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REPORT

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Electricity and gas interconnections in France

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RÉPUBLIQUE FRANÇAISE

CONTENTS

MESSAGE FROM THE CRE

Due to its geographic location, France plays a central role in building European electricity and gas markets. The CRE has supported the development of interconnections for many years. Its participation in voluntary regional initiatives on all of its borders has helped prepare the implementation of target models for use of these interconnections. It is also very much committed to creating European rules in partnership with the other European regulators.

Interconnections are a structuring element of the single European energy market, and currently fully play their role, offering France a competitive and safe energy supply. The general overview is very positive in terms of the cost of energy, but also security of supply, since interconnections have helped address issues of temporary non-availability of part of the nuclear plants, or drops in availability of liquefied natural gas.

However, further progress is required in particular in the operation of existing assets. The priority today must be to ensure full implementation of the measures given in the third European legislative package: this package has established a very ambitious roadmap for harmonising rules for using networks, an ambition that is in line with the goal for completing the single European market.

The challenges now involve the methods used to calculate capacities sold at interconnections. Although the centre-west region of Europe (CWE) was a pioneer in the introduction of market coupling and then Flow Based methods, the application of this capacity calculation method since 2015 has not produced all the benefits expected: internal constraints within transmission networks have sometimes significantly limited the available import capacities, in particular during periods of strain on the system (winter 2016/2017). The CRE continues to work actively with other regulators to ensure that the methods implemented by Transmission System Operators (TSOs) enable optimised use of the interconnections.

Concerning the balancing mechanisms, most of the integration as it is foreseen in the third package has yet to be implemented. France is involved in several platform projects that allow the exchange of various balancing products – manual or automatic – with different activation times. The CRE ensures that they are correctly implemented, and has been particularly involved, in cooperation with all parties to the project, in work related to the "TERRE" project (Trans European Replacement Reserve Exchange), a regional shared platform for TSOs that have a "proactive" approach to balancing, similar to that of RTE. Since 2015, the CRE has also been involved in working with RTE to establish a roadmap, published in 2017, establishing a long-term goal for the French balancing model, and the steps for achieving it by 2021.

The CRE considers that the European institutional framework, currently being revised in the framework of the "Clean energy for all Europeans" package, must remain flexible enough and propose measures in proportion with the benefits expected. This is the case in particular for organising short-term electricity markets; some proposals would directly reduce the time that the network operator has to balance the system in near real-time. In France the network operator is able to take "proactive" balancing actions, which are less costly in the French system. Removing this option would lead to very high transition costs, and neither the relevance nor the benefits of an alternative balancing model have been demonstrated.

Regarding investments in new interconnection projects, a number of projects have been decided on in recent years that will bolster existing capacities.

The Savoie-Piémont interconnection with Italy is in the final construction phase and should be operational in 2019.

The IFA2 interconnector project with Great Britain was approved by the CRE in February 2017. Given the operational and economic uncertainties brought about by the United Kingdom's decision to exit the European Union, the CRE has introduced an incentive-based regulation framework to re-balance the sharing of risks and benefits between RTE and the end consumer, in order not to expose users to high risk. Then, following the British government's activation of the exit procedure in March 2017, the CRE considered that these uncertainties rendered it unable to decide on other interconnection projects, of which there are many at this border (three are currently under consideration).

For the Bay of Biscay project, a cross-border cost allocation decision was adopted with the Spanish regulator in September 2017. It aims to ensure that the costs incurred by RTE reflect the estimated level of benefits for France. The project has also received considerable European funding.

The CRE has approved these projects since they provide proven and documented benefits to the European community, which exceed their costs. Acting in the interests of the end consumer, the CRE considers that decisions to invest in new projects must undergo reliable cost-benefit analyses. The aim is to spare the end user any unnecessary costs.

Europe has implemented a strategy for a massive reduction of its economy's carbon footprint by 2050. European gas consumption will likely stagnate in the coming years. Within this context, any new gas interconnection must be approached with the greatest caution, to avoid generating stranded costs with infrastructures that are unused.

Thus the CRE is seeking new ideas on the European regulatory framework for the development of infrastructures, for gas as well as electricity. Although it is vital to promote and support the development of projects that benefit the community, the process of selecting projects of common interest, which generally takes place several years before their completion, and while their costs and benefits are not clearly identified, creates issues if it leads to automatic confirmation of the project in the end.

PART 1. MAIN EUROPEAN DEVELOPMENTS SINCE 2016

Chapter 1 - The European networks in a historic context

The European energy system as it exists today is the result of a long history. The electricity and gas networks were developed gradually over the course of the 20th century, along with the development of production and consumption. Thus growing from a local industry, the electricity and gas sectors underwent sharp growth to form networks on a European scale. This development involved the creation of large-scale supply systems (electrical plants, gas deposits) combined with logistics chains to concentrate energy flows, thus enjoying effects of scale that have led to a sharp drop in unit costs, while allowing demand to grow rapidly. The movement towards greater centralisation in the network energy sector has created problems, since the connection of formerly isolated systems required the harmonisation of technical standards.

In short, the networks developed locally; their capacity ramp-up gave societies access to abundant energy at a competitive price, a factor that has boosted economic growth and improved levels of comfort accessible to populations. Their characteristics have been greatly influenced by the availability of natural energy resources and their geographic location.

In France for example, high-voltage networks have enabled the rail transport network and major consumption zones, such as the Paris region, to access electricity supply from hydroelectric dams in the Alps, while long-distance pipelines have replaced manufactured gas produced from coal by natural gas from Lacq, then from the Netherlands.

The energy trajectories from Germany and Italy have been substantially different, with massive use of coal in one case, and in the second a mix that is more heavily made up of hydrocarbons (oil and gas). Germany and Italy have given much greater priority to natural gas. In terms of organisation, while some countries such as France chose vertically-integrated public monopolies, others such as Germany had an industry with a regional footprint, with public and private stakeholders and a separation between production and transport on the one hand, and distribution on the other.

The European energy landscape was therefore built from a wide variety of national models influenced by natural availabilities, institutional frameworks, the size of countries, the level of centralisation and development of uses, for example in industry or to satisfy heating requirements. The first challenge involved implementing consistent energy systems on the national scale, and then the issue of interconnections with neighbouring networks arose, according to logics that are substantially different for electricity and gas.

For electricity, the issue of interconnection on an international scale truly emerged in the 1950s. Although these first transnational network projects emerged in the period between the two world wars, in particular around Switzerland, these initiatives remained in the theoretical phase and in a bi-national context. It was at the time of the creation of the union for the coordination of electricity generation and transport (UCPTE) in 1951 (which became the UCTE in 1999) that the construction of a European electricity landscape began, intended to develop solidarity between operators, an initiative that would lead to production plants being synchronised on a European scale.

France played an important part in this process by getting involved at an early stage in the creation of interconnections, a movement that accompanied the construction of the nuclear base and the emergence of France as a major electricity exporter. The electrical interconnections were therefore promoted in terms of security of supply via export contracts and aid agreements to improve the resilience of the European electrical system. As markets have opened up, the role of interconnections has been enhanced since they have become a support to the development of transactions between member states of the European Union, helping to consolidate the idea of the integrated market.

For gas, following local development of networks, around generally small deposits, the discovery of the Groningen gas field (in the Netherlands) marked the emergence of a large-scale gas industry and the gradual creation of international infrastructures. Starting in the 1950s, the use of imports became necessary to support growth in demand. Development of gas was therefore a major aspect of energy policies in Europe. The discovery of large reserves in Siberia, Algeria then Norway, initiated the creation of major international transport corridors.

Financed under long-term supply contracts, international pipelines were built by consortia of operators based on systems that share risks between exporters and importers. This tendency led to increasing interdependence with producing countries, but also between European countries in international transit, given for example that pipelines from Russia cross central Europe before reaching the final destination countries. The length of the supply chain forced consumer countries to acquire physical systems to manage highly seasonal demand, such as underground storage.

Figure 1 – Gas networks in Europe from 1970 to today

The creation of the domestic European market for electricity and gas therefore used infrastructures that were already created, including interconnections. Going beyond the historic objectives of security of supply and imports within long-term contracts required interconnections to be strengthened to make exchanges more fluid and allow new players to emerge. The development of interconnections was a key factor in the introduction of competitive market models that must offer the option of arbitration between production systems. Rules also needed to be created to allow interconnections to assist market development. Improved management of production bases through better use of complementarity between countries was also one of the goals, involving the introduction of market coupling mechanisms. It was a rather long process, and although overseen by European directives and regulations, it used innovations implemented on a limited number of borders, particularly as part of regional initiatives. This is the case for example of electrical market coupling, which was first designed between France, Belgium and the Netherlands, before being extended to Germany and then being used as the reference model for the European market as a whole.

In terms of security of supply, the role of interconnections is at the heart of the European strategy with the aim of exploiting complementarity between member states. It involves improving the resilience of the European energy system by avoiding the duplication of supply systems. This principle of solidarity, which has long been a key component of the operation of the electricity sector, is increasingly present in the gas sector, with a gradual strengthening of the rules for assistance in the event of a supply crisis. The provisions concerning the market have been bolstered by mechanisms aimed at sharing flexibility to preserve supply to "protected" consumers, i.e. those considered particularly vulnerable (individual consumers, public services, etc.).

Chapter 2 - Network codes: evolutions since 2016

Network codes and guidelines are European regulations that set out in detail a number of operational aspects of the energy sector within the European Union (particularly concerning cross-border issues). This chapter presents the main changes that have taken place in terms of the adoption and implementation of network codes since 2016 for gas and electricity.

1.2.1 The European regulations from the third legislative package aim at implementing the integration of European markets

The third legislative package[1], adopted in 2009, signalled a decisive step in the harmonisation of rules for using interconnections in the European Union. The principle was to lift barriers to cross-border energy exchanges by developing and introducing network codes and European guidelines, in the form of regulations. The first two sets of European directives had left the member states a certain degree of flexibility of interpretation when transposing to national law, which gave rise to different choices that sometimes obstruct market integration. This integration was supported within the framework of the third package on the establishment of reference market models, the target models, which were created thanks to initiatives developed locally or regionally, such as entry-exit models with virtual hub for gas and market coupling for electricity. These voluntary initiatives were structuring to then determine the content of European laws.

1.2.2 The regulators are fully involved in the long and complex process of developing then adopting network codes and European guidelines

At the end of May 2018, the Commission adopted thirteen network codes and guidelines in total, eight for electricity and five for gas. These laws complete regulations (EC) no. 714/2009 and EC) no. 715/2009 and cover all the technical aspects necessary for implementing a European energy market, the principle of which, shared by both electricity and gas, involves giving a central role to wholesale markets and interconnections. The wholesale markets establish prices that help organise cross-border flows from areas where prices are low towards areas where prices are higher. The goal is to ensure that resources are better allocated at the European level and thus help reduce supply costs.

The network codes, in their respective field of application, define technical or operational requirements applicable to different categories of actors. They are implemented directly on a national scale, with some detailed application parameters proposed by network operators (TSOs), then approved by the competent national authority (administrative or regulatory authority).

The guidelines establish the principles (for example in terms of operational management of the electrical system and interconnections between member states). They are implemented using a set of application methods created jointly by the TSOs and/or the market coupling operators (NEMOs), at the national level, the regional level (France belongs to four capacity calculation regions[2]: the Channel region, the Core region, the Italy North region and the South-West Europe region - see figure 10), or European level, then subject to the relevant national regulatory authorities, who consult, cooperate and coordinate to reach an agreement. On this basis, each regulatory authority then adopts a decision at the national level. The agreement then confirms that the decisions of regulatory authorities are identical in substance. If no agreement is reached, the decision is passed on to the Agency for the Cooperation of Energy Regulators (ACER).

[1] Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity, Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas, Regulation (EC) no. 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity, Regulation (EC) no. 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and Regulation (EC) no. 713/2009 of the European Parliament and of the Council of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators.

[2] The decision of ACER of 17 May 2017 established eleven capacity calculation regions across Europe, with France belonging to four of these regions, including the Core region which encompasses thirteen member states.

Figure 2 – The families of network codes* and guidelines** concerning electricity

Market and management of interconnections	■ Forward Capacity Allocation** (FCA), the aim of which is the European harmonisation of the system of long-term transmission rights issued by the TSOs. Came into force 17 October 2016. ■ Capacity Allocation and Congestion Management** (CACM), the aim of which is to harmonise interconnection management practices at the European level. Came into force 14 August 2015. ■ Electricity Balancing** (EB), the aim of which is to extend market coupling of European markets to the balancing markets. Came into force 18 December 2017.
Operational management of the electricity grid	■ System Operations (SO): security and operational planning rules, reserve sizing rules and frequency control rules**. Came into force 14 September 2017. ■ Emergency & Restoration procedures* (E&R). Comes into force 18 December 2018.
Connection to the electricity grid	Technical requirements applicable to: ■ Production facilities* (RfG). Came into force 17 May 2016. ■ Distribution networks and consumption facilities* (DCC). Came into force 7 September 2016. ■ Long distance direct current connections and systems * (HVDC). Came into force 28 September 2016.

Network codes dedicated to connection to the electricity grid are not addressed in this report.

Figure 3 – The families of network codes* and guidelines** concerning gas

Market and management of interconnections	■ Framework guideline on congestion management procedures** (CMP), the aim of which is the European harmonisation of tools used to solve contractual congestion situations. Came into force 1 October 2013. ■ Mechanisms for allocating capacity in transmission systems* (CAM), which harmonises the allocation of capacities by the TSOs. Came into force 1 November 2015, with an amendment in force since 5 April 2017. ■ Balancing* (BAL), the aim of which is the widespread introduction of market-based balancing systems, encouraging shippers to balance themselves and promoting the emergence of wholesale liquid markets. Came into force 1 October 2015.
Operational management of the gas network	■ Interoperability and exchange of data*, which aims to align operational, technical and communication procedures used by the European TSOs. Came into force 1 May 2016.
Network tariffs	■ Harmonisation of pricing structures for gas transmission* (TAR), the aim of which is to reinforce obligations of transparency and harmonise the basic principles of transmission system pricing. Came into force 5 April 2017 (some parts of the code will not however fully apply until 31 May 2019).

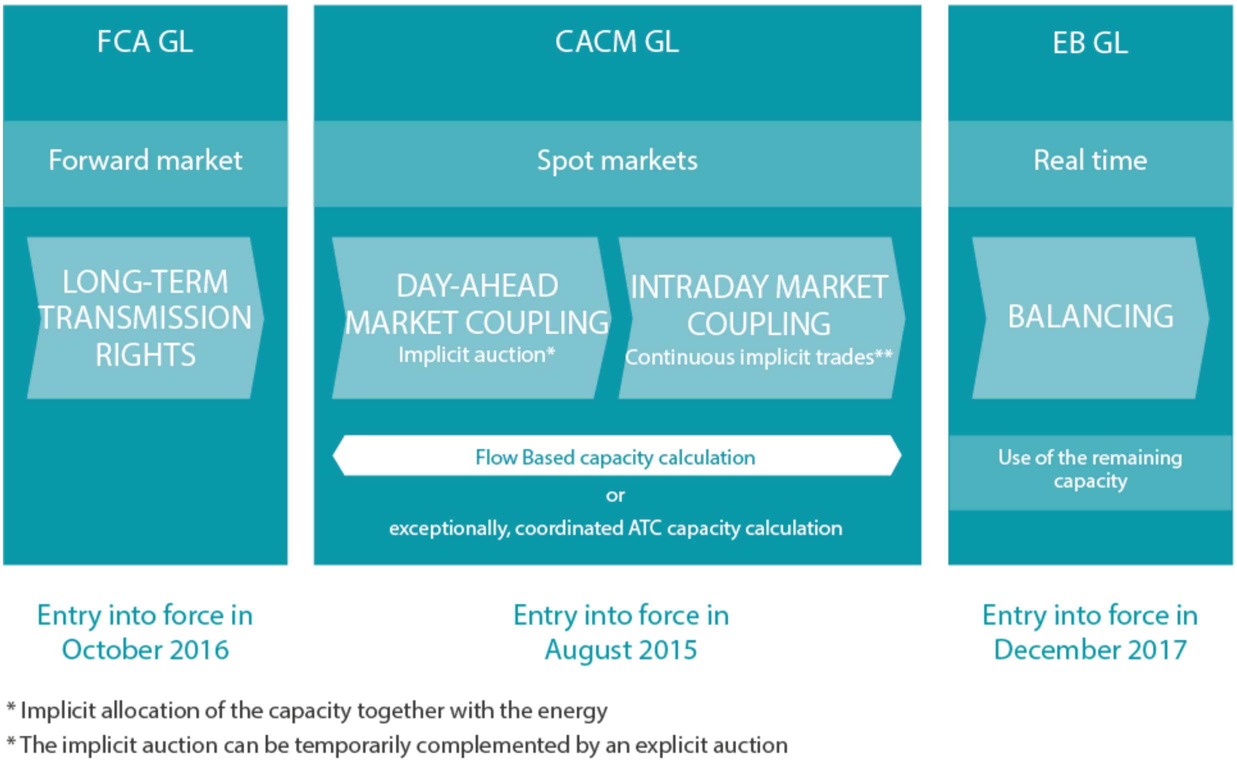
1.2.3 The development and implementation of network codes and European guidelines in the electricity sector have accelerated considerably since 2016

Today there are eight regulations for the electricity sector, adopted based on the third energy package; they aim in particular at implementing harmonised rules for access to interconnections.

1.2.3.1 Implementation of guidelines related to the market and management of interconnections

The purpose of the network codes related to the market and to the management of interconnections is to facilitate exchanges between market areas, from forward timeframes (via the FCA guideline) to day-ahead and intraday timeframes (via the CACM guideline) with the introduction of market coupling, up to balancing (via the EB guideline).

Figure 4– Overview of regulations



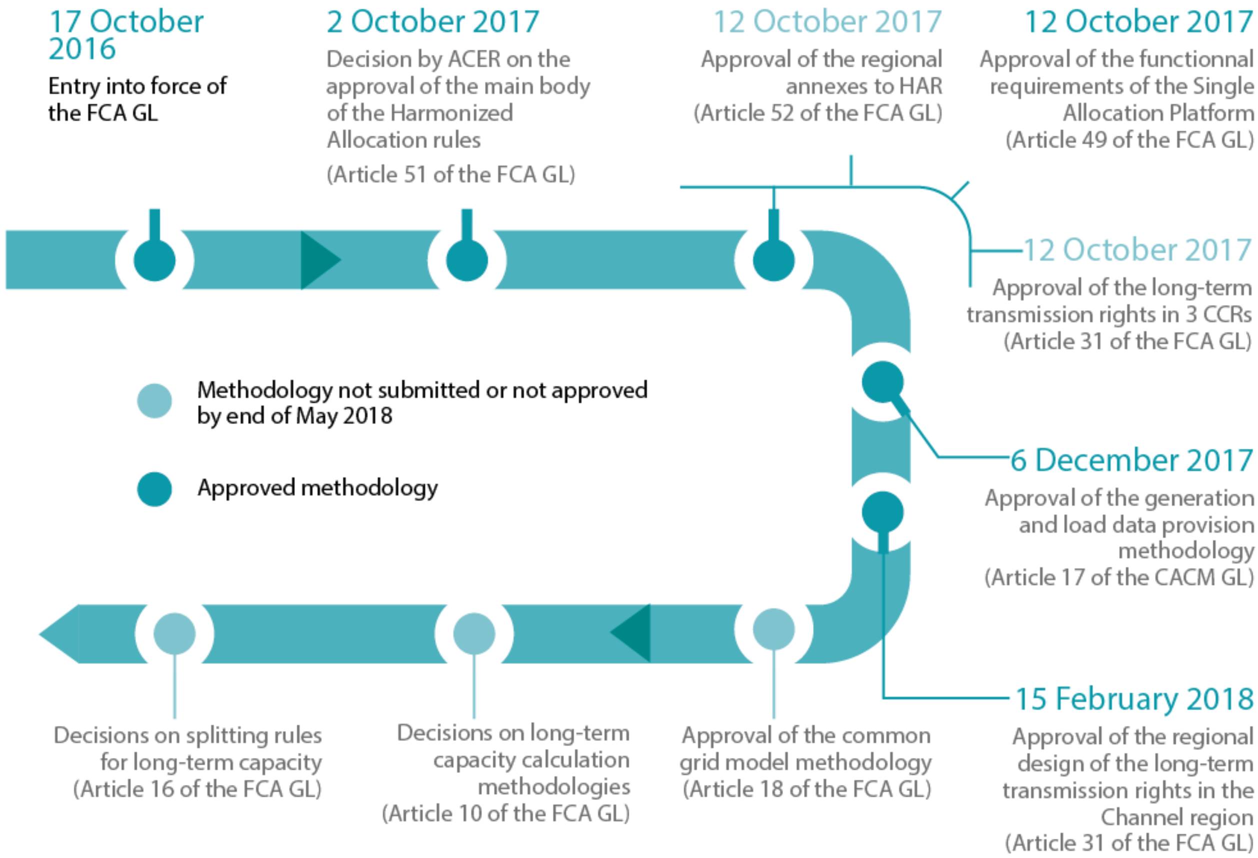
1.2.3.1.1 Regulation concerning allocation of forward capacities

Coming into force on 17 October 2016, Commission Regulation (EU) 2016/1719 establishing a guideline on forward capacity allocation, known as the FCA regulation, governs the operation of long-term transmission rights, which allow market players to secure their cross-border electricity transactions (price spread between two market zones covered) up to one year in advance. It gives a model for allocation of rights by explicit auction[3], according to harmonised rules and via a single platform, and establishes the principles for calculating the forward exchange capacity between two zones. Several European countries, including France, had anticipated voluntary application of this guideline for several years.

Since the FCA regulation came into force, several implementation methodologies have been adopted, at the European level or at the level of each "Capacity Calculation Region" (see figure 5 below).

[3] auctions held by the TSOs which involve only cross-border interconnection capacity, contrary to implicit auctions in which capacity and energy are allocated simultaneously

Figure 5– Decisions adopted as part of the implementation of the FCA regulation



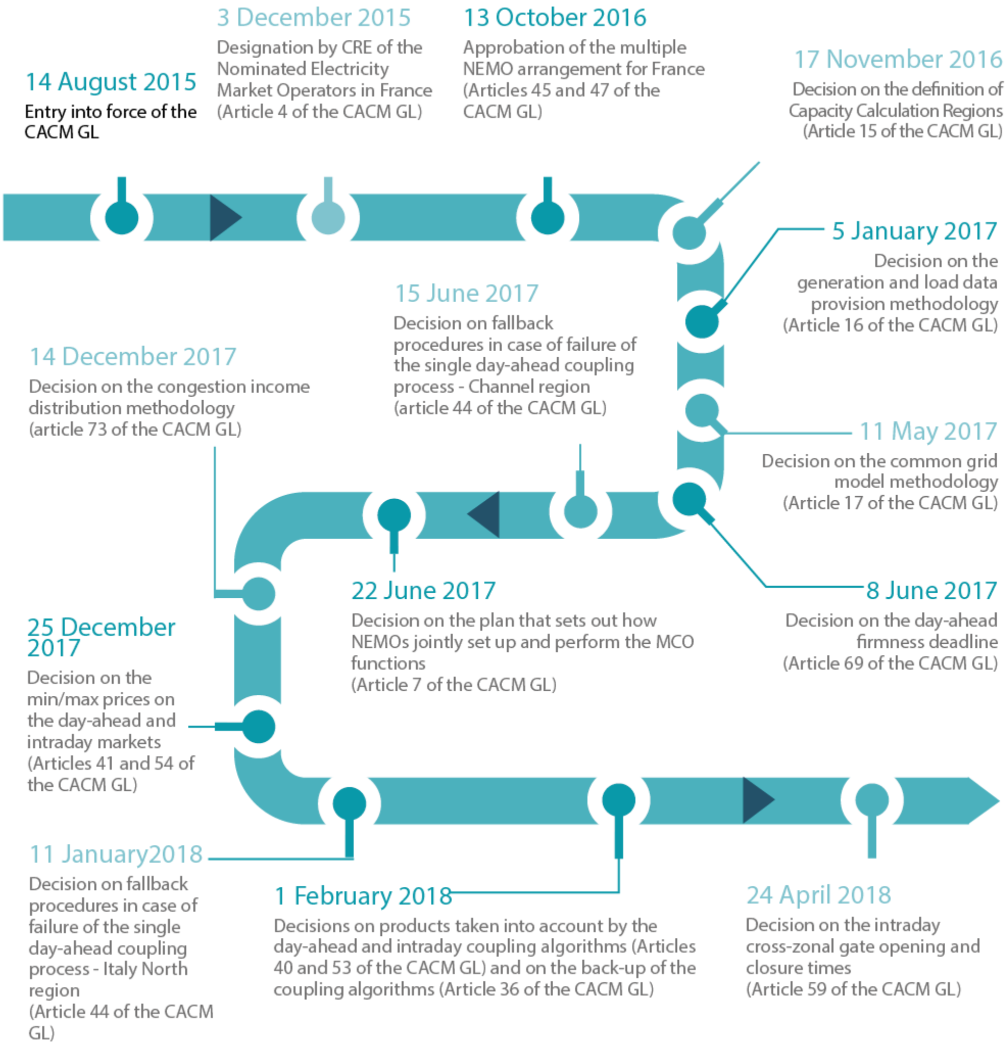
1.2.3.1.2 Regulation concerning allocation of day-ahead and intraday capacities

Coming into force on 14 August 2015, Commission Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management (CACM), governs the calculation and the allocation of capacity at day-ahead and intraday timeframes. It introduces the principle of market coupling by implicit auction into European legislation, and provides for the implementation of a single platform for implicit and continuous cross-border allocation at the intraday timeframe.

The power exchanges that provide market coupling acquire a new status, that of a Nominated Electricity Market Operator (NEMO). The CACM regulation also provides for the elaboration by the TSOs of coordinated capacity calculations in the different capacity calculation regions, based on a single network model for the entire European Union. The aim is to extend market coupling based on flows (Flow Based) at day-ahead and intraday timeframes.

The CACM regulation is composed of some forty methodologies to be developed by the European TSOs and/or the NEMOs and to be approved by the national regulatory authorities. These methodologies may be pan-European, regional or national. At the end of May 2018, 14 methodologies had been adopted, 18 were under consideration by the regulators or ACER, and 9 were being prepared by the TSOs and the NEMOs.

Figure 6– Decisions adopted as part of the implementation of the CACM regulation



1.2.3.1.3 European regulatory framework for electricity balancing

Coming into force on 18 December 2017, Commission Regulation (EU) 2017/2195 establishing a guideline on electricity balancing (EBGL for Electricity Balancing Guideline) extends the coupling of European markets initiated by CACM to the balancing timeframe. It mandates the introduction of balancing energy exchanges via European platforms and the definition of standardised products, and triggers a process of harmonisation of balancing market rules.

Unlike forward, day-ahead and intraday timeframes, today there are few voluntary balancing energy exchange initiatives, since this is carried out mainly at the national level. The introduction of the regulation will thus change the way electrical systems are balanced in Europe.

This cross-border integration of balancing markets as well as the energy transition require the French balancing model to be adjusted. To give visibility to market players, the CRE asked RTE in 2015 to bring these changes forward: in July 2016 RTE submitted its French electricity balancing roadmap.

In its deliberation on 22 June 2017[4], the CRE established a roadmap for balancing the French electricity system, in which it supports the current French balancing model. This roadmap aims, among other things, to anticipate the changes needed to create a European balancing market, and facilitate the participation of new actors, in particular renewable energy producers and aggregators. Furthermore, other measures have been chosen, in particular reinforced incentives to control the demand at peak consumption periods, as well as increased transparency of data on balancing markets and the state of balance of the French system. These changes will be set out over the coming years in the rules governing access to balancing mechanisms (frequency system and adjustment mechanism services).

[4] https://www.cre.fr/en/Documents/Deliberations/Orientation/electricity-system-balancing-roadmap

1.2.3.2 Rules concerning the operational management of the electrical system

1.2.3.2.1 Guideline on electricity transmission system operation

Coming into force on 14 September 2017, Commission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation (SO) sets out detailed rules on operating security, quality of frequency and effective use of the interconnected network.

The SO regulation must also be implemented through various methodologies to be developed by the European TSOs and to be approved by the national regulatory authorities at the pan-European, regional or national level.

Over the course of 2018, TSOs will have to submit seven methodologies to the national regulatory authorities for approval. Most of these methodologies will involve services that must be provided by regional coordination centres (such as Coreso) in particular:

- creation of the shared European common grid model;
- the coordinated security analyses (and activation of corrective actions);
- management of coordinated non-availabilities.

1.2.3.2.2 Network code on electricity and restoration

Commission Regulation (EU) 2017/2196 establishing a network code establishing a network code on electricity emergency and restoration (E&R) came into force on 18 December 2017. The provisions of the E&R regulation establish the rules to preserve operating security and prevent the spread or deterioration of an incident, in the aim of avoiding a large-scale disturbance or a widespread breakdown. In application of this regulation, the TSO must develop network defence and restoration plans that will be submitted to the competent national authority for approval (administrative authority or regulator) in December 2018.

1.2.4 Continuation of the implementation of gas network codes in France

The CRE has gradually implemented the various gas network codes set out in the third energy package. Thus, the first version of Commission Regulation (EU) no. 984/2013 establishing a Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems (CAM), adopted on 14 October 2013 was quickly taken into account in the national regulation (deliberations of 29 March 2013[5] and 13 February 2014[6]). The CAM network code harmonised the capacity products offered by the European TSOs (annual, quarterly, monthly and daily) and their allocation rules (auctions held according to a common calendar via the Prisma platform for French TSO, as for the majority of European TSOs). It also introduced bundled allocation of firm capacities on each side of interconnections inside the European Union. Lastly, the CAM code ensures that all capacities are not booked in the long-term by setting aside two minimum quotas of 10% of available capacity for durations of less than five years and less than one year.

The main provisions of Commission Regulation (EU) no. 312/2014 establishing a Network Code on Gas Balancing of Transmission Networks were already applied before it was even adopted on 26 March 2014. The deliberation of 10 September 2015[7] finalised their implementation (certain adjustments have since been made by the deliberation of 15 September 2016[8]). These deliberations approved the imbalance settlement prices by the TSOs, the introduction of flexibility services proposed by the TSOs and the experimentation by GRTgaz of local balancing products. The deliberation of 15 September 2016 also specified the distribution of imbalances between GRTgaz and Teréga within the TRS (Trading Region South - the trading area in the south of France).

Lastly, Commission Regulation (EU) 2015/703 establishing a network code on interoperability and data exchange rules was adopted on 30 April 2015 and has been applied since 1 May 2016. For France, one of the main challenges was the quality of gas (the odorisation) which did not allow physical flows towards Germany. The investments needed for deodorisation of the main French transmission network and decentralised odorisation of the regional networks are no longer part of projects of common interest (PIC) selected by the European Commission in 2017, since their costs exceed the expected benefits. The CRE therefore asked GRTgaz to stop studies on this project in its deliberation of 22 March 2018[9] on examination of the 10-year network development plan.

[5] https://www.cre.fr/en/Documents/Deliberations/Decision/cam-network-code
[6] https://www.cre.fr/en/Documents/Deliberations/Decision/european-network-code-gas
[7] https://www.cre.fr/en/Documents/Deliberations/Approval/balancing-rules2
[8] https://www.cre.fr/en/Documents/Deliberations/Approval/balancing-rules-of-gas-transmission-networks-on-1-october-2016
[9] https://www.cre.fr/en/Documents/Deliberations/Approval/10-year-development-plans-of-GRTgaz-and-TIGF

Since 2016 the network code on harmonised transmission tariff structures was adopted, along with an amendment of the CAM code (Commission Regulation (EU) 2017/459) on the development of so-called "incremental" capacities, meaning that they are added to already existing capacities.

1.2.4.1 Network code on harmonised transmission tariff structures for gas

Adopted on 16 March 2017 after over six years of negotiations, the Commission Regulation (EU) 2017/460 establishing a network code on harmonised transmission tariff structures for gas (known as "tariff network code") aims at improving transparency of transmission tariffs within the European Union, to avoid discrimination between shippers and to encourage integration of markets. This network code complements those adopted previously, and in particular the CAM network code which introduced allocation rules via explicit auctions on all European interconnections. These auctions feature a reserve price: the aim of the tariff network code is to determine a method for calculating this price, which ensures that there is no discrimination between domestic transport and transit. The determination of costs and their allocation to the networks' various entry and exit points was the main task when developing the network code. This involves the rules for publishing the elements that make up the authorised income of TSOs and the cost factors used for the calculations. Capacity and distance are the main two factors used in the code. The price code will be introduced gradually until 2019.

The main provisions of the tariff network code are as follows:

- The network code does not impose a specific pricing structure but introduces obligations to justify the structure implemented. Moreover, it requires that a single pricing method be applied in a given balancing zone, respecting the principle according to which the cross-border flows and flows intended for domestic consumption are handled in an equivalent manner. Thus, the unit costs (meaning in relation to the distance and capacity subscribed) applied to each type of user must be similar. Furthermore, the code describes a reference structure (known as the Capacity Weighted Distance method - CWD) with which the pricing structures of each TSO must be compared.
- One of the most important provisions of the tariff network code concerns the strengthening and harmonisation of the obligations of transparency and consultation incumbent on the TSOs and regulators. A two-month consultation will now be mandatory before the start of a new tariff period (around once every four years in France). The network users must have the necessary information to understand the construction, and as far as possible, anticipate price changes. The determining parameters for calculating the authorised income of TSOs and the assumptions of use of their networks must be published.
- The network code sets out a method for establishing the price level for new capacities that would be created at the request of the market. This provision is linked to the new version of the CAM code.

The tariffs introduced by the CRE already comply with most of the provisions of the tariff network code, particularly concerning the obligations of transparency and identical processing of transit flows in relation to domestic flows. The CRE is nonetheless concerned about the difficulty in implementing certain parts of the network code compared to the expected benefits. It is concerned about the concrete difficulties posed by the CWD method, even if the method has only a value of comparison.

1.2.4.2 Capacity allocation mechanisms

A new version of the network code on allocation of gas capacities (CAM) was also adopted on 16 March 2017. This new version takes into account the new network code on harmonisation of tariff structures: the schedule for capacity auctions was amended to improve structuring with the tariff calculation periods. The annual auctions are therefore postponed from March to July for capacities that can be used as of 1 October.

The revision of the CAM network code also introduces new provisions to harmonise the methods for creating and allocating incremental capacities. This development meets an expectation of the stakeholders in relation to the development of incremental capacities in the event of recurring congestion. Mentioned when the CAM network code was initially created, but postponed to a later date, these new rules introduce certain principles applied within open seasons. Incremental potential capacities are included in the capacities offered at annual auctions: an economic test is then applied once the result is known, to determine whether the subscription levels and the prices reached justify the considered investments. These new rules also state that, every two years, the TSOs consult the stakeholders about their needs for incremental transmission capacities. A first consultation of this type was conducted during the summer of 2017. While the players had the chance to express their incremental capacity needs to European TSOs, no request was made in France.

Chapter 3– The network codes: feedback and lessons learned

1.3.1 Important work accomplished, and very positive progress

The development of network codes and guidelines is a long process, and it took almost seven years after adoption of the third package in 2009 for all rules in discussion to be formally integrated into European legislation.

The network codes transposed to European legislation the guidelines that had been proposed at the regional level at the initiative of regulators and network operators, such as day-ahead market coupling, implemented in 2007 between France, Belgium and the Netherlands, and gradually extended to several European countries since. It allows optimisation of exchanges at interconnections, unlike the historic mechanisms that could result in use of interconnections going against the price spread (meaning exports from a more expensive zone to a less expensive zone). The CACM guideline transposed these indications into binding rules that apply to all member states and now constitutes the central law for effective integration of the European electricity market at day-ahead and intraday timeframes.

Based on this experience, the network codes and guidelines portray greater ambitions by establishing road maps to lead the European Union towards an integrated market model for all timeframes, from forward to balancing, in both gas and electricity.

For electricity, three guidelines render the target model legally binding by requiring the sharing of order books at the European level. They have been added to by regulations to harmonise the technical requirements requested of users for their connection to the network, as well as rules for using and operating networks, to reinforce operating security of the interconnected electrical network.

For gas, the four network codes adopted have profoundly changed the operation of the European market with the widespread use of the "entry-exit" system around a virtual hub. This organisation allows credible price references in north-west Europe, with two truly liquid markets (TTF and NBP), including for forwards timeframes, and a strong correlation with the other market places (including the *PEG Nord*). It offers shippers the option to arbitrate between a variety of supply sources and develop financial hedging instruments against risks. This system offers a great deal more flexibility and allows the supply configuration to adjust to strained situations.

By way of illustration, on Tuesday 12 December 2017, a serious accident (with one victim) interrupted operation of the Austrian network at Baumgarten through which 40 Bcm of gas from Russia travels each year. During the same period, North Sea production encountered operational difficulties. The European market could have experienced a significant gas supply crisis. The consequences in the end were very limited: transit to Italy, Slovenia and Croatia was interrupted for only a few hours, and the European market places quickly adjusted to this situation (with prices in Italy and Austria doubling) without showing any sign of panic. In the end no consumers suffered outage.

1.3.2 The challenges for the future

1.3.2.1 The implementation of these codes remains a major and weighty technical challenge: concrete progress must be a priority

Recent changes have brought about a major improvement in cross-border electricity and gas exchanges, at all timeframes.

For electricity however, over two years after the adoption of the CACM regulation, several methodologies have yet to be adopted and in some areas, the emergence of a consensual technical solution is proving very difficult. The implementation of widespread Flow Based market coupling is a considerable challenge: while its operation requires improvement in the CWE region (see focus 2), its extension to the Core region, then beyond in the long-term, poses complex technical challenges.

At the intraday timeframe, the launch of the XBID platform (cross-border intraday market project), a unique project for cooperation between markets with different statuses (NEMO in competition, NEMO in monopolies) and regulated TSOs, is a real improvement for extension of intraday market coupling in Europe. However, the implementation of such projects must not to be to the detriment of the target, nor the needs of the market stakeholders. As such, the introduction of complementary regional intraday auctions in addition to the XBID platform in the Iberian peninsula is concerning (see section 2.1.3.1). It is indeed harmful that the additional auctions lead to allocation interruptions at the France/Spain border. The implementation of XBID should be complete on all borders. At the time when significant interconnection reinforcements between France and Spain were decided (see focus 4), it is important to ensure that the allocation methods used fully exploit these infrastructures.

Thus the priority must remain the concrete implementation of the deliverables set out in the third package and its network codes, namely extended coupling of the markets, a reliable capacity calculation allowing maximised use of the network elements and sharing of balancing reserves between TSOs.

1.3.2.2 The lessons on implementation of network codes for the construction of the domestic energy market: avoiding over-regulation

Although a high level of harmonisation is needed to ensure that markets operate effectively, European integration must not be a synonym for standardisation at any cost. Experience of European network codes shows that it is important to think about the expected benefits considering the difficulties of implementation, at the time these codes are created. Strategic thinking on what an efficient system would look like is vital but must be accompanied by a review of the existing system.

As such, the electricity balancing guideline gives for example the definition of standard products, which will put balancing service providers in competition in a fair way, and thus minimise the costs of balancing to the benefit of all. However, it seems to be neither necessary nor useful to systematically harmonise all characteristics of national mechanisms, as supported by the CRE in its deliberation on the French electricity balancing road map: the costs of such harmonisation could be very high, compared with the slight or non-existent benefits. An example is the time of scheduling gate closure time and intraday cross-zonal gate closure time: set at one hour before the delivery time in France, this period allows RTE to manage balancing in a proactive, centralised and integrated manner. Reducing this period would require a new balancing method, and thus considerable transition costs, whereas the benefits of the harmonisation of this balancing management have not been proven.

The implementation of the network code on harmonisation of tariff structures of the gas transmission networks provides another example of potential over-regulation. The CRE shares the main principles of this network code (strong transparency obligations, non-discrimination between internal flows and transit, tariffs reflecting the capacity subscribed and the distance travelled, weighting of short-term capacity product prices, annual adjustment of the tariffs of all capacities subscribed, etc.). However, rather than focus on the essential elements, the writers of the code chose to propose a very detailed and technical approach, sometimes difficult to interpret, and had to write a number of exceptions to adjust to different national situations.

The CRE considers that a simpler code, focusing on the main principles and entrusting their application to the regulators, would have been preferable. The technical provisions of the current code will be tedious to implement, but will provide little added value, given the scale of the possible variations.

This feedback on the development and implementation of the network codes is the basis for the positions of the CRE on the draft of the fourth package (Clean energy package – see section 1.4.2). These positions are guided by the ambition to create a domestic energy market that benefits consumers, given that total harmonisation of all market structures is neither possible nor desirable, and that European legislation must leave the necessary leeway in a rapidly changing sector.

Chapter 4 - The « Clean energy for all Europeans » legislative package

On 30 November 2016, the European Commission presented a package of measures addressing the changes on energy markets induced by the transition to clean energy (Clean energy package or CEP). It is a set of texts - legislative proposals, impact assessment, evaluation reports - intended to fight climate change and support Europe's energy transition at a controlled cost, and to provide clean energy accessible to all European consumers.

The content of these proposals is in line with the long-term goals of the European Union and in compliance with its commitments under the Paris climate accord (COP 21), in particular in terms of reducing greenhouse gases. This reform is intended to promote the development of renewable energies and energy efficiency. It also conveys the ambition to place consumers at the heart of the energy system.

1.4.1 The Commission's proposal

1.4.1.1 A large portion of the legislative proposals of the Clean Energy Package will have a direct impact on the functioning of the electricity markets

Among the thirty-seven texts of varying nature and importance in the Clean Energy Package, there are eight legislative proposals that make up the backbone of the European ambition. Half of these eight texts will have a direct impact on how the electricity market works. These include:

- the draft directive on common rules for the internal market in electricity: this text proposes an recast of directive 2009/72/EC in order to place consumers at the heart of the energy markets, offering them the option to play a more active role in production, to better control their energy use and expenses, and to be better informed about market changes;
- the draft regulation on the internal market for electricity, which recasts regulation (EC) no. 714/2009 on conditions for access to the network for cross-border exchanges in electricity: the Commission wishes to strengthen regional cooperation between member states and provide greater flexibility of intra-European electrical exchanges;
- the draft regulation on risk-preparedness in the electricity sector replaces directive 2005/89/EC and proposes implementing shared risk assessment methods to foresee which crisis situations would affect several member states at the same time;
- the draft recast of the regulation establishing a European Union Agency for the Cooperation of Energy Regulators provides for a broadening of the missions entrusted to ACER and a strengthening of its powers.

1.4.1.2 The ambitions of the European Commission

1.4.1.2.1 More flexible electricity markets

The draft directive and regulation on the internal electricity market aim to update the operating rules for the electricity market (market design). The changes initially proposed in relation to current laws may be classified in two main categories:

- on the one hand, measures aiming at providing a framework for certain activities that were not addressed by existing legislation, such as electricity storage, rules for valuation of demand-side response on electricity markets or development of consumption of self-produced energy in "local energy communities";
- on the other hand, measures aiming at go beyond existing legislation and pursue the creation of the European target model a little further, with better integration of short-term markets, strict rules for the implementation of capacity mechanisms, implementation of regional operational centres (ROC) with operational responsibilities extended to TSOs, new methods for establishing bidding zones, procedures to encourage gradual convergence of the establishment of transmission and distribution network tariffs, criteria for using congestion rent or methods for evaluating resource adequacy on a European scale.

1.4.1.2.2 A European agency with strengthened authority

The draft ACER regulation aims to substantially change the way this Agency works. The changes proposed involve firstly the ACER's internal modes of governance (voting rules within the Regulators council, going from a two-thirds majority to a simple majority), as well as the scope of its missions, which would be broadened to include decisions on the methodologies given in the regulations that establish network codes or guidelines - today approved by each regulator.

1.4.1.2.3 Shared risk assessment methods

The draft regulation on risk-preparedness adapts the provisions of the regulation concerning security of gas supply (see section 1.5) to the electricity sector. It sets out a process for identifying risks related to security of supply within regional groups. It aims to implement greater transparency and shared crisis management rules.

1.4.2 The CRE's vision

1.4.2.1 Sharing the CRE's expertise with key stakeholders in negotiation

Since the European energy markets are increasingly interdependent, the missions of national regulators cannot be on a purely national scale. Since it was established, the CRE has been working towards improved integration of European energy markets. It works actively, within ACER, to facilitate energy exchanges and ensure that electrical networks are flexible and interoperable.

The CRE has wished to provide the various stakeholders in the European decision-making process with its analysis, expertise and experience in regulation in order to help them in their efforts.

In March 2017 it organised a meeting-debate in Paris with Klaus-Dieter Borchardt, Director for Internal energy market at the European Commission, to allow French representatives from the energy sector to share their visions of the reform. In June 2017, the CRE also published thirteen position papers on the Clean energy package and reacted to the positions of the European Parliament. It also cooperates within the Council of European Energy Regulators (CEER) to develop common positions shared by all regulators on the various proposals.

Lastly, the French energy code states that the CRE can be involved in preparing the French position in European negotiations, at the request of the minister for energy. It is thus present in Brussels at the meetings of the European Union's Energy Council working group and also provides its expertise to the Members of the European Parliament.

1.4.2.2 Maintaining a flexible market that respects national particularities

The CRE shares the analysis according to which the energy sector plays a vital role in achieving the goal of 40% reduction in greenhouse gases by 2030 and considers that the development of electricity production using renewable energy is an essential condition in Europe for achieving the goals of the Paris climate Agreement.

The proposals of the European Commission to adapt the market rules and operation of the network to this new production - more variable and decentralised and requiring greater flexibility - are considered to be overall positive by the CRE.

However, the institutional framework must remain flexible enough to take into account feedback in implementation of current regulations, respect national particularities, adapt to market changes and benefit from technological innovations. The CRE analysed all the proposals of the Commission in terms of these principles and published its positions, summarised hereafter.

On the one hand, the considerable increase in the volume of measures proposed by the Commission, and the level of detail to which they refer, makes one wonder if these measures are proportional and whether extremely detailed rules should be included in the legislation that governs operation of the internal energy market. Thus, the CRE believes that prescriptive rules on calculating interconnection capacity should not be included in a European regulation, while the extremely comprehensive framework provided by the CACM network code has not yet been implemented.

Generally speaking, the CRE believes that the provisions already given by the network codes must be applied, and their effectiveness assessed, before going any further. Further harmonisation can only be decided if it produces benefits that outweigh its costs. For balancing markets in particular, the balance found in the drafting of the guidelines must be maintained, whether for recommendations for procuring reserves, the timespan for the transition to a 15-minute imbalance settlement period or the size of the exclusive window for TSOs.

Furthermore, the CRE emphasises that European harmonisation efforts must focus on areas that represent a true challenge for building an internal market, and that national particularities must be taken into account. As such, the CRE believes it would be counter-productive to pursue harmonisation of network tariffs or to introduce very prescriptive rules for the use of congestion rent (income for the TSO resulting from use of interconnections).

Lastly, the rules of procedure for ACER must be reviewed with respect to evolution of its role. The Commission's proposals broaden the scope of the Agency's responsibilities, to include the approval of certain pan-European proposals. This type of development is legitimate, to the extent that the implementation of certain provisions of the network codes has shed light on the difficulties for regulators in agreeing on common rules. Within this context, it is vital that ACER rules of governance ensure that the methodologies adopted by the Agency reflect a consensus among regulators. For this reason, the CRE believes that the two-thirds majority rule must be preserved, and that regulators must be able to amend the draft decisions submitted by the Agency Director.

1.4.2.3 Promoting a balanced development of interconnections

In 2002, the European Council set a goal of 10% of interconnection in relation to the installed production capacities in each Member State, to be reached by 2020. This goal was raised to 15% by 2030 at the proposal of the European Commission and included in the draft regulation on the governance of the Energy Union.

Since new interconnections are costly and complex projects, the CRE believes that the investment decisions concerning these projects must be taken based on in-depth analyses demonstrating on a case-by-case basis the benefits achieved for the community, in order not to create over-investment in networks whose cost is borne by European consumers. However, a pre-established interconnection goal, especially if it is uniform on a European scale, does not allow specificities of the various borders to be considered, and in particular the geographic location and thus the costs of projects, as well as complementarity of the production capacities in the countries in question. Moreover, this target seems now unsuited to the electrical system, whose operation has changed considerably since the start of the 2000s, with the development of renewable energy.

In 2016 the European Commission commissioned an expert group to re-assess the way in which an electrical interconnection threshold is created. In its conclusions[10], this group proposed to identify the need to strengthen interconnections based on three criteria: the existence of price spreads of more than €2/MWh between two countries, interconnection capacities under 30% of peak demand or interconnection capacities under 30% of installed renewable capacities of each member state. It also recommends introducing the condition that a stand-alone positive cost/benefit analysis is required for completion of new projects.

The CRE welcomes the approach proposed by the expert group. Indeed, the costs of the infrastructure projects may be particularly high, and in some cases may not achieve the level of the benefits expected. Although some elements of the analysis, such as price spreads, may inform of the potential need to strengthen networks, the creation of new interconnections must not be motivated solely by the need to achieve a uniform set goal for the entire European Union, but must take into account the technical and economic characteristics of each project.

As such, the CRE does not favour a principal target, such as it is set out in the initial draft regulation on governance of the Energy Union. This political goal, which is beneficial to strengthening the integration of energy markets in Europe, should be completed on two points: on the one hand, specifying that the goal is for information purposes and is non-binding, and on the other hand, indicating that the needs for strengthening interconnections must be identified based on a stand-alone positive cost/benefit analysis.

[10] https://ec.europa.eu/energy/sites/ener/files/documents/report_of_the_commission_expert_group_on_electricity_interconnection_targets.pdf

Chapter 5– European legislative changes in the gas sector: the security of supply regulation

Security of supply is one of the pillars of European energy policy. Although the ambition of the internal market is to contribute to this pillar by eliminating a certain number of obstacles to cross-border flows, and thus improving the diversity of supply sources accessible to Member States, recurring crises between Russia and Ukraine have revealed a certain number of weaknesses that the market alone cannot correct. In 2004, the European Union established a directive on security of gas supply. It was repealed in 2010 and replaced by a regulation in reaction to the interruption of deliveries of Russian gas by Ukraine in January 2009. This event signalled the materialisation of a risk that had until then been deemed unlikely. The organisation of networks in Europe has been in difficulty at that time, and was unable to efficiently mitigate the missing Russian gas deliveries suffered by the countries furthest to the East. Regulation (EU) no. 994/2010 thus introduced the widespread possibility of reverse flows at the borders; it also provided for the introduction of gas emergency plans, and an early warning system, and introduced the principle of an "N-1"[11] criterion for gas.

Given the worsening conflict between Ukraine and Russia, the Commission decided to revise the 2010 regulation by adding measures intended to further improve the resilience of the European gas system in the event of a supply crisis. Adopted on 25 October 2017, the new regulation has three goals: to strengthen regional cooperation between member states, to raise the level of transparency on commercial agreements and to explicitly provide for solidarity mechanisms in the event of a crisis.

This regulation improves some of the provisions of the previous regulation, with a new method for calculating the "N-1" criterion and strengthening reverse flow obligations at interconnection points. Exceptions to this principle are however possible: those granted before the new regulation came into force remain valid, such as for example at the France/Germany border. Indeed, the difference in practice in terms of gas odorisation prevents French gas from being sent to the German transmission network. The first experiments on introduction of decentralised odorisation have not enabled to confirm the economic relevance of such a situation (TSOs are currently studying a deodorisation pilot project). The relevance of such reverse flows in terms of security of supply has not been demonstrated either. This project was therefore not selected as a Project of Common Interest.

Among the new measures, the regulation requires the competent authorities of each member state to conduct a risk analysis based on simulations conducted by ENTSOG (European Network of Transmission System Operators for gas). These analyses must be conducted as part of regional groups of the countries concerned by similar supply risks. France is concerned by four supply corridors: gas B from the Netherlands, Norwegian gas, Algerian gas and Russian gas. The risk analyses are used to develop action plans - preventive plan and emergency plan - which must indicate the definition of protected clients used, as well as crisis measures to be implemented. These plans are created at the national level and feature a regional section.

New measures also cover the supply contracts. If they are considered key for security of supply, with a threshold set at 28% of the annual consumption of a member state, they must be notified to the European Commission.

As a last resort, the regulation provides for solidarity mechanisms between member states during supply crises. The principle is to give priority to protected consumers[12] by ordering the interruption of gas supply to consumers that do not belong to this category, when a neighbouring country cannot supply all of its protected consumers. The member states solicited are then required to provide assistance to their neighbour, to the extent of their capacity and in exchange for financial compensation. The member state concerned by the crisis may call upon several neighbours and chose whether or not to accept their offer.

In February 2018 the European Commission published a guidance document on the elements to be included in arrangements between Member States, which includes the way to determine the level of financial contribution required for solidarity, which must now be specified by the competent authorities[13].

[11] Respecting this criterion characterises the technical capability of the gas infrastructures to meet total gas demand for the area covered in the event of failure of the largest gas infrastructure for a period of exceptionally high demand.
[12] For France, these are all customers connected to the distribution systems.
[13] The competent authority in France is the minister for energy.

PART 2. OVERVIEW OF THE USE OF ELECTRICITY AND GAS INTERCONNECTIONS

Chapter 1– Operating rules for electricity interconnections at French borders: evolutions since 2016

The introduction of the third package led to important progress in terms of allocation of transmission capacities at interconnections, with widespread implementation of market coupling (with the exception of Switzerland) and gradual transition to capacity calculation rules at the day-ahead timeframe. The level of harmonisation is improving, although significant differences remain, depending on borders.

2.1.1 Forward timeframes: a capacity allocation framework that has remained stable since 2016, but changes to come in terms of capacity calculation

The purpose of long-term transmission rights is to permit market players to secure their cross-border transactions up to one year in advance. Sold at auction by the TSOs, these rights may offer physical coverage (possibility of effectively nominating cross-border exchanges via PTRs - Physical Transmission Rights), or financial coverage (payment to the owner of compensation equal to the day-ahead price spread, via FTRs - Financial Transmission Rights). In order for the TSOs to be able to honour their commitments, it is important to have consistency between the volumes of rights sold and the transmission capacities effectively available in the short term, at the time the rights are exercised. In the event that unforeseen events reduce the transmission capacities available, the rights allocated for the long-term may be reduced, provided that the owners are compensated (see section 2.2.1.3); the terms of this compensation determine the degree of "firmness" of the forward rights.

The FCA guideline establishes the principles for calculating and allocating forward capacities, described notably in the HAR (Harmonised Allocation Rules) and their regional annexes applied since 1 January 2018, an anticipated version of which was implemented at French borders from as early as 2015. The underlying principle of these rules is the allocation of long-term rights via explicit auctions with payment at the marginal price; these auctions must be held at least annually and monthly. The entry into force of new HAR reinforces the firmness of rights at the France/Great Britain border, since compensation in the event of curtailment is now based on the day-ahead price spread between the two countries, without an upper limit to this spread as was previously the case. On each French border, the total amount of compensation remains limited by the total congestion rent received by the TSO at the border[14]. At the France/Switzerland border, which is not part of the scope of the FCA regulation, compensation is always based on 110% of the initial price of allocation of the right.

The FCA regulation also requires the establishment of a single platform for allocation of long-term rights in Europe. At the end of 2017, European TSOs proposed to use the JAO platform for this purpose, since it already allocates rights on 29 European borders. Migration to this platform by the end of 2019 will represent an important step in terms of harmonisation for the France/Great Britain border, the only French border for which rights are still allocated on a specific platform (CMS).

In terms of the forward products offered, the TSOs submitted proposals in 2017, in each capacity calculation region, which were approved by the regulators concerned insofar as they responded appropriately to the needs of the market players. The type, form and allocation timeframes currently applied on French borders are summarised in the table below:

Figure 7– Type, form and allocation timeframes applied to long-term transmission rights at the French borders

Border	Type of products	Form of products	Allocation timeframes
FR <> GB	PTR	Base	Annually/Twice annually/Quarterly/Monthly/Each weekend
FR <> BE	FTR	Base	Annually/Monthly
FR <> DE	PTR	Base	Annually/Monthly
FR > CH[15]	PTR	Base	Annually/Monthly
FR <> IT	PTR	Base	Annually/Monthly
FR <> ES	PTR	Base	Annually/Monthly

Significant changes to forward capacity calculation methods should be submitted after approval of those relating to short-term capacity calculation. Indeed the methods for calculating or recalculating capacity offered at each forward timeframe at French borders are currently not harmonised: they present variable degrees of coordination between

[14] This limit is annual for all borders except the France/Great Britain border where it is monthly, as permitted by article 54 of the FCA regulation, due to the nature of the interconnection (direct current connection).

[15] The France/Switzerland border has not seen a decision for implementation of the FCA regulation, since Switzerland is not within its scope. The forward rights at this border are offered only from France towards Switzerland, since the entire capacity in the other direction is reserved for discretionary forward energy contracts.

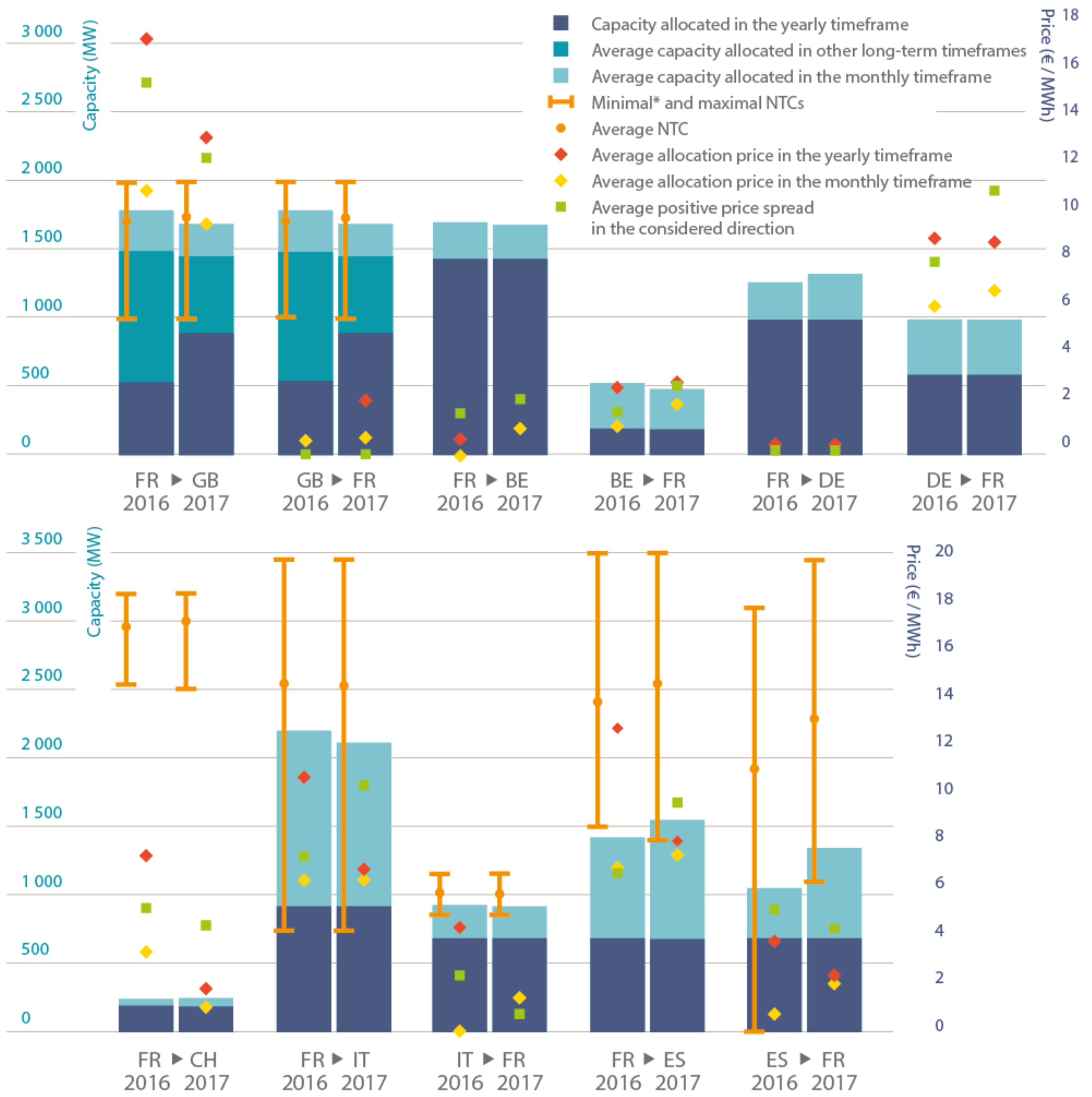
TSOs and in some cases (for the France/Great Britain border), no capacity calculation is performed. The FCA regulation provides for a systematic calculation of capacity before each allocation timeframe and details the calculation principles to be applied (use of a shared European network model and a set of shared scenarios). Thus the methods for calculating future forward capacity should allow the optimisation of cross-border capacities offered to the forward market. Moreover, the distribution of capacities between the various timeframes will be reviewed when the methodology on this subject is submitted, as mentioned in article 16 of the FCA regulation.

FOCUS 1 – LONG-TERM TRANSMISSION RIGHTS IN ELECTRICITY

Long-term transmission rights play a vital role in the organisation of the European electricity market, since they allow players to secure their cross-border transactions up to one year in advance, by setting the price spread between zones. Issued by the TSOs, the long-term transmission rights support the hedging products offered on the electricity markets in each zone.

Figure 8 below presents a panorama of long-term transmission rights allocated at French borders in 2016 and 2017:

Figure 8 – Volume and valuation of long-term transmission rights at French borders in 2016 and 2017



** to eliminate the atypical values resulting from very occasional curtailments, 5% of the lowest NTCs were excluded*

Source: RTE and JAO, CRE analysis

The value of long-term transmission rights between two zones corresponds in theory to the average price spread anticipated between these zones during the delivery period[16]. The prices at which rights are allocated are supposed to reflect the structural price discrepancies between zones. However, as illustrated in figure 8, the price spread observed ex-post coincides only rarely with the allocation prices. These prices change even according to the allocation timeframe, although no systematic hierarchy is seen between these various valuations from one border to another. This stems from the fact that the system status is not known with any certainty at the time the rights are allocated. However, there must be consistency between the value of forward cross-border rights and that of the corresponding forward energy products (whether traded on markets or OTC) at the time of allocation.

The volumes offered by the TSOs at forward timeframes change little from one year to the next[17]; however, they vary considerably depending on borders. This is the reflection of differences between the interconnections from a physical capacity standpoint, forward capacity calculation methods and the distribution of capacity between timeframes. The total commercial capacity available is given by the NTC (Net Transfer Capacity) ranges, i.e. commercial capacity calculated two days before real time) shown in yellow on the graph[18]: depending on the case, the forward volumes allocated represent a majority portion of the NTC (which is the case for Great Britain for example, where only around 10% of the 2000 MW of the interconnection is reserved for day-ahead allocation[19]) or on the contrary, a smaller portion (which is the case for Spain, where around one third of capacity is allocated for short term[20]). Splitting of capacities between forward timeframes is itself variable; we note that it changed between 2016 and 2017 on the France/Great Britain border, which gave rise to an opinion from the CRE[21].

Given that the rules for distribution of capacities between forward timeframes must be covered by a methodology submitted by the TSOs in each capacity calculation region, in application of the provisions of article 16 of the FCA regulation, CRE wished to consult the market players, upstream of the European consultation process, in order to gather their opinions on the rules to be applied at French borders. More generally, it consulted these players on the characteristics of the long-term rights currently allocated and on their suitability with respect to their needs, in order to guide future developments of the terms of forward risk coverage. While methodologies adopted until now in the implementation of the FCA regulation have been essentially in line with the existing system, amendments can still be made according to changing needs, and according to the terms described in article 4(12) of the FCA regulation.

The responses received underline first of all the importance granted by the players to long-term rights issued by the TSOs, contrary to the hedging instruments traded on markets without intervention of TSOs, such as the contracts for difference that exist in the Nordic region. These instruments are likely to encounter market liquidity issues and give rise to transaction costs that do not exist with long-term transmission rights.

The majority of players are satisfied by the physical rights (PTRs), which are offered on all French borders, with the exception of the Belgian border, particularly due to the flexibility that they provide. They allow a day-ahead energy exchange to be nominated, or the price spread to be received between zones via the "use it or sell it" mechanism; PTRs in this case are used as financial rights. In practice, PTRs are used largely in this way at the French borders, since the nomination rates are low overall (see section 2.2.4). The players are also satisfied overall by the allocation timeframes offered, even if they are in favour of an increase in the number of timeframes, provided that they are consistent with the timeframes for which there are sufficiently liquid energy products.

However, many players consider that the forward capacities offered to the market by the TSOs are too low in volume, which is attributed to the TSOs' desire to preserve operating margins, manage internal congestion, or minimise the costs related to the firmness of rights (redispatching, countertrading). In this respect, submission by the TSOs of the long-term capacity calculation methodologies, in application of the provisions of article 10 of the FCA regulation, will be an opportunity to specify the elements that may or may not be taken into account in the calculation of the capacity offered to the

[16] taking into account only cases where it is positive since the products offered at the French borders (PTRs or FTRs) are optional.
[17] The only significant variation concerns the average volume offered at a monthly timeframe on the Spain/France border; it is explained by scheduled maintenance performed in 2016 on certain cross-border lines or those close to the France/Spain border, leading to non-allocation of the monthly product for certain months.
[18] On borders in the CWE region, Flow Based capacity calculation is applied; the NTCs are therefore not available.
[19] The distribution of capacities between timeframes on the France/Great Britain interconnection is as follows since 2017: annual product: 900 MW; half-yearly product: 200 MW; quarterly product: 300 MW; monthly product: 300 MW; day-ahead product: 300 MW.
[20] Switzerland also has very low volumes for forward rights offered on the market in relation to the available NTC, but this is due to the existence of long-term contracts that have access to the off-market interconnection, see section 2.1.2.3.
[21] *Deliberation of the CRE of 27 October 2016 ruling on the rules for distribution of capacities on the electrical interconnection between France and Great Britain.* The purpose of this change was to eliminate a forward timeframe that was not much used by market players (i.e. Financial Year) and to increase the capacity allocated to the day-ahead timeframe to bring the distribution rules in line with those in force on the other French borders.

market; this capacity will be re-calculated for each allocation timeframe, in accordance with article 9 of the FCA regulation.

Furthermore, a majority of players would like the capacities calculated at forward timeframes to be fully allocated furthest from real time, without capacity reservation for later timeframes, in order to maximise the possibilities of coverage. The later timeframes would be used only for adjustments if re-calculation of capacity reveals the possibility of allocating additional volumes, and rights already issued would be traded on the secondary market until the timeframe. These elements will be taken into account when examining the methodologies for splitting the long-term capacity between forward timeframes; note however at this stage that, in the current state of affairs, the possibilities of trading rights on the secondary market are limited, since there is no organised market and only OTC trading is possible.

For all characteristics of the long-term rights, harmonisation between the various French borders is considered welcome, but it does not constitute an end in itself; the market players are not opposed to maintaining different characteristics if different situations between borders justify it.

2.1.2 Day-ahead timeframe: limited developments over the past two years pending a number of improvements to come linked with the implementation of the CACM regulation, in particular the capacity calculation methodologies

2.1.2.1 Market coupling continued to extend in Europe in 2016 and 2017

At the day-ahead timeframe, market coupling constitutes the target model established by the CACM regulation. In France, 2015 marked the extension of day-ahead market coupling on all borders, with the exception of Switzerland, as well as the launch of Flow Based in the "centre-west Europe" region (CWE, featuring France, Belgium, the Netherlands, Germany and Luxembourg). Today France is coupled via the PCR project (Price Coupling of Regions) with all of its neighbours from the European Union. The principle is to organise pooling of the order books of market operators (NEMOs) up to the available interconnection capacities.

Figure 9– Market coupling in the European Union at the end of Mai 2018

The plan for exercising the functions of market coupling operator ("MCO plan"), submitted by the NEMOs in application of the CACM regulation and approved by all regulators in June 2017[22], establishes the PCR and XBID projects as the pan-European projects at the basis of the single European market coupling for day-ahead and intraday timeframes respectively. All uncoupled countries or those coupled via the 4MMC project must also join PCR in the coming years.

2.1.2.2 High expectations for coordinated capacity calculation methods

The development and proper use of interconnections must allow the use of the most economically efficient resources to satisfy electricity supply in Europe. Within this context, the aim of the capacity calculation methods is to estimate the maximum volume of exchanges that may transit at the borders, while respecting the system's security.

[22] https://www.cre.fr/Documents/Deliberations/Approbation/nemo-plan-ocm

A coordinated day-ahead calculation has been introduced at the borders of the Italy North region since February 2016, in the direction of imports to Italy. Approved by the CRE in December 2015[23], the proposal of RTE and of the other TSOs in the region introduced a calculation at a day-ahead timeframe performed two days before real time (D-2), while the results of the annual calculation were previously used for the day-ahead timeframe; it also aimed to improve the coordination of TSOs (in the direction of exports from Italy, capacity is not always calculated at D-2). By reducing uncertainties using a calculation closer to real time and improving coordination, this methodology should help increasing the level of available capacity for market players; the feedback communicated by RTE to the CRE at the end of 2016 indicated an average improvement of only 135 MW for all borders in the Italy North region, of which 37%[24] was at the France/Italy border. This low increase was then confirmed, since between 2015 and 2017 export capacities from France to Italy increased by only an average of 70 MW.

The CRE considers that the increase of capacity offered to the market could be much higher by improving the current capacity calculation method and eliminating the many limitations presented by this method, in particular the validation of calculation results coordinated by each TSO. As an example, the capacity calculated in a coordinated manner at D-2 is systematically checked so that it is included in a band (Lower TTC - Upper TTC) that does not exceed 600 MW higher than and 500 MW lower than calculated capacity from the annual calculation. Over one and a half years of implementation (from February 2016 to October 2017), this limitation reduced capacity 23% of the time for an average curtailment of 1,025 MW. The Lower TTC generated a capacity increase in only 8% of cases over the same period. Furthermore, it was an increase of only 103 MW on average.

The methodology for calculating capacity will be improved as part of the implementation of the CACM regulation: in application of the provisions of article 20 of the regulation, the TSOs of each capacity calculation region had to submit to the relevant regulators a coordinated capacity calculation methodology for day-ahead and intraday timeframes in September 2017. The CACM regulation establishes the Flow Based capacity calculation as a target, though an NTC coordinated calculation is however possible if the TSOs of a region demonstrate that it would be at least as efficient as Flow Based or, in the case of the Italy North region, as long as Switzerland has not joined the day-ahead market coupling.

These methodologies are currently being studied by the regulators of each region, including the CRE, and they should be approved in 2018 for implementation by 2020.

In the SWE and Channel regions, they will allow introduction of a fully coordinated day-ahead and intraday capacity calculations instead of the calculation that is performed today (where each TSO calculates the capacity itself, and where the minimum of the two values is used) in order to improve the capacity levels offered to the market.

Moreover, pending the approval and implementation of a coordinated capacity calculation in the Core region, work continues in the Centre West Europe region (CWE) to improve operation of day-ahead Flow Based that has existed since 2015 (see focus 2).

[23] https://www.cre.fr/en/Documents/Deliberations/Approval/capacity-calculation-methodology
[24] The calculation lets you determine an overall exchange capacity for all borders in the Italy North region (TTC), the capacity available at each border is then calculated based on splitting factors (around 50% for Switzerland, 37% for France, 9% for Slovenia and 4% for Austria).

Figure 10 – Capacity calculation regions including France

2.1.2.3 Further progress is required to be able to use the France/Switzerland interconnection in an optimum fashion, but the capacities proposed at the day-ahead timeframe have increased thanks to the expiration of certain forward contracts

While implementation of the CACM regulation continues on all French borders, the interconnection with Switzerland is an exception. Indeed, given that Switzerland is not part of the European Union and in application of the provisions of article 1(4) of the CACM regulation, Switzerland cannot at this point take part in single day-ahead and intraday market coupling projects, although this is technically possible. This exclusion of Switzerland from the search for optimised exchanges with the European Union is due to the lack of intergovernmental agreement on cooperation in the field of electricity between the Union and Switzerland. At the day-ahead timeframe, the available interconnection capacity is thus allocated through an explicit auction, which takes place the day before delivery, from 9am (the time the auction specifications are published) to 9:45am (the time the offer submission closes). Currently at the intraday timeframe, the interconnection capacity is allocated both explicitly and continuously. Allocation begins at 9:05pm the day before the delivery. These allocation methods are set to change when the XBID platform is launched. Indeed, article 1(4) of the CACM regulation bans Switzerland from taking part in single day-ahead and intraday market coupling, the France/Switzerland border is not part of this project. At the launch of the XBID platform in June 2018, implicit allocation between Switzerland and France will no longer exist; only continuous explicit allocation will be maintained at this border.

In addition to the absence of pan-European market coupling at day-ahead and intraday timeframes, long-term contracts remain at this border, with priority and free access to the interconnection capacity, which exists on no other French border. Some of these contracts were signed in the 1950s and some run to beyond 2050. They benefit from particularly flexible conditions for access to interconnections, allowing their owners for example to make late nominations, thus limiting the possibility that unused capacities under long-term contracts will be offered to market players during day-ahead explicit capacity auctions. Until the start of 2012 and at the expiration of a portion of a contract for 610 MW, long-term contracts saturated the entire interconnection in the direction of export to Switzerland, namely around 3,100 MW. The CRE and its Swiss counterpart - Elcom - decided that the capacity released by the expiration of portions of forward contacts would be provided to market players and offered at the day-ahead timeframe.

Although the interconnection has a specific operation that does not optimise allocation of capacities at this border, an increasing capacity volume is offered to players at explicit day-ahead auctions.

In its public consultation on 20 April 2018 on the use of forward cross-border transmission rights at French borders, the CRE asked market players whether they considered it useful to allocate part of the interconnection capacity released by the expiration of long-term contracts on the France/Switzerland border at forward timeframes, or if they preferred, as is currently the case, that this entire capacity be offered at a day-ahead timeframe. Almost all market players that gave an opinion said they preferred allocation of the released capacity at forward timeframes, in order to offer options for covering forward risks on this border.

2.1.3 Intraday timeframe: a timeframe that is changing with the extension of continuous market coupling via the XBID project

2.1.3.1 Le launch of the XBID platform constitutes a decisive step for the implementation of the target model at the intraday timeframe as described in the CACM regulation

The CACM regulation extends market coupling as a target model to the intraday timeframe. Contrary to market coupling at day-ahead timeframe which takes place through an auction mechanism, intraday market coupling takes place continuously (24/7) on a "first come first served" basis. Up to one hour before real time, market players have access to organized market to perform transactions.

In France, the methods for allocating capacities at intraday timeframe are now different depending on the borders:

- implicit and continuous allocation is already in place at the borders with Germany (since 2011), Switzerland (since 2013) and Belgium (since 2016): on the first two borders, explicit continuous access also exists;
- at the borders with Great Britain, Spain and Italy, allocation is made via explicit auctions: cross-border capacity is allocated separately from the purchase/sale of electricity on each side of the border.

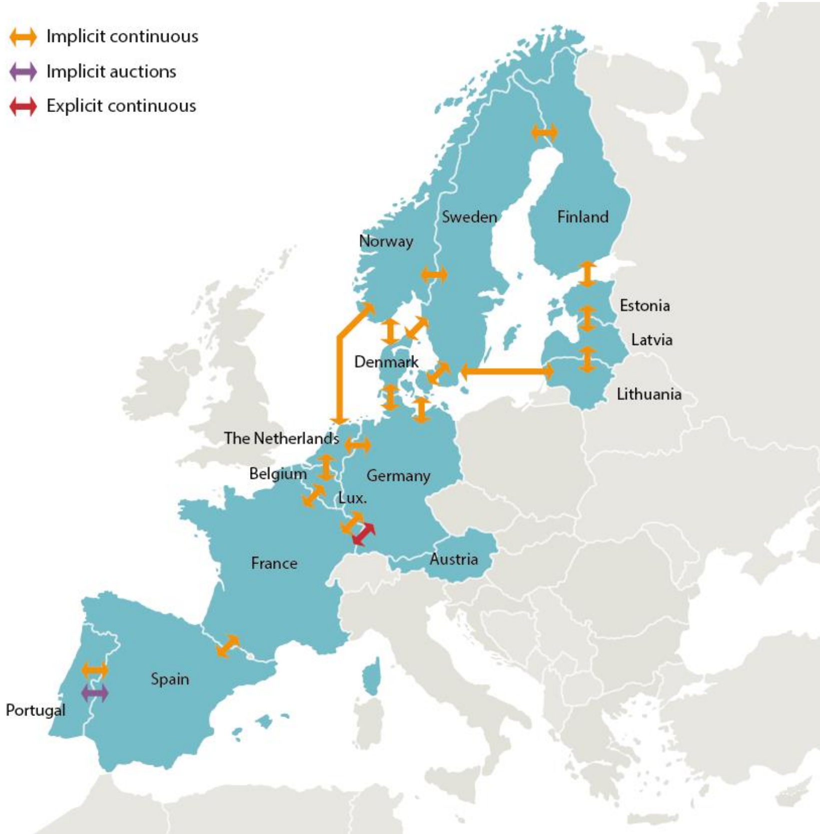
These allocation methods will be harmonised via the European XBID project in which all member states of the European Union will participate with time. The aim of this project is to establish a platform on which, at the intraday timeframe, all interconnection capacities would be allocated implicitly and continuously at the scale of the coupled region.

Initiated in 2012, it is a unique example of Europe-wide cooperation of NEMOs and TSOs. In France, the NEMOs designated by the CRE deliberation of 3 December 2015[25] - Nord Pool and EPEX Spot - will be active. All orders submitted to any one of the NEMOs active in France will be shared on the shared order book in the XBID platform, from the intraday cross zonal gate opening time, established by the ACER as 3:00pm on the day before delivery, starting on 1 January 2019[26], until the intraday cross zonal gate closure time, one hour before the start of delivery of products. Only products not covered by the XBID platform after the day-ahead cross-border market opens may be exchanged on the local French market. The CRE emphasises the importance of this initiative to regroup liquidity on the European platform, which appears all the more important since in France the cross-border volumes may represent more than two thirds of all volumes exchanged at intraday timeframe.

For France, the borders with Germany, Belgium and Spain belong to the "first wave" of borders to take part in the project. The border with Italy should join the XBID platform in 2019. The work with Great Britain is for now suspended given uncertainty related to Brexit.

[25] https://www.cre.fr/en/Documents/Deliberations/Decision/day-ahead-and-intraday-electricity-market
[26] ACER's decision of 24 April on all transmission system operators' proposal for intraday cross-zonal gate opening and intraday cross-zonal gate closure time

Figure 11 – Interconnections included in the first wave of the XBID project



The launch of the XBID project at the French borders in June 2018 will lead to changes in the intraday interconnection capacity allocation methods. These changes were approved by the CRE on 31 May 2018.

At the border with Germany, the implicit and explicit allocation methods will be maintained. Indeed, in application of the provisions of article 64 of the CACM regulation, it is possible for TSOs to allocate capacity explicitly, temporarily, as long as non-standard products are not offered on the pan-European platform. Hourly and half-hourly products (in existence since March 2017) can be exchanged on this border.

At the border with Belgium, intraday interconnection capacities are currently allocated implicitly since September 2016. As of the launch of the XBID platform, this implicit allocation method will remain available at this border. At this interconnection, the products exchanged will be hourly only.

Monitoring of the implementation of implicit continuous allocation continues at the France/Spain border

The changes at the interconnection with Spain will be the most substantial ones, since interconnection capacity is currently allocated via two explicit auctions. The launch of XBID and implementation of single intraday market coupling should help optimising capacity allocation at this border. However, additional regional auctions between Spain and Portugal as approved by the CNMC and ERSE in their decision of 12 April 2018 will affect exchanges at the border with France. Thus at the launch of XBID, continuous trading sessions between France and Spain will be restricted at times between two Iberian auctions (namely periods of a few hours before physical delivery, instead of possible trading all day on the German and Belgian borders). This limitation of the periods of continuous exchange sessions should continue until November 2018, at which time all hours of the electrical day will be available for the border between France and Spain on the XBID platform, with a few exceptions. Indeed outages on this border are to be expected at the end of each Iberian auction: they should be limited to a maximum of 10 minutes according to article 63 of the CACM regulation. Since the auction terms approved by Iberian regulators limit the possibilities of exchanges on the XBID platform between France and Spain, the CRE, in collaboration with its counterparts from the CNMC and ERSE, is working to implement the XBID project fully and effectively and ensure that the provisions of the CACM regulation are respected. In particular, the CRE is working to ensure that the implementation of European projects does not constitute a step backwards for market players and is ensuring that access to interconnections is optimised, particularly within the context of the development of interconnections.

2.1.3.2 Use of auctions at day-ahead timeframe must not affect continuous allocation via XBID

In addition to implicit and continuous allocation of interconnection capacity, conducted via the XBID project, the CACM regulation states that the intraday interconnection capacity must be priced. Thus in application of the provisions of article 55 of the CACM regulation, within 24 months following the entry into force of the CACM regulation, all European TSOs developed a proposal for a method for pricing intraday capacity, submitted to the national regulatory authorities in February 2017.

The intraday capacity pricing proposal via an auction mechanism is currently being studied by European regulators, who must make a joint decision by August 2018. This methodology raises a number of questions, related to its connection to continuous exchanges on XBID and to the relevant times for conducting such pan-European auctions. It would be useful to conduct this type of auction once the intraday capacity has been re-calculated. However, the methodologies for calculating capacity, currently being studied for each region, do not necessarily indicate recalculation times harmonised across Europe, making it more difficult to find a suitable time for this auction. Furthermore, conducting this type of auction too early in the afternoon means that there may be no added value compared with the day-ahead market coupling auction.

The use of intraday auctions in addition to continuous market coupling is also possible at the regional level, according to article 63 of the CACM regulation. This article states that, 18 months after the CACM regulation comes into force, the NEMOs and TSOs wishing to do so may submit a proposal for additional intraday regional auctions.

Such a proposal was drafted by all TSOs and all NEMOs active at the Italian borders and was submitted to the Italian, French, Austrian, Slovenian, Swiss and Greek regulators on 14 February 2017.

This methodology proposes the introduction of implicit auctions at the Italian borders, which would complement the continuous allocation to be implemented at these borders in 2019, once the XBID project is operational. The TSOs and NEMOs are proposing to introduce two implicit auctions, one at 10:00pm the day before delivery (covering all times on the day of delivery), the other one at 7:30am on the day of delivery (covering the hours from 12:00pm to 12:00am). Capacities not allocated at these auctions will be offered on the XBID platform. This proposal is being studied by the regulators from the region in question, who must make a joint decision by June 2018.

The CRE is working with its European counterparts to ensure that the market design chosen for the intraday timeframe remains clear for the market players. For the CRE, priority must be given to the implementation on all coupled borders of the XBID platform. The intraday auction initiatives at the pan-European level for pricing of capacity or only on a few borders within regional auctions, must not negatively impact continuous exchanges on XBID.

2.1.3.3 Towards implementation of coordinated intraday capacity calculation

Today no intraday capacity calculation is made systemically at the French borders, nor in Europe: these are residual intraday capacities that are offered on the market. As for day-ahead timeframe and in application of the CACM regulation, TSOs in each capacity calculation region submitted methodologies for coordinated intraday capacity calculations to the relevant regulators, in September 2017. These methodologies are being studied and should be approved in the second half of 2018; coordinated intraday calculations will however begin after the day-ahead capacity calculations are implemented in each region, thus by 2020.

In parallel to the improvements made by the introduction of network codes, the CWE region was a pioneer in the developments of the intraday capacity calculations. Once Flow Based was approved in March 2015, all CWE regulators, including the CRE[27], asked the TSOs to introduce a systematic intraday capacity calculation. Since the development of Flow Based intraday capacity calculation was longer than expected, in February 2016, the CWE regulators approved a temporary solution proposed by TSOs to increase the capacity offered to the market by daily re-assessment of residual day-ahead capacities, introduced in March 2016.

Despite creation of the CORE region by the ACER decision of 17 November 2016 on the capacity calculation regions, and thanks to the flexibility permitted by this decision, the CWE TSOs and regulators decided at the end of 2016 to continue the efforts begun in the CWE region following approval of day-ahead Flow Based; it is important that the CWE processes be continually improved since Flow Based in the Core region will be operational at best at the end of 2019 for day-ahead and 2020 for intraday. It is within this framework that the CWE region regulators approved the general principles for intraday Flow Based capacity calculation in September 2017 in the CWE region. A new proposal, taking into account the results of the tests conducted, must be submitted by the TSOs to the CWE regulators in July 2018 for a decision by the end of 2018 and introduction of the capacity calculation in the second quarter of 2019.

[27] Deliberation of the CRE of 26 March 2015 approving Flow Based market coupling and the related capacity calculation method: https://www.cre.fr/en/Documents/Deliberations/Approval/flow-based-market-coupling

2.1.4 Balancing

2.1.4.1 Use of cross-border capacity after the intraday timeframe, to offset the system balancing needs

In February 2016, RTE joined the International Grid Control Cooperation (IGCC) project, which aims to reduce activations of automatic frequency restoration reserves of participating TSOs, by cancelling their activations in opposite directions. This project has involved the TSOs of eight countries since 2016. It will be used as the basis for the European imbalance compensation platform which will be implemented by all European TSOs within the framework of the EBGL guideline.

The compensation between TSOs of their imbalances helps limit the volumes of automatic frequency restoration reserve energy that they may have had to activate in opposite directions, if there was no compensation. Compensation is possible only when all cross-border capacities remaining after the intraday markets close, allow the corresponding energy exchange.

2.1.4.2 Regional coupling to build the frequency containment reserve

Since February 2017, RTE has contracted its needs for frequency containment reserve capacity as part of the Frequency Containment Reserve (FCR) cooperation through weekly calls for bids conducted by the TSOs of the six partner countries (Austria, Belgium, France, Germany, Netherlands, Switzerland). In application to the EBGL guideline, the TSOs taking part in this cooperation submitted the terms of the cooperation for approval by the regulators from the countries concerned, on 26 April 2018, as well as its future developments.

The product thus contracted concerns the delivery of frequency containment reserve for the same power upwards and downwards (symmetrical product), and continuous over one week. The reserve suppliers from the countries concerned submit offers for provision of frequency containment reserve on a shared platform. These offers are selected such that they satisfy the need expressed by each TSO by minimising the cost of building this reserve, while respecting the frequency containment reserve import and export limits defined by the System Operation regulation; the regional cooperation thus allows preferably the use of frequency containment reserve capacities in countries where they are less costly. The frequency containment reserve energy exchanges resulting from this joint contracting do not require the availability of cross-border exchange capacity since they are taken into account in the margins available at the interconnections.

In 2017, 27 weeks of 50, RTE imported on average 60 MW of frequency containment reserve, and the rest of the time exported on average 54 MW of frequency containment reserve. The joint contracting allowed reduction of the average price of the reserve by around 20% compared with the regulated price previously in force.

2.1.4.3 Continued work on European exchanges of other reserves

For automatic frequency restoration reserves, manual frequency restoration reserves and replacement reserves, TSOs and national regulatory authorities have continued their cooperation and their work on several energy exchange platform projects.

The TERRE project (Trans-European Replacement Reserves Exchanges) aims to implement a platform for the exchange of balancing energy from replacement reserves, i.e. balancing products that can be activated in under 30 minutes. Given the scale of future developments, several TSOs[28], including RTE, initiated the definition of the platform architecture in 2013. This work was conducted with a group of regulators headed by CRE, which ensures its consistency with the work done to develop the EBGL guideline. They provided common opinions[29] on the project architecture, after two public consultations conducted by the TSOs. Within the framework of the formal implementation of the EBGL guideline, TSOs performing the reserve replacement process must submit an implementation framework for the exchange of balancing energy from replacement reserves to their respective national regulatory authorities before 18 June 2018.

The MARI project (Manual Activated Reserves Initiatives) will conclude with the implementation of a platform for the exchange of balancing energy from manual frequency restoration reserves. These products can be activated in under 15 minutes and are used by all European TSOs. They will be shared on a single platform made up of two economic merit order lists: one for scheduled activations and the other for continuous activations. The EBGL guideline requires TSOs to submit an architecture proposal for the future platform to the national regulatory authorities before December 2018. A public consultation was launched by the TSOs in the second quarter of 2018. The platform must be made operational before December 2021.

[28] In 2017, the project involved RTE (France), National Grid (Great Britain), REN (Portugal), REE (Spain), Swissgrid (Switzerland) and Terna (Italy).

[29] Deliberations of the CRE on: http://www.cre.fr/documents/deliberations/orientation/projet-terre and http://www.cre.fr/documents/deliberations/orientation/projet-terre2

Lastly, a third exchange platform for standard projects will be operational before December 2021: it will be the platform for the exchange of balancing energy from the automatic frequency restoration reserve (PICASSO project - "Platform for the International Coordinated of Automated Frequency Restoration and Stable System Operation"). This reserve, whose activation is controlled automatically, can be activated in a time constant that today varies between 5 and 15 minutes, depending on countries. This platform will bring about significant changes in the architecture of the French market, in that it will require a switch from a prorated reserve activation mode (all flexibilities supplying the reserve are activated simultaneously) to an economic merit order activation. A public consultation on the architecture of this platform was launched by TSOs in April 2018, and they will then submit an architecture proposal to the national regulatory authorities before December 2018.

Chapter 2– Overview of the use of electricity interconnections

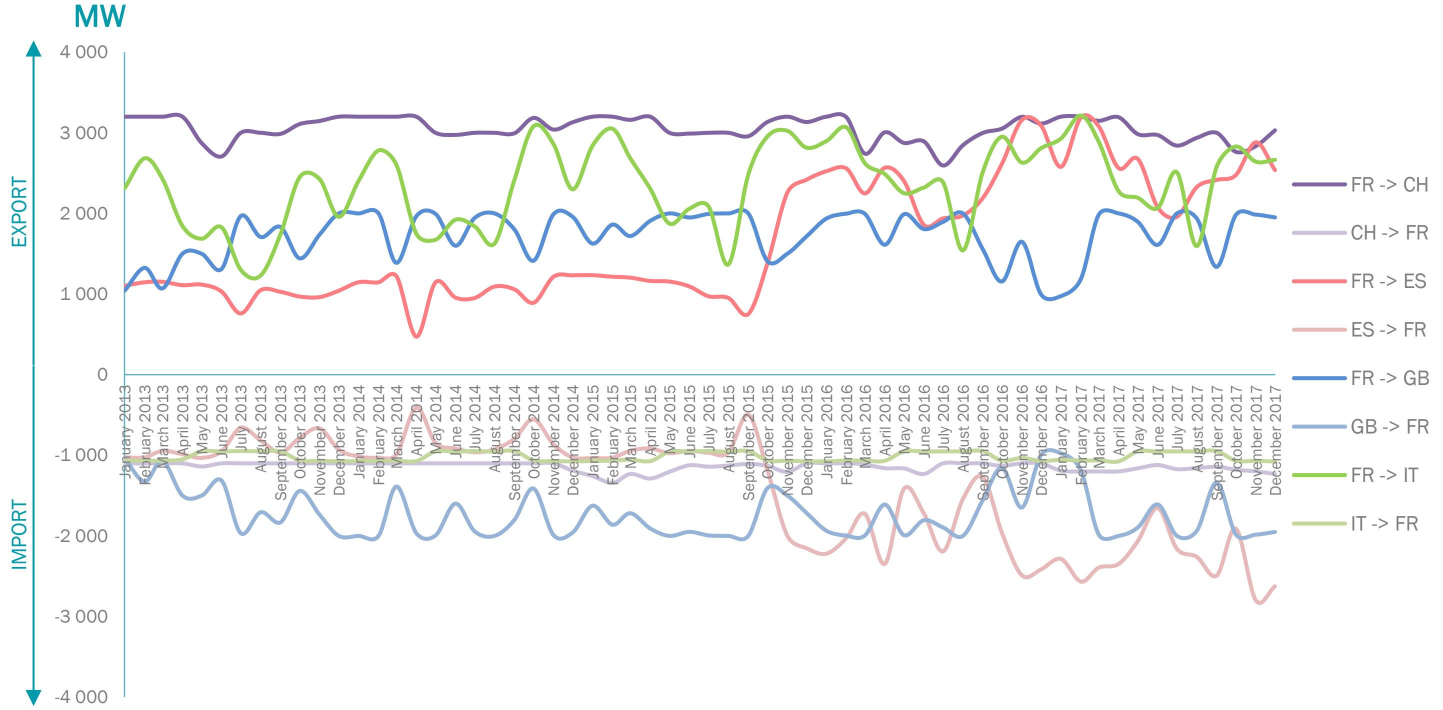
2.2.1 Evolution of interconnection capacity levels at French borders

2.2.1.1 A structural increase counter-balanced by a slight situational drop in interconnection capacities

Commercial interconnection capacities represent exchange capacities that are offered to market players; they may differ from the physical capacities of transmission infrastructures, known as thermal capacities. Commercial capacities are calculated for each hourly step by TSOs to ensure that the physical flows resulting from commercial cross-border exchanges do not jeopardise the network's security. Since Flow Based was implemented in May 2015, exchange capacities in the CWE region are no longer determined ex-ante according to border (France/Belgium on the one hand and France/Germany on the other), but for all exchanges for the region, taking into account the interdependence of flows between borders.

Metropolitan France is now interconnected with Great Britain, Belgium, Luxembourg[30], Germany, Switzerland, Italy and Spain. Commercial exchange capacities between France and these countries, apart from Belgium and Germany, which were 8.7 GW for export and 5.1 GW[31] for import on average in 2015, reached 9.8 GW for export and 6.2 GM for import in 2017. Since 2013, exchange capacities have increased by 2.2 GW for export and 1.6 GW for import. The differences in level between import and export can be explained by the configuration of transmission networks on either side of the various borders, historically organised to maximise French exports.

Figure 12– Commercial interconnection capacities (excluding CWE), monthly averages (2013-2017)



Source: RTE, CRE analysis

The increase in France's exchange capacities is related to the commissioning of a new interconnector with Spain (Baixas Santa Llogaia) in October 2015 and to the reinforcement of the Spanish network (commissioning of the phase-shifting transformer in Arkale in June 2017). Exchange capacities with Spain have gone from 1 GW to 2.6 GW for export and from 0.9 GW to 2.3 GW for import.

The increase of exchange capacities with Italy brought about by the implementation of the coordinated capacity calculation for export in February 2016 was lower than expected, since the commercial capacities increased by only 70 MW on average between 2015 and 2017 (even if the variation range of exchange capacities has become more important: they may sometimes reach 3.3 GW compared with 3.1 GW maximum before February 2016). This

[30] Luxembourg belongs to the market area shared with Germany and Austria for electricity.
[31] 8.4 GW for export and 4.9 GW for import before the introduction of the Baixas-Santa Llogaia interconnection with Spain in October 2015.

moderate increase underlines the method applied today, and which should be improved under application of the CACM regulation (see section 2.1.2.2).

Exchange capacities with Switzerland dropped significantly in 2016 (on average by 120 MW for export and 60 MW for import), before increasing slightly in 2017 (30 MW for export and 50 MW for import), since works on the network led to unavailability of the interconnection.

The interconnection between France and Great Britain suffered an incident related to a storm in the English Channel at the end of November 2016. Four of the eight interconnection cables were damaged, thus limiting exchange capacities until February 2017. The annual average commercial capacities offered in 2016 and in 2017 was thus slightly lower than the previous years (around 1.7 GW instead of 1.8 GW usually).

2.2.1.2 Limiting TSO

When the coordinated capacity calculation has not yet been implemented at a border, the network operators independently calculate the cross-border capacity level that they can offer the market, while respecting the security of their network, then take the smaller value from among those calculated. The TSO that proposes this value is known as the "limiting TSO". In France, a coordinated capacity calculation was implemented with the CWE region and Italy. At the border with Great Britain, the entire capacity of the cable (2 GW) is provided to the market, except in the case of maintenance or incident.

At the France/Switzerland border, imports are usually limited by the Swiss TSO, Swissgrid (68% of the time in 2017), whereas for export, RTE and Swissgrid simply check that their networks can withstand a capacity of 3,000 MW in summer and 3,200 MW in winter.

At the Spanish border, RTE limited capacity 19% of the time for import and 17% of the time for export in 2016, a little more than in 2015 (respectively 17% and 11% of the time). The reinforcement work carried out on the Spanish network in 2016 and 2017 allowed REE (*Red Eléctrica de España*) - the Spanish network operator - to limit capacities less, as a result mechanically rebalancing distribution between the two TSOs. RTE thus became the limiting TSO 34% of the time for import, and 49% of the time for export in 2017 (the two TSOs proposed the same capacity level around 6% of the time for import and for export). The capacities used when each TSO was a limiting TSO are thus higher in 2017 than in 2016, illustrating the slight impact of internal constraints on the capacities offered to the market.

2.2.1.3 Capacity curtailments

When the level of forward capacities sold at auction is higher than the physical capacity actually available at the timeframe, if there is an incident affecting the network for example, the TSOs may be forced to carry out capacity curtailments, meaning that they cancel previously allocated rights. According to the terms of the FCA regulation (see section 2.1.1), these capacity curtailments can take place only before the day-ahead firmness deadline, set at one hour before the day-ahead ahead gate closure, in order to give market players time to rebalance their positions if needed on the day-ahead market.

As illustrated by the graph and table below, the number of curtailments varies a great deal from one border to another. In Belgium and Germany for example, there has been no curtailment since 2011[32]; similarly, no curtailment was recorded on the France/Switzerland border in 2017. On the contrary, there are many curtailments on the France/Great Britain border, on a large scale, more in 2016 and 2017 than in previous years. These differences can be explained by several factors:

- The meshing of the interconnection: at the German, Belgian or Swiss border, the networks are dense and allow a certain flexibility. On the contrary, the Great Britain border, a single direct current connection supplies all exchanges; any problems or maintenance on this connection automatically leads to major capacity curtailments. Damage to four of the eight cables on the interconnection led to a considerable capacity curtailment between November 2016 and February 2017.

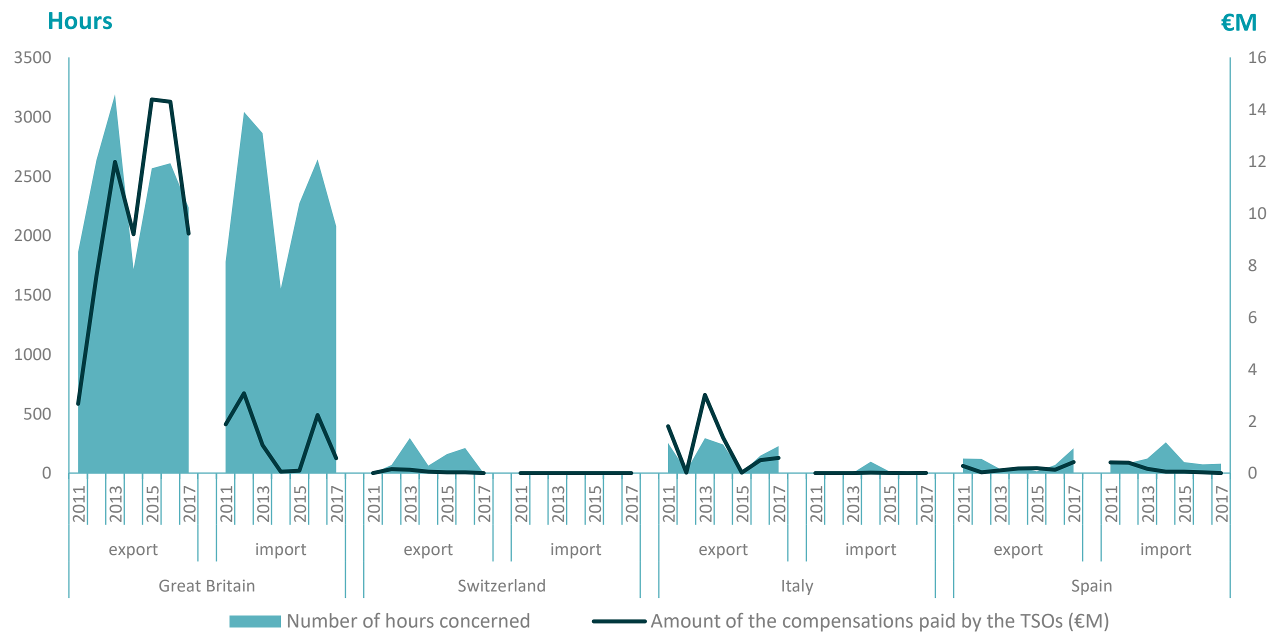
- The terms for calculating capacity offered at forward timeframes, which give varying margins to help in dealing with contingencies, and the splitting of capacities between allocation timeframes. At the Great Britain border, no capacity calculation is performed; the entire physical capacity of the cable is thus offered to the market, at timeframes that are mostly very distant from real time (twice yearly or yearly). As a result, a high volume of forward capacity is exposed to curtailments when the connection fails.

[32] With the exception of October 2015, from Belgium to France, where TSOs had to carry out 23.33 MW of curtailment on average over three days. The Flow Based in place since 2015 in the CWE region limits the curtailments of forward rights, in that it includes in the capacity calculation performed at D-2 a procedure known as LTA inclusion, which guarantees that the Flow Based domain calculated at this timeframe covers at least the forward rights already allocated, if necessary at the price of costly remedial actions.

- The random occurrence of incidents on the network or production facilities, as well as scheduled maintenance, which affects different borders in different ways.

In the event of capacity curtailment, the TSO informs the market player that holds these capacities that it cannot honour them and pays financial compensation according to terms that are set out by the FCA regulation (see section 2.1.1). Figure 13 below shows that the compensation amounts are significant only at the border between France and Great Britain.

Figure 13– Number of hours of forward capacity curtailment per border and the related compensations, from 2011 to 2017, excluding CWE



Source: RTE, CRE analysis

Figure 14 – Average volume of curtailments per border, from 2011 to 2017

Average volume of curtailments (MW)		2011	2012	2013	2014	2015	2016	2017
Great Britain	Export	465	654	32	28	33	536	333
	Import	477	684	33	37	51	521	351
Switzerland	Export	0	317	12	24	17	40	0
	Import	0	0	0	0	0	0	0
Italy	Export	526	44	14	9	22	351	231
	Import	0	0	0	50	24	0	794
Spain	Export	423	291	39	15	23	179	596
	Import	626	623	18	13	16	341	353

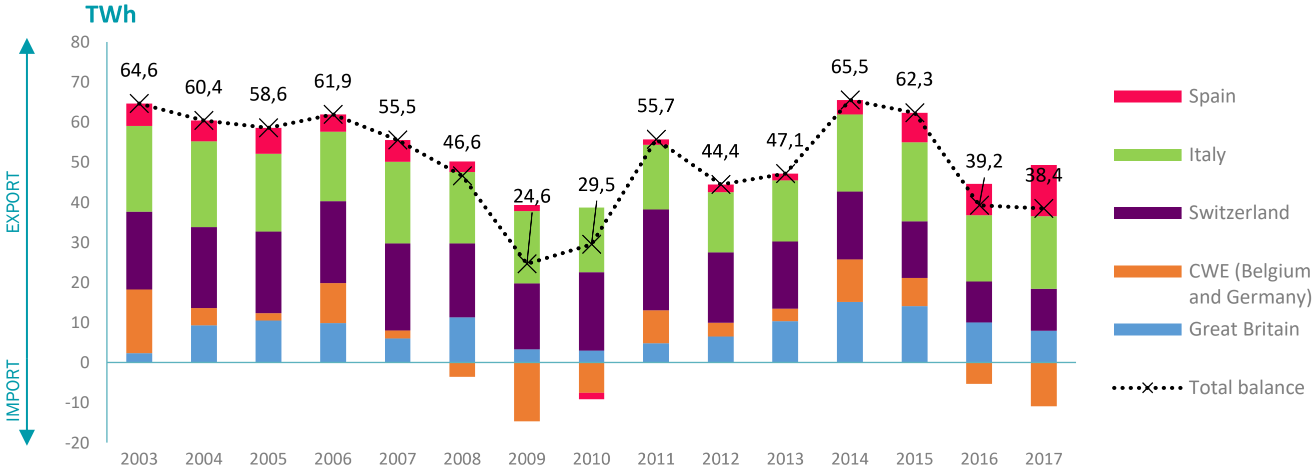
Source: RTE, CRE analysis

2.2.2 Commercial exchanges at French borders

2.2.2.1 An export balance in sharp decline in 2016 and 2017

The balance of electricity exchanges in France reached a historic low in 2016 and 2017, of around 39 TWh (see figure 15 below), without however dropping to the 2009 level (24.6 TWh). This is due to both the very sharp drop in exports (from 91 TWh in 2015 to 72 TWh in 2016 and then 74 TWh in 2017), and to a slight upturn in imports (of 30 TWh in 2015 and 35 TWh in 2017).

Figure 15– Annual net commercial flows by border

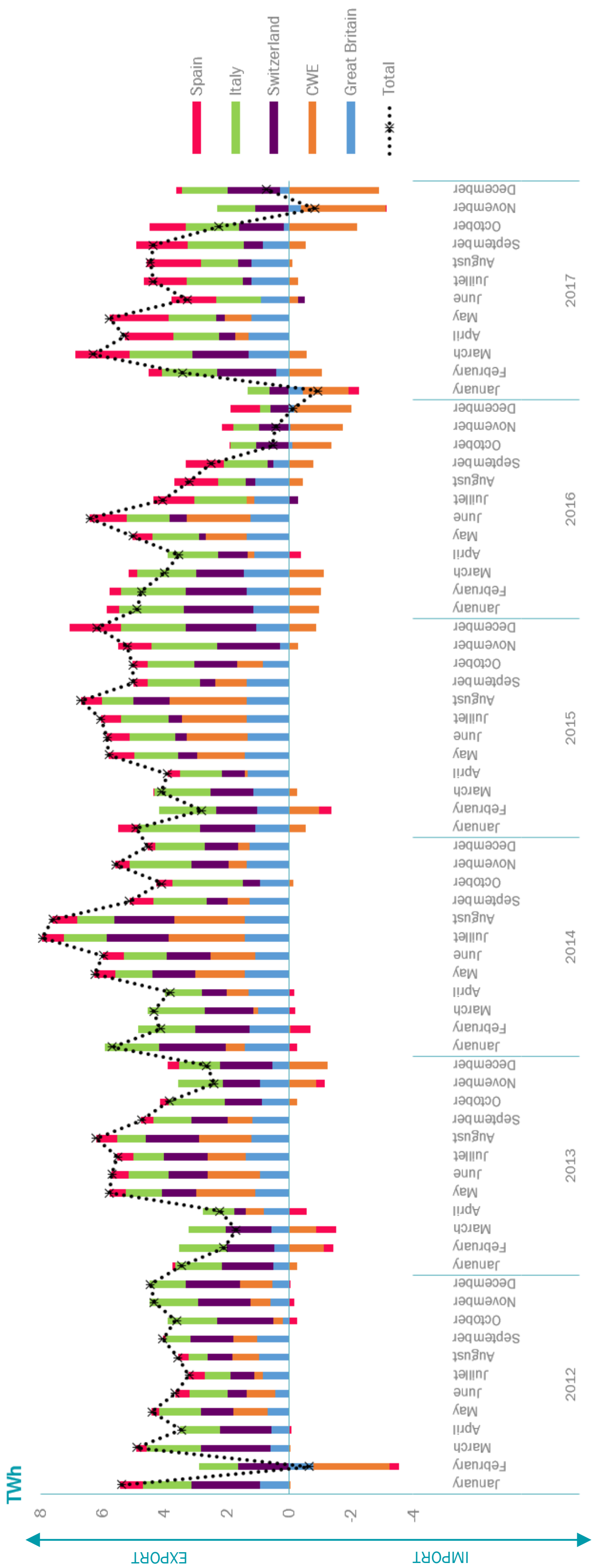


Source: RTE, CRE analysis

This phenomenon is directly linked to the period of tension that occurred in winter 2016/2017: the unavailability of part of the French nuclear plants, combined with temperatures well below seasonal norms, affected the price of French electricity and changed the usual balance of exchanges (see box below for an analysis of the situation in winter 2016/2017). France's net balance reached particularly low levels: it was close to nil in October and November 2016 (around 0.5 TWh per month), then negative in December 2016 (-0.1 TWh) and January 2017 (-0.9 TWh). France had not had a monthly import balance since the cold snap of February 2012 (-0.7 TWh). In comparison, France's export balance was 6.2 TWh in December 2015.

Although exchange balances in 2016 and 2017 were comparable, the seasonal change in flows was different over these two years. 2016 was marked by a high export balance during the first half of the year (with a peak of 6.4 TWh in June), then a fall in exports combined with a rise in imports during the second half of the year, due to the drop in nuclear generation from September on.

Figure 16– Monthly net commercial flows by border



Source: RTE, CRE analysis

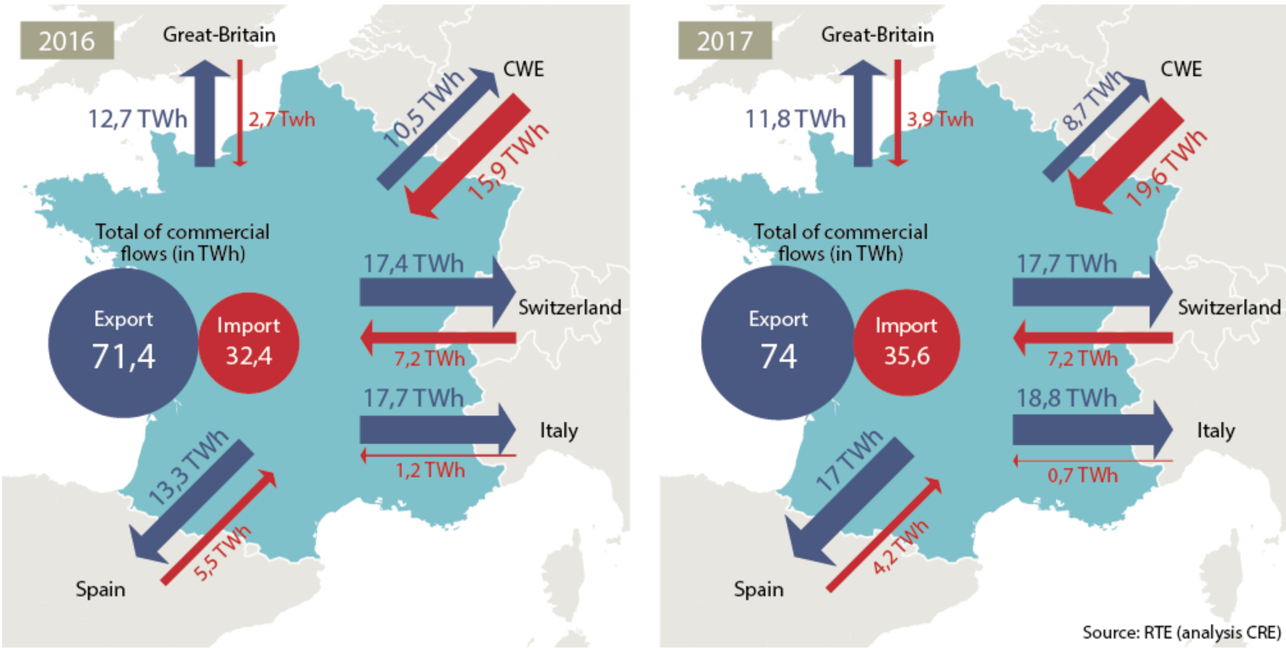
The profile for 2017 is different, with a relatively high export balance between March and September, but very low in January, February, and during the final quarter (with an import balance of 0.8 TWh in November 2017, given new unavailabilities of nuclear facilities and temperatures that were 0.8°C below seasonal norms in France). France was a net importer for 52 days in 2017 (46 days in 2016), which was the highest level since 2010 (72 days).

France's import record, in February 2012, was beaten at the end of 2017 with 10.6 GW in imports on Saturday 2 December 2017 at 11:00pm (with a French spot price of €63/MWh, compared with €54/MWh on average in neighbouring countries). This type of value remains very rare, since the second highest French import level of 2017 was 8.9 GW on 3 December at 1:00am.

The export record of July 2015 was also beaten on 30 March 2017 at 6:30pm, reaching 17 GW (for a French price of €36/MWh and €41/MWh on average in neighbouring countries). French exports exceeded the level of 15 GW around a dozen times during the month of March 2017.

2.2.2.2 Contrasting situations at French borders

Figure 17– Commercial flows[33] at French borders in 2016 and 2017



The change in exchanges is also different depending on the borders considered. Net over the year, France preserved its status as an exporter country to Great Britain, Switzerland, Italy and Spain in 2016 and 2017, but was a net importer from the CWE region, which had not occurred since 2010.

Net exchanges with Great Britain, highly variable depending on years, reached a peak in 2014 with a French export balance of 15 TWh, before dropping to 10 TWh in 2016 then to 8 TWh in 2017 (imports rose sharply in 2017). On a monthly scale, France was a net importer from Great Britain from October 2016 to January 2017, then in November 2017, i.e. during periods of strain for the French system (France imported 83% of the time from Great Britain in January 2017). Outside of winter periods, the France/Great Britain interconnection is used almost exclusively for export.

The balance of exchanges with Switzerland was also reduced compared with 2015, but this is in keeping with a more general trend, since the export balance, more or less stable at around 20 TWh since 2003, has fallen each year since 2012 with the expiry of long-term contracts associated with this border (it reached 10 TWh in 2016 and 2017, compared with 14 TWh in 2015). The drop observed in 2016 and 2017 can also be explained by the unavailability of French nuclear plants, to whose energy the forward contracts are attached. The seasonality of exchanges with Switzerland is relatively unusual compared with other borders, since imports are higher during the summer months. This phenomenon is attributable in particular to hydroelectric generation in Switzerland (up to 59%

[33] excluding loop variations, shared back-up between TSOs and make-up of losses and variations

of electricity generation in 2015 according to the Swiss federal energy office), relatively available during the summer months, despite a filling deficit in recent years due to relatively mild winters.

France is historically a high exporter to Italy, but experienced a fall in the balance of its exchanges to this country, from 19.7 TWh in 2015 to 16.5 TWh in 2016, before increasing to 18.2 TWh in 2017. This change is due to increased imports from Italy during the winter of 2016/2017, with France however not frequently in a net importer position over this period (26 days between October 2016 and February 2017).

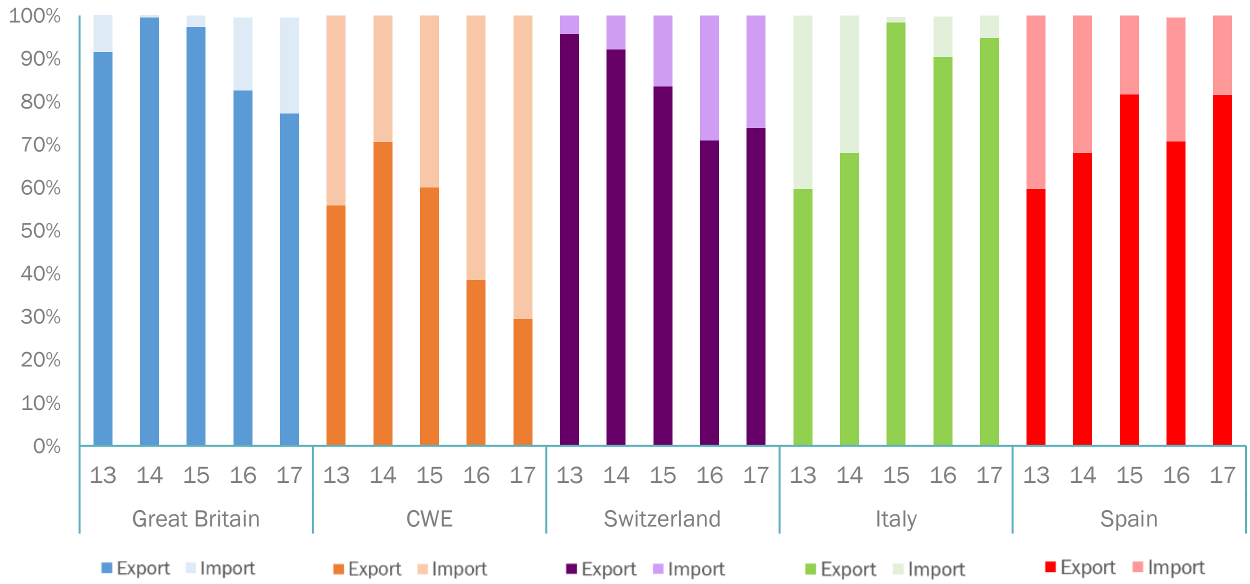
Spain is the only country with which the French export balance has increased since 2015. Relatively limited in 2016 (+0.4 TWh), this increase was more pronounced in 2017, reaching a balance of 12.8 TWh. The commissioning of the new interconnector in October 2015 allowed an increase in exchanges with Spain, even though the change in the net balance was limited during the winter of 2016/2017. There was indeed an increase in both imports, from 2 TWh in 2015 to 5.5 TWh in 2016, and to 4.2 TWh in 2017, and exports, from 9.3 TWh in 2015 to 17 TWh in 2017. Exports to Spain were at times particularly high between March and September 2017, with Spanish hydraulic stocks during this period at their lowest point since 2008.

Lastly, France was a net importer from the CWE region (Belgium, Germany and the Netherlands) in 2016 and in 2017, for the first time since the 2008-2010 period. Exchanges with this region are historically characterised by considerable seasonal variability, with higher exports in summer than in winter (with France often a net importer between November and January, due to sensitivity of demand to temperatures). This seasonality and the volumes exchanged were particularity pronounced both in winter 2016/2017 and at the end of 2017, thus explaining France's position as net importer over these two years.

The variability of exchange levels according to borders and seasons highlights the importance of interconnections to exploit the complementarity of generation facilities and national consumer profiles. They thus provide France with a flexibility that helps manage peak during winter cold snaps (the level of electricity consumption in France is particularly influenced by temperatures: 2,400 MW of additional power is needed for each degree lost in winter during the peak demand, which represents half of the temperature sensitivity of European consumption in winter).

Figure 18 below shows the direction of use of the various French interconnections (in percentage of time), independent of the level of flows. The interconnections with Switzerland and Great Britain are almost always used for export (to a lesser extent in 2016 and 2017), whereas the interconnection with the CWE region is used above all for import, all the more so over the past two years. The interconnections with Spain and Italy are increasingly used for export (not taking into account the effects of winter 2016/2017). This reflects the fact that French wholesale prices are generally lower than those of all the neighbouring countries, with the exception of Germany.

Figure 18– Direction of use of French interconnections



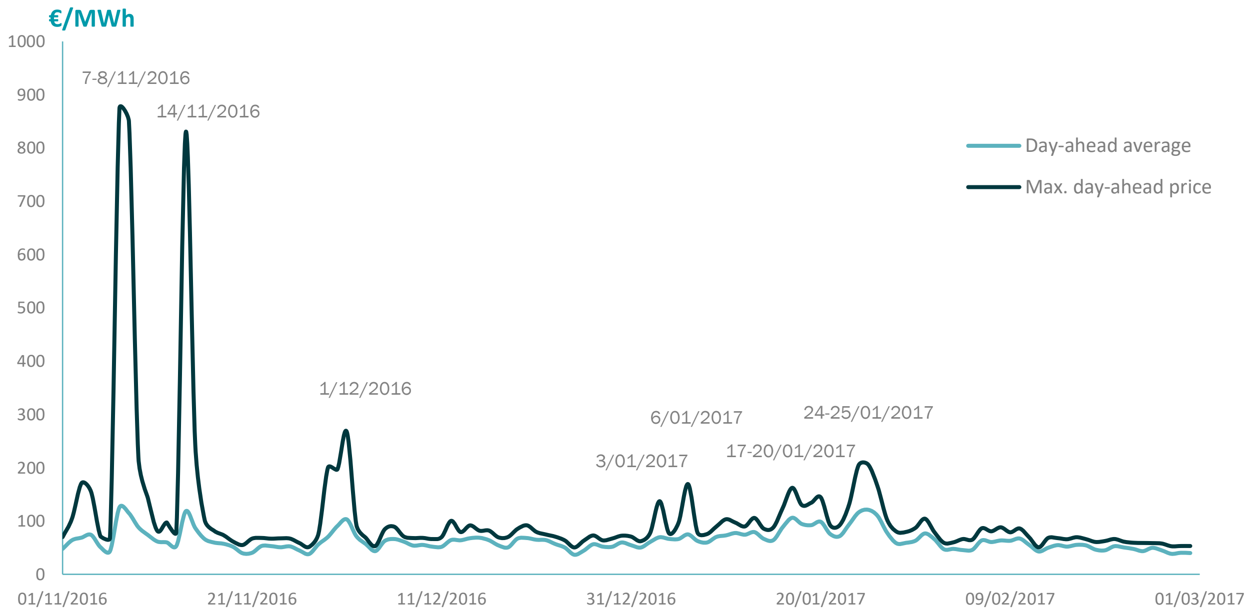
Source RTE, analyse CRE

Period of strain October 2016 - February 2017

The French electricity system - and the European one to a lesser extent - experienced a period of strain between October 2016 and February 2017. Two separate periods were observed however, with very high but rare price peaks in November 2016, and slightly lower but more frequent peaks at the start of 2017 (see figure 19 below).

The final quarter of 2016 saw unscheduled unavailability of part of France's nuclear plants, but also of certain plants in Belgium and Switzerland, which led to massive use of fossil fuel heat production facilities (6.7 TWh in France, the highest level since February 2012). This contributed to the price increase observed in November 2016 with particularly high peaks, particularly in France. Spot prices reached a maximum of €874/MWh on 7 November at 6:00pm, and again exceeded €800/MWh on 8 and 14 November at 6:00pm, for an average spot price of €65/MWh for the month. The level of 9 February 2012 (€1,938/MWh) was not reached however. France remained a net exporter for the month.

Figure 19– Average day-ahead spot prices in France (winter 2016/2017)

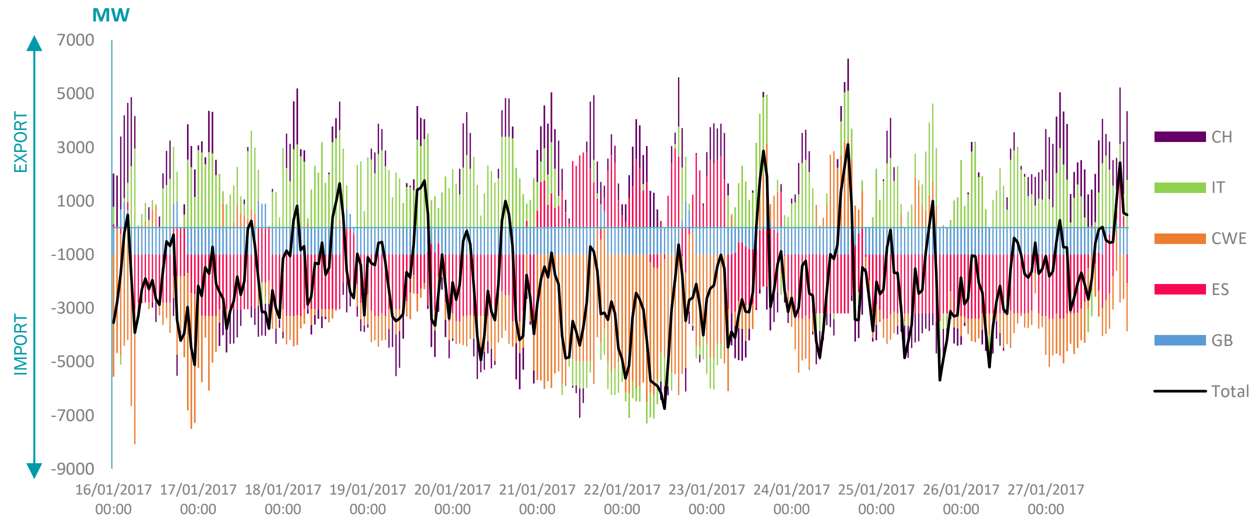


Source: RTE, CRE analysis

The effect of the non-availability of French nuclear plants was accentuated by the increase in gas and coal prices in southern Europe (see section 2.4.1.3), the low renewable production and the cold snap that hit the region in early 2017, leading to another spot price increase. This was the case in particular during the second half of January, with lower price peaks than those in November 2016 (€206/MWh on 25 January), but higher average prices (€121/MWh on average on 25 January, and €78/MWh on average over the month).

France was a importer most of the time during the second half of January (89% of the time), reaching the highest import balance since 1980 (0.9 TWh), with a significant flow reversal with Spain and Great Britain. Although on average France imported mostly during consumption peak periods (between 7:00am and 11:00am and between 6:00pm and 7:00pm), the highest flows were observed mainly during the weekend of 21 to 22 January (while strain on the French system was lower): the import maximum (6,759 MW) was reached on Sunday 22 January at 12:00pm, when the French spot price was €75/MWh, the German price was €37/MWh and those of other neighbouring countries were €70/MWh on average. In comparison, at the time of the highest price peak (on 25 January at 8:00am), France imported only 4,860 MW (only 308 MW of it from the CWE region - see focus 2).

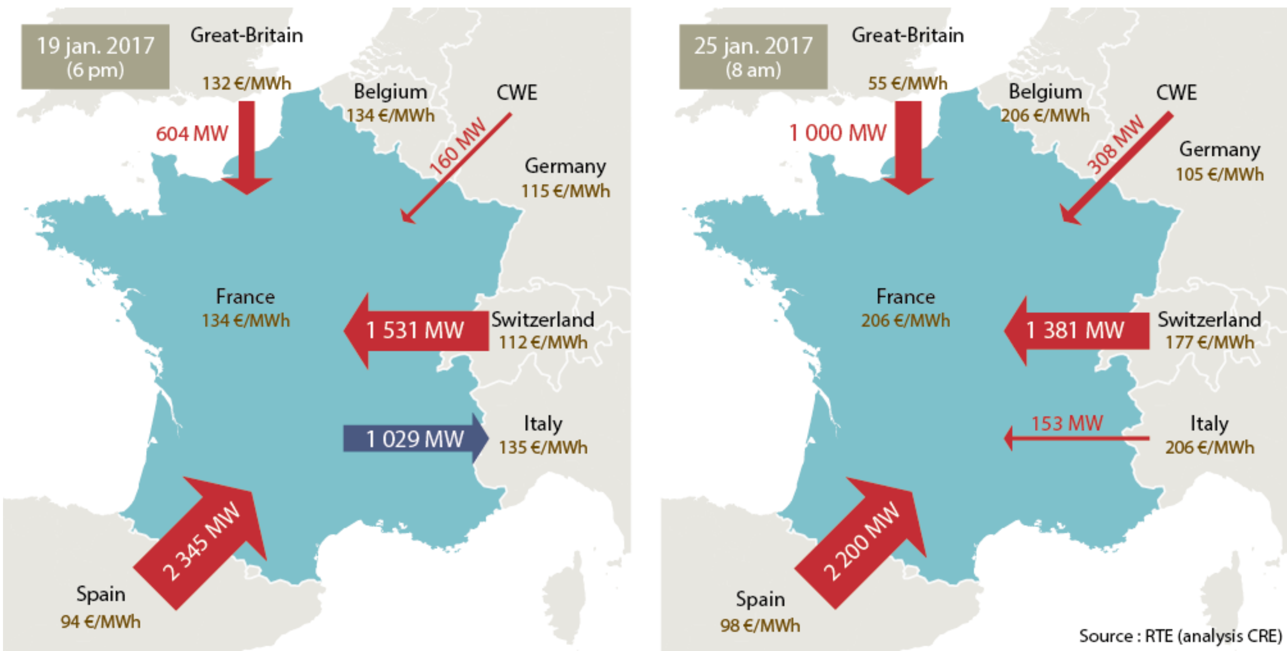
Figure 20– Hourly exchanges from 16 to 27 January 2017



Source : RTE, analyse CRE

Market coupling thus facilitated the joint evolution of European prices during this period of strain, limiting the price spreads at certain peaks (see maps below). On 19 January at 6:00pm, France converged with Italy, Belgium and Great Britain[34] at €134/MWh, whereas the full-capacity use of interconnections between Spain and Switzerland led to spreads of €40/MWh and €22/MWh respectively. A similar situation was observed at the price peak on 25 January at 8:00am: France converged with Italy and Belgium (€206/MWh), and maintained a price spread with Great Britain, Switzerland and Spain with 100% use of interconnections. Exchanges with the CWE region remained very limited on these two time slots (160 MW and 308 MW) despite very significant price differences with Germany.

Figure 21– Prices and commercial flows at the French borders



[34] Taking into account losses on line

FOCUS 2 – IMPROVEMENTS NEEDED IN THE IMPLEMENTATION OF FLOW BASED IN THE CWE REGION

Although the Central West Europe (CWE) region was a pioneer in implementing first coupling then the Flow Based approach, the application of this method of calculating capacity since 2015 has not delivered all the expected benefits: internal restrictions within the TSOs' systems have sometimes significantly limited the import capacities available, particularly during periods of tension (winter 2016/2017). The CRE continues to work actively with its counterpart regulators to ensure that the methodologies implemented by the Transmission System Operators (TSOs) use the interconnections to best advantage.

1. Description of the Flow Based capacity calculation

With regard to capacity calculation, the CWE (Central-West Europe) region, comprising the France, Germany-Luxembourg-Austria, Netherlands and Belgium[35] zones, has played a pioneering role as it was the first to carry out early implementation of Flow Based calculations. This new method of determining cross-border exchange capacities, which was launched on the 21 May 2015 after two years of testing in the CWE region, constitutes the target model specified by the CACM regulations for day-ahead and intraday timeframes.

The idea of the *Flow Based* method is to reflect as faithfully as possible the physical limitations of the network in the constraints imposed on commercial exchanges, taken on entry to the market coupling algorithm. Thus a domain of possible net positions[36] of bidding zones is defined by taking into account the maximum capacities of potentially limiting system elements (called "critical branches"[37]), and coefficients reflecting the impact of cross-border exchanges on each of these critical branches (called "influencing factors"[38]). This domain is called the *Flow Based* domain.

Contrary to this method of calculating capacity in which the possible net positions are interdependent, the NTC (*Net Transfer Capacity*) method involves thinking in terms of bilateral commercial flows, and in determining a set of maximum commercial flows which can be carried out at the same time. This method requires selection of an *in principle* sharing rule of the margin available on each critical branch between the various bilateral flows[39], independently of the value generated by these flows in market coupling. From the same basic data, the NTC domain obtained is therefore more limited than the *Flow Based* domain, and the latter makes it possible to generate a greater social welfare[40]; thus, during the test phase, the collective gain in social welfare allowed by the *Flow Based* method has been assessed at more than €130M over 2014 for the CWE region.

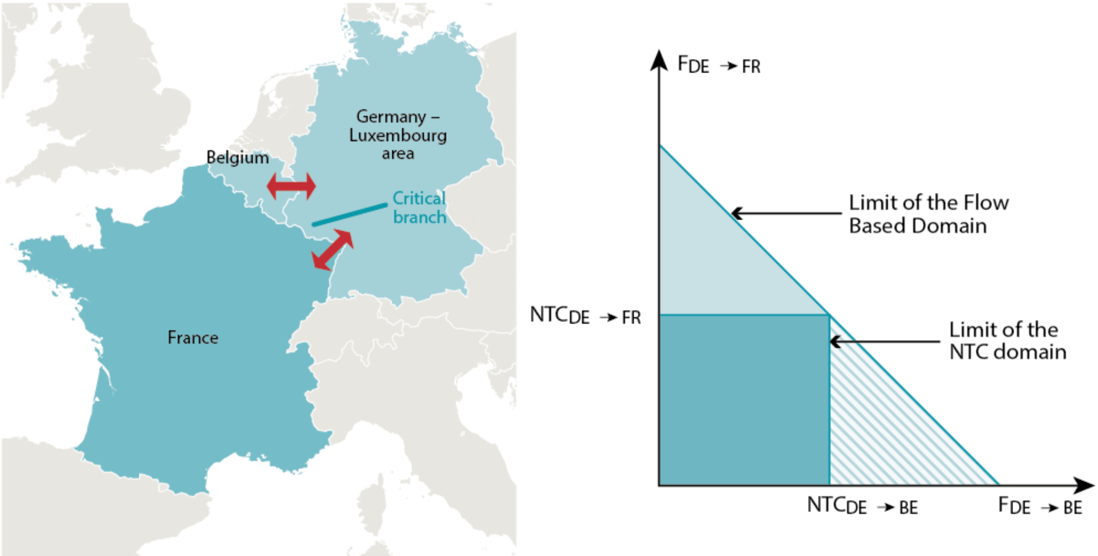
This description of the *Flow Based* method and its link with the NTC method is illustrated in the simplified example below.

Only three zones of the CWE are involved (FR and BE on the one hand, and DE as net exporter on the other) and two physical interconnections (FR-DE and DE-BE[41]). There is only one limiting critical branch in Germany: on this branch, an export of 1 MW generates a flow of 1 MW[42], whether this is directed to the FR zone or to the BE zone. The possible combinations of $F_{DE\rightarrow FR}$ and $F_{DE\rightarrow BE}$ flows which comply with the capacity constraint for the critical branch are represented by the bright green line on the graph: for example, it is possible to give 1 MW of $F_{DE\rightarrow BE}$ flow if the $F_{DE\rightarrow FR}$ flow is set to 0, and *vice versa*.

In the NTC approach, this 1 MW constraint could on the other hand be predetermined in a pair of independent NTC values, separately limiting the $F_{DE\rightarrow FR}$ and $F_{DE\rightarrow BE}$ flows to 0.5 MW maximum each (dark green lines in figure 22 below).

[35] This region was a result of voluntary cooperation and is now incorporated into the Core capacity calculation region in compliance with the decision of ACER of 17 November 2016.
[36] The net position of a zone is the difference between the total production and total consumption in this zone.
[37] Or " critical network elements" in the CACM regulation
[38] The coefficients equating to the variation in flow undergone by the system element during a bilateral exchange of 1 MW between two zones.
[39] In general, equal sharing is adopted.
[40] The social welfare includes the profits of the producers, the consumer surplus and the congestion rents of the TSOs.
[41] In reality, there is no physical interconnection between Germany and Belgium; the flows between these two countries transit via France or the Netherlands.
[42] This therefore corresponds to DE→FR and DE→BE influencing factors of 100% each.

Figure 22– Illustrative example of the operation of the Flow Based method



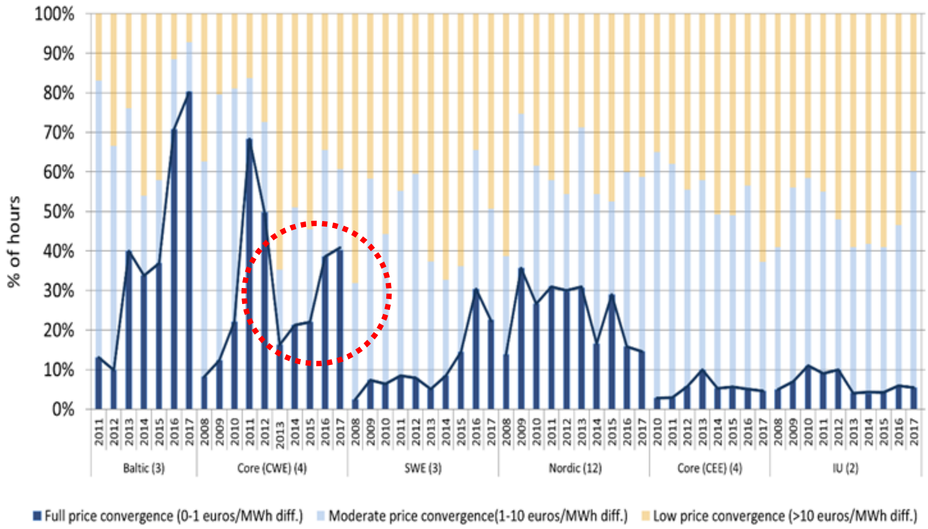
In the NTC approach, it is therefore possible for the flows for the BE zone to be limited by the $NTC_{DE \to BE}$ constraint to 0.5 MW, while the maximum $F_{DE \to FR}$ import flow of 0.5 MW for the FR zone is not saturated and there is therefore unused interconnection capacity on the FR-DE border; this is shown by a convergence in the p_{FR} and p_{DE} prices, while the p_{BE} price remains higher.

Changing to the *Flow Based* approach could lead to an increase in the $F_{DE \to BE}$ flow up to 1 MW while the $F_{DE \to FR}$ flow could be null. The lowering of imports into the FR zone here goes hand-in-hand with an increase in imports in the BE zone and exports from the DE zone. This can increase the overall social welfare, the prices being established in accordance with the new hierarchy as follows: $p_{DE} < p_{BE} = p_{FR}$.

2. Estimate of the Flow Based capacity calculation in the CWE region

The implementation of the *Flow Based* method has contributed to an overall increase in the convergence rate between the prices of the four zones making up the CWE region, as illustrated by the chart below: between 2014 and 2017, this went from 21% of the time to more than 40%.

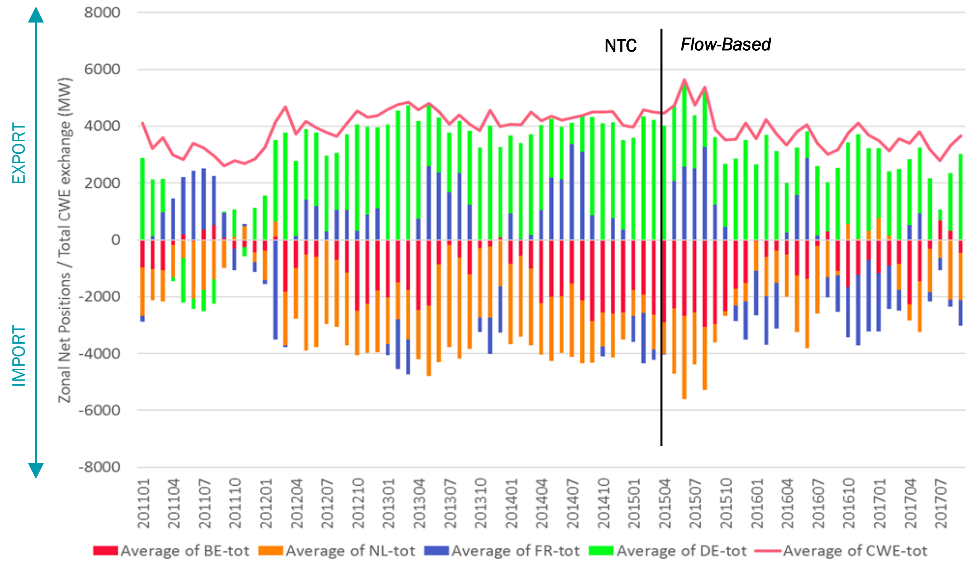
Figure 23 – Taux de convergence des prix dans les différentes régions de calcul de capacité, entre 2012 et 2017



Source: ACER

The *Flow Based* method also results a significant increase in the maximum exchanges between zones due to the widening of the capacity domain relative to the NTC approach: so joint imports by France and Belgium from the other zones of the CWE region reached 9608 MW in 2017, i.e. more than double that which would have been allowed by the maximum NTC values seen before the implementation of the *Flow Based* method.

Figure 24 – Convergence rate of prices in the various capacity calculation regions, between 2012 and 2017



Source: CREG

However, it emerges from the study of the resulting coupling flows in the CWE region (see figure 24 above[43]) that after a short period of increase immediately following the entry into force of the *Flow Based* capacity calculation, the average cross-border exchanges have had a tendency to reduce significantly relative to their previous level[44]. Although it is difficult to distinguish in these flows the effects of the capacity domain offered from market fundamentals[45], this observation tends to show that, during the hours when prices do not converge, there is more congestion after implementation of the *Flow Based* method than before, which is the opposite effect to that expected.

Furthermore, in spite of the average increase in the convergence rate, it should be noted that during periods of tension on the system in particular during the winter of 2016/2017 where a significant proportion of French nuclear power plants were unavailable although temperatures were low, the *Flow Based* method did not prevent strong divergences in price in the CWE region associated with price peaks in certain zones (up to €874/MWh on 7 November 2016 in France while the CWE cross-border flows were low: less than 4000 MW in total including less than 2500 MW import for France). More generally, the high import flows for France are more often than not observed outside the peak consumption periods in France: only 31% of import flows greater than 6000 MW were observed between 07:00 and 21:00 in 2017; the limits on import possibilities are such as to penalise the French consumer.

From the above, it emerges that implementing the *Flow Based* method has not brought all the expected benefits: this is notably due to the way it was implemented by the TSOs of the CWE region, which led to frequent limits to the capacity domain offered to the market[46]:

- The maximum flow of electricity on the critical branches depends directly on the maximum admissible current on these branches which itself varies according to the ambient

[43] This chart includes long-term nominations in order to overcome changes of volume and of long-term rights type over time.

[44] As a reminder, France was a net exporter to the CWE region in 2014 (10.6 TWh) and in 2015 (7 TWh), and net importer in 2016 (5.3 TWh) and 2017 (10.9 TWh).

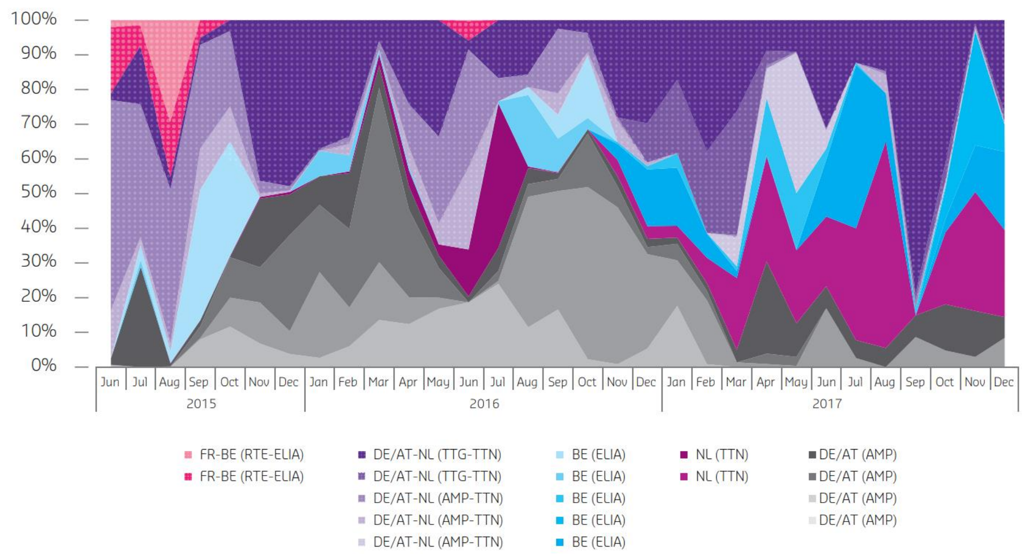
[45] It should be noted in particular that the structure of the production plants in the CWE region changed a lot between 2015 and 2017 due to the closure of conventional power plants (- 5 GW in Germany including - 2 GW nuclear, - 7 GW in France) and the rapid increase in installed wind and solar capacity. As the latter are intermittent, they tend to increase the level of uncertainty to be taken into account when calculating capacity.

[46] The *Flow Based* methodology provides for, if necessary, an artificial widening of the domain to ensure that it covers at least the long-term rights allocated (explicitly and using an NTC approach); it is interesting to note that this procedure (called "LTA inclusion") which was only activated 7% of the time after the results of the test phase, was actually activated 70% of the time during the winter of 2016-2017. Without this procedure, the *Flow Based* domain would have been empty in many cases, preventing any cross-border exchanges.

conditions (it is higher at lower temperatures); the usual practice adopted by TSOs is therefore to take into account values which differ according to the season. Now, up to the end of 2016, the German Amprion TSO, for example, kept the summer values all year on a number of critical branches which resulted in a restriction of 15 to 20% of their maximum flow in winter. This, for example in the tensed month of November 2016, led to an average reduction of more than 25% in French imports and an average increase in €3.5/MWh in the day-ahead French price[47]. However, from the end of 2016, Amprion introduced season-dependent maximum flow values on most of its critical branches which has made them significantly less limiting (*see below*).

- Capacity limitations were also applied by the TSOs through global import and export constraints (*external constraints*), or *ex-post* reductions in the capacities offered to the market. At the request of the regulators, most of the limitations which were not really justified were removed in 2017, particularly in France, or should be by the end of 2018, especially in Germany.
- Lastly, critical branches internal to the German system which had not been included during the test phase of the *Flow Based* method were added by Amprion during the summer of 2015; these critical branches proved to be especially limiting since they represented nearly 25% of the limiting critical branches between May 2015 and December 2016.

Figure 25 – Categorisation of the ten most limiting branches each month between June 2015 and December 2017



Source: Amprion, in Flow based market coupling – Development of the market and grid situation 2015 – 2017

The chart above, which represents the proportion of various critical Belgian, German, French and Dutch branches in the ten most limiting branches each month shows that the limits due to the Amprion critical branches were considerably reduced since the start of 2017, in particular through the use of maximum flow values differentiated by season.

However, the limiting branches were mostly still the internal critical branches (mainly Belgian or Dutch) rather than the cross-border branches, which poses the question on the selection of critical branches in the *Flow Based* method and the discrimination between internal flows and cross-border flows. Indeed, although the zone-based model implicitly assumes that the network internal to a zone does not cause congestion, internal elements may, in actual fact, limit cross-border exchanges. According to the current selection criterion, they may be included in the critical branches if their maximum influencing factor is greater than 5%. In certain cases, the exchanges internal to a zone may therefore cause pre-congestion to the internal critical branches in this zone[48], leaving little or no margin for cross-border

[47] Assessment carried out by the Belgian Commission for Electricity and Gas Regulation (CREG): see the study *Functioning and design of the Central West European day-ahead flow based market coupling for electricity: Impact of TSOs Discretionary Actions* of 21 December 2017.

[48] or even in another zone in the case where there are loop flows, i.e. flows which start and finish in the same zone (therefore do not vary the net position of this zone), but transit via an adjacent zone. Such loop flows appear in particular when high levels of wind farm production in northern Germany are consumed in the south after transiting via neighbouring countries. They are also generated by

exchanges which could however have significant value. As such, the development of national networks is essential to guarantee sufficient exchange capacities.

3. Improvement measures taken by regulators in the CWE region

Aware of the difficulties associated with the implementation of the *Flow Based* capacity calculation, the regulators in the CWE region together asked their respective TSOs at the beginning of 2018 for measures to improve the situation:

- In the short term, the TSOs of the CWE region must automatically offer 20% of the maximum thermal capacity of each critical branch to the market to carry out cross-border exchanges within the CWE region. This guarantee of a minimum capacity amounts to ignoring a proportion of the internal flows in the capacity calculation and dealing with the resulting congestions. The preliminary impact analysis carried out by the TSOs showed an increase in the social welfare and an increase in French imports and German exports, particularly during winter days. This measure was applied from 24 April 2018 (for the delivery day of 26 April 2018).
- In the long term, the selection rules for the critical branches will need to be reviewed by the TSOs. A study on this subject was requested by the regulators from March 2015 as part of the approval of the *Flow Based* calculation. In May 2018, the TSOs recommended, following this study, to keep the current parameters of the *Flow Based* calculation, along with the obligation to automatically offer 20% of the maximum thermal capacity for each critical branch to the market. The regulators requested additional supporting documentation; the work should continue over the coming months and be fleshed out following the introduction of the electrical border between Germany and Austria.

Indeed the TSOs in the CWE region proposed that this new electrical border between Germany and Austria be included in the *Flow Based* capacity calculation for the CWE region. The decision needs to be taken by the regulators before the 1 September 2018 to allow effective implementation from 1 October 2018. Theoretically, the introduction of this border and the allocation of capacity associated with the *Flow Based* method should make it possible to manage exchanges between the two countries more efficiently by limiting their amount based on a capacity calculation, while they are treated nowadays as internal flows and are not therefore limited, generating significant loop flows which limit the possibilities of exchanges with neighbouring countries. However, the implementation of a long-term 4.9 GW capacity allocation over this border in both directions is questionable: since the *Flow Based* domain can be changed depending on the volumes allocated in long-term timeframes, such an amount could have a significant impact on the efficiency of congestion management at this border.

The CRE remains committed to improving the *Flow Based* capacity calculation in cooperation with its fellow regulators. It will ensure that the coming changes to the calculation method form part of the roadmap which had been defined during its approval in March 2015 (see deliberation of the CRE of 26 March 2015 approving flow based market coupling and the method of calculating the associated capacities).

Moreover, work is under way in the "Core" region (see figure 10) to extend the *Flow Based* capacity calculation method to all the countries on the continental plate.

exchanges between Germany and Austria which at the moment belong to the same bidding zone.

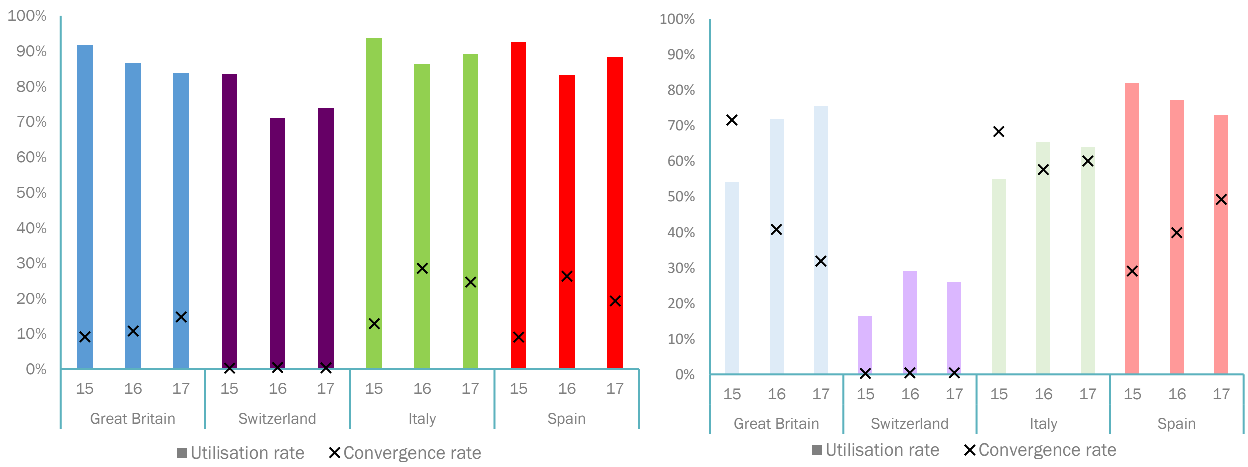
2.2.3 French interconnections are managed effectively

At borders where market coupling was implemented (i.e. all French borders except that with Switzerland), the commercial flows are systematically orientated from the country where the prices are the highest to those where the price is lowest. This automatically established a link between the price spreads in the day-ahead market and flows at the borders.

The combined analysis of the utilisation rate[49] of each interconnection (ratio between the flow and the commercial capacity) and the convergence rate of the prices at each border shows how the interconnections are used. An interconnection is managed efficiently if it is used while there is a price spread between the two countries it connects (this is the case with market coupling). A low saturation of an interconnection implies a significant convergence rate between the two market places.

The French interconnections show quite high utilisation rates, above all on export although the situations differ from one border to another (see figure 26 below[50]).

Figure 26 Utilisation rate of interconnections and price convergences 2015 to 2017 (excluding CWE), for export (left) and import (right)



Source: RTE, CRE analysis

The utilisation rate of the interconnection with Great Britain on export remains very high (greater than 80%), but has been decreasing since 2015. This decrease was accompanied by an increase in the convergence rate (from 9% to 15%) and a decrease in export price spreads (from €17.8/MWh to €11.9/MWh). On the other hand, an increase in the utilisation rate of the interconnection on import was observed since 2015 along with a decrease in the convergence rate and an increase in the price spread on import (from €2.6/MWh to €12.5/MWh between 2015 and 2017), associated with the unavailability of French nuclear power plants during the winter of 2016/2017 which weighed on the French spot prices.

The France/Switzerland interconnection is marked by a lower utilisation rate than at the other borders (62% on export and 63% on import in 2017), due to the absence of day-ahead market coupling. The change in the utilisation rate of the interconnection nevertheless reflects the average price spreads: price spread on export reduced since 2015 (going from €6.2/MWh to €4.5/MWh), while the price spread on import reached a peak in 2016 (€4.3/MWh). Although the price spreads between France and Switzerland are relatively low, the convergence rate remains very low (less than 0.5 %) due to the absence of day-ahead market coupling at this border. The persistence of long-term contracts (see below) and the absence of market coupling have also lead to a usage of the interconnection in the opposite direction to the price spreads[51] (35% of the time in 2017).

The price spread between France and the Italy North zone[52], traditionally very high (€14.4/MWh in absolute terms in 2015), was considerably reduced in 2016 (€7.4/MWh), before rising slightly again in 2017 (€9.8/MWh). The French prices were in effect close to the Italian prices during the periods of tension observed over recent winters. The interconnection remains extensively used (at more than 85% on export). The exchange capacities with Italy will increase with the entry into service of the Savoie-Piémont interconnection currently under construction.

49 The absence of a commercial capacity calculation for each border on a daily basis in the CWE region prevents the utilisation rates of the interconnections for this region from being analysed (see Focus 2).
50 Convergence rate calculated at 0.01 €/MWh for Italy, Great Britain and Switzerland and corrected for the cost of losses for Great Britain.
51 Usage in the opposite direction to the price spreads refers to when the interconnection is used on import while the French prices are lower than the Swiss prices and *vice versa*.
52 Italy is divided into six bidding zones. France is interconnected with the "North Italy" zone

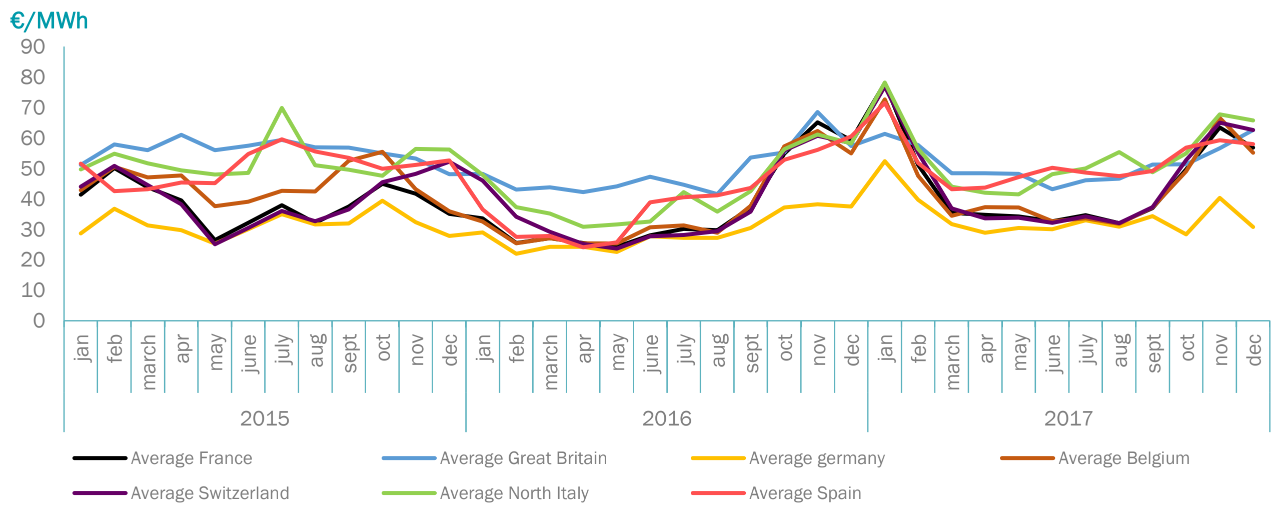
The entry into service of the Baixas Santa-Llogaia interconnection, in October 2015, has enabled the price convergence rates between France and Spain to increase significantly, going from 13% in 2015 to 25% in 2017[53]. The price spreads also decreased, going in absolute terms from €14.8/MWh to €10.2/MWh over the same period. The French/Spain border is the only French border characterised by a high utilisation rate on both import and export, even if it has reduced with the increase in capacities. This is explained by the high variability in the price spreads between France and Spain in winter, which leads to flow reversals with French imports over the 07:00-14:00 and 18:00-20:00 time slots due to the time difference between the peak consumption periods between the two countries. The interconnection however remains almost exclusively used for export during summer (see border file in the annexes).

Evolution of spot prices

2016 was marked by a lowering in European spot prices during the first half-year associated with low fuel prices and an increase in renewable sources of electricity, particularly in Germany. A significant increase in prices then took place between October 2016 and February 2017 due to a combination of low availability of French, Swiss and Belgian nuclear power plants, an increase in fuel costs and the cold snap, which increased electricity consumption. This situation thus had a major impact on prices, which reached €78/MWh on average in January 2017 in France. The spot prices then decreased again between March and September 2017 (although remaining higher than at the same period in 2016 due to lower hydraulic production caused by the drought and higher fuel prices), before reaching a peak in November. During periods of peak prices in winter, west-european prices had a tendency to converge with the exception of German prices, which tended to remain lower.

The spot prices also reached historically high and totally extraordinary prices over the last two years in Great Britain (€1,174/MWh in September 2016), in France (€874/MWh and €696/MWh in November 2016) and in Belgium (€696/MWh in November 2016), reflecting occasional periods of tension on the European electrical system. Moreover, the frequency with which negative prices appeared increased in Germany (145 hours in 2017 as against 64 in 2014). The occasional emergence of negative prices was also observed in Switzerland (24 hours in 2016), in Belgium (6 hours in 2016) and in France (2 hours in May 2016, and 4 hours in 2017, in April and in August). These negative prices should be monitored carefully.

Figure 27– Spot prices (monthly average, 2015-2017)



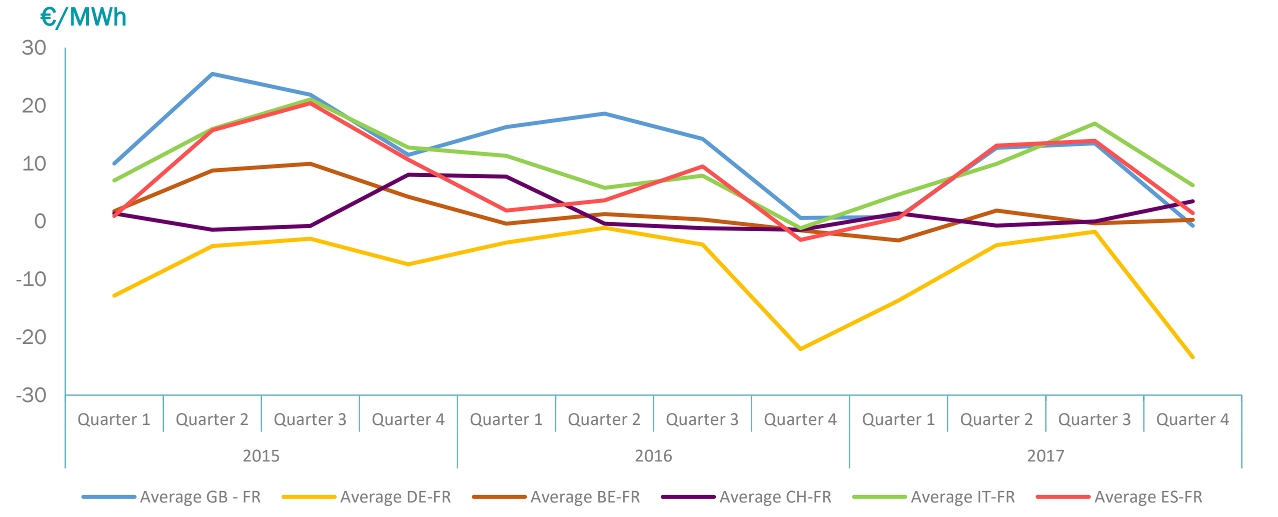
Source: RTE, CRE analysis

In 2016 and 2017, the French spot prices remained on average lower than the British, Swiss, Italian and Spanish prices, but higher than the German prices. It should be noted on the other hand that the Belgian prices, higher than the French prices in 2015, became, averaged over the year, very slightly lower over the last two years (by €0.1/MWh in 2016 and €0.4/MWh in 2017).

The spot price spreads for France lowered with all neighbouring bidding zones, except for Germany since 2015 (the price spread with France went in absolute terms from €7.5/MWh in 2015 to €10.9/MWh in 2017). The highest price spread remains the one with Great Britain which went in absolute terms from €18/MWh to €12/MWh over the same period.

[53] The market coupling implemented in 2014 had already made it possible to increase the convergence rate which was less than 6% before this date.

Figure 28– Average spot price spreads (2015-2017)



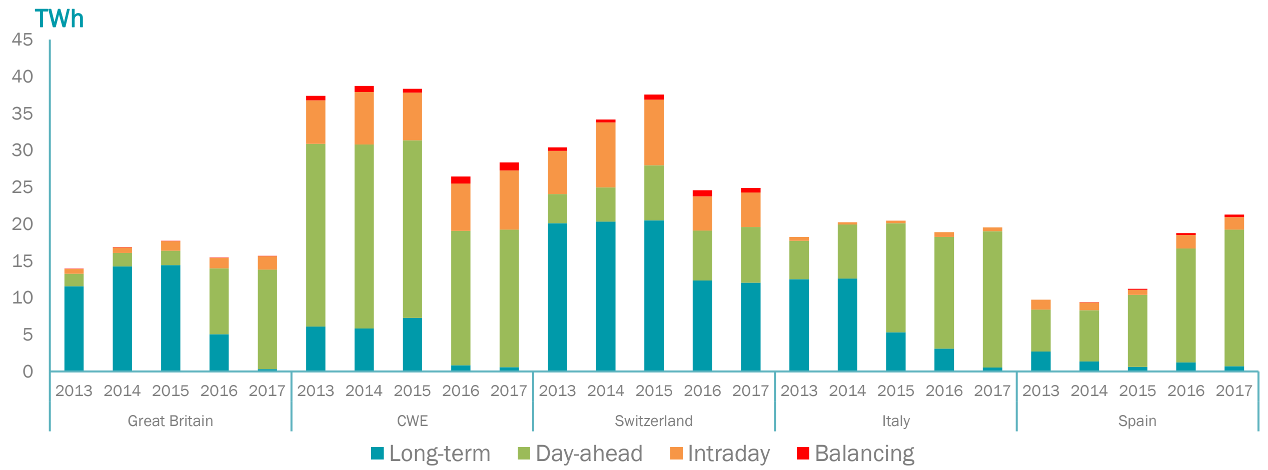
Source: RTE, CRE analysis

2.2.4 Distribution of nominations by timeframe and border

The decrease of long-term nominations and the increase of day-ahead nominations over the five borders where the day-ahead market coupling was implemented (i.e. all except Switzerland), already observed in 2015, strengthened in 2016 and 2017. The long-term thus represents no more than 2% of the nominations at the France/Great Britain interconnection, like those with the CWE region, and 3% of those at the interconnections with Spain and Italy. Indeed, with market coupling, long-term products are being used more and more as coverage products (see Focus 1). Day-ahead exchanges now represent about 82% of nominations at coupled borders.

The proportion of long-term nominations at the France/Switzerland border has also lowered slightly, but still represents 48% of the total nominations, due to the persistence of the long-term energy purchase contracts at this border.

Figure 29 – Distribution of nominations by timeframe

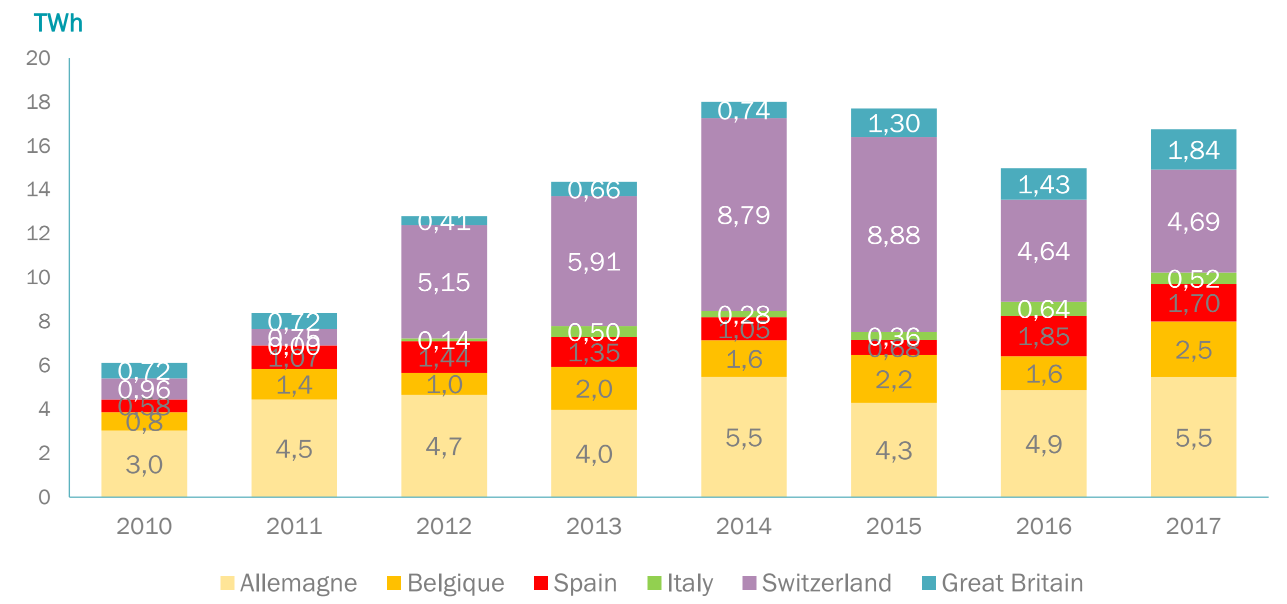


Source: RTE, CRE analysis

The French intraday timeframe, although marginal in comparison with the day-ahead one, is on the increase (+3% in volume between 2016 and 2017). Its dynamism comes in large part from exchanges at the interconnections, which can represent more than two thirds of the volumes exchanged at this timeframe. The overall increase in intraday nominations (considering all borders) that started from 2010 continued in 2016 and 2017 in spite of a net decrease in energy exchanged at this timeframe at the Swiss border. Intraday exchanges with Switzerland however remain relatively high relative to the other borders due to the absence of day-ahead market coupling on this interconnection and of the pre-eminence of long-term contracts: the intraday timeframe is therefore more used by stakeholders who wish to purchase energy and interconnection capacities over the short term, in particular in the

Switzerland to France direction. Intraday exchanges are also numerous at the German border, the German market being very liquid at this timeframe. In 2017, the volumes exchanged on the German continuous intraday market were indeed high, at 39 TWh (+15% compared with 2016). Lastly, an increase in intraday exchanges at the Spanish and British borders since 2015 should be noted.

Figure 30 – Volume of intraday cross-border exchanges



Source: RTE, CRE analysis

2.2.5 Evolution of the congestion rent

The congestion rent corresponds to the overall revenues generated by the allocation of interconnection capacities at the various timeframes (revenues from long-term auctions, day-ahead implicit allocation[54] and intraday allocation). These revenues are used to guarantee the actual availability of the allocated capacities (firmness of the products), increasing interconnection capacities through investments and by deducting the usage tariff of the transmission system.

The level of the congestion rent at each border reflects the volumes exchanged at the interconnections and the price spreads between the interconnected countries. After a particularly marked increase in 2015, the congestion rent went back down to levels equivalent to those of 2013-2014, ending up at €390M in 2017 (see figure 31 below).

This reduction was particularly marked at the borders with Italy and Great Britain where the congestion rent went respectively from €104M to €87M and from €194M to €95M between 2015 and 2017.

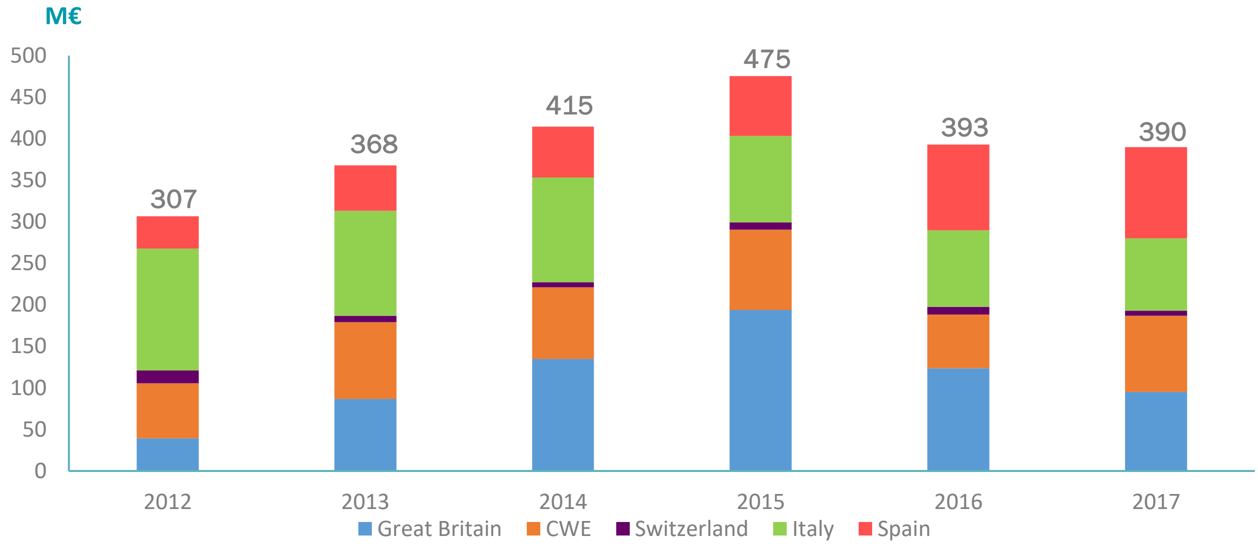
The congestion rent coming from the France/Spain border increased since 2015 (+€38M) in spite of a lowering in the price spread between the two countries: this was due to the increase in exchanges observed following the commissioning of the Baixas Santa-Llogaia interconnection in 2015.

Lastly, in spite of a lowering in 2016, the congestion rent with the CWE region remained stable relative to the other years (€92M in 2017): the distribution of the congestion rent between the various French borders (excluding Switzerland) was thus balanced in 2017, unlike in previous years.

The low level of the congestion rent at the France/Switzerland interconnection (€6M in 2017) is explained by the priority of access to the interconnection capacity and free access granted to the historic contracts.

[54] Explicit allocation only at the Swiss border

Figure 31 – Congestion rent at French interconnections (2012-2016)



Source: RTE, CRE analysis

Chapter 3– Operating rules for gas interconnections at French borders: evolutions since 2016

2.3.1 Impact of the revision of the CAM network code on the allocation rules for interconnection capacities

The allocation rules for transmission capacities at gas interconnection points between member states and/or market zones located in the territories of member states have been organised at European level since the adoption on 14 October 2013 of Commission Regulation (EU) no. 984/2013 establishing a Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems, annulled and replaced in 2017 by regulation (EU) 2017/459 (CAM network code, see 1.2.4.2). In France, this relates to interconnections with Belgium (Virtualys and Taisnières B), Germany (Obergailbach) and Spain (Pirineos), along with the North-South link up to 1 November 2018. This regulation frames the capacity products proposed in terms of characteristics and volumes along with the way in which the auctions are organised.

These interconnection capacities are allocated on the Prisma platform, created in 2013. During the annual auctions, capacities may be offered as yearly products up to 15 years ahead. To avoid an excessive level of long-term subscriptions acting as a barrier to entry of new actors, a quota of at least 10% is reserved to annual products over a horizon of five years. Furthermore, at least 10% of the available firm annual capacity must be dedicated to short-term products, i.e. to auctions of quarterly capacities. Therefore, from the 6th to the 15th year, subscriptions cannot exceed 80% of the firm capacities. At the end of each auction capacities, remaining unsold are re-offered in shorter-term auctions.

Adopted in 2013, these rules underwent amendments in 2017 regarding the allocation of incremental capacities and the auction calendar for annual and quarterly products. Firm, interruptible and backhaul capacities are from now on offered according to the following calendar:

- Annual products: during auctions on the first Monday of July (from 2018).
- Quarterly products: during auctions on the first Mondays of August, November, February and May (all remaining auctions for the gas year are offered at each new auction).
- Monthly products, the third Monday of each month.
- Day-ahead products, the previous day before 16:30.
- Intraday products, every hour.

The entry into force of the CAM network code led to changes in the allocation rules for interruptible capacities from 1 October 2017[55]. Previously, interruptible capacities were offered if at least 98% of the corresponding firm capacities had been allocated (95% for the North-South link). For capacities with a duration of greater than one day, the sale of interruptible capacities is from now on only possible if the corresponding standard product for firm capacities was sold with an auction bonus, is exhausted or has not been proposed due to lack of availability.

2.3.2 The new allocation rules for capacities at Dunkirk come close to the provisions of the CAM network code

In order to apply consistent rules to each French interconnection point, the CRE took the decision to apply some of the rules of the CAM network code to the Dunkirk interconnection, although its application is optional at interconnection points with non-EU Countries. GRTgaz was therefore asked in 2013[56] to study the possible implementation of these rules at this interconnection point. The new allocation mechanism proposed by GRTgaz was approved by the CRE in its deliberations of the 27 July 2017[57] and 8 March 2018[58]. It came into force on 1st June 2018.

The new allocation rules are similar to those set by the CAM network code regarding the types of product (annual products with long notice periods are now offered independently, and the rolling annual products have been replaced by quarterly products matched with a tariff multiplier). Quotas of capacities are set aside for short term bookings in order to enable new entrants to access Norwegian gas (only 80% of the firm capacity and 80% of the annual interruptible capacity can be allocated over a longer period than one year).

55 http://www.cre.fr/documents/deliberations/decision/commercialisation-des-capacites2
56 https://www.cre.fr/en/Documents/Deliberations/Decision/european-network-code-gas
57 https://www.cre.fr/en/Documents/Deliberations/Decision/capacity-selling-arrangements
58 http://www.cre.fr/documents/deliberations/decision/pir-dunkerque2

Unlike the interconnection points where the CAM network code applies ("CAM points"), the allocation of capacities is not carried out through auctions with a reserve price, but through *Open Subscription Period* for annual, quarterly and monthly products. Unsold monthly products and day-ahead products are offered on a "first come, first served" basis. The interconnection capacities are offered before those of the CAM points (a month earlier with regard to annual and quarterly capacities). Lastly, upstream capacities are offered independently by the upstream transmission system (Gassco).

2.3.3 The CRE has approved allocation rules for new entry capacities to Oltingue

The CRE approved in 2014 the development of a 100 GWh/d entry capacity in France at the Oltingue network interconnection point (IP)[59], in order to allow an additional procurement source to access the French market. The core network was not reinforced to limit the amount of investments, in compliance with the market requests. This entry point will therefore use the existing network core structures, initially sized to guarantee firm capacities only at the Taisnières H and Obergailbach IPs. The entry capacities offered at Oltingue cannot be considered as firm as those at the other interconnection points.

The allocation rules for these capacities were approved by the CRE in its deliberation of 27 July 2017[60]: the firm capacities for the Oltingue entry point will be offered after those of Taisnières H and Obergailbach. The amount of capacity actually offered will be calculated taking into account the firm capacities already booked at these two points. Interruptible capacities will only be offered as quarterly and monthly products once all the firm capacities for these timeframes have been sold. Lastly, if security of supply dictates, GRTgaz could increase the firm offered capacities at Taisnières H and Obergailbach to the detriment of Oltingue.

These rules will make possible to offer the entry capacities at Oltingue while preserving the already-existing firm capacities at the Taisnières H and Obergailbach IPs and ensuring security of supply for France.

2.3.4 The congestion management rules (CMP annex) are now applied at all French borders

The decision of the European Commission of 24 August 2012 amending annex I of Regulation (EC) no. 715/2009, dealing with congestion management procedures (CMP – *Congestion Management Procedures* - annex) introduces a number of mechanisms with the aim of preventing contractual congestion situations at interconnection points (when users cannot contractually book transmission capacities while they are actually physically available).

The CRE approved in 2013[61] the terms and conditions for implementing this text at all French borders, and asked Teréga to continue their negotiations with Enagás to implement the oversubscription and buy-back scheme at interconnection points with Spain. Indeed, the increase in technical capacities at the Larrau point on 1st April 2013 did not provide enough time to take stock of the behaviour of the stakeholders in order to define suitable rules.

Teréga with Enagás has therefore produced and submitted to CRE in September 2017 a proposal to implement an oversubscription and buy-back scheme at the Pirineos virtual interconnection point. This mechanism allows offering additional capacity (relative to the technical capacities) on a daily basis. They can be bought back by the TSOs if the nominations at the border are eventually too high. The CRE approved the proposal from the TSOs on 26 October 2017[62]. It was implemented since November 2017.

2.3.5 Entry into service of the virtual interconnection point with Belgium (Virtualys)

Since 2015 and the commissioning of the "Flanders" pipeline, firm and backhaul capacities can be offered with Belgium (entry at the Taisnières H IP and exit at the Alveringem IP). In its deliberation of 19 March 2015, the CRE requested GRTgaz to coordinate with the Belgian TSO Fluxys the creation of a virtual IP between France and Belgium. Indeed, when several interconnection points connect two entry-exit systems, the CAM network code provides them to be integrated together within Virtual Interconnection Points (VIP) in order to simplify the capacity offer with a single service in each direction.

Following the proposal from GRTgaz, the CRE approved, in its deliberation of 2 February 2017[63], the creation of the "Virtualys" VIP between France and Belgium, which brings together the Taisnières H and Alveringem IPs, effective from 1 December 2017. The capacity volumes offered (including backhaul capacities) and the prices in force beforehand have not been changed.

[59] to commissioned on 1st June 2018
[60] https://www.cre.fr/en/Documents/Deliberations/Decision/capacity-selling-arrangements
[61] https://www.cre.fr/en/Documents/Deliberations/Decision/congestion-management-procedures
[62] http://www.cre.fr/documents/deliberations/decision/interconnexion-pirineos
[63] https://www.cre.fr/en/Documents/Deliberations/Decision/creation-of-a-virtual-interconnection-point-between-france-and-belgium

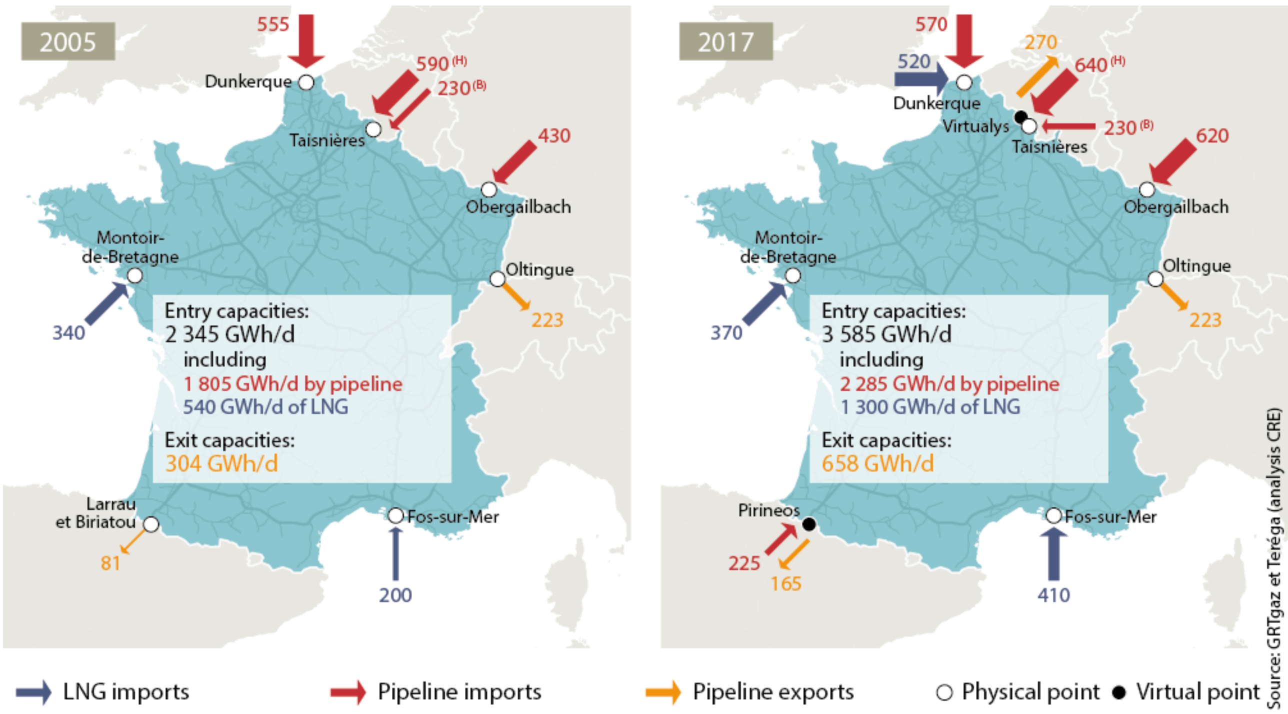
Chapter 4– Overview of the use of gas interconnections

2.4.1 The interconnection capacities bring flexibility, diversity and security of supply to France

2.4.1.1 The interconnection capacities of France have increased by more than 50% since 2005

France has terrestrial interconnection points with Belgium, Germany, Switzerland and Spain and is directly connected *via* the Franpipe gas pipeline to the Norwegian production fields located in the North Sea. France also has four liquefied natural gas terminals (Fos-Tonkin, Fos-Cavaou, Montoir de Bretagne and Dunkirk LNG).

Figure 32 – Map of interconnections and LNG entry points in France in 2005 and 2017



At the end of 2017, and following the commissioning of the liquefied natural gas terminal at Dunkirk, France had about 3,600 GWh/d of import capacity, including 1,300 GWh/d of LNG. 100 GWh/d of additional entry capacity was brought into service in June 2018 at Oltingue, the interconnection point with Switzerland. The exit capacities to neighbouring systems are 660 GWh/d.

France also possesses storage capacities of about 135 TWh, i.e. the equivalent of 100 days of average consumption, which makes the French gas system one of the most robust in Europe with a wide diversity of sources of supply. The new regulation for storage infrastructures put in place by the CRE (deliberations of 22 March 2018[64] and 27 March 2018[65]) encourages stakeholders to subscribe more to storage capacities and also strengthens the security of supply of France.

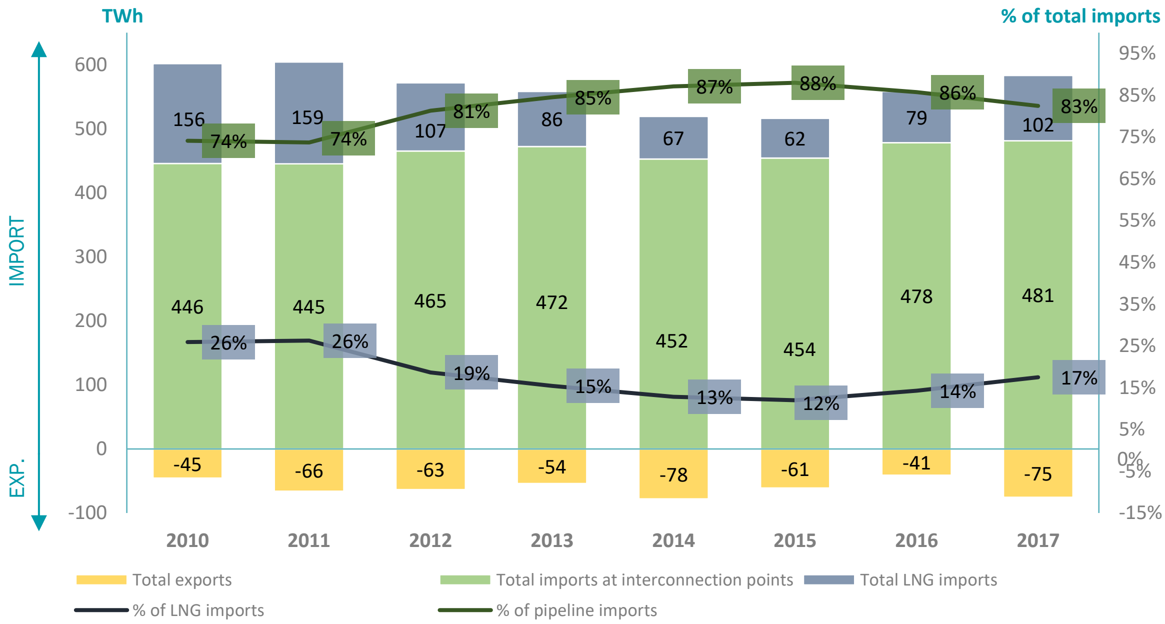
Note that part of the firm non-subscribed capacity[66] on the German side of the Obergailbach IP has been reallocated by the German TSOs to other points on their system since 2012, thus resulting in an asymmetry between the firm capacities offered either side of the interconnection (about 40 GWh/d): the CRE regrets this situation and will ensure that the choice made by the German TSOs does not affect the security of supply of France.

[64] https://www.cre.fr/en/Documents/Deliberations/Decision/storage-tariff-term and https://www.cre.fr/en/Documents/Deliberations/Decision/underground-natural-gas-storage-infrastructures
[65] http://www.cre.fr/documents/deliberations/decision/terme-tarifaire-stockage-1er-avril-2018
[66] Stakeholders can withdraw from their long-term subscriptions contracts when the transmission prices increase more than inflation according to German law.

2.4.1.2 Interconnections contribute to the French diversified gas supply

France's gas supply mainly transits *via* pipeline (83% in 2017). At 102 TWh in 2017, LNG deliveries remain at a low level although they had increased since 2016. After having been almost halved between 2011 and 2015, they remain much lower than the level reached in 2011 (159 TWh). The Fukushima crisis had indeed led to the re-routing of a large amount of deliveries to the Asiatic markets which had become more remunerative (see figure 33 below). The lowering of demand in the Asiatic markets allowed the LNG prices to return to levels comparable with the ones of gas imported by pipeline from 2015 on, and therefore to redirect certain volumes to Europe. With regard to re-exports, France attained, in 2017, a level near to its historic maximum observed in 2014 after the entry into service of transmission capacities to Spain at Larrau.

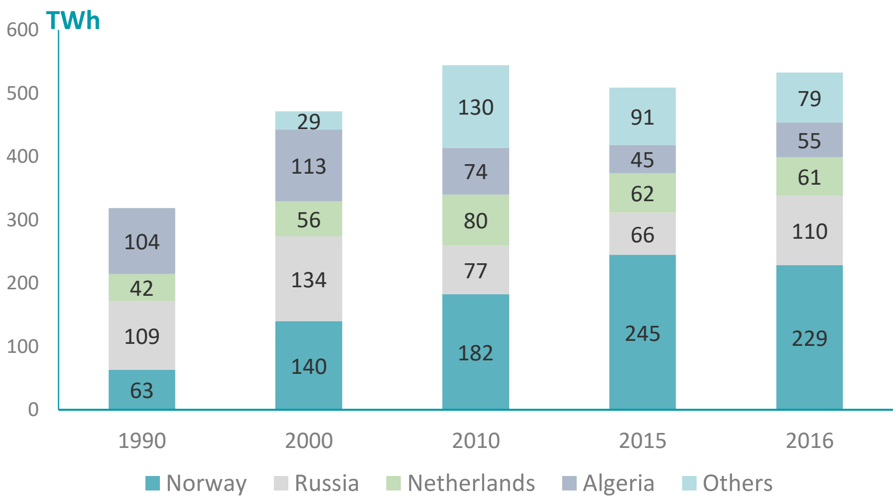
Figure 33 – Gas imports and exports in France (2010-2017)



Sources: GRTgaz and Teréga, CRE analysis

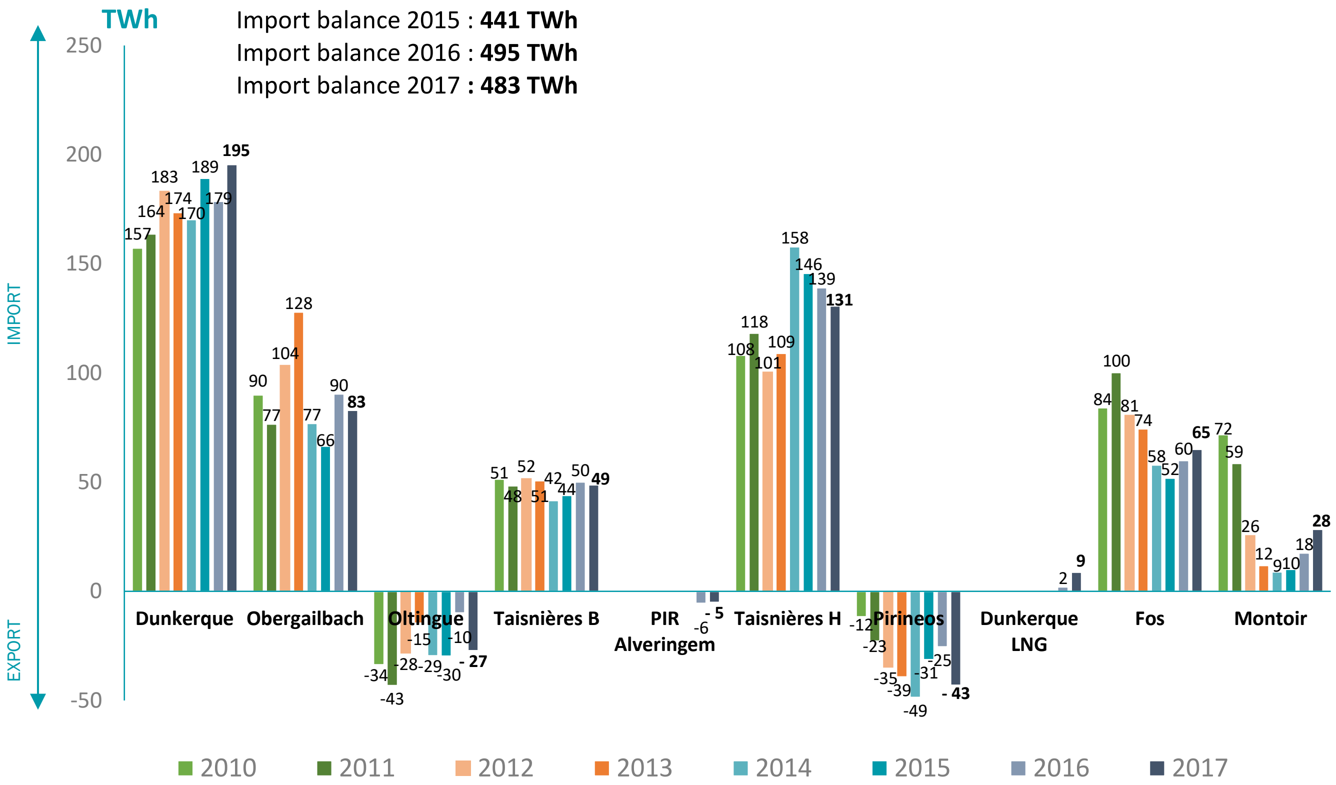
France has four main sources of gas imports (Norway, Russia, the Netherlands and Algeria), and gets supplies also from other countries in the form of LNG (Algeria, Nigeria and Qatar, mainly) and on the European wholesale markets. Norway is France's main supplier (43% of imports in 2016) before Russia (21%), from which the proportion has risen after having reached a minimum of 13% in 2015 (also see below).

Figure 34 – French imports of natural gas, by source



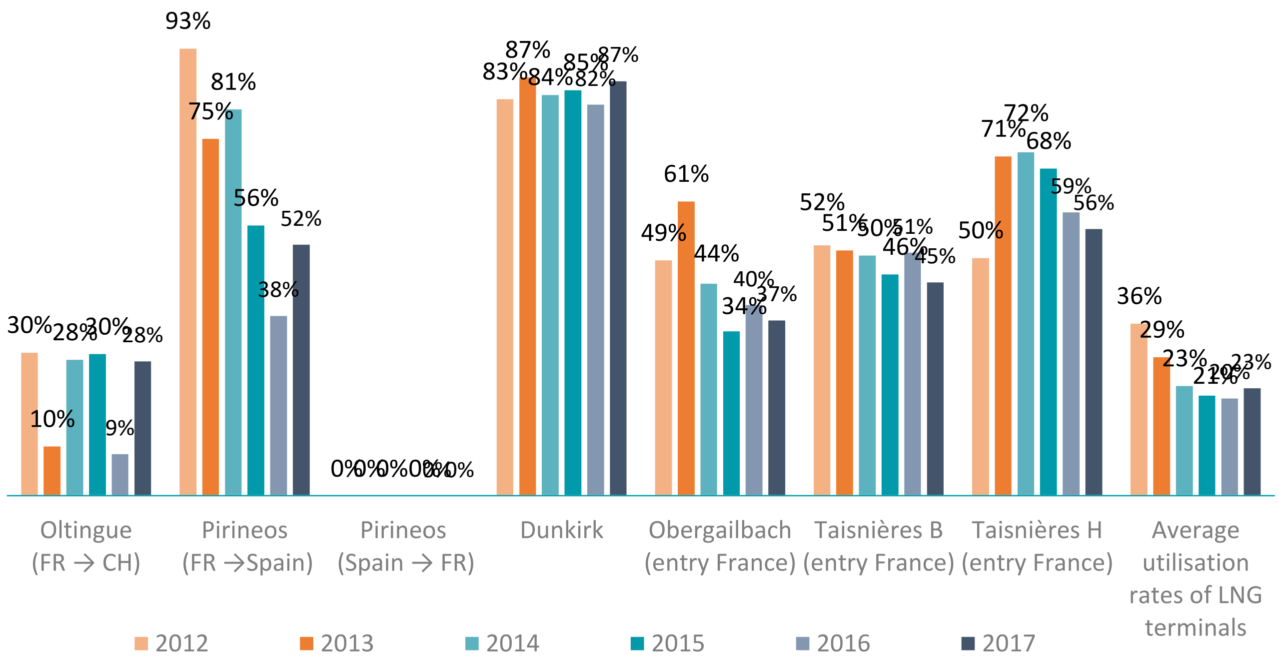
Source: SDES

Figure 35 – Evolution of balance of import/export at the French interconnection points and LNG terminals (2010-2017)



Sources: GRTgaz and Teréga, CRE analysis

Figure 36 – Average utilisation rate of French interconnections and LNG terminals (physical flows as a percentage of the effective technical capacity)



Sources: GRTgaz and Teréga, CRE analysis

Regarding flows by interconnection point, the volumes exchanged are the largest at the Dunkirk IP. They reached 195 TWh in 2017, i.e. 33% of the total of French imports. A proportion of these volumes is re-exported to Spain and Italy.

France has three interconnection points with Belgium. Taisnières B imports gas with low calorific value from the Groningen field (Netherlands), while Taisnières H is the entry point for gas with high calorific value from the production fields in the North Sea which transit via Belgium. Lastly, the Alveringem point is used to ship non-odourised gas from the Dunkirk LNG terminal and from the Franpipe. With 131 TWh imported in 2017, Taisnières H is the second entry point to the French system. In total, imports from Belgium are comparable with those at the Dunkirk IP.

The interconnection with Germany at Obergailbach provides access to gas from Russia. After a net lowering of imports in 2014 and 2015 (compensated by an increase in flows from Taisnières H), the entry flows at Obergailbach rose from 2016 (90 TWh), then reached 83 TWh in 2017, i.e. 14% of the total imports, but remaining far from the historic maxima.

France has two physical interconnection points with Spain, grouped together in the "Pirineos" virtual interconnection point. Able to operate in both directions, these gas pipelines are almost exclusively used in the France-Spain direction: a physical flow in the Spain-France direction was observed for the first time on 28 February 2018. France is thus a transit country for Spain and more generally for the Iberian peninsula for which the rest of the supply is based on LNG and Algerian gas. In 2017, Spain imported 43 TWh from France: this level, the highest since 2014, is explained in particular by the increase in the production of electricity from Spanish gas-fired power stations in a context of low availability of hydraulic production facilities in this country.

The Oltingue IP is used to export gas to Italy through Switzerland: 27 TWh were exported by France in 2017.

Lastly, France imported a little more than 100 TWh through its LNG terminals in 2017, i.e. more than 15% of its imports.

The variability of the flows at each French interconnection point year on year shows the flexibility they bring, which is reflected in their utilisation rate (see Figure 36). These interconnections make it possible to arbitrate between the various French supply sources depending on their relative competitiveness.

2.4.1.3 A contrasted situation between the two French zones

There is a marked contrast in the situations of the two French market places. The *PEG Nord* benefits from its proximity to the rest of the market places of the North-West European plate, which are particularly liquid (in particular TTF in the Netherlands and the NBP in Great Britain), while the Trading Region South (TRS) is turned towards the South-West Europe plate where supply depends greatly on LNG. With its four terrestrial interconnection points and its two LNG terminals, the *PEG Nord*, which represents about two-thirds of French consumption, thus has a greater variety of supply sources than the TRS.

The differences between the market places in France result in spreads in wholesale prices, which are sometimes significant. The difference in average price between the *PEG Nord* zone and the TRS zone, which was reduced in 2015 (€0.5/MWh), widened in 2016 and 2017, establishing themselves respectively at €1.3/MWh and €1.9 €/MWh. Differences were more especially observed in August and September due to maintenance operations on the North-South link as well as in December 2016 and January 2017 (with a maximum of €19.1/MWh on 26 and 27 January) due to an increase in consumption from the gas power stations associated with low deliveries of LNG at Fos and in Spain (see below). A new period of price decorrelation occurred at the end of 2017 due to tension on the LNG supply in the TRS zone.

The commissioning of the Gascogne-Midi and Val de Saône gas pipelines will remove the existing congestion on the West-East and North-South axes respectively. Their implementation (for an investment cost of €823M), associated with the zones merger to be carried out in November 2018, will enable to improve the level of diversification of sources of supply for all French consumers and to put an end to the recurring wholesale price spreads between the north and south of the country.

Evolution of spot prices

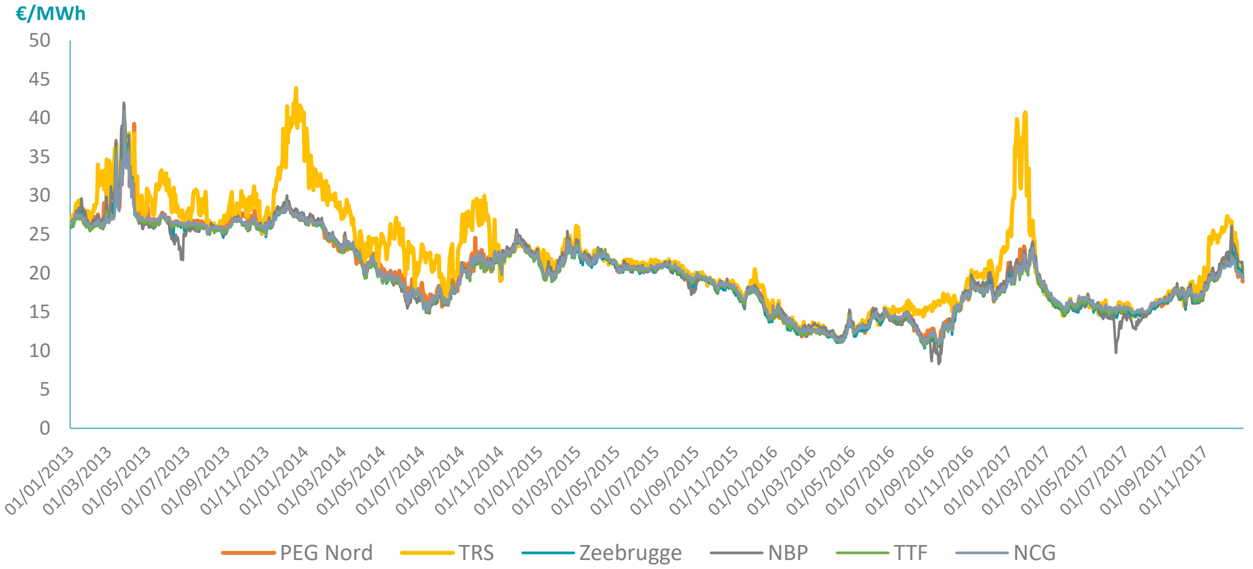
European spot prices have continued the decrease initiated in 2015 up to September 2016 (reaching a low point in France on 13 September 2016, with a price of €10.6/MWh in the *PEG Nord* zone), in a context of decreasing raw materials prices.

The winter of 2016/2017 was, however, characterised by a major increase in spot prices (see figure 37 below), with an average price of €21.1/MWh in the *PEG Nord* zone and €34.1/MWh in the TRS zone in January 2017. The winter of 2016/2017 was indeed marked by an increase in raw materials prices, an increase in consumption by gas-fired power plants (see 2.2.2.2) and tension on the LNG market.

The spot prices then lowered between March and September 2017, without however returning to 2016 levels, before rising again in the last quarter of 2017 in a context of increasing demand for gas in Europe and tension on the international LNG market (high demand in Asia).

The prices in the *PEG Nord* zone are, generally speaking, strongly correlated with those of the rest of the North-West Europe plate, with an average price spread of €0.3/MWh in 2016, and €0.1/MWh in 2017 with the TTF.

Figure 37 – Gas spot prices in Europe (2013-2017)



Source: Heren, CRE analysis

2.4.2 Capacity subscriptions at interconnections

2.4.2.1 Auction results at interconnections

The shippers' demand for capacity has been low over recent years. Few auctions have resulted in the effective booking of capacities, particularly with regard to long-term products. The annual auctions which took place on the Prisma platform in March 2016 and March 2017 for French interconnections gave results comparable with those of previous years (5% of auctions resulted in capacity booking in 2016, 7% in 2017). The levels of capacity bookings observed during the monthly and quarterly auctions have also been very low.

Figure 38 – Percentage of annual auctions that resulted in capacity booking (as a percentage of auctions launched on PRISMA)

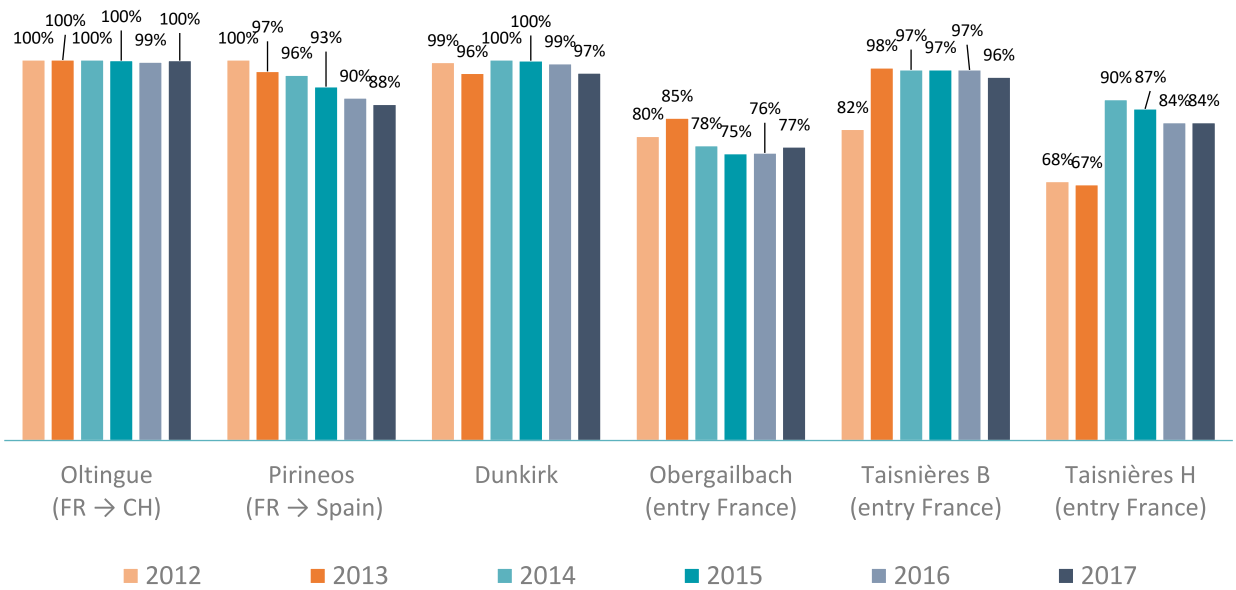
	March 2015 annual auctions	March 2016 annual auctions	March 2017 annual auctions
Obergailbach	5%	4%	10%
Taisnières H	14%	0%	5%
Taisnières B	0%	0%	0%
Oltingue	0%	0%	0%
Pirineos	3%	7%	7%

Source: PRISMA, CRE analysis

2.4.2.2 The subscription rates at French interconnections remain very high

The low level in demand shown in the auctions is mainly explained by the level of capacities already subscribed over the long-term, which is very high (between 77 % and 100 % in 2017), mainly at Dunkirk and Taisnières B. Excluding Dunkirk, whose capacities are almost entirely used, the subscription rates of the interconnections are much higher than the utilisation rates. This situation arises from the historic way interconnections were developed, backed by import contracts or long-term subscriptions, a model which made it possible to finance the capacities created.

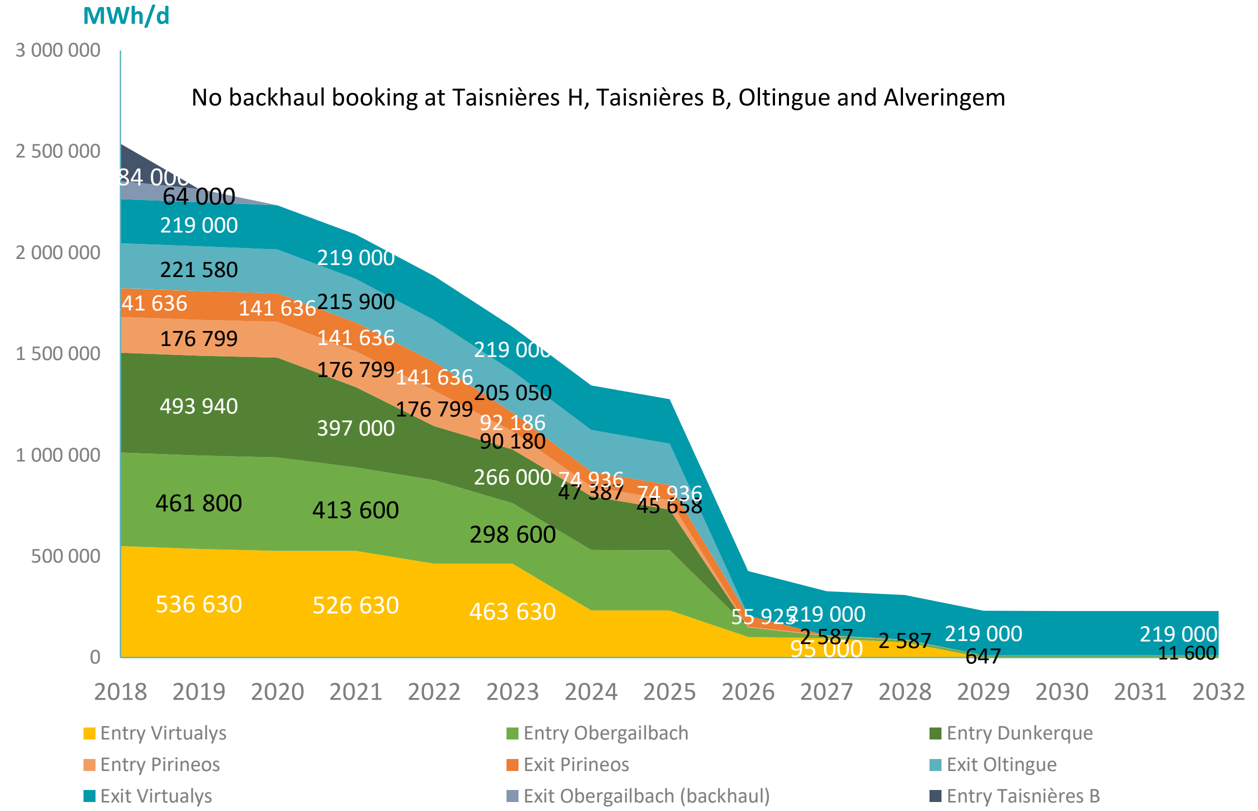
Figure 39 – Firm capacity bookings at French interconnections (as a percentage of the firm capacities offered)



Sources: GRTgaz and Teréga, CRE analysis

The next ten years will however be marked by the arrival of most long-term commitments at French interconnections at their expiry dates, since only two contracts will remain after 2029 (see figure 40 below).

Figure 40 – Long-term capacity bookings at the French interconnections (2018-2032)



Sources: GRTgaz and Teréga, CRE analysis

Up to now, the shippers had protected their supply routes through these long-term commitments, which brought a certain degree of stability to the French gas supply system. European integration nowadays leads them to turn to shorter timeframes for their supply. Occurring in a context of decreasing gas consumption observed in France since the start of the 2010's, this evolution could lead to significant changes, particularly with regard to pricing structures and market volatility.

PART 3. DEVELOPMENT OF INTERCONNECTION CAPACITIES

Chapter 1– Infrastructure package and related European works

The development of trans-European energy networks has been part of the objectives of the European Union since 1992 through the Maastricht Treaty, providing for the identification of projects of common interest in order to ensure the development of such networks.

The third energy package (particularly regulations (EC) no. 714/2009[67] and (EC) no. 715/2009[68]), then regulation (EU) no. 347/2013[69] of the European Parliament and Council on guidelines for trans-European energy infrastructure, (known as the "infrastructure package") completed the regulatory framework intended to promote the integration of electric and gas systems in the European Union. To ensure the consistency and relevance of investment decisions for energy infrastructures, the selection of Projects of Common Interest comes under a more general process of the production of ten-year network development plans by the TSOs, who use long-term scenarios tracing prospects for change in the production and consumption of energy in Europe.

3.1.1 Elaboration of network development tools on a Europe-wide scale

The third energy package has established the principle of drawing up, every two years, TYNDPs or Ten-Year Network Development Plans by ENTSOE (European Network of Transmission System Operators for Electricity) and ENTSOG (European Network of Transmission System Operators for Gas). Although these plans are non-binding, the infrastructure package has turned them into decision-making tools, since only projects included in the most recent TYNDPs can claim the status of Project of Common Interest (PCI, see 3.1.2). Moreover, the cost-benefit analysis methodologies for interconnection projects defined by ENTSOE and ENTSOG are extensively used for PCI selection. Furthermore, ten-year national development plans must be consistent with the TYNDP.

3.1.1.1 Common scenarios for gas and electricity at European level, but too little diversified

TYNDPs are based on models produced by ENTSOE and ENTSOG and which are intended to simulate the operation of the European market with or without interconnection projects. These simulations must make it possible to assess the economic advantage for the community to develop new cross-border investments: the structure and the assumptions which characterise these models therefore carry considerable stakes. Long-term scenarios are an essential parameter: they must put forward a representation of the energy future for Europe using a number of assumptions, including the concrete implementation of energy policy guidelines.

It is also important that the long-term views put forward by ENTSOE and ENTSOG are consistent. Firm progress has been made in this area since, for the first time, the ENTSOE and ENTSOG produced common scenarios, which will serve as a basis for their development plans on their respective networks. Published in March 2018, these plans include an analysis for the period to 2020, 2025, 2030 and 2040. With regard to 2030 and 2040, three scenarios were produced ("Sustainable transition", "Distributed Generation" and "Global Climate Action"), to which was added the "EuCo" scenario from the European Commission.

Even so, one can only regret that there is little diversity in these scenarios as they lack a contrasting representation of the development of renewable energies. The approach adopted so far consisted of designing limit energy trajectories which "framed" the future. One could thus consider the average of the scenarios as a reasonable reference for assessing interconnection projects. It should be added that the scenarios proposed on a European scale sometimes differ significantly from those developed by the national TSOs, in particular with regard to electricity for France. The differences in perception between various stakeholders relating to their view of the change in energy systems over the long-term are certainly not surprising but demonstrate the necessity for diversity along with the implementation of sensitivity analyses in producing scenarios over such a long period (see focus 3).

The current approach could thus lead the CRE to adopt additional scenarios to those developed by ENTSOE and ENTSOG for the validation of new investments in interconnections.

[67] https://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0015:0035:EN:PDF
[68] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009R0715&from=EN
[69] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32013R0347&from=FR

3.1.1.2 The regulators support ENTSOE and ENTSOG in improving their methodologies in relation to network development

The assessment of the investment needs in the European network (TYNDP and cost-benefit analysis methodologies), introduced by the third package in 2009 and the infrastructure package in 2013 is a relatively new exercise at European level. It requires significant harmonisation work between the TSOs.

Since 2013, ENTSOE and ENTSOG worked continuously in improving their methodologies for producing TYNDPs and cost-benefit analyses (CBAs). The ENTSOs will publish in 2018 the second version of their CBA methodologies[70], which were submitted for the approval of the European Commission after assessment by ACER in 2017. They are also working on producing an interlinked electricity and gas market and network model.

The regulators support these changes as part of an ongoing dialogue with ENTSOE and ENTSOG. They issue their opinion on the methods and analyses proposed by the TSOs, produced in the framework of ACER infrastructure task forces in which CRE is actively involved. Regulators are particularly concerned with the transparency and rigour of the methodologies used by the ENTSOs with the aim of ending up with robust and objective results. The latest requests by regulators to ENTSOE deal, for example, with the consistency of the methodologies and design assumptions for the various benefits of the projects. For gas, regulators have made proposals for simplifying the cost-benefit analysis methodology proposed by ENTSOG, by recommending the abandonment of a number of physical indicators in favour of better monetisation of the advantages provided by the projects evaluated.

3.1.2 The Projects of Common Interest, instruments of the European energy policy

The concept of the Project of Common Interest was to a large extent specified by the infrastructure package in 2013, which has in effect defined the current adoption procedure for the list of PCIs. Renewed every two years, this list is adopted by the European Commission on the proposal of the Regional Groups made up of representatives of Member States, national regulatory authorities, transmission system operators, representatives of ENTSOE, ENTSOG, ACER and the European Commission.

To be declared as being of common interest, projects must comply with certain criteria (potential benefits - as assessed by the regional groups - exceeding their costs, existence of a cross-border impact, contribution to market integration, to security of supply or to sustainability). On this basis, regional groups agree on an analysis methodology for candidate projects in order to establish a proposal for a list: the list adopted in November 2017 by the European Commission[71] included 173 projects, 15 of which involve France.

The main aim of the analysis carried out by regional groups, sometimes on immature or competing projects, is to assess their consistency with the main principles of European energy policy. This is therefore not a sophisticated in-depth technical-economic analysis, comparable with the one to be performed before the formal approval of a project: granting PCI status to a project does not necessarily prejudge its economic value and it is thus totally conceivable that a project identified as PCI does not ultimately generates benefits which, compared to its costs, would make it worthwhile carrying out.

The PCI label nevertheless makes the selected projects eligible for certain mechanisms aimed at facilitating their execution, such as accelerated procedures for granting administrative authorisations. They can, furthermore, benefit from special incentive measures where they have high risks in relation to those usually associated with comparable projects, coordinated Cross-Border Cost Allocation (CBCA) decisions by the regulators concerned and European financial support for studies or works via the Connecting Europe Facility (CEF).

Since the infrastructure package was adopted, the CRE has taken two CBCA decisions, in 2014 for the Val de Saône gas project[72], and in 2017 for the Biscay Gulf electricity interconnection (see focus 4). Both these decisions were adopted in jointly with the Spanish regulator. In compliance with ACER recommendation[73], an allocation of costs that was different than their geographical distribution was implemented for the Biscay Gulf project: indeed, the imbalance of the cost and benefit allocation initially resulted in a net negative benefit for France, corrected by the CBCA.

[70] See assessment by ACER on the preparatory version by the ENTSOE: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2005-2017.pdf
[71] https://ec.europa.eu/energy/sites/ener/files/documents/annex_to_pci_list_final_2017_en.pdf
[72] https://www.cre.fr/en/Documents/Deliberations/Decision/val-de-saone
[73] https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2005-2015.pdf

FOCUS 3 – DECISION-MAKING PROCESS FOR INVESTMENTS IN INTERCONNECTIONS AND THE ROLE OF CRE

Interconnection projects are generally speaking complex and costly projects. New infrastructures, built and financed with an operating lifetime of more than 25 years, are nowadays developed in a particularly uncertain context marked by rapid changes in the energy sector. The development of intermittent renewable energies, biogas, smart grids and self-consumption, along with a tendency for stagnation in French energy consumption (a decrease with regard to gas consumption), leads to significant uncertainties weighing on energy systems over the medium and long term. As such, new interconnection projects must be properly analysed and investment decisions taken only when the benefits of the projects exceed their costs. Compliance with this principle of a positive cost-benefit analysis for a project has furthermore been confirmed by the September 2017 report from the expert group on interconnection targets appointed by the European Commission (see section 1.4.2.3).

1. Tariff regulation at the service of the development of interconnections

The CRE, responsible for defining the methodology for network tariffs and setting their level, closely monitors interconnection projects and has implemented *ad hoc* incentive mechanisms in compliance with the provisions of the French energy code.

New interconnections, as all TSO investment projects, must appear in their Network Development Plan (NDP) published each year. For gas, as for electricity, and in a similar way to what is done on a European scale, French TSOs define these plans according to the scenarios they have designed beforehand. The investments are then approved by the CRE, and included in the TSO Regulated Asset Base (RAB), and remunerated at the Weighted Average Cost of Capital (WACC), the level of which is fixed for each tariff period.

The CRE accompanies the TSOs in carrying out interconnection projects and pays particular attention to cost and schedule control: the aim of the regulation mechanisms for interconnection projects put in place for gas and electricity is to provide incentives to the TSOs to carry out projects which are the most relevant to the community and to control investment costs. This incentive therefore consists of a part associated with the benefits of the project for the community and of two variable elements, which relate to the difference between the planned and actual costs and the utilisation rate of the connection. These bonuses come with a lower limit, which ensures that the payment to the TSOs for the project cannot be less than the WACC - 1%.

Although the reference conditions for developing interconnections are the regulated regime described above, other projects may benefit from an exemption when they involve building and operating interconnections with a particularly high degree of risk. To do so, they must obtain an exemption from the application of certain legislative provisions from the regulators of the countries concerned under article 17 of regulation (EC) no. 714/2009 of 13 July 2009[74].

2. The decision-making process requires the assessment of the projects against a set of diversified scenarios

Cost-benefit analyses are the practical decision-making tool for project promoters and regulators with regard to new interconnection projects. These analyses are based on a set of assumptions which form a representation of the future electrical system for each scenario considered and which make it possible to assess the value of the project by evaluating its impact on the electricity or gas markets.

The main assumptions affecting the value of interconnections are the consumption, the energy mix and the level of interconnection in the market zones considered. The choice of scenarios taken into account is therefore crucial in supporting the decision-making process, considering the uncertainties weighing on the development of the European energy systems: the scenarios must therefore offer a set of assumptions sufficiently diversified to be able to represent all plausible assumptions for the electrical and gas systems, and present sensitivity analyses on the items having the greatest impact on the economic assessment of the projects in order to base decisions on sufficiently robust elements.

With regard to the cross-border cost allocation decision for the Biscay Gulf project in 2017, the CRE and CNMC have agreed to carry out the cost-benefit analysis of the project based on the four scenarios of the 2016 TYNDP: these scenarios represent quite contrasting views so that the average of the results of the analysis according to the four scenarios can be considered a reasonable assessment of the relevance of the project for the European community.

[74] https://www.cre.fr/en/Documents/Deliberations/Communication/interconnections

3. The decision-making process as part of the infrastructure package

The CRE is particularly attentive to the fact that the investment decisions taken by the TSOs are taken on the basis of market tests and solid cost-benefit analyses in order to ensure the networks are correctly sized and the investments committed do not increase consumers' bills unduly, by not being compensated by a reduction at least equivalent of the rest of the energy system costs.

The decision-making process resulting in the implementation of these projects therefore plays a fundamental role. As part of the infrastructure package, the first step of this process is the integration of projects in the list of PCIs. This status gives project promoters the possibility of filing an investment request to the regulators concerned who must take a cross-border cost allocation decision and include these costs in the TSOs' tariffs. Obtaining the PCI label therefore leads to a *de facto* near-approval of the projects although this designation is granted far early in the development of the projects and therefore on potentially insufficient bases for carrying out a robust cost-benefit analysis (the characteristics of the project and therefore its costs are for example quite often subject to a high degree of uncertainty). Moreover, the final selection of PCIs includes a substantial qualitative dimension and inevitably incorporates additional objectives to the technical-economic analyses. As an example, to adopt the third PCI list in 2017, the regional groups decided to give more weight to the criterion of reaching 10% of interconnections in assessing electrical projects as the objective set by the European Council (see 1.4.2.3). Certain projects have therefore been selected on this basis while their costs remain too high in relation to their benefits.

In a similar way, some gas projects were included in the PCI list while the analyses available should have resulted in discarding them. The STEP project was evaluated under an *ad hoc* study commissioned by the European Commission (see 3.3.3), which was carried out at the same time as the selection process for the third list. It has therefore not been assessed within the general framework planned for all candidate projects. Despite the results of the study, this project was eventually included in the list of PCIs in the last stages of the selection process.

These factors call for an additional analysis of each project to be carried out when they are being considered for implementation. Thus, if a PCI turns out to be too costly relatively to the benefits it can bring to the European community, the regulatory authorities should be able to stop it from being carried out. Indeed the regulator's control over the effectiveness of the costs incurred by the operators (and therefore in particular the large-scale investment decisions) is a fundamental principle of regulation: this must be respected, including in matters of interconnection projects. Furthermore, when the cost/benefit analysis is positive for the European community but the costs represent too large a cost for the stakeholders, the regulators must be able, in certain cases, to make the CBCA conditional to a European subsidy.

Chapter 2– Development of electricity interconnections

Three new interconnections are currently under construction in France, with Italy (Savoie-Piémont), and Great Britain (ElecLink and IFA2). With the Biscay Gulf project (France/Spain interconnection), approved in 2017, this represents an increase in exchange capacities of 5.2 GW.

Figure 41 – Development of French electricity interconnections

3.2.1 The CRE has approved the construction of a new interconnection between France and Spain

The commissioning of the Baixas Santa-Llogaia interconnection in October 2015 combined with the Arkale phase-shifting transformer in Spain in June 2017 helped increase greatly the exchange capacities between France and Spain, which almost doubled between 2015 and 2017 (see 2.2.1.1).

The CRE has moreover approved the construction of a new interconnection between the two countries by taking a cross-border cost allocation decision for the Biscay Gulf project with the Spanish regulator on 21 September 2017 under regulation (EU) no. 347/2013[75] (see focus 4). This new interconnection will help reach exchange capacities of 5 GW between France and Spain. The CRE has moreover put in place an incentive mechanism in order to ensure the costs of the project are controlled by RTE (deliberation no. 2017-224 of 27 September 2017[76]), as well as a flow incentive (deliberation of 17 May 2018[77]).

Other interconnection projects between France and Spain are still mentioned within the framework of the High-Level Group on interconnections in south-west Europe[78]. Given the increase in exchange capacities which will be effective

[75] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32013R0347&from=FR
[76] http://www.cre.fr/documents/deliberations/decision/golfe-de-gascogne2
[77] http://www.cre.fr/documents/deliberations/decision/interconnexion-golfe-de-gascogne2
[78] set up by the European Commission following the Madrid declaration of 4 March 2015, it includes the Commission, the regulators and the French, Spanish and Portuguese governments.

after the commissioning of the Biscay Gulf project, the CRE considers it necessary to assess the situation following this new capacity increase before making a decision on new interconnections. Furthermore, the technical-economic characteristics of the new projects considered across the Pyrenees (cost assessment, layout, network reinforcements necessary, estimated benefits) are not yet defined, which does not make it possible at this stage to give a verdict on their relevance for the community. Lastly, environmental constraints do not speak in favour of these projects.

3.2.2 An interconnection with Italy is under construction

The development of interconnection capacities with Italy is also under way with the construction of the Savoie-Piémont line, which started in March 2015 on the French side. This project has had the status of Project of Common Interest (PCI) since 2013 and consists in the construction of two DC cables with a capacity of 600 MW each that will connect the electrical stations of Grande Ile (Savoie) and Piossasco (near Turin) via the Fréjus tunnel taking the line of the A42 motorway in France and the A32 in Italy. The line will stretch over 190 km and should be commissioned in 2019.

The Savoie-Piémont project benefits from an incentive mechanism set up by the CRE in 2015, made up of a fixed bonus relating to the usefulness of the project assessed *ex-ante* and two variable bonuses relating to the actual costs of the project (the amount of the investment for RTE retained by the CRE is €465M) and its usefulness measured ex-post by the effective utilisation rate of the interconnection (deliberation of 26 Match 2015[79]). One of the two cables on the Italian side of the interconnection benefited from an exemption on the basis of regulation (EC) no. 714/2009, granted by the CRE and the Italian regulator[80]. By August 2017, 40 km of cables had been laid on the French side, and 12 km in Italy.

3.2.3 The France/Great Britain border is marked by an abundance of interconnection projects despite the uncertainties linked to Brexit

Numerous interconnection projects are under construction or at the design stage at the France/Great Britain border, which currently has 2 GW exchange capacity through the IFA 2000 interconnection built in 1986. The most advanced project is ElecLink whose first stone was laid on 23 February 2017 and which will add 1 GW capacity via a line passing through the Channel Tunnel.

The CRE has also approved the IFA2 project developed by RTE and the British system operator National Grid on 2 February 2017[81]. Included in the list of PCIs by the European Commission since 2013, it will connect the Caen region (Calvados) with that of Southampton in England and increase the interconnection capacities between the two countries by 1 GW.

This project was approved against a particular background, namely after the British referendum dealing with the exit from the European Union (Brexit) which took place a few months previously on 23 June 2016, but before the effective date of the British Government formalising the exit request on 29 March 2017.

The decision to leave the European Union has led to institutional, operational and economic uncertainties with regard to electricity interconnection projects between Great Britain and the rest of the European Union. In particular, the rules for using these interconnections could differ from those currently in force with the result that the infrastructures might not be used to their full potential.

The IFA2's project promoters consider that Brexit would not call into question the economic fundamentals of the project. The CRE has however taken these uncertainties into account when defining the incentive regulation mechanism which will apply and which were set by the same deliberation approving the investment. The aim of this incentive framework is to provide a better risk distribution between RTE and the users of the French public transmission system by making the TSO assume a larger proportion of the risks and benefits of the project. RTE took its final investment decision for the IFA2 project taking this regulatory incentive framework into account on 5 April 2017 and work started in January 2018: the line, for which RTE's investment cost as retained by the CRE is €370M, should be commissioned in 2020.

Three other interconnections at this border are also under study: FAB Link (1.4 GW), Aquind (2 GW), and GridLink (1.4 GW). FAB Link is developed by RTE and Transmission Investment *via* the FAB Link Limited joint venture, while Aquind and GridLink are at this stage proposed by private project promoters.

[79] http://www.cre.fr/documents/deliberations/decision/interconnexion-savoie-piemont
[80] http://www.cre.fr/documents/deliberations/decision/interconnexion-france-italie
[81] https://www.cre.fr/en/Documents/Deliberations/Decision/interconnector-ifa2-project

Aquind applied for an exemption[82] to the French and British regulators (*Office of Gas and Electricity Markets* – Ofgem) on 16 August 2017. Given the uncertainties caused by Brexit on the regulatory and economic framework in force once the United Kingdom out of the European Union, the CRE considered that it was not able to rule on the benefits for the European community of any new interconnection project between France and Great Britain before the exit conditions have been clarified. This decision is based mainly on the results of the study carried out by Artelys and Frontier Economics[83] on the value of Franco-British interconnections in the context of Brexit. The CRE and Ofgem thus transferred the exemption request to ACER at the end of 2017 (deliberation no. 2017-253 of 16 November 2017[84] with regard to the CRE). In its decision of 19 June 2018, ACER rejected Aquind's exemption request.

3.2.4 Interconnection project with Ireland

An interconnection project between France and Ireland, developed by RTE and the Irish system operator Eirgrid is also under consideration. This involves a DC line with a capacity of 700 MW which would connect the Martyre station (Finistère) to that of Knockraha in Ireland, travelling 560 km, for an estimated cost of €930M. This project has been included in the list of PCIs since 2013 and will undergo a more in-depth technical-economic analysis in the TYNDP 2018.

3.2.5 RTE also plans reinforcements of existing interconnections

These reinforcements relate to interconnections with Switzerland, Belgium and Germany and are included in RTE's Ten-year Network Development Plan (SDDR – *Schéma de Développement du Réseau*)[85].

Work carried out at the France/Switzerland border should increase exchange capacities by more than 1 GW. The first development phase consisting of increasing the transit capacity of the Génissiat Verbois line was commissioned at the end of 2017. Two other phases are planned until 2030.

The increase in capacities between France and Belgium through the Avelin Avelgem reinforcement project is estimated at between 0.6 GW and 1 GW for a total cost of €140M (including €40M for RTE).

Two projects are envisaged for reinforcing the exchange capacities between France and Germany: these are the increase in voltage of the circuit between Muhlbach (Alsace) and Eichstetten (Bade), which will go from 225 kV to 400 kV (for an increase in interconnection capacities estimated between 150 and 300 MW), and the increase of the capacities of the two circuits between Vigy (Moselle) and Uchtelfangen (Sarre), which could increase the interconnection capacities between the two countries by 1,500 MW.

[82] Regulation (EC) no.. 714/2009 (https://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0015:0035:EN:PDF) states that interconnection projects may benefit from an exemption from certain provisions of European legislation applicable, amongst other things, to the use of interconnection revenues, subject to the joint agreement of the regulatory authorities concerned.
[83] https://www.cre.fr/en/content/download/17042/209401
[84] https://www.cre.fr/en/Documents/Deliberations/Orientation/interconnector-projects-with-the-united-kingdom
[85] http://www.rte-france.com/sites/default/files/sddr-2016_volet_national_vf.pdf

FOCUS 4 – THE BISCAY GULF INTERCONNECTION PROJECT

On 21 September 2017, the CRE adopted a decision, jointly with the CNMC, on the treatment of the cross-border cost allocation request for the Biscay Gulf project. This is an offshore interconnection located between Cubnezais (Gironde) and Gatika (Spanish Basque region) which will take the interconnection capacity between the two countries from 2800 MW to 5000 MW and will supplement recent developments with the entry into service in October 2015 of the Baixas Santa-Llogaia line and that of the Arkale phase-shifting transformer in 2017.

Developed by RTE and REE (*Red Eléctrica de España*), Biscay Gulf has been on the list of Projects of Common Interest of the European Union since 2013. It is considered as a key element in the integration of the Iberian Peninsula with the rest of the European market. This interconnection will consist of two high-voltage DC lines of 1000 MW capacity each, along with four conversion stations. With a total length of 370 km, 280 km of which will be in the Atlantic Ocean, this line will be located 70% in France and 30% in Spain. It will avoid going over the Pyrenees but implies crossing an undersea canyon, the Gulf of Capbreton, a major natural obstacle. After studies carried out by the TSOs, the preferred technical option is a directional drilling near the French coast. Thus, this solution represents a significant technological challenge.

The investment costs assessed by the TSO and retained by the regulators in the cost allocation decision amounts to €1750M[86], 68% of which is associated with work carried out on French territory. The estimated benefits of the project on the other hand represent a very different geographical distribution, most of which returning to Spain. This imbalance means the net value of the project could be negative for France in the absence of a reallocation of costs with regard to Spain.

This aspect is reflected in the joint cost allocation decision taken by the CRE and CNMC[87] following the filing of an investment request by RTE and REE on 27 March 2017. While the case was being investigated, the regulators officially recognised the imbalance between the costs and benefits allocation: it was thus concluded that, for the project not to have a negative impact on France, RTE's contribution should not exceed €528M. In their decision, the CRE and CNMC allocated the costs equally between RTE and REE, subject to obtaining a European subsidy that would lower the net contribution of RTE to this level.

Given the positive fallout of the project for the Union in terms of innovation, security of supply, market integration and sustainability, the CNMC and CRE supported its application for a European grant as part of the Connecting Europe Facility (CEF). On 9 February 2018, the European Union decided to allocate a grant of €578M to the project allowing the joint decision taken by the two regulators to be implemented.

Cross-border cost allocation decisions for PCIs as part of the Infrastructure regulation (regulation (EU) no. 347/2013)

Regulation (EU) no. 347/2013[88] (called the "Infrastructure package") puts in place mechanisms facilitating the financing of PCIs in order to ensure they are effectively carried out. The projects involved can, in particular, benefit from a cross-border allocation of their costs. To do this, they must file an investment request file to the regulators concerned who then have six months to take a joint decision.

ACER has adopted a recommendation on the treatment of these requests by the regulators in December 2015 (no. 5/2015[89]). It recommends, in particular, only proceeding with a cost allocation where the project has a net negative impact on one of the host countries.

Projects having received a cross-border cost allocation decision are eligible, under certain conditions, for obtaining European border grant via the Connecting Europe Facility (CEF).

[86] The amount described by the TSOs includes a margin of uncertainty of €200M.
[87] https://www.cre.fr/en/Documents/Deliberations/Decision/biscay-gulf-project
[88] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32013R0347&from=FR
[89] https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2005-2015.pdf

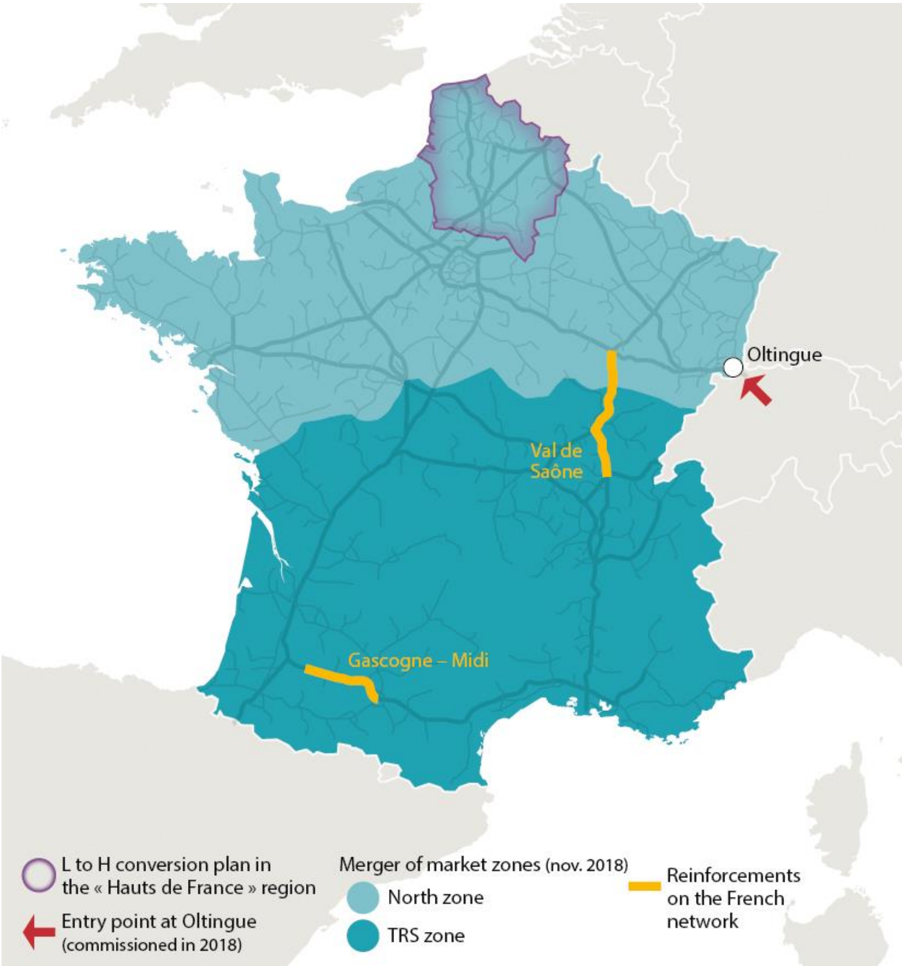
Chapter 3– Development of gas interconnections

Since 2005, the CRE has supported the development of gas interconnections by using open seasons. These procedures aim to dimension a new infrastructure depending on users' requirements and to allocate the corresponding capacities in a non-discriminatory way. These procedures furthermore make it possible to secure the financing for a project and to reduce the risk for end consumers of supporting, via the transmission tariff, the costs of infrastructures which may be under-used.

These open seasons have made it possible to create significant firm interconnection capacities both in entry and exit with Germany, Belgium and Spain. These investments nowadays allow the French gas system to be flexible and closely integrated with the rest of the European market. The stakeholders can thus arbitrate between different gas sources and cope efficiently with any changes in the flow patterns.

Since 2016, 100 GWh/d of entry capacities have been commissioned at the Oltingue IP (June 2018). Reinforcements have also been carried out on the French network in order to allow for the zones merger to take place in November 2018, while the conversion plan of the Hauts-de-France region to H gas is currently being finalised.

Figure 42 – Development of gas interconnections and reinforcements to the French network related to the interconnections



3.3.1 Interconnection with Belgium and conversion plan for the Hauts de France region to H gas

The construction of a liquefied natural gas terminal at Dunkirk was the occasion to create new interconnection capacities with Belgium at Alveringem. The initial aim of this gas pipeline was to enable the terminal to access both the French and Belgian markets: it thus offered the opportunity to create physical transmission capacities between the *PEG Nord* and the Belgian market by shipping non-odourised gas from the Dunkirk terminal and the Franpipe pipeline. The odorisation of gas on the French transmission network had in fact constituted an obstacle to the development of backhaul capacities to Germany and Belgium due to gas quality issues.

With these investments, France is now interconnected with Belgium at Taisnières (two gas pipelines, one dedicated to H (high calorific value) gas, the other to L (low calorific value) gas) and Alveringem (H gas). Commercially speaking, the two H gas structures were brought together within a single two-directional virtual interconnection point called Virtualys (see 2.3.5).

The Taisnières B interconnection point receives gas from the Groningen field in the Netherlands which is mainly consumed in the Hauts de France region (by 1.3 million customers connected to the distribution system and 96 customers connected to the transmission system). The Groningen field has entered its last period of operation, the supply contracts will end between 2021 and 2030 (in 2029 for France) and will not be renewed. Conversion plans must be in place in regions currently supplied with L gas so they can be supplied with H gas once the contracts have finished. In France, the decree of 23 March 2016[90] provides guidelines for the conversion of the L zone. In compliance with the mechanisms put in place, the operators concerned (TSO, DSO and storage operator) proposed a conversion plan to the government in September 2016 on the basis of which the CRE produced an economic and technical assessment in 2017. This plan allows for a pilot phase between 2018 and 2020 before the rollout phase which should last until 2029. On 21 March 2018, the CRE issued a favourable recommendation[91] to the plan put forward by the operators. The ministries concerned should issue their decision in the coming months.

3.3.2 Backhaul capacities with Switzerland

The interconnection with Switzerland, historically created to supply Italy with gas from Norway, only offers exit capacities at the moment (along with a virtual backhaul offer of 45 GWh/d). The CRE approved in December 2014[92] the creation of 100 GWh/d physical entry capacities in order to open access to gas supply sources going through Italy and Switzerland (coming for example from Libya, Algeria or Azerbaijan via the future *Trans Anatolian Pipeline*) at an investment cost estimated to be €17M commissioning on 1 June 2018. The allocation rules for these capacities were approved by the CRE in July 2017 (see 2.3.3).

3.3.3 Project of developing new interconnections with Spain

The French and Spanish markets are interconnected via two gas pipelines crossing the border at Larrau and Biriatou. In total, the transmission capacities amount to 225 GWh/d from Spain to France and 165 GWh/d firm and 60 GWh/d interruptible in the opposite direction. These levels were reached after significant developments decided following open seasons in 2009 and 2010.

The observed utilisation rates of these capacities shows that the level of interconnection between the French and Spanish markets is satisfactory. While the interconnection is almost constantly used in the France to Spain direction, there are non-subscribed capacities in both directions and a significant proportion of subscribed capacities, which are unused, in particular in the Spain to France direction. Moreover, available capacities should increase over the coming years when existing long-term reservations approach expiry.

Commitments made by the shippers during the open seasons of 2009 and 2010 were not sufficient for a decision to be made on the MidCat project which aims to create a third interconnection point between France and Spain east of the Pyrenees. This project provides for the creation of 230 GWh/d of firm capacities in the Spain-France direction and 180 GWh/d in the France-Spain direction, and could require the strengthening of the internal French network including in particular the “Eridan” and “Est Lyonnais” projects, at a cost of more than €2Bn according to an assessment by the TSOs. In its report on the operation of interconnections published in 2016, the CRE made known its very strong reservations with regard to the MidCat project, stating the need to carry out solid cost-benefit studies before any investment decision is taken.

Given the considerable cost of the Midcat project, Enagás and Teréga wanted to investigate the realization of a less ambitious project which in France would only involve a new gas pipeline between Perthus and the Barbaira compression station on the Teréga system. This project, called STEP (*South Transit East Pyrenees*), would, however, create only "interruptible" transmission capacities, the availability of which would depend in particular on the transmission levels from the Fos and Barcelona LNG terminals, a conclusion which emerges from a technical study carried out by Enagás, GRTgaz and Teréga within the framework of the High Level Group on interconnections for South-West Europe.

[90] Decree no. 2016-348 of 23 March 2016 relating to the project to convert the low calorific value natural gas system in the departments of Nord, Pas-de-Calais, Somme, Oise and Aisne
[91] http://www.cre.fr/documents/deliberations/avis/conversion-zone-nord-de-la-france-gaz-h
[92] https://www.cre.fr/en/Documents/Deliberations/Approval/grtgaz-s-investment-programme-2015

The European Commission has decided to carry out a specific cost-benefit analysis for the STEP project in order to assess the appropriateness of carrying it out, or otherwise. This study, carried out by the consulting firm Poÿry, was published on 27 April 2018[93]. It was carried out in line with the methodology defined by ENTSOG and in compliance with European best practices in this area. The terms of reference, assumptions and scenarios adopted were discussed completely transparently within the High Level Group. The study assesses the effects of the project according to different gas supply and demand scenarios, focusing on distinguishing the benefits for the various member states. It concluded that the costs of the project exceed its assumed benefits under most scenarios; the project would only bring net benefits for the community if the following conditions were met simultaneously over the whole lifetime of the project: (i) low gas consumption in Europe, (ii) significant restrictions on the availability of Algerian gas and (iii) very tight global LNG market. In all cases, the economic benefits of the project would be located exclusively in the Iberian Peninsula.

The STEP project was nevertheless included by the European Commission in the third list of Projects of Common Interest published in November 2017, which opened the way for the project promoters to jointly file an investment request to the French and Spanish regulators. At the end of May 2018, the CRE deemed that the file sent was not complete and does not allow the request to be processed.

3.3.4 French zones merger will take place on 1 November 2018

In July 2012, the CRE defined a roadmap which aimed to create a single market area for gas in France, involving the reinforcement of the Burgundy artery (Val-de-Saône project) and carrying out the Gascogne-Midi project. These investments should remove most of the congestions between the North zone and the TRS (*Trading Region South*) zone while minimising the associated costs. Both projects will enter service on 1 November 2018 to create the single zone.

The creation of a single market area in France will notably provide greater fluidity in gas trade between the Iberian Peninsula and the rest of the European market and should put an end to congestion problems on the North-South connection. The Spanish market will thus be connected to a large market directly linked to the North-West hubs of Europe.

The CRE has chosen to implement the single zone in France by following an optimised investment policy, avoiding the creation of too costly infrastructures which would only be relevant under rare circumstances. Thus, market mechanisms for managing residual cases of congestion must be implemented in addition to the investments made (up to €823M to strengthen the network by carrying out the Val de Saône and Gascogne-Midi projects). These market mechanisms were put forward by the TSOs, in discussion with the various stakeholders, and approved by the CRE in its deliberation[94] of 26 October 2017. At the end of May 2018, the progress in the works needed for the merger, in compliance with the schedule, has enabled the TSOs to confirm the date of 1 November 2018 for merging the zones.

[93] https://ec.europa.eu/energy/en/studies/cost-benefit-analysis-step-first-phase-midcat
[94] https://www.cre.fr/en/Documents/Deliberations/Decision/single-gas-market-area-in-france

ANNEXES

GENERAL OVERVIEW

France is now extensively connected with neighbouring countries, both as regards gas and electricity. A number of interconnection projects have been implemented over recent years (Baixas Santa-Llogaia with Spain in 2015, entry capacities to the gas network from Switzerland in 2018). while three electrical interconnection projects are under construction (Savoie-Piémont with Italy, ElecLink and IFA2 with Great Britain), and the Biscay Gulf project with Spain was approved in 2017. In spite of a significant decrease in the net balance of exchanges in 2016 and 2017, France remains an electrical exporter and has a diversified gas supply.

As the European Union is in the process of adopting a new legislative package entitled "Clean Energy for all Europeans", the completion of the single European market is in line with the implementation of the third legislative package adopted in 2009. The integration process that started more than twenty years ago with the initial directives opening up to competition has enabled a pan-european market to be built, which will provide greater efficiency in the management of supply systems for gas and electricity. The CRE was a pioneer in implementing the domestic energy market. For example, it organised the first electricity market coupling with Belgium and The Netherlands in 2007 and has driven the development of the Flow Based method since 2015 with Germany and the Benelux countries (CWE region). France was one of the first continental European countries to implement entry-exit zones for its gas market. Today, it remains fully involved, with its fellow regulators, in drafting and implementing European rules.

1. The development of gas and electricity interconnections has continued since 2016

With regard to electricity, the commissioning of the Baixas Santa-Llogaia interconnection in 2015 and of the Arkale phase-shifting transformer in June 2017 have almost doubled the exchange capacities with Spain. The commercial exchange capacities between France and its neighbours (excluding Belgium and Germany[95]) which amounted to 8.4 GW on export and 4.9 GW on import before the commissioning of the Baixas Santa-Llogaia line, reached 9.8 GW on export and 6.2 GW on import in 2017.

Three additional interconnection projects are currently under construction:

- The Savoie-Piémont project, which represents an increase in capacities of 1,200 MW with Italy, should be commissioned in 2019.
- Work on the ElecLink project, approved by the CRE in 2014, started in February 2017: this project will increase exchange capacities with Great Britain by 1,000 MW.
- Lastly, the CRE approved the IFA2 project in February 2017, which also plans to increase interconnection capacities by 1,000 MW with Great Britain and for which construction started in January 2018.

The CRE furthermore concluded an agreement with the Spanish regulator in September 2017 on the cross-border allocation of the Biscay gulf interconnection costs. This 2,000 MW project connecting the Gironde to the Spanish Basque region via the Atlantic Ocean has received significant financial support from Europe. Projects of reinforcements of the existing interconnections with Switzerland, Belgium and Germany are currently also under study.

The French gas network is currently well integrated into the European network: by the end of 2017, France had 3,585 GWh/d of entry capacity and 658 GWh/d of exit capacity, i.e. about twice as much as in 2005. The 100 GWh/d entry capacity from Switzerland at the Oltingue IP, approved in 2014 by the CRE, was commissioned in June 2018.

The merger of the *PEG Nord* and TRS zones, requiring completion of the Val de Saône (strengthening of the Burgundy artery) and Gascogne-Midi projects will be implemented on 1st November 2018.

2. Overview of the use of interconnections

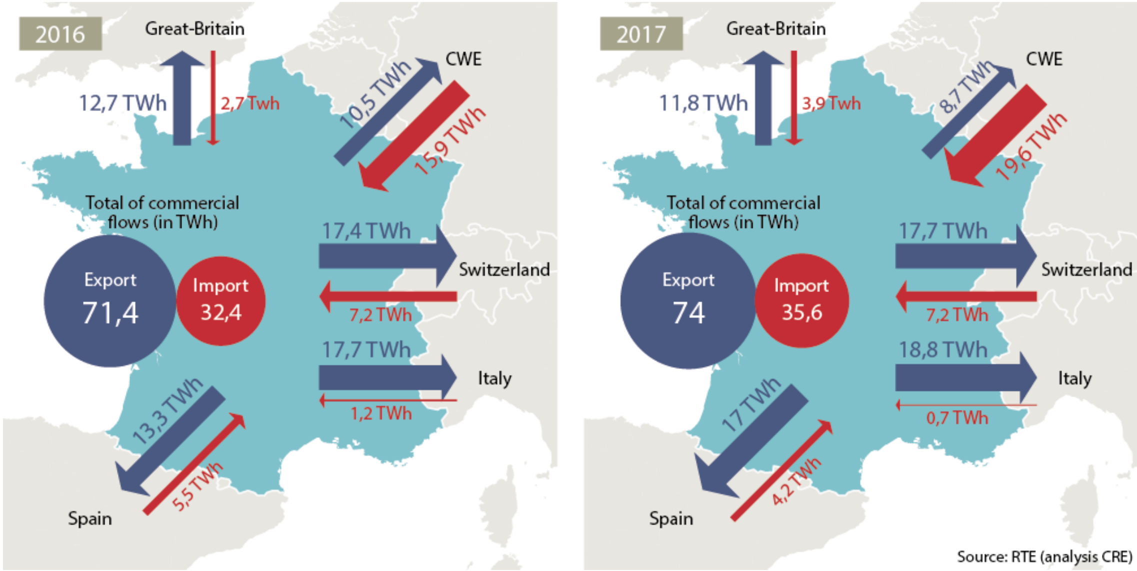
2.1. Electricity interconnections

The balance of electricity exchanges for France underwent a strong decline in 2016 and 2017 (ending up at around 39 TWh, see the maps below) without at the same time reaching the 2009 level. (24.6 TWh). This change was due both to a decrease in exports (from 91 TWh in 2015 to 74 TWh in 2017) and a slight increase in imports (of the

[95] From the implementation of the *Flow Based* system in May 2015, the exchange capacities in the CWE (*Central Western Europe*) region are no longer determined ex-ante by border (France-Belgium on the one hand and France-Germany on the other), but for all exchanges in the region, taking into account the interdependence of flows between borders

order of 30 TWh in 2015, and 35 TWh in 2017). France however maintains a net positive export balance with all neighbouring countries with the exception of the CWE (*Central West Europe*) region.

Figure 43 – Electricity commercial flows at the French borders in 2016 and 2017



This result is linked to the tensions to which the French electrical system was subjected during the winter of 2016/2017. The temporary unavailability of part of the French nuclear plants, combined with temperatures well below the average for the season, adversely affected the price of electricity in France (with a spot price that reached a maximum of €874/MWh on 7 November 2016 at 18:00) and changed the structure of the exchanges usually observed (France was a net importer in December 2016 (-0.1 TWh) and January 2017 (-0.9 TWh), which hadn't happened since 2012).

The spot price spreads between France and neighbouring bidding zones lowered at all borders since 2015, except for Germany (for which the price spread with France went from €7.5/MWh[96] in 2015 to €10.9/MWh in 2017). This trend was particularly marked with Spain (the price spread went from €14.8/MWh to €10.2/MWh in two years), thanks to the commissioning of the new interconnection (the price convergence rate had furthermore significantly increased, going from 13% in 2015 to 25% in 2017).

The results of the implementation of the Flow Based capacity calculation within the CWE region (in May 2015) is more mitigated. Although it resulted in a significant increase in the maximum exchanges between the bidding zones of the region, it appears that the average cross-border exchanges had a tendency to lower relatively to their previous level. Moreover, the terms and conditions of the methodology's implementation (in particular regarding the critical branches) resulted in frequent limitations in the capacity domain offered to the market. The regulators of the CWE region asked the TSOs to apply a number of measures at the start of 2018 in order to improve the situation.

In other regions, in application of the regulations on capacity allocation and congestion management (CACM), the system operators are working on implementing coordinated capacity calculation methodologies. The CRE monitor this process to ensure that these allow effective optimisation of the existing interconnection capacities.

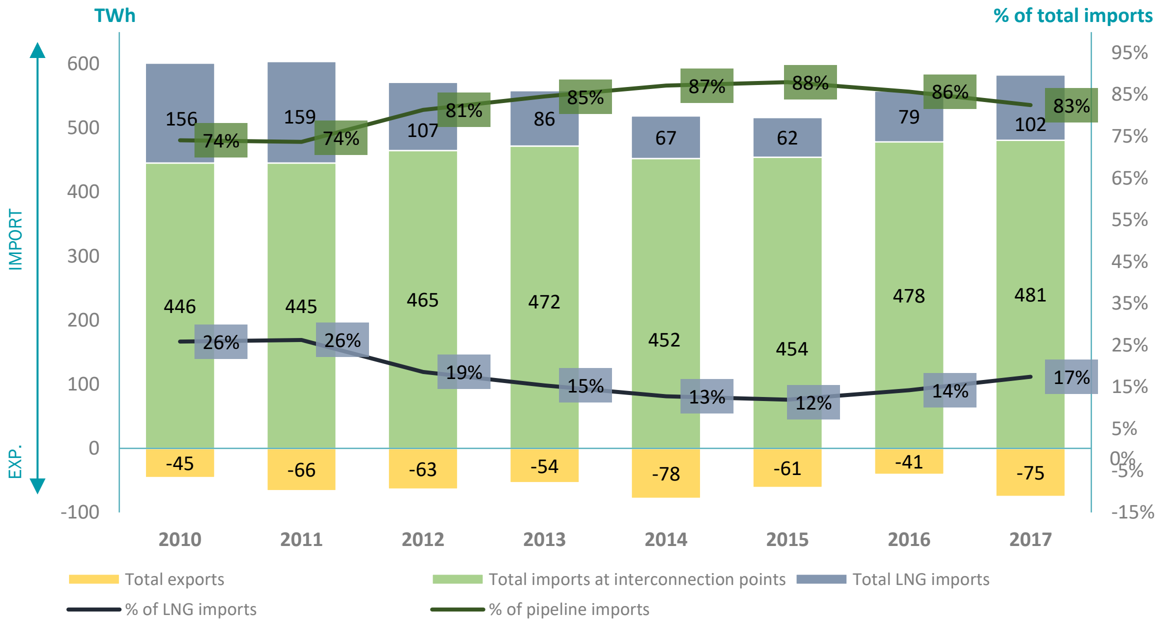
2.2. Gas interconnections

France has a diverse gas supply via four liquefied natural gas terminals, terrestrial interconnection points with Belgium, Germany, Switzerland and Spain, as well as direct access via the Franpipe gas pipeline to the Norwegian production fields located in the North Sea, which represents 33% of total French imports in 2017. The French gas system is therefore one of the most robust in Europe. The natural gas storage reform adopted in March 2018 and the merging of market zones effective on 1st November 2018 all contribute to strengthening the security of supply for France.

In 2017, imports by gas pipeline represented 83% of the supply. LNG deliveries remained at a relatively low level (102 TWh), but are on the increase since 2015, following a lowering of tension in the Asiatic markets which helped redirect flows to Europe. With regard to re-exports, France attained, in 2017, a level near to its historic maximum observed in 2014 with high volumes to Spain (43 TWh).

[96] the price spreads are shown in absolute values

Figure 44 – Gas imports and exports in France (2010-2017)



The European spot prices continued the decrease started in 2015 up to September 2016 before increasing significantly during the winter of 2016/2017, marked both by an increase in raw material prices, an increase in consumption by gas-fired power plants and tensions on the LNG market.

The prices in the *PEG Nord* zone are, generally speaking, strongly correlated with those of the rest of the North-West Europe plate, with an average price spread of € 0.3/MWh in 2016, and € 0.1/MWh in 2017 with the TTF. On the other hand, the TRS was subject to strong price volatility with differences that reached more than €15/MWh relative to the *PEG Nord* zone during winter 2016-2017. The creation of a single market zone for France, made possible by significant investments at the core of the French network (Burgundy artery and Gascogne-Midi gas pipeline) will be effective on 1 November 2018. It will put an end to differences in wholesale prices between the north and south of the country while improving the level of liquidity in the French market.

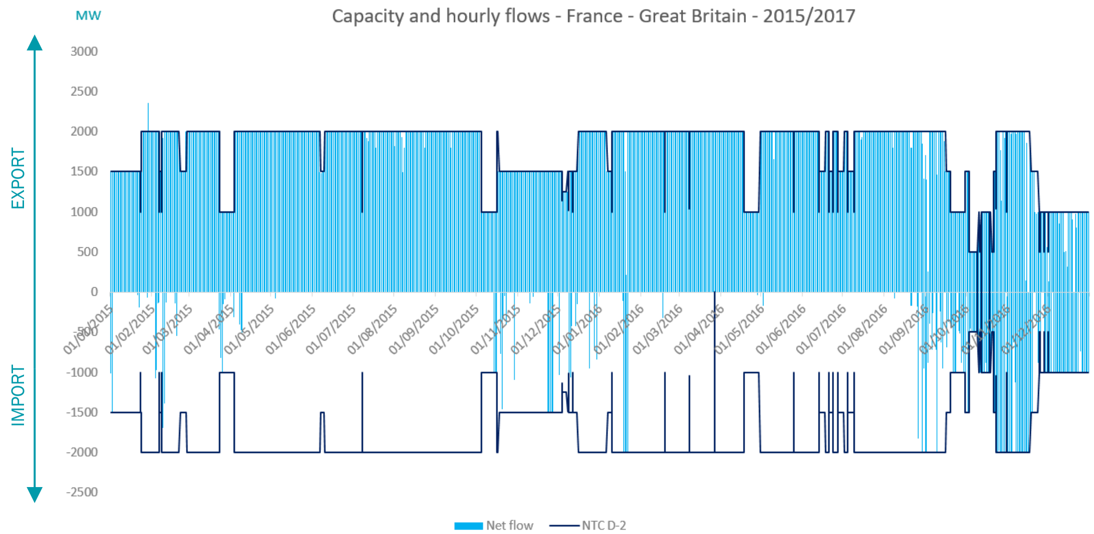
The subscription rates at the French gas interconnections remain very high, their development being linked to import contracts or long-term subscriptions. The next ten years will however be marked by the end of most of the long-term reservation contracts for these interconnections, since only two contracts will continue after 2029.

3. The implementation of the third package accelerated since 2016

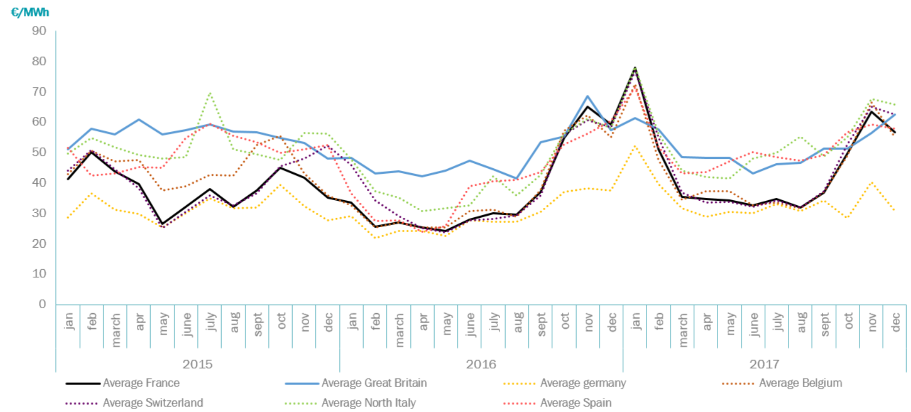
The third legislative package, adopted in 2009, entered its final implementation phase. All the guidelines and network codes were adopted enabling harmonisation of the rules for using interconnections across the European Union. In the electricity sector, after the adoption in 2015 of the CACM regulation on day-ahead and intraday timeframes, 2016 and 2017 saw the adoption of eight regulations, two of which were dedicated to market rules (allocation of long-term capacities and balancing), along with six "technical" regulations dealing with the operational management of the network and grid connections. As far as gas is concerned, the network code on harmonisation of tariff structures has been added to the four texts adopted previously.

The full implementation of these regulations will take several more years, nevertheless the European energy market is now a reality, which organises electricity and gas flows according to relative price levels between countries, thus minimising supply costs at the European level.

ELECTRICITY INTERCONNECTION WITH GREAT BRITAIN

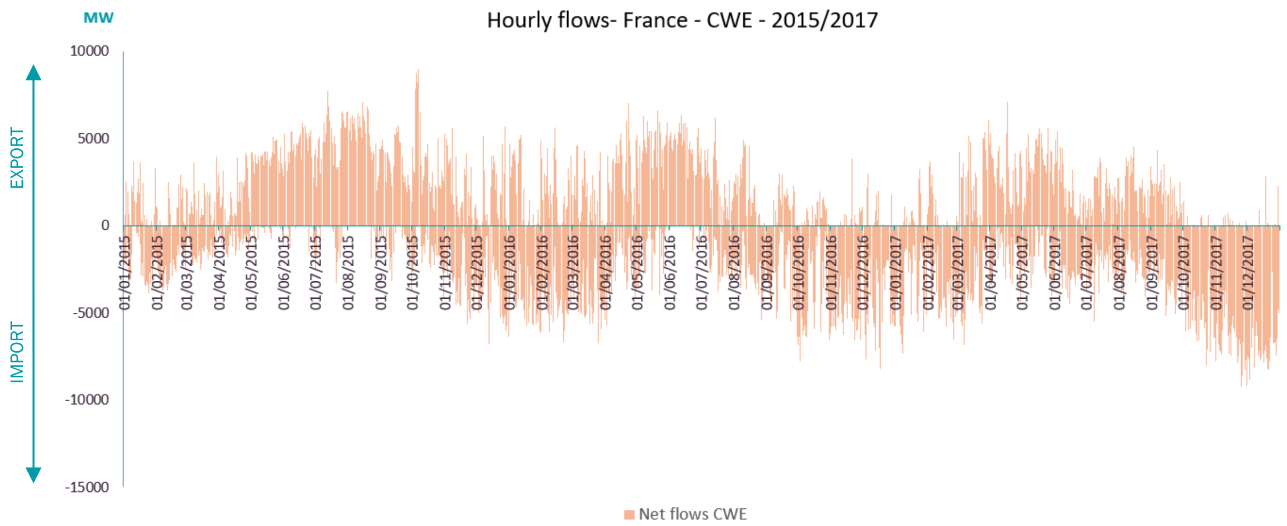


	2015	2016	2017
Average recorded capacity – export	1805 MW	1715 MW	1740 MW
Average recorded capacity – import	- 1805 MW	- 1715 MW	- 1740 MW
Net export balance	14 TWh	10 TWh	7,9 TWh
exports	*15,9 TWh*	*12,7 TWh*	*11,8 TWh*
imports	*- 1,8 TWh*	*- 2,7 TWh*	*- 3,9 TWh*
Utilisation rate– export	92%	87%	84%
Utilisation rate – import	54%	72%	75%
Percentage of time of utilisation for export	97%	83%	77%
Average absolute price spread	16,5 €/MWh	14,4 €/MWh	11,2 €/MWh
Price convergence	14%	17%	20%

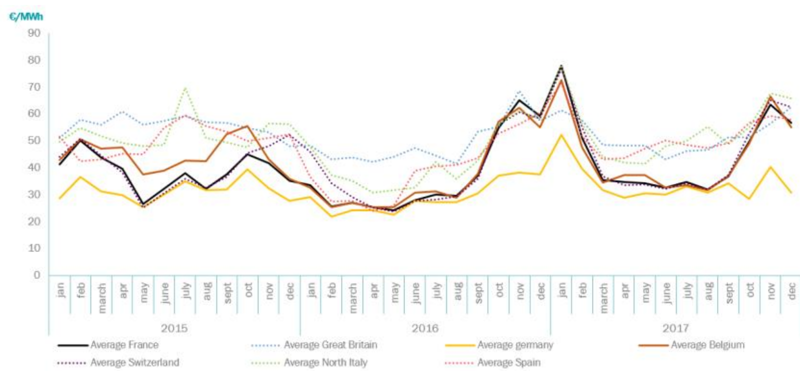


Highlights: ElecLink and IFA2 projects in construction (commissioning planned for 2020).

ELECTRICITY INTERCONNECTION WITH THE CWE REGION



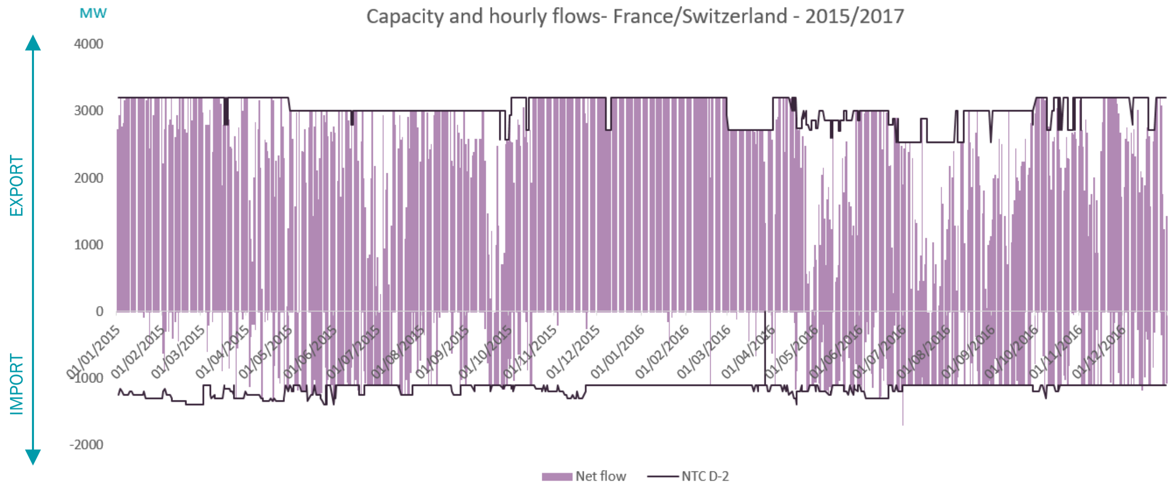
	2015	2016	2017
Net import balance	7 TWh	-5,3 TWh	-10,9 TWh
exports	*22,7 TWh*	*10,5 TWh*	*8,7 TWh*
imports	*- 15,6 TWh*	*- 15,9 TWh*	*- 19,6 TWh*
Percentage of time of utilisation for export	60%	39%	30%
Average absolute price spread with Belgium	6,3 €/MWh	2,6 €/MWh	3,8 €/MWh
Price convergence with Belgium	44%	44%	45%
Average absolute price spread with Germany	7,5 €/MWh	8 €/MWh	10,9 €/MWh
Price convergence with Germany	27%	36%	35%



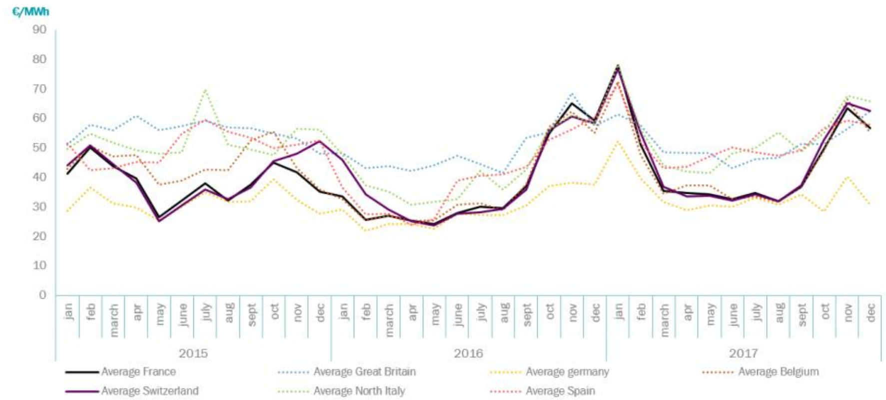
Highlights: integration of CWE in the Core region at its creation in November 2016 (harmonisation works in progress).

Discussions in progress for the amelioration of the Flow Based in the CWE region.

ELECTRICITY INTERCONNECTION WITH SWITZERLAND

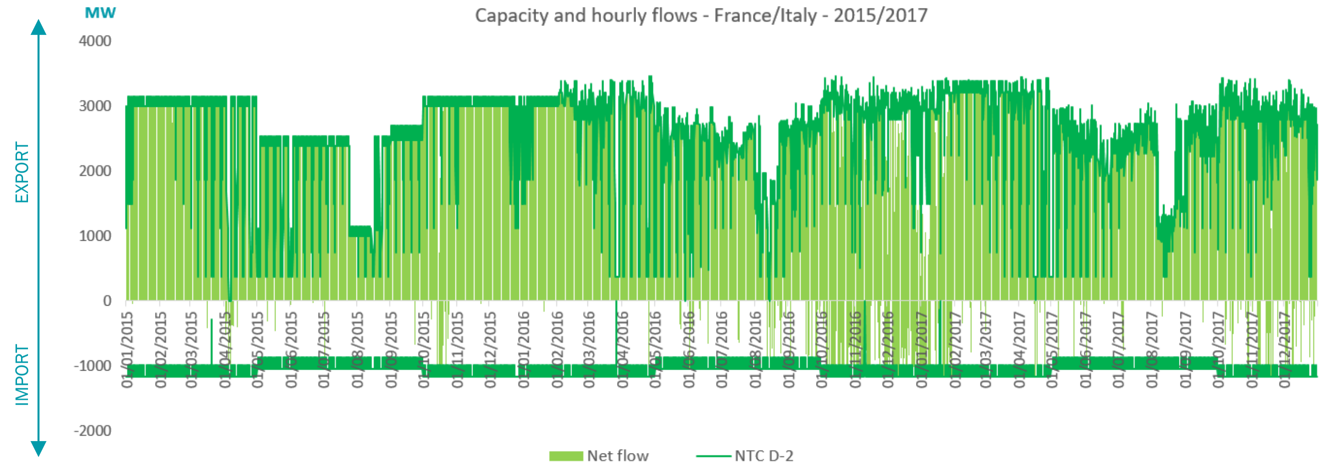


	2015	2016	2017
Average recorded capacity – export	3095 MW	2975 MW	3005 MW
Average recorded capacity – import	- 1190 MW	- 1125 MW	- 1180 MW
Net export balance	14,2 TWh	10,2 TWh	10,4 TWh
exports	*25,9 TWh*	*17,4 TWh*	*17,7 TWh*
imports	*- 11,7 TWh*	*- 7,2 TWh*	*- 7,2 TWh*
Utilisation rate – export	67%	64%	62%
Utilisation rate – import	65%	68%	63%
Percentage of time of utilisation for export	83%	71%	74%
Average absolute price spread	5 €/MWh	4,9 €/MWh	4,1 €/MWh
Price convergence	0,3%	0,4%	0,4%

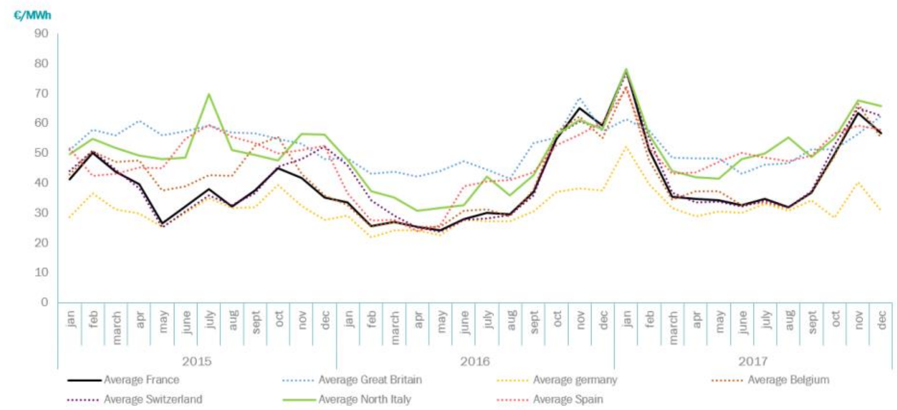


Highlights: relative importance of intraday exchanges at the Swiss border (only non-coupled border at the day-ahead timeframe).

ELECTRICITY INTERCONNECTION WITH ITALY

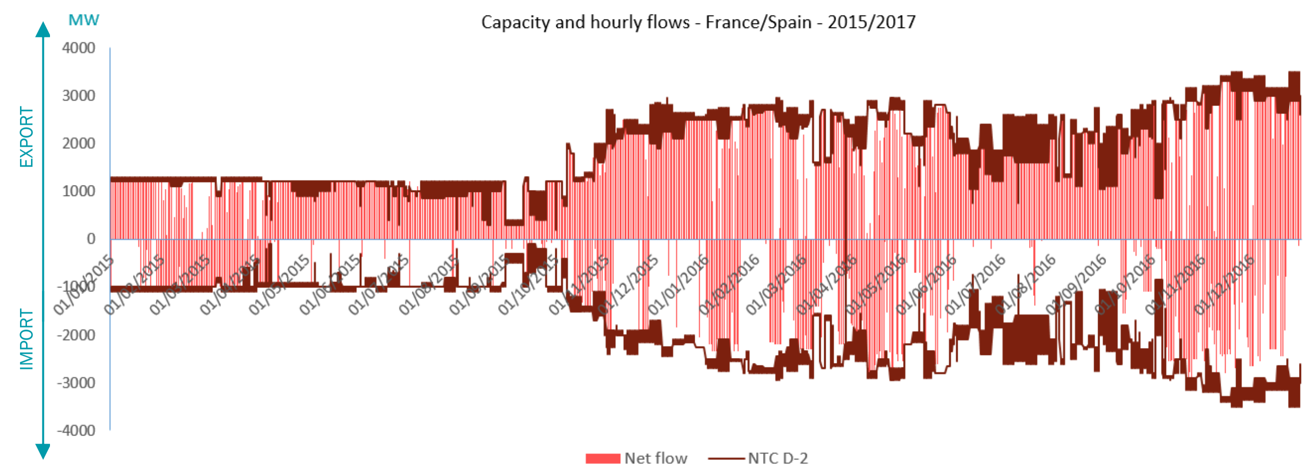


	2015	2016	2017
Average recorded capacity – export	2460 MW	2545 MW	2530 MW
Average recorded capacity – import	-1020 MW	-1020 MW	-1020 MW
Net export balance	19,7 TWh	16,5 TWh	18,2 TWh
exports	*20,1 TWh*	*17,7 TWh*	*18,8 TWh*
imports	*-0,4 TWh*	*-1,2 TWh*	*-0,7 TWh*
Utilisation rate – export	94%	86%	89%
Utilisation rate – import	55%	65%	64%
Percentage of time of utilisation for export	98%	90%	95%
Average absolute price spread	14,4 €/MWh	7,4 €/MWh	9,8 €/MWh
Price convergence	13%	31%	26%

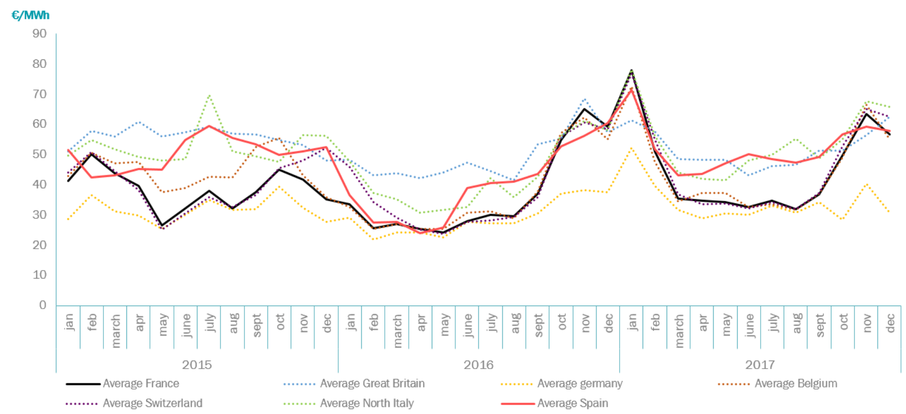


Highlights: Savoie-Piémont project in construction (commissioning planned for 2019).

ELECTRICITY INTERCONNECTION WITH SPAIN

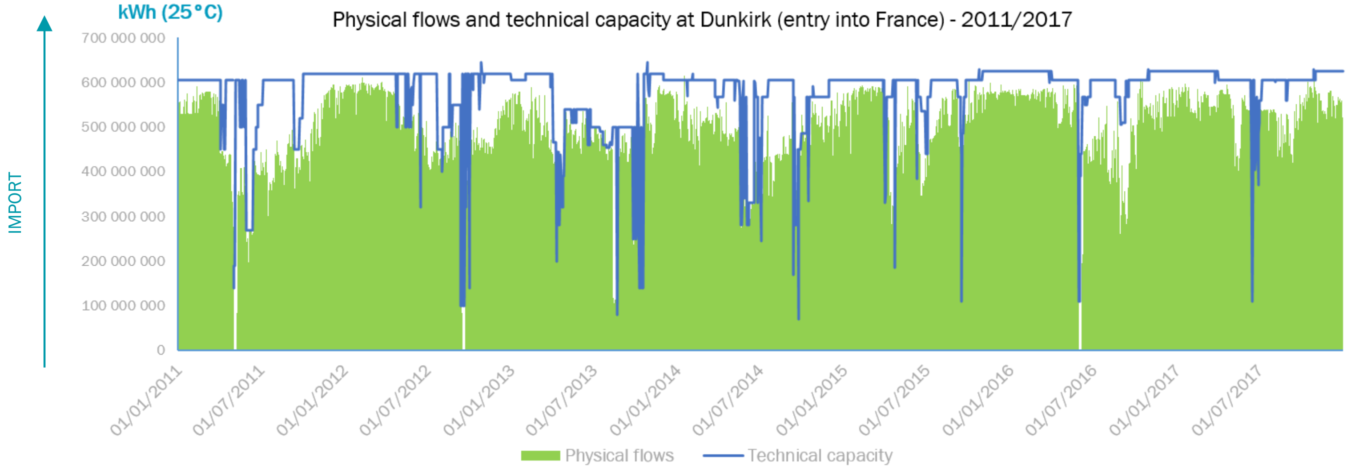


	2015	2016	2017
Average recorded capacity – export	1315 MW	2425 MW	2560 MW
Average recorded capacity – import	- 1135 MW	- 1945 MW	- 2295 MW
Net export balance	7,3 TWh	7,8 TWh	12,8 TWh
exports	*9,3 TWh*	*13,3 TWh*	*17 TWh*
imports	*- 2 TWh*	*- 5,5 TWh*	*- 4,2 TWh*
Utilisation rate – export	93%	83%	88%
Utilisation rate – import	82%	77%	73%
Percentage of time of utilisation for export	82%	71%	82%
Average absolute price spread	14,8 €/MWh	8 €/MWh	10,2 €/MWh
Price convergence	13%	30%	25%



Highlights: commissioning of Arkale phase-shifting transformer (06/2017) – cross-border cost allocation agreement with CNMC for the Bay of Biscay projects (09/2017).
Inclusion to the XBID platform: work in progress to improve the implementation of the implicit continuous allocation at the France/Spain border.

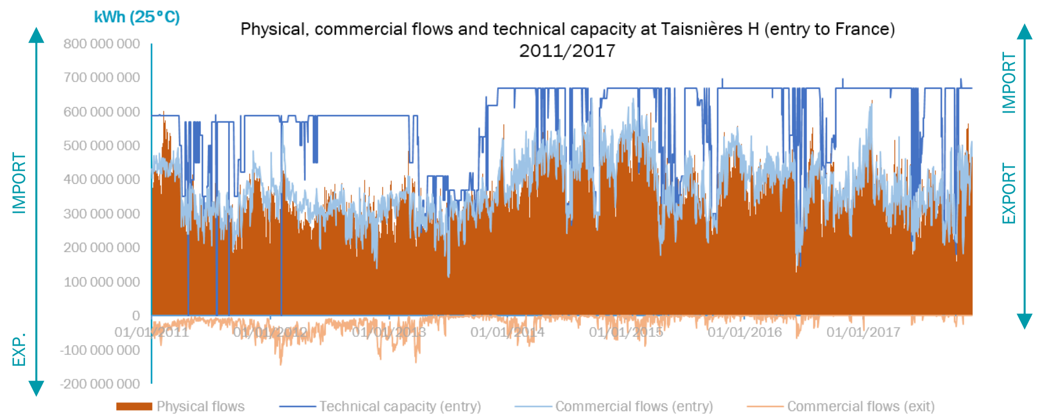
GAS INTERCONNECTION WITH NORWAY (DUNKIRK IP)

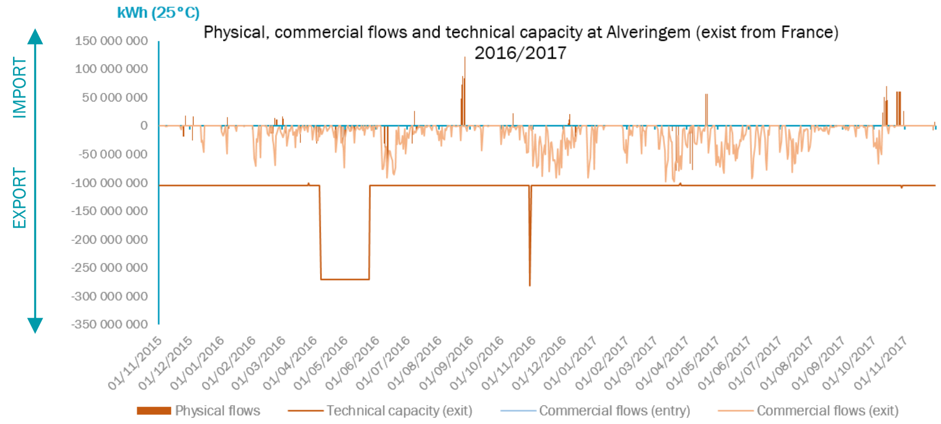


Imports from Norway via Dunkirk	Average annual utilisation rates
2015 : 189 TWh	2015 : 85 %
2016 : 179 TWh	2016 : 82 %
2017 : 195 TWh	2017 : 87 %

Highlights: approbation of new capacity allocation rules, in place since 1er June 2018.

GAS INTERCONNECTION WITH BELGIUM– H GAS (TAISNIERES H IP AND ALVERINGEM IP)



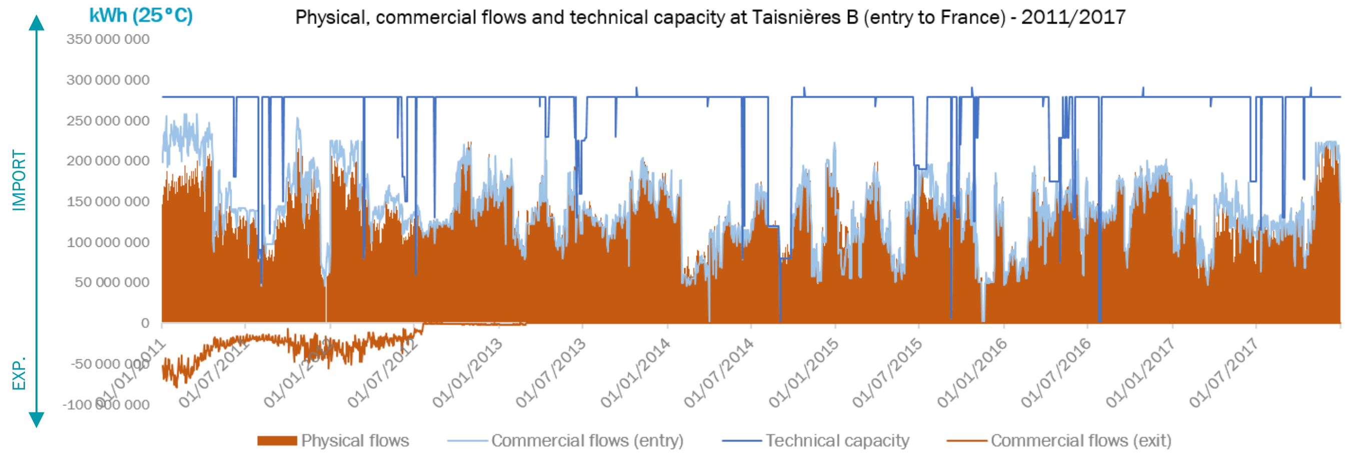


Imports from Belgium via Taisnières H	Average annual utilisation rates	Exports to Belgium via Alveringem	Average annual utilisation rates
2015 : 146 TWh	2015 : 68 %		
2016 : 139 TWh	2016 : 59 %	2016 : 6 TWh	2016 : 0%
2017 : 131 TWh	2017 : 56 %	2017 : 5 TWh	2017 : 0%

Highlights: Commissioning of the Alveringem IP in November 2015 and of the Virtualys VIP in November 2017.

The implementation of the Virtualys VIP materialises the integrated management of the border already put in place by the TSOs (physical entry flows at Alveringem).

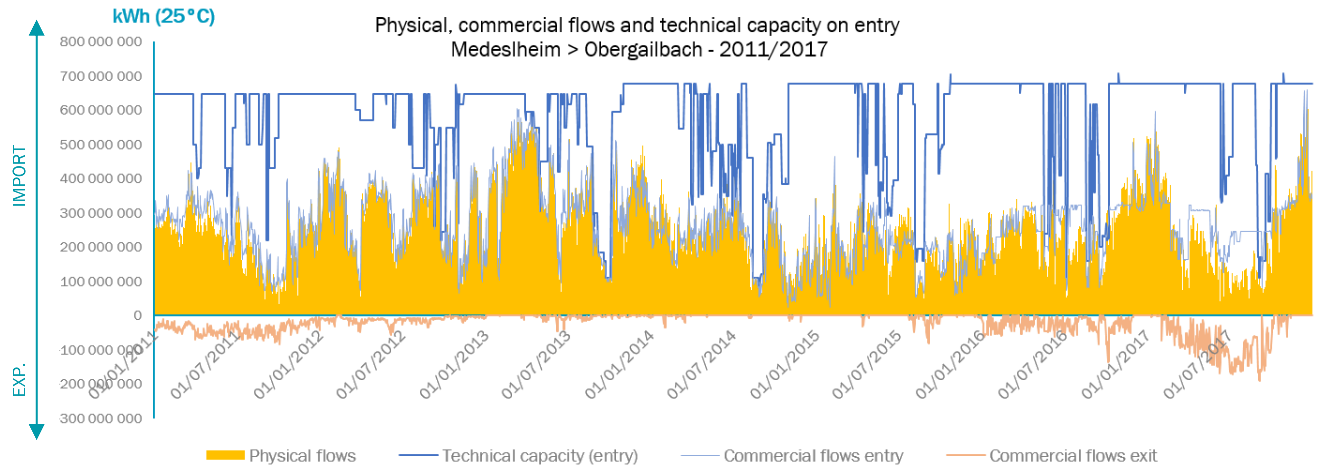
GAS INTERCONNECTION WITH BELGIUM – L GAS (TAISNIERES B IP)



Imports from via Taisnières B	Average annual utilisation rates
2015 : 44 TWh	2015 : 46%
2016 : 50 TWh	2016 : 51%
2017 : 49 TWh	2017 : 45%

Highlights: planned conversion of the Hauts-de-France zone to H gas with the end of the exploitation of the Groningen field (L gas).

GAS INTERCONNECTION WITH GERMMANY (OBERGAILBACH IP)

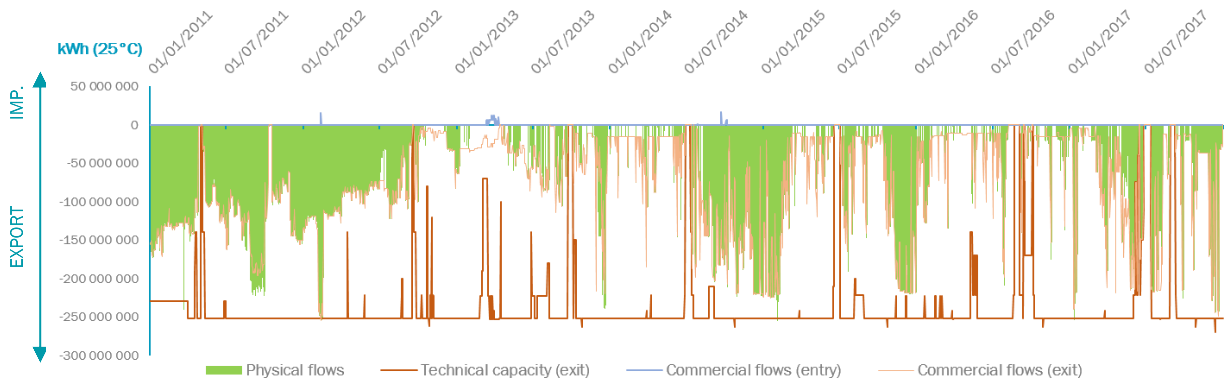


Imports from Germany via Obergailbach	Average annual utilisation rates
2015 : 66 TWh	2015 : 34 %
2016 : 90 TWh	2016 : 40 %
2017 : 83 TWh	2017 : 37 %

Highlights: increase of imports from Russia through Germany after a decrease in 2014 and 2015.

GAS INTERCONNECTION WITH SWITZERLAND AND ITALY (OLTINGUE IP)

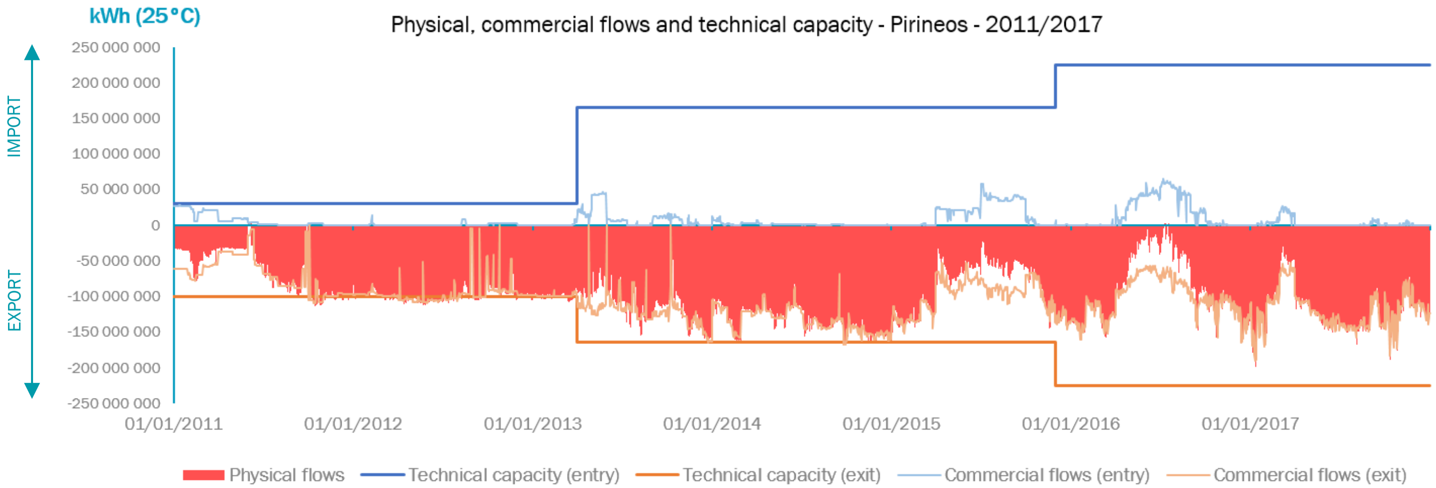
Physical, commercial flows and technical capacity at Oltingue (exit from France) - 2011/2017



Exports to Italy through Switzerland via Oltingue	Average annual utilisation rates
2015 : 30 TWh	2015 : 30%
2016 : 10 TWh	2016 : 9%
2017 : 27 TWh	2017 : 28%

Highlights: commissioning or 100 GWh/j of entry capacity at Oltingue (1er June 2018).

GAS INTERCONNECTION WITH SPAIN (ILARRAU AND BIRIATOU IPs THEN PIRINEOS VIP)



Exports to Spain via Pirineos	Average annual utilisation rates
2015 : 31 TWh	2015 : 56%
2016 : 25 TWh	2016 : 38%
2017 : 43 TWh	2017 : 52%

Highlights: increase of entry and exit capacities to 225 GWh/d in December 2015.

IMPLEMENTATION OF THE CACM REGULATION

CACM regulation articles	Methodologies	In elaboration	Under investigation	Decision
Article 4	Designation of the day-ahead and intraday electricity market operators in France			3 December 2015
Article 7	All NEMOs plan that sets out how to jointly set up and perform the market coupling operator's functions			22 June 2017
Article 15	Determination of capacity calculation regions			17 November 2016
Article 16	Methodology for the delivery of the generation and load data			5 January 2017
Article 17	Common grid model methodology			11 May 2017
Article 20	Capacity calculation methodology for the day-ahead and intraday timeframes within the Channel region		X	
	Capacity calculation methodology for the day-ahead and intraday timeframes within the Italy North region		X	
	Capacity calculation methodology for the day-ahead and intraday timeframes within the South West Europe region		X	
	Capacity calculation methodology for the day-ahead and intraday timeframes within the Core region		X	
Article 32	Methodology to be used in the existing bidding zone review process		X	
Article 35	Methodology for coordinated redispatching and countertrading in the Italy North region		X	
	Methodology for coordinated redispatching and countertrading in the South West Europe region		X	
	Methodology for coordinated redispatching and countertrading in the Italy North region		X	
	Methodology for coordinated redispatching and countertrading in the Core region		X	
Article 36	Back-up methodology for the price coupling algorithm			
Articles 40 et 53	Methodology concerning products that can be taken into account in the single day-ahead and intraday coupling			1 February 2018
Articles 41 et 54	Methodology concerning harmonised maximum and minimum clearing prices to be applied in single day-ahead and intraday coupling			25 December 2017
Article 43	Methodology for calculating scheduled exchanges resulting from single day-ahead coupling		X	

Article 44	Methodology for fallback procedures in the event that the single day-ahead coupling process is unable to produce result – Channel region		X	15 June 2017
	Methodology for fallback procedures in the event that the single day-ahead coupling process is unable to produce result – Italy North region		X	11 January 2018
	Methodology for fallback procedures in the event that the single day-ahead coupling process is unable to produce result – Core region		X	
	Methodology for fallback procedures in the event that the single day-ahead coupling process is unable to produce result – South West Europe region		X	
Articles 45 et 57	RTE's technical solution enabling the operation of several NEMOs in France			13 October 2016
Article 55	Methodology for pricing intraday cross-zonal capacity		X	
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GLOSSARY

4MMC: name of the market coupling project used in the Czech Republic, Slovakia, Hungary and Romania.

ACER: the Agency for the Cooperation of Energy Regulators is a European agency endowed with legal personality, instituted by regulation (EC) no. 713/2009 and created in 2010. The ACER is operational since the 3rd March 2011. Its headquarters is located in Ljubljana in Slovenia. The objective of the ACER is to help the national regulatory authorities in exercising and coordinating their regulatory tasks at the European level, and, if necessary, to complement their activities. It plays a key role in the integration of the electricity and gas markets.

Amprion: German electricity transmission system operator (with 50Hertz, TenneT and Transnet BW).

ARERA: Italian regulatory authority.

Automatic frequency restoration reserve: load reserve activated automatically by a signal from the TSO.

Backhaul capacity: entry to or exit capacity from a gas interconnection point that is in the reverse direction to the main physical flow (a backhaul capacity is available if the net flow remains in the same direction as the main physical direction of the flow).

Back-up allocation: allocation method used in case of a major failure of the single coupling platform at the intraday timeframe. It has not yet been developed at the European level.

BAL (network code): Commission regulation (EU) no. 312/2014 establishing a Network Code on Gas Balancing of Transmission Networks.

BE: Belgium.

BnA: German regulatory authority.

Board of regulators: body gathering the regulators' representatives at ACER.

CACM (guideline): Commission regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management.

CAM (network code): Commission regulation (EU) 2017/459 establishing a network code on capacity allocation mechanisms in gas transmission systems.

Capacity calculation region: in electricity, geographic area in which coordinated capacity calculation is applied.

CBA: cost-benefit analysis

CBCA: Cross-Border Cost Allocation for a Project of Common Interest.

CEER: The Council of European Energy Regulators is an association created in 2000 at the initiative of the national energy regulators of the EU and EEA member states. The CEER organisation structure is composed of a general assembly, sole decision-maker, a Board, working groups specialised in various domains (electricity, gas, consumers, international relations, etc.) and a secretariat that is based in Brussels. A work program is published every year. In conformity with the statuses, decisions are based on consensus and, failing that, by qualified majority voting.

CEF: Connecting Europe Facility.

Central West Europe region (CWE): electricity capacity calculation region containing Belgium, France, Germany, Luxembourg and the Netherlands.

CEP: Clean Energy Package for all Europeans, presented by the European Commission on November 2016.

CH: Switzerland.

Channel region: electricity capacity calculation region containing Belgium, France, Great Britain and Netherlands.

CMP: Congestion management procedures in the event of contractual congestion.

CMS: explicit allocation platform for cross-border rights, notably for the long-term timeframe, at the France/Great Britain border.

CNMC: Spanish regulatory authority.

Common grid model: Union-wide data set agreed between various TSOs describing the main characteristic of the power system (generation, loads and grid topology) and rules for changing these characteristics during the capacity calculation process.

Congestion rent: revenues created by the allocation of interconnection capacities at the various timeframes.

Continuous allocation: allocation method for which orders are executed directly when being placed on the order book (competing orders are executed in an order depending on their price and then their entry time).

Contractual congestion: situation where users of an interconnection can't contractually obtain transport capacity, even though they are physically available.

Core region: electricity capacity calculation region containing Austria, Belgium, Croatia, the Czech Republic, Germany, France, Hungary, Luxembourg, the Netherlands, Poland, Romania, Slovakia and Slovenia.

Coreso: the regional security coordinator for Western Europe.

CREG: Belgian regulatory authority.

Curtailment (of capacity): in electricity, cancellation of an interconnection's utilisation right already allocated.

CWD (Capacity Weighted Distance): method to determine the tariffs pricing structure based on the capacity and distance as weighing factors in the TAR network code.

Day-ahead market coupling: auctioning procedures in which the orders received are matched and the exchange capacity between the bidding zones is allocated simultaneously on the day-ahead market.

DCC (network code): Commission regulation (EU) 2016/1388 establishing a Network Code on Demand Connection.

DE: Germany.

DSO: distribution system operator.

E&R (network code): Commission Regulation (EU) 2017/2196 establishing a network code on electricity emergency and restoration.

EBGL (guideline): Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing.

Eirgrid: Irish electricity transmission system operator.

Elcom: Swiss regulatory authority.

Elia: Belgian electricity transmission system operator.

Enagás: Spanish gas transmission system operator.

Entry-exit system: system of access to the transmission networks that allows the shippers to subscribe separately entry and exit capacities.

ENTSOE (*European Network of Transmission System Operators for Electricity*): the TSOs cooperate at the EU level through the ENTSOs to promote the implementation and the functioning of the internal gas and electricity markets and cross-border exchanges, and to ensure an optimal utilisation, a coordinated exploitation and a robust technical evolution of the gas and electricity transmission systems. In this context, the ENTSOs elaborate the European network codes on the basis of the guidelines established by the ACER and in close cooperation with the Agency.

ENTSOG: European Network of Transmission System Operators for Gas, see ENTSOE.

EPEX Spot: electricity stock exchange.

ERSE: Portuguese regulatory authority.

ES: Spain.

Explicit auction: auction organised by the TSOs and that concerns only the allocation of the cross-border interconnection capacity.

Fallback procedure: allocation method used in case of a major failure of the single coupling platform at the day-ahead timeframe (and at the intraday timeframe in the two months following its launch).

FCA (guideline): Commission Regulation (EU) 2016/1719 establishing a guideline on forward capacity allocation.

FCR: Frequency Containment Reserve

Firm capacity: interconnection capacity whose utilisation is contractually guaranteed.

Flow Based market coupling: market coupling consisting in reflecting as faithfully as possible the grid physical limitations on the constraints imposed to commercial flows, included to the market coupling algorithms. It constitutes the target model prescribed by the CACM regulation for the day-ahead and intraday timeframes.

Fluxys: Belgian gas transmission system operator.

Frequency containment reserve: load reserve automatically activated depending on the measured grid frequency to stabilise it.

FTR (Financial Transmission Rights): long-term rights that don't allow to nominate energy, but guarantee their holders to receive the concerned bidding zones' price spread.

Gassco: the operator of the upstream gas pipelines in the North Sea.

GB: Great Britain.

GRTgaz: French gas transmission system operator (with Teréga).

HAR: Harmonised Allocation Rules for long-term rights.

HVDC (network code): Commission Regulation (EU) 2016/1447 establishing a network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules.

IGCC: (International Grid Control Operation): project aiming at decreasing the automatic frequency restoration reserve activations of the involved TSOs by cancelling their activations in the opposite direction.

Implicit auction: auction organised by the NEMOs and the TSOs and that concerns at the same time the capacity and the energy, which are allocated simultaneously.

Incremental capacity: a possible future increase via market-based procedures in technical capacity or possible new capacity created where none currently exists that may be offered based on investment in physical infrastructure or long-term capacity optimisation and subsequently allocated subject to the positive outcome of an economic test.

Infrastructure package: regulation (EU) no. 347/2013 of the European Parliament and of the Council on guidelines for trans-European energy infrastructure.

Interlinked electricity and gas market and network model: model established jointly by ENTSOE and ENTSOG in order to model the links between the gas and electricity networks for the PCIs' cost-benefit analysis.

Interoperability and data exchange rules (network code): Commission Regulation (EU) 2015/703 establishing a network code on interoperability and data exchange rules.

Interruptible capacity: interconnection capacity whose utilisation is not contractually guaranteed.

IP (Interconnection Point): interconnection between the main network of a TSO and either an adjacent TSO or an upstream pipeline.

IT: Italy.

Italy North region: electricity capacity calculation region containing Austria, France, Italy and Slovenia.

JAO: allocation platform for the electricity long-term rights.

LNG: liquefied natural gas.

Local energy communities: grouping of consumers, producers and/or prosumers with the objective of optimising and balancing their energy generation and consumption.

Loop flow: in electricity, flows that origin and have their destination in the same bidding zone but transit through an adjacent zone.

Manual frequency restoration reserve: load reserve activated manually by the TSO, with an activation time of less than 15 minutes.

MCO Plan: NEMOs plan that sets out how to jointly set up and perform the market coupling operator's functions.

N-1 criterion: rule according to which the elements still functioning within a TSO's control area after a hazard are able to face the situation without breaching the system operational safety.

National Grid: British gas and electricity transmission system operator.

NBP: British gas market zone.

NCG: German gas market zone (with Gaspool).

NEMO: Nominated Electricity Market Operator.

Net position: netted sum of electricity exports and imports for each market time unit for a bidding zone.

Nord Pool Spot: electricity stock exchange.

NTC (Net transfer capacity) in electricity, commercial capacity offered to the market.

Ofgem: British regulatory authority.

Open Season: procedure used to dimension a new infrastructure based on the market needs, and to allocate the corresponding capacities in a non-discriminatory manner.

PCI: Project of Common Interest.

PEG Nord: market zone of the North of France that will merge with the TRS zone on 1st November 2018.

PITTM (*Point d'Interface Transport Terminal Méthanier*) – LNG terminal

Price convergence: percentage of time during which the wholesale prices of two bidding zones are equal.

Prisma: booking platform for gas transport capacity.

PTR (Physical Transmission Rights): long-term rights that give a physical access to cross-border capacity, by allowing their holders to nominate energy exchanges between the concerned zones.

RAB: regulated asset base.

REE: Spanish electricity transmission system operator.

REN: Spanish gas and electricity transmission system operator.

Replacement reserve: load reserve manually activated by the TSO, with an activation time of more than 15 minutes.

Reserve price: eligible floor price in an auction.

RfG (network code) : Commission Regulation (EU) 2016/631 establishing a network code on requirements for grid connection of generators.

ROC: Regional Operational Centre.

RSC (regional security coordinator): entity detained or controlled by the TSOs, in one or several capacity calculation regions, which executes tasks related to the coordination of the TSOs regional security.

RTE: French electricity transmission system operator.

SDDR (*Schéma Décennal de Développement du Réseau*) : RTE's Ten-year Network Development Plan

Snam: Italian gas transmission system operator.

SO (guideline): Commission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation.

South West Europe region (SWE): electricity capacity calculation region containing France, Portugal and Spain.

Swissgrid: Swiss electricity transmission system operator.

TAR (network code): Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas.

Teréga: French gas transmission system operator (with GRTgaz).

Terna: Italian electricity transmission system operator.

TRS: (Trading Region South) – South of France market zone that will merge with the *PEG Nord* zone in November 2018.

TSO: transmission system operator.

TTF: Dutch gas market zone.

TYNDP: Ten-Year Network Development Plan, developed by the ENTSOs every two years.

UCPTE: Union for the coordination of electricity generation and transport

UCTE: Union for the Coordination of Transmission of Electricity

VIP: (Virtual Interconnection Point) – two or more interconnection points which connect the same two adjacent entry-exit systems, integrated together for the purposes of providing a single capacity service.

WACC: weighed average cost of capital.

XBID: « *Cross Border Intraday Trading Solution* » European project to which all interconnected EU member states will participate. Its objective is to establish a platform on which, at the intraday timeframe, all interconnection capacities will be allocated in a continuous and implicit manner at the level of the coupled region.

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