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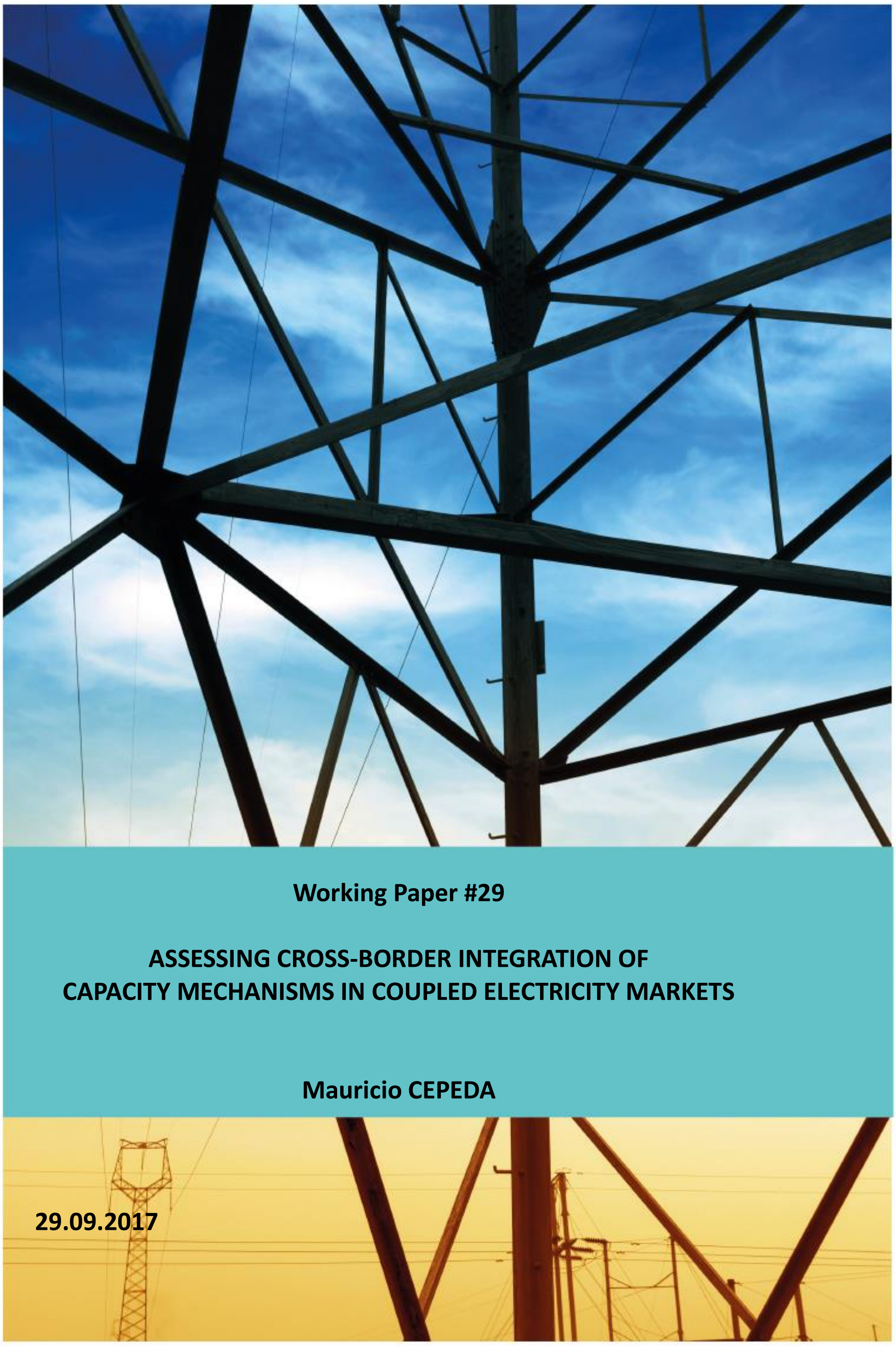

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ASSESSING CROSS-BORDER INTEGRATION OF CAPACITY MECHANISMS IN COUPLED ELECTRICITY MARKETS

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ASSESSING CROSS-BORDER INTEGRATION OF CAPACITY MECHANISMS IN COUPLED ELECTRICITY MARKETS

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Abstract
There is momentum in a number of European electricity markets towards the implementation of national generation capacity mechanisms. This renewed interest in capacity mechanisms raises the question of the cohabitation of both relatively well-integrated short-term energy markets and national generation capacity mechanisms. This paper examines a key issue of generation adequacy policies in a multi-market environment: the effect of foreign generators and interconnectors' inclusion in national capacity mechanisms. The results show that the absence of cross-border participation could lead to significant social welfare losses associated with over- and under- capacity procuring risk. We also find that the inclusion of foreign generators in national capacity markets increases efficiency relative to the case where only interconnectors can participate.

Keywords: Capacity mechanisms, Interconnections, Security of supply, Market coupling, Europe.

I. INTRODUCTION

To date, a large number of EU members have already implemented a certain type of capacity remuneration policy or are considering doing so to address national generation adequacy concerns[1]. The functioning principles and the pace of implementation of the capacity mechanisms differ considerably from one country to another, as they are being driven by case-by-case scenarios to achieve the best fit to the local requirements. The specifics of market-based capacity mechanisms range from the central buyer solution, such as the capacity auction implemented in GB in 2014, to the supplier obligation solution, such as the decentralised capacity market implemented in France in 2016 (De Vries, 2007; Finon and Pignon, 2008; Cramton *et al.*, 2013). Alternatively, a targeted mechanism for strategic reserves exists or is being installed in several European countries such as Sweden, Finland, and Poland. Thus, capacity mechanisms can either remunerate all generation or demand contributing to the long-term security of supply (capacity markets), or can contract generation assets that will only be used if markets no longer clear or if the price exceeds a strike price (strategic reserves). These differences suggest that there is no standard design of capacity mechanism and that a consistent European solution for capacity remuneration, therefore, is unlikely in the short-term.

Through the Energy Union strategy (EC, 2015a) and the so-called "Winter Package" of energy laws (EC, 2016a), the European Commission (EC) has raised concerns that the security of supply goal may be undermined by the fact that market design decisions are made at the national level and are weakly harmonised across Europe[2]. The EC is of the view that uncoordinated capacity mechanisms may distort

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[1] Capacity market is not a new concept. Several markets in the US and South America have implemented capacity markets with varying degree of success (Finon and Pignon, 2008; Joskow, 2008).

[2] EC also launched in April 2015 a sector-wide inquiry (EC, 2015b; EC, 2016b) into capacity mechanisms. The inquiry gathered information on capacity mechanisms to examine whether they ensure sufficient electricity supply without distorting competition. It was initially focus on Belgium, Croatia, Denmark, France, Germany, Ireland, Italy, Poland, Portugal, Spain, and Sweden. The EC's final report points out that many Member States currently have inadequate security of electricity supply frameworks in place and they use outdated and

cross-border trade and hinder the achievement of the Internal Electricity Market in Europe. Therefore, market capacity mechanisms must be open to explicit cross-border participation in order to minimise distortions to cross-border competition and trade, ensure incentives for continued investment in interconnection and reduce the long-term costs of European security supply (ACER, 2013; EC, 2016a; EC, 2016b).

Still from the EU perspective, the Third Package[3] (EC, 2009) promotes the European Electricity Target Model (ETM)[4], which aims to enhance competition by opening the national markets to foreign participants, thereby increasing supply security and cost efficiency. By design, the ETM, optimises cross-border flows by combining the demand and the supply curves for electricity of coupled markets to set market clearing prices, with and without cross-border transmission constraints. Under the ETM, if two neighbouring countries experience a stress event simultaneously, power would tend to flow out of the country with the lowest prices, irrespective of whether that country had called upon its capacity providers to deliver greater supply. However, the cohabitation of the ETM and capacity mechanisms raises concerns about the reliability of the direction of flow for an interconnector during a period of power system stress (RAP, 2013). Because congestion in the interconnections split the collective good "adequacy" between interconnected markets, if power is going to flow according to the ETM it might be difficult for a foreign generator to take on an obligation that is beyond their control (Crampton *et al.*, 2013; Finon, 2014). While the risk of coincident stress events and/or market inflexibilities may be relatively small, these are genuine risks and impact short- and long-term efficiency.

Several possible approaches may be adopted to address the question of the cross-border competition in an interconnected electricity market with capacity mechanisms. These approaches take into account different methods of cross-border participation in capacity mechanisms: i) the statistically likely contribution from interconnectors (i.e. implicit cross-border participation with no trade of capacity rights); ii) the explicit participation of the interconnectors in capacity mechanisms; iii) the actual cross-border participation of foreign generation capacity under heterogeneous capacity mechanism; iv) the actual cross-border participation of foreign generation capacity under harmonised capacity mechanisms and; v) the implementation of pan-European capacity mechanism.

In practice, European countries started implementing capacity mechanisms under purely national schemes without providing for a remuneration of cross-border capacity (e.g. GB, France, Nordic Countries, Italy, and Ireland). The most used approach has been an implicit methodology, which calculates the statistically likely contribution from interconnectors when deciding the domestic generation capacity to procure. However, several countries are currently considering adapting their capacity mechanisms to cross-border capacity participation (AEEG, 2013; DECC, 2013; RTE, 2014).

In the GB capacity mechanism, for example, interconnectors are eligible to bid into the capacity auction since 2015 for the delivery year 2019/2020 onwards and have the same obligations to deliver energy than conventional generation capacity[5]. The interconnectors are the bidding parties and become the holder of a capacity agreement up to the level of the de-rated capacity. They receive the clearing price in the auction and hold the capacity obligation in line with the requirements for the other technologies. This modification in the market design has also raised the interest of merchant

inconsistent approaches to assessing security of electricity supply. It also states that Member states must not restrict capacity in their territory from participating in foreign capacity markets.

[3] The term "Third Package" refers to a package of EU legislation on European electricity and gas markets that entered into force on 3 September 2009.

[4] The ETM is set out in the Framework Guideline on Capacity Allocation and Congestion Management for Electricity (CACM FG) published by the Agency for the Cooperation of Energy Regulators (ACER) in July 2011.

[5] Interconnectors were unable to participate in the first capacity auction held in December 2014. Amendments to the Regulations have been laid in Parliament to enable interconnectors to participate in the Capacity Market. https://www.gov.uk/government/news/interconnectors-to-participate-in-the-capacity-market-from-2015.

interconnectors[6] seeking additional revenues to cover their capital cost. From the public authorities' perspective, it is presented as an opportunity to deal with the lack of interconnector investments, which has been commonly pointed out as one of the main barriers towards an efficient integration of the European electricity markets.

The impact assessment of the interaction of capacity mechanisms in a multi-market environment has been a critical issue for consideration among regulators, policy makers and academics when designing and implementing generation adequacy policies. Although most previous researchers have centred on the heterogeneity of the capacity mechanisms in interdependent electricity markets and the relevance of the cross-border generation participation (Cepeda and Finon, 2011; Finon, 2014; Meyer and Gore, 2015), little attention has been focused on the dynamics of the market interconnection and its impacts on the long-term equilibrium in coupled markets with capacity mechanisms. While externalities generated by the use of the interconnectors for trade between markets, such as deferring generation investments and contributing to reliability, lead to sub-optimality of interconnector investment[7]; this paper argues that cross-border participation in capacity mechanisms partially corrects for these externalities.

The purpose of this paper is to investigate a key issue of generation adequacy policies in a multi-market environment: the effect of both foreign generators and interconnectors' inclusion in national capacity mechanisms. For this, we examine four different cases: (case 1 – reference case) two inter-linked markets with interconnector and foreign generation participation in capacity mechanisms; (case 2) two inter-linked markets with interconnector participation but without foreign generation participation in capacity mechanisms; (case 3) two inter-linked markets without any type of cross-border generation participation in capacity mechanisms; and (case 4) one energy-only market linked with one market with capacity mechanism without any type of cross-border participation in capacity mechanism. The purpose here is to compare over time the dynamic evolution in two inter-linked markets for these different cases, assessing the economic performances of different policies (e.g. the evolution of the generation technology mix, the reliability criteria, and the overall social welfare).

We rely on a long-term dynamic model of two inter-related markets to assess different cross-border generation adequacy policies. The model is based on Cepeda and Finon (2011) and is expanded to incorporate both strategic bidding behaviour in the energy market and endogenous development of the interconnection capacity. It has been developed using concepts and tools from system dynamics, which is a branch of control theory applied to economic and management problems. This methodology has been extensively used in electricity market modelling to represent capacity expansion planning in wholesale markets (Forrester, 1961; Bunn and Larsen, 1992; Ford, 1997, 1999; de Vries and Heijen, 2008; Cepeda and Finon, 2011). In the following section, we examine the question of competition among interconnected electricity markets with capacity mechanisms and merchant interconnectors. Section 3 describes the long-term dynamic model of two-coupled electricity markets with capacity mechanisms and linked by merchant interconnectors. Section 4 presents the results of the simulations. We conclude in Section 5.

[6] Merchant interconnectors are considered as a commercial alternative to regulated TSO investments. Unlike regulated interconnectors, merchant interconnectors are repaid through congestion revenues over the interconnector instead of the regulated transport tariff. Merchant interconnectors may be granted exemptions from regulations such as: tariff, regulation, non-discriminatory third-party access and ownership unbundling.

[7] Interconnection investments provide another externality. It reduces market power in the generation market by creating additional options for meeting domestic demand (Stoft, 1997; Borenstein *et al.,* 2000).

II. COMPETITION IN INTERCONNECTED ELECTRICITY MARKETS WITH CAPACITY MECHANISMS

In interdependent electricity markets, generation adequacy should ideally be treated under a common mechanism. In Europe, given the intrinsic differences among the capacity mechanisms in place or others still in the process of implementation, a Pan-European approach seems highly unlikely in the short-term. If a regional implementation is not possible, a unilateral implementation of capacity mechanisms based on a harmonised approach should be the next best option. This solution, however, supposes a co-ordination of the capacity mechanism or coordinated exchanges in trading platforms, which seems unrealistic for the same reasons as per for the Pan-European approach. If it is not possible to harmonise capacity mechanisms, the cross-border exchange of capacity rights is assumed to be socially efficient despite the heterogeneity of the different capacity mechanisms (Finon, 2014).

In this context, we focus our discussion on cross-border competition among interconnected markets by considering the potential consequences when capacity mechanisms are introduced in few or all the coupled markets. First, we look at the economic inefficiencies due to the non-participation of explicit or implicit cross–border capacities in capacity mechanisms. Second, we discuss the long-term impacts of the explicit participation of interconnectors in capacity mechanisms.

For the sake of simplicity in our discussion, we use the term "capacity mechanism" to refer to a wide range of mechanisms that make payments for the availability of capacity and encompass three different principles: coordination by price (e.g. capacity payments), coordination by quantity (e.g. capacity obligation, capacity forward auction and reliability option auction), and a command and control approach (e.g. targeted mechanism for strategic reserves) (Finon and Pignon, 2008). We believe that our general observations would similarly apply in coupled markets with any of these different adequacy policy approaches.

Relevance of cross-border participation in capacity mechanisms

The interaction of markets in different zones, and for different products, allows increase of efficiency gains by benefiting from the complementarity of production and demand patterns between markets (e.g. substitution of cheaper generation for more expensive generation). This benefit will tend to increase with the scale and geographical reach of the interconnected markets.

In terms of delivering short- and long-term security of supply, the benefits of interconnection are well known such as the reduction of the ancillary services costs and the deferral of investment in generation (Billinton and Allan, 1996; Cepeda *et al.,* 2009; Newbery, 2014). Not taking account of interconnection in the generation adequacy assessment could lead to investment in more domestic generation than necessary, increasing costs for consumers[8]. Conversely, not fully taking account of the fact that interconnections may not always deliver power during a stress event due to power loops flows[9] could signal the need for less domestic generation than necessary.

As for cross-border trading with capacity mechanisms, excluding interconnectors from participating in a capacity mechanism (directly or indirectly via generators located abroad) would skew investment signals in favour of local generation. Even if it were cheaper to provide capacity to meet security of supply standards by developing more interconnection capacity, investors may choose to develop new

[8] For example, in the GB context, the Transmission System Operator, National Grid, determined an expected de-rated contribution from interconnectors at times of system stress for 2019/20 equal to 2,900 MW (National Grid, 2015). This amount is a direct reduction of generation capacity to procure for 2019/20 which is, in terms of installed capacity.

[9] Power loop flows occur when a country does not have enough internal grid infrastructure to handle new production, for example from wind, and so the power is diverted through neighbouring countries' grids and then back into a different part of the producing country. Such loop flows have become more common since Germany developed large amounts of wind power in its northern states, but did not develop the grid infrastructure to transfer the output south to where the demand is.

local power plants due to the additional investment incentive provided by the capacity mechanism over and above that provided by the energy price. The effect would be to raise the cost of meeting the reliability standard if the lowest cost sources of capacity (across the set of possible generator and interconnector projects) were not developed. In contrast, from a long-term perspective, if the capacity of country A is built because it successfully participated in the country B capacity mechanism, country B benefits from lower costs of reliability, compared to a situation in which only capacity from country B can bid into its capacity mechanism.

Another consideration regards the fact that Governments and TSOs can verify domestic capacity providers reasonably easily by imposing pre-qualification requirements and testing administratively that participants are able to physically deliver their firm capacity commitment. On the contrary, from a regional perspective it might be difficult for Governments and TSOs to make the same verifications on capacity providers in different countries.

A way to deal with this problem of the credibility of commitment of foreign generators is the reservation of interconnection capacity. For example, generation units of country A committed in the capacity mechanism of country B would have a priority access considered by the market coupling algorithm, as if they implicitly had a share in the interconnections, provided that they have bought forward transmission rights (ENTSO-E, 2014). This reservation of capacity might thus ensure the availability of cross-border transmission capacity for foreign capacity providers to meet capacity commitments. Nevertheless, this approach that specifically reserves interconnector capacity for use in scarcity periods would mean that the interconnector capacity could not operate in the standards energy market on a day-to-day basis, which would be detrimental to social welfare by reducing cross-border energy trades. Booking interconnection capacity of foreign generation adequacy providers would therefore not give any additional guarantees on the firmness of cross-border contribution to security of supply[10].

Direct participation of interconnectors in capacity mechanisms to fix discrepancies between transmission costs and benefits

Given the additional revenue provided by capacity mechanisms to incentivise new investments, the direct cross-border participation of interconnectors in this scheme inevitably raises the widely known question, and still not fully solved, on investment in interconnection capacity.

In theory, the optimal capacity investment decision made by an interconnector would be that which equates the average spread between marginal cost and revenue with the marginal cost of capacity, whereas the social optimum would be larger, equating the spread price with the marginal cost of capacity. Notwithstanding, interconnection undergoes returns to scale and lumpiness, as well as major externalities, both positive and negative, which leads to underinvestment (Brunekreeft, 2003; Turvey, 2004; McInerney and Bunn, 2013).

On the one hand, returns to scale and lumpiness make merchant interconnectors recover their proportional costs to capacity from the congestion rents but not costs that are independent of the line capacity (i.e. fixed costs). In other words, optimal interconnection investments will simply not generate enough congestion rent to pay for them, which means merchant interconnectors will build less than the social optimal investment. On the other hand, the sub-optimality of interconnection investments comes also from the fact that any interconnector's benefit arises from deferring other investment and from contributing to reliability is an externality, provided that there is no agreement

[10] In the GB capacity market, The Department of Energy & Climate Change (DECC) took the decision to let the market coupling algorithm determine the flows and to prevent interconnectors to exert influence over them. Furthermore, to mitigate any risk of introducing a policy that runs counter to market coupling, penalties are capped at the level of annual payments and interconnectors will not be subject to greater penalties if they are exporting.

with the system or transmission operator for a contribution to its revenue (Turvey, 2004). Thus, any new interconnection investment allows postponement of investment in new generation in one of the two systems, which it links. This avoided cost for the whole system will constitute a beneficial externality[11].

On some European borders, merchant interconnector investment decisions are made in response to marked-based incentives such as the congestion revenues, long-term transmission rights[12] and profits from locational arbitration[13]. Merchant interconnectors can also benefit from capacity revenues by participating in capacity mechanisms as per the GB capacity market (Ofgem, 2014a)[14]. This additional revenue from capacity mechanisms becomes a driver for new investments in interconnection capacity as it partially compensates network externalities losses. In turn, additional interconnector capacity increases the economic gains of cross-border participation by allowing a larger participation of foreign generators[15].

III. THE STRUCTURE OF THE MODEL

The model is based on Cepeda and Finon (2011) and is expanded to incorporate interconnector investments, while preserving the essential features of the model: thermal generation modelling and its long- and short-term uncertainties (i.e. demand growth rate uncertainty, generation unit outages and load thermo-sensitivity), reliability modelling, short-term interaction between local electricity markets, anticipation of demand growth and supply in the investment decision process. In this paper, we model integration of interconnectors into the price formation mechanism and into the investment decision process, including their participation in the capacity mechanism; and strategic bidding behaviour in the energy market.

[11] The only case in which it might not be an externality is when the postponement interconnector makes its prices higher than they otherwise would be, with a favourable effect upon the profitability of the interconnector.

[12] Transmission rights could be either Physical Transmission Right or Financial Transmission Right acquired in a Forward Capacity Allocation. Financial Transmission Rights are either based on an obligation entitling its holder to receive obliging its holder to pay a financial remuneration based on the Day Ahead Market results between two Bidding Zones; or based on an option entitling its holder to receive a financial remuneration based on the Day Ahead Market results between two Bidding Zones. Financial Transmission Rights are part of the Network Code on Forward Allocation Capacity (Entso-e, 2014).

[13] Interconnectors can also provide capacity agreements to traders and generators which provides more secure revenue than the uncertain price differences.

[14] There are other mechanisms to incentivise new investments in interconnection capacity. For example, the GB energy regulator put in place in 2014 a new regulated route for near term interconnector investment, known as the cap and floor regime (Ofgem, 2014a). Under this approach developers build interconnectors and there is a cap and floor mechanism to regulate how much money a developer can earn. The Transmission System Operator (TSO) will set the levels of the cap and floor *ex-ante* and they will remain fixed (in real terms) for the duration of the regime. Thus, any revenue earned above the cap will be returned to the concerned TSOs on a 50:50 basis and the TSOs will then reduce their electricity transmission network charges in both countries. If revenue falls below the floor then the interconnector owners will be compensated by the concerned TSOs. The TSOs will recover the costs through their network charges. This regulatory design seeks to reduce risk of exposure for investors while ensuring that excess revenues are returned to the TSOs to benefit GB consumers.

[15] Economics gains through capacity mechanisms cannot be seen as first best solution, which one could obtain from the theoretical centralised approach of the benevolent planner where interconnection and generation capacity are optimised for expected load growth. In fact, because generation is not planned, interconnectors must forecast future generation and load many years in advance to assess their profitability. Thus, merchant interconnectors do not have control or direct knowledge of future generation investments, and face both complex cost structure and network externalities which causes underinvestment without being entirely overcome through revenues from capacity mechanisms.

The main relationships included in our modelling of investments in new generation capacity and interconnectors follow the structure of the causal-loop diagram depicted in Figure 1. Expected profitability is determined by expectations of future prices, congestion revenues and the payments from the capacity mechanisms. As this additional revenue increases, expected profitability and generation/interconnection capacities raise, thus electricity spot prices decrease. In addition, as long as installed generation or interconnection capacity increases, expectations regarding future electricity prices go down, which in turn lowers expectations of future prices. As a result, the economic attractiveness of new investments is reduced.

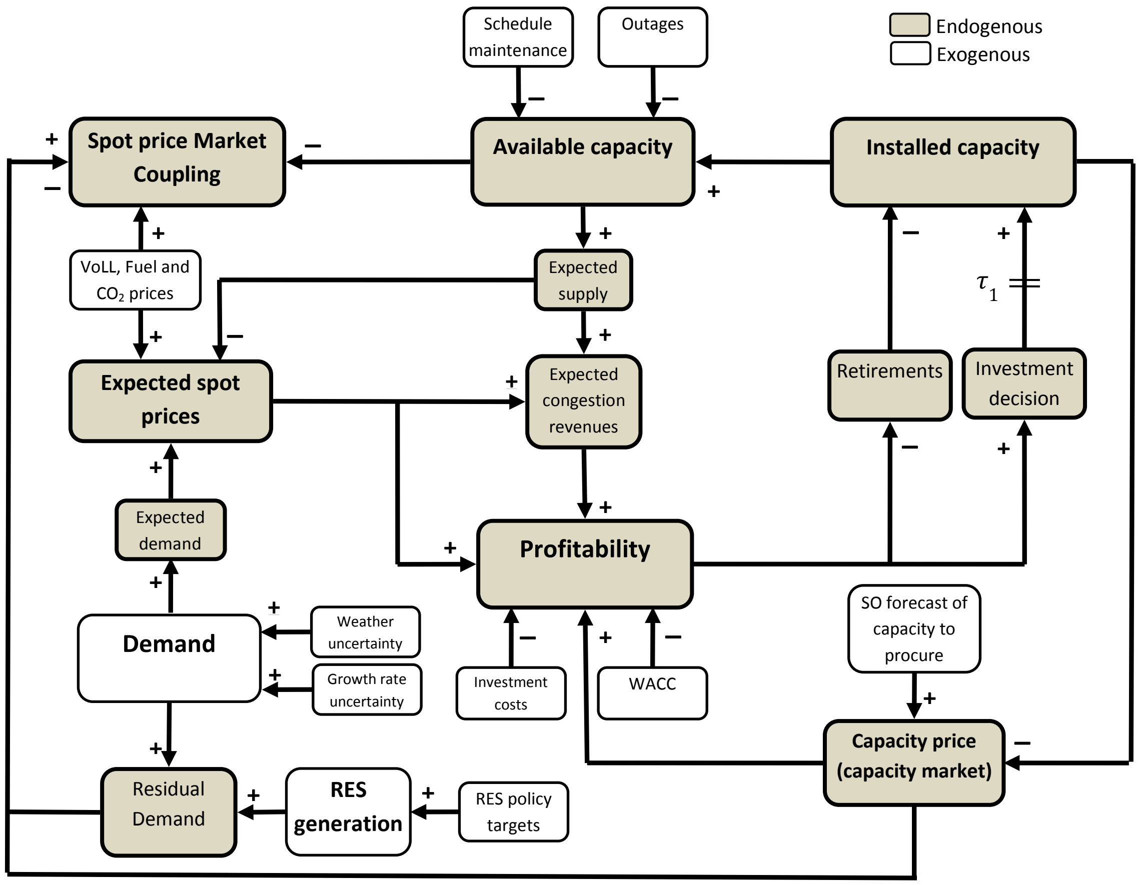


Figure 1. Causal-loop diagram of a coupled electricity market

The representation of the coupled electricity market

The modelling of thermal generation, demand curtailment, electricity price formation and reliability are explained thoroughly in Cepeda and Finon (2011). We distinguish between the perfect competition framework and the strategic bidding behaviour of the market participants in the energy market. In the former case, electricity producers have no market power, neither in fuel markets nor in the electricity market. Thus, the price is generally settled by the marginal cost of generation, i.e. the variable cost of the marginal technology. If demand exceeds the available generation capacity, the electricity price is set at the value of loss of load (VoLL).

As for the strategic bidding behaviour case, as Eager *et al.* (2012) and Hach *et al.* (2015), we introduce marginal bid curves by allowing price mark-ups as a function of the scarcity of generation capacity. Thus, we represent a form of exercise of market power in which generators can cover their fixed costs during fewer hours, which means less need for electricity prices set at the VoLL. Precisely, the price mark-up function $\beta(K_m^{t,i,\tau})$ depends on the generation margin $K_m^{t,i,\tau}$ in the price zone i, for the period τ and time step t; which is defined as follows:

$$K_m^{t,i,\tau} = \frac{(\sum_j K_j^{i,\tau}) - L^{t,i,\tau}}{\sum_j K_j^{i,\tau}} \tag{1}$$

where $K_j^{i,\tau}$ is the available capacity of the technology j and $L^{t,i,\tau}$ is demand for the time step t.

Given the generation margin $K_m^{t,i,\tau}$, the electricity price increase due to the strategic bidding behaviour is described as:

$$p_{sb}^{t,i,\tau}\left(K_m^{t,i,\tau}\right) = p^{t,i,\tau} \cdot \left(1 + \beta\left(K_m^{t,i,\tau}\right)\right) \tag{2}$$

Modelling investment and capacity mechanisms in coupled electricity markets

In the model, investment decisions in new generation capacity and interconnectors mainly depend on the expected prices, which reflect expected market conditions, which in turn are a function of expected demand and expected generation availability. We model a ''forward merit-order dispatch'' to calculate the future electricity prices. We implement a second-order smoothing process to forecast the expected growth rate of demand and the available generation for each technology, using a variant of the procedure adopted by Cepeda and Finon (2011). We calculate these expectations from the built-in function forecasting in MATLAB. In addition, the algorithm of the model verifies the age of all power plants and interconnectors against their economic lifetime and retires all plants for which the age exceeds the lifetime.

In a coupled electricity market with a capacity mechanism, investment decisions depend on the expected revenue jointly earned from the capacity remuneration mechanism and, through sales on the energy market for generators and congestion revenues for interconnectors. In the model, the capacity market operates three years ahead of real time, with a target corresponding to the peak period of any future year[16]. For the sake of simplicity, we assume that there is a vertically integrated generation-supply; interconnectors are independent parties and not vertically integrated; and the TSO is responsible for organising the capacity auction (as per the GB capacity mechanism). On behalf of the suppliers, the TSO buys a prescribed level of available capacity to meet future peak demand and an additional security margin.

We model the auction mechanism based on the financial call option principle with a price cap in the energy market acting as a strike price when the option is exerted by the TSO. We assume that the price cap or the strike price, given by sp^i, is exogenous and fixed *ex ante* in the model. Thus, while revenues from the energy market are capped over peak-load hours, generators and interconnectors will receive additional revenue from the capacity market according with their de-rating factor[17]. Producers and interconnectors pay a penalty, given by pen^i, when commitments are not met which means that their resources are not available to the system when the TSO requires them.

A rational power generator determines his bid price in the capacity auction $p_{cm,j}^{i,\tau}$ (i.e. his desired premium fee in the auction for availability generation capacity) at the period τ for an amount of $q_{cm,j}^{i,\tau}$

[16] We assume that both generator and interconnectors offer their full available capacity in the capacity market.
[17] The de-rating factor determines the level of capacity agreement that can be secured in the capacity market by a given resource. They are generally set by both Regulators and TSOs from historical and forecasting methodologies. They reflect the different characteristics of the technologies used in terms of maintenance scheduling and outages duration. Unlike generators, de-rating factors for interconnectors are based on future and expected flows. DECC (2015a) provides further details.

MW equal to the product of the de-rating factor $DF_j^{i,\tau'}$ for the future delivery period τ' of the technology *j* in the price zone *i* and the installed capacity $K_j^{i,\tau'}$, defined as follows:

$$p_{cm,j}^{i,\tau} = E\left[\sum_{\forall t \rightarrow sp^i < \hat{p}^{t,i,\tau'}} \left[(1 - FOR_j{}^{i,\tau'}) \cdot (\hat{p}^{t,i,\tau'} - sp^i) \cdot \frac{\hat{q}_j^{t,i,\tau'}}{K_j^{i,\tau'} \cdot DF_j^{i,\tau'}}\right]\right] +$$

$$E\left[\sum_{\forall t \rightarrow sp^i < \hat{p}^{t,i,\tau'}} \left[(FOR_j{}^{i,\tau'}) \cdot (\hat{p}^{t,i,\tau'} - sp^i + pen^i) \cdot \frac{\hat{q}_j^{t,i,\tau'}}{K_j^{i,\tau'} \cdot DF_j^{i,\tau'}}\right]\right] \tag{3}$$

The first term in Eq. (3) represents the missing money in the future energy market if resource availability commitments are satisfied, since for a generator, the energy price has a maximum value equal to the strike price sp^i. The summation extends to every period where, for the expected aggregated generation $\sum_t \sum_j \hat{q}_j^{t,i,\tau'}$, the expected spot price $\hat{p}^{t,i,\tau'}$ for the delivery period τ' and time step t is higher than the strike price sp^i. The second term in Eq. (3) represents the potential penalties pen^i to be paid when generators are not able to meet their generation availability commitments. $FOR_j{}^{i,\tau'}$ represents the probability of occurrence of the outages event i.e. when generators or interconnectors are not able to be available for the capacity committed in the auction $q_{cm,j}^{i,\tau}$. We can underline that, on the one hand, the option premium which is required by a certain block of capacity is independent from the generators' production costs and, on the other hand, that it increases as its availability decreases. This means that the more reliable a generator is, the more competitive it will be in this capacity market, and that his competitiveness will not be affected by criteria other than reliability.

As to interconnectors, the hourly profit of the interconnector depends on both the price difference between adjacent markets and the power flow transmitted by the interconnection. Thus, their bid prices in the capacity auction are a function of the future missing money which is based on the congestion revenues $\left(\Delta\hat{p}^{t,\tau'} - \Delta sp^i\right)$; where $\Delta\hat{p}^{t,\tau'}$ is the future spread price between adjacent markets, Δsp is the future spread strike prices between adjacent markets and F_{i-i}' is the expected power flow through the interconnector (i.e. the flow from the zone price *i* to the zone price *-i*). Consequently, the bid price offered by interconnectors in the market capacity is defined as follows:

$$p_{cm,int}^{\tau} = E\left[\sum_{\forall t \rightarrow \Delta sp^i < \Delta\hat{p}^{t,i,\tau'}} \left[(1 - FOR_{int}{}^{\tau'}) \cdot (\Delta\hat{p}^{t,i,\tau'} - \Delta sp^i) \cdot \frac{|F_{i-i}'|}{K_{int}^{\tau'} \cdot DF_{int}^{\tau'}}\right]\right] +$$

$$E\left[\sum_{\forall t \rightarrow \Delta sp^i < \Delta\hat{p}^{t,i,\tau'}} \left[(FOR_{int}{}^{\tau'}) \cdot (\Delta\hat{p}^{t,i,\tau'} - \Delta sp^i + pen^i) \cdot \frac{|F_{i-i}'|}{K_{int}^{\tau'} \cdot DF_{int}^{\tau'}}\right]\right] \tag{4}$$

The capacity price $p_{cm}^{*,i,\tau}$ is determined by the marginal bid (i.e. the highest accepted bid) in the auction mechanism and all the accepted bids receive the desired premium that was solicited by the marginal bid. Unlike the energy market, we implicitly assume that the capacity price is determined under perfect competition. In practice, asymmetric information can result in strategic bidding behaviours, which undermines social welfare. Accordingly, the model neglects further distortions and distributive effects that may occur in the capacity auction.

From this capacity price, we can infer the expected revenue for the technology *j*, given by $\hat{\pi}_j^{i,\tau'}$ (or $\hat{\pi}_{int}^{\tau'}$ for interconnectors), associated with an investment level $K_j^{i,\tau'}$ in generation or $K_{int}^{\tau'}$ in interconnection capacity for the delivery period τ'. This revenue will depend on capacity prices, and infra-marginal and scarcity rents earned on the energy market for the generators or congestion revenues for the interconnectors:

Generator's annual revenue:

$$\hat{\pi}_j^{i,\tau'} = \left[\sum_{\forall t \to \hat{p}^{t,i,\tau'} \leq sp^i} \left(\hat{p}^{t,i,\tau'} - VC_j^{t,i,\tau'}\right) \cdot \hat{q}_j^{t,i,\tau'}\right]_{\forall\, \hat{p}^{t,i,\tau'} > VC_j^{t,i,\tau'}} + \left[\sum_{\forall t \to sp^i < \hat{p}^{t,i,\tau'}} p_{cm}^{*,i,\tau} \cdot K_j^{i,\tau'} \cdot DF_j^{i,\tau'}\right] \cdot (1+r)^{\tau'-\tau} \tag{5}$$

Interconnector's annual revenue:

$$\hat{\pi}_{int}^{\tau'} = \left[\sum_{\forall t \to \Delta\hat{p}^{t,i,\tau'} \leq \Delta sp^i} \Delta\hat{p}^{t,i,\tau'} \cdot |F_{i-i}'|\right] + \left[\sum_{\forall t \to \Delta sp^i \leq \Delta\hat{p}^{t,i,\tau'}} p_{cm}^{*,i,\tau} \cdot K_{int}^{\tau'} \cdot DF_{int}^{\tau'}\right] \cdot (1+r)^{\tau'-\tau} \tag{6}$$

where $\hat{q}_j^{t,i,\tau'}$ and $VC_j^{t,i,\tau'}$ are respectively the expected generation and variable cost of the technology *j*. *r* is the discount rate. The first term in Eqs. (5) and (6) represents the revenue from the energy sold on the energy market when the energy price is less than or equal to the strike price sp^i. The second term in Eqs. (5) and (6) corresponds to the commitment generation payment when the option is exercised by the TSO and the energy price is above the strike price sp^i.

The economic assessment for investing in the installed capacity $K_j^{i,\tau}$ (or K_{int}^{τ}) can be formulated as follows:

$$NPV_j^i = \sum_{\varepsilon=1}^{\varepsilon=T_j^{i,v}} \left[\hat{\pi}_j^{i,\varepsilon} \cdot (1+r)^{-\varepsilon} - I_j^i \cdot K_j^{i,\tau}\right] \tag{7}$$

where $T_j^{i,v}$ and I_j^i are respectively the economic life cycle and the annualised fixed cost of the technology *j* in the price zone *i*.

Simulation data

The interconnected electricity system comprises of two interlinked electricity markets, as shown in Figure 2.

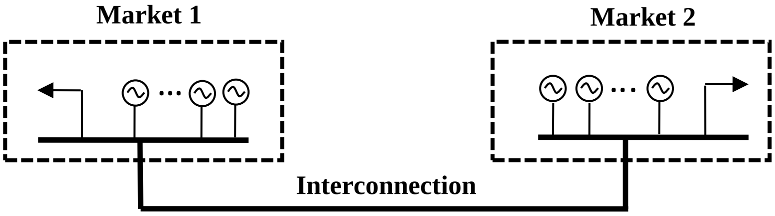


Figure 2. Scheme of the test system

Each adjacent market holds thermal-generating units with four different technologies including nuclear (N), hard-coal (HC), combined cycle gas turbine (CCGT) and oil-fired combustion turbine (CT). The thermal technologies, along with the interconnections, are characterised by outages and schedule maintenance. The parameters used in the simulations for each power plant and interconnection are shown in Table 1.

Table 1. Generation data used in simulations[18]

		Nuclear	Coal	CCGT	Oil	Interconnection
Initial capacity - GB [MW]		9,900	18,900	31,625	1,530	2,000
Number of plants - GB		9	21	55	18	1
Initial capacity - France [MW]		62,700	2,700	6,325	6,630	2,000
Number of plants - France		57	3	11	78	1
Generation capacity per unit [MW]		1,100	900	575	85	1,000
Overnight cost [£ /MW]		4,310,000	2,567,000	1,489,063	1,162,880	400,000
Investment cost [£ /MW*year]		348,239	220,257	139,494	108,937	35,531
Variable cost in 2015 - GB [£/MWh]		11.31	27.82	33.91	107.22	-
Variable cost in 2015 - France [£/MWh]		11.31	15.64	28.33	95.50	-
Economic life [years]		60	35	25	25	30
Fuel Intensity [GJ/MWh]		3.6	9.0	6.1	12.0	--
CO_2 intensity [tCO_2 /MWh]		0	0.77	0.35	0.73	--
Construction period [years]		6	4	3	2	3
Ramp up [%/(plant*h)][19]		55	70	100	100	--
Ramp down [%/(plant*h)]		55	70	100	100	--
Forced outage rate		0.042	0.036	0.051	0.041	0.05
Schedule maintenance [% of installed capacity]	**Winter**	6%	10%	2%	6%	5%
	Spring	29%	33%	12%	23%	5%
	Summer	23%	24%	10%	17%	5%
	Autumn	16%	19%	7%	13%	5%

Data used here are based on available public sources and try to mimic real system characteristics of the GB and French electricity markets. These interconnected markets have been selected due to the current developments as to the participation of interconnectors in the GB and French capacity markets. In addition, the use of real data enables to illustrate simulations results for real size cases.
The investment costs of interconnections are based on the project Eleclink[20] (Eleclink, 2013). Right-of-way and the O&M costs are added to complete the total cost of the interconnection. The former are the costs of land and the legal right to use and service the terrain on which the interconnection is located. The O&M costs are regarded as independent of the level in which the link operates and assumed constant through the simulation period.

[18] Data is obtained from IEA (2015) and DECC (2013b). The discount rate and exchange rate are set at 8% and 0.64 £/USD respectively.
[19] Ramping data are based on Hach *et al.* (2015).
[20] This project consists in building and operating a merchant power interconnector through the Channel Tunnel to provide a transmission link between the GB and France with a capacity of a 1,000 MW in either direction of flow. The total cable length of 51 km inside the Channel Tunnel operating under HVDC system and using symmetrical monopole convertors and land based cables. Eleclink was granted an exemption, subject to certain conditions, from certain aspects of European legislation (Ofgem, 2014b).

We assume a development of fuel prices for coal, gas, and oil and CO_2 prices (Figure 3) according to the baseline case projections of the Department of Energy and Climate Change (DECC, 2015b). As to the carbon price, we factor its premium into the short-run marginal cost of the GB generation units. This premium, called carbon price support, creates an artificial spread between the GB and European costs of carbon (Figure 3). In the model, the carbon cost for the GB generation units is consistent with the carbon price support rate cap at £18/tCO_2 from 2016/17 to 2019/20 (HM Revenue & Customs, 2014). However, as described hereafter, we use other sets of CO_2 prices values for sensitivity analyses purposes.

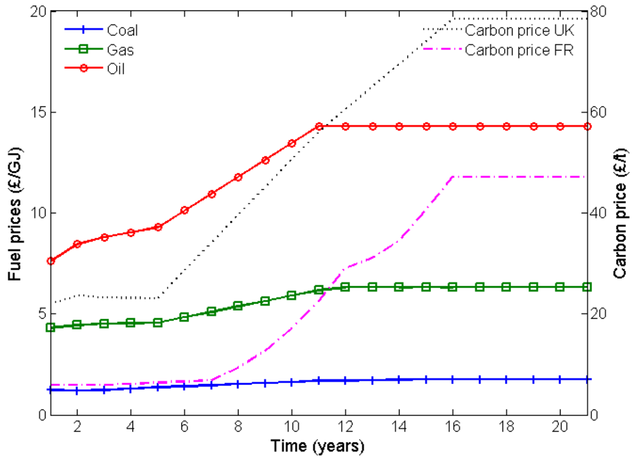


Figure 3. Carbon and fuel prices scenarios

We assume RES to be exogenous to the model because our model is focused on evaluating the impact of the participation of interconnectors in national capacity markets[21]. We rely on RES production profiles in hourly granularity to include realistic fluctuation and distributions. For offshore and onshore wind and solar PV, we multiply average historical capacity factors by installed capacity. We use the capacity factors according to Cepeda and Finon (2013) and DECC (2015c). We scale these generation capacities up, following the GB and French governments' policy targets for RES and the adequacy forecast of the European Network of Transmission System Operators ENTSO-E adequacy forecast (ENTSO-E, 2014b; DECC, 2015b). We consider only RES at a transmission level; and embedded generation is shown as a reduction in demand level.

Electricity demand is characterised by a load-duration curve, which illustrates a cumulative distribution of demand levels over each year during the simulation period, and is derived for each market from data on both the GB and French electricity consumptions in 2015[22]. We split the load-duration curve (Figure 4) in 40 segments of extreme peak hours, and 40 segments of 218 hours each for the remaining hours (peak, intermediate and off-peak hours). As discussed above, we consider two uncertain components affecting demand: its growth rate and thermo-sensitivity[23]. In addition we discount the available RES energy from the total hourly demand. The residual demand or net demand is issued when determining the short-term equilibrium price (Figure 4). The VoLL is set at 20,000 €/MWh in both markets.

[21] We consider the discussion around the RES promotion scheme outside the scope of this paper. Cepeda and Finon (2013) assess the effectiveness of the capacity mechanism to correct for the negative externalities of large-scale RES development.
[22] See http://www2.nationalgrid.com/ and http://www.rte-france.com/
[23] These components are modeled and parameterized as in Cepeda and Finon (2011).

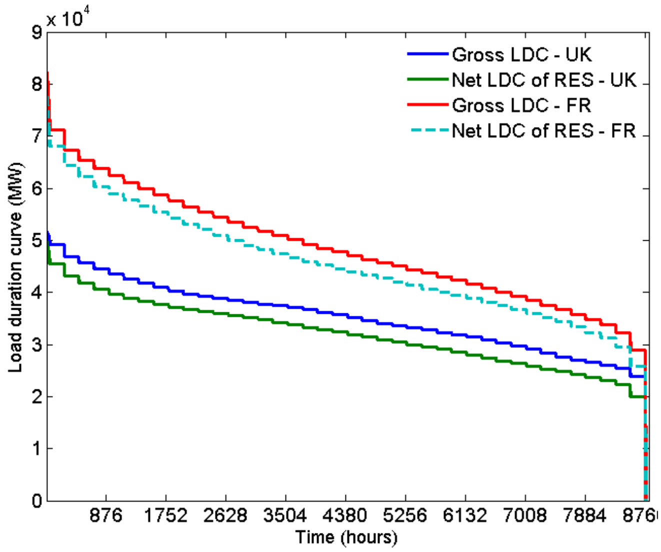


Figure 4. Load-duration curves of the model at the beginning of the simulation period

We report results for a 20-year time frame (2015-2035). The resolution time-step of the model is one year using the simplifying assumption that investment decisions can only be made at the beginning of each year. To test the level of uncertainty, 10,000 random scenarios, on 20-year period each, are generated through a Monte Carlo simulation method. The presented results correspond to the average results over these 10,000 random scenarios. The model has been developed as a set of programmes using MATLAB version R2016a.

IV. RESULTS

In the following, we evaluate the investment dynamics in two-interdependent electricity markets by comparing the results for different adequacy policies, which were obtained from running the dynamic capacity investment model with the aforementioned parameters and assumptions. The most suitable combination is the one that ensures efficiency in terms of overall social costs. We analyse four different cases:

Case 1(reference case): two inter-linked markets with interconnector and foreign generation participation in national capacity mechanisms.

Case 2: two inter-linked markets with interconnector participation but without foreign generation participation in capacity mechanisms.

Case 3: two inter-linked markets without any type of cross-border participation in capacity mechanisms.

Case 4: one energy-only market linked with one market with capacity mechanism without any type of cross-border participation in capacity mechanism

The purpose of these tests is to compare, for each type of generation adequacy policy, the results between scenarios with different degrees of cross-border participation. As Hach *et al.* (2015) we consider three groups of performance indicators which are defined to factor the capacity mechanism objectives into our assessment: affordability, sustainability, and reliability. To measure affordability, we report three performance indicators: social cost (i.e. variable, capacity and shortage costs), average annual electricity price and average capacity price. As to reliability we focus on the evolution of the security margin and the expected hours of shortage per year (or loss of load expectation - LoLE). Regarding sustainability, we capture this dimension from the system's annual CO_2 emissions performance indicator.

The model also provides changes in generation portfolio, hours of congestion and price convergence over the 20-year timeframe. In the sensitivity analysis presented at the end of this section, some intermediary cases are studied to verify the robustness of the results.

Figure 5 depicts the performance indicators for each market as well as for the global performance of the interconnected system. As to total social cost – computed as the sum of the investment in generation and interconnection capacity, production, and outages total costs – we find that the cross-border participation in capacity mechanisms gives rise to a more efficient outcome (i.e. lower social cost) of the interconnected system (Cases 1 – "*CMs, I, FG"* and Case 2 – "*CMs, I"*) compared to the scenarios where generation capacity is defined as a local product (Cases 3 – "*CMs"* and Case 4 – "*CM, EO"*).

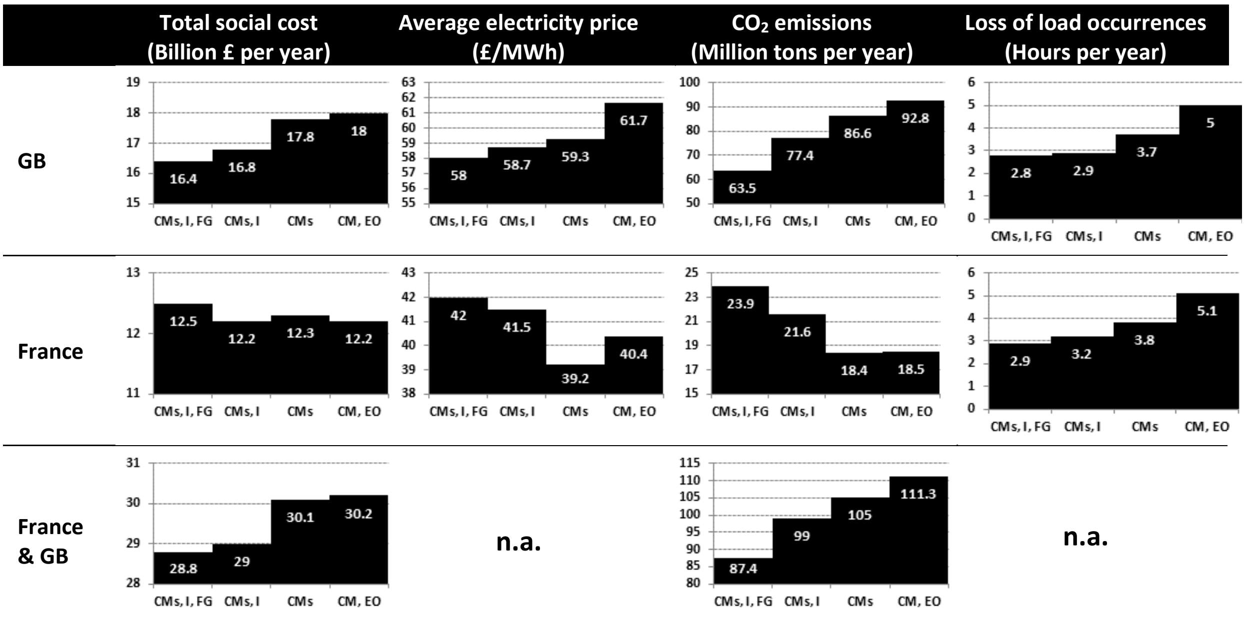
When comparing cases 1 and 2, the results show that the participation of foreign generation in local capacity markets brings about lower total costs. This suggests that interdependency between capacity markets enables emerging efficiency gains by harnessing the generation portfolio complementarities between power systems. Inclusion of foreign generators in local capacity markets also increases competition in capacity auctions which, in turn, gives rise to lower capacity prices than in the case where only interconnectors can participate.

It is interesting to note that, when referring to the total social cost, the French market does not follow the pattern of the whole regional market. The French market has an excess of generation capacity at the beginning of the simulation and a lower short-run marginal cost of generation, which results in an unequal distribution of short- and long-term benefits of the independence between markets.

On the one hand, GB consumers harness French excess of generation adequacy which gives rise to both lower investments and generation costs in the GB market. On the other hand, the total social cost raises for the French consumers due to its over contribution to the regional generation adequacy as the cross-border participation in capacity markets increases (Case 1 – "*CMs, I, FG"* compared to Case 2 - "*CMs, I*").

The average electricity price, which includes the capacity price, reveals the difference caused by presence or absence of cross-border participation in capacity mechanisms. Irrespective of cross-border adequacy policy, as limited investments in generation and interconnection occur, generation shortages happen more often leading to higher electricity prices. However, the simulation results show that cross-border participation lead to asymmetric effects on electricity prices. In the GB market, electricity prices fall as the cross-border participation increases, which is the opposite of what happens in the French market.

As to the total CO_2 emissions, simulation results also suggest asymmetric effects between coupled markets. In the GB market, cross-border participation in capacity markets reduce CO_2 emissions as: first, French excess generation adequacy contributes to ensure GB generation adequacy which reduces the need for more carbon intensive technologies; and second, coal generation is phased out from 2025 and replaced by gas-fired and nuclear generation (see Figure 6 and Figure 7). In contrast, CO_2 emissions in France increase due to two reasons. One the one hand, the excess of carbon intensive peak-load generation in France is used to contribute to supply GB consumers; and on the other hand, the share of electricity from nuclear is significant reduced over time and replaced by gas-fired and RES generation (see Figure 6 and Figure 7).



***CMs, I, FG (Case 1)**: two inter-linked markets with interconnector and foreign generation participation in national capacity mechanisms.*
***CMs, I (Case 2):** two inter-linked markets with interconnector participation but without foreign generation participation in capacity mechanisms.*
***CMs (Case 3):** two inter-linked markets without any type of cross-border participation in capacity mechanisms.*
***CM, EO (Case 4):** one energy-only market linked with one market with capacity mechanism without any type of cross-border participation in capacity mechanism.*

Figure 5. Overview of simulation results

It is worth noting that asymmetric distributed effects between countries for the aforementioned indicators stem from differences between generation and demand structures at the beginning of the simulation. Given the long economic life of generation assets, equally distributed benefit would be noticeable once the entire generation fleet in both markets has been renewed. As to reliability, the loss of load occurrences decline in both markets when cross-border capacity participates in local capacity markets which reinforces the well-known benefit of interconnection grids for security of supply.

Generation portfolio

For the sake of clarity, explanatory notes are needed to discuss dynamics of the generation portfolio. First, as mentioned in the previous section, RES generation capacity is introduced exogenously[24]. Second, the French government has set a policy target to limit the share of nuclear energy output to 50% of its current level by 2025. This is reflected by the decrease in nuclear installed capacity in the four scenarios in the French market.

[24] See the top range of the charts in Figure 6 and Figure 7.

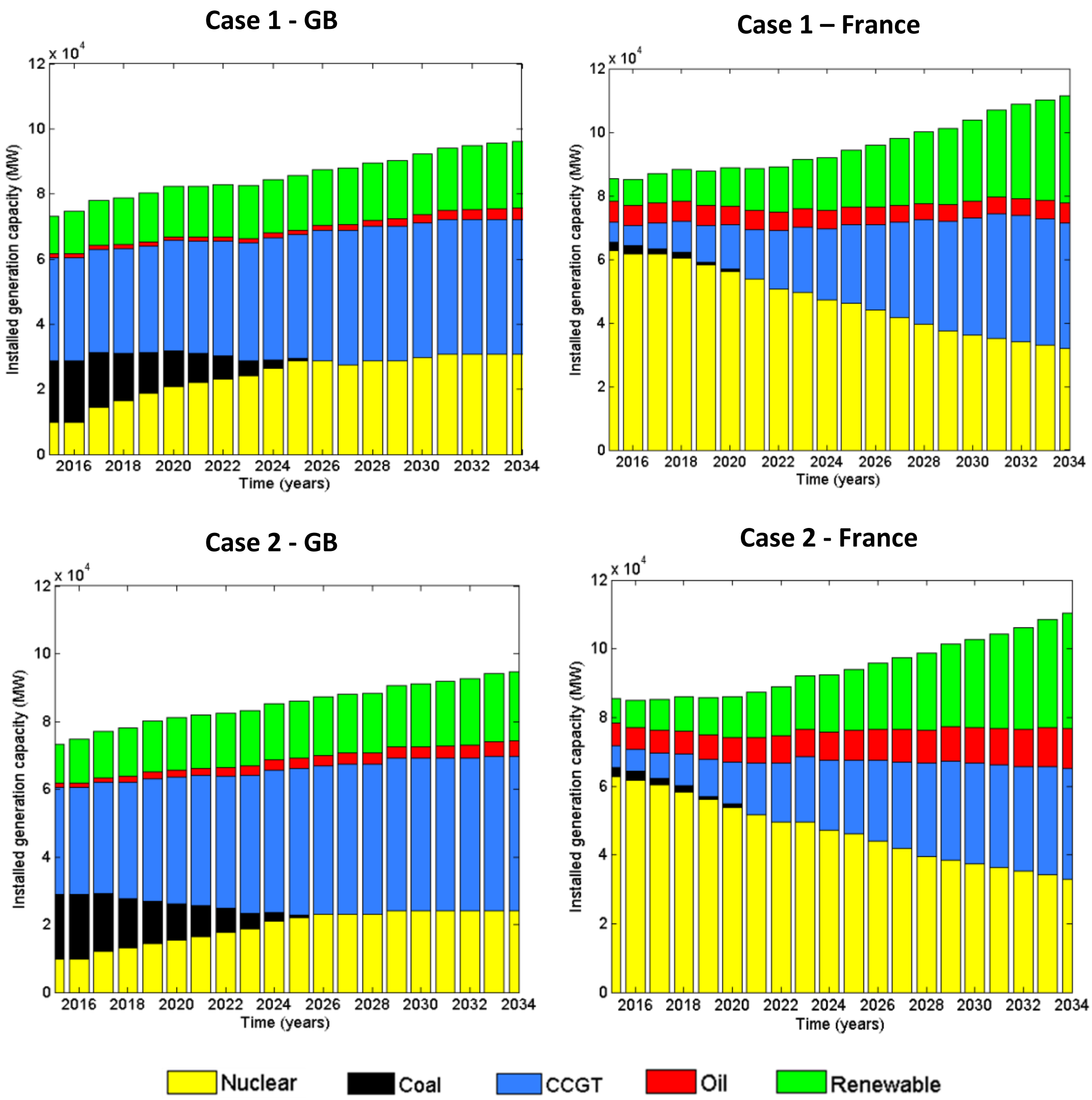


Figure 6. Changes in generation portfolio in interconnected markets with cross-border participation in capacity mechanisms (Case 1 and Case 2)

Eventually, as for coal generation in GB, the dynamics of the model considers the GB government's decision on the phase-out of coal power plants by 2025. Hence, no GB coal-fired generation is expected to serve the market after 2025 across all four scenarios.

The Figure 6 and Figure 7 show the changes in generation portfolio over 20 years in both the French and GB markets. For the cases 1 and 2 with cross-border participation in capacity mechanisms (see Figure 6), it is immediately apparent that there is a consistent increase in the share of both nuclear and gas generation in GB over the first 10 years of the simulation period whilst coal generation decreases sharply. However, the magnitude of the increase of these two technologies is different when comparing cases 1 and 2. The inclusion of foreign generation in the local capacity mechanisms (case 1) lead to a faster growth of nuclear installed generation capacity in GB. In the French market, generation portfolio dynamics is mainly driven by the significant decrease of nuclear generation due to the French decommissioning targets. This fall is compensated by the rise in both RES and gas power generation, with the latter being larger when considering the participation of foreign generation in the capacity mechanisms (case 1).

As to the cases 3 and 4 without cross-border inclusion in capacity mechanisms (Figure 7), it is of note that the surge of nuclear generation in GB over the first 10 years is less significant compared to the cases with cross-border participation. However, in the case when France is assumed to be an energy-only market, we can observe a marginal but gradual increase of GB nuclear generation over the entire simulation period. We see that the technologies in both countries profiting the most from the exclusion of the cross-border capacity are the middle-and peak load technologies with low capital and high marginal costs.

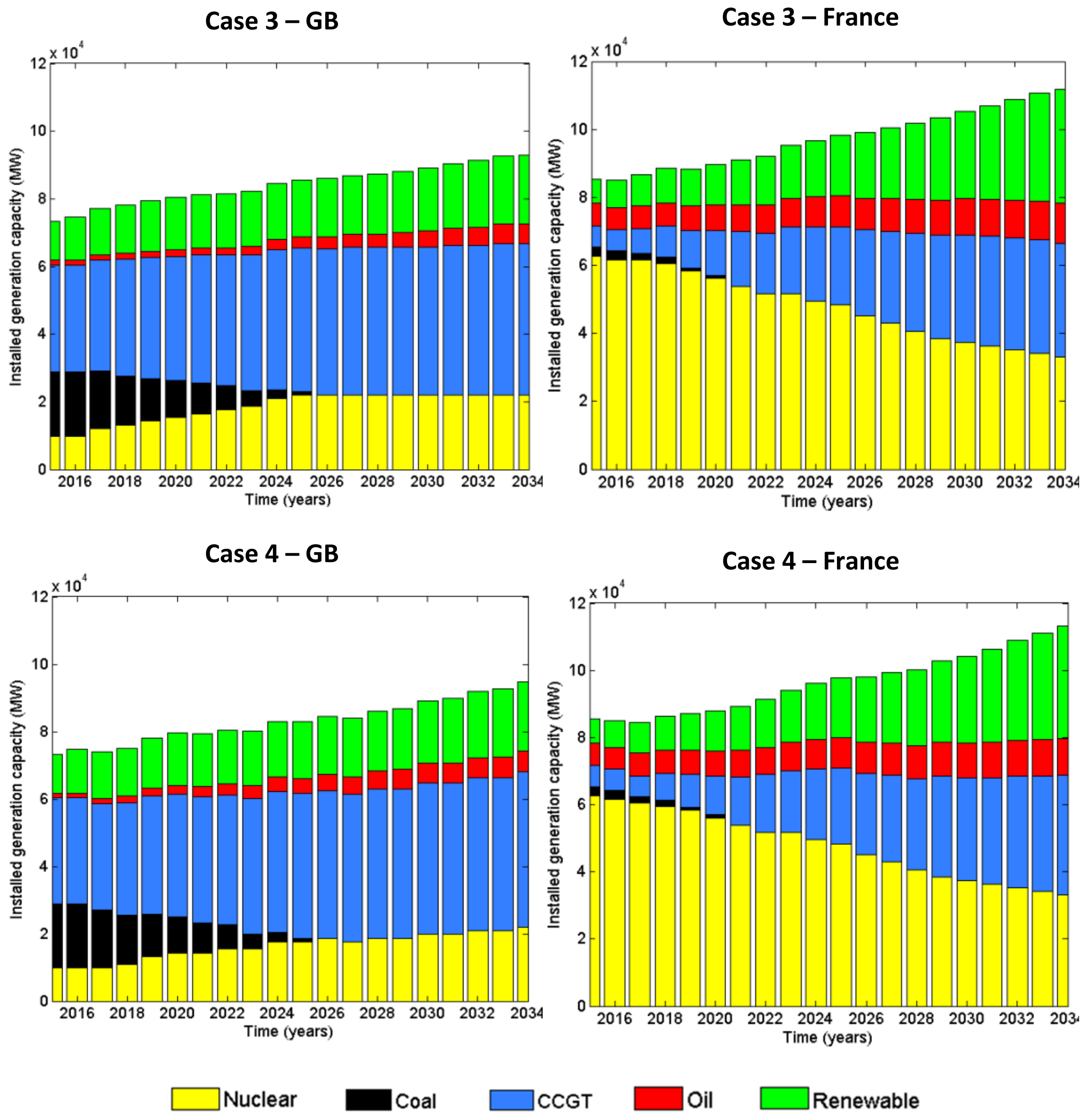
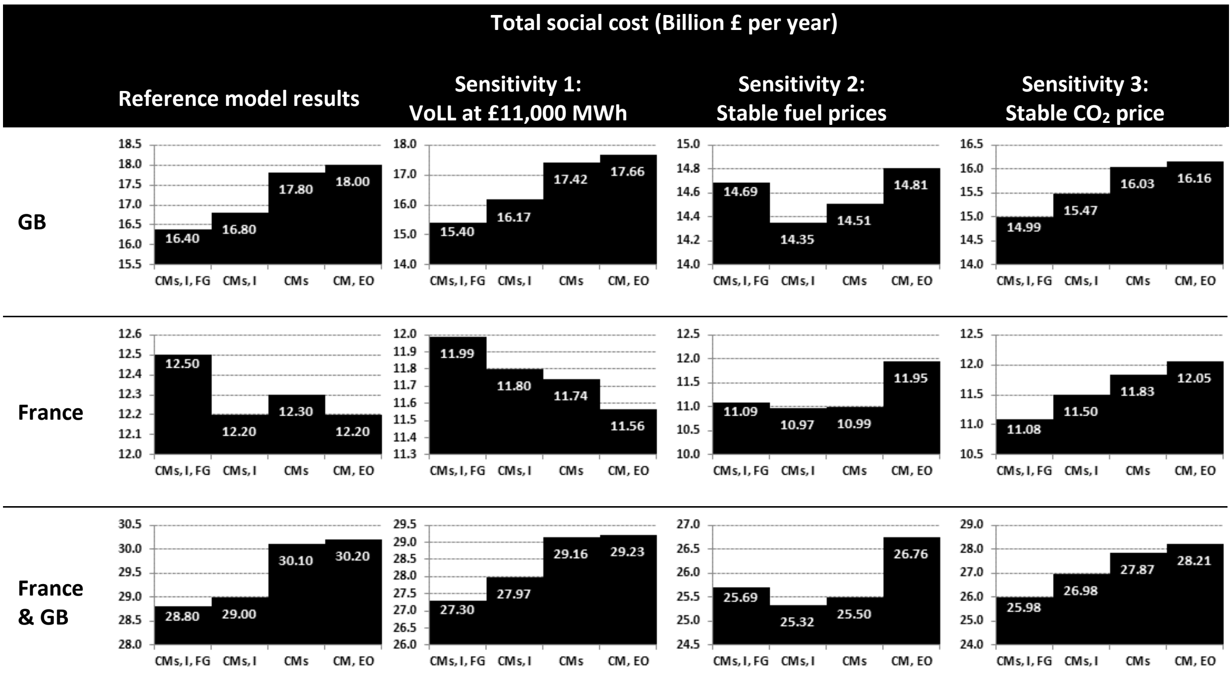


Figure 7. Changes in generation portfolio in interconnected markets without cross-border participation in capacity mechanisms (Case 3 and Case 4)

Sensitivity analysis

We also analyse the sensitivity of the results to assess the robustness of the model with respect to three parameters: VoLL, fuel prices and CO_2 price. The results are depicted in Figure 8.



***CMs, I, FG (Case 1)**: two inter-linked markets with interconnector and foreign generation participation in national capacity mechanisms.*
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***CM, EO (Case 4):** one energy-only market linked with one market with capacity mechanism without any type of cross-border participation in capacity mechanism.*

Figure 8. Sensitivity results – changes in total social cost with changes in VoLL, fuel prices and CO_2 price

First, we test the effect at different levels of VoLL from £22,000/MWh to £11,000/MWh. The results show that a lower level of VoLL results in only a slight reduction of total social cost for all the cases. The reason is that a reduction of VoLL implies lower scarcity prices which, however, are offset by an increase of the number of shortage hours. Thus, the simulation results are almost unaltered by changes in VoLL.

Second, we change the fuel prices assumptions by keeping their values constant over the simulation period. Compared to the increasing fuel prices scenario used in the reference model (Figure 3), this sensitivity can be seen as a decrease in fuel prices. We find that total social cost falls for all the cases. In fact, with the CO_2 being equal, a fall of fuel prices leads to a lower marginal cost bidding in the energy market which reduces social costs. However, the level of this reduction depends on the cross-border adequacy policies. The cases with capacity mechanisms in both markets (cases 1, 2 and 3) are more positively affected by lower fuels prices. The reason is that revenues from capacity mechanisms offset for the missing money created by lower energy prices, which are driven by low fuels prices. Thus, interconnected capacity mechanisms ensure enough revenues to invest and adequate generation capacity without further social costs.

In the case with different adequacy policies between interconnected markets (case 4), the benefits from a reduction in fuel prices are less significant. Structurally, lower energy prices result in less appetite for new investments as investment decisions in energy-only markets are only driven by energy prices. In turn, lower investments lead to both tighter physical margin and higher long-term energy prices with more scarcity hours set at the VoLL, which increases total social costs.

Eventually, as per the fuel prices sensitivity, we set the CO_2 price over the simulation at the level of the first year, which means lower CO_2 prices compared to the reference model (Figure 3). Under this sensitivity test, global welfare can be increased by implementing cross-border capacity mechanisms.

Further research

It is worth noting that although the model includes a wide range of features of the GB and French electricity markets, a number of complexities have been left out. Further research should be oriented towards the extension of the presented model to other interconnected markets in order to include the effects of loop flows. Even though the model includes strategic behaviour in the energy market, another area for further research regards to the strategic behaviour in the capacity market. Eventually, a more stylized modelling of embedded generation and demand side response might better mirror the current patterns of the GB and French electricity markets.

V. CONCLUSION AND POLICY IMPLICATIONS

To examine the effects of the inclusion of both foreign generators and interconnectors in national capacity mechanisms, we relied on a long-term dynamics model of two inter-related electricity markets developed by Cepeda and Finon (2011) and expanded to incorporate both strategic bidding behaviour in the energy market and endogenous development of the interconnection capacity.

This paper has argued that the unilateral implementation of the capacity mechanisms could jeopardise the effectiveness of trans-national generation adequacy policies unless there is a cross-border participation of both interconnection and foreign generation in national capacity schemes. Excluding interconnectors and foreign generation from participating in national capacity mechanisms would skew investment signals in favour of local generation. Thus, the natural tendency to protect the old national equilibrium will not solve the local issues faced by the Member States but only postpone the progress towards a more efficient trans-national generation adequacy policy. An alternative is to hope that a Pan-European approach could be implemented to drive optimal trans-national generation and interconnection investments. However, practical considerations make this solution a complex task: the heterogeneity of the current capacity mechanism along with country specific features including portfolio mix, short-term market arrangements, level of interconnection and demand structure.

In view of the above, in the absence of a wider EU single capacity mechanism, the inclusion of foreign generators and interconnectors in national capacity mechanisms should ensure the most efficient cohabitation of the EU Single Market and national capacity mechanisms. However, multiple participation in different capacity mechanisms can efficiently deliver added value in specific situations, as long as overlapping generation commitments are avoided and feasible solutions are identified. Unlike closed national capacity markets, a practical obstacle that inclusion of cross-border participation in national capacity mechanisms may face is the Government and TSO's verification of foreign capacity providers, including pre-qualification requirements and testing administratively that foreign participants are able to physically deliver their firm capacity commitment. The policy challenge is to overcome this obstacle through a closer coordination among TSOs, which should require clear rules set out in trans-national network codes.

Another lesson to draw from our analysis is that inclusion of interconnectors in local capacity mechanisms would induce investment by merchant interconnectors by adjusting their profit level on the basis of the interconnection cost. Although social gains from this approach cannot be seen as a first best, which one could obtain from the theoretical centralised approach by optimising simultaneously generation and interconnection, revenues from capacity mechanisms might partially compensate for network externalities which are one of the main barriers for investment in interconnections. In addition, and to a lesser extent, additional interconnector capacity incentivised by capacity mechanisms increases the economic gains of cross-border participation by allowing a larger participation of foreign generators in both energy and capacity markets.

In Cepeda and Finon (2011), we examine the effect of heterogeneous generation adequacy policies between two interdependent markets assuming an exogenous level of capacity interconnection. We went on to show how free-riding behaviour might occur where generation adequacy policies are adopted in one market but not the other. However, the assumption of exogenous interconnection capacity underpinning this result is strong. In this paper, our analysis then proceeded to examine the relaxation of this assumption. Taken together, our findings suggest that both homogeneity among capacity mechanisms and cross-border participation in local capacity mechanisms not only would ensure sufficient trans-national generation adequacy but also further allows cost-effective development of the interconnections. Capacity mechanisms compatibility needs considerable and urgent reform from a cross-border perspective as they can deliver investments decisions, which are made in a relatively short period of time, have not only national but also trans-national consequences for decades.

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