Monitoring Benchmark Report 2011

Monitoring Benchmark Report published under section 63 (4) and (5) in conjunction with section 35 of the Energy Act

Bundesnetzagentur für Elektrizität, Gas,
Telekommunikation, Post und Eisenbahnen
Monitoring, Marktbeobachtung - Energie -
Tulpenfeld 4
53113 Bonn
Tel.: +49 228 14-5920
Fax: +49 228 14-5973
harald.doerr@bnetza.de

Foreword

2010 once again saw considerable changes to the German energy market. This 2011 Monitoring Report documents, analyses and evaluates these developments in the individual levels of the value chain for electricity and gas. In agreement with the Bundeskartellamt, the report will illustrate the progress achieved through regulation, as well as indicate where the Bundesnetzagentur sees the need for further action in the regulated network and in competitive up- and downstream markets.

The development of electricity generation in 2010 was characterised again by a significant increase in generation capacities based on renewable sources of energy. This was accompanied by the decommissioning of eight nuclear power plants in early 2011. This loss of non-volatile generation capacities, along with the integration of the renewable energy sources places particular demands on network operators, making network expansion "the topic on everyone's lips". The 2011 Monitoring Report and the Bundesnetzagentur's reports on the impact on the transmission networks of exiting nuclear power thus show that the networks have reached the limits of their capacity as a result of the large number of transport duties in the last few years and the changes in the structure of generation. The lawmakers have created the possibility of treading new paths with the network development plans in the Energy Act (EnWG) and the new procedures and responsibilities set out in the Grid Expansion Acceleration Act (NABEG). These accelaration possibilites must be tapped quickly now.

In addition to accelerating the network expansion, a further area of focus is the widespread involvement of the public. The real problems of network expansion involve acceptance by the public and understanding for the fact that the move to sustainable energy supply cannot succeed without expansion of the grid. The Bundesnetzagentur is aware of its responsibility in this respect and will contribute to achieving acceptance with an increased openness to dialogue.

In addition to the network sector, positive developments have also been observed in other areas of the energy market. This includes a milestone in the integration of electricity markets in the European Union at the end of 2010, an achievement to which the Bundesnetzagentur contributed significantly. Following the successful introduction of market coupling between Germany and the northern market in November 2009, market coupling has now been introduced in the Central-West Europe region. Through the coupling of the electricity markets in north-western Europe (Germany, France, Benelux and Scandinavia), the national electricity spot markets of nine countries are now integrated at a wholesale level.

Further success has also been achieved in the gas market since 2009 by merging market areas. While there were still six gas market areas in 2009, with three for L-gas and three for H-gas, since October 2011, the number has been reduced to two dual-quality market areas.

The dynamic development of the retail market in the gas sector is also welcome news. Since the start of regulation, competition development on the gas market had always lagged some years behind the electricity market. In 2010, however, the gas market had developed to such an extent that it actually overtook the electricity market in the household customer sector. That year, a proportionately greater number of customers switched gas suppliers than electricity suppliers. Moreover, a significantly lower number of household customers in the gas sector received basic supply than in the electricity sector. In addition, the wholesale prices for electricity and gas, which had decreased significantly since the second half of 2008, have had a positive influence on household customer prices in the gas sector for some time now, whereas a similarly significant effect on electricity prices for household customers is yet to be seen. While customers still do not have such a wide choice of suppliers in the gas market as they do in the electricity market, the aforementioned factors nevertheless indicate that satisfactory competition development is not only dependent on the quantity of suppliers and products.

Matthias Kurth
President, Bundesnetzagentur
für Elektrizität, Gas, Telekommunikation,
Post und Eisenbahnen

Contents

Part I Important market developments

Electricity market

Summary

As in 2009, developments in the electricity generation field in 2010 were characterised by a significant increase in generation capacities from renewable sources. This expansion of generation based on volatile sources is primarily the result of solar power systems and, to a lesser extent, wind energy capacities.

Alongside the expansion of generation based on volatile sources, 2011 also witnessed a decline in generation from non-volatile sources resulting from the decommissioning of nuclear energy capacities in line with the amended Atomic Energy Act. Alongside this fall-off in nuclear energy, a further reduction in generation from non-volatile sources is planned by end of 2014. Despite this, it is expected that this entire reduction can be compensated for by the expansion of non-volatile power station capacity by 2014. However, the delays to a series of power station projects as already described in the 2010 Monitoring Report have, according to the monitoring data available for 2011, been further exacerbated. Furthermore, the total volume of non-volatile power station projects has fallen by nearly 18 percent within a year. To safeguard system security, it is necessary to ensure that the power stations that are already under construction are completed in line with their current scheduling. Of crucial importance in this context is the continued expansion of non-volatile generation capacity in southern Germany. The situation here will remain uncertain even after completing the larger-scale power station projects that are currently under construction.

Both the integration of renewables and the decommissioning of non-volatile generation place particular demands on network operators. These challenges will continue to grow as a result of expansion plans for both onshore and offshore wind farms and photovoltaic systems. Consequently, security of electricity supply is currently a key issue that will persist over the coming years and one which the Bundesnetzagentur is already addressing in detail through its three reports on the implications of the decommissioning of nuclear capacities for the transmission systems and the security of supply[1]. Overall, these reports have shown that although the current network situation is manageable, it requires network operators to intervene increasingly frequently in system operation. Nonetheless, the network infrastructure in the electricity sector remains stable and secure.

In the event of any threat to or malfunction in the electricity supply network, transmission system operators (TSOs) are both authorised and obliged to remedy the associated problems through the adoption of network and market-related measures. Network-related measures, in particular with network switching, were implemented every single day of the year during 2010. Market-related measures, in particular those relating to congestion management, were taken on 129 days during the same year. In addition, the TSOs undertook commercial transactions on 157 days of the year in order to eliminate threats to or malfunctions in the network.

The continuously high level security of electricity supply can only be guaranteed in the future if massive investments are made at all levels of the network. The Power Grid Expansion Act (EnLAG) of 2009 is intended to greatly simplify the implementation of the necessary expansion measures. The Act identifies 24 projects for immediate, prioritised implementation. So far, two of these projects have been completed. There are clear delays to the approval and implementation plans of twelve of the 24 EnLAG projects, with the result that the intended commissioning dates have been exceeded by several years in some cases. The reports submitted by the TSOs to the

1 http://www.bundesnetzagentur.de "Impact of the nuclear power moratorium on the transmission networks and security of supply".

Bundesnetzagentur regarding the state of implementation of their planned network expansions also document these delays. In the second quarter of 2011, a total of 149 expansion projects were planned throughout 2014, including 19 measures related to the connection of offshore wind farms. Of the total volume of expansion measures, 73 were behind schedule or had postponed completion dates at the end of the second quarter of 2011. Accordingly, the investment data reported within the framework of the 2011 monitoring activities provide further evidence of the fact that the new building and expansion projects planned for the transmission systems are significantly behind schedule.

The strong expansion of generation installations based on renewable energy sources, coupled with the legal obligation to connect and purchase regardless of network capacity, also represents a considerable challenge to distribution system operators (DSOs). Alongside traditional expansion measures, network operators are primarily responding to these challenges by increasingly restructuring their networks, putting in place smart technology, which allows them to adapt to changing requirements over time. Consequently, the number of DSOs conducting measures to optimise, reinforce and expand their networks grew once more during 2010. In addition, network operators have the option of restricting the output from installations operated under the Renewable Energy Sources Act (EEG) if they are unable to take up the energy generated from renewable sources because no conventional power station can be adjusted to compensate. So far, this type of adjustment of EEG installations has only been required to a small degree in the context of feed-in management in the northern network areas where there is a high level of installed wind power capacity. Nevertheless, the downward adjustment of energy from EEG installations in 2010 was 70 percent higher than in 2009. This illustrates the growing challenge that the rapid growth of renewables is already posing to networks and that will become increasingly intense over the coming years.

In 2010, the German wholesale market for electricity was extremely liquid. The wholesale volume in 2010 amounted to approximately seventeen times the actual electricity requirement in Germany. Without taking account of the transactions cleared on the exchange, the over-the-counter (OTC) trade volume in 2010 was more than fourteen times greater than the volume traded on the markets (EEX and EPEX Spot). More than half of the wholesale volume was traded over broker platforms and more than a third of the trade volume was accounted for by bilateral transactions between parties. However, the volumes traded on the markets rose greatly compared to 2009. In 2010, the electricity trade volume on the EEX and EPEX Spot was a good 70 percent higher than the corresponding figure for 2009. The volumes traded on the day-ahead and intraday markets rose by more than 50 percent. However, the increase in the intraday trade volume is primarily due to the sale of electricity under the EEG by the TSOs on the EPEX Spot market. The sale of EEG electricity volumes also had a dampening effect on day-ahead prices during 2010, with the result that prices rose only slightly in this sector. On the futures market, price levels in 2009 and 2010 remained practically constant at base load while falling by seven percent at peak load.

One trend observed in both the futures and spot markets is the considerable reduction in price volatility compared to previous years. This reduced level of price fluctuation is due, at least in part, to the EEG electricity volumes that have been marketed on EPEX Spot since January 2010 and the coupling of the German and Nordic markets as of the end of 2009. Following the successful launch of the German/Nordic market coupling in November 2009, the focus in 2010 shifted to the introduction of market coupling in the central-western European region. The coupling of the electricity markets in north-western Europe (Germany, France, Benelux and Scandinavia) in the end of 2010 represented the accomplishment of a milestone towards the integration of electricity markets within the European Union. Following this, the national electricity spot markets of nine countries have been interconnected at wholesale level. The expected positive effects on market results have been achieved. In particular, it has been possible to align prices between the individual countries.

The German electricity retail sector in 2010 was characterised by a marked increase in volumes supplied to industrial customers as well as by increases in the prices paid by industrial, business and household customers. After the clear fall in sales of electricity to industrial customers in

2009, an increase of over 14 percent was observed in 2010. Electricity sales to business and household customers remained comparatively stable. Overall, electricity sales grew by approximately seven percent in 2010 to regain their level of 2008.

After a continuous succession of increases in the prices paid by household customers in recent years, the year 2011 has seen the greatest rise in electricity prices since regulation was introduced. The causes for this lie primarily in the increase in the surcharge payable under the EEG and the growing importance of the "energy and supply" price component. Although several factors are responsible for the sharp increase in the EEG surcharge which is used to promote renewable sources, the largest of these is the increase in overall feed-in tariff payments to installation operators. The increase in the "energy and supply" price component is due in part to the rise in the undertakings' supply revenues as well as to the fact that in 2011, wholesale prices, which had fallen markedly as of the second half of 2008, failed to have the expected positive effect on electricity prices to household customers due to changes in the undertakings' procurement strategies.

Household customers who are not satisfied with their electricity suppliers' price practices are able to change their supplier. Thanks to the continuous improvement in market conditions, household customers in 2011 are able to choose between an average of 147 suppliers in each network area. In 2011, some consumers are still able to achieve significant savings by switching supply contract or supplier. On average, basic supply according to § 36 EnWG continues to be the most expensive form of electricity supply; it is more price-effective for household customers to make use of their possibility to change and select another tariff from their basic supplier or a tariff from another electricity supplier. However, nearly 44 percent of all household customers have not yet taken advantage of this option. 41 percent of all household customers are covered by a special contract with their basic supplier and only 15 percent by a special contract concluded with a competitor.

To summarise, alongside the positive observation that a growing number of consumers are changing their electricity supplier, it is nevertheless still unfortunately the case that the majority of consumers fail to move from their habitual supplier to a competitor despite the potential reduction in prices such a change can bring about. It is therefore increasingly difficult for competitors to gain customers who are not already considered to be in the consumer segment that is open to changing. Even though more consumers changed supplier in 2010 than they did in 2009, only approximately 25 percent of these changes helped to overcome the domination of the former regional monopoly areas. If household customers do decide to switch their supplier, only a small number of companies are generally in a position to profit from this. Approximately 45 percent of all household customers who switch are acquired by one of Germany's four largest suppliers either directly or via other marketing channels. Since these undertakings have been confronted with a significant loss of customers in the network areas in which they provide basic supply, the market share held by the four largest electricity suppliers has fallen when being viewed at from the national level. At the regional level, however, these local basic suppliers continue to dominate despite the increasing number of consumers who are changing operator or supplier.

Against this background, the Bundesnetzagentur – along with the Bundeskartellamt (Federal Cartel Office) – would once again encourage all household consumers to find out about switching their contract or supplier so as to benefit from the opportunities competition brings.

Generation

Connection of electricity generators to transmission and distribution system operators, by to energy source[2]

A picture of the total installed generation capacity in Germany and the feed-in to the public supply network is provided through the data on all generation installations connected to TSOs and DSOs by energy source[3] (excluding installations eligible for payment in accordance with the EEG) gathered in the 2011 monitoring survey, as well as through the EEG data collection.[4]

As of 31 December 2010, 160.5 GW generating capacity was connected to the networks of the TSOs (77.6 GW) and DSOs (82.9 GW). Compared to 31 December 2009 (152.7 GW), this represents an increase of approximately 7.8 GW. This increase is primarily due to the contribution of solar (+7.1 GW) and wind (+1.7 GW) power. Only small changes were observed in the other energy sources. Renewables account for 54.2 GW of the total volume of 160.5 GW. 50.7 GW of the renewables are paid for in accordance with EEG tariffs. This means that renewables represent approximately 34 percent of overall capacity.

Due to the significant changes in the structure of generation, this increase in renewables means that more generating capacity is now connected to the distribution systems (82.9 GW) than to the transmission systems (77.6 GW).

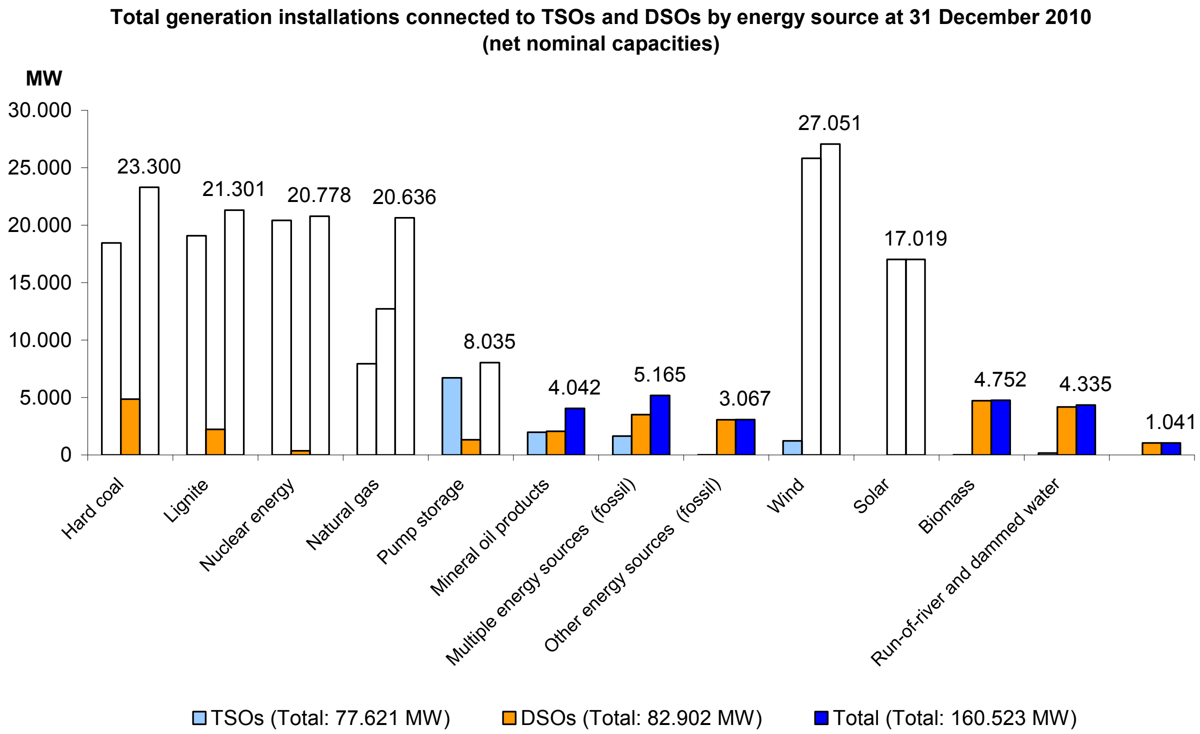


Figure 1: Total generation installations connected to TSOs and DSOs by energy source at 31 December 2010 (net nominal capacities[5])

2 Further information can be found in part II of this Report under the heading "Elektrizität, Erzeugung, Anschluss Elektrizitätserzeuger bei Übertragungs- und Verteilernetzbetreibern nach Energieträgern" (available in German only).
3 Generation installations physically connected directly or indirectly (e.g. via an area or industrial network) to transmission and distribution systems (all network and substation levels) (including temporarily decommissioned but excluding definitively decommissioned installations).
4 For market coverage details relating to the data collection for distribution system operators, see part II "Elektrizität, Allgemeine Marktdaten und Marktabdeckung" (available in German only).
5 Net capacity is the power supplied from a generating unit to the supply system (transmission and/or distribution networks, final consumers); nominal capacity is the permanent capacity of a generation installation as commissioned in the supply contract (see glossary (available in German only)).

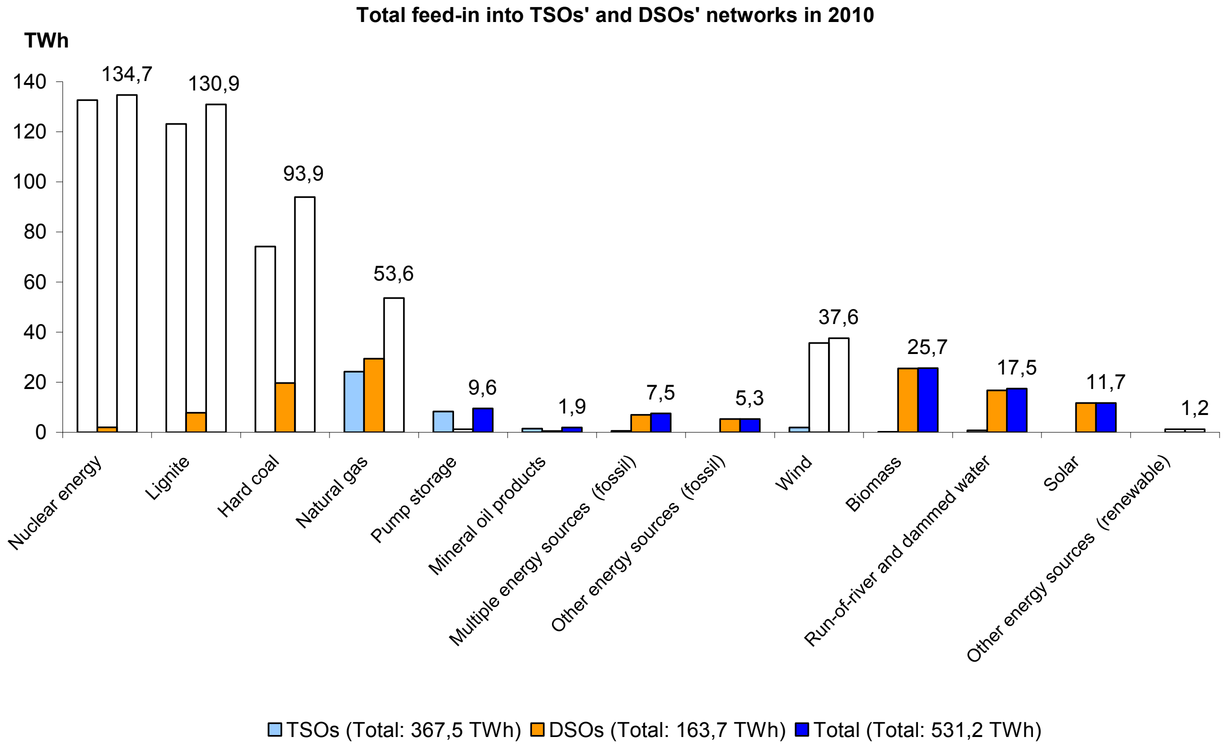


Figure 2: Feed-in 2010 (total) to TSO and DSO networks in TWh
(Solar: on-site consumption not included in the feed-in volume)

In 2010, a total of 531.2 TWh was fed into the TSO and DSO systems. The amount fed into the TSO networks was 367.5 TWh and the amount fed into the DSO 163.7 TWh. The volume fed in from renewable sources was 93.7 TWh, of which 80.7 TWh were remunerated in accordance with the EEG. This means that feed-in from renewables represents approximately 18 percent of the total feed-in volume, a proportion that therefore lies below the 34 percent of total generation capacity accounted for by these sources.

The period of utilisation of renewable sources is shorter than that of conventional sources. This is primarily due to solar and wind power. Although it represents 10.6 percent of capacity, solar energy accounts for only 2.2 percent of the volume fed in. However, it should be noted here that solar installations expanded significantly during 2010 and that the corresponding volumes were therefore not fed in across the entire year. Wind installations (1,391 h/a) have a greater annual period of utilisation than solar installations (686 h/a)[6]. Despite this, wind power accounts for only 7.1 percent of energy feed-in although representing 16.9 percent of capacity. In contrast, biomass (5,400 h/a) and hydroelectric power (4,028 h/a) sources have greater annual periods of utilisation that are similar to those of conventional energy sources.

Development of electricity generation remunerated in accordance with EEG[7]

As part of its monitoring role under the Renewable Energy Sources Act (EEG), the Bundesnetzagentur annually collects data from approximately 900 distribution system operators (DSOs), the four transmission system operators (TSOs) and some 1,100 electricity suppliers. This Monitoring Report is based on the EEG accounting data supplied by these companies for the year 2010. As of 31 December 2010, the total capacity of the installations eligible for payment under the EEG in Germany was approximately 50.7 GW (31 December 2009, approximately 41.4 GW). The installed capacity of all the installations receiving payments in accordance with

6 The annual period of utilisation is the ratio of the fed-in volume to the installed capacity expressed as a proportion of a year (8,760 h/a).
7 Further data can be found in part 2 of this Report under the heading "Elektrizität, Erzeugung, Entwicklung nach EEG vergüteter Elektrizitätserzeugung" (available in German only).

the EEG therefore grew by approximately 9.3 GW in 2010. This corresponds to relative growth of approximately 23 percent in a year.

At 31 December 2010, the EEG installations' share in the total capacity of all generation installations connected to TSOs and DSOs (160.5 GW) was 31.6 percent, or 50.7 GW.

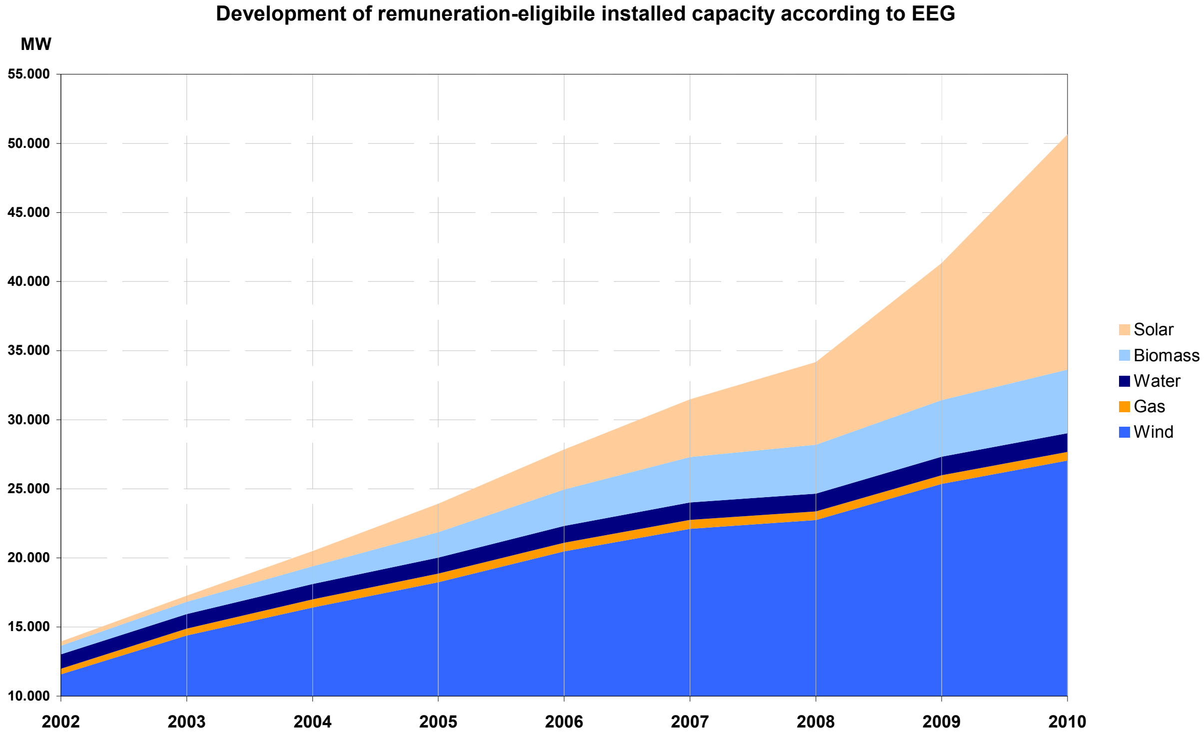


Figure 3: Development of installed capacity of installations receiving payment in accordance with EEG from 2002 to 2010

The year 2010 saw a massive expansion of solar installations. New systems with a capacity of approx. 7.1 GW were installed (in 2009, the corresponding value was approximately four GW). This represents an increase in solar installations of approximately 72 percent in 2010. In 2010, the installed capacity of wind power plants increased by approximately 1.7 GW or 6.7 percent.

The capacity of biomass installations increased by some 0.5 GW or 12.5 percent. The installed capacities of the other EEG energy sources were similar to their corresponding 2009 values.

When fed into the public network, the EEG electricity generated from renewable sources by the installation operators is remunerated by the DSOs at a tariff laid down by law, which differs greatly for the individual forms of generation.

According to the collected EEG data, the total annual energy feed-in during 2010 was 80,700 GWh (2009: 74,153 GWh), while the minimum amount paid to installation operators totalled 13,182m euro (2009: 10,779m euro). This means that feed-in from all EEG installations increased by approximately eight percent between 2009 and 2010 whereas the overall remuneration paid increased by approximately 22 percent.

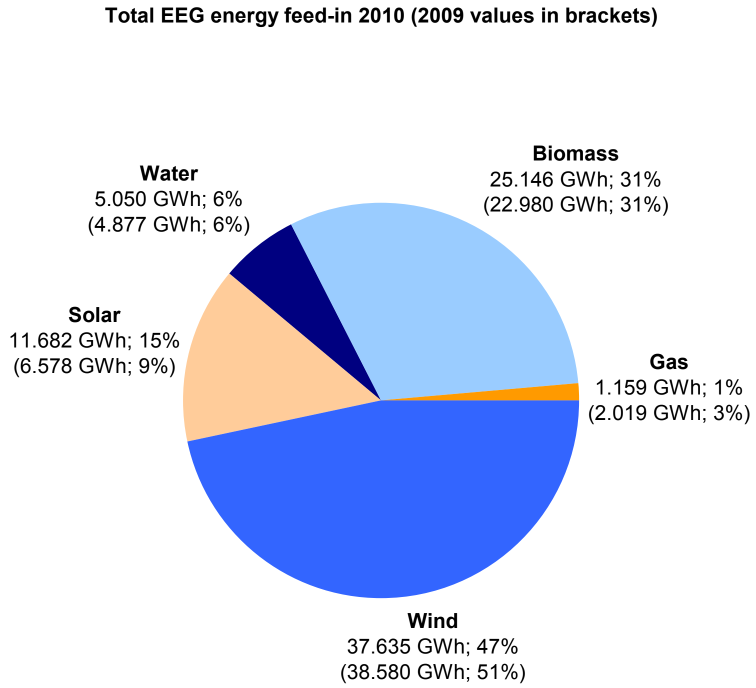


Figure 4: Annual EEG energy feed-in for 2010 per energy source as absolute and percentage amounts (Values for 2009 in brackets). Due to the low level, the values for "Geothermal energy" are not shown.

Feed-in development compared to 2009 differs greatly for each individual energy source. For example, wind power stations fed in approximately 2.4 percent less energy into the network than in 2009, with the minimum remuneration to be paid to the installation operators falling by a similar proportion. The reason for this was the relatively low wind level in 2010, which was below the ten-year average.

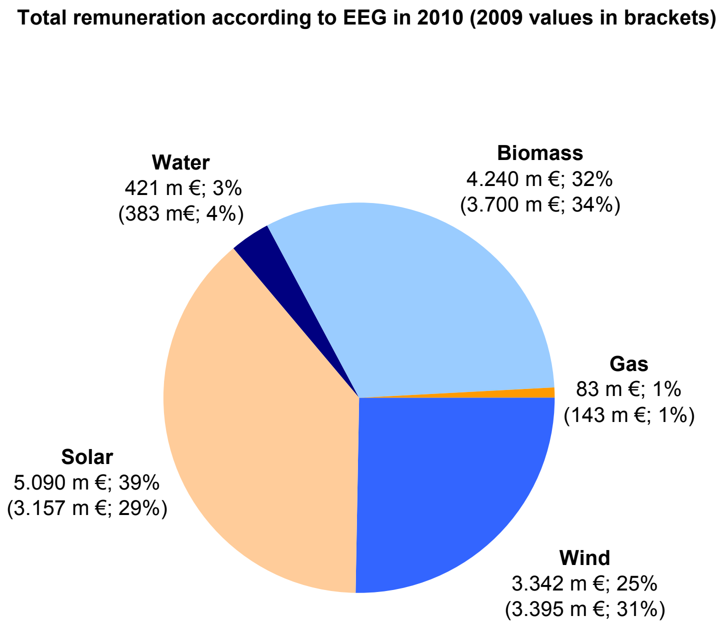


Figure 5: Remuneration for feed-in under the EEG in 2010 per energy source as absolute and percentage amounts (Values for 2009 in brackets). Due to the low level, the values for "Geothermal energy" are not shown.

Due to the extremely strong expansion of solar installations in 2010 as depicted above, both the annual energy feed-in at an absolute value of 11,682 GWh (2009: 6,572 GWh) and the remuneration paid at an absolute value of 5,090m euro (2009: 3,156m euro) lay significantly above the corresponding 2009 levels. However, in total, solar power systems contributed only approximately 15 percent of the entire EEG feed-in for 2010, an amount which represents only approximately 2.4 percent of sales to final consumers during the year. In contrast, with 39 percent, solar energy consumes a considerable share of EEG remuneration payments. These payments continue for a period of 20 years after the connection of an installation. The tariff level does not change during this period. Irrespective of the way the expansion of solar power progresses in the future, the total remuneration payable to the operators of solar installations will remain at a very high level during the coming years.

Structure of the generation sector

During the collection of its monitoring data, the Bundesagentur questioned both generators and network operators with regard to the generation sector. To permit comparison between the two surveys, Monitoring Reports as of 2011 focus on power stations that are not eligible for remuneration under the EEG.

In its sector inquiry of Electricity Generation and Wholesale Markets published in January 2011, the Bundeskartellamt noted that electricity generated and marketed in accordance with the EEG does not form part of the competitive primary electricity sales market.[8] However, the generation and feed-in of electricity from installations receiving remuneration under the EEG are not without consequences for the competitive primary electricity sales market, including generation in conventional power stations.

Consequently, unlike in previous years, the market shares of the four largest generation companies are now calculated on the basis of the power station capacity that is not eligible for remuneration payments under the EEG as well as the electricity feed-in to the public supply network exclusive of EEG electricity. This permits a more accurate view of the share of the market-led generation market held by the four largest generation companies. In contrast, generated volumes for which EEG remuneration is paid are not assigned to the market led generation market since for these feed-in volumes remuneration is paid as defined in the EEG.

As of 31 December 2010, the generating companies included in the monitoring data possessed a net maximum capacity[9] of 107.0 GW for which no remuneration is paid under EEG provisions. In the calendar year of 2010, these installations fed 450.9 TWh into the public power supply networks.[10]

In terms of recorded capacities (107.0 GW excluding EEG), the share of the four largest generators (E.ON, EnBW, RWE and Vattenfall) calculated using the dominance method was approximately 77 percent as of 31 December 2010 (82.8 percent). In the calendar year 2010, energy feed-in to the public supply networks by the four largest generating companies, excluding EEG electricity, amounted to 370.7 TWh or approximately 82 percent.

---

8 Published at
http://www.bundeskartellamt.de/wDeutsch/download/pdf/Stellungnahmen/110113_Bericht_SU_Strom__2_.pdf,
Pages 63-69, 73f., 249-260. (in German),
English summary available at:
http://www.bundeskartellamt.de/wEnglisch/download/pdf/2011-05-05_SU_Strom_Executive_Summary_EN_final-2.pdf,
9 Net capacity is the power supplied from a generating unit to the supply system (transmission and/or distribution networks, final consumers); maximum capacity is a generating unit's maximum permanent capacity under normal conditions.
10 The survey of the connected capacity and feed-in volumes of the transmission and distribution system operators revealed a total of 109.8 GW or 450,5 TWh not remunerated under the provisions of the EEG .

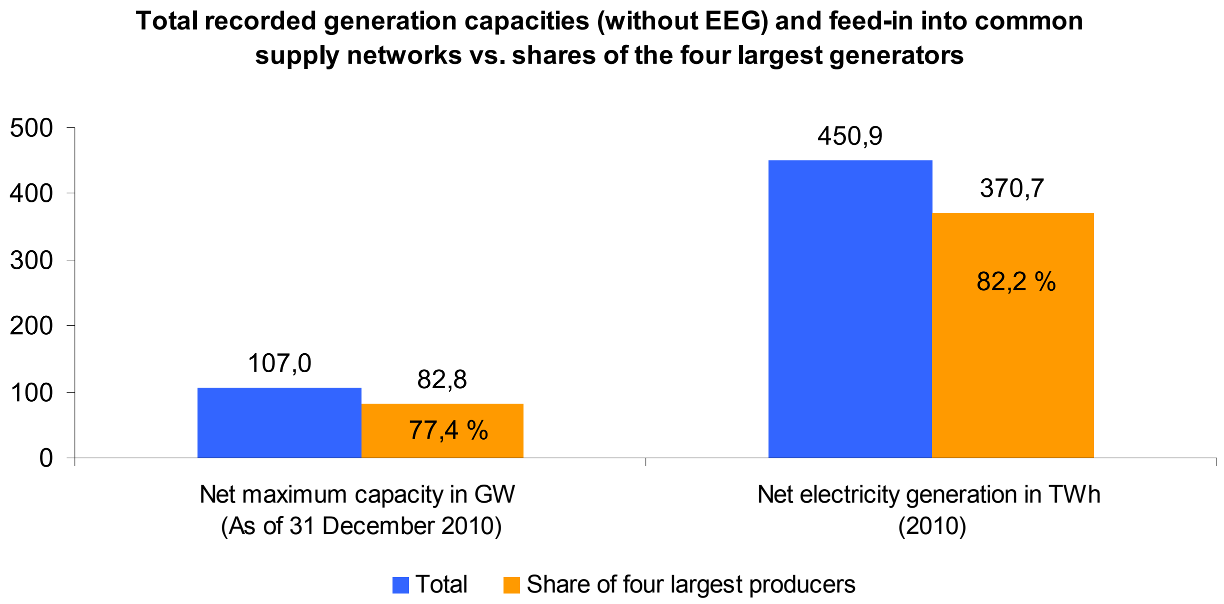


Figure 6: Recorded generating capacities (without EEG) and energy feed-in to the public supply networks together with the proportion for the four largest generating companies

Expected expansion and reduction of non-volatile power station capacities[11]

There currently is approximately 12,900 MW of non-volatile power station capacity under construction in Germany. These projects are scheduled for completion by 2014. However, there are a number of imponderables such as the issue of boilers. Thus, the use of boilers with the innovative, high temperature-resistant, pressure-resistant steel alloy T24 (7 CrMo VTiB 10 10) has given rise to technical problems. These problems have already led to postponing the scheduled commissioning dates at a number of the coal power stations currently under construction.

Out of the total number of non-volatile power station projects currently in the construction phase, 18 projects - representing a total capacity of 12,300 MW - have an individual minimum capacity of 100 MW. A comparison with the monitoring data collected for 2010 shows that there are delays to the scheduled commercial start-up dates at eleven of these projects. In six of the projects (5,000 MW), the delay is one year, in four of them (2,900 MW) it is two years and in one of them (1,100 MW) it is three years. This means that the delays to a series of power station projects noted in the 2010 Monitoring Report have, according to the monitoring data available for 2011, been further exacerbated. In addition, the total volume of investment projects in the field of non-volatile power stations is falling. Thus, within a year, the total volume has fallen by around 18 percent to approximately 7,300 MW.

[11] Further data can be found in part II of this Report under the heading "Elektrizität, Erzeugung, Erwarteter Zu- und Rückbau von dargebotsunabhängigen Kraftwerkskapazitäten" (available in German only). Power stations based on non-volatile energy sources are power stations that are not dependent on the presence of stochastically available energy sources (such as wind, sun or, to a lesser extent, water).

Power stations based on non-volatile energy sources in Germany ≥ 5 MW					
Expected take-up of electricity feed-in	**Projects under construction in MW**	**Projects with[12] authority approval in MW**	**Projects awaiting authority approval in MW**	**Projects not yet in the authority approval phase in MW**	**Total planned investments or investments under construction in MW**
Total non-volatile energy sources Monitoring 2010 (2010 - 2020)	**13,826**	**2,055**	**16,461**	**9,067**	**41,409**
Total non-volatile energy sources Monitoring 2011 (2011 - 2019)	**12,925**	**1,356**	**10,614**	**9,182**	**34,077**
Difference	**-901**	**-699**	**-5,847**	**115**	**-7,332**
Difference in percent	**-6.5%**	**-34.0%**	**-35.5%**	**1.3%**	**-17.7%**

Table 1: Reduction in non-volatile power station projects.

The eight nuclear power plants with a total capacity of 8,400 MW that were shut down in the wake of the German government's moratorium on nuclear power stations are due to be decommissioned in compliance with the amended Atomic Energy Act. In addition to the loss of this nuclear capacity, a further reduction of approximately 4,000 MW of non-volatile generating capacity is planned by the end of 2014. It is expected that the construction of approximately 12,900 MW of new non-volatile power station capacity will cancel out the loss of a total of 12,500 MW of power station capacity by 2014. To safeguard system security, it is necessary to ensure that the power stations that are already under construction are completed in line with their current scheduling.

The data presented below is based on the information collected by the Bundesnetzagentur in 2011 for power stations with a net maximum capacity[13] of at least 5 MW. With reference to the expected construction of new power station capacity, the figure below takes account only of the non-volatile power stations that are currently under construction.

[12] Authority approval relates to approval under the Federal Imission Control Act (BImSchG).

[13] Net capacity is the power supplied from a generating unit to the supply system (transmission and/or distribution networks, final consumers); maximum capacity is a generating unit's maximum permanent capacity under normal conditions.

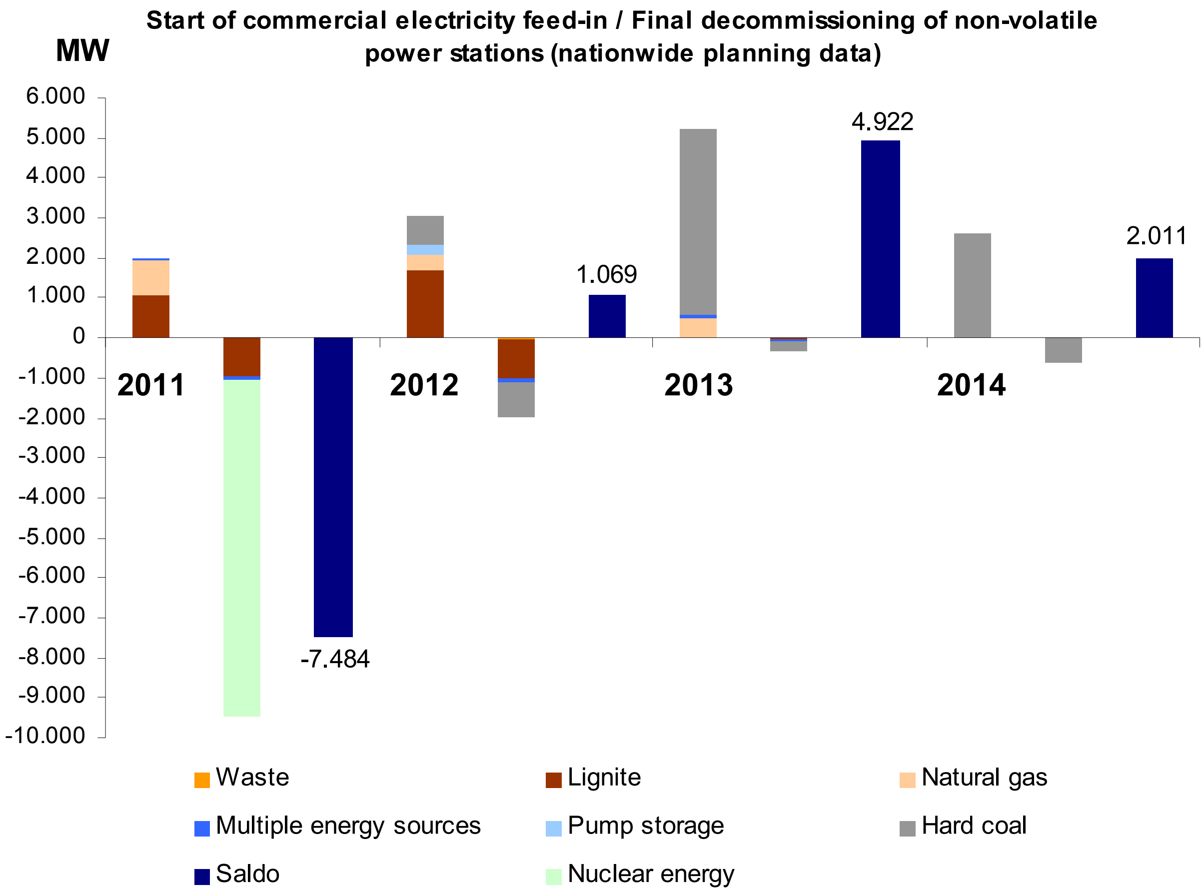


Figure 7: Start of commercial electricity feed-in / Final phase-out of non-volatile power stations (nationwide planning data for net maximum capacities)

Additional non-volatile power station capacity in southern Germany is of particular importance for the stability of the transmission systems. As the data reported below indicates, no significant changes in the generation situation in southern Germany are expected in 2012. It can therefore be assumed that the generation situation in the winter 2012/13 will be similar to that of the winter 2011/12.

An increase in non-volatile power station capacity of a total of approximately 1,700 MW in southern Germany due to the completion of two hard coal power stations is not expected until 2013 and 2014. However, even after completing these two power stations, the generation situation in southern Germany will remain tense since approximately three GW of non-volatile generating capacity are lacking in the region compared to the situation prior to the decommissioning of five nuclear power stations.

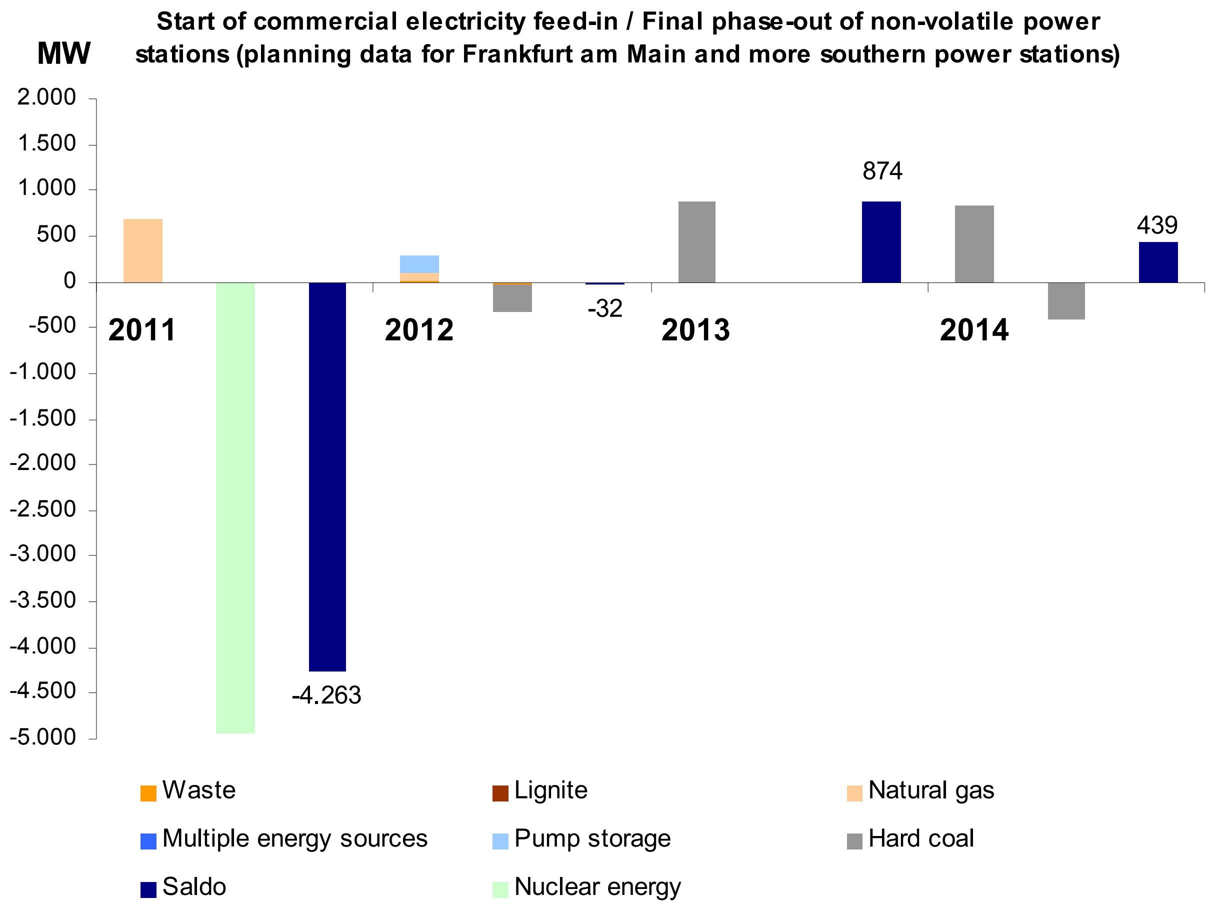


Figure 8: Start of commercial electricity feed-in / Final phase-out of non-volatile power stations (planning data for Frankfurt am Main and more southern power stations indicating net maximum capacities in MW).

Nationwide, a reduction in non-volatile generating capacities of approximately 29,500 MW is expected by 2022. This figure includes the eight nuclear power plants representing a total of 8,400 MW that were decommissioned in 2011. In addition to the 12,900 MW of capacity that is currently under construction, a further 16,600 MW of non-volatile power station capacity will have to be built in order to compensate for the reduction in capacity throughout 2022. It is important that this takes the form of additional, new power station capacity which is not subsequently reduced by the elimination of power generation units due for decommissioning at the same site.

Juxtaposed with the need for the construction of 16,600 MW of new capacity, the survey conducted by the Bundesnetzagentur for its 2011 Monitoring Report indicates that authority approval has as yet been obtained only for non-volatile power station projects representing a total of approximately 1,400 MW. A further 10,600 MW are currently in the authority approval phase. The authority approval process has not yet got underway in respect of generating capacity totalling 9,200 MW.

Of crucial importance in this context is the continued construction of new non-volatile capacity in southern Germany. Compared to the context before the German government's moratorium on nuclear power stations, the situation in southern Germany will continue to be serious and more prone to risk than in the past, even after completing the large-scale power stations currently under construction.

The expected reductions of non-volatile power stations in southern Germany significantly exceed the currently scheduled new construction activity. Given this context, it may prove necessary to consider the introduction of allocation incentives to attract new non-volatile power stations to the south of the country.

Networks

Power Grid Expansion Act – EnLAG project status
With the introduction of the Power Grid Expansion Act (EnLAG) in August 2009, the lawmakers responded to the necessity of expanding the transmission networks. The expansion was made necessary in particular by the increasing transportation distance and the increased use of renewable energy sources (e.g. offshore wind farms). The EnLAG requirement plan includes 24 expansion projects which are to be realised as soon as possible. These projects will require the construction of 1807 km of new lines. By way of comparison, the existing extra-high voltage network comprises 17,610 km[14] of routing.

The approval and implementation status of the EnLAG projects is as follows:

- Approximately 214 km of the 1807 km of lines due for construction have been completed.
- 12 of the 24 projects are behind schedule with delays of between 1 and 4 years expected.
- Of the projects listed in the requirement plan, 7 are in the planning phase, 6 are in the regional impact assessment phase, 8 in the plan approval process, 1 under construction and 2 completed.

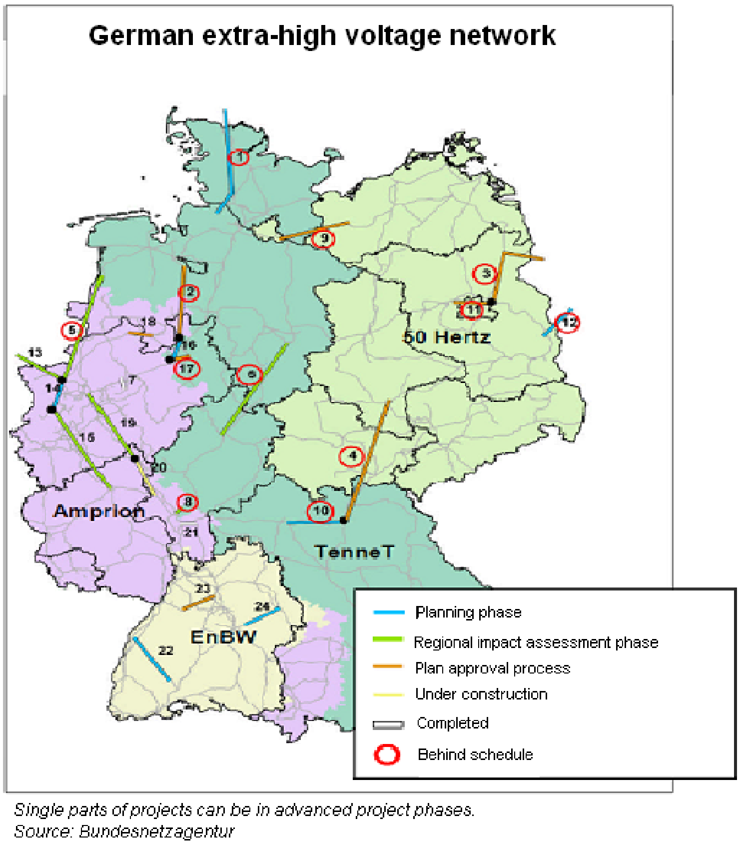


Figure 9: Status of the EnLAG projects as of 20 September 2011

The status of the individual projects and their approximate level of progress can be seen in the figure above. The 12 projects that the Bundesnetzagentur considers to be suffering from delays are circled in red. The four control areas of the German transmission system, the existing network and the 16 federal states are also depicted

[14] See Part 2, "Elektrizität, Allgemeine Marktdaten und Marktabdeckung" (p.87 of this report, available in German only).

The Bundesnetzagentur has already approved the respective investment budgets for 21 of the 24 projects in the EnLAG requirement plan. These approvals include acquisition and production costs totalling 4.2 bn euro. A further project is due to be approved shortly. For two EnLAG projects, investment budget applications have not yet been submitted to the Bundesnetzagentur.

Project overview: EnLAG projects

As of 20 September 2011

Project status: **- delayed -**

	Planning	Regional Impact Assessment (RIA)	Plan Approval Process (PAP)	Under cnst.	Realised or partially realised	TSO	Already realised (in km)	Route length, full project (in km)
1	Kassø (Denmark) – Hamburg/Nord – Dollern					TenneT		187
2			Ganderkesee – Wehrendorf			TenneT and Amprion		93
3			Neuenhagen – Bertikow/Vierraden – Krajnik (PL)			50Hertz		115
4			Lauchstädt – Redwitz		1st section Lauchstädt-Vieselbach in operation (76 km) 2nd section Vieselbach-Altenfeld in planning approval stage 3rd section Altenfeld-Redwitz RIA (03/11) concluded and planning approval in preparation	TenneT and 50Hertz	76 km	200
5		Diele – Niederrhein				TenneT and Amprion		166
6		Wahle – Mecklar				TenneT		230
7					Bergkamen – Gersteinwerk	Amprion	9 km	9
8		Kriftel – Eschborn				Amprion		10
9			Hamburg/Krümmel - Schwerin		Section Schwerin to border MV/S-H in operation (UW Görries to border/UW Zarrentin ca. 48.5 km)	50Hertz	48.5 km	68.2
10	Redwitz – Grafenrheinfeld					TenneT		96
11			Neuenhagen – Wustermark			50Hertz		75
12	Eisenhüttenstadt – Baczyna (PL)					50Hertz		6.5
13		Niederrhein / Wesel – border NL				Amprion		35

Project overview: EnLAG projects

A of 20 September 2011

Project status: **- delayed -**

	Planning	Regional Impact Assessment (RIA)	Plan Approval Process (PAP)	Under cnst.	Realised or partially realised	TSO	Already realised (in km)	Route length, full project (in km)
14	Niederrhein – Utfort – Osterath					Amprion		42
15		Osterath – Weißenthurm			Section Weißenthurm station - Pt. Neuenahr completed, Approx length: 33 km	Amprion	33 km	136
16	Wehrendorf – Gütersloh					Amprion		70
17			Gütersloh – Bechterdissen			Amprion		26
18			Lüstringen – Westerkappeln			Amprion		20
19		Kruckel – Dauersberg				Amprion		116
20				Dauers-berg – Hünfeld en	1st cnst. section Pt. Hünfelden - Limburg station and 2nd cnst. section Limburg station - Pt. Fehl-Ritzhausen completed, Approx. length 40 km	Amprion	40 km	65
21					Pt. Marxheim – Kelsterbach station completed, Approx. length: 7km	Amprion	7	7
22	Weier – Villingen					EnBW		70
23		not required	Neckarwestheim – Mühlhausen			EnBW		25
24	Bünzwangen – Lindach; Lindach – Goldshöfe					EnBW		60

Network status and expansion planning – transmission systems (incl. cross-border connections)

Based on the network status and network expansion planning reports to be drawn up in accordance with section 12(3a) of the Energy Act (EnWG), the TSOs must report quarterly on the implementation status of their network expansion projects planned up to 2014. As of the second quarter 2011, a total of 149 (Q2 2010: 139) expansion measures were planned, including 19 (Q2 2010: 14) for the connection of offshore wind farms. According to the TSOs, at the end of the second quarter 2011, a total of 73 (Q2 2010: 37) of these were affected by delays or a postponement to the timescale. The TSOs claim that among others, this increase is due to the higher network load resulting from the shutdown of the eight nuclear power plants. The changes in the load flow make the task of shutting down lines that are due for conversion considerably more difficult. However, project progress itself and the associated need to decide on concrete measures and coordinate activities in the individual project stages can also lead to delays.

Further reasons for delays are:

- Delays to the authority approval process
  (e.g. due to resistance from the local population)
- Complaints about plan approval decisions
- Necessary changes to the authority approval process due to changes to the legal framework
  (e.g. caused by the Underground Cable Law of Lower Saxony)
- Supply bottlenecks at system manufacturers, and
- Technical reasons

Investments in and expenditure on network infrastructure by the four German TSOs totalled approx. 807m euro in 2010 (2009: 739m euro). This also includes investments in and expenditure on cross-border connections amounting to approx. 5m euro (2009: 5m euro). There continues to be a difference – due primarily to delays to network expansion projects – between the actual expenditure on network infrastructure and the planning data provided in the 2010 Monitoring Report (planning value for 2010: approx.905m euro).

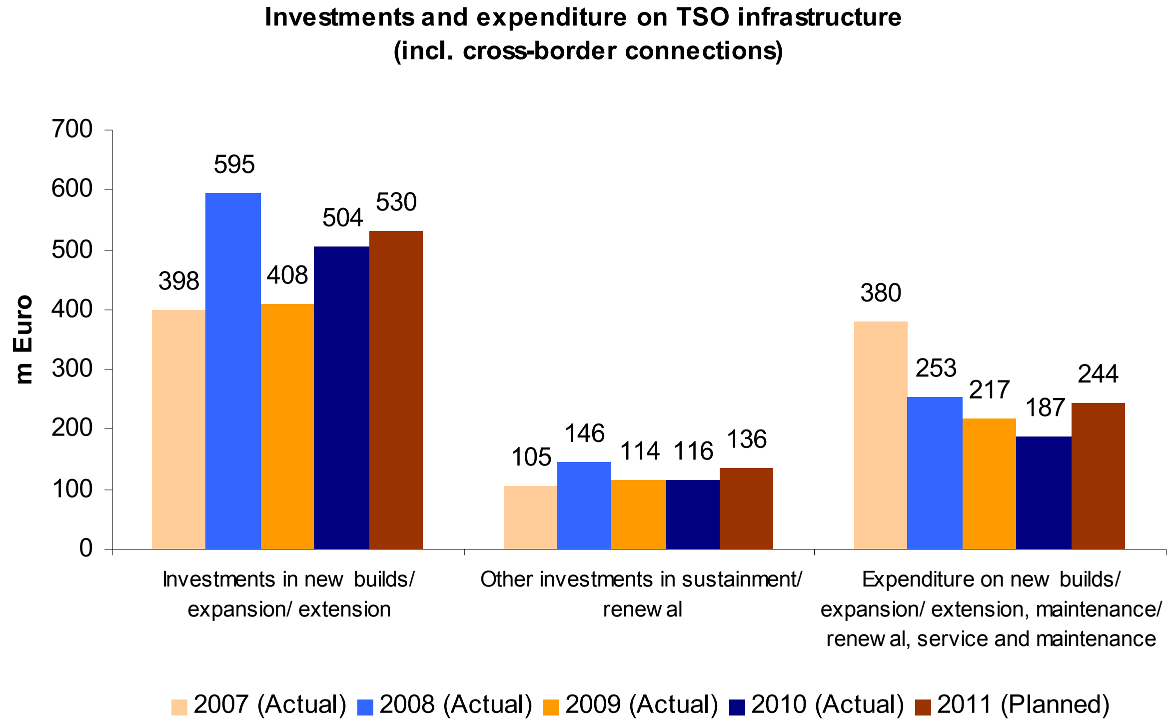


Figure 10: Investment in and expenditure on TSO network infrastructure since 2007 (incl. cross-border connections)

Network status and expansion planning – distribution systems

Investments in and expenditure on network infrastructure by the 686 evaluated DSOs totalled approximately 6,401m euro in 2010 (2009: 5,752m euro). This figure includes investments in and expenditure on metering/control devices and communication infrastructure amounting to approximately 432m euro(2009: 448m euro). An upward trend was again observed in investments in new construction/ expansion/ extensions as well as maintenance and renewal. As a result, the actual investments in network infrastructure made by the DSOs in 2010 (3,189m euro) were higher than the corresponding values reported during the 2010 monitoring survey (3,091m euro).

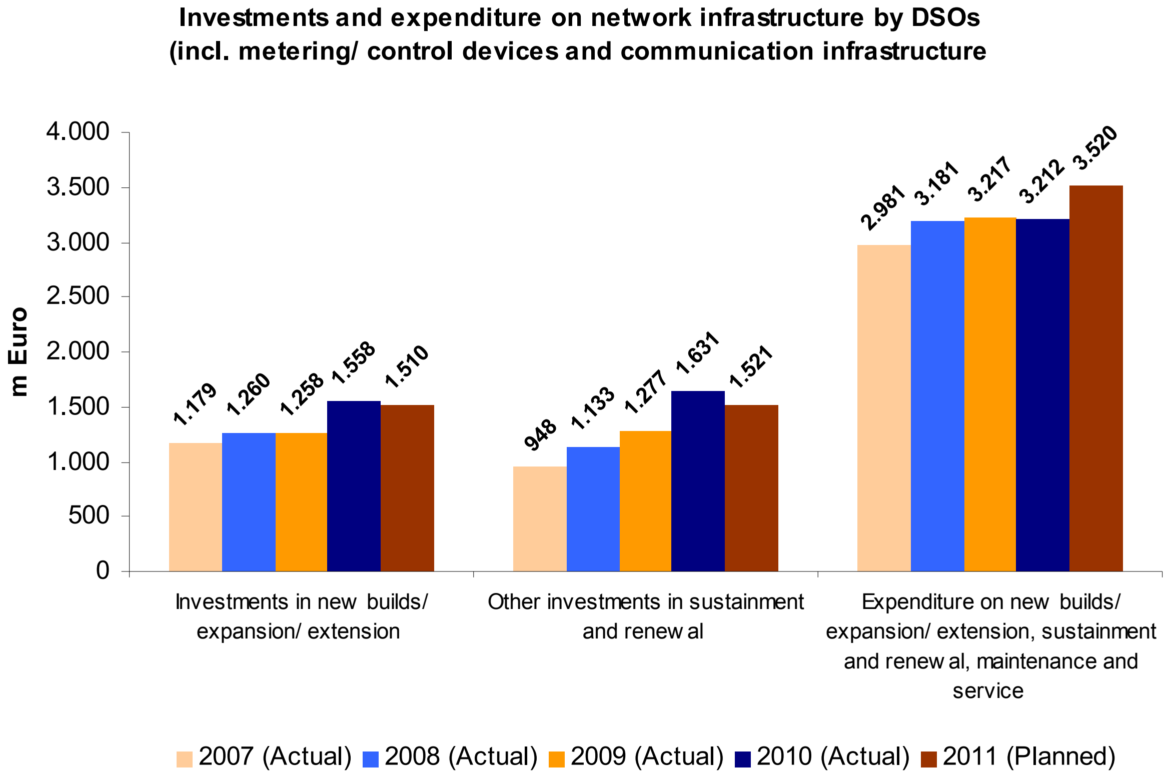


Figure 11: Investment in and expenditure on network infrastructure (incl. metering/control devices and communication infrastructure) by DSOs since 2007

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 purchase, transmission, and distribution of electricity - in particular from renewable sources or pit gas. 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 increasingly restructuring their networks on an intelligent basis which allows them to adapt to changing requirements over time. Intelligent restructuring here means that returns of capital from the existing network is also used to finance network adaptations intended to respond to the changing energy needs of the future.

The figure below indicates the extent to which the DSOs are implementing measures to optimise, reinforce and expand their networks. A comparison with previous years shows that the number of DSOs that were taking measures to optimise (324), reinforce (364) and expand (352) their networks has risen once again (all values measured on 1 April 2011).

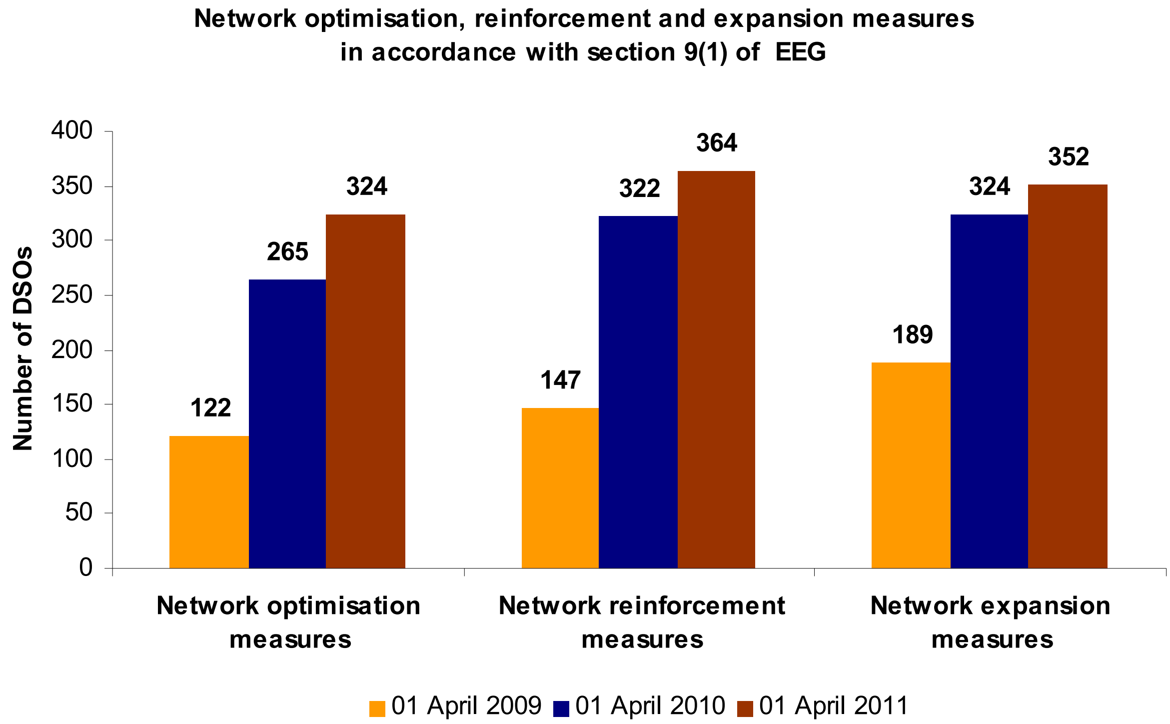


Figure 12: Measures for network optimisation, reinforcement and expansion in accordance with section 9(1) of the EEG

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

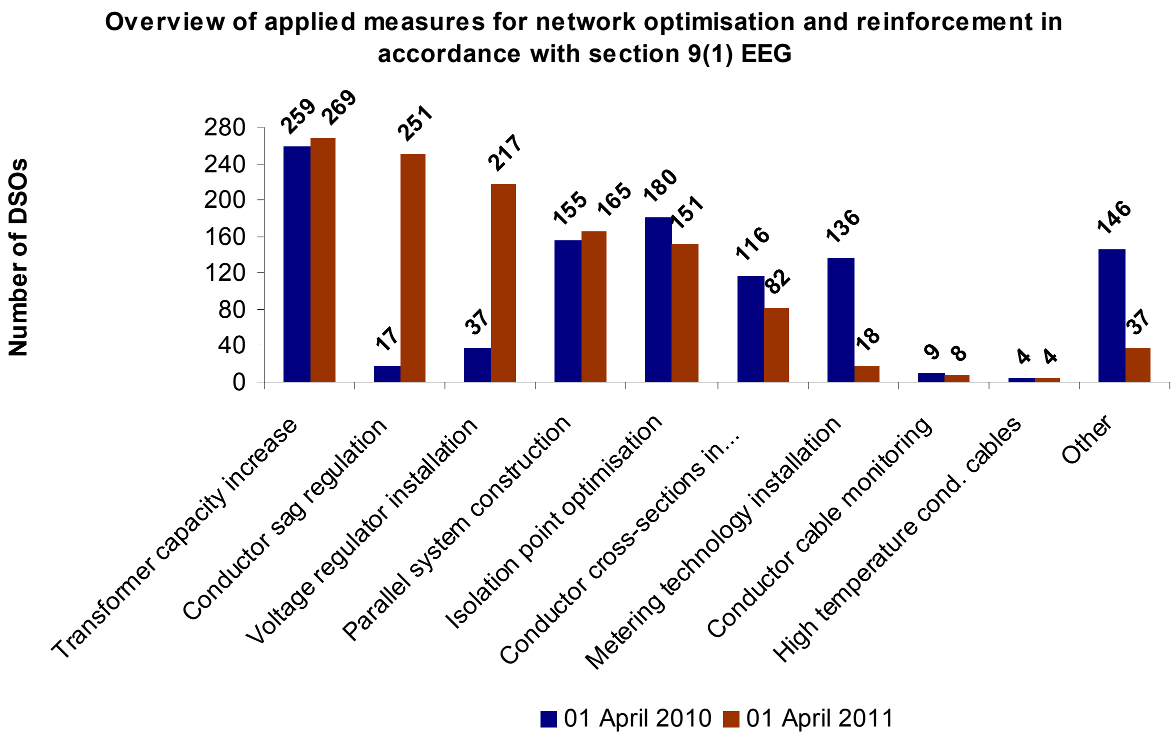


Figure 13: Overview of network optimisation and reinforcement measures applied in accordance with section 9(1) of the EEG

Compared to 2010, it is noticeable that the number of DSOs installing voltage regulators (217 compared to 37 in 2010) and regulating conductor sags (251 compared to 17 in 2010) has risen sharply. In contrast, only 18 DSOs installed metering technology in 2011 (1 April 2010: 136), a number that is well short of the 2010 level.

Grid connection of offshore wind farms

The grid connection of the Baltic offshore wind farm (OWF) EnBW Baltic 1 was completed during 2010. The OWF with its 21 wind power plants officially came on line on 2 May 2011. Alongside the North Sea OWFs alpha ventus and BARD Offshore 1, this means that a third OWF is now feeding energy into the German electricity supply network.

The position paper on the grid connection obligation in accordance with section 17(2a) of the EnWG published by the Bundesnetzagentur in October 2009 was extended in January 2011 by an annex based on initial experiences of grid connections conducted subsequently to the paper's appearance. This annex provides more concrete details relating to certain passages, in particular with regard to the joint connection of multiple OWFs to the grid (collective connections). In particular, the requirements set out by the Bundesnetzagentur – transparent connection criteria, the definition of key dates and guidelines on the allocation of overcapacities – permit the structured implementation of collective connections in a way that avoids stranded investments and takes account of the need for swift, on-time grid connection. Within the framework of its continuing discussions, the Bundesnetzagentur remains in regular contact with all parties involved in order to assist in the practical implementation of the position paper and newly drafted annex.

After awarding contracts for the collective connections for the BorWin (800 MW), HelWin (576 MW) and DolWin (800 MW) clusters in the summer of 2010, the TSO TenneT, after a call to tender, awarded a contract for a further collective connection (864 MW) for OWFs in the SylWin cluster in January 2011. TenneT also awarded the contract for the installation of the grid connection for the Riffgat OWF. Calls to tender were also issued for two further collective connections for OWFs in the HelWin (690 MW) and DolWin (900 MW) clusters in the summer of 2011. In early 2011, TenneT issued a call to tender for the third collective connection for the OWFs in the DolWin cluster as well as for the Nordergründe OWF.

To date, 20 applications have been submitted to the Bundesnetzagentur for the approval of an investment budget for the connection of OWFs with a total volume of approx. 10.9bn euro, of which 13 with a volume of 5.4bn euro have already been approved (as of October 2011).

Measures in accordance with section 13(1) of the EnWG

In accordance with section 13(1) of the EnWG, the TSOs are both authorised and obliged to remedy any threat to or malfunction in the electricity supply network through the adoption of system-related and market-related measures. To the extent electricity distribution system operators are responsible for the security and reliability of the electricity supply in their networks, DSOs are also authorised and obliged to implement such measures under section 14(1) of the EnWG.

Network-related measures, in particular network switching, were implemented by the TSOs on every day in 2010. To a large extent, the market-related measures took the form of congestion management measures. Here, it is necessary to differentiate between redispatching and countertrading: Redispatching is the preventive or corrective modulation of generator capacity by the TSO in order to prevent or eliminate short-term congestion. This measure can be applied either internally within control areas or across control areas. By reducing the feed-in capacity of one or more power stations while simultaneously increasing the feed-in capacity of one or more other power stations, it is possible to keep the overall energy feed-in capacity 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.

In 2010, the four TSOs implemented redispatching in the form of capacity increases on 39 days over a total of 364 hours, with a maximum capacity of 1,316 MW and a total volume of electricity of 67,429 MWh. The TSOs initiated capacity reductions during 1,447 hours spread over 90 days, with a maximum capacity of 3,036 MW and a total volume of electricity of

238,423 MWh. In addition, the TSOs undertook commercial transactions in order to eliminate threats to or malfunctions in the network. This resulted in the four TSOs together purchasing a maximum capacity of 1,675 MW and a total volume of electricity of 73,495 MWh spread over 253 hours on 43 days. They also sold a maximum capacity of 4,209 MW and total volume of electricity of 1,758,018 MWh spread over 1,607 hours on 114 days.

Measures in accordance with section 13(2) of the EnWG

In accordance with section 13(2) of the EnWG, TSOs are authorised and obliged to adapt the feed-in, transit and output 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 system and market-related measures pursuant to section 13(1) of the EnWG. To the extent electricity distribution system operators are responsible for the security and reliability of the electricity supply in their networks, DSOs are also both authorised and obliged under section 14(1) of the EnWG to implement adaptation measures pursuant to section 13(2) of the EnWG. Furthermore, section 14(1a) of the EnWG requires DSOs to support the measures taken by the TSOs by implementing their own measures as instructed by the latter (supporting measures).

In 2010, one TSO undertook adaptation measures pursuant to section 13(2) of the EnWG for 45 hours spread over six days. This resulted in a reduction of electricity feed-in by a maximum capacity of 150 MW and a total volume of electricity of 4,005 MWh. In addition, in 2010, four DSOs undertook adaptation measures pursuant to section 13(2) of the EnWG for 39 hours spread over twelve days. Electricity feed-in was reduced by a maximum capacity of 40 MW and a total volume of 304 MWh. Supporting measures pursuant to section 13(2) and section 14(1a) of the EnWG implemented by five DSOs resulted in a reduction of electricity feed-in by a maximum capacity of 75 MW and a total volume of approximately 2,619 MWh for 118 hours spread over 13 days

Feed-in management measures in accordance with sections 11 and 12 of the EEG

Despite appropriate network optimisation, reinforcement and expansion measures, the increasing amount of electricity fed in from renewable sources – particularly wind and photovoltaic systems – may temporarily result in situations in which not all generators are able to feed in unlimited amounts of electricity. Since 2009, network operators have been able to adjust electricity feed-in from renewable sources, combined heat and power and pit gas installations with a capacity of over 100 kW to a lower level, while taking into account the requirements stated in section 11(1) sentence 1 of the EEG.

The adjustment of feed-in from EEG installations to a lower level and thus the deviation from feed-in priority for EEG installations are described as feed-in management measures (FMM). The network operator responsible for the network requiring FMM is obliged to pay compensation under section 12 of the EEG for the unused energy and heat. According to the monitoring survey, the following use was made of this regulation in 2010:

	Unused energy in accordance with section 11 EEG [kWh]		Compensation payments in accordance with § 12 EEG [€]	
Total	**126,809,699**	100 %	**10,233,938**	100 %
Share compensated by network operator to whose network the installations were connected	73,437,553	58 %	6,038,296	59 %
Share compensated by the upstream network operator whose network caused the requirement for FMM	49,799,360	39 %	4,195,642	41 %
Share as yet uncompensated	3,572,786	3 %		

Table 2: Feed-in management measures (FMM) in accordance with sections 11 and 12 of the EEG in 2010

In 2010, feed-in management measures were applied almost entirely (98.67 percent) to wind power plants and, to a very minor degree, to biomass, solar and CHP installations. Recourse to these measures focused primarily on the northern network areas where there is a high level of installed wind capacity. Relative to the volume of unused energy, in 2010 FMMs were called on mostly by those network operators who were already in need of these measures in 2009.

At around 127 GWh, unused energy as a proportion of total feed-in from EEG installations in 2010 amounted to approximately 0.16 percent (2009: 0.1 percent). The corresponding value as a proportion of total wind power feed-in was 0.34 percent (2009: 0.2 percent). Compared to 2009, the proportion of unused energy grew by approximately 72 percent (2009: approximately 74 GWh).

The origin of a good 40 percent of the FMM resulting in unused energy and compensation payments lay in an upstream network (2009: approximately 30 percent). Compensation payments increased from an absolute value of 6m euro in 2009 to over 10m euro in 2010. This corresponds to a relative growth in compensation payments of 70 percent. Three percent of the unused energy remained without compensation at the time of the survey. Reasons for this include compensation requests not or not yet made by the installation operators, or delays to payments due to legal disputes.

Wholesale

Trade volume

The German wholesale market is extremely liquid. In 2010, the volume of wholesale trade amounts to an estimated 10,600 TWh, which is more than 17 times the actual electricity demand in Germany.

More than half of wholesale trading takes place through broker platforms. In 2010, exchange trading accounted for only six percent of the overall trade volume, making the volume of off–exchange trading more than 14 times the volume of on-exchange trading (EEX and EPEX spot markets).[15] Compared to the previous year, however, exchange trading has increased

[15] Without OTC clearing.

significantly. More than a third of the trading volume is agreed upon on a purely bilateral basis between the contracting parties (see following chart):

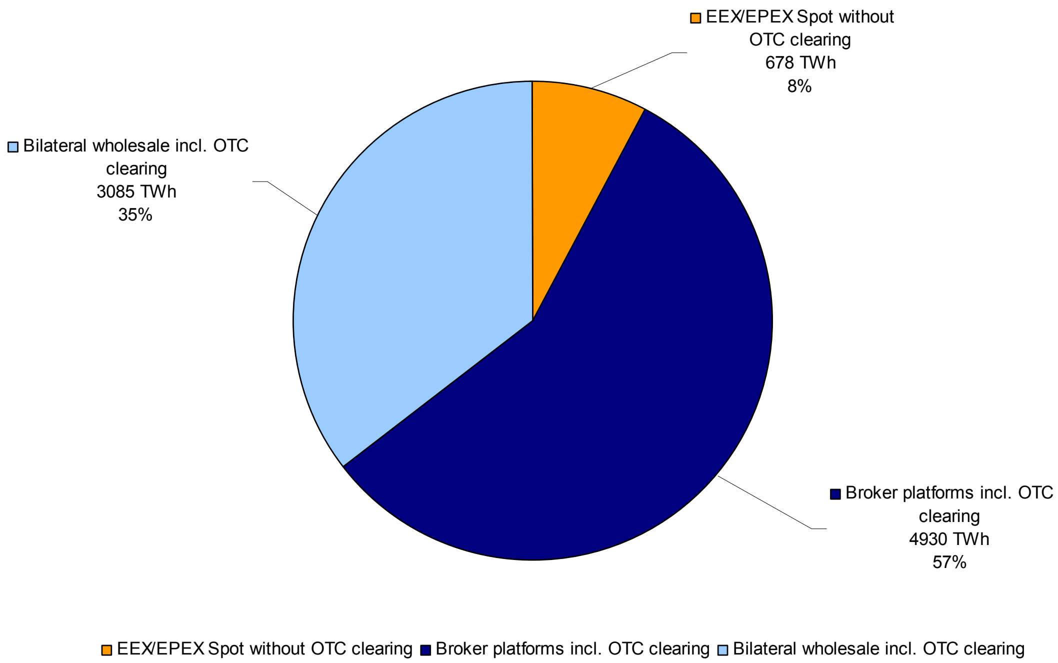


Figure 14: Comparison of total electricity trade volumes for German at the EEX/ EPEX spot markets[16], broker platforms and in purely bilateral trade[17] in 2010

The focus of trading activity is on trading electricity with delivery in the year following the transaction (see following chart). This makes up the majority of trade at all exchanges. Longer-term transactions take place more through bilateral trade. For trade periods of less than a year, the exchange presents an attractive place to do business.

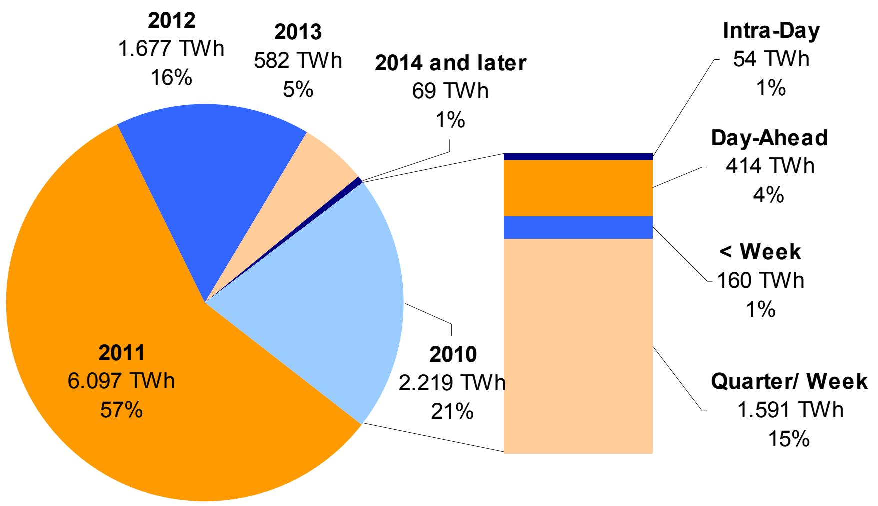


Figure 15: Electricity trade volume for Germany (year of transaction 2010)

[16] Without OTC clearing.
[17] The volume of bilateral trade is based on projections, as well as on average values derived from information on trade volumes.

On the whole, trade in electricity at the EEX and EPEX spot markets has increased significantly, and for 2010 it has exceeded the trade volume of the previous year by some 70 percent. The volumes of day-ahead and intraday exchange trading have increased by more than 50 percent. Day-ahead trading at the EPEX Spot increased to 205 TWh, and intraday trading increased to 10.3 TWh. In 2010, trading by the TSOs in the spot market amounted to 81 TWh; in 2009, it was only 20 TWh. Additionally, at a level of 4.4 TWh, a significant share of the intraday-traded volume (43 percent) can be attributed to buying and selling electricity by TSOs within the framework of the EEG. The increase in trade volume, therefore, is primarily a result of the sales of EEG electricity through TSOs at the EPEX Spot.

Although at 463 TWh the role of exchange trading is still relatively small on the whole, the futures trading volume at the EEX (+80 percent) has seen a significant increase.

Price development

The price level of day-ahead trading in 2010 has, compared to the year 2009, increased slightly, which is also due to price increases for primary energy sources. On average, the base load wholesale price at the EPEX Spot was at 44.49 euro/MWh (Phelix-Day-Base) and the peak load price was at 50.95 euro/MWh (Phelix-Day-Peak). The sale of EEG electricity at the EPEX Spot, which began in early 2010, has had a dampening effect on prices, so that prices increased only slightly on the whole. The increased coupling of markets, begun in late 2010, will bring about a further price alignment with neighbouring countries.

In the futures market, the price level for the base load remained nearly constant in 2009 and 2010. The Phelix Future annual averages for the following year were 49.90 euro/MWh for the base load and 64.48 euro/MWh (peak) for the peak load. This amounts to a decrease by seven percent compared to the year 2009. In the first six months of 2011, however, the average price level of futures for the following year (2012) increased to 56.39 euro/MWh for the base load and 69.29 euro/MWh for the peak load. This increase is at least partially due to bottlenecks in energy generation associated with the exit from nuclear power. This means that peak load prices are once again at 2009 levels, while base load prices are more than 15 percent above 2009 prices.

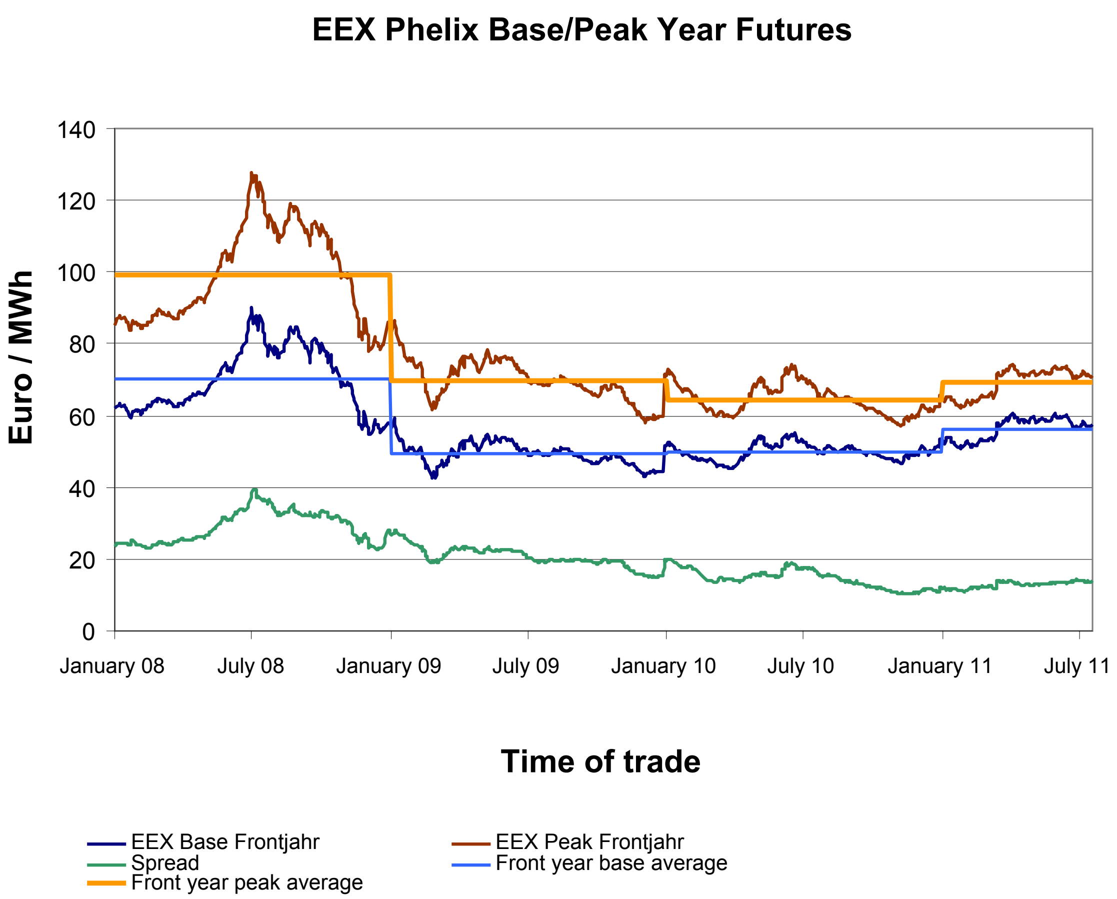


Figure 16: Price development EEX Phelix-Base/Peak-Year Futures for the consecutive year between 1 January 2008 to 30 June 2011

One trend that can be seen both in the futures and in the spot market is a significant decrease in price volatility (fluctuations of prices) compared to previous years. While the Phelix-Day-Base ranged from 153.17 euro/MWh in 2007 to 109.97 euro/MWh in 2008 and 121.93 euro/MWh in 2009, in 2010 this range fell to 56.12 euro/MWh. The decreasing level of price fluctuations is at least partially due to the coupling of the German and the Nordic markets, which has been in place since late 2009, as well as due to the sale of electricity under the EEG on the EPEX Spot since 1 January 2010.

Lower price volatility tends to have a positive effect on planning certainty and can lead to lower risk premiums. At the same time, it can lead to a lesser willingness to invest in conventional, and in particular, in flexible power plants. The expected expansion of power generation based on intermittent energy sources will likely lead to a reduction in the number of operating hours of flexible, conventional power plants in the future. Against this background, investments in power plants could become unprofitable, since the shorter the operating time of the power plant, the more difficult it is as a rule to generate a positive contribution to profits and to recoup investment costs. Given this fact it is questionable whether or not the markets will continue to provide sufficient signals for the investment in conventional power plants in the future. This has triggered a discussion on the possible introduction of so-called capacity markets, a topic that the Bundesnetzagentur and the Bundeskartellamt will continue to explore.

Market coupling of European wholesale electricity markets

On 9 November 2010, with the coupling of electricity markets in north-western Europe (Germany, France, the Benelux countries and Scandinavia), a milestone was reached in the integration of electricity markets in the European Union. Since then, the national electricity spot markets of nine countries have been linked at the wholesale level. The expected positive effects in terms of market results have come about. In particular, there has been a price harmonisation between the countries. As a result, during approximately 70 percent of hours, there is now price parity in Germany, France and the Benelux countries. Prior to the introduction of market coupling, this was the case for less than one percent of the hours of a year. This constitutes a remarkable leap in efficiency.

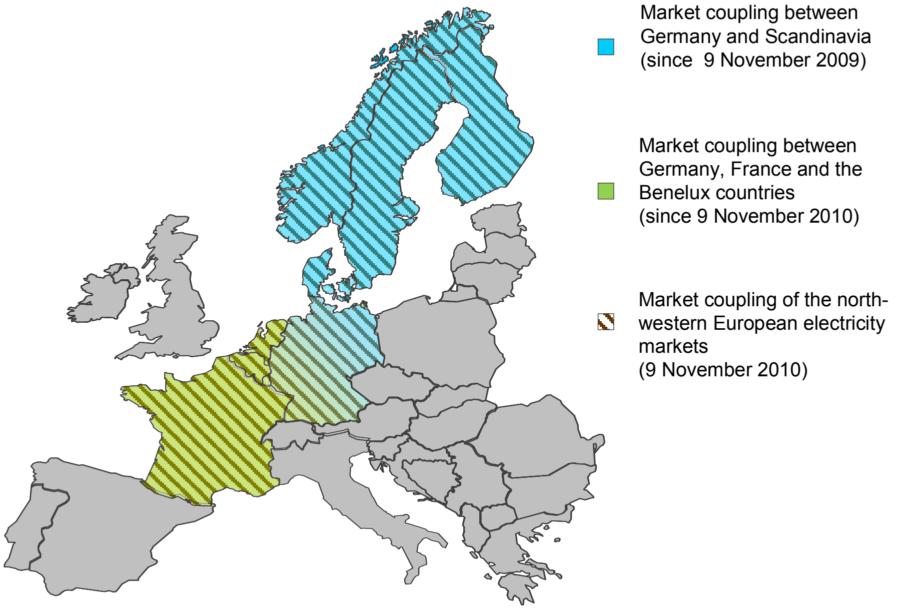


Figure 17: North-western European market coupling

In the past, electricity trading on the exchange and the utilisation of cross-border transmission capacities were two completely separate activities. The national wholesale electricity markets were operated independently of each other and did not take cross-border trading possibilities into consideration. Market coupling links these two areas by taking cross-border transmission capacities into consideration already when the results on the exchanges are being determined.

Prior to that, electricity traders who wished to sell electricity that was produced in Germany to France, for example, were required not only to complete an electricity transaction, but also to purchase the corresponding transmission capacities. This separation introduced significant disadvantages, one of these being that in the case of congestion in cross-border power lines, it was possible that not enough transmission capacity could be purchased. Another disadvantage was that if capacities were purchased, that they could ultimately become worthless because of the low electricity price in the target country. Market coupling prevents such inefficiencies. Cross-border electricity trade only comes about when the required transmission capacities are available and when the transaction makes sense economically.

Ultimately, market coupling leads to a harmonisation of prices on the electricity exchanges. One of the reasons for the price differences is that until now, cross-border transmission capacities have hardly played a role in determining prices. Trading potentials went untapped, and the significant price differences reflected an inefficient utilisation of transmission capacities.

Following the successful start of market coupling between Germany and the Nordic market in November of 2009, in 2010 the focus turned to the introduction of market coupling in the region of Central-Western Europe (CWE)[18]. A particular challenge lay in coordinating the

[18] Benelux countries, Germany and France.

market coupling between Germany and the Nordic market and the new market coupling of the CWE region. Substantial coordination of both projects was necessary to ensure a smooth start, as the operative organisation of each electricity interconnection is still very different. For Germany in particular, which is at the intersection of both projects, this coordination was especially important.

Market coupling will, in the coming years as well, continue to be an important topic for the work of the Bundesnetzagentur. At European level, ACER, the Agency for the Coordination of Energy Regulators, has transferred to the Bundesnetzagentur the project management for the implementation of pan-European market coupling through 2014. The Bundesnetzagentur is committed to gradually expanding the north-western European market coupling to other regions or markets.

The next objective is an integration of the Swiss market into the electricity interconnection. Additionally, the Bundesnetzagentur supports efforts to coordinate the operative organisation of both market coupling regions in CWE and in northern Europe. This would mean, on the one hand, an additional increase in efficiency; on the other hand it would also simplify future expansion to other countries and regions in Europe.

Retail

Development of electricity prices for household customers

Since the introduction of regulation, no general decrease in overall electricity prices for household customers has been achieved, despite the significant drop in network tariffs. However, regulation has led to an improvement in household customers' ability to switch contract or supplier. This gives at least customers who are willing to switch their contract or supplier the possibility of reducing their electricity prices.

In addition to reducing network charges and creating market conditions that enable effective and undistorted competition, the success achieved by regulation can be seen in the establishment of necessary electricity price transparency. For example, the breakdown of the electricity price has been changed so that costs which in the early days of regulation were contained in excessive network tariffs now have been cut back or fall under the price components they originate in.

This fact must always be borne in mind when considering the developments of individual price components provided in the following. For example, the sevenfold increase of the price component “supply” is in part a result of the fact that cross-subsidisation of the supply sector by excessive network tariffs is no longer permitted. Therefore, this does not necessarily represent an improper price increase, but instead can be seen as the result of a more appropriate composition of electricity prices.

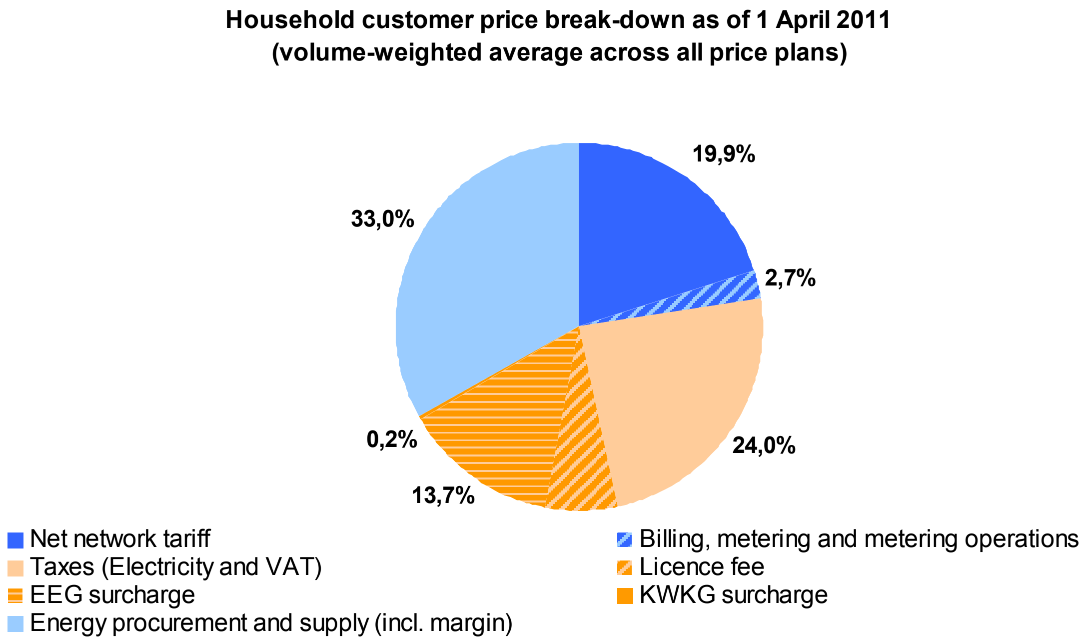


Figure 18: Division of the retail price for household customers as of 1 April 2011

Compared to 2010, the portion of network tariffs (including billing, metering and metering operations) has fallen by 2.2 percent, the portion of taxes by 0.7 percent and the portion of “energy procurement and supply” by 1.6 percent. In contrast, the portion of fees (concession fees as well as EEG and KWKG surcharges) has increased by 4.5 percent.

Electricity prices for household customers have increased by 8.7 percent (2.0 ct/kWh) between 2010 and 2011. This constitutes the highest increase in a consecutive series of price increases since the beginning of regulation.

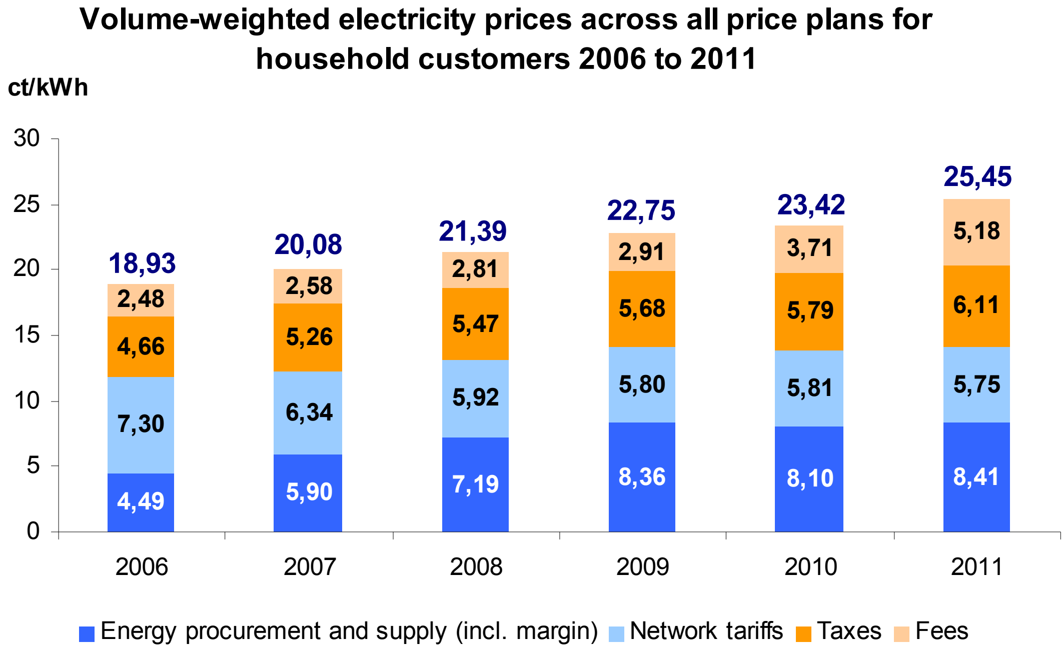


Figure 19: Volume-weighted electricity prices across all price plans for household customers 2006 to 2011

At first glance, the reason for this seems to be clear. From 2010 to 2011, fees (concession fees, KWKG and EEG surcharges) have increased by 1.5 ct/kWh, an increase which can almost exclusively be traced back to the 1.5 ct/kWh increase of the EEG surcharge. While this significant increase of the EEG surcharge can be attributed to numerous factors, the main portion of the increase is due to the increased total sum of remuneration payments to system operators. Whereas the forecast for the year 2010 was at 12.7bn euro, in 2011 it is at 17.1bn euro. Of the 17.1bn euro, approximately 8 billion are accounted for by remuneration for solar power systems. Another factor in the increase of the EEG surcharge in 2011 is the low forecast of the EEG surcharge in the year 2010. The resulting 1.1bn euro deficit in the EEG account leads to an increase of the EEG surcharge by 0.3 ct/kWh in 2011.

Concession fees have increased by approximately 0.1 ct/kWh, while the KWKG surcharge has fallen by proximately 0.1 ct/kWh. In contrast to the increase in fees, network tariffs (including billing, metering and metering operations) have only seen minimal changes from 2010 to 2011 (-0.06 ct/kWh); increases in the price component “energy and supply” (+0.31 ct/kWh) as well as in taxes (+0.32 ct/kWh) are only part of the reason for the significant price increase.

The parts of the total electricity price set by the government are taxes and fees. This means that at first glance the government components, which have increased by a total of 1.8 ct/kWh (company price components increased overall by +0.3 ct/kWh), are predominantly responsible for the increase in electricity prices between 2010 and 2011. With regard to the electricity price increase from 2010 to 2011, however, it is important to bear in mind that the company price component, made up of the price components electricity procurement, supply and network tariffs, could have fallen significantly in particular because of the lower wholesale prices in 2009 and 2010 for the year of delivery 2011 on the futures market, which is particularly relevant for household customers. There was an overall expectation of a reduction in the price component “energy and supply”, a reduction which would have at least partially compensated for the price increase as a result of the higher EEG surcharge. The monitoring survey, however, shows an increase in the price component “energy and supply” by 0.3 ct/kWh, bringing this price component above the level of 2009, i.e. above the price level of the year in which particularly high wholesale prices from the year 2008 had to be, to a large extent, passed on to consumers.

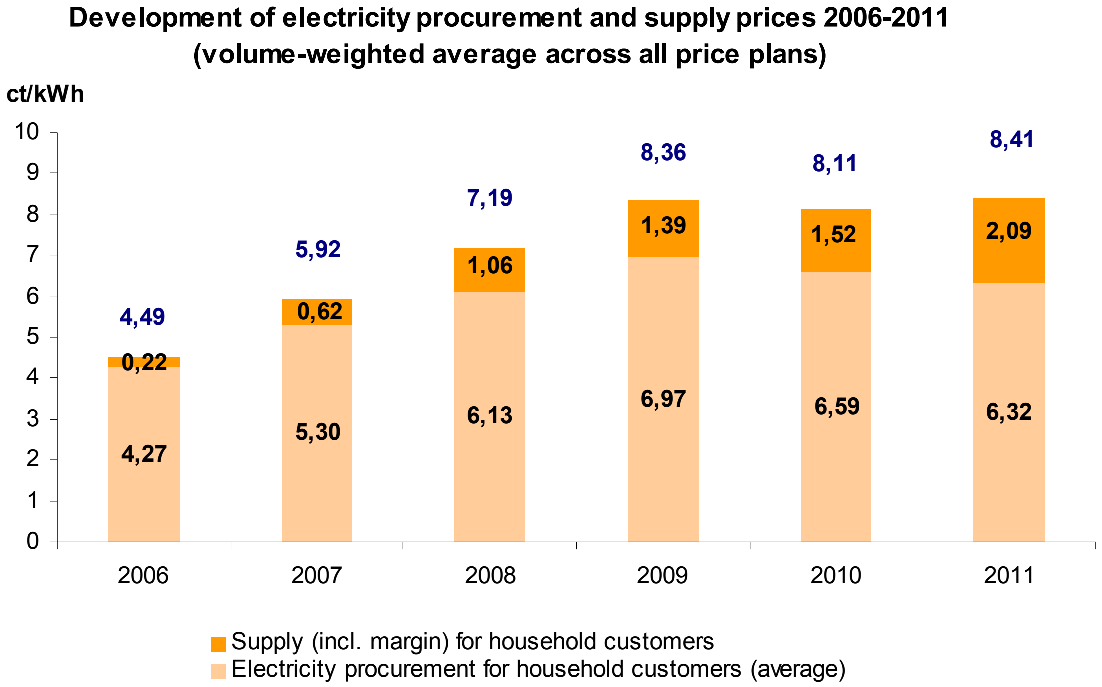


Figure 20: Development of energy and supply 2006 to 2011 in ct/kWh[19]

The network tariffs for household customers, as a result of the drop in the price component “billing, metering and metering operations”, have fallen by 0.06 ct/kWh. Thus, as in previous years, the network tariffs again had a price reducing effect on the overall price of electricity.

Development of network tariffs for household customers 2006 to 2011

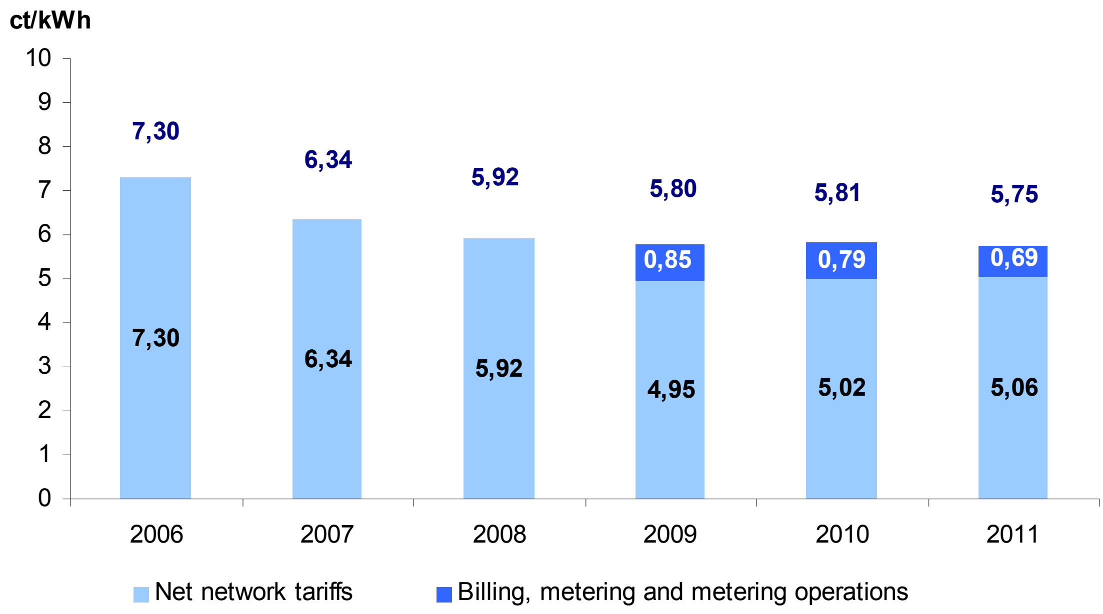


Figure 21: Development of network tariffs incl. billing, metering and metering operations 2006 to 2011 in ct/kWh[20]

According to figures collected for the 2011 monitoring survey, there are also changes in the area of electricity procurement in comparison to previous report periods. Particularly striking in this context are the changes in the procurement strategy of energy suppliers with regard to the time of procurement. As is evident from the following table, approximately 85 percent of the required electricity amounts for the years of delivery 2009 and 2010 were procured in the two calendar years prior to the year of delivery. For 2011, the energy suppliers surveyed stated that they ordered only approximately 70 percent of the their electricity volumes in the two calendar years before delivery, and that they had already ordered one quarter of the required electricity volumes for 2011 in the third calendar year before the year of delivery 2011, i.e. in 2008.

Year of delivery	Year of transaction	Average base in €/MWh	Average peak in €/MWh	Procurement (B70/P30) in €/MWh	Average distribution of volumes purchased in precent	Procurement according to monitoring survey in ct/kWh	Proportional procurement (over 24 months) in ct/kWh
2011	**2011**	51.44[21]	56.90[22]	53.08	5[23]	**6.32**	**5.78**
	2010	49.90	64.48	54.27	30		

[19] For the period 2006 to 2008, no figures were collected to determine electricity procurement; for this reason, the price component electricity procurement from 2006 to 2008 was calculated using information for 2009 (which ends up being virtually identical with a proportional procurement over 24 months).

[20] For the period 2006 to 2008, the price component "accounting, metering and metering operations" was not surveyed separately and is therefore included in the net network charges.

[21] Preliminary value based on averages of Spot market, Phelix-Day from 1 January to 10 October 2011.

[22] Preliminary value based on averages of Spot market, Phelix-Day from 1 January to 10 October 2011.

[23] Forecast value, no company information.

	2009	53.90	78.43	61.26	40		
	2008	70.04	100.43	79.16	25		
2010	**2010**	44.49	50.95	46.43	5	**6.59**	**6.67**
	2009	49.20	69.84	55.39	40		
	2008	69.15	98.97	78.10	45		
	2007	54.92	79.52	62.30	10		
2009	**2009**	38.85	46.83	41.24	5	**6.97**	**7.08**
	2008	70.33	99.40	79.05	50		
	2007	55.40	79.46	62.62	35		
	2006	54.61	79.29	62.02	10		

Table 3:Electricity procurement for household customers 2009 to 2011 according to survey of electricity wholesalers and suppliers

Taking into account various assumptions, it was possible to synthetically calculate preliminary procurement costs for the year of delivery 2011. The following calculations pertain exclusively to the simulation of wholesale prices, i.e. they are purely product prices. Ancillary procurement costs for structuring measures, adjustments for higher or lower volumes or services are not shown here. The calculation of “procurement costs according to monitoring” makes use of the volumes and other figures provided by energy suppliers at the time of the conclusion of the business transaction. The so-called “proportional procurement costs” depict an electricity procurement for retail customers that, irrespective of the volumes specified by the energy suppliers, remains constant over a period of 24 months. Both simulation calculations of electricity procurement are based on average wholesale prices for electricity on the EEX. In practice, however, bilateral electricity procurement also plays an important role, in addition to on-exchange procurement. Both model calculations are based the assumption of an identical, approximate distribution, derived from company figures, of procured electricity volumes in base and peak products according to a distribution key of 70 percent base and 30 percent peak products.

Electricity procurement was calculated using figures provided by the electricity suppliers taking part in the 2010 and 2011 monitoring surveys, as well as using wholesale prices for electricity on the EEX. For this purpose, the electricity suppliers provided data as to the volumes of electricity they purchased, and in which years they purchased these volumes on the wholesale electricity markets for the year of delivery to households. In addition, data was compiled pertaining to the approximate distribution of procured volumes by base and peak loads.

As a starting point for the calculation, the three arithmetic averages of the previous year's wholesale prices for base and peak products for the respective year of delivery were used, as well as the arithmetic average of the spot market for the year of delivery. With the help of the figures provided by suppliers on base load and peak load distribution – on average a ratio of 70 percent (base load) to 30 percent (peak load) – and based on average wholesale prices for electricity, the respective procurement price of one year for the respective year of delivery was calculated. In the next step, information regarding how much electricity the electricity suppliers procured in which year on wholesale markets was used to calculate an approximate percentage distribution of the volumes purchased in the procurement years for the respective year of delivery. Based on this percentage distribution and the previously calculated respective procurement prices of one year for the respective year of delivery, average approximate values for the procurement costs for the years of delivery 2009, 2010 and 2011 could be calculated. In the table above, the procurement prices calculated according to the detailed assumptions are contrasted with a constant, proportional procurement over the course of 24 months.

The procurement costs that follow from the assumptions are 6.32 ct/kWh for 2011, whereas a proportional procurement over 24 months in the year 2011 would have amounted to procurement costs of 5.78 ct/kWh. It is notable that, given the assumptions listed, the proportional procurement for the year 2011 would have resulted in more favourable procurement conditions than is the case based on the figures provided by the companies.

It is important to note that only average values are shown in the calculation of electricity procurement. The resulting information does therefore not allow for any conclusions about individual companies. The average value of 6.59 ct/kWh for 2010, as shown above, thus corresponds to a range from 4.5 to nine ct/kWh, depending on the company. The average value of 6.32 ct/kWh for electricity procurement in 2011 corresponds to a range of five to ten ct/kWh. Furthermore, in terms of the various procurement strategies, it is important to bear in mind that short-term procurement strategies usually contain greater risk. Although the long-term procurement strategy practised by most energy suppliers is less advantageous with falling exchange prices, in the event of rapidly climbing prices it does reduce the risk of considerable retail price increases.

If the simulated procurement costs are placed in relation to the price component "energy procurement and supply", as reported by the energy suppliers, the amount accounted for by supply and ancillary procurement costs is 2.09 ct/kWh. Between 2009 and 2011, this amount has increased by 0.7 ct/kWh, or 50 percent. While between 2006 and 2009 the increases in this price component could, among other things, be traced back to the fact that as of 2006, regulatory conditions meant that supply could no longer be cross-subsidised through excessive network tariffs, and therefore had to increase significantly to cover the actual supply costs incurred, this scenario does not explain the increases between 2009 and 2011.

Irrespective of the restrictions made in the calculation of the price component "supply", it is evident that the sum of these two price components "network tariffs" and "supply" has increased since the introduction of regulation. Since network tariffs decreased for household customers between 2006 and 2011, the total increase for the two price components of 4.8 percent indicates that the supply component has experienced a disproportionate rise – taking into consideration the assumptions made in the calculation. If the increase in the supply component were due solely to the end of cross-subsidisation by the network tariffs, it would have at most increased by the amount by which the tariffs decreased. It is also important to note that the regulation of network tariffs has led to the reduction of inefficiencies in network operations that did not cross-subsidise supply.

Development of network tariffs and supply for household customers 2006 to 2011 (volume-weighted average across all price plans)

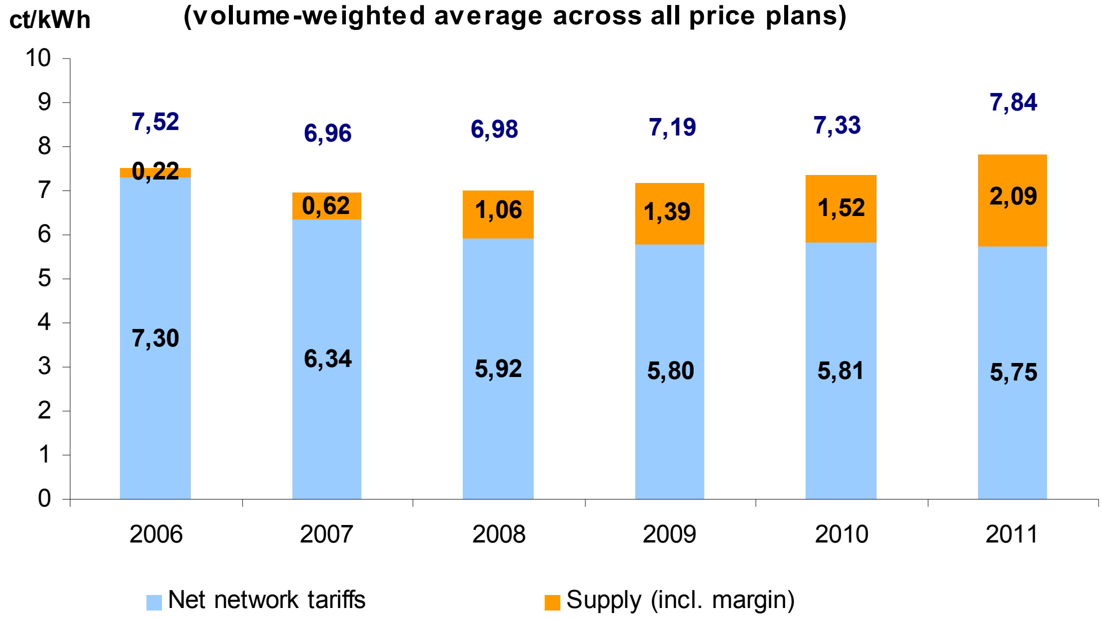


Figure 22: Development of network tariffs and supply 2006 to 2011 in ct/kWh

The graph also shows that the reduction in network tariffs for household customers was not able to reach consumers, as the reduction in network tariffs was fully compensated by an increase in the supply component. Network regulation was therefore able to slow the increase of overall electricity prices, but has not yet led to a general decrease in prices for household customers.

On the whole, a detailed study of the development of electricity prices from 2010 to 2011 clearly shows that the cause of the price increase is not as obvious as it might appear at first glance. While a main reason for the price increase can be found in the government fees and taxes, the company share for energy and supply is also responsible for a portion of the price increase, since instead of the expected decrease, this component increase by 0.3 ct/kWh on average.

However, the average value method that has thus far been used for all participating energy suppliers and their various price plans does not take into consideration the companies' individual pricing policies and the respective tariffs that they offer. As all suppliers have the same non-discriminatory access to customers and therefore the same costs for network tariffs, taxes and fees, the difference between the various price plan categories is to be found in the "energy and supply" price component. This is the component in which electricity suppliers compete with each other, which is why it is calculated quite differently according to each company and price plan. Depending on the price plan, for example, there is a notable difference in the average level of the "energy and supply" price component.

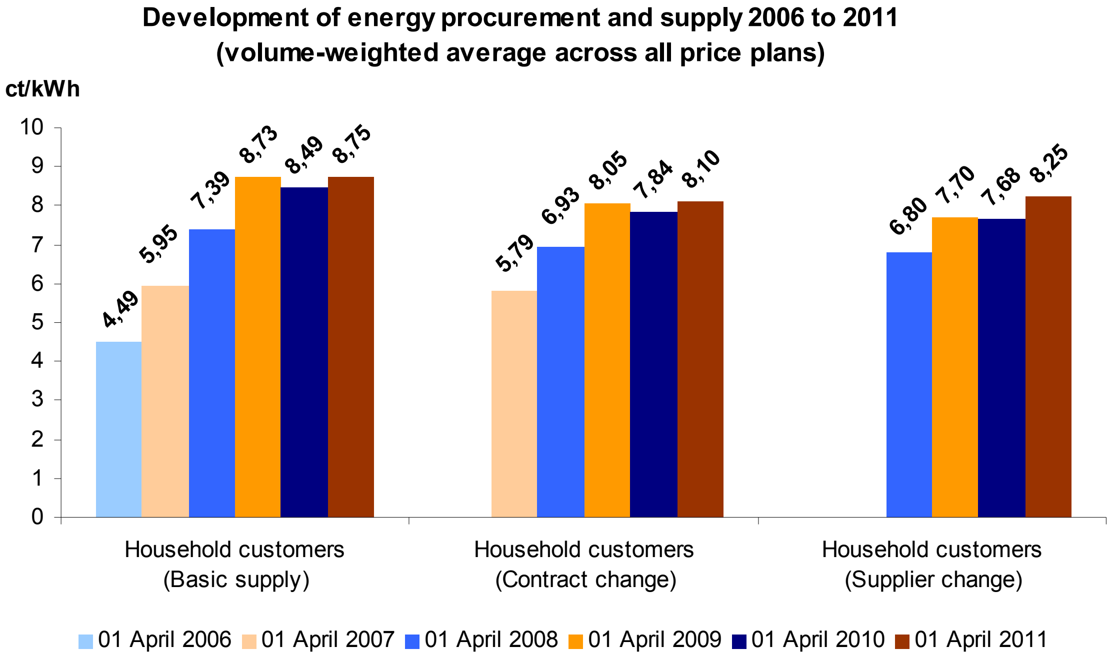


Figure 23: Development energy procurement and supply 2006 to 2011 in ct/kWh

A comparison of the three price plan categories makes it clear that there are price differences between the average values of the price plans. Basic supply continues to be the most expensive form of electricity supply.[24] It is more price-effective for consumers to make use of their possibility to change and select another tariff from their standard, or default, supplier or a tariff from another electricity supplier.

[24] There are legitimate reasons why a basic supply plan is more expensive than a price plan resulting from switching contract or supplier. Basic suppliers need to include higher costs for reminders, collection and bad debts. However, there are higher marketing, advertising and acquisition costs for price plans involving a change of supplier, since they as a rule cannot benefit from a pre-existing customer base.

Comparisons within the price plan categories illustrate the individual pricing policies of the suppliers. For example, the range for "energy and supply" in the basic supply price plan is between around six and 16 ct/kWh, depending on supply region. To illustrate this, the following graph depicts the revenue from the supply business (including margin) of basic suppliers per average household customer (3,500 kWh annual consumption) in the basic supply price plan as of 1 April 2011.

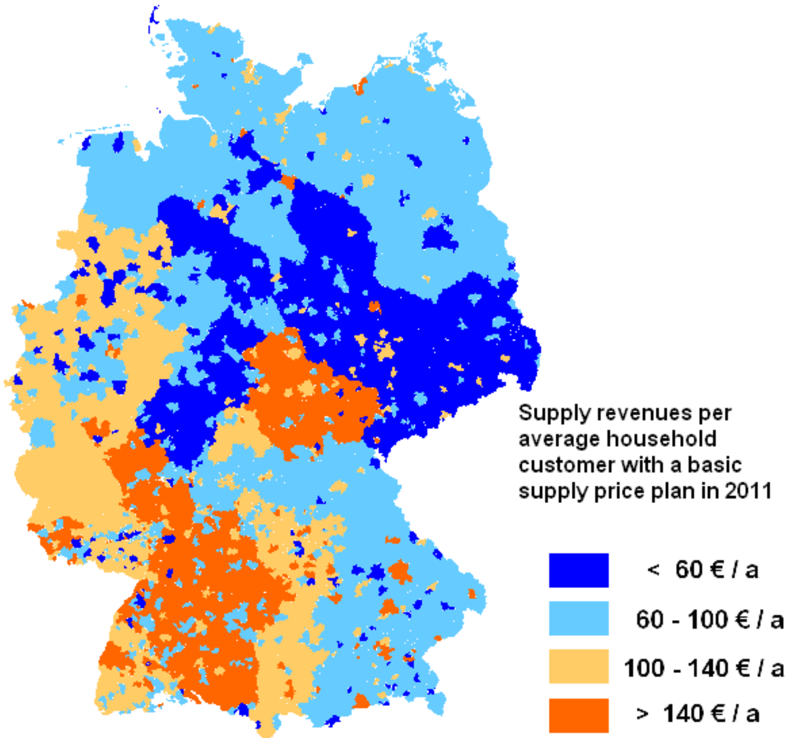


Figure 24: Annual revenue from supply per average household customer in basic supply price plan as of 1 April 2011, by network area

The graph is based on the assumption that all of the basic suppliers depicted had to pay the average price of 6.32 ct/kWh that was calculated in the monitoring survey for their electricity procurement. On average, that puts the revenue from the supply business (including margin) per household customer with a basic supply price plan at approximately 85 euro per year.

If one looks at all price plans and all household customers, the average revenue from supply (including margin) per household customer is at approximately 73 euro per year. Given that approximately 200 price plans pay a one-time bonus for switching of an average of 48 euro per year, projected onto the approximately 2,200 price plans examined, this amounts to an average bonus payment of some four euro per year. If this average bonus payment is deducted from the average revenue from supply, this results in an average revenue from the supply business (including margin) of approximately 69 euro per year per household customer. In 2009, by contrast, the average revenue from supply (including margin) per household customer amounted to around 49 euro per year.

The following chart shows that there is a tendency towards lower procurement and supply costs in the north-eastern part of Germany than in the south-western part of the country. In contrast, however, the network tariffs in the north-east are significantly higher than in the south-west of Germany. On the whole, these two price components balance each other out, so that overall electricity prices in both regions are at similar levels.

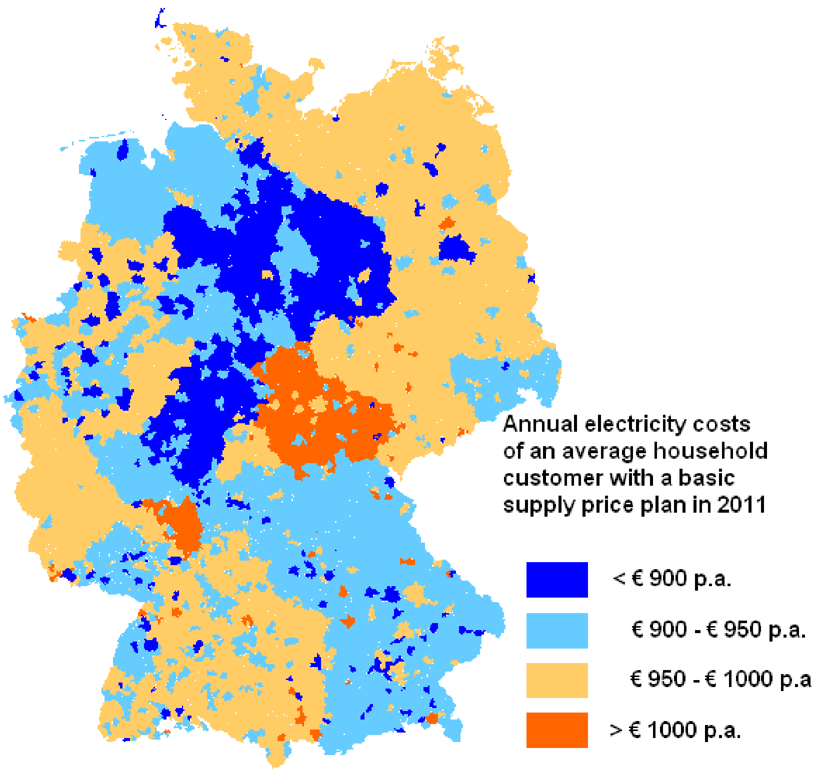


Figure 25: Depiction of the electricity price level of household customers with a basic supplier 2011

Nevertheless, for household customers receiving electricity from basic suppliers, there can be regional price differences far in excess of 100 euro per year. As a result, depending on where they live, there can be significant differences in the price that household customers with a basic supply price plan pay for their electricity. It is clear that these price discrepancies cannot exclusively be traced back to structural differences between the supply regions, i.e. to differences in the amounts of network tariffs or concession fees, but rather that they also depend on how the respective basic supplier makes use of its dominant position and the unwillingness of household customers to switch suppliers.

Another finding for the year 2011 is that the average price level of special contract plans by basic suppliers (contract switch) is, for the first time, lower than the price level of the special contracts offered by competitors (switching suppliers). The reason for this can be seen when the offers for switching supplier are divided into price plans offered by basic suppliers and price plans offered by new suppliers. On average, basic suppliers provide electricity in other regions at virtually the same price as in their own basic supply region, supplied through a special contract plan (contract switch). This tendency has been evident over the past few years. The average tariff for a supplier switch, however, was lower in past years, as new suppliers offered cheaper price plans, thereby lowering the price level of this price plan category.

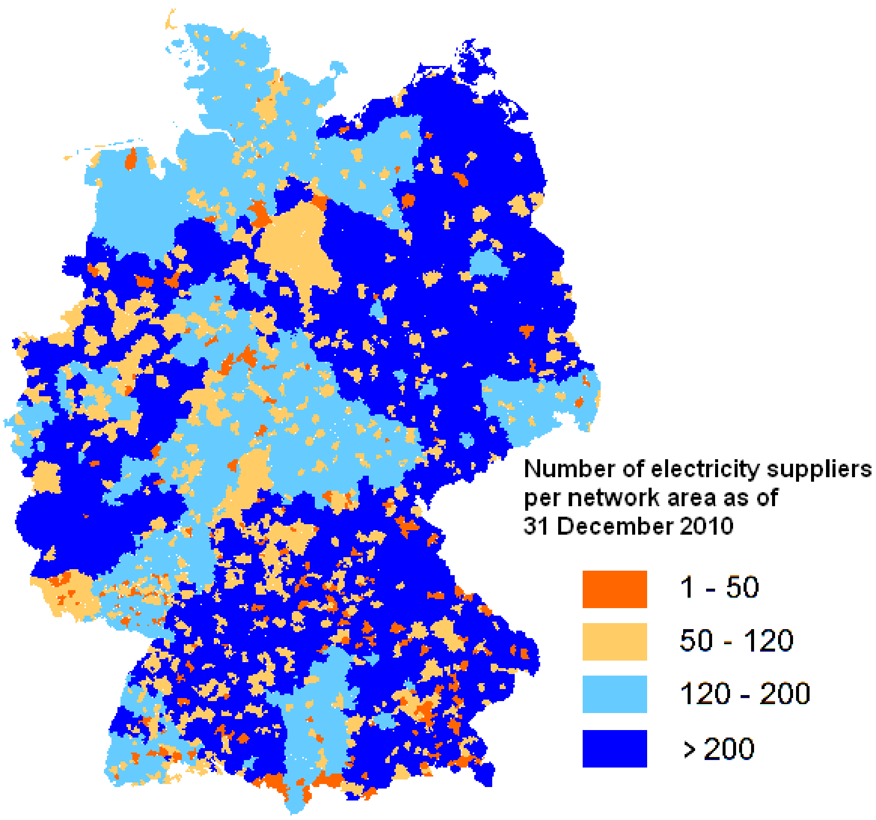
In 2011, for the first time, there are new suppliers offering electricity supply, in volume-weighted average values, at more expensive terms than the suppliers providing basic supply in other network areas. This is explained by the significant price increases instituted by such new suppliers who had already succeeded in acquiring high numbers of customers. If this small number of new suppliers are taken out of the average value calculation of price plans of all new suppliers, the price level is significantly lower than that of basic suppliers, with a price component for "energy procurement and supply" of 7.4 ct/kWh. This means that the absolute majority of new suppliers still offers electricity at significantly lower prices than do established basic suppliers.

An additional finding is that price plans offered by suppliers that are the basic supplier in other network areas provide household customers with hardly any savings potential in comparison with the less expensive price plans of the regionally-based basic supplier. New suppliers, however, who are not basic suppliers at the start of their activities and who must pursue a strategy of new customer acquisition, usually offer electricity at significantly lower prices. It is therefore the offers of new suppliers, for the most part, that continue to lead to price-based competition for household customers.

However, the current price increases by new suppliers that already succeeded in acquiring a large customer base are also an indication that consumers who have already switched to a less expensive supplier have no guarantee that the new supplier will, in subsequent years of delivery, continue to offer low prices. One aspect that must be kept in mind in this context is that the one-time bonus payment ends after the first year of delivery, often rendering the price advantage from switching contract or supplier obsolete. That is why the Bundesnetzagentur advises all consumers to constantly stay informed about their own electricity prices, as well as about alternative offers, and to switch as needed.

Development of competition in the household customer segment[25]

The reluctance of household customers to switch suppliers despite the price discrepancies which exist with respect to competitors means that existing potential for price reduction remains untapped in many places. The unwillingness to switch cannot be attributed to the lack of alternatives: There is a large number of suppliers throughout Germany which has continued to grow in 2010, the year under review. On 31 December 2010, there was an average of 147 suppliers per network area, weighted by the number of inhabitants. Among other things, this high number of competitors shows that the necessary conditions exist for effective and undistorted competition in the segment of electricity end customers.



[25] This chapter relates to the entire household customer segment. Thus the statements here do not reflect the distinction made in antitrust law between the markets for standard profile customers (basic supply customers, special contract customers, heat current customers).

Figure 26: Number of electricity suppliers per network area on 31 December 2010

However, given the number of suppliers, it must be questioned whether suppliers that serve (virtually) no customers in other network areas actually help boost competition in these network areas. Although many suppliers offer their price plans in more and more network areas, these offers often provide customers with insignificant financial benefits. Due to the accompanying low level of new customer acquisition, many suppliers would not be able to establish themselves in other network areas if they were not already functioning as basic suppliers in their own basic supply areas.

In addition, the high number of suppliers across all network areas does not mean that most of these electricity suppliers are active throughout the country. On the contrary, the majority of electricity suppliers, in particular those in the household segment, restrict their activity to the supply of individual regions. For example, 90 percent of all basic suppliers conduct no notable service to household customers in other network areas. Furthermore, over 70 percent of all suppliers are active in a maximum of ten network areas. In this respect there are significant differences between new suppliers and established basic suppliers. Dividing these suppliers into two groups, it becomes clear that, while new suppliers are active in an average of 200 network areas, established basic suppliers are active only in an average of 31 network areas.

In 2010, the year under review, a total of approximately 2.7 million household customers switched suppliers and 2.2 million changed contracts. This means that in 2010, more customers decided to change supplier than decided to switch to a new price plan with their existing supplier. However, accumulating all household customers who have left their basic supply plan since 1998 shows that in total, more customers have opted for a contract change with their basic supplier than have opted to switch to a new supplier. Based on this customer behaviour, the regional dominance of the basic suppliers remains in place, with an 84.5 percent share of the supply of household customers.
This is also evident from examining the contract structure of household customers. While the share of household customers who were served by a supplier other than the basic supplier increased by 4.8 percent between 2007 and 2008, this share only increased by 2.6 percent between 2008 and 2009 and only 1.7 percent between 2009 and 2010. This means that in 2010, the year under review, only an average of 15.5 percent of electricity delivered to household customers was delivered by suppliers other than the basic supplier.

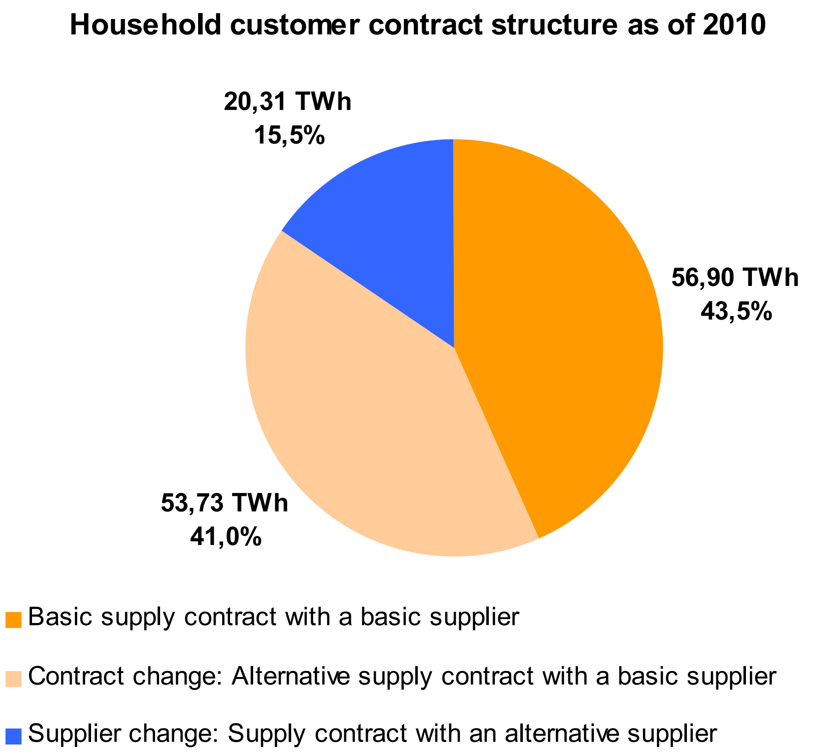


Figure 27: Household customers' change of contract and change of supplier, as of 2010

Since from a competitive standpoint, not only the change of supplier but also the change of contract are relevant factors, it can be seen as positive that as of 2010, of the 84.5 percent of household customers supplied by basic suppliers, nearly half have a price plan other than the standard price plan. The relatively high proportion of contract changes compared to supplier changes is an indication that a majority of suppliers are focussed on retaining existing customers rather than on acquiring new customers. Irrespective of the number of suppliers active in a network area, a regional dominance by the respective basic supplier remains in place. Only in isolated cases, therefore, do we see a share of less than 70 percent of basic suppliers among all household customers served within a respective network area.

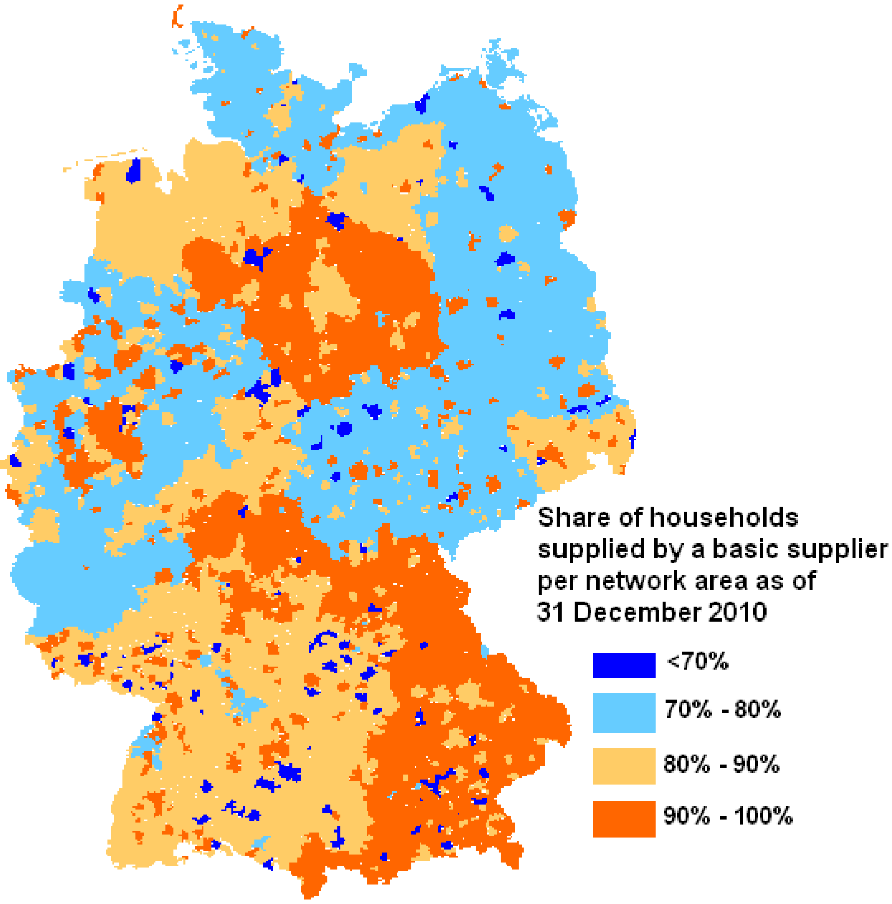


Figure 28: Percentage of household customers served by basic suppliers per network area on 31 December 2010

Approximately 90 percent of basic suppliers do not provide significant service to household customers in other network areas; competition was therefore not boosted until new suppliers began to emerge. Around 73 percent of household customers who have changed their supplier since 1998 were served by new suppliers in 2010. Established basic suppliers, by contrast, were only able to secure 27 percent of all household customers who changed suppliers.

As a result, because of the less expensive price plans and the high level of new customer acquisition, it was particularly the factor of new suppliers which led to a boost in competition in the household customer segment. However, the term new suppliers includes all suppliers that are not active as basic suppliers and/or became active in the household customer segment of the German electricity markets. This means that subsidiaries or newly founded brands of the established energy utilities are also counted as new suppliers. The loss of customers or market shares by the established utilities can thus be compensated through other supply channels. It can be observed, through calculations using the dominance method[26], that as of 2010, approx. 45 percent of the household customers who changed suppliers were acquired by the four largest utilities. [27] The share of service provided to household customers is lower in the supplier's own basic supply network than in other network areas.

[26] See glossary for dominance method (available in German only).
[27] The "size" of the energy utility was determined based on the total amount of electricity supplied to household customers.

2010			
Supply to household customers	**Projected[28] supply volumes in TWh**	**Volumes supplied by the four big companies in TWh**	**Percentage of projected total**
In network areas where they provide basic supply	120.6	52.7	43.7
Outside network areas where they provide basic supply	22.2	9.9	44.6
Total	**142.8**	**62.6**	**43.8**

Table 4: Shares of the big four electricity suppliers in supply to household customers in 2010

Although the four big electricity suppliers were able to acquire, directly or through other supply channels, 45 percent of the customers who have so far changed, this could not compensate for the substantial customer losses that they experienced in the network areas where they provide basic supply. The shares of the four largest electricity suppliers in serving household customers at national level therefore continue to decrease. While in 2008 the share of the four largest electricity suppliers in the overall household customer segment was still at 50.1 percent, and in 2009 at 48.2 percent, in 2010, the year under review, this share is at 43.8 percent; this amounts to a drop of 6.3 percent within two years.

This positive trend at national level, however, does not change the continuously dominant position of local basic suppliers at regional level. Local basic suppliers' regional dominance could end, however, if household customers make much greater use of the possibility of switching supplier and change from their basic supplier to an alternative supplier.

In recent years, the number of household customers switching supplier has, with the exception of a stagnation in 2009, steadily and significantly increased. In 2010, the number of household customers changing suppliers increased by around half a million. The number of supplier changes that took place without moving house is, after a slight decrease in 2009, once again on the increase in 2010. The number of supplier changes that took place upon moving house, however, is stagnating. Therefore, given that nearly four million households move each year,[29] it can be assumed that roughly every tenth household that moves now chooses a different energy supplier than the local basic supplier to supply its electricity.

In 2010, the number of changes by other end customers increased significantly, by around 92,000, to nearly 255,000 changes. On the whole, the number of supplier changes for 2010 has for the first time reached the mark of three million.

[28] As the electricity suppliers included in the monitoring activities for 2011 account for 92 percent of the market, coverage of 100 percent was assumed in determining the shares of the four big suppliers.
[29] Federal Statistical Office; Demographic trends in 2009: 5.1m moves beyond federal state borders, of those, 3.6m domestically.

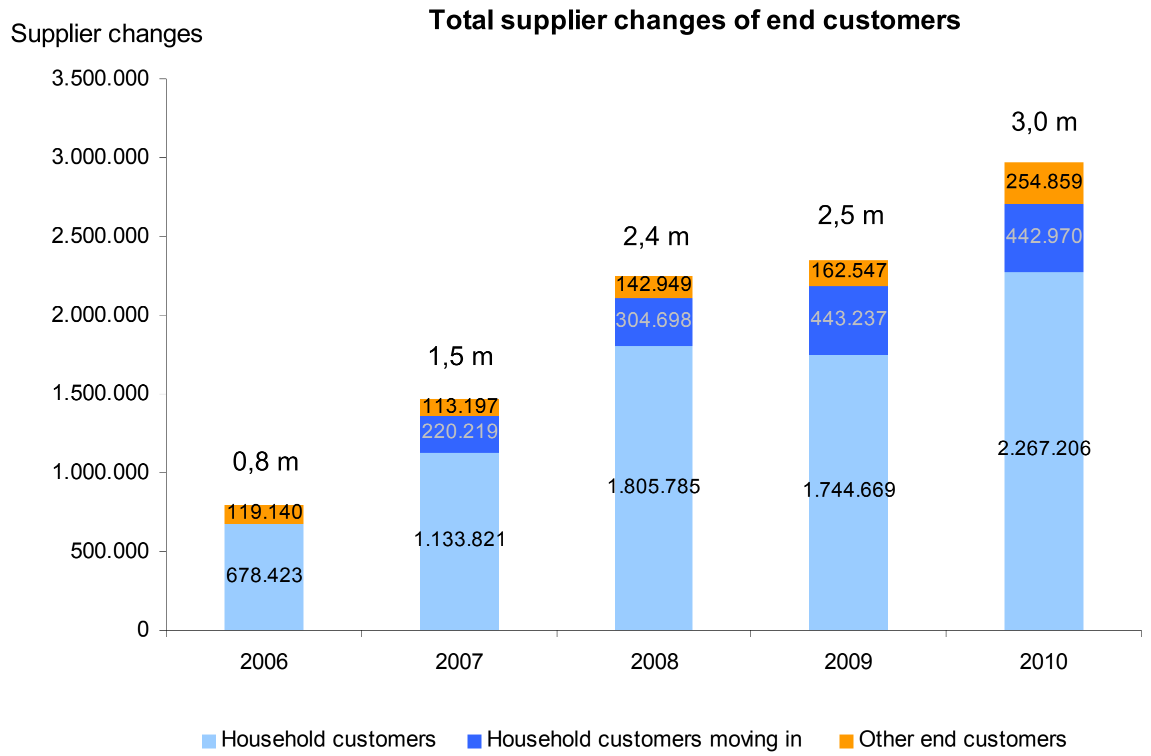


Figure 29: Number of end consumers switching supplier (2006 to 2010)

The significant increase in the number of supplier changes is also confirmed in the rate of household customers switching supplier. The numbers-based rate of supplier change increased by 1.3 percent (to 6.0 percent), while the volume-based rate of supplier switch increased by 1.5 percent (to 6.8 percent). In 2010, as in previous years, the volume-based rate of supplier switch was slightly higher than the numbers-based rate. This is an indication that high-consumption households are more prone to switching suppliers than households with lower consumption. The average consumption of household customers who switched their supplier is approximately 3,400 kWh. By comparison, household customers served by basic suppliers consume only approx. 2,600 kWh on average. Household customers who changed their contract with a basic supplier have the highest consumption, with an average of 3,800 kWh.

Category	2010 Supplier change in TWh	Percentage of take volume	2010 Supplier change in numbers	Percentage of number of final consumers
Household customers choosing a supplier other than the basic supplier without moving house	8.01	5.7	2,267,206	5.0
Household customers choosing a supplier other than the standard supplier directly on moving house	1.50	1.1	442,970	1.0
Total	**9.51**	**6.8**	**2,710,176**	**6.0**

Table 5: Household customers switching supplier in 2010 according to data from DSOs

The main conclusion with regard to household customers switching supplier remains a trend that has been evident since 2008. It was noticed then that some ten percent of supplier switches were made by customers who had already changed supplier in preceding years. In line with this finding is that from 2008 on, it was not the case that more and more customers were switching for the first time, but rather that increasing numbers of customers who had already switched were now switching again. Household customers were not switching from their basic supplier to alternative providers, but rather customers were beginning to switch between new suppliers. As a result, the number of supplier changes was considerably greater than the number of households switching from basic supplier to alternative supplier. To envision this trend, note that in 2009, for up to 49 percent of household customers that had switched suppliers, this was not the first time. This share has even increased to some 75 percent in 2010. Consequently, the share of those end customers that migrate from the former monopolistic supplier to an alternative one has been declining since 2008.

In conclusion, besides the positive developments relating to the continuing increase in the numbers of household customers switching provider and supplier, it must be pointed out that the established basic suppliers mainly pursue a strategy of tying in their customers in the areas in which they are the basic supplier, and are less interested in acquiring new customers in other network areas. Likewise, many consumers opt to remain with their original supplier instead of switching, despite existing potentials for price reduction. It is increasingly difficult for new competitors to gain new customers who are not already in a consumer group that is willing to change. While in 2010, the number of supplier changes increased in comparison to 2009, only 25 percent of these supplier changes contributed to a de-concentration of the former regional monopoly areas. If household customers do decide to switch suppliers, only few utilities benefit. Around 45 percent of all customers who switch are acquired by one of Germany's four biggest suppliers. In terms of the whole of the country, while the shares of the four largest electricity suppliers have been significantly reduced, at regional level, despite the growing number of suppliers and the rising numbers of supplier changes, the local dominance of the basic suppliers remains in place.

Gas market

Summary

Gas imports stabilised at the 2009 level and amounted to 1384 TWh (2009: 1.373 TWh). Over the same period exports increased from 418 TWh in 2009 to 463 TWh in 2010. The production of domestic gas continues to decline, amounting in 2010 to some 12.63bn m^3 (2009: 14.36bn m^3). Statistical range has increased from 10.5 to almost 11 years as a result of a reassessment of gas reserves.

A further step was taken in 2010 to enhance market transparency with the revised Gas Network Access Ordinance (GasNZV). The TSOs were required to reduce the number of market areas for L-Gas to one and for H-Gas to two by 1 April 2011. The former market areas Thyssengas H-Gas and Thyssengas L-Gas along with the market area OGE L-Gas were integrated in the NetConnect Germany market area. Thus for the first time, Germany had a dual-quality market area. Technically, the L-gas and the H-gas networks must continue to be operated separately. This is no longer of any relevance for shippers and traders, since all the entry and exit points and hence all customers are incorporated in one large balancing area. In this way, shippers and traders can supply their customers with gas, regardless of the quality. Previously, this had not been possible.

In connection with the report evaluating the portfolio balancing and the system balancing energy arrangements presented by the Bundesnetzagentur, this has proved a boost for competition, as had been hoped. Besides the markedly improved competition for household customers, liquidity in the trading markets has also increased. The dynamic generated by the portfolio and system balancing energy regime makes further progress likely. The total costs of this balancing energy system are in suitable relation with the expenditure required. Admittedly, the balancing energy levy rose considerably in the last few contribution periods, but it has been possible to stop or even reverse this trend in some market areas.

With regard to security of supply, reference must be made to both the investments in gas pipelines (Nord Stream, OPAL and NEL) and to new EU legislation. The new gas pipeline projects will add further to securing supplies of natural gas in Germany. The Nord Stream pipeline and the Ostsee-Pipeline-Anbindungsleitung (OPAL) with an annual transport capacity of some 35bn m^3, will become operational in the end of 2011. In 2012, the Norddeutsche Erdgasleitung (NEL) with an annual capacity of around 20bn m^3 is scheduled to be completed, carrying gas westwards from Nord Stream. EU Regulation No 994/2010 was adopted in response to the supply disruption between the Russian Gazprom and the Ukrainian Naftogaz in early 2009, which also affected eastern parts of the European Union. The EU Regulation aims to avert any gaps in gas supply in future.

The maximum useable volume of working gas in underground storage is 20.97bn m_N^3. Of this, 9.19bn m_N^3 is accounted for by cavern storage and 11.78bn m_N^3 by pore storage. Reflecting the structure of the German gas market, the largest part of the storage facilities, by far, is designed for the storage of H-gas. As of 31 December 2010, there was a great increase in the volume of freely bookable working gas in comparison to previous years. The main reason for this is most likely that several customers of the major storage facility operators made heavy use of the possibility to return booked capacity.

The national wholesale gas market has continued to experience dynamic development, encouraged by combining the H-gas and the L-gas market areas. The volume of trading on the exchange grew steadily, recording an increase of 216 percent in 2010 over 2009. One of the main reasons for this was the additional procurement on the exchange of system balancing energy by the two balancing zone operators, NetConnect Germany and Gaspool. All the same, the 47.110 GWh traded on the EEX for spot and futures products was less than three percent of OTC trading. Parallel to this, there was strong growth in OTC trading, so that the volume traded on the EEX hardly changed in percentage terms.

There was a strong recovery in the German economy in 2010. As a result, higher gas consumption was recorded, accompanied by a rise in prices. The price of natural gas on the wholesale market jumped on average by almost 30 percent in 2010, compared to 2009. It took until summer, however, until the trading prices had reached the level of the border (import) prices. The border price is currently moving upwards as a result of the continued frequent indexing to the (rising) oil prices and was two to three euro above the spot market prices at the end of April.

The retail market is still experiencing dynamic development. This is particularly true in respect of changes of supplier and the number of suppliers in the individual networks. Whereas household customers could not switch suppliers in 2006 on account of the lack of framework conditions, some 720,000 household customers did so in 2010. While the volume of supplier switches in 2009 grew by a modest ten percent, the volume of gas supplied doubled in 2010 from 47.18 TWh in 2009 to 110.38 TWh in 2010. With an offtake volume of 1014.49 TWh in 2010 this corresponds to a switching rate of 10.88 percent.

If the majority of household customers in 2008 could choose between one and five suppliers only, the majority in 2009 could already choose between six and ten. In 2010, most household customers had a choice of between 11 and 20 suppliers. In 36 network areas, a household customer can already choose from over 50 suppliers. This pleasing and healthy diversity indicates that the regional and supraregional gas markets in Germany are highly attractive.

As of 1 April 2011, the gas price for household customers with standard, or default, supply was 6.64 ct/kWh. The network tariffs in this consumer category stand at 1.37 ct/kWh, which amounts to a share in the total gas price of approx. 20 percent.
Following a fall in prices in 2010, the gas prices for household customers are now rising again, though they have not reached the peak prices from 2009 again yet.

Networks

Changes in the gas market area landscape

In Germany, there were still six gas market areas on 1 October 2009, three for L-gas and three for H-gas. The extent of these areas – separated according to gas quality – can be seen in the figures below.

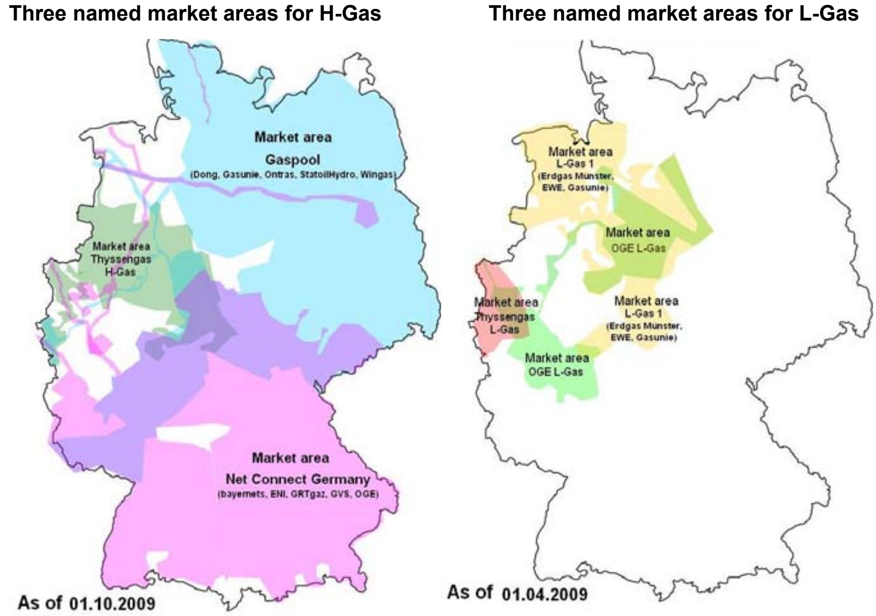


Figure 30: Market area landscape in the gas sector as of 1 October 2009.

The new Gas Network Access Ordinance (GasNZV) took effect on 9 September 2010. Under section 21(1) of this Ordinance, the transmission system operators were required to reduce the number of market areas for L-gas to one and for H-gas to two by 1 April 2011. A market area is deemed an H-gas market area when it has natural gas predominantly in H-gas quality.

The former market areas Thyssengas H-Gas and Thyssengas L-Gas along with the market area OGE L-Gas were integrated in the NetConnect Germany market area on 1 April 2011. Thus for the first time, Germany had a dual quality market area. Technically, the L-gas and the H-gas networks must continue to be operated separately. This is no longer of any relevance for shippers and traders, since all the entry and exit points and hence all customers are incorporated in one big balancing area. In this way, shippers and traders can supply their customers with gas, regardless of the quality. Previously, this had not been possible. The challenges in dealing with the technical restrictions that still exist between the different quality networks are today a matter solely for the network operators, which is why contractual amendments and supplementary framework conditions were also needed to complete consolidation. A conversion charge was also introduced. This charge is payable by shippers and traders when they supply their customers with H-gas in the L-gas area or with L-gas in the H-gas area. Further, some firm capacity was converted into interruptible (conditionally). All the same, the remaining firm capacity has much greater free useability and reach as a result of the widened market area than it had in the formerly separate areas. The figure below shows the greater extent of the NetConnect Germany market area compared to the previous figure.

Figure 31: Market area landscape in the gas sector as of 1 April 2011.

No matter whether the market area expands with one or two qualities of gas, this will always mean that earlier booking points (with a limited amount of capacity) between the former market areas lapse and are converted into so-called internal interconnection points. Here, shippers no longer determine the flow of gas with their nomination; instead, the network operators use this internal point according to gas requirements. However, use of this point of interconnection is often limited, particularly for those that can only be operated in one flow direction.

In addition, the remaining booking points reach significantly greater range, i.e. usability for shippers. All exit points in the former market area A can now be combined with all entry points in market area B. As there is congestion in the transport flows between the formerly separated networks (market areas), the volume of firm freely usable capacities at the remaining booking points is reduced due to the market area set-up.

For the 2010 survey, shippers were asked which solutions they would prefer for the capacity restrictions at the remaining booking points. The options were securing a firm capacity amount by obtaining flow commitments, or transforming firm allocated capacities – at least partially - into conditionally firm allocated capacities. For the latter, the firm nature of the capacity often depends on the forecast temperature for the following day. As a rule, a lot of gas flows through the networks when the temperature is low, thus fixing capacities. When it is warmer and, as result of the lower gas flows, the flexible use of entry points (northern or southern booking point) increases, only interruptible use is possible. However, that does not mean that the nominated transport need actually be interrupted. Additionally, a local component can increase the firm nature of these capacity products, in which, for example, the use of a southern entry point in combination with a southern exit point in a defined area is possible in principle, regardless of the forecast temperature of the previous day, on a firm basis, without the risk of interruption.

As the response options were mutually exclusive, shippers were asked to rate one option with 1 or 2, and the other with 3 or 4, with 1 being "very important" and 4 "not important". Shippers were divided into three categories in order to illustrate the results: shippers with no capacities in the 2009/10 gas year (outer blue circle), and shippers that had booked total entry and exit points amounting to less than (orange circle) or more than (inner blue circle) 1m kWh/h capacity. The size of the circles corresponds to the response combination frequency of both options.

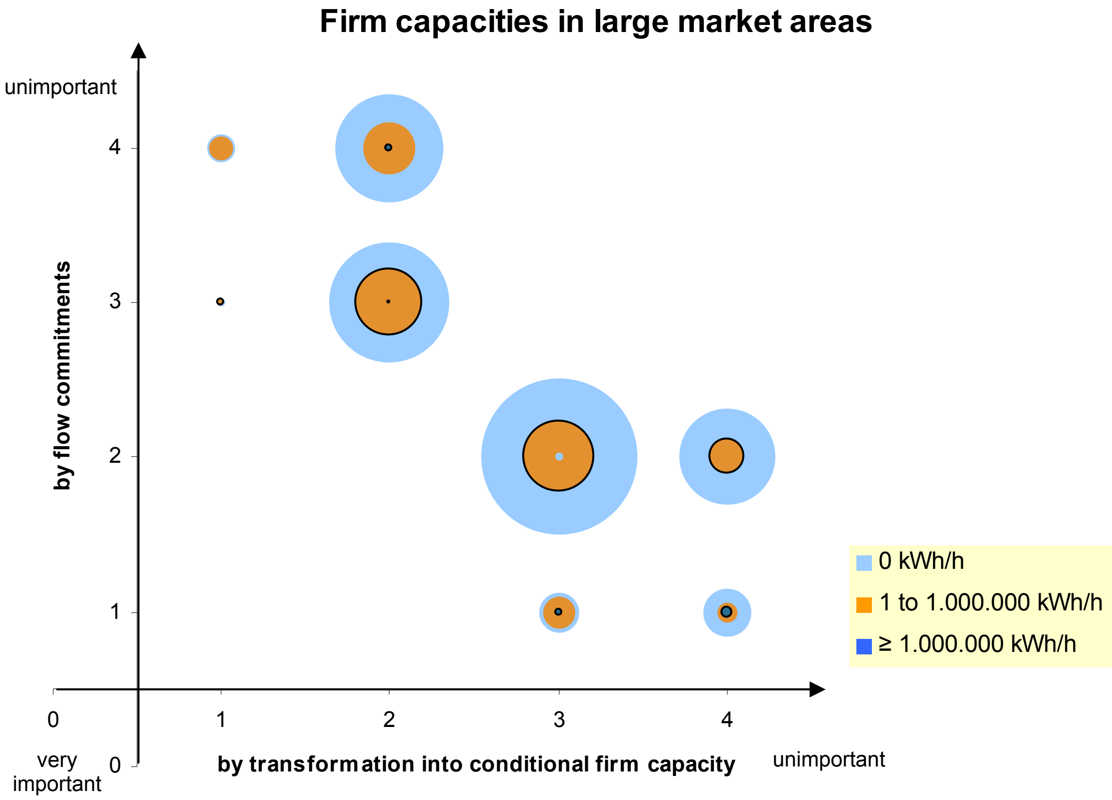


Figure 32: Shipper evaluation of the two options illustrating firm capacity in large market areas

Over 60 percent of shippers with high or missing capacity bookings, as well as wholesale customers and suppliers without capacity booking prefer the option of ensuring firm capacity amounts by obtaining flow commitments, meaning that just under 40 percent express a preference for transforming capacity into conditional firm capacity. There is an even spread (50/50) of shippers with bookings under 1m kWh/h across the two options.

Shippers with high bookings who prefer a (partial) capacity transformation into conditionally firm capacity commitments over the purchase of flow commitments should already have some experience with these capacity products – particularly with the likelihood of interruption. Furthermore, liquidity in the remaining market areas is improving all the time, meaning that alternatively procuring gas on the spot market is an option for safeguarding against potential interruption. This is accompanied by the fact that obtaining flow commitments from network operators is increasingly difficult and cost-intensive. For this reason, conditionally firm capacity committments may gain significance in future. Nevertheless, in this option the network operators should take the aforementioned local components into greater consideration, in order to further reduce interruption scenarios. This would appear to be a good way of also providing the large market areas in Germany with sufficient capacity.

The issue of which measures can illustrate or increase firm allocated capacities in large market areas - either via flow commitments, (partial) capacity transformation or efficient network extension – still needs to be investigated by the Bundesnetzagentur.

<u>Capacity on offer</u>

This year, questions on capacity allocation were asked for the first time. In order to illustrate the results, shippers (wholesale customers and suppliers) were divided into three categories: shippers with no capacities in the 2009/10 gas year, and those who had booked total entry and exit points amounting to less or more than 1m kWh/h capacity. The shippers were asked to indicate on a scale of 1 (very important) to 4 (not important), how important the individual capacity procurement aspects enquired about are to them. The results are presented below.

Short-term capacity procurement

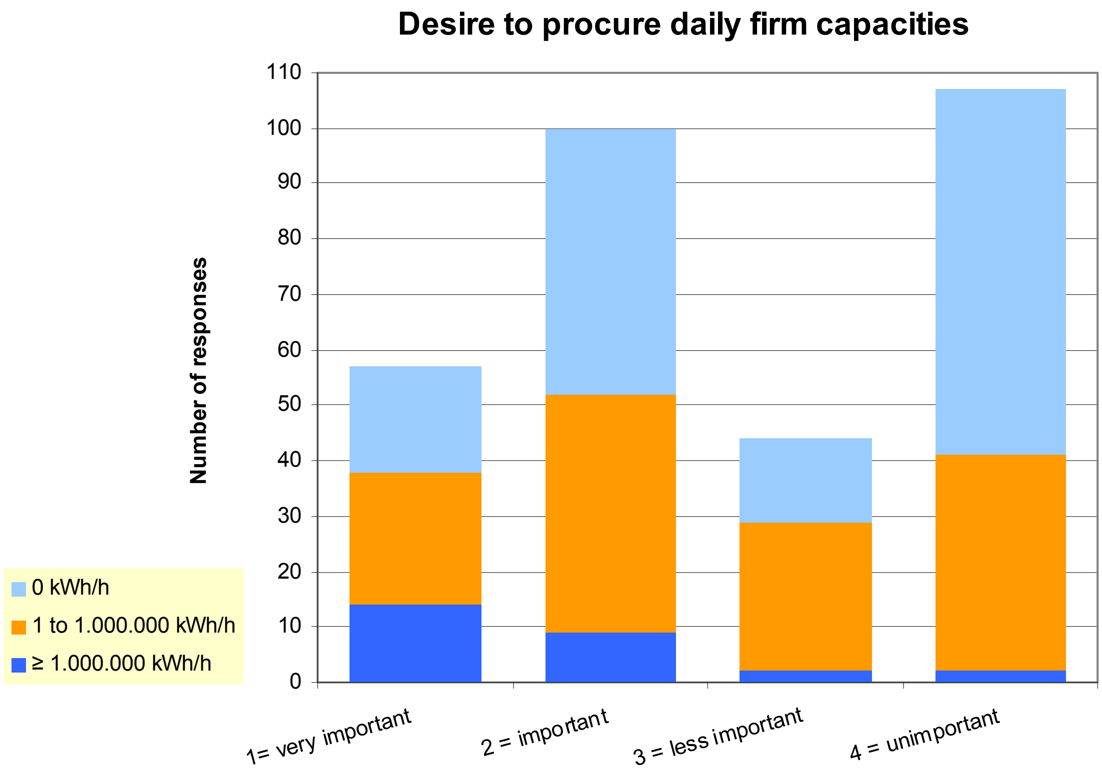


Figure 33: Survey results on importance of the possibility of daily firm capacity procurement

The overall view indicates that shippers are divided in their opinion of the importance of being able to procure daily firm day-ahead capacities. A look at the responses in the individual categories shows that the large capacity holders (over 85 percent) in particular give this point high priority. It is equally striking that almost 50 percent of shippers who made no capacity bookings consider this issue not important. Day-ahead capacities are particularly important for trade, whereas these short-term products are of no central significance to suppliers, who focus instead on quarterly and annual capacities. Many shippers (predomiantly suppliers) who made no capacity bookings at all in the 2009/10 gas year have communicated that capacity procurement is essentially not important to them, as they obtain their natural gas almost completely from preliminary suppliers via the virtual trading point. Separate capacity booking is thus not necessary.

By introducing restrictions to renomination rights by setting capacity arrangements and auctions in the gas sector (KARLA)[30], there should be more free firm capacities on a day-ahead basis in future. Due to the renomination rules, these capacities would be able to be offered by network operators from 1 April 2011 at the latest on a daily basis in both flow directions, regardless of the technical operation possibilites in the network. The results of the survey thus confirm that setting is having the right effect in terms of meeting market requirements.

Contractual congestion can be alleviated at least in part by the restrictions on renomination. Nevertheless, these existing network capacities can only be sold at auction after the initial nomination time for the long-term capacity products (eg annual, quarterly or monthly capacities). This is currently 2 pm on the previous day. The auction on day-ahead capacities

[30] Ref: BK7-10-001.

(D-1) should thus start at 3.30 pm in accordance with the TSOs' concept[31]. If successful, shippers receive the capacities following the evaluation of the auction, planned for 4.45 pm.

Shippers were thus asked in the Monitoring survey whether they preferred early or late initial nomination and the early or late procurement of day-ahead capacities that comes with this. As the response options were mutually exclusive, shippers were asked to rate one option with 1 or 2, and the other with 3 or 4, with 1 being "very important" and 4 "not important". The size of the circles corresponds to the response combination frequency of both options.

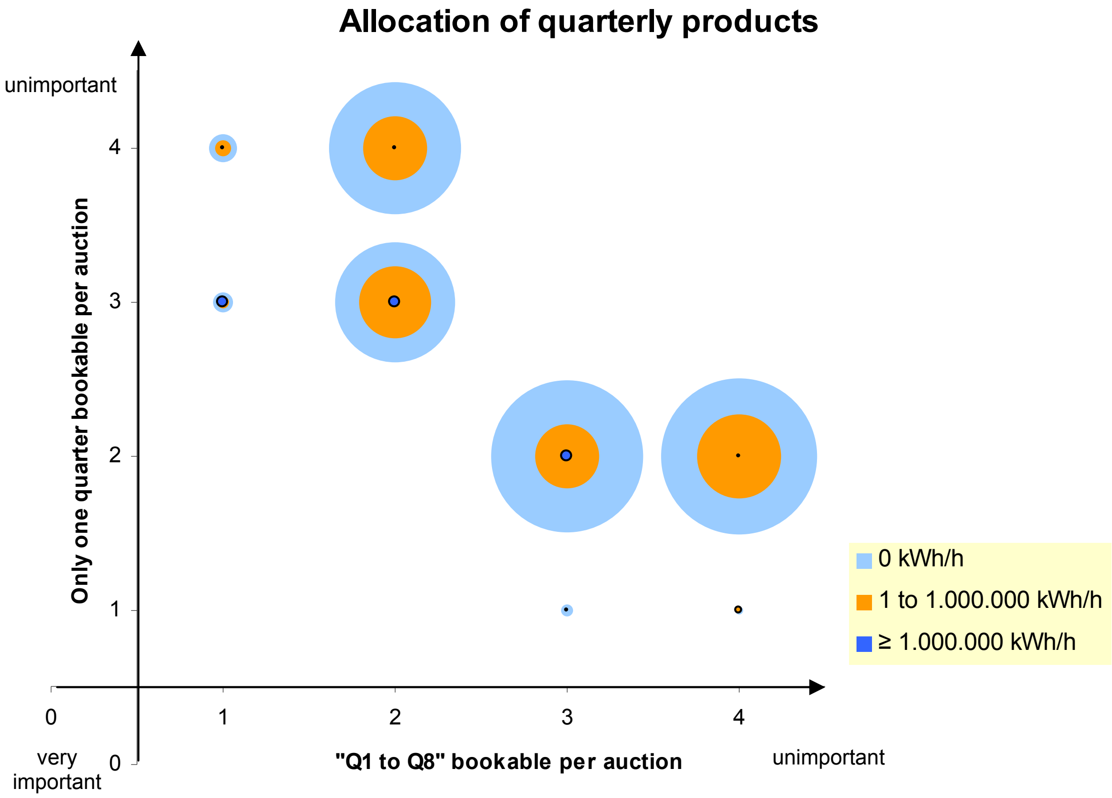


Figure 34: Survey results on timing of daily capacity procurement

While shippers with large bookings or no bookings at all found the current nomination time more important than an earlier start to the day-ahead auction and thus earlier allocation of capacity (68 percent), shippers with bookings under 1m kWh/h are virtually indifferent in this respect.

31 Primary capacity platform concept 5.0, as of 17 May 2011.

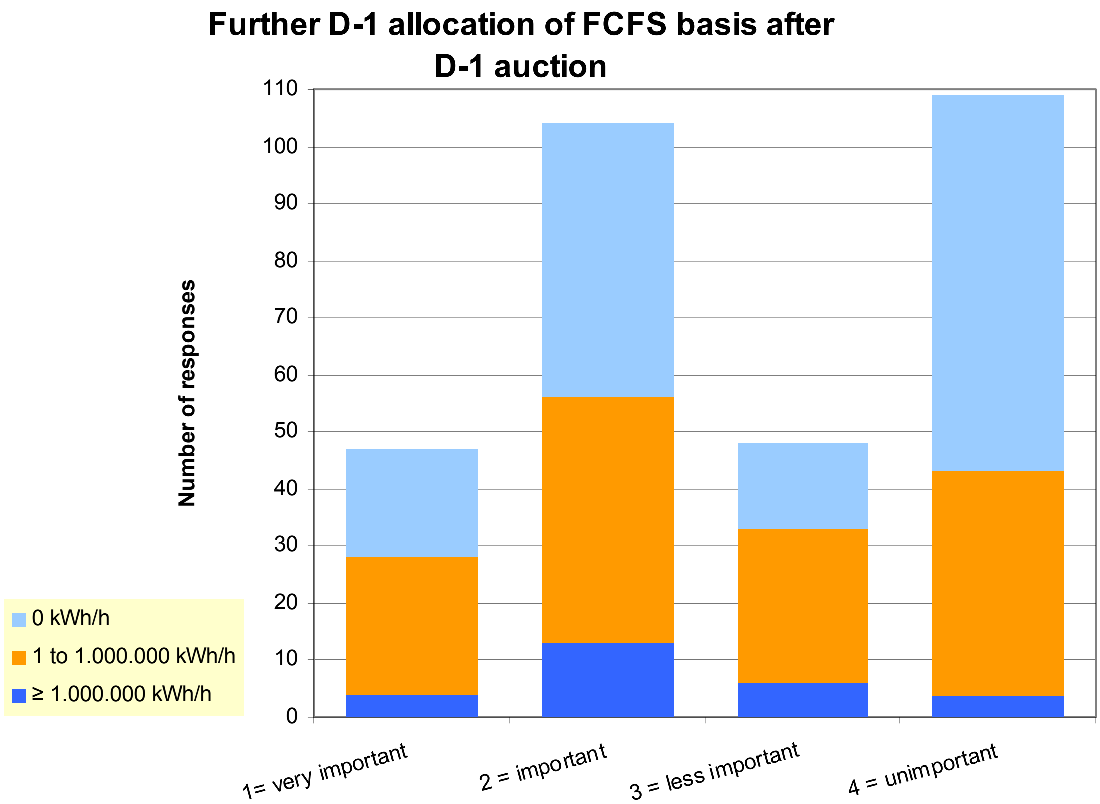


Figure 35: Survey results of how important the necessity is for further allocation of D-1 capacities on a first-come first-served basis after the D-1 auction

As a result of the low level restriction of renomination rights, the selling of daily firm day-ahead capacity products is ensured. Furthermore, all additional capacities not yet sold will also be considered in the capacity offered in the daily auction. As long as demand is lower than supply, in other words, that unsold capacities are available following the day-ahead auction, there is the question of whether and if so, how and when these capacities were to be sold. To this end, transport customers were asked how important they find the option of obtaining firm day-ahead capacities on a first-come first-served basis after the day-ahead auction.

Of the total responses submitted, 51 percent of shippers do not consider additional procurement of day-ahead capacities to be important, while 49 percent answered this question with very important or important. It is worth noting here that particularly within the group of shippers with bookings of 1m kWh/h or more, additional capacity procurement on a first-come first-served basis following the auction is considered important or very important (63 percent).

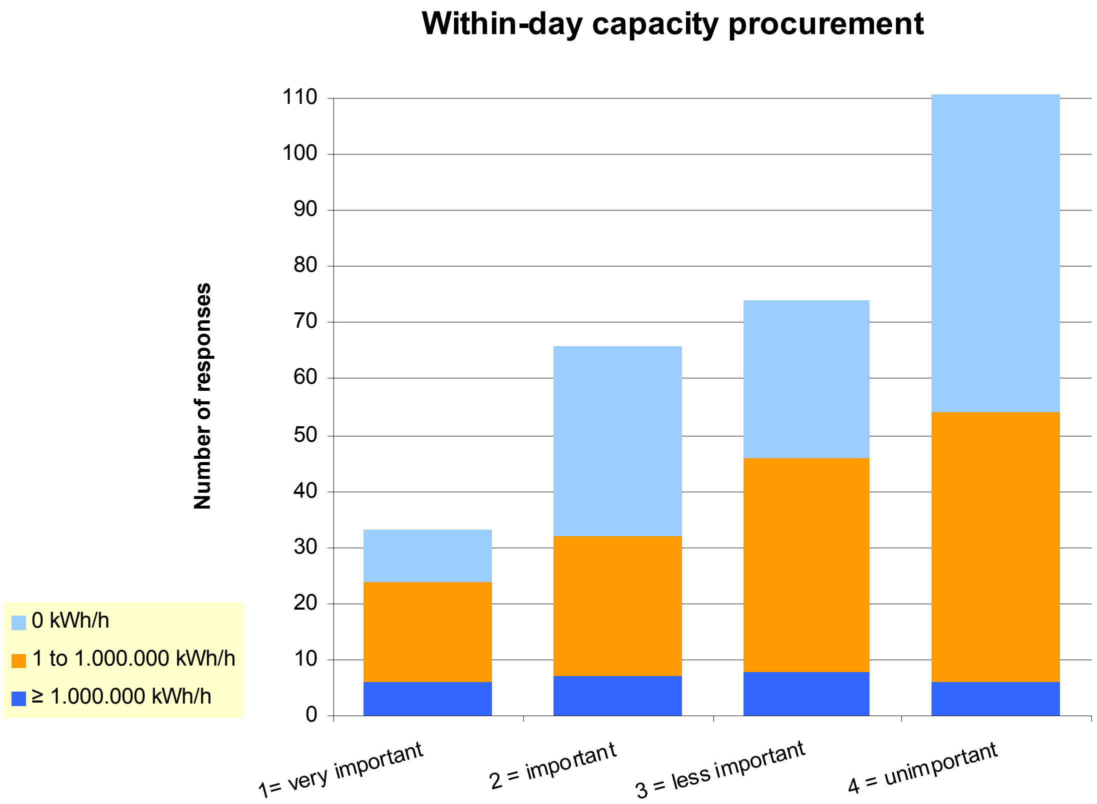


Figure 36: Survey results on importance of the possibility of daily firm within-day capacity procurement

Similarly, shippers were asked for their opinion on within-day capacities. Procuring within-day capacities was viewed as less important or not important in 70 percent of responses submitted.

What is striking here is that shippers with large bookings consider the option of obtaining within-day capacities as important and not important in equal measure.

If day-ahead capacities are continued to be allocated on a first-come first-served basis after the auction, this would most likely lead to a reduced offer of within-day capacities the following day. Shippers with large bookings do not seem to see this risk, however. On the contrary, both additional allocation options are considered either important or not important.

Generally speaking, a trend can be recognised in which the more capacities a shipper has booked, the greater importance he places on the possibility of short-term procurement of firm capacities. The reason for this may be that other shippers either have not yet made any bookings and also have no intention of doing so in the near future, or that as a result of only partially optimising their purchasing decisions, they currently see few economic advantages for them in short-term procurement. This is accompanied by the fact that the group of shippers with large capacity bookings consists primarily of dealers for whom procurement of short-term products is considerably more important than it is for suppliers who tend to fall into the categories with smaller bookings.

Longterm capacity procurement

In order to gain a more comprehensive picture, questions were asked regarding the long-term allocation of capacities, as well as that of short-term capacity products.

As part of the KARLA gas determinations, in terms of capacity allocation for the next two years (Y1 and Y2), two different options for product structuring were consulted[32]. Option A provided only for quarterly products (a total of eight) for the next two years Y1 and Y2). Option B focused on two annual products. Following evaluation of the comments, a majority emerged in favour of option A, which is the option used by the TSOs at the start of the auction process. In this year's survey, shippers were asked again if they wished to obtain capacities for the next two years (Y1 + Y2) individually as annual products.

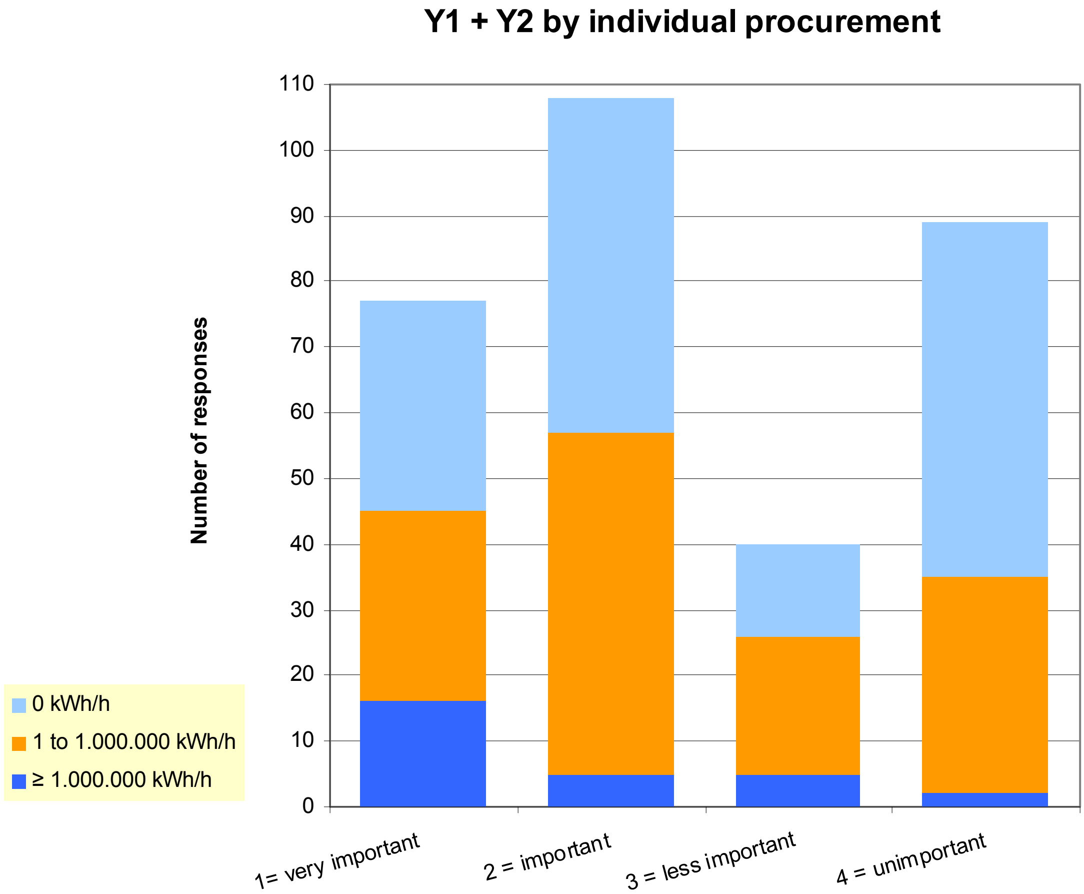


Figure 37: Survey results regarding importance of individual procurement of annual capacities for the next two years Y1 + Y2

In particular shippers with large bookings rated the procurement of annual capacities as contiguous annual products as very important or important (75 percent of all responses submitted in this category). The ratings from shippers with medium-sized bookings were not as strong here, yet they were nevertheless clearly positive with 60 percent.

Shippers were also asked whether they wished to book individual quarters at short notice at each auction date, without the option of obtaining additional later quarters at the same time, or whether they preferred the alternative, namely procuring several consecutive quarterly capacities (Q1 to Q8) at the same time, which includes the risk that no capacities can be offered for individual quarters at the next quarterly auctions (Q2 to Q8, Q3 to Q8 and Q4 to Q8).

As the response options were mutually exclusive, shippers were asked to rate one option with 1 or 2, and the other with 3 or 4, with 1 being "very important" and 4 "not important". The size of the circles corresponds to the response combination frequency of both options.

[32] Primary capacity platform concept 3.0, as of 15.10.10.

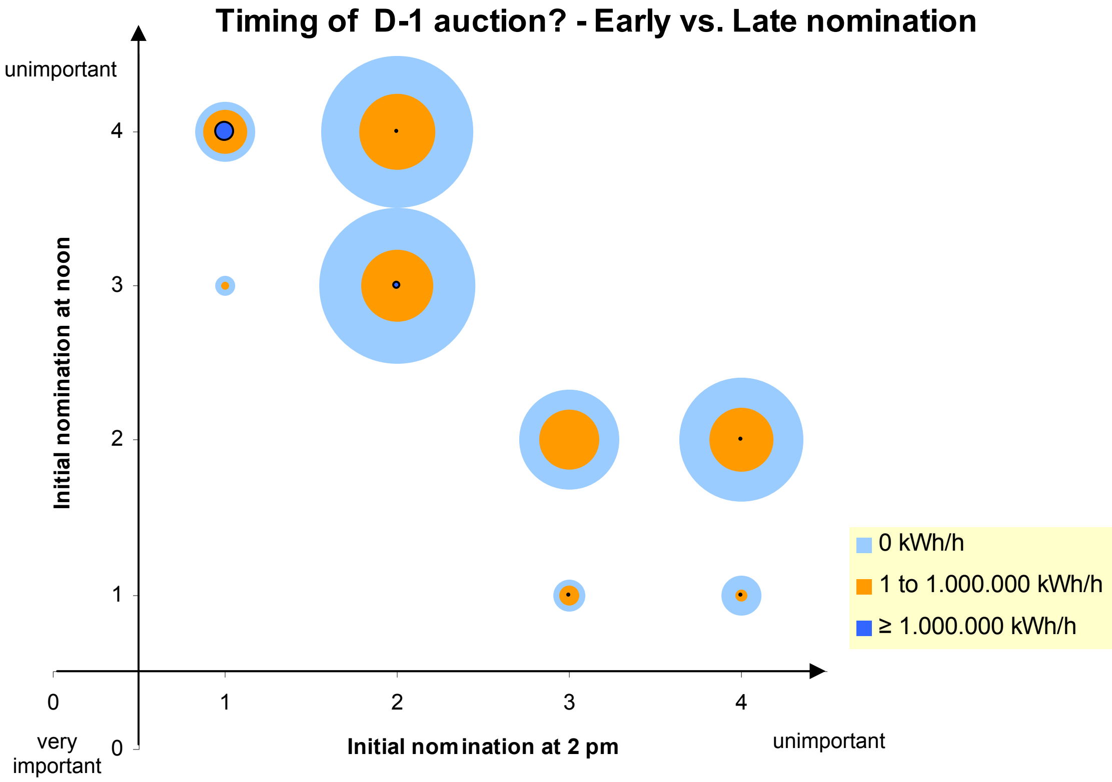


Figure 38: Survey results regarding allocation of quarterly products

Overall, the responses were evenly split across both options. One half preferred the option of individual quarterly products, while the other half expressed a preference for being able to procure several consecutive quarters on the same auction date.

A closer analysis of the responses from shippers with large bookings shows that, in connection with the previous question, a majority of those who rated the individual procurement of annual capacities (Y1 +Y2) as very important expressed a preference here for booking just one quarter per auction. On the contrary, those shippers who viewed the individual procurement of Y1 and Y2 capacities in the form of annual products as less important or not important preferred to obtain several consecutive quarterly capacities simultaneously.

However, in the initial phase of the auction on the primary capacity platform, allocation of capacities for the next two years (Y1 + Y2) will take place in line with the TSOs' concept 5.0, ie only quarterly products for the next two years' capacities, but several quarterly capacities simultaneously per auction (Q1 to Q8, Q2 to Q8, etc.) The planned annual evaluation of the auction process will show whether adjustments are necessary once the first auctions have been carried out. Adjustments may also be necessary as a result of developments on a European level.

Assessment of security of supply

Bringing new gas pipeline projects into service will increase security of German natural gas supply.

In parallel to the construction of the Nord Stream pipeline, work has started on the Ostsee Pipeline Anbindungsleitung (OPAL) with an annual transport capacity of some 35bn m³. Both lines will start operation at the end of 2011. In 2009, the Bundesnetzagentur decided to exempt the OPAL extensively from third party access and rates regulation requirements for a period of 22 years.

The Norddeutsche Erdgasleitung (NEL) is scheduled to be completed in 2012. This pipeline will allow approx. 20bn m³ of gas to be transported annually from the Nord Stream towards the west. The 440 km-long natural gas pipeline will lead to the gas storage facility in Rheden, the largest facility of its kind in Western Europe with a working gas volume of over 4bn m³.

In terms of security of supply in addition to the significant investments made in transport infrastructure by European and Russion natural gas companies, attention must be drawn to measures by EU legislation. EU Regulation No 994/2010 concerning measures to safeguard security of gas supply came into force in December 2010. This new regulation was - among other things - a reaction to the conflict between the Russian gas producer Gazprom and the Ukrainian gas supply company Naftogaz in January 2009, which led to interrupted gas transit through the Ukraine. In some south-eastern European states in particular, this interruption in supply led to consumers in some areas being unable to receive gas at times. Although gas imports at the border points with Austria and the Czech Republic were significantly reduced for a period of around two weeks in Germany, no real risk to security of supply was recorded.

An interruption such as this with comparable effects on import flows did not occur again. Nevertheless, with the new EU Regulation, the European legislator aims to ensure a high degree of security of supply to household customers in all EU member states. This pursuit makes sense in light of the European Union's high level of dependency on natural gas imports, pointing out the need for particular protective measures against potential comparable interruptions to supply. Furthermore, the EU regulation aims to prevent restrictions to the security of supply resulting from technical disruptions such as, for example, the failure of a compresser station, occuring in the member states.

The EU Regulation thus provides for a certain infrastructure and supply standard to be complied with in each member state. By meeting the infrastructure standard set out in the EU regulation, it is ensured above all that the import infrastructure in a member state is designed in such a way that in the event of the failure of the largest gas import line, the gas volumes missing as can be transported into the respective member state via alternative import routes. In terms of the transport infrastructure in Germany, this requirement was met without any problems. Due to its central location in Europe, Germany is particularly well ingrained in the European gas transport network and is able to obtain gas via import points at its borders with the Czech Republic, Poland, Denmark, Norway, the Netherlands, Belgium and Austria.

The supply standard set out in the EU Regulation aims to guarantee, among other things, that a minimum amount of natural gas is always available for household customers in Germany even under extreme winter conditions with resulting high gas consumption and simultaneous failure of the main import pipeline. This is to be ensured by the gas supply companies using suitable measures. With a working gas volume of approx. 20bn m³, Germany has the largest gas storage capacities of all European states.

Under the amended Energy Act, the Bundesnetzagentur was given individual executive functions relating to the EU Regulation, including the drafting of a report on assessment of the risk to security of supply.

Wholesale

The dynamic of the national wholesale market in recent years was maintained in 2010 via the continuation of a range of positive framework conditions such as the good European supply situation via classic pipeline imports and LNG deliveries. Not only did liquidity on the three H-Gas markets (NetConnect Germany, Gaspool, Thyssengas H-Gas) increase over 2009 by more than 50 percent with a total of 1,490,000 GWh. This effect is especially due to the nascent influence of the market area expansions from NetConnect Germany and Gaspool at the beginning of the gas year in October 2009 being fully felt in 2010.

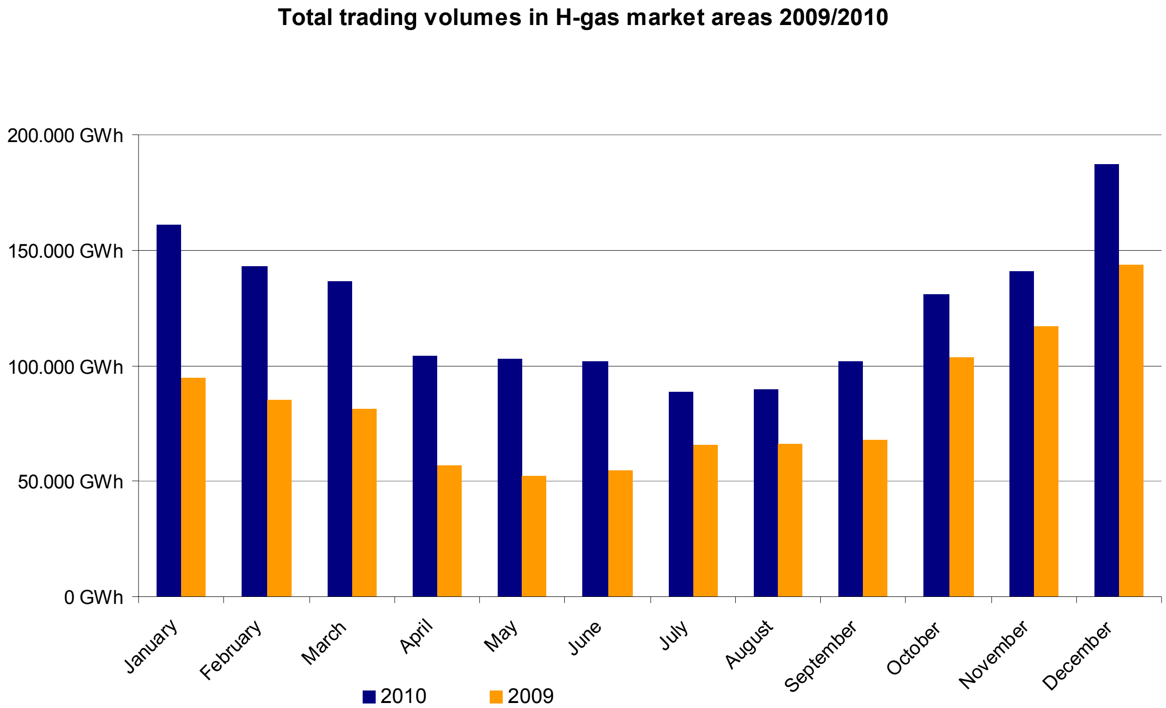


Figure 39: Liquidity development in 2009 and 2010. These are aggregated values from the three H-Gas market areas of NetConnect Germany, Gaspool and Thyssengas (H-Gas).

Development on the L-gas markets (L-Gas 1 of Aequamus, Open Grid Europe, Thyssengas L-Gas) was also up almost 25 percent from the 2009 value. More stimulation for 2010 came through the implementation of further combining of market areas as provided for under section 21(1) of the Gas Network Access Ordinance (GasNZW) into a total of just three.

Strong dominance by H-gas trade can be observed. Although, in some cases, over 75 dealers per market area trade low-calorific gas, almost 90 percent of volumes traded in Germany are H-gas, a trend which has continued from 2009. The low liquidity on the L-gas markets make evaluation and creation of a market-oriented reference price more difficult. Due to the low level of liquidity and demand, trading of L-gas products is also not offered on the EEX energy exchange.

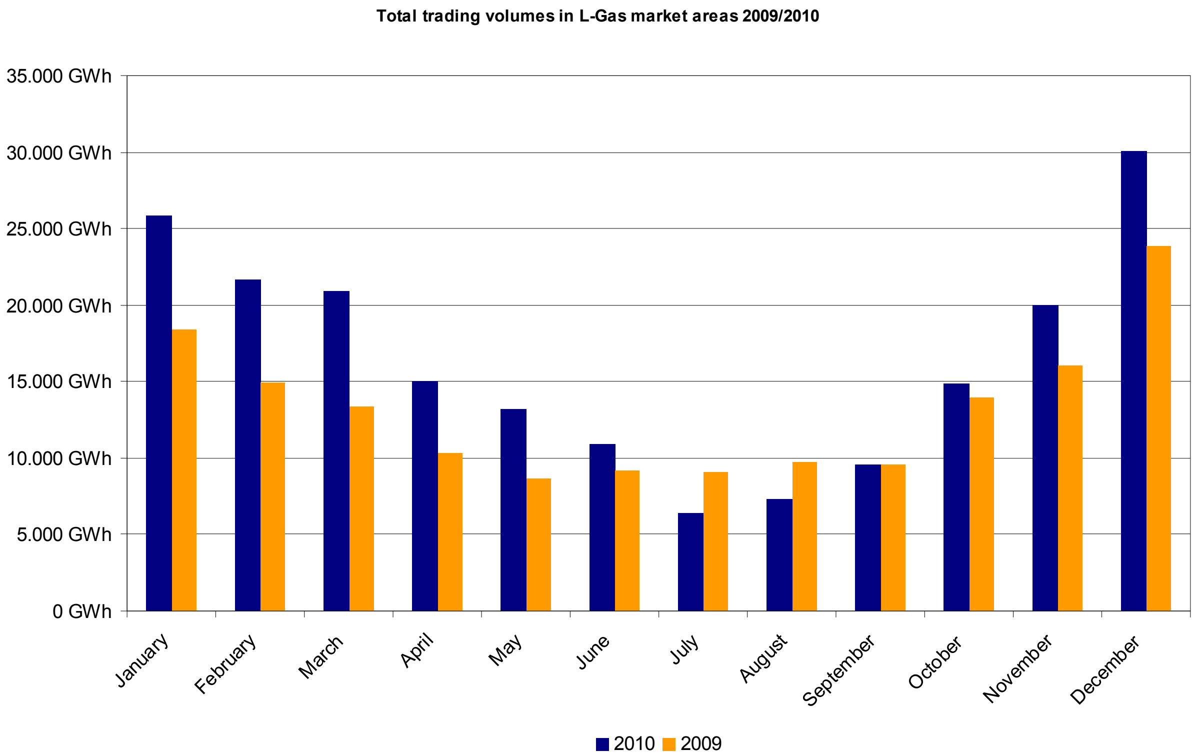


Figure 40: Liquidity development in 2009 and 2010. These are aggregated values from the three L-gas market areas of Aequamus (L-Gas 1), Open Grid Europe and Thyssengas (L-Gas).

Development of the European gas trading markets

Compared to other key European trading points on the continent, the highest volumes were found at the six German trading points, with 1,686,670 GWh. This development is also confirmed by the latest analyses for the current year, 2011. The Dutch Title Transfer Facility (TTF) is considered particularly liquid, with a trading volume of 1,156,360 GWh – almost 46 percent less than in Germany. Following at a significant distance is the Belgian trading point in Zeebrugge with an annual volume of 724,000 GWh. Gas trading is also promoted in other European countries, with data frequently published. However, as liquidity remains low in comparison to the trading points mentioned, in-depth evaluation has not been carried out in order to provide a clearer overview.

Despite a constantly increasing number of traders in Germany, with over 300 over market rate in some cases, the churn rate[33], one of the key factors in measuring the development of a trading point, has stagnated. It remains at its highest in the NetConnect Germany market area, although the values scarcely exceed 3.0. The UK's NBP has a churn rate of up to 16, by way of comparison. Values of 50 or more are found at the largest gas hub in the USA. Market participants are divided in their view of whether such a high churn rate is desirable for the development of the gas trading market.

[33] The churn rate indicates the ratio of traded volume to physically transported volume.

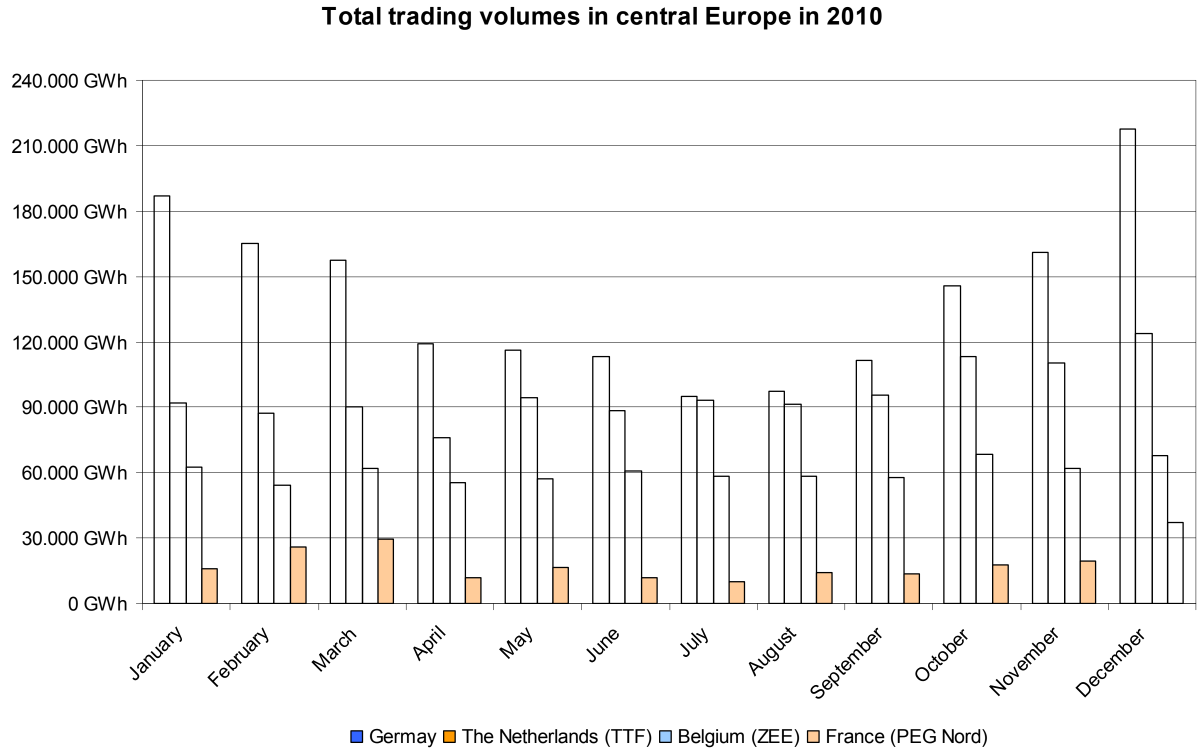


Figure 41: Development of German gas trading markets consisting of the six German market areas compared to other continental European trading points.
Source: Huberator, GTS, CRE.

Development of EEX energy exchange

Since mid-July 2007, in addition to coal, electricity and CO2 certificates, energy traders can also anonymously trade natural gas on a German exchange. The EEX in Leipzig was able to record significant growth rates, especially in the first two years of trading. Following a somewhat stagnating year in 2009, strong growth of 216 percent was recorded for 2010. One of the main reasons for this was the additional procurement on the exchange of system balancing energy by NetConnect Germany and Gaspool.

All the same, the 47.110 GWh traded on the EEX for spot and futures products was less than three percent of OTC trading. That the share has not increased, despite increased liquidity on the exchange, is also due to the significant growth rates for OTC trade and, moreover, is not unusual in European terms. Compared to other European exchanges, the EEX has assumed a key role. The expansion of trading points to include the Dutch TTF at the end of May 2011, the introduction of 24/7 trade and the reduction of minimum contract sizes from ten MW to one MW suggest that further growth in liquiditiy can be expected. Furthermore, the market acceptance of the new EGIX price index is to be monitored. The EEX expects this price index, consisting of monthly average prices, to be increasingly used in delivery contracts in future.

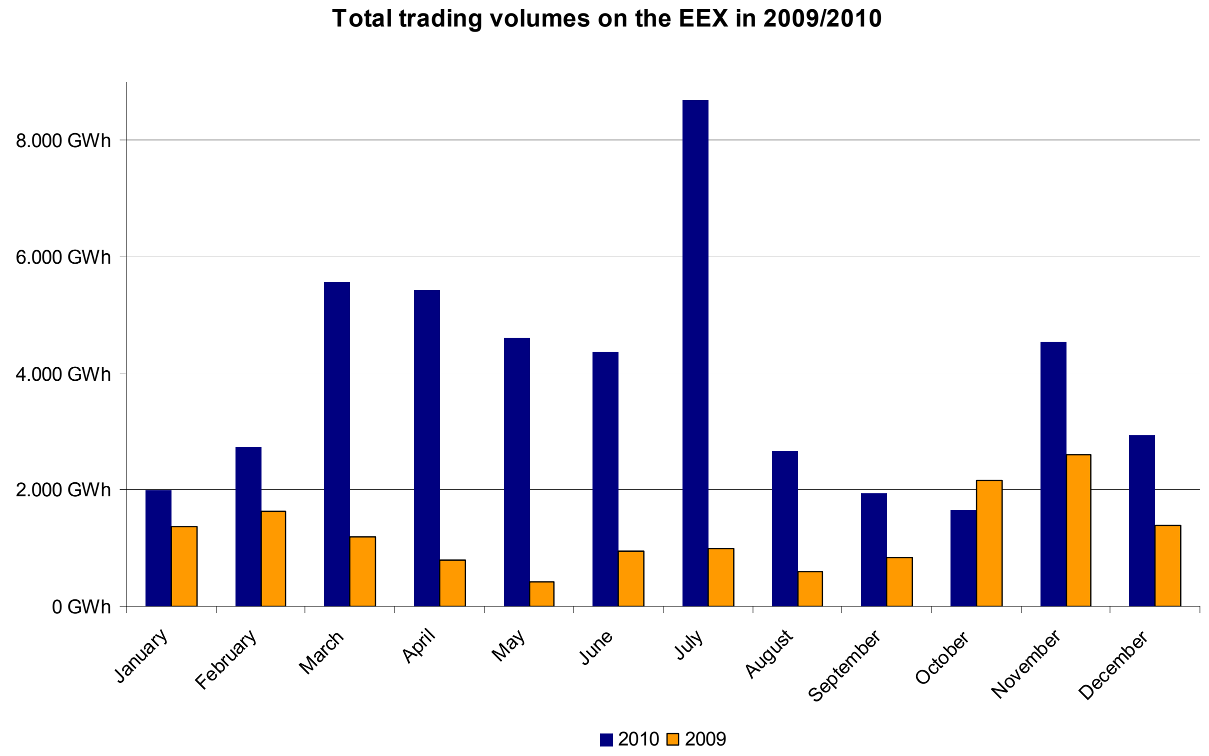


Figure 42: Development of gas trading on the EEX in 2009 and 2010.
Thus far, only two market areas could be traded. NetConnect Germany and Gaspool. The graphic shows aggregated values.

OTC trading via brokers

For the second time running, the Monitoring survey included and evaluated data from the largest European brokers. In OTC trading in particular, market players often use the services of brokers to have transactions performed in line with set criteria. The gas volumes traded via brokers last year reflect the overall positive developments in liquidity on the market.

As in last year, the share of the spot market is smaller than that of the futures market; however, this can be explained by the shorter supply periods. A transaction of, for example, ten MW flows into the evaluation as a "day-ahead" product with 240 MWh (10 MW x 24 h), and as a "month ahead" with 7,200 MWh (10 MW x 720 h). As a rule, it can be said that the further away the delivery period is, the lower the trade involved is. Unlike on the energy exchange, no standardised products were traded for the 2010 supply year. This was an important aspect for traders if they still required certain remaining volumes or wanted to get rid of these.

In total, 728,140 GWh were traded via the brokers surveyed, more than double the volume in 2009. Only a small share amounting to barely 13,000 GWh was secured via the energy exchange's clearing house. Obviously, clients are saving fees for this and do not require coverage in event of a failure, as they have had positive experiences with their trading partners over many years.

Figure 43: OTC natural gas volumes traded via brokers, according to short-term trade for the 2010-2014 supply periods or longer. The graphic shows aggregated values.

Price development in the gas trading markets

Following a quite spectacular drop in wholesale prices on the gas trading markets in 2009, the reverse trend could be seen from the second quarter of 2010. However, it took until the summer for trading prices to reach the level of the cross-border prices[34]. Although the market is well provided for by the LNG supplies not only from the Middle East, but increasingly also from the USA, the improvement in the ecomomic climate and the rise in demand for gas this has brought have led to a price increase. Consequently, the annual average for wholesale gas in 2010 increased by 30 percent compared to 2009. Even though gas was at times available for a lower price through the long term supply contracts, an increasing number of market players pushed for contractual linking to trading prices. According to press reports, however, these wishes have met with limited success so far. Further development is to be awaited here. The border price is currently moving upwards as a result of the continued frequent indexing to the (rising) oil prices and was two to three euro above the spot market prices at the end of April 2011.

[34] The Federal Office of Economics and Export Control (BAFA) calaculates the statistical average value of German gas imports from gas trading companies. German gas tax is not included.

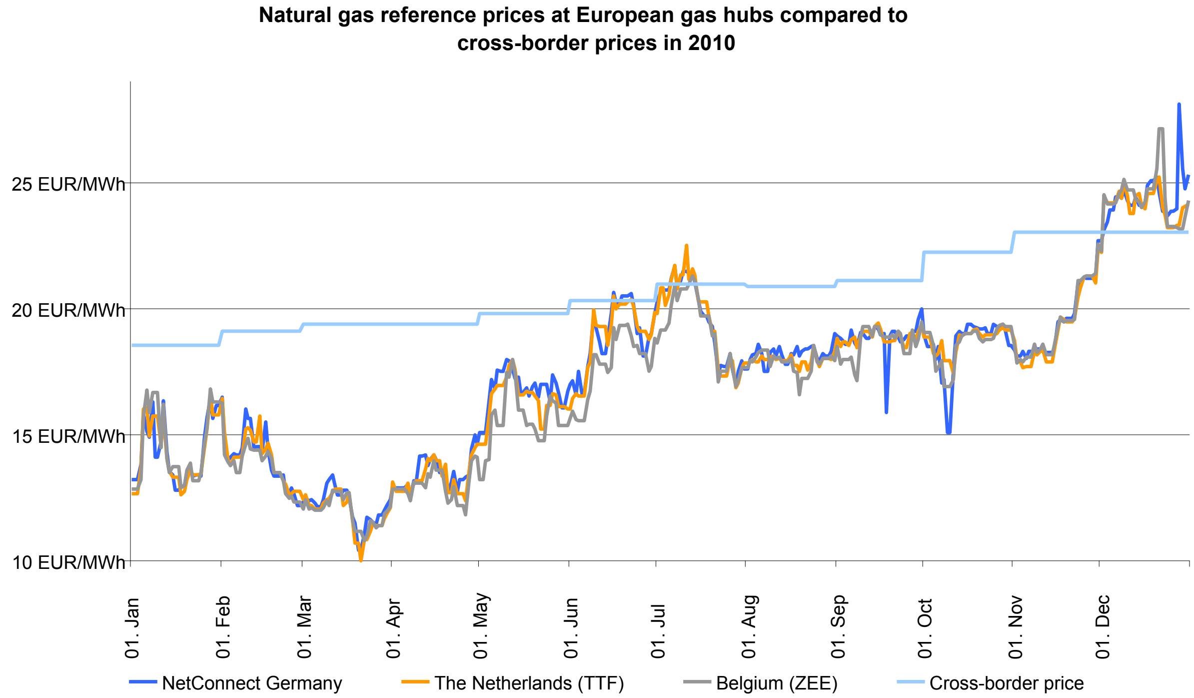


Figure 44: Development of daily reference prices in the OTC spot market in 2010. Compared with the cross-border price for natural gas (aggregated monthly values).
Source: NetConnect Germany, BAFA.

Retail

<u>Development of gas prices for household customers</u>

Following a fall in price as of 1 April 2010, the gas prices for household customers as of 1 April 2011 had risen again. All three customer segments demonstrated a slight price increase, although the highest price level to date, namely as of 1 April 2009, was not reached. Gas supplied at standard rates remains the most expensive form of supply for household customers. Changing contract with the current supplier or switching to a new supplier can mean significant price reductions.

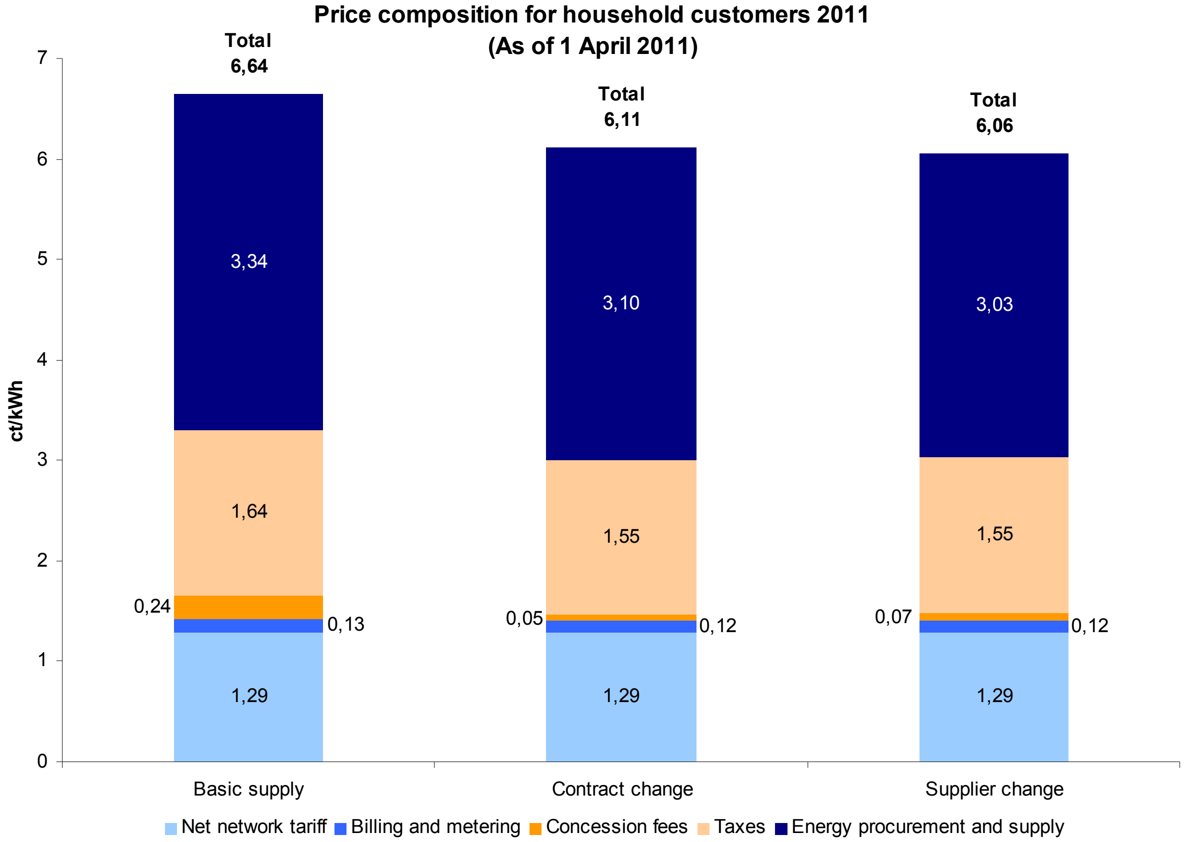


Figure 45: Gas price composition – summary view across all household customer segments

Taking a look at the individual components of which the basic supply gas price is composed, it is evident that most parts remain unchanged. The dominant price component is energy procurement and supply, followed by the tax component, which includes gas tax and VAT. The third most dominant price component is network charges, which have increased slightly.

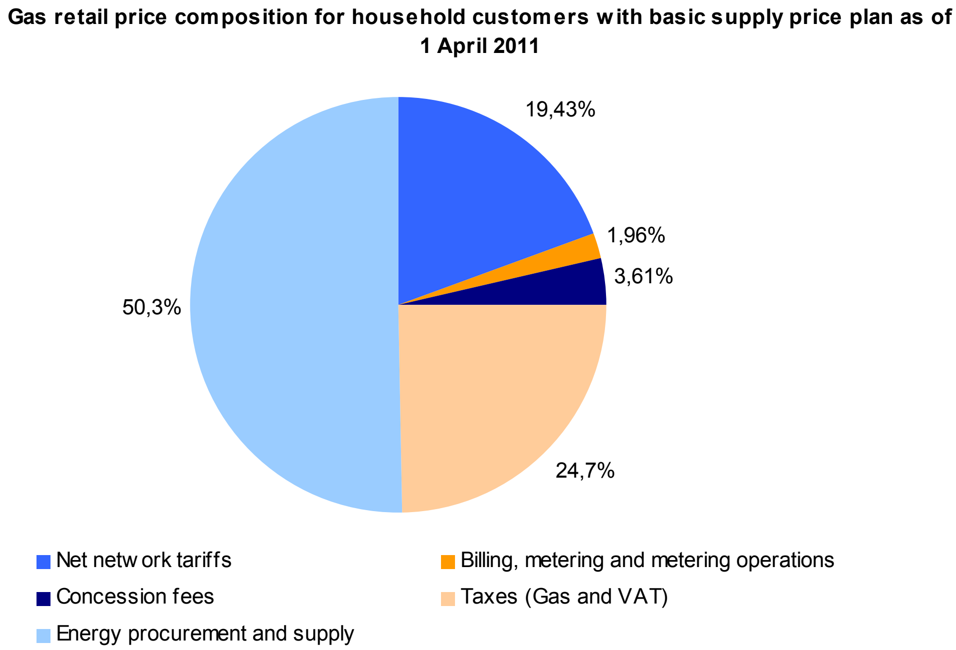


Figure 46: Composition of gas retail price weighted according to volume for household customers with standard supply. Price as of 1 April 2011 according to survey of wholesalers and suppliers.

The decrease in price as of 1 April 2010 was able to be partially offset this year, although it did levels did not reach the heights of 2007 to 2009. The price increase for basic supply is 2.5 percent, while prices for non-default contracts have seen an increase of 2.9 percent and prices for contracts with non-default suppliers have increased by 2.4 percent.

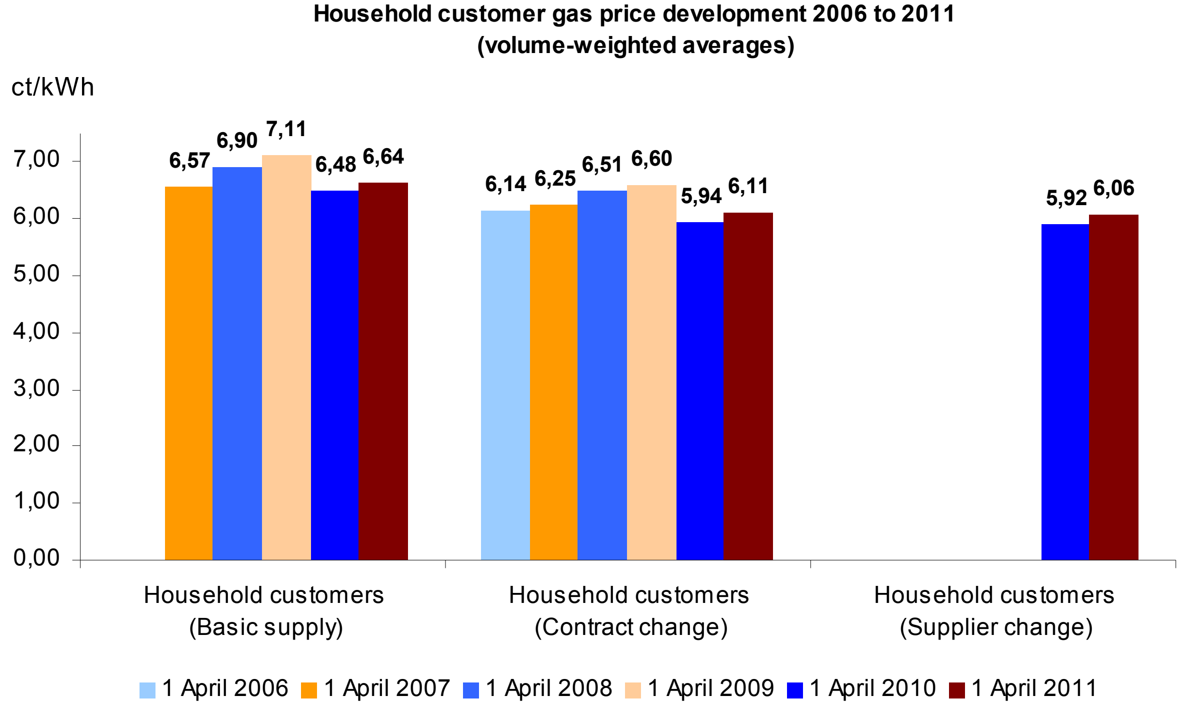


Figure 47: Development of gas prices weighted according to volume for household customers between 2006 and 2011. Prices as of 1 April 2011 according to survey of wholesalers and suppliers.

The energy and supply costs - which decreased significantly last year - have increased as of 1 April 2011, without reaching anything near the high level of 2007 to 2009. The slight increase in these costs, of around 2.5 to 3 percent in total, can also be explained by the positive economic development and the resulting increased demand for gas.

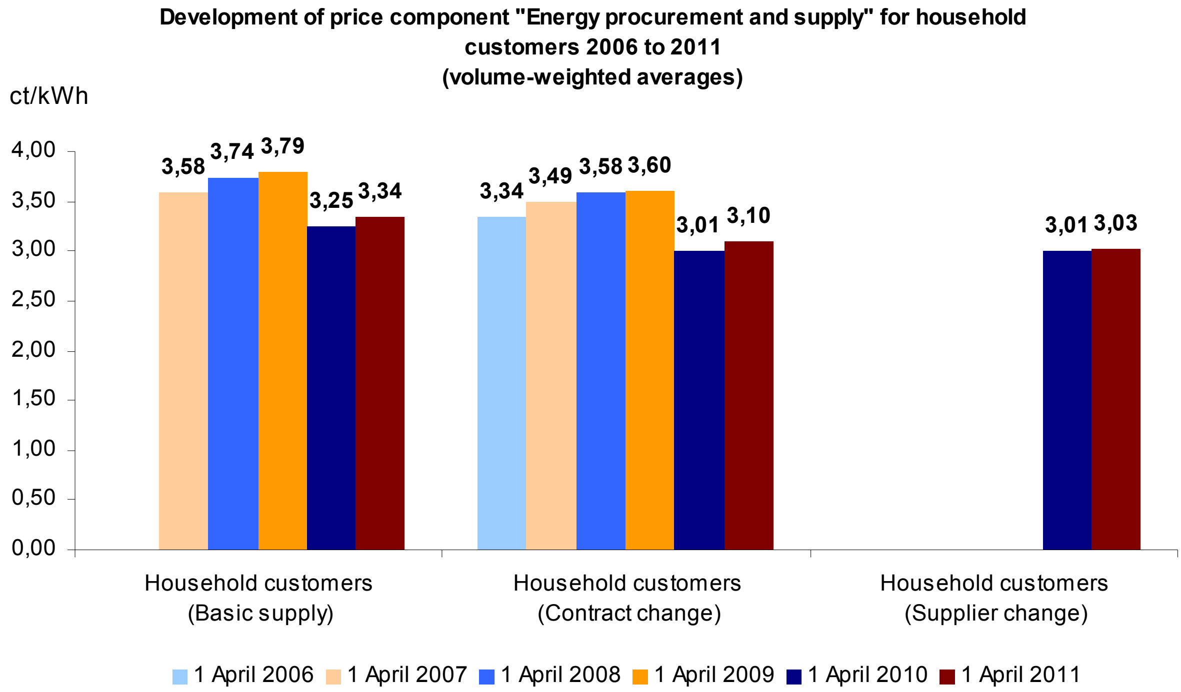


Figure 48: Development of ”energy procurement and supply” price component for household customers between 2006 and 2011. Prices as of 1 April 2011 according to survey of wholesalers and suppliers.

The network charges weighted according to volume, including the charges for billing, metering and metering operations provide a varied picture. Network charges for household customers have risen slightly and thus reached a new high of around 1.41 ct/kWh. Network charges for business customers have, contrary to the trend, decreased, while the network charges for industrial customers have increased.

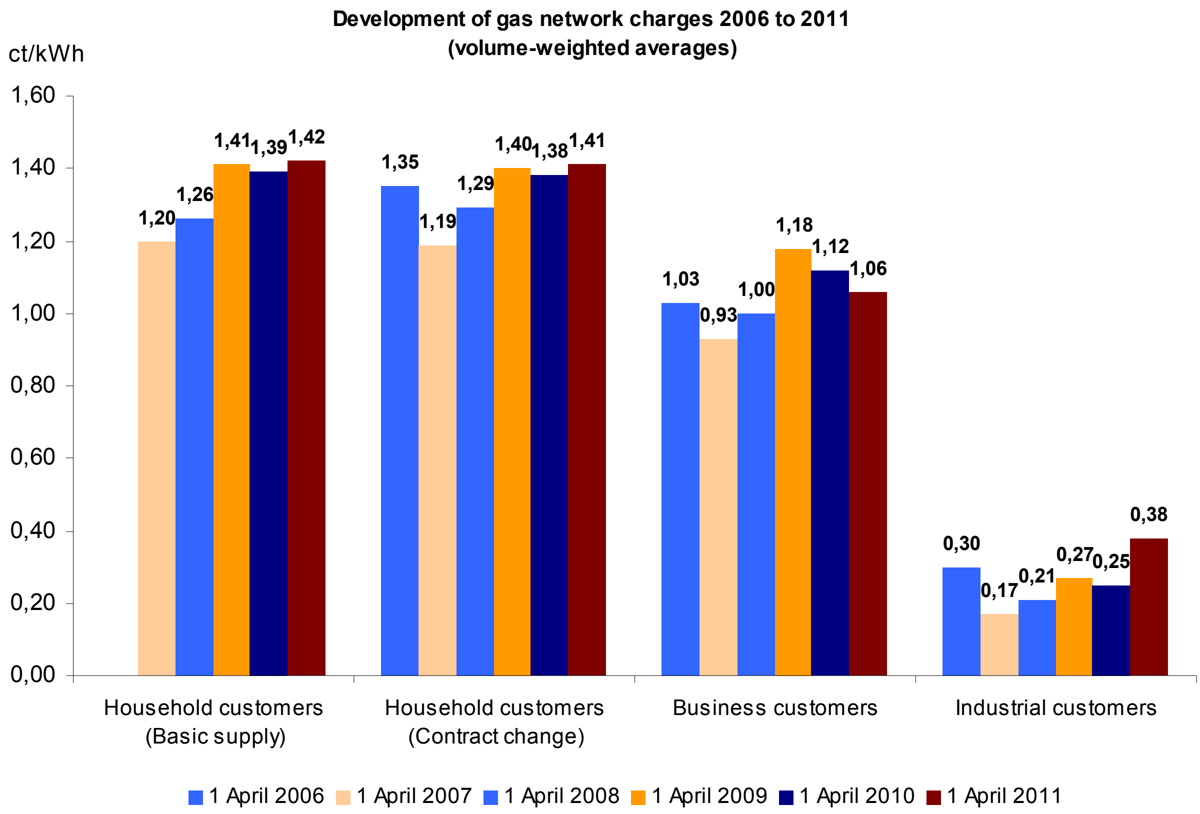


Figure 49: Development of network charges weighted according to volume for household customers between 2006 and 2011. Prices as of 1 April 2011 according to survey of wholesalers and suppliers.

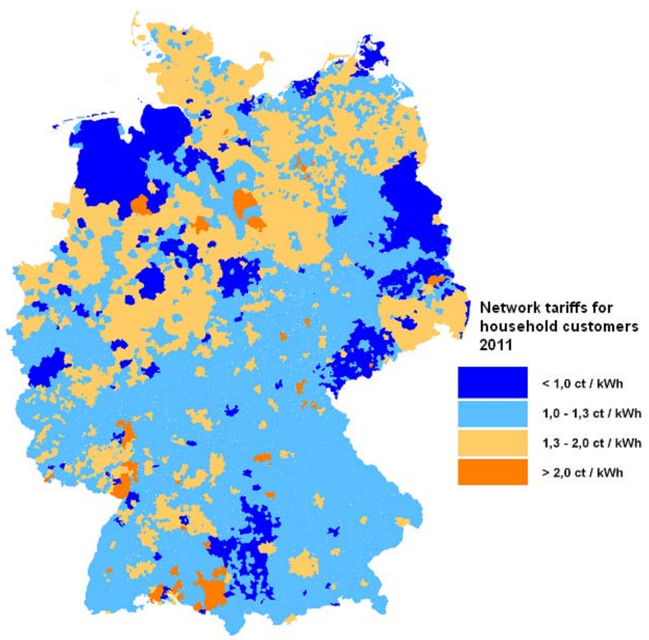


Figure 50: Network charge level for basic supply to household customers.
Price as of 1 April 2011 according to survey of gas wholesalers and suppliers.

For household customers with an average consumption of 20,000 kWh, the moderate increase in price represents an annual additional charge of 32 euro for basic supply, 34 euro and 28 euro for switching their contract or supplier, respectively.

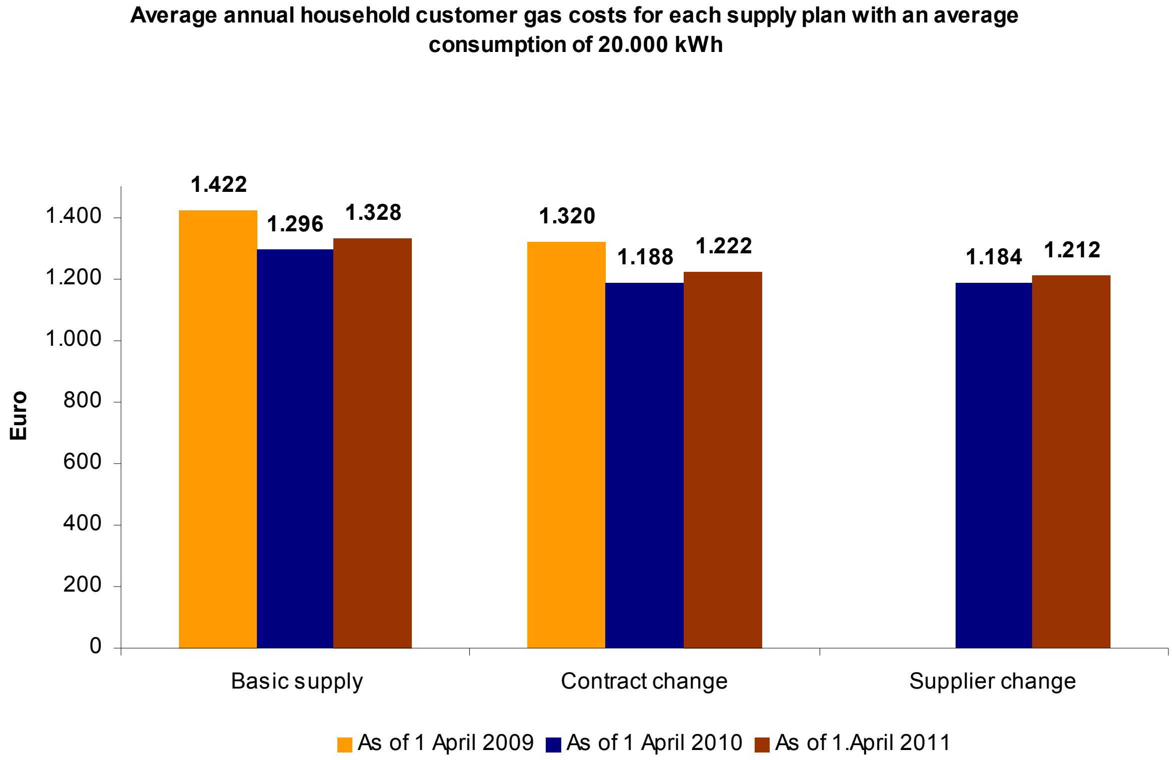


Figure 51: Average annual gas costs for a household customer across the various forms of supply with average consumption of 20,000 kWh.

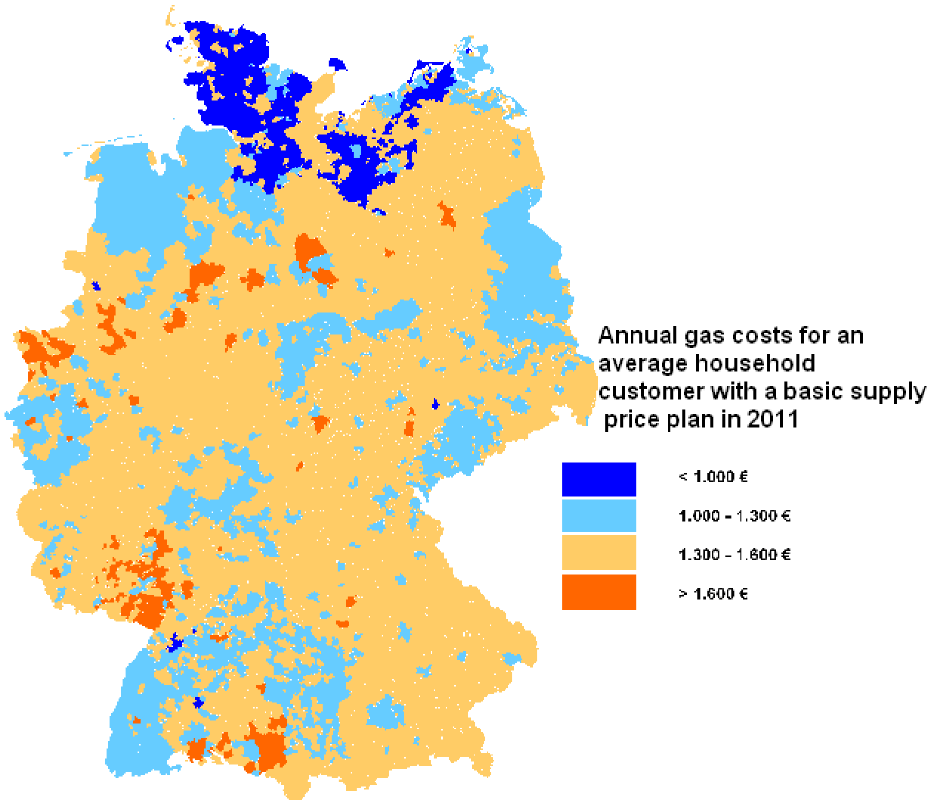


Figure 52: Annual gas costs for an average houshold customer receiving basic supply. Price as of 1 April 2011 according to survey of gas wholesalers and suppliers.

Number of suppliers in a network area

A basic indicator of well-functioning competition between gas suppliers is the number of suppliers available per network area. If the majority of household customers in 2008 could choose between one and five suppliers only, the majority in 2009 could already choose between six and ten. In 2010, most household customers had a choice of between 11 and 20 suppliers. The range of suppliers remains at the low level of two years ago in just 14 gas networks. Overall, there is very dynamic development in terms of growth of new suppliers and the expansion of active supply to new network areas. In 36 network areas already, a household customer can choose from over 50 suppliers. This pleasing and healthy diversity indicates that the regional and supraregional gas markets in Germany are highly attractive.

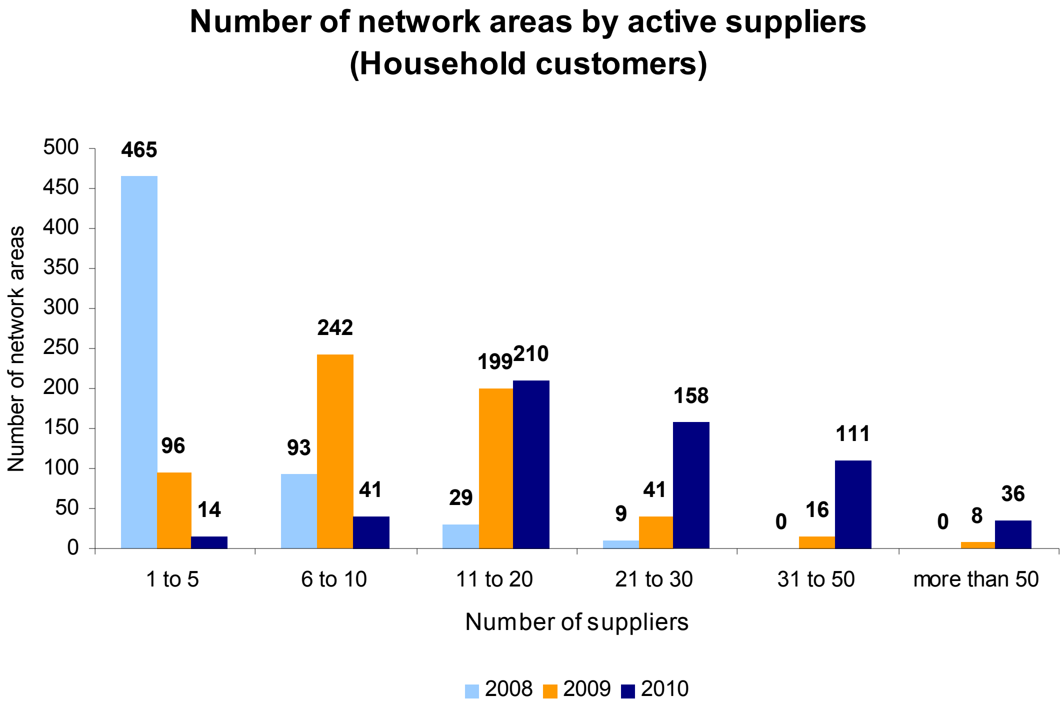


Figure 53: Number of network areas according to number of suppliers active there (household customers) according to survey of gas DSOs for 2008 – 2010.

A continuation of the previous year's trend (2009) can also be observed in terms of the number of network areas to which gas suppliers said they deliver. The number of suppliers active in just one network area continues to decline - in 2010 it was 277. At the same time, the number of suppliers operating in several networks has grown, as has the number of gas suppliers active in over 100 networks simultaneously. Nevertheless, most gas suppliers continue to have a regional focus and limit themselves to supplying customers in their home region.

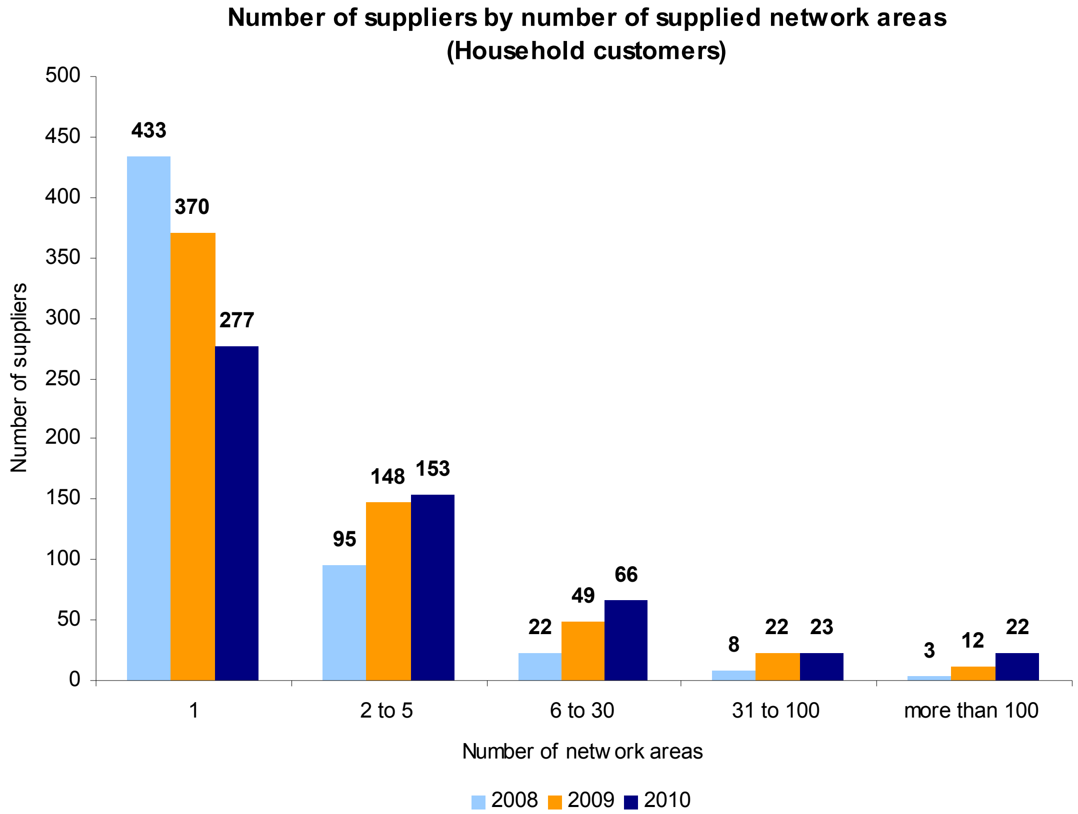


Figure 54: Number of suppliers according to number of network areas they supply (household customers) as per survey of gas wholesalers and suppliers.

Contract and supplier switching by end consumer

Domestic customers can be supplied with gas in three different ways. Besides standard service from the basic supplier, customers can also be supplied on special terms. With this option, the customer stays with his current supplier but signs a new contract with special terms (change of contract).

Switching supplier refers to a process by which a final consumer at a metering point (eg connection in the building) changes his current supplier for a new one. The number of supplier switches is a key indicator for competition development in the retail sector in Germany.

Taking an overall view of all DSOs and TSOs surveyed and the number of switches they recorded, a two-fold increase can be observed in the latter. While the volume of supplier switch in 2009 grew by a modest ten percent, the volume of gas supplied doubled in 2010 from 47.18 TWh in 2009 to 110.38 TWh in 2010. With an offtake volume of 1014.49 TWh in 2010 this corresponds to a switch rate of 10.88 percent. This highly positive development corresponds with the increased supplier figures in individual networks already mentioned. Final consumers, and in particular household customers, have a larger choice of gas suppliers and are taking advantage of the opportunities offered by switching supplier.

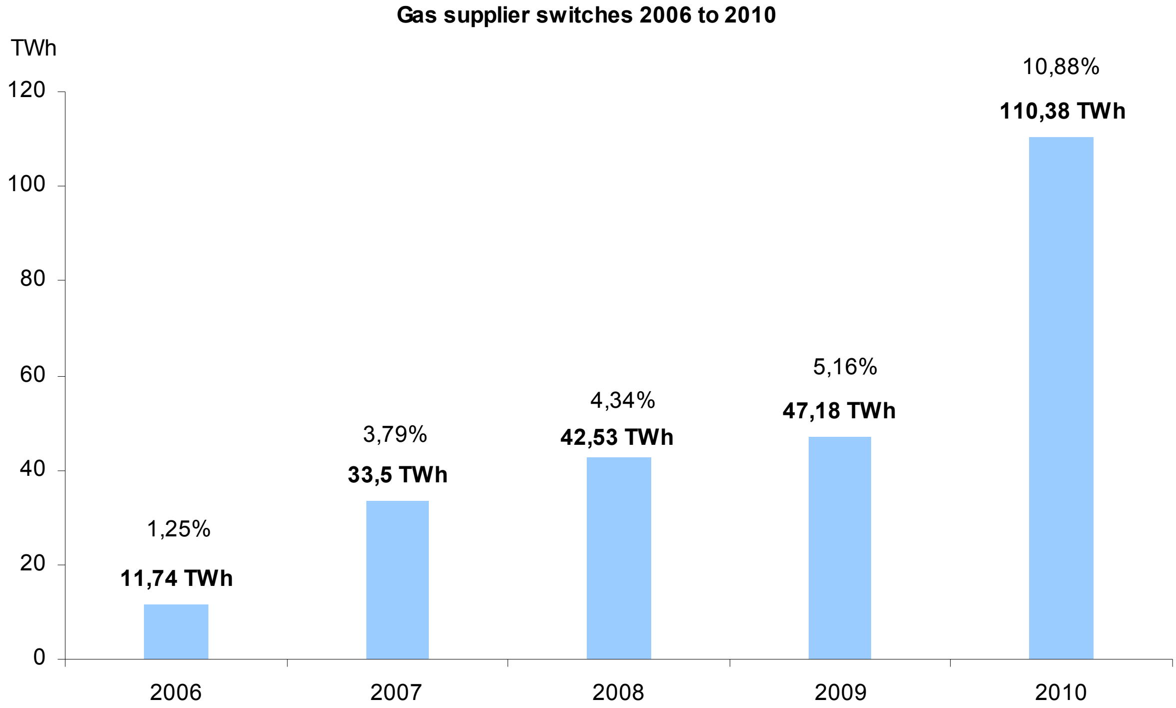


Figure 55: Development of supplier switching volumes in TWh and suppliers switching rate (2006 to 2010) according to survey of DSOs and TSOs.

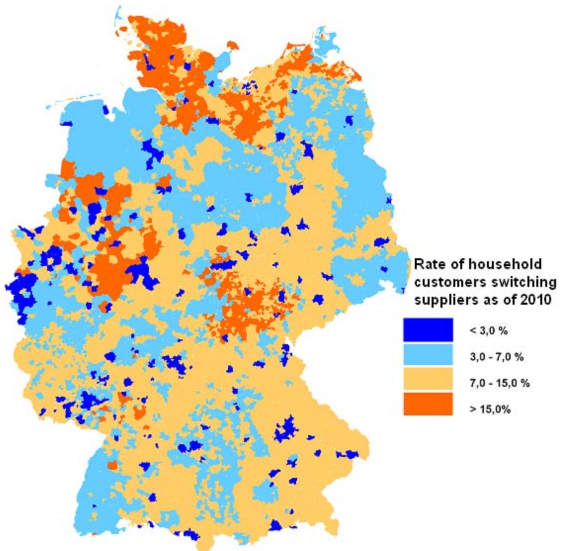


Figure 56: Household customers suppliers switching rate 2006 to 2010 according to survey of DSOs and TSOs.

This positive image is consolidated when taking a look at the number of supplier switches in progress. Household customers in particular increasingly took the opportunity to switch supplier in 2010, the year surveyed. A total of 720,039 switches of supplier by household customers were recorded for that year. That is more than 317,000 compared to 2009, representing an increase of over 75 percent.

In 2010, a total of 88,947 domestic customers switched suppliers upon moving into the premises, preferring not to stay with the basic supplier. This figure was 48,668 in 2009. The positive trend is still evident in this category, too, and gives weight to the assumption that household customers compare prices before their first delivery from a supplier at their new address, deciding for a more cost-effective supplier than the default. This fact in particular indicates a greater price sensibility on the part of household customers.

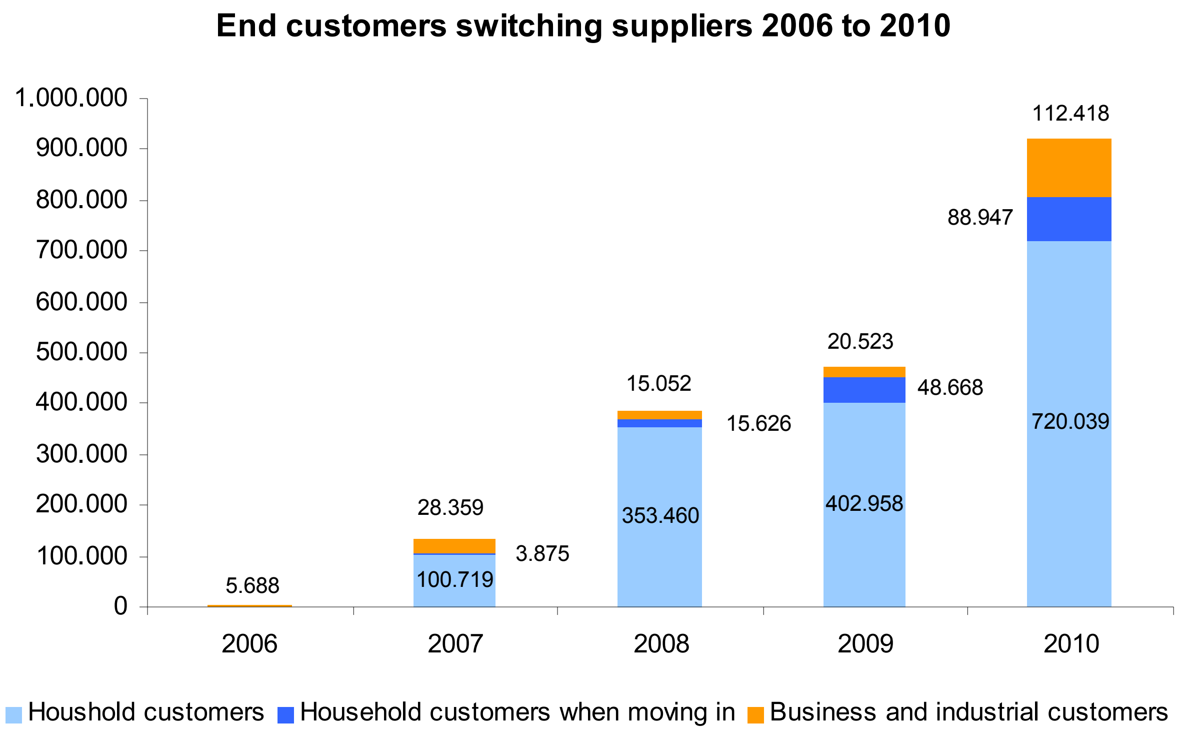


Figure 57: Number of supplier switches by end consumers (2006 to 2010).

Looking at customer migration between the individual forms of supply and individual groups of suppliers, it must be borne in mind that due to the fact that this is no full-scale survey, there is still an amount outstanding. As a result of the incomplete information from the companies it cannot be ascertained how the remaining customers are spread across the supplier groups. It can be determined, however, that both smaller and larger suppliers have experienced customer losses in the basic supply sector. 2010, the year of this report, was the first in which customers who had left the basic supplier were considered separately. One option for these customers is to choose a rate from outwith the basic supply, but within its network area, representing a change of contract. The other option is to select a rate both outwith both the basic supply and its network area, which represents a change of supplier.

While small and medium-sized suppliers recorded more acquisitions in 2009, while large and very large suppliers saw customer numbers drop, the picture in 2010 is somewhat more varied. While all companies are losing customers for basic supply, they are gaining new customers in the form of those switching supplier. It is also worth noting that large and very large companies are also losing customers who change contract. Overall, however, the 2009 trend is confirmed. The increase in customers for small and medium-sized companies offset the losses for the most part, while large and very large companis record net customer losses.

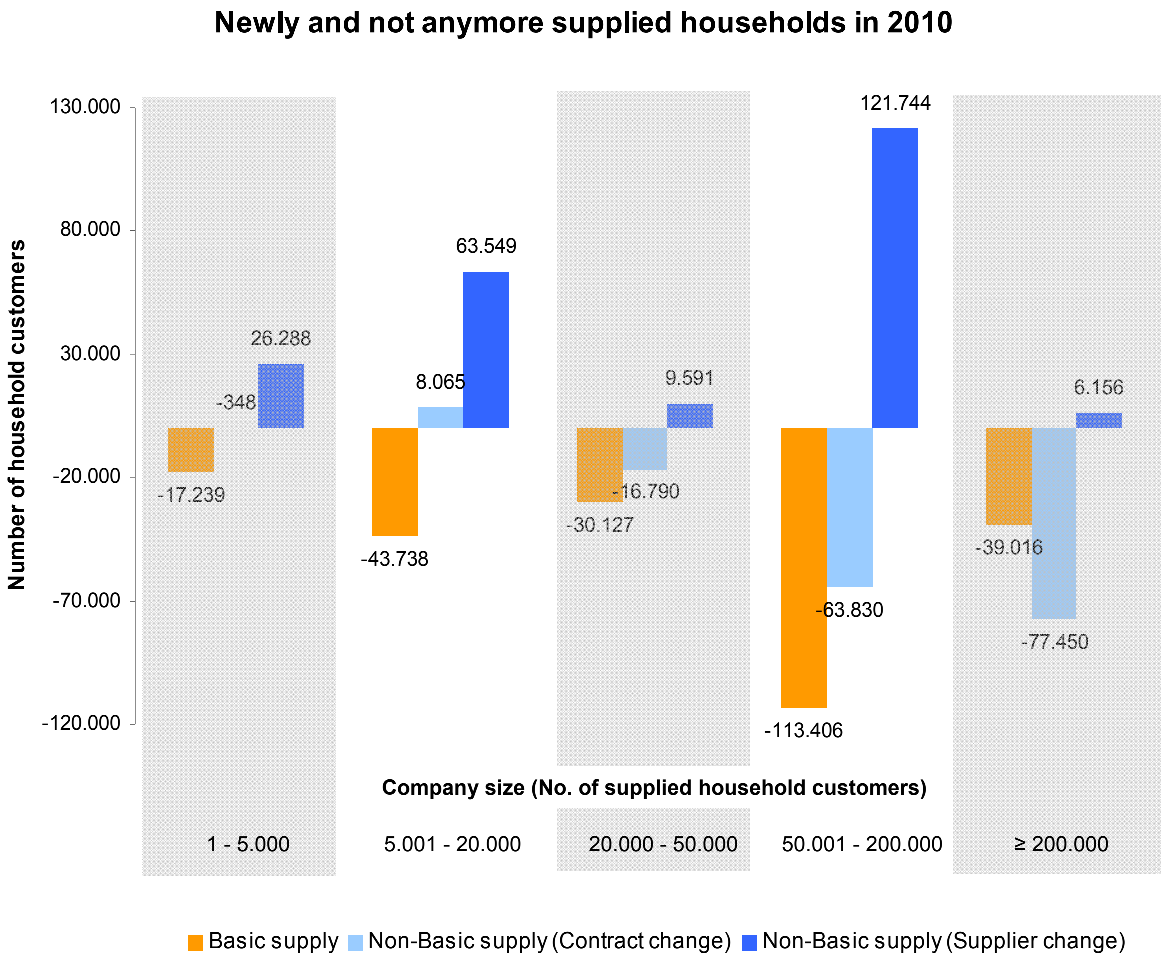


Figure 58: New and departing household customers in 2010 – balances. It must be borne in mind here that it is not possible to counterbalance the figures for new and departing customers. The difference is based on incomplete information from the market players.

The contract structure for supply to household customers as of 31 Decemebr 2010 highlights the sustained trend towards switching contract or supplier. Despite this positive development, only six percent of household customers obtain their gas from a supplier other than the default, ie a genuine competitor. Around 70 percent of household customers still receive their gas from their basic supplier at a special rate. Almost 25 percent of the gas volume delivered to household customers comes from basic supply.

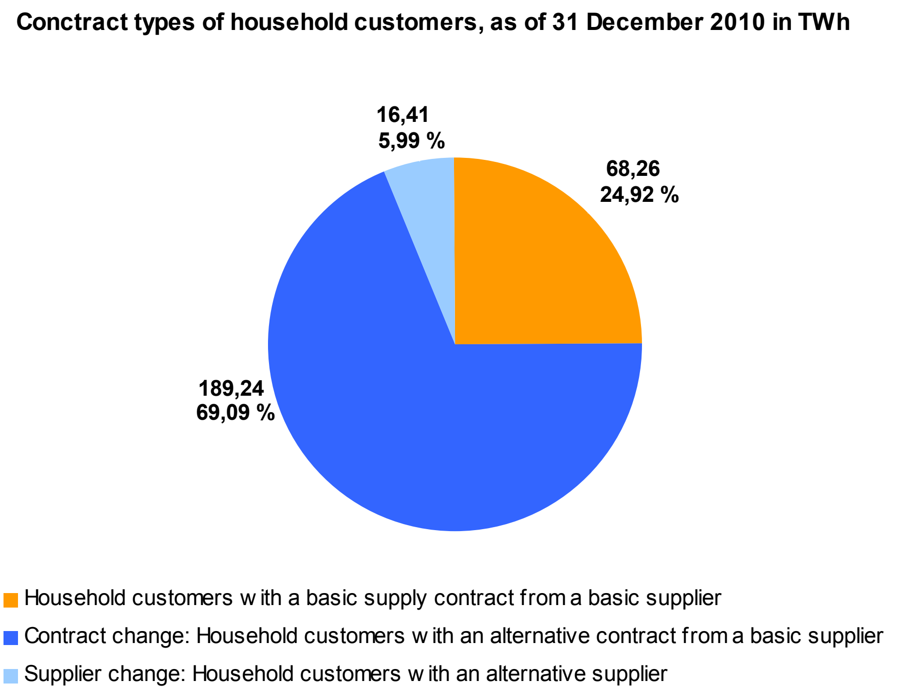


Figure 59: Contract structure for household customers according to survey of wholesalers and suppliers, as of 31 December 2010

The basic supply share of the total delivered is falling constantly, however. In 2006, the household customer share of basic supply was more than 40 percent, while in 2010, around a quarter of household customers recevied gas via basic supply.

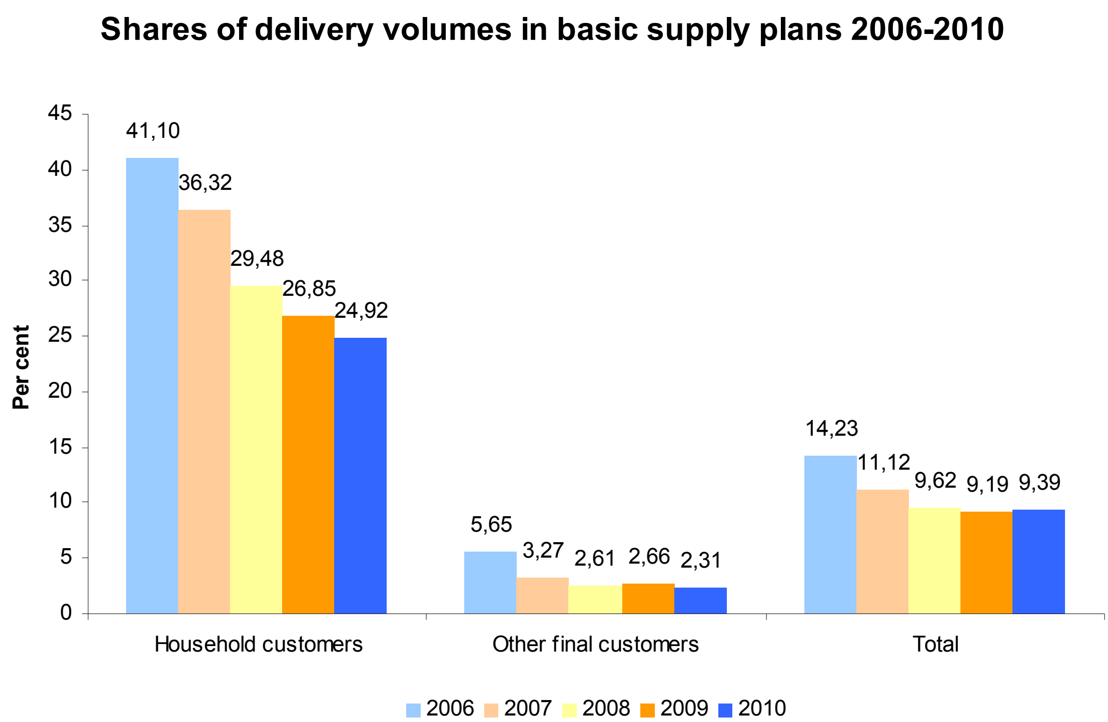


Figure 60: Share of delivery volumes from wholesalers and suppliers for basic supply from 2006 to 2010 by customer category.

Transparency and monitoring in European energy trading

The importance of electricity and gas trading in Europe increased yet again in 2010. The volume of electricity trading in Germany is estimated to account for more than 10,600 TWh. Wholesale gas trading amounted to approx. 1,686 TWh. Energy trading has become an important tool for energy producers and large users for limiting losses from fluctuations in energy prices (so-called hedging). The importance of electricity and gas trading is also growing because small and municipal companies, in particular, can derive competitive advantage from more flexible trading strategies in supplying their customers. And another reason is the growing role of trading on the exchange for the integration of renewables.

The growing economic importance and Europeanisation of electricity and gas trading have made it necessary to fundamentally enhance the supervision of trading in Europe. Market supervision is intended to counteract the likewise growing risk of abuse (market manipulation and insider trading). In December 2010, the European Commission (EC) published a draft of oits Regulation on energy market integrity and transparency (REMIT). The Commission's proposal was oriented heavily to recommendations put forward by the energy and financial market regulators in 2008. The regulators, in a joint working group, established that the current arrangements for the supervision of the financial markets were not enough to secure suitable integrity in the energy markets. They therefore recommended issuing sector-specific, tailored arrangements to prevent market manipulation in order to eliminate these weak points.

The proposal presented by the Commission contained rules prohibiting market abuse as well an obligation to disclose inside information and the relevant information on insider trading as well as an efficient reporting system from the energy supply companies to the Agency for the Cooperation of Energy Regulators (ACER).

The European Council and the European Parliament have meanwhile reached agreement on the Regulation so it is likely to enter into force before the end of 2011. This Regulation will present ACER and the national authorities with new tasks.

In addition to monitoring energy trading, it is particularly important also to have a high level of transparency in relation to fundamental data. Fundamental data in the energy sector refers to data on the utilisation of the energy infrastructure and the generation/production capacity. Providing transparency on fundamental data is crucial for preventing excessive speculation, as it gives the market players a clear picture of the real supply and demand situation. In order to enhance the competitive environment in wholesale trading in European markets, it is also particularly important to ensure that the publication requirements are similar in all Member States. This prompted the energy regulators to draw up a joint proposal[35] in 2010 – for the electricity sector in cooperation with the European Network of Transmission System Operators for Electricity (ENTSO-E) – to adopt binding, pan-European regulations on the transparency of fundamental data. The proposal is based on the transparency requirements that have already been successfully implemented in Germany[36]. The EU Commission intends to issue these requirements as legally binding throughout Europe and began setting the relevant process in motion in the autumn of 2011. It is anticipated that a binding regulation will be issued in 2012.

---

[35] cf. http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_CONSULT/CLOSED%20PUBLIC%20CONSULTATIONS/ELECTRICITY/Comitology%20Guideline%20Electricity%20Transparency/CD/E10-ENM-27-03_FEDT_7-Dec-2010.pdf

[36] For further information, please go to www.bundesnetzagentur.de (http://www.bundesnetzagentur.de/cln_1911/DE/Sachgebiete/ElektrizitaetGas/AllgemeineInformationen/TransparenzStrommarkt/TransparenzStrommarkt_node.html)

Fundamental data has been published in Germany since the end of 2009 through the EEX transparency platform. In 2010, the Bundesnetzagentur stepped its efforts up to enhance transparency in Germany. For instance, companies which had not yet published the information on this central EEX platform were requested to meet their publication requirement. This led to an increase in the number of companies providing information. Meanwhile (as of October 2011) the EEX transparency platform says that it covers around 91 percent of installed capacity. The information the Bundesnetzagentur received in the first six months of 2011 on the power plants installed in Germany is of course included. In addition, the Bundesnetzagentur is examining whether the companies are publishing all the relevant data on the EEX platform and whether they are doing so in a timely fashion.

It is viewed as positive that since the end of July 2011, fundamental data on Austria has also been published on the EEX transparency platform. This means the EEX transparency platform has become a model for European solutions.

Focus of cartel authorities in monitoring competition

With regard to merger control, there were two merger cases alongside basic proceedings that were of major importance from the Bundeskartellamt's perspective. The majority of proceedings instituted by the Bundeskartellamt within the framework of its supervision of anti-competitive practices by dominant companies were brought to a conclusion in the last period under review. During the period under review, the Bundeskartellamt was chiefly concerned with combating anti-competitive practices. It also focused on conducting a sector inquiry in the area of electricity generation and wholesale electricity trading.

Merger control

After the Bundeskartellamt approved the merger[37] between EnBW/EWE/VNG in 2009, subject to certain ancillary conditions, its requirement was met in the period under review: The Bundeskartellamt agreed to the takeover of GESO by Technische Werke Dresden envisaged in the conditions.[38] In addition, Düsseldorf Higher Regional Court dismissed the appeal lodged against the EnBW/VNG decision. The Court dismissed the appeal and backed the decision taken by the Bundeskartellamt. The Court also agreed with the grid-related delimitation of the gas markets by the Bundeskartellamt. However, it did indicate that further developments in geographical market delimitation should not be ruled out.[39].

Furthermore, the Bundeskartellamt cleared two mergers involving RWE in the main examination proceedings subject to certain conditions being met. One merger involves the establishment of Energieversorgung Plauen, a joint venture which RWE and the municipality of Plauen had participations in. The second merger involves two participations RWE held in the municipal utilities of Lingen and Radevormwald being cleared for an unlimited period. The original deadline for these had been 31 December 2010. RWE's stakes would have further strengthened its dominant position on the electricity supply markets; for this reason the merger was cleared under the condition that RWE would sell its participation in Energieversorgung Halle[40].

Control of abusive practices by dominant companies

[37] cf. Bundeskartellamt, decision of 6 July 2009, ref. B8-96/08 - EnBW/EWE, downloadable at: http://www.bundeskartellamt.de/wDeutsch/download/pdf/Fusion/Fusion09/B8-96-08.pdf?navid=80; Bundeskartellamt, decision of 24 August 2009, ref. B8-67/09 - EnBW/VNG downloadable at: http://www.bundeskartellamt.de/wDeutsch/download/pdf/Fusion/Fusion09/B8-67-09.pdf?navid=80 .

[38] cf. Bundeskartellamt, case report of 26 February 2010, downloadable at: http://www.bundeskartellamt.de/wDeutsch/download/pdf/Fusion/Fusion10/Kurzberichte/B8-023-10.pdf?navid=92.

[39] cf. Düsseldorf Higher Regional Court, ruling of 13 October 2010, ref. VI-2 Kart 2/09 (V).

[40] cf. Bundeskartellamt, case report of 30/04/2010, downloadable at: http://www.bundeskartellamt.de/wDeutsch/download/pdf/Fusion/Fusion10/Kurzberichte/B08-109-09-Fallbeschreibung.pdf?navid=92.

After focusing on the control of abusive pricing under Sections 19 and 29 of the Act against Restraints of Competition (Gesetz gegen Wettbewerbsbeschränkungen) (GWB) in recent periods under review, the Bundeskartellamt did not institute any new nationwide price abuse proceedings in the period under review. Most of the abuse proceedings against dominant heating electricity suppliers that were instituted in 2009 were brought to a conclusion. The companies have agreed to lower their prices to ease the burden on customers. Furthermore, the heating electricity suppliers under investigation, including the peer companies, agreed to initiate measures that would open up the market.

Restriction of competition

The Bundeskartellamt investigated numerous cases involving restriction of competition on energy markets in the period under review. Restrictive practices were identified, inter alia, in electricity purchase agreements, in the granting of concessions and in the form of resale bans in agreements with some gas and electricity suppliers. Many of the anti-competitive practices sealed off the respective markets, thereby hampering competition. In the vast majority of cases, the companies concerned have already given assurances to the Bundeskartellamt to stop engaging in anti-competitive practices. This meant that the Bundeskartellamt was able to terminate proceedings with commitments pursuant to section 32b of the GWB.

Sector inquiries

In the period under review, the Bundeskartellamt continued with the sector inquiries it had already launched. The sector inquiries are based on section 32e of the GWB and focus on entire branches of industry in order to identify potential restrictions of competition. In its sector inquiry into "electricity generation / electricity wholesale market", the Bundeskartellamt conducted comprehensive investigations into electricity generating markets and wholesale markets. New methods of proving market power and the abuse of a dominant position in the market by withholding capacity were taken into account.

In addition, the Bundeskartellamt continued conducting its inquiry into the district heating sector in the period under review. This inquiry is due to be completed shortly.

Competition advocacy

During the period under review, the Bundeskartellamt repeatedly highlighted the importance of competition in the energy sector as well as what has been achieved with the liberalisation of the energy markets. In a guidance developed in cooperation with the Bundesnetzagentur on the takeover of concessions, the Bundeskartellamt drew up guidelines on granting rights of way in compliance with competition law. Furthermore, the Bundeskartellamt commented on several legislative projects in the period under review. In relation to the Energy Concept presented by the Federal Government in September 2010, the Bundeskartellamt had highlighted the impact on competition of the life-span extensions for nuclear power plants, which had been approved at the time. In addition, the Bundeskartellamt admonished in this context the lack of market orientation in the generation and sale of electricity from renewable energies. The Bundeskartellamt expressly welcomed the plan to establish a market transparency unit that will monitor energy generation and wholesale trading markets in electricity and gas referred to in the Federal Government's Energy Concept. Furthermore, the Bundeskartellamt dealt with a draft regulation proposed by the European Commission on energy market integrity and transparency ("Regulation on Energy Market Integrity and Transparency")[41]. In the Bundeskartellamt's opinion, the current version of the draft regulation goes further than the actual objective of the regulation, which is to close a supervisory gap in energy wholesale trading markets. From the Bundeskartellamt's perspective, some aspects of the regulation could potentially jeopardise the success of the liberalisation of energy generation and energy wholesale trading markets and create the risk of indirect price and investment regulation of competitively-organised energy markets.

[41]cf. the proposal for a Regulation of the European Parliament and of the Council on energy market integrity and transparency, COM (2010) 726 final, 2010/0363 (COD), downloadable at http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=COM:2010:0726:FIN:EN:PDF.

Bundesnetzagentur resources

The Bundesnetzagentur is a separate higher federal authority within the scope of business of the Federal Ministry of Economics and Technology and is managed within the latter's budget. In 2010, the Bundesnetzagentur's expenditure for energy regulation totalled around 18 million euro, accounting for a share of 11.6 percent of its total expenditure which amounted to 155.4 million euro.

The Bundesnetzagentur has a workforce of around 2,500. Around 185 employees are involved with the regulation of electricity and gas networks.

The amendment to the energy law by the legislator in July 2011 presented the Bundesnetzagentur with a host of new tasks. The amendment involves, inter alia, stricter unbundling requirements, examination and consultation of TSOs' and DSOs' national investment plans, more intensive cooperation between national regulatory authorities (at EU and regional level) and within ACER as well as more intensive monitoring of markets. The Grid Expansion Acceleration Act (NABEG) has bestowed new tasks on the Bundesnetzagentur in relation to federal sectoral planning and, subject to the issuance of a statutory ordinance, also planning approval procedures for concrete power line projects.