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Generation capacity adequacy in interdependent electricity markets

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Abstract : This paper deals with the practical problems related to long-term security of supply in regional electricity markets with transmission constraints. Differences between regulatory policies and markets designs in terms of generation adequacy policies may distort the normal functioning of the neighboring markets, as well as their respective reliability of supply. We test the efficiency of different approaches in two interdependent markets: energy-only market, price capped market without capacity mechanisms, price capped markets with capacity payments or with forward capacity contracts. We rely on a long-term market simulation model in system dynamics that characterizes expansion planning in a competitive regime. The results show mutual influences on price and reliability between markets coming from differences in market designs The main finding is that in a regional market, the lack of design harmonization between local markets may lead to undesirable side effects in the neighboring markets by distorting their normal functioning.

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1. Introduction

Electricity is a non-storable good essential for welfare and economic activities; power shortages are hardly acceptable. In liberalized electricity industries, energy-only markets do not appear to offer adequate incentives for the development of capital intensive investments in new generation capacity, in particular for peaking units. Random revenues are waited from high price spikes during extreme peaks in demand in order to recover the fixed costs of these units whilst there is the possibility that the regulator may decide to impose a price cap for political acceptability reasons. That raises the issue of long-term reliability of supply Different approaches have been proposed and implemented around the world to ensure a sufficient level of capacity adequacy by adding incentives for investment in generation capacity by capacity payment or capacity obligation for stabilizing generators' income (De Vries, 2007 and Finon and Pignon, 2008).

While most of these mechanisms have mostly been designed and implemented at the electricity system level, generation adequacy relies in fact on interdependency between adjacent electricity systems in regionalised electricity markets. So it may be affected by interconnection constraints and a lack of harmonisation of approaches of capacity adequacy regulations, which can lead to undesirable side effects. Considering the interactions between neighbouring power systems is particularly important due to three factors. First, as we already mentioned, generation adequacy policies are mainly set up at the national level even in regional electricity markets. Second, the type and size of the adequacy problem in each system could vary depending upon the type of generation units, their exposure to specific random events and their flexibility on one side and the patterns of total consumer loads on the other side. This second point is particularly important in Europe given the differences in technology portfolios among European countries and in electrical heating market shares. Moreover, concerns also exist regarding the level of the reserve capacity in European electricity markets. Third, given that interconnections between electricity markets may be limited in capacity, transmission constraints need to be considered. In the case of a national shortage in a market without capacity mechanisms, that extends beyond its boundaries, the negative externality on the generation adequacy of the neighboring markets will have an impact. In addition, the institutional rules regarding generation adequacy are different between countries or jurisdictions in the European Union or in the USA: some countries have chosen to explicitly refer to an investment criteria, and have put in place the regulatory mechanisms needed to ensure that this criteria will be met; others have decided to keep a legally non-binding investment criteria only, and others yet have decided to let the market energy prices decide on the level of investment in generation capacity without any criteria whatsoever.

In this paper, we extend the treatment of the generation adequacy as a public good by regulatory instruments to an international setting. We describe a bottom-up simulation model developed to evaluate the long-term evolution of two markets when they are linked by means of transmission interconnection, in terms of generation capacity i.e. technology mix and reserve margins, also in terms of reliability indexes, electricity prices and social welfare. In order to investigate the effects of differentiation of approach of capacity adequacy in the two systems, we test several cases differentiated by the capacity mechanism used or not used in the adjacent market, with the case of two energy-only markets being the benchmark case. We test also the influence of the interconnection when there is a differentiation of approaches. Priorities for further adequacy policy in a regional electricity market are identified.

In the following section, we first examine the adequacy problem in regional electricity markets, in Section 2. A description of the two-systems model of systems dynamics model developed from analyzing interdependencies is presented, in Section 3. We analyze these interdependencies in simulation cases of couples of different designed markets in Section 4 and 5. We present our conclusions in Section 6.

2. The investment incentive mechanisms in regional electricity markets

There is a deeply ingrained tradition in the power industry to view generation adequacy as a public good to be managed by the regulator and the system operator. As a result, system operators continue to operate their power systems rather from an “obligation to serve” than from an “obligation to serve at a price” by controlling the evolution of the reserve margin of the system. If we consider generation adequacy under the traditional “obligation to serve” paradigm as a collective good, the issue is becoming regional while it has been coped at the one-system level up to now. In electricity markets, this question about the expansion of the collective good to a regional perspective –such as generation adequacy- had not been raised at the beginning of the liberalization process because of all the efforts of regulators and policy makers have been focused on the definition of market rules at a national level.

2.1. The treatment of the collective good in one electricity system

The provision of generation capacity is associated with an externality as a result of which a market is not able to value it. This external effect of any new capacity is materialized by a benefit to all users of the power system that the owner of this new capacity cannot charge to consumers to recover part of its fixed cost, if this was possible it would increase the incentives to invest in generating units and insure system generation adequacy. The effects of this market failure are amplified by others -including technological barriers to demand response, local market power, as well as regulatory imperfections such as price cap measure which are decided by the regulator for limiting magnitude of price spikes. This price cap results in depressed energy prices and “missing money” preventing producers from recovering their fixed costs in peaking units (Cramton & Stoft, 2006; Joskow, 2007). Thus, these market failures and regulatory imperfection justify a regulatory intervention by the implementation of incentive mechanisms that will ensure the necessary investment so that, in the medium term, demand can be satisfied by the supply of producers in the widest array of states of the world in terms of extreme load demand and generators’ availability. The various capacity mechanisms (strategic reserves, capacity payment, exchangeable capacity obligations, forward capacity auctioning) are supposed to solve this problem by stabilizing generators’ income and creating incentives for investment in generation capacity. Incentive mechanisms are used for sending adequate signals about capacity scarcity to competitors either by price or by obligation, allowing them to reach - in a decentralized way -decisions concerning production and investment that are efficient for the whole community. If such mechanisms are to operate besides efficient energy markets, the market would deliver socially desirable reliability levels. These stakeholders must be able to interpret and use the price signals transmitted by the contracts, without being able to manipulate them.

2.2. Externality between neighboring electricity markets

When interconnected energy-only markets with different price cap policies trade energy, the ones with price cap will loss in reliability and reduced costs relative to the other. Neighboring markets interdependencies may lead to “leakage” of generation capacity from markets with price caps to more profitable adjacent markets without higher pricing limits in exceptional situations[1]. This will force the market with the price cap to adopt higher cap. The same problem is raised when an energy-only market is the neighbor of a market with a capacity mechanism. Within electricity markets where the interconnection capacity with adjacent markets is large related to their peak load demand, the implementation of a capacity payment mechanism impacts the long term inter-market trade during peak and extreme peak, which reduces the economic efficiency of the mechanism in this country.

Neighboring markets without capacity mechanism could profit from higher capacity margins of the other market by importing electricity during exceptional situations at home, and their consumers could profit from a lower price and avoid paying extremely high prices, without having to pay for the new peaking capacity on the other market.

When we mix price cap regulation and capacity adequacy policy, – which is relevant because a capacity instrument is generally adopted to compensate the lack of generators’ revenues during extreme peaks – interdependencies could play also in the direction of creating inefficiencies. The outcome is that an electricity market with price cap regulation and adequacy policy, which is interconnected with electricity markets without adequacy policy and price cap and so higher price spike, will be exposed to the risk its reserves would be bought out at crucial times by the market without adequacy policy. Thus, consumers in electricity markets including an adequacy policy could pay the adequacy policy cost without benefiting from gains in reliability to consumers.

The issue of interdependencies between neighboring markets with different capacity adequacy policies includes the question of the extent to which TSOs of adjacent markets with capacity mechanisms should respect or not the exporting transactions of local generators who sold to these markets, when their own power system is in critical situation. If they do not, these generators will be penalized by the capacity mechanism, because they could have more revenues in the neighboring markets without capacity mechanism in these situations.[2] So there is a need for the development of incentive capacity mechanisms in each adjacent market, if not a need for harmonization with existing regulations of spot prices on the energy markets. But as perfect harmonization is not feasible in the absence of a binding directive, the adoption of different approaches between countries has to be tested in order to evaluate if it will have significant inefficiency effect.

[1] Although some adequacy policies include rules to protect against “leakage” of generation capacity by giving TSO the right to recall capacities (e.g. PJM’s capacity market), the fact remains that once the penalty is paid, exports to high pricing limits is more economical advantageous for the producers .

[2] Another aspect that may produce undesirable effects, in interconnected electricity markets, is the difference of the TSOs’ approaches to evaluate generation adequacy. In Europe, two types of security criterion can be found: either a LOLE criterion, or a capacity margin criterion (see for instance, UCTE,2009).

3. The structure of the model

This section presents the model for the supply and the demand side of an interconnected market. The different hypotheses on expectation formations are discussed jointly with the model of investment responsiveness. The input variables of the model and the causal relations among them are explained as well. We then proceed to develop the different versions of the model for the purpose of representing specific market designs: an energy-only market, a market with capacity payments and a forward capacity market.

3.1. Model overview

To elucidate the efficiency of different market designs a bottom-up simulation model using system dynamics was built. Systems dynamics is a branch of control theory applied to economic and management systems. This methodology has been extensively used in electricity market modeling to represent capacity expansion planning. It was pioneered by Forrester (1961), used in the regulated electricity industry (Ford, 1997) and the competitive electricity industry (Bunn and Larsen, 1992). System dynamics is especially useful to understand the feedback mechanisms in a system (Ford, 1999). Recent developments have recently appeared, in particular on transmission network modeling (Ochoa, 2007; Ojeda et al., 2007) and interaction between system dynamics (Ford, 2006). Modeling of capacity mechanisms based on systems dynamics have been examined by De Vries and Heijen (2008), and Assili et al. (2008). De Vries and Heijen present an analysis of the effectiveness of capacity mechanisms under uncertainties regarding the growth rate of demand. Assili et al. (2008) investigate the effects of fixed as well as variable capacity payment mechanisms on generation adequacy.

The model allows the addition of base-, middle- and peak-load generation units according to their profitability calculated relying on a NPV assessment. Each generation facility is represented in the model by a set of equations that respect the Law of conservation of Mass and Energy. An important feature is the modeling of optimal power flow which permits the incorporation of the interdependencies that exist between adjacent electricity markets as well as transmission constraints, as in Ojeda et al. (2009). Furthermore, we introduce short-term correlated uncertainties on demand between electricity markets, outage generation units and schedule maintenance.

The main relationships included in our modeling of investments in new generation capacity follow the structure of the causal loop diagram depicted in Fig. 1. These relationships reflect the way operating and investment decisions are made in the power industry. In the causal loop diagram, causal relationships between two variables, x and y, are identified by arrows. The positive (negative) sign at the end of each arrow can be understood as a small positive change in variable x that provokes a positive (negative) variation on variable y. The double bar crossing an arrow implies a delay in that relationship. A circle arrow with a sign indicates a positive feedback loop (reinforcement) or a negative feedback loop (balancing).

In Fig. 1, two major feedback loops may be observed (showed by the dashed line). The first one is a negative loop linking installed generation capacity and expected spot prices. It states that as long as installed and available generation capacity increases the expectations regarding future electricity prices go down, which in turn lowers expectations of future prices.

As a result, the economic attractiveness of new generation investments is reduced. This feedback loop is considered as a balancing loop that limits the investments in new generation units.

The delay τ_1 refers to the time needed to secure permits and to build generation power plants. The second feedback loop, also a negative one, is caused by the interaction between local electricity markets. In the model, national demand is affected by exports (imports) to (from) the adjacent market. When imports increase, the residual national demand goes down, thus electricity spot prices decrease. On the other hand, when exports increase, a contrary effect is produced, demand for the native producers increases as well as electricity spot prices.

We represent electricity demand by introducing long and short-term uncertainties. The model simulates the evolution of the structure and performance of a hypothetical two linked electricity markets in the next 30 years using insights from system dynamics, microeconomics and market design. The resolution time of the model is one year, using the simplifying assumption that investment decisions can only be made at the beginning of each year. The list below shows the main variables and parameters in the model, which are further referred to in the presentation of the model below.

Fig.1 Causal-loop diagram of the regional electricity market

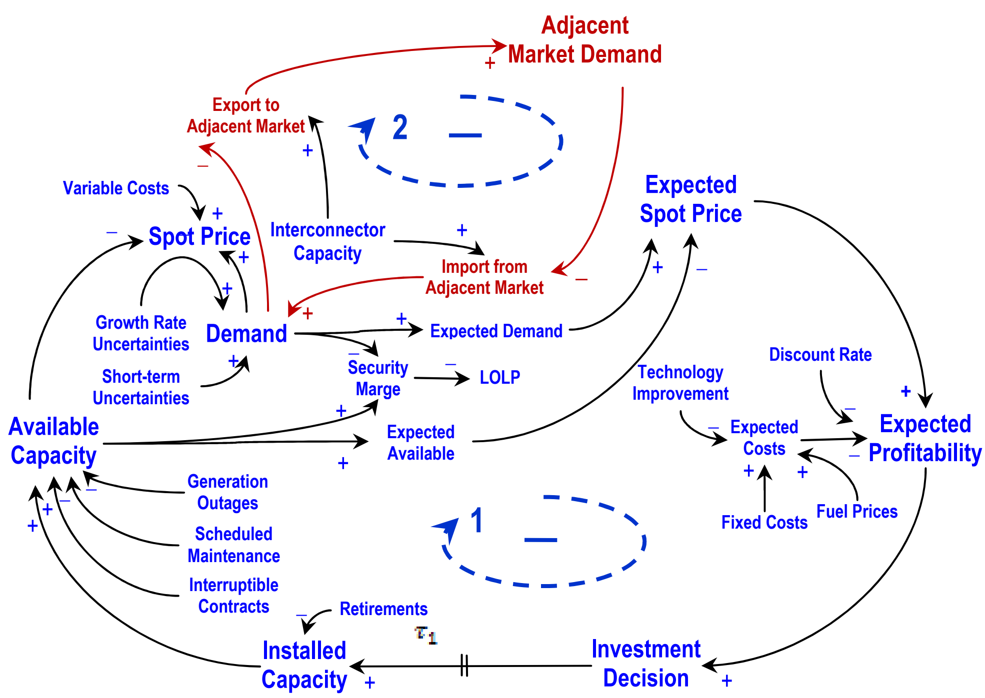


Table 1. List of Variables and Parameters

Indices and Sets		*Units*
$i \in I$	set of electricity markets	
$j \in J$	set of technologies	
$t \in T$	set of time periods (with T = 8760 hours)	[hour]
$n \in N$	set of time resolution of the model (with N = 30 year)	[year]
Parameters		
r	discount rate	
FOR_j	the forced outage rate of the technology j	
IC_j	the investment cost of the technology j	[€ /MW-an]
M_i	the volume of interruptible contracts in the market i	[MW]
C_i	interruptible contract price in the market i	[€ /MWh]
$VOLL_i$	the average value of lost load in the market i	[€ /MWh]
PC_i	Price cap in the market i	
$Pmax_j$	maximal power generation unit of the technology j	[MW]
T_j^c	construction period of the technology j	[year]
T_j^a	amortization period of the technology j	[year]
F_{max}	Interconnector capacity	[MW]
Quantity variables		
$p_i(t)$	electricity spot price in the market i	[€/MWh]
$\hat{p}_i(t)$	electricity spot price forecast in the market i	[€/MWh]
$L_{ni}(t)$	the load-duration curve in the year n and the market i	[MW]
g_{ni}	the growth rate of $L_{ni}(t)$ in the year n and the market i	
$RL_i(t)$	remaining demand in the market i	[MW]
$Ag_i(t)$	available generation capacity in the market i	[MW]
P_{Gij}	output of technology j in the market i	
TIC_{ni}	total installed capacity in the year n and the market i	[MW]
$TOg_i(t)$	total capacity off line due to outage in the market i	[MW]
$TSm_i(t)$	total capacity off line due to schedule maintenance in the market i	[MW]
$Sm_i(t)$	capacity of technology j off line due to schedule maintenance in the market i	[MW]
$Og_{ji}(t)$	capacity of technology j off line due to outage in the market i	[MW]
$RM_i(t)$	the reserve margin in the market i	
$F_{i-i}(t)$	power flow from the market i to the adjacent market $-i$	[MW]
$\rho_{\mu_i(t), \mu_{-i(t)}}$	Corrected factor between weather random variables of the market i and the adjacent market $-i$	
$\rho_{g_{ni}, g_{n-i}}$	Corrected factor between growth rate of demand in the market i and the adjacent market $-i$	
$\mu_{ni}(t)$	hourly random variable due to the weather in the market i	
VC_j	the variable cost of the technology j	[€/MWh]
NPV_{ji}	the net present value of the technology j in the market i	[€]
W_{ni}	Welfare in the year n and in the market i	[€]
$B_t(t)$	Gross benefit	[€]
$OC(t)$	Total outage cost	[€]
TC_{ni}	Total cost in the year n and in the market i	[€]
ENS_i	Energy-not-served in the market i	[MWh]

3.2. The representation of the electricity markets

Detail of the representation of electricity markets is exposed in appendix 1. The model represents two linked local markets. Each local market holds thermal-generating units with four different technologies including nuclear plants (N), hard-coal (HC) power plants, gas-fired combined cycles (CCGT) and combustion turbine (CT). These technologies are characterized by outages and schedule maintenance. The outages in generation units are modeled relying on the two-sate probabilistic generation model. A forced outage rate (FOR) is assumed for each technology *j*. Interruptible contracts are seen as a generation technology which has a variable cost C_i and no fixed cost.

The demand in each local market *i* is characterized by a load duration curve $L_{ni}(t)$ and modeled on an hourly basis. The growth rate of demand is represented by a discrete random variable g_{ni} following a triangular distribution function similar to De Vries and Heijen (2008)[1]. In order to consider the influence of electricity trading between local-markets on spot prices, demand $L_{ni}(t)$ is modified according to the power flow $F_{ni-i}(t)$.

To calculate the electricity price we assume a perfect competition framework and it is generally settled by the marginal cost of generation which in turn corresponds to the variable cost of the marginal generation technology. However, if demand exceeds the available generation capacity $Ag_i(t)$, the electricity price is equal to the cost of interruptible load contracts C_i.

3.3. Modelling interaction between local markets in relation to their interconnection capacity

In regional electricity markets, local markets continuously interact. These interactions allow not only to use the most efficient generation resources, but also to increase security of supply. In order to consider these interactions, we rely on a simplified version of an optimal power flow (OPF) algorithm, which dispatches generation assets according to the regional merit order (least-cost) subject to the physical constraints of the interconnector. Here, the power flow through the transmission line is the result of the free interaction of generation and demand in both markets until the constraint of transmission capacity are reached. The problem is formulated as:

$$min_{F_{i-i}P_{Gj}} \sum_i \sum_j CV_{ij}(P_{Gij}) \tag{8}$$

Subject to:

$$|F_{i-i}| \leq F_{max} \tag{9}$$

$$\sum_i \sum_j P_{Gij} = \sum_i P_{Li} \tag{10}$$

$$0 \leq P_{Gj} \leq P_{Gmax\,j} \tag{11}$$

[1] Triangular distribution reflects the tendency towards cycles in the general economy which creates related cycles in the demand for electricity.

As mentioned above, the power flow $F_{i-i}(t)$ is used to calculate the remaining demand for local generators. It is assumed that system operators will not interrupt exports to adjacent markets in case of a domestic emergency of supply. This seems to be the purpose stated in Article 24 of Directive 2003/54/EC: ''In taking the measures to be adopted in emergency situations, Member States shall not discriminate between cross-border contracts and national contracts''.

We consider that the interconnector capacity is constant and perfectly reliable throughout the simulation period. Although the relationship between the dynamics of generation and transmission investments is strongly linked, we isolate the dynamic nature of generation investment in order to focus on the impact of market design on generation investment.

3.4. Investor's behavior

Investor's anticipation in an imperfect information context. The key economic agents in the model are the power producing companies. Their decisions cover investment in and decommissioning of power plants. In the model, investment decisions in new generation capacity mainly depend upon the expected prices that result from the expected market condition which is established by the expected demand and expected available generation. We model a ''forward merit-order dispatch'' in order to calculate the future electricity prices. In a mature and liquid electricity market, spot prices forecasting should be driven by forward markets. However, in most electricity markets, forward markets are insufficiently developed to provide a firm indication of future demand for generation capacity. Alternatively, investors may make their own forecasts. In an ideal situation without risk aversion and with perfect information, these price forecasts should converge with the price for the long-term contracts, had it existed.

Similar to De Vries and Heijen (2008), we consider that firms know quite well the new generation capacity that competitors firms are bringing online and that should be dismantled. Thus, a strong price signal may not necessarily result in an investment, if there already is much new capacity under construction. Due to imperfect information, lumpy investments and long lead-times, investment decisions cannot be optimal. These investments are prone to cycles, which are characterized by lumpy adjustment and frequent periods of inactivity.

At this stage of the model description, it is relevant to discuss about the way in which producers make use of the information available to calculate their demand and available generation forecasting. We adopt an approach based on the fact that, firms do not know, precisely, the system specifications and therefore, forecasting models and many other model parameters must often be estimated. This reasonable approach for modeling aggregate expectation formation in a market with a large number of firms is known as the bounded rationality hypothesis (BRH) (Sterman, 1988, 2000). We characterize, therefore, investor's behavior as a descriptive rather than normative representation, as opposed to the prevailing approach in the neo-classical economic literature, which assumes an optimal forecasting behavior. Thus, our methodology used for modeling "the expected market condition" aims to represent the manner how generation firms form their expectations.

Under the bounded rationality hypothesis, more freedom is allowed to modelers regarding the adjusting of their forecasting models. In Sterman (2000), it is shown that only through backward-looking rules, it may be able to well replicate the expectations on many economic variables. Adaptive expectation formulations based on exponential smoothing and trend extrapolation may be reasonably applied for forecasting behavior. In this paper, we implement a first-order smoothing process to forecast the expected growth rate of demand and the available generation for each technology. We calculate these expectations from the built-in function forecasting in MATLAB.

Investor's investment decision. We assume that firms invest in new generation units when the expected profitability is high enough to recover their total costs during the life cycle of power plants. A Net Present Value analysis is used to calculate the profitability of a new generation unit. Since several technologies exist, there could be more than one technology with a positive NPV. A further condition is therefore added in order to select the technology, which has the higher profitability. The economic assessment of the generation technology *j* can be formulated as follows:

$$NPV_{i,j} = \sum_{k=1}^{T_j^a} \left[\left[\sum_{t=1}^{T} max(\hat{p}_{it} - VC_j, 0) \cdot P_{Gijt} \right] - IC_{jk} \right] \cdot (1+r)^{-k-T_j^c} \qquad (12)$$

This analysis takes into account the cash flow for each year during the amortization period. We also retain the assumption that producers behave in a risk-neutral manner with respect to investment.

3.5. Modelling market design with capacity mechanisms

Different versions of the model described above were created to represent specific market designs: an energy-only market, a market with capacity payments and a forward capacity market. These versions only differ with respect to the market design's (ability?) to incentivize new capacity investments. In all other respects, the different versions of the model are identical.We do not represent strategic behaviors in the model, hence excluding the potential effect of market power. Obviously, in the real world of markets including capacity mechanisms, this would be an important issue to consider. Here, the focus is only on the dynamic efficiency of market designs with respect to capacity adequacy and reliability on one side, and electricity price smoothing and welfare (net social cost) on the other side.

Energy-only market design as the benchmark case. The model described above represents the classical ''energy-only'' market design. In this approach, firms' revenues are provided by their sales in the spot market and their investment decisions are driven only by electricity prices. In theory, fixed costs of generation capacity at long run equilibrium are exactly covered by infra-marginal and scarcity rents. Empirical evidence of market imperfections (in particular in terms of risk management for peaking units investment) have shown the limits of this approach to stimulate sufficient investment in new generation capacity. Moreover price volatility in extreme peak exposed to market power exercise has led regulators to deviate from the ideal economic market model by imposing price caps for reasons of social acceptability problems.

The effectiveness of this approach is highly sensitive to the level of the price cap. On one hand, a high price cap leads to high prices which tend to be socially and politically unaccepted and besides, it would be an incentive to generators for withholding generation capacity. On the other hand, a low price cap does not allow generators companies to cover their fixed costs. In a regional perspective a further difficulty would be considered for electricity markets with energy-only approach. In fact, it is highly unlikely that adjacent markets have the same value of lost load, or in case of need, the same price cap. While incentives to invest in peaking unit in the ‘‘higher-price cap market’’ can lead to an adequate generation, in the lower-price cap market there should be underinvestment. As a result, the market with the low price cap can take advantage of the higher reserve capacity in generation capacity of the high price cap market.

We study two cases for this market design: a symmetric and an asymmetric case. The first one assumes that both electricity markets have the same VOLL and no price cap is fixed. The asymmetric case considers that a market implements a price cap PC_i at a lower level than the VOLL, while the adjacent market remains without price cap.

Capacity payment. We consider capacity payments in markets with a price cap, which should contribute to price stability. In this market design, a subsidy is paid to generators in proportion to the amount of capacity they provide to the market each hour they declare to be available either to be called as operating reserve or to produce after bidding successfully on the day ahead market. It is like a subsidy which acts as a revenue stream separated from the revenue that generators receive from the energy sold on the market. In this model capacity payments are assumed to be fixed like in Argentina, Chile and Peru, with the capacity payment calculated in relation to the investment cost of a peaking unit (in €/MW-year)[1]. The economic assessment is calculated with the same equation as the energy-only market (eq.12), but this time we add the capacity payment.

$$NPV_{i,j} = \sum_{k=1}^{T_j^{\beta}} \left[\left[\sum_{t=1}^{T} max(\hat{p}_{it} - VC_j, 0) \cdot P_{Gijt} \right] - IC_{jk} + CP_{jk} \cdot Pmax_j \right] \cdot (1+r)^{-k-T_j^c} \quad [€] \quad (13)$$

Capacity obligation with a forward capacity market. Under this type of capacity mechanism, suppliers are obliged to commit with regard to the TSO and the regulator in contracts with producers and capacity ownership up to a capacity covering their peak load demand to be supplied augmented by a reserve margin of 10 to15%. The need of suppliers to guarantee property rights on capacity is supposed to influence the investment decision of the producer in time (when to invest?), in technology (what importance of peaking units among the power generation technologies to select?) and in capacity (how much capacity to build?). For being sure of having this reserve margin needed for the whole system, the TSO is in charge of organizing auctions for helping the different suppliers satisfy their obligations. Consequently electricity production companies decide their amounts of new capacity to be developed as well as their committed unit capacities to be available in the peak load period in the next period and to produce with regard to the capacity of each unit. The auction is organized three years ahead of real time, which corresponds to the peak season of a future period. In this auction, the system operator (SO) purchases the commitment from generators to produce a prescribed quantity of energy. In the short term, operating decisions are made and the energy market is cleared. The producers’ decisions in the short run are constrained by their

[1] A system dynamics model with a variable capacity payment, like in the mechanisms provided for the mandatory Anglo-Welsh market until 2001, is studied in Assili et al. (2007).

generation capacities, the interconnection capacity and the commitment decision made in the previous years. A penalty is added in order to induce electricity producers to have all their equipments ready to operate when needed during peak periods. Under this system which is used in the New England, PJM and New York regional markets, there is an implicit price cap above which producers do not receive any more revenue than the capped price because in parallel they also receive a payment from their capacity contracts with the suppliers. In order to distinguish this mechanism from the former one which is used in markets with price cap, we shall call below this implicit price cap, a strike price denoted sp_i because the capacity contracts act as an option contract with this price acting as the strike price when the option is called by the TSO[1]. So actually, under a long term perspective, a rational producer calculates his bid auction price (i.e. desired premium fee) in the auction as:

$$BAP_{ij} = E\left[\sum_{sp<\hat{p}}(1-FOR)(\hat{p}_{it}-sp_i)\right] + E\left[\sum_{sp<\hat{p}}(FOR)(\hat{p}_{it}-sp_i+pen)\right] \quad [\text{€/MW}-\text{year}] \quad (14)$$

The first term represents the revenue that a producer, if its commitments are satisfied, will not receive from the spot market, since for him the market price has a maximum value equal to the strike price sp_i. The summation extends to every period where the expected spot price $\hat{p}_{it}$ is higher than the strike price sp_i. The second term represents the potential penalties to be paid whenever the generator is not able to respect his commitments. In fact, producers pay a penalty fee *pen* (pen? Is this a symbol: check) whenever their commitments are not satisfied. The strike price sp_i is exogenous and fixed ex ante in the reliability model. The market is cleared as a simple auction and all of the accepted bids receive the desired premium that was solicited by the marginal bid.

From eq. 14, we can observe that, on one hand, the premium fee which is required by a certain block of capacity is independent from the generator's 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 market, and that his competitiveness will not be affected by criteria other than reliability.

3.6. Definition of case studies

In this section, we rely on numerical simulations to investigate the efficiency of the three different market designs in regional electricity markets. As explained above, the electricity system which is modeled is composed of two linked local markets, as shown in Fig. 2. We choose to consider two identical markets on the first year for a main methodological reason: to identify the effects of interaction between systems with different capacity adequacy policies without the interference of other determinants such as the difference in the size and the equipment fleet of interdependent electricity systems, as well the interconnection capacity related to the size of two adjacent markets.

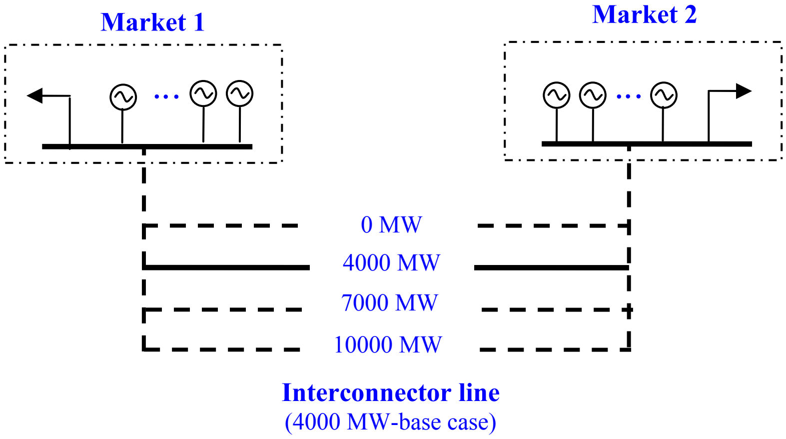
In each test four hundred scenarios, of 30-year period each, are generated through a Monte Carlo simulation method. As a result, the efficiency of the two intertwined

[1] For a parallel between the forward capacity contracts used in the US and the reliability options mechanism proposed by I. Pérez Arriaga (see Perez Arriaga (2007), Finon and Pignon (2008), Battle and Pérez Arriaga (2008)).

markets design without and with capacity mechanisms are evaluated in exactly the same technological characteristics and the same uncertainty profile, which means that differences in their performances are exclusively due to differences in their designs.

Both interconnected markets have thermal generation units including four different technologies (nuclear, hard coal, CCGT, CT) [just a note I don't think 'CT' has been defined earlier in the paper]. Characteristics of the generation technologies in initially identical markets are depicted in the second part of Table 2 (second part). The identical initial merit-order in each local market is depicted in Fig.3. Interruptible contracts are added in the merit-order as a further technology with a variable cost equal to 600 €/MWh. When generation resources and interruptible contracts are exhausted, electricity prices jump up to VOLL which is set to 10000 €/MWh.

Fig.2 Scheme of the test system



Electricity demand is assumed to be price-inelastic. At the beginning of the simulation, in both markets the level of demand is similar, thereafter due to uncertainties affecting each annual demand growth, it evolves differently in each market during the simulation. The load-duration curve is plotted in Fig. 4. Note that both markets have the same level of adequacy (i.e. security margin) in the first year of the simulation because of the similarity both in peak load and total installed generation capacity.

Fig.3. Merit-order of both markets

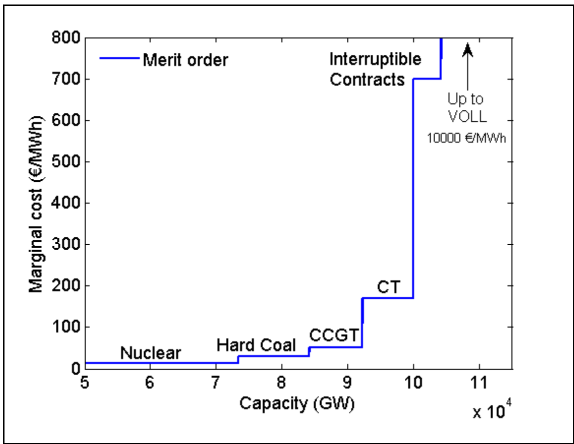
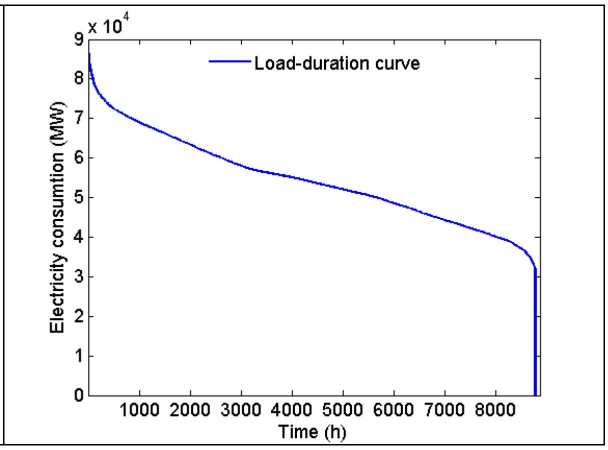


Fig.4. Load-duration curve of both markets



4. The influence of energy market designs and capacity mechanisms between two interdependent markets

In the following paragraphs, we will assess capacity adequacy policies by making a comparison to the results obtained in different cases with price caps and/or with capacity payment instruments with the benchmark case of two interdependent energy-only markets in a context in which the interconnection capacity is established once for all at 4000 MW (4% of each initial capacity). But a complementary analysis of the impact of the interconnection capacities on the generation adequacy in two different market designs is presented in the last subsection to show the impact of this parameter.

We analyze six different cases:

- Case 1 which is the benchmark case with two linked energy-only markets with no price cap policy
- Case 2: two linked energy-only markets, one with no price cap policy and the other one with a price cap at 3000 €/MWh. The main purpose here is to show how that the market with a price cap "free rides" at the expense of the market with no price cap
- Case 3: two linked markets, one with an energy-only market with no price cap policy and the other one with a price cap and a capacity mechanism. We test two sub-cases with two different mechanisms: the capacity payment (case 3.1) and the forward capacity market mechanism (case 3.2). The purpose here is to show that if the preceding drawback of a price cap imposed on one market (market 2) on the neighboring market (market 1) by the two capacity instruments and if one of the two capacity instrument is more efficient than the other one.
- Case 4: two linked markets both with a price cap and a forward capacity market mechanism. The purpose of this test is to compare the effects of the parallelism of capacity adequacy approach, with the effect of the parallelism of energy-only design choice in the benchmark case [I am not sure I understand what is meant by 'parallelism']
- Case 5: two linked markets, one with a capacity payment mechanism and the other one with a forward capacity market mechanism. The purpose of this test is to compare the effects of the two different capacity mechanisms used respectively in two interdependent markets in order to eventually identify if one market does not benefit from the policy adopted in the other market, and this in regard of the benchmark case.

Case 1: the benchmark case of two linked energy-only designed markets. Figs. 5 and 6 illustrate the results of the Monte Carlo simulation (of the 400 runs) for the two linked markets in the benchmark case. In the left Y-axis we report the peak demand and installed generation capacity. The right Y-axis shows the annual average electricity price and, the X-axis shows the years of the simulation. As shown in Fig. 5, during the simulation periods in market 1 with sufficient capacity are followed by periods of tight supply. As the difference between installed generation capacity and peak load becomes tight the annual average prices increase. This scarcity of supply leads to price spikes that trigger investments. This investment dynamics reveals that investor behavior appear in waves causing cyclical variations in electricity prices, which are particularly sensitive to the security margin as shown in Fig. 7. This is a result of the stepped marginal cost and the high level of the VOLL (10000 €/MWh). Figs. 6 and 8 illustrate the investment dynamic for the market 2. Similar to market 1, in the first years of the simulation, security margin becomes more and more constraining. This period is followed by an investment wave but this is dissipated afterwards by demand growth.

Fig.5 Energy-only, market 1 (benchmark case)

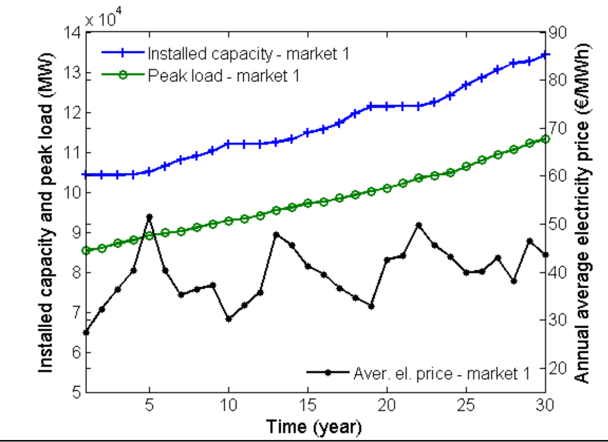
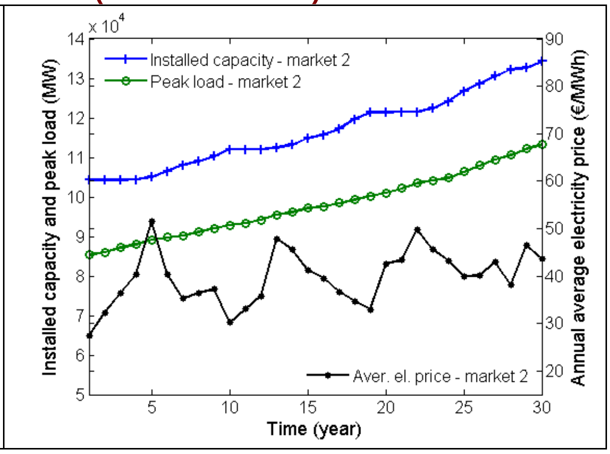


Fig.6 Energy-only, market 2 (benchmark case)



Since at the beginning of the simulation both markets are identical with respect to technology portfolio, load duration curve and market design, the investment dynamics as well as the evolution of prices are equal in both markets. This result is similar to the one which would be obtained in a case where both electricity markets were isolated.

Fig.7. Installed capacity, peak-load and security margin in the energy-only market 1

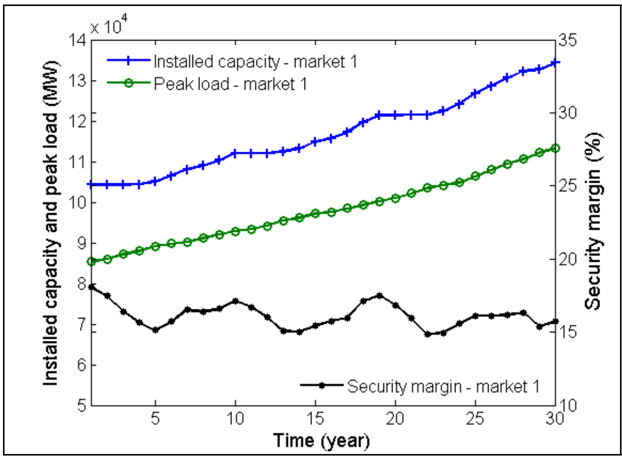
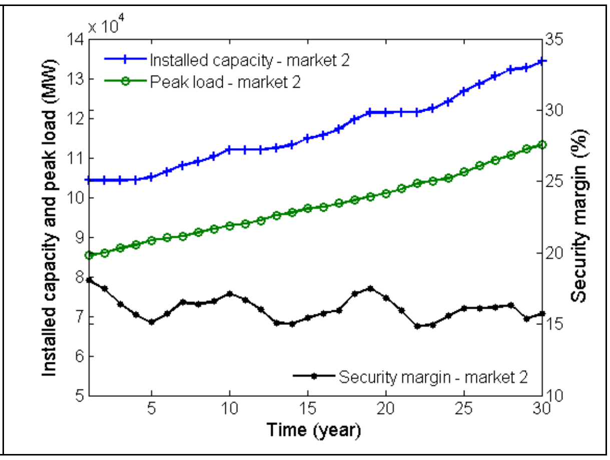


Fig.8. Installed capacity, peak-load and security margin in the energy-only market 2



To conclude on the benchmark case, it is worthwhile to note that in our two interdependent markets modeling, a universal “energy only market” solution without price cap appears to give some guarantee of capacity adequacy in the two markets. Moreover, neither of them profits from higher capacity investment and reserve margin in the neighboring market.

Case 2: One energy-only market with price cap policy and one energy-only market without. In Case 2, we consider the respective performance of energy-only markets with asymmetry in price cap policy. Market 1 is an energy-only market with no price cap policy (or a price cap set at the level of the VOLL) and market 2 is limited by a price cap, set at 2500 €/MWh[1].

Fig.9. Energy-only market 1 with no price cap policy

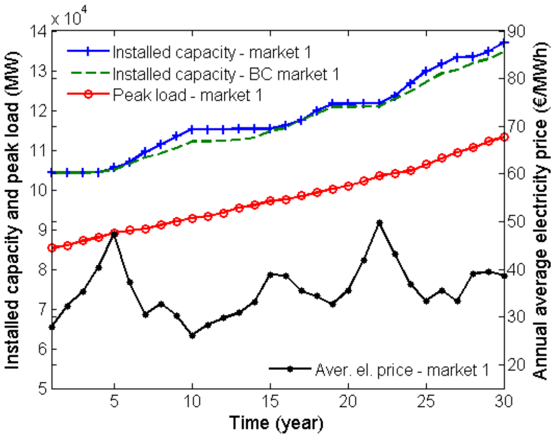
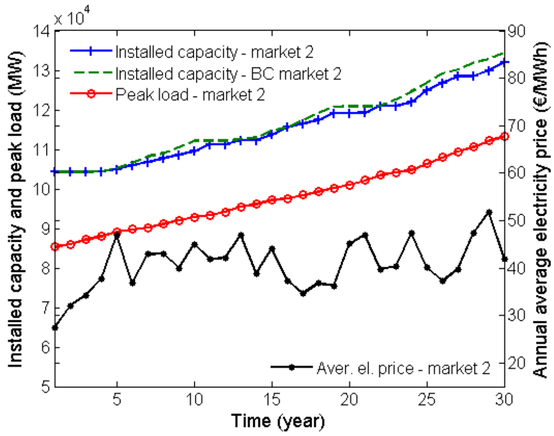


Fig.10. Energy-only market 2 with price cap policy



Figures 9 to 12 display investment developments in both markets 1 and 2. In order to compare results with Case 1, we add-in the figures the capacity and security margin evolutions in the benchmark case as a dashed line which refers to the left Y-axis and is noted “BC markets”. Similar to capacity development in the benchmark case, the first cycle in markets 1 and 2 is characterized by under-investment which brings of the level of total capacity to under a reasonable reserve margin level in the first years until year 5. In this year supply becomes quite tight; in turn this leads to a price spike that triggers investment in the second five-year period.

In the second investment cycle, investment dynamics are different between market 1 and market 2. Indeed, even though spike prices are similar in year 5, investment response in market 1, the energy-only market without price cap, is stronger than in market 2, the energy-only market with a price cap. This is because producers take investment decisions based upon the expected prices which will be higher in the market without the price cap policy. Market 1 is economically more attractive for investors than market 2. The high probability of congestion on the 4000 MW interconnection from low priced market 2 and higher priced market 1 gives way to such price conjecture for investing producers in market 1. The result is a period of over-capacity in market 1 between the year 7 and 15 which leads average prices in market 1 to decrease under the average price in the market 2.

Price cycles are more recurrent in market 2 with more frequent spike prices but not high enough to encourage more new investments than in market 1. This leads to a decrease of the security margin in market 2. Typically market 2 appears to free ride inside the integrated set of market 1 and market 2 in the limits imposed by the interconnection capacity of 4 GW during critical periods. Indeed the fact that installed capacity and security margin in this simulation of market 2 are lower than those in the benchmark case for the same market 2 shows this (see Fig. 12).

[1] Another possible interpretation of this asymmetry between the two markets is that, there could not be any price cap policy but simply two interdependent energy-only markets with different VOLLs. However, we will refer to this case as an energy-only market with a price cap policy.

Fig.11. Installed capacity, peak-load and security margin in market 1 - case 2

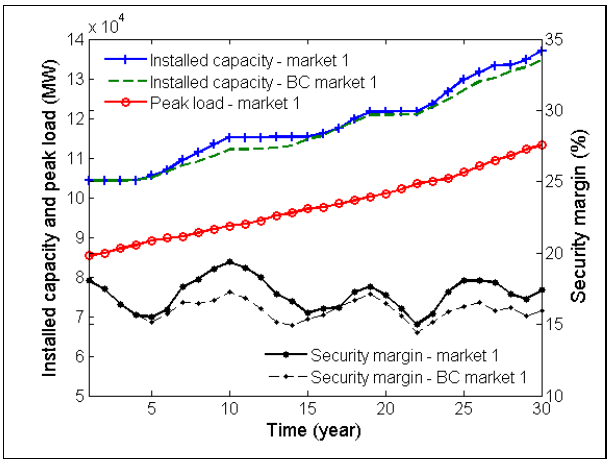
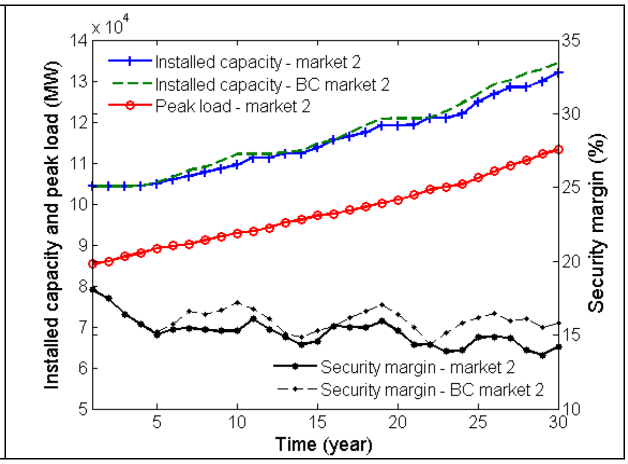


Fig.12 Installed capacity, peak-load and security margin in market 2 - case 2



Case 3: Interdependency between an energy-only market and a market with a capacity mechanism. We consider two sub-cases for market 2 which now includes a capacity mechanism in its design to compensate for the effect of a price cap set at 3000 €/MWh : one case with a capacity payment and one with a capacity forward market mechanism. In these two sub-cases we shall try to identify if the capacity mechanism adjunction in market 2 helps alleviate the risk of free riding by market 2 in the integrated "market 1-market 2 system".

Case 3.1. Interdependency between an energy-only market and a market with capacity payment mechanism. Capacity payments could be seen as a market design in which generation capacity is considered as a distinct product that is priced independently for encouraging new generation investments, in particular in peaking units. All things being equal, the higher the capacity payment the more capacity it will be economically advantageous to build. As mentioned in section 3, different capacity payment designs were adopted around the world. These differences are due to the degree of compatibility with the energy market. In this model, we retain solely the approach in which capacity payments mechanism consists of defining the capacity price *ex ante* by taking into account expected conditions such as available generation and peak load. In order to avoid unnecessary complexity in the calculations a capacity payment equivalent to 28000 €/MW- year costs is adopted at the beginning of the simulation which amounts to about 50% of the fixed costs of a new combustion turbine. This subsidy is modified yearly ex ante according to the expected evolution of the available generation and peak load. The results of the simulation for case 3.1 are shown in Figures 13 and 14. The market with capacity payments produces significantly more investments, which result in lower prices and high reliability (see Figs. 15 and 16). The opposite effect is observed in market 1 which is interdependent with market 2, where lower incentives for investments in capacity than in market 2 leads to a decrease in generation reserve, which in turn increases spot prices. This differs from the version of case 2 in which it was the energy only market (market 1 which was the more dynamic in terms of capacity installation). In addition, the capacity payment mechanism in market 2 appears to lead to a level of capacity which is above the reserve margin needed, which is a drawback of this approach. This comes from the fact that even in periods of overcapacity, all capacities in new generation units in peaking units are subsidized. Such periods of inefficient subsidization may be inevitable, as capacity payments do not fully suppress investment cycles. Consequently, as consumers finance capacity payments via a TSO uplift, consumer surplus is altered in market 2 because this loss of surplus is not compensated at the overall level by the surplus gain of the producers in market 1.

Fig.13. Energy-only market with no price cap policy – case 3.1

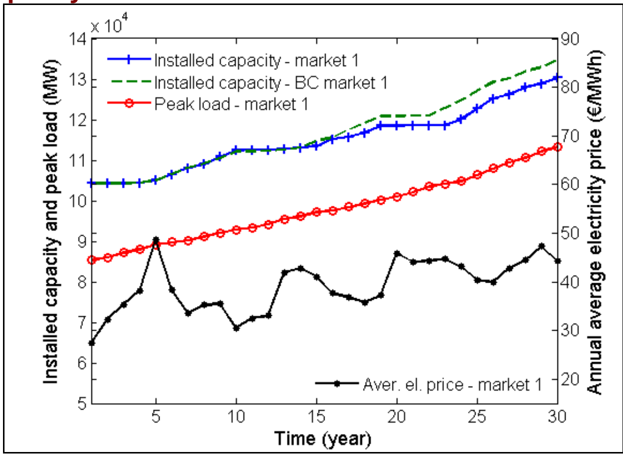
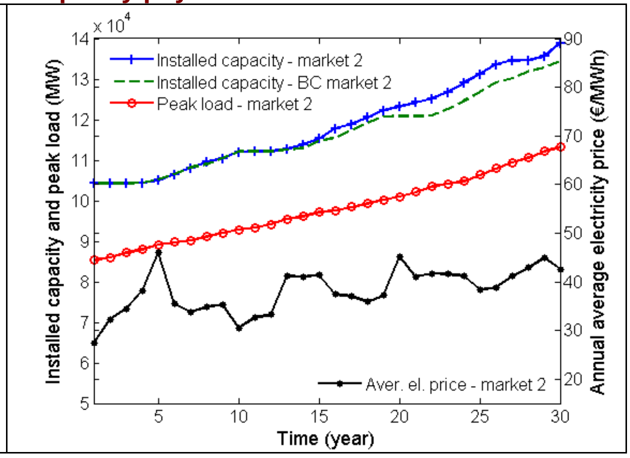


Fig.14. Market with a price cap and a capacity payment mechanism - case 3.1



On the other hand, excess capacity in the market 2 can be exported to the market 1 and improves consumer surplus by the reduction of outage risk and the lowering of average price by price spike limitation in comparison to a scenario of an isolated market 1. Conversely the result in market 2 is that prices are higher by the way of trade from market 1, the energy-only market with no price cap policy and no capacity payment. Thus, even though installed capacity is increased in market 2 compared with the benchmark case, the level of average electricity price is similar to the benchmark case in the last years of the simulation, this effect being the result of interdependencies with market 1, thanks to the exchanges. Note, however, that more stable average prices result in both markets compared with the benchmark case.

Fig.15. Installed capacity, peak-load and security margin in market 1 - case 3.1

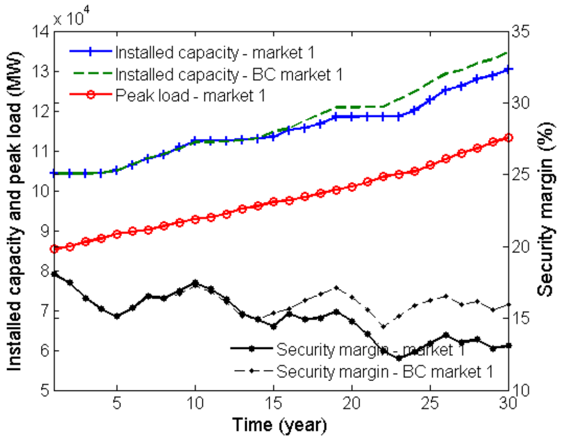
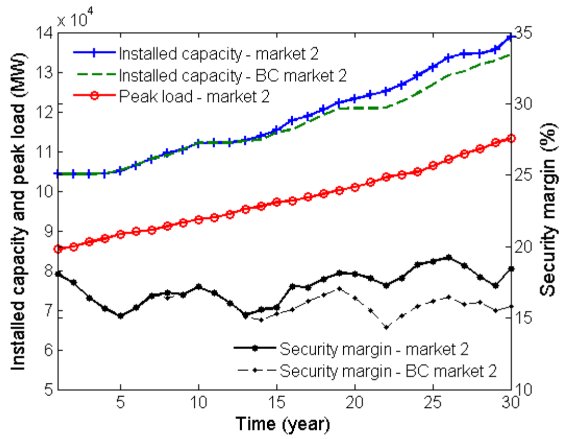


Fig.16. Installed capacity , peak-load and security margin in market 2 - case 3.1



Case 3.2. Interdependency between an energy-only market and a market with a forward capacity market mechanism. Forward capacity market aims to provide more stable investments. For this, the investment signal is developed before actual periods of capacity shortages develop. Thus, more stable prices and fewer outages

result. Forward capacity market react better to demand and supply shocks but also prevents some of them. The results of the simulation for this case are depicted in Figs.16 and 17. Annual average electricity prices and security margins in market 1 remain similar to the case in which there is a capacity payment mechanism in market 2. Contrary to the previous case, forward capacity markets avoid large periods of overcapacity in market 2. Considerable benefits in reliability (i.e. security margin) are obtained in market 2, as shown in Fig. 19. Regarding prices price volatility in market 2 decreases in comparison to the benchmark case.

Fig.16. Energy-only market with no price cap policy – case 3.2

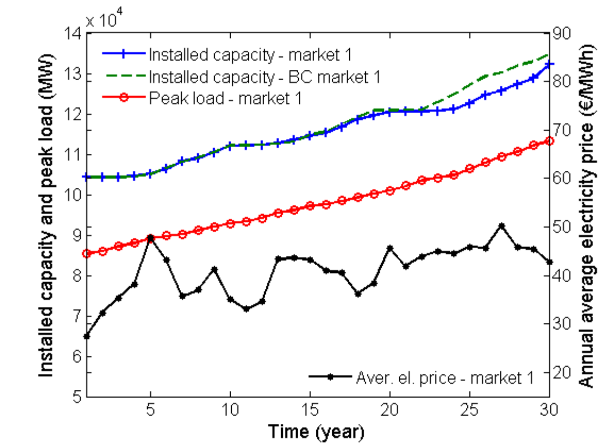


Fig.17. Market with a price cap and a forward capacity market mechanism- case 3.2

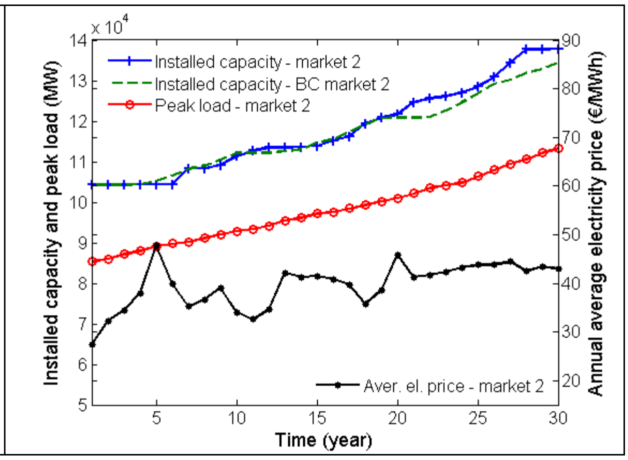


Fig.18. Installed capacity, peak-load and security margin in market 1 - case 3.2

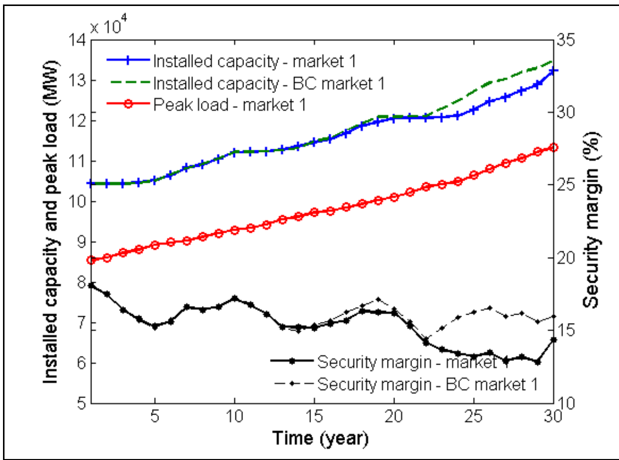
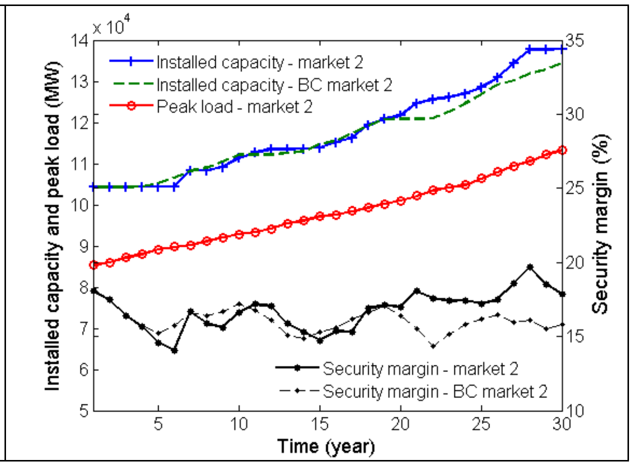


Fig.19 Installed capacity, peak-loa and security margin in market 2 case 3.2



Case 4: Interdependency between a market with a capacity payment and a market with a forward capacity market mechanism. Referring to figures 20 to 23 which display results for this case, capacity investment development and annual average prices evolution are quite similar in both markets. This means that the differences of capacity mechanism designs have fewer undesirable effects than the differences between markets without capacity instruments and the market with capacity instruments modelled in the previous cases. Regarding reliability, the security margin in both markets remains similar to the security margin in the benchmark case of two energy-only markets without price caps.

Fig.20. Market with a forward capacity market mechanism - case 4

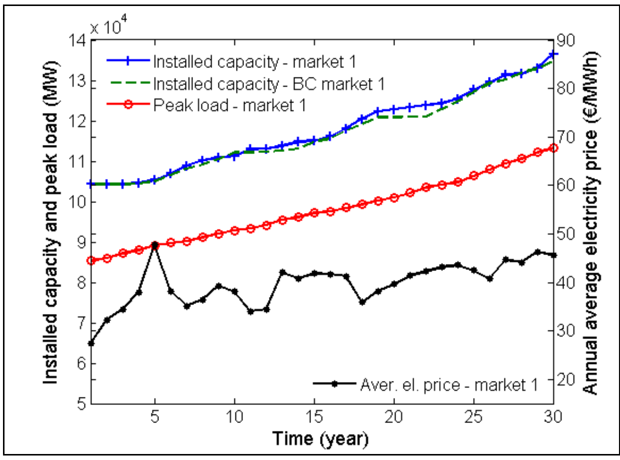


Fig.21. Market with a capacity payment mechanism – case 4

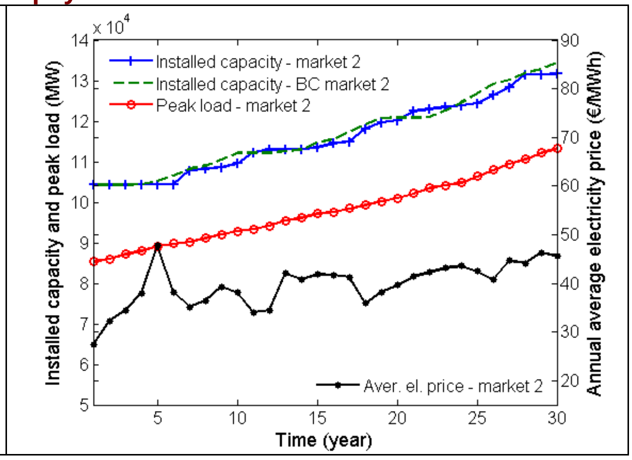


Fig.22. Installed capacity , peak-load and security margin in market 1 - case 4

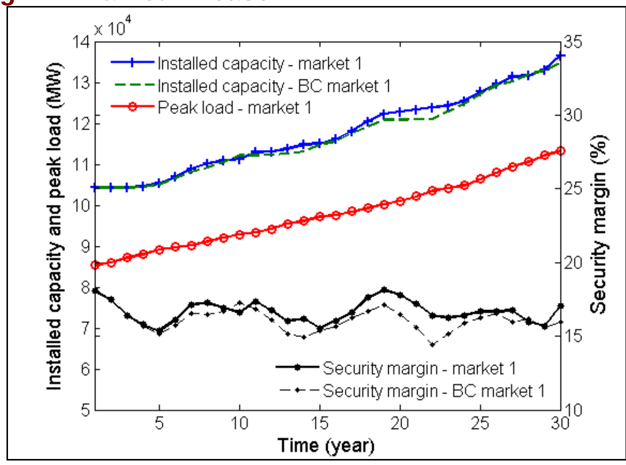
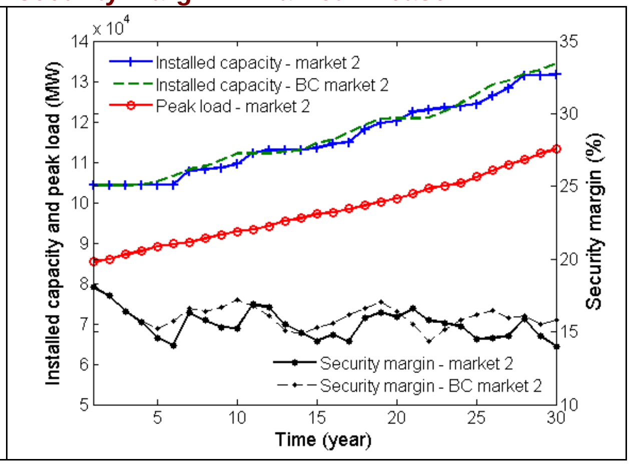


Fig.23. Installed capacity , peak-load and security margin in market 2 - case 4



Case 5: Two linked markets with identical FCM capacity mechanisms. Figs. 23 to 26 show the results of the harmonization of the forward capacity market. In order to allow a price equilibrium to develop, the penalty is partly elastic (i.e. dependent on the capacity margin). In practice, this is necessary to reduce price volatility in the capacity credit market. The penalty is set at 10 €/MWh, slightly higher than the fixed costs of a new CCGT generator, for capacity margins less than 10% over annual peak demand. The capacity obligation increases the predictability of the (regulatory determined) demand for capacity and reduces investment risk by providing more stable revenues. At the beginning of the model the capacity obligations are not met, which results in a degree of lack of investment in the first years. In practice, this could be dealt with by phasing in the capacity obligations. This new capacity becomes available just as demand growth levels off. A subsequent increase in demand growth leads to a decrease in the reserve margin. At the end of the run, security margin increases considerably compared with the benchmark case. A price cap of 2000 €/MWh limits scarcity prices and therefore also price volatility, while the capacity market provides the investment incentive. Prices are more stable and lower than in case 4 as a result of the reserve margin that is created by the capacity obligations. This serves to demonstrate that a capacity obligation can effectively dampen investment cycles, leading to high reliability (i.e. reduce regional power shortages) at average prices.

Fig.23. Market 1 with a forward capacity market mechanism - case 5

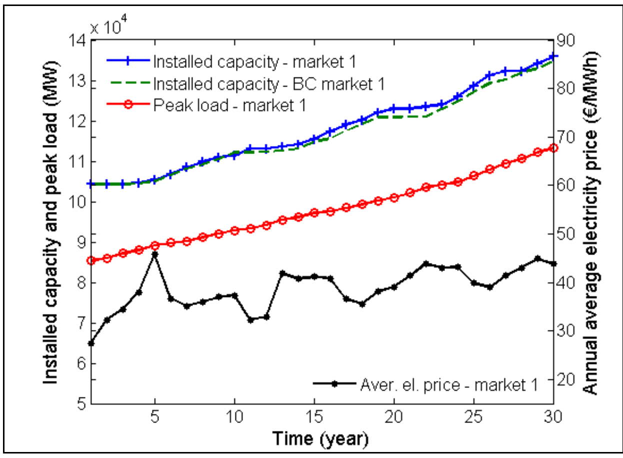


Fig.24. Market 2 with a forward capacity market mechanism - case 5

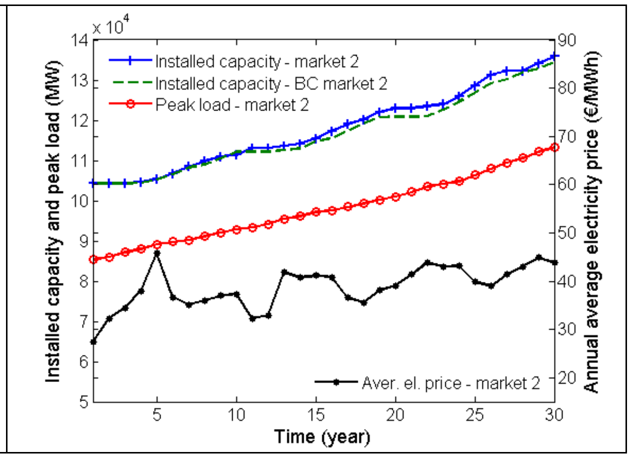


Fig.25. Installed capacity, peak-load and security margin in market 1 - case 5

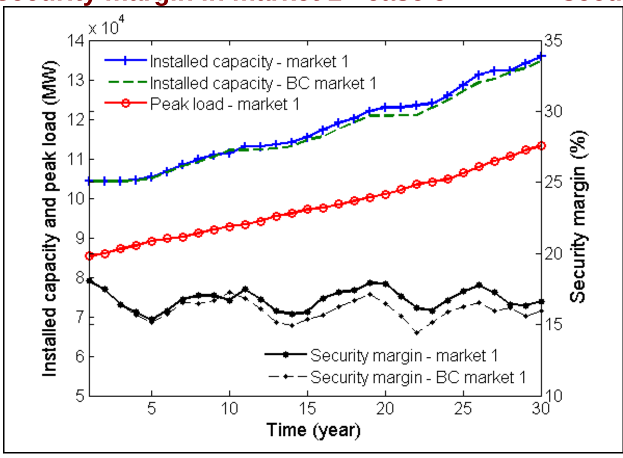
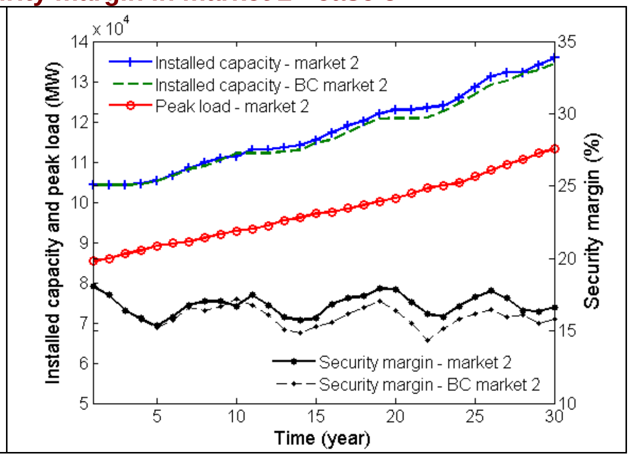


Fig.26. Installed capacity, peak-load and security margin in market 2 - case 5

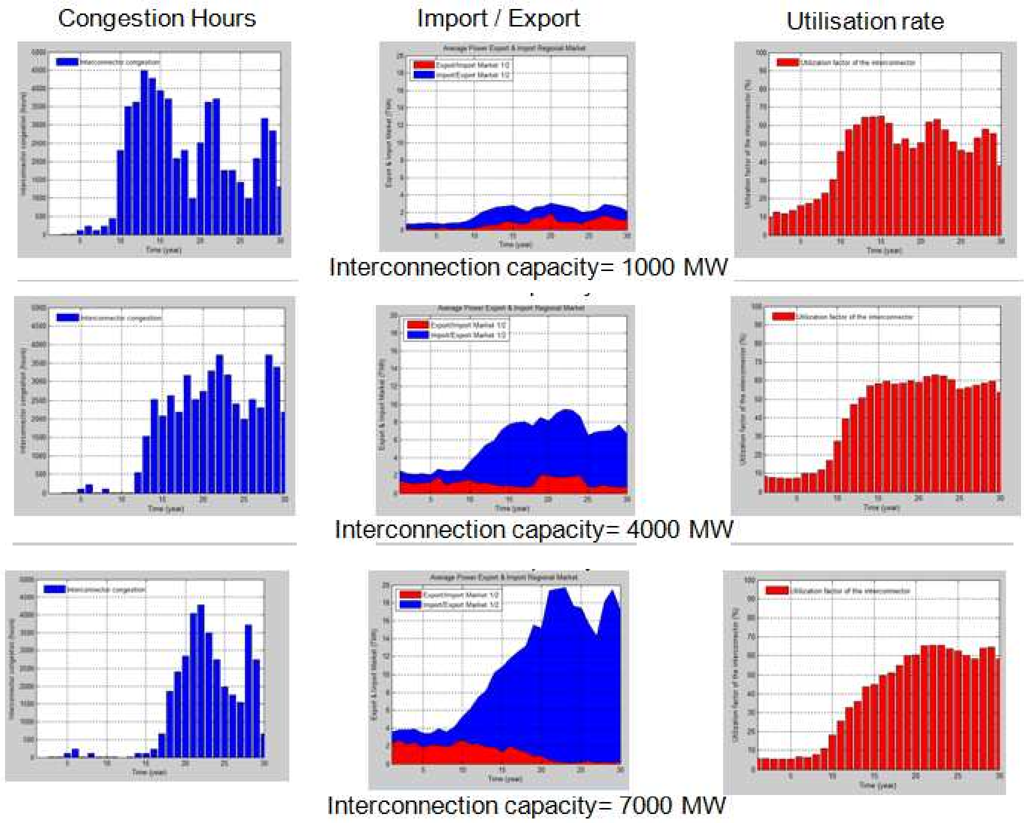


The influence of interconnection capacity in a situation of asymmetry of market designs. We consider three different transmission capacities: 1000MW, 4000 MW and 7000 MW (i.e. respectively 1%, 4% and 7% of initial installed capacities, in order to analyze the impact of interconnector constraints on interdependency between electricity markets. Figure 27 shows for the successive thirty years of the simulation: the number of yearly congestion hours, the flows of imports and exports, and the utilization rate of the interconnection in the different scenarios of transmission capacity. We only consider a situation analogous to case 4 - two interdependent markets, an energy-only market with no price cap policy and a price-capped market with a forward capacity market mechanism.[1] Because of the difference in price between the two markets due to the price cap in market 2, there is an intrinsic tendency that, on a year with fixed generation capacities, market 2 generators prefer to export to market 1 during the periods when the price cap is reached by market price in market 2, provided that interconnection capacity exists.

[1] We do not learn any more by considering different interconnection capacities in the cases 2 in which there is difference in price cap policies and the case 3 in which there is different adequacy policies.

The early years in the simulation are characterized by low levels of congestion. In the following years congestion hours increased cyclically, which influences the congestion rent captured by the interconnection owners by the difference between the two energy market prices. This can be interpreted as a risk for the TSO for new investments in interconnection capacity.

Fig.27. Comparison of congestion hours, import/export flows and interconnection utilization rate for different interconnection capacities. Notice on import/export. Grey zone : flows from market 1 to market 2; Black zone: flows from market 2 to market1 1



Increases of congestion hours around the year 10 are due to the asymmetry of adequacy policies that progressively creates differences in the technology mix in each local market, compared with the homogeneity of the two technology mixes at the beginning of the simulation period. In turn this differentiation increases dramatically energy exchanges between local markets, but mainly from market 2 which has a capacity mechanism, to market 1 without capacity mechanism. With regard to trade flows, the larger the interconnection capacity is, the more imports to market 1 from market 2 increase. This means that the benefits of interconnection capacity on generation adequacy are not symmetrically shared between the two interdependent markets. In economic terms, one can assert that in presence of asymmetry of capacity adequacy policies, increasing interconnection capacity creates a positive externality for one of the markets, the one which has no capacity mechanism, that leads to a free-riding from the part of the regulator and the consumers in this market.

5. Lessons from the difference in results between cases of interdependency between two markets

In this section we compare the effects of the choice of a market design on the performance of the concerned market, as well as the positive and negative externalities resulting from the interaction between markets with different designs. We characterize these effects in terms of the average of annual average price on the 30-year period and its variability, as well as in terms of loss of load expectations LOLE (expressed in expected hours of shortage per year) and its distribution. We calculate the mean annual price. In markets with a capacity mechanism we add the revenue coming from the capacity payment for the sake of relevance. Indeed, in these markets, the volume of installed capacity results from the revenues by sales on the energy market and by the capacity instrument, while in energy only markets, the installed capacity is only determined by revenues by the energy market price. Moreover, it is the sum of energy costs and capacity costs that consumers will pay in markets with capacity instruments, but they only pay energy costs in energy-only markets.

Table 3 provides an overview of performances of the two interdependent markets in several cases of market designs. It is noteworthy that, when there is a price capped market, there is no free riding from the other market in energy-only design (case 2), as well as, when there is a price capped market with a capacity mechanism, the other market in energy-only design does not profit at all from the policy of the other (case 3.1 case 3.2 compared to case 1 and case 2). Let us explain these observations.

Effects of the different market design choices of a market on the performances of the adjacent market. Over the whole period, the variant of case 2 in which the market 2 has a price cap as well the cases 3.1 and 3.2 with market 2 with price cap and a capacity instrument in adjacent market 1 in the same design of energy-only market (case 2, case 3.1 and 3.2) lead to a higher mean price in market 2 than in the benchmark case with market 2 in energy-only design (43.16- 42.85- 41.56 €/MWh versus 39.65 €/MWh in the benchmark case) ***[the previous sentence was not completely clear to me, I have tried to edit, but you may need to re-work it as I am not sure].***

Differences between market 2 and market 1 are significant with a much lower average price level (36.91 to 39.70 €/MWh in market 1 in the three cases). With respect to the reliability index of loss of load expectation (LOLE), while reliability is logically reduced in the price capped market approach in market 2 (case 2) on one side, capacity payment (CP) in market 2 (case 3.1) and forward capacity market (FCM) in market 2 (case 3.2) improve reliability in the adjacent market.

Table 3. Comparison of the effects of asymetrical market designs and capacity mechanisms.
(Acronyms. EO: Energy only, CP: capacity payment, FCM: Forward Capacity Market)

		Annual average price [€/MWh]		LOLE [h/y]	
		Mean	Standard deviation	Mean	Standard deviation
Case 1 (Benchmark case): Market 1: EO Market 2 : EO	Market 1	39.65	5.79	6.46	6.99
	Market 2	39.65	5.79	6.01	6.73
Case 2: Market 1: EO Market 2 : EO with price cap	Market 1	36.91	4.81	5.80	6.82
	Market 2	43.16	4.10	15.94	13.73
Case 3.1: Market 1: EO Market 2: price cap and CP	Market 1	39.70	5.37	10.90	2.85
	Market 2	42.85	4.57	1.42	2.41
Case 3.2: Market 1: EO Market 2: price cap and FCM	Market 1	38.14	5.32	6.13	5.53
	Market 2	41.56	4.63	1.72	1.46

Interaction effects between markets with different capacity payment mechanism designs. Concerning now the different effects that result from neighboring markets with different designs, a price cap regulation in market 2 has few effects on prices in market 1 in the “energy-only design” scenario. But it significantly alters the level of average prices and reliability at home, because of “energy leakages” from market 2 to market 1 when prices reach the price cap in market 2. In the long term it results in higher installed capacity in market 2 than in the benchmark case, and higher average prices are needed in order to make profitable investment in new capacities, given that part of them will be oriented towards exports to market 1 during the period of price capping in market 2.

The capacity payment mechanism in market 2 (case 3.1) is the most problematic approach with the significant effect of annual average price increases in market 1 (energy-only market) (from 36.91 €/MWh to 39.70 €/MWh). This influence between markets could be observed also on the variability of the price in the market 1 in the same case 3.1. Curiously we do not observe such influences of market 2 on the price in market 1 when market 2 is designed with the forward capacity mechanism as in case 3.2. This difference is explained by the fact that we model the capacity payment mechanism in its most basic form and the subsidy per unit of generating capacity is not accompanied by an obligation on the part of the generating companies. Such obligation could be added, in which case the mechanism may evolve in the direction of the forward capacity market mechanism. Thus, electricity generating companies do not integrate in their objective function the probability of paying an explicit penalty if their plants are not available when requested, which in turn reduces the potential profit of investing in a new power plant. The outcome is that both the electricity producers in markets 1 and 2 will be more encouraged to invest in market 2 even though it could be more expensive socially in the long run. This reduces the level of investment in market 1 resulting in a higher average electricity price in case 3.2 with respect to case 3.1

Concerning the effects on the respective LOLE when market 2 is designed with a capacity instrument and market 1 is still “energy only” designed (case 3.1 and 3.2), we observe that in case 3.1 and case 3.2, an alteration of the reliability performances in market 1 (from a LOLE of 5.8 h/y in case 2 to a LOLE of 10.9 h/y in case 3, or to a LOLE of 6.13 h/y in case 3.2), which is partly compensated by a decrease of the standard deviation of the LOLE from the case 2.

Interaction effects between near symmetrical cases. Furthermore cases 4 and 5 show that the adoption of a capacity mechanism in markets 1 and 2 suppresses any negative impact of market 2 with a capacity mechanism on market 1. Moreover the comparison of the “asymmetric markets” cases 3.1 and 3.2 with cases 4 and 5 in which both markets are designed with a capacity mechanism shows much lower average prices in market 2 in the case 4 and case 5 than in cases 3.1 and 3.2 (39.55 and 39.03 €/MWh compared to 42.85 and 41.56 €/MWh), and a bit lower in market 1, while reliability performances are improved significantly in market 1 in case 4 and case 5 in comparison of its performance when it is energy-only designed (case 3.1 and case 3.2). That reflects the fact that efforts in investments are parallel in markets 1 and 2, and they result in quite similar reserve margins; the exchanges for reliability are just necessary in years when there have been asynchronous capacity developments. Finally the prices in the two markets are similar and as low as the prices in the benchmark case of two energy-only designs, and the respective LOLEs are low in the two markets. That would be a good argument in favor of capacity policies harmonization.

Table 4. Comparison of the effects of symmetrical market designs and capacity mechanisms
(Acronyms. EO: Energy only, CP: capacity payment, FCM: Forward Capacity Market)

		Annual average price [€/MWh]		LOLE [h/y]	
		Mean	Standard deviation	Mean	Standard deviation
Case 1 (Benchmark case): Market 1: EO Market 2 : EO	Market 1	39.65	5.79	6.46	6.99
	Market 2	39.65	5.79	6.01	6.73
Case 4: Market 1: price cap and FCM Market 2: price cap and CP	Market 1	39.25	4.32	1.35	1.26
	Market 2	39.55	4.28	1.81	1.35
Case 5: Market 1: price cap and FCM Market 2: price cap and FCM	Market 1	38.23	4.43	1.22	1.26
	Market 2	38.03	4.39	1.47	1.35

Comparison of the effects of different capacity market designs in market 2 on market 1. As shown by cases 3.1 and 3.2 and cases 4 and 5, regarding the impact of any capacity mechanism in market 2 on the reliability in price-capped market 2, capacity payment and forward capacity market in market 2 significantly improve reliability in this version of market 2 compared with the price-capped variant market 2 without capacity mechanism. Capacity payment appears to be less performing than forward capacity mechanisms: it improves reliability, but increases price level and dampens price variability (volatility) only to a limited degree, while forward capacity markets reduce both price volatility and the risk of shortages.

Concerning the impacts on market 1 in “energy-only”, they are negative in terms of price and reliability if we refer to the benchmark case. The design with a forward capacity mechanism in market 2 has a less negative effects on market 1 than the design of capacity payments has in market 2, as said above. The positive results are not transferred from market 2 to market 1.

6. Conclusion

In order to test the effects of differences of market designs in two interconnected local markets i.e. a regional market, we have developed a system dynamics model of two interdependent local markets in a supposed perfectly competitive regional market. We compare situations with an energy-only market on one side and price capped markets with possibility of two different capacity mechanisms on the other side. In such a regional market, asymmetries of policies between price-capped and non price-capped markets may lead to “leakage” of generation capacity from the price-capped market to the adjacent non-capped market (because it is more profitable). Capacity payment added in the price-capped market, if they are high enough, provide a sort of stabilizing force to the energy leakage towards the neighboring energy-only market but is not robust against regional shortages. Forward capacity market react better to demand and supply shocks and also prevent some of them from occurring in the first place.

These results contradict the intuitive opinion according to which countries without adequacy policies would free ride on the adequacy policies of neighboring markets. When there is a price capped market, there is no free riding from its part vis-à-vis the other energy-only design market; as well as, when there is a price capped market with a capacity mechanism, the other market in energy-only design does not profit at all from the policy of the other. The results show the opposite: i.e. the negative externalities of this market with capacity mechanism in market 2 on the performances in market 1. Finally results in the cases in which the two markets have a common approach of capacity adequacy (case 1, case 4 and case 5) show that average price and reliability benefit the most from harmonized policies, not only for each market, but also for the two integrated markets.

In other words in a regional electricity market the lack of harmonization between local markets regarding price cap and capacity mechanisms, may lead to undesirable side effects in the neighbored markets by distorting their normal functioning. Results show the interest of having harmonization in any case either in the sense of the same energy only market design with price cap, or if there is a cap, the same level of the cap and the adoption of the same capacity mechanism. Results show also that increasing transmission capacity under asymmetric market designs could create several concerns. Therefore, local regulators should integrate into their rules, practices and decisions a view with respect to the interactions of their price cap and capacity adequacy policies, and at the same time take into account the influence of existing interconnection capacities. The question is whether it is politically feasible to implement the same price cap and capacity policies jointly in adjacent electricity systems.

APPENDIX 1
The representation of the electricity markets in the model

1. The demand side

The demand in each local market *i* is characterized by a load duration curve $L_{ni}(t)$ and modeled on an hourly basis. Similar to Olsina et al. (2006), De Vries and Heijnen (2008) and Assili et al. (2008), we assume that the pattern of demand $L_{ni}(t)$ does not change during the simulation. However, we consider two uncertain components affecting demand: the growth rate g_{ni} and the weather (random) $\mu_{ni}(t)$. The growth rate of demand is represented by a discrete random variable g_{ni} following a triangular distribution function similar to De Vries and Heijen (2008)[1]. As for the weather random variable $\mu_{ni}(t)$, it is assumed to follow a normal distribution function $N(1, \sigma_{\mu_{ni}})$. We model relationships between local market demands by introducing correlation factors $\rho_{g_{ni}, g_{n-i}}$ and $\rho_{\mu_{i\,(t)}, \mu_{-i(t)}}$ for each uncertainty described above, respectively. Demand in the year *n* can thus be written as:

$$L_{ni}(t) = (1 + g_{ni}) \cdot \mu_{ni}(t) \cdot L_{n-1i}(t) \tag{1}$$

where,

$$\rho_{g_{ni}, g_{n-i}} \neq 0 \text{ and } \rho_{\mu_{ni}(t), \mu_{n-i}(t)} \neq 0$$

In order to consider the influence of electricity trading between local-markets on spot prices, demand $L_{ni}(t)$ is modified according to the power flow $F_{ni-i}(t)$. We define the remaining demand for local generators $RL_{ni}(t)$ as follows:

$$RL_{ni}(t) = L_{ni}(t) \pm F_{ni-i}(t) \tag{2}$$

In Equation 2, the power flow $F_{ni-i}(t)$ can be interpreted as a further source of generation capacity or as additional demand depending on the supply and demand in both local-markets in a given time *t*. Thus, the sign of $F_{ni-i}(t)$ is negative (positive) when market *i* is exporting (importing) to (from) the adjacent market. The power flow through the interconnector is determined from the optimal power flow described in the section 2.7.

Although demand is modeled as price inelastic in the short term, we modeled a volume of consumers M_i that corresponds to a fixed percentage of peak demand which has interruptible contracts which are triggered at a spot price C_i. In other terms, interruptible contracts could be seen as a generation technology which has a variable cost C_i and no fixed cost.

2. The supply side

The model represents two linked local markets. Each local market holds thermal-generating units with four different technologies including nuclear plants (N), hard-coal (HC) power plants, gas-fired combined cycles (CCGT) and combustion turbine (CT). These technologies are characterized by outages and schedule maintenance. The outages in generation units are modeled relying on the two-sate probabilistic generation model. A forced outage rate (FOR) is assumed for each technology *j*. Random outages on generation units are generated by using the inverse function of a binomial distribution. They are calculated exogenously to the model for a 30-year period on an hourly basis. In contrast to the demand uncertainties, outages are considered not to be correlated from year to year or between technologies. It means that the model assumes that all generation units can fail and be repaired independently of failures and repairs of other units. Under this

[1] Triangular distribution reflects the tendency towards cycles in the general economy which creates related cycles in the demand for electricity.

assumption probability of a capacity outage level $TOg_i(t)$, with *k* generation units on outage and *n* number of total units, can be calculated combining the single probabilities of each generation unit.

$$\Pr(TOg_i(t)) = \sum_k \binom{n}{k} FOR^k (1 - FOR)^{n-k} \tag{3}$$

In order to avoid unnecessary complexity in calculations, schedule maintenance is adopted as a constant coefficient of unavailability. However, it differs for each technology *j* and varies by season; for this, we use a concentration factor in the spring and autumn period. Indeed, most of the planned maintenance is scheduled during spring and autumn when there are lower peak loads and higher hydro generation.

Although changes in fuel prices directly influence the operating costs of thermal generation units which in turn affect the dynamic of electricity prices, they are kept constant to avoid adding other sources of dynamics. We nevertheless consider the effects of learning and incremental innovations by gradually increasing the efficiency and reducing operating costs for new facilities the coming years. Thus, all things being equal, new generation units are assumed to have lower variable costs than the incumbent power plants. We introduce an exogenous variable in the model to represent efficiency increases, which differs depending on each technology *j*.

Once defined the variables that affect the available generation capacity in market *i*, available generation capacity can be calculated by reducing installed generating capacity TC_{ni} for unavailable capacity due to outages $TOg_i(t)$ and maintenance power plants $TSm_i(t)$ and, adding the volume of the interruptible contracts M_i. Thus, available generation capacity $Ag_i(t)$ can be expressed as:

$$Ag_i(t) = TC_{ni} - TOg_i(t) - TSm_i(t) + M_i \tag{4}$$

where,

$$TC_{ni} = \sum_j Pmax_{ji}\,, \quad TOg_i(t) = \sum_j Og_{ji}(t)\,, \quad TSm_i(t) = \sum_j Sm_{ji}(t)$$

3 Modeling reliability

Reliability can be improved by investing in new generation capacity. In the model, this is measured by the common reliability index *LOLP* (i.e. loss of load probability), which is the probability that remaining demand $RL_i(t)$ excess the available generation capacity $Ag_i(t)$:

$$LOLP_i = \Pr[\,RL_i(t) > Ag_i(t)] \text{ or } LOLP_i = \Pr[\,RM_i(t) < 0] \tag{5}$$

Where $RM_i(t)$ is the reserve margin, which can be formulated as: $RM_i(t) = \frac{Ag_i(t) - RL_i(t)}{RL_i(t)}$.

In addition to *LOLP*, we use another index, the loss of load expectation (LOLE), which represents the expected number of days in the year in which the load will exceed available generation.

$$LOLE_i = \sum_t^T [\Pr[\,RM_i(t) < 0] \cdot t] \tag{6}$$

The electricity-not-served ENS_i during this time period can be obtained from the difference between the remaining demand $RL_i(t)$ and the available generation $Ag_i(t)$ when $RL_i(t) > Ag_i(t)$. It may be interpreted as the energy supplied by a generation unit with unconstrained capacity and variable cost equal to VOLL.

4. Calculation of the electricity price in an energy-only market

We assume a perfect competition framework. We assume that electricity producers have no market power, neither in fuel markets nor in the electricity market. Thus, the electricity price is the result of the interaction between supply and demand, which is generally settled by the marginal cost of generation which in turn corresponds to the variable cost of the marginal generation technology. However, if demand exceeds the available generation capacity $Ag_i(t)$, the electricity price is equal to the cost of interruptible load contracts C_i. Finally, if the volume of interruptible contracts M_i is exhausted as well, the electricity price is set at a value of lost load $VOLL_i$[1]. In theory, this price

[1] Some modifications in the formation of electricity prices have been included in the model to represent capacity mechanisms. They will described in the section 2.9

represents consumers' true willingness to pay for electricity in scarcity periods. To sum up, the electricity price is given by the following expression:

$$p_i(t) = \begin{cases} VOLL_i \ , & Ag_i(t) + M_i < RL_{ni}(t) \\ C_i \ , & Ag_i(t) < RL_{ni}(t) \leq Ag_i(t) + M_i \\ VC_{ji} \ , & 0 < RL_{ni}(t) \leq \sum_j Ag_{ji}(t) \end{cases} \quad (7)$$

Note that the model considers interaction with the adjacent market through the remaining demand (see Eq. 2). Wholesale energy is assumed to be traded in the energy market and, therefore, ancillary services are not taken into account.

5. Modeling interaction between local markets in relation to their interconnection capacity

In regional electricity markets, local markets continuously interact. These interactions allow not only to use the most efficient generation resources, but also to increase security of supply. In order to consider these interactions, we rely on a simplified version of an optimal power flow (OPF) algorithm, which dispatches generation assets according to the regional merit order (least-cost) subject to the physical constraints of the interconnector. Here, the power flow through the transmission line is the result of the free interaction of generation and demand in both markets until the constraint of transmission capacity are reached. The problem is formulated as:

$$min_{F_{i-i}, P_{Gj}} \sum_i \sum_j CV_{ij}(P_{Gij}) \quad (8)$$

Subject to:

$$|F_{i-i}| \leq F_{max} \quad (9)$$

$$\sum_i \sum_j P_{Gij} = \sum_i P_{Li} \quad (10)$$

$$O \leq P_{Gj} \leq P_{Gmax\,j} \quad (11)$$

As mentioned above, the power flow $F_{i-i}(t)$ is used to calculate the remaining demand for local generators. It is assumed that system operators will not interrupt exports to adjacent markets in case of a domestic emergency of supply. This seems to be the purpose stated in Article 24 of Directive 2003/54/EC: ''In taking the measures to be adopted in emergency situations, Member States shall not discriminate between cross-border contracts and national contracts''.

We consider that the interconnector capacity is constant and perfectly reliable throughout the simulation period. Although the relationship between the dynamics of generation and transmission investments is strongly linked, we isolate the dynamic nature of generation investment in order to focus on the impact of market design on generation investment.

APPENDIX 2
Input parameter values for the simulations

Description	Notation	Value
Interruptible contract price [€/MWh]	C_i	700
Discount rate [%]	r	8%
VOLL [€/MWh]	$VOLL_i$	10000
Price cap [€/MWh]	PC_i	2000
Capacity Payment in t=1 [€ /MW-year]	CP_j	28000
Price of operating reserves [€/MWh]	Pr_i	2000
Volume of interruptible contracts [MW]	M_i	$5\% \cdot \max[L_{ni}(t)]$
Growth rate random variable	g_{ni}	Triangular distribution : mean =1.01, upper limit = 1.02, lower limit =1.00
Weather random variable	$\mu_{ni}(t)$	$N(1, \sigma_{\mu_{n,t}})$ with $\sigma_{\mu_{n,t}} = 4 \cdot g_{ni}$
Correlation factor between growth rate of demand in the market 1 and the growth rate of the adjacent market 2	$\rho_{g_{n1} g_{n2}}$	0.8
Correlation factor between weather random variables of the market 1 and the adjacent market 2	$\rho_{\mu_{1(t)}, \mu_{2(t)}}$	0.8
Interconnection Capacity (MW)	F_{max}	4000 (benchmark case)

Description		Notation	Nuclear	Hard Coal	Gas Turbine	Combustion Turbine
Initial installed capacity [MW] **(market 1)**		TC_{ji}	66830	14400	9000	9625
Initial installed capacity [MW] **(market 2)**		TC_{ji}	66830	14400	9000	9625
Investment cost [€ /MW-an]		IC_j	308588	210 000	122 000	57142
Variable cost [€/MWh]		VC_j	11	27	44	158
Amortization time [year]		T_j^a	40	35	25	25
Lead time [year]		T_j^c	6	4	3	2
Average unit capacity [MW]		$Pmax_j$	1630	900	450	175
Forced outage rate [%]		FOR_j	0.035	0.047	0.031	0.026
Schedule maintenance [%]	Winter		11.8	7.5	5.4	6.9
	Spring / Autumn		15.8	11.5	9.4	10.9
	Summer		21.8	18.5	16.4	17.9

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