The functioning of the electricity, CO_2 and natural gas wholesale markets in 2011-2012

November 2012

Introduction

"The Commission for Energy Regulation [(CRE)] monitors electricity and natural gas transactions carried out between suppliers, traders and producers, transactions carried out on the organised markets as well as cross-border trades. It monitors the consistency of the offers […] made by producers, traders and suppliers […] with their economic and technical constraints" (Article L. 131-2 of the Energy Code).

CRE's mission of monitoring wholesale markets aims to ensure that wholesale market energy prices are consistent with the technical and economic fundamentals of these markets. In particular, CRE strives to verify that no market power is exercised in such a way that a participant abuses its situation to attain abnormal prices, notably with regard to its costs.

This task is now also in line with the Regulation on Energy Market Integrity and Transparency known as REMIT. REMIT came into force on 28 December 2011 and implements a regulatory framework adapted to energy markets: it prohibits market abuse, especially in relation to physical fundamentals, and coordinates the monitoring of these markets at a European level by assigning tasks to the Agency for the Cooperation of Energy Regulators (ACER), in collaboration with national regulators. Any investigations and sanctions fall within the remit of national regulators, who should have been granted the necessary powers to guarantee bans on market abuses and the obligation to publically disclose inside information by 29 June 2013 at the latest.

The monitoring of energy markets is based on the registration of all wholesale energy market stakeholders and a centralised collection of trading and fundamental data by ACER. The contents and exact fields of these data will be set out by implementing measures of the European Commission which should be adopted during 2013 and which will mark the start of the operational implementation of REMIT. Market participants should register within three months following the adoption of these implementing acts, and the data collection will start six months after this date. CRE actively contributes to the implementation of REMIT by taking part in the working groups of ACER and the CEER on market integrity and transparency. It was particularly active in drafting the first two editions of the guidelines published by ACER on the application of the REMIT definitions as well as the recommendations of ACER about the data collection.

The REMIT regulation is related to the European financial regulation, which is itself in the process of being reviewed. Indeed, any wholesale energy products which fall under the definition of financial instruments are subject to the prohibitions set out in the market abuse directive (MAD). Moreover, if there is a proposal for CO_2 allowances to be included in the review of the markets in financial instruments directive, REMIT provides that the monitoring of wholesale energy markets by ACER takes into account interactions with the carbon market. The harmonised monitoring of European energy markets will consequently require effective cooperation between energy and financial regulators, ACER and the European securities and markets authority (ESMA).

In France, the banking and financial regulation law of October 2010 broadened the scope of supervision of CRE to transactions on the CO_2 market carried out by market participants within its scope and established a principle of enlarged cooperation with the AMF, formalised by a memorandum of understanding in December 2010. This regulatory framework thus allows for an efficient implementation at the national level of the targeted architecture of regulation at the European level.

This fifth surveillance report of the CRE presents and analyses the developments of wholesale markets in France in 2011 and the first semester of 2012 for electricity, gas and CO_2. It also details the investigations carried out in relation to the behaviour of stakeholders or in case of particular market events.

On the electricity market, the average spot price increased slightly and was established at €49/MWh (baseload), i.e. an increase of 3% compared with 2010; the price of the Calendar 2013 product increased following the German moratorium on nuclear energy before gradually decreasing over the second half of the year. The announcement of the moratorium also resulted in a price differential reversal with Germany (German prices becoming more expensive) until February 2012. Volumes traded also remained stable despite a drop in trade on the futures market.

On the gas market, the LNG offer in Europe and France clearly fell on account of trade-offs with the Asian market where demand greatly increased following the accident of Fukushima, with gas replacing nuclear in electricity generation. Gas prices rose on average but remained more stable than in 2010 both on spot markets and futures markets. They progressed, however, at a lower rate than oil products on which long term supply contracts are indexed. The discrepancy between prices on wholesale gas markets on the one hand and prices of oil products on the other yet again widened as from the second half of 2011. In this context, volumes traded continued to grow and reached 400TWh in 2011.

In the first half of 2012, the development of wholesale electricity and gas markets lost momentum, as volumes traded fell sharply on term contracts markets in particular. The cold snap of February 2012 also resulted in price spikes on electricity and gas spot markets. The CRE led investigations into these market episodes and published its conclusions in the decisions of 10 May and 26 June 2012.

On the CO_2 market lastly, the 2011 price of the EUA fell by 10% in relation to 2010, to €13/t. In the first half of 2012, the price continued to fall and reached €7/t at the end of June 2012, in a context of excess supply of allowances. The possibility of banking allowances from phase II to phase III which will begin on 1 January 2013 constitutes the main factor to prevent a price collapse by the end of 2012. Given the price levels for coal and gas, the weakness of CO2 price encourages European industrials to produce coal-based electricity despite the comparative advantage of the gas sector in terms of CO_2 emissions.

The report also includes details about the data collection of CO2 transactions carried out by CRE among market participants who fell within the scope in 2011.

Summary

Electricity market

- **Electricity prices and trade**

In 2011, in a context marked by milder temperatures than in 2010 and a falling national electricity consumption, the volumes traded on the French intermediate wholesale markets remained stable at 696 TWh. This stagnation conceals a contrasting development between a fall in trade on the futures markets and an increase in volumes traded in relation to spot products. The fall in volumes of term contracts transactions was particularly heightened in the first half of 2012.

French net exports doubled in 2011, mainly due to a sharp fall in imports. This development relates to nuclear availability which was particularly high in spring and summer compared with previous years. Cross-border flows displayed a certain continuity for the first six months of 2012, except on the border with Germany where the balance became negative again as a result of the cold snap of February 2012 which led to a rise in imports and lower nuclear availability.

The average spot price slightly increased in 2011 to €48.9/MWh in baseload and €60.7/MWh in peakload, i.e. an increase of 2.9% for these two products compared with 2010. In the first half of 2012, marked by price spikes during the cold snap in February, the baseload price remained at a similar level while the peak price reached an average of €62.4/MWh, representing a rise of 4% compared with the same period in 2011. Over the whole period, the variations of French spot prices were in line with fundamentals and especially with the power supply system margin indicators. The February price spikes were analysed specifically.

On the term contracts market, if prices increased on average in 2011 compared with 2010, they experienced a downwards trend as from the mid-point in 2011 which continued throughout the first half of 2012, in conjunction with coal prices.

The price changes in France and Germany must be looked at in the context of the extension of the trilateral market coupling to Germany at the end of 2010 then the German moratorium on the production of nuclear power announced in March 2011 after the accident of Fukushima. The market coupling clearly improved the convergence rate of hourly prices, which was established at 64% in 2011. This convergence rate was, however, reduced when the moratorium was announced. On the term contracts market, the prices spread in Y+1 contracts between France and Germany was sharply reduced in 2011 and French prices were lower than German prices as from June 2011. The price spikes of February 2012 put an end, however, to this price reversal.

- **The analysis and transparency of production**

In 2011, on account of the particularly high nuclear availability, the nuclear production rate reached 78%, i.e. the highest level since 2007. If this trend continued over the first three months of 2012, the availability and production rates of nuclear power plants sharply fell in the second quarter. This fall is particularly related to the time taken to return shut down nuclear power plants to working order (cf. section 3.1).

2011 was particularly dry and the water reserves remained at very low levels compared with those from previous years. The levels of reserves were restored in the second quarter of 2012 on account of the very wet spring (cf. section 3.2).

The marginality of the various technologies drastically changed in 2011 compared to 2010: the marginality duration of the hydroelectric power plants fell sharply on account of the low hydraulicity, while the borders and the thermal fossil fuel power plants were more often marginal in 2011. The marginality of nuclear power plants remained limited at 12% (cf. section 3.2).

Concerning the transparency of generation data, the system implemented by the UFE (French Electricity Union) and RTE (transmission system operator) was supplemented by the publication of the wind power day-ahead geenration forecasts, the publication of day-ahead generation forecasts for the reference fleet and by the publication, within one hour, of the generation data for the units of more than 100 MW. In 2012, the transparency platform was equipped with a page enabling producers to declare any additional information to the data already published, especially data related to forecasts and unplanned outages. This development enables the generators to fulfill the obligations of the regulation on wholesale energy market transparency and integrity (REMIT) (cf. section 3.3).

If improvements have been made to the transparency system, the data transmission rate declined in 2011: for availability forecasts, 84% of the necessary information was sent in 2011 as opposed to 90% in 2010. CRE also continued to monitor the difference between day-ahead forecast and actual availability for nuclear facilities. In 2011, this gap fell compared to that observed in 2010 (cf. section 3.3).

Regarding the use of EDF generation assets, CRE conducts a particular monitoring of the gaps existing between the prices on the spot market and the marginal costs of the EDF system resulting from calculations by its daily optimisation models. On average, in 2011, the price-cost gap increased by almost 2 points to 5% as opposed to 3.2 % over 2010 but remains lower than the gap observed in 2009 (6%). EDF explained this increase by a more significant difference in costs in the area of discontinuity of its supply curve where generation switches from nuclear to coal. Prices were also formed near this area of discontinuity more frequently than in 2010. CRE considers that the gap observed throughout 2011 is at levels which do not constitute an abuse of a dominant position (cf. section 3.4).

CRE carried out a similar analysis in relation to the gaps between the bids submitted on the balancing mechanism and the marginal costs of EDF's thermal power plants and observed greater gaps than on the spot market. EDF provided a certain number of explanations, and, in particular, the application of an additional cost element on all their bids on the balancing mechanism to cover costs and risks particular to this mechanism. Based on the update of the latest data, EDF revised downwards this additional cost element. CRE will continue extensive work on the magnitude of the differences (cf. section 3.4).

- **Transactions analysis**

Analysis of the offers submitted on the EPEX SPOT Auction platform shows, like in 2010, that the level of offers reflects the tension on the electrical system and that the supply between 100 and €300/MWh remains limited. Moreover, demand below €100/MWh decreases while demand at any price increases (cf. section 4.1).

Concerning cross-border trading, CRE assesses individual transactions of market participants compared to price spreads. CRE also investigated the use of intraday interconnection capacity on the France-Germany and France-Switzerland borders (see Analysis and Investigations part).

CO_2 market

- **Development of the institutional framework**

Since the end of 2010, pursuant to the banking and financial regulation law, the CRE monitors the CO_2 market for participants which enter its scope of supervision. The regulatory framework for the CO_2 market set out at the European level foresees the inclusion of CO_2 within the scope of the financial regulation with the qualification of the CO_2 allowance as a financial instrument (cf. section1.1).

Within the framework of the memorandum of understanding of 2010, CRE and the AMF developed an efficient cooperation, with complementary monitoring scopes of the CO_2 market, joint analysis work and a regular trading data collection by CRE from the AMF (cf. section1.2.1).

Phase III of the EU Emissions Trading Scheme (EU ETS) which will enter into force on 1 January 2013 and last for eight years will bring about significant changes in the distribution of allowances. About half of the allowances will be sold at auctions (100% for the electricity sector). Auctions for Phase III will initially take place on the joint transitional platform EEX as well as on the individual platforms EEX in Germany and ECX in the UK[1] (cf. section1.3.1).

[1] Germany, UK and Poland decided to opt for individual platforms whereas 24 other European members will use the joint auction platform for Phase III.

- **The bilateral collection of 2011 transactions data carried out by CRE**

Failing a generalisation in the centralised collection of CO2 data, CRE launched in March 2012 a bilateral data collection relating to transactions carried out in 2011 by market participants which enter the scope of supervision. These include all the companies active on the electricity and gas markets in France and recorded as a balancing responsibility entity or shipper. The bilateral collection has spread over time and required many exchanges with the market players. A centralised data collection approach is therefore still favoured through the implementation of a systematic collection from European exchanges and brokers platforms, until a generalised collection is implemented at the European level. A new bilateral collection may be conducted by CRE if brokers have still not adhered to the approach, or if an exceptional event occurs on the market (cf. section1.2.2).

Of all the data collected, non-intermediate bilateral transactions represent a limited volume (10%). On the intermediate market (exchanges and brokers), the share of trading data within the scope of CRE represents almost half of total European transactions for all products (cf. section 2.4).

- **The European CO_2 market and its fundamentals**

The volumes traded on CO_2 markets increased by 15% in 2011, with over 9.6 billion tonnes of CO_2 in 2011 compared with 8.3 billion in 2010. These transactions relate primarily to futures products (cf. section 2).

The EUA price decreased by 10% in 2011 and reached an average of €13/ t. In the first half of 2012, the price fell again and stabilised around an average price of €7/t. The CO_2 allowance price notably varied according to announcements on European energy policies. Thus, the announcement of the German moratorium on nuclear power caused the price increase in March 2011 while the draft directive on energy efficiency helped to bring down the price as from June 2011. The low CO_2 price was mainly due to the surplus of allowances that characterised the European carbon market at the end of Phase II. Under these conditions, the possibility of bankability or carrying forward allowances from Phase II to Phase III was the main factor that would prevent a price collapse by the end of 2012 (cf. section 3).

In 2011, the allowance offer again exceeded demand, in line with the trend observed since 2009. The excess allowances thus amounted to 11% in 2011 compared to 7% in 2010. The accumulated surplus of allowances prompted the European institutions to consider setting aside a portion of the allowances for Phase III. Thus, the Commission proposed three options for reducing carbon allowances or delaying auctions for Phase III, while the European Parliament was in favour of a reduction of 1,400 Mt of market allowances (cf. section 4.1).

Finally, the CO_2 and coal price levels contributed to the widening gap between clean sparkspread and clean darkspread (which respectively measure the theoretical profit of gas-powered plants and coal-fired power stations) in favour of the latter and encourage industrialists to produce electricity from coal (cf. section4.2).

GAS MARKET

- **Prices and gas trading**

2011 was characterised by a decline in the demand for gas due to the economic downturn, the lack of competitiveness of gas compared to coal and especially on account of the mild temperatures compared to 2010. The gas supply remained abundant on global markets, especially due to the significant production of unconventional gas in the United States. The LNG supply in Europe decreased significantly, however, due to trade-offs with the Asian market, where gas prices were higher (cf. sections1 and 2.4).

In this context, stakeholders continued to rely more and more on wholesale markets. Nearly 400 TWh were traded on the intermediate French markets, i.e. an increase of over 60% compared to 2010. Volumes delivered to PEGs (Point d'Echange Gaz – gas trading hubs) show the same development with 467 TWh delivered, a level close to the French final consumption. The first half of 2012 however breaks the trend compared to previous years, with a decline in trading volumes, especially on term contracts markets (cf. sections1.1 and 1.2).

Wholesale gas prices in France on the spot market were higher on average than in 2010 (+30% to €22.9/MWh), but remained relatively stable in 2011 as there was less volatility. Prices reached record levels in the first half of 2012 when the cold snap struck in February; this was an episode that has been specifically analysed by the CRE (cf. section 2.1). Moreover, the spread between spot prices on PEG Nord and PEG Sud reached particularly high levels in the first half of 2012 in a context of tight supply in the south of France due to the decline in LNG supplies, the saturation of the North/South link of GRTgaz and increased flows to the TIGF zone (cf. section 2.2). This episode is under investigation by the CRE.

On term contracts markets, gas prices followed a similar pattern and stabilised in 2011 at a higher level than in 2010. This increase remained significantly lower than that of oil products on which long term supply contracts are indexed. The disconnection between the prices on the wholesale gas market and the prices of oil and its derivatives thus widened again in the second half of 2011 (cf. sections 2.3 and 2.5).

Moreover, the price gap between European and U.S. markets more than doubled in 2011, reaching €13/MWh, as the price at Henry Hub continued to decline throughout the year. This gap widened in the first half of 2012 (up 41% compared to the first half of 2011), averaging €17/MWh. In a context of more stringent environmental laws, low gas prices encouraged electricity generation from gas-powered units instead of coal-fired units in the US. In Europe, coal prices were therefore contained by lower U.S. demand, as gas prices rose in 2011 compared to 2010 (cf. section 2.4).

- **Usage of infrastructures**

In the first half of 2012, the import capacity of France amounted to 2,900 GWh/day, including 2,375 GWh/day in the North zone, an increase of 10% since 2010. Since October 2010, the commitments of GDF SUEZ vis-à-vis the European Commission to release input capacity, improved the access of newcomers to Obergailbach Taisnières, Montoir and Fos Cavaou. In addition, the number of active shippers on transmission grids increased significantly in 2011 and the first half of 2012 (cf. section 3.1.1).

If the number of users of LNG terminals remained stable, unloading activity sharply fell in the first half of 2012 due to the diversion of cargoes to Asia where gas prices are higher than in Europe. The fall in unloading operations was also greater at the Montoir terminal than at terminals of the South zone. This difference is explained by the structural difficulties linked to supplying the South zone which are a guarantee of the minimal use of the Fos terminals (cf. section 3.1.2).

Regarding the use of storage facilities, the number of users of the Storengy storage areas fell in 2011, as some stakeholders favoured the PEGs. Since 2008, there has been an overall decline in the loading rate at the start of winter, a trend that can be explained particularly by the low spread between winter and summer products on the markets. The cold snap of February 2012 as well as severe temperatures in March involved a large-scale withdrawal during this period, leading to particularly low gas storage levels on 1 April 2012 totalling 31.5 TWh (cf. section 3.1. 3).

In relation to the North/South link, available capacity remained stable in 2011/12 and amounted to 70%-75% of the maximum technical capacity. The tight situation in the South zone in the first half of 2012 resulted in an increased usage of the connection, reaching 92% of the technical capacity available in the second quarter of 2012. Moreover, the reduction rate of interruptible capacity fell in the first half of 2012 compared with 2011 (cf. section 3.1.43.1.3).

Significant investment decisions were made in 2011, including the decision to double the size of the major Rhone pipeline, to double the size of the Hauts de France pipeline and create the Arc de Dierrey, to connect the Dunkerque LNG terminal and to create a new interconnection with Belgium at Veurne. Regarding the development of PEGs, CRE set out the guidelines towards the creation of a single PEG by around 2018, initially with a single PEG Nord by 1 April 2013 followed by a common PEG between GRTgaz Sud and TIGF in 2015 (cf. sections 3.2.1 and 3.2.23.1.3).

Finally, European structural work for access to transmission capacity got underway including the drafting of network codes which will set out common rules for the functioning of gas markets in Europe (cf. section 3.2.3).

- **The supply of newcomers**

There was an increased use of the PEG by newcomers again in 2011 which represented 63% of their supplies, with the rest coming from imports (cf. section 4).

If the supply structure of the North Zone is a continuation of the national model, LNG imports represented a change in newcomers' supply in the South. They accounted for 11% of supplies in 2011 as opposed to 1% in 2010 while the contribution of the North/South connection fell sharply. As regards the South-West area, imports from the South zone more than doubled and newcomers became net exporters on the border between France and Spain.

INVESTIGATION AND ANALYSIS

Pursuant to the provisions of Article L.131-2 of the French Energy Code, "with respect to electricity and natural gas, CRE monitors transactions carried out between suppliers, traders and producers, transactions carried out on organised markets as well as cross-border trades. It monitors the consistency of the offers […] made by producers, traders and suppliers […] with their economic and technical constraints" This surveillance mission now falls within the framework of the European regulation REMIT relating to the transparency and integrity of energy markets. Entered into force on 28 December 2011 REMIT prohibits market manipulation and insider trading on wholesale energy markets.

In 2011 and the first half of 2012, the CRE conducted a number of in-depth assessments on specific market events or into the behaviour of particular stakeholders. Some of these analysises are ongoing.

On the electricity market, analysis was conducted in relation to stakeholders whose behaviour triggered internal alerts or whose trading volumes had risen sharply: all stakeholders interviewed provided technico-economic evidence that could justify their behaviour.

The first quarter of 2012 was marked by concomitant price peaks on electricity and gas markets, at the beginning of February 2012, when a severe cold snap descended on the whole of Europe. Hourly prices during daily auctions on EPEX SPOT France for February 9, were close to €1,000/MWh for several hours in the morning, even reaching € 1,938.5/MWh at 10am. The baseload price was set at €367.6/MWh on Thursday, February 9 and €147.3/MWh the next day: a second auction procedure, or second fixing was triggered for these two days. CRE's deliberation on May 10, 2012[2] reported on the investigations relating to electricity price peaks in February 2012.

CRE concluded that the tension between supply and demand was responsible for the high prices and that the balance between supply and demand had been guaranteed by the maximum usage of most interconnections, except those with Italy and Switzerland. On both these boundaries, the usage of interconnections could be improved by the introduction of market coupling.

CRE also noted that for the auction which took place on February 8, the baseload price after the second auction was higher than the price initially obtained, with significant differences during hours when prices were very high. CRE considered that the changes made by three

[2] http://www.cre.fr/documents/deliberations/communication/pics-de-prix-de-l-electricite-des-9-et-10-fevrier-2012

participants in particular had to be specifically examined, especially by the exchange. CRE therefore made a number of recommendations to the EPEX SPOT to provide all members with the sufficient level of transparency on these findings and improve, if necessary, the second fixing procedure. Finally, CRE is currently completing specific work in the case of the three participants mentioned above.

CRE also analysed the behaviour of some participants during the allocation process of intraday capacity on the border between France and Germany (first half of 2011) and between France and Switzerland (first half of 2012) which reserved capacity at the opening of the window, then cancelled it shortly before the time of delivery, thereby resulting in a blockage of the capacity. The analysis conducted by CRE did not reveal market manipulations within the terms of REMIT. They did however show that these behaviours could lead to sub-optimal use of the interconnection. In its decision of 19 July 2012[3], CRE therefore approved changes in the rules proposed by RTE for the purpose of preventing these behaviours and also made recommendations for the effective use of the interconnection between France and Switzerland.

On the gas market, CRE questioned a market participant whose volumes had increased sharply in late 2010 and early 2011, resulting in a very large market share for a particular market place. CRE reported on its investigations in the previous monitoring report: although no market manipulation was detected, CRE pointed out areas for improvement in terms of risk management and data conservation according to the standard set out by the third package. The concerned market participant informed CRE that it had taken action on these two points. This market episode also involved discussions with the trading venue. CRE reminds the importance of monitoring activity conducted independently by trading venues, which is part of the implementing context of REMIT[4].

During the cold snap in February 2012, the gas prices on the French spot market reached €40.5/MWh and €45.7/MWh at PEG Nord for delivery on February 7 and February 8 respectively, i.e. the highest levels seen since 2006. Although prices increased on all European hubs, France experienced substantial price differentials with some neighbouring markets. In its decision of 26 June 2012, CRE reported on the analysis conducted in relation to this market event[5].

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[3] http://www.cre.fr/documents/deliberations/approbation/regles-d-allocation-de-la-capacite-d-interconnexion-france-allemagne-et-france-suisse

[4] Article 15 of the REMIT regulations provides that "*any person arranging transactions in relation to wholesale energy products in their capacity as a professional promptly notifies the national regulatory authority if they have reason to believe that a transaction may be in breach of Articles 3 [prohibition of insider trading] or 5 [prohibition of market manipulation*]". Article 15 also states that "*persons arranging transactions in relation to wholesale energy products in their capacity as professionals establish and maintain effective provisions and procedures to identify breaches of Article 3 or 5.*"

[5] http://www.cre.fr/documents/deliberations/communication/vague-de-froid-fevrier-2012

CRE considered that the tension between supply and demand explained the high prices on the various European spot markets, but also noted that an improved use of interconnection capacity could have helped reduce the price spreads observed between the French market and neighbouring countries. An investigation into the individual actions of certain market participants has not shown any unjustified behavior, in light of their economic and technical constraints.

Finally, CRE opened an investigation into price formation in the South zone[6]. The second quarter of 2012 was indeed marked by a significant spread between the prices at PEG Nord and PEG Sud. The day-ahead price spread indeed rose sharply in the second quarter of 2012, exceeding the threshold of €6.0/MWh on several occasions. As part of this investigation, the CRE will analyse all individual transactions on the wholesale market, as well as the availability and the usage of gas infrastructures.

Lastly, **on the CO_2 market**, the CRE conducted a thorough analysis, in cooperation with the AMF, into the fall in the CO_2 price at the time of a statement of the European Commission on the draft directive on energy efficiency in June 2011.

[6] Press release of 27 July 2012: http://www.cre.fr/documents/presse/communiques-de-presse/la-cre-ouvre-une-enquete-sur-les-prix-de-marche-du-gaz-au-sud-de-la-france/consulter-le-communique-de-presse

Section I: Wholesale electricity markets

The development of the main segments of the wholesale market

Activity on wholesale electricity markets is mainly related to the optimisation, by producers, of the flexibility of their means of production, trading operations, cross-border trading and the hedging by the market participants of their projected consumption to meet customer needs.

In 2011, the net fall in hydropower generation (-25.6%, or -17.3 TWh) due to the conditions of drought in spring and autumn, was offset by the increase in nuclear generation (+ 13.2 TWh) and the increasing development of renewable sources of energy (27.0% or 4.1 TWh). In total, volumes produced totalled 542 TWh, slightly down (-1.5%) compared to the volumes observed in 2010 (550 TWh).

Particularly mild temperatures and the economic downturn contributed to the decline in domestic electricity consumption. This amounted to 444 TWh (consumption of end clients with the exclusion of pumping consumption and network losses of system operators), i.e. a decrease of 33 TWh compared to the volume consumed in 2010. Electricity trade reflected the decline in consumption and the increased nuclear availability, but also the decision to suspend the use of nuclear power taken by the German government. This resulted in a sharp increase in the net balance (+26.7 TWh), due to less of a reliance on imports, which decreased by 18.1 TWh. In this context, trade on intermediary wholesale markets reached 696 TWh, which reached a similar level to 2010. The decline in trading of futures products was offset by an increase in volumes traded in relation to spot products.

Trends in the first half of 2012, however, were marked by reduced availability of nuclear power and a decline in volumes traded.

Physical deliveries between stakeholders, as a result of contracts placed OTC on wholesale markets (intermediate and bilateral), represented 367 TWh during the same year, or an increase of 8 TWh (+2%) compared to 2010. Figure 1 displays a simplified view of these various flows for the years 2011 and 2010 (figures in brackets).

Graphs 2a and 2b also present the electricity balance of EDF published by the group during the presentation of its half-yearly results[7]. These graphs show that EDF held a net purchasing position on the wholesale market in 2011 and the first half of 2012.

The volumes and valuation of transactions on the French wholesale electricity market are displayed first. The respective developments in volumes traded at borders and volumes purchased for losses by system operators are then presented in the second and third sub-parts. The analysis of the VPP auction mechanism and the concentration of stakeholders involved is addressed in the final part, and the subject of the ARENH (Regulated Access to Incumbent Nuclear Electricity) is deliberately excluded.

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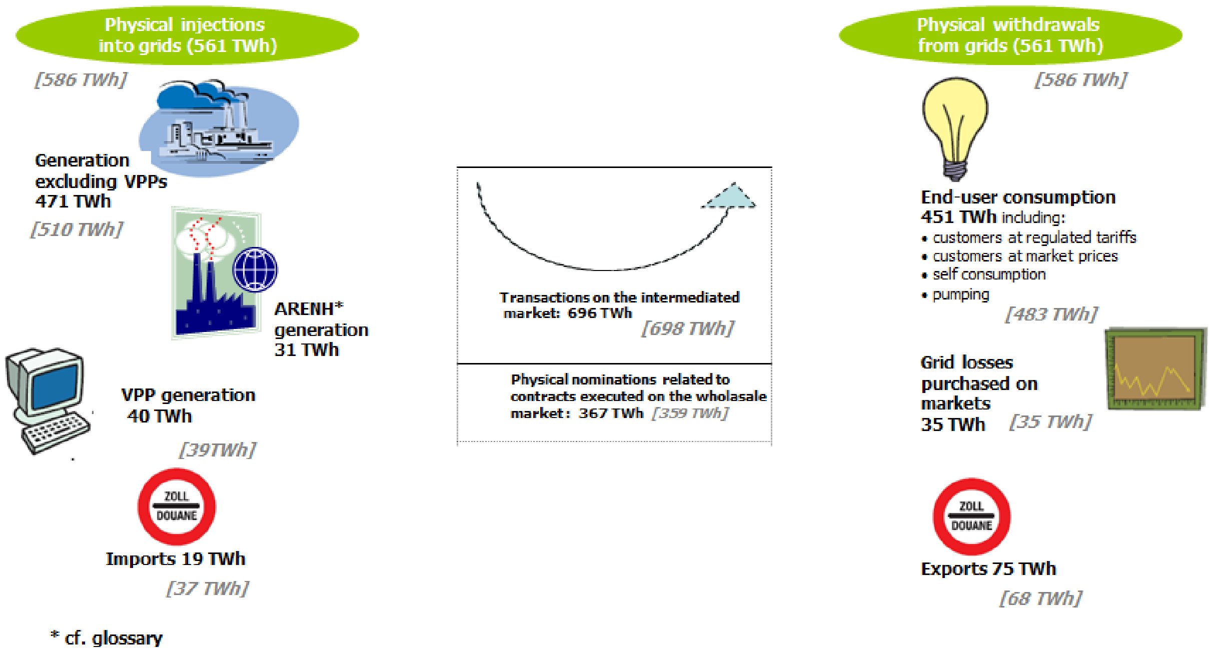
[7] http://finance.edf.com/fichiers/fckeditor/Commun/Finance/Publications/Annee/2012/2011EDFGroupResultats_final_vf.pdfhttp://finance.edf.com/fichiers/fckeditor/Commun/Finance/Publications/Annee/2012/H12012/H12012EDFGroupResultats_5_vf.pdf

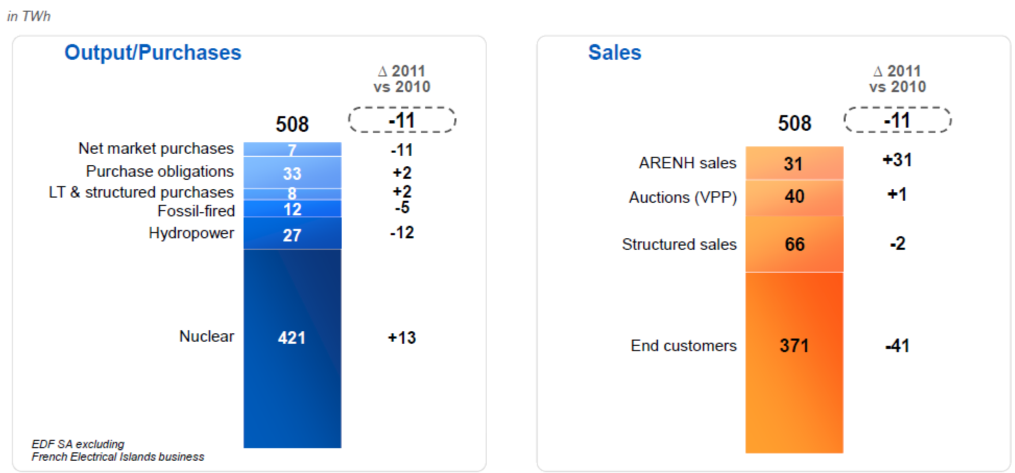
Figure 1: Energy flows between downstream and upstream segments of the French wholesale electricity market in 2011



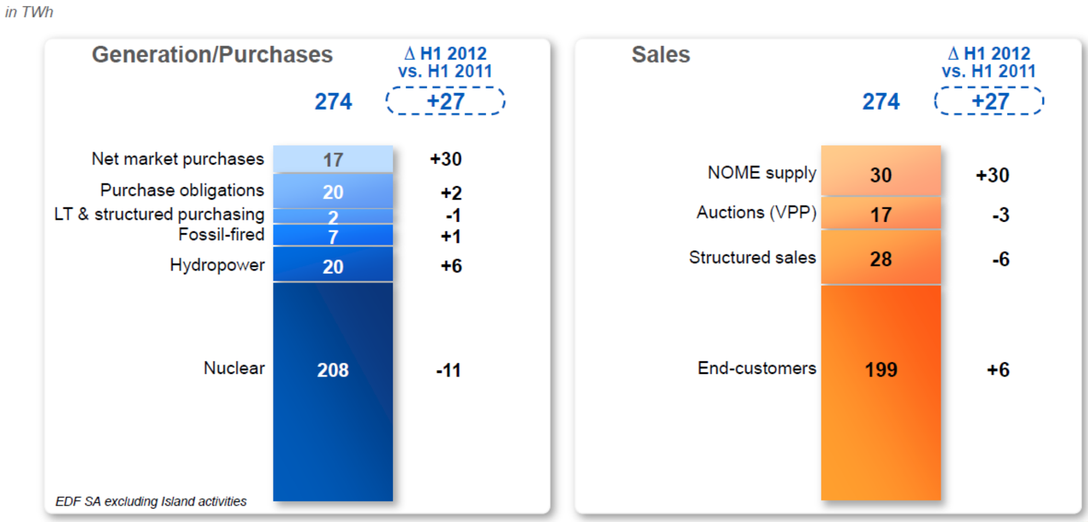
Source: RTE – Analysis: CRE

Figure 2: Electricity upstream/downstream balance of the incumbent operator

a. Electricity upstream/downstream **balance in 2011**



b. **Electricity** upstream/downstream **balance in the first half of 2012**



Source: EDF

DECELERATION OF THE INTERMEDIATE WHOLESALE MARKET IN 2011 WHICH CONTINUED IN A MORE MARKED MANNER IN THE FIRST HALF OF 2012

Activity on the French intermediate wholesale market includes transactions concluded on organised markets and intermediate OTC (brokerage platforms). This covers most of the activity on the French wholesale electricity market, with the remainder being completed by direct bilateral transactions between market participants.

Compared to 2010, the volumes traded on the wholesale market stagnated and amounted in 2011 to 696 TWh for 197, 846 transactions (Table 1). Relating to macro-economic data, trading of electricity in 2011 represented approximately 154% of French consumption, i.e. an increase of nearly 10 percentage points compared to 2010.

In 2011, if the volumes traded on spot products (intraday, Day-Ahead continuous and Day-Ahead auction) increased (+15.6%), they fell on the futures/forwards market (-2.3%) despite the slight increase in the number of transactions in this market segment (Figure 3). This downwards trend in activity on futures markets has strengthened in 2012: the volumes traded in the first half (232 TWh) decreased by 28.4% compared to the first half of 2011.

Table 1: Transactions

a. Volume of transactions

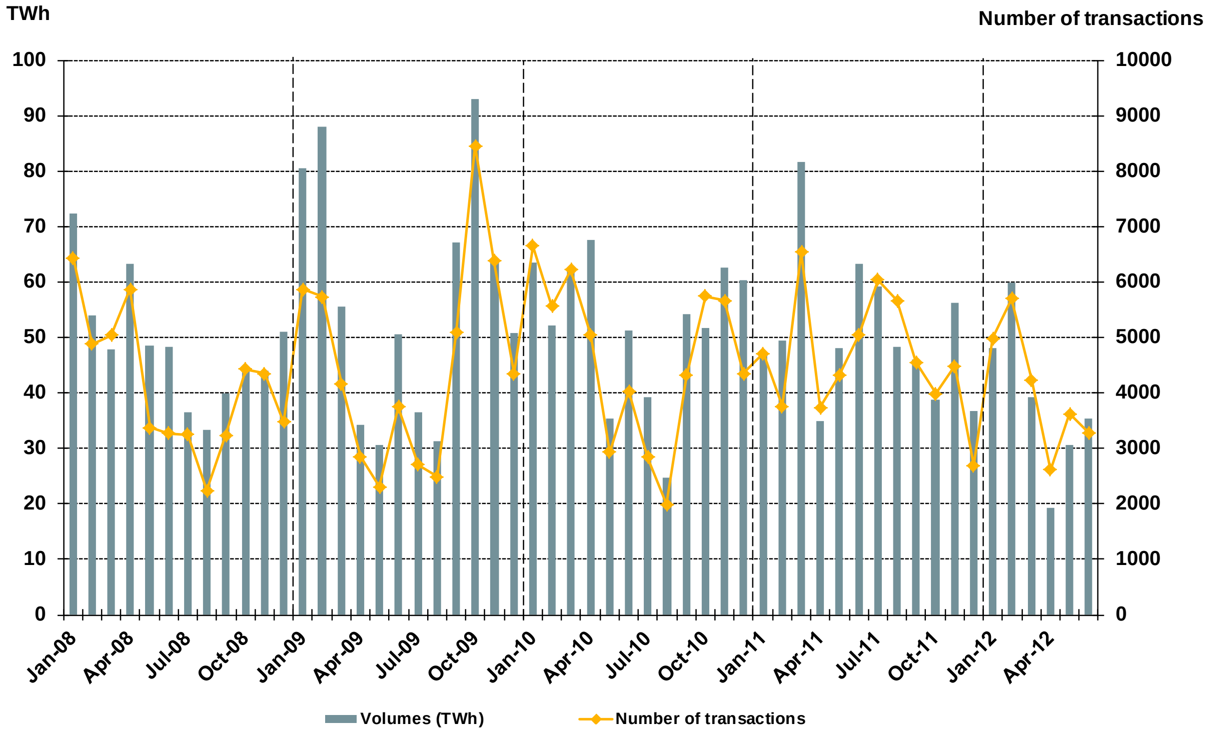
Volumes (TWh)	2010	2011	H1 2011	H1 2012
Intraday	1.1	2.9	1.4	1.6
Continuous Day-Ahead	20.2	22.8	11.1	11.4
Day-Ahead Auction	52.6	59.7	30.2	29.8
Futures market	624.4	610.1	324.6	232.4
Total	**698.3**	**695.5**	**367.3**	**275.2**

b. Number of transactions

Number of transactions	2010	2011	H1 2011	H1 2012
Intraday	31,816	92,486	41,591	57,601
Continuous Day-Ahead	43,045	49,830	23,191	26,531
Day-Ahead Auction	N/A	N/A	N/A	N/A
Futures market	55,320	55,530	28,115	24,448
Total	**130,181**	**197,846**	**92,897**	**108,580**

Sources: Brokers, EPEX SPOT France, EPD France– Analysis: CRE

Figure 3: Monthly changes of volumes and the number of transactions on the intermediate futures/forwards market



Sources: brokers, EPD France ; Analysis: CRE

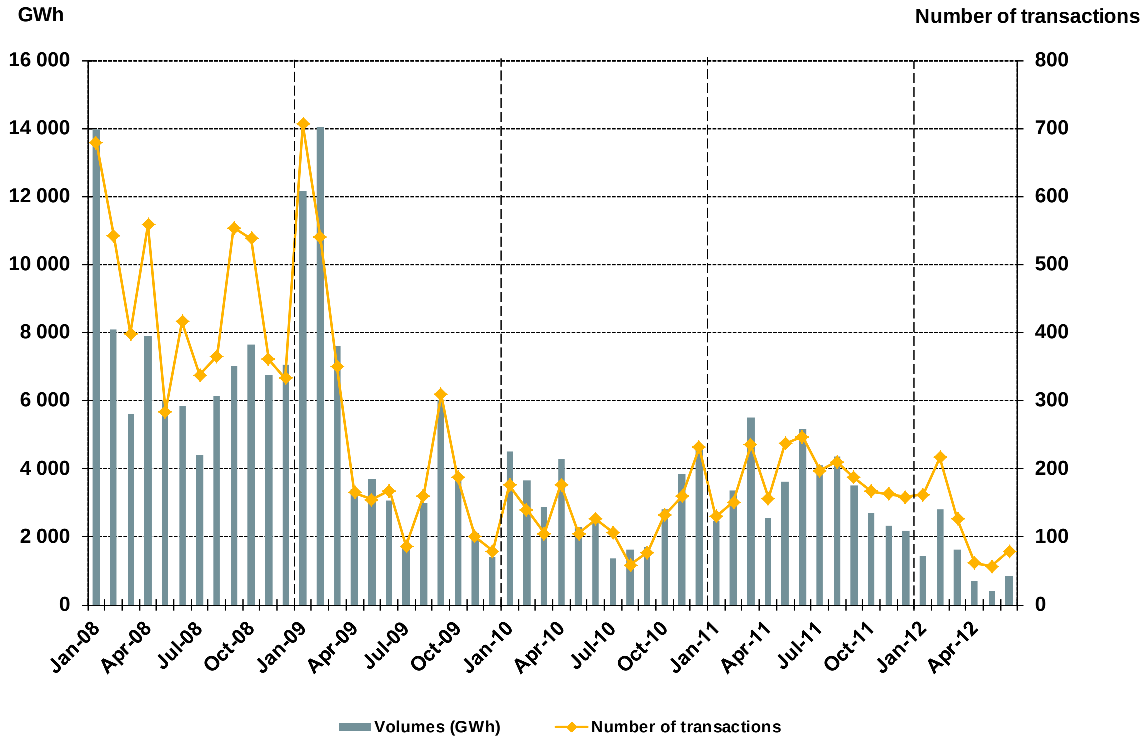
Table 2 describes the quarterly development of trading by product type (monthly, quarterly, annually) by comparing the first half of 2012 to the first half of 2011. The decline recorded in the first half of 2012 was due to a sharp decline in volumes traded in relation to the quarterly and annual products in the second quarter. The decline in futures transactions was also particularly pronounced in the case of exchanges on the organised market (cf. Figure 4).

Table 2: Quarterly distribution of volumes traded by products in the first halves of 2011 and 2012 (in TWh)

Maturity	Q1 2011	Q1 2012	Q2 2011	Q2 2012	H1 2011	H1 2012
M+1	16.9	20.4	17.8	14.5	34.7	34.9
M+2	6.5	6.2	5.6	5.5	12.2	11.8
M+3	2.4	2.1	4.1	2.4	6.6	4.5
Q+1	21.1	18.8	18.1	12.9	39.1	31.7
Q+2	14.2	12.9	23.7	7.7	37.9	20.6
Q+3	21.9	14.9	7.1	2.0	29.0	16.9
Q+4	4.1	4.0	2.6	0.7	6.7	4.7
Y+1	48.0	30.4	36.4	12.0	84.5	42.4
Y+2	15.7	11.2	7.4	6.1	23.1	17.3
Others	27.5	26.5	23.4	21.2	50.9	47.7
Total	**178.3**	**147.2**	**146.3**	**85.2**	**324.6**	**232.4**

Sources: brokers, EPD France ; Analysis: CRE

Figure 4: Monthly changes of volumes and the number of transactions on the organised futures/forwards market



Source: EEX Power French Derivatives

This decline can be linked to the economic downturn, which led stakeholders to shorten their scope of activity on futures/forwards markets. Beyond the macroeconomic context, several specific factors can serve to explain this decline and were in particular raised by market stakeholders:

- A lower recourse to the market since the introduction of ARENH (e.g. .sourcing of losses). In its financial communication for the purpose of publishing its accounts for the first half of 2012, EDF stated that "*the net volumes sold on the wholesale markets were down 30.1 TWh compared to first half of 2011 mainly due to sales to ARENH over the first half of 2012 (up 30.2 TWh).*"[8]

- The end of the VPP (Virtual Power Plants cf. 1.4) auction system;

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[8] According to the financial report of the EDF group, "The net volumes sold on the wholesale market decreased by 30.1 TWh compared to the first half of 2011 mainly on account of the sales to the ARENH ain relation to the first half of 2012 (as much as 30.2 twh), with no equivalent in relation to the first half of 2011".

http://finance.edf.com/fichiers/fckeditor/Commun/Finance/Publications/Annee/2012/H12012/H12012EDFGroupRapportGestion_vf.pdf

- **The number of balancing responsible entities active on the French market grew in 2011**

The number of balance responsible entities active on the French market grew in 2011. This increase is particularly explained by the rise in the number of new French and European newcomers (Table 3).

Table 3: Balancing responsible entities active on the French market

Classification	No. of active BRE					
	2007	2008	2009	2010	2011	H1 2012
Integrated European producers	34	34	37	35	34	35
Other financial traders	24	31	23	25	29	30
New European stakeholders	13	16	18	23	29	29
French producers	8	9	8	6	5	5
New French stakeholders	5	6	6	5	10	11
Industries	5	6	4	5	6	7
LDC[9]	5	4	4	4	4	4
Others	3	4	4	7	6	7
Total	97	110	104	110	123	128

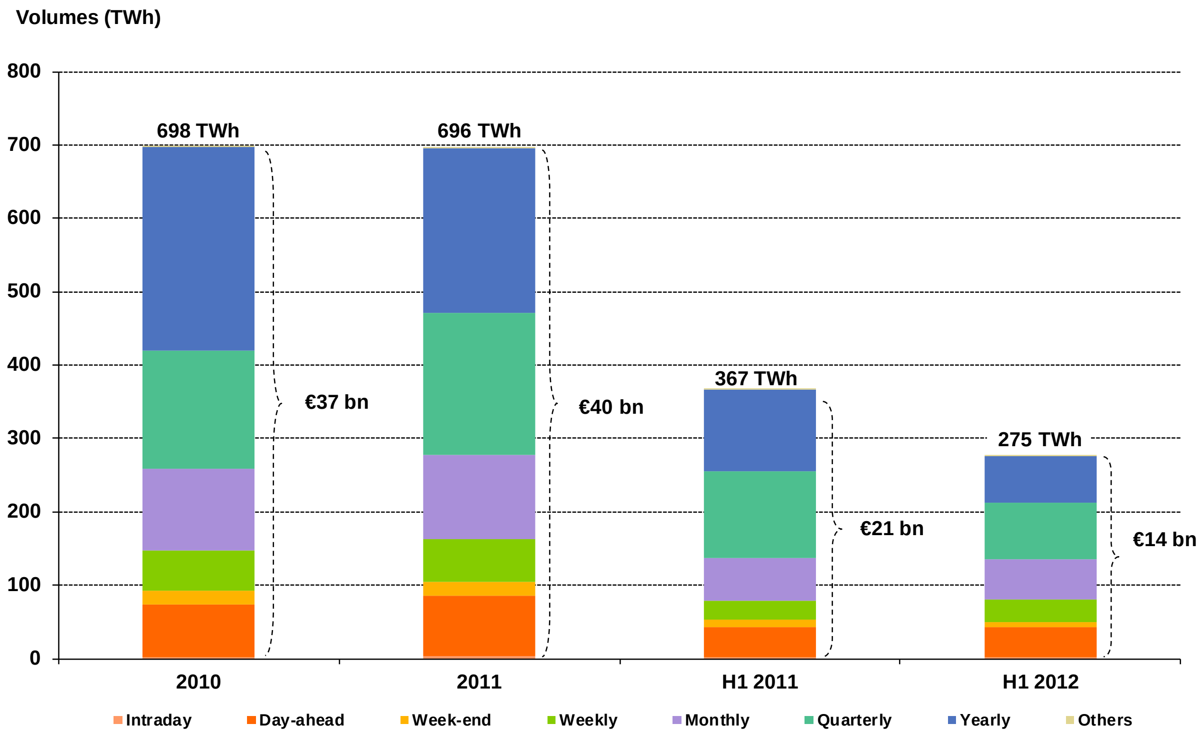
Data: RTE – Analysis: CRE

- **The size of the electricity wholesale market in France reached 40 billion Euros in 2011**

The valuation of trading on the French electricity market increased year on year, from 37 billion Euros in 2010 to 40 billion Euros the following year (Figure 5). This increase in value comes as the total volume traded decreased by approximately 2 TWh. However, at the same time as this decrease, the prices of futures products increased. The same observation can be made about the products of shorter duration and day-ahead products. The increase in market value thus stems from the combination of a positive price effect and a negative volume effect, as the price effect was predominant.

[9] Local distribution companies

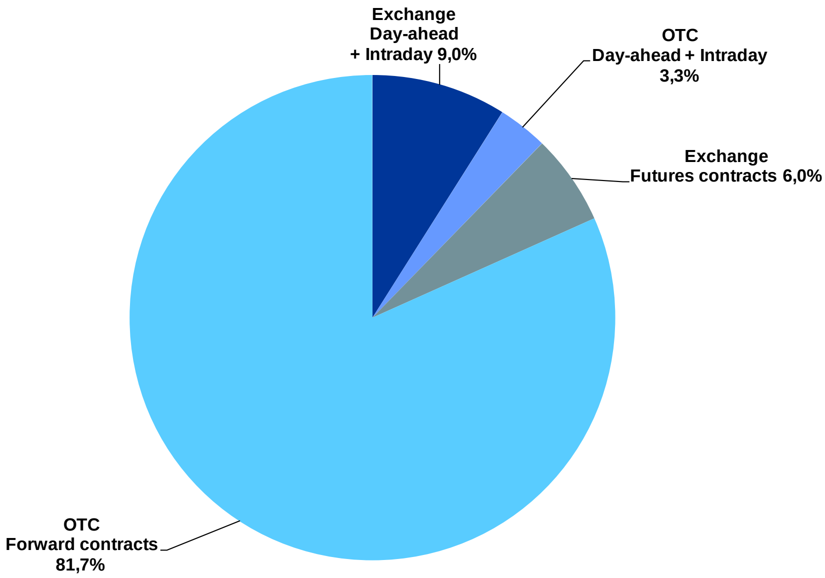
Figure 5: Trading volume and valuation by product (in billions €)



Data: Brokers, EPEX SPOT France, EPD France– Analysis: CRE

Futures product transactions represented 88% of the value traded on the markets. In addition, as the majority of trade are made by mutual agreement, OTC trading platforms amassed about 85% of the value traded on the market, with the remaining 15% being traded on the organised markets (Figure 6).

Figure 6: Trade broken down by platform and by term (%)in 2011



Source: Brokers, EPEX SPOT France, EPD France– Analysis: CRE

CROSS-BORDER NET VOLUMES DOUBLED IN 2011, IN THE CONTEXT OF IMPROVED NUCLEAR AVAILABILITY

- **A very strong increase in net exports due mainly to a decline in volumes imported in 2011**

Table 4 details the maximum values observed for interconnection capacity (NTC) on the various borders in 2011. The interconnection capacity between France and neighbouring countries represented, as regards exports, about 13% of installed generating capacity in France and 11% as regards imports. This percentage is in compliancewith the criterion published in the conclusions of the European Council in Barcelona in March 2002 aiming to set the level of interconnection of countries at 10% of the installed capacity.

In 2011, the volume of electricity traded at borders represented 74.4 TWh for exports and 18.6 TWh for imports (Table 5). The net export balance, at 55.8 TWh, climbed sharply compared to the 2010 (net exports of 29.1 TWh). This increase was essentially related to the imported volumes being halved from 36.6 TWh in 2010 to nearly 18.6 TWh in 2011, combined to a significant increase in exported volumes (8 TWh).

Table 4: Maximum import and export capacities between France and neighbouring countries in 2011 (in MW)

	Germany	Belgium	Spain	Italy	UK	Switzerland	Total[10]
Import	4,500	1,950	1,500	995	2,000	2,600	13,545
As a % of the French network	3.6 %	1.5 %	1.2 %	0.8 %	1.6 %	2.1 %	10.7 %
Export	3,000	3,800	1,550	2,460	2,000	3,200	16,010
As a % of the French network	2.4 %	3.0 %	1.2 %	2.0 %	1.6 %	2.5 %	12.7 %

Source: RTE -Analysis CRE

Table 5: Cross-border trade flows

	Germany			Belgium			Spain			Italy		
in TWh	Imp.	Exp.	Net	Imp.	Exp.	Net	Imp.	Exp.	Net	Imp.	Exp.	Net
2008	19.0	6.4	-12.6	1.9	10.9	9.0	3.0	5.8	2.8	1.8	19.6	17.8
2009	19.2	7.2	-12.0	5.8	3.0	-2.8	3.8	5.3	1.5	1.2	19.3	18.1
2010	16.0	9.2	-6.7	4.7	3.8	-0.9	3.5	1.9	-1.6	1.2	17.4	16.1
2011	7.8	10.3	2.5	1.9	7.6	5.7	3.0	4.5	1.5	0.8	16.8	16.0
H1 2011	4.5	5.6	1.0	0.6	4.6	4.0	1.8	1.3	-0.5	0.4	9.0	8.6
H1 2012	7.1	2.4	-4.7	1.5	5.6	4.1	1.9	3.4	1.5	0.3	8.7	8.4

[10] It should be specified that the import/export capacities per country may not be used at the same time as their maximum at any given time

in TWh	UK			Switzerland			Total		
	Imp.	Exp.	Net	Imp.	Exp.	Net	Imp.	Exp.	Net
2008	1.4	12.7	11.3	7.7	26.1	18.4	34.7	81.4	46.7
2009	4.2	7.4	3.2	9.2	25.7	16.5	43.4	67.9	24.6
2010	5.4	8.3	2.9	5.8	25.1	19.3	36.7	65.8	29.1
2011	2.9	7.7	4.8	2.1	27.4	25.3	18.6	74.4	55.8
H1 2011	1.6	4.0	2.4	1.3	13.9	12.6	10.2	38.3	28.2
H1 2012	1.4	3.8	2.4	3.0	12.5	9.4	15.2	36.4	21.2

Source: RTE - Analysis CRE

The sharp decline in imports observed in 2011 was primarily related to flows from Germany, down 8.1 TWh compared to 2010. Reduced imports were also observed with other borders, albeit to a lesser extent: imports from Switzerland were down 3.7 TWh, Belgium and the United Kingdom reduced their exports to France by 2.8 TWh and 2.5 TWh respectively, while flows from Italy and Spain fell by slightly less than 0.5 TWh. The decline in imports was related to the significant fall in consumption, and good nuclear availability recorded in 2011.

France became a net exporter yet again in 2011 vis-à-vis all her neighbouring countries, while Germany, Belgium and to a lesser extent Spain were net exporters to France in 2010. This finding is consistent with price spreads in 2011 between France and these three countries. French net exports to Germany increased from -6.7 TWh to 2.5 TWh; they rose from -0.88 TWh to 5.7 TWh with Belgium and from 19.3 TWh to 25.3 TWh with Switzerland. They reached 25.3 TWh (3.1 TWh) and 4.8 TWh (1.9 TWh) with Spain and the United Kingdom respectively. Finally, net exports were marginally reduced as regards the Italian border (-0.04 TWh), as exports were reduced slightly more than imports.

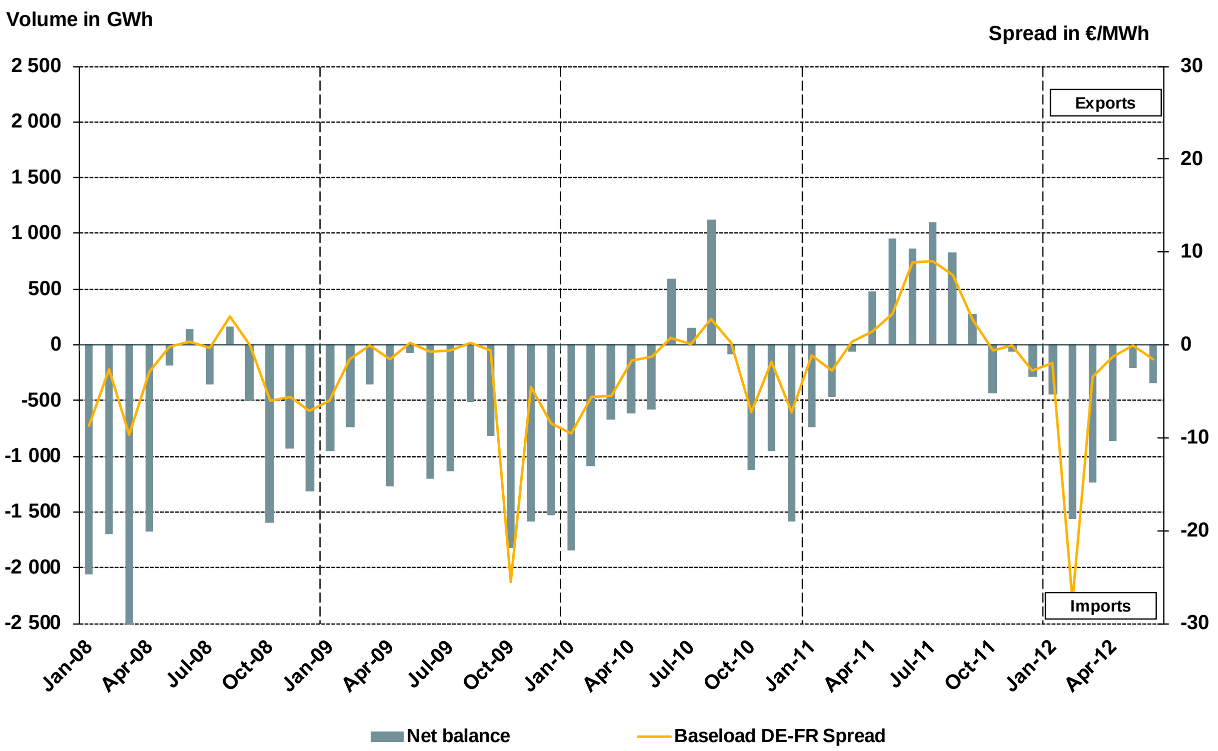
With the exception of Germany, data for the first six months of 2012 show stable flows on interconnections, compared with the same period in 2011. France regained the status of importer with Germany, as exports were reduced by more than half and imports almost doubled compared to the first half of 2011. While the decision about the moratorium on nuclear power taken by the German government in spring 2011 had led to an increase in net exports on this border, the upgrading of electricity prices in France compared to Germany after the cold snap and the very strong growth in renewable generation in Germany reversed the situation in the first half of 2012.

- **Cross-border flows were in accordance with price spreads**

From a general perspective, the observed trade balances on all borders were consistent with the direction of average price spreads in relation to France (day-ahead, off-peak). Monthly changes in net cross-border trade balances are correlated with variations in price differentials, with this correlation being particularly clear in the case of Germany and the UK (Figure 7). The overall consistency of cross-border flows with price differentials did not necessarily imply consistency of all the individual cross-border transactions. At a campany scale, analysis of the behaviour of stakeholders during their interconnection D-1 nominations appear in Section 4.2 of the report.

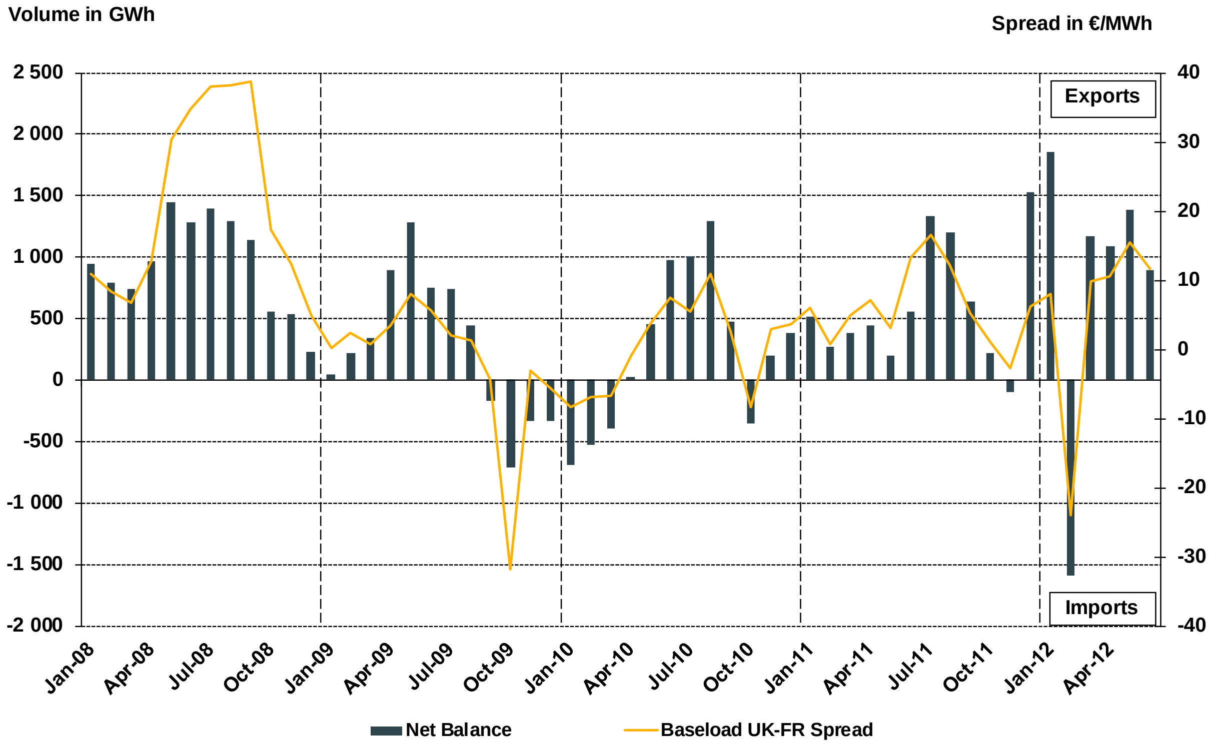
Figure 7: Net export balances and price differentials with neighbouring countries

a. France – Germany



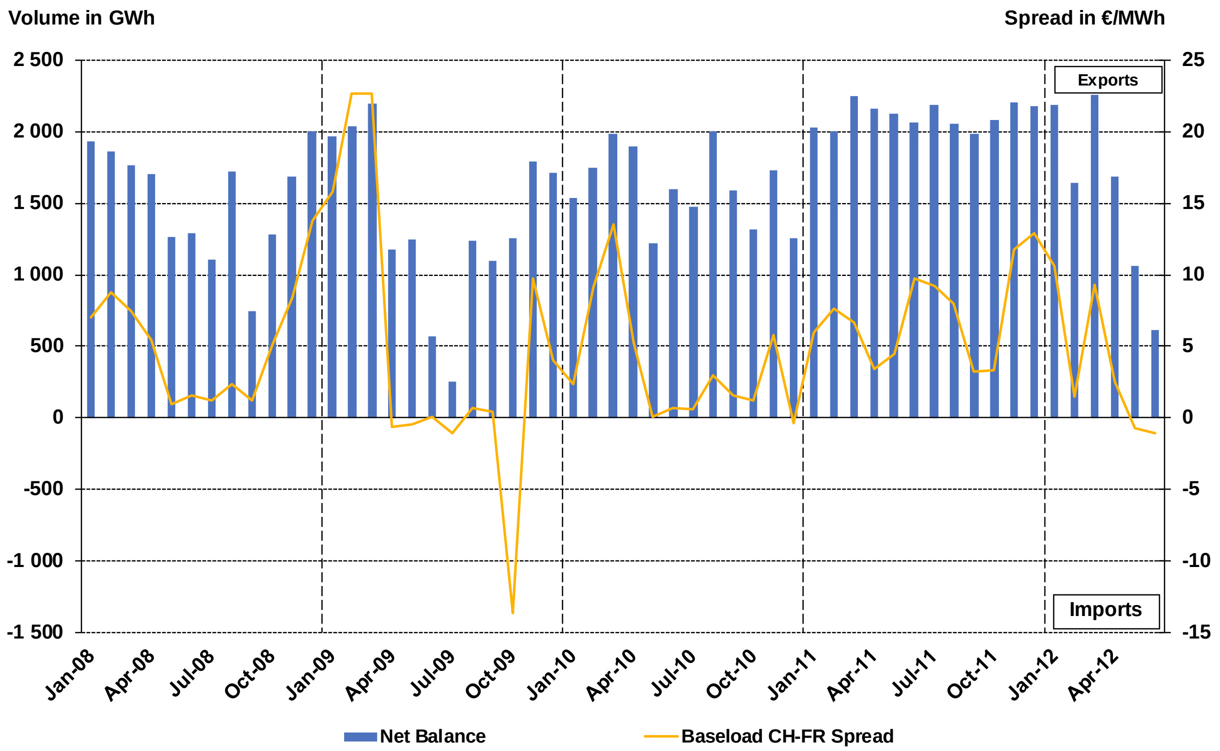
Sources: RTE, EPEX SPOT ; Analysis: CRE

b. France – UK



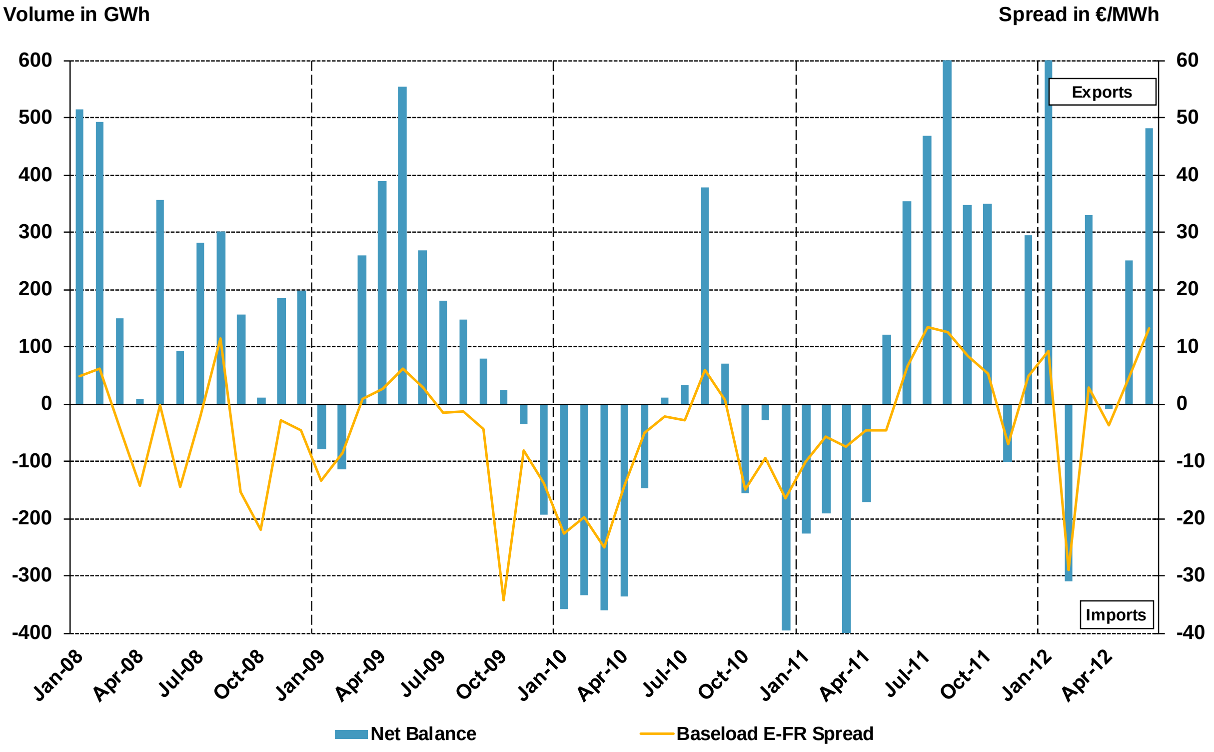
Sources: RTE, EPEX SPOT ; Analysis: CRE

c. France – Switzerland



Sources: RTE, EPEX SPOT ; Analysis: CRE

d. France – Spain

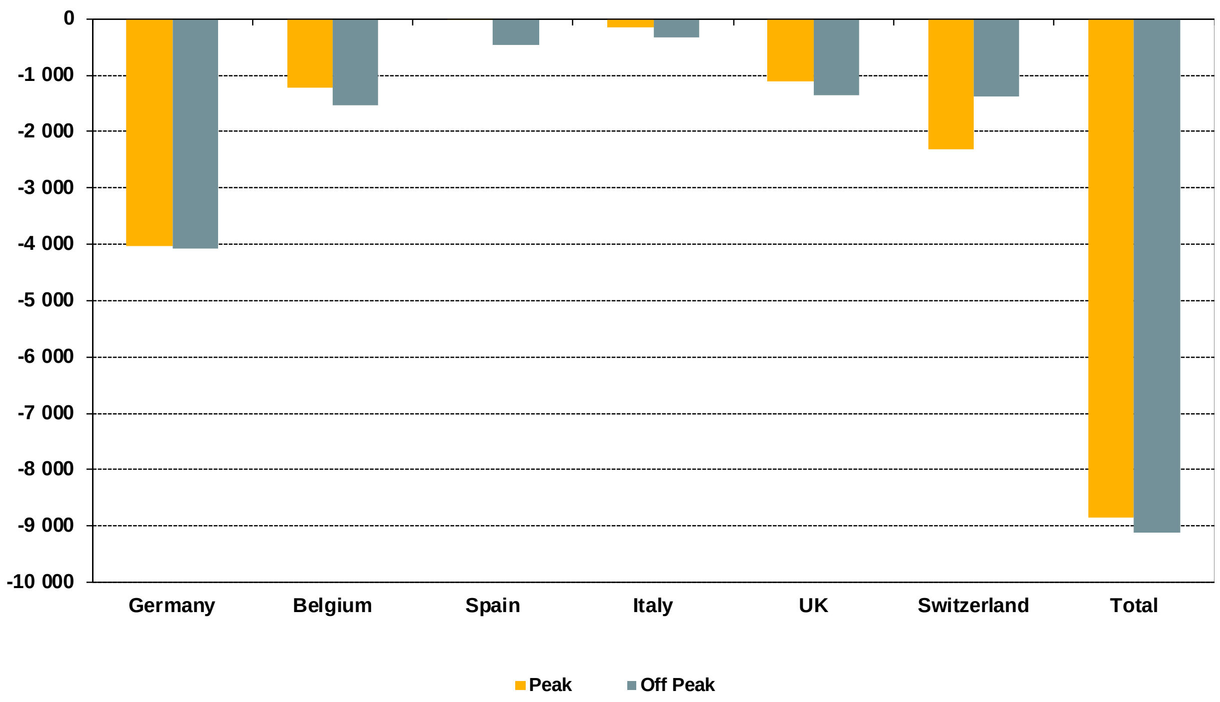


Sources: RTE, EPEX SPOT ; Analysis: CRE

- **A general decline in imports, both at peak and off-peak times, against a backdrop of lower demand**

The decline in imports was evenly distributed between peak and off-peak hours: nearly 51% of the fall in imports may be related to imports at off-peak times (Figure 8).

Figure 8: Changes in cross-border imports between 2011 and 2010 (distribution between peak and off-peak hours)



Source: RTE ; Analysis: CRE

THE VOLUME OF LOSSES PURCHASED BY SYSTEM OPERATORS DECREASED IN 2011 AND THE FIRST HALF OF 2012

Transmission and distribution systems generate energy losses. As a result, when transmitting electricity, system operators EDF and ERDF must purchase a volume representing the amount of the loss.

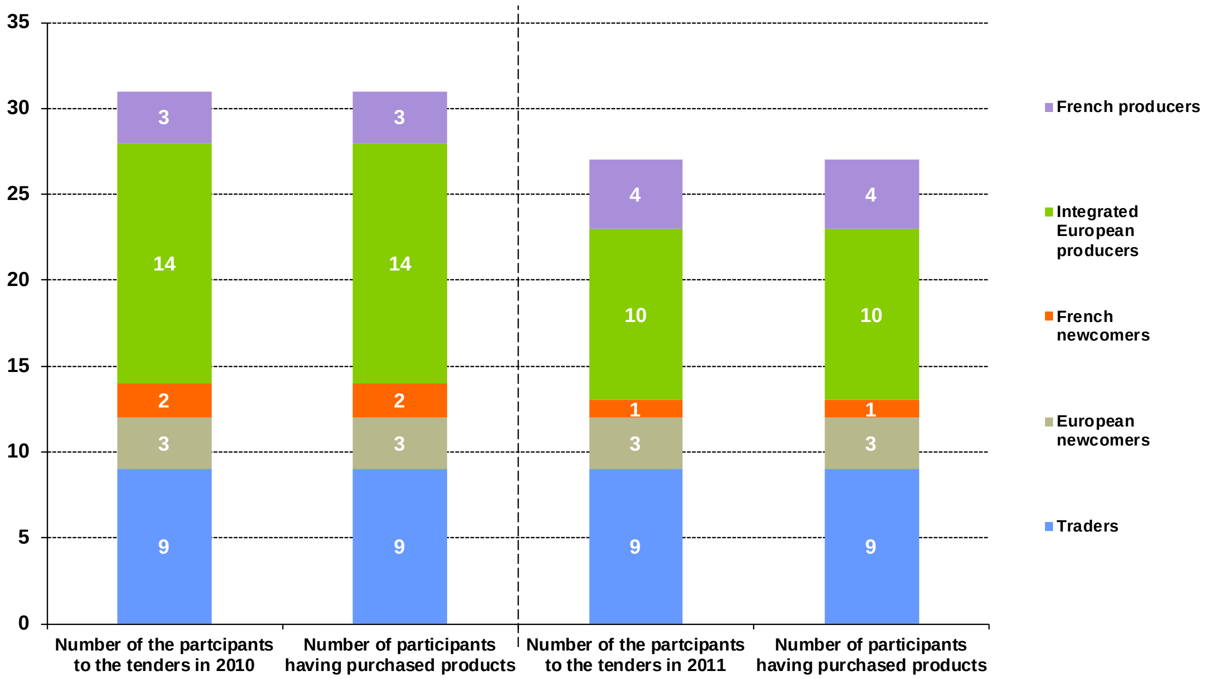
Purchases by RTE and ERDF system operators, as required to compensate for their losses, accounted for 35 TWh in 2011. This figure was down from the 2010 level (37 TWh, or -5.7%). In the first half of 2012, these purchases also declined by 1 TWh compared to the same period in 2011.

Purchases of losses are made during consultations held several times a month by network managers. In 2011, 106 calls for tender were organised by both system operators (121 in 2010); 36 were held in the first half of 2012. Figure 9 shows the number of participants in these consultations.

During these calls for tender, system operators purchased products for which various delivery scenarios were set out: monthly (from M+1 to M+22), quarterly (Q+1 to Q+5), and annual deliveries (Y+1 to Y+4).

It should be noted that system operators may, with effect from 1 July 2013, use ARENH for the purpose of sourcing their losses.

Figure 9: Number of participants in the tenders



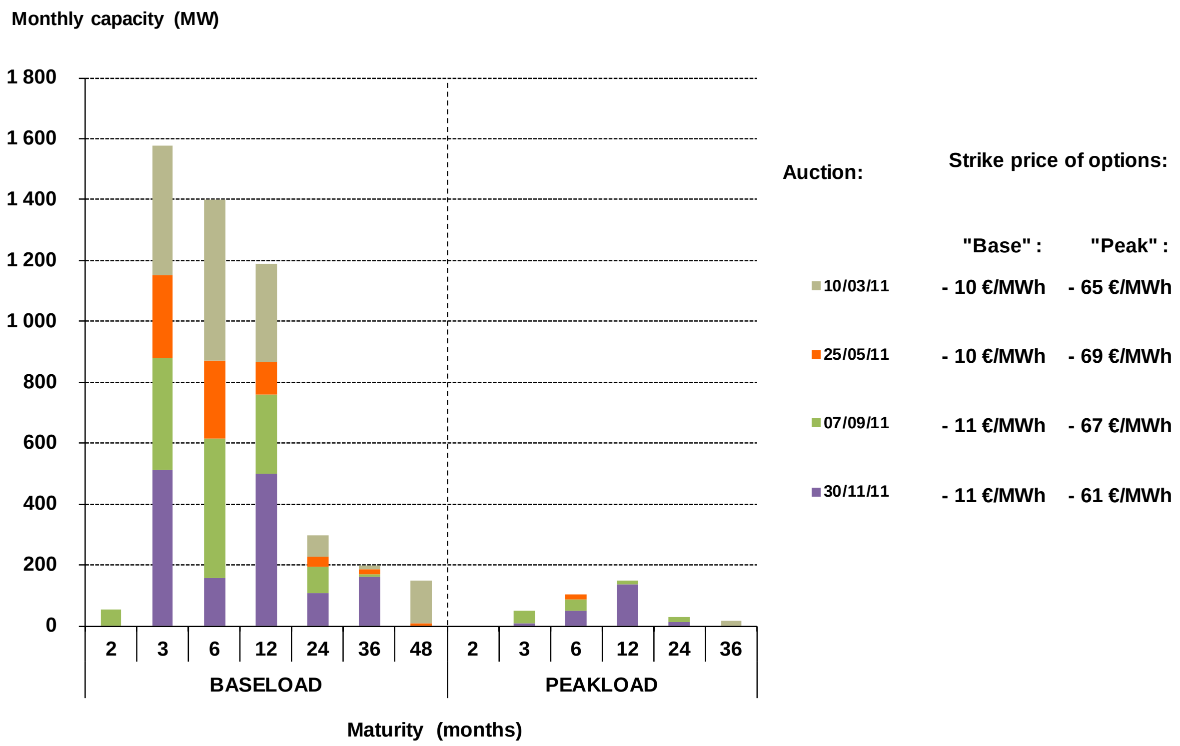
Data: RTE, ERDF ; Analysis: CRE

FOR THEIR FINAL YEAR, THE CONCENTRATION ON VPP ("VIRTUAL POWER PLANT") CAPACITY AUCTIONS REMAINED MODERATE IN 2011

Since 2001, EDF has provided access to 5,400 MW of generating capacity located in France during quarterly auctions, 4,400 MW in the form of base products and 1,000 MW in the form of peak products.Base products, whose exercise price remained low compared to the market price, were comparable to firm products. "Peak" products, whose exercise price was higher, retained, however, a marked optional character.

During the 2011 auctions, the highest purchased products were, in order, base products with a maturity of 3, 6, 12, and 24 months. Figure 10 summarises the maturities of the products sold and the exercise price of the optional products purchased.

Figure 10: Maturity of the products sold at theVPP auction



Data: EDF-Analysis CRE

The European Commission, by a decision of 30 November 2011[11], ended the VPP auctions program. As a result there was a gradual disappearance of VPP capacity available for delivery after 1 January 2012 (Figure 11).

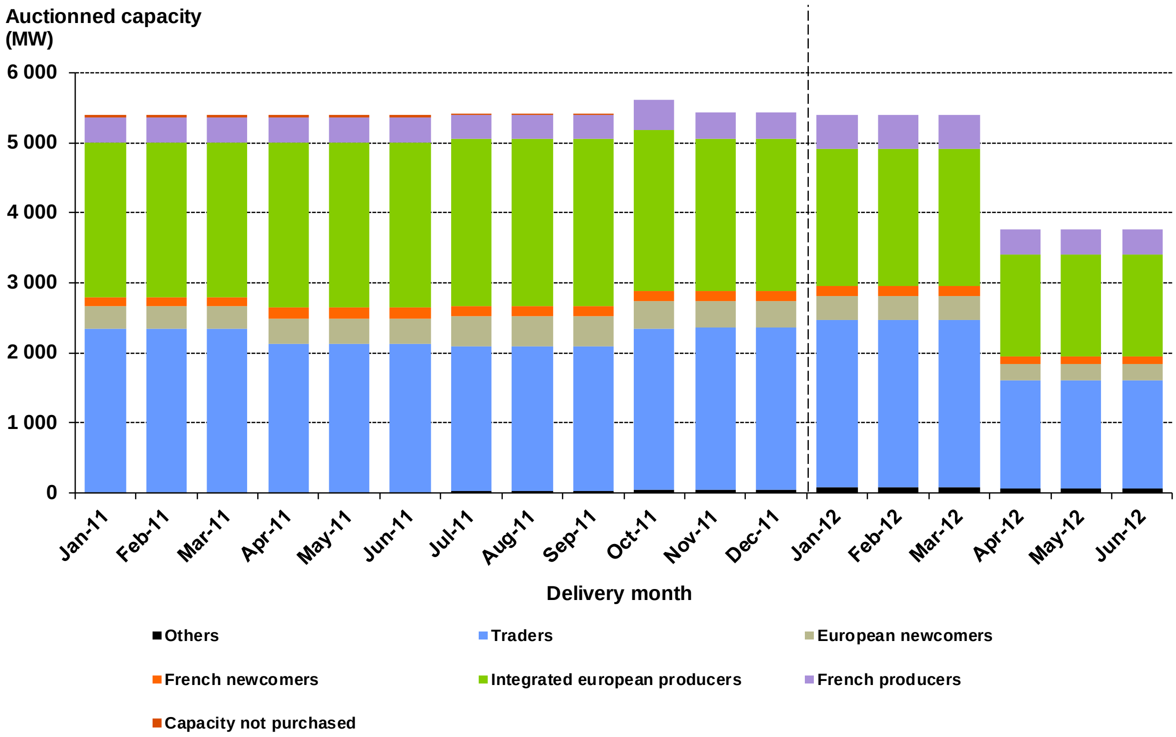
Analysis of the VPP capacity held by each of the stakeholder for a given delivery month, makes it possible to conclude that there was a moderate concentration of this market (Figure 11). Thus, from January 2011 to July 2012, the largest market share at no time exceeded 17% for the base product and 26% for the peak product. In addition, maximum monthly HHI indices recorded during this period were 1,695 for the peak product and 1,231 for the base product, which demonstrated that this market segment was open to a satisfactory degree. These values were, however, higher than in 2010.

"Commodities" had a low exercise price: €10/MWh at auction held in the first half of 2011 and €11/MWh at those held in the second half of 2011. The day-ahead prices in France were more than €10/MWh for 99.4% of the hours in the first half of 2011 and more than €11/MWh for 96.8% of the hours in the second half of 2011. Therefore, the option value of these products was only rarely exercised and it was expected to be awarded at a price which was very close to that of the futures prices of corresponding maturities.

[11] http://encherescapacites.edf.com/fichiers/fckeditor/File/Encheres/DecisionCE_Fin_VPP_301111.pdf

"Peak" products had a high exercise price: between €61 and €69/MWh at auction in 2011. The value of these products was strongly related to the level and expected volatility on day-ahead prices.

Figure 11: Monthly capacities purchased at the auction for delivery in 2011 and the first half of 2012



Data: EDF ; Analysis: CRE

Electricity prices

The development of electricity prices on the spot market from January 2011 to June 2012 should be analysed in a context of slowing economic activity, after the recovery in 2010. The consequent decline in the demand for energy and stagnant commodities prices were determining factors in this development.

The electricity market in 2011 was mainly affected by the effects of the nuclear accident in Fukushima and, subsequently, the German moratorium. This decision had an impact on European energy prices, and especially electricity, both on the spot market and the futures products market. The average baseload price in 2011 increased to €48.9/MWh on the spot market (+€1.4/MWh compared to 2010), while the average price of the Y+1 Calendar baseload contract reached €56.0/MWh against €52.4/MWh in 2010.

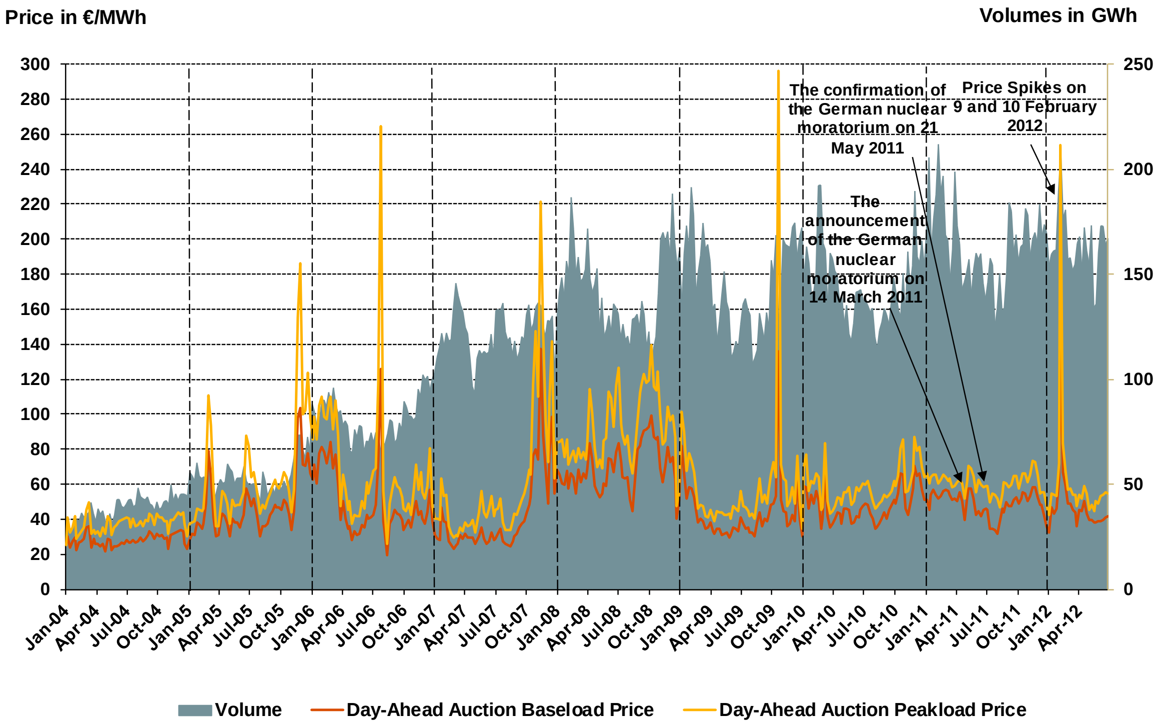
As for the first half of 2012, it was mainly influenced by the hourly price spikes that occurred on the spot market for delivery on 9 and 10 February 2012, in the context of the exceptional cold snap which result in record consumption levels. Although heavily weighted up by the episode of the price spikes, the baseload spot price in the first half of 2012 shows an average of €48.6/MWh, down €2.4/MWh compared to the first half of 2011. Concerning the Y+1 Calendar baseload contract, it fell sharply to €51.2/MWh on average in the first six months of 2012, while it averaged €57.3/MWh during the same period in 2011.

THE 2011 FRENCH SPOT MARKET WAS AFFECTED BY THE EFFECTS OF THE GERMAN MORATORIUM. THE WINTER OF 2012 SAW SIGNIFICANT PRICE SPIKES WHICH WERE INVESTIGATED BY CRE.

The average baseload electricity price reached €48.9/MWh in 2011, an increase of €1.4/MWh compared to 2010 (€47.5/MWh). Concerning the peakload electricity price, the increase was less significant, with the average megawatt hour price averaging €60.7 against €59.5 in 2010.

In the first half of 2012, average baseload and peakload prices on the spot market were €48. 6/MWh and €62.4/MWh respectively, down €2.4/MWh and up €2.4/MWh respectively compared to the same period in 2011. By removing the prices observed throughout the cold snap during the week of 6 to 12 February 2012 (see Box 1), average baseload and peakload prices were €44.8/MWh and €54.8/MWh respectively.

Figure 12: Development of spot prices in France (average weekly prices and volumes)

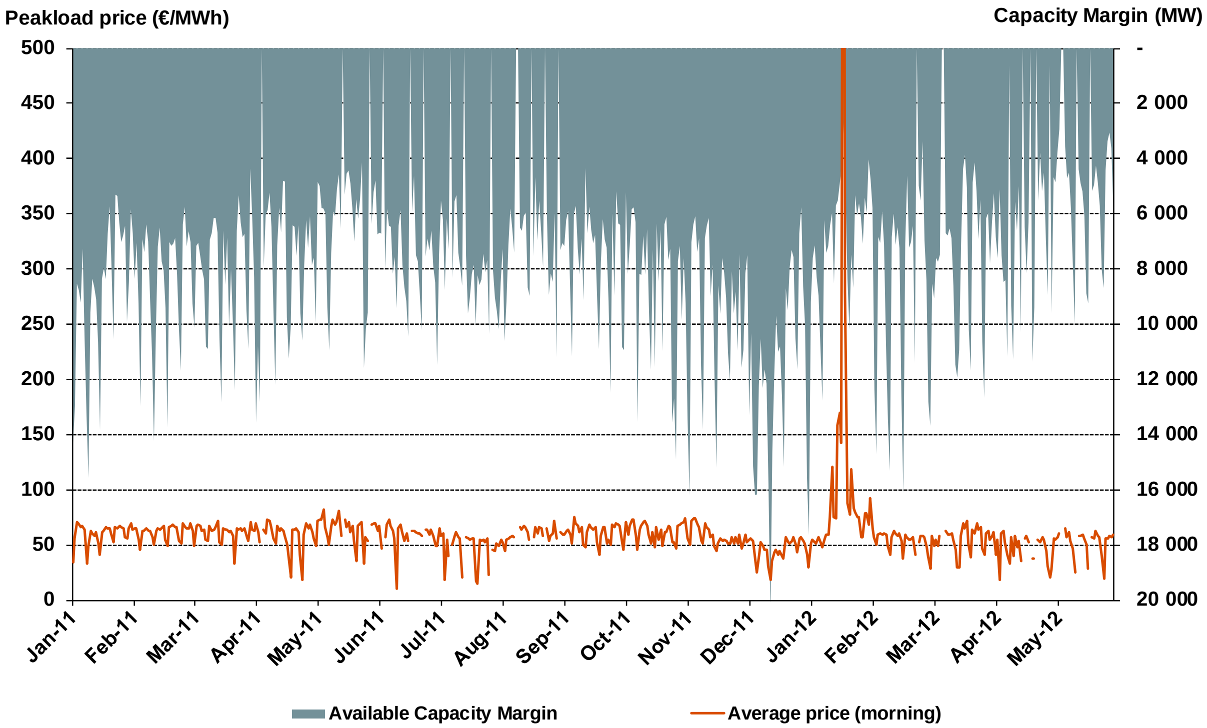


Source: EPEX SPOT

Hourly spot price formation depends strongly on the margin of the system, that is to say, the differential between available generating capacity and load. We see that prices follow an upwards trend when the margin is reduced, especially when it is below 10,000 MW: indeed, more than 70% of prices are therefore greater than or equal to €70/MWh (in 2011 and the first half of 2012). When there is a significant margin between generating capacity and expected consumption, only the less expensive means of production are called upon, resulting in low marginal costs of the system and therefore low spot prices. Conversely, in the event of tension in the power system, more expensive peak generation capacity means are used, which has an impact on the price resulting from the daily auction. During 2011, nuclear availability was very good, thereby increasing the available hourly margins compared to the previous year (more than 28 GW on average compared with nearly 22.7 GW in 2010). Periods of tension on the network were therefore much less frequent. As the first half of 2012 registered a cold snap and a poorer nuclear availability, hourly margins were slightly reduced, regaining an average level similar to 2010. Hourly prices above €100/MWh observed when the margin fell below 10,000 MW were observed during this period, which was not the case in 2011.

Each day, RTE publishes themargin level of the French power system for the morning and evening peak periods (hours of which vary from one day to the next). The comparison of these margins with average spot prices observed during these peak hours reveals the expected relation between the tension level on the French power system and prices set during the daily auction (Figure 13).

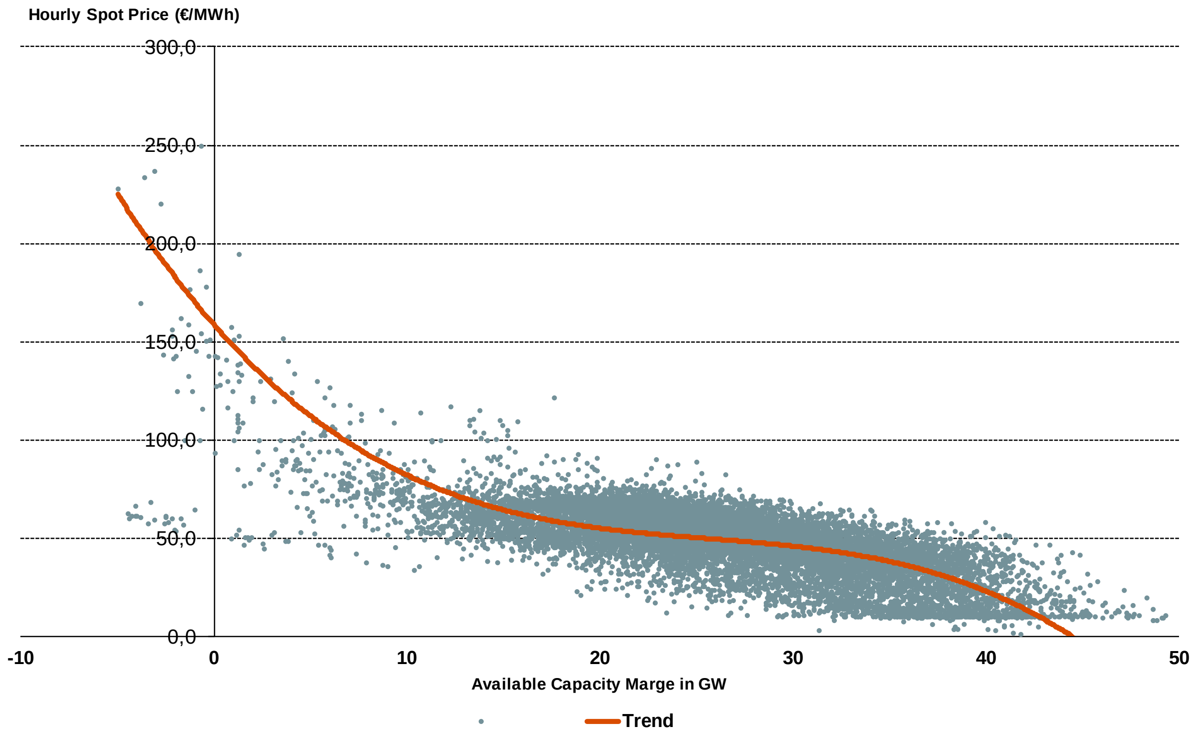
Figure 13: Spot price and RTE margin



Sources: RTE – EPEX SPOT

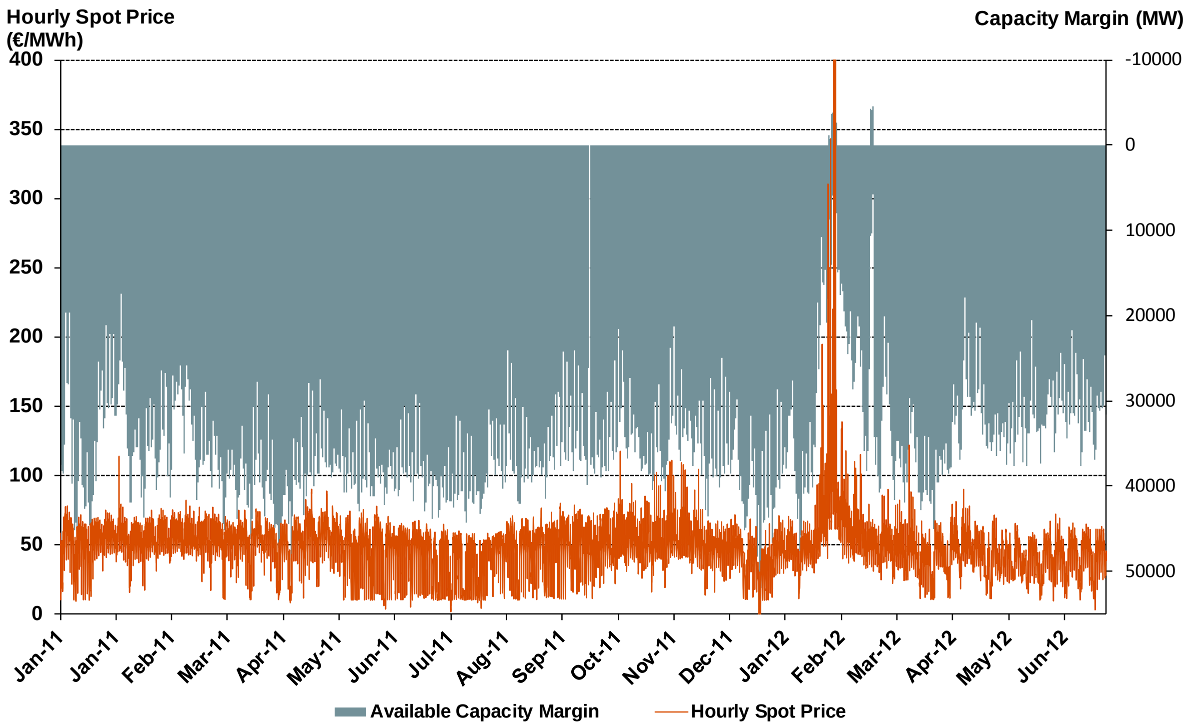
Since July 2009, RTE has also published on its website the availabilities observed (*a posteriori*) for generation units with a capacity exceeding 20 MW (RTE reference generation capacity). This new piece of data allows calculating the margin of the French power system at an hourly scale, defined as the total observed availability of the RTE reference generation capacity minus the actual consumption for a given hour, excluding power plants with capacity of less than 20MW. Unlike the peak margin previously calculated by RTE, this indicator does not take into account the electricity traded at the borders, nor a part of the power plants. Only its variations are therefore significant. A negative correlation is expected with the spot price. This is highlighted by Figure 14 of which each point represents a system margin/spot price pair. Finally, as with the daily scale, hourly spot price fluctuations also follow for the most part those of the margin indicators (cf. Figure 14). Thus, we see that when the hourly margin indicator increases (respectively decreases), the corresponding spot price decreases (respectively increases) in 83% of cases in 2011 and 78% of cases in the first half 2012 (Figure 15). In 2010, this rate was 75%.

Figure 14: Hourly spot price andgeneration margin of the French power system



Sources: Producers – Analysis: CRE

Figure 15: Hourly spot price and generation margin



Sources: Producers – Analysis: CRE

Box 1 : Electricity price spikes in February 2012

The price of electricity on the French spot market (EPEX SPOT Auction) reached on Thursday 9 February 2012 €367.6/MWh for the baseload product and €627.6/MWh for the peakload product. The following day, these prices settled at €147.3/MWh and €192.2/MWh respectively. Hourly prices exceeded the threshold of €500/MWh on several occasions, thereby triggering these two days a second auction procedure or second fixing. For delivery on 9 February in particular, prices were close to €1,000/MWh for several hours in the morning, even reaching €1,938.5/MWh at 10am. These very high price levels were recorded in a particular climatic context: from 1 to 13 February, France and, more generally, Europe were struck by a cold snap, with temperatures well below seasonal averages.

However, only France experienced such high price levels on the electricity spot market. As part of its systematic analysis in the event of a market event of this magnitude, CRE opened an investigation into the factors behind these price levels. In particular, it examined the fundamentals of the French power system which were decisive for the interventions of market stakeholders as well as the operating sequence of the EPEX SPOT exchange that led to the fixing of these prices, and reported on its investigation in its decision of 10 May 2012[12].

CRE found that the tension between supply and demand resulted in the formation of high prices, especially for 9 February. The assessment of actual and forecast availability and consumption data supported this conclusion.

The balance between supply and demand was ensured by the maximum use of most interconnections, with the exception of those with Italy and Switzerland. For these two borders in particular, daily mechanisms could be improved by the implementation of market coupling. In the case of Italy, the establishment of an intraday mechanism, begun in June 2012, should also help improve the use of this interconnection.

In its analysis of the operating sequence of the EPEX SPOT exchange, CRE noted that, for the auction which took place on 8 February, the final price at the end of the second auction was €367.6/MWh, slightly higher than that initially obtained during the first auction (€350.2/MWh). CRE observed, however, greater differences between the initial results and the final results of the second auction, especially during the hours when prices were very high. The way in which different members of EPEX SPOT changed their offers during the second auction led to these results. CRE considered that the changes made by three stakeholders in particular should be investigated specifically, especially by EPEX SPOT in light of the market rules which apply to all of its members. Market rules stipulate that "in case of a Second Auction, only Orders modifications which improve the imbalance between purchase and sale are allowed"[13].

In its decision, CRE therefore recommended that EPEX SPOT examined, in consultation with

[12] http://www.cre.fr/documents/deliberations/communication/pics-de-prix-de-l-electricite-des-9-et-10-fevrier-2012

[13] Article 1.7 of the operational rules of EPEX SPOT

its members, the measures required to:

- provide all of its members with the sufficient level of transparency on these findings;

- improvetheir understanding of the conditions for triggering and conducting the second fixing;

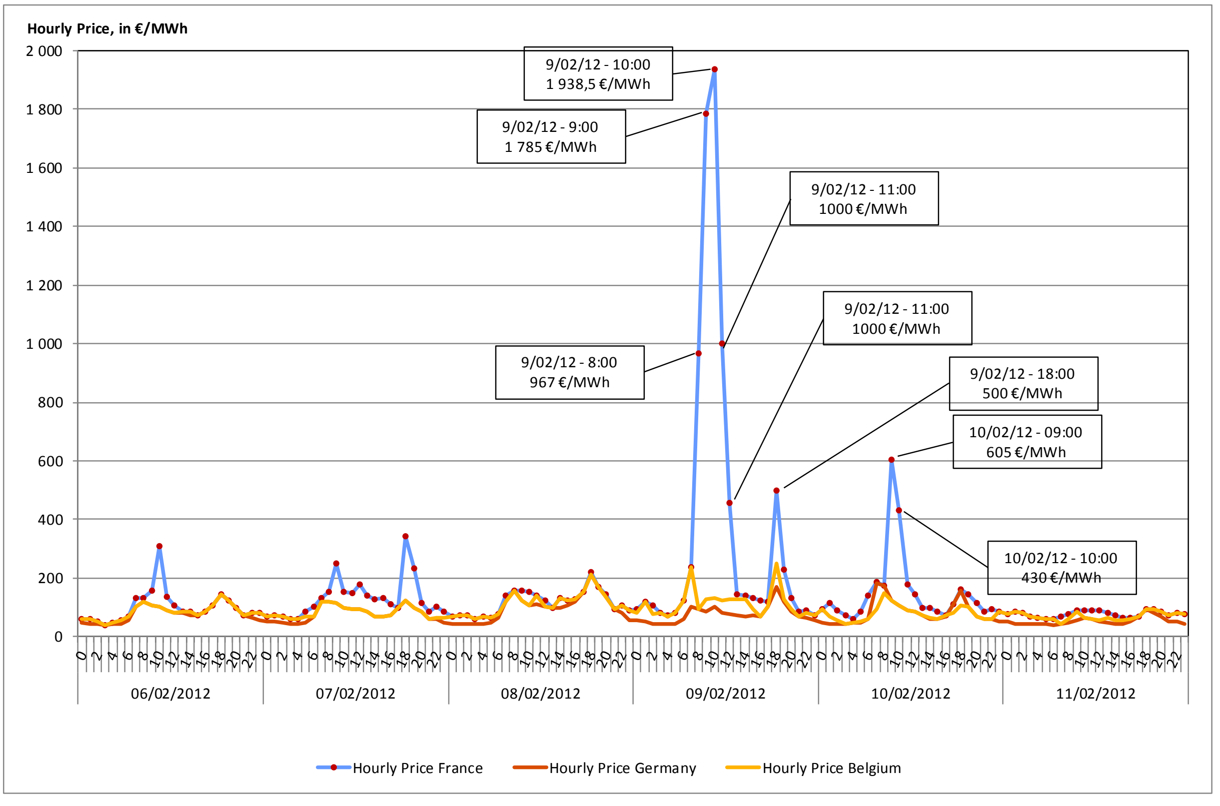
- improve, if necessary, the second fixing procedure;

- set up, if required, operational safeguards.

EPEX SPOT has since responded to the recommendations of CRE in a communication sent to all its members on 5 July 2012. This communication recalls the principles of a second auction and details the results of the analysis carried out by the exchange in relation to five episodes of second auctions, especially the episode of 9 February for the French market. EPEX SPOT clarified its market rules on 16 October 2012 and is working to set up operational limits. Finally EPEX SPOT should send formal letters to the members considered to have broken the rules and should continue to closely monitor the behaviour of stakeholders during second auctions.

Finally, CRE is currently completing specific work in the case of one of the three stakeholders mentioned above.

Figure 16: Hourly spot prices from 6 to 11 February 2012



Sources: EPEX SPOT France / Germany, Belpex – Analysis: CRE

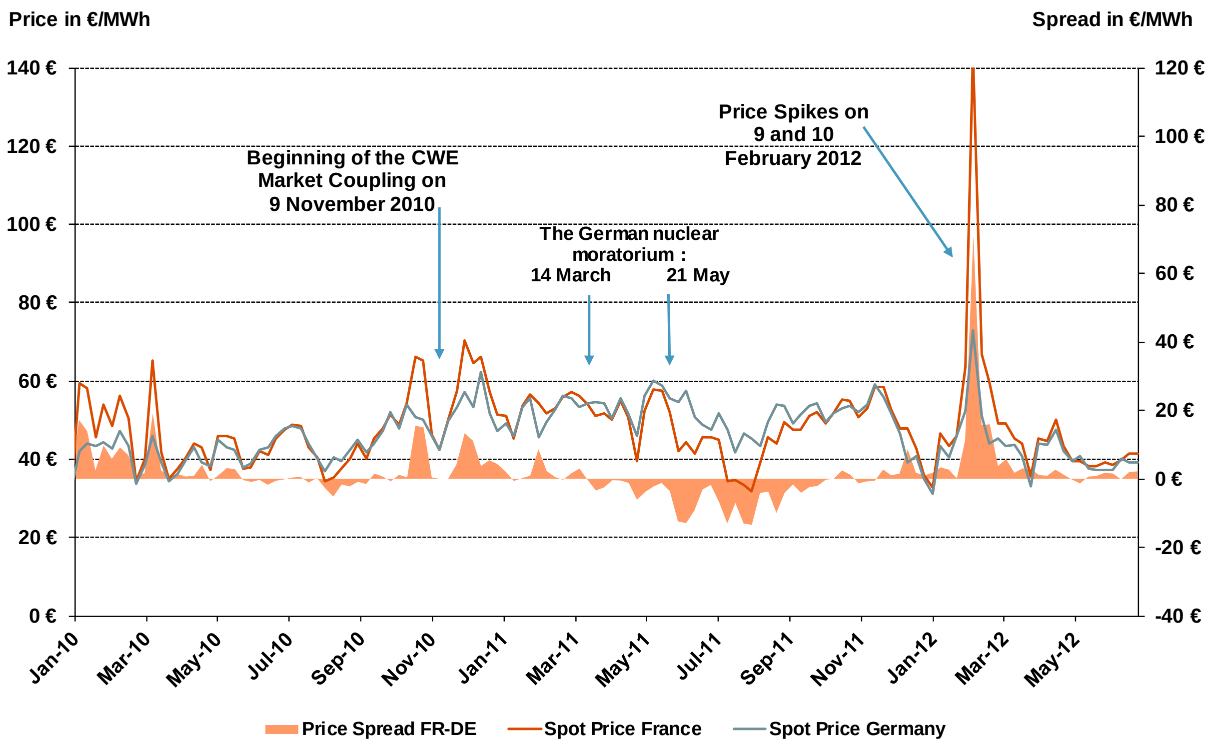
- **In the context of market coupling, the development of French and German prices in 2011 was influenced by the German moratorium on nuclear power while the first half of 2012 was affected by the cold snap in February**

The rate of hourly price convergence between France and Germany[14] amounted to almost 64% in 2011 and the first half of 2012, while it did not exceed 1% before 9 November 2010. At this date was the trilateral coupling (France - Belgium - Netherlands), in place since 21 November 2006, actually extended to include Germany, thus becoming the CWE market coupling. The convergence rates with Belgium exceeded 97% in 2011 and reached 91% in the first half of 2012. Concerning other countries bordering France which were not coupled with(Switzerland, Italy, Spain), the hourly convergence only occurred infrequently (between 0 and 1% of the time).

The French spot price was lower than the German spot price by an average of €2.3/MWh in 2011, a gap that might have exceeded €10/MWh for some weeks. In 2010, the French spot price averaged €3/MWh more expensive than the German spot price. As from the moratorium, the spot price spread between France and Germany changed sign, with the electricity day-ahead price in Germany becoming higher than in France (Figure 17). This reversal of the price spread became more apparent as from confirmation of the moratorium on 21 May 2011 and continued until October 2011. French prices became higher again as the winter delivery period approached, due to the thermal sensitivity of electricity consumption in France.

[14] Defined as the percentage of hours for which the absolute differential of prices is lower than €0.01/MWh

Figure 16: France-Germany spot prices and spread (weekly averages)



Source: EPEX SPOT – Analysis: CRE

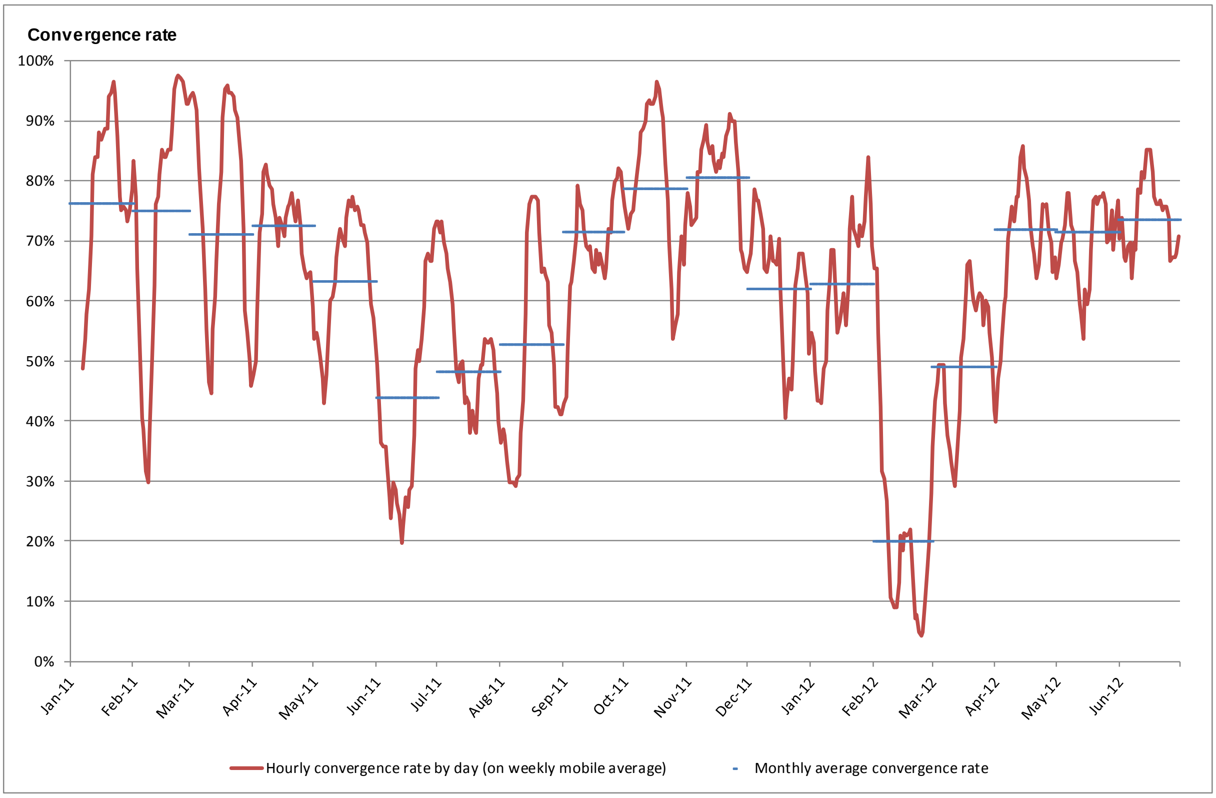
Figure 18 shows the effects of the German moratorium, with two successive falls in the hourly convergence rate after the dates of 14 March 2011 and 21 May 2011. This decrease can also be attributed to the very mild weather conditions in France; they led to very low spot prices at off-peak hours, where the baseload generation technologies were marginal and saturated both French consumption and export capacities, while German spot prices at the same times seemed to be determined by conventional thermal power plants at higher costs.

2011 was also marked by the CWE market decoupling on 27 March due to a technical incident related to the transition to summer time (see Box 1 of the Monitoring Report 2010/11).

In the first half of 2012, the French spot price was higher by €5.8/MWh on average than the German spot price, especially because of price spikes which occurred in France. If the week of 6-12 February 2012, corresponding to the severe cold snap, is taken away, the average difference between the spot prices in France and Germany is reduced to €3.2/MWh as opposed to €-1.7/MWh in the first half of 2011. French nuclear availability was lower than the same period in 2011, while generation from photovoltaic power plant in Germany increased significantly compared to the previous year.

Price convergence severely dropped during the months of February (20%) and March (50%), mainly as a result of the cold snap that occurred in this period and price spikes observed in France in February.

Figure 17: Daily convergence rate of hourly prices between France and Germany



Source: EPEX SPOT – Analysis: CRE

The detailed analysis of French and German prices points out that the convergence in 2011 was better during peak hours (8am to 8pm), while off-peak hours in the months from April to September showed that convergence rates were below 50%. This is due to the saturation of the interconnection capacity from France to Germany during the 2011 spring-summer off-peak period, when the French marginal production cost was lower than the German market price. In contrast to the first half of 2012, there was a decrease in the peak hourly convergence rate, indicating a saturation of the interconnection capacity from Germany to France during the times of the day when the marginal production cost was higher than the German market price.

On 1 and 2 January 2012, negative hourly prices settled for the first time on the French spot market, as a result of the market coupling with Germany where negative prices are seen more frequently (Box 2).

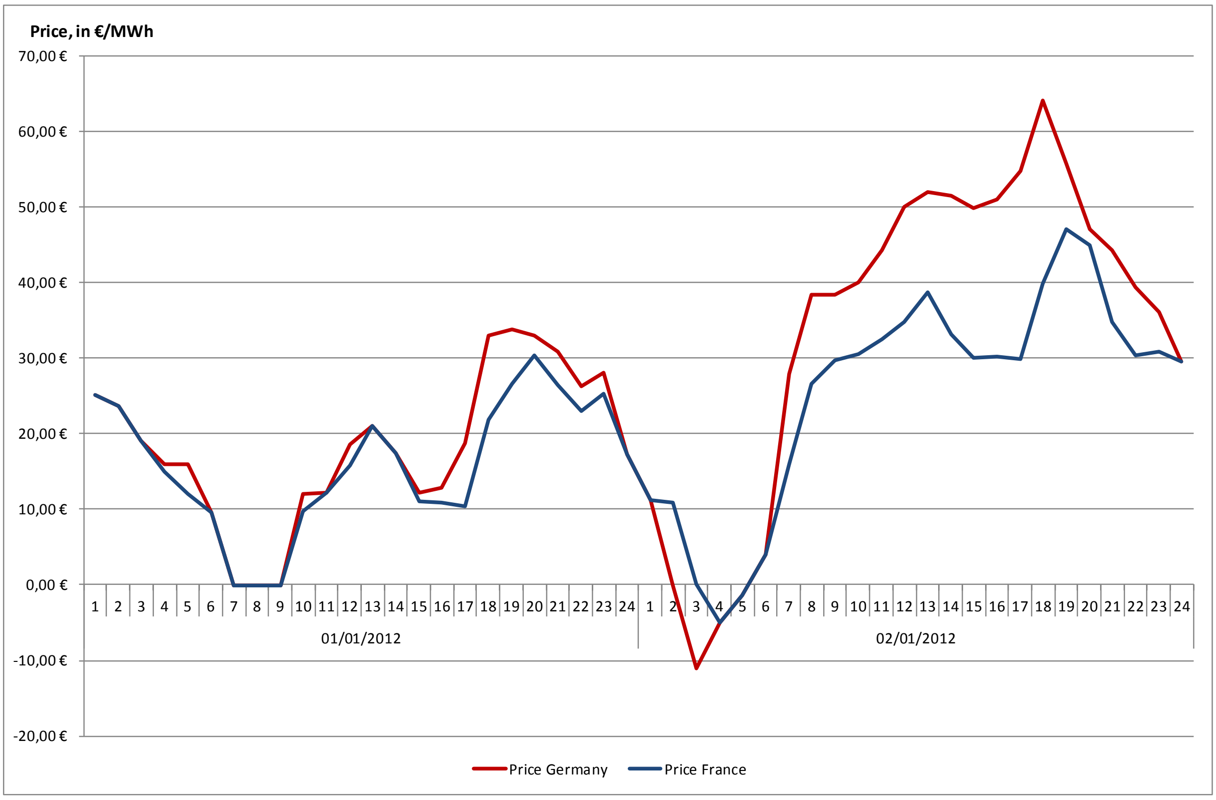
Box 2: Negative prices on 1 and 2 January 2012

France experienced its first strictly negative day-ahead prices in early 2012: hourly prices were set between € -0.01/MWh and € -0.08/MWh on 1 January between 6am and 9am, and between €-1.48/MWh and €-5.03/MWh for January 2 between 3am and 5am. These prices had been allowed by the market rules of EPEX SPOT since the market coupling had been extended to include Germany in November 2010.

The negative prices of 1 and 2 January 2012 originated in German market fundamentals - high inevitable production and low level of consumption - and the weak French consumption at a time of reduced economic activity and very mild weather conditions. Under these circumstances, the lack of flexibility in the generation assets in operation on either side of the border led to the formation of these negative prices. When demand is very low (or lower than expected), and since electricity cannot be stored on a large scale, it may be advantageous for a thermal producer to offer its electricity on the market at negative prices rather than bear the costs related to switching off and re-starting its plant in a tight time interval.

This market episode took place barely a month before the price spikes in early February 2012.

Figure 19: Hourly spot prices for 1st and January 2, 2012

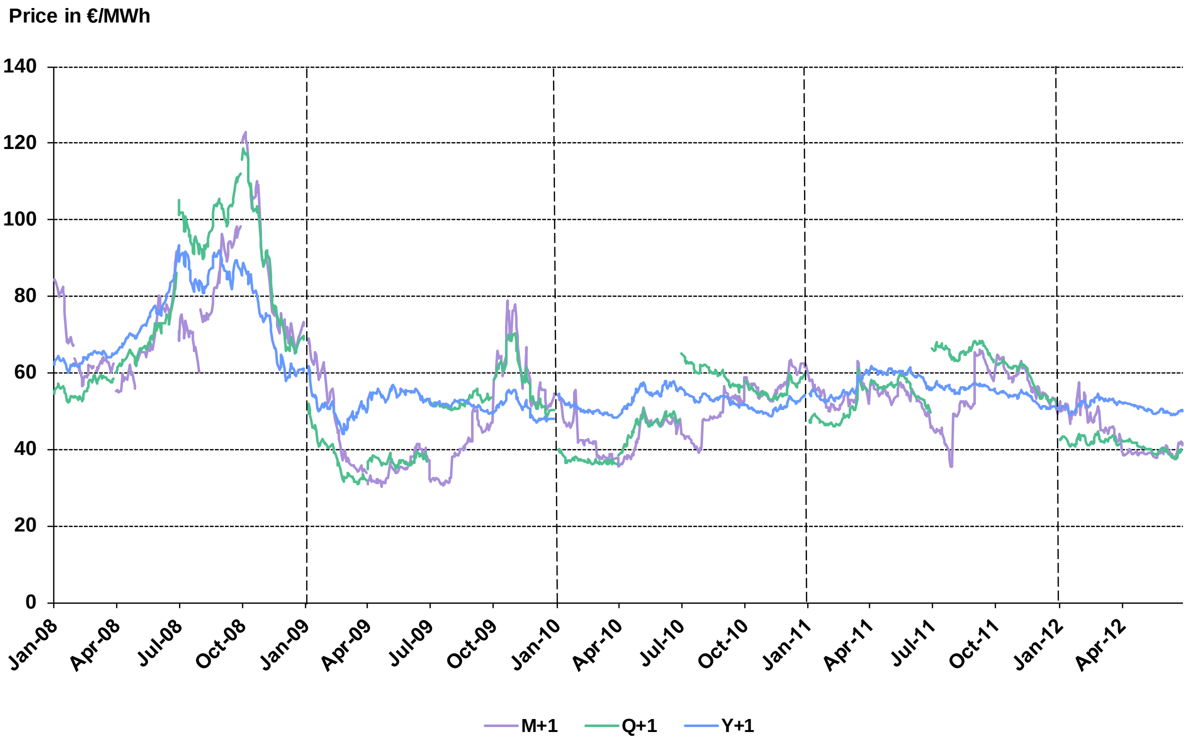


Sources: EPEX SPOT France / Germany – Analysis: CRE

POST-FUKUSHIMA: AFTER A PERIOD OF RISING FUTURE/FORWARD PRICES LINKED TO THE EFFECTS OF THE GERMAN MORATORIUM, PRICES FOLLOWED A DOWNWARDS TREND IN THE WAKE OF COAL PRICES

In 2011, the average price level of term contracts on the EEX Power Derivatives market increased compared to 2010. Y+1 calendar baseload product was on the rise, with an average of €56.0/MWh against €52.4/MWh in 2010. The Y+1 product price particularly increased following the announcement of the German moratorium on nuclear power on 14 March 2011. Monthly and quarterly futures products (which are seasonal by nature) rose even more sharply compared to 2010: monthly M+1 and quarterly Q+1 products settled at €54.3/MWh (+ €6.0/MWh) and €57.6/MWh (€7.6/MWh) respectively. Figure 20 shows the development of the prices of these three contracts. Over the last twelve months, there has been a gradual reduction in the price of the Y+1 product, being valued on average at €51.2/MWh in the first half of 2012 (€57.3/MWh in the same period in 2011). The same applies to Q+1 and M+1 products, as the prices were much lower in 2011 than during the first half of 2012, reaching respectively €41.28/MWh and €44.0/MWh on average.

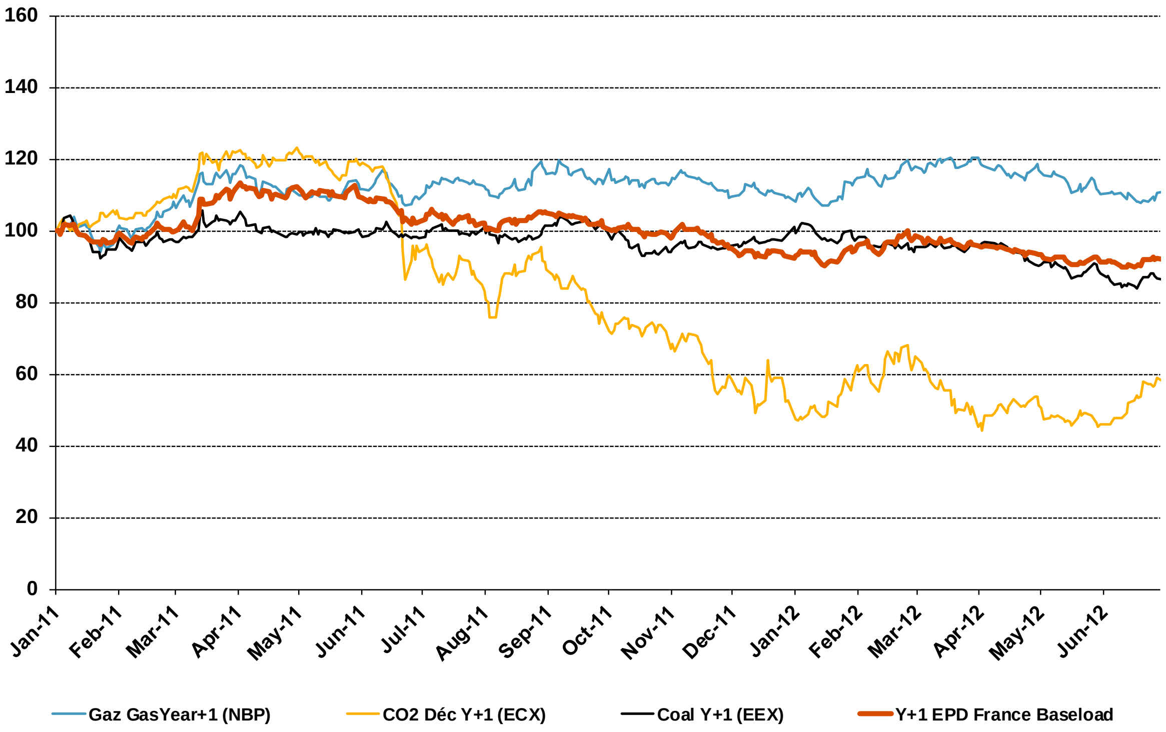
Figure 18: Future/forward products prices - France



Source: EEX Power Derivatives – Analysis: CRE

Setting the development of the Y+1 product price of electricity against the prices of fossil fuels (Figure 21) shows that the price of electricity is strongly correlated with the price of coal. During 2011 and the first half of 2012, the correlation effectively reached 72% against 67% in 2010. There was also a disconnection between the prices of electricity and gas at the end of the first half of 2011: the correlation rate, which was 43% in 2010, reduced to less than 11% throughout 2011 and the first half of 2012.

Figure 19: Fossil fuels and electricity prices - Base 100 January 2011

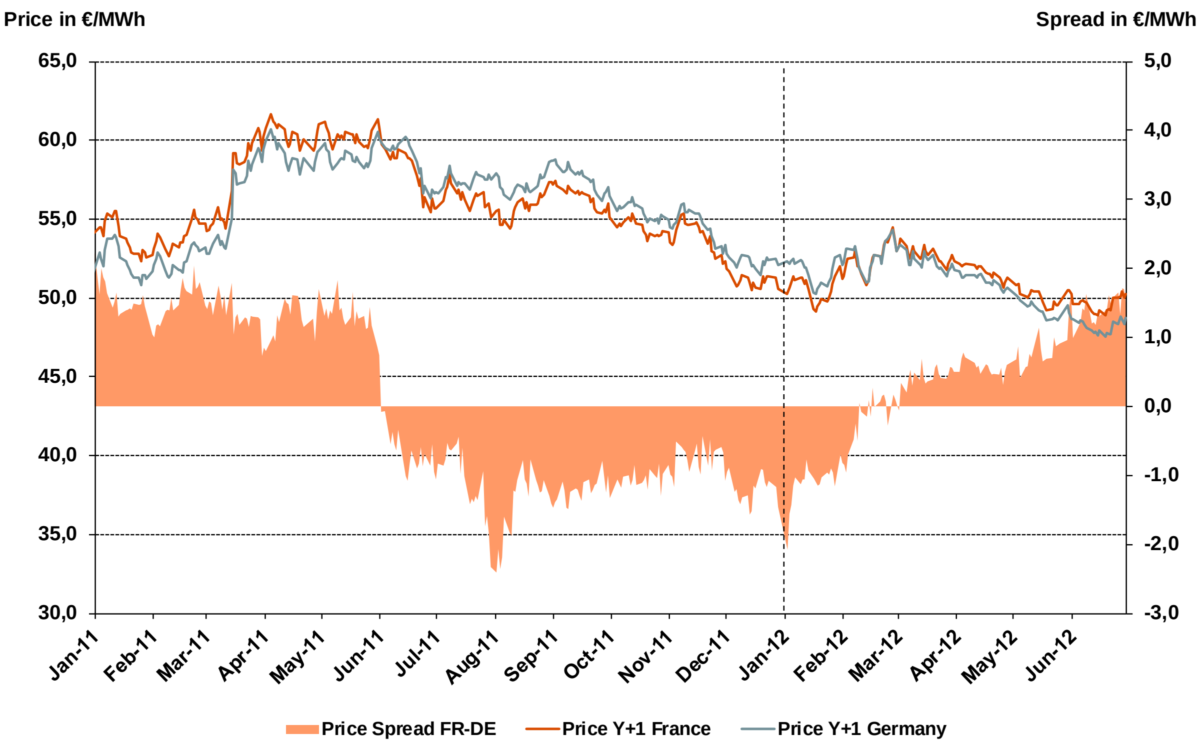


Sources: EPD, ECX, Heren – Analysis: CRE

- **Price spikes in February 2012 put an end to the reversal of the Y+1 baseload contract price spread between France and Germany, observed as from the confirmation of the moratorium on nuclear power**

A reduction in the Y+1 price spread (France more expensive) was observed after the introduction of market coupling in November 2010 between France and Germany. Its change of sign in early June (France cheaper) reflected a structural change, which can be attributed to the German moratorium on nuclear power (Figure 22). Baseload Y+1 term contracts prices rose sharply in mid-March in France and Germany with a reversal in the spread between these products, at the beginning of June 2011, following the confirmation on 21 May 2011 of the phase-out of nuclear power plants in Germany by 2022. However, this reversal in the Y+1 price spread between France and Germany ended in the first quarter of 2012. Among the factors behind this price spread re-inversion are the following: the price spikes of February on the French spot market (which can be considered as a factor in re-valuing the thermal sensitivity of consumption in France), the very strong increase of photovoltaic power generation in Germany, as well as the smaller nuclear availability in France in the first half of 2012.

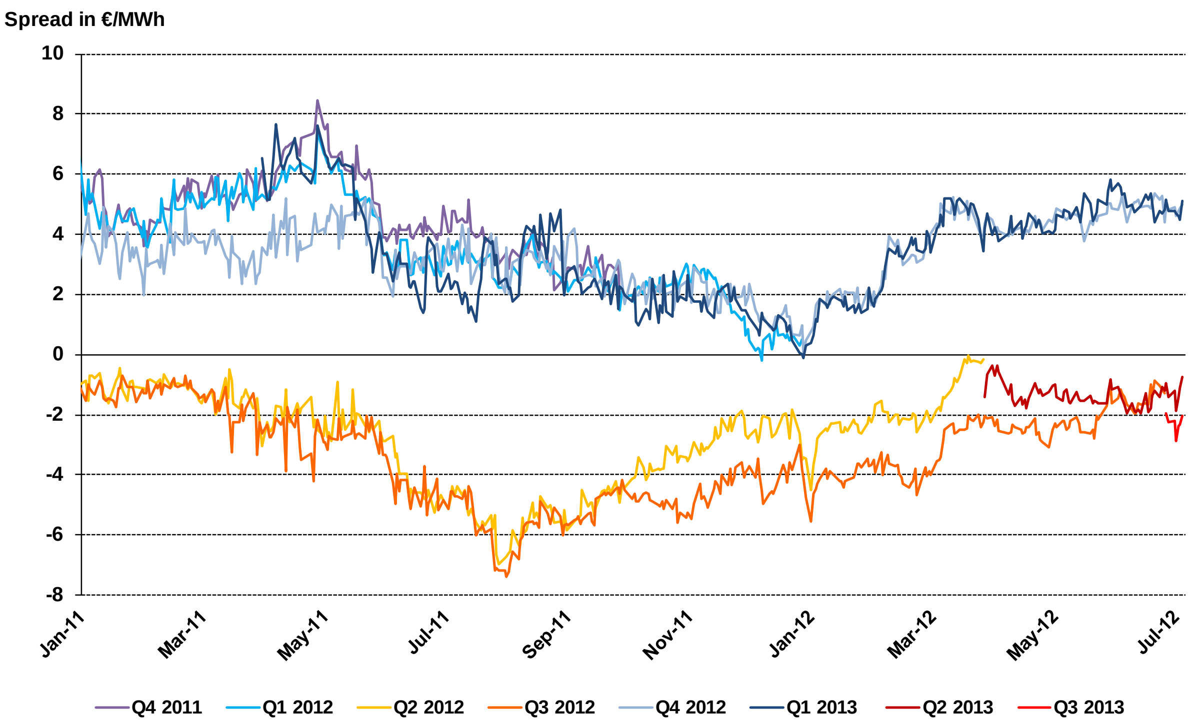
Figure 20: Y+1 prices and *spread* between France and Germany



Source: EEX Power Derivatives – Analysis: CRE

The development of quarterly futures products spreads between France and Germany is illustrated by Figure 23.

Figure 21: quarterly futures products prices *spreads* between France and Germany

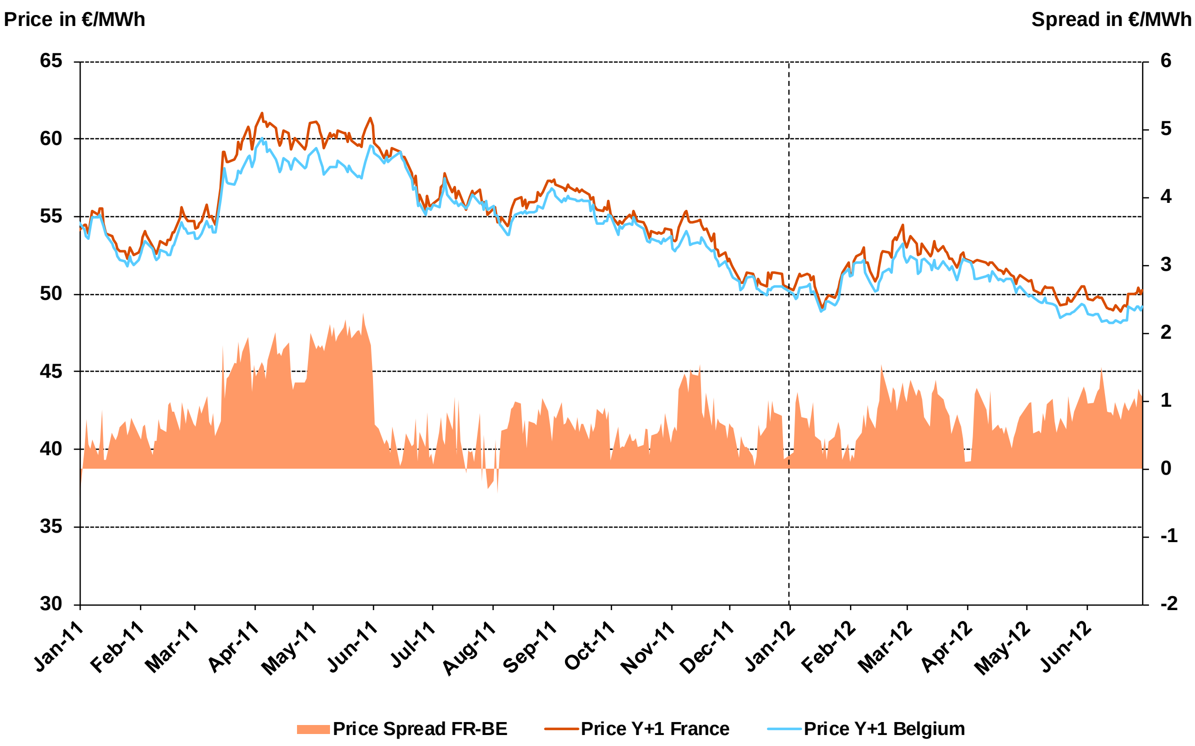


Source: EEX Power Derivatives – Analysis: CRE

- **Futures price spreads narrow with Belgium and are reversed with the Netherlands**

The spread between baseload Y+1 calendar products in France and Belgium (Figure 24) fell between 2010 and 2011, from an average of €2.3/MWh to €0.82/MWh. A temporary increase in 2011, however, was observed between the announcement of the German moratorium on 14 March 2011 and its confirmation on 21 May 2011, with the French price reaching an average of €1.66/MWh higher during the period. Finally, we observe that in the first half of 2012, the spread has taken slightly higher values than during the second half of 2011 (€ 0.8/MWh as opposed to €0.6/MWh).

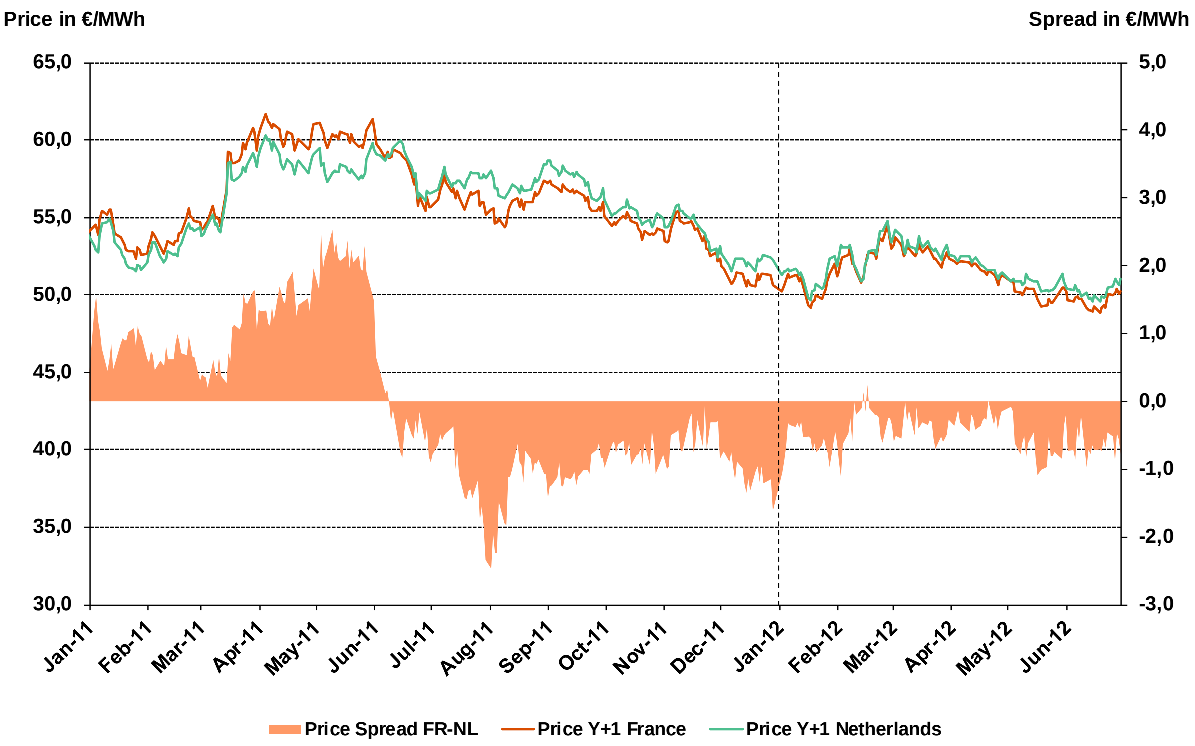
Figure 22: Y+1 prices and spread between France and Belgium



Source: EEX Power Derivatives, APX-ENDEX – Analysis: CRE

Between France and the Netherlands, there was a reversal in the spread in early June 2011 as the price of the Y +1 product became more expensive in the Netherlands (Figure 25).

Figure 23: Y+1 prices and *spread* between France and the Netherlands

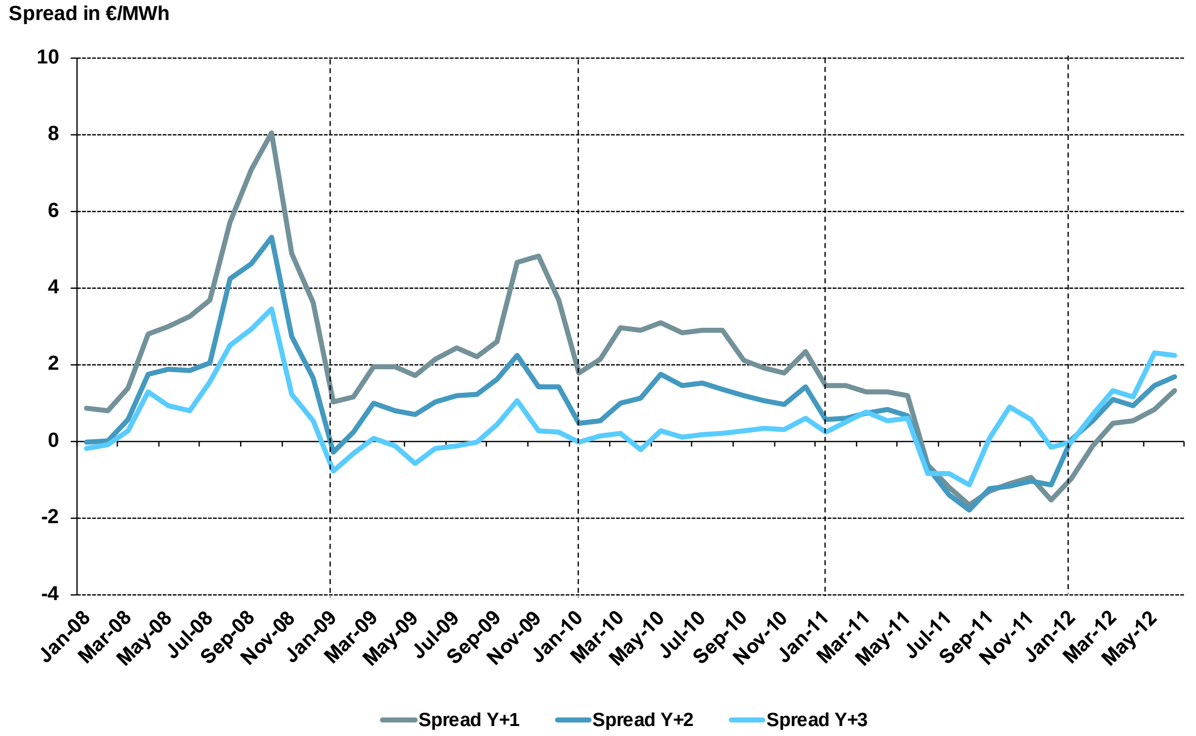


Source: EEX Power Derivatives, APX-ENDEX – Analysis: CRE

- **A decrease followed by an increase in the calendar (Y +1 to Y +3) product price differentials between France and the countries of the CWE market coupling**

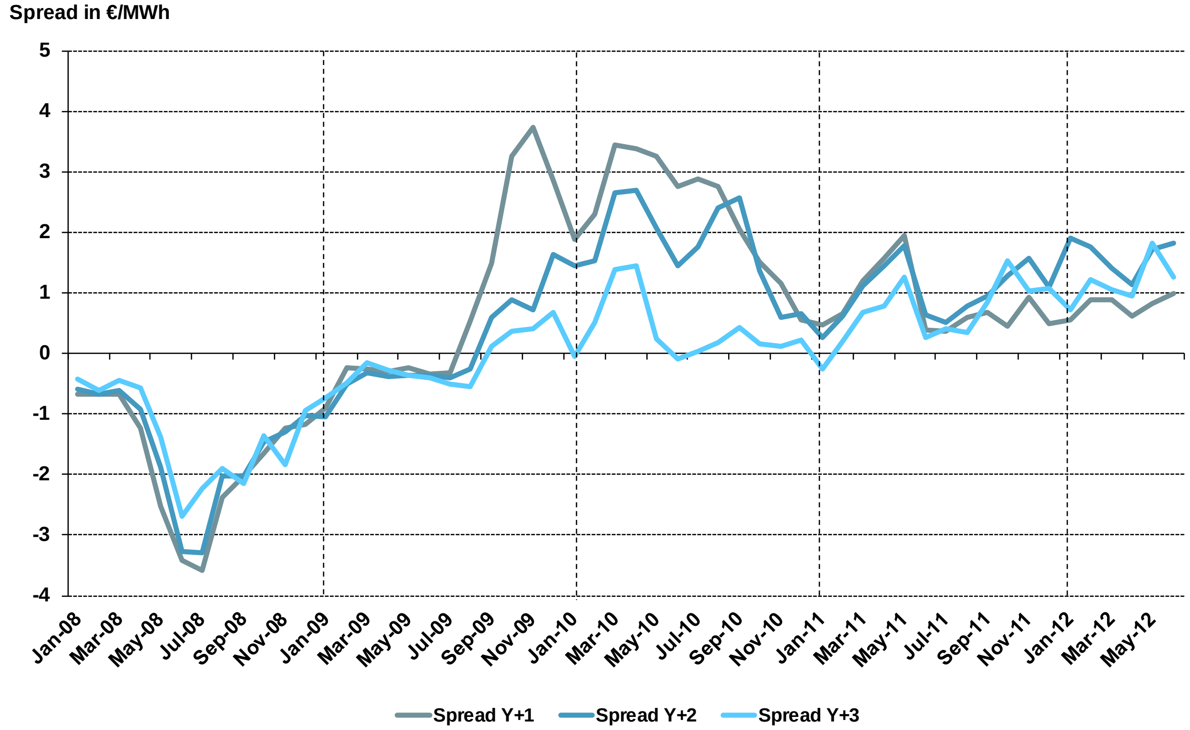
Until May 2011, it was noted that the price differentials between countries in relation to calendar products were higher when maturity was near. From mid-2011, however, when the spreads reversed (with Germany and the Netherlands) or narrowed (with Belgium), the price differentials were lower in relation to Y+1 products that Y+2 and Y+3 products. This finding was observed for the three countries (Figures 26 to Figure 28).

Figure 24: Price spreads in calendar products between France and Germany (monthly averages)



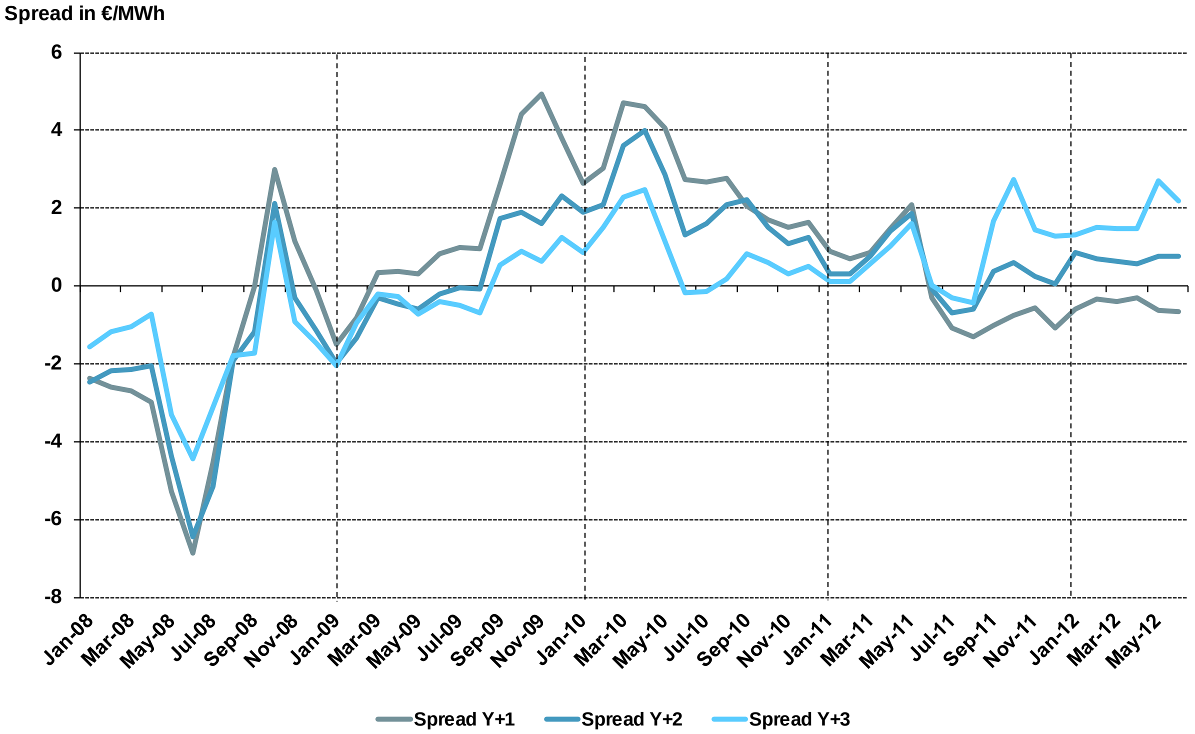
Source: EEX Power Derivatives – Analysis: CRE

Figure 25: Price spreads in calendar products between France and Belgium (monthly averages)



Source: EEX Power Derivatives, APX-ENDEX – Analysis: CRE

Figure 26: Price spreads in calendar products between France and the Netherlands (monthly averages)



Source: EEX Power Derivatives, APX-ENDEX – Analysis: CRE

Analysis of the electricity generation and transparency of generation data

On 1 January 2012, the installed generation capacity in France amounted to 126.5 GW according to RTE[15], i.e. an increase of 3 GW in the past year. Figure 29 provides a breakdown of this total capacity according to the various generation technologies and its variation. In relation to the transmission grid, the power increase was mainly due to the connection of two combined cycle gas plants and two combustion turbine plants with a total capacity of 850 MW. The distribution network experienced sustained growth in connected renewable capacity with more than 1,300 additional MW of photovoltaic power and 875 MW of wind power.

If we exclusively focus on the reference facilities connected to the transmission grid, the installed capacity totalled 106 GW, of which nearly 63.1 GW was for the single nuclear generation capacity which thus represented 59.7% of thisfacilitities. Hydroelectric generation capacity constituted a 22.9% share including a narrow majority of "lake" type generation units, managed according to hydro-storage available in barrier lakes and the remainder made up of so-called “run-of-river” plants, the production of which is conditioned by the availability of water. The remaining capacity mainly comprised thermal combustion power plants which were still dominated by oil and coal-based generation (6.6% and 6.5%), although the gas generation capacity(4.3%) experienced strong growth.

The installed generation capacity operated by the EDF group represented more than 96 GW or approximately 91% of the reference facilities. The main competitors of the incumbent French producer on the electricity production market are:

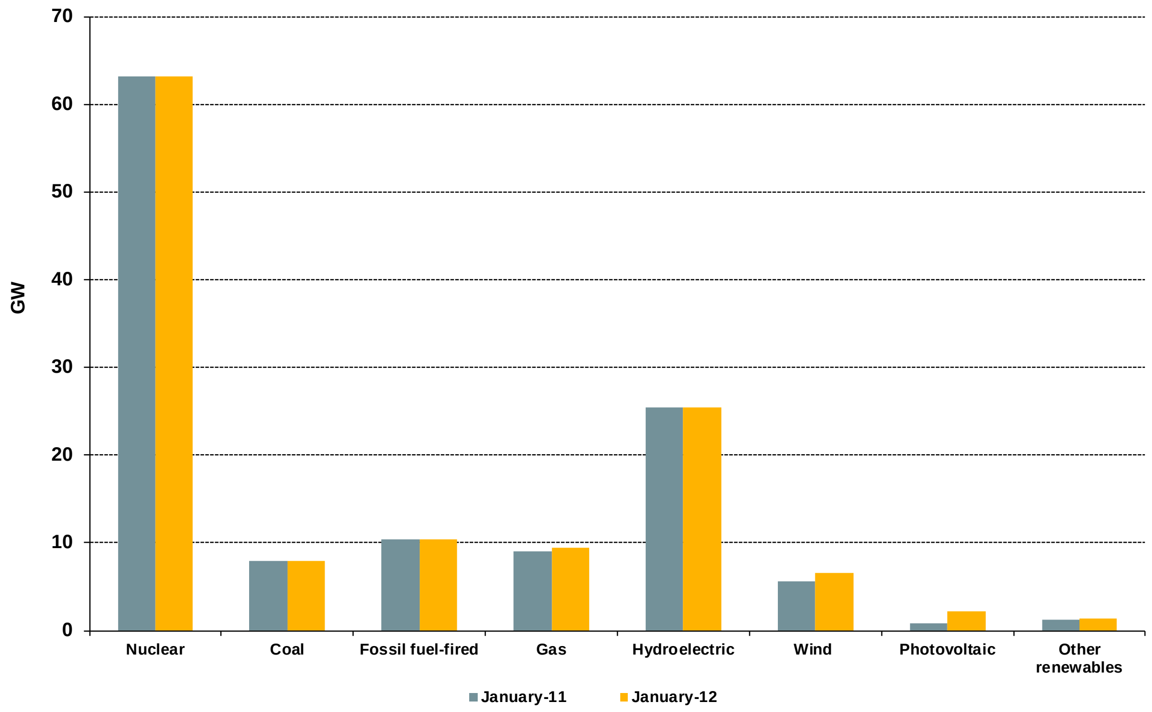
• GDF SUEZ which, through the CNR and the SHEM, its generation assets and aforementioned holdings in the nuclear power plants, holds 5.5% of the total generation capacity of the reference;

• E.On France (the SNET, E.On group), which holds 3% of the installed capacity.

These three producers operate a total of more than 99% of the reference generation capacity in total.

[15] http://www.rte-france.com/uploads/Mediatheque_docs/vie_systeme/annuelles/Bilan_electrique/RTE_bilan_electrique_2011.pdf

Figure 27: French electricity generation facilities production network (levels of various generation technologies)



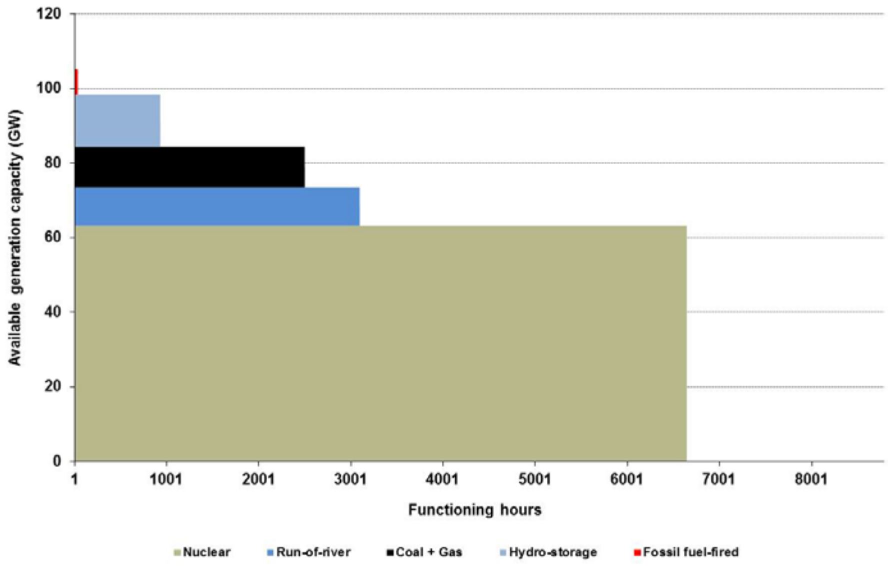
Source: RTE

THE UTILISATION RATES OF THE VARIOUS GENERATION TECHNOLOGIES REFLECT THE RELATIVE LEVELS OF MARGINAL PRODUCTION COSTS. THE AVAILABILITY OF THE NUCLEAR POWER PLANTS, UP SHARPLY IN 2011, FELL IN THE SECOND QUARTER OF 2012

The relationship between total energy production and installed capacity makes it possible to define the rates of utilisation of each type of generation technologies. These rates are converted into equivalent utilisation period and are shown in Figure 30. These equivalent periods reflect both the availability and the utilisation (base- or peak-load) of the various generation technologies. This shows that the highest period of utilisation related to the nuclear power plants in 2011, with 76% of the time compared to 73% in 2010, on account of increased availability. In contrast, fuel oil power plants, which constitute the peakload, are only used 0.4% of the time.

The highest equivalent utilisation periods thus correspond to the generation technologies with lowest marginal cost, with the exception of "inevitable" and "unfirm" production such as hydroelectric run-of-river or wind power.

Figure 28: Utilisation period of the various generation technologies in 2011



Source: RTE - Analysis: CRE

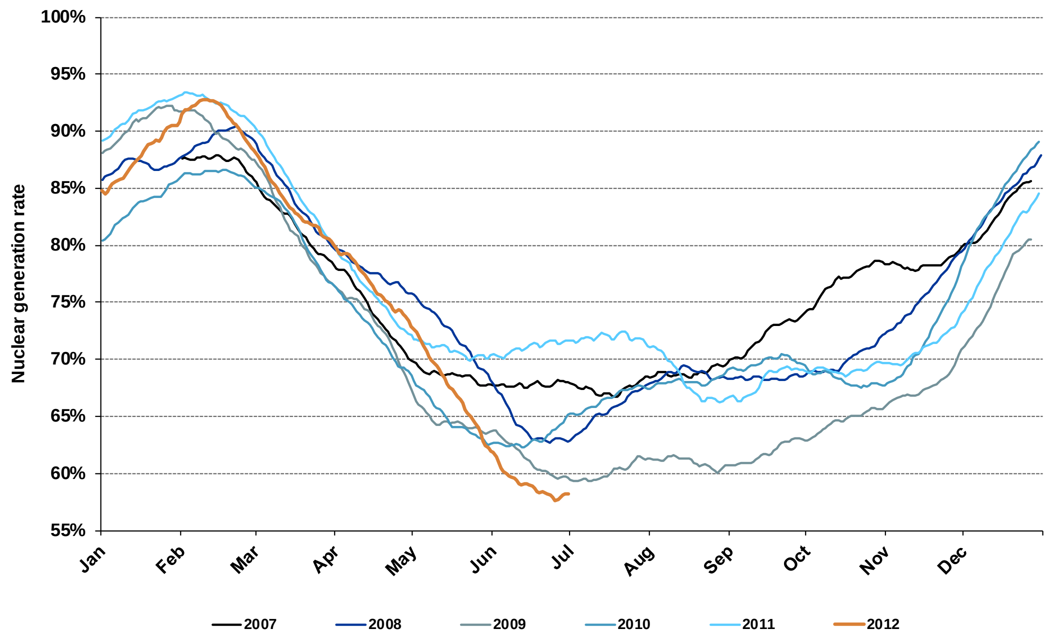
- **Generation rate and availability of the nuclear power plants increased significantly in 2011, but have shown strong signs of decline in 2012**

Characterised by a significantly seasonal nature related to that of the demand for electricity, nuclear generation recorded a production rate of 77.7% in 2011, a rise compared to the 74.1% in 2010. This level was the highest rate recorded since 2007. The total production of nuclear power plants amounted to 421 TWh, up 3.2% from the previous year.

Increasing the availability of the nuclear power plants in 2011 resulted in a sharp rise in net exports, which recovered from May 2011 until it regained summer values close to those observed in 2007 (Figure 31 to Figure 33).

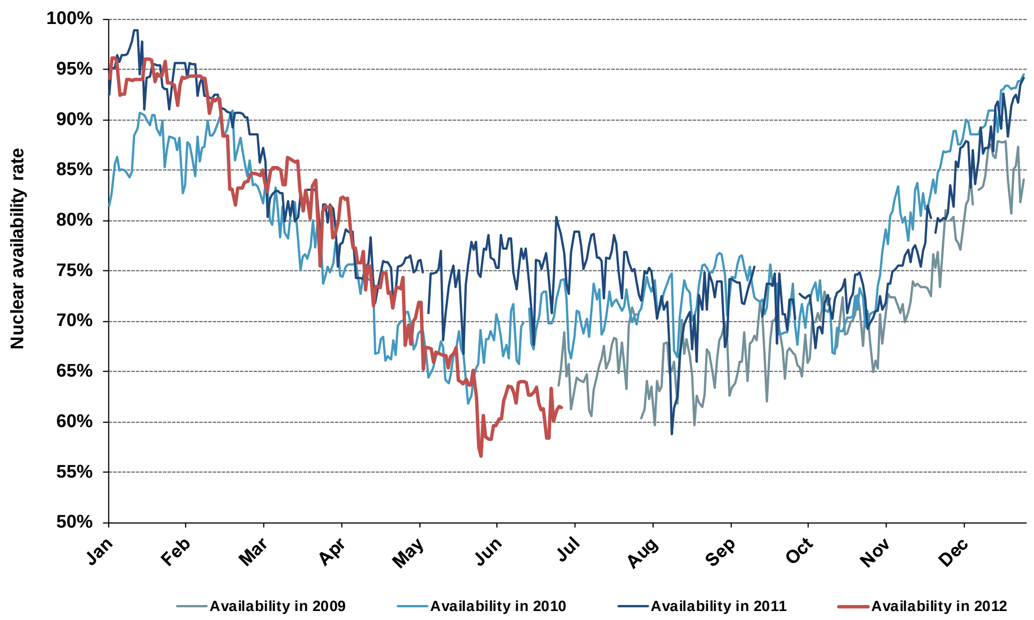
The beginning of 2012 was characterised by a production rate and availability of nuclear power plants which were similar to those of the previous year. The second quarter of 2012, however, marked a significant decline in the rate of nuclear generation compared to that observed in previous years. This decline can be attributed in part to the sharp decline in nuclear availability in May and June during which plans to return many nuclear plants in shutdown mode to working order were put back (Figure 32). The availability of the nuclear power plants in May and June reached a low point and fell by more than 10 percentage points compared to the level recorded during the same month of the previous two years.

Figure 29: Nuclear generation rate 2007-2012 (Actual Nuclear generation/ Installation nuclear capacity - moving average over 30 days)



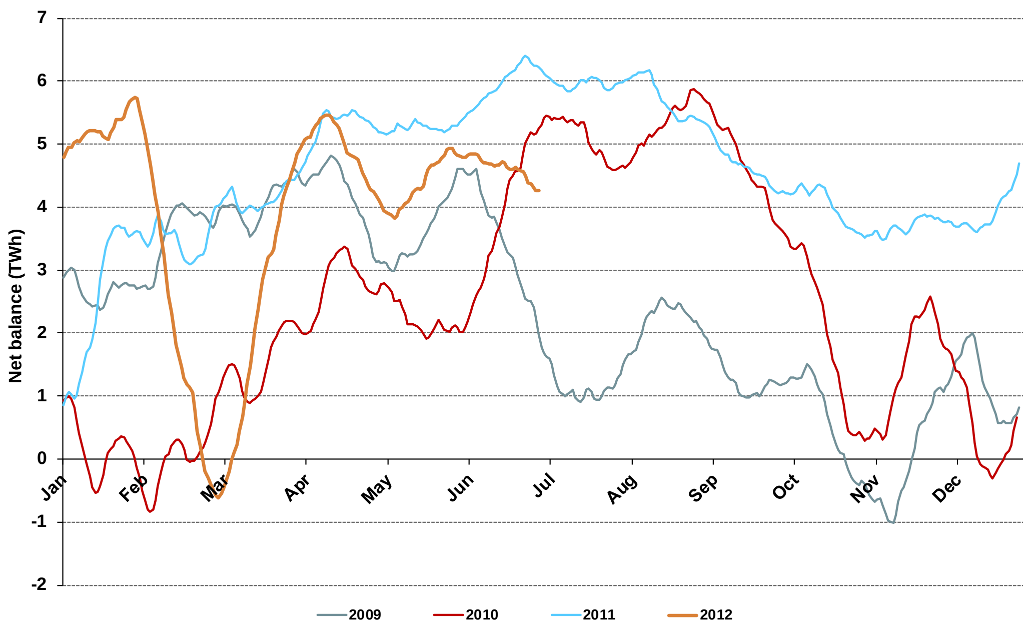
Sources: RTE - Analysis: CRE

Figure 30: Nuclear availability rate 2009-2012 (Available nuclear capacity/Installed nuclear capacity)



Source: RTE - Analysis: CRE

Figure 31: Monthly export balance 2009-2012 (Moving average over 30 days)



Sources: RTE - Analysis: CRE

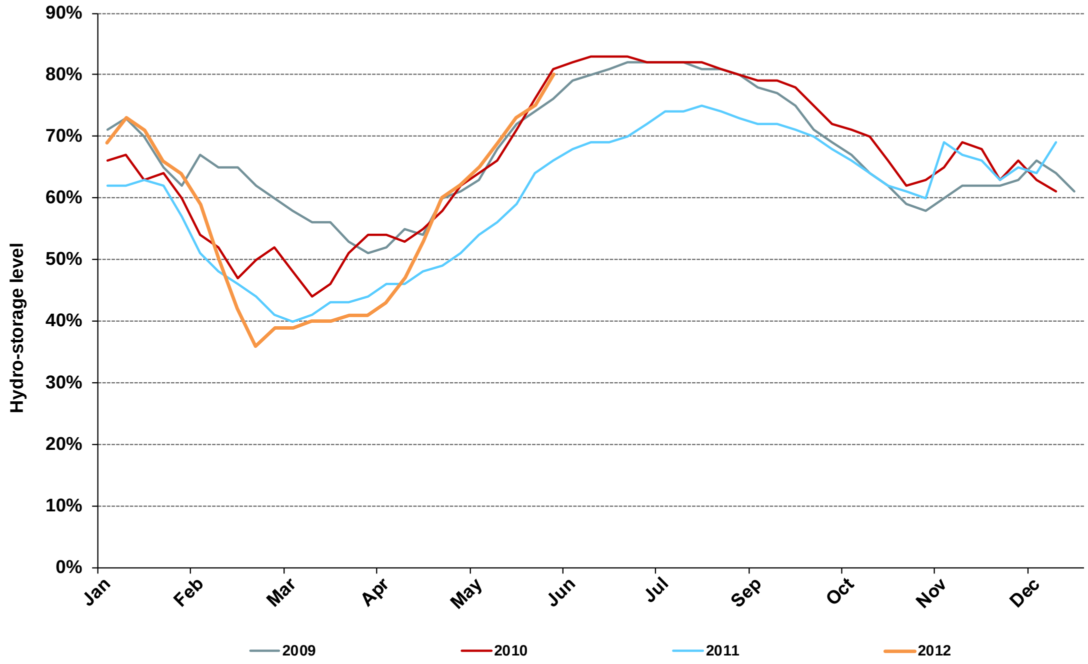
- **Hydro-storage levels fell on account of the low rainfall in 2011 but experienced a significant recovery in 2012**

In 2011, there was a sharp decline in hydro-storage levels recorded in reservoirs reaching a minimum of 40% in March. Thus, as shown by Figure 34, this value was particularly low compared to the levels seen in previous years thereby demonstrating the low hydraulicity during 2011. According to French weather forecasts, on account of an exceptionally dry spring (the driest since at least 1959), but also a rather wet autumn, 2011 is one of the driest years that France has experienced in the last fifty years .

During the first few months of 2012, the hydro-storage levels reached a particularly low level in relation to previous years with a minimum of 36% recorded during the month of February. Indeed, from a historically high level seen at the beginning of January, water reserves fell sharply during the cold snap that affected the whole of Europe in early February. Over the second quarter of 2012, a significant increase in rainfall helped to restore water reserves to levels similar to those recorded over the same period in 2009 and 2010.

In 2011, the total Hydroelectric generation amounted to 50.3 TWh, or a decrease of almost 26% in relation to 2010. Generation from fossil fuel power plants also fell by almost 14% (Table 6: Electricity production for the various sectors). The decline in this group was mainly driven by the coal industry with only 13 TWh produced in 2011, down 29.9% from the previous year. With regard to wind and photovoltaic generation, there was a strong increase as their installed capacity were developed.

Figure 32: Hydro -storage



Sources: RTE - Analysis: CRE

Table 6: Electricity production for the various generation technologies

Generation technology	Total energy produced (TWh)	Variation 2011/2010	Production rate (% of installed power)
Nuclear	421.1	+3.2%	76.1%
Coal	13.4	-29.9%	19.3%
Fuel oil	8.1	+0.7%	8.9%
Gas	29.7	-0.5%	35.7%
Hydropower	50.3	-25.6%	22.6%
Wind	11.9	+22.8%	20.5%
Photovoltaic	1.8	+208.7%	9.2%
Other renewable	5.6	+12.3%	50.3%

Sources: RTE

IN 2011, THE HYDROELECTRIC GENERATION WAS ALMOST NEVER MARGINAL. THE BORDERS AND CONVENTIONAL THERMAL GENERATION WERE NOW MORE OFTEN MARGINAL AND THE RESULTS OBTAINED AT BORDERS WERE ALSO IN KEEPING WITH THE EXPANSION OF THE CWE COUPLING

A generation technology is called marginal when its marginal production cost determines the market price, that is, in theory, when the highest production cost unit in order to satisfy electricity demand belongs to this type of technology.

Analysis of marginality consists in practice of identifying, for each hour of the day, the type of generation technology to which the price set by the market corresponded; that is, searching for the operating power plant for which the marginal production cost was closest to the market price.

The analysis presented here uses both a price criterion and a power criterion in order to determine the unit and thus the marginal facility at a given time:

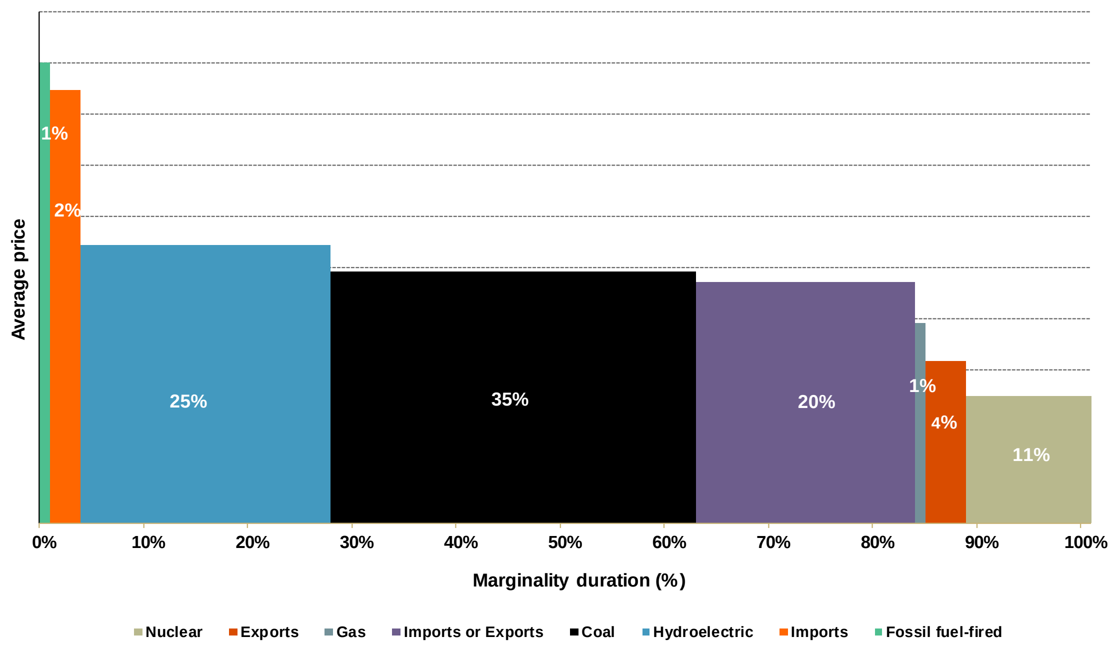
• the price criterion selects power plants for which the difference between market price and production cost is less than €5/MWh;

• the power criterion leads to consideration only of units with production lying between 15% and 85% of the theoretical maximum generation capacity.

Of all the units which meet with these two criteria, those units whose marginal production cost is closest to the market price are then considered. However, if no units fulfils the criteria, price levels are then deemed to be explained by the supply and demand from abroad, and the borders are then considered to be marginal.

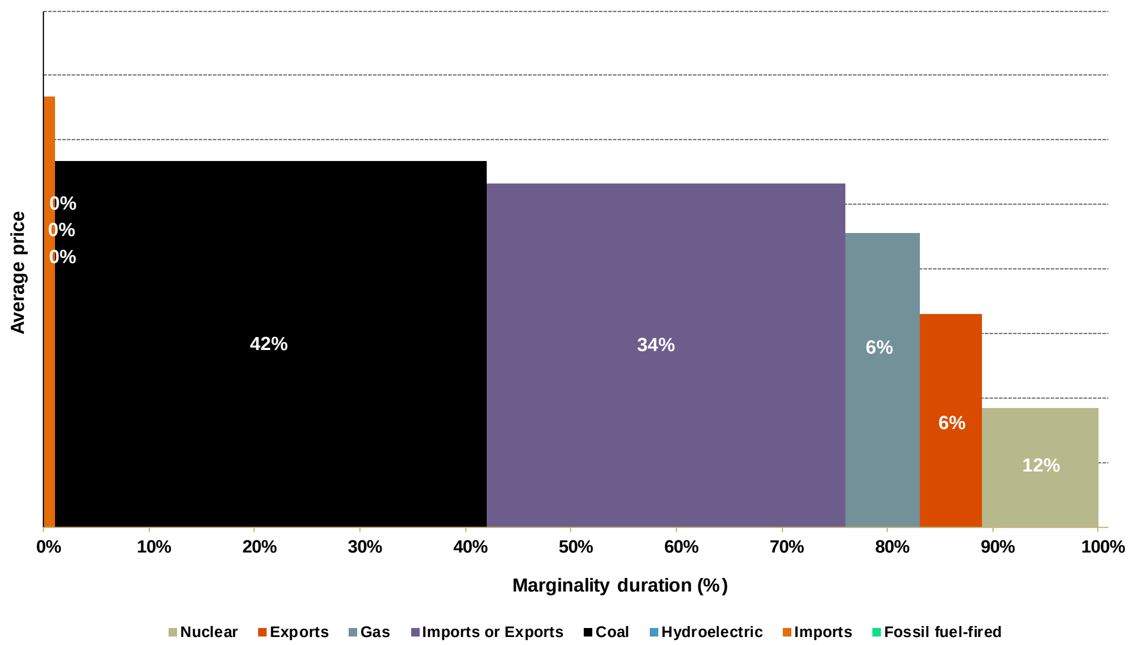
The results of these estimates are summarised for 2010 and 2011 in the Figures below. It should however be noted that these results are highly dependent on the computational method and thresholds taken into consideration. They may, however, determine a fairly stable classification of generation technologies according to their marginality duration.

Figure 33: Marginality duration of the various generation technologies in 2010



Source: CRE

Figure 34: Marginality duration of the various generation technologies in 2011



Source: CRE

The development of the results obtained in 2010 and 2011 highlights:

• Stability in the marginality duration of the nuclear nuclear power plants which only determines the price, however, in 12% of cases (for generation accounting for 78% of generation in 2011);

• A strong decrease in the marginality duration of the hydroelectric power plants: it was marginal 25% of the time in 2010, and this rate barely increased in 2011;

• And, on the other hand, an increase in the marginality duration of borders (27% in 2010 to a total of nearly 40% in 2011) and coal and gas power plants.

Prices observed during the marginality hours of thermal fossil fuel power plants increased significantly. These findings are in keeping with the rising price of fuel in 2011. By contrast, a decrease was observed in the case of the nuclear power plants.

In total, in 2011, the market price could not be explained by the marginal cost of any generation unit (at the threshold of €5/MWh) in 40% of cases. Compared to the level observed in 2010, this marginality duration at borders significantly increased in 2011 (+48%). In these cases, as stated above, we take the view that it is cross-border trade that determined the prices on the French market.

The results obtained with respect to borders and also the marginality of the coal power plants are in keeping with the expansion of the CWE coupling. Since November 2010, the German market has indeed joined the trilateral coupling (TLC) between France, Belgium and the Netherlands.

THE TRANSPARENCY MECHANISM WAS DIVERSIFIED IN 2011 AND 2012 AND PROVIDES A RESPONSE TO THE REQUIREMENTS OF THE REMIT REGULATIONS. THE QUALITY OF FORECASTS IS IMPROVING ALBEIT WITH A DECLINING TRANSMISSION RATE

- **The transparency system was enhanced in 2011 and since 1 January 2012, it has made it easier to comply with transparency obligations imposed by the REMIT Regulations**

Since November 2006, the French Union of Electricity (UFE) has contributed to the transparency of the electricity market by publishing, in partnership with RTE, part of the data relating to the production of electricity in France. This mechanism, based on a collection of this information from members of the UFE, covers nearly 90% of French production and affects all units with a nominal power above 20 MW.

Essential to the correct functioning of wholesale electricity markets, the CRE had requested the UFE to improve the transparency of production data[16]. This transparency is vitally important for all market stakeholders, especially so that they can assess the development of the electricity supply/demand balance.

Since 1 July 2010, the short and medium term availability forecasts have been published on the RTE website for each generation unit with a capacity exceeding 100 MW. This mechanism was also boosted in December 2010 with the publication of unplanned outages for these units, within a period of 30 minutes, to be completed no later than the following morning of the outage and including the causes and the estimated date of a return to service.

The UFE continues to develop its transparency mechanism with improvements adopted in 2011 and the first half of 2012. Additional information which has now been published since 1 January 2012 is a vector allowing stakeholders to meet the transparency requirements imposed by REMIT Regulations:

- During 2011, the UFE expanded its system by implementing several measures which seek to increase the degree of transparency on the French market:

• Since 25 January 2011, the publication of estimates made by RTE in relation to day-ahead wind generation has been made available to stakeholders on a daily basis;

• Since 13 December 2011, the publication, within an hour, of production data of groups of more than 100 MW and production forecasts of the UFE network for the next day.

- A new improvement was also made as from 1 January 2012 with the creation of a page on the transparency platform of the network manager dedicated to information which supplements that already issued including provisional availability and unplanned outages of the electricity generation network . This new information, in the form of statements by producers, may thus concern, for example, partial unplanned unavailability or delays in restoring generation groups to service. This publication allows all market stakeholders to assess the supply situation of producers who are part of the UFE more precisely still. This measure actively contributes to the transparency of the French electricity market and eases the implementation of current and future regulatory provisions relating to transparency.

It may be recalled that EDF changed the calculation method of the return dates on the network of nuclear generation groups in July 2011. While the work return dates displayed as "at the earliest" dates for sections of the outage, corresponding to a technically feasible minimum period, return dates now include temporary margins in line with delays recorded when feedback is given.

The CRE takes the view that all these developments meet with the expectations of market stakeholders.

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[16] See, in particular, the decision of the CRE of 20 November 2009

With the notable exception of the transmission rate, several statistical indicators show the improvement of the quality of forecasts

- **A decreasing transmission rate**

The transmission rate observed in the case of availability forecasts fell in 2011 compared to 2010. A total of 84.3% of the information necessary for the preparation of availability forecasts per production sector was transmitted on average, as opposed to 89.6% in 2010. If this transmission rate is weighted per installed generation capacity taken into account for each forecast, we also obtained a decreasing rate at 89% in 2011 as opposed to 94% in the previous year.

Table 7: Projected availability of the various generation technologies

Generation technologyData	Coal	Hydroelectric, run-of-river	Fuel oil	Gas	Nuclear	Hydroelectric, lake	Total
Level of exhaustive projections	93.6%	82.1%	95.6%	54.8%	93.6%	85.9%	84.3%
Average statistical deviation at 7-days	478 MW	86 MW	242 MW	98 MW	1404 MW	124 MW	2433 MW
(D-7) average statistical deviation in % of the installed capacity	6.1%	0.8%	2.3%	1.0%	2.2%	0.9%	2.1 %
(D-7) average statistical deviation2010	6.4%	0.0%	2.8%	2.9%	3.1%	0.6%	2.4 %

Analysis: CRE, based on information collected and transmitted by RTE

**Comprehensive forecast rate is the ratio between the number of comprehensive forecasts received and the total number of forecasts expected for daily forecasts (D-1 to D-7) and weekly (S-1 to S-12). A forecast is considered comprehensive when all stakeholders concerned by this production sector have submitted a forecast for the date and maturity considered.*

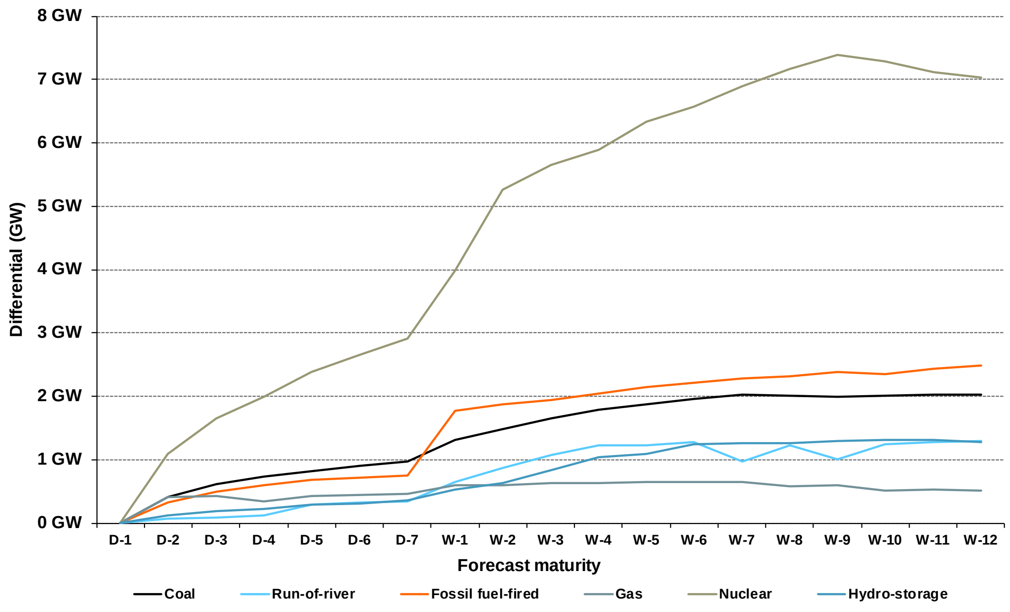
- **The projected availability of generation units is generally improving**

To measure the quality of the information published for the various sectors, the gap between the projected availability announced on the various due dates and the value recorded is measured.

As seen last year, there was a positive statistical difference positive for all thermal generation technologies. This gap decreased compared to 2010. In the case of nuclear generation, the gap between 7-day forecasts recording availability averaged 1.4 as opposed to GW 1.9 GW in 2010. This decline may be related to the improvement previously recalled as regards the methods used to calculate return dates for sections of EDF outages.

Figure 37 represents the average differences observed between the published availability forecasts and the 1-day forecast, as the final known forecast, for durations of less than 12 weeks.

Figure 35: Average deviation between projections the availability and the last projection (D-1)[17]



Source: RTE ; Analysis CRE

- **The availability recorded remained statistically lower than D-1 forecasts published for the nuclear generation, but the gap is narrowing**

Comparing the provisional availability announced on D-1 and that actually recorded reveals a statistical overestimation of provisional forecasts announced within the framework of the transparency mechanism. In relation to all sectors, this was estimated at about 686 MW for

[17] Growth in the forecast difference with its maturity results from the rules defined by the producers about the submission of availability forecasts. The "transparency" specifications of the UFE, in II.e. indicate in effect that "*the provisional available power published on a given date only takes into account unavailability when this is certain, it does not include any risk assessment of unexpected outages.*". This precise definition therefore excludes any assessment of the inability of a power plant to maintain its availability or to become available again.

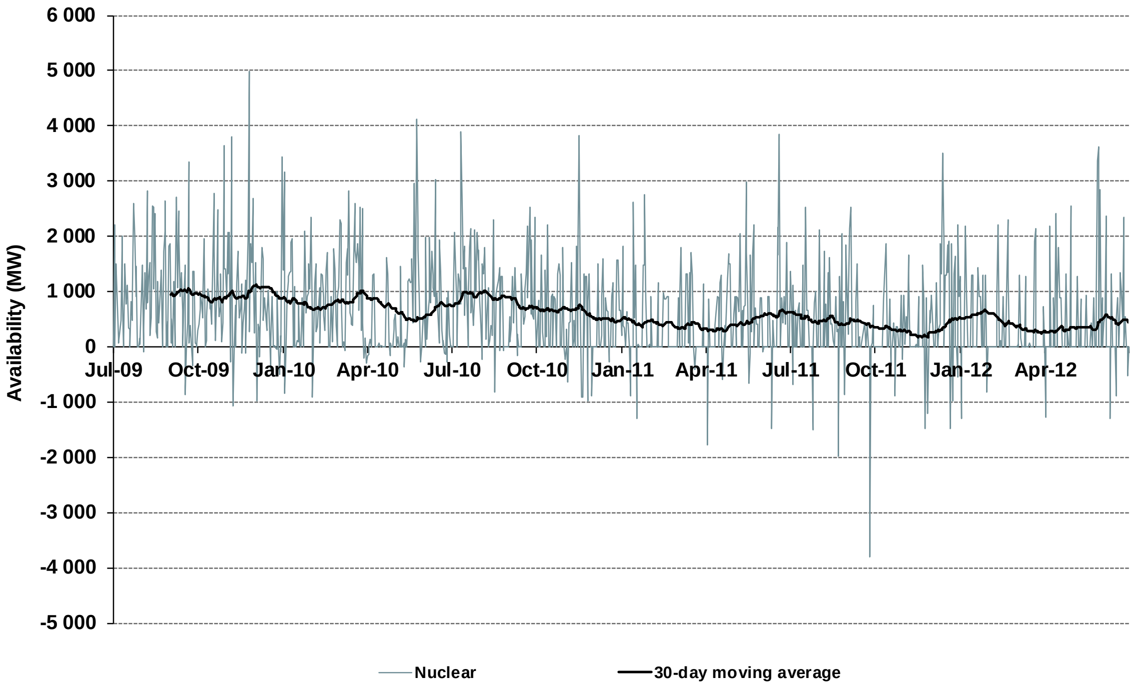
2011 as opposed to 1,048 MW in 2010. This reduction was in large part due to the decline in the difference recorded for the nuclear industry, which fell from 716 MW to 435 MW in 2011 (Figure 38).

Table 8: Average differences between D-1 provisional availability and that actually recorded

Coal	Hydroelectric, run-of-river	Fuel oil	Gas	Nuclear	Hydroelectric, lake	Total
135 MW	15 MW	100 MW	-43 MW	435 MW	44 MW	686 MW

Source: RTE ; Analysis CRE

Figure 36: Average difference between the (D-1) forecast and the nuclear availability recorded



Source: RTE - Analysis CRE

A SLIGHT INCREASE IN THE GAP BETWEEN PRICES AND MARGINAL COSTS OF THE EDF SYSTEM IN 2011 FOR WHICH EDF HAS PROVIDED TECHNICAL AND ECONOMIC SUPPORTING EVIDENCE. THE ENHANCEMENT IN EDF BIDS ON THE BALANCING MECHANISM IS COVERED BY A PARTICULAR ASSESSMENT

- **Offers on markets which are broadly in keeping with marginal costs**

Regarding the use of EDF production resources, the CRE is coordinating a particular monitoring process of the differences existing between prices on the spot market and the marginal costs of the EDF generation technologies arising out of the calculations of its daily optimisation models.

This study focuses on the hours for which the EDF offers are supposed to determine the auction price. On average, the price-cost difference in 2011 was 5.0% as opposed to 3.2% in 2010. As a reminder, this difference was 6% in 2009 (cf. Monitoring Report 2009-2010 published in October 2010). The CRE has questioned EDF on the causes of such a rise. EDF was mainly able to justify the increase in the price-cost difference by the following reasons:

• the amplitude of cost fluctuations in areas of discontinuity in the supply curve of EDF increased, especially at the change of the nuclear-coal generation technologies, due to the rising price of coal and small hydropower generation;

• the lower demand and greater availability of the nuclear generation led to a price formation within the vicinity of the discontinuity area of the nuclear-coal generation technologies in a slightly more frequent manner in 2011 than in 2010. In this discontinuity area of the supply curve of the low variance in relation to the volume addressed to EDF may have a highly significant impact on the marginal cost indicators and thereby generate significant differences.

In total, the CRE takes the view that, over this year, the gap between prices and marginal costs was at levels that do not constitute an abuse of a dominant position.

- **The enhancement policy of EDF in relation to the balancing mechanism is under particular scrutiny**

The CRE extended the previous analysis (differences between spot price and marginal cost of the EDF system) to include the bids activated by RTE on the balancing mechanism and the marginal costs of EDF's thermal generation technologies.

Over 2011, the CRE found average differences for the increasing and decreasing offers which were more significant than those observed between prices on the spot market price and the marginal costs of the EDF generation technologies.

The CRE questioned EDF about the reasons for these differences. EDF provided the following explanations:

The establishment of EDF's offers on the balancing mechanism was based on the generation costs including, besides the direct variable cost of production, costs and risks particular to the balancing mechanism:

• extra costs linked to lower power plant reliability resulting from load following imposed by the balancing;

• Risk of traceability gaps between RTE and EDF;

• costs related to the management of bids on the balancing mechanism.

Coverage of these various elements is generally tantamount to the application of a additional cost to all bids proposed by EDF on the balancing mechanism, without differentiation per generation technology.

EDF provided technical and economic evidence in support of these explanations, in particular an assessment of the impact in terms of availability of the functioning in load following of its power plants.

EDF also noted that the amplitude of the timeslots of the balancing mechanism (6 price ranges ranging from 3 to 6 hours) involved risks that were to be covered. On this point, EDF stated to the CRE that it was completing a test stage of its information systems to retain, in the expectation that these slots be reduced, less caution. This development was set for November 2012.

With regard to the amplitude of the additional cost, the update of the latest data available to EDF led it to revise this additional cost down.

Finally, this additional cost is applied in a uniform manner regardless of the production sector underlying the bid developed on the balancing mechanism. EDF is considering the possibility of distinguishing this additional cost per generation tehcnology. The CRE takes the view that such a development would be likely to clarify the contribution of the production costs of each generation technology to the cost of the balancing of the overall system and improve the methods by which EDF acts on the balancing mechanism.

Extensive work on the magnitude of the differences is ongoing.

Analysis of bids on the spot market and interconnection nominations

ON THE SPOT MARKET, THE CONSISTENCY OF OFFERS WITH THE PHYSICAL STATE OF THE POWER SYSTEM IS VERIFIED

This section analysed the bids submitted by the various market stakeholders on the EPEX SPOTAuction platform for France.

- **As in 2010, the supply level on the spot market was correlated with the system margin, and few offers fell between €100 and €300/MWh**

Figure 39 relates the sales order books (volumes offered at different prices) and the margin indicator, that is to say, the excess capacity available that reflects the state of tension of the French power system.

In 2011, hourly offers at all prices (for €0/MWh) averaged 3,838 MWh, a decrease of 8 per MWh compared to 2010.

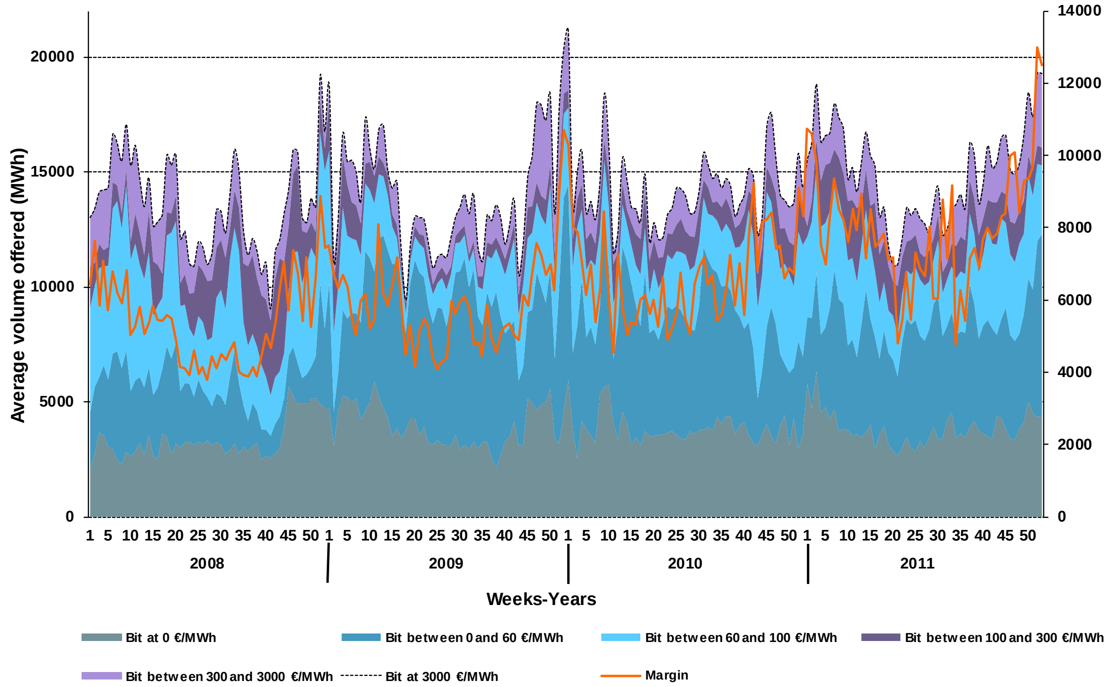
During 2011, it was observed that bids between €0 and €60/MWh represented 32% of the volume offered with an average volume of approximately 4,721 MWh. It was noted that this proportion increased during the year, thereby following the trend reversal of the price of fuel.

The average hourly supply volume between €60/MWh and €100/MWh totalled 3,134 MWh, an increase of 4% compared to 2010.

Beyond €100/MWh, the average hourly supply increased from 870 MWh to 3,270 MWh, including 1,539 MWh for the €100-€300/MWh section. These bids corresponded to bids for peak and extreme peak production equipment with a functioning duration of a few hundred hours per year.

Overall, there was a fairly clear correlation between the margin indicator and the total volume offered on EPEX SPOT.

Figure 37: Aggregate bid and margin indicator - 2011



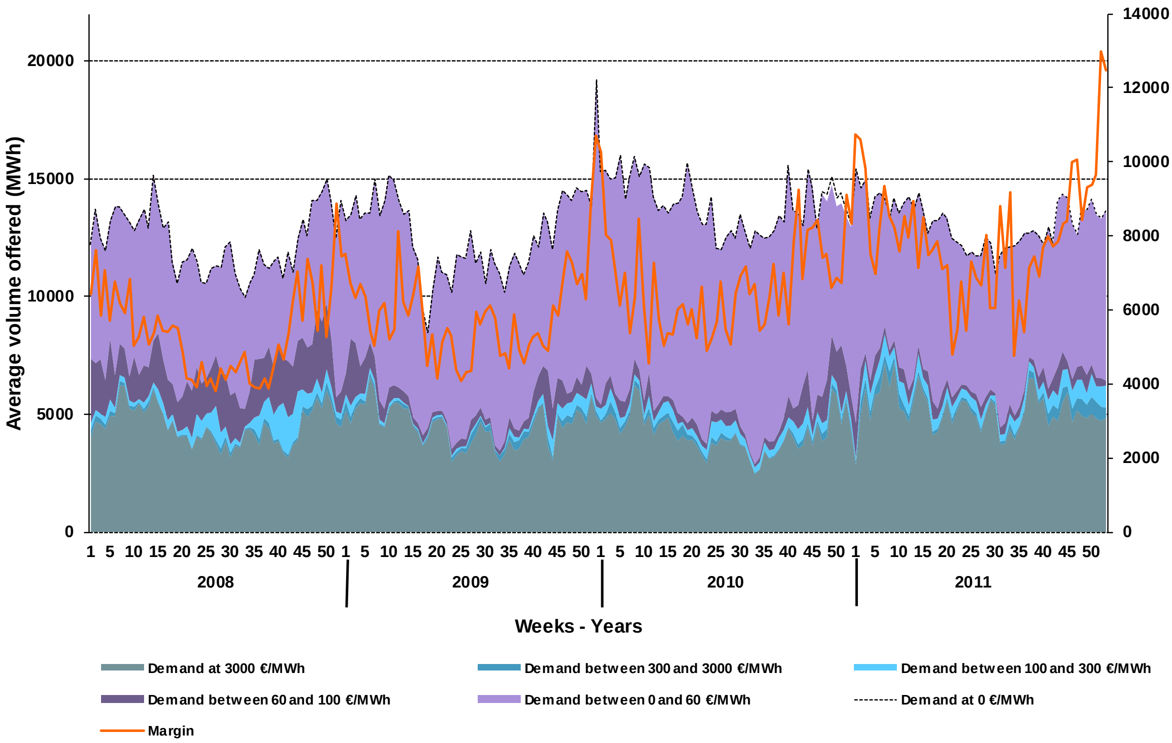
Source: EPEX - Analysis CRE

- **Demand below €100/MWh decreased while demand at any price increased**

In 2011, 54% of the aggregate demand was characterised by a willingness to pay between €0 and €100/MWh (Figure 40) as opposed to 66% in 2010. The average hourly volume demanded for a willingness to pay between €100/MWh and €300/MWh was relatively low (about 530 MWh).

The average volume of hourly bids of the demand at any price represented an hourly average of 5,154 MWh in 2011 or an increase of 992 MWh compared to 2010.

Figure 38: Aggregate demand and margin indicator - 2011



Source: EPEX - Analysis CRE

BEHAVIOUR OF STAKEHOLDERS AT THE BORDERS: A SPECIFIC INVESTIGATION WAS CARRIED OUT IN RELATION TO INTRADAY INTERCONNECTION TRADE WITH GERMANY AND SWITZERLAND

- **Energy nominations of hourly prices of daily capacity prices in opposite directions tended to stagnate in 2011**

An energy nomination in opposite directions occurs when a stakeholder imports or exports energy contrary to the price differential between the two countries, by nominating a daily interconnection capacity, that is to say after becoming aware of the reference spot price. For example, the stakeholder imports by using a daily interconnection capacity while the day-ahead prices was lower in France.

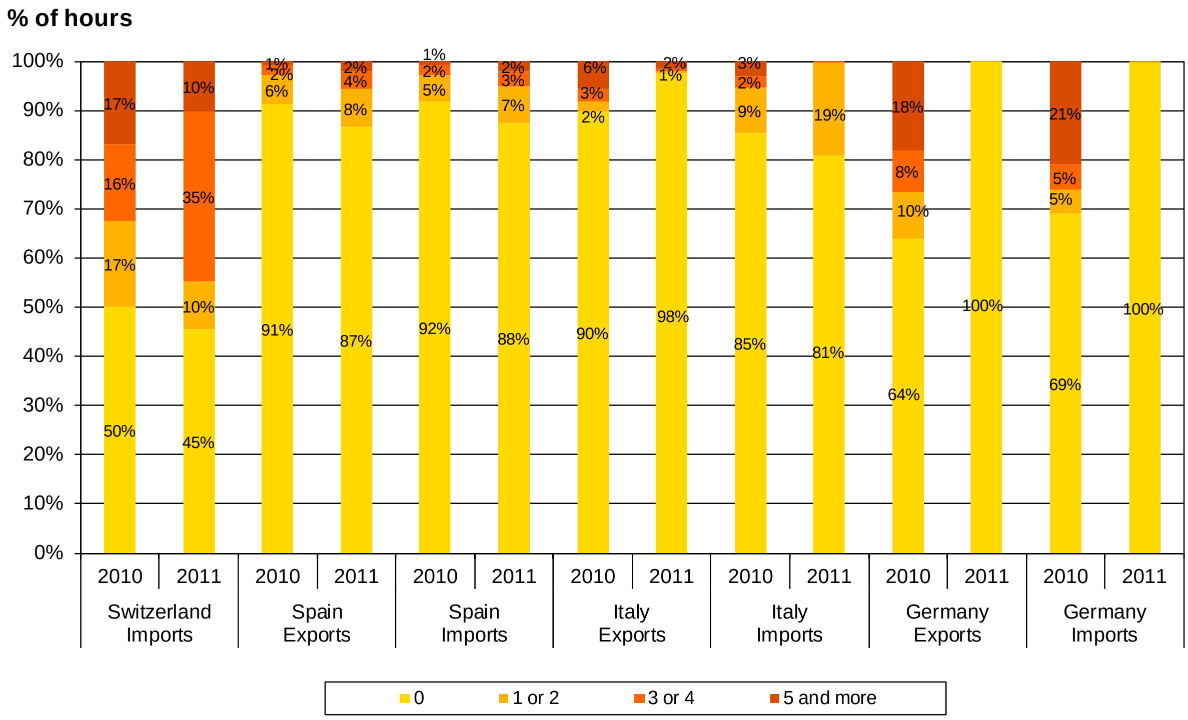
The analysis was conducted based on hourly price differentials using price references from exchanges.

Between 2010 and 2011, Figure 41 shows that the proportion of hours recording nominations in opposite directions increased by 4 points on the border with Spain in relation to imports (12%) and exports (13%), by 5 points on the Swiss border in relation to imports (55%) and by 4 points on the border with Italy in relation to imports (19%). In contrast, the share of hours with flows in opposite directions fell by 8 points on the Italian border in relation to exports, falling to 2% in 2011. On the German border, the introduction of market coupling as of

November 2010 optimised the use of the daily interconnection capacity, thereby removing the possibility of nominations in opposite directions.

However, it must be taken into consideration that some stakeholders may nominate in relation to several consecutive hours, and therefore not taking into account individual hourly prices, but their average in relation to the nominated hours. Thus, nominations in relation to several hours deemed to be in opposite directions vis-à-vis some hourly prices could be justified if compared to block prices.

Figure 41: Proportion of hours during which nominations in opposition to hourly prices occurred and number of stakeholders who nominated in opposition in 2010 and 2011



Sources: EPEX SPOT, IPEX, OMEL, RTE - Analysis: CRE

- **Use of intraday interconnection capacity on the borders between France and Germany and between France and Switzerland**

In the first half of 2011 for the interconnection between France and Germany and in the early months of 2012 for the interconnection between France and Switzerland, the following behaviour was observed during the explicit allocation process of the intraday capacity:

• Some market participants reserved all or part of the remaining capacity for a given delivery time as soon as it is made available;

• shortly before the end of the allocation process, these same players reserved a similar volume for the same delivery time in the opposite direction thus cancelling out the initial reservation.

This behaviour is possible in view of the allocation mechanism currently in place on these borders. The mechanism introduced on 18 January 2012 on the France-Switzerland border is in effect continuous and fully explicit. The allocation on the border between France and Germany has been continuous and both implicit and explicit since December 2010. In the case of an explicit allocation, the capacity allocation and energy purchase/sale are not coupled. Moreover, the available intraday interconnection capacity for each hour of the day is proposed the day before from 9:05 p.m.: it is free and allocated on a first come, first served basis.

As part of its monitoring operation of wholesale markets and cross-border trade, CRE conducted an analysis on the behaviour of participants during the intraday allocation of capacity on the France and Germany and France-Switzerland interconnections; this analysis was reported in its decision of 19 July 2012[18].

CRE interviewed two active market participants on the France-Germany interconnection and five active participants on the France-Switzerland interconnection regarding the technical and economic reasons which may justify such behaviour.

In the case of the border with Germany, and in the context of market coupling between the French and German spot markets, CRE also asked the players concerned to provide the details of their transactions both on the French and German intraday markets, insofar as transactions completed on the German market are likely to have an impact on the French intraday or spot prices.

Explanations provided by all players related to the fact that they were seeking to use interconnection capacity to be able to take advantage of trade-off situations (price differentials, re-optimisation of production assets) or to cover themselves in case of imbalance. The players questioned stressed that the lag time between the capacity reservation stage, the actual transactions and the delivery time could explain the cancellation of the reserved capacities. Therefore the conditions of price and production may change very significantly and differently from as anticipated between the point in time when the capacity is made available, i.e. the evening before, and the delivery time. Furthermore, the low liquidity in the French and Swiss intraday markets does not always allow purchase/sale transactions on either side of the border to utilise the reserved capacity..

CRE also noticed that, on the French-German border, both involved players indicated they had taken operational steps to ensure that reserved capacities would correspond as much as possible to definite requirements and be used to transfer energy. However, only one player took a similar commitment on the French-Swiss border.

CRE finally observed that all players were able to provide technical/economic explanations which, according to them, could justify the behaviour identified within the current operational rules for intraday capacity allocation. Furthermore, the analysis carried out by CRE of the various cases did not reveal market manipulations within the terms of REMIT.

[18] http://www.cre.fr/documents/deliberations/approbation/regles-d-allocation-de-la-capacite-d-interconnexion-france-allemagne-et-france-suisse

Insofar as such behaviour is likely to lead to a less than optimum utilisation of the interconnection capacity, CRE was in favour of adapting the rules governing the explicit allocation of the intraday interconnection capacity allowing this to be avoided.

In its decision of 19 July 2012, CRE therefore approved changes to the rules proposed by RTE and also made recommendations to ensure an effective use of the interconnection between France and Switzerland, especially by advocating the set up of an implicit allocation also between France and Switzerland.

Section II: CO_2 markets

1. CO_2 Markets: evolution of the institutional framework and future prospects

THE PROPOSED REGULATORY FRAMEWORK AT EUROPEAN LEVEL FOR THE INTEGRITY OF THE CO_2 MARKET PROVIDES FOR THE INCLUSION OF CO_2 WITHIN THE SCOPE OF MIFID

In December 2010, the European Commission published a communication in favour of improved CO_2 market surveillance at European level. At the time, three options were presented:

- the creation of a specific regulatory framework for the carbon market;
- the inclusion of the European carbon market under the framework of the financial regulation;
- the inclusion of the European carbon market under the regulation for energy markets (REMIT, Regulation (EU) No. 1227/2011).

Since, the inclusion under REMIT has been discarded and the final version of the text of REMIT in December 2011 does not qualify CO_2 allowances as "wholesale energy products". REMIT nevertheless establishes "the monitoring of wholesale energy markets by ACER, in close collaboration with national regulatory authorities, and taking into account the interactions between the Emissions Trading Scheme and wholesale energy markets."[19] REMIT provides ACER with access to transactional data collected by the authority responsible for monitoring CO_2 markets[20].

The European Commission now favours - in the proposed revision of MiFID (Markets in Financial Instruments) and MAD (Market Abuse directive) of October 2011[21] - the inclusion of allowances in the list of products qualified as financial instruments and, therefore, within the scope of the financial regulation.

Finally, we can recall that the CO_2 market underwent various shocks linked to the theft of allowances and fraud. The European Commission suspended trading on the CO_2 spot market on 19 January 2011 for over a week following the theft of allowances in several countries, in order to reinforce the security of the registry.

[19] Cf. REMIT, regulation (EU) No. 1227/2011, Article 1

[20] REMIT, Article 10.3

[21] The proposals of MiFID and MAD are still under discussion and should enter into force in 2014/2015.

IN 2011, CRE IMPLEMENTED ITS NEW MONITORING COMPETENCY ON THE CO_2 MARKET IN COOPERATION WITH THE AMF

EFFICIENT COOPERATION WITH THE AMF

The banking and financial regulation law (LRBF) of 22 October 2010 conferred additional competences to the two authorities. The AMF oversees the market infrastructure and detects market manipulations in relation to spot and futures trades conducted on BlueNext. CRE analyses the consistency between transactions conducted on CO_2 markets and the fundamentals of energy markets. The scope monitored by CRE consists of active players on the French electricity and natural gas markets (suppliers, traders, producers) whatever the location and the means of the transactions are (exchange, broker, bilateral). The common part of the monitoring scopes of CRE and the AMF therefore corresponds to the activity on BlueNext of members active on the French electricity and natural gas markets.

CRE and the AMF have worked together and analysed market events, such as the fall in CO_2 price following the declaration of the European Commission on the project of the energy efficiency directive in June 2011.

Regarding regulatory issues, regular meetings between CRE and the AMF enabled exchanges to take place in particular concerning the implementation of EMIR regulation and the review of MiFID and MAD.

CRE regularly collects BlueNext's transactional data via the AMF, which details CO_2 prices and transactions on the spot market as well as data relating to the compensation of bilateral transactions (OTC clearing). The transmission of data between the two Authorities spares the concerned players from submitting the same reports twice. Since mid-2011, CRE also collects data from the English stock exchange ICE ECX via the AMF and its British counterpart, the FSA.

This data does not, however, cover the entire perimeter within the monitoring scope of CRE. So far, amongst the market places, the main brokers (members of London Energy Brokers Association) have indeed not yet adhered to CRE's approach. The brokers are believed to represent nearly half of the perimeter monitored by CRE (cf. section 2.4).

CRE therefore launched a bilateral data collection for the year 2011.

AS CERTAIN MARKET PLACES FAILED TO SUBMIT DATA, CRE LAUNCHED A BILATERAL DATA COLLECTION RELATING TO 2011 TRANSACTIONS FOR PLAYERS WITHIN CRE'S MONITORING SCOPE

In March 2011, pursuant to Articles L. 131-3, L. 133-6 and L. 134-18 of the French Energy Code (see Box 3), CRE launched a bilateral collection of CO_2 data from market players. Indeed, pending the introduction of generalised data collection at a European level, and being unable to obtain the relevant transactional data from all the concerned market places[22], CRE conducted a data collection directly from the market players within its perimeter.

[22] BlueNext, EEX and recently ECX submit regular trading data within the monitoring perimeter of CRE.

Market players within CRE's scope include all the companies active on the electricity and natural gas markets in France and registered as balance responsible entities or shippers (around 200 firms). CRE requested that each of these players provide details of all EUA, CER and ERU spot and derivative transactions concluded in 2011, including transactions conducted in France and abroad, on French and foreign market places.

The bilateral data collection launched in March 2011 has spread over time and required many exchanges with the market players (see the questions asked to CRE in Box 3). Almost all of the participants responded to CRE's request. The few participants who have not yet responded are being chased up.

A centralised approach for data collection is privileged. However, a bilateral data collection may be renewed for 2012 if the brokers have still not adhered to the approach, or if an exceptional event occurs on the market.

CRE has conducted analysis in terms of volume of data received from participants within its scope, i.e. all EUA, CER and ERU spot and derivative transactions concluded in 2011, including transactions conducted in France and abroad, on French and foreign exchanges, bilateral transactions and on the intermediated OTC market, with at least one participant within the scope of the CRE. For analysis in terms of volume of CO_2 transactions collected by the CRE for 2011, refer to section 2.4.

Box 3: Articles of the Energy Code governing the collection of CO_2 data conducted by CRE and frequently asked questions to CRE during the collection

Article L. 131-3 of the Energy Code:*"In the framework of its activities, Commission de Régulation de l'Energie monitors transactions entered into by suppliers, traders and producers of electricity and natural gas, concerning greenhouse gas emission reduction allowances […] as well as underlying term contracts and financial instruments, in order to analyze the consistency of these transactions with the economic, technical and regulatory constraints of activities carried out by these suppliers, traders and producers of electricity and natural gas."*

Article L. 134-18 of the Energy Code: *"With regards to the achievement of its missions, Commission de Régulation de l'Energie collects all the necessary information from the ministers in charge of economy, environment and energy, from electricity transmission and distribution systems operators, from natural gas transmission and distribution systems operators and liquefied natural gas facilities operators, from end consumers suppliers on the mainland territory benefiting from regulated access to historical nuclear power referred to in Article L. 366-1, from carbon dioxide geological storage and transport network operators as well as from the other companies operating on the electricity and gas markets or on carbon dioxide capture, transport and geological storage markets. Commission de Régulation de l'Energie can also ask to audition any person who is likely to contribute to its information."*

Frequently Asked Questions to the CRE:

***Question*:** Are all transactions concerned or only those involving a French counterpart?

CRE's Answer: CRE collects all spot and derivative CO_2 trades, including trades conducted in France and abroad, on French and non-French exchanges, bilaterally and on the OTC intermediated market. These trades must include at least one counterpart, French or not, active on the French market for electricity and gas within the perimeter of CRE, i.e. *"transactions by suppliers, traders and producers of electricity and natural gas, for greenhouse gas emission reduction quotas"* (Article L. 131-3 of the Energy Code). If necessary, participants may submit the names of counterparts that are listed within the scope of the CRE only, replacing the other names by "Outside of the perimeter".

Question: Should intra-group transactions be submitted?

CRE's answer: according to Article L.131-3 of the Energy Code, intra-group transactions are within the scope of CRE. For the purposes of the data collection in 2011, internal transactions do not have to be submitted to CRE. CRE will consider whether this type of transactions should be systematically collected in the future. If market events lead to it, an ad hoc collection request of such transactions could be considered.

Question: should transactions conducted before 2011 and delivered in 2011 be submitted?

CRE's answer: No. Only transactions conducted in 2011 are included within the scope.

Question: what about the confidentiality of data and the means used to submit data to CRE?

CRE's response: Article L.133-6 of the Energy Code stipulates that *"Members and agents of Commission de Régulation de l'Energie are sworn to professional secrecy for facts, acts and information that they came to know through their role".* The process of data transmission to CRE has been ongoing for six years in the framework of the wholesale electricity and gas markets monitoring and ensures confidentiality of data. With regards to the transmission of data, CRE has access to a secure web platform where participants can upload their data files. Participants can use this platform or any other platform of their choice.

Question: In the absence of a centralised data collection system, will there be other bilateral data collections carried out by CRE?

CRE's Answer: CRE does not expect to conduct bilateral data collections on a frequent basis. A new data collection may be carried out if relevant market places fail to submit the required data or if an exceptional event occurs on the market.

PENDING THE DEVELOPMENT OF ITS INSTITUTIONAL FRAMEWORK, THE MARKET WAS AFFECTED BY ENERGY POLICY ANNOUNCEMENTS

SIGNIFICANT CHANGES IN TERMS OF AUCTIONING HAVE APPEARED FOR PHASE III OF THE EU ETS

Phase III of the EU ETS (EU Emissions Trading Scheme) will come into force on 1 January 2013 and will last for eight years, until 31 December 2020. The main differences between Phase II and Phase III are presented in the below table (see Table 9).

Approximately 50% of allowances - roughly one billion allowances per year - will be auctioned, versus less than 4% during the second phase of the EU ETS (2008-2012). With regards to the electricity sector, 100% of allowances will be auctioned (except for certain Member States)[23]. Early auctions planned for Phase III will take place from October to December 2012, with the sale of approximately 120 million EUA (European Union Allowance) and 30 million EUAA (European Union Aviation Allowance; the aviation sector has been included since 1 January 2012). An equivalent volume of allowances will be

[23] Certain Member States will receive free allowances for their power plants at the beginning of Phase III.

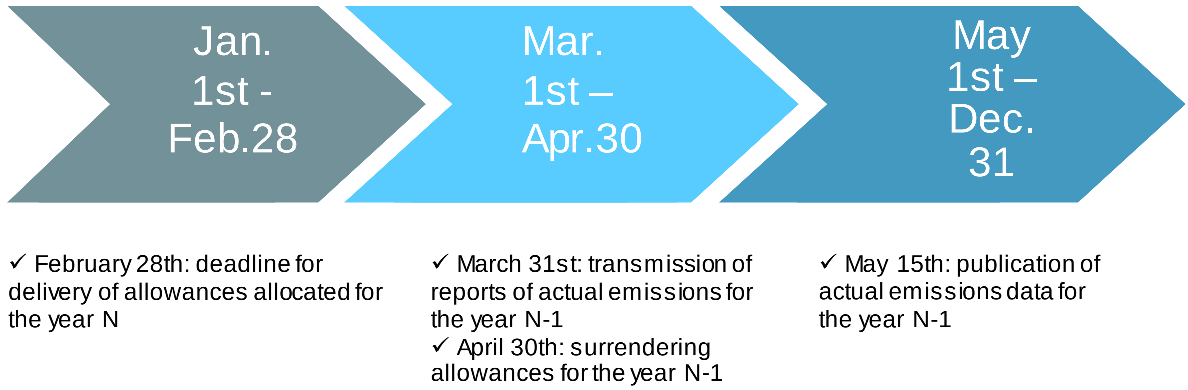
removed from volumes to be auctioned for the years 2013 and 2014, so that the total volume of auctions for Phase III remains unchanged.

In preparation of Phase III auctions, a common transitional platform was chosen for twenty-four Member States out of the twenty-seven. The German platform EEX was awarded the tender launched for this purpose in September 2012 and will auction about 250 million allowances before the definite common platform is selected. As for Germany, Poland and the UK, they have chosen not to participate in the common auction platform and are therefore in an "opt out" position. EEX has also been selected as the individual platform for Germany while ICE/ECX has been selected as the individual platform for the UK. There is still no individual platform for Poland. In June 2012, a single European carbon registry was introduced for all European Member States.

Phase III auctions will be monitored by the "auction monitor" and the competent national financial services authority who will work together. The auction monitor will be selected jointly by the Commission and the Member States (including Germany, Poland and the UK) to ensure transparency and fair access to auctions. The competent national financial services authority will oversee the auctions which will take place on the platform of its country. It will ensure that there is no violation or market abuse.

Regarding free allocation and surrender of the allowances, the compliance schedule for Phase III is identical to that of Phase II (cf. Figure 42).

Figure 42: Compliance schedule for players on the European Union Emissions Trading Scheme (EU ETS)



Source: European Commission

Table 9 Main differences between phase II and phase III

	Phase II (2008 – 2012)	Phase III (2013 – 2020)
Concerned units	12,000	More than 12,000
Concerned countries	27 Member States of the European Union, Liechtenstein, Norway and Iceland.	Same as phase II. Switzerland could take part as of 2013.
Concerned sectors	Electrical power, iron, steel, cement and lime, oil refineries, glass, ceramics, pulp and paper. Civil aviation has been involved since 2012.	Same as phase II, plus the ferrous and non-ferrous metals, aluminium, nitric acid, glycolic acid, ammonia, soda dust, hydrogen, petrochemicals
Concerned greenhouse gases	CO_2	CO_2, N_2O, PFC
Free allocation method	National allocation plans	Allocation at EU level
Free allocation	96% of the quotas allocated for free, 4% auctioned.	0% (with exceptions) for the production of electricity. The principle of free allocation of allowances is retained for certain industrial sectors exposed to a significant risk of international competition, this allowance being made at a European level on the basis of standards corresponding to 10% of the lowest emitting installations in Europe. Decreasing rate from 80% to 30% for other sectors from 2013 to 2020. In total approximately 50% of allowances will be allocated freely for 2013.
Transfer of allowances between phases	An unlimited amount of allowances can be transferred from phase II to phase III.	Unlimited transfer between two successive phases.
Sanctions	Non-discharging penalty of €100/t if the allowances are not surrendered in time.	Same penalty as for Phase II, adjusted for inflation (for aircraft operators, the penalty can even be an operating ban).

Source: Directorate General for Energy and the Climate

SEVERAL ANNOUNCEMENTS ON ENERGY POLICIES AND REGULATIONS HAVE HAD AN IMPACT ON THE EU ETS MARKET

During 2011 and 2012, several political statements have had visible short-term effects and a substantial impact on the price of CO_2 allowances (cf. section 3.1).

On 14 March 2011, following the nuclear crisis that struck Japan, **Germany announced a moratorium** on nuclear power. The EUA spot carbon price on BlueNext increased from €14.86/tCO_2 on 11 March to €16.59/tCO_2 on 28 March 2011. During the same period, the Y+1 futures price on ECX substantially increased from €15.73/tCO_2 to €17.29/tCO_2.

In the framework of the EU 20-20-20 targets[24] and an increased effort to reduce energy consumption by 20%, the European Commission proposed on 22 June 2011 a new **Directive on Energy Efficiency** (EED) for entry into force late 2012. The announcement of the proposal of the European Commission resulted in a risk of oversupply of allowances, which led to a fall in EUA spot prices on BlueNext from €14.62/tCO_2 on 22 June to €12.21/tCO_2 on 24 June 2011 and triggered a downwards trend to a low point of about €7/tCO_2 at the end of 2011.

In order to reverse the decline in the carbon spot price, which fell below €7/tCO_2, due to the surplus of allowances accumulated since 2010 and to the weakening of the industrial activity, the European Parliament's environment committee voted on 20 December 2011 in favour of setting aside a **significant volume of allowances** of the EU ETS before the beginning of Phase III, and a volume of 1.4 billion EUA was discussed. On the same day, the EUA spot price rose by 23% on BlueNext, reaching €8.46/tCO_2, before falling again during the next few days.

[24] The 20-20-20 targets consist of reducing greenhouse gas emissions by 20%, reducing energy consumption by 20% and increasing renewable energy by 20% by 2020 compared to 2005 levels.

Volumes traded on the CO_2 market

In this section, the characteristics of transactions carried out on the European market (exchanges and intermediated OTC), i.e. all of the EU ETS, are analyzed. The corresponding data has been made public (except section 2.4).

TRADING VOLUMES INCREASED IN 2011 COMPARED TO 2010 LEVELS AND THE TURNOVER RATE INCREASED

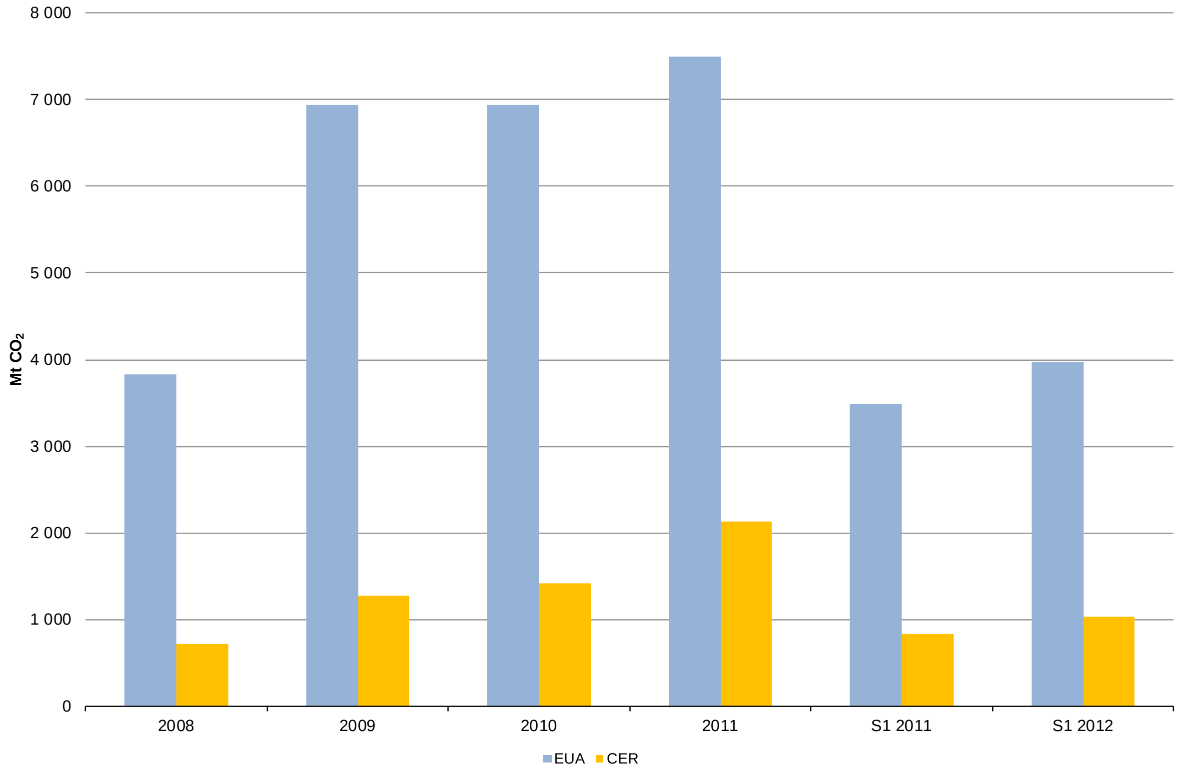
The total volumes traded increased by 15% in 2011 compared to 2010: they totalled 9,638 Mt (million tonnes of CO_2), as opposed to 8,366 Mt in 2010. The increase between the first half of 2011 and the first half of 2012 was 16% (from 4,311 to 5,005 Mt).

EUA (European Union Allowance) volumes traded on the secondary market increased by 8% between 2010 and 2011 (from 6,941 to7,500 Mt). Allowances distributed on the primary market (free allowances and auctioned allowances) represented 2,078 Mt in 2011 compared to 2,076 Mt in 2010. The EUA allowance turnover rate, that is to say the ratio between the number of allowances traded on the secondary market and the number of distributed allowances increased from 334% in 2010 to 361% in 2011. The value of EUA trades represented 100.0 billion Euros in 2011, versus 101.7 billion Euros in 2010; this decrease of nearly 2% was due to a decrease in prices. In the first half of 2012, the volume of EUA traded increased by 14% compared to the first half of 2011 (from 3,484 to 3,969 Mt).

On the CER (Certified Emission Reduction) market, volumes traded increased by 50% between 2010 and 2011 (from 1,425 to 2,139 Mt) and their value by 13% (from 17.5 to 19.7 billion Euros). In the first half of 2012, the volumes of CER traded increased by 25% compared to the first half of 2011 (from 827 to 1,036 Mt). This strong increase in CER volumes since 2011 is linked to the price spread which has widened between EUA and CER products (cf. section 3.1).

Finally, the ERU (Emission Reduction Unit) market traded 52.7 Mt units in 2011 versus 3.3 Mt units in 2010. The ERU market clearly grew in terms of volume, however, this figure is still very low compared to the total EUA and CER transactions. The ERU valuation was estimated at about 0.6 billion Euros in 2011.

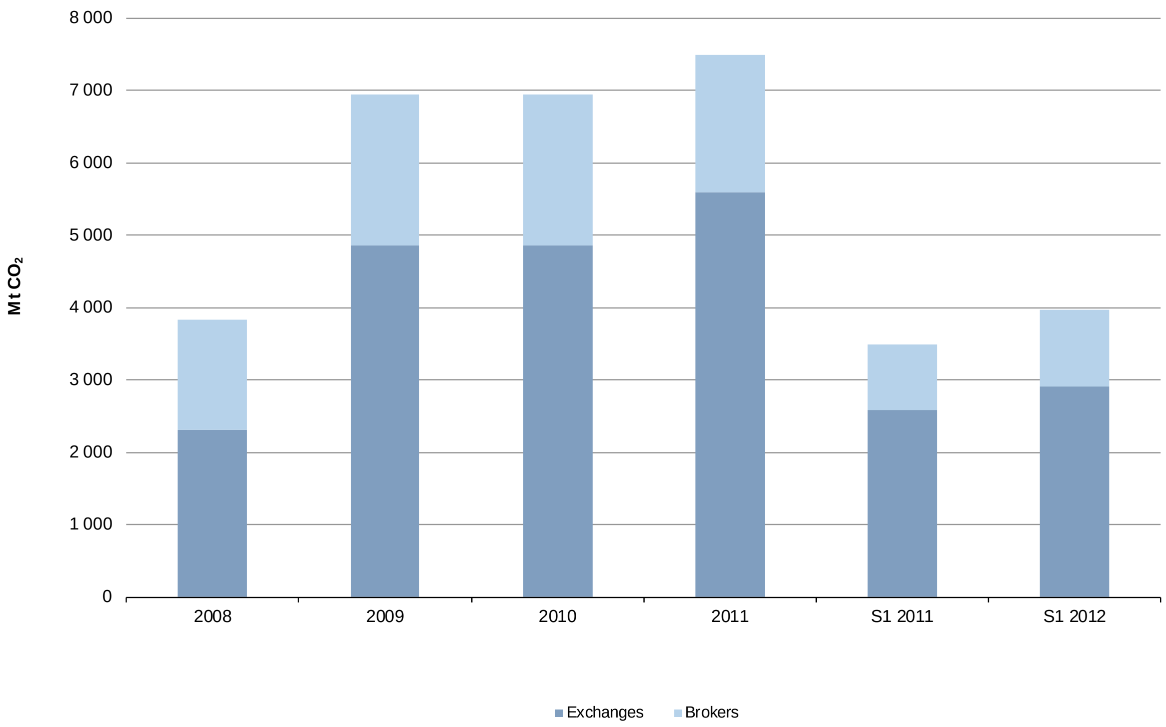
Figure 39: Annual EUA and CER volumes since 2008



Sources: BlueNext, ECX, EEX, LEBA

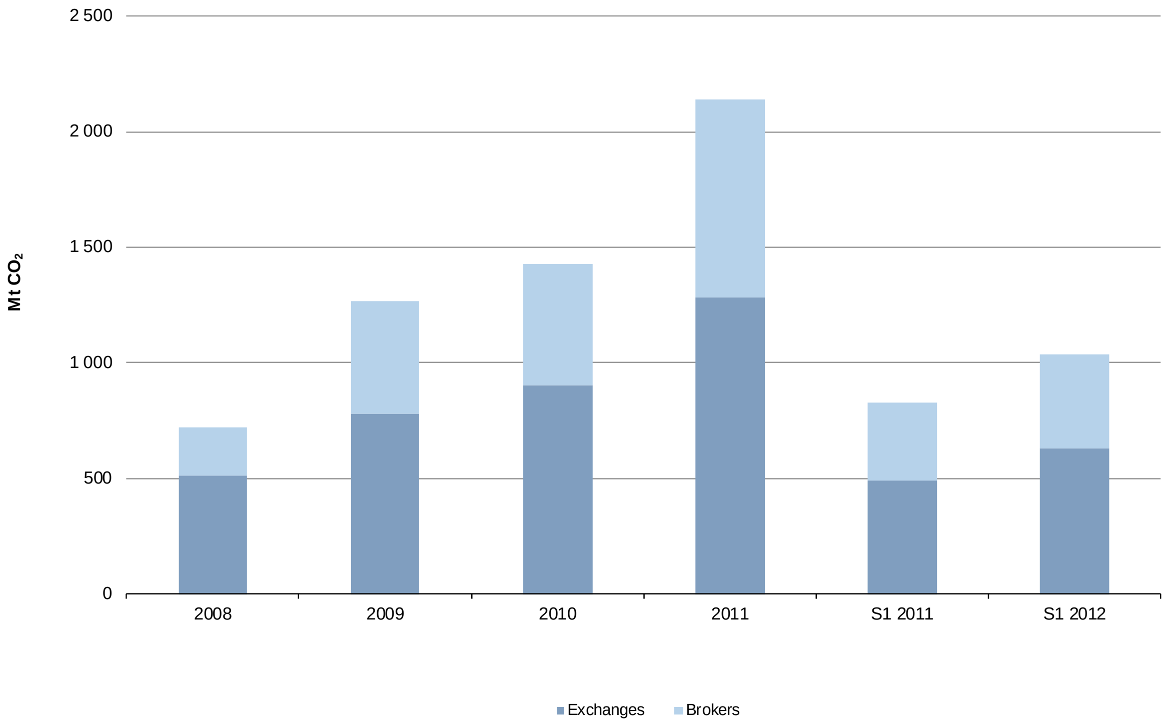
Figure 44 and Figure 45 illustrate the exchanges' and brokers' market shares for EUA and CER products since the start of Phase II.

Figure 40: Annual EUA Volumes



Sources: BlueNext, ECX, EEX, LEBA

Figure 41: Annual CER Volumes



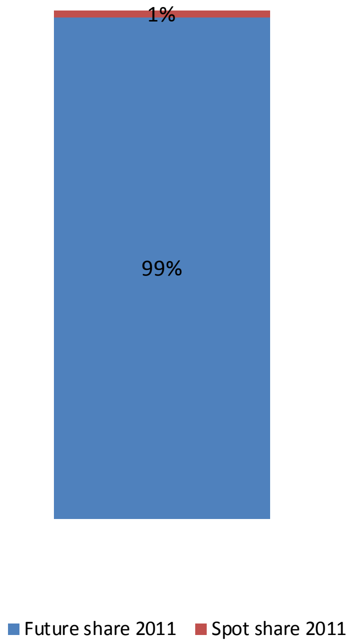
Sources: BlueNext, ECX, EEX, LEBA

THE CO_2 EXCHANGE MARKET HAS CONSISTED ALMOST EXCLUSIVELY OF FUTURES PRODUCTS SINCE 2011

In 2011, almost all transactions completed on exchanges concerned futures products (cf. Figure 46), most of which were conducted on the ECX platform.

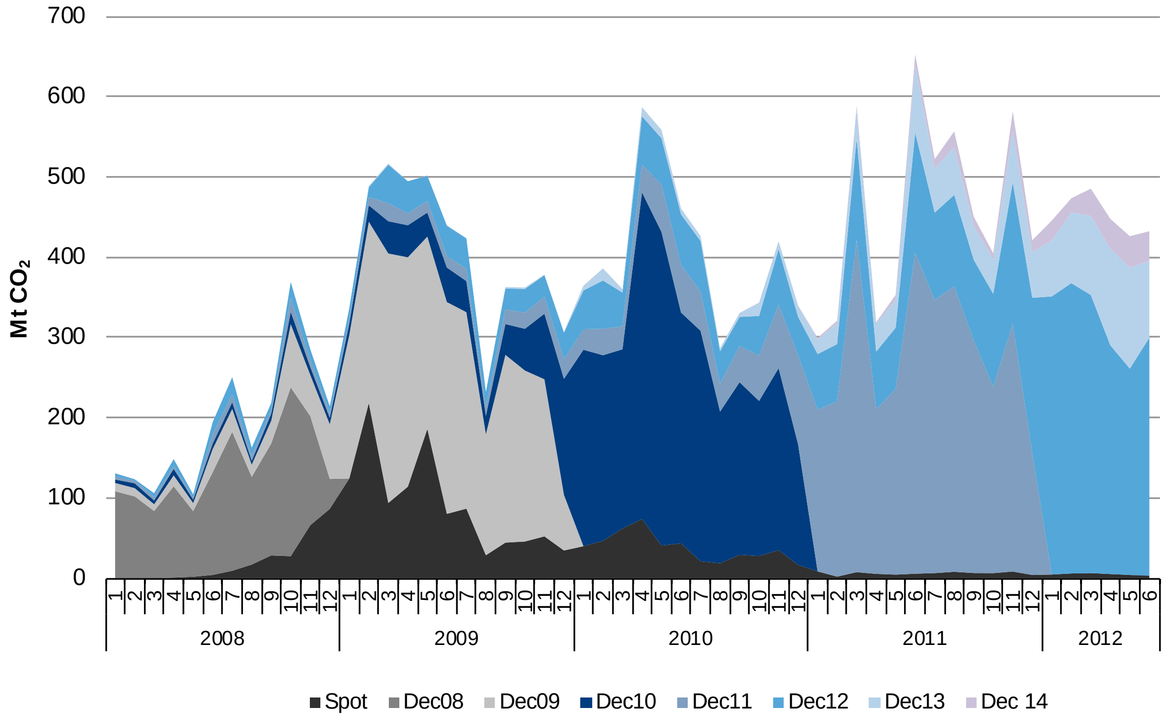
For any given year, most traded contracts relate once again to deliveries for the end of the current year: that means that players are essentially covered one year in advance for their actual emissions, knowing that a potential surplus of allowances can be banked for the following compliance schedule and that any default in allowances can be acquired on the spot market before surrendering the allowances in April (cf. Figure 47 and Figure 48).

Figure 42: Spot and futures market shares on exchanges



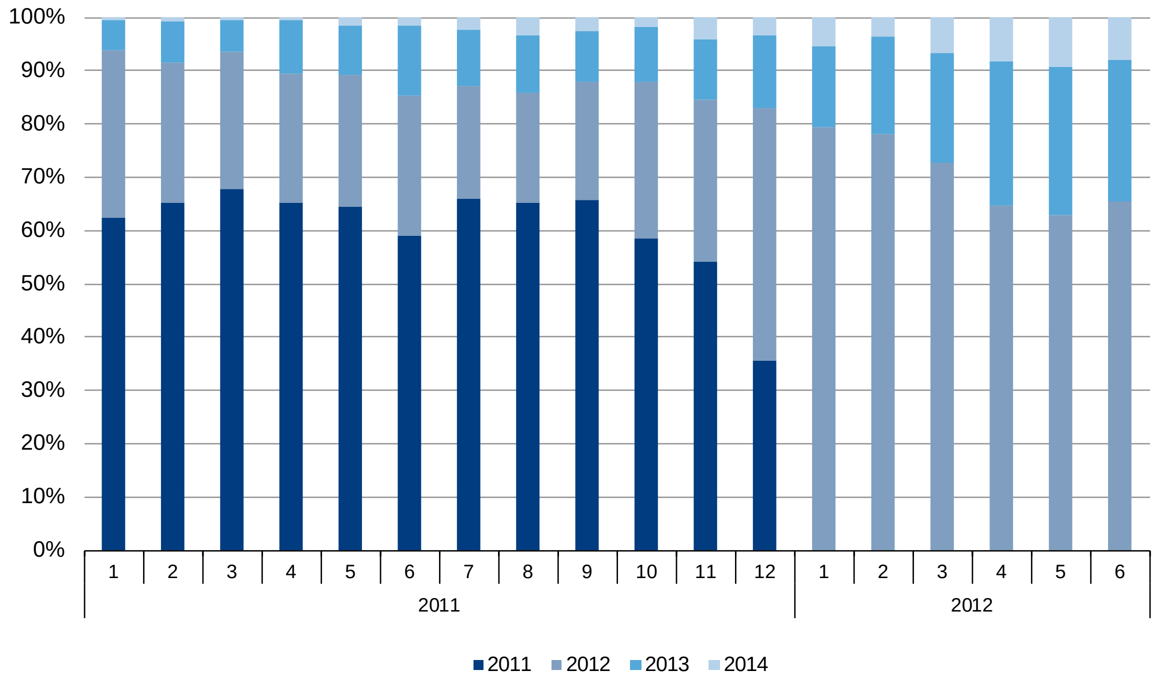
Sources: BlueNext, ECX, EEX

Figure 43: Evolution of EUA trades by maturity



Sources: BlueNext, ECX, EEX

Figure 44: EUA Volumes by maturity on the ECX platform



Sources: ECX

PARTICIPANTS PRESENT ON THE CO_2 MARKETS

A classification of participants on the CO_2 markets can be made from public lists of members of Bluenext, ECX and EEX platforms, as presented in Table 10.

The key observations are that:

- energy companies - that is to say shippers, balance responsible entities, producers of electricity, natural gas and oil- as well as financial players make up 90% of players on the European CO_2 market. Financial players, which include financial institutions and pure traders, intervene on the carbon market for arbitration on their own behalf or on behalf of third parties;

- there are very few industry and other players subject to the EU ETS which intervene directly on the CO_2 markets;

- energy companies and financial players make up 95% of the participants within CRE's scope. Participants within CRE's scope represent nearly half of the participants of the European CO_2 market;

- The volumes of CO_2 transactions conducted in 2011 by players which fall within CRE's scope are analysed in the following section.

Table 10: Classification of participants in the CO_2 market

Type of market stakeholder	CRE scope	Outside of CRE scope	Total
Energy company	86	69	155
Financial player	53	94	147
Industry	7	8	15
Others	0	16	16
Total	**146**	**187**	**333**

Sources: BlueNext, ECX, EEX, Analysis CRE

ANALYSIS IN TERMS OF VOLUME OF CARBON DATA COLLECTED BILATERALLY BY CRE FROM PARTICIPANTS WITHIN ITS SCOPE FOR THE YEAR 2011

The analysis of the data collected (cf. Figure 49 to Figure 53) provides the following key observations:

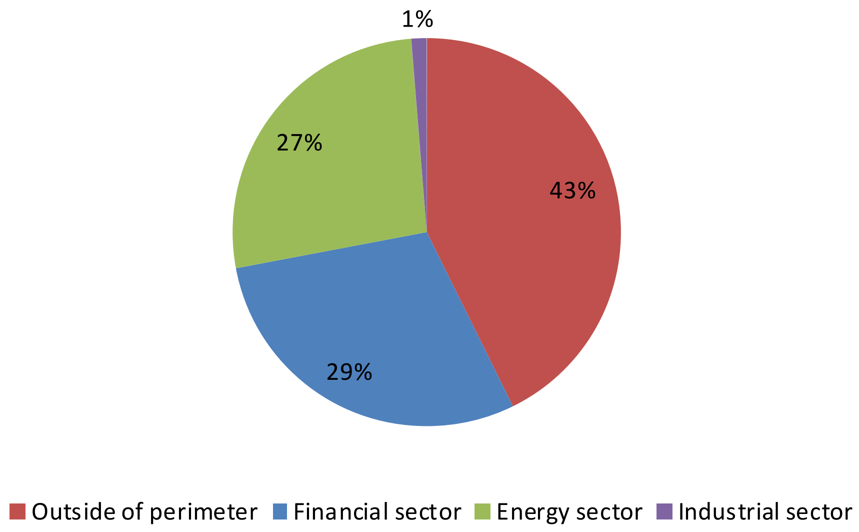
Energy companies and financial players each represent nearly 50% of the trading volumes within CRE's scope, whilst industry players represent a very small proportion of trades.

Exchange and OTC intermediated markets have similar market shares in terms of volume, respectively 43% and 47%, all carbon products included, while bilateral transactions have a limited volume of 10%.

In line with the market, transactions falling within the monitoring scope of CRE predominantly concern EUA (75%) and CER (23%) products. The share of transactions in relation to ERU products is marginal.

The share of carbon data collected by CRE and traded via the main exchanges and brokers represents around half of the total European transactions via exchanges and brokers, all products included.

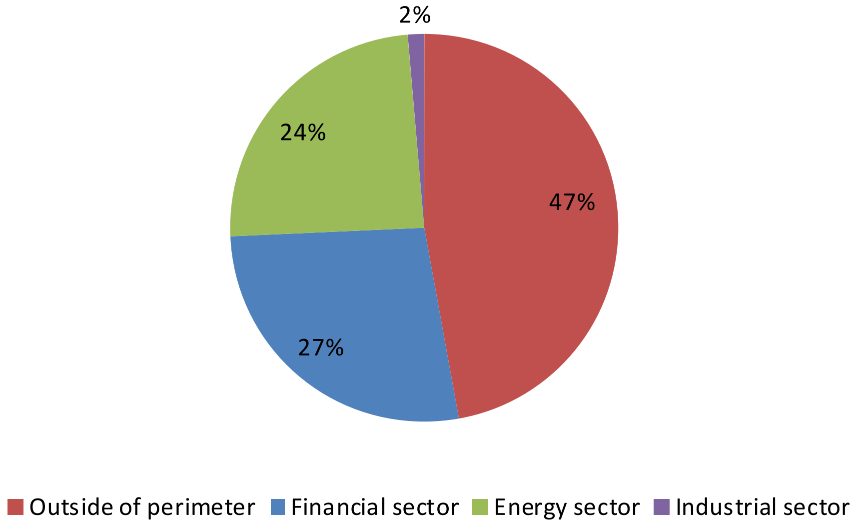
Figure 45: Classification of participants on the carbon market in purchasing volume



Source: CRE data collection

NB: the participants who are outside of perimeter are counterparties of transactions involving a player within the scope of CRE

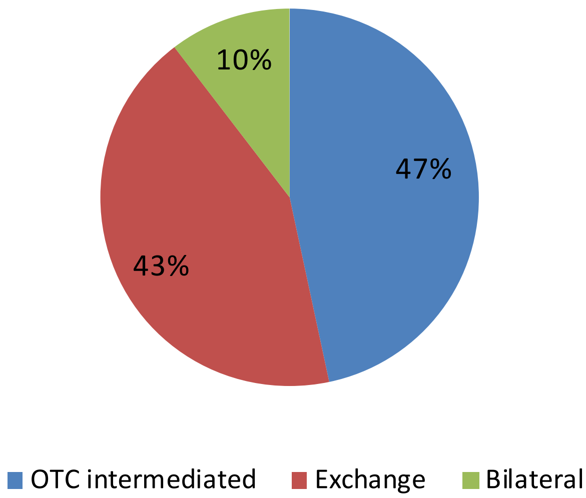
Figure 50: Classification of participants on the carbon market in sales volume



Source: CRE data collection

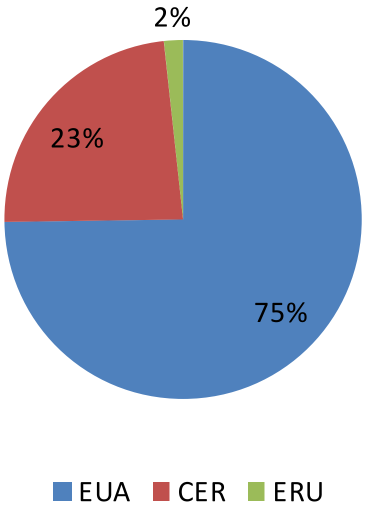
NB: the participants who are outside of perimeter are counterparties of transactions involving a player within the scope of CRE

Figure 46: Share of each market place in volume, all products included



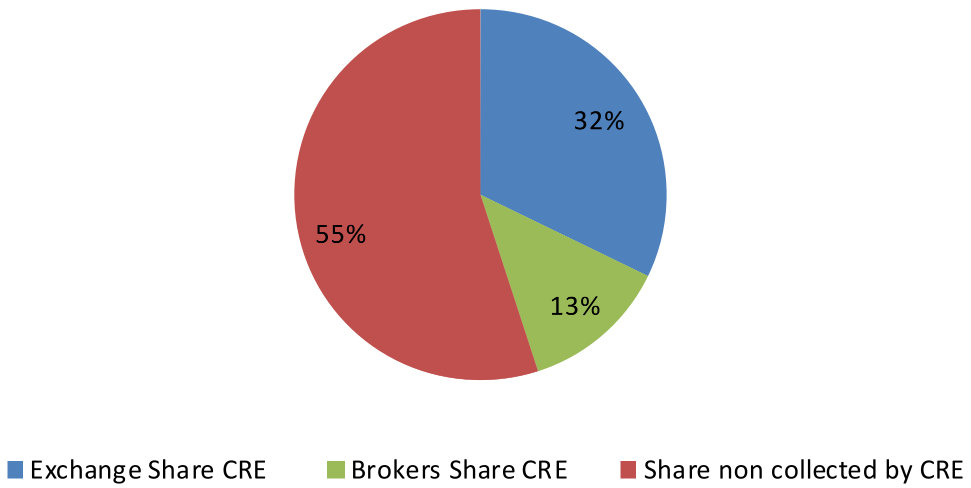
Source: CRE data collection

Figure 47: Share of each product in volume, all market places included



Source: CRE data collection

Figure 48: Share of data collected by CRE and traded via the main brokers and exchanges as a percentage of total European volume



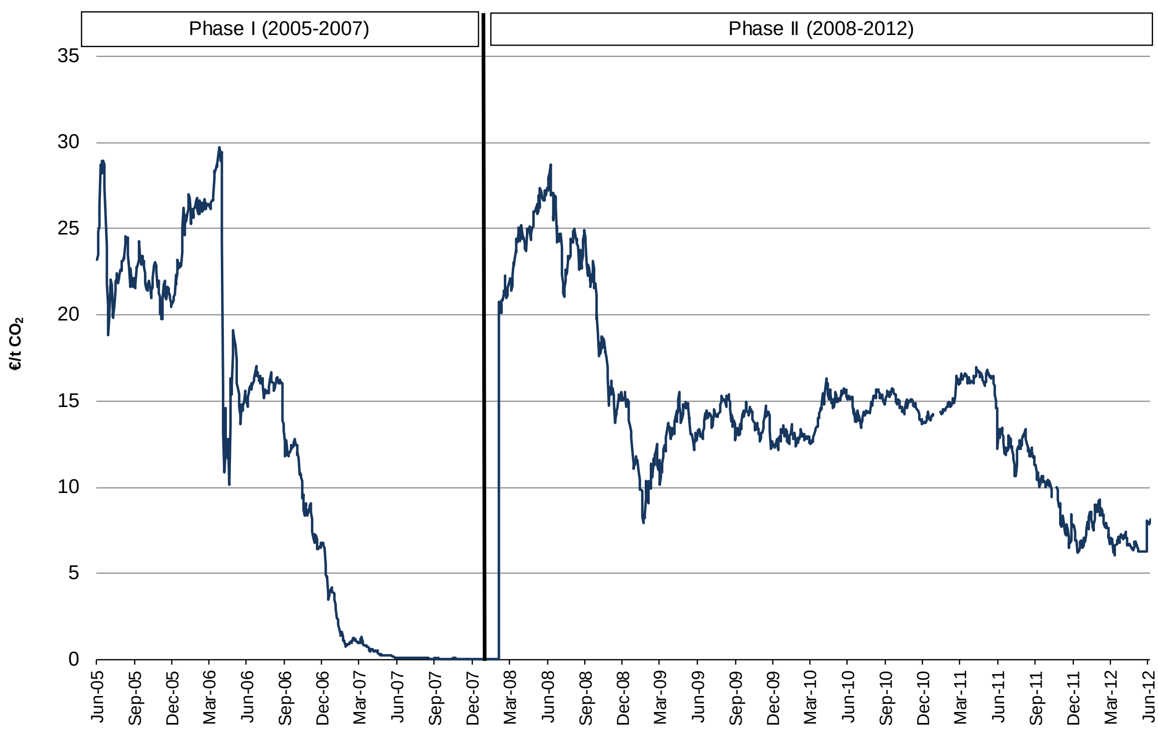
Sources: CRE data collection, Bluenext, EEX, ECX, GreenX, LEBA

A PRICE TREND CHARACTERISED BY THE FALL IN PRICES OF ALLOWANCES AND THE WIDENING OF THE EUA-CER PRICE SPREAD

The EUA spot price decreased by 10% in 2011 compared to 2010, from €14.34/t to €12.95/t, with an increase in prices during the announcement of the German moratorium on nuclear power in March 2011 and when the European Parliament expressed its support for a set-aside of allowances in December 2011; and with a fall in prices from June 2011, related to the Energy Efficiency Directive proposal (cf. section 1.3). In the first half of 2012, the EUA price stabilised at a low level and ranged between €6.04/t and €9.27/t, with an average price of €7.23/t (cf. Figure 54).

The EUA price is low because of the accumulated surplus of allowances since 2010 (cf. section 4.1) and the prolonged slowdown of the industrial production due to the economic crisis. At such price levels, the incentive for reducing carbon emissions is low. Lower price levels would probably be recorded if there was no possibility of banking allowances for compliance of Phase III of the EU ETS (2013-2020). As a reminder, the EUA price had reached zero at the end of Phase I in 2007, as allowances could not be used for compliance of Phase II.

Figure 49: Evolution of the spot price since 2005



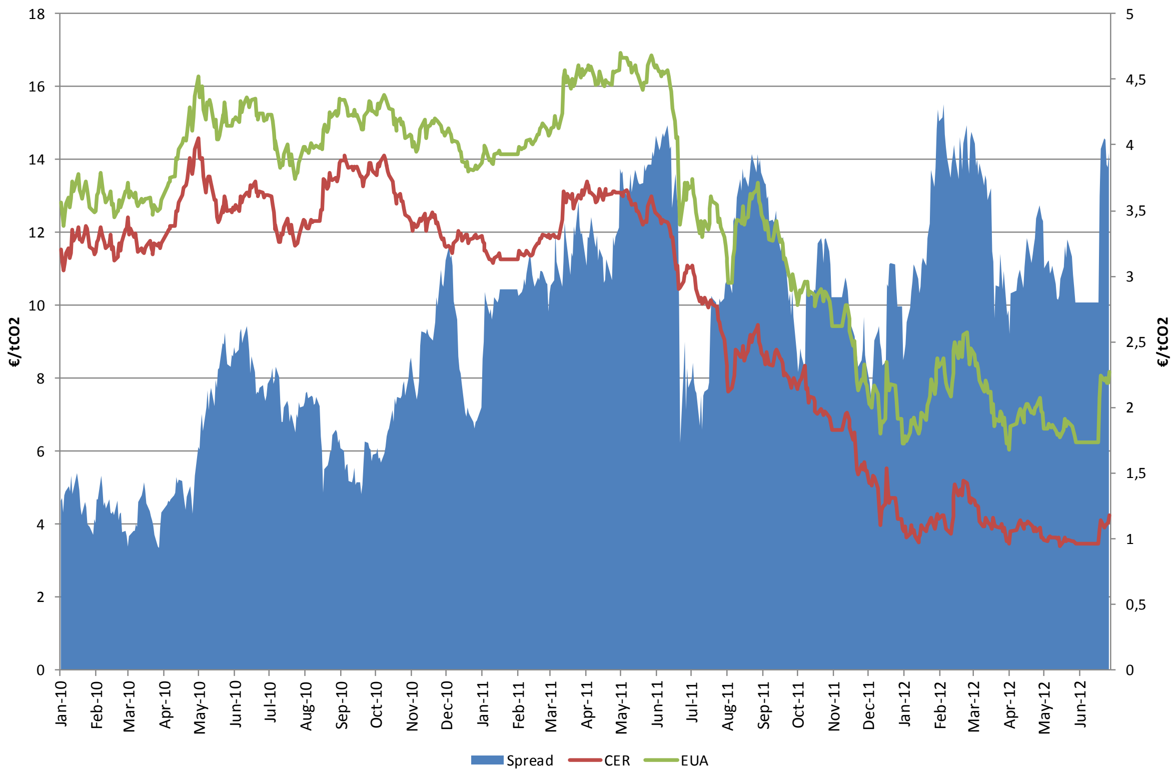
Sources: BlueNext

The European CER allowance spot price fell by 21% in 2011 compared to 2010, from €12.52/t to €9.88/t, with a sharp drop from June 2011. In the first half of 2012, the CER price fell to a very low level between €3.4/t and €5.18/t, with an average price of €3.93/t (cf. Figure 55).

The price of CER allowances is in line with that of EUA prices, since CER and EUA can be surrendered interchangeably for compliance purposes, within the ceiling for CER units set by the EU ETS. The CER price therefore followed a similar trend to that of the EUA and was also marked by the political and regulatory announcements as mentioned above.

However, the average price spread between EUA and CER spot products increased by 68% between 2010 and 2011, from €1.82/t to €3.06/t. During the first half of 2012, the average price spread between EUA and CER widened to €3.32/t (cf. Figure 55) and an EUA allowance was on average equal to 1.85 times a CER unit. The steeper decline in CER prices - compared to those of EUA prices - is attributed by market analysts to the large volume of CER products on the market, and the removal from May 2013 of certain CER products from projects no longer accepted by the European Commission for compliance with the EU ETS. As a result, the market perceives an increased risk in using these CER products.

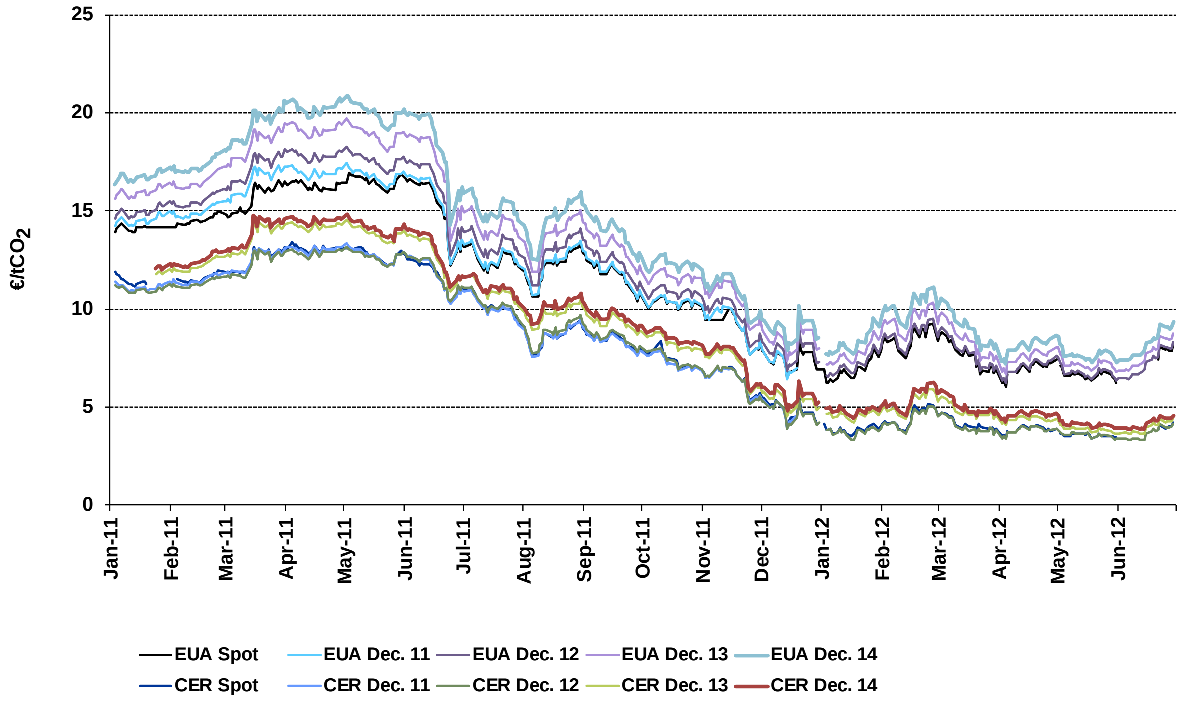
Figure 50: Evolution of the EUA and CER spot price spread



Sources: BlueNext

Futures product prices followed a downward trend similar to that of the spot market (see Figure 56).

Figure 51: Evolution of prices since 2011



Sources: Bluenext, ECX

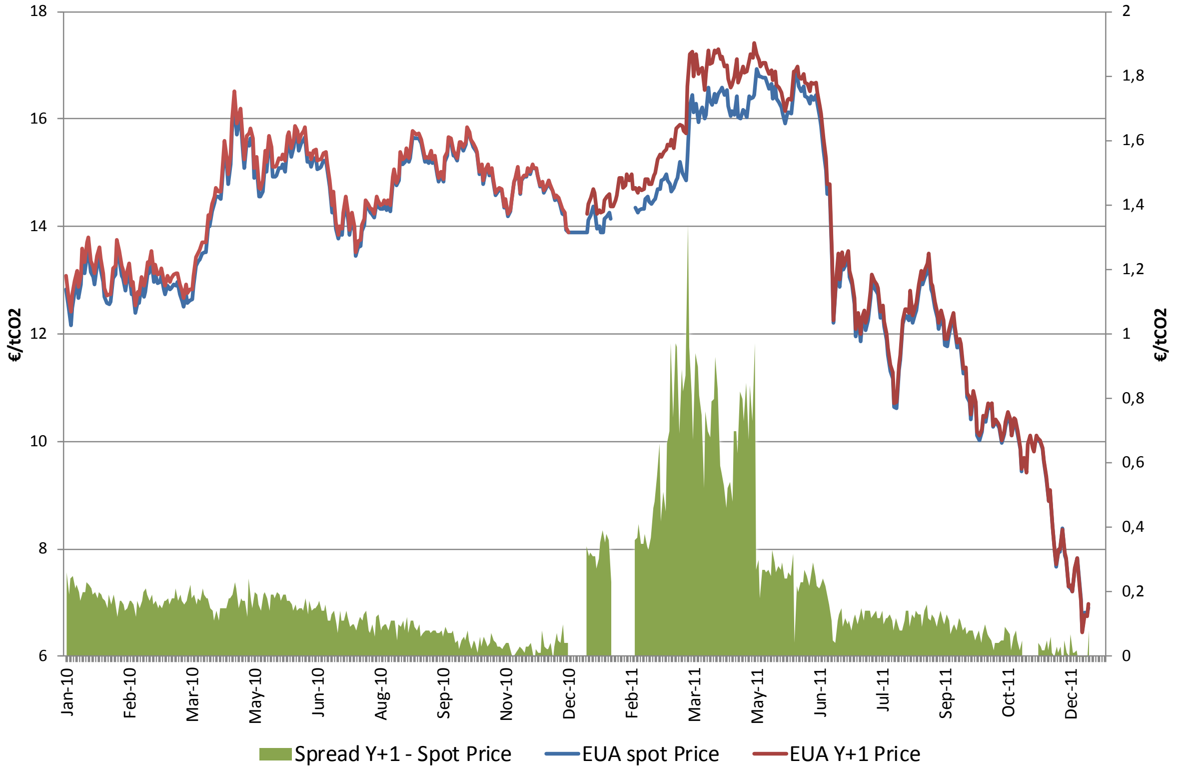
2011 WAS MARKED BY VARIATIONS ON FUTURES PRICES RELATED TO THE IMPACT OF THE GERMAN MORATORIUM ON NUCLEAR POWER

In 2011, futures products accounted for almost all of the trades on the CO_2 market (cf. section 2.2), and Y+1 products (for delivery in December 2011) represented more than half of these futures trades.

EUA futures products for delivery in December are formally identical to those traded in December on the spot market. Indeed, the curve representing the spread between Y+1 prices and spot prices convergences towards zero at the end of the year (Cf. Figure 57).

The average spread between the Y+1 price and the spot price was €0.28/ t in 2011 versus €0.12/t in 2010. In particular, the price spread was very high during the first half of 2011 and reached €0.45/t versus € 0.17/t during the first half of 2010. In January 2011, Bluenext exchange temporarily closed due to the suspension by the European Commission of all transactions on the CO_2 spot market, which followed the stealing of allowances on several registers of the EU ETS (cf. section 1.1). When the exchange re-opened in February 2011, the relative loss of confidence in the spot market resulted in an increase of the Y+1 price versus the spot price, which led to an increase in the price spread between the two products. The price spread significantly increased when the German moratorium on nuclear power was announced on 14 March 2011, linked to the market expectation of a transfer of production from nuclear power to the coal sector at the end of the year.

Figure 52: Spread between EUA price for delivery in December and EUA spot price



Sources: Bluenext, ECX

Fundamentals of the European CO_2 market

CO_2 prices are formed on the basis of the supply/demand balance of the allowance market, as perceived by market players:

- In the case of the EUA, the supply is the amount of allowances delivered in the primary market within the context of free allocation and auction. In the case of CER and ERU units, the offer is based on the execution of reduction projects and the validation of new projects. While all EUA products marketed by the Member States are intended to be used by sites located in the European perimeter according to their compliance with the EU ETS Directive, CER products are released on a global scale: therefore, they can be purchased outside of the European perimeter (for example through voluntary compensation);

- Demand depends on the actual verified emissions of industrial sites subject to compliance. Therefore, they depend on the level of activity, particularly on the level of power generation. Hence, the fundamentals of CO_2 prices share common characteristics with those of electricity prices, as they are influenced by the price of fossil fuels at least indirectly.

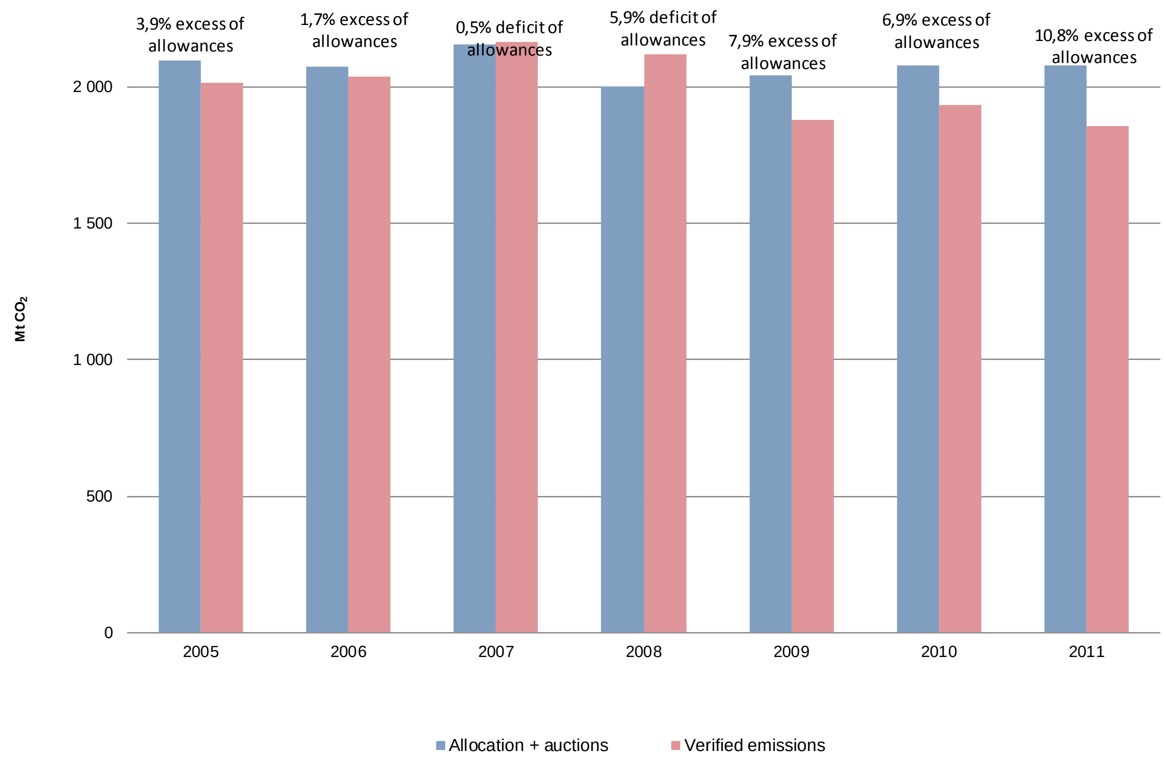
WITH AN OVERALL SUPPLY OF ALLOWANCES EXCEEDING DEMAND ONCE AGAIN IN 2011, THE SURPLUS OF ALLOWANCES HAS INCREASED, PROMPTING EUROPEAN INSTITUTIONS TO CONSIDER SETTING ASIDE PART OF THE ALLOWANCES DURING PHASE III

THE OVERALL SURPLUS OF ALLOWANCES INCREASED IN 2011 VERSUS 2010. THE ACCUMULATED SURPLUS CURRENTLY REPRESENTS AROUND 20% OF EMISSIONS ALLOCATED ANNUALLY

Actual emissions of installations subject to allowances are published once a year in April. Actual/verified emissions can be compared with allocated emissions, in order to show the net balance of installations participating in the European system (Figure 58).

The total supply of allowances in 2011 (EUA free allowances and auctions) was similar to that of 2010 at around 2,078 Mt, while actual emissions decreased from 1,933 Mt in 2010 to 1,854 Mt in 2011,i.e. a decrease of 4%. The supply of allowances exceeded demand again in 2011, continuing a trend which began in 2009, with an excess of EUA allowances of 224 Mt in 2011 (i.e. 10.8%) versus 143 Mt in 2010 (i.e. 6.9%). The accumulated surplus of EUA at the end of 2011 was around 400 Mt, i.e. around 20% of allowances allocated in 2012, taking into account that this figure only reflects the cumulated difference between distributed allowances and actual emissions, without taking into account the fact that some of emission rights are also surrendered in the form of Kyoto units (CER or ERU). This means that the total surplus of allowances at the end of 2011 was even higher. Some market analysts value the surplus at levels corresponding to several months of emissions. In July 2012, the European Commission proposed three different options in order to reduce the number of carbon allowances for Phase III: 400 Mt, 900 Mt and 1,200 Mt respectively. The European Parliament, meanwhile, is in favour of a reduction of 1,400 Mt of quotas.

Figure 53: Supply and demand of allowances since 2005

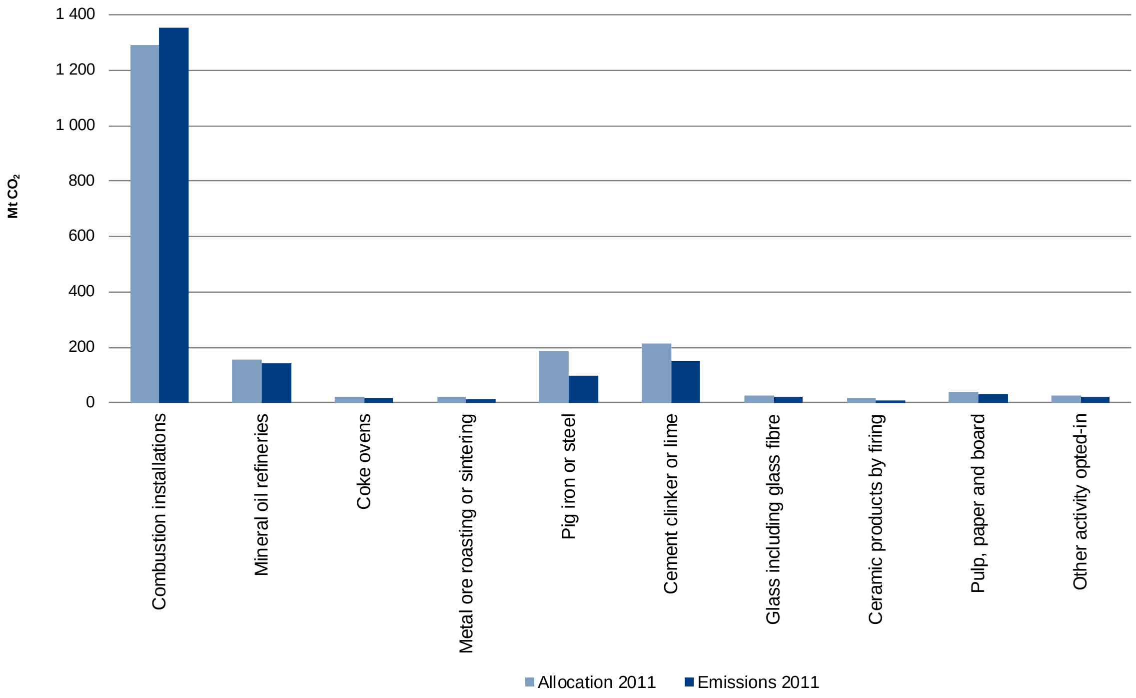


Source: CITL

IN ALMOST ALL SECTORS, SUPPLY EXCEEDED DEMAND OF ALLOWANCES, WHILST THE DEFICIT OF ALLOWANCES FOR COMBUSTION SITES WAS REDUCED IN 2011

In 2011, an analysis by sector shows that combustion sites, consisting primarily of electricity production installations and covering 73% of the industrial emissions of the EU ETS, were once again the only installations to have an allowance deficit (Figure 59). However, emissions from combustion sites decreased by 4% in 2011 due to a decrease in energy production, hence the allowance deficit declined by nearly half, from 128 Mt in 2010 to 66 Mt in 2011.

Figure 54: Allocations and actual emissions by type of site in 2011



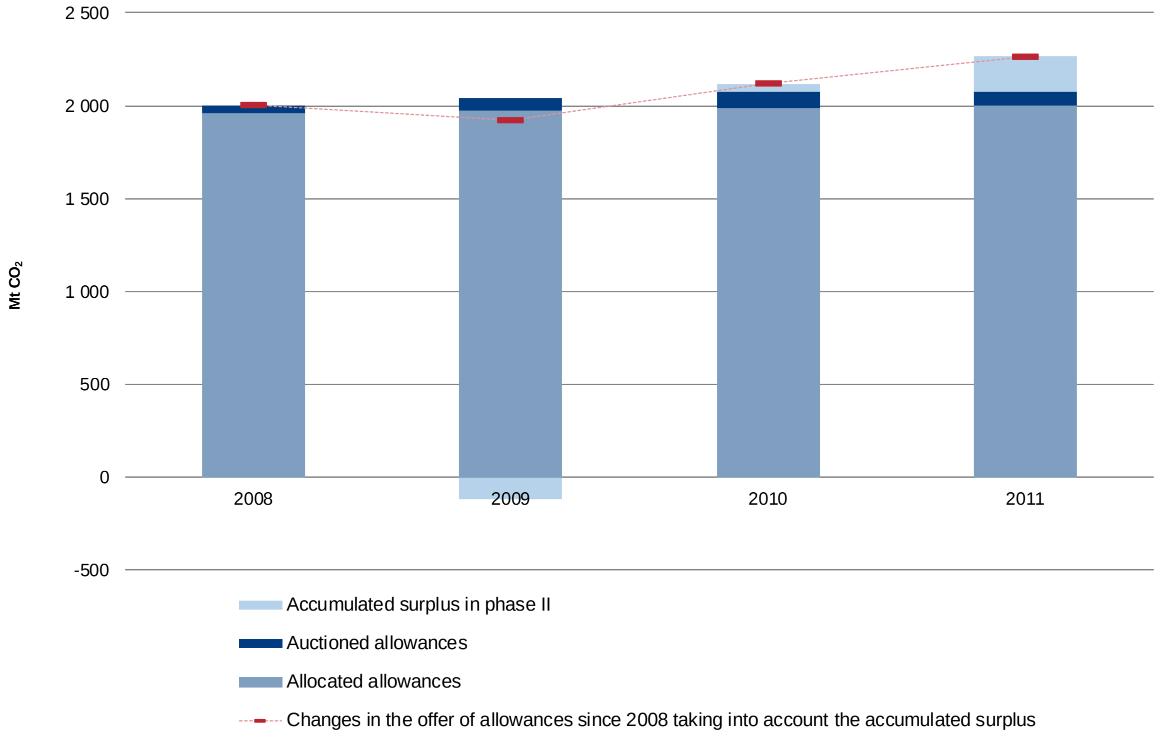
Source: CITL

THE SURPLUS OF ALLOWANCES INCREASED IN 2011 AND GAVE RISE TO DISCUSSIONS ON SETTING ASIDE PART OF THE ALLOWANCES DURING PHASE III

In December 2011, to curb the accumulated surplus of allowances (cf. Figure 60), the European Parliament's environment committee voted in favour of setting aside a significant volume of quotas. By the end of 2012, the European Commission is to take position on the volume of allowances to be set aside, the potential consequences it would have on the EU ETS and which regulations should thereby be modified. The European Commission is also considering the possibility of delaying the auctioning of allowances during Phase III, thereby temporarily reducing the volume of allowances on the market. An agreement between the Members States of the European Union and the European Parliament needs to be reached, in order to decide what is the best solution to adopt to improve the price signal for investors, and to reduce greenhouse gas emissions.

Lastly, the potential impact of measures resulting from the energy efficiency directive could push the carbon price down and should also be taken into account in view of potential changes to EU ETS regulations.

Figure **60: Accumulation of the allowance surplus in Phase II**



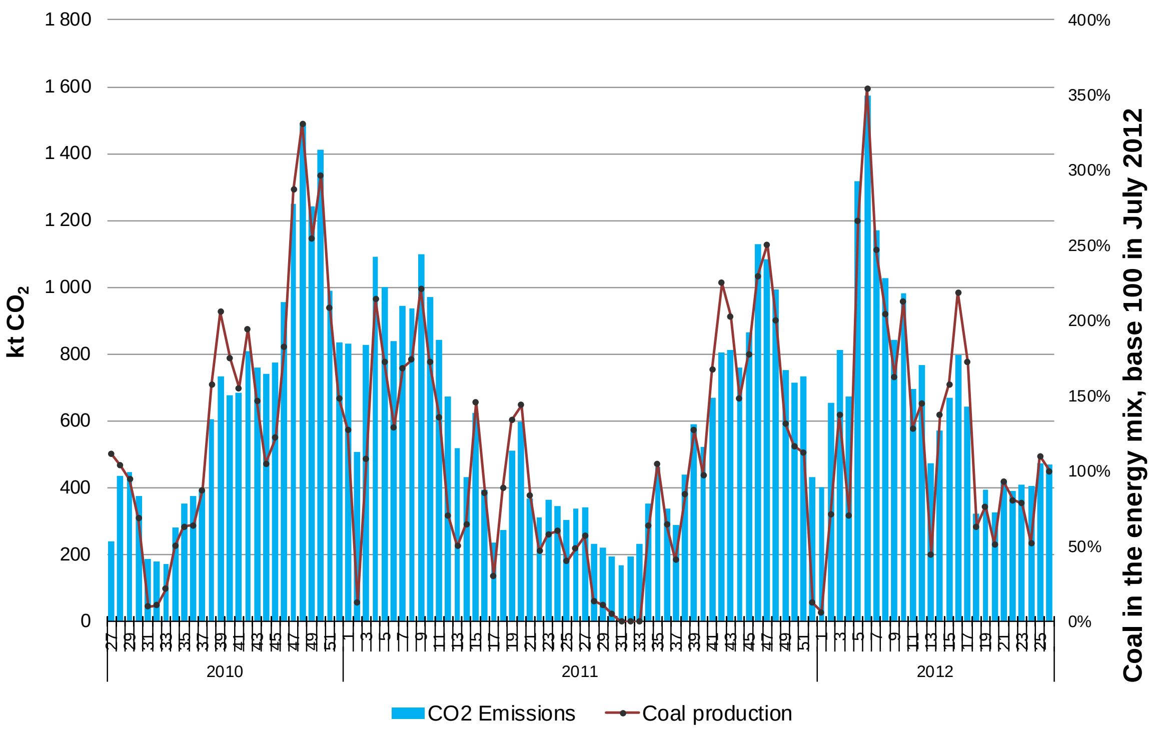
Source: CITL, European Commission (assuming a 2012 supply level equivalent to that of 2011)

LOW CO_2 PRICES AS WELL AS THE RELATIVE BALANCE BETWEEN GAS AND COAL PRICES ENCOURAGE COAL-FIRED ELECTRICITY GENERATION

Emissions from electricity generation plants are related particularly to the presence of coal in the energy mix. Greater contribution of thermal power plants results in greater emission levels. Thus, emissions are higher during the winter, at the beginning and the end of the year (Figure 61). During the cold wave of February 2012, the peak in electricity demand resulted in a peak of coal production which went hand in hand with a peak of CO_2 emissions.

Since 2011, in a context of relatively low prices for coal compared to gas, it has become more profitable for energy companies to produce electricity from coal.

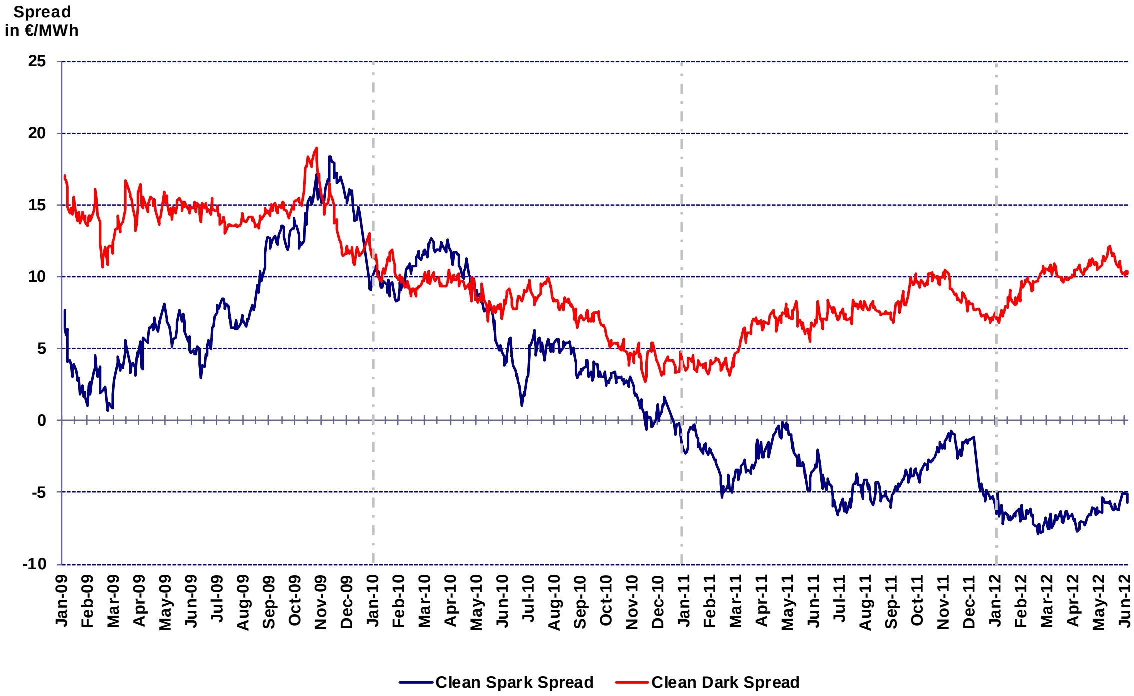
Figure 55: Emissions of the French production coal plants



Source: RTE

The *clean dark spread* and *clean spark spread* represent the theoretical short-term profit of the respective owners of a coal and a gas plant (Figure 62). A sustained drop in one of these values compared to the other reflects the loss of competitiveness of one of the production sectors versus the other.

Figure 56: *Clean dark & spark spreads*



Sources: EEX, ECX, Heren (Y+1 price)

Table11: Formula used to calculate the *clean dark & spark spreads*

Clean Dark Spread (€/MWh) = $p_E - (\alpha p_C + \beta p_{CO2})$	Clean Spark Spread (€/MWh) = $p_E - (\gamma p_G + \delta p_{CO2})$
• p_E price Y+1 baseload Germany (€/MWh) • p_C price Y+1 coal (€/MWh) • p_{CO2} price Y+1 CO_2 (€/MWh) • α includes the calorific power value and the coal yield[25] • β the coal emission factor[26]	• p_E price Y+1 baseload Germany (€/MWh) • p_G price Y+1 gas (€/MWh) • p_{CO2} price Y+1 CO_2 (€/MWh) • γ the gas yield[27] • δ the gas emission factor[28]

[25] Based on the assumption of a calorific power of 8.14 MWh/t for coal and a yield of 35% for coal-fired plants. It should be noted, firstly, that these yields correspond to new reference installations and therefore may be quite different from the yields of existing installations, and, secondly that other costs, including transportation, are not taken into account.

[26] Based on an assumed emission factor of 0.96 t CO_2/MWh for coal-fired plants.

[27] Based on an assumed yield of 49% for gas plants.

From January 2011, the difference between the clean dark spread and the clean spark spread increased in favour of the clean dark spread compared to 2010: the gas sector was indeed less competitive than the coal sector despite its comparative advantage in terms of CO_2 emissions, due to the decline in carbon prices in 2011 (cf. section 3.1) and the context of high gas prices and low coal prices.

[28] Based on an assumed emission factor of 0.41 t CO_2/MWh for gas plants.

Section III: Gas wholesale markets

2011 was characterised by falling demand due to the economic downturn, the lack of competitiveness of gas compared to coal and, especially, the mild temperatures while these same temperatures had been relatively low in 2010.The gas supply remained abundant on global markets, especially on account of unconventional gas production in the US and LNG, the capacity of which is experiencing constant growth.

The LNG supply in Europe, however, experienced some drastic changes during 2011 and the first half of 2012, which resulted in massive diversions of cargo caused by the strong growth in Asian demand and especially Japan, following the outage of several nuclear power plants in the wake of the Fukushima accident. As the Arab revolutions affected producing countries (Egypt, Libya and Yemen), there was an additional variable voltage which impacted on the availability of the LNG supply. These factors put upward pressure on the price of LNG in Asia and therefore favoured trade-offs in this area to the detriment of the Atlantic basin.

In 2011, prices on European wholesale markets were generally higher than those in 2010. Their increase was still, however, markedly less than that of oil products on which long term supply contracts are indexed. Many European suppliers had entered a renegotiation phase of these contracts in 2010 with their suppliers from producing countries, in order to obtain conditions closer to those of short term markets, by introducing, for example, more significant market indexations, by reducing the length of contracts and replacing "take or pay" clauses with "take or release" clauses.

In this context, the wholesale gas markets continued to be an attractive source of supply for importers, suppliers and consumers and to represent a market for producers with respect to non-purchased gas volumes within the framework of long term contract flexibility clauses. Trading on the wholesale gas markets thus continued to grow in 2011.

1. The development of gas trading

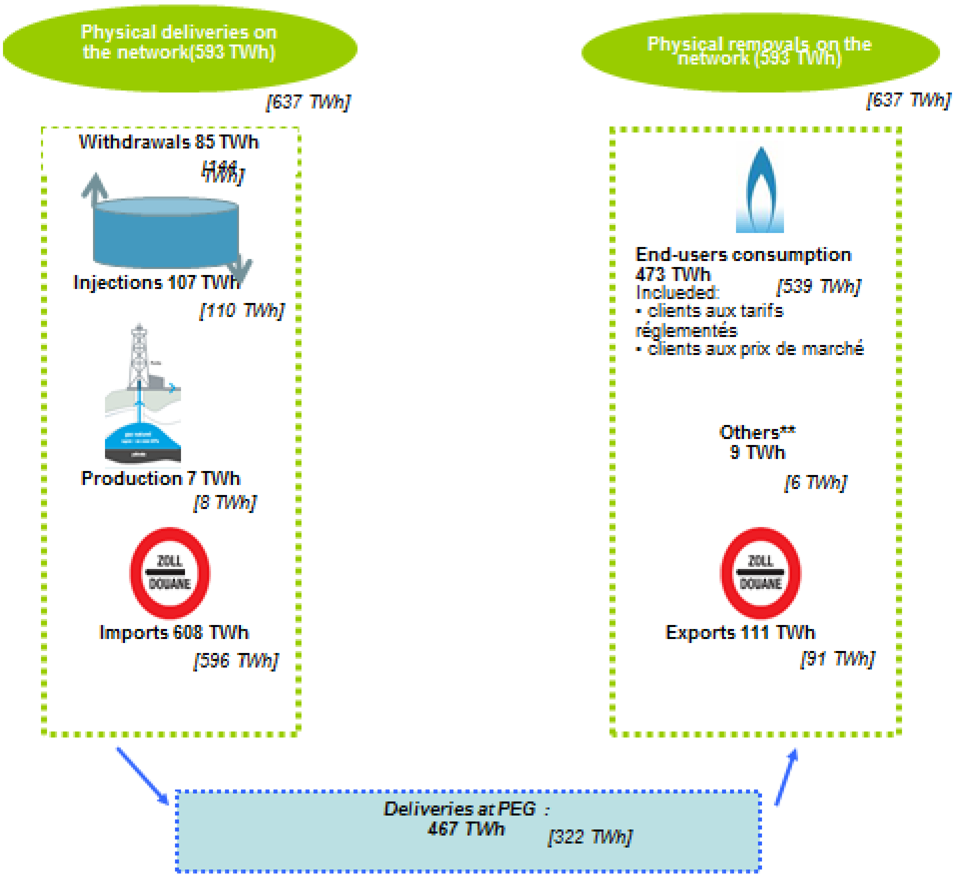
Gas flows in France in 2011 (Chart 63) reflected the aforementioned factors of the context. In 2011, physical deliveries on the network fell 44 TWh compared to 2010 levels. This decrease was related to a lesser consumption of end clients in 2011, down nearly 20% compared to the previous year. Exports, however, increased by 22% with 111 TWh exported in 2011.

With a volume of 608 TWh in 2011, imports again increased after two successive years in decline. Physical movements related to storage and destocking helped to balance the regular flow of imports with the seasonal needs of consumers, focused on winter. Use of storage/destocking was less significant in 2011 and ended with a net volume stored of 22 TWh in 2011 as opposed to the net volume extracted of 34 TWh in 2010.

Physical deliveries and removals at Gas Exchange Points (PEG) resulted in trade recorded on wholesale markets. Deliveries to PEG increased by more than 45% compared to 2010, reaching 467 TWh in 2011. This increase, which was more rapid than that of consumption, was a net reflection of the development of the wholesale market.

The wholesale gas market developed in a very different way during the first half of 2012: if the first quarter saw a strong increase in trade at the PEG, in particular due to the February cold snap of 2012, the second quarter marked a sharp net decline in volumes traded.

Figure57: Supplies and opportunitiesof the French gas market - Year 2011 [Year 2010]



Source: GRTgaz, TIGF – Analysis: CRE

DELIVERIES TO PEG SHARPLY GREW DURING 2011, ALBEIT WITH A SLOWDOWN IN DELIVERIES TO THE PEG NORD IN THE FIRST HALF OF 2012

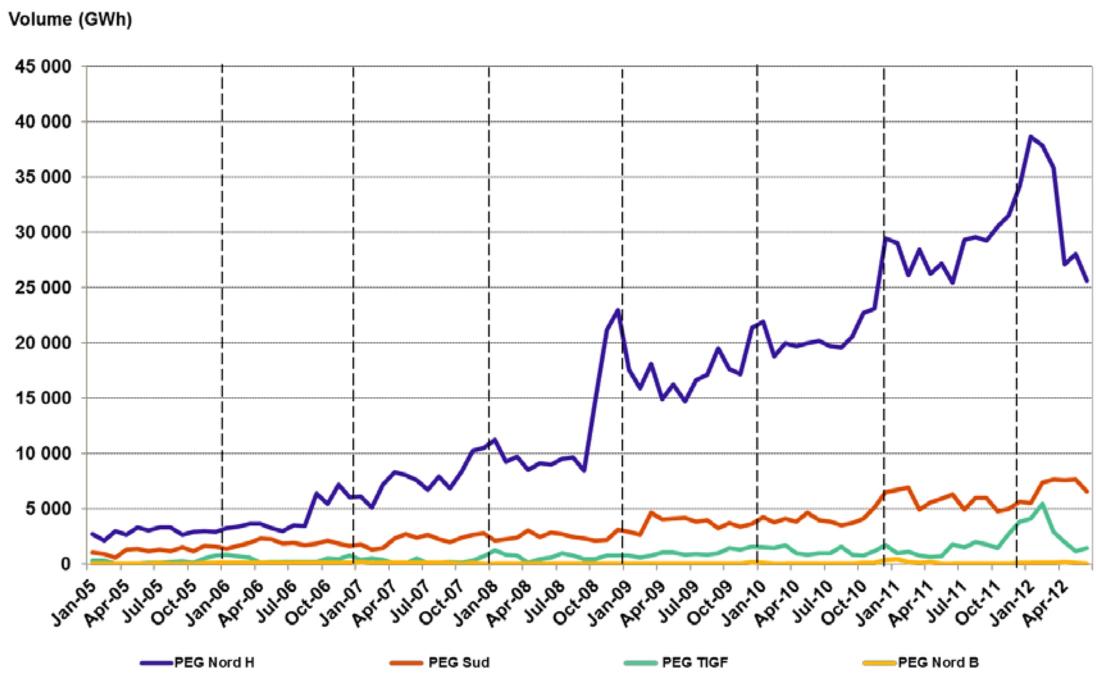
Deliveries to the Gas Exchange Points PEG[29] represent the sum of shipper nominations to the various French PEG (PEG Nord, Sud and TIGF). These deliveries arose from trade between the various stakeholders of the French market and made it possible to value the extent to which the wholesale market was used, whether this was purely bilateral or intermediate (PowernextGas Exchange since November 2008 or brokers' platforms). These deliveries also included purchases or sales of Transmission Network Operators (TSO) carried out by them to cover their balancing needs and their own consumption.

[29] Deliveries to PEG at a given period reflected all transactions completed on the wholesale spot or futures market and delivered during this period. This volume did not represent the volume of completed transactions between the stakeholders on this date, as a gas volume for a set period may be renegotiated between two or more stakeholders before being delivered.

2011 was characterised by high delivery levels to PEG which were higher than in 2010 (+145 TWh). Deliveries at the PEG were experiencing constant change in 2011 with growth of about 29TWh per month at the PEG Nord and 6 TWh per month at the PEG Sud, recording a more significant increase in relation to the PEG Nord at the end of the year in comparison to the same period of the previous year (more than 34 TWh per month at the PEG Nord and 6 TWh per month at the PEG Sud). The growth in delivered volumes observed in 2011 at the three French PEG (Nord, Sud and TIGF) was mainly driven by activity at the PEG Nord. However, volumes were up 33% at the PEG Sud after the complete commissioning of the methane terminal of Fos-Cavaoude in November 2010. In relation to the PEG TIGF the delivered volumes increased in the same proportions as those of the PEG Sud throughout 2011, with an acceleration of activity at the end of the year.

Deliveries to the PEG in the first half of 2012 generally increased (+23%) compared to the first half of 2011 and totalled a monthly average of 42.1. However, after reaching 39 TWh in January 2012, deliveries to the PEG Nord noticeably decreased during the second quarter of 2012 falling to 26 TWh in June 2012.

Figure58: Deliveries to PEG (monthly data)



Source: GRTgaz, TIGF – Analysis: CRE

- **An increasing number of shippers in 2011, a rise which was maintained during the first half of 2012**

During 2011, a total of 82 shippers were active on at least one PEG in France, representing 12 more compared to the previous year, including 5 suppliers of final customers. In addition, there were a total of 16 stakeholders supported by players known in the financial sector.

The number of shippers remained stable in the first half of 2012 compared to 2011.

Table 12: Number of shippers active in removal and/or delivery at the PEG

	2010	2011	H1 2011	H1 2012
Total number of active shippers	70	82	70	80
Including financial traders	10	16	9	15

Source: GRTgaz, TIGF – Analysis: CRE

GAS TRADING ON THE INTERMEDIATE MARKET IS STILL INCREASING IN 2011 BUT IS FALLING IN THE SECOND QUARTER OF 2012

In 2011, volumes traded on these intermediate markets[30] rose by 71% compared to 2010, recording a volume of 420 TWh (cf. Table 13) with about 52,000 transactions concluded. This upwards trend was observed on all maturities traded. The volumes traded on the day-ahead products were up 48% compared to their 2010 level. Futures products recorded a larger increase (+82%).

The aforementioned structural factors undeniably continued to be a driving force behind the increased liquidity of wholesale markets (trade-offs between supply through contracts indexed on oil products and cheaper market purchases, deferred non-remouved amounts in relation to these contracts for resale on wholesale markets).

The first half of 2012 was, conversely, marked by a fall in trading volumes, which totalled 162 TWh during this period as opposed to 230 TWh in the first half of 2011 (Table 13 and Chart 65). This decrease was primarily driven by the futures product sector which declined by 42% compared to the first half of 2011, with seasonal products being impacted to the largest extent. The largest decline occurred in the second quarter of 2012, particularly affecting seasonal products, which can be explained, in part, by the strengthening of the positions of stakeholders for the summer season. Trading volumes recorded one of the lowest levels since the beginning of the organised market PowernextGas Futures at the PEG Nord, and the volume of futures products remained lower than that of spot products throughout the entire second quarter of 2012. This fall in volumes traded on the futures market was also partly due to the peak in activity of a stakeholder in the first few months of 2011. This stakeholder, who was not an incumbent stakeholder on the French market, had participated in the CRE of a considerable development of its trading activities on the wholesale market. This stakeholder told the CRE that it had subsequently reduced its activity in the context of the development of the company strategy in trading activities and the strengthening of its risk management methods.

Spot product trading generally increased by 7% during the first half of 2012 and recorded a 27% increase in relation to day-ahead products.

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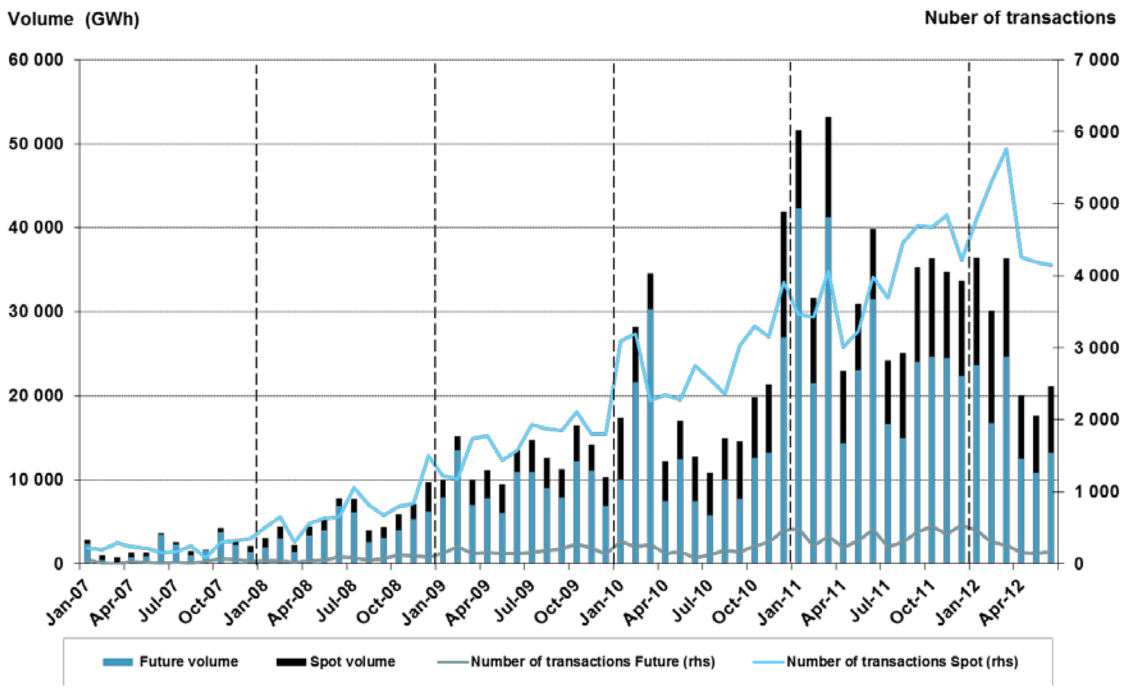
[30] The activity on the French intermediate wholesale market includes transactions concluded on the organised market (Powernext) and on the intermediate OTC market (brokers)

Figure 59: Development of trading volumes and number of transactions (Spot and futures market)



Source: Brokers, Powernext – Analysis: CRE

Table 13: Transactions on the intermediate spot and futures market

a. Trading volume

Volume (TWh)	2010	2011	H1 2011	H1 2012
Spot market	80	118	56	60
Day-ahead products	39	58	27	34
Futures/Forwards market	165	301	174	102
Monthly products	57	115	45	36
Seasonal products	68	130	96	53
Total intermediate market	246	420	230	162

a. Number of transactions

Number of transactions	2010	2011	H1 2011	H1 2012
Spot market	34,230	47,749	21,173	28,458
Day-ahead products	23,264	32,215	13,845	20,196

Futures/Forwards market	2,691	4,587	2,131	1,481
Monthly products	2,067	3,395	1,353	1,049
Seasonal products	340	711	527	322
Total intermediate market	36,921	52,336	23,304	29,939

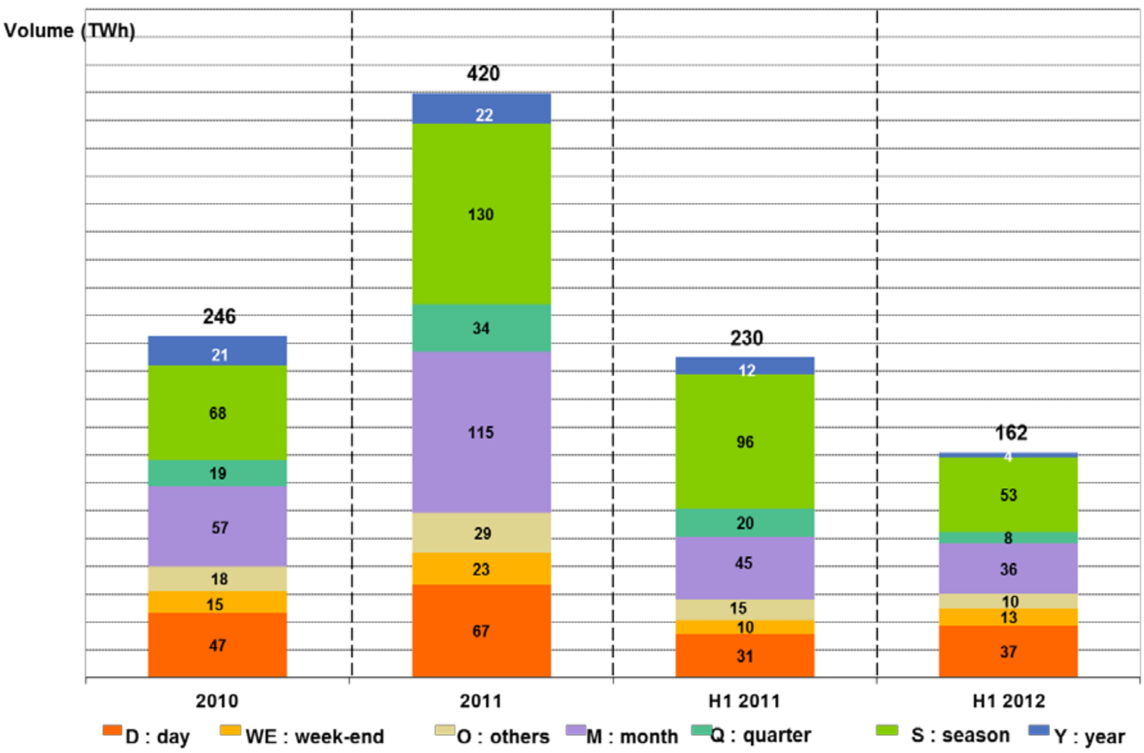
b. Average size of transactions

Average volume (GWh) per transaction	2010	2011	H1 2011	H1 2012
Spot market	2.3	2.5	2.7	2.1
Day-ahead products	1.7	1.8	1.9	1.7
Futures/Forwards market	61.5	65.6	81.7	68.6
Monthly products	27.8	34.0	33.4	34.1
Seasonal products	199.5	182.9	183.0	165.4
Total intermediate market	6.7	8.0	9.9	5.4

Source: Brokers, Powernext – Analysis: CRE

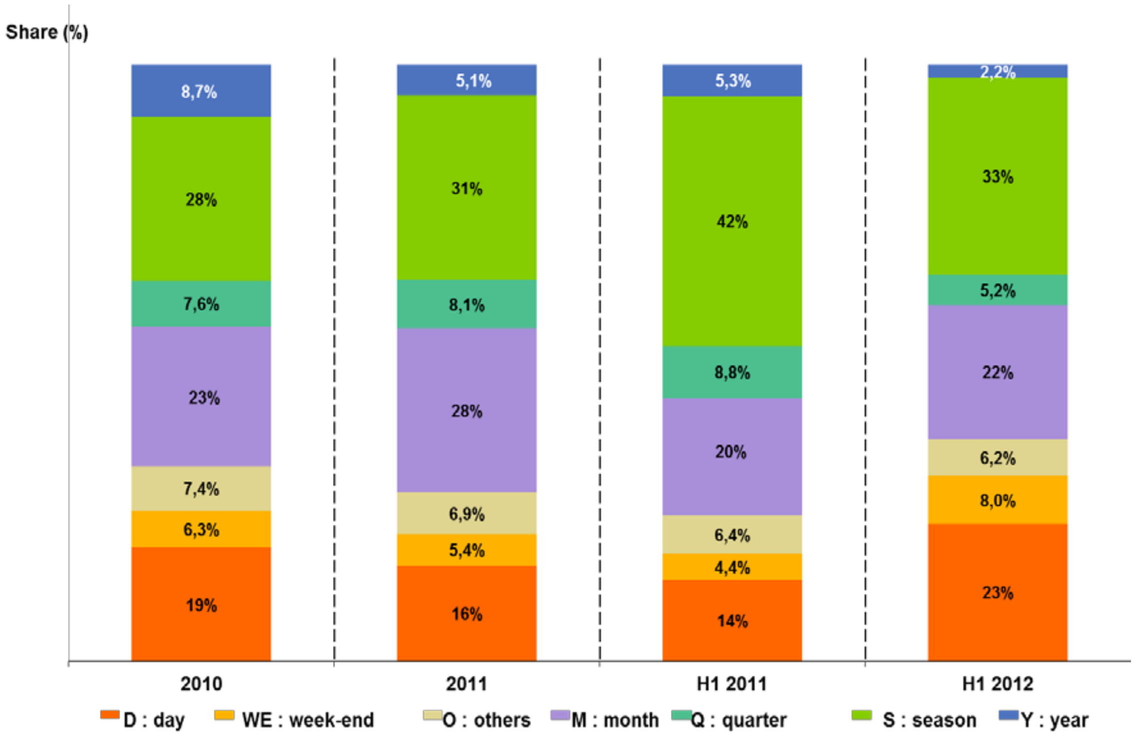
Figure 60: Distribution of trading volumes by product

a. In TWh



Source: Brokers, Powernext – Analysis: CRE

b. By percentage

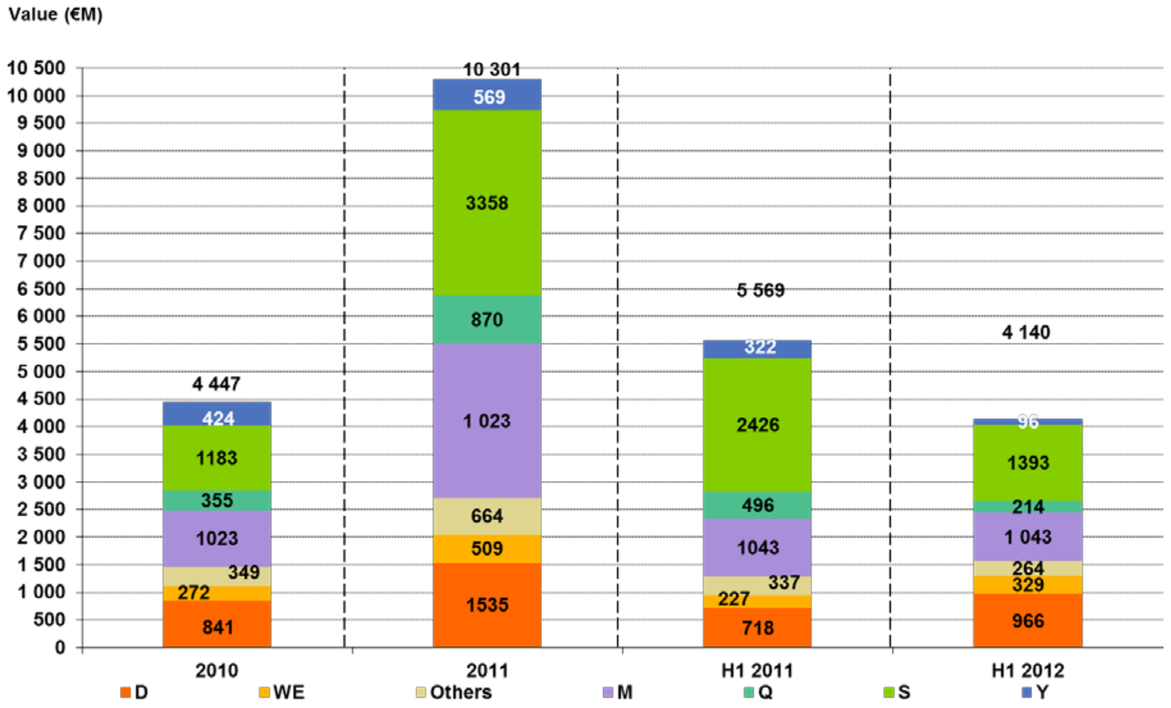


Source: Brokers, Powernext – Analysis: CRE

- **The size of the wholesale market in France more than doubled in 2011, representing 10.3 billion Euros**

The value of trade completed on the markets more than doubled in 2011 going from €4.4 billion in 2010 to €10.3 billion. This increase was related to the growth of trading volumes and higher gas prices over the period concerned. In contrast, during the first half of 2012, despite the continued rise in prices, the trade value was down 26% compared to the first half of 2011 on account of lower trading volumes.

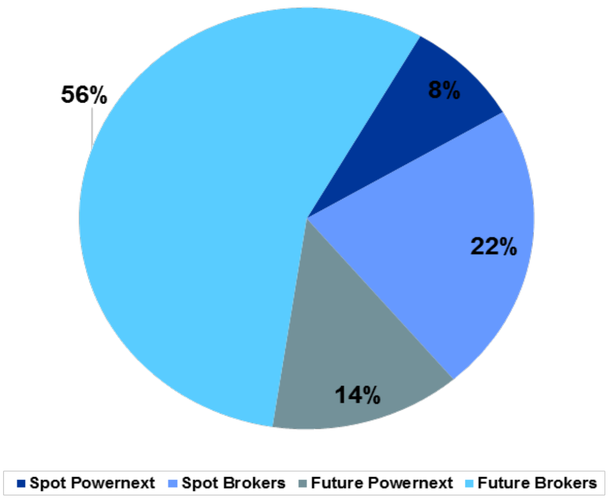
Figure 61: Valuation of trading volumes (in €M)



Source: Brokers, Powernext – Analysis: CRE

78% of volumes traded in 2011 were traded on brokers' platforms and the remaining 22% were traded on organised markets (cf. Figure 68), with the latter continuing to gain market shares year on year.

Figure 68: Distribution of spot and futures volumes traded at PEG hubs by type of intermediation (2011)



Source: Brokers, Powernext – Analysis: CRE

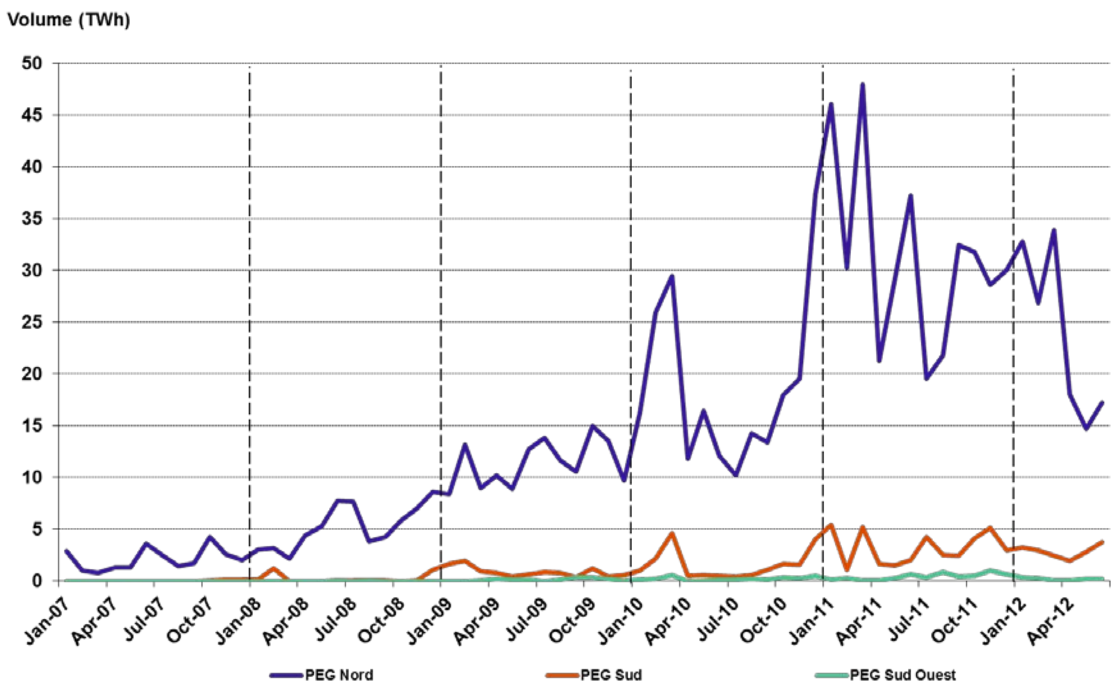
- **Trading is constantly developing at the PEG Nord**

In the manner of deliveries to PEG, the distribution of volumes traded according to the three areas shows the preponderance of trading at the PEG Nord. About 90% of the trading volume was concentrated there in 2011 (Figure 69).

The volumes traded at the PEG Sud, which represents 27% of domestic consumption also increased during 2011 (33.9 TWh in 2011 as opposed to 18.6 TWh in 2010). The introduction of the PEG Nord/ PEG Sud spread product in May 2011 contributed to the recovery of trade on the spot market, particularly at the PEG Sud where it accounted for about 61% of the total volume traded between May 2011 and June 2012.

Although rising, liquidity at the PEG TIGF remained stable with a traded volume of 5.2 TWh in 2011, while the TIGF zone represented approximately 3% of domestic consumption.

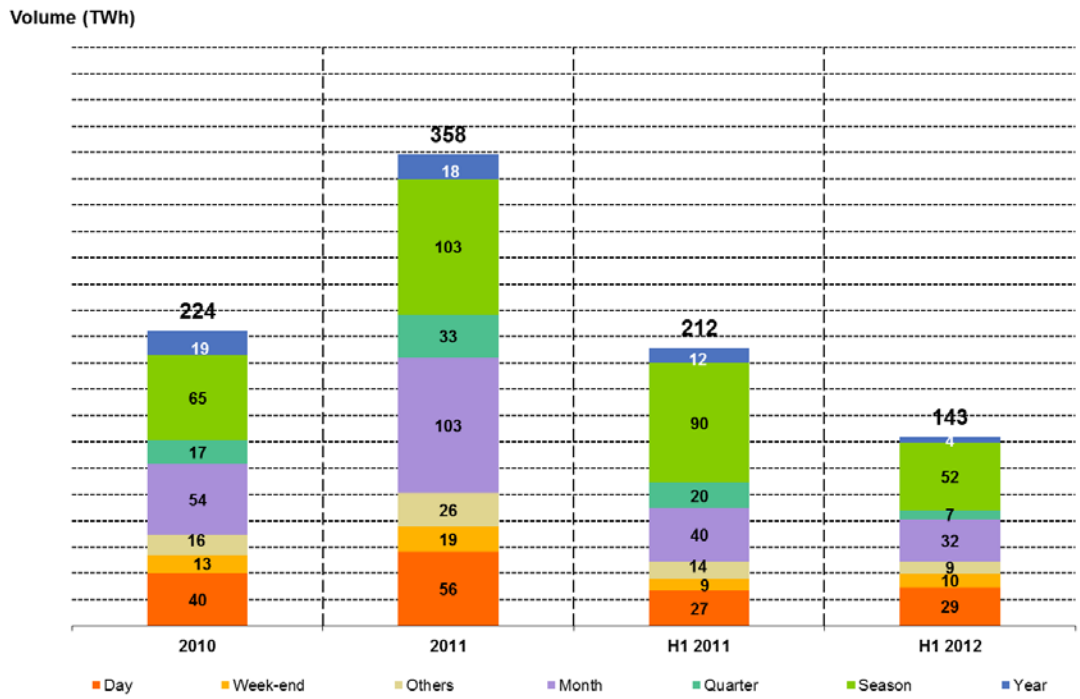
Figure 62: Trading volumes by PEG at the intermediate market (monthly data)



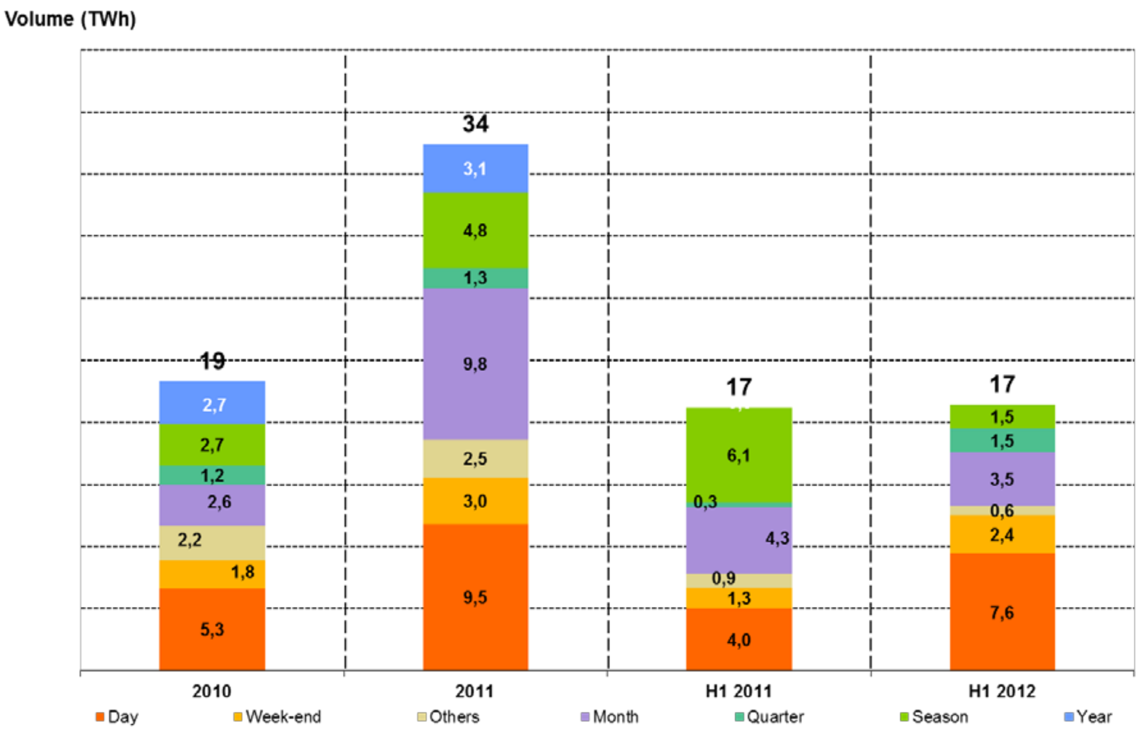
Source: Brokers, Powernext – Analysis: CRE

Figure 63: Distribution of trading volumes by product and PEG

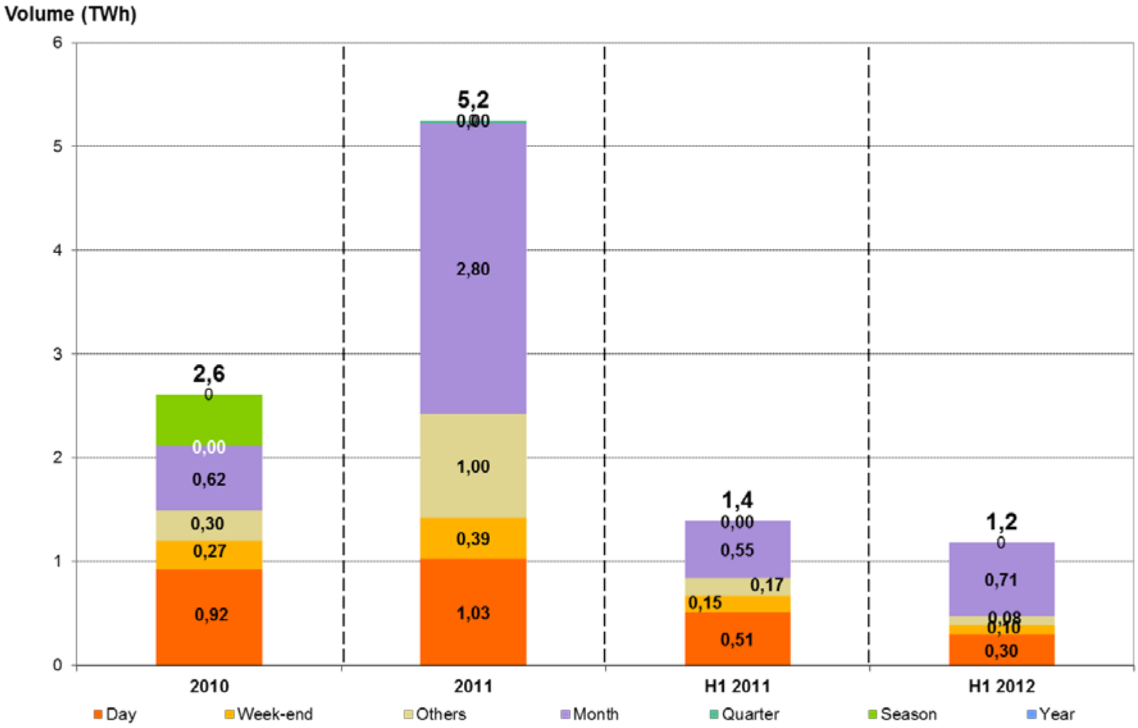
a. PEG Nord



b. PEG Sud



c. **PEG TIGF**



Source: Brokers, Powernext – Analysis: CRE

- **A large number of active stakeholders are involved at the PEG Nord; the other two areas remaining concentrated**

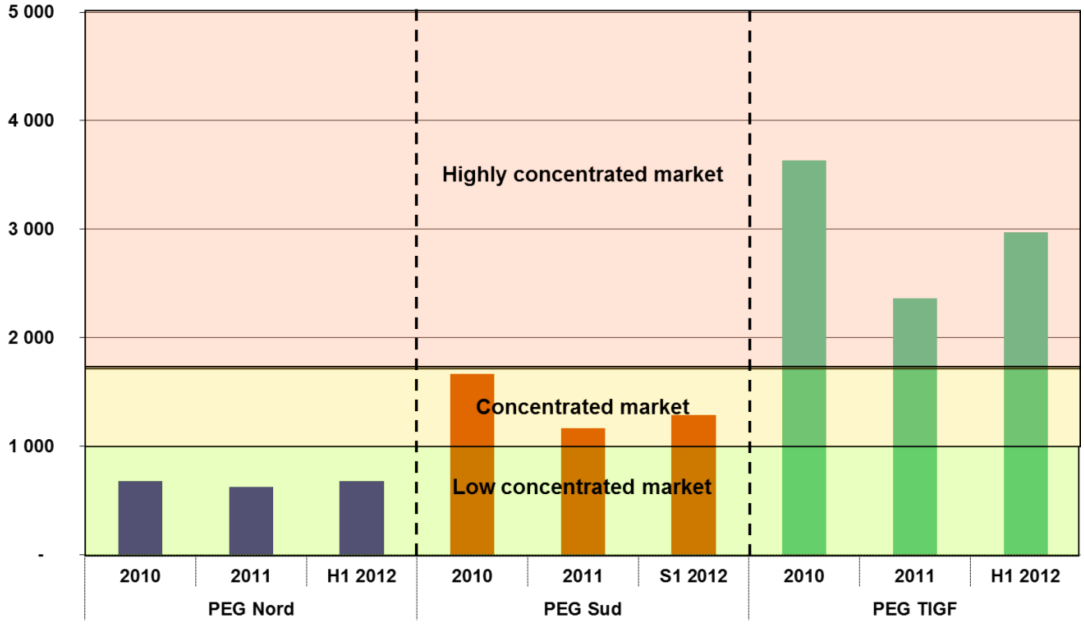
Figure 71 illustrates the degree of market concentration at the PEG Nord, PEG Sud and PEG TIGF. The North zone, both in terms of purchases and sales of all products, corresponds to HHI indices which are representative of a market which is not very concentrated. This finding is also reflected in the development of market shares. The accumulated market share of the three largest stakeholders at the PEG Nord has been decreasing continuously since 2009 and seems to have stabilised, both in terms of removals/deliveries and in terms of transactions (Figure 72). In the first half of 2012, the three largest stakeholders accounted for approximately 33% of the market share for removals/deliveries and 35% for purchases/sales.

At the PEG Sud, the HHI indices also decreased both in terms of purchases and sales during 2011 but the concentration of sales was greater than the concentration of purchases (Figure 72).

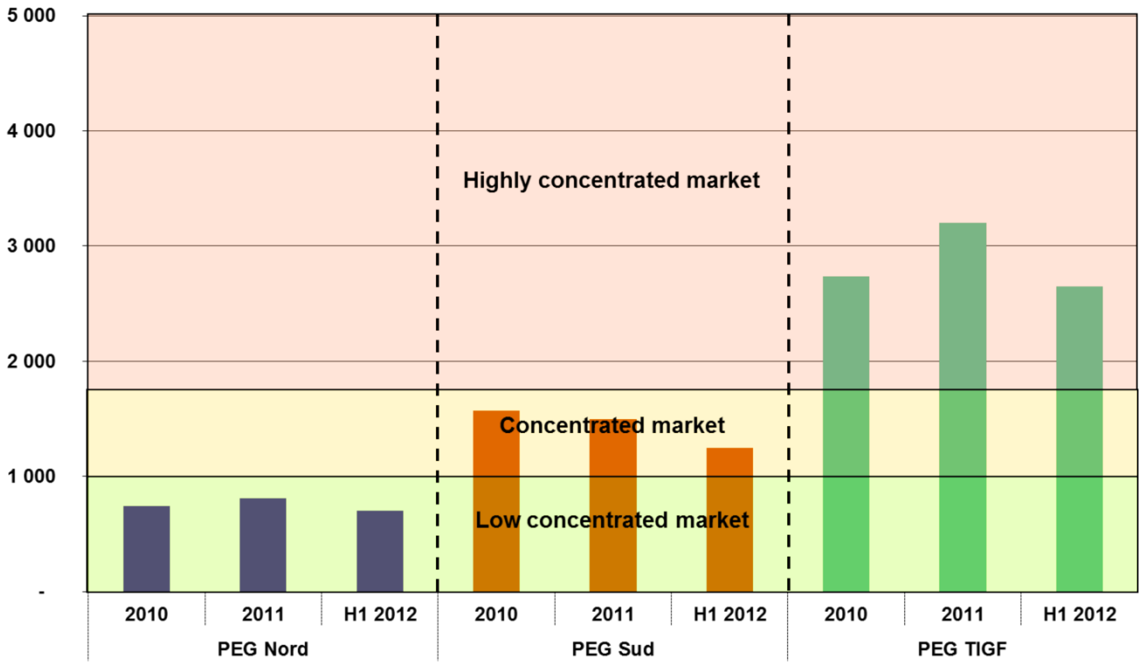
The PEG TIGF remains the most concentrated market place in France. In 2011 and the first half of 2012, an increase in HHI indices was observed in futures products trading. This activity was related to the involvement of some stakeholders who, because of the low liquidity of the market in this area, were able to take significant market shares with modest volumes. The analysis of changes in the HHI indices at the PEG TIGF leads us to the particular observation, once again, of its low liquidity despite an increase in trading volumes in this area.

Figure 71: HHI index in the different markets, 2011 and H1 of 2012, by PEG

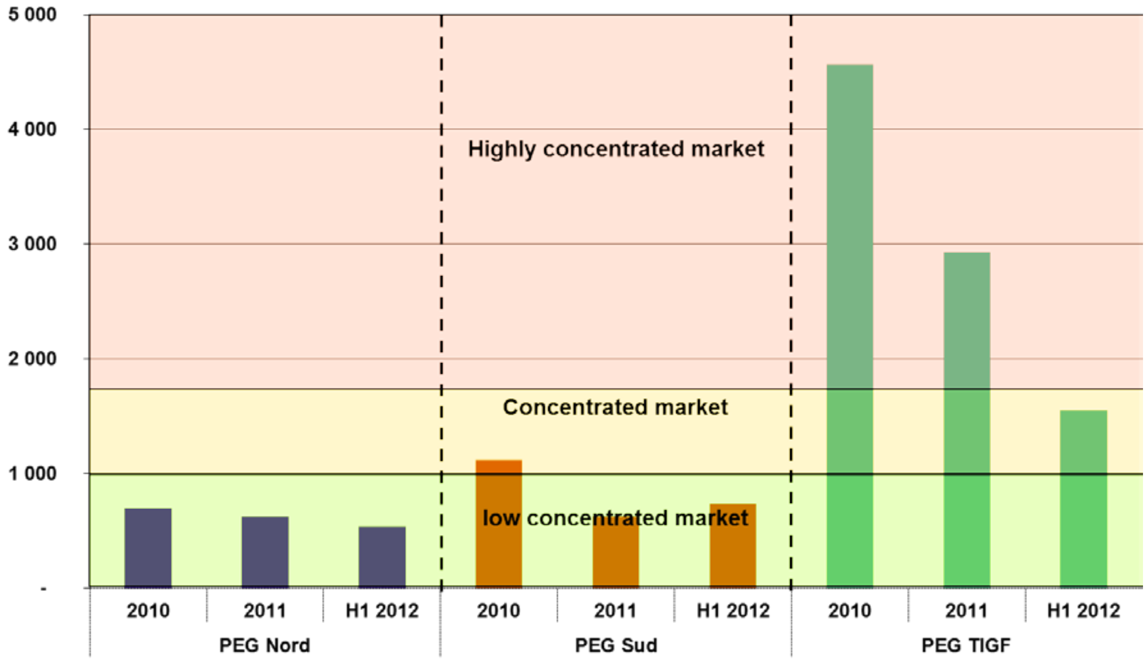
a. For sale on the spot markets



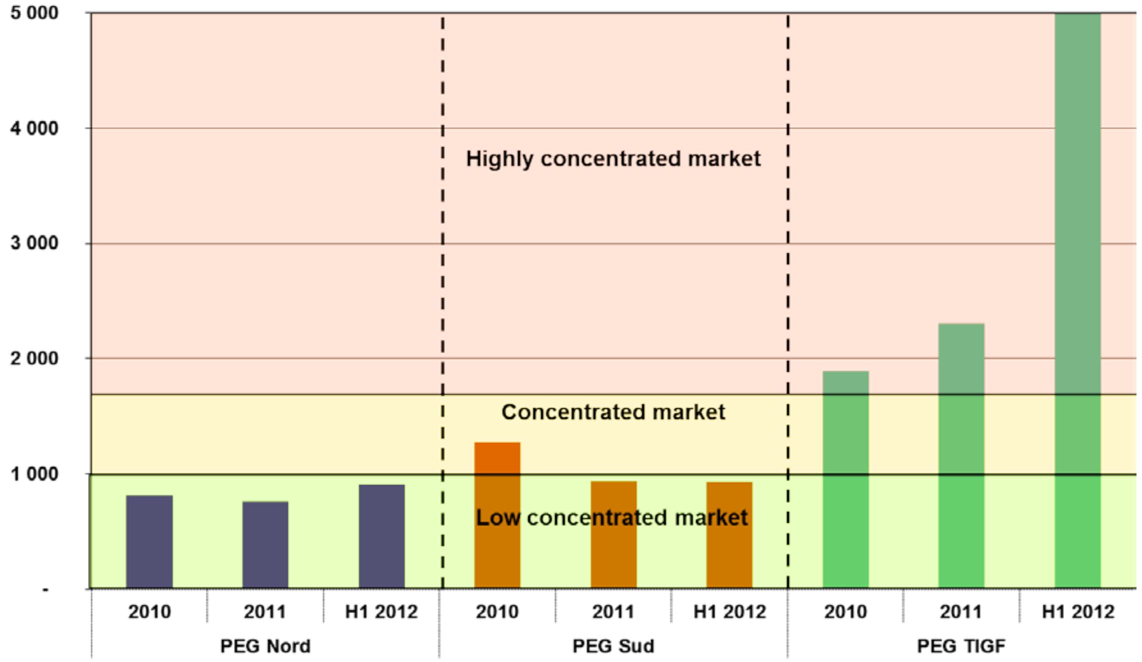
b. For sale on the futures market



c. For purchase on the spot market



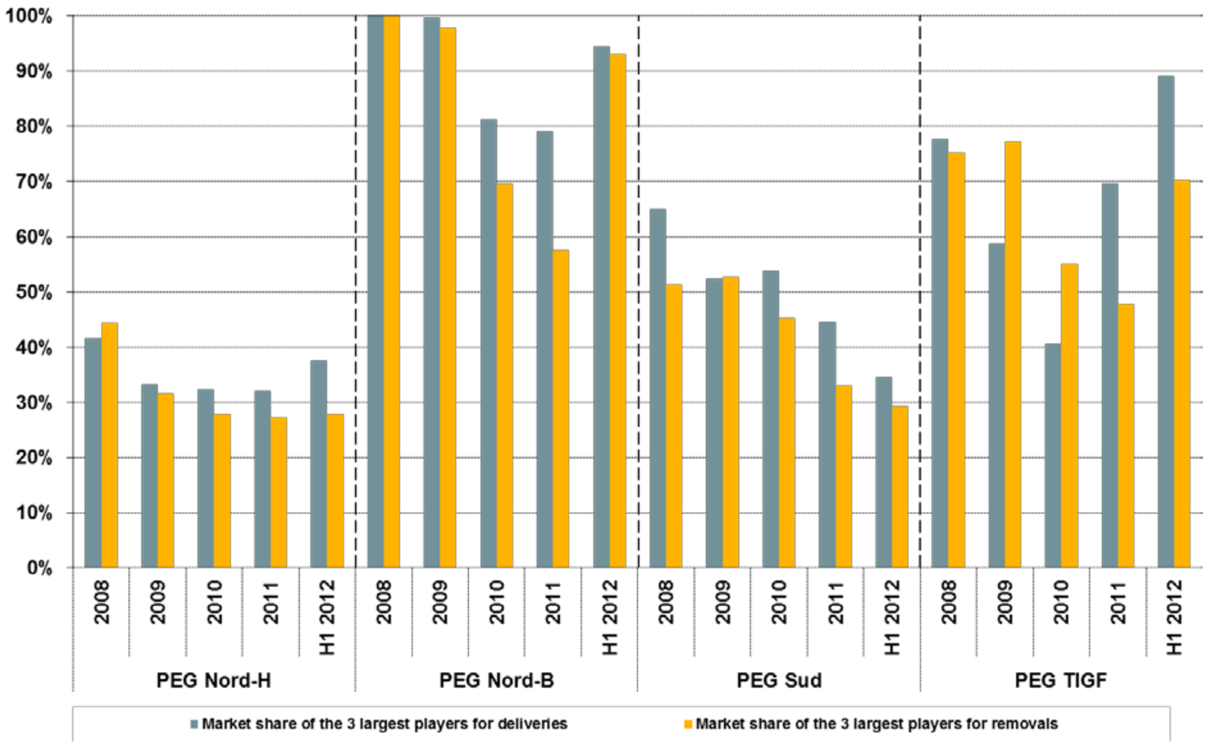
d. For purshase on the futures market



Source: Brokers, Powernext – Analysis: CRE

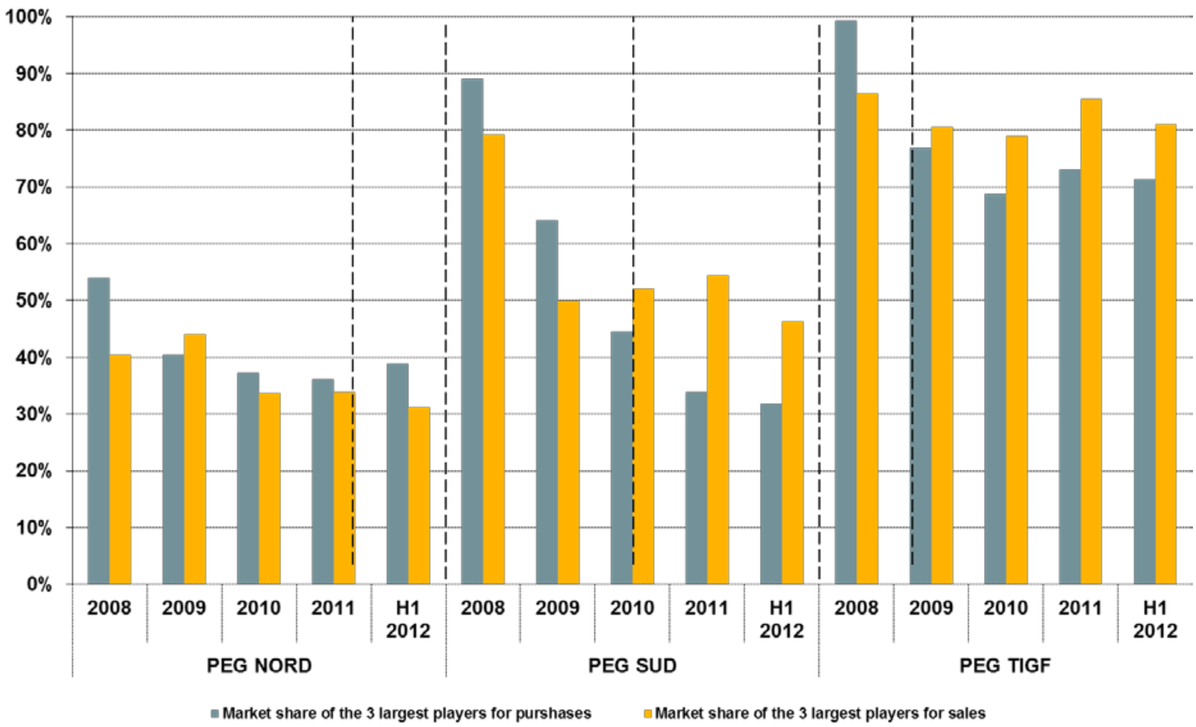
Figure 64: Combined market share of the 3 largest stakeholders by PEG

a. Removals and deliveries at the PEG



Source: GRTgaz, TIGF – Analysis: CRE

b. For purchases and sales on the intermediate market



Source: Brokers, Powernext – Analysis:: CRE

Gas prices

After experiencing a strong upwards trend since mid-2009, gas prices in Europe generally stabilised during 2011 and the first half of 2012. The difference between wholesale gas prices and those of oil-based products continued to widen, especially from the second half of 2011. The development of unconventional gas in the United States and the lack of infrastructure to export it on a large scale serve to explain the price difference between the U.S. and European markets (the latter being more expensive). While low gas prices in the United States, related to more stringent environmental laws, promote gas generation, coal prices remain lower than gas prices in Europe, which promotes the use of coal power plants.

The first half of 2012 was marked by a price spike on European spot markets, as a result of a cold snap virtually affecting the entire continent and creating a situation of tension as regards the supply. This episode was investigated by the CRE in relation to the prices setting in France (see box 4).

French prices followed the development of prices in neighbouring hubs during 2011. However, a significant disconnection occurred from April 2012 between the PEG Nord and the PEG Sud and TIGF in a context of tension as regards the supply to the south of France. This episode is currently being investigated by the CRE[31].

The developments observed related to gas prices as from 2011 may be related to several factors:

- Economic uncertainty in the euro zone;

- The rise in prices of oil products;

- Geopolitical events, especially related to the Arab revolutions;

- Climatic hazards.

WHOLESALE GAS PRICES IN FRANCE ROSE IN 2011. A SPOT PRICE SPIKE WAS RECORDED DURING THE FEBRUARY COLD SNAP OF 2012

Day-ahead prices at the PEG Nord increased by 30% between 2010 and 2011, averaging €22.9/MWh (cf. Figure 73). Despite this increase in the annual average, spot prices followed a relatively stable trend over of 2011 and lower volatility was observed (cf. Table 14). The variations observed between September and October 2011 can be attributed to the uncertainty surrounding maintenance of several liquefaction facilities in Qatar, the unavailability of the Interconnector (linking the UK and Belgium) between 7 and 22 September, as well as above normal seasonal temperatures at the beginning of winter 2011/2012.

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[31] Press release relating to the launch of the investigation into the market prices in the South of France, of 27 July 2012 (http://www.cre.fr/documents/presse/communiques-de-presse/la-cre-ouvre-une-enquete-sur-les-prix-de-marche-du-gaz-au-sud-de-la-france/consulter-le-communique-de-presse).

During the first half of 2012, day-ahead prices at the PEG Nord averaged €24.7/MWh, an increase of 8% compared to the first half of 2011. This price increase can be partly attributed to the cold snap in early February 2012, which caused a price spike to appear on European spot markets (see Box 4) and a significant increase in volatility.

Futures market prices followed a similar trend to that of the spot market and were sustained by higher oil prices. At the PEG Nord, the prices of the main futures products rose from 25% to 40% in 2011 and from 3% to 5% in the first half of 2012.

Box 4: Gas price spikes at early February 2012

French spot market prices at the PEG Nord reached, respectively €40.5/MWh and €45.7/MWh for delivery on 7 and 8 February 2012, i.e. the highest levels since 2006[32] (cf. Chart 73). These very high prices occurred during exceptional weather conditions: from the 1 to 13 February, France, and Europe more generally, were affected by a cold snap, with temperatures well below seasonal averages.

As part of its systematic analyses in the case of market events of this nature, CRE undertook an investigation into the reasons of these price levels, analysing in particular flows through the French gas network, as well as the activity of market participants[33].

Although spot prices increased on all European hubs during this period, France experienced price differentials that reached €7.0/MWh with some neighbouring markets. The rise in spot price only slightly spread to term contracts and, in particular, to the M +1 (with prices lower than €25.5/MWh) and French futures/forward prices were not disconnected from those of adjacent hubs. CRE consequently notes that the price reference used in the regulated gas tariffs formula was not affected by this episode[34].

In France, average consumption between 6 and 10 February was 3.6 TWh/day, reaching a record of 3.7 TWh consumed on 8 February, thereby exceeding the previous record from January 2010 (3.3 TWh). As a comparison, the average consumption was 2.2 TWh/day on the same dates in 2011. This increased pressure on demand went hand in hand with restrictions at interconnection points upstream of the French network, linked in particular to a fall in Russian gas deliveries to Europe and very high exports to Spain and Italy.

LNG deliveries were also relatively low. The increase in demand in France was covered especially by storage withdrawals (47% of supply from 6 to 10 February) and land imports

[32] The North PEG had reached €66.0/MWh in March 2006.

[33] Decision of the CRE of 26 June 2012 on the communication about the price spikes at the beginning of February 2012 (http://www.cre.fr/documents/deliberations/communication/vague-de-froid-fevrier-2012/consulter-la-deliberation).

[34] The calculation of the regulated sales tariff uses the average monthly gas prices at the TTF (Q +1) as gas market price reference (http://www.cre.fr/marches/marche-de-detail/marche -du-gas). This index stood at €24.2/MWh on 7 February.

(about 40% over the period).

The price spike period in France was accompanied by greater demand on the wholesale gas market which increased deliveries at PEGs and trading on the intermediate market[35]. The access to the wholesale market allowed suppliers to balance their portfolios during this period, which helped secure supply for their clients.

The available import capacity at the main interconnection points along the French network (mainly Obergailbach and Taisnières H) was not fully utilised during the cold wave, despite the significant price difference between the North PEG and its neighbouring hubs. Between 1 and 7 February 2012, 20% of the subscribed entry capacities (2.2 TWh) went unused (9% of French consumption over this period). Insofar as better utilisation of entry interconnection capacities could have reduced the significant price differences between the French market and its bordering countries, CRE decided to question the three main actors who did not fully use the import capacities to which they had subscribed at the entry points during the period when the price spikes occurred.

In their replies, these shippers pointed out the unusual weather conditions, the high demand this caused and the tension it created, especially in the south of Germany, exacerbated by the limited supplies of gas coming from Russia. Two of the actors mentioned the decision by the Italian authorities to force shippers to "maximise" imports of natural gas to Italy that resulted in a significant increase in exports via Oltingue (Swiss border). With regard to the German border (Obergailbach), two parties cited the disruptions of their interruptible exit capacities from Germany towards France. On the Belgian border, one participant mentioned the balancing restrictions on the Belgian network that made impossible to reduce backhaul flows due to uncertainties in consumption and recalled that the GRTgaz rules state that subscribed capacities must only be compared to forward flows (gross flows entering France) and not to net flows (net forward flows of reverse flowsWith regard to this last point, CRE nevertheless notes that an entry capacity of 76-100 GWh/day was available for subscription at Taisnières H for both 6 and 7 February. Finally, at the Spanish border, one actor mentioned contractual transportation obligations and pointed out that in the absence of any day-ahead reference price for the Spanish market, it was impossible to determine the difference in price between France and Spain.

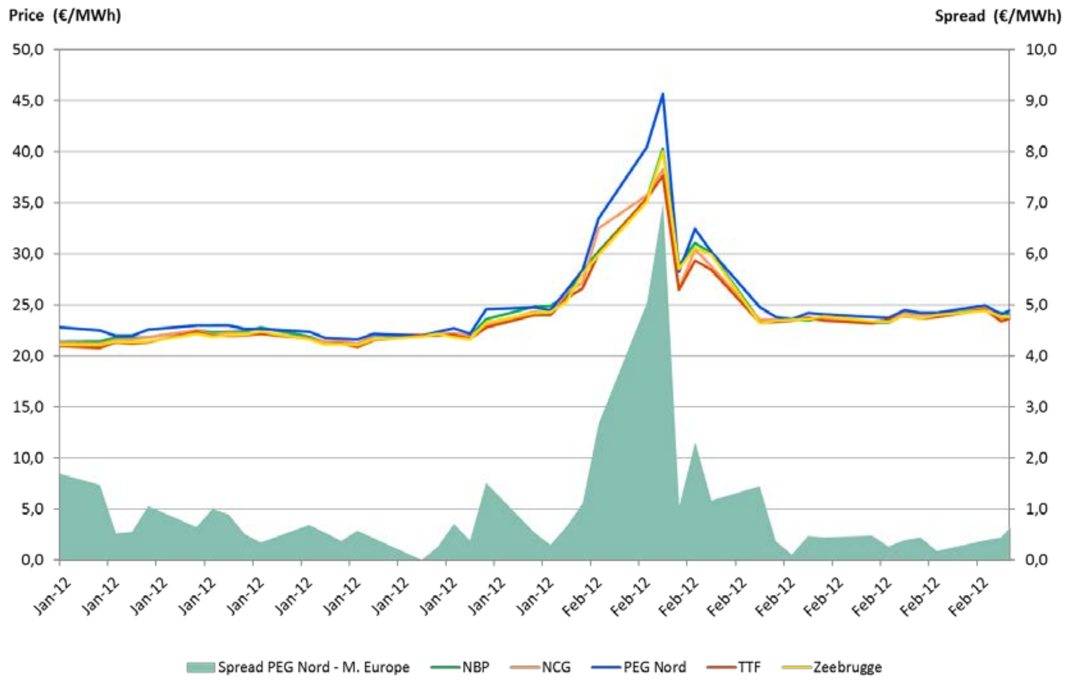
In its decision of 26 June 2012, CRE found that each of these parties had provided technical and economic reasons to justify their under-usage of the interconnections. Based on the information available to CRE on that date, the possibility of a market abuse was discarded.

CRE also observed that discussions into how to coordinate the decisions of the Member States on security of supply, market mechanisms and the harmonised pan-European management of strained conditions such as those that occurred during this event would be

[35] The volume delivered to the PEG increased by an average of 1.7 TWh/day during January 2012 to 2.3 TWh/day between 6 and 10 February 2012. The volumes traded on the French intermediate market (brokers and exchange) for day-ahead and intraday sectors and for delivery between 6 and 10 February, reached an average of 467 GWh/day, an increase of 42% compared to the average of January 2012.

welcome. Some aspects in the current design of the European gas markets could also be improved in order to make the wholesale markets run more smoothly. This in particular applies to the definition of interruptible and firm capacities to be harmonised either side of the borders. This topic will be discussed with a view to implementing bundled capacity products, as provided for by the network codes (CAM) by 2015.

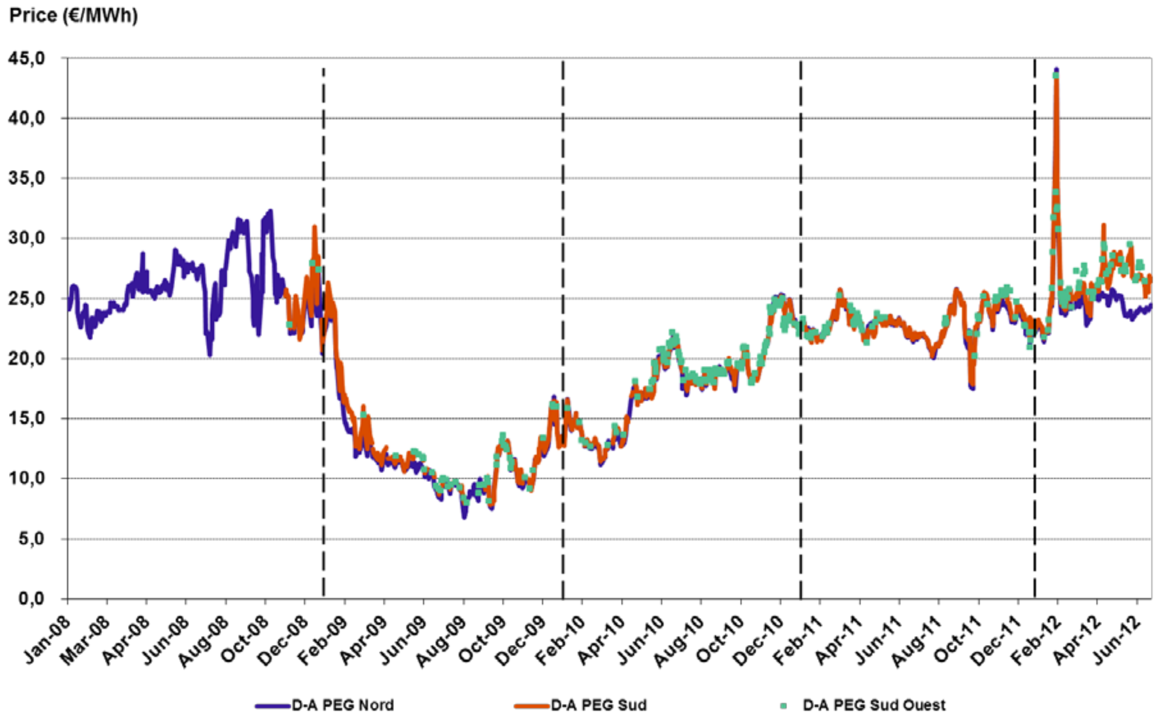
Figure 65: Spot prices spike of gas in Europe at early February 2012



Sources: Heren; Analysis: CRE

Figure 66: Development of prices on the French market (daily data)

a. Day-ahead prices



b. Futures prices at the PEG Nord

Sources: Heren, Powernext – Analysis: CRE

THE DIFFERENCE BETWEEN SPOT PRICES OF THE PEG NORD AND PEG SUD WIDENED IN LATE 2011 AND REACHED RECORD LEVELS IN THE FIRST HALF OF 2012 IN THE CONTEXT OF SATURATION OF THE NORTH-SOUTH LINK

The price spread between the PEG Nord and PEG Sud has risen sharply since the end of 2011 (cf. Figure 75). The differential between the two PEG increased by an average of €0.1/MWh in 2011 (the PEG Sud was more expensive) to €1.65/MWh in the first half of 2012[36]. Historical levels exceeding €6.0/MWh were recorded for delivery on 19 April and 31 May 2012. These very wide differences appeared in a context of tension as regards the supply to the south of France, characterised by the saturation of the North/South link (rate with which available capacity[37] of the North-South link was used reached an average of 88% during the first half of 2012 as opposed to 66% in the same period the previous year), lower emissions from the two terminals of Fos-sur-Mer, and considerable export rates to Spain (cf. Chapter 3). The voltage in the south of France increased between 16 and 23 April during a social movement which strongly affected emissions from the Fos terminals, and then as from late April, when maintenance work was carried out on the North/South link which restricted transit between the North and South zones of GRTgaz.

This gap spread to a lesser extent to the futures market and in particular to monthly products. Thus, the price gap between the North PEG and PEG Sud in relation to M+1 products rose from €0.4/MWh to €2.0/MWh between the first and second quarter of 2012[38].

In this context, the CRE opened an investigation into price formation conditions in the South of France[39]. As part of this investigation, the CRE will analyze all individual transactions on the wholesale market, and the availability and use of gas infrastructure. This investigation is ongoing.

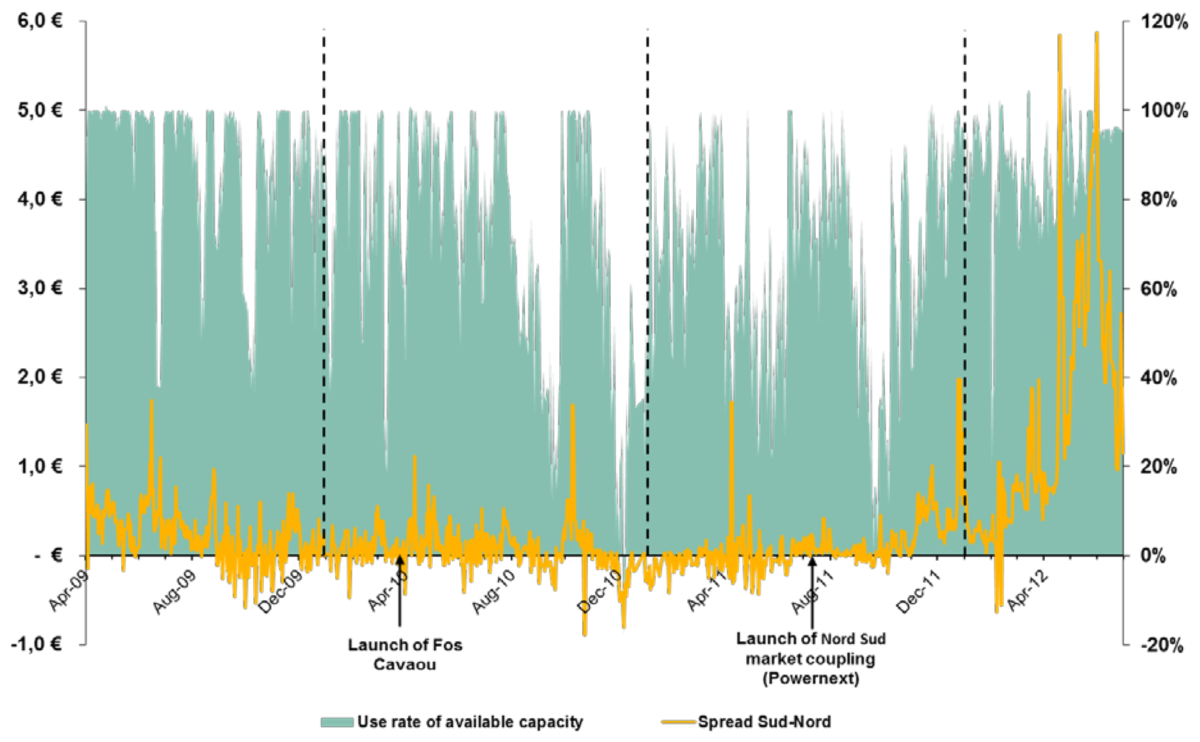
[36] Calculation based on EOD indices of Powernext

[37] Ratio between net allocations and reduced capacity in the direction of North to South as published by GRTgaz

[38] ICIS Heren indices

[39] Press release of 27 July 2012: http://www.cre.fr/documents/presse/communiques-de-presse/la-cre-ouvre-une-enquete-sur-les-prix-de-marche-du-gaz-au-sud-de-la-france/consulter-le-communique-de-presse

Figure 67: PEG Sud– PEG Nordspread and use of the link from the North to the South



Source: GRTgaz, Powernext – Analysis: CRE

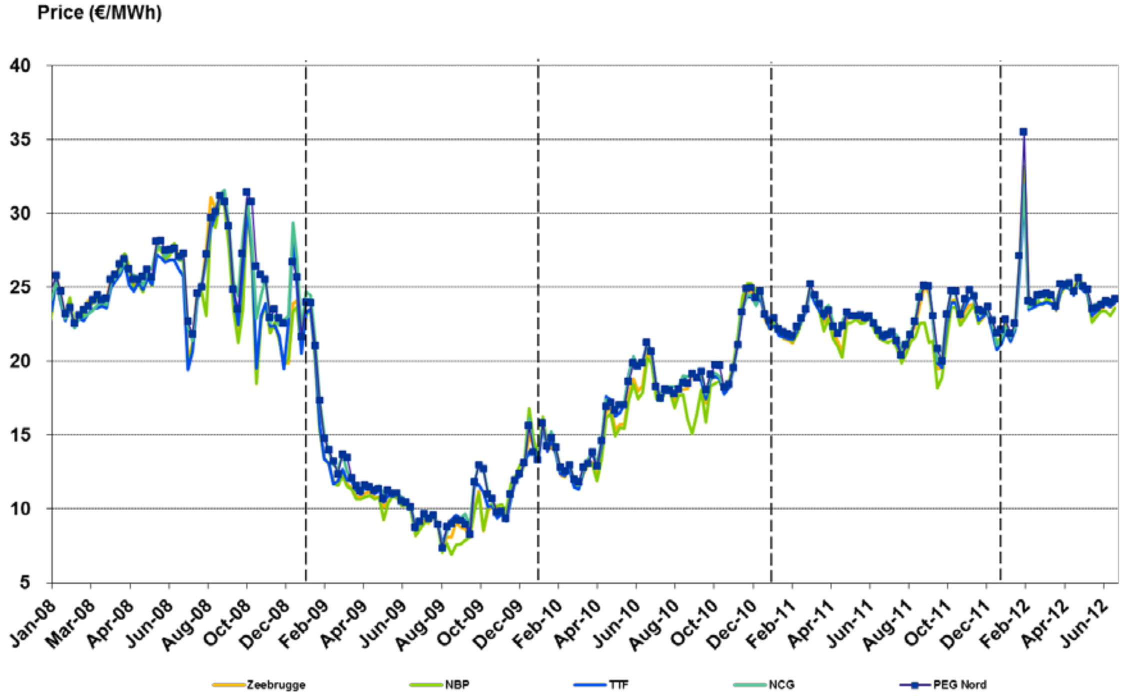
WHOLESALE GAS PRICES AT THE FRENCH PEG NORD AND ON THE MAIN EUROPEAN HUBS CHANGED IN A CLOSELY CORRELATED MANNER IN 2011 AND DURING THE FIRST HALF OF 2012

Gas prices on spot markets developed in a similar way across all European market places (cf. Figure 76), and stabilised in 2011 after rising almost continuously since late 2009.

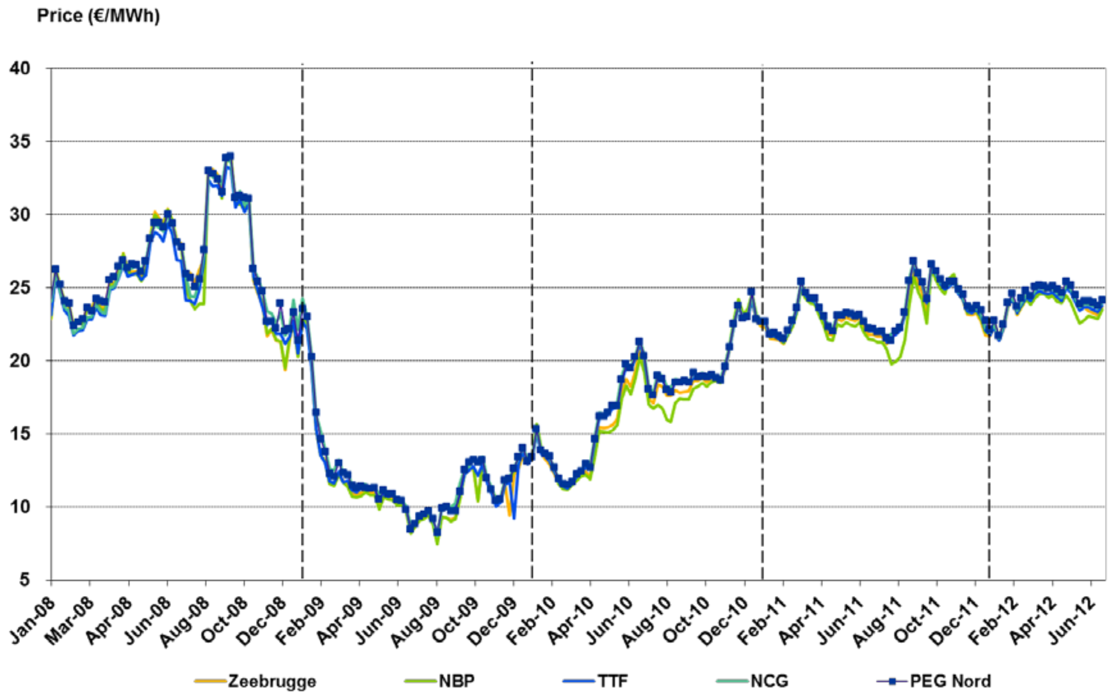
The disconnection of spot prices during September 2011 between the British NBP and the remaining European hubs was an effect of the unavailability of the Interconnector from 7 to 22 September, preventing gas from being exported from the United Kingdom to Belgium. When the Interconnector was re-opened, there was a reduction in this gap responsible for dragging continental price indices down and pulling those of the NBP up. At the end of September, spot prices of all European hubs developed in an unusual way, recording particularly low levels (the lowest in 2011 for all hubs with an average of €17/MWh). Higher than average seasonal temperatures indeed affected gas consumption at the end of September and beginning of October. This decline in European consumption was accompanied by comfortable LNG supplies at the end of September. During the first few days of October, spot prices have returned to their levels prior to this episode as normal seasonal temperatures gradually returned and usual supply resumed.

Figure 68: France – Europe prices (weekly averages)

a. Spot prices (day-ahead)



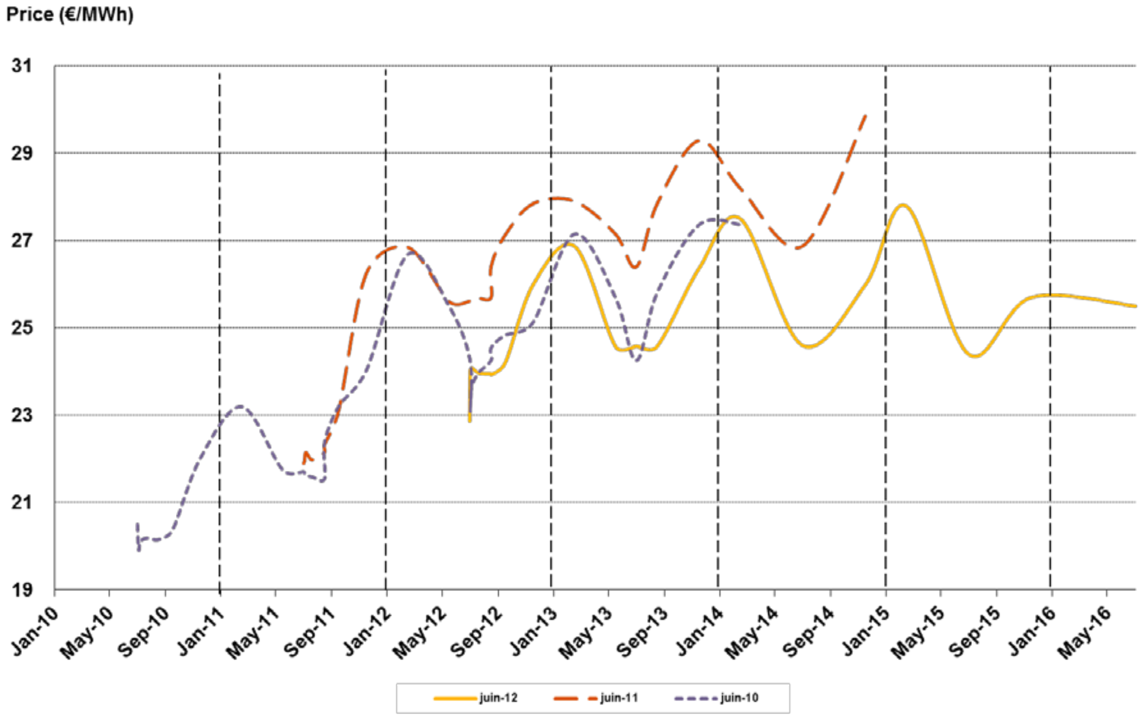
b. Futures prices (M+1)



Sources: Argus, Heren, Powernext - Analysis: CRE

As for the spot market, prices on the futures market in Europe stabilised in 2011 and the first half of 2012, following an upwards trend since late 2009. The futures curve in June 2012 (cf. Figure 77) reflects the trend towards the stabilisation of prices in Europe in the medium and long term.

Figure 69: Futures price curve on the TTF



Sources: Heren, Powernext - Analysis: CRE

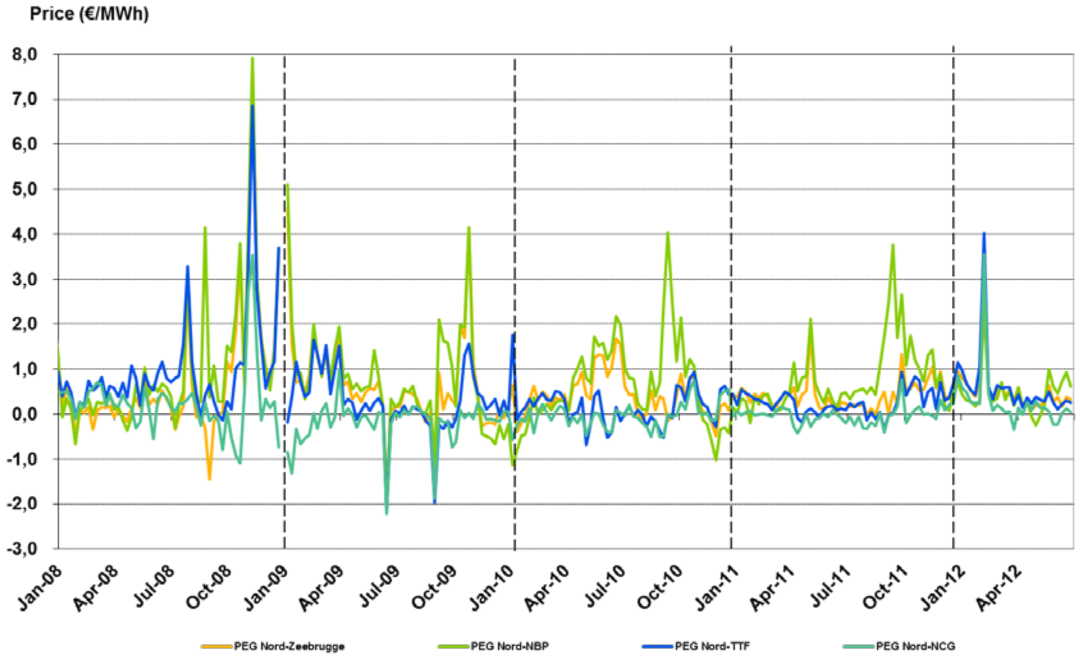
The day-ahead prices at the PEG Nord continued to develop in a closely correlated manner to that of the main European hubs (NBP, TTF, NCG and Zeebrugge). In 2011, the price differential between the PEG Nord and the NCG and Zeebrugge hubs stagnated, while the gap with the TTF widened. The spread with the NBP also remained the most significant (cf. Table 14).

The price differential between the French spot price and the remaining European hubs increased sharply in the first half of 2012, with an average of €0.45/MWh as opposed to €0.18/MWh in the first half of 2011. This development was largely due to the price spike period (cf. Chart 78 and Box 4) during which the average difference totalled as much as €7/MWh.

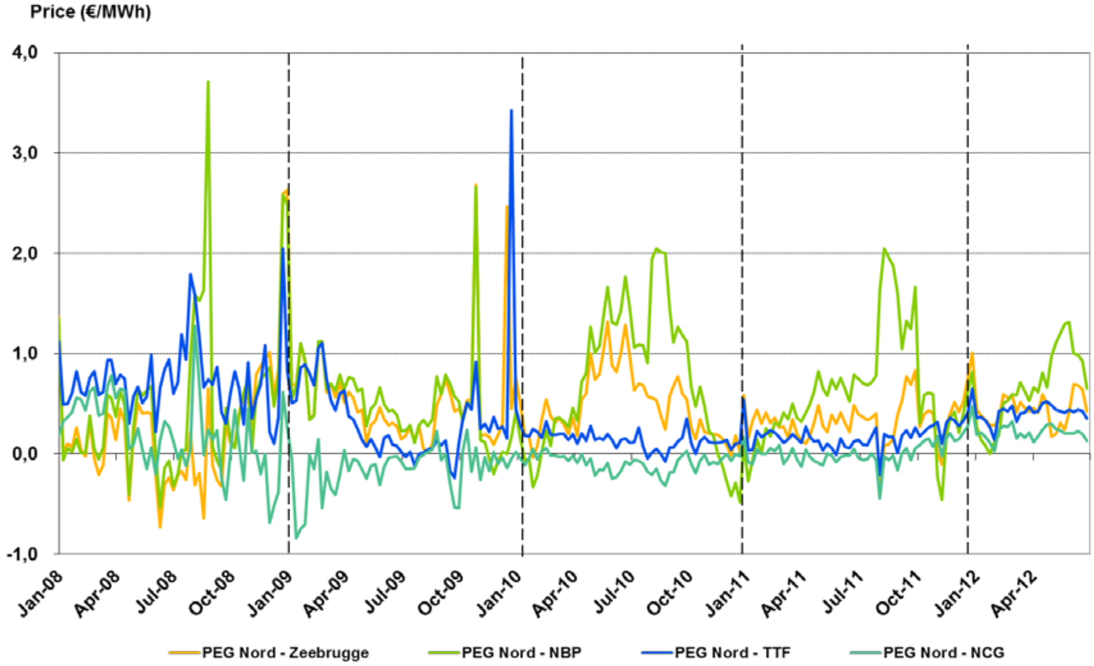
Concerning the futures market, the price difference between the PEG Nord and adjacent hubs (Zeebrugge, TTF and NCG) stabilised at around an average of €0.18/MWh in 2011 (with the PEG Nord being more expensive) . This differential, however, increased during the first half of 2012, reaching €0.35/MWh. A discrepancy between the French futures price and that of the TTF and NCG gradually appeared as from the end of 2011 and, unlike the spot market, it was not a direct consequence of the cold snap which began in February 2012.

Figure70: France – Europe price differentials (weekly averages)

a. Spot prices (day-ahead)



b. Futures prices (M+1)



Sources: Argus, Heren, Powernext - Analysis: CRE

Table 14: spreads

a. On spot prices (*Day-ahead*)

Average differential in €/MWh	2008	2009	2010	2011	H1 2012
Zeebrugge (B)	0.69	0.65	0.42	0.42	0.51
NBP (GB)	0.95	0.78	0.63	0.76	0.47
TTF (PB)	0.93	0.36	0.17	0.27	0.59
NCG (All)	0.27	-0.11	-0.04	-0.01	0.27

b. On futures prices (Month-ahead)

Average differential in €/MWh	2008	2009	2010	2011	H1 2012
Zeebrugge (B)	0.20	0.49	0.48	0.33	0.43
NBP (GB)	0.44	0.52	0.70	0.63	0.65
TTF (PB)	0.72	0.31	0.14	0.18	0.40
NCG (All)	0.20	-0.15	-0.09	0.01	0.20

Note: average of daily difference (PEG Nordprice – foreign price)

Sources: Argus, Heren, Powernext - Analysis: CRE

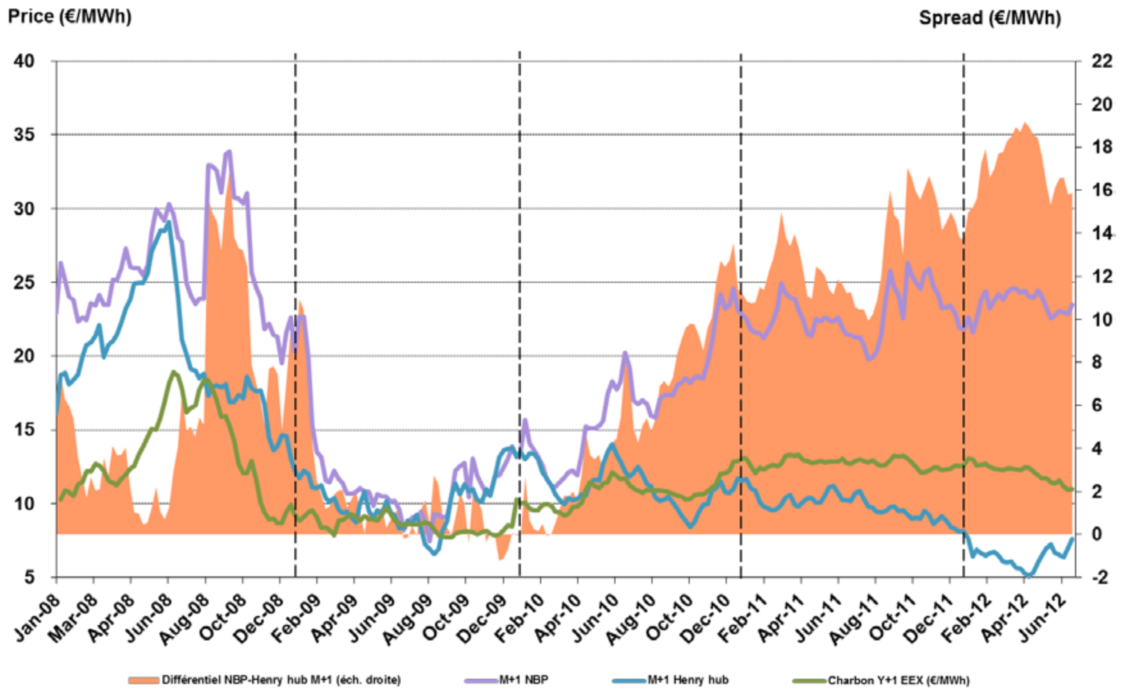
THE PRICE SPREAD BETWEEN EUROPEAN AND AMERICAN MARKETS CONTINUES TO INCREASE WHEN LNG PRICES ON THE ASIAN MARKET ARE SOARING

Following opposite trends, US and European gas prices grew even further apart in 2011 and the first half of 2012 (cf. Figure 79). On average, the price spread between the NBP and Henry Hub rose from €5.3 /MWh in 2010 to €13.0/MWh in 2011 and €17.1/MWh in the first half of 2012. While European markets recorded an increase during 2011 and the first part of 2012, prices at the Henry Hub decreased progressively, despite an exchange rate between the euro and the dollar which had been falling since mid-2011. The sharp rise of unconventional gas in the United States and the absence of liquefaction facilities for large-scale exports serve to explain the price spread between European and US markets.

The difference between the European gas price and coal price widened in 2011 particularly during the first half of 2012 (cf. Figure 79). Low gas prices on the Henry Hub related to more stringent environmental laws encouraged gas-based power generation from the US to the detriment of the use of coal.

The decline in U.S. demand for coal thus led to lower coal prices in Europe during 2011 compared to 2010, at the same time as when gas prices were higher. Unlike in the US, this development had a negative impact on the competitiveness of gas-fired power plants.

Figure 71: M+1 gas prices (UK and US) and coal price[40]



Sources: Heren, Bloomberg, EEX – Analysis: CRE

LNG deliveries to Europe were affected also by a growing demand and more attractive prices in Asia (Figure 80), largely as a result of an increase in consumption in China and India and the accident at the Fukushima nuclear power plant in Japan in March 2011, leading to the replacement of part of the nuclear generation with natural gas.

[40]Based on an assumed calorific value of coal of 6,000 kcal/kg.

Figure 72: LGN import prices in Asia vs. wholesale gas prices in Europe and the US[41]

Sources: Heren, Bloomberg – Analysis: CRE

THE DISCONNECTION BETWEEN THE WHOLESALE GAS MARKET PRICES AND OIL PRICES AND ITS DERIVATIVES BEGAN TO GROW AGAIN IN THE SECOND HALF OF 2011 AND DURING THE FIRST HALF OF 2012

The difference between gas prices and oil-based product prices six months earlier widened during 2011 (cf. Figure 81), particularly in the second half of the year, on account of a relatively greater increase in oil prices. The rise in oil prices intensified in early 2011 against a tense geopolitical backdrop particularly linked to the Arab Spring, which affected supply. Gas prices in Europe, on the other hand, had been stagnating since mid-2011, particularly because of the mild temperatures recorded over most of the winter and the context of uncertainty concerning the macroeconomic situation in Europe.

This context made wholesale prices appearing more attractive, causing several providers to renegotiate the market indexation in their supply contracts with producing countries[42].

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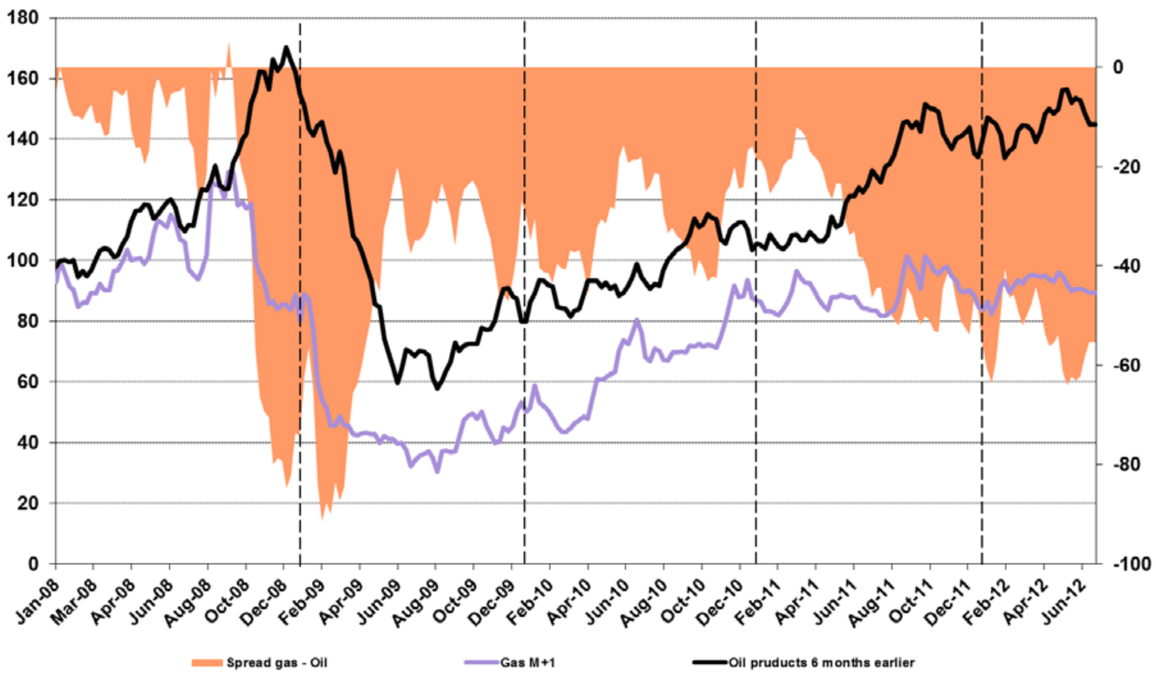
[41]The import prices of LNG in Japan are only available on a monthly scale and include transport costs to Japan

[42] As an illustration, see the press release of GDF Suez of 9 February 2012 on the group's results http://www.gdfsuez.com/document/?f=files/fr/cp-gdf-suez-fy-2011- VA.pdf p. 3: "*Long-term gas contracts have almost entirely been reviewed to increase the indexation on market price above 25%*" and the floor 25 of the presentation of annual results of 2011 of GDF Suez http://www.gdfsuez.com/wp-content/uploads/2012/05/fy-2011-results-vf-3.pdf: "Increasing indexed market share: above 25% (January 2012) as opposed to 10% (January 2011) "

Figure 73: Gas prices (market indices) and the prices of oil and its derivatives (composite index of oil-based product prices 6 months earlier)

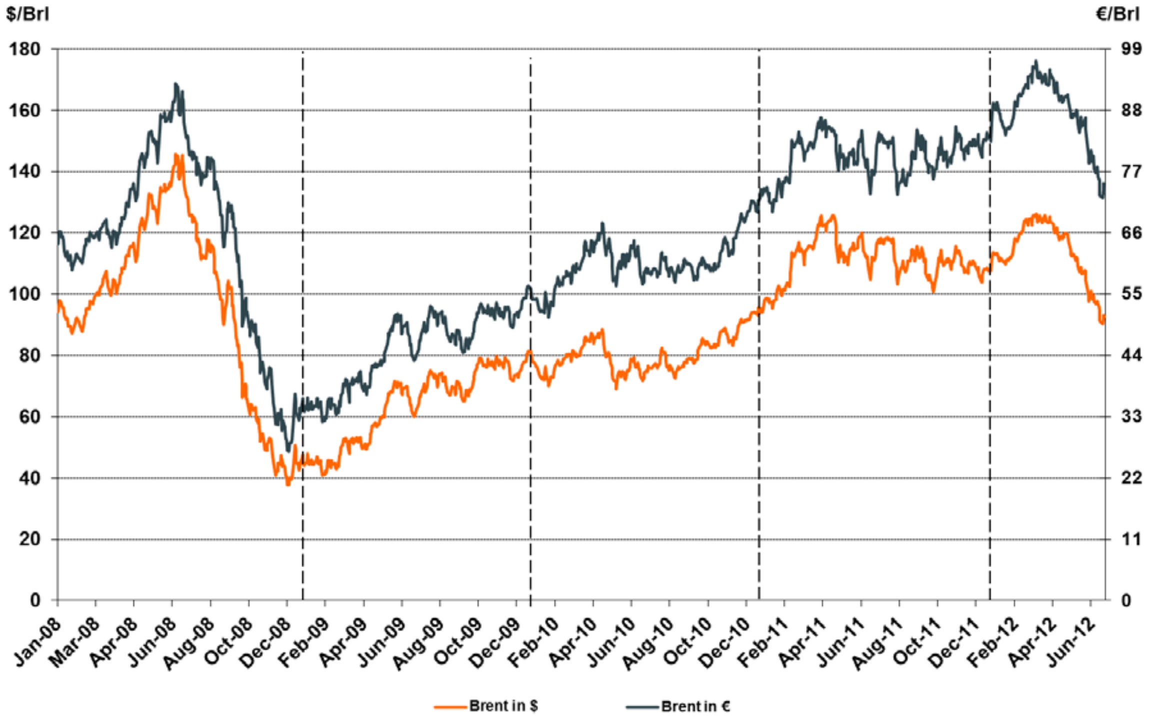


Sources: Heren, Bloomberg - Analysis: CRE

The prices of Brent rose sharply in 2011, with an average of €79.6/brl, an increase of 31% compared to 2010 (€60.6/brl). The increase was primarily related to Brent the geopolitical tensions associated with a number of conflict in North Africa in 2011. This tension added an element of uncertainty to the market and affected oil production in several countries. In addition, the global economic climate introduced an uncertain effect in markets which largely explained the wide variations in prices over the year. The decline in the exchange rate between the euro and the dollar also contributed to the increase in the price of Brent in Euros from mid-2011.

In the first half of 2012, the price of Brent increased by an average of 10% compared to 2011 and stood at €87.6/brl. The upwards trend in late 2011 increased during the first quarter 2012.Le price of Brent recorded levels above €90/brl in March, then fell sharply during the second quarter of 2012 to end the first semester at a lower level of €75/brl. Tensions on the supply of markets as mentioned in the previous paragraph increased in early 2012 at the same time as the macroeconomic outlook improved, especially in the US. The fall in prices during the second quarter can be attributed to the fact that tensions between Iran and the Western countries eased the increased production of some OPEC countries, and the prospect of declining consumption especially given the economic climate in Europe.

Figure 74: Changes in Brent prices



Source: Bloomberg – Analysis: CRE

The measurement of volatility calculated from the gas and oil-based product market prices appears in Table 15 and Figure 83.

Table 15: Annual volatility of market and petrolium products prices (daily data)

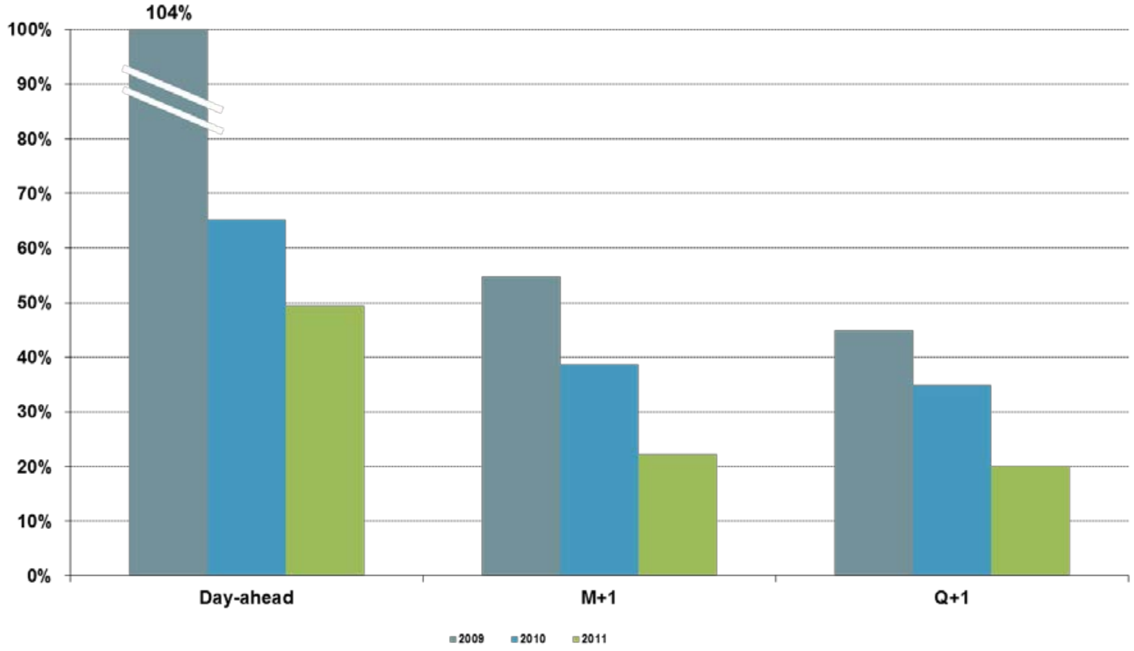
	Gas market price				Petrolium product price		
	North PEG	NBP	Zeebrugge	TTF	Brent	DHO	HFO
2008	64%	105%	95%	77%	52%	37%	65%
2009	81%	127%	101%	95%	41%	46%	52%
2010	54%	79%	76%	63%	24%	26%	26%
2011	40%	46%	42%	49%	25%	21%	22%
H1 2012	69%	77%	79%	78%	21%	16%	20%
2008-2012	62%	92%	82%	74%	33%	33%	42%

Note: Day-ahead North PEG, NBP, Zeebrugge, TTF - Brent, DHO and HFO in Euros

Sources: Argus, Heren, Bloomberg, DGEC - Analysis: CRE

The decreasing volatility trend of prices on European gas markets was maintained in 2011 and the first half 2012. The expected link between volatility and maturity is illustrated in Figure 83.

Figure 75: Annualised historical volatility between 2009 and 2011



Note: The volatility calculation for the Q+1 index has been verified
Source: Heren – Analysis: CRE

Gas infrastructure

THE USE OF GAS INFRASTRUCTURE IS HIGHLY DEPENDENT ON MARKET CONDITIONS

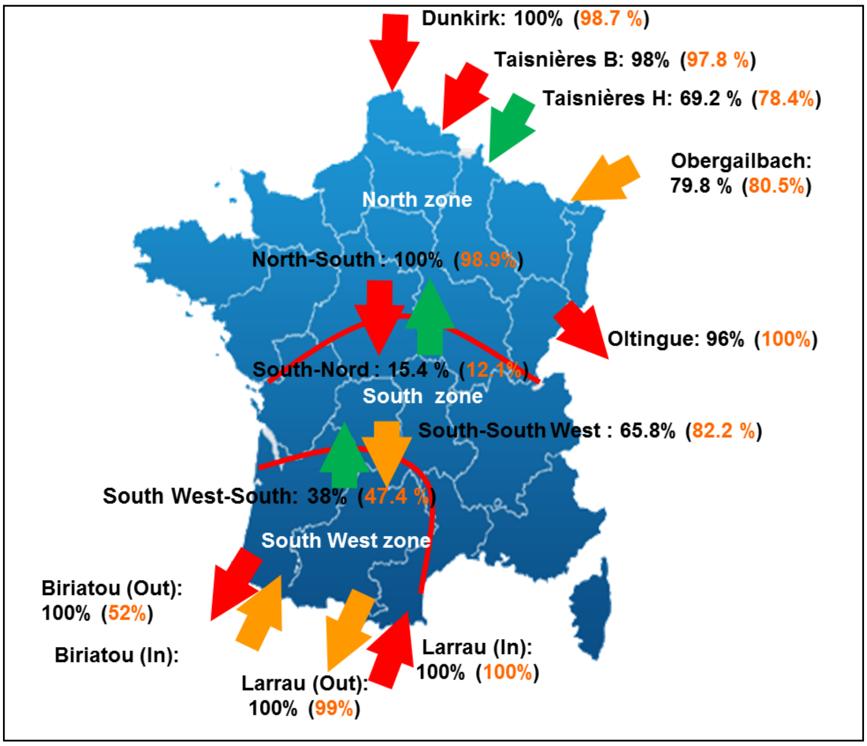
In the first half of 2012, the import capacity of France amounted to 2,850 GWh/day. The commitments of GDF Suez vis-à-vis the European Commission improved access for new shippers at the entry points of Obergailbach, Taisnières, Montoir and Fos Cavaou as from October 2010. In addition, the number of active shippers on transmission grids increased significantly over the period covering 2011 and the first half of 2012. In contrast, the numbers of users of LNG terminals and storage facilities stagnated or even decreased.

ACCESS CONDITIONS TO GAS TRANSMISSION NETWORKS ARE SATISFACTORY

The number of shippers registered on GRTgaz and TIGF networks increased by 15% and 35% respectively between 1 January 2011 and 1 July 2012. These increases were particularly attributable to the development of activity of some industrial consumers at the PEG which optimised their procurement costs by directly accessing wholesale markets.

Capacity at entry points of the North zone were still held by a limited number of stakeholders. However, there was a decrease in the HHI index, especially at the entry point of Taisnières H, where firm capacity was still available.

Figure 84: Development in firm capacity subscriptions to transmission grid interconnections between the first half of 2012 and 2011



Source: GRTgaz, TIGF - analysis: CRE

At the entry point from Belgium (Taisnières H), the utilisation rate has been in steady decline since January 2011. Thus, in the first quarter of 2012, it stood at 64%, as against 75% in the previous year. The same phenomenon was observed in the second quarter, with a usage rate of 55% in 2012, in relation to 78% over the same period in 2011.

At the entry point from Germany (Obergailbach), the rate at which capacity is used remained stable, averaging 80% over the period from January 2011 to June 2012.

At the exit point to Switzerland (Oltingue), an accident which occurred in July 2010 on the Swiss gas pipeline Transitgas had led to the interruption of flows for more than four months flows from Switzerland and Italy. Since January 2011, the date on which flows resumed, the use of firm capacity has been at its maximum.

In the TIGF zone, the output flows to Spain at Larrau and Biriatou increased. Thus, 64% of the capacities at Larrau was used in the first quarter 2011 and more than 95% was used as from the fourth quarter of 2011. This sharp increase reflected the increasing amount of imports from France to Spain to compensate for the reduction in its LNG unloading activity at its methane terminals.

A REDUCTION IN UNLOADING OPERATIONS AT LNG TERMINALS

The commitments of GDF Suez led to capacity being marketed in 2010 at the Montoir and Fos Cavaou terminals. Some capacity was subscribed on this occasion by newcomers. However, the limited appeal of the European market for LNG in terms of high prices in Asia led to a sharp fall in new subscriptions as from 2011. Thus, 1 Gm^3 of annual capacity was still up for sale at the Fos Cavaou terminal as of 1 April 2013.

In addition, Fukushima accident led to a reduced use of LNG terminals in Europe and particularly in France. Indeed, Japan, which replaced its nuclear power generation with gas, purchased the LNG at significantly higher prices than the European wholesale gas price. Thus, although the number of shippers remained stable at terminals, the terminal usage rate was greatly reduced. However, there were disparities between the Montoir terminal, located in the North zone and the Fos Cavaou and Fos Tonkin terminals, located in the South zone. In the first half of 2012, emissions from the Montoir terminal fell by 56% compared to the same period of the previous year, while this decline stood at 20% for the Fos Tonkin and Fos Cavaou terminals. The higher use of the Fos terminals is explained by the structural difficulties related to supplying the South zone on account of the congestion between the North and South zones of the GRTgaz network. The Fos-sur-Mer terminals are still the second source of supply of the South zone, after the North-South link of GRTgaz.

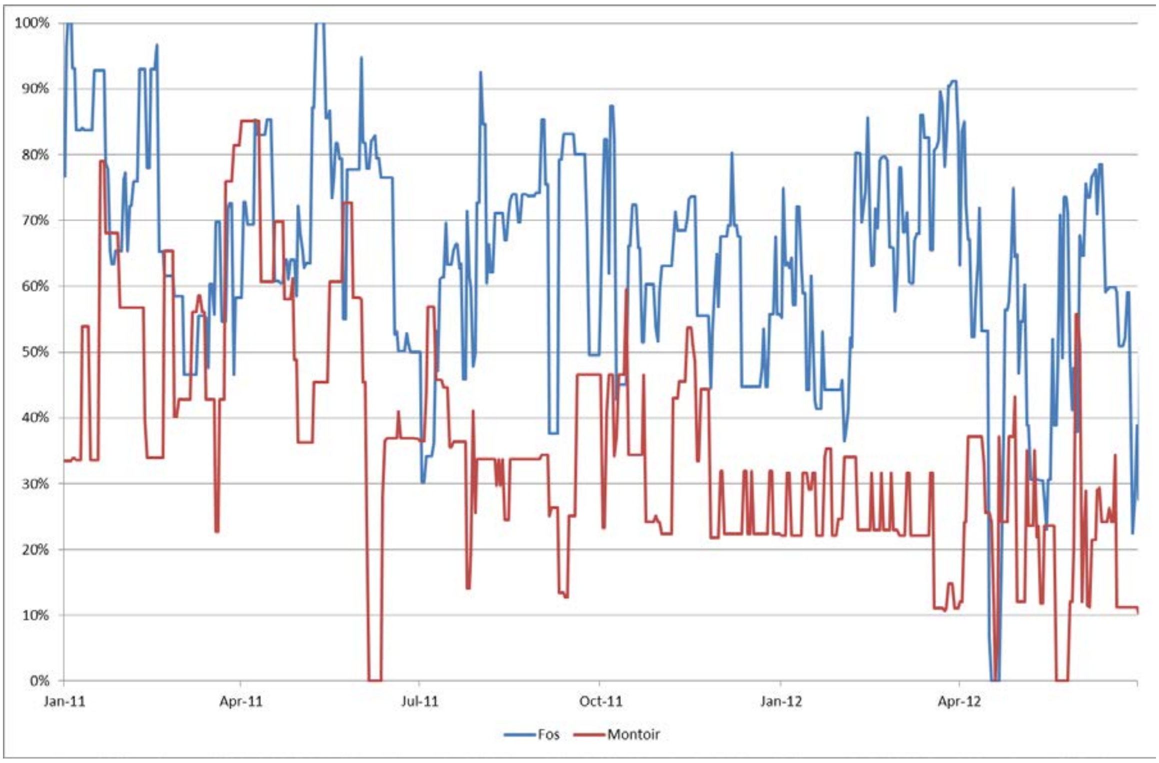
Table16: Number of users on methane terminals

Number of active clients	12/31/2009	12/31/2010	12/31/2011	06/30/2012
Montoir	6	6	6	6
Fos Tonkin	1	2	2	1
Fos Cavaou	-	2	3	3

Source: Elengy, Fosmax LNG - analysis: CRE

This decline in the use of regasification capacity is also illustrated by the number of cargos and the quantities unloaded. Thus, in the first half of 2012, 82 vessels unloaded 58.7 TWh at all French terminals, or the equivalent of half of the quantity unloaded in the first half of 2011 to 126.9 TWh, with a total of 125 vessels (cf.Figure 85). In addition, the spot service marketed by these terminals and subscribed on four occasions in 2010, has remained unused since January 2011.

Figure 85: Usage rate of gas capacities at PITTM (entry points on the transmission system from LNG terminals)



Source: GRTgaz – Analysis: CRE

To enhance the attractiveness of their terminals, operators set up an experimental service in the first half of 2012 so that vessels can unload at the Montoir and Fos Cavaou terminals. The first operation was performed in April 2012 at the Montoir de Bretagne terminal.

A CONFIRMED DECLINE IN STORAGE CAPACITY RESERVATIONS

TABLE16: NUMBER OF USERS OF STORAGE FACILITIES

	01/01/2010	01/01/2011	01/01/2012	07/01/2012
Storengy	30	24	24	22
TIGF	10	11	13	13

Sources: Storengy, TIGF - analysis: CRE

Since 1 January 2011, there has been a decrease in the number of users of the Storengy storage facilities and a significant reduction in working gas volumes[43] subscribed and therefore gas reserve level at the beginning of winter. The main reason for this trend was the low spread level between winter and summer products on wholesale markets. On 1 November 2011, France had a gas reserve level of 128.3 TWh. These levels were lower than in previous years, when the gas reserve level exceeded 130 TWh. Therefore, there was a decrease in the reserve loading rate on the eve of the winter, to 89% on 1 November 2011, as opposed to 96% in 2009. On 1 April 2012, the gas reserve level was down compared to previous years mainly because of the February cold snap in 2012.

Table17: Storage levels in France

TWh	2007	2008	2009	2010	2011	2012
1st January	104.6	99.8	103.0	112.1	73.6	96.1
1st April	49.0	60.5	44.5	51.4	32.4	31.5
1st July	82.1	92.2	87.0	85.3	83.0	61.5
1st November	127.8	133.0	136.1	123.9	128.3	-
Working gas volume	134.0	137.0	142.0	142.0	143.6	145.5
Fill rate of storage facilities	95%	97%	96%	87%	89%	

Sources: Storengy, TIGF – Analysis CRE

[43] Volume available for the purpose of being marketed

Box 5: Use of the intraday flexibility

The intraday flexibility of a site corresponds to its need to vary its gas consumption during the day beyond or below its average hourly consumption throughout the day.

When the charge per use of the transmission grid of GRTgaz was updated, effective as of 1 April 2011, the CRE introduced an intraday flexibility service intended for strongly modulated sites and mainly gas power plants. This service, which is charged per use, allows the GRTgaz to meet the needs of the users of its network in transparent and non-discriminatory conditions.

This service targets sites with an average daily modulated volume of more than 0.8 GWh. The number of sites increased from 6 to 11 between April 2011 and September 2012. These are 9 combined cycle gas turbines (CCGT) and two combustion turbines, which amount to an installed capacity of 5287 MWe.

Because of the insufficiency of its linepack, from November 2011, GRTgaz had relay on external flexibility sources. For this purpose, contracts were signed by GRTgaz with Storengy, Elengy for the Fos Tonkin terminal and Fosmax LNG for the Fos Cavaou terminal.

During the period concerned, the intraday flexibility service was never reduced or suspended by GRTgaz and worked effectively from the time of its inception. The need for modulation observed for these sites was, however, twice as low as what had been anticipated in the technical and economic study produced in 2010 by GRTgaz and TIGF and revised in 2011 by GRTgaz.

CAPACITY AT THE LINK BETWEEN THE NORTH AND SOUTH ZONES ON THE GRTGAZ NETWORK ARE USED IN A SATISFACTORY MANNER

Between 2011 and 2012, the firm capacity of this link was fully subscribed and the interruptible capacity was at an average close to 60%.

In 2011, market conditions led to a partial use of the link between the North and South zones (about 62% of the available capacity was used in summer and 75% in winter).

During the first half of 2012, the tense situation in the South zone resulted in an increased use of the capacity on the North and South link (close to 86% in the first quarter and 92% in the second).

From May, GRTgaz introduced a process whereby a new product of a monthly interruptible capacity was allocated which enabled the use of the technical capacity available to be increased daily on the link. The subscription rate was thus 100% in June. The reduction rate of the interruptible capacity averaged 45% over the year 2011[44] with high levels during the

[44] This figure corresponds to the share of the capacity which was covered by nomination requests by shippers who subscribed to the interruptible capacity and who were not satisfied by GRTgaz.

summer due to maintenance (approximately 61% on average). In 2012, these rates were lower, at levels near to 9% and 24% respectively in the first and second quarters.

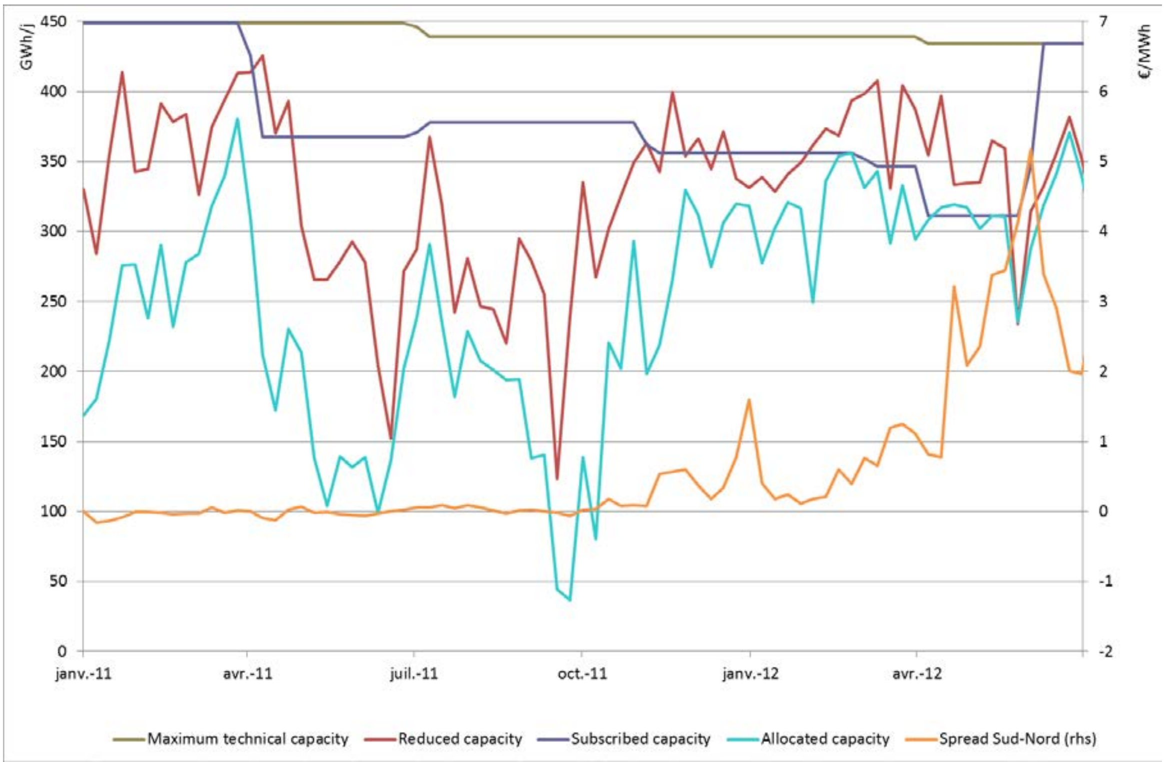
Table 19 shows that the average available capacity level was the same between the starts of 2011 and 2012.

Table18: Availability, use and subscription of the capacity at the link between the North and South zones

	H1 2011	H2 2011	H1 2012
Average availability of the maximum technical capacity	74%	69%	73%
Average use of available capacity	67%	70%	89%
Average subscription rate of the maximum technical capacity	91%	85%	83%

Source: GRTgaz – analysis: CRE

Figure 76: Parallel development of the use of the capacity of the link between the North and South zones and the price differential (weekly averages)



Source: GRTgaz, Powernext – analysis: CRE

MEDIUM TERM OUTLOOK

SIGNIFICANT INVESTMENT DECISIONS IN 2011

- **Doubling the size of the main Rhône pipeline is the first step towards a merger of zones**

The project to double the size of the main Rhone pipeline, known as ERIDAN, was launched on 2 February 2011 by GRTgaz. The CRE approved the investment decision of the operator (for €484 million) in its decision of 19 April. The aim of the ERIDAN project is to strengthen the core of GRTgaz network in the South of the territory, by creating 120 GWh/day input capacity in the South zone. It thus promotes the development of new gas infrastructure in the South zone (LNG terminals, storage facilities, interconnections).

The expected benefits of this project concern, on the one hand, the French market by developing fluidity in the South zone and eventually facilitating the merger of the North and South zones and on the other hand, the European market by helping to complete the North-South Corridor in Western Europe. This project has been identified as a priority and necessary for the integration of the South of France and the Iberian Peninsula into the heart of the European market. As such, it will benefit from a European subsidy of a maximum amount of €74 million.

- **Doubling the size of the Hauts de France pipeline and creating the Arc de Dierrey will help to make the network more fluid**

These investments make it possible relieve congestion at the heart of the network in the North zone of GRTgaz and lift the minimum flow constrain at Obergailbach. In addition, they will increase the capacity of GRTgaz to provide intraday flexibility on account of a greater linepack (equivalent contribution for this purpose of about 23 sections of 400 MW).

- **Connecting the Dunkerque LNG terminal**

The shareholders of Dunkerque LNG (65.01% EDF, 25% Fluxys and 9.99% Total) took their final investment decision on 27 June 2011. The terminal, which is scheduled to be commissioned in late 2015, will have a gas regasification capacity of 13 Gm^3/year.

The Dunkerque terminal benefits from a total exemption from regulated access of third parties and tariff regulation for all its capacity for a period of twenty years. This exemption was granted to Dunkerque LNG by a decision of 18 February 2010, following the favourable opinion of the CRE dated 16 July 2009 and in accordance with the opinion of the European Commission of 20 January 2010.

In its decisions of 12 July and 22 December 2011, CRE approved the investments of GRTgaz which are required to connect the terminal to the transmission grid. To enable the Dunkerque LNG terminal to transmit at full capacity (519 GWh/day) to the French market, it is necessary to strengthen the major Hauts de France pipeline.

- **The creation of a new interconnection with the Belgium interconnection at Veurne**

The construction of a methane terminal in Dunkirk offers the possibility of physically exporting non odorised gas to Belgium by creating a new interconnection point with Belgium Veurne. Following the decision of the CRE of 29 April 2010, GRTgaz launched, on 11 December 2011, in coordination with Fluxys, the open-season phase for the creation of firm gas transmission capacity from France to Belgium. This operation was concluded on 6 March 2012 with the following results: 270 GWh/day of firm capacity will be developed by 2015. In addition, pursuant to the third energy package, capacity will be available as from the third year after commissioning. They will be marketed in keeping with the rules to be laid down by the European network codes

GUIDANCE ON THE DEVELOPMENT OF MARKET PLACES (PEG)

In mid-2012, the CRE set out the guidelines for the development of the contractual structure of balancing zones in France. In its decisions of 29 May and 19 July 2012, the CRE set out the outlook for the development of future PEG structure in France:

- On 1 April 2013, creation of a single PEG Nord with the merger of the balancing zones North H and North B;
- In 2015, creating a common PEG between GRTgaz Sud and TIGF, with the balancing zones of both carriers able to remain separate;
- In 2018 at the latest, creation of a single PEG in France.

The European target model provides for the implementation of efficient market places. The guidelines set out by the CRE must enable this objective to be achieved.

- **The creation of a single PEG Nord on 1 April 2013**

The network of gas with a low calorific value (L gas) of GRTgaz provides power to a consumption area of about 50 TWh per year located in the north of France. This network is different from the network of gas with a high calorific value (H gas). In its decision of 29 May 2012, the CRE set out its guidelines for the creation of a single Northern market place for H and L gases on the GRTgaz network. As H and L gas networks remain physically separate, the merger will be accompanied by measures to ensure that the L gas infrastructure continues to be used to physically balance the L gas network.

The expected benefits of the selected merger scheme are widely recognised by the market, especially with regard to the development of competition on the L gas retail market and the increased liquidity of the wholesale market in Northern France.

- **The creation of a PEG France by 2018**

The French H gas market currently comprises three marketplaces: the North and South PEG on the GRTgaz network and the PEG of TIGF. PEGs are essential tools to suppliers active on the gas market in France to optimise and secure their supplies. CRE considers that the eventual existence of a single market place and therefore a single gas price over the whole territory is essential for the completion of an effective wholesale market, for the benefit of gas consumers.

Firstly, a shared PEG between GRTgaz Sud and TIGF will be created by 2015. This can be done by maintaining two separate balancing zones, along the lines of the "trading region" model. An assessment into how this shared PEG functions will be carried out when the single North-South PEG is created and no later than 2018.

Box 6: KEMA study on the merger of the North and South zones of GRTgaz

Following approval for the ERIDAN project, CRE asked GRTgaz to conduct a study on the possibilities of merging the North and South zones of GRTgaz. Based on the physical developments in French transmission grids by 2015-2016, as well as flow assumptions within these networks (based themselves on the price assumptions of the various sources of gas supplies) , KEMA has identified several risks related to congestion, including a risk of structural congestion in the direction from North to South. These congestion issues, necessary to create a single GRTgaz PEG, can be managed either through investments in the GRTgaz network or by making use of contractual tools. Exclusive reliance on contractual tools could cost more than €300 million per year. The contractual removal of these congestions through investments is estimated to cost €1,800 million. Due to their costs, market stakeholders do not consider these two approaches to be satisfactory. The KEMA study has also identified a third approach whereby the main risk of congestion is dealt with by an investment which is estimated at less than €600 million and the other risks of congestion are managed by contractual tools for an amount less than €25 M per year.

This approach has been welcomed by market stakeholders and the CRE expressed that it favoured this approach in its decision of 19 July 2012.

EUROPEAN STRUCTURAL WORK FOR ACCESS TO TRANSPORT CAPACITY

The 3rd European package seeks to create internal gas and electricity markets. To this end, Article 6 of Regulation 715/2009 on the conditions for access to the natural gas transmission networks provides for the drafting by the ENTSOG (European Network of Transmission System Operators for Gas) of network codes that will define common rules for the functioning of the gas market in Europe.

- **The network code on capacity allocation (CAM)**

On 17 September 2012, ENTSOG submitted to the ACER (Agency for the Cooperation of Energy Regulators) a revised version of the network code on gas transmission capacity allocation. The purpose of this network code is to simplify access to interconnections, especially for newcomers, to improve cross-border coordination, to standardise and render more effective the allocation procedure. The code particularly provides that, at each boundary point, the output capacities of an area and the input capacities of the adjacent area will be marketed as a group ("bundling"). These capacity products of an annual, quarterly, monthly, daily and intraday term will be auctioned on common marketing platforms and according to a standardised schedule. Adjacent TSOs should cooperate to maximize the capacity on offer and synchronise the allocation process. The Code provides for an implementing period of 18 months as from the time at which it enters into force. In this perspective, sixteen European transmission grid managers, including GRTgaz, announced in April 2012 the development of a common capacity marketing platform. At the meeting of 27 September 2012 at the regional initiative, gaz sud encouraged carriers of Spanish and French gas to join this platform, and in particular TIGF.

- **Guidelines for congestion management (CMP)**

Guidelines on contractual congestion management were proposed directly by the European Commission and adopted by the Member States of the European Union on 20 April 2012. They provide for four measures to fight against the capacity retention and make more capacity available to the market:

- A system of excess reservation and buyback

- Recovery of contractual capacities

- A use-it-or-lose-it (UIOLI) mechanism of firm capacity supply to one day,

- A UIOLI mechanism of long term capacity supply.

Regarding the incentive mechanism for when capacity is oversold, its volume will be set beyond the technical capacity, based on statistical scenarios of usage of the contracted capacity. In addition, the TSO should provide for a buyback mechanism to handle a situation in which the nominated capacity is greater than the technical capacity. This device raises questions in terms of costs for TSOs and financial compensation for shippers.

The text also introduces a voluntary capacity surrender mechanism for network users, in the absence of available capacity and when there is a corresponding demand for capacity by a new buyer.

These mechanisms will be implemented with effect from 1 October 2013 and will be the subject of the *Concertation Gaz* consultation process and a public inquiry by CRE in 2013.

- **The network code on balancing transmission grids**

On 13 April 2012, ENTSOG published for consultation a draft of the network code on gas transmission capacity allocation. A final version should be submitted to the ACER in November 2012, which is expected to coordinate the comitology process in 2013 and adopt the network code at the end of the year. The network code could then be implemented at the end of 2014 or early 2015.

The network code will particularly specify that transmission grids must be balanced in one step every day, although some intra-day constraints can be applied. In addition, TSOs must balance their network by using, as a priority, the market and not by using flexibility services subscribed over the long term (with a storage operator for example). Shippers' imbalances will be balanced at a representative price of the market price and transactions recorded by the TSO to balance its network. The network code also harmonises the procedures for nominations and the level of information which must be provided by the TSO to shippers so that they can be balanced.

Supply and markets of stakeholders/newcomers

A GLOBALLY STABLE SUPPLY MODEL FOR NEWCOMERS[45], WITH AN INCREASED USE OF TITLE TRANSFER POINTS (PEG)

Newcomers generally use the wholesale market for the purpose of optimising their portfolios and securing the supply of their clients. Unlike incumbent suppliers, who favour imports, especially by pipeline, the wholesale market remains the most significant source of supply for newcomers and its share continued to increase in 2011 and the first half of 2012[46].

Although their share in the supply of newcomers continued to decline during 2011 and the first half of 2012, imports can cover the overall consumption of their clients. This reflects the good conditions of access to gas infrastructure for newcomers. The LNG supply of these stakeholders, which accounted for 10% of their imports in 2011, fell by 69% in first half of 2012 whereas they increased by 79% between 2010 and 2011.

The exports of newcomers totalled 7% of their market in 2011 as opposed to 4% in 2010. In the first half of 2012, exports accounted for 5% of the markets, i.e. a level similar to that of the first half of 2011. Approximately 41% of the exports of newcomers in 2011 were recorded at the interconnection with Germany (Obergailbach)[47].

The main market opportunities for newcomers arise from sales at PEGs and deliveries to end clients. Sales at PEGs represented almost 65% of the market opportunities of newcomers, unlike incumbent suppliers for whom a similar proportion is attributed to deliveries to end clients.

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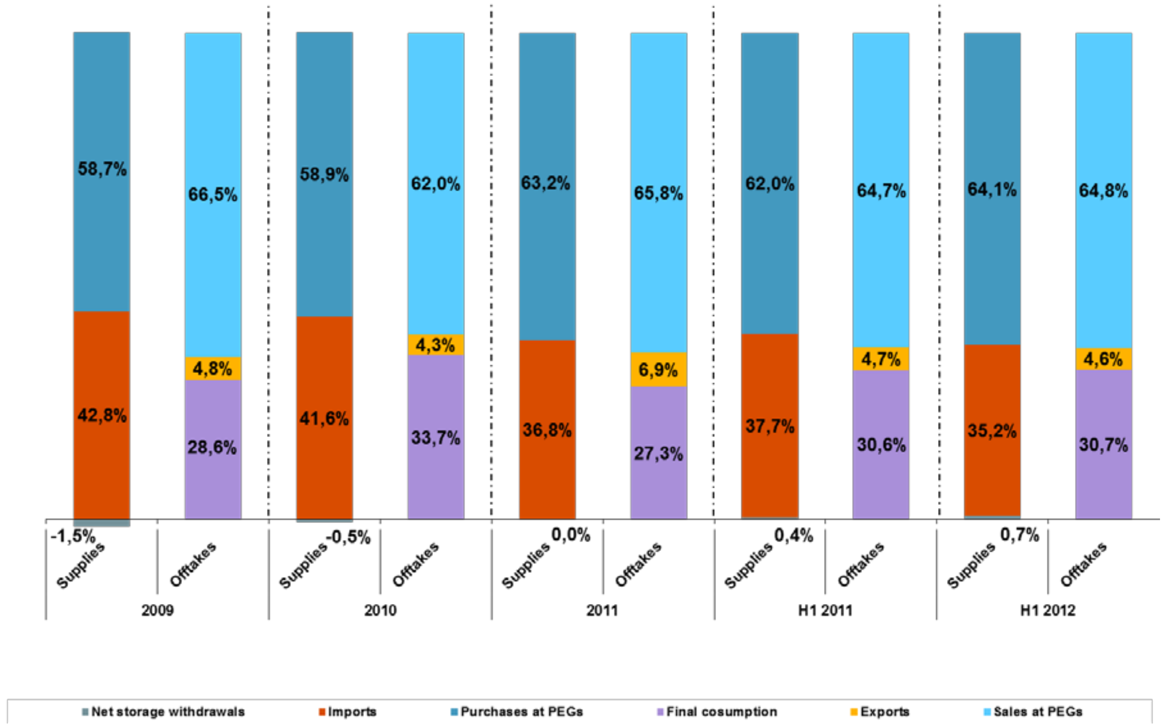
[45] Newcomers include all shippers who are not incumbent suppliers in France.

[46] Although imports increased by 17% between 2010 and 2011, the rise in the purchases of newcomers at PEGs was more significant (+41%).

[47]

Figure 77: Suppliers and outlets for of newcomers in France

- as a %, 2009 – H1 2012 –



Sources: GRTgaz, TIGF - Analysis: CRE

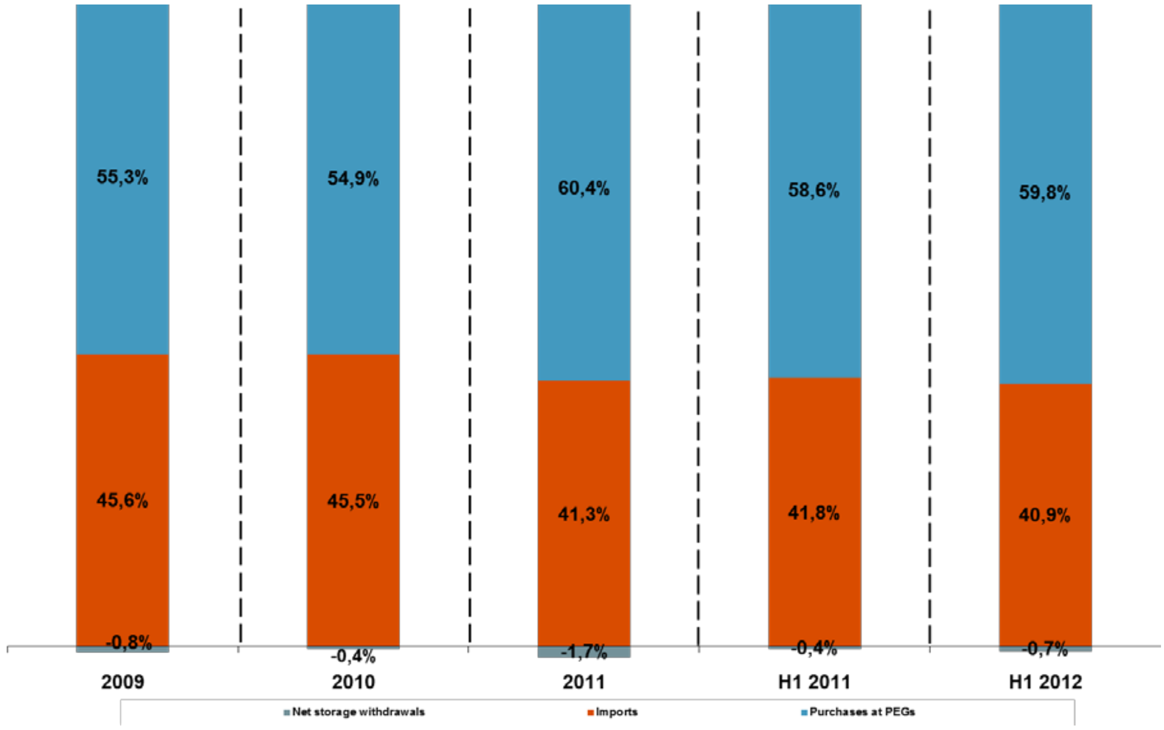
A SUPPLY STRUCTURE IN THE NORTH ZONE IN LINE WITH THE NATIONAL MODEL

Since its emergence as a result of the merger of three balancing zones in January 2009, the GRTgaz North zone has enabled newcomers to gain greater access to infrastructure and market liquidity to grow. Trading volumes and the number of stakeholders involved on the PEG Nord has gradually increased since 2009.

Use of the market for the supply of newcomers in the North Zone has increased, representing a share of 60% in 2011 as opposed to 55% in 2010. This proportion remained stable in the first half of 2012.

Figure 78: Supplies of newcomers in the North zone by source [48]

- as a %, 2009 – H1 2012 -



Sources: GRTgaz, TIGF - Analysis: CRE

LNG IMPORTS MARKED A CHANGE IN THE PROCUREMENT WAY OF THE SOUTH ZONE

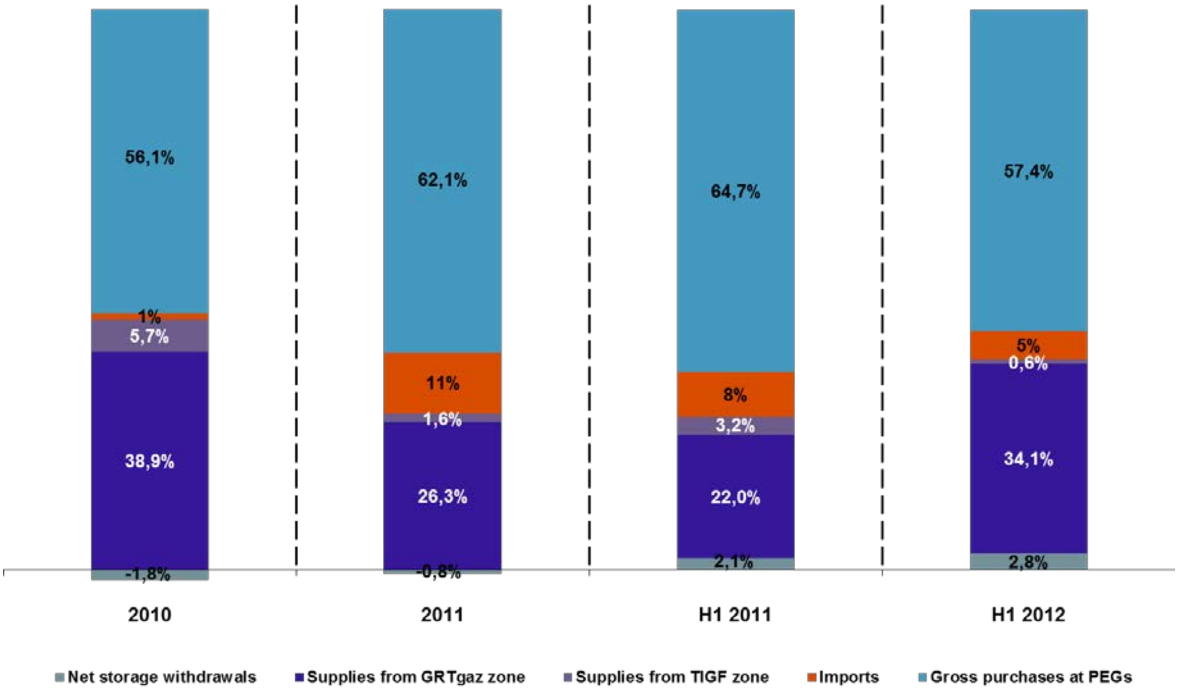
The supply structure of newcomers changed considerably between 2010 and 2011 (cf. Figure 89). Imports (LNG only) accounted for 11% of supply in 2011 as opposed to 1% in 2010 while the contribution of the North/South link waned significantly (from 39% to 26%) as well as the share of imports from the South West zone (6% to 2%). Following the trend of the national model, the wholesale market share in terms of the supplies of newcomers increased from 56% to 62%.

This trend was reversed in the first half of 2012. Compared to the first half of 2011, imports from the North zone via the North/South link rose sharply while the use of the South PEG and LNG imports remained relatively stable. New supplies from the North Zone were generally intended to cover the increase in sales at the South PEG, which increased from 46% to 52% of total market of newcomers between the first half of 2011 and the first half of 2012.

[48] The link between the South and the North is not taken into consideration as imports are still marginal from the South zone.

Figure 79: Supplies of newcomers in the South zone by source

- as a %, 2010 – H1 2012 -



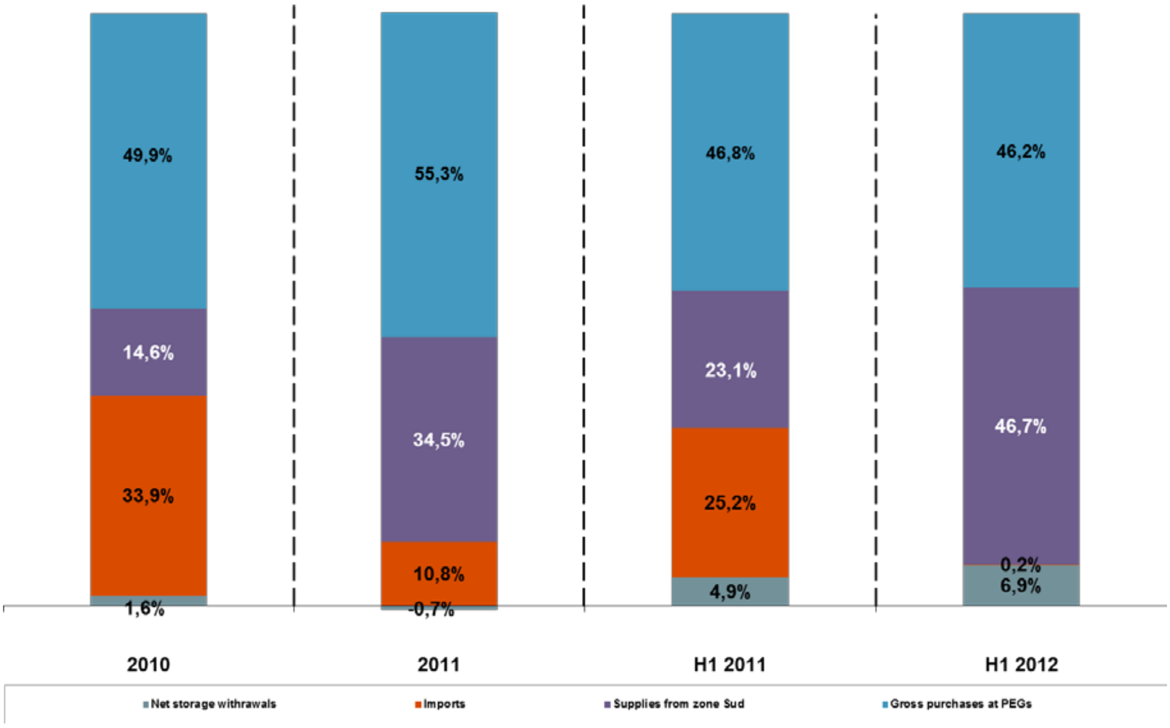
Sources: GRTgaz, TIGF - Analysis: CRE

THE SOUTH-WEST SUPPLIES FROM THE SOUTH ZONE GREATLY INCREASED IN 2011 AND THE FIRST HALF OF 2012

The supply structure of newcomers in the South-West zone changed dramatically between 2010 and 2011. Imports from the South zone more than doubled and newcomers went from importers to net exporters on the Spanish border, reducing imports via the Larrau and Biriatou interconnections by about 63%. Purchases at PEGs rose 29% between 2010 and 2011, contributing as much as 55% to the supplies of newcomers (cf. Figure 90).

Figure 80: Supplies of newcomers in the South-West by source

- as a %, 2010 – H1 2012 -

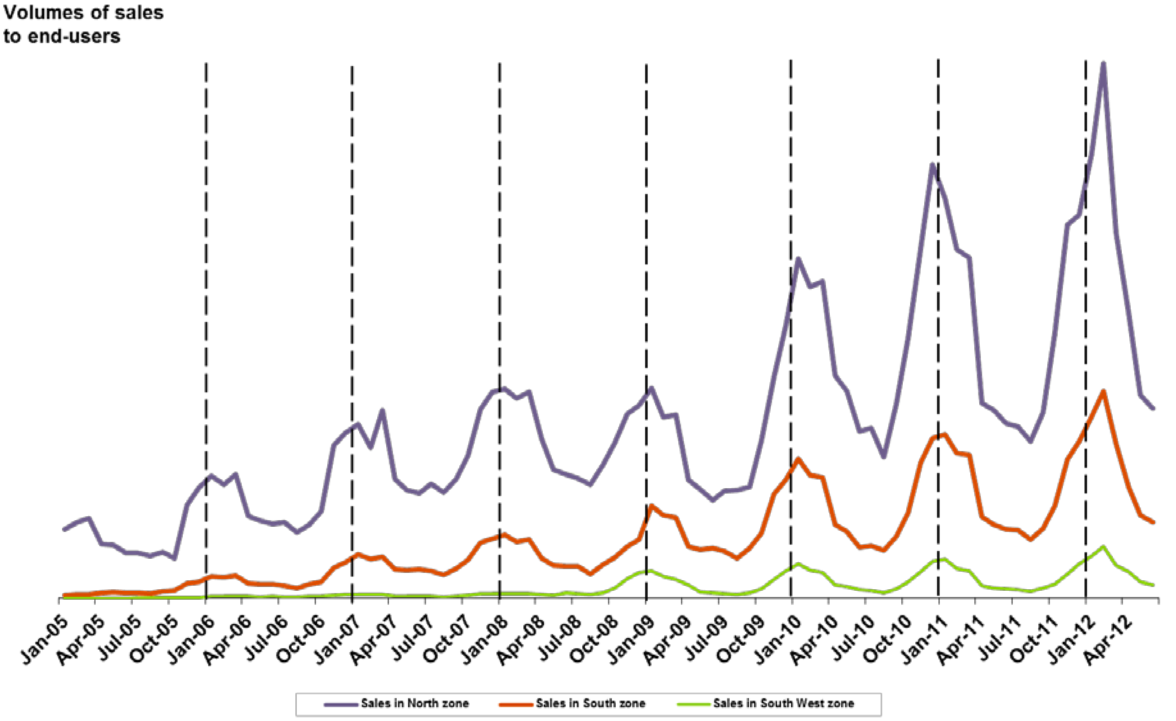


Sources: GRTgaz, TIGF - Analysis: CRE

SALES OF ALTERNATIVE SUPPLIERS MAINTAINED THEIR UPWARDS TREND IN 2011

Since 2009, the sales of alternative suppliers have continuously grown in all zones (cf. Chart 91). In total, they increased by 5% between 2010 and 2011 and by 22% between the first half of 2011 and the first half of 2012. The share of alternative suppliers in the supply of end customers increased from 22% to 28% between 2010 and 2011 from 26% to 30% between the first half of 2011 and the first half of 2012.

Figure 81: Monthly sales of alternative suppliers to end clients in relation to the three zones (2005 – H1 2012)



NB: Sales to end clients include deliveries to clients connected to the transport and distribution network
Sources: GRTgaz, TIGF

Section IV: Appendices

1. Glossary

ACER: Agency for the Cooperation of Energy Regulators, established by Regulation (EC) No. 713/2009 (third energy package).

EMIR: Regulation (EU) No 648/2012 concerning OTC derivatives, central counterparties and trade repositories published in the Official Journal of the EU on 27 July 2012.

MAD: Directive 2003/6/EC on insider dealing and market manipulation as published in the Official Journal of the EU on 12 April 2003. The directive and regulations are currently under review.

MIF: Directive (EU) on markets in financial instruments published in the Official Journal of the EU on 30 April 2004. Directive and Regulations are currently being revised.

REMIT: Regulation (EU) No. 1227/2011 concerning the integrity and transparency of wholesale energy markets published in the Official Journal of the EU on 8 December 2011. REMIT prohibits market abuse on the European electricity and gas markets and entrusts the monitoring of these markets to ACER, in cooperation with national regulators.

ELECTRICITY

MAIN POWER EXCHANGES IN EUROPE (ORGANISED MARKETS)

APX: Amsterdam Power Exchange spot market, mandatory for Dutch imports and exports, held by the APX-ENDEX group (www.apx.nl).

Belpex: Belgium Power Exchange spot market, held by the APX-ENDEX group (http://www.belpex.be/).

ENDEX: Dutch futures market, held by the APX-ENDEX group (www.apxendex.com).

EPD: EEX Power Derivatives, French and German futures markets, held by EEX and Powernext.

EPEX Spot France: non-mandatory French spot market, held by EEX and Powernext (www.epexspot.eu).

EPEX Spot Germany: non-mandatory German spot market, held by EEX and Powernext (www.epexspot.eu).

NordPool: non-mandatory Scandinavian market (www.nordpool.no).

Omel: quasi-mandatory Spanish pool (www.omel.es).

WHOLESALE PRODUCTS:

Base: 24 hours a day, 7 days a week.

Day-ahead: contract signed on one day for delivery the next day.

Future or Forward: standard contract signed for the delivery of a given quantity at a given price according to a defined schedule, requiring payment of a premium and a security deposit. The proposed schedule varies according to the organised market (weekly, monthly, quarterly, half-yearly or yearly). The schedule Y+1 corresponds to the calendar year following the current year.

Peak (continental Europe): from 8am to 8pm, Monday to Friday.

WHOLESALE MARKET SEGMENTS:

Wholesale purchases and sales (OTC) : Declaration of block exchanges (i.e. day-ahead nominations to RTE) which are not concluded at the Powernext platform.

End consumption: sales to sites as a balancing entity or in the form of blocks.

Imports and exports:

http://clients.rte-france.com/lang/fr/clients_traders_fournisseurs/vie/bilan_annu.jsp

Sales to network operators to compensate for their losses:

http://clients.rte-france.com/lang/fr/clients_traders_fournisseurs/vie/vie_perte_RPT.jsp

http://www.erdfdistribution.fr/electricite-reseau-distribution-france/fournisseurs-d-electricite/compensation-des-pertes-130105.html

VPP: Virtual Power Plant or capacity auctions organised by EDF following a decision by the European Commission (see Case DG COMP/M.1853 - EDF/ENBW).

http://encherescapacites.edf.com/accueil-com-fr/encheres-de-capacite/presentation-114005.html)

VPP base: products reflecting a power plant operating in base mode. The principle is that bidders pay a fixed premium (in €/MW) every month to reserve available capacity, and submit a capacity usage schedule to EDF on a regular basis. They then pay a striking price for each MWh withdrawn, which is close to the marginal cost for EDF's nuclear power plants. The pricing structure therefore takes the form of "fixed cost + variable cost".

VPP peak: products reflecting a power plant operating in peak mode. The principle is the same as for VPP base products, but the price paid for each MWh withdrawn is an estimate of the marginal cost for EDF’s power plants operating in peak mode. Given this high variable cost, the fixed premium paid by the bidders is lower than for the VPP base products.

Wholesale purchases and sales (OTC): notifications of exchanges of blocks, i.e. nominated quantities, to RTE on a given day for the following day, excluding transactions on Powernext.

OTHER TERMS:

Electricity system margin: difference between the available generation capacity and the estimated consumption.

CO_2

Banking: possibility for registrants to use an allowance issued at the beginning of a previous compliance period for compliance purposes.

BlueNext: carbon exchange based in Paris (www.bluenext.eu).

Borrowing: the borrowing of an allowance for compliance purposes, giving registrants the option to use an allowance granted at the beginning of the following compliance period (allowances for Year N are entered on the registers before 28 February, while on 30 April in Year N, allowances must be returned in respect of emissions for Year N-1).

Carbon dioxide (CO_2): main greenhouse gas, produced primarily from the combustion of fossil energies.

CDM: Clean Development Mechanism. This is one of the flexibility mechanisms under the Kyoto Protocol, which enables developed countries to finance emissions reduction or greenhouse gas sequestration projects in developing countries and to claim Certified Emissions Reduction units (CERs), which they can accrue to fulfil their own emissions reduction obligations. CDM projects aim to encourage the transfer of environmentally-friendly technologies and to promote sustainable development in developing countries.

CER: Certified Emissions Reduction units from projects deployed under the Clean Development Mechanism (CDM). Some countries and companies make use of credits from CDM projects and joint application projects to comply with their Kyoto objectives. **CITL**: Community Independent Transaction Log, a reporting platform managed by the European Commission, which incorporates the information submitted by the national registers on a daily basis.

ECX: *European Climate Exchange*, carbon exchange based in London (www.theice.com)

Emission allowance (or emissions permit): unit of account under the EU Emission Trading Scheme. The allowance is a quantity of GHG emissions (expressed in tonnes of CO_2 equivalent) that cannot be exceeded over a given period, which is granted to a country or an economic agent by an administrative authority (intergovernmental organisation or government agency).

Energy - climate package: a set of EU laws adopted late 2008, relating to energy and climate change.

ERU: *Emission Reduction Unit*, carbon credits generated by Joint Implementation (JI) projects, in accordance with the rules defined by the Kyoto Protocol. Companies falling within the scope of the European Union Emission Trading Scheme (EUETS) can use these credits to meet their greenhouse gas emission reduction obligations.

EUA: *European Union Allowance*, European emission allowance which authorises the holder to emit the equivalent of one tonne of carbon dioxide in greenhouse gases.

EU ETS: the European Union Emission Trading Scheme is an EU mechanism that aims to reduce the global emission of CO_2 and achieve the European Union's objectives under the Kyoto Protocol. It is the largest greenhouse gas emission trading scheme in the world.

GHG: greenhouse gas. Gas contributing to the greenhouse effect (see Greenhouse effect). Not all GHGs make the same contribution to the greenhouse effect. In order to compare the different greenhouse gas emissions, their effects are expressed in terms of tonnes of carbon dioxide.

Greenhouse effect: effect causing a natural process, which maintains the lower atmosphere at an average temperature of 15°C. It is linked to the presence of certain gases in the atmosphere, such as carbon dioxide and methane, which trap the radiation emitted by the Earth and reflect some of it in the direction of the sun. As the quantity of greenhouse gases produced by humans is too high, temperatures are increasing significantly.

Kyoto Protocol: international treaty aiming to reduce greenhouse gas emissions. The Protocol sets out detailed commitments for the industrialised countries concerned, for reducing or limiting greenhouse gas (GHG) emissions during the first, so-called commitment period, i.e. 2008-2012 (-5.2% in relation to 1990). To achieve this, these countries are obliged to define policies and national measures to fight climate change.

Phase III: the third phase of the EU ETS for the period 2013-2020, during which significant changes in terms of auctioning will take place.

Set aside: option of setting aside a share of the allowances for Phase III proposed by the European institutions, in order to curb the surplus of allowances of EU ETS.

GAS

Backhaul capacity: capacity on the main network enabling the shipper to make nominations in the opposite direction to the dominant direction of flow when the gas can only flow in one direction. It can only be used on a given day if the overall flow resulting from all of the shippers' nominations is in the dominant direction of flow.

Day-ahead product: contract signed on one day for delivery the following day.

DFO: 0.1% domestic fuel oil.

ERGEG (European Regulators' Group for Electricity and Gas): established by the European Commission under the Directives of 2003, the purpose of the ERGEG is to advise and assist the Commission in consolidating the domestic energy market, by helping to fully implement the European directives and regulations and to prepare future legislation in the areas of gas and electricity. The ERGEG comprises the European Commission and the independent regulators in the European Union's 27 member states. The member states of the European Economic Area, together with the candidate countries for EU membership, are also invited as observers. In order to meet its objectives, which are also the subject of a public work programme, the ERGEG has a comparable structure to that of the Council of European Energy Regulators (CEER). The ERGEG also widely consults the players in the energy sector on matters on which it is asked to put forward opinions. These opinions also involve the European Commission, which may then impose applicable restrictions through the Community's committee procedure.

Flexibility clause: provision set out in long-term import contracts giving the purchaser the option to reduce or increase the volumes withdrawn, within the limits of a pre-defined range.

Forward product: contract signed for the delivery of a given quantity at a given price according to a defined schedule.

Future product: a forward contract negotiated on an exchange (organised market). The proposed schedules vary according to the organised market (weekly, monthly, quarterly, half-yearly or yearly). The schedule Y+1 corresponds to the calendar year following the current year (delivery from 1 January to 31 December).

Gas exchange point (PEG): virtual point on the French gas transmission network at which shippers can trade volumes of gas. There is one PEG in each of the balancing zones on the French network.

Gas release: obligation on the part of a supplier to release a share of his gas resources to other suppliers for a given period. The general purpose of this operation is to allow competition to develop, by offering alternative suppliers the option to secure supplies without having to negotiate by private agreement with the traditional supplier.

Gas wholesale market coupling: mechanism based on one or more stock markets for comparing the supply and demand on the coupled markets and allocating concurrently and implicitly the interconnection capacities between the balancing zones (North and South in this instance). This mechanism would see benefits from some of the advantages of a merger between the balancing zones, without a need to invest heavily in infrastructures. The market coupling between GRTgaz's North and South zones respects the specific nature of the gas market: day-ahead market prices for gas are determined continuously (each transaction is made at a specific price) rather than by fixing, as is the case for electricity (a single auction is operated by the market to determine the price for each hour of the following day).

Herfindahl-Hirschmann Index (HHI): this is equal to the sum of the squares of the market shares of the companies, and is a measure of market concentration. The more concentrated the market, the higher the HHI index will be. Generally speaking, a market is considered to have a low concentration ratio if its HHI is below 1,000, and a high concentration ratio if its HHI is above 1,800.

HFO: heavy fuel oil with low sulphur content.

Intra-daily: market for contracts finalised on a given day for delivery on the same day or on the following day, if the transaction occurs after the main period of activity on the day-ahead market.

NBP (National Balancing Point): gas hub in the United Kingdom. Due to the large volumes traded on this notional hub, the prices used serve as an important reference for gas wholesale trading in Europe.

Net-back: mechanism for establishing the prices of long-term gas purchasing contracts, based on a logic of pricing natural gas in relation to the energies competing with it, and taking account of the cost of transporting the gas from the producer country to the consumer country.

Nomination: quantity of energy, expressed in kWh (GCV 25°C), notified by the shipper to the transport network operator each day the shipper asks the network operator to withdraw, transport or deliver energy. By extension, the verb "nominate" defines the action of notifying the transport network operator of a nomination.

Short term: the short-term market comprises the Day-ahead, Weekend, Weekly and Other products.

Spot: short-term market, including operations for delivery within a short time scale. The spot market covers intra-daily and day-ahead products.

Take-or-pay: clause in a gas or electricity supply contract, in which the seller guarantees the availability of the gas or electricity to the purchaser, who in return guarantees to pay for a minimum amount of energy, whether delivery is taken or not.

Uniform service: a cargo of LNG is regasified with constant emission over 30 days.

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