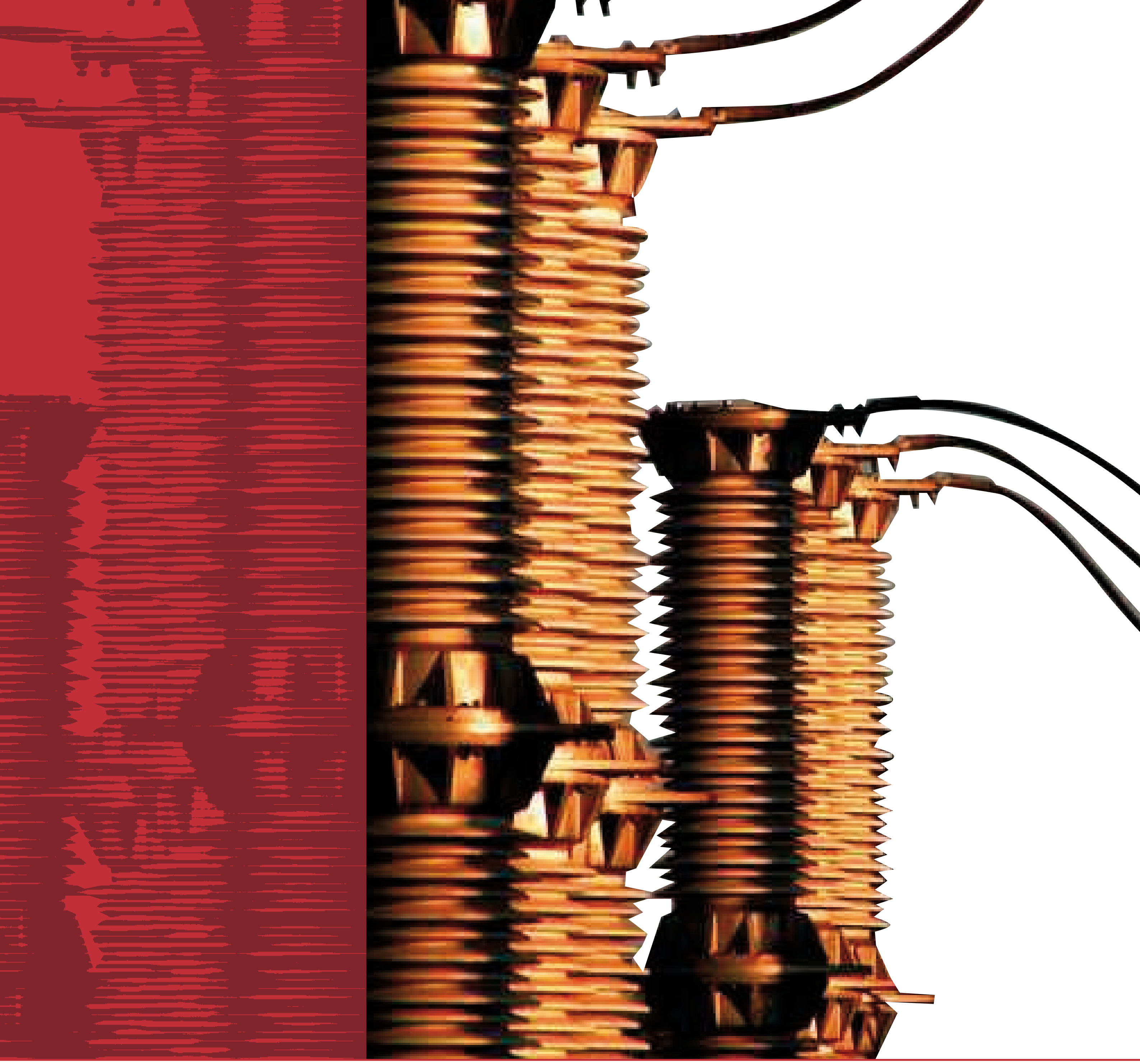

Report on electricity interconnection management and use

June 2008

COMMISSION
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Foreword by Commissioner Piebalgs

The single electricity market could not exist without electricity interconnections, and the lack of a European electricity market, as for gas, weighs heavily on the internal market as a whole.

This is why it is essential to optimize the use of interconnections, and to invest in the "missing links". This is the wish of the European Commission, which was specifically stated in the Strategic Plan for Interconnections published in January 2007 within the framework of the Strategy for a European energy policy. In this respect the completion of the France-Spain electricity interconnection will constitute a test.

In order to complete the Community's legal arsenal, the European Commission has made new proposals in the "third legislative package". In particular, these proposals aim to provide National Regulation Authorities with the same powers in this field, based upon the greatest common denominator. It should not be forgotten that their mission consists in ensuring the compliance of methods for managing interconnection congestion with the provisions of European regulations, as well as their efficiency. Apart from this "upward harmonisation" it is equally important to reinforce cooperation between national regulators, which led to the proposal to set up an Agency for cooperation between them at community level. This Agency has received very broad support.

The work undertaken under the leadership of the European regulators group for electricity and gas (ERGEG), within the framework of the Electricity Regional Initiatives, has already allowed a consensus to be reached at European level around the target mechanisms likely to guarantee the efficient use of interconnections.

However, this essential joint movement also requires a frontier-by-frontier approach. The second annual report of the French energy regulatory commission (CRE) on the management and use of electricity interconnections is in line with this perspective. As well as assessing the efficiency of existing methods of congestion management, it highlights the work which remains to be done to obtain efficient methods of congestion management for the totality of French frontiers.

This report has the merit of leading to recommendations whose impact could be measured on a European continental scale. They are all the more necessary for being included in a context which is rich in major projects, whether the 2009 extension of the coupling of the French, Belgian and Dutch markets to the German and Luxembourg markets, or the development of reciprocal balancing trades on the interconnection between France and England.

As usual, the most difficult exercise is moving from recommendations to actions. This raises the unavoidable question of incentivising transmission system operators to improve interconnection management rapidly. The third energy package sketches the outlines for this. Regulators should therefore take on board the tools offered by this new regulatory framework, in order to undertake the progressive improvement of the management and use of all interconnections.

These are just so many small steps that, taken together, will strengthen the market integration process.

Mr Andris Piebalgs, EU Energy Commissioner

Summary

Apart from some concrete advances in interconnection management, the most striking event of 2007 has to be the emergence of a consensus at European level on the general principles of the target mechanisms for interconnection management. Three major projects currently undergoing development by the TSOs and the exchanges – the setting up of a single auction platform for allocating long- and medium-term products and of "flow-based" market coupling in the Central-West region (Belgium, Luxemburg, the Netherlands, Germany, France), and in the France-UK-Ireland region, the introduction of reciprocal balancing exchanges on the France-England interconnection – should lay the foundations for the future management of congestion on interconnections in Europe.

The completion of these projects, planned for the end of 2008 for the single auction platform project in the Central-West region and for mid-2009 for the other two, will be an important turning point in the construction of the European electricity market. This will be one of the successes of the Regional Initiatives process launched by ERGEG just over two years ago. However, this should not hide the fact that the regulators have experienced many difficulties during the regional integration of the markets and that the market operators have the general impression that this process could progress much more quickly.

These difficulties and this relative slowness are mainly explained by:
- a lack of consensus on the target market design the national markets would gradually tend towards,
- a lack of harmonisation of the powers and competencies of the regulators when it comes to cross-border trades, the immediate consequence of which is a lack of incentives for TSOs to accelerate market integration.

Several sizeable challenges await all the stakeholders over the coming months and years if market integration is to be a success:
- How can the "third legislative package" give all the necessary competencies regarding cross-border trades to the national regulatory authorities – or to the Agency for the Cooperation of Energy Regulators (ACER)?
- How can Switzerland be integrated effectively into the regional market integration process?
- What status should the organised markets be given in future, taking account of the crucial role they have to play in cross-border trades and eventually in the construction of the European electricity market?
- How can the projects to be developed within the four Regional Initiatives in which France is taking part be prioritised?
- How can the calculation of interconnection capacities be improved and how can we prevent cross-border trades from being discriminated against in favour of flows within a country?
- How can the quality of access to interconnections be improved, and particularly the firmness with which capacity is offered by the TSOs, without affecting the level of capacity made available to the market?
- How can the TSOs be incentivised to speed up integration of the markets, especially of the balancing markets, which are the foundation of national market design?

The publication of this second report by CRE concerning electricity interconnection management and use provides an opportunity to launch the debate on all these crucial issues and consider together the responses that can be applied to make market integration a success.

Introduction

1. Background

1.1. Role of the interconnections

Although the electricity interconnections between the different European countries were originally set up to enable the TSOs to help one another out if there was a sudden technical failure, and in the case of synchronous grids, to allow the frequency to be jointly regulated, they are now the cornerstone of the single market in electricity.

The purpose of creating a single market in electricity is to take advantage of the complementary nature of generation capacities and demand for electricity in the different Member States, for the benefit of the end consumer. The aim of market integration is also to stimulate competition between European operators, again for the benefit of the end consumer.

However, the creation of a single European electricity market has come up against a major obstacle: the interconnections between Member States, which have a limited capacity, create bottlenecks that must be, if not cleared, at least reduced. This requires both the development of new transmission infrastructure and also more efficient use of the existing cross-border capacity.

1.2. 2005 and 2006: a major turning point in interconnection management

Until 2004, interconnection capacities between France and its neighbouring continental European Member States were managed using administrative mechanisms: priority lists and pro rata mechanisms. These congestion management systems originated from the period when interconnections were mainly used, in addition to their role of grid safety, to export surplus nuclear electricity generated in France, under long-term contracts.

With the prospect of setting up a European electricity market, these administrative mechanisms had to evolve into market mechanisms that would allow competition to develop, in accordance with Community regulations and case law (Regulation (EC) No 1228/2003[1] and the Judgment of the European Court of Justice of 7 June 2005[2]).

In its roadmaps drawn up jointly with the regulators in neighbouring Member States in 2005, CRE took particular care, having consulted the market operators, to implement the EU's requirements by demanding the introduction by 1 January 2006 of auction mechanisms to allocate interconnection capacities on France's borders with the other Member States (inset 1).

In 2006, two important events occurred that had an impact on interconnection management:

- In February, the launch by ERGEG of the Regional Electricity Initiatives with the aim of speeding up market integration at a regional level so as to end up with a single European Union market. France belongs to four of the seven regions (see inset 2) defined by the European Commission and ERGEG:
  - Central-West (with Germany, Belgium, Luxembourg and the Netherlands);
  - Central-South (with Germany, Austria, Greece, Italy and Slovenia);
  - South-West (with Spain and Portugal);
  - United Kingdom and Ireland.

1. Regulation (EC) No 1228/2003 of the European Parliament and of the Council of 26 June 2003 on conditions for access to the netwinfluenork for cross-border exchanges in electricity.
2. ECJ 7 June 2005, VEMW and others, Case C-17/03 (European Court Reports 2005 Page I-04983).

- In December, the entry into force of the new guidelines for Regulation (EC) No 1228/2003[3]. While the Regulation set out the general principles for congestion management, the new guidelines explain precisely the improvements to be made to the current mechanisms. In particular, they require a coordinated approach at regional level for the calculation and allocation of interconnection capacities.

Inset 1 – The principle changes in interconnection management in 2005 and 2006

December 2004	CRE asks RTE to allocate 50% of export capacity to Italy using an explicit auction mechanism, with the other half of the capacity being allocated to its Italian counterpart[4].
January 2005	The CRE-CNE common position establishes a framework for setting up coordinated explicit auctions, followed by market coupling on the France-Spain interconnection[5].
November 2005	The France-Germany [6] and France-Italy-Austria [7] roadmaps establish the framework for setting up explicit auctions at these borders with annual, monthly and daily timeframes.
December 2005	The France-Belgium-Netherlands[8] roadmap establishes the framework for setting up explicit auctions on these two borders, and encourages the introduction of daily coupling in these three markets.
	On the basis of the judgment issued by the European Court of Justice on 7 June 2005, CRE asks RTE to no longer grant priority access to historical contracts between France and the other Member States[9].
January 2006	On all interconnections between France and its neighbouring Member States, auctions of capacities are held.
February 2006	ERGEG launches the Regional Initiatives to speed up the market integration process.
May 2006	The joint decision by CRE and the Spanish Ministry of Industry, Tourism and Trade permits the launch of a coordinated explicit auction mechanism from June 2006 on the Spanish border, including for the allocation of intraday capacities[10].
November 2006	CRE authorises the setting up of market coupling between France, Belgium and the Netherlands[11].
December 2006	The new guidelines for Regulation (EC) No 1228/2003 enter into force.
	A coordinated explicit auction mechanism between the French and Italian transmission system operators is set up for all export capacity to Italy.
	Secondary capacity markets are set up for the interconnections with Germany, Belgium and Italy.

3. Commission Decision of 9 November 2006 amending the Annex to Regulation (EC) No 1228/2003 on conditions for access to the network for cross-border exchanges in electricity.
4. http://www.cre.fr/fr/content/download/1488/24739/file/1104245627910.pdf
5. http://www.cre.fr/fr/content/download/2954/51135/file/1106931200640.pdf
6. http://www.cre.fr/fr/content/download/2951/51117/file/1132574638257.pdf
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9. http://www.cre.fr/fr/content/download/2944/51058/file/1133864405419.pdf
10. http://www.cre.fr/fr/content/download/2939/51016/file/1147256830476.pdf
11. http://www.cre.fr/fr/content/download/2937/51004/file/1161932458933.pdf

Inset 2 : The regions involving France, as defined by the European Commission and ERGEG at the launch of the Regional Electricity Initiatives

Central-West

Central-South

South-West

France – UK – Ireland

1.3. 2007: growing consensus on a target mechanism

Apart from some concrete advances in interconnection management (inset 3), the most striking event of 2007 has to be the emergence of a consensus at European level on the general principles of the target mechanisms for interconnection management (inset 4).

The ERGEG 'Coherence and Convergence' report presented at the Florence Forum in September 2007 explained the position shared by all the European regulators on efficient mechanisms for managing interconnection capacity, which should be used in every region.

Inset 3 – The principle changes in interconnection management in 2007	
February 2007	The regulators from the Central-West region publish a regional action plan setting out the concrete stages for the next two years in order to speed up the regional integration of electricity markets[12].
March 2007	The regulators from the Central-South region draw up an action plan for 2008.
May 2007	A procedure for the pro rata allocation of intraday capacities is set up on the border with Belgium.
July 2007	A secondary capacities market is set up on the interconnection with Spain.
September 2007	The action plan presented by the regulators in the South-West region is approved by all the stakeholders.
October 2007	The regulators from the France-UK-Ireland region give the green light for the transmission system operators to start work on developing a new computer system for the allocation, management and invoicing of capacity on the France-England interconnection, ensuring compliance with the Regulation and harmonisation with existing mechanisms on the other European borders.
December 2007	The auction rules in the Central-South region are improved and a major drive at harmonisation is undertaken.

2. Report objectives

Under the terms of paragraph 1.10 of the new guidelines for Regulation (EC) No 1228/2003, the national regulatory authorities are required to evaluate the congestion management methods on a regular basis.

In May 2007, CRE published its first report on interconnection management in 2006. This report gave an – assuredly positive – assessment of the entry into force of the auction mechanisms and the suppression of priority access for long-term contracts. Areas for improvement of the mechanisms in force were proposed in Part 2 of the report.

The present report on interconnection management in 2007 once again has two objectives.

Firstly, it intends to give an assessment of interconnection management in 2007 (Part 1):
- For this reason, the general indicators prepared for the previous report are set out, showing how they have changed.
- The efficiency of cross-border trades is also evaluated in detail for each timeframe (long-term, daily, intraday and balancing).
- Finally, capacity management by the transmission system operators is evaluated.

The second objective of this report is to explain the target mechanisms on which there is now a consensus in Europe, and draw up a list of the important issues still to be resolved to achieve these targets (Part 2). Although the general principles of these target mechanisms have been clearly established (see inset 4), actually setting them up raises many questions that still need to be answered.

12. http://www.cre.fr/fr/content/download/1394/23903/file/1171273743222.pdf

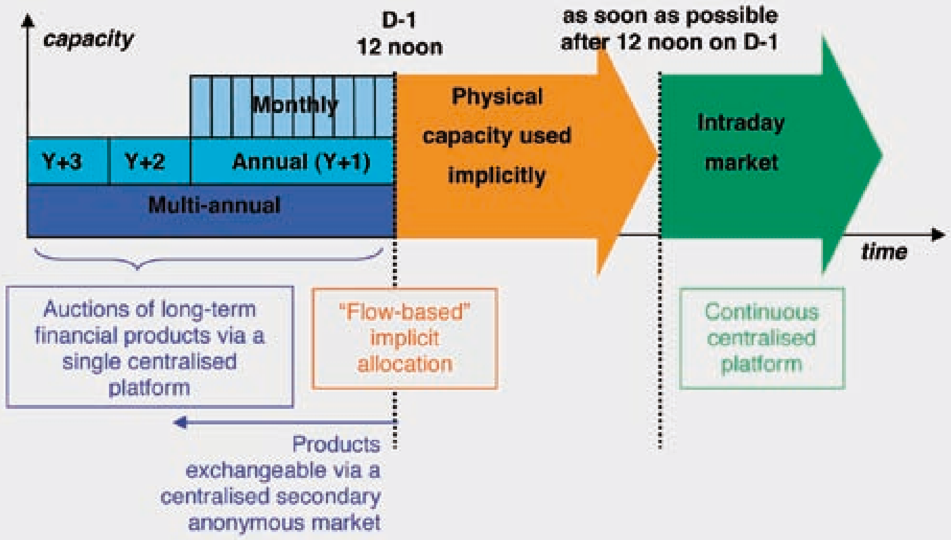
Inset 4: Summary of the target model for managing congestion on interconnections

For allocating long-term capacity, the target mechanism is an explicit auction mechanism harmonised throughout Europe, with:

- a single set of rules;
- identical products on all interconnections;
- a single interface for all participants.

For day-ahead capacity allocation, the "flow-based" implicit methods allow optimal use of capacity according to the prices on the different markets. So the target mechanism on which there is a European consensus is market coupling for of day-ahead organised market, and in the longer term, the merging of these markets, with separate price zones in line with congestion (market splitting).

For allocating intraday capacity, the mechanism on which there is a European consensus is continuous implicit capacity allocation. It would consist of a single platform, which would allocate capacity implicitly where an offer of electricity in one Member State corresponded to demand for electricity in another Member State.



Part 1:

Review of interconnection management in 2007

1. Overall indicators

1.1. Comparative values of interconnection capacities

Allocation mechanisms by auction, whether explicit or implicit, mean that the value the market gives to interconnection capacities can be estimated.

The average hourly price revealed by the auctions for each interconnection MW, for all timeframes, is one way of comparing the various interconnections on the French borders (Table 1). Notably, it can be used:

- within the perspective of investment in new interconnection lines; as an indication, the cost of constructing an alternative current interconnection line is 300 to 500k€/MW, and 600k€ to 800k€/MW for direct current[13];
- to improve the method used by RTE for sharing France's export capacity on its borders to the East (inset 5).

Table 1 – Prices attributed to interconnection capacities in 2007

		Average prices		**Total**	*2006*
		€/MWh	€/MW	**€/MW**	*€/MW*
Germany	Export	1.89	16,582	**34,317**	*22,253*
	Import	2.02	17,734		
England	Export	5.06	44,443	**62,657**	*123,550*
	Import	2.08	18,213		
Belgium	Export	2.43	21,248	**30,917**	*18,016*
	Import	1.10	9,669		
Spain	Export	5.16	45,210	**89,406**	*65,969*
	Import	5.05	44,196		
Italy	Export	18.28	160,117	**161,112**	*109,803*
	Import	0.11	995		

Source: RTE – Analysed by CRE

1.2. Level of interconnection capacities use

The last column of Table 2 below shows the congestion levels of the interconnections, i.e. the percentage of hours in the year during which the capacities available at the time of the daily allocation were used to their maximum, in the direction of the price differential between the French market and the neighbouring markets.

It can be seen that apart from the France-Italy interconnection, which is used at its maximum for 80% of the year, the other French interconnections are rarely saturated, despite the existence of opportunities for arbitrage (i.e. price differential) between the two markets. However, it should be noted that on the Spanish interconnection, the 30% use rate observed for the use of day-ahead capacities is taken to 55% by significant use of intraday capacities (see section 4.2 below).

13. CRE estimates based on the most recent constructions. The total cost of interconnection infrastructure is likely to vary widely according to the length of the link, scale of the associated work (construction work on stations, upgrading of national links, dismantling of existing links, etc.), the nature of the environment (plains, mountains, etc.), and adaptation to planning constraints (landscaped pylons, burial, modification of the route, etc.). In addition, the commercial capacity available may be less than the technical capability of the link and fluctuates according to the change in flows on the grid.

The first column of Table 2 also shows the significant price convergence between France and Belgium, whose interconnection is managed by market coupling (see section 3.3 below).

Table 2 – Congestion levels of French interconnections in 2007[14]

	Percentage of time when the price differential is less than 1€/MWh	Percentage of time when the price differential is greater than 1€/MWh, and when the interconnection is not used at its maximum	Percentage of time when the price differential is greater than 1€/MWh, and when the interconnection is used at its maximum
Germany	16 %	74 %	10 %
Belgium	91 %	4 %	6 %
Spain	9 %	61 %	30 %
Italy	2 %	18 %	80 %
Switzerland	15 %	61 %	24 %
England	(market prices not considered)[15]	81 %	19 %

Source: RTE, Powernext, EEX, Belpex, OMEL, IPEX and SwissiX – Analysed by CRE

Inset 5 – Distribution method of the physical margins on the East borders

From a reference basis, RTE determines the physical margin still available on each of the elements in the transmission grid after application of the 'N-1' criterion, which says that the element in question has to support the additional flows caused by the accidental loss of another part of the grid.

RTE distributes the physical margin obtained on the element experiencing the greatest stress according to the 'rule of thirds', which allocates 1/3 of the physical margin to each of the three borders (France-Belgium, France-Germany and France-Switzerland; the capacity on the France-Italy interconnection is fixed).

The available transfer capacities (ATCs) that can be used simultaneously are calculated by dividing the physical margin allocated to each border by the Power Transfer Distribution Factor (PTDF)[16] of this exchange on the element under stress.

This distribution of the physical margin is certainly not ideal for attributing capacities to the borders that need them most. Only the application of a flow-based method of allocating capacities could make up for this lack of optimisation in the long term.

14. A margin of 1% of capacity is taken here: an interconnection is considered 'congested' if the net flow on the interconnection is more than 99% of the net (import or export) capacity.

15. The lack of an hourly price at D-1 in England means that it is not possible to compare the use of the interconnection (at half-hourly intervals) with the price differential, like at other borders.

16. The Power Transfer Distribution Factor of an exchange x-y, on a grid element z, is the flow of additional power in grid element z resulting from the increase in volume of the exchange x-y. This factor is expressed as a %.

1.3. Economic signal for market failure

The previous indicator provides a way of comparing the market operators' inclination to pay for cross-border capacities at the different French interconnections. Here we look at the real congestion income (i.e. the auction revenue), which reflects this inclination to pay, along with an indicator of the theoretical congestion income, whose calculation is based on ex-post hourly price differentials between the national markets[17] (Table 3).

Table 3 – Real and theoretical congestion incomes in 2007[18]

		Total gross income from auctions[19] (M€)	Theoretical congestion income (M€)	Ratio	*2006*
Germany	Export	33.51	53.68	**62 %**	*28 %*
	Import	77.60	220.02	**35 %**	*34 %*
England	Export	87.28	-	-	-
	Import	35	-	-	-
Belgium	Export	33.43	22.77	**147 %**	-
	Import	2.75	4.50	**61 %**	-
Spain	Export	50.13	60.95	**82 %**	*39 %*
	Import	17.66	17.54	**101 %**	*92 %*
Italy	Export[20]	400.37	695.30	**58 %**	*51 %*
	Import	0.99	42.65	**2 %**	-
Switzerland	Export	-	188.50	-	-
	Import	-	35.08	-	-

Sources: RTE, Powernext, EEX, Belpex, OMEL and IPEX – Analysed by CRE

Ideally, the real congestion income should equal the theoretical congestion income. In reality, that is not generally the case, because of:

- the difficulty the market operators experience with forecasting day-ahead price differentials, and all the more so, for one month or one year ahead;
- the market operators' preference for trades of longer-term products (such as baseload and peakload products of a day), along with the difficulty or even impossibility for the market operators to carry out arbitrage in hourly steps;
- failures in the interconnected markets (small number of operators, information asymmetry, size differences).

17. The theoretical congestion income for export from market A to market B is the sum of the interconnection capacity multiplied by the price differential between the two markets, for all the hourly steps in the year when the market B price is higher than the market A price.

18 The empty cells in this table are explained as follows:
- in England, the lack of a fixed hourly price at D-1 makes it impossible to calculate the theoretical congestion income that can be calculated for the other borders;
- the same was true for Belgium before Belpex was launched at the end of 2006;
- on the Italian border, there were no auctions for import capacities in 2006.

19. The income from France-Spain intraday auctions is not included in this total because the price attributed to intraday capacities cannot be compared with the price differential between day-ahead markets.

20. Including the congestion costs invoiced to the operators (30 cents for each of the two Member States per nominated MWh).

Nevertheless, inter-temporal monitoring of the ratio between the real income revealed by market mechanisms and this theoretical congestion income is deemed useful to reveal congestion management mechanism failures, incompatibility between market designs, or lack of competition at the interconnection[21].

It could also be used to evaluate the impact of modifications of the interconnection access rules and changes in national market designs and to assess, whether, and to what extent, the process is evolving towards the establishment of an internal electricity market.

For 2007 there is a tendency for the ratio between the real income and the theoretical income to increase. This increase may be due in particular to the introduction of secondary markets in 2007, since the possibility of selling on the capacities they have bought means that the market operators can reduce their risk premium.

On the Belgian border, in the export direction, it can be seen that real income far exceeded theoretical income. The strong convergence of prices in 2007 between Belpex and Powernext (the prices were the same for 91% of the year) had not been anticipated by the operators.

1.4. Congestion income

The French share of the gross income from auctions in 2007 was 376.5 million euros, after the income had been shared with the neighbouring Member States (compared with 331 million euros in 2006)[22]. On each interconnection, the French share represents half of the total income, except on the France-England interconnection where the rules on sharing are more complex.

When the second tariff (TURPE 2) was drawn up, the annual income from auctions was estimated at 103 M€ on average in 2006-2007 (income estimated at 114 M€ in 2006 and 92 M€ in 2007). This estimate, made on the basis of the price indexes available at the time, did not take account of the suppression of priority access for long-term contracts or of the setting up of auctions on the borders with Germany, Belgium and Spain, which came after the tariff was proposed by CRE. In accordance with Article 6(6)(c) of Regulation (EC) No 1228/2003, this forecast revenue was considered as income deductible from the charges to be paid under the tariff for utilisation of the public electricity grids (TURPE). Additional revenue earned in 2007 (284 M€) was paid into the ‘expenses and revenues clawback account’.

To make up for the small amount of investment in interconnection infrastructure in 2008, noted in its decision of 20 December 2007 on RTE’s investment programme for 2008, some of the income from auctions in the next tariff period (TURPE 3) could be allocated to investment to increase interconnection capacities in accordance with Article 6.6(b) of Regulation (EC) No 1228/2003. This system must respect the following requirements at the very least:

- This share of the auction income must be allocated to specific projects named in advance, which contribute to reducing the congestion in question and can be implemented within a reasonable timeframe.
- The mechanism must incentivise RTE to make the investment subject to the best conditions of cost and lead-time.
- In implementing this system, it is necessary to ensure that it does not result in a cash flow advantage for shareholders.

21. The monitoring of this ratio will be more precise if a distinction is made between the different timeframes according to which the capacities are allocated (see sections 2.1 and 3.1).

22. These are the accounting values given by RTE, which differ slightly from the economic calculations shown in Table 3.

1.5. Competition at interconnections

The number of users of each of the French interconnections is quite high (Table 4), with a total of 74 operators active on the French borders.

Table 4 – Indicators of competition on interconnection use

		2007			2006		
		Number of operators	Largest share	HHI[23]	*Number of operators*	*Largest share*	*HHI*
Germany	Export	42	41 %	1,837	*39*	*23 %*	*895*
	Import	44	25 %	952	*36*	*17 %*	*795*
England	Export	24	25 %	1,224	*24*	*18 %*	*1,040*
	Import	21	28 %	1,211	*21*	*24 %*	*1,117*
Belgium[24]	Export	18	32 %	1,563	*24*	*26 %*	*1,081*
	Import	13	22 %	1,635	*20*	*35 %*	*1,934*
Spain	Export	17	43 %	2,335	*22*	*32 %*	*1,849*
	Import	17	25 %	1,343	*23*	*30 %*	*1,566*
Italy	Export	35	14 %	754	*23*	*47 %*	*2,477*
	Import	18	35 %	1,785	*16*	*28 %*	*1,835*

Source: RTE – Analysed by CRE

2. Analysis of the long-term capacity allocation mechanisms

On all the interconnections between France and other Member States, capacities are allocated on several different timeframes. The long-term products on offer are as follows:
- annual: at the end of each calendar year, a capacity band is allocated for the whole of the next year;
- monthly: every month, a capacity band is allocated for the next month;
- on the France-England interconnection, seasonal, quarterly and annual products throughout the financial year (April to March) are also offered.

Holding long-term capacities is one of the main methods for market operators to gain a lasting position on a foreign market. In this regard, both improving the quality of the products offered by the TSOs and maximising interconnection capacities are important challenges for developing competition and constructing the European electricity market.

2.1. Long-term capacity valuation

As for any commodity, the price that the market operators are willing to pay to obtain this commodity depends on the intrinsic characteristics of the product sold: the more reliable the product sold is (firmness, compensation in the event of curtailment, etc.) and easy-to-use (existence of a secondary market, nomination procedure, financial/physical nature, etc.), the more valuable it is.

Market operators wishing to participate in long-term auctions can consider two price references in order to determine their willingness to pay for the capacity. On the one hand, if they are involved in long-term arbitrages, they can consider the price differential of forward products available on the day of the auction. On the other hand, if they are interested in shorter-term arbitrages, this initial value has to be supplemented by their estimate, for the period in question, of price differential volatility on an hourly, (or daily, weekly, etc.) basis.

23. The HHI (Herfindahl-Hirschman Index) provides a measure of the concentration of a market: it is the sum of the squares of the market share (as a %) of the operators. If it is less than 1000, the concentration is said to be low; if it is between 1000 and 1800, the concentration is said to be moderate; if it is between 1800 and 10 000, the concentration is said to be high.

24. The flows nominated for market coupling on the France-Belgium interconnection are excluded from the calculations of market share. The reduction observed in the number of users of this interconnection is due to the absence of operators for the daily capacities because of the implicit method.

As CRE does not have access to these estimates, which differ for every market operator, this report considers the theoretical value of capacities, calculated ex-post, based on volatility of hourly price differentials. When the operators' forecasts do not materialise, typically in the case of unexpected weather conditions (heat wave, very cold spell, etc), this value may be lower than the marginal auction price. With this exception, the marginal price revealed by annual (or monthly) auctions must, in principle, be:
- at least the same order of magnitude as the price differential of annual (or monthly) forward products, observed on the date the auction is held;
- lower than the theoretical capacity value, calculated ex-post based on the hourly price differential between the organised markets throughout the year (or month)[25].

• Annual auctions

It was noted at the time of the report on 2006 that the annual capacities for 2007 were generally valued higher than those for 2006. This increase could be seen as:
- a sign of greater competition at interconnections,
- a sign of growing market confidence in the allocation mechanisms in force,
- a consequence of the introduction of secondary capacity markets (see section 2.3).

Across all the continental borders, there is a marked increase in the absolute value of import capacities to France for the 2008 annual capacities sold at auction in late 2007. On the border with England, this value fell slightly, which is consistent with the change in the forward price differential.

On the interconnection with Italy, annual auctions were held in the import direction for the first time, and the prices for these capacities turned out to be relatively high (nearly 2€/MWh).

These high values for import capacities reveal the market's growing interest in importing energy into France. This can be seen as a sign of better exploitation of the complementary nature of national production facilities and, more generally, as a sign that the electricity markets are working better on the continent.

Generally speaking, annual capacity values correlate strongly with the price differentials of annual forward products (Table 5).

It is difficult for the operators to take account of the hourly volatility of prices (the amplitude of which gives the theoretical value of the capacity), because of uncertainty when the annual auctions take place about how the prices will change in future. For example, the value attributed to the annual export capacity to Belgium proved to be higher than the theoretical value of that capacity: the operators who realised short-term arbitrages on that interconnection could have been subject to a net loss. The same was true for the import capacities from Spain.

On the France-Italy border, the absence of a forward market in Italy means that it is not possible to compare the valuation of the annual capacities and a forward price differential. However, it should be noted that the price attributed to annual export capacities (of the order of 15€/MWh) is low in view of the theoretical value of the capacity (which is approximately double), while the risks on this border are low with a price differential favourable to exports to Italy for 93% of the time in 2007.

25. The theoretical value of the annual (or monthly) export capacity from market A to market B is the average of the price differential between the two markets over all the hourly steps in the year (or month) during which the market B price is higher than the market A price.

Table 5 – Results of annual auctions in 2006, 2007 and 2008[26]

		2006				2007				2008		
		Capacity sold (MW)	**Price (€/MWh)**	Forward differential (€/MWh)	Theoretical value (€/MWh)	Capacity sold (MW)	**Price (€/MWh)**	Forward differential (€/MWh)	Theoretical value (€/MWh)	Capacity sold (MW)	**Price (€/MWh)**	Forward differential (€/MWh)
Germany	Export	900	**0.61**	-0.70	5.84	800	**3.03**	0.65	3.21	700	**2.76**	-4.00
	Import	1,500	**1.01**	0.70	4.34	1,200	**2.22**	-0.65	6.10	1,000	**6.22**	4.00
England	Export	500	**19.48**	21.13	-	500	**6.56**	4.62	-	550	**7.25**	6.43
	Import	500	**0.44**	-21.13	-	500	**1.95**	-4.62	-	550	**1.78**	-6.43
Belgium	Export	1,300	**0.76**	0.80	-	1,300	**2.06**	2.73	1.23	1,300	**0.90**	1.75
	Import	800	**0.11**	-0.80	-	400	**0.25**	-2.73	0.34	400	**0.56**	-1.75
Spain	Export	-	-	-2.75	8.98	150	**5.17**	-3.40	6.38	150	**4.55**	-7.60
	Import	-	-	2.75	7.58	100	**8.46**	3.40	7.92	100	**12.92**	7.60
Italy	Export	400	**7.68**	-	27.40	1,550	**15.48**	-	32.28	1,730	**15.06**	-
	Import	-	-	-	1.94	-	-	-	2.17	700	**1.93**	-

Sources: RTE, Powernext, EEX, Belpex, OMEL, IPEX and Platts – Analysed by CRE

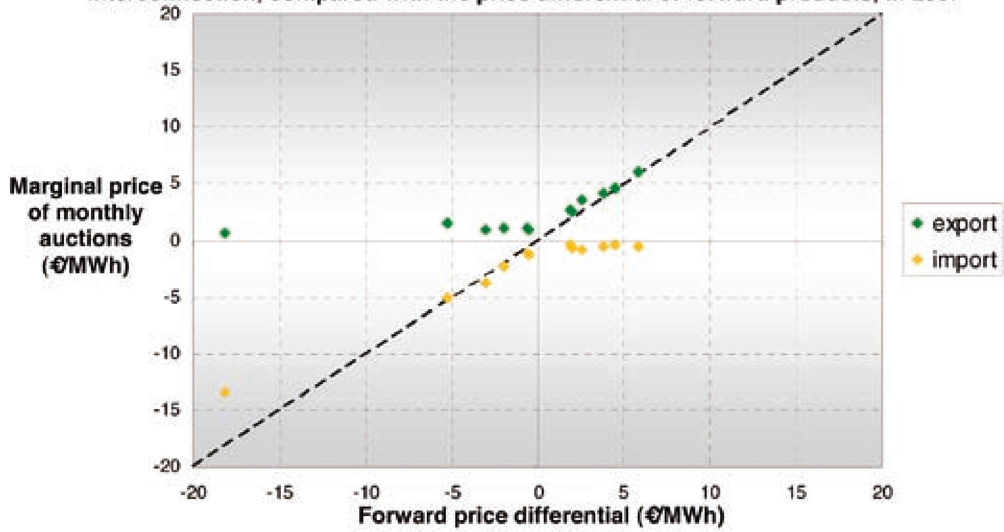
26. The empty cells in this table are explained as follows:
- in Italy, forward products are not quoted, so it is impossible to compare the annual auction price with the forward price differential;
- in England, the fact that a reliable hourly price does not exist makes it impossible to calculate the theoretical value of capacities that can be calculated for the other borders;
- the same was true for Belgium before Belpex was launched at the end of 2006;
- there were no annual auctions for 2006 on the Spanish interconnection;
- the same was true for imports from Italy for 2006 and 2007.

• Monthly auctions

In 2007, the prices at the monthly auctions overall were consistent with the forward price differentials. When making offers to buy capacity, participants in the monthly auctions take account of the volatility of the prices they are anticipating, since on all the borders it is generally the case that the price attributed to monthly capacities is higher than the forward differential. But even over a timescale of just one month, this volatility is difficult to evaluate; consequently, it is generally underestimated by the operators.

On the German border, this consistency can be clearly seen (Figure 1). On average, the price attributed to monthly capacity exceeded the forward differential by less than 1€/MWh, while actual price volatility was 1.50€/MWh on exports and 3.60€/MWh on imports. This difference corresponds to the risk premium of users of the interconnection.

Figure 1 – Marginal price of monthly capacities on the France-Germany interconnection, compared with the price differential of forward products, in 2007

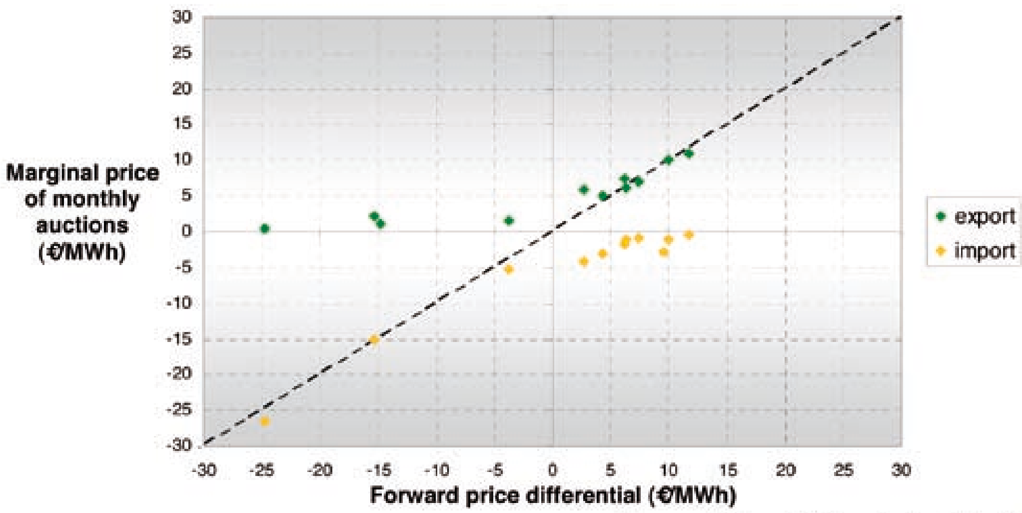


Sources: RTE, Powernext and EEX – Analysed by CRE

This consistency can also be clearly seen on the Spanish border (Figure 2). On average, the risk premium of users of the interconnection was 1.60€/MWh on exports and 0.8€/MWh on imports.

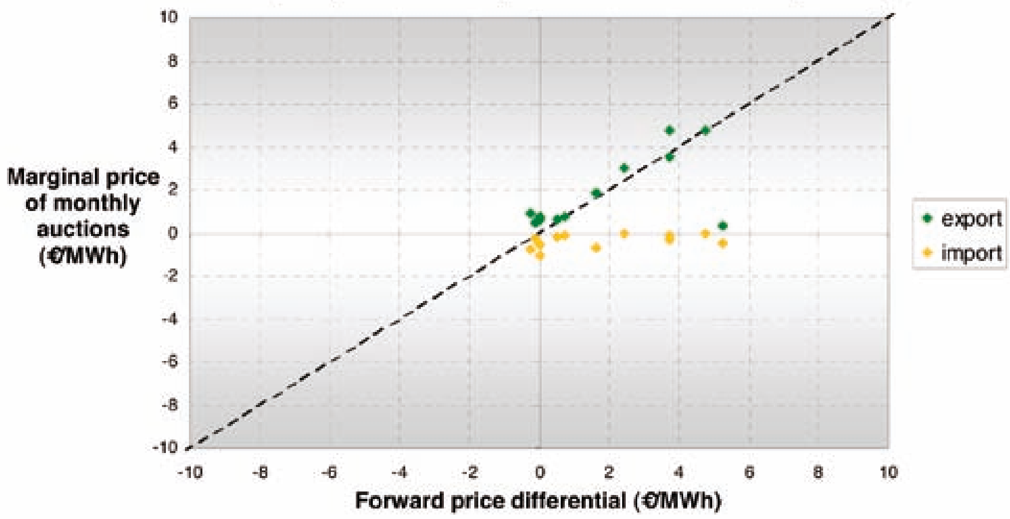
On the Belgian border, there is also consistency between the monthly auction price and the price differential for forward products (Figure 3). On the other hand, as we saw with the annual auctions, both the forward prices and the monthly auction prices seem to overestimate the interconnection value: the French and Belgian hourly prices were aligned for 91% of the time in 2007 (see section 3.3 below), which drastically reduced the theoretical value of the interconnection.

Figure 2 – Marginal price of monthly capacities on the France-Spain interconnection, compared with the price differential of forward products, in 2007



Sources: RTE and Platts – Analysed by CRE

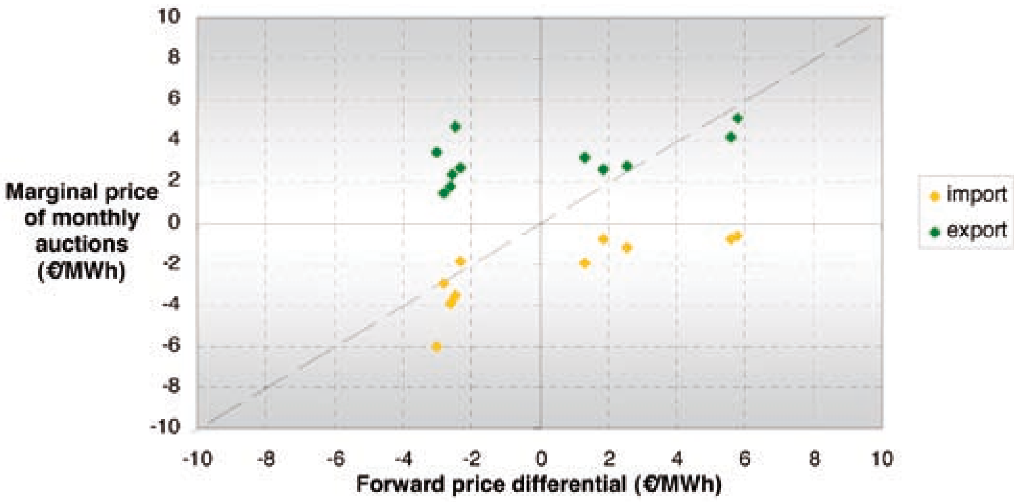
Figure 3 – Marginal price of monthly capacities on the France-Belgium interconnection, compared with the price differential of forward products, in 2007



Sources: RTE and Platts – Analysed by CRE

Unlike the continental French interconnections, on the border with England, correlation between the price attributed to monthly capacities and the price differential for forward products is very low, as shown in Figure 4.

Figure 4 – Marginal price of monthly capacities on the France-England interconnection, compared with the price differential of forward products, in 2007



Sources: RTE and Platts – Analysed by CRE

On the Italian border, the absence of a forward market in Italy means that it is not possible to compare the monthly capacities valuation with a forward price differential. The margin retained by the operators between the price of the capacities and their theoretical value was lower than for the annual capacities (in the order of 6.60€/MWh on average for an average export capacity price of 25.60€/MWh).

2.2. Long-term capacity use

Holders of long-term capacities must state on a daily basis how much capacity they plan to use during each hour of the next day (nomination step). The use of long-term capacities is therefore to be viewed in relation to the hourly price differential between the markets.

In this section, the analysis will look at the interconnections with Germany, Belgium, Spain and Italy. On the France-England interconnection, because long-term capacities are not nominated firmly by the operators, it is not possible to differentiate between the use of long-term capacities and the use of daily capacities, analysed below (section 3.2).

Ideal use of long-term capacities would correspond for each hour in the year to:
- maximum use in the direction of the price differential;
- no use in the opposite direction to the price differential.

Table 6 below should be read as follows:
- the first column gives the annual average for nominations in the opposite direction to the price differential;
- the second column, for the number of hours when the price differential was in a particular direction, gives the ratio of the number of hours during which the nominations were in the opposite direction;
- the third column gives the annual average capacity not nominated in the direction of the price differential;
- finally, the fourth column gives the number of hours during which the capacity was not fully nominated in a particular direction divided by the number of hours during which the price differential was in the same direction.

The ideal use of capacities described above would therefore produce all zeros in this table. However, it can be seen that the actual use of long-term capacities is far from this ideal.

Table 6 – Use in the opposite direction and under-use of long-term capacities in 2007

		average capacity used in the opposite direction to the price differential (MW)	*proportion of hours concerned*	average capacity not used in the price differential direction (MW)	*proportion of hours concerned*
Germany	Export	534	*63 %*	388	*72 %*
	Import	625	*70 %*	1137	*74 %*
Belgium	Export	652	*100 %*	90	*45 %*
	Import	2	*2 %*	138	*100 %*
Spain	Export	99	*44 %*	72	*39 %*
	Import	17	*19 %*	63	*60 %*
Italy	Export	1735	*100 %*	78	*30 %*

Sources: RTE, Powernext, EEX, Belpex, OMEL and IPEX – Analysed by CRE

On the Belgian and Italian borders, it can even be seen that long-term capacities are systematically used for export, regardless of the direction of the price differential. On the Belgian border, the long-term import capacities are systematically under-used.

In fact, the use of long-term capacities seems to be governed more by a ‘business-as-usual’ logic, or by long-term arbitrages, than by hourly arbitrages. This use has to be explained by the long-term capacity nomination step, which occurs before the day-ahead price fixing takes place.

But if netting and “use-it-or-lose-it” are correctly applied to the capacities by the TSOs, that is, when the amount of long-term capacities unused or used in the opposite direction is added to the daily capacities available, this poor use of long-term capacities has no impact on the overall use of the interconnection. However, the use of the daily capacities is crucial (section 3.2).

2.3. Experience feedback from secondary markets

On all the French interconnections (excluding with Switzerland), there are secondary capacity markets, which enable the holders of long-term capacities to sell on or transfer their products. These secondary markets were set up:

- on the France-England interconnection (IFA), on 1 April 2001 for capacity resale (version 1 of the rules) and on 3 September 2001 for capacity transfer (version 2 of the rules); the transfer rule was made more flexible in version 6 of the rules, dated 31 October 2006;
- on 1 January 2007 on the interconnections with Germany, Belgium and Italy;
- on 1 July 2007, on the interconnection with Spain.

Two mechanisms coexist:

- *resale of capacities:* long-term capacities can be sold on at daily auctions (at hourly time intervals), at the request of holders of capacities at least 2 days before day D (the original holder of the capacity then receives the daily auction price); similarly, annual capacities can be sold on in the form of a band, at monthly auctions[27];
- *transfer of capacities:* the operators can trade long-term capacities bilaterally over a period of their choice (hourly time intervals).

27. On the France-England interconnection, the other long-term capacities (seasonal, quarterly) can also be resold on a monthly basis.

It should be noted that both mechanisms only concern the Italian border in the export direction because, before 2008, no long-term capacity had been allocated from Italy to France.

• Resale of capacities

On the continental interconnections, the capacity resale mechanisms were quite well used in 2007, with a third of long-term capacity holders using the services, taking all interconnections together (Tables 7 and 8). It was mainly the resale of long-term capacities on a daily basis that was used, enabling the operators that used it to convert the “use-it-or-lose-it” principle into “use-it-or-sell-it”.

Although the secondary market for the interconnection with England is free of charge for users, no operators used this mechanism in 2007. The secondary market as it currently exists on the France-England interconnection allows the operators to resell or transfer to one another only 24-hour capacity bands (in accordance with the products sold on the primary capacities market). The lack of flexibility of the product, because of the impossibility of transferring or reselling capacities in hourly intervals, could explain why there was little interest among the operators in the resale mechanism on this interconnection.

Table 7 – Resale of annual capacities by the month (2007)

		number of operators using this service	*proportion of operators using this service compared with the number of holders of long-term capacities*	average capacity resold in year (MW)	*average share of long-term capacities*
Germany	Export	2	*22 %*	171	*21 %*
	Import	2	*5 %*	61	*5 %*
England	Export	0	*0 %*	0	*0 %*
	Import	0	*0 %*	0	*0 %*
Belgium	Export	1	*8 %*	16	*1 %*
	Import	1	*20 %*	25	*6 %*
Spain	Export	1	*33 %*	6	*4 %*
	Import	1	*33 %*	49	*49 %*
Italy	Export	3	*12 %*	270	*17 %*

Source: RTE – Analysed by CRE

Table 8 – Resale of long-term capacities by the day (2007)

		number of operators using this service	*proportion of operators using this service compared with the number of holders of long-term capacities*	average capacity resold in year (MW)	*average share of long-term capacities*
Germany	Export	12	*28 %*	444	*32 %*
	Import	12	*24 %*	530	*24 %*
England	Export	0	*0 %*	0	*0 %*
	Import	0	*0 %*	0	*0 %*
Belgium	Export	2	*8 %*	484	*25 %*
	Import	3	*15 %*	426	*51 %*
Spain	Export	4	*29 %*	140	*33 %*
	Import	5	*36 %*	35	*15 %*
Italy	Export	13	*33 %*	347	*4 %*

Source: RTE – Analysed by CRE

• **Transfer of capacities**

There were no bilateral transfers of capacities on the interconnections with England and Spain, and they were very rare on the interconnections with Belgium and Germany (Table 9). However, on the Italian border, transfers were more common with 10 operators out of 39 making them. The fact that the names of holders of capacities are published for this border only is probably the reason for this difference.

Table 9 – Long-term capacity transfers (2007)

		number of operators using this service	*proportion of operators using this service compared with the number of holders of long-term capacities*	average capacity transferred in year (MW)	*average share of long-term capacities*
Germany	Export	2	*5 %*	4	*0.3 %*
	Import	0	*0 %*	0	*0 %*
England	Export	0	*0 %*	0	*0 %*
	Import	0	*0 %*	0	*0 %*
Belgium	Export	2	*8 %*	18	*1.1 %*
	Import	2	*10 %*	4	*0.5 %*
Spain	Export	0	*0 %*	0	*0 %*
	Import	0	*0 %*	0	*0 %*
Italy	Export	10	*26 %*	118	*4.7 %*

Source: RTE – Analysed by CRE

3. Analysis of daily capacity allocation mechanisms

3.1. Valuation of daily capacities sold by explicit auction

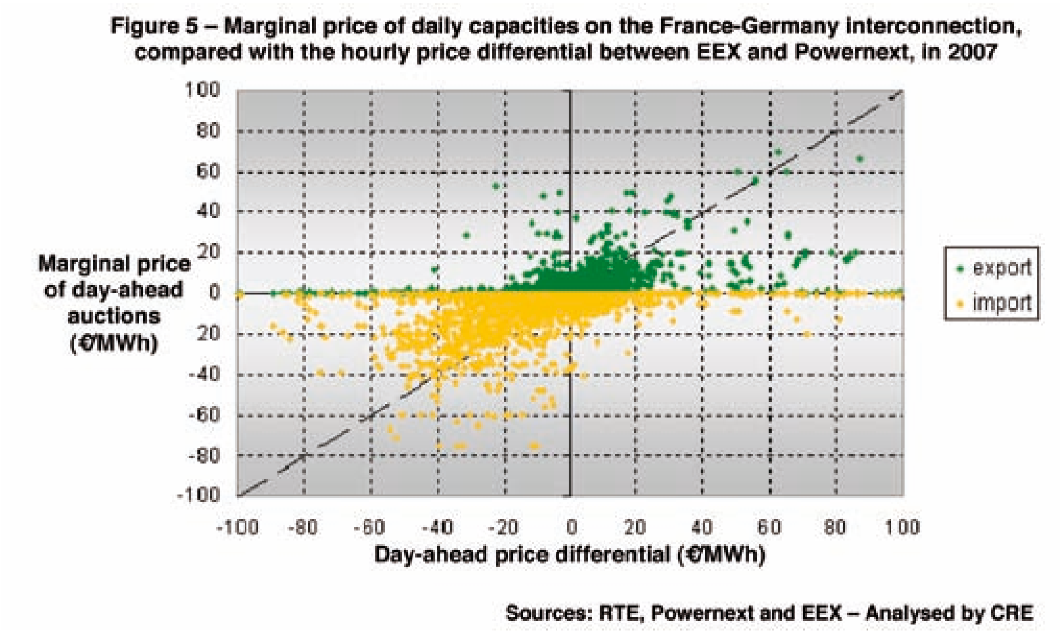
The value of the daily capacities, hour by hour, should be viewed in relation to the hourly price differential between the markets.

In theory, the price of the daily capacities should be equal to the price differential of the day-ahead markets. In Figures 5 to 8 below, this theoretical use would be shown by:

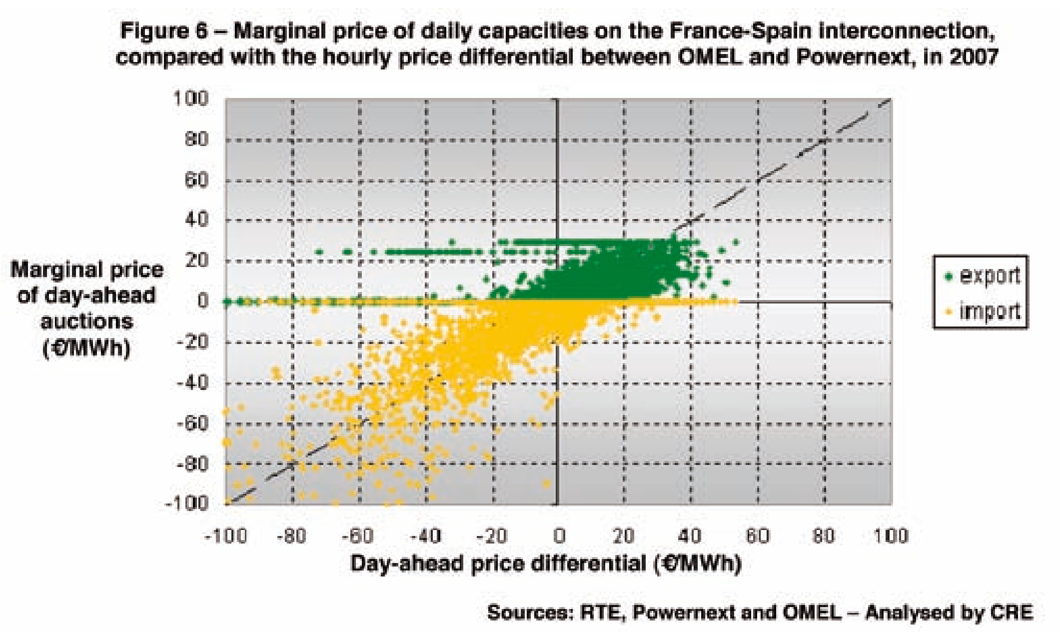
- a value of zero for capacity when the price differential is in the opposite direction (a cluster of points aligned to the line “y=0”),
- a value equal to the price differential when this is in the correct direction (a cluster of points aligned to the line “y=x”).

In reality, because the daily explicit auctions take place before the prices are fixed on the organised markets, those taking part in the auctions can only use estimates of the price differential, and this could partially explain the difference between the auction result and the price differential. This is one characteristic of the separation of the energy and transmission markets (allocation by explicit auctions).

On the German border (Figure 5), it can be seen that the price attributed to daily capacities in 2007 had little in common with the price differential between the organised markets. This suggests that anticipating the price differential a few hours before the prices are fixed on the exchanges is still difficult for the operators.

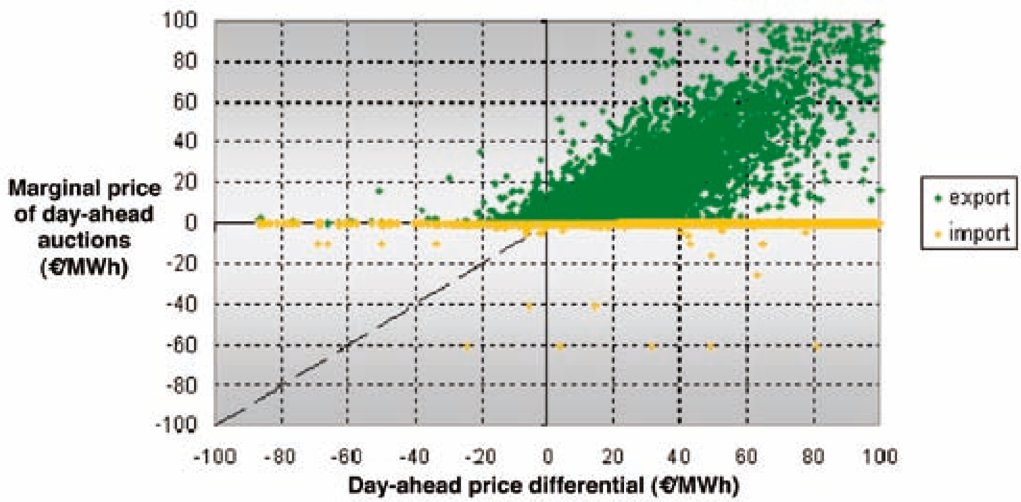


The same is true on the Spanish border (Figure 6). On this interconnection, export capacities have often, inexplicably, been bought at a very high price of between 25 and 30€/MWh, though the price differential between OMEL and Powernext favoured exchanges in the opposite direction.



On the Italian border (Figure 7), because the price differential is easier to predict, the valuation of daily export capacities to Italy is closer to the theoretical value, though there is still quite a large margin for error. On the other hand, import capacity valuations have proven to have very little connection with the price differential between IPEX and Powernext. On top of the inherent inefficiency of separating the transmission and energy markets, this is also explained by the unsuitable design of these daily auctions: in 2007, the daily import capacities were allocated and automatically nominated on D-2, well before the fixing of prices on the organised markets. Since 1 January 2008, at the request of regulators and market operators, import capacities have corresponded to options, allocated and nominated on D-1, like on the other borders.

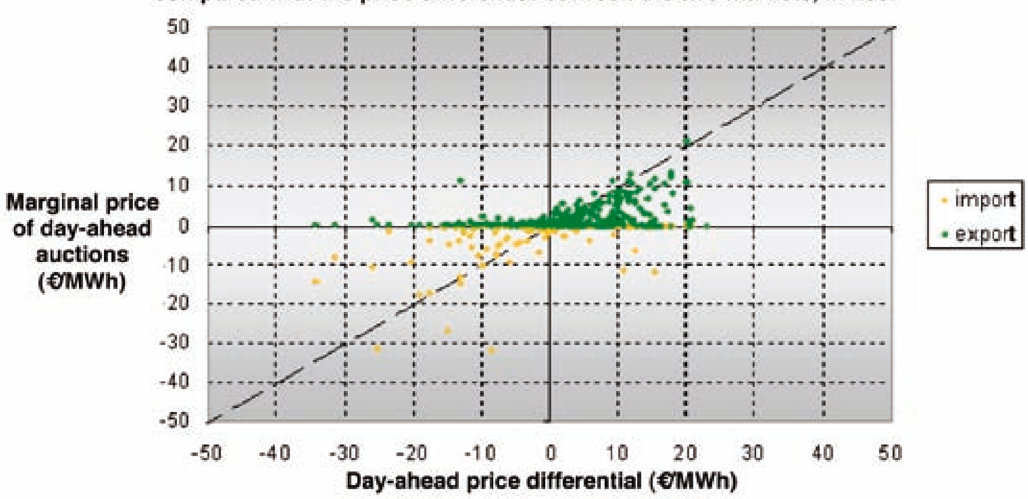
Figure 7 – Marginal price of daily capacities on the France-Italy interconnection, compared with the hourly price differential between IPEX and Powernext, in 2007



Sources: RTE, Powernext and IPEX – Analysed by CRE

On the English border, the products sold in daily auctions are 24-hour bands, unlike the products sold on the continental borders, which offer 24 separate blocks. Therefore, on this border, the price of daily capacities should be viewed in relation to the base daily price differential; the absence of day-ahead price fixing in England means we have to look at an OTC price index. In Figure 8, the clusters of points created in this way are therefore smaller in amplitude than those for other interconnections, because looking at daily and not hourly prices tends to strike out the price differential. However, this figure shows the same inefficiency as for the other interconnections, since the price attributed to daily capacities shows little correlation with the price differential between the markets.

Figure 8 – Marginal price of daily capacities on the France-England interconnection, compared with the price differential between the two markets, in 2007



Sources: RTE and Platts – Analysed by CRE

3.2. Use of daily capacities sold by explicit auction

Ideal use of daily capacities would correspond for each hour in the year to:

- maximum use in the direction of the price differential: the rate of use of these capacities (nominated capacities divided by available capacities) should be equal to 1;
- no use in the opposite direction to the price differential: the rate of use should then be zero.

This ideal use would appear in Table 10 below (which should be read in the same way as Table 6 on long-term capacity use) as all zeros, and in Figures 9 to 13 below as two 'S'-shaped clusters of points (see figure 14 further on for a graphical illustration of ideal use).

Table 10 – Use in the opposite direction and under-use of daily capacities in 2007

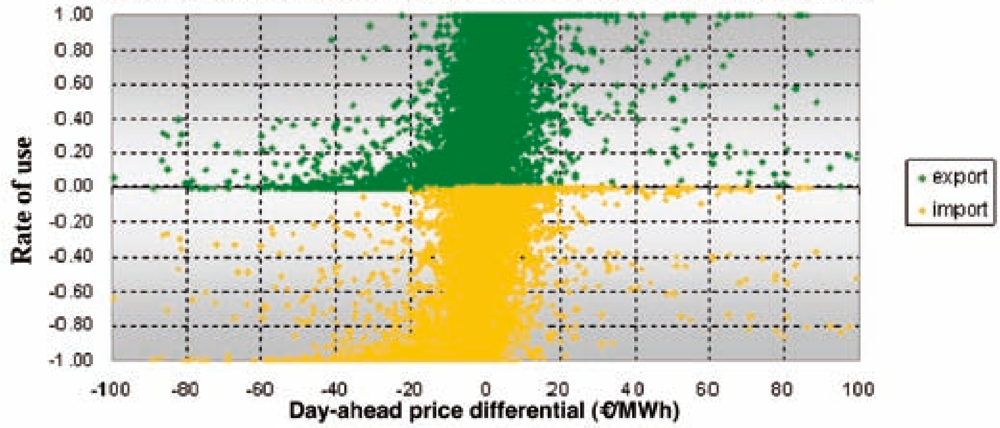
		capacity used in opposite direction to price differential (MW)	*proportion of hours concerned*	capacity not used in the price differential direction (MW)	*proportion of hours concerned*
Germany	Export	298	*80 %*	843	*83 %*
	Import	732	*86 %*	2,159	*88 %*
England	Export	317	*69 %*	612	*73 %*
	Import	110	*27 %*	1,150	*97 %*
Spain	Export	350	*97 %*	86	*28 %*
	Import	13	*13 %*	127	*42 %*
Italy	Export	336	*81 %*	91	*13 %*
	Import	24	*9 %*	849	*94 %*
Switzerland	Export	2,911	*100 %*	111	*50 %*
	Import	332	*98 %*	1,219	*98 %*

Sources: RTE, Powernext, EEX, OMEL, IPEX, Swissix and Platts – Analysed by CRE

Reading Table 10, it can be seen that the level of capacities used in the opposite direction to the price differential and under-used capacities was high in 2007.

On the France-Germany interconnection, the daily capacities were almost always used simultaneously in both directions, regardless of the price differential, even where the differentials were very high (Figure 9).

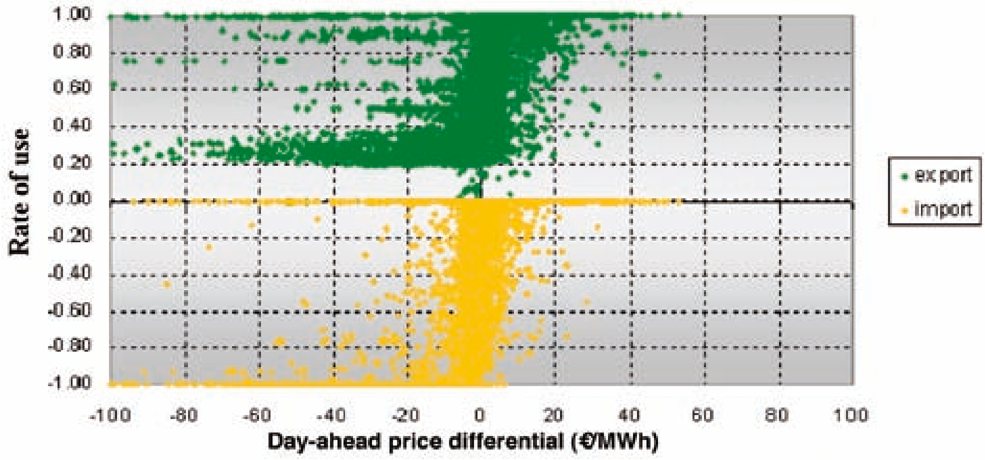
Figure 9 – Rate of use of daily capacities on the France-Germany interconnection, compared with the price differential between EEX and Powernext (2007)



Sources: RTE, Powernext and EEX – Analysed by CRE

On the France-Spain interconnection, the export capacities were systematically used at a level of 300 MW minimum, regardless of the price differential. However, the import capacities were used more responsively to the price differential (Figure 10).

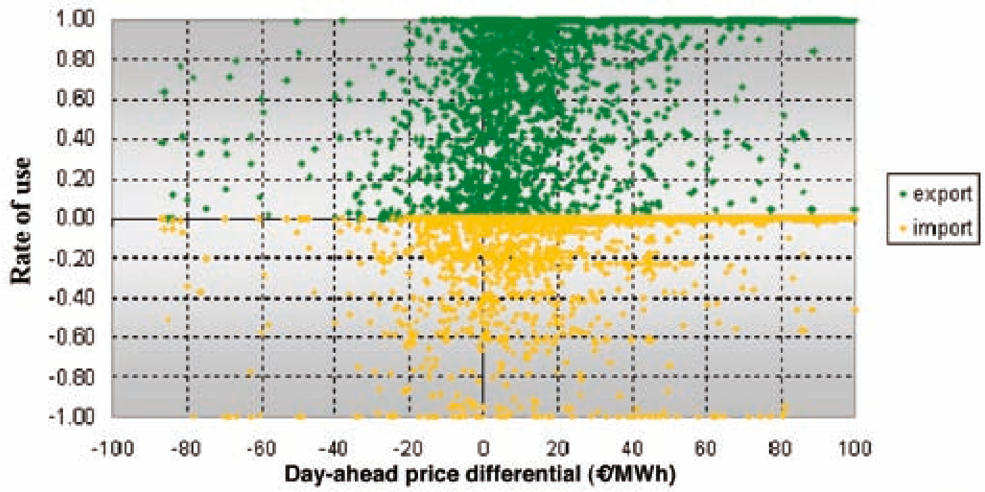
Figure 10 – Rate of use of daily capacities on the France-Spain interconnection, compared with the price differential between OMEL and Powernext (2007)



Sources: RTE, Powernext and OMEL – Analysed by CRE

On the France-Italy interconnection, the price differential was almost always favourable to exports (93% of the time), and logically the export capacities were saturated almost continuously. When the price differential was reversed, which happened mainly at the end of the year during price peaks on Powernext, exports were still made and the import capacities were used in a way that reacted little to the price differential (Figure 11). This is explained in part by the unsuitable 'design' of the daily auctions in the import direction (obligations sold on D-2).

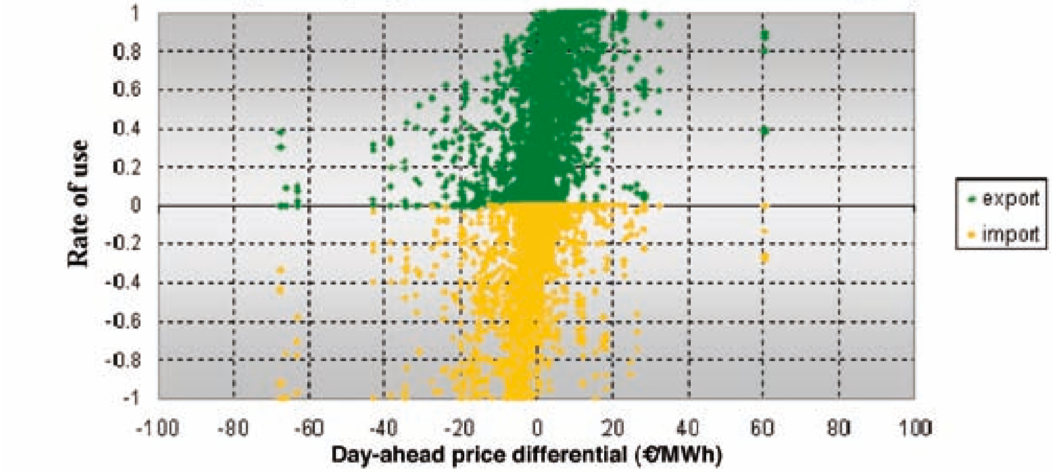
Figure 11 – Rate of use of daily capacities on the France-Italy interconnection, compared with the price differential between IPEX and Powernext (2007)



Sources: RTE, Powernext and IPEX – Analysed by CRE

Analysis of the use of capacities on the France-England interconnection differs from analyses for the continental connections for two reasons. The first is that, as mentioned above, the long-term capacities are not nominated firmly before the daily capacities are allocated. So an analysis of capacity usage can only relate to the whole of the interconnection capacity, and not to the capacity allocated on a daily basis. The second, and this is what makes it difficult to produce reliable analyses, is that on the British market, there are no hourly prices fixed on D-1 as there are on the continental organised markets. So the hourly use of the interconnection capacities can only be compared with the average prices over 12 hours (peak and off-peak), which strikes out the price differential. The figures shown in Table 10 should therefore be considered with caution. Despite these approximations, it can be seen that the same inefficiencies apply to the use of this interconnection as to that of the French continental interconnections (Figure 12).

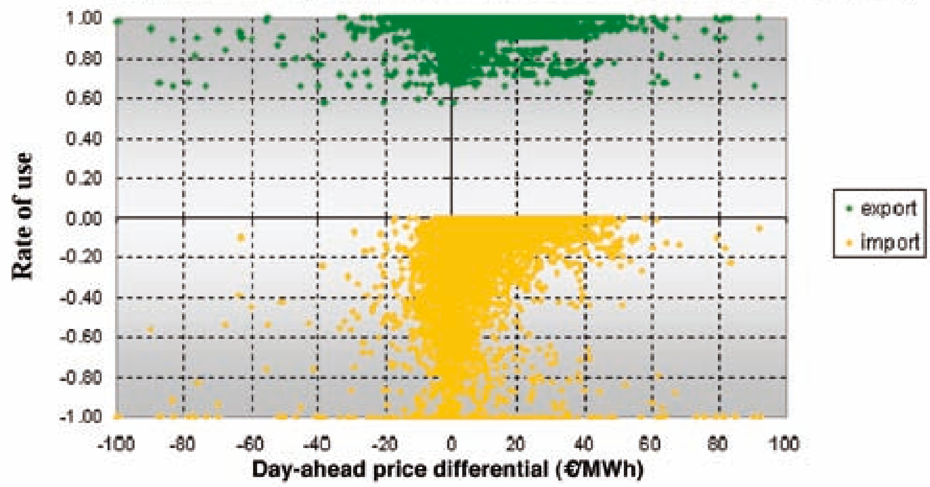
Figure 12 – Rate of use of capacities on the France-England interconnection, compared with the peak/off-peak price differential between the two markets (2007)



Sources: RTE and Platts – Analysed by CRE

On the France-Switzerland interconnection, it is not possible to make the same calculations because export capacities are not allocated since long-term contracts still have priority there. However, it is possible to compare the nominations on the interconnection with net import and export capacity, and to view the capacity usage rate calculated in this way in relation to the price differential between the two organised markets (Figure 13).

Figure 13 – Rate of use of net capacities on the France-Switzerland interconnection, compared with the price differential between SwissIX and Powernext (2007)



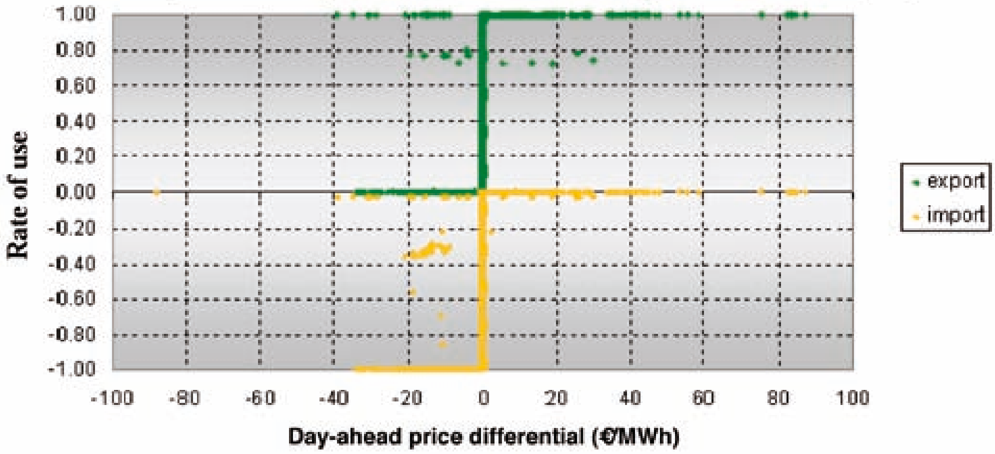
Sources: RTE, Powernext and Swissix – Analysed by CRE

3.3. Experience feedback on trilateral market coupling

Trilateral market coupling (or TLC) allowed the allocation and use of daily capacities between France, Belgium and the Netherlands for 363 days in 2007. On 28 and 29 April, coupling did not work because of a technical problem on one of the three exchanges. In application of the TLC degraded mode procedures, the national day-ahead markets operated in uncoupled mode and the cross-border capacity was allocated by explicit auctions.

On the 363 'coupled' days, the daily flows were perfectly consistent with the prices (by definition of the coupling algorithm), which allowed optimal merit order for offers made on the three exchanges. In Figure 14, the points indicating poor use of daily capacities in relation to the price differential correspond to the 48 hours where the markets were uncoupled.

Figure 14 – Rate of use of daily capacities on the France-Belgium interconnection, compared with the price differential between Belpex and Powernext (2007)



Sources: RTE, Powernext and Belpex – Analysed by CRE

Coupling the markets produced strong price convergence in the three organised markets (Table 11). In particular, the Powernext and Belpex prices were the same for 91% of the year. The prices on all three organised markets were the same for 63% of the year, though the APX and Powernext prices had been aligned for only 10% of the time in 2006.

Table 11 – Convergence of Powernext, Belpex and APX hourly prices in 2007[28]

	proportion of hours in 2007	*2006: APX-Powernext convergence[29]*
Three prices the same	63%	*10%*
Only Powernext and Belpex prices the same	27%	
Only APX and Belpex prices the same	9%	
No prices the same	1%	

Sources: Powernext, Belpex and APX – Analysed by CRE

28. Apart from the two days when the three exchanges were uncoupled (the three prices were never aligned at these times).

29. Proportion of hours during which the price differential between APX and Powernext was below 1€/MWh, from 1 January 2006 to 21 November 2006 (start of market coupling). No comparison of this type is possible for Belgium because the Belpex exchange was set up when coupling began.

Furthermore, the daily capacities were used for 29% of the time in the direction of imports to France, compared with 25% of the time in 2006 (Table 12).

Table 12 – Direction of daily flows between France, Belgium and the Netherlands in 2007[30]

	proportion of hours in 2007	*comparison with 2006*[31]
France → Belgium → Netherlands	56%	
France → Belgium ← Netherlands	15%	
Total with France exporting:	**71%**	*75%*
France ← Belgium ← Netherlands	24%	
France ← Belgium → Netherlands	5%	
Total with France importing:	**29%**	*25%*

Sources: RTE and Elia – Analysed by CRE

3.4. Estimate of the "loss in social welfare" associated with the absence of implicit methods

The "loss in social welfare"[32] associated with the absence of market coupling on the German, English, Spanish, Italian and Swiss borders is estimated as follows: for each hour, it is the product of the positive part of the price differential between the exchanges and the daily capacity that remains unused or is used in the opposite direction. This estimate should be considered with caution (inset 6). However, it does at least give an idea of the scale of this loss of social welfare on each border (Table 13).

Table 13 – Loss of social welfare associated with the absence of market coupling in 2007

		Loss in social welfare estimated (M€)	Total (M€)
Germany	Export	45	110
	Import	65	
England	Export	22	57
	Import	34	
Spain	Export	3	21
	Import	18	
Italy	Export	18	47
	Import	29	
Switzerland	Export	32	97
	Import	65	
		Total:	**332**

Sources: RTE, Powernext, EEX, OMEL, IPEX, SwissIX and Platts – Analysed by CRE

30. Apart from the two days when the three exchanges were uncoupled.

31. From 6 January 2006 (the launch date of the daily explicit auctions) to 21 November 2006 (start of market coupling).

32. Or loss of collective surplus.

Inset 6 – Limitations of this estimate

• The estimate assumes "all else being equal" and in particular it does not take account of the possible change in behaviour of the market operators in the organised markets following the introduction of market coupling. It is difficult to make an ex ante assessment of the impact of introducing market coupling on the buying and selling offer strategies of market operators in the organised markets.

• The estimate does not take account of market resilience, i.e. the impact on prices of altering the volumes exchanged. Better use of daily capacities would lead to price convergence; the figures given in Table 13 are therefore the upper bounds of actual loss of social welfare, which can only be estimated precisely using aggregated curves of supply and demand on each market.

• Regarding imports from Italy, this estimate was made as part of the allocation mechanism in force in 2007 (obligations sold on D-2). So the loss of social welfare associated with the absence of coupling is, on the face of it, greater than when options are allocated on D-1. Furthermore, the price used to make this estimate is the average Italian price (as a reminder, Italy operates on the basis of internal market splitting).

• Regarding England, because of the absence of an hourly price fixed on D-1 on this market, the peak and off-peak prices are used to produce this estimate.

• Regarding Switzerland, this estimate is based on the net transfer capacity, and on the flows that occurred in 2007 including those made under long-term contracts (taking the hypothesis that with coupling, all capacity would be allocated on a daily basis). The price reference used for the Swiss market (SwissIX) should also be considered with caution, because of the low volumes traded on this exchange.

3.5. Market coupling and price peaks

In 2007, there were three price peaks on the French organised market, at 6 pm on 29 October, 8 pm on 12 November and 6 pm on 15 November. The Powernext prices rose at these times to 1,236€/MWh, 2,500€/MWh and 1,762€/MWh respectively.

Table 14 – Energy flows and prices on neighbouring organised markets during the price peak at 6 pm on 29 October (1,236€/MWh)

		Nominations of long-term capacities (MW)	Nominations of daily capacities (MW)	Unused import capacities (MW)	Price on neighbouring market (€/MWh)	Price differential (€/MWh)
Germany	Export	0	301	**1,750**	198	1,038
	Import	583	1,957			
England	Export	1,398	500	**3,347**	115	1,121
	Import	-	51			
Spain	Export	0	230	**230**	54	1,182
	Import	181	119			
Italy	Export	2,077	95	**2,997**	174	1,062
	Import	-	75			
Switzerland	Export	2,866	-	**2,971**	134	1,102
	Import	180	1,515			

Sources: RTE, Powernext, EEX, OMEL, IPEX, SwissIX and Platts – Analysed by CRE

At the same time, it was seen on the interconnections that:

- a large import capacity volume remained unused (11,295 MW, 9,943 MW and 4,470 MW respectively for each of the price peaks) on all borders, and the prices on the neighbouring organised markets were all, with the exception of those on Belpex, much lower than the Powernext prices (see Table 14 for the peak on 29 October);
- France found itself exporting electricity again at the peak price times with export volumes of 1,126 MW, 995 MW and 2,501 MW respectively.

The under-use of interconnection capacity and the use of capacity in the opposite direction to the price differentials clearly highlight that the interconnection capacity allocation mechanisms currently in force do not allow sufficiently reactive management of the interconnections.

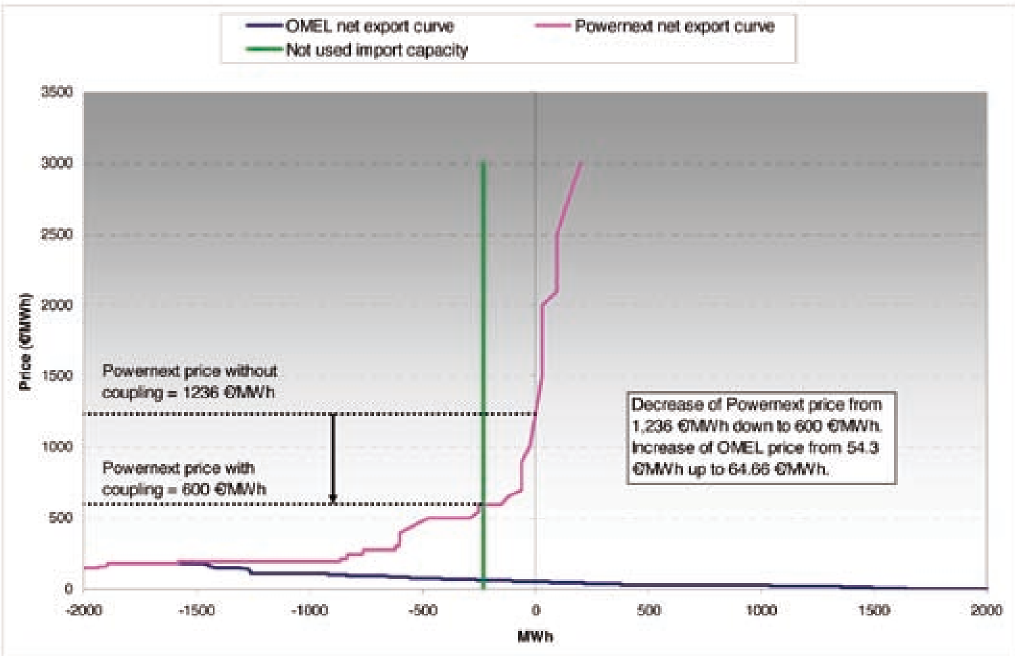
Market coupling for the allocation of daily products would have meant that cheaper offers from neighbouring countries could have been taken up. This would have increased the low-price supply on Powernext, which would undoubtedly have prevented these price peaks from occurring.

To estimate the benefits of the implementation of implicit auctions, the effect of market coupling with Spain during the price peak on 29 October has been simulated. The decision to use this Member State is linked to the fact that OMEL is the only Power Exchange to publish a history of its aggregate supply and demand curves, which are essential for this kind of analysis. The benefits of market coupling can be estimated more accurately for this particular day, using this data, than in the previous section.

At 6 pm on 29 October, when the price differential between Powernext and OMEL was 1,182€/MWh, France could have imported an extra 230 MW from Spain (Table 14). Introducing market coupling for the allocation of daily products with Spain would therefore have made it possible to benefit from 230 MW of cheaper supply. According to the OMEL and Powernext supply and demand curves, this would have halved the price on Powernext, which would have dropped from 1,236€/MWh to 600€/MWh (Figure 15). Meanwhile, the price on OMEL would have increased by only 10€/MWh.

It is also interesting to note that the unused import capacity on the Spanish border was lowest of all the countries under consideration, which suggests that market coupling with Germany, Italy, England or Switzerland would have even more of an effect on Powernext prices.

Figure 15 – Market coupling between France and Spain during the peak on 29 October 2007



Sources: RTE, Powernext and OMEL – Analysed by CRE

4. Intraday capacities

4.1. Review of intraday trades in 2007

Access to cross-border intraday trades offers operators greater flexibility for balancing their position when coping with an unexpected event, and also enables them to engage in short-term arbitrages.

In 2007, three intraday allocation mechanisms co-existed on the French interconnections:
- allocation of options through an "improved pro rata" type mechanism, used by RTE on the Swiss border for exports, on the German border and on the Belgian border (from 22 May 2007);
- allocation of options for nomination, allocated through the explicit auctions mechanism on the Spanish border (in both directions);
- allocation of obligations for nomination through a "first-come, first served" type mechanism, used by the German TSOs RWE and EnBW on the German border, in both directions. This allocation mechanism used by the German transmission system operators was therefore superimposed on the RTE pro rata mechanism on this border.

On the other borders, no intraday capacity allocation mechanisms are used, for various reasons:
- because congestion has not proved to be a problem (imports from Switzerland);
- because nominations of daily capacities can be changed up to an hour before supply (interconnection with England);
- because intraday exchanges do not exist within the neighbouring market (Italy).

Except on the Spanish border, use of intraday capacities has been very low, as Table 15 shows. In Belgium, the usage rate of intraday capacities, which were first allocated from May 2007, has been particularly low.

Table 15 – Use of intraday capacities in 2007

		Capacity available (MW)	Capacity used (MW)	*Usage rate*
Germany	Export	1,239	76	*6.2 %*
	Import	2,991	88	*2.7 %*
Belgium[33]	Export	758	15	*1.8 %*
	Import	2,042	16	*<1 %*
Spain	Export	347	141	*24 %*
	Import	961	130	*13 %*
Switzerland	Export	441	22	*4.3 %*

Source: RTE – Analysed by CRE

4.2. France-Spain interconnection

On this interconnection, the daily capacities are systematically used in the export direction to Spain, up to a level of 300 MW minimum, regardless of the price differential between OMEL and Powernext (see section 3.2). Through the netting of daily capacities, this capacity is automatically offered as intraday capacity in the direction of imports from Spain. The fact that this minimum capacity of 300 MW is offered systematically enables the market operators to use intraday capacity for arbitrages

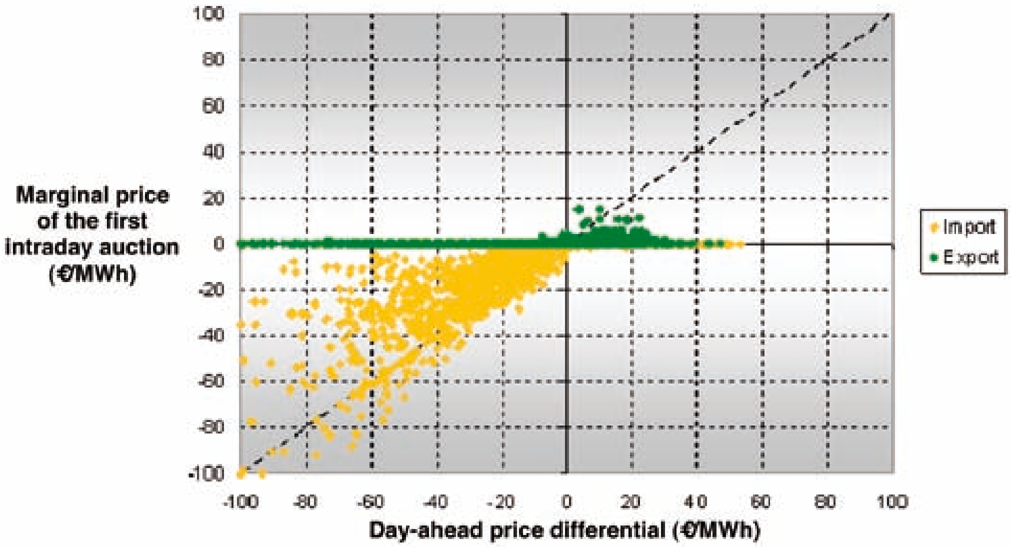
33. Since 22 May 2007.

between the markets organised on a day-ahead basis, though this was not originally intended to be the purpose of intraday exchanges since intraday capacity, which is allocated after the organised markets have closed, can be zero (no intraday capacity is reserved).

In the case of imports from Spain, the possibility of using intraday capacity for arbitrages on the day-ahead markets is very useful for the market operators because the net import capacity is very low (in the order of 290 MW). The capacity offered at the daily auctions for times when the price differential on day-ahead markets was favourable to imports was 270 MW on average, while the capacity offered for these same times at the first intraday auction was 500 MW on average.

As shown in Figure 16, there is a clear correlation between the price at intraday auctions for imports and the day-ahead price differential between OMEL and Powernext. The income from these auctions during 2007 was 6.8 M€ for imports, which represents 26% of total auction income for imports. For exports, this income was only 145,000 €.

Figure 16 – Marginal price of the first intraday auction on the France-Spain interconnection, compared with the hourly price differential between OMEL and Powernext, in 2007



Sources: RTE, Powernext and OMEL – Analysed by CRE

5. Balancing trades

CRE actively supports the development of balancing trades with neighbouring countries because these trades:
- help to improve security of supply,
- allow a reduction of the imbalance settlement price by providing the TSO with cheaper supplies and by increasing competition on the balancing market,
- constitute a step towards the integration of the balancing mechanisms acknowledged as necessary if the internal market in electricity is to work properly (conclusions of the 13th Florence Forum and European Commission Communication of 10 January 2007[34]).

34. COM(2006) 851 final.

5.1. Review of balancing exchanges in 2007

Balancing trades between France and its neighbours can now take place:

- either within the framework of the balancing mechanism (BM): foreign offers are merged with French offers and are called up when their merit order determines,
- or within the framework of emergency reserve exchange contracts entered into between RTE and its neighbouring transmission system operators: foreign offers are only called up as a last resort, once the offers available on the balancing mechanism have been used up.

During normal operation of the balancing mechanism, only the Swiss and German operators actively participate in supplying balancing offers on the French system. In theory, access to the balancing mechanism is also open to British, Spanish and Italian operators. But in practice, the organisation of the intraday market in these Member States combined with the obligation on balancing operators to acquire interconnection capacity to supply balancing offers makes their participation in the French balancing mechanism impossible.

In 2007, the participation of foreign operators in the French balancing mechanism is therefore limited, like last year, to balancing offers activated by RTE from Swiss and German operators, which therefore constitute most of the competition for the historic operator, which dominates the French balancing mechanism.

Table 16 shows that in 2007 the market share of the Swiss and German operators fell slightly on 2006, from 21% to 20% for upward balancing and from 9% to 7% for downward balancing. The German operators increased their market share on upward offers.

Table 16 – Participation of foreign operators in the French balancing mechanism in 2007

	Upward offers in 2007	*2006*	Downward offers in 2007	*2006*
Average capacity activated[35] in the balancing mechanism	312 MW *(-30 % /2006)*	*447 MW*	398 MW *(-8 % /2006)*	*433 MW*
Average participation by foreign operators[36]	62 MW *(20 %)*	*96 MW (21 %)*	27 MW *(7 %)*	*39 MW (9 %)*
Average participation by Swiss operators	50 MW *(16 %)*	*93 MW (19 %)*	18 MW *(4.5 %)*	*22 MW (5 %)*
Average participation by German operators	12 MW *(4 %)*	*12 MW (3 %)*	9 MW *(2.5 %)*	*17 MW (4 %)*

Source: RTE – Analysed by CRE

35. Regardless of the reason for activating the offers, excluding the reconstitution of systems services.

36. An upward offer accepted corresponds, for a foreign operator, to an import into France and a downward offer to an export from France.

The French market operators are at present unable to participate in the balancing mechanisms of neighbouring Member States. This situation results mainly:

- in Spain, from a legal obstacle: only sites directly connected to the Spanish grid are authorised to submit balancing offers;
- in Germany and Belgium, from the management of the balance between supply and demand, which is based almost exclusively on contractual reserves. The contractualization of reserves forces suppliers to guarantee the availability of these reserves at any time. This availability requirement excludes de facto the supply of a cross-border reserve, which is subject to the availability of the interconnection capacity. The availability of the interconnection capacity for balancing exchanges cannot be guaranteed, so reserving interconnection capacity for balancing would be incompatible with efficient interconnection capacity management and in particular with the obligation in Article 6 of Regulation (EC) No 1228/2008 to make any unused capacity re-available to the market;
- in Italy, from the absence of an intraday market and therefore the fact that it is impossible for the operators to modify their offers near to real time in accordance with the balancing needs of their portfolio.

French balancing offers can be activated by RTE at the request of National Grid to meet the needs of the UK grid[37] (Table 17). However, the price of RTE's offers to National Grid is not linked to the price of the offers available on the French balancing mechanism.

Table 17 – Requests by National Grid under the BASA contract (GWh)[38]

	2006	2007
Exchange in the France → England direction	278	307
Exchange in the England → France direction	154	134

Source: RTE – Analysed by CRE

Under the emergency reserve exchange contracts between TSOs, balancing exchanges can only take place as a last resort, once the available offers have all been used up. These reserves are therefore called upon by RTE outside the normal functioning of the balancing mechanism, just before it resorts to exceptional resources[39]. The offers are exchanged by the TSOs at a price worked out the previous day from prices on the organised markets, using a method provided for in the contract. The availability of these reserves is not guaranteed and one of the TSOs may at any time make its reserves unavailable to cope with difficulties on its own system. When they are available, these emergency reserves can be activated in 10 minutes.

RTE has contracts to exchange emergency reserves with all its neighbouring countries except Spain, because Spanish legislation does not permit this at present.

The electricity activated under the emergency contracts in 2007 is shown in Table 18. For RTE activations under its emergency contracts (Import in Table 18), the price of the electricity it bought varied in 2007 between 90 and 340€/MWh (it was between 142 and 300€/MWh in 2006). The volumes called upon by RTE in 2007 to maintain a balance between supply and demand in France were much lower than in 2006.

37. These offers are activated under the BASA contract (Balancing and Ancillary Services Agreement for the provision of commercial ancillary services) between RTE and National Grid.

38. These figures take account of activations of the BASA contract by National Grid within the normal operation of the British balancing mechanism, but also where there are insufficient offers available ('emergency' section of the contract). For the most part, the exchanges result from activation of the contract within the normal functioning of the British balancing mechanism.

39. These are available resources, the use of which is limited by restrictive conditions on the balancing operator and RTE, and emergency resources (drop in voltage, load-shedding).

Table 18 – Activation of emergency reserves (MWh)[40]

	Export (activation from RTE)		Import (activation by RTE)	
	2007	*2006*	2007	*2006*
Germany	0	*0*	300	*0*
Belgium	8 075	*1 613*	890	*3 293*
Italy	3 000	*44 400*	1 350	*13 062*
Switzerland	125	*0*	312	*0*

Source: RTE – Analysed by CRE

5.2. Development potential of balancing trades

As explained above, only the Swiss and German operators can participate in the French balancing mechanism at present, but this arrangement is not reciprocal. Consequently, a major effort is necessary to develop access by other foreign operators to the French balancing mechanism and, reciprocally, access by French operators to the balancing mechanisms in neighbouring countries.

A review of the use of interconnection capacities shows that an important share of the capacity that remains unused by the market operators could be used for balancing trades (see Table 19).

Table 19 – Unused interconnection capacity available for balancing exchanges, in 2007

	Average capacity available for export (MW)	Percentage of hourly steps when capacity available for balancing exports is above 500 MW	Average capacity available for import (MW)	Percentage of hourly steps when capacity available for balancing imports is above 500 MW
Germany	1 180	50 %	3 970	97 %
England	1 000	50 %	880	90 %
Belgium	1 180	70 %	2 280	99 %
Spain	300	23 %	1 060	80 %
Italy	120	8 %	3 400	100 %

Source: RTE – Analysed by CRE

6. Capacity management by the TSOs

6.1. Evolution in capacities

The question of capacity levels is a very difficult one, and a major challenge for the development of the European energy market.

The challenge in the short term is to optimise the use of existing infrastructure by making available to the market operators *"the maximum capacity of the interconnections and/or the transmission networks affecting cross-border flows […], complying*

40. Excluding England, because data for the use of the emergency section of the BASA contract are not yet available.

with safety standards of secure network operation" (Article 6(3) of Regulation (EC) No 1228/2003). At present, however, we have to aknowledge that there is great disparity between the information available to regulators and TSOs on the margins for manoeuvre actually available to the TSOs to increase the interconnection capacity available to the market operators.

In the longer term, the challenge is to develop new transmission infrastructure. This requires, on the one hand, major coordination by the TSOs to identify actual investment needs, and on the other, the simplification of authorisation procedures for the construction of new lines, and finally, coordination between the regulators on financing investment.

Several options are being discussed, within the framework either of current regulatory obligations or of the third legislative package, to meet these substantial challenges, which include:
- an obligation of transparency on the part of TSOs when calculating the capacities made available to the market;
- an obligation to improve coordination between the TSOs, both for calculating capacities and for preparing regional investment plans;
- the introduction of suitable indicators, with the ultimate objective of accelerating market integration.

In this section we look at the growth in capacities on the various French interconnections, with particular emphasis on capacities allocated over the long term (annual and monthly). A number of observations have arisen from this analysis, which in turn have led to the following questions:
- How do we explain the tendency towards a reduction in the total capacities made available to the market, observed since the market mechanisms for allocating interconnection capacities were set up (France-Germany mainly in the import direction, France-Spain in both directions and France-Italy in the import direction)?
- How do we explain the fact that before the auction mechanisms were introduced, the net flows on the France-Germany interconnection were regularly higher than the declared net capacities? Should we conclude that at this time, the TSOs had chosen to authorise larger cross-border flows, and were assuming this risk?
- On some interconnections, not all the capacities that could be allocated on long-term timeframes were made available to the market. To the extent that mechanisms for reselling long-term capacities on a daily basis already exist and a "use-it-or-sell-it" type mechanism will soon be set up on all the French interconnections, is reserving part of the capacities for daily timeframes still justified?
- Finally, on some interconnections (France-Germany in both directions and France-Belgium in the export direction), in 2008 a reduction in the volume of long-term capacities made available to the market was observed. How can this be justified?

• Evolution of the net transfer capacities two days before delivery (NTC D-2)[41]

Every day, the TSOs estimate the total capacity they will be able to allocate two days later. This estimate is based on:
- consumption and production forecasts,
- predictions of the grid configuration, and particularly lines being maintained.

France-Germany interconnection

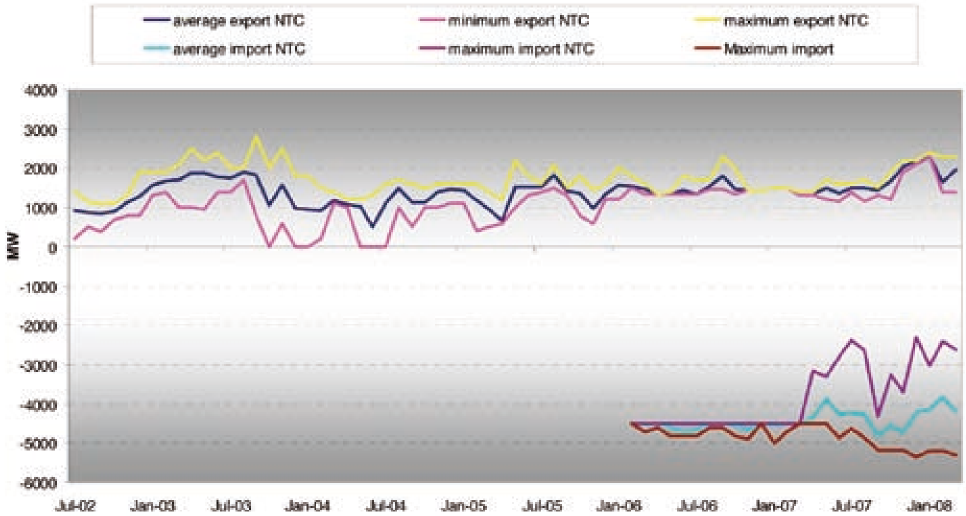
The NTC D-2 annual average for exports has remained relatively constant over the last four or five years (at between 1,400 and 1,500 MW between 2004 and 2007 with a peak in 2003 of 1,623 MW). It was also in 2003 that the NTC D-2 maximum reached its highest levels (up to 2,800 MW compared with 2,400 MW between 2004 and 2007).

41. On RTE's website, "Net Transfert Capacity on D-2" is called "Proposed Net Capacity".

For imports, a long-term comparison is not possible because the TSOs do not publish a history beyond January 2006. However, before the auction mechanisms were set up, the German TSOs were in the habit of not setting limits on export capacities to France.

In this direction, the average annual NTC D-2 for 2007 was 4,370 MW, which is lower than the value for 2006 (4,530 MW). However, the NTC D-2 did regularly exceed 5,000 MW, while the NTC maximum in 2006 was 5,000 MW (Figure 17).

Figure 17 – Evolution of net transfer capacities on D-2 (average, maximum and minimum) for import and export on the France-Germany interconnection



Source: RTE – Analysed by CRE

Table 20 shows the number of hours in the year when the net flow was greater than the NTC D-2.

Before the auctions were set up in January 2006, the allocation of daily products by the TSOs took place at 9.30 am, so well before the nomination of the long-term contracts and the daily nominations for import (at around 2 pm). To be able to allocate daily products, the TSOs were taking the risk of anticipating the result of these nominations, even if it meant having to carry out redispatching actions in real time. That was why, before 2006, there were regularly net flows higher than the export NTC calculated at D-2. Since priority access for long-term contracts was ended and the market mechanisms were introduced on 1 January 2006, the TSOs have not been taking these risks and have been making available to the market exactly the NTC D-2, reduced by the nominations of long-term import and export products very early on D-1.

Table 20 – Number of hours in the year when the net flow was higher than the NTC D-2 on the France-Germany interconnection

	Net exports > export NTC D-2	Net imports > import NTC D-2
2002 (since July)	456	-
2003	112	-
2004	106	-
2005	1	-
2006	29	0
2007	0	0

Source: RTE – Analysed by CRE

France-Belgium interconnection

On this border, the TSOs do not practise netting (see section 6.4 below). Consequently, the NTC D-2 published by the TSOs corresponds in practice to the maximum exports and imports that the operators can make.

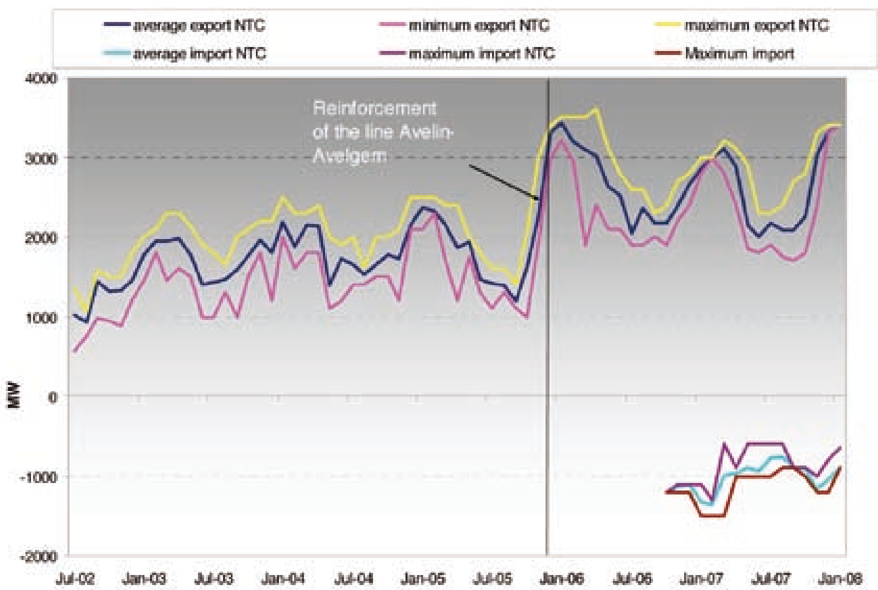
Since July 2002, RTE has published the export NTC D-2. Since that date, ELIA and RTE have upgraded the 400 kV Avelin-Avelgem line (the project came to an end in November 2005), which has increased the interconnection capacity by approximately 70%. Since the line was upgraded, the TSOs have made approximately 800 MW extra available to the operators in summer and 1 000 MW extra available in winter (Figure 18).

In 2007, the average NTC D-2 was 2 575 MW, which is slightly lower than the average for 2006 (2 640 MW).

For imports, the TSOs have only been publishing the NTC D-2 since October 2006, which means it is not possible to find out the gains from upgrading the Avelin-Avelgem line.

However, before the line was upgraded, the import flows were equivalent to the maximum NTC values published since October 2006. This is because, when the long-term contracts had priority access, the TSOs engaged in netting, which released approximately 1 000 MW of additional capacity.

Figure 18 – Evolution of net transfer capacities on D-2 (average, maximum and minimum) for import and export on the France-Belgium interconnection



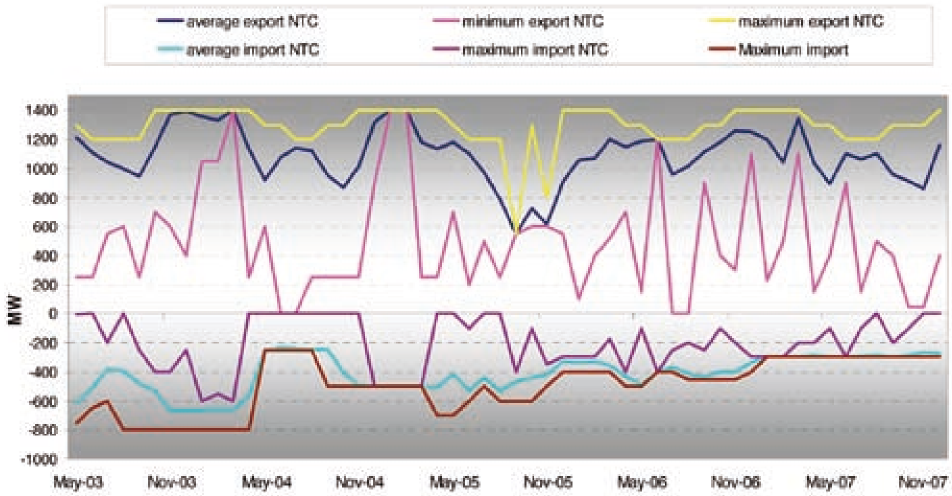
Source: RTE – Analysed by CRE

France-Spain interconnection

In 2007, the average annual export NTC D-2 was 1 057 MW. With the exception of 2005, which was affected by the outage of Cantegrit-Saucats line, this average is the lowest observed since 2003.

For imports, there is a downward trend in the NTC D-2. The average was 289 MW in 2007, though it had been 532 MW in 2003 and 392 MW in 2006. In addition, it can be seen that the NTC was never more than 300 MW in 2007, though in previous years it had sometimes been above 600 MW (Figure 19).

Figure 19 – Evolution of net transfer capacities on D-2 (average, maximum and minimum) for import and export on the France-Spain interconnection



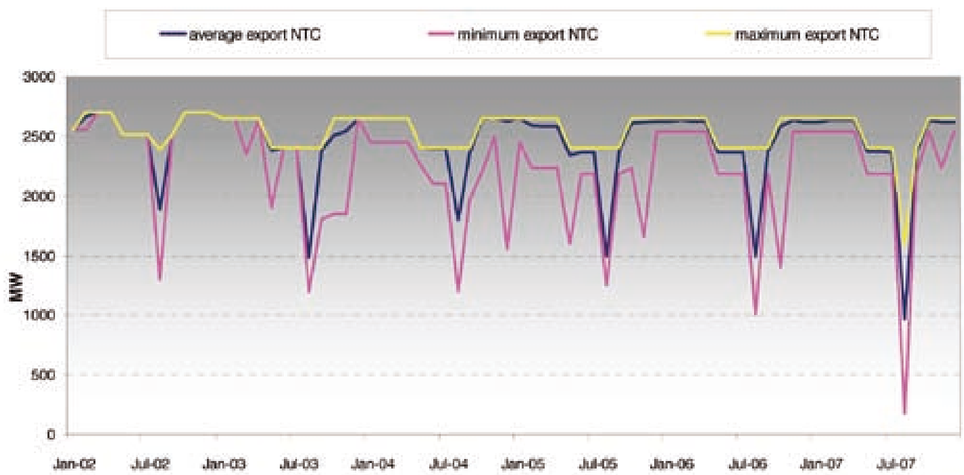
Source: RTE – Analysed by CRE

France-Italy interconnection

The capacity offered for Italy is a guaranteed capacity, which is fixed each year for the next year. Since 2003, the TSOs have been offering 2 650 MW in winter and 2 400 MW in summer (Figure 20), except in August when the capacity is lower because maintenance is regularly carried out during this period.

For imports, the capacity offered since January 2007 has also been a guaranteed capacity. This is 995 MW in winter and 870 MW in summer. Before 2007, the TSOs did not calculate capacity in this direction for the interconnection.

Figure 20 – Evolution of net transfer capacities on D-2 (average, maximum and minimum) for import and export on the France-Italy interconnection



Source: RTE – Analysed by CRE

• Evolution of capacities proposed in long-term auctions

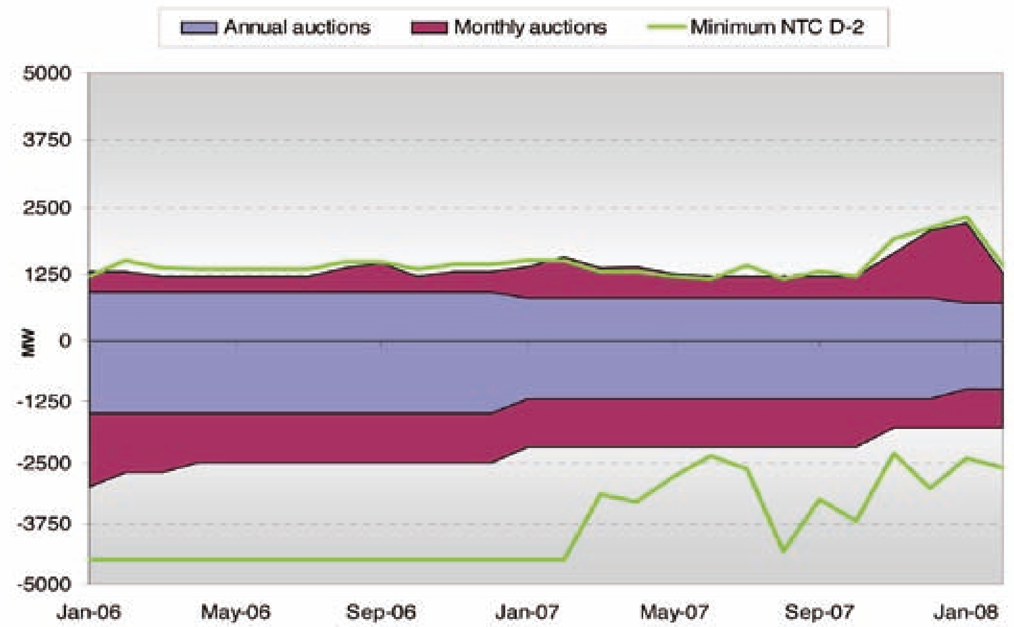
France-Germany interconnection

Since 1 January 2006, the TSOs have been allocating interconnection capacity in a coordinated manner for annual, monthly and daily timeframes, using an explicit auction mechanism. It has been seen that:

- the capacity proposed at annual auctions has fallen, both for export and for import;
- the average capacity proposed at monthly auctions for export increased between 2006 and 2007;
- the average capacity proposed at monthly auctions for import fell between 2006 and 2007.

Figure 21 compares the capacities proposed at the long-term auctions with the NTC D-2 monthly minimum. The NTC D-2 monthly minimum can be seen as the maximum capacity the TSOs can allocate at long-term auctions.

Figure 21 – Evolution of long-term capacities (annual and monthly) and comparison with the NTC D-2 minimum on the France-Germany interconnection



Sources: RTE and RWE – Analysed by CRE

With exports, it can be seen that the difference between the capacities proposed at the time of the annual allocations and the NTC annual minimum remains very large. This difference was 300 MW in 2006 and 350 MW in 2007. Despite this comfortable margin, the TSOs have proposed less annual capacity in 2008 than in 2007. However, we should remember that it was agreed, before the first auctions in 2006, that 70% of minimum capacity should be allocated on an annual basis, 20% on a monthly basis and 10% on a daily basis. This breakdown of capacities could be reviewed so it is better suited the needs expressed by the market operators, with a maximum capacity allocated to long-term timeframes. Regarding the monthly auctions, it can be seen that the margin retained by the TSOs, i.e. the difference between the NTC D-2 monthly minimum and the capacities proposed at the long-term auctions, was very small and in some cases negative. This means that the TSOs allocated to the auctions all the capacity that could possibly be guaranteed.

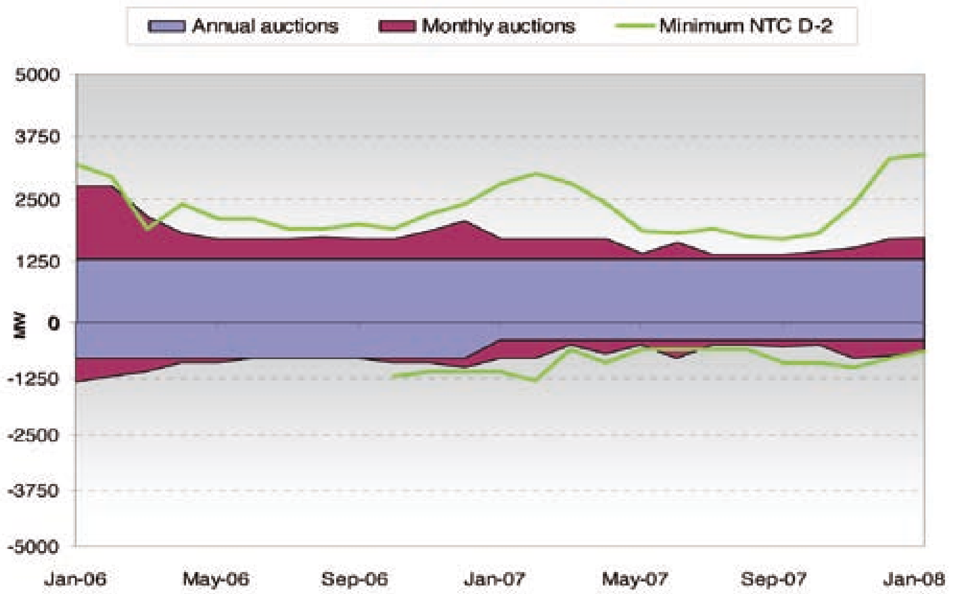
With imports, the difference between the capacities proposed annually and the NTC annual minimum was very large: 3,000 MW in 2006 and 1,112 MW in 2007. As with exports, the TSOs have proposed less annual capacity in 2008 than in 2007. As regards the monthly allocation, unlike exports, the margin retained by the TSOs was very large in 2007. If the capacity proposed at the long-term auctions had been equal to the NTC D-2 monthly minimum, the TSOs would have been able to propose on average nearly 1,200 MW extra.

France-Belgium interconnection

Since 1 January 2006, the TSOs have been allocating interconnection capacity for annual, monthly and daily timeframes using an explicit auction mechanism. In addition, since 22 November 2006, daily capacities have been allocated using a market coupling mechanism. It has been seen that:

- The 'guaranteed' capacity on the interconnection, which is the same as the minimum capacity that the TSOs can guarantee throughout the year, has fallen. In 2007, the TSOs guaranteed 1 700 MW in the export direction, but for 2008 they are only guaranteeing 1,600 MW. With imports, the TSOs are guaranteeing 600 MW for 2008, which is the same as for 2007.
- The capacity proposed at the annual auctions for import fell between 2006 and 2008.

Figure 22 – Evolution of long-term capacities (annual and monthly) and comparison with the NTC D-2 minimum on the France-Belgium interconnection



Source: RTE – Analysed by CRE

With exports, the same can be seen as for the German border. The difference between the capacities proposed at the time of the annual allocations and the NTC annual minimum is quite large (600 MW in 2006 and 400 MW in 2007).

As regards the monthly and daily allocations in the export direction, in 2007 the TSOs divided the capacities still available in the following way:

- A minimum of 400 MW was reserved for the daily allocation and a minimum of 100 MW for the monthly allocation.
- Any extra on top of this 500 MW was split so that 25% went to the monthly allocation and 75% to the daily allocation.

This division meant that a much smaller long-term (i.e. annual and monthly) capacity was allocated than the NTC D-2 minimum observed. If this rule had not been applied, the TSOs would have proposed on average 730 MW extra at the monthly auctions.

With imports, in 2007 the difference between the capacities proposed at the time of the annual allocations and the NTC D-2 annual minimum was 200 MW.

The TSOs also divided the capacities still available for monthly and daily allocation up equally (50% for monthly, 50% for daily). As for exports, this division rule generally meant that the long-term capacity allocated was less than the NTC D-2 minimum observed. If this rule had not been applied, the TSOs would have proposed on average 180 MW extra at the monthly auctions.

As for the German border, the rule used to divide capacities between the various timeframes could be revised.

France-England interconnection

On this border, the interconnection capacity is 2000 MW. In 2007, 90% of this 2000 MW was allocated at the time of the long-term auctions (annual, monthly, seasonal and quarterly auctions). Between April 2005 and June 2006 it can be seen that 97% of the interconnection capacity was allocated at long-term auctions.

The availability of allocated capacities is subject to “target availability”, which is between 95% and 97% for long-term products. This means that the TSOs allocate their capacities less firmly than happens on the continental interconnections. Because the interconnection regularly experiences technical failures, this degree of firmness allows the TSOs to reduce the interconnection capacity without having to compensate the operators.

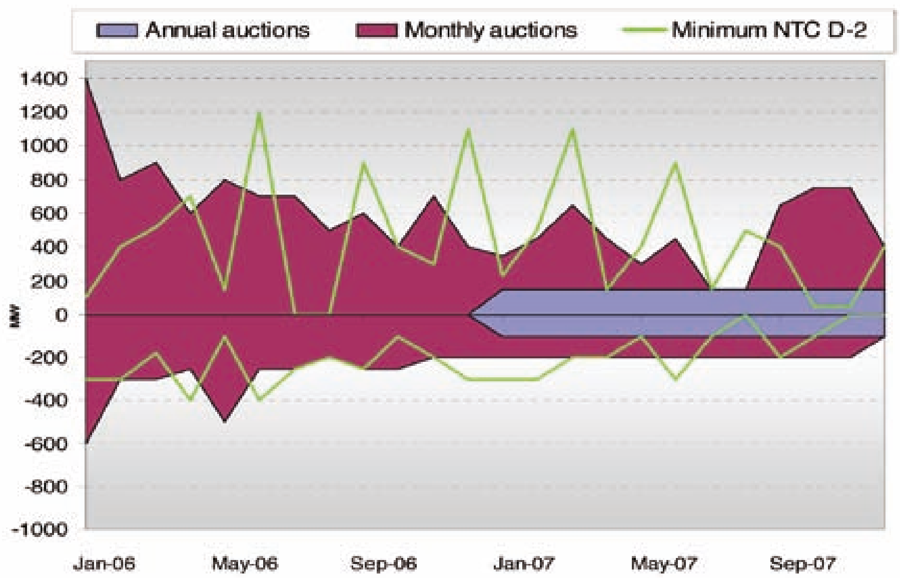
France-Spain interconnection

The TSOs allocate interconnection capacity annually (since 1 January 2007), monthly (since 1 January 2006), daily (since 1 February 2006) and on an intraday basis (since 12 July 2006) using an explicit auction mechanism. It can be seen that:

- The minimum value of the NTC D-2 observed over one hour in a month is very variable and regularly reaches zero. It is therefore risky to propose capacity on long-term timeframes with a high degree of firmness.
- The capacity proposed at the long-term auctions fell for both exports and imports between 2006 and 2008.

Figure 23 compares the capacities proposed at the long-term auctions with the monthly minimum NTC D-2.

Figure 23 – Evolution of long-term capacities (annual and monthly) and comparison with the minimum NTC D-2 on the France-Spain interconnection



Source: RTE – Analysed by CRE

In 2007, for export and import, the capacities proposed at the long-term auctions were subject to a number of constraints:
- The product offered for import in 2007 was interruptible (63 days in the year) and the product offered for 2008 only covers 255 days out of 366. This constraint is justified because the NTC D-2 since 2004 has sometimes been lower than the capacity proposed annually, i.e. 100 MW. However, since 2004 the number of days when the NTC has been much lower than 100 MW (the value of the capacity proposed annually) has been 18 maximum (Table 21).
- The capacities proposed at the monthly auction are regularly not valid for the whole month. This also seems justified because the NTC has often been lower than the sum of the products allocated long-term.

Table 21 – Occurrence of NTC D-2 less than 100 MW on the France-Spain interconnection

	Number of hours when NTC D-2 < 100 MW	Number of days when NTC D-2 < 100 MW
2004	283	17
2005	227	14
2006	0	0
2007	34	18

Source: RTE – Analysed by CRE

France-Italy interconnection

The capacity proposed on this interconnection is very stable and experiences few problems. This stability enables the TSO to allocate the full capacity at the long-term auctions.

6.2. Capacity curtailments and redispatching costs

The TSOs regularly have to deal with situations where not all the long-term capacities they have allocated can be physically used, because that would jeopardise the safety of the grid. Five tools are potentially available for them to cope with these constraints:
- *Repurchase of capacities by the TSOs:* the TSOs could participate in the secondary market like any other operators, enabling them to buy back the "excess" capacity allocated to the market operators. For the TSOs this means outsourcing the management service of the secondary market, which has to be provided in the form of an anonymous organised market. At present this facility is not available to the TSOs.
- *Curtailment of the allocated capacities:* subject to payment of a compensation, holders of long-term capacities can have some of their transfer rights reduced.
- *Countertrading by the TSOs on D-1:* the TSOs could use existing allocation mechanisms to trade in the opposite direction to the price differential, to remove the constraint. This would be particularly easy in a market-coupling situation because it is the TSOs who convey the trades, but this procedure is not used at present.
- *Redispatching:* the TSOs can activate offers through the balancing mechanisms on both sides of the border, to lift the constraints.
- *Changing the topology of the grid:* the TSOs can use phase-shifting transformers installed on certain lines to redirect flows on the grid in real time.

Not all these tools are equivalent or as effective as one another for dealing with the constraints. Repurchasing capacity and reducing capacity only work if the decision to do so is made far enough in advance – and in any case before the long-term capacities are nominated – as a *preventive* measure that helps to guarantee the safety of the grid. To the extent that they can only have an indirect impact on the physical flows, without any guarantee that the change this causes to the physical flows will actually lift the constraint, these tools cannot in any way be seen as last-resort curative solutions to guarantee the safety of the grid.

On the other hand, since they have a direct impact on the physical flows and on the constraints, redispatching and changing the topology of the grid are the only effective curative actions to guarantee the safety of the grid approaching real time.

All these tools have a cost for the TSOs. For example, installing phase-shifting transformers to change the grid topology amounts to a substantial fixed cost. Redispatching also has a cost, which is that of the offers activated in the balancing mechanism (Table 22). These offers have to be activated in increasing price order so that, in accordance with point 1.3 of the new guidelines for Regulation (EC) No 1228/2003, the action taken by the TSOs is economically efficient. The method to be used by RTE to work out the cost of international congestion and internal congestion on the French grid is currently under discussion (inset 7).

Table 22 – Redispatching costs presented by RTE to guarantee the level of interconnection capacities in 2007

	Costs declared by RTE (M€)
Germany	0.46
England	0.11
Belgium	0.56
Spain	0.03
Italy	3.72
Switzerland	1.84
Total:	**6.72**

Source: RTE

Inset 7 – Method applied by RTE to divide up the redispatching costs

For its studies, RTE divides its grid into 7 electricity regions. The grid is linked to the rest of Europe by 6 interconnections.

RTE divides the cost of managing congestion into national congestion costs and international congestion costs. RTE makes this division pro rata to the sum of the Power Transfer Distribution Factors (PTDFs)[42] it has calculated for the 7 regions and the 6 interconnections. RTE only takes account of PTDFs of more than 3% that are actually making the constraint worse, when making the calculation.

CRE and RTE are discussing whether it would be appropriate to modify this method of division, by calculating for example a single PTDF for the whole of France and a second single PTDF for the six interconnections.

42. The PTDF of an exchange x-y, on a grid element z, is the flow of additional power in grid element z resulting from the increase in volume of the exchange x-y. This factor is expressed as a %.

Similarly, capacity curtailments are also at a cost to the TSOs, which have to compensate the operators who lose their rights (Table 23). The current compensation scheme for continental interconnections is the rule known as the ‘110% rule’: the loss of an allocated transfer right is compensated at 10% of its initial value, in addition to its reimbursement. The implementation of a compensation scheme that pays the day-ahead market price differential is being considered (see section 1.2 in Part 2).

Table 23 – Capacity curtailments in 2007 on the continental borders and cost of compensation

		Average depth of curtailments (MW)	Average share of long-term capacity	Number of hours affected in the year	Cost of compensation using the 110% rule (k€)	Cost of compensation at the price differential (k€)
Germany	Export	0	0 %	0	0	0
	Import	0	0 %	0	0	0
Belgium	Export	0	0 %	0	0	0
	Import	0	0 %	0	0	0
Spain	Export	141	55 %	266	175	66
	Import	128	75 %	230	930	1,944
Italy	Export	980	37 %	5	106	179
				Total:	**1,211**	**2,189**

Sources: RTE, Powernext, OMEL and IPEX – Analysed by CRE

On the Spanish border, in addition to the capacity curtailments in the import direction, the annual product was also interrupted for 456 hours in 2007. Because this was planned and specifically stated in the auction specifications, these interruptions did not give rise to compensation. The reason for the ‘unplanned’ curtailments was mainly work on the RTE or REE internal grids, or a low production margin in Spain. The interruptions of the annual product for which no compensation was paid were because of work on the interconnection lines.

On the Italian border, the few curtailments that did occur were due to work on the RTE grid.

On the English border, the mechanism is radically different from the simple 110% rule applied on the other French borders. The specific features of congestion management on the France-England interconnection, listed below, therefore prevent any similar analyses to those made for the other French borders:

- *the firmness of the products is not guaranteed:* the capacities allocated on different timeframes come with a target availability defined in the auction specifications;
- *the long-term and daily capacities are not nominated firmly:* the market operators let the TSOs know on D-1 what their intentions are for nominating the capacities acquired and can change their nominations at any of the 6 intraday gate closures, within the intraday transfer limits defined by the interconnection operators (RTE on the French side and National Grid Interconnector Licence or NGIL on the English side);
- *the capacity curtailments can take place in real time.*

On this basis, RTE and NGIL calculate, ex-post, the actual availability of each type of capacity for each market operator. The impact of a curtailment on the long-term and short-term capacities therefore differs from one operator to another depending on the capacities held by the operator and the nominations it has made.

The TSOs then compare the actual availability of the capacities of each operator with the target availability defined for each type of capacity acquired.

If the actual availability of capacities is deemed to be less than the target, the capacity holders are paid by TSOs for the capacity curtailed beyond what was stated, based on the prices they paid for the capacity. Conversely, when the actual availability of capacities is deemed to be higher than the target, the capacity holders must pay the TSO for the additional capacity it has used.

Each interconnection operator is responsible for calculating the reconciliation invoice in one interconnection direction. In 2007, in the export direction to England, 483k€ was paid to the operators (Table 24). In the import direction, 795k€ was paid to the market operators.

Table 24 – Capacity curtailments in 2007 on the France-England interconnection and cost of compensation[43]

	Average depth of curtailments (MW)	Number of hours affected in the year	Compensation to market operators (k€)
Export	618	1 713	483
Import	632	2 391	795

Source: RTE – Analysed by CRE

6.3. Auction cancellations

According to information from RTE, the only auction cancellations were daily auctions on the ARIBA platform, following problems with the information system.

Table 25 – Daily explicit auction cancellations in 2007

		Number of daily auctions cancelled
Germany	Export	2
	Import	0
England	Export	0
	Import	0
Spain	Export	7
	Import	6
Italy	Export	3
	Import	0
	Total:	**18**

Source: RTE – Analysed by CRE

43. An equipment failure led to capacity being limited only in the England-France direction in July and August; consequently, the curtailments are not the same on both sides for 2007.

6.4. Cost of the absence of netting on the interconnection with Belgium

The netting of long-term capacities allows for long-term capacity nominated in the opposite direction to be reallocated at the daily auctions. Netting, which is a requirement of Regulation (EC) No 1228/2003, is applied to all French continental interconnections, except the France-Belgium interconnection.

On this interconnection, the long-term capacities are well used in the export direction to Belgium (856 MW on average). When the price on Powernext and Belpex is favourable to imports into France (approximately 253 hours in 2007, i.e. 4% of the time), the absence of netting means that the capacities cannot be reallocated via the coupling of the markets.

This results in a loss of social welfare. This can be estimated by multiplying the capacity that has not been offered by the price differential, when it was favourable to the use of this capacity. As with the evaluation of loss of social welfare associated with the absence of implicit auctions (section 3.4), this calculation does not take account of price resilience, which overestimates the actual loss of social welfare.

According to this estimate, the loss of social welfare due to the absence of netting on the France-Belgium interconnection was nearly 1.7 M€ in 2007 (Table 26).

Table 26 – Loss of social welfare associated with the absence of netting on the France-Belgium interconnection in 2007

	Average capacity not proposed (MW)	Estimate of loss of social welfare (k€)
Export	35	16
Import	856	1 649
	Total:	**1 664**

Sources: RTE, Powernext and Belpex – Analysed by CRE

Part 2:

Target mechanisms and future developments

For each timeframe (long-term, daily, intraday and balancing), the target mechanisms on which there is a consensus among the European regulators are explained here, and a list of the main questions still up for discussion is given. The progress made in the various regional initiatives with implementing these mechanisms is also described.

1. Long-term capacity allocation

1.1. Target mechanism

The target mechanism for allocating long-term capacity is an explicit auction mechanism harmonised throughout Europe, with:
- a single set of rules,
- identical products on all interconnections,
- a single interface for all participants.

At present, if only on the French borders, there are:
- a different set of rules for each interconnection, for example in terms of compensation for capacity curtailment (see section 6.2 in Part 1),
- allocated products that are different, for example in terms of timeframe (quarterly and seasonal products are available on the France-England interconnection only) and firmness (the annual capacity on the France-Spain interconnection was interruptible in 2007),
- special interfaces for the France-England interconnection and for the France-Germany interconnection in the import direction, while the allocation of capacities on the other French borders uses the same interface (ARIBA).

1.2. Open questions

Certain principles related to the access rules for long-term capacities are still the subject of discussion:

• Firmness of capacities

Long-term capacities before nomination

Because the long-term capacities allocated by the TSOs play a major role in the development of competition and construction of the European electricity market, they must have the maximum possible availability. However, the TSOs cannot guarantee that the capacities they have sold on an annual timeframe, or even a monthly one, will be physically available every day. They have tools to cope with these situations (see section 6.2 in Part 1). Consequently, when the TSOs are unable to buy excess capacity already allocated back via the secondary market, they can choose for example to curtail the capacities allocated over the long term, before their nomination.

In accordance with Regulation (EC) No 1228/2003, any curtailment in capacities must be compensated, except in cases of force majeure (where a simple reimbursement is made). Currently, on the French continental borders, the compensation scheme is based on the initial price of the curtailed capacity: the holder of the capacity that has been unable to use its right receives 10% of the initial price of the capacity as a compensation, in addition to its reimbursement (110% rule).

This compensation scheme does not reflect the real cost of curtailments for interconnection users. A market operator wanting to transfer electricity from Member State A to Member State B via a long-term capacity, must sell its electricity on market A and buy the same quantity on market B if its capacity is curtailed. Consequently, the loss it suffers for every curtailed megawatt-hour is the price differential between market B and market A. The compensation scheme for curtailments should therefore be based on this differential, to take account of the direct loss caused to the operators. Therefore, if the physical firmness of the capacities cannot be assured, their "financial" firmness is guaranteed, making capacity curtailments harmless from a financial point of view for the market operators concerned.

The example given in inset 8 gives a clear illustration of the importance of guaranteeing the firmness of long-term capacities for the market operators (reduction of the risk associated with cross-border trades).

Inset 8 – Example illustrating the importance for the market operators of having financially firm capacities

If we consider two market zones and one market operator that:

- buys electricity in zone 1, through a monthly product, for 40€/MWh,
- sells electricity in zone 2, through a monthly product, for 45€/MWh,
- buys at auction a monthly right to capacity from zone 1 to zone 2, for 4€/MWh.

For each hour of the month, this operator will therefore make a minimum profit of 1€/MWh. This profit could be higher if it engaged in day-to-day arbitrages during this month.

One might reasonably assume that a curtailment of the monthly capacity from zone 1 to zone 2, by creating a surplus of electricity in zone 1 and a deficit in zone 2, causes an increase in the price differential between the two zones, for example with prices at 35€/MWh in zone 1 and 90€/MWh in zone 2. If the market operator cannot use at least part of its monthly transfer right, so that it is not short it must:

- resell the amount corresponding to its curtailed capacity in zone 1 (at 35€/MWh),
- buy back the same amount in zone 2 (at 90€/MWh).

In this case, with compensation at the price differential, the operator's profit during each hour of the curtailment is exactly the same as its minimum initial profit would have been, i.e. 1€/MWh in this case. However, with the 110% rule, the operator receives a compensation of 4.40€/MWh though its loss is 54€/MWh.

Furthermore, it is important to note **that the users of interconnections are not generally the reason for capacity curtailments,** which are usually due to unexpected failures of generation means or parts of the grid. Under these circumstances, it seems unfair that the interconnection users should have to bear the risk of capacity curtailments.

In addition, **this financial firmness is essential for developing competition, since it will make access to the interconnections easier for the smallest market operators.**

Finally, **guaranteeing the financial firmness of the capacities would also have a positive impact on income from the auctions.** Compensation at the price differential gives the market operators financial security, which effectively lowers the risk premium they need to apply when buying interconnection capacity at auction.

For all the advantages financial firmness offers, it seems justified that the costs borne by the TSOs to guarantee this firmness should be socialised in the grid access tariff.

However, it has to be said that there is marked opposition to compensation at the price differential from the TSOs, and there are questions about it from some European regulators.

From the regulators' point of view, this reticence is certainly due to the difficulty with getting a clear picture of the financial risk associated with socialising the costs of firmness in grid access tariffs. In particular, the volatility of market prices and scale of the differentials at certain times could lead to fears that the grid users would have to carry too high a risk (see inset 9 on these risks).

From the point of view of the TSOs, it is probably because of the regulatory framework, which perhaps does not give them sufficient guarantees that the costs they would have bear to guarantee the firmness of capacities would indeed be covered by the grid access tariff. Since the law does not force the TSOs to guarantee this firmness, it is therefore easy to see why some of them are refusing to introduce a price differential compensation scheme of this kind.

Whatever the case, the question of transferring the risk from the interconnection users to all grid users should be considered carefully. Introducing a price differential compensation scheme with, for example, a cap on the price differential or on the compensation period could perhaps be a way of unblocking the situation, by reassuring the regulators about the risks of taking account of the costs of firmness in the tariffs.

Inset 9 – Aren't the real risks of introducing a price differential compensation scheme overestimated?

In the first place it should be remembered that the number of capacity curtailments is very small on French interconnections (see Table 23, section 6.2 in Part 1).

On the Spanish border, where curtailments are most common, the cost of price differential compensation would have been lower for export than 110% compensation (66k€ instead of 175k€). Also on this interconnection, in the import direction, the cost of price differential compensation (1.9M€) would have been much higher than compensation at 110% (930k€). But that should be put into perspective with the total congestion income on this interconnection (65M€), and with the likely increase in income from the auctions because of this compensation scheme.

It should also be remembered that, apart from the France-Italy interconnection where the maximum capacity is allocated on long-term timeframes, the TSOs keep some of the available capacity throughout the year for the daily timeframe. In addition to this, the TSOs have to take safety margins when they calculate the capacities, there is at present no incentive mechanism for TSOs to maximise capacity, and finally, pursuant to Article 6.2 of Regulation (EC) No 1228/2003, the capacity curtailments should occur as a last resort measure. So curtailments should continue to be relatively limited.

Consequently, the financial risk associated with sharing a market price differential compensation scheme in the tariff is relatively low.

Daily capacities and exchange programmes

The closer you are to real time, the less physical impact the capacity curtailment measures used by the TSOs have on the physical flows. A curtailment announced late in the day does not give the market operators time to balance their positions on each side of the border concerned, and therefore help to make the grid safe.

Normally the TSOs consider that the deadline from which there is no value in making curtailments is before the prices are fixed on the day-ahead markets. That is why the capacities allocated on D-1 and the exchange programmes (i.e. the nominated capacities) are firm on most European interconnections, including the majority of French interconnections.

Anyway, within the framework of the implicit allocation of daily capacities, firmness of the exchange programmes is essential. If the capacity allocated and automatically nominated when the prices were fixed on the exchanges has to be curtailed, this means:

- *Either that the exchanges bear this curtailment risk:* in this case, they need to be prepared to re-fix the prices as a matter of urgency, thereby cancelling all transactions on each national market; coupling means that transactions involved in cross-border trades and transactions involved in national trades cannot be identified.
- *Or that the TSOs bear this risk:* in this case, the TSOs have to guarantee grid safety using redispatching measures.

Because the first case is unacceptable for the Power Exchanges, the TSOs naturally have to bear the risk; in any case, this was one of the conditions when the trilateral market coupling between France, Belgium and the Netherlands was launched. To ensure non-discriminatory treatment of the different types of trades, the TSOs must also guarantee the firmness of long-term capacities when they are nominated.

In all cases

In order to facilitate the electricity trades and market integration, the firmness of the capacities must be guaranteed by the transmission system operators, whether by means of physical firmness or financial firmness.

How is the financial risk associated with socialising the cost of capacity firmness evaluated?

How can the TSOs be incentivised to trade off fairly between the level of capacity and the cost of firmness?

How can confidence in the price references from the organised markets, on which price differential compensation would be based, be improved for all stakeholders?

Could the implementation of caps to limit the cost of compensation (cap on the price differential level and/or on the compensation period and/or on the total amount of the compensation) be an acceptable transitional step for the market operators and TSOs? If so, at what level should these caps be fixed?

• Physical and financial rights

At the moment, the TSOs allocate physical rights: the holders of these rights use the underlying interconnection capacity themselves (nomination stage). Long-term financial rights would allow the holders to receive the daily auction price, by which all the physical capacity would be allocated. In the case of day-ahead market coupling, this means a hedge product is sold against the price differential between the organised markets.

Financial rights offer several advantages, particularly in the case of day-ahead market coupling:

- The debate on the distribution of capacities between the long-term and daily timeframes would be irrelevant, since the maximum amount available would be allocated for each timeframe, in the form of financial products for long-term timeframes and in the form of physical products for the daily timeframe.
- The daily step of nominating long-term capacities would no longer take place. For the TSOs, the calculations associated with netting and "use-it-or-lose-it" would no longer be necessary. For the market operators, especially those with particularly limited resources, participation in the capacities market would be easier.
- The mechanism for reselling long-term capacities on demand at daily auctions would also not be needed.
- The phenomenon where nominations take place in the opposite direction to the price differential would also disappear automatically.
- Finally, the liquidity of the day-ahead organised markets would increase, improving the reliability of the price reference they supply.

Where day-ahead markets are coupled, replacing physical long-term transmission rights by financial ones would have one disadvantage for the market operators: going through the organised markets, and therefore paying the transaction fee they charge, would be mandatory for any operator wishing to make cross-border trades. At present, the fees applied by the Power Exchanges are not regulated. They therefore vary widely from one market to another.

Consequently the market operators are still quite reluctant to see long-term products become financial. They prefer the introduction of a mechanism that allows long-term capacities to be resold as daily capacities, applied systematically (or "use-it-or-get-paid-for-it"), which would leave them the choice between the physical or financial use of their rights.

Would the extra cost to the market operators of converting long-term capacities into financial products (which would have to be done through the organised markets) not be largely compensated for by the savings associated with the simplification of procedures for accessing the interconnections and the increase in liquidity of the organised markets?

Would converting long-term capacities into financial products not be an effective way of increasing the liquidity of the organised markets, and consequently improving confidence in the price references?

• Secondary markets

The long-term capacities acquired at auction can now be transferred between operators on all interconnections between France and the other Member States (section 2.3 in Part 1). The possibility of reselling capacities acquired on the "primary" market was much in demand by operators. However, it was used very little in 2007.

Setting up an anonymous organised market would be one way of making capacity transfers easier for the operators. It would also, indirectly, mean that long-term capacities were better valued and better used. Finally, it would give the TSOs an additional tool for guaranteeing the firmness of capacities (buying back of capacities).

Setting up a project of this kind would require major changes to the transmission system operators' information system, which would be costly in terms of time and resources. If long-term capacities were to be sold in the form of financial rights, or as physical rights with a "use-it-or-get-paid-for-it" mechanism, would setting up an organised secondary market really be necessary? Would it really be used more than at present? Publishing the names of the holders of primary capacities, as is done on the France-Italy interconnection, would be a way of expanding transfers of capacities.

Leaving aside the buying back of capacities by the TSOs to avoid curtailments, would the added value offered by an anonymous secondary organised market be enough to make it a high priority?

What additional flexibility would the market operators like?

Why do some market operators not want the names of holders of capacities on the French interconnections (excluding the France-Italy interconnection) to be published?

• Scope of the auction platforms

For maximum simplification and efficiency of the allocation of long-term capacities, the auction platform should cover the widest possible area: ultimately all the European interconnections on which long-term capacities are allocated.

At present, no project on this scale is being considered; the projects in progress are limited to regional areas (see next section). From the point of view of France, involvement in four regional initiatives will mean that RTE is participating in the development of four different auction platforms.

Ideally, the most successful auction rules and allocation platform in a region should be adopted in the other regions, to minimise the development costs for the transmission system operators and to simplify procedures for the market players. Obviously this would mean that the rules would have to suit the regulators, TSOs and market operators and be compatible with the design of each market, and that the governance of the initial platform would have to be sufficiently flexible to allow the necessary evolutions.

Should separate projects be rolled out in all regions, or should the progress made with one be used to save resources in the others?

1.3. Progress of regional initiatives

In the Central-West region, an ambitious project is under way with the creation of an entity common to the seven TSOs involved[44] (CASC, or Capacity Allocation Service Centre), the purpose of which is to allocate all long-term capacities in the Central-West region through a single interface. This interface should be operational by the time of the next annual auctions (end of 2008). It will replace the three interfaces[45] currently used within the Central-West region. Whether or not the regional interface is operational in time, long-term capacities will be allocated according to a single set of rules, to which the TSOs and regulators are already working, in close cooperation with the interconnection users.

In the Central-South region, a major harmonisation drive was undertaken in 2007, enabling the capacities for 2008 to be allocated according to a single set of rules, though with many special features on each border. This effort at harmonising and improving the rules is being continued in 2008.

In the France-UK-Ireland region, efforts to improve the congestion management mechanisms, begun in 2007, are continuing in 2008. To do this, the interconnection operators, NGIL on the English side and RTE on the French side, are developing a new information system (i.e. auction platform) for the allocation, use, management and invoicing of France-England interconnection capacities. The objectives are:

- compliance with the congestion management guidelines in the Annex to Regulation (EC) No 1228/2003 (implementation of an intraday allocation mechanism, daily product allocated in hourly basis, firm nomination of long-term products, application of the netting and of “use-it-or-sell-it”/”use-it-or-lose-it” rules),
- harmonisation with the mechanisms in force in continental Europe (compensation scheme in the event of capacity curtailments, auction at marginal price rule, removal of the intraday transfer limits and simplification of the rules).

In the South-West region, the setting up of a regional platform for the allocation of long-term products is under discussion between regulators and TSOs. Allocation of annual, quarterly and monthly products will soon be introduced on the Spain-Portugal interconnection; all the capacity is currently allocated on a daily basis by market splitting.

2. Allocation of daily capacities

2.1. Target mechanism

Implicit allocation of daily capacities simultaneously with the electricity transactions means they can be used optimally in accordance with the prices on the different markets. So the target mechanism on which there is a European consensus is market coupling for national day-ahead markets, or even the merging of these markets, with separate price zones depending on congestion (market splitting).

In addition, as regards the calculation of the capacities made available for coupling, the ‘flow-based’ method would allow greater use to be made of the interconnected grids, taking account of the impact of overall cross-border flows on the lines under constraint, as opposed to the ‘ATC-based’ method used at present.

2.2. Open questions

In addition to the technical questions still to be answered on algorithm design and grid modelling, there are some more general issues still to be resolved.

44. EnBW, E.On and RWE for Germany, Cedegel for Luxembourg, Elia for Belgium, TenneT for the Netherlands and RTE for France.

45. ARIBA on the France-Belgium interconnection and for exports on the France-Germany interconnection, a platform managed by RWE for imports from Germany, and TSO Auction Office for the Netherlands’ borders with Belgium and Germany.

• Compatibility and order of the coupling projects

Several projects are being run in parallel in Europe to expand the implicit allocation of daily capacities.

The lack of coordination between these projects among other things raises problems associated with the sequencing of the algorithms. If a zone managed by internal market splitting (such as Nordpool, Italy or the Iberian peninsula) is coupled with another zone, the two algorithms (the coupling algorithm and the splitting algorithm) cannot run simultaneously because the results from one (price in each zone and volumes exchanged between the zones) are the input for the other, and vice versa. It is therefore necessary to decide, arbitrarily, in what order the algorithms should be run. Regardless of the order, the sequencing of the algorithms leads to sub-optimal use of the capacities with, for example, flows in the opposite direction from the price differential.

The same applies to coupling between two zones already managed by market coupling.

The ideal solution, if an implicit method was going to be used on several zones, would be to use just one algorithm for all the zones, whether market coupling (one exchange per zone) or market splitting (one single exchange) was being used. However, this would require consultation between all the stakeholders at European level.

> **How could the various coupling projects currently in progress be coordinated at interregional or European level? From an operational point of view, how can the interaction between the next two market couplings, such as the coupling of France and Benelux with Germany and of Germany with Denmark, be managed effectively?**
>
> **What priority can be given to the different coupling projects? On the basis of what criteria?**

• Status of the electricity exchanges

As explained earlier in relation to financial transmission rights, implementing market coupling gives the Power Exchanges a monopoly on the management of day-ahead cross-border trades. The multiplication of coupling projects as well as the major role that organised markets will play soon in cross-border trades' management, raises the question of the status of Power Exchanges. Could Power Exchanges continue to operate in a competitive market, as it is the case at present for many of them? On the contrary, should their status evolves for allowing for an ex ante regulation, as it is the case of Nordpool, the Scandinavian Power Exchange?

Furthermore, ones could question on the way to incentivise organised markets, which operate in a competitive market, to speed up the implementation of coupling projects.

> **How can the development of coupling projects, which naturally involves the Power Exchanges, be reconciled with their current unregulated status?**
>
> **Would changes to the regulatory framework of the Power Exchanges be desirable? If so, what changes?**

2.3. Progress of regional initiatives

In the Central-West region, an ambitious flow-based market-coupling project is in progress to extend the trilateral market coupling of France, Belgium and the Netherlands to Germany. It should be set up by early 2009. In parallel with this regional project, coupling between Germany and Denmark is planned in the coming months, to extent the coupling on the "Kontek" cable between the island part of Denmark and the control area of the German TSO Vattenfall to the whole of this interconnection. In addition, another coupling project is under way on the "NorNed" cable between the Netherlands and Norway.

In the Central-South region, an action plan has been put forward by the TSOs and Power Exchanges to look into the feasibility of using implicit methods in this region. Within this framework, the current differences in market design that hinder the setting up of coupling will be studied: for example, the difference in the closing times of the organised markets (9 am in Italy and in principle 12 noon in France), or the compatibility of coupling with the current market splitting in Italy.

In the South-West region, two studies presented by the TSOs in the region and OMEL are analysing potential obstacles to the setting up of coupling between the Iberian market[46] and the Central-West market. Apart from the harmonisation needed in exchange closing times (10 am on MIBEL and in principle 12 noon on the Central-West exchange), the type of offers on each of the two markets could also constitute an obstacle: on Powernext and the other exchanges in the Central-West region, the operators submit simple offers linking prices with quantities or price limited block orders; on MIBEL on the other hand, the operators submit 'complex' offers specifying the physical characteristics of an offer (for example, a gradient production condition).

In the France-UK-Ireland region, it is more the 'design' differences between the two markets, particularly the lack of an hourly price reference determined on a day-ahead basis on the English market, that currently restrict the coupling potential of the two markets. Remember that the NETA was mainly introduced in 2001 to switch from the obligatory pool system with day-ahead price fixing to a system in which more trades were bilateral. Consequently, only base or peak OTC prices are published, for example on APX Power UK or Platts.

3. Allocation of intraday capacities

3.1. Target mechanism

The principle on which there is a consensus in Europe for intraday capacities is implicit capacity allocation, preferably continuously, as opposed to the current explicit allocation gate closures.

At present, a French operator that has to balance its position after the day-ahead organised market closes can:
- buy on the French intraday market,
- or else, if it wants to buy on a neighbouring market:
  - carry out an electricity trade on the neighbouring market on a trading platform (organised markets, brokers) or by directly seeking an opposite party with which to trade,
  - participate in the mechanism for allocating intraday capacity between the two markets at the time of an allocation gate closure or explicit auction depending on the border (see section 4.1 in Part 1),
  - nominate the capacity it will have acquired in this way at a nomination gate closure.

An implicit, continuous capacity allocation platform would simplify these procedures considerably. The various possible models are explained below.

46. MIBEL, the market shared by Spain and Portugal, set up on 1 July 2007, in which congestion management operates on the basis of market splitting.

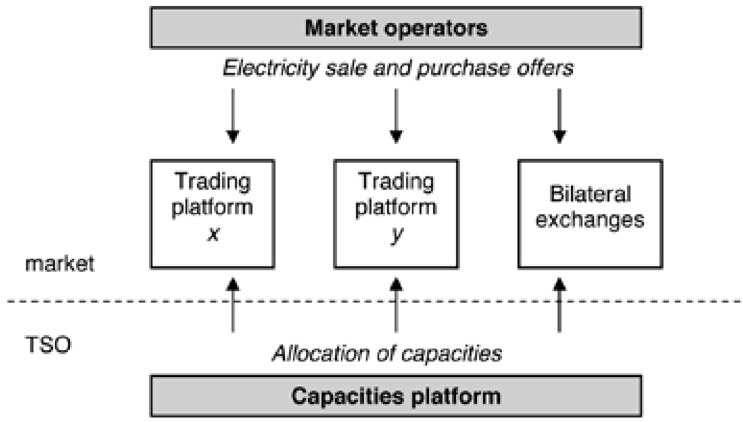
3.2. Open questions

• Management of electricity exchanges

There are several possible models for managing electricity intraday trades. In the first, the TSOs allocate capacity continuously to different trading platforms, or else directly to operators making bilateral exchanges, as soon as an electricity transaction has been made (Figure 24).

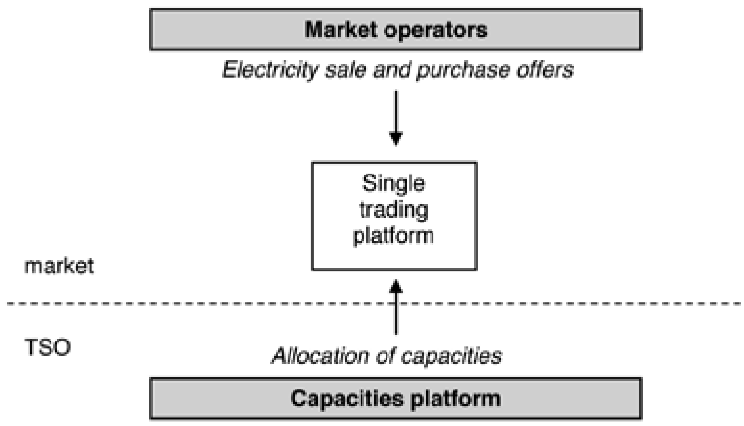
This model has the advantage of letting competition operate between the trading platforms, since the TSOs only manage capacity allocation. The disadvantage is the risk of poor liquidity on each of the platforms.

Figure 24 – Model for intraday exchanges with several competing trading platforms



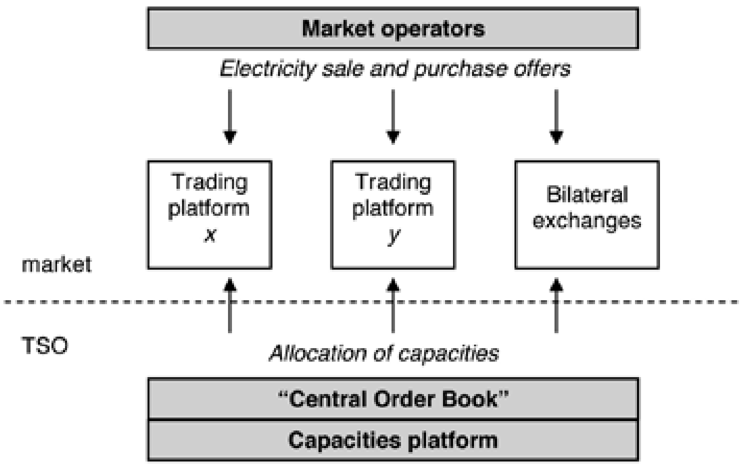
In the second model, the intraday electricity exchanges between two zones would be managed by a single trading platform, chosen for example by a tender procedure by the TSOs for a certain period (Figure 25). The advantage of this model is greater liquidity for this trading platform for intraday exchanges. With this model, the organised markets have a major role to play in the management of intraday trades. In the Northern region, the ELBAS trading platform, which has been running since 1999, enables market operators to conduct intraday trades continuously up to one hour before real time on this model.

Figure 25 – Model for intraday exchanges with a single trading platform



Finally, in a third model, the TSOs include a central order book in the capacity platform, in which offers to sell and buy on each trading platform are recorded. This model would have the advantage of guaranteeing sufficient liquidity for intraday trades without challenging the existence of the current trading platform.

Figure 26 – Model for intraday exchanges with a capacity platform centralising offers made on different trading platforms



How can sufficient liquidity for intraday trades be guaranteed (model 2 or 3)?

Is competition between the intraday trading platforms (model 1) viable in the long term, or will it finish up with the emergence of a single platform?

If a monopoly developed, should it be regulated? If yes, how?

• Project added value

Implementing a continuous implicit capacity allocation platform, regardless of the model chosen, is a project of some scale for the TSOs, particularly in terms of the information system. In addition, to ensure the added value of the mechanism is substantial, the capacities platform should be on a regional or even multiregional scale.

What intraday mechanisms should the TSOs introduce in the short term? And in the medium term?

In the current context, where improvements are being made to the long-term auctions, day-ahead market coupling is being extended and balancing market integration is being envisaged, what priority should be given to setting up more sophisticated intraday mechanisms?

3.3. Progress of regional initiatives

In the Central-West region, mechanisms for allocating intraday capacities on a pro rata basis or on a "first-come-first-serve" will soon be introduced on the borders of the Netherlands with Belgium and Germany, following the models for the mechanism already in place on France's borders with Belgium and Germany. These are only interim mechanisms until the launch of a regional continuous implicit allocation platform.

In the France-UK-Ireland region, as part of improvements to the congestion management mechanisms, the TSOs are proposing a flexible system that could work with different intraday mechanisms, and could easily be upgraded to the target mechanism.

In the South-West region, the TSOs are studying the possibility of introducing continuous allocation of intraday capacities.

4. Balancing trades

The development of balancing trades is one of the objectives of the Regional Initiative action plans in which France is involved. Although the need to integrate the balancing mechanisms is recognised, there is currently no consensus on how to achieve this.

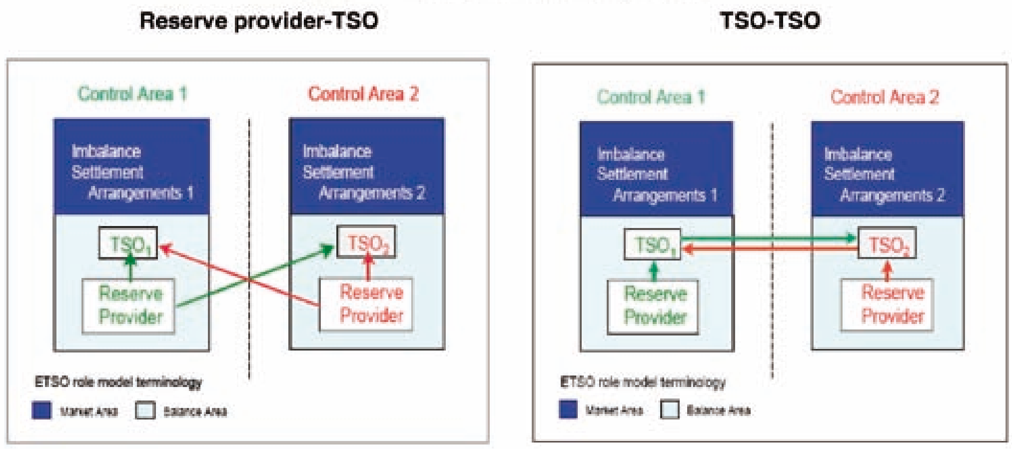
4.1. Different theoretical models

Two models exist for balancing trades: one in which the operators are in direct contact with the neighbouring TSO, and the other in which the TSOs play the role of intermediaries.

• "Reserve provider-TSO" model

In this model, the balancing operators in country A are in direct contact with the TSO in country B (Figure 27). The advantage of this is that the offers submitted by the operators do not have to be filtered by the TSO they are attached to. On the other hand, they have to conform to the offer transmission procedures of the foreign TSO (balancing offer and information system characteristics). Furthermore, the balancing actors have responsibility on the one hand for notifying their TSO of changes to their production when such changes are requested by the neighbouring TSO and, on the other hand, for acquiring and nominating the interconnection capacity needed for the balancing supply.

Figure 27 – Models for balancing trades



Source: ETSO

These last two constraints make cross-border balancing supplies tricky in practice: the amount of time needed to nominate production programmes and exchange programmes on the borders is incompatible with the needs of the balancing process, which has to be rapid and flexible. In practice, in this model, trades can only take place in one direction, from the country where there are fewest constraints on production programming to the country where the constraints are greatest. Consequently, this model does not allow reciprocal exchanges to be made, in the absence of any extensive harmonisation.

The Reserve provider-TSO mechanism, through which the Swiss and German operators take part in the French balancing mechanism, is in fact a hybrid of the Reserve provider-TSO model and the TSO-TSO model. Swiss and German operators can modify their production programmes very close to real time (T-15 minutes) and the TSOs take responsibility for modifying the exchange programmes at the interconnection. This means that the Swiss and German operators can provide the balancing supply in only 30 minutes compared with several hours on the other borders.

• "TSO-TSO" model

In this model, the balancing operators in country A have access to the balancing market in country B through their TSO (Figure 27). The two TSOs pool standard balancing offers. The TSOs are responsible on the one hand for modifying the production programmes to suit the requested balancing offers, and on the other for modifying the associated flows on the interconnection.

This model allows reciprocal trades to be carried out without the need for total harmonisation of the existing national balancing mechanisms.

4.2. Target mechanism under discussion

In the Nordel synchronised zone (Norway, Sweden, Finland and Denmark), balancing offers, which can be manually activated and sent by the balancing actors to their TSO one hour before real time, are collected and ranked by price in a central list, accessible by all the TSOs, using a shared information system (the Nordic Operation Information System, or NOIS). When a balancing need arises within Nordel, the Norwegian and Swedish TSOs coordinate to activate the balancing offers necessary to keep the system balanced. The balancing order is then sent to the balancing actor through its own TSO. The balancing offer can only be activated if the interconnection capacity is available.

By pooling balancing offers among the four TSOs, a balance can be maintained between supply and demand within the synchronised zone at the best possible cost, while optimising the use of the balancing resources available throughout the whole zone. Furthermore, when there is no congestion on the interconnections, the cost of balancing is shared by all the countries in the zone.

This balancing mechanism was set up in 2002 on the basis of existing mechanisms in the Scandinavian countries. In 2007, it was upgraded so that there was greater harmonisation, though it is still not completely harmonised. In particular, the offer remuneration scheme (marginal price), calculation of imbalances and calculation of the settlement price of these imbalances, and the times of the daily and intraday gate closures for submitting the production programmes and balancing offers to the TSOs (45 minutes before the start of the operating time), were all harmonised. On the other hand, the dimensions of the operating reserves that can be manually activated and the way the TSOs constitute these reserves and use them are not yet harmonised.

The mechanism developed by the Scandinavian countries could therefore usefully be used as a model for the target mechanism in Europe that will gradually be introduced into the various regions.

4.3. Open questions

• Access to interconnection capacity

Two scenarios can be envisaged at the moment:

- balancing trades can only take place when commercial trades nominated by the operators are not saturating the interconnection capacity;
- part of the interconnection capacity is reserved to allow balancing trades to take place under all circumstances.

It should be noted, however, that Article 6(3) of Regulation (EC) No 1228/2003 states that: *"The maximum capacity of the interconnections and/or the transmission networks affecting cross-border flows shall be made available to market participants, complying with safety standards of secure network operation."*

> **Should interconnection capacity be reserved beyond the needs resulting from the pooling of primary reserves to allow balancing exchanges?**

• Model for managing the balance between injections and withdrawals

The answer to the previous question could in fact prohibit balancing trades from taking place with some TSOs, which rely on the use of secondary reserves to maintain a balance between injections and withdrawals. These reserves are activated automatically and are the subject of contracts to guarantee their availability at all times.

> **Under what circumstances should the balance between injections and withdrawals be guaranteed almost exclusively by secondary reserves?**

• Desirable degree of harmonisation

Full harmonisation of the balancing mechanisms is not essential for balancing trades to be allowed in the TSO-TSO model. The development of balancing trades has to take account of the specific features of the different electricity systems.

> **What degree of harmonisation of the balancing mechanisms is desirable, particularly as regards:**
>
> - **the formats of balancing offers,**
> - **the remuneration principle of balancing offers,**
> - **the calculation of imbalances and the settlement price of the imbalances?**

4.4. Progress of regional initiatives

Concrete proposals have been made under the France-UK-Ireland regional initiative: reciprocal access will be opened to the French and British balancing mechanisms and balancing trades based on a TSO-TSO model will begin in mid-2009 between France and the UK, with an interim step from mid-2008.

This project is the first step towards the target mechanism described above (section 4.2). Several further changes will still be necessary to achieve the same degree of integration as the Scandinavian countries.

Within the framework of this project, TSO-TSO balancing trades will enable RTE to receive balancing offers from British balancing actors through National Grid. RTE can merge them with all the offers in the French balancing mechanism. The development of these trades should improve the security of supply of the French system and reduce balancing costs.

Under the contract between National Grid and RTE[47] French balancing actors can already have their offers taken up to meet the balancing needs of the British system. However, a single offer is sent to National Grid by RTE at a single price, determined the day before for the whole day, so it is fairly unrepresentative of the market price of the balancing in real time. From now on, several offers will be exchanged between the TSOs and the price of these offers will be updated every hour on an intraday basis better to reflect market prices.

This project to develop balancing trades between France and the UK has the following advantages:

- *Reciprocal, non-discriminatory access to the national balancing markets and more competition:* bids and offers by balancing actors in both Member States will be in competition, which increases the chance for each balancing actor of being approached and should lead to more competitive balancing costs.
- *Maintenance of security of supply in each system:* the balancing offers exchanged by the TSOs will only be the volumes available above the operating reserves the TSOs need in order to keep the likelihood of a break in supply on their systems below a certain threshold.
- *No reservation of interconnection capacity:* cross-border balancing exchanges will only take place if the interconnection capacity is not being used by the market operators. For this to be the case, the balancing trades will take place between the interconnection capacity nomination intraday gate closure and the expiry of the neutralisation deadline associated with this gate closure.
- *Economic efficiency and transparency:* the TSOs will exchange standard blocks (blocks of 50 MW over one hour, which can be activated in less than 30 minutes), compatible with the market design on either side of the interconnection. The price of these blocks will be worked out from the price of the offers submitted to the TSOs, estimated two hours before real time. The method for determining prices, as well as the exchanged and activated offers (prices and volumes) will be public.

47. BASA contract between RTE and National Grid (Balancing and Ancillary Services Agreement for the provision of commercial ancillary services).

Conclusion

Efficient use of the interconnections is crucial for the construction of the single electricity market. It is therefore important that the mechanisms considered most efficient are implemented as quickly as possible.

However, as we saw in 2007, the market integration process at regional level is making slow progress, and has come up against a number of obstacles:

- The target mechanisms for congestion management have been clearly identified but the market designs have not been harmonised. The examples below illustrate how differences in market design can hamper projects aimed at facilitating cross-border trades:
  - In England, there is no organised market with day-ahead price fixing, unlike in the continental European Member States. This makes it difficult to introduce day-ahead market coupling on the France-England interconnection.
  - Because there is no intraday market in Italy, it is currently not possible to develop intraday trades on the France-Italy interconnection.
  - In Germany and Belgium, management of the balance between supply and demand relies mainly on automatic reserves secured under contract by the TSOs. In these circumstances, cross-border balancing trades of electricity seem incompatible with the requirements of Regulation (EC) No 1228/2003.
  - On the Iberian Peninsula, offers submitted by operators in the Spanish and Portuguese market are physical only and directly linked to production units, which creates difficulties when it comes to the algorithm for coupling the Iberian market with the French market.
  - In France, one of the obstacles to market coupling in the Central-West region is the difficulty with setting all the operational processes of the operators back by one hour to make the price fixing time on Powernext 12 noon instead of 11 am.

- The transposition into national law of Directive 2003/54/EC[48] has given very different powers to the regulators in the various Member States. On one border, one regulator might have the power of formal approval over the rules for accessing interconnection capacity (as is the case with the Belgian regulator), while the other may only have a consultative role (as is the case with the majority of national regulators)[49]. In the case of regional projects (long-term capacity allocation platform, day-ahead market coupling, intraday capacity allocation platform), the lack of symmetry between the competencies of the regulators is even more problematical where projects involve a large number of Member States.

- Where the target mechanisms are intended to be regional – or even multiregional – the number of stakeholders in the projects is quite large. This can slow matters down where rapid progress is needed on a project. For example, in the case of the market coupling project for the Central-West region, four exchanges, seven TSOs, five regulators and five government ministries are seated around the table.

One of the challenges of the “third legislative package” proposed by the European Commission is to remove some of these obstacles, particularly by:

- harmonisation – from the top – of the competencies of the regulators, or else the granting of decision-making powers to the Agency for the Cooperation of Energy Regulators (ACER) for interconnection management,
- the implementation of incentive mechanisms applied to TSOs to speed up market integration so that the projects reach a swift conclusion.

A detailed exploration at European level of the market design towards which the Member States should be converging, which should include the status of the Power Exchanges, is also essential.

48. Directive 2003/54/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in electricity.

49. No regulator has the power to introduce amendments to interconnection access rules.

List of abbreviations

ACER	Agency for the Cooperation of Energy Regulators, the creation of which is proposed in the European Commission's third legislative package
ATC	Available Transfer Capacity
BASA	Balancing and Ancillary Services Agreement for the provision of commercial ancillary services – Contract between RTE and National Grid
BM	Balancing Mechanism
CASC	Capacity Allocation Service Centre – Future auction platform for the Central-West region
CNE	Comisión Nacional de Energía – Spanish regulatory authority
ECJ	European Court of Justice
ERGEG	European Regulators Group for Electricity and Gas
ETSO	European Transmission System Operators
IFA	"Interconnexion France-Angleterre" (France-England interconnection)
NETA	New Electricity Trading Arrangements
NGIL	National Grid Interconnector License
NTC	Net Transfer Capacity
OTC	Over The Counter
PTDF	Power Transfer Distribution Factor
RTE	Réseau de Transport d'Electricité
TLC	TriLateral Coupling – Market coupling between France, Belgium and the Netherlands
TSO	Transmission System Operator
UIOLI	"Use It Or Lose It" – Loss of long-term rights if they are not nominated
UIOSI	"Use It Or Sell It" – Resale in daily auctions of long-term rights if they are not nominated

COMMISSION
DE RÉGULATION
DE L'ÉNERGIE

2, rue du Quatre-Septembre - 75084 Paris Cedex 02 - France
Phone: 33 (0)1 44 50 41 00 - Fax: 33 (0)1 44 50 41 11
www.cre.fr