Assessing dynamic effects of capacity remuneration mechanisms on generation investment: comparison between strategic reserve mechanism and capacity market

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Abstract

Following power reforms in recent decades, the ability of liberalized markets to provide satisfactory incentives for capacity investments has become a major concern of the energy system. In particular, the current energy markets are prone to a phenomenon of investments cycles. Thus, new mechanisms, called capacity remuneration mechanisms (CRM) have been (or will be) implemented with the objective of providing optimal investments and solving adequacy issue.

The purpose of this paper is to assess the dynamic effects of different CRMs, namely the capacity market and the strategic reserve mechanism, and to study to what extent they can correct the cyclical tendencies and the investments issues prone to happen in the current energy markets. Moreover, these two mechanisms are compared based on social welfare, which is evaluated thanks to generation costs and shortage costs. A model, based on systems dynamics programming, has been developed to simulate the functioning of both CRMs and to model investment decisions.

The results highlight the benefits of deploying capacity remuneration mechanisms to solve the adequacy issue: shortages are strongly reduced by implementing such CRMs. Moreover, through the comparisons, the capacity market appears to be more beneficial than the strategic reserve mechanisms from the economic point of view, since it experiences fewer shortages and the generation costs are lower. These comparisons based on social welfare can be used by electricity market designers (in particular from a European point of view, considering state aids issues) to determine which CRM to adopt.

Keywords

Electricity market, generation investment, capacity remuneration mechanism, system dynamics

Introduction

Power reforms in recent decades have highlighted coordination problems which did not exist when power systems were integrated into a vertical monopoly. In the beginning of liberalization, these coordination issues have been deeply studied for short-term markets and new mechanisms have been implemented to operate them in an efficient and reliable way (Glachant, 2003; Glachant and Finon, 2003). More recently, new questions have been identified regarding long-term efficiency and investment issues (for instance, Finon and Pignon, 2006; Roques, 2008; Léautier, 2013). The development of competition on the generation side has indeed changed the way investors take decisions (Dyner and Larsen, 2001). In previous regulated systems, investments risks were passed through the tariffs and born by consumers. Coordination in generation investments was easier since there was only one player involved. Now, investors perform their own development planning in reaction to complex and hardly predictable price signals, aiming to earn the highest profit. It makes coordination in investments more complex.

Extended literature has shown that many market failures can disturb the achievement of an optimal level of investment under the so called "energy-only" market design (De Vries, 2004; Hobbs and al, 2001; Joskow, 2007; Bidwell and Henney, 2004). Thus, new mechanisms called capacity remuneration mechanisms (CRM) have been implemented (or are going to be) with the objective of providing optimal investment signals and solving adequacy issues. Capacity markets, capacity payments or strategic reserve mechanisms are some examples of these mechanisms.

In Europe, two types of CRMs are being mainly debated: the capacity market and the strategic reserve mechanism. Both are volume-based mechanisms. In the capacity market (also known as capacity requirements), an obligation of installed capacity is computed some years in advance, equal to the peak demand forecast together with a capacity margin, and proportionally shared between suppliers. A new market for capacity is then created, juxtaposed to the commodity energy market, to exchange capacity credits and reach this capacity obligation. This design has been selected or is being considered in France, in Great-Britain and in Italy. In the strategic reserve mechanism, the TSO sets, several years in advance, the amount of required strategic reserves based on the difference between estimated peak demand (plus a capacity margin) and what the market would otherwise provide without the mechanism. These reserves are provided through a competitive tender and are deployed only at last resort to avoid shortages. It has been implemented in Sweden and in Finland and recently in Belgium.

The implementation of these mechanisms has to be validated by the European Commission. Indeed, such mechanisms should comply with State aids or State intervention guidelines, having as main criteria the effectiveness (*i.e.* how mechanisms reduce shortages) and the efficiency of the mechanism, in particular to avoid implementing mechanisms which can cost too much to society. In particular, the European Commission recommends the implementation of a strategic reserve mechanism which it assesses as less distortionary for the energy market and easier to implement (European Commission, 2013).

Meanwhile, the efficiency of these mechanisms and their ability to reestablish correct investment decisions and adequacy issues is still being assessed. Some authors have thus compared qualitatively the different CRMs with regard to a selection of economic criteria, *e.g*. provision of adequate incentives, feasibility, risks of market power abuse (see Finon and Pignon, 2006, for more details

about performances of each mechanism). However, thorough studies are still lacking as dynamic aspects of investment issues need consideration, as well as quantitative studies.

Indeed, generation adequacy requires not only to invest in the optimal amount of capacity but also to invest at the right time[1]. Generally, these dynamics aspects have been underestimated as it is assumed that power system will reach equilibrium and temporal aspect was not the main issue. One can imagine that if market experiences shortages, peak prices will provide incentive to build new capacity and that this new capacity will reduce shortage events, creating a negative feedback which can guarantee long-term equilibrium[2]. Indeed, power systems and private investors behavior present many characteristics which can take the system away from this equilibrium (e.g. time of construction, long lifetime, lack of long-term contracts, bounded rationality, imperfect information …) and could be accounted for in generation investment issues. In particular, the available literature on dynamic analysis of generation investments highlights the risk of cyclical tendencies in generation capacity (Ford, 1999, 2000, 2001; Green, 2006). These tendencies are known as boom-and-bust cycles and are materialized by phases of under capacity and overcapacity. They are prejudicial to society since more shortages than optimal are required during under capacity phases and more plants than optimal are built during overcapacity phases.

Regarding this important aspect of generation investments, comparisons between CRMs seem limited in scope. They often compare the performance of CRMs regarding shortages but efficiency (*i.e.* total costs of generation capacity) is less studied. However, this point is as essential as adequacy when studying CRMs implementation. Moreover, the strategic reserve mechanism, one of the main CRMs implemented or in consideration in Europe, is still rarely studied from a dynamic perspective in the current literature.

Therefore, the purpose of this paper is to assess the dynamic effects of two of the main different CRMs considered in Europe, namely the capacity market and the strategic reserve mechanism, and to compare them with regard to the effectiveness and efficiency criteria. To do so, a model of an electricity market, based on system dynamics programming, is developed. It simulates investment decisions in a liberalized market regime under three different market designs, the energy-only market, the capacity market and the strategic reserve mechanism. Then, these market designs are compared based on social welfare, which is evaluated thanks to generation costs and shortage costs.

This paper is organized as follows: Section 1 studies cyclical tendencies on generation investments and in particular why power systems are prone to these dynamics. Section 2 present the model used in this paper to study investments decisions under the energy-only market, the capacity market and the strategic reserve mechanism. Section 3 introduces main parameters used and how simulations are run. Results of these simulations and comparisons of market performances are introduced in section 4. Finally, conclusions are outlined in section 5.

[1] In theory, it also requires to optimally invest in specific types of technologies (base, peak… to deal with flexibility issues in particular) and in specific locations (to limit congestions). These two requirements are not studied in this paper.

[2] Stoft (2002), amongst others, outlines this idea: *"Economics focuses on equilibria but has little to say about the dynamics of a market. Once economics shows that a system has a negative feedback loop so that there is a point of balance, it considers its job done. Engineers move beyond this stage of analysis to consider whether a system will sustain oscillations and, if not, whether it is over- or under-damped. Economics understands that investment dynamics can produce ''cycles'' but has faith that rationality will generally prevent this".*

1. Boom-and-bust cycles in generation investments: reasons, evidence and models

Studies of CRMs performances from a dynamic aspect require assessing how these mechanisms can correct cyclical tendencies in generation capacity. This section recalls main reasons and evidence in literature to such tendencies and summarizes use of models of cycles tendencies, in particular such related to CRMs.

1.1 Reasons and evidence of cyclical tendencies in generation investments

Power systems and private investor's behavior present many characteristics which can take the system away from equilibrium and explain why investments are prone to cycles. They can be sorted into two categories, regarding the period of overinvestment and the period of underinvestment.

Uncertainty, impossibility to predict in a perfect way future prices and risk aversion are the main reasons which can delay investment decisions and cause under capacity phases (De Vries, 2004). Besides, the uncertainties faced by investors are even more prejudicial that they are increased by long lead time for construction, which only deepens the effects of these uncertainties on investment decisions. These effects are also increased by capital intensive and irreversible investments. Thus, investors tend to delay their investments to be sure their plants will be profitable. They tend not to invest immediately when they expect a profit but instead wait for clearer signals of profitability and for additional information (Dixit and Pindyck, 1994). As a result, new power plants come in operation too late, after major shortages appeared.

Conversely, once investments seem to be profitable enough and uncertainties are cleared, players are prone to overinvestment, *i.e.* to invest more than what would be optimal. It can be explain by a herd behavior, as Green (2006) mentions: "*In the absence of a coordination device, however, they are in danger of over-reacting–too many investors read the high prices as a signal that their own investment will be profitable, and somehow fail to take the likely actions of others into account [which is the so called herd behavior]".* Even if investors are aware of investments made in the previous years by rival companies (TSO reports, construction permits…), Ford (2001) says that skepticism about completion of announced power plants can discount plants under construction (for example due to environmental activism or administrative issues). Above all, players have limited information about the investment decisions which are made at the same moment by competitors. Therefore, there is a risk of overinvestment which can cause fall of power prices, massive plants closure and bankruptcy for investors. This might lead to a spiral of massive losses for investors, which might then increase their risks aversion again, consequently emphasizing delays in investment decisions and exacerbating cycles.

Analogies with other markets, which share particular characteristics with power market (for instance capitalistic investments, long lead time for construction, uncertain demand…) and which experience cyclical behaviors (for instance the oil tankers industries, the aluminum industries or the real estate market, see Arango et Larsen (2011) for more references and details), can confirm this reasoning. These markets are notably known to provide easier demand and supply balancing thanks to stock or demand elasticity. Therefore, such a phenomenon should be highlighted in electricity market where balancing is more complex. Laboratory experiments also support a cycle hypothesis. In particular,

experiments made by Arango (2006) show that "*subjects have a tendency to initiate new projects when they perceive high price, while they tend to ignore capacity under construction and the construction delay*".

Finally, Arango and Larsen (2011) find empirical support for investments cycles in Chilean and England power markets.[3]

1.2 Models of cyclical tendencies and CRMs in the literature

Several authors have studied the cyclical investments behavior thanks to system dynamics (SD) programming, a methodology developed by Forrester (1961). SD is one of the main representations, with the agent based models, of simulation models. SD programming is based on a top-down approach whereas the agent based model uses a bottom-up approach in which individual players' behaviors are first defined in an explicit way. Both methods are useful to study inter-relationships among the different components and understand feedback mechanisms (see Teufel et al. (2013) for a review of system dynamics models in generation capacity simulation). Thus, contrary to equilibrium model, SD programming enables the modeling of risk aversion, bounded rationality, herd behavior, long lead time and other characteristics which can lead to cycle behavior (Gary and Larsen, 2000).

Ford (1999) and Bunn and Larsen (1992) show that such characteristics can lead to under and over capacity phases and jeopardize power systems. Olsina et al. (2006), Syed Jalal and Bodger (2010) and de Vries (2004) have also studied cycle tendencies thanks to SD programming.

As mentioned previously, literature has also tried to compare different CRMs to select the most effective one, in particular from a dynamic perspective. SD programming is once again the basis of these comparisons. For instance, Assili et al (2008) and Park et al. (2007) study how a variable capacity payment mechanism can reduce investments cycles. De Vries and Heijnen (2008) compare capacity payments, operating reserves pricing and capacity markets. All these mechanisms perform better than a competitive energy-only market. Moreover, the capacity market has the strongest stabilizing effect in respect to both investment and prices. Hobbs et al (2007) assess the capability of the capacity market in the PJM system to reduce investments cycles. They show that a downward sloping demand curve on the capacity market reduces investments risks and therefore fluctuations in installed capacity and consumers prices, compared to a vertical curve. Hasani and Hosseini (2011) compare the capacity payment mechanism and the capacity market through nine technical and economic indicators (in particular regarding shortages, electricity prices and revenues of peak technology). Cepeda and Finon (2011) study the practical problems related to long-term security of supply in regional electricity markets with transmission constraints.

From this review of literature, the study of the strategic reserve mechanism appears to be limited. Moreover, comparisons are often based on adequacy criteria and the efficiency aspect, *i.e.* the cost of the mechanism for the society, is often disregarded. Yet, efficiency is one of the main criteria to consider from an economic point of view: CRMs have to reduce shortages but not at any cost for society.

These missing aspects of the literature will be studied in our model. The strategic reserve mechanism will be modelled and compared to the capacity market. Moreover, to consider generation costs and

[3] Such empirical evidence is however limited. Indeed, recent liberalization provides few data about private investor behaviors, especially as most markets tend to begin with overcapacity.

to compare efficiency, contrary to current literature, endogenous shutdowns decisions will be modelled here.

2. The model

In this section, the model developed to assess the performances of both strategic reserve mechanism and capacity market will be introduced. In a first part, an overview of the model is given, and then each market (the energy-only market and both CRMs) is described more precisely.

2.1 Overview of the model

To study investments decisions in liberalized power systems and how CRMs can modify these investments, a model based on system dynamics programming is used. It is based on the research developed by Hobbs (2005) and Hobbs et al (2007).

The logic of the original model is kept here. It is presented in figure 1, thanks to a simplified causal-loop diagram. This diagram, typical for system dynamics programming, depicts a causal relationship between two system variables by an arrow. The (+) symbol describes a positively related effect (an increase in the first variable will cause an increase in the second one). The (-) symbol specifies the contrary.

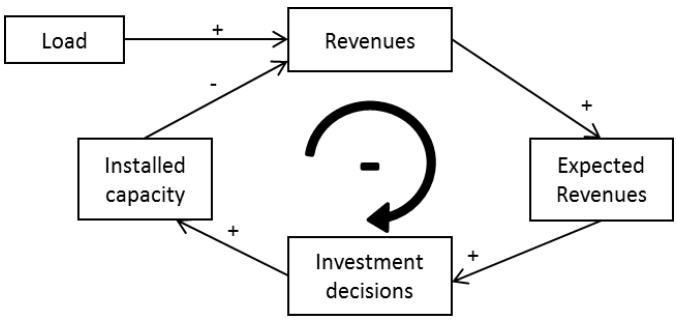

Figure 1: Simplified diagram of the model

Each year, revenues (from the energy market or/and from CRMs) are computed. These revenues are used by players to assess future profitability of their plants and then to make investment decisions. These decisions will in turn impact the installed capacity, which will result in changes in revenues. A negative feedback loop can be noticed.

The main assumptions made by Hobbs are kept here: annual time step is used, perfect competition is considered (there is no strategic behavior), load is summarized by the annual peak load, uncertainty is limited to load growth (uncertainties due to economic growth rate deviation or weather conditions are modelled thanks to two normal distributions), only peak technologies are modelled (which are characterized by a lead time of four years), revenues from the energy market are assessed thanks to exogenous functions (and not by modelling a short-term energy market), expected profits are computed thanks to previous and current profits…

In the original model, only the capacity market is modelled. This model is improved here to consider a more complex bidding behavior. Two other market designs are added: the strategic reserve

mechanism and the energy-only market, which will be used as a reference case to assess cyclical tendencies.

Moreover, to compare efficiency of CRMs, power plant closures are now endogenous (investors decide to close their plants or not, regarding expected profitability). Increasing O&M costs are modelled to reflect ageing of plants. Thus, it will be more and more costly to operate these plants and investors may prefer closing them and built new plants. Figure 2 indicates how these maintenance costs increase with age. They are constant during the first half of assumed lifetime of the plant and exponentially increase after. Maintenance costs are assumed equal to annualized investment cost of a plant at the end of the assumed lifetime of the plant (20 years).

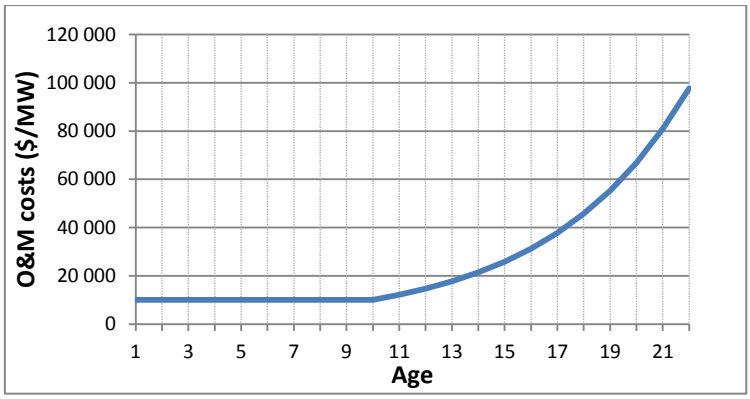

Figure 2: Evolution of O&M costs in function of age of plants

Three cases are introduced thereafter: one with an energy-only market, one with a capacity market and the last one with a strategic reserve mechanism. The aim of this study is to compare the last two mechanisms. The energy-only market is introduced as a reference design, the two other designs are the ones to be studied and compared.

To facilitate understanding, the energy-only market model will be presented first, including details of modeling in particular different assumptions with respect to Hobbs works. Complementary mechanisms to the energy-only market, *i.e.* the capacity market and the strategic reserve mechanism, are then introduced.

2.2 Energy-only market

Figure 3 describes in a simplified way how the energy-only market is modelled here.

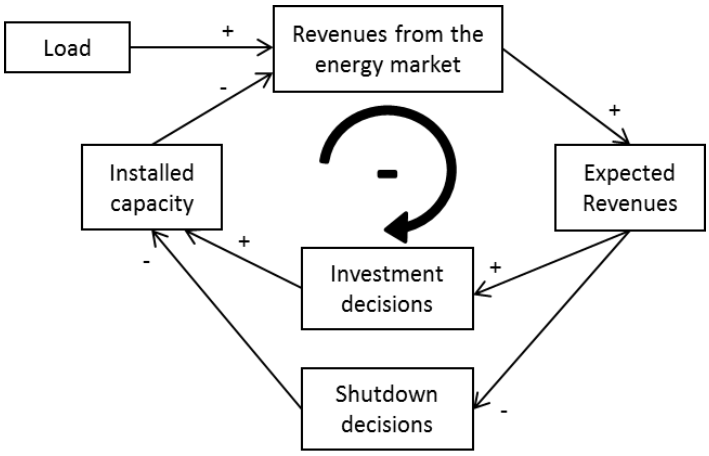

Figure 3: Simplified diagram of the energy-only market

Revenues from the energy market

Hobbs considers that profits, defined as revenues earned from energy and ancillary services markets minus variable costs, can be expressed as a function of the ratio of installed capacity over the peak load (figure 4). The smaller this ratio is, the more important profits are, since capacity becomes scare and expensive actions (e.g., demand response) or shortages are needed.

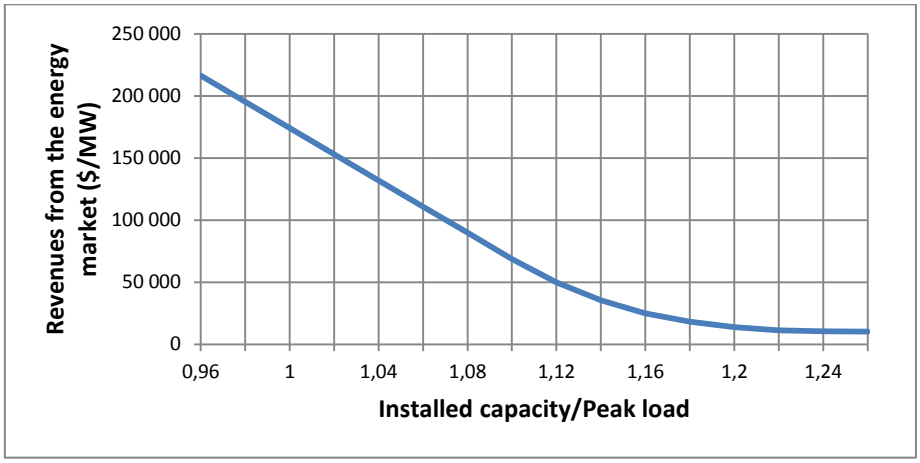

Figure 4: Revenues from the energy market

Investment and shutdown decisions

To decide if they invest or close plants, investors have to assess future profitability of their power plants. Since four years are necessary to build a plant, decisions to invest will be made four years ahead. To simplify the model, the same assumption is made for plant closure.

Figure 5 describes the different steps of the decision process, which are explained below.

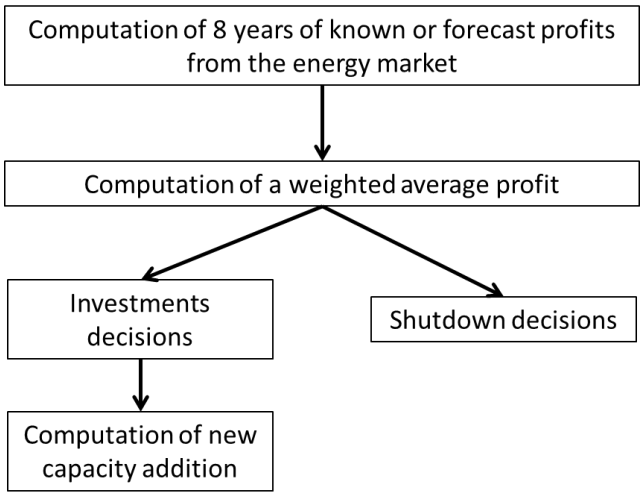

Figure 5: Steps of the decision process

Firstly, investors have to compute expected profitability of their plants. As Hobbs modelled it, players base this computation on eight past and future profits, from year y-3 to year y+4 (y is the current year when decisions are made). For the years y-3 to y, profits from the energy market are known since those years have already passed or in process. For years y+1 to y+3, they are unknown and have to be estimated based on expected demand (players can anticipate correctly future demand, apart from uncertainties) and expected available capacity (investors know capacity under construction or which is going to close, since such decisions have already been taken and often made public, through media or TSO reports). For the year y+4, as Hobbs, the profits are assumed to be the same as the profits during year y+3.

Then, given those profits, investors attach a set of weights to each year of profits to represent how they assess future profitability. For instance, they can only consider profits in year y+4 or they can consider eight years of profits. Thus, investors can compute the weighted average of those profits to assess the expected profitability.

To model players' decisions regarding investments or shutdowns, a rational economic behavior is modelled, which leads players to balance their expected profits (earned on energy market) and their avoidable costs.

As avoidable costs are different considering investments or shutdowns, decisions will differ: for investments, avoidable costs are investment, O&M and variable costs; for shutdown decisions, investments costs are sunk and only O&M and variable costs can be avoided. In both cases, as the function used to compute revenues from the energy market (figure 4) already takes into account variable costs, they are not considered thereafter.

For investments decisions, players compare the expected profits during the economic lifetime of the plants (20 years) with investment and O&M costs. The previously computed profitability is assumed to remain constant during the economic lifetime. NPV is then computed. If it is positive (expected profits cover at least avoidable costs), investors decide to add new capacity in the system. Otherwise, no investment decision is made. As done in previous literature on this subject, the more investors

expect a high profitability, the more they invest. However, a saturation level is generally considered, to limit capacity additions. Since participants expect a high attractiveness for investing, they are aware of the potential danger of a wave of massive investments. It is particularly true in concentrated market where participants can limit investments to avoid low prices which could endanger their capacities in place. There are also constraints, in particular financing constraints or land constraints, which can limit investments (Olsina et al, 2006). Figure 6 describes investments addition in function of NPV. For simplicity, a linear function is modelled, defined by three parameters: capacity addition when NPV is zero, maximum capacity addition and NPV at which this maximum addition is reached.

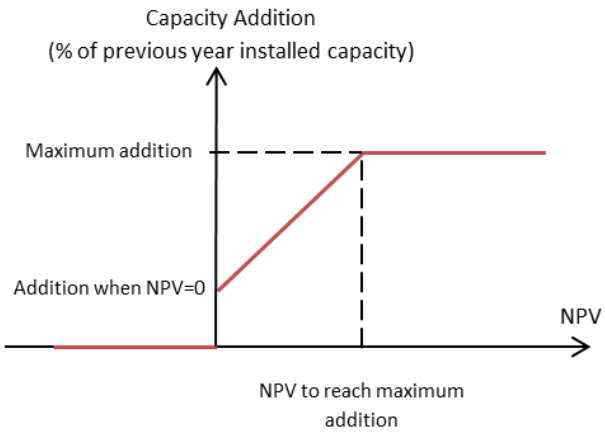

Figure 6: Relationship of capacity addition to NPV

Regarding shutdown decisions, each year, players will decide to continue running their plants or to decommission them, considering expected profits and O&M costs. If these costs appear to be higher than expected profits, they decide to close their plants. Otherwise, plants are running one more year. Moreover, as for investments decisions, there is a maximal amount of capacities which can be decommissioned each year (players are partially aware of competitors shutdown decisions and they do not close all their capacity in the same year).

At last, once investors have come to a decision about shutdowns and investments, next year demand is computed, and the decision loop starts again.

2.3 Capacity market

Added to the traditional energy market, a new market for capacity is implemented (figure 7). In the model, a centralized capacity market is considered. In such a market, the TSO assesses several years ahead what the capacity need is for the energy system to deal with its peak load. Then, it contracts this capacity thanks to auctions in which players offer existing or new capacity. A capacity price is determined, which creates complementary revenues for plants. This price plays an important role since it coordinates investment decisions: if there is a lack of capacity, the capacity price will raise to attract new investments. On the contrary, it will decrease to force expensive plants to close or to postpone investments. Thus, the capacity market is believed to solve investments issues on energy-only market.

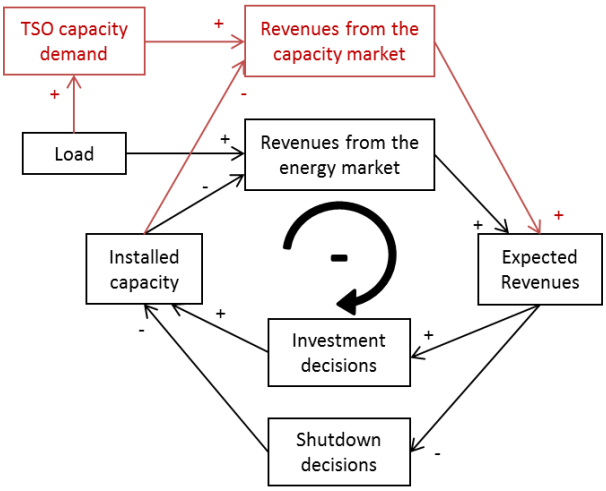

Figure 7: Simplified diagram of the capacity market

Compared to the previous energy-only model, a new step is added in the model which simulates the capacity market. Auctions for capacity available in year y are considered to take place four years before that time (which is the lead time for peak technologies). This market is modelled by a supply curve, determined by offers made by players (which will be described below), and a demand curve, resulting from the TSO capacity requirement (see figure 8). This demand curve is characterized by a maximum price and by a target capacity corresponding to the expected peak demand plus a margin. Matching supply with demand will determine a price for capacity.

Figure 8: Capacity auctions

As capacity price is now a component of players' revenues, it has to be included in expected profitability computation. Like profits earned on the energy market, eight years of capacity prices are considered to estimate profitability. For years y-4 to y+3, prices are known as auctions have already taken place. For year y+4, capacity price is assumed to be the same as in year y+3. As previously, investors compute an expected profitability from these eight profits.

To compute the offers that they make on the capacity market, players have to balance their expected profits (earned on capacity and energy markets) and their avoidable costs.

- For existing capacity, the only avoidable costs are O&M costs for the year y+4. The economically rational offer price has to guarantee that players will cover these costs thanks to profits from the energy market and from the capacity market. Profits from the energy market can be estimated from the previous computation. If they are greater than costs, players bid zero on the capacity market (they do not need revenues from the capacity market to break-even). On the contrary, if expected profitability from the energy market is less than O&M costs, actors will bid the difference on the capacity market. Thus, if their offer is accepted, they will at least cover their avoidable costs (provided that they correctly estimate revenues from the energy market). In all cases, players offer all their available capacity.

- For new investments, contrary to existing capacity, the investment decisions are still pending and the investment costs are considered as avoidable. Therefore, expected profitability during the economic lifetime of assets has to cover both investments and O&M costs. Players are assumed to use a NPV method to compare expected profits from both capacity and energy markets and avoidable costs. If NPV is positive, investors will invest and bid zero on the capacity market. Otherwise, investors have to bid considering the project's expected net present value shortfall. Indeed, as the capacity price is guaranteed for a single year only, investors cannot rely on a capacity price above expected capacity price for the rest of the economic lifetime but only for the first year. Therefore, they have to bid the total shortfall on the first year auctions, addition to the expected capacity price, to break-even for sure[4]. Investors always offer the maximum capacity addition on the capacity market (which can be refused totally or partially according to capacity demand and offers from existing capacities).[5]

Therefore, having computed the supply and demand curves, a capacity price can be determined. Players with accepted offers will invest or will keep their plants in operation. Players with refused offers will close their plants or will not invest.

[4] For instance, if the avoidable costs are $150 000/MW-year, the expected profits from the energy market $60 000/MW-year and the expected profits from the capacity market $80 000/MW-year, investors have to earn the shortfall between costs and expected revenues on the first year auction. If the economic lifetime of the plant is 20 years, the total shortfall equals 20*(150 000-60 000-80 000)=$200 000/MW, when discounting is not regarding. The project break-even if it could earn this shortfall on the first year auction, addition to the expected capacity price. Thus, the economically rational offer would be: ($80 000+$200 000)/MW. (see Wilson, 2010 for more explanations).

[5] Indeed, as previously, saturation level in investments is likely to happen because of financing or land constraints.

2.4 Strategic reserve mechanism

A strategic reserve mechanism, described in figure 9, consists in a set of generation units kept available for emergencies by an independent agent, typically the system operator. Contracted capacity is taken out of the market and is activated in last resort to avoid shortages. The agent determines the amount of capacity to contract, resulting from expected load and investments and shutdowns decisions on the energy market, and gets it thanks to auctions.

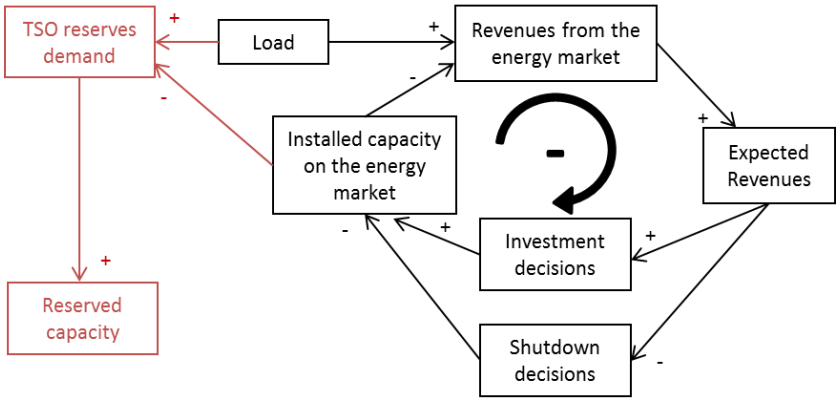

Figure 9: Simplified diagram of the strategic reserve mechanism

Therefore, capacity can be sorted into two exclusive markets: one for strategic reserves, called strategic reserve mechanism below, and one for non-reserved capacity, called energy market below. These markets are exclusive since capacity on the energy market cannot participate in strategic reserves auctions and so its sole profits come from the energy market. Reciprocally, reserved capacity cannot sell energy on the energy market, except in last resort when the TSO requires it. Conditions of deployment and use of contracted capacity have to be well defined to minimize interferences with the energy market[6]. Here, strategic reserves are deployed when there is no more available capacity on the energy market and they are sold at the energy market price cap. Therefore, for a producer on the energy market, there is no difference in its revenues in times of shortage or high tension.

Figure 10 illustrates how these two exclusive markets are modelled, as well as the links between them and the investments and shutdowns decisions.

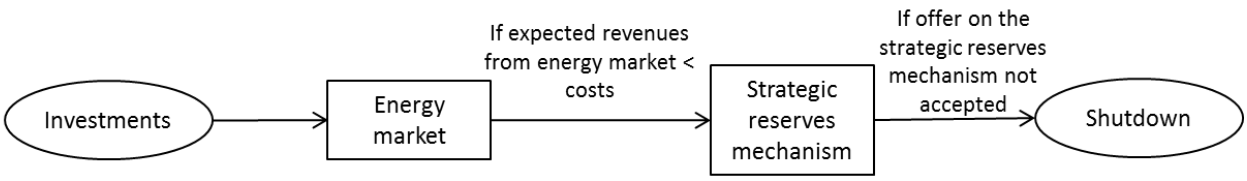

Figure 10: Energy market and strategic reserve mechanism

Players can only invest on the energy market (investments on strategic reserve mechanism seem too risky to happen, as players cannot sell energy and the reserves price is guaranteed for one year only).

[6] For instance, if contracted capacity is deployed at a price lower than the highest supply bid, it will increase the disincentives to invest for producers on the energy market.

They participate in the energy market year after year until they expect to be in deficit (*i.e*. their expected profits from the energy market are lower than their costs). Thus, players attempt to pass their capacity on to strategic reserves and make offers for their capacities on the strategic reserve mechanism. If their offers are not accepted, plants are decommissioned. Otherwise, plants become reserved capacity and make offers each year on the auctions until their offers are refused.[7]

For the energy market, there is no major difference with the energy-only market described previously. Since strategic reserves are considered to be deployed only when shortages occur and are sold at the energy market price cap, existing plants generate the same revenue no matter whether shortages happen or whether strategic reserves are deployed. Thus, the profits earned on the energy market can be calculated thanks to the function described in the figure 4, provided the system margin is computed with the capacity available on energy market, and not with total system capacity (which includes reserved capacity). Then, as previously, generation companies compute an expected profitability from eight years of revenues earned on the energy market and decide consequently to invest or to decommission their plants, four years ahead (with the same parameters as for the energy-only market).

The strategic reserve mechanism works differently. Every year, in order to ensure that the system experiments enough capacity and prevents shortages, the TSO can reserve capacity which starts to produce at last resort. The TSO first estimates future demand (except growth uncertainties) and future capacity on the energy market (the TSO is assumed to hold auctions once players make their decisions to invest or to shut down). Then, if the margin is expected to be under the target margin, auctions are organized to contract enough reserves to reach this target. However, the TSO cannot contract extensive volume of reserves compared to existing capacity. Thus, a maximal volume of reserves is modelled, as well as a reserve price cap on the auctions.

Two categories of players can bid on these reserves auctions: players who have capacity on the energy market and who decide to shut down (because expected profitability on energy market is not high enough to break-even) and players who already have capacity on the strategic reserve mechanism. As previously, players will bid their avoidable costs[8], *i.e.* their O&M costs, and offer all their available capacity. If offers are accepted, they will at least cover their avoidable costs. Otherwise, they will shut down their reserved plants.

[7] Once capacities enter into the reserves market, they cannot return to the energy market, to insure credibility of this mechanism.

[8] Reserved capacities are paying their variable costs when they are deployed. Thus, they do not make profits by selling energy and their sole revenues come from the auctions

3. Data and simulation

In this section, main parameters used in the simulations are introduced, as well as how simulations are run, in particular how indicators are computed.

3.1 Parameters for the reference case

Most data used in this model are the same as Hobbs uses for the PJM system. As the aim of this study is not to predict future evolutions of a precise power system but to compare different market designs, these data are not updated.

Table 1 presents main parameters taken for the reference case.

Table 1: Main parameters for the reference case

Parameters	Value for the reference case
System margin target	15% of load
Shortage margin (margin below which shortages happen)	10% of load
Peak load growth	1.7%
Peak load growth standard deviation	1%
Weather standard deviation	2%
WACC	10%
Investments costs	$600 000/MW
O&M costs	See figure 2
Years considered to compute expected profits for investments decisions (y is the year when decisions are made)	y-3 to y+4
Weight given to each year profit to compute average profit for investments decisions	Each year has the same weight
Years considered to compute expected profits for shutdowns decisions (y is the year when decisions are made)	y-3 to y+4
Weight given to each year profit to compute average profit for shutdown decisions	Each year has the same weight
Maximum capacity addition (see figure 6)	10% of previous year installed capacity
NPV to reach maximum capacity addition (see figure 6)	400 000
Capacity addition when NPV=0 (see figure 6)	1.7%
Maximum capacity shutdowns	20% of previous year installed capacity
Maximum amount of reserved capacities	20% of previous year installed capacity
Price cap on capacity market	$200 000/MW
Price cap on strategic reserve mechanism	$400 000/MW

3.2 Simulation and indicators

The model is implemented on Matlab®. It is run for 100 years, for the three market designs. Then, some economic indicators are computed to assess the performances of each market design.

The social welfare should be used to evaluate functioning of markets or mechanisms. Since demand is considered as inelastic, it can be computed thanks to the cost of shortages and costs of generation (see De Vries, 2004). Below, effectiveness is used to deal with shortage costs and efficiency to deal with generation costs[9].

Effectiveness is assessed in respect to the system margin. Arbitrarily, shortages are considered to happen if the system margin is less than a certain threshold[10]. For each year of the simulation, curtailed demand compared to peak demand is computed. Then, these values are averaged over the last 50 years of simulation (in order to filter out any transition effects that might occur during the first years of the run). At the end, the result stands for the mean curtailed demand by year as % of peak demand.

Efficiency is estimated through costs indicators. Investments and maintenance costs are considered[11]. For each year, these costs are computed and divided by peak demand. Then, average value is calculated over the last 50 years of simulation. The final result is expressed in $.MW of peak load.

Moreover, as uncertainties are introduced in this model, Monte Carlo simulations are run to compare the performances under various demand growth scenarios. For each random draw of demand growth uncertainty, the model is run for the three market designs and then indicators are compared. The differences in the results are therefore entirely caused by differences in the market designs, not by random differences between the input data. 200 different random draws of demand growth, called scenario below, are simulated.

[9] In theory, shortage costs can be computed by assuming a cost for load reduction, known as VOLL in literature. However, there is no consensus on VOLL value. To avoid giving a larger weight to shortages or generation costs (by assuming an inadequate VOLL value), these two values are assessed separately.

[10] To deal with maintenance operations and outages, the installed capacity has to be greater than the peak demand. Thus, shortages can happen even if the system margin is positive.

[11] Variable costs are not considered here. Indeed, they are the same in the three mechanisms most of the time, except when one market design experiences shortages and other market designs do not curtail capacity. However, these variable costs during curtailed hours are insignificant compared to other costs.

4. Model results

This section provides the results of the comparisons between the capacity market and the strategic reserve mechanism thanks to the model previously described. In a first section, the results of simulation regarding the capability of both CRMs to reduce cyclical tendencies on generation investments are presented. Then, efficiency and effectiveness comparisons are introduced. Finally, the robustness of the results is studied through a sensitivity analysis.

4.1 Study of the cyclical tendencies in the three markets

To study the cyclical tendencies on the energy-only market and to what extent the CRMs can reduce them, the evolution of the system margin for one average scenario of load growth is presented here. Only the last 50 years are drawn (to avoid possible initial transition phase). Two different system margins can be computed. The first one, called the actual system margin, is calculated as the total installed capacity (*i.e*. capacity on the energy market + reserves if any) over the actual peak load. The second one, the expected system margin, does not consider the actual peak load but the expected peak load when decisions are made, four years ahead. Performances regarding capacity adequacy mainly depend on two factors: 1) how markets provide adequate incentives to have enough installed capacity regarding the expected peak load and 2) how this expected load differs from the actual load. This second point does not depend on the considered market, but only on random deviations. Thus, to perfectly understand how markets work, focus is made on the first factor and on the expected system margin.

Figure 11 describes evolution of this expected system margin for the last 50 years of one scenario of load. For the strategic reserve mechanism, the margin on the energy market (*i.e*. without considering reserved capacities) is plotted. The target margin and the shortages margin are also drawn.

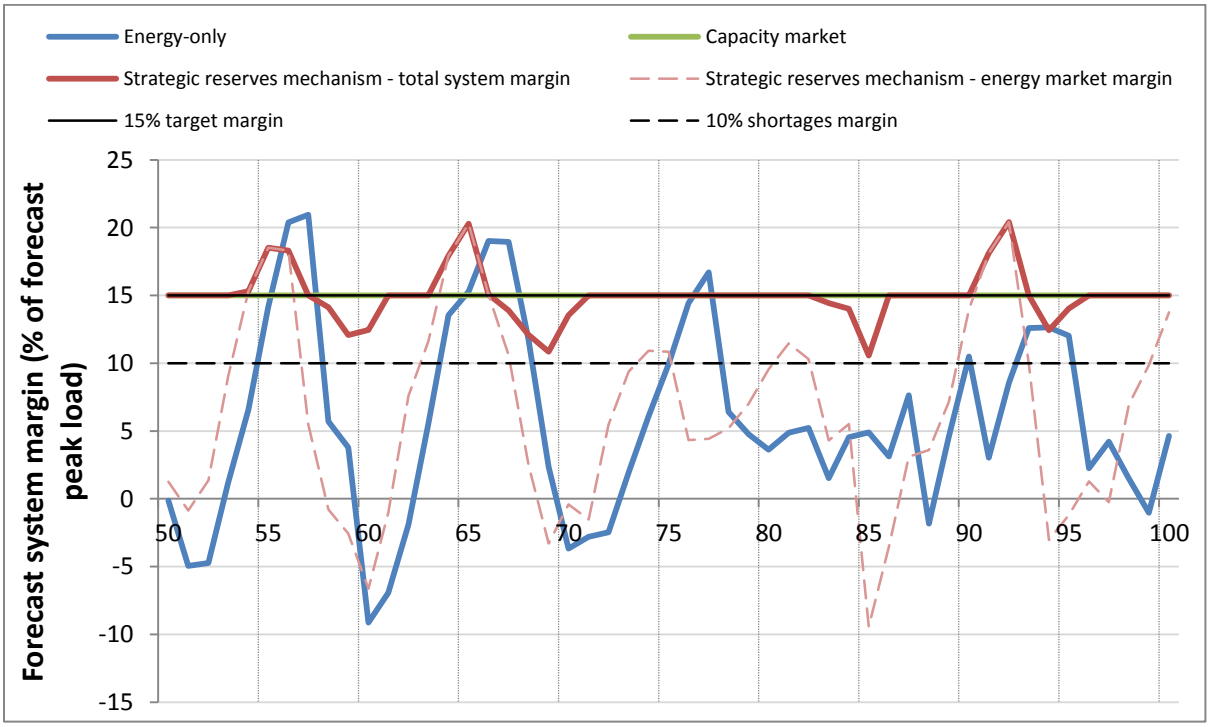

Figure 11: Evolution of expected system margin for one scenario of load growth in the reference case

The adequacy performances of each market present important differences. In this scenario, the energy-only market (the blue curve) experiences high cyclical investments and shutdowns decisions. These cycles are mainly due to herd behavior, bounded rationality (modeled by the way players compute expected profitability) and incomplete information (about future load, investment and shutdown decisions made by other players). Compared to the results available in the literature, these cycles are here exacerbated since endogenous decommission is considered. If low profits are expected, players can close their plants, that makes the margin decrease quickly (and more quickly than in current literature where plants cannot be decommissioned if profits are low). It is also to be observed that the average margin, which is around 5% here, is well different from the 15% target margin. Indeed, revenues earned from the energy market when margin is equal to 15% are not high enough to attract new investments (revenues for this margin are around $30 000/MW while the annualized investment cost is around $70 000/MW). Thus, the implementation of a CRM is required to reach this target margin.

When a capacity market or a strategic reserve mechanism is implemented, the cyclical behavior is reduced and the system experiences fewer shortages. For the capacity market (green curve), the system margin is always equal to the 15% target margin. This result seems logical since the capacity market explicitly defines a target to reach. If there is not enough plants, the capacity price will rise so that new plants or existing plants break-even. In some extreme cases (which is not the case here), this 15% target cannot be reached if capacity price reaches the capacity price cap.

The results of the strategic reserve mechanism (red solid line), if better than those of the energy-only market, show a lesser ability of the CRM to reduce cycles compared to the capacity market. Under-capacity phases are reduced but there are still overcapacity phases.

Indeed, in the energy market, there is no explicit target for the system margin and the energy price is the only signal to coordinate decisions and to give incentives for investments or shutdowns, like in the energy-only market (since reserved capacity is considered not to interfere with the energy market). Therefore, this price leads to the same consequences as in the energy-only market, *i.e.* cyclical behavior and a mean margin well below the 15% target. It can be noticed with the red dashed line which described decisions on the energy market. Compared to the energy-only market, the TSO is however able to react as a last resort by contracting strategic reserves to avoid shortages. Thus, phases of under capacity are reduced compared to the energy-only market, but in a less effective way than the capacity market since the total system margin is not always equal to the 15% target margin. Three parameters limit the well-functioning of the reserved capacity in this respect. First, the TSO cannot contract above 20% of existing capacity, even if large shortages are expected. Second, since only the capacity which will be decommissioned can participate to the reserves auctions, offers can be lower than the TSO's demand. Finally, the reserve price cap could be reached, which would limit accepted capacity. Therefore, there is an important difference between the capacity required to reach the target margin and capacity which is actually accepted. All this explains why the strategic reserve mechanism cannot have the same effectiveness as the capacity market.

The limitations are higher with regard to the capability of the strategic reserve mechanism to reduce overinvestment phases, as the CRM does not perform any better than the energy-only market. Herd behavior and thus overinvestment are likely to happen if investors expect large profits. There is no signal to avoid this and the TSO cannot force players to postpone their investments.

Most importantly, these overcapacity phases undermine the well-functioning of the whole mechanism with regard to shortage risks. It is clearly noticeable in figure 11: after each overcapacity phase (around year 55, year 65, year 93), there is not enough reserved capacity to reach the 15% target. After an overcapacity phase, there is no reserved capacity and no investments take place for some years, whereas large decommissions are likely. In the beginning, these decommissions are not dangerous for the security of supply since the system margin is still above the 15% target margin. However, once it decreases below 15%, the TSO needs reserved capacity to offset not only decommissioned capacity but also the increasing of peak load. However, only plants which are decommissioned the same year can participate at the auctions. Thus, the TSO cannot acquire enough capacity to offset the increasing of peak load and margin decreases below 15%. The margin decreases until investments take place. Thus, after each overcapacity phase, the TSO cannot deal with peak increase and some shortages can happen during several years.

The actual system margin is presented in figure 12. As explained previously, margins are different from the expected ones due to growth uncertainties and the functioning of CRMs is less perceptible. For instance, in year 64 (where green line is below the red one in figure 12), the capacity market experiences some shortages whereas the strategic reserve mechanism does not, because growth deviations made the actual load higher than expected capacity. These shortages are not due to an ineffective capacity market but to a particular deviation growth.

However, the same general conclusions can be drawn for the functioning of the three markets when assessing the actual system margin instead of the expected margin. In particular both CRMs limit shortages and the capacity market seems to be more effective than the strategic reserve mechanism (for instance during years 59, 67, 85)

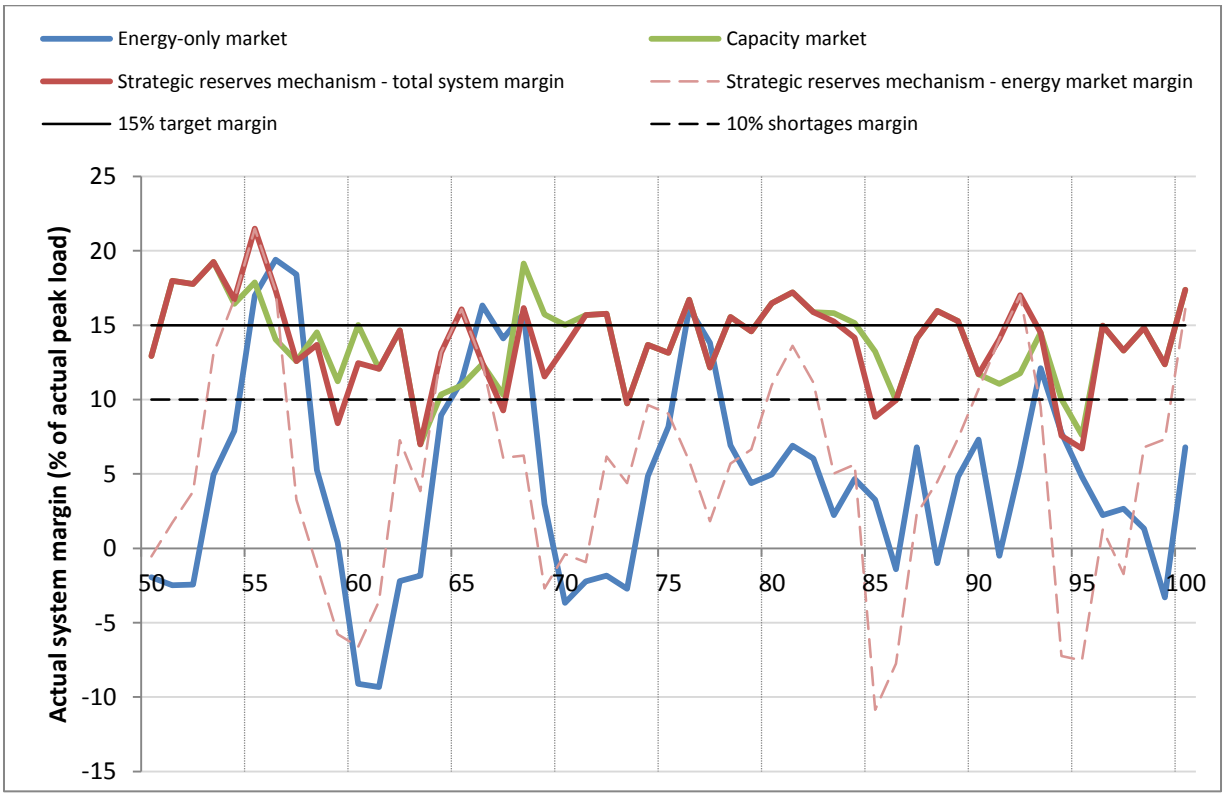

Figure 12: Evolution of actual system margin for one scenario of load growth in the reference case

In conclusion, for this particular scenario, both CRMs can limit underinvestment phases which happen in the energy-only market. However, the strategic reserve mechanism appears to be less effective in some cases, due to several limiting factors. Furthermore, this mechanism cannot deal with overinvestments and so overcapacity phases are likely, which is not the case for the capacity market. These overcapacity phases are prejudicial since they can undermine the well-functioning of the strategic reserve mechanism and cause shortages later on.

Moreover, since the strategic reserve mechanism does not modify the way investors make their decisions on the energy market, the adequacy performances of this mechanism highly depend on revenues earned from the energy market and on cycles characteristics. If the cycles are smoother than those on figure 11, the mechanism performs better considering effectiveness since overinvestment is less likely to happen and less reserved capacity is needed. On the contrary, if cycles are stronger, the performances of the strategic reserve mechanism can worsen. Regarding the capacity market, as it explicitly defines a target margin, it will always reach this target (unless it reaches limiting factors, like the capacity price cap, which is unlikely in moderate scenarios) and so the strategic reserve mechanism can at best have the same effectiveness as the capacity market.

4.2 Comparisons of the capacity market and the strategic reserve mechanism

The analysis of previous results shows that the capacity market seems to be more effective, for one specific random scenario. Monte Carlo simulations are run to verify this statement for various load scenarios. Moreover, efficiency is computed and compared for both CRMs.

200 simulations of demand growth scenarios are run for the capacity market and the strategic reserve mechanism. For each scenario, both indicators are computed and then the value of the indicator for the capacity market is subtracted from the value of the indicator for the strategic reserve mechanism. If this difference is positive, it means that capacity market is more efficient or effective, according to the considered indicator. These differences are displayed in a figure similar to the figure 13. Each point depicts the efficiency and effectiveness differences compared to the capacity market for one scenario of demand growth.

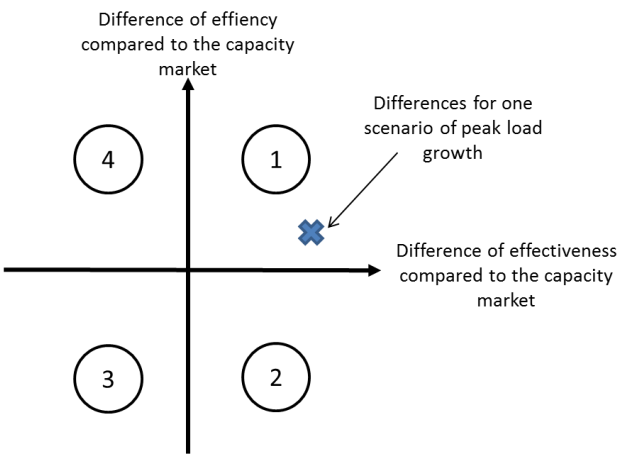

Figure 13: Graphical depiction of differences of indicators for each load scenario

Three cases can be identified. If the capacity market experiences less shortage and generation costs are lower than for the strategic reserve mechanism (quarter 1), one can conclude on the superiority of the capacity market from a society point of view. In the opposite case (quarter 3), the strategic reserve mechanism is the best mechanism from the economic point of view. In the last cases (quarters 2 and 4), since there is no assumed cost of shortages, no conclusion can be directly draw from these results.

Results for the reference case are displayed in figure 14.

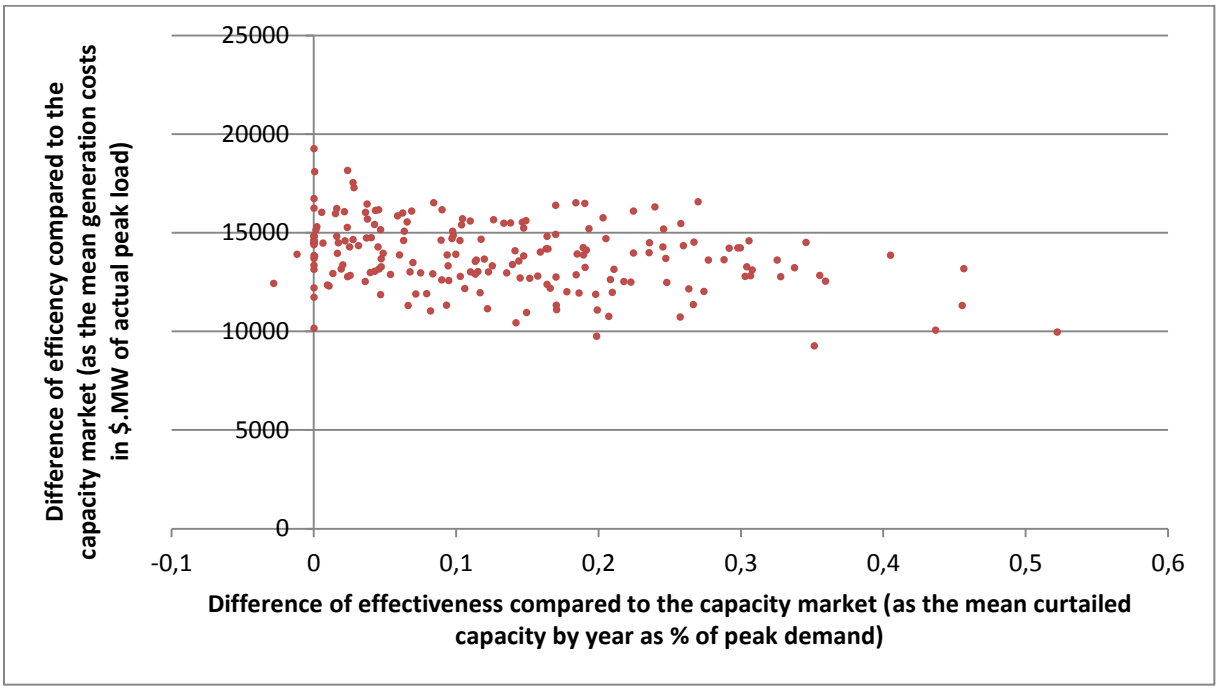

Figure 14: Comparisons of effectiveness and efficiency for the reference case

Most scenarios are in quarter 1, where the capacity market is more effective and more efficient than the strategic reserve mechanism. In a few cases, the strategic reserve mechanism has the same effectiveness, even very slightly smaller.

Regarding the effectiveness indicator, the superiority of the capacity market has been explained in the previous section. In some extremes cases, the strategic reserve mechanism can be a little more effective: it happens in particular scenarios when uncertainties make load higher than expected. If, the strategic reserve mechanism experiences overinvestment during this period of unexpected high peak, the actual system margin is larger than in the capacity market and there are less shortages (like in year 64 in figure 12). One should also notice that the differences are weak (about 1% of peak load every 10 years). Two reasons can explain that: first, the strategic reserve mechanism succeeds in providing enough reserved capacity most of the time ; secondly, since shortages are assumed to happen below a 10% margin, this mechanism can provide less than the 15% target and still not experience any shortage.

Regarding generation costs, the superiority of the capacity market is clear. Costs of reserved capacity explain these differences. As figure 12 shows, the TSO needs a large amount of reserved capacity to avoid shortages (for each scenario, the average of reserved capacity is about 10% of existing

capacity). Since reserved capacity is made of old plants which are decommissioned from the energy market, their O&M costs are important. Thus, it results in significantly higher generation costs to avoid shortages. In the capacity market, plants are younger since an arbitrage is made between existing capacity and new capacity during the capacity auctions. If the existing capacity is too old and more expensive than new capacity, it will close and new investments take place. In the strategic reserve mechanism, there is no similar arbitrage and the reserved capacity is necessarily old and expensive.

Therefore, for this reference case, the capacity market appears to be more effective and more efficient than the strategic reserve mechanism. Shortages are less likely to happen and the total costs of generation are less important.

4.3 Sensitivity analysis

In this section, the robustness of previous results is tested through a sensitivity analysis.

Main parameters which can modify efficiency and effectiveness of the strategic reserve mechanism are tested here, namely the price cap set on strategic reserve mechanism, the herd behavior of investors, the maximum amount that TSO can reserve and the way investors compute profitability (*i.e.* years that they take into account). These alternative cases, presented in table 2, are run for the same load growth scenarios as the reference case.

Table 2: alternatives cases

Alternative case	Varying parameter	Value
1	Price cap on the strategic reserve mechanism	$200 000/MW
2	Maximum amount of reserved capacities	30%
3	NPV to reach maximum capacity addition (see figure 6)	200 000
4	NPV to reach maximum capacity addition (see figure 6)	600 000
5	Years considered to compute expected profits for shutdown decisions (y is the year when decisions are made)	y+3

Results are presented in table 3. Averages of efficiency and effectiveness indicators for the 200 scenarios are computed for the reference and alternatives cases, as well as the numbers of scenarios in each quarter of figure 13.

Table 3: Results for the base and alternative cases

	Mean difference of efficiency	Mean difference of effectiveness	Number of scenarios in quarters 2 or 4[12]
Reference case	13 856	0,128	2
Alternative case 1	5 959	1,360	0
Alternative case 2	14 128	0,110	1
Alternative case 3	8 487	0,169	5
Alternative case 4	19 351	0,070	1
Alternative case 5	8 017	0,300	3

[12] For each case, there is no scenario in the quarter 3.

In each alternative case, the capacity market is still more efficient and more effective than the strategic reserve mechanism, since mean differences of each indicator are positive and most scenarios are in the quarter 1.

In each case except the fifth, the parameters do not modify how the capacity market works and consequently its effectiveness and efficiency. Differences between cases are only due to different functioning of the strategic reserve mechanism. These differences are mainly explained by the arbitrage between the adequacy objective and the costs to reach this target. To reduce shortages, more reserved capacities are required, which increases generation costs.

For alternative case 1, a lower reserve price cap means that old and expensive plants cannot be reserved anymore, contrary to the reference case. Thus, in some years, the TSO does not succeed in contracting enough strategic reserves and more shortages happen. It leads to lower generation costs since less expensive strategic reserves are used. In case 2, the TSO can contract more reserved capacity if needed than in the reference case. It reduces shortages but increases generation costs. In case 3, a more important herd behavior is modeled. Cyclical tendencies are more pronounced than in figures 11 and 12. As explained previously, these larger phases of overinvestments undermine the well-functioning of the strategic reserve mechanism, since no investments take place for some years and the TSO cannot contract enough capacity to deal with the peak growth some years later. Moreover, more cyclical tendencies lead to significant phases of under capacity on the energy market, that the TSO cannot avoid entirely by reserving capacity (*e.g.* if the maximal amount of reserved capacity is reached). On the contrary, for alternative case 4, there is no overcapacity phase and investments take place on a more regular basis (*i.e.* there is less phases of overinvestments following by phases when no investments take place). Thus, the TSO succeeds in reserving enough capacity to avoid shortages, but it leads to more important costs. Finally, for alternative case 5, the functioning of both markets is modified but differences in terms of efficiency and effectiveness remain similar.

Alternative parameters regarding load growth or investments and O&M costs have also been studied. They do not modify the main conclusions: the capacity market is still more efficient and effective.

To conclude this section, as the strategic reserve mechanism does not change the way players make decisions on the energy market, the same consequences happen as in the energy-only market, namely cyclical tendencies and a mean system margin well below the 15% target. Therefore, the TSO has to contract large strategic reserves which are necessarily old and expensive. Moreover, these cycles can undermine the well-functioning of this mechanism in cases of overcapacity (since the TSO cannot contract enough reserves to offset the load growth) and of large under capacity (since the limits of this mechanism – volume or price – are likely to be reached). On the contrary, for the capacity market, there is an explicit volume target and the capacity price increases or decreases to reach this target. Moreover, this target margin can be reached in a more efficient way with the capacity market since there is an arbitrage each year between existing capacity and new investments.

5. Conclusion

The objective of this paper was to study how CRMs, namely the capacity market and the strategic reserve mechanism, can correct the cyclical tendencies and the investments issues prone to happen in energy-only markets and to compare them. These comparisons are based on social welfare, which is evaluated thanks to generation costs and shortages costs.

Systems dynamics programming has hence been used to simulate functioning of both CRMs. Based on simulation results, the capacity market appears to experience fewer shortages and to present lower generation costs than the strategic reserve mechanism.

Since the strategic reserve mechanism is considered not to interfere with the energy market, cyclical investments are likely to happen. Under capacity can be avoided to some extent thanks to strategic reserves acquired by the TSO, even though the TSO's actions can be limited due to volume or price restrictions and shortages cannot then be avoided. Besides, the TSO cannot limit overcapacity phases, which can jeopardize producers' revenues and undermine the well-functioning of the mechanism by creating shortages some years later. On the contrary, the capacity market explicitly defines a target margin and the capacity price increases or decreases to reach it. There are no cyclical tendencies and no shortages. Thus, effectiveness of the strategic reserve mechanism is lower than in the case of a capacity market.

Regarding generation costs, there are lower for the capacity market. In the strategic reserve mechanism, to deal with shortages, the TSO holds auctions to acquire strategic reserves. Only decommissioned plants are however able to participate to such auctions. These plants are old and so they have high O&M costs, which make generation costs increase sharply. For the capacity market, an arbitrage is made every year during the capacity auctions, between existing capacity and new investments. Thus, capacity is less old and generation costs are lower. A sensitivity analysis confirms these different results.

Therefore, from these results, the capacity market appears to be more beneficial than the strategic reserve mechanisms from the economic point of view, since it decreases shortages at lower costs. In practice, other criteria, like electricity price or facility of implementation, have also to be taken into account to choose the most suitable CRMs and should be weighted against these results.

An interesting further extension of this model is to implement a short-term market to compute more precisely revenues from the energy market and to consider participation of base-load technologies to investments cycles. Moreover, flexibility issues, in particular how the energy-only market and the different CRMs give adequate incentives to invest in plants with enough flexibility (for instance, having enough flexible plants to deal with intermittent energy sources), should also be studied.

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