CRE Thematic report

Access to long-term capacity for electric interconnections: towards a single European set of rules

May 2010

Contents

Preamble: why this report?

In the space of a few years, important changes have taken place in terms of management of congestion at French and European interconnections. The implementation of market-based allocation mechanisms has, in particular, made it possible to significantly improve the use of electric interconnections[1], to the point where, progressively, a consensus has been reached at European level on the target-mechanisms that would favour efficient management of congestion at interconnections at the different timeframes (long-term, daily, intra-daily and in real-time).

In this fist thematic report on the electric interconnections, CRE has chosen to focus on the allocation of long-term products (monthly, annual and multi-annual). This particular interest in long-term products can be justified by two reasons :

- The importance of long-term products for the development of competition and the creation of a European electricity market ;
- The already high level of harmonisation of allocation rules[2], which shows that the journey towards reaching a target-mechanism (i.e. a common set of rules at European level) is within reach.

This report has a double objective: To identify what is at stake behind the issues still being debated within the European consultation authorities (whether concerning firmness, the level of capacities offered to the market, the type of long-term products offered on the market or the importance to be given to the development of secondary markets) and to propose solutions that could potentially promote an integrated European electricity market.

---

[1] See CRE's various reports on management and use of electric interconnections :
2006 : http://www.cre.fr/en/content/download/3950/74239/file/070512Rapport+interconnexionsUK.pdf
2007 : http://www.cre.fr/en/content/download/5677/122968/file/080708Rapport2008InterconnexionsUK.pdf
2008 : http://www.cre.fr/en/content/download/8845/155560/file/090715InterconnectionsReport2008.pdf

[2] See ERGEG's benchmark on rules for allocating long and medium-term capacity:
http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_CONSULT/OPEN%20PUBLIC%20CONSULTATIONS/ERI%20Benchmarking%20report1/CD/E09-ERI-23-03_LT%20Auction%20Rules_26-Feb-10.pdf

Summary:

Guaranteeing firmness of interconnection capacity (or compensating curtailments based on the daily market prices) is a key element to the design of the integrated European electricity market.

However, although the European energy regulators are on the way to reaching a consensus on the target to be met in terms of firmness, there is less consensus on how this target can be reached[3], which means the two following key questions will have to be duly addressed:

- ***How can we improve confidence in the daily price references used to compensate interconnection capacity holders in cases of curtailment?***
- ***How can we encourage transmission system operators to allocate a maximum of financially firm capacity, at a lesser cost for network users?***

In the short-term, in the absence of appropriate incentive mechanisms to maximise capacity, the regulators have no other choice but to guarantee transmission system operators that costs related to firmness of capacity allocated at the different timeframes will be covered.

In this perspective, transitory solutions can be implemented by regulators in order to limit the risk borne by network users (for example, by introducing caps on price differentials and/or on the budget available for compensating curtailments).

The choices in terms of capacity and how it is distributed between the different timeframes (daily, monthly, annual and multi-annual) are also important decision variables, as these could limit the risk borne by network users. In such, as they are responsible for guaranteeing the interests of network users, the regulators should decide what level of capacity should be made available to the market. This decision should be taken in close collaboration with the network operators, who have all the expertise needed in terms of calculating capacity.

Finally, on the interconnections where a market-coupling mechanism exists, the regulators should ask the transmission system operators to allocate the long-term interconnection capacity in the form of options to receive the price differential if positive.

[3] In particular when no liable and transparent price reference exists on the market.

1. Firmness of interconnection capacity: a key element to designing the European electricity market

Holding long-term capacity is one of the main ways for market players to have a strong position on an exterior market. In this respect, improving the quality of products offered by the system operators is an important way to develop competition and construct the European electricity market.

Due to this observation, an increasing consensus is emerging between European regulators on the importance of guaranteeing firmness of interconnection capacity rights in order to develop exchanges and market integration.

Pursuant to reaching this consensus, ERGEG officially advocated, in July 2008, the principle of physical firmness (see box n°1) of capacities after the nomination stage[4]. To date, this principle of physical firmness is applied on a majority of European interconnections[5].

Box 1 – Physical firmness versus financial firmness of nominations

In its strictest version, physical firmness means system operators cannot curtail capacity once it has been offered and this, whatever the timeframe (multi-annual, annual, monthly, daily or intra-daily).

The financial firmness principle consists in implementing a compensation mechanism in the case of curtailments that make market players financially indifferent between using their transmission right and having it reduced.

In practice, financial firmness of nominations is not an efficient way of contributing to ensuring the system's security. Indeed, the closer we come to real-time, the less measures of capacity curtailment at the borders carried out by the TSOs have an impact on physical flows : a curtailment announced late leaves little possibility for market players to balance their positions on either side of the concerned border, and thus to participate in the network's security. They will thus end up being unbalanced, and the TSO itself will have to guarantee global balance. Moreover, even if the market players are able to be in balance, the implemented measures will not necessarily be efficient to lift the network constraint.

ERGEG's official position paper[6] advocates that the allocated capacities be physically firm once nominated. In such, if there is congestion on the network after the nomination stage (i.e. close to real-time), it was judged preferable to let the transmission system operators take over, as they have several tools (balancing mechanism, reserves,…) allowing them to take

---

[4] http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_ERGEG_PAPERS/Electricity/2008/E08-EFG-29-05_FirmnessTransmissionCapacity_2008-07-15.pdf

[5] See ERGEG's benchmark on the rules for allocating long and medium-term capacity http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_CONSULT/OPEN%20PUBLIC%20CONSULTATIONS/ERI%20Benchmarking%20report1/CD/E09-ERI-23-03_LT%20Auction%20Rules_26-Feb-10.pdf

[6] http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_ERGEG_PAPERS/Electricity/2008/E08-EFG-29-05_FirmnessTransmissionCapacity_2008-07-15.pdf

appropriate emergency measures (redispatching measures targeted at generation facilities situated at various points of the limiting constraint, etc.) to lift the constraint rather than curtail capacity at the interconnections.

Solving the question of firmness of capacities before the nomination stage is also an essential step towards constituting a single European market. It should normally lead to, in the very near future, an ERGEG position similar to that of July 2008. A major difference resides in the fact that curtailments of allocated capacities decided prior to the nomination stage leave market players enough time to adapt their plan of action or to trade on the markets in order to be in balance. In such, the curtailments can represent an efficient preventive measure for guaranteeing network security. The key question that then arises is what compensation should be paid to market players who see their capacity curtailed prior to nomination. In order to ensure the market players that allocated capacities will be firm; the financial firmness principle (i.e. compensating curtailments based on the daily price[7] differential) is the most adapted solution[8].

ERGEG's decision on financial firmness of capacities prior to nomination is even more awaited since the degree of capacity firmness has a strong impact on other subjects still being debated within the European consultation authorities, i.e. :

- The level of capacities offered on the market ;
- The ever more financial nature of transmission products.

Moreover, the development of liquidity on secondary transmission capacity markets and the financial firmness of capacities appear to be two very much interrelated subjects.

If the European energy regulators are finally beginning to reach a consensus on the target to be met in terms of firmness, they agree less on how to reach this target, which means the following two key questions will have to be duly addressed:

- **How can we improve confidence in the daily price references used to compensate interconnection capacity holders in cases of curtailment?**
- **How can we encourage transmission system operators to allocate a maximum of financially firm capacity, at a lesser cost for network users?**

1.1 How can confidence in the daily price references, used to compensate interconnection capacity holders in cases of curtailment, be improved?

One of the fundamental pre-conditions for this confidence is to be able to have, on each interconnected market, a liable price reference representing the market fundamentals and which should be calculated in a transparent way, according to well-established market rules, by an "organised" market. However, as ERGEG's position on physical firmness after nomination shows, when looking at the existing national markets as a whole, not all countries have stock exchanges or standardised trade structures providing a liable price reference.

[7] This compensation should reflect the cost of substitution associated to the capacity curtailment suffered by the interconnection users, as it is recorded at the moment this curtailment is observed. Its value corresponds to the price differential observed between the market places. A price reference for the calculation of this differential is given by the day-ahead prices on organised markets. For countries with several price zones and different purchase and sale prices (Italy, for example), the price reference can be difficult to define.

[8] For more details, see paragraph 1.2 of the 3rd section of the 2008 interconnection report.

The fundamental questions concerning market structures (number and size of market participants) and the architecture of the markets (mandatory implementation of a pool, degree of vertical integration of players, purchase of the system operator's losses via the organised market, etc.) have a determining impact on the functioning of the markets. There are measures that are efficient on the short-term for developing the liquidity, which regulators have more control over. Among these measures, developing solutions for market coupling and transforming long-term transmission products into financial products (see section 3) are most certainly the most promising[9].

1.2 How can transmission system operators be encouraged to allocate a maximum of financially firm capacity, at a lesser cost for network users?

According to article 6 (3) of Regulation (EC) n° 1228/2003 of 26 June 2003 on conditions for access to the network for cross-border exchanges in electricity, « *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* ». Thus, the maximisation of the level of interconnection capacity is a legal obligation for system operators. However, it is difficult for regulators to ensure that TSOs respect this obligation. Indeed, the calculation of capacity is carried out by the TSOs according to various parameters, and is at the heart of the TSOs' profession. The regulators have few technical means of ensuring that this calculation is optimal nor, if it is not, of establishing the room, or means, for improvement: for example, the regulators could employ a group of experts who would verify the capacity made available using previous data and comparisons, or organising repeated audits to ensure the TSO is doing the work correctly. However, these solutions are costly and tricky to implement. This is the well-known problem of the asymmetry of information between regulators and regulated.

To remedy this problem, incentive mechanisms could be established. ERGEG took up this issue and produced a document[10], submitted to public consultation, to open the debate.

Box 2 – Should the market architecture be changed in order to create a genuine European electricity market?

The integration of European markets comes up against a number of fundamental obstacles, which means that several issues concerning the market's architecture are recurrently being raised within the European authorities. Indeed, a combination of different factors could, in the medium-term, have negative impacts on the level of interconnection capacity made available to the market, and at the same time raise questions on the decentralised and zoned market design, on which most European markets are based today. Among these factors, we can note :

- Difficulties for transmission system operators in the Central-West (France-Germany-Benelux) and Central-East (Germany, Austria, Poland, Czech Republic, Slovakia, Hungary) regions to implement flow-based allocation methods which should make it

[9] On the institutional side, regulators are currently working at the European level to implement a monitoring framework in order to insure market integrity.

[10] « Incentive Schemes to promote Cross-Border Trade in Electricity » : http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_CONSULT/OPEN%20PUBLIC%20CONSULTATIONS/Cross%20Border%20trade%20incentives%20electricity/CD/E08-ENM-07-04_IncentiveSchemes_10-Dec-2009.pdf

possible, thanks to a better assessment of the electric flows on the transmission network, to offer more capacity;
- Difficulties transmission system operators have in developing new transmission infrastructures that would allow congestion zones to be relieved, thereby facilitating exchanges;
- The uncertainty transmission system operators are faced with, when calculating interconnection capacities, concerning generation programmes. This translates into a sometimes important security margin, making exchanges more difficult. It should be noted that this uncertainty is likely to be enhanced with the important development of intermittent generation facilities.

Therefore, it seems more and more difficult to reinforce the electric network or to resolve congestion on a national level without limiting exchanges. Analysing the network and congestion management on a regional or European level would be a fundamental step towards solving this issue. In the long run, a centralised approach, combining network management and valuation of the electricity, at a very fine mesh – even nodal – could allow the network, the generation installations, and potentially the flexibility of demand to be managed more efficiently.

Maximising the level of firm capacity sold on the long-term is not a legal obligation for TSOs as opposed to maximising global capacity. They can, on the contrary, have a tendency to want to decrease the level of long-term capacity. Indeed, it is more convenient for TSOs to allocate more capacity at the daily timeframe, since they have, at this stage, a better understanding of the flows on the network, with, as a consequence, a lower risk of resorting to redispatching.
This being said, as mentioned above, long-term products allow market players to have a long-lasting position on neighbouring markets. This is why most of them consider the increase of the level of long-term capacities as one of their main requests. On the other hand, some consider that the acquisition of long-term capacity is restricting and are worried that they will be excluded from cross-border exchanges. The main restrictions evoked are:
- The existing financial barrier to accessing long-term auctions. Indeed, market players are often obliged to supply sometimes high financial guarantees before even having acquired transmission capacity.
- The low liquidity of transmission capacity transfer markets, which makes it difficult to resell the part of the product that the purchaser does not want to use. Thus, capacity holders need to wait for the monthly or daily auctions to resell part of their product.

CRE believes that maximising long-term products will be determining for the development of competition and the construction of the European electricity market to the end consumer’s advantage. Moreover, this maximisation falls within the framework of the long-term model defined by the PCG[11]. As it is, however, advisable to guarantee access to all market players and to give optimal access to the different markets, the study carried out by ERGEG comparing long-term rules is an important step, since it makes it possible to both retain the best conditions for access and define the path towards a single set of rules for the European market.

---

[11] Project Coordination Group. This is a working group made up of representatives of the different types of stakeholders of the electricity market, established during the 2008 Florence Forum. The conclusions of this working group can be consulted on : http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_WORKSHOP/Stakeholder%20Fora/Florence%20Fora/PCG/meeting_17_2_pcg_presentation.pdf

Box 3 – How can we encourage system operators to firmly allocate a maximum of long-term capacity at a lesser cost for the network users?

Taking the hypothesis that regulators of a same region would like to encourage TSOs to offer more long-term capacity, the former should have more responsibility in the determination of the level of long-term capacities (firm), through an incentive mechanism applied to the TSOs, which would periodically be re-assessed.

For example, the regulators could draw up a contract, of a binding nature, with the TSOs, which would indicate the level of capacities made available to the market at the previous annual auction, as well as a target financial sum aiming to cover costs incurred due to firmness (physical or financial) of these capacities (costs of compensation in cases of curtailments, of redispatching…). If the TSOs accept such a contract, their annual performance would be measured by the difference between the target financial sum defined with the regulator in the contract and the actual sum realised. The difference, positive or negative, would be shared out between the TSOs and the network users, according to a specific rule (for example 50%-50%) defined in the contract. This rule should benefit TSOs enough to encourage them to reduce their costs.

The regulators could even choose or propose to TSOs to choose among a menu of contracts, defining different combinations of levels of annual capacity and associated costs, a higher level of capacity implying a higher target-sum to ensure firmness, and/or with a distribution rule which would be more beneficial to TSOs.

Given current regulation, beyond the difficulty of defining a menu of contracts, implementing such an incentive mechanism is a challenge :

- Indeed, this step would only make sense on a larger scale: for example, if we take the French borders, the export capacities on the eastern borders (Belgium, Germany, Switzerland and Italy) influence each other; an incentive mechanism aiming to maximise firm capacity on the long-term should thus involve these four borders in a coordinated way. This raises the issue of the number of parties in the contract (regulators and TSO), as well as that of the distribution of profits and costs between the different borders.
- Moreover, the idea of paying back part of the profits realised to the TSOs could be perceived as detrimental to network users. An educational approach would be necessary to explain the virtuous aspect of such an incentive mechanism.
- Finally, the TSOs themselves could be against the idea that part of the possible additional costs, respective of the fixed target, be at their charge.

Whilst waiting for these obstacles to be lifted, the regulators have no other choice but to cover, via the tariff for accessing the network, the costs arising from capacity firmness, whether it be physical (costs of redispatching) or financial (cost of compensation). Any other approach would be counter-productive: if the TSOs have no guarantee that their costs will be covered, they will implicitly be encouraged to minimise their costs and consequently to reduce the capacity available on the long-term.

Thus, when implementing a compensation mechanism based on the price differential in cases of curtailments of long-term capacity allocated at the France-Spain interconnection, CRE and CNE guaranteed RTE and REE that the costs of compensation for capacity curtailments would be covered by the tariffs for accessing the network.

2. How can the financial risk borne by transmission network users be limited?

The regulators' decision to cover the costs of interconnection capacity firmness is not easy to implement. Indeed, there are cases of sometimes important capacity curtailments on some interconnections (see tables 1 and 2). Moreover, the prices on organised markets, on which the price spread compensation scheme would be based, can sometimes reach levels that are disconnected from the economic reality, which leads to a rapid increase in the compensation costs. Furthermore, it is theoretically possible that costs of financial firmness be much higher than rent from auctions of long term products, which is not the case with "standard" compensation mechanisms[12]. These elements underline the difficulty for the regulator to make the network users cover the cost of financial firmness of interconnection capacity.

Table 1 : Frequency of curtailments on French borders in 2008

2008		Average depth of curtailments (MW)	Number of hours concerned in the year	Number of curtailment periods
England	Export	591	1780	29
	Import	689	207	5
Italy	Export	644	151	3
	Import	0	0	0
Spain	Export	204	98	10
	Import	155	207	8

Source: RTE - Analysis: CRE

Table 2 : Frequency of curtailments on French borders in 2009[13]

2009		Average depth of curtailments (MW)	Number of hours concerned in the year	Number of curtailment periods
Italy	Export	627	409	26
Spain	Export	321	478	20
	Import	90	24	4

Source: RTE - Analysis: CRE

However, the following tables, that show the cost of compensating curtailments of allocated capacity by applying different compensation mechanisms[14] for the years 2008 and 2009 on the interconnections that were subject to curtailments allow us to see that depending on the interconnection or the direction considered, the cost of the "standard" compensation mechanisms may be lower or higher than that of financial firmness (i.e. compensation based

[12] « Standard » « 100% » or « 110% » compensation costs: This compensation mechanism is called « 100% » or « 110% » because compensations are the auction price's reimbursement of curtailed transmission capacity for each curtailed MW or this reimbursement plus a 10% increase.
Cost of financial firmness: market participants are compensated by being paid, if positive, the full hourly price spread for each curtailed MW.

[13] Excluding England and Italy in the import direction as data is not available.

[14] Cost of standard compensation « 100% » or « 110% »: the compensation mechanism is called « 100% » or « 110% » as the compensation is equivalent either to a refund based on the auction price of the product curtailed for each reduced MW, or to a refund plus an additional 10%.
Cost of financial firmness: the impacted market player is compensated with the price differential, if it is positive, for each reduced MW.

on the price differential on organised markets[15]). From these tables again, it appears that on the interconnection with England, where the difference between the costs of the "standard" compensation mechanisms and that of financial firmness is the most important, and the latter remains far lower than the congestion rent issued from the long-term product auctions.

Table 3 : Cost of financial firmness on French borders in 2008

						products
England*						
It						
Sp						

* T

**

Source: RTE - Analysis: CRE

Table 4 : Cost of financial firmness on French borders in 2009[16]

2009	M€	Cost of traditional compensation 100%	Cost of traditional compensation 110%	Cost of financial firmness	Revenues generated by LT products	Ratio cost of financial firmness/revenues of LT products
Italy**	Export	2,67	2,94	7,51	184,70	4%
Spain	Export	0,37	0,40	0,36	15,27	2%
	Import	0,02	0,02	0,03	32,45	0%

** The national price (PUN) was used

Source: RTE - Analysis: CRE

If,the cost of financial firmness can appear to be higher than that of the "standard" compensation mechanisms, its implementation represents an important improvement in the quality of long-term products which should translate into a better valuation, thereby decreasing its relative cost.

Whilst waiting for the pre-conditions to be met, and in particular for the confidence in price-references to emerge, **the regulators can still take transitory measures to limit the financial risk borne by network users in the case where a compensation mechanism based on the market price differential is adopted**. In the rest of this section, we will be focussing on two types of transitory measures, those on the compensation mechanism and those on the level of long-term capacities made available to the market.

a- Introducing caps on the compensation mechanism based on the price differential

This is the simplest solution, and the easiest to implement. It can be a fair compromise between, on the one hand, the need for firmness expressed by market players participating in cross-border trades and, on the other, the need for regulators to protect network users from the market failures.

[15] The British market does not yet have a price reference for the daily market equivalent to that existing in France and on most continental markets. The calculations are based on the Platts index for peak and off-peak periods published for each day of exchanges.

[16] Excluding England and Italy in the import direction as data is not available.

For the first time in Europe, a compensation mechanism based on the price differential in the case of curtailment of transmission capacity was implemented in June 2009 with the entry into force of the new rules for allocating interconnection capacity between France and Spain. The regulators decided, whilst waiting for a market-coupling solution to be implemented on the interconnection, to introduce two caps in the compensation mechanism to limit the financial risk borne by the users:

- The first aims to prevent the monthly sum of compensations from exceeding the level of profits generated through the auctions of long and medium-term products. In practical terms, the monthly budget available for compensating players includes the revenue from the corresponding monthly auction and 1/12 of the revenue from the annual auction;
- The second fixes a cap on the price differential selected for compensation. This cap is different for each of the two directions of the interconnection. In practical terms, the regulators have chosen to not select the highest price differentials observed over one year between the two markets. It has thus been arbitrarily decided to exclude 5 % of the highest price differentials.

Since the implementation of this mechanism, a few curtailments took place in June, November and December 2009. None of the caps were reached for the calculation of the compensation. Moreover, over the period considered, this compensation mechanism proved overall less costly than the traditional compensation mechanism based on the price of the initial auction (see table below).

Table 5 : Cost of the financial firmness with caps on the France-Spain border

€	Compensation	June	July	August	September	October	November	December	TOTAL
France - Spain	At the price differential with cap at	32 292	0	0	0	0	0	0	**32 292**
	110%	36 310	0	0	0	0	1 850	3 922	**42 082**
Spain - France	At the price differential with cap at	196	0	0	0	0	25 440	0	**25 636**
	110%	8 888	0	0	0	0	11 386	0	**20 274**

Data: RTE

It should, however, be noted that these results only cover a relatively short period of time. The real impact can only really be discussed with more extensive data.

b- *Adapting the level of long-term capacities made available to the market*

The way capacities are distributed between the different timeframes is also a factor that is likely to have a strong impact on the financial risk borne by network users if a compensation mechanism based on the price differential is adopted.

The distribution between different timeframes has been discussed between regulators and the TSOs, resulting in the establishment of strict criteria. This is the case for the interconnection between France and Belgium, where it was necessary to ensure liquidity was sufficient for market coupling. However, the TSOs generally decide alone on the distribution between different timeframes. The following tables show the distribution of capacity on the different French interconnections in 2008 and 2009.

Table 6[17] : Distribution of capacity allocated between the different timeframes in 2008

2008	MW	Net capacity allocated on average Annual	Monthly	Daily*	Total	% LT
Belgium	Export	1300	167	1065	2532	58%
	Import	400	179	255	834	69%
England	Export	900	900	174	1974	91%
	Import	900	900	144	1944	93%
Germany	Export	699	761	514	1974	74%
	Import	999	575	1763	3337	47%
Italy**	Export	1799	630	71	2500	97%
	Import	700	249	79	1028	92%
Spain**	Export	150	259	652	1061	39%
	Import	100	76	137	313	56%

* The additional capacities arising from the UIOLI or the UIOSI or from netting are not taken into account

** The periods of unavailability have been excluded from the calculations

Source: RTE - Analysis: CRE

Table 7 : Distribution of capacity allocated between the different timeframes in 2009

2009	MW	Net capacity allocated on average Annual	Monthly	Daily*	Total	% LT
Belgium	Export	1300	203	999	2502	60%
	Import	400	245	443	1088	59%
England	Export	900	900	175	1975	91%
	Import	900	900	172	1972	91%
Germany	Export	900	558	611	2069	70%
	Import	1000	461	1782	3243	45%
Italy**	Export	1800	639	127	2566	95%
	Import***	699	242			
Spain**	Export	200	288	457	945	52%
	Import	400	141	22	563	96%

* The additional capacities arising from the UIOLI or the UIOSI or from netting are not taken into account

** The periods of unavailability have been excluded from the calculations

*** No data on resells

Source: RTE - Analysis: CRE

We can infer from these two tables that the distribution of capacity between long-term products (annual and monthly) and short-term products (daily and week-end for the interconnection with England) is relatively different from one border to the other or even, on one same interconnection, from one direction to the other. **The most important fact concerns the Italian and English borders where an extremely large part of the total capacities (superior to 90% and up to 97%) is allocated in long-term in both directions**. This can be explained by the specificities related to these two interconnections:

- Due to considerable netting between the national transmission networks in the north of Italy, the TSOs in this region decide together on a target net capacity per border from one year to the next. This visibility allows them to allocate nearly all of the available capacity at medium and long-term timeframes.

[17] On the interconnection with England, the different products proposed have been grouped as follows in all of the tables :

- Annual : annual products, both for the calendar and financial year
- Monthly : seasonal, quarterly and monthly products
- Daily : week-end and daily products

- The calculation of the available capacity on IFA is less complex as it is an interconnection in direct current. Similarly, this specificity favoured the allocation of medium and long-term products.

With this in mind, it is not surprising that it is precisely on the two interconnections where the part of medium and long-term products is the greatest that the cost of firmness would be the highest.

The following two tables assess, in hindsight, the capacities that network operators could have made available to the market at the long-term timeframe for a few hours in the year (a limit corresponding to 8 hours was arbitrarily fixed) of additional specific measures (redispatching…) for 2008 and 2009.[18]

Table 8 : Capacity attainable with fewer than 8 hours of specific measures in 2008

2008	MW	LT capacities offered in annual	Capacity attainable in annual with fewer than 8h of additional specific measures	LT capacities offered in monthly	Capacity attainable in monthly with fewer than 8h of additional specific measures
Belgium	Export	1300	1700	1467	2125
	Import	400	600	579	733
England	Export	900	1000	1800	1475
	Import	900	0	1800	975
Germany	Export	699	1400	1460	1679
	Import	999	1251	1574	2223
Italy*	Export	1799	2182	2429	2407
	Import	700	870	949	984
Spain*	Export	150	50	409	563
	Import	100	0	176	200

* The periods of unavailability are excluded from the calculations

Source: RTE - Analysis: CRE

Table 9 : Capacity attainable with fewer than 8 hours of specific measures in 2009

2009	MW	LT capacities offered in annual	Capacity attainable in annual with fewer than 8h of additional specific measures	LT capacities offered in monthly	Capacity attainable in monthly with fewer than 8h of additional specific measures
Belgium	Export	1300	1700	1503	2225
	Import	400	600	645	925
England	Export	900	1000	1800	1417
	Import	900	0	1800	1083
Germany	Export	900	1300	1458	1800
	Import	1000	1501		2081
Italy*	Export	1800	1182	2439	1992
	Import	699	870	941	933
Spain*	Export	200	0	488	480
	Import	400	0	541	383

* The periods of unavailability are excluded from the calculations

Source: RTE - Analysis: CRE

The second and fourth columns of these tables allow us to draw interesting conclusions on the potential room for manoeuvre available to transmission system operators for allocating more capacity on the long-term:

- **On the German and Belgian interconnections, we can note that the system operators could allocate a lot more firm capacity on the long-term (on average, 40% more) without making the network users bear too high a risk** ;

[18] For further information on these calculations, see paragraph 6.1 of the first section of the 2008 interconnection report.

- **On the English, Italian and Spanish interconnections, we can note, on the contrary, that the level of long-term capacities currently offered by the system operators is either equivalent or superior to the level of capacities attainable for a few hours of specific measures (redispatching…). This observation leads us to think that, on these interconnections, the room for manoeuvre available to system operators to allocate more long-term capacities is limited, or nil.**

In conclusion, it is important to stress that **there is room for manoeuvre available to regulators and transmission system operators to limit the financial risk borne by users, with the implementation of a compensation mechanism based on the daily market price differential**.
This room for manoeuvre is different from one interconnection to the next.
In some cases (German and Belgian interconnection), it appears that the regulators could decide to allocate more financially firm long-term capacity without the system users bearing too high a risk.
In other cases (English, Spanish and Italian interconnection), financial firmness of capacities should be introduced along with measures to limit the financial risk borne by the network users. These measures could either be caps on the mechanism for compensation at the price differential (as was done on the France-Spain interconnection), or a better distribution of capacities between the different timeframes (for example on France-England and France-Italy).

It is also important to stress that the regulators, being responsible for guaranteeing the interests of network users, have a major role to play in these decisions. The regulators should, indeed, be more involved in the choice of the compensation criteria proposed in the allocation rules, but also in the determination of the level and distribution of the capacities made available to the market. Regulator involvement in this type of decision is still, too often, far from what it should be. Indeed, transmission system operators have a strong tendency to announce the level of capacity available for the annual auction very late on in the year and without prior consultation, neither with the market players, nor with the regulators.

Of course, these decisions must be taken in close collaboration with the system operators that have all the expertise needed in terms of capacity calculation, weighing out the pros and cons between, on the one hand, the financial risk borne by network users in the case where a compensation mechanism based on the market price differential is implemented and, on the other hand, the level of capacities.

Box 4 – Data which, in being made available by transmission system operators, would allow regulators to be more involved in the distribution of capacities between the different timeframes

Only the system operators have access to the necessary data and expertise to estimate the level of capacities that can be allocated on the long-term (including on the multi-annual timeframe). The regulator can, nonetheless, intervene in the choice of capacities to allocate if the system operator provides him with :

- Data on the probability of being able to maintain a certain level of capacity during several years/the whole year (or the whole month) (possibly excluding periods of planned maintenance work) without resorting to specific actions (redispatching or counter-trading) ;

- An estimation of costs related to allocation of a volume of long-term capacity that is likely to generate redispatching, counter-trading or curtailments and consequently, compensation.

The regulators could estimate the risk that the system operators should be prepared to bear to offer more capacity at the considered timeframe. This data could also allow them to measure the financial impact of different mechanisms for compensating curtailed capacity.

3. The interest in moving on to financial transmission products

Although there is currently a debate on the European target model for rights to use long-term capacity, regulators have not been able to reach a final consensus on the nature of allocated products. There are two options:

- A first option would be to continue to allocate interconnection capacity in the form of "options to be nominated" or "Physical Transmission Rights" (PTRs). These PTRs would allow their holder to choose between nominating the corresponding energy or taking advantage of the automatic resell of capacity that was not nominated in the daily auction (called the "Use-It-Or-Sell-It" principle) ;
- A second option would be to allocate the same amount of interconnection capacity in the form of Financial Transmission Rights (FTRs).

These two options – i.e. FTRs and PTRs with the UIOSI principle – are very similar in cases where the markets are coupled, but moving on to FTRs has many advantages which we will describe further on. Before this, it is important to specifically define the different notions which are often, and with no distinction, referred to as FTRs (see box n°5)

Box 5 - Taxonomy of financial transmission rights[19]

- ***PTR with UIOSI A→B***: This is the optional right to use the interconnection capacity by nominating an electricity flow from a price zone A towards a price zone B. The UIOSI mechanism allows the player who is not exercising his option to nominate to receive the income from the resell of this right at the daily auction price. This daily auction may be explicit (in this case, the PTR holder receives the daily auction price) or implicit if there is market coupling (in this situation, the PTR holder receives the price spread differential if positive). The amount of PTRs offered to the market is computed by TSOs on the basis of a common network model. The PTRs can be acquired from the TSOs, through an independent Auction office or on a secondary market. This tool is implemented on most European interconnections.

- ***Option FTR A→B***: This is the financial right which authorises the holder to receive the price spread between market B and market A if positive. The amount of FTRs offered to the market is computed in the same as PTRs, which means based on a common network model. In a similar way, the option FTRs can be acquired via auctions, through an independent Auction Office, or on a secondary market. However, to make option FTRs available, two adjacent markets have to be coupled via an implicit daily auction mechanism. This tool is implemented in the United States.

- ***Obligation FTR A→B***: This is the financial right which authorises the holder to receive/pay the issuing TSO, when the right has expired, a sum equal to the price differential observed between the two daily markets. Even if it is not a right for a

[19] More details available in the following document: http://www.entsoe.eu/fileadmin/user_upload/_library/publications/etso/Congestion_Management/Short%20ETSO%20Risk%20hedging%20in%20CM_final%20PUBLIC.pdf

physical delivery of electricity, the TSO cannot allocate more FTRs than capacity available outside of netting, otherwise it runs the risk of paying more than the daily congestion rent he receives. The obligation FTRs can be acquired via auctions, through an independent Auction Office, or on a secondary market. However, to make obligation FTRs available, two adjacent markets have to be coupled via an implicit daily auction mechanism. This tool is implemented in the United States.

- ***« Pure » FTR (Contract for Difference or CfD) A→B***: This is the purely financial right that links together two players who want to implement an « opposite » energy transaction. As opposed to the aforementioned transmission right, the CfD is not managed by a TSO. The CfD will link a player wanting to buy energy in zone « A » to resell it in zone « B » with another player wanting to buy energy in zone « B » to resell it in zone « A ». The CfD thus authorises this contract's buyer to receive from the seller, when it has expired, a sum equal to the price differential between these two price zones. On the contrary, if the price differential is negative, it is the buyer who must pay the price differential to the seller. To make CfDs available, it is not necessary for two adjacent markets to be coupled, and the sum of CfDs is not limited to the transmission capacity available between two markets. This tool is implemented on Nordpool.

Given that CfDs are purely financial products, developed on market's request, a priori with no relation to the physical availability of the network computed by the TSOs, CRE does not have to take position on the development of these products. It can only say that this kind of product, if the market requests it, can only act as a complement to the other kind of products where the physical availability of the network is taken into account (like PTRs or FTRs).

Whether "optional" or "physical", FTRs, as long as they are firm, give an insurance to market players: to be hedged against the price difference volatility. As option FTRs are the closest products to the currently available products (PTR with UIOSI), they are the ones that will be considered in the remaining text as FTRs.

N.B: Contrary to the widespread misconception, FTRs are no miracle solution to the problems referred to above. The difficulty of arbitrating between, on the one hand, the financial risk borne by the users (due to the guarantee of firmness) and, on the other, the level of capacity made available to the market, is still very much an issue.

As was highlighted in the second CRE report on the management and use of electric interconnections, as soon as day-ahead coupling of the daily markets existed between two markets, implementing FTRs had two important advantages:

- **a simplification of the operational processes for traders, but also for system operators, due to the suppression of the nomination stage for long-term capacity, and thus a reduction of operational costs** ;

- **an increase in the volumes exchanged on the organised markets;** and consequently, possible improvement in the confidence in price references: indeed, the absence of the possibility to nominate long-term products implies that all cross-border exchanges will be processed by organised coupled markets and will play a part in defining daily prices.

Despite these advantages, when CRE's 2007 report on the management and use of interconnections was published, several players showed certain reserves concerning the implementation of FTRs:

- the issue of tracing renewable electricity during cross-border exchanges: as all nominations take place in the context of market coupling, by definition being anonymous, will a player holding financial transmission rights be able to prove the origin of the generated electricity ?

- the issue of the regulatory framework and the regulation applicable to financial transmission rights. Some market players and TSOs raised the question of which regulation would be applicable to transmission rights if they became financial and what impacts this would have.

- The obligatory transition through organised markets to carry out a cross-border transaction.

In the remainder of this section, we will analyse the validity of the reserves some of the market players expressed.

a- The issue of tracing renewable electricity during cross-border exchanges

The implementation of FTRs cancels out the possibility of nominating long term physical electricity transfers. In such, it can be in contradiction with the need in some of the Member States' regulation to trace a physical flow. Indeed, some countries, such as Italy, need to trace the origin and the physical transit of the renewable energy to be certified.

First of all, it is important to differentiate two notions which today make it possible to ensure the traceability of energy from renewable sources:

- The green certificate which is issued by a private, voluntary system ;
- The guarantee of origin (GO) which is governed by EC Law [20].

The green certificate is a private norm originating from the Renewable Energy Certificate System (RECS) association. This voluntary certification system makes it possible to guarantee that the electricity is generated by a producer of renewable energies and is sold only once.

Exchanges (import /export) of green certificates are completely disconnected from the use of the network and thus do not require nomination of physical electricity transfers in order to be valid.

[20] The act setting the guidelines for the energy policy of July 13th, 2005 implemented a system of guarantee of origin, labelling the origin of the electricity generated in co-generation plants or in plants generating energy from renewable resources. Decree 2006-1118 of September 5th, 2006 and the order of November 8th, 2007 state the conditions for implementing these guarantees of origin.

A guarantee of origin makes it possible to certify that a part, or the quantity of energy sold to the end consumer, was generated from renewable energy resources. In France, it is granted by the distribution or transmission system operator concerned[21]. The electricity labelled with a guarantee of origin is either of renewable origin or generated by co-generation. Depending on the countries' legislation, the exchanges of guarantees of origin can be related to physical electricity transfers.

Directives 2001/77/EC[22] and 2009/28/EC[23] provide that guarantees of origin issued by Member States will be mutually recognised. Any refusal to recognise guarantees of origin must be based on objective, transparent and non-discriminatory criteria.

These directives do not state that transfers of guarantees of origin from one Member State to another need to be associated to a physical electricity transfer[24].The German, British[25], Belgian[26], Spanish[27], French, Luxembourgish [28] and Dutch Regulations do not state that importations of guarantees of origin must be correlated with a physical electricity transfer.

However, Italian Law[29] does not authorise importations of guarantees of origin if there is no physical import of electricity correlated with the importation of guarantee. There is also a British type of certificate; called « LECs[30] » (which is not recognised by the EC Directives). The British producer wanting to import LECs must prove he has bought interconnection capacity in order to guarantee the physical electricity transfer.

<u>In conclusion, regulation on the traceability of electricity exchanged on the French borders, green certificate trading, and guarantee of origin trading do not hinder the implementation of FTRs, except on the France-Italy interconnection and in the specific case of British LEC certificates.</u>

b- <u>The question of which regulation is applicable to financial transmission rights</u>

Some market players and TSOs are raising the question of which regulation will be applicable to financial transmission rights, and the consequences such regulation might have.

In the proposed model, the volume of FTRs put up for auction should be determined by the system operators based on the commercial capacity available, as would be done for PTRs.

---

[21] Article 1 of decree n° 2006-1118 of September 5th, 2006
[22] Article 5 of Directive 2001/77/EC
[23] Article 15 of Directive 2009/28/EC of 23 April 2009 relating to the promotion of the use of energy generated from renewable resources, that must be adapted in all Member States before 5 December 2010
[24] Preamble 52 of Directive 2009/28/EC
[25] An equivalent of the guarantees of origin (" REGOs") is defined in British Community Law: The Electricity (Guarantees of Origin of Electricity Produced from Renewable Energy Sources) Regulations 2003.
[26] Decree of April 12th, 2001 relating to the organisation of the regional electricity market
[27] Chapter 1, article 11 of Order ITC/1522/2007, of 24 May 2007
[28] Article 3 of the Grand-ducal Regulation of February 8th, 2008 relating to the generation of electricity based on renewable energy resources
[29] Article 20 of the Decreto Legislativo 29/12/2003 n°387
[30] Levy Exemption Certificate described in : The Climate Change Levy (General) Regulations 2001 (Statutory Instrument (SI) 2001 No. 838)

The system operators would still calculate the « commercial » interconnection capacity based on a method approved by the regulators in accordance with article 5 (2) of Regulation (EC) n° 1228/2003 and with article 30 of the terms and conditions applicable to the public electricity transmission network. This « commercial » capacity would still be allocated according to rules approved by the regulator.

In view of this, the regulatory framework would thus remain unchanged, as would the competences of the energy regulators in terms of approval of rules for allocation of commercial capacities at interconnections.

Were FTRs to be qualified as financial tools and thus come under Directive 2004/39/EC of 21 April 2004 and its adaptation to the Monetary and Financial code, the only impact would be on system operators, who would have to apply the relevant provisions of adaptations of the Directive 2004/39/EC of 21 April 2004.

Concerning the market players, such a qualification would not imply any particular changes. The participation to FTR auctions would suppose the players had signed a declaration of participation to the rules of capacity allocation, which is currently the case.

c- <u>The obligatory transition through organised markets to carry out a cross-border transaction</u>

Some players do indeed regret the fact that moving on to FTRs cancels out the possibility for PTRs to physically nominate these long-term products or to use them as FTRs through the automatic resell mechanism (UIOSI). FTRs would thus oblige players wanting to carry out cross-border transactions to do this in the context of market coupling, which could thus imply paying a fee for participation in organised markets.

This criticism, raised by various market players concerning FTRs, is to be considered whilst keeping the following two points in mind:

- The first concerns the fact that **a majority of long-term interconnection capacities is already used as FTRs on the coupled markets** (see table below). The rates of resell of long-term products in daily are very high within the TLC, which means that long-term capacity holders would prefer to receive the price differential than to physically use these rights by nominating them. The high proportion of cross-border transactions carried out via the organised markets tends to show that the obligatory transition through the organised markets, far from being a barrier to the development of cross-border exchanges, is essential for the market players.

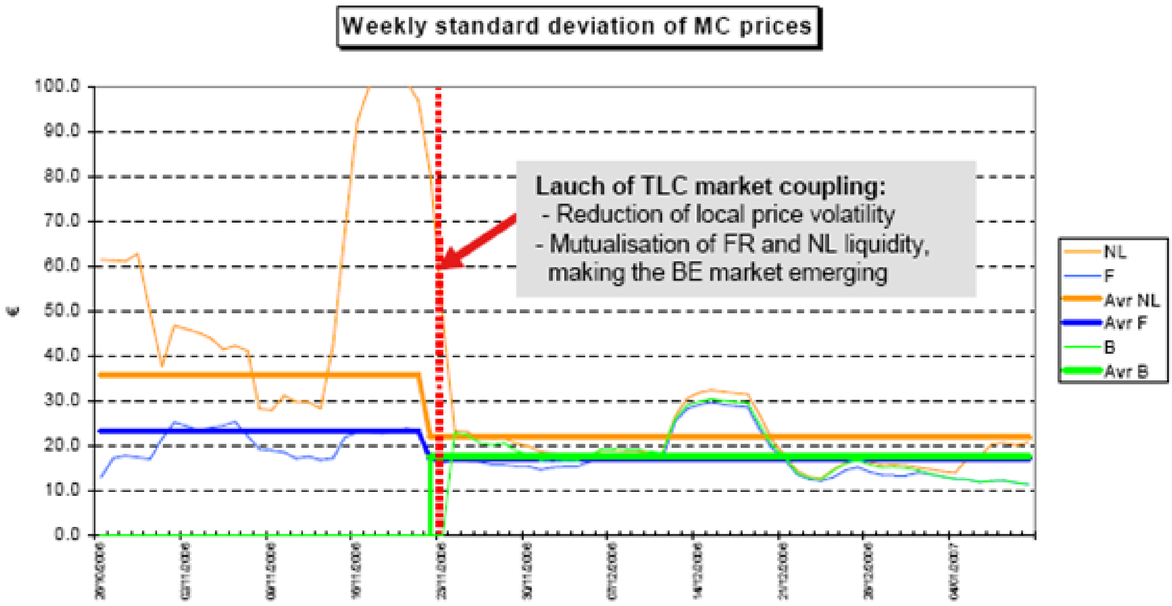
2008	Share of LT capacities resold in daily
France - Belgium	52%
Belgium - France	88%
The Netherlands - Belgium	77%
Belgium - The Netherlands	73%

Source: RTE - Analysis: CRE

- The second concerns the lack of coherence in the positioning of various players. Indeed, it is interesting to note that **the market players that are the most reluctant**

to participate in the liquidity of the organised markets – and thus in the liability of price references – are often those who unconditionally request the implementation of a compensation mechanism for interconnection capacity curtailment based on the price differential on organised markets.

Moreover, concerning the second point, the introduction of FTRs would not precede the implementation of market coupling. Yet, market coupling is a way of reducing price volatility on the organised markets and of considerably increasing the quality of these prices and the confidence we can have in them.
The graph below illustrates the net reduction in volatility on the French and Dutch markets, once coupled. The mutualisation of their liquidity along with the creation of a Belgian market made it possible to have more liable price references.



Source: Powernext

However, it is still legitimate to question the implementation of FTRs: the obligatory transition through the organised markets in order to carry out a cross-border transaction will in fact grant a monopoly position to these organised markets for carrying out these transactions. Yet these are generally not regulated entities. In such, the extension of market coupling and the implementation of FTRs raise the question of which governing method should be implemented vis-à-vis the power exchanges.

To conclude this section, it seems that **the reserves expressed by some market players concerning the implementation of FTRs on the interconnections where a market coupling solution exists are not all legitimate or pertinent**. However, the question of how to govern the power exchanges still needs to be answered.

Given the many advantages – including potential improvement in the confidence in daily price references –to allocating interconnection capacity under the form of options to receive the price differential (when it is positive), it is in the regulators' best interest to

encourage and facilitate their implementation. This calls for deep reflexion on the way to govern the power exchanges[31].

[31] To this effect, there is a consultation group dedicated to the question of the method for governing the power exchanges created after the Florence Forum in December 2009 - link : AHAG - expert group

4. How can the liquidity on secondary markets be developed?

According to article 2.12 of the Congestion Management Guidelines[32], « *Capacity shall be freely tradable on a secondary basis* […] ». The implementation of secondary markets has several advantages:

- In allowing capacity holders to resell the products, the existence of a secondary market makes these products more attractive. Thus, since an exchangeable product is necessarily more valuable than a non-exchangeable product, the implementation of a secondary market implies an increase in the valuation of capacities and thus, all other things being equal, of the revenue of auctions.

- Moreover, in allowing potential new players, for example, to acquire annual capacity, the implementation of a secondary market would increase competition on the capacity market, and consequently increase competition on the wholesale electricity markets, to the energy consumers' advantage.

On France's borders with other Member States, the secondary markets have been implemented. Three mechanisms coexist:

- **The resell, on demand, of annual capacities at the monthly auctions**: the holder of a band of annual capacity can notify the TSOs that he wishes to resell, at the next monthly capacity auction, in the form of a monthly band; he will receive for this band the price arising from this auction. This mechanism is seldom used on the French borders.

Table 10 : Resell of annual capacity at monthly auctions[33]

2009		Annual capacity resold on average at the monthly auctions	Share of the year capacity allocated
Belgium	Export	11	1%
	Import	0	0%
Germany	Export	43	5%
	Import	14	1%
Italy	Export	39	2%
Spain	Export	18	12%
	Import	3	1%

Source: RTE - Analysis: CRE

- **The automatic resell of monthly capacity at the daily timeframe (Use-It-Or-Sell-It, or UIOSI)**: this mechanism, which was initially used on demand as was the previous one, makes it possible to automatically resell long-term capacity as long as it is not nominated, at the price of the daily auction. On the borders managed by market coupling, this would correspond to using PTRs as FTRs since the price of daily

[32] Commission Decision of 9 November 2006 amending the Annex to Regulation (EC) n°1228/2003 on conditions for access to the network for cross-border exchanges in electricity.
[33] No data available for Italy in the import direction.

capacity is the price differential between the markets. As presented above, this service is widely used within the TLC. For 2009, on the border between France and Belgium, we can note that the rate of resell of long-term capacity is close to 70% in both directions.

- **Transfer of capacity by mutual agreement**: long-term capacity holders can also resell all or a part to another player, at a price agreed freely between them. The transferred product is not necessarily a band but can be broken down into fractions of an hour. Despite the flexibility of this service, it is only seldom used: indeed, the exchanges recorded for 2009 only concerned the interconnection between France and Italy for an average of 87 MW. The publication of the names of the long and medium-term capacity holders can explain this characteristic.

The implementation of secondary markets, in particular with the possibility of transferring capacity between players, was a strong demand from market players. The low rate of use of these transfers shows that this demand from the players is not completely satisfied. Several reasons can be given for this situation:

- The absence of transfers of financial obligations relating to transmission rights during a sale by mutual agreement is crippling for the initial holders. In this situation, the holders legitimately have reserves concerning the sale of all or part of their rights to a third-party since if the latter does not pay, the system operator will turn to them.

- The absence of a dedicated platform, with a clearing mechanism, does not facilitate transfers. Searching for a purchaser or a seller, without such a platform, is both inefficient and time-consuming. If such a platform does not exist, the list of the capacity holders should at least be accessible to players who are willing to acquire capacity. Such a system exists on the France-Italy interconnection only, where the names of the capacity holders are published.

- Due to the low liquidity on the secondary market, the TSOs are not encouraged to implement a platform that would enable supply to meet demand in an anonymous way. But the existence of such a platform would allow them to purchase, if necessary, any possible over-sold capacity, at the correct price. Such an instrument, which would allow them to a certain extent to avoid capacity curtailments and their compensation, would allow TSOs to detach themselves from the implicit incentive to reduce the level of capacities offered on the long-term. Moreover, this mechanism of repurchase of capacities by the TSOs would also make the platform more attractive to players and the liquidity on the secondary market would thus be enhanced.

- The implementation of the automatic resell mechanism (UIOSI) makes capacity transfers less attractive. For a capacity holder, the automatic resell mechanism makes it possible to easily optimise one’s positions with no effort or risk, since a capacity holder receives the price of the daily auction as long as he has not nominated long-term capacity in D-1. On the contrary, capacity transfers have to be notified in D-2 or even in D-3 or D-4, depending on the day of the week.

- To a lesser extent, the absence of financial firmness hinders the secondary market’s liquidity, in the same way that it hinders the auction’s liquidity, by excluding market players that are particularly prone to curtailments (such as those with no generation capacity or only situated in one country) from participating in cross-border trades, out of fear of having to re-balance.

To conclude, it is important to stress that the development of secondary markets gives system operators an additional tool for guaranteeing firmness of capacities as well as a better valuation of the capacities. Indeed, the implementation of a dedicated platform would also help to develop liquidity on the mutual agreement market, which would allow system operators to repurchase the possible excess capacity and market players to better manage their needs in terms of transmission rights. Finally, on the interconnections where a market-coupling solution is not conceivable on the short term, the implementation of PTRs with the automatic resell mechanism should be favoured.