, very few suppliers actually wish to stop doing business with their customers. In 2012 suppliers terminated contracts with around 123,000 customers.

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 average retail price charged by their companies. Suppliers were asked to consider all the elements which go to make up the price billed to the final customer (kilowatt-hour price, service price (for load-metered customers), base price and prices for metering and billing, etc.). The prices stated were for standardised volumes used by a household, a commercial business and an industrial customer on the key date of 1 April 2013 in ct/kWh. At the same time, a detailed breakdown of prices in net network tariffs, charges for billing, metering and metering operations, taxes (electricity and value-added tax) and other price components determined by the state, such as surcharges under KWKG, EEG, section 19 StromNEV, and for offshore liability as well as the price components "energy procurement and supply". Average prices in each case were calculated using the volume-weighted average. This is done by weighting and aggregating prices notified by companies with the volume of electricity they delivered in the relevant customer segment and then determining the average prices which final customers must pay for electricity supplied to them in Germany[93].

4.1 Business and industrial customers

The following section examines the development of retail prices for industrial and business customers. The depictions of the retail price level for industrial customers are based on the following purchase case:

- 24 GWh/year annual consumption
- 4,000 kW annual peak load and 6,000 hours annual usage time

[93] When evaluating the volume-weighted average it is only possible to use prices for which companies had also provided information in the corresponding customer category on volumes purchased by final customers. As data on the volume of electricity sold to final customers in the applicable customer category is not available from all the companies which provided information about the price level, the number of companies in the evaluation for the volume-weighted average deviates from the number of companies for the arithmetic mean.

- Medium voltage supplies (10 or 20 kV).[94]

The suppliers reporting on industrial customer prices were asked to provide plausible estimates, based on the conditions applicable as of 1 April 2013 for the amount charged to their company's customers with a purchase structure comparable to the stated purchase case[95]. The evaluation of information provided by 206 companies (volume-weighted average: tariffs and volumes) produced the results shown in the following table:

Table 29: Average retail price level (fixed and variable price components) on 1 April 2013 for industrial customers according to survey of wholesalers and suppliers[96]

Industrial customers (volume weighted) 1 April 2013	Price component ct/kWh	Share of total price in percent
Net network tariff	1.78	10.37
Charge for billing	0.002	0.012
Charge for metering	0.002	0.012
Charge for meter operations	0.003	0.017
Concession fees	0.11	0.62
Surcharge under EEG	5.28	30.74
Surcharge under section 19 StromNEV	0.05	0.29
Surcharge under KWKG	0.06	0.33
Surcharge for offshore liability	0.05	0.29
Tax (electricity and VAT)	4.79	27.89
Energy procurement and supply (incl. margin)	5.05	29.44
Total	17.17	100

The average volume-weighted total price for industrial customers in Germany is at 17.17 ct/kWh. The arithmetically determined price level, which is not shown here, is approximately 0.9 ct/kWh above the volume-

[94] The following additional assumptions were made for the category of industrial customers: It was assumed that the compensation scheme for large electricity-consuming enterprises and rail operators pursuant to sections 40 to 44 EEG are not applied and that the provisions under section 9(7) sentence 3 KWKG, section 17 f EnWG and section 19(2) StromNEV also does not apply.

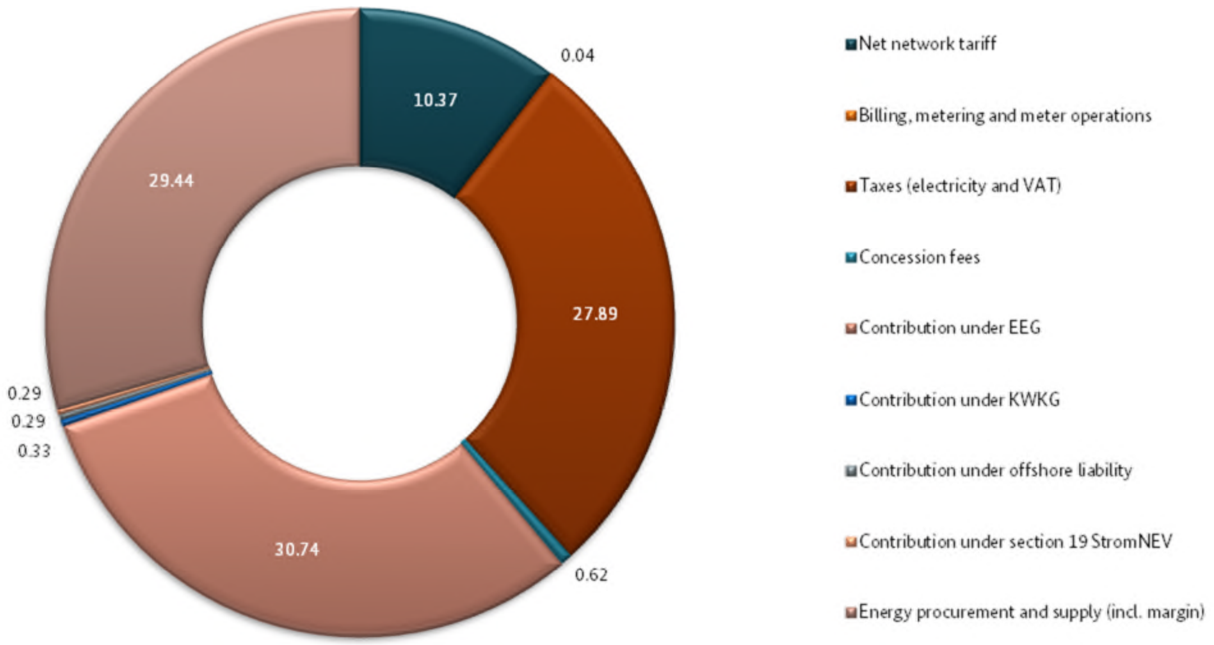
[95] Since industrial customers have a wide range of offtake volumes, while the survey refers to only one concrete purchase case, the use of estimated values represents a sufficient basis for data. The weighting itself, which was undertaken here, is a further estimate. In particular because of the wide range of offtake volumes, the weighting in the industrial customer sector does not have the same significance as in other customer categories.

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

weighted price level. Depicted here for the first time is the newly introduced surcharge for offshore liability[97], which is being charged since 1 January 2013.

The following figure shows the share of the individual price components in percent:

Figure 69: Retail price composition for industrial customers on 1 April 2013, in percent[98]



As the diagram shows, the net network tariff[99] accounts for a share of 10.4 percent of the entire electricity price for industrial customers. Charges for billing, metering and meter operations account for only 0.04 percent of the total price. The competitive price component "energy procurement and supply" accounts for 29.4 percent of the total electricity price for industrial customers. Taxes (electricity and value-added tax) account for 27.9 percent and the sum of all levies (surcharges under the EEG, KWKG, section 19 StromNEV and for offshore liability as well as concession fee) amounts to approximately 32.3 percent. The EEG surcharge, at 30.7 percent, accounts for the biggest share by far. In other words, taxes and levies make up nearly 60 percent of the electricity price charged to industrial customers. However, it must be noted that the monitoring survey, in order to enable the greatest possible degree of uniformity in survey results, expressly does not take into account the special compensation scheme for electricity-intensive companies. As this issue is of consider-

[97] The surcharge is intended to offset reimbursement payments from TSOs to the operators of offshore wind farms in the case of delays or interruptions in the grid connection. The costs are covered by all final consumers.

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

[99] The term "net network tariff" is used in the Monitoring Report to mean an exclusively network-based charge and does not include charges for billing, metering and metering operations. If these components are included, the term "network tariff" is used.

able general interest, the following section provides a brief exemplary calculation of the maximum possible benefits for an electricity-intensive company in the category of the purchase case of 24 GWh/year.

Assuming that such a company can fulfill all prerequisites for compensation measures provided for in the relevant ordinances and laws, this leads to reductions in the net network tariff, as well as in the surcharges under the EEG, KWKG, section 19 StromNEV and in the surcharge for offshore liability[100]. A further assumption is an exemption from the concession fee, which is possible according to section 2(4) sentence 1 KAV[101]. The maximum possibilities of reductions for a typified electricity-intensive company with an offtake volume of 24 GWh are listed in the following table, together with the other, non-reduced price components:

Table 30: Components of the price paid by industrial customers (24 GWh), taking into account the maximum possibilities of reduction[102]

Industrial customers (volume weighted) 1 April 2013	Price component ct/kWh	Share of total price in percent
Net network tariff	0.36	3.78
Charge for billing	0.002	0.02
Charge for metering	0.002	0.02
Charge for meter operations	0.003	0.03
Concession fee	0.00	0.00
Surcharge under the EEG	0.45[103]	4.72
Surcharge under section 19 StromNEV	0.03	0.31
Surcharge under the KWKG	0.03	0.31
Surcharge for offshore liability	0.03	0.31
Tax (electricity and VAT)	3.57	37.47
Energy procurement and supply (incl. margin)	5.05	53.01
Total	9.53	100

100 Reductions for electricity-intensive companies and rail operators under sections 40 to 44 EEG, the provisions of section 19 StromNEV, section 9(7) sentence 3 KWKG and section 17 f EnWG.

101 The determining factor for an exemption is that the average electricity price paid by the company is lower than the average electricity price of all special contract customers. This price, established by the Federal Statistical Office as a price limit, was 11.57 ct/kWh for the year 2013 (base year 2011).

102 Totals may deviate slightly owing to rounding differences.

103 Results from the scaling according to volume of consumption provided for in section 41(3) EEG.

The resulting average total price is an exemplary value of 9.53 ct/kWh. The maximum reduced price is thus nearly 50 percent lower than the price without any possibility of reductions. Of particular significance in this context are the compensation measures in respect of the EEG surcharge, as these bring about a drastic reduction of the charge from 4.83 ct/kWh to 0.45 ct/kWh. The surcharges payable under the KWKG, section 19 StromNEV and for offshore liability are reduced by approximately half. With regard to the net network tariff, the assumed case was a maximum possible reduction of 80 percent pursuant to section 19(2) sentence 1 StromNEV. With regard to the tax burden it must be noted that there are also exemption and reimbursement possibilities for the electricity tax of 2.05 ct/kWh (cf. section 9a StromStG), which since they must take place ex-post are not given any further explanation here.

In addition to providing information on industrial customers, suppliers were also asked to provide information on prices for business customers. Retail prices shown are based on the purchase case:

- 50 MWh/year annual consumption,
- 50 kW annual peak load and 1,000 hours annual usage time,
- Low-voltage supply (0.4 kV) (where the load profile of business customers is not measured, the value was stated on the basis of delivery without load metering).

Table 31: Average retail price level (fixed and variable price components) on 1 April 2013 for business customers according to survey of wholesalers and suppliers[104]

Business customers (volume weighted) 1 April 2013	Price component ct/kWh	Share of total price in percent
Net network tariff	5.49	20.53
Charge for billing	0.08	0.28
Charge for metering	0.04	0.14
Charge for meter operations	0.06	0.23
Concession fee	1.24	4.65
Surcharge under the EEG	5.28	19.73
Surcharge under the KWKG	0.13	0.47
Surcharge under section 19 StromNEV	0.33	1.23
Surcharge for offshore liability	0.25	0.93
Tax (electricity and VAT)	6.31	23.59
Energy procurement and supply (incl. margin)	7.54	28.21
Total	26.74	100

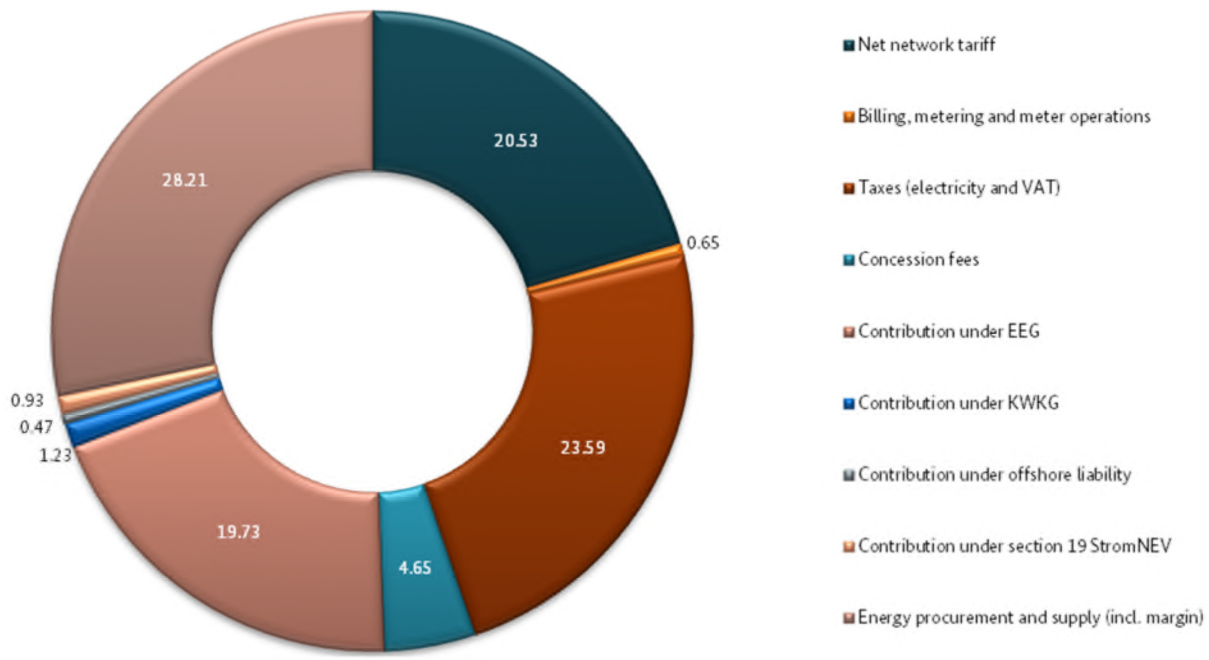
[104] Totals may deviate slightly owing to rounding differences.

641 companies provided information on tariffs and volumes for the category of business customers. This produced the results shown in Table 31.

The average, volume-weighted total price for business customers in Germany thus amounts to 26.74 ct/kWh. The arithmetically averaged price level, which is not shown here, is approximately 0.6 ct/kWh below the volume-weighted price level.

The following figure shows the percentage share of the individual price components.

Figure 70: Retail price composition for business customers on 1 April 2013, in percent[105]



The analysis shows that the net network tariff accounts for a share of 20.5 percent of the entire electricity price for business customers. This share is approximately twice as high as that for industrial customers. Charges for billing, metering and meter operations account for 0.6 percent of the total price. The competitive price component "energy procurement and supply" accounts for 28.2 percent of the total electricity price for business customers. This is comparable to the share for industrial customers. Taxes (electricity and value-added tax) account for 23.6 percent, which is approximately four percent below the share for industrial final consumers. The sum of all levies (surcharges under the EEG, KWKG, section 19 StromNEV and for offshore liability as well as concession fee) amounts to approximately 27 percent for business customers. That is approximately five percent below the share for industrial customers. The EEG surcharge, at 19.7 percent, accounts for the biggest share of levies to business customers by far. That figure is significantly lower than that for industrial consumers. In total, taxes and levies make up around half of the price charged to business customers.

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

The figures clearly show that a large portion of retail prices for industrial and business customers are accounted for by the state-controlled price components such as taxes and levies, as well as by network charges. The competitive portion in both customer segments now makes up less than a third of the retail price. This shift is due in part to the significant price increase that has taken place in particular in the area of levies. A detailed depiction of this development can be found below.

Table 32: Change in electricity price: 1 April 2013 to 1 April 2012 (absolute and in percent)[106]

Volume-weighted average	Industrial customer		Business customer	
	ct/kWh	percentage	ct/kWh	percentage
Net network tariff	0.11	6.6	0.54	10.9
Charge for billing	0	0	0.01	7.8
Charge for metering	0	0	0.01	24.3
Charge for meter operations	0	0	-0.01	-11.6
Concession fee	0	0	0.05	4.5
Surcharge under the EEG	1.69	47.0	1.69	47.0
Surcharge under the KWKG	0.02	40.0	0.13	640.0
Surcharge under section 19 StromNEV	0	0	0.18	119.3
Surcharge for offshore liability	0.05	-	0.25	-
Tax (electricity and VAT)	0.18	3.8	0.32	5.3
Energy procurement and supply (incl. margin)	-0.66	-11.5	-0.31	-3.9
Total	1.39	8.8	2.85	11.9

Compared with the previous year, cutoff date 1 April 2012, the average (volume-weighted) retail prices for industrial and business customers increased by 8.8 and 11.9 percent respectively. Table 32 shows the change in ct/kWh in the volume-weighted average of the individual price components as well as in the total electricity price for industrial and business customers between 1 April 2012 and 1 April 2013. It also shows the percentage change of the relevant price components.

Compared to the previous year (cutoff date 1 April 2012) and in relation to the volume-weighted average of price components for industrial and business customers, there has been a price increase in surcharges, network tariffs (including billing, metering and meter operations) as well as in taxes. The increase in the EEG surcharge is particularly significant. The surcharge for offshore liability is depicted for the first time. For business customers, there is also a marginal increase in the charges for metering and in the concession fee, while

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

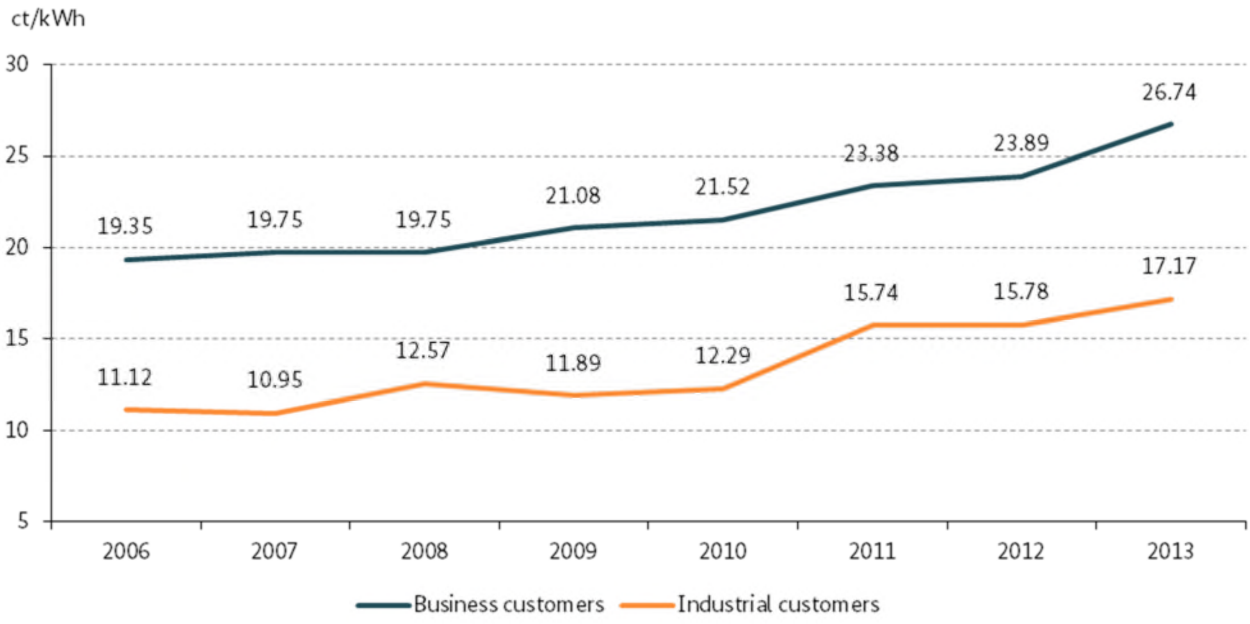
the charges for meter operations have decreased negligibly. The increase in all taxes and levies as well as in network tariffs for industrial customers amounted to 2.04 ct/kWh, while for business customers it was as high as 3.16 ct/kWh.

These significant increases were cushioned by another reduction in the price component "energy procurement and supply". Compared to the previous year, the share for industrial customers has fallen by 0.66 ct/kWh, and for business customers by 0.31 ct/kWh. Since 2011, the price component for energy procurement and supply has thus decreased for industrial customers by a total of 1.15 ct/kWh and for business customers by 0.4 ct/kWh. This is most likely due in large part to lower wholesale prices. The fact that these price reductions are passed on to final customers in the industrial consumer sector to a greater extent than is the case in the business consumer sector is largely due to differing procurement strategies. Suppliers' procurement portfolios have a much more short-term orientation for industrial customers than for other customer groups. These mechanisms have also been confirmed in the analyses of previous monitoring reports.

Compared with the previous year, the total price for industrial customers has increased significantly, by 1.39 ct/kWh. For business customers, there was an even more dramatic increase in the total price, by 2.85 ct/kWh. This is the greatest price increase within the course of one year since the beginning of monitoring activities in 2006. Since that point in time, the price for business customers has increased from an average of 19.35 ct/kWh to 26.74 ct/kWh. This amounts to an increase of 38.2 percent or 7.34 ct/kWh. During the same time period, the prices for industrial customers have also increased significantly, from 11.12 ct/kWh in the year 2006 to 17.17 ct/kWh in 2013. The increase in this customer segment thus amounts to 54.4 percent or 6.05 ct/kWh. However, it must be noted that the price survey for industrial customers in past years has also not taken into account the special compensation scheme.

A detailed depiction of the price curves for industrial and business customers can be seen in the following figure.

Figure 71: Development of prices for industrial and business customers from 2006 to 2013[107]



4.2 Household customers

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

Prices continued to increase substantially for industrial and business customers during the period under review in the consumer group of household customers. Compared to previous years, prices again rose substantially for all consumer groups – default supply services, special contract with default supplier, special contract with a third supplier.

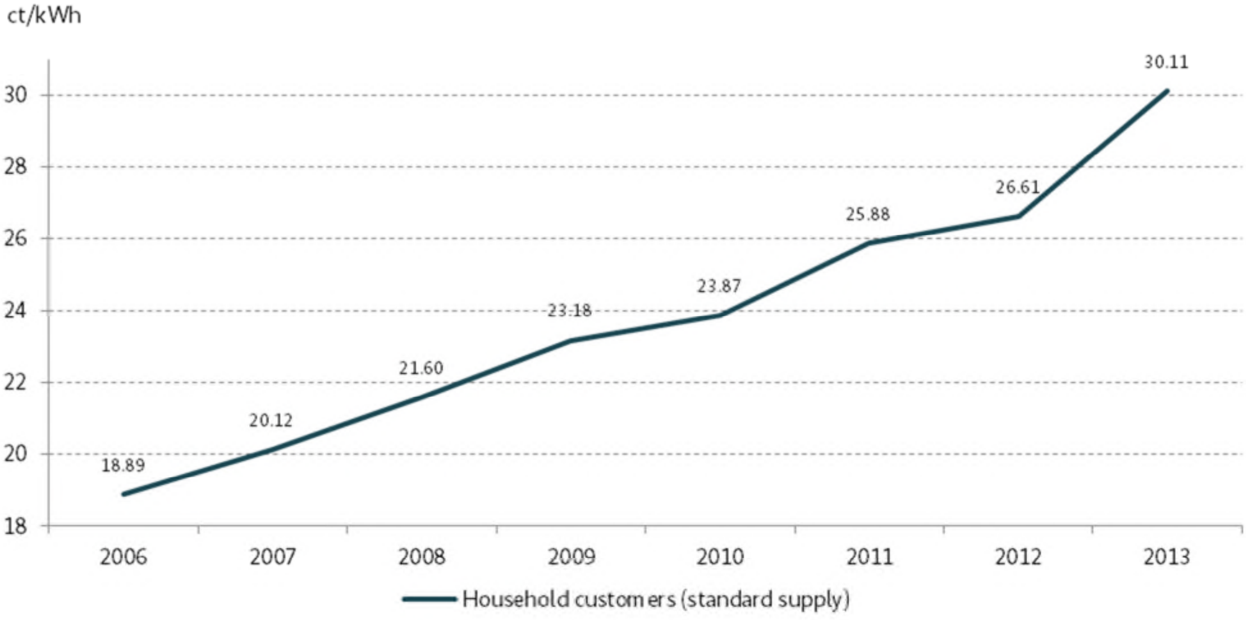
688 companies provided information in the 2013 Monitoring on tariffs and volumes for the default supply service category. Based on the reported data a volume-weighted average price of 30.11 ct/kWh was determined for 1 April 2013[108]. This means that, on the key date of 1 April 2012, the price for customers receiving default supply services had rise by 13.2 per cent or 3.50 ct/kWh compared with the previous year. This is the strongest increase in prices since 2006. Within seven years the price has risen by 11.22 ct/kWh from an origi-

[107] The figures in the graph have been adjusted in line with the amendments to electricity tax legislation in each year.

[108] The arithmetical mean value is around 0.6 ct/kWh below the volume-weighted result.

nal price of 18.89 ct/kWh. This corresponds to an increase of 59.4 percent. The detailed development of volume-weighted average prices for default supply services is shown in the following diagram.

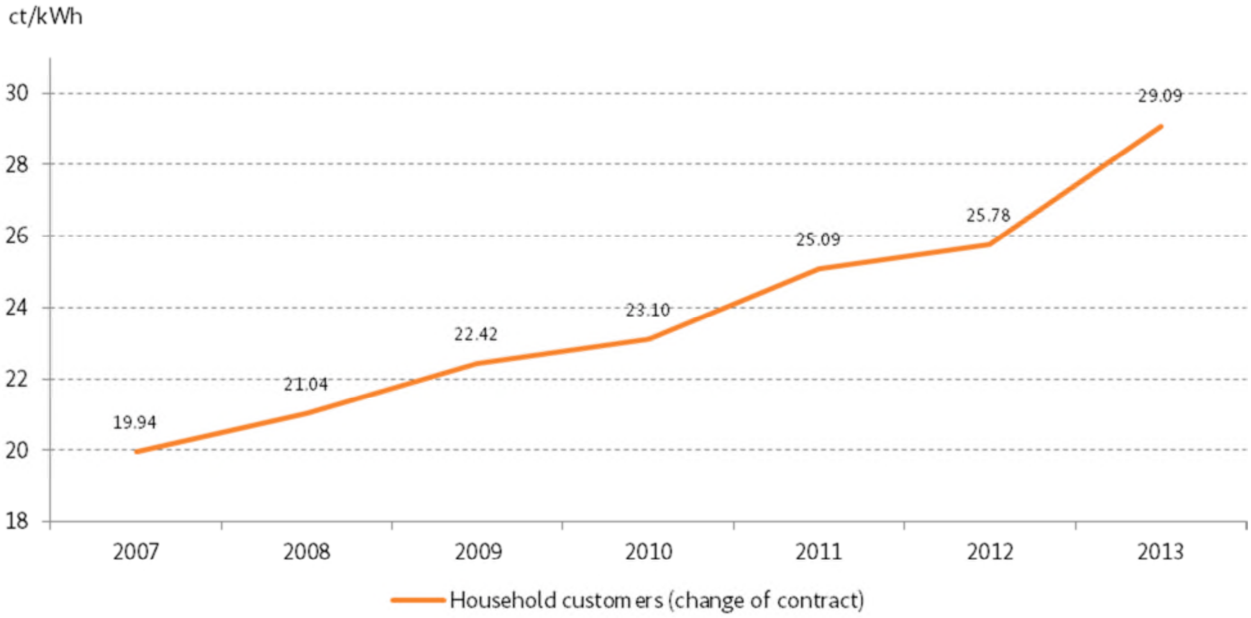
Figure 72: Development of household customer prices for default supply services from 2006 to 2013 (volume-weighted average) in ct/kWh



635 suppliers provided information on tariffs and volumes for the "special contract with a default supplier" tariff group. Based on the reported data a volume-weighted average price of 29.09 ct/kWh was determined for 1 April 2013[109]. This means that the price for customers who have changed to special contracts with default suppliers is 12.8 percent or 3.31 ct/kWh higher than in the year 2012. This is the biggest rise in prices in this tariff category since the survey was launched. Within six years the price has risen by 9.15 ct/kWh. This corresponds to an increase of 45.9 percent. The development of volume-weighted average prices for a change of contract is shown in the following diagram.

109 The arithmetical mean value is 1.0 ct/kWh below the volume-weighted result.

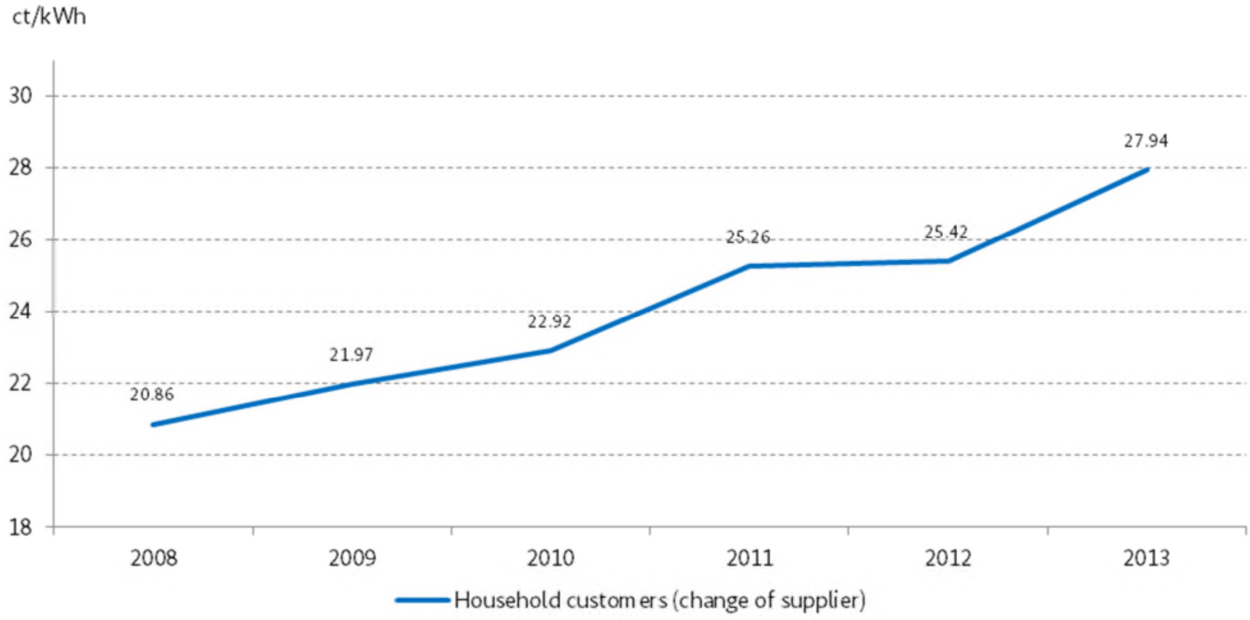
Figure 73: Development of household customer prices for a change of contract from 2007 to 2013 (volume-weighted average) in ct/kWh



459 companies provided information on prices and volumes for the change of supplier category. Based on the reported data a volume-weighted average price of 27.94 ct/kWh was determined for 1 April 2013[110]. This means that the price for customers who have a special contract with a supplier who is not the local default supplier is around 9.9 percent or 2.52 ct/kWh higher than last year. In percentage terms, this is the second largest increase in prices since the survey began in 2008. Within five years the price has risen by 7.08 ct/kWh. This corresponds to an increase of 33.9 percent. The detailed development of volume-weighted average prices for a change of supplier is shown in the following diagram.

[110] The arithmetical mean value is around 0.2 ct/kWh above the volume-weighted result.

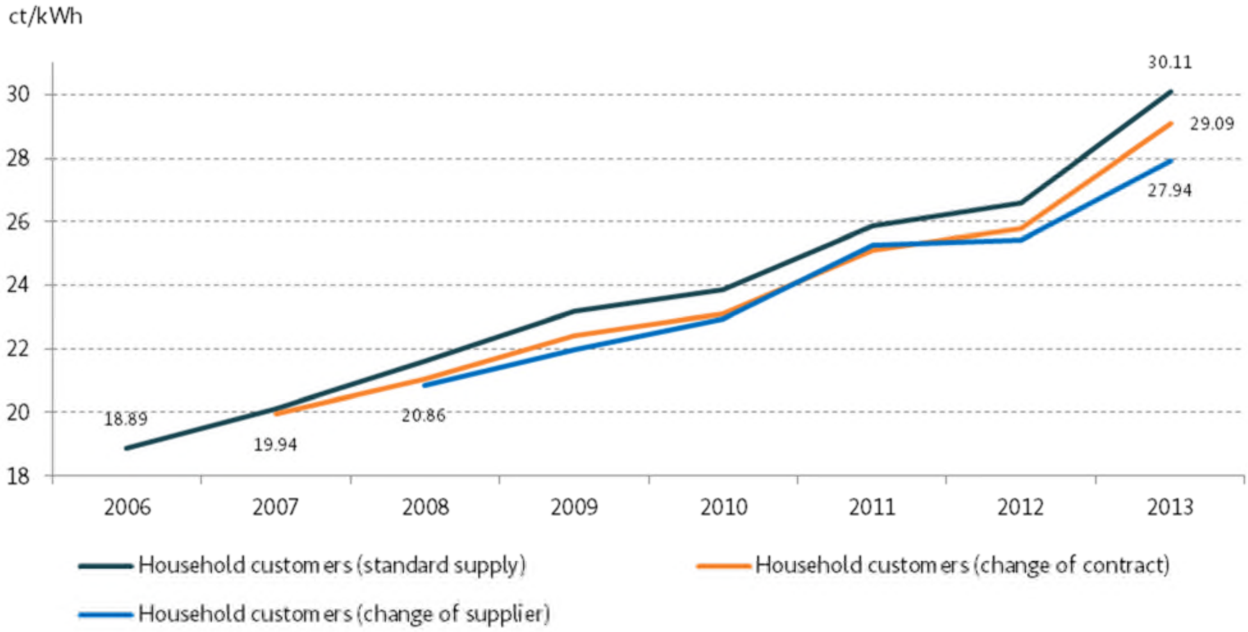
Figure 74: Development of household customer prices for a change of supplier from 2008 to 2013 (volume-weighted average) in ct/kWh



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 (change of supplier) - shows that default supply services continue to be the most expensive form of service.

Household customers can pay lower prices if they change contract or supplier, whereby changing supplier is the more cost effective alternative. A comparison of the average values for the three categories over the entire reporting period (Monitoring 2008 to 2013) shows that the provision of default supply services is consistently the most expensive category of electricity supply for household customers. Over the monitored period, the change contract category is cheaper than default supply every year. Considered over the entire period the change supplier category is also, on average, cheaper than default supply services. In five of the six years monitored the average price in the category change supplier was – more or less clearly – below that for the category change contract.

Figure 75: Development of household customer prices 2006 to 2013 (volume-weighted average per tariff) in ct/kWh

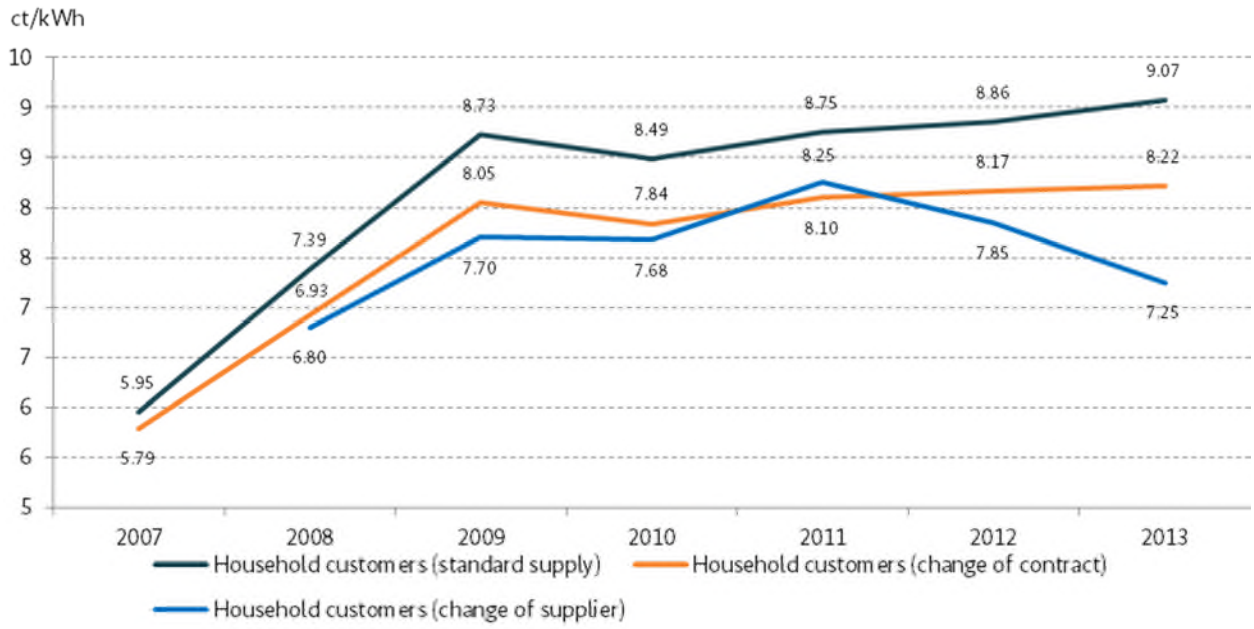


The survey of default suppliers to household customers also recorded the overall price and individual price components. As certain components of the price are mandated by law (surcharges, electricity tax) or are regulated for the default supply area (net network tariff), a key price variable in comparisons between default supply services and special contracts with a default supplier is "energy procurement and supply". In this context information obtained from almost 690 (default supply services) and 630 (change of tariff) suppliers was evaluated. Suppliers who supply customers in a default supply area other than their own (change of supplier) were asked separately about how much the "energy procurement and supply" component contributed to the price. The following diagram is based on data obtained from around 460 suppliers.

On 1 April 2013 the average price for the tariff category supplier change was 2.17 ct/kWh or 7.8 percent under the price for default supply services. The difference between default supply services and a change of contract is 1.02 ct/kWh or a difference of 3.5 percent. The difference between a change of contract and a change of supplier is 1.15 ct/kWh or 4.1 percent. The divergence in consumer prices for the two possible contractual arrangements with default suppliers and change of supplier has widened for the second year in succession. This is because the costs of energy procurement and supply reported by suppliers have developed so differently.

At 9.07 ct/kWh, the energy procurement and supply costs for default supply services in 2013 were 25 percent above the average for the change of supplier category for which average costs of 7.25 ct/kWh were reported. In 2012, there was still a difference of 13 percent between the two categories. On average the costs of energy procurement and supply on changing to a special contract with a local default supplier are 8.22 ct/kWh. The applicable average costs in this category are thus ten percent lower than those in the default supply service category. A detailed overview of this development is provided in the following diagram.

Figure 76: Development of "energy procurement and supply" 2007 to 2013 (volume-weighted averages per tariff) in ct/kWh



A comparison of the price elements "energy procurement and supply" in all three tariff categories shows that the corresponding costs in the change of supplier category have fallen since 2011 while they have increased in the two contractual arrangements with default suppliers. Although it was found in the chapter on "Business and industrial customers" that lower wholesale prices have been passed on to final customers, this appears only to be the case for household customers whose suppliers are active outside the standard supply network area.

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 tariff categories are shown in the following table.

Table 33: Average retail price for household customers per tariff category, 2013

Household customers (volume-weighted) 1 April 2013 (in ct/kWh)	Default supply tariff	Non-standard supply tariff (change of contract)	Non-standard supply network area (change of supplier)
Net network tariff		5.83	
Charge for billing		0.35	
Charge for metering		0.09	
Charge for metering operations		0.25	
Energy procurement and supply	9.07	8.22	7.25
Concession fees		1.67	
Surcharge under EEG		5.28	
Surcharge under KWKG		0.13	
Surcharge under section 19 StromNEV		0.33	
Surcharge for offshore liability		0.25	
Electricity tax		2.05	
Valued-added tax	4.81	4.64	4.46
Total	30.11	29.09	27.94

Special contracts (change of contract; change of supplier) may have a number of other features, in addition to the overall price, which are used by suppliers in competition 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. Subject to special rules, average commitment periods can vary between ten and 13 months.

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

Table 34: Special bonuses and arrangements for household customers in 2013

Special bonuses and special arrangements (1 April 2013)	Household customers (Contract change)		Household customers (Supplier change)	
	Number of tariffs	Average scope	Number of tariffs	Average scope
Minimum contract term	321	10 months	343	10 months
Price stability	200	13	246	13
Advance payment	65	11	41	11
One-off bonus payment	115	€ 55	64	€ 34
Deposit	2	-	0	-
Other bonuses and special arrangements	41	-	36	-

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. 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 electricity offtake. The average price for household customers calculated in 2013 was 29.38 ct/kWh. This is 3.32 ct/kWh or 12.7 percent higher than in 2012. In detail the price is composed of the following elements.

Table 35: Average volume-weighted retail price for household customers per tariff category, 2013[111]

Household customers, 1 April 2013 (across all tariff categories)	Volume-weighted average across all tariffs in ct/kWh	Share of total price in percent
Net network tariff	5.83	19.8
Charge for billing	0.35	1.2
Charge for metering	0.09	0.3
Charge for metering operations	0.25	0.9
Energy procurement	6.25	21.3
Supply (incl. margin)	2.21	7.5
Concession fees	1.67	5.7
Surcharge under EEG	5.28	18.0
Surcharge under KWKG	0.13	0.4
Surcharge under section 19 StromNEV	0.33	1.1
Surcharge for offshore liability	0.25	0.9
Electricity tax	2.05	7.0
Valued-added tax	4.69	16.0
Total	29.38	100

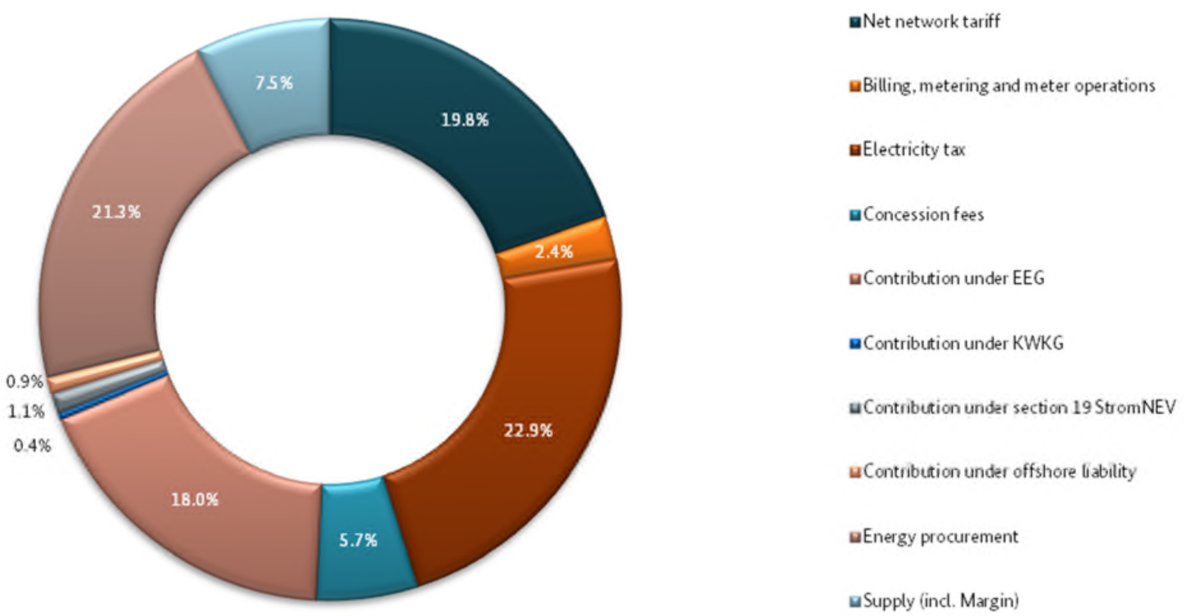
Previous presentations have been expanded to include a differentiated disclosure of the various components of the "energy procurement and supply" elements of volume-weighted consumer prices in all tariff categories[112]. Average energy procurement costs in 2013 were 6.25 ct/kWh; the cost of supply, including margin, averaged at 2.21 ct/kWh.

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

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

[112] The breakdown of the "energy procurement and supply" elements of prices (as the difference between overall price and the total of all other price elements) into "energy procurement" and a "residual amount" which covers supply and margins, is based on a further survey of suppliers. The resulting statistical population of data on this detailed issue is smaller than that obtained from the survey of all price components.

Figure 77: Electricity retail price composition (volume-weighted average across all tariffs) for household customers on 1 April 2013



The net network tariff accounts for 19.8 percent of the total electricity price for household customers. The charges for billing, metering and metering operations account for 2.4 percent of the overall price. Energy procurement accounts for 21.3 percent and supply (including margin) 7.5 percent. Taxes (electricity and VAT) add up to a share of 22.9 percent and total levies (surcharges under the EEG, KWKG, section 19 StromNEV and offshore liability as well as concession charge) to around 26.1 percent. At 18 percent, the EEG surcharge makes up the largest share. Total taxes and levies make up almost 50 percent of the average electricity price paid by household customers.

The following table shows the development of the volume-weighted electricity price for all tariffs from 2012 to 2013. The electricity price rose significantly in 2013 by 12.7 percent (+3.32 ct/kWh) compared with 2012. This is mainly due to higher network tariffs and higher taxes and levies. The EEG surcharge in particular has gone up substantially. In total taxes and levies rose by 2.78 ct/kWh. The marginal reduction in concession fees is the only area in which levies have fallen. There was also a slight drop in energy procurement costs. In contrast, the cost of supply (including margin) have gone up slightly by 0.10 ct/kWh[113].

[113] For changes of this order price assessments can only be made on the statistical fringes.

Table 36: Development of volume-weighted price level for household customers for all tariffs

Household customers (volume-weighted across all tariffs)	in ct/kWh	in percent
Net network tariff	0.45	8.4
Charges for billing, metering and metering operations	0.03	4.6
Energy procurement	-0.03	-0.01
Supply (incl. margin)	0.10	4.7
Concession fees	-0.01	-0.01
Surcharge under EEG	1.69	47.1
Surcharge under KWKG	0.13	640
Surcharge under section 19 StromNEV	0.18	83.3
Surcharge for offshore liability	0.25	-
Taxes (electricity and VAT)	0.53	8.5
Total	3.32	12.7

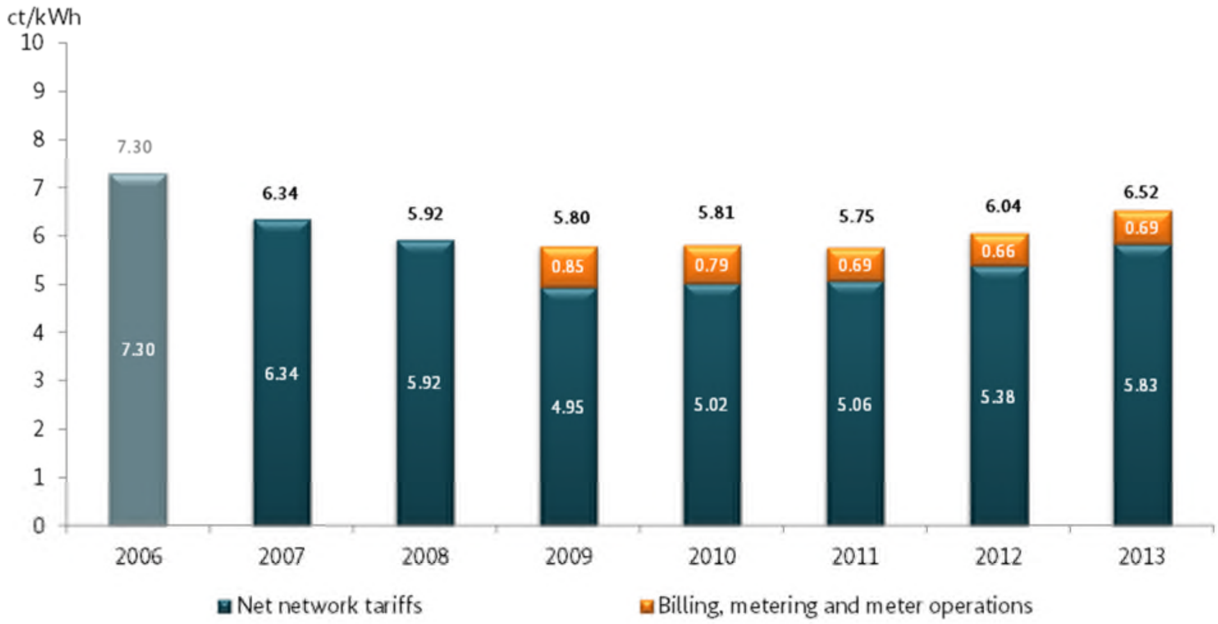
The development of the key price blocks for the volume-weighted electricity price for household customers is shown below. First consideration is given to network tariffs. After a period during which these charges consistently fell up to 2011, network tariffs[114] again went up in 2013, by 7.9 percent (+0.48 ct/kWh) compared with the previous year 2012. Network tariffs fell by an average of 10.7 percent over a period of seven reporting periods. This analysis encompasses network tariffs excluding surcharges under section 19 StromNEV of 0.33 ct/kWh[115].

Compared to 2012, network tariff components for billing, metering and metering operations have gone up by almost five percent. Since 2009 these price components have fallen by a total of 18.8 percent. The ratio in 2013 between charges for billing, metering and metering operations and network tariffs is 11:89.

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

[115] 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.

Figure 78: Development of network tariffs for household customers 2006[116] to 2013[117]



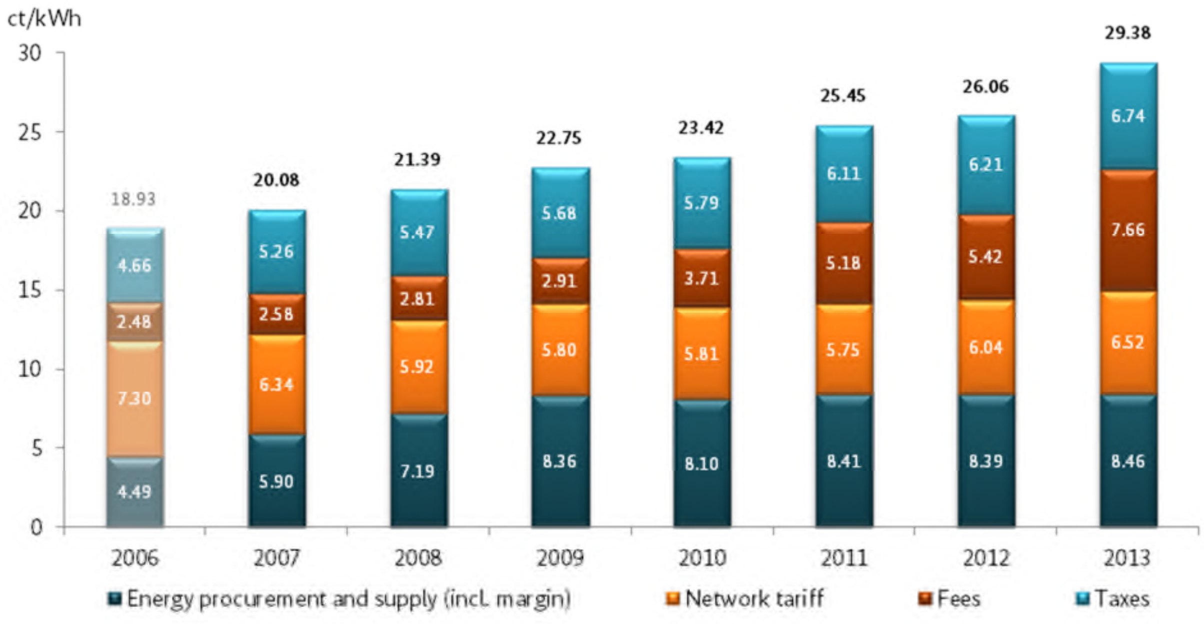
Below is an overview of the remaining price components of volume-weighted household customer prices in all tariff categories. The share of the electricity price made up of taxes and levies has risen since 2006. Over a period of six years levies have gone up by 197 percent and taxes by 28.1 percent. Between 2012 and 2013 levies have risen by 41.3 percent, the largest rise since monitoring began. The share of the price made up of energy procurement and supply (incl. margin) costs rose by 43.4 percent in the period up 2013. The largest increase occurred between 2007 and 2009. Since 2011 the share of these price components has remained at a similar level. It is striking that, despite lower wholesale prices, reductions in procurement prices have not been passed on to household customers in any tariff category[118]. The contrary is the case for industrial and business customers.

[116] 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 consequentially partly a result of reductions in network tariffs. 2006 is therefore the reference year for a time series comparison which is of very limited suitability.

[117] 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.

[118] This applies in particular to the default supply services and special contract tariff groups, as the analysis on page 144 illustrates. Costs actually rose in this area. In the change of supplier tariff category, in contrast, the energy procurement and supply components of the price fell and were overcompensated for by increases in other categories.

Figure 79: Volume-weighted electricity price for household customers for all tariffs, 2006[119] to 2013[120]

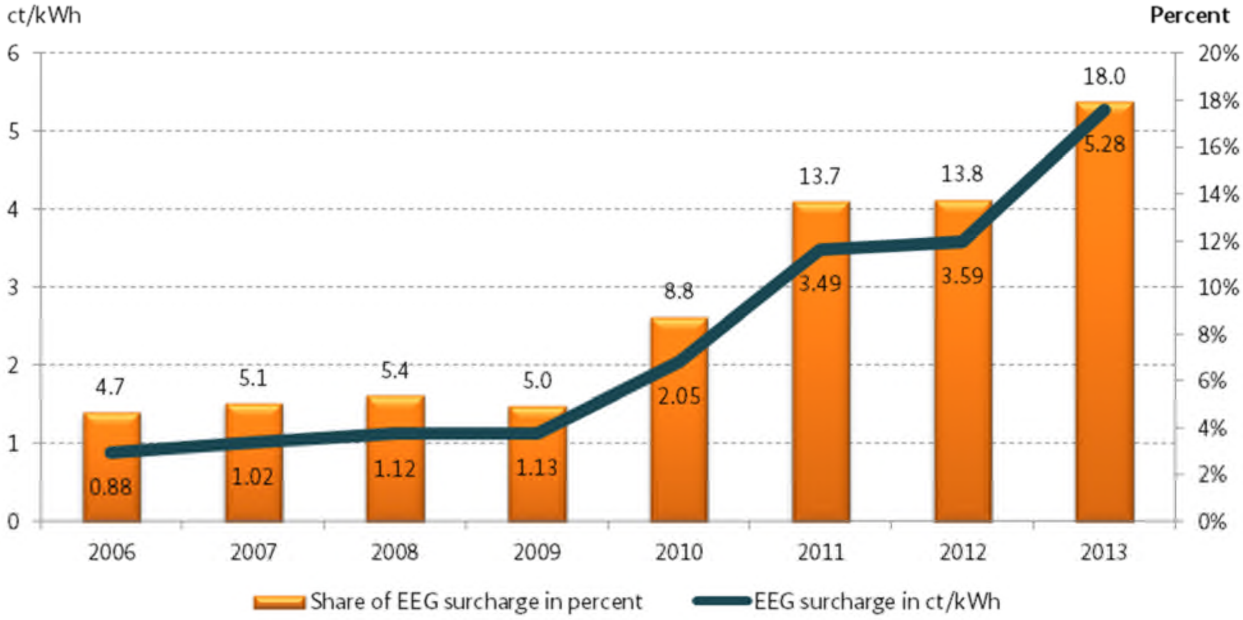


The EEG surcharge makes up a particularly large share of increases in levies. The EEG surcharge is used to balance out the transaction costs for EEG energy sales incurred by TSOs and the remuneration payments to installation operators and EEG energy sales by TSOs on the spot market. The surcharge level is announced every year by the TSOs 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 2013 went up to 5.28 ct/kWh. This reflects the widening gap between EEG surcharge payments made by TSOs to operators and the revenue obtained from marketing electricity on power exchanges. Significantly more new EEG-supported capacity can also be expected to be installed. The lower the price on power exchanges is, and the more systems are remunerated, the higher the surcharge will rise. The disproportionately strong increase in the EEG surcharge has resulted in it accounting for an ever greater share of the price of electricity. It is now 18 percent 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 percent of the total price. The following figure shows in detail how the surcharge has increased.

[119] 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 consequentially partly a result of reductions in network tariffs. 2006 is therefore the reference year for a time series comparison which is of very limited suitability.

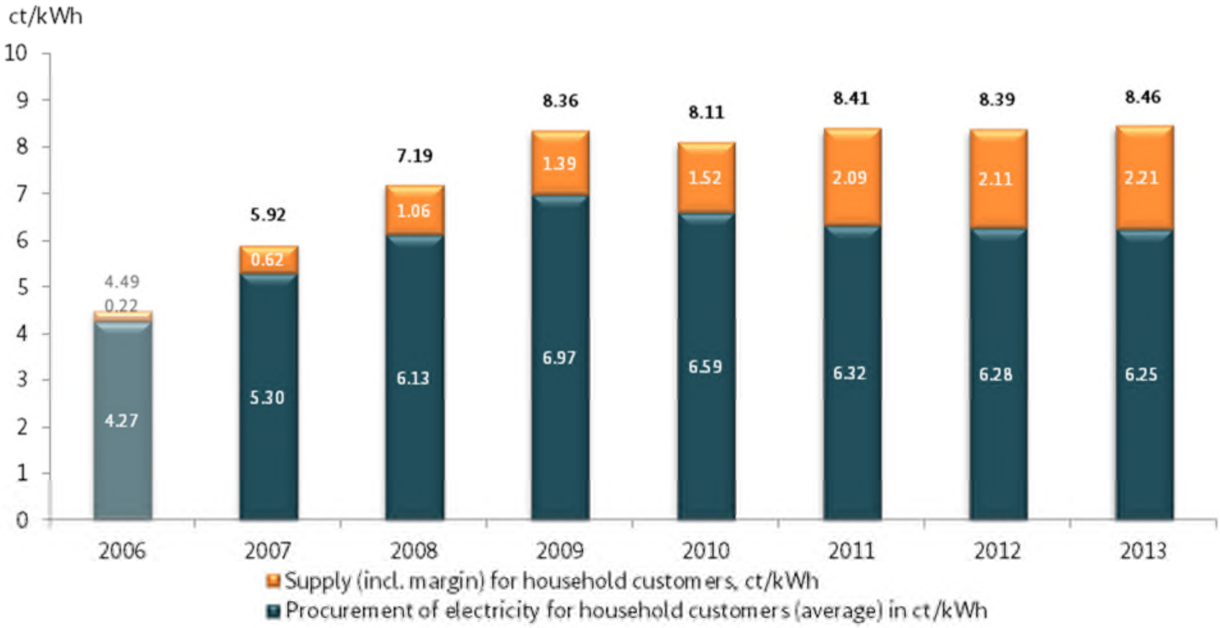
[120] Totals may deviate slightly owing to rounding differences.

Figure 80: Development of EEG surcharge and its share of household customer prices from 2006 to 2013 (volume-weighted averages for all tariffs)



The relationship between energy procurement and sales is studied in greater detail in the following. In the past the costs of energy procurement were estimated indirectly by the Bundesnetzagentur from the data available. The energy procurement and supply cost elements of the price paid by household customers were determined separately for the first time in the 2012 reporting year. The data collected fit well with the estimated data used in last year's report as shown in Figure 81. Supply costs make up 26 percent of the total price components consisting of supply, including margin, and energy procurement costs. Energy procurement accounts for 74 percent. The relationship between the two price components in 2013 is therefore much the same as it was last year, with a slight shift in weighting towards supply (ratio in 2012: supply: 25 percent, energy procurement: 75 percent).

Figure 81: Development of energy procurement and supply 2006[121] to 2013 (volume-weighted average across all tariffs)[122]

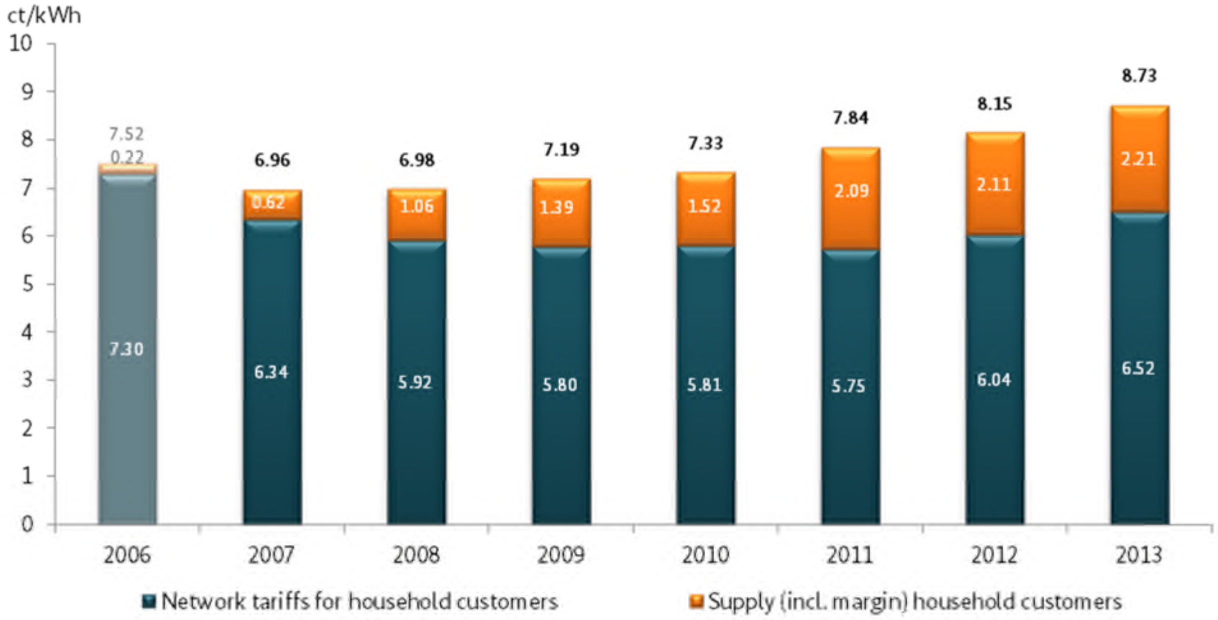


For the second year running the relationship between network tariffs and supply costs (including margin) has shifted somewhat towards network tariffs. In 2011 the ratio was 73 : 27 (network tariffs : supply), the ratio for 2013 was 75 : 25 (network tariffs : supply). While supply costs also rose slightly during this period, this increase was more than compensated for by a strong increase in network tariffs.

[121] 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 consequentially partly a result of reductions in network tariffs. 2006 is therefore the reference year for a time series comparison which is of very limited suitability.

[122] 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.

Figure 82: Development of network tariffs and supply 2006[123] to 2013 (volume-weighted average across all tariffs)



5. Interruptible consumer equipment (night storage heaters, heat pumps)

The data on volumes supplied and supplied metering points [124] 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 742 suppliers[125]. In the reporting year 2012 they supplied a total of around 2 million metering points with around 15.3 TWh of electricity. This corresponds to the supply of almost 7,700 kWh/year per metering point.

[123] 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 consequentially partly a result of reductions in network tariffs. 2006 is therefore the reference year for a time series comparison which is of very limited suitability.

[124] Dual-rate metres had to be reported as a single metering point.

[125] The evaluation for the reporting year 2011 was based on information provided by 621 companies.

Night storage heaters are supplied by 717 and heat pumps by 686 providers. Most of the companies which provide heating current (661) supply both night storage heaters and heat pumps[126]. A volume of electricity of around 13.2 TWh was used for night storage heaters. On average, around 7,800 kWh/year was supplied at the 1.6 million metering points. This contrasts with a supply volume to heat pumps of around 2.2 TWh to fewer than 330,000 metering points; this averages out at 6,900 kWh/year (rounded). Night storage heaters use by far the most electricity (rounded to 84 percent of metering points and 86 percent of supply volume) with heat pumps, in contrast, playing a comparatively minor (rounded to 16 percent of metering points and 14 percent of supply volume).

Almost 98 percent of consumer equipment (making no distinction between night storage heating or heat pumps) was supplied by the default suppliers. At over two percent, the number of customers (based on metering points or volumes supplied) who have a supplier other than the local default supplier in this area is still very low, but higher than determined in last year's survey (1.7 percent). Fewer than 50 suppliers are exclusively active on a non-local basis in this area.

77 percent of the total volume of electricity supplied to interruptible consumer equipment was delivered by the 30 highest-volume suppliers (not differentiated according to type of consumer equipment). This is much the same as determined last year (76 percent).

The analysis of prices for night storage heaters (supply by the locally responsible default supplier) is based on the evaluation of information provided by 581 suppliers. The analysis assumed a "household 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 2013.

Accordingly the total price (arithmetic mean) was 20.3 ct/kWh (compared with 17.6 ct/kWh for last year's survey). One relevant change since last year is the increase in the EEG surcharge (net 1.69 ct/kWh) and the introduction of the offshore liability surcharge (net 0.25 ct/kWh). A comparison of the changes in each of the price components results in an additional tax liability of 2.3 ct/kWh. 5.8 ct/kWh (compared to 5.7 ct/kWh in 2012) is payable on the energy procurement and supply components of the price.

477 suppliers provided information enabling the energy procurement and supply price component to be split up into its "procurement" and "residual amount" parts (this includes supply costs and margin). The average for energy procurement and supply for this section of suppliers is 5.9 ct/kWh. Energy procurement accounts on average for 5.4 ct/kWh and consequently an average residual amount of 0.5 ct/kWh[127].

The framework conditions exist for more competition in supplies to interruptible consumer equipment. 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

[126] 56 suppliers had no heat pump customers at all; 25 suppliers had no night storage heater customers.

[127] In addition to locally responsible default suppliers, suppliers who are more widely active (suppliers who are not default suppliers or who operate outside their own default supply area) were also surveyed concerning the breakdown of the energy procurement and supply components of the price into "procurement" and "residual amount". The data available was not sufficient to be able to arrive at reliable conclusions.

record household electricity. At the same time, the low change rate shows that the competition situation for the provision of interruptible consumer equipment is still not satisfactory.

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. This situation, which is unsatisfactory from the point of view of customers, may change as more information becomes available on consumer advice internet portals[128]. Consumer portals, which have previously offered local support with the search for alternative providers of household electricity, began this year to extend the range of information they offer to include night storage heaters and heat pumps. Greater transparency could stimulate competition.

6. Green electricity segment

The suppliers participating in the 2013 monitoring survey provided information about the volume of green electricity delivered to final customers. There was again an increase both in the number of customers supplied with green electricity and in the volume delivered. In 2012, a total of 44.6 TWh of green electricity was supplied to 7.25m final customers, a significant increase of 11 TWh compared to 2011. The volume of green electricity accounted for ten percent of the total volume of electricity supplied, 2.6 percentage points higher than in 2011. Green electricity customers made up 15.2 percent of all final customers, representing a year-on-year increase of 3.4 percentage points. A detailed breakdown of the volume of green electricity delivered to final customers is given in the following table.

Table 37: Green electricity delivered to household customers and other final customers in 2012

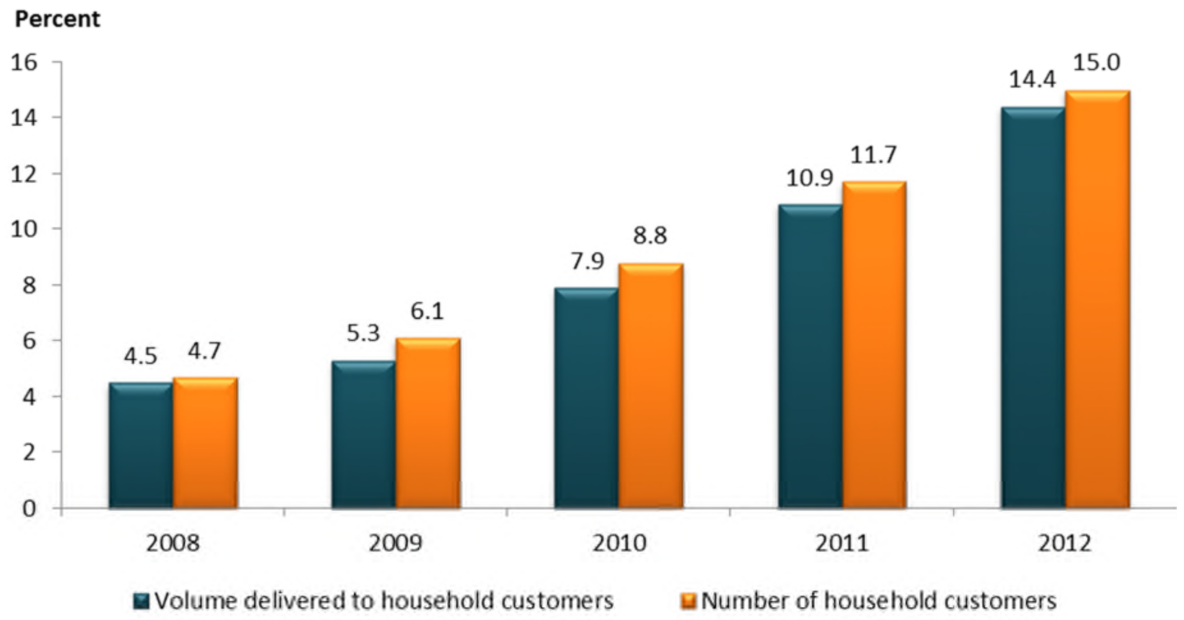
Category	Total electricity delivered (TWh) (Figures in brackets: number of metering points)	Total green electricity delivered (TWh) (Figures in brackets: number of metering points)	Percentage of total volume delivered (Figures in brackets: percent)
Household customers	128.9	18.5	14.4
	(43,163,104)	(6,470,250)	(15.0)
Other final customers	319.3	26.1	8.2
	(4,589,104)	(800,001)	(17.4)
Total	448.2	44.6	10.0
	(47,752,207)	(7,270,251)	(15.2)

14.4 percent of the total volume of electricity delivered to household customers was green electricity, while 15 percent of all household customers were supplied with green electricity. This shows that, relatively speaking,

[128] Refer for example to www.stromvergleich.de (off-peak calculator); www.verivox.de (comparison of electricity prices / heating electricity).

green electricity customers use slightly less electricity than other household customers. This is a continuation of the pattern seen in previous years, as illustrated below.

Figure 83: Green electricity volumes and household customers



A key component of green electricity prices, too, is energy procurement and supply (including margin).

Table 38: "Energy procurement and supply", volume-weighted average for household customers (green electricity) in 2013

Green electricity customers 1 April 2013	**Household customers (ct/kWh)**	**Comparison 2012:2013 (ct/kWh)**
Energy procurement and supply (including margin)	8.27	-0.15

As with conventional electricity, green electricity suppliers have introduced a range of special bonuses and schemes for household customers, offering lower prices. These most frequently comprise minimum contract periods or fixed prices for a set period of time.

Table 39: Special bonuses and schemes for household customers (green electricity) in 2013

Special bonuses and schemes (1 April 2013)	Household customers (green electricity)	
	Number of tariffs	Average
Minimum contract period	321	10 months
Fixed price guarantee	246	12 months
Advance payment	63	11 months
One-off bonus payment	67	€57
Deposit	2	-
Other bonuses and special schemes	37	-

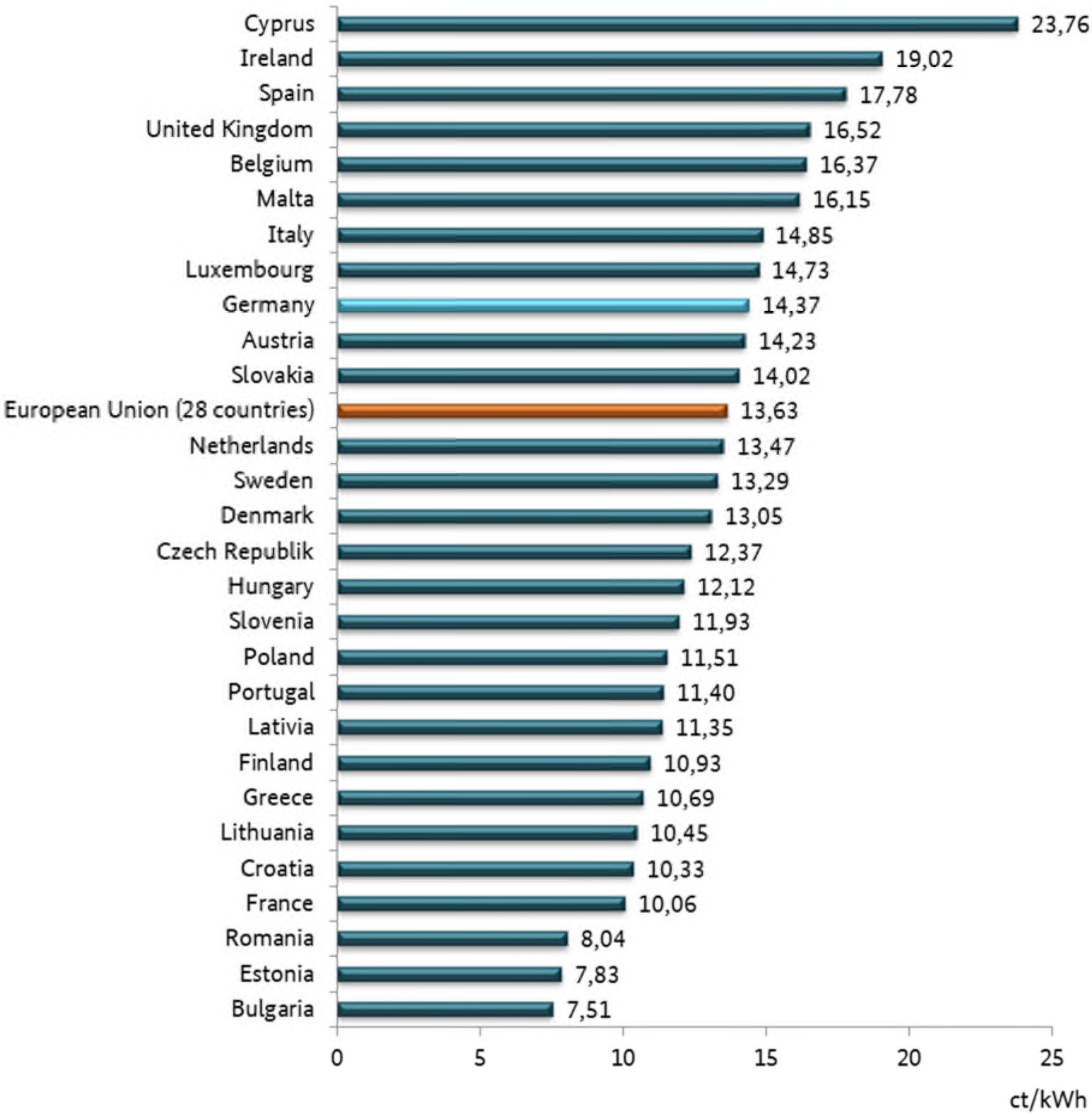
7. Comparison of European electricity prices

A comparison of electricity prices across the European Union shows that retail prices in Germany are still above average or among the highest in Europe, largely depending on whether or not taxes and levies are included. The comparison is based on data from a Eurostat survey of national average prices for household customers in 2012[129].

The average price for household customers in Germany, excluding taxes and levies, according to Eurostat was 14.37 ct/kWh, compared to the overall European average of 13.63 ct/kWh. This means that Germany's average price was five percent higher than the European average. As in the previous year, Bulgaria had the lowest average price at 7.51 ct/kWh and Cyprus the highest at 23.76 ct/kWh. The exact figures for all EU countries covered in the survey are shown below.

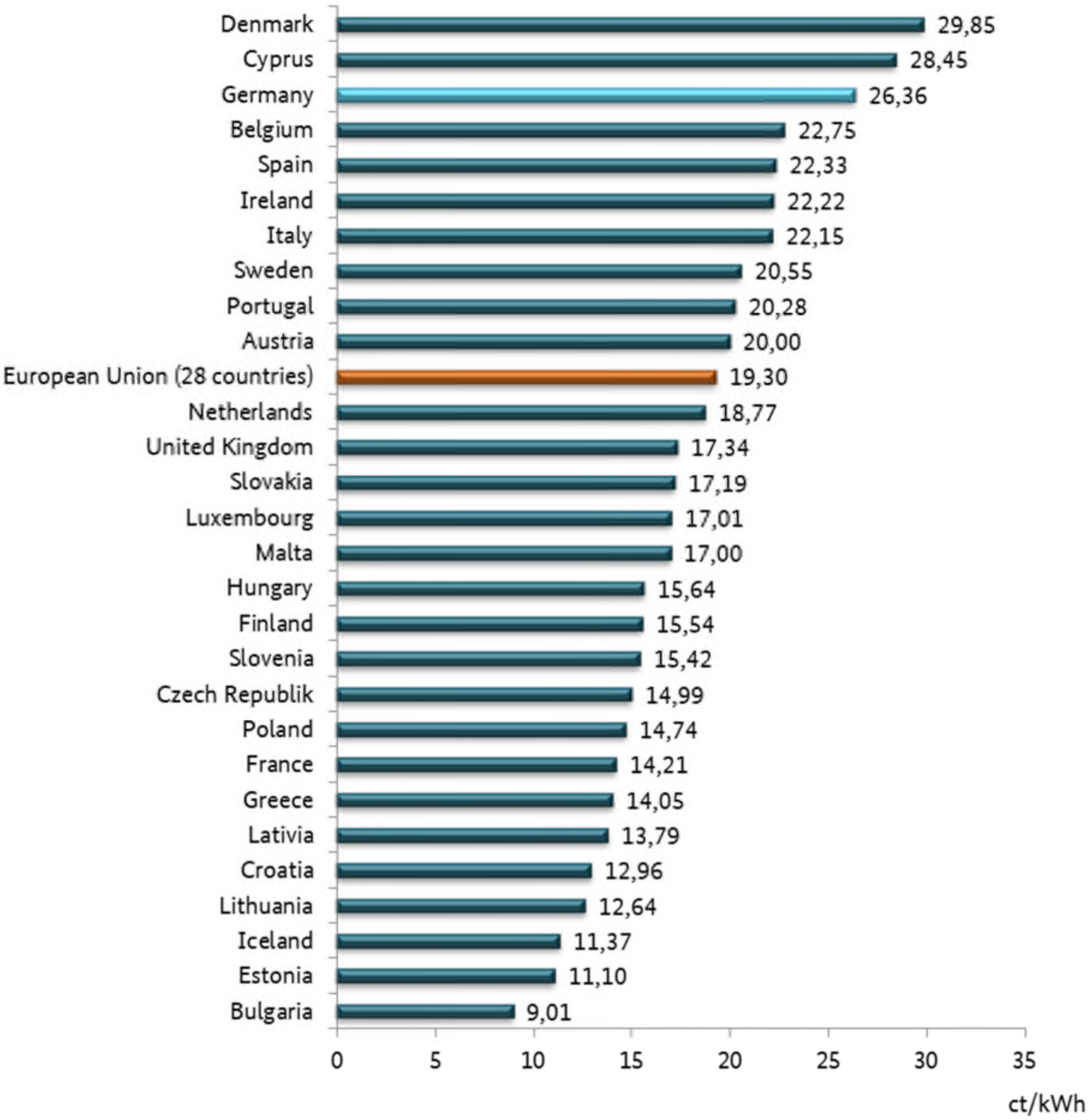
[129] The survey covered households in the Dc band with an annual consumption between 2,500 kWh and 5,000 kWh. The average was calculated for the first and second half of 2012 (2012S1 and 2012S2); overall figures for EU 28 are provisional ("p"). Deviations from the monitoring results are due to a different observation period and a different calculation methodology. Cf: http://epp.eurostat.ec.europa.eu/portal/page/portal/energy/data/database. (As of: 5 August 2013).

Figure 84: Comparison of European electricity prices for private households in 2012, excluding taxes and levies



The average price for household customers in Germany including taxes and levies was 26.36 ct/kWh. This puts Germany in third place, with its average price 36 percent higher than the European average. Denmark had the highest average price at 29.85 ct/kWh and Bulgaria the lowest at 9.01 ct/kWh.

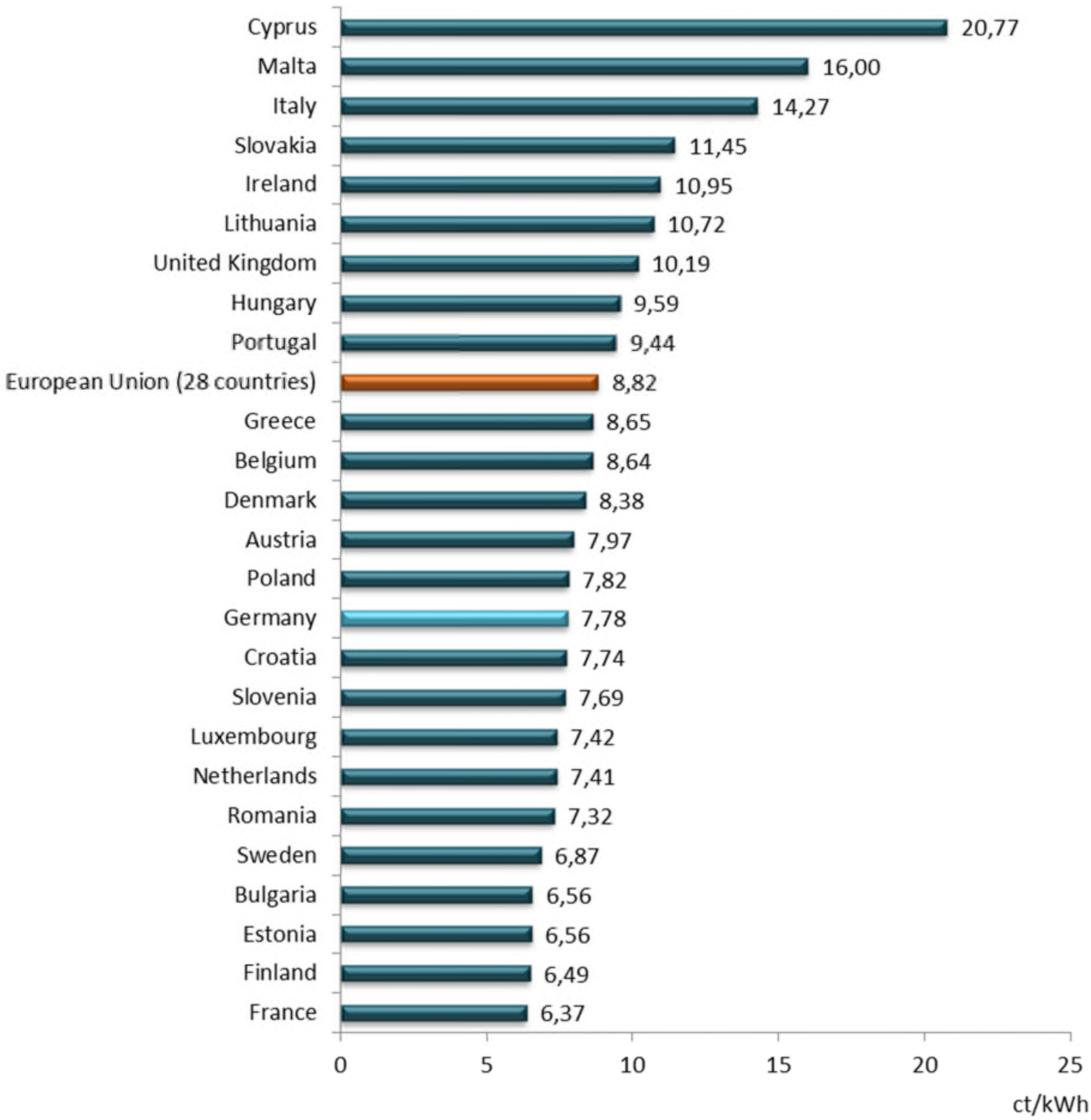
Figure 85: Comparison of European electricity prices for private households in 2012, including taxes and levies



The average price for industrial customers[130] in Germany was 7.78 ct/kWh, which was lower than the European average of 8.82 ct/kWh. Cyprus had the highest average price and Norway the lowest. The detailed figures are shown below.

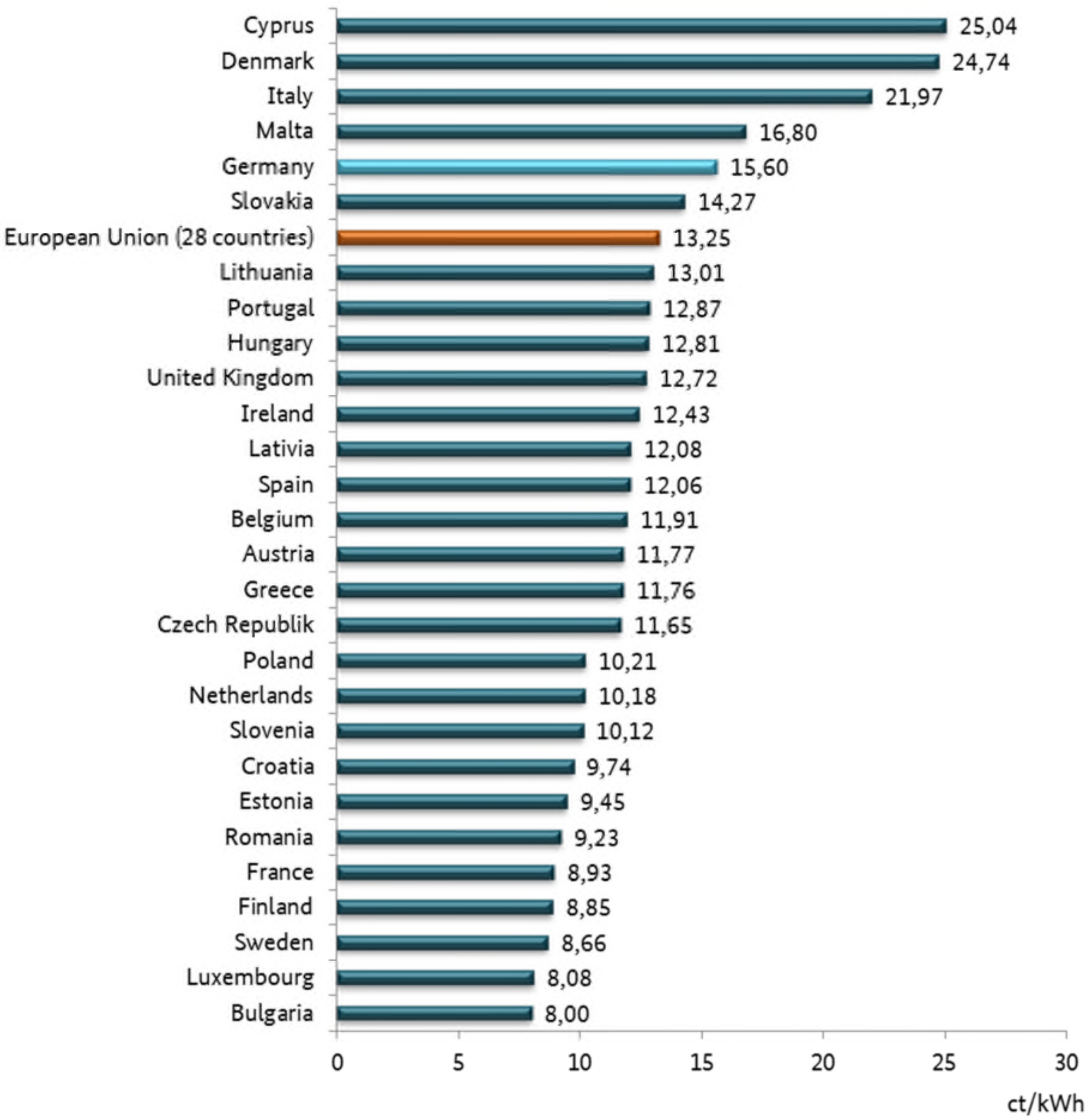
[130] The survey covered national average prices excluding taxes for industrial customers in the Id band with an annual consumption between 2,000 MWh and 20,000 MWh for the first and second half of 2012 (2012S1 and 2012S2). Overall values for EU 28 are provisional ("p"). Cf: http://epp.eurostat.ec.europa.eu/portal/page/portal/energy/data/database. (As of: 5 August 2013)

Figure 86: Comparison of European electricity prices for industrial customers in 2012, excluding taxes and levies



The average price in Germany including taxes and levies was 15.60 ct/kWh, 18 percent above the European average.

Figure 87: Comparison of European electricity prices for industrial customers in 2012, including taxes and levies



The comparison of prices across Europe shows that in 2012 Germany's retail prices were again above average. This is mainly due to taxes and levies. The prices paid by final customers in Germany, in particular household customers, are consequently among the highest in Europe: in 2012, German household customers paid on average 7 ct/kWh and industrial customers 2.3 ct/kWh more than the European average.

I Metering

In the 2013 monitoring survey, data was collected from network operators providing metering services under their primary responsibility and from independent meter operators; an independent meter operator may be the customer's supplier or a company that is neither the network operator nor the supplier. In the 2013 survey, 783 companies responded to the questions about metering. The questions differed from those in the previous year's survey on account of changes made to the legislation. The figures derived from the responses to similar questions therefore differ.

Network operators providing metering services and independent meter operators

647 network operators stated that they provided metering services to customers under their primary responsibility. 102 network operators stated that they provided metering services to customers outside their primary responsibility. 21 companies are suppliers that also provide metering services to their customers; two of these companies also provide metering services to customers whom they do not supply. Six companies are independent meter operators providing metering services to customers for whom they are neither the network operator nor the supplier. Seven companies did not belong to any of the suggested categories.

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

The 2011 revised version of the EnWG redefined the requirements for smart metering systems and laid down rules as to when smart meters are mandatory:

a) buildings which have been newly connected to the energy supply network or which have undergone major renovation;
b) final customers with an annual consumption exceeding 6,000 kWh;
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).

In 2013, the companies surveyed were asked to state the number of metering points for which a smart metering system would be mandatory under section 21c EnWG:

Category a) metering points: 343,642
Category b) metering points: 4,398,207
Category c) metering points: 136,176

The number of metering points actually fitted with an electronic metering system was given as follows:

Category a) metering points: 141,510
Category b) metering points: 171,461
Category c) metering points: 23,226
Other metering points: 33,627

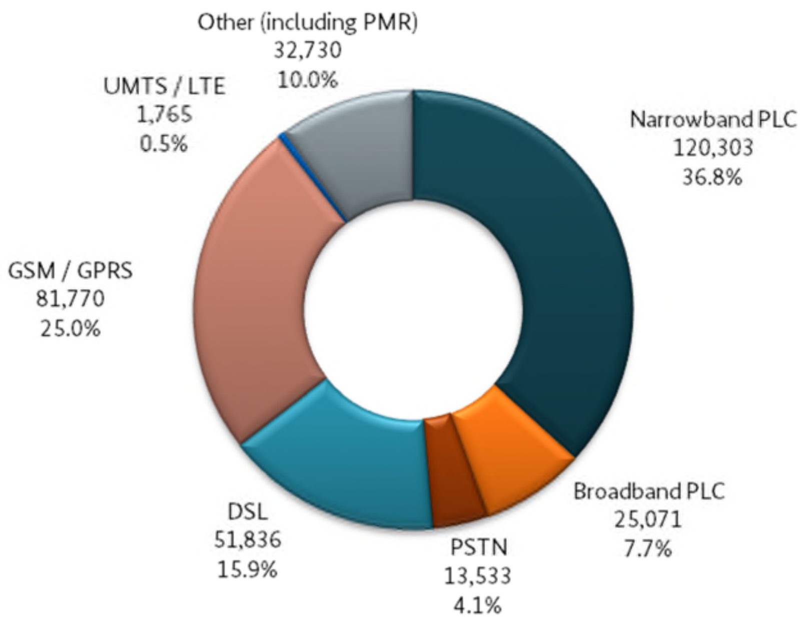
The smart meters at metering points not in categories a) to c) were fitted above all on account of section 21c(1d) EnWG (meters installed before the legislation was changed), at the customer's request or as a routine replacement.

A comparison of these figures (the number of metering points for which a smart metering system would be mandatory and the number fitted with such a system) shows the following: 41.2 percent of new and renovated buildings, 3.8 percent of customers with a consumption exceeding 6,000 kWh and 17.1 percent of installations subject to the provisions of the EEG or KWKG are fitted with the required metering systems.

Meter technology for standard load profile (SLP) customers

The majority of the domestic meters used for SLP customers are still Ferraris meters. A total of 45,190,243 such meters are in use, of which 3,089,734 (around seven percent) are two-tariff or multiple-tariff meters. The following data transmission technologies are used for electronically read meters:

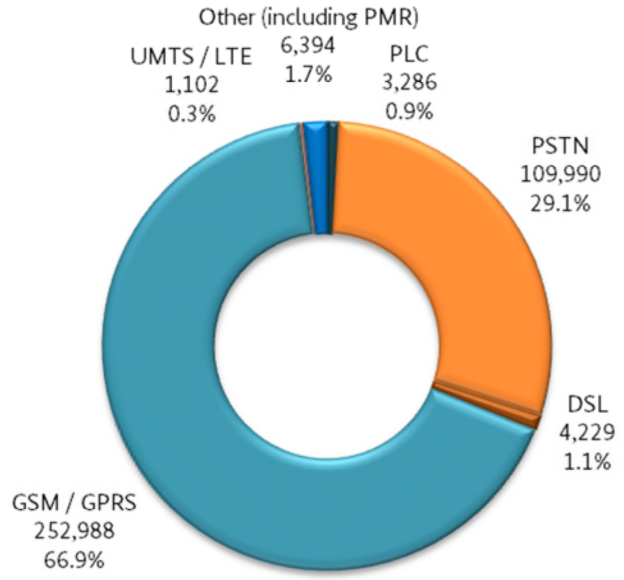
Figure 88: Transmission technologies for remotely read meters for SLP customers



Meter technology for interval-metered customers

The metering points for interval-metered industrial and business customers are fitted as follows: 386,993 with a flow meter, 17,732 with a meter conforming to sections 21d and 21e EnWG (revised version), and 5,562 with another type of meter. The following data transmission technologies are used:

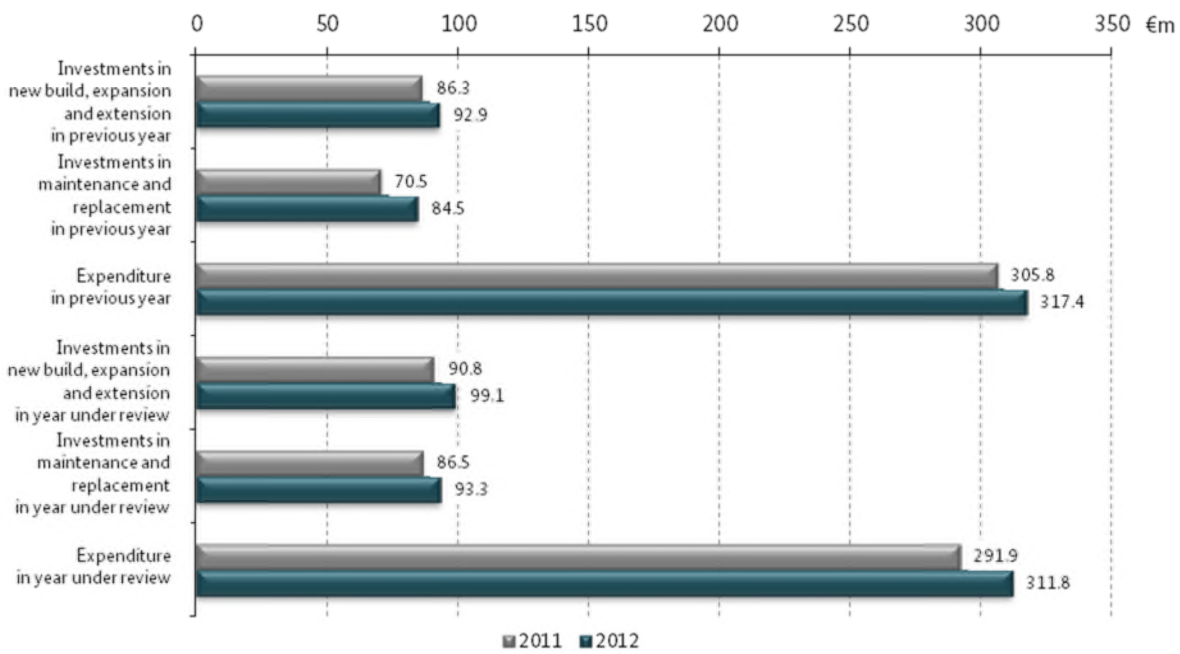
Figure 89: Transmission technologies for interval-metered customers



Investments and expenditure for metering

Investments and expenditure remained at about the same level as in 2011:

Figure 90: Investments and expenditure for metering



II Gas markets

A Developments in the gas markets

1. Key findings

In 2012, the year under review, production of natural gas in Germany decreased by 1.2bn m³ (9.7 percent) to 10.7bn m³. The decline in natural gas reserves and production is chiefly due to the increasing exhaustion and dilution of existing deposits. The total reserves-to-production ratio as of 1 January 2013 was approximately ten and a half years.

In 2012, the volume of gas imported into Germany rose by some 124 TWh (8.78 percent) from 1,411 TWh (2011) to 1,535 TWh. The main sources of imports remain Russia/CIS, Norway and the Netherlands.

The volume of gas exported increased from 516.8 TWh in 2011 to 667.3 TWh in 2012 (29.12 percent), the main recipients being the Czech Republic, France, the Netherlands and Switzerland.

On account of the long 2012/2013 heating period, underground gas storage facilities were heavily depleted, reaching a storage level of 17.5 percent in mid-April 2013. Large volumes were, however, injected from the beginning of June 2013 onwards, and on 15 September 2013 the storage level stood at approximately 70 percent[131]. Injections continued until the beginning of November 2013, achieving a maximum storage level of over 90 percent, in terms of the total working gas volume at the beginning of the previous winter. The completion of new storage facilities led to an increase in the working gas volume in 2013 of some one billion m³, resulting in a maximum storage level of around 91 percent.

There was an increase of approximately 18 percent in the investments made in 2012 by the gas distribution system operators (DSOs) in new builds/expansion/extension and sustainment and renewal, compared to 2011. In contrast, the investments in maintenance and servicing fell by around five percent.

The dual-quality (H-gas and L-gas) OTC trading volume at the virtual trading points in the NCG and Gaspool market areas increased from a total of some 2,066 TWh in 2011 to 2,460 TWh in 2012, a rise of about one fifth. The trading volume on the EEX amounted in 2012 to approximately 76 TWh (2011: around 59 TWh); this represents an increase of some 29 percent. The average daily reference price at the virtual trading points rose to €25.19/MWh (2011: €22.81/MWh). The average border price was around €29/MWh (2011: €25.75/MWh). The average gas price for futures on the EEX was €24.66/MWh (2011: €23.53/MWh).

The volume of gas delivered by gas suppliers to final customers (including gas-fired power plants) in 2012 amounted to 815.4 TWh, five percent more than the volume in 2011. The volume of gas delivered to private households was almost ten percent more than that in the previous year. Gas network operators (transmission system operators (TSOs) and DSOs) in Germany reported an output volume of 955.68 TWh in 2012. There was an increase of nearly eight percent in the volume of gas delivered to private households and small businesses.

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[131] Based on a working gas volume of 23.53bn m³ (see also II.H.2 “Access to underground storage facilities” on page 253).

The trend towards greater choice of supplier strengthened in the year under review. In almost 86 percent of the network areas final customers can now choose from 31 or more gas suppliers.

According to the network operators, the volume of gas affected by supplier switching in 2012 was around 102.06 TWh, which is 5.8 TWh or 5.37 percent lower than in the previous year. In the smallest category of household and small business customers (≤300 MWh/year) the supplier switching volume fell by 4.89 TWh.

The network operators reported 1,039,471 supplier switches in 2012, representing a decrease of 236,177, or about 18 percent, compared with 2011. This is almost entirely attributable to the decrease in the number of household and small business customers (≤300 MWh/year) switching.

The prices for business and industrial customers have developed as shown below.

Table 40: Development of the volume-weighted average gas prices

	Volume-weighted average price on 1 April 2013 (ct/kWh)	**Volume-weighted average price on 1 April 2012 (ct/kWh)**	**Difference (percent)**
Business customers with change of contract tariffs	6.28	6.26	0.32
Industrial customers with a change of contract with the same supplier	4.68 (arithmetic average)	4.61 (arithmetic) average)	1.52
Household customers with default supply	7.09	6.95	2.01
Household customers with change of contract tariffs	6.69	6.58	1.67
Household customers with change of supplier tariffs	6.66	6.48	2.78

The following table shows how Germany's prices compared with European prices in 2012.

Table 41: Comparison of gas prices in Germany and Europe including and excluding

	Germany (ct/kWh)	Europe (ct/kWh)	Difference (percent)
Household customer prices excluding taxes and levies in 2012	4.81	5.22	-7.85
Household customer prices including taxes and levies in 2012	6.43	6.74	-4.60
Industrial customer prices excluding taxes and levies in 2012	4.40	3.70	18.91
Industrial customer prices including taxes and levies in 2012	5.72	4.78	19.66

A comparison of gas prices across Europe gives a more differentiated picture. While Germany's prices for household customers are mid range, the prices for industrial customers are among the highest. Taxes and levies do not account for as much of the end customer price as in the electricity sector.

2. Market overview

2.1 Shares of the largest companies

The market shares held in 2012, the year under review, by the largest companies in each sector of the gas market – production, imports, exports, volume of working gas in underground storage and gas delivered to final customers – were determined by analysing the majority shareholdings of the 850 or so companies participating in the 2013 survey and allocating the market shares to the consolidated parent company using the dominance method[132].

Calculations of the companies' market shares in the nine sectors reviewed (see **Fehler! Verweisquelle konnte nicht gefunden werden.**) show that a total of twelve companies were present in the groups of the three largest and five largest companies across all the sectors. In most cases, the majority of the shareholders are German.

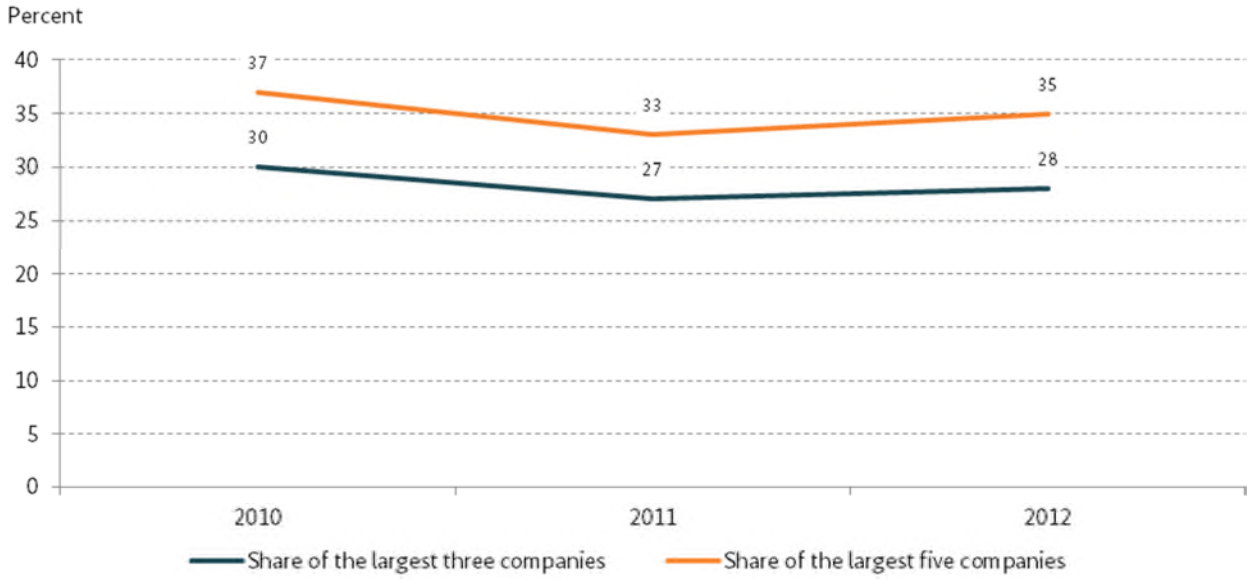
The three largest and five largest companies account for a high percentage of imports, exports and production. The level of market concentration in the supply of gas to the customer groups shown below is considerably lower. The following table shows the market shares of the three largest and five largest companies in each sector reviewed, as calculated using the dominance method.

[132] In the dominance method, the volume of gas delivered by dominated (consolidated) companies is fully allocated to the relevant dominant company. Volumes of companies in which two companies each hold a 50 percent share are allocated on a 50/50 basis to the owner companies.

Table 42: Shares of the three largest and five largest companies in each sector of the gas market, 2010-2012

	Shares of the three largest (percent)			Shares of the five largest (percent)		
Year	**2010**	**2011**	**2012**	**2010**	**2011**	**2012**
Production	66.2	67.1	67.3	82.6	79.2	83.1
Imports	56.4	55.8	59.9	72.9	69.2	68.5
Exports	66.0	67.6	69.0	82.7	82.2	94.7
Storage – working volume	56.0	58.9	49.4	72.2	72.0	53.7
Total gas delivered to final customers	29.5	27.1	28.5	37.1	33.3	35.5
Gas delivered to final customers ≤300 MWh/year	26.7	23.6	23.0	31.5	29.3	28.6
Gas delivered to final customers >300 MWh/year ≤100,000 MWh/year	25.5	20.5	25.5	33.3	27.6	34.4
Gas delivered to final customers >100,000 MWh/year	46.7	43.8	51.4	57.7	54.0	60.2
Gas delivered to gas-fired power plants	39.2	38.2	35.6	50.0	40.6	39.4

Figure 91: Shares of the largest wholesalers and suppliers in the total volume of gas delivered to final customers, 2010-2012



The shares of the three largest and five largest wholesalers and suppliers in the total volume of gas delivered to final customers increased slightly in 2012, compared to 2011.

Figure 92: Shares of the three largest wholesalers and suppliers in the total volume of gas delivered to final customers, broken down into customer categories, 2010-2012

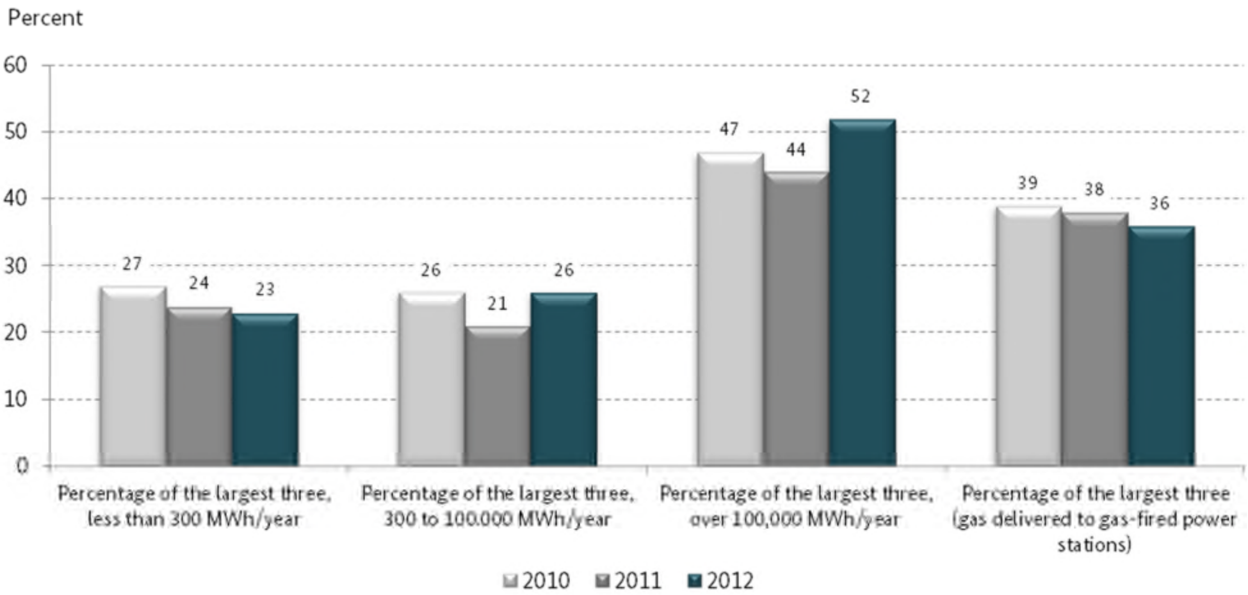


Figure 93: Shares of the five largest wholesalers and suppliers in the total volume of gas delivered to final customers, broken down into customer categories, 2010-2012

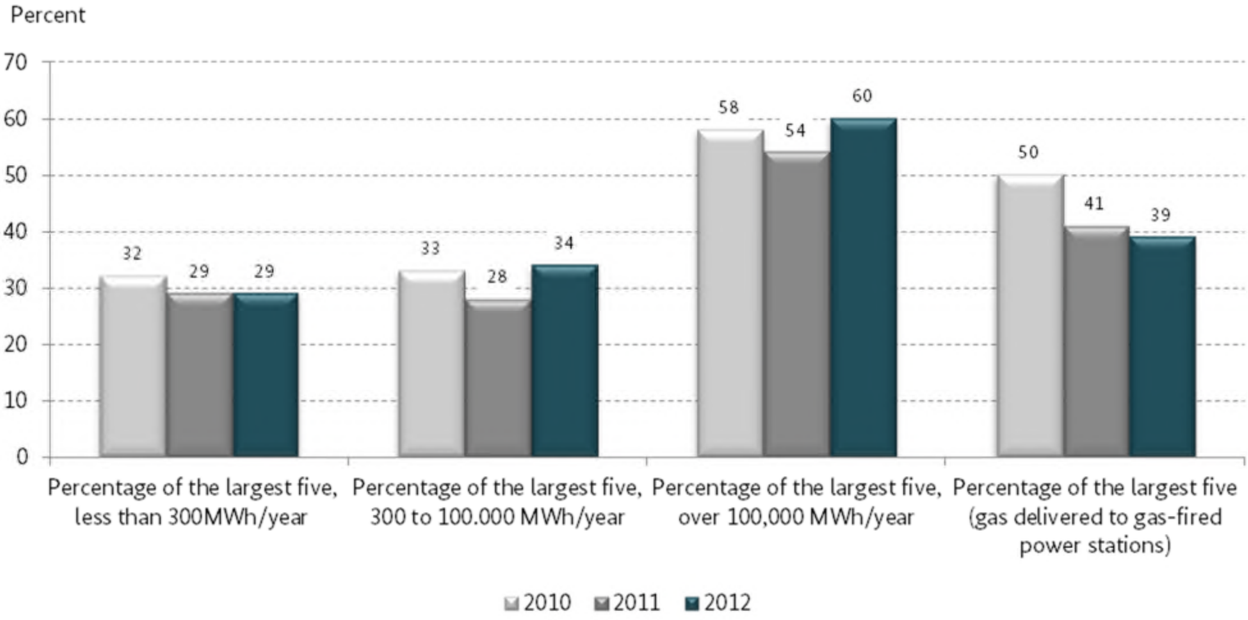
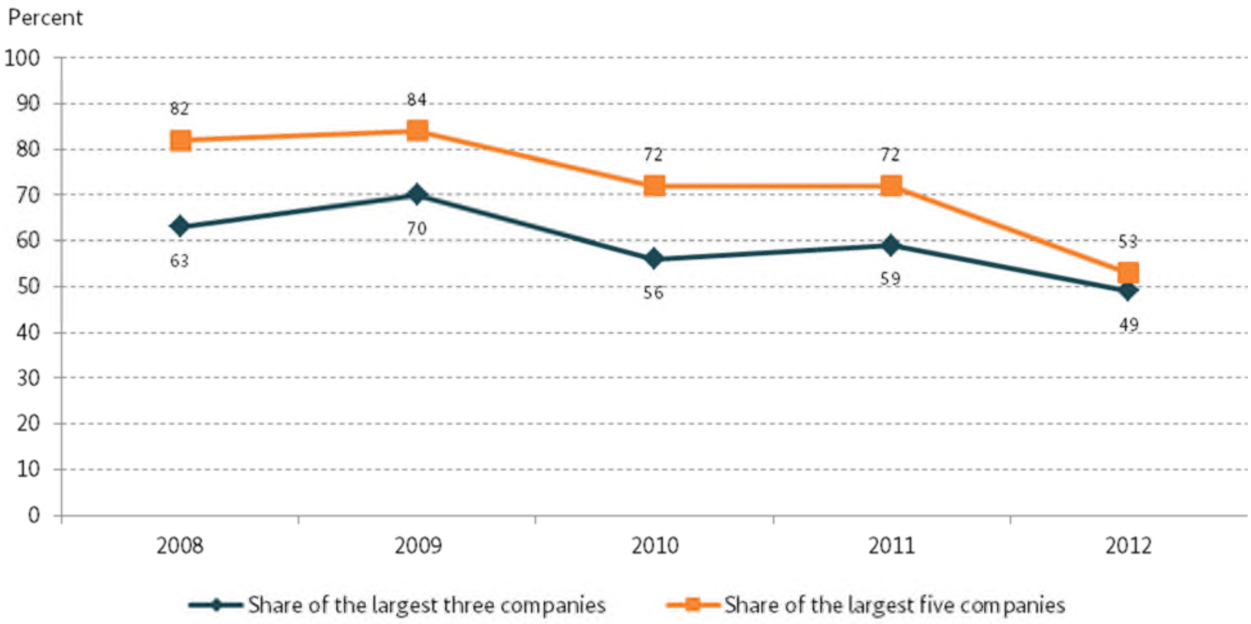


Figure 94: Shares of the largest gas storage facility operators in the maximum usable working gas volume



In 2012, the shares allocable to each operator using the dominance method were calculated solely on the basis of the maximum usable volume of working gas in underground storage facilities and the operators of such facilities.

The survey showed that a total of 22 underground storage facility operators held a usable working gas volume of 23.531bn m^3 in 2012. In the same year, the three largest and five largest companies held over 49.0 percent and 53.3 percent respectively of the maximum usable working gas volume (see Table 42). The decrease in the shares of the largest five companies compared to 2011 is due to the sale of company shares, with the result that the consolidation threshold of 50 percent as calculated in the dominance method is not reached. The increase in the volume of working gas stored is a result of the opening of additional underground storage facilities.

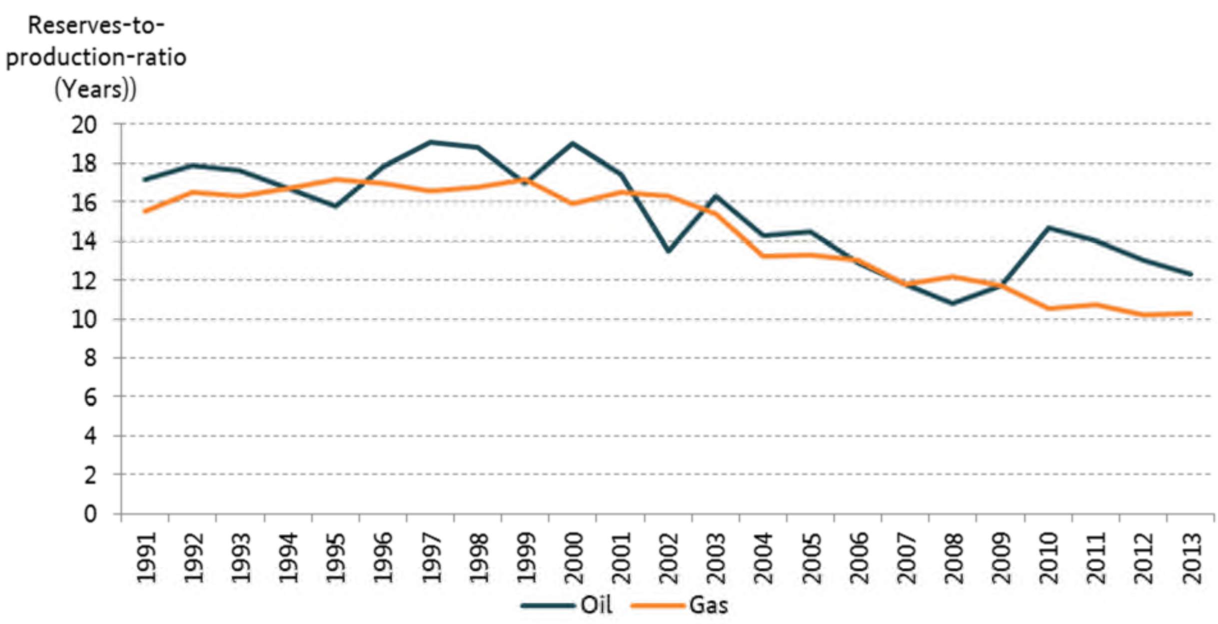
B Production of natural gas in Germany and imports & exports / security of supply

1. Production of natural gas in Germany and imports/exports

1.1 Production of natural gas in Germany

Natural gas production in Germany decreased by 1.2bn m^3 to 10.7bn. m^3 in 2012. This corresponds to a decline of 9.7 percent compared to the previous year. This 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 the proven and probable natural gas reserves, that is the ratio based on calculations from the previous annual production and reserves, is 10.5 years on 1 January 2013 and has improved slightly compared to last year's value. The reserves-to-production ratio does not take the natural decline in output from the deposits into account and therefore should not be seen as a forecast, but rather as a snapshot and guideline figure, (source: Oil and natural gas reserves in the Federal Republic of Germany on 1 January 2013; State Authority for Mining, Energy and Geology; Lower Saxony).

Figure 95: Reserves-to-production ratio of German oil and gas reserves since 1991,



1.2 Development of gas imports and exports

In 2012, the volume of gas imported into Germany increased by some 124 TWh (8.78 percent) from 1,411 TWh (2011) to 1,535 TWh.

Figure 96: Countries of origin of the gas volumes imported to Germany in 2012

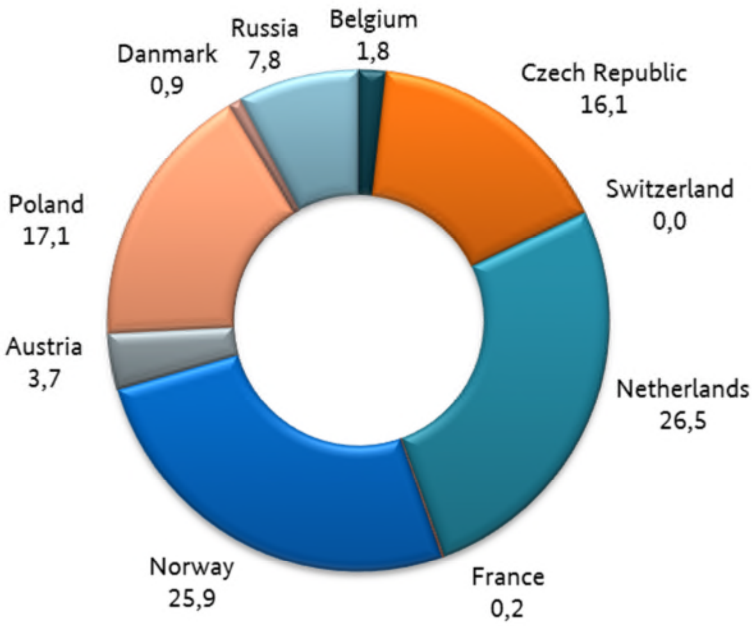
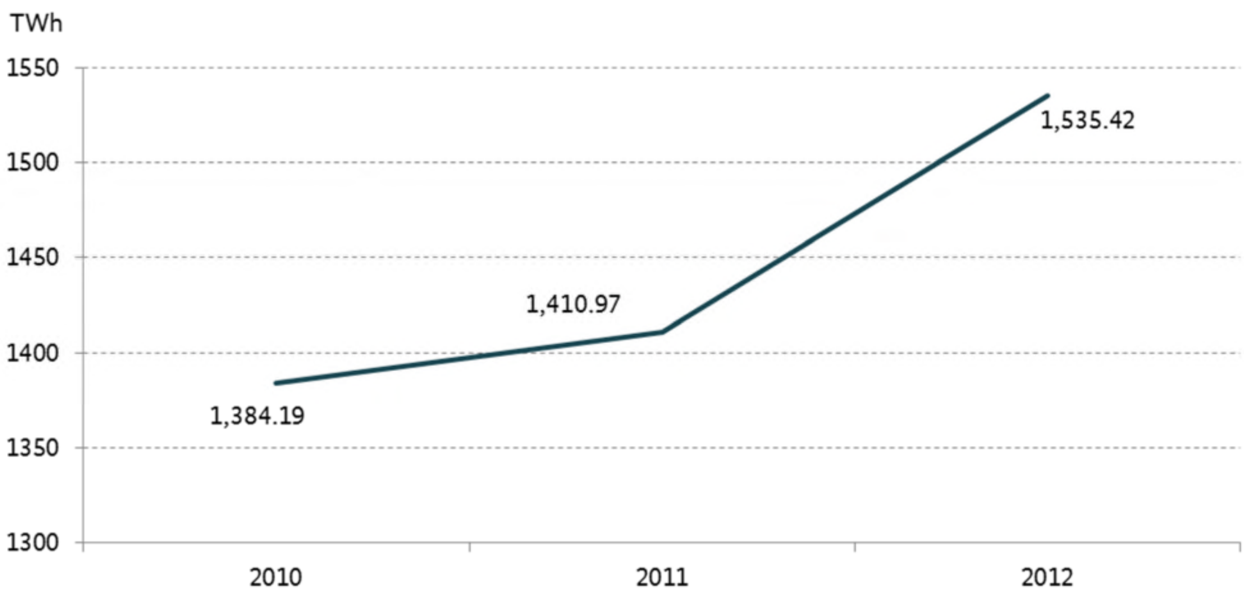


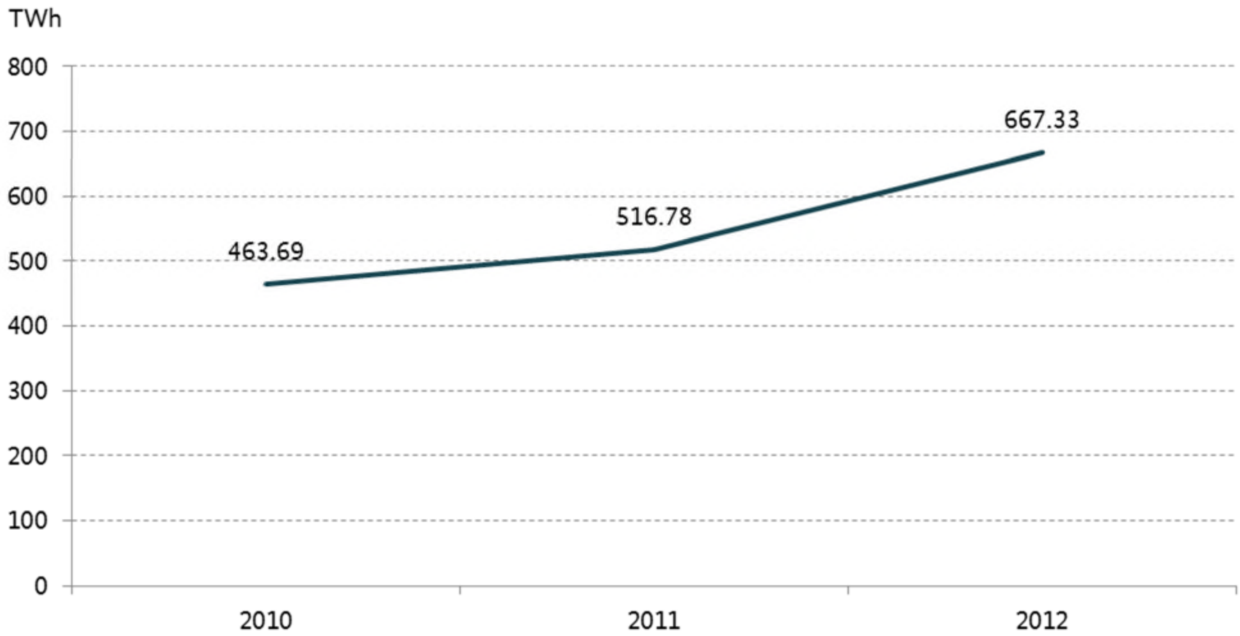
Figure 97: Development of gas imports



The most important sources of gas supplied to Germany are still Russia / CIS countries and Norway. However, the Netherlands, as an established and liquid trading hub in Europe and point of arrival for LNG shipments with connections to natural gas fields in Norway and the United Kingdom, is also a significant source of imports for Germany. Improved integration of national markets and more efficient management of cross-border capacities has eased trading and provided further alternatives for gas traders. The first operational year of the Nord Stream pipeline in the Baltic lead to an increase of gas imports from Russia/CIS states. The share of gas imported from Russia/CIS states compared to the total volume of gas imported is approx. 45 percent.

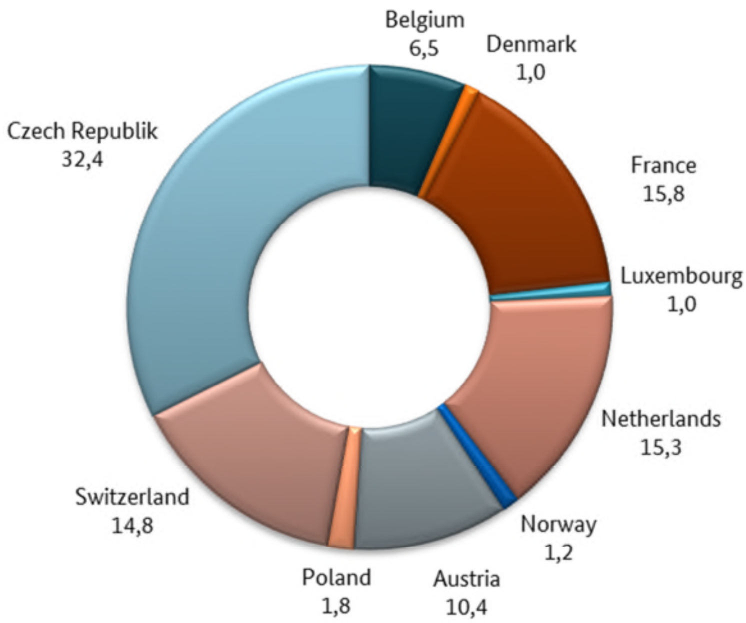
Gas exports have also risen. In 2011 gas exports have risen from 516.8 TWh to 667.3 TWh in 2012 (a rise of 29.12 percent).

Figure 98: Development of gas exports



Compared to 2011, changes that are in some cases considerable can be noted when analysing the countries to which gas was exported from Germany. Particularly striking is the substantial increase in exports to the Czech Republic which has doubled in volume as a result of the new Nord Stream pipeline and the Baltic Sea connecting pipeline. The share of exports to the Czech Republic rose to 32.4 percent from 20.3 percent. The increase in exports to France was weaker, increasing by 24 percent compared to 2011. Exports to Denmark decreased. The rest of the exports to other countries stayed more or less constant, however with a reduction in the percentage due to the significantly increased volume of total exports.

Figure 99: Distribution of the volumes of gas exported to neighbouring countries in 2012[133]



2. Security of supply

Duties to report supply disruptions under section 52 EnWG

As in previous years the Bundesnetzagentur undertook a comprehensive survey of all disruptions in gas supplies. Section 52 of the EnWG requires gas network operators to report all supply disruptions to the Bundesnetzagentur by 31 April each year. The Bundesnetzagentur uses these reports to calculate the SAIDI (System Average Interruption Duration Index) value for all final customers. This indicator expresses the average duration of supply disruptions experienced by a customer over a period of one year. The SAIDI value does not take into account scheduled interruptions, nor those caused by force majeure, for example by natural disasters. Only unplanned interruptions caused by third-party intervention, ripple effects from other networks or other disturbances in the network operator's area are included in the calculations.

The SAIDI value was 1.91 minutes (rounded off) in 2012. For each German final customer, this meant an average interruption of gas supplies in 2012 of just under two minutes. Gas supplies thus continued to be very reliable in Germany in 2012 and were on a par with the multiannual mean.

The 2012 results of the comprehensive survey of supply disruptions in all gas networks in the Federal Republic of Germany registered in the Bundesnetzagentur's energy database (approximately 720) were as follows:

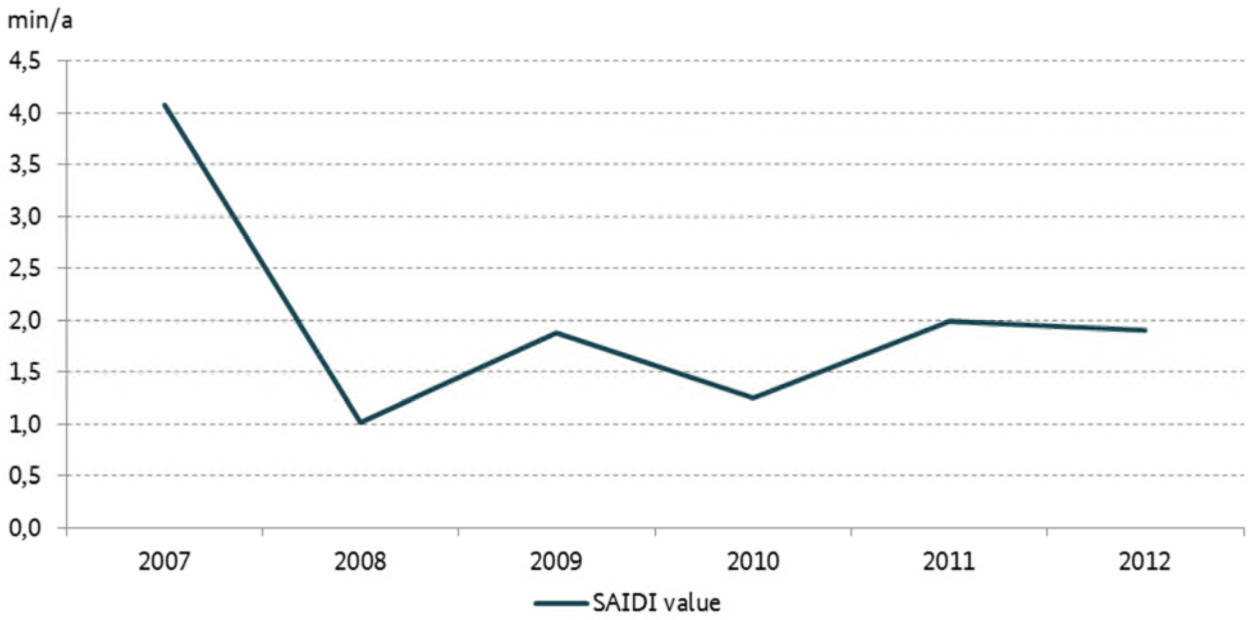
133 Figures may not sum exactly owing to rounding.

Table 43: Survey results for 2012

Pressure range	Specific SAIDI	Notes
≤ 100 mbar	0.795 min/a	Households and small consumers
≤ 100 mbar	1.111 min/a	Major consumers
≤ 100 mbar	2.777 min/a	Downstream network operators
Independent of pressure range	1.906 min/a	SAIDI value for all final consumers

The SAIDI value for German gas network operators has been calculated by the Bundesnetzagentur since 2006. These measurements are reflected in the following time series:

Figure 100: SAIDI values over time (2006 - 2012)



C Networks / Investments / Network tariffs

1. Networks / Investments

1.1 Network data

Network operators were asked about the total length of their network, as well as its length subdivided according to pressure ranges (nominal test pressure in bar). The findings were as follows:

Table 44: Total length of the networks divided up according to pressure range

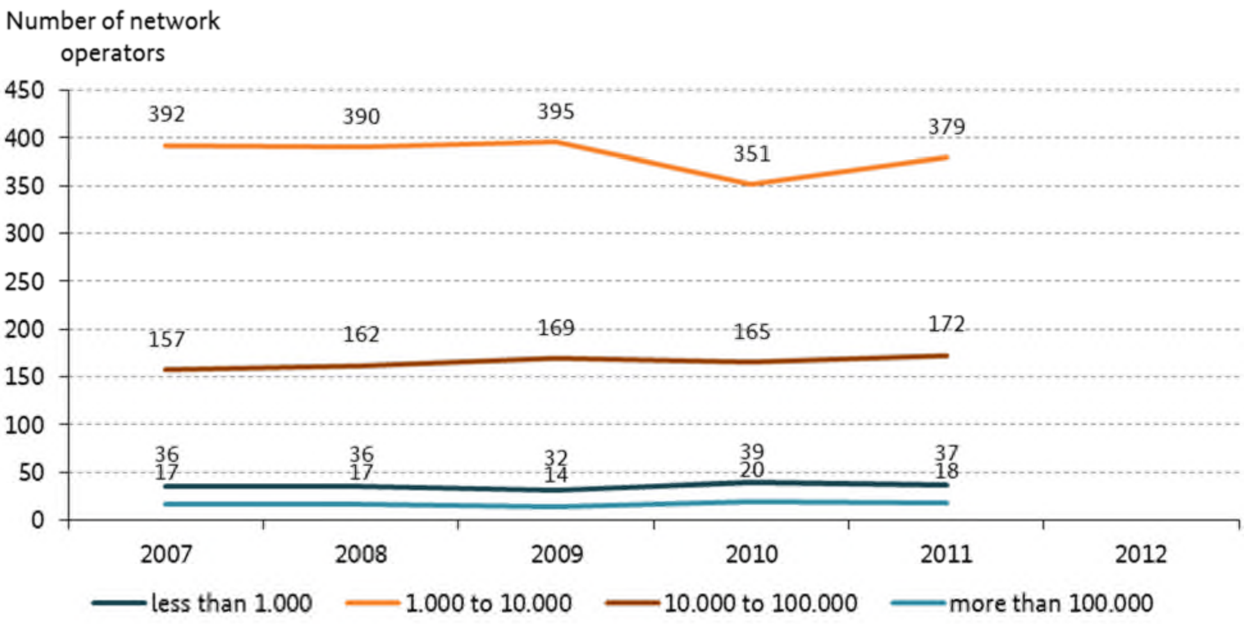
	Total length	Pressure range ≤ 0.1 bar	Pressure range > 0.1 – 1 bar	Pressure range > 1 bar
Distribution system operators	470,433 km	154,505 km	223,075 km	92,853 km
Transmission system operators	37,695 km	0 km	1 km	37,694 km

97 percent of surveyed companies have published this data in accordance with section 27(2) of the Gas Network Charges Ordinance (GasNEV); three percent have not done so or did not respond. There is a total of 5,413 entry points to all gas networks, of which 198 entry points are for emergency entry only. 77 percent of companies which responded can access upstream network operators at several interconnection points; this is not the case for 22 percent, and one percent did not respond.

DSOs were asked whether they had placed an internal order under section 8 of the cooperation agreement KoV IV with upstream network operators in the reporting year 2012 or, alternatively, whether they had notified the required capacity in accordance with section 13 KoV IV. This was the case for 93 percent of companies which responded; five percent gave a negative response and two percent did not reply at all. Companies which responded with "yes" were also asked whether their internal orders had been reduced by the upstream network operator. This was the case for almost eleven percent of the relevant companies. In almost all cases these were alternatively offered interruptible capacities for internal bookings. 52 percent of companies exceeded their internal bookings or notified capacity in the reporting year 2012, a considerable increase compared to the previous year (14 percent).

The number of exit points developed as follows between 2007 and 2012:

Figure 101: Development of exit point figures



1.2 Gas Network Development Plan 2012 and 2013

The Gas Network Development Plan, to be published on an annual basis as provided for by 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 Plan focuses on the one hand on expansion issues arising via the connection of new gas power plants - there is particular overlap here with the electricity market - and 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 2012 was presented to the Bundesnetzagentur by the TSOs within the specified period on 1 April 2012. The document was then submitted for comprehensive consultation by the Bundesnetzagentur[134]. Taking the results of the consultation into account, the Bundesnetzagentur formulated a modification request addressed to the TSOs on 10 December 2012. The TSOs were, among other things, instructed to present all binding network expansion measures for the next ten years in a complete and transpar-

[134] The statemens made as part of the consultation process have been published on the website of the Bundesnetzagentur (http://www.bundesnetzagentur.de/cln_1931/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/NetzentwicklungundSmartGrid/Gas/NEP_Gas2012/netzentwicklungsplan_Gas2012-node.html)

ent manner. Additionally, TSOs were obliged to execute specific network expansion measures[135]. The Gas Network Development Plan 2012 became binding on the TSOs with the announcement of the modification request. The revised Gas Network Development Plan 2012, ie including the modification request of the Bundesnetzagentur, is has been published on the website of the TSOs[136].

The total investment volume for the binding network expansion measures specified in the Network Development Plan 2012 is €3,200m. By 2022, the measures translate into line construction of a total length of 1,320km and additional compressor capacity of 485 MW[137]. This comprises network expansion measures that do not directly result from the network calculations of the Network Development Plan 2012 and were already in the process of being implemented during the creation of this Plan.

On 1 April 2013 the TSOs presented the Bundesnetzagentur with the Gas Network Development Plan 2013, which contains several modelling variations that vary especially in terms of the capacity products and/or levels for gas power plants, storage facilities and downstream networks that are applied for network calculation. Depending on the modelling approach taken, the resulting required investment for gas transmission networks is between €1,400m and €3,243m. The TSOs propose a variant based on efficient capacity products that involves a total cost of €1.6bn. The document was made available by the Bundesnetzagentur for consultation up to 21 June 2013[138]. An evaluation of the consultation results and the drafting of a modification request had not been completed at the time of the editorial deadline of the Monitoring Report.

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[135] see modification of the Bundesnetzagentur from 10 Dezember 2012 (http://www.bundesnetzagentur.de/cln_1931/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/NetzentwicklungundSmartGrid/Gas/NEP_Gas2012/netzentwicklungsplan_Gas2012-node.html)

[136] http://www.fnb-gas.de/netzentwicklungsplan/nep-2012/nep-2012.html

[137] Cf. Network Development Plan 2012, annex 3

[138] see draft of the network development plan 2013 (http://www.fnb-gas.de/netzentwicklungsplan/nep-2013/nep-2013.html)

Figure 102: Graphical representation of the results of the gas network development plan in 2012

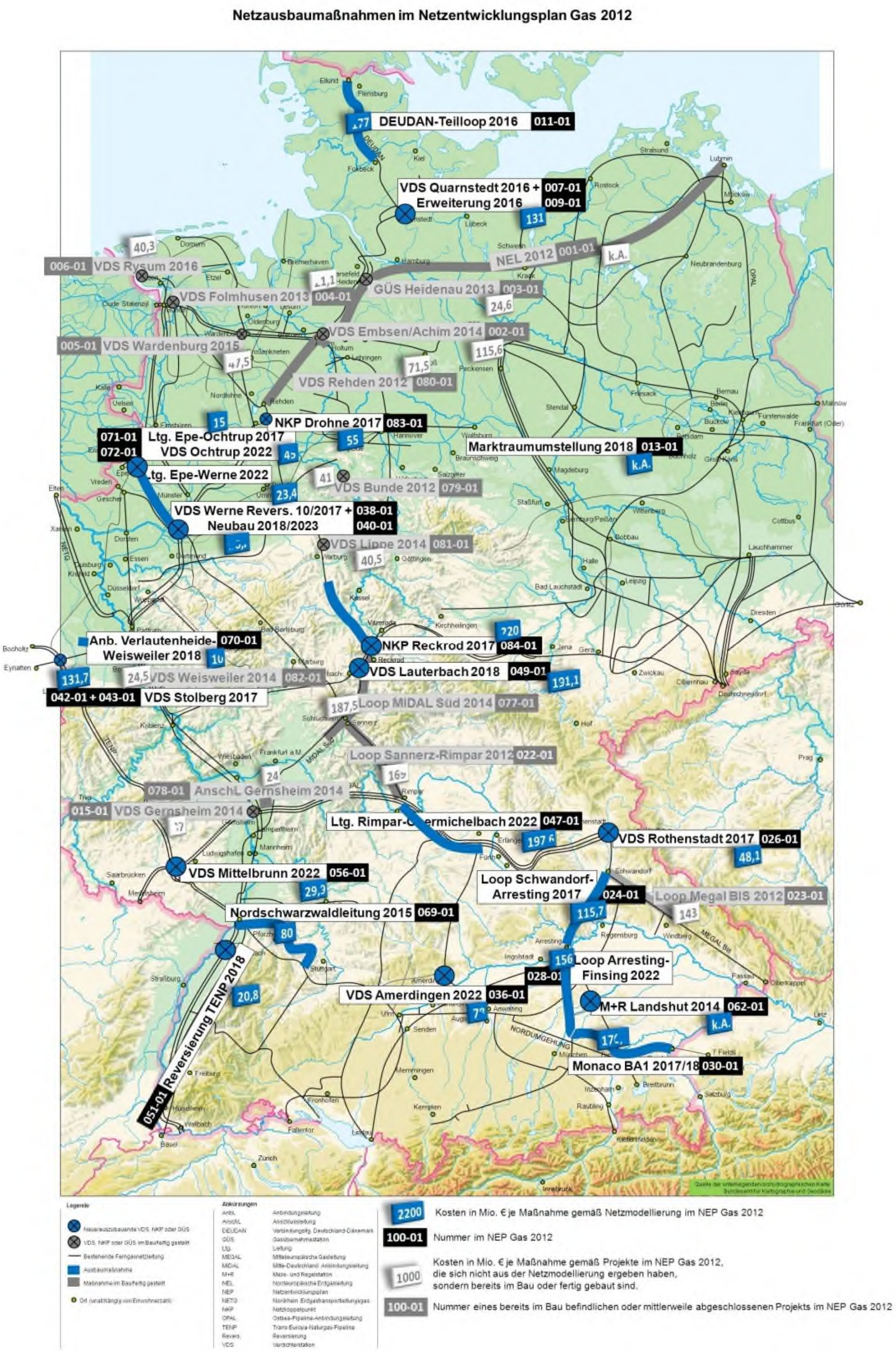
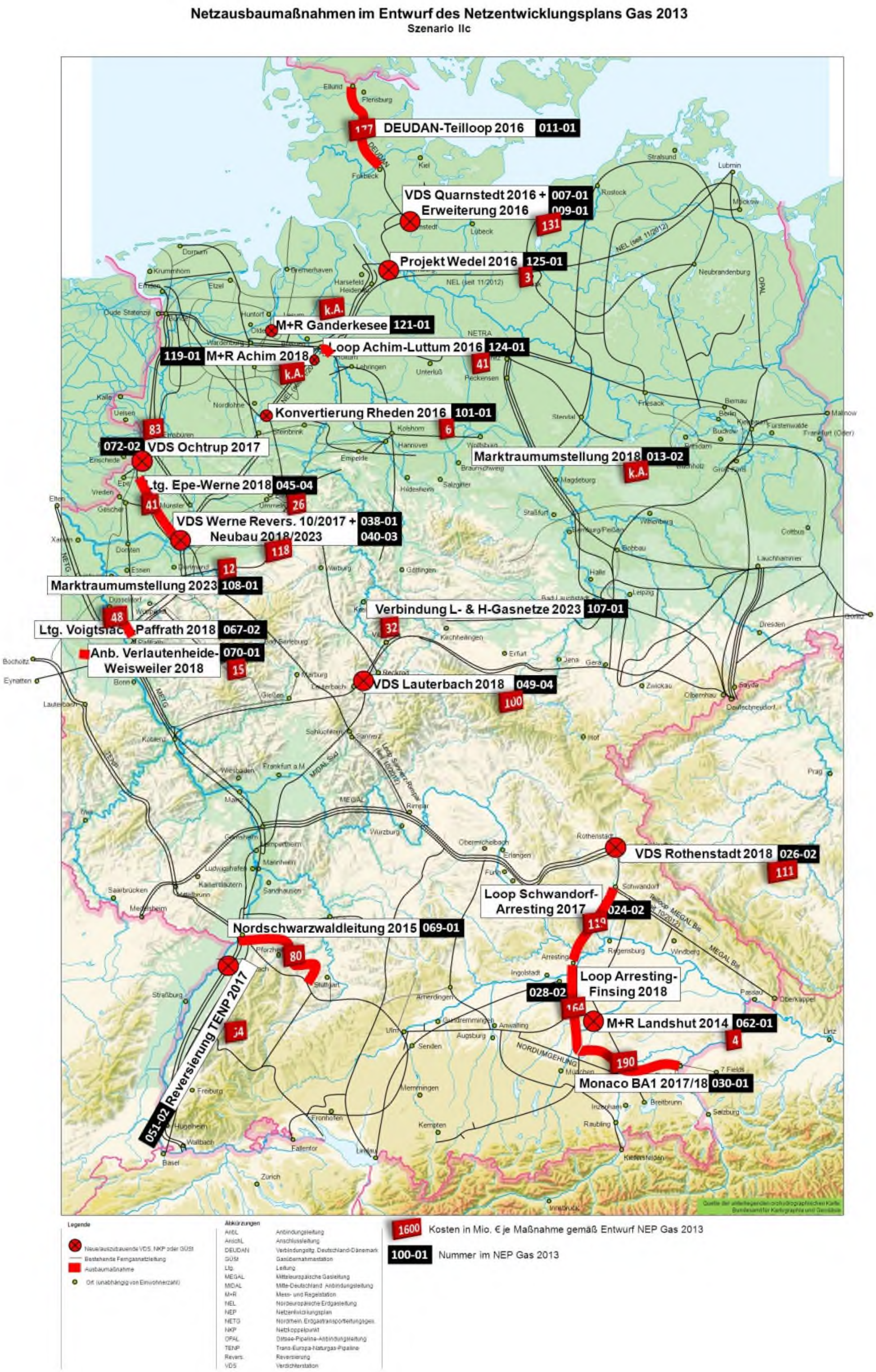


Figure 103: Graphical representation of the results according to the draft network development plan, gas 2013 (Scenario IIc)



1.3 Capacity offer and marketing

As in the previous reporting year, the questions asked dealt with the booking, use, availability and booking preference for transport capacity in 2012. 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. Much as in last year's report, 143 of the shippers surveyed (a 60 percent majority) preferred the two-product model. The other 40 percent (96 shippers) favour additional firm capacity products. The corresponding figures for the previous year (the 2010/2011 gas year) were 55 to 45 percent for the two-product model. The absolute figures are shown inside the column in the diagram.

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 bFZK or DZK). Load flow commitments are contractual agreements between a network operator (TSO) and a third party (usually a shipper or a storage user) regarding the provision or the restriction of a specific gas flow at an entry or exit point or zone in the network. During the planning phase such commitments appear to be not only necessary to ensure that the supply of FZK can be raised to a sufficient level, but also capable of doing so. They can be offered by third parties which have either import, export or market area interconnection points or storage facilities or consumption installations in their portfolio and are prepared, against payment by the network operator, to adapt the originally free use of their capacities, when necessary, to the TSO's requirements.

A 59 percent majority of shippers (158 in total) were in favour of using load flow commitments. 41 percent (110 shippers) preferred the alternative, ie the offer of other capacity products. When the responses are collated – irrespective of whether both questions were answered – it seems clear that a majority of shippers favour the two-class capacity model (firm and interruptible capacity only), where necessary with FZK safeguarded by load flow commitments. But a closer look at individual replies exposes a contradiction in the response of nearly one third of the shippers. On the one hand they said they preferred to be offered only interruptible capacity alongside FZK. On the other, no load flow commitments should be entered into as a means of ensuring a sufficient supply of FZK, but additional firm capacity products such as bFZK or DZK should be offered instead.

1.4 Capacity transformation

In the 2011/2012 gas year only one shipper stated that part of its exit capacity (6.7m kWh/h FZK) had been transformed into other capacity products. On the entry side not a single existing capacity contract underwent such transformation. Compared with the 2010/2011 gas year this meant a decrease of 47m kWh/h. One reason that made the transformation of FZK contracts into contracts for other capacity products necessary in the last reporting period was the consolidation of market areas. As there was no such consolidation in the current reporting period, one of the main reasons for transformation was non-existent. There were nevertheless changes in the supply of entry and exit capacity. The changes had less to do with a reduction of quantity, as in the last report, than with an overall shift away from the entry to the exit side. In the NetConnect Germany market area entry capacity fell by 5.6m kWh/h as against a rise of 23.5m kWh/h in the supply of exit capacity.

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 104: Offer of entry capacity in the market areas of NetConnect Germany and Gaspool

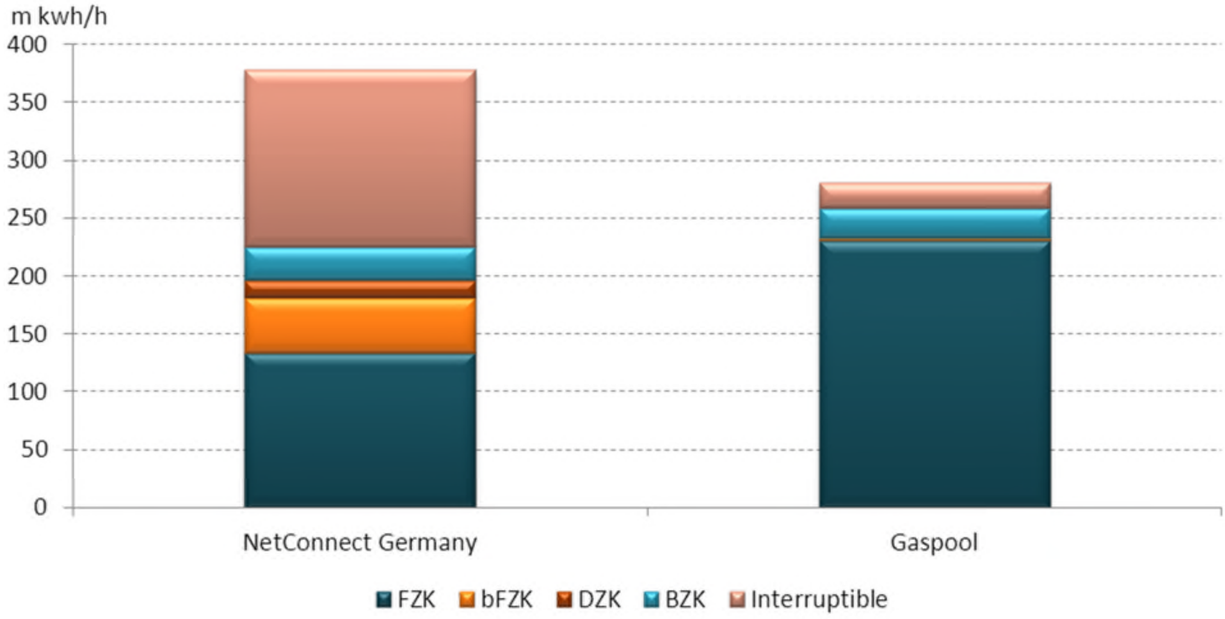
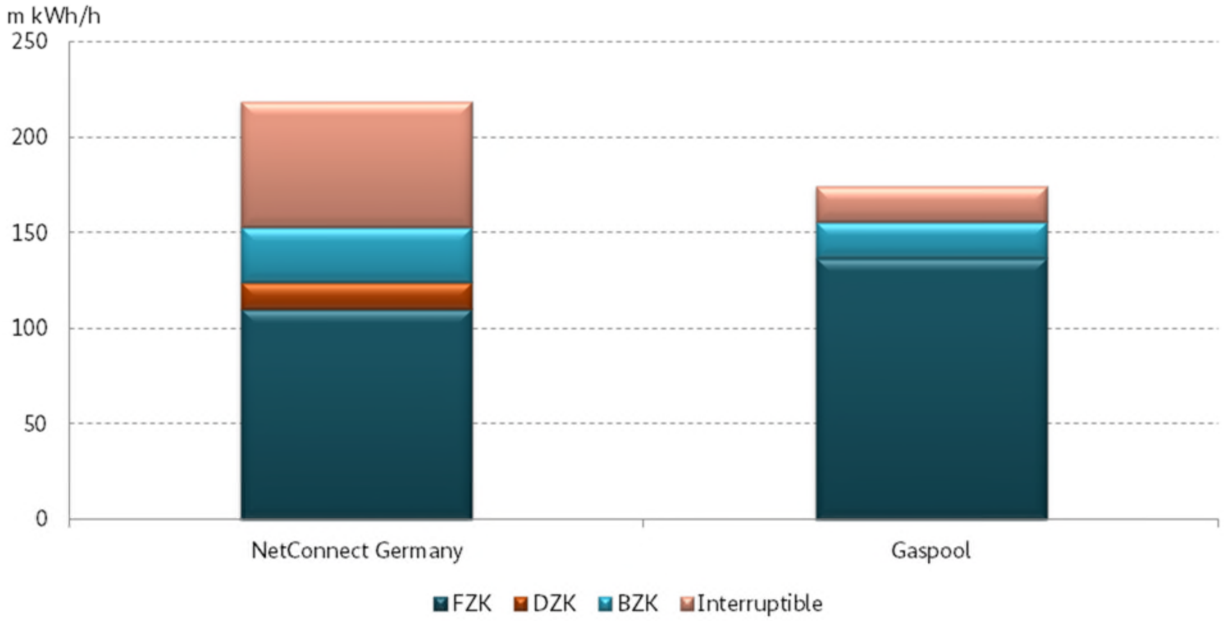


Figure 105: Offer of exit capacity in the market areas of NetConnect Germany and Gaspool

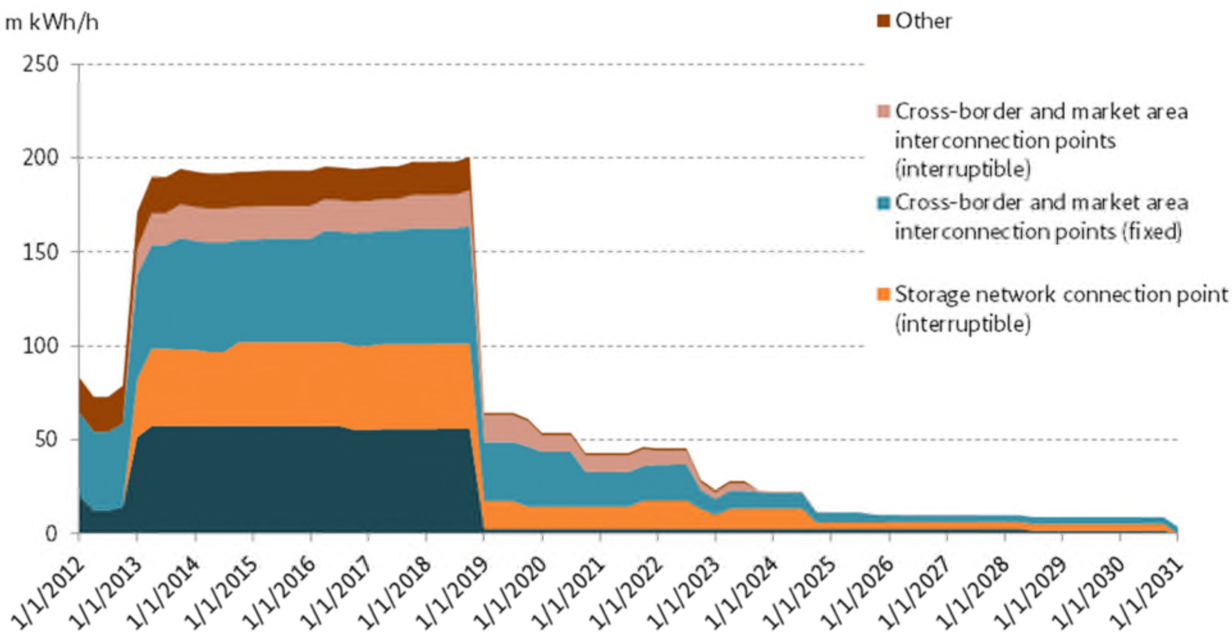


1.5 Capacity contract terminations

A large number of long-term capacity contracts entered into by shippers with the TSOs were terminated in the reporting period on grounds of price adjustments. Most of these contracts had terms between 2013 and 2018, the peak being reached at a volume of about 200m kWh/h. This represents nearly a quarter, or around 834m kWh/h, of median total booking volume (excluding internal orders). The terminations specifically surveyed were those involving price increases. Contracts can however also be terminated if major changes are made to the terms, so the total given does not necessarily reflect the actual level of terminations but only those resulting from tariff increases. Because a significantly lower capacity volume was marketed and the network operators' revenue caps remained more or less the same, there will be another rise in the specific capacity tariffs, as is already evident in the TSOs' price sheets for 2013. Whether this will lead to further terminations of long-term capacity contracts remains to be seen.

The figure below shows the volumes of the terminated contracts on the basis of the duration originally contracted for, broken down into quarter years. The terms of individual contracts may also start or end inside a quarter. This can result in a marginally higher result for particular quarters.

Figure 106: Capacity contract terminations (cf median total booking volume 2012: approx 834m kWh/h)



The following factors may have brought about terminations of capacity contracts:

- 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 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. It is also apparent that there is little demand for long-term firm transport capacity at storage facilities, which raises the question of how much importance storage customers really attach to constantly firm (freely allocable) transport capacity and what they are prepared to pay for it (see Chapter II.H Storage facilities, page 255). 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. Consequently substantial tariff fluctuations must be expected from one year to the next.

1.6 Capacity offer; interruptible capacity

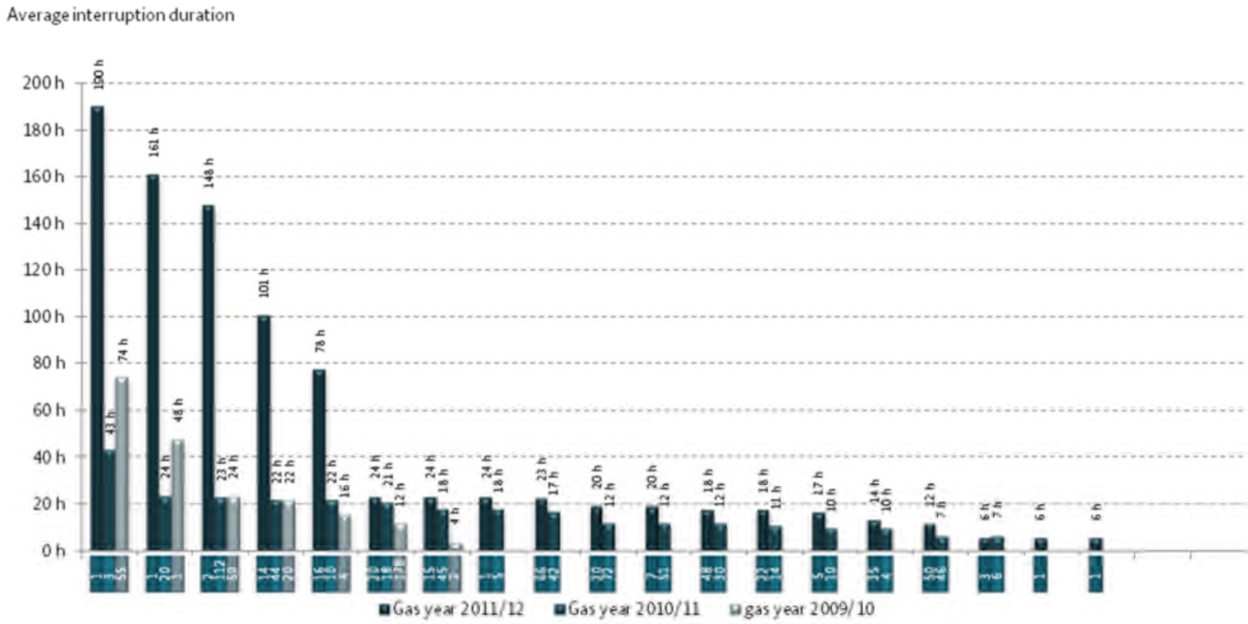
Interruptible gas capacity is basically less expensive than firm capacity. It does however involve the risk that the gas transport desired may not be possible.

Bookings of interruptible capacity stayed at much the same level as in the previous year. However, according to the TSOs, the proportion of interruptible bookings rose on the entry side but fell on the exit side. In the current reporting period the total share of interruptible bookings, based on median booking volume, was 38 percent on the entry side and 23 percent on the exit side. This meant a significant year-on-year decline of booked interruptible exit capacity (2011: 35 percent).

The market area mergers in the last reporting periods and the fact that it is consequently no longer possible to book points between what were formerly separate market areas means that the offer of firm transport capacity, in particular firm and freely allocable capacity (FZK), has been reduced. One result was that less firm capacity was booked and the relative share of interruptible bookings in relation to firm capacity bookings rose during the year under review.

19 of the 60 gas wholesalers and suppliers working under interruptible capacity contracts stated that they had in fact experienced interruption in the 2011/2012 gas year. As in recent reporting years there was 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, 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: 26 hours as against 17 in the year before. This places it at the level of the 2009/2010 gas year, when there was a similar total volume of interruptible capacity under contract. There was, however, a marginal year-on-year decrease in the total length of interruption for all affected companies (from 8,787 hours in 2010/2011 to 8,648 hours in 2011/2012).

Figure 107: Number of interruptions and average interruption duration per company for the 2009/2010, 2010/2011 and 2011/2012 gas years

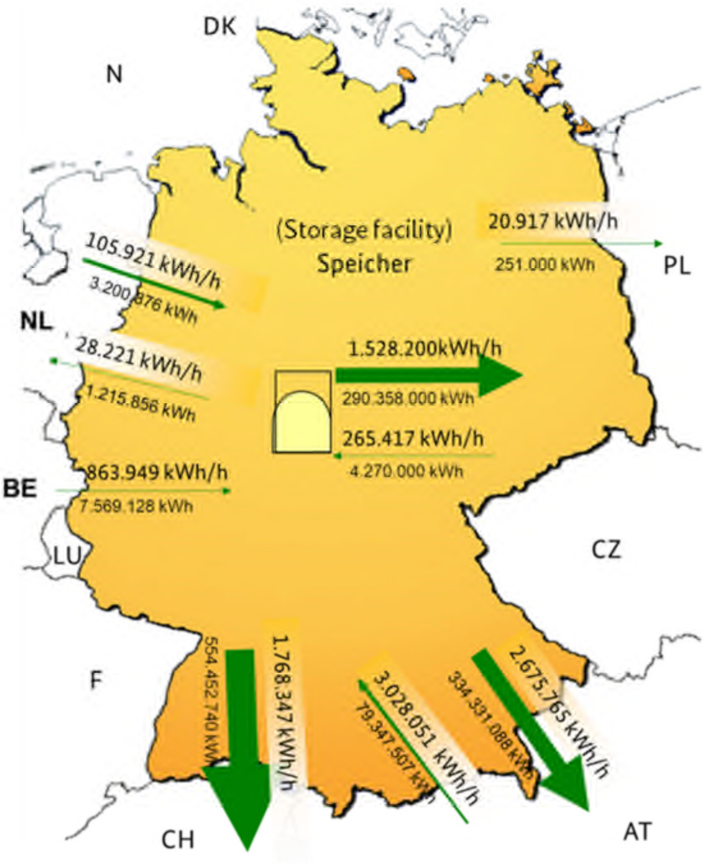


The diagram can be elucidated by a brief explanation of a single example. The company with the highest interruption duration in gas year 2010/11 (column 1) experienced a total of one interruption lasting 190 hours. A second company (column 4 for gas year 2011/2012) was interrupted much more frequently (14 interruptions), on average however for just 101 hours in each case. As a result, the total interruption duration for this company is 1,414 hours, significantly higher than for the first company with 190 hours.

Similarly, network operators were asked about 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 2011/2012 gas year, the volume of gas that was not transported through all entry and exit points was 1.3bn kWh, compared with 3.3bn kWh in the previous reporting period. Nearly all the interruptions (99.7 percent) were of interruptible capacity. The effect of the interruption of firm capacity products was that a total of 4.3m kWh of the initially nominated volume was not transported; the corresponding figure for 2011 was 30.5m kWh. Most of these interruptions affected bFZK capacity. In relation to the total volume transported in the gas year under review (2,690bn kWh), only 0.05 percent of the nominated gas volume was actually interrupted.

The following map sets 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. The capacity is shown as a weighted average in relation to total interruptions in hours and the total nominated volume across all points in the respective region. This means that where median capacity (capacity level) is identical but the arrows differ in width, interruptions were more frequent where the arrows are wider. This can be illustrated using the example of the interruption of exit capacity from storage facilities and exit capacity destined for Switzerland. The average interrupted exit capacity for storage facilities (1,528,200 kWh) is more or less the same as at the exit points in the direction of Switzerland (1,768,347 kWh). But the arrow in the direction of Switzerland is much wider than that at the storage facility. In order to interrupt the same volume of gas, either a greater capacity has to be interrupted in the same period of time, or less capacity over a longer period (or more frequently). As the capacity is more or less the same, gas transmission in the direction of Switzerland was interrupted for a longer period (exit capacity Switzerland 856 hours, exit capacity at the storage facilities 190 hours).

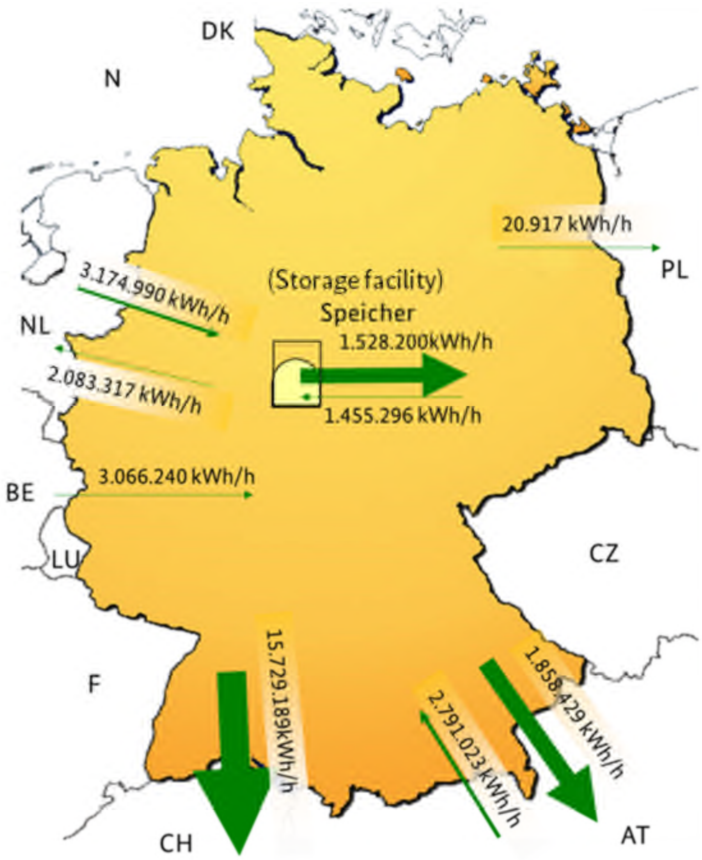
Figure 108: Regional overview of interruption capacity and volumes in the 2011/2012 gas year



The average capacity interrupted in the direction of Austria was 2,675,765 kWh/h. Larger capacity was interrupted from Austria to Germany, but the interruptions were less frequent and consequently affected smaller gas volumes (cf arrow width).

Interruptions of supply to final consumers are not included in the diagram. In relation to total interrupted volume, the volume affecting final consumers was extremely small at 0.08 percent of the total. There were no interruptions at the market area interconnection points, in contrast to the previous reporting period, when the corresponding figure was 10 percent.

Figure 109: Interruptions by highest hourly capacity in the 2011/2012 gas year



1.7 Contractual disconnection agreements

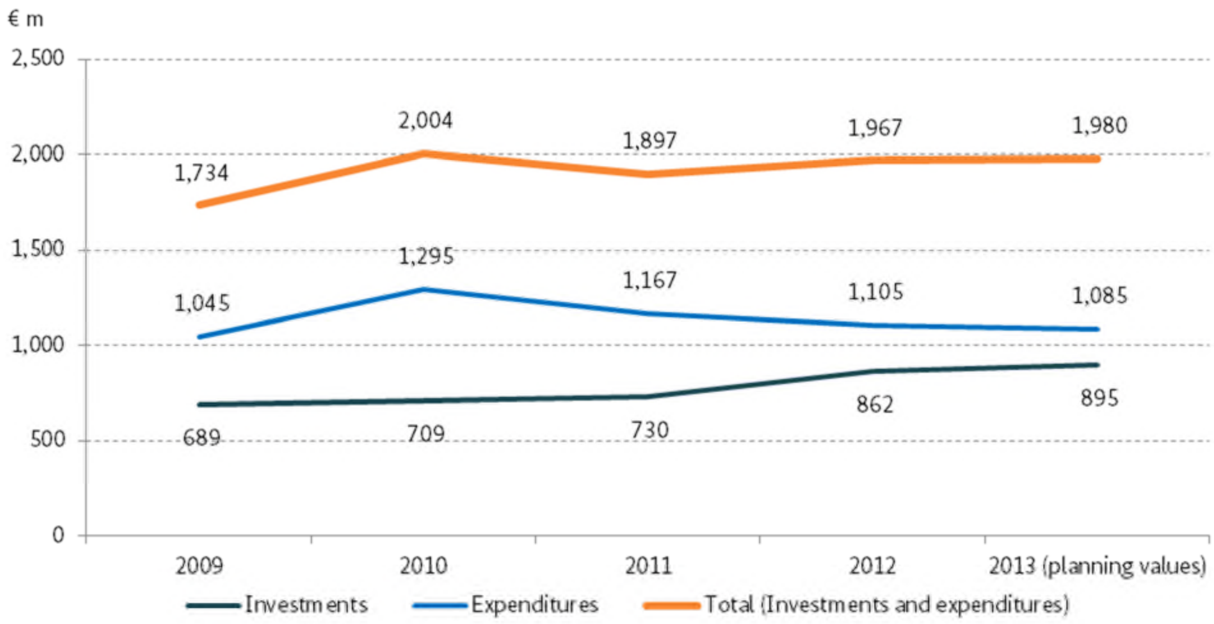
For the 2013 Monitoring Report, network operators were asked for the first time about any disconnection contracts they had concluded with their customers. An amendment to section 14(b) of the Energy Act (EnWG) had enabled them to enter into such contracts on condition that and for as long as the contract served the purpose of averting congestion in the upstream network. Seven percent of them had availed themselves of disconnection contracts, 87 percent had not, and six percent gave no response.

The average number of disconnection contracts per network operator was 3.9, with the highest number in any one case being 23. As a rule these contracts have a limited term of one year and offer the customer a tariff reduction of a maximum of 80 percent (average cut: 48 percent). The average capacity that may be disconnected is 64,276 kW per network operator, the highest single case being 1,232,640 kW. The possibility of a disconnection was actually utilised in 67 percent of the contracts entered into. In reply to the question of how the offer of a disconnection contract was made known, 33 percent of the network operators stated that they had published it in their price sheet, 54 percent had selected another, unspecified method, and 13 percent had used their own website.

1.8 Investment in and expenditure on network infrastructure by gas DSOs

Gas distribution system operators were asked about total annual investment in and expenditure on new builds/expansion/extensions and sustainment/renewal of network infrastructure (excluding metering technology) in 2012, as well as the relevant forecasts for 2013.

Figure 110: Investment in and expenditure on network infrastructure by gas DSOs



In the “Investment in new builds/expansion/extensions” category a comparison of the actual figure for 2012 (€581 million) with that for 2011 (€461 million) shows a clear year-on-year increase in investment. This is largely due to greater investment by some of the major network operators, mainly in the area of connecting biogas installations to the network. Their forecasts for 2013 suggest they expect investment levels to remain more or less the same. The forecasts for the “Investment in sustainment/renewal”category indicate a slight rise, while the tendency for “Expenditure on maintenance/servicing (new installations/expansion/extension, sustainment and renewal” shows a marginal decline[139].

2. Network tariffs

2.1 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

[139] For investment by gas TSOs in network infrastructure see Chapter II.C.1.2 Gas Network Development Plan 2012 and 2013 (page 184)

cap. 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 2012, a total of 75 applications for expansion factors were made; 92 applications were received in 2013.

2.2 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 data submission form is available on the Internet. 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.

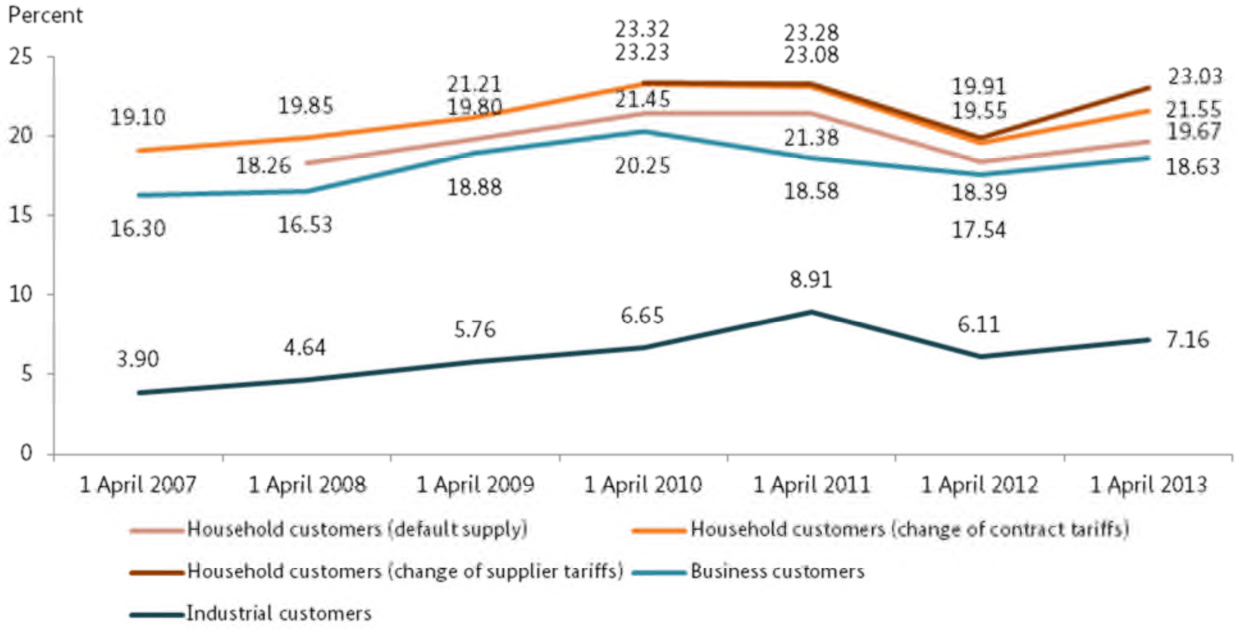
2.3 Network interconnection points under section 26(2) ARegV

In 2012, a total of 24 applications concerning network transfer, merging and splitting in the gas sector were submitted under section 26(2) ARegV to the Bundesnetzagentur. The 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.

2.4 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.

Figure 111: Share of volume-weighted network tariff in gas price between 2007 and 2013.
Prices as of 1 April 2013 according to survey of gas wholesalers and suppliers.



The share accounted for by the network tariff in the overall gas price rose again for the first time in two years in all customer categories except for the group of industrial customers; here, there was another slight decrease in 2013. The increase in the other customer categories is due to the fact that special conditions no longer apply: additional revenues generated unfairly by the operators in the past had led to a decrease in the network tariffs in the last few years, but the balance has now largely been met.

2.5 Cost examination as per section 6 ARegV and for efficiency benchmarking as per section 22 ARegV

The Bundesnetzagentur established the base level for determining the revenue caps for the second gas regulatory period (2013-2017) in a cost examination. In total, 249 operators of gas supply networks were obliged to submit to the Bundesnetzagentur the necessary documents for determining the base level as per section 6(1) ARegV for the second regulatory period (2013-2017). Of the 249 operators, 106 are taking part in standard proceedings (benchmarking), while 143 are involved in simplified proceedings.

The Bundesnetzagentur carried out efficiency benchmarking for the second regulatory period in accordance with sections 12, 13 and 14 ARegV. In the year under review, 106 operators falling under the Bundesnetzagentur's remit on account of section 54 of the Energy Act (EnWG) or an official delegation of powers took part in the efficiency benchmarking. The 106 operators included twelve TSOs who took part in a separate benchmarking procedure. The benchmarking produced efficiency levels between 81.95 percent and 100 percent, with 34 operators achieving an efficiency level of 100 percent. Most of the TSOs achieved an efficiency level of 100 percent in their benchmarking procedure. In the first regulatory period, all of the operators achieved efficiency levels between 60.04 percent and 100 percent.

According to section 15(1) sentence 1 ARegV, the efficiency level established under sections 12 to 14 must be adjusted using a markup if an operator can demonstrate the existence of special supply circumstances, in terms of unusual structural features, that have not been taken into proper consideration in the efficiency benchmarking by the choice of the parameters according to section 13(3) and (4) and cannot be controlled by the operator, and these increase the costs established under section 14(1) paras 1 and 2 by at least five percent. Just over 20 operators made use of this option and submitted applications. These applications are currently being examined, and the operators will be informed of the outcome in an official revenue cap ruling.

In addition to the cost examination, the Bundesnetzagentur reviewed and finalised the amounts to be added to or deducted from the revenue caps for the second regulatory period to balance the gas incentive regulation account. The Bundesnetzagentur also looked in detail at the effects of the revision of the Network Charges Ordinance. It is planned to take account of these changes in the final revenue cap decisions.

2.6 Preparation and performance of efficiency benchmarking for gas DSOs and TSOs for the second regulatory period

Status of efficiency benchmarking for gas DSOs for the second regulatory period

The second regulatory period for the DSOs began on 1 January 2013. In 2012, the Bundesnetzagentur completed national efficiency benchmarking for the DSOs in accordance with section 12(1) ARegV. The efficiency calculations were carried out by the Bundesnetzagentur, assisted by Frontier Economics and Consentec. The required structural and cost data (base year 2010) were provided by the Bundesnetzagentur and the regulatory authorities of the federal states. Consultation on the individual efficiency levels of the 186 operators participating in the standard benchmarking procedure began in December 2012. The calculations produced an unweighted average efficiency level of 92.1 percent, which is 4.8 percentage points higher than that in the first efficiency benchmarking in 2008. The Bundesnetzagentur set the revenue caps for the second regulatory period on the basis of the efficiency levels. A general efficiency level of 89.97 percent was determined for operators participating in the simplified procedure in accordance with section 24(2) ARegV.

Status of efficiency benchmarking for gas TSOs for the second regulatory period

The second regulatory period for the TSOs began on 1 January 2013, as with the DSOs. In 2012, the Bundesnetzagentur completed national efficiency benchmarking for twelve TSOs in accordance with section 22(3) ARegV. The efficiency level calculations were carried out by a consortium of consultants comprising Frontier Economics and Consentec. The required structural and cost data were provided by the Bundesnetzagentur. Eleven out of the twelve TSOs achieved an efficiency level of 100 percent; in the first regulatory period ten out of twelve TSOs achieved this level. The Bundesnetzagentur set the revenue caps for the second regulatory period on the basis of these efficiency levels.

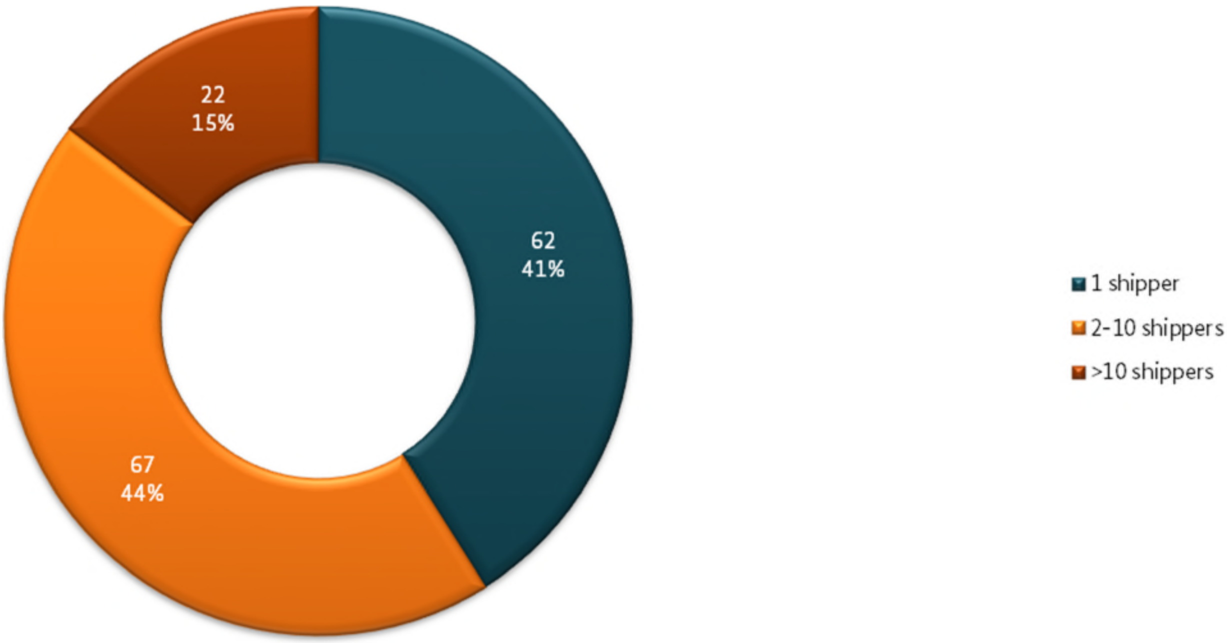
D Balancing

1. Hourly transmission of metering data to shippers

The provision of relevant information to shippers is a key element of the Bundesnetzagentur's gas balancing arrangements known as GABi Gas. The provision of information to shippers also plays a fundamental role in the Balancing Network Code, which aims to harmonise the balancing rules in place in the European Union. Ideally, the shippers receive all the relevant data which they need to fulfil their balancing obligations and which they can process with their existing information systems.

In the period under review, a total of 151 operators – including two TSOs – transmitted hourly metering data from interval-metered exit points to shippers requesting hourly updates. The majority of operators, however, had not received requests for hourly metering data. 15 percent of the operators (ie 22 operators) transmitting metering data on an hourly basis provided data to more than ten shippers each. 45 percent (or 67 operators) transmitted hourly data to between two and ten shippers. The remaining 40 percent (62 operators) provided data to just one shipper.

Figure 112: Hourly transmission of metering data to shippers



2. Customer groups and group switching

The GABi Gas balancing system categorises final customers according to their offtake and capacity as standard load profile (SLP) customers, interval-metered business and industrial customers with a daily flat supply, and interval-metered business and industrial customers without a daily flat supply. Final customers with a capacity exceeding 300 kWh/h are generally allocated to the group of interval-metered customers without a daily flat supply and those with a lower capacity to the group of interval-metered customers with a daily flat supply. Group switching enables the shippers, however, to allocate their interval-metered customers to a different group. In addition to the groups mentioned above, there are also interval-metered exit points supplied using a substitute nomination procedure.

In the 2013 monitoring survey, 414 shippers/gas traders provided information about the groups to which their interval-metered customers were allocated and about group switching in the gas year 2011/2012. The information provided shows that a larger number of interval-metered customers with a daily flat supply chose to switch to the group of interval-metered customers without a daily flat supply. The figures show that many balancing group managers often found it economically more attractive to accept the lower hourly balancing group deviation tolerance (two percent compared with 15 percent for customers with a daily flat supply) and then avoid the expense of the balancing energy contribution. The following figures show that this evasion of the balancing energy contribution is also reflected by the fact that more than 80 percent of the final customers in the group of interval-metered customers without a flat daily supply in both market areas have a capacity lower than 300 kWh/h and are therefore not in the group corresponding to their capacity. This percentage is slightly higher than in past review periods. The costs of the balancing energy contribution are hence borne by a smaller number of final customers.

Figure 113: Group switching among interval-metered customers in NCG market area

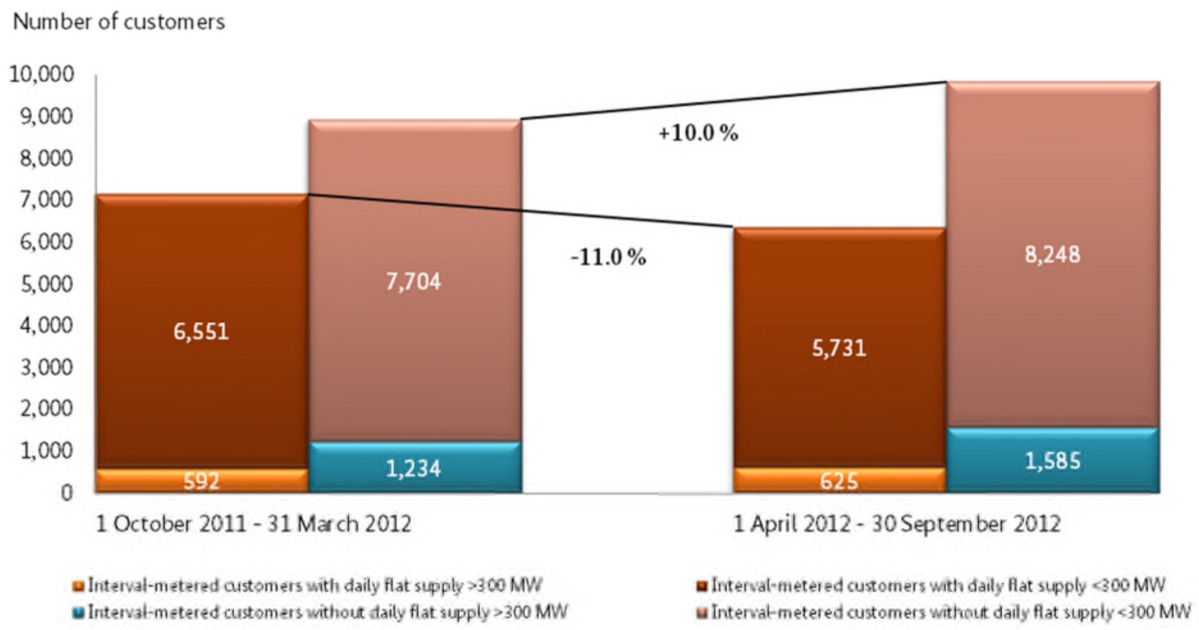
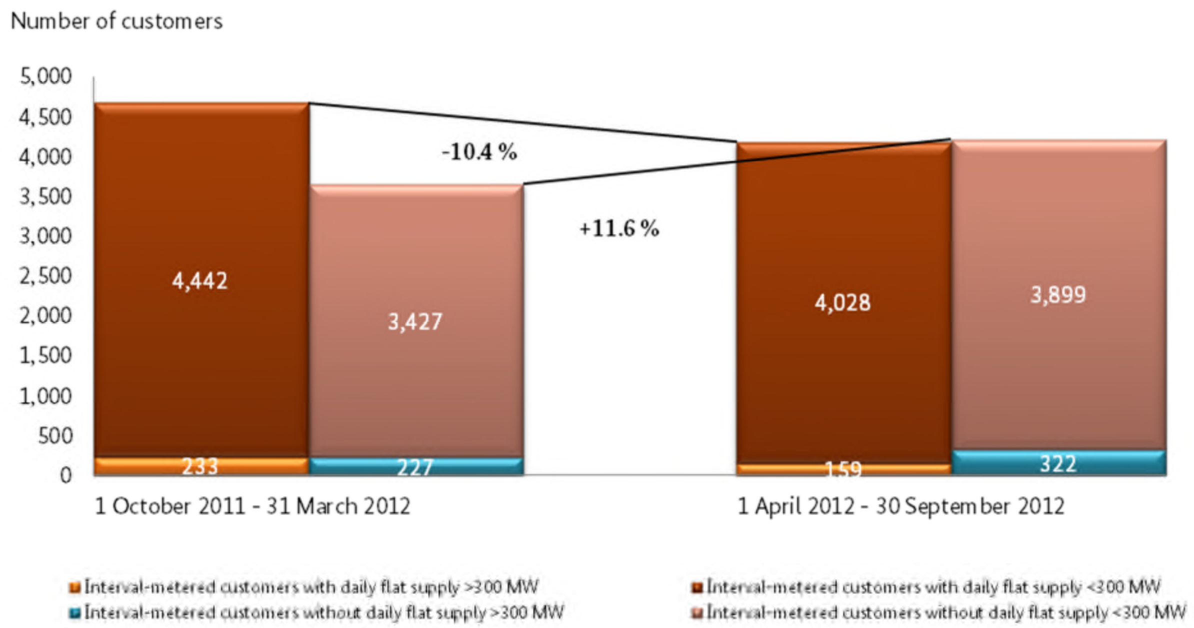


Figure 114: Group switching among interval-metered customers in Gaspool market area



Switching group is generally possible unless the market area manager is concerned that a switch could lead to an unacceptable degradation in system stability. In this case, the balancing group manager's notice of a planned switch can be rejected. In the gas year 2011/2012, the balancing group managers issued 4,903 such notices; none of these were rejected on technical grounds by the market area manager.

E System balancing energy

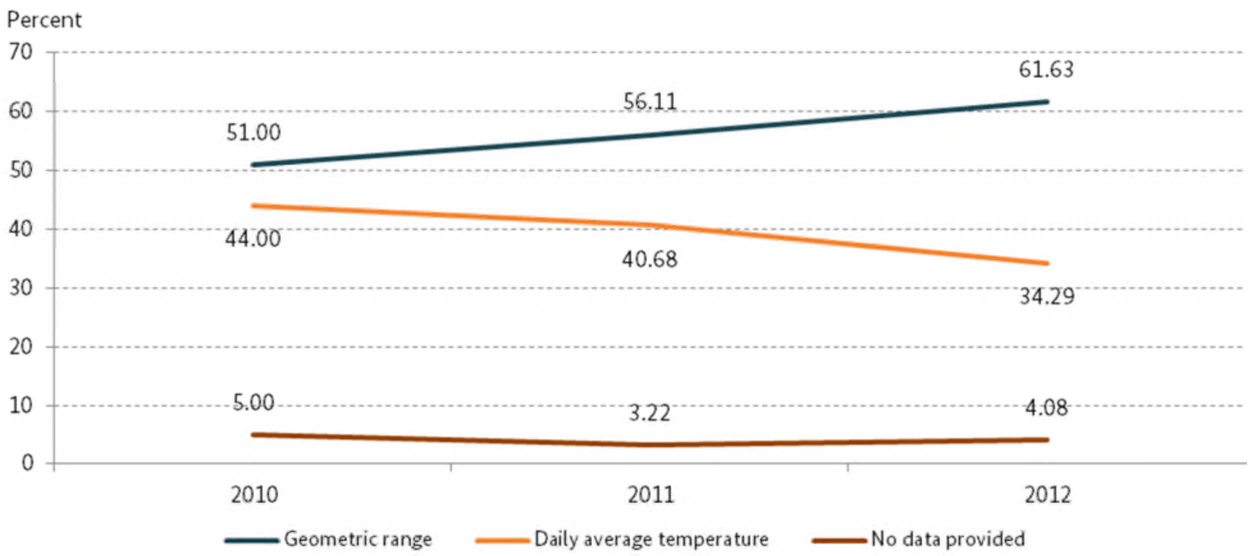
1. Standard load profiles

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 2012, synthetic profiles were used by 89.6 percent of operators; analytical profiles were used by 10.4 percent, compared with 9.7 percent in 2011.

The significance of standard load profiles is evident in the fact that nearly all exit operators (98.5 percent) 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 95.2 percent. This figure remains virtually unchanged compared with 2011 (96.5 percent).

The TU München offers a range of different profiles which reflect the offtake behaviour of various customer groups. 50.7 percent of the operators stated that all available profiles were applied, compared with 47.8 percent in 2011. 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 were used for business customers, compared with six in 2011.

Figure 115: Choice of weather forecast[140]



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

It is becoming increasingly clear that the quality of the load profiles also depends significantly on the quality of the weather forecast. As shown in Figure 115, more operators have started to use a geometric range of the previous days' temperatures instead of the daily average temperature. This option is now used by 61.6 percent of operators; the trend of recent years thus continues.

Standard load profiles, as forecasts, are naturally marked by inaccuracies. The average deviation between allocation and actual offtake on a daily basis was 5.1 percent, slightly lower than in 2011 (5.7 percent). This figure is slightly less meaningful than that for 2011 as only 57.9 percent of operators provided information for the current report (2011: 63 percent). The average maximum deviation on one day was 45.7 percent and about the same as in the previous year (44.7 percent), as shown in Figure 116. 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 it could be assumed that the operators with a comparatively high forecast quality tended to respond.

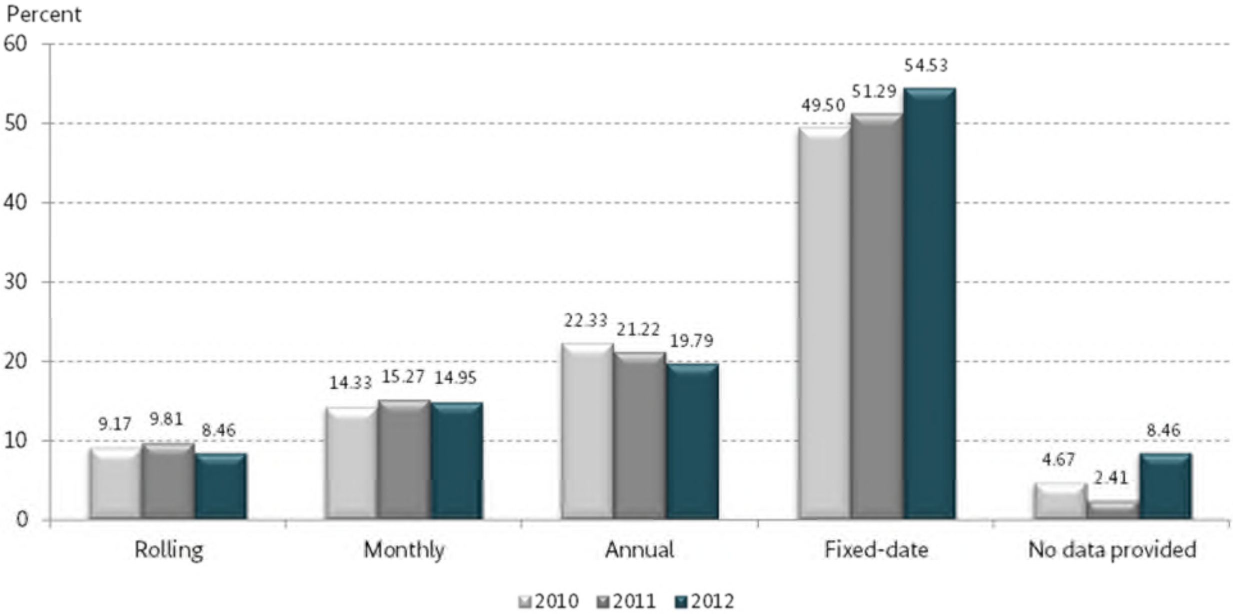
Figure 116: Deviations from standard load profiles

18.1 percent of operators made fixed adjustments to the load profiles owing to the deviations; this represents another slight increase compared to the previous year (2011: 13.3 percent).

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 117.

Figure 117: Billing for higher/lower volumes



On average, around 423 operators had completed billing for SLP customers for the period surveyed between October 2010 and September 2012 (see Figure 118). This number was considerably smaller in the 2012 monitoring survey. Around 335 operators had completed billing for the gas financial year from October 2011 to September 2012. This is considerably more than the 265 operators in 2011. The dip in the curve is due to the different billing periods in the various procedures.

Most exit network operators now appear to have the initial problems associated with billing higher or lower volumes for interval-metered customers under control. This is clear from the comparatively large number of operators who have already completed billing, with an increase from 430 in 2011 to 495, as shown in Figure 119.

Figure 118: Billing for higher/lower volumes for SLP customers

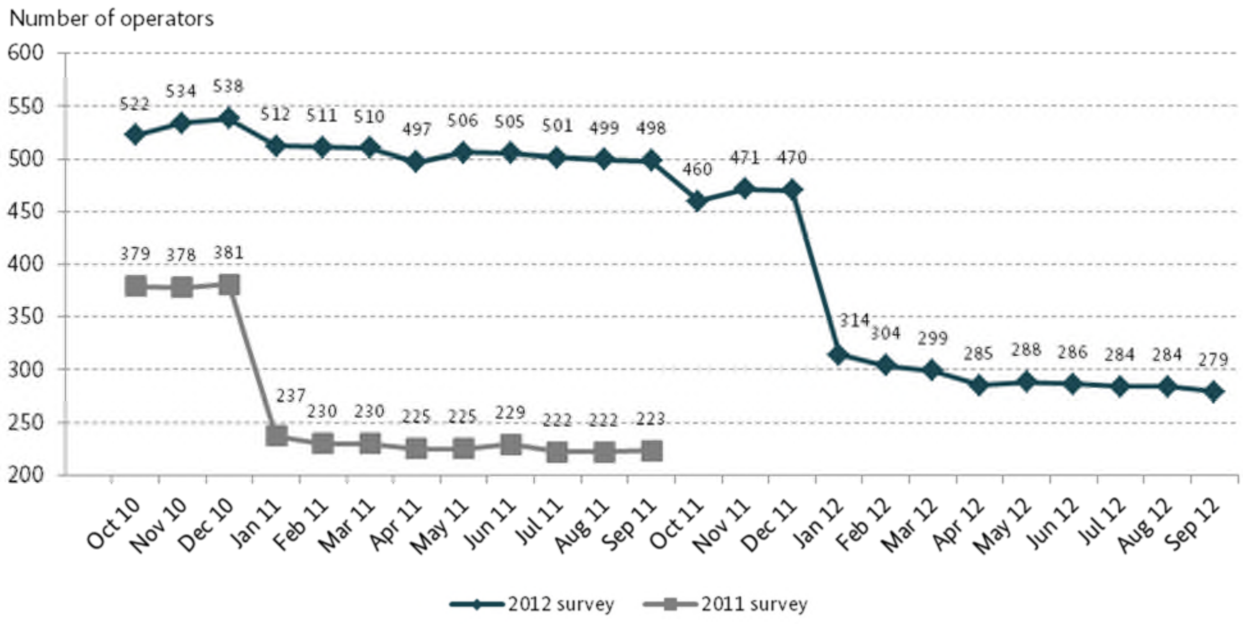
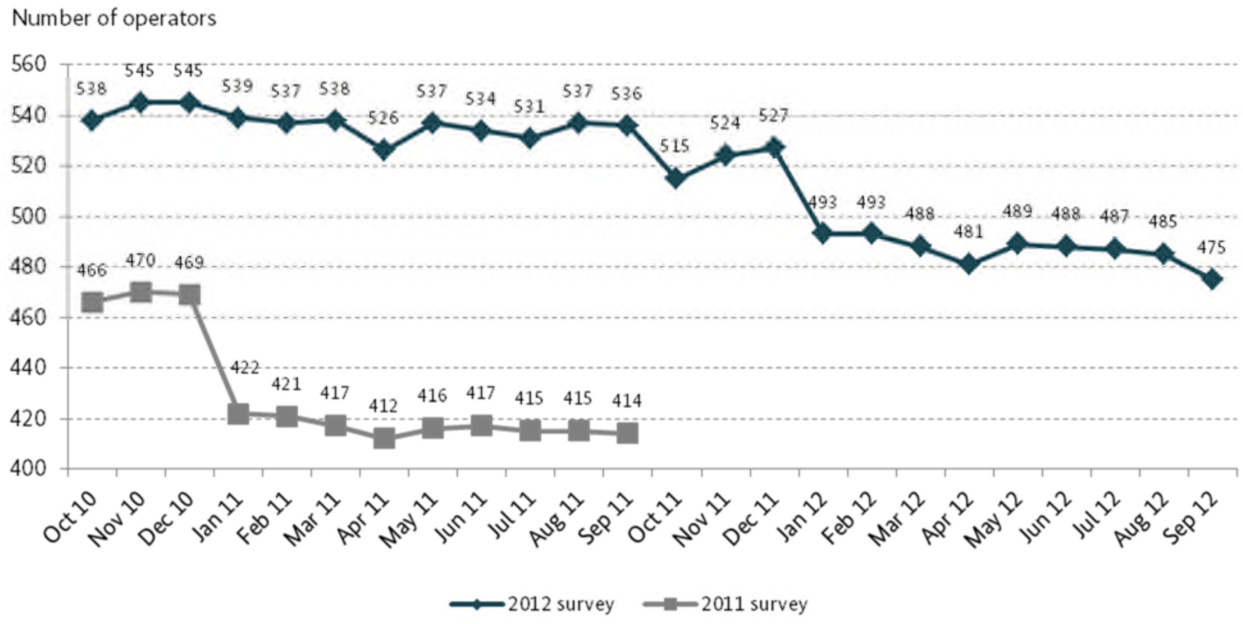
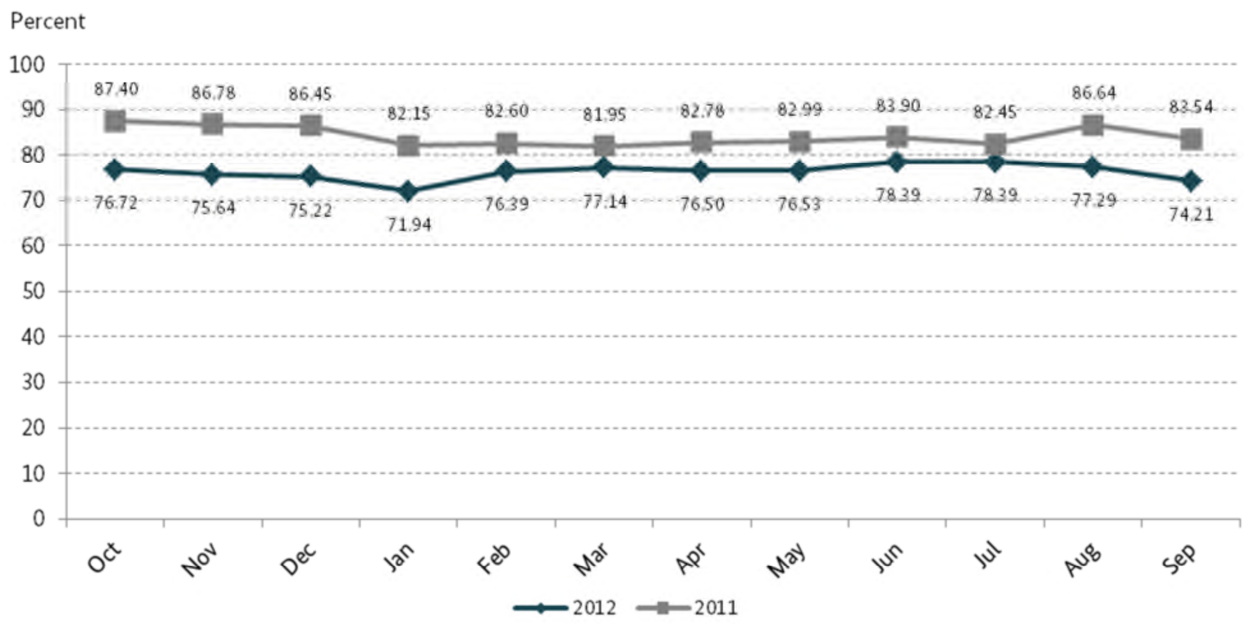


Figure 119: Monthly billing for higher/lower volumes for interval-metered customers



On average, billing for higher or lower volumes for interval-metered customers for the gas financial year from October 2011 to September 2012 had been carried out for 76.2 percent of the offtake volume (see Figure 120). This figure is lower than that in 2012: at the time of the survey, billing had been carried out for 84.1 percent of the volume in the comparable period.

Figure 120: Percentage of volumes billed for interval-metered customers



F Wholesale

1. Developments in the gas markets

Wholesale natural gas trading covers trading transactions between professional market participants which do not generally have as their object the participants' own gas consumption. Wholesale markets play a crucial role in the market developments along the entire value added chain, from natural gas procurement to the supply to final customers. With increasingly diverse options for the short-term and long-term procurement of gas at the wholesale level, companies are less dependent on committing themselves to long-term supply contracts. Efficient and liquid wholesale markets increase the market participants' options of e.g. choosing from a large number of trading partners or holding a diversified portfolio of short-term and long-term trading contracts. Liquid futures markets enable market participants to procure natural gas strategically, without long-term supply contracts. Liquid markets make market entry easier and thus promote competition for final customers.

2. Development of OTC trading

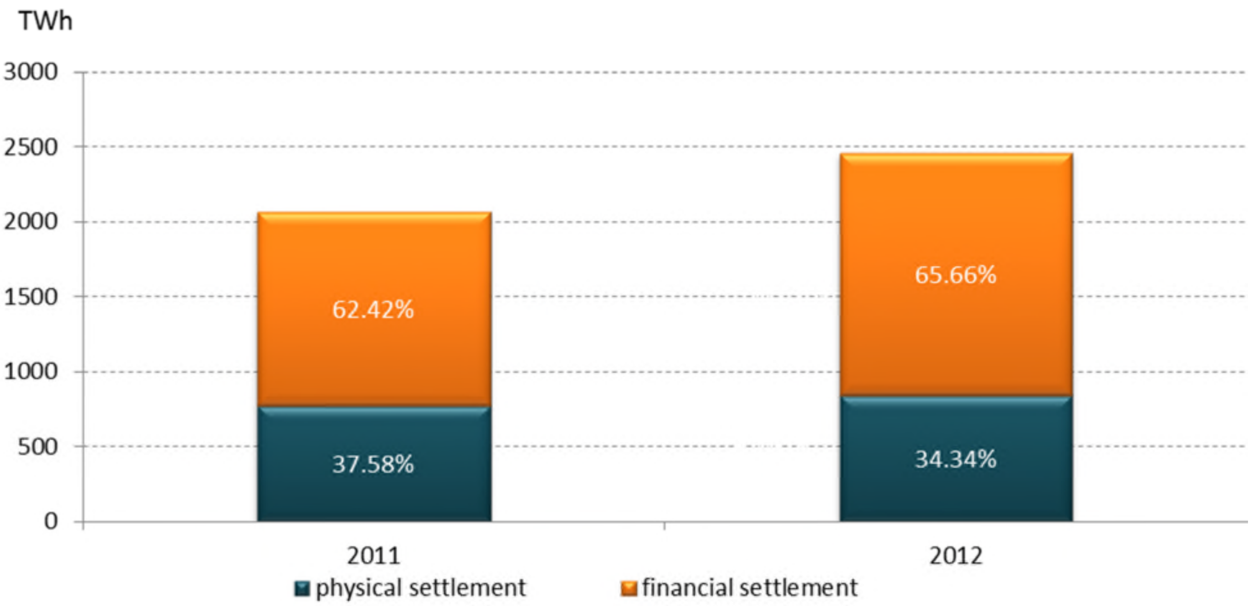
The majority of wholesale natural gas trading transactions take place off exchange, i.e. bilaterally `over the counter` (OTC) between two trading partners who selectively contact each other. The advantage of bilateral trading is that transactions can be carried out flexibly on a short-term basis, i.e. without being obliged to use standardised contracts. An alternative to direct bilateral trading is OTC trading via a broker platform (see below).

Bilateral natural gas trading takes place via the virtual trading points in the German market areas. Since 1 October 2011 there have been only two market areas in Germany; NetConnect Germany (NCG) and Gaspool (cf. Monitoring Report 2012). Already in 2011, with the consolidation of the market areas, an increase of liquidity at the virtual trading points could be observed in comparison to the year 2010. This trend also continued in the year under review.

The improvements in framework conditions for the award of capacities introduced in the previous years probably also accounted for the increase in liquidity. These improvements consist of rules for the award of entry and exit capacities at the interconnection points between market areas and cross-border interconnection points (under the German Gas Network Access Ordinance, GasNZV, of 3 September 2010) and, secondly, the decision on capacity management and auction procedures in the gas sector (KARLA Gas of 24 February 2011).

The OTC trading volume at the virtual trading points of the NCG and Gaspool market areas increased for all types of natural gas (H-gas and L-gas) from a total of approx. 2,066 TWh in 2011 to 2,460 TWh in 2012 (cf. Figure 121). This represents an increase of about one fifth. In the 2012 total trading volume, transactions with physical settlement represented a share of 34.3 percent, somewhat less than the 37.6 percent of the previous year. In absolute numbers the physically procured volumes of natural gas increased from 777 TWh to 845 TWh. The so-called paper trades, i.e. financial transactions, accounted for almost two thirds of the trading volume.

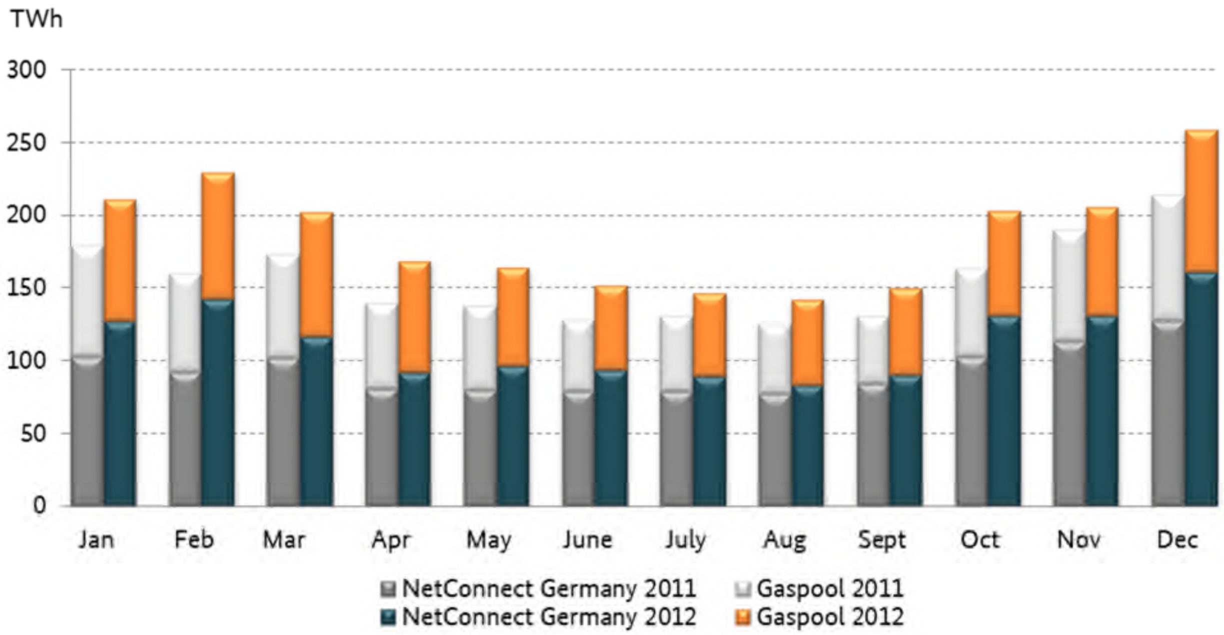
Figure 121: OTC trading volume 2011/2012[141]



In 2012 the OTC trading volume in the H-gas sector increased by 363 TWh to a total of approx. 2,235 TWh. This represents an increase of about one fifth over the previous year. This development was observed throughout Germany: 234 TWh were accounted for by the NCG market area and 129 TWh by the Gaspool market area, which represents an increase by 21 percent or 17 percent, respectively. The combined monthly trading volumes (Gaspool plus NCG) exceeded those achieved in the previous year (cf. Figure 122).

[141] The figure shows the total trading volume in both market areas, NCG and Gaspool, for both types of gas together (H-gas, L-gas), differentiated according to physical or financial settlement.

Figure 122: OTC trading volume H-gas 2011 / 2012[142]

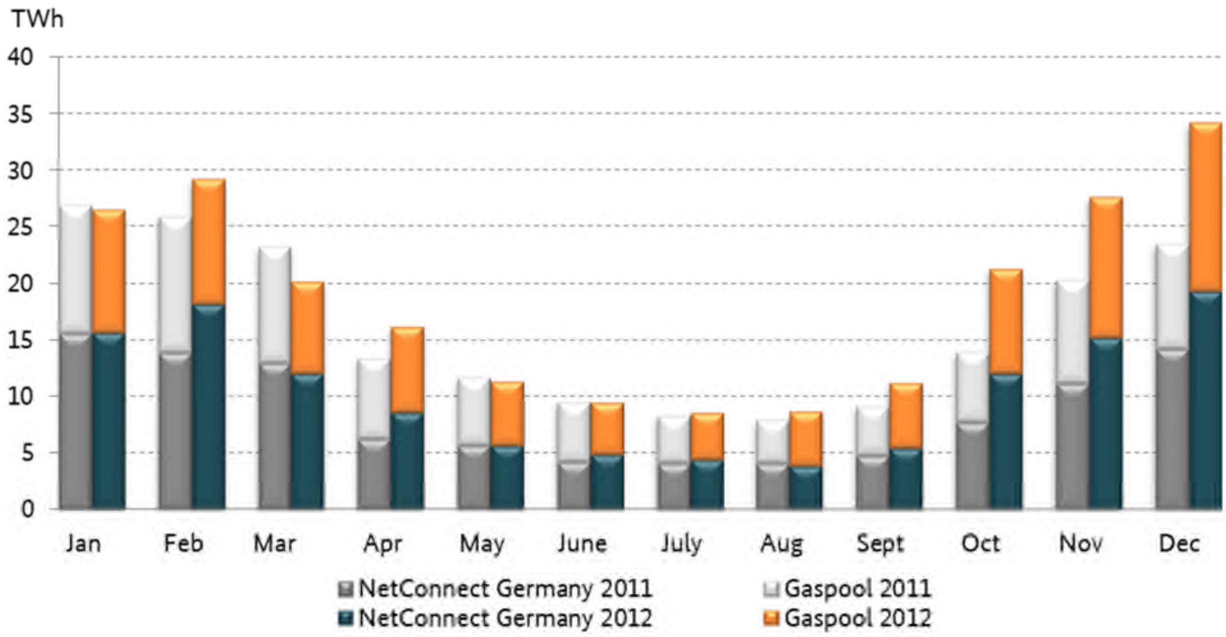


As expected, there are seasonal differences in the trading volumes: In the months from June to September 2012 the OTC trading volume was under or just above 150 TWh while reaching an annual peak level of more than 250 TWh in December 2012.

In 2012 the OTC trading volume in the L-gas sector amounted to approx. 224.5 TWh. This represents an increase of about 30 TWh or 16 percent over the previous year, which shows that the stagnation observed during the previous year has not continued. This development was mainly due to the trading activity in the NCG market area. However, considerable fluctuations could be observed during the year under review. The increases observed from October to December 2012 mainly contributed to the overall positive development (cf. Figure 123).

[142] The trading volumes in the NCG market area up to and including March 2011 are the NCG and Thyssengas trading volumes (H-Gas).

Figure 123: OTC trading volumes L-gas 2011/2012[143]



The number of active trading participants who have placed at least one offer or bid per respective month increased in both market areas. In the Gaspool market area the annual average of active participants rose significantly in 2012 by 37.9 percent (L-gas) and 39.9 percent (H-gas) to 120 and 277 respectively. In the NCG market area the number of active participants increased to a lesser extent by 14.7 percent (L-gas) and 6.6 percent (H-gas) to 117 and 257 respectively.

A significant indicator of a trading platform's liquidity is the churn rate which indicates the ratio between traded and physically transported natural gas volumes. High churn rates are an indication of high liquidity in the market. In 2012, the churn rates of H-gas were again higher in both market areas than the churn rates for L-gas. In both the NCG and the Gaspool market areas the churn rate for H-gas remained largely unchanged at just under 3. The churn rates for L-gas stagnated in both market areas and amounted in each case to around 1.5, about the same figure as the previous year. The increased number of active trading partners is therefore mostly reflected in the increased amount of physically traded gas. In contrast to the two NCG and Gaspool market areas, the annual average of traded natural gas at the major trading hub in Zeebrugge (Belgium) amounted in 2012 to 4.5 times the physically transported natural gas volumes; the trade volume amounted to around 742.5 TWh[144].

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[143] The trading volumes in the NCG market area up to and including March 2011 are made up of the Open Grid Europe (L-gas) and Thyssengas (L-gas) trading volumes. The Gaspool trading volumes up to and including September 2011 correspond to the trading volumes of the Aequamus market area.

[144] www.huberator.com, Notice "Traded Volumes: Zeebrugge Beach confirms strong traded volumes“(accessed 27 August 2013).

As is the case with trading on the exchange, the use of a broker platform expands the circle of possible trading partners for trading participants. Brokers act as intermediaries between buyers and sellers and pool information on the demand and supply of short-term and long-term natural gas trading commodities. Engaging a broker reduces research costs and generally facilitates the realisation of larger transactions. At the same time, it allows for a greater diversification of risks. Finally, brokers offer to register transactions they have brokered for clearing at the exchange, thereby enabling the parties to cover their trade risks.

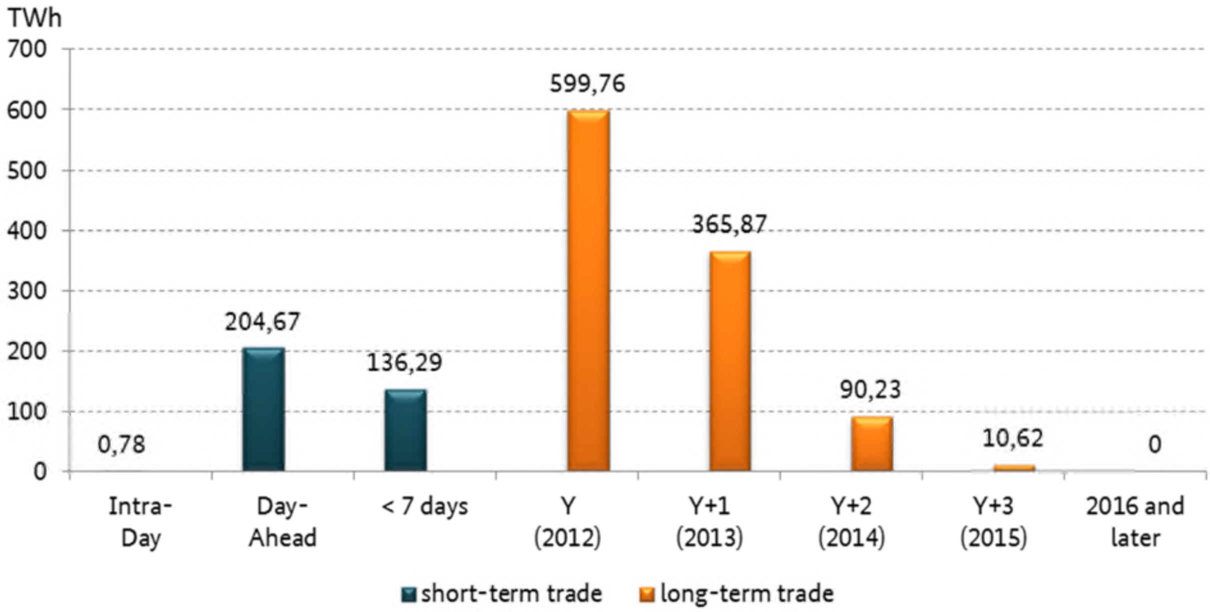
The data used in this report are based on information provided by four European brokers who broker transactions with Germany as the place of delivery and who together account for a major part of the European natural gas brokerage business relating to Germany. The brokers had already participated in last year's survey. Accordingly, as in the previous year, in 2012 brokers were mainly engaged for long-term trade transactions. Trade volumes decrease the longer-term the delivery date is. In the survey, long-term transactions are transactions where the delivery of natural gas takes place at the earliest one week after the transaction was concluded; the date of delivery can also be several years later. Short-term trade with natural gas, on the other hand, refers to transactions with a delivery period of no more than one week, starting with the respective trading day on which the transaction was concluded.

In 2012, the total volume of natural gas traded via the above mentioned brokers and delivered to destinations in Germany amounted to 1,408 THh (cf. Figure 124). This corresponds to approx. 57.3 percent of the OTC trading volume at the virtual trading points of the Gaspool and NCG market areas. The trading volume of the four brokers in 2011 was approx. 1,012 TWh natural gas (which corresponded to about 49 percent of the OTC trading volume in 2011[145].) The long-term trading volumes clearly exceed the short-term trading volumes (cf. Figure 124)[146].

[145] A total of five brokers participated in the survey for the Monitoring Report 2012. Their trade volume for 2011 amounted to around 1,114 TWh (cf. Monitoring Report 2012).

[146] Although the data indicated here do not cover the total sum of broker activities in Europe with Germany as the place of delivery, the brokers that participated in the survey account for a substantial part of the European brokerage business for natural gas products with delivery to Germany. The trading volume of the brokers that are members of the London Energy Brokers Association (LEBA) amounted to around 1,538 TWh in 2012 (NCG and Gaspool market areas) (http://www.leba.org.uk/pages/index.cfm?page_id=59&title=leba_data_notifications). The monitoring report covers about 92 percent of the LEBA brokerage business relating to Germany.

Figure 124: OTC contracts traded via brokers in 2012



3. Developments in exchange trading

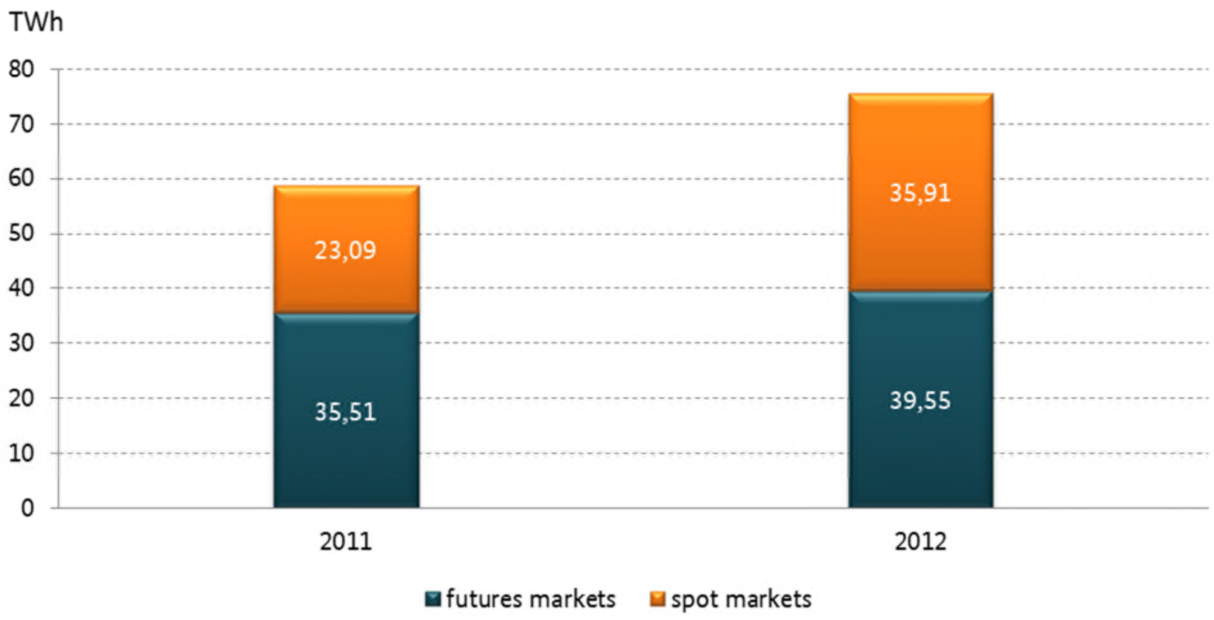
In Germany, natural gas is traded via the EEX European Energy Exchange AG, or since 1 January 2012 via its subsidiary EGEX European Gas Exchange GmbH. At the EEX spot market and futures market contracts can be traded (see below). Exchange trading constitutes an alternative to broker trading and non-brokered bilateral trading. With regard to total (on-exchange and off-exchange) natural gas trading volumes (excluding brokered transactions), around 3.5 percent of the wholesale trade in 2012 was concluded on the EEX. This figure corresponds to the previous year's amount.

On the spot market of the EEX, trade contracts for delivery to the virtual trading points of the German Gaspool and NCG market areas and the Dutch Title Transfer Facility (TTF) are concluded. At the EEX, natural gas can be traded for delivery the same day with a lead time of three hours (within-day contract), for one or two days ahead (day contract) and for the following weekend (weekend contract). Since 2011 this is also possible on a continuous basis (so-called 24/7 trade).

The minimum contract size is one MW. In this way companies are able to purchase or sell even smaller amounts of natural gas on a short-term basis. This makes it potentially easier to integrate trading with balancing energy into exchange trading. Multiples of the minimum contract size can also be traded such as the standard contract of 10 MW.

In 2012 the spot market reached a volume of around 35.9 TWh, which was smaller than that of the futures market at 39.5 TWh but signified a much stronger growth than in the previous year (cf. Figure 125). Compared to 2011, the growth rate in the area of short-term procurement amounted to 56 percent and in the area of long-term procurement 11 percent. The EEX's incentive programme, which was introduced in February 2012 and ended in July 2012, might have contributed to this increase in growth rates[147]. The programme provides for a monthly bonus for the three most active exchange participants in the Gaspool, NCG or TTF market areas, provided they reach certain volume thresholds. It includes all day-ahead products for natural gas. All participants admitted to the spot market for natural gas are automatically included in the ranking. Excluded are the market area coordinators. The incentive programme was launched to increase liquidity. Other measures introduced in 2011, such as the expansion of the spot market to 24/7 trading and the introduction of spot trading to the Dutch TTF market area, will possibly also further this development.

Figure 125: Trading volumes on the EEX spot and futures markets 2011/2012[148]

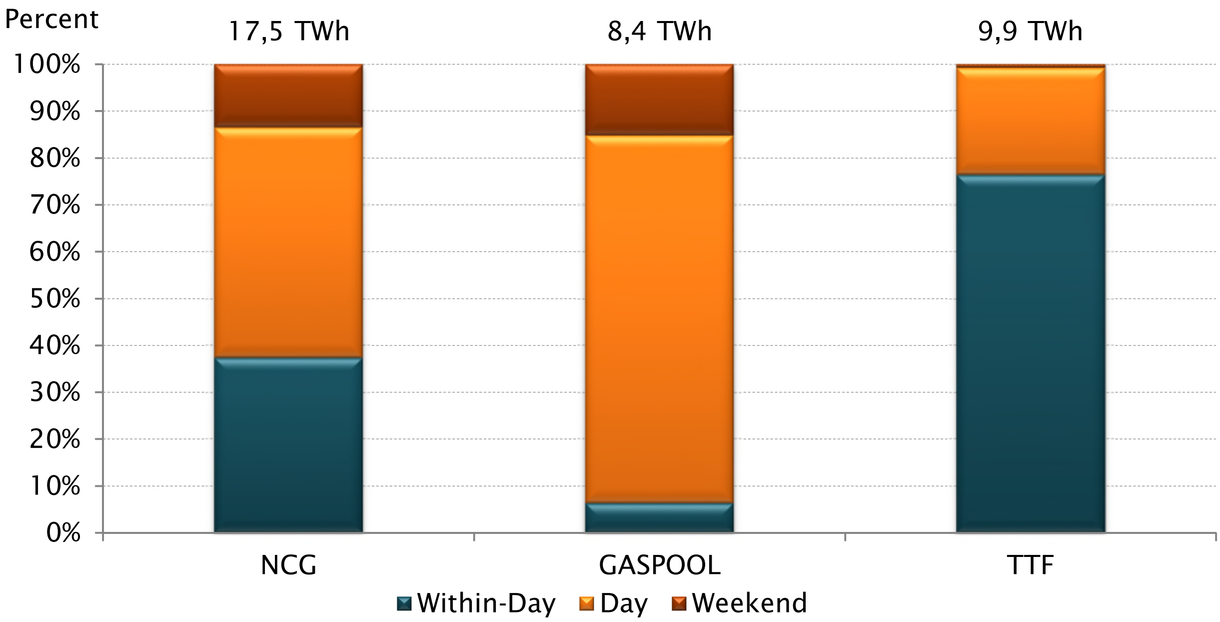


In the short-term trade segment, around half of the transactions were concluded in the NCG market area (17.5 of a total of 35.9 TWh). The predominant type of contract for this market area, as also for the Gaspool market area, was the day contract. The predominant type of contract for the TTF market area was the within-day contract (cf. Figure 126).

[147] http://www.eex.com/de/Presse/Pressemitteilung%20Details/press/103476

[148] The futures market consists of the NCG and Gaspool market areas, the spot market of the NCG, Gaspool and TTF market areas. Source for spot market data: EEX (2013): EEX annual report 2012, p.3.

Figure 126: Trading contracts at the EEX spot market in 2012



On the EEX futures market, as on the EEX spot market, trading contracts are concluded for delivery to the virtual trading points of the Gaspool and NCG market areas. However, other than on the spot market, this excludes delivery to the Dutch TTF market area. Tradable delivery periods are the remainder of the current month (Balance of the Month Future, BoM) and the following six months (Month Futures), seven quarters (Quarter Futures) or six calendar years (Year Futures), as well as the next four seasons for the NCG market area (Season Futures; a difference is made between summer season and winter season). Trading on the futures market takes place daily from 8.00 to 18.00 hrs (CET).

In addition the EEX offers clearing for transactions conducted off-exchange for standardised futures market products for delivery to the German virtual trading points. OTC clearing is a service offered by the exchange which enables trading partners to have the transactions they have concluded off exchange registered for clearing and settlement in the clearing house (so-called trade registration). This is provided that the transactions correspond in their contract specification to exchange transactions. The aim of OTC clearing is to minimise credit risks which could arise from the default of the trading partner and the future development of market prices. In doing so the EEX takes the place of the counterparty. Meanwhile, OTC Clearing is also available for spot market trading and the trade with futures products at the British National Balancing Point (NPB) and the Italian virtual trading point PSV (Punto do Scambio Virtuale). This has further improved connections to the European gas markets. OTC futures transactions are cleared and settled by European Commodity Clearing AG (ECC). The minimum size of contract is ten MW in the case of exchange trading or one MW for the registration of OTC transactions.

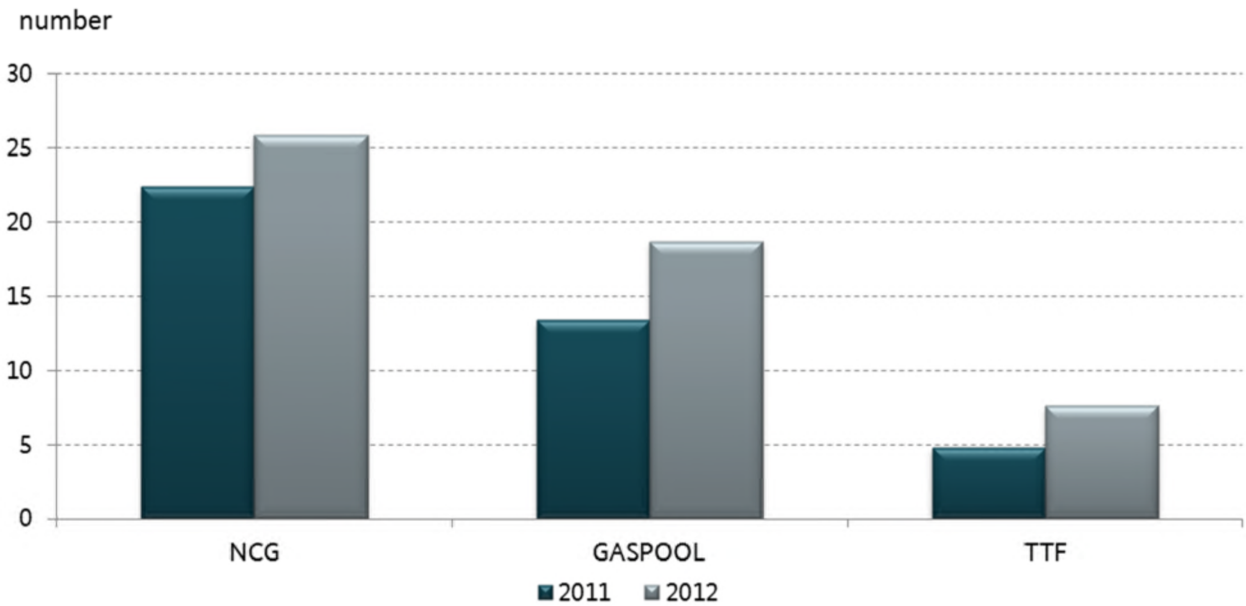
The futures market facilitates the long-term procurement of gas and portfolio optimisation and hedges against price and quantity risks. As in the previous year, the trading volume on the futures market rose by eleven percent to currently 39.5 TWh (cf. figure 125). The volume-based system of incentives for all participants admitted to and products offered on the futures market for natural gas is likely to have played a role. This expired in September 2012 and also provided for the payment of a bonus to the three most active exchange participants in a specific month[149].

Two opposite developments have led to the increase in trading volume: Whilst the transactions with physical settlement significantly increased in absolute terms and amounted to 21 TWh after 9.5 TWh in the previous year, the trade with financial settlement shrank in both absolute as well as relative terms; compared to a share of approx. 70 percent of the total trading volume (26 TWh) in the previous year this accounted for only 45 percent (18 TWh) in 2012. Significantly less use was also made of the possibility of clearing OTC transactions via the ECC (a decrease of over 50 percent in both market areas).

In respect of the market areas, the trading volume for the NCG trading point rose significantly whilst there was a slight decrease in volume for the Gaspool trading point although there was a significant increase in absolute terms in transactions with physical settlement here as well.

The number of participants admitted to the EEX rose only marginally in 2012 from 219 to 221. The increase in the number of active participants (i.e. participants, whose bids were actually executed) is at least notably higher on the spot market, and across all market areas (cf. Figure 127). The increased liquidity in exchange trading on the spot market is thus accompanied by an increased (average) number of active trading participants.

Figure 127: Active trading participants on the spot market in 2011 / 2012



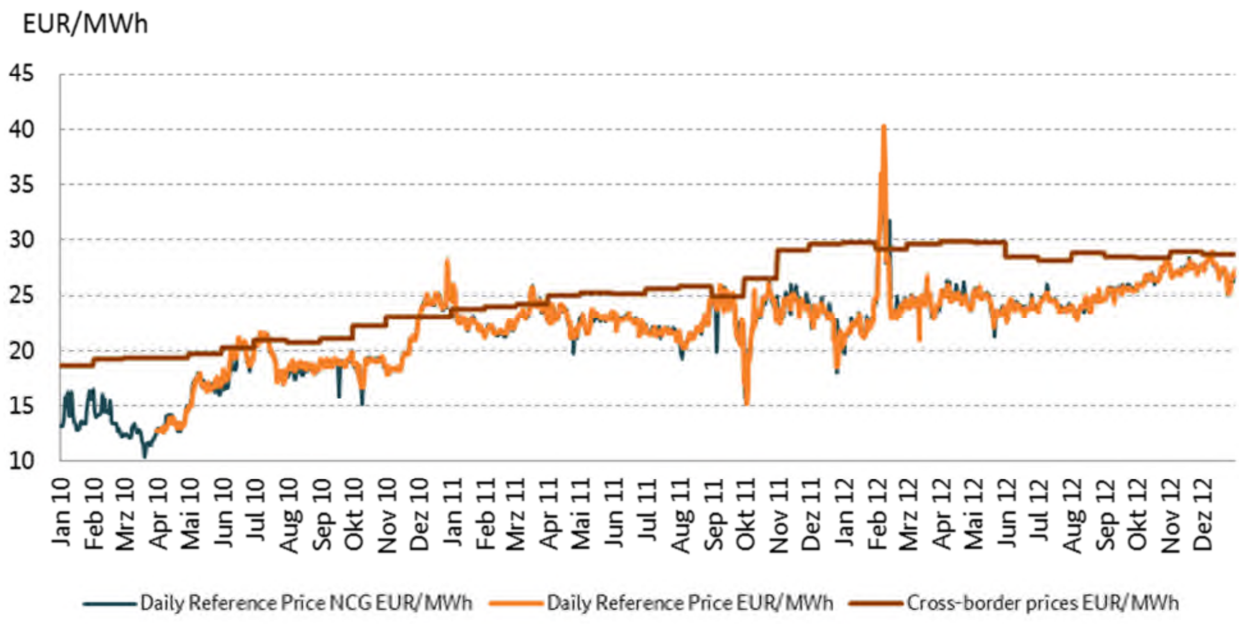
[149] The incentive programme was in place from August 2011 until the end of September 2012. It was scheduled to run out at the end of June 2012 but it was decided during the operational period to extend it for another three months (http://www.eex.com/de/Presse/Pressemitteilung%20Details/Press/show_detail/111560).

4. Trading prices

At the spot market the EEX establishes daily reference prices for the Gaspool and NCG market areas by calculating the volume-weighted average of the prices of all trading transactions (1 MW and 10 MW contracts) for gas delivery days on the last trading day before physical settlement. The EEX publishes the daily reference prices at 10:00 hrs CET on the respective delivery day. They are an indicator for the price levels of spot market transactions.

Whereas the average daily reference price for natural gas at the NCG and Gaspool virtual trading points was 22.81 euros/MWh in both areas in 2011[150], it averaged 25.19 and 25.11 euros/MWh in the reporting year (cf. figure 8). At the same time temporary bottlenecks in the supply of natural gas also became apparent in February 2012, which led to a significant price increase to 40 euros/MWh.

Figure 128: Price developments in natural gas wholesale[151]



The price levels on the spot market give an indication of the average costs of the short-term procurement of natural gas. The price of the procurement of natural gas based on long-term supply contracts can, on the other hand, be estimated from the border price for natural gas. The border price is formed by the ratio of the total value of all natural gas imports from Russia, the Netherlands, Norway, Denmark and Great Britain (in euros) to the volume of gas imported into the network (in TJ). This mainly represents the import volumes agreed in import contracts, which do not include in their entirety spot volumes procured at short notice outside of

[150] The method of calculating the daily reference price was changed in May 2011.

[151] Source: EEX, Federal Office of Economics and Export Control

these contracts. Whereas the older contracts were generally based on a price agreement linked to the oil price, there has been a shift away from this in contracts concluded over the last few years. A gradual decoupling of the border price from the oil price is therefore likely in future. The price is expected to increasingly reflect the (delayed) effect of price revision negotiations between importers and gas producers. The spot market prices which may also be used for indexing are of particular importance in this respect.

In 2012 border prices for natural gas largely remained at the level already reached in the fourth quarter of 2011. In 2012 they again averaged above the values of the previous year, i.e. at 29.00 euros/MWh compared with an average price of 25.75 euros/MWh in 2011 and 20.66 euros/MWh in 2010. The gap between border price and daily reference price has widened further in the year ended.

It is also possible to procure gas on the EEX futures market. With the introduction of the EGIX European Gas Index in 2011 the EEX has published an exchange-based reference price for the futures market. The gas price index is published daily at the exchange after the conclusion of trading for the Gaspool and NCG market areas as well as for a virtual Germany market area. EGIX is based on exchange futures transactions which were concluded in the respective current front month contracts in the NCG and Gaspool market areas, i.e. for the month in which the month contract can be traded with all delivery days. The volume-weighted average price is calculated daily at the exchange on the basis of all trading transactions. The index represents the arithmetic average of all daily prices so far established which refer to the same front month. It ultimately represents the current price on the exchange for gas deliveries of the following month.

The EGIX also registered an increase in 2012 and, following an average value of 23.53 euros/MWh in 2011, stood at 24.66 euros/MWh last year[152]. Whilst in 2011 it stood within a range between daily reference price and border price, it fell below the average daily reference price in 2012.

[152] Cf. EEX, EEX Reference Prices, https://cdn.eex.com/document/142972/20130801_EEX_Reference_Price_EGIX.pdf

G Retail

1. Market coverage

The number of companies taking part in the 2013 monitoring survey increased this year once again. In nearly all market areas, the existing high level of market coverage was expanded, which in turn created a solid database for this section of the report on the gas market. The following information provides a brief overview of the market coverage for gas, while certain sections include statements that go beyond the database used.

Gas transmission system operators

17 transmission system operators (TSOs) took part in the 2013 data survey. Market coverage in this area is thus at 100 percent.

Distribution system operators

The number of distribution system operators (DSOs) increased once more relative to the number taking part in the 2012 survey. A total of 674 data reports were submitted (compared to 629 companies in 2012). A market coverage of 96 percent was reached regarding the supply of gas to final consumers in Germany.

Wholesalers and suppliers

The number of data reports submitted by wholesalers and suppliers for the 2013 data survey also increased. In this area, 792 data reports were submitted (versus 726 submissions in 2012). Relative to the total volume of gas supplied to final consumers, this amounts to a market coverage of over 93 percent.

Importers and exporters

Within the framework of the 2013 survey, 38 gas importers and gas exporters submitted data reports (compared to 41 companies in 2012). Here too, this amounts to almost complete market coverage.

Storage system operators

With 28 data reports submitted, market coverage in this area also remained at a high level relative to the 2012 data survey (24 companies reporting). The market coverage here amounts to over 96 percent.

2. Market opening and competition

2.1 Delivery volumes of gas suplliers

The gas volume delivered by gas suppliers to final consumers (including gas power plants) in the year 2012 amounts to 815.4 TWh. This is five percent higher than the value for 2011. The delivery volume to private households exceeded the previous year's value by nearly ten percent.

Based on the TSOs' and DSOs' output volume of 955.68 TWh in Germany in 2012, the calculated market coverage of the gas wholesalers and suppliers participating in the survey amounts to over 93 percent. As of

31 December 2012, gas suppliers in Germany delivered gas to approximately 13 million final consumers. Of that number, nearly 11 million final consumers belonged to the segment of household customers within the meaning of section 3 para 22 EnWG. The following table shows the volumes delivered by gas suppliers registered in the 2013 survey for the years 2011 and 2012, broken down by category of consumer.

Table 45: Volume of gas delivered to final consumers in 2011 and 2012 according to the survey of gas wholesalers and suppliers, broken down by category of consumer[153]

Category	2011		2012	
	Delivered volumes in TWh	Share of total in percent	Delivered volumes in TWh	Share of total in percent
≤ 300 MWh/year	277,08	35,71	303,54	37,23
> 300 MWh/year ≤ 100.000 MWh/year	183,66	23,67	200,57	24,60
> 100.000 MWh/year	207,53	26,75	216,76	26,58
Gas power plants	107,59	13,87	94,52	11,59
Total	780,66	100	815,39	100

Regarding the supply of final consumers with natural gas, the Bundeskartellamt principally differentiates between a market for the supply of SLP customers (customers with a standard load profile) and a market for the supply of load-metered customers. The supply companies surveyed reported serving a total of approximately 13 million SLP customers and about 65,300 load-metered customers in Germany.[154] SLP customers were supplied with a total of around 353.38 TWh, while load-metered customers were supplied with around 435.03 TWh.[155]

2.2 Output volumes of gas network operators

Gas network operators in Germany reported an output volume of 955.68 TWh in 2012. In private households and small businesses, the volume of gas delivered increased by nearly eight percent. In total, as of the relevant date of 31 December 2012, 13.42m metering points were registered by gas network operators. Of that number,

[153] The sum of gas deliveries across individual categories is smaller than the total volume supplied because some gas suppliers did not provide information on the individual categories.

[154] The information refers specifically to metering points of standard load profile and load-metered customers.

[155] The sum of gas deliveries to SLP and load-metered customers is smaller than the total gas supply because some gas suppliers did not break down delivery volumes by final consumer group. The same applies to the number of final consumers.

approximately 12.42m metering points belonged to the segment of household customers within the meaning of section 3 para 22 EnWG.

Table 46: Output volumes of gas in 2011 and 2012 by category of final consumer according to survey of gas TSOs and DSOs[156]

Category	2011		2012	
	Delivered volumes TSOs and DSOs in TWh	Share of total in percent	Delivered volumes TSOs and DSOs in TWh	Share of total in percent
≤ 300 MWh/year	312,44	33,45	336,91	35,25
> 300 MWh/year ≤ 100.000 MWh/year	192,99	20,66	212,46	22,23
> 100.000 MWh/year	304,85	32,64	274,98	28,77
Gas power plants	123,80	13,25	131,33	13,75
Total	934,61	100	955,68	100

[156] The sum of gas deliveries across individual categories is smaller than the total volume supplied because some gas network operators did not provide information on the individual categories.

Table 47: Number of gas metering points in 2012 by category of final consumer, according to survey of gas TSOs and DSOs[157]

Category	Number of metering points DSOs gas	Number of metering points TSOs	Number of metering points TSOs and DSOs
≤ 300 MWh/year	13.542.633	55	13.542.688
> 300 MWh/year ≤ 100.000 MWh/year	153.150	332	153.482
> 100.000 MWh/year	1.516	162	1.678
Gas power plants	870	62	932
Total	13.698.169	611	13.698.780

3. Default supply

In the data survey for the 2013 Monitoring Report, the gas suppliers were asked to submit information about the volume of gas supplied to final consumers within and outside of default supply. The following table depicts the share that default supply makes up of the total volume of gas delivered in the respective customer category. The gas supply to household customers within the meaning of section 3 para 22 EnWG amounted to 228.73 TWh in 2012; of that amount, 61.56 TWh were supplied within the framework of default supply.

In the segment of household customers, the share of default supply relative to the overall supply decreased slightly from 27.82 percent to 26.91 percent. In the category of "other final consumers", which includes all final consumers who are not household customers (commercial and industrial customers), the volume of gas delivered amounted to 566.05 TWh. Default supply accounted for 12.65 TWh, which translates into a default supply rate of 2.23 percent. In the overall assessment, given a reported gas delivery volume of 794.78 TWh and a share of 74.21 TWh stemming from default supply, this results in a total default supply rate of 9.34 percent.[158] In total, the share of default supply remains constant relative to that of previous years. Of the volume of gas delivered to all final consumers, 7.75 percent was supplied to households receiving default supply services. 1.59 percent of the gas deliveries to final consumers was delivered to final consumers who are not households within the meaning of section 3 para 22 EnWG within the framework of default supply. The remaining 90.66 percent of the gas volume delivered to final consumers was delivered to final consumers outside of default supply contracts. Of the total volume of 353.38 TWh of natural gas delivered to SLP customers, 20.9 percent was accounted for by default supply. Compared to rate for the previous year (21.7 percent), this

[157] The sum of gas metering points across individual categories is smaller than the overall sum of gas metering points because some gas network operators did not provide information on individual categories.

[158] This figure deviates from the figure in Table 45 because not all suppliers answered this question.

means that there was a slight decline in the default supply rate.[159]

Table 48: Volumes delivered by suppliers to customers in default supply plans according to customer category 2007 to 2012

Category	Reporting year	Delivered volume in TWh	Delivered volume in default supply in TWh	Share default supply of total amount in percent
Household customers	2007	199,60	72,34	36,24
	2008	236,01	69,58	29,48
	2009	228,00	61,21	26,85
	2010	273,91	68,26	24,92
	2011	211,01	58,71	27,82
	2012	228,73	61,56	26,91
More final customers	2007	638,40	20,86	3,27
	2008	669,14	17,48	2,61
	2009	615,66	16,36	2,66
	2010	602,66	13,88	2,30
	2011	549,18	12,79	2,33
	2012	566,05	12,65	2,23
Total	2007	838,00	93,20	11,12
	2008	905,15	87,06	9,62
	2009	843,66	77,57	9,19
	2010	876,57	82,14	9,37
	2011	760,19	71,50	9,41
	2012	794,78	74,21	9,34

[159] Suppliers were asked in the questionnaire to provide volumes in the category default supply if they had problems attributing volumes (eg in the case of alternate supply). As a result, 0.4 percent of the 435.03 TWh of gas supplied to load-metered customers was listed under the category "default supply".

Figure 129: Share of volumes delivered by suppliers to final consumers in default supply plans

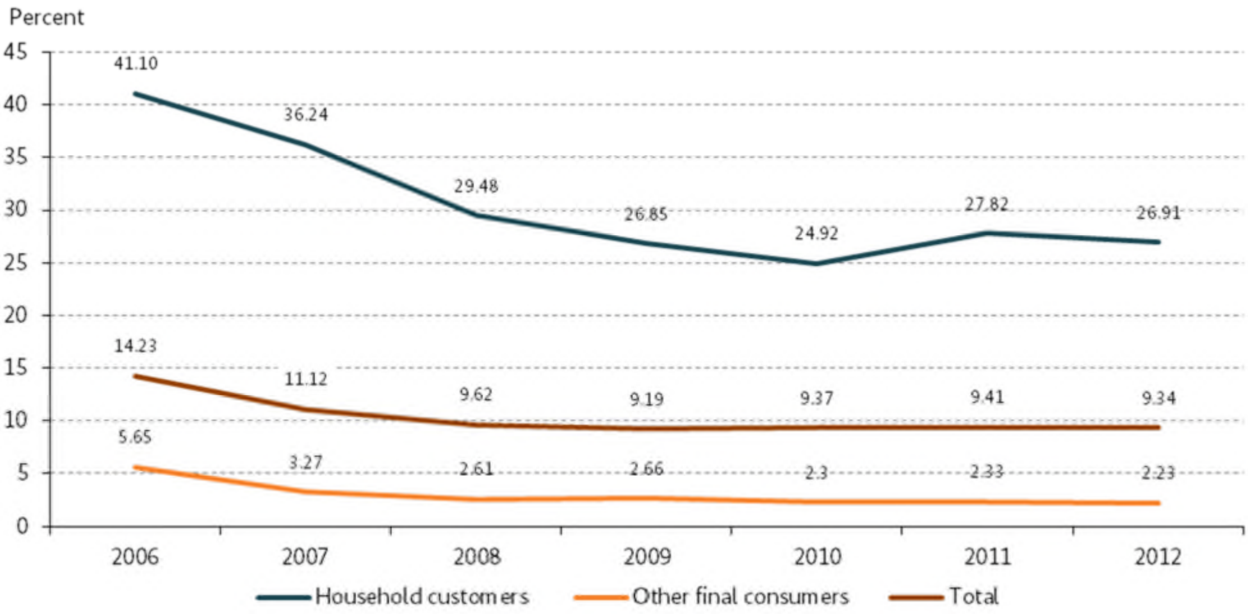
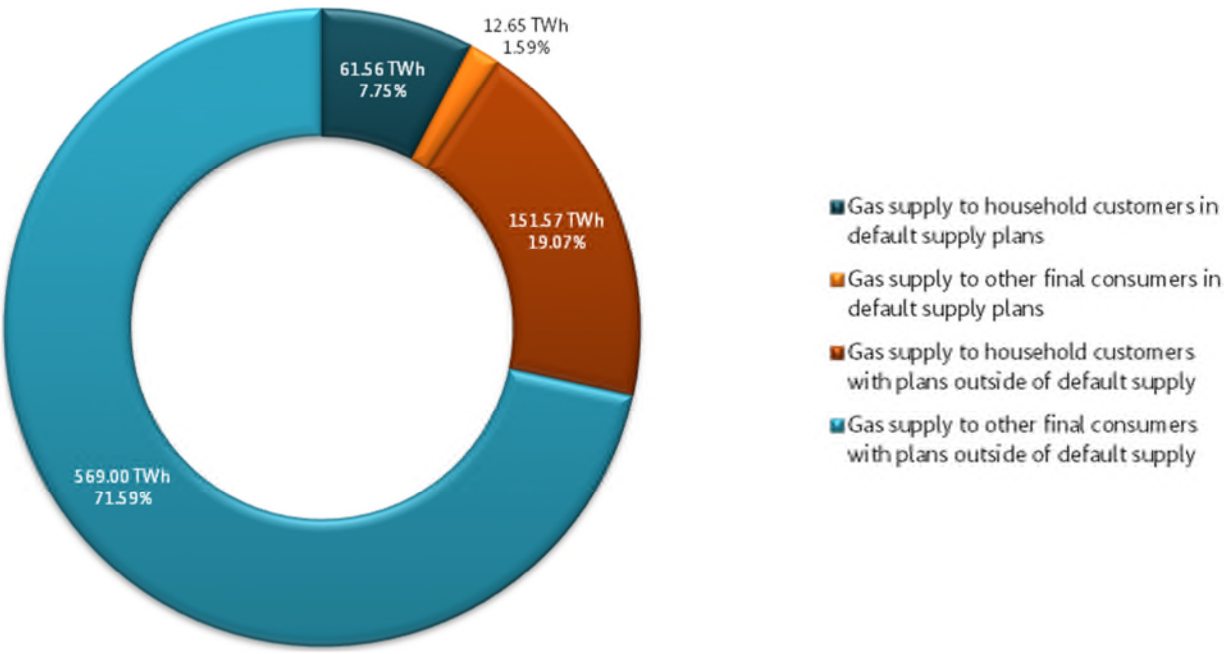
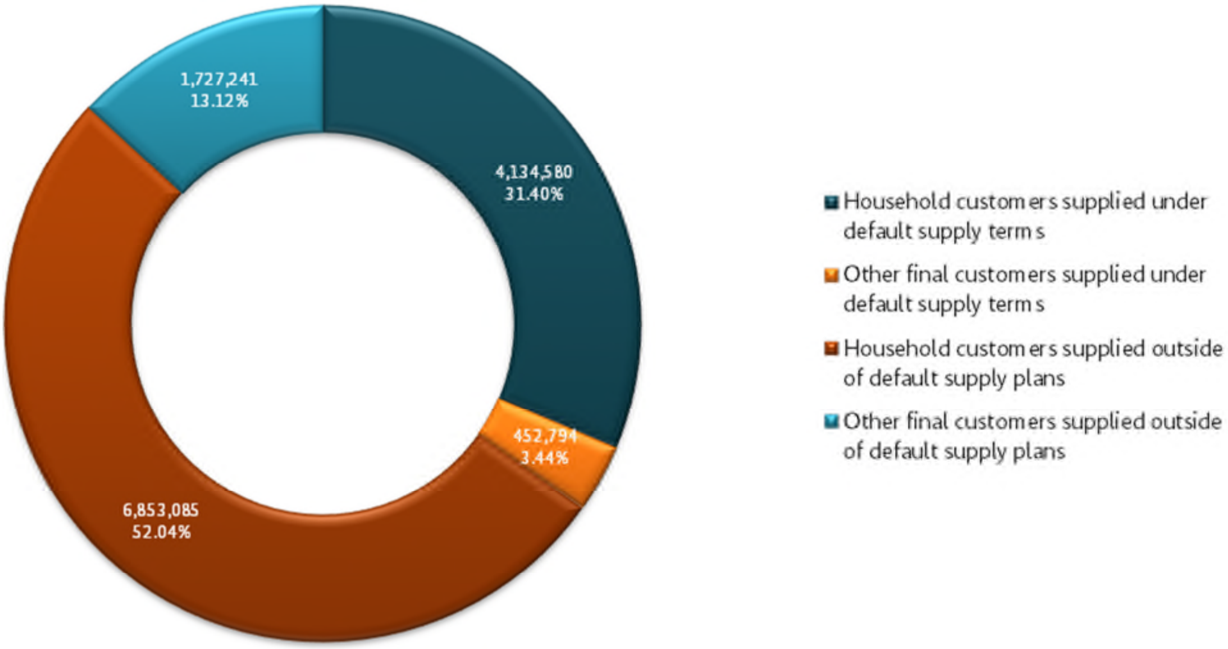


Figure 130: Volumes, in TWh, delivered to final consumers within and outside of default supply in 2012 according to survey of gas wholesalers and suppliers



The following diagram illustrates the distribution in terms of numbers of final consumers supplied according to the various possibilities of gas supply. Approximately 4.1 million household customers, or 31.4 percent of all final consumers, are supplied under default supply terms. Approximately 6.8 million household customers are supplied outside of default supply contracts, which corresponds to a rate of 52.04 percent of all final consumers.

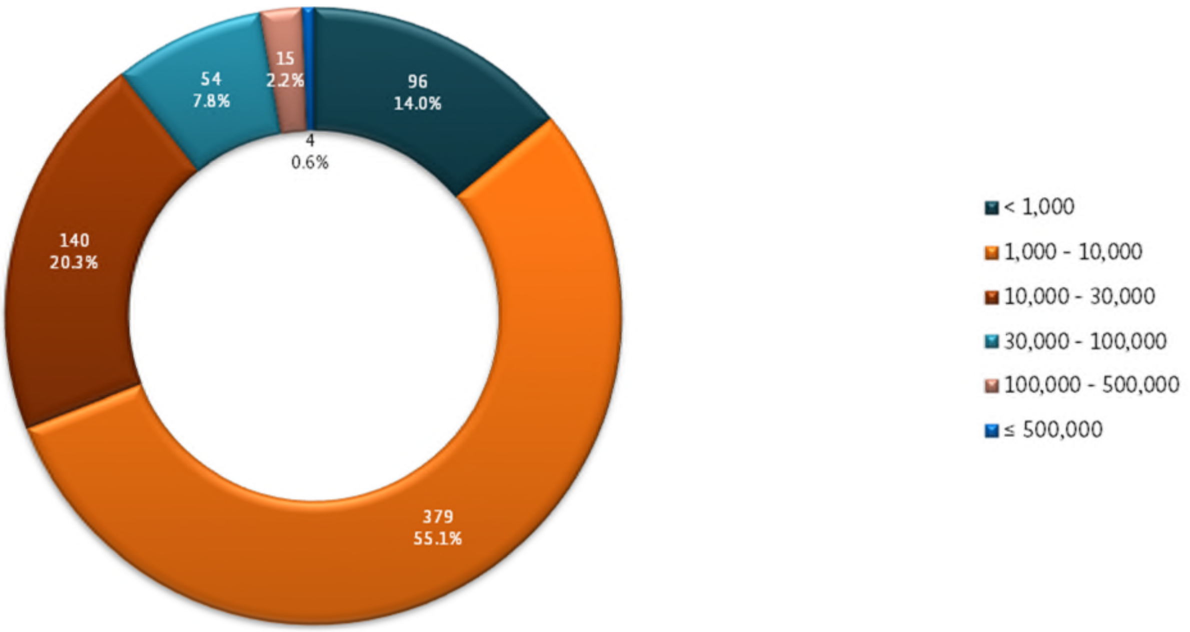
Figure 131: Number of final consumers supplied within and outside of default supply in 2012



4. Number of suppliers

The following diagram depicts the situation according to metering points and company affiliation, taking into account the five largest suppliers using the dominance method. Over three-quarters of all suppliers in Germany deliver gas to less than 30,000 metering points. The largest share is made up of the group of suppliers with 1,000 to 10,000 metering points. Nearly three percent of suppliers deliver gas to more than 100,000 metering points.

Figure 132: Suppliers according to number of metering points supplied according to company affiliation



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 supplier available per network area. Within the context of the 2013 monitoring survey, gas network operators were asked to report on the number of suppliers serving at least one final consumer in their networks.

Since market opening 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. In 2012, the year under review, the trend toward more diversity has continued. In nearly 86 percent of network areas, 31 or more gas suppliers were available to final consumers. In 2010, for example, this was true for only approximately 38 percent of networks. By now, in nearly 60 percent of networks, a final consumer can choose from over 50 gas suppliers. Only in less than one percent of network areas are there five utilities or fewer supplying gas to final consumers (see Figure 133**Fehler! Verweisquelle konnte nicht gefunden werden.**).

A separate examination of the customer category of household customers in Figure 134 paints a picture that is similar to the above situation for all final consumers. In the majority of network areas, more than 50 different providers supply gas to household customers.

Figure 133: Percentage of network areas in which the given number of suppliers operates (all final consumers) according to survey of DSOs 2008 - 2012[160]

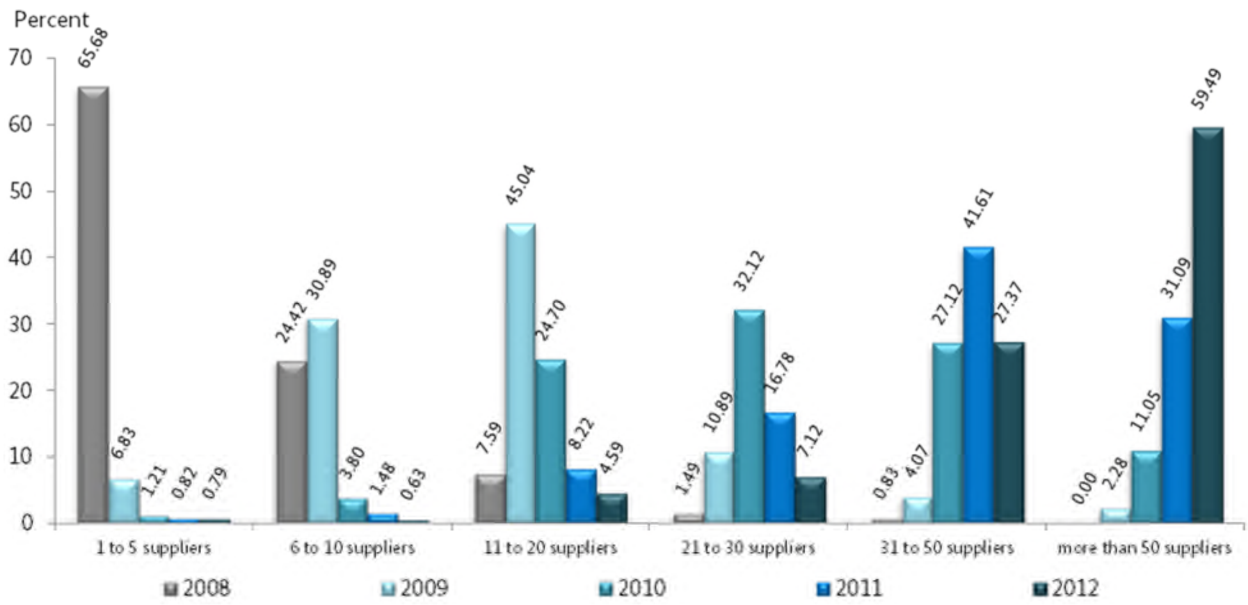
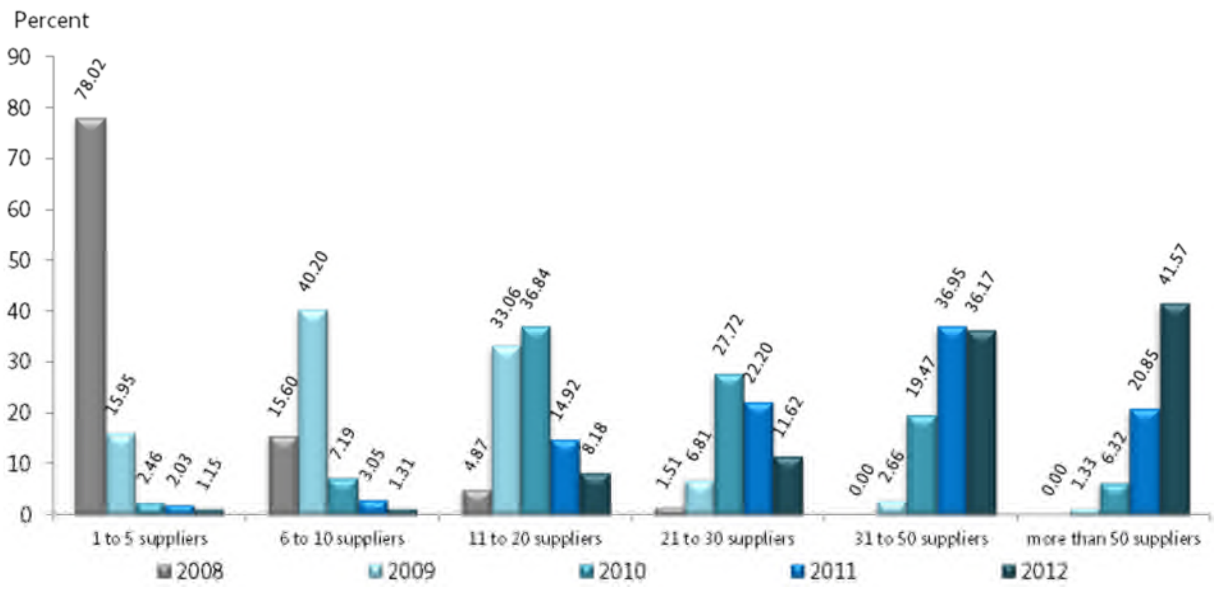


Figure 134: Percentage of network areas in which the given number of suppliers operates (household customers) according to survey of gas DSOs 2008 - 2012



160 Totals may deviate slightly owing to rounding differences.

5. Contract structure and change of supplier

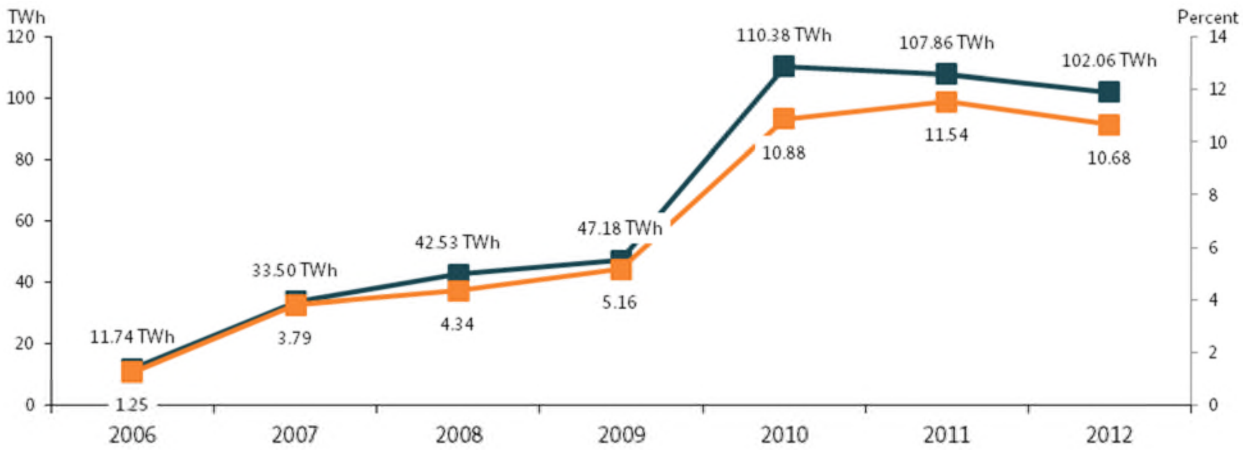
5.1 Change of supplier

There are three different contractual possibilities for final consumers to be supplied with gas. In addition to delivery under default supply terms, the default supplier can also supply customers under special contract terms. With this supply option, the final consumer remains with his current supplier but signs a new supply contract under special terms (change of contract).

Change of supplier refers to the process by which a final consumer at a metering point (eg the connection point in the building) changes his current supplier (old supplier) for a new supplier. Supplier switches resulting from customers moving into or out of a residence, or moving from one residence to another, or supply contracts transferred as a result of a concession change, are not considered to be changes of supplier. The number of changes of supplier is a key indicator for the development of competition in the retail sector in Germany.

According to the gas network operators surveyed for the 2013 monitoring, the supplier switching volume amounted to 102.06 TWh in 2012. The rate of supplier switches is similar to that of previous years.

Figure 135: Development of supplier switching volumes in TWh and of the supplier switching rate (2006 - 2012) according to survey of gas TSOs and DSOs



In the smallest category "≤ 300 MWh/a" of household and small business customers, the supplier switching volume declined by 4.89 TWh. In the category of gas power plants, the supplier switching volume decreased in the year under review, after having increased slightly the previous year. Many of these customers, however, are bound by longer-term contracts, so that a short-term supplier change, as is possible for household customers, is often out of the question.

Table 49: Total changes of supplier by final gas consumers in 2010 and 2012 by category of final consumers according to survey of gas TSOs and DSOs[161]

Category	2011 Changes of supplier TSOs and DSOs in TWh	2012 Changes of supplier TSOs and DSOs in TWh	Changes 2011 to 2012 in TWh
≤ 300 MWh/year	31,56	26,67	-4,89
<300 MWh/year ≤ 100.000 MWh/year	26,95	32,10	5,15
> 100.000 MWh/year	33,82	36,80	2,98
Gas power plants	15,80	6,49	-9,31
Total	107,86	102,06	-5,80

Table 50: Share of total change of supplier by final gas consumers in 2011 and 2012 by category of final consumers in the total gas output volume according to survey of gas TSOs and DSOs[161]

Category	2011		2012	
	Changes of supplier TSOs and DSOs in TWh	Share of total gas output in percent	Changes of supplier TSOs and DSOs in TWh	Share of total gas output in percent
≤ 300 MWh/year	31,56	7,11	26,67	7,92
> 300 MWh/year ≤ 100.000 MWh/year	26,95	11,35	32,10	15,11
> 100.000 MWh/year	33,82	16,00	36,80	13,38
Gas power plants	15,80	9,37	6,49	4,94
Total	107,86	10,88	102,06	10,68

161 Totals may deviate slightly owing to rounding differences.

In 2012, network operators reported a total of 1,039,471 changes of supplier. Compared to 2011, the total number of changes of supplier thus decreased by around 18 percent, or 237,177. Almost the entire decrease in the number of supplier switches is accounted for by the customer category "≤ 300 MWh/a". Placed in relation to the number of 1,021,793 supplier switches, the switching volume of 26.67 TWh translates into an average switching volume of approximately 26,000 KWh per final customer in the category of household customers and small businesses (≤ 300 MWh/a). The average consumption level of a household customer switching supplier was thus higher than the average consumption level of 20,000 kWh.

In terms of all final consumers, the number-based supplier change rate of 7.59 percent is lower than the volume-based supplier change rate of 10.68 percent.

Table 51: Number of final consumers and number of changes of supplier in 2012 by category of final consumers, according to survey of gas TSOs and DSOs

Category	Number of final customers TSOs and DSOs	Number of changes of supplier VNB und FNB	Share number of changes of supplier of number of final customers in percent
≤ 300 MWh/year	13.542.688	1.021.793	7,54
<300 MWh/year ≤ 100.000 MWh/year	153.482	17.459	11,38
> 100.000 MWh/year	1.678	189	11,26
Gas power plants	932	30	3,22
Total	13.698.780	1.039.471	7,59

When household customers are viewed separately within the meaning of section 3 para 22 EnWG, the data submitted by gas suppliers paints the following picture: Altogether, 677,839 household customers switched gas suppliers in 2012. That is nearly 260,000 fewer household customers than in 2011, which corresponds to a decrease of around 28 percent. In 2012, a total of 156,544 household customers chose a supplier other than the default supplier on moving to a new place of residence. This shows that new gas customers continue to take the opportunity of moving house to go with a new and less expensive supplier at their new place of residence. The number of business and industrial customers switching suppliers increased by around 27,000 customers to 191,694.

Figure 136: Number of changes of supplier by final consumers (2006 to 2012)

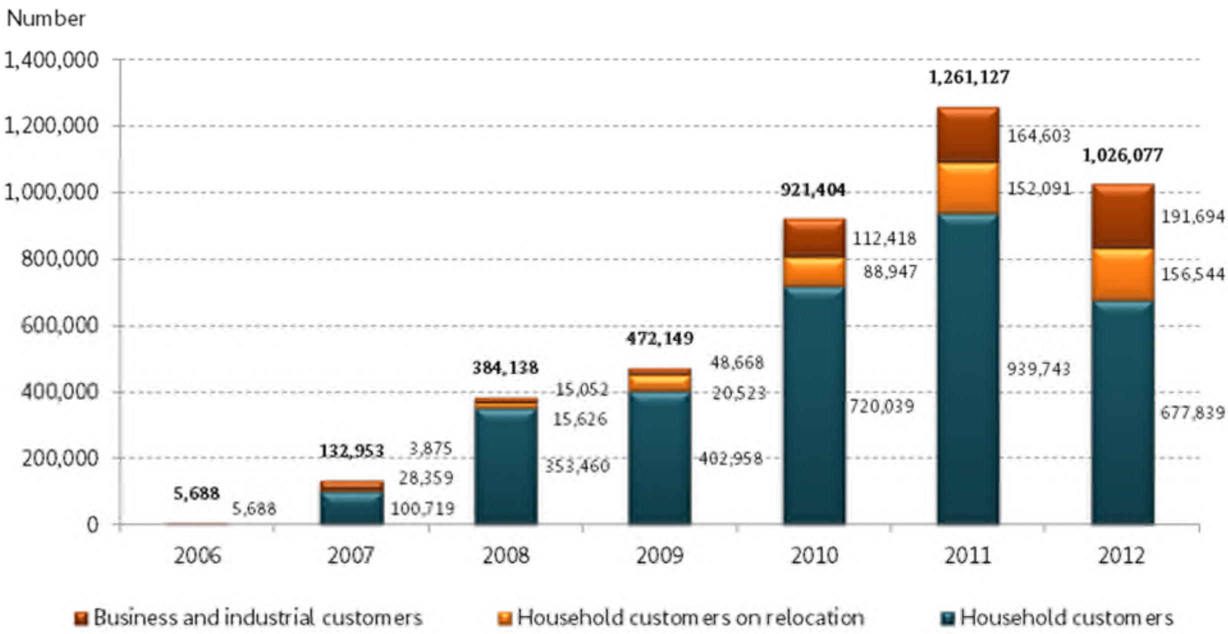
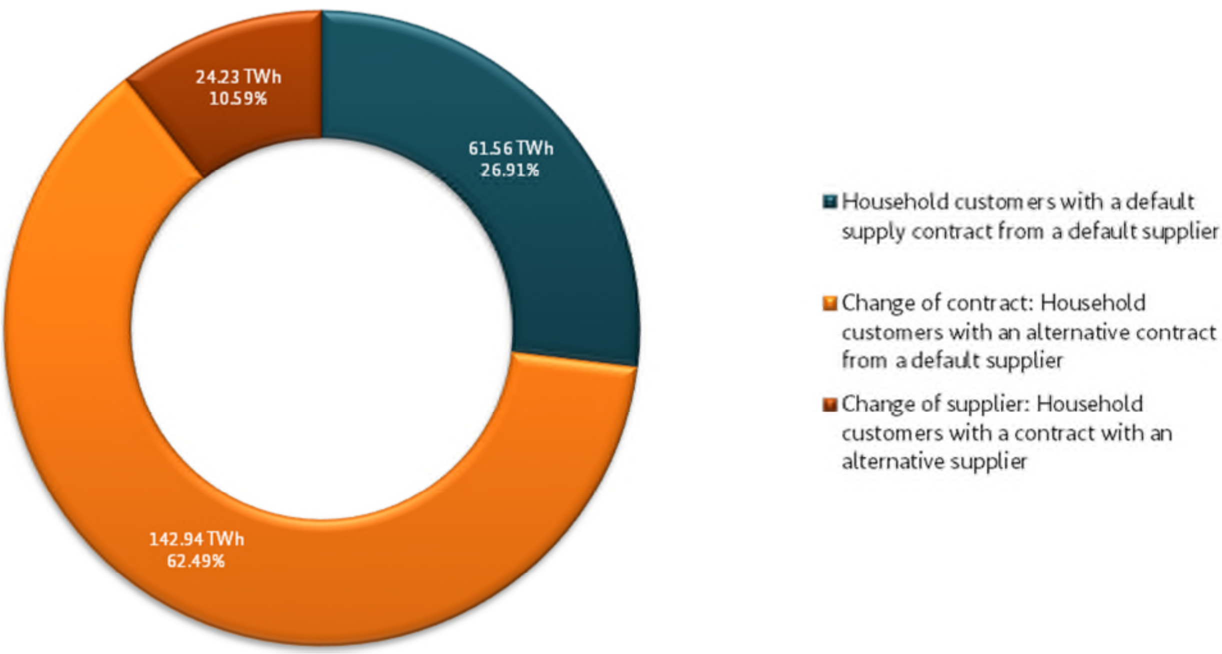


Figure 137: Contract structure of household customers according to survey of wholesalers and suppliers, as of 31 December 2012



In terms of the supply structure of household customers as of the relevant date of 31 December 2012, the above diagram shows the following: A total of eleven percent of household customers was served by gas suppliers other than the default suppliers. Approximately 63 percent of household customers received gas from their default supplier under special contract terms. Nearly 27 percent of the volume of gas delivered to household customers was provided within the framework of default supply. Finally, customers with special contracts, for example heating gas customers, continued to take advantage of the possibility to switch suppliers and terminated their contract with the previous default supplier in order to sign on with a competitor.

The majority of DSOs (75 percent) carry out the business processes involved in switching suppliers themselves. 25 percent of DSOs use a service provider for this. 82 percent of DSOs do not use a converter, which secures the data transmission in the Electronic Data Interchange For Administration, Commerce and Transport (EDIFACT) format; instead, they generate the corresponding message types through their own IT system. The results of the monitoring survey show that the designated EDIFACT message types are used nearly to their full extent within the framework of the implementation of the GeLi Gas ruling. 96 percent of DSOs report using all of the designated EDIFACT message types for data exchange purposes. Following the transition to regular operations, 90 percent of DSOs still use e-mail as the dominant means of transmission. Two percent of DSOs use access to an FTP server as the means of transmission. Two percent of DSOs use other means of transmission. Six percent of DSOs did not specify.

6. Disconnection notices, disconnections, tariffs and terminations

6.1 Disconnection of supply

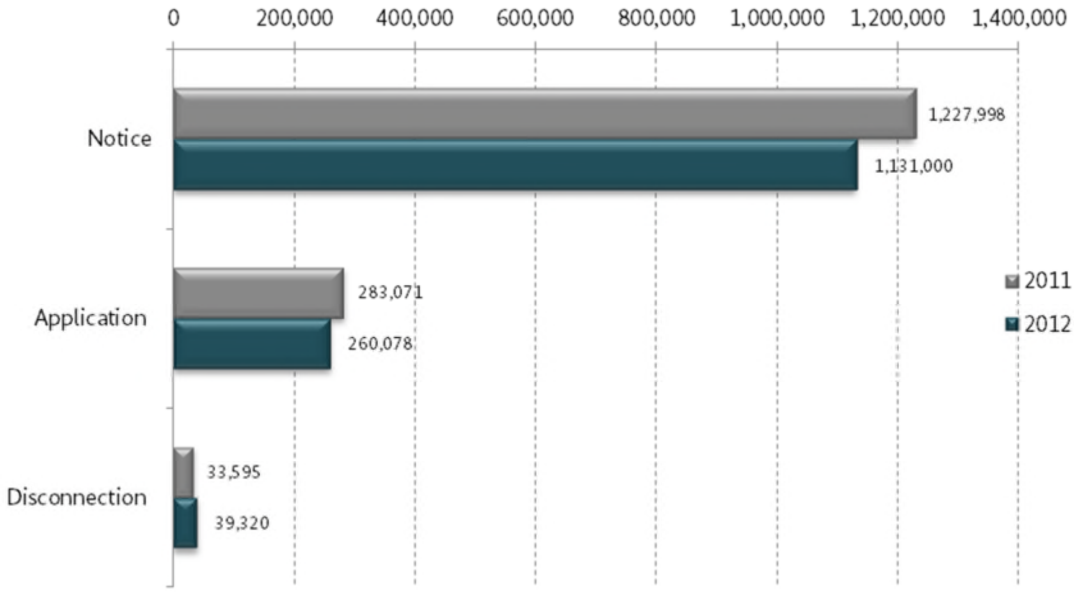
In 2012, the Bundesnetzagentur for the second time carried out surveys of the tariffs offered, and asked network operators as well as gas suppliers about threatened disconnections, disconnection orders as well as the number of actual disconnections under section 19 para 2 of the Gas Default Supply Ordinance (GasGVV) and the associated costs. Section 19(2) of the GasGVV entitles default suppliers to disconnect supplies to customers, in particular upon failure to fulfil payment obligations, and after a corresponding reminder has been given. In contrast to the terms for a disconnection of the electricity supply, a minimum level of arrears of 100 euros is not required for a disconnection of the gas supply. In the area of default gas supply, too, there has been an increase in the number of disconnections carried out compared to last year. Here too, some companies were not able to provide precise figures, but instead submitted estimates. On the whole, here too the ratio between threatened disconnections, disconnection orders and actual disconnections was similar to that reported in 2012.

Gas network operators were asked at how many metering points (customers) they had successfully disconnected or reconnected supplies in the year 2012 at the request of a default or alternate supplier. Gas network operators reported 39,320 disconnections of supply.

Gas network operators billed suppliers an average of 40 euros for cutting off gas supplies, with the actual costs charged ranging to 271 euros. At the same time, suppliers and wholesalers were asked how often in 2012 they had issued disconnection notices warning customers in arrears that they may be disconnected or informing them that they had applied to the respective network operator for supplies to be disconnected. The companies reported that they had issued approximately 1.13 million disconnection notices to customers. Although the GasGVV ordinance does not stipulate a minimum level of arrears, on average a disconnection notice was not issued until arrears reached 107 euros. Only in around 260,078 cases did disconnection notices result in gas being cut off by the respective network operator.

On average, suppliers charged their customers 36 euros for disconnecting the gas supply, with the actual charge made ranging between 0 and 192 euros.

Figure 138: Disconnection notice, application to the network operator and disconnection of gas supply



6.2 Tariffs and terminations of contract

Under section 40(3) EnWG, suppliers are obligated to offer final consumers monthly, quarterly or semi-annual settlement. However, in the sector of gas supply, there is only little demand on the part of final consumers for such settlement options. 88 companies reported a total of 2525 customers requesting such settlement periods of less than a year.

In the gas sector, only few suppliers terminate service with their customers. In 2012, suppliers delivered a total of approximately 24,000 notices of service termination to their customers. However, as in the electricity sector, the overwhelming majority of contracts appear to have been terminated by just a few, young interregional operative companies, while the regional providers rarely or never terminated service with their customers.

7. Price level

In the 2013 monitoring survey, wholesalers and suppliers were asked to submit to the Bundesnetzagentur the average retail price level of their company, as of 1 April 2013, for the three customer categories listed (see below). The overall price had to take into account all fixed and variable price components charged to the final consumer, including kilowatt-hour price, service price, base price and price for metering and billing. In addition, an estimated breakdown of the price was required into average net network tariff, up-stream network costs, average charge for billing, metering and meter operations, as well as average concession fees, current gas tax and average value added tax. The average value for the price components energy procurement and supply was also requested, including the supplier's margin.

There are three different contractual possibilities for final consumers to be supplied with gas. Besides gas supply within the framework of default supply according to default supply tariffs, two other possibilities of supply are particularly relevant in terms of competition. The supply of gas outside of the default supply structure but still in the supplier's default supply area is considered supply under change of contract terms. With this supply option, the final consumer stays with his local supplier, but signs a new contract under special terms. Supply outside of a supplier's default supply area means that the final consumer also signs a supply contract with a supplier according to special terms. This is considered supply after a switch of supplier.

In the case of household and business customers, the following diagram depicts both the weighted and unweighted average values of the retail price level (see below). In the case of industrial customers, the 2013 monitoring survey does not depict the volume-weighted values.[162] To calculate the volume-weighted average values, for each customer category the companies' sales volumes were multiplied by the respective price components, aggregated and divided by the total sales volume of all gas suppliers. In the customer category "household customers", volumes sold to household customers as reported by wholesalers and suppliers were used for the weighting. The weighting of the price components in the customer category "business customers" is based on the volumes sold to this customer group in the category "consumption volumes below 300 MWh/a", as reported by wholesalers and suppliers, less the volume sold to household customers, which was reported separately.

As was the case in previous monitoring reports, the following diagrams show, in addition to the average net network tariff (including up-stream network costs), the average charges for metering and meter operations as part of the same sum. The tables, however, show separate individual figures.

The evaluation of the questionnaires sent to gas suppliers produced the following results, by customer category.

7.1 Business / industrial customers[163]

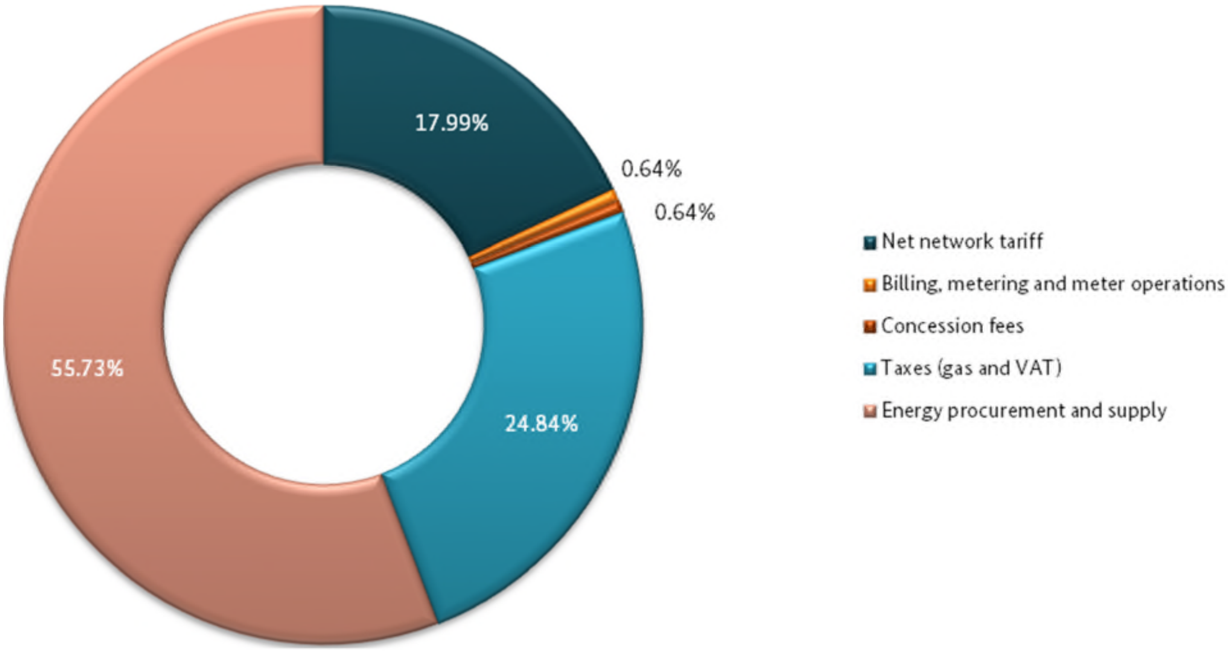
As of the cutoff date of 1 April 2013, there was only a slight increase in gas prices in the segment of business customers: The average, volume-weighted gas price in this segment increased to 6.28 ct/kWh (unweighted average: 6.31 ct/kWh) from 6.26 ct/kWh as of the cutoff date of 1 April 2012 (unweighted average: 6.24 ct/kWh) (cf. table 52). The price level was only approximately 0.3 percent above the previous year's value, so that the increase was much less steep relative to the previous year's value (around ten percent). However, the price level as of 1 April 2013 still reached its highest level since the first survey with cutoff date of 1 April 2009. The most recent price increase is attributable to the increased network usage charges, including upstream network costs, which have increased within one year from a volume-weighted level of 1.05 ct/kWh to 1.13

[162] The statistical spread of information provided by the industrial customers surveyed was too broad to undertake an effective volume-weighting of the price components.

[163] It can be assumed that the purchase cases for business and industrial customers reported on by the default supplier apply exclusively to customers with special contracts.

ct/kWh. The weighted price component, by contrast, which is made up of energy procurement and supply, decreased from a level of 3.58 ct/kWh as of 1 April 2012 to 3.50 ct/kWh. The highest share of the price, 55.7 percent, continued to be accounted for by the product itself (cf. Figure 139).

Figure 139: Composition of volume-weighted gas retail price level for business customers with change of contract tariffs. Prices as of 1 April 2013 according to survey of gas wholesalers and suppliers[164]



[164] Due to rounding differences, slight deviations in the sum of individual components are possible.

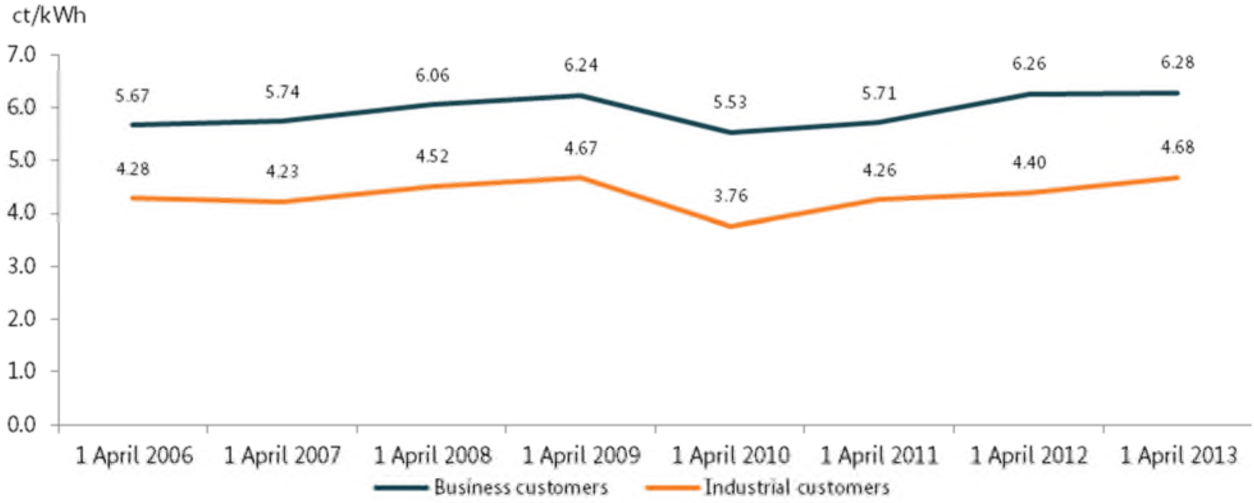
Table 52: Average retail price level for category business customers. Prices as of 1 April 2013 according to survey of gas wholesalers and suppliers[165]

Relevant date: 1 April 2013	Arithmetic average ct/kWh	Percentage of total value	Volume-weighted average ct/kWh	Percentage of total value
Average net network tariff including upstream network costs in ct/kWh	1.16	18.38	1.13	17.99
Average charge for billing	0.01	0.16	0.01	0.16
Average charge for metering	0.01	0.16	0.01	0.16
Average charge for meter operations	0.03	0.48	0.02	0.32
Average concession fees	0.05	0.79	0.04	0.64
Current gas tax	0.55	8.72	0.55	8.76
Average VAT	1.01	16.01	1.01	16.08
Average price component for energy procurement and supply	3.49	55.31	3.50	55.73
Total	6.31	100	6.28	100

An examination over time shows a clear trend toward a higher gas price, which was only interrupted by the price drop in 2010.

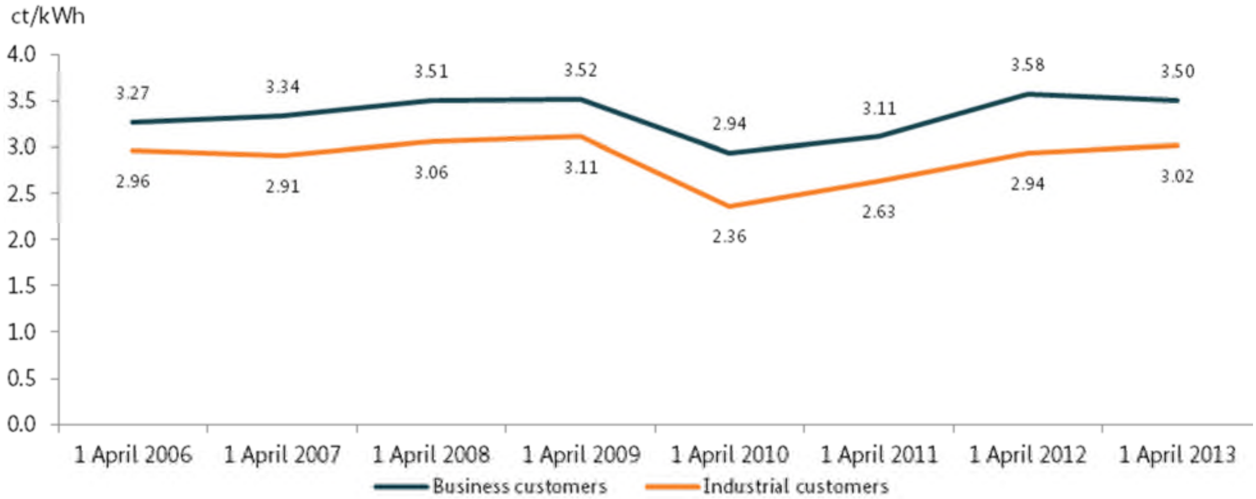
[165] Due to rounding differences, slight deviations in the sum of individual components are possible.

Figure 140: Development of gas prices for business and industrial customers 2006 – 2013.
Prices as of 1 April 2013 according to survey of gas wholesalers and suppliers



An examination of the development of the price component energy procurement and supply over the multi-year period shows a significant price drop in 2010 in the segment of business customers, accompanied by at times substantial price increases in subsequent years. This trend has not continued during the monitored period; instead, the volume-weighted price level as of the cutoff date of 1 April 2013 has declined slightly.

Figure 141: Development of price component "energy procurement and supply" for business and industrial customers 2006 – 2013. Prices as of 1 April 2013 according to survey of gas wholesalers and suppliers



In the area of supply of industrial customers, the average price level increased from 4.61 ct/kWh to 4.68 ct/kWh (cf. Table 53)[166]. This amounts to an increase of 1.5 percent. The reasons for this are the slightly increased average prices for the price components energy procurement and supply as well as network tariffs (including upstream network costs). The price component for natural gas procurement and supply thus increased from 2.99 ct/kWh as of 1 April 2012 to 3.02 ct/kWh as of 1 April 2013. This price component amounted to around 64.5 percent of the average gas price, which is comparable to the previous year's level (cf. Figure 142). The average net network tariff (including upstream network costs) increased from 0.33 ct/kWh to 0.36 ct/kWh, which amounted to around 7.7 percent of the average overall price as of the cutoff date of 1 April 2013, compared to 7.2 percent in the previous year.

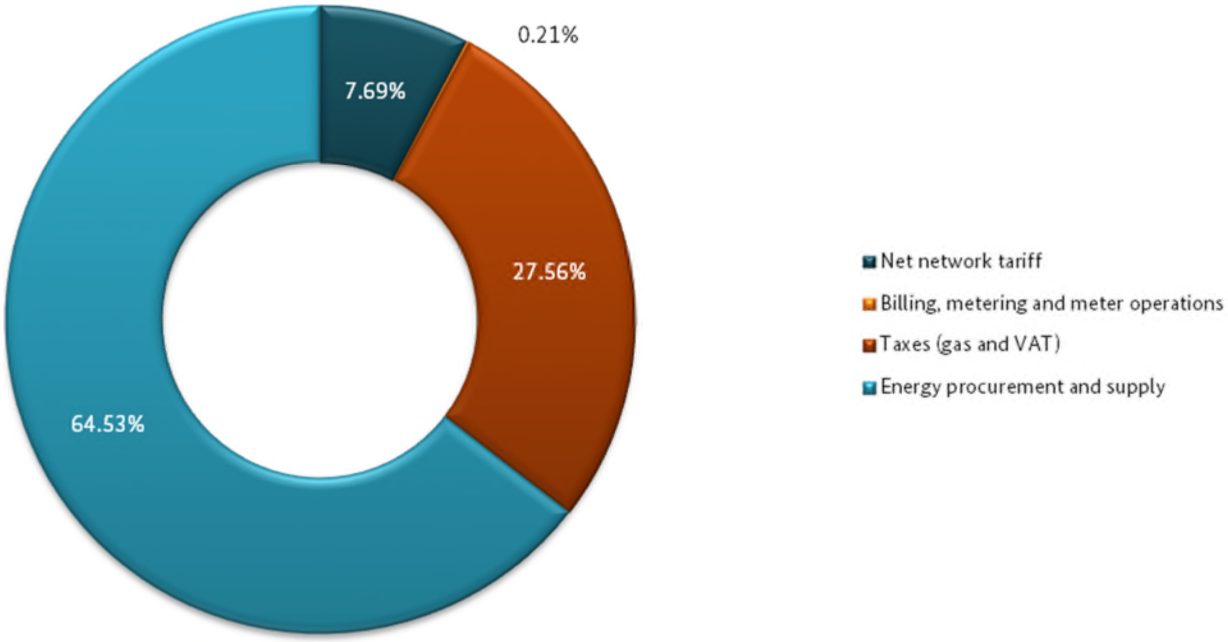
Table 53: Average retail price level for category industrial customers according to survey of gas wholesalers and suppliers[167]

	Relevant date: 1 April 2012		Relevant date: 1 April 2013	
	Arithmetic average in ct/kWh	Percentage of total value	Arithmetic average in ct/kWh	Percentage of total value
Average net network tariff including upstream network costs	0.33	7.16	0.36	7.69
Average charge for billing	0.00	0.00	0.00	0.00
Average charge for metering	0.00	0.00	0.00	0.00
Average charge for meter operations	0.00	0.00	0.01	0.21
Current gas tax	0.55	11.93	0.55	11.75
Average VAT	0.74	16.05	0.74	15.81
Average price component for energy procurement and supply	2.99	64.86	3.02	64.53
Total	4.61	100	4.68	100

[166] The 2013 Monitoring Report does not depict volume-weighted values, since a weighting of the purchase case with the offtake volumes is not practical given the specifics of the supply of industrial customers. Values in the table are depicted with a maximum of two decimal points. Values lower than 0.01 are thus depicted as 0.00.

[167] Due to rounding differences, slight deviations in the sum of individual components are possible.

Figure 142: Composition of volume-weighted gas retail price level for industrial customers. Prices as of 1 April 2013 according to survey of gas wholesalers and suppliers[168]



7.2 Household customers

Gas prices for household customers as of 1 April 2013 again showed increases in all three customer categories; this applies to both the weighted and the unweighted average prices. The volume-weighted prices for customers switching their contract or supplier were the highest since 2008; the price for default supply customers was slightly lower than the highest level, recorded in 2009.

The volume-weighted price for household customers with a standard contract with their default supplier increased from 6.95 ct/kWh to 7.09 ct/kWh within one year. This represents an increase of 2.1 percent. The average net network tariff (including upstream network costs) rose from 1.16 ct/kWh to 1.27 ct/kWh. The share of the total price rose accordingly from around 16.7 percent to approximately 18 percent.

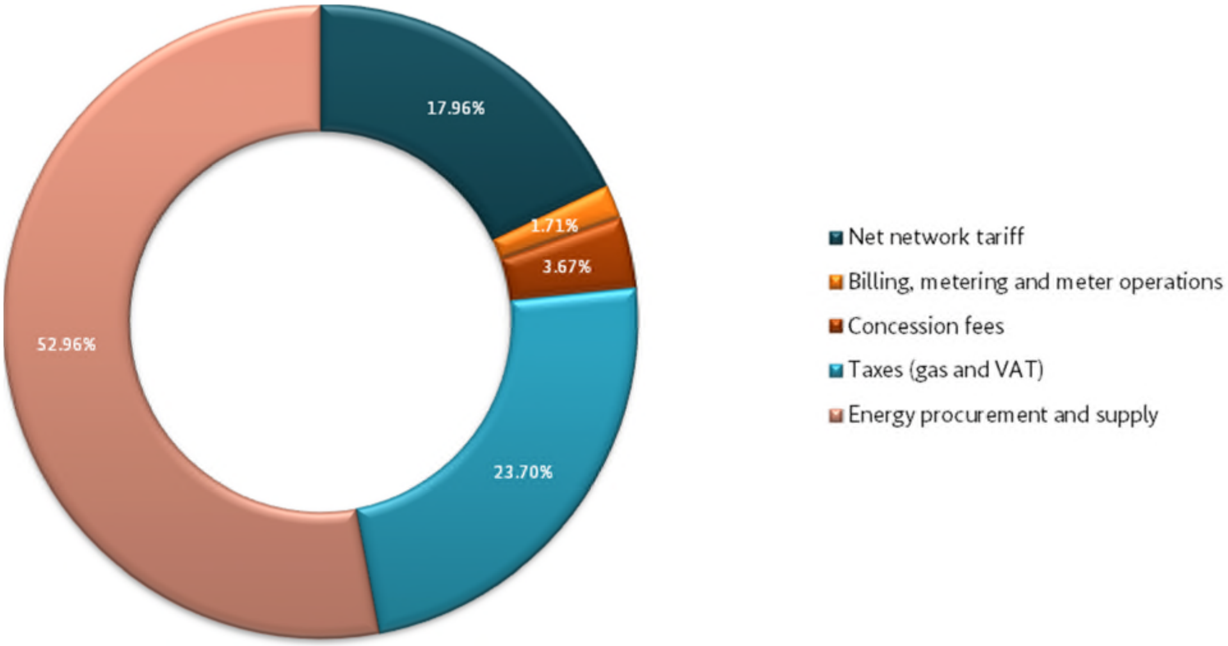
[168] Due to rounding differences, slight deviations in the sum of individual components are possible.

Table 54: Average retail price as of 1 April 2013 for default supply household customers, according to survey of gas wholesalers and suppliers[169]

As of 1 April 2013	Arithmetic average (ct/kWh)	Share of total (in percent)	Volume-weighted average (ct/kWh)	Share of total (in percent)
Average net network tariff including upstream network costs	1.36	18.48	1.27	17.96
Average charge for billing	0.05	0.68	0.05	0.71
Average charge for metering	0.02	0.27	0.02	0.26
Average charge for meter operations	0.06	0.82	0.05	0.74
Average concession fees	0.25	3.40	0.26	3.67
Current gas tax	0.55	7.47	0.55	7.76
Average VAT	1.18	16.03	1.13	15.94
Average price component for energy procurement and supply	3.89	52.85	3.75	52.96
Total	7.36	100	7.09	100

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

Figure 143: Composition of volume-weighted gas retail price as of 1 April 2013 for default supply household customers, according to survey of gas wholesalers and suppliers



The average prices as of 1 April 2013 for customers switching contract or supplier (see below) were again lower than the average price for default supply customers.

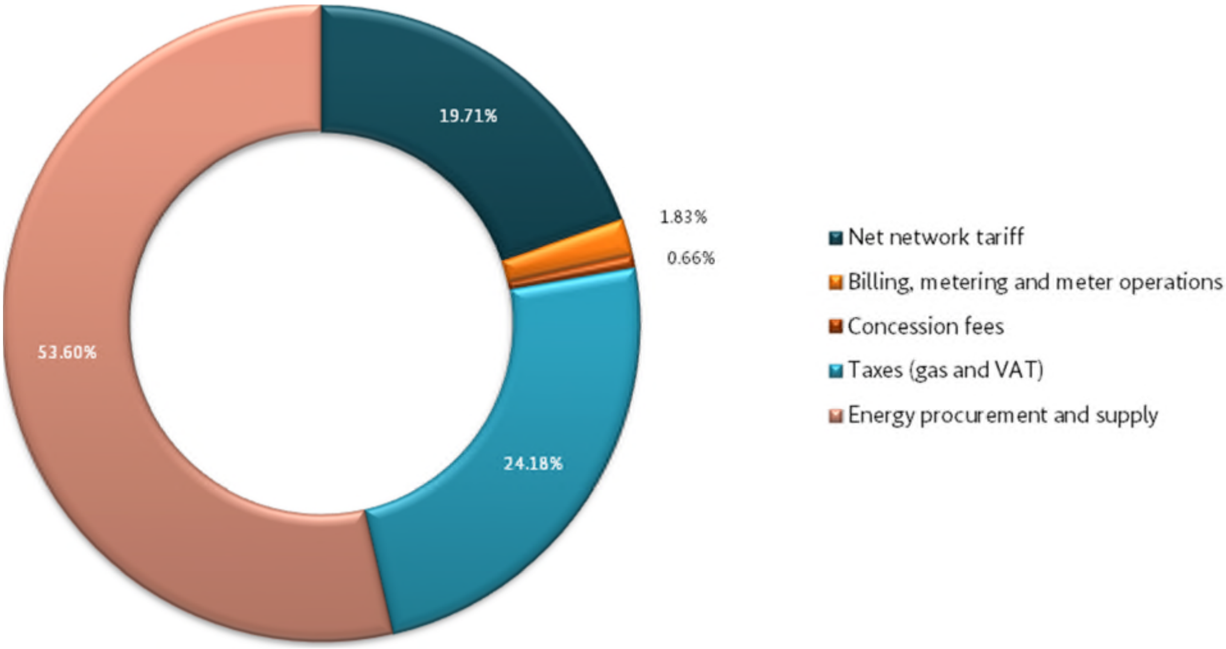
The volume-weighted average gas price for customers with a new contract rose from 6.58 ct/kWh on 1 April 2012 to 6.69 ct/kWh on 1 April 2013. This represents an increase of less than two percent, smaller than the price increase for default supply customers. The price component for energy procurement and supply showed a year-on-year decrease from 3.65 ct/kWh to 3.59 ct/kWh, compared to the substantial increase of around 18 percent in the previous year. The average net network tariff (including upstream network costs) also rose in this customer category, from 1.17 ct/kWh to 1.32 ct/kWh. The network tariff accounted for around 19.7 percent of the total price, which is about two percentage points higher than in the previous year.

Table 55: Average retail price as of 1 April 2013 for household customers switching contract, according to survey of gas wholesalers and suppliers[170]

As of 1 April 2013	Arithmetic average (ct/kWh)	Share of total (in percent)	Volume-weighted average (ct/kWh)	Share of total (in percent)
Average net network tariff including upstream network costs	1.37	20.21	1.32	19.71
Average charge for billing	0.05	0.74	0.05	0.79
Average charge for metering	0.02	0.29	0.02	0.28
Average charge for meter operations	0.05	0.74	0.05	0.77
Average concession fees	0.06	0.88	0.04	0.66
Current gas tax	0.55	8.11	0.55	8.22
Average VAT	1.08	15.93	1.07	15.96
Average price component for energy procurement and supply	3.60	53.10	3.59	53.60
Total	6.78	100	6.69	100

170 Figures may not sum exactly owing to rounding.

Figure 144: Composition of volume-weighted gas retail price as of 1 April 2013 for household customers switching contract, according to survey of gas wholesalers and suppliers[171]



As in the other customer categories, the average price for household customers switching supplier also increased. The volume-weighted price as of 1 April 2013 was 6.66 ct/kWh, representing a year-on-year increase of nearly three percent. This is larger than the prices increases for the other two customer categories. As with the price for customers switching contract, there are two opposing developments behind the increase in the volume-weighted price for customers with a new supplier: an increase in the average net network tariff (including upstream network costs) and a decrease in the price component for energy procurement and supply. This component accounted for only around 52.0 percent of the total price as of 1 April 2013, compared with some 54.8 percent in the previous year.

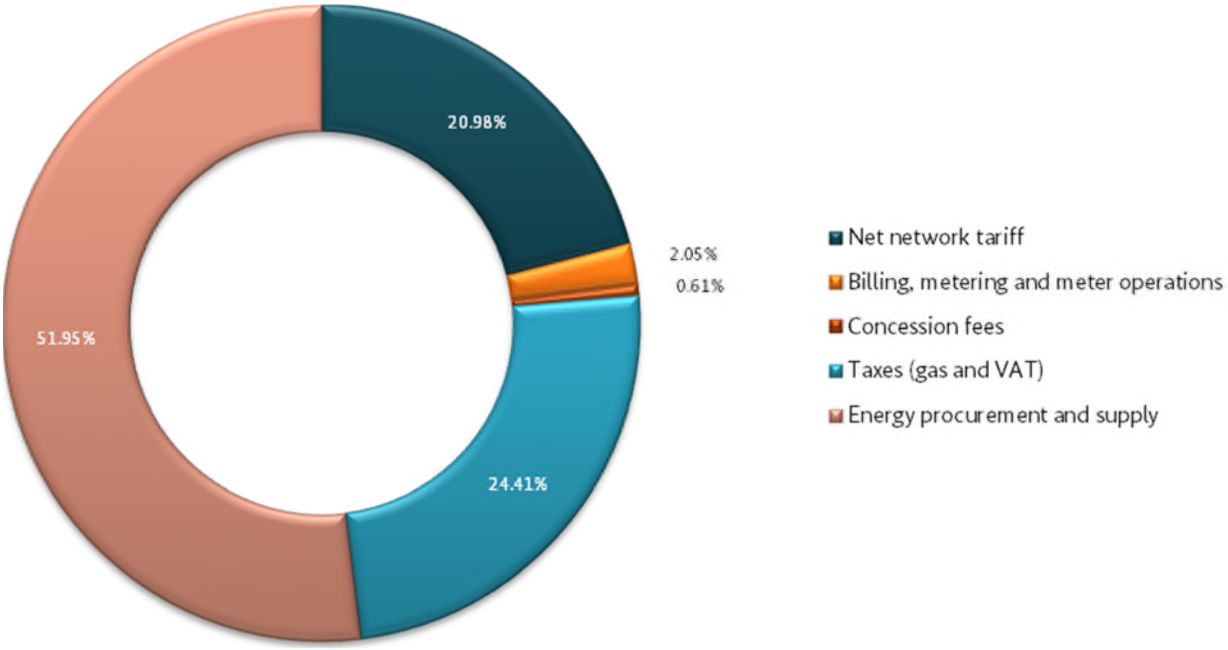
[171] Figures may not sum exactly owing to rounding.

Table 56: Average retail price as of 1 April 2013 for household customers switching supplier, according to survey of gas wholesalers and suppliers[172]

As of 1 April 2013	Arithmetic average (ct/kWh)	Share of total (in percent)	Volume-weighted average (ct/kWh)	Share of total (in percent)
Average net network tariff including upstream network costs	1.39	20.78	1.40	20.98
Average charge for billing	0.05	0.75	0.06	0.83
Average charge for metering	0.02	0.30	0.03	0.40
Average charge for meter operations	0.05	0.75	0.05	0.82
Average concession fees	0.05	0.75	0.04	0.61
Current gas tax	0.55	8.22	0.55	8.26
Average VAT	1.08	16.14	1.08	16.34
Average price component for energy procurement and supply	3.50	52.32	3.46	51.95
Total	6.69	100	6.66	100

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

Figure 145: Composition of volume-weighted gas retail price as of 1 April 2013 for household customers switching supplier, according to survey of gas wholesalers and suppliers



In the period under review, the gap between the prices paid by default supply customers and those paid by customers switching contract or supplier again widened slightly. The difference increased from 0.37 ct/kWh as of 1 April 2012 to 0.40 ct/kWh. This shows that there is still an incentive for customers to switch contract. Looking at the prices over a period of several years, there is an upward trend in both groups.

A look at the development of the price component for energy procurement and supply over time reveals a tendency to stagnate (default supply customers) or fall (customers with a new contract or supplier) (cf Figure 147).

Pure energy procurement costs make up more or less the same share of the price component for energy procurement and supply in all customer categories: around 81 percent for default supply customers, 85.8 percent for customers with a new contract and about 86.5 percent for customers with a new supplier[173].

[173] Based on unweighted averages.

Figure 146: Development of volume-weighted gas prices for household customers, 2006-2013.

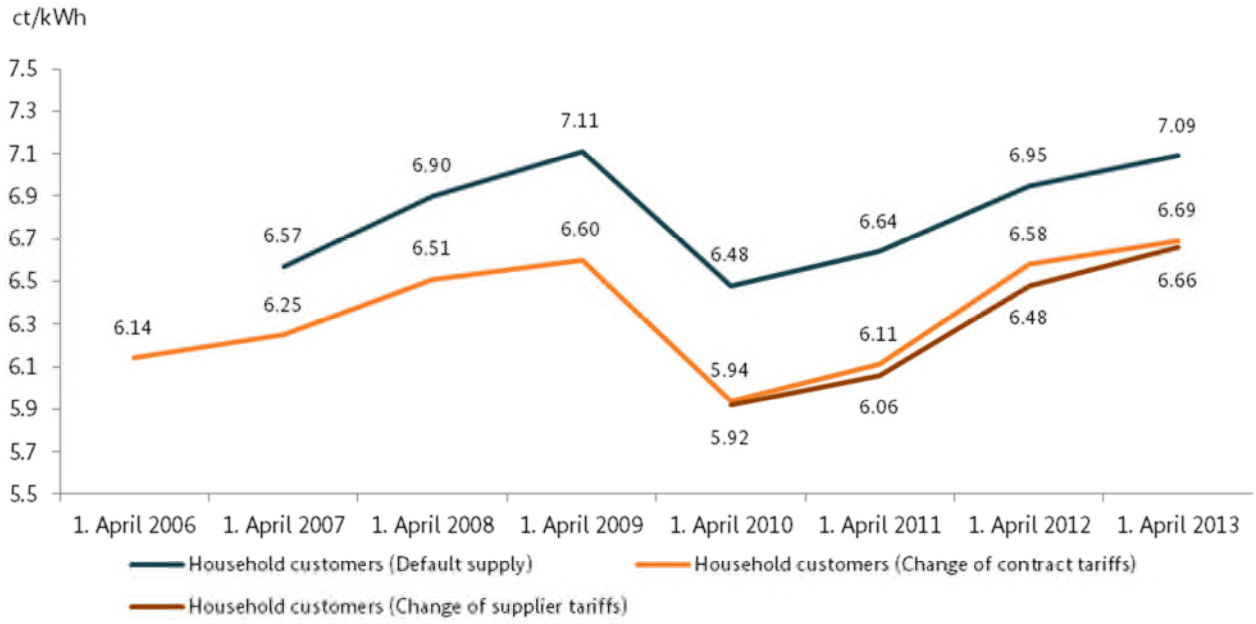
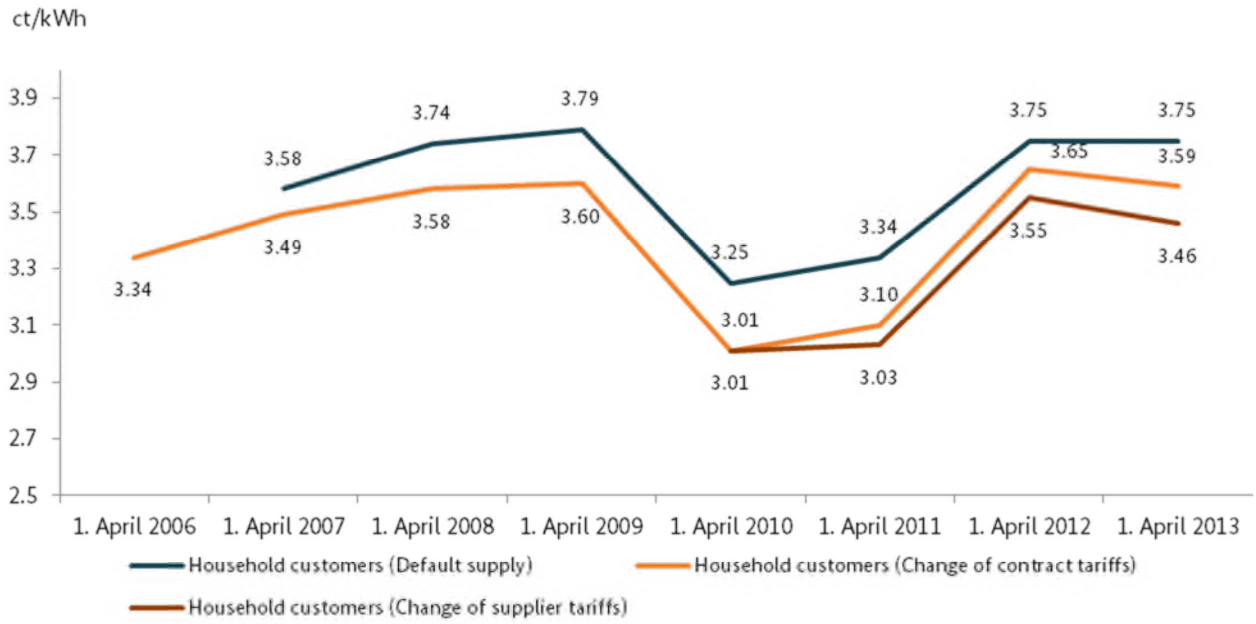
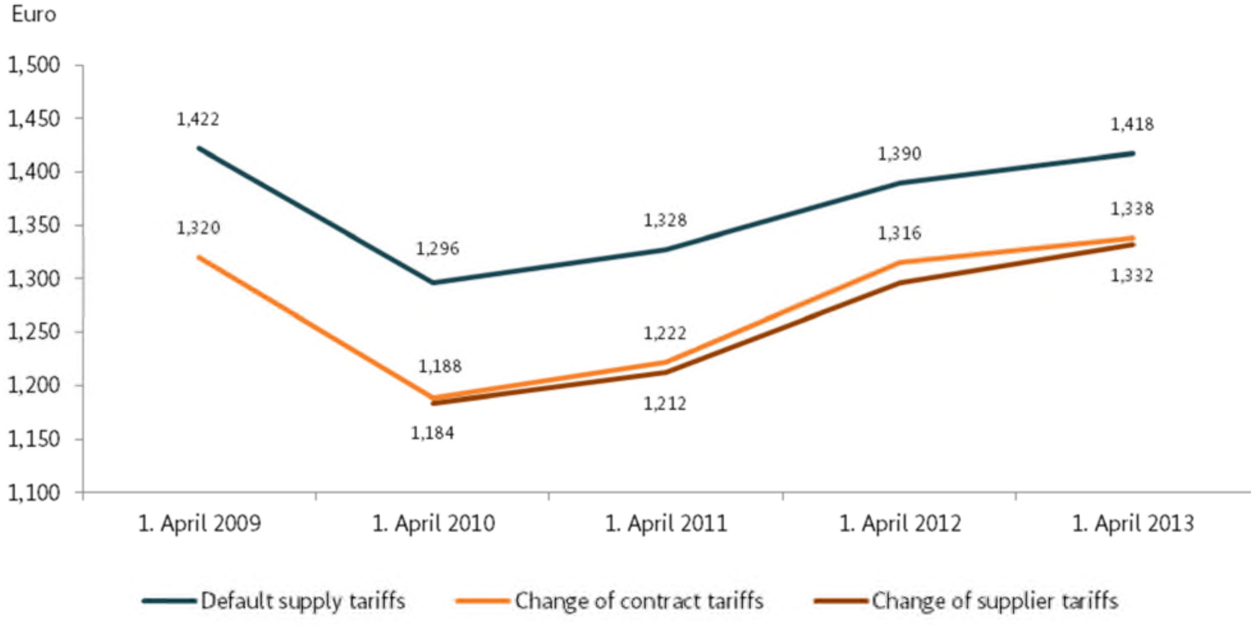


Figure 147: Development of price component for energy procurement and supply for household customers, 2006-2013, as of 1 April 2013 according to survey of gas wholesalers and suppliers



As there was an increase in the gas prices for customers in all categories, the additional costs were calculated for a hypothetical household customer with an annual consumption of 20,000 kWh in each category. A default supply customer would have needed to pay around €28, a customer with a new contract about €22 and a customer with a new supplier some €36 more than in the previous year.

Figure 148: Average annual gas costs for a household customer with an average annual consumption of 20,000 kWh in each category, 2009-2013



The gas suppliers participating in the 2013 survey were asked if they offered their customers special bonuses or contractual arrangements. The type of bonus most frequently offered is a one-off bonus payment credited to the customer's first annual bill. The sums paid range from €5 to €170, the average being around €50. The bonus payments for customers switching supplier vary between €5 and €330, the average here being some €65.

Special contractual arrangements for household customers include contractually agreed fixed prices; these cover the price components such as energy procurement and supply that the companies themselves can influence. Fixed price periods for customers with a new contract range from one to 31 months, the average period being 14 months, while those for customers with a new supplier vary between one and 36 months, the average again being 14 months.

Another special option available is advance payment, which is frequently offered together with a significant price discount. Although customers can make substantial savings in costs, the risk may be incalculable as customers usually have to pay suppliers their gas costs a whole year in advance. Nearly ten percent of the suppliers who responded "yes" or "no" offer an advance payment scheme to customers switching contract. Customers are required to pay their costs between three and twelve months in advance, the average being twelve months. Almost seven percent of the respondents have an advance payment option for customers switching supplier. These customers also need to pay their costs between three and twelve months in advance, the average again being twelve months.

A further special arrangement is a minimum contract period. Tariffs with low prices or special bonuses, in particular, may be linked to a minimum term. The minimum periods applicable to customers switching contract or supplier range from one to 24 months, the average in both cases being twelve months.

8. Comparison of European gas prices

A comparison of the gas prices in the European Union shows that, in the area of household customers, prices in Germany are close to the European average. The comparison is mainly based on data from a Eurostat survey of national average prices for household customers[174]. Based on these data, an average price of 4.81 ct/kWh was calculated for 2012 (2011: 4.57 ct/kWh), excluding taxes and levies; including taxes and levies, the average was 6.43 ct/kWh (2011: 6.14 ct/kWh). Compared with 2011, the gas prices paid by German household customers in 2012 were markedly lower than the average prices paid across Europe as a whole. The influence of taxes and levies changes the ranking in the overall comparison to a slight degree. Prices for household customers are lowest in Romania and highest in Sweden. Values for Greece are available for the first time as from the second half of 2012. The exact figures for all EU countries covered in the survey are shown below.

[174] The survey covered households in the D2 band with an annual consumption between 20 and 200 GJ. The average was calculated for the first and second half of 2012 (Survey 2012S1, 2012S2). Cf: http://epp.eurostat.ec.europa.eu/portal/page/portal/energy/data/database (As of 26 August 2013).

Figure 149: Comparison of European gas prices for private households in 2012, excluding taxes and levies (source: Eurostat)

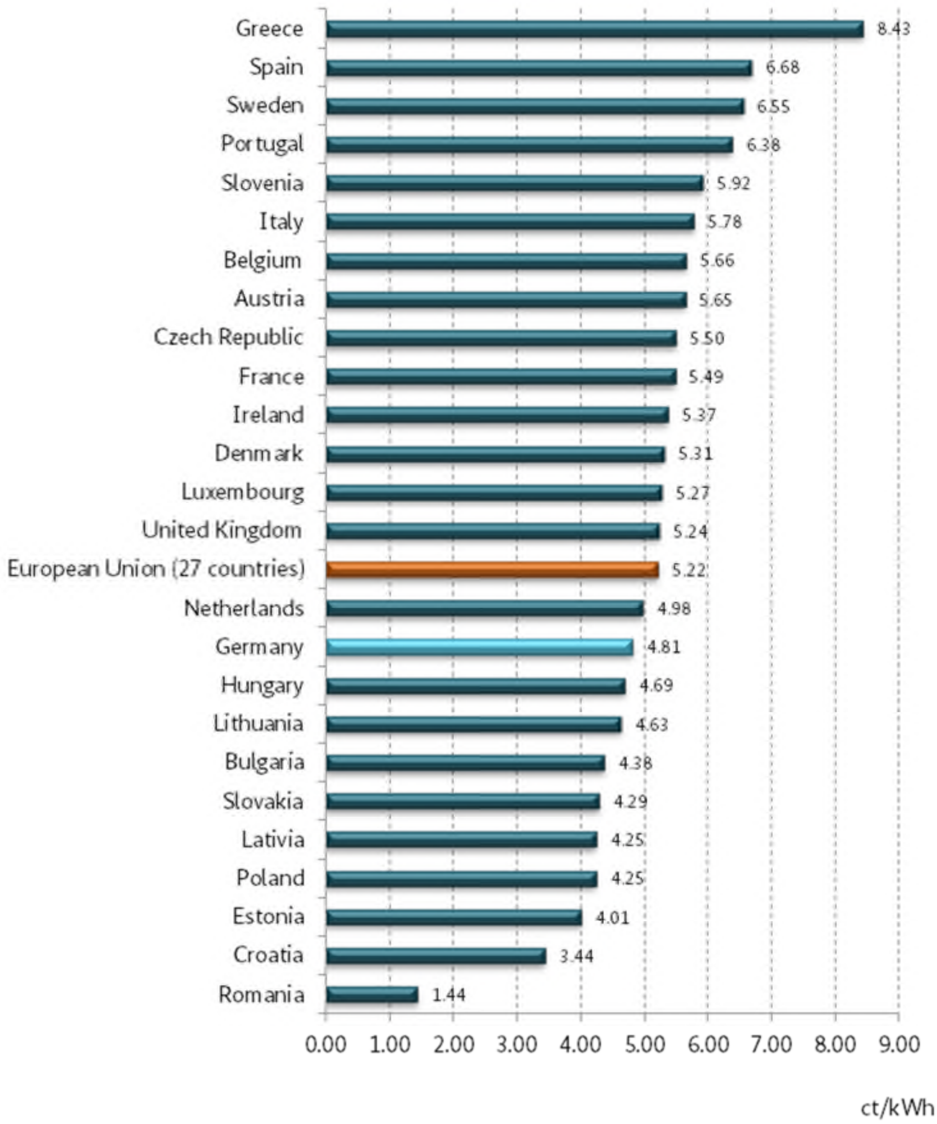
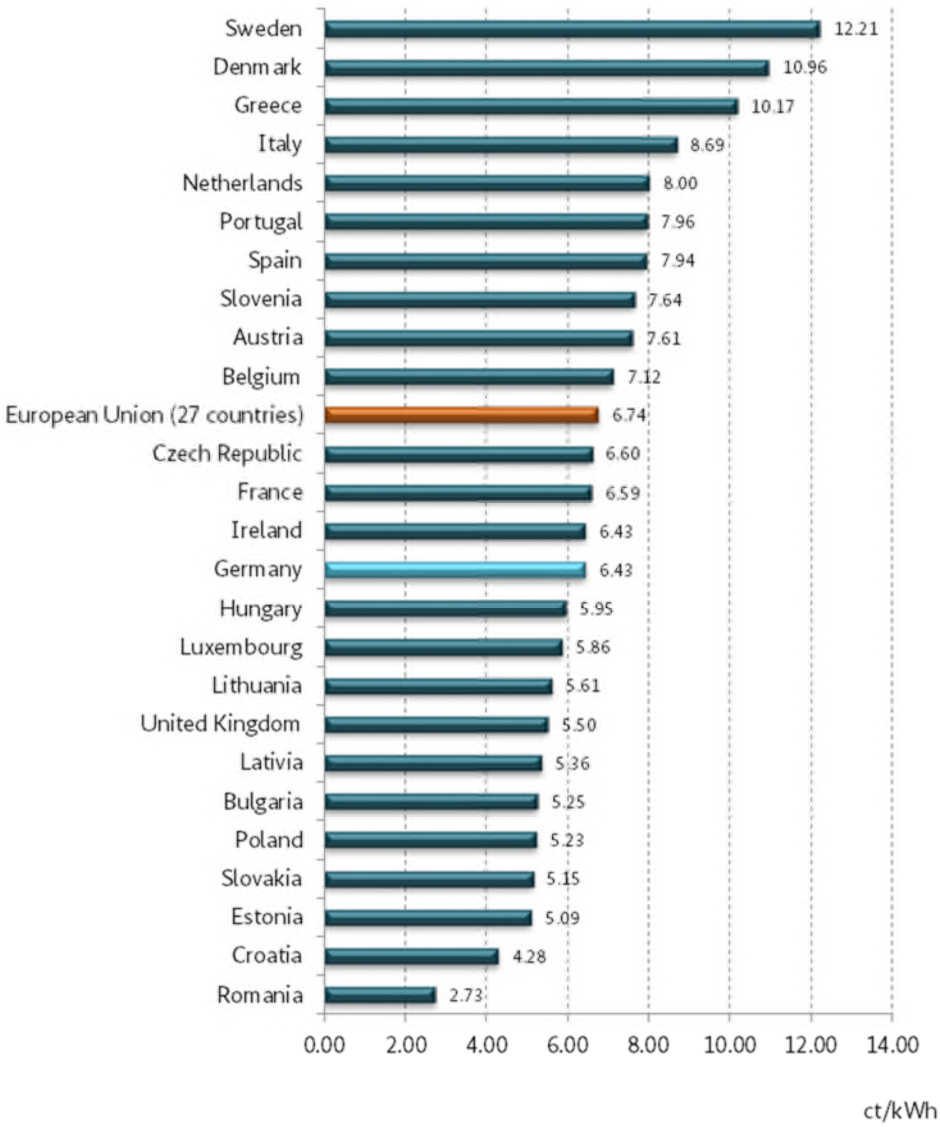


Figure 150: Comparison of European gas prices for private households in 2012, including taxes and levies (source: Eurostat)



In a comparison of European gas prices for industrial consumers[175] Germany does not do so well. In this customer segment, Germany's 2012 price of 4.40 ct/kWh (2011: 4.37 ct/kWh) excluding taxes, or 5.72 ct/kWh (2011: 5,68 ct/kWh) including taxes and levies, is above the respective overall European average, putting it in the top tier again. Here too, the influence of taxes and levies changes the ranking in the overall comparison

[175] The survey looks at national average prices paid by medium-sized industrial consumers in the Ic group with an annual consumption between 500 and 2,000 MWh. The average was calculated for the first and second half of 2012 (survey 2012S1, 2012S2). Cf: http://epp.eurostat.ec.europa.eu/portal/page/portal/energy/data/database (As of 26 August 2013).

only to a slight degree. Values for Greece are available for the first time as from the second half of 2012. The exact figures for all EU countries covered in the survey are shown below.

Figure 151: Comparison of European gas prices for industrial consumers in 2012, excluding taxes and levies (source: Eurostat)

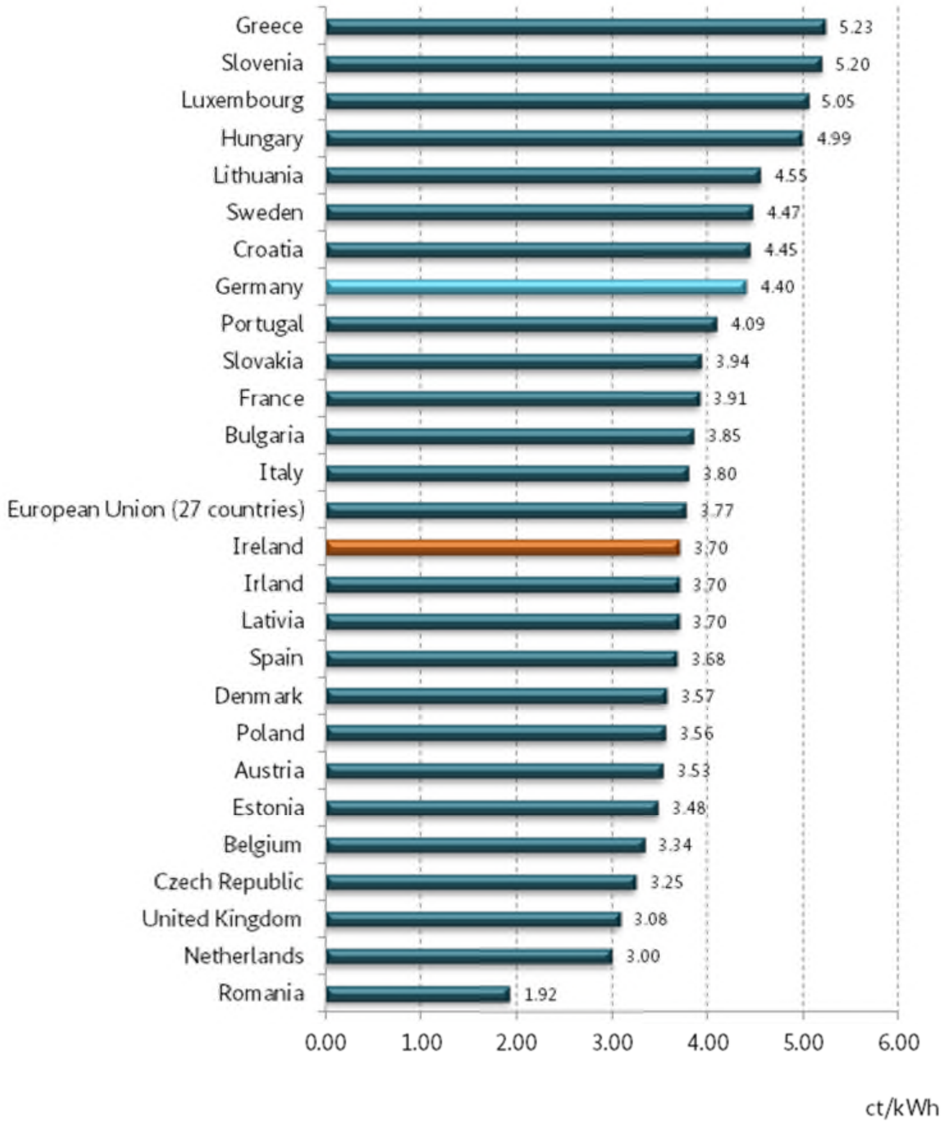
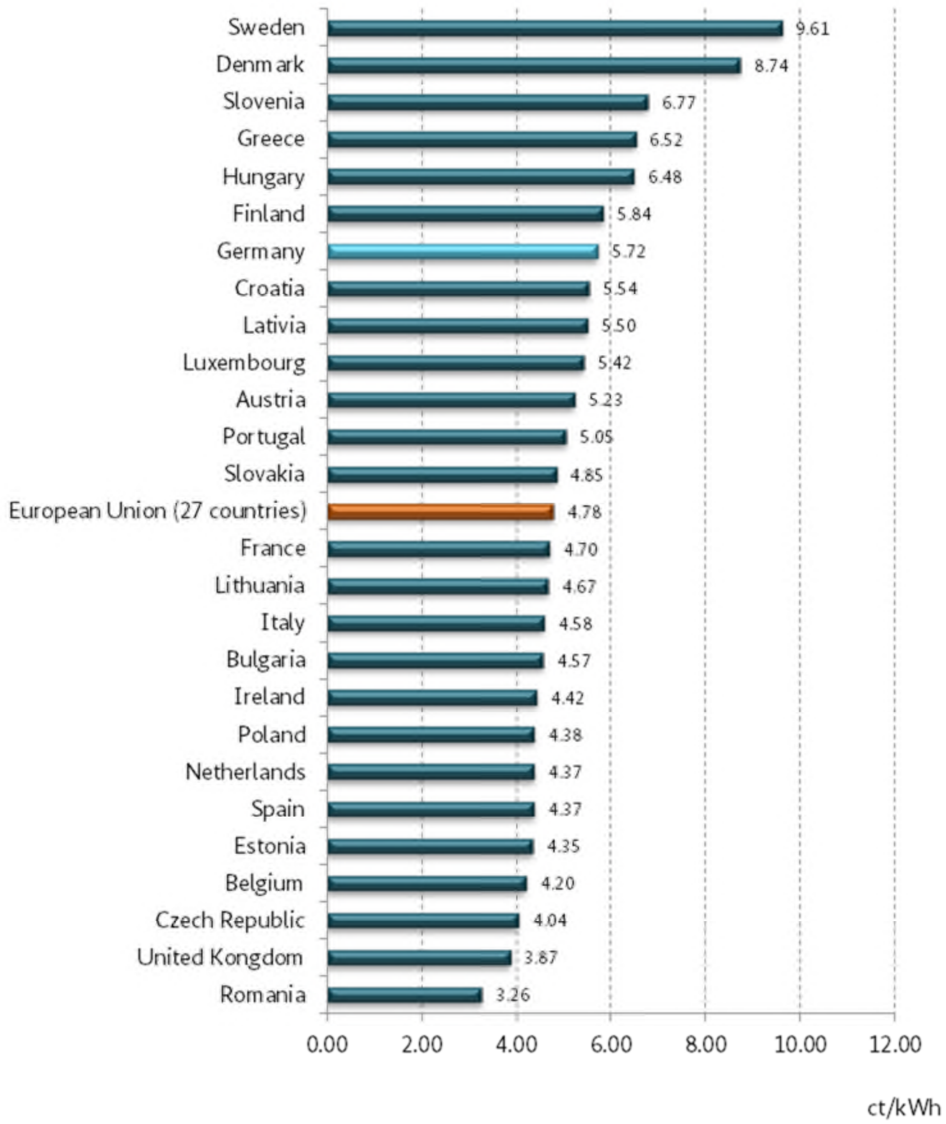


Figure 152: Comparison of European gas prices for industrial consumers in 2012, including taxes and levies (source: Eurostat)



The picture is more differentiated when gas prices are compared across Europe as a whole. While in the household customer segment Germany is positioned in the middle of the field, prices for industrial customers in Germany are above average. The influence of taxes and levies on the retail prices does not have as significant an impact as it does in the area of electricity.

H Storage facilities

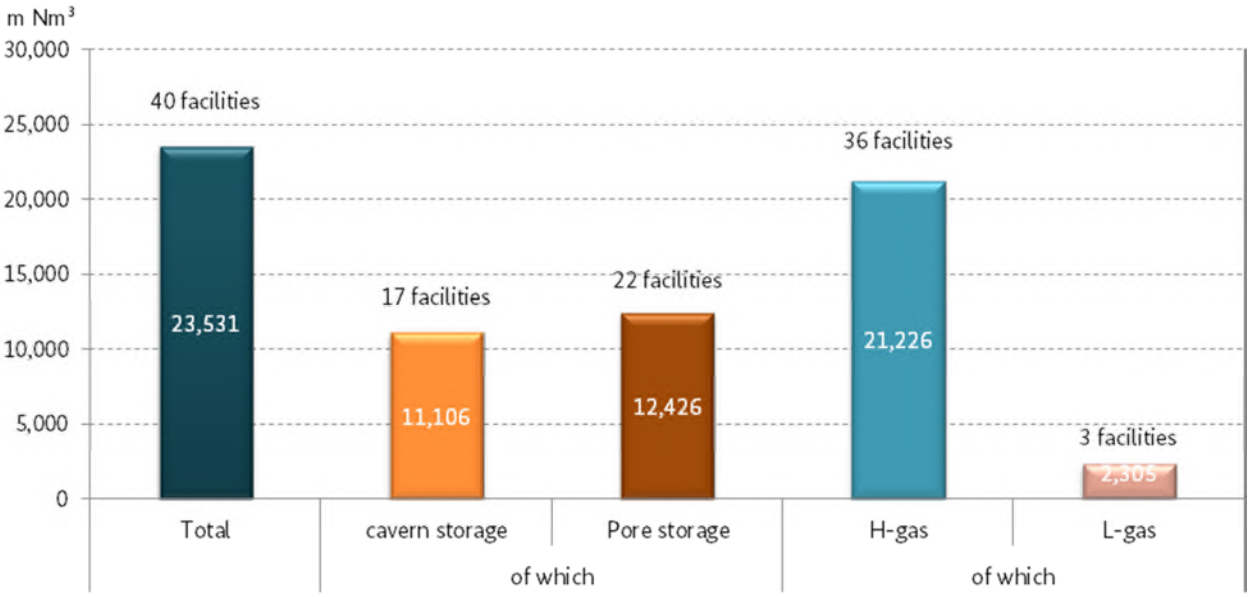
1. Gas injections (precautions for winter 2013/2014)

On account of the long 2012/2013 heating period, underground gas storage facilities were heavily depleted, reaching a storage level of 17.5 percent in mid-April 2013. Large volumes were, however, injected from the beginning of June 2013 onwards, and on 30 September 2013 the storage level stood at approximately 74 percent[176]. Injections will continue until mid-October 2013 to achieve an estimated storage level of at least 80 percent. Storage capacity bookings for 2013/2014 indicate that most of the storage capacity has been marketed and that the storage customers will also use the capacity. An adequate supply of gas is therefore expected to be available for household customers.

2. Access to underground storage facilities

22 companies operating and marketing a total of 39 underground natural gas storage facilities took part in the 2013 monitoring survey. The total maximum usable volume of working gas in these storage facilities is 23.53bn Nm³. Of this, 11.11bn Nm³ is accounted for by cavern and 12.43bn 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 (21.23bn Nm³ compared to 2.30bn Nm³ for L-gas).

Figure 153: Maximum usable volume of working gas in underground natural gas storage facilities in 2012



[176] Based on a working gas volume of 23.53bn m³ (see also II.H.2 "Access to underground storage facilities" on page 260)

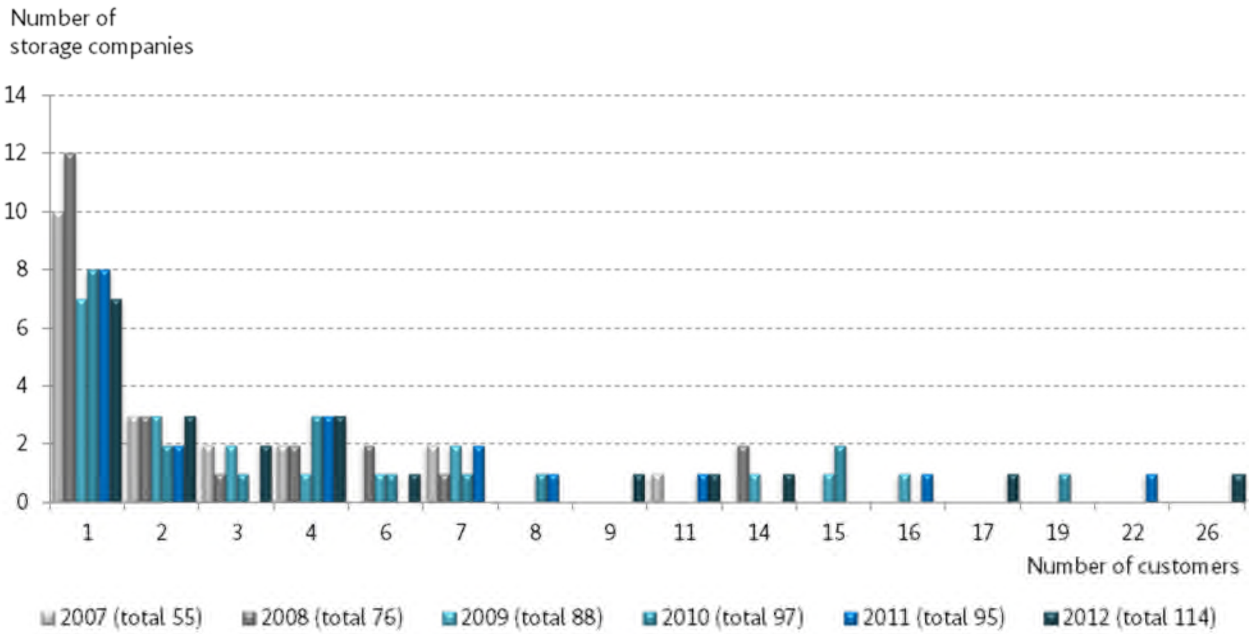
3. Use of underground storage facilities for production operations

In 2012, less than one percent (the same as in 2011) of the maximum usable volume of working gas in underground natural gas storage facilities was used for production operations in a storage facility. After deducting the working gas volume used for production operations, the total working gas volume accessible to third parties in 2012 was 23.37bn Nm^3 (2011: 22.09bn Nm^3), the injection capacity 11.37m Nm^3/h and the withdrawal capacity 19.94m Nm^3/h.

4. Use of underground storage facilities by third parties – customer trends

According to the companies' data, the average number of storage customers in 2012 was 5.4 (2008: 3.2; 2009: 4.2; 2010: 4.4; 2011: 5.0). The following chart shows the trend in the number of customers per storage facility operator since 2007:

Figure 154: Number of customers per storage facility operator between 2007 and 2012

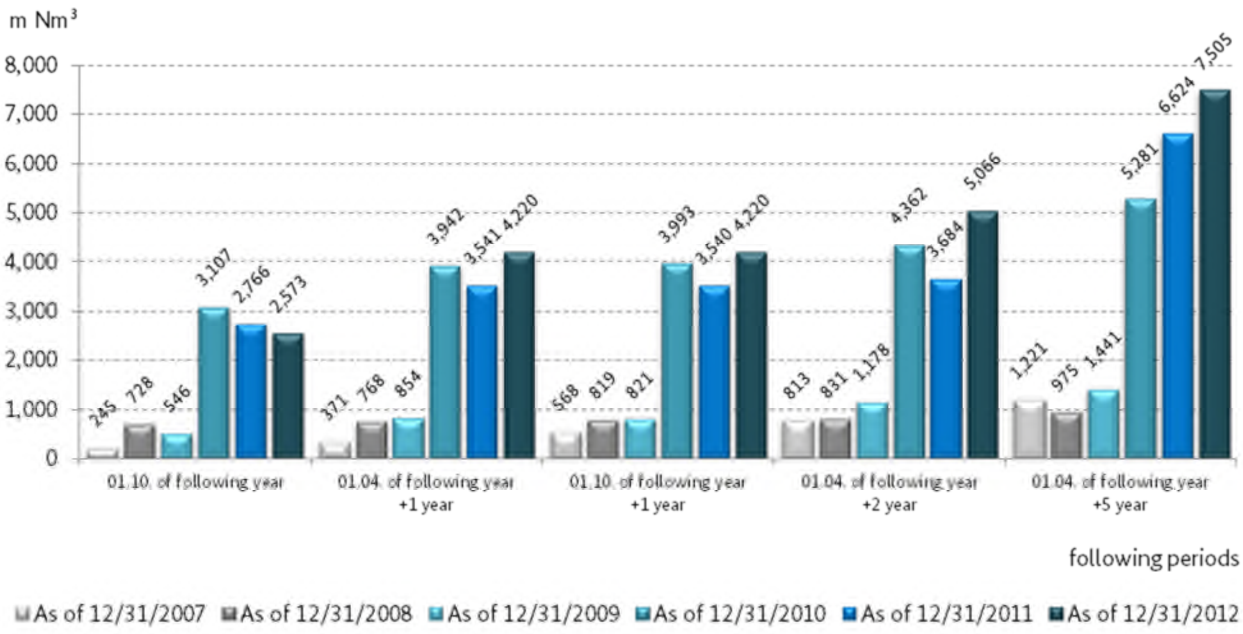


The number of storage customers increased from 95 in 2011 to 114 in 2012. The survey again showed, however, that one third of the storage companies have only one customer. The storage company with the most customers had up to 26 customers in the year under review.

5. Capacity trends

The following chart shows the free working gas volumes in underground natural gas storage as of 31 December 2012 compared to the previous years.

Figure 155: Fixed-date freely bookable working gas volume on offer in the following periods between 2007 and 2012



There was another slight decrease in the volume of short-term (up to 1 October 2013) freely bookable working gas whilst the volume of longer-term bookable working gas increased again. Here, too, there is a clear shift in the market towards shorter-term bookings, which is consistent with the fact that many long-term network capacity bookings, in particular at storage connection points, have been cancelled.

I Metering

Since the complete liberalisation of electricity and gas metering which became effective with the amendment of section 21b EnWG in 2008, electricity and gas customers have been free to choose their provider for meter operations and metering services. If the customer does not switch to another provider, the network operator continues to provide these services.

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 tables show in which capacity the meter operators are present in the market and the breakdown in meter operation and meter reading activities:

Table 57: Meter operator function

	Number
System operator acting as meter operator within the meaning of section 21b(1) EnWG	645
System operator acting as meter operator within the meaning of section 21b(2) EnWG, providing (metering) services in the market	4
Supplier with meter operator activities	6
Independent meter operator	0

Table 58: Meter operation and meter reading activities

	Number of metering points
Meter operation including meter reading and data transmission within the meaning of section 21b of the EnWG	13,937,039

Gas DSOs

According to the DSOs, the number of metering devices rose by 7.5 percent year on year, reaching a total of almost 14 million in 2012. The proportion of interval meters decreased to 0.4 percent (2011: 0.5 percent). 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 around 583,000.

Meter operators

The following table shows the types of metering equipment used by the meter operators for standard load profile customers:

Table 59: Metering equipment for standard load profile customers

Metering equipment used by the meter operator for standard load profile customers	Number of metering points according to meter size		
	G1.6 to G6	**G10 to G25**	**G40 upwards**
Diaphragm gas meter with mechanical counter	9,360,264	306,724	40,930
Diaphragm gas meter with mechanical counter and pulse output	3,849,595	127,175	12,655
Diaphragm gas meter with electronic counter	9,351	312	805
Interval meters as for interval-metered customers	228	533	4,224
Other mechanical gas meters	4,722	1,989	23,384
Other electronic gas meters	2,557	7	1,173
Total number of meters within the meaning of section 21f EnWG	106,536	5,599	1,281
Total number of meters that can be upgraded within the meaning of section 21f EnWG	891,946	21,778	4,410

The table below shows how the meter operators linked the metering devices up to a metering system within the meaning of section 21d of the EnWG:

Table 60: Communication link-up with a metering or communication system for standard load profile customers

	Number of metering points
Pulse output	343,166
Radio technology (eg Zigbee)	844
UMTS / LTE	597
PLC	1,207
M-Bus*	2,399
wireless M-Bus*	1,663
OMS standard	839
Other (eg encoder)	2,261

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 and ownership percentage.

Table 61: Metering equipment for interval-metered customers

	Number of metering points
Transmitting meter with pulse output/encoder meter and recording device/data storage	14,720
Transmitting meter with pulse output/encoder meter and volume corrector	6,604
Transmitting meter with pulse output/encoder meter and volume corrector and recording device/data storage	16,690
Other	117

The following table shows the various possibilities for remote communication links and the customers‘ contribution in percentage.

Table 62: Communication links for interval-metered customers

	Number of metering points
PLC	102
PSTN (analogue, ISDN)	9,651
DSL, broadband (cable)	254
Own control line	177
Mobil radio / GSM / GPRS / UMTS / LTE	26,008
Digital interface for gas meters	895
Other	151

III General topics

A Joint activities by the Bundeskartellamt and the Bundesnetzagentur

Market Transparency Body

With the Act on the Establishment of a Market Transparency Body for Electricity and Gas Wholesale Trading (Gesetz zur Einrichtung einer Markttransparenzstelle für den Großhandel mit Strom und Gas), which came into force on 12 December 2012, and Regulation (EU) No 1227/2011 on Wholesale Energy Market Integrity and Transparency (REMIT) of 28 December 2011, the Bundesnetzagentur and the Bundeskartellamt have been given new competencies. A project team has been set up to establish organisational structures and other prerequisites for carrying out the new statutory tasks.

The project team is preparing the establishment of the Market Transparency Body at the Bundesnetzagentur. The tasks of the Market Transparency Body, i.e. the continuous monitoring of the German electricity and gas wholesale and generation markets, are undertaken jointly by the Bundesnetzagentur and the Bundeskartellamt. Both the Bundesnetzagentur and the Bundeskartellamt will assign staff to the Market Transparency Body. In organisational terms, the monitoring tasks of the Market Transparency Body as well as the enforcement and organisational tasks under REMIT will be assigned to a Bundesnetzagentur unit.

The Market Transparency Body will monitor energy trading and play an important role in overseeing competition in the sector of electricity and gas wholesale trading.

The energy trading monitoring system is based on the REMIT Regulation which prohibits insider trading and market manipulation in the wholesale energy markets. The prohibitions are to contribute to ensure that wholesale trading prices are based on fair competition and that no profits can be gained from market abuse. While ongoing market monitoring and the investigation of indications of violations of the REMIT Regulation are carried out by the Market Transparency Body, the Bundesnetzagentur investigates suspect cases and enforces the relevant prohibition decisions.

The Market Transpareny Body supports the Bundeskartellamt in its monitoring of the energy markets under competition law and places a special focus on the prohibition of abuse of a dominant position. The Market Transparency Body also supports the Bundeskartellamt in its merger control activities and sector inquiries. Assistance is also provided to the Bundesnetzagentur and the Bundeskartellamt with regard to their respective monitoring tasks (under Section 35 EnWG, Section 48(3) GWB).

To fulfil its tasks the Market Transparency Body must collect large amounts of data from market participants. For this collection the Market Transparency Body is required to use, as far as possible, "existing sources and notification systems" (Section 47b(3) GWB). The most important source is the data collection under REMIT carried out at the European level by the Agency for the Cooperation of Energy Regulators (ACER). By means of implementing acts in accordance with Article 8(2) and Article 8(6) of REMIT the European Commission is currently specifying the market participants' obligations to report information to ACER. The collection of information by ACER will start six months after the implementing acts have come into force, probably in the

3rd quarter of 2014. The Market Transparency Body will receive all these basic and trading data as far as they concern German electricity or gas wholesale trading.

Apart from the information received from ACER the Market Transparency Body can collect further information to fulfil its tasks. The overall framework for the collection of information is defined under Section 47g GWB. The amount of information to be collected in excess of the information received from ACER is to be determined by the Market Transparency Body. This will be determined on the basis of a statutory order to be issued by the Federal Ministry of Economics and Technology under Section 47f GWB. The earliest possible starting point for any collection of information by the Market Transparency Body in excess of the information collected by ACER will probably be the date at which ACER starts collecting information.

The Market Transparency Body will examine the data and information it receives for indications of infringements of prohibitions under REMIT, Sections 1, 19, 20, 29 GWB, Articles 101 or 102 of the Treaty on the Functioning of the European Union, the German Securities Trading Act and the German Stock Exchange Act.

Market monitoring under REMIT

A key element of REMIT is the prohibition of insider trading and market manipulation in wholesale energy trading (Articles 3 and 5 of REMIT). This applies to all energy wholesale products which are not subject to financial market supervision (in accordance with Article 9 of Directive 2003/6/EC, the so-called Market Abuse Directive, implemented in Germany by the Securities Trading Act).

ACER plays an essential role in the practical implementation of REMIT. Article 7 and Article 8 of REMIT stipulate that data collection and the initial evaluation of data for market monitoring purposes are to be carried out by ACER. The national energy regulatory authorities can also monitor trading activity at national level in co-operation with national market monitoring bodies (in Germany the Market Transparency Body). They are responsible for enforcing the prohibition of insider trading and market manipulation, the publication requirements regarding insider information and the registration of market participants.

To develop a mutual understanding of the interpretation of REMIT between ACER and the European energy regulators, ACER has developed a 'non-binding Guidance' on the application of the definitions set out in REMIT, based on Article 16(1) of REMIT. This Guidance will be regularly updated and published on ACER's website.

The Bundesnetzagentur is significantly involved in designing the European market monitoring system. Since mid-2013, together with the Spanish regulatory authority, it has been chairing the ACER Market Integrity and Transparency Working Group (AMIT WG) where all issues relevant to REMIT are discussed by the European regulatory authorities and ACER. Since 2011 it has also been the chair of one of the three sub-working groups.

The Market Transparency Body's tasks under competition law

Apart from its trade-related responsibilities, it is also the task of the Market Transparency Body to support the Bundeskartellamt in its intensified monitoring of the electricity and gas wholesale markets.

In its 2007 special opinion on grid-bound energy (Tz. 211) the Monopolies Commission had called for intensified monitoring and advocated the "introduction of market monitoring" by "a special market monitoring body".

In the course of its sector inquiry into electricity production and wholesale, the final report of which was published in early 2011, the Bundeskartellamt developed new concepts specifically for monitoring under competition law the economic sectors affected. One of the concepts focuses on proving single market dominance of (potentially) more than one company in the market for selling electricity at the point of first sale. Another concept provides the basis for in-depth analysis of potentially abusive conduct by dominant electricity producers holding back capacities.

The Market Transparency Body makes it possible to further develop and adjust these concepts in order to be able to apply them on a continuous basis, which is not possible within the scope of a single sector inquiry. This provides the basis for assessing under competition law aspects and with sufficient quantitative precision the effects of the rapid changes in the German electricity generating sector caused by the transformation of Germany's energy system.

Registration of market participants

Under Article 9 of REMIT all market participants "...entering into transactions which are required to be reported to the Agency in accordance with Article 8(1) shall register with the national regulatory authority in the Member State in which they are established or resident or, if they are not established or resident in the Union, in a Member State in which they are active". Registration starts “[n]ot later than 3 months after the date on which the Commission adopts the implementing acts set out in Article 8(2)" and must be concluded by the start of the reporting of information, which will be six months after adoption of the implementing acts.

For this purpose the Bundesnetzagentur will set up a registration portal on its website where all market participants which are based in Germany must register. Market participants that are not based or resident in the European Union must register in the Member State or one of the Member States in which they are active.

The information to be requested from market participants has already been laid down by ACER on 26 June 2012 on the basis of Article 9(3) of REMIT and has been published on ACER's website ("ACER Decision 01/2012“).

B Activities of the Bundeskartellamt

1. Areas of focus of competition law enforcement

Of particular relevance for the Bundeskartellamt's merger control practice was the re-evaluation of vertical participations of large energy suppliers in municipal utilities and distributors. A significant development for the control of abusive practices was the fact that the Federal Court of Justice confirmed a Bundeskartellamt decision of principle on excessive gas concession fees. Another proceeding that was concluded with a formal decision involved the abuse of a dominant position and concerned the award of rights of way for electricity and gas networks. In addition, upon conclusion of the district heating sector inquiry, abuse proceedings were initiated against several district heating suppliers on suspicion of their charging excessive prices.

2. Merger control

The Bundeskartellamt has cleared in the first phase of merger control the plan to convert a temporary participation of RWE Deutschland AG (RWE) in the municipal utility Stadtwerke Ahaus GmbH (SW Ahaus) into a permanent one. There was no evidence of a weakening of competition (in particular no strengthening of a dominant position) on the relevant markets. With the implementation of the project RWE will permanently hold 36% of the shares in SW Ahaus. In the 1990s, energy suppliers had acquired more than 30 temporary participations in municipal utilities. The participation of RWE in SW Ahaus was limited until 31 December 2013. The conversion of the temporary participation into a permanent one constitutes a concentration within the meaning of Section 37 (1) of the German Act against Restraints of Competition (Gesetz gegen Wettbewerbsbeschränkungen, GWB), because without this step RWE would have had to end its position as a shareholder of SW Ahaus.

On account of several market developments, the Bundeskartellamt no longer expects a weakening of competition from vertical effects if a large energy supplier acquires a minority holding in a municipal utility. In particular, the big electricity companies seem to no longer pursue a strategy of acquiring participations in a large number of municipal utilities. In view of the fact that meanwhile there is a high level of liquidity on the electricity wholesale markets, it seems no longer plausible that a customer foreclosure strategy could be successfully pursued by the acquisition of participations in municipal utilities. For the same reasons, the Bundeskartellamt has cleared three other permanent participations of RWE - in Energieversorgung Oelde GmbH, WEV Warendorfer Energieversorgung GmbH, and Energieversorgung Beckum GmbH&Co. KG.

In the gas sector the Bundeskartellamt examined the participation of the supra-regional gas transmission company VNG in goldgas, a (regional) distributor supplying end customers. Other than in previous cases where participations were concluded in direct supplier-buyer relationships, in this case one intermediate supply level was skipped (that of the regional gas transmission companies). A similar merger case concerned the participation of the supra-regional gas transmission company Wingas in Hellweg Energie. Both projects could be cleared because there was no risk that they would create or strengthen a dominant position for the participating companies. Also cleared was the participation of the regional distributor Stadtwerke München in the regional gas transmission company Bayerngas. The merger, by which the municipal utility increased its participation in a potential upstream supplier, could be cleared in the first phase of merger control proceedings.

Another project that concerned the gas sector was the plan to increase the number of shareholders of the PRISMA European Capacity Platform (until the end of 2012: Trac-X Transport Capacity Exchange) by three further transmission system operators, namely the German Gasunie Deutschland, the French GRTgaz and the Italian Snam Rete Gas. This project was initiated to implement the "Regulation (EC) No 715/2009 on conditions for access to the natural gas transmission networks" and to meet further (future) requirements. In its "Framework Guidelines on Capacity Allocation Mechanisms for the European Gas Transmission Networks" ACER stipulated that the "Network Code on Capacity Allocation Mechanisms" which was to be prepared by ENTSOG should provide for a reduction of the number of platforms and the ultimate establishment of a single EU-wide platform in the future. The project could be cleared because, although it will strengthen an existing dominant position, it will also improve the conditions of competition to such an extent that this will outweigh the negative effects.

3. Control of abuse by dominant companies

The Federal Court of Justice has confirmed a Bundeskartellamt decision of principle by which municipal gas network operators may not charge external gas suppliers abusively high concession fees (KVR 54/11). In September 2009 the Bundeskartellamt had prohibited GAG Gasversorgung Ahrensburg GmbH in Schleswig-Holstein from charging new gas suppliers excessive concession fees (case ref: B10-11/09). The company's appeal on points of law has now been rejected by the Federal Court of Justice as the court of last resort. The court of first instance, the Düsseldorf Higher Regional Court, had already confirmed the Bundeskartellamt's decision (VI-3 Kart 1/11[V]). The Federal Court of Justice confirmed that the Bundeskartellamt was the competent authority to issue rulings on abusive practices against network operators associated with a municipality if the charging of concession fees for the granting of rights of way was concerned. The Federal Court of Justice was of the opinion that the municipality has a monopoly position with regard to the granting of rights of way against payment. According to the court's decision, the municipality may only charge external gas suppliers the concession fee (of max. 0.03 ct/kWh) that applies in the case of special contract customers, provided the external suppliers only supply special contract customers.

Following the decision of the Federal Court of Justice, two similar pending proceedings concerning the cities of Karlsruhe and Rüsselsheim could be terminated in return for written commitments. A further 200 gas suppliers have also undertaken to observe the court's decision.

In abuse proceedings relating to the granting of exclusive rights of way, the Bundeskartellamt has prohibited the city of Mettmann from assigning the rights of way for the municipality's electricity and gas network "in-house" to its subsidiary without a transparent and non-discriminatory procedure. The city of Mettmann had first launched a Europe-wide award procedure in which it sought a cooperation partner willing to have a minority share in its envisaged new municipal utility. It was planned that the municipal utility should then be awarded the rights of way for the electricity and gas networks without a further selection procedure. Competitors that were only interested in the rights of way (and not in the participation) would therefore have been excluded from the procedure, even if they were able to operate the networks more efficiently and with greater benefit to consumers. The city of Mettmann had inadmissibly based its decision on its financial interests rather than on network-specific aspects or the objectives of Section 1 of the Energy Industry Act (EnWG) ("a network supply of electricity and gas that is as secure, cheap, consumer-friendly, efficient and environmentally friendly as possible"). The Bundeskartellamt's prohibition decision is final. The Higher Regional Courts of Düsseldorf and Schleswig and the Higher Administrative Court of Baden-Württemberg have also held that an in-house award violates Section 46 (1), (2) and (4) EnWG and Sections 19, 20 GWB. (Cf. Düsseldorf Higher Regional Court, decision of 09.01.2013, VII-Verg 26/12 – Münsterland, juris para 79f; Schleswig Higher Regional Court, decision of 22.11.2012, 16 U (Kart) 21/12, juris para 100; and Higher Administrative Court of Baden-Württemberg, decision of 22.08.2013, 1 S 1047/13, juris para 28, with reference to Administrative Court Stuttgart, decision of 29.04.2013, 7K 929/13, juris para 31f.)

The Bundeskartellamt has instituted proceedings against seven district heating suppliers on suspicion of their charging excessive prices. The investigations will focus on around 30 different supply areas throughout Germany.

One relevant aspect of the district heating sector is that customers can only choose once between different supply channels, which is when they make an initial decision in favour of a certain heating system. Once they have opted for district heating, they are bound in the long term. In order to protect consumers, it is therefore appropriate for the Bundeskartellamt to initiate abuse proceedings where prices are excessive. Apart from this, being connected to the respective heating network is mandatory in many supply areas, which means that it is neither physically nor legally possible for customers to switch to another energy source.

For its sector inquiry into district heating (which was concluded in August 2012) the Bundeskartellamt collected data from district heating suppliers for 2007 and 2008 and compared revenues. It found that the average revenues earned by some companies from the supply of district heating clearly exceeded those of the respective comparison group. The Bundeskartellamt is following up the initial suspicion of abusive pricing raised by these findings. In order to update the information gathered from the sector inquiry, data was collected for 2010 to 2012 from the companies concerned and from eight potentially comparable suppliers with on average very low revenues and low district heating prices.

District heating providers often supply several areas. Tariffs of the same provider may deviate in the different supply areas. Also in the case of the companies against which the Bundeskartellamt has instituted proceedings, there is no indication that excessively high revenues have been generated in all of their supply areas. The different levels of district heating supply, i.e. generation, network operation and distribution, are normally integrated in one company. Different structural conditions, such as e.g. generation and network structures, can justify different revenue and price levels, which has to be examined on a case by case basis. 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 become even more pronounced with the reduced profitability of electricity generation (as a result of the feed-in of electricity derived from renewable energy sources).

In the gas sector, the Bundeskartellamt has informed two transmission system operators (OGE and Thyssengas) of its preliminary assessment that their alignment of fees charged at jointly operated entry and exit points constitutes a restraint of competition within the meaning of Article 101 TFEU and Section 1 GWB which does not qualify for exemption. The Bundeskartellamt is generally worried about a trend in this area to further reduce the already limited competition, either by individual agreements or by endeavours to further restrict the scope of action of market participants through regulation.

4. Competition Advocacy

The Bundeskartellamt strongly advocates competitive structures in the grid-bound energy sector. Also with regard to the transformation of Germany's energy system, it strongly advises that the competition principle be observed.

The current system of subsidising renewable energies is based on state planning rather than market mechanisms and threatens to overstrain consumers and industry with its massive cost increases. The Bundeskartellamt therefore advocates a fundamental reform of the Renewable Energy Sources Act. New generation devices at least should be directly integrated into the market by making the direct marketing of the energy generated by them obligatory.

The debate on a new market design for conventional electricity generation should not prematurely abandon the principle of competition. Where state intervention is necessary to secure supply, this should, as far as possible, follow market mechanisms and be confined to what is absolutely necessary.

The tendency towards "remunicipalisation", i.e. endeavours by the municipalities to play an active role in the energy supply sector, should also be carefully monitored. This is particularly evident where the rights of way for supply networks for electricity and gas are concerned. Here the Bundeskartellamt not only actively advocates the competition principle but is conducting formal proceedings as well (see above). The rights of way must be assigned by the municipalities at regular intervals in a competitive and non-discriminatory procedure. The municipality is not prohibited from applying for the rights of ways itself via a municipality-owned subsidiary. However, the rights of way must be awarded in a non-discriminatory and transparent award procedure which must correspond to the statutory rules, as explained in the joint guidelines of the Bundesnetzagentur and the Bundeskartellamt.

C Selected activities Bundesnetzagentur

1. The Bundesnetzagentur's role in the Agency for the Cooperation of Energy Regulators (ACER)

The Agency for the Cooperation of Energy Regulators (ACER) took up its work on 3 March 2011 with the entry into force of the Third Energy Package. Participating in the Agency's Board of Regulators and its working groups, the Bundesnetzagentur assists in fulfilling the Agency's tasks and represents German energy regulation interests so as to give them the weight at European level that befits the German energy market.

1.1 Development of framework directives and network codes

The EU set itself the goal in 2011 of completing the internal market for electricity and natural gas by the end of 2014. To achieve this, national regulatory authorities, market participants, the European Commission and the Member States are drafting legally binding rules to make the cross-border electricity and gas markets simpler, more efficient, more transparent and more secure.

The European Network of Transmission System Operators for Electricity (ENTSO-E) and the European Network of Transmission System Operators for Gas (ENTSOG) draw up network codes on the basis of ACER's framework guidelines. These network codes become legally valid following a comitology procedure initiated by the European Commission with the participation of the Member States. The Bundesnetzagentur, in the ACER working groups, has provided considerable input for the framework guidelines and the opinions on the network codes and plays a supporting role to the Federal Ministry of Economics and Technology in the ongoing comitology procedures.

The following table shows the current state of play of these projects.

Table 63: Current state of the comitology procedures

Electricity	Framework guideline (ACER)	Network code (ENTSO-E)	ACER response	State of play Comitology
Capacity Allocation and Congestion Management for Electricity	29/07/2011	27/09/2012	Recommended with amendments on 14/03/2013	Not yet initiated
Capacity Allocation and Congestion Management for the long-term timeframe	29/07/2011	Not yet submitted		
Electricity Grid Connections	20/07/2011	26/06/2012	Recommended with amendments on 25/03/2013	Not yet initiated
DSO connection and industrial load	20/07/2011	21/12/2012	Recommended with amendments on 25/03/2013	Not yet initiated
Operational Security	02/12/2011	27/02/3013	Opinion on 28/05/2013	Not yet initiated
Operational Planning and Scheduling	02/12/2011	28/03/2013	Opinion on 19/06/2013	Not yet initiated
Load-Frequency Control and Reserves	02/12/2011	28/06/2013	Not yet submitted	
Electricity Balancing	18/09/2012	Not yet submitted		

Gas	Framework guideline (ACER)	Network code (ENTSOG)	ACER response	State of play Comitology
Capacity Allocation Mechanisms	03/08/2011	06/03/2012	Recommended with amendments on 04/10/2012	Network code adopted on 15/04/2013
Gas Balancing in Transmission Systems	18/10/2011	26/10/2012	Recommended on 25/03/2013:	Not yet initiated
Interoperability and Data Exchange Rules	26/07/2012	Not yet submitted		

The network codes referred to in the tables will be expanded on in the following.

Network Code for Requirements for Grid Connection Applicable to all Generators

As with the other network codes, the technical codes "Network Code for Requirements for Grid Connection Applicable to all Generators" (NC RfG) and "Network Code on Demand Connection" NC DCC) are based on ACER framework guidelines requested by the European Commission under Article 6(2) of Regulation (EC) No

714/2009 (Electricity Regulation). The Framework Guidelines on Electricity Grid Connections were then published by ACER on 20 July 2011.

On matters of the NC RfG an intensive informal dialogue with stakeholders already took place before the formal act initiating the network code, from summer 2009 until the Electricity Regulation took effect on 3 March 2011. The results of this dialogue were incorporated in the subsequent negotiations on the details of the framework guidelines.

The NC RfG sets the technical requirements for connecting electricity generators to the grid. It also covers synchronous generators, individual asynchronous power generating modules and offshore systems. Additionally, the network code sets the framework conditions requiring the operators of supply networks to make use of generating facilities in a transparent, non-discriminatory and suitable manner in order to secure fair conditions for competition in the European Union's future internal energy market.

The original version of the NC RfG was submitted to ACER by the European Network of Transmission System Operators for Electricity (ENTSO-E) on 13 July 2012. In line with the procedure set out in Article 6(7) of the Electricity Regulation ACER then sent ENTSO-E its reasoned opinion on the NC RfG. This also included input from a committed user group and from an expert DSO group. ENTSO-E then made amendments to the original version of the NC RfG in light of ACER's reasoned opinion and resubmitted the amended version to ACER on 8 March 2013. The amended version incorporates the comments received during the consultation phase at ENTSO-E.

On 25 March 2013 ACER then submitted the NC RfG of 8 March 2013 to the Commission by means of recommendation, advocating that it be adopted on condition that a change be made to the provisions that largely exempted emerging technologies from the code's area of application. The problems are as follows. Under Article 57 of the previous version of the NC RfG the network code, to the greatest possible extent, was not to be applied to any generating facility that qualified as an emerging technology on the day of its connection to the grid. Only such generating facilities as are "commercially viable" can be classed as an emerging technology, according to the code. ACER does not find this term sufficiently clear and is concerned that, in legal practice, an interpretation could gain ground that could prove detrimental to emerging technologies because they are not sufficiently removed from the code's area of application. ACER therefore recommended to the European Commission that the term "commercially viable" be replaced by "commercially available" and that more clarification be provided on this criterion.

Network Code on Demand Connection

Submission of the NC DCC as of 21 December 2012 by ENTSO-E to ACER on 4 January 2013 was likewise preceded by a wide-ranging dialogue with stakeholders which took place in a number of working meetings, workshops and a call for stakeholder input. The NC RfG defines the technical requirements for connecting significant demand facilities, distribution networks and distribution network connections. It provides a common framework for network connection agreements between network operators and demand facility owners or distribution network operators.

ACER, by its recommendation of 25 March 2013, submitted the NC DCC as of 8 March 2013 to the European Commission under Article 6(9) of Regulation (EC) No 714/2009, confirming that the code upheld the requirements of the Framework Guideline on Electricity Grid Connections and accordingly recommended the

Commission to adopt the code. At the same time ACER submitted suggestions for improvement to the Commission, relating mainly to a lack of legal clarity such as incomplete references, imprecise definitions, inconsistencies and the like.

There had been thoughts of merging the two codes, but this idea was rejected at the Planning Group Meeting in Brussels on 12 April 2013 in which the European Commission, ACER and ENTSO-E took part. Thus both codes will now undergo the comitology procedure.

1.2 Energy infrastructure package

The new TEN-E Regulation (EU) No 347/2013 of the European Parliament and of the Council on guidelines for trans-European energy infrastructure entered into force on 15 May 2013.

For projects of common interest it lays down the treatment of the project in accelerated permit granting processes (Articles 8ff), special cost allocation procedures between TSOs in the case of cross-border lines (Article 12), the granting of special investment incentives by the regulatory authorities and the MS for higher risk projects (Article 13) and possible financial assistance from EU funds as a result (Articles 14f).

The European Commission has been making preparations for project selection since February 2012. The Bundesnetzagentur has assisted in the selection process in the eight regional groups (total in electricity and gas) for the assessment and in the ACER Infrastructure Task Force.

Other tasks for the regulatory authorities under the Regulation such as the publication and granting of incentives and possible cost allocation decisions for projects of common interest are prepared and carried out in close cooperation with ACER. Here too, the Bundesnetzagentur provides its specialist input.

2. The role of the Bundesnetzagentur in the Council of European Energy Regulators (CEER)

The Bundesnetzagentur has been a member of the independent Council of European Energy Regulators (CEER) since 2005. CEER will continue in existence even after the foundation of ACER, focusing more on topics that do not fall under ACER's remit, for instance, consumer protection, regulatory aspects of retail markets, the promotion of renewables and international cooperation. In many respects, CEER provides back-up for ACER's work.

2.1 Consumer protection developments in Europe

Through its work in CEER's Customers and Retail Market Working Group (CRM WG) the Bundesnetzagentur again played an active part in 2012 in drafting seminal documents on consumer protection issues. In this, interaction with the European Commission has also been crucial, its work on retail market design being oriented by the CEER guidelines.

Against the backdrop of the changing energy landscape CEER, in collaboration with the European Consumer Association, has drawn up a 2020 Vision focusing on the energy customer and designed to strengthen consumer rights further. The 2020 Vision was shaped and refined at a consumer conference in June 2012 jointly organised with the European Commission in which all the relevant stakeholders took part. It is based on four core areas that characterise the relationship between the energy industry and its customer groups: a reliable energy supply, an affordable energy supply, simplicity and transparency in respect of offers, and protection and empowerment for the consumer.

Further, CEER drew up a status review of the implementation of specific consumer protection aspects of the third package (Status Review of Customer and Retail Market Provisions from the 3rd Package as of 1 January 2012). The review looked at the progress reached by 1 January 2012 in achieving particular targets of the package in respect of universal service, switching energy supplier, vulnerable consumers, customer information, dispute resolution procedures and regulated retail prices. The review sets out the efforts and the progress made by the Member States in transposing these into national legislation. The approaches taken sometimes varied considerably, yet the targets have been achieved to a very high degree. There is still room for improvement, however, in the maximum length of time for an energy supplier switch and for dispute resolution.

According to a study presented by the European Commission at the Third Citizens' Energy Forum, consumers do not have access to independent, objective information enabling them to take a more active role in the internal market and, for instance, to switch supplier. CEER therefore organised a public consultation which presented provisional recommendations and in which 36 stakeholders took part. These stakeholders were invited to a public hearing in March 2012. The outcome was a document setting out 14 recommendations, entitled Guidelines of Good Practice on Price Comparison Tools. To the greatest possible extent they should be independent, transparent, exhaustive, clear and comprehensible, correct, user-friendly, accessible and empower the customer.

The Third Package requires CEER to draw up an annual report on the progress of development in the energy markets. The Bundesnetzagentur contributed through its membership of CEER to compiling the first ACER/CEER Market Monitoring Report. The report also aims to show how retail markets can be improved and made more efficient.

2.2 International cooperation

The Bundesnetzagentur's participation in the International Strategy Group helped CEER's international positions and the dialogue with strategically important partners to be continued and coordinated. CEER's international strategy as set out in the document entitled "CEER’s International Activities: Core Strategy and Objectives" focuses on three main areas: exchanging best regulatory practices with regulators and regulatory associations worldwide, providing assistance on specific regulatory issues, and raising awareness of independent and accountable energy regulatory practices at international level. The role of the national regulatory authorities has been further consolidated at international level, most notably in respect of external energy policy. It was also important to progress common regulatory practice through exchanges of views and drafting best practices. To this end there was again an intensive exchange with the Russian regulatory authority (Federal Tariff Service) and the states comprising the Eastern Partnership Platform of the European Commission.

In addition, the topic "Sound regulation for energy infrastructure" was defined as a priority for the Russian G20 presidency. This is the background against which the G20+[177] energy regulators were called upon to help

[177] Argentina, Australia, Brazil, Canada, China, France, Germany, India, Indonesia, Italy, Japan, South Korea, Mexico, Saudi Arabia, South Africa, Turkey, UK, USA. Further states and regional organisations may take part upon invitation from the presidency.

draw up the final declaration for the Summit in September and for which the Bundesnetzagentur provided input.

In addition, contact with the International Energy Agency (IEA) was intensified. The IEA regularly publishes studies on regulatory issues such as renewable energies, energy market or energy efficiency reforms; in future, regulators are to be involved in these and provide input.

Further, a report on developments in the states bordering the coast of the Mediterranean was drawn up, analysing the current situation and making recommendations for action. In cooperation with the Association of Mediterranean Energy Regulators for Electricity and Gas (MEDREG), dialogue with these states is to be intensified and regular forums for exchanges of experience set up to consolidate the achievements to date.

3. Report on investment conditions in European countries

CEER's Efficiency Benchmarking Task Force, run by the Bundesnetzagentur, again looked into investment conditions in European countries in 2012 and compiled a report on these[178].

The report analyses the investment conditions in the electricity and gas networks of 23 European states with a view to providing an overview of the role of energy regulation in the overall investment environment. To this end it looks particularly at key elements of energy regulation such as value for money, efficiency and returns on investment in energy network infrastructure across Europe.

Given the complex and different nature of the regulatory regimes in the European countries, comparability in respect of particular indicators is only possible in an overall view. The findings of the report affect the national regulatory authorities' perception of their tasks in highly diverse ways. This "Report on investment conditions in European countries" was drawn up in 2011 for the first time. An update for 2013 is currently in progress, along with an electronic version for a CEER database.

4. Investment measures / Incentive regulation

The Incentive Regulation Ordinance (ARegV) offers network operators the possibility of recouping costs for expansion and restructuring investment beyond the approved revenue cap via the network charges. Under section 23 ARegV the Bundesnetzagentur approves individual projects, provided the relevant conditions are met.

In 2012 a total of 123 applications for investment measures were submitted to the Ruling Chamber responsible. The total investment volume was approximately €15.2bn. For electricity projects there were 102 applications worth approximately €13.4bn. The four TSOs together accounted for some €12.3bn. Gas network operators submitted 21 applications, worth around €1.8bn in all. Both the number and the financial volume of the applications were higher than in 2011. In 2011 the total number of applications was 89 and the financial volume totalled €8.7bn.

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[178] A summary of the report was published as a CEER Memo on Regulatory aspects of energy investment conditions in European countries: http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Cross-Sectoral/Tab/C13-EFB-09-03_Investment%20Conditions_memo.pdf

Since the amendment of section 23 ARegV in spring 2012 an investment project now only has to be approved on merit. Once approval has been granted, the network operator can adjust its revenue cap itself in line with the operating costs and capital costs of the project. The stated costs are checked by the Bundesnetzagentur in ex post controls. The amendment also made provision for the adjustment of the revenue cap to be made directly in the year in which the costs were incurred, ie no longer with a delay of two years, and for consideration of a deductible amount in changing from investment measures to the general revenue cap. The Bundesnetzagentur in 2012 adapted a total of 104 existing approvals to the new situation arising from the amendment of the Ordinance.

Approvals under section 19(2) of the Electricity Network Charges Ordinance

Under section 19(2) sentence 1 of the Electricity Network Charges Ordinance (StromNEV) network customers can reduce their network charges if their peak load contribution diverges considerably from the simultaneous annual peak load of all offtake at their network or voltage level (atypical usage). This arrangement reflects the fact that the costs of an electricity network are determined by the maximum capacity that has to be transported over this network. Final customers whose peak load contribution is predicted to diverge considerably from the simultaneous annual peak load of all offtake at the network or voltage level thus contribute to lowering the network costs. That is why they are given the possibility of agreeing an individual charge with the network operator, the capacity share of which is reduced by the amount to which the load is shifted. The individual network charge may not be less than 20 percent of the general network charge, however.

2012 saw a sharp rise over the previous year in the number of applications for approval of such an individual network charge. In all, 3,153 applications were received. To date, approximately one third have been approved. The amount saved as a result is some €42m. These figures are based in part on actual consumption figures for 2012 and in part on forecasts.

In addition to the applications for individual network charges, 137 applications were received for exemptions for energy-intensive undertakings pursuant to section 19(2) sentence 2 StromNEV (old version.). This said that undertakings with a consumption of more than ten GWh and a minimum of 7000 hours of use at one particular supply point were eligible for exemption. This arrangement favours offtake patterns that stabilise the network, as steady, continuous offtake (band load) reduces the relative range of fluctuation of the load as a whole. This leads to more accurate forecasting and to a more efficient use of the entire power plant pool and hence to a positive effect on supply for all network customers. When demand is spread evenly over the year it also facilitates forecasting the network infrastructure needed. Network operators affected then face forecasting uncertainty just for fluctuations in consumption above the relatively secure band load, which they can possibly compensate for by additional grid expansion. This has a positive effect on the network costs if only because the forecasting uncertainty for a network with steady continuous offtake is less than for a network without steady continuous offtake.

To date, all the applications for exemption from network charges have been turned down. The reason for this was the doubts expressed by the European Commission regarding the compatibility of the exemption provisions with European state aid provisions and the doubts expressed by Düsseldorf higher regional court in summary proceedings about adequate authorisation for the ordinance.

The amounts saved in 2012, together with the amounts saved in 2011, will be distributed proportionately among final customers across the country.

On 5 December 2012 the Ruling Chamber concerned issued a determination on the approval requirements for individual network charges pursuant to section 19(2) sentence 1 StromNEV. This determination reflects the fact that the previous criterion of relative load shift was not enough in itself, in the DSOs' experience of the lower voltage levels, to fully replicate the actual strain-relieving effects. Hence the additional requirement of an absolute shift in the load by 100 kW was introduced. This must be observed in all applications as from 1 January 2013.

D Unbundling

Checking compliance with the unbundling requirements was mainly done in the period under review via the newly introduced TSO certification process. At DSO level, the chief focus was compliance with the legal requirements on the unbundling of corporate communication and branding between network operators and distributing companies. Both have their origin in the European Union's Third Energy Package in 2009 and were transposed into German law in 2011 by way of an amendment of the Energy Act.

1. Certification

Certification is a procedure under which transmission system operators (TSOs) are required to demonstrate proof of compliance with unbundling / organisational requirements in one of three forms, or models, outlined below:

- the full ownership unbundled TSO (section 8 EnWG),
- the independent transmission operator (sections 10ff EnWG), and
- the independent system operator (section 9 EnwG).

All active transmission operators and transmission system owners were required to apply for certification by 3 March 2012. The process and its rigid time limits can be depicted as follows:

Figure 156: Time limits in the certification process

4 month	Deadline for a decision on certification (beginning with complete application)
imme-diately	Sending the draft decision to the EU KOM
2 month	Deadline for opinion by the EU KOM
2 month	Extension of the deadline for the opinion of the EU Commission if ACER is included
2 month	Deadline for the final decision on the certification by the Federal Network Agency (beginning with receipt of the opinion) or fiction if inaction
X	Publication of the decision Official Journal → at the same time naming

19 applications for certification were received by the Bundesnetzagentur in 2012 from the following undertakings:

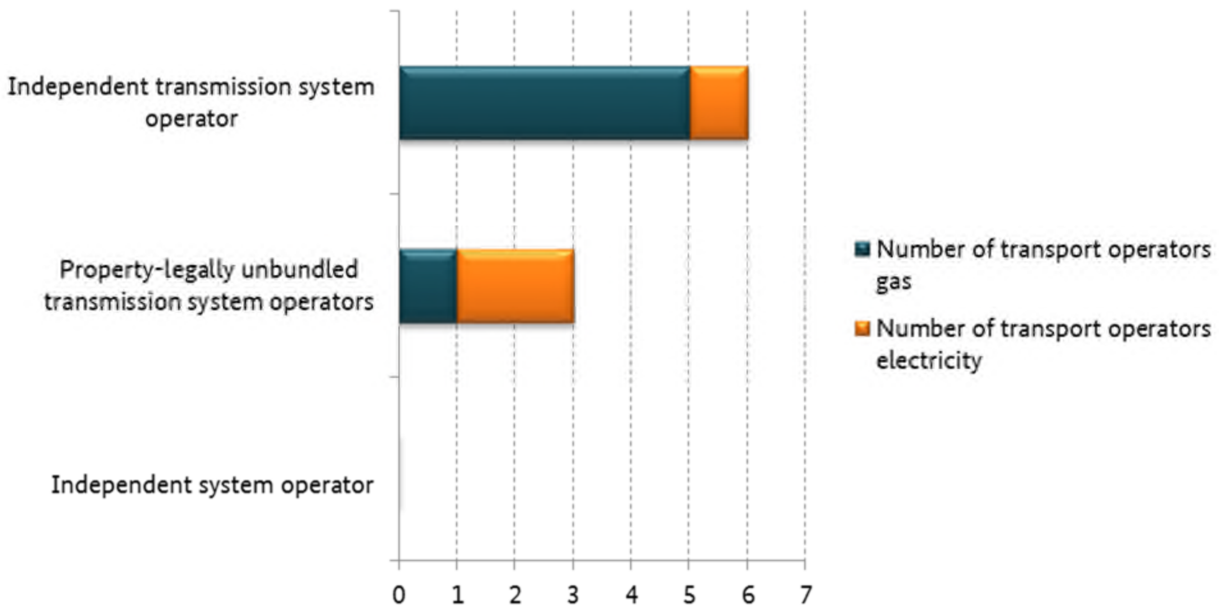
Table 64: List of undertakings applying for certification in 2012

TSO	Industry
Amprion GmbH	Electricity
50Hertz Transmission GmbH	
TenneT TSO GmbH	
TransnetBW GmbH	
bayernets GmbH	Gas
Fluxys Deutschland GmbH	
Fluxys TENP GmbH	
GASCADE Gastransport GmbH	
Gastransport Nord GmbH	
Gasunie Deutschland Transport Services GmbH	
Gasunie Ostseeanbindungsleitung GmbH	
GRTgaz Deutschland GmbH	
jordgas Transport GmbH	
NEL Gastransport GmbH	
Nowega GmbH	
ONTRAS - VNG Gastransport GmbH	
Open Grid Europe GmbH	
terranets bw GmbH	
Thyssengas GmbH	

Of these, nine cases were completed in 2012. Certification was granted in eight cases subject to conditions. Certification was not granted in one case because the network operator did not have the financial resources to meet its connection obligation. At the end of the year the other cases were at the draft decision / Commission opinion stage.

The model chosen in the majority of cases completed by the Bundesnetzagentur in the period under review was that of independent transmission operator. This model allows vertically integrated supply companies to retain a stake in a transmission system operator, albeit with greatly reduced rights. However, in three cases the option of ownership unbundling was chosen. The structural requirements had already been met before certification, however. There was no instance of a vertically integrated undertaking selling its network directly because of certification. No applications were received for certification as an independent system operator.

Figure 157: Transmission operator under the certification model



Network operators have become clearly more independent as a result of the new arrangements. The structural changes made were needed for this to happen, however. The extent of network operator involvement in vertically integrated energy supply companies has declined markedly.

Nevertheless, TSOs in 2012 were still experiencing incomplete restructuring. Conditions from the certification decisions still have to be met after the end of the year. Thus for instance,

- certain services may not be provided in future,
- physical separation must be effected,
- profit transfer agreements must be terminated or adapted,
- rules of procedure must be changed,
- agreements on the surrender of the use and benefit of network infrastructures must be invalidated in order to comply with the legal requirement of ownership of the transmission network.

2. Corporate communication and branding

A basic change for DSOs in the new EnWG arises from the obligation to provide differentiated communication and branding in respect of integrated distribution and sales activities. In 2011 already, 76 percent of the network operators reported to the Bundesnetzagentur that they had begun their implementations. In the year under review, on 16 July 2012, an interpretation guide ("Gemeinsame Auslegungsgrundsätze III der Regulierungsbehörden des Bundes und der Länder zu den Anforderungen an die Markenpolitik und das Kommunikationsverhalten bei den VNB (§ 7a Abs. 6 EnWG))" was published on this. However, full implementation by all the DSOs subject to this obligation has not yet been achieved. For instance, roughly half of the obligated network 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, Ruling Chamber proceedings were opened in the period under review.

E Consumer protection and service

Transposition of the Third Energy Package into German energy law in August 2011 brought about the inclusion in the Energy Act of consumer complaints and dispute resolution procedures. Consumer rights were strengthened particularly through a shortened process of switching supplier and new and extended contractual, information and billing requirements for suppliers, to be fully implemented by the undertakings by spring 2012. The amended Energy Act made the Bundesnetzagentur the central information point for energy consumers.

The consumer complaints and dispute resolution procedures and the Bundesnetzagentur's new role as the central information point for energy consumers have necessitated a reallocation of tasks between the Bundesnetzagentur and the new Energy Dispute Resolution Panel set up on 1 November 2011. Energy consumers are now entitled to have a complaints procedure carried out with their supply company. If the supply company cannot provide a remedy within a period of four weeks, energy consumers can then turn to the Energy Dispute Resolution Panel for redress. In the first year of its existence, until the beginning of November 2012, the Panel received some 14,000 applications. As a rule, the dispute resolution procedure is free of charge for consumers. The conciliatory proposal is not binding, however, so that both consumers and supply companies still have the option of going to court.

As the central information point, the Bundesnetzagentur must advise energy consumers of the legal situation, their rights as domestic customers and the dispute resolution option. The Bundesnetzagentur's Energy Consumer Service in 2012 received a total of 22,112 queries and complaints, 19,771 on electricity and 2,341 on gas issues. A considerable number of consumer queries and complaints in both sectors had to do with inconsistencies in bills, as last year, and what the contracts actually meant. Considerable delays in sending out annual and final bills, irregularities with reimbursements and bonus payments for customers, along with the many complex contractual structures were the main reasons for the large number of queries and complaints.

Network operators and suppliers were given time until 1 April 2012 to implement the IT processes necessitated by the amended energy regulations of August 2011. Companies were required by then to have adapted their data exchange routines to the changed processes laid down by the Bundesnetzagentur. On account of frequent complaints about delays in switching supplier, attributable to non-compliance with the electronic market communication arrangements, the Bundesnetzagentur in June 2012 threatened a large regional network operator with a penalty of €1.2 million.

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