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Introduction

The Energy Regulatory Commission (CRE) monitors transactions by participants on the French wholesale electricity and gas markets since 2006 and it monitors CO_2 trading since late 2010 in cooperation with the AMF. This power is granted by Articles L. 131-2 and L. 131-3 of the Energy Code that provides:

- "*The Energy Regulatory Commission 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) and.*

- "*The Energy Regulatory Commission monitors greenhouse gas emission allowance transactions by suppliers, traders, and producers of electricity and natural gas ... as well as the contracts and financial futures instruments they underlie, to analyse the coherence of these transactions with the economic, technical and regulatory constraints of the activity of these suppliers, traders, and producers of electricity and natural gas*" (Article L. 131-3).

Therefore, in the context of its monitoring mission, CRE ensures that wholesale energy market 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 mission is now also part of the European Regulation on Energy Market Integrity and Transparency of 25 October 2011 (REMIT). The REMIT organises wholesale energy market monitoring, prohibits market abuse (insider trading and market manipulation), and requires market participants to disclose any inside information they hold. It entrusts market monitoring, at European level, to the Agency for the Cooperation of Energy Regulators (ACER) in cooperation with national regulatory authorities responsible for national investigations and sanctions. The Brottes law of 15 April 2013 expressly entrusted CRE with the mission of ensuring REMIT implementation and CoRDis jurisdiction to sanction any breaches of the regulation.

The energy markets are experiencing major change. The emergence of unconventional hydrocarbons in North America has profoundly changed the global balance of gas and oil production. American gas market prices dropped due to abundant supply causing a significant decline in imports of liquefied natural gas (LNG) from across the Atlantic and a strong incentive to produce electricity in gas-fired plants to the detriment of coal-fired plants. This significant decline in demand for coal in the United States significantly weakened global coal prices.

World energy demand is mainly driven by emerging markets, particularly China and India. More specifically, the Fukushima disaster in March 2011 had the effect of greatly increasing Japan's demand in LNG and raising new questions about the role of nuclear power in its energy mix. For its part, Europe is struggling to emerge from an economic crisis that has particularly affected it since 2008. The decrease in activity resulted in a significant reduction in emissions, a surplus of allowances, and a fall in CO_2 trading prices. Low CO_2 prices and the significant drop in coal prices are not an economic incentive to produce electricity from low-carbon fossil fuels such as gas. Moreover, the shut-down of German nuclear power plants was offset by the development of new capacity from renewable sources which is developing at a steady pace and changing the face of electricity.

French electricity and gas markets were influenced by the profound changes that have affected prices and electricity supply and generation patterns in 2012 and the first half of 2013. On the electricity market, the strong development of renewable energies in Germany, combined with the falling price of coal and CO_2, resulted in a significant drop in prices. Germany's influence was also reflected by a reversal of flow in the interconnection between the two countries in 2012 compared to 2011 with France becoming a net importer again. On the gas market, LNG supply fell sharply, mainly due to very high Asian demand, which led to tightening supplies in the south of France. Gas prices were also supported by the high price of petroleum products, even if the proportion of long-term import contracts indexed on the gas markets is now significant. Changing market conditions affected the profitability of certain infrastructures. Combined cycle gas plants (CCGP) are no longer profitable due to the drop in electricity prices and the rise in gas prices, particularly in the South zone. Gas storage is competing with other available sources of flexibility available and is losing shipper's interest. Some of storage facilities have been "mothballed" by their operators due to continuing financial difficulties.

This sixth CRE Monitoring Report includes a new section on the REMIT Regulation and its implementation. Developments in the French electricity, gas, and CO_2 wholesale markets in 2012 and the first half of 2013 are also presented. The report then reviews closed or ongoing investigations on the behaviour of certain participants and market events.

Overview

REMIT

- ### General context of the regulation

European Regulation on Wholesale Energy Market Integrity and Transparency of 25 October 2011 ((EU) Regulation No. 1227/2011), known as REMIT, organises wholesale energy market monitoring, prohibits insider trading, market manipulation, and requires market participants to disclose any inside information they hold (Section I, 1.1).

In this context, ACER's mission is to monitor wholesale markets to detect and prevent trading based on inside information and market abuse. National regulators monitor the markets at national level in cooperation with ACER and are responsible for conducting investigations of detected market abuse (Section I, 1.2).

- ### REMIT operational implementation

The adoption of implementing acts by the European Commission will mark the start of the operational implementation of the procedure under REMIT: collection of transactional and fundamental data will begin six months after the acts have been adopted and market participants will then be required to register in the national registry that regulators must implement within three months of the adoption of the acts (Section I, 2.1).

Participants must register with national regulators which will then transmit information to ACER to feed a European market participant Register. Under no circumstances will registration replace an authorisation to trade or supply authorisation which are issued by the competent authorities (Section I, 2.2).

Transactional and fundamental data will be collected by ACER from market participants or via trade repositories. To avoid double reporting, the data can then be shared with national regulators, financial regulators, and competition authorities in compliance with strict terms of confidentiality and data protection (Section I, 2.3).

REMIT entrusts powers of investigation and sanctioning to national regulators. In the event that ACER considers that a breach has a transborder impact, it may establish and coordinate an investigatory group constituted of representatives of national regulators concerned and, if it deems appropriate, representatives of financial regulators or any other relevant authority.

On the national level, the Brottes law of 15 April 2013 entrusts CRE with the mission of ensuring REMIT implementation and entrusts CoRDis jurisdiction to sanction any breaches of the regulation (Section I, 2.4).

- ### Implementation support

On 20 December 2011, 28 September 2012, and 29 October 2013, ACER published guidelines on the implementation of REMIT which provide insights on the definition of "wholesale energy products" and "market participants" as well as the concepts of "inside information" and "market abuse". Cases for exemption are also clarified.

The format of the market participant register was published on 26 June 2012 and CEER wrote to the main European associations to remind them which participants need to register and what the registration process is (Section I, 3.1).

CRE is actively involved in European work on REMIT implementation. In particular, it is the vice-chair of ACER and CEER working groups on market integrity and transparency and participates in the various working sub-groups. CRE contributed to drafting and assessing public consultations initiated by ACER as well as guidelines also published by it.

Finally, CRE is considering developing a dedicated web page summarising all the information on REMIT's content, implementation, and practicalities (Section I, 3.2).

ELECTRICITY MARKET

- **Electricity prices and trading**

During 2012, the volumes traded on the intermediated wholesale electricity markets declined by 17% compared to 2011, to stand at 578 TWh. This decline is mainly noted in the futures markets. This is consistent with the level of economic activity in 2012 but can also be related to a reduced reliance on the market since the introduction of ARENH and the end of VPP auctions. This downward trend in intermediated wholesale market activity however reversed in 2013: the volumes traded in the first half (308 TWh) increased by 12% compared to the first half of 2012 (Section II, 1.1).

French net exports of volumes traded at interconnections dropped in 2012. This development is related to nuclear availability which deteriorated compared to that of the previous year and the significant volumes imported during the cold wave in February 2012. Net exports in the first six months of 2013 improved slightly due to an increase in volumes exported to Belgium and the UK (Section II, 1.2).

In 2012, the average spot price stood at 46.9 €/MWh in baseload and 59.5 €/MWh in peakload, respectively down by 4% and 2% compared to 2011 despite the significant price spikes in February 2012. In the first half of 2013, marked by significant negative prices for 16 June 2013, average baseload and peakload prices stood at 43.8 €/MWh and 55.3 €/MWh, respectively down by 10% and 11% compared to the same period in 2012. Over the whole period, trends in French spot prices were in line with fundamentals and especially with the electricity system margin indicators (Section II, 2.1).

For 2011 and the first half of 2012, the rate of convergence of French and German prices on the spot market significantly improved to 64%. For 2012 and the first half of 2013, it fell to 56%. The hourly convergence rate tended to deteriorate sharply during the winters of 2012 and 2013 (Section II, 2.1).

On the futures market prices continued to drop in 2012 and the first half of 2013 in the wake of coal and CO_2 prices. The one-year price differential between France and Germany dropped sharply in 2011 and the French prices were under German prices from June 2011. However, the price spikes in February 2012 ended this inversion of the one-year price *spread*. The price differential then tended to increase (Section II, 2.2). During the recent period, Y+1 French product transactions tended to polarise around 42 €/MWh which is the ARENH's price level. This polarisation reflects trade-offs performed by participants due to ARENH optionality. The resulting price differential with the German Y+1 price are consistent with France-Germany price differentials on the spot market. CRE analyses transactions performed on the French Y+1 product in detail as part of its monitoring missions.

- **Electricity generation and generation data transparency analysis**

2012 was marked by less nuclear availability, particularly during the summer of 2012, and therefore less nuclear generation. The nuclear sector therefore recorded a generation rate of 73% in 2012 which was lower than that in 2011 (76%). In the first half of 2013, nuclear generation remained stable at 207.7 TWh. A clear improvement in the availability of nuclear power plants in the second quarter of 2013 was noted due to a decrease in unplanned outages (Section II, 3.1).

Heavy rainfall led to increased use of hydropower power plants in 2012. Total hydropower electricity generation stood at 63.8 TWh representing an increase of nearly 26% compared to 2011 (Section II, 3.2). generation from fossil fuel fired power plants decreased by 7% compared to 2011 due to lower gas and oil generation (-22%). However, coal generation increased by 35% (Section II, 3.1).

Marginality of the different generation technologies changed significantly in 2012 compared to 2011: nuclear power marginality duration fell sharply due to low availability, while border marginality duration increased sharply (Section II, 3.2).

The generation data transparency procedure established by the UFE and RTE was supplemented on several occasions in 2010 and 2011. Since 1 January 2012, the Transmission System Operator transparency platform provides a page for producers to disclose any supplementary information to data already published on projected availability and unplanned outages. This change facilitates compliance with transparency obligations imposed by the 714/2009 Regulation of 13 July 2009 and the obligation to publish inside information under the REMIT. In 2013, another improvement was made by increasing the frequency of information updates on the projected availability of generation facilities. However, the data transmission rate deteriorated in 2012: for projected availability, 81% of the necessary information was transmitted in 2012 against 84% in 2011. CRE also continued to monitor the difference between projected day-ahead availability and actual availability for nuclear facilities. In 2012, this difference fell compared to that observed in 2011 (Section II, 3.3).

- **Analysis of *day-ahead* market offers and adjustment mechanism**

Analysis of the offers submitted on the EPEX SPOT Auction platform shows, as in 2011, that the volume offered on the spot market is correlated to the electricity system margin (difference between available generation capacity and projected consumption) (Section II, 4.1).

EPEX SPOT market electricity prices are more sensitive to changes in volumes of purchase or sale offers in France than in Germany, reflecting a greater risk of strain on the balance between supply and demand (Section II, 4.1).

CRE conducts special monitoring of the difference between spot market prices and marginal costs of EDF facilities. This study is based on the hours for which EDF offers are assumed to determine the auction price. On average, the price - cost difference was 22% in 2012 against 5% in 2011(Section II, 4.1).

For 2012, although volumes were down 10% for upward adjustments[1], they were up 15% on downward adjustments. In all, RTE enabled 7.7 TWh of adjustments, or 1.7% of consumption (excluding transmission

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[1] See definition of "Adjustment Mechanism" in the Glossary

system operator losses), against 7.4 TWh in 2011. Lower adjustment volumes reflect a tendency for participants to provide excess supply during periods of high consumption, especially during the cold wave in 2012 (Section II, 4.2).

CO_2 market

- **CO_2 market monitoring**

The European Commission, the European Parliament, and the Council favour, in the context of revising MIF (Markets in Financial Instruments) and MAD (Directive on Market Abuse) texts, the inclusion of allowances in the list of products qualified as financial instruments and consequently also in the scope of financial regulation (Section III, 1.1).

The national carbon market was marked by the close of Bluenext exchange on 5 December 2012. These developments have changed the scope of supervision of CRE and the AMF without affecting the relevance of regular exchanges between the two authorities. CRE and the AMF continue to work closely with each other on regulatory developments and monitoring methods. Operationally, CRE also collects data from the English stock exchange ICE ECX via the AMF and its British counterpart, providing CO_2 prices and transactions on the futures and spot markets (Section III, 1.1).

CRE regularly collects data on carbon market transactions for participants falling within its scope. However, transactions on broker platforms are still not disclosed. Therefore, in March 2012, CRE launched a bilateral collection of transactions performed in 2011 from participants active on the French electricity and gas markets. Pending the introduction of generalised data collection at European level, CRE could submit further ad hoc data requests to participants if market events justify it (Section III, 1.2).

- **Development of the institutional framework and future prospects**

The European Commission proposed to postpone (or "*backload*") the auction of 900 million carbon allowances on 12 November 2012. This backloading proposal was followed by a period of uncertainty on the CO_2 market regarding its potential implementation. Discussions between the European institutions are currently under way on the final version of the backloading text. The European Commission also published a report in November 2012 in which it identified six structural measures that could be used to reform the European Union Emission Trading Scheme (EU ETS) and reduce the surplus of allowances in circulation. A public consultation was launched on the subject and several meetings with stakeholders were held early 2013 (Section III, 2.1).

Phase III of the EU Emissions Trading Scheme (EU ETS) entered into force on 1 January 2013 and will end on 31 December 2020. This period is characterised by the auctioning of about 50% of emission allowances against less than 4% in Phase II. Regarding the electricity sector, 100% of allowances should be auctioned, except for some Member Countries which have been exempted for 2013 by the European Commission (Section III, 2.2).

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

Total EUA[2] and CER[3] volumes traded on CO_2 markets increased by 24% in 2012 to reach about 12 billion tonnes of CO_2. In the first half of 2013, while EUA trading volumes continued to increase, CER trading volumes dropped significantly, mainly due to some CER products being excluded from the EU ETS market from May 2013, due to new compliance requirements with Phase III rules (Section III, 3.2).

Analysis of 2012 market transaction data shows that the market almost exclusively consisted of futures products and financial players had a dominant role on the markets (Section III, 3.3). Moreover, further analysis following CRE's collection of data for 2011 showed the important role of market intermediaries and in particular brokers (about 25% of the market) in the total volume of trade within CRE's scope of monitoring (Section III, 3.4).

In 2012, the allowance offer exceeded demand once more, in line with the trend observed since 2009. Excess allowances, calculated as the difference between allocated allowances (free allowances and auctioned allocation) and actual emissions, increased from 410 Mt in 2011 to 814 Mt in 2012. In this context, the EUA allowance price dropped by 43% in 2012 to stand at an average of 7.34 €/t. In the first half of 2013, prices dropped again to an average of 4.24 €/t. The price of CO_2 allowances experienced significant daily variations which can be explained by the uncertainty around the adoption and entry into force of the backloading proposal (Section III, 4.2).

Low CO_2 and coal price levels contributed to widening the gap between *clean spark spread* and *clean dark spread* (which respectively measure the theoretical short-term profit of gas-powered plants and coal-fired power stations) in favour of the latter and encourage electricity generation from coal. Producers of electricity from gas are currently experiencing major difficulties (Section III, 4.3).

GAS MARKET

- **Development of trade**

Volumes traded on the intermediated wholesale market fell by 19% in 2012. Although the spot market experienced increased activity, partly due to the different episodes of stress on the French system during the period, the volumes traded on the futures market fell by about 26%. Activity on the futures market was particularly affected by the European economic crisis and a decrease in gas-fired power plant activity. Moreover, the French futures market was subject to competition from other more liquid European futures markets, including TTF (Holland) and NCG (Germany) (Section IV, 1.2).

The majority of intermediated trading was done at the PEG Nord which remains the least concentrated zone on the French market. Although the PEG Sud's traded volume increased it experienced a higher concentration mainly due to increased needs of some participants following tensions in the South of France. PEG TIGF remained the least developed zone of the French market and concentration levels remained very high (Section IV, 1.3).

The number of storage and LNG terminal user fell sharply in 2012. Although tensions on the global LNG supply explain why French terminals are less used, European market conditions and particularly the narrow price

[2] See Glossary for the definition of "EUA"

[3] See Glossary for the definition of "CER"

differential between summer and winter contracts have resulted in lower storage capacity subscriptions (Section IV, 1.3).

- **Wholesale price**

French and European wholesale market price trends in 2012 and the first half of 2013 were particularly influenced by international markets. The disconnection between the European, Asian, and North American markets continues to grow due to Asian tension on the LNG market and the development of unconventional gas in the United States (Section IV, 2.1.1 and 2.1.2).

The trends in oil prices continued to influence the gas market through long-term contracts despite the significant indexation of the gas market prices. Brent prices fluctuated significantly due to a tense geopolitical context and uncertainties in the macroeconomic stability of the Eurozone. The price of oil products remained at a historically high level helping to maintain disconnection between indexed oil prices and gas prices. This disconnection decreased slightly following the renegotiation of long-term contracts (Section IV, 2.1.3).

The French market followed the trend of the main European market places (NBP and TTF). The European spot market was marked by a price spike caused by a cold snap covering most of Europe in February 2012. There were also price spikes in March 2013 in a context of tightened European supply. Moreover, as a result of the tensions observed in March 2013, a price spike occurred specifically in France on 9 April 2013 (Section IV, 2.2.1).

The French spot market was characterized by particular tension in the South zone. A significant spread between PEG Sud Nord and PEG Sud emerged in April 2012 in the context of congestion on the GRTgaz North-South link primarily caused by the significant drop in LNG imports to the South of France and high exports to Spain. These tensions continued into the first half of 2013 (Section IV, 2.2.2).

On the futures market, low summer/winter seasonalspreads affected European storage capacity sales which are struggling to compete with other sources of flexibility. In France, this situation led Storengy to "mothball" two of its sites and raises concerns about the security of supply during the 2013/2014 winter on the French system (Section IV, 2.3).

- **Market outlook**

Projects to reinforce the French network, such as Hauts-de-France and Arc de Dierrey, continued in 2012. These projects will primarily relieve transport congestions in the heart of the French network, connect the new LNG terminal in Dunkerque, and create a new interconnection with Belgium. In addition, reinforcements in Larrau (Spanish border) allowed 165 GWh/d of capacity in both directions to be marketed on 1 April 2013, contributing to the integration of the French and Spanish markets (Section IV, 3.1).

A single PEG Nord was created on 1 April 2013 by merging the North H and North B zones. CRE also requested TSOs GRTgaz and TIGF work on creating a common GRTgaz South - TIGF PEG by 2015. CRE has also launched a cost-benefit analysis of the investment required to implement a single PEG France in 2018 (Section IV, 3.2).

The third European legislative package on energy continues to be applied and implemented on gas transmission networks. CRE, as part of ACER, continues to work on developing several network codes, including those relating to procedures for managing congestion and capacity allocation and transmission network balancing mechanisms. Most of the mechanisms provided for in these network codes will be implemented in France between 2013 and 2015. Moreover, ENTSOG has drafted a network code on the interoperability of transmission networks and should be drafting the code on the harmonisation of gas transmission network user tariffs in 2014. This work aims to bring together European gas markets in a target "hub to hub" model (Section IV, 3.3).

DETAILED ANALYSIS

In 2012 and the first half of 2013, CRE conducted a number of detailed analyses on market events or the behaviour of specific participants. Some of these analyses are still under way.

Electricity market

- **Price spike in February 2012**

The first quarter of 2012 was marked by concomitant price spikes on electricity and gas markets at the beginning of February 2012 when a severe cold wave descended on the whole of Europe. Hourly prices during the EPEX SPOT France auction for delivery on 9 February were close to 1,000 €/MWh for several hours in the morning, even reaching 1,938.5 €/MWh at 10 am. The baseload price was set at 367.6 €/MWh on Thursday, 9 February and 147.3 €/MWh the next day: a second auction procedure was initiated for these two days. On 10 May 2012, CRE deliberated on the investigations into the electricity price spikes in February 2012[4].

CRE concluded that tension between supply and demand was responsible for the high prices and that the balance between supply and demand had been obtained by the maximum usage of most interconnections except those with Italy and Switzerland. The use of interconnections on these boundaries could be improved by introducing market coupling.

CRE also noted that, for the auction held on 8 February, the baseload price resulting from the second auction was higher than the price initially obtained, with significant differences during hours when prices were very high. CRE therefore made a number of recommendations to the EPEX SPOT to provide all members with sufficient transparency on these findings and improve, if necessary, the second auction procedure.

CRE also completed specific work on the case of a participant whose changes in the order book during the second auction did not improve the supply-demand balance. This work focused on the conformity of its trading activity in relation to REMIT obligations, as transactions were made on 8 February following the unexpected shut-down of one of its generation power plants. In this context, and because the volumes purchased were lower than the corresponding losses caused by the unavailability of the plant, CRE concluded that these interventions came within the scope of the exemption defined in Article 3.4.b)[5] of the REMIT. However, CRE reminded this market participant of its obligations to disclose of inside information (which must be prompt and sufficiently) and provide ACER and the relevant regulator pertinent information on its transactions. CRE also reminded the participant that a declaration is available on the ACER website to help market participants meet their obligations.

- **Negative prices in June 2013**

Electricity prices for delivery on 16 June 2013 were negative with an average of -40.99 €/MWh and a minimum at -200 €/MWh between 5 and 8 am. These were record price levels on the French market. The day

[4] View CRE's deliberation of 10 May 2012 on its website

[5]This Article excludes from the prohibition of insider trading any transactions the"*purpose of which is to cover the immediate physical loss resulting from unplanned outages*".

was characterised by low consumption, good availability of French-Belgian generation means, but also a significant proportion of non-flexible generation such as hydraulic run-of-river power in France and Switzerland in the morning and solar and wind power in Germany in the afternoon. Interconnections with neighbouring markets were rationally used, except on the Swiss border, once again highlighting the advantages of integrating this market into the coupling mechanism.

CRE services are currently analysing the events of that day and are questioning several participants in particular on their transactions.

- **Product Y+1 futures price level**

2012 and the first half of 2013 were also marked by a substantial fall in futures prices, particularly for the 2014 baseload calendar contract. After starting 2012 at nearly 55 €/MWh, the price of electricity for delivery in 2014 declined steadily to stabilise at 42 €/MWh between May 2013 and late June 2013 while the German prices continued to fall. 42 €/MWh is the price set by ARENH on 1 January 2012 to give alternative suppliers access to electricity supply from the incumbent supplier at a fixed price. In this context, CRE analysed the behaviour of electricity wholesale market participants to ensure that their actions were not biased by this ARENH requirement. In particular, the transactions and orders by the various participants are being analysed.

Gas market

- **Price spike in February 2012**

During the cold snap in February 2012, the prices on the French spot market reached 40.5 €/MWh and 45.7 €/MWh at PEG Nord for delivery on 7 and 8 February respectively which were the highest prices since 2006. Although prices rose 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 of this market event[6].

CRE considered that tension between supply and demand explained the high prices on the various European spot markets but also noted that better use of interconnection capacity could have helped reduce price differentials between the French market and those of neighbouring countries. CRE considered that this tension was exacerbated by the limited output of the German network to France and the Italian authorities' decision to require shippers to maximise their gas imports to Italy. Analysis of individual participant behaviours did not reveal any behaviour that did not correspond to economical and technical constraints.

- **South zone prices and differential with PEG Nord**

Following major tensions in the South zone during the second quarter of 2012, CRE analysed price formation in the South zone[7]. While prices in the South were in line with those of the North zone in 2010 and 2011, the spread between PEG Nord and PEG Sud increased sharply to an average of 1.65 €/MWh in 2012 and 2.26 €/MWh in the first half of 2013. This increase was accompanied by high volatility with a spike of 7.62€/MWh

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[6] View CRE's deliberation of 26 May 2012 on its website

[7] Cf. the press release of 27 July 2012

on 24 July 2012. As part of its analysis, CRE collected all the transactions by major market participants on PEG Sud and PEG TIGF as well as data on the use of gas infrastructures with the various operators for the period between March and August 2012.

CRE adopted a decision on gas pricing in the South of France on 29 May 2013[8]. In this deliberation, CRE mentioned that tightening supplies in the South zone was mainly due to low LNG entries in France and higher exports to Spain. Other factors could increase the level and volatility of the spread; in particular, the lack of transparency on the use and availability of certain infrastructures, liquidity problems in the South France market and atypical behaviour of the market coupling mechanism. CRE encouraged short-term measures, such as marketing additional daily firm capacity on the GRTgaz North-South link, improving the functioning of market coupling, and improving the transparency of LNG terminal use[9], which could improve the price formation process and reduce volatility. Investments to reduce transmission congestion which are currently under study will provide a long-term solution.

CRE services are completing the detailed analysis of participant behaviour during March and August 2012. Given the persistence of price differentials and volatility in 2013, CRE continues to monitor price formation specifically in the southern zone.

- **PEG Nord prices on 9 April 2013**

The PEG Nord experienced a price spike on 9 April 2013 with transactions at over 42 €/MWh which represented a differential of over 10 €/MWh with neighbouring markets. This price spike was particularly high at the end of the day and generated a significant differential between the *Powernext Gas Spot End of Day* (41.48 €/MWh) and *Powernext Gas Spot Daily Average Price* (34.52 €/MWh) indexes. The day was marked by maintenance on the Dunkirk and Taisnières entry points. CRE services are, however, focusing analysis on this day.

- **CO2 market**

The end of 2012 and the first half of 2013 were marked by several announcements on EU ETS policy and regulatory orientations, in particular on backloading 900M of allowances during Phase III. Prices strongly fluctuated during voting by the European Parliament's ITRE and ENVI committees as well as voting by its Plenary Session on the backloading measure. Substantial price variations were recorded during institutional announcements on 23 January, 19 February, 16 April, and 3 July of 2013. CRE services are analysing price movements and market participant behaviour on all of these dates.

[8] View CRE's deliberation of 23 May 2013 on its website

[9] View CRE's deliberation of 20 June 2013 on its website

SECTION I: REMIT implementation

1 GENERAL CONTEXT OF THE REGULATION

1.1 REMIT establishes a supervisory framework adapted to the energy sector

Since 28 December 2011, CRE has performed energy wholesale market monitoring under the regulation on wholesale energy market integrity and transparency ((EU) regulation No. 1227/2011 of 25 October 2011) called REMIT.[10] This European regulation is directly applicable to all Member countries.

REMIT organises wholesale energy market monitoring, prohibits market abuse (insider trading and market manipulation), and requires market participants to disclose any inside information they hold[11]. The Regulation establishes a supervisory framework for the electricity and gas sectors and related to the physical characteristics of supply and demand. It interacts with the financial regulation which is currently under review and provides that wholesale energy market monitoring takes interactions with the carbon market[12] into account even if emission allowances are not qualified wholesale energy products.

REMIT applies to market participants, namely any natural or legal person carrying out transactions on the wholesale energy markets. The wholesale energy products concerned are contracts for the supply of electricity or natural gas where delivery is in the Union and contracts relating to the transportation of electricity or natural gas tin the Union on both the spot and derivative markets.

REMIT does not apply to contracts for supply and distribution to end-customers, with the exception of final consumers consuming over 600 GWh per year. Finally, prohibition on market manipulation and insider dealing does not apply to wholesale energy products that are financial instruments subject to the regulation on market abuse (MAR). However, these products are still covered by the obligation of public disclosure of inside information under REMIT.

1.2 Role of ACER and national regulators

REMIT entrusts the monitoring of wholesale energy markets to the Agency for the Cooperation of Energy Regulators (ACER) in collaboration with national regulatory authorities (NRAs).

ACER monitors wholesale markets to detect market abuse. NRAs are responsible for implementing market abuse prohibitions under REMIT and conducting investigations in case of detection of market abuse. Investigations involving several markets and regulators are coordinated by ACER. NRAs can also monitor markets at national level in cooperation with ACER. They cooperate with each other and with the ACER to complete their missions[13].

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[10] Cf. (EU) regulation no. 1227/2011 of 25 October 2011 on wholesale energy market integrity and transparency

[11] Cf. Articles 3, 4, and 5 of the REMIT

[12] Cf. Articles 1 and 10.3 of the REMIT

[13] Cf. Article 16 of the REMIT

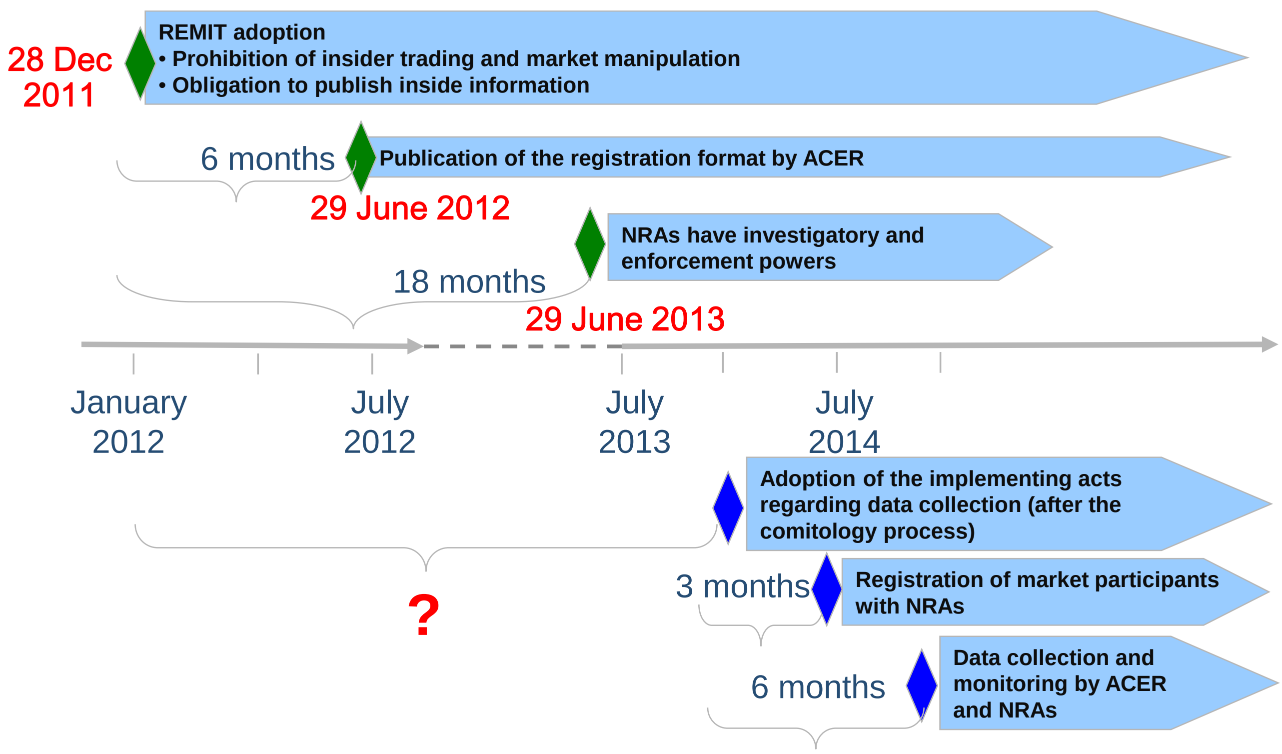
In this context, a Memorandum of Understanding was established between ACER and each NRA[14]. It details the practical arrangements for cooperation between energy regulators, NRA notifications to ACER in the event of a breach of REMIT, ACER queries to NRAs when requesting information or opening an investigation, and the coordination of cross-border investigations when required.

People professionally organising transactions are also involved in detecting market abuse under REMIT and must warn NRAs of any suspected breaches on the market[15].

2 REMIT IMPLEMENTATION

2.1 REMIT implementation schedule

Figure 1: REMIT entry into force and implementation schedule



Source: ACER

Prohibitions on insider trading and market manipulation as well as the obligation to publish inside information have been applicable since REMIT's entry into force (Section I, 1.1).[16]

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[14] This Memorandum has not yet been made public.

[15] Cf. Article 15 of REMIT

At the end of 2011, an ACER notification platform was provided to market participants[17] to allow them to declare the cases of exemption of the prohibitions and obligation under REMIT[18] and report suspected breaches on the market.

On 26 June 2012, ACER published a decision on the registration format of market participants with the NRAs[19] which has five sections (Section I, 2.2).

Each NRA should have implemented investigatory and enforcement powers by 29 June 2013.[20] CRE has had these powers since April 2013 (Section I, 2.4).

The European Commission's adoption of the implementing acts will mark the start of operational implementation of the mechanism provided for in REMIT. NRAs will then have three months to put in place the register. Market participants must register before data collection starts, i.e. six months after the implementing acts have been published[21].

2.2 Focus on national registration of participants

To be able to trade on wholesale energy markets, market participants must first register with the NRAs. Market participant registration is done in a national register implemented by each NRA. NRAs may choose to either use the registration system developed by ACER or their own registration system. They must transmit information in their register to ACER which is in charge of establishing a European register of market participants[22]. ACER will make part of the European register public[23].

ACER's decision of 26 June 2012 concerning the registration format specifies the content of information required for each market participant:[24]

1. general information and a unique identifier called the ACER code,
2. information on natural persons linked to market participant (responsible for trading decision, responsible of operational decision, contact person for communications),
3. information on the ultimate controller or beneficiary of the market participant,
4. information about the corporate structure of the market participant,
5. information on delegated parties for reporting on behalf of the market participant.

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[16] Cf. Articles 3, 4, and 5 of REMIT

[17] http://www.acer.europa.eu/remit/Pages/Important-information-for-market-participants.aspx

[18] Cf. Articles 3.4 and 4.2 of REMIT

[19] http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Directors%20decision/ACER%20Decision%2001-2012.pdf

[20] Cf. Article 13 of REMIT

[21] Cf. Article 22 of REMIT

[22] Cf. Article 9.3 of REMIT

[23] Cf. Article 9.3 of REMIT

[24] http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Directors%20decision/ACER%20Decision%2001-2012.pdf

There will initially be two stages to the registration. Participants must first complete sections 1, 2, 3 and 5 of the register. They will then provide the data required by section 4 (company structure and related undertakings) once ACER has published part of the register, including the ACER code.

It is important to note that the registration of participants in ACER's European registry does not constitute either an authorisation nor a licence to trade on wholesale energy markets.

2.3 Focus on data collection

ACER is responsible for collecting data relative to market participants[25]. ACER can collect this data from trade repositories. To avoid double reporting, data can then be shared with national regulators, financial regulators, and competition authorities. In this context, strict terms of confidentiality and data protection are required.

Market participant obligations regarding data collection will enter into force six months after the implementing acts have been adopted.

Market participants' data collection concerns transactional and fundamental data (capacity and use of facilities for generation, consumption, transmission, storage, LNG, and unavailability of facilities). Details on the scope, content, and reporting format will be defined by the European Commission's implementing acts.

2.4 National investigation and enforcement powers

In the case of suspected market abuse or non-disclosure of inside information, ACER may request a national regulator to open an investigation. The NRA is then required to investigate and, if necessary, sanction the market participant(s) in an effective, proportionate, and dissuasive manner[26]. In the event that ACER considers that a potential breach could have a cross-border impact, it may establish and coordinate an investigatory group constituted of the national regulators concerned and representatives of financial regulators or any other relevant authority.

Member states had until 29 June 2013 to ensure that their NRAs had sufficient powers to ensure the enforcement of REMIT prohibitions and its obligation[27]. In France, the Brottes law of 15 April 2013[28] amended the Energy Code to provide CRE with the task of ensuring compliance with REMIT and to provide The Committee for disputes and sanctions (CoRDiS) with the task of sanctioning breaches according to REMIT. Thereby, Article L. 131-2 of the Energy Code provides that: *"The Energy Regulatory Commission shall ensure compliance by any person who enters into transactions in one or more wholesale energy markets of the prohibitions provided for in Articles 3 and 5 of (EU) Regulation No. 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency and the obligation provided for in Article 4 of the said regulation".* Article L. 134-25 of the Energy Code provides that: *"The Committee for disputes and sanctions may* […] *sanction breaches defined in Articles 3.4 and 5 of (EU)*

[25] Cf. Articles 8 and 10 of REMIT

[26] Cf. Articles 13 and 18 of REMIT

[27] Cf. Articles 3, 4, and 5

[28] Law no. 2013-312 of 15 April 2013 on preparing for the transition to a low-energy system and containing various provisions on water and wind power pricing

Regulation No. 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency or any other breach that could seriously affect the functioning of the energy market".

3 IMPLEMENTATION SUPPORT

3.1 ACER and CEER work

ACER oversees a number of REMIT implementation working groups and task forces which national regulators actively contribute to. In parallel, the Council of European Energy Regulators (CEER) has also established a working group on energy market transparency and integrity.

ACER has published guidelines on REMIT implementation for national regulators. It was initially published on 20 December 2011[29] and then a second version was published on 28 September 2012[30] which, among other things, specified the definitions of "wholesale energy products" and the concepts of "insider information" and "market abuse". Another version was published on 29 October 2013[31] with an entire section devoted to market participant registration.

ACER launched a consultation on the registration format early 2012 before publishing its decision on 26 June 2012[32]. In the second half of 2012, ACER launched a consultation on the data to collect under REMIT (transactions, insider information, and fundamental data). ACER submitted recommendations to the European Commission regarding data collection in order to prepare the implementing acts. At the end of 2012, the European Commission also launched a public consultation on the data to be collected. In the first half of 2013, ACER launched public consultations on regulated information services and registered reporting mechanisms ("*RIS*" and "*RRM*") as well as on technical data collection standards[33].

ACER should also submit a report on its activities under REMIT to the European Commission at least once a year. ACER's first report should be released in quarter four of 2013.

Finally, on 17 June 2013, CEER sent a letter regarding the market participant registration phase to European associations for distribution to their members[34]. The letter lists the categories of market players which need to register and specified registration information and timeline.

3.2 Work at CRE's level

CRE contributes significantly to implementing REMIT, including its role as vice-chair of ACER and CEER working groups on market integrity and transparency. It actively participates in various task-forces working on the

[29] See http://www.acer.europa.eu/remit/Documents/1st_edition_ACER_guidance.pdf

[30] See http://www.acer.europa.eu/remit/Documents/2nd%20edition%20of%20ACER%20Guidance%20on%20the%20application%20of%20REMIT.pdf

[31] See http://www.acer.europa.eu/Media/Events/Public_workshop2_on_REMIT%20implementation/Document%20Library/1/REMIT%20ACER%20Guidance%203rd%20Edition_FINAL.pdf

[32] See http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Directors%20decision/ACER%20Decision%2001-2012.pdf

[33] See http://www.acer.europa.eu/Official_documents/Public_consultations/Pages/PC_2013_R_01-on-technical-requirements-for-data-reporting-under-REMIT--.aspx

[34] CEER sent the newsletter to ENTSO-E, ENTSOG, LEBA, EFET, EUROPEX, EURELECTRIC, EUROGAS, and EACH

principles of supervision, market governance, and IT. It also attends meetings of experts attached to each of these task forces that bring together ACER representatives, energy market participants (producers, traders, exchanges, etc.), and national regulators. Ad hoc meetings are also held with various departments of the European Commission (Directorate general for markets and Directorate general for energy) to discuss the evolution of energy market regulation.

CRE contributed to various ACER public consultations on the registration format and the type of transactional and fundamental data to be collected[35]. On this last point, CRE analysed and evaluated some of the consultation responses[36] and contributed to the drafting of recommendations on data collection that ACER submitted to the European Commission on 23 October 2012[37].

CRE participated in the drafting of the first two editions of the guidelines published by ACER in December 2011 and September 2012 [38] (Section 3.1). It also participated in the drafting of the third edition of ACER guidelines published in October 2013[39], in particular, regarding market participant registration to national regulators and exemptions under the REMIT.

CRE is considering creating a web page dedicated to REMIT providing relevant information on content, implementation, and practicalities to market participants. It is also planning to communicate with market participants subject to REMIT at national level.

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[35]See http://www.acer.europa.eu/remit/Documents/Evaluation%20of%20responses%20-%20ACER%20Recommendations.pdf

[36] See http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Directors%20decision/ACER%20Decision%2001-2012.pdf

[37] See http://www.acer.europa.eu/remit/Documents/Recommendations%20on%20REMIT%20Records%20of%20transactions.pdf

[38] See links in Section 3.1

[39] See links in Section 3.1

SECTION II: Electricity wholesale markets

1 DEVELOPMENT OF THE MAIN WHOLESALE MARKET SEGMENTS

Activity on the wholesale electricity markets is mainly related to producer optimisation of the flexibility of their means of generation, trading operations, cross-border trades, and market participant hedging of their projected consumption in order to satisfy customer needs.

In 2012, the decrease in nuclear generation (-4% or 16.2 TWh) due to low nuclear plant availability during the summer and lower gas and oil generation (-7% or -8.3 TWh) was offset by the increase in hydropower generation (+13.2 TWh), coal generation (+4.7 TWh), and the increasing development of renewable sources (+23.4% or 4.7 TWh). In all, generation volumes totalled 542 TWh, stagnating compared to the volumes observed in 2011.

The relatively cold temperatures (especially in February, April and November), and the number of working days in 2012 which was a leap year (impact +1.5 TWh) contributed to the increase in domestic electricity consumption. This stood at 453 TWh (end-client consumption excluding pumping and Transmission System Operator losses) which represents an increase of 9 TWh compared to the volume consumed in 2011. Electricity trade was marked by the decline in nuclear availability and the increase in domestic consumption related to the major cold wave in February 2012. This resulted in increased recourse to imports (+10.5 TWh) and therefore significantly less net exports (-11.6 TWh compared to 2011).

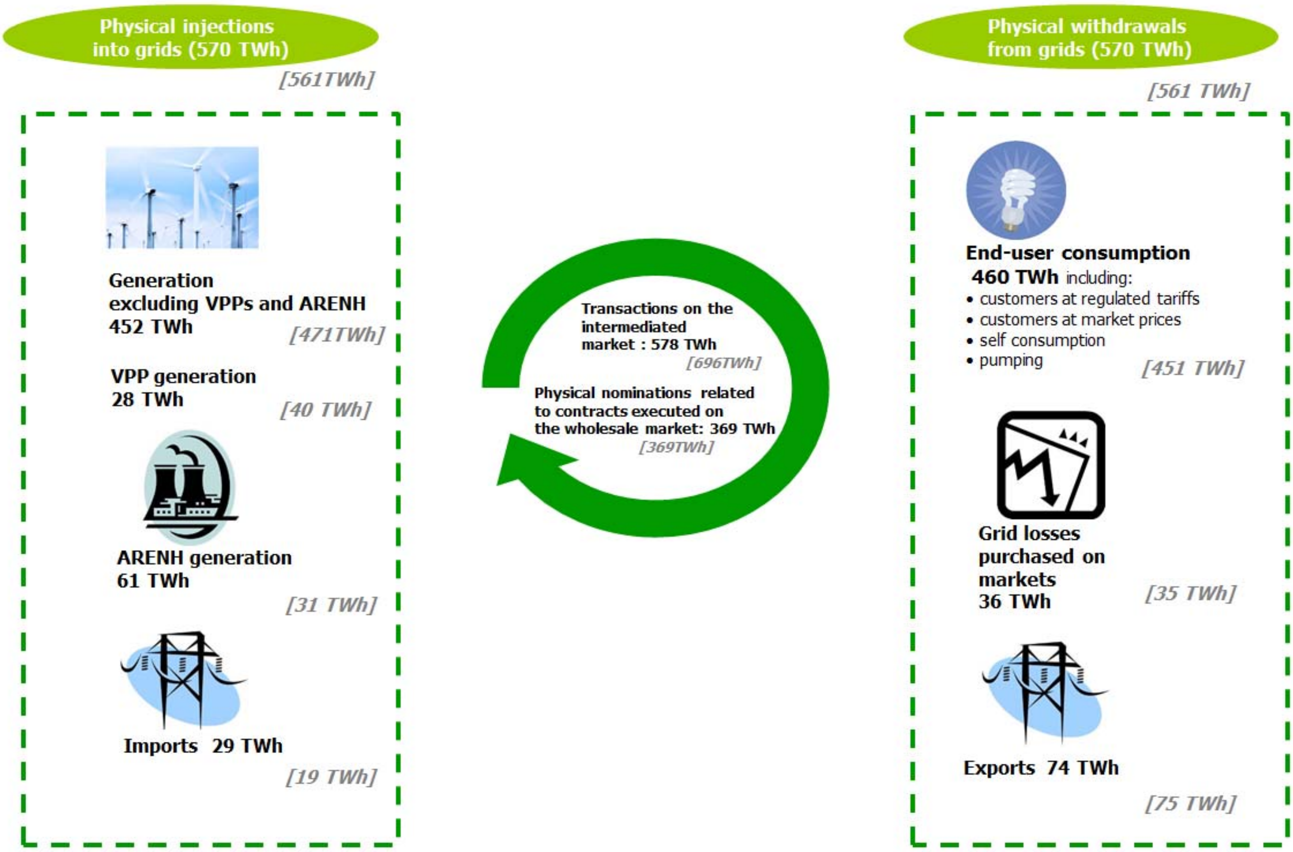
Trade on the intermediate wholesale electricity markets reached 578 TWh which represented a decrease of 17% compared to 2011. This drop involved in particular trade in futures products.

Physical deliveries between participants, as a result of negotiated contracts on the wholesale markets (intermediate and bilateral), represented 369 TWh in the course of this year, stagnating compared to 2011. figure 2 shows a simplified view of these various flows for 2012 and 2011 (figures in brackets).

Figures 2a and 2b also present EDF's electricity balance published by the group in the presentation of its interim results[40]. These figures show that, as in 2011, EDF held a net purchasing position on the wholesale market in 2012 and the first half of 2013.

[40] View the presentation of EDF's 2012 interim results on its website

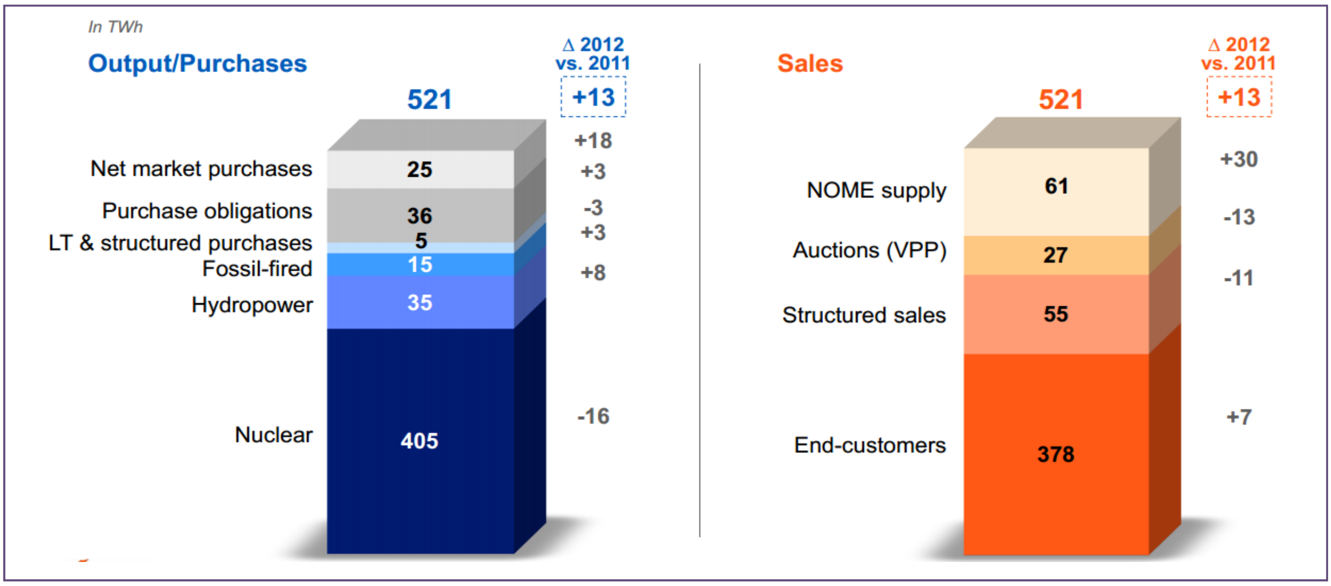
Figure 2: Energy flows between French wholesale electricity market upstream and downstream segments in 2012 [*Year 2011*]



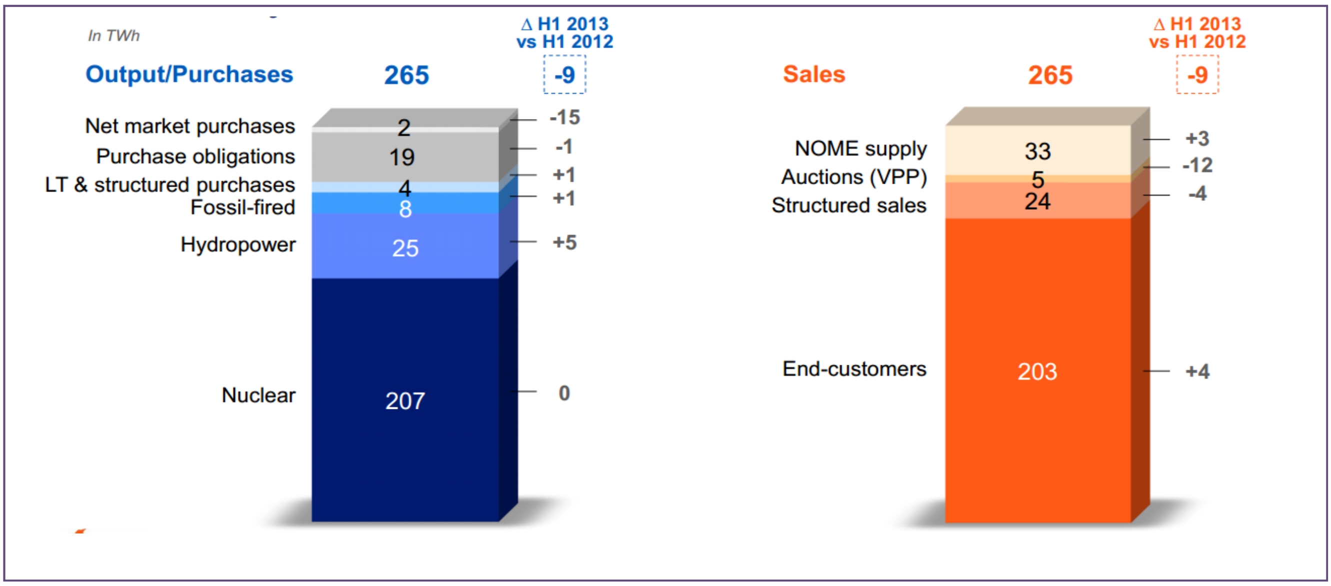
Source: RTE – Analysis: CRE

Figure 3: Electricity balance of the incumbent operator

a. Electricity balance for 2012



b. Electricity balance for the first half of 2013



Source: EDF

1.1 Sustained downturn of the intermediated wholesale market in 2012 but growth in the first half of 2013

Activity on the French intermediated wholesale market includes transactions concluded on organised markets and intermediated OTC (brokerage platforms). This covers most of the activity on the French wholesale electricity market and the remainder is materialised by direct bilateral transactions between market participants.

Compared to 2011, volumes traded on the wholesale market fell to stand at 578 TWh for 229,003 transactions in 2012 (Table 1). Relating to macro-economic data, electricity trading represented approximately 126% of French consumption in 2012, i.e. a decrease of nearly 19 points compared to 2011.

In 2012, although volumes traded on the intraday product increased (+14%) and stagnated on the Day-Ahead product (Day-Ahead continuous and Day-Ahead auction) (-1%), they fell sharply on the futures market (-19%) (Table 1). This downward trend in futures market activity however reversed in 2013: the volumes traded in the first half (265 TWh) increased by 14% compared to the first half of 2012.

Table 1: Trades

a. Volume of transactions

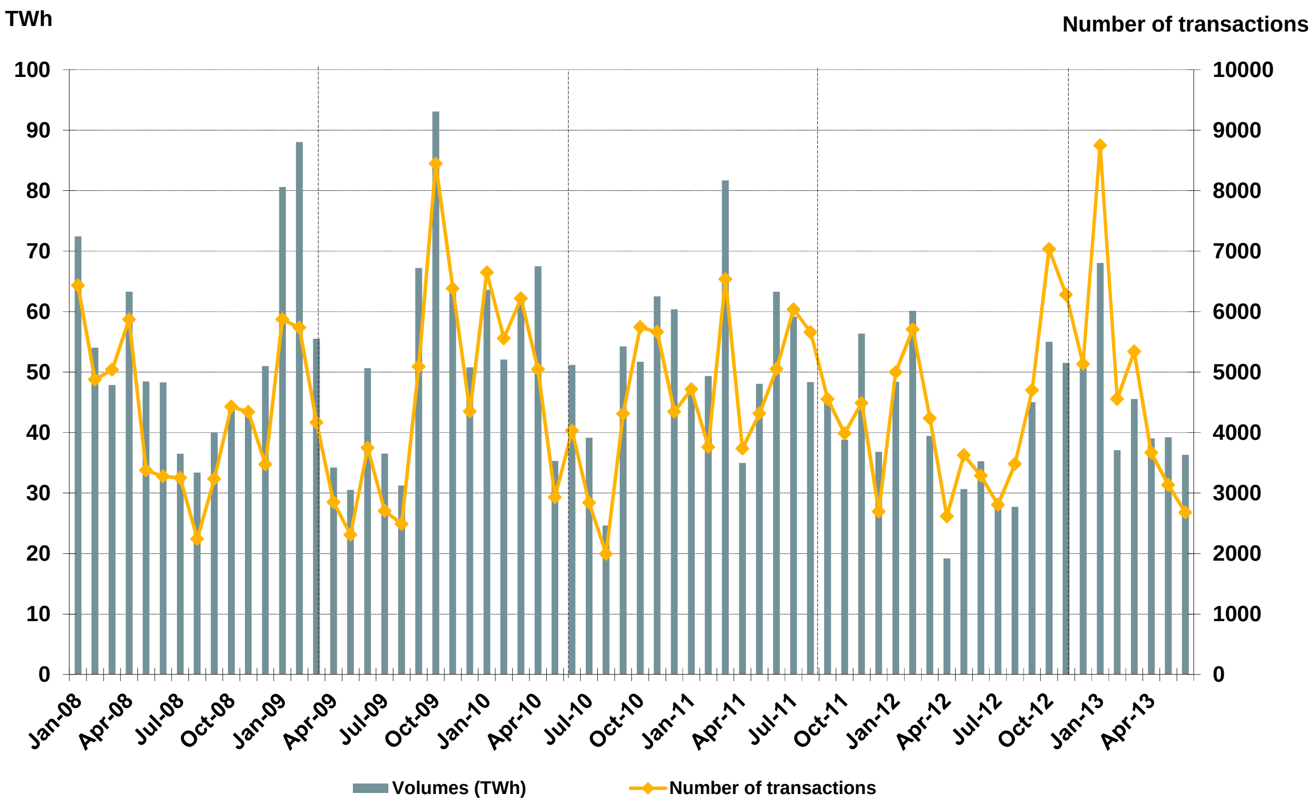
Volume (TWh)	2011	2012	H1 2012	H1 2013
Intraday	2.9	3.4	1.6	1.9
Day-Ahead Continuous	22.8	22.1	11.4	11.6
Day-Ahead Auction	59.7	59.3	29.8	29.3
Futures Market	610.1	493.6	232.4	265.3
Total	**695.5**	**578.3**	**275.2**	**308.2**

b. Number of transactions

Number of transactions	2011	2012	H1 2012	H1 2013
Intraday	92,486	124,055	57,601	75,901
Day-Ahead Continuous	49,830	51,038	26,531	25,460
Day-Ahead Auction	n.a.	n.a.	n.a.	n.a.
Futures Market	55,530	53,910	24,448	28,120
Total	**197,846**	**229,003**	**108,580**	**129,481**

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

Figure 4: Monthly variation in volumes and number of transactions on the intermediated futures market



Source: Brokers, EPD France; Analysis: CRE

table 2 breaks down the quarterly trends in trading by product type (monthly, quarterly, annual) by comparing 2012 to 2011. During the first three quarters of 2012 the fall in trade was driven by products of all maturities (weekly to yearly) while being more pronounced for quarterly and yearly products and “Other” products including short-term products such as weekly. This drop in trading volumes is related to the economic downturn which has led participants to shorten their prospects on the futures markets. Beyond the macroeconomic context, several specific factors could explain this decline and, in particular, are raised by market participants:

- less recourse of the market since the introduction of ARENH (e.g. sourcing of losses). EDF stated in its financial communication issued when its 2012 interim accounts were released that "net volumes sold on the wholesale markets were down 30.1 TWh compared to the first half of 2011 mainly due to sales to ARENH in the first half of 2012 (30.2 TWh)" [41],
- the end of VPP auctions (Virtual Power Plants, Section II, 1.4).

In the last quarter of 2012, the downward trend observed in the first three quarters was reversed. The increase in volumes was mainly due to a sharp increase in activity on trading platforms that concentrated most of trade in futures products; however, the increase on the exchange was less pronounced.

[41] View EDF's interim financial report of 30 June 2012 on its website

Table 2: Quarterly breakdown of volumes traded by product in 2012 and 2013 (in TWh)								
Maturity	Q1 2012	Q1 2011	Q2 2012	Q2 2011	Q3 2012	Q3 2011	Q4 2012	Q4 2011
M+1	20.4	16.9	14.5	17.8	23.0	25.5	33.1	12.2
M+2	6.2	6.5	5.5	5.6	5.4	8.7	6.8	3.8
M+3	2.1	2.4	2.4	4.1	1.9	3.6	2.7	1.9
Q+1	19.0	21.1	12.9	18.1	21.1	25.9	18.3	8.9
Q+2	12.9	14.2	7.7	23.7	5.3	9.2	6.4	8.4
Q+3	14.9	21.9	2.0	7.1	0.5	6.4	4.7	5.4
Q+4	4.0	4.1	0.7	2.6	0.6	3.7	3.5	4.1
Y+1	30.9	48.0	12.0	36.4	18.6	28.2	34.9	49.7
Y+2	11.2	15.7	6.1	7.4	6.6	9.2	11.4	15.4
Other	26.5	27.5	21.2	23.4	18.8	33.3	36.6	22.2
Total	**148.0**	**178.3**	**85.2**	**146.3**	**101.9**	**153.6**	**158.5**	**132.0**

Source: Brokers, EPD France; Analysis: CRE

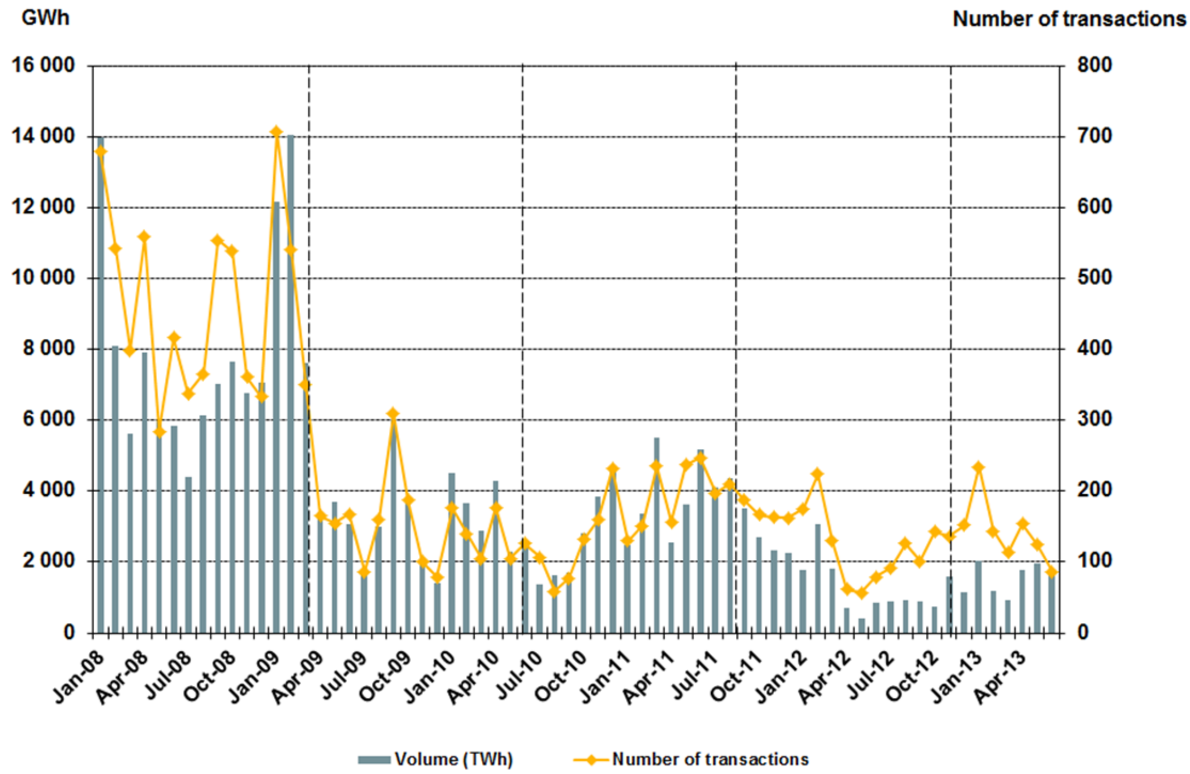
table 3 breaks down the quarterly trends in trading by product type (monthly, quarterly, annual) by comparing the first half of 2013 with the first half of 2012. The increase recorded in the first half of 2013 was primarily driven by volumes of monthly products traded in the first quarter and yearly products in the second quarter. This growth occurred in a context of falling electricity, coal, and CO_2 futures prices (Section II, 2.2).

Table 3: Quarterly breakdown of volumes traded by product in the first halves of 2012 and 2013 (in TWh)						
Maturity	Q1 2013	Q1 2012	Q2 2013	Q2 2012	H1 2013	H1 2012
M+1	33.9	20.4	16.0	14.5	49.8	34.9
M+2	7.6	6.2	4.7	5.5	12.4	11.8
M+3	2.3	2.1	2.1	2.4	4.3	4.5
Q+1	10.4	19.0	9.8	12.9	20.2	31.9
Q+2	9.1	12.9	11.9	7.7	21.1	20.6
Q+3	8.8	14.9	2.5	2.0	11.3	17.0
Q+4	3.4	4.0	1.0	0.7	4.5	4.7
Y+1	29.5	30.9	28.2	12.0	57.8	42.9

Y+2	7.7	11.2	18.0	6.1	25.7	17.3
Other	37.9	26.5	20.4	21.2	58.3	47.7
Total	**150.7**	**148.0**	**114.6**	**85.2**	**265.3**	**233.2**

Source: Brokers, EPD France - Analysis: CRE

Figure 5: Monthly variation in volumes and number of transactions on the organised futures market



Source: EEX Power French Derivatives

- **The number of balancing responsible entities active on the French market decreased in 2012**

The number of balancing responsible entities active on the French market decreased in 2012. This decrease is explained in particular by the drop in the number of financial players and French and European newcomers (Table 4). These categories increased once more in the first half of 2013.

Table 4: Balancing responsible entities active on the French market

Classification	Number of active RE						
	2007	2008	2009	2010	2011	2012	H1 2013
Integrated European producers	34	34	37	35	34	34	32
Financial traders	24	31	23	25	29	25	28

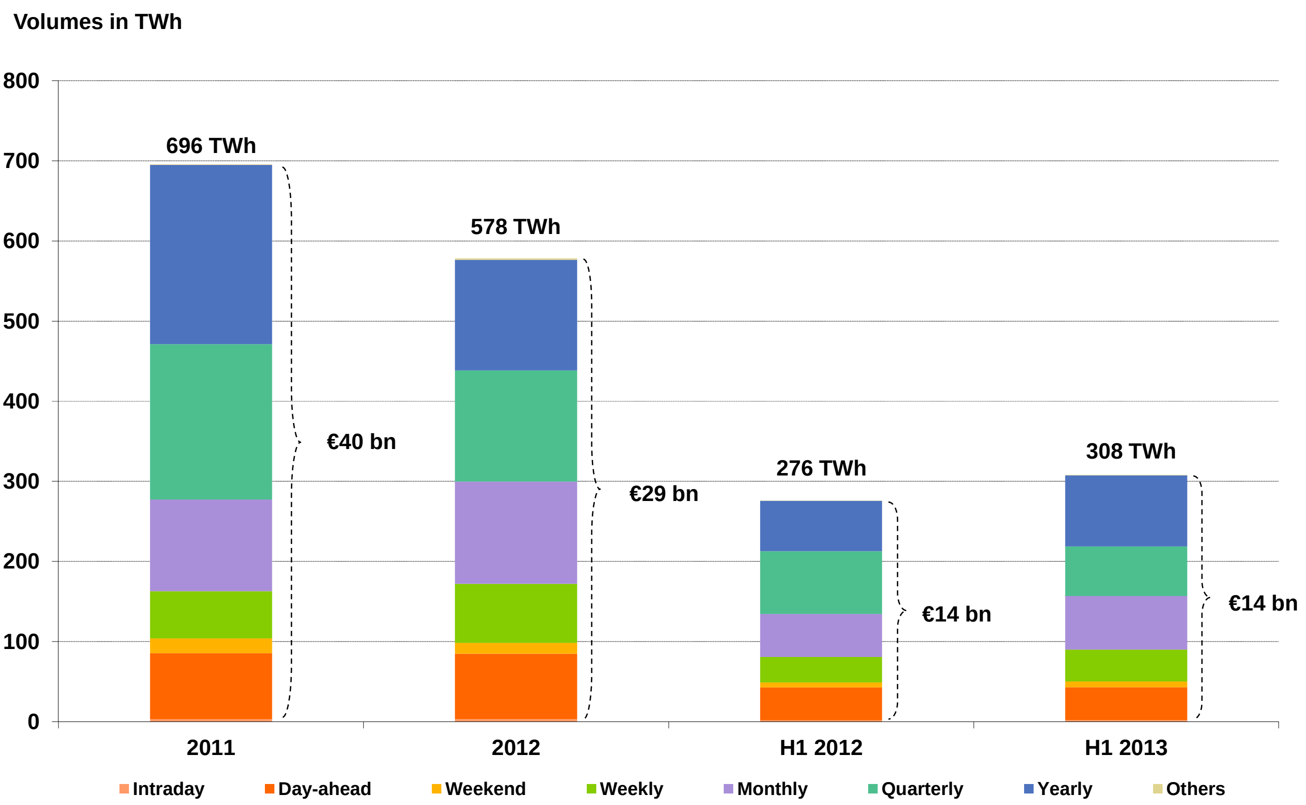
European newcomers	13	16	18	23	29	26	29
French producers	8	9	8	6	5	7	7
French newcomers	5	6	6	5	10	6	7
Industries	5	6	4	5	6	7	8
ELD[42]	5	4	4	4	4	4	4
Other	3	4	4	7	6	4	5
Total	**97**	**110**	**104**	**110**	**123**	**113**	**120**

Data: RTE – Analysis: CRE

- **The volume of trade on the French electricity wholesale market stood at 29 billion Euros in 2012**

The value of trade on the French electricity market decreased year on year, from 40 billion Euros in 2011 to 29 billion Euros in 2012 (Figure 6). This decrease in value is mainly due to a decrease in the overall volume traded of about 117 TWh and a decrease in the price of spot and futures products (Section II, 0).

Figure 6: Volume and value of trade by product (in bn €)

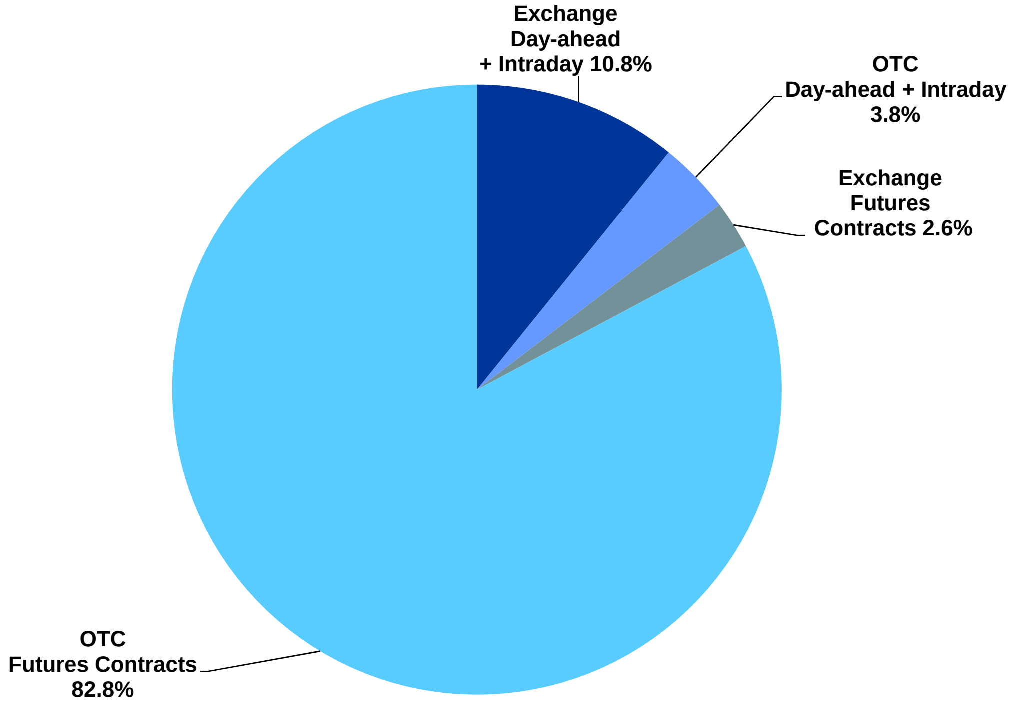


Source: Brokers, EPEX SPOT France, EPD France – Analysis: CRE

[42] Local distribution companies

Because of their intrinsically higher value, transactions of futures products represent 86% of the value of transactions made on the markets. Moreover, the majority of trades were made by mutual agreement with OTC trading platforms accounting for approximately 87% of the value traded on the market, with the remaining 13% traded on organised markets (Figure 7)

Figure 7: Trade broken down by platform and by term (%) in 2012



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

1.2 Cross-border net traded volumes dropped in 2012 due to reduced nuclear generation availability and a major cold wave during the winter

- **Decrease in net exports mainly due to an increase in volumes imported in 2012**

Table 5 gives the maximum values observed for interconnection capacity (NTC) on the various borders in 2012. Interconnection capacity between France and neighbouring countries represented about 12% of installed generating capacity in France for exports and 11% for imports. This percentage complies with the criterion published in the Barcelona European Council's conclusions of March 2002 intended to establish country interconnection levels at 10% of installed capacity.

In 2012, volumes of electricity traded at borders represented 73.3 TWh in exports and 29.1 TWh in imports (Table 6). Net exports, at 44.2 TWh, fell sharply compared to 2011 (net exports of 55.8 TWh). This decresase is mainly related to the substantial increase in volumes imported, from 18.6 TWh in 2011 to almost 29.1 TWh in 2012, while volumes exported only decreased by 1 TWh.

Table 5: Maximum import and export capacities between France and neighbouring countries in 2012 (in MW)

	Germany	Belgium	Spain	Italy	United Kingdom	Switzerland	Total[43]
Imports	4,950	1,600	1,550	995	2,000	2,600	13,695
In % of French installed capacity	3.9%	1.3%	1.2%	0.8%	1.6%	2.1%	10.8%
Export	2,800	3,650	1,550	2,495	2,000	3,200	15,695
In % of French installed capacity	2.2%	2.9%	1.2%	2.0%	1.6%	2.5%	12.4 %

Source: RTE - Analysis CRE

Table 6: 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
2012	13.9	5.2	-8.7	1.9	13.8	11.9	4.0	5.9	1.9	0.6	15.7	15.1
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
H1 2013	8.3	2.3	-5.9	1.0	8.8	7.8	2.7	2.4	-0.3	1.1	8.7	7.7

[43] It should be noted that import/export country capacity cannot be used simultaneously with their maximum at a given time.

	United Kingdom			Switzerland			Total		
in TWh	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
2012	1.9	8.4	6.5	6.8	24.4	17.6	29.1	73.3	44.2
H1 2012	1.4	3.8	2.4	3.0	12.5	9.4	15.2	36.4	21.2
H1 2013	0.8	5.2	4.3	3.8	12.1	8.3	17.7	39.6	21.9

Source: RTE - Analysis CRE

The increase in imports is particularly related to flows from Germany and Switzerland which respectively increased by 6.1 TWh and 4.7 TWh compared to 2011. Imports also slightly increased on the Spanish border (4 TWh against 3 TWh in 2011). Imports were reduced from the United Kingdom (-1 TWh) and Italy (-0.2 TWh) while levels remained stable from Belgium. The increase in imports is related to the major cold wave in February 2012, and lower nuclear availability recorded in 2012.

Exports varied differently on the borders. The drop in exports to Germany (-5.1 TWh) was offset by higher flows to Belgium (+6.2 TWh). Exports to Spain and the United Kingdom increased slightly while those to Italy decreased slightly. As a result of these variations, total exports actually changed very little decreasing by only 1.1 TWh compared to 2011.

In the first half of 2013, net exports were slightly higher (+0.6 TWh) compared to the same period in 2012, increased exports (to the United Kingdom and Belgium in particular) were however partially offset by an increase in imports (from Germany, Italy, and Spain). Note that in March 2013, imports from Germany were at a record 1.85 TWh (Figure 8) which had not been seen since March 2008. However, France became a net exporter to Germany (0.19 TWh) for the first time since September 2011 in June 2013.

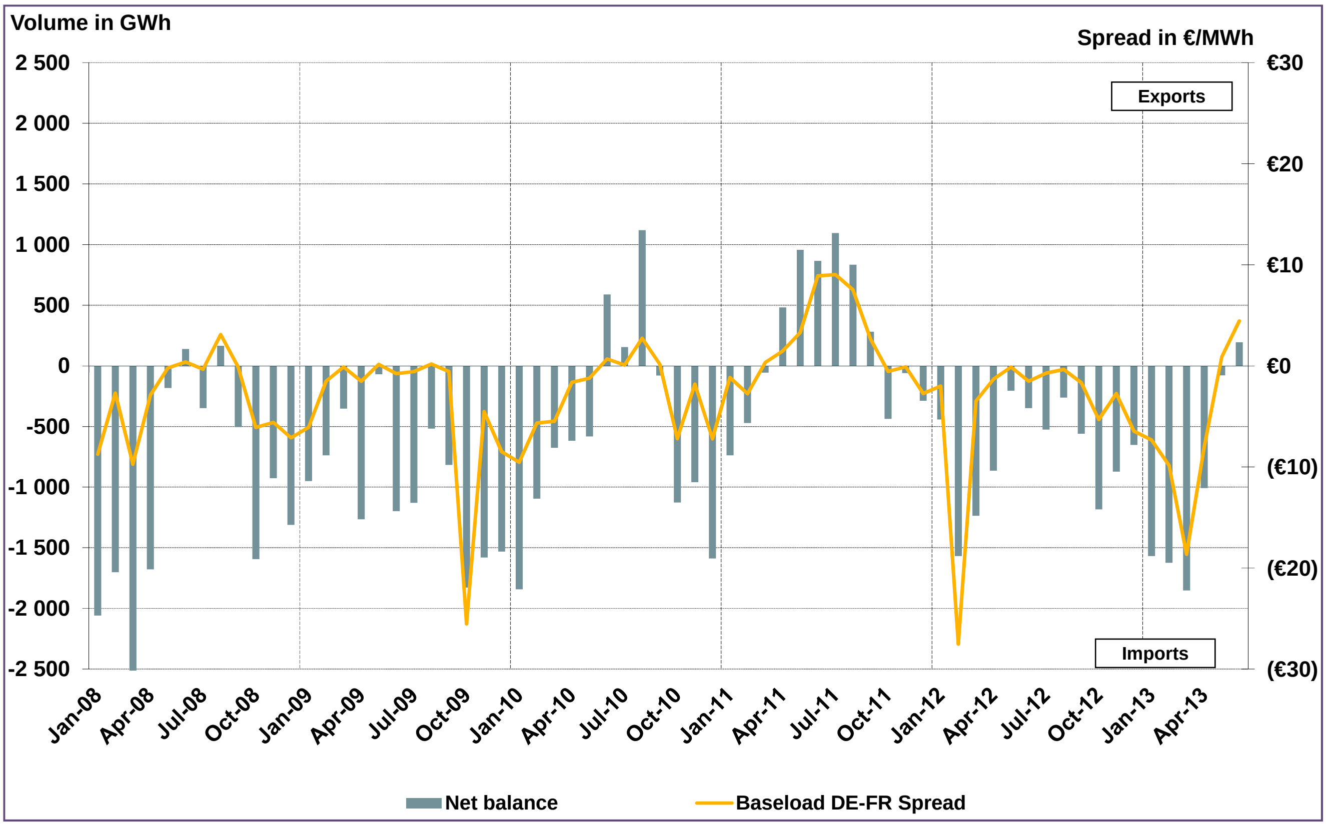
The highest drops in net exports were recorded on the German and Swiss borders with price differentials against France. In contrast, the export balance improved to Belgium (due to extended unavailability of two Belgian nuclear power plants, Doel 3 and Tihange 2, since June and September 2012 respectively) and the United Kingdom (due to the cost of generating electricity from gas which is higher than from coal).

- **Cross-border flows are consistent with price differentials**

From a general perspective, trade balances on all borders were consistent with the direction of average price differentials in relation to France (day-ahead, baseload). Monthly trends in net cross-border trade balances were correlated with trends in price differentials and were particularly clear for Germany and the UK (Figure 8). A disconnection occurred at France - Belgium border: the unavailability of two Belgian nuclear power plants generated increased flows from France saturating interconnection capacity despite the market coupling mechanism in place and generating a price differential. CRE's 2012 "Cross-border electricity exchanges" report extensively reviewed interconnection use and management[44].

Figure 8: Net export balance and price differential with neighbouring countries

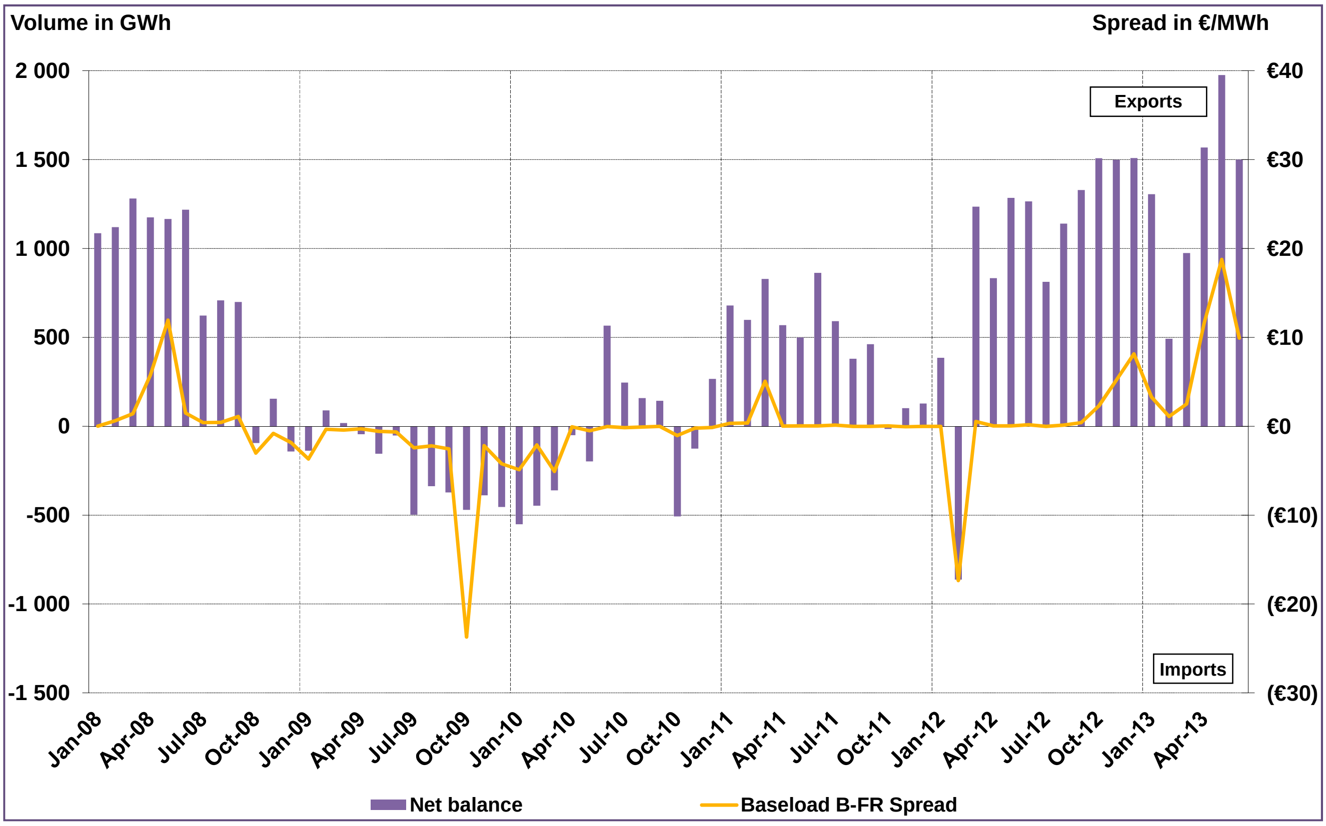
a. France - Germany



Source: RTE, EPEX SPOT - Analysis: CRE

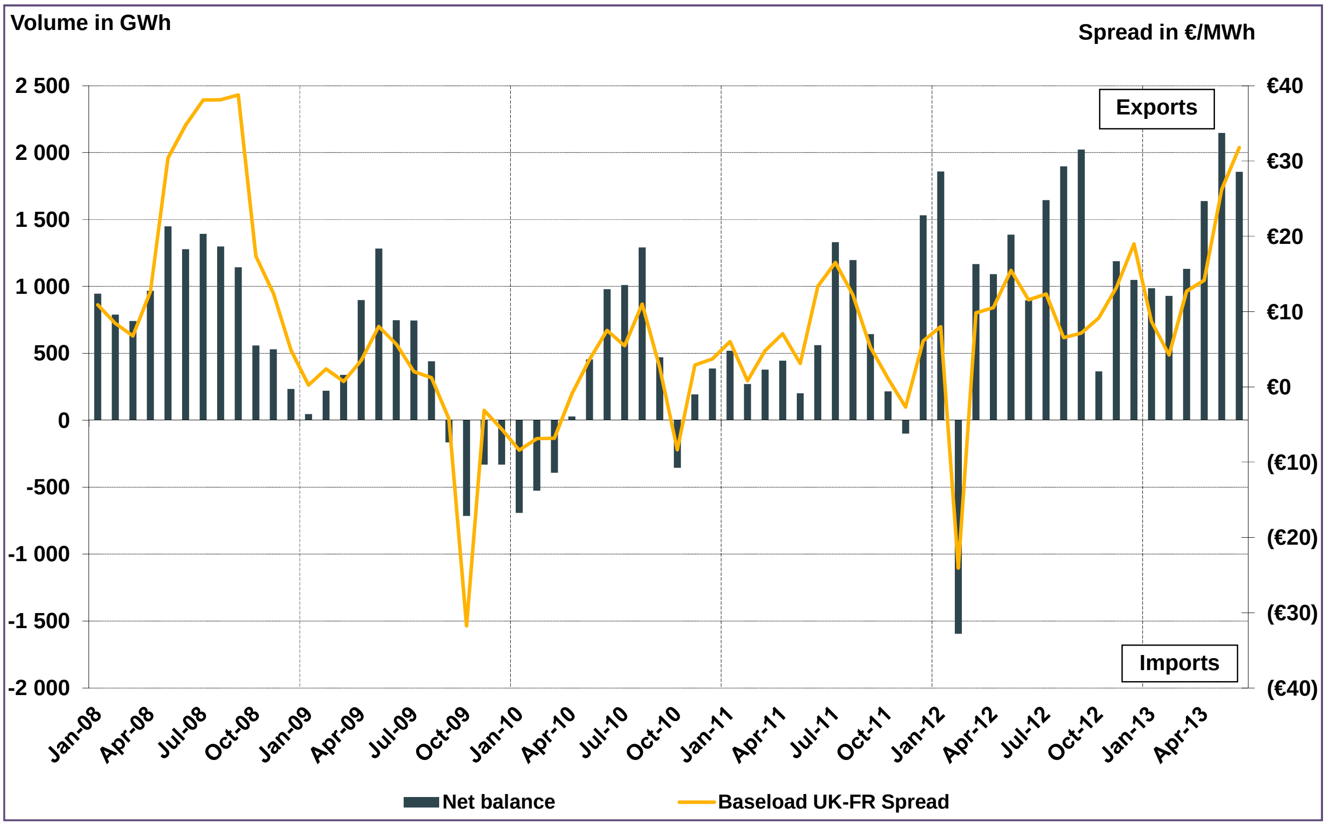
[44] View CRE report, *Cross-border electricity exchanges: interconnection use and management in 2012* on its website

b. France - Belgium



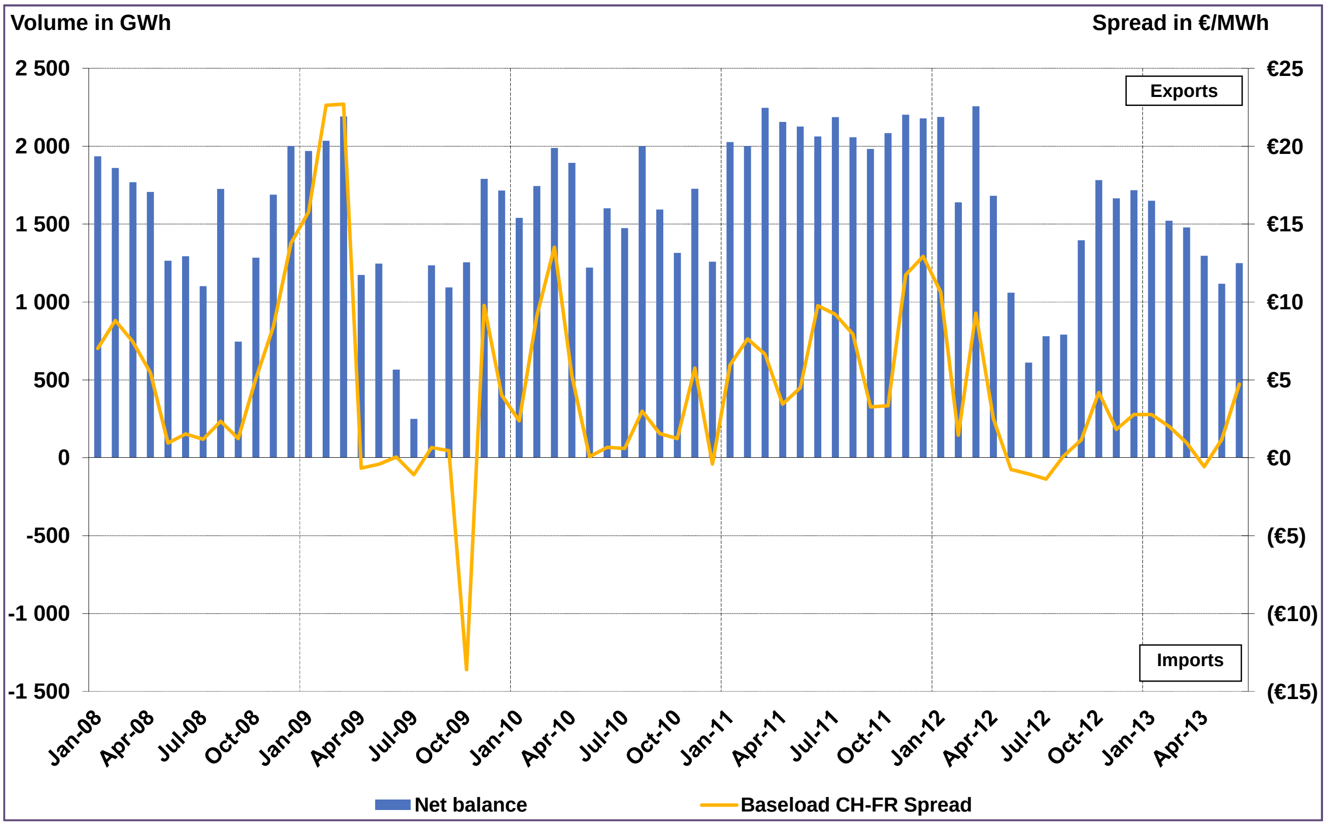
Source: RTE, EPEX SPOT, Belpex - Analysis: CRE

c. France - United Kingdom



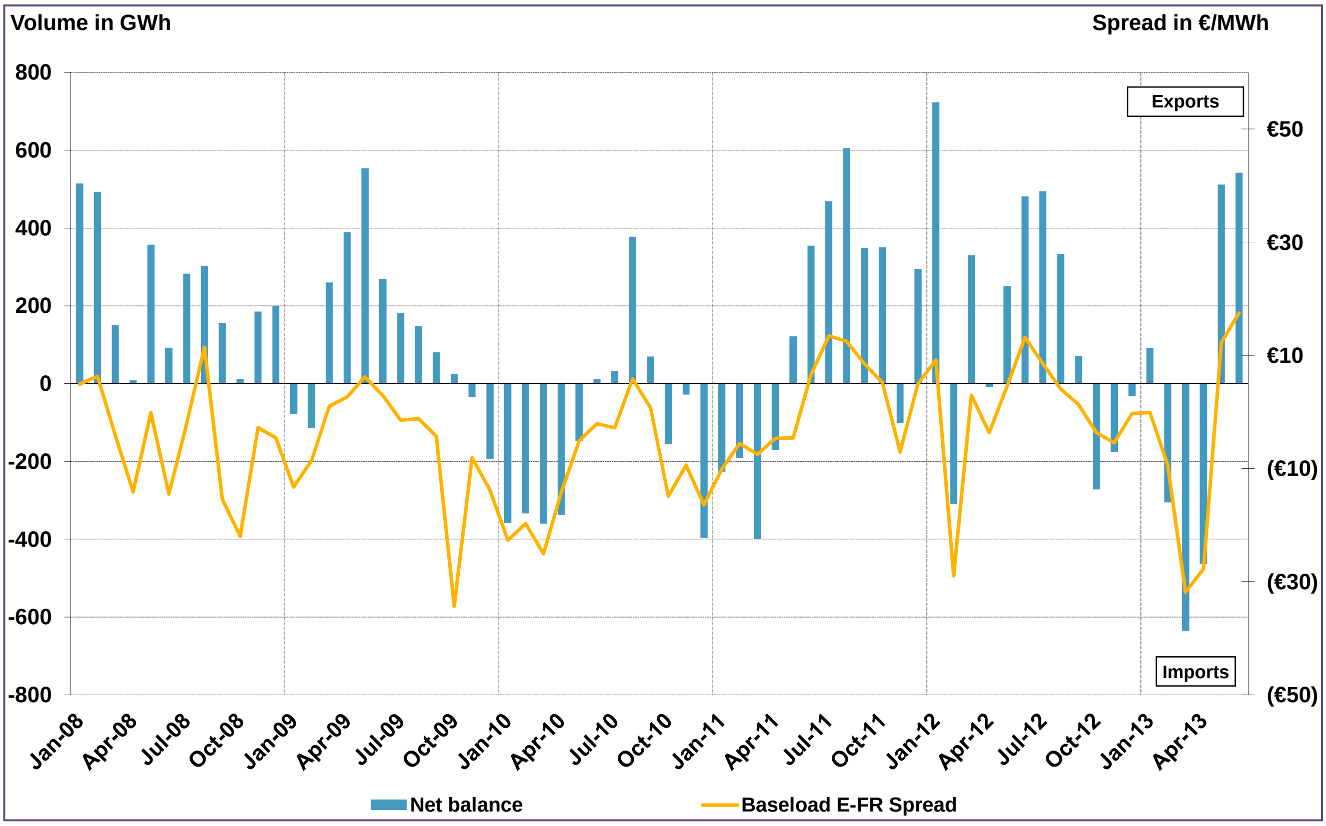
Source: RTE, EPEX SPOT, N2EX - Analysis: CRE

d. France - Switzerland



Source: RTE, EPEX SPOT - Analysis: CRE

e. France - Spain

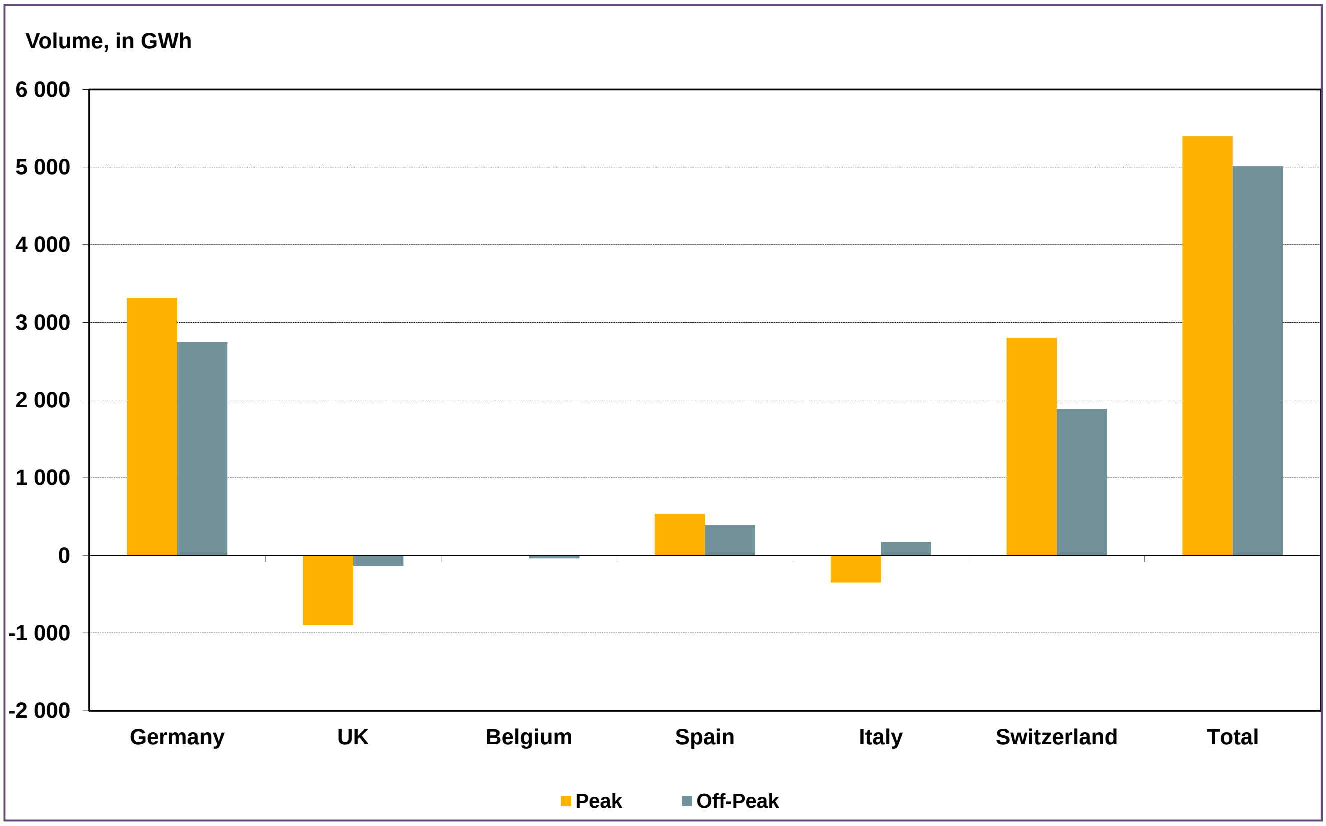


Source: RTE, EPEX SPOT, OMEL - Analysis: CRE

- **Imports, mainly from Germany and Switzerland, were slightly higher for peak hours than for off-peak hours**

The increase in imports was mainly from Germany and Switzerland and was slightly higher for peak hours than off-peak hours: nearly 52% of the additional imports were recorded during peak hours (Figure 9).

Figure 9: Variation in cross-border imports between 2012 and 2011 (distribution between peak and off-peak hours)



Source: RTE – Analysis: CRE

1.3 The volume of losses bought by network operators remained stable in 2012 and the first half of 2013

Transmission and distribution networks generate energy losses. Therefore, transmitters and distributors must buy a volume representing the amount of losses.

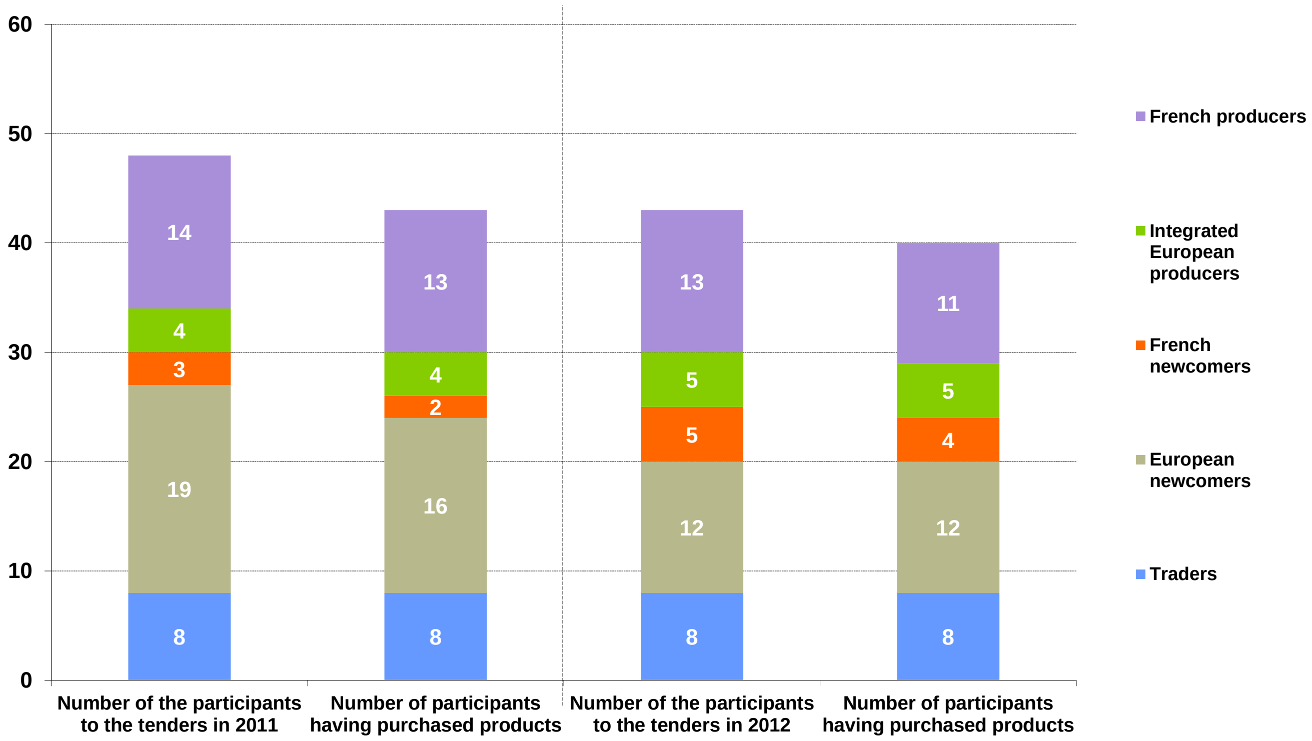
Purchases by network operators RTE and ERDF, required to compensate their losses, represented 35 TWh in 2012. This figure is constant compared to 2011. In the first half of 2013, these purchases were also constant compared to the same period in 2012 (19 TWh).

Purchases of losses are made in consultations organised several times per month by network operators. In 2012, 110 calls for tender were organised by the two network operators (against 166 in 2011) and 70 were organised in the first half of 2013. figure 10 shows the number of participants in these consultations.

During these calls for tender, network operators bought products covering various delivery horizons: monthly (M+1 to M+22), quarterly (Q+1 to Q+5), and yearly (Y+1 to Y+4) deliveries.

In the first half of 2013, network operators launched public consultations on the contractual arrangements of "specific ARENH contracts" whose characteristics are defined in CRE's deliberation of 22 December 2011. Contracts concluded within the framework of these consultations are for delivery post-2014.

Figure 10: Number of participants in consultations



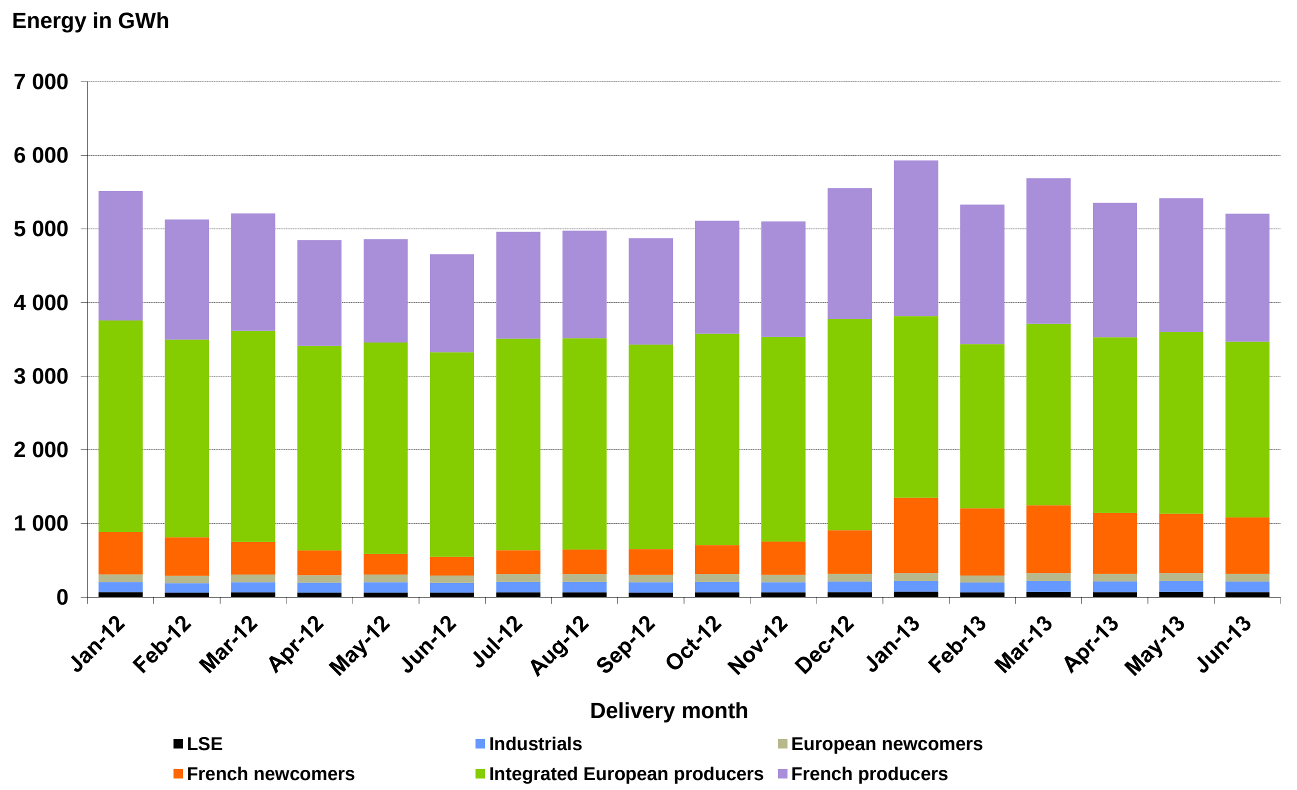
Source: RTE, ERDF - Analysis: CRE

1.4 Half yearly volumes delivered to ARENH stagnated in 2012. The concentration of VPP ("virtual power plant") capacity purchased during auctions remained moderate in 2012

The NOME law of 7 December 2010 implemented the regulated access to historical nuclear energy (ARENH) mechanism with entered into force on 1 July 2011. This mechanism allows alternative electricity suppliers to access electricity produced by EDF's nuclear power plants. Access is regulated and its price which was set at 42 €/MWh by the public authorities must reflect the economical conditions of existing nuclear power plant electricity generation. The total annual ARENH volume sold to all suppliers is capped at 100 TWh. This electricity is exclusively destined for end-users located in mainland France.

figure 11 shows the monthly volumes delivered in 2012 and the first half of 2013. EDF has delivered about 30 TWh to alternative suppliers under ARENH every six months since the mechanism was implemented. Analysis of ARENH volumes delivered between 1 January 2012 and 30 June 2013 identified Herfindahl-Hirschman indexes (HHI) represented a concentrated segment (1,656 in 2012 and 1,682 in the first half of 2013).[45] This observation was also reflected in changes in volume shares. The cumulated volume of the three largest participants account for approximately 63% and 60% of the total energy volume delivered respectively in 2012 and the first half of 2013.

Figure 11: Monthly energy purchased under ARENH for delivery in 2012 and the first half of 2013



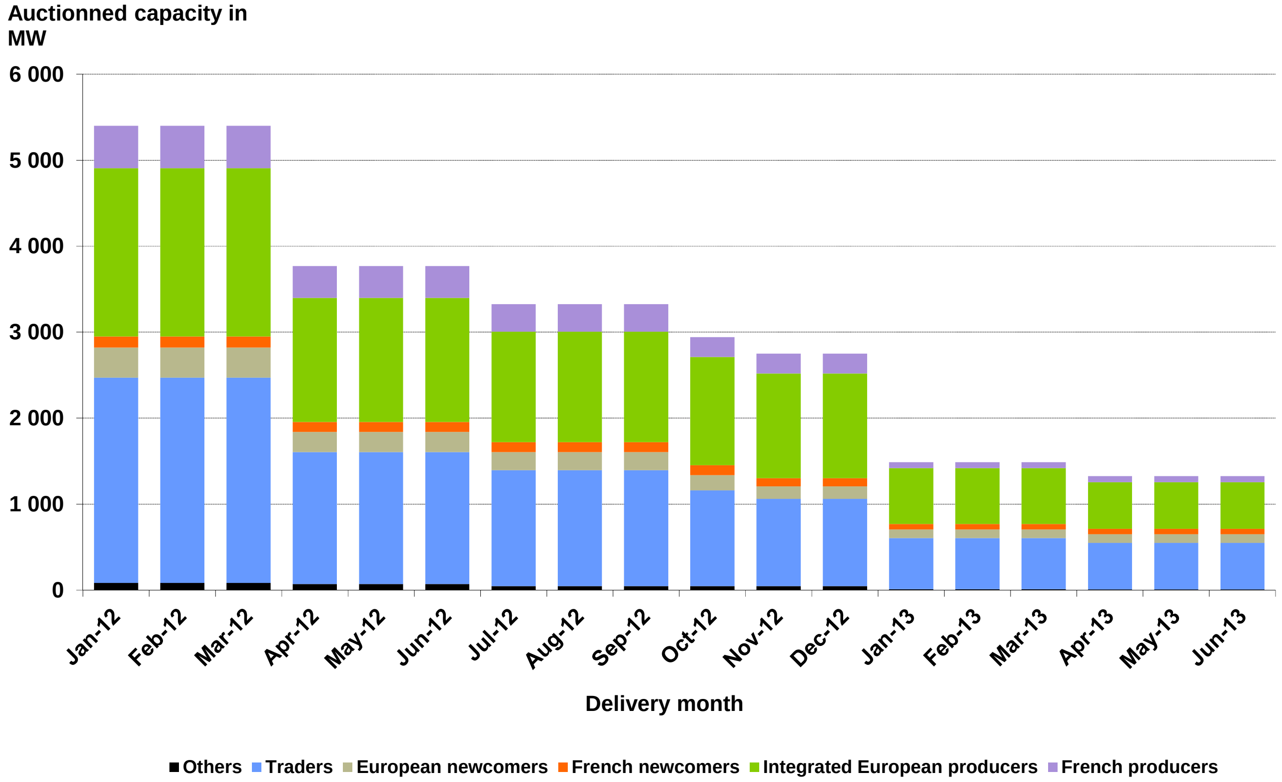
Source: EDF - Analysis: CRE

[45] See Glossary for the definition of "Herfindahl-Hirschmann Index (HHI)"

The European Commission ended the VPP auction programme[46] by decision of 30 November 2011. Therefore, VPP capacity available for delivery after 1 January 2012 has gradually diminished (Figure 12).

Analysis of the VPP capacity held by each participant for a given delivery month showed that there was a moderate concentration on this market (Figure 12). Therefore, from January 2011 to July 2012, the largest market share newer exceeded 17% for baseload and 26% for peakload. In addition, maximum monthly HHI indices recorded during this period were 1,873 for the peakload product and 787 for the baseload product showing that this market segment was open to a satisfactory degree. These values were however higher for peakload products and lower for baseload prices compared to 2011 (respectively 1,695 and 1,231).

Figure12: Monthly capacities bought at auctions for delivery in 2011 and the first half of 2012



Source: EDF - Analysis: CRE

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

2 ELECTRICITY PRICES

The variation in electricity prices on the spot market from January 2012 to June 2013 should be analysed in the context of slowed economic activity following the rebound in 2010. Stagnating energy demand and sharp reductions in coal and CO_2 prices are key factors in this evolution.

In 2012, the electricity market in was primarily marked by hourly price spikes on the spot market for delivery on 9 and 10 February 2012 due to the exceptionally cold weather resulting in consumption records. Despite these prices spikes, the average day-ahead and intraday prices were lower in 2012 than in 2011. The Y+1 baseload product price fell sharply, also affected by coal and CO_2 price drops.

In the first half of 2013, day-ahead and intraday prices continued to drop. These six months were marked by negative price spikes on several hours for delivery on 16 June 2013. The Y+1 calendar baseload product price also continued to fall before stabilising at around 42.0 €/MWh.

2.1 The French spot market was marked by significant price spikes in February 2012. The first half of 2013 was characterised by increased consumption due to cold weather and June's significant negative prices

Table 7: Average Day-Ahead and Intraday price

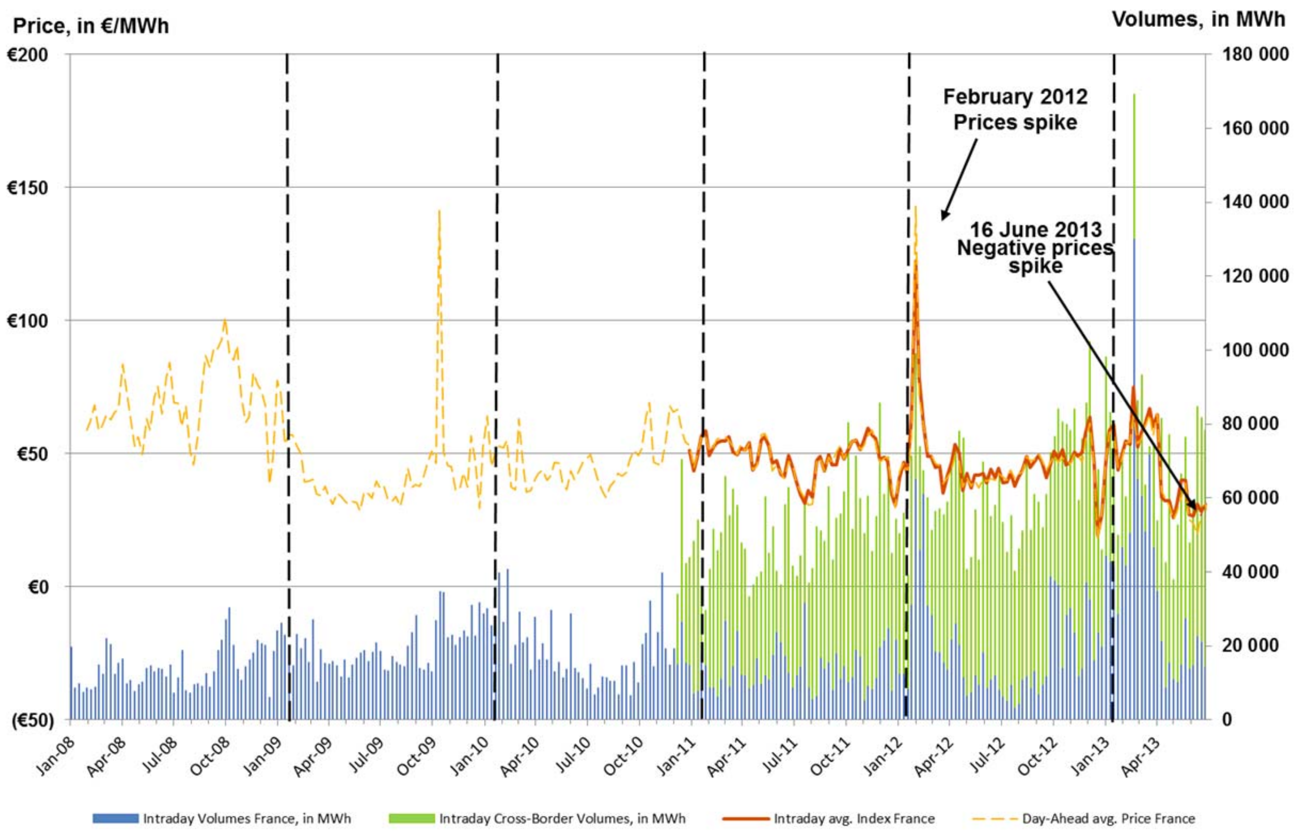
	Average Day-Ahead Price	Average Intraday Price
2011	48.9 €/MWh	48.8 €/MWh
2012	46.9 €/MWh	46.1 €/MWh
H1 2012	48.6 €/MWh	48.8 €/MWh
H1 2013	43.8 €/MWh	45.7 €/MWh

Source: EPEX SPOT

- **Intraday**

The average intraday price on the EPEX SPOT market in 2012 stood at 46.1 €/MWh which was lower than in 2011. It stabilised at 80 centimes below the day-ahead price which was a much higher difference than in 2011. However, this difference significantly reversed in the first half of 2013 to 1.9 €/MWh over the day-ahead price with the average intraday price dropping to 45.7 €/MWh. These differences with day-ahead prices are partly due to the day-ahead market's price sensitivity (Section 4) especially during price spikes (February 2012 and June 2013) where they reached more extreme levels than intraday prices.

Figure 13: Trends in intraday prices in France (average weekly prices and volumes)



Source: EPEX SPOT - Analysis: CRE

- **Day-Ahead**

The average baseload electricity price stood at 46.9 €/MWh in 2012 decreasing by 2.0 €/MWh compared to the previous year. The fall was less significant for peakload prices with the average price per megawatt hour standing at 59.5 € against 60.7€ in 2011. This fall in day-ahead electricity prices is all the more significant as they have been heavily weighted upwards by the price spikes in February 2012. If the prices between 6 and 12 February 2012 are removed, average baseload and peakload prices are respectively 45.1 €/MWh and 55.7 €/MWh.

Box 1: Price spike in February 2012

During the cold wave of February 2012, electricity prices on the French spot market (EPEX SPOT Auction) reached 367.6 €/MWh for delivery on Thursday, 9 February 2012 and 147.3 €/MWh for the next day. Hourly prices exceeded the threshold of 500 €/MWh several times triggering a second fixing procedure for the two days. In particular, prices were close to 1,000 €/MWh for several hours in the morning, even reaching 1,938.5 €/MWh at 10 am, for delivery on 9 February.

CRE services analysed the factors underlying the formation of these high prices. The initial results of these analyses were released in CRE's decision of 10 May 2012 and its report on the functioning of wholesale energy markets in 2011-2012[47] which highlighted strong tension between supply and demand and that the use of boundaries could be improved. CRE also analysed the causes of the second auction's higher hourly prices compared to the initial price for delivery on 9 February. In particular, changes in the orders of certain participants were not compliant with EPEX SPOT rules and did not improve the market's supply-demand balance.

In its previous monitoring report, CRE indicated that it was continuing its work on a market participant's behaviour. This work, conducted in conjunction with ACER, focused on compliance of this participant's trading activity with Regulation No. 1227/2011 of 25 October 2011 (REMIT). To justify its order changes between the first and second auction and the transactions made later on the intraday market, this participant told CRE that these transactions were the result of the unexpected shut-down one of its generation plants. However, the participant only made this plant's unavailability public after the end of its transactions on EPEX SPOT. The issue of the qualification of information concerning the plant's unavailability and therefore transactions made on the basis of this information, under Article 3 of the REMIT prohibiting insider trading, was raised.

Concerning the qualification of privileged information, CRE services concluded that the plant's unavailability did constitute insider information under the REMIT despite it not being located in France but on a border market insofar as it could influence prices in France as the analysed transactions took place on the French market.

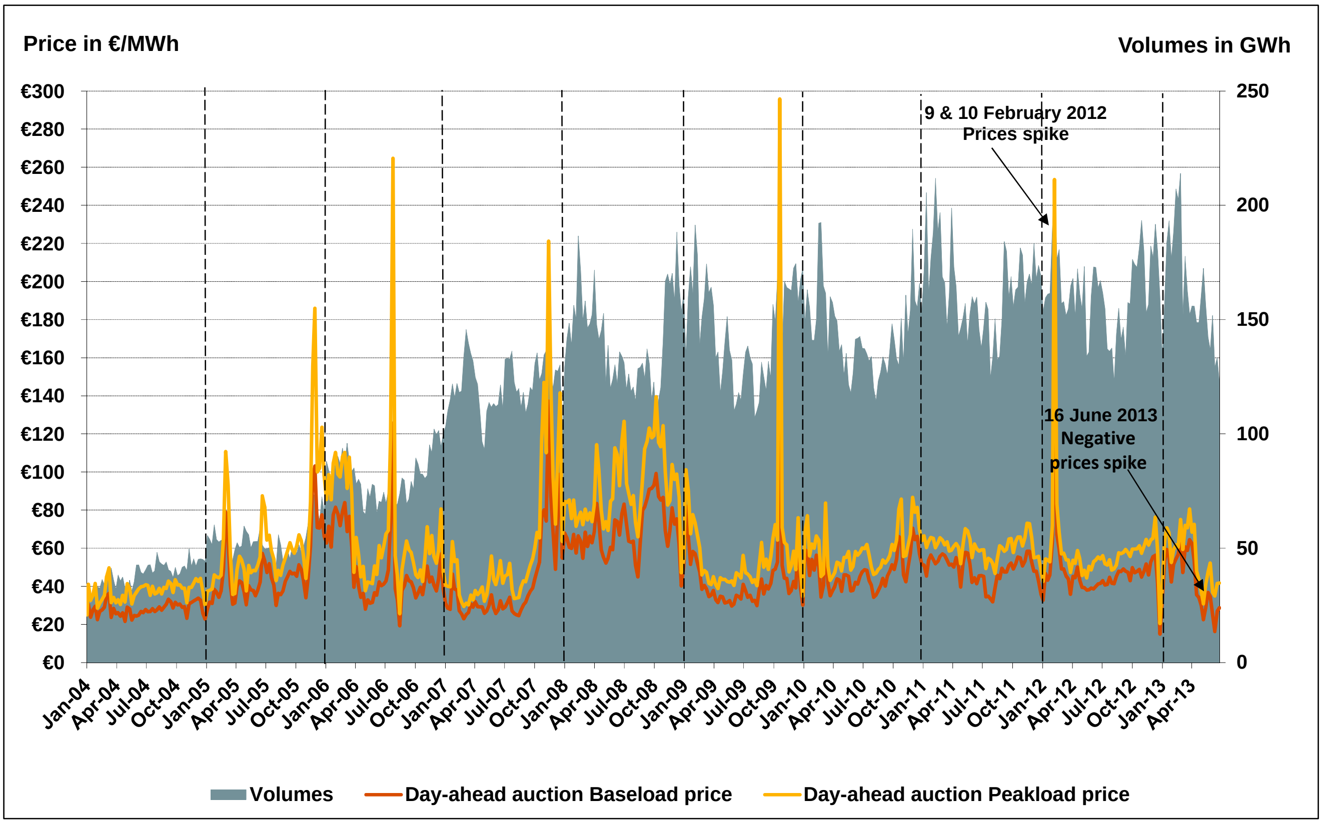
However, it appears that the transactions could not be qualified as insider dealing because they come under the exemption defined in Article 3.4.b) of the REMIT. This Article excludes from the prohibition of insider trading any transactions the "*purpose of which is to cover the immediate physical loss resulting from unplanned outages*". In this case, the transactions analysed by CRE focused on purchased volumes that were lower than the volumes corresponding to the losses caused by plant unavailability.

Under these conditions, CRE informed the market participant that the transactions at issue came under the exemption. However, it did remind the participant of its obligation to notify ACER and the relevant regulator of pertinent information relating to such transactions and that ACER provides an exemption declaration form on its website, as well as its obligation to publish inside information. This must be prompt and sufficiently detailed, in line with ACER guidelines which recommend a maximum period of one hour.

[47] View the 2011-2012 Monitoring Report and the CRE's decision of 10 May 2012 on CRE's website

On the 1st and 2nd January 2012, (weak) negative hourly prices settled on the French electricity spot market for the first time. These prices were the result of market coupling with Germany where negative prices are more common due to the large proportion of electricity produced by renewable energies (Box 3). However, France experienced higher negative prices which fell to -50 €/MWh for delivery between 7 and 8 am on 25 December 2012. This was also a consequence of market coupling with Germany where hourly prices were much lower, reaching values between -50 €/MWh and -222 €/MWh for delivery from midnight to 8 am.

Figure 14: Trends in spot prices in France (average weekly prices and volumes)



Source: EPEX SPOT

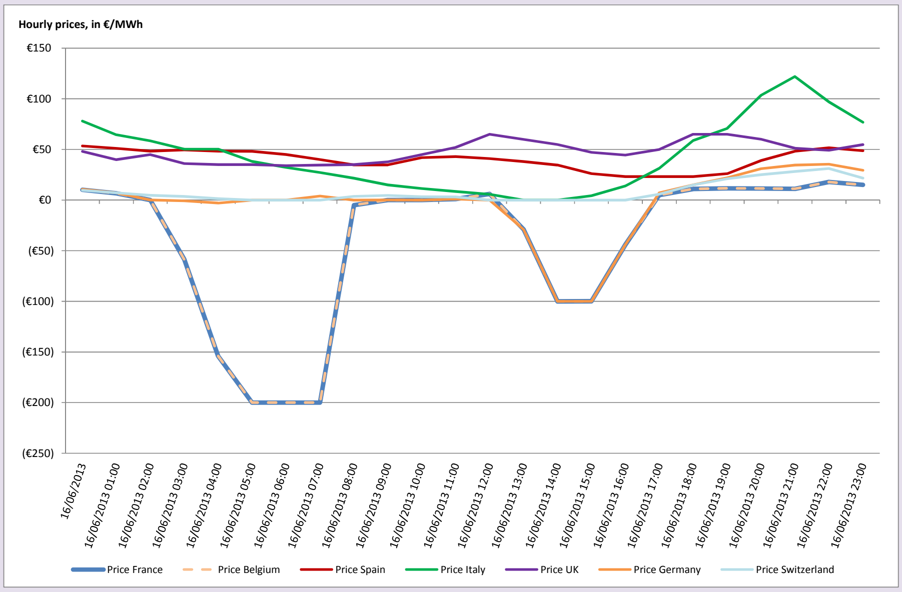
In the first half of 2013, average baseload and peakload prices were respectively 43.8 €/MWh and 55.3 €/MWh which were both lower than for the same period in 2012 (respectively 4.8 €/MWh and 7.1 €/MWh). The downward impact of negative price of 16 June 2013 (Box 2) on the baseload price is about 0.5 €/MWh. In addition, negative prices only represented 0.2% of the occurrences of hourly prices in 2012 and the first half of 2013.

Box 2: Negative electricity price spikes in June 2013

France experienced significant negative prices for certain hours during the EPEX SPOT auction for delivery on Sunday, 16 June 2013 with a baseload price at -40.99 €/MWh. Hourly prices were very negative for the morning and afternoon, reaching -200 €/MWh from 5 to 8 am and -100 €/MWh from 2 to 4 pm.

Only French and Belgian hourly prices converged for all hours of the day. German prices were disconnected and higher in the morning when French prices were at their lowest. Germany's non flexible generation from renewable energy was therefore not at the origin of the morning's negative prices nor the three occurrences of -200 €/MWh. However, the afternoon's negative prices do seem to be related to Germany where wind and solar generation of about 30 GW was expected (against less than 10 GW for morning hours).

Figure 15: Hourly spot prices for delivery on 16 June 2013

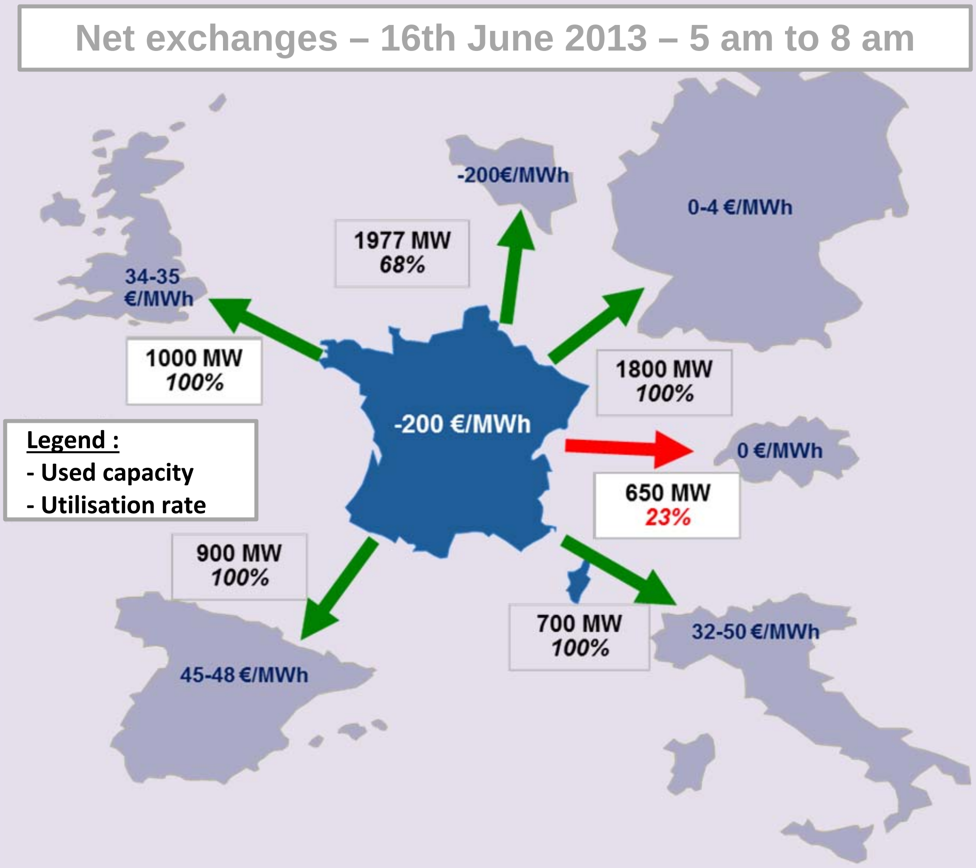


Source: EPEX SPOT France / Germany / Switzerland, Belpex, OMEL, GME, N2EX – Analysis: CRE

Fundamental analysis revealed a surplus of supply. Consumption during the morning was low compared to previous days (especially compared to the previous day) while the availability of generating facilities which had declined over the week finally began to increase on D-1. This added to increased nuclear power availability (about 800 MW more). With regard to actual generation, almost all consumption and exports were covered by nuclear and hydropower generation. In addition, run-of-river generation reached 7 GW during the hours with the lowest prices, i.e. 20% of total generation. Finally, the Belgian market was also affected by a surplus supply, exacerbated by the re-commissioning of the Doel 3 and Tihange 2 nuclear power plants respectively on 2 and 4 June. These two plants had been unavailable since the summer of 2012.

The use of interconnectors was generally rational with optimised exports on all borders except Switzerland. On this border, daily allocation only covers a limited part of the interconnection capacity due to the existence of long-term contracts and specific rules for their use. In addition, it appears that the holders of long-term export contracts from France to Switzerland did not fully activate them. Therefore, only 23% of the interconnection was used. More appropriate interconnection access rules for long-term contract holders defended by CRE and debated between the European Union and Switzerland as well as homogenised procedures for auctions between Switzerland and France and a market coupling mechanism would have allowed a better flows optimisation. Intraday electricity exchanges on this border would have only partially allowed this interconnection to be used more effectively.

Figure 16: Exchange balance - Sunday, 16 June 2013 - 5 - 8 am



Source: RTE – Analysis: CRE

CRE also analysed EPEX SPOT's auction procedure. As some hourly prices from the auction for delivery on 16 June 2013 were under -150 €/MWh, the exchange opened a RFQ procedure[48] (second auction) to improve balance in accordance with its operational rules. Order books have changed very little between the two auctions. However, one participant did increase its demand volumes (+40 MW) for the two hours where prices were strongly negative.

At this stage, CRE considers that these negative prices are consistent with the fundamentals of supply and demand with, on one hand, low energy consumption and, on the other hand, high generation availability which even increased the day before. The Belgian market experienced a similar situation contributing to lowering prices. The imbalance between generation and consumption was caused by non-flexible energy generation: French and Swiss nuclear power and run-of-river hydropower in the morning and German solar and wind power in the afternoon. Therefore the day's lowest prices which occurred between 5 and 8 am were not related the German renewable energy generation. However, as part of systematic monitoring of this type of unusual market event the transactions of some participants were questioned.

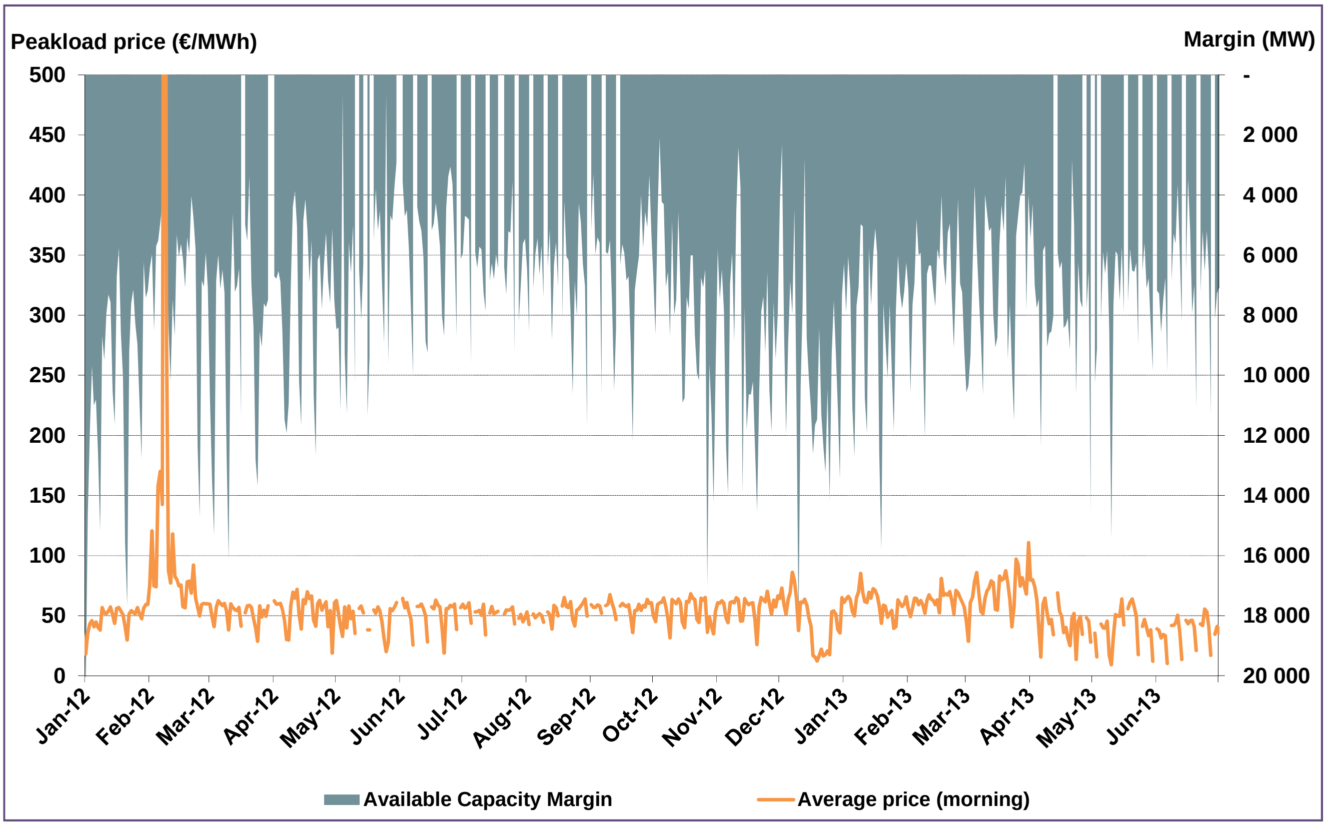
[48] "*Request for Quotes*"

Hourly spot price formation strongly depends on the system's margin forecast, i.e. the difference between D-1 forecasts for available generation capacity and consumption. Prices therefore follow an upward trend when margins decrease, in particular when it is under 10,000 MW: 70% of prices were over or equal to 70 €/MWh for 2012 and the first half of 2013. When there is a significant margin between generation capacity and forecast consumption, only the least costly generation means are used resulting in low system marginal costs and spot prices. Conversely, if there are tensions on electricity system, the more expensive generation means are used increasing daily auction prices.

In 2012, nuclear plant availability declined reducing available hourly margins compared to 2011 (an average 25 GW against over 28 GW in 2011). Tensions on the network were therefore more frequent in 2012 and February was marked by a major cold wave. Margins significantly reduced to a level slightly above that of 2010. Hourly prices over 100 €/MWh when the margin was under 10,000 MW were observed in February 2012 and the winter of 2013 which was not the case in 2011.

RTE publishes the margin level of the French electricity system for the morning and evening peakload times (which vary from one day to the next) every day. Comparison of these margins with average spot prices observed during these peakload hours highlights the expected relationship between French electricity system tension levels and the prices set during the daily auction (Figure 17).

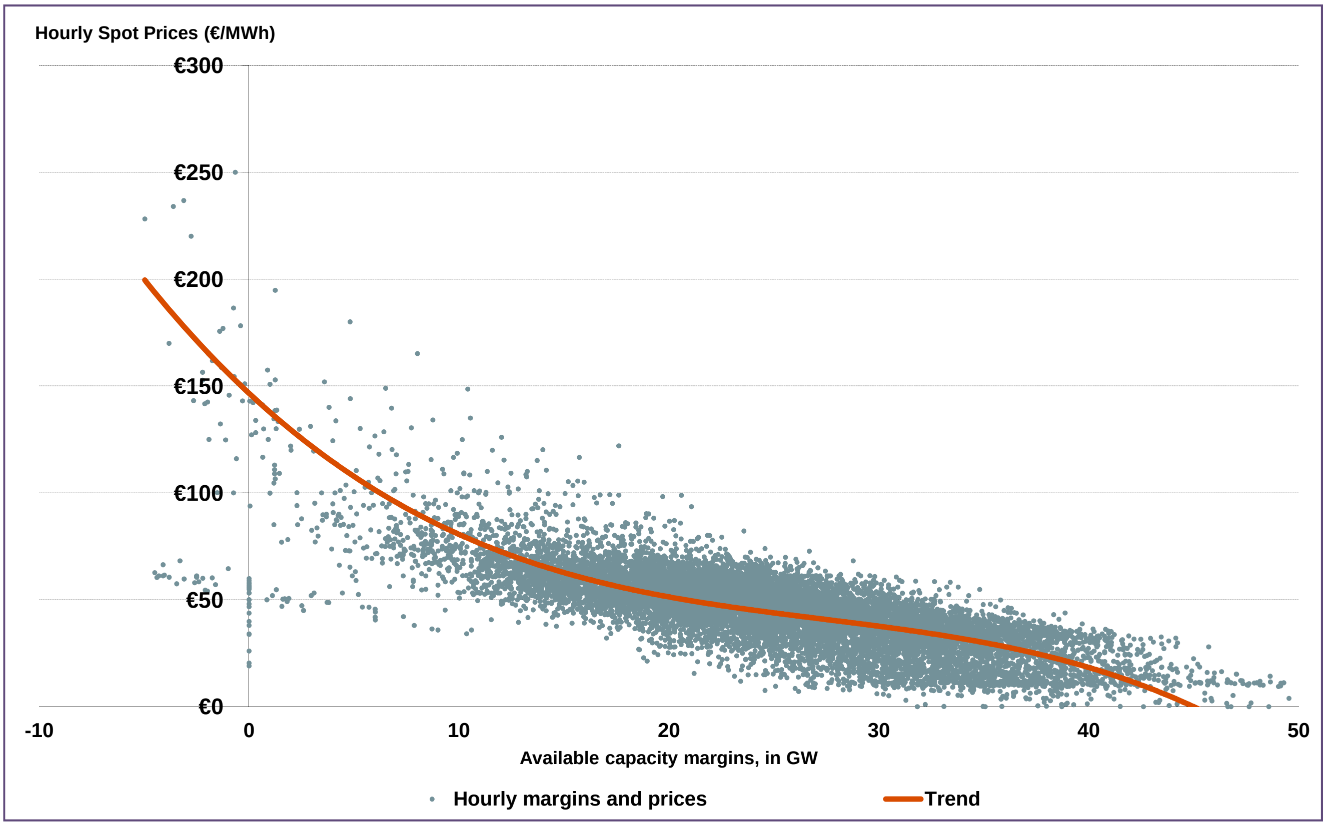
Figure 17: Spot price and RTE margin



Source: RTE, EPEX SPOT - Analysis: CRE

A negative correlation between the margin and spot prices is expected. This is also shown by figure 18 where each point represents a system margin/spot price pair. Hourly spot price fluctuations also generally followed those of margin indicators. Therefore, when the hourly margin indicator for D-1 increases (respectively decreases), the corresponding spot price decreases (respectively increases) in 71% of cases in 2012 and the first half of 2013 against 70% in 2011.

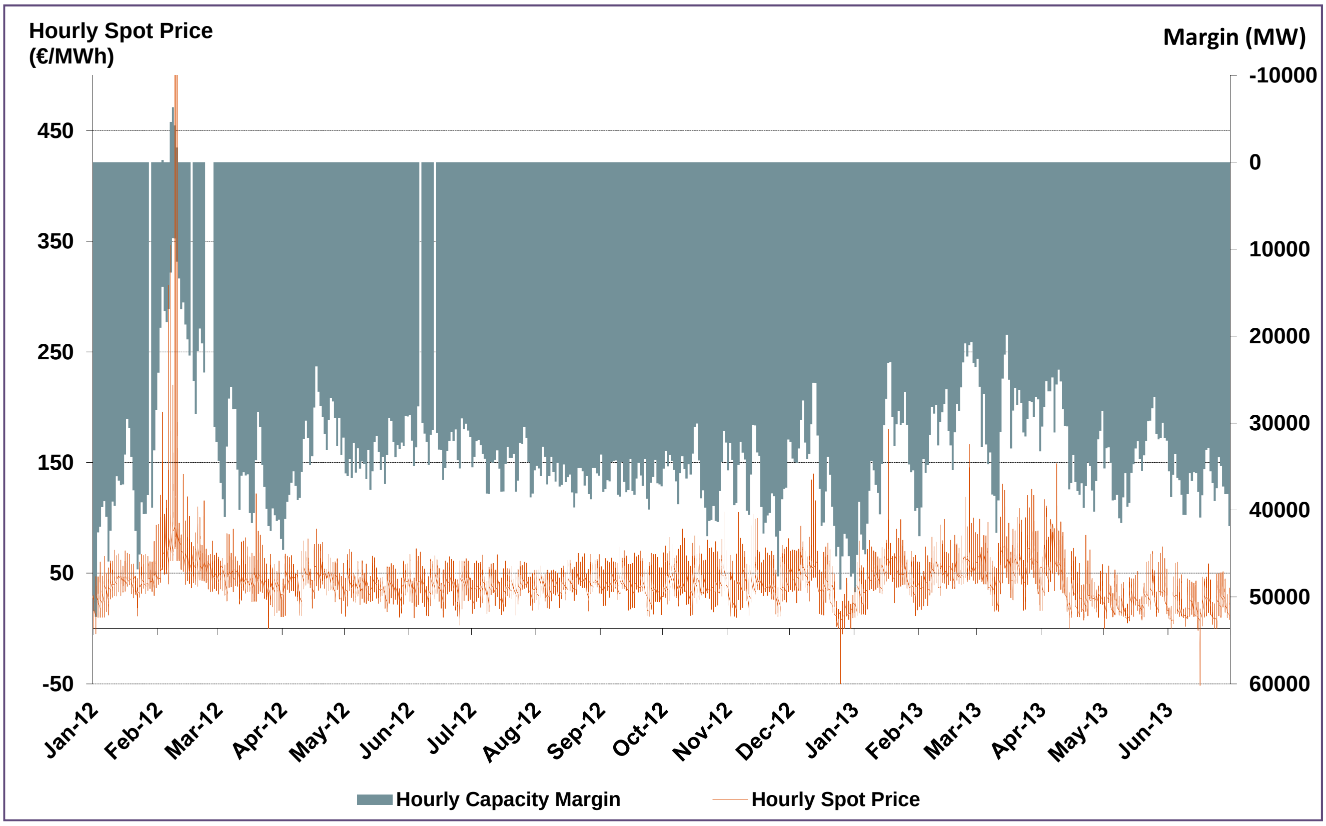
Figure 18: Hourly spot price and French electricity system generation availability margin



Source: RTE, EPEX SPOT - Analysis: CRE

Since July 2009, RTE has also published availabilities observed (a posteriori) for generation units with a capacity exceeding 20 MW (RTE reference generation capacity) on its website. This new data is used to calculate hourly French electricity system margins, excluding power plants with a capacity of less than 20 MW, defined as the total observed availability of the RTE reference generation capacity less actual consumption for a given hour. Unlike peak margins previously calculated by RTE, this indicator does not include electricity traded at the borders nor all power plants. As for the forecast margin indicator (D-1), only its variations are therefore of use. A negative correlation is also expected with the spot price as shown by figure 19 where when the hourly margin indicator increased (respectively decreases), the corresponding spot price decreased (respectively increases) in 79% of cases in 2012 and 77% of cases in the first half of 2013. In 2010, this rate was 83%. These results reflect price levels that are consistent with trends in the system's margin.

Figure 19: Actual spot prices and hourly margin



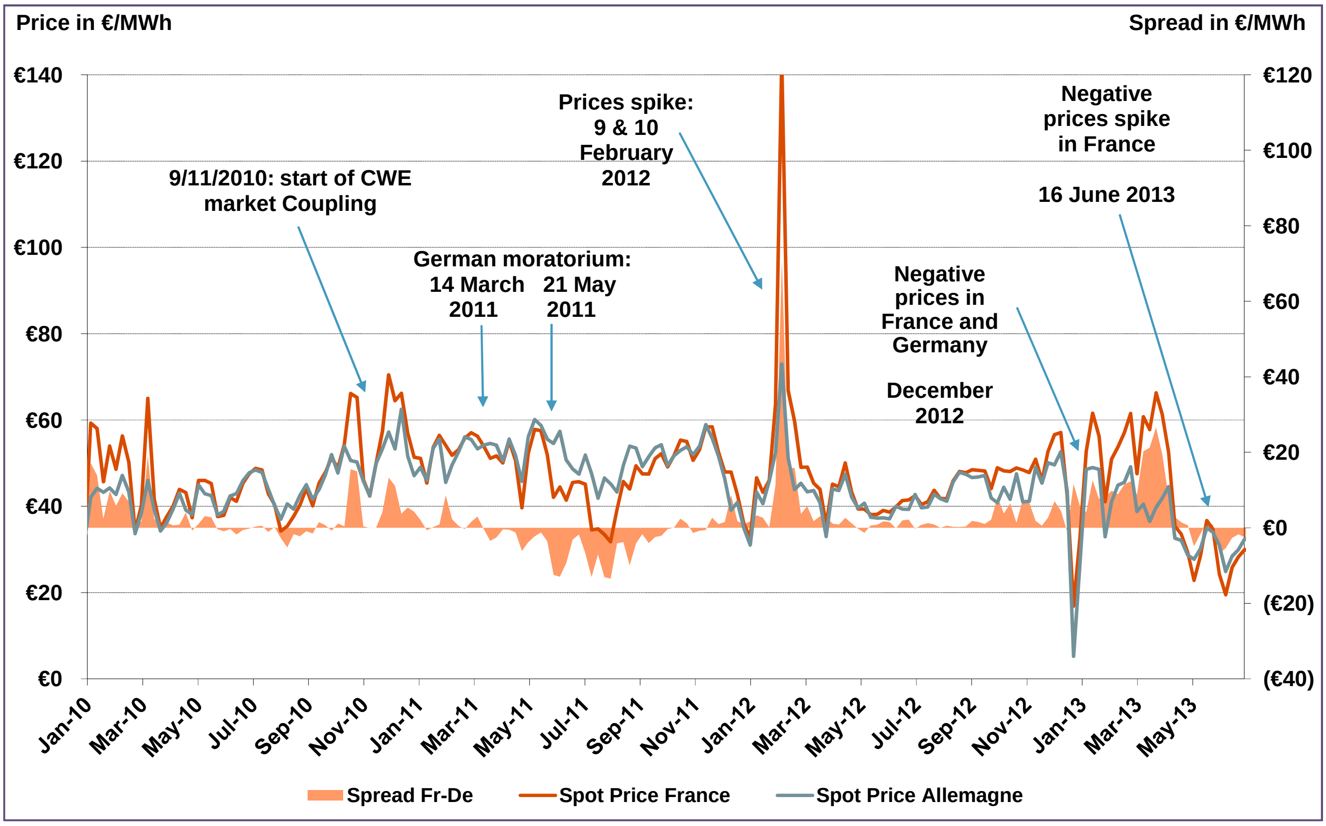
Source: RTE, EPEX SPOT - Analysis: CRE

- **In 2012 and the first half of 2013, French and German prices were affected by episodes of positive and negative price spikes. Hourly market price convergence fell sharply.**

In 2012, the French spot price was higher than the German spot price by 4.3 €/MWh on average prices and the price differential is reversed compared to 2011 when French prices were lower by 2.3 €/MWh. In 2012, French prices were again higher than German prices due to lower nuclear availability and also the price spikes observed during the cold wave in February 2012. If the week of 6 and 12 February 2012 corresponding to the cold wave is removed, the average French and German spot price differential is reduced to 3.0 €/MWh. The strong growth of renewable energy generation in Germany is also a factor driving German market prices down compared to French prices.

The price differential between France and Germany, which tends to increase during the winter, has continued to increase since autumn 2012 (Figure 20). In the first half of 2013, the average price differential rose to 6.4 €/MWh disfavouring France in a context of increased consumption, especially in March. This reversed in the spring and significant negative prices occurred on 16 June 2013 on the French market (Box 2).

Figure 20: France-Germany spot prices and differential (weekly averages)



Source: EPEX SPOT - Analysis: CRE

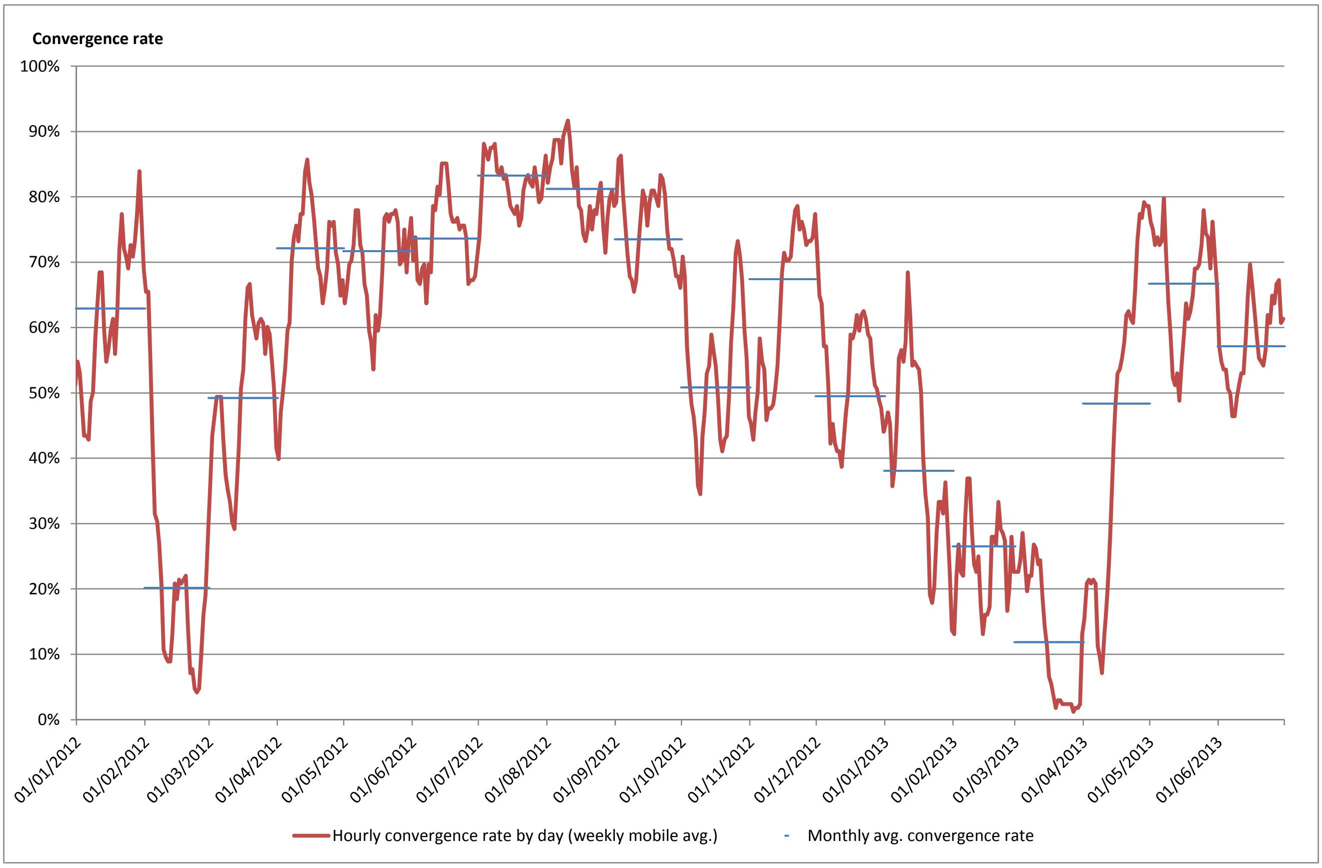
The hourly price convergence rate between France and Germany[49] stood at almost 56% in 2012 and the first half of 2013. This rate is lower than that for the period between 1 January 2011 and 30 June 2012 where it stood at 64%.

figure 21shows the effects of the cold wave in February 2012, with a sharp decline in the hourly convergence rate for the month. The thermo-sensitivity of French consumption was felt for the entire 2012-2013 winter period and increased imports lead to saturated flows on the France-Germany interconnection: the increased France-Germany price differential was accompanied by a significant reduction in the hourly convergence during this long period of cold weather in France.

The convergence rate with Belgium reached 84% in 2012 but fell to 56% in the first half of 2013. The price convergence rate which was nearly 98% in 2011 fell sharply due to the unavailability of two Belgian reactors for almost a year (Doel 3 and Tihange 2). For other border countries which are not coupled with the French market (Switzerland, Italy, and Spain), hourly convergence seldom occurred (between 0 and 1% of the time).

[49] Defined as the percentage of hours for which the absolute price differential is less than 0.01 €/MWh

Figure 21: Daily France-Germany hourly price convergence rates



Source: EPEX SPOT - Analysis: CRE

Detailed analysis of French and German prices showed that the convergence in 2012 and the first half of 2013 was better in the morning (7 to 9 am) and early evening (4 to 8 pm). This was due to less frequent saturation of the France-Germany interconnection during these times compared to the rest of the day. In contrast to 2011, price convergence rates were better during peakload times showing that there was sufficient interconnection capacity between the two countries. It should however be noted that France became a net exporter to Germany in 2011 which was no longer the case in 2012 and 2013 (despite a return of net exports in June 2013). In 2011, interconnection capacity provided to market coupling was sufficient to give French exports a good convergence rate which was not the case in 2012 and 2013 despite the flows being reversed.

- **The start of the Flow-Based market coupling mechanism in 2014 should help reconcile prices and improve hourly price convergence rates between markets**

The start of the Flow-Based[50] market coupling mechanism scheduled for early 2014 should influence CWE (France, Germany, Austria, Holland, Belgium, and Luxembourg) area market prices to tighten price differentials and improve hourly convergence rates. Parallel run simulations[51] are currently being performed on 2013 data by exchanges and transmission network operators to assess the impact of this mechanism on market prices. table 8 and figure 22 provide an overview of what 2013 market prices would have been under the Flow-Based mechanism compared to actual results related to the current interconnection capacity calculation method ("ATC").

Table 8: Flow-Based market prices derived from parallel run simulation results

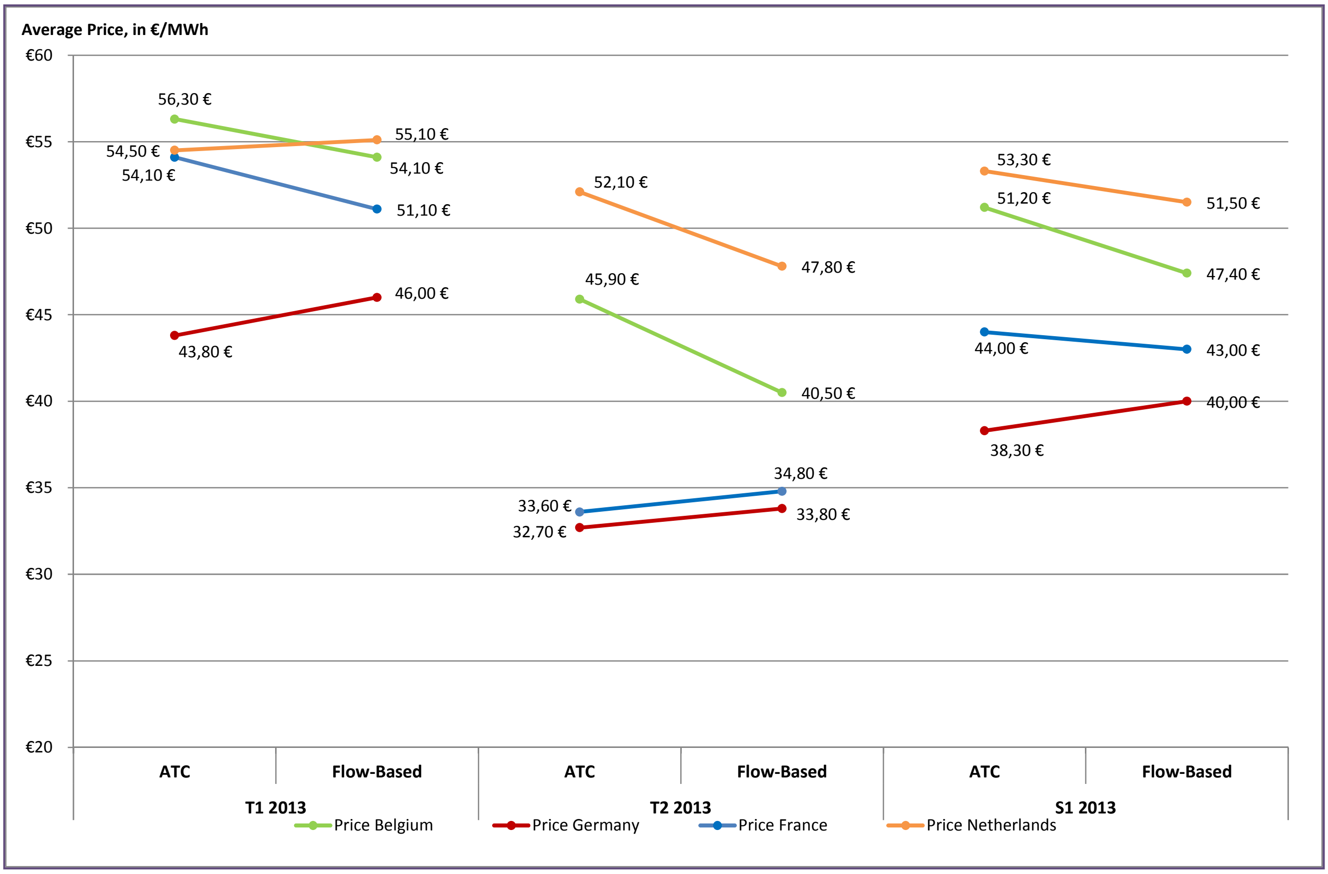
		Belgium	Germany	France	Holland
Q1 2013	ATC	56.3 €/MWh	43.8 €/MWh	54.1 €/MWh	54.5 €/MWh
	Flow-Based	54.1 €/MWh	46.0 €/MWh	51.1 €/MWh	55.1 €/MWh
Q2 2013	ATC	45.9 €/MWh	32.7 €/MWh	33.6 €/MWh	52.1 €/MWh
	Flow-Based	40.5 €/MWh	33.8 €/MWh	34.8 €/MWh	47.8 €/MWh
H1 2013	ATC	51.2 €/MWh	38.3 €/MWh	44.0 €/MWh	53.3 €/MWh
	Flow-Based	47.4 €/MWh	40.0 €/MWh	43.0 €/MWh	51.5 €/MWh

Source: CASC – Analysis: CRE

[50] For more information see CRE's annual report, Cross-border electricity exchanges: interconnection use and management in 2012 on its website

[51] Results are not available for 43 days in the first half of 2013.

Figure 22: Effects of Flow-Based market coupling on market prices

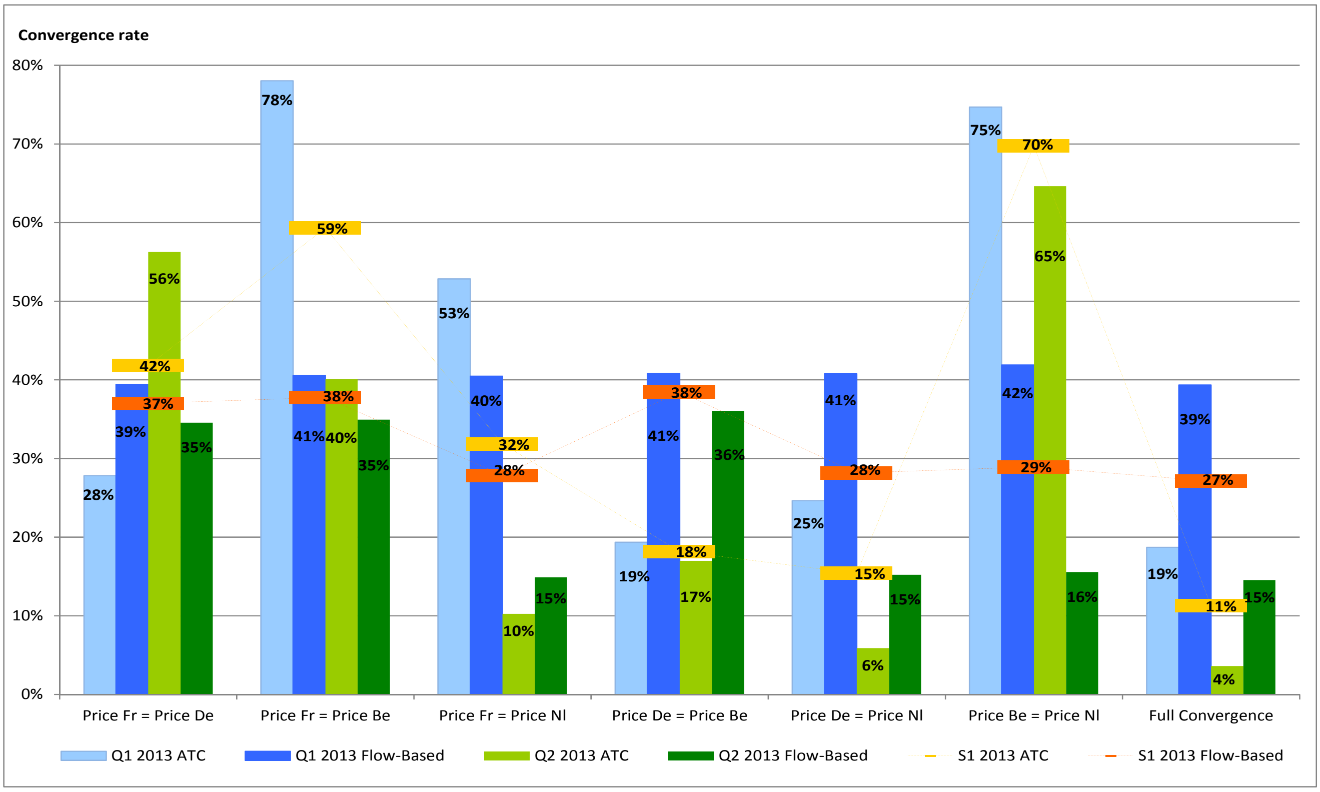


Source: CASC – Analysis: CRE

In the first half of 2013, the Flow-Based market coupling mechanism therefore tended to reduce market prices in France, Belgium, and Netherlands while they increased in Germany. Average prices aligned as a result of a coupling mechanism based on flow, indicating better optimisation of the use of interconnection capacity compared to the current situation. However, the effects between Quarter 1 and Quarter 2 of 2013 can be reversed for the same country.

figure 23 assesses the future effects of the Flow-Based coupling mechanism on hourly price convergence rates in the CWE area. Compared to a situation with ATC market coupling, convergence in the first half of 2013 improved for the following market couples: Germany / Belgium and Germany / Netherlands. During the six months, convergence deteriorated between France and Belgium, France and Germany, France and Netherlands, and finally between Belgium and Netherlands. However, for the entire CWE area, Flow-Based market coupling has a positive effect on changes in convergence rates on the four markets ("Full convergence" in figure 23, i.e. when the price is exactly the same in all four areas): it increased from 11% under ATC coupling to 27% under Flow-Based coupling.

Figure 23: Effects of Flow-Based market coupling on market price convergence



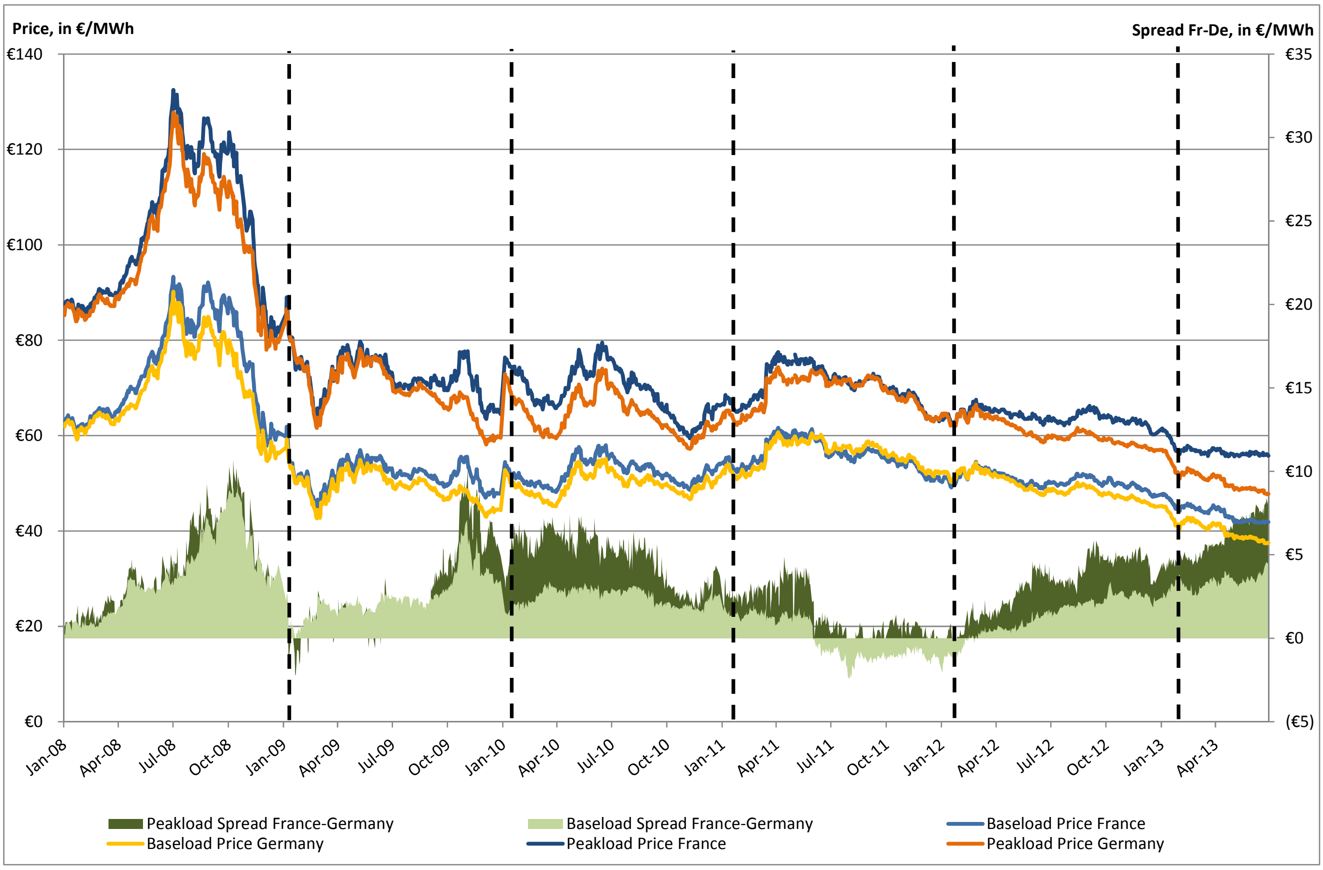
Source: CASC – Analysis: CRE

2.2 After an increase related to the effects of the German moratorium on nuclear power, futures prices followed a downward trend, strongly influenced by coal prices

- **French futures prices were significantly influenced by the German market**

After a significant price increase in spring 2011, with the announcement of the German moratorium on nuclear power, a gradual reduction in the price of futures products on the EEX Power Derivatives market was observed. Y+1 product prices fell from an average of 56.0 €/MWh in 2011 to 50.6 €/MWh in 2012 and continued to fall with an average of 43.7 €/MWh in the first half of 2013 (against 51.2 €/MWh for the first half of 2012) to reach is lowest level of 41.7 €/MWh on 21 June 2013.

Figure 24: French and German Y+1 calendar product prices



Source: EEX Power Derivatives – Analysis CRE

Monthly and quarterly futures products (which are seasonal) sharply decreased compared to 2011:

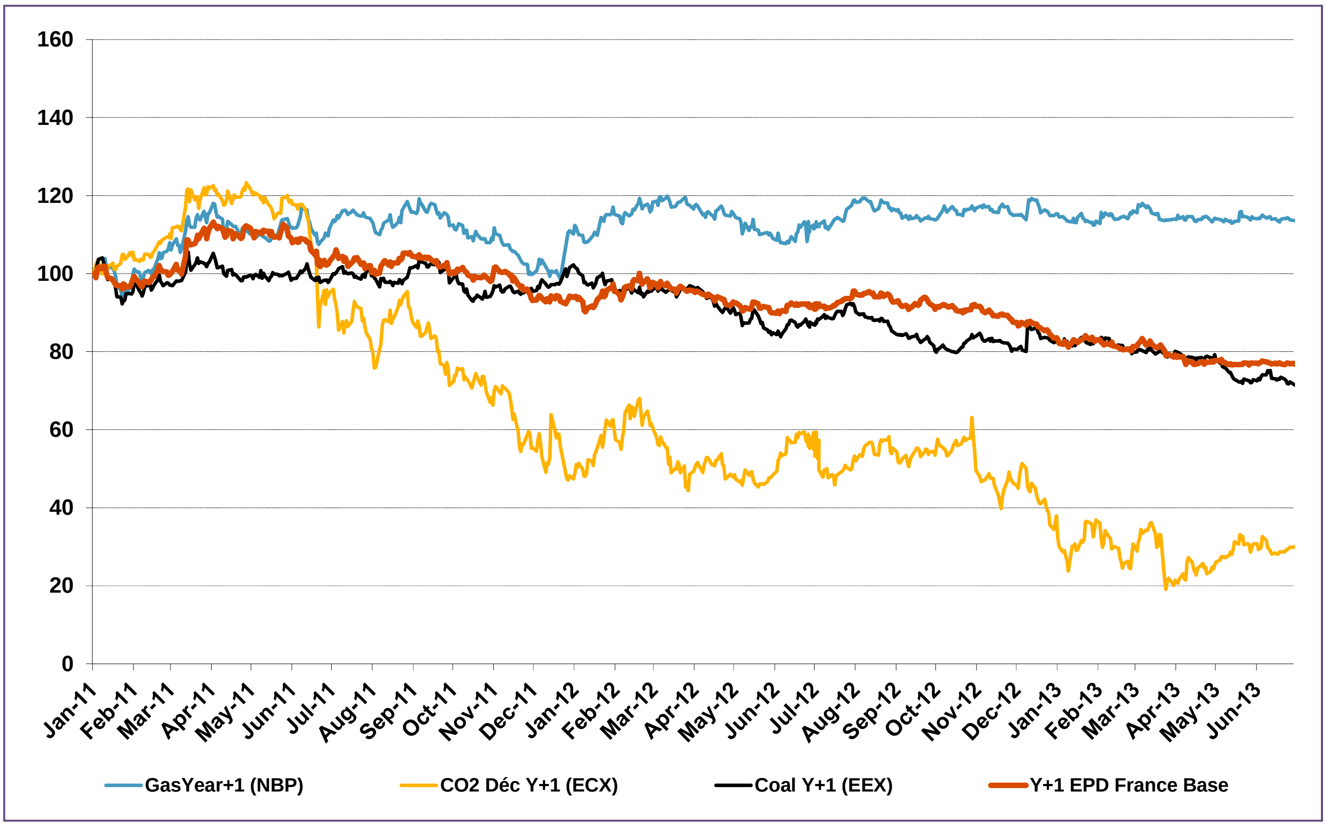
Table 9: Average Y+1, Q+1, and M+1 prices

€/MWh	Maturity Y+1	Maturity Q+1	Maturity M+1
2011	56.0	57.6	54.3
2012	50.6	48.8	47.1
H1 2012	51.2	41.3	44.0
H1 2013	43.9	36.3	39.9

Source: EEX Power Derivatives – Analysis CRE

The fall in futures prices is strongly related to price developments of the various fuels and carbon. 2011 and 2012 were marked by a significant fall in coal and CO_2 prices resulting in reduced generation costs for coal-fired plants and increased competitiveness of the generation technology, particularly in comparison to gas-fired plants.

Figure 25: Fossil fuel and electricity prices - Base 100 January 2011



Source: EEX Power Derivatives, ECX, Heren – Analysis: CRE

In addition, the development of renewable energy capacity continued in Germany and was accompanied with new coal generation capacities[52]. This change in supply occurred in a context of stagnating consumption, especially in France where short and medium term forecasts tended to be lower[53]. In this context, electricity prices fell accordingly.

- **Price spikes in February 2012 put an end to the reversal of the Y+1 price spread between France and Germany which is now increasing**

On the electricity futures markets, German prices are traditionally lower than French prices. However, these prices tended to align as a result of market coupling in November 2010. The announcement of the German moratorium on nuclear power in mid-March 2011 caused a strong rise in Y+1 baseload futures product prices

[52]Germany plans for about 6 GW of new coal generation capacity (*source Bundesnetzagentur*)

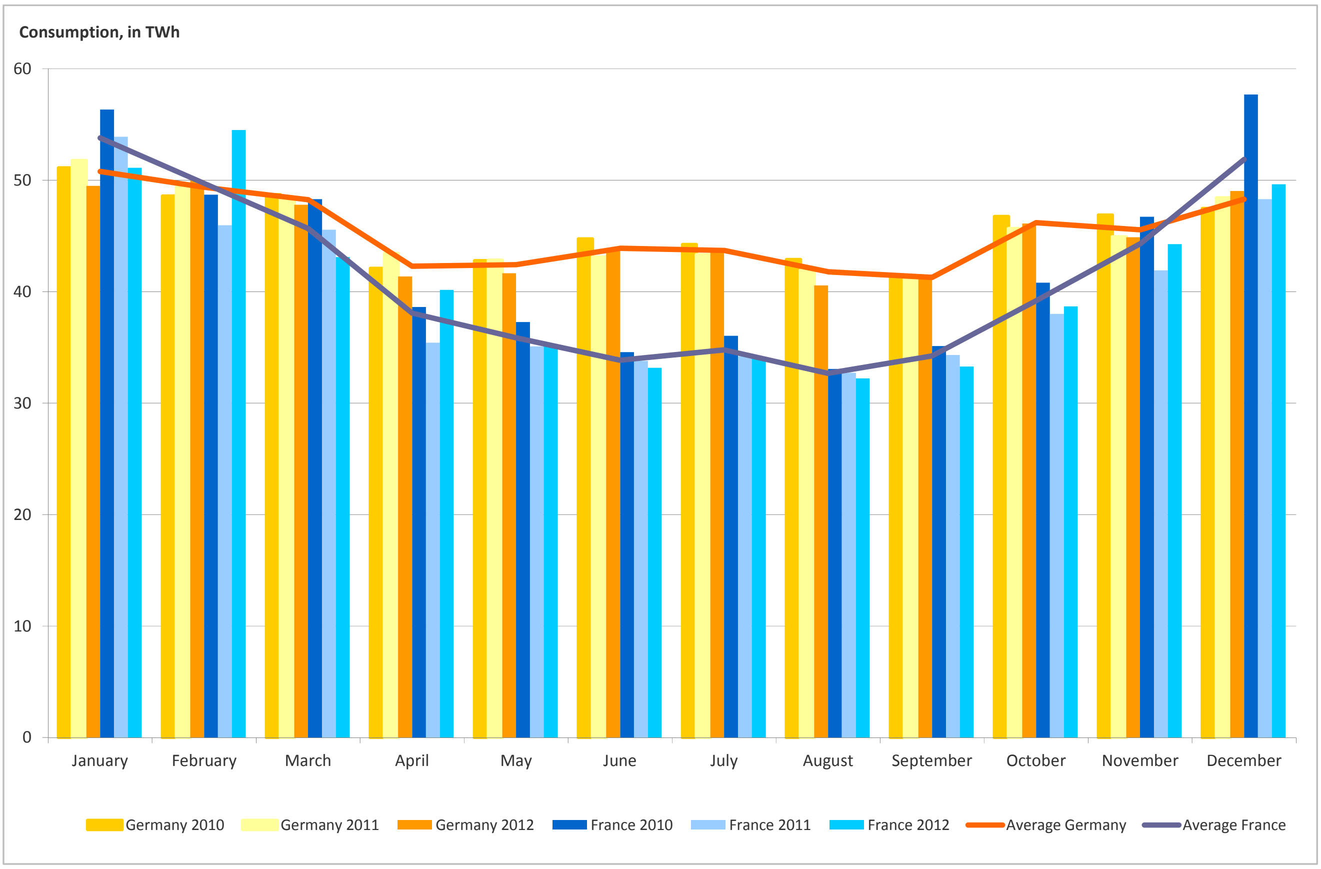
[53]View the RTE's Forecast analysis of the electricity supply-demand balance in France (2013) on its website

in both France and Germany. The *spread* between Y+1 calendar products was reversed and the German price overtook the French price after the moratorium was confirmed on 21 May 2011. However, the reversal of the differential in French and German futures prices ended in February 2012, following the major price spike in France. The differential has since increased, placing the French price 4 €/MWh above the German price in June 2013.

- **Risk premium related to consumption thermo-sensitivity**

In 2012, a risk premium was observed on the French market compared to the German market due to higher French consumption thermo-sensitivity (Figure 26). Tensions on the French system margins were noted on several occasions causing high market prices and even price spikes. German generation capacity relieved the French system but only for the interconnection capacity available between the two countries. When this is saturated the two markets are disconnected and high price differentials are observed between the two countries.

Figure 26: Monthly electricity consumption in France and Germany

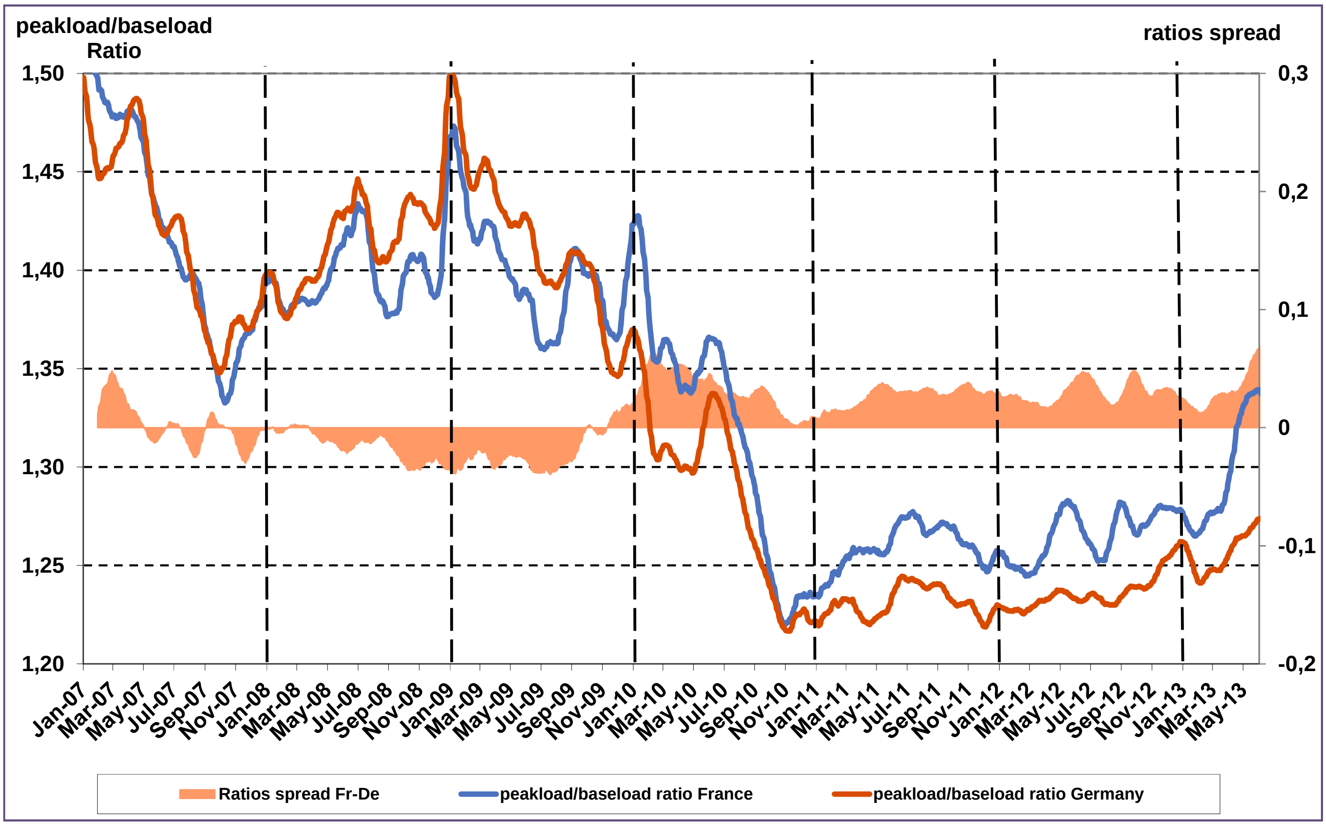


Source: ENTSOE – Analysis: CRE

During the first quarters of 2012 and 2013, respectively characterised by periods of severe (February 2012) and lasting (March 2013 was on average 1.5°C below normal seasonal temperatures[54]) cold, French day-ahead prices were over 10 €/MWh (Q1 2012) and 12 €/MWh (Q1 2013) higher than German prices.

This risk premium is reflected in the ratio between the Y+1 peakload calendar product and the Y +1 baseload product (Figure 27) which was higher in France than in Germany and has risen sharply since early 2013. The evolution of this ratio reflects increased peakload tension in France which is confirmed by the announcement of a system margin of less than 1 GW from 2016[55], reflecting a greater risk of failure.

Figure 27: French and German Y+1 calendar peakload / baseload product ratio (data in 20-days running averages)



Source: EEX Power Derivatives – Analysis: CRE

[54] http://climat.meteofrance.com/chgt_climat2/bilans_climatiques/bilanclim?document_id=27795&portlet_id=95999

[55] View the RTE's Forecast analysis of the electricity supply-demand balance in France (2013) on its website

Quarterly futures product price spreads between France and Germany increased and also showed an increased risk premium on the French market compared to the German market during the winter (Q4 and Q1 products).

Table 10: Quarterly product prices on 28 June 2013 in France and Germany

	French Price	German Price	France-Germany Spread
Q4 2013 Baseload	49.1 €/MWh	39.2 €/MWh	10.0 €/MWh
Q1 2014 Baseload	52.5 €/MWh	41.4 €/MWh	11.1 €/MWh
Q2 2014 Baseload	34.0 €/MWh	33.4 €/MWh	0.6 €/MWh
Q3 2014 Baseload	34.0 €/MWh	34.2 €/MWh	-0.2 €/MWh

Source: EEX Power Derivatives – Analysis CRE

- **Futures prices and ARENH mechanism**

The 2014 baseload[56] calendar product for delivery in France remained stable at about 42 €/MWh for May and June while the German price tended to fall (Figure 28). The price differential between France and Germany therefore increased from 3.4 €/MWh on 2 May 2013 to 4.4 €/MWh at the end of June 2013.

The regulated access to historical nuclear energy (ARENH) mechanism entered into force on 1 July 2011. It allows alternative suppliers to have access to an electricity supply at a fixed price from the incumbent supplier. The price was initially set at 40 €/MWh between July 2011 and January 2012, then at 42 €/MWh from January 2012.

When the baseload calendar product market price is over 42 €/MWh, ARENH supply substitutes wholesale market purchases for alternative suppliers. However, when the wholesale price is at 42 €/MWh or lower, subscribing to ARENH is called into question by more favourable market conditions. Therefore, for supply for 2014, this mechanism provides alternative suppliers with trade-off opportunities until 15 November 2013 when alternative suppliers must define the firm quantities they wish to purchase under the ARENH. In parallel, the incumbent operator (EDF) must anticipate and act on the markets to ensure that the ARENH volumes that will be ordered will be covered.

The stabilisation of French prices at 42 €/MWh in May and June 2013 reflects actions on the market by participants involved in the ARENH mechanism. This mechanism explains the polarisation of transaction around 42 €/MWh.

Moreover, at this price level, the price differential with Germany on 2014 calendar products is consistent with the price differential recorded for spot prices in 2012 (4.3 €/MWh) and the first quarter of 2013 (6.4 €/MWh).

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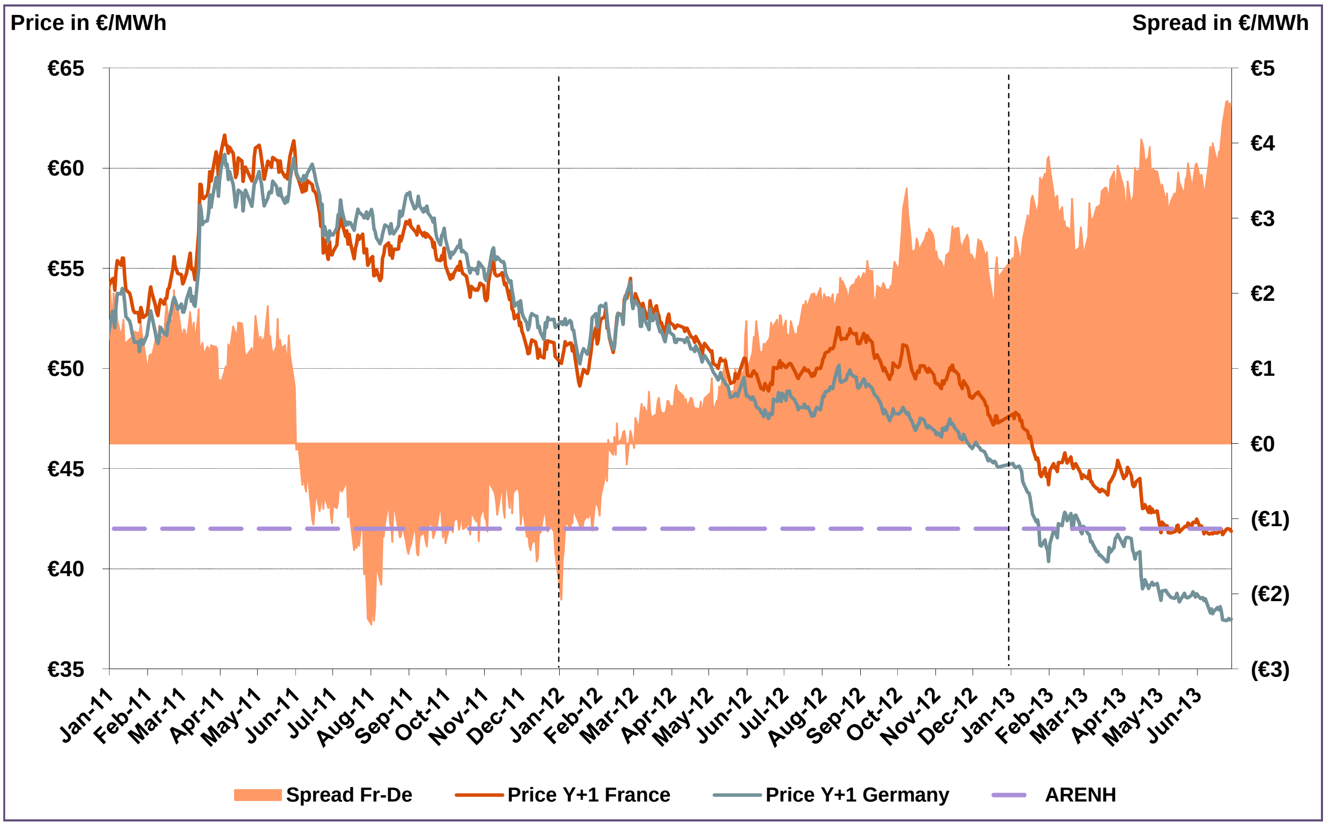
[56] See Glossary for the definition of "Baseload"

However, there are doubts on whether the behaviour of participants with buyer and seller interests has been biased by ARENH. CRE has undertaken extensive research on participant behaviour and is focusing detailed analysis on posted transactions and orders. These analyses are conducted under the REMIT Regulation and are intended to ensure that there is no market price manipulation.

Figure 28: Y+1 price and France-Germany spread

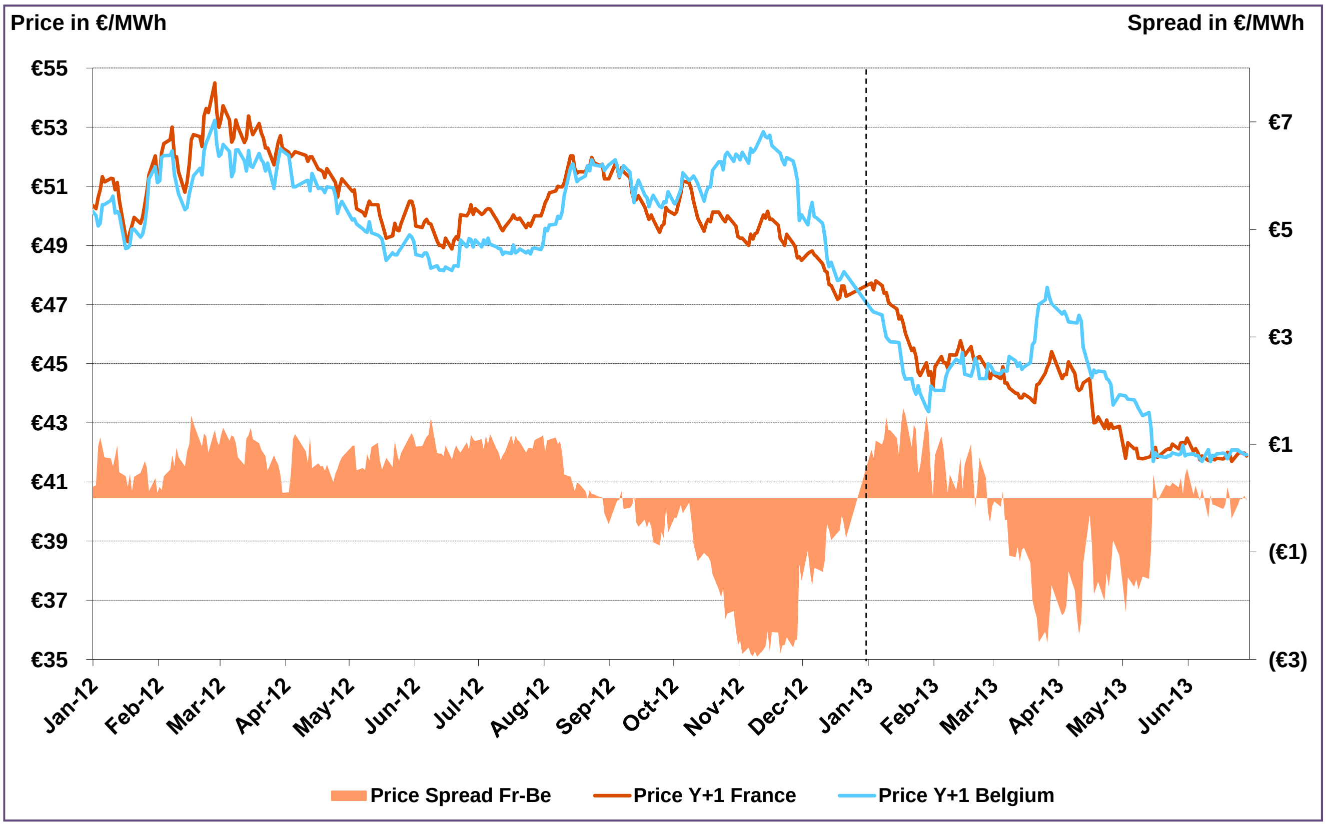


Source: EEX Power Derivatives – Analysis: CRE

- **Futures price differentials with Belgium and Holland favouring France**

The spread between French and Belgian Y+1 baseload calendar products (Figure 29) narrowed between 2011 and 2012, moving from 0.82 €/MWh to 0.1 €/MWh on average (France more expensive). In the first half of 2013, this differential reversed standing at -0.3 €/MWh. Belgian Y+1 calendar product prices were also severely disrupted by developments related to the unavailability of the Doel 3 and Tihange 2 nuclear power plants during the summers of 2012 and 2013. Finally, a stabilisation of French and Belgian prices at around 42 €/MWh since May 2013 was noted reflecting market participant forecasts of a 2014 price convergence (in connection with the market coupling mechanism).

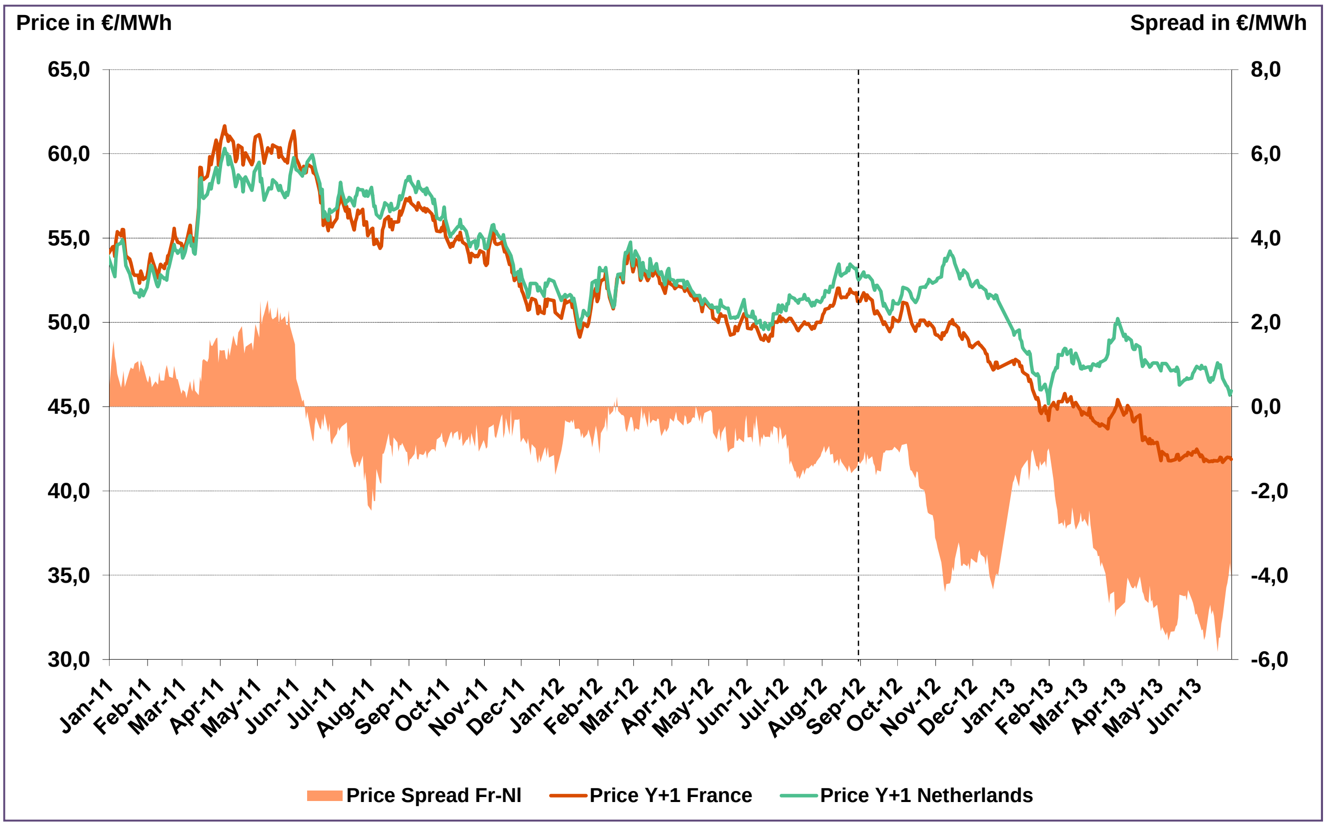
Figure 29: Y+1 price and France - Belgium spread



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

The spread was reversed between France and Holland in June 2011 with higher Y+1 product prices in Netherlands. In 2012 and the first half of 2013 (Figure 30), the Y+1 product increased strongly due to the different composition of French and Dutch generation facilities. While French Y+1 prices fell sharply following the drop in coal prices, Dutch electricity prices remained heavily depending on gas whose prices remained high. In this context, the Y+1 baseload calendar product price in Netherlands did not fall much in comparison to the French price, significantly increasing the price differential.

Figure 30: Y+1 price and France - Netherlands spread



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

3 ELECTRICITY GENERATION AND GENERATION DATA TRANSPARENCY ANALYSIS

On 1 January 2013, France's installed generation capacity was 128.7 GW[57] according to RTE which represents an increase of 1.5% over the year. figure 31 breaks down this total capacity by the various generation technologies showing its evolution since 2010. The capacity increase was mainly driven by the distribution network due to the respective development of wind and solar power by 0.8 GW and 1 GW. On the transmission network, while the power of generation facilities remained generally stable, conventional thermal power plants experienced a decline in installed oil capacity concomitant with the increase in the installed capacity of thermal gas-fired power plants due to:

- the closure of conventional thermal power plants using fuel oil or natural gas which led to a decrease of 1.3 GW of installed capacity[58],
- the connection of three gas-fired combined cycle power plants for 1.2 GW of power in Martigues near Marseille and Croix de Martigues in Toul.

If only reference facilities [59]connected to the transmission network are considered, installed capacity totals 106.3 GW of which some 63.1 GW is nuclear representing 59.4%. Hydroelectric generation constituted 22.9% with a small majority of "lake" generation units managed according to water availability dam reservoirs and a balance constituted of "run-of-river" plants whose generation is dependent on water availability. The remainder of capacity is mainly constituted by thermal power stations using coal, natural gas, and oil derivatives such as fuel (respectively 6.0%, 5.2%, and 6.5%).

Installed capacity operated by the EDF group represents over 97 GW or about 91% of the reference facilities. The main competitors of the incumbent French producer on the electricity generation market are:

- GDF SUEZ which, through the CNR and the SHEM, its generation assets, and the aforementioned holdings in nuclear power plants, holds 5.4% of the total generation capacity of the reference facilities,
- E.On France (the SNET, E.On group), which holds 3% of installed capacity.

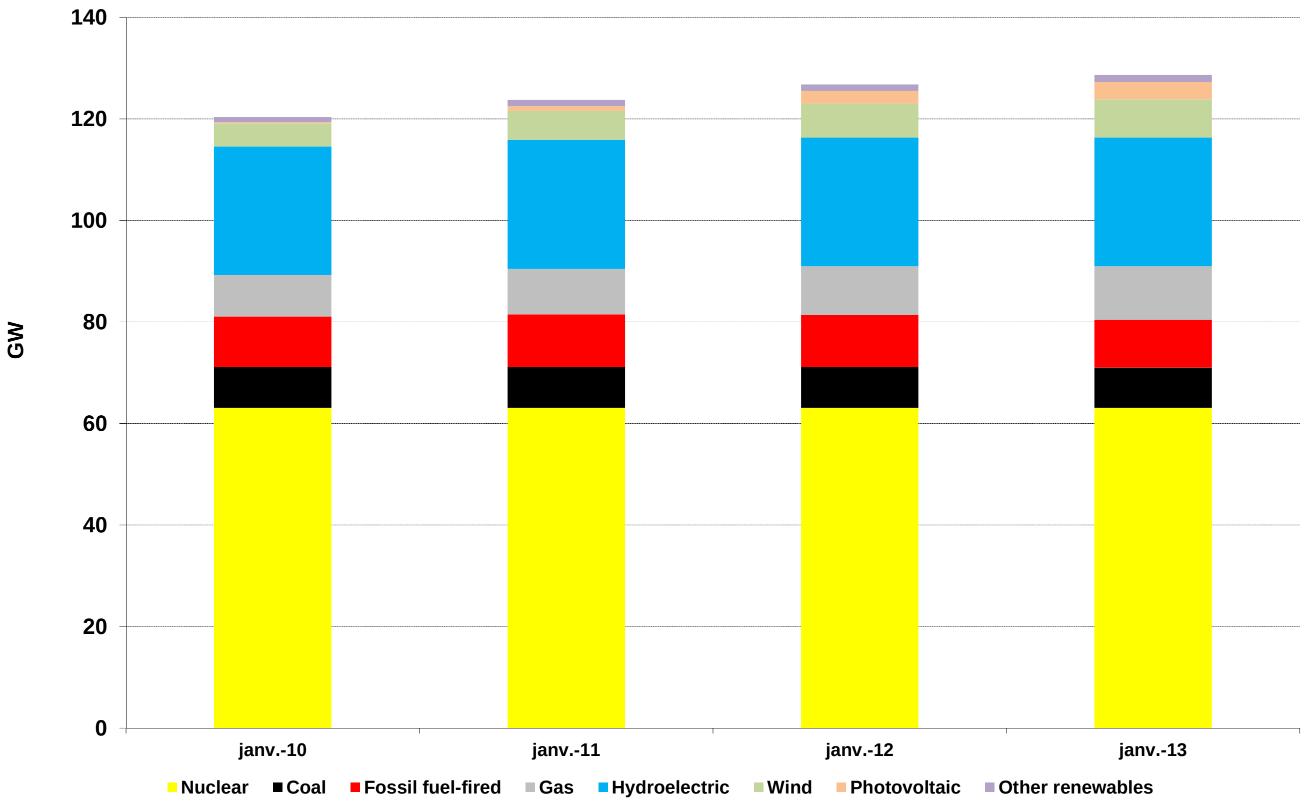
These three producers operate a total of over 99% of the reference generation capacity.

[57] View RTE's 2012 Electricity report on its website

[58] The decrease in thermal power plant installed capacity is mainly due to the decrease in the number of co-generation power plants due to of the end of commercial contracts with purchase obligations signed a dozen years ago.

[59] Reference facilities are constituted of all generation units generating over 20 MW for which hourly metering data is available D+1 for D in reasonably acceptable economic conditions, located in mainland France, and belonging to the sectors and producers mentioned above.

Figure 31: French electricity generation facilities (levels of the various generation technologies)



Source: RTE – Analysis: CRE

Box 3: The development of renewable energy sources (RES) impacts wholesale market electricity prices

In the European Union, electricity produced by renewable energy sources benefit from priority access rights to the electricity system and support schemes adapted to each generation technology. The "inevitable" generation is injected on the market independently to supply and demand conditions which determine price levels[60]. The variable nature of some generation from renewable energy sources (solar, wind) requires increasing flexibility. Generating facilities are currently mainly composed of low variable cost equipment but which have rather inflexible operational constraints such as baseload or middle-baseload coal-fired or nuclear power plants. Gas-fired plants are more flexible but are penalised by the exceptionally low coal and CO_2 prices (Box 6). This context negatively impacts wholesale prices and occasionally leads to negative prices.

The development of renewable energies contributes to lower wholesale prices

In 2012, the average French baseload spot price fell to 46.9 €/MWh which was 4% lower than in 2011. In countries with a high connection of renewable energy, such as Germany[61], the fall in the spot price was higher, reaching nearly 17% in 2012. An inverse correlation between the injection of additional megawatts from renewable energy sources on the electricity network and lower spot prices had already been identified in 2012. This is the case on the German market where spot prices were estimated to fall by 1.34€/MWh for an additional 1,000 MW of wind generation and 0.82 €/MWh for solar generation[62]. Given the prospects of French renewable generation prospects and energy exchanges with neighbouring markets with a large share of green energy in their energy mix, the effects of price reductions could be accentuated.

To cope with demand, electricity generation facilities are mobilised according to their *merit order* which is established according to their marginal cost of generation,. The market will use energy produced by power plants with the lowest marginal cost of generation. Then, when they are operating at maximum power, the more expensive plants are used and finally the plants with the highest marginal cost of operation are used as a last resort.

The marginal cost of generation for renewable energy is very low due to low operating and maintenance costs. For this reason and because of the priority network access for renewable energy, the increasing integration of renewable energy generation in the energy mix is changes the merit order of other means of generation. [63]

Wind and solar energy generation can even exclude technologies with a marginal cost of generation that is too high to meet demand from the *merit order*. This exclusion, which is usually only partial, may be total if the guaranteed renewable energy generation capacity is greater than the available capacity of all flexible

[60] In the case of green certificate obligations imposed on suppliers, green electricity purchased by suppliers from producers is also injected into the market as soon as it is produced.

[61] 67.7 GW of installed wind and solar capacity at the end of 2012 against 11.0 GW in France

[62] BDEW, Erneuerbare Energien und das EEG: Zahlen, Fakten, Grafiken (2013) http://www.bdew.de/internet.nsf/id/17DF3FA36BF264EBC1257B0A003EE8B8/$file/Energieinfo_EE-und-das-EEG-Januar-2013.pdf

[63] Directive 2009/28/EC of 23 April 2009 (Art. 16.2.b)

facilities. It negatively affects spot prices for some of the year's hours.

A phenomenon of rising prices was observed during some hours although it does not offset the main effect of falling prices. Given the variability of renewable generation over a day (depending on the wind or the sun), the balance between generation and consumption must be provided by more or less flexible conventional technologies. Frequent changes in operating modes which are implemented to monitor fluctuations in net demand after including inevitable renewable energy generation push up operating costs. The costs of power plants with flexible technologies required to frequently start and stop are spread over shorter periods of operation. To cover these costs, plant operators are obliged to propose higher hourly prices. Part of these generation facilities are therefore excluded from the *merit order*. In a scenario without energy from renewable sources and for the same hourly demand, these plants could offer their products for certain hours at lower prices than those they are obliged to ask for to remain profitable.

Renewable energy, combined with inflexible means of generation, can lead to the appearance of negative prices

The increasing introduction of RES and the variable nature of their generation can result in negative prices. French generation facilities are effectively partially constituted of inflexible means of generation such as nuclear and coal-fired power plants. Therefore, in a situation of significant variation in renewable energy generation, holders of inflexible means of generation may prefer to sell their electricity at negative prices rather than shutting down their generation plants. This is the case of the negative prices that occurred in France on 25 December 2012 at 7am (-50.06 €/MWh).

The weather at the end of December 2012 was particularly mild. Combined with the weak economic activity on 25 December, this led to very low electricity consumption in France that day. At the same time, German consumption was low whereas wind energy generation was relatively high.

This situation in Germany led to exports to France during the off-peak morning hours of 25 December 2012. *Day-ahead* price decoupling and saturated German exports to France during off-peak hours preceding the occurrence of negative prices on the morning of 25 December 2012 was observed.

In summary, German market fundamentals in Germany (high inevitable generation and low consumption levels) and low French consumption at a time of reduced economic activity and very mild climatic conditions explain the occurrence of negative prices on 25 December 2012. The lack of flexibility in available generation means on both sides of the border resulted in the formation of these negative prices.

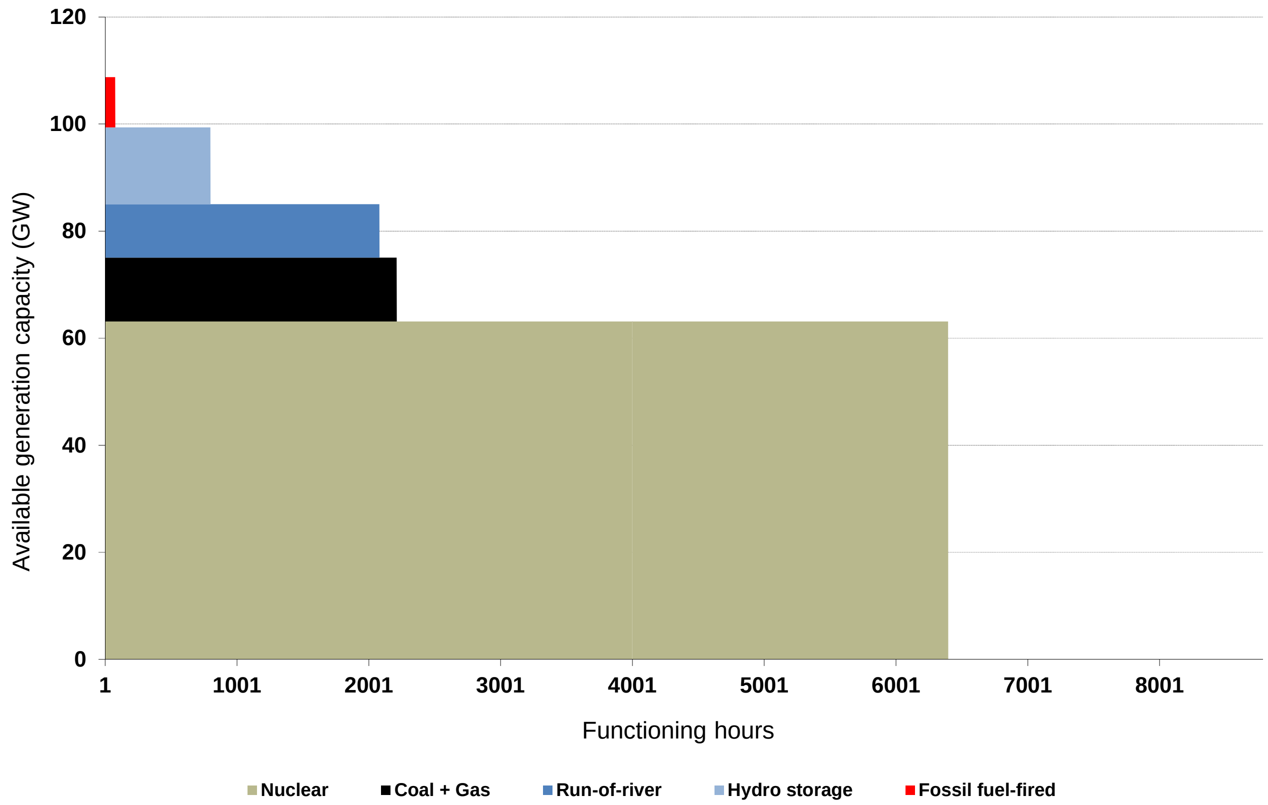
Increased sources of uncertainties on the centre-west region's electricity systems due to the high penetration of inevitable energy and increasing thermo-sensitivity in France could cause more frequent extreme events in the future. However, it should be noted, as already mentioned in Section II (Box 2), that RES are not always the cause of negative prices.

3.1 The utilisation rates of the various generation technologies reflected related marginal cost of generation levels. Nuclear plant generation availability, which fell sharply in 2012, increased in the second quarter of 2013

The total energy generation and installed capacity ratio is used to define the rate of utilisation of each type of generation technology. Converted to the equivalent utilisation period, these rates are shown in figure 32. The equivalent periods of use reflect both the availability and utilisation (baseload and peakload) of the various generation technologies. Therefore, it would seem that the period of highest use in 2012 concerned nuclear power plants with 73% of the time against 76% in 2011, due to less availability. In contrast, the oil power plants, which is responsible for peakload generation, was only used 1.0% of the time.

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

Figure 32: Period of use of the various generation technologies in 2012



Source: RTE – Analysis: CRE

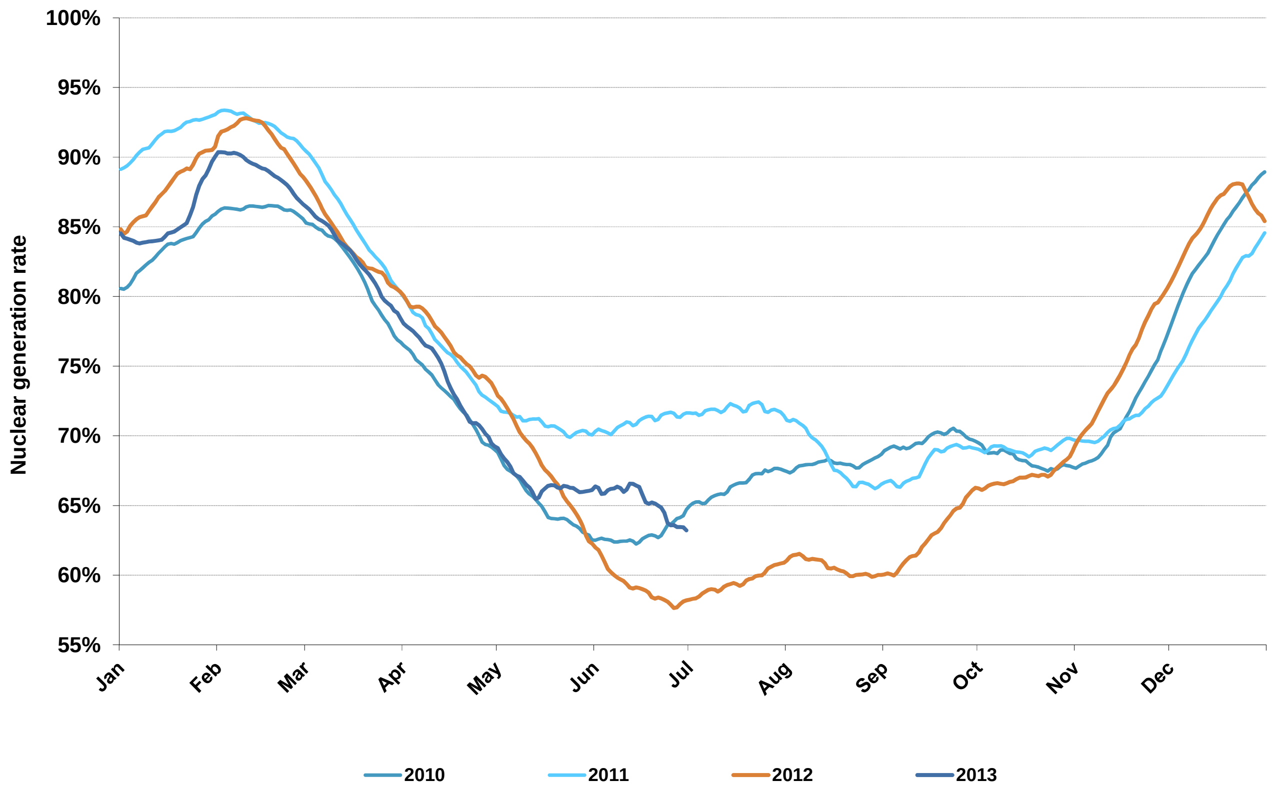
- **Generation rate and availability of the nuclear power plants decreased in 2012 but have strongly increased in 2013**

Characterised by a significantly seasonal nature related to electricity demand levels, nuclear generation recorded a rate of 73% in 2012 which was lower than the 76% of 2011. This level is the lowest rate recorded since 2010. Total nuclear generation fell by 3.8% to 405 TWh compared to the previous year (Figure 33). This fall can be partially attributed to the sharp fall in nuclear generation availability during the summer where many scheduled start-ups of shut-down nuclear power plants were posted (Figure 34).

Reduced nuclear availability in 2012, combined with the cold wave in February that resulted in high consumption, led to a slight decline in net exports which rebounded in April and September to values that were closed to those observed in summer 2011 (Figure 35).

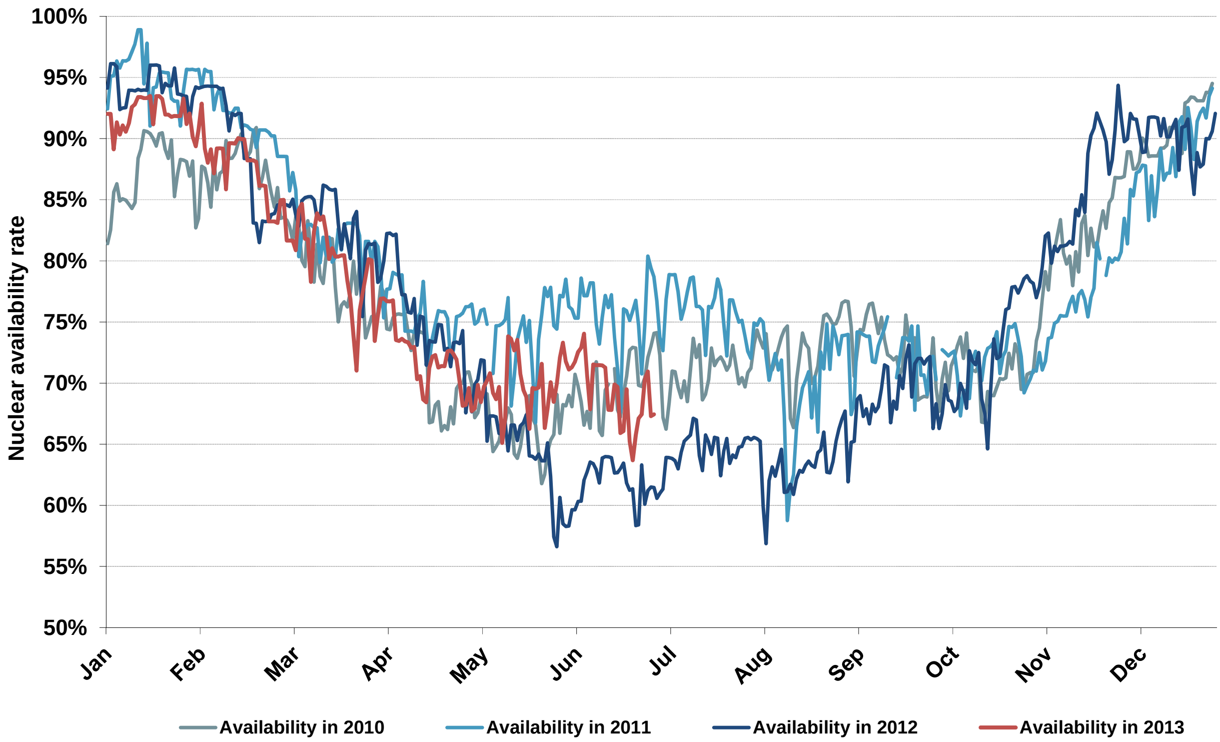
In the first half of 2013, nuclear generation remained stable at 207.7 TWh (+0.2% compared to the first half of 2012). A clear improvement in the availability of nuclear power plants in the second quarter of 2013 was noted due to a decrease in unplanned outages. However, nuclear generation was equivalent to that in the first half of 2012 due to a larger number of scheduled shut-downs begun prior to the first half of 2012. Nuclear power plant availability at the end of June increased by almost 6 points compared to June 2012.

Figure 33: Nuclear generation rate 2010-2013 (Actual Nuclear generation/ Installed nuclear capacity - 30-day moving average)



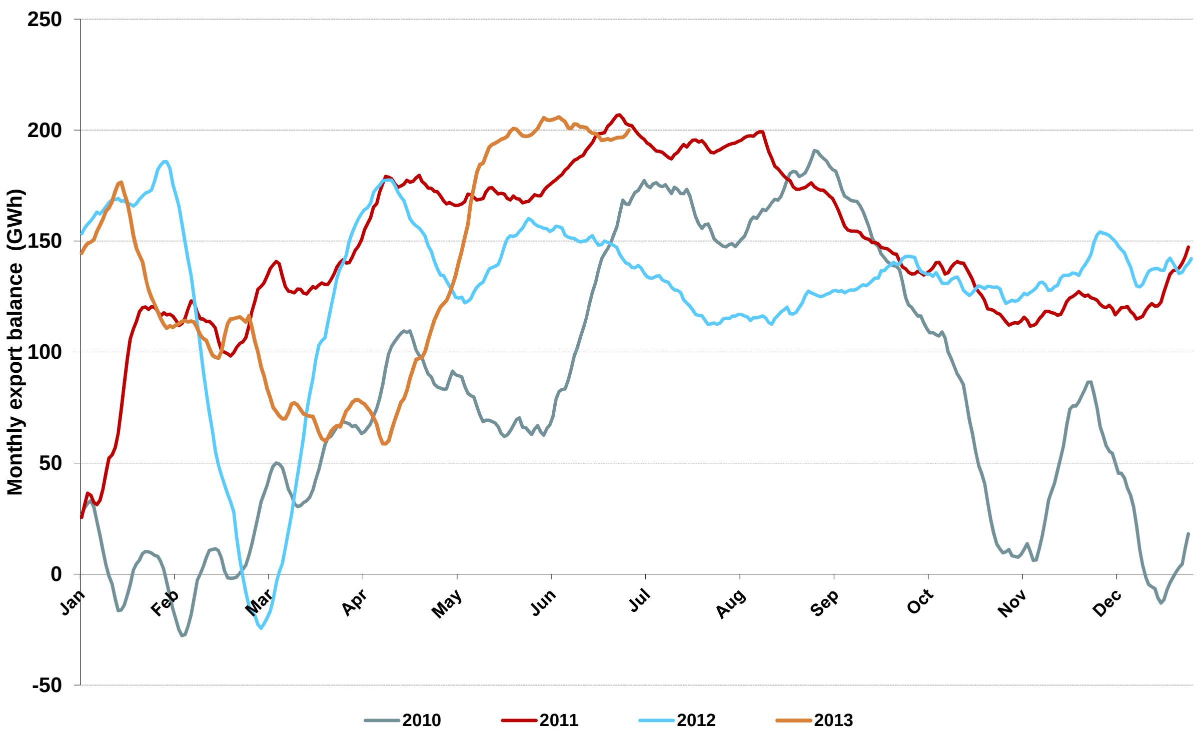
Source: RTE – Analysis: CRE

Figure 34: Nuclear generation availability rate 2010-2013 (Available nuclear capacity/ installed nuclear capacity)



Source: RTE – Analysis: CRE

Figure 35: Monthly export balance 2010-2013 (30-day moving average)



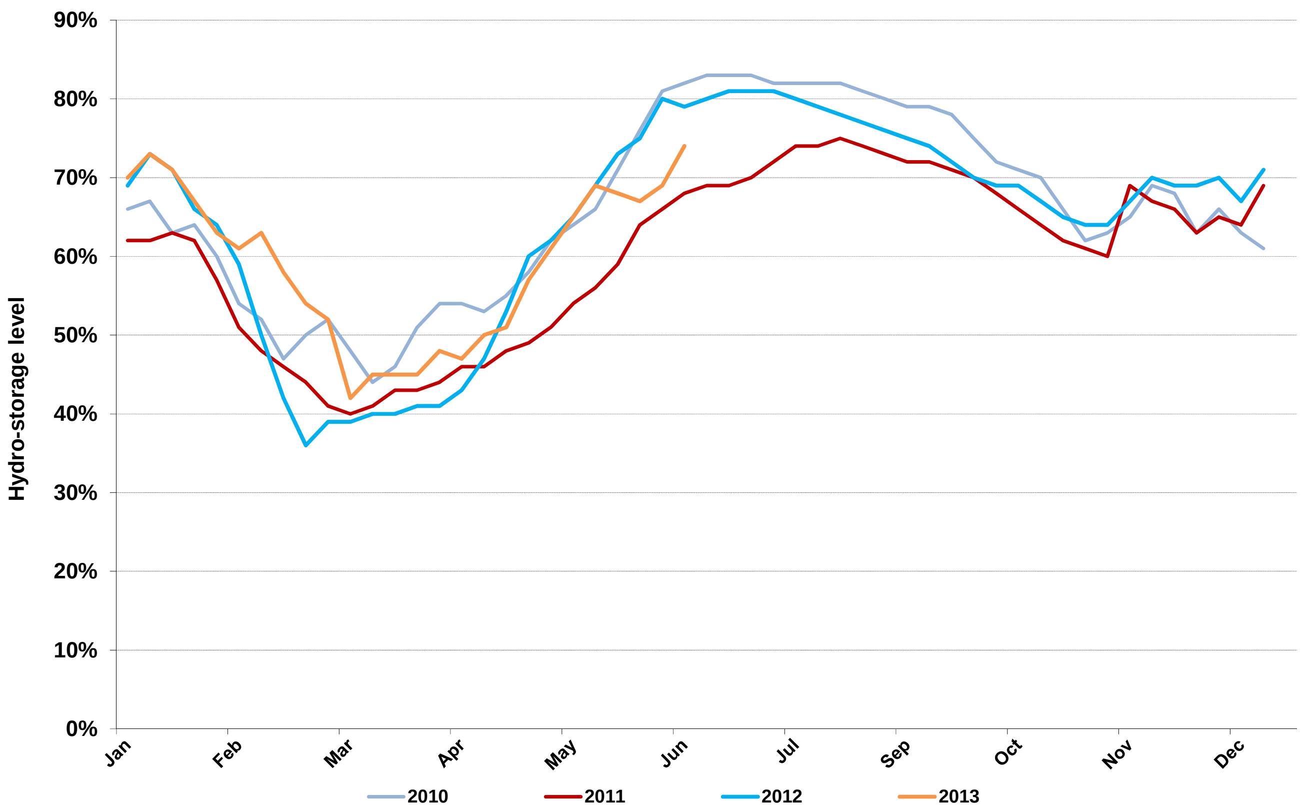
Source: RTE – Analysis: CRE

- **Hydraulic generation returned to normal but less gas and oil electricity generation**

Unlike 2011, which experienced an exceptionally dry spring (the driest since 1959) and rather dry autumn, 2012 was marked by high rainfall allowing better use of hydroelectric power plants. However, there was a sharp decline in water stocks during the first few months of the year reaching a minimum of 36% in February. As shown by figure 36, this particularly low value indicates high use of these stocks during the cold wave in early February 2012. Over the second quarter of 2012, a significant increase in rainfall helped to restore water reserves to levels over those recorded for 2011.

During the first half of 2013, heavy rainfall in South Europe along with abnormally cold temperatures up to the end of May helped restore water stocks to a level similar to those in 2010.

Figure 36: Hydro Storage



Source: RTE – Analysis: CRE

In 2012, the total Hydroelectric generation stood at 63.8 TWh representing an increase of almost 26% in relation to 2011. Generation from fossil fuel power plants fell by almost 7% (Table 11). The drop in this type of generation was mainly driven by coal and oil generation technologies with only 30 TWh produced in 2012, down 22% compared to the previous year. This decline was slowed by coal prices which were low on world markets in 2012 and the use of fossil-fired power plants during the cold wave in February 2012. With regard to generation from renewable energy sources excluding hydroelectric there was a strong increase of 23% explained by the development of facilities. It represented almost 25 TWh or 4.6% of French electricity generation.

Table 11: Electricity generation for the various generation technologies

Generation technology	Total energy generation (TWh)	Variation 2012/2011	Generation rate (% of installed capacity)
Nuclear	404.9	-3.8%	73.3%
Coal	18.1	+35.1%	26.1%
Oil	6.6	-13.2%	8.0%
Gas	23.2	-23.7%	25.2%
Hydraulic	63.8	+26.8%	28.7%
Wind	14.9	+23.1%	22.8%
Solar	4.0	+66.7%	13.0%
Other sources of renewable energy	5.9	+5.4%	48.5%

Source: RTE

3.2 In 2012, borders were often marginal unlike in the nuclear and hydroelectric generation technologies

A generation technology is deemed marginal when its marginal cost of generation determines the market price, i.e. when daily auction prices correspond to the marginal costs of a unit belonging to that generation technology.

Analysis of marginality consists in identifying the type of generation to which the price set by the market corresponds for each hour of the day; i.e. finding a power plant in operation for which the marginal cost of generation was closest to the market price.

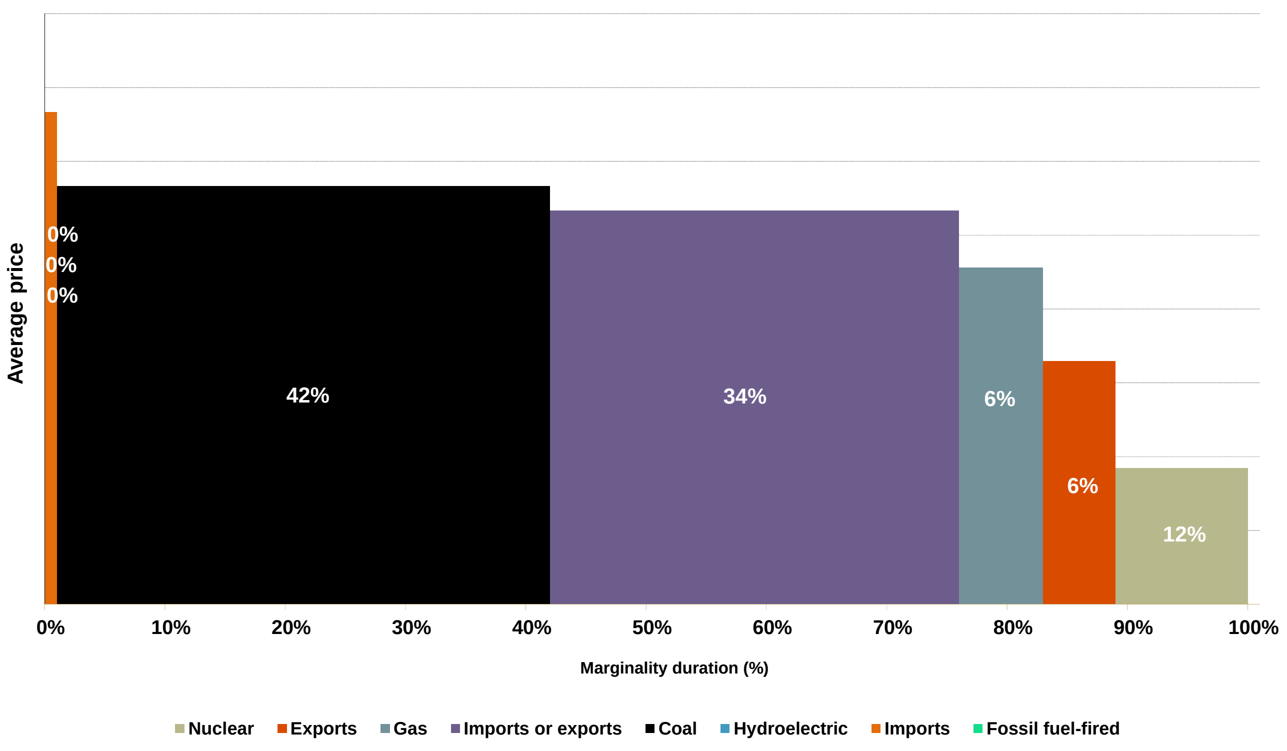
The analysis presented here retains both a price and power criterion to identify the unit and therefore the marginal generation technology at a given time:

- the price criterion selects power plants for which the difference between market price and generation marginal cost is less than 5€/MWh,
- the power criterion leads to only considering units with generation between 15% and 85% of the theoretical maximum generation capacity.

Of all of these units meeting the two criteria, only units with generation costs closest to the market price are then considered marginal. However, if no units meet the criteria, price levels are then deemed to be explained by foreign supply and demand and the borders are therefore considered marginal.

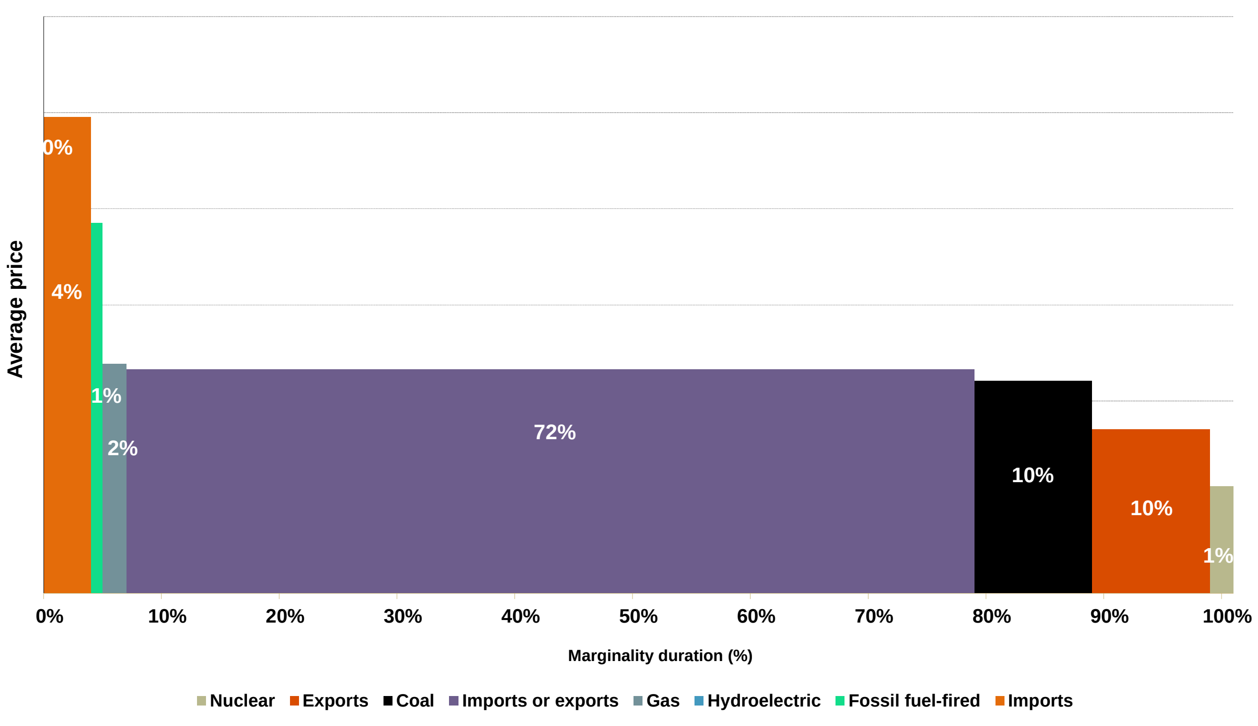
The results of these estimates are summarised for 2011 and 2012 in the figures below. It should be noted that these results are highly dependent on the calculation method and thresholds used. They do, however, help determine a fairly stable classification of generation technologies according to the duration of marginality.

Figure 37: Marginality duration of the various generation technologies in 2011



Source: CRE

Figure 38: Marginality duration of the various generation technologies in 2012



Source: CRE

The evolution of the results obtained in 2011 and 2012 highlights:

- a sharp decrease in the duration nuclear power marginality which only determined the price in 1% of cases (for 73% of generation in 2012),
- no marginality for hydropower, as in 2011, this generation technology did not determine any prices in 2012,
- a strong decrease in the duration of marginality of coal which was marginal 42% of the time in 2011 but only 10% in 2012, and a decrease in the gas generation marginality,
- and on the other hand, a strong increase in the duration of marginality of the borders (from 40% in 2011 to nearly 86% in 2012) and a slight increase in oil generation marginality.

Average prices observed during the marginality hours of gas-fired power plants increased although it did fall when the coal generation technology determined market prices. These findings are consistent with the evolution of gas and coal prices in 2012.

Overall, market prices could not be explained by the marginal cost of any French generation unit (at the threshold of 5 €/MWh) in 40% of cases in 2012. Compared to the level observed in 2011, this duration of border marginality significantly increased in 2011 (+113%). As mentioned earlier, in these cases, it is considered that cross-border trade determined the prices on the French market.

The results obtained with regard to the hours when borders were marginal show that during these times the average price was close to the marginal cost levels of coal power plants in neighbouring countries. These results are consistent with the competitiveness of coal due to its low prices on world markets in 2012 (Cf. Section 2.2).

3.3 The transparency mechanism continued to improve and provided a response to REMIT obligations in 2012 and 2013. Forecast quality deteriorated slightly but did reduce the overall statistical difference between actual and forecast D-1 availability.

The transparency mechanism has facilitated compliance with transparency obligations imposed by the 714/2009 Regulation of the European Parliament and Council of 13 July 2009[64] since 1 January 2012 and it continues to develop now including increasing the refresh rate of generation facility availability forecasts

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

CRE had requested the UFE to improve generation data transparency[65]. This transparency is essential to the correct functioning of wholesale electricity markets by allowing market participants to assess the development of the electricity supply/demand balance.

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[64] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0015:0035:FR:PDF

[65] Cf. Decision of CRE of 20 November 2009

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

During 2011, the UFE expanded its mechanism by publishing the RTE's daily estimates on day-ahead wind generation and with the publication, within the hour, of actual generation data of units of more than 100 MW and the UFE's generation forecasts for the next day. It may be recalled that EDF changed the method to calculate nuclear power unit network return dates in July 2011. While the work return dates displayed as "at the earliest" dates for the sections shut down and corresponding to a technically feasible minimum period, return dates now include temporary margins in line with delays recorded during feedback.

The UFE continues to develop its transparency mechanism with improvements adopted in 2012 and the first half of 2013. Additional information which has been published since 1 January 2012 is a vector allowing market participants to comply with the transparency requirements imposed by Regulation no. 714-2009:

- Since 1 January 2012, the UFE expanded its mechanism with the creation of a page on the network operator's transparency platform dedicated to information supplementing that already issued including forecast availability and unplanned unavailability of electricity generation facilities. This new information, in the form of statements by producers, can therefore concern, for example, partial unplanned unavailability or delays in restoring generation units to service. This publication allows all market participants to better assess the supply situation of producers who are part of the UFE. 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,
- A further improvement was also made in March 2013 with the increase in the refresh rate of expected generation availability. Data on forecast available generation capacity power is now updated every day (and not every week) medium-term (between 2 and 13 weeks) and weekly (instead of monthly) for long-term (14 weeks and next three years). In particular, more frequent updates of medium-term facility availability applies to information collated by generation technology (nuclear, coal, gas, oil, hydraulic) for all generation units as well as those broken down by generation unit when their power is over or equal to 100 MW. This increased publication frequency of is intended to provide more specific information.

CRE considered that all these developments meet electricity market participant expectations.

- **Decreasing transmission rates**

The transmission rate observed in the case of availability forecasts fell in 2012 compared to 2011. 81.4% of the information necessary to prepare availability forecasts by generation technology was transmitted on average, as opposed to 84.3% in 2011. If this transmission rate is weighted by the installed capacity of reference facilities used for each forecast, the rate also decreased to 88% in 2012 against 89% in 2011.

Table 12: Forecast availability of the various gerneration technologies

Generation technology Data	Coal	Hydraulic run-of-river	Oil	Gas	Nuclear	Hydraulic lake	Total
Comprehensive forecast rate	98.9%	66.5%	96.8%	51.1%	95.0%	80.0%	81.4%
Average 7-day statistical difference	631 MW	9 MW	158 MW	59 MW	2,119 MW	116 MW	3,092 MW
Average (7-D) statistical difference in % of generation	9.9%	0.1%	2.3%	1.1%	3.4%	0.8%	2.9%
Average (7-D) statistical difference in % of generation (2011)	6.1%	0.8%	2.3%	1.0%	2.2%	0.9%	2.1%

Analysis: CRE, based on information collected and transmitted by the 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 (W-1 to W-12). A forecast is considered comprehensive when all participants concerned by this generation technology have submitted a forecast for the date and maturity considered.*

- **Forecast availability is generally decreasing**

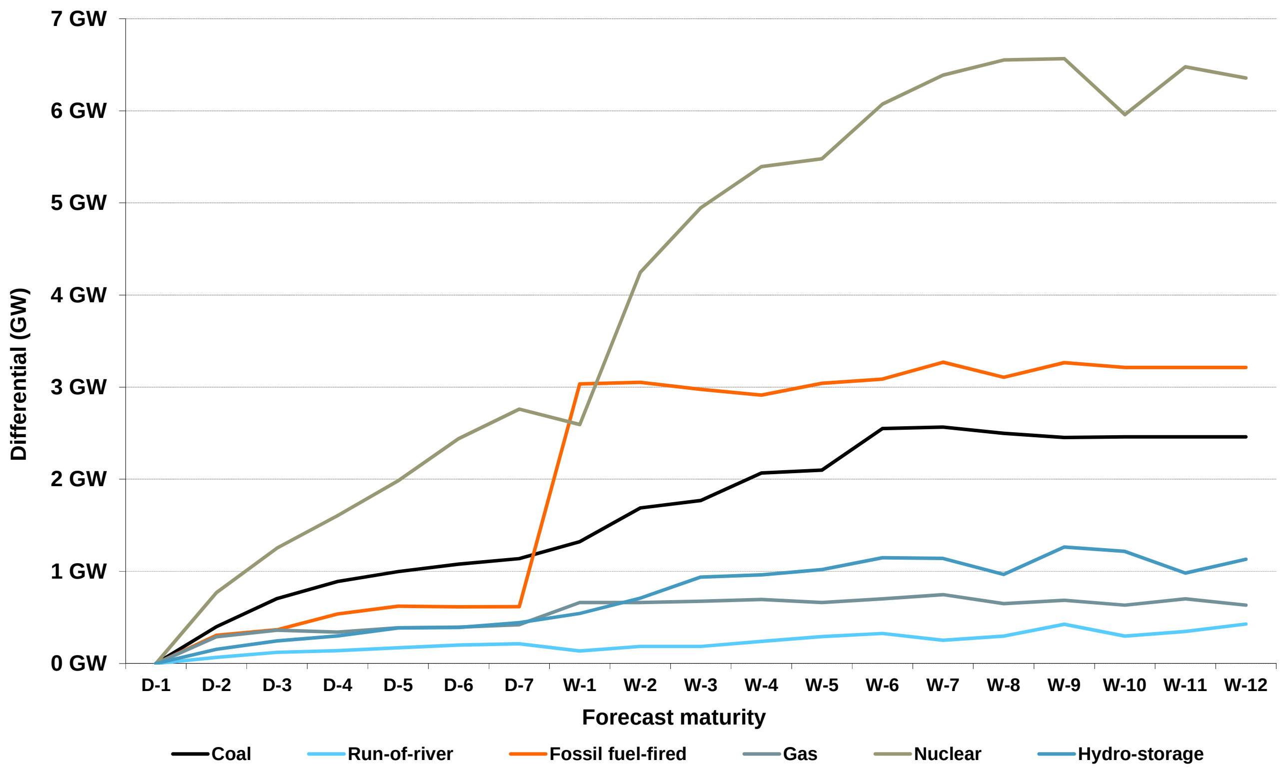
To measure the quality of the forecasts published for the various generation technologies, the difference between the forecast availability announced on the various due dates and the value recorded is measured.

As seen last year, there was a positive statistical difference[66] for all thermal generation technologies which was particularly significant for coal (in relation to installed facilities). In the case of nuclear generation, the difference between seven-day forecasts and actual availability averaged 2.1 GW against 1.4 GW in 2011. This decrease can be related to lesser availability of nuclear facilities in the second quarter of 2012.

[66] Remember that this difference is due to the methodology used which leads producers to declare the capacity they deem to be available in the future without statistically considering inevitable accidental incidents randomly affecting generation units.

figure 39 represents the average differences observed between the published availability forecasts and the one-day forecast, as the final known forecast, for durations of less than twelve weeks.

Figure 39: Average deviation between availability forecasts and the last forecast (D-1)[67]



Source: RTE - Analysis CRE

[67] Growth in the forecast difference with its maturity results from the rules defined by producers regarding the submission of availability forecasts. The UFE's "transparency" specifications effectively indicate 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 unforeseen unavailability". This precise definition therefore excludes any assessment of the inability of a power plant to maintain its availability or to become available again.

- **Actual availability remained statistically lower than D-1 forecasts published for nuclear generation but the difference is narrowing**

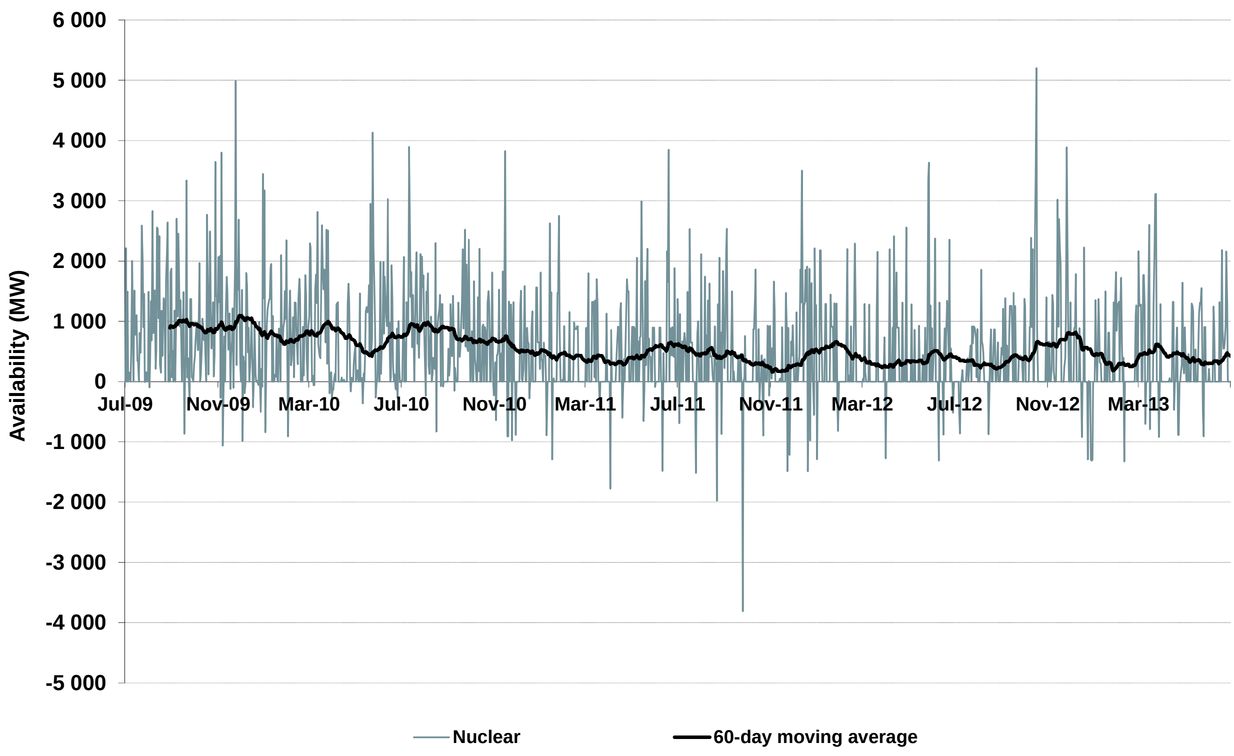
Comparing the provisional availability announced on D-1 and that actually recorded reveals a statistical overestimation of availability forecasts announced under the transparency mechanism. Across all generation technologies, this was estimated at about 654 MW for 2012 against 686 MW in 2011. This reduction was in large part due to the decline in the statistical difference recorded for the nuclear generation technology which fell from 435 MW to 398 MW in 2012 (Figure 40).

Table 13: Average differences between D-1 provisional availability and actual availability

Coal	Hydraulic run-of-river	Oil	Gas	Nuclear	Hydraulic lake	Total
148 MW	-17 MW	73 MW	-13 MW	398 MW	64 MW	654 MW

Source: RTE - Analysis CRE

Figure 40: Average difference between the (D-1) forecast and actual nuclear generation availability



Source: RTE - Analysis CRE

4 ANALYSIS OF SPOT MARKET OFFERS AND THE ADJUSTMENT MECHANISM

4.1 Offer consistency with the physical condition of the electricity system is verified on the spot market

Offers submitted by the various market participants on the French EPEX SPOT Auction platform are analysed in this section.

The supply level on the spot market was correlated with the system margin and few offers were between 100 and 300 €/MWh. Hourly offers at all prices increased strongly in 2012.

figure 41 shows the relationship between sales order books (volumes offered at different prices) and the margin indicator, i.e. the excess capacity available reflecting the state of tension on the French power system.

In 2011, hourly offers at all prices (for €0/MWh) averaged 4,902 MWh which represents a strong increase of 1,064 MWh compared to 2011. This increase is consistent with the strong development of RES and increased run-of-river hydropower generation in 2012, which are technologies with extremely low generation costs. Hourly offers at all prices represented 34% of offered volumes.

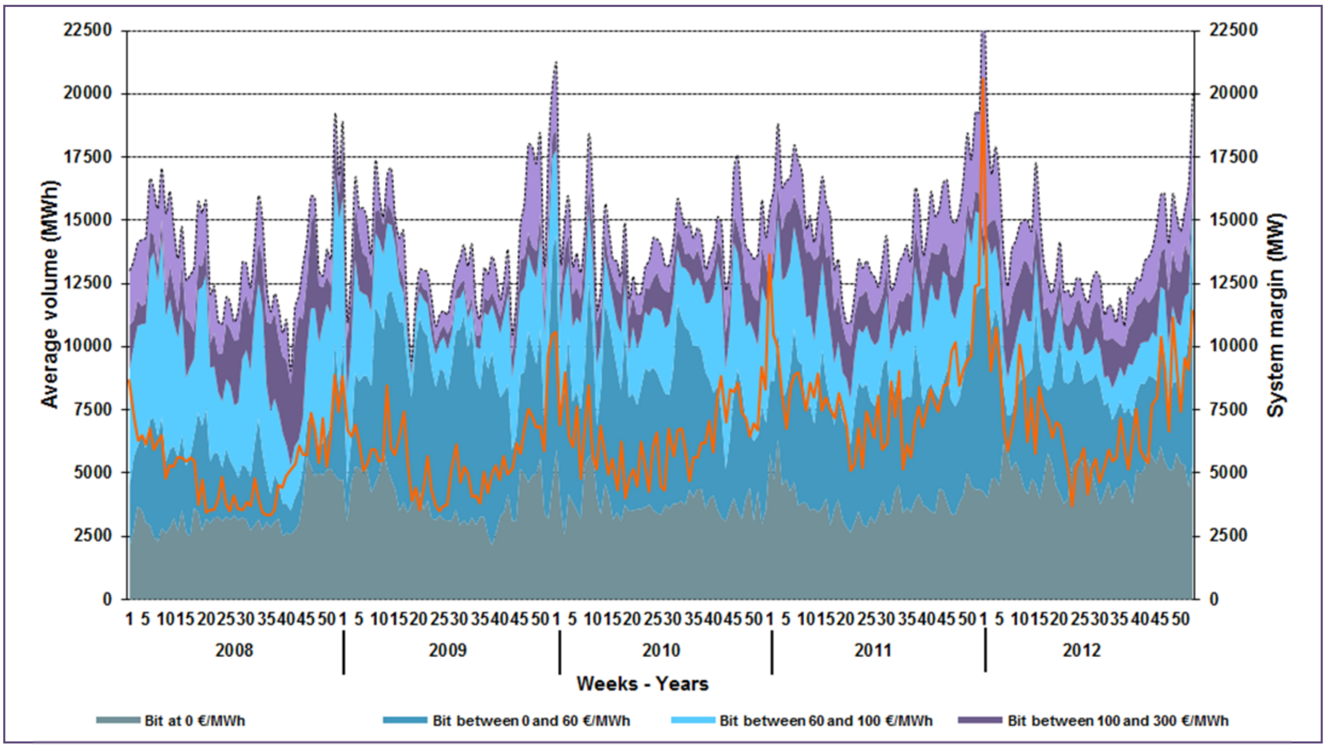
30% of offered volumes on average were at price levels between 0 and 60 €/MWh. This represents an offered volume of 4,207 MWh on average which is a decrease of 11% compared to 2011. This decrease is related to increased unavailability of French nuclear generation facilities in 2012.

The average hourly supply volume between 60 and 100 €/MWh fell to 1,744 MWh which was a fall of 44% compared to 2011. This proportion decreased during the year, following the trend of competitiveness of the gas generation generation technology (Section 2.2).

Above €100/MWh, average hourly supply increased from 3,270 MWh to 3,388 MWh, including 1,520 MWh for the €100-€300/MWh range. These offers corresponded to peakload and extreme peakload generation equipment offers with running time 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 41: Aggregate offer and margin system indicator - 2012



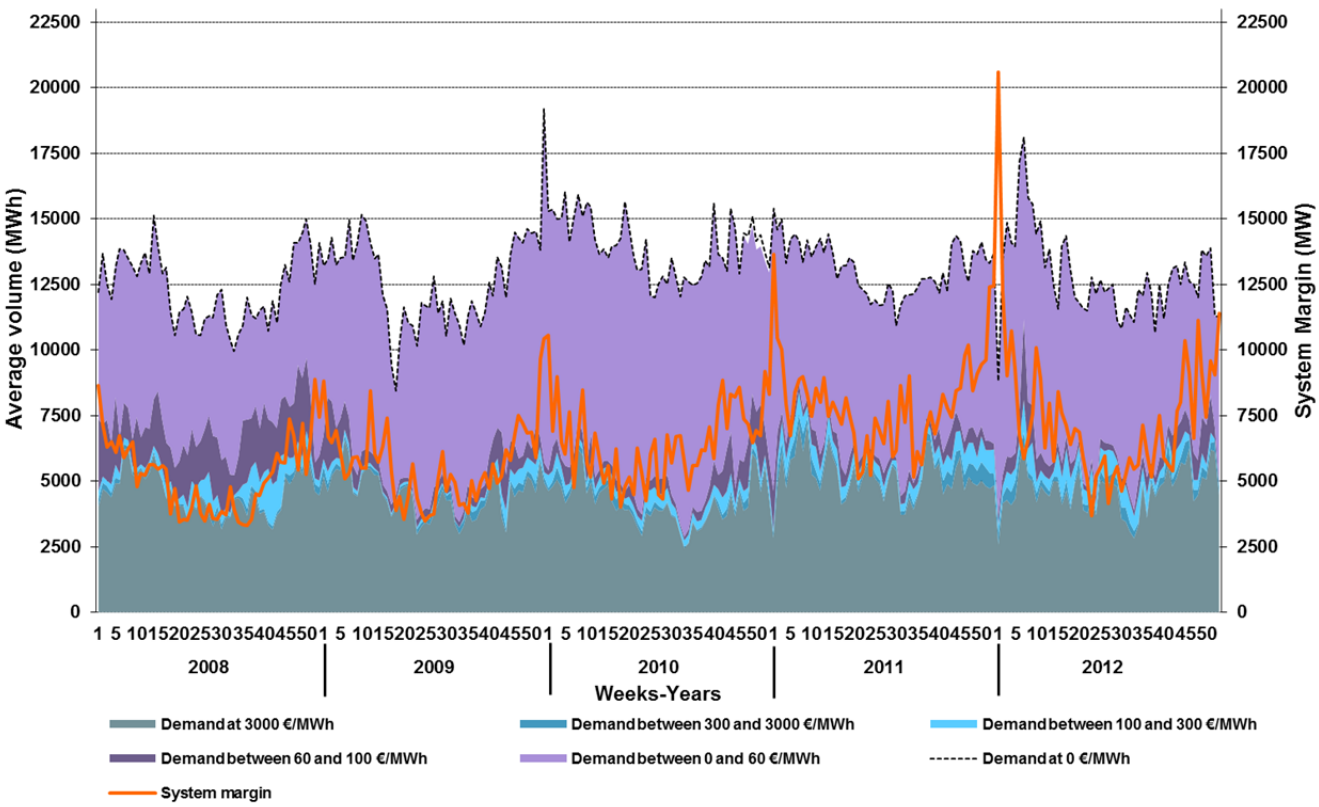
Source: EPEX - Analysis CRE

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

In 2012, 57% of the aggregate demand was characterised by a willingness to pay between 0 and 100 €/MWh (Figure 42) as opposed to 54% in 2011. The average hourly volume demanded between 100 €/MWh and 300 €/MWh was relatively low (about 590 MWh).

The average volume of hourly offers of demand at any price represented an hourly average of 4,643 MWh in 2012 which is a decrease of 511 MWh compared to 2011.

Figure 42: Aggregate demand and margin system indicator - 2012



Source: EPEX - Analysis CRE

- **Greater sensitivity of the EPEX SPOT day-ahead market price in France than in Germany**

EPEX SPOT publishes price resiliency data for its French, German, and Swiss markets every day. For supply shocks (buy or sell) at any price, EPEX SPOT recalculates what the market price would have been. As the German and French markets are coupled, a supply shock on one side or the other of the border will impact both markets. This data are used to assess market price sensitivity and by extension market liquidity and depth on EPEX SPOT auctions. The tables below show average price variations resulting from a supply (-500 MW or -1,000 MW) or demand (+500 MW or +1000 MW) shock from either the home market or a neighbouring market, for the French and German markets. When the interconnection capacity between France and Germany is used to its maximum, market sensitivity compared to its neighbour is much more limited.

Table 14: Average variations in prices for supply / demand shocks on the home market

		-1,000 MW	-500 MW	+500 MW	+1,000 MW
2012	France	-2.4 €/MWh	-1.29 €/MWh	+1.61 €/MWh	+3.4 €/MWh
	Germany	-1.86 €/MWh	-0.78 €/MWh	+0.93 €/MWh	+1.76 €/MWh
H1 2013	France	-2.62 €/MWh	-1.33 €/MWh	+1.33 €/MWh	+2.74 €/MWh
	Germany	-1.99 €/MWh	-1.01 €/MWh	+1.11 €/MWh	+2.18 €/MWh

Source: EPEX SPOT - Analysis: CRE

Table 15: Average trends in prices for supply / demand shocks on the neighbouring market

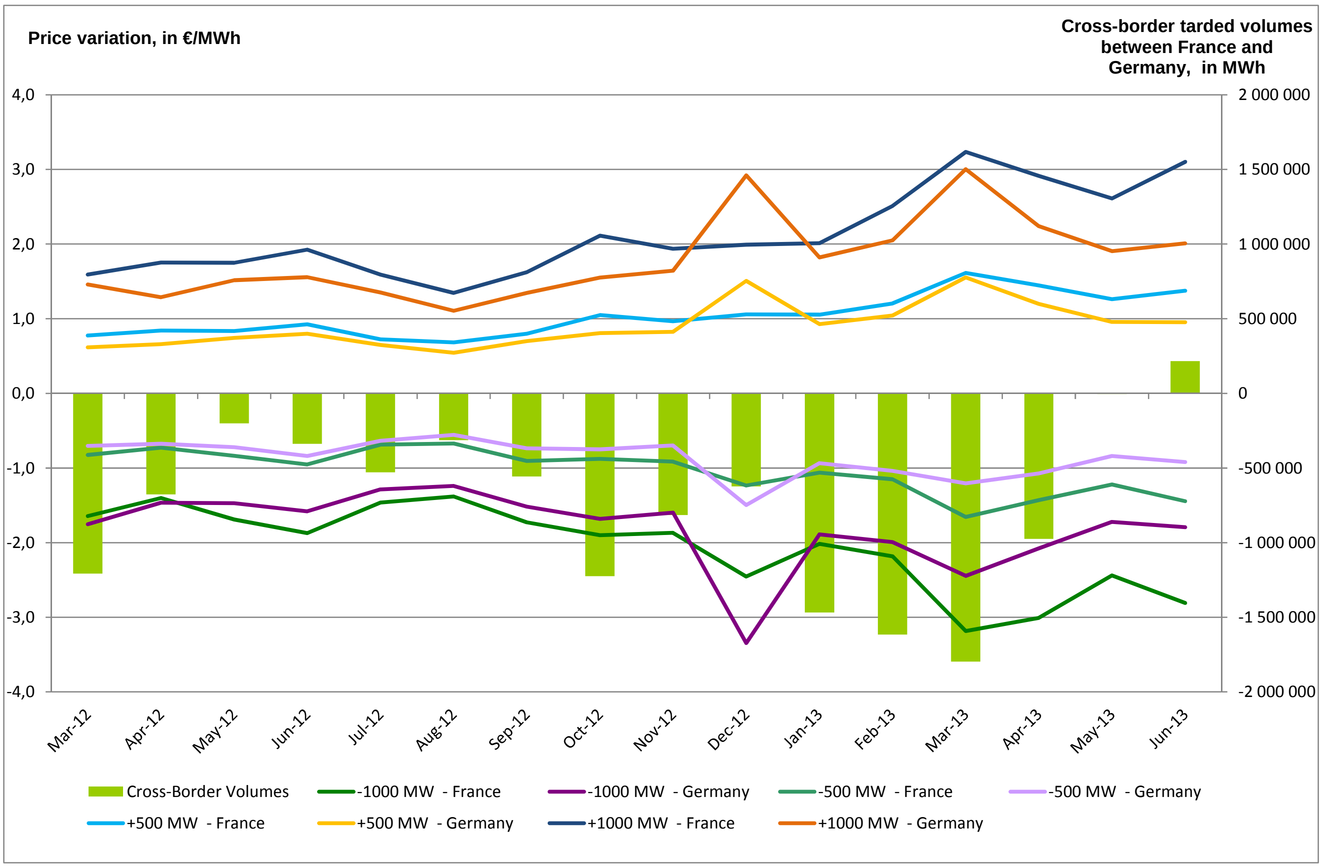
		-1,000 MW	-500 MW	+500 MW	+1,000 MW
2012	France	-0.57 €/MWh	-0.22 €/MWh	+0.43 €/MWh	+0.78 €/MWh
	Germany	-0.59 €/MWh	-0.25 €/MWh	+0.44 €/MWh	+0.80 €/MWh
H1 2013	France	-0.44 €/MWh	-0.21 €/MWh	+0.29 €/MWh	+0.58 €/MWh
	Germany	-0.47 €/MWh	-0.24 €/MWh	+0.27 €/MWh	+0.55 €/MWh

Source: EPEX SPOT - Analysis: CRE

This data shows that there is a greater sensitivity of French market prices, indicating a risk that extremes can be reached more easily when the balance between supply and demand is strained.

In a more detailed analysis of EPEX SPOT resilience data, several elements are highlighted. For a home market supply shock (Figure 43), market prices are more sensitive in winter than in summer due to the thermo-sensitivity of power consumption (especially in France). It was also found that price sensitivity in Germany rose sharply in December 2012 where significant negative prices were observed. Exchanges between France and Germany are higher when supply shock price sensitivity is high, as illustrated by March 2013. This highlights the role of interconnections in supply security by mitigating the impacts of supply shocks on the home market.

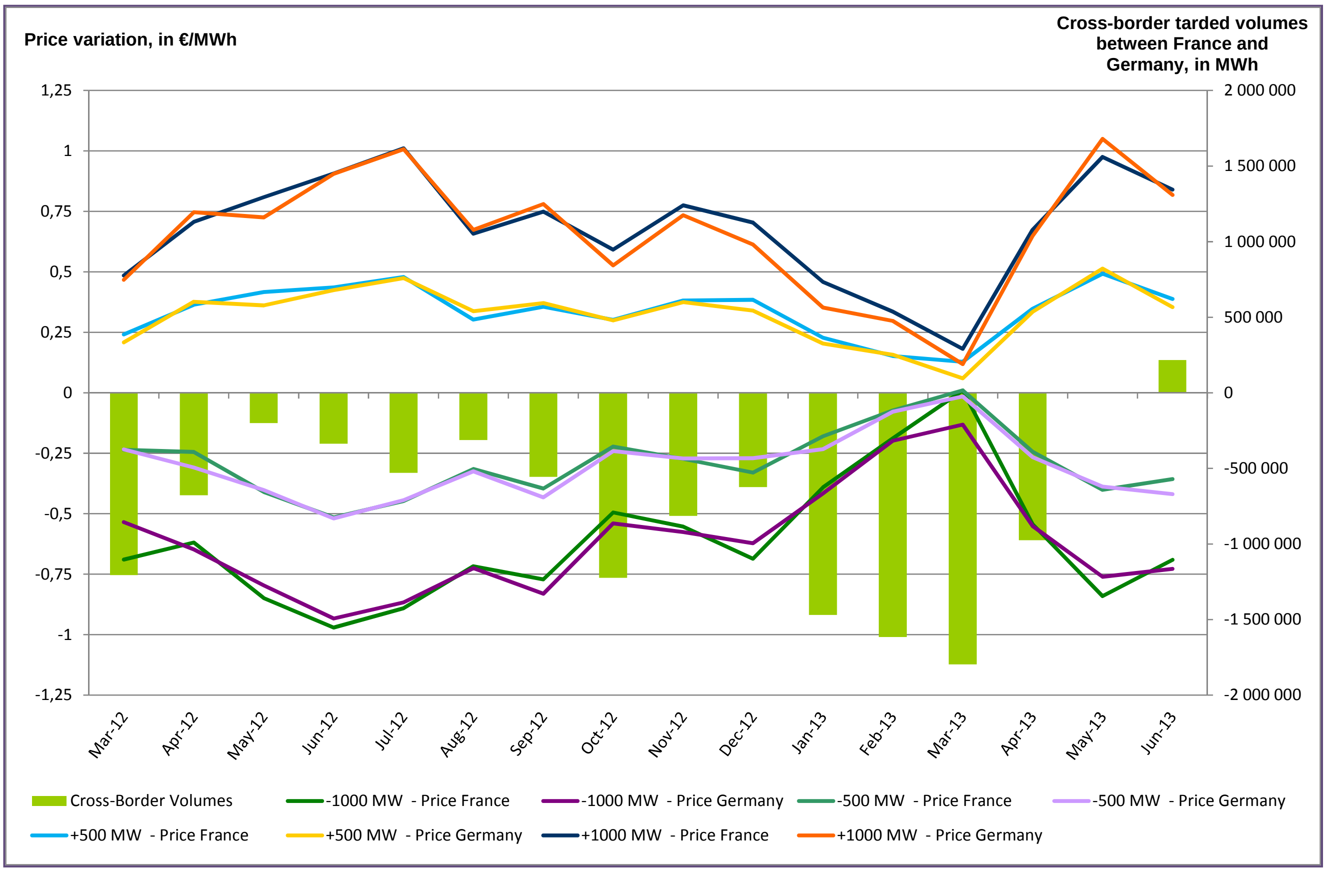
Figure 43: Sensitivity of hourly prices during a supply shock on the market, by month



Source: EPEX SPOT, RTE - Analysis: CRE

In contrast, price sensitivity of supply shocks from a neighbouring country (Figure 44) decreases with cross-border trading volumes as interconnection saturation isolates the markets. Therefore, in March 2013, when the interconnection was regularly saturated, French and German price sensitivity to supply shocks from across the border was greatly reduced.

Figure 44: Sensitivity of hourly prices during a supply shock from the neighbouring country, by month



Source: EPEX SPOT, RTE - Analysis: CRE

- **The difference between the EDF system prices and marginal costs decreased in 2012**

EDF offers on the markets were broadly consistent with its marginal costs.

Regarding the use of EDF generation resources, CRE specifically monitors existing differences between prices on the spot market and the marginal costs of the EDF generation facilities determined by the calculations of its daily optimisation models

This indicator helps to understand the exercise of market power. This analysis is performed on a daily time step based on data received monthly and focuses on the hours for which EDF offers are supposed to determine the auction price. On average, the price-cost difference during these periods in 2012 was 2.2%. As a reminder, this difference was 5.0% in 2011, 3.2% in 2010, and 6% in 2009 (cf. Monitoring Reports for 2011-2012[68], 2010-2011, and 2009-2010).

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[68] View the report on CRE's website

Beyond this average value, high variances for shorter periods are also subject to specific questioning. This was the case in 2011 when the difference increased for several weeks. EDF justified the increase[69]. Such levels were not achieved during 2012 or the first half of 2013.

4.2 With regard to balancing mechanisms, competition on lower balancing volumes remained limited. Hydropower remains the main contributor to the supply and demand balance.

The balancing mechanism which has been implemented since 1 April 2003 provides the RTE with power reserves that it can mobilise as soon as a supply and demand imbalance occurs, at any time. The balancing actor provides the RTE with technical and financial conditions to allow it to modify its generation, consumption, and trade programmes.

In 2012, although upward balancing volumes decreased (-10%), downward balancing volumes increased (15%) (Figure 45). The system was therefore generally long, with 57.4% of half-hourly steps for which RTE anticipated a surplus of energy on the electrical system. In all, RTE enabled 7.7 TWh of adjustments, or 1.7% of consumption (excluding Transmission System Operator losses), against 7.4 TWh in 2011.

During the cold wave in 2012, the good availability of generation facilities maintained the supply-demand balance without the use of special measures and there was even a downward trend on the on the balancing mechanism. Throughout February, the RTE activated significantly less volumes especially for supply and demand balancing. The cold wave was responsible for a price spike of 1,939.2 €/MWh that occurred on 9 February for two half-hours between 6 and 7 am.

The significant downward balancing volumes reflect a tendency for participants to over-supply during periods of high consumption. Using the few available units (at a high marginal cost) to compensate for a potential uncertainty would effectively be particularly expensive during these periods and it was therefore more prudent to anticipate a possible short positions. This strategy of participants partly explains the regular downward trend of the electricity system during the winter 7 pm peakload.

Over the first half of 2013, upward and downward balancing volumes increased (respectively +14% and +8%) compared to the first half of 2012 and 28 March 2013 was a particularly tense day. Record volumes were recorded for the balancing mechanism with nearly 87 GWh used by RTE which is the seventh highest for the generation - consumption balance since the mechanism was created. The exceptional situation on this day was due to a combination of factors:

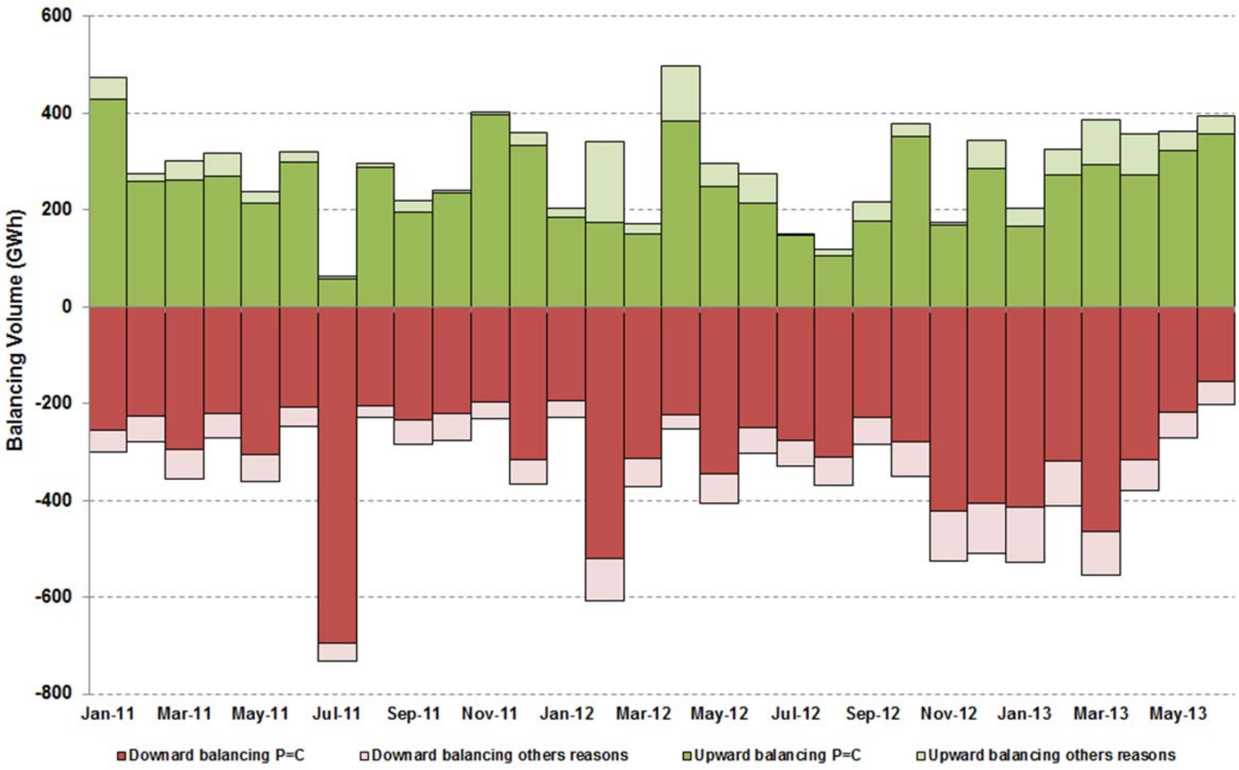
- a social movement by EDF employees which resulted in lower generation[70],
- higher consumption than that anticipated by the RTE and balancing responsible entities generally in a short position during the day.

Despite rebalancing by participants, the loss of 9 GW required the mobilisation 3 to 4 GW upward balancing throughout the day; this increase in volume caused a price spike of 650.0 €/MWh on two half hours between 7 and 8 pm.

[69] Ibid.

[70] EDF did announce the strike and provided the RTE with an estimate of falls with volumes between 10 000 and 12 000 MW for morning and evening peakloads on 27 March.

Figure 45: Upward and downward balancing volumes[71]



Source: RTE – Analysis: CRE

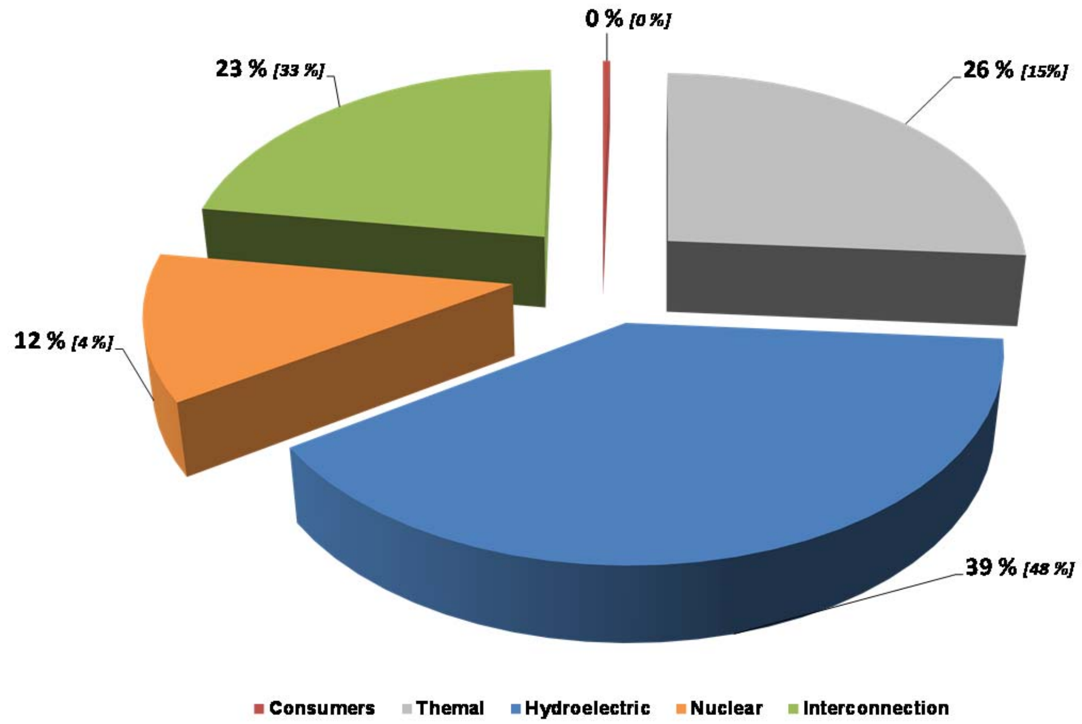
The market share of nuclear and fossil-fuel fired power plants on upward balancing increased significantly compared to 2011 (Figure 46). This increase which was at the expense of hydropower offers is explained by a greater use of conventional fuel-fired power plants during the cold wave in February 2012 and nuclear power plants in December 2012 which was also marked by very low electricity consumption.

The market share of the hydroelectric generation technology increased against 2011 for downward balancing. The intermittency created by the development of RES effectively generated increasing flexibility needs which are covered by the hydroelectric generation technology to mitigate infra-marginal variations in supply and demand.

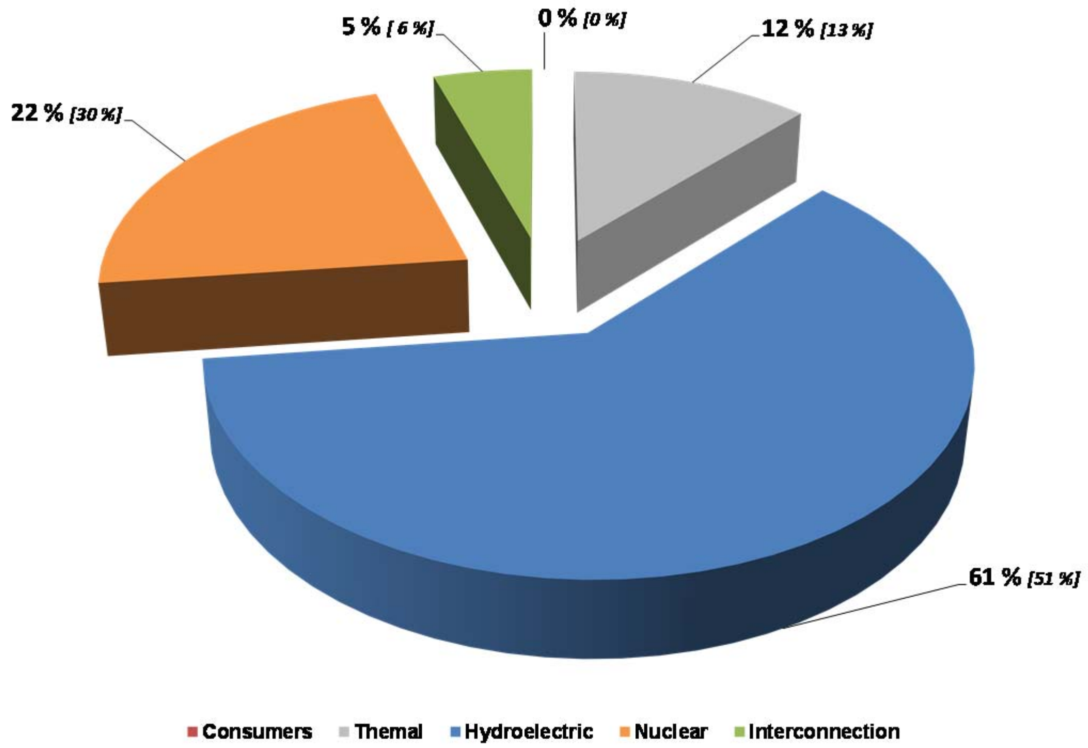
[71]Variation of active balancing volumes (where P=C and all reasons). P=C: generation-consumption balancing; other reasons: resolution of network constraints such as congestion, recovery of system services and operational margins at intervals (8h, 2h, and 15 minutes)

Figure 46: Balancing shares by technology in 2012

a. Upward balancing shares



b. Downward balancing shares



Source: RTE – Analysis: CRE

In 2012, the market share of French participants on upward balancing increased compared to 2011, with 80% of the volume activated against 69% in 2011. This steady increase in French participant contributions to upward balancing can be explained by:

- the development of load shedding towards industrial and services sectors connected to the Public Transmission Network[72],
- increased generation capacity exploited by participants other than EDF,
- more competition in the market balancing reserves (including rapid and complementary reserves) with the emergence of new participants.

Box 4: Load shedding development on the French electricity system

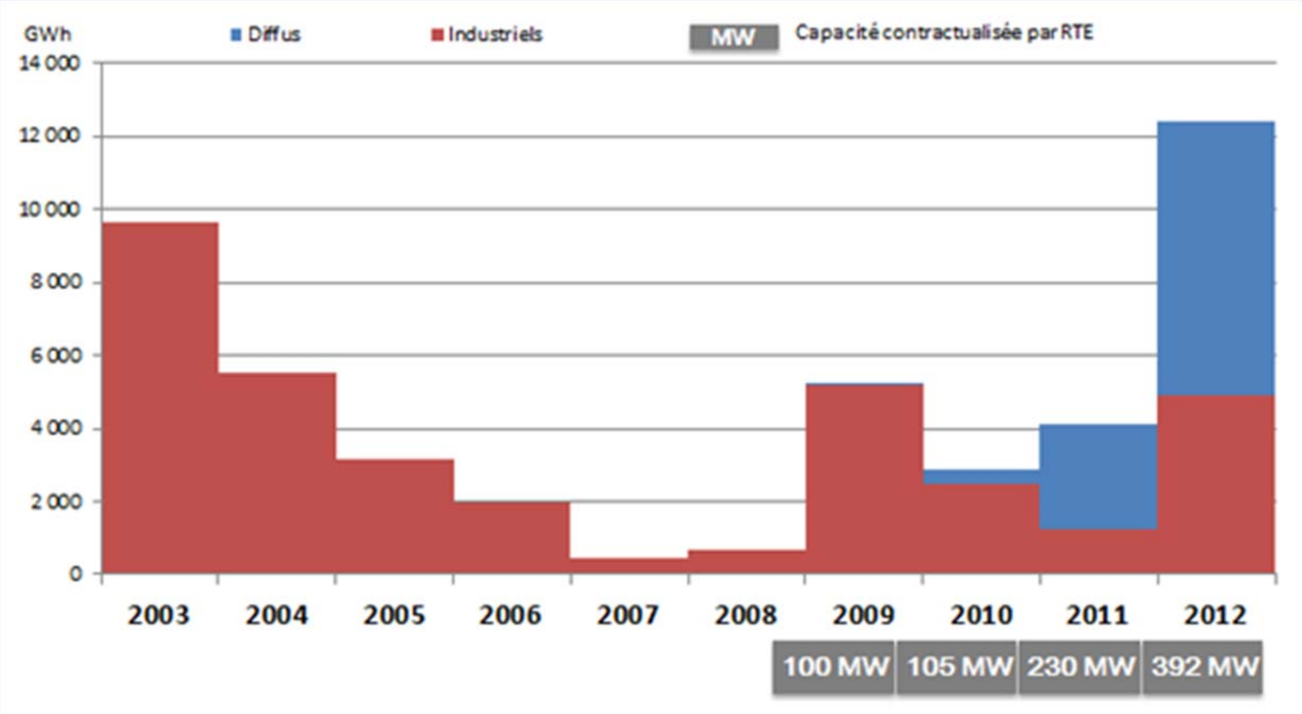
Electricity load shedding involves changing consumer behaviour to temporarily reduce withdrawal. Therefore, load shedding helps reduce the overall level of consumption at a given time, for example during price spikes or expected imbalance between supply and demand.

Load shedding can be performed on behalf of a supplier, reducing the overall consumption of its portfolio. If the cost of activating load shedding is lower than the using a generation unit, or a market purchase, it helps the supplier reduce its supply costs. This type of load shedding, performed by the supplier itself or a third-party is said to be "implicit" as it is not directly sold on the market. Conversely, load shedding can be "explicitly" sold, meaning it is directly provided to the market via an energy offer on the wholesale market or an upward balancing offer.

Therefore, explicit load shedding has directly contributed to real-time electricity system balancing management since the creation of the balancing mechanism in 2003. CRE has worked with the RTE to gradually open the balancing mechanism, which has been open to large industrial consumers since it was created, up to smaller load shedding capacities. In December 2007, CRE approved the launch of an experiment to sell diffuse load shedding mainly consisting of aggregating the load shedding capacity of residential consumers. From 2008, call for tenders were implemented to remunerate load shedding capacity provided in addition to activated energy and the opening of rapid and complementary reserves to load shedding helped boost declining load shedding volumes offered on the balancing mechanism. In all, almost 1 GM of load shedding capacity was active on the balancing mechanism in 2013.

[72]These stakeholders have significant load shedding capabilities which are activated for the balancing mechanism. Contractual capacity, in response to Article 7 of the NOME law, was 400 MW in 2012.

Figure 47: Explicit load shedding volumes activated on the BM and contractual capacities since 2003



Source: RTE – Analysis: CRE

However, the lack of a clear legal framework limited the development of explicit load shedding, in particular beyond the balancing mechanism. Law no. 2013-312 of 15 April 2013 now provides the legal framework allowing the sale of load shedding volumes on electricity markets. It effectively provides that a Council of State decree based on a proposal by CRE would establish a methodology to implement rules governing the sale of load shedding volumes on the markets as well as a methodology to calculate a premium paid to load shedding operators based on the benefits of such load shedding for the community. CRE therefore submitted its draft decree to the Ministers of Economy and Energy on 25 July 2013. Pending the implementation of the decree, the law also provides for an experiment on the sale of load shedding volumes.

Parallel to preparing the draft decree providing durable rules governing the sale of load shedding volumes, CRE and the RTE also worked with market participants to develop an experimental version of these rules. This experimental version was submitted for approval to CRE in October 2013 and should allow the sale of the first explicit load shedding volumes on the market in early 2014.

These provisions will increase competition in the energy markets as load shedding operators will be able to participate on these markets alongside and in the same conditions as generation means. Load shedding could also contribute to increased security of supply and peak load clipping, particularly during price spikes such as those experienced in France during the cold wave in February 2012.

Regarding downward balancing, the market share of French participants remained stable at around 96%. A new source of competition in downward balanced volumes could still emerge in the future with:

- alternative suppliers being more present and therefore more able to propose generation reduction offers,
- some load shedding participants which would like the possibility of stimulating consumption when the electricity system is long to be worked on as they believe that this could be an interesting area to develop.

SECTION III: CO_2 markets

1 CRE CO_2 MARKET MONITORING

1.1 Evolution of the institutional framework and operational context of CRE's activities

The European Commission, the European Parliament, and the Council favour, in the context of revising MIF (Markets in Financial Instruments) and MAD (Directive on Market Abuse)[73] texts, the inclusion of allowances in the list of products qualified as financial instruments and consequently also in the scope of financial regulation.

REMIT nevertheless provides for "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"[74], even though CO_2 allowances are not qualified as wholesale energy products. REMIT provides ACER with access to transactional data collected by the authority responsible for monitoring CO_2[75] markets.

The review of MIF and MAD directives does not affect the relevance of monitoring carried out by the sector regulator. As carbon prices influence the formation of electricity prices, CRE's monitoring of this market contributes to the overall monitoring of wholesale energy markets.

In France, the carbon market was marked by the close of Bluenext exchange on 5 December 2012.

These developments have changed the scope of supervision of CRE and the AMF without affecting the relevance of regular exchanges between the two authorities. CRE and the AMF continue to work closely with each other on regulatory developments and monitoring methods. Operationally, CRE also collects data from the English stock exchange ICE ECX via the AMF and its British counterpart, providing CO_2 prices and transactions on the futures and spot markets. [76]

1.2 Data collection and analysis

In 2012 and 2013, all of the carbon exchanges (BlueNext up to the end of 2012, EEX, and ECX) regularly transmitted transactional data on the CO_2 market falling within CRE's scope of monitoring.

However, data on OTC market intermediaries, including brokers, is still missing.

In March 2012, in the absence of data reporting from certain market places, CRE launched a bilateral data collection. Pursuant to Articles L. 131-3, L. 133-6 and L. 134-18 of the French Energy Code, CRE launched a bilateral collection of transactions carried out in 2011 from market participants within its scope, namely all companies active on the French electricity and gas market and registered as balancing responsible entity or shipper (some 200 participants). CRE requested that each of these participants provide details of all EUA, CER,

[73] Cf. the European Council's proposed revision of the MiFID text of June 2013 http://register.consilium.europa.eu/pdf/en/13/st11/st11006.en13.pdf

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

[75] REMIT, Article 10.3

[76] Cf. the Memorandum of Understanding between CRE and the AMF signed on 10 December 2010

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 required many exchanges with the market participants, which all answered CRE's request.

An initial analysis of data from CRE's collection was published in the 2011-2012 monitoring report concerning all EUA, CER, and ERU spot and derivative transactions made in 2011 that were carried out in France and abroad, bilaterally on French and foreign markets and the intermediated OTC market which included at least one participant within CRE's scope. Detailed analysis of this data, focusing on the share of intermediated participants in all trades, is presented in Section 3.4 of this report.

Pending the introduction of generalised data collection at European level, CRE could submit further ad hoc data requests to market participants if market events justify it.

2 CO_2 MARKETS: EVOLUTION OF THE INSTITUTIONAL FRAMEWORK AND FUTURE PROSPECTS

2.1 Several announcements on regulatory orientations influenced the EU ETS market

In 2012 and 2013, several policy statements on the European Union Emissions Trading Scheme (EU ETS) had a significant impact on the carbon market, including on carbon price levels (cf. Section 4).

- **Review of the European Commission's allowance backloading proposal**

On 25 July 2012, the European Commission published a proposal to revise the implementation of the EU-ETS phase 3 auctioning and change the auctioning schedule.[77]

On 12 November 2012, the European Commission proposed to postpone (or "*backload*") the auction of 900 million carbon allowances from 2013 to 2015 (400M in 2013, 300M in 2014, and 200M in 2015) and put them back on the market in 2019 and 2020 (300M in 2019 and 600M in 2020). This announcement was followed by a period of uncertainty up to the end of 2012 concerning the vote of this measure and its implementation.

The European Parliament's ITRE (Industry, Research and Energy) and ENVI (Environment, Public Health and Food Safety) Committees reviewed the draft texts before the plenary session.

On 23 January 2013, the European Parliament ITRE Committee voted against the European Commission's "*backloading*" proposal with 42 votes for and 18 votes against the proposal. The ITRE Committee's refusal of the measure had an immediate effect on carbon prices (Section 4). On 19 February, the European Parliament's ENVI committee voted in favour of the European Commission's *"backloading"* proposal with 38 votes for, 25 votes against, and 2 abstentions.

On 16 April, the European Parliament voted against the proposed *"backloading"* of allowances during a plenary session and the text was returned to the ENVI Committee to be revised. Carbon prices were heavily impacted a fell sharply over the day (Section 4). On 19 June, the European Parliament's ENVI committee voted again in favour of *"backloading"* allowances, for an amended version of the text.

[77] See http://ec.europa.eu/clima/news/articles/news_2012072501_en.htm

On 3 July, the *"backloading"* proposal was approved during the European Parliament's plenary session. The text stated that the European Commission's *"backloading"* measure would be unique and that the 900 million allowances would be temporarily withdrawn from the carbon market between 2013 and 2015 to be reintroduced on the market in 2019 and 2020.

Discussions between the European institutions are currently under way on the final version of the text.

- **Long-term EU-ETS measures**

In August 2012, the European Commission and the Australian Ministry of climate change announced their intention to link the two emission trading schemes by July 2018.

In November 2012, the European Commission published a report on the functioning of the EU ETS market, identifying six categories of structural measures to reform the system and reduce the surplus of allowances in circulation.[78] A public consultation was launched on this subject. In early 2013, several stakeholder meetings were held regarding the long-term reforms of the carbon market.

Finally, the European Commission presented a Green Paper on the long-term financing of the European economy in April 2013.

2.2 Initiation of Phase III of the EU-ETS

1 January 2013 marked the start of Phase III of the EU-ETS (2013-2020)[79]. The phase is characterised by the auctioning of approximately 50% of allowances, representing roughly one billion allowances per year against less than 4% during Phase II of the EU ETS (2008-2012). With regards to the electricity sector, 100% of allowances should be auctioned, except for certain Member States which have been exempted for 2013 by the European Commission[80].

[78] See http://ec.europa.eu/clima/policies/ets/reform/docs/com_2012_652_en.pdf

[79] Cf. Directive 2009/29/EC and Regulation No. 1031/2010 on allowance auctioning

[80] Hungary, Bulgaria, Cyprus, Czech Republic, Estonia, Lithuania, Poland, and Romania received free allowances for their power plants in 2013.

Box 5: Start of Phase III of the EU-ETS

Auction platforms:

During the last quarter of 2012 and the first half of 2013, Phase III allowance auctions took place on EEX, which is a common platform for most of the Member countries, and the individual German EEX and British ECX platforms.

During Phase III, allowance supply is more frequent than in Phase II, with weekly auctions. The European Commission has approved the following auction schedule:

- EEX holds common European auctions twice a week,
- EEX holds auctions for Germany once a week,
- ICE ECX holds British auctions every two weeks,
- The platforms also held some aviation sector auctions.

Under Phase III, some 90M EUA[81] were auctioned in 2012 and some 400M in the first half of 2013 (figure 48).

Operation of auctions:

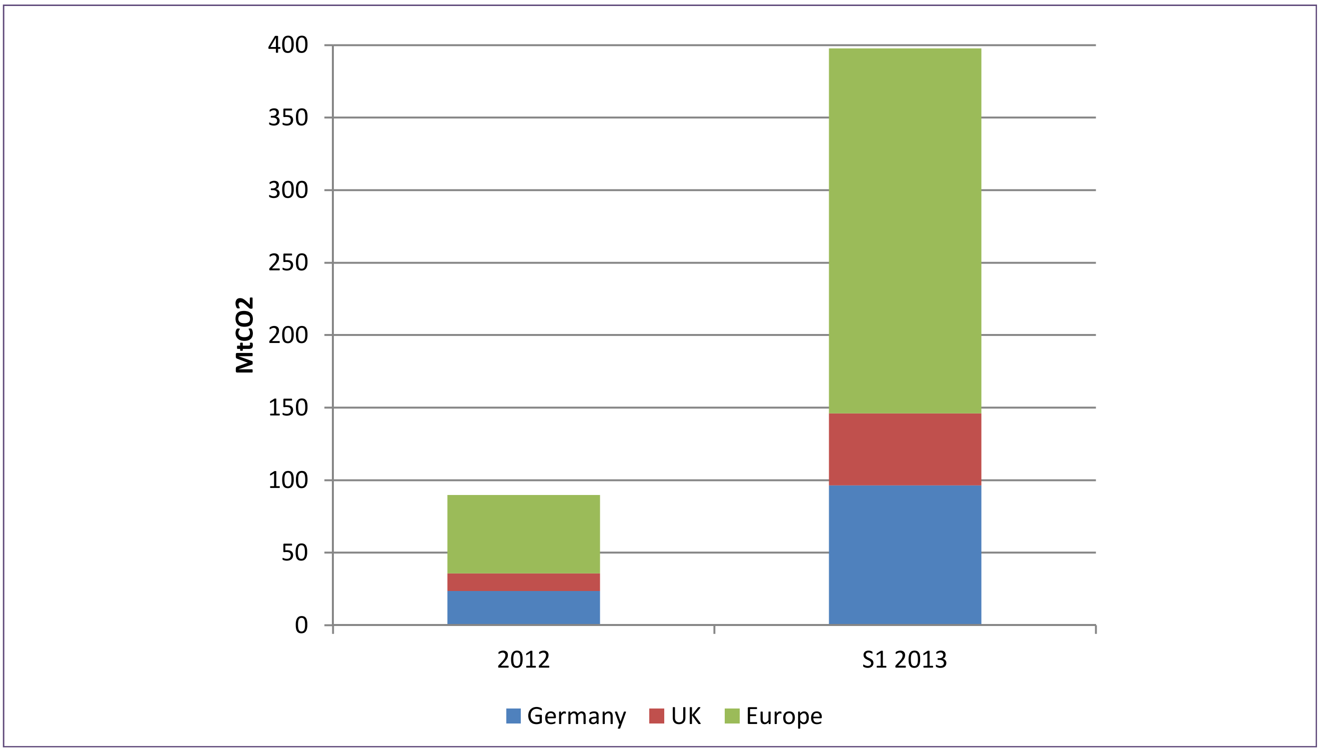
Allowance auctions operate as single orders in a single round, a price based on the marginal offer and a uniform price for all bid winners. A reserve price is confidentially determined and an auction can be cancelled if the auction price is significantly lower than the allowance price on the secondary market. Three auctions were thereby cancelled during the first quarter of 2013 due to weak demand from market participants: 18 January (German auction), 22 February (German auction), and 12 March (European auction).

The European Commission has published the first reports on Phase III allowance auctions.[82] These reports show that auction prices were generally in line with allowance prices on the secondary market.

[81] See Glossary for the definition of "EUA"

[82] See http://ec.europa.eu/clima/news/articles/news_2013051701_en.htm

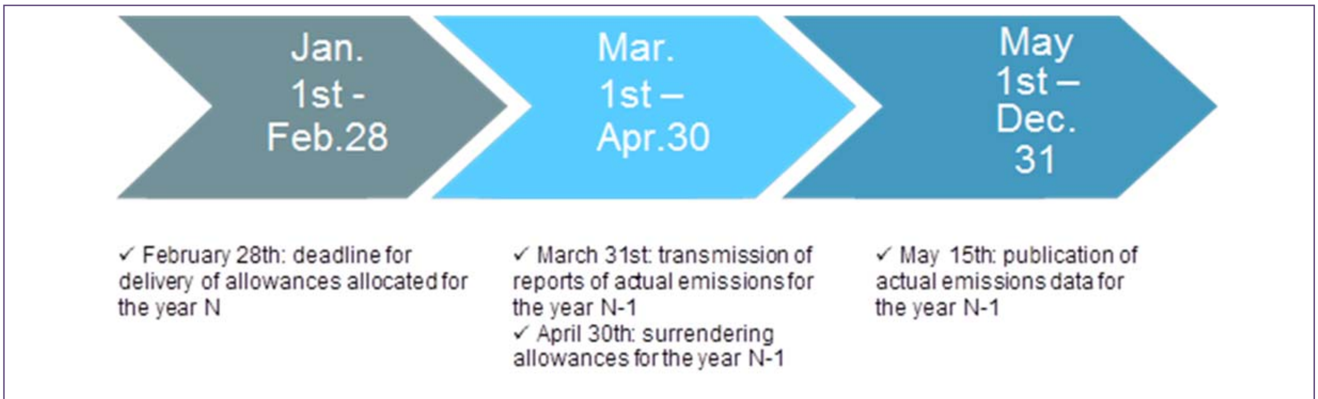
Figure 48: Phase III auctions in 2012 and the first half of 2013



Source: ICE ECX, EEX, analysis CRE

Participants subject to the EU ETS were required to surrender 2012 allowances on 30 April 2013. This was also the final date to surrender allowances for Phase II. The Phase III allowance schedule is identical to that of Phase II (Figure 49). Bankability of allowances from Phase II to Phase III took place during the month of June 2013.

Figure 49: Compliance schedule for EU ETS participants



Source: European Commission

3 VOLUMES TRADED ON THE CO_2 MARKET

In this section, the characteristics of transactions performed on the European market (exchanges and brokers) are analysed.

3.1 Participants present on the CO_2 market

The classification of participants on the EU ETS market was established from public member lists on ECX and EEX platforms, as presented in table 16.

This analysis showed that:

- The number of participants registered on the CO_2 market has fallen by nearly 30% since 2012. This is primarily due to the closure of Bluenext, the French carbon exchange, in December 2012,
- Energy companies, i.e. shippers, balancing responsible entities, energy, gas, and oil producers, and financial stakeholders constitute once again almost all of the participants of the European CO_2 market (94%). Financial stakeholders, which include financial institutions and pure traders are involved in the carbon market for trade-offs for themselves and for third parties. Industry companies subject to the EU ETS and other stakeholders are very few to intervene on CO_2 markets,
- Participants within CRE's monitoring scope represent almost half of the participants registered on the European CO_2 market. They are all energy companies or financial stakeholders (except for one industry stakeholder),
- The volumes of CO_2 transactions performed in 2011 by participants within CRE's scope are analysed in Section 3.4.

Table 16: CO_2 market participant classification

Market participant type	CRE scope	Outside of CRE Scope	Total
Energy company	63	54	117
Financial stakeholder	40	65	105
Industry	1	5	6
Other	0	8	8
Total	**104**	**132**	**236**

Source: ECX, EEX – Analysis CRE

3.2 Volumes traded increased in 2012 compared to 2011

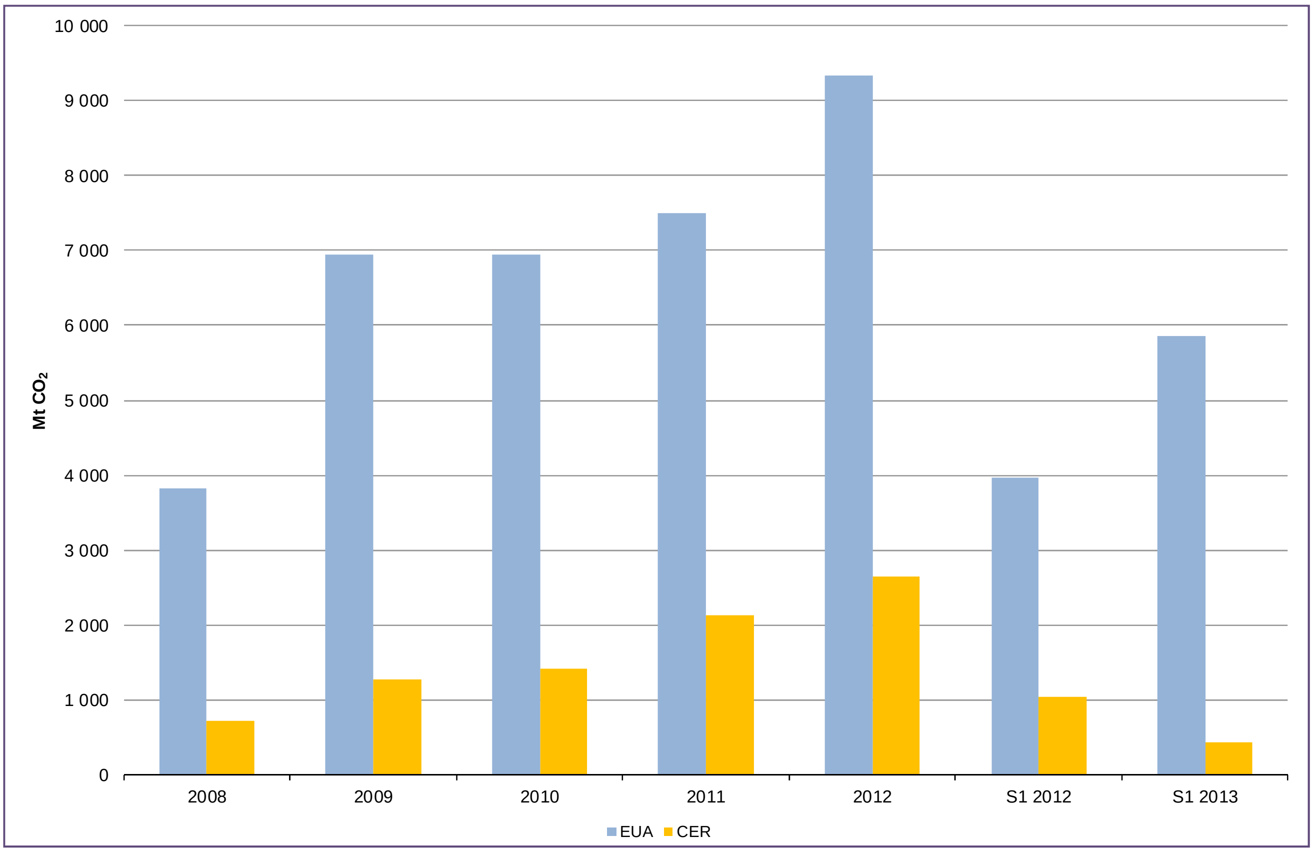
figure 50 presents the total volumes of EUA and CER traded since 2008.

The total volumes of EUA and CER traded increased by 24% in 2012 compared to 2011 totalling 11,979 Mt (million tonnes of CO_2) against 9,638 Mt in 2011.

In the first half of 2013, while EUA volumes nearly doubled compared to the first half of 2012 (5,857 Mt), CER volumes fell by more than 50% (430 Mt).

The value of EUA trades represented 68 billion Euros in 2012 against 100 billion Euros in 2011; this decrease was due to a fall in prices (Section 4.2). The value of CER trades represented 8 billion Euros in 2012 against 20 billion Euros in 2011. This sharp fall of nearly 60% is related to the fall in CER prices (Section 4.2).

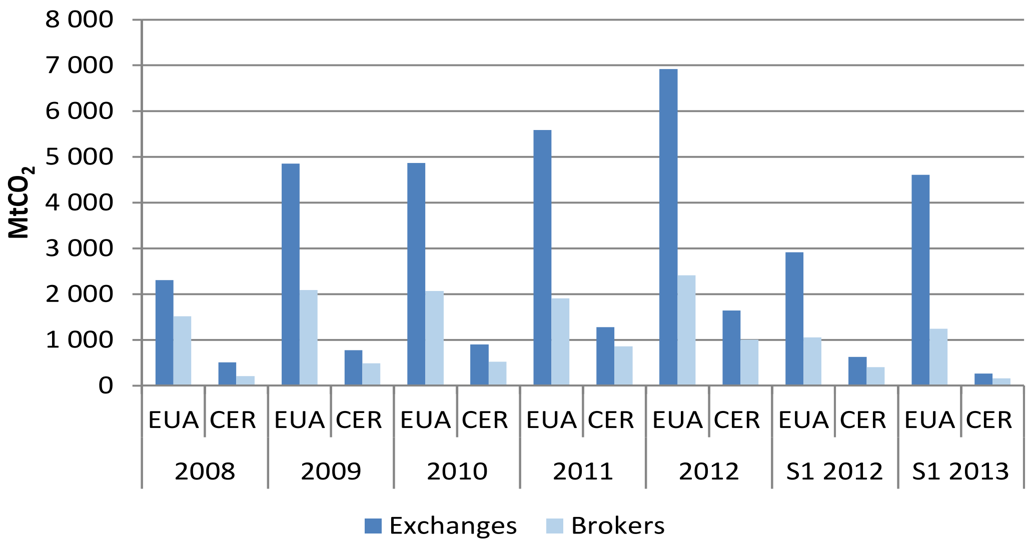
Figure 50: Annual EUA and CER volumes



Source: Bluenext (up to 5 December 2012), ECX, EEX, LEBA figure 51 shows exchange and broker market volumes for EUA and CER products since 2008.

In 2012, the volume of EUA increased on both the exchanges (+24%) and through brokers (+26%) compared to 2011 to reach 9,332 Mt in 2012 against 7,500 Mt in 2011. In the first half of 2013, EUA volumes traded significantly increased compared to the first half of 2012 (+48%), mainly due to the increase of volumes traded on the exchanges (4,610 Mt). In 2012, the volume of CER increased on both the exchanges (+28%) and through brokers (+17%) compared to 2011 to reach 2,647 Mt in 2012 against 2,139 Mt in 2011. In the first half of 2013, CER trading volumes dropped significantly across all platforms compared to the first half of 2012 (-58%). This is particularly related to the fact that some CER products were excluded from the EU ETS from May 2013 due to the new compliance requirements in Phase III.

Figure 51: Annual EUA and CER volumes

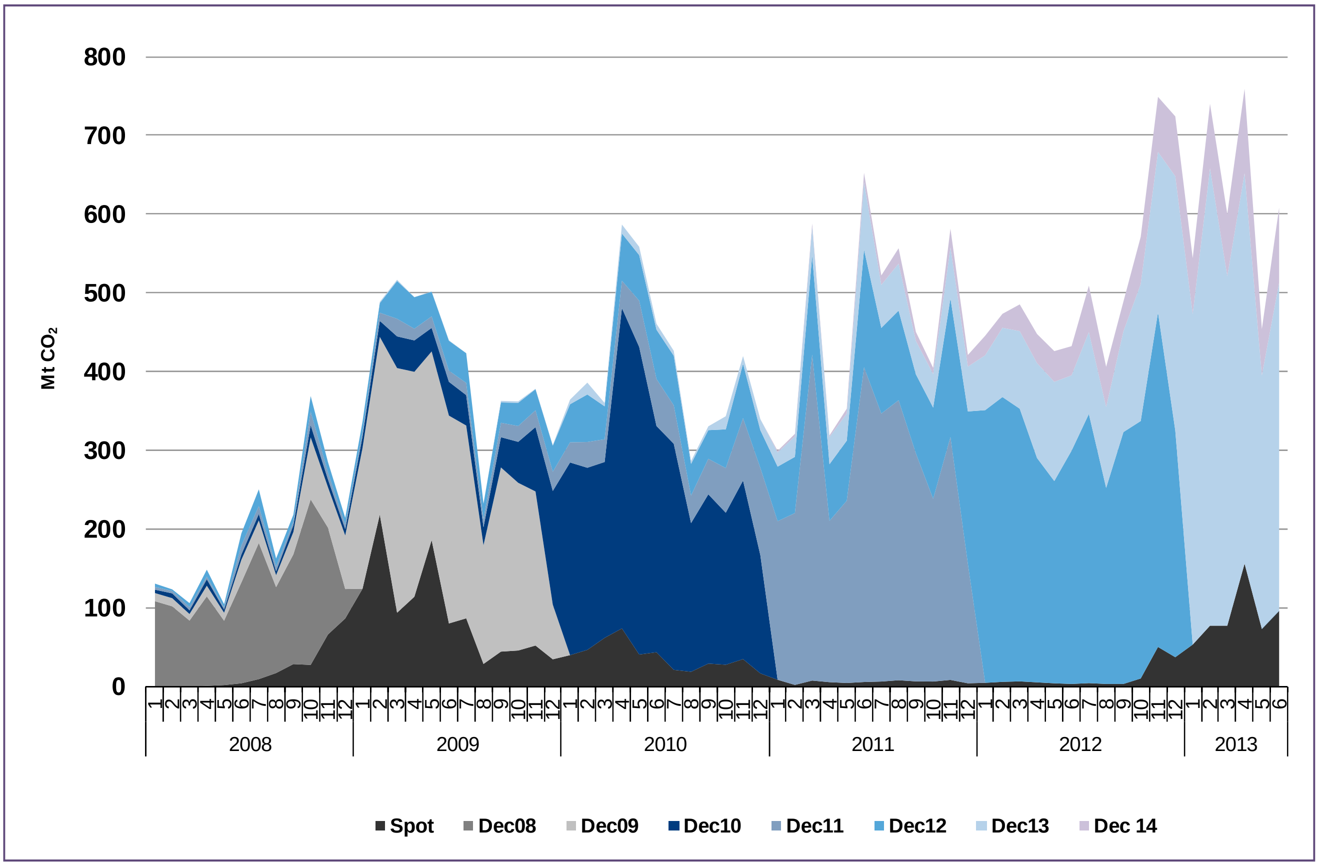


Source: Bluenext (up to 5 December 2012), ECX, EEX, LEBA

In 2012, almost all EUA volumes traded on exchanges concerned the futures market once more, mainly Y+1 futures products (figure 52). For any given year, most traded contracts are for delivery for the end of the current year, meaning that participants are essentially covering their actual emissions a year in advance 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.

At the end of 2012 and the first half of 2013, the volume of transactions on the spot market increased: about 532 Mt were traded in the first half of 2013 against 28 Mt in the first half of 2012. This can be explained in particular by the uncertainties related to the *"backloading"* of allowances during the period and short-term trade-offs related to the various announcements by European institutions (Section 1). In particular, a significant volume of allowances was traded on the spot market in April 2013: 156 Mt compared to 5 Mt in April 2012, including a large volume of spot transactions on 16 April 2013 when the European Parliament voted against the *"backloading"* of allowances (Section 1).

Figure 52: Variation of EUA trades by maturity



Source: Bluenext (up to 5 December 2012), ECX, EEX

3.3 Analysis of 2012 market transaction data shows that the market almost exclusively consisted of futures products and that financial players had a dominant role on the markets.

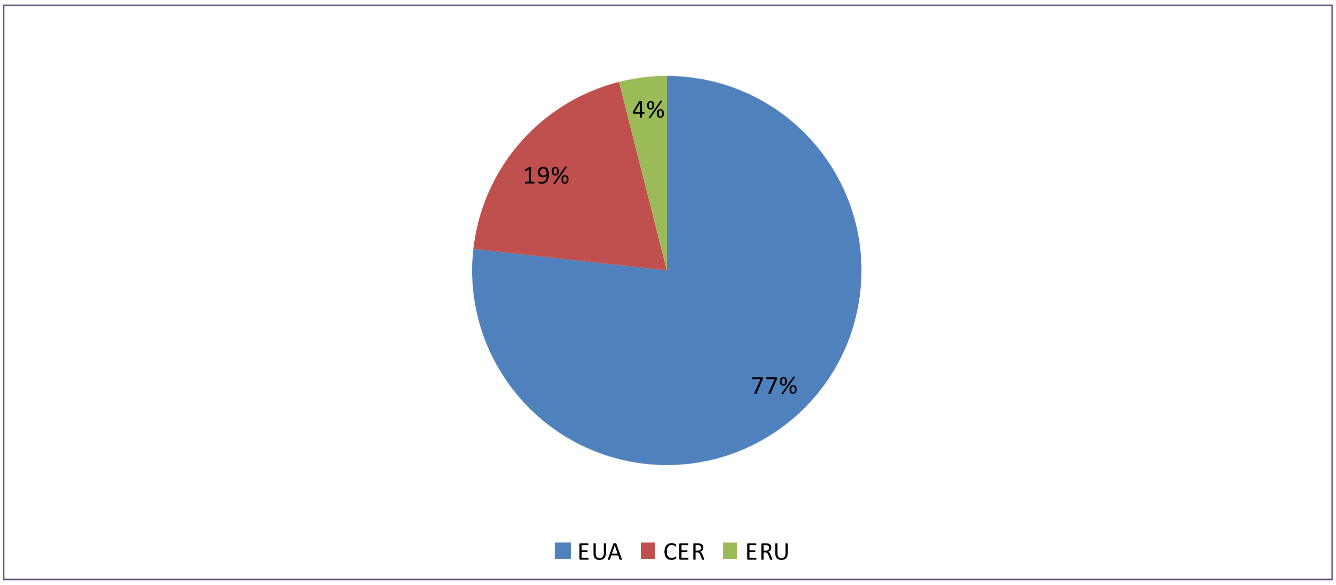
Since 2011, EEX and Bluenext have been providing CRE with transactional data on carbon markets. Since 2012, ICE ECX has been regularly providing CRE with data falling within its scope via the AMF and the FCA. Thereby, EUA, CER and ERU transactions on spot and futures markets falling within CRE's scope were analysed for 2012. [83]

The analysis showed that:

- EUA products were the most traded on exchanges (Figure 53),
- transactions by financial stakeholders represented about three quarters of buying and sale volumes (figure 54 and Figure 55),
- transactions by energy companies represented about 10% buying and sale volumes (figure 54 and Figure 55),
- almost all transactions performed on exchanges were for futures products (99% of trades).

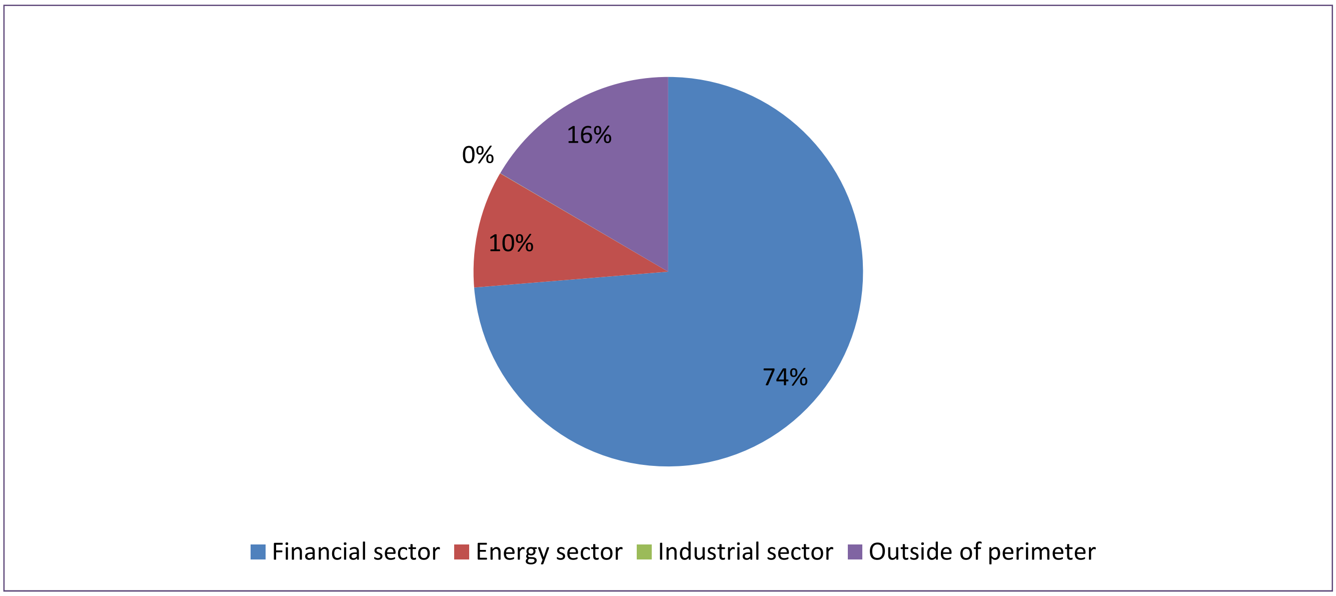
[83] See Glossary for the definition of "FCA"

Figure 53: Share of the various products on the exchanges in total volume (CRE scope)



Source: Bluenext, EEX, ECX - Analysis: CRE

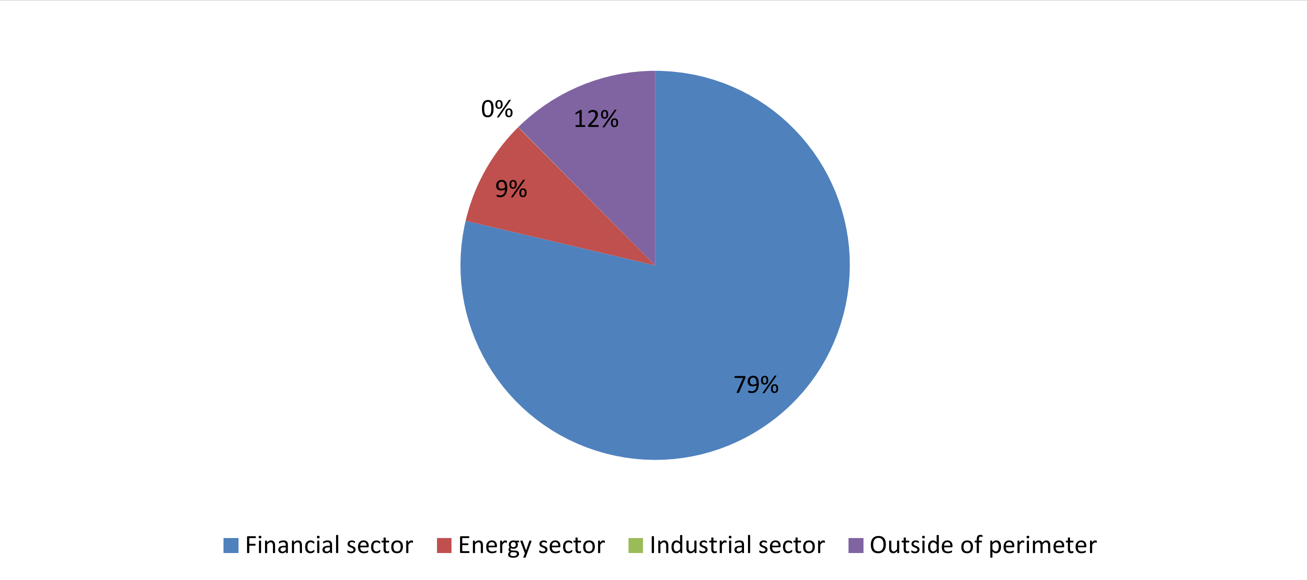
Figure 54: Classification of participants on exchanges in buying volume (CRE scope)



Source: Bluenext, EEX, ECX - Analysis: CRE

N.B. Transactions can involve a seller within CRE's scope and a buyer which does not. Volumes concerned by these transactions are shown in the "outside of perimeter" category

Figure 55: Classification of participants on exchanges in sales volume (CRE scope)



Source: Bluenext, EEX, ECX - Analysis: CRE

N.B. Transactions can involve a buyer within CRE's scope and a seller which does not. Volumes concerned by these transactions are shown in the "outside of perimeter" category

3.4 Analysis of the volume of data collected by CRE in 2011 from participants within its scope

The analysis of the bilateral collection of data transmitted by market participants to CRE in 2011 (Section 1.2) followed on from the initial analysis in the 2011-2012 monitoring report. It focused on the involvement of market intermediaries in trades falling within CRE's monitoring scope and helped establish the following conclusions: [84]

- brokers represented about a 25% market share of volumes for all products,
- market intermediaries other than brokers (notably banks) represented about 22% of volumes for all products,
- about a quarter of transactions in volume performed by a market intermediary (broker and non-broker) concerned CER products,
- the share of spot transactions performed by brokers was about 16% which was much higher than the spot share in exchange transactions.

Table 17: Classification of intermediary participants in data collection

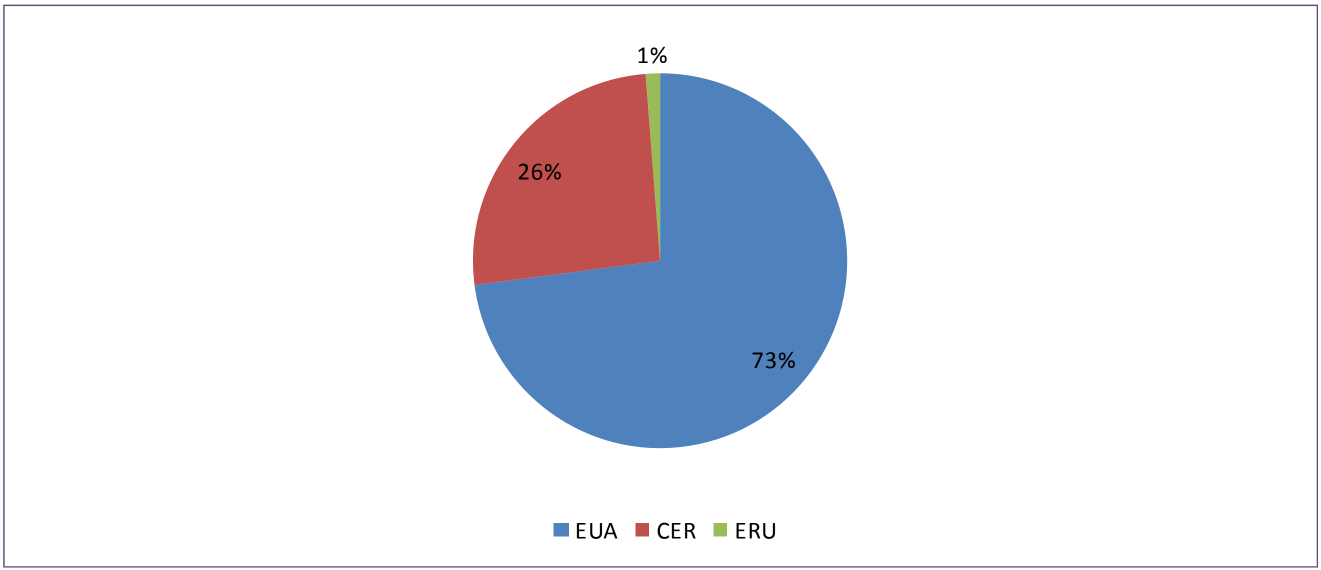
Type of intermediary participant	Number

[84] In particular, the analysis revealed that transaction data collected by CRE represented almost half of the total volume of European broker and exchange transactions for all products.

Bank	3
Broker	8
Other	6
Total	17

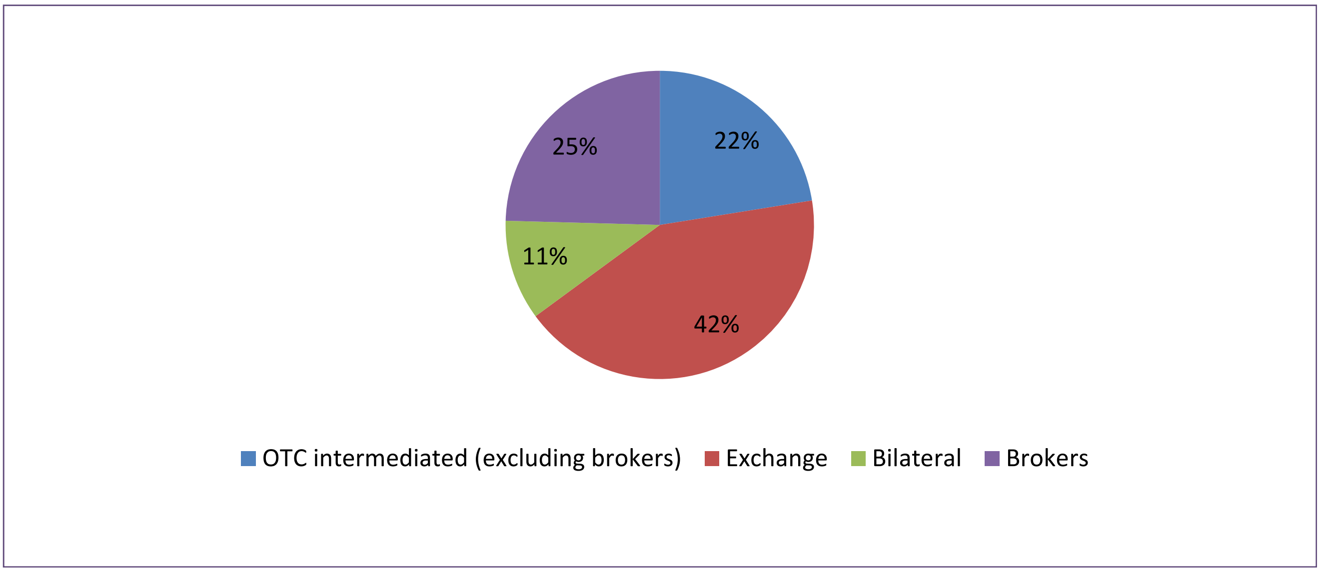
Source: CRE data collection

Figure 56: Share of the various products in intermediated transactions (in volume)



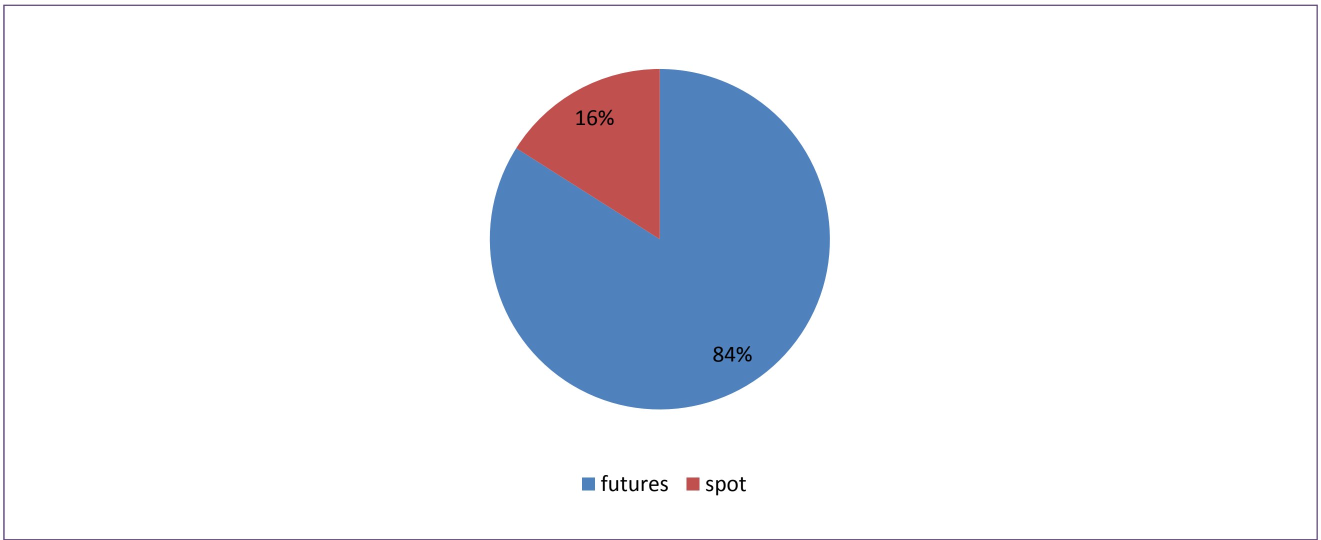
Source: CRE data collection

Figure 57: Share of the various market places in volume, all products combined



Source: CRE data collection

Figure 58: Share of Spot and futures products traded by brokers, all products combined



Source: CRE data collection

4 CO_2 PRICES AND FUNDAMENTALS IN EUROPE

4.1 With a global offer of allowances exceeding demand once again in 2012 and 2013, the surplus of allowances has increased

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

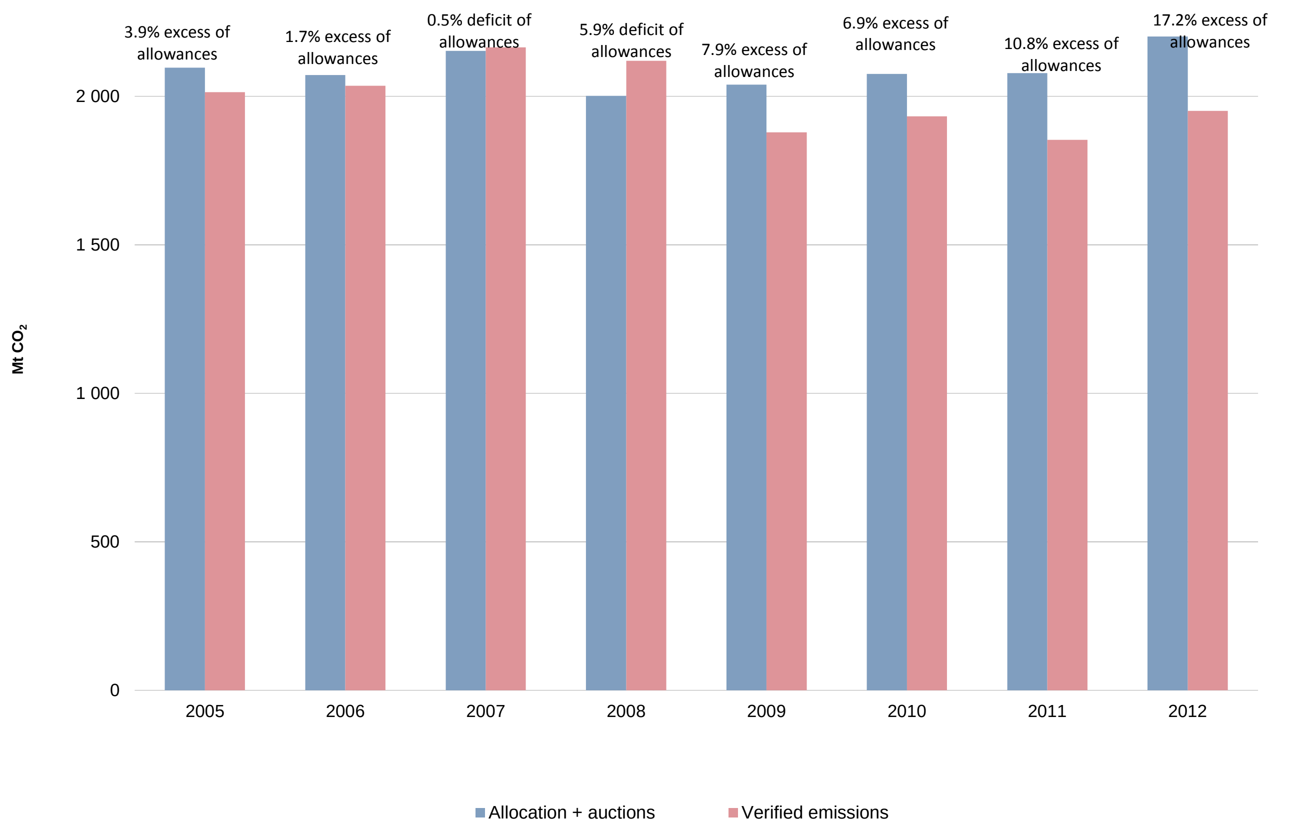
- The EUA offer corresponds to the amount of allowances in circulation on the primary market through free allocation and auctioning. From 2013, about 50% of the total volume of allowances is freely allocated and 50% is auctioned.
- EUA demand depends on the actual verified emissions of industrial sites subject to compliance. These depend on the level of activity and especially on the level of electricity generation. The fundamentals of CO_2 prices therefore share common characteristics with those of electricity prices as they are influenced by the price of fossil fuels, at least indirectly.

4.1.1 The overall surplus of allowances increased in 2012 compared to 2011. The accumulated surplus currently represents over a third of emissions allocated every year

Actual emissions of installations subject to the EU ETS are published every year in April. Actual or verified emissions can be compared with allocated emissions (free or auctioned) to show the net balance of facilities participating in the European system (Figure 59).

The total supply of allowances in 2012 was higher than that of 2011 at 2,355 Mt due to the integration of aviation sector activities in the EU ETS and the early auctioning of 90 Mt of allowances for Phase III. Verified emissions also increased to 1,951 Mt in 2012, representing a 5% increase compared to 2011. The supply of allowances exceeded demand again in 2012, continuing the trend which began in 2009, with an EUA allowance surplus of 404 Mt in 2012 (17.2%) against 224 Mt in 2011 (10.8%).

Figure 59: Supply and demand of allowances since 2005

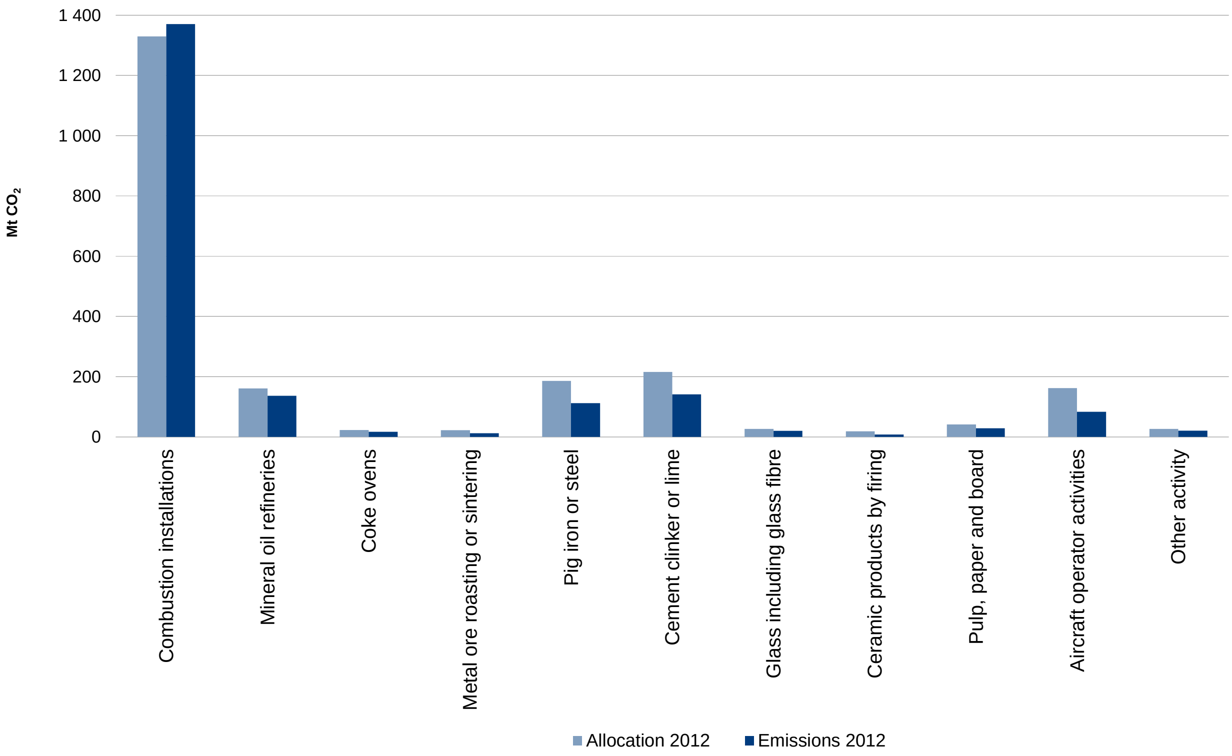


Source: CITL

4.1.2 In almost all sectors, allowance supply exceeded demand, whereas combustion sites had a lower allowance deficit in 2012

Aviation industry activities were added to the list of industries subject to the EU ETS. An analysis by sector showed that combustion sites, consisting primarily of electricity generation installations and representing 60% of EU ETS industrial emissions, were once again the only facilities with an allowance deficit (figure 60). Their deficit dropped from -66 Mt in 2011 to -41 Mt in 2012. However, emissions from combustion sites slightly increased (1,370 Mt).

Figure 60: Allocations and actual emissions by type of site in 2012



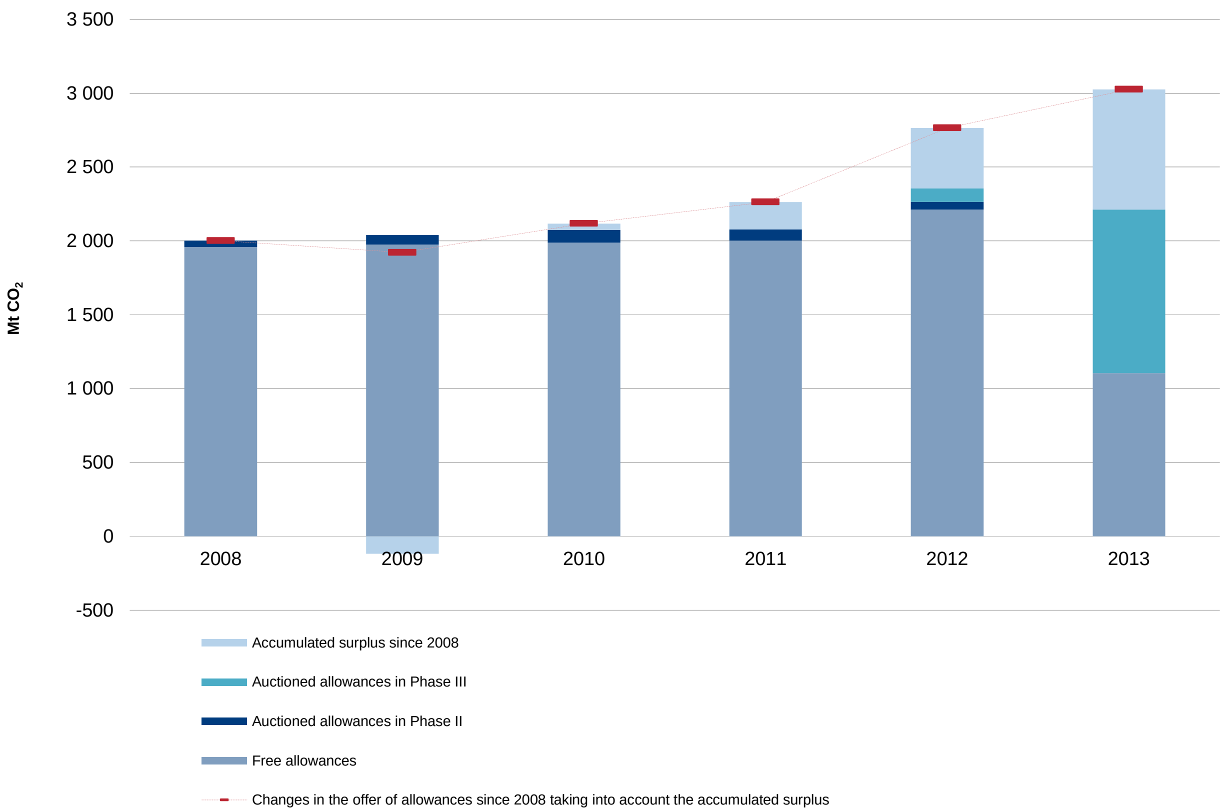
Source: CITL

4.1.3 The surplus of allowances increased at the end of Phase II

Accumulated surplus of allowances increased from 410 Mt in 2011 to 814 Mt in 2012 (figure 61). This figure only reflects the cumulative difference between allocated allowances (free allocation plus auctioning) and the EU ETS's actual emissions and does not take into account the fact that some emission rights were surrendered as Kyoto units; the surplus of EUA allowances at the end of 2012 was therefore much higher than this figure. Some market analyses quote it at levels corresponding to one year's emissions. 2013 is characterised by the fact that 50% of the total volume is freely allocated and 50% is auctioned. Early auctions for Phase III were also held in 2012 and represented about 90 Mt of CO_2.

Short-term *"backloading*" and longer-term measures have been considered by European institutions since 2012 to reduce the surplus of allowances and curb the falling CO_2 prices (Section 2.2).

Figure 61: Accumulation of allowance surplus since 2008



Source: CITL, European Commission (assuming a 2013 supply level of free quotas equivalent to half the level of 2012)

4.2 2012 and 2013 were marked by events related to the EU ETS policy, however they did not succeed in supporting carbon prices which were at an all-time low.

The EUA spot price fell significantly in 2012 compared to 2011, dropping from an average 12.95 €/t to 7.34 €/t (-43%) with downward movements in late 2012 and early 2013. On average, allowance prices fell from 7.23 €/t to 4.24 €/t between the first half of 2012 and the first half of 2013.

In 2012, CO_2 prices were low due to the surplus of allowances in circulation which had accumulated since 2010 (Section 4.1) and the continued slowdown in industrial generation in a context of economic crisis. In late 2012, following proposals from the European Commission to "*backload*" 900 million allowances during Phase III and other long-term structural reforms of the EU ETS, carbon prices increased temporarily (9 €/tCO_2). CO_2 prices then began to dwindle, explained by uncertainty around the adoption and entry into force of the "*backloading*" proposal. In addition, the early auctioning of allowances for Phase III began in October 2012, increasing the supply of allowances in circulation on the market.

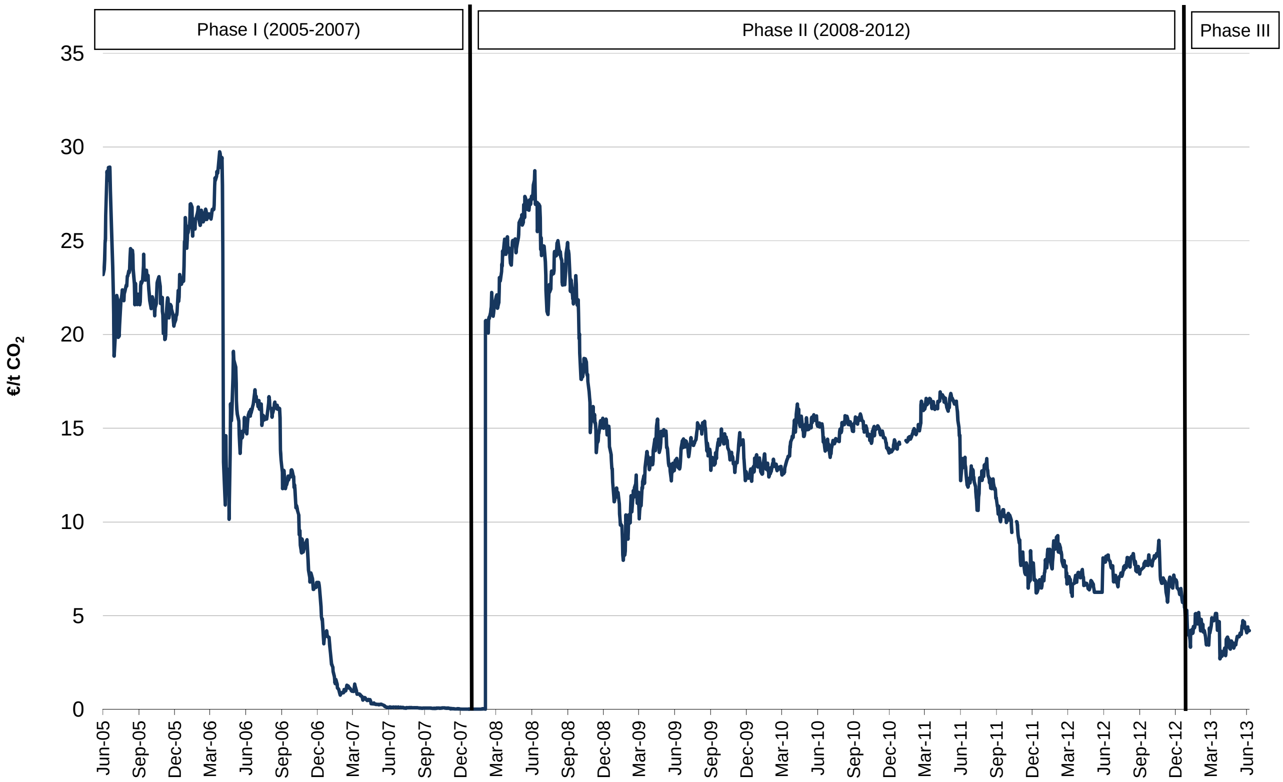
From 23 January 2013, CO_2 allowance prices fell below an average of 5 €/t due to the rejection of the European Commission's *"backloading"* measure by the European Parliament's ITRE committee (Section 2). Prices then slowly increased pending the vote of the Parliament's ENVI committee on 19 February 2013 in favour of the "*backloading*" measure (Section 2) before falling again.

On 16 April 2013, following the European Parliament's rejection of the "*backloading"* measure during its plenary session (Section 2), CO_2 prices fell below 4 €/t. Prices recovered slightly towards 19 June when the

ENVI committee voted again on the measure, this time in favour, before significantly rising (4.66 €/tCO_2) when the European Parliament voted in favour of allowance *"backloading"* during its plenary session on 3 July.

In 2012 and the first half of 2013, CO_2 prices therefore varied according to the increasing surplus of allowances on the market and announcements by European institutions on the EU ETS. Detailed analysis of price movements in relation to the dates mentioned above is currently being carried out.

Figure 62: CO_2 spot prices since 2005



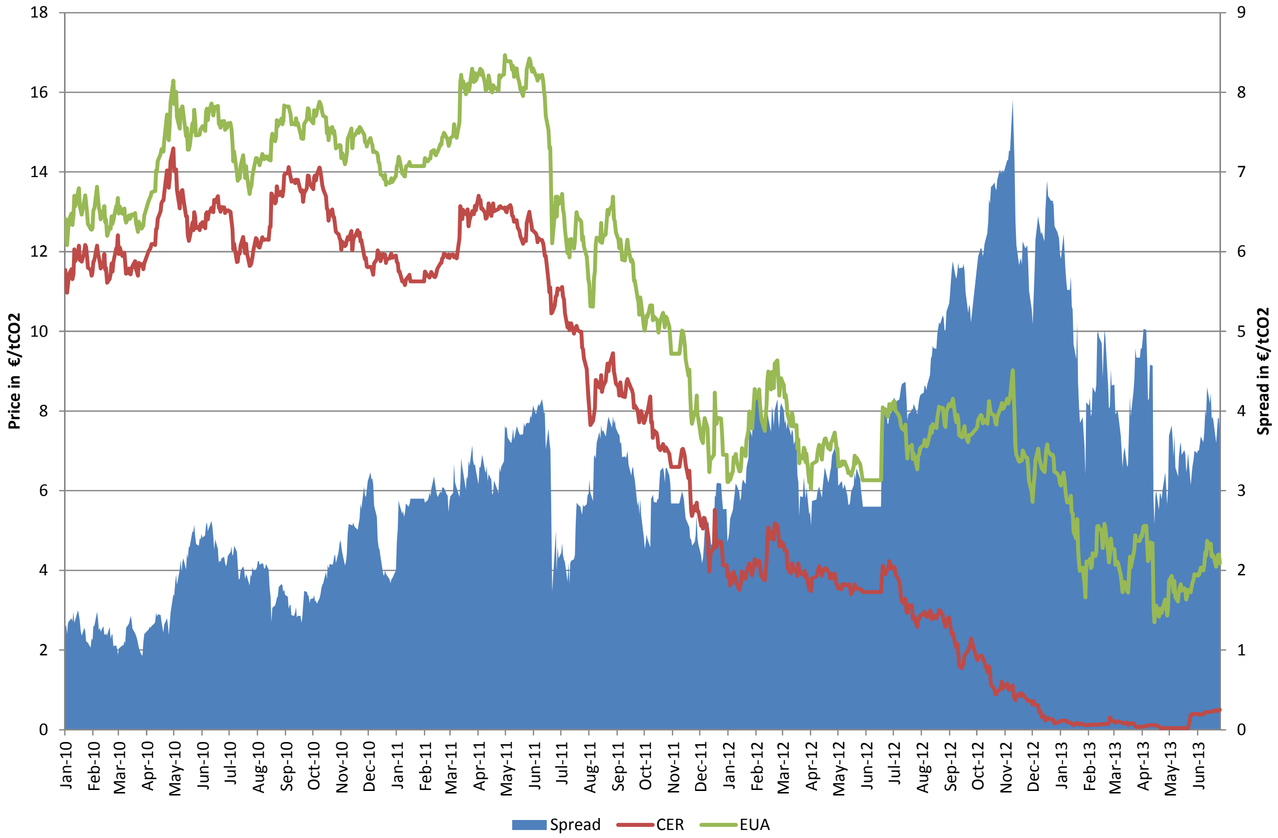
Source: Bluenext (up to 5 December 2012), ECX

Spot prices for CER allowances fell sharply from 9.88 €/t in 2011 to 2.90 €/t in 2012 (-71%). The price of CER reached near-zero levels in the first half of 2013, compared to an average of 3.93 €/t in the first half of 2012. Moreover, ICE ECX temporarily barred CER products from the platform for most of the month of May 2013 in the context of the transition from Phase II to Phase III.

The near zero CER prices in late 2012 and early 2013 can be attributed, in particular, to the large volume of CER on the market and the exclusion of certain CER products from the EU ETS from the end of the Phase II compliance period. Therefore, market participants anticipated that certain CER would have a zero value from 1 May 2013.

Thereby, in late 2012 and early 2013, CER prices were disconnected from EUA prices.

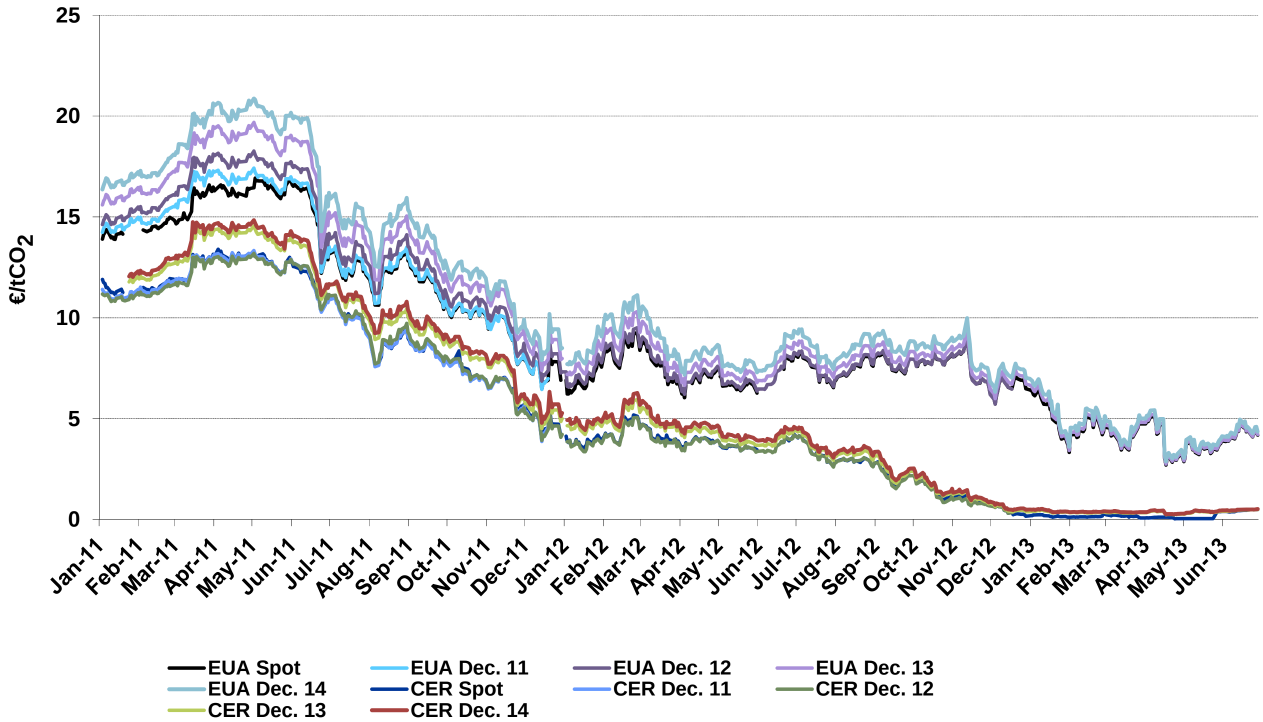
Figure 63: Trends in the EUA and CER spot price differential



Source: Bluenext (up to 5 December 2012), ECX

EUA and CER futures prices have followed a downward trend similar to that of the spot market (figure 64) and have fallen sharply since 2012. CER futures product prices were near zero in the first half of 2013. At these price levels, the carbon emission reduction incentive is low.

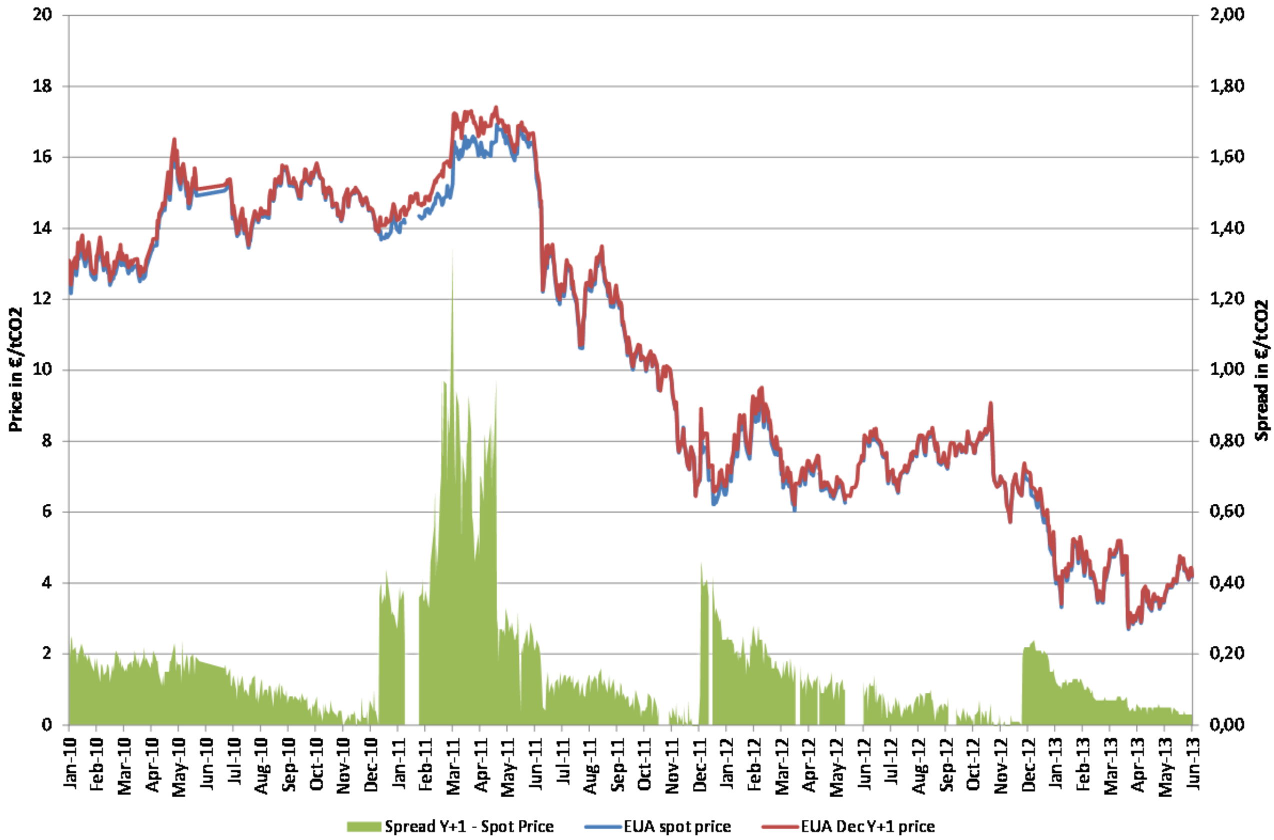
Figure 64: Trends in prices since 2011



Source: Bluenext (up to 5 December 2012), ECX

EUA futures products for delivery in December are strictly identical to those traded in December on the spot market. Therefore, the curve representing the difference between Y +1 and spot prices shows a convergence around the zero mark at the end of the year (figure 65). The average spread between Y+1 and spot prices decreased from 0.28 €/t in 2011 to 0.11 €/t in 2012. It stood at 0.09 €/t in the first half of 2013. Lower short-term interest rates can partly explain the decrease of this spread.

Figure 65: EUA - Differential between the price for delivery in December and the spot price

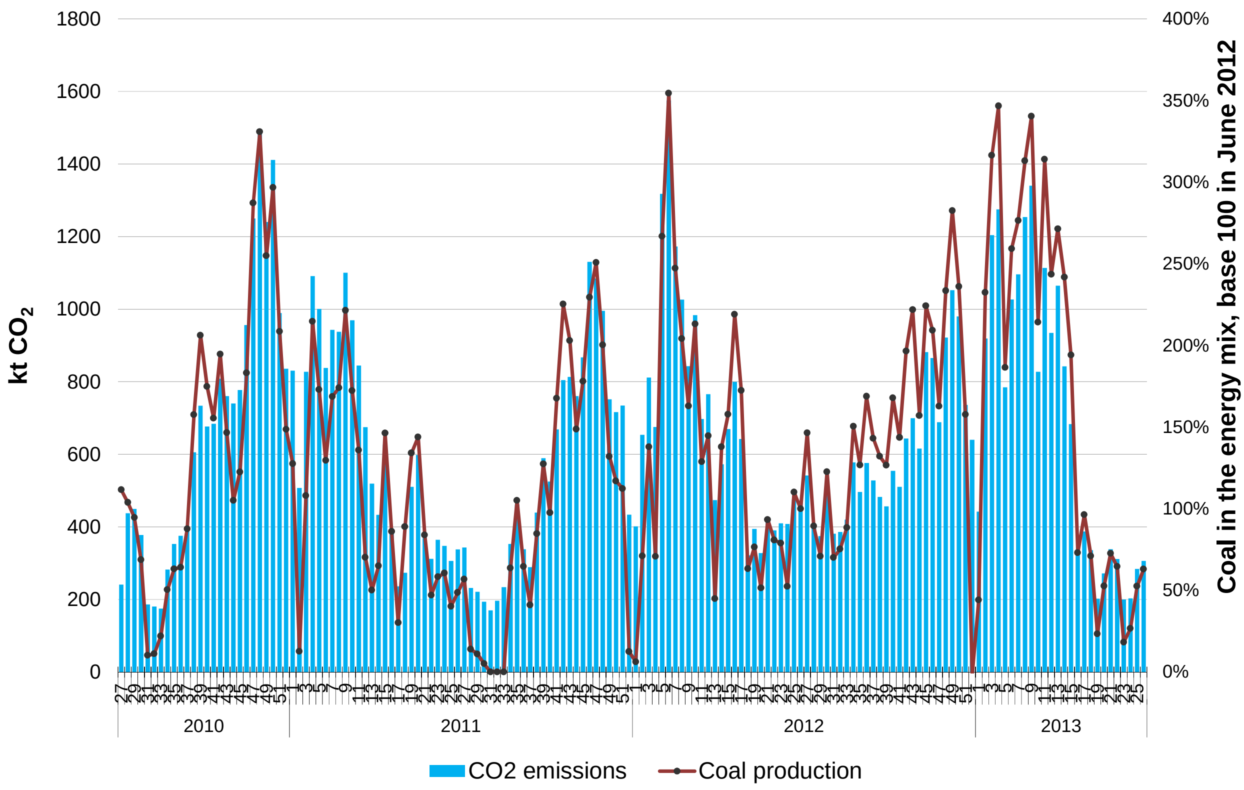


Source: Bluenext (up to 5 December 2012), ECX

4.3 Low CO_2 prices and the relative balance of gas and coal prices maintained a strong incentive to produce electricity from coal

Emissions from electricity generation facilities are particularly related to the presence of coal in the energy mix. Significant contribution of thermal power plants result in greater emission levels. Therefore, emissions are higher during the winter periods, at the beginning and the end of the year (Figure 66).

Figure 66: Emissions of the French coal-fired 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 67). A sustained drop in one of these values compared to the other reflects the loss of competitiveness of one of the generation sectors.

In 2012, the difference between the *clean dark spread* and the *clean spark spread* increased in favour of the *clean dark spread* compared to 2011. The gas sector was less competitive than the coal sector, despite its comparative advantage in terms of CO_2 emissions, due to the decline in carbon prices in 2012 and the respective levels of gas and coal prices. This gap widened in the first half of 2013.

Figure 67: *Clean dark* (theoretical short-term profit of a coal-fired plant) *& spark spreads* (theoretical short-term profit of a gas plant)

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

Table 18: Formula used to calculate *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 Y+1 baseload price Germany (€/MWh) • p_C Y+1 coal price (€/MWh) • p_{CO2} Y+1 CO_2 price (€/MWh) • α includes the calorific power value and the coal yield[85] • β coal emission factor[86]	• p_E Y+1 baseload price Germany (€/MWh) • p_G Y+1 gas price (€/MWh) • p_{CO2} Y+1 CO_2 price (€/MWh) • γ gas yield[87] • δ gas emission factor[88]

Box 6: CO_2, gas, and coal price trends affect the profitability of combined cycle gas turbine (CCGT)

The development of unconventional gas in the United States and more stringent environmental laws on CO_2 emissions have had the effect of greatly reducing the use of coal in electricity generation on the U.S. market.

Although Europe has benefited from lower coal prices due to lower U.S. demand, gas prices have not been influenced by Henry Hub prices, mainly due to the current lack of infrastructure to export north American gas.

The very low CO_2 price levels helped bring down coal generation costs more than those of gas plants (figure 67).

Therefore, when selecting generation means according to economic criteria, the European *merit order* now promotes the use of coal rather than gas.

Gas demand for electricity generation has declined sharply in Europe. In particular, in France, gas plant consumption fell sharply by 38%[89] between 2011 and 2012. New project developers have been much more cautious in the development of combined cycle gas turbine (CCGT). Given the economic challenges faced by this sector, some producers decided to mothball some of their plants. Therefore, on 23 April 2013, GDF Suez announced that it had mothballed three CCGTs: Cycofos, Fos-Sur-Mer, for three years and Combigolfe, Fos-

[85] 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 that these yields correspond to new reference installations and therefore may be quite different from the yields of existing installations and that other costs, including transportation, are not taken into account.

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

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

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

[89] http://www.grtgaz.com/fileadmin/analyses/annuelles/fr/analyses_annuelles_consommations_2012.pdf

Sur-Mer, and Spem, Montoir-de-Bretagne, for at least the summer of 2013.

The economic environment is particularly difficult for plants located in the south of France whose profitability has been further penalised by high differentials between the North and South PEGs and low market liquidity in the south.

This reflects both the increasing influence of international markets on the profitability of French generation facilities and the difficulties encountered by the EU Emissions Trading Scheme (EU ETS) to achieve its objective of encouraging the use of low emission production means.

SECTION IV: Gas wholesale markets

French and European wholesale market trends in 2012 and the first half of 2013 were particularly influenced by international markets. The disconnection of gas prices between the Asian, European, and American markets kept increasing due to a limited supply of LNG and disparities in the supply/demand balance between these areas. The sharp increase in gas demand in Asia, particularly in Japan, has caused a massive diversion of LNG cargoes to these markets to the detriment of European markets. In the United States, the excess supply created by the production of unconventional gas is maintaining pressure on Henry Hub prices.

Trends in spot prices on the various European gas markets were marked by several episodes of tension. There was a price spike in early February 2012 due to the cold wave that covered most of Europe leading to supply problems in several countries. In March 2013, European markets experienced tensions in particular related to a long winter, very low stocks, and low LNG imports. In that same context, there was a price spike on the French market in early April 2013 due to maintenance on the Taisnières H and Dunkirk entry points.

A lasting and significant differential has emerged between PEG Nord and PEG Sud spot prices since the summer of 2012. This differential occurred in a context of tensions in the south of France where lower LNG imports and high exports to Spain have saturated the North-South link.

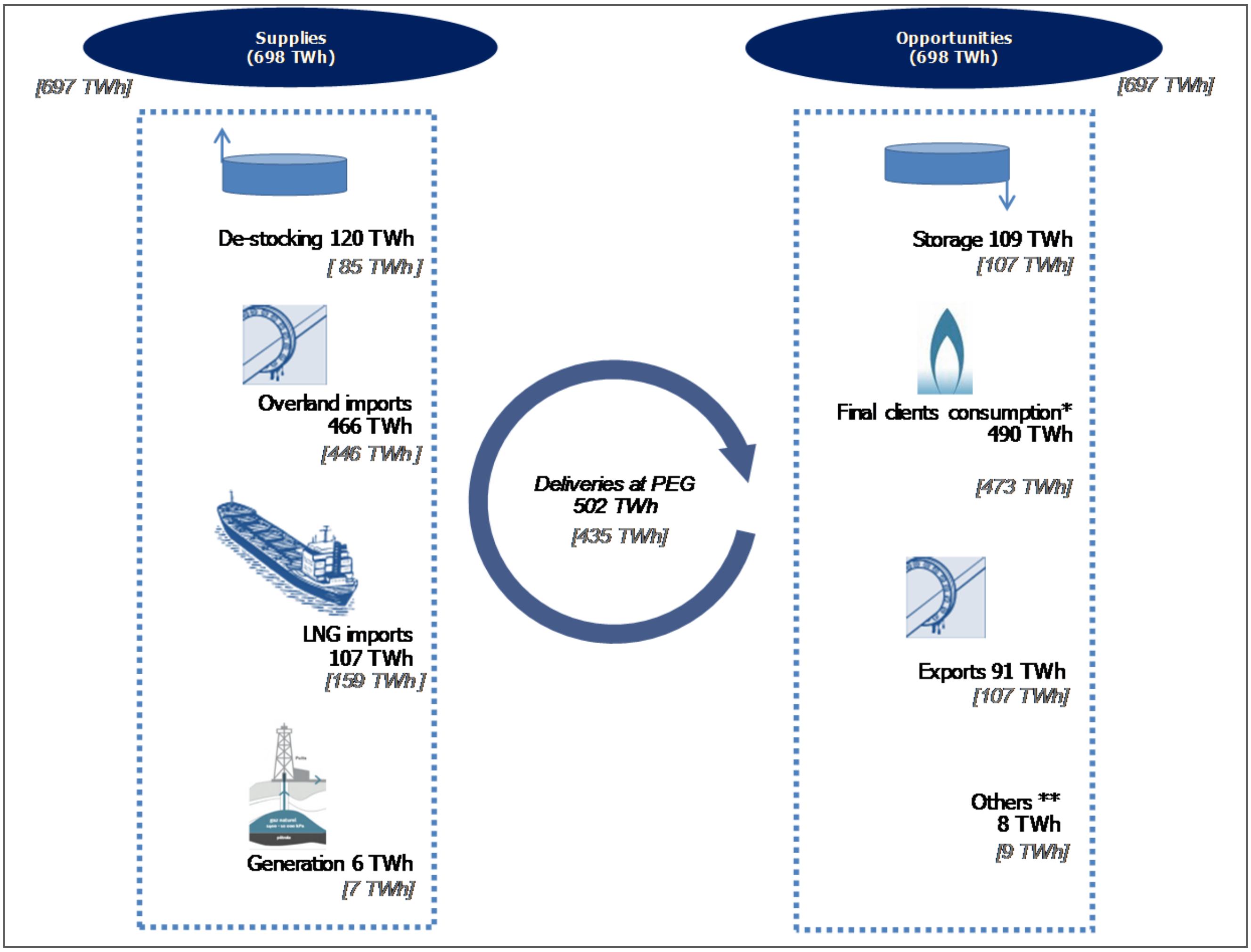
The French wholesale market continued its dynamic growth on the spot market, partially supported by the episodes of tension mentioned above. However, trading activity on the futures market tended to decrease in relation to the European economic slowdown and the decline in the consumption of electricity plants running on gas. This slowdown was exacerbated by competition from other more developed European futures markets.

Concentration levels still reflect significant disparity between the three French zones. PEG Nord maintains its position as the most developed market in France and most of the intermediated market's activity is performed on it. Despite its growth in volumes, the concentration of activity in PEG Sud is increasing. Finally, PEG TIGF remains the least developed hub in France where concentration levels are still very high.

The number of LNG terminal and French storage area users fell sharply in 2013. Although the decline in LNG terminal activity is related to global LNG supply tensions, low storage capacity sales are a consequence of the conditions on the European futures market and particularly the downtrend of the summer and winter price differential.

1 DEVELOPMENT OF GAS TRADING

Figure 68: Supplies and opportunities of the French gas market in 2012 [2011]



Source: GRTgaz, TIGF – Analysis: CRE

** Including both clients with regulated tariffs and clients with gas at market price*

*** Others refer to gas consumption by TSO and DSO to assure the network exploitation (self-consumption, measuring errors, losses …)*

Gas flows through French network reflect the level of use of facilities by shippers. Between 2011 and 2012, flows slightly increased although they were still below the levels recorded in previous years.

Regarding supply, 2012 was marked by a substantial drop in LNG imports which was offset by an increase in overland imports and de-stocking. LNG supply to Europe was particularly affected by the sharp increase in Japanese demand after the Fukushima nuclear accident in March 2011 and by high energy demand from other Asian countries to meet their rapid growth.

Regarding opportunities, French consumption increased slightly compared to 2011 despite a 38%[90] drop in demand from power plants running on gas. This increase was driven by the residential sector and was mainly

[90] Cf. Box 6 on the profitability of gas-fired electricity plants

due to the different climate conditions of 2011 and 2012. Although exports to the Spanish border have been high since the second half of 2011, exports at the interconnection with Switzerland (Oltingue) fell significantly as a result of a gradual convergence of market prices between the Italian hub (PSV) and the major European hubs. This convergence is consecutive to the establishment of an auction system for the short-term allocation of interconnection capacity between the Italian and Austrian markets in 2012 which has reduced the influence of oil products and favoured the effect of other European market places (including TTF) on the formation of wholesale prices in Italy.

Storage movements have changed dramatically from net injections in 2011 to high net withdrawals in 2012. This was partly due to the severity of the end of the 2011/2012 winter when stocks played a central role in supply, contrasting with a particularly mild early season. There was also a downward trend in sales of storage capacities that resulted in a lower annual injection balance.

1.1 Deliveries to PEGs increased in 2012 and the first half of 2013

Most of wholesale gas trading in France relies on OTC trading through bilateral trading or brokers, the lasting part being traded on the organised market Powernext. These exchanges can include deliveries from long-term contracts and procurement by infrastructure operators for their own requirements.

Trade on the French wholesale market materialises at gas exchange points (PEG) which are virtual points attached to each balancing zone where participants deliver gas to their counterparts according to their obligations[91].

This report makes a distinction between volumes traded on intermediated markets (exchange and brokers) and deliveries to PEGs. For a given period, the first concerns all contracts between the various participants, while the latter sums net daily deliveries for each pair of PEG participants.

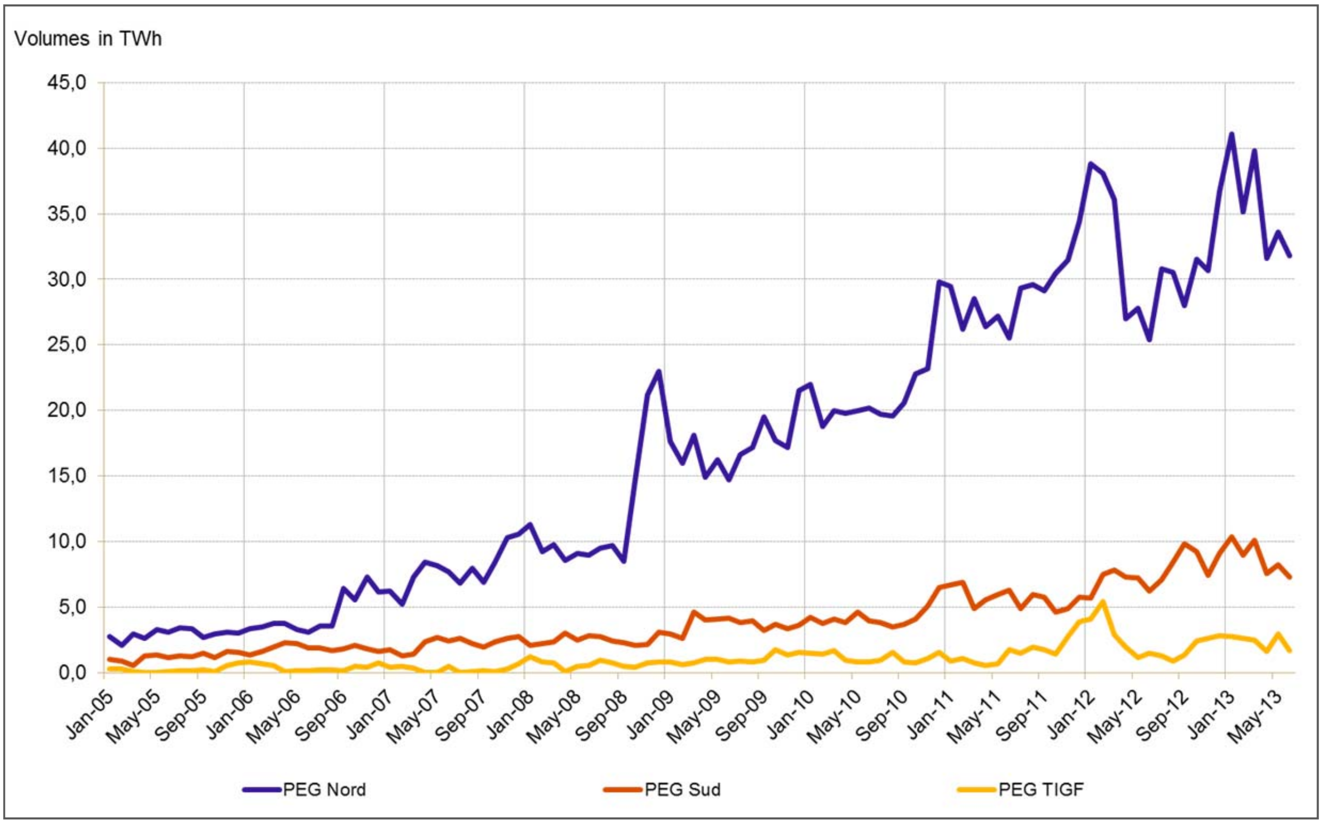
PEG deliveries continued to increase in 2012 and early 2013 (Figure 69). It should be noted that 2012 was the first year that PEG deliveries exceeded consumption, reflecting the healthy development of the wholesale market.

PEG Nord deliveries increased despite a significant slowdown in the summer of 2012. Lower delivery levels from April were primarily related to the slowdown of activity on the intermediated futures market (cf. Section IV, 1.2).

The increase in deliveries to the PEG Sud is particularly related to the increase in trade on the spot market which had been favoured by tensions between the northern and southern areas of the French system since the summer of 2012. Deliveries to the PEG TIGF sharply increased during the 2011/2012 winter and experienced a price spike in February 2012. This increase was mainly due to bilateral trade between market participants.

[91]Trade related to long-term contracts can also be performed at the French network's border points. This trade are beyond the scope of this report.

Figure 69: PEG delivery



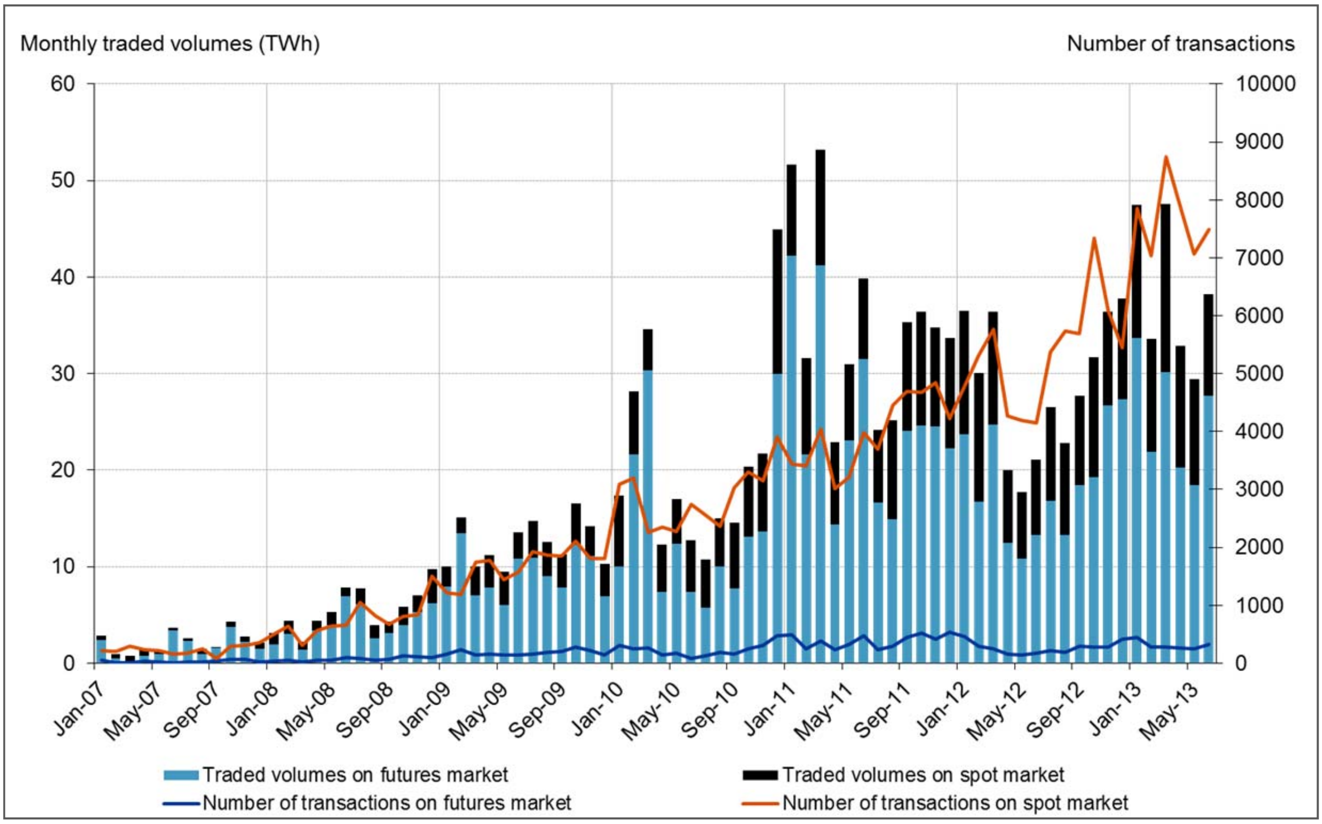
Source: GRTgaz, TIGF – Analysis: CRE

Note: Data for the PEG Nord before April 2013 includes deliveries to the PEG Nord H and PEG Nord B

1.2 Trade on the intermediated market fell in 2012 but resumed growth in the first half of 2013

The upwards trend of French intermediate market activity was reversed in 2012 with traded volumes falling by 19% compared to 2011 (Figure 70). While the spot market is experiencing increased traded volumes and transactions, trade on the futures market fell by about 26%. Activity in the intermediated market recovered in the first half of 2013 with traded volumes reaching levels similar to those observed during the same period in 2011.

Figure 70: Variation in traded volumes and number of transactions on the French intermediated market



Source: Powernext, brokers - Analysis: CRE

In 2012, activity on the French futures market was affected by Europe's economic slowdown and the loss of competitiveness of gas-fired electricity plants. The recovery of trading on the futures market since late 2012 is related to the increase in quarterly and seasonal product trade. It responds to the seasonal nature of futures trading, the better macroeconomic outlook in Europe, and the strategy of some participants seeking to hedge part of their summer needs on the market, at the expense of storage (Section 2.3.3).

However, the size of the French futures market is smaller than other European markets, particularly the TTF (Holland) and the NCG (Germany). Competition with these more liquid markets also partially contributed to the downturn in the French market during the summer of 2012.

Table 19 compares the average of Bid-Ask spreads for main maturities on the various European hubs. This is an average of the price difference between the best purchase and sale limits and is one of the indicators for monitoring market liquidity. While Bid-Ask spreads experienced a downward trend on the NBP, TTF, and the NCG in 2012 and the first half of 2013 that of the PEG Nord increased, particularly for futures products. The PEG Nord's growing liquidity premium has led participants to prefer adjacent market places to hedge their futures positions on.

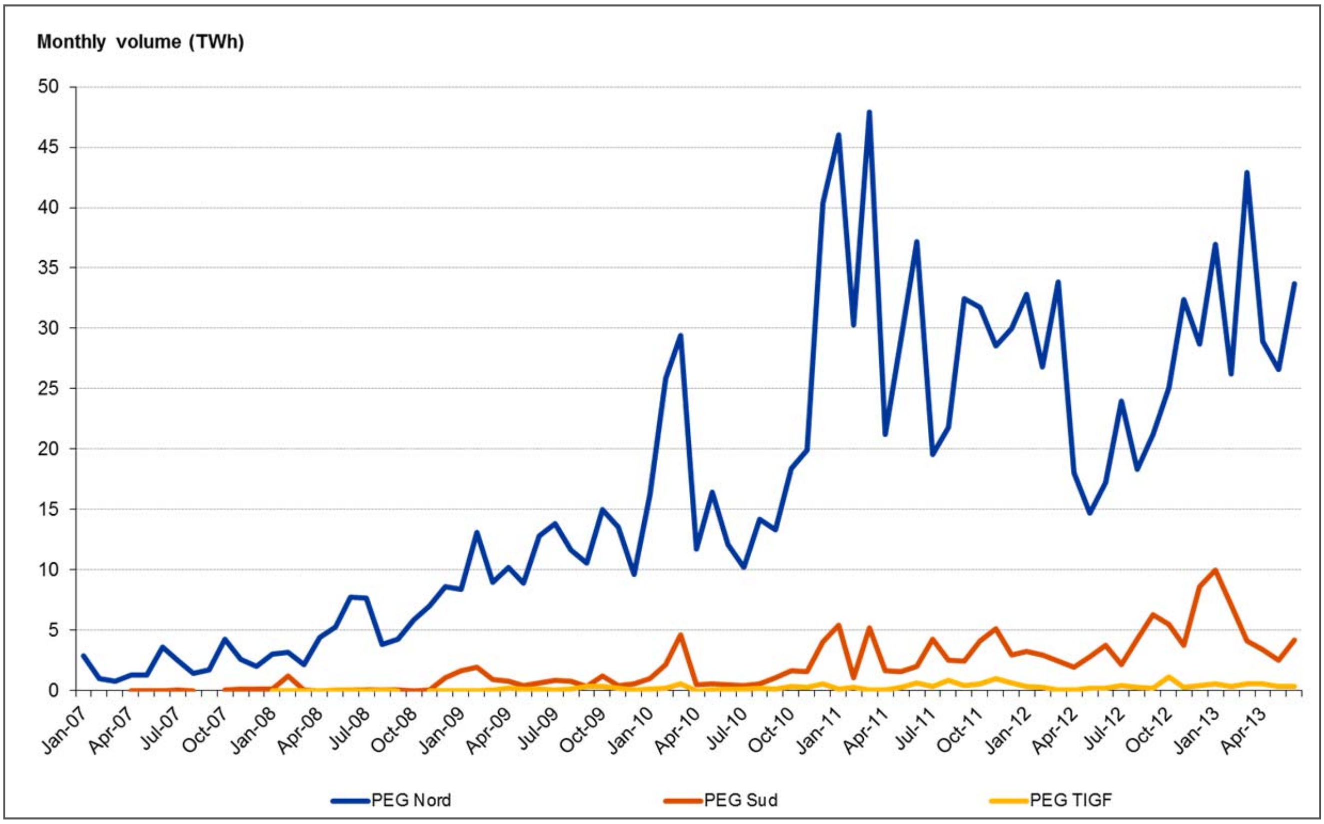
Table 19: Comparison of the *Bid-Ask* difference between the various European hubs

	2010	2011	2012	H1 2012	H1 2013
Day-ahead					
NBP	0.024	0.025	0.026	0.025	0.032
TTF	0.113	0.089	0.063	0.059	0.073
NCG	0.177	0.152	0.128	0.151	0.097
PEG Nord	0.159	0.124	0.127	0.122	0.223
M+1					
NBP	0.059	0.052	0.054	0.060	0.045
TTF	0.132	0.111	0.075	0.081	0.052
NCG	0.217	0.160	0.112	0.126	0.075
PEG Nord	0.224	0.194	0.228	0.246	0.297
Q+1					
NBP	0.090	0.080	0.089	0.093	0.072
TTF	0.186	0.162	0.110	0.108	0.112
NCG	0.291	0.270	0.202	0.239	0.148
PEG Nord	0.330	0.322	0.340	0.370	0.387
H+1					
NBP	0.084	0.073	0.087	0.091	0.064
TTF	0.182	0.163	0.121	0.115	0.107
NCG	0.275	0.243	0.185	0.209	0.120
PEG Nord	0.365	0.358	0.330	0.340	0.400

Source: Heren - Analysis: CRE

On the spot market, monthly trading volumes reached a record in March 2013 (17.4 TWh) due to tension on European supply (Section 2.2.1). Liquidity particularly increased on the PEG Sud mainly due to continuing tensions which had appeared on this hub at the beginning of the summer of 2012 (Section 2.2.2). The volumes traded on this PEG therefore increased by approximately 49% between 2011 and 2012 and 44% between H1 2012 and H1 2013.

Figure 71: Volumes traded on the intermediated market depending on PEG



Source: Powernext, brokers - Analysis: CRE

Table 20: Statistics of trade on the French intermediated market

	2010	2011	2012	H1 2012	H1 2013	2012 / 2011	H1 2013 / H1 2012
TRADED VOLUME (TWh)							
Spot	80	118	121	60	77	+2 %	+28 %
* of which *day-ahead* products	41	60	69	34	42	+15 %	+25 %
Futures	169	301	223	102	152	-26 %	+50 %
* of which monthly products	57	115	80	36	41	-31 %	+13 %
* of which seasonal products	72	130	93	53	91	-29 %	+71 %
Intermediated market total	**420**	**725**	**586**	**285**	**404**	**-19 %**	**+42 %**
NUMBER OF TRANSACTIONS							
Spot	34 214	47 653	64 112	28 457	46 106	+35 %	+62 %
* of which *day-ahead* products	24 739	33 239	44 727	20 195	29 928	+35 %	+48 %
Futures	2 706	4 587	3 122	1 481	1 828	-32 %	+23 %
* of which monthly products	2 067	3 395	2 232	1 062	1 302	-34 %	+23 %
* of which seasonal products	355	711	507	322	381	-29 %	+18 %
Intermediated market total	**64 081**	**89 585**	**114 700**	**51 517**	**79 545**	**+28 %**	**+54 %**
MOST COMMONLY TRADED VOLUME (MWh/d)							
Spot	1,500 (19%)	1,500 (19%)	1,000 (15%)	1,500 (13%)	1,000 (25%)		
* of which *day-ahead* products	1,500 (20%)	1,500 (21%)	1,000 (15%)	1,500 (15%)	1,000 (25%)		
Futures	750 (58%)	750 (52%)	720 (28%)	750 (40%)	720 (44%)		
* of which monthly products	750 (59%)	750 (52%)	720 (27%)	750 (44%)	720 (45%)		
* of which seasonal products	750 (54%)	750 (55%)	720 (32%)	720 (31%)	720 (45%)		
Intermediated market total	**1,500 (10%)**	**1,500 (10%)**	**1,000 (8%)**	**1,500 (7%)**	**1,000 (14%)**		

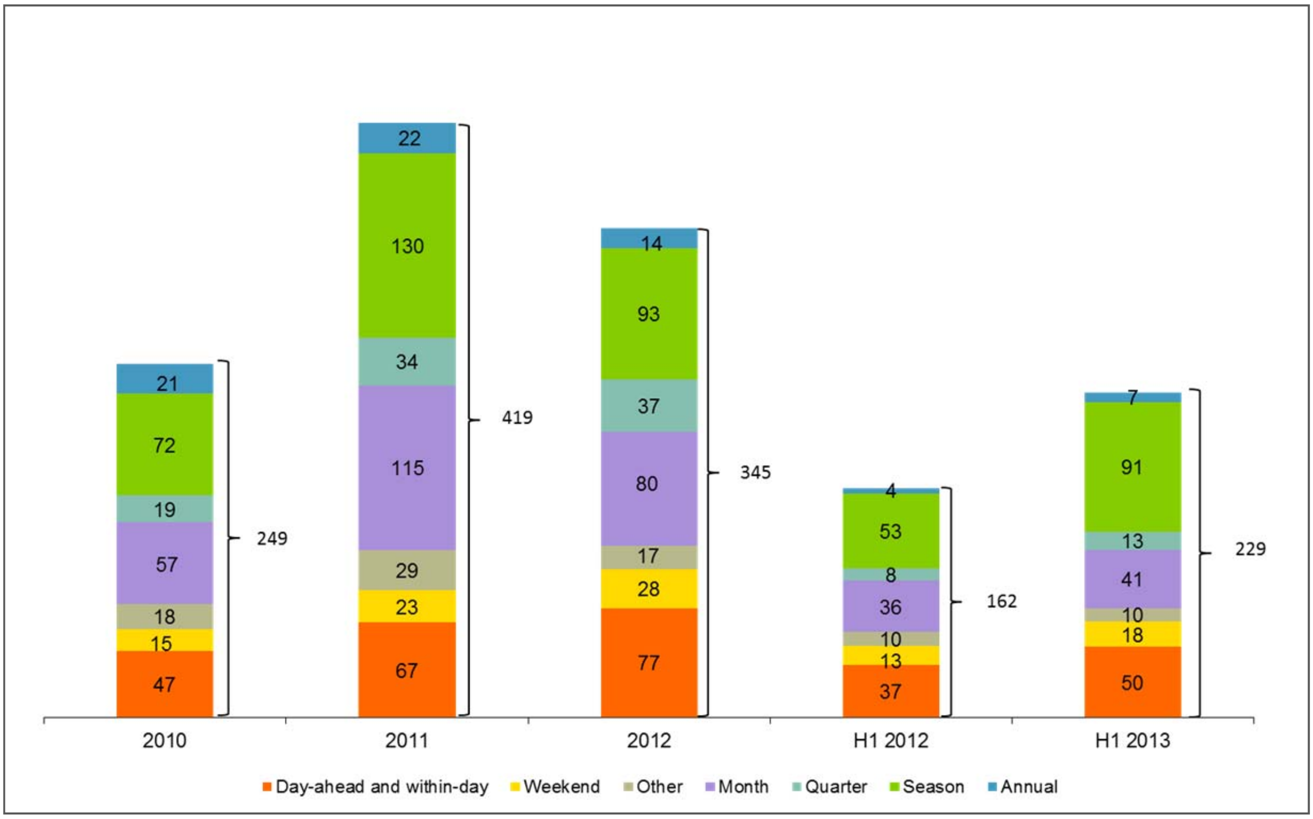
Source: Powernext, brokers - Analysis: CRE

The volumes traded on the intermediated market were still dominated by season products, especially *front-season*[92] products (Figure 72). The share of monthly products continued to decline in the face of the increase in daily and, in particular, *day-ahead* products.

The most commonly traded unit volume on the French futures market was 720 MWh/d in 2012 and the first half of 2013. This volume corresponds to the TTF market's reference unit (30 MW or 720 MWh/d) confirming the influence of this market on the PEG Nord where volumes are mainly drawn from "PEG Nord / TTF *spread*" transactions. However, the most commonly short-term traded volumes corresponds to multiples of 250 MWh/d (mainly 750, 1,000, or 1,500 MWh/d), which is the standard reference unit on the French market, showing a certain autonomy of the French market for these maturities.

Figure 72: Volumes traded on the French intermediated market by product type

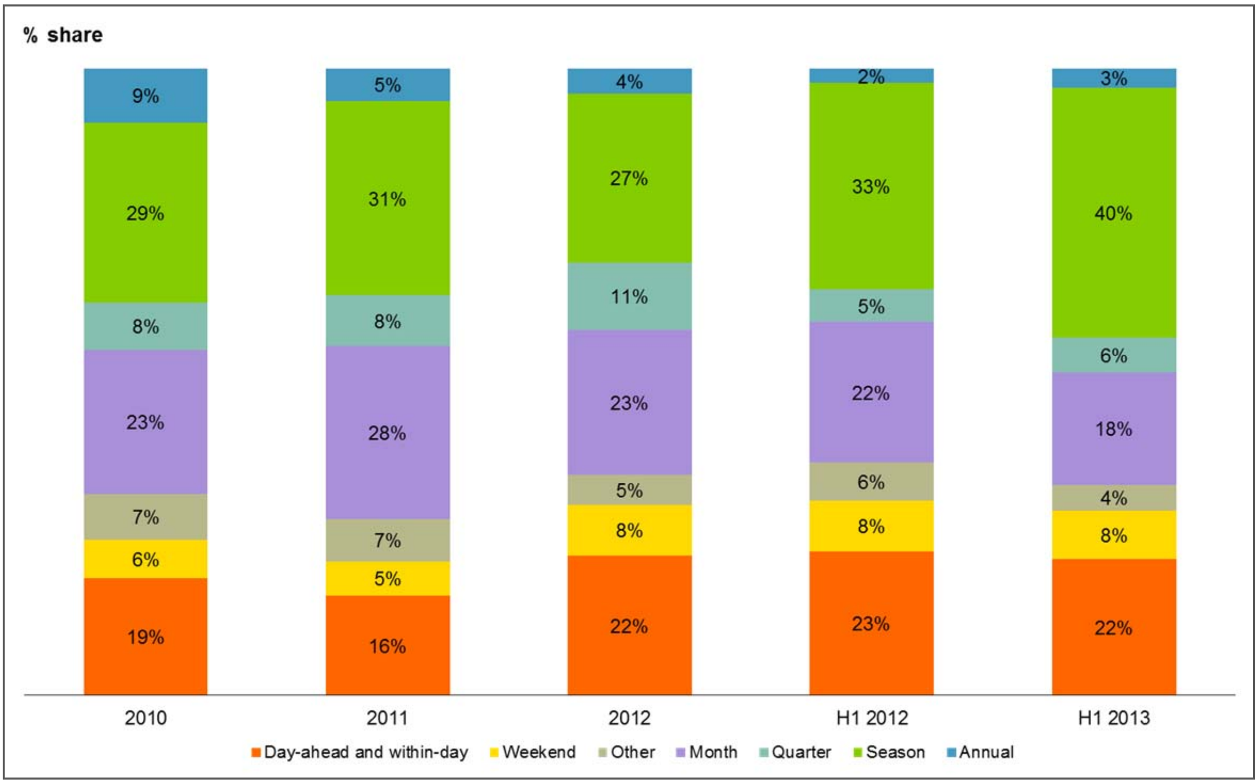
a. Volumes in TWh



Source: Powernext, brokers - Analysis: CRE

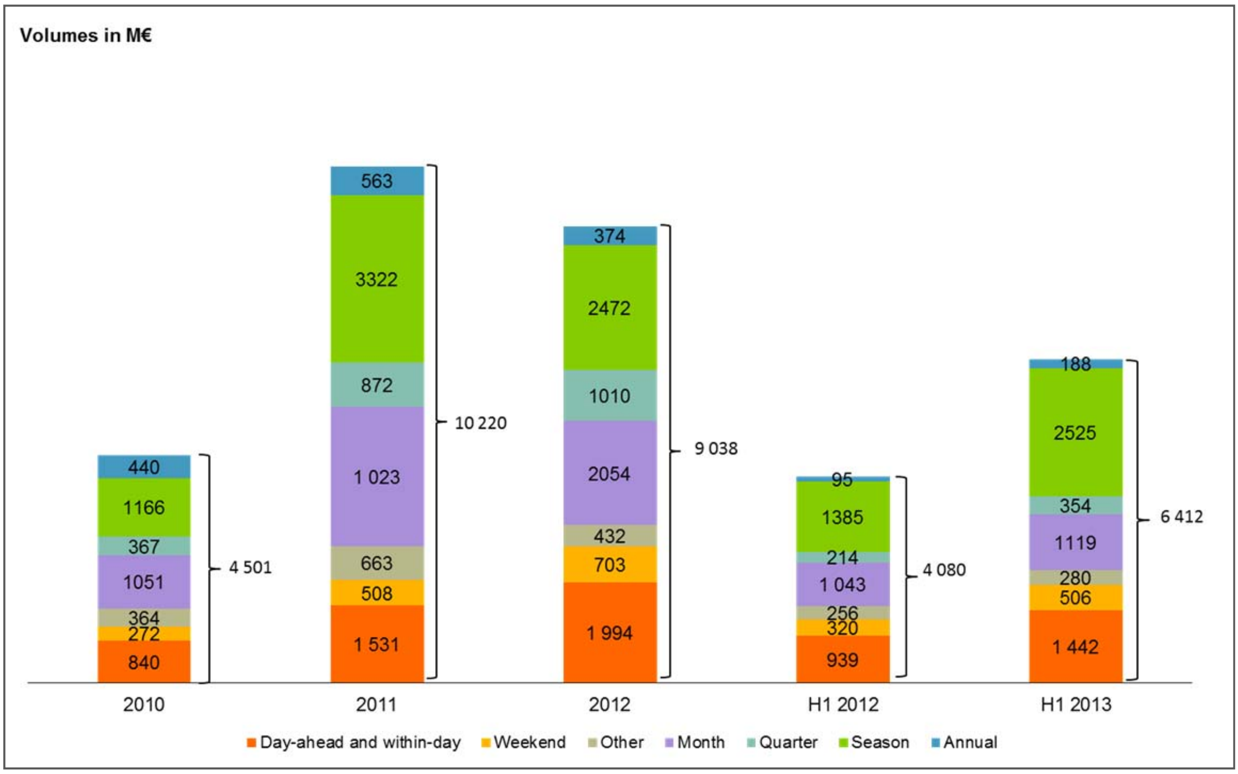
[92] See Glossary

b. Distribution of traded volumes



Source: Powernext, brokers - Analysis: CRE

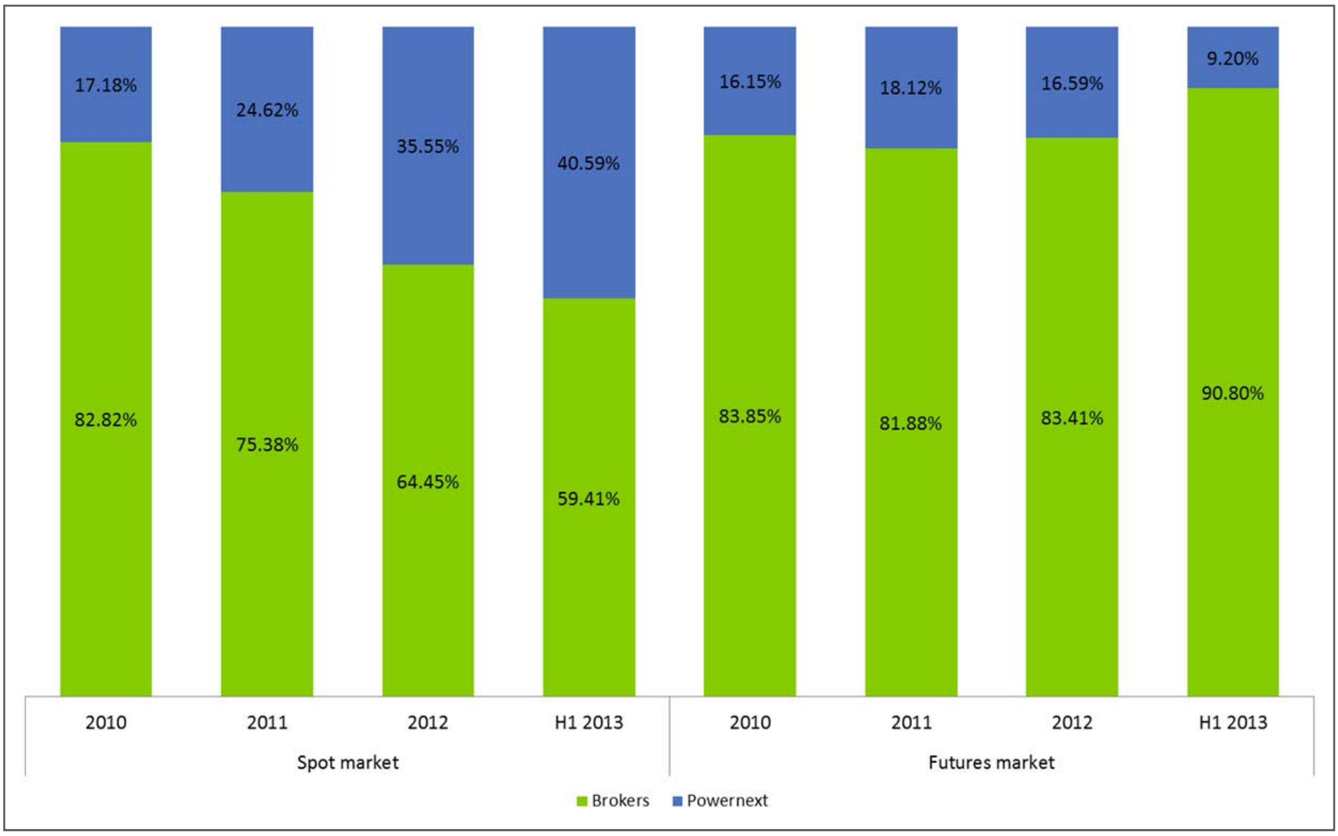
c. Exchange volumes in M €



Source: Brokers, Powernext - Analysis: CRE

The share of Powernext in spot volumes continued to grow in 2012. The introduction of swap products between PEG Nord and PEG Sud in May 2011 and the market coupling mechanism in July 2011, in partnership with GRTgaz, contributed to this development. On the *day-ahead* maturity which is the largest on the spot market, North/South spread products represented about 76% of the volumes traded on the Powernext platform at the PEG Sud in 2012. However, brokers remained the preferred way of intermediation on the futures exchanges and continued to increase its market share compared to Powernext.

Figure 73: Distribution of spot and futures volumes traded by type of intermediation



Source: Brokers, Powernext - Analysis: CRE

1.3 Development of competition on PEGs and gas facilities

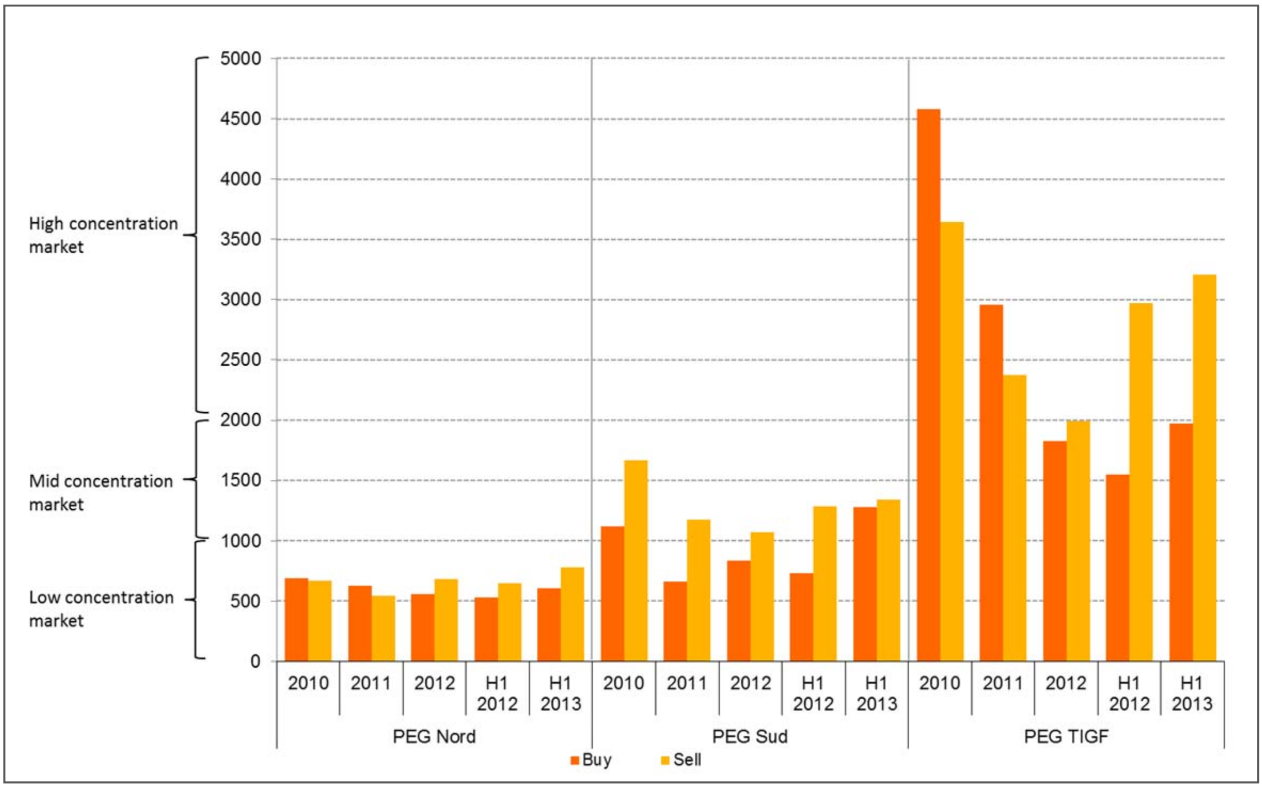
The differences between the three French PEGs concentrations remained stable in 2012 and the first half of 2013 (Figure 74). PEG Nord remains the least concentrated French hub displaying stable indices characterising a low concentration market both for purchases and sales on spot and futures products.

Spot concentration at PEG Sud increased in 2012 and particularly in the first half of 2013 in connection with the increased needs of certain participants due to tensions in the south of France (Section 2.2.2). The futures market on this PEG, which is characterised by its low development, showed a sharp increase in sales concentration during the first half of 2013.

Due to the small number of participants on the market, PEG TIGF remains the French hub with the highest concentrations. However, despite a slight increase in the first half of 2013, spot market concentration levels are falling. This is partially due to the arrival of TIGF on the Powernext Gas Spot in December 2011 to cover part of their daily balancing requirements.

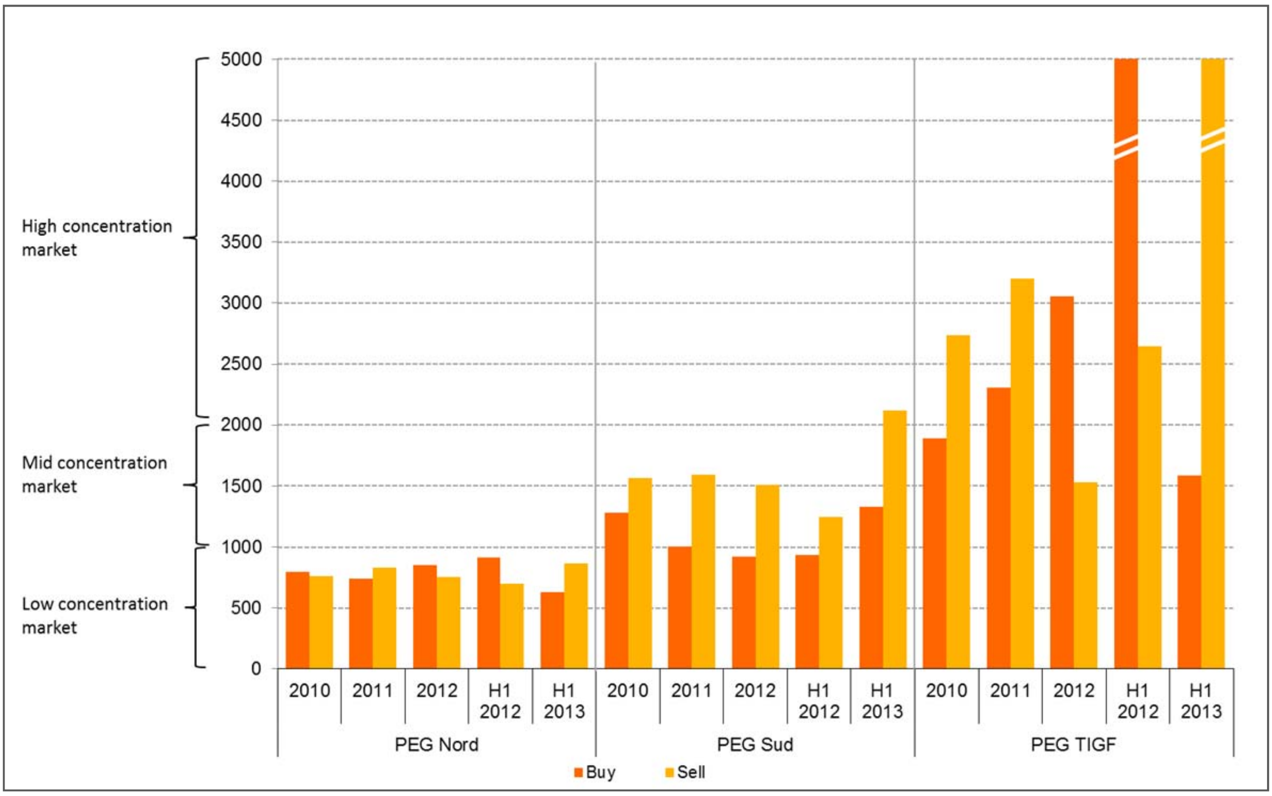
Figure 74: French wholesale market concentration indices

d. Intermediated spot market



Source: Courtiers, Powernext - Analysis: CRE

e. Intermediated futures market



Source: Brokers, Powernext - Analysis: CRE

Although increasing, the number of active participants on the French wholesale market seems to have stabilised in 2012 and the first half of 2013 (Table 21). The same trend is observed on the transmission distribution interface points (PITD). However, the number of active participants on interconnections (PIR) and also especially on transmission storage interface points (PITS) and LNG terminals is falling, particularly in 2013.

The decline in the number of active shippers on storage facilities is related to lower sales of capacity for these facilities (Section 2.3.3). The decline in the number of participants on LNG terminals is related to less LNG arrivals to France.

Table 21: Number of participants on the French market

	2007	2008	2009	2010	2011	2012	H1 2013
PEGs	29	37	42	59	66	68	71
Of which traders	2	5	8	11	16	17	17
PIR	27	34	40	43	47	46	41
PITD	13	12	19	24	25	28	25
PITS*	22	25	30	38	37	38	25
LNG terminals **				7	6	5	2

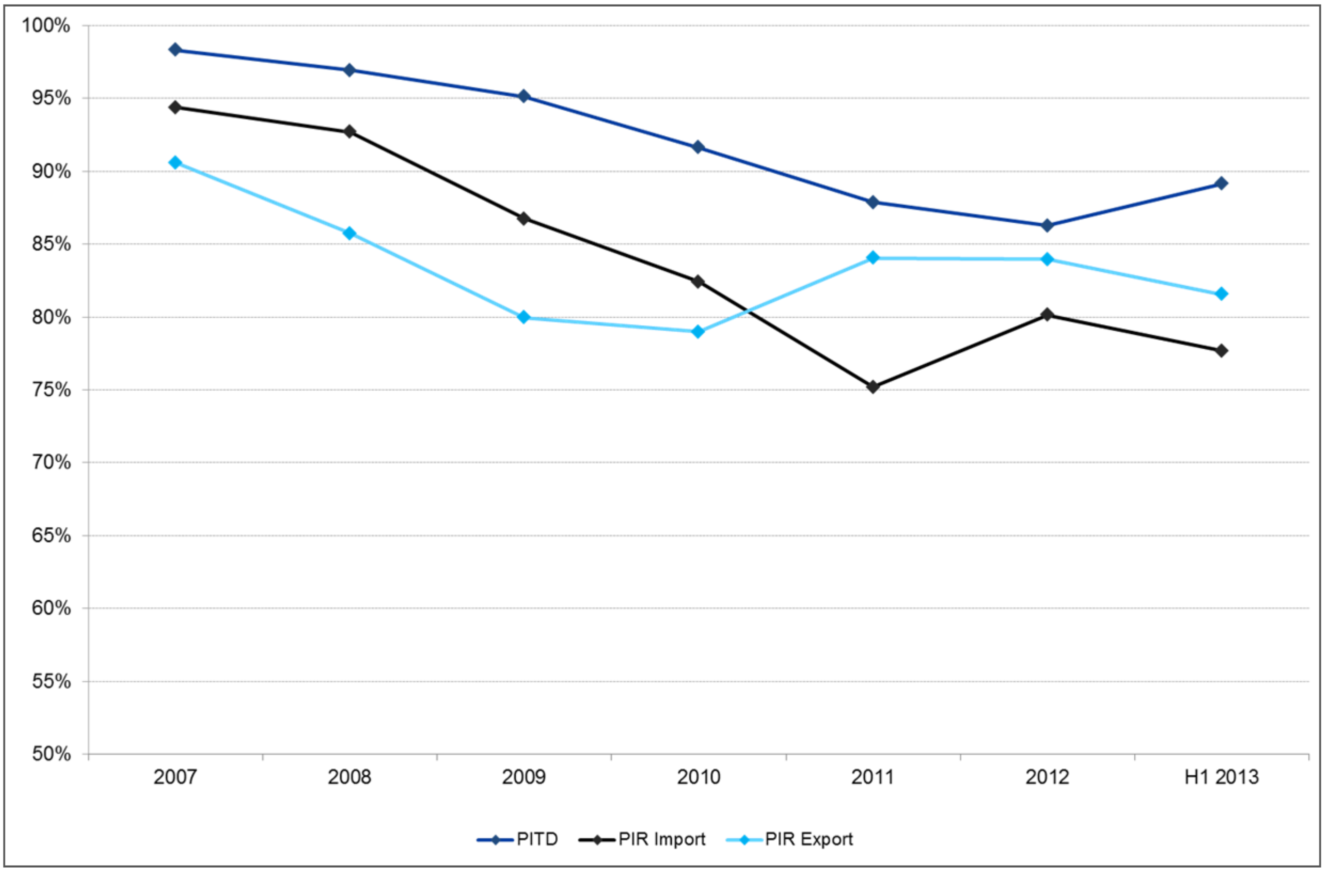
Source: GRTgaz, TIGF – Analysis: CRE

** For PITD, the number of active participants is calculated for the period between April,1st of year N and March, 30th of year N+1*

*** Only analysed after 2010*

The downward trend of the market share of the three main participants on PITDs observed in previous years was reversed in the first half of 2013 (Figure 75). For interconnections, this indicator remains stable for export while stagnating for import after being on a downward trend since 2007. The increase of concentration on PITD and the stagnation on PIR can be partially explained by the decline in the number of participants at these network points due to a reorganisation of their activities.

Figure 75: Aggregate market share of the three largest participants on the various infrastructures



Source: GRTgaz, TIGF – Analysis: CRE

2 GAS PRICES

2012 experienced a slight increase in gas prices in Europe, which are gradually approaching the levels reached before the financial and economic crisis of 2008. Gas price trends are linked to the balance between supply and demand on wholesale markets and to long-term supply contract prices. They are also increasingly influenced by international markets and, in particular, the Asian market. While demand in Europe remained weak, Asia and especially Japan continued to massively import gas for electricity generation. Active participants on the LNG market continued their trade-offs between these two markets as well as with the South American market which has strongly increased its LNG imports.

On the North American market, the production on unconventional gas continues to develop and resulting in very attractive prices. Electricity generation using gas is therefore preferred compared to coal in Europe causing a sharp fall in coal prices.

The trends in oil prices continued to influence the gas market through long-term contracts despite the significant market indexation of these contracts. The prices of oil products generally stabilised in 2012 but remain at historically high levels. However, they varied strongly during the period as a result of geopolitical and macroeconomic uncertainties in particular.

European gas prices are therefore experiencing geographical and sectoral competition with upward pressures related to the LNG market and the high prices of oil products. The loss of competitiveness of gas over coal in European electricity generation (Section III, Box 6) has led to combined cycle gas plant projects being postponed and existing plants being mothballed.[93]

The French market followed the trends observed on neighbouring market places (NBP, TTF) but encountered specific tensions on the South related to the diversion of LNG to Asian markets. A significant spread between PEG Nord and PEG Sud appeared in April 2012 which prompted CRE to conduct a detailed analysis and deliberate on 29 May 2013[94]

2.1 Prices influenced by international markets

2.1.1 The price differential between European and American markets increased in 2012

In 2012, the price of natural gas in the United States reached its lowest price in ten years, going under \$2/MMBtu[95] on the Henry Hub (about 5 €/MWh). Despite this very low price level, the large-scale exploitation of unconventional gas, including shale gas, continued. As a result of this development, the production of natural gas in the U.S. increased by 5% in 2012 returning to volumes that had not been reached since 1970. This increase in production led to a sharp reduction in LNG imports and pipeline imports from Canada. The abundance of resources greatly helped meet growing demand which made gas price fall sharply. Therefore, American wholesale gas prices are about 2.5 times lower than European prices (Figure 76).

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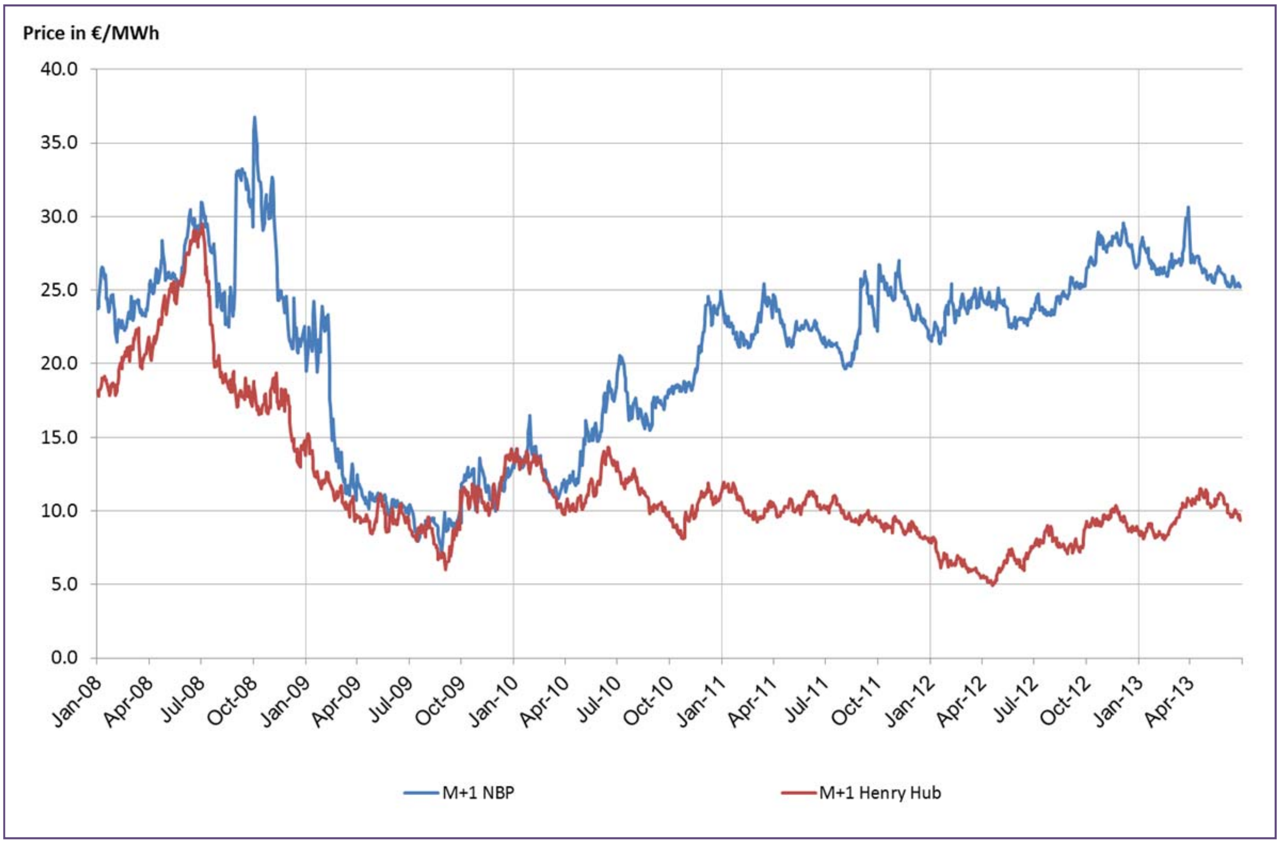
[93] AFP dispatch of 11 April 2013: *GDF Suez to announce that three of its four gas-fired plants in France are going to be mothballed*

[94] See CRE's deliberation of 23 May 2013. The reader can also refer to Box 7 in this report.

[95] Source: CME Group. See Glossary for the definition of "MMBtu"

Figure 76: M+1 Gas prices (UK and USA)



Source: Heren, Bloomberg- Analysis: CRE

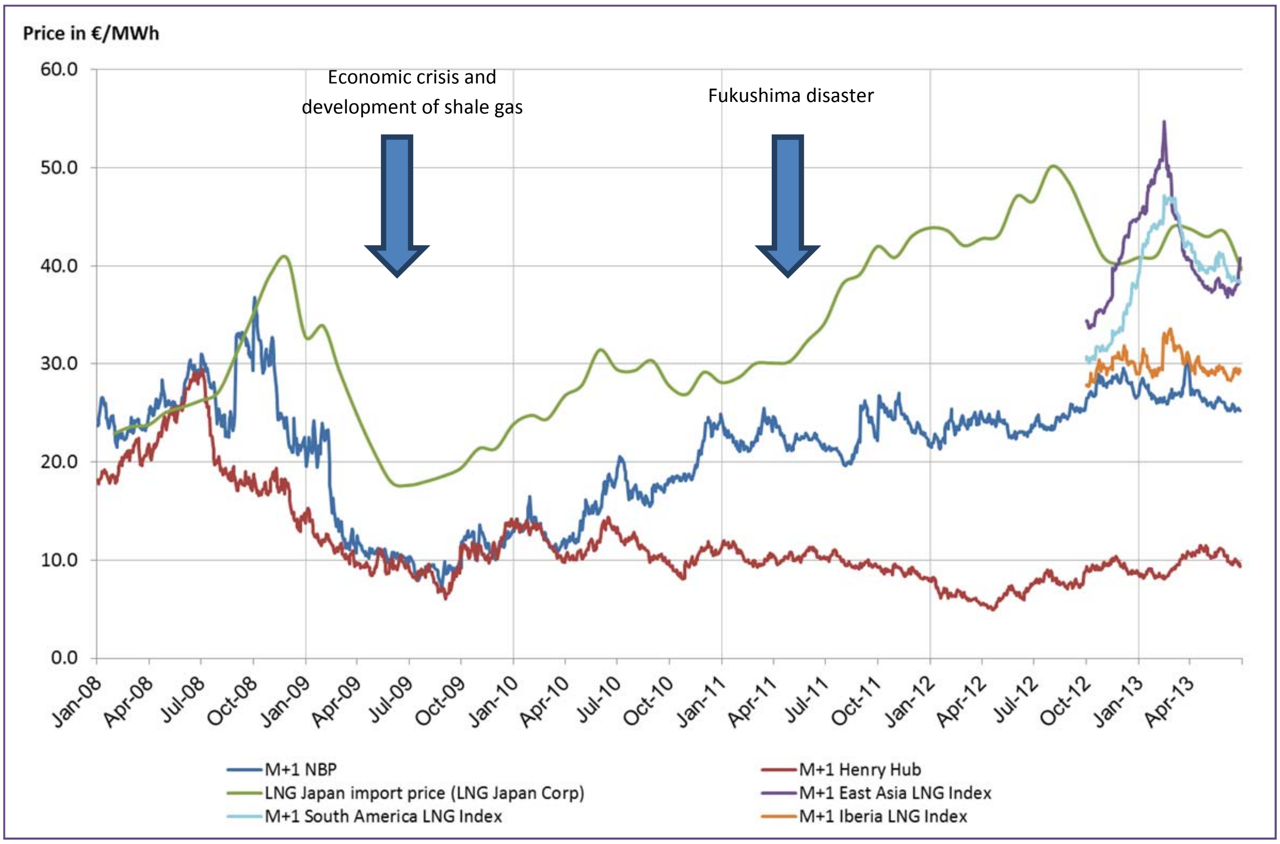
The lack of LNG export capacity in North America explains the strong disconnection with other wholesale gas markets and contributes to forming a North American gas "island". However, the first export agreements for U.S. gas in the form of LNG have been concluded. On 25 March 2013, Centrica announced that it had signed a twenty-year export contract (with an option of an additional ten years) for a volume of 26.7 TWh of LNG with the U.S. company Cheniere Energy Partners. The LNG, the first deliveries of which are expected in late 2018, will be shipped from the liquefaction plant at Sabine Pass, Louisiana.[96]

[96] http://www.centrica.com/index.asp?newsid=2693&pageid=1041

2.1.2 European markets are influenced by the increase in LNG prices in Asia and South America

Asian prices increased sharply on average in 2012 compared to 2011, due to the Fukushima disaster and the substitution of a portion of nuclear generation by natural gas. The differential between Japanese LNG import prices and the NBP M+1 represented on average 19.3 €/MWh in 2012 against 13.2 €/MWh in 2011. South American prices also sharply increased in late 2012 and are currently at a level similar to Asian prices. Therefore, European prices evolve somewhere between North American and Asian prices (Figure 77).

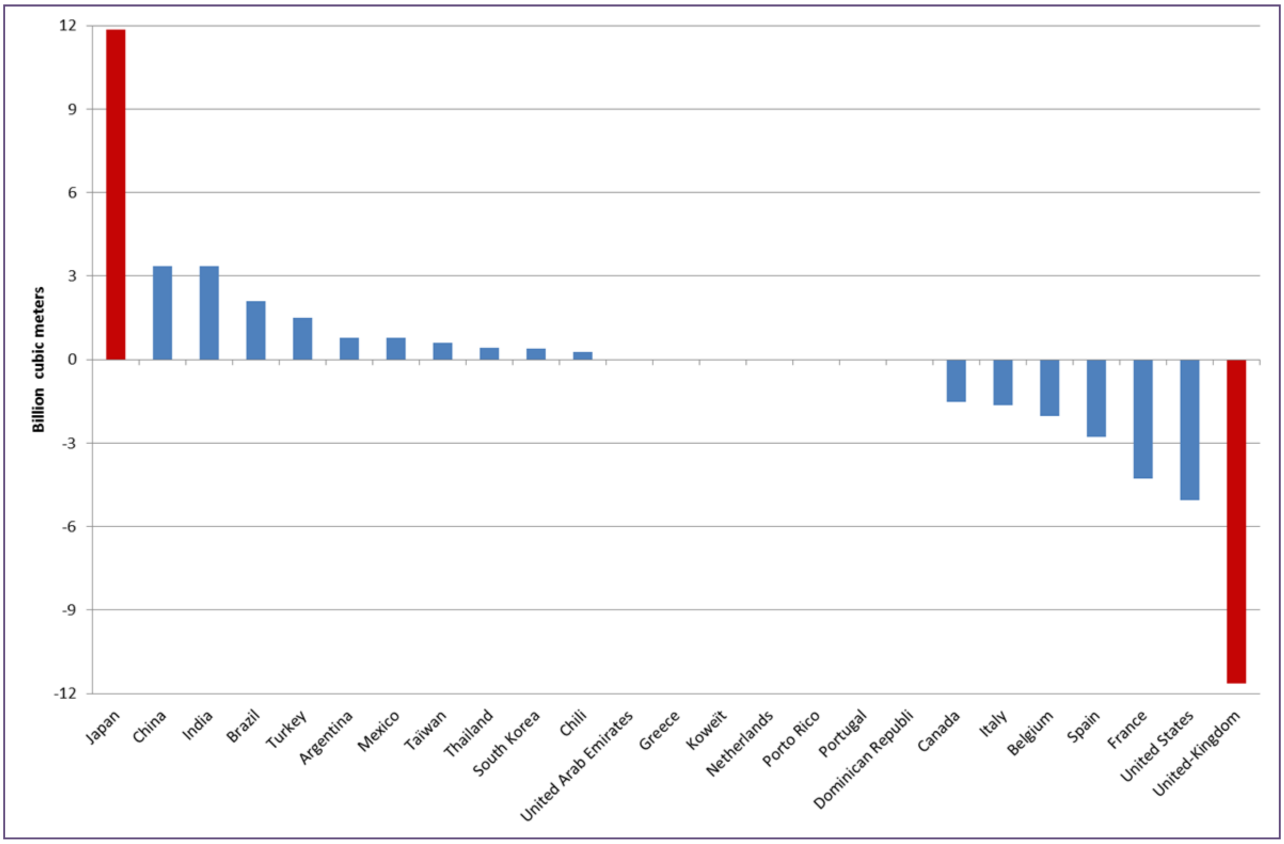
Figure 77: Gas prices in Europe, USA, Latin America, and Asia



Source: Heren, Bloomberg- Analysis: CRE

The significant price differential between European markets and the Asian and South American markets has resulted in the diversion of LNG cargoes to the markets offering the best prices. LNG imports therefore significantly varied across countries between 2011 and 2012 with a very significant increase in Japan, China, and India and on the contrary a very significant decline in European (United Kingdom, France, Spain etc.) and North American markets (Figure 78).

Figure 78: Trends in LNG imports 2011-2012 (YoY)



Source: Bloomberg / British Petroleum statistics – Analysis: CRE

Lower LNG imports created tension in some areas of Europe which are very dependent on these arrivals and relatively little interconnected with other markets unlike Spain or southern France.

LNG import volumes to the United Kingdom fell sharply in 2012. Although the United Kingdom was the largest European importer of LNG in 2011 (25*bcm*[97]), just ahead of Spain (24 *bcm*), the drop in LNG imports was steeper in 2012. Two factors could explain this phenomenon. Unlike Spain, the British system has other supply flexibilities which offset the deficit in LNG. In particular, imports by pipeline increased by approximately 7.6 *bcm* in 2012. On the other hand, the fact that LNG cargoes are less valued on the NBP than in Spain (Figure 77) also explains why the UK has suffered more diversions of LNG tankers.

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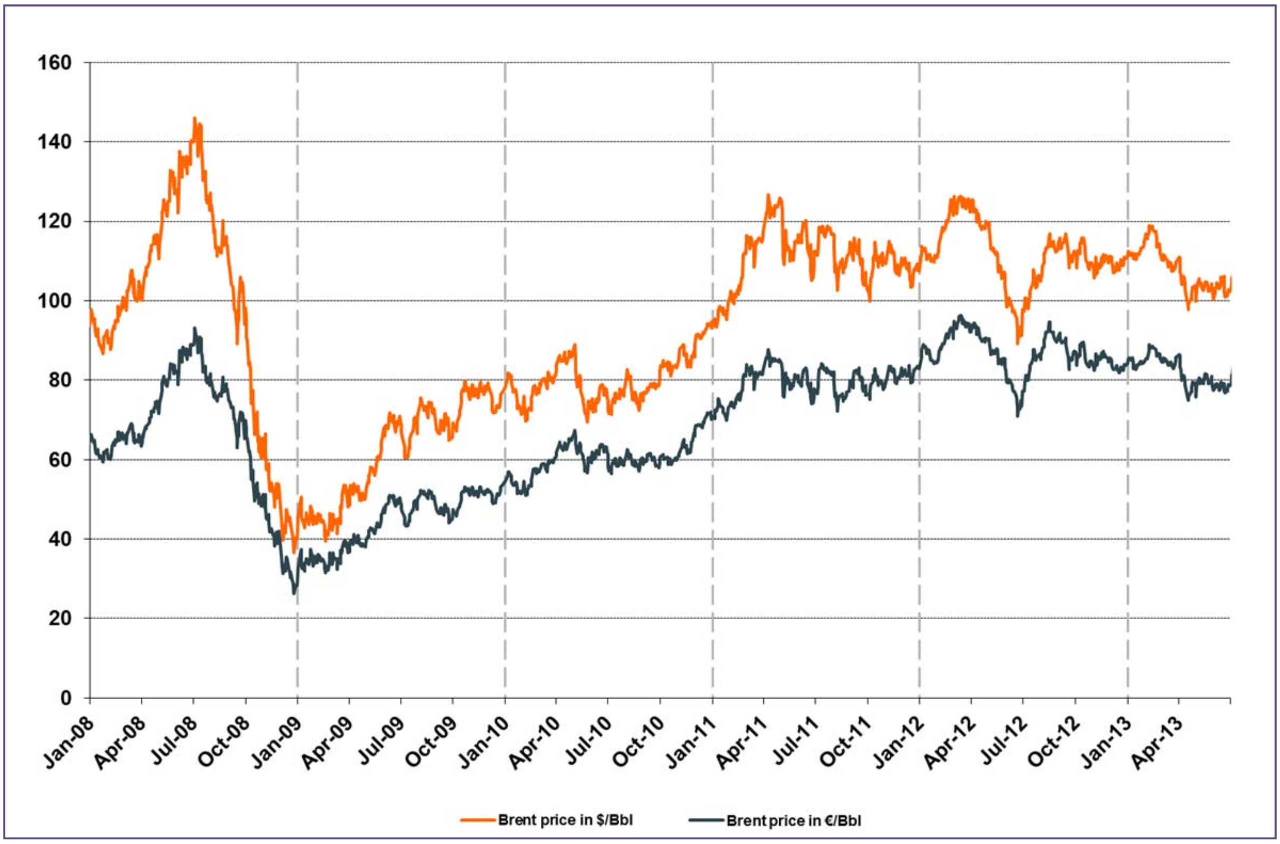
[97] See Glossary for the definition of "bcm"

2.1.3 ***The disconnection between market prices and wholesale prices of oil products was still relevant in 2012***

The price of Brent[98] in 2012 and the first half of 2013 was stable although marked by strong variations (96 €/bbl in March 2012, 71 €/bbl in June 2012, and 89 €/bbl in February 2013). Although Brent prices did not achieve the record set in July 2008 of over 144 $/bbl, Brent denominated in €/bbl exceeded the record of 2008 (93.07 €/bbl) several times with historically high levels (Figure 79).

The oil embargo on Iran decided in January 2012 by the European Commission was the main factor in rising prices during the first part of the year. Concerns about the financial stability of the Eurozone subsequently weighed heavily on prices between June and August. The decline was exacerbated by the currency effect of a stronger dollar.

Figure 79: Trends in Brent prices



Source: Bloomberg – Analysis: CRE

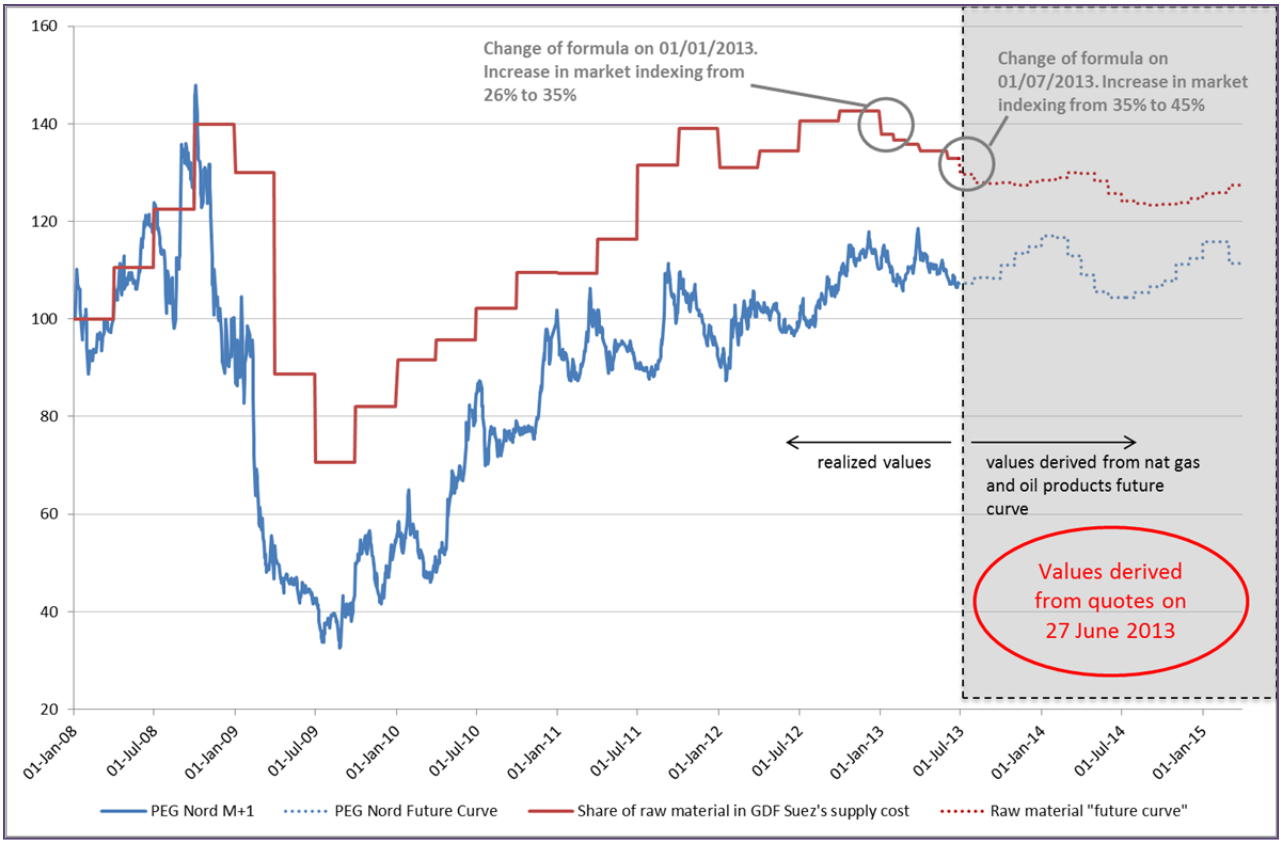
Since 2009, the steeper rise in oil prices caused a progressive disconnection between long-term supply contract prices and wholesale gas market prices. This disconnection persisted in 2012 and led many European suppliers to renegotiate their supply contracts with companies in producing countries. This allowed more gas market indexing and less oil product indexing to be introduced in supply contracts.

[98] ICE Future contract, first maturity

In France, in order to take these developments into account, these contract renegotiations resulted in a subsequent adjustments to the regulated gas tariff (TRV) formula with an increasing share indexed on the wholesale gas market. Therefore, the decree of 27 June 2013 on regulated gas tariffs[99] increased the share indexed on the wholesale natural gas market to 45% in the GDF Suez supply cost calculation formula. This share was only 26% in 2012.

The futures values of figure 80, derived from futures product prices on the market on 27 June 2013, show a slight narrowing of the difference between gas prices and long-term contract prices particularly due to the growing share of indexing on the gas market. It should be noted that these values do not predict an actual change in gas prices or supply costs included in the regulated tariffs.

Figure 80: Comparison between gas prices on wholesale markets and those from the TRV formula (base 100 on 1 January 2008)



Source: Argus, Bloomberg, Powernext – Analysis: CRE

Note: (1) The blue solid line represents the PEG Nord month-ahead product price. (2) The blue dotted line represents PEG Nord future curve recorded on 27/06/2013. (3) The red solid line represents the evolution of the share of raw material in GDF Suez's supply costs and includes the various formula changes. (4) The red dotted line represents the "future" evolution of the share of raw material, calculated from futures quotes of indices used in the current formula recorded on 27/06/2013.

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[99] JORF no. 0150 of 30 June 2013 page 10952 text no. 12

2.2 Wholesale prices in France rose on the Spot market in 2012 and early 2013 with several price spikes and persistent tensions on the North/South differential

2.2.1 Wholesale prices rose on the European spot markets in 2012 and the first part of 2013, with several occurrences of price spikes

After a year of stagnation in 2011, gas prices rose in Europe in 2012-2013 (Figure 81). The French market followed the European trend. Therefore, in France, while prices had generally ranged between 20 and 25 €/MWh since 2011, PEG Nord has been trading at higher levels (between 25 and 30 €/MWh) since August 2012.

2012 was marked by a significant price spike on the European spot markets in February which was the result of a cold snap covering virtually the entire continent which tightened supply. CRE analysed the conditions of price formation in France during this episode (see CRE's deliberation of 26 June 2012[100] and the 2011-2012 Report on the functioning of wholesale markets[101]).

Average temperatures in February 2012 were at least five degrees lower than usual, making it the fourth coldest February since 1950. This phenomenon led to record consumption in France[102] and historical spikes in *day-ahead*[103] prices. Tension on the European markets was exacerbated by restrictions on imports from Russia. The Italian authorities' decision to force shippers to maximise their gas import capacity to Italy also exacerbated tension on the French system via the interconnection with Switzerland (Oltingue).[104]

Despite this tension, the available import capacity at major interconnection points of the French network (including Obergailbach and Taisnières H) was not fully used during the cold wave, despite the strong price differential between PEG Nord and neighbouring hubs. Between 1 and 7 February 2012, 20% of entry capacity sold (2.2 TWh) was not used (9% of French consumption during this period). Market participants therefore indicated that the under use of capacities resulted from balancing constraints on the Belgium network and congestion on the German network.

[100] Deliberation of CRE of 26 June 2012 regarding the price spikes in early February 2012

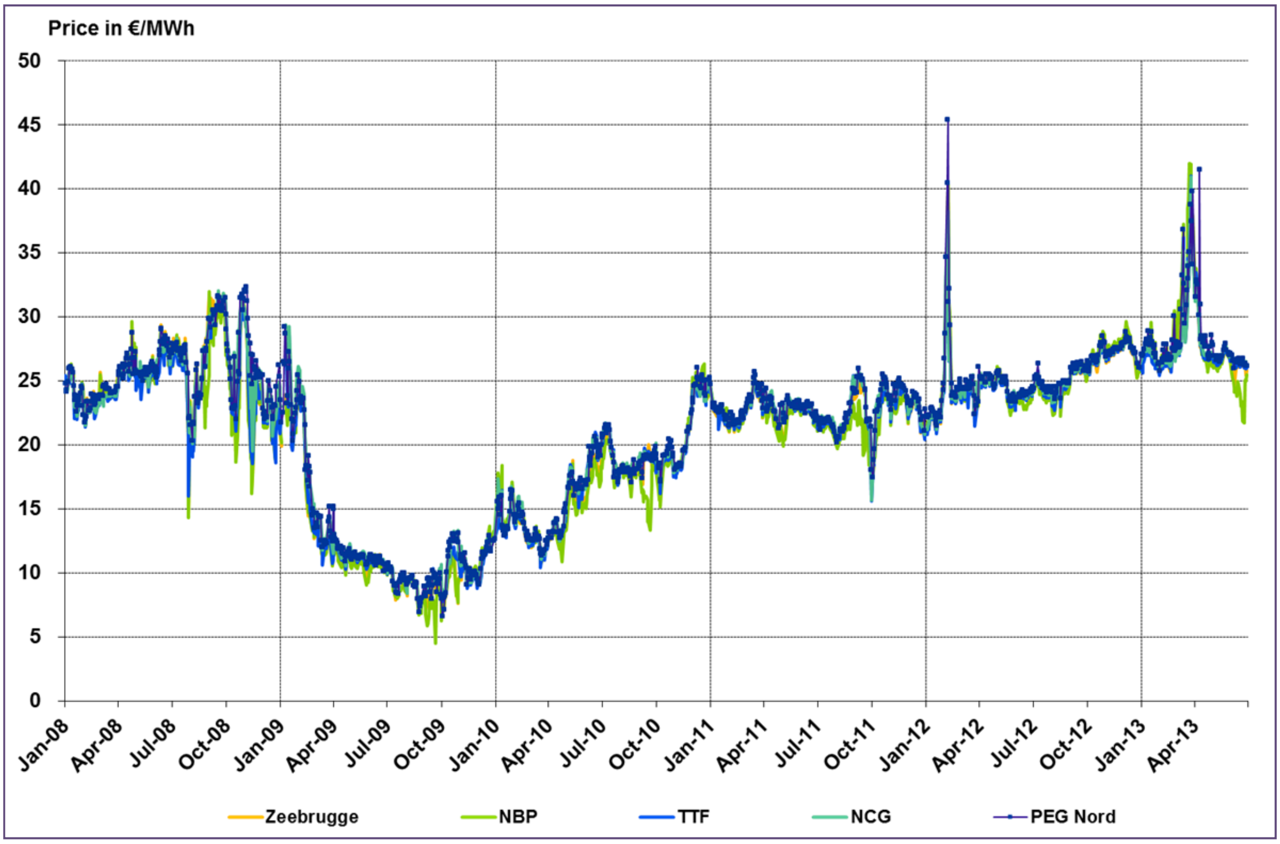
[101] Cf. p.117 in the 2011-2012 Wholesale market monitoring report

[102] French consumption stood at 3,643 TWh on 7 February and 3,673 TWh on 8 February 2012

[103]PEG NordPEG *day-ahead* prices reached 40.5 €/MWh for delivery on 7 February and 45.7 €/MWh for delivery on 8 February 2012

[104] Circular of 6 February 2012 issued by the Italian Ministry of Industry for all capacity holders at Italian network entry points.

Figure 81: Trends in European *day-ahead* prices



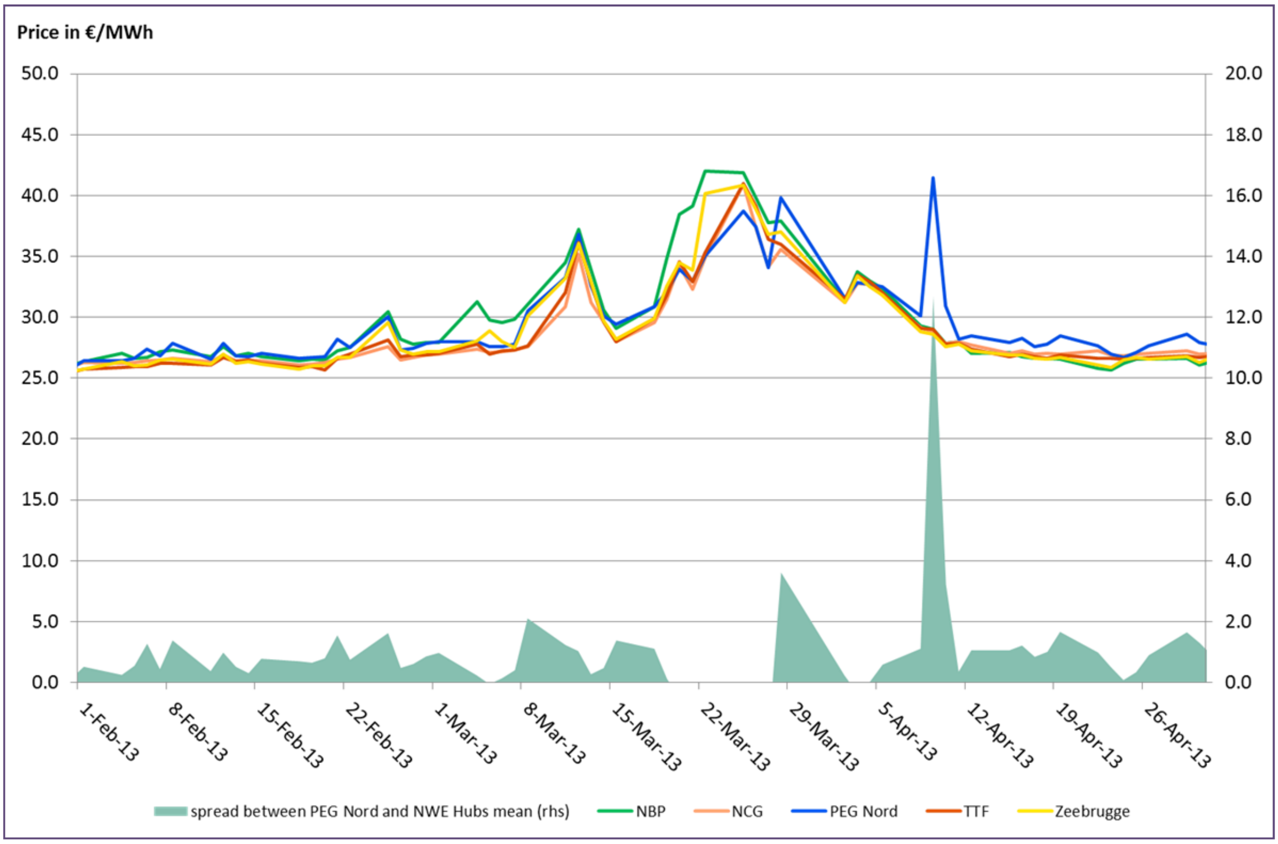
Source: Heren, Powernext – Analysis: CRE

Between 1 March and 1 May 2013, other price spikes occurred on the French wholesale market (Figure 82): on 12 March with prices above 36 €/MWh, on 25 and 28 March with prices above 38 €/MWh, and on 9 April with a spike above 42 €/MWh.

The price spikes in France and Europe during March 2013 are concomitant with a tense situation in the supply of the British system, and more generally the European system. The UK was affected, in the context of prolonged cold, by very low stock levels, lacking LNG supply, and a series of technical problems that significantly reduced inflows on its network. Available supply was particularly reduced due to incidents in Norway that limited gas production in March and due to an unexpected disconnection of the interconnection linking the UK to the Zeebrugge hub (Belgium) on 22 March.

The price spike on 9 April 2013 was, however, specific to the French market. This price spike was characterised by strong variations in day-ahead prices[105] over the day. This was concomitant with significant reductions in capacity of Dunkirk (bringing gas from Norwegian fields) and Taisnières (bringing gas from the Belgian hub) entry points. However, the level of interruption had been known for several weeks. Specific analysis of CRE services during that day are in progress.

Figure 82: European gas *spot* price spike (March/April 2013)

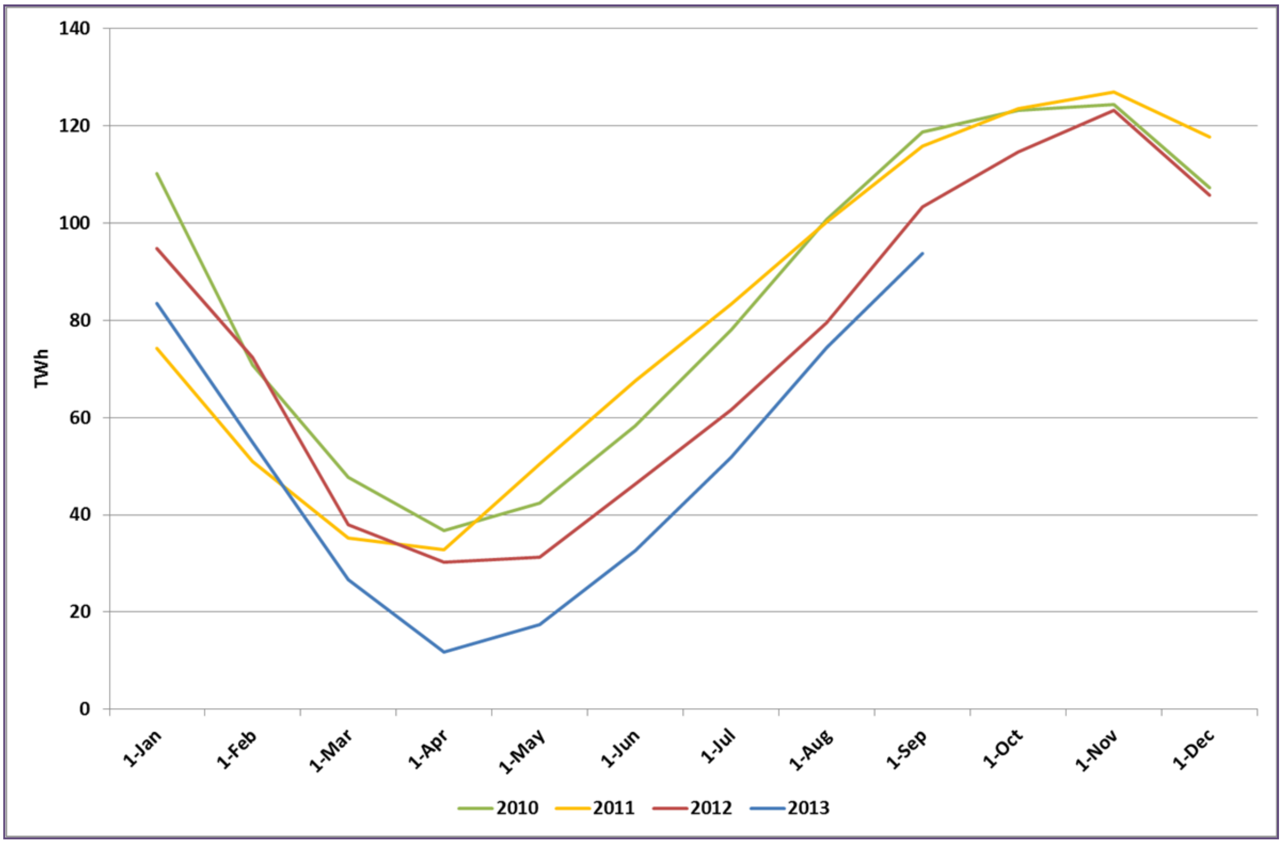


Source: Heren, Powernext – Analysis: CRE

[105] The *Powernext Gas Spot End of Day* index stood at 41.48 €/MWh that day while the Powernext Gas Spot Daily Average Price index, which includes all of the day's transaction, only stood at 34.52 €/MWh.

These high prices and supply tensions in March and April resulted in heavy withdrawals from French (and European) storage which reached an all-time low in April 2013 (Figure 83). The injection campaign during the summer of 2013 started very late and required an acceleration of injections to ensure that storage facilities were adequately filled by 1 November 2013. However, the sale of storage capacity was low in April 2013 and stock levels at the beginning of the 2012/2013 winter were especially low (Section 2.3.3).

Figure 83: Aggregate stock levels in France



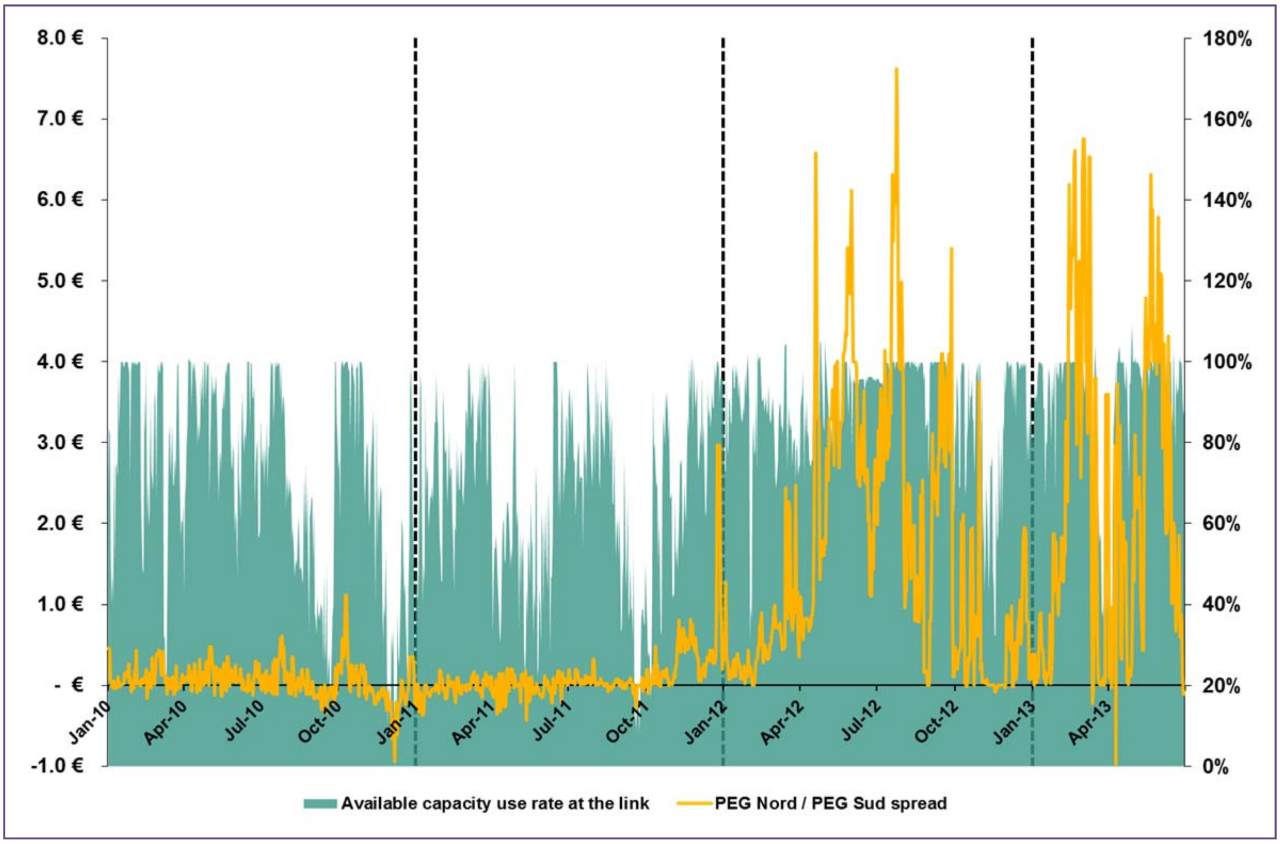
Source: Storengy, TIGF – Analysis: CRE

2.2.2 The differential between PEG Nord and PEG Sud prices increased sharply in 2012

The *day-ahead* price differential between PEG Nord and PEG Sud increased sharply in 2012 (Figure 84 and

Table 22), reflecting significant tensions on supply in the South zone. The differential repeated exceeded 6 €/MWh and a record spike at 7.62 €/MWh was recorded for delivery on 24 July 2012. This tension continued into the first half of 2013 where the spread stood at 2.26 €/MWh on average. These phenomena were accompanied by very high volatility in PEG Sud *day-ahead* prices which could vary by over 5 €/MWh in the same day.

Figure 84: *PEG Nord/PEG Sud spread* and use of the North-to-South link



Source: GRTgaz, Powernext – Analysis: CRE

Table 22: *North/South* Spread and utilisation rate of the link

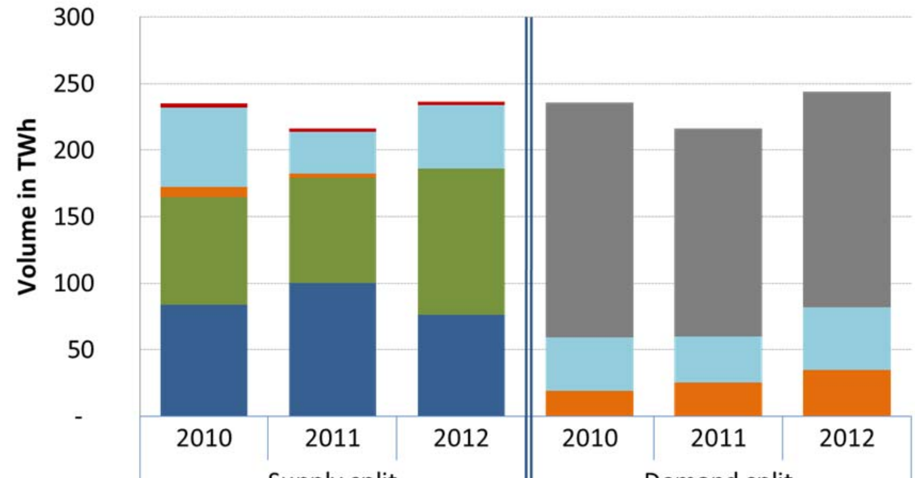
	Average PEG Nord - PEG Sud *spread* (€/MWh)	Average utilisation rate of the North-South link
2010	0.06	73%
2011	0.10	68%
2012	1.65	90%
H1 2013	2.26	91%

Source: GRTgaz, Powernext – Analysis: CRE

Note: the PEG Nord/PEG Sud spread is the difference between EOD indices (including day-ahead and weekend). The utilisation rate is calculated as the ratio between North-to-South flows and actual technical capacity

The South zone is primarily supplied by the North-South link that links the North and South zones and by Fos-Tokin and Fos-Cavaou LNG terminal. However, the diversion of LNG cargoes, that were originally scheduled to be unloaded in France, to the market offering the best price greatly reduced the activity of French LNG terminals with a significant decrease in the quantities unloaded between 2011 and 2012 (Table 23). The decrease in LNG supply to the South zone was off-set by increased use of the North-South link which saturated transmission capacities and caused a price differential between the North and PEG Sud (Figure 85).

Figure 85: Entry / exit balance for the South of France (2010 - 2012)



	2010	2011	2012	2010	2011	2012
	Supply split			Demand split		
Consumption	0	0	0	177	156	162
Production	3	3	2	0	0	0
Storage	60	32	48	40	35	47
Spain interconnection	7	3	0	19	25	35
North-South link	81	79	110	0	0	0
Fos LNG Terminals	84	100	76	0	0	0

Source: GRTgaz, TIGF – Analysis: CRE

It should be noted that Montoir-de-Bretagne terminal activity, although located in the northern zone, partially contributed to increasing North-South capacity during summer season. Gas emissions from Montoir-de-Bretagne allowed GRTgaz to reduce congestion upstream of the connection and increase flows to the South. Therefore, the reduction in emissions of the terminal in 2012 did not maximise the availability of this infrastructure and actually contributed to congestion. Fos arrivals stabilised during the first half of 2013 but those of the Montoir-de-Bretagne terminal continued to fall.

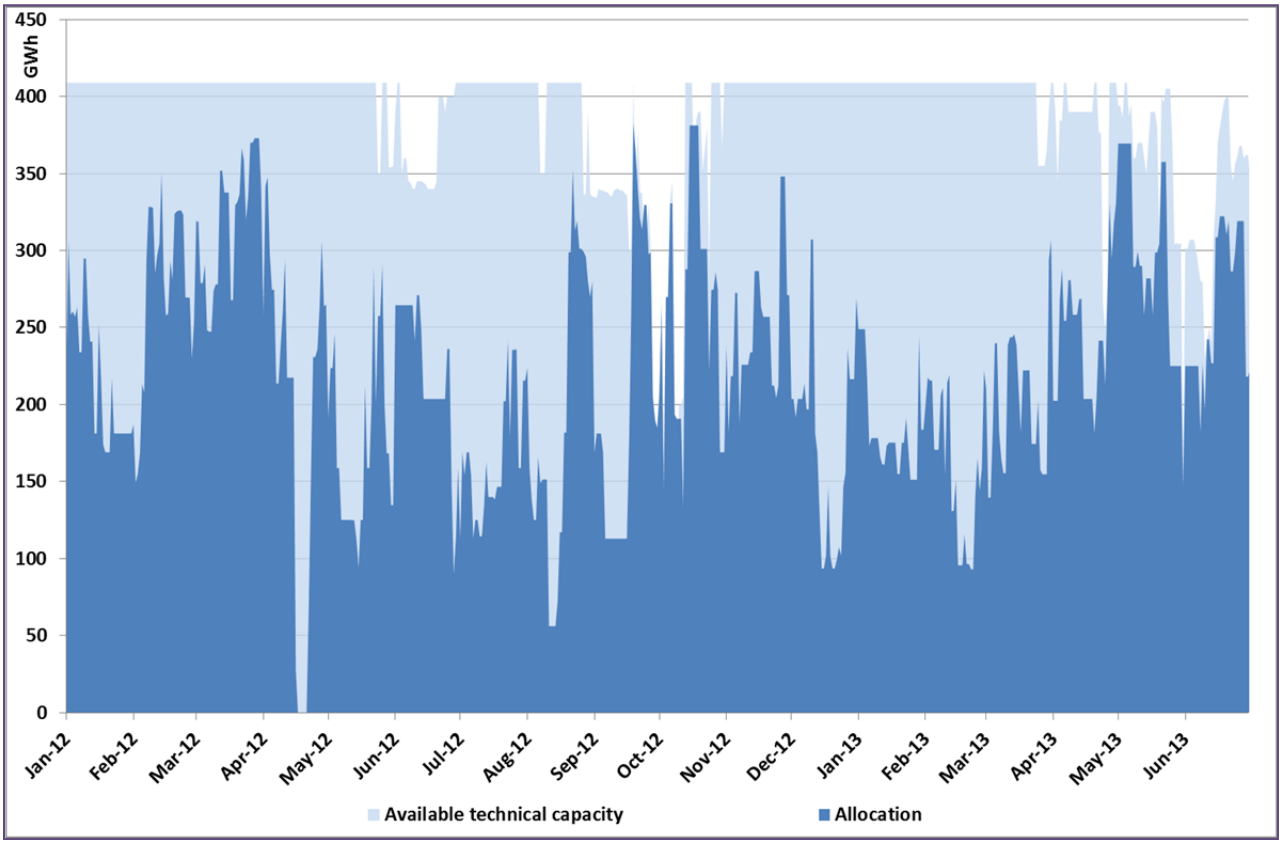
Table 23: French LNG terminal activity

	Montoir-de-Bretagne		Fos-Tonkin		Fos-Cavaou	
	Number of tankers	Net energy unloaded (TWh)	Number of tankers	Net energy unloaded (TWh)	Number of tankers	Net energy unloaded (TWh)
2010	75	72.97	128	51.32	30	32.11
2011	60	57.39	101	43.53	59	57.81
2012	35	30.64	74	35.00	57	47.96
H1 2013	9	6.44	37	17.74	30	23.61

Source: Elengy, FosmaxLNG – Analysis: CRE

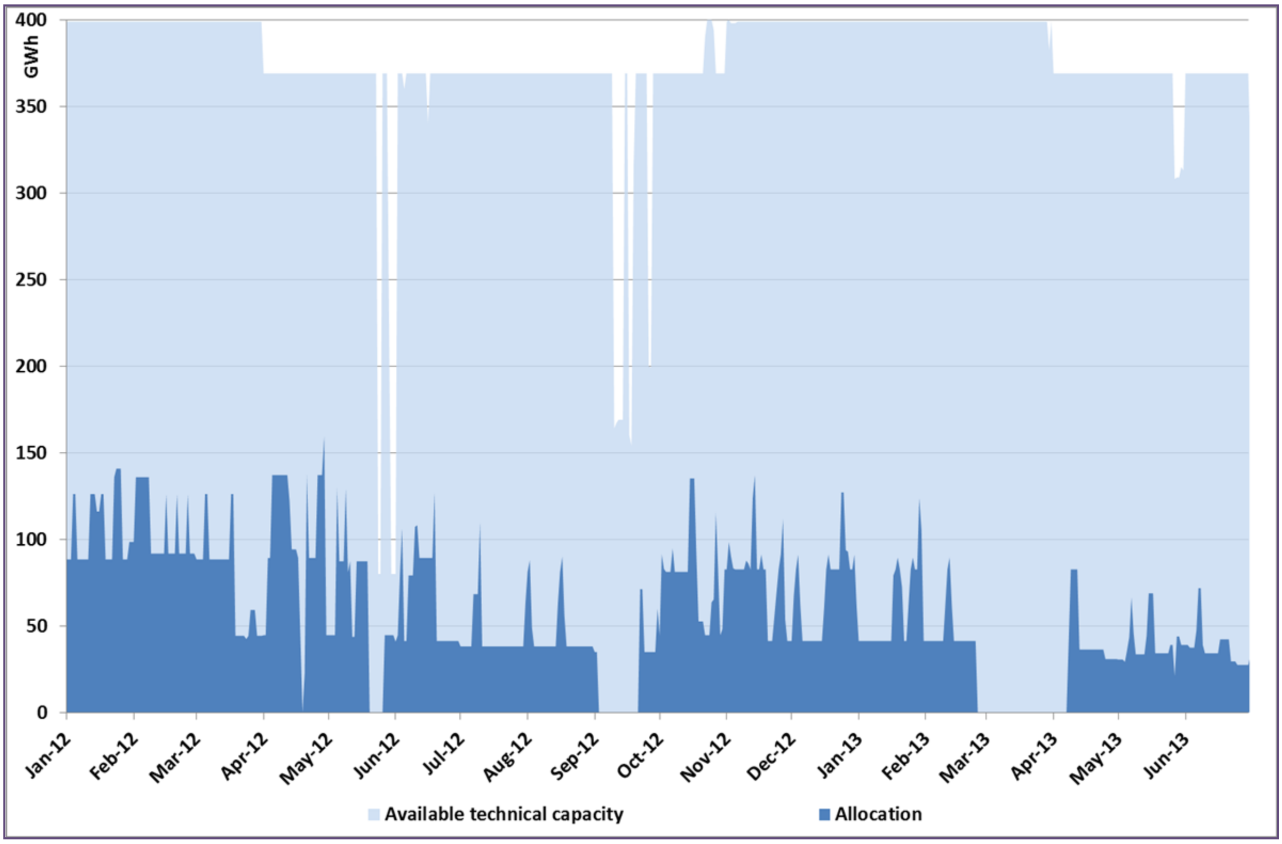
Note: "Net energy unloaded" field offsets unloading operations with reloading operations

Figure 86: Fos Transmission-LNG terminal interface point allocations



Source: GRTgaz – Analysis: CRE

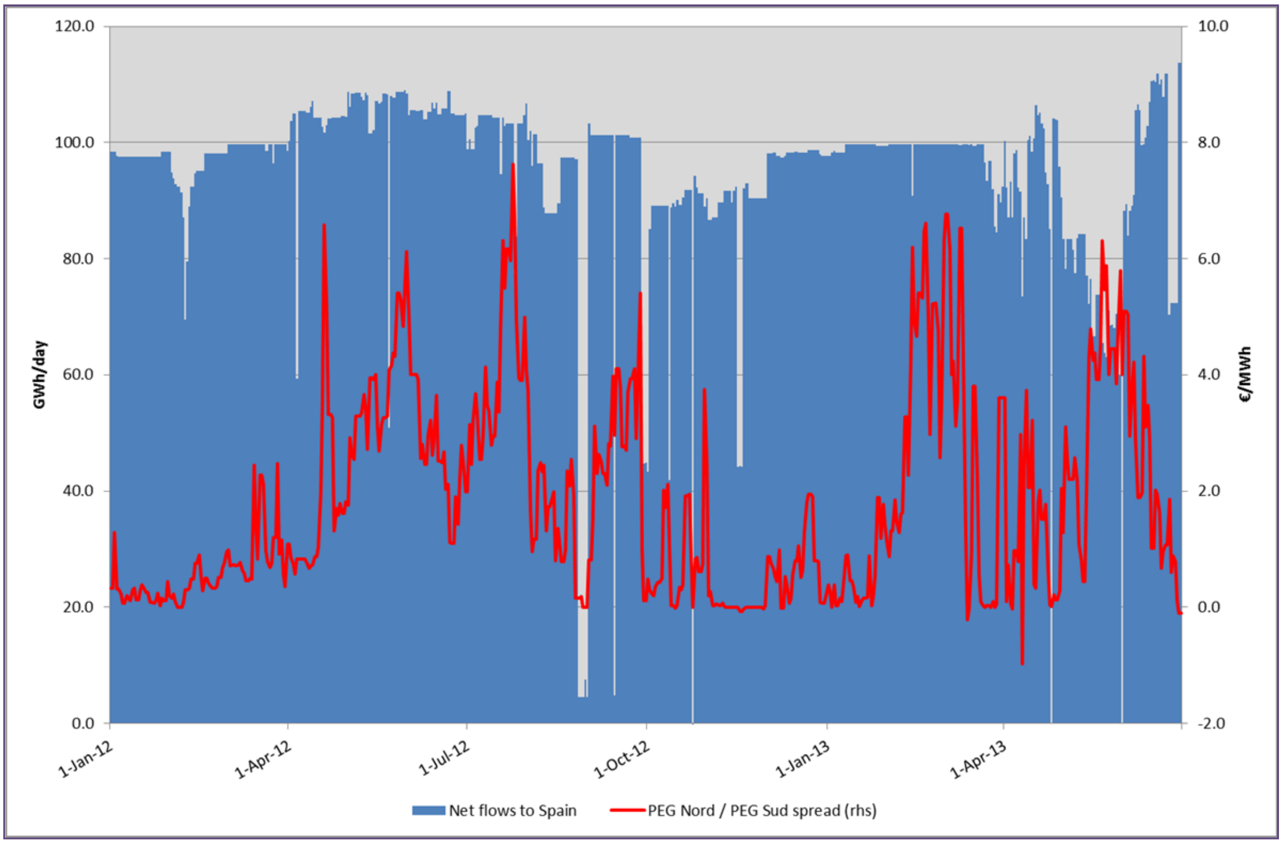
Figure 87: Montoir-de-Bretagne transmission-LNG terminal interface point allocations



Source: GRTgaz – Analysis: CRE

Spain is also very dependent on LNG flows and is affected by low cargo arrivals in Europe. The Spanish market has partially offset lower LNG supply with gas imports by pipeline from the TIGF network despite new Spain - France transmission capacities being delivered on 1 April 2013. This growing demand from Spain is another factor explaining continuing tensions in South of France supply. The North-South differential is therefore particularly sensitive to exports to Spain (Figure 88).

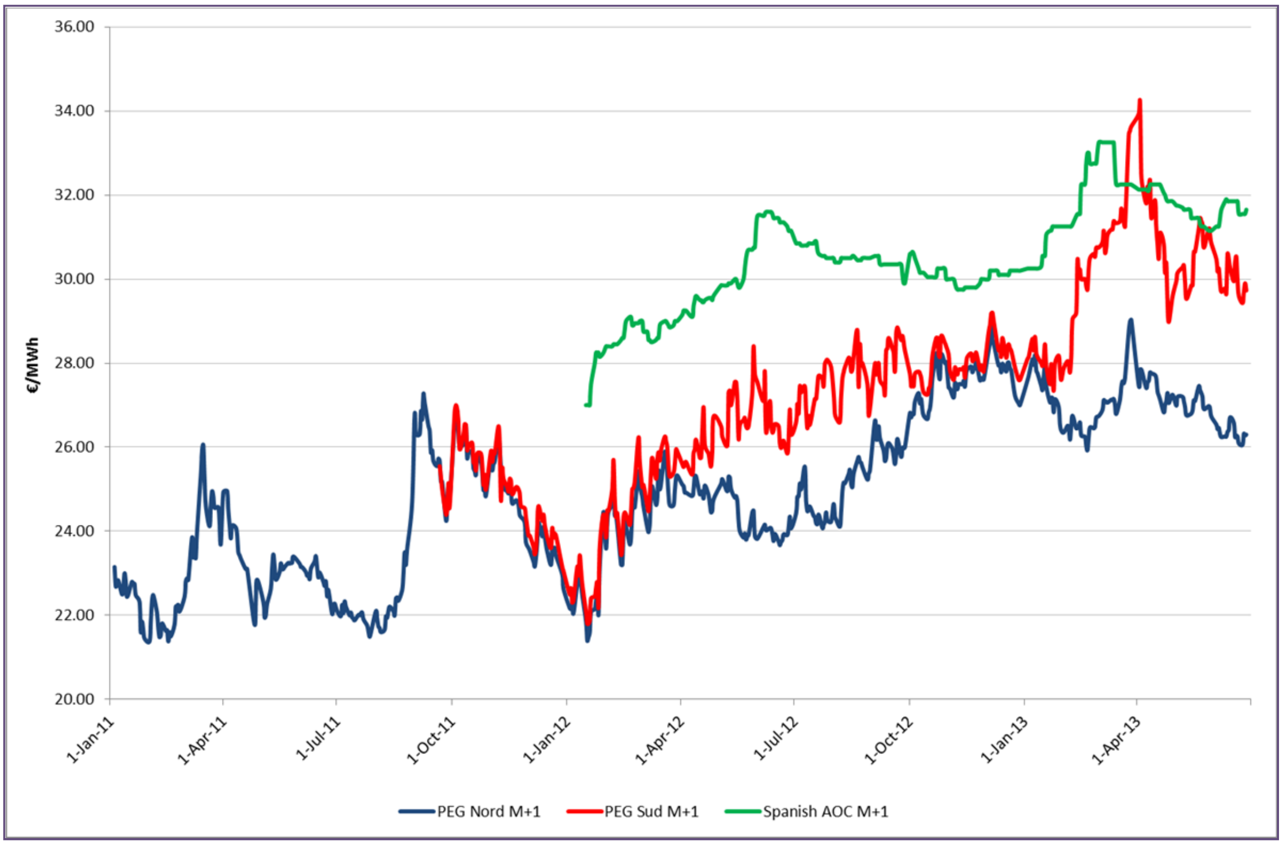
Figure 88: Effect of France-Spain exports on the North/South spread



Source: TIGF, Powernext – Analysis: CRE

Gas was traded on PEG TIGF at levels close to those of PEG Sud. It should be noted that the link connecting GRTgaz and TIGF networks to the South is not congested (average utilisation rate on exit from the GRTgaz network towards the TIGF network was 47% in 2012). Saturation on the interconnection exiting to Spain (93% in 2012) is partially due to the continuing differential between PEG Sud and Spain prices (Figure 89).

Figure 89: Comparative analysis of PEG Nord, PEG Sud, and Spanish prices



Source: Powernext, Heren – Analysis: CRE

Box 7: Decision of 29 May 2013 regarding gas pricing in the South of France[106]

In view of the significant price differential between PEG Nord and PEG Suds during summer 2012, CRE conducted a detailed analysis on the conditions of price discovery in the South of France[107]. Therefore, CRE collected all the transactions by major market participants on PEG Sud and PEG TIGF as well as data on the use of gas infrastructures with the various operators for the period between March and August 2012.

Initial analyses revealed the essential role of the global context of the gas market in the evolution of gas prices in the South. Tightening supplies are linked to low LNG arrivals in the South of France and increasing demand on the Spanish border. These tensions are therefore structural. North zone transmission capacity to the South zone were therefore more used to supply the South zone, the TIGF zone, and Spain, involving a significant differential between the North and PEG Sud prices.

Analysis identified factors could specifically increase the level and volatility of the spread such as the lack of transparency on the use and availability of certain infrastructures, liquidity problems in the PEG Sud market and atypical behaviour of the Powernext market coupling mechanism.

CRE is examining all possible measures that might improve the functioning of the gas market in the South of France. New measures to optimise the use of the North-South capacity have been implemented:

- The sale of an additional 15 GWh/d of firm capacity per day on 1 June 2013 released by GRTgaz and Storengy optimising the use of gas transmission and storage facilities in the North,
- Measures to encourage shippers to increase cargo unloading at Montoir-de-Bretagne in summer. Elengy and GRTgaz proposals in this direction have been included in the consultation on North-South capacity allocation rules in June 2013,
- Measures to improve the functioning of market coupling, after consultation of market participants and approval of CRE. Since 1 April 2013, any capacity unsold following the implementation of the market coupling mechanism is now proposed under the UBI ("Use it and buy it") service.

To improve transparency on infrastructure use, CRE invited GRTgaz to continue and strengthen its efforts to reduce the impact of its maintenance programme for summer 2013 and launched a public consultation on 12 April 2013 on the guidelines proposed to enhance transparency of LNG terminal use.

CRE considers that structural tensions affecting supplies to the South of France explain the formation of a price differential between PEG Nord and PEG Sud. However, CRE is finalising its analysis on the behaviours of individual participants in the southern zone between March and August 2012. Moreover, given the persistence of the price differential and volatility beyond this period, CRE is currently closely monitoring price discovery in the South zone.

CRE considers that the short-term measures taken are likely to improve the price discovery process and reduce volatility, and new investments to reduce network congestion will provide a long-term solution. In this context, CRE set guidelines for the further evolution of the structure of the French gas market in its deliberations of 19 July 2012 and 13 December 2012. Therefore, a common marketplace will be created on 1 April 2015 for GRTgaz South and TIGF balancing zones and will be a first step towards a PEG France and a single gas price in 2018. The final investment decision for the creation of a single French PEG will be made during the first half of 2014.

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[106] http://www.cre.fr/documents/deliberations/communication/formation-des-prix-du-gaz-au-sud-de-la-france

[107] CRE press release, 27 July 2012.

Following the deliberation of 29 May 2013, CRE took steps to improve the transparency French LNG terminal use in its deliberation of 20 June 2013[108].

2.2.3 *Differentials vis-à-vis neighbouring hubs are widening*

Despite their reduding trend, differentials between PEG Nord's *day-ahead* price and that of the other major European hubs increased slightly between 2012 and H1 2013 (Table 24).

The increase of these differentials is the result of episodes of supply tensions on the French gas system mentioned above. Occurrences of Europe-wide price spikes in 2012 and 2013 also increased regional disparities and amplified tensions towards hubs on the NWE network periphery.

Table 24: Average differential between PEG Nord and the main European hubs (day-ahead product)

Average differential in €/MWh	Zeebrugge (B)	NBP (GB)	TTF (N)	NCG (De)
2008	0.72	0.98	0.96	0.29
2009	0.64	0.78	0.34	-0.13
2010	0.43	0.64	0.18	-0.03
2011	0.46	0.80	0.31	0.02
2012	0.48	0.35	0.47	0.26
H1 2012	0.56	0.52	0.65	0.33
H1 2013	0.60	0.41	0.69	0.57

Source: Argus, Heren, Powernext – Analysis: CRE

Note: average of daily differentials (EOD PEG Nord - foreign prices)

[108] See CRE's deliberation of 20 June 2013 on its website

The increase in geographical spreads between France and neighbouring hubs should in theory lead to greater use of the French gas system's interconnection capacity. In practice, available capacity use values are actually increasing (Table 25) although there are still market imperfections preventing the complete arbitration of these differences. For example, PEG Nord traded 0.60 €/MWh higher than Zeebrugge hub in 2013. However, average use of France-to-Belgium capacity stood at 18%. Imperfections that prevent interconnections from being used effectively include the disparity of balancing systems and adjacent market capacity reservations, European transmission network entry/exit system, and constraints on long-term contract delivery to border points. The harmonisation of European rules on balancing and capacity allocation should improve the consistency between flow and spread levels (Section IV, 3.3).

Table 25: Development in the use of effective technical capacities

Interconnection	Direction	2011	2012	H1 2013
Dunkirk	Entry	79%	85%	92%
Taisnières B	Entry	62%	57%	51%
Taisnières H	Entry	68%	55%	69%
	Exit	19%	22%	18%
Obergailbach	Entry	42%	52%	67%
	Exit	39%	10%	3%
Oltingue	Exit	49%	32%	14%
North-South link	North to South	68%	90%	91%
	South to North	0%	1%	1%
South-TIGF link	South to TIGF	45%	47%	41%
	TIGF to South	7%	6%	10%
Spanish border	Entry	9%	1%	7%
	Exit	67%	93%	81%

Source: GRTgaz, TIGF – Analysis: CRE

A volatility study (Table 26) revealed that while it tended to decline during 2008-2001, *day-ahead* price volatility rebounded in 2012-2013. For PEG Sud, this sharp increase in 2012 reflects the variability of the zone's supply conditions[109].

In H1 2013, the increase in volatility of European hubs is related to episodes of tension previously mentioned and the many outages and maintenance of various infrastructures in Europe. This phenomenon was particularly marked in France in the first half of 2013 due to its peripheral position in the European network and market-specific events such as the price spike of 9 April.

Gas *day-ahead* price volatility remains at approximately twice that of oil.

Table 26: Comparative analysis of *day-ahead* price volatility

	Gas market price					Brent
	PEG Nord	PEG Sud	NBP	Zeebrugge	TTF	
2008	65%		105%	96%	77%	51%
2009	95%	99%	138%	111%	104%	43%
2010	58%	56%	81%	77%	66%	24%
2011	39%	41%	46%	43%	49%	27%
2012	56%	71%	54%	53%	53%	21%
H1 2013	93%	88%	67%	62%	59%	18%
2008-2013	68%	66%	89%	79%	71%	34%

Source: Argus, Powernext, Heren, Bloomberg – Analysis: CRE

Note: Annualised volatility (based on 252 days) of EOD day-ahead indices in €/MWh at PEG Nord, PEG Sud, NBP, Zeebrugge and TTF, and of Brent front-month contract closing price quoted in €/bbl.

2.3 Futures wholesale prices were slightly higher on European markets in 2012 and the first part of 2013.

2.3.1 *Trends in futures prices*

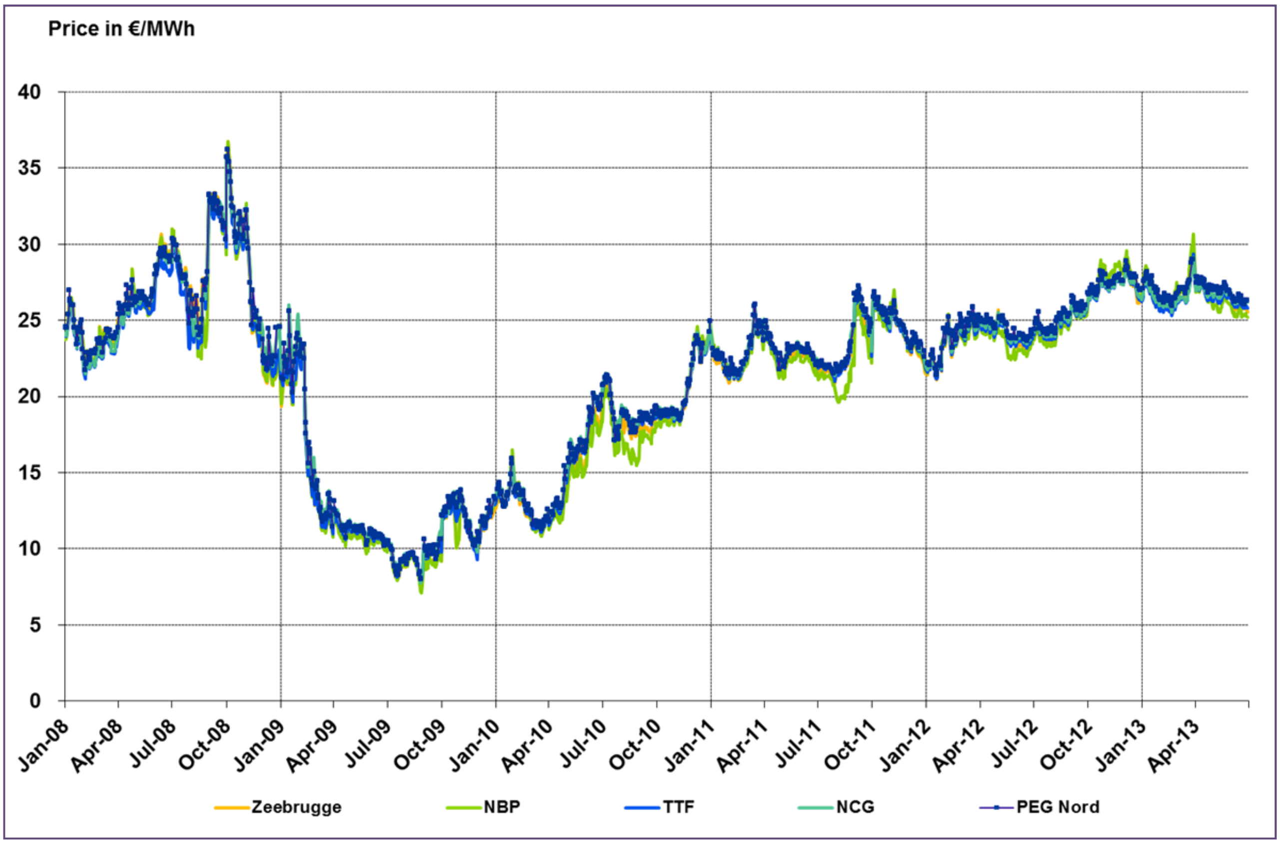
Similarly to the spot market, futures prices showed an upward trend in 2012 and the first half of 2013. The lower prices recorded in the spring of 2012 both on the prompt and back end of the curve were the result of the sharp fall in oil product prices. Supply/demand imbalance events on the European gas market such as winter and periods of tensionhave particularly impacted the evolution of futures products on the nearest maturities.

[109] In particular, it is difficult for operators to predict the rate of reduction applied to their transmission capacity on the North/South link by GRTgaz.

- **Month-ahead price trends influenced by short-term market fundamentals**

Episodes of tension on the various European spot markets at the end of the 2012/2013 winter had an impact on futures prices and especially on shorter maturities. This effect is particularly significant for European storage facilities, particularly in the United Kingdom and France, which ended the winter with very low fill rates. Therefore, *month-ahead* trading for delivery in March and April 2013 jumped at the same time as the price spikes observed on spot prices. This reflects participant nervousness and uncertainty on hub supply and weather conditions. The increase in M+1 gas prices was concomitant with other increases observed on the electricity market.

Figure 90: Trends in the *month-ahead* contract on the main market places

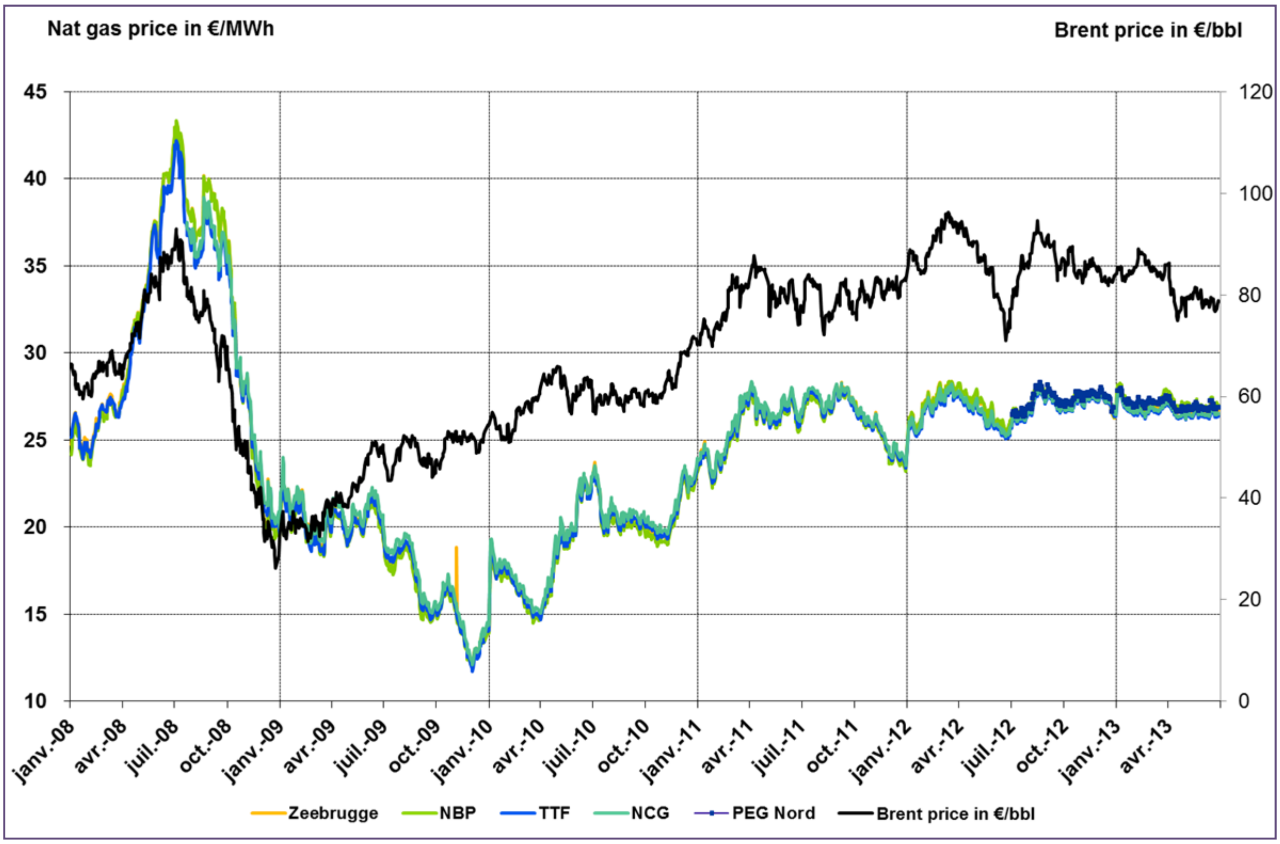


Source: Powernext, Heren – Analysis: CRE

- **Long-term price trends influenced by the oil market**

Gas prices on the French market are highly correlated to the prices on the largest European markets (NBP, TTF, Zeebrugge, and NCG). Price trends beyond the *month-ahead* product continued to be quite heavily influenced by the oil product prices in Europe. Upward and downward trends recorded in the first half of 2012 on calendar products were related to Brent trends. There has been a slight downward trend on both PEG Nord gas prices and Brent barrel prices since September 2012.

Figure 91: Trends in gas prices on Y+1 products and Brent prices



Source: Argus, Powernext, Heren, Bloomberg – Analysis: CRE

2.3.2 *PEG Nord futures prices are correlated to those of the main North-Western European hubs*

PEG Nord prices on the futures market is correlated to the North-Western European hub prices (Figure 90 and Figure 91). Futures price differentials between PEG Nord and the various European hubs were fairly low and often under the cost of transmission capacity to go from one hub to another.

Table 27: Average differential between PEG Nord and the main European hubs (*month-ahead* prices)

Average differential in €/MWh	Zeebrugge (B)	NBP (GB)	TTF (N)	NCG (De)
2008	0.19	0.43	0.72	0.20
2009	0.49	0.52	0.32	-0.13
2010	0.49	0.73	0.15	-0.08
2011	0.35	0.65	0.19	0.03
2012	0.42	0.43	0.42	0.26
H1 2012	0.46	0.66	0.42	0.22
H1 2013	0.52	0.40	0.60	0.40

Source: Argus, Heren, Powernext – Analysis: CRE

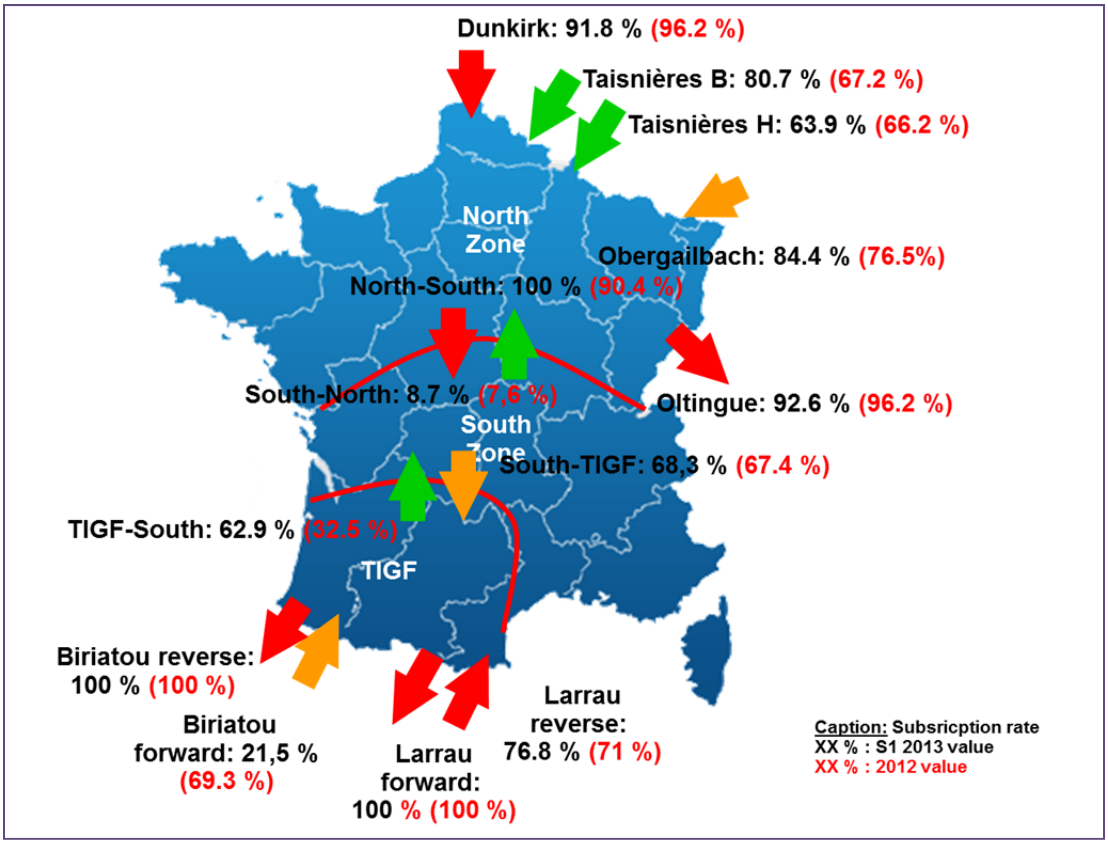
Note: average of daily differentials (PEG Nord Settlement Price - foreign prices)

However, there was a slight increase in the average differential for 2012 and the first half of 2013 on *month-ahead* products reflecting the forecast of greater use of pipeline import capacity in France.

This slight increase in the differential between PEG Nord and other market places favoured the additional sale of capacity between 2012 and the first half of 2013, particularly at Obergailbach and Taisnières B.

With regards to South of France, tensions on market prices naturally prompted participants to purchase the entire firm and interruptible capacity available on the North-South link. Capacity exiting to Spain was also fully sold out.

Figure 92: Trends in the sale of firm and interruptible capacities on transmission network interconnections between the first half of 2013 and 2012



Source: GRTgaz, TIGF

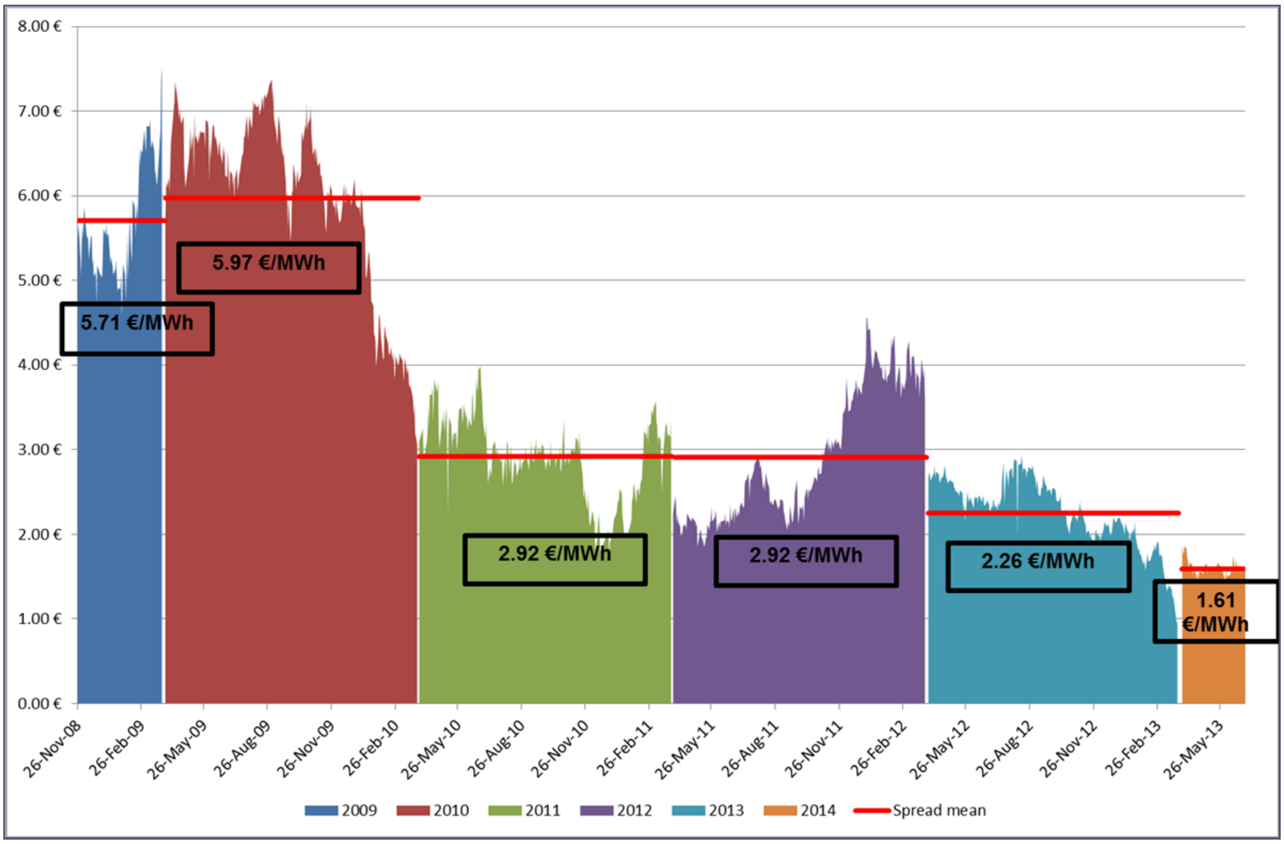
2.3.3 Low price differentials between winter and summer affected the sale of storage capacity

Alerts multiplied on the low level of gas in underground storage across Europe. France is no exception to this. On 30 June 2013, gas storage levels were 16% below those of 30 June 2012 and 34% below those of 30 June 2011.

The French market experienced an unprecedented level of consumption in February 2012 with a peak at over 3,700 GWh on 8 February, soliciting a record level of stocks, with a withdrawal of 1,750 GWh/d for Storengy and nearly 390 GWh/d for TIGF. This period highlighted the essential role of storage in French market supply security.

At the beginning of each year N, storage capacity available for the period beginning on 1 April N and ending on 31 March N+1 is for sale. The storage year that began on 1 April 2013 was marked by low storage capacity purchase by market participants, indicating a lack of interest in this product compared to other available sources of flexibility. Indeed, price differentials between summer and winter on the wholesale markets has been steadily declining for several years, as shown in the figure below. Market participants therefore perform a trade-off between reserving storage capacity and hedging their seasonal needs on the market.

Figure 93: Trends in the summer / winter spread on PEG Nord



Source: Powernext – Analysis: CRE

Note: summer/winter spread = N/n+1 winter price - summer N price

For France, capacity reserved on 1 July 2013 represented 96 TWh against 112 TWh on 1 July 2012. For the operator Storengy, only two-thirds of capacity on sale had been reserved on 1 July 2013 (decline of 14 TWh compared to the capacity reserved at the start of the 2012/2013 winter). This was also reflected in significantly lower levels of gas in stock than in previous years which was also due to the particularly long 2012/ 2013 winter and a late injection campaign (Table 28).

Table 28: Levels of gas in storage in France (Storengy + TIGF)

(TWh)	2010	2011	2012	2013
1-Jan.	110.2	74.2	94.8	83.5
1-Apr.	36.7	32.9	30.2	11.7
1-July	78.0	83.3	61.5	51.8
1-Sept.	118.8	115.8	103.2	93.7
1-Nov.	124.4	127.0	123.2	

Source: Storengy, TIGF – Analysis: CRE

During the Storage Convention on Friday, 16 November 2012, Storengy mentioned that it had "mothballed" two storage sites (Soings and Trois-Fontaines for a total capacity of 3.5 TWh) in response to the sharp drop in sales. On 1 September 2013, 30% of Storengy's available capacity still had not been sold. Low sales of Storengy's stocks contributed to their weaker filling and storage operator was obliged to purchase approximately 14 TWh for sale in winter to maintain the performance of its facilities.

This occurred in a context of weak LNG arrivals to France which also led GRTgaz to communicate[110] with market participants calling for a higher fill-rate of underground storage facilities ensuring supply for the coldest periods next winter. GRTgaz stated that *"the supply / demand equilibrium could also be difficult to maintain in case of concomitant sustained cold (such as the situation encountered in February 2012) and failure, even occasional, of a source of supply"*.

This alert was relayed by the Directorate General for Energy and the Climate (DGEC) which reminded the various shippers of public service obligations necessary to ensure the continuity and diversification of supply.

This situation is not specific to the French market as GSE (Gas Storage Europe) stated on its transparency platform[111] that the level of gas in storage in all European storage facilities totalled 34.7 billion m^3, or 44.85% of the fill rate, compared to 48.3 billion m^3 (or 64.02% of the fill rate) the previous year.

Open Grid Europe also alerted on the consequences for Germany and Europe[112] as a whole of a cold wave equivalent to that of February 2012 or a failure in supply as was the case in the Russian-Ukrainian gas conflict of 2009 on its website.

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[110] ShipOnline no. 75, 5 July 2013

[111] https://transparency.gie.eu.com/index.php

[112] http://www.open-grid-europe.com/cps/rde/xchg/SID-F9E02F87-AF50A14B/open-grid-europe-internet/hs.xsl/3283.htm

Despite these calls for a better fill rate of storage facilities, market priced do not always include a risk premium related to potential price spikes next winter, with a summer/winter differential of 1.53 €/MWh (*Winter 2013* product – *Q3 2013* product) on 27 June 2013. These market conditions could continue for winter 2014/2015. The storage situation led the Directorate General for Energy and the Climate to launch a public consultation which CRE responded to on 26 September 2013.[113]

3 PROSPECTS FOR FRENCH WHOLESALE GAS MARKET DEVELOPMENT

3.1 Major investments in 2012

No investment decision generating additional transmission capacity was taken in 2012. However, delays are anticipated in the realisation of several projects such as the Hauts-de-France and the Arc de Dierrey pipelines however it will not affect the planned availability dates of yet sold capacity. Note that these investments will help reduce congestion in the heart of the network in GRTgaz's North zone, connect the Dunkirk terminal, and create a new interconnection with Belgium in Veurne.

On April, 1st 2013, in the South of France, investments in Larrau have increased capacity in both directions to 165 GWh/d at the interface point between the TIGF network in France and the ENAGAS network in Spain contributing to further integration of the French and Spanish markets.

3.2 Guidance on market place trends (PEG)

The entry into force of the new access transmission tariffs (ATRT5) on April, 1st 2013 helped merge GRTgaz's North H and B zones.

Moreover, in its deliberation of 19 July 2012, CRE asked TSOs to work on creating a sole PEG unifying both GRTgaz South and TIGF PEGs by April, 1st 2015 while maintaining two independent balancing zones. The functioning of this common PEG will be reviewed by April, 1st 2018 which is the indicative date given by CRE in its guidelines on the organisation of the French gas market to create a sole national PEG comprising current PEG Nord and new south PEG zones. Given the high investment costs involved, CRE launched a cost - benefit analysis of investment needed to implement the single PEG France by 2018.

For its part, GRTgaz is currently conducting a public consultation on these investments114. The final investment decision will be taken in the first half of 2014. Creating a single PEG France will remove price differentials between the north and the south of France moving to a single gas price for the entire country. It will improve the efficiency of the French wholesale gas market by simplifying market access for transmission network users, concentrating liquidity on a single market place, and by direct competition of gas supply sources.

[113] http://www.cre.fr/media/fichiers/reseaux/reponse-a-la-consultation-publique-de-la-direction-generale-de-l-energie-et-du-climat-relative-a-l-acces-des-tiers-aux-stockages-souterrains-de-gaz-naturel

[114] Arc Lyonnais and Val de Saône Projects: http://www.debatpublic-arclyonnais-valdesaone.org/

3.3 European work to structure the access to transmission capacity

In 2013, the third European energy package continued to be applied and implemented on gas transmission networks. National regulators, including CRE, are working within the ACER[115] to develop several network codes which will become European regulations once they are finalised. There are several stages to this task:

- ACER drafts framework guidelines,
- ENTSOG prepares a network code draft text[116] based on these guidelines,
- after consultation with the regulators, the proposal is forwarded to the European Commission,
- the network code is validated by the gas committee (composed of representatives of Member Countries) and adopted by the Commission.

Work is at different levels of progress for the various themes:

The Appendix of the Congestion Management Procedure (CMP) entered into force on 1 October 2013. French TSO supply contracts have been amended accordingly. CRE's deliberation of 27 June 2013 details how to implement the following mechanisms:

- an over-reservation system allows the carrier to offer additional firm capacity above the technical capacity of the interconnection points based on statistical transmission capacity use scenarios,
- if the entire capacity is required, carriers can use a procedure to buy back capacity to maintain the system's integrity,
- network users can also return sold capacity to the carrier to allows them to re-sell it during customary capacity allocation processes.

The network code on Capacity Allocation Mechanism (*CAM*) was adopted on 15 October 2013 as a European Commission regulation and was published in the Official Journal of the European Union. It provides that capacity at the interconnection points between European Union entry-exit systems:

- will be allocated during auctions, in the form of products with standardised durations, according to a common schedule, and to the extent that firm capacity is available on both sides of an interconnection point,
- will be offered as bundled capacity on allocation platforms that are jointly managed by European transmission network operators.

Its provisions will become binding as of 1 November 2015. However, CRE and French TSOs would like it to be gradually implemented in France. This is a key step in the process of market integration and it is important that market participants appropriate the new rules before wider application.

To this end, GRTgaz initiated sales of bundled monthly and daily products with German TSOs and bundled daily products with Belgian TSO via the PRISMA pilot platform that brings together almost twenty European TSOs. TIGF and the Spanish TSO Enagas have also announced their intention to join the PRISMA platform extending the pilot project to the Franco-Spanish border in 2014. A provisional timetable to extend auctions

[115] Definition in the Glossary

[116] Definition in the Glossary

to all products covered by the CAM network code by November 2015 will be proposed by the French TSOs in autumn 2013 and submitted for approval to CRE.

The network code on balancing gas transmission networks was also validated in comitology on 3 October 2013 and should enter into force in 2014. It provides for extending daily balancing based on the short-term trading market to Europe. CRE and French TSOs have implemented a roadmap to converge towards this European target for several years.

ENTSOG has also drafted a network code on transmission network interoperability which should be adopted in 2014. This text will complement other network codes focused on the organisation of cross-border trade as it aims to remove technical and operational barriers that may hinder the actual movement of gas on the European network.

Finally, the ACER should complete its framework guidelines on harmonising gas transmission network user tariffs. ENTSOG will draft the corresponding network code in 2014.

All of these regulations should help to gradually move towards the European market target model. They aim to develop a "hub to hub" model that sees the European market as a set of entry- exit zones connected by interconnections with simplified access.

APPENDICES

1 GLOSSARY

1.1 REMIT

ACER: Agency for the Cooperation of Energy Regulators established by Regulation (EC) No. 713/2009 of 13 July 2009.

CEER: Council of European Energy Regulators which was created in 2000 at the initiative of national energy regulators of members of the European Union and the European Economic Area.

EMIR: (EU) regulation no. 648/2012 of 4 July 2012 on OTC derivatives, central counterparties, and trade repositories.

MAD: directive 2003/6/EC of 28 January 2003 on insider dealing and market manipulation (market abuse). The directive is currently being revised.

MIF: directive 2004/39/EC of 21 April 2004 on Markets in Financial Instruments. The directive is currently being revised.

REMIT: (EU) regulation no. 1227/2011 of 25 October 2011 on wholesale energy market integrity and transparency. the 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.

1.2 Electricity

- **Main European Electricity Exchanges (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 (*or baseload*): 24 hours a day, 7 days a week.

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

Future* or *Forward: standard contract 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). Schedule Y+1 corresponds to the calendar year following the current year.

Peak (*or Peakload*) for continental Europe: from 8am to 8pm, Monday to Friday.

- **Wholesale market segments**

ARENH - Regulated Access to Historical Nuclear Energy: implemented by law no. 2010-1488 of 7 December 2010 concerning the new organisation of the electricity market (NOME), the ARENH system allows suppliers, for the supply of electricity to end users residing in continental France and/or TSOs for their losses, to source historic nuclear electricity from EDF for volumes at defined pricing conditions.

Wholesale purchases and sales (OTC): Declaration of block exchanges, i.e. day-ahead nominations to RTE that 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

Adjustment mechanism: market mechanism, managed by the transmission network operator, intended to balance consumption and electricity generation in real time.

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 monthly fixed premium (in €/MW) 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 bidders is lower than that for VPP base products.

- **Other**

Electricity system margin: difference between available generation capacity and estimated (d-1) or actual consumption.

Price resilience: price sensitivity of the hourly EPEX SPOT auction markets assessed by recalculating prices for variations in supply and demand at any price.

Marginality analysis: this is used to identify for each hour of the day what kind of generation matched the price set by the market, i.e. to find the most expensive means of generation in operation used to meet hourly demand.

1.3 CO_2

Backloading: option to set aside a portion of emission allowances at the beginning of Phase III and then put them back on the market at the end of Phase III; proposed by the European institutions to offset surplus allowances on the European carbon market.

Banking: option for registrants to use an allowance delivered at the beginning of a previous compliance period to meet compliance requirements.

BlueNext: French carbon market that closed on 5 December 2012.

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 on Year N, allowances must be returned in respect of emissions for Year N-1).

CER: *Certified Emissions Reduction* are units from projects deployed under the Clean Development Mechanism (CDM). Some countries and companies use the 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 information submitted by the national registers on a daily basis.

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

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

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

ERU: *Emission Reduction Units* are 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 EU-ETS can use these credits to meet their greenhouse gas emission reduction obligations.

EUA: *European Union Allowance,* is part of the EU ETS which authorises the holder to emit the equivalent of one tonne of carbon dioxide in greenhouse gases.

FCA: *Financial Conduct Authority*, a body regulating financial firms on British wholesale and retail markets.

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

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 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 promote sustainable development in developing countries.

Emissions permit: see Emissions allowance.

Climate and energy package: set of European legal texts relating to energy and climate change adopted in late 2008.

Phase III: third phase of the EU-ETS for 2013-2020 during which significant changes will be made to how auctions are conducted.

Kyoto Protocol: international treaty intended to reduce greenhouse gas emissions. The Protocol sets out detailed commitments for the industrialised countries concerned to reduce or limit 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 combat climate change.

Emissions 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 granted to a country or an economic agent by an administrative authority (intergovernmental organisation or government agency).

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.

***Set aside*:** see "*backloading*".

1.4 Gas

Bcm: *billion cubic metres*. Equals one billion cubic metres of gas.

Reverse capacity: capacity on the main network enabling the shipper to make nominations in the opposite direction to the dominant flow direction when 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.

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.

Gas wholesale market coupling: mechanism based on one or more stock markets to compare supply and demand on coupled markets and allocate concurrently and implicitly interconnection capacities between balancing zones (North and South in this instance). 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).

ENTSOG: *European Network of Transmission System Operators for Gas*, entity created by the European Commission to facilitate cooperation between gas transmission network operators of Member Countries and the creation of a European gas network.

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 European directives and regulations and to prepare future legislation on gas and electricity.

Unconventional gas: unconventional gas includes three types of natural gas: *shale gas*, *coal bed methane*, and *tight gas*. Unlike so-called conventional gas, unconventional gas is present in low permeability rocks which are difficult to access. Extraction is done using two techniques: horizontal drilling and hydraulic fracturing.

Liquefied Natural Gas (LNG): LNG is natural gas condensed to its liquid state (by reducing its temperature to about -160°C at atmospheric pressure), where volume is reduced to about 1/600. It is mainly transported by sea in ships known as *LNG tankers* and unloaded at LNG terminals which are capable of re-gasifying it to inject it into the transmission network.

Gas release: obligation of a supplier to release a share of its 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.

Herfindahl-Hirschmann Index (HHI): this is equal to the sum of squares of the market shares of the companies and is a measure of market concentration. The more concentrated the market, the higher the 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.

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

Spot market: the spot market includes *Intraday*, *Day-ahead*, Weekend, and Week products and Other maturities that are less than monthly products.

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

Gas exchange point (PEG): virtual point on the French gas transmission system at which shippers can trade volumes of gas. There are three PEG in France, each associated to a balancing zone.

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

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

Future *product*: a *forward* contract negotiated on an exchange (organised market).

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.

Balancing zone: geographic area representing part of the transmission network where shippers balance their incoming and outgoing flows from a set of input and output points. In France, two balancing zones are associated to the GRTgaz network and one to the TIGF network.

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Key figures

Electricity market for 2012 and the first half of 2013

	2011	2012	H1 2012	H1 2013
Generation	**542 TWh**	**541 TWh**	**282 TWh**	**289 TWh**
Non-ARENH and VPP generation	471 TWh	452 TWh	235 TWh	251 TWh
ARENH generation	31 TWh	61 TWh	30 TWh	33 TWh
VPP generation	40 TWh	28 TWh	17 TWh	5 TWh
Gross consumption	**486 TWh**	**496 TWh**	**260 TWh**	**267 TWh**
End-user consumption	451 TWh	460 TWh	242 TWh	248 TWh
Network losses	35 TWh	36 TWh	18 TWh	18 TWh
Net Export Balance	**56 TWh**	**45 TWh**	**22 TWh**	**22 TWh**
Exports	75 TWh	74 TWh	37 TWh	40 TWh
Imports	19 TWh	29 TWh	15 TWh	18 TWh
Volumes traded on the market	**695.5 TWh**	**578.3 TWh**	**275.2 TWh**	**308.2 TWh**
Intraday Market	2.9 TWh	3.4 TWh	1.6 TWh	1.9 TWh
Day-Ahead Market	82.5 TWh	81.4 TWh	41.2 TWh	40.9 TWh
Futures Market	610.1 TWh	493.6 TWh	232.4 TWh	265.3 TWh
Market Price	**2011**	**2012**	**H1 2012**	**H1 2013**
Intraday Market	48.8 €/MWh	46.1 €/MWh	45.7 €/MWh	48.8 €/MWh
Day-Ahead Market	48.9 €/MWh	46.9 €/MWh	43.8 €/MWh	48.6 €/MWh
Futures Market (Y+1 Base)	56.0 €/MWh	50.6 €/MWh	51.2 €/MWh	43.9 €/MWh

CO_2 market for 2012 and the first half of 2013

	2011	2012	H1 2012	H1 2013
Allowance auctioning Phase III	**x**	**90 Mt**	**x**	**398 Mt**
Europe	x	54 Mt	x	252 Mt
Germany	x	24 Mt	x	96 Mt
Great Britain	x	12 Mt	x	50 Mt
Total volumes traded	**9,638 Mt**	**11,979 Mt**	**5,005 Mt**	**6,287 Mt**
EUA	7,500 Mt	9,332 Mt	3,969 Mt	5,857 Mt
CER	2,138 Mt	2,647 Mt	1,036 Mt	430 Mt
Exchange rate values	**120 B €**	**76 B €**	**35 B €**	**25 B €**
EUA	100 B €	68 B €	31 B €	25 B €
CER	20 B €	8 B €	4 B €	77 M €
Average allowance price	**x**	**x**	**x**	**x**
EUA	12.95 €/t	7.34 €/t	7.23 €/t	4.24 €/t
CER	9.88 €/t	2.90 €/t	3.93 €/t	0.18 €/t
Accumulation of allowances	**224 M**	**404 M**	x	x
Number of stakeholders on the market	310	333	x	236

Gas market for 2012 and the first half of 2013

	2011	2012	H1 2012	H1 2013
Basics				
Consumption	473 TWh	490 TWh	282 TWh	294 TWh
Imports by gas pipelines	446 TWh	466 TWh	249 TWh	246 TWh
LNG imports	159 TWh	107 TWh	58 TWh	47 TWh
Exports	107 TWh	91 TWh	57 TWh	33 TWh
Net Storage (+) / Destocking (-)	22 TWh	- 11 TWh	- 34 TWh	- 33 TWh
Use of infrastructure				
Stock levels on 1 April	32.9 TWh	30.2 TWh	30.2 TWh	11.7 TWh
Stock levels on 1 November	127.0 TWh	123.2 TWh		
Active stakeholders on LNG terminals	6	5	3	2
Utilisation rate of the North-South link	68%	90%	89%	91%
Traded on the wholesale markets				
Number of active stakeholders in the PEG	66	68	63	71
PEG Delivery	435 TWh	502 TWh	252 TWh	279 TWh
Intermediated spot market	118 TWh	121 TWh	60 TWh	77 TWh
Intermediated futures market	301 TWh	223 TWh	102 TWh	152 TWh
Market Price				
Day-Ahead PEG Nord	22.9 €/MWh	25.5 €/MWh	24.7 €/MWh	28.3 €/MWh
PEG Nord / PEG Sud *Spread*	0.07 €/MWh	1.70 €/MWh	1.66 €/MWh	2.18 €/MWh
PEG Nord S+1	25.6 €/MWh	26.4 €/MWh	25.7 €/MWh	27.2 €/MWh