COMMISSION
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Markets

French wholesale electricity and natural-gas markets in 2007

Monitoring Report

December 2008

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Contents

Preface

A ROLE DEFINED IN THE LEGISLATION

CRE is assigned the task of monitoring the French wholesale electricity and natural-gas markets under the French Law dated 7 December 2006 relating to the energy sector.

Article 28 of the law of 10 February 2000 provides that in respect of the powers granted to it, the French Energy Regulation Commission (CRE) monitors electricity and natural gas transactions between suppliers, traders and producers, transactions carried out on organized markets and cross border trades. CRE makes sure that proposals made by suppliers, traders and producers are compliant with economical and technical constraints. As defined in the legislation, CRE's monitoring of the French electricity and gas markets has specific features that derive from the nature of these markets. Thus unlike financial-market monitoring, energy-market monitoring cannot be restricted to identifying operations or transactions intended to manipulate prices. It means analyzing the absolute level of the prices for each product, with regard to the physical situation, the balance between supply and demand, and the utilisation of each player's physical assets.

Such analyses require technical information which preparation takes significant time from the players involved. In addition, analyses reviewing physical assets' utilisation and the consistency of pricing are complex and take a considerable time to process and interpret.

Thus market monitoring as defined in CRE's brief cannot take place in "real time". Several months must necessarily elapse after the end of the period under review, before the analyses relating to that period are ready.

FOSTERING MARKET DEVELOPMENT, IMPROVING MARKET TRANSPARENCY AND INCREASING PLAYERS' CONFIDENCE

Given the characteristics of the French wholesale markets, in particular their high concentration, effective monitoring is essential if they are to function correctly. In practice, monitoring is important in two ways: firstly, it improves market transparency, and secondly, it provides assurance about how the markets operate, not only to active players, but also to those who are considering participating.

CRE may carry out ad-hoc investigations following particular incidents. For example, in April 2008 it published an investigation into the price spikes recorded during the autumn of 2007 on the French day-ahead electricity market. Similarly, in the summer of 2008, it gathered information on some transactions made in 2007 on the futures markets. These related both to electricity (to analyze price movements observed in products with an annual contract), and to gas (to review the consequences of the end of the gas-release programmes). CRE is currently analyzing this data.

In addition to such ad-hoc investigations, CRE has decided to publish a periodic Monitoring Report. The report will provide indicators of wholesale-market operation, and will present players with the conclusions from both the recurrent analyses carried out by CRE and the additional analyses that CRE considers necessary. CRE may also use it to recommend measures to improve the way the markets function.

Clearly, it is essential that the monitoring methods do not obstruct trading activity. Thus in preparing this report (as it will in preparing future reports), CRE has gathered data relating to players' decisions as centrally as possible: most of the information has been taken from network operators and trading intermediaries (such as commodity markets and brokers).

SCOPE OF ANALYSIS DEFINED INITIALLY, THEN GRADUALLY EXTENDED

This first report relates to the calendar year 2007.

For electricity, CRE has analyzed the wholesale market's liquidity and concentration and the macroscopic factors associated with price movements, in particular evolution of the balance of supply and demand, and evolution of the price of fuel and CO_2. It has analyzed the decisions of the generators, who play an essential role in setting prices, and the information that they publish on the status of their generating facilities. It has reviewed the behaviour of players on the day-ahead market operated by Powernext, the price-setting mechanism on the futures market and the conduct of VPP auctions run by EDF. Lastly, it has analyzed the relevance of players' cross-border transactions.

For gas, CRE has analyzed the liquidity and concentration of the wholesale market. It has also studied the relationship between price movements on the day-ahead market and evolution of the balance between supply and demand. It has reviewed the structure of players' sources of supply and outlets. Lastly, it has looked at how competition has developed between suppliers and between their various sources of supply on the French market.

SUMMARY

Summary - Electricity

1. THE DEVELOPMENT OF TRADING IN FRANCE

1.1 The development of trading and market structure

The salient feature of the French market is the domination, in both generation and end-user supply, of a single player, EDF. This pronounced vertical integration impedes the development of the liquidity seen on other markets of similar size. Thus in 2007, only a small part of the energy delivered in France was either exchanged between balancing responsible entities or delivered via cross-border markets.

1.2 Trading activity, liquidity and concentration

Activity on the wholesale market increased only slightly. Although the Spot (day-ahead and intraday) market was dynamic, liquidity on the futures market changed very little, even after full retail-market deregulation on 1 July 2007.

The reasons for this are essentially the failure of alternative suppliers to gain retail-market share, and the direct and indirect impact of applying the transitional regulated tariff for market adjustment (*Tarif Réglementé Transitoire d'Ajustement du Marché - TaRTAM*).

2. EVOLUTION OF WHOLESALE PRICES

2.1 Day-ahead prices

Changes in day-ahead prices have generally been in line with changes of the balance between supply and demand. The analysis of movements in daily pricing shows that in almost 80% of cases, price increases coincided with a narrowing of the supply-demand margin on the French market.

Nevertheless, some of the price spikes observed during the last quarter of 2007 occurred even when there was no excessive stress on the supply-demand balance. Such situations were investigated by CRE, and their conclusions were published on 17 April 2008.

2.2 Futures prices

There appears to be a relationship between the future prices for electricity and the prices of gas, coal and CO_2: short-term changes of the prices of these fuels had a marked impact on electricity futures prices. On the other hand, oil prices do not seem directly to affect price-setting.

There is also a link between futures prices for the calendar year 2008 and day-ahead prices. In particular, CRE found a correlation between an upward trend in futures prices at the year end and rising day-ahead prices. However, localized price spikes do not seem to have incurred marked increases in futures prices.

Although EDF was a net buyer of baseload products for the calendar year 2008, if VPP sales are included, EDF was a net seller of calendar year 2008 products.

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CRE will further analyze futures price setting in 2007. This will involve analyzing product price movements for the calendar years 2008 and 2009, using information it gathered during 2008 on transactions agreed for the product in 2007.

In addition, CRE will ask EDF to explain why the company bought so extensively on the futures markets during 2007. It will also analyze the effect of EDF's strategy on the operation of the short-term markets in 2008.

3. USE OF GENERATING FACILITIES

3.1 Marginal generation

The nuclear generation is rarely in a position to set prices on the French wholesale market. In 2007, it was the marginal fuel type 15% of the hours.

By contrast, the cost of coal-based generation, which was marginal for between 25 and 30% of the hours, had a controlling effect on prices. Similarly, the value placed on hydroelectric reserves played an important role, as hydroelectricity was marginal for around 25% of the hours.

Lastly, prices on the cross-border markets had a significant influence on the French prices, which they set for between 20 and 25% of hours during the year.

When nuclear or hydroelectric power stations were the marginal fuel type, the day-ahead price reflected the value placed on these power stations by EDF. This value was generally higher than the marginal generating cost for these power stations, and is based on the method EDF uses to optimize the use of its energy stocks.

3.2 Nuclear generating facilities

The method used by EDF to price nuclear energy for the wholesale market means that the generator assigns a use value to the output of some power stations on top of their marginal generating cost. This technique is aimed at optimizing the use of generating facilities based on seasonal variations in demand.

At this stage, the legitimacy of the costings determined by EDF, which had a significant effect on prices when French nuclear output was the marginal fuel type, remains to be verified.

CRE will audit the method used by EDF to manage fuelling constraints in its nuclear facilities and to cost output from its power stations for the wholesale market.

In the great majority of cases, the use of nuclear generating facilities was optimal, i.e. consistent with observed market prices. However, there were several prolonged periods during which the price was high, even though a significant portion of the nuclear capacity was unused. These variances could have added several tens of euros to the average price per MWh during the hours concerned[1].

From the additional information obtained, it has not been possible to determine if all these situations were justified by technical or economic constraints.

CRE will ask EDF to explain how situations arose in which nuclear generating facilities appear to have been underused. Such situations were observed for some tens of hours.

3.3 Coal-fired generating facilities

Most offer prices used by generators to value their product for this market were consistent with the estimated marginal generating costs calculated by CRE.

Nevertheless, CRE identified situations in which the offer price from some power stations differed noticeably from CRE's estimates. Based on the information available, it was not possible to arrive at a satisfactory explanation of the costing methods used by some EDF power stations.

CRE is waiting for EDF to explain how it valued production from some of its coal-fired power stations for the last quarter of 2007.

Most coal-fired power stations were employed efficiently. CRE has not observed any behaviour aimed at price manipulation.

3.4 Hydroelectric dams

The method used by EDF and the French electricity generator Société Hydroélectrique du Midi (SHEM) to price hydroelectricity for the wholesale market means that generators assign a use value to the output from some power stations on top of the (low) marginal generating cost. This technique is aimed at optimizing the use of hydroelectric resources based on seasonal variations in demand.

At this stage, the legitimacy of the costings determined by the generators, which have a decisive effect on prices when French hydroelectricity production is the marginal fuel type, remains to be verified.

CRE will audit the method used by hydroelectricity generators to optimize their generating facilities and value their output for the wholesale market.

CRE has also identified many instances in which the use of hydroelectric power stations appeared inconsistent with the costings declared to CRE.

CRE is waiting for additional information from EDF on the use of its hydroelectric plants.

3.5 Oil-fired power stations (excluding combustion turbines)

The offer price from some of these power stations sometimes differed noticeably from CRE's estimates. The reasons put forward by EDF (stricter regulation of fuel quality, sourcing problems and stock management) could well explain the variances.

However, oil-fired power stations appear to have been under-utilized for many hours during which the price was very high. These variances could have added several tens of euros to the average price per MWh during the hours concerned[2].

From the additional information obtained, it has not been possible to determine if this underuse was justified by technical or economic constraints.

CRE will ask EDF to explain how some situations arose in which some oil-based power stations appear to have been underused. Such situations were observed for some tens of hours.

4. TRANSPARENCY IN GENERATION

EDF, GDF Suez and the French electricity generator Société Nationale d'Electricité et de Thermique (SNET) are all members of the French Electricity Union (*Union Française de l'Electricité - UFE*), and as such published voluntarily at the end of 2006 aggregated data on the delivered output and forecast availability of their generating facilities.

This helped improve the transparency of the French market, but these publications still require further enhancement.

CRE notes that whichever was the fuel type or generator concerned, and whatever the time horizon for the forecast, the availability forecast for a particular date was almost always higher than what was actually achieved. This is to do with the way the published data is compiled, as defined in the requirements specification used by generators who are members of the UFE.

In addition, data for the medium and long term[3] forecasts were updated each week or month. Short-term data was updated every weekday, but not at the weekend. Because all the forecasts were not updated continuously, market players might have acted on the basis of information that could have differed noticeably from that available to the generators.

In sum, the quality of the information published in 2007 was not satisfactory. Firstly, because some generators had failed to send in returns, much of the information published was incomplete. Secondly, the values for some availability forecasts for some fuel type were at certain times statistically deviant. Thirdly, the quality of the forecasts was not consistent for every day in the week.

It should be noted, however, that 2007 was the year that the UFE publications started, which could explain some of the quality shortcomings; some generators have acknowledged that there were mistakes and say that they have since implemented appropriate controls.

5. THE BEHAVIOUR OF PLAYERS ON THE PRICE-FIXING OF POWERNEXT DAY-AHEAD AUCTION

5.1 Price fixing

CRE continues to carry out comprehensive analyses to check that the full flexibility of unused generating capacity were offered each hour on the wholesale market.

However, it appears that Powernext Day-ahead Auction is generally deep enough to represent the actual position of the French market.

5.2 Individual behaviour

On Powernext Day-ahead Auction, no behaviour aimed at manipulating prices was identified. The price increases observed during the period October-December 2007 correlated with an overall reduction in supplies offered via the platform rather than with an increase in demand. Very many participants were seen to have reduced their offers. Nevertheless, CRE identified several players who reduced their offers exceptionally.

These players have told CRE that they did so for one of two reasons: either they had less energy to offer on the day-ahead market (because of production constraints or limitations on import options), or they had moved their offers to the bilateral market.

6. CROSS-BORDER TRADING

6.1 The development of cross-border exchanges

Except at certain periods, the French market was overall a net exporter in 2007. On the other hand, the market was an overall importer from Germany into France.

Most cross-border flows were of moderate or low concentration, apart from imports from Italy and exports to Spain, Germany and Switzerland, which were very highly concentrated.

6.2 Use of daily capacity at interconnections

CRE noted individual daily-capacity nominations at interconnections that could not, on first analysis, be justified by the price differential between the markets concerned.

CRE also noted that some players often nominated daily capacities for import and export simultaneously across the same border.

CRE questioned market players where such behaviour was frequently observed during 2007. The responses provided demonstrated that the current market organization has features that prevent those with capacity from deploying it optimally.

No behaviour intended to manipulate prices via daily-capacity nomination interconnections was identified.

7. EDF'S AUCTION OF VIRTUAL POWER PLANTS (VPPS)

EDF organized four VPP auctions in 2007.

7.1 Purchase price

CRE notes that the prices of baseload VPPs sold at auction in 2007 were aligned with the price of futures products traded on the markets. It also considers that, given the volatility of day-ahead prices, the prices for peakload VPPs sold at auctions in 2007 were consistent with the prices of futures products.

7.2 Activity on the wholesale markets in the days preceding the auctions

CRE has identified situations where the monthly and quarterly product prices rose sharply as an auction approached. In general, these movements were not associated with any particularly significant activity by EDF on the futures market.

Nevertheless, CRE questioned EDF about several transactions where some products had increased sharply in price.

CRE asked EDF for additional information regarding several of its transactions on the futures market as the VPP auctions approached.

Summary - Gas

CRE carries out different analyses for the gas and electricity wholesale markets. These two markets differ in their situation and activity.

In particular, the gas market was less liquid than the electricity market. Without gas release programmes at periodic auctions, as found in some European markets, there was no system to promote its liquidity. The market remained essentially bilateral and without intermediaries; in 2007, there was no gas trading platform.

In addition, French generation is very limited compared with size of the French market, so that monitoring involving reviewing method of optimized production and transparency is not a high priority.

On the other hand, since the wholesale market is not sufficiently liquid to allow alternative operator to obtain supplies and balance their portfolios, it is essential to analyze how operators structure their procurement.

1. THE DEVELOPMENT OF TRADING IN FRANCE

1.1 The development of trading and market structure

The salient feature of the French market is the domination of a single player, GDF Suez, in both gas procurement and supply to final customers. This pronounced vertical integration and the absence of any new programme similar to gas release[4] prevents the French market becoming more liquid. Thus in 2007, only a small portion of the energy delivered in France was exchanged between operators.

1.2 Trading activity, liquidity and concentration

In 2007, the vast majority of transactions on the French wholesale market were bilateral contracts with no intermediary.

Volumes exchanged on the French market via brokers remained very small compared to the size of the physical market (less than 10% of national consumption in 2007). However, liquidity increased throughout the year.

Around 70% of transactions via brokers were related to spot products (intraday and day-ahead). Almost all the activity concerned North-H zone, and to a much lesser extent the East zone.

CRE notes that the GDF Suez Group is not one of those most active on the market via brokers.

In order for the French wholesale market to operate properly, its development must be assessed and its transparency improved. To this end, CRE will collect data from market players on the volume of their purchases and sales on the bilateral market. It will then be able to publish aggregated and anonymized information on bilateral trading activity. The methods of data collection will be defined in consultation with the market operators.

2. EVOLUTION OF DAY-AHEAD PRICES

Day-ahead prices for delivery to the North Gas Exchange Point (*Point d'Echange de gaz - PEG*) did not reflect the balance between supply and demand on the French market: they remained very close to the prices observed at Zeebrugge, and were overall higher.

The year 2007 was characterized by a period when these prices dropped (between January and April 2007), followed by a period when they climbed sharply.

During the first three quarters of 2007 (and capped by the volumes offered on the market), if operators were able and wished to make daily arbitrage deals, it was generally better for them to buy gas on the French day ahead markets than rely on long-term import contracts. From October 2007, the differential between day-ahead prices and prices for long-term contracts reversed.

3. PLAYERS' SOURCES OF SUPPLY AND OUTLETS

CRE analyzed the structure of sources of supply and outlets for all those active in the French gas market.

It notes that during 2007, the activity of all types of operators increased markedly.

At the same time, CRE identified fundamental and persistent differences between the position of suppliers who were European incumbents[5] and other suppliers, referred to in this document as "newcomers". Newcomers rely only marginally on imports for their supplies, and acquire most of their gas on the French market directly from the incumbent suppliers.

CRE is undertaking additional analyses of these operators' futures purchases and sales. To do so, it is using information collected during summer 2008 about transactions agreed in 2007 relating to calendar and seasonal products for 2008 and 2009. It is analyzing in particular how the end of the gas release programmes affects how alternative suppliers source supplies and develop their activity.

4. CROSS-BORDER TRADING

The number of active players increased in 2007, because there were more participants on the Belgium border.

The French market was a net importer from Belgium, Germany and the North Sea, and of LNG supplies. GDF Suez sourced almost all LNG imports into France, and the two French incumbents were responsible for almost all the flows from the North Sea. By contrast, flows at the Belgian and German borders were less concentrated.

The French market was a net exporter to Switzerland and Spain. Long-term contracts meant that GDF Suez remained responsible for almost all exports to Switzerland, and the two French incumbents, GDF Suez and Total, managed almost all the flows to Spain.

DETAILED REPORT

Definitions

CLASSIFICATION OF PLAYERS TRADING ON THE FRENCH WHOLESALE MARKETS

In order to analyze the aggregated activity of companies active in the French wholesale markets, CRE divides them into the following categories:

Electricity
French incumbents
Alternative French generators
European incumbents
French newcomers
European newcomers
Traders
Others

Gas
French incumbents
Foreign incumbents
Newcomers
Traders
Others

The activity of French incumbents is calculated including the activity of both the parent company and all the subsidiaries. Local Distribution Companies (*Entreprises Locales de Distribution - ELD*) are classed as French incumbents.

Incumbent European or foreign operators are companies that had a monopoly in a foreign market before market deregulation. They include, for instance, RWE, E.On Ruhrgas, Electrabel and Gazprom.

Newcomers (European or French depending on where their principal market is located) are companies whose activity started after the markets were opened up to competition.

Incumbent European or foreign operators and European or French newcomers will sometimes be referred to as “alternative suppliers”.

The category “Traders” includes companies whose principal activity is energy trading (purchase for resale) on the wholesale markets.

“Others” includes manufacturers active in the wholesale market and some companies with a low level of market activity whose classification is open to interpretation.

MEASURING THE CONCENTRATION OF MARKET SEGMENTS

The degree of concentration in the markets under review is assessed by calculating the Herfindahl-Hirschman Index (HHI). The HHI is the sum of the squares of the market shares of each player involved.

The HHI tends towards zero if the market is fragmented. A market segment with an HHI below 1,000 is considered to have no or low concentration. A market segment with an HHI between 1,000 and 1,800 is considered to have medium concentration. A market segment with an HHI above 1,800 is considered to have high concentration.

Detailed report - Electricity

1. THE DEVELOPMENT OF TRADING IN FRANCE

1.1 The development of trading and market structure

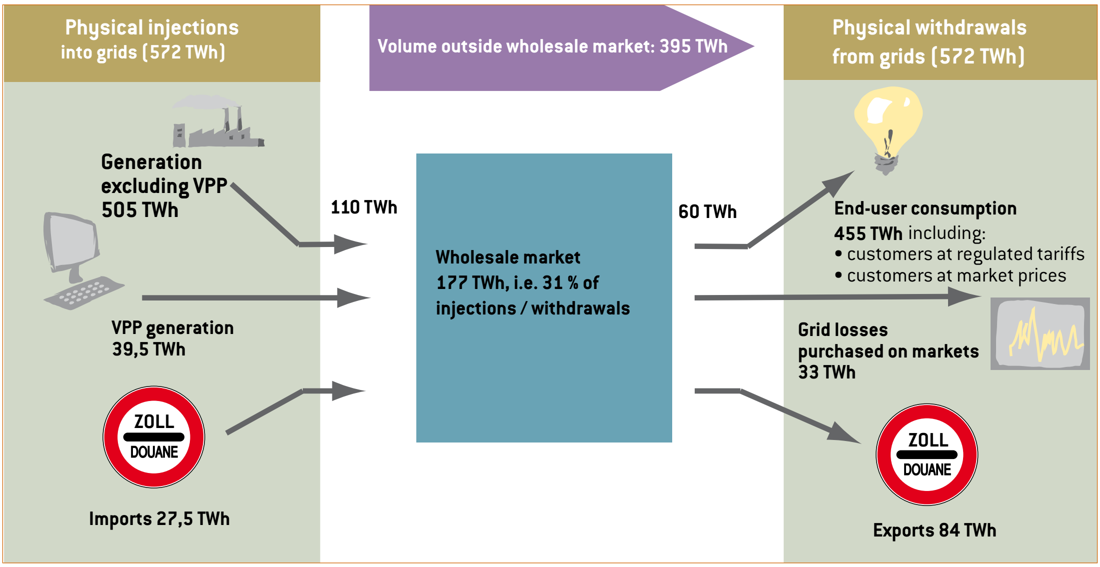
CRE notes that in 2007, only a minor proportion of the energy delivered in France went trough the wholesale market. Of the 572TWh physically injected into the French market, 395TWh were produced by generators and delivered directly by them to their end customers. Only the remaining 177TWh was either exchanged between balancing responsible entities or delivered via cross-border markets.

Wholesale market activity is directed mainly at:

- optimizing the flexibility of means of production (generators),
- covering the forecast consumption of end customers (suppliers),
- trading (either arbitrage transactions with the cross-border markets or to adopt a speculative position).

The key features of the French market are the domination, in both generation and supply, of a single player, EDF; and the pronounced vertical integration between generation and supply activities. The combination of these two factors is a structural impediment that reduces the activity associated with trading by generators and suppliers on the wholesale market. The French market structure thus impedes the development of the liquidity apparent on other markets of a similar size.

Energy flows between upstream and downstream segments of the French wholesale market in 2007



Data: RTE; Analysis: CRE

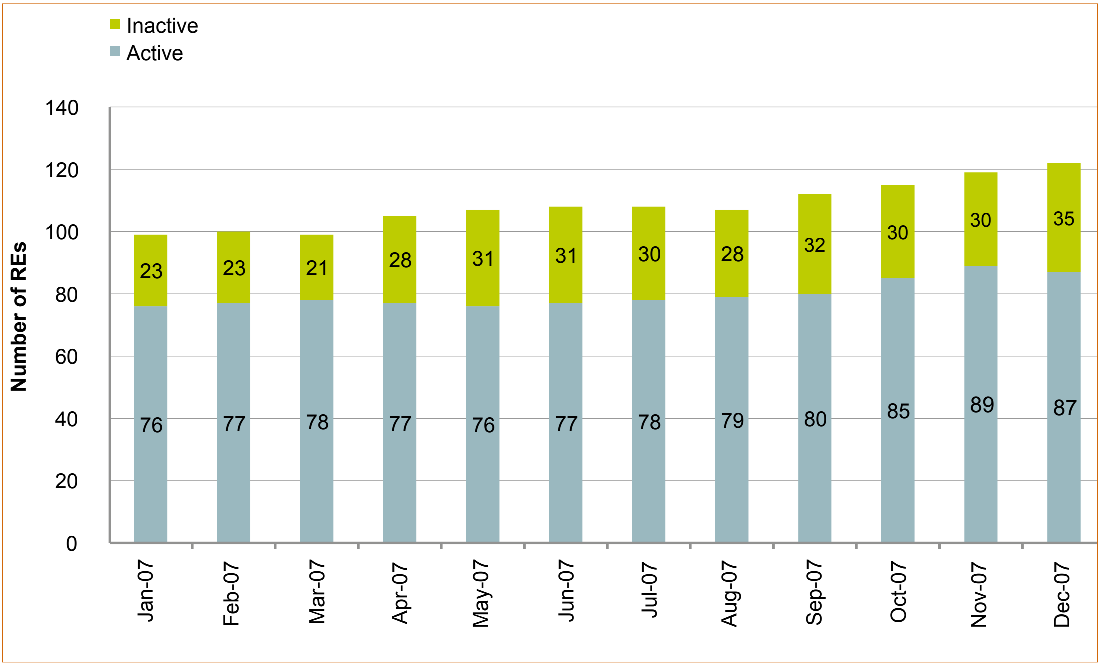
1.2 Trading activity, liquidity and concentration

CRE has analyzed the activity of French balancing responsible entities (*Responsables d'Equilibre - RE*). You should note that the number of REs does not reflect exactly the number of businesses, since some of them use several separate balance perimeters for their activities.

Many new participants joined the French wholesale market in 2007. Thus at 31 December 2007, 122 balancing responsible entities (REs) were registered, or 25 more than one year earlier.

Similarly, the number of balancing responsible entities considered to be active (i.e. who had nominated at least one delivery on the French wholesale market) increased from 80 in 2006 to 95 in 2007. REs whose involvement started in 2007 are for the most part trading companies.

Growth in the number of balancing responsible entities in 2007



Data: RTE; Analysis: CRE

Number of active balancing responsible entities, based on their principal activity in 2006 and 2007

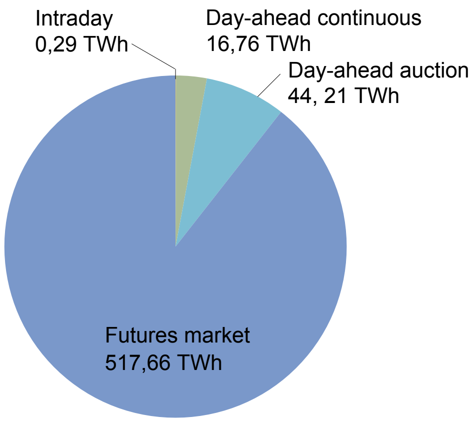
Classification	Number of active REs	
	2006	2007
French incumbents	8	7
European incumbents	31	33
Alternative French generators	5	5
French newcomers	4	6
European newcomers	11	15
Traders	14	22
Others	7	7
Total	80	95

Data: RTE; Analysis: CRE

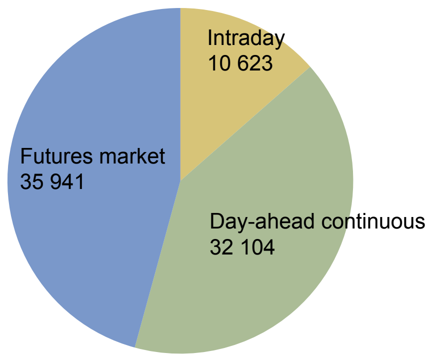
CRE analyzed activity on the intermediated French wholesale market, looking at transactions made via one of the five principal brokers active in France (GFI, ICAP, Spectron, TFS and Tullett Prebon) and those made on Powernext. This covers most activity on the French wholesale market.

CRE has thus been able to calculate that the volumes exchanged on the wholesale market amounted to 579TWh in 2007, or around 127% of French internal consumption. 78,500 transactions were agreed.

Split of activity by settlement date By volume Intermediated market in 2007



Split of activity by settlement date By number of transactions Intermediated market in 2007



Data: Powernext, Brokers; Analysis: CRE

This level of activity is certainly higher than that observed by the European Commission in its report on energy sector inquiry. For the period June 2004 – May 2005, the Commission's estimate of activity was around 90% of the national consumption. However, it has grown only slowly, and the size of the market is still modest compared with other European markets. Although the spot (day-ahead and intraday) market was dynamic, liquidity on the futures market changed very little, even after full retail-market deregulation on 1 July 2007.

This restricted growth could well be linked to the failure of alternative suppliers to make inroads into the retail market, and to the direct and indirect consequences of applying the transitional regulated tariff for market adjustment (TaRTAM). Suppliers of customers benefiting from the TaRTAM have less incentive to optimize their procurement. In addition, TaRTAM has probably given alternative suppliers the message that the regulatory risk on the French market is higher.

Spot traded volumes as a percentage of national electricity consumption (June 2004 - May 2005)

	Power exchanges	OTC brokered
OMEL - Spain	84.02%	negligible
GME - Italy	43.67%	n.a.
Nord Pool - Nordic region	42.82%	n.a.
EEX - Germany	13.24%	5.40%
APX - The Netherlands	11.88%	5.90%
Belgium	no power exchange	0.04%
Powernext - France	3.37%	1.50%
EXAA - Austria	2.96%	n.a.
UKPX - UK	2.17%	8.60%
Pol PX - Poland	1.28%	n.a.

Source: exchanges' and brokers' data
Note: this table does not contain an exhaustive list of all power exchanges in Europe.
OTC brokered numbers refer to volumes reported to us by major energy brokers.

Traded volumes in futures/forward contracts as a percentage of national electricity consumption (June 2004 - May 2005)

	Power exchanges	OTC brokered	Power exchange + OTC
OMEL - Spain	no exchange trading	negligible	n.a.
GME - Italy	no exchange trading	n.a.	n.a.
Nord Pool - Nordic region (2005)	196%	327%*	523%
EEX - Germany	74%	565%	639%
Endex - The Netherlands (since dec. 2004)	39%	509%	548%
Belgium	no exchange trading	22%	22%
Powernext - France	6%	79%	85%
EXAA - Austria	no exchange trading	n.a.	n.a.
Pol PX - Poland	no exchange trading	n.a.	n.a.
UKPX - UK	0%	146%	146%

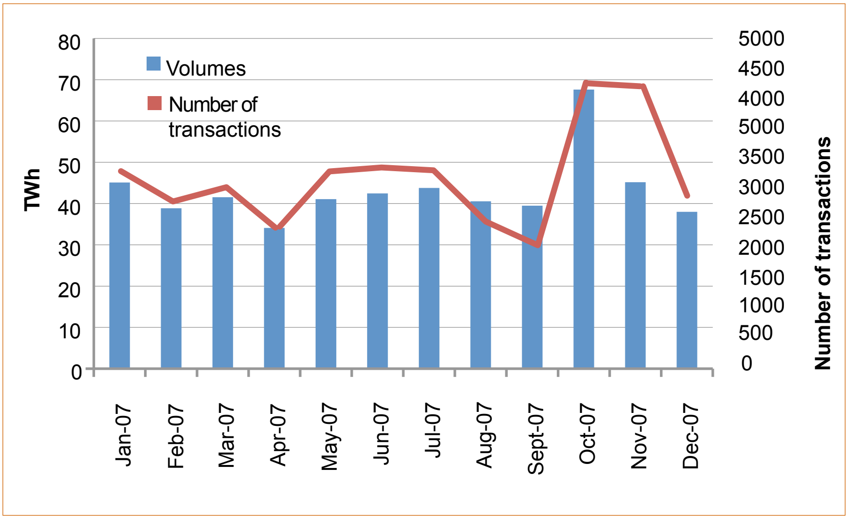
Source: exchanges' and brokers' data
Note: OTC brokered numbers refer to volumes reported to us by major energy brokers.
* This figure only includes bilateral contracts cleared by Nord Pool

Data: DG Competition – report on energy sector inquiry – 10 January 2007

1.2.1 The forwards and futures market

The volume exchanged on the forwards and futures market amounted in 2007 to 518TWh, or around 110% of internal French consumption, with a total of 36,000 transactions. Activity on the forwards and futures market was relatively stable throughout the year, except for October, which was a period of high activity.

Evolution of monthly volumes and transaction numbers Intermediated forwards and futures market in 2007

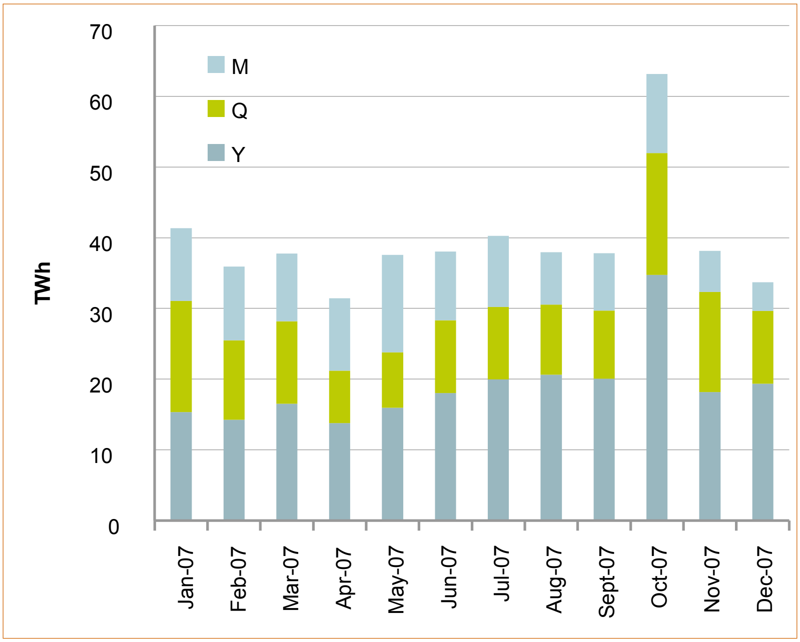


Data: Powernext, Brokers; Analysis: CRE

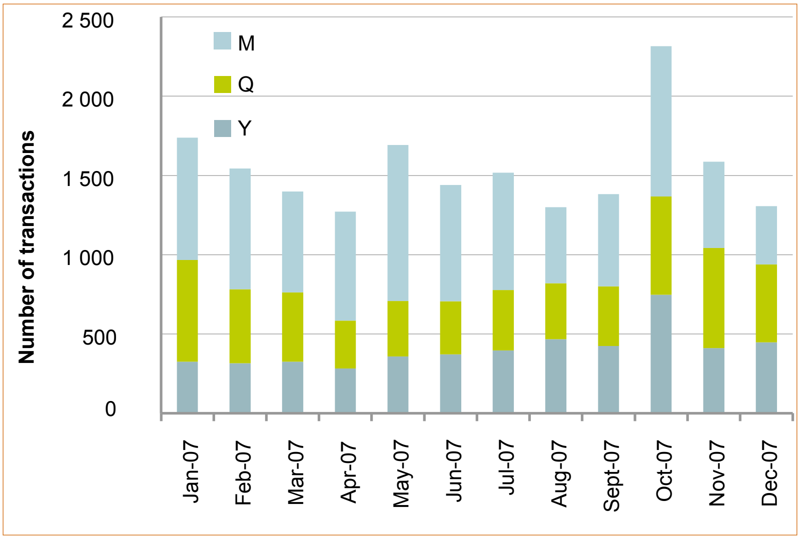
The products most traded (by number of transactions) were those with the shortest term (monthly settlement dates). In addition, the average transaction size was much greater for short-term products. This indicates some reluctance by players to take a pronounced position over the longer term, probably reflecting a lack of confidence in the market's future development.

The graphs below show the split of volumes exchanged and transaction numbers for monthly (M), quarterly (Q) and annual (Y) products.

Split by month of volumes traded in Y, Q and M products
Intermediated forwards and futures market in 2007

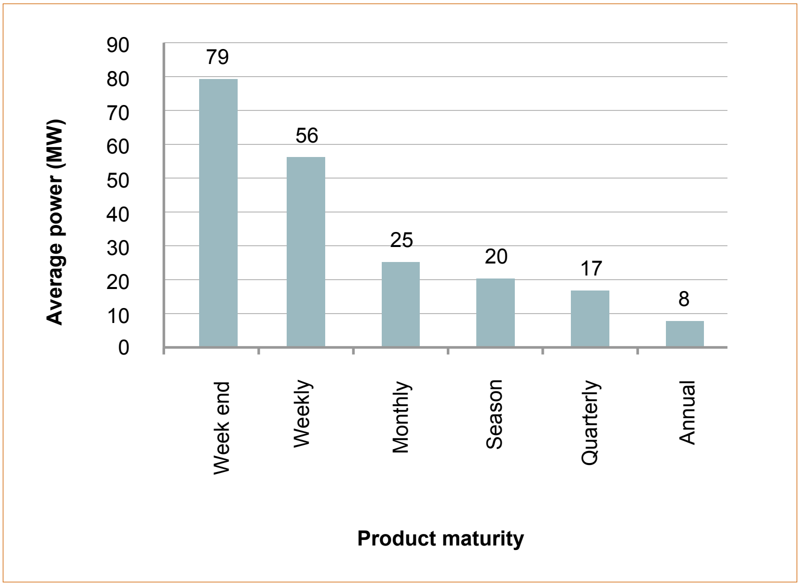


Split by month of transaction numbers for Y, Q and M products
Intermediated forwards and futures market in 2007



Data: Powernext, Brokers; Analysis: CRE

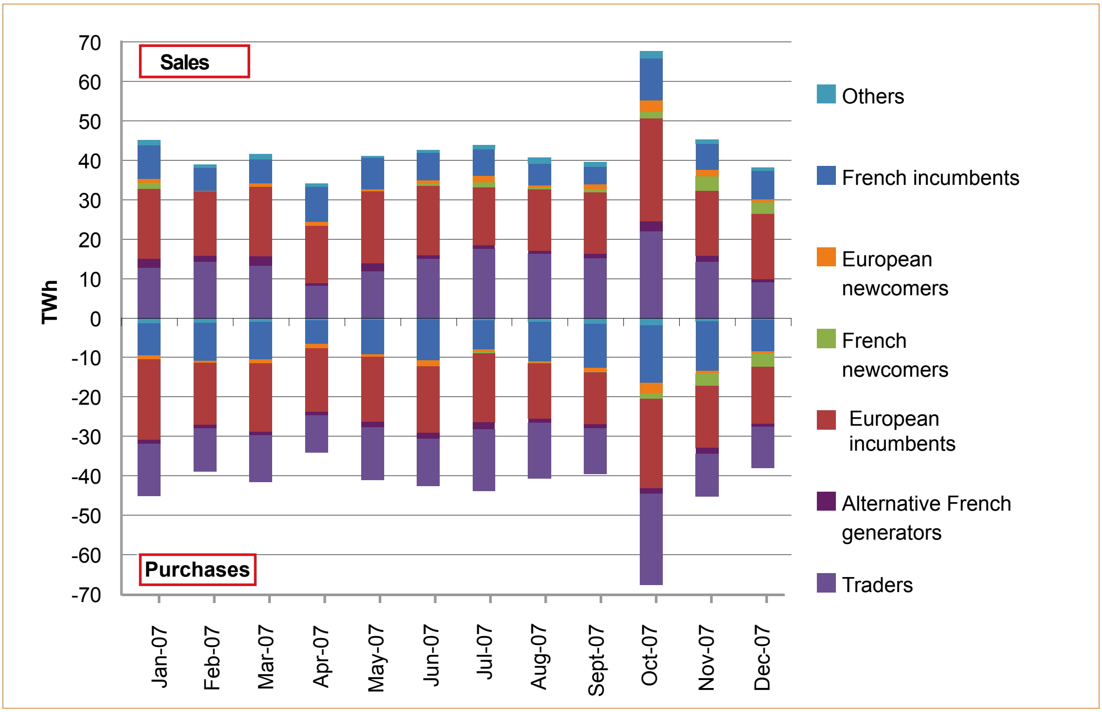
Average power traded in a transaction
By product category
Intermediated market in 2007



Data: Powernext, Brokers; Analysis: CRE

Most activity on the futures market, both buying and selling, was driven by the trading companies and the European incumbents. No player dominated either purchase or sales transactions.

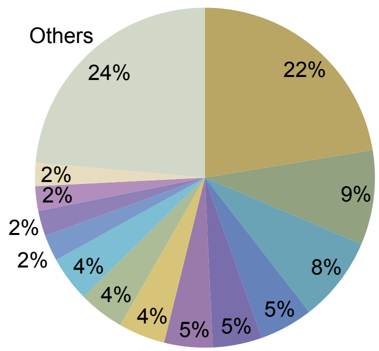
Split by month of purchases and sales by category of player Intermediated forwards and futures market in 2007



Data: Powernext, Brokers; Analysis: CRE

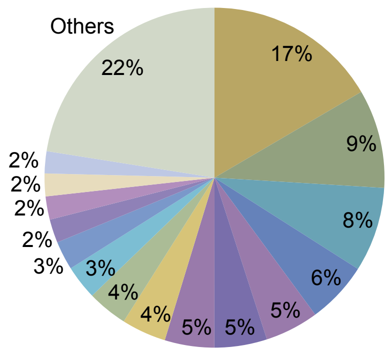
Market shares of players By volumes purchased Intermediated forwards and futures market in 2007

- Players with a market share greater than 2% -



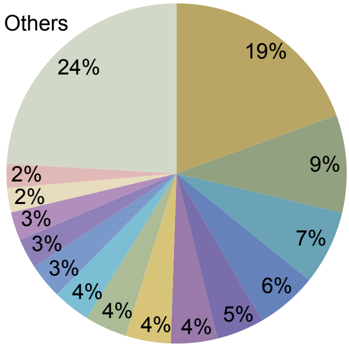
Market shares of players By volumes sold Intermediated forwards and futures market in 2007

- Players with a market share greater than 2% -

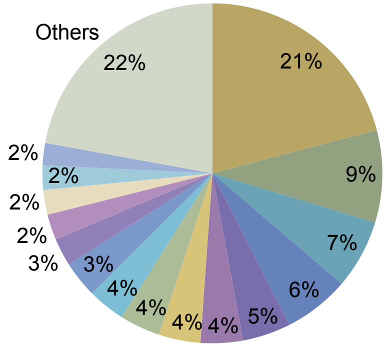


Data: Powernext, Brokers; Analysis: CRE

Market shares of players
By number of purchase transactions
Intermediated forwards and futures market in 2007
- Players with a market share greater than 2% -



Market shares of players
By number of sales transactions
Intermediated forwards and futures market in 2007
- Players with a market share greater than 2% -

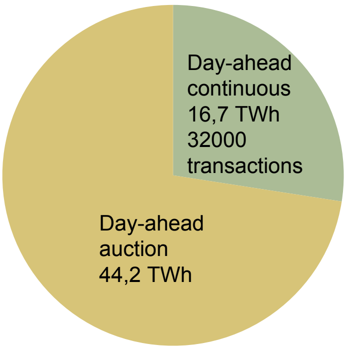


Data: Powernext, Brokers; Analysis: CRE

1.2.2 The day-ahead market

The volume exchanged on the day-ahead market amounted in 2007 to 60.9TWh, or around 13% of internal French consumption. A total of 32,000 transactions were agreed (excluding day-ahead price fixing).

Volumes and number of transactions
Intermediated day-ahead market in 2007



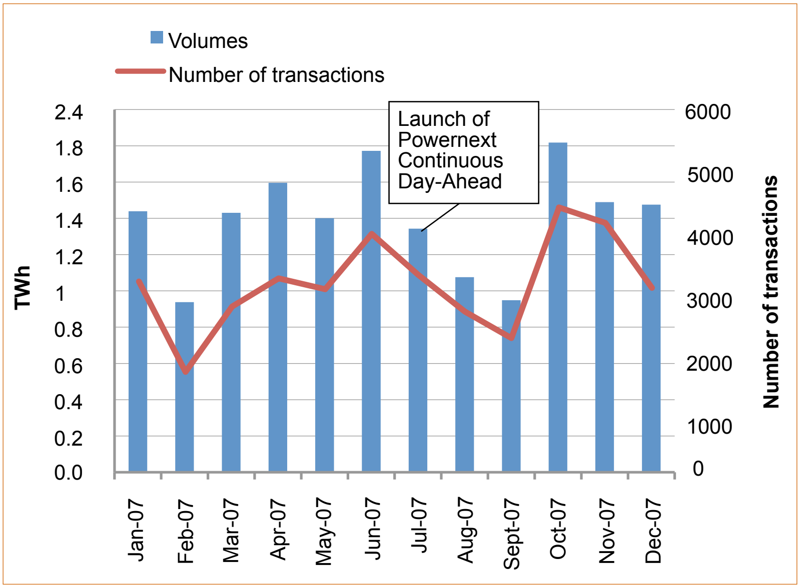
Data: Powernext, Brokers; Analysis: CRE

1.2.2.1 The continuous day-ahead market

16.8 TWh were exchanged on the continuous day-ahead market, with a total of 32,000 transactions. The level of activity fluctuated considerably over the year.

Volumes traded did not rise significantly when Powernext's continuous trading platform was introduced.

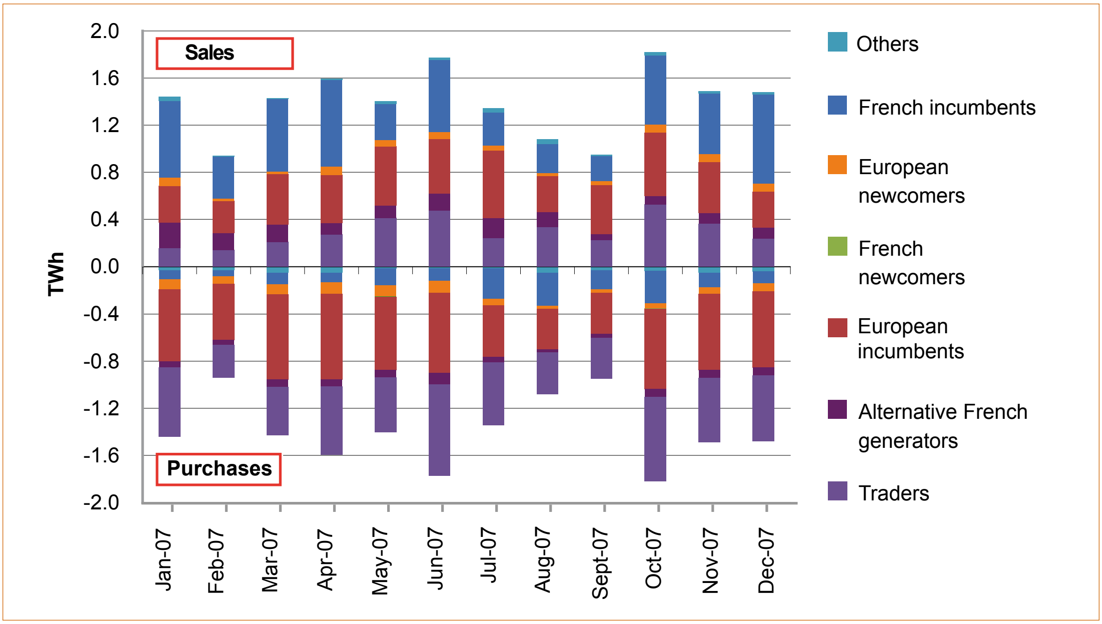
Evolution of monthly volumes
Intermediated continuous day-ahead market in 2007



Data: Powernext, Brokers; Analysis: CRE

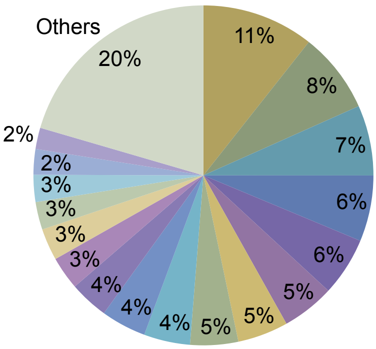
Most of the selling activity on the market was driven by French incumbents.

Split by month of purchases and sales by category of player
Intermediated continuous day-ahead market in 2007

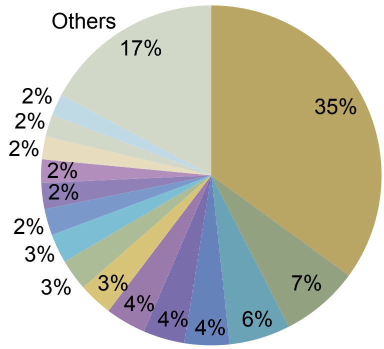


Data: Powernext, Brokers; Analysis: CRE

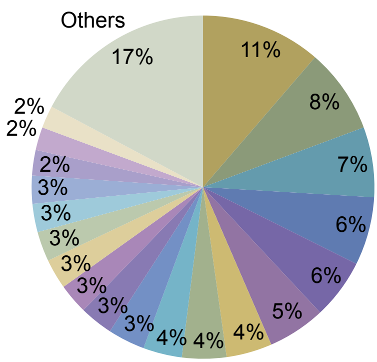
Market shares of players – By volumes purchased Intermediated continuous day-ahead market in 2007
- Players with a market share greater than 2% -



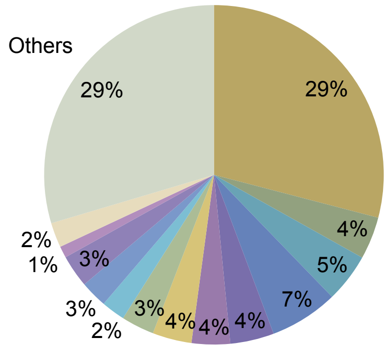
Market shares of players By volumes sold – Intermediated continuous day-ahead market in 2007
- Players with a market share greater than 2% -



Market shares of players By number of purchase transactions Intermediated continuous day-ahead market in 2007
- Players with a market share greater than 2% -



Market shares of players – By number of sales transactions – Intermediated continuous day-ahead market in 2007
- Players with a market share greater than 2% -

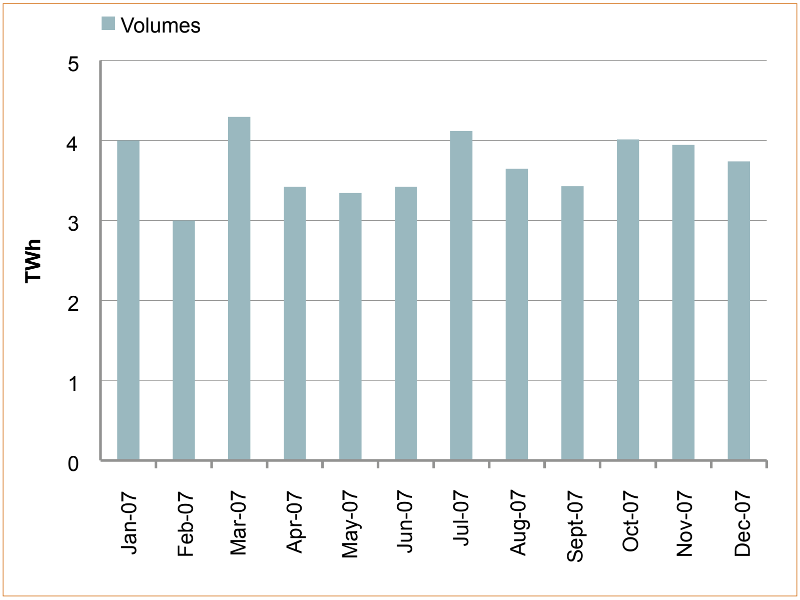


Data: Powernext, Brokers; Analysis: CRE

1.2.2.2 Day-ahead price fixing

Power amounting to 44.2TWh was traded on Powernext Day-ahead Auction during 2007. The market was under pressure at the end of the year, but this does not appear to have had a significant effect on the volumes traded.

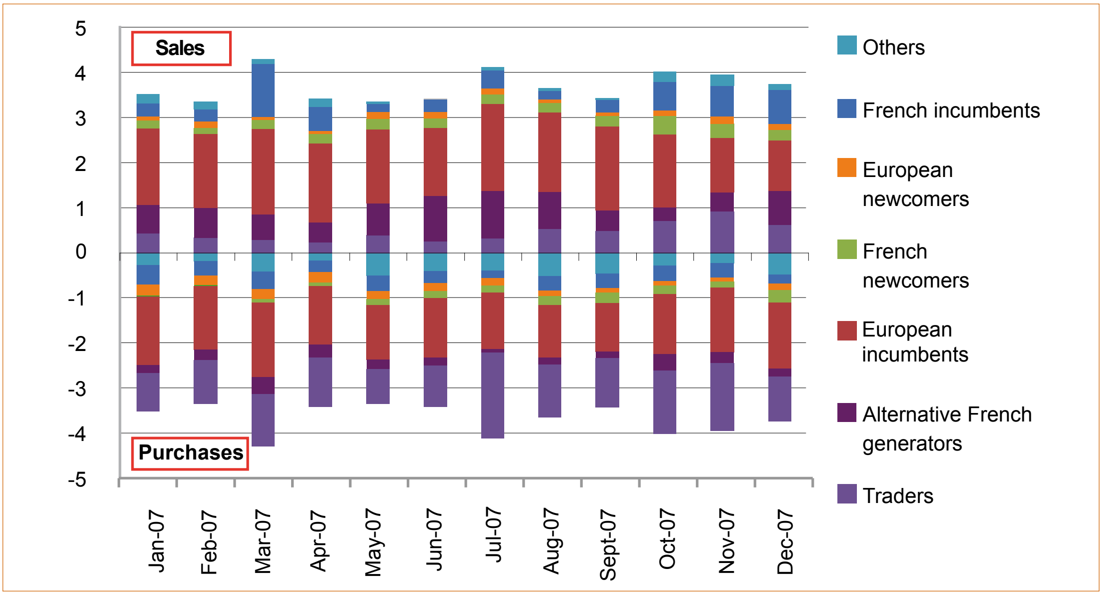
Evolution of monthly volumes Day-ahead auction in 2007



Data: Powernext; Analysis: CRE

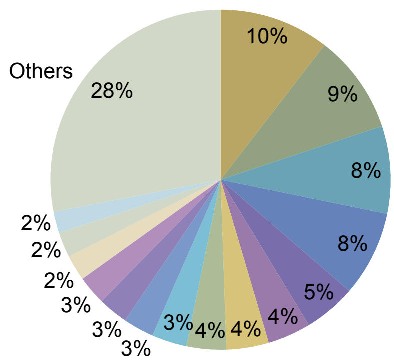
Most of the market activity was driven by the trading companies and the European incumbents. No one player dominated in either purchases or sales.

Split by month of purchases and sales by category of player Day-ahead auction in 2007

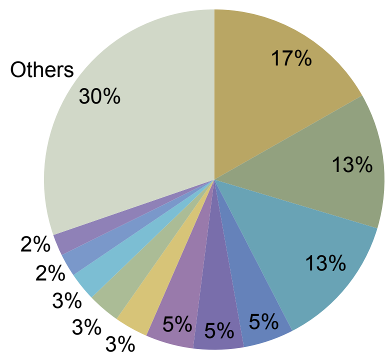


Data: Powernext; Analysis: CRE

Market shares of players
By volumes purchased
Day-ahead auction in 2007
- Players with a market share greater than 2% -



Market shares of players
By volumes sold
Day-ahead auction in 2007
- Players with a market share greater than 2% -

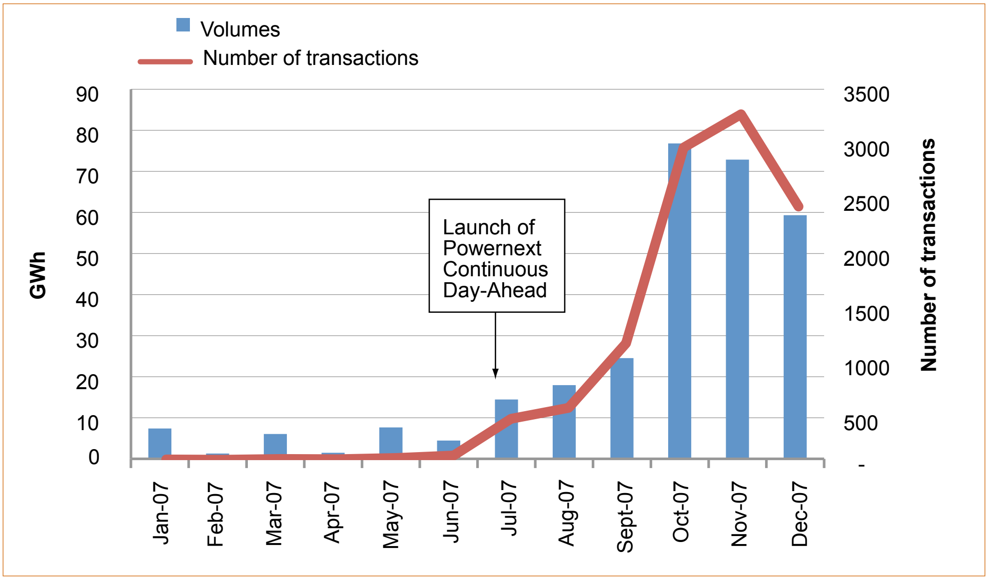


Data: Powernext; Analysis: CRE

1.2.3 The intraday market

Activity on the intermediated intraday market was very low at the start of the year, but grew strongly once the Powernext Intraday Platform was introduced in July 2007. Volumes exchanged on all platforms amounted to around 300GWh and 10,600 transactions.

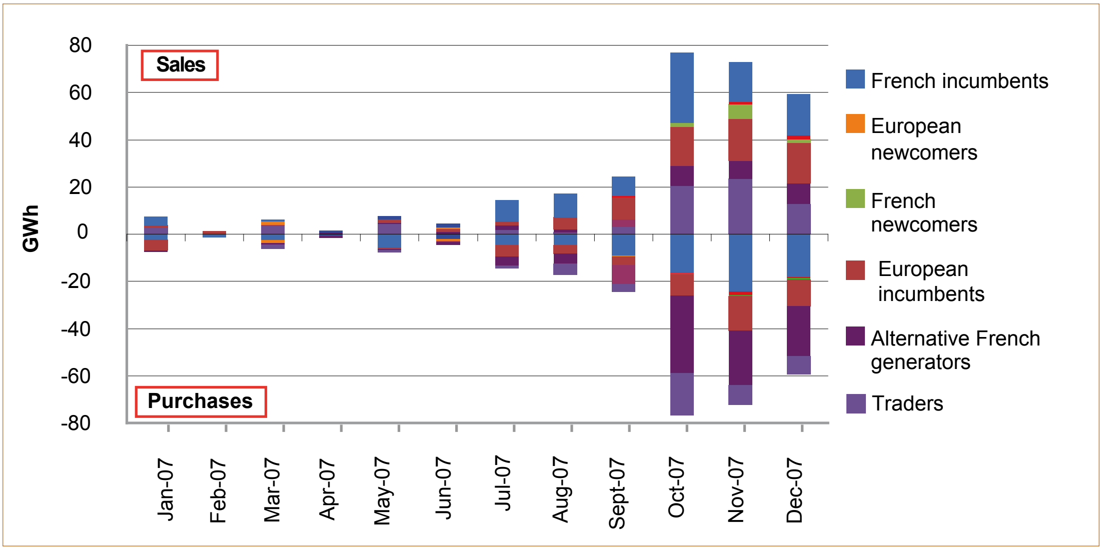
Changes in monthly volumes Intermediated intraday market in 2007



Data: Powernext, Brokers; Analysis: CRE

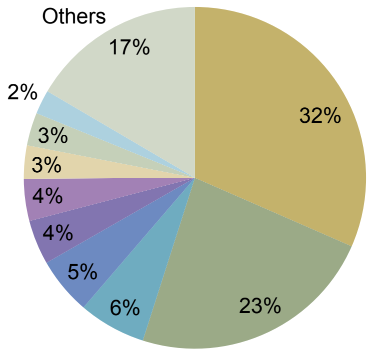
Most of the market activity, both purchase and sale, was driven by French incumbents.

Split by month of purchases and sales by category of player
Intermediated intraday market in 2007

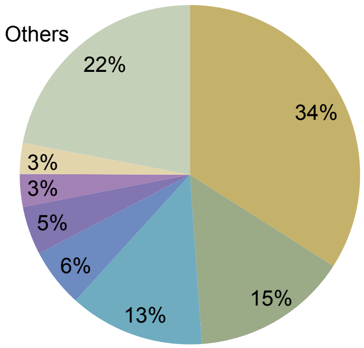


Data: Powernext, Brokers; Analysis: CRE

Market shares of players
By volumes purchased
Intermediated intraday market in 2007
- Players with a market share greater than 2% -



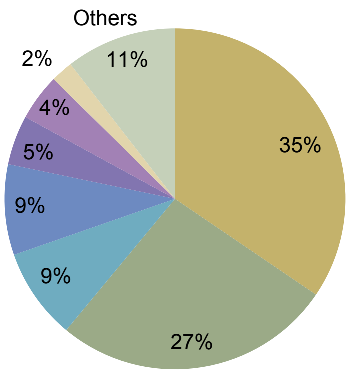
Market shares of players
By volumes sold
Intermediated intraday market in 2007
- Players with a market share greater than 2% -



Data: Powernext, Brokers; Analysis: CRE

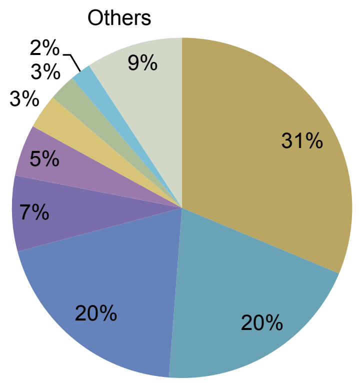
Market shares of players
By number of purchase transactions
Intermediated intraday market in 2007

- Players with a market share greater than 2% -



Market shares of players
By number of sales transactions
Intermediated intraday market in 2007

- Players with a market share greater than 2% -



Data: Powernext, Brokers; Analysis: CRE

2. EVOLUTION OF WHOLESALE PRICES

2.1 Day-ahead prices

2.1.1 Movements of prices

A particular feature of 2007 was the difference between prices recorded over the first three quarters and those seen during the last three months of the year.

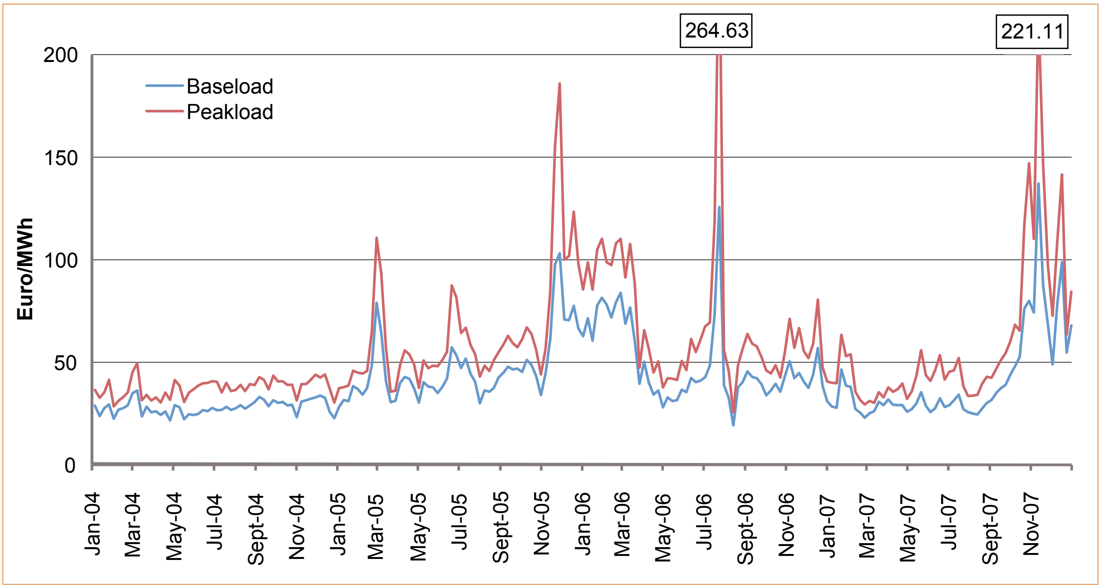
Between January and September 2007, prices were low compared with previous years. During that time, prices stood on average at around €30/MWh, as against €52/MWh during the same period in 2006 and €41/MWh in 2005. The daily average prices never exceeded €57/MWh.

By contrast, during the last quarter of 2007, prices were high compared with the previous years. The average price during the period was around €72.70/MWh. Unprecedented price spikes were recorded:

- €1,236 /MWh for delivery on Monday, 29 October 2007 between 6:00pm and 7:00pm;
- €2,500 /MWh for delivery on Monday, 12 November 2007 between 8:00pm and 9:00pm;
- €1,762 /MWh for delivery on Thursday 15 November 2007 between 6:00pm and 7:00pm.

These peaks were investigated by CRE, who published their conclusions on 17 April 2008.

Day ahead prices on Powernext – averaged over a week

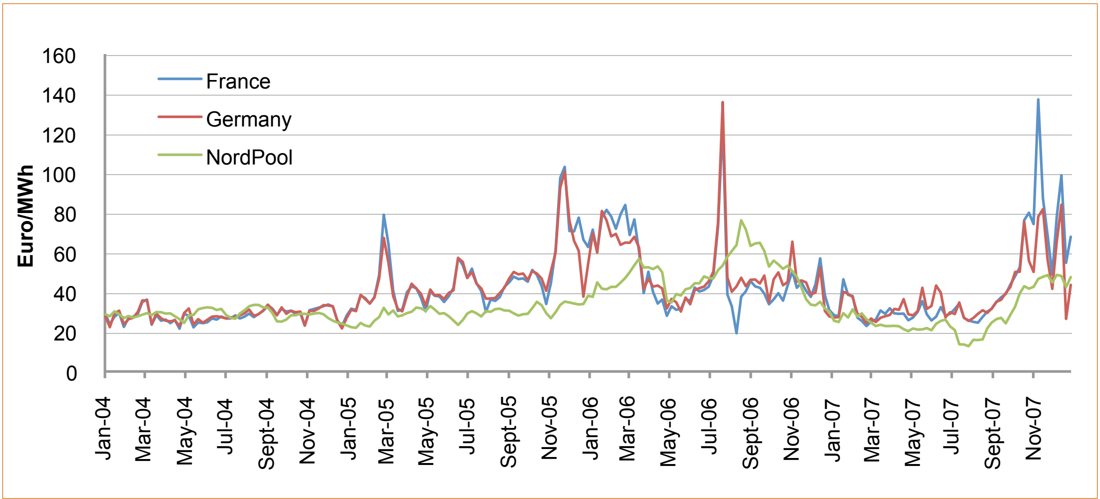


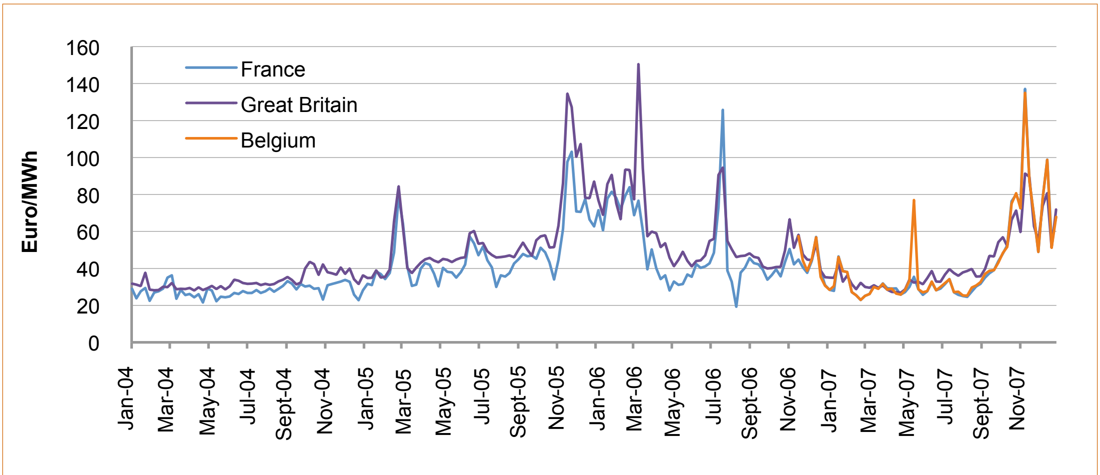
Data: Powernext; Analysis: CRE

During the first three quarters, French prices were lower than those observed on all the European markets, apart from Nord Pool. On the other hand, during the last quarter of 2007, only Italian and Swiss prices were higher than French prices.

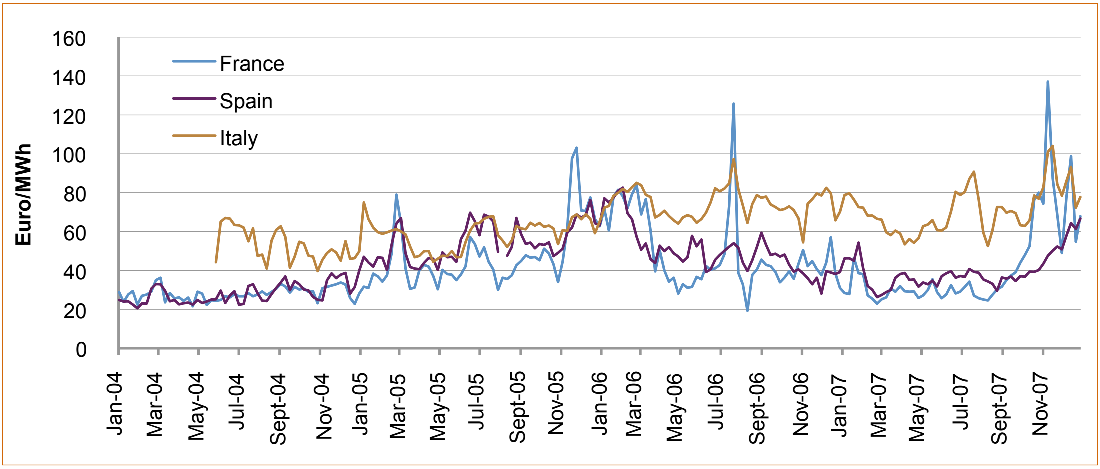
In particular, although for the first time since the end of 2005, the French day-ahead prices were generally lower than German prices for the first three quarters of 2007, during the last quarter, they again became on average more expensive than in Germany.

Day ahead prices on the main European markets – averaged over a week





Data: Powernext, EEX, Platts, Belpex, Omel, Nord Pool, Ipex; Analysis: CRE



Data: Powernext, EEX, Platts, Belpex, Omel, Nord Pool, Ipex; Analysis: CRE

2.1.2 Correlation with the evolution of the balance of supply and demand

CRE analyzed the correlation between movements in day-ahead prices and evolution of the balance between market supply and demand. To do so, it calculated a margin indicator for the supply-demand balance on the French electricity market. The indicator is calculated for every hour in the year, and includes the reserves of generated power actually usable on D-1 by French generators, and the residual import margins at the interconnections.

CRE notes that price movements have generally been in line with evolution of the balance of supply and demand on the French market.

During the first three quarters of 2007, the physical balance between supply and demand on the French market was well-adjusted, and the hydroelectric reserves were at historically high levels. By contrast, during the last quarter, margins on the French markets and the hydroelectric reserves were both very much reduced.

The analysis of movements in daily pricing shows that in almost 80% of cases, price increases coincided with a narrowing of the supply-demand margin on the French market.

Nevertheless, some of the price spikes observed during the last quarter of 2007 occurred even when there was no excessive stress on the supply-demand balance. Such situations were investigated by CRE, and their conclusions were published on 17 April 2008.

2.1.2.1 Method

The equilibrium reached by the electricity marketing system varies with the difference between available generating capacity and the forecast demand. CRE has calculated an indicator that quantifies the stresses on the supply-demand balance. The indicator takes into account:

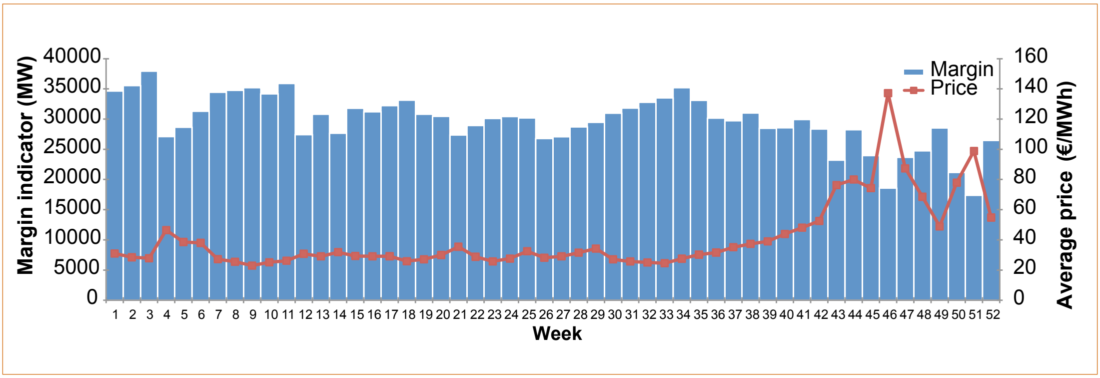
- the gap between available capacity and power output from industries where it is possible to decide beforehand what is generated. (These include the nuclear, fossil fuel, and hydroelectricity industries);

- the gap between the net import capacity nominated by players and the maximum transfer capacity available for import at the interconnections (NTC).

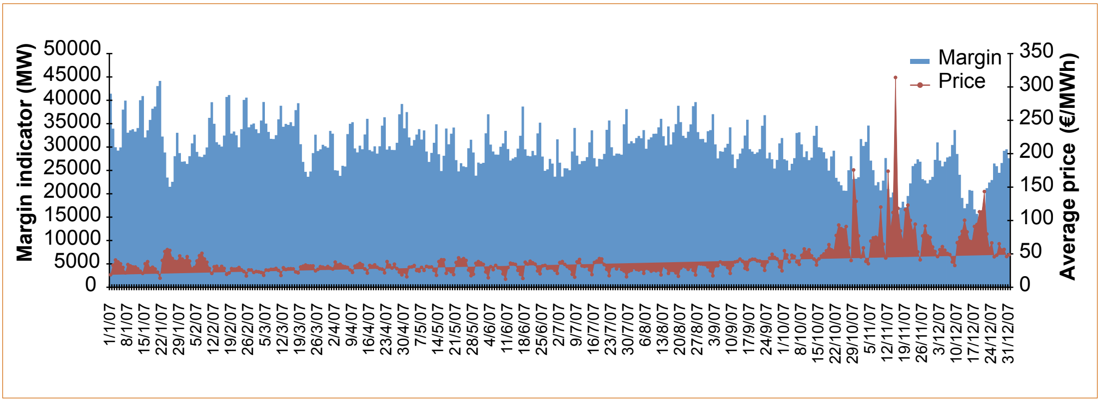
2.1.2.2 Results

- **Weekly and daily periods**

Price movements and margin indicator, weekly averages



Price movements and margin indicator, daily averages



Data: RTE, Powernext; Analysis: CRE

Indicator and price appear indeed to be correlated. When the margin indicator rises (or falls), the price falls (or rises):

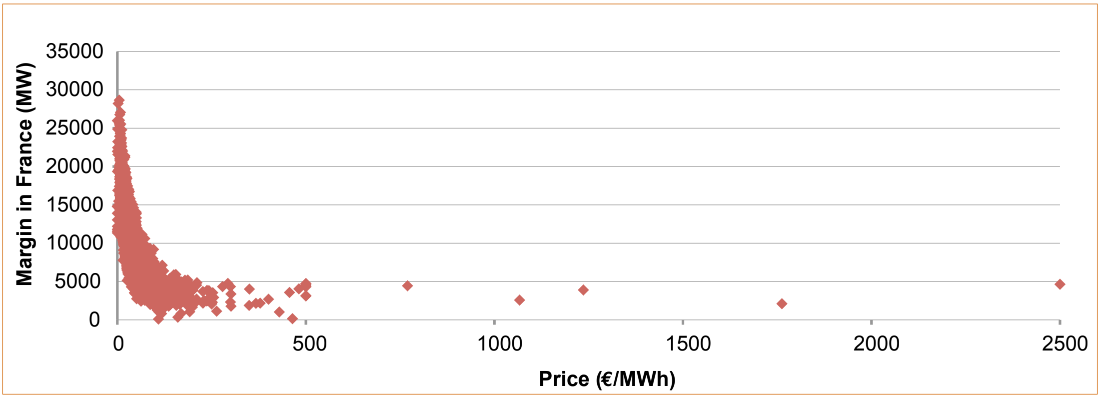
- in 71% of instances for the analyses over one week,
- in 78% of instances for analyses over one day,

Most noticeably, a significant reduction in the indicator at the end of the year was accompanied by a sharp rise in prices.

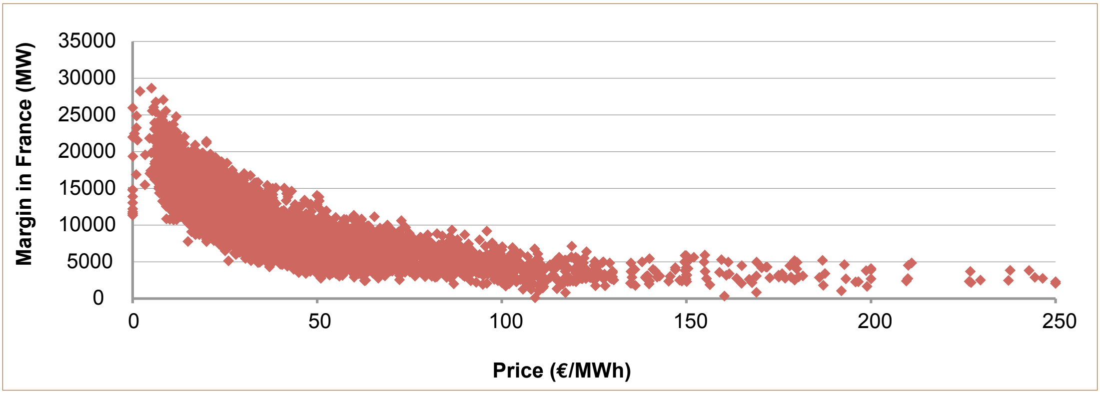
- **Hourly time span**

The analyses based on an hourly time interval showed the closest correlation when the margin for the supply-demand balance was calculated based only on the available generated power. When the import margins at interconnections were included, the results were less clear. This result is not surprising, as capacity at the interconnections is not optimally employed for each individual hour (see the section on Cross-border trading).

Relationship between the price and the margin indicator - Hourly averages -

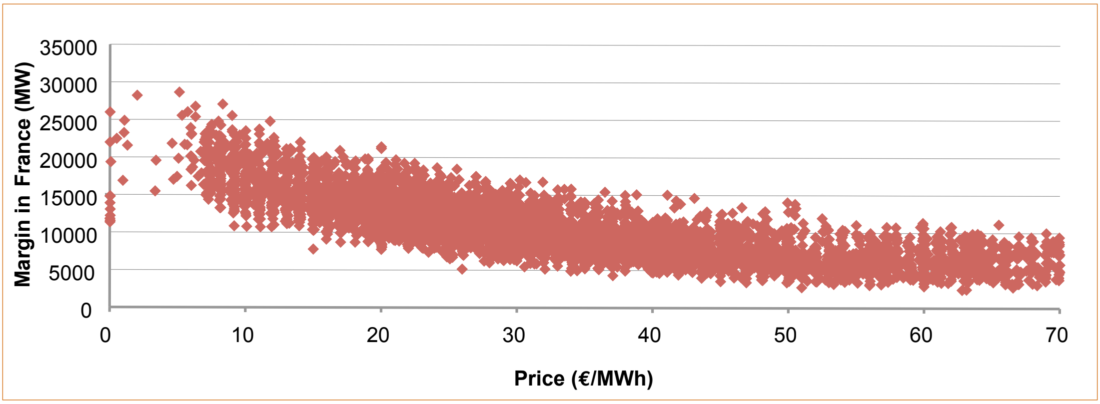


Detail on the interval €0-250 /MWh



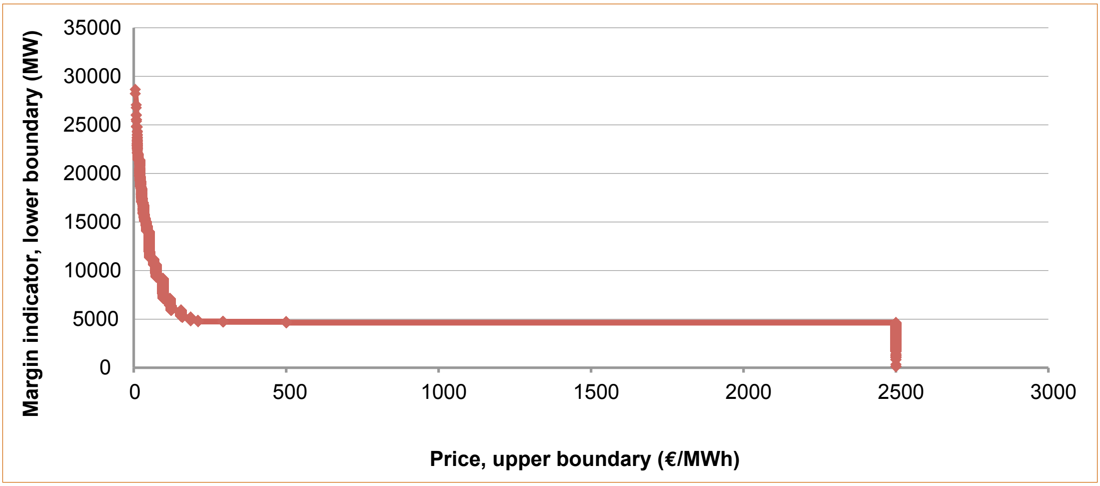
Data: RTE, Powernext; Analysis: CRE

Detail on the interval €0-70 /MWh



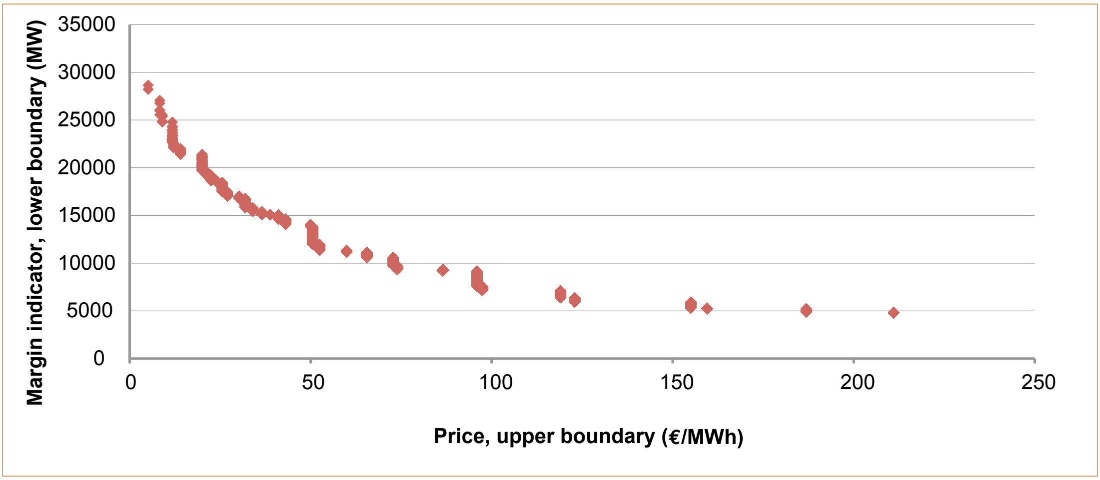
Data: RTE, Powernext; Analysis: CRE

Upper boundary of the "margin indicator/price" curve



Data: RTE, Powernext; Analysis: CRE

Detail on the interval €0 – 250 /MWh



Data: RTE, Powernext; Analysis: CRE

The curve immediately above shows that when the margin indicator was higher than 12,000 MW (Y-axis), the price was always lower than €50 /MWh (X-axis). When the price was above €50 /MWh, the margin indicator was always below 12,000 MW.

Taken together, these results show that price is highly dependent on the supply-demand balance in the electricity marketing system.

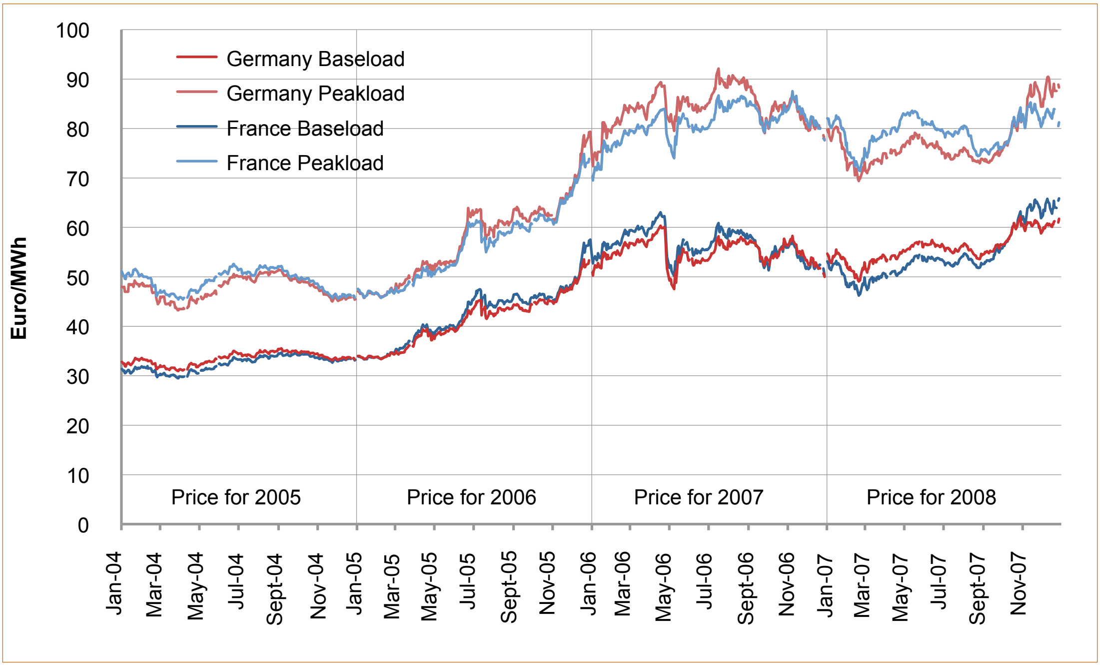
2.2 Futures prices

2.2.1 Movements of prices

The price of the baseload product for the calendar year 2008 was volatile throughout 2007. Although it started the year at around €55 /MWh, it fell until March, and then recovered to a value close to €55 /MWh during the summer. During the last quarter of 2007, it again rose sharply, reaching around €65 /MWh by the end of the year.

French prices were lower than German prices until September, then the difference reversed during the final quarter, and finally levelled out right at the end of the year. British prices were lower than French prices until March 2007, when they rose above them. Lastly, prices on Nord Pool remained below French prices throughout the whole of 2007.

Prices of Y+1 futures in France and in Germany – daily prices



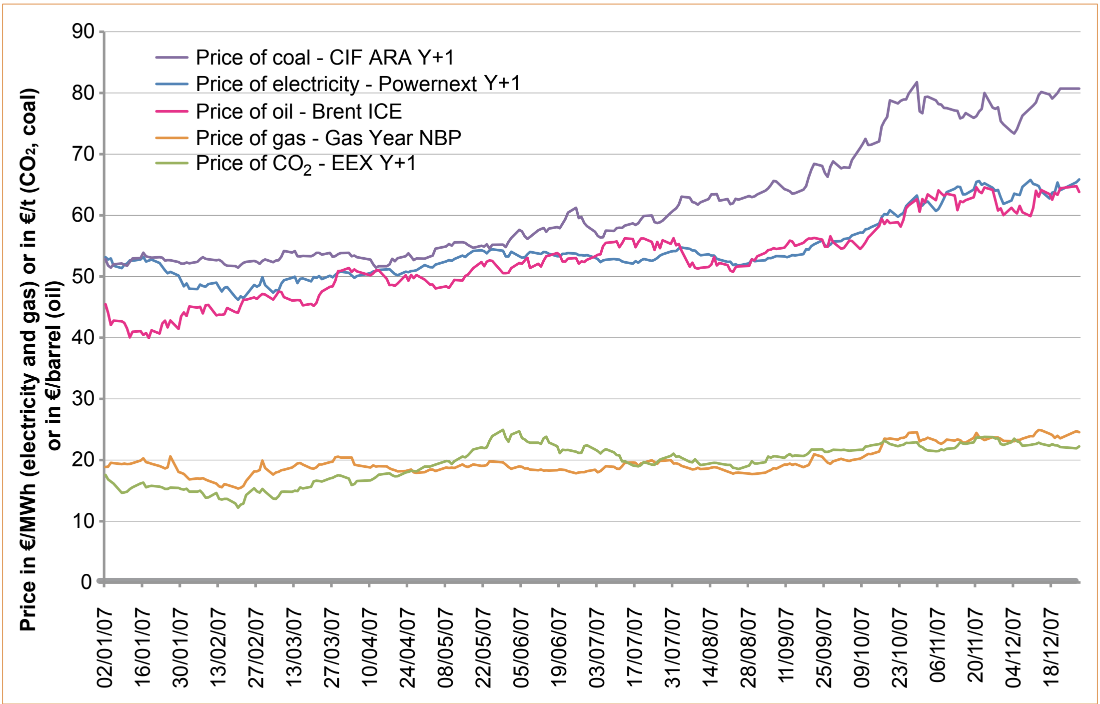
Data: Powernext, EEX

2.2.2 Correlation with factors normally affecting movements in futures prices

2.2.2.1 Links between electricity futures prices and the prices of underlying commodities

CRE studied the statistical relationship between the price of the baseload product for the calendar year 2008 (referred to as “Y+1” in the remainder of this document), the prices of fossil fuels on the international markets and the trading prices for CO_2-emission permits. The analysis looked at the price levels and their day-to-day variations during 2007.

Daily prices for electricity and fuels in 2007



Data: Powernext, EEX, Argus

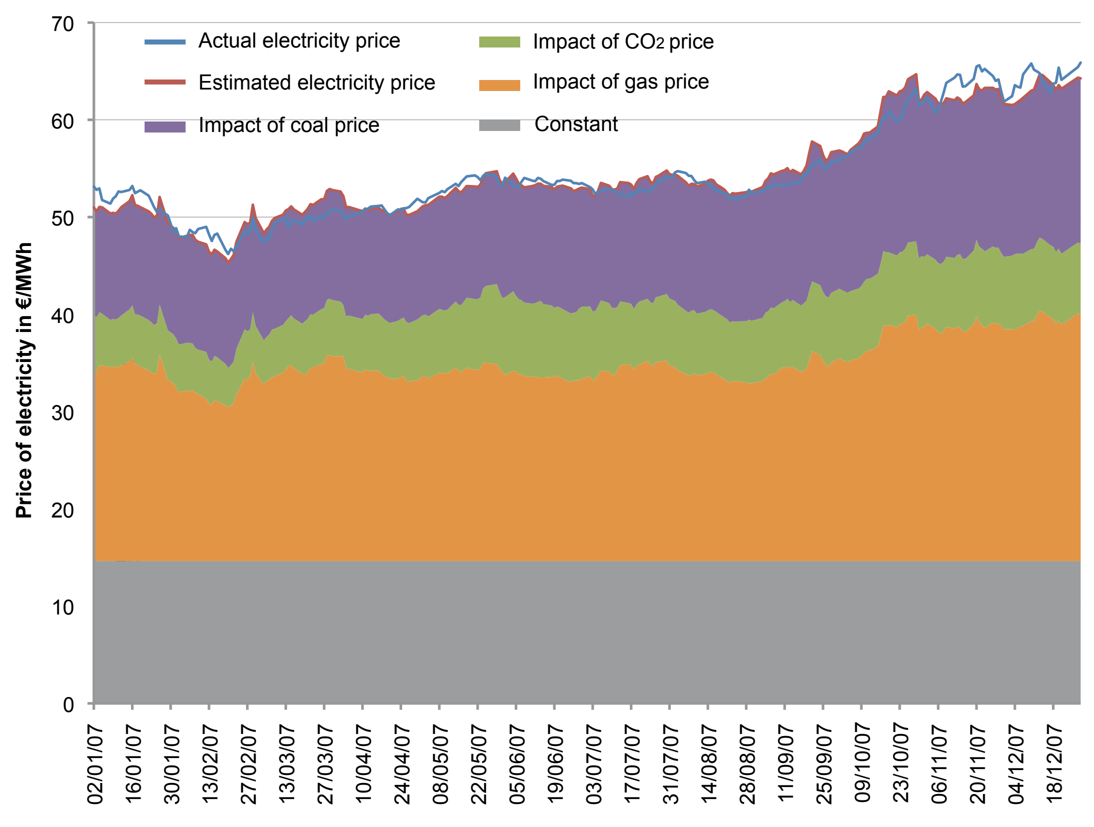
The price of electricity correlated closely with prices for gas, coal and oil. To a lesser extent, it was also correlated with the CO_2 price.

There is no simple model that provides a statistical relationship[6] predicting under all circumstances the product price for the calendar year 2008 from the fuel and CO_2 prices. Nevertheless, CRE noted that in 2007, the prices of electricity, gas, CO_2 and coal were linked by a cointegration relation. This means it was possible to define a good-quality linear equation to predict the price of electricity from the price of these commodities. On the other hand, it is clear that the oil price has had no direct influence on the electricity price.

This model thus demonstrates that in 2007, electricity prices were linked to the prices of gas, CO_2 and coal by a long-term equilibrium.

Results based on the long-term equation between electricity price and the prices of gas, CO_2 and coal

– Estimated from the daily quotation of Y+1 prices in 2007 –



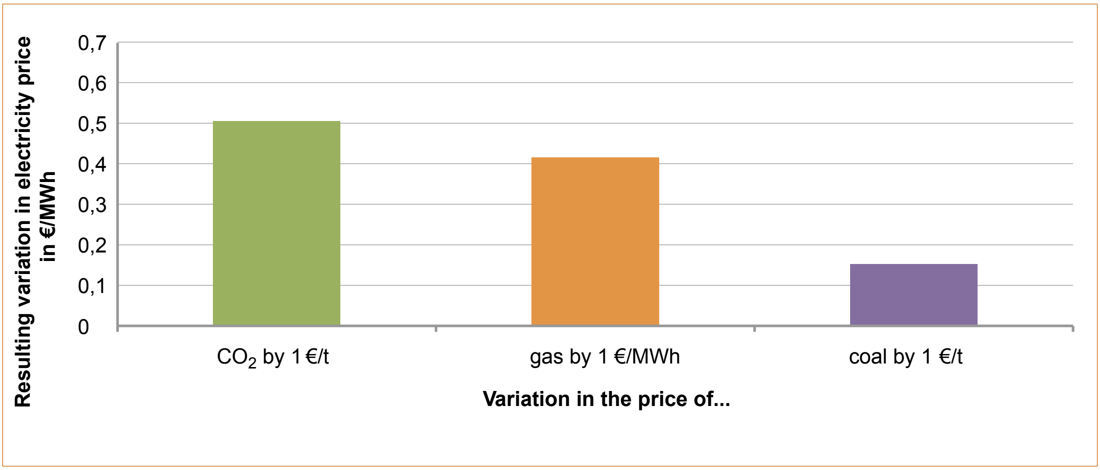
Data: Powernext, EEX, Argus; Analysis: CRE

An analysis of the impact of variations in the prices of the underlying commodities on the electricity prices shows that changes in the prices of CO_2 and gas had most influence on electricity prices. Fluctuations in coal prices also affected electricity prices, whereas neither petrol (Brent ICE) nor oil (BTS spot price) had any significant impact.

However, variations in the prices of CO_2, gas and coal are insufficient alone to explain all price movements.

Impact of changes in the price of each fuel on the change in electricity price

– Change in electricity price between 1 January and 31 December 2007
following a one-euro change in a commodity price –



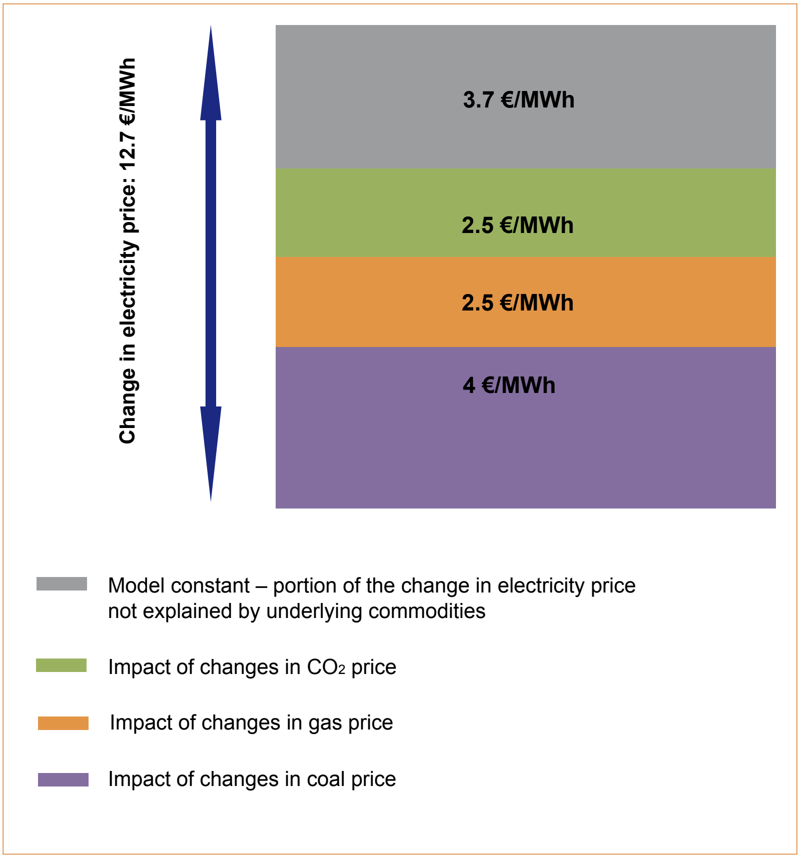
Data: Powernext, EEX, Argus; Analysis: CRE

In relative terms, evolution of the price of coal had the least impact on fluctuations in electricity price. However, since coal prices rose most in absolute terms during the year, variations in coal price had most impact in raising electricity prices.

The coefficient measuring the impact of evolution of CO_2 price on electricity price may be interpreted as the CO_2 content implicit in producing the energy (in t CO_2/MWh). Its estimate, close to 0.5, appears particularly strong[7].

We also reiterate that fluctuations in the price of coal, gas and CO_2 do not appear to account completely for the rise in the price of electricity in 2007. The fraction not explained by the model (constant) is shown in grey in the graph below.

Impact of the evolution of fuels prices on the change in electricity price
– Changes observed between 1 January and 31 December 2007 –



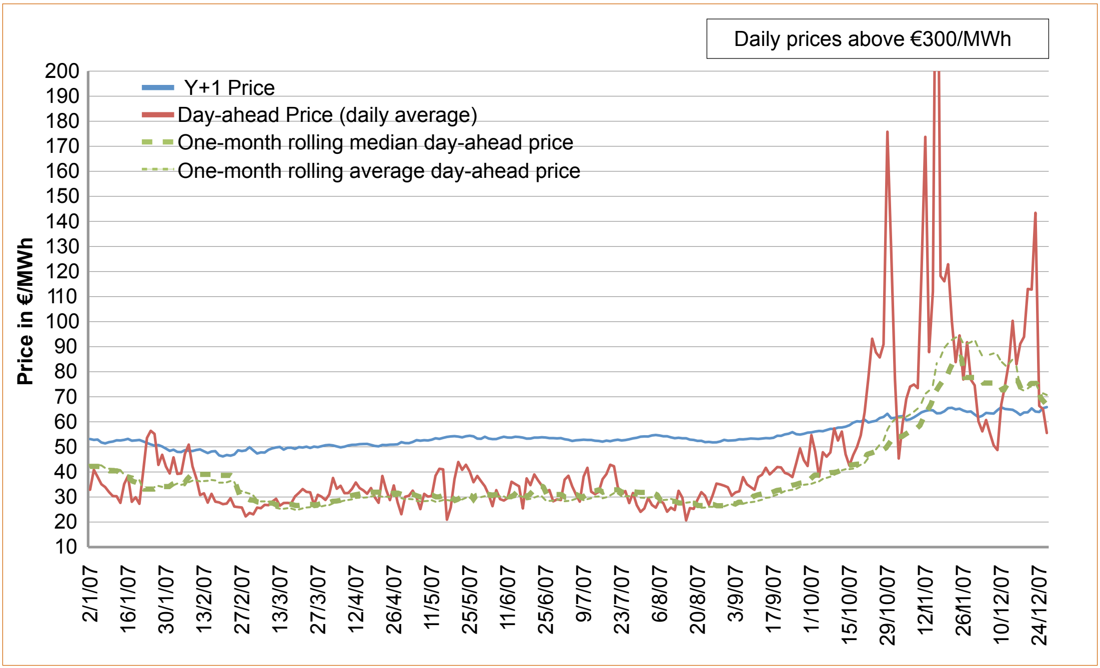
Data: Powernext, EEX, Argus; Analysis: CRE

2.2.2.2 Links between electricity futures prices and day-ahead prices

Variations in day-ahead electricity prices can affect futures prices, by influencing the expectations of market players.

CRE has studied the statistical relationship between the price of the baseload product for the calendar year 2008 (referred to as "Y+1" in the remainder of this document) and the day-ahead prices. The analysis looked at the price levels and their day-to-day variations during 2007.

Y+1 and day-ahead prices in 2007
– Quoted on Powernext – Daily averages –



Data: Powernext; Analysis: CRE

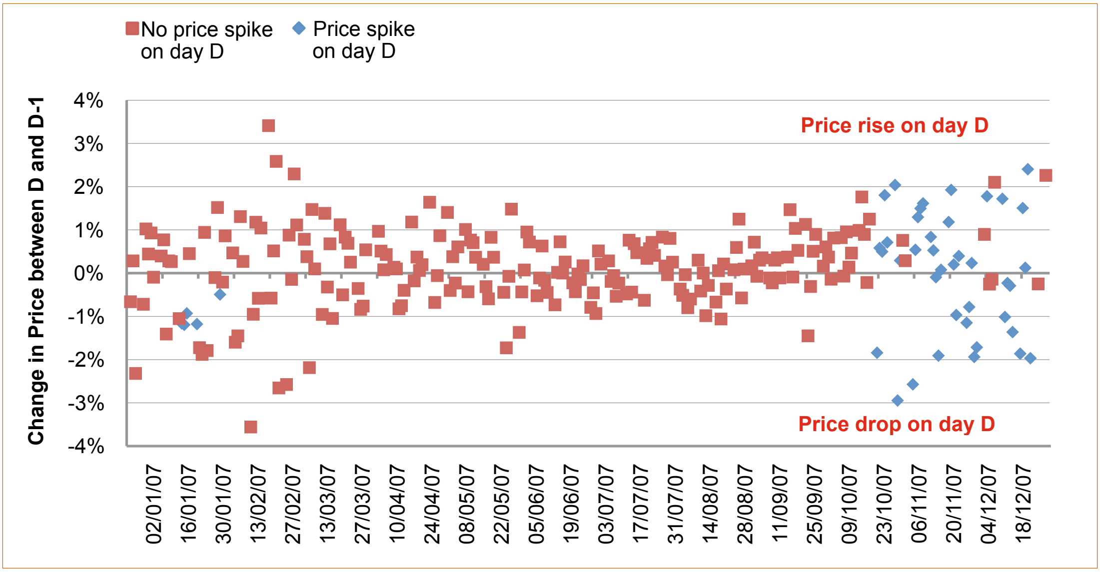
Daily movements in the Y+1 price correlated with movements in the day-ahead price, and even more closely with the trend (moving average and median) in day-ahead prices.

CRE carried out some analysis to see if the Y+1 price increased systematically on days when the day-ahead price spiked, and if these increases were more marked than on other days. The results showed that this was not the case: individual price spikes did not affect the Y+1 prices.

The following graphs analyze the variation in the Y+1 price from one day to the next, depending on whether or not there is a price spike[8] on Powernext Day-ahead Auction on the same day or the one before:

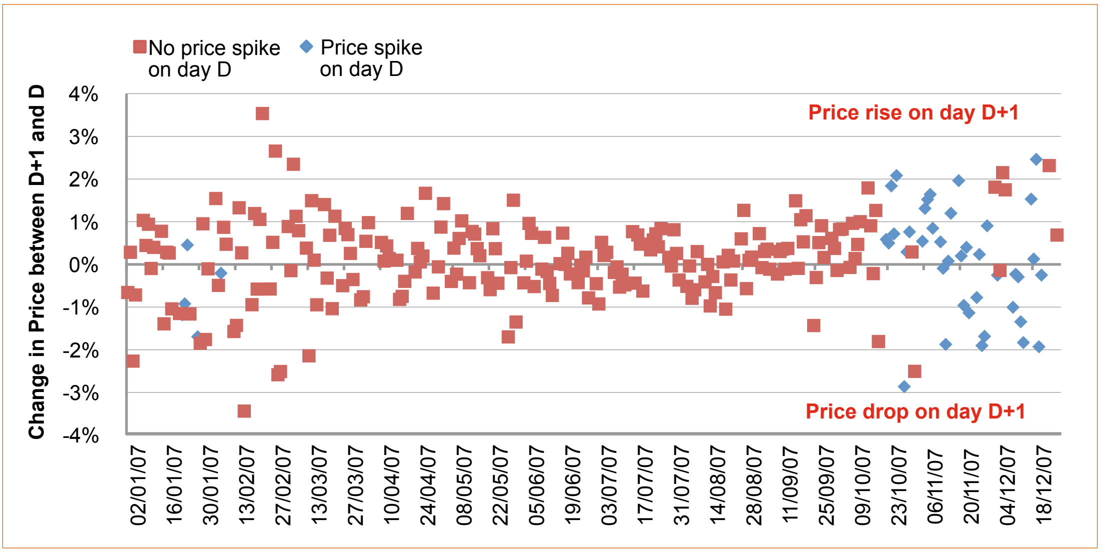
- the first graph shows the impact of price spikes on the Y+1 price quoted on the day of the peak,
- the second graph shows the impact of these price spikes on the Y+1 price quoted the following day.

Effect of day ahead price spikes on the daily change in Y+1 prices
Effect on the day of the price spike
– Quotation on Powernext in 2007: daily averages –



Data: Powernext; Analysis: CRE

Effect of day ahead price spikes on the daily change in Y+1 prices
Effect on the day after the price spike
– Quotation on Powernext in 2007: daily averages –



Data: Powernext; Analysis: CRE

These analyses show that on days when the day-ahead price spiked (in blue), the Y+1 price did not systematically increase; rises in the Y+1 price were as numerous as falls. In addition, the variations were of the same order of magnitude as on other days (in pink).

The analysis of quoted prices on the following day gives the same result. The day after a day when the day-ahead price spiked (in blue), the Y+1 price did not systematically increase; rises in the Y+1 price were as numerous as falls. In addition, the variations were of the same order of magnitude as on other days (in pink).

It is therefore reasonable to conclude that rises in the Y+1 price are related to an upward trend in day-ahead prices, caused by an accumulation of high prices, and not to localized price spikes.

3. USE OF GENERATING FACILITIES

3.1 Fuel type that are marginal

CRE analyzed the proportion of hours for which each fuel type was marginal and thus guided the price. The year 2007 was characterized by two distinct periods.

Throughout the first three quarters, coal-fired generation (between 30 and 40% of the time) and hydroelectric generation (between 30 and 35% of the time) appeared to be the predominant fuel type that were marginal. Nuclear generation was marginal for between 15 and 20% of the time. Oil-fired generation was marginal for fewer than 5% of the hours. Lastly, for between 10 and 15% of the time, the price appeared to be determined by prices on the cross-border markets.

During the last quarter, at a time when the balance between supply and demand was more stressed, the foreign markets were the predominant influence: for more than half the time, the price moved away from the marginal cost for French fuel types and aligned with prices on the cross-border markets. The hydroelectric and coal fuel types seem only to have guided the price during fairly short periods (between 20% and 15% respectively of the time) and the time the nuclear fuel type remained marginal fell to less than 5%. By contrast, the proportion of time for which the oil fuel type was marginal rose (to between 5 and 10%).

Thus we note that:

- the nuclear fuel type was rarely in a position to set prices on the French wholesale market,
- by contrast, the cost of coal-fired production, and the valuation of hydroelectric reserves had an overriding effect on prices.
- prices on the cross-border markets determined the French price for a significant proportion of the year.

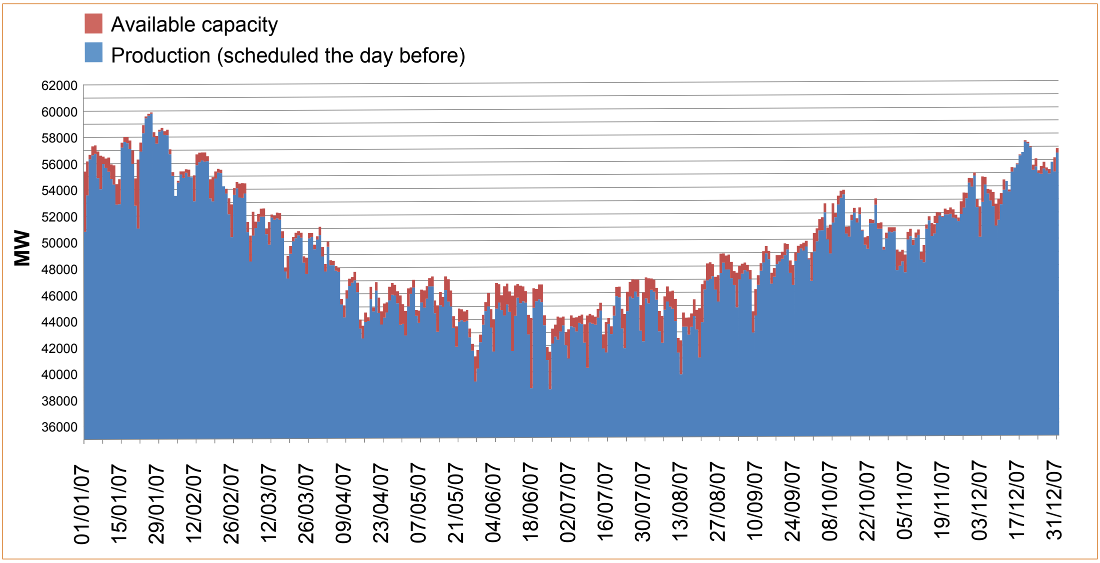
3.1.1 Method of decision to run the different fuel types

In the following paragraphs, CRE has analyzed how the generating capacity available from each fuel type is used. To do so, the production generators scheduled each day for the next day (situation at 4:00pm) was compared with the maximum power available, as published via the balancing mechanism.

3.1.1.1 CRE notes that nuclear generation was used for base load and also for semi-base load. It was used to balance the supply at different seasons and intraday.

CRE notes that nuclear generating facilities were used to meet not only base load requirement (fixed proportion of the consumption throughout the year), but also for part of the semi-base -load requirement (variable proportion of the consumption). In particular, by scheduling most of the planned shutdowns in summer, most of the capacity was made available during the winter, when demand is high. Thus the nuclear fuel type, together with cogeneration, has been instrumental in meeting seasonal variations in demand. During periods of low consumption (for instance at night), traditional electricity generators reduced their production to a minimum, so that nuclear energy often became the marginal means of production for French generating facilities.

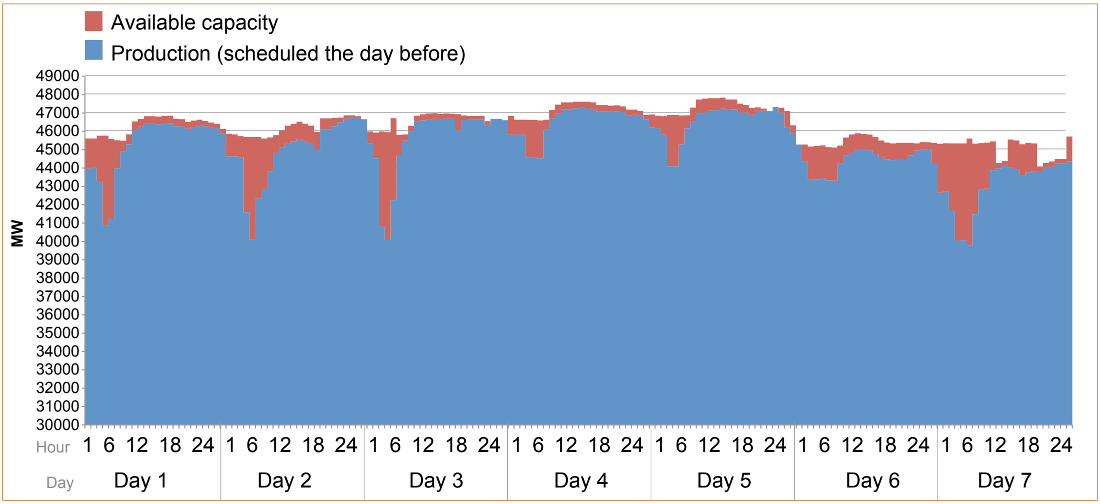
Movements in scheduled nuclear production in 2007
- Daily averages -



Data: RTE; Analysis: CRE
In this graph, the available capacity corresponds to the maximum technical capacity from which capacity used for the reserve is withdrawn.

As shown in the graph, nuclear generating facilities were more available in the winter. The available power (after deducting supplies held in reserve) was on average more than 57,000 MW in January, as compared to 45,000 MW in July. Thus nuclear energy was very important in balancing the seasonal differences in supply between winter and summer. (There was a difference of more than 12 GW between January and July.)

Movements in scheduled nuclear production in for a particular week
- Hourly averages -



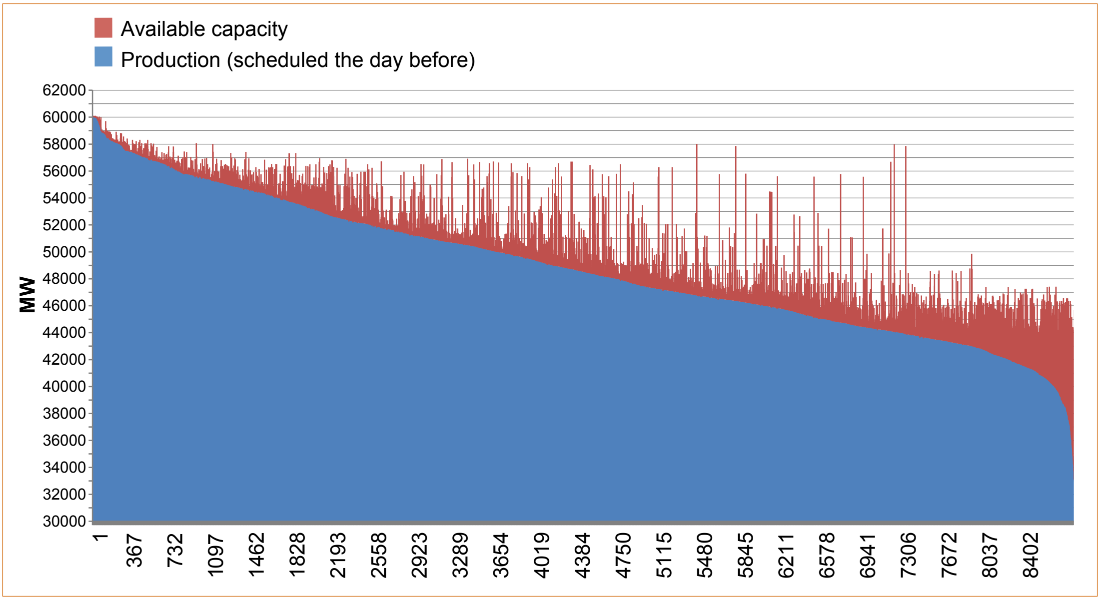
Data: RTE; Analysis: CRE
In this graph, the available capacity corresponds to the maximum technical capacity from which capacity used for the reserve is withdrawn.

Nuclear generating facilities were employed virtually all day at maximum capacity. However, nuclear generation was reduced during periods of low consumption (in particular, between 2:00am and 5:00am). During these times, the facilities were capable of varying the total delivered power quickly by several GW (up to 4,750 MW in one hour, the maximum recorded in 2007) so that to a certain extent, they could track evolution of demand, both upward and downward.

Each reactor can vary the delivered power relatively quickly. It is not unusual for a power station to reduce its production to the technical minimum (i.e. to some hundreds of MW) for several hours to respond to a drop in consumption. In particular, where a reactor is assigned a use value (see section 3.2. Analysis of costs and player behaviour), it may have to make this type of adjustment several times a week.

The monotonic power curve shows that the power used was highly dependent on the power available from the fuel type.

Monotonic curve for the scheduled nuclear production



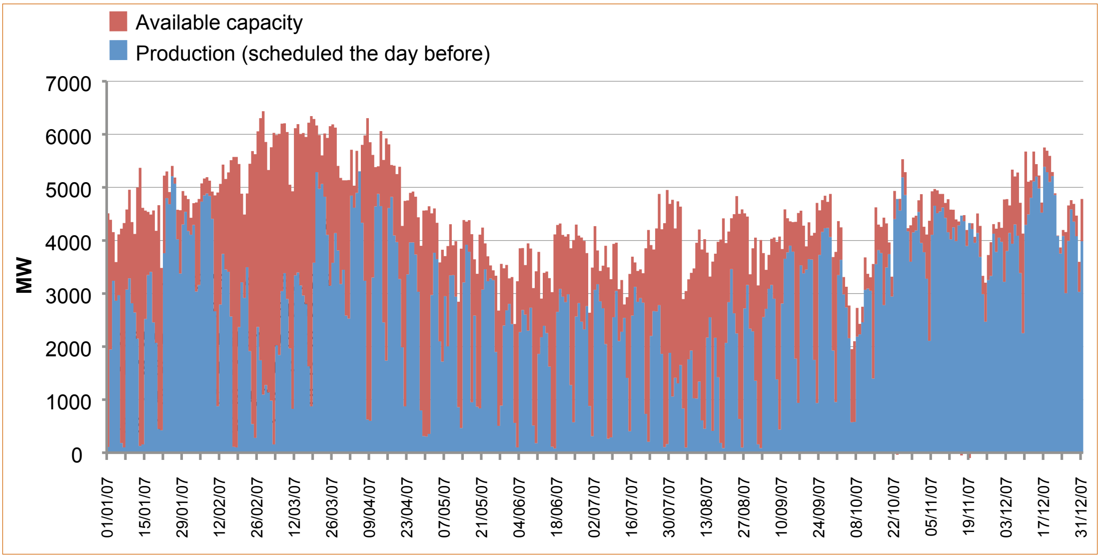
Data: RTE; Analysis: CRE

The scheduled production capacity fell to a minimum 33,000MW and rose to a maximum of some 60,000MW.

3.1.1.2 CRE notes that coal-fired production was used to meet changes in the intraday demand

Coal-fired power stations were instrumental in meeting demand at semi-base loads (variable proportion of the consumption). In particular, they were used to adjust the supply between the working week and the weekend, and between times of medium and high consumption.

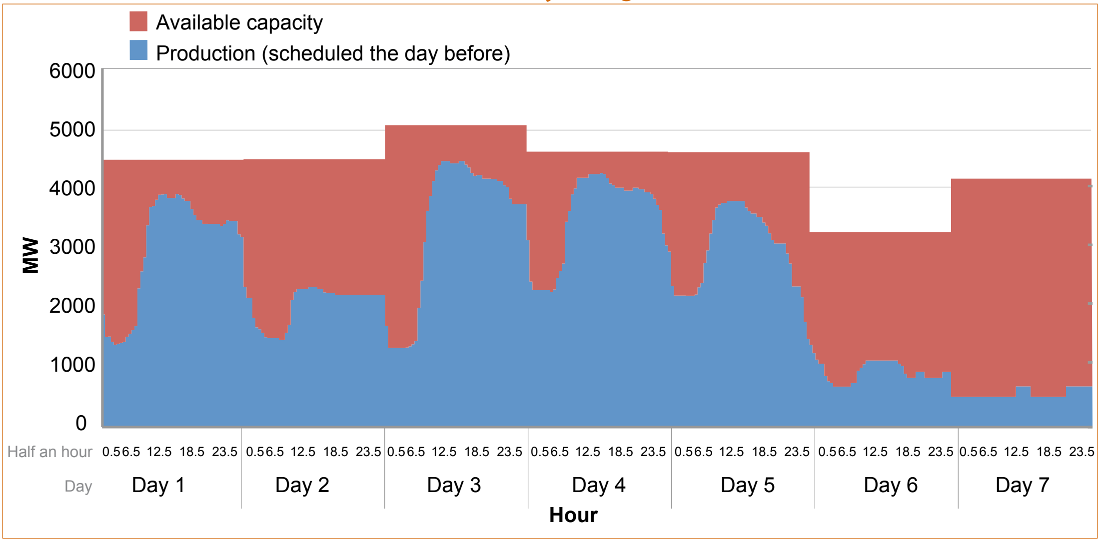
Movements in scheduled production from coal-fired facilities in 2007
- Daily averages -



Data: RTE; Analysis: CRE

The average power available from coal-fired generating facilities was above 4,500 MW in 2007, as against a scheduled power averaging at around 2,800 MW. The power stations have slightly less availability in summer than winter (a difference of about 1GW between the average availability observed during the six winter months (October to March inclusive) compared with that calculated for the six summer months (April to September inclusive).

Movements in scheduled production from coal-fired facilities for a particular week
- Half-hourly averages -



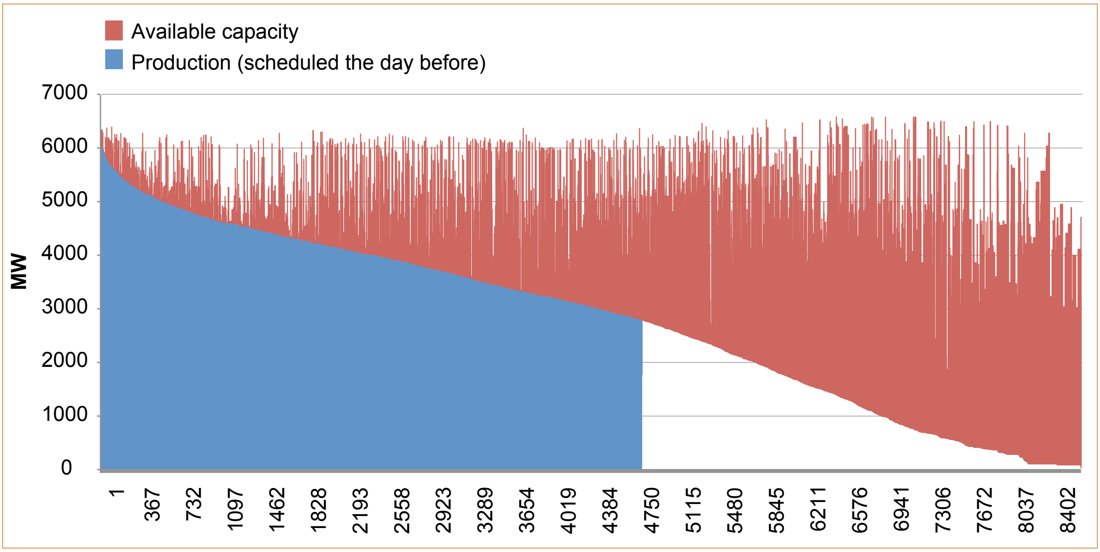
Data: RTE; Analysis: CRE

Coal-fired facilities adjusted their output depending on:

- **the day of the week:** the averaged scheduled output was around 3,300MW during the week (peaking on Wednesday), as against 1,900MW on Saturday and 1,300MW on Sunday. Coal-fired power stations were generally shut down just once a week, at the weekend.
- **the time of day:** the delivered power was reduced to a technical minimum during the night and reached a maximum in the early morning, remaining there until the middle or end of the afternoon, depending on demand.

The fuel type's monotonic power curve shows that evolution of the use made of its output during the year were not conditioned by availability.

Monotonic curve for the scheduled power from coal-fired generating facilities

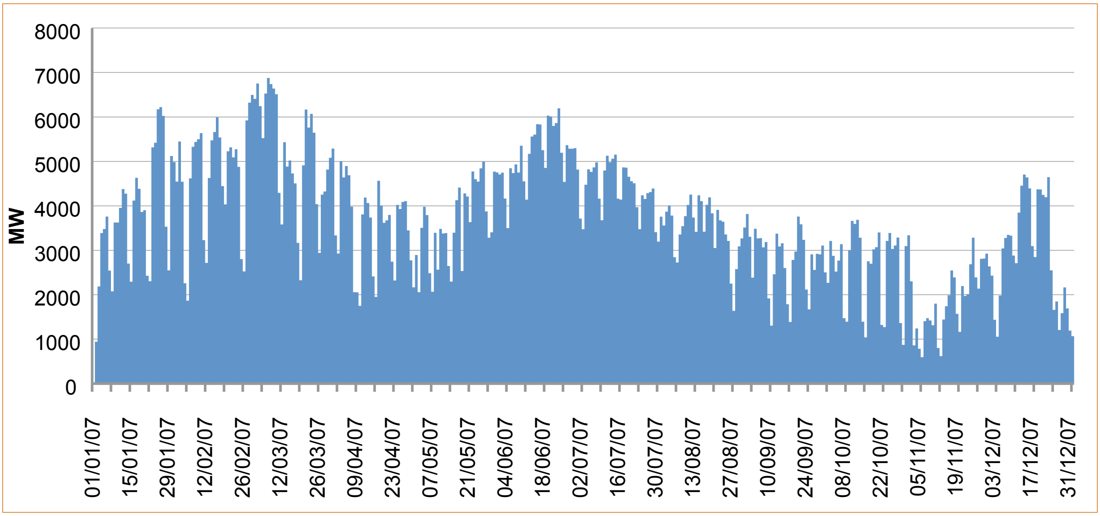


Data: RTE; Analysis: CRE

3.1.1.3 CRE notes that hydroelectric dams were used to meet peaks in consumption during the day

When nuclear and coal-fired generating capacity was insufficient to satisfy demand, dams were used to balance supply and demand. They were used in particular to meet requirements during peak hours, and to a lesser extent, to adjust the supply between the working week and the weekend.

Movements in scheduled production from hydroelectric reservoirs and daily or weekly storage in 2007
- Daily averages -



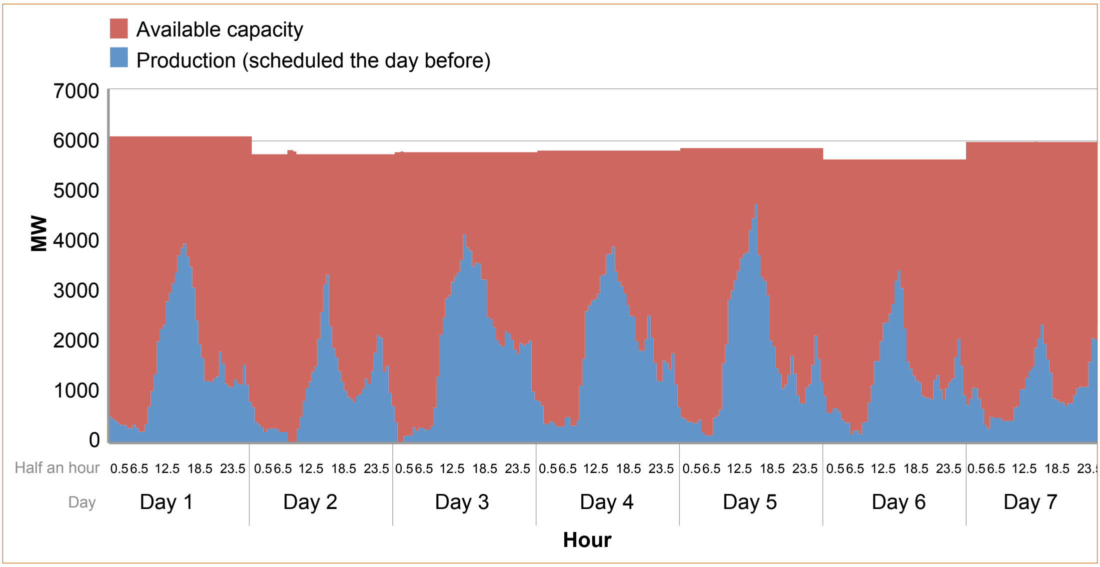
Data: RTE; Analysis: CRE

Hydroelectric dams were used throughout the year, depending both on how full they were and on demand. They were not used to balance the supply at different seasons. On the contrary, their use depended on:

- the day of the week: they were employed more on working days than on public holidays or during the weekend;
- the time of day: dams were instrumental in meeting peaks in demand at particular times of day when demand was greatest (around midday in summer and between 7:00pm and 10:00pm in winter).

The graph below shows the theoretically-available and scheduled production from hydroelectric generating facilities. It should be noted that the value for theoretically-available power never applies in practice, because of the technical constraints in operating the installation, and restrictions regarding the hydroelectric reserves.

Movements in scheduled production from hydroelectric reservoirs for a particular week
- Half-hourly averages -

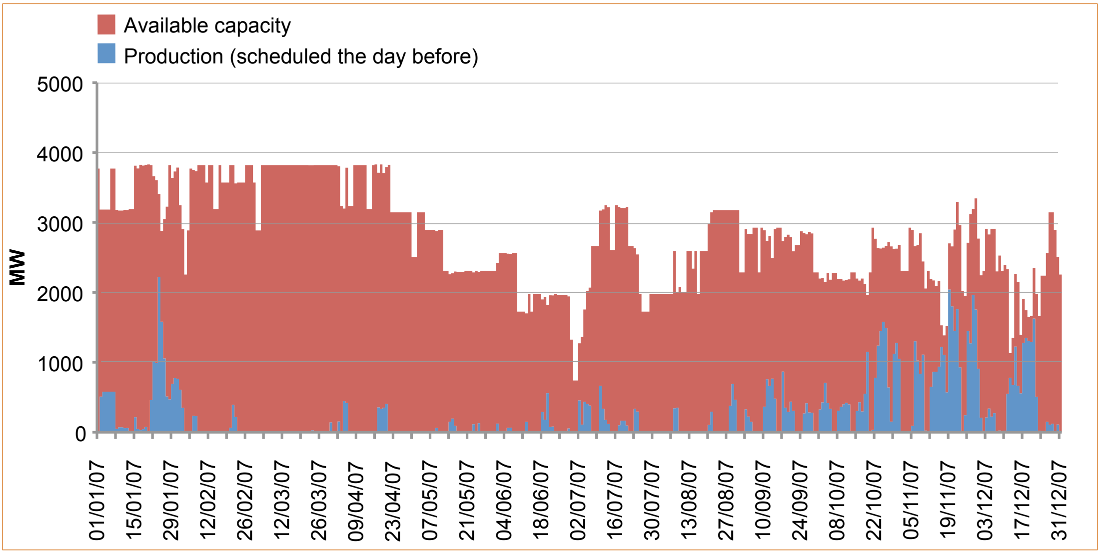


Data: RTE; Analysis: CRE

3.1.1.4 CRE notes that oil steam cycles were used as back up at times when the balance between supply and demand was stressed.

Oil was a useful standby at times when demand was particularly high.

Movements in scheduled production from oil-fired facilities in 2007
- Daily averages -

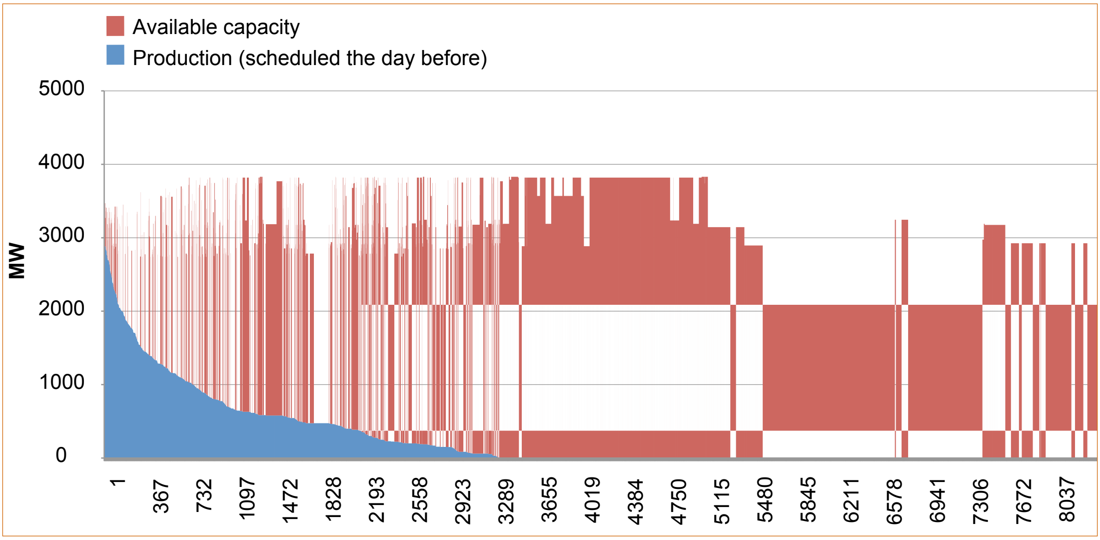


Data: RTE; Analysis: CRE

Oil-fired power stations did not operate regularly throughout the year. They were shut down for most of the time, and worked intermittently during periods when there were stresses between supply and demand. In 2007, they were used mostly at the end of the year.

The monotonic curve for the scheduled power from oil-fired power stations shows that evolution of the use made of its output during the year were not conditioned by availability.

Monotonic curve for the scheduled power from oil-fired power stations

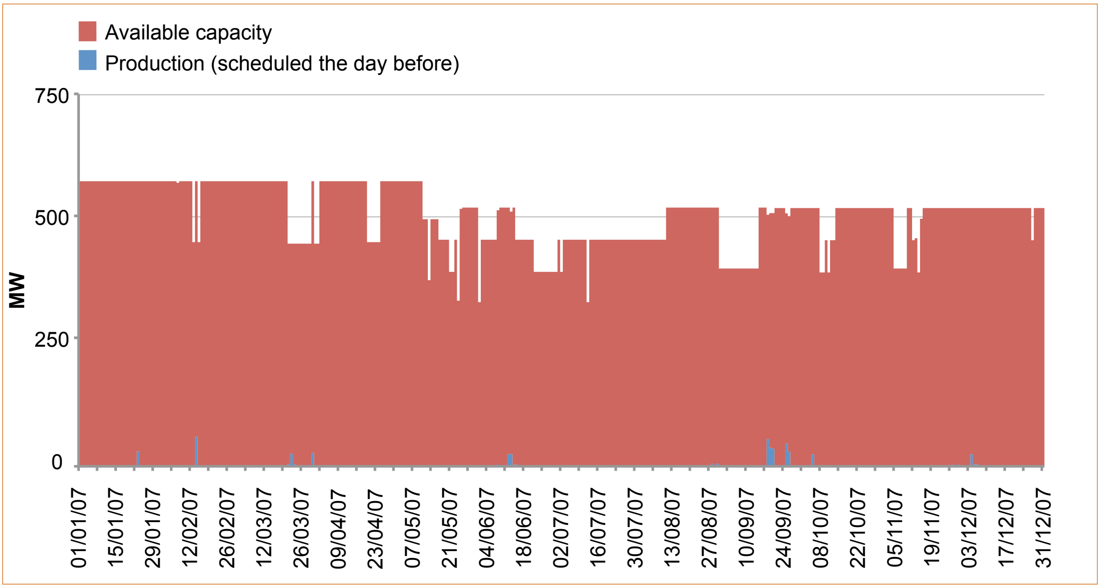


Data: RTE; Analysis: CRE

3.1.1.5 CRE notes that the use of oil-fired combustion turbines was restricted to intraday contingencies and to the balancing mechanism.

Combustion turbines were normally used to manage contingencies. Their production was not generally scheduled on the day-ahead market.

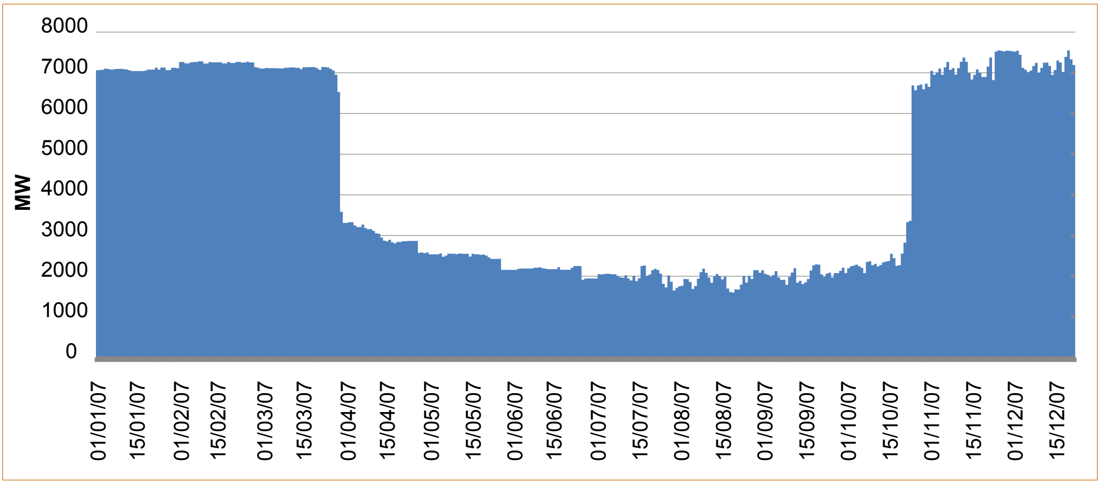
Movements in scheduled production from oil-fired combustion turbines in 2007
- Daily averages -



Data: RTE; Analysis: CRE

3.1.1.6 CRE notes that cogeneration was used to balance the supply at different seasons. However, its use was not aligned with market principles

Movements in production from cogeneration in 2007
- Daily averages -



Data: RTE; Analysis: CRE

Most cogeneration facilities benefit from EDF and local distribution companies' obligation to buy electricity at a guaranteed price. Thus the structure of the pricing tariff for these purchases, which encourages constant maximum production between 1 November and 31 March, largely determines the way cogeneration works. As a result, the cogeneration's power curve is in the form of a plateau, high in winter and low in summer (with a difference of around 4.5 GW).

3.1.2 The concept of and method used to determine the fuel type that wasmarginal

3.1.2.1 The concept of "fuel type marginality"

In a highly efficient market, the short-term price is driven by the marginal cost of production, which is the cost of producing an additional MWh by the most expensive power station required to satisfy the demand. This cost depends on the balance between supply and demand in the market concerned, and on the costs of the fuel and CO_2-emission permits required for the production.

To study the marginality of the fuel types, CRE used data supplied by the players themselves relating to the value they placed on their production. This valuation is itself reviewed in a later section (see 3.2. Analysis of costs and player behaviour). In particular, it should be noted that in the nuclear and hydroelectric fuel types, because generators use a particular method to optimize the use of their energy stocks, the values assigned are generally higher than the straightforward marginal cost of production for these power stations. Of course, if a generator, even a dominant generator, optimizes its income, it cannot be censured unless it abuses its dominant position or manipulates prices.

3.1.2.2 Impact of the regionalization of the electricity market on the concept of fuel type marginality

Cross-border interconnections mean that the least expensive power stations at regional level may be called on first. Thus the marginal unit satisfying French demand is not necessarily based in France, and so price it charges may differ from the marginal cost for French generating facilities. The analysis must therefore also take into account the effect on French prices of prices on neighbouring markets.

In 2007, the French price was equal to at least one price at the border for 98% of the time. It deviated only for 170 hours from the price on all the markets interconnected to France.

CRE took a two-stage approach. Firstly, it calculated the times for which the various industries generating power in France were marginal. Secondly, it quantified the border effect by calculating the hours during which the price did not reflect the marginal French cost, but a price at the border.

3.1.3 Estimates of fuel type marginality for French generating facilities

3.1.3.1 Problems in determining the fuel type marginality

CRE sought to calculate the times during which the various fuel types were marginal in 2007, given the day-ahead forecast. The calculation is based on an analysis of the generating facilities' scheduled operation on D-1, the flexibility with which each means of production may in practice increase or decrease its output, the way each fuel type costs its production, and on the cross-border markets prices.

Currently only CRE has all the information to make this calculation. It should be borne in mind that it is only an approximation. Determining the marginal power station is a theoretical exercise: production decisions are taken by various generators without any coordination. In addition, the complexity of the constraints limiting how the means of production are exploited makes it difficult to determine their capacity to produce one additional MWh to meet a hypothetical increase in demand.

3.1.3.2 The different methods tested

Only the four main fuel types were included in the marginality analysis: nuclear, coal-fired, hydroelectric and oil-fired.

There is currently only one gas combined-cycle power plant in France, so that its influence on price may be considered negligible. However, given the planned future development of this type of unit and its operating mode (semi-base load), the gas fuel type will undoubtedly have a significant impact on price setting in the near future.

In addition, oil-fired combustion turbines were excluded, partly because they generally operate only for a very limited number of hours, and partly because in 2007, they were not scheduled for the day ahead during hours when the price was high.

Several different methods were tested. Their results were all broadly similar, so that the calculation is considered relatively reliable.

- **Method 1: Unit where the costing is closest to the price**

This method calculated the average share of each fuel type from the total number of units where the cost for a given hour was close to the price (gap less than 5 €/MWh).

Estimated marginal fuel type for *French* generating facilities in 2007
- Method 1 -

	Nuclear	Coal-fired	Hydroelectric	Oil-fired
January - September	22%	40%	35%	2%
October - December	10%	26%	29%	12%
Annual average	**19%**	**37%**	**33%**	**5%**

Analysis: CRE

On average, for the hourly time period considered, more than one third of power stations with a costing close to the price (difference less than 5 €/MWh) were coal-fired power stations, another third were hydroelectric reservoirs or daily or weekly storage units, and a fifth were nuclear reactors.

• Method 2: predefining some behaviours as "abnormal" such as "pending arbitrage deals"

Marginal units were in theory those where the decision whether or not to produce did not matter, since the value they placed on their production was equal to the price. Thus their production facilities were most likely to have a production schedule "intermediate" between production at full capacity and production at minimum power or even power-station shutdown. Based on this assumption, it was possible to identify and count the number of units in each fuel type that showed this type of behaviour. They were production units behaving as follows:

- the power station made a theoretical profit (the difference between the marginal valuation of production and the price on the day-ahead market) and operated, but not at full capacity (it used power escalation to reach an optimum value);
- the power station made a theoretical loss (the difference between the marginal valuation of production and the price on the day-ahead market). It delivered power higher than its minimum technical output but less than its maximum (reduced its production).

The limitation of this method is that technical constraints not allowed for in the analysis may prevent a power station from running at its theoretical optimum[9].

Estimated marginal fuel types for *French* generating facilities in 2007
- Method 2 -

	Nuclear	Coal-fired	Hydroelectric	Oil-fired
January - September	19%	35%	44%	2%
October - December	14%	32%	46%	8%
Annual average	**18%**	**34%**	**45%**	**3%**

Analysis: CRE

• Method 3: industries with intermediate production levels: the "global" method

The concept of "marginal fuel type" assumes that there are groups of production units using the same technology, that cost marginal production comparably and have a joint capacity representing a significant proportion of the fuel type's total capacity. A particular technology is said to be marginal when a fraction, and only a fraction, of its constituent units is in production. The relative production thresholds (based on minimum and maximum technical power output) defined beforehand for each fuel type can therefore be used to identify those likely to be marginal[10]. Limitations on this method derive from the need to define arbitrary thresholds, the values of which may impact significantly on the result. Different simulations show that the results can vary noticeably. Thus although this analysis may be used to gain an initial idea of the times for which the different fuel types are marginal, it is not entirely satisfactory. The table below shows ranges of values.

Estimated marginal fuel types for *French* generating facilities in 2007
Ranges of values
- Method 3 -

	Nuclear	Coal-fired	Hydroelectric	Oil-fired
January - September	20 - 30%	20 - 40%	35 - 55%	0 - 10%
October - December	5 - 15%	20 - 40%	30 - 50%	20 - 30%
Annual average	**15 - 30%**	**20 - 40%**	**35 - 55%**	**5 - 10%**

Analysis: CRE

• **Method 4: industries with intermediate production levels: the "local" method**

Rather than considering all the production units in one fuel type, it might be better to restrict the analysis to power stations where the costing is close to the price (for instance, where the value departs from the price by just one €/MWh). If this restriction is introduced, then as in the analysis for "global" production, the marginal fuel type can be identified from the production thresholds. However, this approach means that absolute criteria may be set (in MW), (such as baseline production and minimum margin of capacity (defined as the difference between production and maximum technical capacity)) and applied to all fuel types in exactly the same way.

Then if no fuel type fulfils the threshold conditions[11], this method allows the number of power stations taken into account to be increased, by opening up the price window (broadening the gap between the production units' costing and the price, from 1 to 2 €/MWh for example). The method thus works by successive iterations so that the price window under consideration can be progressively enlarged.

It largely overcomes the problem of the arbitrary definition of relative production thresholds appropriate to each fuel type. Of course, thresholds still exist, but they are defined in absolute terms (MW), and can be applied in exactly the same way to all fuel types[12].

Estimated marginal fuel types for *French* generating facilities in 2007
Bounded* values
- Method 4 -

	Nuclear	Coal-fired	Hydroelectric	Oil-fired
January - September	22 - 24%	40 - 42%	30 - 38%	3 - 4%
October - December	9 - 11%	28 - 30%	35 - 43%	18 - 19%
Annual average	**18 - 19%**	**35 - 37%**	**32 - 40%**	**6 - 7%**

*bounded values obtained for thresholds (production baseline and distance from production ceiling) varying between 100 and 500 MW.
Analysis: CRE

The results obtained using this method are consistent with the results obtained using the previous methods. In addition, as the table above shows, the results of this analysis depend very little on the choice of production baseline and ceiling.

This appears to be the best method of determining the times each fuel type is marginal in France spends.

3.1.4 Marginality estimating, taking into account the "border effect"

The marginal French fuel type is not necessarily the one that sets the French price. At certain times, the price deviates from the marginal cost of French generating facilities to align with prices on one (at least) of the borders.

We considered that when the French price deviated by more than €5/MWh from the marginal cost of French generating facilities, then border prices were probably influencing French prices.

Estimated marginality fuel type and the border influence

	Nuclear	Coal-fired	Hydroelectric	Oil-fired	Border
January - September	17 - 19%	31 - 34%	25 - 30%	1 - 2%	14 - 19%
October - December	3 - 4%	10 - 14%	15 - 18%	3 - 4%	56 - 61%
Annual average	**14 - 15%**	**26 - 29%**	**22 - 27%**	**1 - 2%**	**21 - 25%**

Average price during periods when different fuel types were marginal

When the following fuel types are marginal:	Nuclear	Coal-fired	Hydroelectric	Oil-fired	Border	Average price, all hours taken together
January - September	14 €	27 €	42 €	51 €	30 €	30 €
October - December	21 €	40 €	95 €	90 €	80 €	75 €
Annual average	14 €	29 €	49 €	74 €	58 €	41 €

Analysis: CRE

During the first three quarters, the price overall reflected the marginal cost of French generating facilities. By contrast, at the end of the year, the influence of the costing of French generating facilities was much reduced. Prices in practice deviated from these costings for more than half the time over the last three months, compared with just over 10% of the time over the first three quarters. During the last quarter, the influence of the borders was particularly noticeable when oil was marginal (around 13% of time on average), and reduced the impact of the oil-fired fuel type on prices.

The nuclear fuel type is rarely in a position to set prices on the French wholesale market. In 2007, it was marginal for 15% of the hours. At times when the nuclear fuel type was marginal, the average price during 2007 was €14 /MWh. This price reflects the value placed by EDF on production from nuclear power stations when generating marginally. As we have seen, this valuation of nuclear energy may be above the proportional cost of production from the reactors.

By contrast, the cost of the coal-fired fuel type, which was marginal for between 25 and 30% of the hours, had a controlling effect on prices.

Similarly, costing for hydroelectric reserves played an important role, as hydroelectricity was marginal for around 25% of the hours.

Prices on the cross-border markets also had a significant influence on the French price, which they set for between 20% and 25% of hours during the year.

3.2 Costs analysis and player behaviour

EDF owns most French generating facilities. This gives the Group strong and on-going market power, particularly in the short-term markets. At certain times of year, when the balance between supply and demand is stressed, some producers in competition with EDF also hold a measure of market power, but only sporadically and to a much lesser extent.

Such market power may in theory be used to make inappropriate decisions about the use of generating facilities or lead to unjustified pricing practices. For instance, it is possible for a generator to drive up prices by failing to offer all its available production on the market (the practice of withholding capacity) or by selling only at an artificially high price (the practice of over-pricing). Similarly, a generator with market power can also drive prices down.

CRE analyzed:

- the price at which production from the main French generators was offered on the day-ahead market (production valued on the market);
- the consistency of production decisions taken by French generators, the availability of their generating facilities and the value they placed on what they produced.

To monitor the use of production resources, we needed in particular to obtain from players the price they used to value their production for the market, for each individual power station. This valuation of production did not necessarily correspond to the actual marginal cost for the power stations, especially for hydroelectricity and nuclear power.

Because managing power plants is technically very complex, we were particularly careful at several stages in the analysis to minimize the chances of an erroneous conclusion.

The monitoring covered the larger units (capacity over 50 MW) whose production could be subject to arbitrage on the electricity market. Conversely, production resources that either had significant technical constraints or could not be scheduled were excluded from the analysis (they include cogeneration, wind power and small hydroelectric plants, etc.).

Scope of the analysis of production decisions: fuel types analyzed by number of units and associated capacity

	Nuclear	Coal-fired	Hydroelectric	Oil-fired	Gas	Total
Number of units analyzed	58	20	20	15	2	115 units
Total installed capacity (GW)	63	6.7	5.1	5.1	0.75	81 GW

3.2.1 Nuclear generating facilities

3.2.1.1 Costing production on the day-ahead market

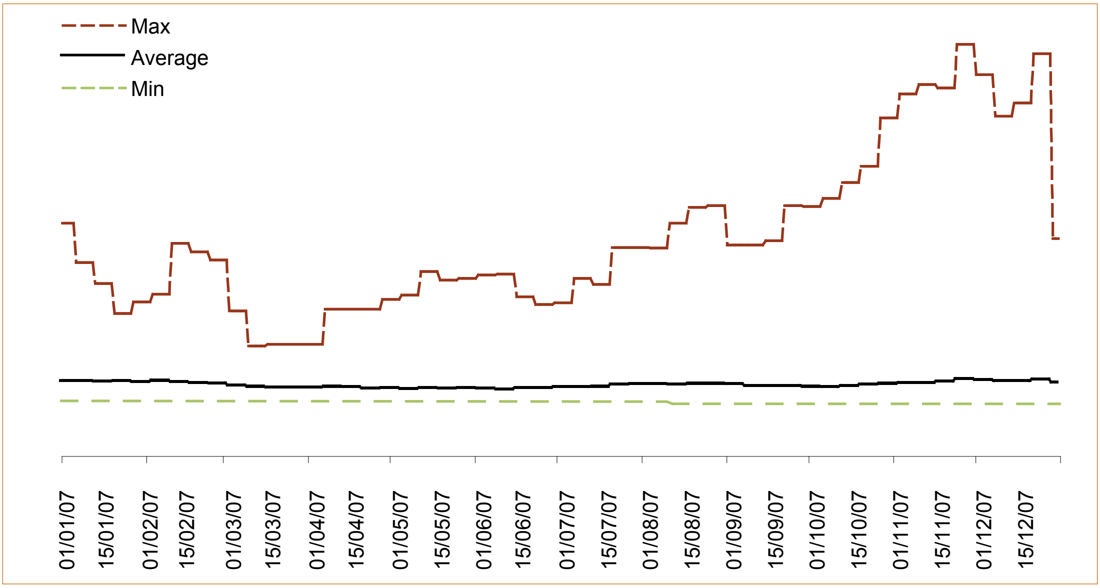
Almost all the generated nuclear power offered on the wholesale day-ahead market was supplied at a price corresponding to the marginal cost of production.

Nevertheless, at anytime during 2007, there was at least one nuclear power station which offer price was above the actual marginal cost of production, sometimes reaching five times this marginal cost. According to EDF, this sort of valuation is used to optimize the use of the energy stored in a reactor when energy has been consumed faster than forecast, and ensures that the fuel is not spent before the next refuelling.

Such a rationale, if applied appropriately, could well optimize the use of nuclear generating facilities at times when their production is the most significant, and ensure shutdowns are scheduled at the right times of year. However, the legitimacy of costings at this level, which had a significant effect on prices when French nuclear production was marginal, remains to be verified.

Monitoring costings of this type is also important because, since no competitor generates nuclear power in France, EDF is under no competitive pressure when valuing its production.

Movements in the costing by generators of output from nuclear power stations



Data: EDF; Analysis: CRE

3.2.1.2 Use of power stations

In the great majority of cases, the use of nuclear generating facilities was optimal, or in other words, consistent with observed market prices.

At the same time, CRE identified from an initial analysis some instances of what appeared to be non-optimal use of nuclear generating capacity that had no simple explanation. Each nuclear unit appeared to have been used sub-optimally for on average around one hundred hours. These instances, observed for less than two hours per week on average, were spread relatively evenly throughout the year.

In 94% of cases, the apparently sub-optimal use of production capacity related to scheduled power output that was below the maximum capacity technically available, even though the output was costed at below the price (apparent under-production).

• Instances identified by CRE of apparent under-production of nuclear power with no simple explanation:

In the vast majority of cases (93%), the apparent under-use coincided with a slow-down in production at the power station, rather than a shutdown. Overall, during the time when a unit was under-producing, the average difference between the scheduled power output and the maximum power technically achievable was 327 MW. However, across all generating facilities, it rarely exceeded 1,000 MW (only for 400 hours) and when it did, the average price was relatively low (€30 /MWh on average). More generally, the apparent under-use of nuclear generating capacity occurred at times at which profits are lowest.

In addition, of the 350 hours at which the price was highest (above €100 /MWh), energy appeared to be under-produced during only 100 of hours. During those hours, the average difference between the scheduled power and the maximum power technically available was 150 MW.

• Instances identified by CRE of apparent over-production of nuclear power with no simple explanation:

We observed very few instances of production at a loss (fewer than 6 hourly intervals per year per unit). They were generally periods during which the price was slightly below the production costing (€14 /MWh on average). The difference between actual production and minimum production technically feasible (usually the minimum technical capacity) was then on average 482 MW.

For nuclear generating facilities as a whole, the most significant instances of over-production were generally at times during which the price was very slightly lower than the power-station costing.

• Explanations provided by EDF:

CRE requested additional information concerning the most marked instances. EDF supplied explanations for all the cases reviewed by CRE, giving the reasons as either technical or personnel-related (strikes).

Nevertheless, in some instances, CRE was not able to determine from the additional information obtained if the situation was fully justified by technical or economic constraints.

3.2.1.3 Potential impact on price of any sub-optimal use of nuclear generating capacity

CRE was able to use data regarding resilience on the Powernext exchange to calculate the potential impact on price of instances where use of generating facilities was clearly sub-optimal. It considers that there were several prolonged periods of high prices, during which a significant portion of the nuclear capacity remained idle, even though it could have been used. These variances could have added an average of several tens of euros to the price per MWh during the hours concerned[13].

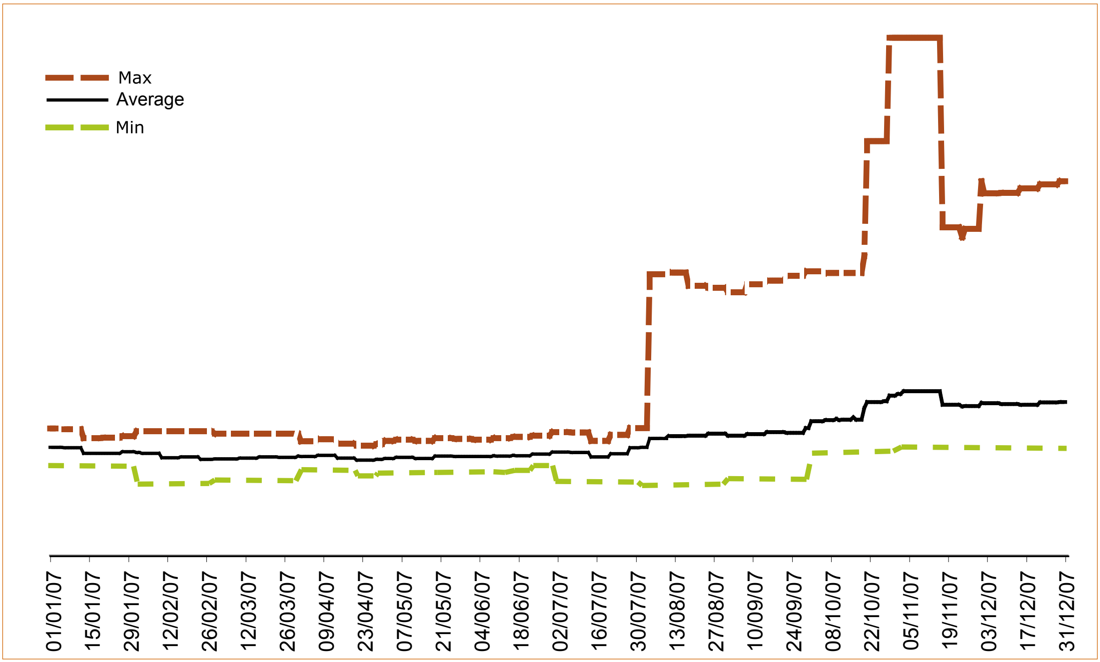
3.2.2 Coal-fired generating facilities

3.2.2.1 Costing production on the day-ahead market

The various coal-fired power stations all costed their production in roughly the same way. Most offer prices used by generators were consistent with the marginal generating costs calculated by CRE.

Nevertheless, CRE identified situations in which the offer price from some power stations differed noticeably from these estimates. The legitimacy of the costings for some EDF power stations is not as yet established.

Movements in the costing by generators of output from coal-fired power stations, 2007



Data: EDF, SNET; Analysis: CRE

3.2.2.2 Use of power stations

Most coal-fired power stations seem to have been used efficiently.

However, CRE found from an initial analysis that several power stations had often operated in a way that in theory was not predictable from their minimum and maximum technical capacities. Over the entire year, instances of sub-optimal use represented on average slightly fewer than 10 hours per week.

Most often, such instances related to under-use of available capacity.

• Instances identified by CRE of apparent under-production with no simple explanation:

During the time when a particular unit was under-producing, the average difference between the scheduled power output and the maximum power technically achievable was 134 MW (based on an average capacity per unit of approximately 370 MW). However, this average covers two different situations: a slow-down in production in two thirds of cases, and a shutdown for the remaining third.

• Instances identified by CRE of apparent over-production with no simple explanation:

For all instances of loss-making production that we reviewed, the average difference between the minimum power technically feasible and the scheduled power output was 74 MW per Unit per hour (based on an average capacity per unit of approximately 370 MW). The average price was €24 /MWh, and the average associated loss was €12 /MWh.

• Explanations provided by the generators:

CRE requested additional information concerning the most marked instances. Those involved put forward various reasons to explain why the supply was sometimes sub-optimal:

- contingencies that occurred after Powernext fixed the prices at 11:00am (and which were not therefore taken into account when placing bids);
- dynamic constraints that made rapid variations impossible;
- the gradual fall or rise in production when shutting down or restarting;
- social movements;
- a contractual obligation to schedule a power station's operation after Powernext price fixing.

The explanations put forward by those involved appeared satisfactory.

3.2.3 Hydroelectric dams

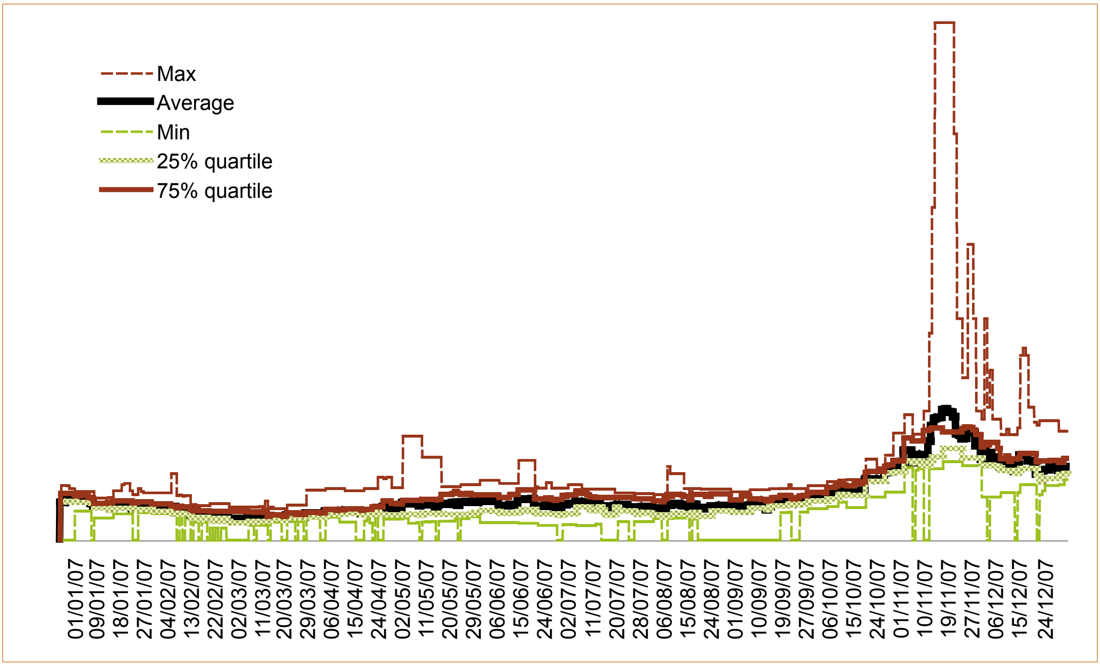
3.2.3.1 Costing production on the day-ahead market

Generators of hydroelectricity offered power from dammed reservoirs at market prices higher than the infrastructure's variable cost of production, which is low. Offer prices moved relatively consistently for all dams throughout the year, with a strong upward trend, particularly during the last quarter.

Such a pricing rationale, if applied appropriately, can optimize the use of hydroelectric resources at times when they are most useful, for instance by taking into account the constraints that apply to each dam, seasonal variations in rainfall and snow melt, and forecast prices. This type of production costing, known as "use value" is employed by the principle generators of hydro energy, in France and worldwide.

However, the legitimacy of the costings, which have a decisive effect on prices when French hydroelectricity production is marginal, remains to be verified. We note that in the review it commissioned as part of its sector inquiry, the European Union also concluded that there was no straightforward way of assessing if hydroelectric resources were used appropriately in France or the impact of that use on prices.

Movements in the generators' costing of output from hydroelectric power stations, 2007



Data : EDF, SHEM; Analysis: CRE

Because of their technical limitations, costings for some hydroelectric power stations (particularly run-of-river installations) often fell to zero. (When stations cannot build up further reserves, using the turbines makes sense whatever the price.)

3.2.3.2 Use of power stations

CRE noted from an initial analysis that the use of hydroelectric generating resources did not always appear consistent with the costings declared to CRE. The percentage of hours for which the use of resources did not align directly with wholesale market prices exceeded 20% for all power stations, irrespective of the generator.

Most of the variances from optimal production tended towards under-production. They related mainly to periods during which the station was shut down, even though the market price was clearly higher than the price assigned to hydroelectric power by the operators. In particular, during the price spikes in October and November, the hydroelectric capacity of the reservoirs was not always used to the maximum.

Explanations provided by the generators:

CRE requested additional information concerning the most marked instances. The operators stressed that dam management was subject to many constraints:

- technical: dams in the same valley are interdependent; there must be trade-offs between power and energy for dams with low reserves; they provide resources for the service "reserve in 13 minutes";

- **commercial:** concession agreements may reduce flexibility of use;

- **economic:** they need to maintain reserves at a certain level to meet contingencies;

- **other:** for instance, constraints related to agriculture or tourism, maintaining minimum flow rates or levels for environmental reasons.

However, CRE has identified many instances in which the use of EDF's hydroelectric power stations does not appear to align directly with the costings declared to CRE.

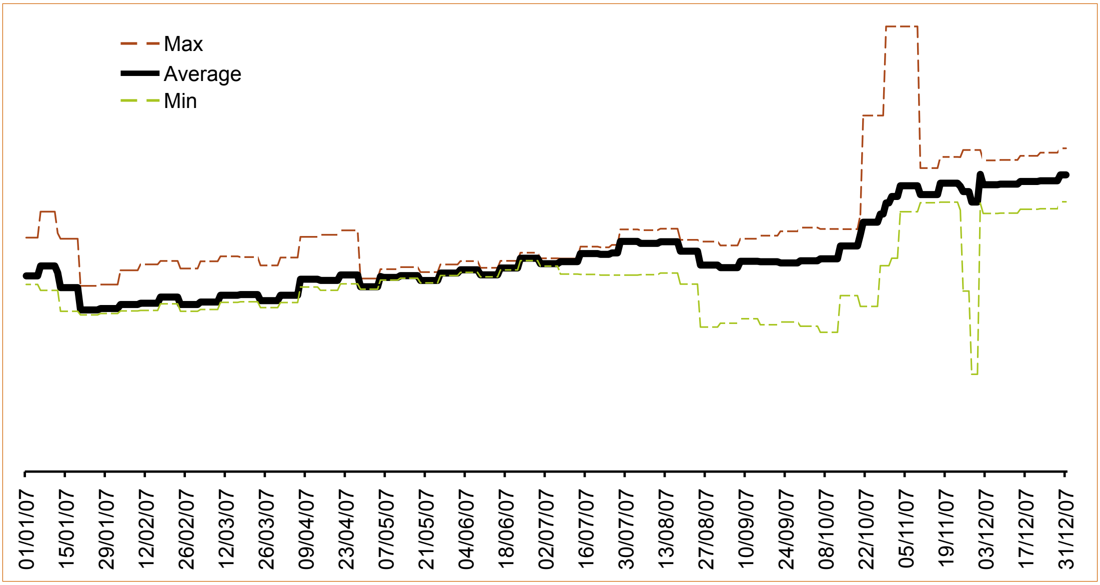
3.2.4 Oil-fired power stations (excluding combustion turbines)

3.2.4.1 Costing production on the day-ahead market

The various oil-fired power stations all costed their production in roughly the same way.

The offer price from certain power stations sometimes differed noticeably from the estimates made by CRE. The reasons put forward by EDF (stricter regulation of fuel quality, sourcing problems and stock management) could well explain the variances.

Movements in the costing by generators of output from oil-fired power stations, 2007



Data: EDF; Analysis: CRE

3.2.4.2 Use of power stations

- **Oil-fired power stations:**

From CRE's initial brief analysis, it is clear that oil-fired power stations should have scheduled operation at full power for an average of around 450 hours, but because of limitations on their technical capacity, did so only for about half of those hours (230 hours). For 80 hours (or 1% of the hourly time-slots during the year), thermal generating stations had a costing well below the price, and were scheduled to output power below the maximum available, or were even shut down (on one occasion in two). For one of the oil-fired power stations reviewed, the average difference between the scheduled power and the maximum power technically feasible over those 80 hours was 330 MW (or an average of 90% of maximum capacity), and the average theoretical profit was around €63 /MWh.

For the generating facilities as a whole, the average difference between the scheduled power and the maximum power technically feasible exceeded 500 MW[14] for 220 hours (the maximum overall capacity of the facilities was 3,000 MW). During that period, the price averaged €152 /MWh.

• Explanations provided by the operators:

CRE requested additional information concerning the most marked instances. In some instances, EDF put forward technical, social (strikes) or operational reasons; otherwise, they stated that they had used inaccurate assumptions to cost the generating facilities for the market, and had failed to anticipate the Powernext price (especially during the peaks at the end of the year).

CRE wishes to stress that a failure to anticipate the pricing levels should have no impact on production optimization, since capacity is offered on the market at a price reflecting accurately the cost of production.

• Impact on potential price associated with sub-optimal use of oil-fired power stations

CRE was able to use data regarding resilience on the Powernext exchange to calculate the potential impact on price of instances where use of generating facilities was clearly sub-optimal. Based on the responses provided by EDF, CRE considers that oil-fired power stations have in fact been under-utilized for many hours during which the price was very high. These variances could have added an average of several tens of euros to the price per MWh for the hours concerned[15].

4. TRANSPARENCY OF GENERATION

The principal French generators, EDF, GDF Suez and SNET, are all members of the French Electricity Union (*Union Française de l'Electricité - UFE*), and as such publish voluntarily since the end of 2006 aggregated data on the delivered output and forecast availability of their generating facilities.

This information, which is published on RTE website, is currently all that is publicly available concerning French generating facilities. If the market is to function correctly, it is essential that the forecast figures, particularly for nuclear power, are reliable and of good quality. Any error may result in the dissemination of inaccurate information, because the information held by generators would differ from that available to their competitors. Publishing inaccurate information may, in some respects, be more detrimental than not publishing it at all.

CRE analyzed the information supplied by each individual generator before aggregation, for all the time horizons used in forecasting (from 1 day to 3 years ahead), and for each fuel type (nuclear, coal-fired, oil-fired, hydroelectric (daily or weekly storage and run-of-river), and hydroelectric (reservoir).

As a result of the recommendations made by CRE in April 2008 during its investigation into the price spikes observed in the autumn of 2007, the UFE proposed improvements which they recently formally communicated. CRE supports the new arrangements, but nevertheless considers that the generators have still significant progress to make as regards transparency.

4.1 Completeness of data

The forecasts relate to three periods:

- **short term:** forecasts for the next seven days (D-1 to D-7);

- **medium term:** forecasts for the next 13 weeks (W-2 to W-13);

- **long term:** forecasts for the next 36 months (M-4 to M-36);

CRE noted that the quality of the data published in 2007 was not satisfactory. Much of the published information was incomplete because some generators often failed to to transmit their data. We noted significant omissions from the medium-range forecasts for gas and coal, and from the short- and medium-range forecasts for hydroelectricity. When data relating to a generator was missing, the published forecasts reiterated earlier forecasts, which might no longer have been valid. In 2007, market players were not alerted to such situations, and they were not mentioned on RTE's website.

CRE recognizes that the UFE began to publish only in 2007, which may explain some of the shortcomings in quality. Some generators have recognized that errors were made, and have stated that they have since put appropriate controls in place.

4.2 Data quality

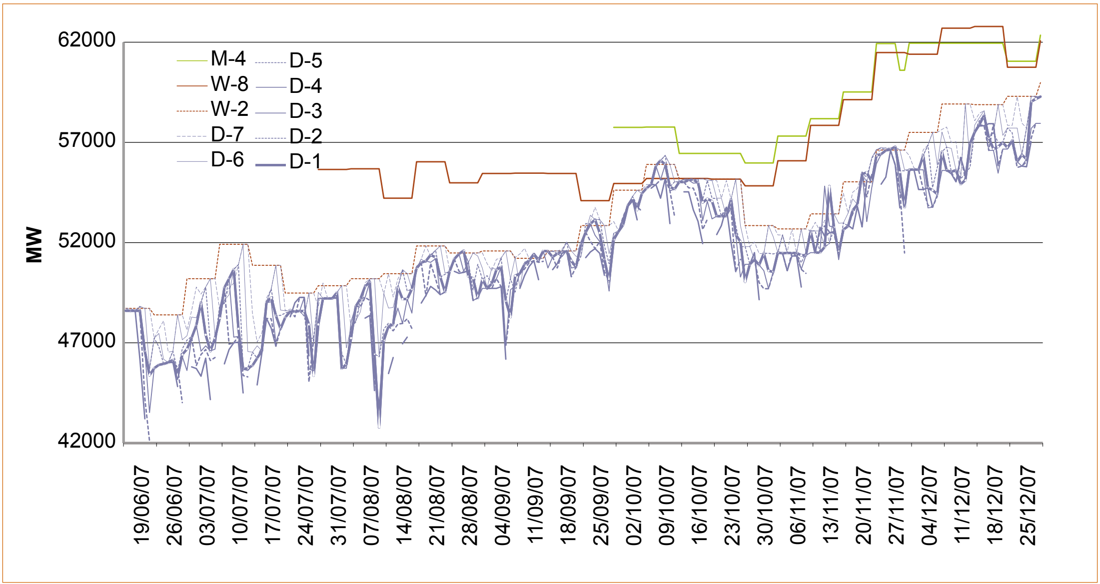
Throughout certain periods, the medium and long-term forecast capacity for some fuel types (particularly hydroelectricity and oil, at the end of the year) differed considerably from the most recent forecast. This indicates that the process of preparing, communicating and publishing the data is not effectively controlled.

In addition, the quality of the forecasts was not consistent for every day in the week. Significant average discrepancies were observed, for instance, between the weekend and the working days, with the quality of forecasts for Saturday and Sunday less good than for working days.

The graphs below show for each day in the period reviewed (19 June to 31 December 2007), the forecast availability published over different time horizons.

4.2.1 Nuclear

Movements in forecasts for different time horizons as a function of the date of the forecast



Data: RTE; Analysis: CRE

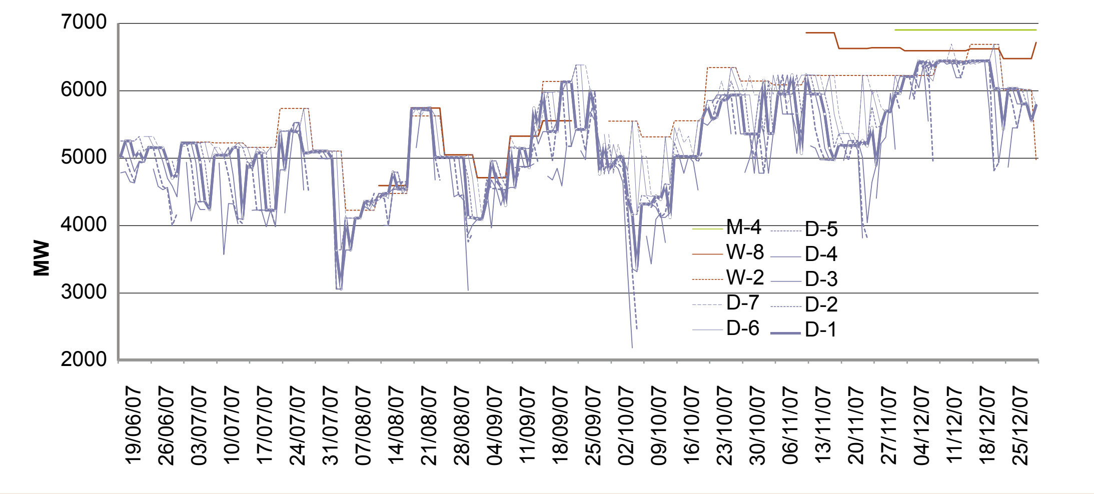
The forecasted capacity on W-2 (forecast on the Friday of the second week before the date concerned, shown in deep blue on the graph) is almost always greater than the available capacity forecast seven days before the date concerned (D-7 to D-1, in red on the graph). Similarly, forecasts available from D-7 to D-2 (red, not bold) always appear above those supplied on D-1 (red, bold).

Similarly, a positive bias appears systematically for forecasts at 4 months (in green).

The difference between capacities forecast at W-2 and for the day ahead (on D-1) is particularly striking in July and December, reaching as much as 5 GW (or 10% of overall nuclear capacity).

4.2.2 Coal

Movements in forecasts for different time horizons as a function of the date of the forecast



Data: RTE; Analysis: CRE

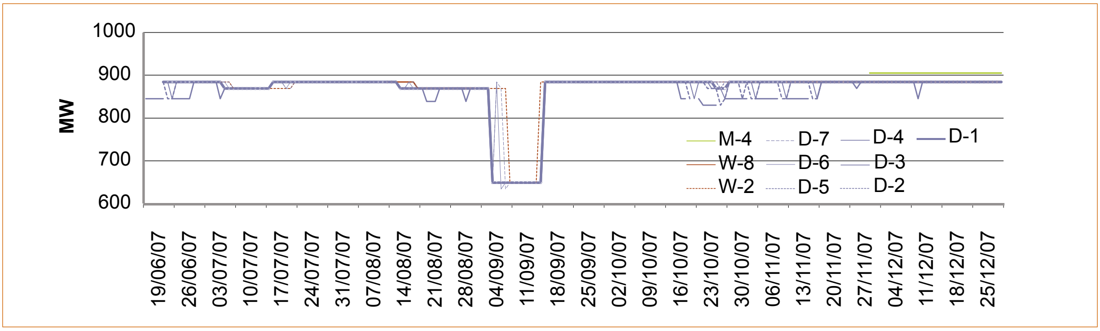
The forecasted capacity on W-2 (forecast on the Friday of the second week before the date concerned, shown in deep blue on the graph) is almost always greater than the available capacity forecast seven days before the date concerned (D-7 to D-1, in red on the graph). Similarly, forecasts available from D-7 to D-2 (red, not bold) always appear above those supplied on D-1 (red, bold).

The various series of short-range forecasts (D-7 to D-1) sometimes appear to resemble each other (for instance, from the end of October to the end of November). This occurs when the forecasts published on one particular date are identical for several successive days: for instance, if the forecast available capacity published today for tomorrow, and for the day after, etc. are all the same.

The quality of the forecasts is particularly poor in October (from 2 to 10) and in November (from 10 to 30).

4.2.3 Gas

Movements in forecasts for different time horizons as a function of the date of the forecast

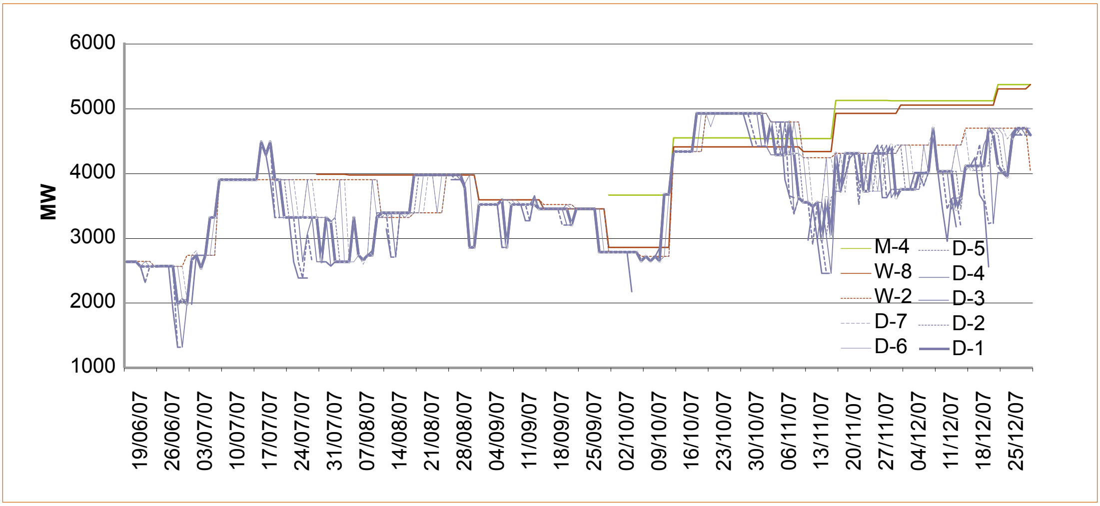


Data: RTE; Analysis: CRE

Overall, the forecasts appear relatively reliable. However, the overestimate in M-4 (green) of capacity available at the end of the year is surprising.

4.2.4 Oil

Movements in forecasts for different time horizons as a function of the date of the forecast



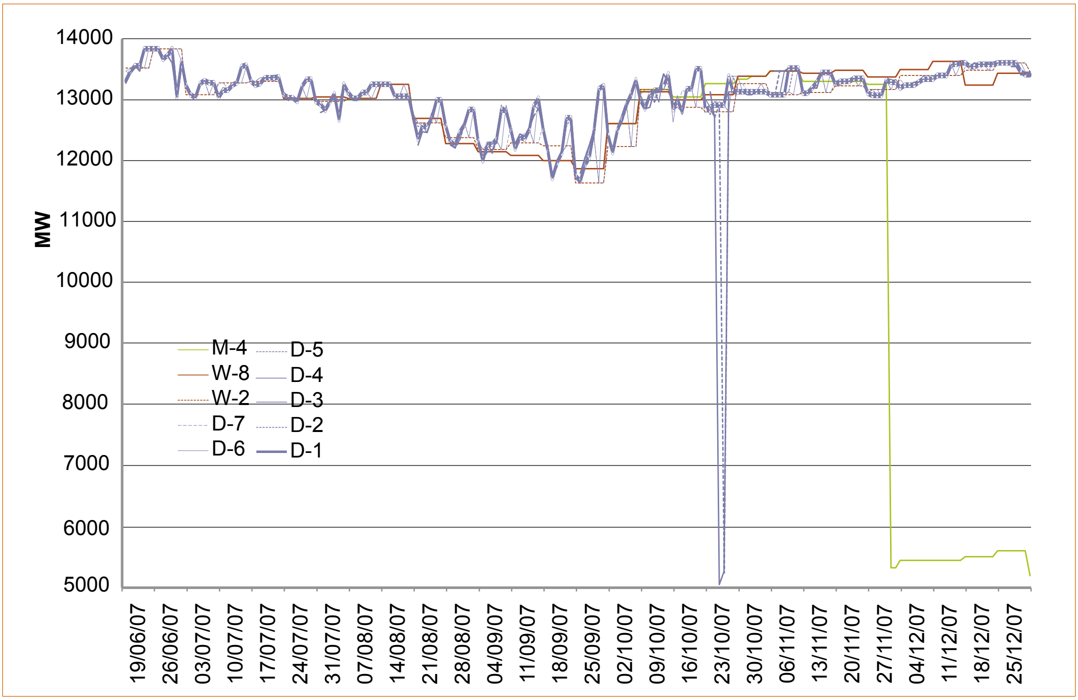
Data: RTE; Analysis: CRE

It appears that the quality of the forecasts declined in the summer (from the end of July until mid August) and at the end of the year (from the end of November). In particular, the long-range forecast (M-4, green) appears statistically deviant.

The various series of short-range forecasts (D-7 to D-1) sometimes appear to resemble each other (for instance, at the end of July). This occurs when the forecasts published on one particular date are identical for several successive days: for instance, if the forecast available capacity published today for tomorrow, and for the day after, etc. are all the same.

4.2.5 Daily or weekly storage and run-of-river

Movements in forecasts for different time horizons as a function of the date of the forecast



Data: RTE; Analysis: CRE

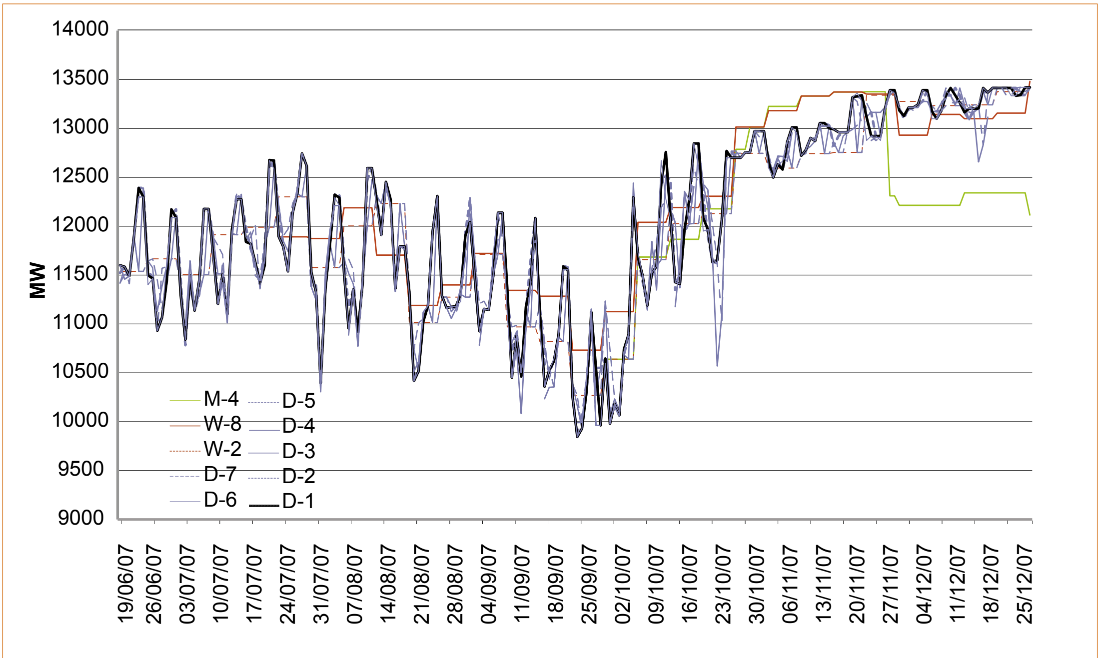
The movement in available capacity forecast on D-1 has a saw-tooth profile with a weekly period.

The forecast at M-4 (in green) plummets from December, moving inexplicably from 13,000 MW to less than 6,000MW.

It is also odd that the forecast on D-1 was around 5,000 MW on 25 October, but between 11,000 and 14,000 MW for the rest of the period.

4.2.6 Reservoir

Movements in forecasts for different time horizons as a function of the date of the forecast



Data: RTE; Analysis: CRE

The movement in available capacity forecast on D-1 has a saw-tooth profile with a weekly period.

The forecast at M-4 (in green) drops after 1 December, moving from over 13,000 MW to less than 12,500 MW.

4.3 Reliability of forecasts

Whichever the fuel type or generator concerned, and whatever the time horizon for the forecast, the availability forecast for a particular date was almost always higher than what was actually achieved.

The reason for this bias is related to the way in which the forecasts are made. According to the specification prepared by the UFE, generators only take into account in their availability forecasts unavailability that is considered certain on the date of the forecast. The estimated probability of unplanned unavailability is not considered.

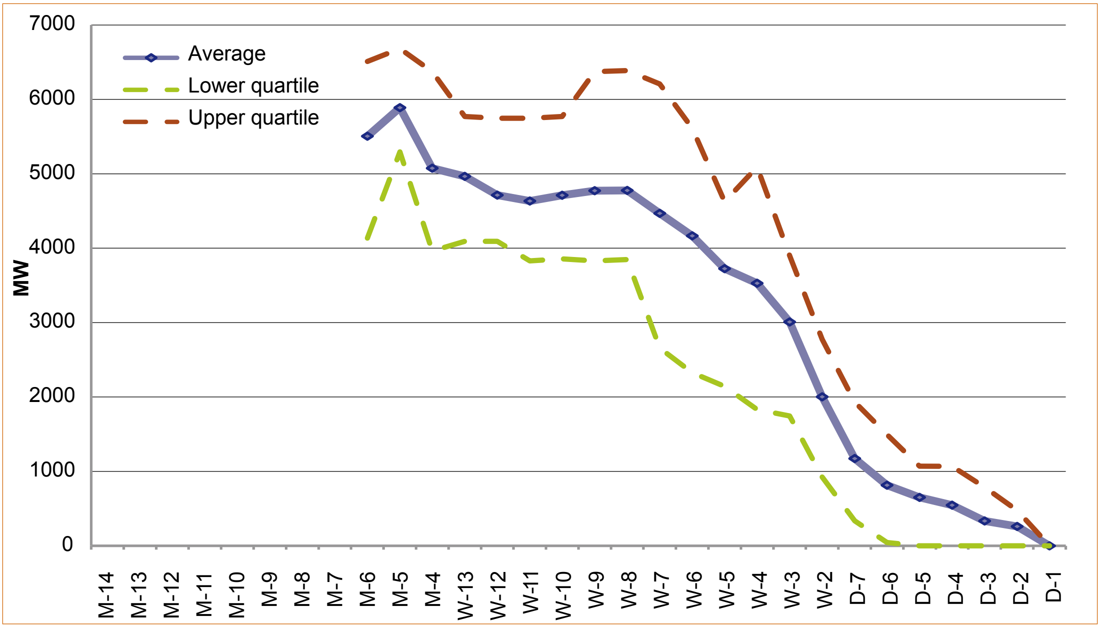
These rules were not clearly displayed on RTE website in 2007, and caused market players to anticipate wrongly the future situation on the French market.

The UFE has told CRE that from the first quarter of 2009 it will publish each day the actual unavailability of the previous day for each fuel type. This will significantly reduce the asymmetry of the information for the day ahead, by allowing players to make their own estimates of future unavailability. It will also, to a certain extent, allow players to improve their medium- and long-term estimates of the capacity that will actually be available on day D. However, for time horizons greater than one day, the information will continue to be partly asymmetric, and it will remain difficult for the generators' competitors to make forecasts for between 2 days to 3 years ahead in conditions comparable to those of the generators.

The graphs below show for each time horizon (D-2, D-3, etc., M-4, etc.) the difference between the forecast for that horizon and the most recent forecast (generally that made the day before (D-1)[16]). The average of the "variation" values represents the bias in the forecast for each time horizon.

4.3.1 Nuclear

Difference (average and quartiles) between the forecasts for various time horizons and the last available forecast, working days



Data: RTE; Analysis: CRE

Statistical data

	M-6	M-5	M-4	W-13	W-12	W-11	W-10	W-9	W-8	W-7	W-6	W-5	W-4	W-3	W-2	D-7	D-6	D-5	D-4	D-3	D-2	D-1
Number of values available	21	43	66	86	91	96	101	106	110	111	116	121	125	126	130	137	108	82	83	82	81	108
Average	**5504**	**5889**	**5076**	**4966**	**4713**	**4634**	**4711**	**4773**	**4776**	**4469**	**4167**	**3725**	**3529**	**3008**	**2003**	**1174**	**814**	**650**	**546**	**334**	**260**	**0**
Standard deviation	1185	979	1507	1284	1408	1428	1727	2032	2026	2014	2237	2241	2065	1654	1366	1065	914	774	898	720	568	0
Minimum	3091	3091	1409	1464	622	567	221	34	12	73	16	98	85	-371	-19	-1049	-960	-1263	-1788	-2073	-1330	0
Maximum	10442	10442	9107	10218	10218	10218	10031	11927	11914	11923	11901	11963	10984	8883	7416	4108	4152	4089	3803	3381	2742	0

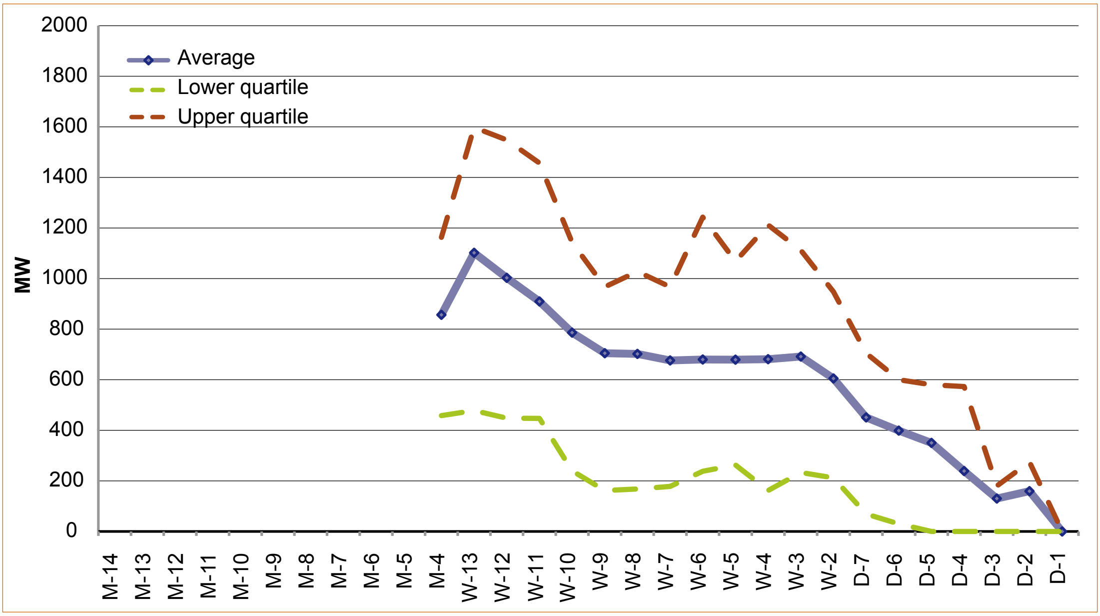
There is an overall positive bias that increases progressively with the time horizon for the forecast. The bias may be compared to the installed generating capacity (around 63 GW).

Approximately three quarters of the very short-range forecasts (less than 7 days) have a positive bias (of the order of 2% of overall capacity for D-7).

Capacity forecasts with a time horizon of four weeks or more are systematically overestimated.

4.3.2 Coal

Difference (average and quartiles) between the forecasts for various time horizons and the last available forecast, working days



Statistical data

	M-4	W-13	W-12	W-11	W-10	W-9	W-8	W-7	W-6	W-5	W-4	W-3	W-2	D-7	D-6	D-5	D-4	D-3	D-2	D-1
Number of values available	21	36	41	46	51	56	66	76	86	96	106	116	126	137	112	84	84	84	84	112
Average	**857**	**1102**	**1003**	**909**	**786**	**705**	**702**	**676**	**680**	**679**	**681**	**692**	**605**	**451**	**399**	**350**	**239**	**130**	**159**	**0**
Standard deviation	502	576	606	633	619	593	597	575	593	545	556	547	515	430	396	373	329	297	325	0
Minimum	448	408	173	-73	-73	-73	-73	-135	-217	-250	-250	-250	-810	-265	-285	-330	-465	-590	-440	0
Maximum	2083	3045	3045	3045	3045	3045	2810	2820	2775	2775	2805	2410	3360	1605	1725	1975	1975	1540	1540	0

Data: RTE; Analysis: CRE

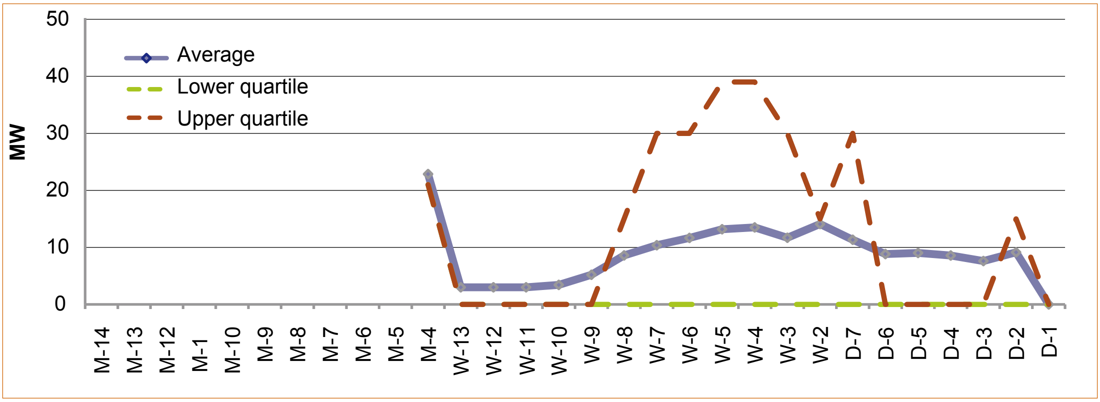
There is an overall positive bias which increases sharply for forecasts with a time horizon of over a week (after W-2). The bias may be compared to the installed generating capacity, which is of the order of 6 GW.

For very short time horizons (less than or equal to seven days), the bias increases with the horizon for the forecast. The bias is around 450 MW for D-7, or around 8% of the capacity of the coal-fired fuel type. However, the variance is equivalent (430 MW).

The bias is very strong for forecasts with a time horizon longer than a week, and is on average between 600 and 1,100 MW, or almost one fifth of the capacity of the coal-fired fuel type. It varies very little for time horizons between 3 and 9 weeks, but rises sharply in W-11, W-12 and W-13.

4.3.3 Gas

Difference (average and quartiles) between the forecasts for various time horizons and the last available forecast, working days



Statistical data

	M-5	M-4	W-	W-	W-11	W-						W-	W-	W-	D-7	D-6	D-5	D-4	D-3	D-2	D-1
Number of values available		21	31	31	31	36	41	51	61	71	81	96	111	126	133	109	104	106	107	106	138
Average		**23**	**3**	**3**	**3**	**3**	**5**	**9**	**10**	**12**	**13**	**14**	**12**	**14**	**11**	**9**	**9**	**9**	**8**	**9**	**0**
Standard deviation		8	9	9	9	10	11	13	14	14	15	27	26	35	24	15	14	14	14	14	0
Minimum	0	21	0	0	0	0	0	0	0	0	0	-15	-15	-15	-15	-15	0	0	0	0	0
Maximum	0	60	39	39	39	39	39	39	39	39	54	235	235	235	235	54	54	54	54	54	0

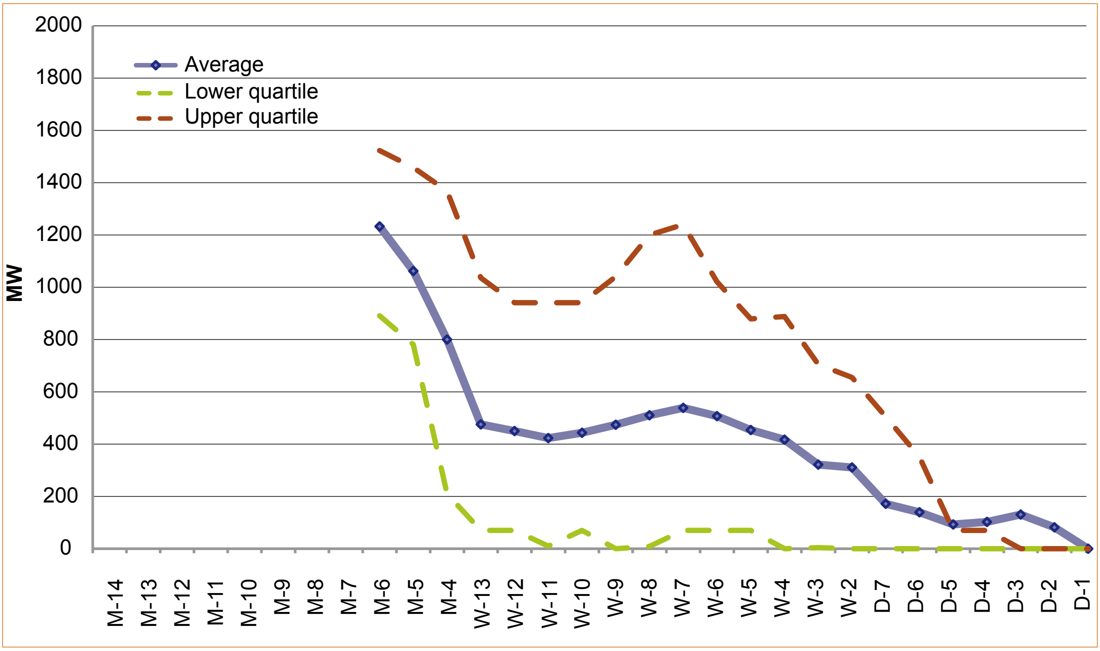
Data: RTE; Analysis: CRE

The forecast is "good" in the vast majority of cases, for both short and long time horizons. The bias may be compared with the installed generating capacity, which is of the order of 900 MW.

The forecasts take only a limited number of values (at most 1 to 4, depending on the time horizon, whereas the "actual" value may take 6 values).

4.3.4 Oil

Difference (average and quartiles) between the forecasts for various time horizons and the last available forecast, working days



Statistical data

	M-6	M-5	M-4	W-13	W-12	W-11	W-10	W-9	W-8	W-7	W-6	W-5	W-4	W-3	W-2	D-7	D-6	D-5	D-4	D-3	D-2	D-1
Number of values available	21	43	66	86	91	96	101	106	111	116	121	126	131	136	140	136	107	81	82	82	81	107
Average	**1233**	**1062**	**800**	**476**	**450**	**423**	**444**	**474**	**510**	**539**	**507**	**454**	**417**	**322**	**311**	**172**	**139**	**93**	**103**	**131**	**82**	**0**
Standard deviation	384	535	648	668	641	623	609	603	610	622	604	600	621	567	482	340	322	267	265	286	231	0
Minimum	438	-241	-375	-818	-818	-888	-888	-818	-818	-818	-818	-818	-1190	-888	-959	-713	-713	-585	-585	-585	-585	0
Maximum	2576	2566	2562	2494	2494	2494	2494	2494	2494	2494	2564	2564	2564	1879	2138	1270	1453	1553	2138	2043	888	0

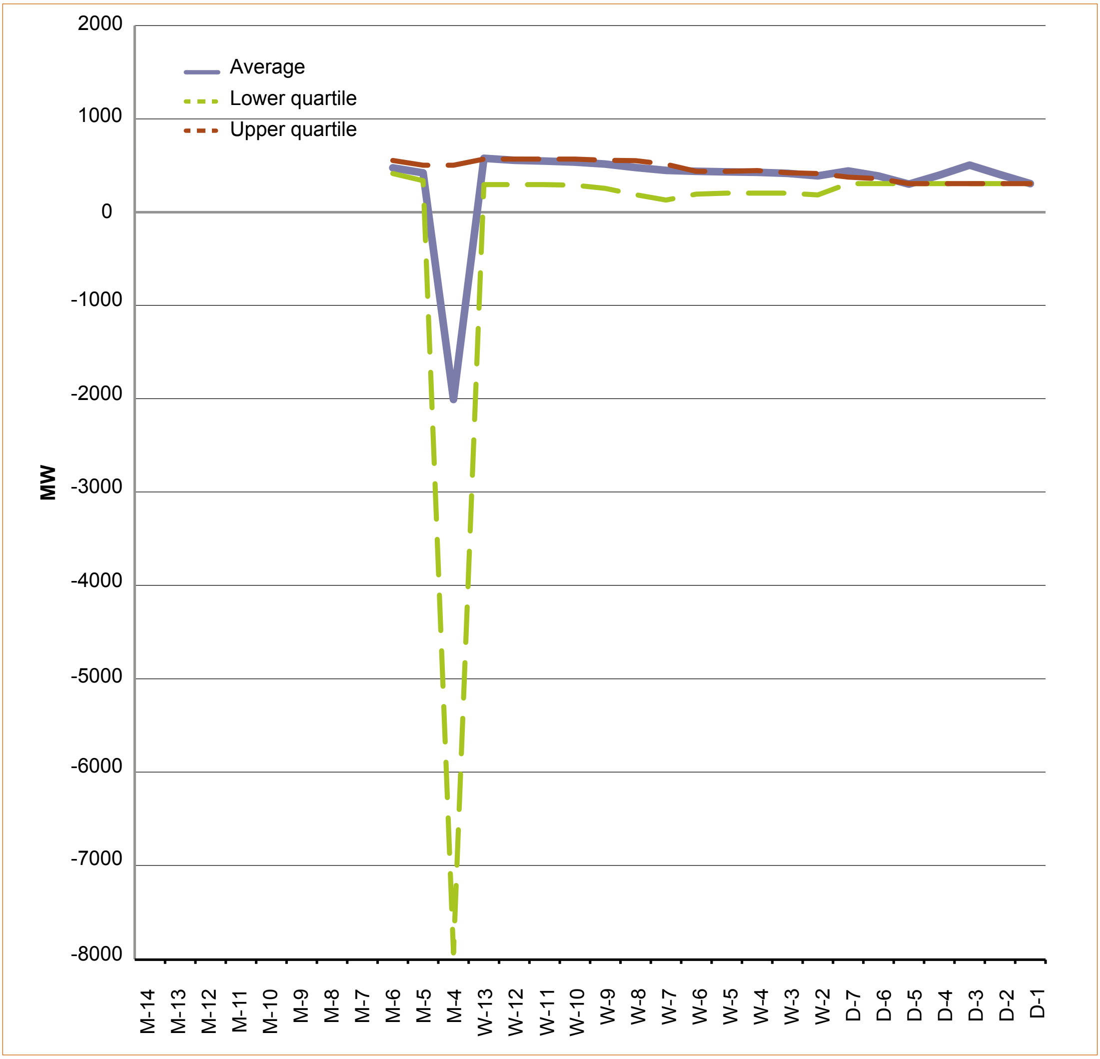
Data: RTE; Analysis: CRE

There is an overall positive bias which increases sharply for forecasts with a time horizon of over four months. The bias may be compared with the installed generating capacity, which is of the order of 5 GW.

For time horizons less than or equal to 5 days, half the forecasts were close to actual unavailability (difference of less than 75 MW, or around 1% of the oil-fired capacity).

4.3.5 Daily or weekly storage and run-of-river

Difference (average and quartiles) between the forecasts for various time horizons and the last available forecast, working days



Statistical data

	M-7	M-6	M-5	M-4	W-13	W-12	W-11	W-10	W-9	W-8	W-7	W-6	W-5	W-4	W-3	W-2	D-7	D-6	D-5	D-4	D-3	D-2	D-1
Number of values available		21	43	66	86	96	101	106	111	116	121	126	131	136	140	140	138	110	83	82	82	82	109
Average		**160**	**109**	**-2182**	**256**	**236**	**228**	**217**	**198**	**163**	**134**	**125**	**119**	**114**	**104**	**79**	**128**	**77**	**-5**	**86**	**187**	**91**	**0**
Standard deviation		97	111	4073	1214	1152	1123	1098	1077	1037	1019	997	977	962	948	917	918	740	95	827	1167	848	0
Minimum	0	-138	-140	-8090	-1290	-1290	-1290	-1290	-1290	-1290	-1290	-1290	-1290	-1120	-1460	-1520	-382	-382	-382	-382	-196	-210	0
Maximum	0	316	326	8088	8088	8088	8088	8088	8088	7918	7918	7918	7918	7920	7920	7636	7802	7746	292	7536	7746	7746	0

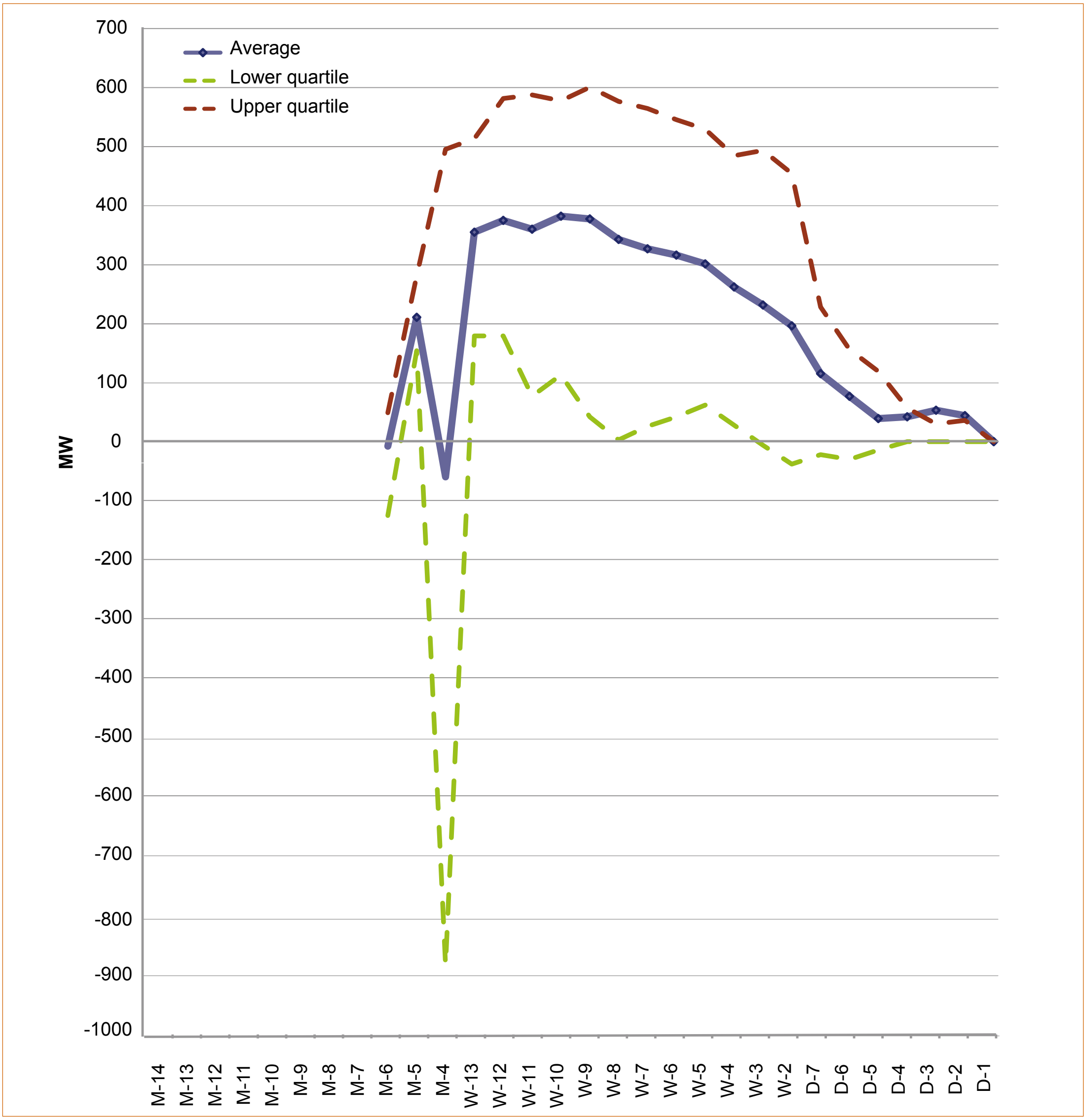
Data: RTE; Analysis: CRE

The forecasts are relatively reliable. The bias may be compared with the installed generating capacity, which is of the order of 12 GW.

Half the forecasts for under 13 weeks are good. The negative peak for forecasts made at M-4 is explained by the very low value of forecasts during December.

4.3.6 Reservoir

Difference (average and quartiles) between the forecasts for various time horizons and the last available forecast, working days



Data: RTE; Analysis: CRE

Statistical data

	M-7	M-6	M-5	M-4	W-13	W-12	W-11	W-10	W-9	W-8	W-7	W-6	W-5	W-4	W-3	W-2	D-7	D-6	D-5	D-4	D-3	D-2	D-1
Number of values available s		21	43	66	91	96	101	106	111	116	121	126	131	136	140	140	138	110	83	82	82	82	109
Average		**-8**	**211**	**-60**	**355**	**375**	**360**	**382**	**377**	**342**	**326**	**316**	**301**	**262**	**231**	**196**	**115**	**77**	**39**	**42**	**53**	**44**	**0**
Standard deviation		181	170	672	340	345	384	380	411	455	426	424	390	389	397	363	236	218	136	158	200	165	0
Minimum	0	-248	-210	-1656	-1484	-1484	-1484	-1484	-1349	-1169	-1119	-1119	-1418	-1625	-1625	-1654	-432	-391	-462	-392	-323	-282	0
Maximum	0	551	779	1608	1836	1836	1760	1760	1760	1737	1751	1653	1853	1903	1905	1559	1083	1083	588	970	1042	1044	0

Data: RTE; Analysis: CRE

The forecasts are biased upwards, and the bias increases with the time horizon. The bias may be compared with the installed generating capacity, which is of the order of 12 GW.

The negative peak for forecasts made at M-4 is explained by the very low value of forecasts during December.

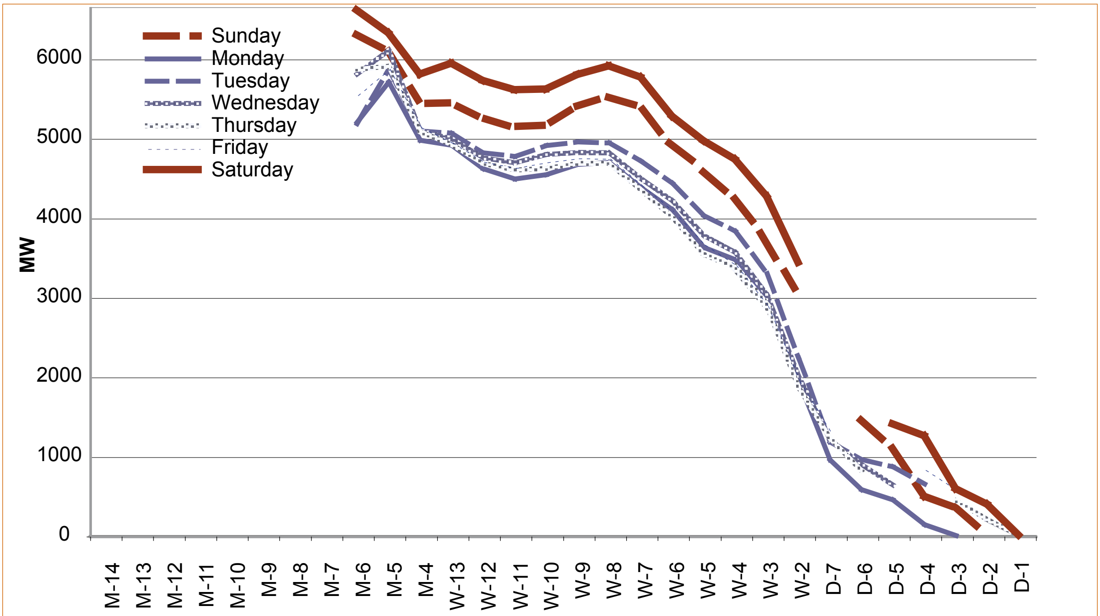
4.4 The quality of the forecast depending on the day of the week

Significant average discrepancies were observed, for instance, between the weekend and working days, the quality of forecasts for Saturday and Sunday being less good than for working days.

In the graphs below, the curve showing variations between forecasts for various time horizons and the most recent forecast has been calculated depending on the day on which the forecast is made.

4.4.1 Nuclear

Average difference between the forecasts for various time horizons and the last available forecast, depending on the day for which the forecast was made

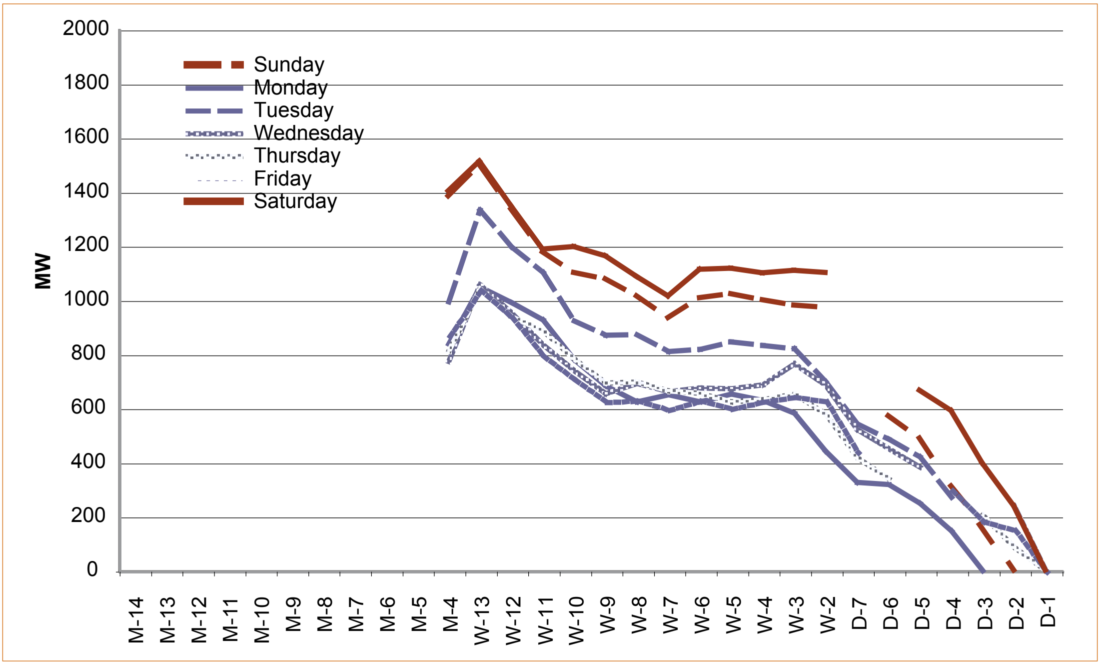


Data: RTE; Analysis: CRE

The forecasts are more biased for the weekend, and in particular for Sunday, when the additional variation is of the order of 1 GW. For medium- and long-range forecasts, this is to be expected, because only one value is available for the entire week. However, this does not explain the variations for short-range forecasts, where there is one value per day. The "least bad" forecast appears to be for Monday.

4.4.2 Coal

Average difference between the forecasts for various time horizons and the last available forecast, depending on the day for which the forecast was made

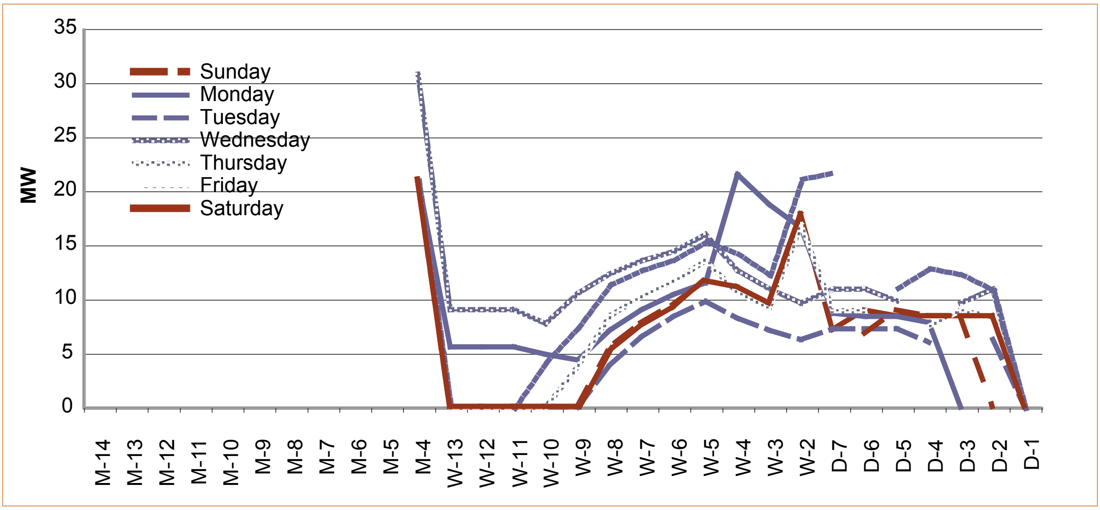


Data: RTE; Analysis: CRE

The forecast for Saturday (and to a lesser extent for Sunday) is particularly biased compared with other days in the week. For medium- and long-term forecasts, this is to be expected, because only one value is available for the entire week. However, this does not explain the variations for short-range forecasts, where there is one value per day.

4.4.3 Gas

Average difference between the forecasts for various time horizons and the last available forecast, depending on the day for which the forecast was made

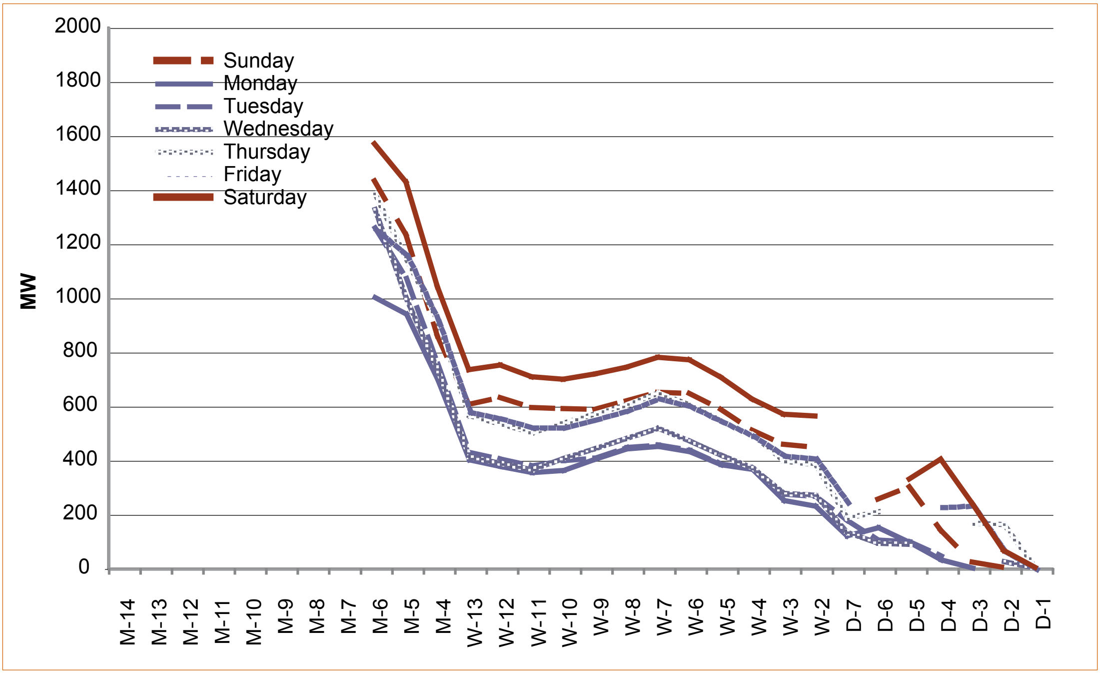


Data: RTE; Analysis: CRE

There does not appear to be any significant difference between the discrepancies in forecasts for different days of the week.

4.4.4 Oil

Average difference between the forecasts for various time horizons and the last available forecast, depending on the day for which the forecast was made



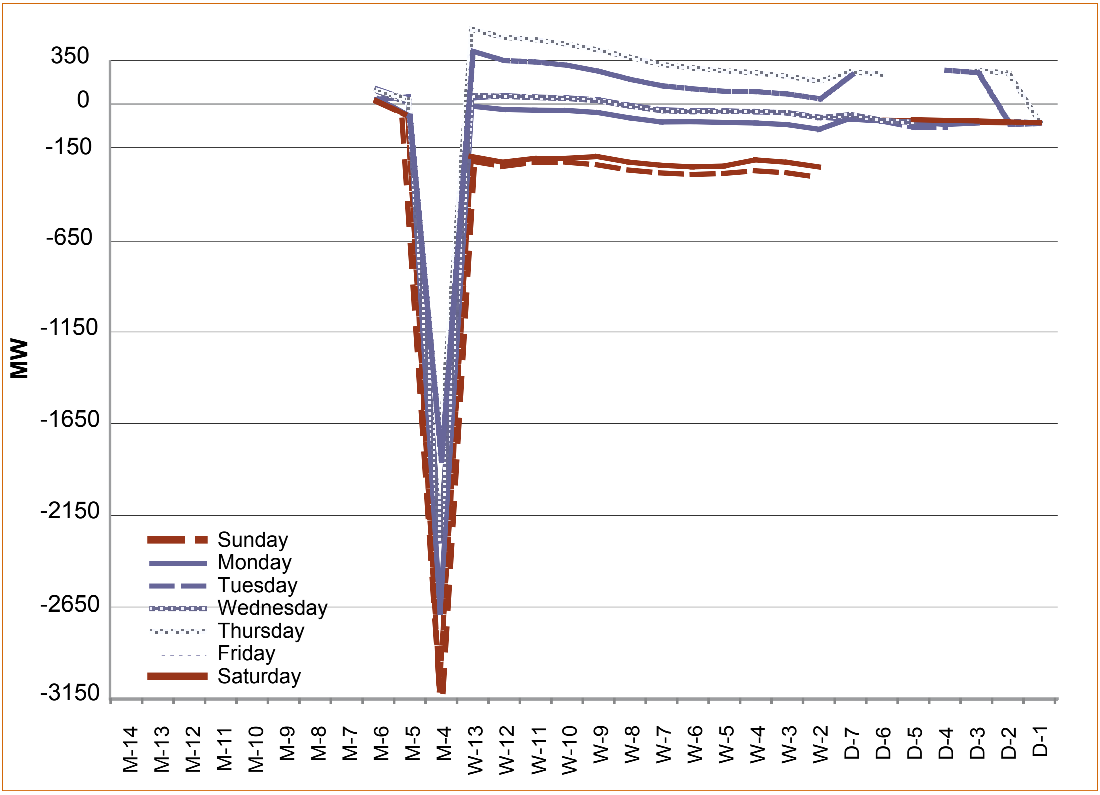
Data: RTE; Analysis: CRE

The forecasts for Saturday and Sunday are out of line with those for other days in the week: this is hardly explainable for very short time horizons.

The forecast with the least bias appears to be that for Monday.

4.4.5 Daily or weekly storage and run-of-river

Average difference between the forecasts for various time horizons and the last available forecast, depending on the day for which the forecast was made



Data: RTE; Analysis: CRE

Values for discrepancies in medium-term forecasts (compared with the most recent forecast available) appear to fall into three groups:

- forecasts for Monday, Tuesday and Wednesday;
- forecasts for Thursday and Friday;
- forecasts for Saturday and Sunday;

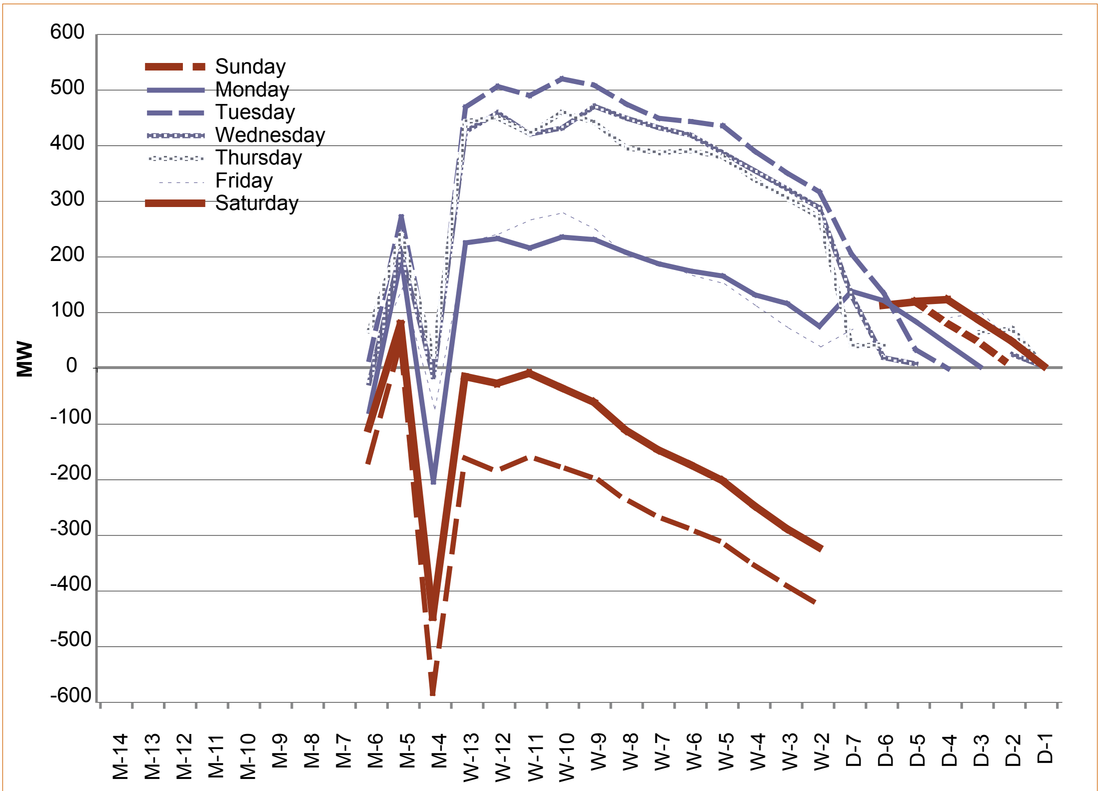
For short-range forecasts, only the variations in the forecasts for Thursday and Friday differ from variations for the other days in the week.

For medium-range forecasts, only one forecast is available for the entire week, which could explain the differences.

For short-range forecasts, the position is explained by the “accident” of the 25-26 October involving data for D-1 supplied by EDF.

4.4.6 Reservoir

Average difference between the forecasts for various time horizons and the last available forecast, depending on the day for which the forecast was made



Data: RTE; Analysis: CRE

The very short-range forecasts are very uneven (very poor for Saturday, for instance; and quite good for Wednesday, Thursday and Friday).

Medium-range forecasts show three sets of values, corresponding to a saw-tooth production pattern: low on Tuesday, Wednesday and Thursday, medium on Monday and Saturday and high on Sunday.

4.5 Frequency of publication update

In 2007, values for the medium and long term forecasts were updated each week or month. Short-term values were updated daily. However, there were no updates during the weekend.

Thus market players traded on the basis of information that could have differed noticeably from that available to the generators. At weekends, players had to base the supply-demand balance that they anticipated at the start of the week on information published on the previous Friday morning, or three days before delivery date.

5. THE BEHAVIOUR OF PLAYERS ON POWERNEXT DAY-AHEAD AUCTION

Between January and September 2007, price sensitivity was not high. An increase in supply or demand of 500 MW during that time would have changed prices only by an average of €1.6 /MWh (or less than 5% of the average price over the period). The change rarely exceeded €10 /MWh.

By contrast, between October and December, price sensitivity climbed sharply. The balance between supply and demand on Powernext Day-ahead Auction was much more stressed. An increase in supply (or reduction in demand) of 500 MW was sufficient to reduce prices by an average of €6.7 /MWh in October, €13.7 /MWh in November and €5.5 /MWh in December. Elasticity was sometimes extremely high, particularly during price spikes. For instance, at 6:00pm on 29 October, the price would have dropped by €636 /MWh, to half its value, if supply had increased by just 200 MW.

5.1 Price setting

Whether or not prices on Powernext Day-ahead Auction are representative depends largely on whether or not French-based producers have assessed appropriately the flexibility of their generating facilities[17]. CRE has therefore analyzed the sensitivity of the Powernext price to changes in supply and demand, to assess how far it is consistent with the flexibility in practice of French generating facilities.

In order to do so, CRE defined an index measuring the elasticity of prices to variations in supply and demand. This elasticity is calculated as the ratio of the change in price due to a change of supply or demand. By definition:

- The elasticity of price to demand is positive: it measures the rise in price that results from an increase in demand at all prices. It also follows that it is equal to the rise in price that results from a reduction in supply at any price.

- The elasticity of price to supply is negative: it measures the fall in price that results from an increase in supply at any price. It also follows that it is equal to the fall in price that results from a reduction in demand at any price.

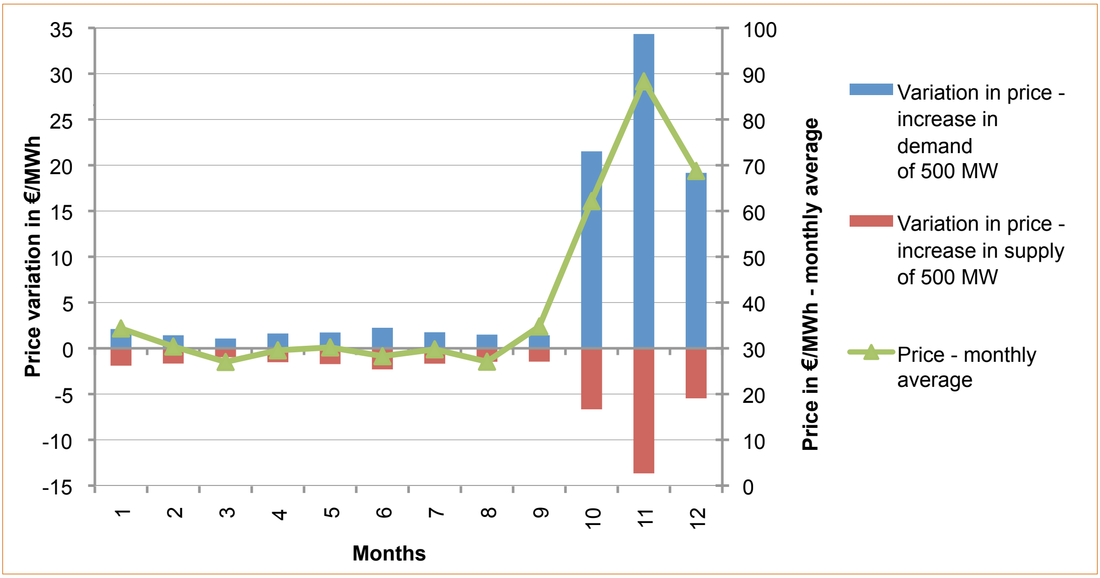
5.1.1 Price sensitivity on Powernext increased sharply at the end of 2007

Between January and September 2007, price sensitivity was not high. An increase in supply or demand of 500 MW during that time would have changed prices only by an average of €1.6 /MWh (or less than 5% of the average price over the period). The change rarely exceeded €10 /MWh.

By contrast, between October and December, price sensitivity climbed sharply. The balance between supply and demand on Powernext Day-ahead Auction was much more stressed. An increase in supply (or reduction in demand) of 500 MW was sufficient to reduce prices by an average of €6.7 /MWh in October, €13.7 /MWh in November and €5.5 /MWh in December. Elasticity was sometimes extremely high, particularly during price spikes. For instance, at 6:00pm on 29 October, the price would have dropped by €636 /MWh, to half its value, if supply had increased by just 200 MW.

The sensitivity of price to demand remained higher than its sensitivity to supply. An increase in demand (or reduction in supply) of 500 MW would have increased prices by an average of €21.5 /MWh in October, €34.3 /MWh in November and €19.2 /MWh in December.

Change in the price on Powernext Day-ahead Auction following a 500 MW increase in supply or demand - Monthly averages for 2007 -



Data: Powernext; Analysis: CRE

5.1.2 The sensitivity of the Powernext price was consistent with the actual equilibrium position of the system

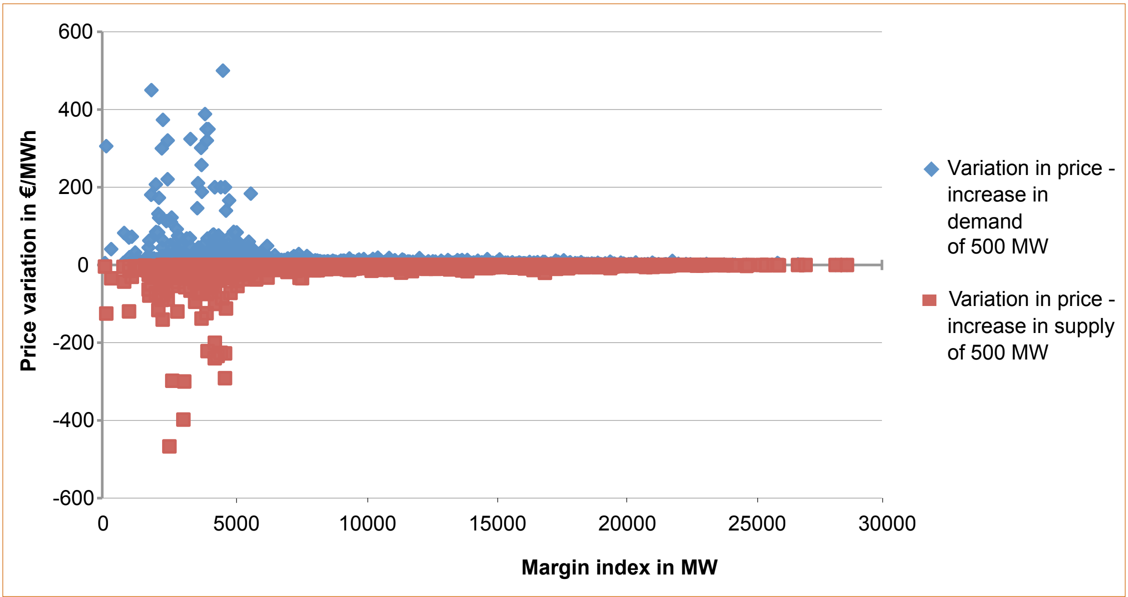
As indicated in the preceding pages, during the first three quarters of the year, the balance between supply and demand on the French market was not particularly stressed, and the fuel types that were most often marginal were the nuclear and coal-fired. Thus on first analysis, it is not unexpected that a change in the supply of 500 MW (which in terms of order of magnitude is the output of one coal-fired generating unit, or 30 to 50% of the output of a nuclear generating unit) had only a limited impact on prices.

By contrast, during the fourth quarter, the French electricity marketing system was stressed. Higher values of hydroelectric reserves and more frequent recourse to peakload facilities such as oil-fired power stations could have helped increase the sensitivity of price to changes in supply.

In general, the day-to-day elasticity of the Powernext price depended on the margin between the supply-demand balance and the price. In particular, when the market was unstressed (high margins), the price was low and the price elasticity (for both supply and demand) small. Very high values for price elasticity were not observed unless the price rose above €60 /MWh. We also note that price elasticity only reached extreme values when the margin was tight. In addition, it was very rare for the price elasticity to reach high values when the margin was not under pressure.

Link between the change in the hourly price on Powernext Day-ahead Auction following a 500 MW increase in supply or demand, and system margin

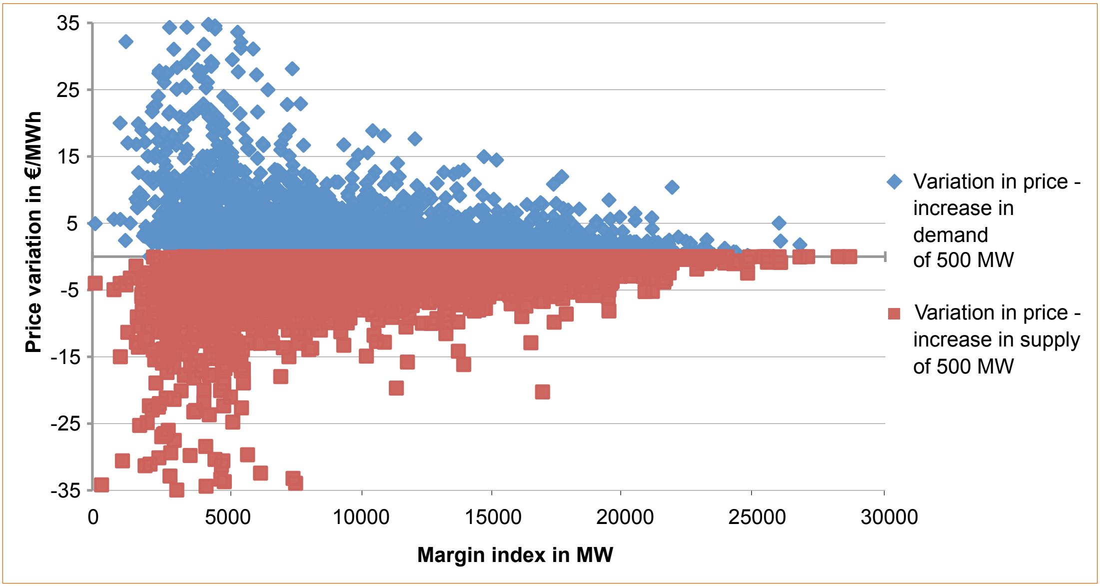
- Hourly data in 2007 -



Data: Powernext, RTE; Analysis: CRE

- Detail of variations between -€35 and +€35 /MWh –

- Hourly data in 2007 -



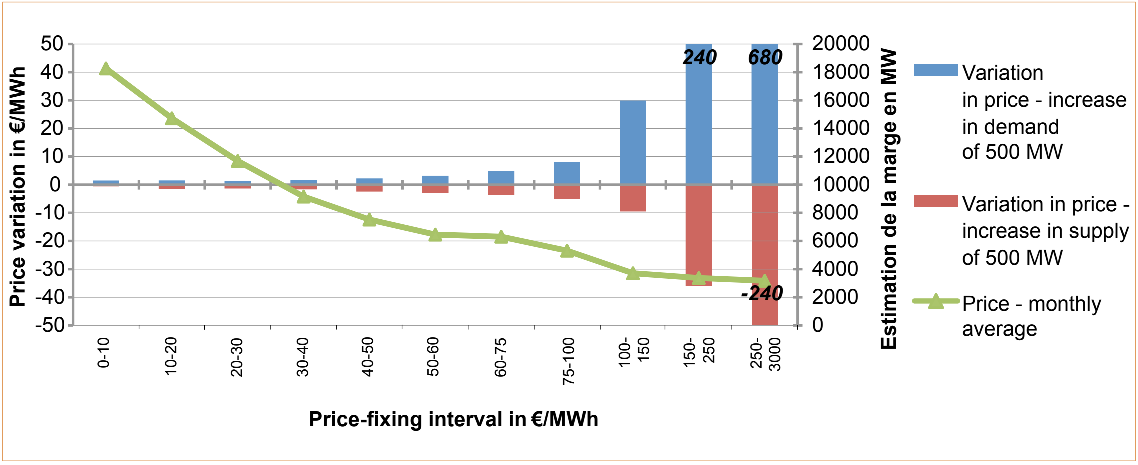
Data: Powernext, RTE; Analysis: CRE

Thus it appears that during periods when the market was moderately stressed, resilience on Powernext Day-ahead Auction was not inconsistent with the position of the supply-demand balance for the French system. This could imply that in the region of the fixing price, bids from generators accurately reflect the upward and downward flexibility of their generating facilities.

However, CRE has not, so far, analyzed the sensitivity of the price to large changes in supply or demand, in order to check that the full flexibility of unused generating capacity is really offered on Powernext, particularly during times of high stress.

The last graph summarizes the correlation between price level, margin and elasticity. It is clear that when prices increased, the margin went down and price elasticity rose.

Elasticity of price on Powernext Day-ahead Auction as a function of price level and margin index



Data: Powernext, RTE; Analysis: CRE

5.2 Individual behaviour

CRE analyzed the supply and demand curves for each hour, sent daily by members of Powernext Day-ahead Auction.

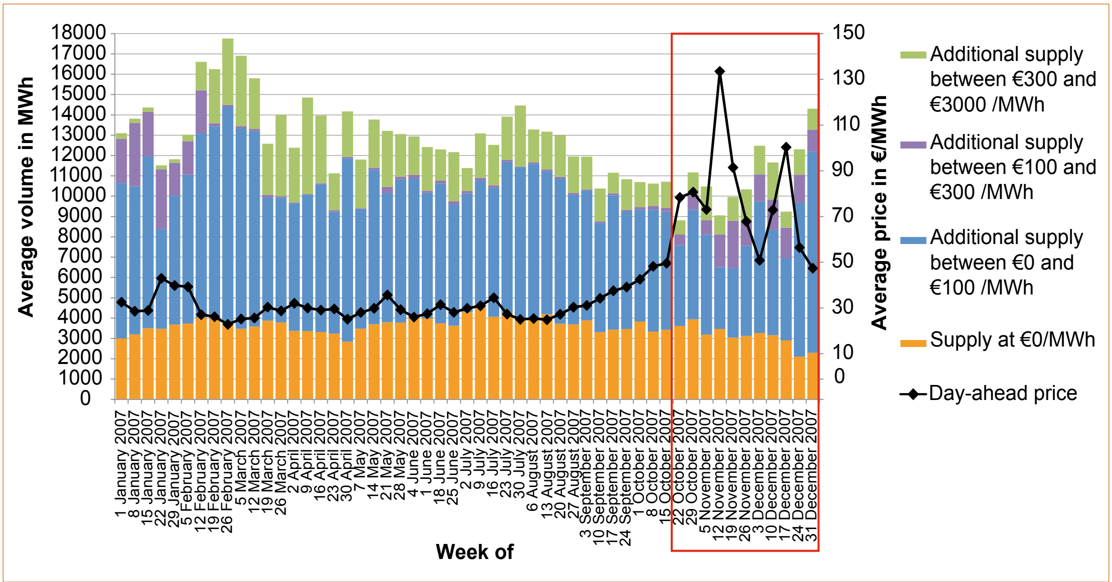
In 2007, the aggregated supply was in general high for €0 /MWh (supply at any price). It then rose sharply between €0 and €100 /MWh, but then little for prices above €100 /MWh. The aggregated demand reduced strongly between €0 and €100 /MWh, but then little for prices above €100 /MWh.

Supply and demand at the price fixed on Powernext Day-ahead Auction were highly variable. Nevertheless, it is possible to ascertain that the price increases observed during the period October-December 2007 were caused more by an overall reduction in supply via the platform than with an increase in demand. Many participants reduced their offer, although CRE identified several who reduced their offers very substantially. Similarly, the increase in demand was widespread.

From week 43, aggregated supply reduced substantially. Between weeks 42 and 43, the maximum average aggregated supply (at €3,000 /MWh) decreased to 1,900 MW and reached the lowest level observed during the year. The supply at prices below €100 /MWh was particularly low during that period.

The following graph shows for each week in the year, the average volume of the supply at €0 /MWh, and the volume of the additional supply for different price bands.

Aggregated supply on Powernext Day-ahead Auction in 2007
- Weekly averages -

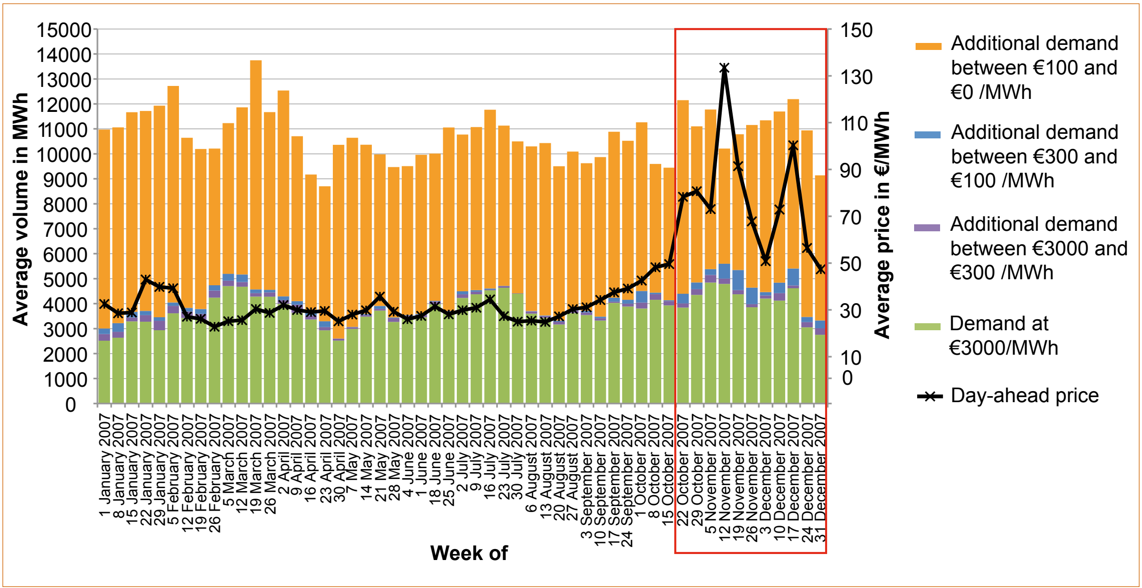


Data: Powernext; Analysis: CRE

The aggregated demand also rose strongly at the end of the year. However, it did not always increase during weeks with price spikes, so that the demand was at levels that had already been reached at times of year with no price spikes. The increase in demand was seen at all price levels.

The following graph shows for each week in the year, the average volume of the demand at the maximum price, and the volume of the additional demand for different price bands.

Aggregated demand on Powernext Day-ahead Auction in 2007
- Weekly averages -



Data: Powernext; Analysis: CRE

CRE has questioned those players whose reduction in supply had most impact on Powernext Day-ahead Auction.

Players who had clearly reduced their supply on Powernext Day-ahead Auction from October 2007 gave two types of explanation.

Some said that they had less available capacity to offer on the day-ahead market, because they had production constraints or limited import opportunities.

Others said that they had offered a proportion of the volume so far offered on Powernext Day-ahead Auction on other markets.

CRE has not observed behaviour aimed at manipulating Powernext Day-ahead Auction prices.

6. CROSS-BORDER TRADING

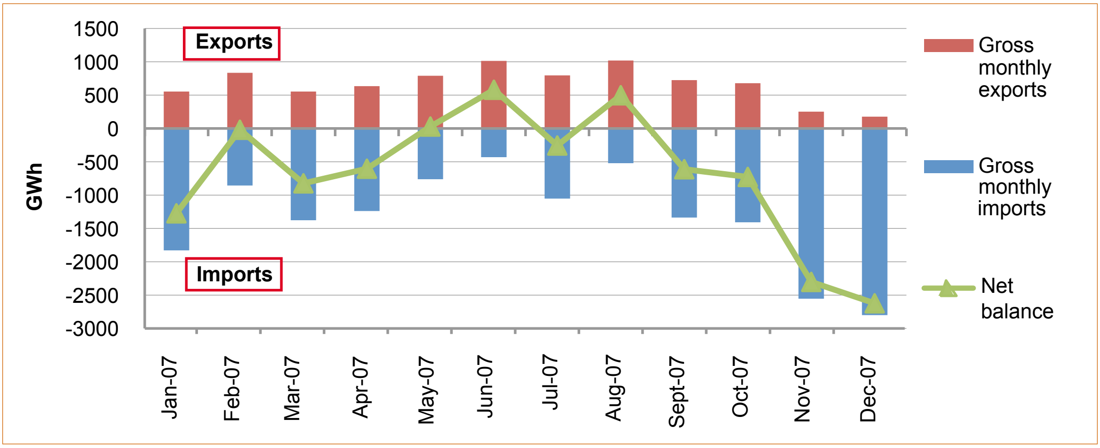
6.1 Cross-border exchanges in 2007

6.1.1 France-Germany

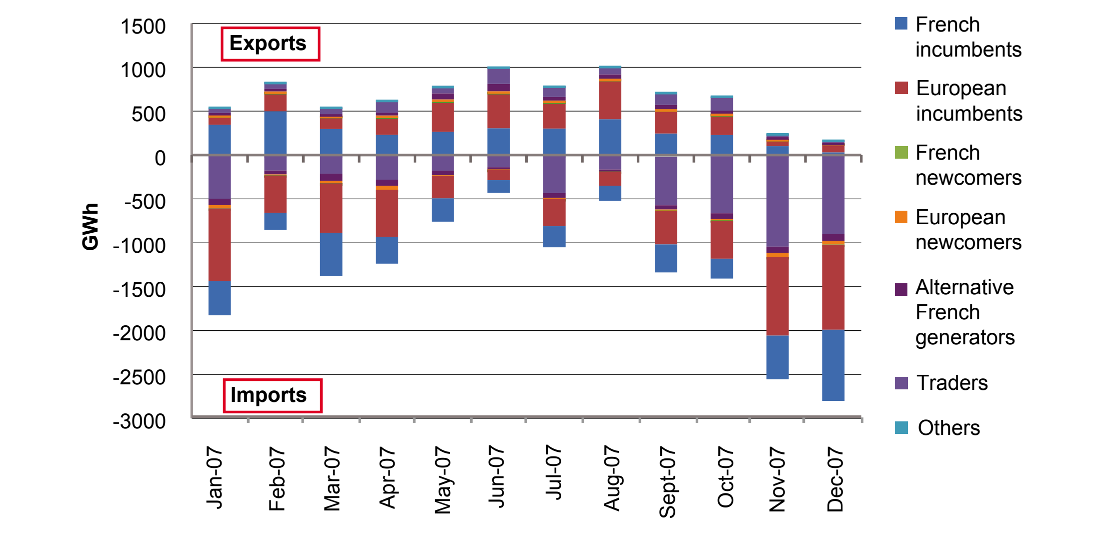
The French market imported around 8TWh net from Germany in 2007. However, the French market was a net exporter to Germany in May, June and August.

The number of companies active on this border grew from 34 to 40 during 2007. Most players on the border are European and French incumbents and traders. The new participants are essentially trading companies. Imports are fairly concentrated; on the other hand, exports are still very highly concentrated, because one player has a large market share.

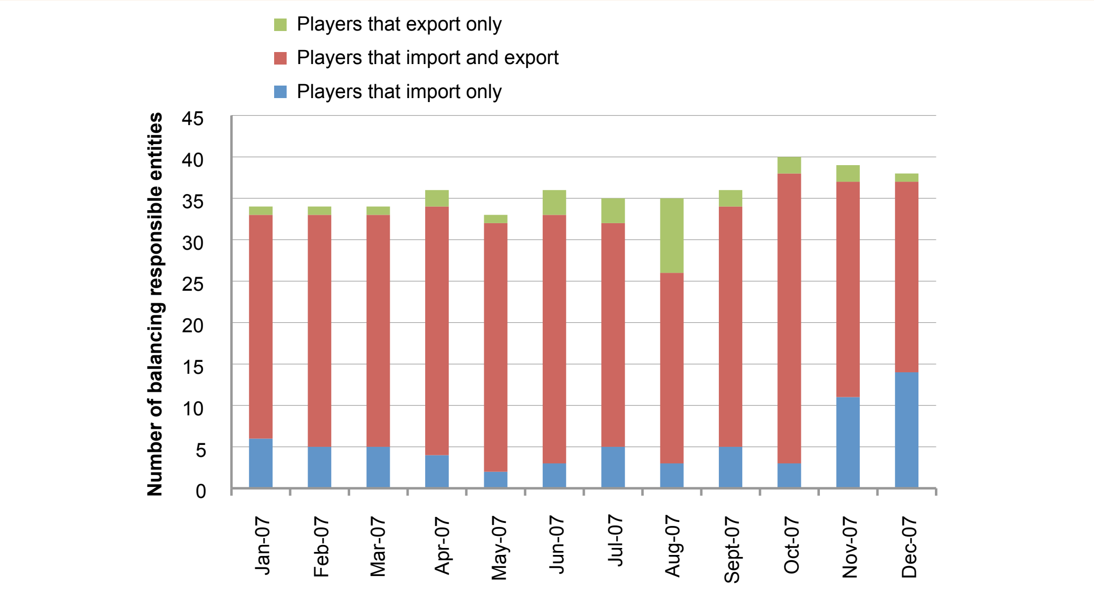
Gross imports and exports at the France-Germany interconnection



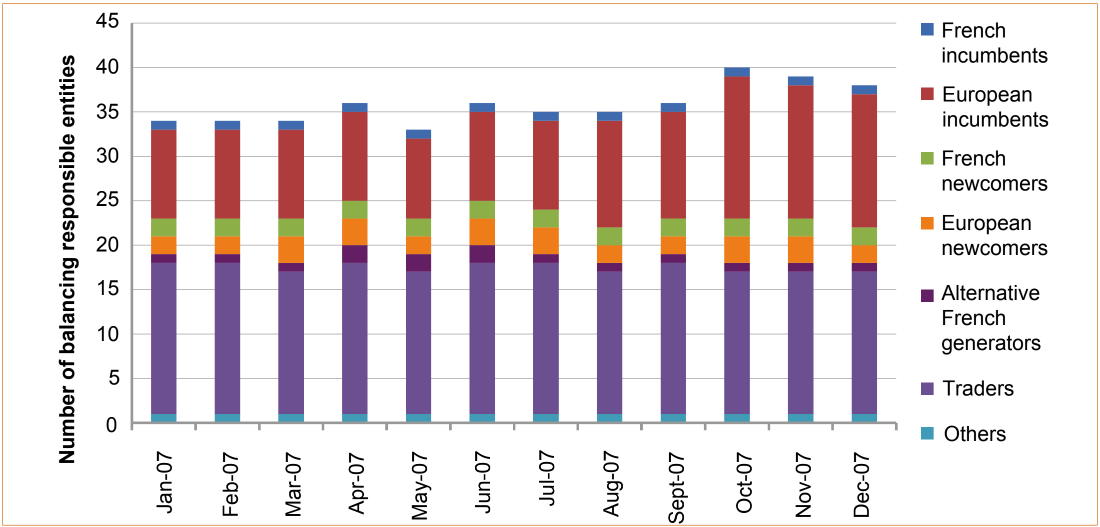
Gross imports and exports at the France-Germany interconnection by categories of player



Number of participants at the France-Germany interconnection

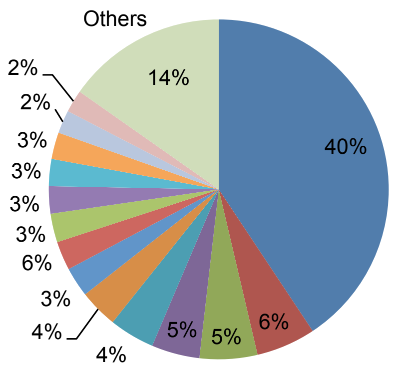


Number of participants by category at the France-Germany interconnection



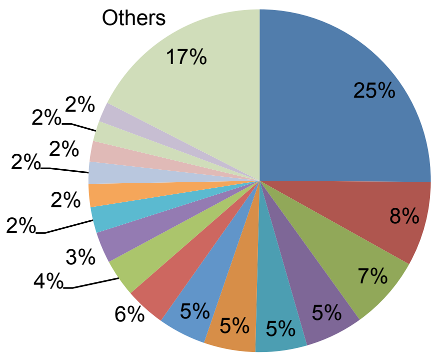
Market share of players by gross volumes exported to Germany in 2007

- Players with a market share greater than 2% -



Market share of players by gross volumes imported from Germany in 2007

- Players with a market share greater than 2% -



Data: RTE; Analysis: CRE

6.1.2 France-Belgium

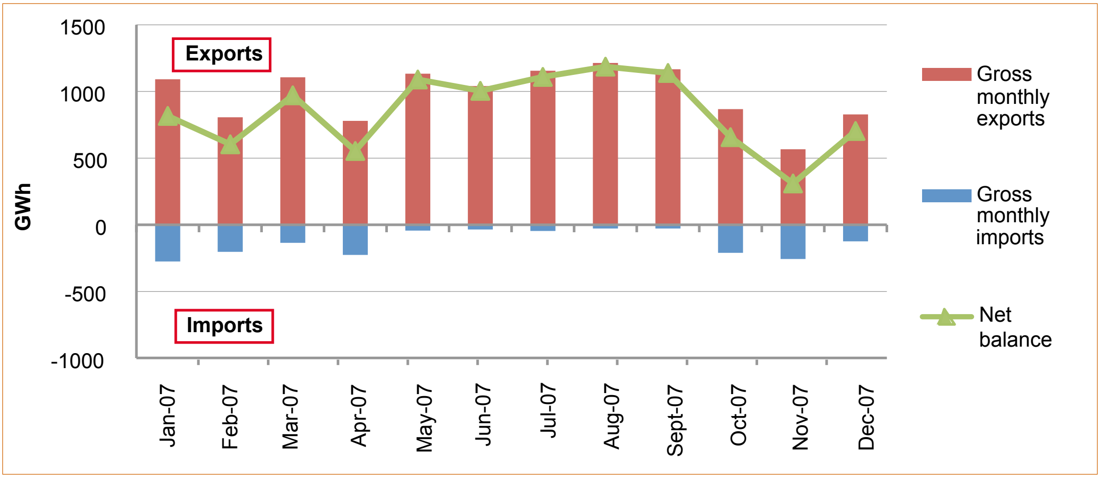
The French market exported around 10TWh net to Belgium in 2007. The French market was a net importer from Belgium only for about 9% of hours.

As regards the day-ahead market, we cannot determine the number of players active on the border, since the market-coupling mechanism is used to define all the daily flows. For capacity reserved over the longer term (periodic capacity), some fifteen participants were active on the Belgian border in 2007. The French and

European incumbents were the source of most volumes traded. The number and type of players did not vary significantly. Flows were moderately concentrated.

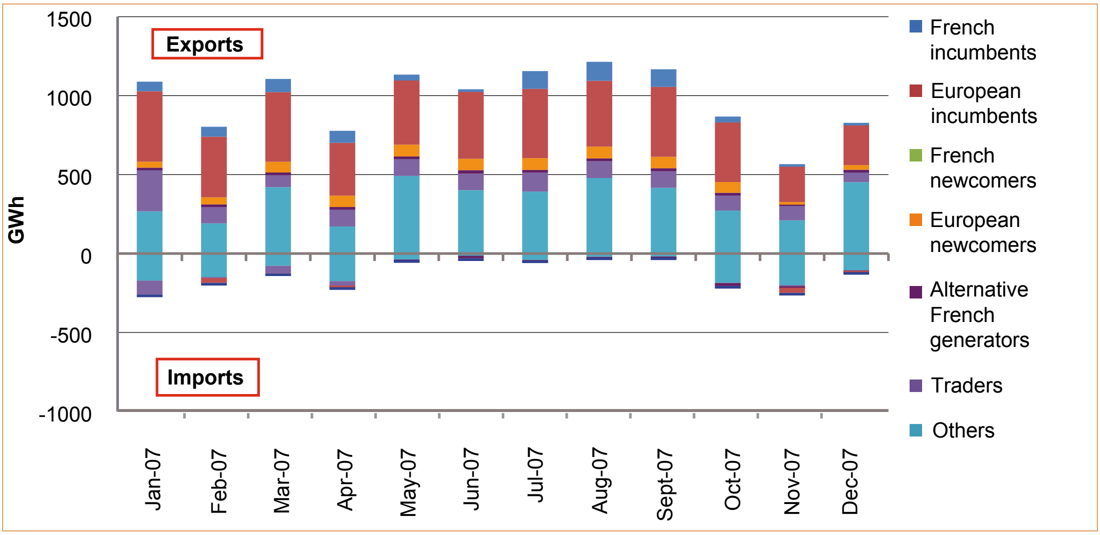
Gross imports and exports at the France-Belgium interconnection

- All flows -



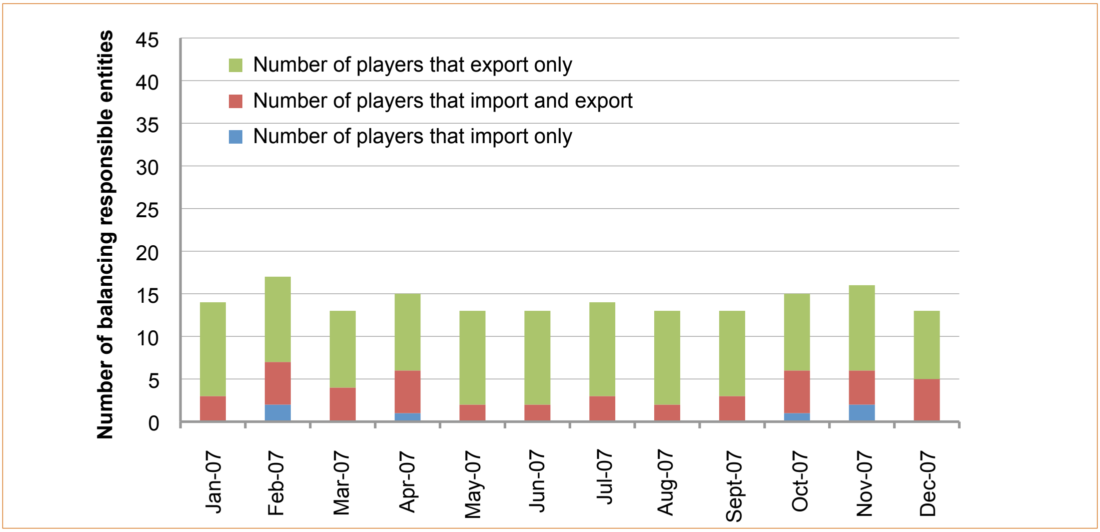
Gross imports and exports at the France-Belgium interconnection by categories of player

- All flows -

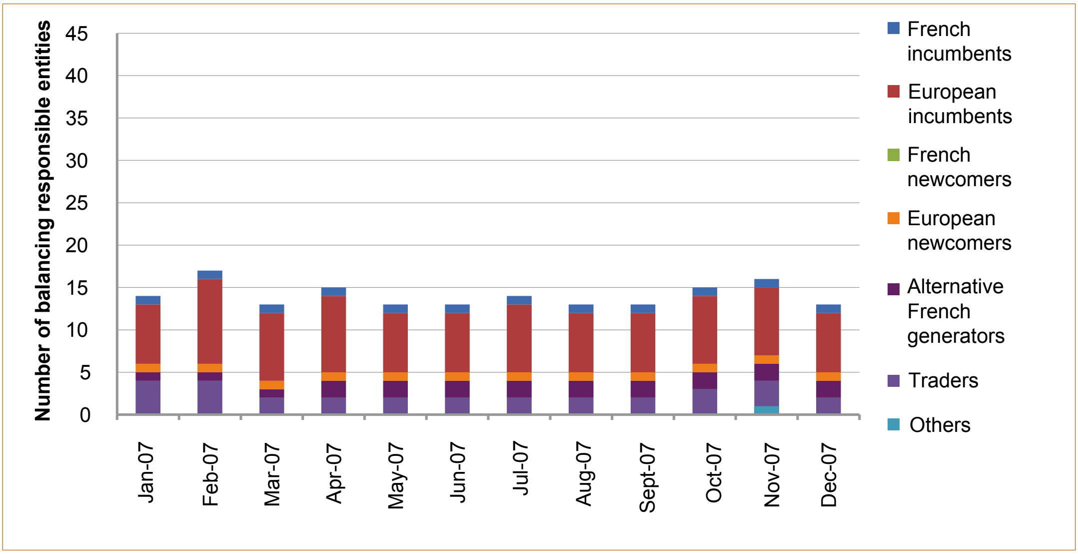


Flows resulting from Market Coupling are included in “Others”

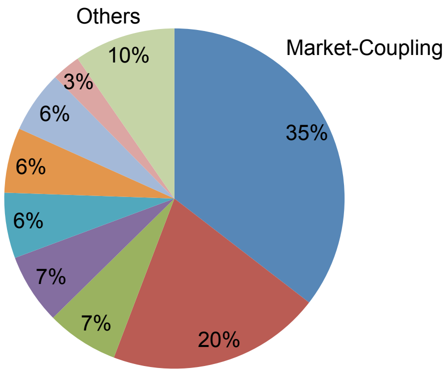
Number of participants at the France-Belgium interconnection
- Excluding daily flows -



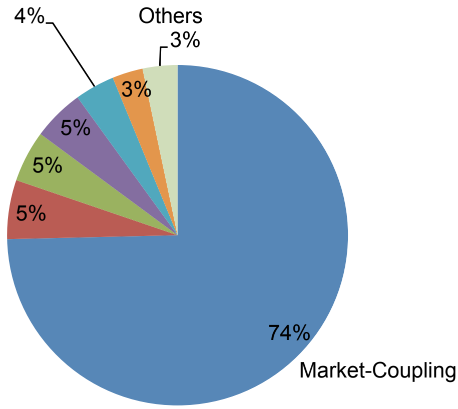
Number of participants by category at the France-Belgium interconnection
- Excluding daily flows -



Market share of players by gross volumes exported to Belgium in 2007
- All flows; players with a market share of over 2% -



Market share of players by gross volumes imported from Belgium in 2007
- All flows; players with a market share of over 2% -



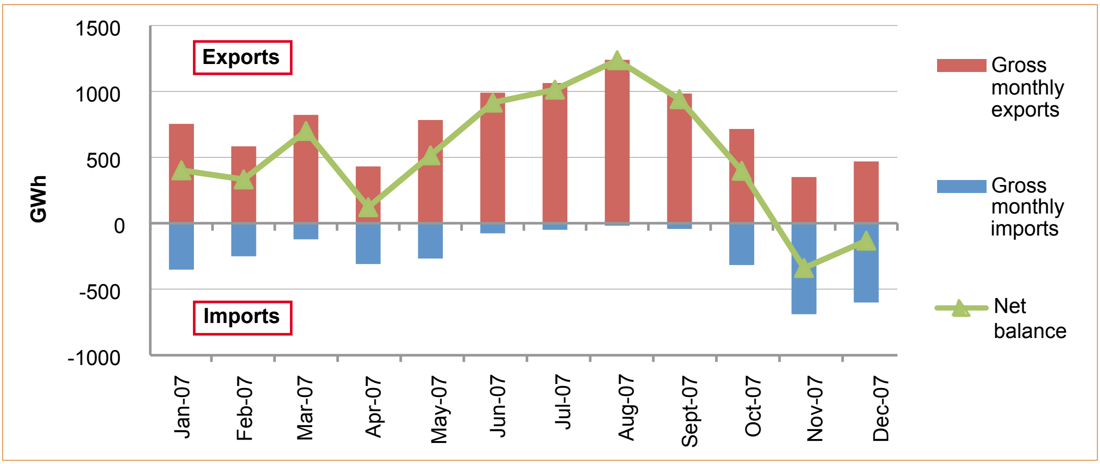
Data: RTE; Analysis: CRE

6.1.3 France-Great Britain

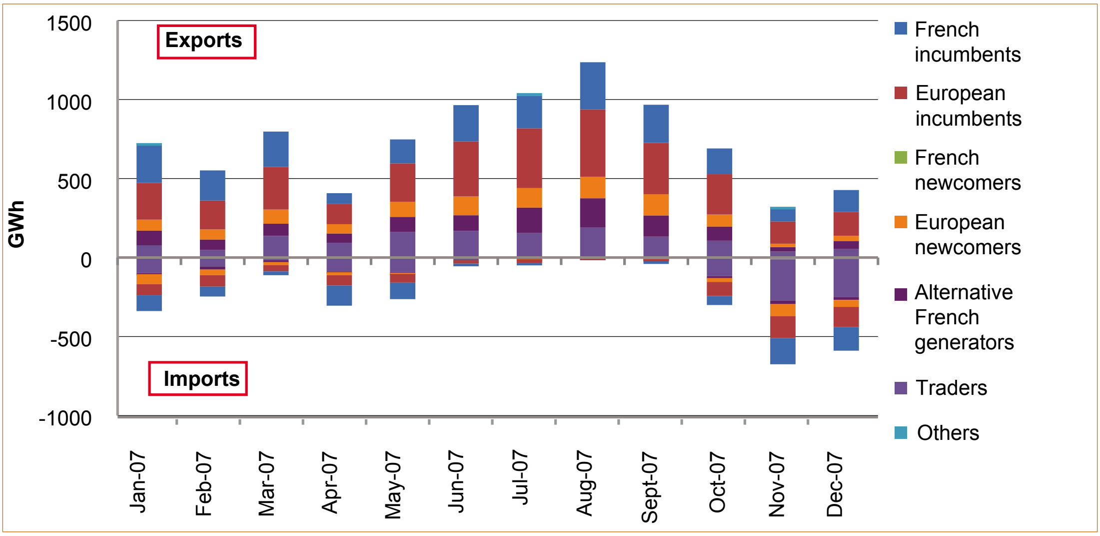
The French market exported around 6TWh net to Great Britain in 2007. However, the French market was a net importer from Great Britain in November and December 2007.

Around twenty participants were active on the British border in 2007. Most were European and French incumbents and traders. The number and type of players did not vary significantly. Exports were moderately concentrated; imports very little concentrated.

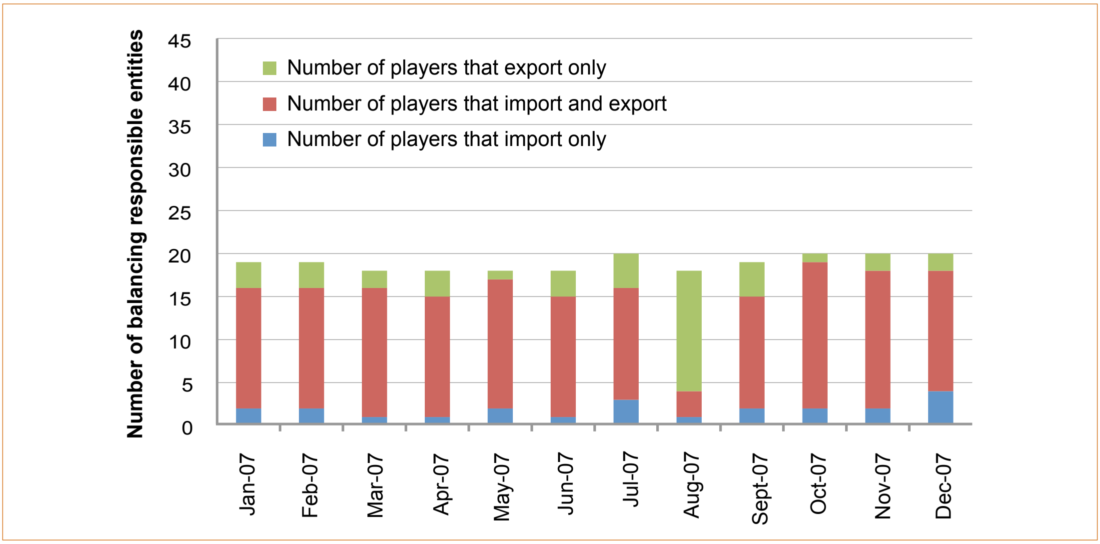
Gross imports and exports at the France-Great Britain interconnection



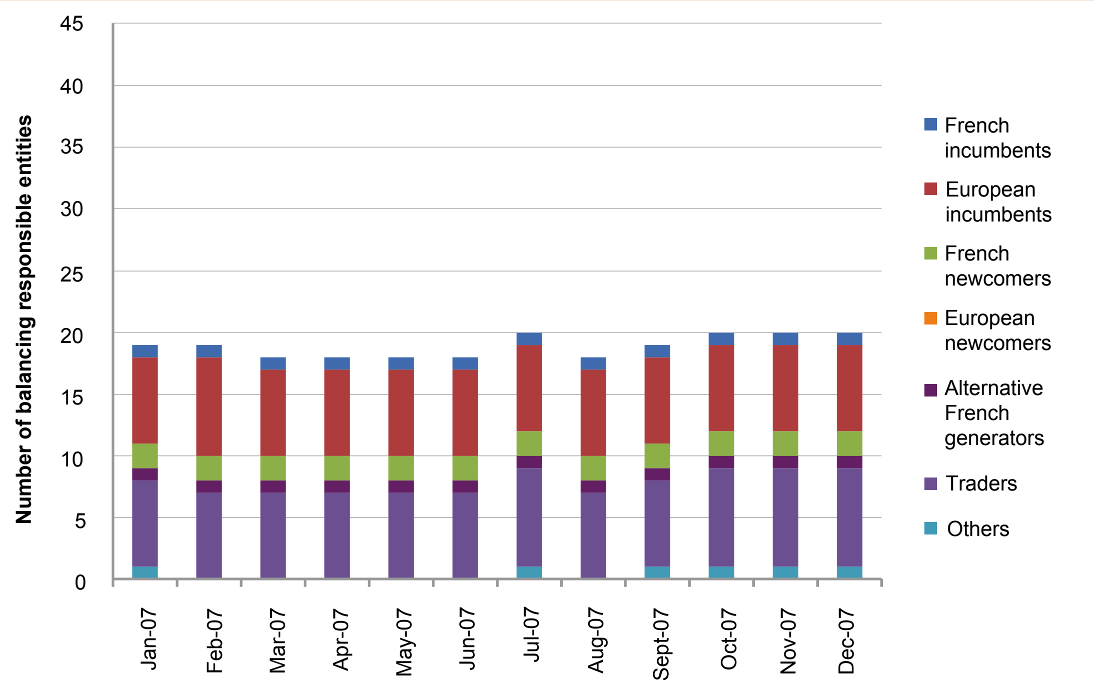
Gross imports and exports at the France-Great Britain interconnection by categories of players



Number of participants at the France-Great Britain interconnection

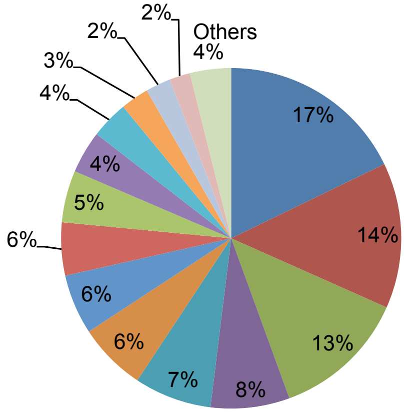


Number of participants by category at the France-Great Britain interconnection



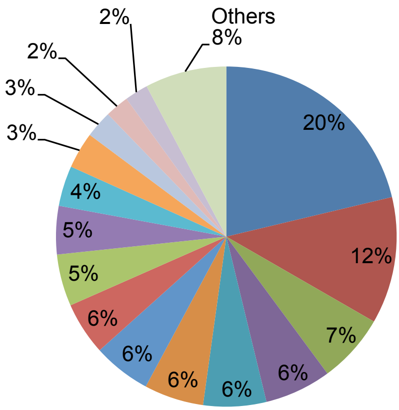
Market share of players by gross volumes exported to Great Britain in 2007

- Players with a market share greater than 2% -



Market share of players by gross volumes imported from Great Britain in 2007

- Players with a market share greater than 2% -



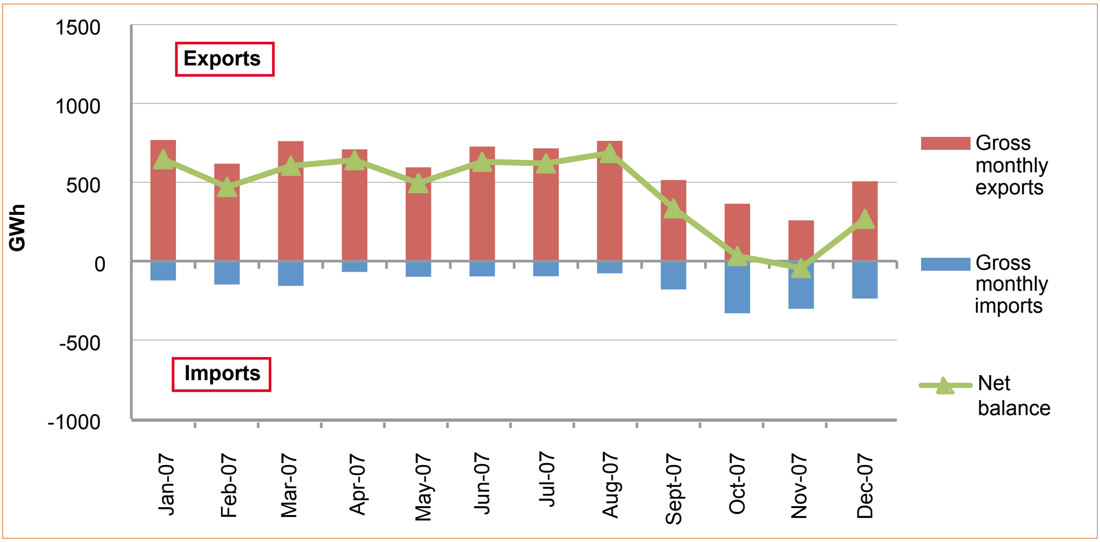
Data: RTE; Analysis: CRE

6.1.4 France-Spain

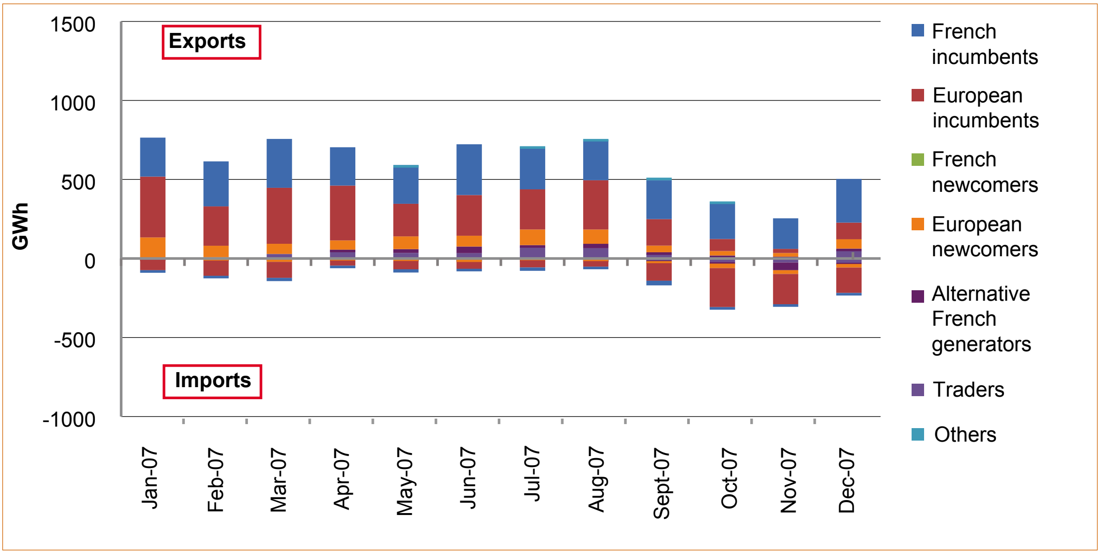
The French market exported around 5TWh net to Spain in 2007. However, the French market was a net importer from Spain for 25% of the hours in 2007. In particular, the French market was an overall importer in November 2007.

More than 15 players were active at the Spanish border by the end of 2007, 4 or 5 more than at the start of the year. This increase was linked to the appearance of numerous trading companies, which however remained a minority compared with the French and European incumbents. Flows across the Spanish border were moderately concentrated.

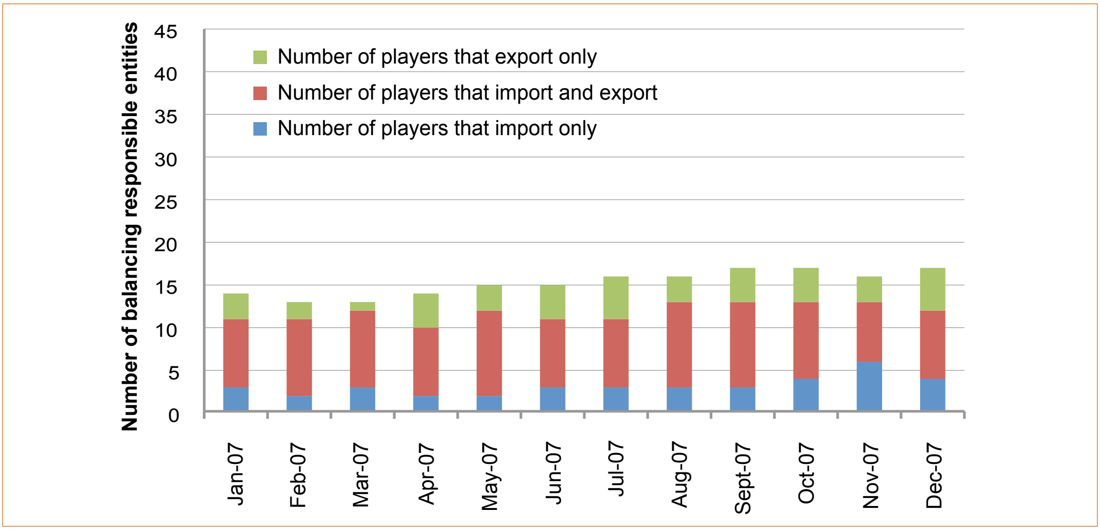
Gross imports and exports at the France-Spain interconnection



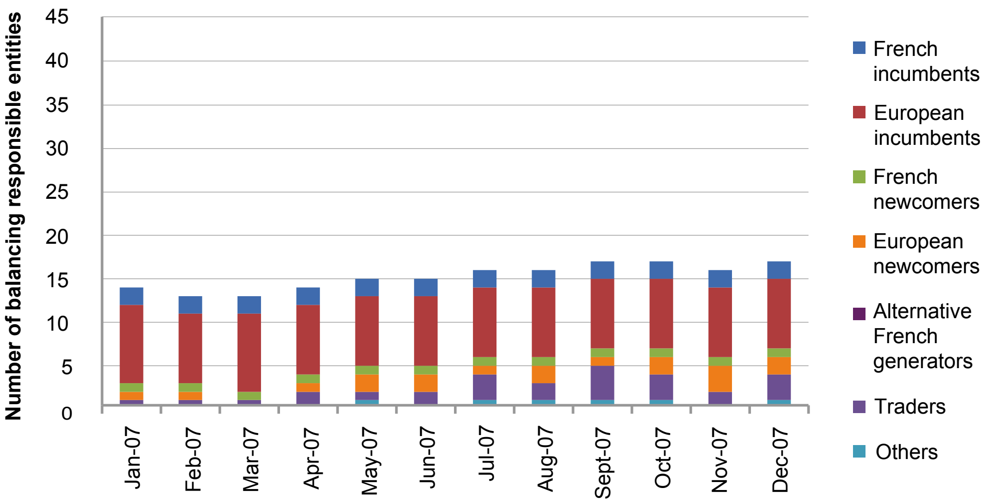
Gross imports and exports at the France-Spain interconnection by categories of player



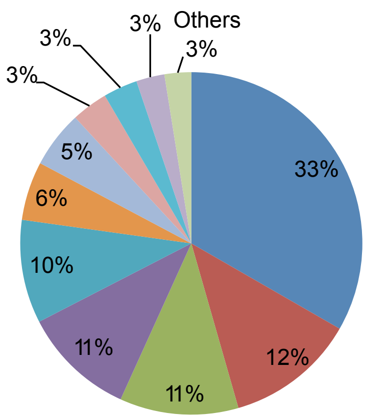
Number of participants at the France-Spain interconnection



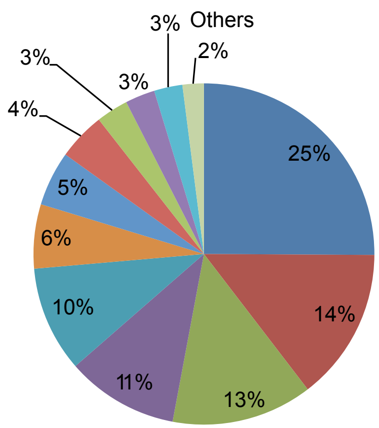
Number of participants by category at the France-Spain interconnection



Market share of players by gross volumes exported to Spain in 2007
- Players with a market share greater than 2% -



Market share of players by gross volumes imported from Spain in 2007
- Players with a market share greater than 2% -



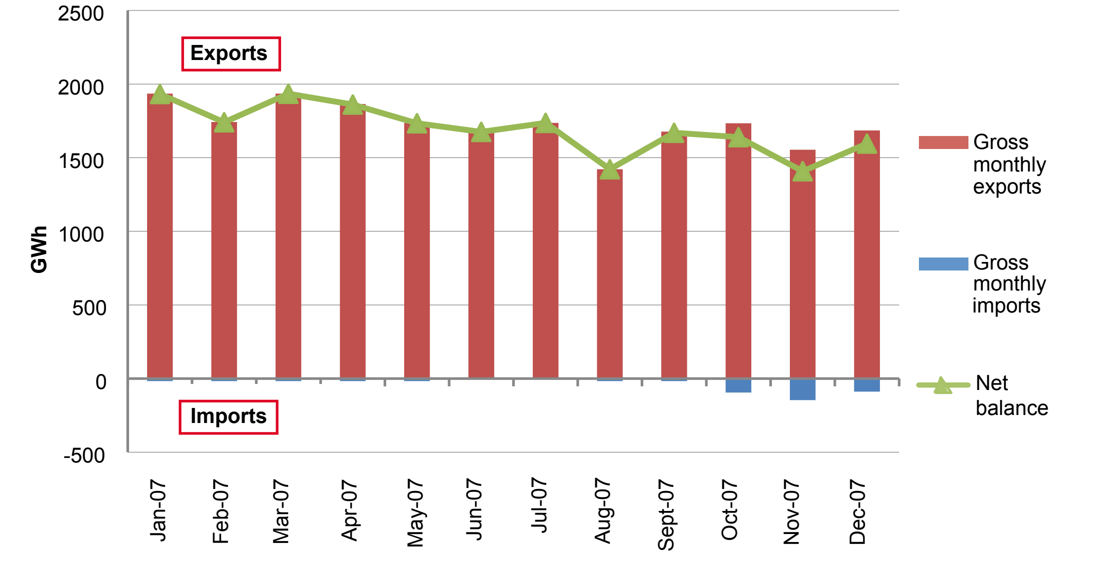
Data: RTE; Analysis: CRE

6.1.5 France-Italy

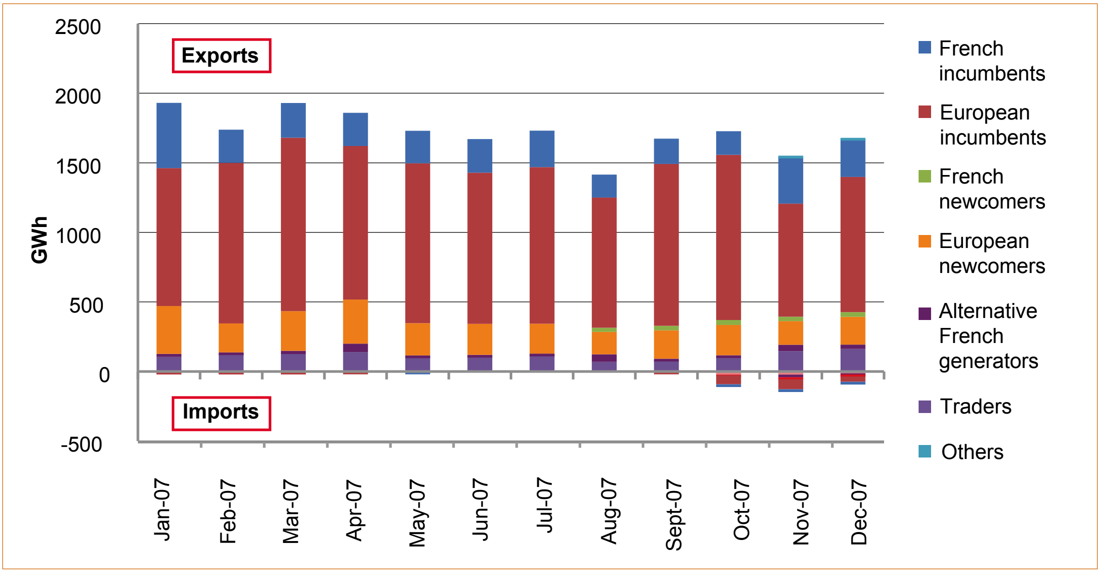
The French market exported around 20TWh net to Italy in 2007. The French market was occasionally a net importer from Italy, but only for very few hours (less than 1% of hours).

The number of companies grew from 22 to 30 during 2007. In particular, the number of newcomer suppliers and traders increased significantly. French and European Incumbents now represent less than half of the players present. Although imports remained highly concentrated, exports were only moderately concentrated.

Gross imports and exports at the France-Italy interconnection

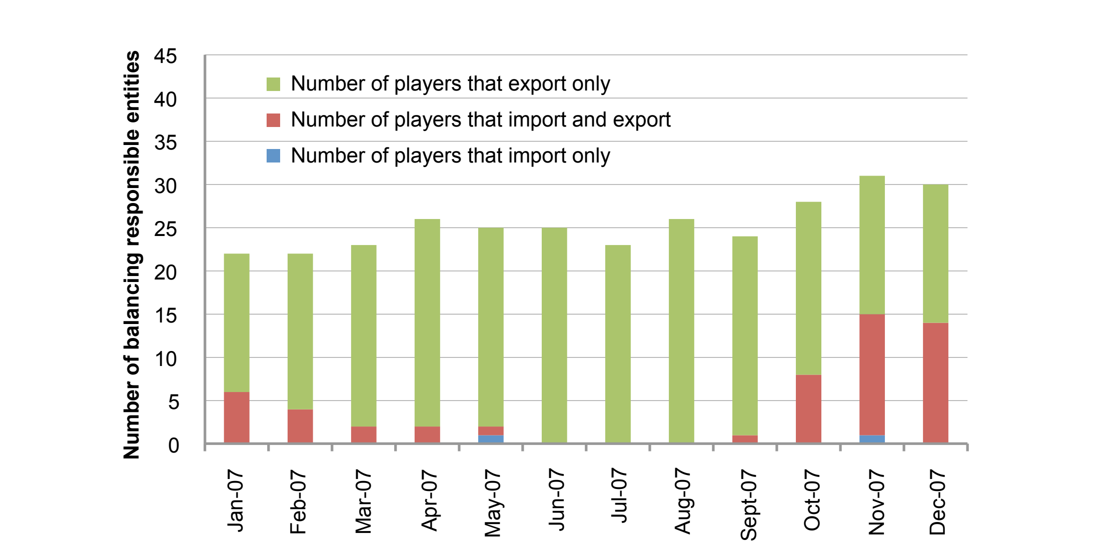


Gross imports and exports at the France-Italy interconnection by categories of player

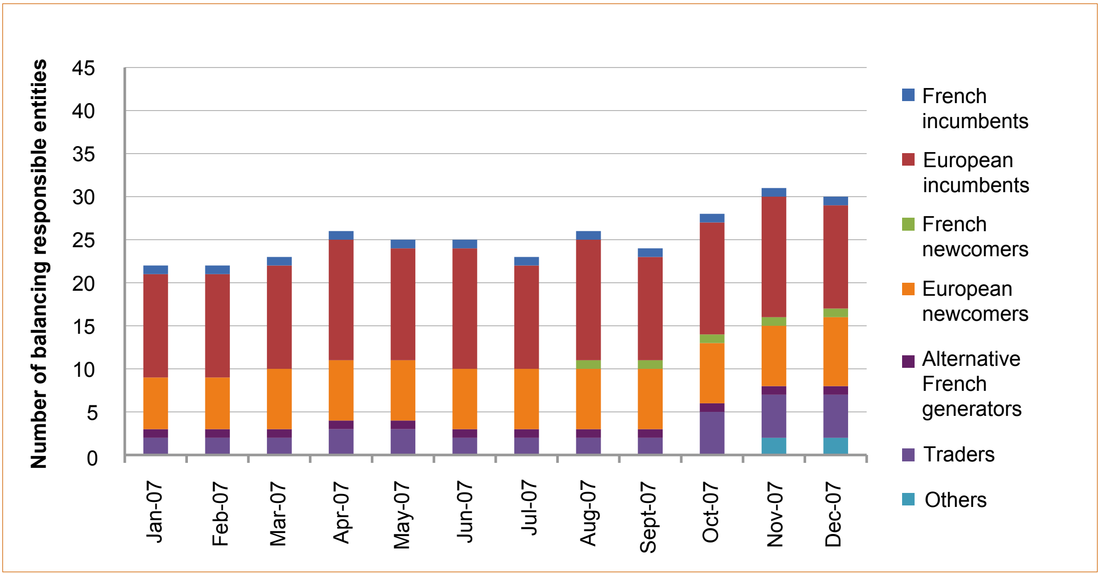


Data: RTE; Analysis: CRE

Number of participants at the France-Italy interconnection



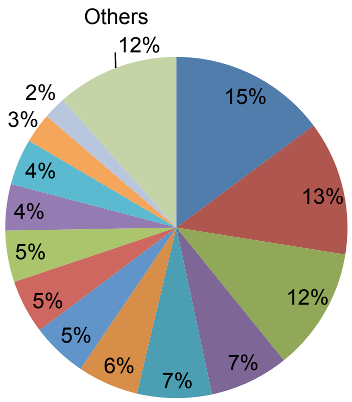
Number of participants by category at the France-Italy interconnection



Data: RTE; Analysis: CRE

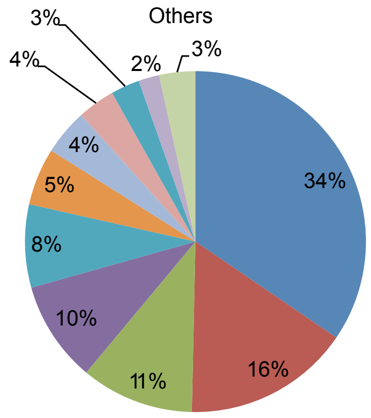
Market share of players by gross volumes exported to Italy in 2007

- Players with a market share greater than 2% -



Market share of players by gross volumes imported from Italy in 2007

- Players with a market share greater than 2% -



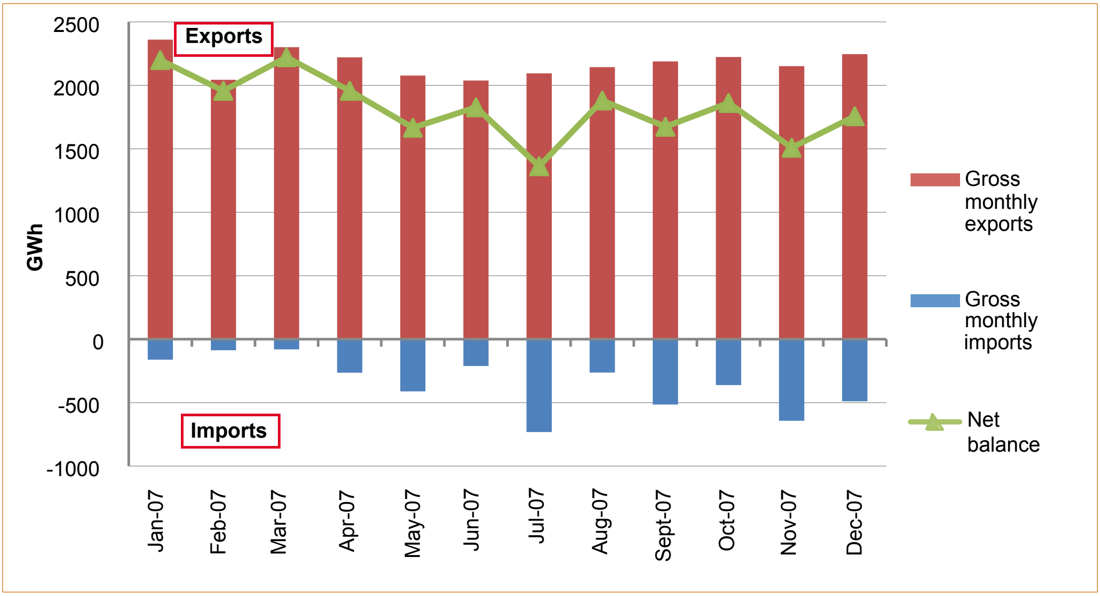
Data: RTE; Analysis: CRE

6.1.6 France-Switzerland

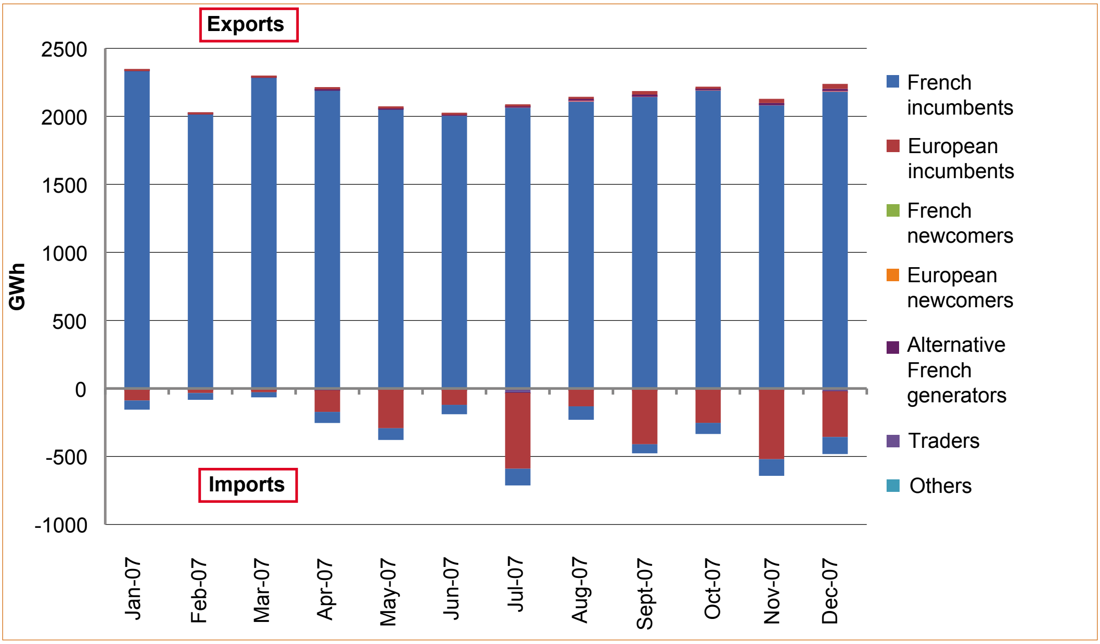
The French market exported around 22TWh net to Switzerland in 2007. The French market was a net importer from Switzerland for only very few hours (less than 1% of hours).

A dozen participants were active on the Swiss border in 2007, the vast majority of whom were French and European incumbents, who exchanged merely all the flows. The number of active players did not vary significantly. Imports were fairly concentrated. Exports remained extremely concentrated. French Incumbents largely dominated export nominations, because their long-term export contracts gave them priority access at the interconnection.

Gross imports and exports at the France-Switzerland interconnection

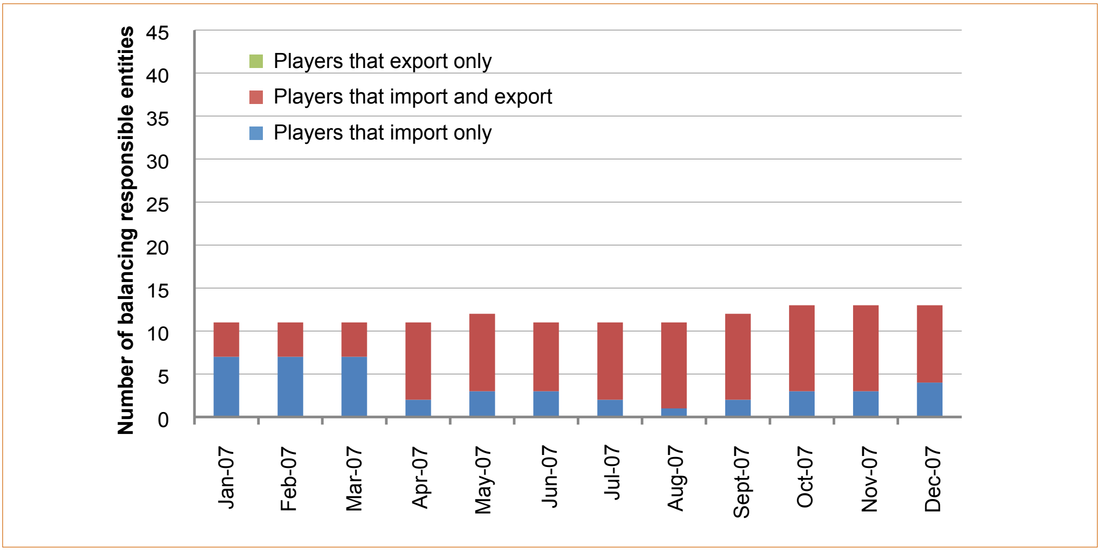


Gross imports and exports France-Switzerland interconnection by categories of player

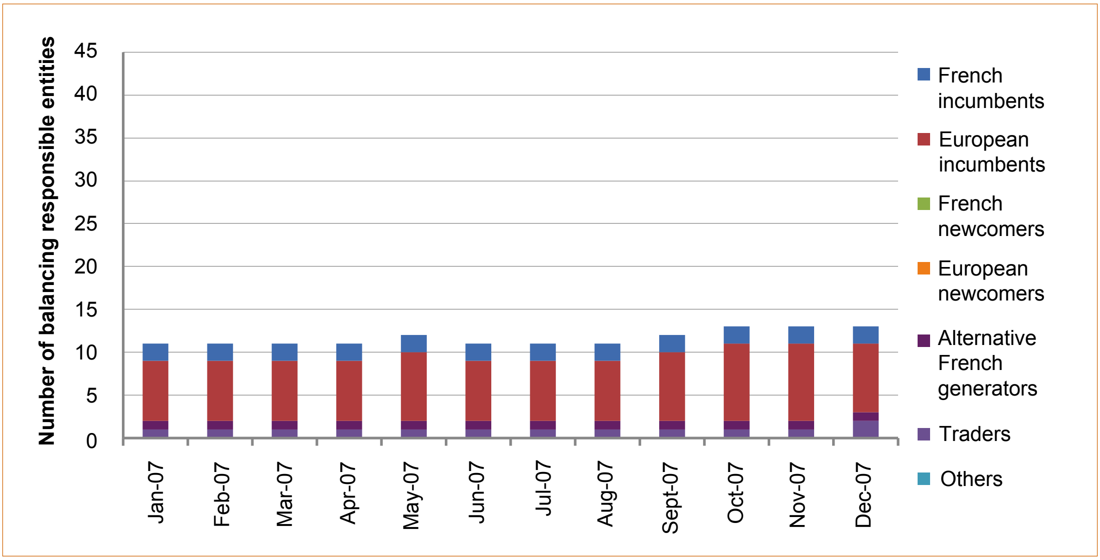


Data: RTE; Analysis: CRE

Number of participants at the France-Switzerland interconnection

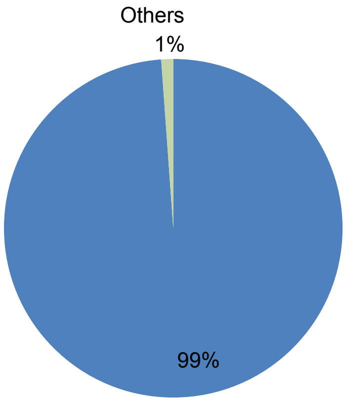


Number of participants by category at the France-Switzerland interconnection

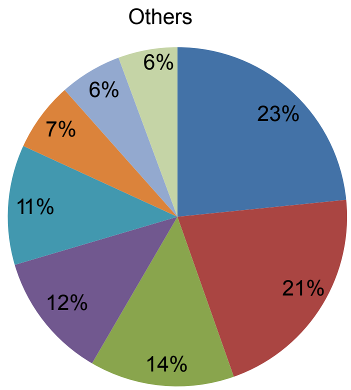


Data: RTE; Analysis: CRE

Market share of players by gross volumes exported to Switzerland in 2007
- Players with a market share greater than 2% -



Market share of players by gross volumes from imported Switzerland in 2007
- Players with a market share greater than 2% -



Data: RTE; Analysis: CRE

6.2 Nominations for daily capacity in 2007

Daily transmission capacities at the interconnections are bought by market players at the start of the day before the supply (day-ahead). They notify RTE how much they want to use (nominate) after the European exchanges have set the prices. Thus when analysing the use of such capacity, one possible indicator is the price differential observed between exchanges.

Since in France the capacity at interconnections is large compared with the margin in the supply-demand balance, its misuse by one or more players can have a significant effect on prices on the day-ahead market:

- by causing energy in France to become artificially scarce or plentiful, thus influencing the price directly;

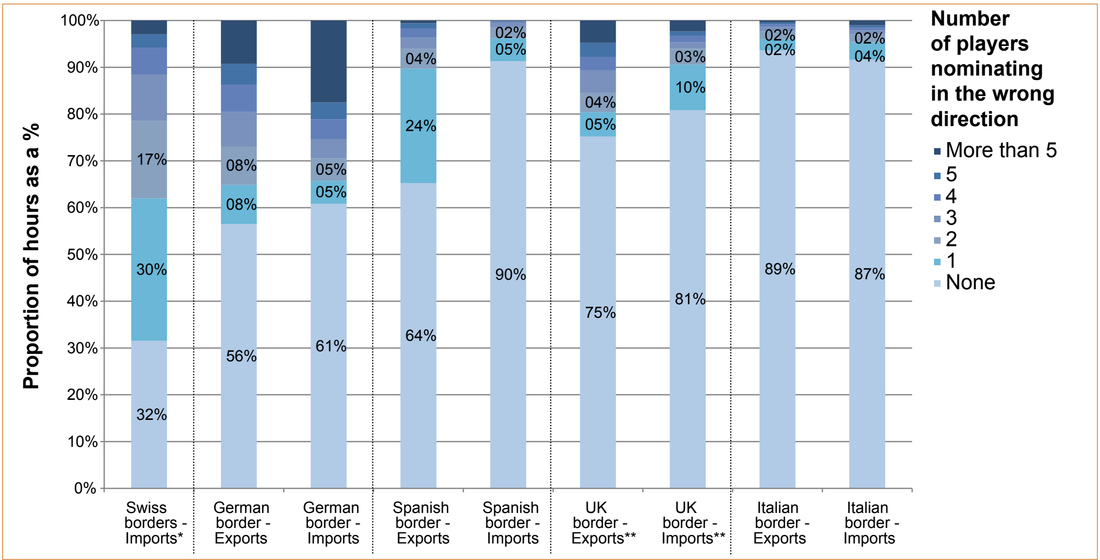
- by giving the market the wrong signals as to the position of the French market.

6.2.1 Nominations in the opposite direction to the price differential

CRE analyzed the individual use made of daily capacity at interconnections. At some borders, there were frequent nominations in the opposite sense to the price differential. This was so at the German border both for export and import, for imports over the Swiss border and for exports over the Spanish and British borders.

The graph below shows the percentage of hours during which flows in the opposite sense to the price differential were observed at each border and in each direction. The number of players involved in these flows is shown.

Proportion of hours for which nominations were in the reverse direction; and number of players nominating in the reverse direction



Data: RTE, Platts, EEX, Omel, Ipex; Analysis: CRE

* No figure is supplied for exports to Switzerland, as there is no mechanism to allocate daily capacity.
** The calculation for the UK border is based on hourly data but on the peak and off-peak blocks so that it is consistent with the price references used.

CRE questioned the market players who had most often nominated flows the wrong way during 2007. Responses from these players were of two kinds.

Firstly, the companies concerned said that the daily nominations were based on anticipations of prices that could prove to be inaccurate.

• Auctions of daily capacity take place at the start of the morning, and require bidders to anticipate the day's market prices. Bidders also place sale and purchase orders on the exchanges based on these anticipated prices. Once the exchanges have set the prices, players are obliged to honour their commitments on the exchanges, whatever the final price differential. Some players said that if their forecasts meant that some of their daily nominations were in the opposite sense to the price differential, they tried to adjust their intraday flows. The players stressed that poor transparency on the French market prevented traders from making good enough forecasts.

• Since some markets are particularly illiquid at the weekend, transactions and nominations for Saturday, Sunday and Monday start on Friday and are only very occasionally changed at the weekend to adjust for different market conditions.

The players also explained that the prices set hourly on the exchanges were not always relevant as indicators to interpret flows, which may be related to bilateral transactions.

• Many players said that nominations often result from bilateral transactions. Prices on the OTC market cannot be aligned with prices on the exchanges.

• Products exchanged at the borders are often standardized blocks. Such transactions may overall be profitable, even if they appear to go against the exchange prices at certain times.

• Two players mentioned that some flows corresponded to transit flows between two countries and were independent of the market conditions in France.

• Lastly, some flows are nominated for the day ahead but are not market based. This applies to flows related to green-certificate trading, and occurs with some long-term contracts that require energy to be shipped from France to another country, irrespective of the market conditions.

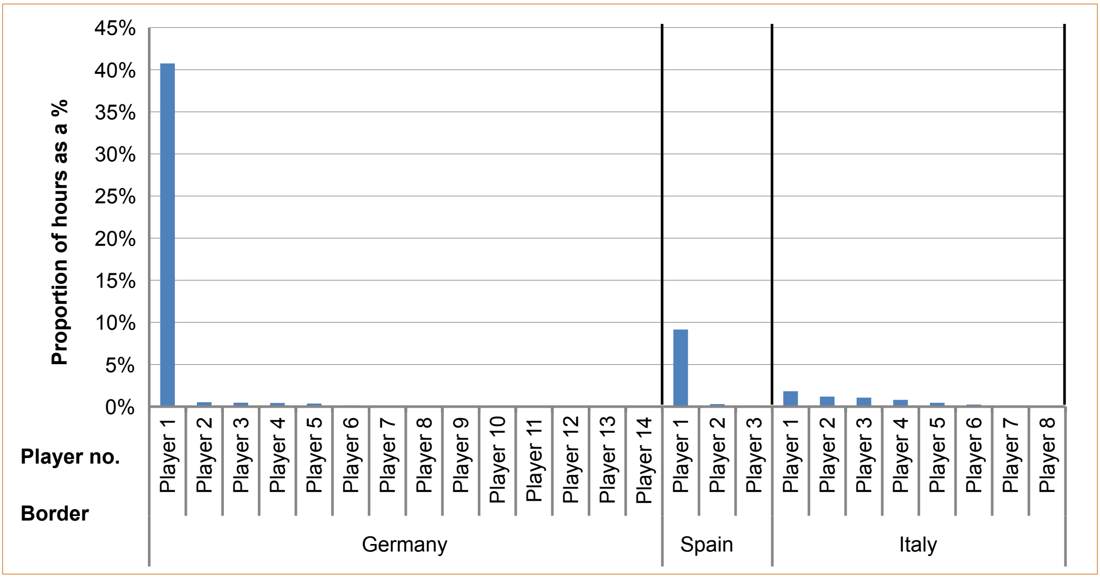
CRE has not observed behaviour intended to manipulate the market via daily-capacity nominations at the interconnections.

6.2.2 Nominations in both directions

CRE noted that some players nominated daily capacities for import and export simultaneously across the same border and for the same delivery time.

This is marginal behaviour for most players; nevertheless, one player uses it frequently at the German border, and one at the Spanish border.

Number of players who nominated in both directions for different borders; And proportion of time for which this behaviour was observed in 2007



Data: RTE; Analysis: CRE

CRE questioned the two players who made these nominations most frequently.

One of them said that it traded green certificates, and that for contractual reasons, it was required to nominate energy in both directions, whatever the differential in the electricity price.

The other player said that it had a long-term contract with a counterpart that required that energy was physically transferred to the other side of the border via the interconnection. When such contracts no longer give priority access to interconnections, players must acquire and nominate daily export capacities at the borders, irrespective of the market conditions.

7. EDF'S AUCTION OF VIRTUAL POWER PLANTS (VPPS)

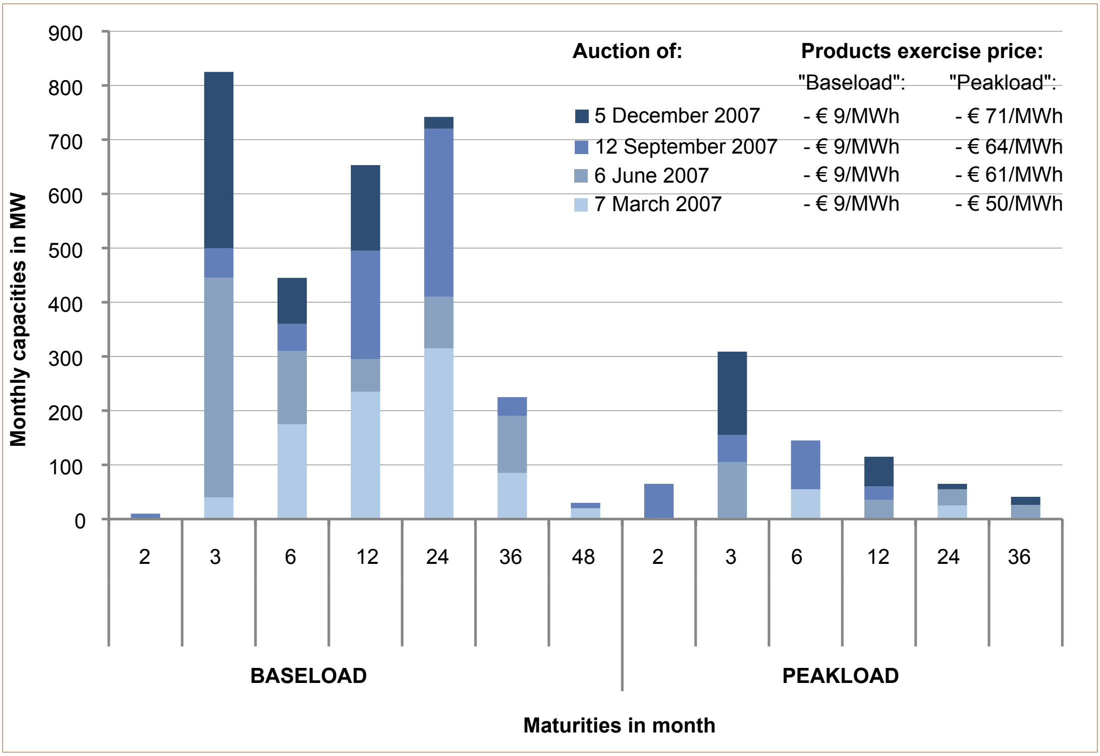
7.1 Auctions of VPPs in 2007

EDF organized four VPP auctions in 2007. They offered two types of product: "Baseload products" with a low strike price (thus comparable to firm products); and "Peakload" products with a high strike price (thus with value as an option).

During the auctions, the products most purchased were baseload products with a maturity of 3, 24, 12, or 6 months; and peakload products with a 3-month maturity.

Delivery of the offered products started at a time that depended on the auction date. For products sold in 2007, the delivery start dates were 1 April 2007, 1 October 2007, 1 November 2007 and 1 January 2008.

Monthly capacities sold at the four auctions held in 2007



Data: EDF; Analysis: CRE

Purchasers of VPPs in 2007

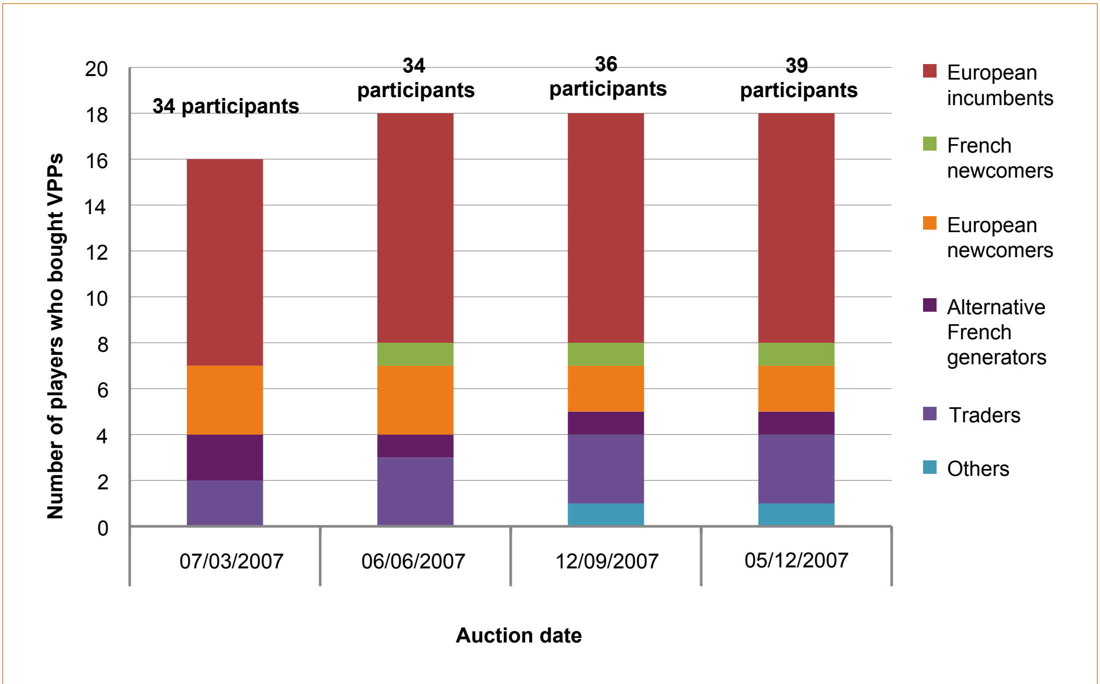
On average, 36 players participated in each auction and 16 of them bought a lot. Thus in 2007, 28 players made successful bids in the course of at least one auction.

Of those 28 players, half were European incumbents. 6 were traders, 4 newcomers to the European markets, 2 alternative French generators, and 1 a newcomer to the French market. The products that had an equivalent on the standardized wholesale market (i.e. non-optional and with a delivery period corresponding to one quarter or one calendar year) were mostly bought by traders. Peakload products were bought mainly by generators and suppliers of final customers.

Players who purchased lots in 2007 participated regularly in VPP auctions. Only 5 of the 28 businesses that purchased capacity in 2007 bought lots at only one auction. Two new participants in auctions won lots in 2007. Twenty of the 28 participants who bought lots in 2007 had already taken part in auctions in 2003.

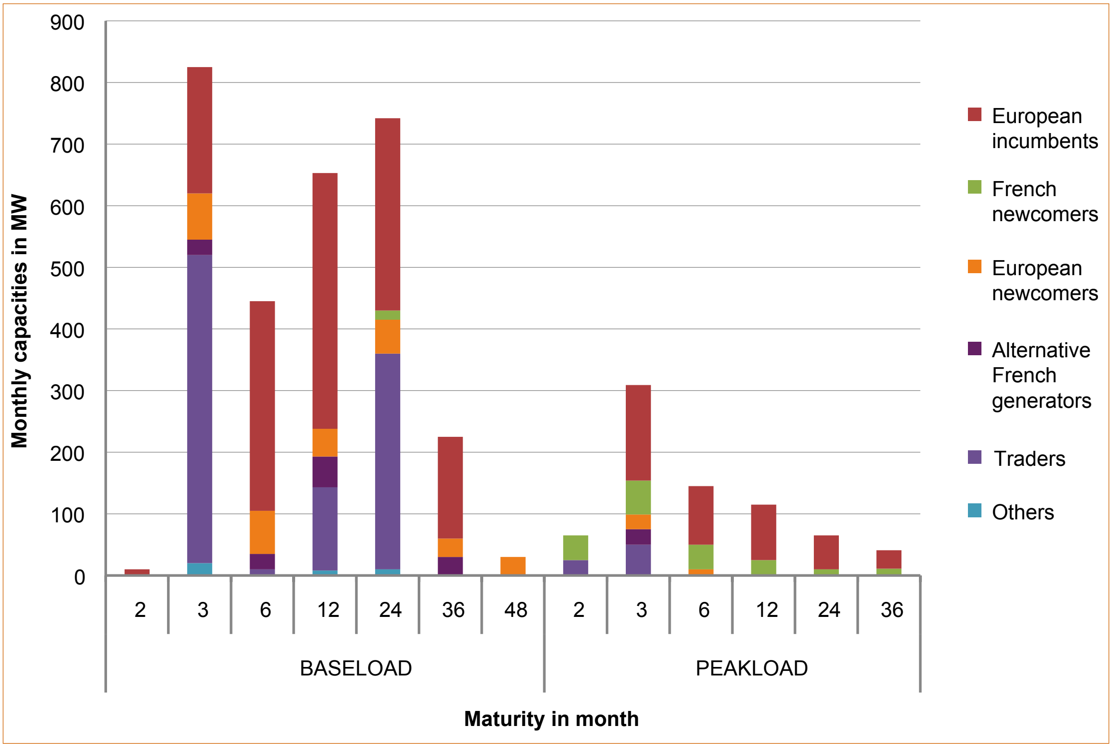
VPP purchases were moderately concentrated.

Number of participants and acquirers at auctions held in 2007

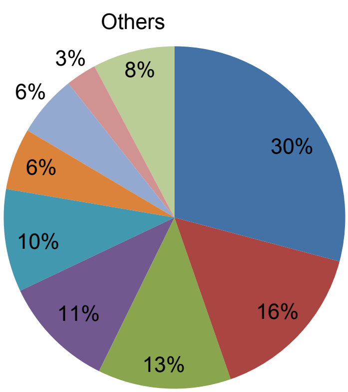


Data: EDF; Analysis: CRE

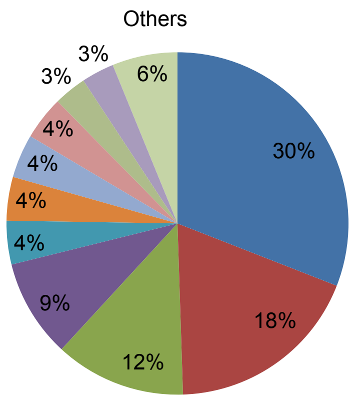
Capacities bought at the auctions



Market shares* for purchases at the VPP auction on 7 March 2007

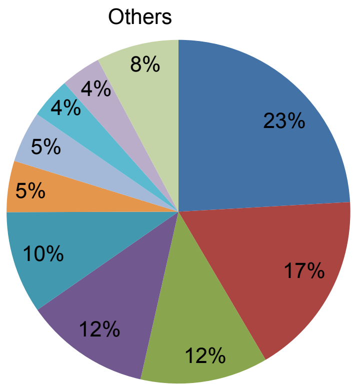


Market shares* for purchases at the VPP auction on 6 June 2007

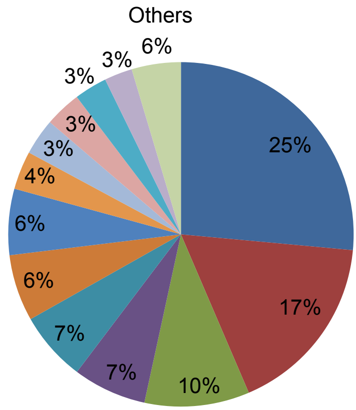


Data: EDF; Analysis: CRE

Market shares* for purchases at the VPP auction on 12 September 2007



Market shares* for purchases at the VPP auction on 5 December 2007



Data: EDF; Analysis: CRE

* In energy equivalent. Assumption: baseload products are used at 100% and peakload products at 50% of capacity

7.2 VPP prices in 2007

7.2.1 The VPP prices set by auction were aligned with prices on the futures market

If the auctions work properly, the VPP price should end up at a level that reflects the wholesale-market price at the time of the auction. CRE analyzed the relationship between the final price for all products, and the price on the markets most appropriate for costing the products, taking into account their option value.

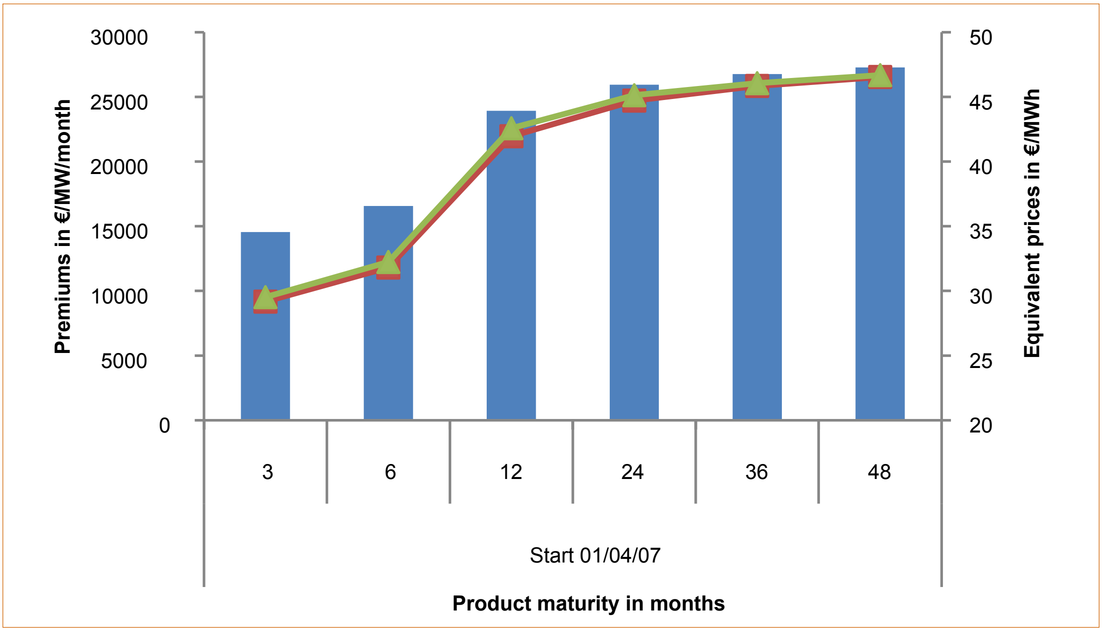
7.2.1.1 Setting prices for “Baseload” products

“Baseload” products have a low strike price (€9.18 /MWh for all auctions held in 2007). Day-ahead prices in France were higher than the strike price for 97% of the hours in 2007. This implies that the “optionality” value of these products is merely nil. Their price must therefore in theory be very close to the market price for equivalent baseload products.

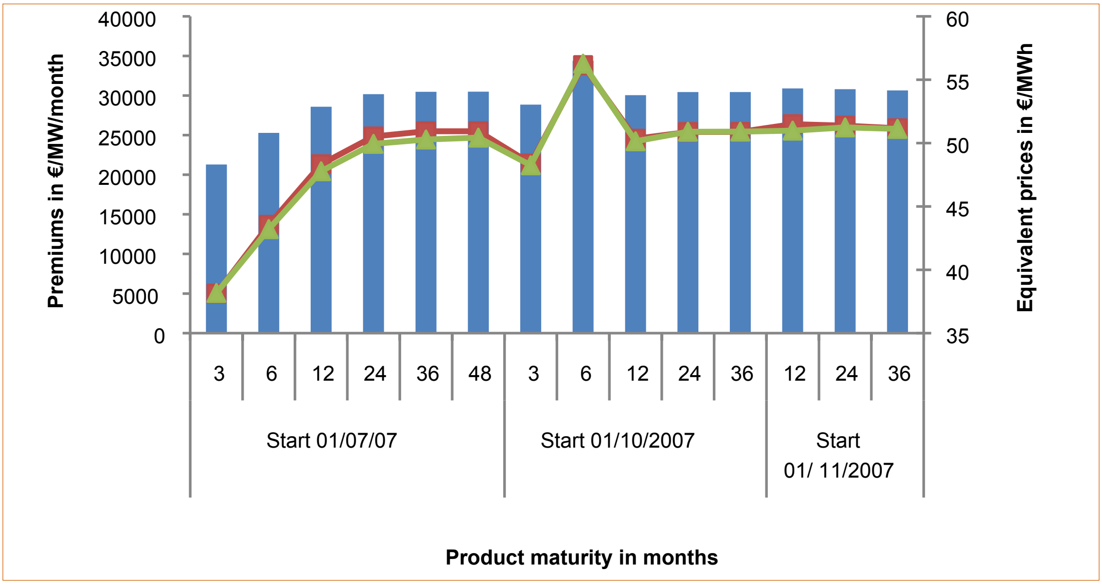
The graphs below confirm that the VPP prices were very close to the Powernext Futures prices for products equivalent to the baseload products sold at auction.

Final prices for baseload VPP in 2007 and Powernext Futures prices

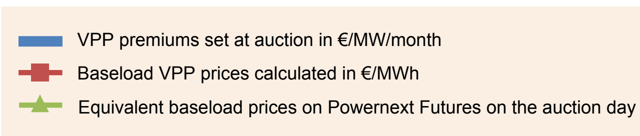
Auction of the 07/03/07



Auction of the 06/06/07

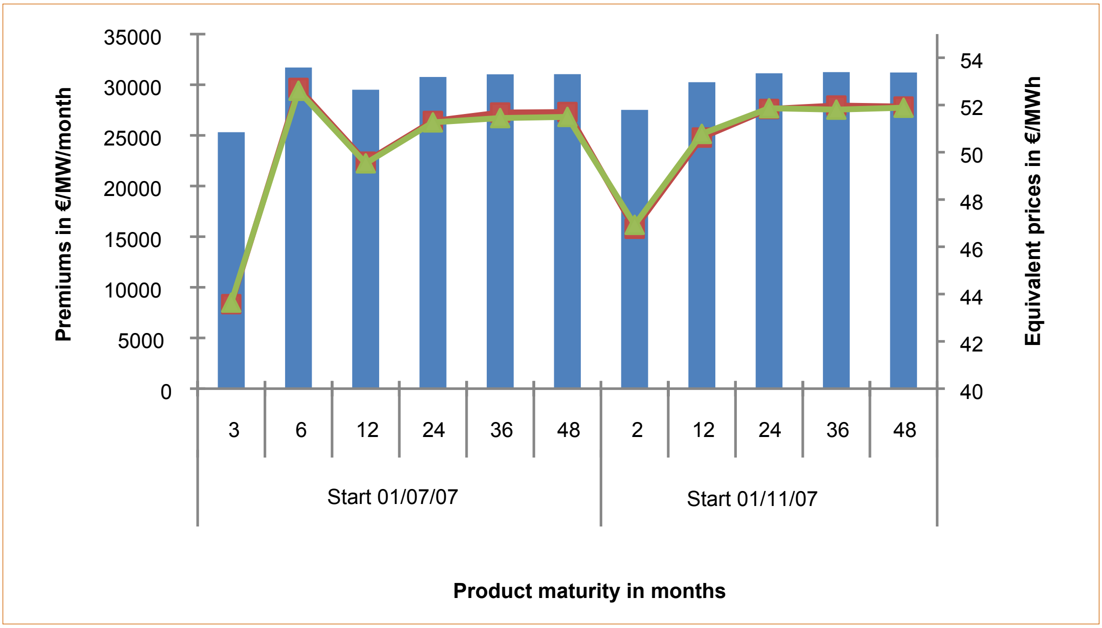


Data: EDF, Powernext; Analysis: CRE

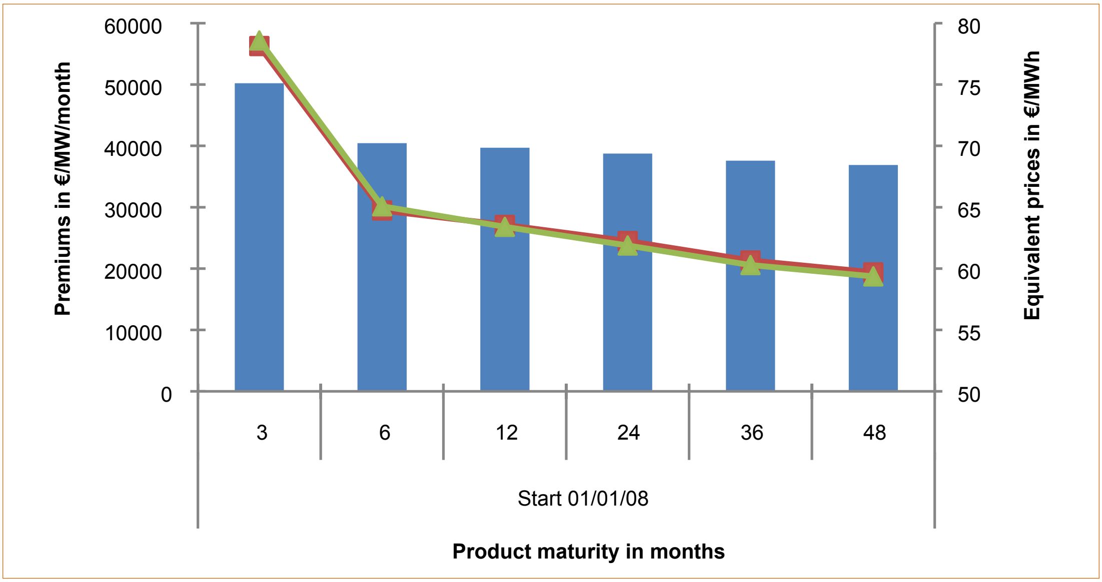


Final prices for baseload VPP in 2007 and Powernext Futures prices

Auction of the 12/09/07



Auction of the 05/12/07



Data: EDF, Powernext; Analysis: CRE

VPP premiums set at auction in €/MW/month
Baseload VPP prices calculated in €/MWh
Equivalent baseload prices on Powernext Futures on the auction day

7.2.1.2 Setting prices for "Peakload" products

Peakload products had a relatively high strike price (between €50.18 and €71.18 /MWh), which gave them a value as an option. This means that the value of such products depended on how market players anticipated future changes in day-ahead prices.

The analysis of prices set at auction for peakload products shows that market players expected a high volatility of prices during auctions in 2007 (an implicit volatility of around 85%).

The volatility of day-ahead prices as calculated post hoc is also very high (the average volatility of day-to-day prices over a month was around 70% between January 2007 and June 2008), and even higher than the anticipated volatility, hence the premiums set at auction.

The final price of peakload VPPs thus appears to have been consistent with market prices.

7.2.2 Futures prices sometimes rose in the run up to a VPP auction

For EDF, VPP auctions represent a certain sale at a date known in advance of a large volume of energy, at prices close to market prices.

CRE analyzed trading on the futures market in the run up to auctions.

Many market prices could affect the VPP final price. The dates for VPP delivery do not start on 1 January, and they have a range of maturities. Products that influence VPP price setting include not only products based on a calendar year, but also monthly and quarterly products.

The tables below show the movement in futures prices during the days preceding each auction.

AUCTION DATE	PERIOD OBSERVED BEFORE THE AUCTION DATE	VARIATION IN BASELOAD PRICES									
		M+1	M+2	M+3	Q+1	Q+2	Q+3	Q+4	Y+1	Y+2	Y+3
7/03/07	10 days before	9%	10%	ns	-1%	1%	2%	-2%	0%	-1%	-1%
	7 days before	14%	14%	ns	-1%	0%	0%	-3%	-2%	-2%	-1%
	3 days before	0%	-1%	-1%	-1%	0%	1%	-1%	0%	-1%	-1%
	1 day before	0%	-1%	-1%	-1%	0%	1%	-1%	0%	0%	0%
6/06/07	10 days before	-11%	-6%	ns	-7%	-5%	-2%	-3%	-1%	-1%	0%
	7 days before	-8%	-4%	ns	-4%	-4%	-1%	-3%	-1%	-1%	0%
	3 days before	-3%	-2%	-2%	-2%	-3%	-1%	-2%	-1%	-1%	0%
	1 day before	-2%	0%	1%	0%	-1%	0%	-1%	0%	0%	0%
12/09/07	10 days before	2%	-1%	ns	1%	1%	2%	2%	1%	1%	0%
	7 days before	2%	0%	2%	1%	1%	1%	1%	0%	1%	0%
	3 days before	1%	0%	1%	1%	0%	1%	1%	0%	0%	0%
	1 day before	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5/12/07	10 days before	-2%	-2%	ns	-3%	1%	-1%	0%	-1%	1%	1%
	7 days before	1%	0%	ns	0%	1%	0%	0%	0%	1%	1%
	3 days before	3%	1%	-1%	1%	2%	1%	1%	1%	1%	1%
	1 day before	2%	2%	1%	2%	-2%	-1%	-1%	0%	0%	0%

Data: Powernext; Analysis: CRE

AUCTION DATE	PERIOD OBSERVED BEFORE THE AUCTION DATE	VARIATION IN PAEKLOAD PRICES									
		M+1	M+2	M+3	Q+1	Q+2	Q+3	Q+4	Y+1	Y+2	Y+3
7/03/07	10 days before	0%	3%	ns	1%	1%	0%	-1%	1%	1%	2%
	7 days before	14%	17%	ns	0%	0%	-1%	-2%	0%	0%	1%
	3 days before	0%	2%	0%	1%	2%	0%	-1%	0%	0%	1%
	1 day before	0%	-1%	1%	0%	1%	0%	-2%	0%	0%	0%
6/06/07	10 days before	-15%	-8%	ns	-9%	-4%	-1%	-2%	-2%	-1%	-1%
	7 days before	-10%	-5%	ns	-6%	-3%	-1%	-2%	-2%	-1%	-1%
	3 days before	-3%	-2%	0%	-2%	-1%	0%	-1%	-1%	0%	0%
	1 day before	0%	2%	2%	1%	0%	0%	0%	0%	0%	0%
12/09/07	10 days before	1%	-3%	ns	-1%	0%	-1%	0%	0%	0%	1%
	7 days before	2%	-2%	0%	0%	0%	0%	1%	0%	0%	1%
	3 days before	0%	-1%	1%	0%	0%	0%	1%	0%	0%	0%
	1 day before	1%	1%	1%	1%	0%	0%	1%	0%	1%	0%
5/12/07	10 days before	-3%	-1%	ns	-2%	-1%	-2%	1%	-1%	0%	0%
	7 days before	1%	2%	ns	1%	-1%	-1%	0%	0%	0%	0%
	3 days before	5%	4%	1%	3%	-1%	0%	1%	1%	0%	1%
	1 day before	4%	2%	-4%	1%	2%	1%	1%	1%	1%	0%

Data: Powernext; Analysis: CRE

If a product was not quoted during the period before the auction, the figure was considered to be not significant (ns).
For instance, for the auction on 7 March, the product "June 2007" was not listed before the beginning of March.

In almost all cases where prices rose by more than 2%, we observed no significant trading by EDF. However, in the run up to some auctions, CRE identified trading by EDF that coincided with sharp rises in the prices of the products M+1, M+2, M+3, and Q+1.

8. SALES OF LOSSES TO NETWORK OPERATORS

8.1 Sales of losses to network operators in 2007

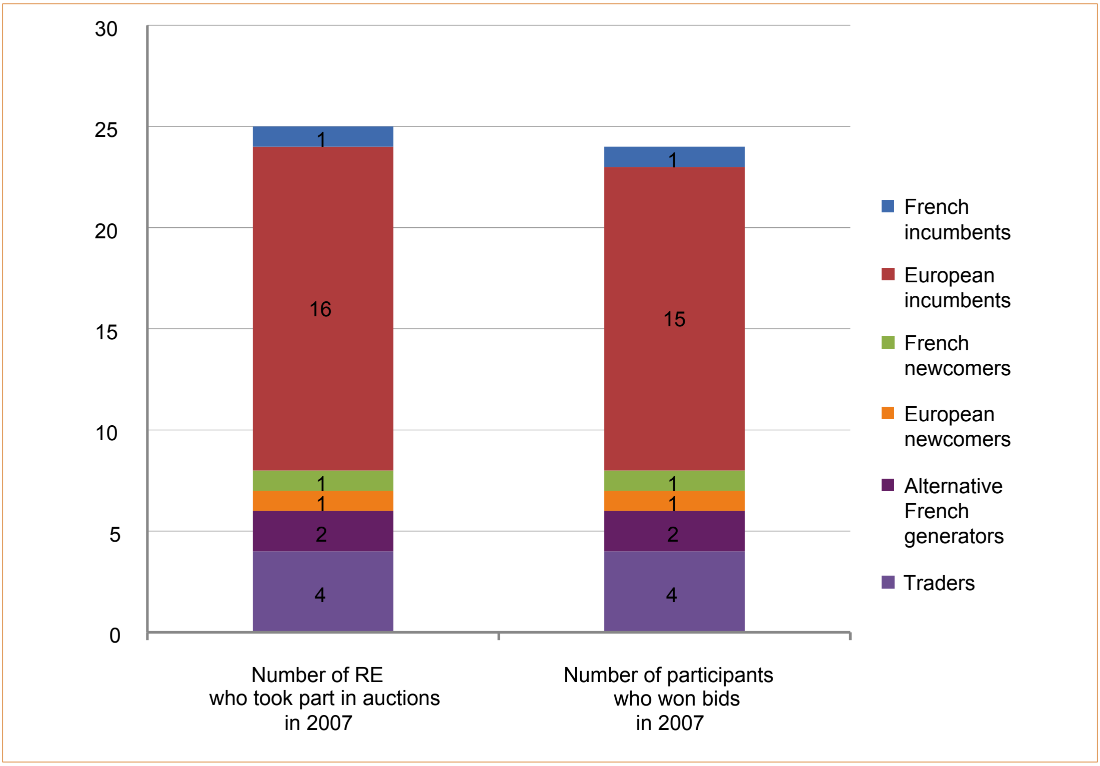
The transmission system operator (RTE) and the distribution system operator (ERDF) arrange tenders several times each month in order to buy products to cover losses in their network. In 2007, the two system operators organized 121 invitations to tender. In 2007, the system operators contracted 39 TWh as firm products and the equivalent of 18 TWh as optional products. The system operators bought monthly (M+1 to M+18), quarterly (Q+1 to Q+4), and annual (Y+1 to Y+4) products.

8.2 Sellers of losses to network operators in 2007

Most of those participating in the tenders and the sellers selected were French and European incumbents. Sales of firm products were not concentrated.

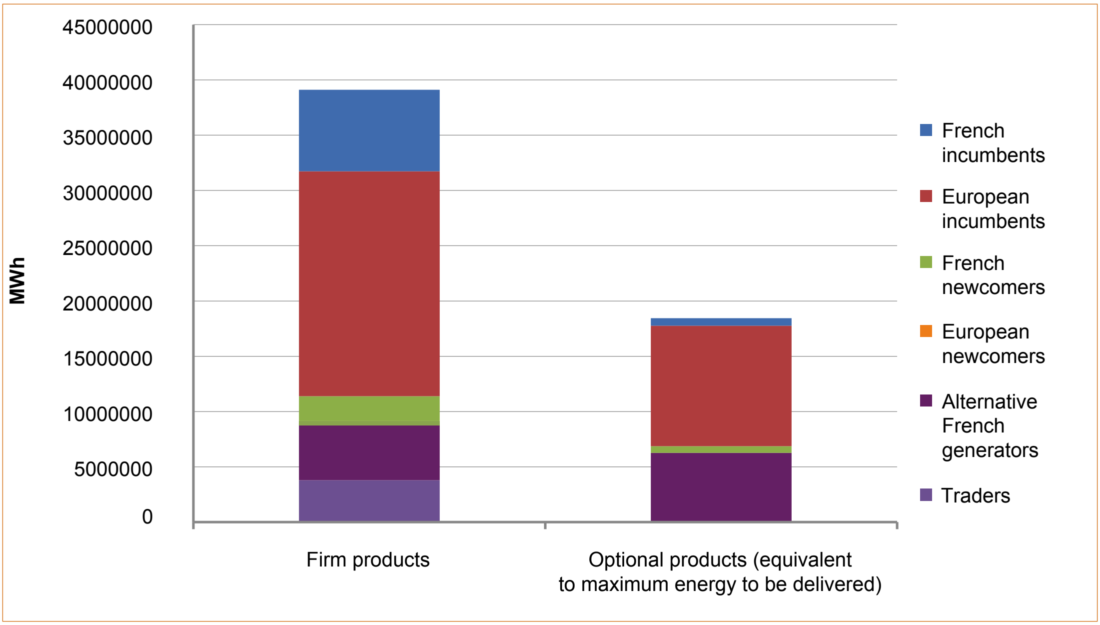
Two alternative French generators accounted for one quarter of the sale of optional products. Sales of optional products were highly concentrated.

Number of participants in tenders held in 2007



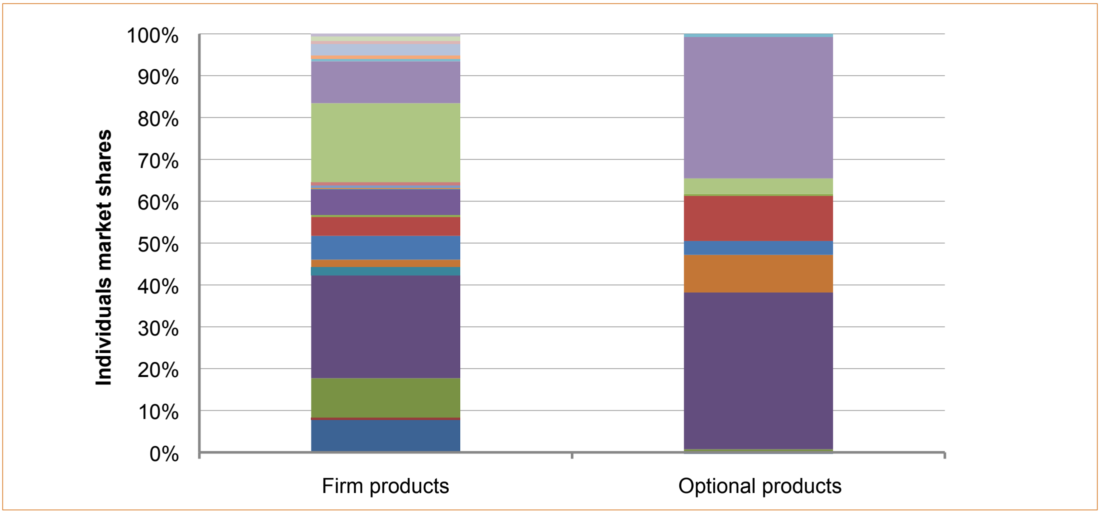
Data: RTE, ERDF; Analysis: CRE

Energy* sold during tenders held in 2007



Data: RTE, ERDF; Analysis: CRE

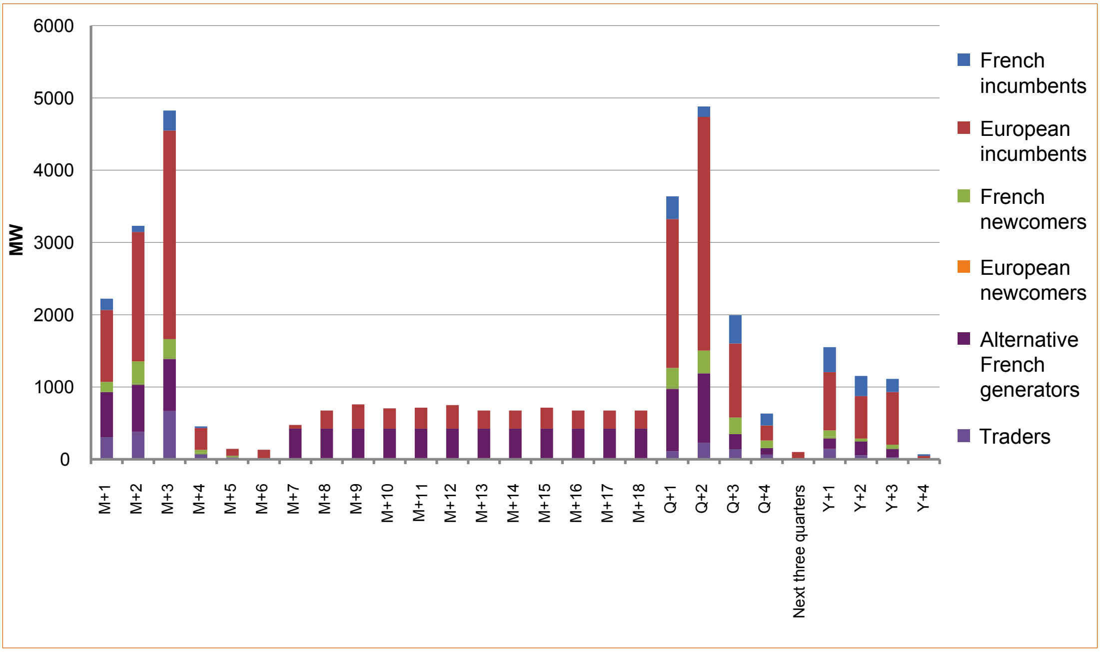
Shares of energy* sold to network operators in 2007



Data: RTE, ERDF; Analysis: CRE

* Assumption: optional products are used at 100% of capacity

Split capacities sold to network operators in 2007 by product



Data: RTE, ERDF; Analysis: CRE

DETAILED REPORT
GAS

1. THE DEVELOPMENT OF TRADING IN FRANCE

1.1 The development of trading and market structure

Activity on the French wholesale market relates mainly to:

- optimization. Holders of import contracts and producers want to optimize the flexibility of their procurement and the transmission and transit capacities that they reserve,

- hedging. Suppliers want to cover the forecast consumption of their final customers,

- trading transactions. These may be either to exploit arbitrage in the cross-border markets or to adopt a speculative position.

The presence of a dominant player in gas procurement and supply, GDF Suez, and the pronounced vertical integration between upstream activities and supply, diminishes in structural terms the level of trading activity by holders of import contracts and suppliers to the French wholesale market.

1.2 Trading activity, liquidity and concentration

CRE has compared the volumes exchanged in the intermediated market (via broker platforms) with the volumes delivered to the Gas Exchange Point, and notes that in 2007, most transactions on the French wholesale market were bilateral contracts with no intermediary.

CRE reviewed activity on the principal broker platforms active in France, but did not collect data on bilateral transactions, and thus has been able to analyze only a small part of the French wholesale market (this analysis is discussed in paragraph 1.2.1).

It cannot therefore form an opinion on changes either to the liquidity or level of concentration in this market. However, it has reviewed (see paragraph 1.2.2), observed deliveries to the Gas Exchange Points, in order to establish if the conclusions from the intermediated market could be applied more generally to the market as a whole.

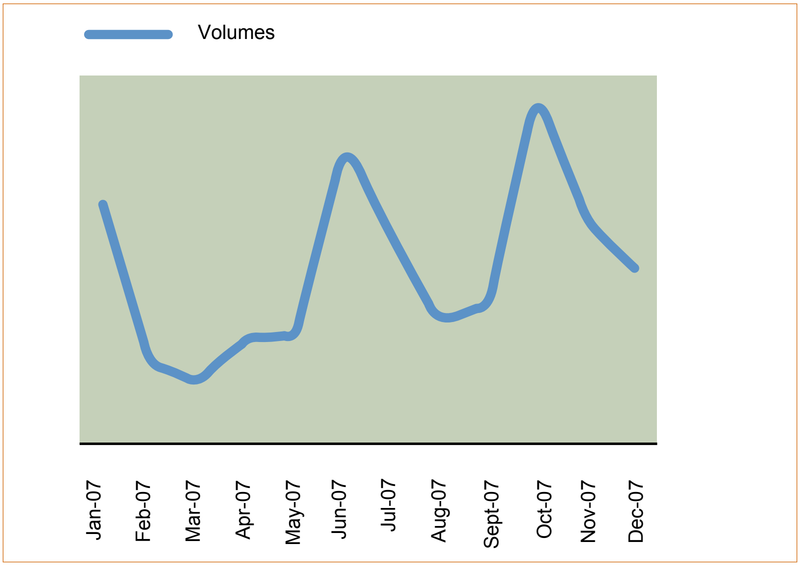
1.2.1 The intermediated market

CRE notes that although the physical size of the French intermediated market is limited, volumes exchanged on the market grew throughout the year.

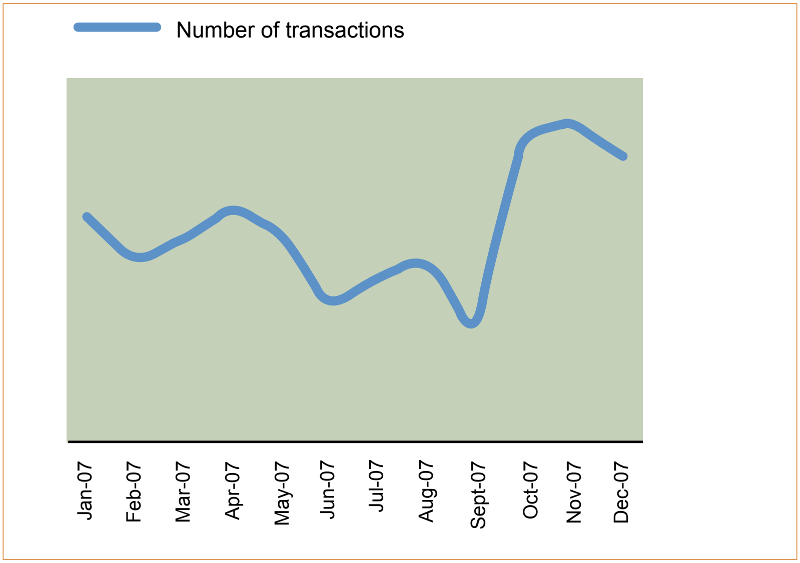
Volumes exchanged on the intermediated market in 2007 remained well below 10% of national consumption. The number of transactions per month usually fluctuated between 100 and 400.

The following graphs show the monthly trends in volumes and in number of traded transactions, on the intermediated French wholesale market in 2007. In order to keep confidential market-share information relating to the (very few) brokers active on the French market, CRE does not show scales for the y-axes.

Monthly trends in volumes negotiated on the intermediated market in 2007



Monthly trends in numbers of transactions on the intermediated market in 2007



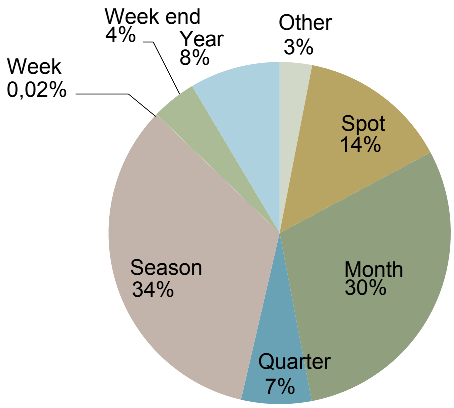
Data: Brokers; Analysis: CRE

Liquidity increased throughout 2007, on both the day-ahead and the futures market. This trend was even more marked in 2008.

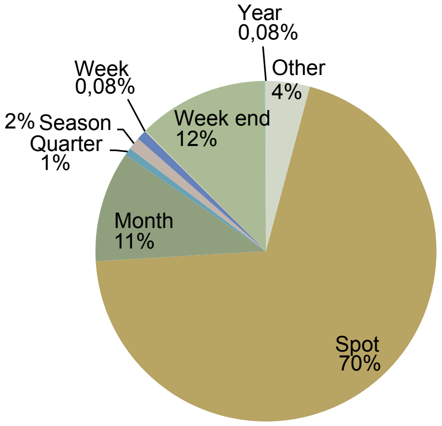
Around 70% of transactions related to spot products (intraday and day-ahead). The remainder related mainly to monthly products. There were few transactions relating to long-term products.

Seasonal and monthly products accounted for more than 60% of the volumes exchanged. They were followed by day-ahead products (almost 15%) and annual products (less than 10% of the volume traded).

Split by maturity (measured as volumes) on the intermediated market in 2007



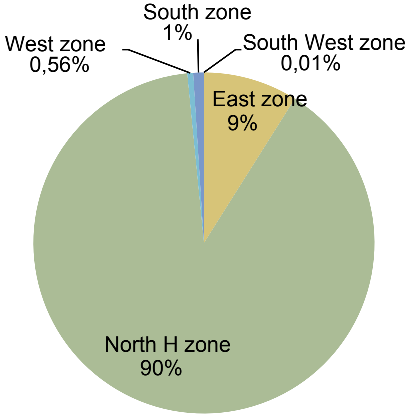
Split by maturity (measured as transaction numbers) on the intermediated market in 2007



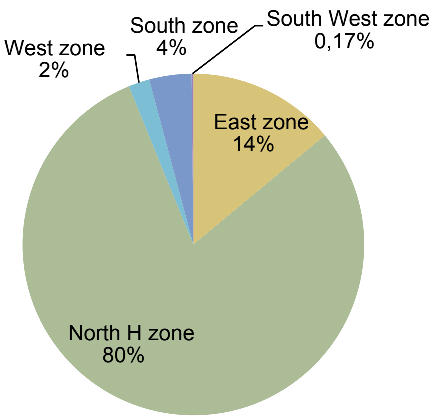
Data: Brokers; Analysis: CRE

Almost all the activity (80% by transaction numbers, 90% by volume) concerned North-H zone, and to a much lesser extent the East zone (13% by transaction numbers, 9% by volume).

Split by delivery zone (measured in volumes) on the intermediated market in 2007



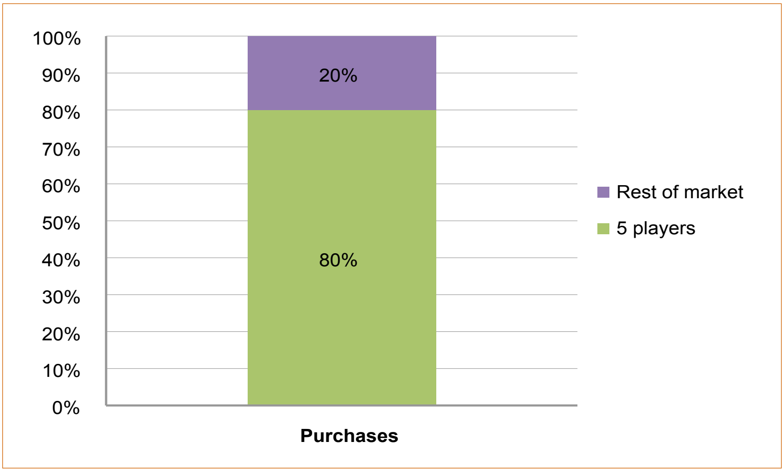
Split by delivery zone (measured in transaction numbers) on the intermediated market in 2007



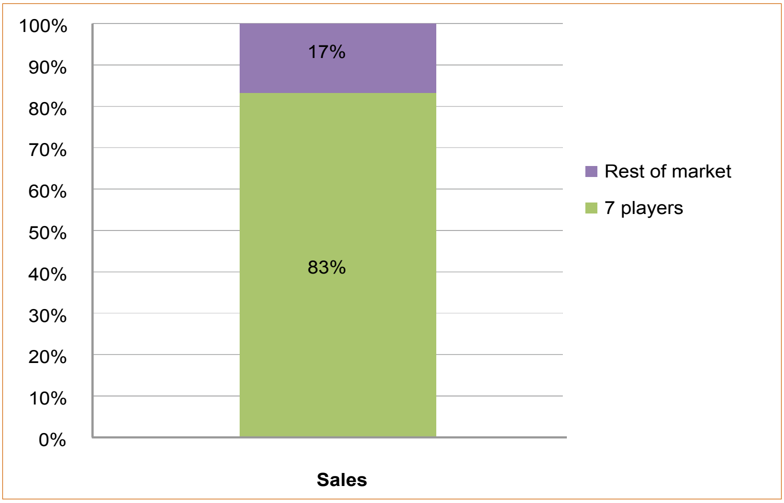
Data: Brokers; Analysis: CRE

The exchanges were not particularly concentrated. Seven players accounted for 83% of the volumes sold, and five players accounted for 80% of purchases. It should be noted that GDF Suez was not a dominant operator on the intermediated market in terms of transaction volumes.

Concentration level (in purchase volumes) on the intermediated market in 2007



Concentration level (in sales volumes) on the intermediated market in 2007



Data: Brokers; Analysis: CRE

1.2.2 Analysis of deliveries at Gas Exchange Points (*Points d'Echange de Gaz - PEG*)

Changes in wholesale-market liquidity cannot be calculated exactly from nominations at Gas Exchange Points.

This is because the PEG nominations made on a particular date reflect the net delivery volume resulting from all previous transactions, not just the transaction volumes traded on the market at that date.

In addition, the volumes delivered to the PEGs are the summed volumes both from short-term trading (whether or not intermediated), and from medium- and long-term contracts (e.g. Gas release programme, or long-term agreements between Gaz de France and Total, etc.).

Nevertheless, CRE notes that in 2007, PEG nominations increased much faster than did deliveries from trading simply on intermediated market. It therefore seems possible to apply the observations made on the intermediated market more generally to the entire bilateral market:

- the number of players grew, with 27 shippers making at least one delivery in December 2007, as against 23 in January 2007. Shippers who started their activity in 2007 were for the most part trading companies and newcomers,

- the market, although limited in size compared with French consumption, was expanding (for instance, at the end of 2007),

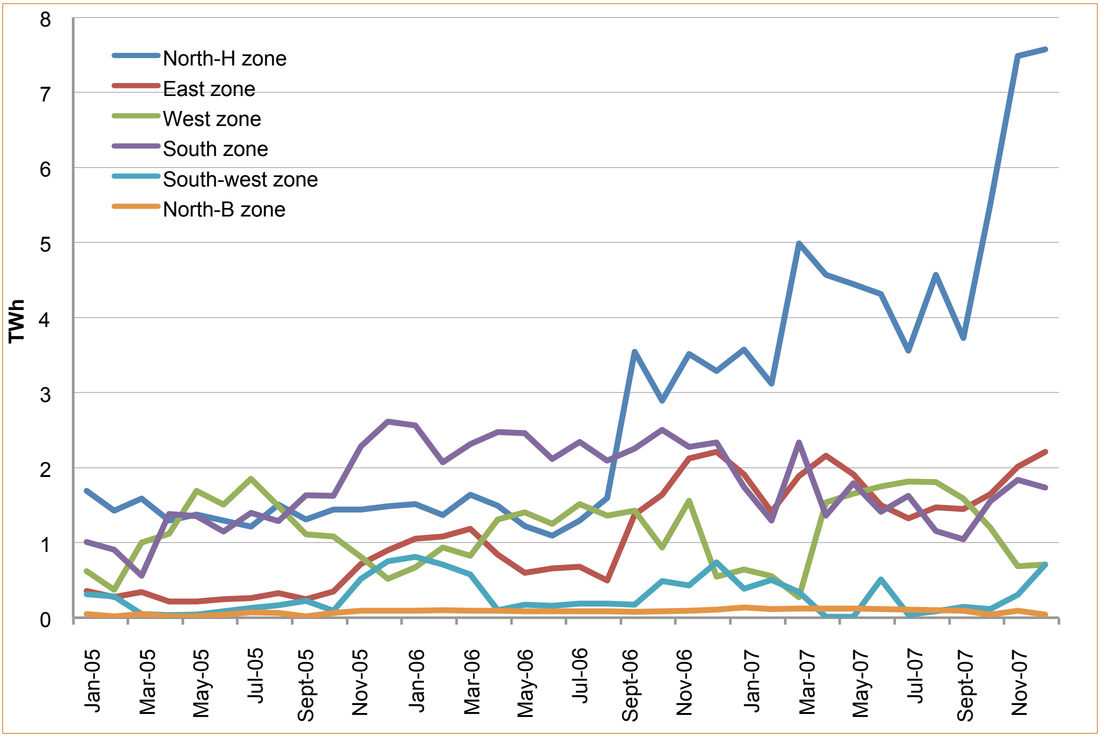
- activity was concentrated in the North-H zone and, to a lesser extent, the East zone,

- the share of total deliveries taken by alternative operators increased significantly.

Volumes delivered between operators on the French market grew strongly between 2006 and 2007. In the fourth quarter of 2006, around 28 TWh was exchanged; by the fourth quarter of 2007, the figure had reached 39 TWh. Activity related to balancing by GRTgaz represented less than 1% of the volumes traded.

As the following graph illustrates, growth was particularly marked in the North-H zone, where delivered volumes more than doubled during the year. The North-H PEG is thus now the primary exchange point in the French market: it delivered 20.6 TWh during the fourth quarter of 2007. In the other PEGs, activity over the same period grew little or not at all.

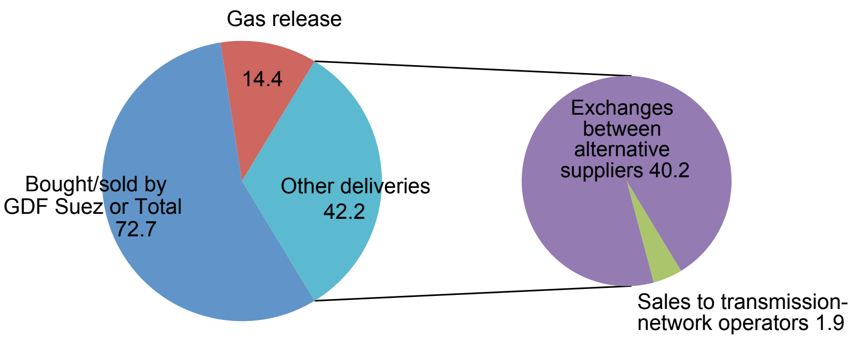
Deliveries at Gas Transfer Points (PEG)
Excluding gas-release deliveries



Data: GRTgaz and TIGF; Analysis: CRE

Deliveries on the French market in 2007 remained highly concentrated: 56.3% of the volumes delivered between operators in 2007 were sold or purchased by GDF Suez or Total. Only 31.1% of deliveries therefore resulted from transactions between alternative suppliers. The graph below gives details of the nominated deliveries at the various PEGs in 2007.

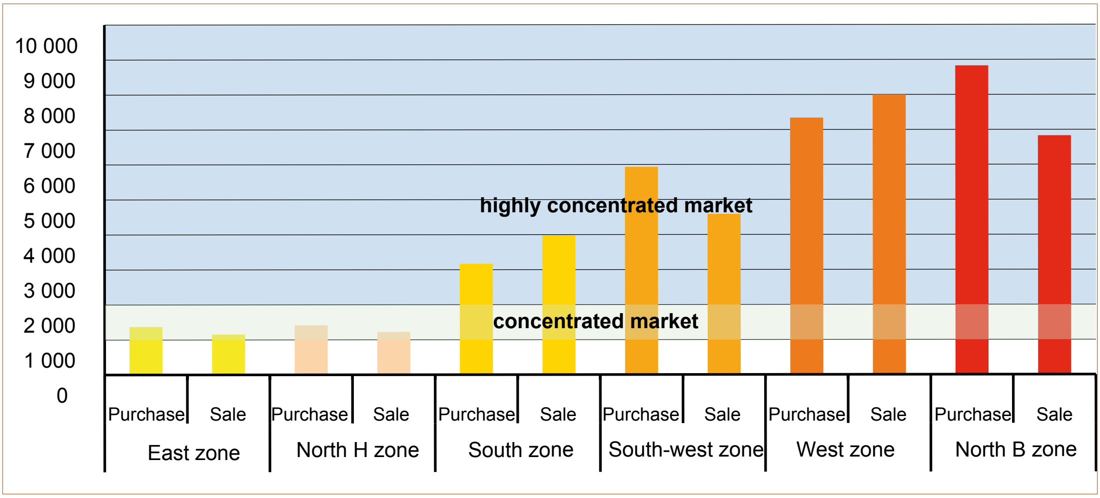
Deliveries between operators on the French wholesale market in 2007 (TWh)



Data: GRTgaz and TIGF; Analysis: CRE

The graph shows the concentration of purchases (withdrawals) and sales (deliveries) at the six PEGs. The most liquid PEGs (North-H and East) are also those where purchases were least concentrated. On the other hand, sales were very concentrated in all zones except the East. The concentration index used is the Herfindahl-Hirschman Index (HHI).

Concentration index (HHI) for deliveries to PEGs in 2007
Excluding gas-release deliveries



Data: GRTgaz and TIGF; Analysis: CRE

The higher concentrations observed in the South, West, South-west and North-B zones should, however, be viewed in the light of the low volumes exchanged in these zones.

2. EVOLUTION OF DAY-AHEAD PRICES

2.1 Movements in price

The year 2007 was characterized by a period when day-ahead prices dropped for the North PEG, followed by a period when they climbed sharply.

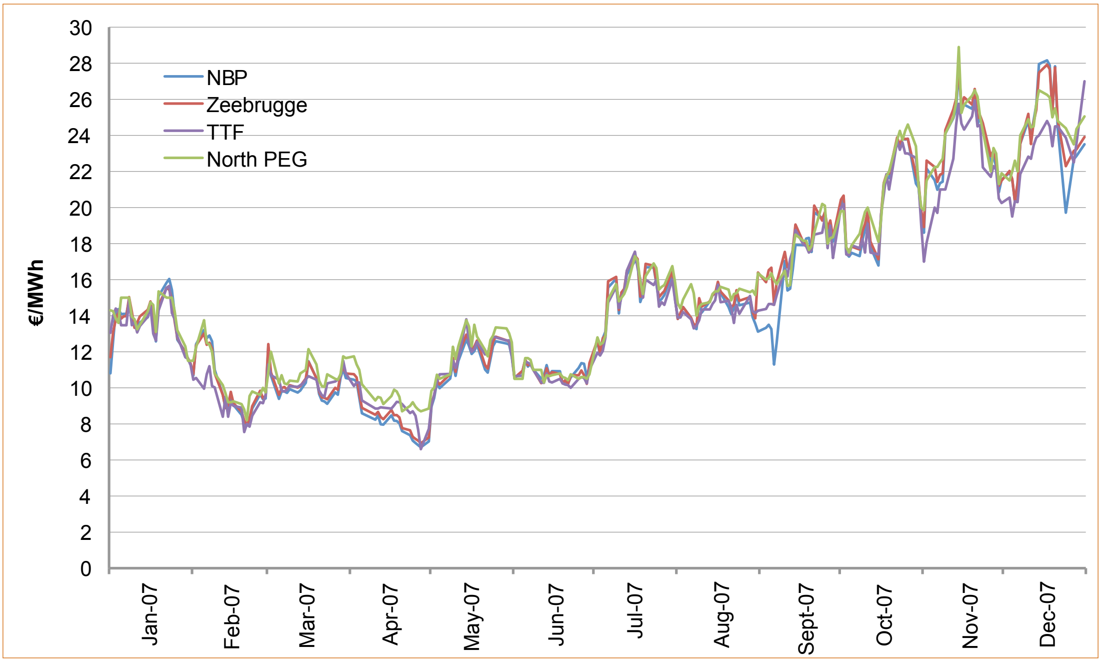
Prices fell between January and April 2007, moving from €14 /MWh to less than €10 /MWh. By contrast, during the subsequent eight months they rose sharply, reaching an average of almost €25 /MWh in December.

Monthly average day-ahead prices for the North PEG in 2006 and 2007

Data: Argus; Analysis: CRE

Prices at the North PEG remained very close to and overall higher than those at Zeebrugge. Between January and April 2007, the price spread became more marked, rising from € 0.3 /MWh to € 1.2 /MWh (averaged over the month). It then gradually reduced, reaching € 0.1 /MWh in December 2007.

Day-ahead prices in 2007

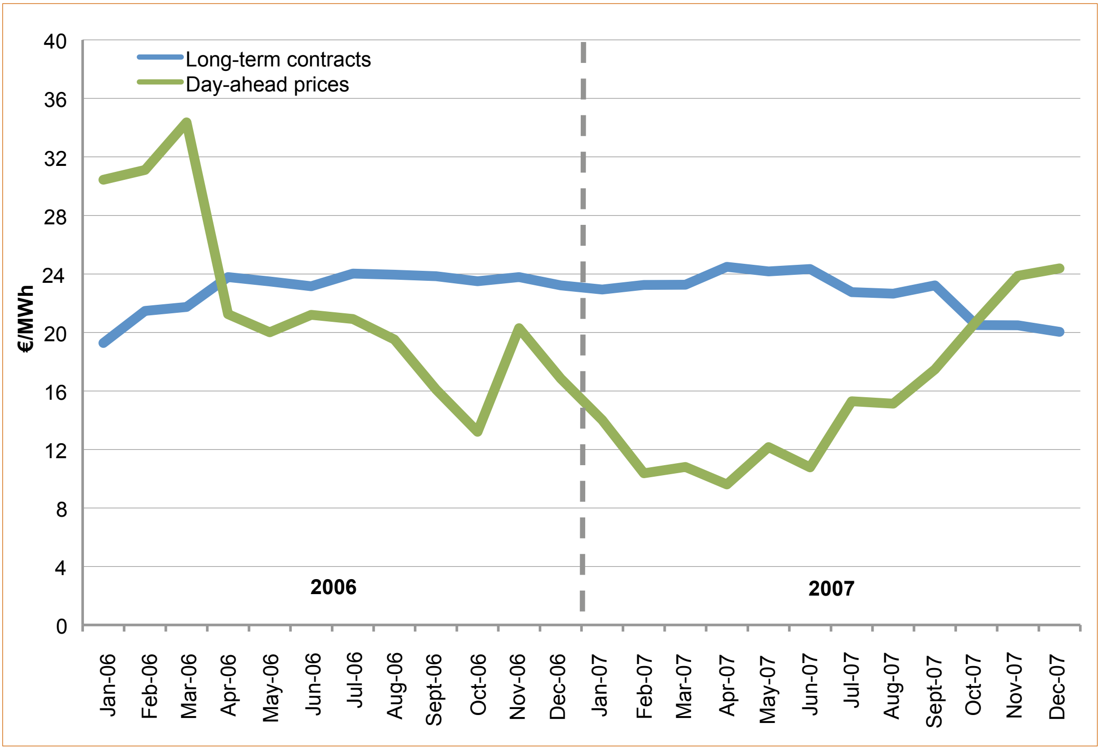


Movement in price spread between Zeebrugge and the North PEG between January 2006 and December 2007

Data: Argus; Analysis: CRE

Throughout 2007, day-ahead prices remained on average € 7/MWh less expensive than prices based on long-term contracts. During the first three quarters of 2007, if operators were able and wished to make daily arbitrage deals (capped by the volumes offered on the market), it was generally better for them to buy gas on the French day ahead markets than to rely on long-term import contracts. From October 2007, the differential between day-ahead prices and prices for long-term contracts reversed.

Comparison of day-ahead prices at the North PEG and prices in long-term contracts: January 2006 and December 2007



Data: Heren, Argus; Analysis: CRE

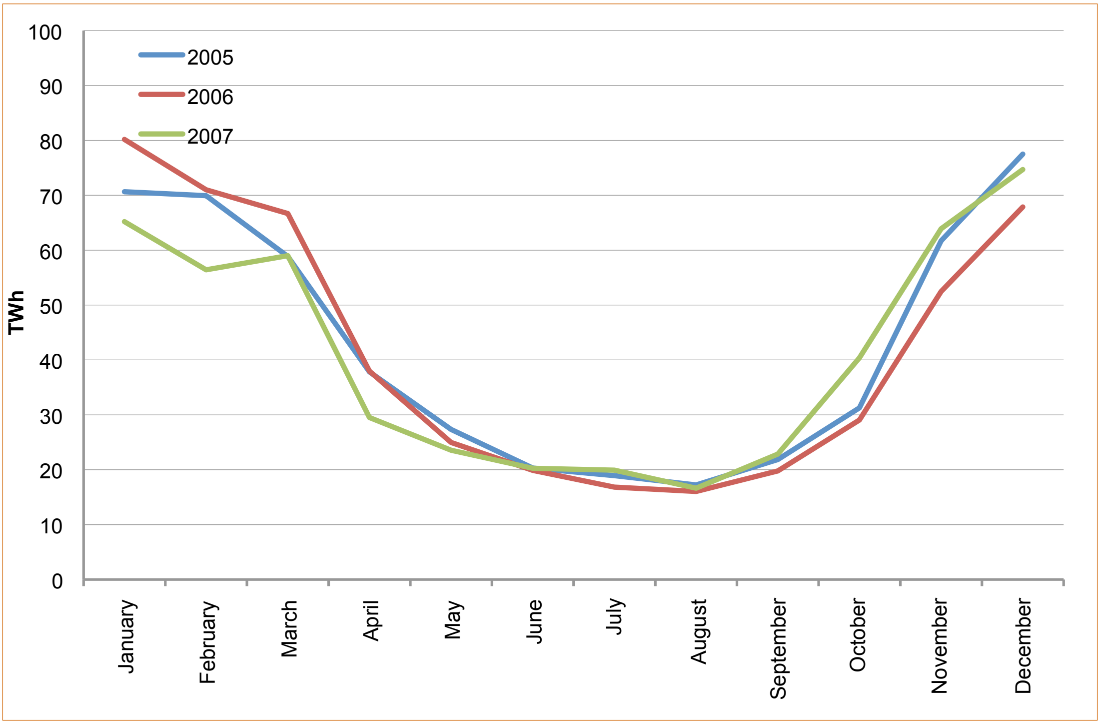
2.2 Correlation with evolution of the balance of supply and demand

CRE analyzed movements in the price spread between the North PEG and the Zeebrugge and NBP markets; and the link with the physical balance between supply and demand on the French market.

CRE noted from an initial analysis that movements both in French prices at the North PEG and in the difference between those prices and prices at Zeebrugge and NBP were generally in line with evolution of the balance of supply and demand on the French market (consumption and storage).

- Since the winter of 2006-2007 was particularly mild, consumption during the first quarter of 2007 was significantly lower than those of previous years for the same period (down 17.1% compared with 2006; and down 9.4% compared with 2005).

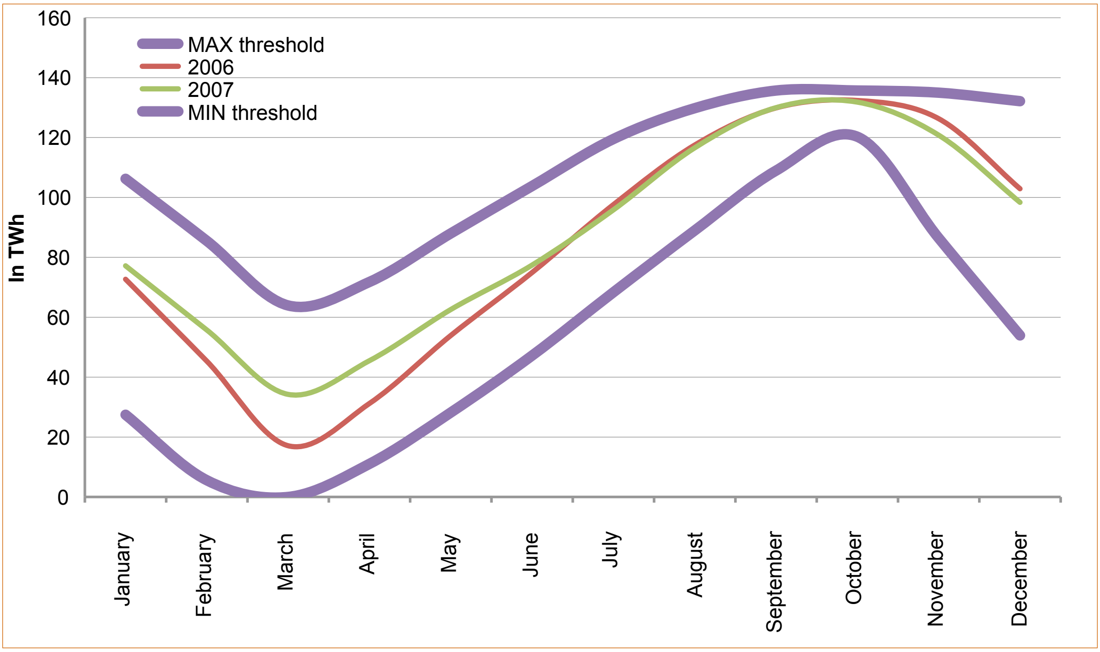
Consumption of final customers on the French market



Data: GRTgaz and TIGF; Analysis: CRE

- Data on storage confirms this analysis. Storage levels during the first quarter of 2007 reached values that were high compared with the past (up 23.7% compared with 2006).

Level of natural-gas stocks



Data: GDF Suez and TIGF; Analysis: CRE

- Consumption during the subsequent three quarters was then generally in line with levels in 2005, and storage levels returned near to those recorded for 2006.

3. PLAYERS' SOURCES OF SUPPLY AND OUTLETS

CRE analyzed the structure of sources of supply and outlets for all those active in the French gas market.

It observed that during 2007, the activity of all types of players increased markedly.

It identified fundamental and persistent differences between the position of suppliers who were European incumbents and other suppliers, referred to in this document as "newcomers". Newcomers rely only marginally on imports for their supplies. They acquire most of their gas on the French market, directly from incumbent suppliers.

CRE is analyzing players' future purchases and sales, based on information collected during summer 2008 on transactions agreed in 2007 relating to calendar and seasonal products for 2008 and 2009. It is analyzing in particular how the end of the gas release programmes affects how alternative suppliers source supplies and grow their activity.

3.1 European incumbents

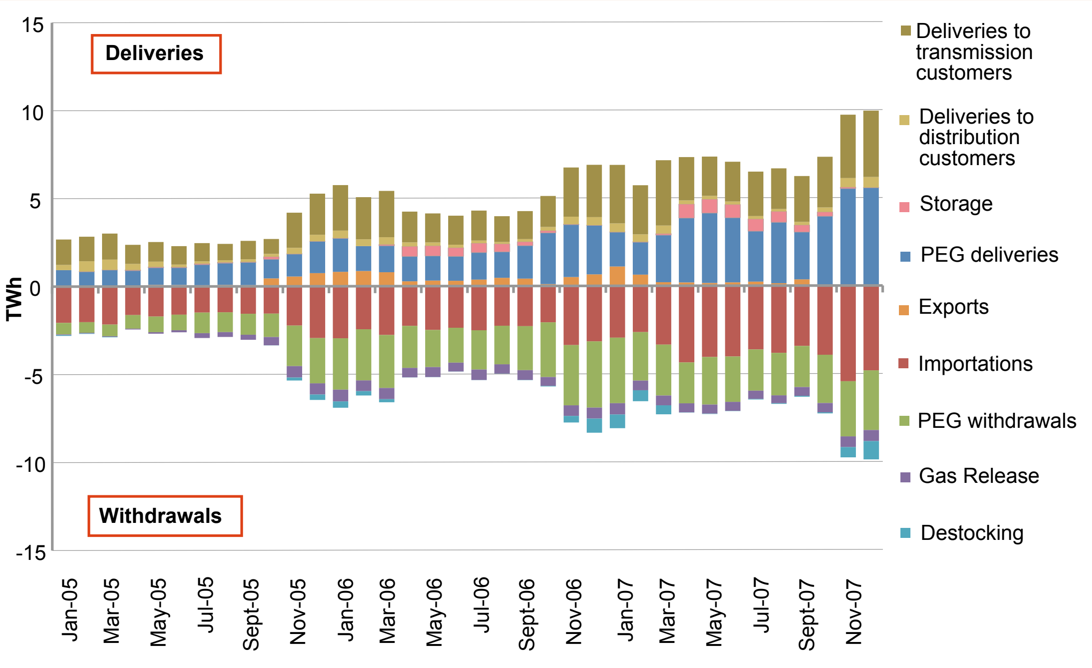
The activity of foreign incumbents based in France represents only a limited proportion of delivered volumes (88TWh of withdrawals and deliveries), but has risen by over 45% in one year.

Foreign incumbents suppliers procure their supplies as follows:

- over half import natural gas at the various French entry points,
- in addition, they purchase in France from a limited number of counterparties, generally other incumbents: French or European,
- some foreign incumbents source a significant part of their supply from the gas release programme set up in 2005 in the South and South-West zones.

These operators use the gas mainly as follows:
- they supply final customers, who are normally connected to the transmission network,
- to an increasing extent, they resell it on the French wholesale market.

Deliveries by foreign incumbents



Data: GRTgaz and TIGF; Analysis: CRE

3.2 Newcomers

The activity of newcomer suppliers in France represents only a limited proportion of delivered volumes (13TWh of withdrawals and deliveries), but has risen by over 60% in one year.

Newcomer suppliers organize their procurement as follows:

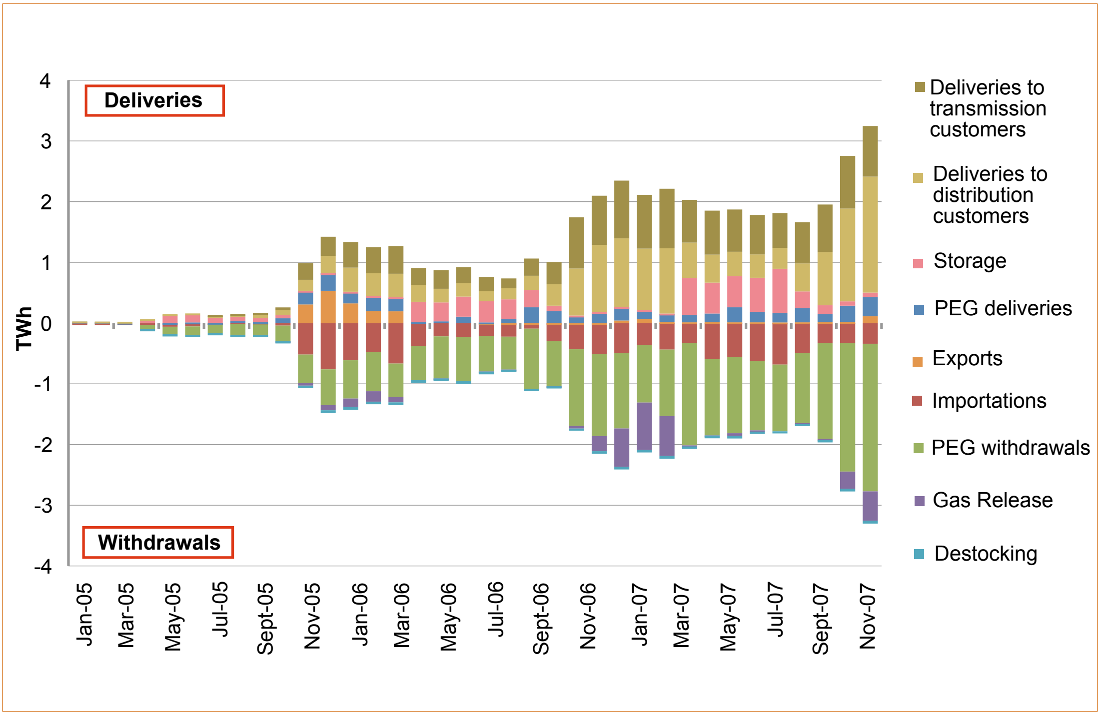
- they purchase supplies mostly from a limited number of French and European incumbents,

- some players use the gas release programme set up in 2005,

- some very few players, and to a very limited extent, import supplies.

These players use the gas mainly to supply final customers connected to the transmission or distribution networks.

Deliveries by newcomers



Data: GRTgaz and TIGF; Analysis: CRE

3.3 Trading companies

The principal activity of trading companies is the purchase of gas for resale on the French and European wholesale markets. Some companies also make use of storage capacity obtained at auctions organized by storage operators.

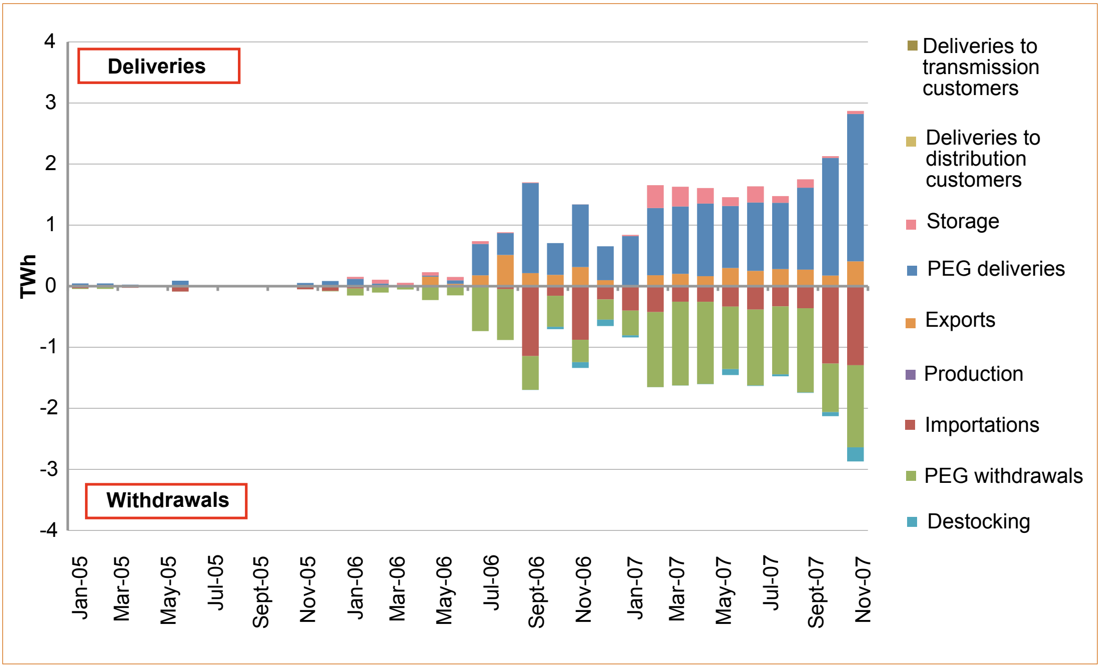
The activity of trading companies in France represents only a limited proportion of the delivered volume (19TWh of withdrawals and deliveries), but has almost quadrupled in one year.

Trading companies purchase:

- mainly on the French wholesale markets (PEGs), from a variety of different counterparties,
- to a lesser extent, but increasingly, on other European markets, particularly on the other side of the Belgian border.

These companies resell the gas:
- mainly on the French wholesale markets (PEGs), to a variety of different counterparties,
- to a lesser extent, on other European markets, particularly on the other side of the Belgian, German and Swiss borders.

Deliveries by trading companies

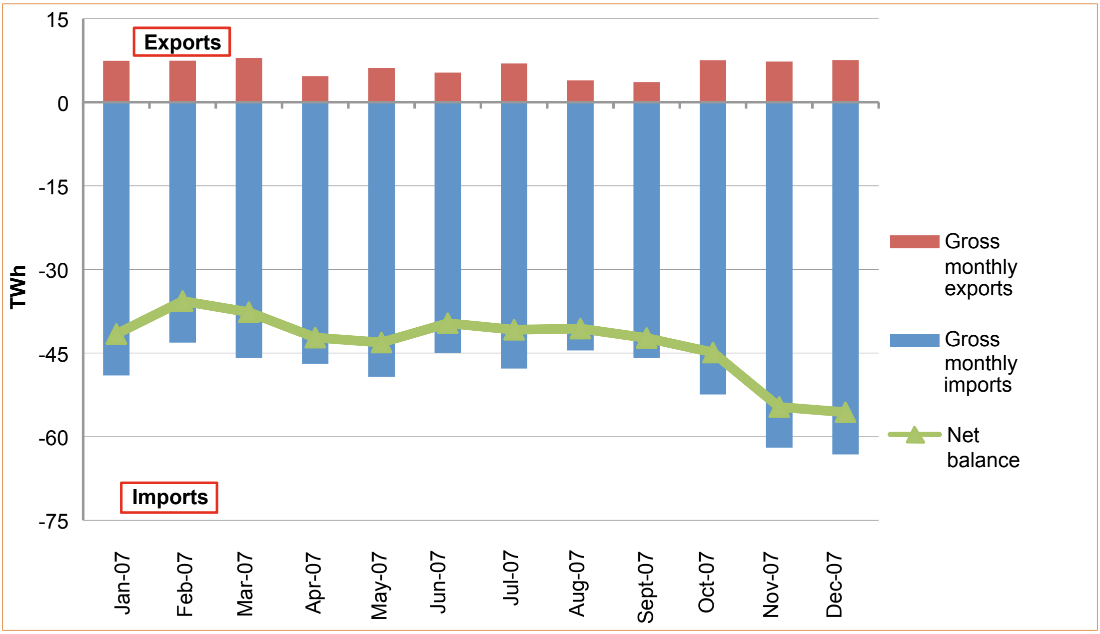


Data: GRTgaz and TIGF; Analysis: CRE

4. CROSS-BORDER TRADING

To cover its requirements for gas consumption, France is a net importer of natural gas. In 2007, players on the French market nominated 595TWh of gas imports and 112.6TWh of exports.

Gross imports and exports at interconnections

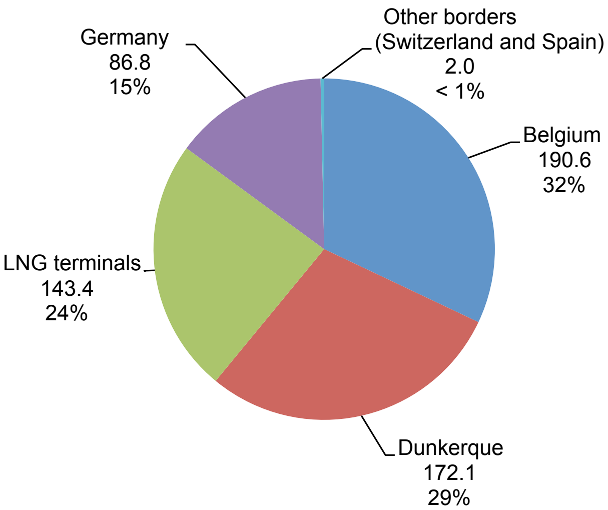


Data: GRTgaz and TIGF; Analysis: CRE

French imports reflect a diversified sourcing strategy. Thus in 2007, gas imports from Belgium (Quevy, Taisnières and Blaregnies), Dunkerque, LNG terminals (Montoir and Fos) and Germany (Obergailbach) represented respectively 32.0%, 28.9%, 24.1% and 14.6% of total imports.

The following paragraphs analyze gross imports and exports nominated by market players at the interconnections. Thus even where an entry point can accept only incoming physical flows, players can nominate gross exports, known as "reverse" flow.

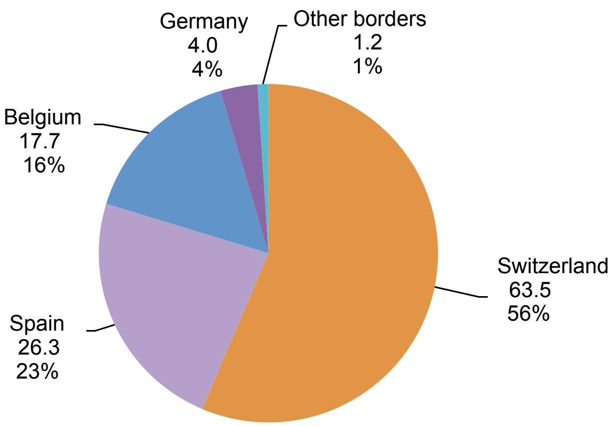
Natural gas imports at the borders in 2007
Gross nominations



Data: GRTgaz and TIGF; Analysis: CRE

Exports from France related largely to transit agreements. In 2007, 56.4% of the gas exported went via Switzerland (Oltingue) en route for Italy, and 23.3% of gas exports went to Spain (Larrau). Gas amounting to 15.7% of French exports crossed the Belgian border (Quevy, Taisnières and Blaregnies) in 2007, and this was the only border where there were significant flows both of imports and exports.

Natural gas exports at the borders in 2007
Gross nominations



Data: GRTgaz and TIGF; Analysis: CRE

In 2007, French incumbents accounted for 89.8% of French imports. In the same year, their export market share amounted to 94.4%.

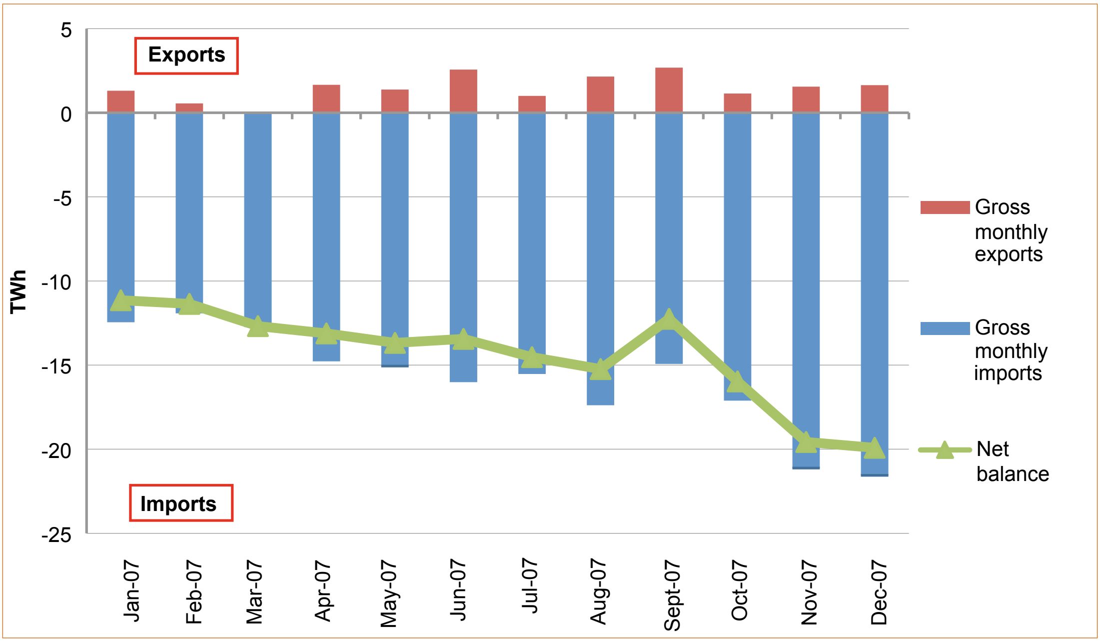
4.1 France-Belgium (Quevy, Taisnières and Blaregnies)

The French market imported around 173TWh net from Belgium in 2007. In 2007, the Franco-Belgian border was the only one where significant exchanges of imports and exports took place. Players active on the border nominated 190TWh of imports, but also 17TWh of exports[18].

The number of companies active on this border rose from 9 to 13 during 2007. In particular, the number of companies active in import only rose from 3 to 9, whilst numbers in other categories of company declined slightly. The new participants are essentially trading companies. Players active on this border remain essentially French or European incumbents.

Alternative operators accounted for more than 12% of the imports and almost 15% of the exports in 2007.

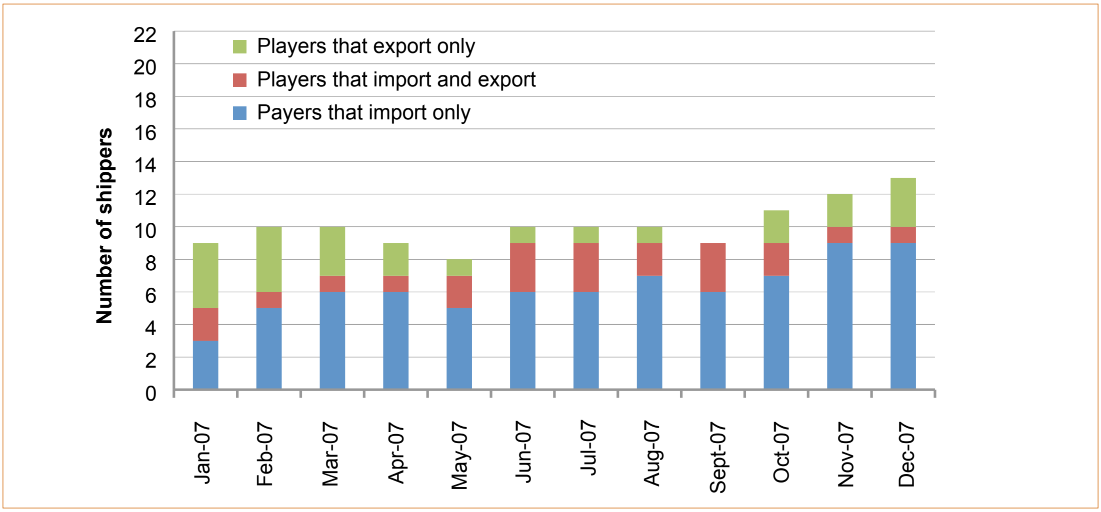
Gross imports and exports at the France-Belgium interconnection



Data: GRTgaz; Analysis: CRE

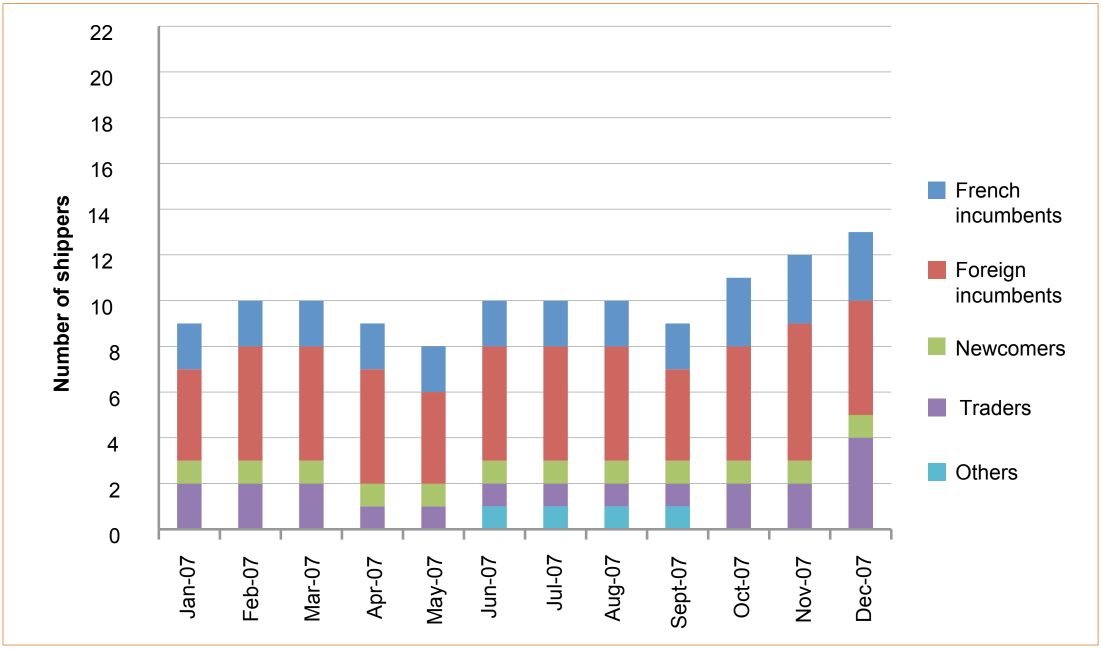
Gross imports and exports at the France-Belgium interconnection by categories of operator

Number of participants at the France-Belgium interconnection

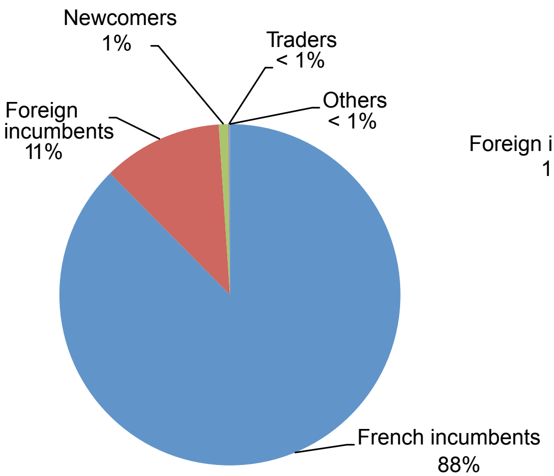


Data: GRTgaz; Analysis: CRE

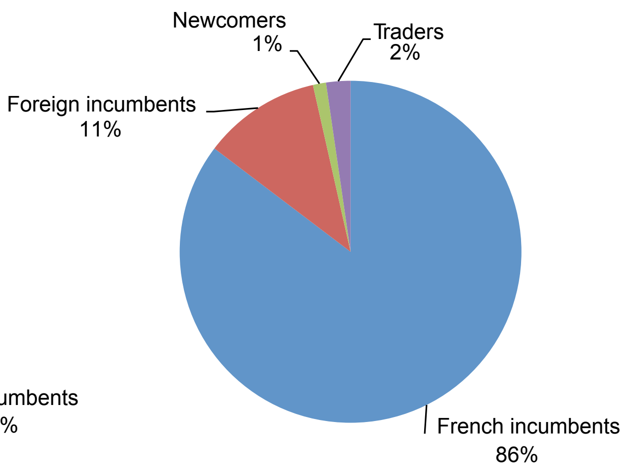
Number of participants by category at the France-Belgium interconnection



Gross imports from Belgium in 2007



Gross exports to Belgium in 2007



Data: GRTgaz; Analysis: CRE

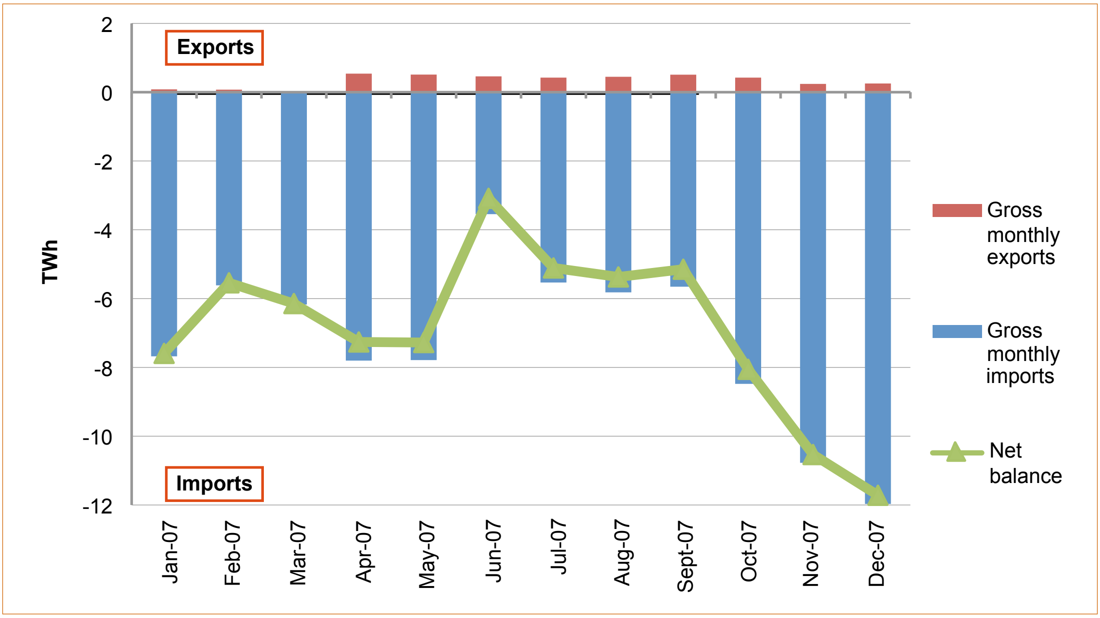
4.2 France-Germany (Obergailbach)

The French market imported around 83TWh net from Germany in 2007. Operators active on the border nominated 87TWh of imports, but also 4TWh of exports[19].

During 2007, 12 companies on average were active each month on this border. Most operators only imported gas. New participants were essentially trading companies. Only half the players active on this border were French incumbents or European operators. Trading companies, in particular, represented one quarter of active players.

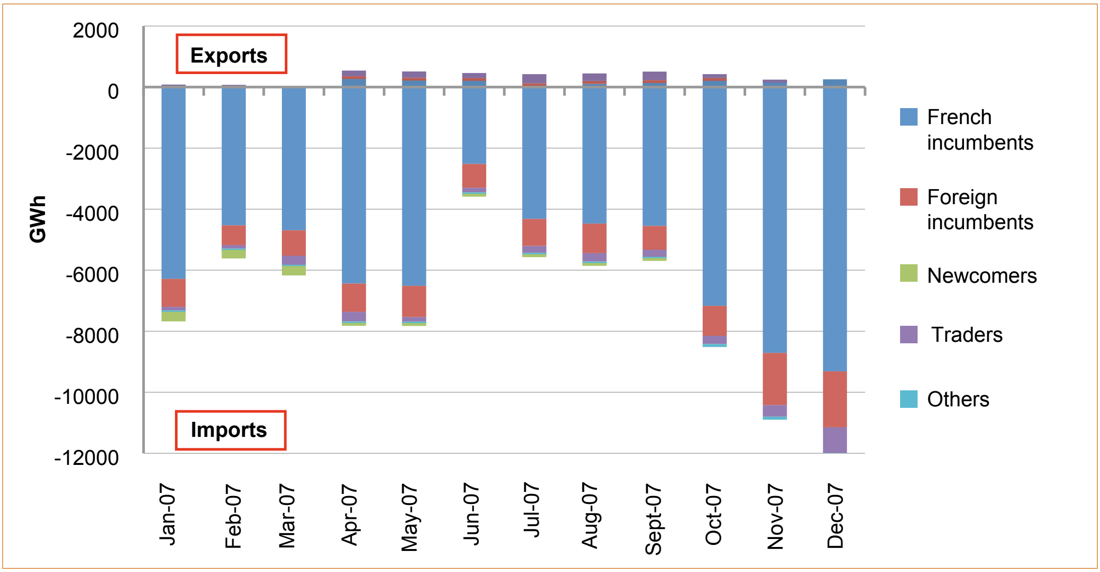
The German border, with the Belgian border, were those where flows were the least concentrated and that had the largest number of active players. In 2007, alternative operators imported 20% of the natural gas.

Gross imports and exports at the France-Germany interconnection

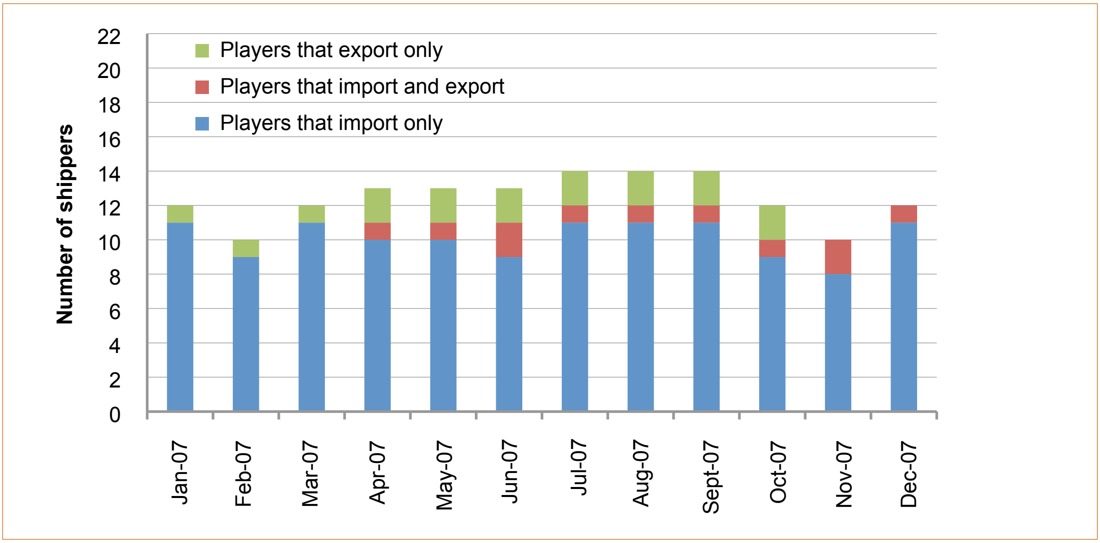


Data: GRTgaz; Analysis: CRE

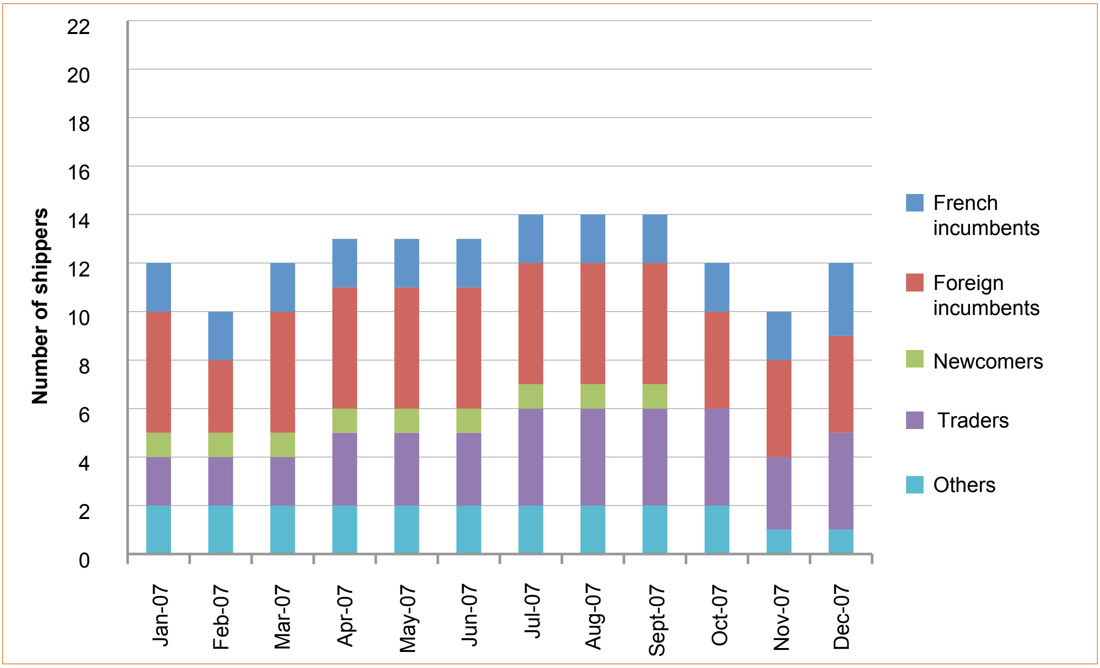
Gross imports and exports at the France-Germany interconnection by categories of operator



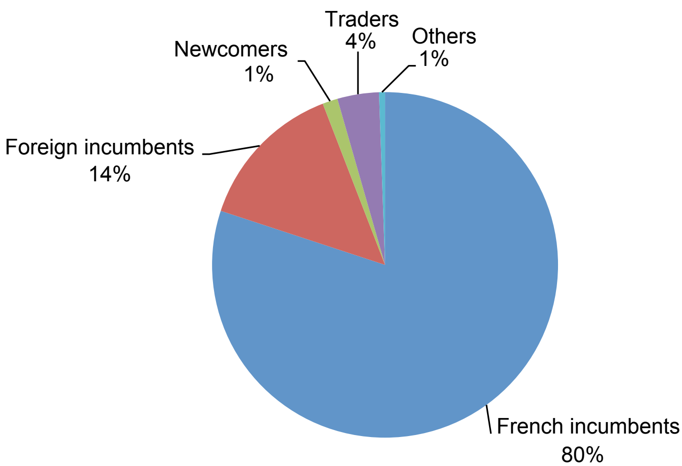
Number of participants at the France-Germany interconnection



Number of participants by category at the France-Germany interconnection



Gross imports from Germany in 2007



Data: GRTgaz; Analysis: CRE

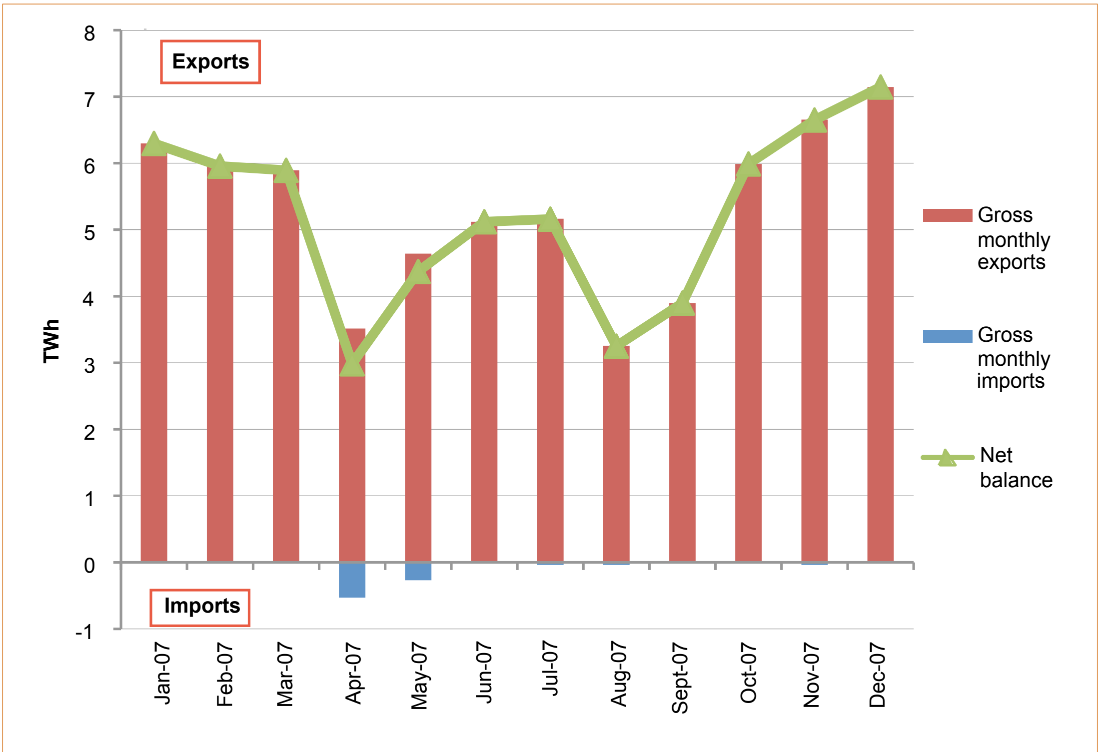
4.3 France-Switzerland (Oltingue)

The French market exported around 63TWh net to Switzerland in 2007. Operators active on the border nominated 64TWh of exports, but also almost 1TWh of imports[20].

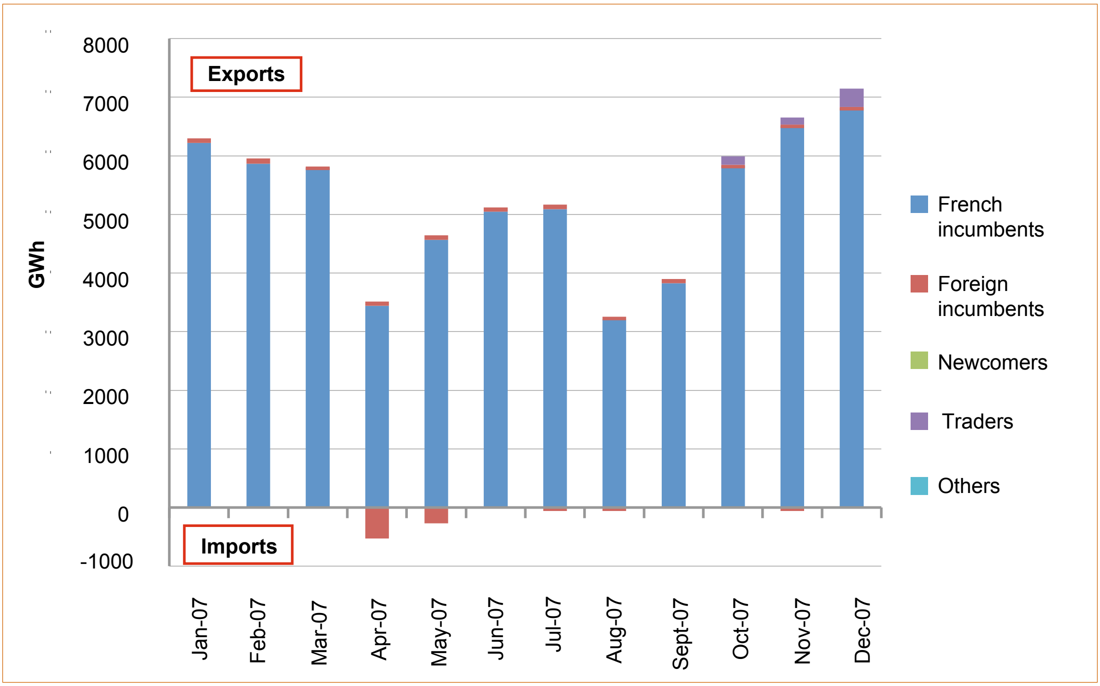
Between the beginning and end of 2007, the number of active players on this border doubled. Although only 3 or 4 companies delivered gas to the border at the beginning of the year, the number doing so had reached 7 by the year end. The new participants were largely trading companies; active operating companies almost all exported only.

Their activity did not match the volumes of gas transported to Italy under long-term contracts, and GDF Suez still handled almost all exports to Switzerland.

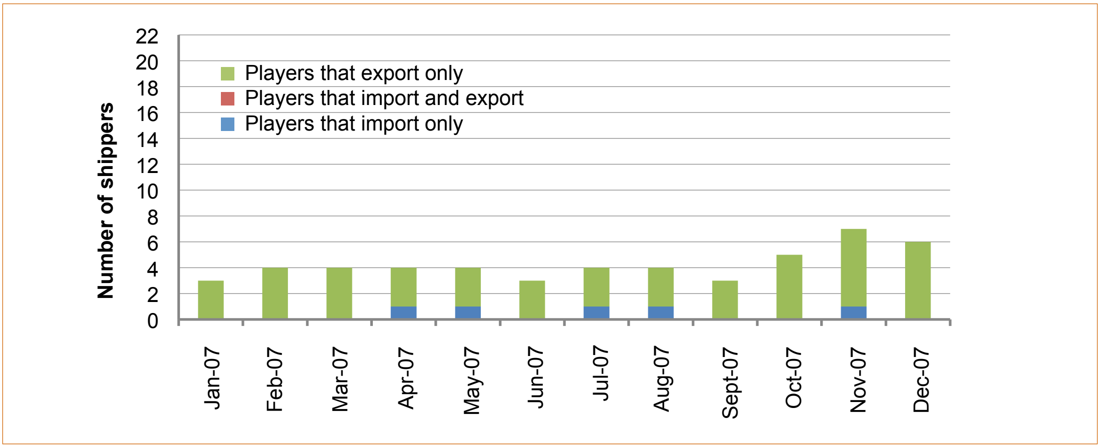
Gross imports and exports at the France-Switzerland interconnection



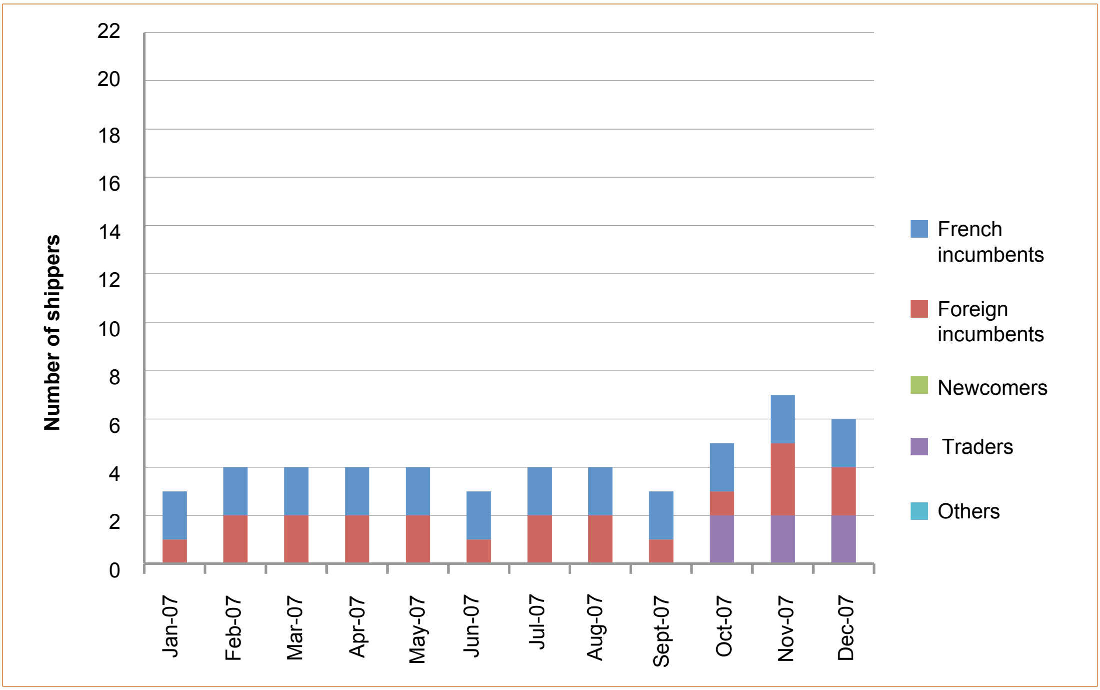
Gross imports and exports at the France-Switzerland interconnection by categories of operator



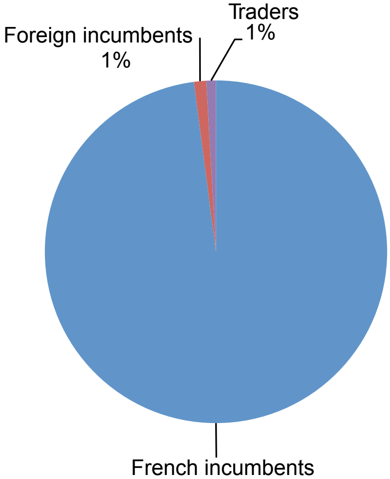
Number of participants at the France-Switzerland interconnection



Number of participants by category at the France-Switzerland interconnection



Gross exports to Switzerland in 2007



Data: GRTgaz; Analysis: CRE

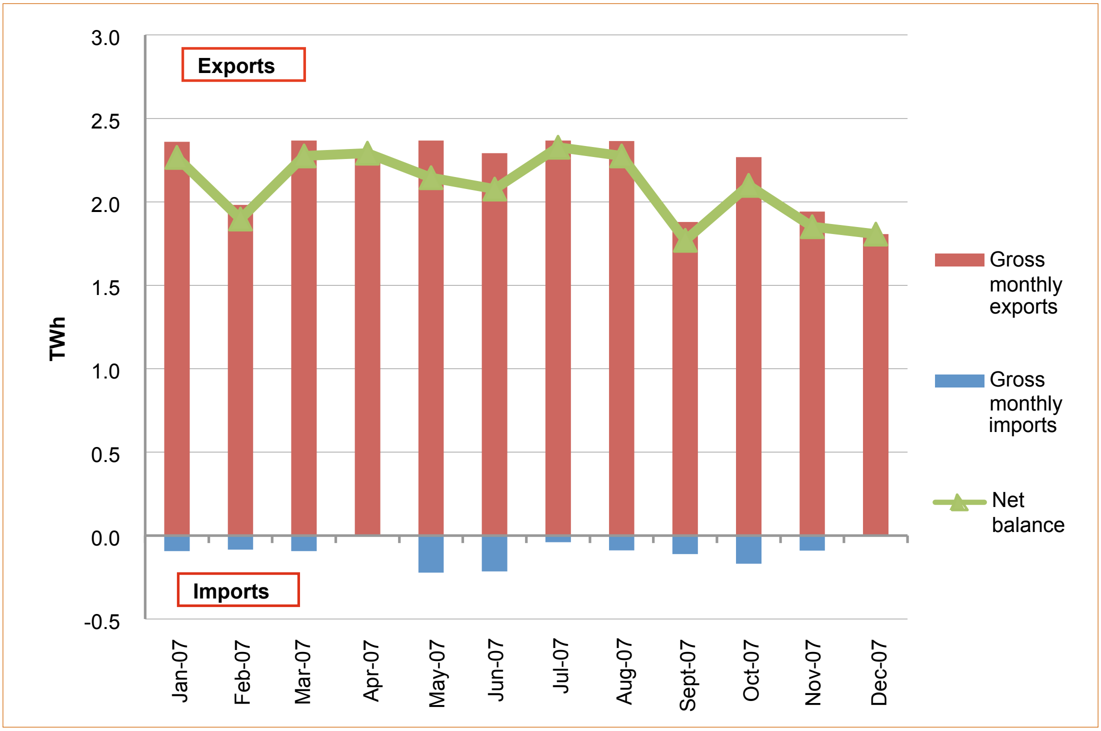
4.4 France-Spain (Biriatou-Larrau)

The French market exported around 25TWh net to Spain in 2007. Operators active on the border nominated around 26TWh of exports, but also almost 1TWh of imports.

For each month during 2007, two or three companies on average were active on this border. Most players active on the border were incumbent European and French operators.

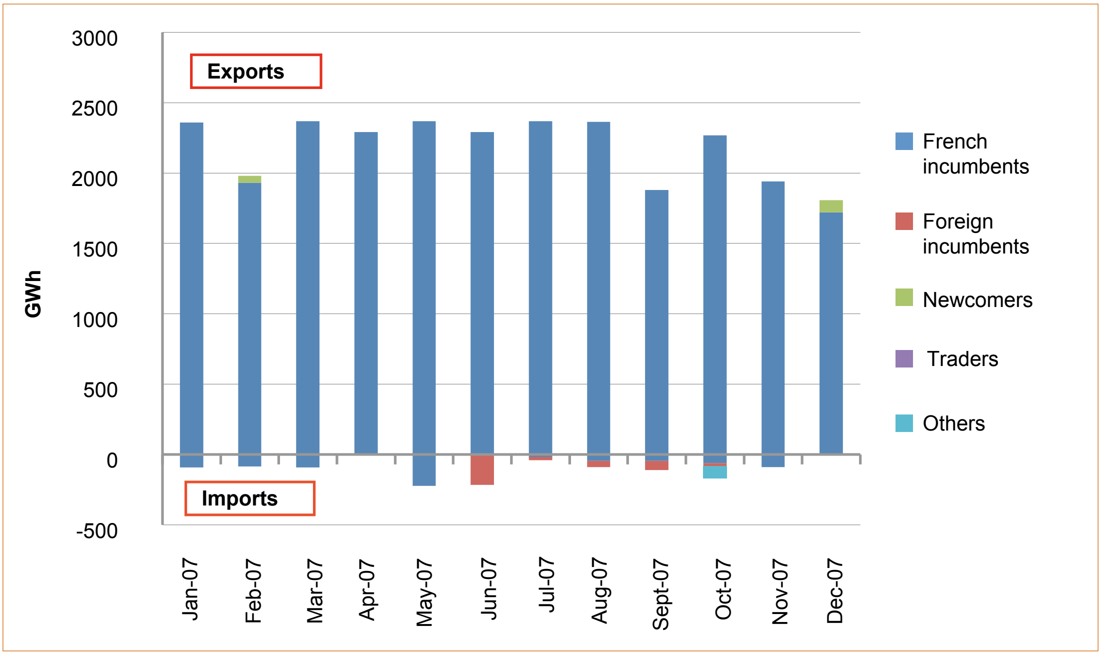
Their activity did not match the volumes of gas transported to Spain under long-term contracts, and GDF Suez, with Total, still handled almost all exports to Spain.

Gross imports and exports at the France-Spain interconnection

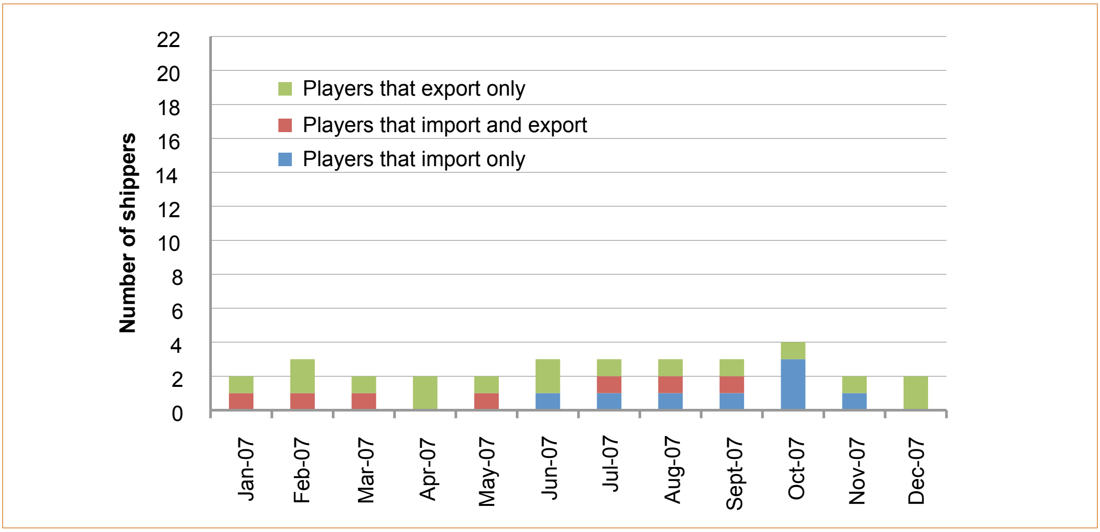


Data: TIGF; Analysis: CRE

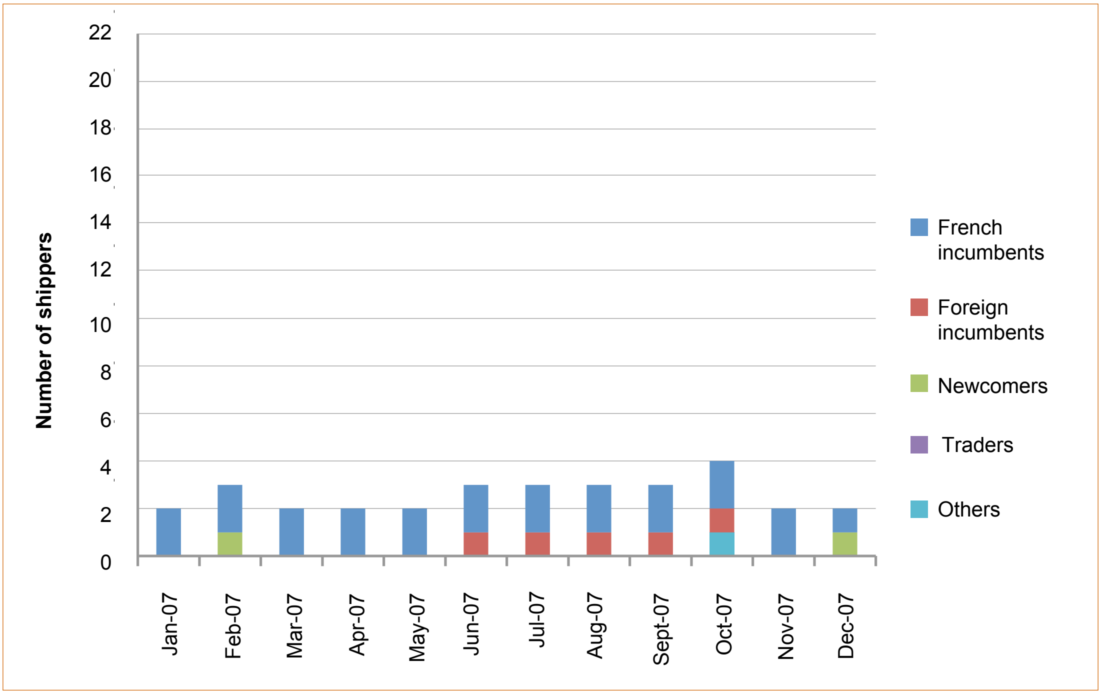
Gross imports and exports at the France-Spain interconnection by categories of operator



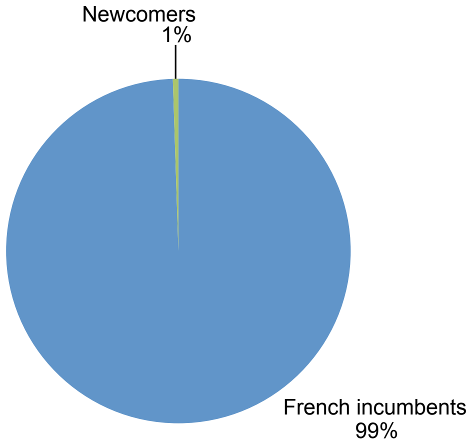
Number of participants at the France-Spain interconnection



Number of participants by category at the France-Spain interconnection



Gross exports to Spain in 2007



Data: TIGF; Analysis: CRE

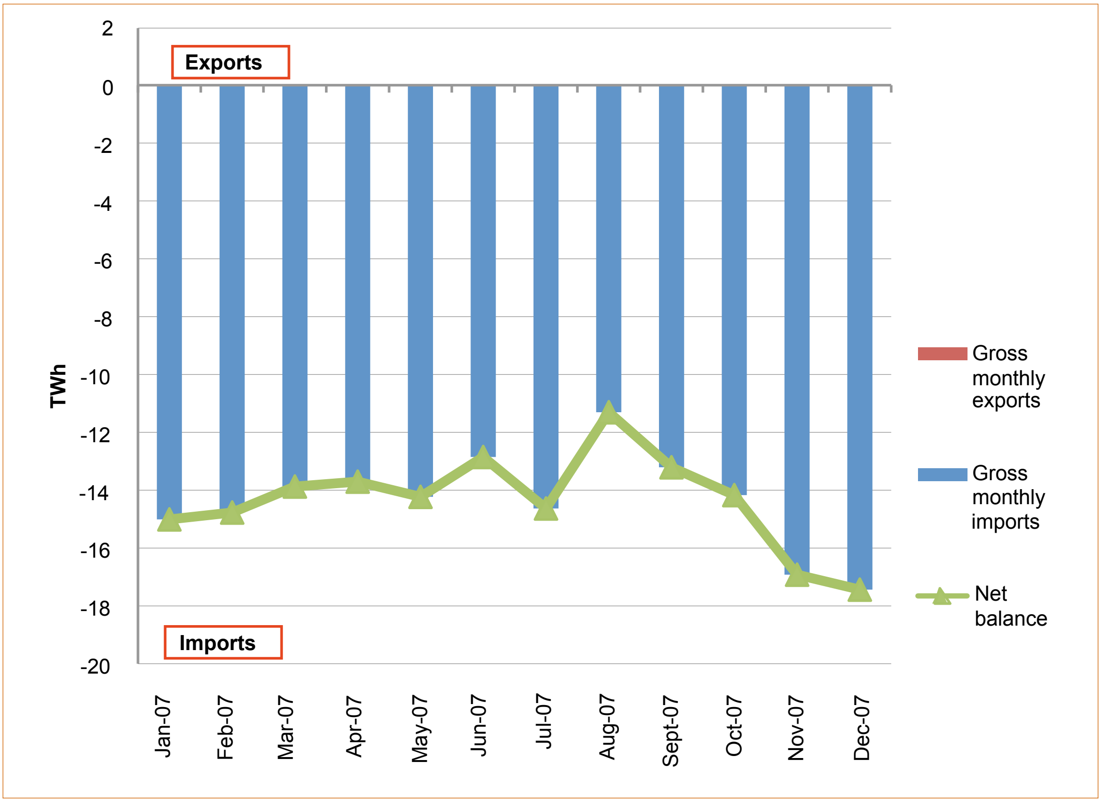
4.5 France-North Sea (Dunkerque)

The French market imported around 172TWh net from Dunkerque in 2007.

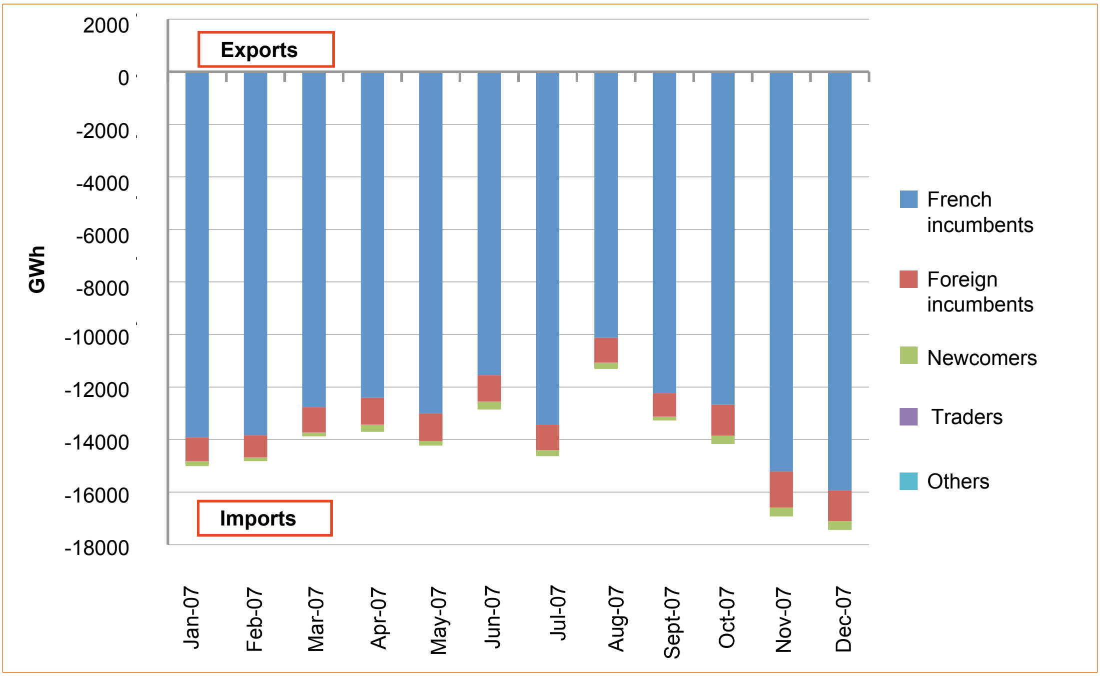
Each month, between six and eight companies on average were active on the border. They were mostly incumbent French or European operators. However, some new operators and traders were active at this entry point in 2007.

In 2007, GDF Suez and Total handled 91% of natural-gas imports.

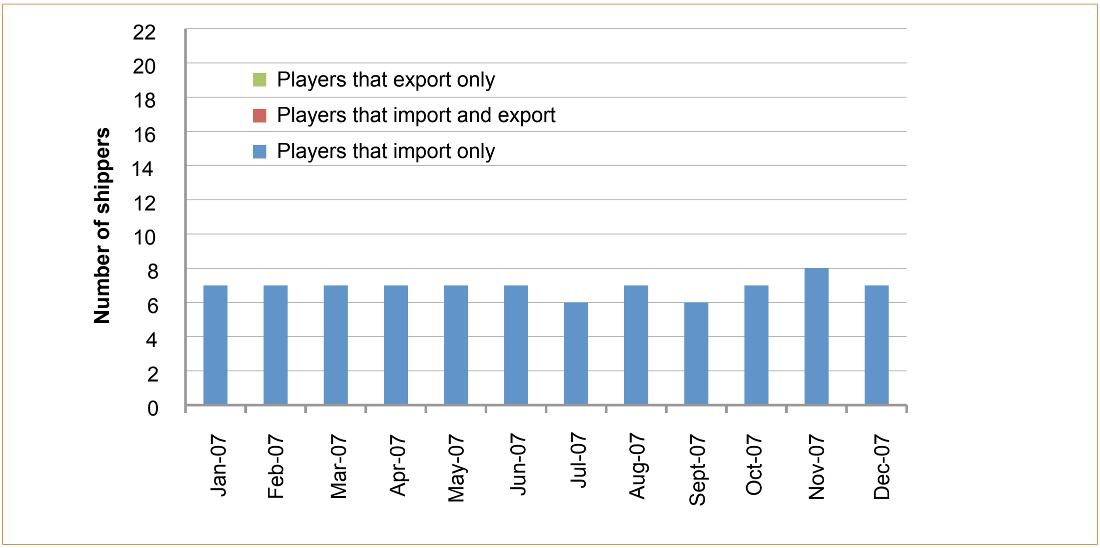
Gross imports and exports at the France-North Sea interconnection



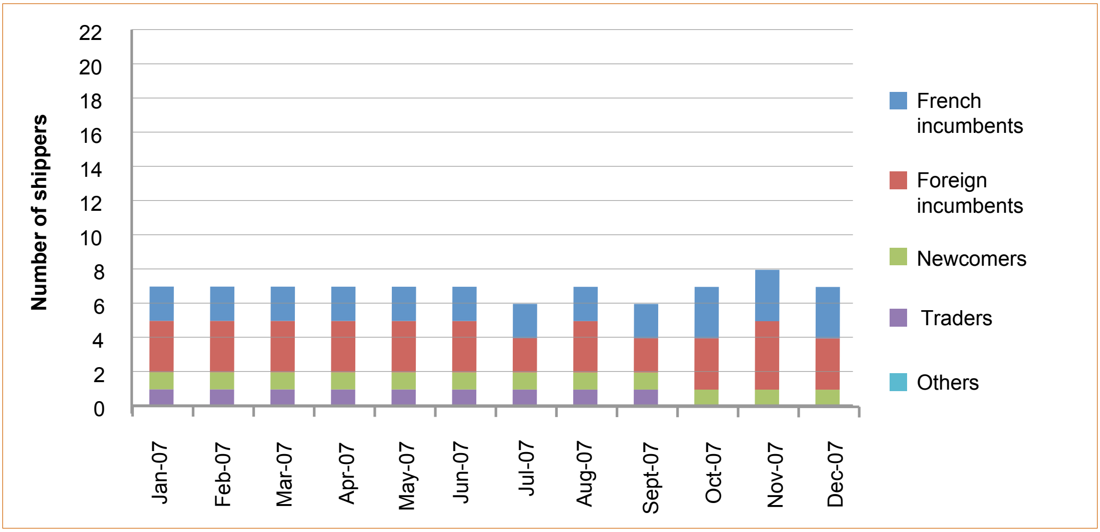
Gross imports and exports at the France-North Sea interconnection by categories of operator



Number of participants at the France-North Sea interconnection

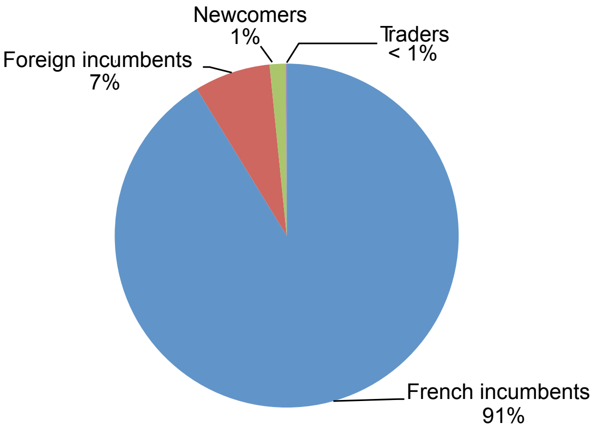


Number of participants by category at the France-North Sea interconnection



Data: GRTgaz; Analysis: CRE

Gross imports from the North Sea in 2007



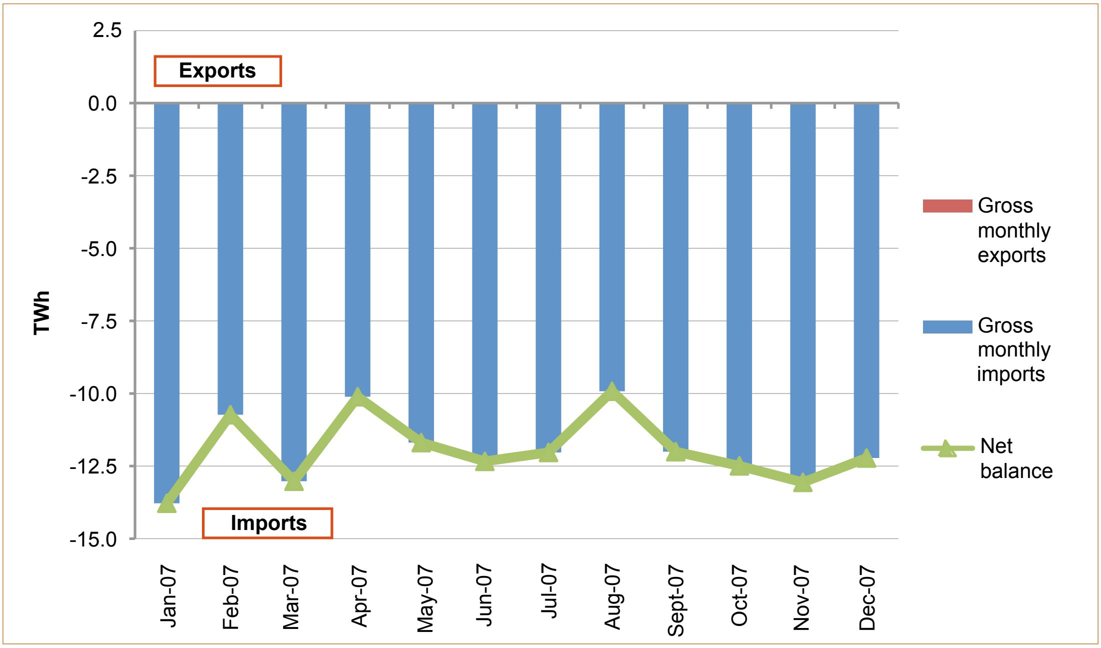
Data: GRTgaz; Analysis: CRE

4.6 LNG terminals (Fos and Montoir)

The French market imported around 143TWh net of LNG 2007.

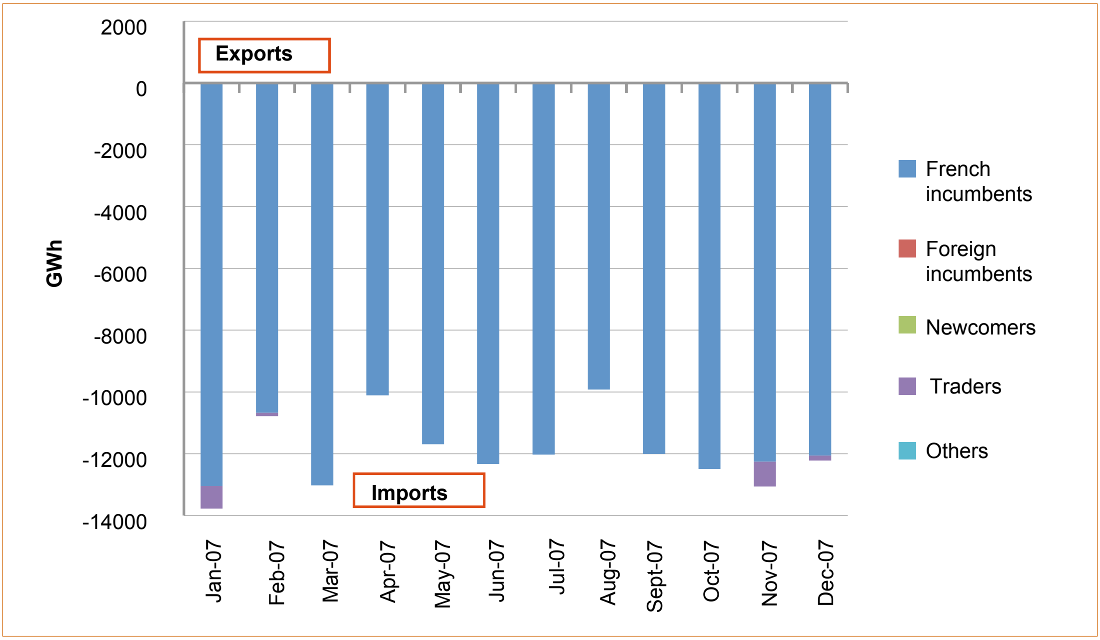
GDF Suez handled almost all LNG imports into France.

Gross imports and exports of LNG at LNG terminals

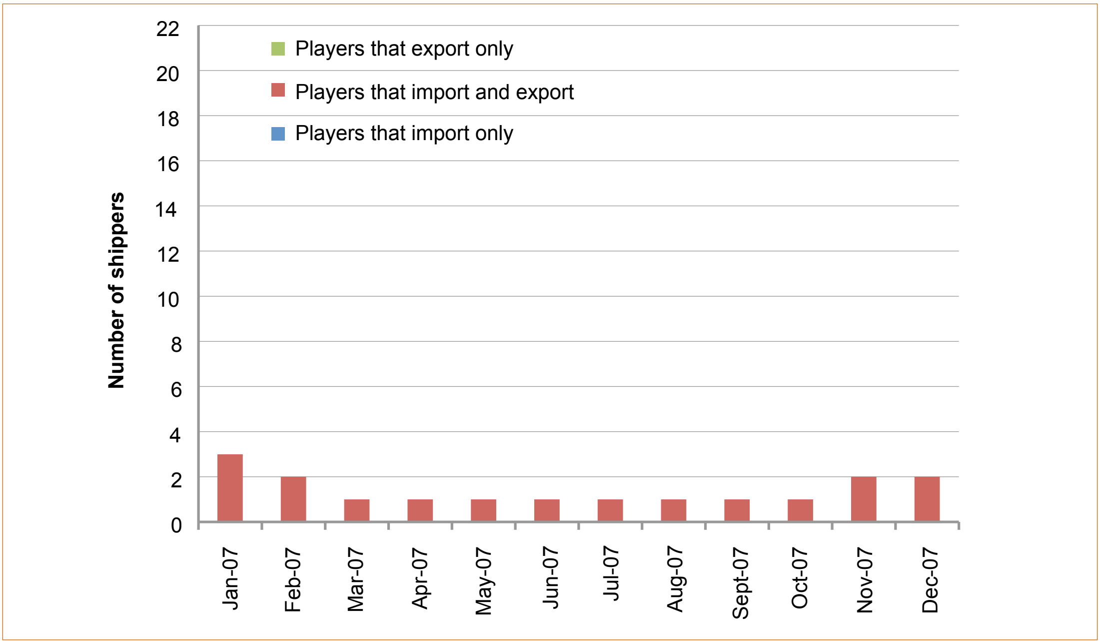


Data: GRTgaz; Analysis: CRE

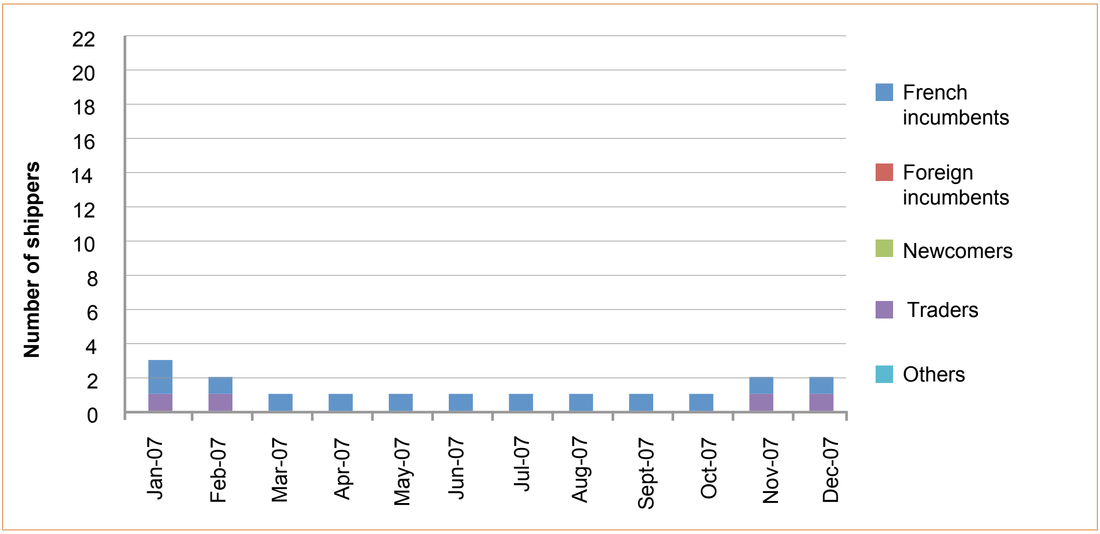
Gross imports and exports of LNG at LNG terminals by categories of operator



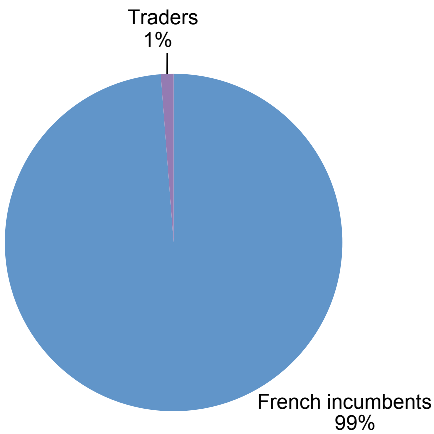
Number of participants at LNG terminals



Number of participants by category at LNG terminals



Gross imports of LNG via LNG terminals in 2007



Data: GRTgaz; Analysis: CRE

French incumbents alone accounted for 98.4% of exports over these two borders.

Notes

1 Calculations based on the price elasticity of supply and demand on Powernext for each hour in the year.

2 Calculations based on the price elasticities of supply and demand on Powernext for each hour in the year.

3 The forecasts are divided into three categories:
- short term: forecasts for the next seven days (D+1 to D+7);
- medium term: forecasts for the next 13 weeks (W+2 to W+13);
- long term: forecasts for the next 36 months (M+4 to M+36).

4 The delivery period for products sold under gas release programmes ran from January 2005 to December 2008.

5 See the definition on page 14

6 The day-to-day price of the commodities studied is highly dependent on the price the day before. It is invalid statistically to apply a simple econometric model to a series where each point depends on the preceding point (a so-called "non-stationary" series). Nevertheless, it is possible in some cases to identify a cointegration relationship between such series, reflecting the existence of a "long-term equilibrium" between them, and this relation may be used to model their relationship. Series that are cointegrated or linked by a "long-term equilibrium", cannot diverge over the long term, but return fairly quickly to their equilibrium value.

7 This variable has a very significant impact. In addition, its estimate varies very little if the period under consideration is extended.

8 For this analysis, a price spike is defined as an hourly price greater than 100€/MWh.

9 For instance, a unit with a valuation well below the price which therefore should run at full power, but where the delivered power was in a range intermediate between the technical maximum and minimum, for reasons not identified in this analysis.

10 For instance, coal-fired facilities are likely to be marginal if the scheduled power is less than 75% of the maximum power available and greater than 50% of the minimum power.

11 For instance, if power stations with a cost close to the price are few in number, or are all shut down, or all producing at maximum capacity.

12 Furthermore, it is not possible to understand the highly-theoretical concept of marginality in real terms without defining thresholds. Here we have chosen to rule out an industry which could be defined as marginal, but whose production is either too low (with a high risk of finding many of the power stations shut down) or too near the maximum (so that it cannot satisfy a small additional demand).

13 Calculations based on the price elasticity of supply and demand on Powernext for each hour in the year.

14 This figure does not include power stations with a profit of less than €5 /MWh. If all power stations in the industry are taken into account, the accumulated "withdrawn" capacity exceeded 500 MW for 370 hours. During that time, the average price was €117 /MWh.

15 Calculations based on the price elasticity of supply and demand on Powernext for each hour in the year.

16 When there is no such forecast, the forecast for the previous day is used as the reference.

17 Producers can take advantage of opportunities for arbitrage by deciding each day to adjust output from their generating facilities for the day ahead upwards or downwards.

18 Note that for technical reasons, physical flows must occur in the direction from France to Belgium, from France to Germany and from France to Switzerland. This means that at these interconnections, imports may only be nominated as reverse exports.

19 See previous reference.

20 See previous reference.

Glossary

Balancing zone: geographical zone in the gas transmission network where there must be a balance between inflows and outflows of gas.

Day-ahead market: the market with contract agreement on day D for delivery the next day or the next working day. See also *Spot*

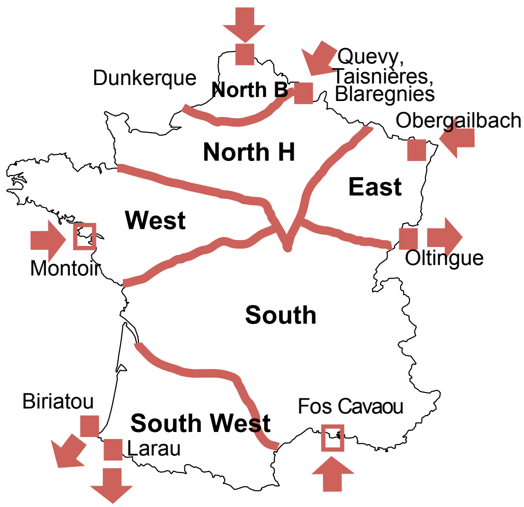
Gas Exchange Point (*Point d'échange de gaz – PEG*): a virtual point attached to balancing zone, where one shipper can deliver gas to another.

Gas release programme: a temporary programme to release gas, introduced in 2005 for a period of three years, to encourage competition in the south of France.
Each year, Gaz de France marketed 15TWh of energy at the South Exchange point. Thus a total of 45TWh was traded throughout the duration of the programme via invitations to tender or the OTC market. Similarly, Total marketed 1.1TWh each year for three years at the South-west Exchange point, or 3.3TWh throughout the period of the programme.

Intraday: the market in contracts agreed on day D for delivery on the same day (or the day after, if the transaction takes place after the main trading activity on the day-ahead market). See also *Spot*

NBP (National Balancing Point): the NBP is Great Britain's national hub.

North-B / North-H zone: the North-B balancing zone is supplied with low-BTU gas (*gaz-B*), which comes mainly from the Netherlands and has an unusually high level of nitrogen. The North-H balancing zone is supplied with high-BTU gas (gaz-H), which is the same as the gas distributed in the rest of the territory.



Spot: the short-term market, where trades are delivered in the near future. The spot market includes both intraday and day-ahead products.

TaRTAM: The transitory regulated tariff for market adjustment (*Tarif Réglementé Transitoire d'Ajustement au Marché - TaRTAM*)

VPP (Virtual Power Plant): VPPs are capacity auction sales set up by EDF as a result of a decision made by the European Commission.
The companies who acquire capacity pay a fixed premium (in Euro/MW), determined at auction, to reserve capacity. There is one auction per quarter. The companies who posess VPPs send a daily schedule to EDF for using these capacities. Using capacity incurs a cost: holders pay a strike price per MWh withdrawn, which value depends on the type of product purchased. VPPs thus have a price structure corresponding to "fixed cost + variable cost".

Zeebrugge: the Zeebrugge hub in Belgium is a physical gas hub and one of the largest in Europe. The Interconnector between it and Bacton (UK) is important because it ties the day-ahead prices at NBP to those at Zeebrugge.

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