COMMISSION
DE RÉGULATION
DE L'ÉNERGIE

Markets

Functioning of the wholesale electricity, CO_2 and natural gas markets

2013-2014 Report

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CONTENTS

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 French law of 15 April 2013 on the transition towards green growth expressly entrusted CRE with the mission of ensuring REMIT implementation and CoRDiS jurisdiction to sanction any breaches of the regulation.

The present report reviews the development of wholesale markets over the course of 2013 and the first half of 2014. It also presents detailed completed or ongoing analyses related to market participants' behaviour or to market events.

The difficulties encountered by energy producers were confirmed during 2013 and the first half of 2014, in particular for electricity producers. The costs of production for coal-fired power stations remained particularly low, due especially to a continued drop in the coal prices and despite a slight increase in the CO_2 prices. Production from renewable energy sources continued to increase, exceeding fossil fuel energy generation during the first half of 2014 in France. Within this context, electricity prices continued to drop, leading to the "cocooning" of a certain number of new combined cycle power plants.

The LNG market remained highly competitive in a context of significant price differences between the different world markets. Asia and South America are the most profitable markets for LNG producers, to the detriment of the European market. This situation creates difficulties for the supply of regions that depend on LNG to function properly, in particular Spain and the south of France. Nevertheless, the first half of 2014 was marked by a closer alignment of prices between the different regions, due however more to conjunctural rather than structural factors.

Lastly, the end of 2013 and the first half of 2014 saw the Ukrainian crisis and uncertainty regarding the supply of gas to Europe from Russia. Supply however remained relatively stable in the first half of 2014 and no country declared any potential risks concerning its short-term supply. However, the memory of the Russian crisis in January 2009 lingered and contributed to maintaining gas prices relatively high for winter 2014/2015 even while short-term prices dropped significantly.

This CRE's seventh monitoring report contains information concerning the implementation of the REMIT regulation at European level, outlines the economic and geopolitical context of energy markets and gives a detailed presentation of the development of wholesale electricity and gas markets in France in 2013 and the first half of 2014.

SUMMARY

REMIT

- **Recent developments in the regulation**

Since 28 December 2011, CRE's wholesale energy market monitoring mission has been governed by REMIT, the European regulation on wholesale energy market integrity and transparency (EU Regulation No. 1227/2011 of 25 October 2011) known as REMIT.

In 2013 and 2014, several texts emerged specifying the respective roles of ACER and national regulatory authorities (NRAs) in monitoring and detecting market abuses in Europe, as well as the principles of cooperation among these authorities, including the memorandum of understanding between ACER and each of the NRAs. Moreover, the implementing acts of the European Commission were voted by the Member States of the European Union on 3 October 2014. These define the information which shall be collected by ACER (see Section I, 1.1).

Energy market monitoring also falls within the framework of the revision of the financial regulation, in particular with regard to new European texts concerning markets in final instruments (MIF II) and market abuse (MAD/MAR) (see Section I, 1.2).

- **Implementation of REMIT**

The prohibitions of insider trading and market manipulation, as well as the obligation to publish inside information have been applicable under the REMIT regulation since December 2011.

The adoption, followed by the entry into force of implementing acts by the European Commission will mark the beginning of the operational implementation of REMIT. In order to carry out transactions in the wholesale energy market, market players must first register with the NRA of the Member State in which they are established, or if they are not established within the European Union, with the NRA of the Member State in which they are the most active. Market players register in a national register set up by each of the NRAs within three months of the adoption of the implementing acts. Market players must register before the start of data collection by ACER (see Section I, 2.1.1).

Data collection from market players by ACER shall start nine months following the entry into force of the implementing acts. The implementing acts outline the type of data to be reported, the frequency of collection and the deadlines. The data fields to be filled in are listed in the tables of the Annex to the implementing acts as well as in technical manuals developed by ACER. The collection by ACER of market participants' data may be done by the market participants themselves, by reporting entities, and also by national and European electricity or gas infrastructure and system operators (see Section I, 2.1.2).

On its website, CRE has set up specific sections dedicated to the implementation of REMIT and the national registration of market participants[1].

[1] See the links: http://www.cre.fr/marches/marche-de-gros/remit-presentation and http://www.cre.fr/marches/marche-de-gros/remit-enregistrement

- **Analyses and investigations conducted by CRE**

Within the framework of its wholesale market monitoring mission, CRE may carry out in-depth analyses following the unusual or suspicious market events detected by its departments, by ACER, by persons professionally arranging transactions or any other participant. In the event that an analysis conducted by CRE reveals a potential suspected breach of REMIT, it may launch an investigation. At national level, the Brottes law of 15 April 2013 on the transition towards green growth amended the French Energy Code and entrusted CRE with ensuring compliance with REMIT, and within CRE, it empowered CoRDiS to sanction breaches of REMIT (see Section I, 2.2).

In 2013, CRE launched 40 requests for information within the framework of in-depth analyses. In the first half of 2014, CRE launched 22 requests for information from market participants.

Two formal investigations were opened, once concerning the electricity market and the other concerning the gas market (see Section I, 2.3).

ECONOMIC AND GEOPOLITICAL CONTEXT OF THE ENERGY MARKETS

- **Interdependent markets and commodities**

Due to their major growth, emerging economies increasingly consume natural gas, in particular for electricity generation. Located far away from producing regions, the Asian and South American continents currently depend mostly on LNG imports. This trend was heightened for the Asian continent with the increase in Japanese gas demand following the shutdown of the country's nuclear power stations in 2011.

LNG plays an increasing role in the world's energy mix and connects the major gas markets by offering arbitrage possibilities. Currently, this arbitrage is to the detriment of European LNG terminals (see Section II, 1.1).

In 2013 and in the first half of 2014, oil prices remained relatively stable hovering around $110/b. Nevertheless, oil price movements have less and less impacts in the determination of gas prices since renegotiation of long-term contracts is continuing. The trend is towards an increase in market share in price index formulas and a decrease in indexation to oil products. In France, these renegotiations resulted in the shift as at 1 July 2014 to gas market indexation of 59.8% in the formula governing GDF Suez's supply costs under the regulated tariffs for the sale of natural gas (see Section II, 1.2).

The European Union Allowances spot prices dropped from 2012 to 2013, going on average from €7.34/t to €4.46/t due to the uncertainty surrounding the backloading proposal made by the European Commission at the end of 2012, which consists in postponing the auctioning of 400 M of allowances and reintroducing them in the market in 2019 and 2020. The allowance price then went back up to €5.57/t in the first half of 2014 with the announcement of fast-tracked implementation of this measure from March 2014 (see Section II, 1.3).

In 2013, the difference between clean dark spread and clean spark spread, representing the theoretical variable margin of a coal-fired powered plant and a gas-fired power plant, continued to rise in favour of clean dark spread compared to 2012 due to the considerable drop in the coal prices in 2013 while the gas prices remained stable. This difference narrowed during the first half of 2014, due to the increase in coal prices and the drop in gas prices (see Section II, 1.4).

- **Evolution of European markets**

Concerning the electricity wholesale market, early July 2014, the German Parliament adopted a reform of the law on renewable energy (EEG), which will differentiate the subsidies granted to renewable energy for new installations and will limit them in 2015 to an average of €120/MWh. The new mechanism places emphasis on the development of cheaper technologies such as onshore wind power and solar photovoltaics and forecasts, by 2017, a remuneration based on a fixed premium determined by calls for tenders. Investors will then have to deal with market price fluctuations (see Section II, 2.1).

Concerning the CO_2 market, the scope of application of the European Union Emission Trading Scheme – EU ETS – was extended in 2013 and now covers 14 new sectors of activity (a total of 25 sectors). The combustion sites endured again an allowance deficit as its freely allocated allowances volume decreased significantly within the framework of Phase III.

In 2014, the allowance surplus stabilised at a level equivalent to that of 2013 (approximately 800 Mt), under the effect of an allowance excess which was not too high for the 2013 compliance cycle (an excess of approximately 50 Mt). The current EUA allowance surplus including Kyoto units however remains largely higher than that figure, estimated at over 2 billion EUAs in 2014. Within this context, measures were drawn up by the European Commission to reduce the accumulated allowance surplus. The main measures are backloading and the market stability reserve. The latter proposal would enable a reserve of emission allowances to be constituted from 2021 which would be topped up depending on the surplus allowances in circulation based on predefined criteria. This measure is currently being discussed among stakeholders and an institutional vote is scheduled for early 2015 (see Section II, 2.2).

Concerning the gas market, production in the European Union continued to decrease in 2013. According to the European Commission, this trend will continue over the next 30 years, which, if demand remains steady, will increase the European Union's dependency on imports, especially from Russia, if no other supply sources are found.

The European markets were marked by the context of the Russia-Ukraine crisis from February 2014. Seeing as Europe had adequate supply in the first half of 2014, spot markets were not affected by these events. However, the futures prices for winter 2014/2015 have been high due to uncertainty surrounding the level of Russian gas supply during that period.

While Europe reduced its dependency on the Ukraine route following the previous crises, the share of Russian gas in its supply continues to increase mainly as a result of a drop in production. These new risks concerning Russian gas highlight the importance of better market integration and security of supply policies within the European Union (see Section II, 2.3).

ELECTRICITY MARKET

- **The fundamentals of electricity generation**

Consumption in France in 2013 stabilised at 462 TWh, excluding consumption for pumping and system losses, i.e. an increase of 1% compared to 2012. The first half of 2013 was marked in particular by a long, cold winter, but which however did not see any extreme consumption peaks. In the first half of 2014, consumption dropped by 9%, against a very mild winter 2013/2014 (see Section III, 1.1 and 1.2).

Electricity generation in France reached 551 TWh in 2013, i.e. a 2% increase compared to 2012. Installed capacity of fossil fuel energy dropped by 8% (-2.2 GW) in 2013, while installed capacity of renewable energy sources increased by 13% (+1.6 GW). Moreover, generation from fossil fuel energy dropped by 7% despite a strong demand for coal and gas at the height of winter 2012/2013, while generation of renewable energy increased by 8%. In the first half of 2014, thermal power generation using fossil fuel (13 TWh) was lower than renewable power generation (15.7 TWh) (see Section III, 1.3).

Against heavy rainfall, the rate of generation of hydroelectricity increased by 19% in 2013. The rate of nuclear power generation stabilised at 72% with a better nuclear availability however in summer compared to 2012. In the first half of 2014, availability of nuclear generating capacity was particularly high during winter and at the start of summer (see Section III, 1.4).

Net exports were very high during summer 2013. Finally in 2013, net balance dropped by less than 1%, but was never negative, as opposed to the year 2012. In the first half of 2014, the meteorological context led to a 62% increase in net exports compared to the first half of 2013 (see Section III, 1.5).

Coal and gas power generation was in very high demand during the long and cold winter in 2013 and at the end of 2013. Fuel oil was used on a very small scale in 2013. In the first half of 2014, the generation rate from fossil energy dropped considerably due to the lack of consumption peaks (see Section III, 1.6).

The use of coal and gas power in the first half of 2014 was lower, for the first time, than the use of hydropower produced from dams, which highlights a sharp decline in thermal power in the French energy mix (see Section III, 1.7).

Analysis of reference French electricity generation shows that, during periods of baseload consumption, the generation system enabled exports, due in particular to the availability of nuclear power units. Periods of extreme peak consumption were less pronounced in 2013 compared to 2012. Moreover, imports were required to cover the demand of consumers during peak and semi-base periods (see Section III, 1.8).

Analysis of the marginality of the different types of power generation in 2013 highlighted on one hand a short duration of marginality of gas power in connection with a low period of operation of plants using gas. On the other hand, the hydropower sector was often marginal, thanks to high hydropower generation in 2013. Border marginality duration remained high with an average price level close to that of coal: French prices continued to be determined by coal power plants located in neighbouring countries (see Section III, 1.9).

The increase in the frequency of updates on the forecast medium-term availability of generation, introduced in March 2013, considerably reduced the difference between forecasted availability and actual availability. This measure had a significant impact in particular on coal and fuel power, reducing the difference between 12 weeks availability forecasts and actual availability by 60% and 76% respectively (see Section III, 1.10).

- **Wholesale market prices**

In 2013, the average day-ahead price stood at €43.2/MWh for baseload and €55.1/MWh for peakload, down by €3.7/MWh and €4.4/MWh respectively compared to 2012. The year 2013 was particularly marked by the negative price spike on 16 June 2013, where prices reached -€200/MWh for few hours of the day. This downward trend increased significantly in the first half of 2014, during which average day-ahead baseload and peakload prices stood at €34.6/MWh and €44.0/MWh respectively, which corresponds in both cases to a 21% drop compared to the first half of 2013. Alongside this downward trend in day-ahead prices, an increase in their volatility was observed in France and in other European countries. The evolution of French spot prices remained in line with market fundamentals, and in particular with electricity system margin indicators. Lastly, due to these low price levels, French net exports improved, particularly with regard to the United Kingdom.

The day-ahead price differential between France and Germany increased in 2013, to €5.5/MWh, accompanied by a major reduction in the French and German hourly price convergence rate to 48% (compared to 63% in 2012). This convergence rate went back up to 58% in the first half of 2014 (compared to 42% in the first half of 2013), in connection with a reduction in the France-Germany price difference to €2.2/MWh.

CRE specifically monitors the differences between the spot market prices and EDF's marginal costs. This monitoring covers the times for which EDF's offers are supposed to determine the auction price. On average, the price-cost difference was 4.5% for 2013 compared to 2.2% for 2012 (see Section III, 2.1).

The futures price for electricity continued to drop in 2013 and in the first half of 2014, with the price of the baseload Y+1 calendar product reaching €43.3/MWh and €42.4/MWh over those two periods respectively. The drop in the price of coal and CO2 is partly responsible for this evolution. Price volatility tended to decrease, both in France and Germany. The France-Germany futures price spread continued to increase in 2013 and in the first half of 2014, following a trend that had started since February 2012 and heightened by the maintenance of the French price at the level of the ARENH (regulated access to historical nuclear electricity) price. While the differences observed in 2013 appear to be consistent with fundamentals, this question has been raised more seriously since the start of 2014[2].

Lastly, there was a large increase in Belgian futures prices during the first half of 2014, in connection with the shutdown of two nuclear reactors in Belgium. This increase reflects tension anticipated in the Belgian market, specifically during winter periods (see Section III, 2.2).

The volumes related to the balancing mechanism dropped in 2013 and in the first half of 2014, with hydroelectricity and nuclear generation being the most concerned. Within the framework of its participation in the balancing mechanism, in 2013 EDF differentiated its offers according to generation types (see Section III, 2.3).

[2] See the section on "Evolution of futures price and ARENH mechanism" in the summary of in-depth analyses or Section III, 2.2

- **Development of the main wholesale market segments**

The EPEX SPOT intraday market's volumes increased by 30% between 2012 and 2013, thanks in particular to the development of cross-border transactions with Germany and, since June 2013, with Switzerland. The volumes traded in the futures markets remained stable in 2013 compared to 2012. However, while they had dropped at the start and end of 2013 compared to the previous year, they increased significantly in the second and third quarters, due in particular to the increase in the trading volumes of the Y+1 calendar product when the price was below the ARENH price (€42/MWh) (see Section III, 3.2).

- **Electricity market development prospects**

The go-live of the flow-based (FB[3]) market coupling mechanism, scheduled for 31 March 2015, aims to optimise market coupling and enable the use of the least expensive generation means for the entire coupled zone.

On 4 February 2014, daily market coupling of the North-West region went live[4]. Since that date, price coupling of regions (PCR) has enabled pooling of electricity offers in the North-West region. The least expensive offers in the zone are therefore selected within the limits of interconnection capacities. Moreover, the market coupling mechanism aims at ensuring that cross-border flows are consistent with the price differential. On 13 May 2014, the South-West zone[5] was coupled with the North-West zone for the day-ahead maturity following the same mechanism, thereby integrating the Spanish and Portuguese markets in the coupling (see Section III, 4.1).

The capacity obligation mechanism aims at ensuring the future security of supply of the French electricity system. Its launch is scheduled for winter 2016-2017. All suppliers will have to justify, depending on the consumption of their client portfolios at peak national consumption periods, a defined amount of capacity guarantees. These capacity guarantees may be obtained by the ownership or development of generation or demand-response capacity, or through the purchase from third parties. Capacity guarantees, fungible products, will therefore be part of a market in which buyers and sellers meet, enabling a capacity market price to be revealed. (see Section III, 4.2).

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[3] For more information, see CRE's annual report - Cross-border electricity exchanges: Use and management of interconnections in 2012 on its website

[4] North-West Region: Germany, Austria, Belgium, Denmark, Estonia, Finland, France, Great-Britain, Latvia, Lithuania, Luxembourg, Norway, the Netherlands, Poland, Sweden

[5] South-West Region: Spain, France, Portugal

GAS MARKET

- **Review of the gas system**

In 2013, the French gas market was marked by a drop in LNG supplies, which was consistent with the low use of regasification capacity observed throughout Europe. Faced with a slight increase in consumption in 2013, the decline in send-out from French LNG terminals was offset by a drop in land exports from the North gas exchange point (PEG Nord). Exports from France to Spain increased following the creation of new capacity at Larrau (see Section IV, 1).

- **Gas prices**

Gas spot prices at PEG Nord increased in 2013. There were several episodes of price spikes at the end of a relatively cold winter 2012/2013, which led to very low stock levels throughout Europe, and to tightness in European supply.

However, spot prices dropped considerably during the first half of 2014, reaching levels that had not been registered since 2010, due to a mild winter 2013/2014 which led to low consumption. In this context, gas from storages was little used and the north-west European markets were comfortably supplied.

Prices at PEG Sud evolved according to the fundamentals specific to the zone: consumption, capacity available at the North-South link, send-out from the Fos LNG terminals, and exports to Spain. This market saw a specific period of tightness in November and December 2013 which resulted in historically high levels in the price spread between PEG Nord and PEG Sud (see Section IV, 2.1).

Since the end of winter 2013/2014, forward prices have been influenced by the course of events related to the geopolitical Russia-Ukraine crisis. While favourable weather conditions calmed fears in summer 2014, concerns about a potential deterioration of supply conditions in the north-west European markets for winter 2014/2015 have kept forward prices high. The widening gap between spot and forward prices for the upcoming winter has, moreover, encouraged players to completely fill their storage capacities (Section IV, 2.2).

- **Development of gas trading**

Physical deliveries at PEGs increased in 2013 but declined in the first half of 2014. This drop is due to the seasonal evolution of deliveries, marked all the more by the mildness of the climate in the first half of 2014, and also by the drop in volumes traded on intermediated markets since April 2014 (sees Section IV, 3.1).

Volumes traded on intermediated gas markets in France increased, despite a decline recorded since the second quarter of 2014. Activity in the futures gas markets continued to stagnate and still facing competition from other European marketplaces. This was accentuated by the absence of structural congestion between the different markets which facilitates hedging strategies on the most liquid marketplaces.

In France, PEG Nord is the most developed marketplace. PEG Sud and PEG TIGF maintain relatively low levels of liquidity due to the limited number of supply sources and the restricted size of these regions (see Section IV, 3.2).

- **Development prospects for wholesale gas markets in France**

Since 2009, CRE has undertaken to reduce the number of marketplaces in France. This work, carried out in consultation with the French market, led to the decision to create a single marketplace in France by 2018. This will be based on the "Val de Saône" and "Gascogne-Midi" investment projects which will relieve most of the congestion between the north and south of France (see Section IV, 4.1 and 4.2).

CRE has decided to auction a part of the capacity at the North to South link and to share the congestion rent with users of the system in the south zone. Moreover, a portion of capacity has been reserved for large gas consumers at a regulated price between October 2014 and September 2018 (see Section IV, 4.3).

Given the major tightness of the market in the south of France, CRE wished to implement for winter 2014/2015 transitional measures to optimise the use of the North-South link until the creation of a single marketplace in France scheduled for 2018. Studies carried out by transmission system operators, in consultation with storage and LNG terminal operators, led to the definition of three mechanisms to increase firm North to South capacity and improve the availability of its interruptible capacity (see Section IV, 4.4).

The development of gas markets in Europe towards better cross-border integration is continuing with the successive adoption of network codes in the third energy package on transmission capacity allocation at interconnection points (in October 2013) and balancing (in March 2014). These codes will profoundly reshape the organisation of gas flows between Member States and will give greater importance to wholesale markets for the physical balancing of the system. A third code on network interoperability and data exchange rules is also in the phase of approval by Member States (see Section IV, 4.5).

IN-DEPTH ANALYSES

In 2013 and the first half of 2014, CRE conducted several in-depth analyses following market events or unusual behaviour of market players. Some of these analyses are still in progress.

ELECTRICITY MARKET

- **Negative price spike on 16 June 2013**

France experienced very significant negative price levels for certain hours during the EPEX SPOT auction for delivery on Sunday, 16 June 2013, with the baseload price reaching -€40.99/MWh. Hourly prices were very negative for the morning and afternoon times, reaching -€200/MWh from 5:00 a.m. to 8:00 a.m. and -€100/MWh from 2:00 p.m. to 4:00 p.m.

Within this framework, CRE analysed the fundamental data specific to this date[6] and interviewed several market players. CRE's analyses served to establish:

- an oversupply of electricity for that day, particularly for the hours during which the prices were very negative;
- a globally rational use of interconnections, with the exception of the interconnection with Switzerland due to the existence of long-term contracts;
- proper operation of the auction conducted by EPEX SPOT, with the negative prices giving rise to an RFQ[7] procedure (second auction in order to improve balancing);
- an amplification of negative prices due to the sale at all prices, by a market participant, of volumes bought inadvertently (technical error) on the Swiss auction one hour earlier.

CRE considers that these negative prices were consistent with supply and demand fundamentals, with the reason for the imbalance between generation and consumption (also observed in Belgium) being the hardly-flexible or non-flexible electricity generation.

Lastly, CRE was able to observe during this negative price episode the limits to the current transparency mechanism. While it enables, within the framework of UFE's (French Union of electricity) transparency mechanism, the publication of all generation capacity available in the French electricity market, i.e. upward generation flexibility, this is not the case for downward generation flexibility. However, this type of information would only be useful for a very limited number of hours in the year (0.15% of hours at negative price in 2013 and in the first half of 2014). Lastly, if this episode was to occur more frequently, CRE would be required to make recommendations within the framework of the UFE transparency mechanism in order to provide relevant information to market participants.

[6] See Report on the functioning of wholesale markets, 2012 – H1 2013

[7] "Request for Quotes"

- **Evolution of futures prices and the ARENH mechanism**

CRE undertook in-depth analyses of the behaviour of participants after observing price stabilisation at around €42/MWh during 2013 while, at the same time, electricity prices in Germany continued to drop. This work consisted in analysing transactions made by market participants and analysing orders posted on the trading platforms during 2013. In addition, CRE interviewed market participants to obtain their analyses of this observation, and in certain cases, to obtain explanations of their behaviours.

Many purchase transactions came from the choice of alternative suppliers, industrial clients or system operators to purchase electricity in the wholesale markets instead of the ARENH mechanism when the price was lower than €42/MWh[8].

CRE did not observe any increase in sales by EDF linked to subscription assumptions for ARENH. The incumbent operator EDF, which delivers electricity within the framework of the ARENH mechanism, stated to CRE that it had no means of "a*nticipating subscriptions by suppliers before notification by CRE of the volumes to be delivered*". EDF underlined that "*the ARENH mechanism requires it to make assumptions of the volumes to be delivered, with the risk, due to optionality, of making errors regarding quantities"*.

EDF's behaviour, combined with that of alternative players, very likely contributed to maintaining the prices around €42/MWh. Low market liquidity favoured this phenomenon. CRE has not identified at this stage any elements likely to characterise market manipulation in the transactions made in 2013 for the 2014 calendar product.

The issue of the consistency of this price compared to market fundamentals has been raised more seriously since the start of 2014. While a price differential of €4.2/MWh between France and Germany seems consistent in 2013 for the 2014 calendar product, this differential increased reaching an average €7.1/MWh in the first half of 2014. In this context, the behaviour of market participants, and in particular, their transactions since the start of 2014, continues to be monitored closely.

Lastly, the progress report scheduled for 2015 by the NOME law will also serve to examine the effects of the ARENH mechanism on the wholesale electricity market in France. On that occasion, the relevance of a mechanism based on a financial settlement for ARENH purchases rather than physical delivery shall be examined.

GAS MARKET

- **Price spike of 9 April 2013**

PEG Nord saw a price spike on 9 April 2013 with transactions exceeding €42/MWh, i.e. a price spread of more than €10/MWh with adjacent markets. This price spike emerged in a context of maintenance operations affecting several entry points in the North zone (Dunkirk, Taisnières H and Obergailbach). These maintenance works prevented a certain number of market participants to supply the French market from neighbouring countries.

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[8] This value was adjusted by certain participants by the profiled character of a portion of the ARENH volumes and by transaction costs and costs related to the ARENH mechanism.

To offset its own capacity reductions, one shipper chose to make purchases on the spot market (day-ahead) and attempt to book important quantities of UBI (use-it-or-buy-it) capacities on 8 April for delivery on 9 April in order to balance its portfolio. This shipper, having not obtained the capacity requested, had to purchase very large quantities on the illiquid within-day market, in particular on the Powernext platform.

In context of major maintenance operations in the transmission system, and given the characteristics of the UBI product, the probability for this shipper to obtain the capacity requested was very low. This action therefore presented considerable physical and financial risks, which jeopardised both this player and the French market and contributed to the formation of the price spike registered at PEG Nord.

CRE therefore recommended that this shipper be more careful in the management of its supplies and do its utmost efforts to anticipate its balancing needs, in particular with regard to the weight that its deals may have in the within-day contracts considering the liquidity and the depth of this market.

Moreover, during this in-depth analysis, the use of the France-Belgium interconnection by shippers was studied thoroughly.

This study highlighted that the import capacity at Taisnières H was not fully optimised on day-ahead since certain shippers use this interconnection for hourly modulation in Belgium. Shippers are required to balance their portfolio on an hourly basis in Belgium, whereas in GRTgaz's system balances are required on a daily basis.

The operational rules at the interface between the two transmission systems enable the necessary flexibility to be offered for hourly balancing of flows from France. This use of the interconnection then limits the possibility for shippers to conduct transit arbitrages between the Belgian and French hubs up to the maximum of their booked capacity.

This matter is mainly a market model issue. A change in balancing rules will not fully homogenise the different European markets in the short term. Therefore, the behaviour of participants within this context continues to be closely monitored.

- **Prices in the south zone and spread with PEG Nord**

The day-ahead price spread between PEG Nord and Sud considerably widened in November and December 2013, largely exceeding the previous historical record of 2012 (€7.6/MWh) and reaching almost €17/MWh towards the end of the year. These very large gaps emerged against particularly tight supply in the south of France, characterised by very little LNG arrivals, relatively high consumption and large exports to Spain.

Although the consumption levels observed during that period are not exceptional, the situation in Fos created physical congestion within GRTgaz's system and difficulties in supplying the south-east of France. These congestions led GRTgaz to take exceptional measures[9], particularly to reduce interruptible capacity available at the North-South link (which was completely saturated during the period) in order to encourage withdrawals from Salins storages in the south-east of the country.

[9] ShipOnline of 29 November 2013:
http://www.grtgaz.com/fileadmin/newsletter/shiponline/shiponline_76_site.html

Moreover, the low stocks of Salins storages prevented GRTgaz from proposing its JTS-winter (joint transport storage) service for 31 gas days between November and December[10].

Exit flows to Spain at Larrau reached historical levels during the last few months of 2013[11]. While since 1 April 2013, daily exit flows reached an average 116 GWh/d, they increased to 143 GWh/d between November and December, with 11 days at around 160 GWh/d in December.

In this context of tightness at PEG Sud, and given the impact of send-out from Fos on market prices and uncertainty about loading and unloading programmes of these terminals, CRE reiterated to market participants their obligations under the REMIT Regulation, especaially with regards to the disclosure of any inside information they may have and which would be likely to significantly affect the prices of wholesale energy products[12].

CRE interviewed the participants present at the Fos-sur-Mer terminals as well as the operators of these LNG terminals and pursues its analyses to ensure compliance of these players' behaviour with Articles 3 (prohibition of insider trading) and 4 (obligation to publish inside information) of the REMIT Regulation.

A more extensive analysis was carried out by CRE for this particular period. At this stage, CRE considers that the very large price spread between PEG Nord and Sud which appeared at the end of 2013 are due to the particularly tight context observed during that period.

Given that this tightness continued beyond the end of 2013, transactions and price formation conditions are still being closely monitored.

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[10] This service enables the auctioning each day of up to 20 GWh/d of additional capacity from the North zone to the South zone.

[11] 80% of exit capacity at the Larrau interconnection was used in November and 90% in December, i.e. the highest levels since April 2013 when capacity increased from 100 GWh/d to165 GWh/d.

[12] CRE press release of 5 December 2013: http://www.cre.fr/documents/presse/communiques-de-presse/tensions-sur-le-marche-du-gaz-la-cre-rappelle-leurs-obligations-aux-acteurs-de-marche/tensions-sur-le-marche-du-gaz-la-cre-rappelle-leurs-obligations-aux-acteurs-de-marche

KEY FIGURES

1.1 Electricity market

Table 1: Review of injections and withdrawals in the French electricity system

Source: RTE	Annual values			Annual variation 2013 / 2012		Half-yearly values		Half-yearly variation H1 2014 / H1 2013	
	2011	2012	2013	In percentage	In values	H1 2013	H1 2014	In percentage	In values
Injections, in TWh									
Generation (excluding ARENH and VPP), in TWh	471	453	478	6%	25,17	251	238	-5%	-13,38
ARENH generation, in TWh	31	61	64	6%	3,55	33	37	12%	3,89
VPP generation, in TWh	40	28	8	-69%	-19,16	5	2	-69%	-3,51
Imports, in TWh	19	29	32	10%	2,77	18	13	-25%	-4,45
Withdrawals, in TWh									
End-user consumption, in TWh	446	455	462	1%	6,44	245	225	-8%	-19,79
Water Pumping, in TWh	6,8	6,7	7,1	6%	0,42	3,5	4,0	13%	0,47
Exports, in TWh	74	73	79	8%	5,87	40	43	10%	3,83
Grid losses, in TWh	32	34	33	-3%	-0,97	18	16	-13%	-2,37

Table 2: Spot and futures prices in the French electricity market

Sources: EPEX SPOT, EEX	Annual values			Annual variation 2013 / 2012		Half-yearly values		Half-yearly variation H1 2014 / H1 2013	
	2011	2012	2013	In percentage	In values	H1 2013	H1 2014	In percentage	In values
Spot Market prices									
Intraday Price France, in €/MWh	48,8	47,0	44,3	-6%	-2,7	45,7	35,3	-23%	-10,4
Day-Ahead Baseload Price France, in €/MWh	48,9	46,9	43,2	-8%	-3,8	43,8	34,6	-21%	-9,2
Day-Ahead Peakload Price France, in €/MWh	60,8	59,5	55,1	-7%	-4,3	55,4	44,0	-21%	-11,4
Spread Baseload Day-Ahead France-Germany, in €/MWh	-2,26	4,35	5,48	26%	1,14	6,45	2,26	-65%	-4,19
Spread Peakload Day-Ahead France-Germany, in €/MWh	-0,53	6,03	6,40	6%	0,38	7,61	3,70	-51%	-3,90
France-Germany Day-Ahead prices convergence rate	67%	63%	48%	-	-15%	42%	58%	-	16%
Futures Market Prices									
M+1 Price France, in €/MWh	54,3	47,1	43,2	-8%	-3,92	39,8	37,6	-6%	-2,3
Spread M+1 France-Germany, in €/MWh	-0,41	2,42	5,41	124%	2,99	2,99	4,76	59%	1,77
Q+1 Price France, in €/MWh	57,5	48,7	43,9	-10%	-4,79	36,2	33,0	-9%	-3,3
Spread Q+1 France-Germany, in €/MWh	0,80	2,41	5,57	131%	3,15	-0,20	0,66	-434%	0,86
Y+1 Price France, in €/MWh	56,0	50,6	43,3	-14%	-7,23	43,9	42,4	-4%	-1,5
Spread Y+1 France-Germany, in €/MWh	-0,04	1,31	4,24	224%	2,93	3,37	7,09	110%	3,72
Ratios Y+1 Peakload/Baseload ratios									
France	1,26	1,26	1,31	3%	0,04	1,30	1,28	-2%	-0,02
Germany	1,23	1,23	1,27	3%	0,02	1,26	1,28	2%	0,02

Table 3: Spot and futures volumes traded in the French electricity market

Sources: RTE, EPEX SPOT, EEX, Brokers	Annual values			Annual variation 2013 / 2012		Half-yearly values		Half-yearly variation H1 2014 / H1 2013	
	2011	2012	2013	In percentage	In values	H1 2013	H1 2014	In percentage	In values
NEB									
NEB volumes, in TWh	333	340	307	-10%	-32,8	158	165	4%	6,5
Ratio NEB/Consumpion in France	75%	75%	66%	-	-8,1%	65%	73%	-	8,6%
Spot Market	**85,3**	**84,8**	**83,6**	**-3%**	**-1,24**	**42,9**	**49,1**	**14%**	**6,21**
Volumes on EPEX SPOT Intraday market, in TWh	2,7	3,3	4,3	29%	0,97	1,9	2,7	45%	0,85
Fr-De Cross-Border Intraday volumes market shares	73%	70%	61%	-12%	-0,09	49%	75%	52%	0,26
Volumes on EPEX SPOT Day-Ahead market, in TWh	59,7	59,3	58,5	-1%	-0,80	29,3	31,5	7%	2,17
Volumes on Brokers Day-Ahead market, in TWh	22,96	22,19	20,79	-6%	-1,41	11,69	14,87	27%	3,18
Futures Market									
Volumes, in TWh	**609,6**	**493,4**	**488,8**	**-1%**	**-4,6**	**264,5**	**373,2**	**41%**	**108,70**
Brokers market share	93,2%	97,0%	96,4%	-	-0,7%	96,7%	94,7%	-	-2,0%
EEX Power Derivatives market share	6,8%	3,0%	3,6%	-	0,7%	3,3%	5,3%	-	2,0%
Number of Transactions	**55 505**	**53 893**	**51 157**	**-5%**	**-2736**	**28 068**	**39 893**	**42%**	**11 825**
Brokers market share	96,0%	97,3%	96,7%	-	-0,6%	97,1%	136,7%	-	39,6%
EEX Power Derivatives market share	4,0%	2,7%	3,3%	-	0,6%	2,9%	5,4%	-	2,6%
Y+1 product									
Volumes, in TWh	161,9	96,5	110,6	15%	14,17	57,7	82,6	43%	24,90
Number of Transactions	3315	1955	2256	15%	301	1163	1613	39%	450
Q+1 product									
Volumes, in TWh	73,9	71,4	47,8	-33%	-23,62	20,1	27,4	36%	7,23
Number of Transactions	3315	1955	2256	15%	301	1163	1613	39%	450
M+1 product									
Volumes, in TWh	72,3	91,0	82,7	-9%	-8,22	49,6	64,3	30%	14,76
Number of Transactions	6843	9141	8665	-5%	-476	4671	7728	65%	3057

Table 4: Installed capacity of electricity generation facilities in France

Source : RTE				Annual variation 2013/2012	
	end 2011	end 2012	end 2013	As percentage	Variation
Installed capaciity (GW)	**126,5**	**128,7**	**128,1**	**0%**	**-0,6**
Nuclear	**63,1**	**63,1**	**63,1**	**0%**	**0,0**
Hydraulic	**25,4**	**25,4**	**25,4**	**0%**	**0,0**
Fossil fuel-fired	**27,8**	**27,8**	**25,6**	**-8%**	**-2,2**
Coal	7,94	7,9	6,3	-20%	-1,6
Fuel	10,36	9,4	8,8	-6%	-0,6
Gas	9,49	10,5	10,5	-0,6%	-0,1
Renewables (excl. Hydro)	**10,14**	**12,4**	**14,0**	**13%**	**1,6**
Wind turbines	6,64	7,4	8,1	9%	0,7
Photovoltaic cells	2,23	3,5	4,3	23%	0,8
Termal renewables	1,27	1,4	1,5	6%	0,1
Parc de référence (GW)	**99,5**	**98,7**	**97,3**	**-1%**	**-1,3**
Nuclear	**63,1**	**63,1**	**63,1**	**0%**	**0,0**
DAM	**13,9**	**13,9**	**13,9**	**0%**	**0,0**
Hydro run-of-river	**10,3**	**10,3**	**10,3**	**0%**	**0,0**
Coal	**6,9**	**6,0**	**5,0**	**-17%**	**-1,0**
Gas	**5,4**	**5,5**	**5,1**	**-7%**	**-0,4**
Fuel	**7,2**	**6,9**	**6,8**	**-2%**	**-0,2**

Table 5: Electricity generation in France

Source : RTE	2011	2012	2013	Annual variation 2013/2012 As percentage	Annual variation 2013/2012 Variation	H1 2013	H1 2014	Half-yearly variation H1 2014 / H1 2013 As percentage	Half-yearly variation H1 2014 / H1 2013 Variation
Generation (TWh)	**541,9**	**541,4**	**550,9**	**2%**	**9,5**	**287,7**	**275,3**	**-4%**	**-12,5**
Nuclear	**421,1**	**404,9**	**403,7**	**0%**	**-1,2**	**207,1**	**208,7**	**1%**	**1,5**
Hydraulic	**50,3**	**63,8**	**75,7**	**19%**	**11,9**	**42,9**	**37,9**	**-12%**	**-5,0**
Fossil fuel-fired	**51,2**	**47,9**	**44,7**	**-7%**	**-3,2**	**24,6**	**13,0**	**-47%**	**-11,7**
Coal	13,4	18,1	19,8	9%	1,7	10,5	4,1	-61%	-6,4
Fuel	29,7	23,2	19,5	-16%	-3,7	11,9	6,9	-42%	-5,0
Gas	8,1	6,6	5,4	-18%	-1,2	2,2	1,9	-13%	-0,3
Renewables (excl. Hydro)	**19,3**	**24,8**	**26,8**	**8%**	**2,0**	**13,1**	**15,7**	**20%**	2,6
Wind turbines	11,9	14,9	15,9	7%	1,0	7,9	9,5	19%	1,5
Photovoltaic cells	1,8	4,0	4,6	15%	0,6	2,2	3,0	38%	0,8
Termal renewables	5,6	5,9	6,3	7%	0,4	3,0	3,2	7%	0,2

Table 6: Generation rate and availability of generation means in France

Source : RTE	2011	2012	2013	Annual variation 2013/2012 Relative variation	H1 2013	H1 2014	Half-yearly variation H1 2014 / H1 2013 Relative variation
Generation rate (%)							
Nuclear	76%	72%	72%	0,0	76%	77%	1,0
Hydraulic	21%	27%	32%	5,0	36%	34%	-2,0
Coal	23%	29%	38%	9,0	41%	20%	-21,0
Gas	40%	19%	17%	-2,0	19%	9%	-10,0
Fuel	1,0%	1,1%	0,6%	-0,5	1%	0%	-0,7
Availability rate (%)							
Nuclear	80%	77%	77%	0,0	80%	81%	1,1
Hydraulic stocks (%)							
Hydro storage capacity rate	60,1%	64,7%	66,2%	1,5	60%	61%	0,8

Table 7: Average use rate of power plants in France

Source : RTE	2011	2012	2013	Annual variation 2013/2012 Relative variation	H1 2013	H1 2014	Half-yearly variation H1 2014 / H1 2013 Relative variation
Average use rate (%)							
Nuclear	75%	72%	72%	0	75%	75%	0
Hydro run-of-river	28%	41%	52%	11	63%	56%	-7
Coal	21%	29%	38%	9	40%	19%	-21
Gas	38%	18%	16%	-2	19%	8%	-11
DAM	15%	16%	16%	0	17%	17%	0
Fossil fuel-fired	0,0%	1,0%	0,0%	-1	1,0%	0,0%	-1

Table 8: French imports and exports

Source: RTE	Annual values 2011	Annual values 2012	Annual values 2013	Annual variation 2013 / 2012 In percentage	Annual variation 2013 / 2012 In values	Half-yearly values H1 2013	Half-yearly values H1 2014	Half-yearly variation H1 2014 / H1 2013 In percentage	Half-yearly variation H1 2014 / H1 2013 In values
Border Balance, in TWh									
Germany	2,5	-8,7	-9,8	13%	-1,10	-5,9	-3,2	-46%	2,70
Spain	1,5	1,9	1,7	-11%	-0,20	-0,3	0,1	-133%	0,40
United-Kingdom	4,8	6,5	10,5	62%	4,00	4,3	7,5	74%	3,20
Belgium	5,7	11,9	12,9	8%	1,00	7,8	7,6	-3%	-0,20
Italy	16,1	15,1	15,3	1%	0,20	7,7	9,2	19%	1,50
Switzerland	25,3	17,6	16,7	-5%	-0,90	8,3	9,1	10%	0,80
Total	**55,8**	**44,2**	**47,3**	**7%**	**3,1**	**21,9**	**30,2**	**38%**	**8,3**

Source : RTE	2011	2012	2013	Annual variation 2013/2012 As percentage	Annual variation 2013/2012 Variation	H1 2013	H1 2014	Half-yearly variation H1 2014 / H1 2013 As percentage	Half-yearly variation H1 2014 / H1 2013 Variation
Imports (TWh)	**18,7**	**29,1**	**31,8**	**9%**	**2,7**	**17,7**	**13,1**	**-26%**	**-4,6**
Peakload imports (TWh)	8,9	12,6	13,7	9%	1,1	7,4	5,8	-22%	-1,6
Offpeak imports (TWh)	9,8	16,5	18,1	10%	1,6	10,3	7,3	-29%	-3,0
Exports (TWh)	**74,5**	**73,3**	**79,1**	**8%**	**5,8**	**39,6**	**43,3**	**9%**	**3,7**
Peak exports (TWh)	25,9	25,6	28,1	10%	2,5	14,3	15,6	9%	1,3
Offpeak exports (TWh)	48,6	47,7	51,0	7%	3,3	25,3	27,7	9%	2,4
Net balance (TWh)	**55,8**	**44,2**	**47,3**	**7%**	**3,1**	**21,9**	**30,2**	**38%**	**8,3**

Table 9: Number of market participants in the different segments of the electricity market in France

Source : RTE, EPEX Spot, Brokers	2011	2012	2013	Annual variation 2013/2012 As percentage	Annual variation 2013/2012 Variation	H1 2013	H1 2014	Half-yearly variation H1 2014 / H1 2013 As percentage	Half-yearly variation H1 2014 / H1 2013 Variation
Balancing responsible	**179**	**195**	**193**			**193**	**190**		
Active in electricity generation	22	29	25	-14%	-4	25	21	-16%	-4
Holder of volumes purchased at VPP	39	31	24	-23%	-7	23	9	-61%	-14
Holder of rights of regulated access to ARENH	16	17	18	6%	1	17	19	12%	2
Final customers provider	31	29	28	-3%	-1	28	26	-7%	-2
Active on imports/exports	80	86	94	9%	8	94	93	-1%	-1
Active on block exchange	104	110	107	-3%	-3	107	103	-4%	-4
Active on exchange	92	93	96	3%	3	96	96	0%	0

Table 10: Market concentration indices (HHI) for the different segments of the electricity market in France

HHI - Market concentration index						
Source : RTE, EPEX Spot, Brokers	2011		2012		2013	
Wholesale energy market		*EDF included*		*EDF included*		*EDF included*
OTC - block purchases	304	*650*	306	*511*	326	*581*
OTC - block sales	346	*682*	387	*519*	417	*620*
EPEX - purchases	430	*777*	525	*593*	381	*423*
EPEX - sales	508	*593*	437	*533*	506	*650*
Injections						
Generation	4285	*8771*	4372	*8702*	4128	*8613*
VPP	644	*0*	727	*0*	1223	0
ARENH	1631	*0*	1656	*0*	1712	0
Imports	1266	*1106*	2110	*1760*	2258	*1835*
Deliveries						
End-consumer consumption	1407	*6922*	1382	*6866*	1451	*6805*
Grid losses	1383	*1250*	1252	*1177*	1254	*1220*
Exports	1139	*1850*	1019	*1273*	771	*1036*

1.2 Gas market

Table 11: Fundamentals of the gas market in France

Market fundamentals	Yearly values			Yearly variation 2013/2012				Yearly variation S1 2014 / S1 2013	
	2 011	2 012	2 013	In percentage	In value	S1 2013	S1 2014	In percentage	In value
Entry and exit flows									
Supply (TWh)	698	699	687	-2%	-12	375	318	-15%	-57
Storages withdrawals	85	120	124	3%	4	79	55	-30%	-24
Imports	607	573	559	-2%	-14	293	263	-10%	-31
Pipeline	448	466	473	1%	7	246	230	-7%	-16
LNG	159	107	86	-19%	-20	47	33	-30%	-14
Production	7	6	4	-35%	-2	3	0	-96%	-3
Demand (TWh)	698	699	687	-2%	-12	375	318	-15%	-57
Storages injections	107	109	116	6%	7	46	54	18%	8
End consumers demand	473	490	497	1%	7	294	228	-22%	-65
Distribution consumers	291	324	335	3%	11	208	157	-24%	-51
Consumers connected to the transmission system	182	166	162	-2%	-4	85	71	-17%	-14
Exports	109	92	67	-27%	-24	33	33	-1%	0
Other	9	8	6	-21%	-2	3	3	10%	0
Deliveries at PEGs (TWh)	435	502	581	16%	78	279	297	6%	18
PEG Nord	348	381	442	16%	60	213	232	9%	19
PEG Sud	68	93	114	23%	22	53	57	9%	5
PEG TIGF	19	28	24	-13%	-4	14	8	-44%	-6
Infrastructure figures									
North-to-south link	68%	89%	94%	5%	5%	90%	100%	10%	9%
Availability of North-to-south link	72%	78%	77%	-1%	-1%	77%	88%	14%	11%
Utilization of Midi interconnection (GRTgaz to TIGF)	44%	47%	52%	11%	5%	40%	61%	51%	20%
Utilization of Taisnieres H interconnection (Entry)	64%	51%	69%	36%	18%	65%	69%	6%	4%
Utilization of Obergailbach interconnection (Entry)	39%	51%	65%	27%	14%	67%	45%	-32%	-22%
Stock levels (TWh as at the end of the Quarter)	74	96	83	-13%	-13	83	78	-7%	-6
Avg. Net variation of French stocks (GWh/j)	22	-11	-8	-28%	3	-33	-1	-97%	32
Avg. LNG terminals senf-out (GWh/j)	435	291	236	-19%	-55	260	181	-30%	-79
Avg. Exports from France to Spain (GWh/j)	69	96	115	20%	19	104	124	19%	20

Table 12: French gas prices

Prices	Yearly values			Yearly variation 2013/2012				Yearly variation S1 2014 / S1 2013	
	2 011	2 012	2 013	In percentage	In value	S1 2013	S1 2014	In percentage	In value
Spot prices (€/MWh)									
PEG Nord day-ahead (avg.)	22,9	25,5	27,6	8%	2,1	28,3	22,1	-22%	-6,3
PEG Sud day-ahead (avg.)	23,0	27,2	30,4	12%	3,3	30,5	26,3	-14%	-4,3
PEG TIGF day-ahead (avg.)	23,6	27,3	30,6	12%	3,4	30,6	26,7	-13%	-3,9
Day-ahead PEG Nord/Sud spread (avg.)	0,1	1,7	2,8	67%	1,1	2,2	4,2	92%	2,0
Day-ahead PEG Nord/TTF Spread (avg.)	0,3	0,5	0,6	22%	0,1	0,7	0,4	-36%	-0,2
Forward prices (€/MWh)									
PEG Nord M+1 (avg.)	23,6	25,3	27,2	7%	1,9	27,0	22,4	-17%	-4,6
PEG Nord Y+1 (avg.)	0,0	0,0	32,5		32,5		27,0		27,0
M+1 PEG Nord/Sud spread (avg.)				-1%	-0,3	27,1	25,3	-7%	-1,8
M+1 PEG Nord/TTF spread (avg.)	0,0	0,0	4,4		4,4		4,6		4,6
Summer-ahead/Winter-ahead spread (avg.)	2,6	2,8	1,6	-43%	-1,2	1,7	2,1	24%	0,4

Table 13: Gas trading in France

Trading activity	Yearly values			Yearly variation 2013/2012				Yearly variation S1 2014 / S1 2013	
	2 011	2 012	2 013	In percentage	In value	S1 2013	S1 2014	In percentage	In value
Wholesale markets activity in France									
Natural gas exchanged at PEG* (TWh)	365	362	422	16%	60	199	223	12%	24
% of national consumption	77%	74%	85%	15%	0,1	0,7	1,0	44%	0,3
Trading volumes in the French intermediated markets									
Spot market (TWh)	118	122	153	26%	32	77	71	-8%	-7
Intraday	7	8	16	97%	7,9	7,8	8,2	5%	0,4
Day Ahead	60	69	83	20%	14,2	42,0	41,6	-1%	-0,4
Exchange (DA, WD, WE, other spot)	29	44	70	62%	26,8	31,3	44,5	42%	13,2
Brokers (DA, WD, WE, other spot)	89	78	83	6%	5,0	45,8	26,1	-43%	-19,7
Forwards market (TWh)	301	224	292	30%	68	152	140	-8%	-12
M+1	93	67	85	26%	17,3	35,7	39,6	11%	3,9
Q+1	21	29	25	-13%	-3,8	5,4	12,8	137%	7,4
S+1	79	64	83	31%	19,5	53,1	44,6	-16%	-8,5
Y+1	18	5	14	196%	9,5	6,9	4,4	-36%	-2,5
Exchange (all maturities)	54	38	29	-23%	-8,7	14,0	19,6	40%	5,6
Brokers (all maturities)	247	186	263	41%	76,8	138,1	120,4	-13%	-17,7
Number of transactions in the French intermediated markets									
Spot market	47 653	64 574	98 407	52%	33833	46106	58268	26%	12162
Intraday	6 374	9 331	18 462	98%	9131	8746	10870	24%	2124
Day Ahead	33 239	45 050	64 758	44%	19708	29928	39013	30%	9085
Exchange (DA, WD, WE, other spot)	19 606	33 813	64 843	92%	31030	27651	43518	57%	15867
Brokers (DA, WD, WE, other spot)	28 047	30 761	33 564	9%	2803	18455	14750	-20%	-3705
Forwards market	4 587	3 134	3 911	25%	777	1828	2117	16%	289
M+1	2 673	1 846	2 475	34%	629	1140	1293	13%	153
Q+1	280	226	227	0%	1	50	103	106%	53
Y+1	47	26	75	188%	49	28	25	-11%	-3
Exchange (all forward maturities)	1 367	1 027	1 061	3%	34	493	764	55%	271
Brokers (all forward maturities)	3 220	2 107	2 850	35%	743	1335	1353	1%	18
Concentration of the natural gas market in France									
Number of shippers active in the market	85	88	96	9%	8	90	100	11%	10
Active in Powernext Gas Spot	40	55	43	-22%	-12	42	48	14%	6
Active in Powernext Gas Futures	28	29	33	14%	4	30	35	17%	5

Table 14: Statistics for French brokered market trading

	2011	2012	2013	S1 2013	S1 2014	2013 / 2012	S1 2014 / S1 2013
Volume traded (TWh)							
Spot	118	121	153	77	71	27%	-8%
day-ahead contracts	60	69	83	42	42	21%	-1%
Forwards	301	223	292	152	140	31%	-8%
monthly contracts	115	80	101	41	46	26%	12%
season contracts	130	93	139	91	70	50%	-23%
Total intermediated market	420	345	446	229	211	29%	-8%
Number of deals							
Spot	47653	64112	98407	46106	58268	53%	26%
day-ahead contracts	33239	44727	64758	29928	39013	45%	30%
Forwards	4587	3122	3911	1828	2117	25%	16%
monthly contracts	3395	2232	2866	1302	1489	28%	14%
season contracts	711	507	611	381	429	21%	13%
Total intermediated market	52240	67234	102318	47934	60385	52%	26%
Most commonly traded volume (MWh/d)							
Spot	1500 (19%)	1000 (15%)	1000 (31%)	1000 (25%)	1000 (43%)		
day-ahead contracts	1500 (21%)	1000 (15%)	1000 (33%)	1000 (25%)	1000 (46%)		
Forwards	750 (52%)	720 (28%)	720 (45%)	720 (44%)	720 (39%)		
monthly contracts	750 (52%)	720 (27%)	720 (46%)	720 (45%)	720 (40%)		
season contracts	750 (55%)	720 (32%)	720 (44%)	720 (45%)	720 (39%)		
Total intermediated market	1500 (10%)	1000 (8%)	1000 (18%)	1000 (14%)	1000 (25%)		

Sources: Powernext, brokers – Analysis: CRE

1.3 CO2 market

Table 15: Spot and futures price of the carbon market

Source : EEX, ICE ECX, Analyse: CRE	2011	2012	2013	Annual variation 2013/2012 — As percentage	Annual variation 2013/2012 — Variation	H1 2013	H1 2014	Half-yearly variation H1 2014 / H1 2013 — As percentage	Half-yearly variation H1 2014 / H1 2013 — Variation
Spot prices (€/tCO2)									
Average spread EUA/CER	**3,07**	**4,44**	**4,10**	**-8%**	**-0,34**	**4,06**	**5,34**	**32%**	**1,28**
Average spot price EUA	12,95	7,34	4,46	-39%	-2,88	4,24	5,57	31%	1,33
Average spot price CER	9,88	2,90	0,36	-88%	-2,54	0,18	0,23	23%	0,04
Futures (€/tCO2)									
EUA									
Average price Dec'13 EUA	14,79	7,93	4,50	-43%	-3,43	4,33	N/A	N/A	N/A
Average price Dec'14 EUA	15,61	8,45	4,68	-45%	-3,77	4,53	5,64	25%	1,12
CER									
Average price Dec'13 CER	10,69	3,28	0,45	-86%	-2,84	0,36	N/A	N/A	N/A
Average price Dec'14 CER	10,95	3,46	0,46	-87%	-3,00	0,40	0,22	-45%	-0,18

	2011	2012	2013	Annual variation 2013/2012 — As percentage	Annual variation 2013/2012 — Variation	H1 2013	H1 2014	Half-yearly variation H1 2014 / H1 2013 — As percentage	Half-yearly variation H1 2014 / H1 2013 — Variation
Coal Y+1 (€/t)	88,88	80,45	67,10	-17%	-13,35	71,92	59,85	-17%	-12,07
Clean Dark spread (forward) (€/MWh)	7,49	11,03	11,96	8%	0,93	10,81	12,89	19%	2,08
Clean Spark spread (forward) (€/MWh)	-2,48	-6,92	-12,66	83%	-5,74	-12,00	-10,65	-11%	1,35

Table 16: Allowances distributed in the carbon market

Source : EEX, ICE ECX, Analyse: CRE	2011	2012	2013	Annual variation 2013/2012 — As percentage	Annual variation 2013/2012 — Variation	H1 2013	H1 2014	Half-yearly variation H1 2014 / H1 2013 — As percentage	Half-yearly variation H1 2014 / H1 2013 — Variation
Allowances (Mt)	**2 078**	**2 265**	**1 955**	**14%**	**-310**				
Auction (Phase II)	**77**	**53**							
Europe	6	9							
Germany	41	16							
UK	31	27							
Poland									
Auction (Phase III)		**90**	**808**	**801%**	**718**	**398**	**327**		**-71**
Europe		54	479		425	252	196		-55
Germany		24	183		159	96	79		-18
UK		12	95		83	50	39		-11
Poland		0	51		51	0	13		-5
Free allowances	**2 001**	**2 212**	**1 057**	**-52%**	**-1 155**				
Verified emissions (Mt)	**1 854**	**1 951**	**1 904**	**-2%**	**-47**				
Surplus (Mt)									
Annual surplus	**224**	**314**	**51**	**-84%**	**-263**				
Accumulated surplus since 2008	**185**	**409**	**722**	**77%**	**314**				

Source : CITL, Analyse : CRE	2011	2012	2013	Annual variation 2013/2012 As percentage	Variation
Verified emissions (Mt)					
Combustion installations	1 398	1 389	1 356	-2%	-34
Petrochemicals	158	150	157	5%	7
Steel industry	106	103	114	11%	11
Non-ferrous metals	0	0	13	2902%	13
Non-metallic minerals	181	169	173	2%	4
Pulp, paper and board	30	29	28	-3%	-1
Chemistry	7	7	38	456%	31
Others	25	20	25	26%	5
Free allowances (Mt)					
Combustion installations	1 332	1 363	279	-80%	-1 084
Petrochemicals	175	178	127	-29%	-51
Steel industry	179	179	152	-15%	-27
Non-ferrous metals	1	1	13	1887%	13
Non-metallic minerals	257	258	200	-23%	-58
Pulp, paper and board	41	42	32	-23%	-10
Chemistry	8	8	46	478%	38
Others	24	26	16	-40%	-10

SECTION I: IMPLEMENTATION OF REMIT

1 Recent developments in the regulation

Since 28 December 2011, CRE's wholesale energy market monitoring mission has been governed by the European regulation on the integrity and transparency of wholesale energy markets (EU Regulation No 1227/2011 of 25 October 2011)[13] known as REMIT. This is a European regulation adapted to the energy sector and directly applicable to all Member States.

A general presentation of REMIT is included in the report on the functioning of energy markets of 2012-2013 (in particular the general context of the regulation and the respective roles of ACER and national regulatory authorities).

1.1 Framework surrounding REMIT at European level

Several texts emerged specifying the role of ACER and regulatory authorities in monitoring markets and detecting market abuses in Europe, as well as the principles of cooperation.

In 2013, a memorandum of understanding was set up between ACER and each of the national regulatory authorities (NRAs), which specifies the arrangements for cooperation between ACER and the NRAs (notifications by the NRAs to ACER in the event of breaches of REMIT, requests by ACER to the NRAs in the event of requests for information or launch of investigations, and coordination of investigations in the event of cross-border cases).

In 2014, a second memorandum of understanding was signed concerning the sharing of data between ACER and each NRA. It specifies access to the information that the NRAs receive from ACER under Articles 7 and 8 of REMIT, concerning supply and transmission contracts, orders to trade, derivative contracts, fundamental data (capacity and use of generation installations, storage, etc.) and public information. Moreover, the NRAs have access to information necessary for the cooperation with ACER in the event of any unusual or suspicious market event.

ACER's data is collected from market participants under the European Commission's implementing acts. Data sharing is contingent upon the operational reliability of the NRAs and the respect of professional secrecy.

The third set of ACER guidelines was published in October 2013[14]. These contain, in particular, information about the registration of market participants and exemptions provided for under REMIT.

Early 2014, a questionnaire was launched at European level to review the implementation of REMIT at national level, in particular with regard to the powers of regulatory authorities in terms of monitoring, investigations and sanctions (Articles 7, 13 and 18 of REMIT)[15]. Twenty-four European regulatory

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[13] Consult Regulation (EU) No 1227/2011 of 25 October 2011 concerning the integrity and transparency of the wholesale energy market

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

[15] See the link http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Cross-Sectoral/2014/C14-MIT-55-03_REMIT_CEER%20Memo_final_18092014.pdf

authorities and two observers filled in the questionnaire. The responses indicated that at the time of the study, the implementation of REMIT was in progress in most Member States, although certain countries had not yet applied REMIT in their national legislation. Results showed that most NRAs intended to carry out monitoring activities, with some of them setting up a specific team. Investigation powers are exercised by the NRAs directly or in collaboration with other competent authorities (financial, legal or competition). The investigation powers of most NRAs were broadened with the implementation of REMIT (for example the right to request a court to freeze or sequester assets). Lastly, sanctioning powers, which are exercised by NRAs directly or with other authorities, are administrative for most countries and criminal for others.

In 2014, a market monitoring manual was drafted concerning the practical coordination between national regulatory authorities and ACER. This manual specifies the interactions between ACER and NRAs in market monitoring, in the event of an investigation and in the coordination of cross-border investigations. The manual also outlines the role of persons professionally organising transactions in the detection of suspected market abuse cases and cooperation with ACER and NRA surveillance.

Lastly, ACER has drafted texts specifying the criteria for collecting data on transactions (Transaction Reporting User Manual – TRUM) and fundamental data (Fundamental Data User Manual – FDUM) as well as registration criteria for registered reporting mechanisms (Registered Reporting Mechanism - RRM). These texts have been submitted for public consultation and will be published following the entry into force of the European Commission's implementing acts. They will specify and complete the provisions of REMIT and the implementing acts.

CRE is contributing significantly to these different activities. In particular, it is the vice-chair of ACER's and CEER's working groups on market integrity and transparency and co-chair of ACER's and CEER's wholesale market surveillance task forces. It also participates actively in task forces concerning the principles of governance of markets and information systems. Occasional meetings are also organised with the different ACER and European Union departments (Directorate-general for Internal market and Directorate-general for Energy) in order to discuss about the evolution of regulation of energy markets.

1.2 Link with financial regulations

The wholesale energy market monitoring mission lies within the framework of the financial legislation which is being revised.

The new directive[16] and the new regulation[17] concerning markets in financial instruments (known as MIF II) were adopted in May 2014 and will enter into force in 2017. The MIF II directive defines in particular the list of financial instruments. It qualifies emission allowances as a financial instrument[18] and provides for an exemption of wholesale future energy products traded in an organised trading facility and that must be physically settled[19].

The prohibition of insider trading (Article 3) and the prohibition of market manipulation (Article 5) within the framework of REMIT do not apply to wholesale energy products which are financial instruments according to the financial legislation[20], unlike the obligation to publish insider information (Article 4)

[16] Consult the Directive (EU) 2014/65/EU of 15 May 2014 on markets in financial instruments and amending Directive 2002/92/EC

[17] Consult the Regulation (EU) 600/2014 of 15 May 2014 on markets in financial instruments and amending Regulation (EU) No 648/2012

[18] See Annex I, section C (11) of Directive 2014/65/EU

[19] See Annex I, section C (6) of Directive 2014/65/EU

[20] See Article 1(2) of REMIT ((EU) No 1227/2011)

and to transmit information to ACER (Article 8) for which REMIIT remains applicable. Therefore, the coordination of the obligation to publish insider information according to the Market Abuse Regulation (MAR) and REMIT must be assessed.

Lastly, in March 2013, technical standards entered into force concerning the European market infrastructure regulation (EMIR)[21], specifying the reporting obligations applicable to derivative contracts of market participants towards trade repositories. Transactions reported within the framework of EMIR and which concern wholesale energy products shall not be subject to double reporting obligations according to REMIT[22].

2 Implementation of REMIT

2.1 REMIT implementation schedule

The prohibitions of insider trading and market manipulation, as well as the obligation to publish insider information[23] have been applicable since the entry into force of REMIT.

At the end of December 2011, a notification platform to ACER was made available to market participants[24] to enable them to notify their cases of exemption from the prohibitions and the obligations under REMIT[25], and so that persons professionally arranging transactions could report suspected cases of breach in the market.

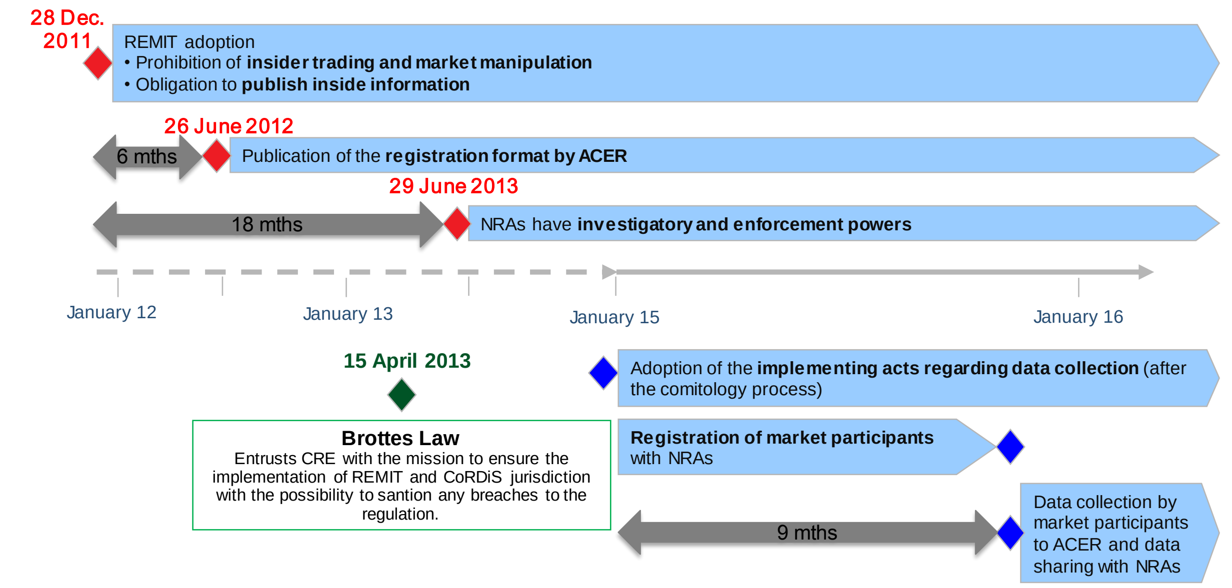
On 26 June 2012, ACER published a decision on the registration format[26] for the registration of market participants with NRAs which includes five sections (see section 2.1.1).

Member States had until 29 June 2013 to ensure that their NRAs had sufficient powers to ensure enforcement of the prohibitions and obligations specified in REMIT[27]. REMIT provisions have been enforced differently across Europe.

The adoption of implementing acts by the European Commission will mark the beginning of the operational implementation of the mechanism provided for under REMIT. This operational implementation was postponed due to the delay in setting up the implementing acts. On 3 October 2014, Member States approved the text of the implementing acts. These were scheduled to enter into force at the end of 2014.

[21] Consult Commission Delegated Regulation (EU) No 153/2013 of 19 December 2012 supplementing Regulation (EU) No 648/2012 of the European Parliament and of the Council with regard to regulatory technical standards on requirements for central counterparties
[22] See Article 8(3) of REMIT
[23] See Articles 3, 4 and 5 of REMIT
[24] http://www.acer.europa.eu/remit/Pages/Important-information-for-market-participants.aspx
[25] See Articles 3.4 and 4.2 of REMIT
[26] http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Directors%20decision/ACER%20Decision%2001-2012.pdf
[27] See Article 13 of REMIT

Graph 1: REMIT entry into force and implementation schedule



Source: ACER

2.1.1 Start of the registration phase at national level

In order to carry out transactions in wholesale energy markets, market participants must first register with the NRA of the Member State in which they are established, or if they are not established within the European Union, with the NRA of the Member State in which they are the most active. Market participants register in a national register set up by each of the NRAs within three months of the adoption of the implementing acts. Market participants must register before the start of data collection by ACER, i.e. nine months following the entry into force of the implementing acts[28]. They must thereafter quickly report to the NRA any change in the information registered[29]. It is in fact market participants which are responsible for the information contained in the national register.

The NRAs may choose to use the registration system developed by ACER or their own registration system. The NRAs must forward the information in their register to ACER, which will establish a European register of market participants. ACER will publish a part of the European register.

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

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,

[28] See the link to the comitology register of the European Commission concerning the implementing acts of REMIT as signed by Member States on 3 October 2014
[29] See Article 9(5) of REMIT

5. information on delegated parties for reporting on behalf of the market participant.

Registration shall be done progressively. Participants must first fill out sections 1, 2 and 3 of the register. They must then complete section 5 once ACER has authorised the delegated parties for information reporting. Lastly, they shall report the information in section 4 (corporate structure and related undertakings) once ACER has published a part of the register which includes 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.

Within the framework of registration at national level, CRE organised an information meeting on 7 October 2014 concerning REMIT regulation and the launch of the market participants registration phase. CRE presented the details of the Centralised European Register for Market Participants (CEREMP) registration system which is planned for at national level. A service level agreement was signed in 2014 between ACER and CRE for the use of CEREMP. It outlines the general conditions of use, provisions on the security of information and the availability of the service.

For any information concerning REMIT and the registration phase, a specific page deditated to REMIT is available on CRE's website[30].

2.1.2 Data collection with phased implementation

During the 2013-2014 period, implementing acts were drafted by the European Commission concerning the information to be reported to ACER (and, where applicable, to the NRAs) within the framework of the operational implementation of REMIT[31]. These acts specify the type of data to be reported, the frequency of collection and the deadlines. They define, among other things, fundamental data, as opposed to transaction data, standard and non-standard contracts and organised market places.

Data collection is a step-by-step phases.

The following data will be collected nine months following the entry into force of the implementing acts:

- standard contracts and transactions carried out on organised market places, including orders to trade (excluding transportation contracts);
- aggregated fundamental electricity and gas data.

The following data will be collected fifteen months following the entry into force of the implementing acts:

- standard bilateral supply transactions;
- transportation contracts, including orders to trade;
- non-standard contracts and transactions related to non-standard contracts;
- individual fundamental electricity and gas data.

The following data will be collected in an ad hoc basis after a reasoned request by ACER:

[30] See the links: http://www.cre.fr/marches/marche-de-gros/remit-presentation and http://www.cre.fr/marches/marche-de-gros/remit-enregistrement
[31] See the link to the comitology register of the European Commission concerning the implementing acts of REMIT as signed by Member States on 3 October 2014

- intragroup contracts and transactions;contracts for the physical delivery of electricity produced by a single production unit with a capacity equal to or less than 10 MW or by production units with a combined capacity equal to or less than 10 MW;
- contracts for the physical delivery of natural gas produced by a single natural gas production facility with a production capacity equal to or less than 20 MW;
- contracts for balancing services in electricity and natural gas.

The European Commission presents the data fields to be filled in in the four tables of the Annex to the implementing acts. ACER specifies these fields in the TRUM, FDUM and RRM documents submitted for public consultation (see part 1.1.1).

The collection by ACER of market participant data may be done by the market participants themselves, by reporting entities, and also by national and European electricity or gas infrastructure and system operators.

The data must then be shared by ACER with the NRAs and any other competent authorities (financial, competition, etc.), provided that strict confidentiality and data protection clauses are in place.

Lastly, REMIT specifies that the collection of data by ACER is without prejudice to the right of the NRAs to collect additional information for national requirements[32].

2.2 CRE's monitoring, investigation and sanctioning powers

Within the framework of its wholesale market monitoring mission, CRE may be required to conduct analyses following the detection of an unusual or suspicious market event. This detection may be done by:

- CRE's wholesale market monitoring department;
- persons professionally arranging transactions, who must immediately alert the national regulatory authority if they suspect a breach of Articles 3 and 5. In that regard, a notification platform has been set up by ACER for all notifications of suspected breaches of REMIT[33];
- ACER as part of its market monitoring activities. In the event of a suspected market abuse or non-disclosure of inside information, ACER may request a national regulator to launch an investigation. If ACER considers that a potential breach of REMIT has a cross-border impact, it may establish and coordinate an investigatory group consisting of the NRAs concerned, as well as representatives of financial authorities or of any other relevant authority;
- any other player that may suspect a breach of REMIT.

As soon as CRE detects or is informed of an unusual event, it conducts an in-depth analysis to ascertain whether REMIT may have been violated or if the event may seriously have affected the functioning of the energy markets. It may launch an investigation if the analysis conducted reveals that there may have been a breach of REMIT.

At national level, the Brottes law of 15 April 2013[34] amended the French Energy Code entrusting CRE with ensuring compliance with REMIT, and within CRE, it empowered CoRDiS to sanction breaches of REMIT. Article L. 131-2 of the French Energy Code provides that: *"The Energy Regulatory Commission guarantees the respect, by any person who enters into transactions in one or more*

[32] See recital (17) of REMIT
[33] See the suspicious transactions reporting platform
[34] Law No 2013-312 of 15 April 2013 aimed at preparing the transition to a low-carbon energy system and containing various provisions on the pricing of water and on wind turbines

wholesale energy markets, of the prohibitions set out in Articles 3 and 5 of Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency, and of the obligation set out in article 4 of the Regulation." In addition, Article L. 134-25 of the Energy Code provides that: *"The Standing Committee for disputes and sanctions (CoRDiS) can (…) sanction breaches of the rules laid down in Articles 3, 4 and 5 of Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale electricity market integrity and transparency or all other breach which is likely to seriously prejudice the functioning of energy markets"*

2.3 Analyses and investigations conducted by CRE

During 2013, CRE launched 40 requests for information within the framework of in-depth analyses. During the first half of 2014, it launched 22 requests for information from market participants.

Two formal investigations were opened, one concerning the electricity market and the other concerning the gas market.

SECTION II: ECONOMIC AND GEOPOLITICAL CONTEXT OF THE ENERGY MARKETS

These last few years have been marked by the emergence of regional energy markets, particularly due to the development of interconnections and market coupling initiatives. As such, the French electricity market is now integrated into a west European market and is influenced by the neighbouring markets. The French gas market has the particularity of being between two major regional markets in Europe: North-West Europe, characterised by very limited congestion and correlated prices, and South-West Europe, characterised by a strong dependency on liquefied natural gas (LNG) supplies. The North-to-South link in France connects these two markets in the west of Europe.

In the commodity sector, certain markets operate at world level, in particular the LNG market and the coal market. Participants pay close attention to these two markets because of their influence on the gas and electricity markets in Europe:

- operators active in the LNG market direct their cargos to the most profitable markets. LNG needs are very low in North America due to the boom in shale gas, unlike in markets located in Asia and South America which depend heavily on LNG. The South-West European market is therefore in competition with these different regional markets;
- coal prices have dropped considerably, due in particular to the drop in American coal demand for electricity generation for the benefit of gas. This drop, combined with a drop in the price of CO_2, a slump in demand and a growth in renewable energy, has a major influence on the prices of electricity in Europe.

Lastly, the gas market is faced with major uncertainty concerning supplies from Russia, in connection with the conflict in Ukraine.

This new section aims to describe the economic, energy and geopolitical context of the French electricity and gas markets.

1 Interdependent markets and commodities

1.1 Growing role of the LNG market in world gas markets

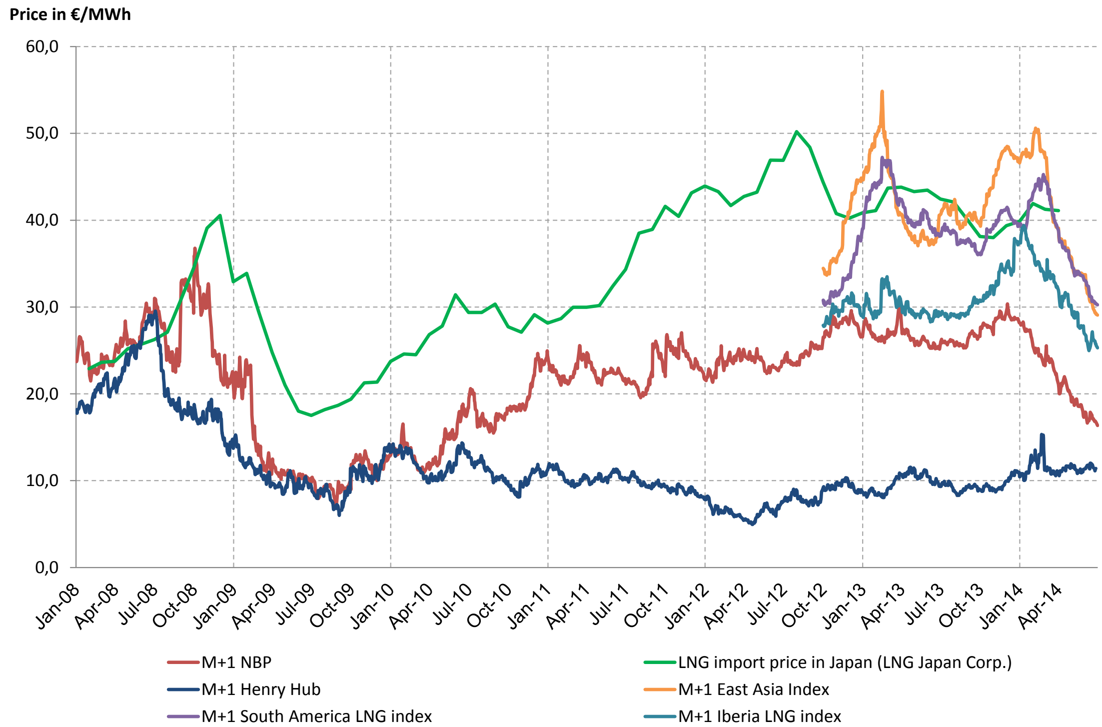
Due to their major growth, emerging economies are increasingly consuming natural gas[35], in particular for electricity generation. Not being sufficiently connected by infrastructure to gas-producing regions, the Asian and South American continents currently depend mostly on LNG imports. This trend was heightened, for the Asian continent, by the sudden increase in Japanese gas demand, following the shutdown of nuclear power stations in Japan in 2011.

In a LNG market in which the volumes available remained limited[36], South American and Asian countries are in competition and must bid to attract LNG tankers available to their regasification terminals. Therefore, Asian and South American LNG prices fluctuated sharply in 2013 and 2014, particularly during the winter period.

[35] According to the International Energy Agency, Asian natural gas demand will double by 2025.
[36] Exports from producing countries did not increase between 2012 and 2013 (source: BP Statistical Review 2013).

Nevertheless, after increasing considerably in November and December 2013, the spot price of LNG in Asia softened significantly in 2014, losing roughly 25% of its value at the end of June compared to February. Large stocks and a mild climate did not entice Asian energy operators to purchase LNG.

Graph 2: Price of gas in Europe, USA, South America and Asia



Sources: Bloomberg, Heren – Analysis: CRE

In this context, and while gas prices remained stable in Europe and the USA in 2013, there was a closer alignment of prices during the first half of 2014 between these two markets.

The USA saw an unprecedented cold wave in the first quarter of 2014. This situation resulted in several price spikes on the Henry-Hub exceeding $6/MMBtu[37] (approximately €15/MWh) in February and March, and the spot prices of certain regional hubs in the north-west of the USA reached records over $40/MMBtu (roughly €100/MWh).

At the same time, the European continent experienced a particularly mild winter which significantly contributed to a softening of gas prices.

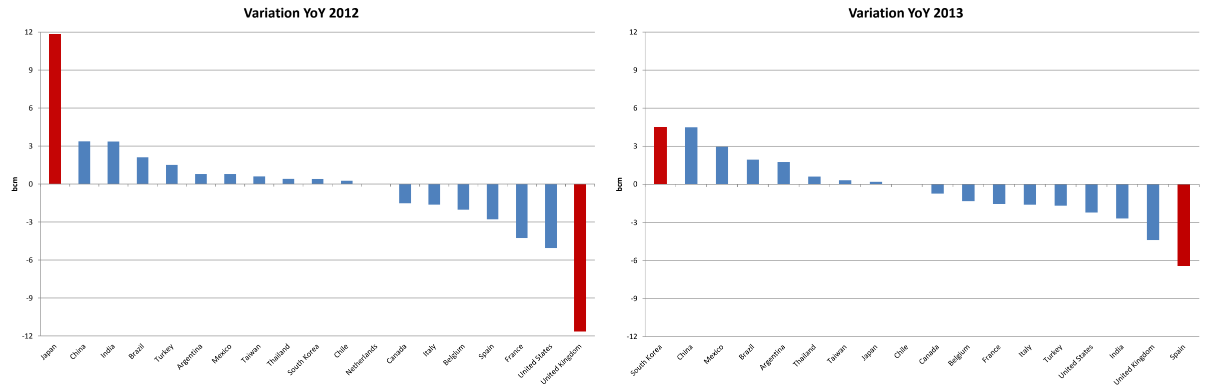
Therefore, the gap between the prices of gas in the USA and Europe considerably narrowed in the first half of 2014 mainly due to conjunctural factors specific to the two continents rather than to a change in their supply/demand fundamentals. The development of shale gas in the USA ensures an abundant and cheap supply of gas for several years.

[37] Such price levels had not been observed since 2009.

Competing demand in the LNG market

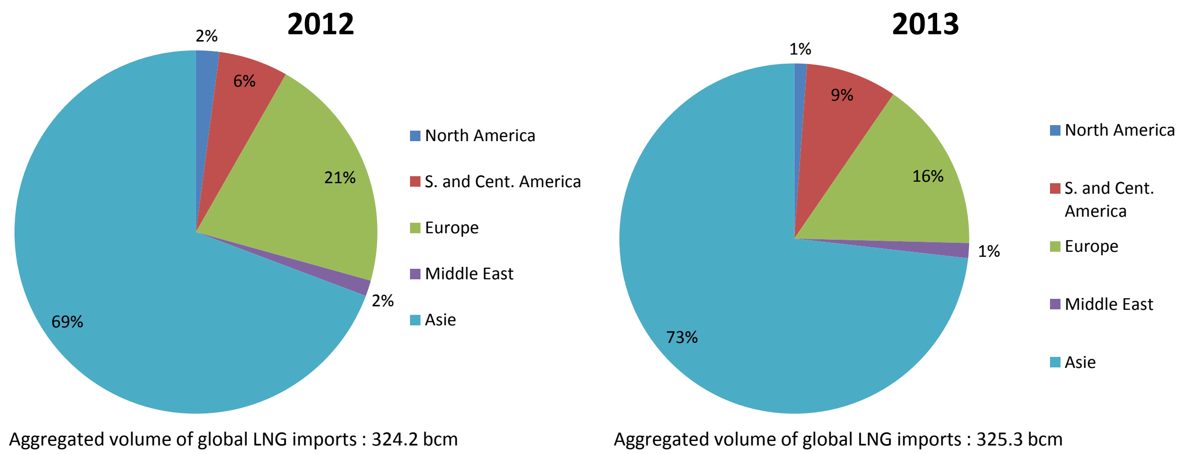
Redistribution of LNG demand stabilised in 2013. Japan, which had to urgently import massive volumes of LNG in 2011 and 2012 following the shutdown of its nuclear reactors, stabilised its imports in 2013. However, new players have appeared in the classification of countries that increased their imports the most (South Korea, China, Mexico, Brazil, Argentina), which indicates that the LNG market is increasingly globalised. This redistribution of volumes was to the detriment of European countries (Spain, United Kingdom, Italy, France) for which, for the third consecutive year, there was a decrease in LNG flows arriving in their terminals.

Graph 3: Annual variation in LNG imports



Sources: BP Statistical Review 2013 – Analysis: CRE

Graph 4: World distribution of LNG imports



Sources: BP Statistical Review 2013 – Analysis: CRE

LNG supply set to rise in the coming years

The tight situation in the global LNG market should be relieved in the upcoming years by the development of new liquefaction factories throughout the world. ExxonMobil's new PNG LNG project in

Papua New Guinea (6.9 million tonnes of annual capacity) was commissioned ahead of schedule in May, offering new volumes in the Asia-Pacific region.

Moreover, the USA has almost 30 ongoing projects (aimed at American shale gas exports, the first of which should be operational in 2016), and others are growing in Australia, Russia (with the Yamal gas field, in the Russian Arctic) and in certain African countries such as Mozambique and Tanzania.

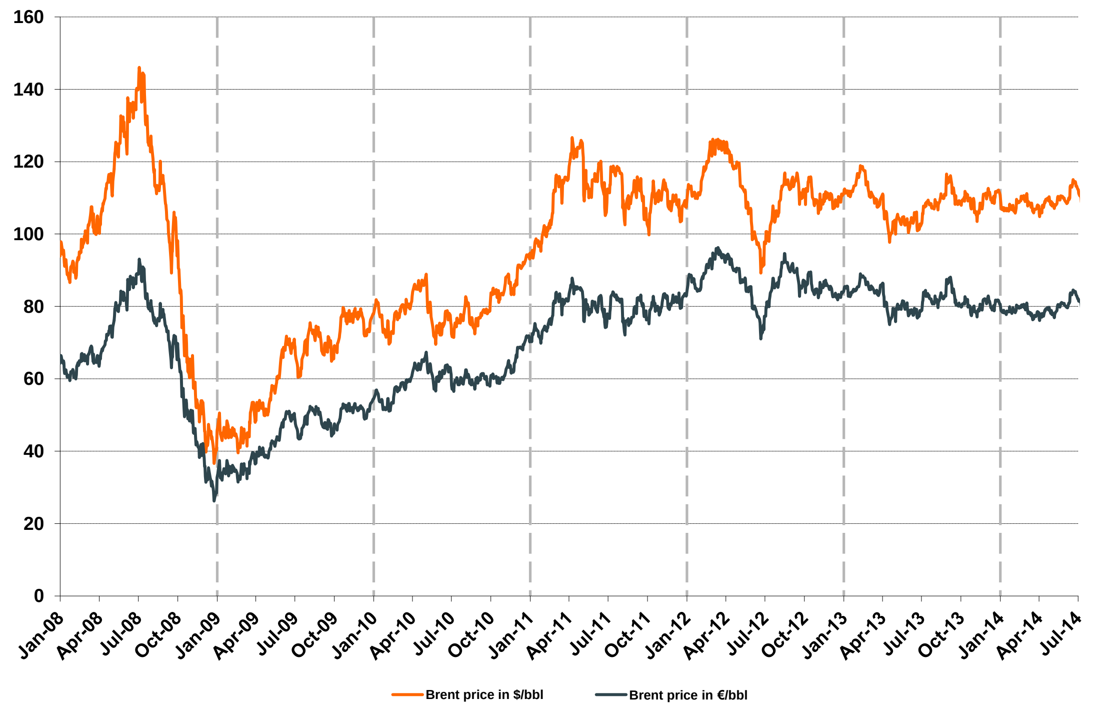
All of these investments will increase global LNG supply from 2015. Moreover, the contract signed on 21 May between Russia and China, for the supply by pipeline of 38 billion cubic metres of gas per year for 30 years, could contribute to reducing Chinese LNG demand and therefore freeing up more volume for other major importing countries.

Nevertheless, the prospects for Europe are uncertain. While certain European energy operators have already announced the signing of agreements to secure, in the long term, new volumes of American LNG available for export, it is highly probable that these additional volumes will be directed first and foremost to the most profitable markets which are in Asia and South America.

1.2 Persistent disconnection between gas and oil prices

In 2013 and in the first half of 2014, oil prices remained relatively stable hovering around \$110/b despite geopolitical tensions in Libya, Iraq and Russia.

Graph 5: Brent prices



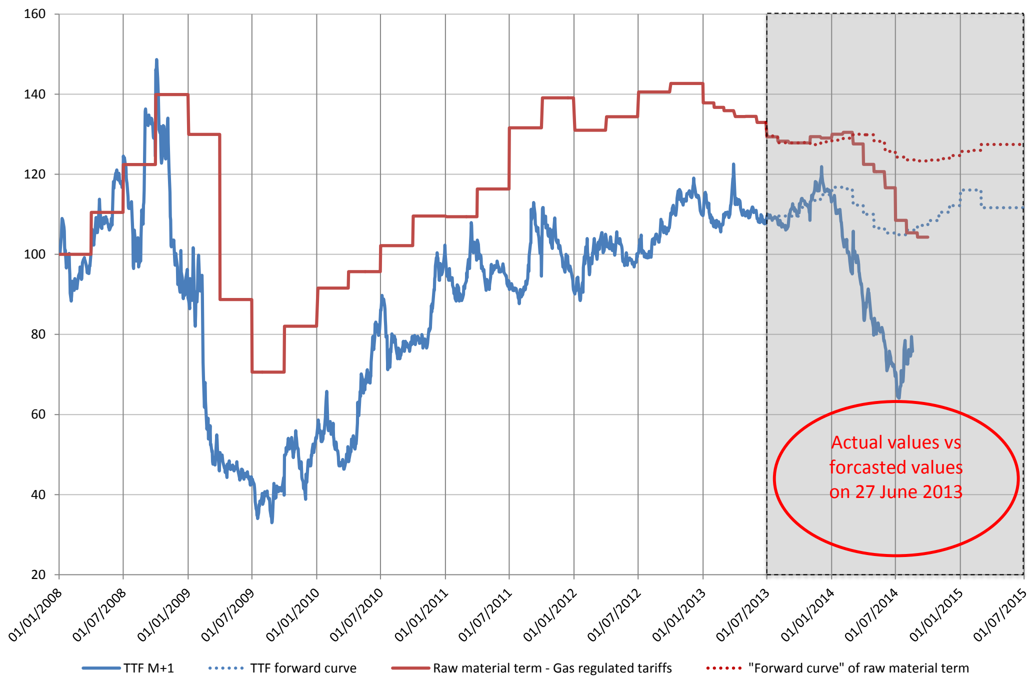
Sources: Reuters – Analysis: CRE

The difference between the gas market prices and long-term oil-indexed prices may be measured through the evolution between month-ahead prices and the formula for regulated tariffs for the sale of gas (TRV) which reflects GDF Suez's supply costs through its long-term contracts. The evolution of the "market" indexed share in the TRV formula reflects the renegotiations of contracts with producing countries which introduced, some years ago, more reference to the gas market in the establishment of their sale price. As of 1 July 2013, the market share went from 35% to 45%, and as of 1 July 2014, it was 59.8% of the formula that referred directly to the wholesale gas markets. This increase in market share mechanically brings the TRV prices closer to wholesale gas market prices.

The forward prices presented in graph 6b, based on the prices of futures products in the markets as of 27 June 2014, show an increase in prices resulting from long-term contracts with price stabilisation in 2015. It should however be specified that these values is not indicative of the actual evolution of gas prices or of the supply costs included in the TRV.

Graph 6: Comparison between gas prices in the wholesale markets and gas prices resulting from the TRV formula (base 100 as of 1 January 2008)

a. At end June 2013: forward curve compared to actual values



Note: the continuous blue curve represents prices for the month-ahead TTF contract. (2) the blue dotted curve represents forward prices at the TTF as observed on 27 June 2013. (3) The red continuous curve represents the evolution of the share of raw material in GDF Suez' supply costs and includes the different formula changes. (4) the red dotted curve represents the "future" evolution of raw material, calculated from forward values of indices entering into the current formula and as observed on 27 June 2013.

b. At end June 2014: forward curve

Sources: Bloomberg, Heren, Reuters – Analysis: CRE

Note: the continuous blue curve represents prices for the month-ahead TTF contract. (2) the blue dotted curve represents futures prices at the TTF as observed on 27 June 2014. (3) The red continuous curve represents the evolution of the share of raw material in GDF Suez's supply costs and includes the different formula changes. (4) the red dotted curve represents the "future" evolution of raw material, calculated from forward values of indices entering into the current formula and as observed on 27 June 2014.

1.3 Progressive recovery of CO_2 prices

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

- The supply of European Union Allowances ("EUA") corresponds to the quantity of allowances in circulation in the primary market within the framework of free allocation and auctioning of allowances. Since 2013, roughly 50% of the total volume of allowances are allocated free of charge and 50% are auctioned.
- The demand for EUAs depends on actual emissions verified at industrial sites subject to compliance with the European Union Emission Trading Scheme (EU ETS).

EUA prices down in 2013 and up in the first half of 2014

The EUA spot price dropped between 2012 and 2013, down on average from €7.34/t to €4.46/t (-39%). The price of allowances then increased to €5.57/t in the first half of 2014 (€4.24/t in the first half of 2013). The price of carbon was low during this period due to the surplus allowances in circulation accumulated since 2010 (see section 2.2.1) and the prolongation of slowed industrial production within the context of the economic crisis.

Early 2013, EUA prices dropped considerably due to the uncertainty concerning the backloading proposal made by the European Commission at the end of 2012 (see Box 1). They averaged €3.86/tCO_2 in the second quarter of 2013, which is a record low.

Following the approval of the backloading measure by the European Parliament on 3 July 2013, allowances prices went back up, within an average €4.60/tCO_2 in the third quarter of 2013. On 10 and 13 December 2013, the European Parliament and Council formally approved the backloading measure and prices reached €4.75/tCO_2 in the fourth quarter of 2013. The Commission then adopted this measure in January 2014, announcing the implementation of allowance backloading from March 2014. As a result of this announcement, the EUA price considerably increased in the first quarter of 2014 (€5.8/tCO_2 on average) and exceeded €7/tCO_2 at the end of February 2014. The EUA price remained at this level for several weeks before dropping again below €5/tCO_2 in May 2014. EUA prices then dropped once more during the second quarter of 2014 to €5.3/tCO_2.

Decline in CER prices

In 2013, the spot price of the certified emissions reductions (CER) dropped from €2.90/t in 2012 to €0.36/t (-88%). As for the first half of 2014, the price of CERs recorded values close to zero for the entire period, with an average price of €0.23/t.

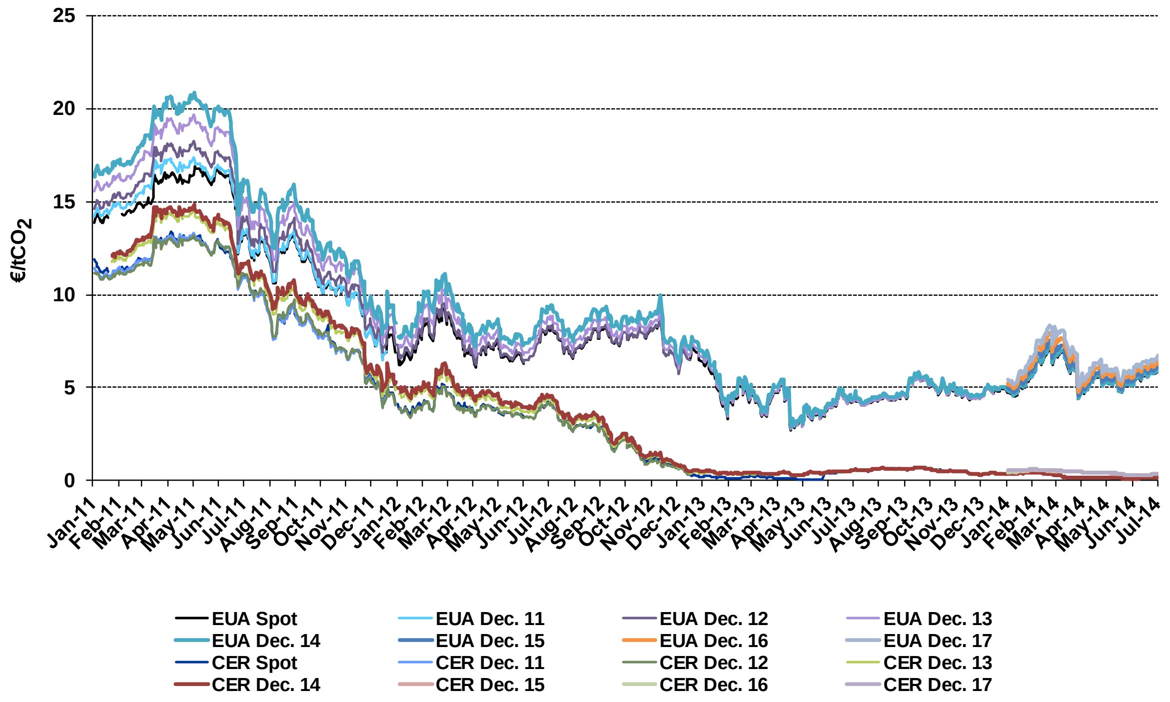
This situation is mainly due to the large volume of CER in circulation in the market.

The disconnection of CER prices compared to EUA prices continued in 2013 and in the first half of 2014, with a price difference between the two products going from €4.44/t in 2012 to €4.11/t in 2013 and €5.34/t in 2014.

Prices of futures contracts

In the course of 2013 and the first half of 2014, the prices of futures contracts followed a very similar trend to that of spot products, both for EUA and CER products. The EUA Y+1 contract went from €7.50/t in 2012 to €4.50/t in 2013 on average and reached €5.64/t in the first half of 2014. The prices of CER Y+1 contract were very close to zero in 2013 and in the first half of 2014.

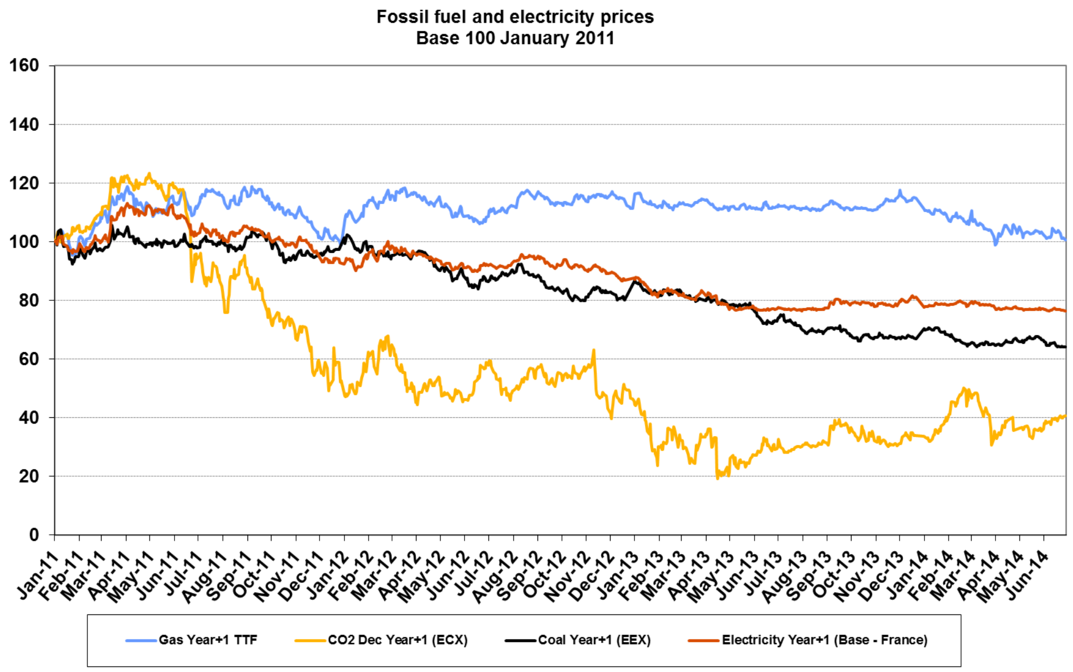
Graph 7: Evolution of futures and spot EUA and CER prices since 2011



Source: BlueNext (until 5 December 2012), ECX

1.4 Coal and gas in competition for electricity generation

Graph 8: Price of fuel prices (base 100 as at 1 January 2011)



Sources: Electricity prices: EEX Power Derivatives France Y+1 base, Price of Gas: Heren TTF Y+1, Price of Coal: EEX CIF ARA Y+1, Price of CO_2: ECX Y+1

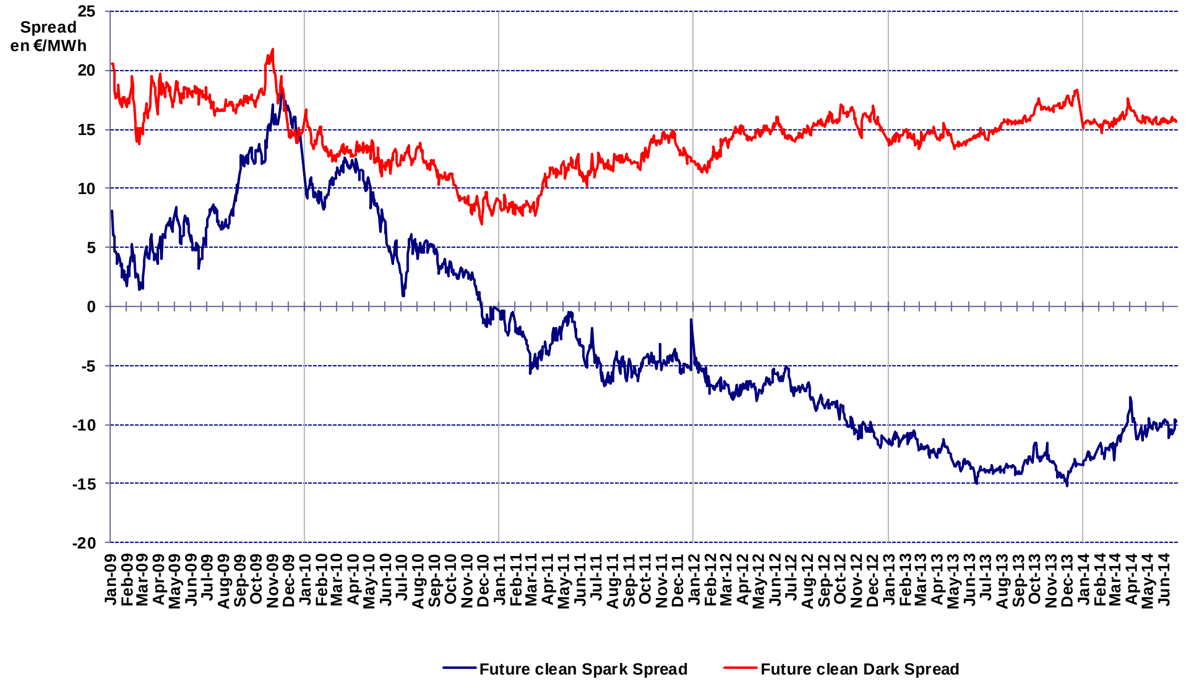
Fuel prices are to be compared to determine the merit order of generation means between coal and gas power plants:

- the coal prices continued to drop in 2013 and the H1 2014. Since 1 January 2012, their prices have dropped by almost 40% due to abundant world supply;
- the gas prices remained stable during 2013 but dropped by almost 15% in H1 2014;
- lastly, carbon allowances stopped their decline of the previous years. In 2013, the EUA price has more than doubled, as a result of the progress of reforms in the EU ETS system such as backloading.

The clean dark spread and the clean spark spread represent the theoretical short-term variable margin of a coal-fired and a gas-fired plant for the generation of a megawatt hour of electricity (see Graph 9). A sustained disconnection of one of these values compared to the other reflects the loss in competitiveness of one of the generation types.

In 2013, the difference between clean dark spread and clean spark spread continued to rise in favour of clean dark spread compared to 2012 due to the considerable drop in the price of coal in 2013 while the price of gas remained stable. This difference narrowed during the first half of 2014, due to the increase in coal prices and the drop in gas prices.

Graph 9: Clean dark & spark spreads



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

Table 17: 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 in France (€/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[38] • β coal emission factor[39]	• p_E Y+1 base price in France (€/MWh) • p_G Y+1 gas price (€/MWh) • p_{CO2} Y+1 CO_2 price (€/MWh) • γ gas yield[40] • δ gas emission factor[41]

2 Evolution of European markets

2.1 Electricity market

2.1.1 Current reflections on renewable energy in Germany

The German Parliament adopted at the start of July 2014 a reform of the law on renewable energy ("EEG"), which entered into force on 1 August 2014. This amendment aims to limit the weight of renewable energy subsidies in the final price paid by the customer, one of the highest in Europe.

The reform aims to reduce and distinguish subsidies depending on the technology. The feed-in tariff went from €170/MWh for all types of renewable energy to €120/MWh on average and encourages the development of the least expensive technologies, particularly onshore wind and photovoltaic energy, set at €90/MWh and €110/MWh respectively. The law also foresees a gradual reduction in the feed-in tariff.

Another amendment brought by the text is the obligation for new installations to sell their electricity on the market[42]. Producers are granted a premium, paid on top of the market price and according to the difference with the feed-in tariff.

This complement is funded through a charge on the energy bill of households and companies. The reform provides for a more and more equitable distribution of the cost of subsidies, limiting its exoneration to electro-intensive companies exposed to international competition and also requesting a contribution for consumption of self-generated electricity.

From 2017 at the latest, the German law provides for tenders to be launched to establish the level of the premium for new installations. The project will be attributed to the most cost-effective offer.

[38] 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.
[39] Based on an assumed emission factor of 0.96 t CO_2 / MWh for coal-fired plants.
[40] Based on an assumed yield of 49% for gas plants.
[41] Based on an assumed emission factor of 0.41 t CO_2 / MWh for gas plants.
[42] For installations with more than 500 KW until 31 December 2015 and 100 KW afterwards, the smallest producers will still be able to benefit from the purchase tariff.

Generation will then be sold in the wholesale markets, with the investor therefore facing any fluctuations in market prices.

2.2 The CO_2 market

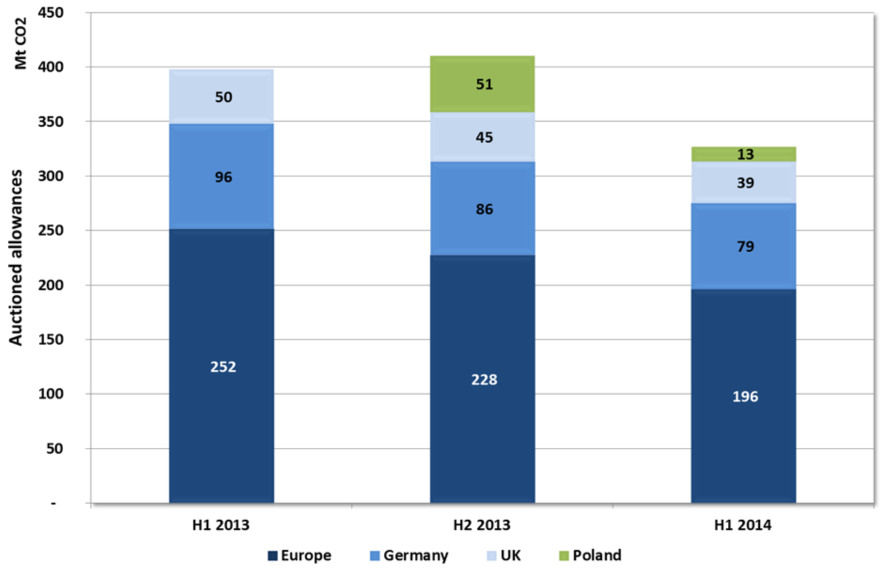
2.2.1 Evolution of the global allowance offer and development of the institutional framework

Allowances auctioned

In 2013, the share of allowances auctioned compared to the total amount of allowances allocated increased significantly within the framework of Phase III. Auctions were held on the EEX and ECX platforms for the European demand and the individual demands of Germany, Great Britain and Poland. Close to 900 M allowances were put up for auction for the year 2013 (roughly 800 M in 2013 plus 90 M allowances put up for auction in advance in 2012), i.e. 48% of overall allowances distributed in 2013. By comparison, the allowances auctioned in 2012 represented less than 3% of allowances distributed.

In the first half of 2014, the share of allowances put up for auction dropped within the framework of the implementation of the backloading measure approved by the European Commission and the European Parliament in 2013 (see Box 1). In fact, roughly 100 M allowances were not put up for auction in the second quarter of 2014 compared to the allowances schedule. In total, 400 M allowances will not be proposed for auctioning in 2014 and will be re-introduced into the market in 2019 and 2020.

Graph 10: Emissions allowances auctioned within the framework of Phase III



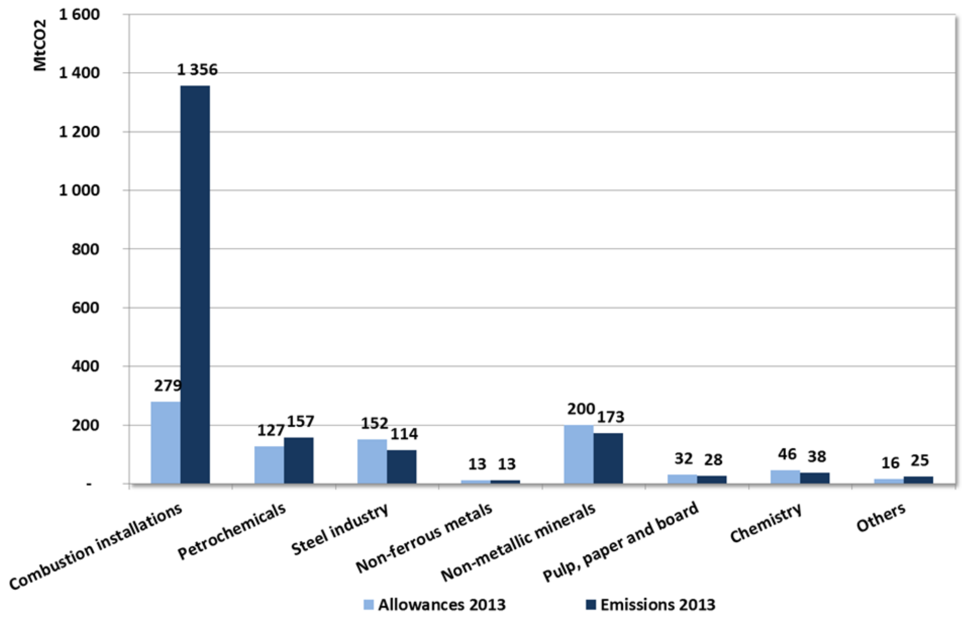
Source: European Commission – Analysis: CRE

Allowances freely allocated

In 2013, the EU ETS allocation scope was extended and now covers new sectors of activity. In addition to the 11 activity sectors concerned in 2012, 14 sectors were added to the list of activities receiving free allowances in 2013. These 25 sectors have been grouped into eight categories of industry for better clarity (see Graph 14).

The combustion sites endured again an allowance deficit as its freely allocated allowances volume decreased significantly within the framework of Phase III. The electricity generation sector has not received free allocations since the start of phase III (with the exception of countries exempted[43]), since these volumes are now distributed directly through auctions. Moreover, the petrochemical industry (refining activities) also has a deficit. Lastly, the aviation sector no longer fall within the scope of EU ETS in 2013 because of the European Commission's "stop-the-clock"[44] measure introduced since 2012 and which defers the obligation for this sector to surrender allowances.

Graph 11: Allocations and actual emissions according to sector type in 2013



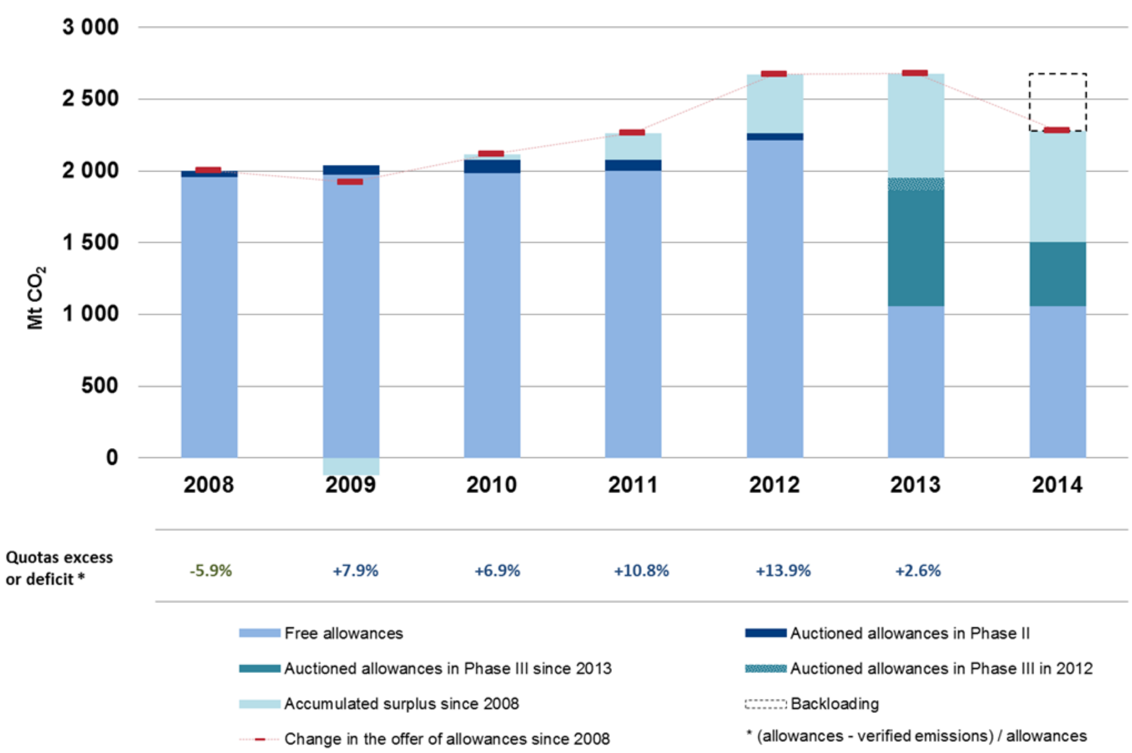
Source: CITL – Analysis: CRE (the 25 activities are classed into 8 sectors)

Global allowance offer and evolution of surplus

In 2014, the allowance surplus stabilised at a level equivalent to that of 2013 (approximately 800 Mt), under the effect of an allowance excess which was not too high for the 2013 compliance cycle (an excess of +2.6%, i.e. approximately 50 Mt) (see Graph 12). This surplus reflects only the difference cumulated between allowances distributed (free allocations plus auctions) and actual EU ETS emissions, without taking into account that a portion of emission rights were surrendered in the form of Kyoto units.

[43] Eight European countries are exempted which enable them to keep a system of free allowances for the electricity generation sector.
[44] See the memo http://europa.eu/rapid/press-release_MEMO-12-854_fr.htm

Graph 12: Accumulation of allowance surplus since 2008



Source: CITL, European Commission – Analysis: CRE (hypotheses for 2014: free allocations in 2014 identical to 2013; number of allowances auctioned in 2014 equivalent to the number of allowances allocated in 2013 and 2012 (phase III) minus 400 M of allowances (backloading))

In this context, structural reforms are currently being discussed and implemented by the European Commission to reduce the allowance surplus accumulated since 2010.

Box 1: Structural reforms of the CO_2 market[45]

The EU ETS market is characterised by a surplus of allowances in circulation estimated at over 2 billion allowances taking into account allowances that may be surrendered in the form of Kyoto units, i.e. the equivalent of one-year compliance. This surplus is partly behind the low price of EUAs, together with prolonged slow industrial production in a context of economic crisis.

Therefore, since 2012, the European Commission has proposed structural reforms to contain the accumulation of the allowance surplus. The main measures are backloading and the market stability reserve.

Backloading measure (during Phase III):

The backloading measure was approved in December 2013 by the European Parliament and Council. This measure aims to postpone the auctioning of 900 M emissions allowances from 2014 and 2016 to 2019 and 2020. Thus, 400 M of allowances must be withdrawn from auctions in 2014, 300 M in 2015 and 200 M in 2016. 300 M allowances must then be re-introduced in 2019 and 600 M in 2020. The implementation of the backloading measure began in the second quarter of 2014 and more than 100 M allowances were then back-loaded[46], i.e. not auctioned.

Proposal to create a market stability reserve (from Phase IV):

The market stability reserve was proposed by the European Commission in January 2014 to respond to the allowance surplus and strengthen the system in the event of a major drop in demand. This measure enables an emission allowance reserve to be created from 2021 based on the level of allowances in circulation.

According to the European Commission's proposal, several cases would arise each year[47]:

- in case the volume of allowances in circulation is higher than 833 M tonnes, 12% of the volume of allowances will be placed in the reserve;

- in case the volume of allowances in circulation is lower than 400 M tonnes, 100 M allowances will be re-introduced into the market;

- between 400 M and 833 M tonnes in the market, there will be no action in the reserve.

The goal is thus to reduce the surplus of allowances in circulation and improve the carbon market's resilience to major shocks.

The market stability reserve proposal is currently being discussed among stakeholders and an institutional vote is scheduled for early 2015.

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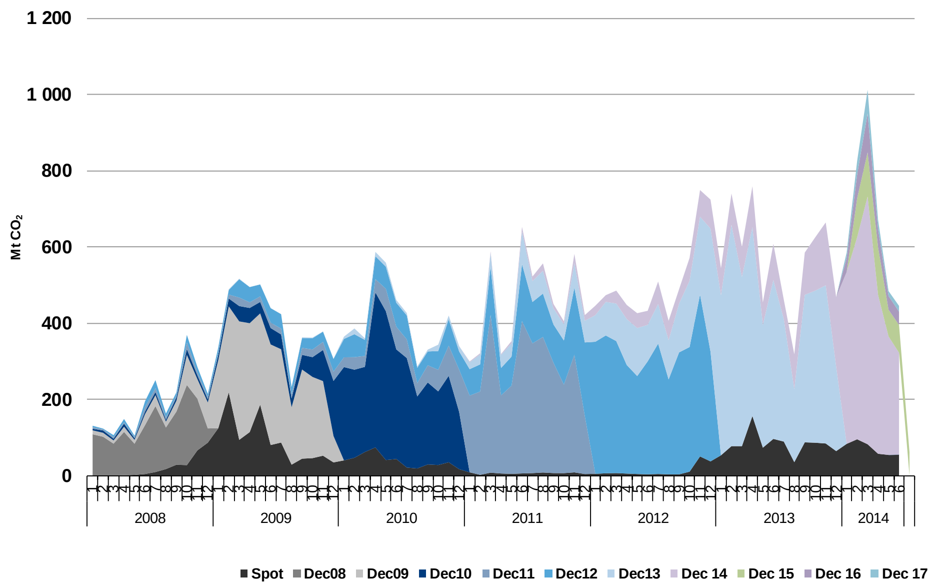
[45] For more information, see http://ec.europa.eu/clima/policies/ets/reform/index_en.htm

[46] See calendars on the EEX website http://www.eex.com/blob/68856/bac06c090e3659f3b066f12ce39fbdc2/2014-auction-calendar-pdf-data.pdf and the ECX website https://www.theice.com/emissionsauctions.jhtml

[47] See the link http://eur-lex.europa.eu/legal-content/FR/TXT/PDF/?uri=CELEX:52014PC0020&from=EN

From November 2012, there was an increase in trades in the EUA spot market, in connection with the successive institutional announcements made by the European Commission. In 2013, approximately 1 bn tonnes of CO_2 were traded in the EUA spot market, compared to 135 M tonnes in 2012. In the first half of 2014, roughly 400 M tonnes were traded in the spot market.

Graph 13: Evolution of EUA trades per maturity



Source: Bluenext (until 5 December 2012), ECX, EEX

2.3 The gas market

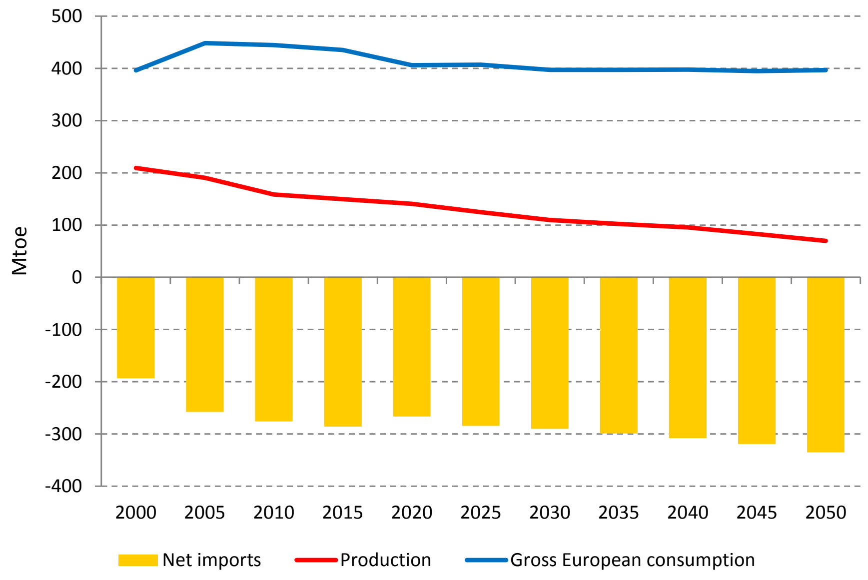
2.3.1 Drop in gas production in Europe

Gas production in the European Union continued to decrease in 2013. This trend is due to the maturity of European gas fields (by way of example, 2013 marked the end of the commercial operation of the Lacq gas field in France). The Dutch government[48] even defined a downward trajectory for the production of its giant onshore Groningue gas field, both to manage the declining reserves, but also to reduce seismic activity around the field and promote the operation of smaller fields.

If the effects of this drop in production have not yet been felt, it is because demand in Europe has dropped since the start of the economic crisis. The European Union projects a declining trajectory for natural gas consumption until 2050[49]. Nevertheless, since the drop in gas quantities produced in the European Union will be much higher (Graph 14), the European Union will, by that time, be more dependent on its imports, particularly those from Russia, if no other supply sources are found.

[48] The Netherlands is the leading natural gas producer in the European Union and represents about half of EU production.
[49] Source: EU Energy, Transport and GHG Emissions Trends to 2050 report, European Commission

Graph 14: Projection of the supply/demand balance of natural gas in the European Union



Source: EU Energy, Transport, and GHG Emissions Trends to 2050 – Analysis: CRE

2.3.2 The Ukrainian crisis

The recent political tension in Ukraine creates concerns regarding the security of gas supply in Europe.

Box 2: markets' reaction to events in Ukraine

The political situation in Ukraine raises concerns regarding the emergence of a new gas crisis affecting Russian flows towards Europe[50]. Despite these tensions, no country has declared any potential risks to its short-term supply, thanks in part to low consumption and high stock levels in the first half of 2014[51]. In the wholesale gas markets in Europe, the situation in Ukraine has had only a small effect on spot prices which saw a major downward trend throughout the first half of 2014 due to a comfortable level of supplies (see section 2.1). Inversely, this situation had some impacts on the future market, where prices of 2014/2015 winter contracts only decreased slightly, causing a considerable widening of the summer/winter spread (Graph 15) and encouraging European market participants to build greater stocks[52]. Futures prices reacted to events such as the announcement by different press sources of Russian troops advancing in Crimea in the beginning of March and new conflicts early April in Eastern Ukraine.

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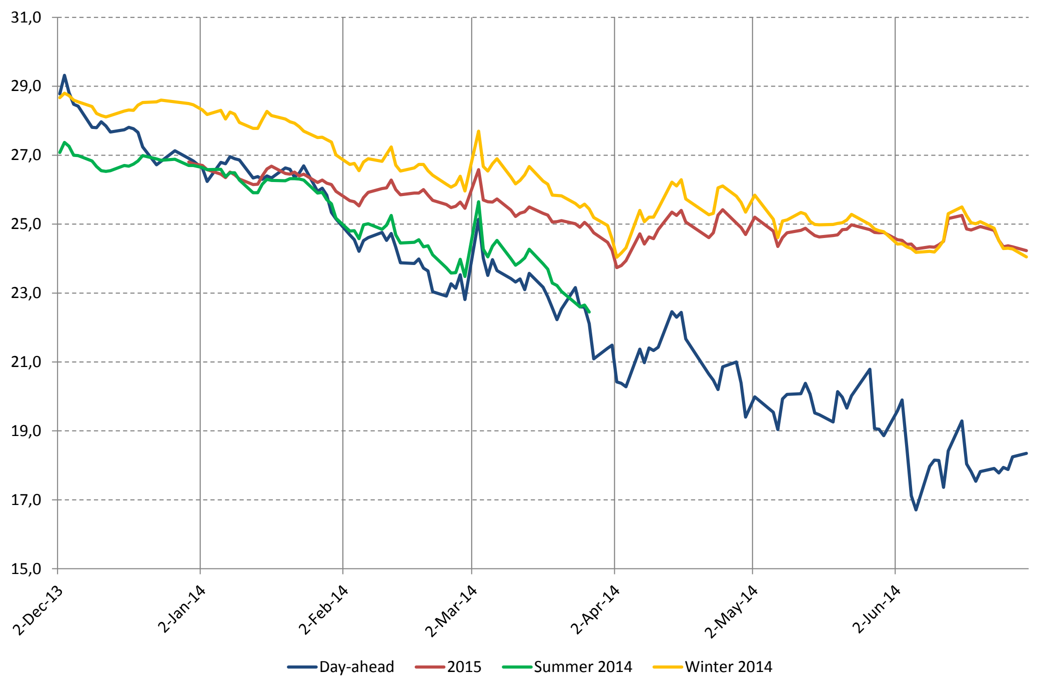
[50] According to IEA, in 2013 Europe depended on Russian gas for 30% of its consumption. Almost half of this gas was shipped via Ukraine. During the last gas conflicts of 2006 and 2009, Gazprom had suspended flows to Ukraine, heavily affecting supply to the rest of Europe.
[51] According to Gas Infrastructure Europe figures, the level of European stocks was around 69% at the end of June 2014.
[52] According to Gas Infrastructure Europe figures, the level of European stocks was around 90% at the end of June 2014.

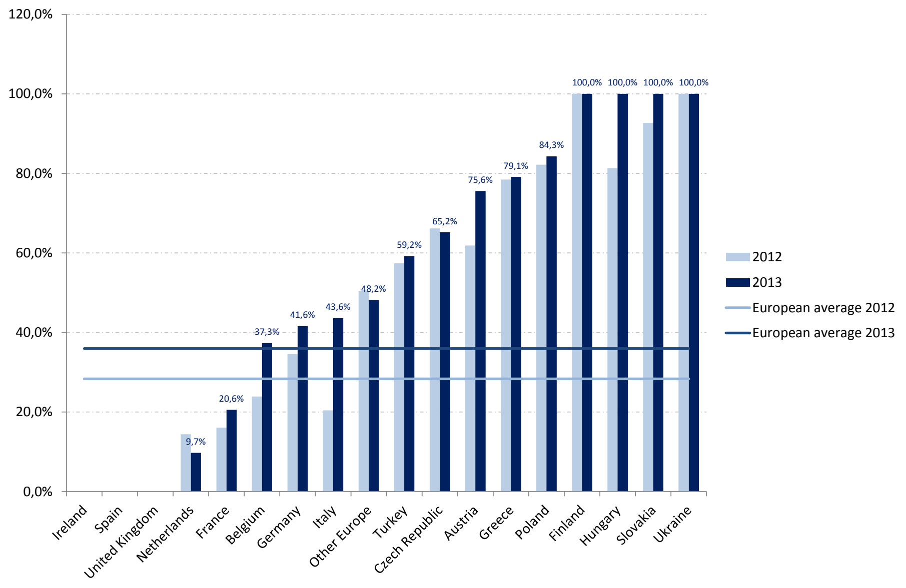
Graph 15: Difference between spot prices and futures prices at PEG Nord in the first half of 2014



Source: Powernext – Analysis: CRE

A possible drop in Russian exports via Ukraine would have contrasting impacts on the supply of European countries. Since the last conflicts, Europe reduced its dependence on the Ukrainian route (67% of Russian gas to Europe could circumvent it), thanks in particular to the new North Stream pipeline directly connecting Russia and Germany via the Baltic Sea. Moreover, the development of new infrastructure, particularly for LNG, has strengthened the security of supply in Europe. However, Russian gas remains predominant in certain EU countries (Graph 16): in 2013, its share stood at 42% of supplies in Germany and over 80% in countries in the east of the EU. In comparison, it only represented 21% of supplies in France. Therefore, substitution in the event of a cut of a major part of Russian gas in certain countries appears to be difficult (especially in Eastern Europe).

Graph 16: Dependency of European countries on Russian gas (2012/2013)



Source: BP Statistical review 2013 and 204

While Europe reduced its dependency on the Ukraine route following the previous crises, the share of Russian gas in its supply continues to increase mainly as a result of a drop in British and Dutch production, stagnating Norwegian flows and tightness in the LNG markets. Inversely, Europe is the main market for Russian gas. This interdependency plays a major role on a geopolitical level, which, in the future, could encourage Europe to continue to diversify its supplies, and Russia to find new buyers.

These new risks concerning Russian gas highlight the importance of better market integration and security of supply policies within the European Union.

SECTION III: WHOLESALE ELECTRICITY MARKETS

Activity in the wholesale electricity markets is mostly related to the optimisation, by producers, of the flexibility of their generation means, trading operations, cross-border trades and hedging by market participants of their forecast consumption in order to meet their clients' needs.

In 2013, electricity generation in France increased by 2% reaching 551 TWh in a context of stable nuclear generation, major increase in hydropower generation (+19%, i.e. +11.9 TWh) due to heavy rainfall, and an 8% increase (i.e. +2.0 TWh) in renewable energy generation which offset the drop in the generation from fossil fuels (-7%, i.e. -3.2 TWh). In the first half of 2014, for the first time, renewable energy generation was higher than fossil fuel generation.

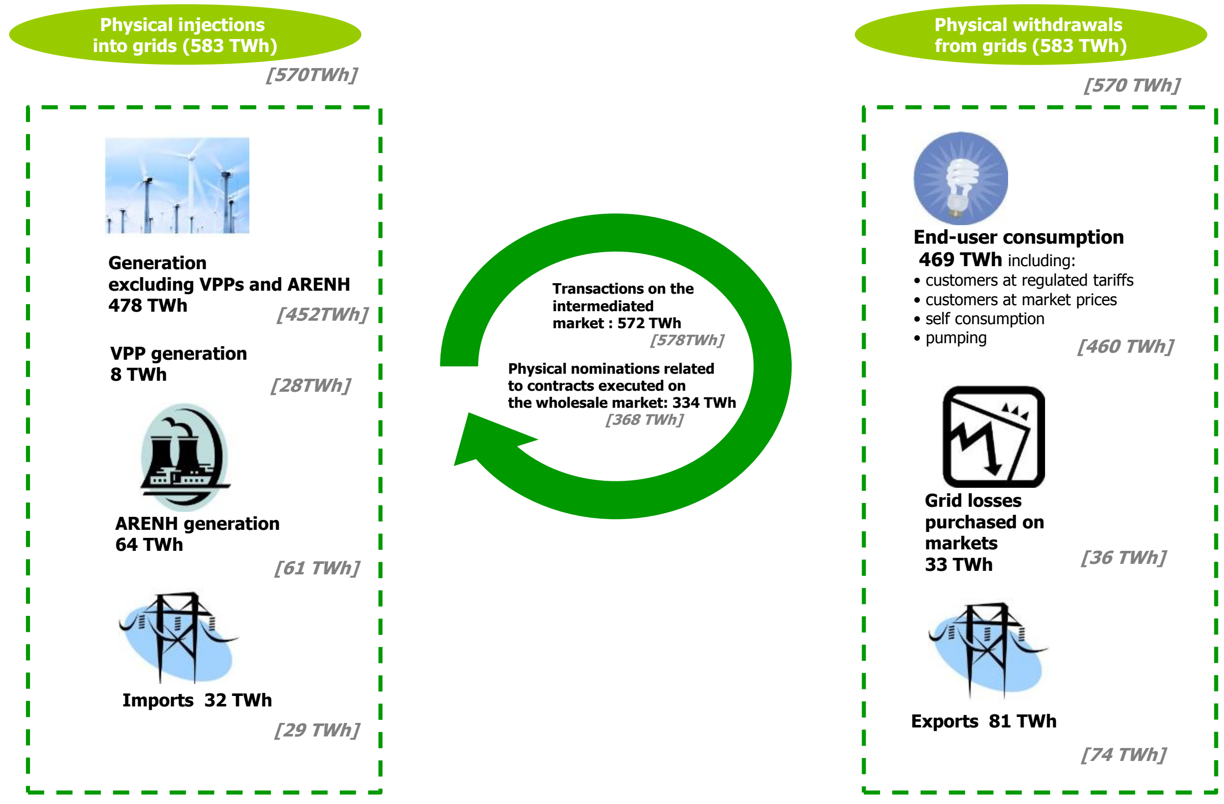
Consumption in France in 2013 stabilised at 462 TWh (consumption of end clients excluding consumption for pumping and system losses).

France's net exports in 2013 dropped by 1% compared to 2012, in connection with a cold and long winter and a cold end of autumn, counterbalanced by very large exports in summer because of a high rate of nuclear and hydropower generation.

1 The fundamentals of electricity generation

1.1 Increase in injections and withdrawals in the electricity system in 2013

Graph 17: Review of injections and withdrawals in the electricity system in 2013 [2012]



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

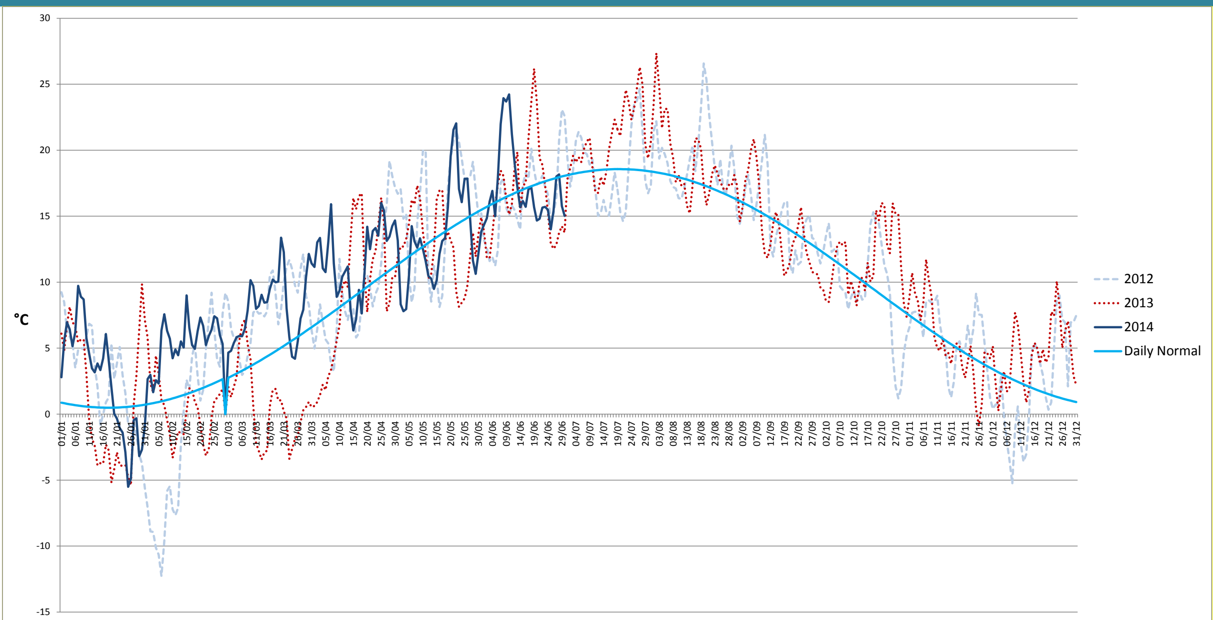
Consumption in France in 2013 stood at 462 TWh (excluding consumption for pumping and system losses), i.e. an increase of 8 TWh compared to 2012. This increase is mainly due to an increase in consumption in the first half of 2013 because of a very cold winter. Electricity flows saw an increase in exports bolstered by improved availability of nuclear generation, as well as an increase in imports due to cold winter temperatures which continued for a good portion of the first half of 2013.

Trades in the intermediated wholesale markets totalled 572 TWh, down slightly (-1%) compared to 2012. This drop affected brokers in particular (-2%), while volumes traded in the exchanges increased (+4%).

Physical deliveries between participants, following contracts signed over the counter in the wholesale markets (intermediated and bilateral), represented 334 TWh during the same year, down by 9% compared to 2012. This drop affected brokers in particular (-11%). Graph 17 presents a simplified version of these different flows for 2013 and 2012 (figures between square brackets). Holders of ARENH rights requested higher volumes from EDF in 2013, while generation within the framework of the virtual power plant (VPP) mechanism[53], for which auctions were terminated in 2012, decreased considerably.

1.2 High consumption in the first half of 2013 against a long, cold winter

Graph 18: Temperatures over the last four years compared to reference temperatures



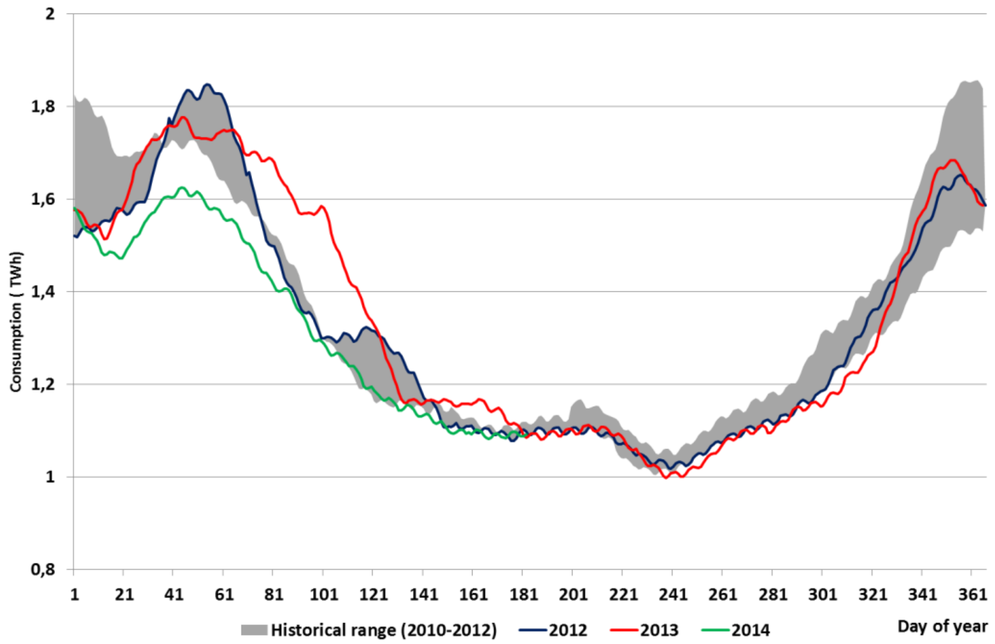
Sources: Reuters

The year 2013 saw a particularly long, cold winter, even though it was not marked by an exceptionally cold period as in 2012. Temperatures in 2013 were on average lower by 0.8°C than reference temperatures, particularly during the first four months of the year. Inversely, the first half of 2014 was particularly warm, especially during winter, with an average temperature 1.4°C higher than the reference average.

[53] EDF offered access to 5,400MW of production capacity located in France following its acquisition of a stake in the German electricity company EnBW in 2001. The mechanism was stopped in 2012, following the sale by EDF of its share in EnBW.

Rainfall in 2013 was 10% higher than the reference annual average. It was particularly rainy in spring 2013. In the first half of 2014, rainfall was lower than normal, with, a 20% deficit in spring 2014.

Graph 19: Consumption in France (2010-2014)

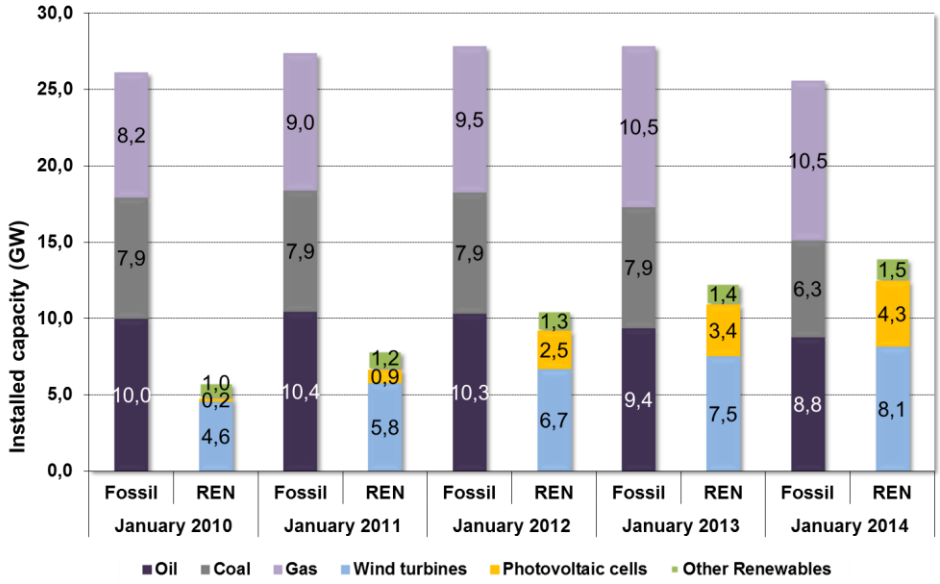


Source: RTE – Analysis: CRE

In 2013, French consumption stabilised at 462 TWh excluding pumping and losses. In the first half of 2013, consumption was high for more than two months. In 2012, consumption had reached higher peaks but over a shorter period. In the first half of 2014, consumption reached historically low levels against the mild winter (see Graph 19).

1.3 Transitioning French generating fleet

Graph 20: Installed capacity in France – comparison between fossil fuel-fired technology and renewable technology (REN) (2010-2014)



Source: RTE – Analysis: CRE

As at 1 January 2014, installed capacity in France stood at 128.1 GW according to RTE, i.e. a drop (of less than 1%) in the installed capacity over the course of the year. But this limited decrease in fact conceals two significant transformations in French electricity generation:

- installed capacity of fossil energy dropped by 8% in 2013, with a 20% decrease for coal power alone, and 6% for fuel. This drop occurred with the context of the shutdown of fuel and coal power plants that were not adapted to the new European environmental rules.
- renewable energy, supported by environmental policies and within a context of energy transition, saw its installed capacity increase by 13%, with, first and foremost, photovoltaic energy up 23%, followed by wind power (+9%) and renewable thermal energy[54] (+6%) (see Graph 20).

Nuclear power represents 49% of this installed capacity, while hydropower and fossil energy each represents 20% of installed capacity. Renewable energy now accounts for 11% of installed capacity in France (see Table 4).

Reference generating facilities[55] connected to the transmission network accounted for 104.4 GW of installed capacity as at 1 January 2014, i.e. a drop of 1% compared to 1st January 2013. Nuclear power represented 60% of this generating capacity with 63.1 GW of installed capacity, and hydropower 23%, with 24.2 GW of installed capacity. Hydropower breaks down into two types of generation: "dam" type generation which depends on the level of hydro stocks available upstream of

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[54] Power using renewable energy (household waste, paper waste, biomass and biogas).

[55] The reference generating capacity is made up of all of the production units with capacity exceeding 20 MW, for which hourly metering data is accessible at D+1 for D, under reasonable economic conditions, located in metropolitan France and belonging to the previously mentioned sectors and producers.

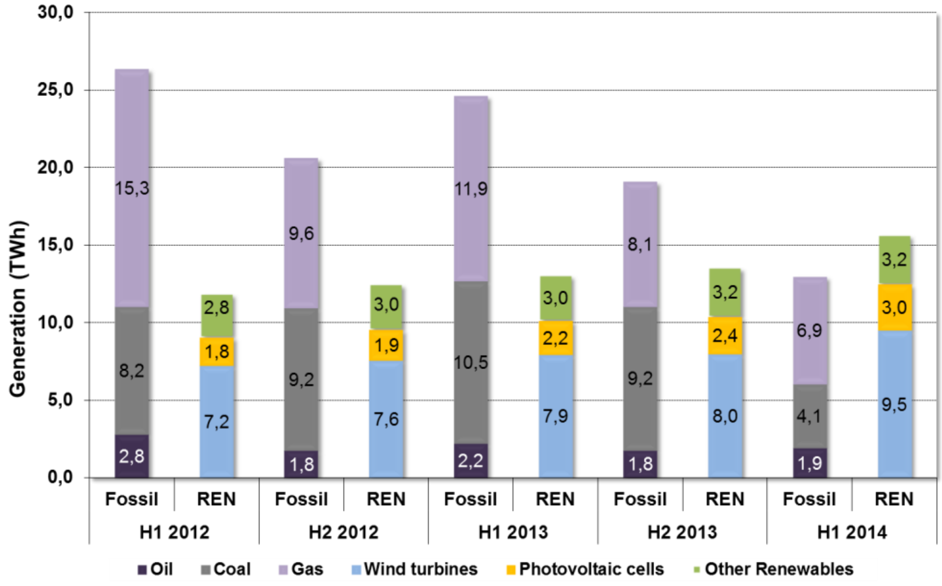
French dams and which represents 57% of hydro capacity in France, and the run-of-the-river type generation which depends on the run-off of the French rivers used. Coal and gas represented 10% of reference installed generating capacity. Fuel accounted for 7% (see Table 4).

Among the main electricity producers in France[56], EDF has more than 96 GW of installed capacity, i.e. roughly 91% of the installed capacity of the reference generating facilities. The other two significant producers are:

- GDF-Suez, which, through its subsidiaries CNR and SHEM, active in generation and involved in nuclear generation, operate roughly 5.4% of installed capacity;
- E.On France (SNET, E.On group), which holds 2.9% of installed capacity.

These three producers operate a total of almost 99% of the installed capacity of the reference generating fleet.

Graph 21: Generation in France – comparison between fossil fuel-fired technology and renewable technology (2012-2014)



Source: RTE – Analysis: CRE

In 2013, electricity generation in France reached 551 TWh, i.e. a 2% increase compared to 2012. Moreover, generation in the first half of 2014 was 4% lower than generation in the first half of 2013, against a mild winter.

Hydropower increased 19% in 2013 compared to 2012, due to heavy rainfall during the year. Renewable energy produced 26.8 TWh, i.e. an 8% increase compared to 2012, driven mainly by photovoltaic energy (+15%). Thermal energy recorded a drop in gas-fired generation (-16%) and fuel-fired generation (-18%), and a 9% increase in coal-fired generation. These trends are directly related

[56] RTE data as at 1 January 2013

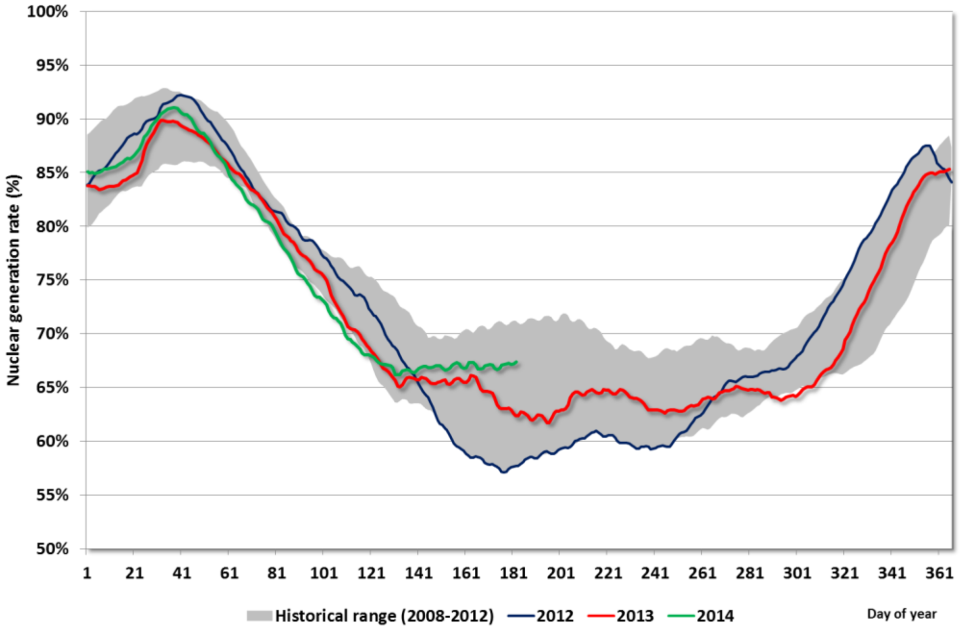
to fuel prices, with, in particular, the price of coal down sharply since the boom of shale gas in the USA which eased American demand for world coal stocks, thus freeing up supply in Europe (see Table 5).

A highlight of the first half of 2014 was fossil-fired generation (13 TWh) being lower than renewable energy generation (15.7 TWh). The very mild winter in fact disrupted seasonal trends which are usually accompanied by major peak/semi-baseload generation to cover large consumption peaks during winter in France. (see Graph 21).

1.4 Good availability of generation means (reference generating capacity)

Characterised by a significant seasonality, the production rate of nuclear power stabilised in 2013 compared to 2012 at 72% (see Graph 22). It can however be noted that the generation rate in 2013 was lower during the first and last quarter compared to 2012, particularly in connection with lower availability of nuclear power (see Graph 22). However, the availability rate and the generation rate of nuclear power during summer 2013 were in the middle of their historical range, as opposed to summer 2012 which had been characterised by very low availability of nuclear power due to the prolongation of numerous unit outages.

Graph 22: Rate of nuclear generation (2008-2014)

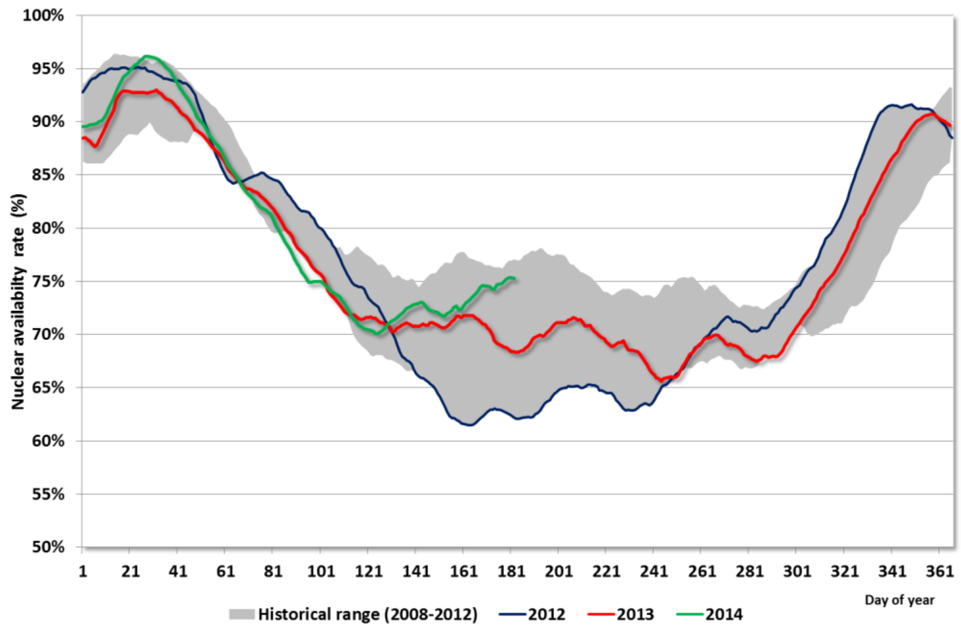


Source: RTE – Analysis: CRE (rolling average over 30 days)

Availability of nuclear generating capacity in the first half of 2014 was high, ensuring a good rate of generation. Afterwards it declined, and then went back up considerably from the month of May reaching the top of the historical range at the end of June 2014. Therefore the generation rate over this period was also higher.

In 2014, the EDF group declared having "optimised the maintenance volume" and modified its work organisation to ensure better management of nuclear unit outages, which occur mainly during summer.

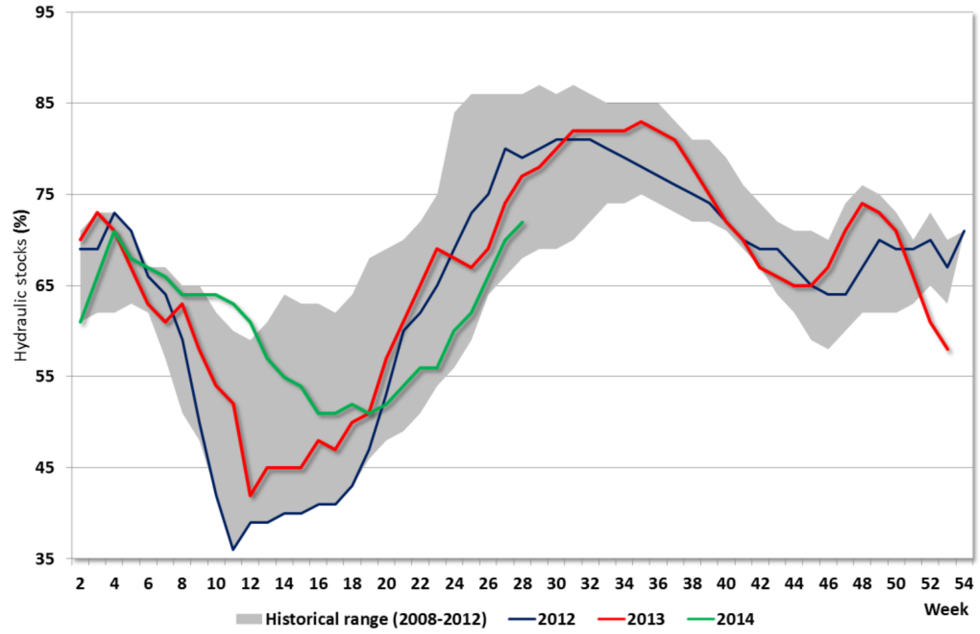
Graph 23: Rate of nuclear availability (2008-2014)



Source: RTE – Analysis: CRE (rolling average over 30 days)

The level of hydro stocks in RTE's reference generating facilities was higher in 2013 than in 2012, at 66.2% compared to 64.7%. Winter 2012/2013, less cold than in 2011/2012, saw hydro stocks to be less required just before spring. Stocks were particularly high at the end of summer 2013 following a rather rainy spring. The last quarter of 2013 was marked by colder temperatures, which used up hydro stocks to a large extent, driving them down to a historically low level at the end of December. However, the mildness of the climate during the first quarter of 2014 led to a comfortable level of hydro stocks to be maintained during the winter period. At the end of June 2014, the level of hydro stocks was at the lower end of the historical range following a late refill of stocks in spring (see Graph 24).

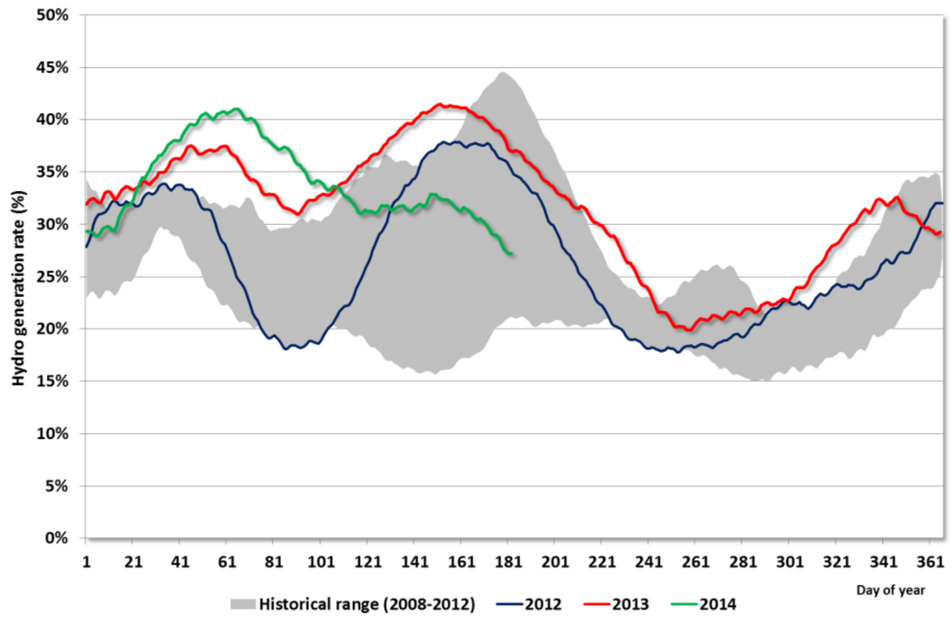
Graph 24: Level of hydro stocks in France (2008-2014)



Source: RTE – Analysis: CRE (rolling average over 30 days)

The rate of hydro power generation was higher in 2013 than in 2012 standing at 32% compared to 27%. The rate of generation was particularly high in the first half of 2013, in a context of heavy rainfall in the spring as in the first half of 2014 (Graph 25).

Graph 25: Rate of hydropower generation (2008-2014)

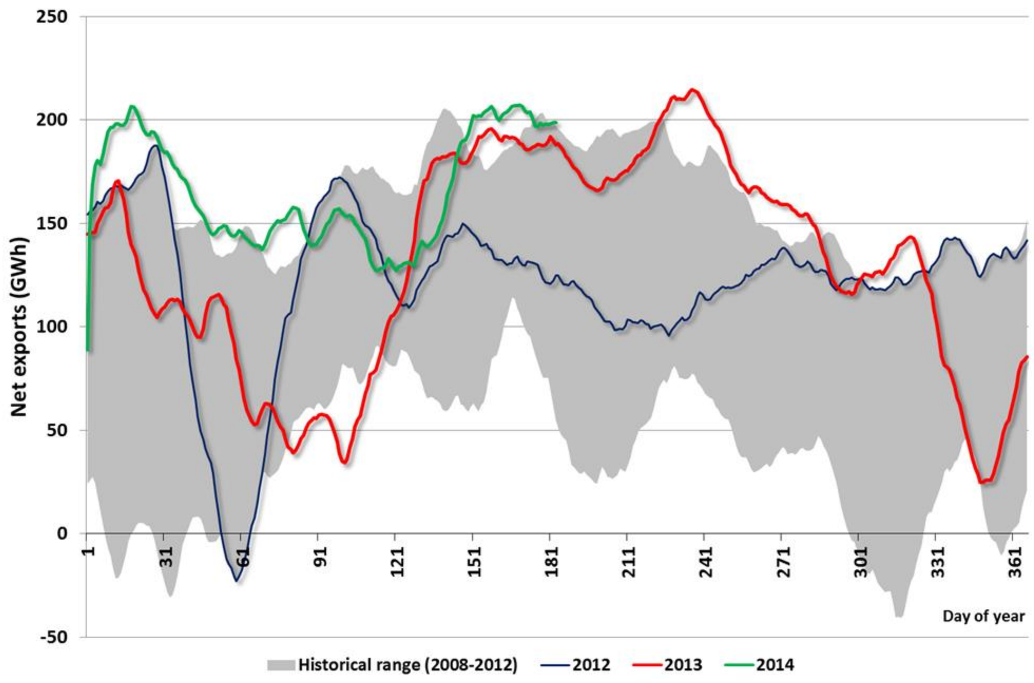


Source: RTE – Analysis: CRE (rolling average over 30 days)

1.5 Net exports strongly linked to meteorology

French net exports in 2013 dropped less than 1% compared to 2012, mainly during off-peak hours. Net exports reached 43.9 TWh in 2013.

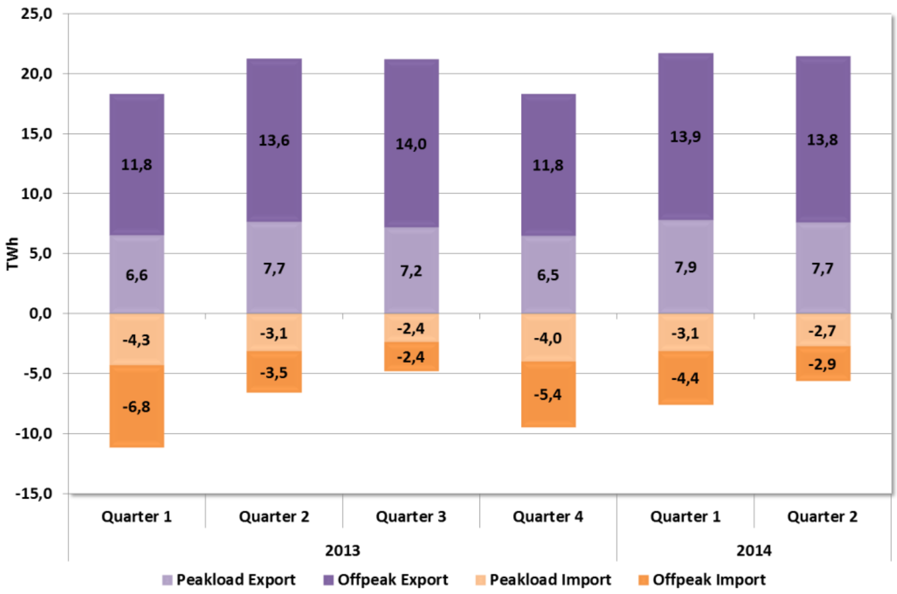
Graph 26: Net exports in France (2008-2014)



Source: RTE – Analysis: CRE

Net exports in 2013 were particularly high during summer, in connection with high nuclear and hydropower generation rates. In the first half of 2014, net exports were very high. On several occasions, it reached historically high levels in the context of a very mild winter, with major hydropower, nuclear and renewable energy generation (see Graph 26).

Graph 27: Imports/Exports in France (2013-2014)



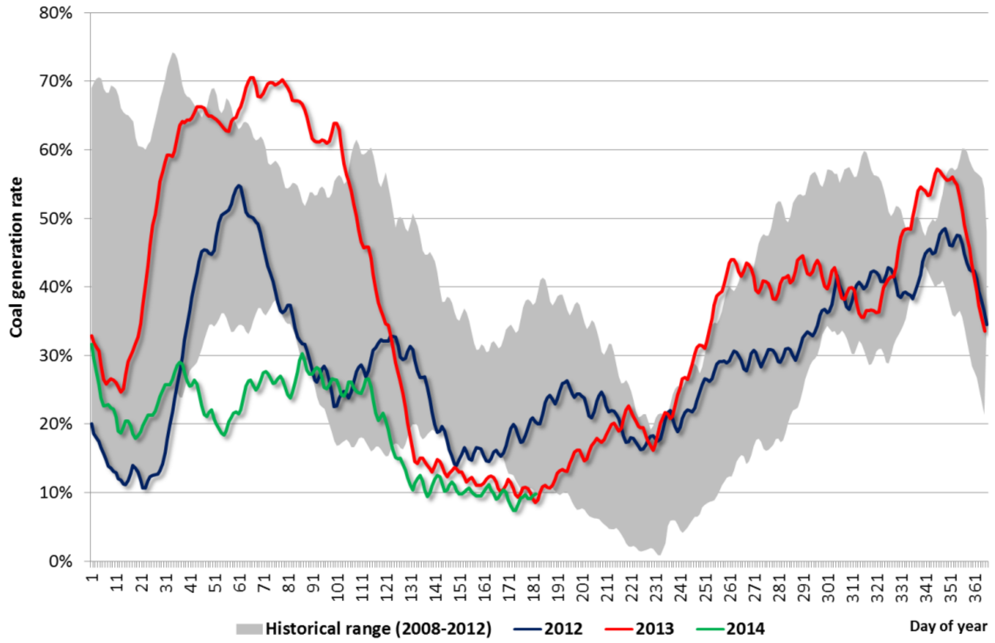
Source: RTE – Analysis: CRE

A highlight in the first quarter of 2014, off-peak and peak exports were higher than in 2013, disrupting the seasonal trends usually observed (see Graph 27).

1.6 Reduced use of fossil thermal energy

In 2013, the generation rate of coal power was 9 points higher than the rate observed in 2012, against a cold winter and particularly low generation of gas and fuel power. Coal-fired generation increased considerably in the first quarter of 2013 during the cold and long winter, as well as in the fourth quarter of 2013 following the drop in temperatures. However, the meteorological context of the first half of 2014 did not enable coal power to operate within its historical range, with a 21-point drop compared to the first half of 2013. During most of that period, generation was below its historical minimum (see Graph 28).

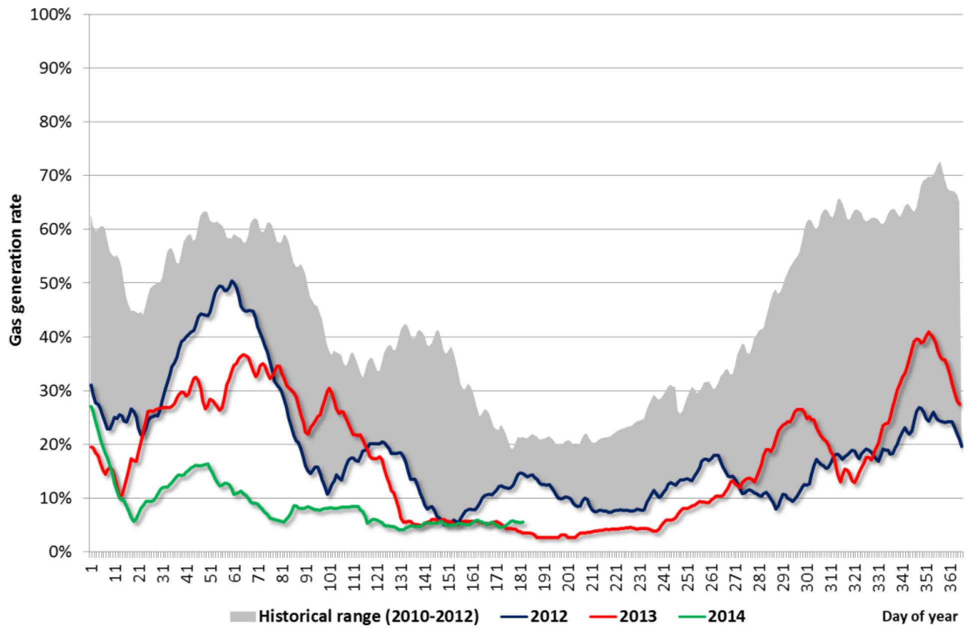
Graph 28: Generation rate of coal-fired power (2008-2014)



Source: RTE – Analysis: CRE (rolling average over 30 days)

The generation rate of gas-fired power was lower than in 2012, with a 2-point drop. Since winter 2012/2013 did not see any exceptional cold wave, gas power was less-used than the previous year. It however was used more in the fourth quarter of 2013 during the cold period at the start of winter 2013/2014. As for coal power, the meteorological context of the first half of 2014 did not enable gas generation to stay within in its historical range (see Graph 29).

Graph 29: Generation rate of gas-fired power (2010-2014)

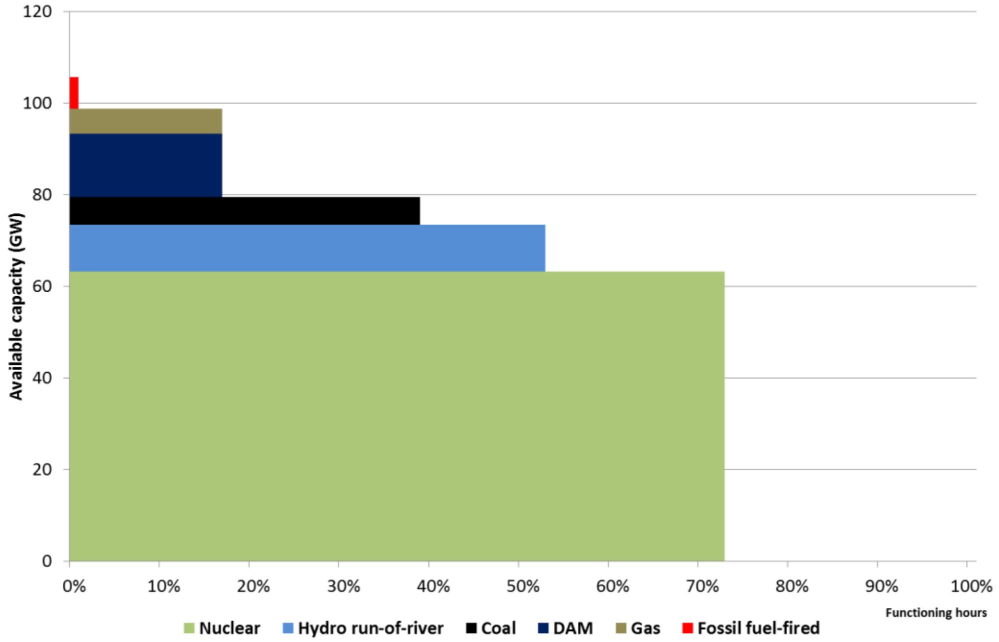


Source: RTE – Analysis: CRE (rolling average over 30 days)

1.7 Rate of use of French reference generating capacity

Analysis of the rates of use of RTE's reference generating capacity in France provides a view of the use of the different generating systems over the course of a given period. The graph represents the rate of use of each type of generating system, i.e. the ratio between the number of hours of use and the installed capacity of each system over the course of the year. The accumulated total of each of these systems, by descending order of rate of use, shows the proportion of time in the year during which a certain level of power is demanded by the electricity system. The highest durations of use therefore correspond to the systems with the lowest marginal costs, non-programmable generation such as run-of-the-river hydropower excluded.

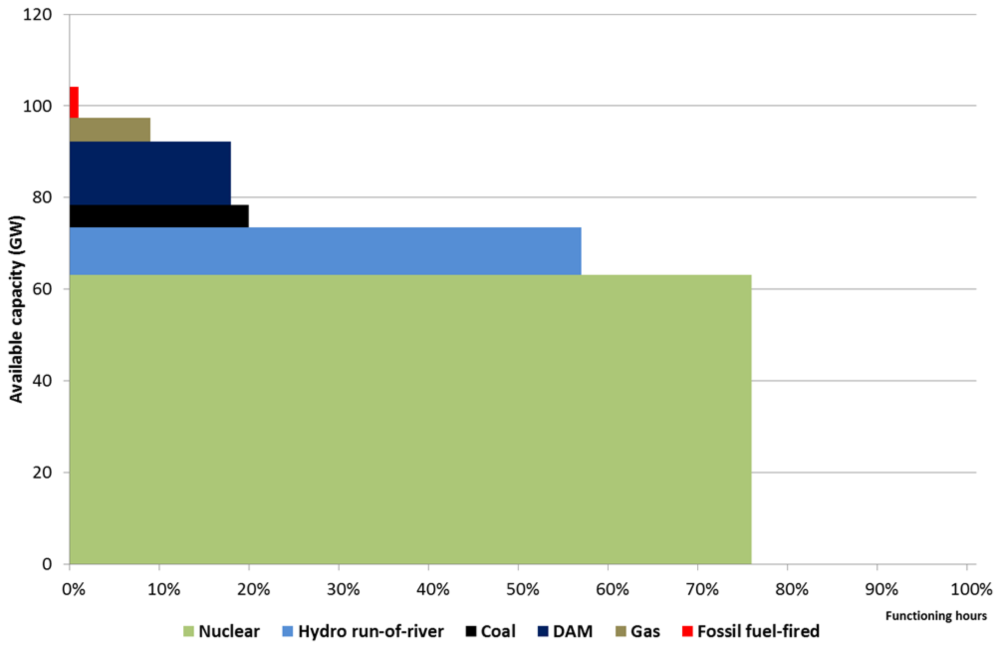
Graph 30: Rate of use of reference generating capacity in 2013



Source: RTE (reference generating capacity) – Analysis: CRE

In 2013, the rate of use of run-of-the-river hydropower increased by 11 points compared to 2012, thus standing at a 52% rate of use compared to 41% in 2012. The rate of use of coal power increased 9 points in 2013 to reach 38%. The use rate of gas however, was down by 2 points. There was little change in the use rate of the other systems (see Graph 30).

Graph 31: Rate of use of reference generating capacity in H1 2014



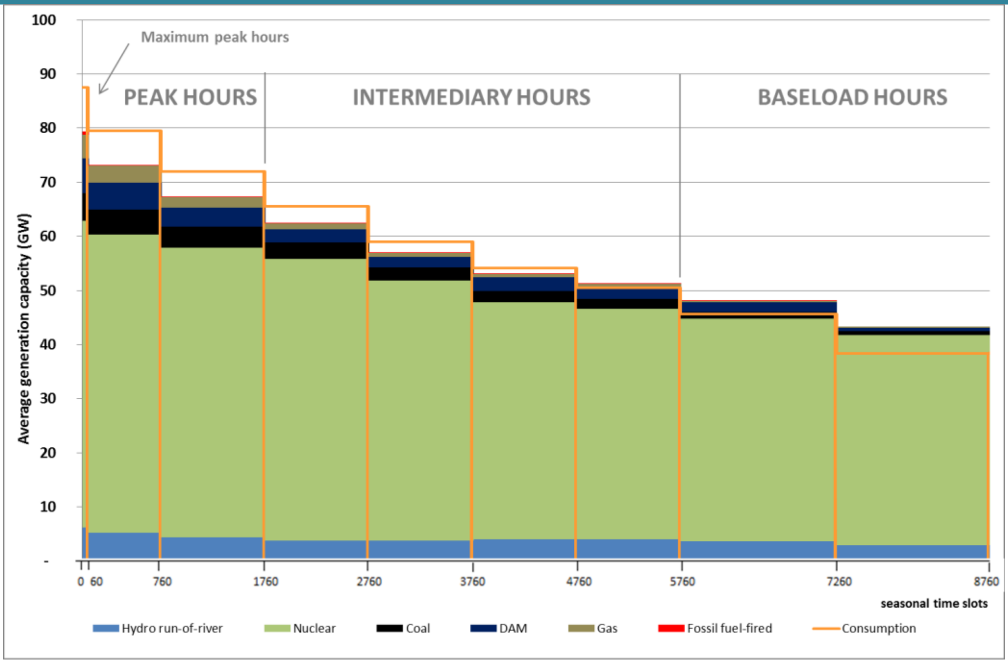
Source: RTE (reference generating capacity) – Analysis: CRE

In the first half of 2014, the rate of use of coal power and gas power dropped considerably: the use rate of coal power dropped 21 points reaching 19%, and the use rate of gas power dropped by 11 points to 8%. This is related to the meteorological context of the first quarter of 2014, but also continued in the second quarter which confirmed a real decline in gas and coal power in France (see Graph 31).

1.8 Load duration of reference generating capacity in France

Graph 32 shows the load duration curve of the French installed reference generating capacity and also facilitates viewing of the total hourly power used (in MW) in the French electricity system for the 8,760 hours of a year.

Graph 32: Load duration curve of reference generating capacity in France in 2013



Source: RTE (reference generating capacity), Union Française de l'Electricité – Analysis: CRE

It breaks down as follows:

- Nine time/seasonality portions are defined to simulate the annual functioning of the electricity system;
- Consumption of French clients, excluding exports, for each hour of the year is classed from the highest to the lowest. The average of this consumption is posted for each hourly portion. This is called load duration;
- Over this load duration is the corresponding total generation power of the French generating systems;
- For each of the time/seasonality portions, the average generation of each of the reference generating systems[57] is calculated and stacked by ascending order of the generation cost of the systems used. The more the power demanded increases, the less amount of time it is used.

It is therefore possible to observe on this graph, both the capacity of the French electricity system to meet customers' demand, by excluding flows at borders and renewable energy, and the distribution of the different generation systems used for each of the 8,760 hours of the year. When consumption is lower than the power demanded, this offers a margin to the French electricity system, and thus potentially leads to exports. Inversely, when consumption is higher than generation, then the French electricity system must call on imports to meet all demands, once the contribution of renewable energy is taken into account.

[57] The production of wind energy, photovoltaic and renewable thermal energy is not shown on this graph, because it is not part of reference generation capacity.

French electricity generation is characterised by a historical asymmetry, with large generation means for the 3,000 baseload hours (nuclear, run-of-the-river) and semi-baseload (nuclear, dam type hydropower, coal), but a deficit in generation capacity during peak periods, accentuated during the few hours when there are extreme consumption peaks.

In 2013, French nuclear generation enabled exports during baseload hours with a good availability of nuclear power particularly in summer. The French electricity system strayed from the load duration curve during the 2,800 hours with the highest demand of the year, requiring foreign supply. Imports can be used because they are less expensive than starting up a means of generation in the territory (hydropower, coal or gas plant, see Graph 33) but also and especially because generating capacity can no longer physically meet demands (see Graph 32).

1.9 Marginality of the different generation systems

A generation system is referred to as "marginal" if the marginal cost of its generation determines the market price, i.e. if the hourly price resulting from daily auctions corresponds to the marginal cost of a unit belonging to that generation system.

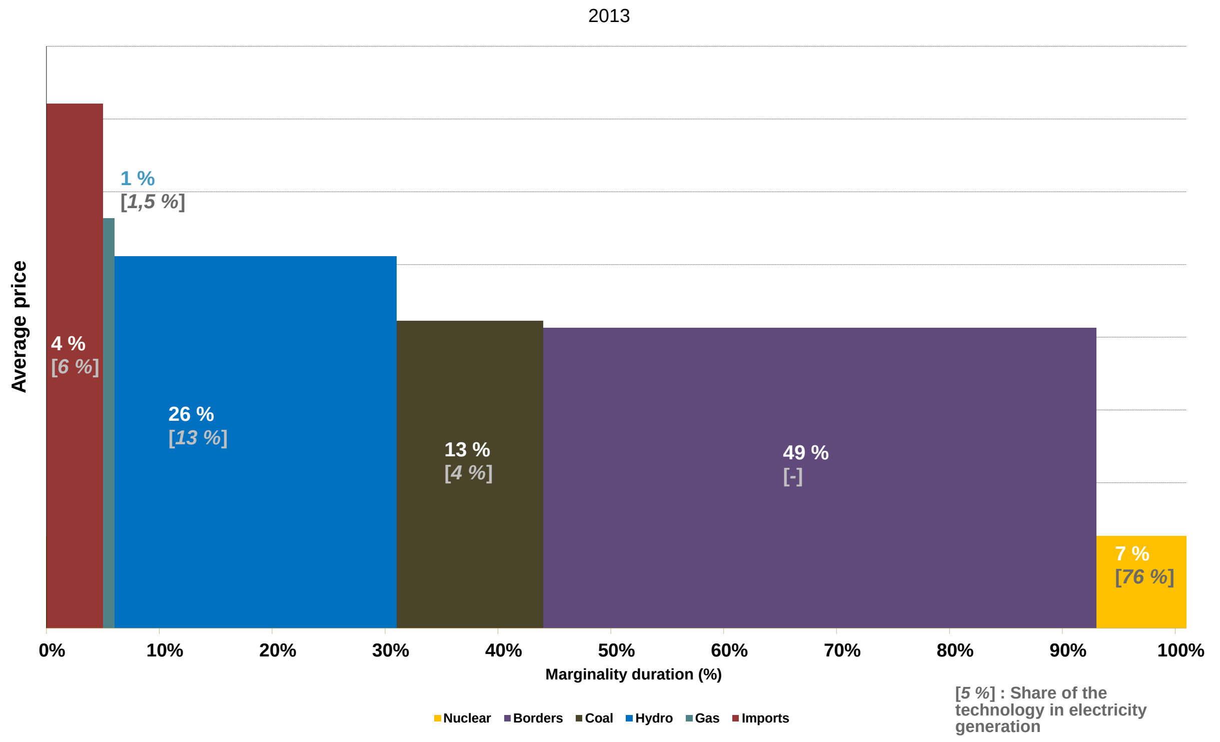
The analysis presented here adopts both a price criterion and a power criterion to determine the unit and therefore the marginal system at a given time:

- the price criterion selects the plants for which the difference between the market price and generation cost is less than €1/MWh;
- the power criterion retains only units whose generation is comprised between 15% and 85% of maximum theoretical capacity.

Among all the units meeting these two criteria, the unit whose generation cost is closest to the market price is considered marginal. If however, no unit meets the criteria, then it is considered that the price levels are determined by foreign supply. A difference is then made between the situation in which France is importing from all neighbouring countries, the corresponding hours are then counted in the category "Imports", and the situation in which France is both importing and exporting from neighbouring countries, the corresponding hours are then counted in the category "Borders".

The results depend largely on the calculation method adopted and the thresholds used. It should also be specified that the reference generating capacity considered for the analysis does not take into account plants whose installed capacity is less than 20 MW, i.e. 50% of gas power plants and 20% of fuel power plants.

Graph 33: Marginality duration of the various generation technologies in 2013



Source: CRE – Analysis: CRE

The analysis of marginality duration of the various generation technologies in 2013, summarised in Graph 33, highlights:

- A short marginality duration of gas generation, in connection with a low time of use of gas plants (only 35% of hours of the year compared to 85% for coal);
- High level of marginality of hydropower generation, whose average price is determined based on the value in use of water, corresponding to a value of substitution of thermal generation over time and therefore linked to the marginal cost of this generation type;
- Borders marginality duration still high with an average price level close to that of coal: French prices continued to be determined by coal plants located in neighbouring countries.

1.10 Frequency and quality of information transmitted improved by the transparency mechanism

Since November 2006, the *Union Française de l'Electricité* (UFE) has participated in ensuring transparency of the electricity market by publishing in partnership with RTE a portion of the data relating to electricity generation in France. This mechanism, based on the collection of information from members of UFE, covers almost 90% of French generation and concerns units with over 20 MW of nominal power. These publications enable all market participants to more precisely assess supply emanating from producers gathered within UFE and actively contributes to the transparency of the French electricity market.

An improvement was made in March 2013 with the increase in the frequency of updates of the forecast availability of generating capacity. The data on forecast available power of generating capacity is now updated every day (and not each week) for the medium term (between 2 and 13 weeks to come), and each week (instead of each month) for the long term (between 14 weeks and 3 years to come). In particular, this improvement in the frequency of publication of the availability of generating capacity in the medium term applies to aggregated information for each generation type (nuclear, coal, gas, fuel, hydropower) as well as the generation units with over 100 MW of power. This increase in the frequency of publication aims to improve the accuracy of information transmitted.

Forecast rate significantly improved

Table 18: Forecast availability of the different generation types

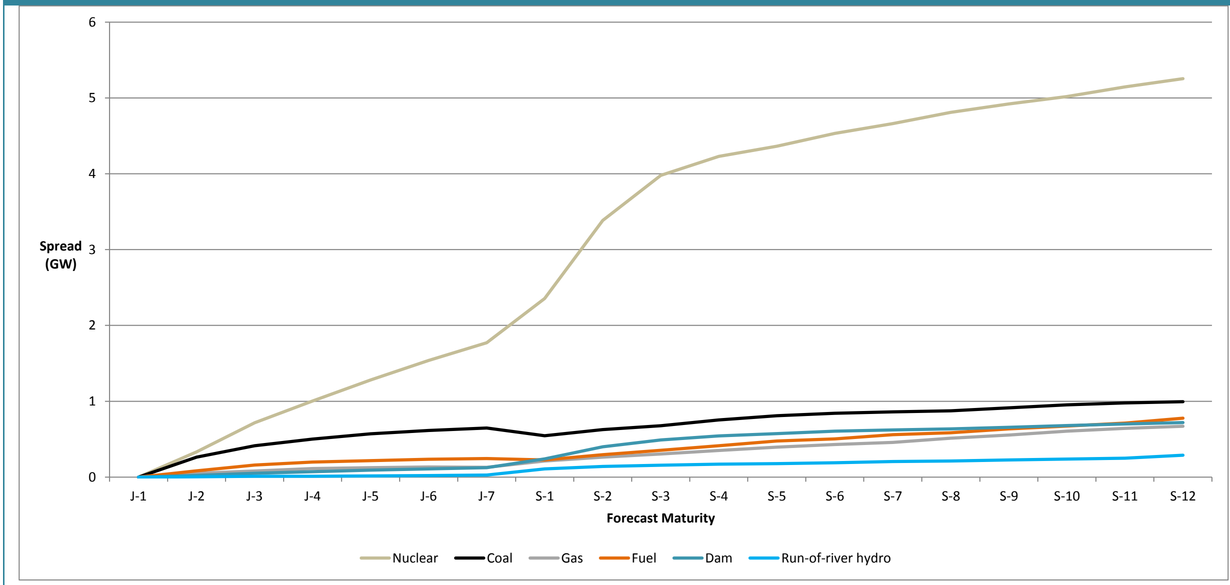
Data/generation type	Coal	Run-of-the-river hydropower	Fuel oil	Gas	Nuclear	Hydropower dams	Total
Rate of comprehensive forecasts	97.8%	93.4%	100%	90.4%	100%	93.4%	95.8%
7-day average statistical difference (MW)	769	31	282	150	2,265	187	3,685
Average statistical difference (D-7) in % of generating capacity	16.0%	0.3%	4.1%	2.7%	3.6%	1.3%	3.5%
Average statistical difference (D-7) in % of generating capacity (2012)	9.9%	0.1%	2.3%	1.1%	3.4%	0.8%	2.9%

Source: RTE – Analysis: CRE

The transmission rate in the case of availability forecasts improved considerably reaching 95.8% compared to 81.4% in 2012, as summarised in Table 18. Going back to 2010, the rate was roughly 89.6%. If this rate is weighted with the installed capacity of reference generation, it reaches 97.9%, considerably higher than in 2012 (88%).

The quality of forecasts improved, especially for coal and fuel

Graph 34: Average gap between availability forecasts and the last forecast (D-1)



Source: RTE – Analysis: CRE

Graph 34 presents for maturities less than 12 weeks, the average differences between published availability forecasts and the forecast at D-1, the last known forecast. There is always a positive statistical difference for thermal generation[58]. However, the difference in forecasts of weekly maturities decreased considerably in 2013 compared to 2012, especially for coal (-60% for W-12 forecasts) and fuel oil (-76% for W-12 forecasts). For nuclear generation, the difference in W-12 forecasts decreased by more than one gigawatt (from 6.4 GW to 5.3 GW). These variations may be due to the increase in the frequency of medium-term forecast updates.

Difference between D-1 forecasts and actual availability increased slightly

Table 19: Average gaps between availability forecast at D-1 and actual availability in 2013

Coal	Run-of-the-river hydropower	Fuel	Gas	Nuclear	Hydropower dams	Total
121 MW	3 MW	36 MW	21 MW	494 MW	62 MW	738 MW

Source: RTE

[58] This difference is due to the methodology used, which leads producers to declare the production capacity that they consider will be available in the future without taking into account statistically unavoidable random incidents affecting production groups.

The comparison of forecast availability announced D-1 with actual availability still reveals an overestimation of forecast availability announced within the framework of the transparency mechanism. For the year 2013, it was assessed at an average 738 MW for all generation types, up 84 MW compared to 2012 (Table 19).

2 Evolution of electricity prices

2.1 Spot market prices

2.1.1 Spot market prices decreased slightly in 2013 despite a long winter. They dropped sharply in the first half of 2014 due to mild temperatures.

Table 20: Average day-ahead and intraday prices

In TWh	Average day-ahead price	Average intraday price
2012	€46.90	€47.00
2013	€43.20	€44.30
H1 2013	€43.80	€45.70
H1 2014	€34.60	€35.30

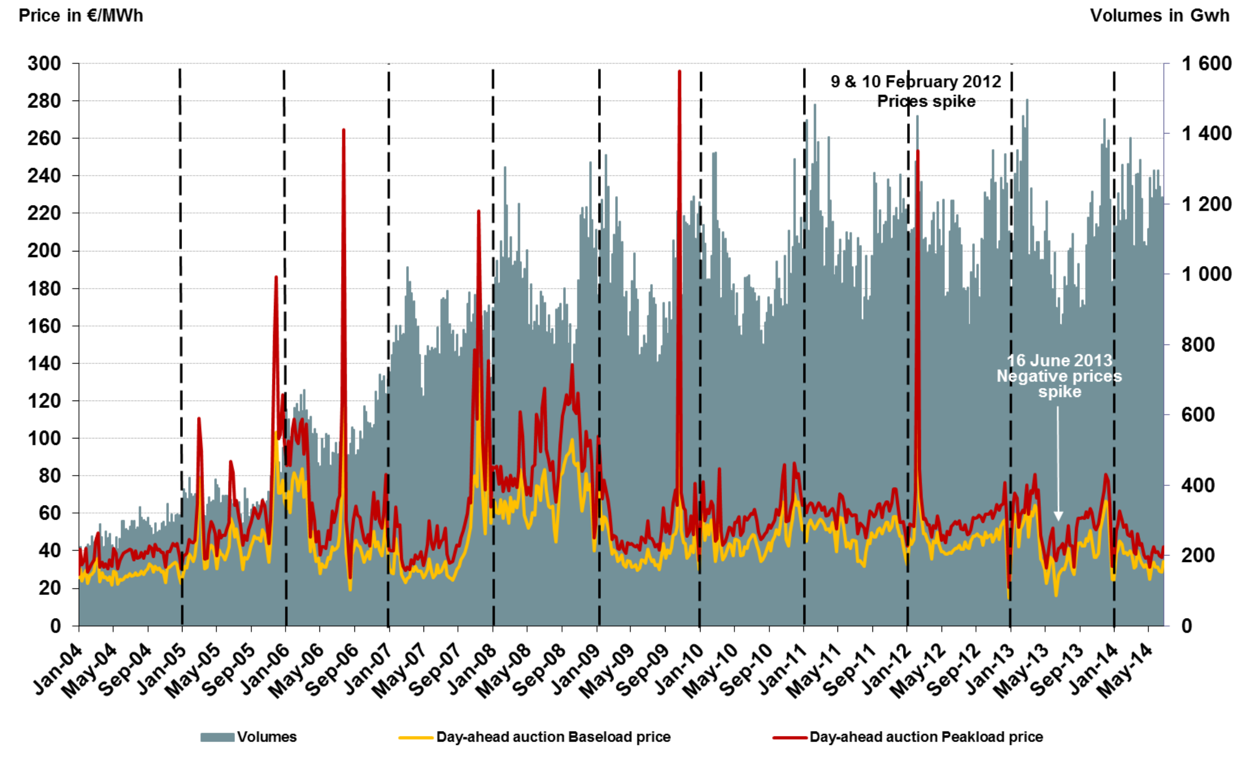
Source: EPEX SPOT – Analysis: CRE

Baseload average price was €43.20/MWh in 2013, i.e. a drop of €3.7/MWh compared to the previous year. For peakload prices, the drop was higher, with the average price of the megawatt-hour at €55.1 compared to €59.5 in 2012. This drop in day-ahead prices was however amplified by the price spikes of February 2012 and the negative price spike of 16 June 2013.

In the first half of 2014, day-ahead prices were very low, mainly due to the mild winter. The average baseload price was €34.6/MWh compared to €43.8/MWh in the first half of 2013, i.e. a drop of more than €9/MWh.

The average intraday price in the EPEX SPOT market in 2013 was €44.3/MWh, down compared to 2012. It stood at €1.10/MWh higher than the day-ahead price, a difference up sharply compared to the previous year. The differences observed with day-ahead prices mainly result from variations in renewable power generation and actual generation availabilitythat may have occurred after the setting of the day-ahead price on D-1.

Graph 35: Evolution of day-ahead prices in France (weekly average and sum of volumes)



Source: EPEX SPOT – Analysis: CRE

France experienced very significant negative price levels for certain hours during the EPEX SPOT auction for delivery on Sunday, 16 June 2013, with the baseload price reaching -€40.99/MWh. Hourly prices were very negative for the morning and afternoon hours, reaching -€200/MWh from 5:00 a.m. to 8:00 a.m. and -€100/MWh from 2:00 p.m. to 4:00 p.m.

Within this framework, CRE analysed the fundamental data specific to this date[59] and interviewed several market players. CRE's analyses served to establish:

- an oversupply of electricity for that day, particularly at the times during which the prices were very negative;
- a globally rational use of interconnections, with the exception of the interconnection with Switzerland due to the existence of long-term contracts;
- proper operation of the auction conducted by EPEX SPOT, with the negative prices triggering an RFQ procedure[60] (second auction in order to improve balancing);
- an amplification of negative prices due to the sale at all prices, by a market participant, of volumes bought inadvertently (technical error) on the Swiss auction one hour earlier.

CRE considers that these negative prices were consistent with supply and demand fundamentals, with the reason for the imbalance between generation and consumption (also observed in Belgium) being the hardly-flexible or non-flexible electricity generation. Nuclear and run-of-the-river generation was actually high in France, and did not offer downward flexibility, while the recent restart of the Doel 3 and Tihange 2 nuclear reactors in Belgium increased the surplus supply in the CWE market zone.

[59] See Report on the functioning of wholesale markets, 2012 – H1 2013
[60] "Request for Quotes"

Lastly, CRE was able to observe during this negative price episode the limits to the current transparency mechanism. While this mechanism enables the publication of all generation capacity available in the French electricity market, i.e. upward generation flexibility, this is not the case for downward generation flexibility. However, this type of information would only be useful for a very limited number of hours in the year (0.15% of hours at negative price in 2013 and in the first half of 2014). Lastly, if this episode was to occur more frequently, CRE would be required to make recommendations within the framework of the UFE mechanism in order to provide relevant information to market participants.

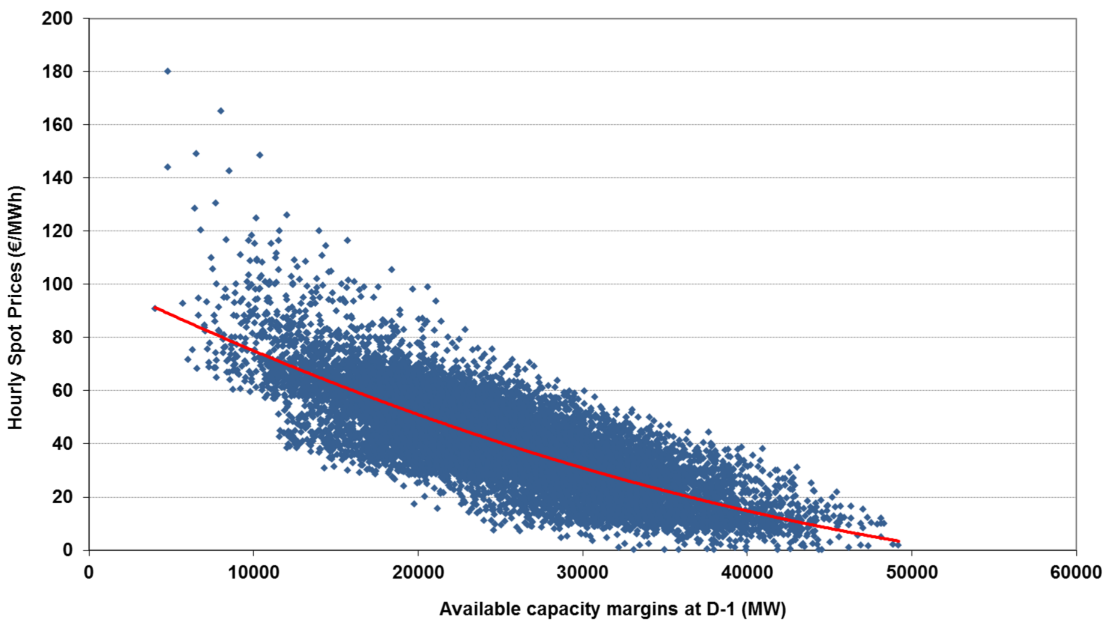
2.1.2 Correlation of day-ahead prices and capacity margin D-1

The formation of hourly spot prices depends largely on the forecast system margin, i.e. the differential for day-ahead forecasts between available generation capacity and consumption. The prices follow an upward trend when the margin decreases, particularly when the latter is lower than 10,000 MW: 77% of prices are then higher than or equal to €70/MWh for the 2013 period (the generation margin was never lower than 10,000 MW in 2014).

In 2013, the available hourly margins remained stable compared to 2012 at an average 25 GW. In the first half of 2014, generation margins were more comfortable (an average 26.5 GW), thanks to more moderate consumption and increased nuclear availability.

Graph 36 shows that fluctuations in hourly spot prices generally follow fluctuations in margin indicators: when the forecast hourly margin indicator at D-1 increased (respectively decreased), the corresponding spot price decreased (respectively increased) in 69% of cases in 2013 and the first half of 2014.

Graph 36: Spot prices and forecast margin at D-1 of the French electricity system, in 2013 and the first half of 2014

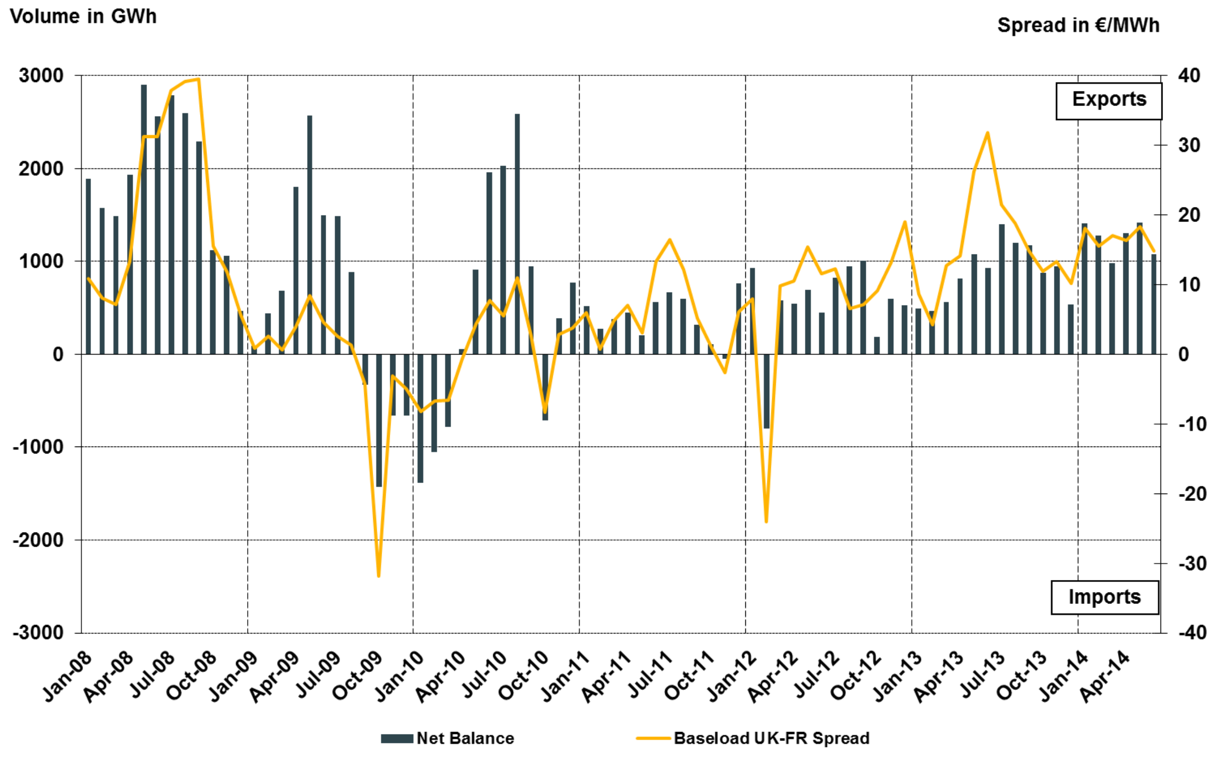


Sources: RTE, EPEX SPOT – Analysis: CRE

2.1.3 Volumes traded at interconnections

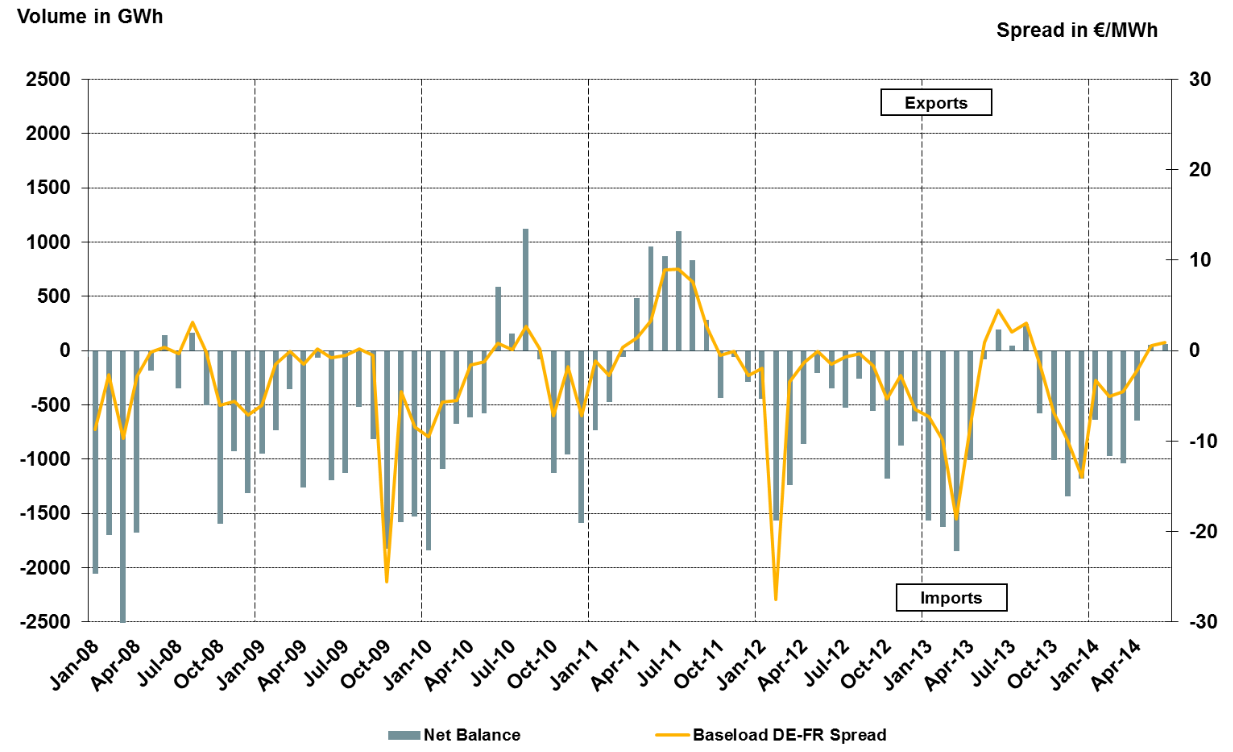
The drop in day-ahead market prices in France brought net exports up, particularly in the first half of 2014 (see Table 1 and Table 8). In 2013, France's net exports improved compared to 2012, particularly due to the increase in net flows to the United Kingdom (Graph 37), and despite a weakening of net exports with Germany. In the first half of 2014, there was a clear improvement in global net exports due to the considerable increase in flows to the United Kingdom, but also thanks to significantly lower imports from Germany (see Graph 37).

Graph 37: Evolution of net exports and the day-ahead price differential with the United Kingdom



Sources: EPEX SPOT, N2EX, RTE

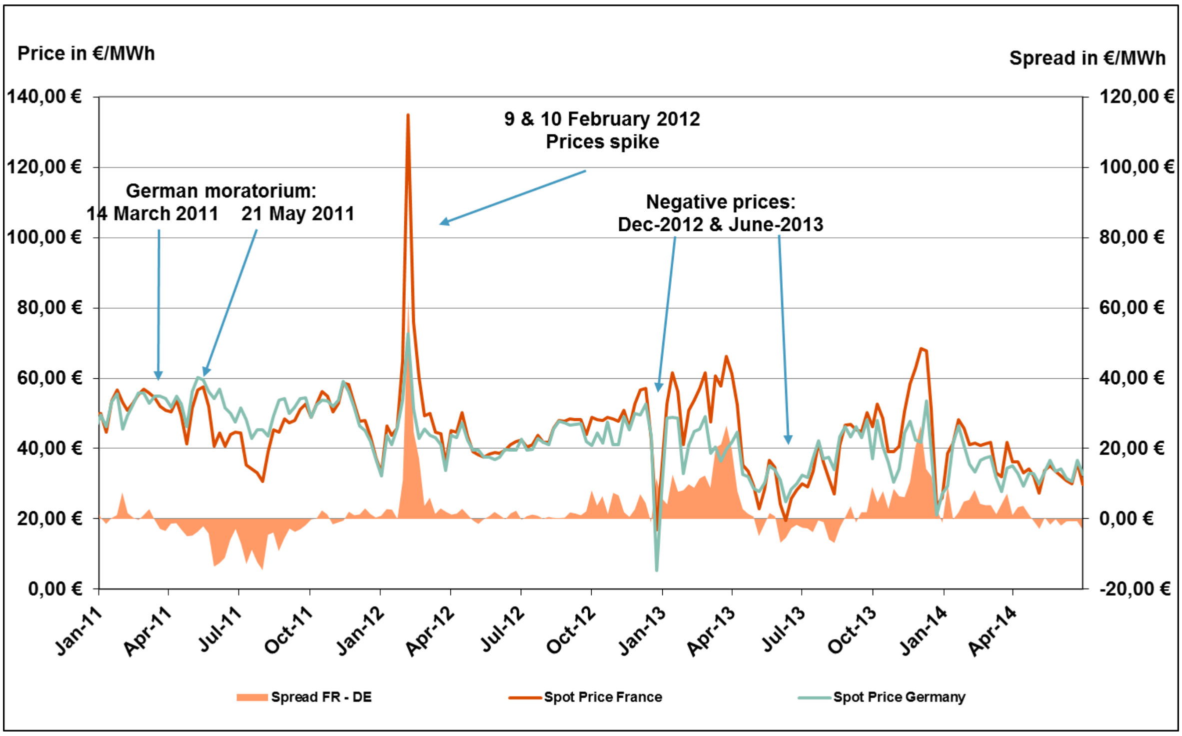
Graph 38: Evolution of net exports and of the day-ahead price differential with Germany



Sources: EPEX SPOT, RTE

2.1.4 France-Germany prices, Spread and Convergence

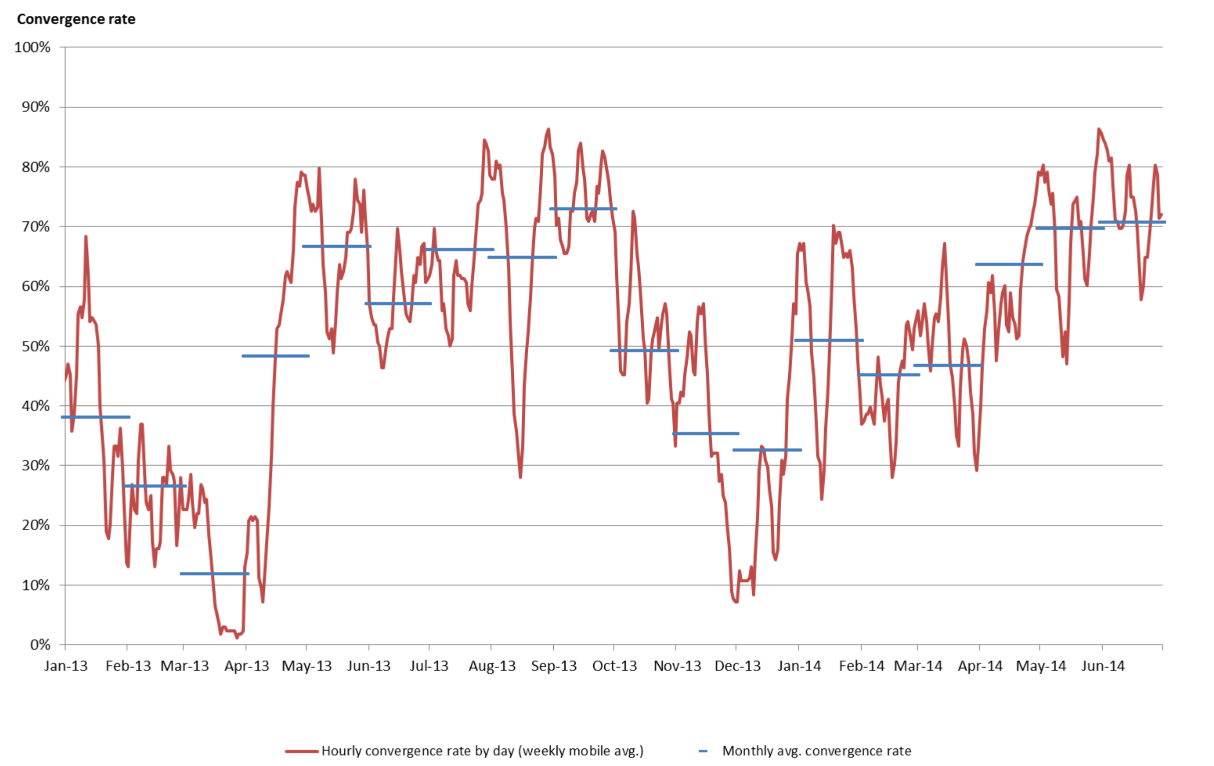
Graph 39: France-Germany spot price and differential (weekly averages)



Sources: EPEX SPOT – Analysis: CRE

The France-Germany price differential increased by more than one euro per megawatt-hour in 2013, reaching €5.4/MWh, mainly due to the rather long 2012-2013 winter. This difference decreased considerably in the first half of 2014, to €2.2/MWh because of the mild temperatures in France.

Graph 40: Daily convergence rate of France-Germany hourly prices

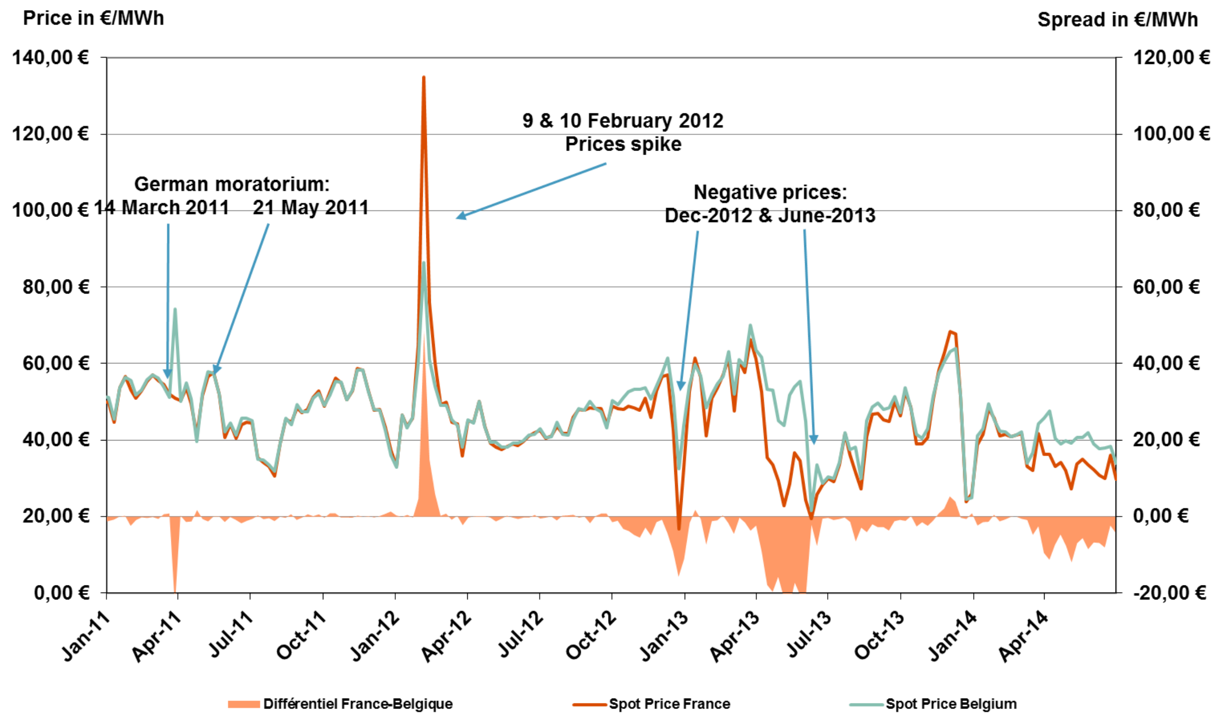


Sources: EPEX SPOT – Analysis: CRE

The rate of convergence between the French and German day-ahead hourly prices also suffered from the lengthy 2012-2013 winter: it dropped to 48% in 2013, compared to 63% in 2012. This level marks a record low since market coupling went live in November 2010. In the first half of 2014, this increased considerably, reaching 58% (compared to 42% in the first half of 2013).

2.1.5 France-Belgium Prices, Spread and Convergence

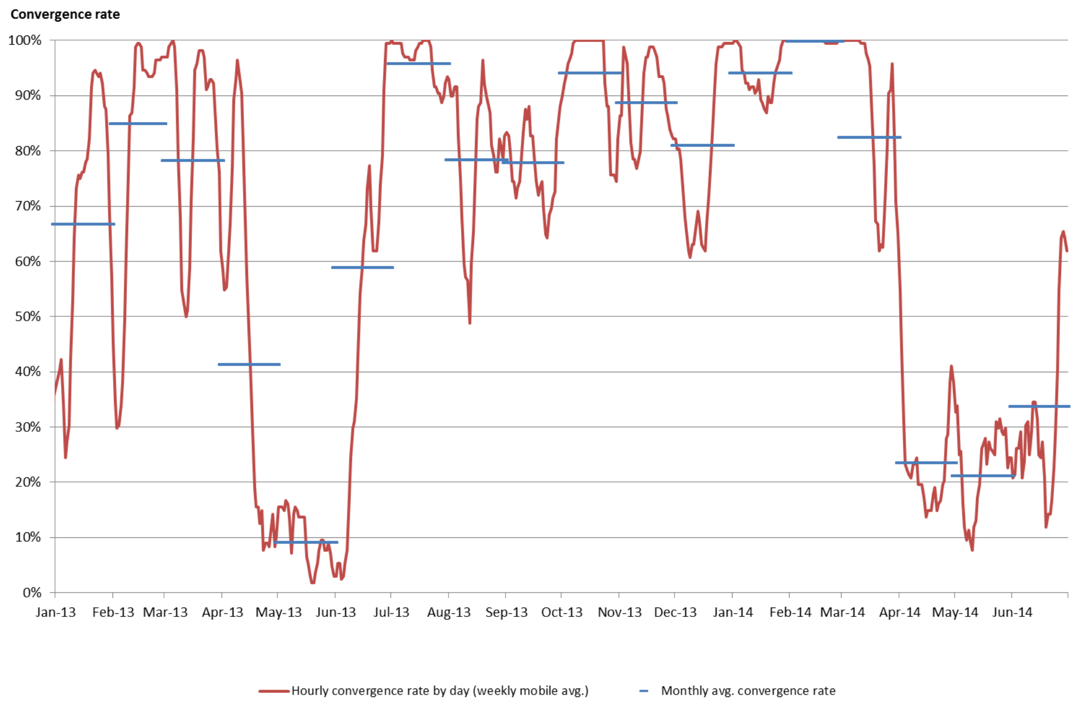
Graph 41: Spot price and France-Belgium differential (weekly averages)



Sources: EPEX SPOT – Analysis: CRE

The France-Belgium price differential increased sharply in favour of France in 2013, to an average of -€4.2/MWh compared to -€0.04/MWh in 2012. In the first half of 2014, this difference was maintained at -€4.3/MWh. The France-Belgium price difference was very sensitive to the availability and effective generation of the Belgian nuclear reactors Doel 3 and Tihange 2: in the first half of 2013, during which these two plants were disconnected from the network, the price differential reached an average -€7.95/MWh.

Graph 42: Daily convergence rate of France-Belgium hourly prices



Sources: EPEX SPOT – Analysis: CRE

The rate of convergence between the French and Belgian day-ahead hourly prices suffered from the situation encountered by the Doel 3 and Tihange 2 plants. Unavailable since summer 2012, these two plants had been restarted early June 2013. They were then re-disconnected from the Belgian transmission system from the end of March 2014. The impact of these two plants on Belgian market prices is clearly identifiable through the evolution of the France-Belgium convergence rate (Graph 42).

2.1.6 Volatility of day-ahead prices increased sharply in France and neighbouring countries

The year 2013 and the first half of 2014 were characterised by increased historical volatility indices for all European countries. In France and Germany, these rates reached 36% and 40% respectively.

Table 21: Historical volatility indices of day-ahead prices in Europe						
	France	**Germany**	**Belgium**	**Switzerland**	**Spain**	**Italy**
2008	26%	27%	27%	20%	6%	14%
2009	28%	25%	22%	20%	12%	17%
2010	20%	21%	20%	19%	26%	14%
2011	28%	20%	30%	17%	15%	9%
2012	26%	27%	23%	26%	24%	14%
2013	36%	40%	32%	36%	53%	16%
H1 2014	35%	29%	28%	33%	62%	20%
H1 2013	38%	43%	29%	41%	72%	19%

Sources: EPEX SPOT, Belpex, OMEL, GME – Analysis: CRE

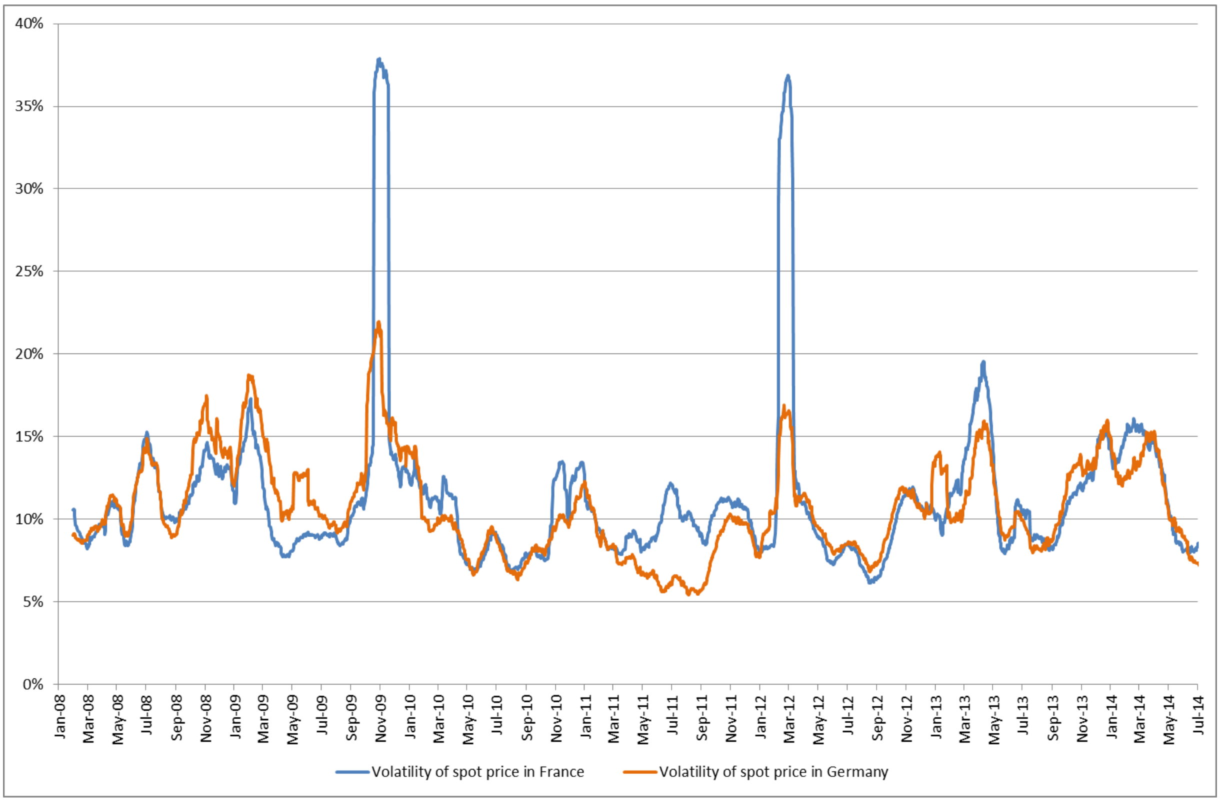
The Daily Velocity based on Overall Average (DVOA)[61] index, represented as a rolling average over one month in the graph below, is a daily index of day-ahead hourly price volatility vis-à-vis a relatively long period (one year in the graph below). Volatility increases are revealed in winter periods, particularly during the price spikes of February 2012 in France.

The volatility in France's and Germany's day-ahead prices have historically evolved closely together, both before and after market coupling went live in November 2010.

[61] $$\mathrm{DVOA}_i = \frac{1}{M}\left\{\left[\left(\sum_{j=1}^{M-1}\left|p_{i,j+1}-p_{i,j}\right|\right)+\left|p_{i-1,M}-p_{i,1}\right|\right]/\overline{p}_{*,*}\right\}$$

where *M* is the number of periods in a day (in this case 24 for the number of hourly prices), *i* is the index for the day, *j* is the index for the period of the day, $P_{i,j}$ the price of energy on day *i* at time *j*, and $\overline{p}_{*,*}$ is the total average of prices over the period studied (the year in this case)

Graph 43: Volatility (Daily Velocity based on Overall Average index, in rolling average over a month) of day-ahead prices in France and Germany



Source: EPEX SPOT – Analysis: CRE

2.1.7 Valuation of EDF's offers in the spot market is specifically examined

With regard to the use of EDF's generation resources, CRE specifically monitors differences existing between the spot market prices and the marginal costs of EDF's generating facilities resulting from the calculation of its daily optimisation models.

This indicator assists in detecting abuse of a dominant market position. This analysis is carried out on a daily basis, 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 2013 was 4.5%. As a reminder, this difference was 2.2% in 2012, and 5.0% in 2011 (see 2012-2013 and 2010-2011 Monitoring Reports).

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[62]. Such levels were not achieved during 2012 or the first half of 2013.

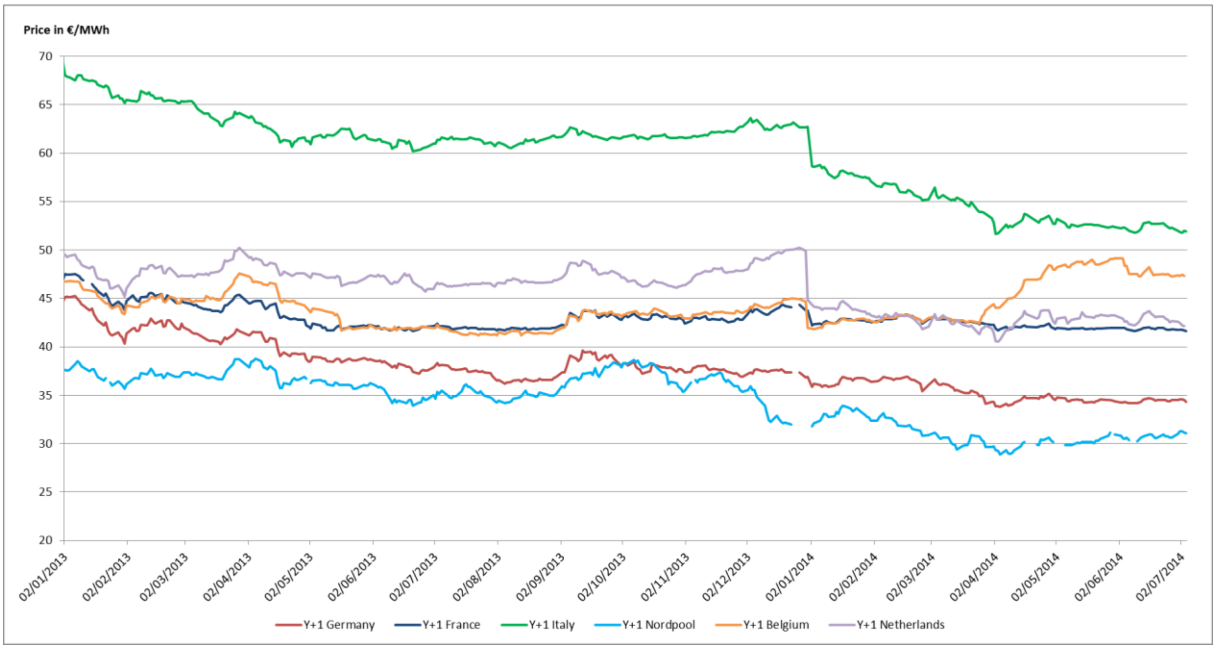
[62] Ibid.

2.2 Futures market prices

2.2.1 *Futures prices decreased and stablished at historically low levels, while the difference in France-Germany prices reached record levels*

Evolution of futures prices in Europe (Y+1)

Graph 44: Prices of Baseload Y+1 calendar products in Europe



Sources: EPD, ICE ENDEX, Heren – Analysis: CRE

In 2013, futures prices in Europe followed a downward trend started in 2011. The first half of 2014 was marked by a stabilisation of prices at historically low levels. This downward trend in electricity futures prices reflects the evolution of spot prices. It is due to the drop in fuel prices, i.e. mainly coal and CO_2, as well as the expansion of renewable energy in France and more particularly in Germany.

Increase in Belgian futures prices in the first half of 2014

At the end of March 2014, the price of the 2015 Belgian baseload calendar product deviated sharply from the French price, standing at an average €47.5/MWh in the months of April, May and June 2014. The difference between France and Belgium significantly widened, with the French price lower by an average €5.55/MWh over that period. This price differential is due to the early withdrawal of the Doel 3 and Tihange 2 nuclear reactors from the Belgian grid. On 25 March 2014, Electrabel announced that it was bringing forward the outage of the two reactors, scheduled initially for 26 April 2014[63]. Results of preliminary tests actually drove the operator to bring forward the scheduled outages. Despite tests planned until autumn 2014, the media and market participants appear sceptical regarding a restart of the activity of the two reactors.

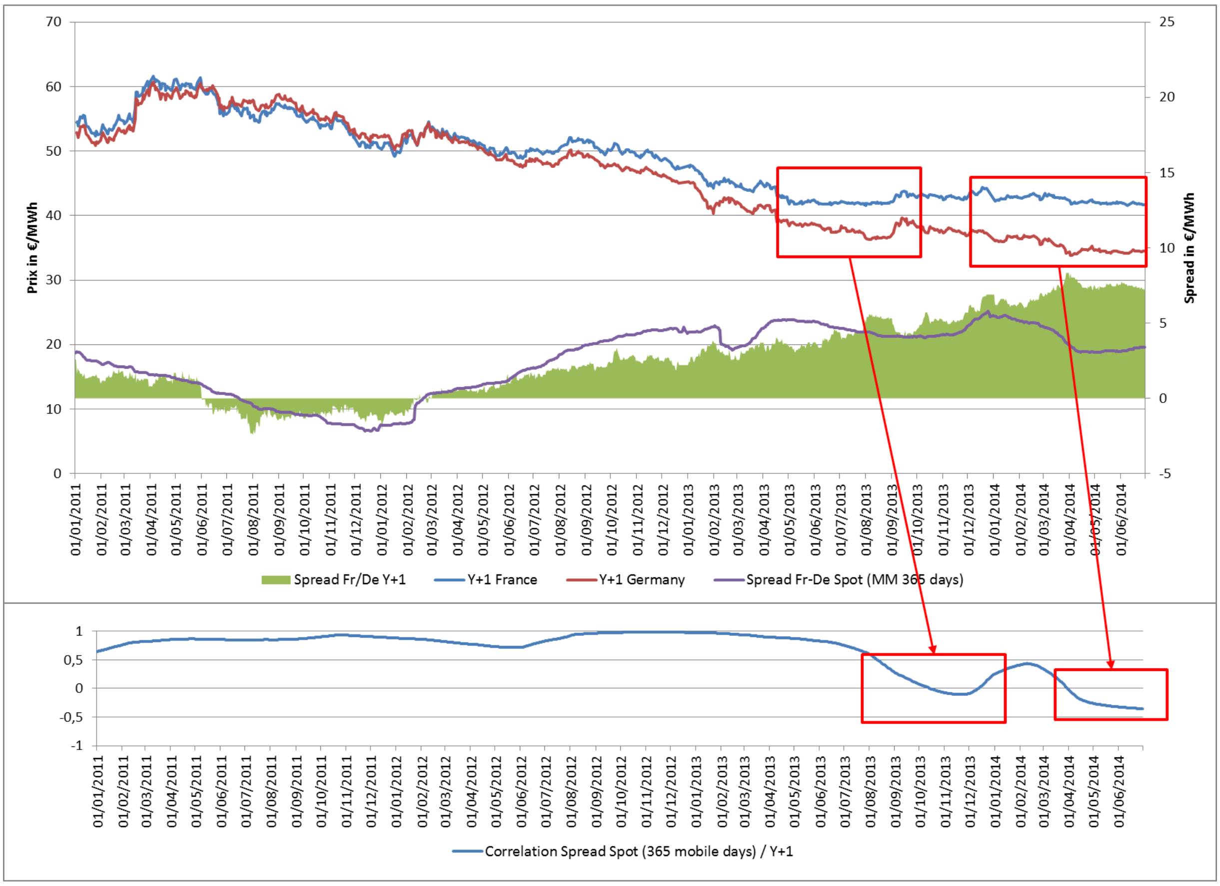
[63] http://www.fanc.fgov.be/fr/news/doel-3/tihange-2-anticipation-de-l-arret-programme-des-reacteurs/668.aspx

A growing price differential between France and Germany

The difference in the futures price between France and Germany increased sharply in 2013 and the first half of 2014. The price difference, which had favoured France since events related to the Fukushima catastrophe, was once again inversed following the cold wave of February 2012, which generated major price spikes in the French day-ahead market. The cold winter of 2012 contributed to amplifying the risk premium linked to thermo-sensitivity of French electricity consumption and valued by the futures market participants.

From 2011 and until the end of 2013, the difference in Y+1 futures prices between France and Germany were consistent with the levels for day-ahead market prices. This consistency however, has not been observed since the first half of 2014, during which the Y+1 futures price differential continued to increase, reaching €8.18/MWh, while the day-ahead price difference observed between France and Germany decreased considerably. Analysis of the correlation between these two indicators reveals a high level of correlation between 2011 and 2013, but this level dropped significantly, and even became negative in 2014 (inverse correlation of prices), particularly when the futures price stabilised around €42/MWh (Graph 45). This analysis tends to show that the evolutions of the France-Germany differential in the futures and spot markets are based on different underlying factors.

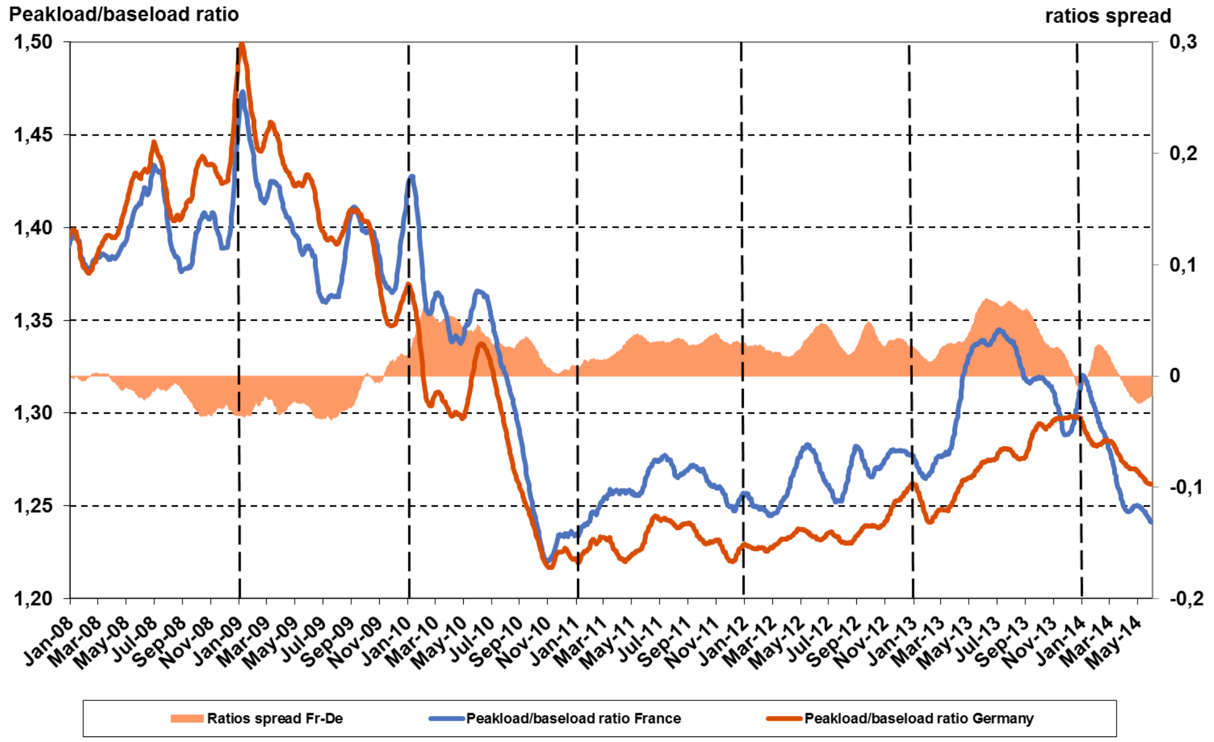
Graph 45: Correlation between the differentials in France-Germany Y+1 calendar and Day-ahead products



Sources: EPD, EPEX SPOT – Analysis: CRE

The distinction between delivery profiles reveals a greater decrease in peakload prices compared to baseload prices in France. This was also observed in Germany, however to a lesser extent (Graph 46). The baseload price difference between France and Germany tends to approach the difference in peakload prices. In France, the valuation of baseload prices compared to peakload prices was accentuated by the stagnation of the base Y+1 price at €42/MWh.

Graph 46: Ratios of Peakload/Baseload prices of Y+1 calendar products



Sources: EPD – Analysis: CRE

2.2.2 Evolution of futures price and the ARENH mechanism

In the previous edition of its report on the functioning of wholesale markets[64], CRE stated that it had undertaken in-depth analyses of the behaviour of participants after observing price stabilisation at around €42/MWh, while, at the same time, electricity prices in Germany continued to drop. This work consisted in analysing transactions made by market participants and analysing orders posted on the trading platforms in 2013. In addition, CRE interviewed market participants to obtain their analyses of this observation (Box 3), and in certain cases, to obtain explanations of their behaviour.

Analyses of CRE's department within the framework of wholesale market monitoring

- Arbitrage with the ARENH mechanism

Many purchase transactions came from the choice of alternative suppliers, industrial clients or system operators to purchase electricity in the wholesale markets instead of through the ARENH mechanism when the price was lower than €42/MWh[65]. This behaviour, which is rational from an economic point of view, increased demand for electricity priced below €42/MWh.

Some of these participants, having purchased electricity futures at a price lower than €42/MWh in planning to reduce their orders under ARENH, chose to resell these volumes once the market price

[64] http://www.cre.fr/documents/publications/rapports-thematiques/fonctionnement-marches-de-gros-electricite-co2-gaz-naturel-2012-2013

[65] This value was adjusted by certain participants by the profiled character of a portion of the ARENH volumes and by transaction costs and costs related to the ARENH mechanism.

exceeded €42/MWh. The rise in prices above this level in fact encouraged players to exercise all of their rights to ARENH.

Other participants decided to sell call options in the markets enabling them to take advantage of the optionality of the ARENH mechanism. The ARENH mechanism is in fact similar to a call option at a price of €42/MWh made available to eligible participants. Financial market participants played an active role in these transactions.

This behaviour, in the context of an illiquid market in which the volumes traded are low compared to the theoretical volumes concerned by the ARENH mechanism, kept prices at a level close to €42/MWh.

- Due to its optional nature, the ARENH mechanism creates major uncertainty concerning the volumes to be delivered and therefore a risk

Close attention was paid to EDF in the analysis of the transactions and order books due to its specific role within the framework of the ARENH mechanism and its important weight in the wholesale market.

When the participants with rights to ARENH increased their purchases when the price was lower than €42/MWh, CRE did not observe any increases in EDF's sales related to subscription assumptions for ARENH.

The incumbent operator EDF, which delivers electricity within the framework of the ARENH mechanism, stated to CRE that it had no means of "*anticipating subscriptions by suppliers before notification by CRE of the volumes to be delivered*". EDF underlined that "*the ARENH mechanism requires it to make assumptions of the volumes to be delivered, with the risk, due to optionality, of making errors regarding quantities*". EDF considers that it poses a major risk to it because of:

- the "*very short maturity in between the notification of volumes of the start of delivery*";
- the "*low market liquidity given the volumes potentially concerned – and particularly in December during end-of-year festivities*";
- the fact that "*the first delivery months (January and February) are the most delicate months in terms of management of physical supply/demand in EDF's portfolio*".

EDF's behaviour, combined with that of alternative market participants, very likely contributed to maintaining the prices around €42/MWh.

Box 3: Participants' analysis of the evolution of the CAL14 price in France

Within the framework of its analysis of the evolution of market prices of the France Baseload 2014 Calendar product, CRE interviewed 21 market participants including both participants concerned by the ARENH mechanism (alternative suppliers, industrial clients, EDF, system operators) and other participants active in the wholesale markets and more particularly in the 2014 calendar product (financial players, utilities, etc.).

Uncertainty about the price level of ARENH

The ARENH price applicable in 2014 remained uncertain until a press release by the Government on 22 October 2013. Pending this announcement, most participants anticipated a price left unchanged at €42/MWh. However, some participants may have been influenced in their supply decisions because of this lack of visibility.

Consistency with market fundamentals

Most market participants considered that the evolution of futures prices was consistent with the evolution of market fundamentals. According to them, the price difference between France and Germany can be explained in particular by winter tightness in France or by the influence of coal and CO_2 prices, whose continuous drop enabled generation costs to decrease. Participants observed that the differential between France and Germany for the 2014 calendar product was comparable to that of the spot market.

<u>Market arbitrage in relation with ARENH</u>

Participants agreed that the ARENH mechanism influenced market prices because of arbitrages:

- by industrial clients,
- by system operators to purchase their losses,
- by suppliers with the ARENH option within the framework of their supply strategy.

While this behaviour appears logical and rational for market participants, some of them stated that these arbitrage strategies alone do not suffice in theory to explain a resistance level at €42/MWh. Market price is first and foremost an anticipation of future spot prices and thus should not move away from a price level representative of the supply/demand balance of the period considered.

EDF stated that "*the phenomenon of futures market price adherence to the ARENH price is observed in the case in which the fundamentals are in the immediate vicinity of the ARENH price, which is the case today*". EDF considers that "*the assumption of a significant difference between the futures price and the fundamentals must be discarded because massive arbitrage between futures markets and the spot market would occur in that case and bring the futures prices back towards that of the fundamentals*".

Moreover, other participants stated that ARENH may have modified participants' collective representations of "market consensus" by creating a reference normative value. Some participants speak of an "ARENHisation" of the electricity market in France.

<u>The low level of liquidity amplified the phenomenon</u>

The low liquidity of the futures market for delivery in France is also likely to have disrupted the formation of prices and contributed to the stabilisation of calendar prices around €42/MWh. First, participants note that the ARENH mechanism greatly affected market liquidity. The participants concerned by the ARENH mechanism physically trade electricity and therefore no longer need to intervene in the wholesale markets.

Arbitrages led to an increase in the volumes proposed for purchase in the market when the price was close to €42/MWh, which resulted in:

- a quick return of the price to €42/MWh, particularly because the volumes concerned by arbitrage with ARENH were very high compared to market liquidity,
- a reduction of price volatility, despite a major risk of volatility following ARENH open subscription periods.

Some players stated that a similar mechanism in Germany, where the market is much more liquid, would not have influenced the market price to that extent. Other participants stated their wish for the financialisation of the ARENH mechanism.

Conclusions

CRE notes that the combined behaviours of participants with ARENH rights and of the incumbent supplier are responsible for the stabilisation of the price around €42/MWh. Low market liquidity may have favoured this phenomenon (Box 5). Moreover, CRE has not identified at this stage any elements likely to characterise market manipulation in the transactions made in 2013 for the 2014 calendar product.

The issue of the consistency of this price compared to market fundamentals has been raised more seriously since the start of 2014. While a price differential of €4.22/MWh between France and Germany seems consistent in 2013 for the 2014 calendar product, this differential increased reaching an average of €7.08/MWh in the first half of 2014. In this context, the behaviour of market participants, and in particular, their transactions since the start of 2014, continues to be monitored closely.

Lastly, the progress report scheduled for 2015 by the NOME law will also serve to examine the effects of the ARENH mechanism on the wholesale electricity market in France. On that occasion, the relevance of a mechanism based on a financial settlement for ARENH purchases rather than physical delivery shall be examined.

2.2.3 As opposed to the day-ahead market, futures prices saw historically low volatility levels

In 2008, French and German electricity futures prices saw historical highs, in connection with oil prices exceeding $140/b in July 2008. They have since dropped in general, along with their associated historical volatility indices (see Table 22). The historical volatility indices of the Y+1 baseload calendar prices, which stood at 24% for France and Germany in 2008, progressively declined down to 8% and 10% respectively for 2013. This trend continued for the first semester of 2014.

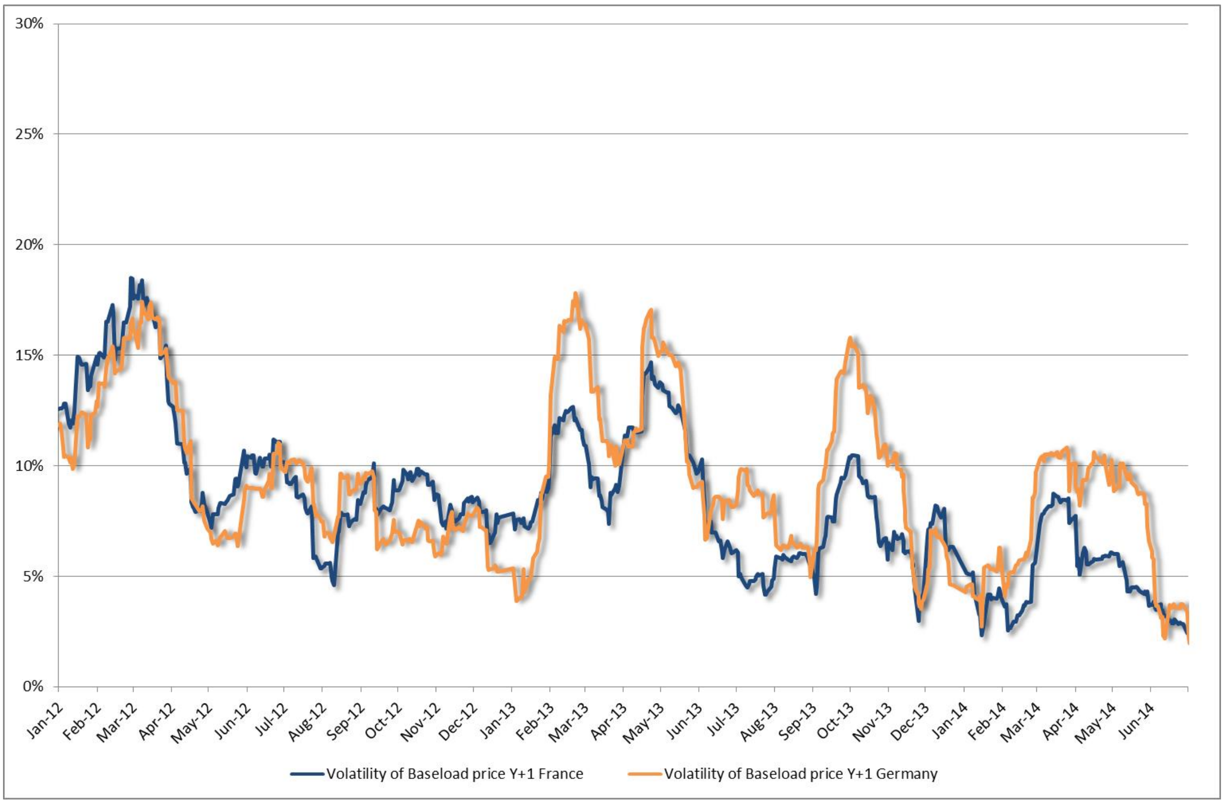
Table 22: Annual historical volatility indices of Y+1 baseload calendar products in France and Germany

	Y+1 France	**Y+1 Germany**
2008	24%	24%
2009	25%	23%
2010	16%	16%
2011	15%	14%
2012	11%	10%
2013	8%	10%
H1 2014	5%	7%
H1 2013	10%	12%

Source: EEX European Power Derivatives – Analysis: CRE

The emergence of a differential, in May 2012, between France and Germany baseload calendar prices, also caused a disconnection of their respective volatilities (Table 22 and Graph 47). The volatility of futures prices was slightly higher in France than in Germany from May 2012 to February 2013, before a major overturn of the situation until presently.

Graph 47: Volatility (moving over one month) of the prices of Y+1 baseload calendar products in France and Germany



Source: EEX European Power Derivatives – Analysis: CRE

2.3 Balancing mechanism

2.3.1 In the balancing mechanism, competition for downward balancing volumes remains very limited. Hydropower generation is still an essential contributor to balancing supply with demand.

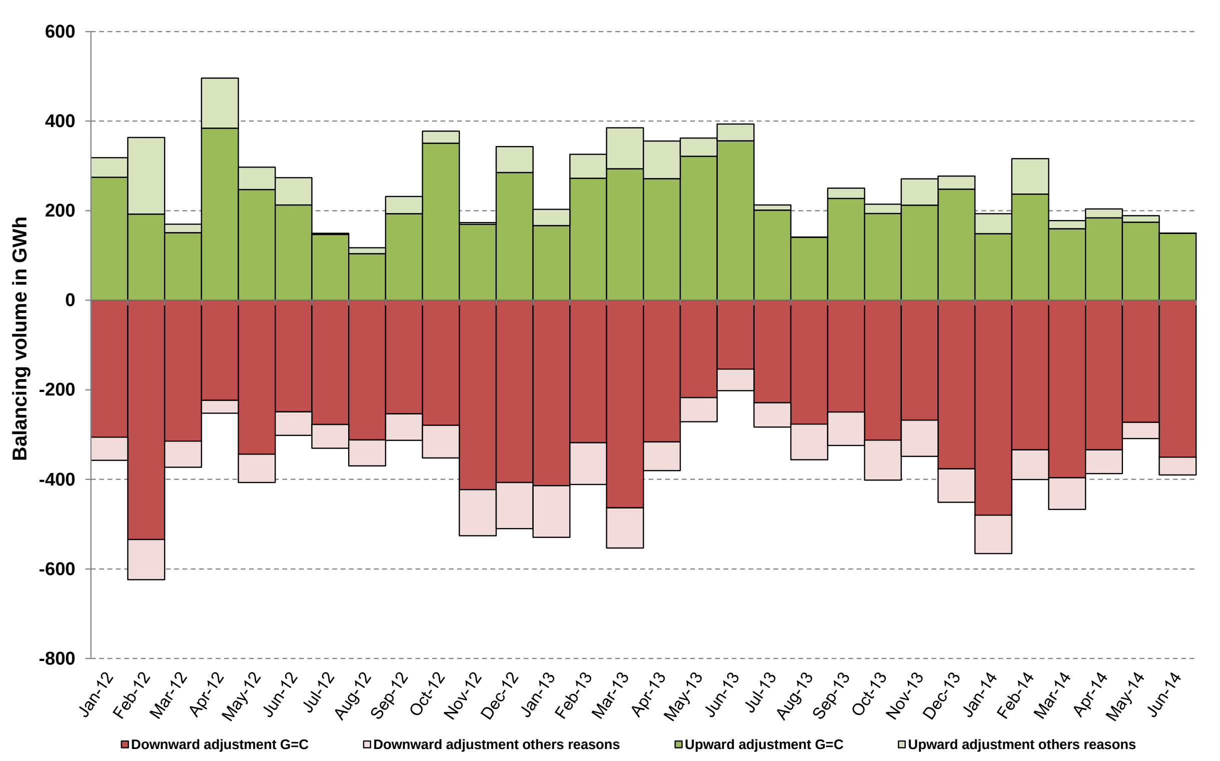
The balancing mechanism, set up on 1 April 2003, enables RTE to have at all times, power reserves to be mobilised any time an imbalance occurs between supply and demand. The balancing actor informs RTE of the technical and financial conditions under which RTE may call on it to modify its generation, consumption or trading programmes.

In 2013, the balancing volumes were stable (-2%), with upward balancing increasing by 2% and downward balancing decreasing by 4% (Graph 48). The system was therefore mostly long, with 59% of half-hourly steps for which RTE anticipated surplus energy in the electricity system. RTE activated a total of 7.9 TWh, i.e. 1.7% of consumption (excluding system operator losses), compared to 8.1 TWh in 2012.

28 March 2013 was a particularly tight day. The balancing system saw record volumes, with almost 87 GWh called by RTE[66].

In the first half of 2014, balancing volumes declined considerably compared to the first half of 2013 (-14%), due to a 39% drop in volumes activated upward, partly offset by a 7% increase in downward balancing volumes.

Graph 48: Upward and downward balancing volumes[67]



Source: RTE – Analysis: CRE

The market shares of nuclear and hydropower generation remained stable with regard to upward balancing compared to 2012 (Graph 49), while balancing volumes from interconnections increased significantly to the detriment of fossil fuel generation.

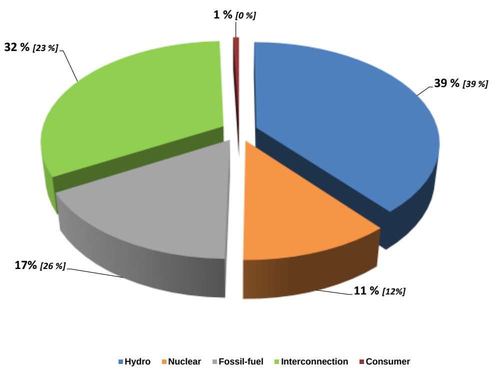
With regard to downward balancing, the market share of hydropower increased sharply compared to 2012, to the detriment of all other generation, including in particular, nuclear generation, which had been heavily solicited in the month of December.

[66] See Report on the functioning of wholesale markets, 2013 – H1 2014

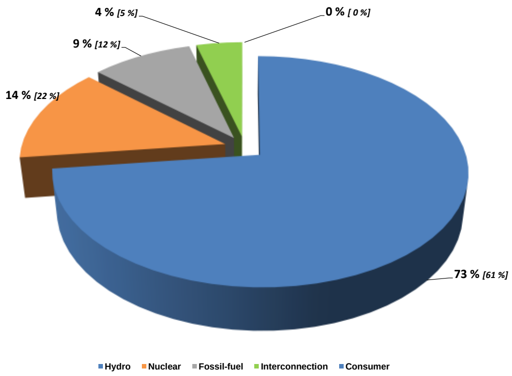
[67] Evolution of activated balancing volumes (for the reason P=C and for all reasons). Reason P=C: production-consumption balancing; other reasons: resolution of network constraints such as congestion, recovery of system services and operational margins at intervals (8hrs, 2hrs, 15 minutes)

Graph 49: Balancing shares per technology in 2013

a. Upward balancing shares



b. Downward balancing shares



Source: RTE – Analysis: CRE

In 2013, the market share of French participants in upward balancing increased compared to 2012, with 89% of volumes activated compared to 80% in 2012.

2.3.2 Valuation of EDF's offers in the balancing mechanism is specifically examined

EDF's offers activated by RTE for the balancing mechanism is regularly monitored by CRE, particularly in connection with the marginal costs of the incumbent operator's electricity generation fleet.

The construction of EDF's offers for the balancing mechanism is based on generation costs, integrating, in addition to the direct variable cost of generation, expenses and risks specific to the balancing mechanism:

- additional costs related to the drop in reliability of plants resulting from variations imposed by balancing;
- risk of traceability differences between RTE and EDF;
- costs related to the management of offers for the balancing mechanism.

Coverage of these different elements results in the application of an additional cost element to all of the offers proposed by EDF for balancing.

This cost element was applied uniformly, independently of the generation source underlying the offer valued in the balancing mechanism. At CRE's request, EDF examined the possibility of differentiating this additional cost element according to generation type. The purpose of this change was to clarify the contribution of the generation costs of each generation type to the cost for balancing the overall system, as well as to improve the conditions of EDF's interventions in the balancing mechanism.

EDF set up this differentiation in October 2013.

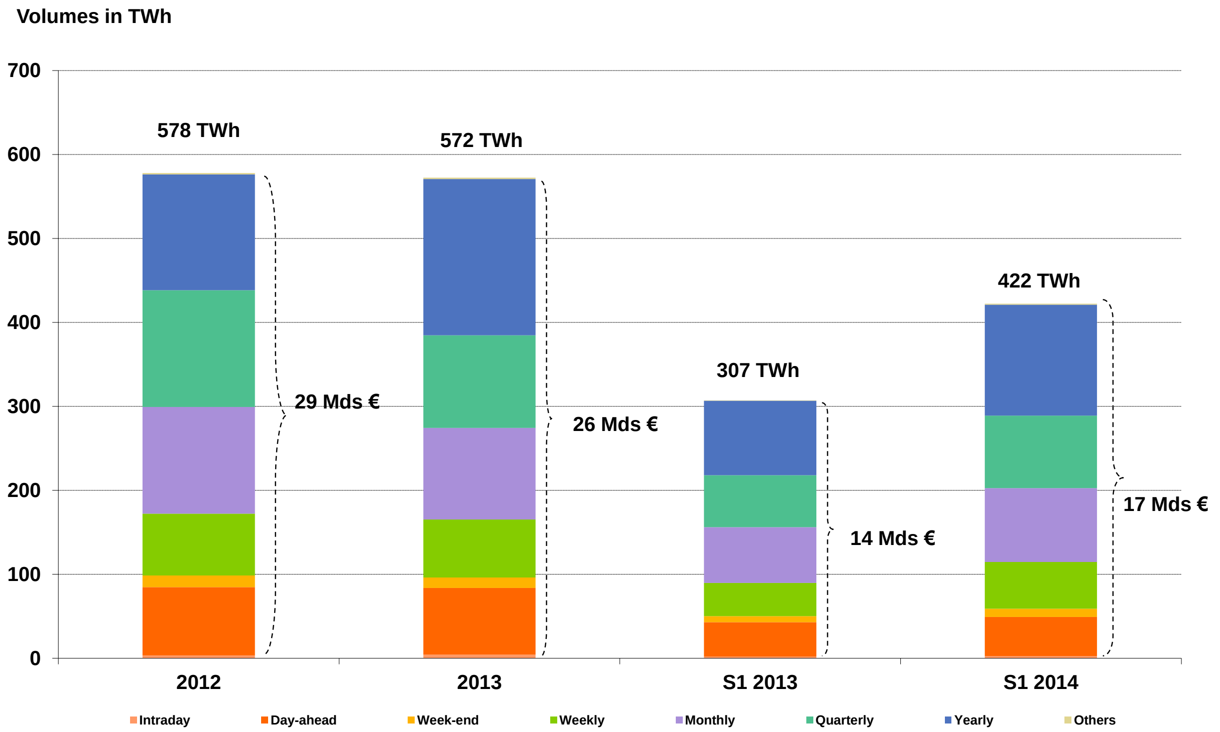
CRE took into account these changes within the framework of the monitoring of the balancing mechanism. In 2013 and the first half of 2014, for its nuclear and classic thermal generation, EDF's offers activated by RTE for the balancing mechanism therefore integrated an additional cost differentiated according to generation type.

3 Development of the main wholesale market segments

Activity in the French intermediated wholesale market combines transactions made in the organised markets and over-the-counter (brokering platforms). This scope covers most of the activity in the French wholesale electricity market, the remaining share being materialised in direct bilateral transactions between market participants.

The volumes traded in the wholesale market in 2013 totalled 572 TWh, stagnant compared to 2012 (-1%) (Key figures, Table 3). Nevertheless, the number of transactions in the wholesale market increased by 23% to 281,934 transactions (Key figures, Table 3). Measured against macro-economic data, electricity trading represented approximately 122% of French consumption in 2013, i.e. a 3-point drop compared to 2012.

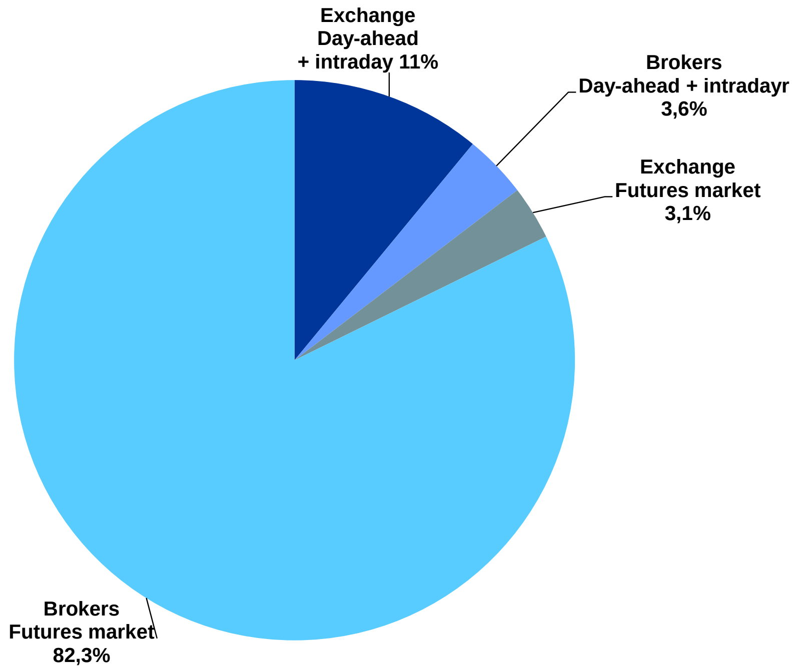
Graph 50: Volume and valuation of trading per product in 2012, 2013 and in the first half of 2014



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

The valuation of trading in the French electricity market dropped slightly, from 29 billion euros in 2012 to 26 billion the following year (Graph 50). This drop is due to the decrease in the volume traded and the drop in spot prices. In the first half of 2014, valuation increased from 14 to 17 billion euros, thanks to a major increase in volumes and despite the drop in spot prices.

Graph 51: Share of trading according to platform and maturity in 2013



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

Due their intrinsically higher value, futures products represent 85% of the volumes traded in the markets. Moreover, since most of trading occurs over the counter, OTC platforms account for approximately 86% of the volume traded in the markets. The remaining 14%, up one point compared to the previous year, is traded in organised markets (Graph 51).

3.1 The spot market

3.1.1 Growth in the intraday market thanks to the development of cross-border trades

Table 3 (Key figures) presents the annual and half-yearly evolution of volumes traded in the spot markets. In the EPEX SPOT intraday market, there was an upward trend between 2012 and 2013 (+30%), both for transactions in France and cross-border transactions related to the coupling of the French and German EPEX SPOT intraday markets. Coupling with Switzerland at the end of June 2013 contributed to the increase in volumes. The trend continued in the first half of 2014 with a 42% increase compared to the first half of 2013.

In the EPEX SPOT day-ahead market, volumes traded decreased slightly in 2013 with a 1.3% drop compared to 2012. Inversely, they increased slightly in the first half of 2014 compared to the first half of 2013. These variations are comparable with global trends observed in the wholesale markets between 2012 and 2014.

3.1.2 Resilience of French and German prices demonstrates the lack of depth of the French market and the role of interconnections in the security of supply

The resilience data published by EPEX SPOT daily can be used to assess the sensitivity of market prices, and by extension the liquidity and depth of the market on EPEX SPOT day-ahead auctions. The tables below show, for the French and German markets, average price variations resulting from a supply shock (-500 MW or -1,000 MW) or a demand shock (+500 MW or +1,000 MW) from the home market, or from the neighbouring market. When interconnection capacity between France and Germany is used at its maximum, the sensitivity of a market to its neighbour becomes much more limited.

Table 23: Average price variations for supply/demand shocks in the home market

		-1,000 MW	-500 MW	+500 MW	+1,000 MW
2012[68]	France	-€1.74/MWh	-€0.86/MWh	€0.87/MWh	+€1.76/MWh
	Germany	-€1.69/MWh	-€0.78/MWh	+€0.79/MWh	+€1.58/MWh
2013	France	-€2.40/MWh	-€1.20/MWh	+€1.25/MWh	+€2.53/MWh
	Germany	-€1.91/MWh	-€0.96/MWh	+€1.02/MWh	+€2.03/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
H1 2014	France	-€2.08/MWh	-€1.07/MWh	+€1.13/MWh	+€2.32/MWh
	Germany	-€1.60/MWh	-€0.84/MWh	+€0.83/MWh	+€1.64/MWh

Source: EPEX SPOT – Analysis: CRE

Table 24: Average price variations for supply/demand shocks in the neighbouring market

		-1,000 MW	-500 MW	+500 MW	+1,000 MW
2012[69]	France	-€0.72/MWh	-€0.34/MWh	+€0.37/MWh	+€0.74/MWh
	Germany	-€0.71/MWh	-€0.34/MWh	+€0.36/MWh	+€0.72/MWh
2013	France	-€0.52/MWh	-€0.24/MWh	+€0.32/MWh	+€0.65/MWh
	Germany	-€0.54/MWh	-€0.26/MWh	+€0.30/MWh	+€0.61/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
H1 2014	France	-€0.83/MWh	-€0.45/MWh	+€0.47/MWh	+€0.93/MWh
	Germany	-€0.87/MWh	-€0.45/MWh	+€0.48/MWh	+€0.94/MWh

Source: EPEX SPOT – Analysis: CRE

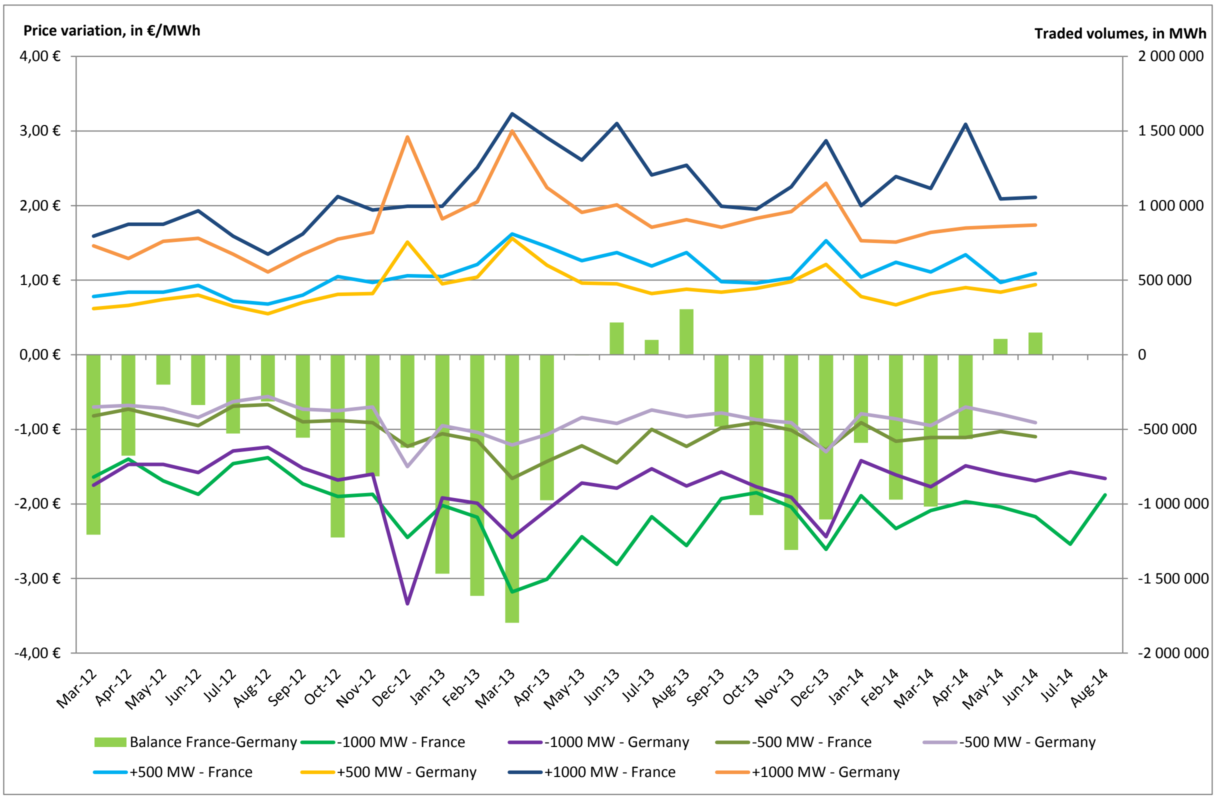
This data reveals, for home market supply shocks, greater sensitivity of French market prices. This observation reflects a higher probability of reaching extremes when the balance between supply and demand is tight.

For a home market supply shock (Graph 52), market prices are more sensitive in winter than in summer due to the thermo-sensitivity of electricity consumption (particularly in France). Trades

[68] Averages for March to December 2012 (no data available before March 2012)
[69] Averages for March to December 2012 (no data available before March 2012)

between France and Germany are higher when the price sensitivity to supply shocks is high, as illustrated in the month of March 2013. This highlights the role of interconnections in the security of supply, which attenuate the impacts of supply shocks from the home market. There was much lower tightness in the first half of 2014 compared to the first half of 2013: market prices were less sensitive to a supply shock in the home market, due to a better absorption of these shocks by the market coupling mechanism.

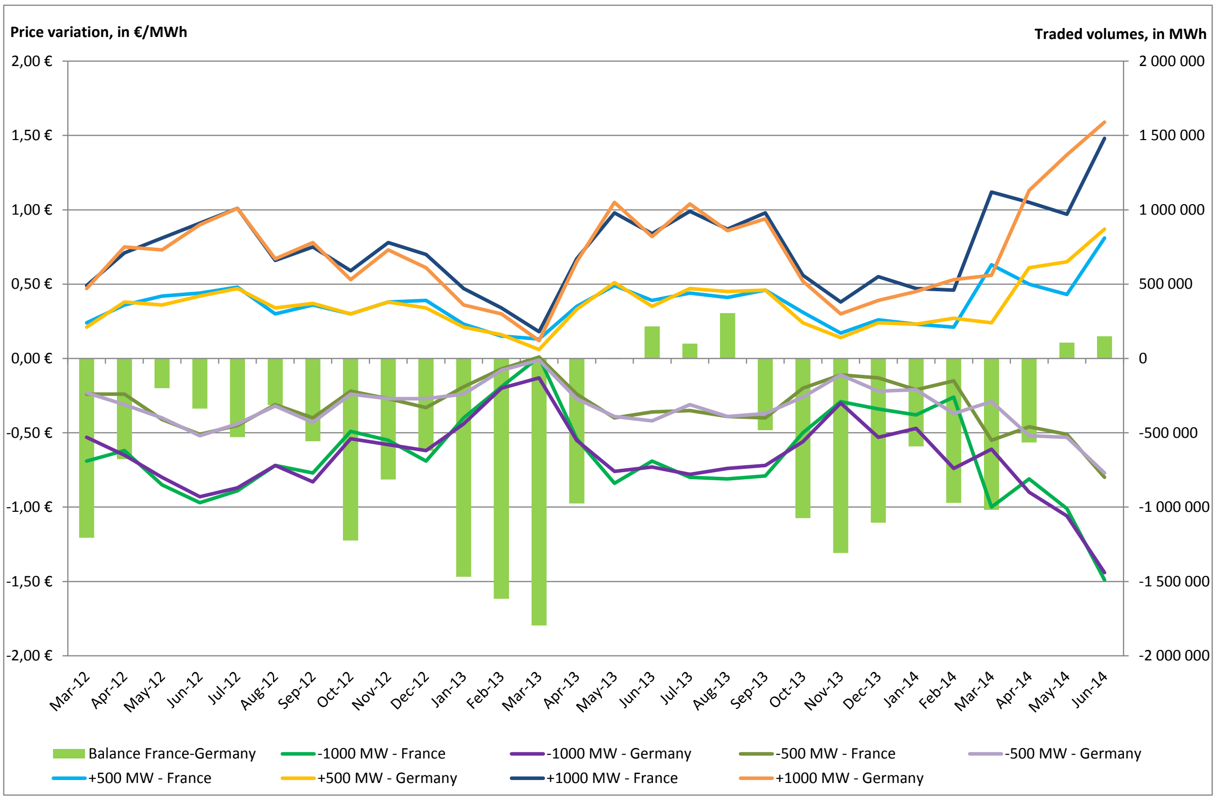
Graph 52: Sensitivity of hourly prices during a supply shock in the market, by month



Source: EPEX SPOT, RTE – Analysis: CRE

Inversely, the sensitivity of prices to supply shocks from the neighbouring country (Graph 53) drops with the volumes traded, with interconnection saturation isolating the markets. In March 2013, during which the interconnection was very often saturated, the sensitivity of French and German prices to supply shocks coming from the other side of the border decreased considerably. In the second quarter of 2014, in which prices tended to converge, reflecting a good availability of the France-Germany interconnection, the sensitivity of hourly prices was very high with regard to external shocks.

Graph 53: Sensitivity of hourly prices during a supply shock from the neighbouring country, by month



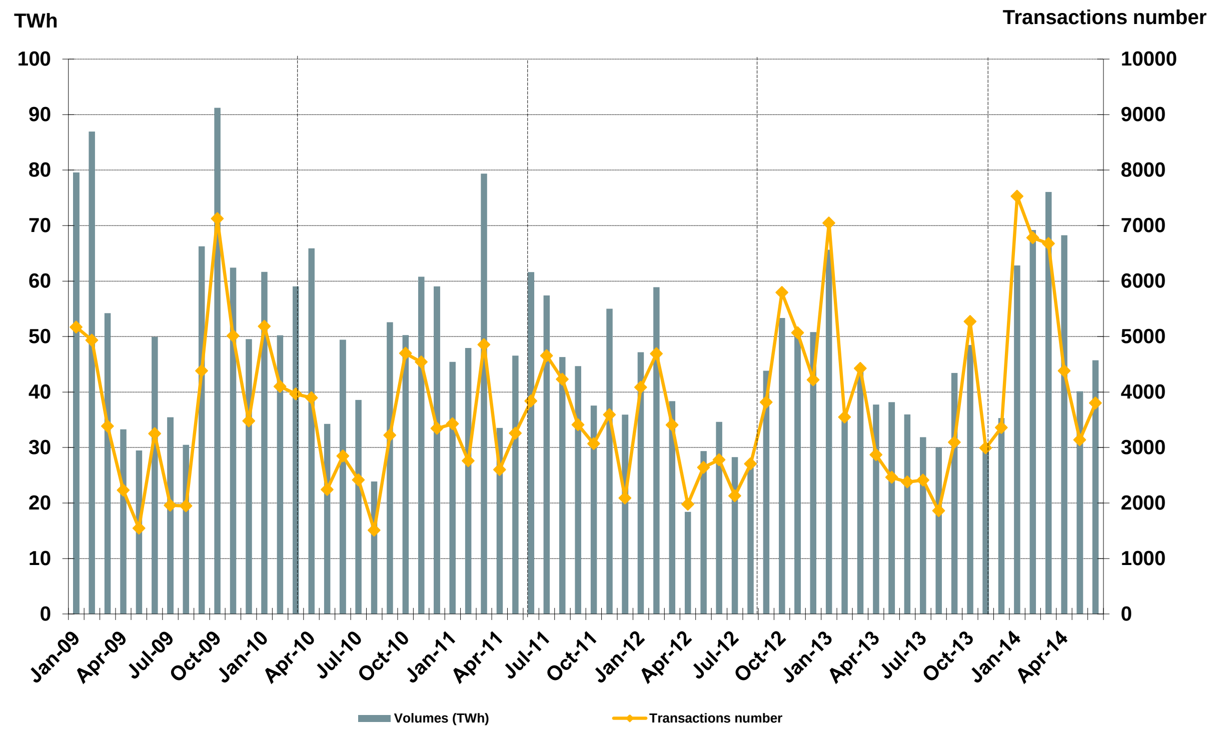
Source: EPEX SPOT, RTE – Analysis: CRE

3.2 The futures market

3.2.1 Increase in the volumes of annual products in the second and third quarter of 2013 following arbitrage with ARENH

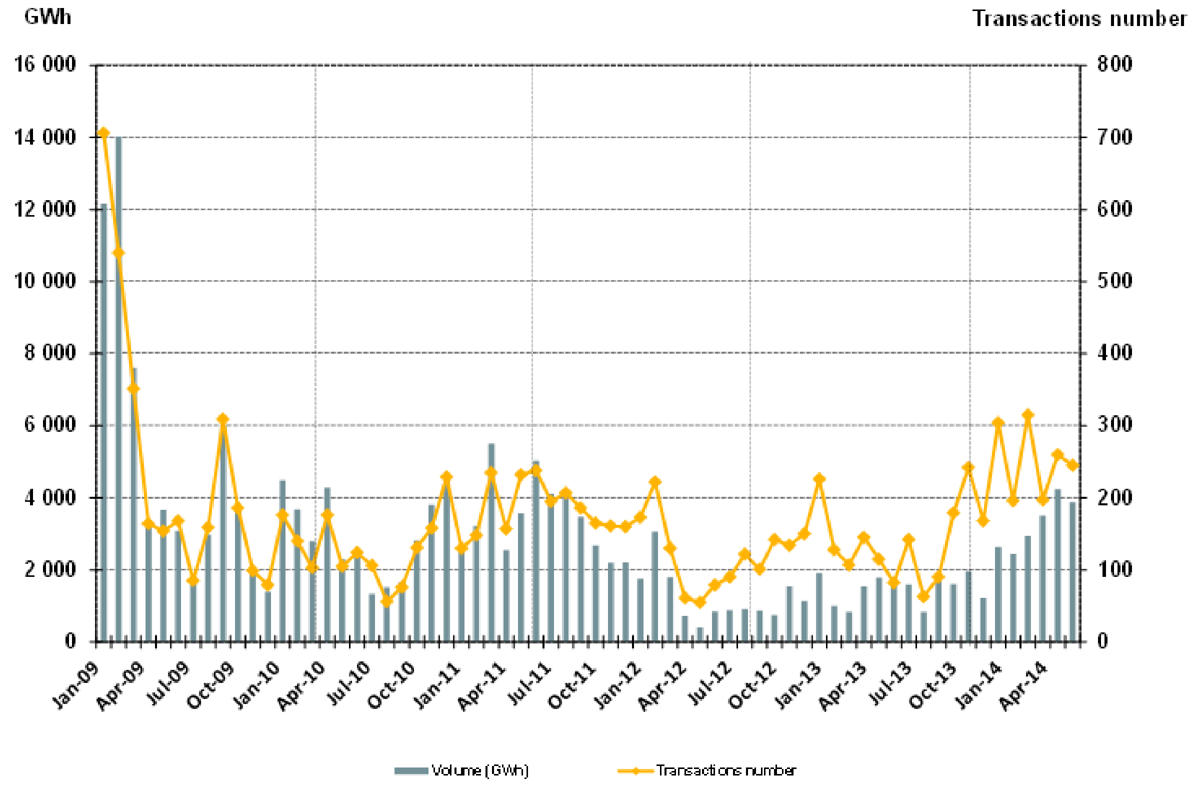
Table 3 (see Key figures) presents the quarterly evolution of trading for the different products (M+1, Q+1, Y+1) and different periods. The volumes traded in 2013 in the futures markets remained stable compared to 2012 (-1%). While monthly and quarterly products decreased (-9% and -33% respectively), the Y+1 calendar product increased by 15% (14TWh) as illustrated in Graph 55. This sharp increase is due to the arbitrage by alternative suppliers after the price of the calendar product fell below the ARENH price (€42/MWh) between the months of May and August (see Graph 44), enticing participants to seek supplies via the Y+1 product rather than the ARENH mechanism. The volumes traded over this period increased by 15 TWh.

Graph 54: Monthly evolution of volumes and of the number of transactions in the intermediated futures market



Source: EEX Power French Derivatives

Graph 55: Monthly evolution of volumes and of the number of transactions in the organised futures market



Source: EEX Power French Derivatives

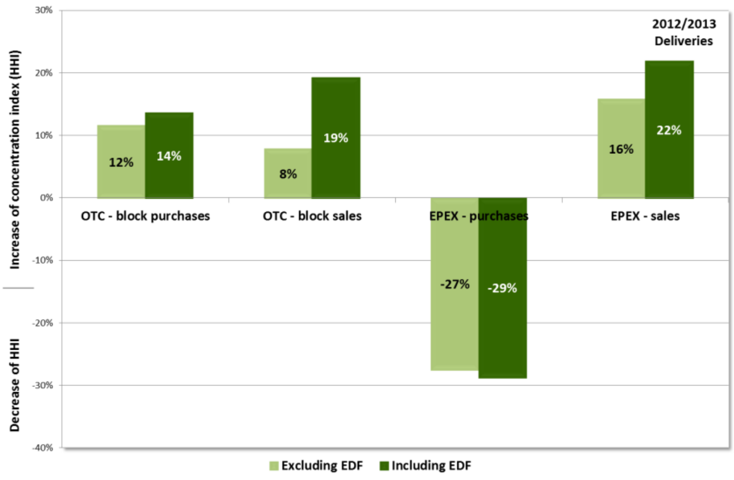
3.3 Concentration indices of the different market segments

Following market concentration indices is important within the framework of a process to open energy markets to competition. The Herfindahl-Hirschmann indices (HHI) may be used in the electricity market in France, to measure the level of concentration of the different activity segments. The lower the number of market participants, the higher the concentration index:

- 0 – 1,000: low degree of concentration;
- 1,000 – 2,000: concentrated market ;
- Higher than 2,000: very concentrated market.

The analysis covers a market including EDF and the same market excluding EDF. It is interesting to distinguish between these two cases given the place occupied by the French incumbent electricity supplier in the new market segments and especially in historical market segments (generation, end customers, etc.).

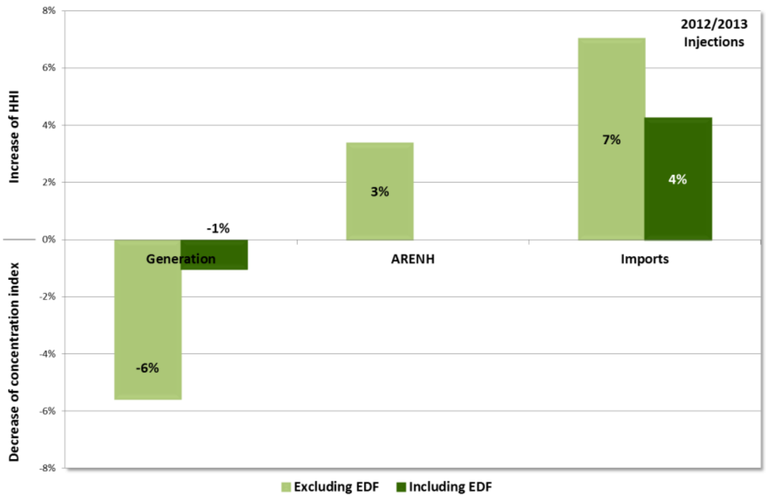
Graph 56: Comparison of 2013 and 2012 HHI - Trading



Source: EPEX Spot, EEX, Brokers, RTE – Analyis: CRE

Trading activities are not concentrated in France (see Table 10). However, concentration in brokerage platforms increased between 2012 and 2013, as well as on the exchange in the direction of sales (sees Graph 56).

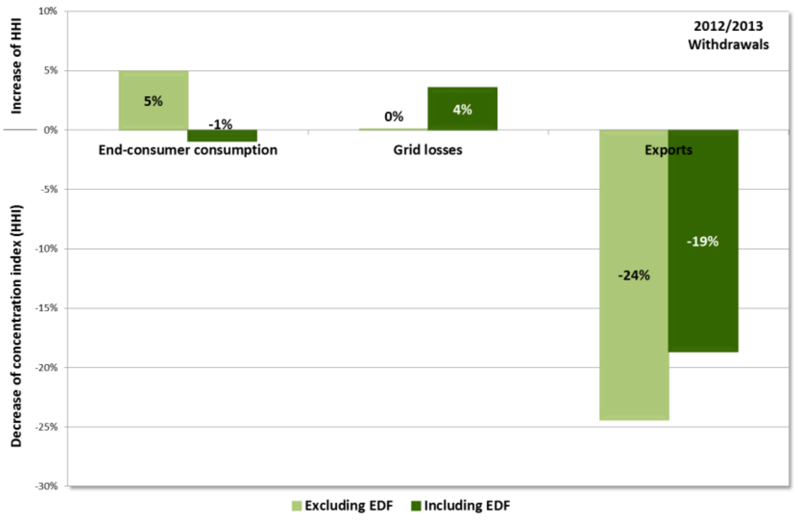
Graph 57: Comparison of 2013 and 2012 HHI - Injections



Source: RTE – Analysis: CRE

Concerning activities related to 'injections', the level of concentration of the generation segment dropped between 2012 and 2013, with or without EDF. Concentration in the ARENH purchase segment increased slightly. The imports sector recorded the highest increase in concentration (see Graph 57).

Graph 58: Comparison of 2013 and 2012 HHI - Withdrawals



Source: RTE – Analysis: CRE

With regard to the activity related to 'withdrawals' in France, the HHI indices increased between 2012 and 2013 for the segment 'consumption of end clients' without EDF. The concentration indices of the 'losses' segment also increased if EDF is taken into account. The export segment was also much more competitive in 2013 compared to 2012 (see Graph 58).

4 Development prospects for the electricity market

4.1 Integration of the European market

4.1.1 Flow-based market coupling mechanism and price effects

The go-live of the flow-based (FB) market coupling mechanism[70], scheduled for 31 March 2015, aims to optimise market coupling and enable selection to a greater degree of the least expensive generation means available across the entire coupled zone. This improvement is possible by henceforth placing all the physical capacity of the network in the service of the most relevant cross-border trades. The trade domain given to the market will be increased with flow-based coupling compared to the current interconnection capacity calculation method (known as ATC).

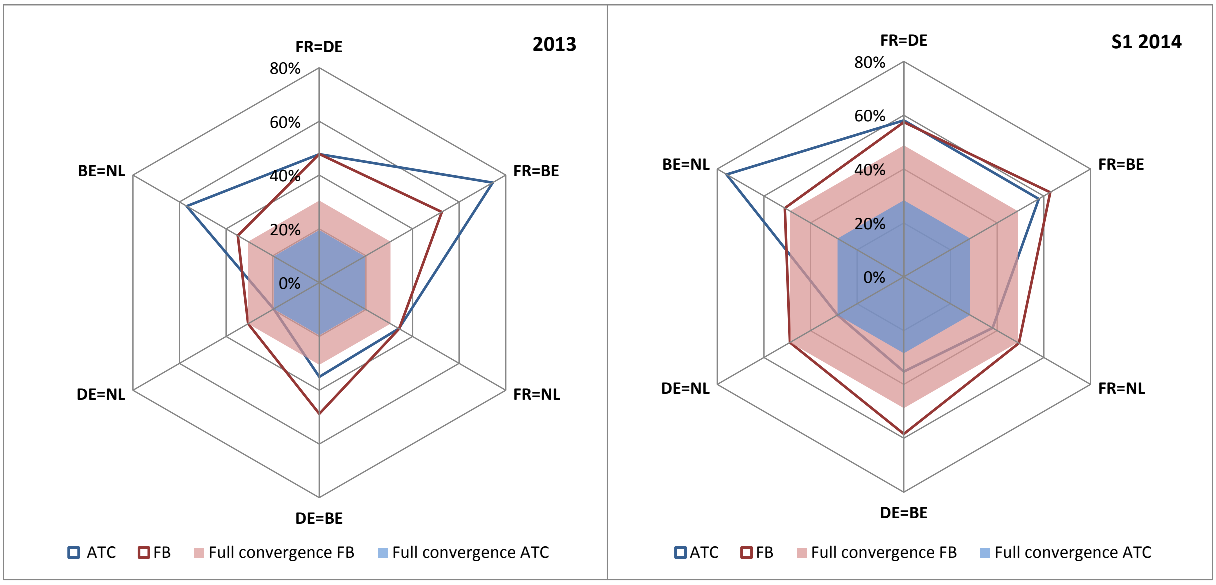
Parallel run simulations have been carried out since the start of 2013 by exchanges and transmission system operators in order to assess the impacts of the mechanism.

Graph 59 enables assessment of the effects of the FB market coupling mechanism on hourly price convergence rates in the Central West zone[71]. Compared to an ATC market coupling situation (in blue), the FB mechanism (in red) tends to bring together the convergence levels between each country, it improves the rate of convergence at borders where it is the lowest and decreases it where it is high. The effect of the mechanism is therefore positive with regard to price convergence in the four

[70] For more information, see CRE's annual report Cross-border electricity exchanges: use and management of interconnections in 2012 on its website
[71] Germany, Austria, Belgium, France, Luxembourg, the Netherlands

markets ("full convergence" in Graph 59), with the rate increasing from 20% in ATC to 31% in FB in 2013 and from 28% to 49% in the first half of 2014.

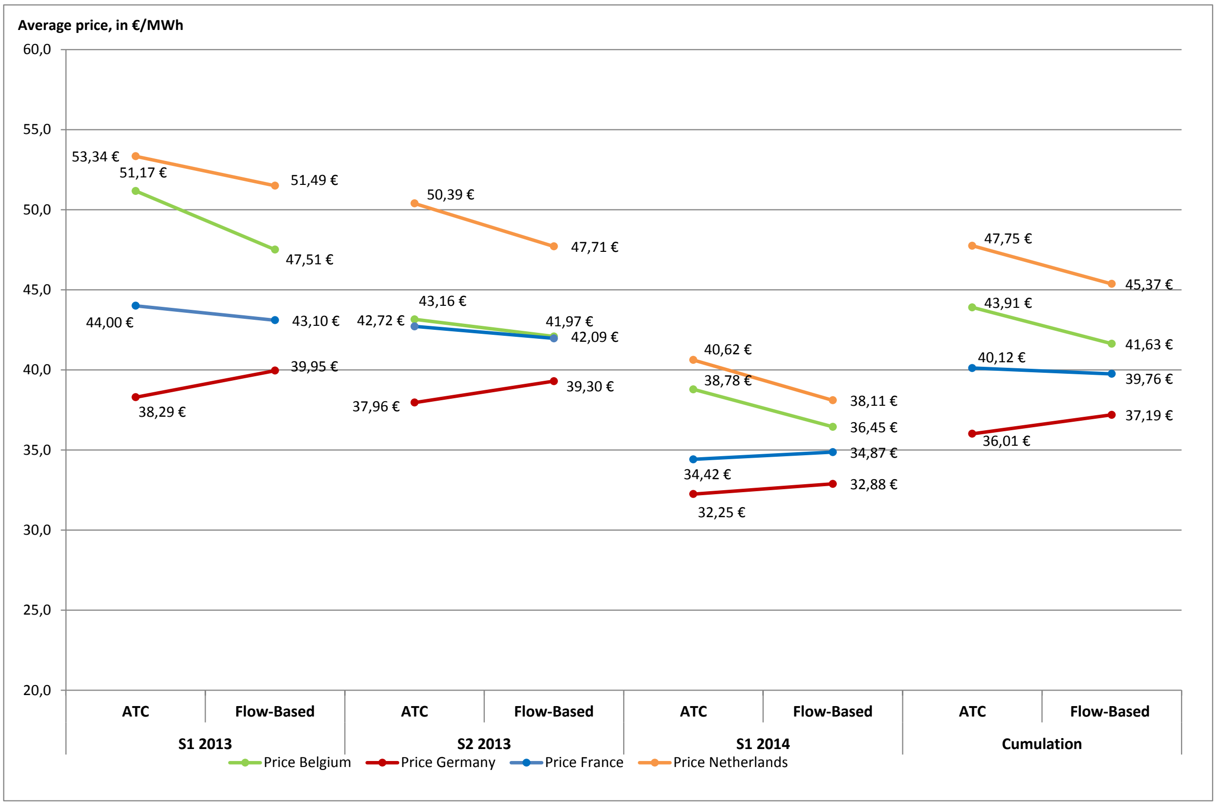
Graph 59: Effects of Flow-based market coupling on price convergence



Source CASC – Analysis: CRE

Graph 60 provides an overview of market prices simulated under the FB mechanism compared to actual prices derived from the ATC method. Simulations show that the mechanism tends to reduce market prices in Belgium and in the Netherlands, while they increase in Germany. In France, the mechanism generally tends to reduce the price, even if for certain periods where the price was particularly low, as in the first half of 2014, the French price could increase. Overall, the average prices converge due to the mechanism, reflecting better optimisation of the use of interconnection capacity. Therefore, for the year 2013, flow-based coupling reduced supply costs in the Central West region by about 100 million euros.

Graph 60: Effects of Flow-based market coupling on market prices



Source CASC – Analysis: CRE

4.1.2 NWE and SWE market coupling

On 4 February 2014, coupling of the daily markets in the North-West region[72] went live. Since that date, price coupling of regions (PCR) has enabled pooling of electricity offers in the North-West region. On 13 May 2014, the South-West zone[73] was coupled with the North-West zone for the day-ahead maturity following the same mechanism, thereby integrating the Spanish and Portuguese markets in the coupling. Since France has been coupled for several years now with Belgium and Germany, the main benefit for France has been the extension of coupling to Great Britain and Spain.

The markets in the South-West and North-West zones cover an electricity consumption of roughly 2,400 TWh per year. More than 3 TWh were traded daily at the start of 2014 in these markets, for an average value of over 200 million euros per day.[74]

The algorithm used (EUPHEMIA) simultaneously calculates the market prices of electricity and the net positions for each market zone based on implicit auctions which result from the pooling of offers in the different exchanges. Market coupling enables automatic allocation of interconnection capacity among electricity networks to the most cost-effective cross-border transactions. The least expensive electricity generation offers in the zone are selected within the limit of interconnection capacity, thereby reducing

[72]North-West Region: Germany, Austria, Belgium, Denmark, Estonia, Finland, France, Great-Britain, Latvia, Lithuania, Luxembourg, Norway, the Netherlands, Poland, Sweden
[73] South-West Region: Spain, France, Portugal
[74] Sourc:e CASC press release

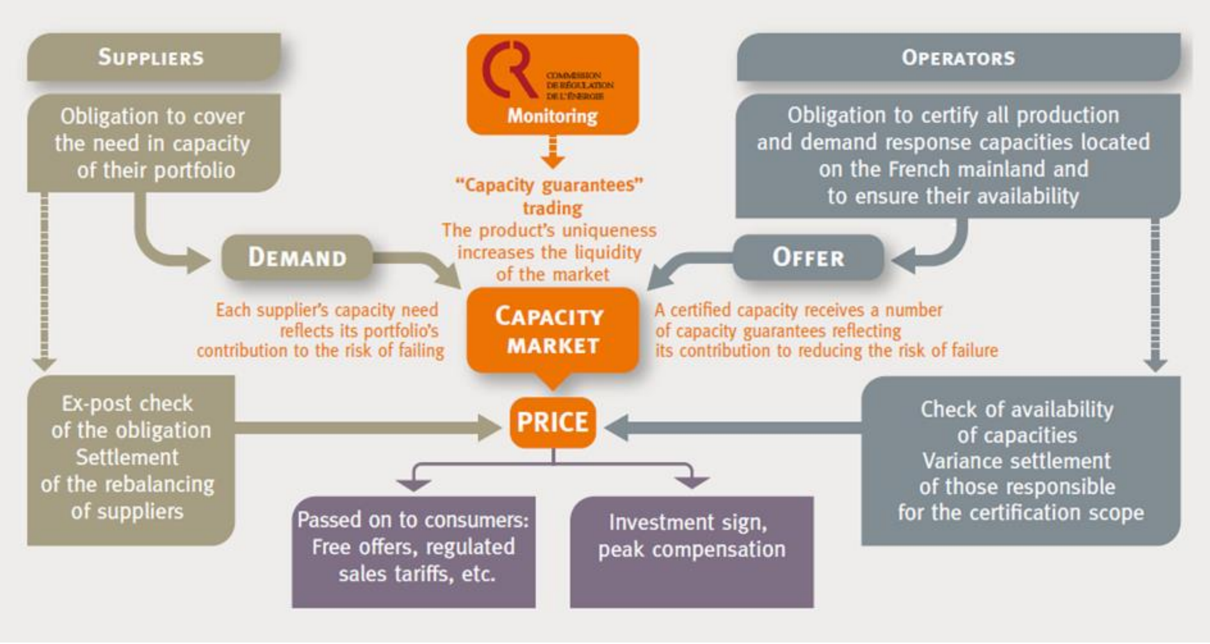
electricity supply cost. Moreover, the coupling mechanism serves to ensure that cross-border flows are consistent with the price differential.

4.2 Capacity mechanism

The capacity obligation mechanism aims to ensure future security of supply of the French electricity system. Its launch is scheduled for winter 2016-2017, and will thus partly respond to the forecast capacity deficit announced by RTE and which could reach up to 2,000 MW[75]. The mechanism will remunerate generation or demand-response capacity effectively available at times when the system is tight, particularly when there is a high level of consumption, in order to ensure the supply/demand balance and meet the system's security needs in line with the security of supply criterion set by the public authorities. It is therefore not the energy produced during peak hours, but megawatts of capacity effectively available that will be remunerated.

The capacity mechanism is based on the principle that each electricity market participant bears the responsibility for the risk to which it exposes the system. In practice, all suppliers shall have to ensure that they have at their disposal, depending on the consumption of their client portfolios at peak national consumption periods, a defined amount of capacity guarantees. These capacity guarantees may be obtained by the ownership or development of generation or demand-response capacity, or through the purchase from third parties. Capacity guarantees, fungible products, will therefore be part of a market in which buyers and sellers meet, enabling a capacity market price to be revealed.

Graph 61: Functioning of the capacity mechanism



[75] http://www.rte-france.com/fr/actualites-dossiers/a-la-une/bilan-previsionnel-de-l-equilibre-offre-demande-d-electricite-des-solutions-a-deployer-pour-preserver-la-securite-electrique-1

CRE's wholesale market monitoring missions

Decree No. 2012-1405 of 14 December 2012, on the contribution of suppliers to the security of electricity supply and on the creation of a capacity obligation mechanism in the electricity sector, entrusts a set of missions to the Energy Regulatory Commission. In this context, the Energy Regulatory Commission, within the framework of its wholesale market monitoring mission:

- shall have access to the capacity guarantee register, as specified in Article 16 (VI) of the decree
- shall collect information on the characteristics of capacity guarantee transfers, including in particular the price, as defined in Article 17 (I) of the decree;
- shall publish at least once per year, in accordance with Article 17 (II) of the decree, statistical data on all of the transactions and public offers for transactions in capacity guarantees and derivative products and on the volumes traded or offered and their price;
- shall define and publish the method of calculating the reference price for each delivery year, as stated in Article 23 (IV) of the decree.

In addition, the third ACER guidelines specify that capacity remuneration mechanisms, once implemented, shall fall within the scope of REMIT since wholesale energy products are traded, including derivative products related to electricity and natural gas, products traded or delivered in the European Union.

SECTION IV: WHOLESALE GAS MARKETS

Wholesale gas markets in France continue to be influenced by international markets. Against limited supply in the LNG markets, price spreads between the different regions (Asia, Europe and North America) led to more diversions of LNG cargoes to Asia and Latin America, to the detriment of Europe. In the USA although gas prices increased in 2013, they remained very low and more competitive compared to coal. On the contrary, in Europe, coal was more competitive than gas in power generation and affected the competitiveness of gas-fired plants.

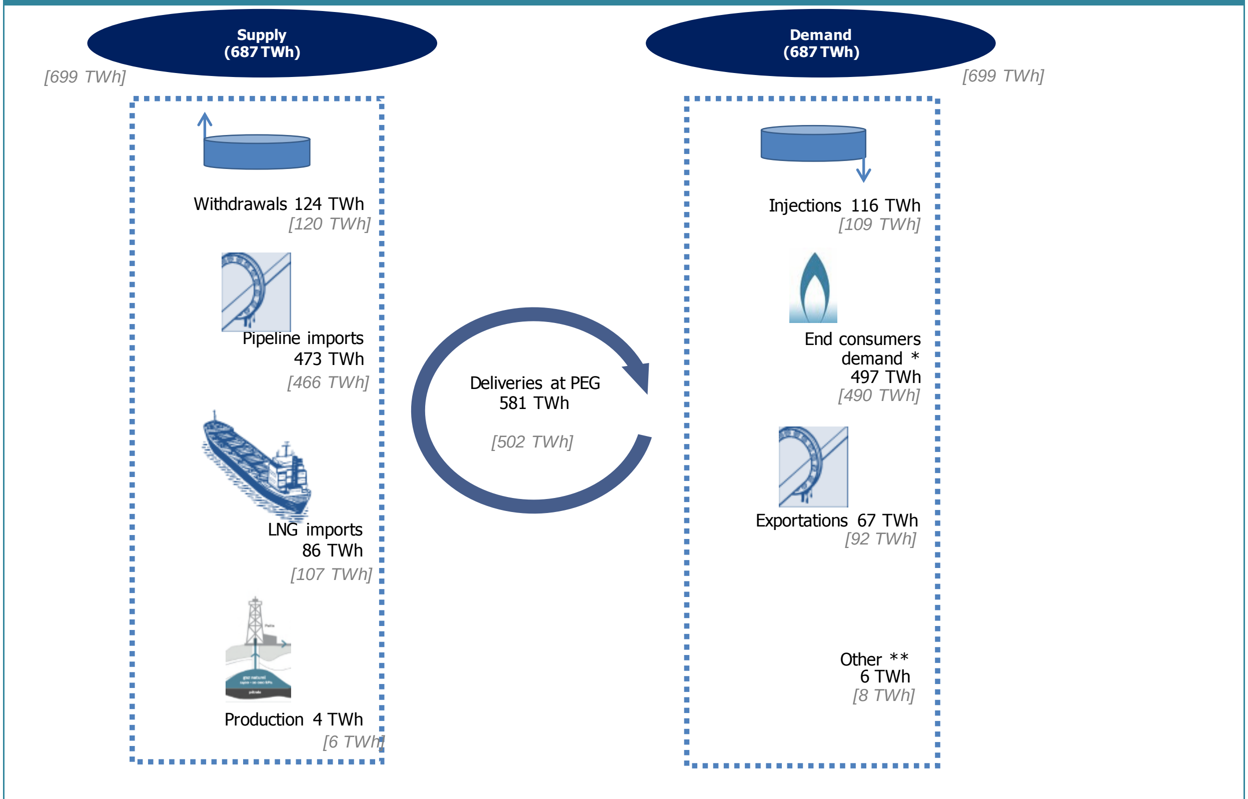
In addition to the international context, temperatures played a particular role in the formation of gas spot prices in Europe. While the relatively cold winter end in 2013 caused major price spikes, the mild temperatures during the first half of 2014 led to a drop in prices to their lowest levels since 2010.

Political instability in Ukraine and tensions between Europe and Russia rekindled concerns about a new gas crisis. The effects in the European markets were felt particularly in the futures price curve from winter 2014-2015.

1 Review of the gas system

LNG supplies in the French system, in line with the trend observed elsewhere in Europe, continued the drop started since the second half of 2011 (Graph 64). Faced with a slight increase in consumption in 2013, the decline in send-out was offset by a drop in land exports. While flows to Spain at the Larrau and Biriatou interconnection points increased by 19%, due in particular to the increase in exit capacity from April 2013, commercial flows from PEG Nord to other markets dropped sharply, in particular at the Oltingue interconnection (border with Switzerland).

Graph 62: Supplies and outlets in the French system 2013 [2012]

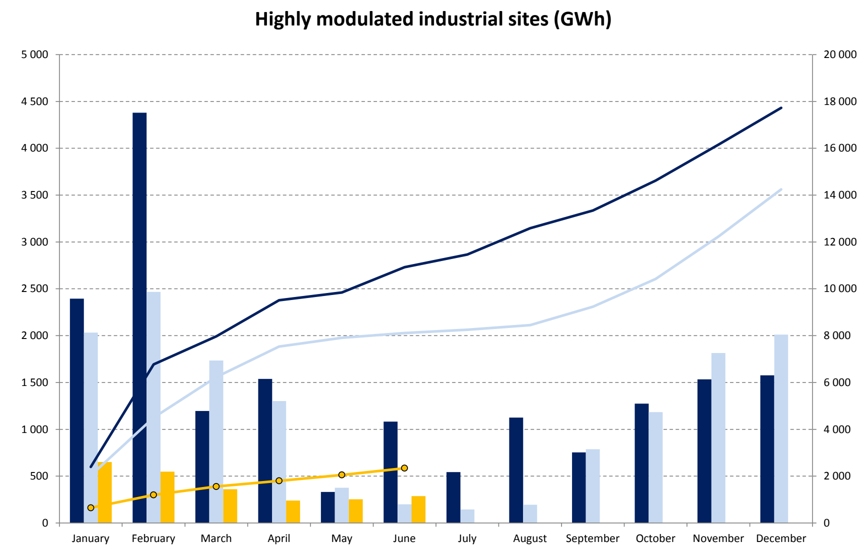


Source: GRTgaz, TIGF – Analysis: CRE

French storage was used more in 2013, due in particular to the relatively cold 2012/2013 winter end which explains the increase in withdrawals. The need to rebuild stocks then resulted in an increase in injections during summer 2013. The decline in inland production in France is related to the end of the commercial operations of Lacq field since November 2013.

The consumption increase in 2013 must be attributed in particular to the residential sector and temperature differences compared to the previous year. Consumption of industrial sites directly connected to the transmission system dropped in 2013 compared to 2012, particularly due to a 20% drop in the consumption of highly modulated sites in the GRTgaz zone (see Graph 63).

Graph 63: Consumption level in GRTgaz's transmission system



Sources: GRTgaz data – Analysis: CRE

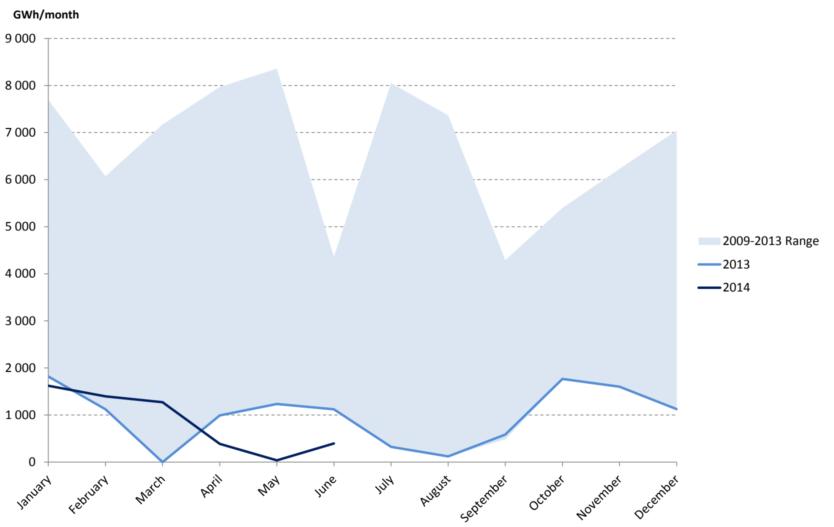
Historically low levels of LNG in France

LNG send-out from the Montoir-de-Bretagne and the Fos-sur-Mer terminals reached historically low levels in 2013 (see Graph 64). The downward trend continued in the first half of 2014. It responds, as stated previously, to global arbitrages in favour of more profitable markets such as Asia and Latin America to the detriment of the European continent. As a result, only 25% of European regasification capacities are used.

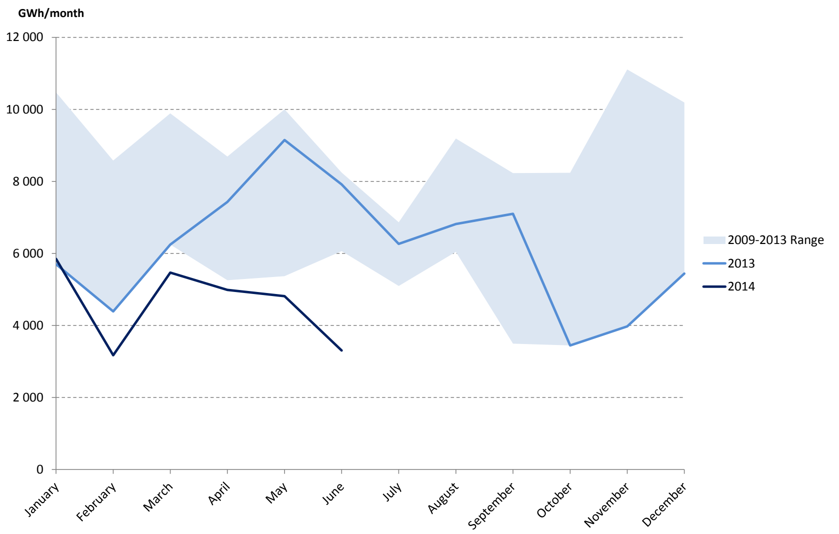
The low send-out at Fos, though higher than that at the Montoir terminal, fuels tightness observed in the markets in the south of France (Section 2.1.2). At Montoir terminal, the lack of LNG deliveries resulted in a send-out shutdown between the end of February and the start of April 2013, and between the end of March and mid-May 2014.

Graph 64: Historical send-out from the French LNG terminals

a. Montoir



b. Fos



Source: FosMax, Elengy – Analysis: CRE

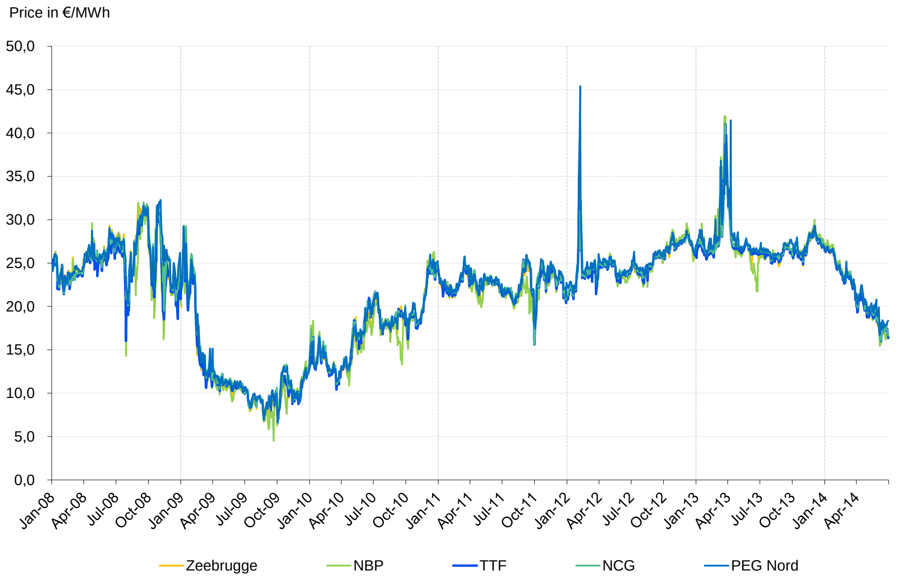
2 Gas prices

2.1 Wholesale spot prices in France

2.1.1 Gas prices at PEG Nord increased in 2013 but dropped sharply in the first half of 2014 due to a very mild winter

Aligned with the prices of the main gas marketplaces in Europe, prices at PEG Nord increased on average in 2013, but then dropped sharply in the first half of 2014 (Graph 65). European gas markets saw a period of major tightness at the end of March and at the start of April 2013 against high consumption, very low stocks following a relatively cold winter and limited arrival of LNG in Europe[76].

Graph 65: Gas spot prices in Europe



Source: Heren, Argus, Powernext

A second price spike episode emerged specifically in the French market on 9 and 10 April 2013. This episode was analysed in depth by CRE.

The price spike of 9 April 2013 at PEG Nord emerged in a context of maintenance operations affecting several entry points in the North zone (Dunkirk, Taisnières H and Obergailbach). These maintenance works prevented a certain number of market participants to supply the French market from neighbouring countries.

To offset its own capacity reductions, one shipper chose to make purchases on the spot market (day-ahead) and attempt to book important quantities of UBI (use-it-or-buy-it) capacities on 8 April for delivery on 9 April in order to balance its portfolio. This shipper, having not obtained the capacity

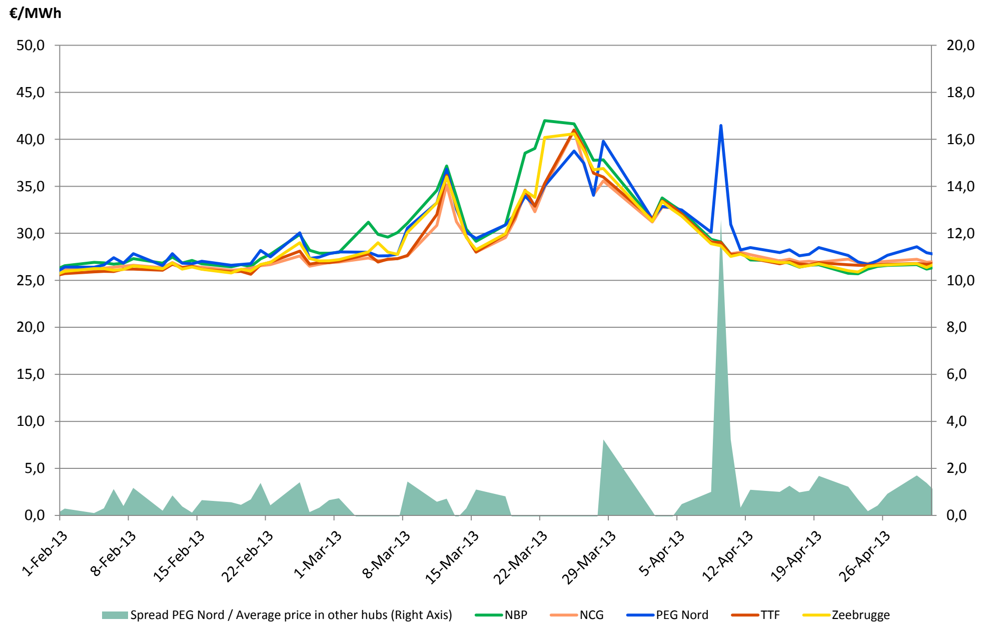
[76] See CRE's report on "The functioning of wholesale electricity, CO_2 and natural gas markets in 2012-2013" http://www.cre.fr/documents/publications/rapports-thematiques/fonctionnement-marches-de-gros-electricite-co2-gaz-naturel-2012-2013)

requested, had to purchase very large quantities on the illiquid within-day market, in particular on the Powernext platform.

During a period of major maintenance operations in the transmission networks, and given the characteristics of the UBI product, the probability for this shipper to obtain the capacity requested was very low. This action therefore presented considerable physical and financial risks, which jeopardised both this player and the French market and contributed to the formation of the price spike registered at PEG Nord.

CRE therefore recommended that this shipper be more careful in the management of its supplies and do its utmost to anticipate its balancing needs, in particular with regard to the weight that its deals may have in the within-day contracts considering the liquidity and the depth of this market.

Graph 66: Price spike of 9 April at PEG Nord



Source: Powernext, Heren – Analysis: CRE

Moreover, during this in-depth analysis, the use of the France-Belgium interconnection by shippers was studied thoroughly.

This study highlighted that the import capacity at Taisnières H was not fully optimised on day-ahead since certain shippers use this interconnection for hourly modulation in Belgium. Shippers are required to balance their portfolio on an hourly basis in Belgium, whereas in GRTgaz's system balances are required on a daily basis.

The operational rules at the interface between the two transmission systems enable the necessary flexibility to be offered for hourly adjustment of flows from France. This use of the interconnection then limits the possibility for shippers to conduct transit arbitrages between the Belgian and French hubs up to the maximum of their booked capacity.

This matter is mainly a market model issue. The evolution of balancing rules will not fully homogenise the different European markets in the short term. Therefore, the behaviour of participants within this context continues to be closely monitored.

Another highlight of 2013 was the disconnection of the NBP during the month of June, with the price in the British market dropping sharply (up to €5/MWh lower than other hubs) against abundant supply. The long situation of the British system during that period is due in particular to works on the Norpipe between 3 and 22 June 2013 (which caused a diversion towards the United Kingdom of flows usually destined for the Netherlands and Germany), and to the Interconnector shutdown between 12 and 27 June (preventing the surplus gas at the NBP to be exported to the continent).

Spot prices at PEG Nord increased during the last months of 2013. This may be associated in part with uncertainty surrounding the capacity of European stocks, which were low at the start of winter 2013/2014, to adequately supply the markets in the event of strong consumptions. Other factors, such as tensions related to the Ukrainian gas debt and uncertainty about Dutch medium- and long-term gas production, also contributed to accentuating this trend.

The first half of 2014 was characterised by a sharp decrease in spot prices. All of the hubs in north-western Europe saw levels below €20/MWh during the last few months of the period, i.e. the lowest levels since 2010. While concerns about the low stock levels had been expressed at the start of winter, the particularly mild temperatures at the end of the season heavily affected consumption, resulting in a very comfortable level of stocks at the start of the refill period and large volumes proposed for sale in the markets, which drove prices down. Although the Ukrainian crisis raised concerns about gas supplies from Russia for winter 2014/2015, the high stock levels at the start of summer limited its effects on spot prices due to a lesser need for refills.

PEG Nord maintained a low spot price spread compared to the main European hubs (Table 25). These differences are due to the absence of structural congestion in the interconnections connecting these markets to the French hub (Table 26). The slightly higher differences in 2013 may be due to the price peak events described previously, while the drop observed in the first half of 2014 is related to the low demand which limited interconnection saturation periods.

Table 25: Day-ahead price spreads between PEG Nord and the main European hubs

Average spread in €/MWh	Zeebrugge (B)	NBP (GB)	TTF (NL)	NCG (GER)
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
2013	0.54	0.30	0.57	0.40
H1 2014	0.45	0.23	0.43	0.15

Source: Powernext, Heren – Analysis: CRE

Table 26 shows the utilization rate of the different interconnections and links in the French system. The utilization of entry capacities of interconnections located in the north of France saw a relatively stable level compared to 2012; however, the utilization of their exit capacities decreased considerably, particularly at Obergailbach and Oltingue. The drop in flows at the Oltingue interconnection is related to the convergence between market prices in Italy (PSV) and those of the other European hubs.

The congestion of the North-South link in the North to South direction increased in 2013 and in the first half of 2014 as a result of the tightness observed at PEG Sud. The drop in the utilization of exit points towards Spain is to be put into perspective given the 100 to 165 GWh/d increase from April 2013 of this capacity. Exports to Spain increased by 19% between 2012 and 2013 and between the first half of 2013 and the first half of 2014. The increase in flows to Spain also explains the higher utilization of the link between GRTgaz and TIGF in the PEG Sud to TIGF direction.

Table 26: Capacity utilization rates of gas infrastructure in France

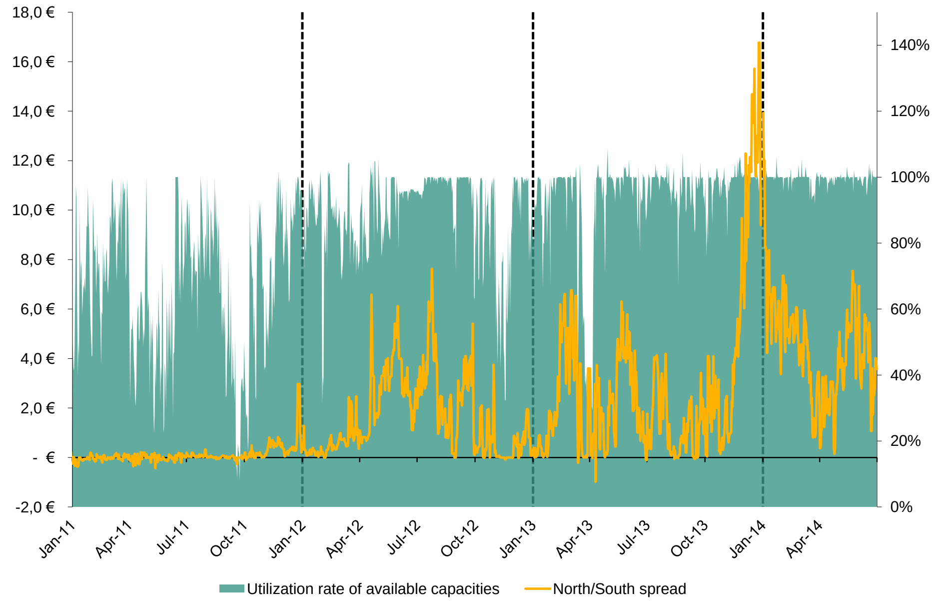
Interconnection	Direction	2011	2012	2013	H1 2014
Dunkirk	**Entry**	79%	85%	89%	86%
Taisnières B	**Entry**	62%	57%	51%	36%
Taisnières H	**Entry**	68%	55%	72%	71%
	Exit	19%	22%	11%	11%
Obergailbach	**Entry**	42%	52%	65%	45%
	Exit	39%	10%	2%	1%
Oltingue	**Exit**	49%	32%	18%	11%
North-South link	**North to South**	68%	89%	94%	99,6%
	South to North	0%	0%	1%	0%
Sud-TIGF link	**Sud to TIGF**	45%	47%	53%	61%
	TIGF to Sud	8%	6%	6%	3%
Spanish border	**Entry**	9%	1%	5%	1%
	Exit	65%	90%	76%	72%

Sources: GRTgaz, TIGF – Analysis: CRE

2.1.2 Greater tension in the North/South spread

The very large spreads between spot prices at PEG Nord and Sud, which emerged during summer 2012, continued in 2013 and in the first half of 2014 (Graph 67). It even widened sharply between the end of 2013 and the start of 2014 against tight supply in the south of France (see Box 4). Despite the easing of the situation between the end of March and all throughout April 2014, the spread widened again in May due to summer maintenances at the North to South link and very low liquidity in the spot market at PEG Sud (see section 3.2).

Graph 67: North/South spread and North to South link's utilization



Source: Powernext, GRTgaz

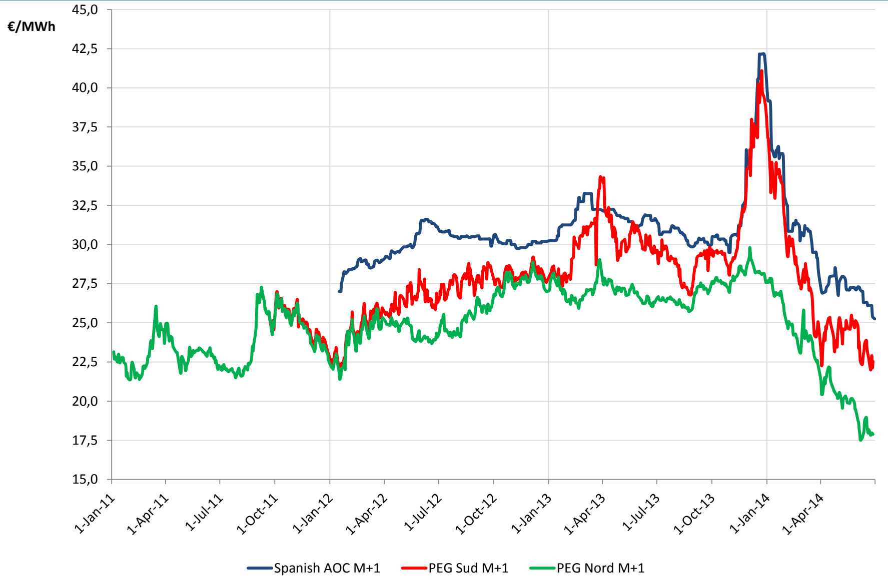
The structural tightness of the south zone observed since 2012 results in the permanent congestion of GRTgaz's North to South link. It is due in particular to tightness in the global LNG markets, which directly affect the arrival of LNG cargoes at the Fos-sur-Mer terminals, and which also results in increased exports to Spain, where they partly substitute LNG diverted to other destinations.

Prices of month-ahead contracts[77] at PEG Sud fluctuate between a lower PEG Nord and a higher Spanish price (Graph 68). On the one hand, the price at PEG Nord reflects wholesale prices in the north-west European markets. On the other hand, the Spanish prices reflect the value of LNG stocks in the Spanish system, this value being dependent on the evolution of prices in the global LNG markets.

The evolution of prices at PEG Sud depends on the supply/demand fundamentals specific to the zone. It should be noted that despite a structural orientation of flows in the France to Spain direction, arbitrages are triggered when the prices at PEG Sud increase considerably, bringing backhaul flows in the Spain to France direction at that interconnection.

[77] The absence of a reference price in the Spanish market does not enable this market to be compared with PEG Sud for the day-ahead segment.

Graph 68: Evolution of M+1 prices at PEG Nord, PEG Sud and in Spain

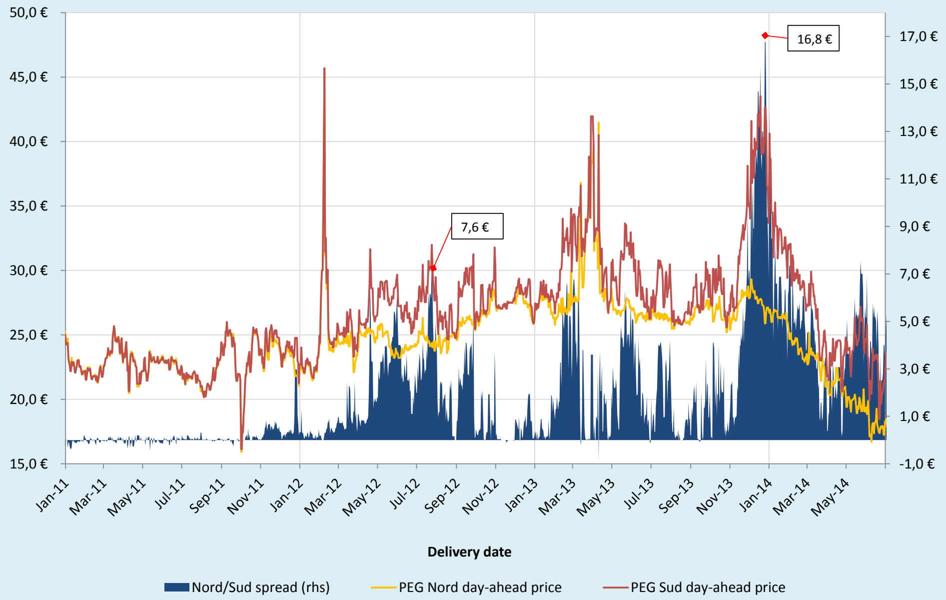


Source: Powernext, Heren – Analysis: CRE

Box 4: Exceptional tightness in the South zone in November / December 2013

The day-ahead price spread between PEG Nord and Sud considerably widened in November and December 2013, largely exceeding the previous historical record of 2012 (€7.6/MWh) and reaching almost €17/MWh towards the end of the year. These very large spreads emerged in a context of particularly tight supply in the south of France, characterised by an important lack of LNG arrivals, relatively high consumption and large exports to Spain (Graph 70).

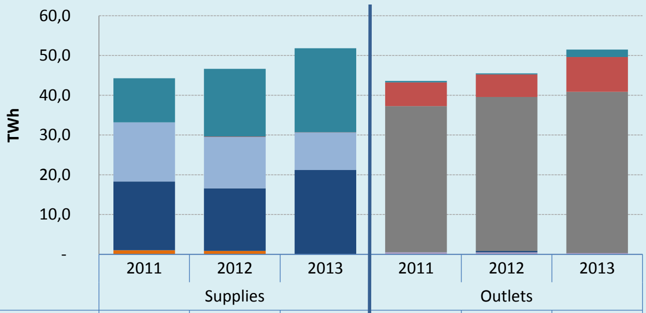
Graph 69: Evolution of the day-ahead spread between PEG Nord and PEG Sud



Source: Powernext, EOD indexes

The last quarter of 2013 was marked by very low levels of send-out from the French LNG terminals (Graph 64). Send-out totalled 17 TWh over that period, i.e. the lowest level in five years. The supplies of LNG in France, particularly in the south at the Fos-sur-Mer terminals, was affected by the unplanned unavailability of Algerian production (in particular in the Skikda installations) and by high demand in Asia, where prices reached levels close to the historical records (around €48/MWh), and in South America. Thus, only 140 GWh/d on average were sent out at the Fos PITTM in the fourth quarter of 2013 compared to 230 GWh/d in the fourth quarter of 2012.

Graph 70: Supplies and outlets in the south of France between November and December in 2013, 2012 and 2011



	Supplies 2011	Supplies 2012	Supplies 2013	Outlets 2011	Outlets 2012	Outlets 2013
Storages	11,08	17,03	21,15	0,38	0,26	1,85
France / Spain interconnection	-	0,07	0,06	5,97	5,68	8,74
Consumption				36,72	38,73	40,54
Fos terminals	14,88	12,94	9,41			
North-south link	17,27	15,72	21,20	0,02	0,34	0,00
Jura point				0,51	0,48	0,33
Production	1,03	0,86	-			

Source: Powernext, GRTgaz – Analysis: CRE

The drop in exit flows from the Fos terminals was concomitant with a significant increase in consumption, following a cold snap particularly affecting the south of France and the Iberian Peninsula, which moreover involved high exports to Spain. Although the consumption levels observed during that period are not exceptional, the situation at Fos created physical congestions within GRTgaz's transmission system and difficulties in supplying the south-east of France. These congestions led GRTgaz to take exceptional measures[78], particularly that of reducing interruptible capacity available at the North-South link (which was completely saturated during the period) in order to encourage withdrawals from Salins storages in the south-east of the country. Moreover, the low stocks of Salins storages prevented GRTgaz from proposing its JTS-winter (joint transport storage) service for 31 gas days between November and December[79]. These constraints on availability of capacity from the north to the south aggravated the tightness in the spot markets[80].

Exit flows to Spain at Larrau reached historical levels during the last few months of 2013[81]. While since 1 April 2013, daily exit flows reached an average 116 GWh/d, they increased to 143 GWh/d between November and December, with 11 days at around 160 GWh/d in December. It should be noted that, for a few days between the end of November and the start of December, the situation at PEG Sud led to backhaul nominations (Spain to France) varying from 1 to 8 GWh/d.

Against this tightness at PEG Sud, and given the impact of send-out from Fos on market prices and uncertainty about the loading and unloading programmes of these terminals, CRE reiterated to market participants their obligations under the REMIT Regulation, especially with regards to the disclosure of any inside information they may have and which would be likely to significantly affect the

[78] ShipOnline of 29 November 2013: http://www.grtgaz.com/fileadmin/newsletter/shiponline/shiponline_76_site.html
[79] This service enables the auctioning each day of up to 20 GWh/d of additional capacity from the North zone to the South zone.
[80] It should however be noted that despite these constraints, availability of the North-South link was higher than that observed during the same period in previous years.
[81] 80% of exit capacity at the Larrau interconnection was used in November and 90% in December, i.e. the highest levels since April 2013 when capacity increased from 100 GWh/d to165 GWh/d.

prices of wholesale energy products[82].

CRE interviewed the participants present at the Fos-sur-Mer terminals as well as the operators of these LNG terminals and pursues its analyses to ensure compliance of these players' behaviour with Articles 3 (prohibition of insider trading) and 4 (obligation to publish inside information) of the REMIT Regulation.

A more extensive analysis was carried out by CRE for this particular period. At this stage, CRE considers that the very large price spread between PEG Nord and Sud which appeared at the end of 2013 are due to the particularly tight context observed during that period.

Given that this tightness has continued beyond the end of 2013, transactions and price formation conditions are still being closely monitored.

The low capacity utilization of LNG terminals in France, particularly compared to certain terminals in north-west Europe, drew CRE's attention, and led it to conduct a public consultation to discover the reasons for this. Concerning the Fos-sur-Mer terminals, the answers provided by most market participants indicate that the absence of liquidity in the futures markets does not allow sellers to secure a price for the entire volume representing a LNG cargo and therefore does not provide incentive for unloading in the south of France and selling these volumes in the wholesale markets.

2.2 Futures prices in France

2.2.1 A downward trend in the forward curve in 2013

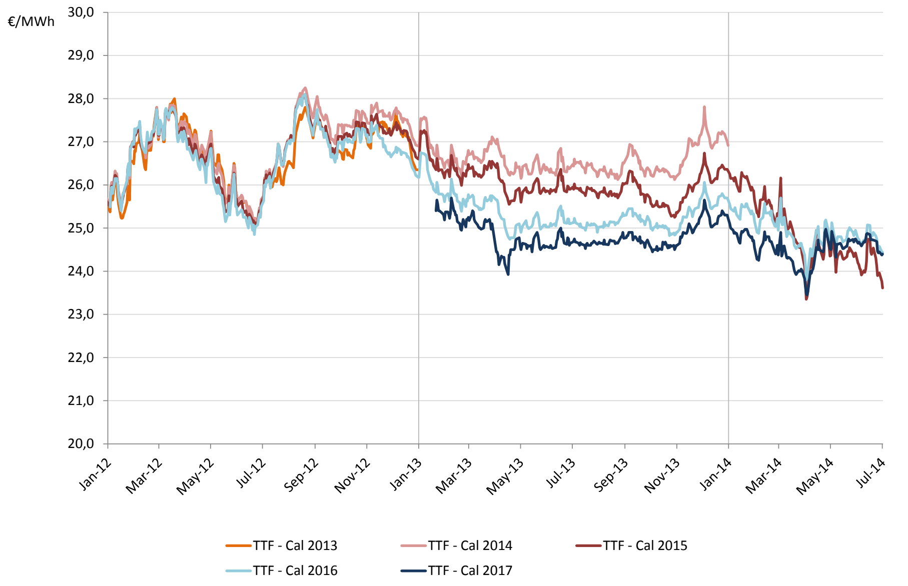
The structure of the forward curve for European gas markets changed considerably in 2013. While the prices of the calendar contracts for delivery in 2014 were relatively stable during the first ten months of the year, those of contracts for delivery from 2015 decreased significantly (Graph 71). Therefore, contrary to the previous years in which the prices of the different calendar contracts were very close, in 2013 they followed different paths with a price for the 2017 contract €2/MWh below the price for the 2014 contract.

Among the factors possibly behind these changes in the structure of the gas curve in Europe are: the evolution of oil prices and especially the changes of its curve structure (in strong backwardation in 2013); the effect of the economic difficulties of the euro zone on forecast consumption; the development of new infrastructure easing tightness in the LNG markets (especially in the USA and Asia-Pacific); the envisaged possibility of a drop in Asian demand in the event of a restart of a portion of the nuclear reactors in Japan.

The entire curve moved upwards since November, reaching a peak on 3 December followed by a sharp decline, and then stabilised around mid-December. These variations are due partly to movements in oil prices as well as to short-term factors such as disruptions in gas deliveries from Norway and market concerns about the arrival of winter (especially because of very low stocks for the period). The uncertainty about the future production of the Dutch Groningen field and tensions between Naftogaz (Ukrainian incumbent supplier) and Gazprom concerning the Ukrainian gas debt also contributed to these variations.

[82] CRE press release of 5 December 2013: http://www.cre.fr/documents/presse/communiques-de-presse/tensions-sur-le-marche-du-gaz-la-cre-rappelle-leurs-obligations-aux-acteurs-de-marche/tensions-sur-le-marche-du-gaz-la-cre-rappelle-leurs-obligations-aux-acteurs-de-marche

Graph 71: Structure of the forward curve at TTF



Source: Powernext, Heren – Analysis: CRE

2.2.2 Drop in forward prices in the first half of 2014

Following the movements in spot prices (section 2.1.1) and the medium-term curve, the prices of Calendar contracts, especially those for delivery in 2015, declined sharply during the first few months of 2014 (Graph 71). Prices also reacted, as a correction move, to the new information from the Dutch government concerning a smaller reduction (compared to estimates in November 2013) of production in the Groningen field in the upcoming years.

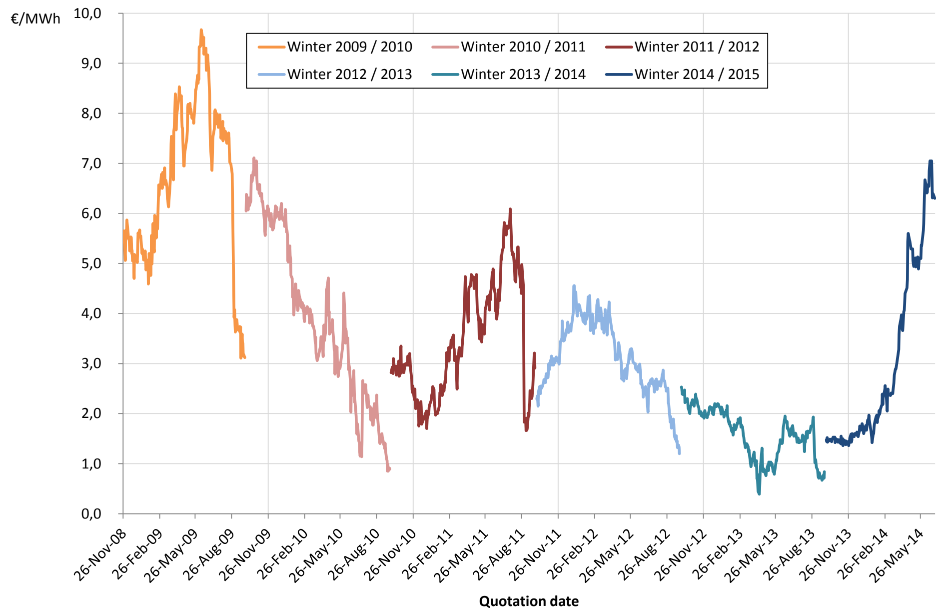
The progressive convergence of the prices of Calendar contracts in the first half of 2014 could be due to the effect, decreasing with the maturity, of short-term fundamentals and especially of the mild 2014/2015 winter. These factors caused a change in the structure of the back side of the curve from March, with the prices of 2015 contracts moving below those for delivery in 2016 and 2017. Additionnally, this forward price convergence was supported by a flatter Brent curve during the period.

Despite this price decrease, the European forward markets did not follow the same trend observed in the spot price during the second part of the six-month period. From March, the increase in oil prices and especially the situation in Ukraine (see Box 2) supported the upward movement of forward gas prices, limiting the drop in the price of the 2015 calendar contract and stabilising the prices of both 2016 and 2017 contracts.

2.2.3 Increase in summer/winter spread in 2014

The difference of price trends between spot and forward prices caused a widening of the spread between contracts for delivery in winter 2014/2015 and those for delivery in summer 2014 (Graph 72). This spread exceeded €7/MWh for certain days in June, i.e. a level that had not been reached since August 2009.

Graph 72: Evolution of the Summer/Winter spread



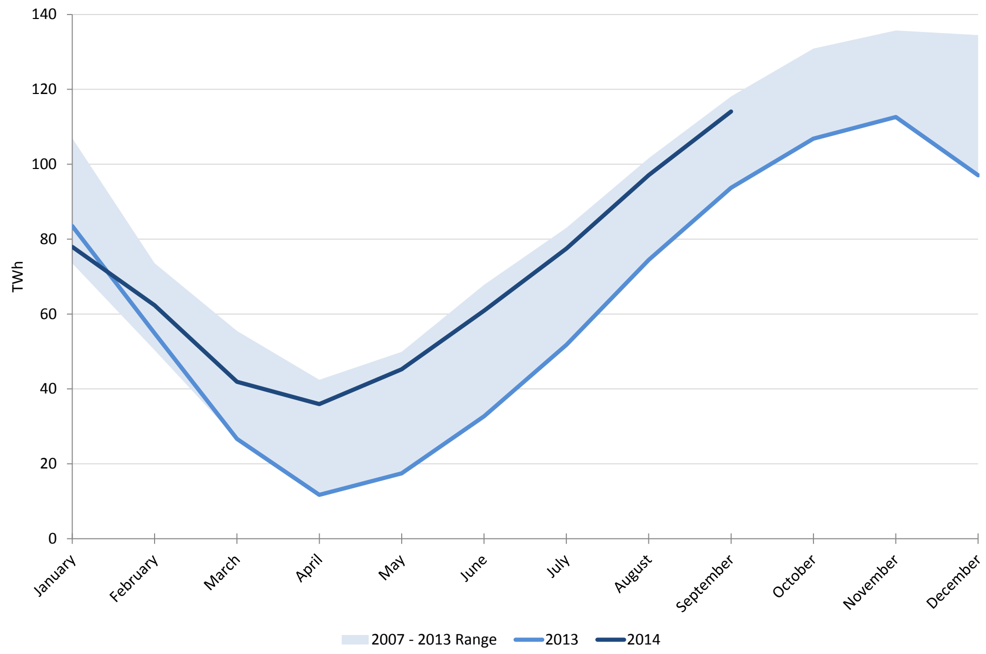
Source: Powernext — Analysis: CRE
NB: For a winter N/N+1, the index is calculated as the difference between the prices of Winter N/N+1 and Summer N contracts between October N-1 and April N, and as the difference between the prices of M+1 contracts and the prices of Winter N/N+1 contracts between April and September N

This spread is decisive for injection programmes at storage facilities since it enables the value of stored gas to be partly measured. The high level of stocks at the end of winter limited injected needs, which contributed to the disconnection between spot and futures prices.

Following the trend of other European markets, French stocks were quite high during summer 2014 (Graph 73), a situation in contrast with the historically low levels observed in 2013. According to GIE's[83] figures, French stocks were 56% full at the end of S1 2014 (92% as at 17 September) compared to 70% for Europe (91% as at 17 September). This very high European stock level reflects market concerns about the Ukrainian crisis and its possible effects on the supply of European markets from Russia for the following winter.

[83] Gas Infrastructure Europe: http://transparency.gie.eu/index.php/historical

Graph 73: Aggregated stock level in France



NB: Level of stocks as at the 1st day of the month Source: Storengy, TIGF – Analysis: CRE

3 Development of gas trading

3.1 Deliveries at PEGs up in 2013-2014

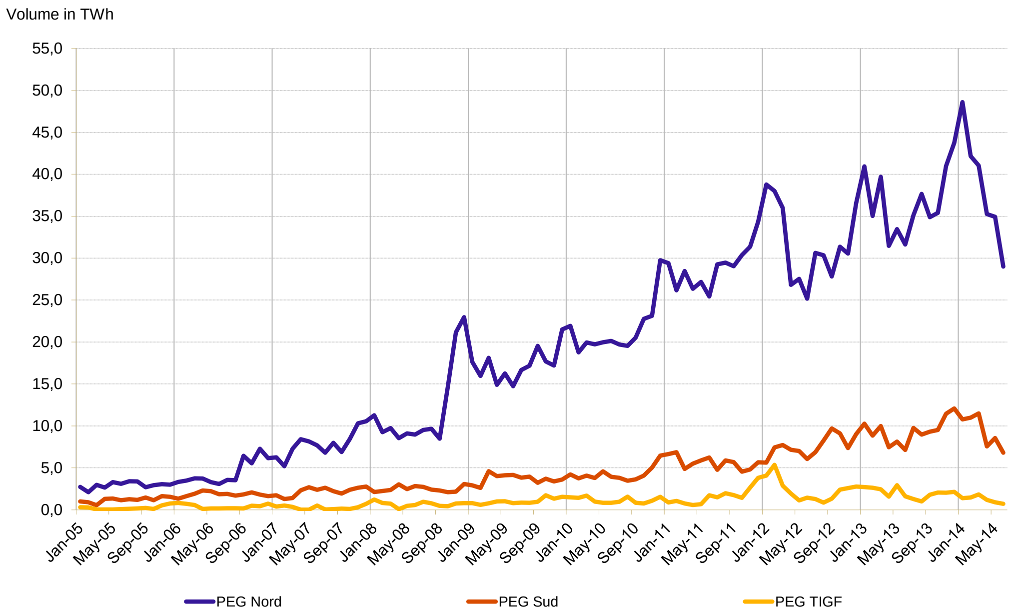
Most of wholesale gas trading in France relies on OTC trading through bilateral trading or brokers, the lasting part being traded on the organised market Powernext.

Trade on the French wholesale market materialises at gas exchange points[84] (PEGs) which are virtual points attached to each balancing zone where participants deliver gas to their counterparts according to their obligations

The present report distinguishes between volumes traded on the intermediated markets and physical deliveries at PEGs:

- intermediated markets include all of the contracts signed between the different participants through the exchange or brokers;
- deliveries at the PEGs cover net daily deliveries made between pairs of participants at the PEGs.

Graph 74: Deliveries at the PEGs



Source: GRTgaz, TIGF – Analysis: CRE

Deliveries at PEGs maintained their upward trajectory in 2013, but declined in the first half of 2014 (Graph 74). This drop is due to the seasonal nature of deliveries, marked all the more by the mildness of the climate in the first half of 2014, but also by the drop in volumes traded in brokered markets since April 2014 (sees section 3.2)

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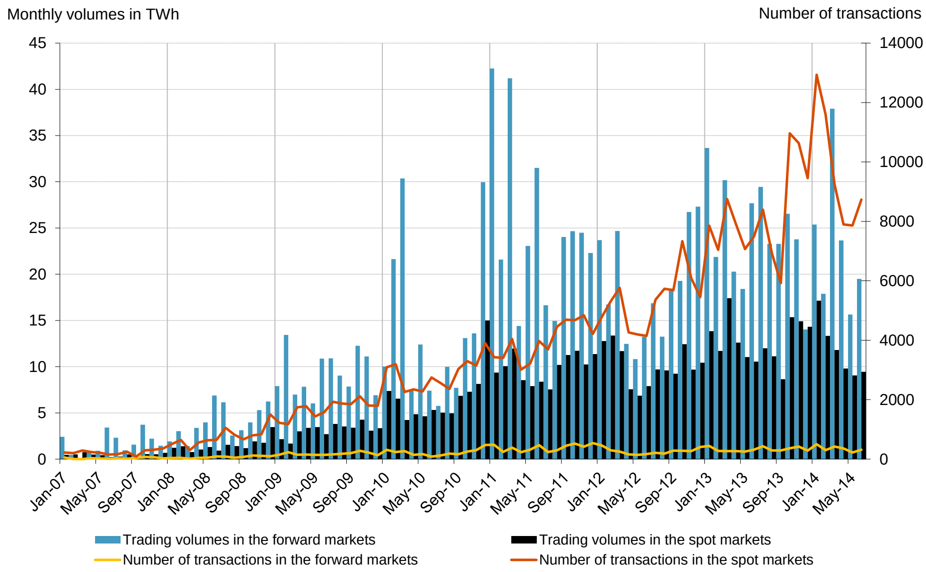
[84] Trading related to long-term contracts can also be conducted at the border points of the French network. These trades do not fall within the scope of this report.

The increase in deliveries at PEG Sud is due in particular to the increase in trades on the spot market, which has been supported by the tightness between the north and south zones of the French system since summer 2012. Deliveries at PEG TIGF decreased slightly.

3.2 Trading activity increased on the intermediated markets in France, despite a decline observed since the second half of 2014

Graph 75: Evolution of volumes traded and of the number of transactions in the French brokered market



Source: Powernext, brokers – Analysis: CRE

The upward trend in activity on the French intermediated market continued in 2013, with the volumes traded for all maturities increasing by 29% compared to 2012 (Graph 75). Transaction volumes however dropped in H1 2014 by about 9% compared to H1 2013. This trend was even more marked in the second quarter of 2014 which saw a 17% drop in volumes for spot maturity (within-day, day-ahead, week-end, balance-of-week and balance-of-month[85]) compared to the second quarter 2013.

If the volumes are broken down by PEG, PEG Nord is much more dynamic than PEG Sud with volumes almost four times higher. The volume peak observed in March 2014 may be due to, as for the previous years, the end of quotation for seasonal products for the summer season. It was moreover supported by geopolitical tensions in Ukraine, which triggered more hedging operations in the futures market during that period. Liquidity of PEG TIGF remained marginal, with participants having a preference for PEG Sud against the absence of congestion between the south zone and the TIGF zone. The merger of these two marketplaces in April 2015 should strengthen liquidity in the south of France.

[85] Balance-of-Week (BOW) is a product for delivery between D+1 (where D is the transaction date) and the last working day of the week in progress. The balance-of-month product (BOM) is for delivery between D+2 and the last day of delivery of the month in progress. When the transaction occurs the day preceding a weekend or a holiday, delivery begins from the following working day.

Box 5: The importance of the development of liquidity in the wholesale markets

The opening of energy markets to competition involved a modification of the electricity and gas market model. While competition for the supply of energy to end customers was made possible (opening of the retail market), the wholesale market was created to enable the different participants to purchase or sell energy wholesale over short-, medium- or long-term maturities. The merging between supply and demand can therefore be organised and a market price resulting from trades between participants can emerge.

The very existence of a wholesale market is not enough to ensure the proper functioning of a market. The market must also be considered liquid. In a liquid market, a participant may buy or sell without considerably influencing the prices. A liquid market is characterised by, among other things, the existence of a reference price for different maturities and by low transaction costs. Market liquidity reflects its level of maturity.

Knowledge of a reference price plays a role in the different maturities:

- in the short term, i.e. for the following day: players will be able to apply a merit order to meet their contractual commitments. A short-term market price (the spot price) encourages participants to mobilise the most efficient means to satisfy a consumption need. The intraday price enables needs to be adjusted depending on the latest known information;
- in the medium term (from D+2 to three years in advance): the market price enables the formulation of commercial offers to end customers over these maturities and also enables decision making regarding the structure of the portfolio (booking of transmission or storage capacity for example) and to carry out hedging operations to manage a risk of spot price variation;
- in the long term (beyond three years): a long-term price signal, when it exists, enables identification of structural needs, and may encourage investments (development of new production means, construction of new interconnection capacity, etc.).

A certain number of exchanges or specialist publications publish the "market price" for each of the maturities. Knowledge of this price however, is only useful if market participants have the real capacity to buy or sell quantities, at times large quantities, at a price close to this theoretical price. When market participants intervene in the wholesale markets, they pay transaction costs which depend mainly on:

- the price difference between the maximum price that buyers are willing to pay, and the minimum price at which sellers are willing to sell the energy (the bid/ask spread);
- the market depth, i.e. the quantity available at the best price posted;
- resilience, corresponding to the variation that the market price experiences when large volumes are bought or sold, and the time required before the market prices recover its balance.

The volumes traded in the markets, the number of participants present and the monitoring of the indicators above are used to measure the liquidity level of a market.

The French energy markets are characterised by a rather low level of liquidity compared to the most mature European markets (the German market for electricity and the British and Dutch markets for gas). First, a reference market price is not always published for the different maturities: There is a reference French price for electricity for up to three years in advance, a gas price for up to two years in advance at PEG Nord, up to a month in advance at PEG Sud, and a short-term gas price at PEG TIGF. Second, participants are confronted with transaction costs that may be high and that may have an impact on their supply or hedging decisions. Two examples illustrate the effects of low liquidity on the functioning of markets:

- arbitrage of market participants between ARENH subscriptions and purchases in the wholesale market (section 2.2.2 of Section III);
- volatility of prices at PEG Sud in a context of tight supply (section 2.1.2).

There is a certain number of factors contributing to a development of market liquidity. Among these factors are:

- The size of the market, determined by its consumption level and by the diversity of the production of transmission or storage capacity;
- Standardisation of trading: maturity, transfer point, volume, contracts, etc.;
- The number of active participants and especially the diversity of these participants: producers, consumers, energy sector players, financial players, new players, etc.;
- The implementation of market mechanisms such as the development of market-based contracts, the allocation of capacity through auctions and the setting up of a balancing system market-based and not on physical tools made available to the TSOs;
- The presence of market makers on trading platforms and the development of robust price references shared by market participants, enabling them to be used within the framework of contracts.

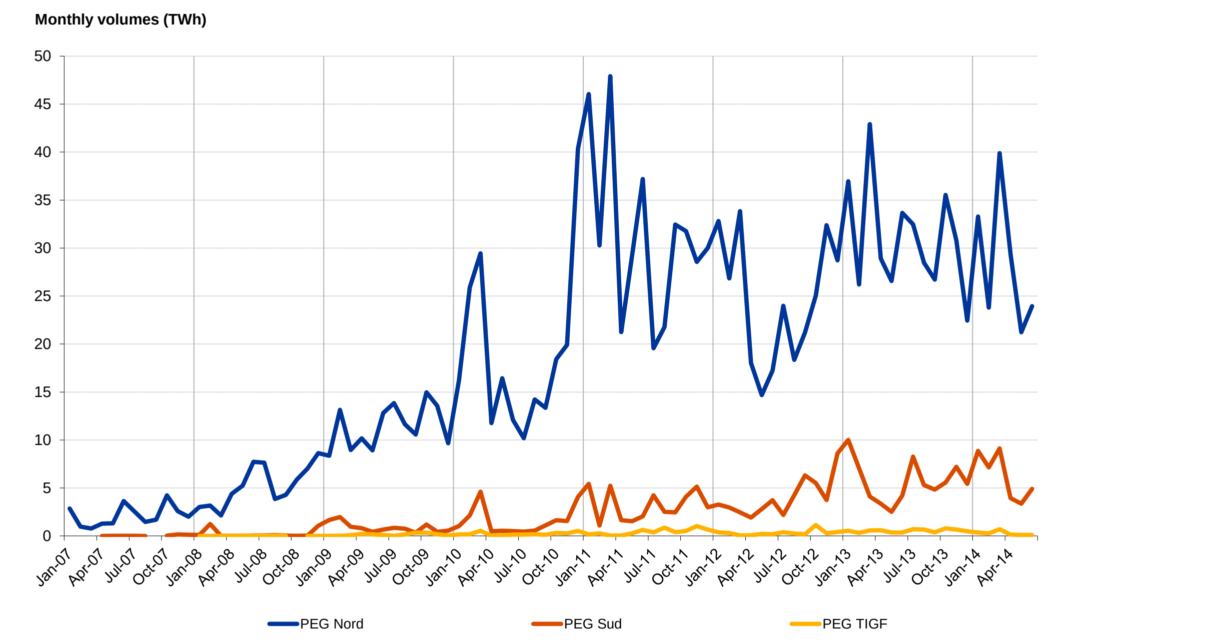
A low level of liquidity has consequences both upstream and downstream in the electricity and gas sector. Upstream, because of the absence of a market price, players may be hesitant to commit in the long term to the construction of production means or the subscription of transmission or storage capacity. Indeed, if the costs are known, the revenue from these commitments is much more uncertain. Downstream, transaction costs may be passed on to suppliers' commercial offers. In the least liquid markets, some suppliers may, in certain cases, decide not to become involved in the energy supply activity due to their incapacity to comfortably obtain supplies in the market, which severely jeopardises the development of competition.

The low development of volumes traded in the futures market can be due to the absence of structural congestion at the interconnection points between the different countries. Shippers, to cover risks of price variation in their portfolio, prefer to carry out their transactions at the most liquid hub (TTF), rather than to hedge their commitment directly at the PEG.

However, this hedging is not perfect, since shippers remain exposed to the risk related to the spot price differential between the two marketplaces, particularly in the case of congestion at interconnections. This "geographical" risk, currently considered low by market participants, is covered when the liquidity at the PEG is highest, i.e. for the short-term maturities.

This risk management policy may however be challenged when the risk of conflict situations emerges, such as a gas crisis between Russia and Europe. A drop in Russian flows could change the supply pattern of European networks and create conjunctural bottlenecks between the different marketplaces, which represents a major risk in spot markets. The correlation of European hubs could no longer be ensured and lead market participants in France to give priority to the PEG to cover their needs in the futures market, which could then develop the liquidity of this market.

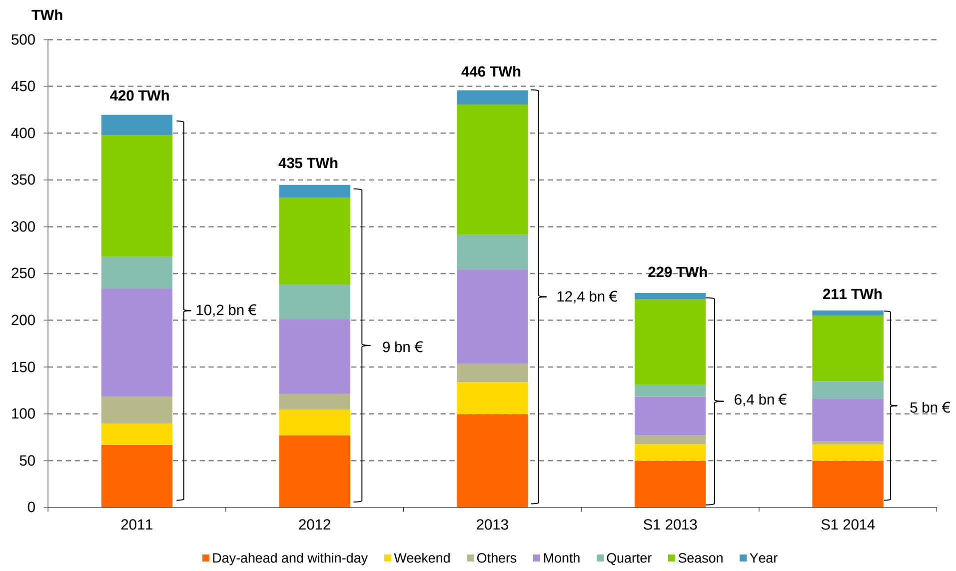
Graph 76: Volumes traded on the intermediated market depending on PEG



Source: Powernext, brokers – Analysis: CRE

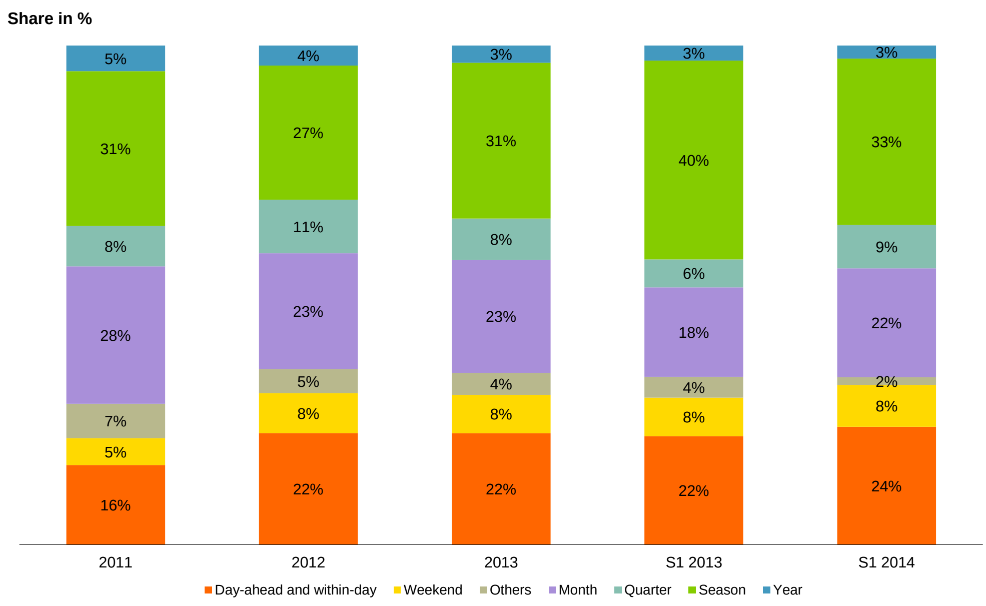
Graph 77: Volumes traded on the French intermediatedmarket depending on maturity

a. Per type of product (in TWh and in €)



Source: Powernext, brokers – Analysis: CRE

b. Distribution of volumes traded



Source: Powernext, brokers – Analysis: CRE

Graph 77b shows that the volume increase in 2013 was uniform across all products while in H1 2014, the drop concerned mostly seasonal products.

3.3 The Exchange continued to develop in the spot market and increased its offer

Powernext launched cooperation with the European Energy Exchange (EEX) in the European natural gas market on 29 May 213. Henceforth, the two partners propose all their gas products in a common trading platform, PEGAS. This platform brings together trading of spot and futures products in the Dutch TTF trading zone, in the German market zones NCG and GASPOOL, and in the French PEG Nord, Sud and TIGF.

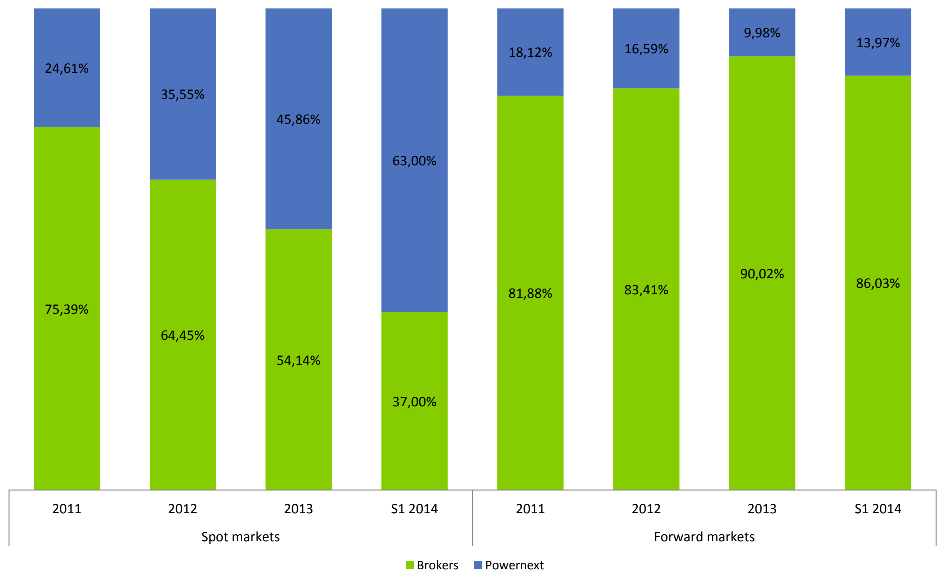
The offer also includes products based on geographical spread between the different hubs. Implicit prices, created via these spread products, increase the liquidity of the individual hubs.

Moreover, Powernext launched a monthly contract "Front Month" at PEG Sud in October 2013. Thanks to the volumes proposed for purchase and sale by market makers, suppliers and customers can cover their needs in advance and better manage their physical and financial risks. In addition to the improvement of participants' visibility into the value of gas in the South zone, the creation of a reference price in the futures market raises hope for a better optimisation of assets in the zone (LNG terminals, transport, storage and combined cycle power plants).

Lastly, in January 2014, Powernext added to its offer a spread product between PEG Sud and PEG TIGF for spot maturities.

All these changes emphasised the development of the Exchange share on the spot segment, but has not enabled it for the time being to increase significantly its market share for futures products (Graph 78).

Graph 78: Distribution of spot and futures volumes traded by type of intermediary



Sources: Powernext, brokers – Analysis: CRE

3.4 Development of competition at PEGs and at the level of gas infrastructure

The differences in concentration indices between the three French PEGs were maintained in 2013 and in the first half of 2014 (Graph 79). PEG Nord remained the least concentrated French hub for spot and futures markets.

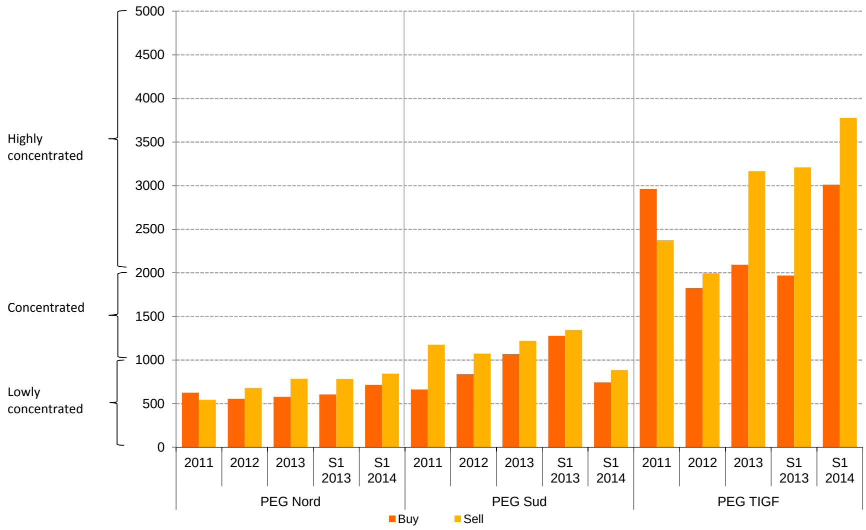
At PEG Sud, despite the development of the liquidity on the spot market, concentration index increased slightly. The concentration levels of the futures market were still high despite the drop in sales concentration index.

The existence of a liquid futures market at PEG Sud remains a prerequisite for attracting more arbitrages with the Spanish market and the global LNG market. The lack of the liquidity both in the spot and futures market is partly the reason for the volatility of the prices observed at PEG Sud.

Due to the low number of participants in the market, PEG TIGF remained the French hub where the concentration levels are highest.

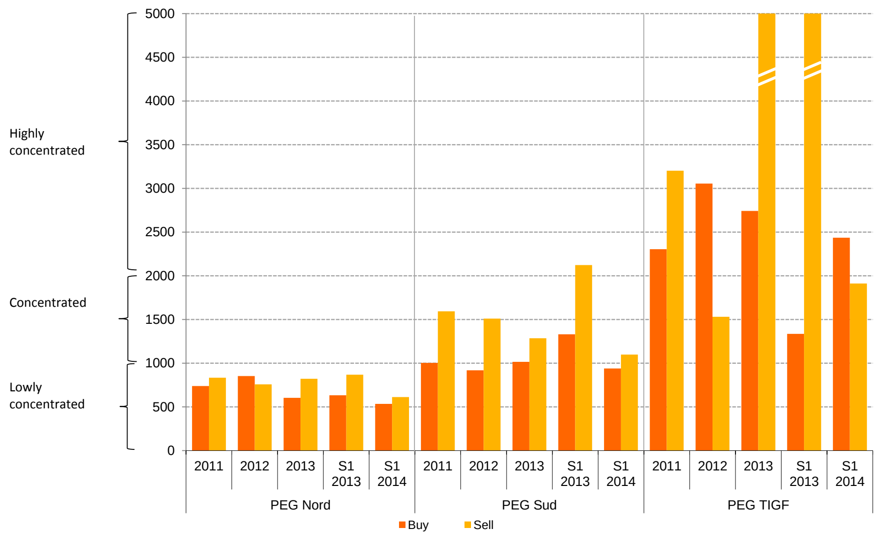
Graph 79: Concentration indices of the French brokered market

c. Spot market



Source: Powernext, brokers – Analysis: CRE

d. Futures market



Source: Powernext, brokers – Analysis: CRE

The number of participants present at the PEGs continued to increase in 2013 and 2014, which is a good evolution for the French wholesale market. The number of shippers present at the interconnections and at PITDs stabilised. However, in 2013 there was a sharp drop in the number of participants present at the PITS and at the LNG terminals. At the PITS, while the movement observed was marked by the withdrawal of several financial players in 2013, the increase in 2014 corresponds to the arrival of several physical traders.

Table 27: Number of participants active in the French market					
	2010	**2011**	**2012**	**2013**	**H1 2014**
PEG	59	66	68	75	81
Of which traders	*11*	*16*	*17*	*18*	*16*
PIR	43	47	46	46	44
PITD	24	25	28	26	29
PITS*	38	37	38	27	34
LNG terminals	7	6	5	2	2

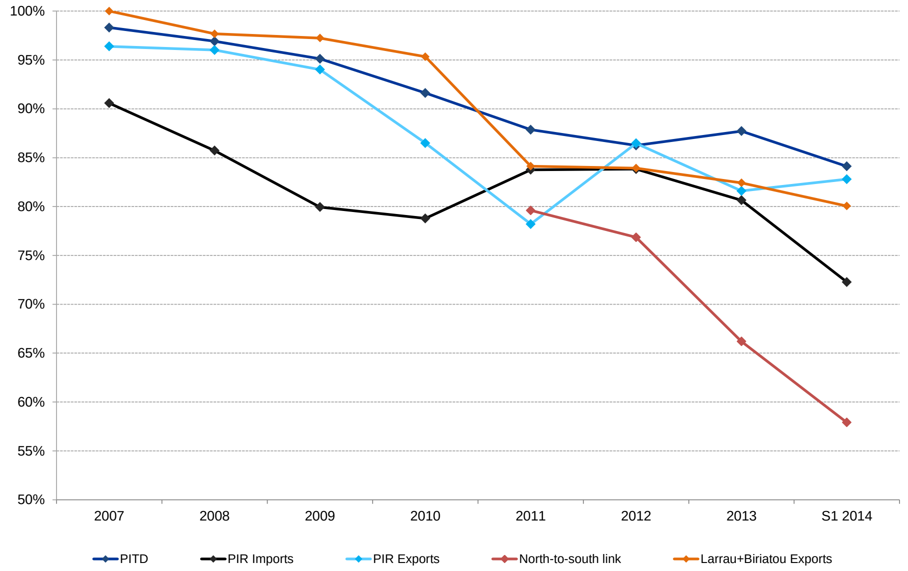
Source: GRTgaz, TIGF – Analysis: CRE
** For the PITS, the number of active participants is calculated for the period from 1 April of a year N to 30 March of the year N+1*

Table 28: Number of participants active at the LNG terminals					
	2010	**2011**	**2012**	**2013**	**H1 2014**
Montoir	6	4	2	1	1
Fos Tonkin	2	2	2	1	1
Fos Cavaou	2	3	3	2	2
Total	**7**	**6**	**5**	**2**	**2**

Source: Elengy, Fosmax LNG – Analysis: CRE

Graph 80 shows the development of competition at the different French infrastructure points. While concentrations remained at rather high levels, there was a downward trend. In particular, the market share of the three largest participants at the North-South link has dropped sharply since 2011. This reflects the interest of the market for this North-South link capacity, in connection with major tightness at PEG Sud. This also illustrates the results of regulatory efforts to improve the functioning of the market in the South region with measures such as the JTS – the service involving the transfer of stored gas between the north and south zones – the market coupling, the use-it-or-buy-it service at the North-South link, and the optimisation by GRTgaz and TIGF of the interface between their two networks.

Graph 80: Aggregated market share of the three main participants calculated based on nominations at the different infrastructure



Source: GRTgaz, TIGF – Analysis: CRE
** The data concerning the North-South link is available only from June 2011*

4 Development prospects for the wholesale gas market in France

4.1 Towards a single marketplace in 2018

Since 1 January 2009, the French gas market is comprised of three marketplaces known as *Points d'échange de gaz* (title transfer points – PEGs): PEG Nord and PEG Sud in GRTgaz system and TIGF PEG in TIGF system.

In 2009, CRE undertook to reduce the number of marketplaces in France in order to improve the functioning of wholesale and retail gas markets for the benefit of end customers.

In 2009 and 2010, GRTgaz and TIGF carried out a study which concluded that there is no structural congestion between their two systems. The creation of a common marketplace in the south of France was postponed nevertheless, since CRE considered that further consultation was necessary.

In the first half of 2012, CRE consulted widely on the future of the French gas market. At the end of this consultation, it defined the roadmap towards the creation of a single marketplace in France (deliberations dated 19 July 2012[86] and 13 December 2012[87]):

- 1 April 2013: merging of the Nord H and Nord B balancing zones;
- 1 April 2015: creation of a single PEG for the GRTgaz Sud and TIGF balancing zones;
- 2018 by the latest: goal to create a single marketplace in France, following the looping of the Bourgogne pipeline ("Val de Saône" project).

[86] CRE's deliberation of 19 July 2012 relating to guidelines for gas marketplace evolution in France
[87] CRE's deliberation of 13 December 2012 deciding on the tariffs for the use of natural gas transmission networks

4.2 The Val de Saône and Gascogne-Midi investment configuration

CRE commissioned the Pöyry firm to perform a cost/benefit analysis of the investments necessary for the creation of a single marketplace in France by 2018 based on entry/exit capacity decided at the time. The firm conducted this analysis between July and November 2013.

Pöyry identified a new investment configuration, associating the Val de Saône and Gascogne-Midi projects, which would ease most of the congestion in GRTgaz system in the North to South direction. Pöyry analysis shows that this investment configuration has the best cost-benefit ratio for the merger of the North and South zones. In addition to the gains for the French market, Pöyry analysis concluded that the investments would bring added value to the gas market of Iberian Peninsula.

CRE considers that the creation of a single PEG represents a major step towards achieving the European gas market. The analysis shows that the Val de Saône and Gascogne-Midi investment configuration would address, under the best economic conditions, situations of tightness in the south of France such as that seen during winter 2013/2014. Moreover, contributors to CRE's public consultation of 18 February 2014[88] were almost all in favour of the creation of a single PEG based on these investments.

In its deliberation of 7 May 2014, CRE confirmed the creation of a single PEG based on the investment configuration associating the Val de Saône and Gascogne-Midi projects by 2018, subject to the completion of works by that time.

In addition, CRE retained, in its deliberation of 30 October 2014, the following target budgets for the projects:

- for the Val de Saône project, in GRTgaz network, the target budget is set at €650 M;
- for the Gascogne-Midi project, in GRTgaz network, the target budget is set at €21 M;
- for the Gascogne-Midi project, in TIGF network, the target budget is set at €152 M.

4.3 Sale of north to south capacity

CRE chose to proceed with the auctioning of gas transmission capacity between north and south zones. Thanks to this method, the congestion rent (i.e. the difference between the regulated price at €0.57/MWh and the price of auctions) is redistributed by the system operator to users of the network in the south zone.

For the 2014-2015 gas year, €164 M will be redistributed, i.e. a reduction estimated at €1.27/MWh for the price of gas for customers in the south of France.

CRE had reserved for gas-intensive customers in the south of France 40 GWh/d of firm capacity and 23 GWh/d of interruptible gas transmission capacity from the north to the south at the regulated price between 1 October 2014 and 30 September 2018 (deliberation of 17 October 2013[89]). The demand of gas-intensive customers in the South during the allocation of this capacity was 92 GWh/d. 55% of the needs of gas-intensive customers is therefore covered over this period at the regulated price (supposing availability of 50% of interruptible capacity).

For their remaining consumption, gas-intensive customers will benefit, as the other users of the networks in the South, from the redistribution of surplus auction income.

CRE, in its deliberation of 29 January 2014, specifies that from 1 October 2014 the surplus received:

- at the North-South link, in the North to South direction, will be redistributed to shippers delivering to end customers at the marketplace in GRTgaz zone, proportionally to the

[88] Public consultation on the creation of a single gas marketplace in France in 2018
[89] http://www.cre.fr/documents/deliberations/decision/commercialisation-des-capacites/consulter-la-deliberation

volumes consumed in GRTgaz South zone for the period considered;

- at the interconnection with Spain, will be redistributed to shippers delivering to end customers in the TIGF zone, proportionally to the volumes consumed in the TIGF zone for the period considered.

4.4 Transitional measures prior to the merger of marketplaces by 2018

Given the major tightness observed in the gas market in the south of France for several months now and in particular during winter 2013/2014, CRE wished to implement for 2014/2015 transitional measures until the creation of a single marketplace in France, scheduled for 2018. In that respect, CRE decided to implement different transitional measures to optimise the use of the North-South link.

CRE requested transmission system operators (TSOs) to study, in consultation with all adjacent operators, storage and LNG terminal operators, mechanisms to create additional firm capacity at the North-South link, and to improve the availability of interruptible capacity. This work led to the definition of three mechanisms.

The modification of the distribution rule for flows between the Cruzy and Castillon compression stations

Flows between the GRTgaz Sud and TIGF zones are distributed between two interconnection points, at Cruzy and Castillon. Changing the rule for flow distribution between these two points created 20 GWh/d of additional firm capacity at the North to South link for the winter.

Joint transport storage service (JTS)

GRTgaz and Storengy proposed to renew for winter 2014/2015 the joint transport storage service (JTS), provided for by the ATRT5 tariff. This service resulting from the optimisation of transport and storage infrastructure will make available to the market on a day-ahead basis, about 20 GWh/d of additional firm capacity at the North-South link.

Creation of a circulating gas system

GRTgaz and the LNG terminal and storage operators Elengy, Fosmax and Storengy proposed a circulating gas system based on gas flows between the tanks of Fos Cavaou and Fos Tonkin LNG terminals and a storage facility located in the North zone. This system would improve the availability of interruptible capacity at the North-South link.

4.5 Structural European work for the development of the French gas market

The implementation of the third package of European energy texts is moving forward with the successive adoption of network codes on allocations of transmission capacity at interconnections (in October 2013) and on balancing (in March 2014), following the adoption of guidelines on the management of congestion in August 2012. A third code on network interoperability and data exchange rules is also under approval by Member States. These texts aim to modify the architecture of the European market by improving cross-border integration through better management of interconnections and a more important role for gas exchange points.

The network code on capacity allocation, whose enforcement will be binding as of 1st November 2015, profoundly modified the organisation of gas trading between Member States. Infrastructure operators set up a new model based on unique capacity products combining a network exit with the concomitant entry in the neighbour's network ("bundled products") which were once booked separately by shippers. Products with different durations (from yearly to intraday) are auctionned; a minimum of 10% of total firm capacity must be allocated to products of duration lower than one year (quarterly, month, day). This model is now applied in France, with capacity products being sold via the online Prisma platform in which a growing number of European transmission system operators participate, including GRTgaz and TIGF. With the exception of the North-South link and the interconnection with Spain, auctions have closed at the reserve price at the cross-border interconnections since April 2013. The absence of tightness regarding access to transmission capacity with Belgium and Germany resulted in an almost perfect alignment between PEG Nord and the hubs in northern Europe (see 2. 2. 1). The Prisma platform also offers secondary capacity market services enabling shippers to trade the capacity booked.

The network balancing code has generalised the principle of market balancing, thus giving a central role to wholesale markets for the physical management of their imbalances and the calculation of penalties. Shippers are encouraged to balance themselves, in order to limit the intervention of system operators for maintaining the balance between supply and demand. In the longer term, a network code on the harmonisation of tariff structures in Europe is being prepared, which will determine the tariffs for the different capacity products and the way in which operators' costs will be allocated to the different entry and exit points of networks. The goal is to establish tariffs that avoid cross-subsidisation between transit and national transport, reflecting costs to flow from one hub to another.

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 CO2

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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