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Electricity market design for long-term capacity adequacy in a context of energy transition

Architectures des marchés de l'électricité pour la sécurité d'approvisionnement à long terme dans un contexte de transition énergétique

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Abstract

The ongoing energy transition, partly characterized by the massive deployment of renewables, has reignited a long-lasting debate on the best market design options to provide adequate investment incentives and ensure capacity adequacy in liberalised electricity markets. To choose the appropriate market design, policymakers need to assess and compare the economic performances of available solutions in terms of effectiveness and cost-efficiency.

This dissertation complements the existing literature on market design for long-term capacity adequacy by focusing on three research topics: (i) understanding how electricity markets perform under different assumptions regarding investors' risk preferences, (ii) analysing the compatibility of private agents' incentives to mothball capacity resources with security of supply objectives and (iii) assessing the economic performance of different market designs in a context of a high penetration of renewables. To this end, the System Dynamics modelling framework is applied to represent long-term dynamics resulting from private agents' decisions in liberalised electricity markets. The dissertation is organised in three chapters corresponding to each of the topics mentioned above. The main results are outlined below.

Firstly, capacity remuneration mechanisms are necessary to deal with the detrimental effects of investors' risk aversion. Energy-only markets are significantly affected by this phenomenon as they experience reduced investment incentives and higher levels of shortages. Capacity markets are more resilient to private investors' risk aversion. However, this resilience depends on the level of the price cap in the capacity auctions. For such a market design to provide satisfactory outcomes in terms of capacity adequacy, this price cap should account for the investment risk faced by market participants.

Secondly, when market participants have the possibility to mothball their capacity resources, these mothballing decisions can potentially modify investment and shutdown dynamics in the long run. Furthermore, in a world with capacity lumpiness (i.e. indivisibilities), mothballing increases the level of coordination needed to ensure capacity adequacy. This is especially true in energy-only markets, where mothballing increases the level of shortages to an extent that seems to outweigh the cost savings it generates at system level. Capacity markets can provide the required coordination to ensure capacity adequacy in a world with mothballing.

Thirdly, among proposed market designs in the literature, capacity markets appear as the preferable solution to ensure capacity adequacy from a social welfare point of view. Nevertheless, from a private investor's perspective and under certain conditions related to high penetration of renewables, capacity markets with annual contracts do not entirely remove the so-called "missing money" problem. The results indicate that granting multiannual capacity contracts alleviates the problem.

Key words: capacity adequacy, electricity market design, investment incentives, renewables, System Dynamics modelling.

Résumé

La transition énergétique, en partie caractérisée par le déploiement massif des énergies renouvelables, a relancé un débat de longue date sur les architectures de marché fournissant les meilleures incitations aux investissements dans les marchés libéralisés de l'électricité. Ces incitations sont essentielles pour garantir la sécurité d'approvisionnement à long terme. Pour choisir l'architecture de marché adéquate, les décideurs publics doivent évaluer et comparer les performances économiques des solutions disponibles.

La présente thèse complète la littérature sur les incitations aux investissements et la sécurité d'approvisionnement en étudiant trois aspects importants : (i) le comportement des marchés de l'électricité en présence d'acteurs averses au risque, (ii) la compatibilité entre les incitations des acteurs à mettre leurs actifs sous cocon et les objectifs de sécurité d'approvisionnement et (iii) les performances économiques de différentes architectures de marché dans un contexte de forte pénétration des énergies renouvelables. Pour ce faire, une modélisation de type *System Dynamics* est utilisée pour représenter les dynamiques de long terme résultant des décisions des acteurs dans un marché libéralisé. La thèse est organisée en trois chapitres correspondant à chacun des points mentionnés ci-dessus. Les principaux résultats sont les suivants :

Premièrement, les mécanismes de capacité sont nécessaires pour faire face aux effets néfastes de l'aversion au risque des investisseurs. Ce phénomène affecte de manière significative les marchés de l'énergie de type *energy-only*, qui subissent alors une baisse des investissements et des pénuries plus importantes. Les marchés de capacité résistent mieux à l'aversion au risque des investisseurs. Cependant, cette résilience dépend du plafond des prix dans les enchères de capacité. Pour qu'une telle architecture de marché donne des résultats satisfaisants en termes de sécurité d'approvisionnement, ce plafond de prix doit tenir compte du risque d'investissement supporté par les acteurs.

Deuxièmement, si les acteurs du marché en ont la possibilité, leurs décisions de mettre leurs actifs sous cocon peuvent modifier les dynamiques d'investissement et de fermeture à long terme. En outre, dans un monde caractérisé par des actifs indivisibles, cette possibilité augmente le niveau de coordination nécessaire pour assurer la sécurité d'approvisionnement. Cela est particulièrement vrai pour les marchés de type *energy-only*, dans lesquels la mise sous cocon augmente le niveau des pénuries, au point de contrebalancer les économies de coûts qu'elle génère. En revanche, les marchés de capacité peuvent fournir la coordination nécessaire pour assurer la sécurité d'approvisionnement même lorsque les acteurs ont la possibilité de mettre leurs actifs sous cocon.

Troisièmement, parmi les architectures de marché proposées dans la littérature, les marchés de capacité apparaissent comme la meilleure solution du point de vue du surplus social. Néanmoins, du point de vue des investisseurs, et dans certaines conditions liées à une forte pénétration des énergies renouvelables, les marchés de capacité avec des contrats annuels ne suppriment pas entièrement le problème dit de *missing money*. Les résultats indiquent que l'attribution de contrats de capacité pluriannuels atténue le problème.

Mots clés : sécurité d'approvisionnement, architecture des marchés de l'électricité, incitations aux investissements, énergies renouvelables, modélisation *System Dynamics*.

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Abbreviations

Abbreviation	Full form
CCGT	Combined Cycle Gas Turbine
CEP	Clean Energy Package
CM / CM-AC / CM-MAC	Capacity Market / Capacity Market with Annual Contracts / Capacity Market with Multiannual Contracts
CRM	Capacity Remuneration Mechanism
CT	Combustion Turbine
CVaR	Conditional Value at Risk
EC	European Commission
EOM / EOM-PCap / ECO-SP	Energy-only Market / Energy-only Market with Price Cap / Energy-only Market with Scarcity Pricing
IRR	Internal Rate of Return
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MS	Member State
NPV	Net Present Value
O&M	Operation and Maintenance
OCF	Operational Cash Flow
PI	Profitability Index
PV	Present Value
RES	Renewable Energy Sources
SD	System Dynamics
SO	System Operator
SoS	Security of Supply
SRM	Strategic Reserve Mechanism
TSO	Transmission System Operator
UK	United Kingdom
USA	United States of America
VaR	Value at Risk
VoLL	Value of Lost Load
WACC	Weighted Average Cost of Capital

General introduction

The liberalisation of electricity markets around the world has revealed problems of incentives regarding long-term investments in capacity resources (generation and demand response). The ability of energy-only markets with price caps to provide adequate investment signals has been particularly questioned in this regard. To deal with this issue, the literature has proposed various alternative market designs ranging from small adjustments – consisting for instance of removing price caps – to the introduction of capacity remuneration mechanisms or CRMs, in different forms (strategic reserves, capacity markets, etc.). The choice of the appropriate market design requires for policymakers to assess and compare the economic performances of available solutions. The ongoing transition in electricity systems, partly driven by the penetration of renewables, complexifies even more policymakers' mission by raising additional concerns about investment incentives in thermal technologies and demand response.

In the following sections, a general overview of the recent developments in the European electricity sector is provided to contextualise the main issues that are currently debated with respect to capacity adequacy. This also sets the ground for the motivation of this dissertation as explained subsequently.

1. Liberalisation of electricity sector and recent developments

Electricity markets around the world, especially in Europe and the USA, underwent an important transformation a few decades ago as they were progressively liberalised to introduce competition notably in the generation segment. This transformation resulted in a complete shift of paradigm regarding the way investments in capacity resources are made. In the previous monopolistic systems, investments were essentially decided on a centralised level by utilities which could forecast the demand and make the required level of investments to ensure long-term security of supply (i.e., capacity adequacy). After liberalisation, investments in capacity became the result of individual competing firms' decisions. These firms relied on their own anticipations of demand as well as decisions from their competitors since these may affect the profitability of their own investments. Capacity adequacy which used to be achieved through a centralised planification of investments therefore became a market-based outcome dependent on private agents' decisions.

In the new paradigm (i.e., liberalised markets), investment decisions are ultimately decided based on the private agents' anticipations about profitability. In this setup, electricity prices which are the main signal for investments are fundamental in market participants appraisal of investment opportunities. Moreover, a variety of other factors which were less relevant in the former monopolistic setup, are now crucial when it comes to investment decisions. Among these factors, are the uncertainties and risks involved in any decision. Uncertainty is important in at least two regards: first it inherently complicates investors' forecasts and second, the allocation of the associated risks between market participants matters for the way investors react to it.

There are several sources of uncertainty that can affect the profitability of a capacity resource in liberalised electricity markets. Assessing the expected cash flows to be generated by a potential investment entails a wide range of forecasts related to costs (fuel costs, technology costs, CO_2 price, etc.), market conditions (gross demand, electricity prices, other sources of revenues) and production levels (impact of renewable infeed, outages, etc.). These forecasts are made over the lifetime of the asset which can range from twenty to sometimes more than sixty years.

In a liberalised setup, most of the aforementioned parameters are uncertain, especially those which are dependent on political or regulatory decisions such as climate policy or environmental constraints (CO_2 price, emission restrictions, out-of-market subsidies for renewables, etc.). Investors therefore make their decisions based on imperfect information which is both incomplete because of their limited foresight and uncertain as explained above. At the same time, they bear most of the risks associated with their forecast mistakes. For instance, if they overestimate demand and invest too much, they create a situation of overcapacity which mechanically jeopardizes the profitability of their assets.

The fact that investment in capacity resources now depends on private agents operating in an uncertain environment, with limited foresight, raises an issue of coordination in liberalised markets. To ensure security of supply, electricity markets should provide the right investment signals and coordinate individual decisions towards a social optimum. This long-term coordination function is at the centre of all debates on capacity adequacy in liberalised markets, whether it is in Europe or in other similar systems such as those in the USA (Batlle and Rodilla, 2010; Cramton and Stoft, 2006; Creti and Fabra, 2007; Finon, 2011; Finon and Pignon, 2008; Green, 2006; Hogan, 2005, 1998; Joskow, 2008, 2006; Lévêque, 2006; Stoft, 2002).

With the ongoing energy transition, new challenges emerge as electricity systems are being transformed to accommodate high shares of low-carbon technologies such as renewables. The push towards low-carbon systems impacts investment signals in power markets. Because of the variability of their generation, renewable energy sources (RES) increase the volatility of electricity prices. Moreover, they create the well-known "merit order" effect which reduces the operation hours of thermal plants, thereby limiting the possibility for them to recoup their fixed costs (Sensfuß et al., 2008). The penetration of RES therefore affects the profitability of thermal technologies. It is paradoxical because the integration of high shares of RES requires more flexibility in the system to cope with their variability. As long as large-scale demand response and storage remain limited, this flexibility will mainly come from thermal generation (gas-fired plants for instance).

There is therefore a legitimate concern that the push for RES may reduce incentives to invest in yet needed thermal technologies, which could in turn undermine security of supply (De Sisternes and Parsons, 2016; Gerres et al., 2019; Newbery et al., 2018; Sisternes and others, 2014). Advocates of the energy-only market – where producers derive most of their revenues from selling electricity generated – argue that it can ensure capacity adequacy and therefore should remain the preferred market design (Hirst and Hadley, 1999; Hogan, 2005; Shuttleworth, 1997). On the other hand, a rich literature has been developed on the limits of the energy-only market design highlighting the existence of several market failures or regulatory issues which can interfere with its ability to achieve capacity adequacy. This literature proposed alternative market designs consisting in the introduction of the so-called capacity remuneration mechanisms (CRMs) to complement energy-only markets (Cramton and Stoft, 2006; De Vries and Heijnen, 2008; Finon, 2011; Finon and Pignon, 2008; Joskow, 2006; Keppler, 2017).

2. Market failures and regulatory issues interfering with the long-term coordination function

1.1. Long-term coordination of investment in theory

The energy-only market is the reference market design for liberalised systems. Coordination of capacity resource investments in this market design is done through price signals in short-term markets (Caramanis, 1982; Stoft, 2002). The theory of spot pricing introduced by Caramanis (1982) shows how short-term electricity prices coordinate long-term investment decisions in liberalised systems. In fact, under spot pricing, perfect competition between private agents in a liberalised system should in theory yield the same long-run equilibrium as would a benevolent planner seeking to maximize social welfare (Caramanis, 1982; Rodilla and Batlle, 2012).

Spot pricing in liberalised markets suggests that electricity prices are set each hour by the short-term marginal cost of the last capacity resource mobilised to satisfy the demand (i.e., the marginal capacity). When existing capacity resources are insufficient to satisfy demand, prices are set the Value of Lost Load[1] or VoLL (this is referred to as scarcity pricing or VoLL pricing). To satisfy demand at the lowest cost, capacity resources are selected on an economic merit-order basis, meaning that capacities are selected by increasing order of marginal cost.

The hours during which electricity prices reach the VoLL due to demand exceeding supply are called scarcity hours. Similarly, the revenues earned during these hours are called scarcity revenues (or scarcity rents) and are crucial for the profitability of capacity resources. Scarcity revenues are particularly important for peaking units for which they constitute the only way to recover fixed costs. During the other hours (i.e., when supply is sufficient to satisfy demand), all selected capacities at the exception of the one setting the price earn inframarginal rents

1 The VoLL is the price that an average consumer would be willing to pay to avoid an involuntary interruption of electricity supply.

which also contribute to recovering fixed costs. In the pricing system described above, microeconomic theory indicates that all agents cover their fixed cost in the long-run equilibrium. Agents will progressively adjust capacity in each technology so that each capacity earns just enough profits to cover its fixed costs, including an appropriate rate of return on investment (Caramanis, 1982; Stoft, 2002).

The functioning of electricity markets described above rely on a set of important assumptions such as perfect competition, perfect foresight of the future by agents, market completeness in terms of risk allocation instruments, the possibility for electricity prices to rise to the VoLL during scarcity hours, the absence of economies of scale and the absence of lumpiness in investments (Rodilla and Batlle, 2012). However, some of these assumptions do not hold in real-world electricity markets as explained below. Four factors in particular impede the theoretical functioning of energy-only markets and at the same time their ability to perform their long-term coordination function:

- The missing money problem induced by low price caps in short-term markets;
- The public good features of capacity adequacy;
- Asymmetrical investment incentives created by peak demand inelasticity and discrete size of investments;
- Incompleteness of markets, imperfect information and agents' risk aversion.

2.1. Missing money induced by price caps in energy markets

The most debated issue regarding the theoretical setup of the energy-only market is the assumption that electricity prices can reach the VoLL during scarcity hours. Implementing a VoLL pricing in real power systems is challenging for at least two reasons[2]: first, it is very difficult to estimate the VoLL because it depends on many circumstantial parameters[3] and second, there is a risk that some agents exercise

2 In addition, VoLL pricing increases price volatility and investment risk. It can also result in higher prices for consumers.

3 For instance, the type of usage of electricity at the time of an outage, the duration of the outage, etc.

market power during scarcity hours to make super profits. Here the focus is made on the second point[4].

To limit the risks of market power exercise, regulators often impose limitations on the maximum value of electricity prices in short-term markets. For instance, in France, prices on the day-ahead market[5] are capped at 3 k€/MWh while the Transmission System Operator (TSO) estimates the VoLL at around 26 k€/MWh (RTE, 2011). These price restrictions limit scarcity rents which are yet critical for peaking units to recover their fixed costs (Joskow, 2006).

Furthermore, even if prices can reach the VoLL (assuming it is properly defined), system operators (SOs) often perform actions[6] to limit the occurrence of scarcity hours because they ultimately translate into shortages (rolling blackouts). This is a fundamental issue in the applicability of scarcity pricing in practice. Public authorities and SOs are averse to shortages because of their impact on the society, and this is regardless of economic efficiency. The aforementioned actions performed by SOs are not valued through any market while at the same time affecting scarcity rents.

All this leads to a "missing money" issue (Cramton and Stoft, 2006; Lévêque, 2006). The missing money problem refers to the situation where capacity resources fail to recover their fixed costs when there is an adequate level of installed capacity. Spot pricing theory indicates that energy-only markets can provide an adequate level of security of supply (i.e., socially optimal level of installed capacity) and ensure full cost recovery for all capacities. However, this is only true when there is no interference in the price formation mechanism in short-term markets[7]. If prices are capped below the VoLL, then the socially optimal level

4 The first point about the estimation of the VoLL is not a market or regulatory failure. It rather complexifies the implementation of the VoLL pricing. In reality, the SO can define a desirable level of security of supply and then calculate a level of VoLL that is consistent with the defined reliability criterion. Then the problem becomes the definition of the optimal level of security of supply from a social point of view. The advantage of the rigorous VoLL pricing is that it reveals this optimal level through market fundamentals, rather than it being exogenously defined by SOs or other relevant entities.

5 It should be noted that price caps in intraday markets are usually higher but still below the VoLL. For instance, in France the price cap in intraday and balancing markets is equal to 10 k€/MWh.

6 They can reduce the voltage of the system to decrease consumption for instance.

7 Prices are allowed to reach the VoLL every time there is a scarcity of supply.

and mix of capacity will create a missing money for some plants, particularly peaking units. This is due to the fact that they do not earn sufficient scarcity rents (since the prices are below the VoLL).

The missing money problem currently discussed in the literature is a temporary missing money in the sense that it should disappear at equilibrium in the long run. Indeed, in a perfectly competitive market with free entry and exit, agents will adjust their capacity in order to guarantee cost recovery, thereby eliminating the missing money issue. However, this would be at the expense of security of supply since they will essentially adjust their capacity until there are enough scarcity hours to allow them to recover their fixed costs. The lower the price cap in the energy market, the higher the required number of scarcity hours to ensure fixed cost recovery at equilibrium. It is therefore a serious impediment to the ability of energy-only markets to provide an adequate level of security of supply.

2.2. Public good features of capacity adequacy

Capacity adequacy presents some features of classic public goods in economic theory. More specifically, it meets the non-excludability criterion as discussed by several authors (De Vries, 2004; Finon and Pignon, 2008; Keppler, 2017; Stoft, 2002). Capacity adequacy benefits to all consumers regardless of who is providing it. If an investor decides to build a power plant for instance, this plant will contribute to improving capacity adequacy. However, given the current state of the technology, it is impossible for the investor to select which consumers will benefit from the improvement of capacity adequacy. All consumers who are connected to network can benefit from capacity adequacy improvement, even if they are not direct clients of the investor.

This creates a problem of under-provision of capacity adequacy, in the sense that private agents’ decisions would result in a provision of capacity that is lower than the social optimum (Keppler, 2017; Oren, 2003). Indeed, any capacity addition leads to a positive externality for all consumers as explained above. The fundamental issue at hand is that private agents’ benefits from improving capacity adequacy are lower than the corresponding social benefit as highlighted by Keppler (2017). If private agents could extract the corresponding social value of their investment through existing markets, then there would be no externality, and no under provision. Current markets and state of technology do not allow them to do so.

It is important to keep in mind that this market failure can be mitigated in the future if technological change enables private agents to restrict consumption to those clients who have a stated willingness to pay that is higher than the private cost of capacity provision. Private agents' incentives will therefore be aligned with the social value of capacity provision. The deployment of smart meters could contribute to creating such systems with the possibility of individual curtailment of consumers.

Another factor exacerbates the under-provision problem and that is the inelasticity of peak demand which, combined with the lumpiness of investments, produces another market failure on the supply side as explained hereafter.

2.3. Asymmetrical investment incentives due to inelasticity of peak demand and lumpiness of investments

There is a structural asymmetry of incentives between overinvestment and underinvestment in capacity. This asymmetry stems from two factors: (i) the inelasticity of peak demand and (ii) the lumpiness of investments.

Peak demand inelasticity and lumpiness of investment have been widely discussed in the literature as a source of market failure (De Vries and Heijnen, 2008; Keppler, 2017; Rodilla and Batlle, 2012; Stoft, 2002). Since investments are only available in discrete size (50, 150 or 450 MW for instance), private agents cannot adjust capacity to exactly match peak demand. They are confronted with an arbitrage between investing in a discrete (marginal) capacity with the risk of creating a situation of overcapacity or not investing in that marginal capacity, which could create costly shortages for society. If peak demand is inelastic as it is the case in most systems, then the outcome between the two decisions are quite different, resulting in asymmetric incentives.

If private agents invest too much, they eliminate scarcity rents but if they underinvest, scarcity rents are potentially significant. Any rational investor, even in a context of perfect competition and perfect information will prefer to underinvest because it is the option that maximizes its profits. If demand was elastic, underinvesting would lead to a reduction of demand until it intersects with supply and the scarcity rents will therefore be limited. In other words, and as stated by Keppler (2017): *"With elastic demand, there would be no policy relevant market failure even in the presence of discretely-sized increments in investment, as underinvestment would be just as costly, in terms of profits foregone, as overinvestment".* The lumpiness of investments alone is thus not a source of market failure. What makes it one is its combination with an inelastic peak demand. This adds to the issue of under provision of capacity adequacy in liberalised energy-only markets.

2.4. Incompleteness of markets, imperfect information and risk aversion

Completing the set of market failures interfering with the long-term coordination function of energy-only market is the combination of private agents' risk aversion, imperfect information and incompleteness of markets. Investments in capacity resources are highly capital-intensive and subject to various uncertainties (see discussion above). In this context, private agents tend to be risk averse (De Sisternes and Parsons, 2016; Meunier, 2013; Tietjen et al., 2016). Risk aversion is not an issue *per se* as long as agents are able to trade their risk by contracting appropriate hedging instruments (Léautier, 2016). However, current electricity and financial markets do not provide enough hedging instruments to cover all types of risks faced by investors. This is where the notion of incomplete markets emerges in the debate on capacity adequacy (Abada et al., 2017; Finon, 2011; Neuhoff and De Vries, 2004; Willems and Morbee, 2010).

Because of risk aversion and the incompleteness of existing markets, private agents will adjust the valuation of their investment opportunities to internalise their perceived risk. This is done through a cut-off on the purely probabilistic expected value of their investments to represent the risk that is not tradable (De Maere d'Aertrycke et al., 2017). The concrete impact in terms of capacity adequacy is that risk averse agents tend to postpone their investments or even reduce them compared to risk neutral agents, especially regarding peaking units (Abani et al., 2018; Petitet et al., 2017; Rodilla and Batlle, 2012). Risk aversion and market incompleteness are therefore aggravating factors in the issue of under provision of capacity in liberalised energy-only markets.

3. Alternative market designs to ensure capacity adequacy

3.1. Capacity remuneration mechanisms and their rationale

The previous sections highlighted several market failures which can prevent energy-only markets, even in their form with scarcity pricing (i.e., VoLL pricing) from delivering adequate levels of capacity. To overcome the problem, alternative market designs commonly called capacity remuneration mechanisms (CRMs) or capacity mechanisms have been proposed in the literature. The fundamental difference between CRMs and the traditional energy-only market is that CRMs explicitly recognize capacity as a tradable good. They provide a revenue based on available capacity in addition to the revenues earned on the energy markets (which are based on energy sales).

A wide literature has been developed around CRMs (Abani et al., 2018; Assili et al., 2008; Bhagwat et al., 2016a; Cepeda and Finon, 2011; Cramton et al., 2013; Cramton and Stoft, 2005; De Vries, 2004; De Vries and Heijnen, 2008; Fernando Olsina et al., 2014; Hary et al., 2016; Hasani and Hosseini, 2011; Hobbs et al., 2007; Joskow, 2006; Petitet et al., 2017). Among all market and regulatory failures mentioned in the previous section, missing money has been the most cited justification for the introduction of CRMs. In addition to providing justifications for CRMs, the existing literature has also focused on the design of these mechanisms to ensure their effectiveness in providing capacity adequacy and their cost-efficiency. CRMs can be characterized following at least two dimensions: (i) quantity-based vs. price-based and (ii) targeted vs. market-wide.

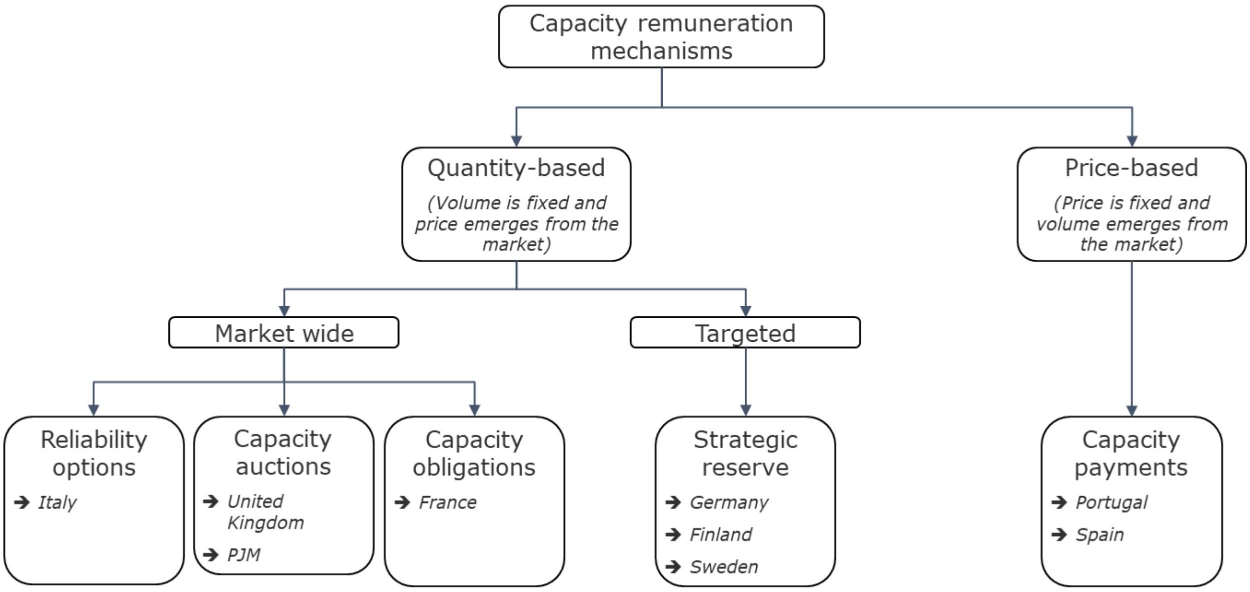
The first dimension relates to the signal used to express the demand for capacity. A quantity-based approach consists of the definition of a capacity target to be contracted while a price-based approach sets a capacity price (which is to be properly determined) and rely on the market to provide the right quantity of capacity. The two approaches are equivalent in theory if there is perfect information and no uncertainty (Weitzman, 1974). However, if these conditions are not satisfied then there may be a preference for one approach over the other[8]. For capacity adequacy questions, Finon and Pignon (2008) argue that quantity-based mechanisms are preferable, but in practice both approaches have been implemented.

The second dimension pertains to the scope of the CRM in terms of beneficiaries. A CRM can be market-wide, meaning that all capacity resources can benefit from it[9]. Conversely, a targeted CRM only benefit a restricted set of capacity resources (for instance only new plants or only old plants that are about to be decommissioned). In general, the choice of the scope is inherent to the choice of CRM, which in turn depends on various factors as discussed subsequently (see section 3.3).

Other dimensions can be considered to further characterize CRMs. For instance, the mode of definition of the capacity needs or the mode of procurement can constitute additional layers of characterization. Regarding the definition of the capacity needs, it could be done by a central authority such as the SO, or by individual suppliers with an *ex post* verification of a central authority. Similarly, the procurement of the capacity resources could be either centralised and performed by a single authority such as the SO or decentralised (each supplier oversees the procurement of its own capacity needs). Figure 1 below highlights the main CRMs currently discussed in the literature.

8 The determining factor is the sensitivity in terms of outcome (social welfare for instance) of a small error in the definition of the right quantity or price. For instance, if an error in the definition of the price is more detrimental than an error in the definition of the quantity, then a quantity-based approach should be preferred.
9 Capacity resources may still be subject to some eligibility criteria (for instance for environmental restrictions), but they are applied to all capacities.

Figure 1. **Taxonomy of main CRMs**[10]



Price-based CRMs consist of capacity payment schemes where a fixed price, determined administratively, is paid to capacity resources. Some capacity payment schemes only target specific resources while others are market-wide.

Quantity-based CRMs are more varied as illustrated on Figure 1. Within this category of CRMs, those which are "targeted" are either focused towards existing capacities or new capacities. Strategic reserve mechanism (SRM) is generally reserved for old existing plants in order to keep them longer in the system in case of emergency. On the other hand, there could be special tenders only for new investments.

The rest of quantity-based CRMs are market-wide. They include centralised capacity auctions, decentralised capacity obligations (or capacity certificates/credits) and reliability options. The first two are variants of what is commonly called a "capacity market". The main difference between capacity auctions and capacity obligations is the mode of procurement and of determination of capacity needs as described above (centralised vs decentralised).

10 Adapted from Meeus and Nouicer (2018).

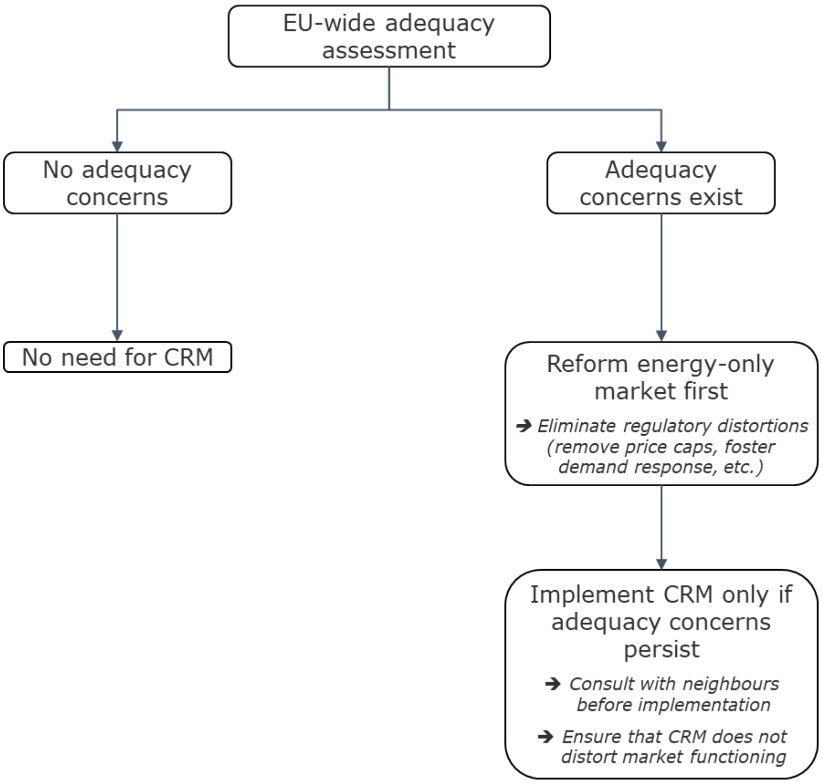
Reliability options correspond to a centralised market-wide CRM in which the products are not physical capacity contracts – as it is the case for all other CMRs – but rather financial call options. A central authority determines the strike price of the call options which effectively acts as a price cap on energy markets. Every time the price on the energy market rises above the strike price, holders of the call options pay the difference between the strike price and the market price. Reliability options incentivize capacities to be available during scarcity hours and protect consumers from high electricity prices (Bidwell, 2005).

3.2. The Clean Energy Package: European Commission's "last-resort" philosophy about CRMs

The debate on CRMs has attracted significant attention from policymakers as well. In Europe, the country-level discussions around CRMs take place within broader framework defined at the European level by the European Commission (EC). It lays out the conditions for the implementation of CRMs and oversees the validation process. The most recent piece of legislation regarding energy policy at the European level is the Clean Energy Package (CEP) presented in its initial version in November 2016 (European Commission, 2016a).

Despite the rich literature supporting the need for CRMs in liberalised markets such as those in Europe, the EC has displayed a strong preference for the energy-only market design, arguing that CRMs may pose competition issues between technologies and distort cross-border trade (European Commission, 2016b; Meeus and Nouicer, 2018; Newbery, 2015). It promotes market reforms aiming at removing the failures of the energy-only market (for instance allowing prices to reach the VoLL during scarcity hours). CRMs are considered by the EC as a last resort means to ensure capacity adequacy. Figure 2 below provides an overview of EC's framework for CRMs (Meeus and Nouicer, 2018).

Figure 2. European Commission's framework for capacity remuneration mechanisms[11]



The framework established by the EC applies to all member states (MS). First the relevant entities in the MS should perform an adequacy assessment to establish the existence or not of adequacy concerns[12]. If the assessment reveals adequacy concerns, then the MS should identify the market failures or regulatory distortions at the origin of the adequacy concerns and undertake reforms to remove them. In doing so, they should propose a clear plan of reforms to be reviewed and approved by the EC[13]. Potential reforms to be considered include implementation of actual scarcity pricing (with energy prices rising to the VoLL during scarcity hours), increased use of interconnectors, promotion of demand side flexibility. If a MS can demonstrate that adequacy concerns will persist despite such reforms, they it can be authorized to implement a CRM, under certain conditions. In this respect, the

11 Adapted from Meeus and Nouicer (2018).

12 The assessment could be limited to the national level but there is a preference for a EU-wide assessment.

13 This phase includes part of the state Aid process.

CEP highlights three aspects that a MS should carefully consider when implementing a CRM: (i) non-discrimination between existing and new solutions, (ii) impacts on climate change goals and (iii) cross-border effects.

Non-discrimination between existing and new solutions for capacity adequacy relates particularly to demand-side response (DSR)[14], which still faces barriers for participation to CRMs in some European countries (European Commission, 2016b). A recent example with respect to that is the suspension of UK's capacity market by the General Court of the European Union (European Union - The General Court, 2018). The decision of the General Court followed a complaint related to the discriminatory aspect of the mechanism regarding DSR providers.

The second important aspect is the impact of CRMs on environmental targets. In the CEP, specific CO_2 emissions limits are proposed for existing and new generation capacities in order for them to be eligible to a CRM. For instance, the recommendations in the CEP propose that new capacities emitting more than 550 gCO2/kWh should not be eligible to CRMs. For existing capacities emitting above this threshold, it is suggested that their commitment in a capacity mechanism must be limited to a maximum of five years (after the entry in force of the new regulation). EC expects these measures to align CRMs with climate policies.

Finally, any MS contemplating the implementation of a CRM should assess and limit its potential impact on neighbouring markets. Cross-border impacts of CRMs represent a major concern for European policymakers as they may undercut the efforts of creation of a single internal market. Hence, EC recommends the participation of cross border capacities to national capacity mechanisms to ensure efficient signals and avoid capacity leakage[15]. It also promotes a high level of coordination between neighbouring countries for an adequate design of the mechanisms so that they do not limit cross-border trade or introduce unnecessary market distortions.

14 It also concerns storage and energy efficiency solutions.

15 Interested readers can find more detailed discussions on cross-border issues in a dedicated literature (Bhagwat et al., 2017c; Cepeda and Finon, 2011; Gore et al., 2016; Lambin and Léautier, 2018).

3.3. Important aspects to consider in the assessment of market designs for capacity adequacy

Whether the debate on market design for capacity adequacy is tackled from a pure academic perspective or in the context of the European Commission's policy framework, it is crucial to assess the merits and limitations of available market design options. This assessment heavily on models that aim to capture the characteristics of liberalised electricity markets (Abani et al., 2018; Bhagwat et al., 2016b, 2017c, 2017b; Bublitz et al., 2019; Cepeda and Finon, 2011; De Vries and Heijnen, 2008; FTI CL - Energy, 2016; Hary et al., 2016; Hasani and Hosseini, 2011; Mastropietro et al., 2016; Petitet et al., 2017; RTE, 2018; THEMA Consulting Group et al., 2013; UFE et al., 2015; UK Department of Energy & Climate Change, 2014a). Three characteristics are particularly important to consider when addressing capacity adequacy issues in the current context of energy transition, using such models:

(i) Cyclical tendency of electricity markets;

(ii) Private agents' behaviour (attitude towards risk, tendency to mothball assets in periods of high uncertainty, herd behaviour, etc.);

(iii) Impact of renewables on investment incentives for thermal technologies or demand response.

As illustrated by Arango and Larsen (2011) Ford (1999), electricity markets exhibit a propensity to capacity cycles, leading to a succession of over and under-capacity phases. These cycles present a threat to security of supply as they increase uncertainty and distort investment signals (Green, 2006). Because of this cyclical tendency, electricity markets usually operate out of equilibrium. An analysis of electricity markets from a dynamic perspective is therefore needed to account for these out-of-equilibrium phases.

Moreover, analysing capacity adequacy by the means of electricity market models requires that all agents' decisions that may affect the level of installed capacity are properly represented. Agents' decisions should be endogenous with respect to their expectations. These decisions include not only investments and shutdowns but also mothballings (Abani et al., 2017; Arango et al., 2013). As discussed in section 2.4 of this general introduction, imperfect information, risk aversion and markets incompleteness can affect private agents' decisions (Meunier, 2013;

Neuhoff and De Vries, 2004; Ousman Abani et al., 2018). They can also display symptoms of herd behaviour as illustrated in some studies (Hary et al., 2016; Olsina et al., 2006). All these factors play a crucial role in agents' decision making and ultimately on capacity adequacy.

At last, another aspect is becoming more and more crucial and that is the impact of RES deployment on investment incentives (De Sisternes and Parsons, 2016; Gerres et al., 2019; Newbery et al., 2018; Pinho et al., 2018; Tietjen et al., 2016). Indeed, the integration of high shares of RES affects the profitability of thermal generation technologies which are still needed to ensure security of supply in the absence of large-scale storage or highly flexible demand response.

In addition to the above-mentioned dimensions, policymakers are also particularly concerned with the impact of CRMs on consumers' welfare or issues such as revenue volatility and investment risk. These are important for the sustainability of the mechanism.

4. Research questions and methodology

4.1. Research questions

This dissertation complements the existing literature on market design for long-term capacity adequacy by focusing on three important issues: (i) understanding how electricity markets perform under different assumptions regarding investors' risk preferences, (ii) analysing the compatibility of private agents' incentives to mothball capacity resources with security of supply objectives and (iii) assessing the economic performance of different market designs in a context of a high penetration of renewables. The corresponding research questions are presented hereafter.

How does investors' risk aversion affect the effectiveness and cost-efficiency of capacity remuneration mechanisms?

Several authors have highlighted the importance of risk aversion for investments in competitive electricity markets (Abani et al., 2018; Fan et al., 2012; Meunier, 2013; Neuhoff and De Vries, 2004; Petitet et al., 2017). The issue is gaining more and more interest due to the many changes currently occurring in the electricity sector (climate policies, deployment of renewables, electric vehicles, etc.), which introduce a lot of uncertainty for investors.

Risk aversion modifies the way investors react to market signals and can lead to sub-optimal decisions in situations of market incompleteness (Abada et al., 2017; Willems and Morbee, 2010). The current state of electricity markets does not provide investors with enough options to trade the risks that they face, which is precisely a case of incomplete markets (Newbery, 2015). The concerns about risk aversion and its impact on investors' behaviour are therefore justified. The first research question aims at providing a discussion on the impact of risk aversion on the performances of different market designs, from a capacity adequacy perspective. Two of the most discussed capacity remuneration mechanisms are analysed (the market-wide capacity market and the strategic reserve mechanism), in addition to the benchmark energy-only market.

Are private agents' incentives for mothballing compatible with security of supply objectives?

Recent evolutions in European power markets has led to waves of mothballing of generation assets (Caldecott et al., 2014; Eurelectric, 2016; EY, 2014). Mothballing consists of a temporary closure of power plants in situations of difficult economic conditions. Its main objective is to protect power plants owners from expected losses while giving them the option to reactivate their plants if market conditions improve. Therefore, it provides an interesting flexibility compared to a permanent shut down.

Mothballing appears as a legitimate recourse for private agents who are seeking to protect their investments. Since 2010, and especially during the period covering 2012 to 2014, power utilities in Europe have mothballed several gigawatts of thermal plants, mainly gas-fired ones (Caldecott et al., 2014). Their decisions were triggered by a combination of unfavourable factors including: a situation of overcapacity due to a slowdown of electricity demand growth, an underestimation of the deployment of renewables which further reduced the residual demand for thermal generation, and a switch of competitiveness between gas coal which made gas-fired generation less profitable.

In case of systemic overcapacity, this would just be an expected response from a competitive market. Nevertheless, some argue that, regardless of overcapacity, the high penetration of renewables would make mothballing a recurrent practice (ENTSOE, 2017). In any case, it remains unclear whether this practice is compatible with capacity adequacy objectives and if it has other long-run impacts. On the one hand it avoids losses for private agents and leads to cost savings in operation and maintenance. On the other hand, it essentially removes capacity from the market, which means that it reduces available capacity. The second research question of the dissertation covers this subject from an economic perspective. It analyses mothballing rationales and their impact on power systems under two paradigms: an energy-only vision and a capacity remuneration mechanism vision.

What are the best market design option(s) to ensure capacity adequacy in a context of high RES penetration and non-increasing electricity demand?

Finally, the last research question builds on the previous ones to address a broader issue, which is the choice of the best market design option(s) to ensure long-term capacity adequacy in a context of energy transition. The ongoing transformation of power systems, partly led by the penetration of renewables, has reignited the debate about market design for capacity adequacy. Renewables tend to push part of the flexible thermal fleet out of the merit order and reduce its profitability (Gerres et al., 2019; Newbery et al., 2018; Sensfuß et al., 2008).

Yet, thermal capacity is needed to cope with the variability of renewables precisely. Many questions are thus being raised about the functioning of a power system with high shares of renewables, and the type of market design needed to ensure capacity adequacy in this context. The last research question consists in a comparison of market design options for long-term capacity adequacy in this type of power system. The comparison is done from a social welfare perspective, with discussions on other specific dimensions that are relevant to policymaking: security of supply (i.e., capacity adequacy itself), costs for consumers, investment risk and profitability of capacity resources.

4.2. Methodological considerations

To address the research questions outlined above, a simulation model is developed based on the System Dynamics (SD) framework. Throughout the dissertation, the model is progressively complemented with additional features to account for the specificities of each research question. The paragraphs hereafter provide more details on the motivations behind the choice of the SD framework.

The literature on liberalised electricity markets provides several approaches for the modelling of these markets. The main approaches include optimization, equilibrium and simulation models (see Ventosa et al. 2005 for an extensive description). The choice of the modelling approach generally depends on the issue at hand.

For the study of capacity adequacy issues in liberalised electricity markets, the modelling approach should allow for the consideration of the key elements mentioned above (cyclical tendency, agents' behaviour and RES development, etc.). Among existing modelling techniques, only simulation models fit these requirements, especially the one regarding the integration of cyclical tendencies. In this regard, the System Dynamics framework is the main simulation model approach that has been used in the literature to represent cyclical tendencies in liberalized electricity markets. It was first introduced by Forrester (1961), to study business cycles and was later widely used in the energy sector as highlighted by Teufel et al. (2013). It has particularly been applied to the study of long term dynamics related to investment decisions in electricity markets (Abani et al., 2016; Assili et al., 2008; Bhagwat et al., 2016b, 2017b, 2017c; Cepeda and Finon, 2011; De Vries and Heijnen, 2008; Hary et al., 2016; Hasani and Hosseini, 2011; Hobbs et al., 2007; Olsina et al., 2006; Petitet et al., 2016a, 2017).

An interesting feature of the SD framework is that it can account for causalities between variables of complex non-linear systems through feedback loops, with representation of time delays and dynamic responses. This makes it suitable for the analysis of systems such as decentralised electricity markets. SD allows for the representation of the cyclical tendencies mentioned above, which is not possible with other modelling techniques (optimisation, equilibrium, etc.). Moreover, the SD framework gives a considerable degree of flexibility in the characterisation of market participants' behaviour. For instance, it can easily accommodate imperfect behaviours related to risk aversion, limited foresight or herd behaviour. These are more difficult to include using other modelling frameworks.

Given the research questions addressed in this dissertation, the choice of the SD framework was primarily motivated by the need to represent cyclical tendencies to properly analyse the dynamics of liberalised electricity markets and assess the economic performance of market designs for capacity adequacy. An additional motivation comes from the possibility offered by the SD framework regarding the modelling of private investors' behaviour and its impact on capacity adequacy. Overall, this approach provides a more realistic representation of liberalised electricity markets, compared to other modelling techniques.

4.3. Structure of the dissertation

This dissertation is structured around three chapters corresponding to each of the research questions stated above.

Chapter I focuses on risk aversion and its impact of the performance of capacity remuneration mechanisms. The chapter is organised in six sections. Section 1 provides more background on the research question. Sections 2 and 3 introduce the modelling framework and the methodology for the analysis. Section 4 discusses the results and their implications. In section 5, the sensitivity of the results to the main assumptions is analysed. Finally, the main conclusions are outlined in section 6.

Chapter II addresses the issue of power plant mothballing in liberalised markets. It is also composed of six sections, following a similar structure to the preceding chapter. Section 1 sets up the context and the motivation behind the research question. Section 2 presents the modelling adjustments introduced to study mothballing decisions. Section 3 describes the approach for simulations. Section 4 discusses the results for energy-only markets while section 5 covers capacity markets. These sections also include some sensitivity analyses. Conclusions are summarised in section 6.

In **Chapter III**, a comparative analysis of market design options for capacity adequacy in a context of high renewable penetration is provided. Once again, the chapter includes six sections. Section 1 introduces the research question and its context. Section 2 covers the methodology, in particular the modelling of a capacity market with multiannual contracts. Section 3 describes the case study used for simulations. Section 4 provides a discussion on the simulations results. A sensitivity analysis is presented in section 5. The main takeaways of the chapter are highlighted in section 6.

The dissertation ends with a **general conclusion** including potential directions for further research.

CHAPTER I. Impact of investors’ risk aversion on capacity adequacy

Abstract

The importance of risk aversion for investments in competitive power markets have long been mentioned in the literature. The issue is gaining increasing interest due to the many changes currently occurring in the electricity sector (climate policies, deployment of renewables, electric vehicles, etc.), which introduce a lot of uncertainty for investors. This chapter analyses the impact of risk aversion on different market designs when investors are facing an uncertain peak load. Three market designs are studied for this purpose: a competitive energy-only market, a capacity market and a strategic reserve mechanism. A simulation model based on the System Dynamics framework is developed to represent investment decisions and analyse the behaviour of each market design. Risk aversion is modelled through the computation of Conditional Value at Risk.

The chapter is organised in six sections. Section 1 provides more background on the research question. Sections 2 and 3 introduce the modelling framework and the methodology for the analysis. Section 4 discusses the results and their implications. In section 5, the sensitivity of the results to the main assumptions is analysed. Finally, the main conclusions are outlined in section 6. This chapter is based on a published paper[16] and a conference paper[17].

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16 Abani, A., Hary, N., Rious, V., Saguan, M., 2018. The impact of investors' risk aversion on the performances of capacity remuneration mechanisms. Energy Policy 112, 84–97.

17 Abani, A.O., Hary, N., Saguan, M., Rious, V., 2016. Risk aversion and generation adequacy in liberalized electricity markets: Benefits of capacity markets, in: 2016 13th International Conference on the European Energy Market (EEM).

Résumé en français

L’importance de l’aversion au risque dans les décisions d’investissements dans les marchés libéralisés a été mentionnée de longue date dans la littérature. La question suscite de plus en plus d'intérêt en raison des nombreux changements en cours dans le secteur de l'électricité (politiques climatiques, déploiement des énergies renouvelables, véhicules électriques, etc.), qui introduisent beaucoup d'incertitude pour les investisseurs. Ce chapitre analyse l’impact de l’aversion au risque sur différentes architectures de marché lorsque les investisseurs sont confrontés à une demande incertaine. Trois architectures de marché sont étudiées à ce titre : un marché basé uniquement sur la rémunération de l’énergie (*energy-only*), un marché de capacité et un mécanisme de réserve stratégique. Un modèle de simulation est développé afin de représenter les décisions d'investissement et d'analyser le comportement de chaque architecture de marché. L'aversion au risque est modélisée par le calcul de la valeur conditionnelle à risque (CVaR).

Le chapitre est organisé en six sections. La section 1 introduit de façon plus détaillée la question de recherche. Les sections 2 et 3 présentent le cadre de modélisation et la méthodologie d'analyse. La section 4 présente les résultats et de leurs implications. La section 5 analyse la sensibilité des résultats aux principales hypothèses. Enfin, les principales conclusions sont exposées dans la section 6.

Contents of Chapter I

1. Introduction

1.1. Context and motivation

Well-designed energy-only markets should in theory send adequate price signals to stimulate needed investments in generation capacity (Stoft, 2002). In the theoretical energy-only market, generators recover a significant part of their fixed costs during scarcity periods (i.e., when the capacity in the system is not enough to satisfy the demand). The revenues earned during these periods are particularly vital for peaking units. At equilibrium, a well-functioning energy-only market with scarcity pricing (i.e., a market in which prices are allowed to reach the Value of Lost Load or VoLL[18] during scarcity periods) enables generators in each type of technology to earn just enough revenues to recover their total costs, therefore inducing a socially optimal mix of capacity in the long run (Caramanis, 1982; Stoft, 2002).

However, for political or social considerations, prices in most electricity markets are capped[19] at a lower level than the VoLL, reducing at the same time scarcity rents[20] for generators. In addition, the increasing penetration of renewables has a significant impact on thermal plants' profitability as it reduces both the frequency and the magnitude of price spikes (Sensfuß et al., 2008). Finally, some aspects related to investors' behaviour and their response to price signals may prevent energy-only markets from achieving their capacity adequacy objective. Among these are: herd behaviour and risk aversion (associated with market incompleteness), which may lead to cyclical tendencies in investments and cause

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18 The Value of Lost Load (VoLL) is defined as the willingness to pay of the consumers in order to avoid being curtailed. Since there are several types of consumers, there should be different VoLLs corresponding to each consumer. However, the problem of the determination of the VoLL is out of the scope of this dissertation and it is assumed that the VoLL has been properly defined.

19 Price caps are generally introduced in order to mitigate the effects of some market imperfections which prevents energy only markets from functioning properly as explained by Stoft (2002) (e.g., lack of sufficient short term price elasticity on the demand side, the inability of a system operator to perform selective curtailment, exercise of market power, etc.).

20 Profits earned during scarcity periods.

deviations from the optimal equilibrium (Arango and Larsen, 2011). All the factors mentioned above constitute barriers to the well-functioning of energy-only markets and can lead to sub-optimal level of investments, resulting in more shortages than what is desired (see section 2 of the general introduction).

In order to restore appropriate investment signals, complementary policy instruments (or market designs), called capacity remuneration mechanisms (CRMs) are being discussed and implemented[21]. These instruments remunerate power plants (or demand response resources) for their capacity, in addition to the revenues received on energy markets. Two CRMs in particular have drawn a lot of attention in theory and in practice: the capacity market (in its various forms) and the strategic reserve mechanism. The first one has been implemented for instance in France, Great-Britain and PJM[22] whereas the second one has been preferred by Germany, Sweden or Finland. Both mechanisms are quantity-based[23] but they differ in their design regarding the determination of the required amount of capacity, the targeted capacities and their interaction with the energy market. The differences between these two mechanisms are discussed more extensively in section 2.5.

To decide which CRM to implement, policymakers should assess their economic performances first, in particular regarding their reliability and their cost (De Vries, 2004). The former refers to the ability of the mechanism to provide adequate investments to ensure security of supply and reduce shortages, while the latter refers to the total costs associated with it (investment costs, variable generation costs and fixed O&M costs).

As power markets are prone to investments cycles, the aforementioned performances should be assessed in a dynamic perspective, relying on simulation models, as demonstrated by the extensive literature on the dynamics of generation investments in liberalised power markets (Arango and Larsen, 2011; Assili et al.,

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[21] See Batlle and Rodilla (2010) or Cramton et al. (2013) for a discussion on design options and typology of CRMs.

22 France has decided to implement a decentralised capacity market, also known as capacity obligations, whereas the UK and PJM run centralised capacity auctions.

23 Meaning that the quantity (i.e., target capacity to be contracted) is explicitly determined by some central body.

2008; Bunn and Larsen, 1994; De Vries and Heijnen, 2008; Gary and Larsen, 2000; Hary et al., 2016; Hasani and Hosseini, 2011; Olsina et al., 2006; Petitet et al., 2016a, 2017).

1.2. Existing literature on risk aversion and capacity adequacy

Most modelling studies on CMRs oversimplify investors' behaviour. For instance, a risk-neutral hypothesis is generally considered for investors. This is the case in Bhagwat et al. (2017c), Cepeda and Finon (2011), De Vries and Heijnen (2008), Hary et al. (2016), Hasani and Hosseini (2011), where the authors tackle the issue of security of supply by analysing the impact of some CRMs on investment incentives. Yet, many sources of uncertainties (e.g., about demand, prices, policy, etc.) can directly alter the behaviour of market players in their investment decision-making (Dyner and Larsen, 2001; Gorenstin et al., 1993; Soroudi and Amraee, 2013).

Moreover, these investments are capital-intensive and irreversible. In this context, the risk neutrality assumption about investors' behaviour is arguable. They are more likely to be risk averse (Abada et al., 2017; Hobbs et al., 2007; Meunier, 2013; Petitet et al., 2017). Moreover, given the incompleteness of electricity markets as highlighted in Willems and Morbee (2010), investors cannot transfer all their risk or trade it on existing markets. This impacts their investment decisions and consequently their reaction to a specific policy instrument. Therefore, investors' risk preferences should be properly accounted for when assessing the performances of policy instruments.

Several studies have investigated the relationship between agents' risk aversion, market design and investment decisions in generation capacity. For example, Meunier (2013) shows, using a stylised equilibrium model, that risk averse agents can invest in more capacity than risk neutral ones in the long run. Such configurations occur when risk averse agents overinvest in peaking units as a means to hedge the risks faced by the baseload technologies. Willems and Morbee (2010) demonstrate that improving market completeness by introducing more derivatives increases investments because it provides better hedging opportunities.

Blyth et al. (2007) develop a real option approach to assess the impact of climate change policy uncertainty on investment incentives in different generation technologies. They illustrate that uncertainty on climate change policies can lead investors to wait for stronger price signals before investing (compared to a case of perfect certainty). Fan et al. (2012) find similar results by using a model based on game theory. They find that various sources of uncertainties (for instance about carbon permits allocation schemes or investment costs) and risk aversion have impacts on investment incentives as they reduce or delay investments. Aghaie (2017) also comes to the same conclusions by analysing the impact of risk aversion on investments in an energy-only market using a stochastic optimization model. He shows in addition that risk aversion leads to more shortages and an increased use of demand response resources in such a market. Although these studies are based on static equilibrium models, they are relevant to this discussion because they highlight the importance of considering investors' risk aversion while assessing policy instruments.

As explained above the cyclical nature of investments in power markets and investors' risk aversion are two fundamental aspects that should be considered by policymakers when comparing policy instruments such as CRMs. Only a limited number of studies take both these aspects into account (i.e., use a dynamic simulation model which considers investors' risk aversion). For instance, Hobbs et al. (2007) develop a representative agent model that accounts for agents' risk preferences in order to simulate investment decisions and to assess the performance of the PJM capacity market for different demand curves. They illustrate that using a sloped capacity demand curve instead of a vertical one can reduce the costs of providing a desired level of reliability. They explicitly represent risk aversion through a quadratic utility function but do not provide any analysis of the impact of agents' risk attitude on the performances of the studied market designs.

Another relevant work is the one by Eager et al. (2012). The authors build a dynamic model to simulate investments in thermal generation in a context of high wind penetration. The concept of Value at Risk (VaR) is used to represent risk aversion. By applying their model to the British power system, they illustrate how a lack of sufficient revenues for peaking units can affect the security of supply. Nevertheless, their analysis focuses on an energy-only market and does not extend to CRMs. At last, Petitet et al. (2017) use a dynamic simulation model to study the influence of risk aversion on the performance of an energy only market (with and without scarcity pricing) and a capacity market. Their results show that taking risk aversion into account significantly modifies the comparison between the studied market designs. However, their study does not consider the strategic reserve mechanism which is yet one of the most discussed CRM.

1.3. Research question

The aim of this chapter is to analyse, in a dynamic perspective, the impact of risk aversion on the performance of CRMs, with investors facing an uncertain peak load. Three market designs are studied for this purpose: a competitive energy-only market (EOM hereafter), a capacity market (CM hereafter) and a strategic reserve mechanism (SRM hereafter). A simulation model based on system dynamics is developed in order to represent investment decisions and analyse the functioning of each market design. Risk aversion is modelled through the computation of Conditional Value at Risk (CVaR). The results are discussed in terms of changes in the reliability (i.e. ability to limit shortages) and the cost (i.e. total generation cost) of the studied market designs.

This chapter contributes to the literature on generation adequacy by bringing some insights about the potential effects of investors' risk aversion on the performance of a CM and a SRM. More precisely, it shows that risk aversion leads to reliability losses and increased costs in all three market designs. However, the CM appears to be the least affected one. Moreover, the benefits resulting from the implementation of a CRM are higher in presence of risk averse investors.

The chapter is organised as follows: section 2 explains the model and the functioning of the three market designs. Section 3 provides a presentation of the simulations. The results are discussed in sections 4 and 5. Finally, conclusions and policy implications are presented in section 6.

2. A single-technology model for market design comparison

2.1. General structure of the model

As explained in the general introduction, the modelling methodology used in this chapter (and the throughout the dissertation) is based on the System Dynamics (SD) approach. The model presented in this chapter is inspired from Hary et al. (2016) and Hobbs et al. (2007). It simulates, on a yearly basis, aggregate investment and shutdown decisions from private agents, who are assumed to behave in the same competitive way[24]. Each year, four main steps are run:

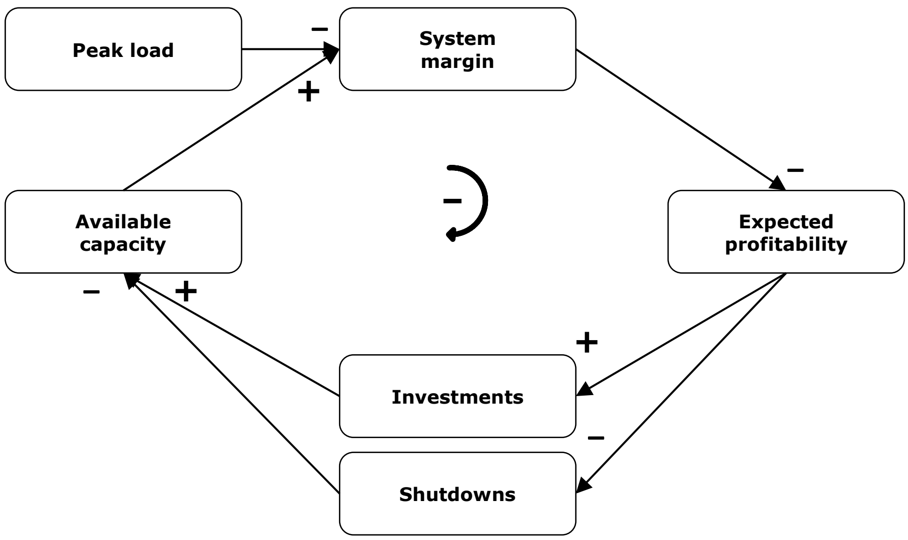
- **Step 1:** agents make anticipations about future market conditions (peak load, installed capacity and capacity price when necessary) and forecast the profitability of their plants with respect to these anticipations;
- **Step 2:** based on the forecast profitability, agents decide how much capacity to shut down and how much to invest in;
- **Step 3:** the installed capacity can thus be updated according to these decisions;
- **Step 4:** agents discover the actual load and system margin. Their actual profits on the energy market are then computed. The process starts back from first step, with agents taking into account the observed market outcome for their future forecasts.

One can notice a feedback loop in the steps presented above. Figure 3 presents the causal loop diagram of the model and illustrates how the main variables interact with one another. The (+) and (—) symbols associated with the arrows describe the nature of the interaction between variables. A (+) symbol means that the variables change in the same direction. For instance, an increase in variable (A) results in an increase in variable (B). Conversely, the symbol (—) indicates that the variables change in opposite directions. The (—) symbol in the middle of

24 This is equivalent to a representative agent approach.

the diagram indicates a balancing behaviour which suggests that the system may reach an equilibrium state.

Figure 3. **Simplified causal loop diagram of the model**



The main assumptions of the model are the following: perfect competition (there is no strategic behaviour), single generation technology (only peak technologies are modelled), lead time of four years[25] (between an investment decision and availability of the power plant) and exogenous function for revenue computation (instead of modelling a short-term energy market). This function is determined empirically based on the work of Hobbs et al. (2007). Even if it does not represent the precise functioning of short-term markets, it does provide a good estimation of expected revenues for peaking units on the energy market, which is sufficient for the analysis carried out in this chapter[26]. Moreover, similar to Hary et al.

25 It includes the construction time which is around 2-3 years based on several sources Bhagwat et al. (2017c), Hary et al. (2016), Petitet et al. (2016b, 2017), Rious et al. (2011), U.S. Energy Information Administration (2017). It also accounts for the time for obtaining all the administrative authorisations and regulatory approvals, which is assumed to be of one year. In reality, the necessary time to complete all administrative and regulatory procedures may depend on specific environmental constraints or land restrictions associated with the location of the plant. A sensitivity analysis regarding the lead time is presented in section 5 of the chapter.
26 In the next chapters of the dissertation, the revenue function is replaced by a proper short-term market.

(2016), increasing O&M costs for ageing power plants and endogenous shutdowns are considered (as explained subsequently).

The model however presents two main differences compared to those introduced by Hobbs et al. (2007) and Hary et al. (2016), from which it is inspired. These differences relate to the agents' forecasts procedure and the modelling of risk aversion, both of which are described in detail in the following sections.

2.2. Uncertainties and agents' forecasts

The main uncertain parameter in the model is the evolution of the peak load. The agents face an exogenous peak load which is subject to random deviations due to economic growth rate deviations and weather conditions. These uncertainties are factored into a normally distributed random variable as it is usually done in the literature (De Vries and Heijnen, 2008; Hary et al., 2016; Hasani and Hosseini, 2011; Hobbs et al., 2007).

Since the peak load is modelled as an uncertain parameter, it has to be forecast[27] by the agents in order to be taken into account in their decisions (investment or shutdown). This forecast represents an important feature of the model. The average, the minimum and the maximum growth rate of peak load over past years are used in a backward-looking strategy in order to forecast it for the future. These values are referred to as the evolution vector.

In order to account for the uncertainty of the load, agents build a scenario tree based on the evolution vector. To be coherent with the considered lead time (four years), they need to make their forecasts of the market conditions four years ahead. The scenario tree is constructed by exploring the possible combinations of growth rates for the years to come, up to the fifth year of operation. This represents a forecast horizon of eight years: four years of lead time which goes from year y (year of the decision) to year $y+4$ (first year of operation), plus four more years going from $y+5$ to $y+8$. The scenario tree is computed by iteration

27 It is assumed that the agents do not have knowledge about the future realisations of the uncertain parameters.

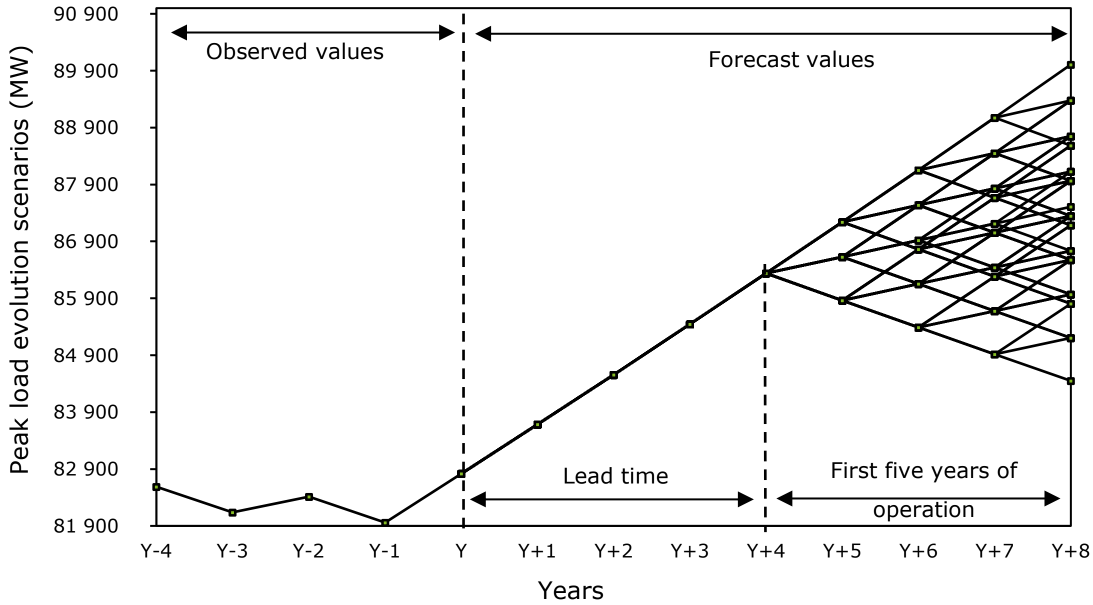
from one year to the next by extending each of the forecast values of the year of interest in three new values, thanks to the evolution vector.

For instance, if X is one of the forecast values of the peak load in year $y+1$, this will result in three new forecast values in year $y+2$, corresponding to a maximum, average and minimum evolution scenario. Figure 4 gives an illustration of the computation of the scenarios tree. Only a portion of the scenario tree is represented on the figure for reasons of simplicity and readability. This illustration shows the observed values of the peak load during years $y-4$ to y. These are actual values of peak load which are used to compute the evolution vector (i.e., the average, the maximum and the minimum growth rate over these years). For years $y+1$ to $y+4$, which correspond to the lead time, only the case corresponding to a series of maximum growth rate is represented on the figure[28]. Finally, for the last years of the forecast horizon ($y+4$ to $y+8$) which correspond to the first five years of operation of the power plant, the figure shows the different peak load scenarios[29].

28 In the model, all the combinations are computed.

29 The total number of scenarios is equal to 3^8 = 6 561. Indeed, each year of the forecast horizon leads to multiplying by 3 the number of previous scenarios. This means that for a forecast horizon of 8 years, the total number of final scenarios is 3^8. However, to reduce the computation time and account for imperfect practical forecasting, the 6 561 scenarios are sampled so that only 6 561/R scenarios are actually used by the agents to assess the expected profitability of their investments. This means that the probability of each selected scenario is 1/(6 561/R) (as all the paths are considered to have the same probability). Here R is equal to 81 (3^4). By reducing the number of scenarios, the CVaR is slightly overestimated. However, it has no impact on the conclusions derived from the modelling, as the main effects are preserved.

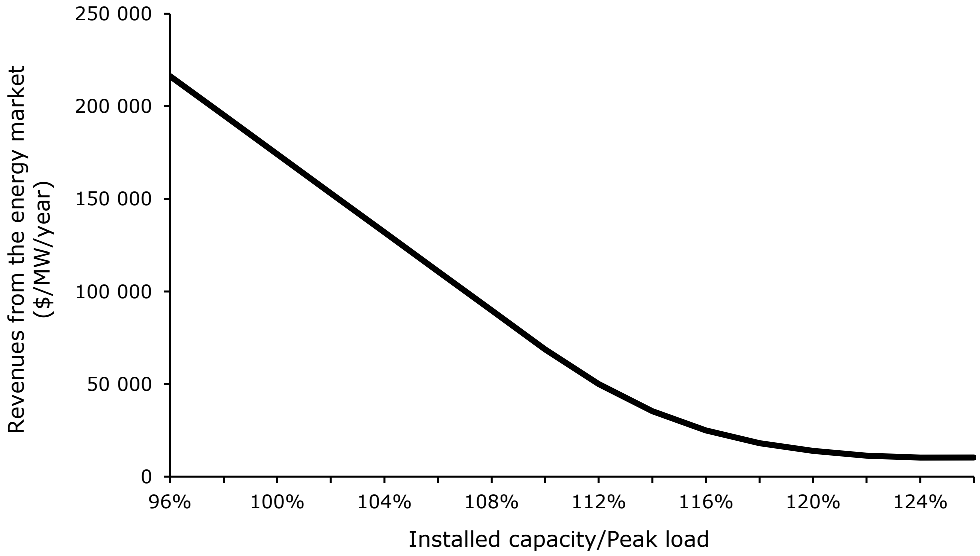
Figure 4. Agents' forecast of peak load



2.3. Profitability assessment

Before making their investment or shutdown decisions, agents need to assess the profitability of their plants. Profitability depends on the expected revenues that the plant will generate, and the expected costs associated with its construction and/or operation. In this chapter, revenues that can be earned from the energy market are computed thanks to an exogenous curve (see Figure 5) similar to the one used by Hobbs et al. (2007).

Figure 5. **Revenue curve from energy market**



This revenue curve[30] gives the relationship between producers’ gross margin and the capacity margin of the system. The gross margin is defined as the difference between revenues from energy market (including ancillary services) and variable costs, whereas the capacity margin corresponds to the ratio between the total installed capacity and the peak load. A low capacity margin will lead to increased revenues, signalling a need for investments in new capacity. Symmetrically, when this margin becomes high due to an excess of capacity, revenues will decrease.

Revenues are hence determined by two parameters, namely the level of installed capacity and the level of the peak load. The previous section explained how the peak load is forecast by the agents. Regarding the level of installed capacity, a simpler procedure is used. Since investment decisions are made four years ahead (because of the lead time), in year y, the installed capacity from $y+1$ to $y+3$ can

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30 The revenue curve illustrated on Figure 5 gives the annual gross margin of a newly built combustion turbine from the PJM energy market as a function of the system margin. The energy price is computed as the marginal cost of generation and reaches the price cap ($ 1 000/MWh) in periods of scarcity (which are defined according to a reliability criterion). The curve used by Hobbs et al. (2007) was computed with a simple model of the PJM market based on a predetermined generation mix and load curve. The generation mix is composed of baseload coal plants, CCGTs and combustion turbines. The load curve represents a combination of the load shapes of PJM-Eastern and PJM-Western.

be perfectly anticipated by the agents[31]. However, they cannot correctly anticipate the installed capacity from $y+4$ to $y+8$, because the corresponding investment and shutdown decisions have not been made yet. For the computation of expected revenues, it is assumed that the installed capacity during these years stays the same compared to its level in year $y+3$[32].

Combining the forecast peak load scenarios and the forecast installed capacity for years $y+4$ to $y+8$ (first five years of operation), the agents can compute a set of 6 561 forecast system margin scenarios (since the forecast installed capacity is unique, there are as many system margin scenarios as peak load scenarios). Each one of the system margin scenarios corresponds to a sequence of forecast revenues during the first five years of operation of the power plant (which can be computed thanks to the revenue curve). After the fifth year, the revenues are assumed to be constant[33] for the remaining years of the expected lifetime of the plant. This approach is consistent with the limited foresight hypothesis which is relevant in the context of electricity markets (see Hobbs et al. (2007) or Petitet et al. (2017)).

Besides, as previously mentioned, increasing O&M costs are considered. Figure 6 illustrates how O&M costs evolve depending on the age of the power plant. These costs are assumed to stay constant during the first ten years of operation before increasing exponentially to account for the fact that the plant is aging.

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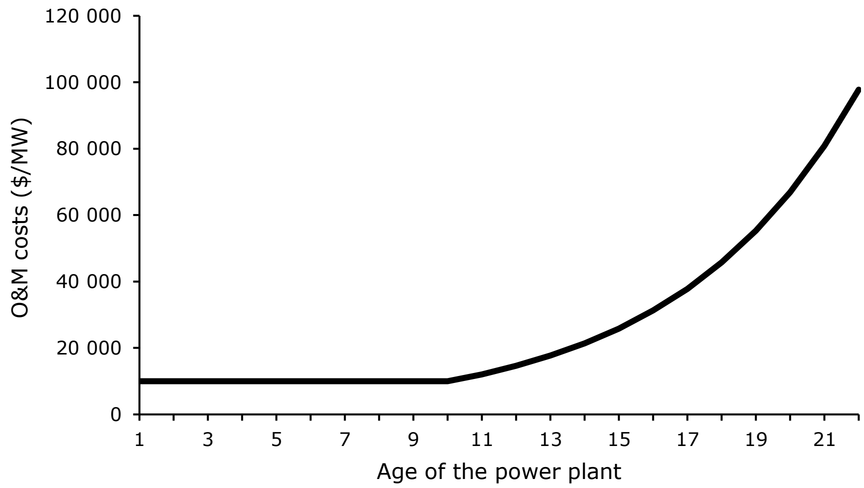
31 All previous investment decisions are assumed to be known by agents.

32 This assumption could be interpreted as if the agents consider that no investment or closure will take place between $y+3$ and $y+8$. However, given the structure of the model used in this chapter, peak load scenarios provide enough information about the uncertainty of the future system investments and margin. Considering multiple scenarios of installed capacity would complexify the model with no real added value for the conclusions. Since only the ratio between installed capacity and peak load is required for the computation of revenues, even when a single scenario of installed capacity is considered, by combining it with all the peak load scenarios, it is possible to cover a broad range of system margin scenarios. This range is not significantly modified by considering several scenarios of installed capacity.

33 The average of the forecast revenues over the first five years of operation is used.

Figure 6. **Aging curve – O&M costs**



The concept of Net Present Value (NPV) is used to assess potential investments' profitability. Based on the forecast system margin scenarios (and their corresponding revenues and costs sequences) agents compute a NPV distribution in which each system margin scenario is associated to a NPV. Then, they compute an estimated NPV which can be either the expected value of the NPV or a risk-adjusted NPV, depending on their risk preferences. The computation of these two values is described in the following section.

2.4. Modelling of risk preferences

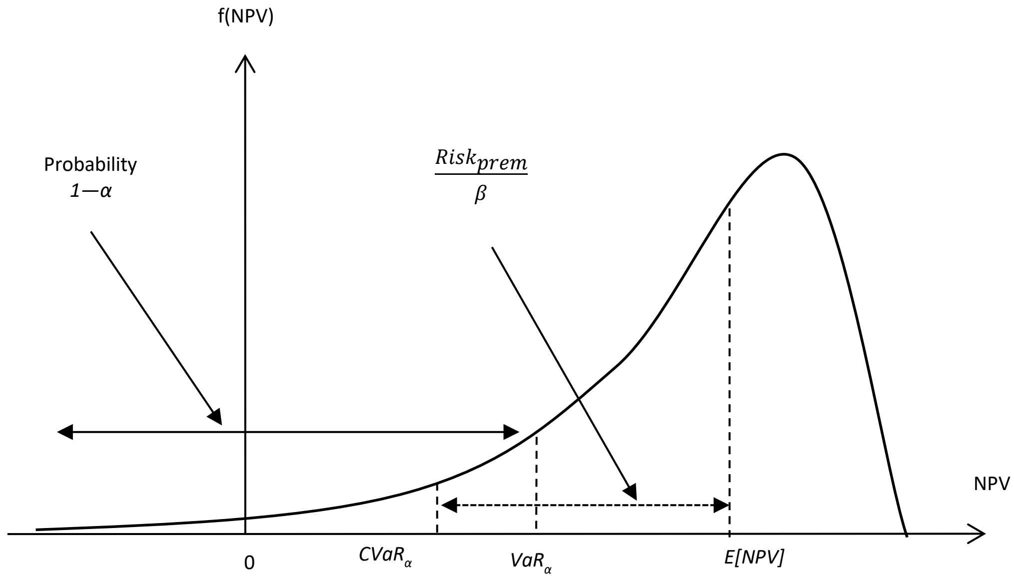
Agents are considered to be either risk averse or risk neutral. Even if both types of agents make their investment decisions based on the NPV distribution, they assess the profitability of contemplated investments differently, depending on their risk preferences.

Several approaches[34] have been introduced to measure risk in the financial and economic literature. The most prevalent ones in energy systems modelling are variance-based measures, Value at Risk (VaR) and Conditional Value at Risk (CVaR). The first one characterizes risk through the variance of a profit or loss

34 This section focuses on risk measures only. Interested readers can find a more extensive discussion on the theoretical properties of these risk measures in Emmer et al. (2015). Furthermore, a discussion on risk management approaches used by companies can be found in Deng and Oren (2006).

distribution. The last two measures (see Figure 7 for a graphical description) are more complex in terms of computation but more intuitive for interpretation than variance-based measures.

Figure 7. **Illustration of the modelling of risk aversion**



Risk measures based on variance gained a lot of interest following the major contribution of Markowitz on modern portfolio theory (Markowitz, 1952). However, one of the main drawbacks of these measures is that they fail to distinguish between negative and positive deviations from the mean of the distribution. They implicitly assume that the distribution of profits or losses is symmetrical around the mean. Yet, for an investor, what really matters is the risk of having a lower profitability than expected. Therefore, only the negative variations from the mean should be considered when assessing the risk. The semi-variance solves this issue. It is very similar to the variance but measures only the down-side risk for investors (still with the assumption of a symmetrical distribution).

VaR gives the lowest quantile of the NPV given a certain threshold α $(0 \leq \alpha \leq 1)$, while the CVaR indicates the expected value of the NPV for the cases which are below the VaR (with level of confidence α). More precisely, for a given profit distribution, the VaR corresponds to the minimum profit that can be expected with a specified confidence level. However, it does not provide any information about the cases where the profit is lower than the VaR. The CVaR overcomes this by giving an expected value of the profit in these cases (Rockafellar and Uryasev, 2000).

Furthermore, CVaR constitutes what is referred to as a coherent measure of risk in the economic and financial literature (Artzner et al., 1999). Artzner et al. (1999) laid out a set of desirable properties for a risk measure based on four axioms[35] (monotonicity, translation equivariance, subadditivity and positive homogeneity). Of all considered risk measures here, CVaR is the only coherent risk measure and this is regardless of the shape of underlying distribution.

While the aforementioned concepts provide a way to quantify risk, they do not directly model or represent risk aversion. To do so, one needs a way to convert a distribution of profits or losses into a certainty equivalent value, which represents the value of profit or loss that an agent would accept now (with certainty), rather than being subject to future uncertain realisations (these realisations may be higher or lower than the certainty equivalent). This is precisely where agents' risk aversion materialises. Indeed, the more risk averse they are, the more likely they are to accept a low certainty equivalent payoff.

In the classical expected utility framework of economic theory, risk aversion is modelled through increasing and concave utility functions (Arrow, 1971; Pratt, 1964; Von Neumann and Morgenstern, 1944). Considering increasing and concave functions means that the utility increases with the level of wealth but at a decreasing rate[36]. These functions can be based on usual mathematical functional forms such as exponential or logarithm (Arrow, 1971; Gollier, 2001). A utility function matches a certain amount of wealth (for instance the NPV of an investment) with a utility. Thanks to this, a distribution of profits or losses can be transposed into a distribution of utility. The certainty equivalent in this case is computed as the level of profit or loss corresponding to the expected value of the utility. Here, risk is implicitly measured through the difference between the

35 Appendix B provides a formal definition of these axioms.

36 In technical terms, this is equivalent to saying that the second derivative of the function is negative.

expected value of the initial distribution (in profits or losses) and the certainty equivalent.

While utility-based risk measures generally satisfy the axioms of monotonicity, translation invariance and sub-additivity, they may fail to satisfy the positive homogeneity axiom (Ben-Tal and Teboulle, 2007; Maes, 2016). Therefore, using utility functions to represent risk aversion may rely on a risk measure that is not coherent in the sense of Artzner. An alternative way of computing a certainty equivalent, using an explicit risk measure, is to adjust the expected value of distribution of profits or losses based on the measured risk level. Modelling risk aversion by the means of this alternative approach, with a coherent risk measure such as CVaR, is therefore more appropriate.

In this chapter (and the dissertation more generally), risk aversion is represented through a function which is based on the CVaR as illustrated on Figure 7. A similar modelling of risk aversion can be found in the works of Abada et al. (2019, 2017), Munoz et al. (2017) or Murphy and Smeers (2005). According to their risk preferences and based on the NPV distribution, agents use the following equations to determine the estimated NPV of a potential investment:

$$NPV_{estimated}^{risk-neutral} = E[NPV] \tag{1}$$

$$NPV_{estimated}^{risk-averse} = E[NPV] - Risk_{prem} \tag{2}$$

with $Risk_{prem} = \beta * (E[NPV] - CVaR_\alpha)$

β is a dimensionless parameter which captures the relative degree of agents' aversion ($0 \leq \beta \leq 1$[37]). The difference between the expected value of the NPV and the CVaR[38] , multiplied by β, is defined as the risk premium. Equation (2) can also be rewritten as follows:

37 There is no mathematical restriction that bounds the coefficient β in the specified interval. This interval was chosen in order to reflect a behaviour of the agents which can be consistent with reality. Choosing a negative β suggests that the agents voluntarily overestimate the profitability of their investments, which is contradictory to the risk averse hypothesis. Similarly choosing a β that is higher than 1 would reflect an extremely risk averse behaviour. Alternatively, the degree of risk aversion could also be adjusted through the coefficient α.

38 The procedure to compute the VaR and CVaR is detailed in Appendix C.

$$NPV_{estimated}^{risk-averse} = E[NPV] * (1 - \beta) + \beta * CVaR_{\alpha} \quad (3)$$

This last equation shows that the estimated NPV in the case of risk averse agents is simply a weighted average between the expected NPV and the CVaR.

2.5. Description of the studied market designs

2.5.1. Energy-only market (EOM)

In the energy-only market, producers are remunerated only through the wholesale market and ancillary services. In this market design, revenues are computed exactly as described in section 2.3. Each year, agents forecast future system margins and assess the profitability of their plants. Depending on the expected profitability, they make their investment and shutdown decisions.

Investment decisions are based on an estimated NPV, depending on the risk preference of agents. The overall level of investments to be made is a function of the estimated NPV according to a linear relationship which is illustrated by Figure 8[39]. Its parameters are taken from Hobbs et al. (2007). The capacity addition curve represents how investment attractiveness influences capacity additions. The higher the estimated NPV, the more agents find investment in new capacity attractive and hence the higher the capacity addition will be. However, due to financing and land availability constraints (Olsina et al., 2006) and because agents are aware that massive investments can ultimately diminish their revenues, a limit to capacity additions from one year to another is considered.

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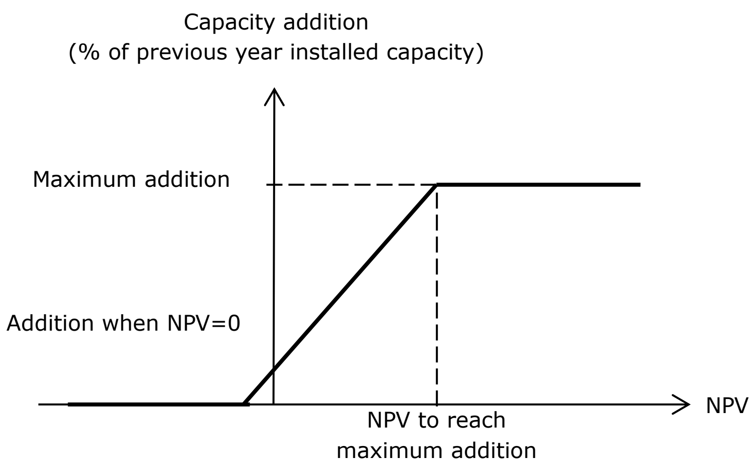
39 This approach has also been used for instance in Hary et al. (2016), Hobbs et al. (2007) and Olsina et al. (2006). While such an approach is an elegant solution for simulating a simplified short-term electricity market in a SD model, one of its limitations is that the revenue curve has a fixed shape. Therefore, it does not account for changes in the shape of the load curve (for example due to an increasing penetration of renewables or the development of demand response).

Figure 8. **Capacity addition curve**[40]



In addition to new investments, agents also have to decide four years in advance which of the existing plants should be shut down and which ones should stay online (for the next year). These decisions depend on expected operating cash flows (i.e. expected revenues minus avoidable costs, which are only O&M costs here). Expected revenues are computed as described above, while O&M costs are determined by the aging curve (see Figure 6). If the expected operating cash flows for the year of interest are negative, then the plant is shut down. Otherwise, it is kept active for one more year. As for capacity additions, the aggregate level of shutdowns in a single year is limited in the model. At the end of each year, the available capacity of the system is updated according to agents' investment and shutdown decisions.

2.5.2. Capacity market (CM)

The capacity market is different from the EOM in the sense that it provides a complementary source of revenue to agents. Indeed, in the CM, in addition to the revenues from the energy and ancillary services markets, agents receive a payment related to the capacity of their plants. As such, each installed megawatt

40 When the NPV is slightly negative, some investments may still be attractive for agents with lower financing or investment costs.

of capacity is remunerated through a capacity price resulting from a centralised auction[41].

The modelling of the capacity auction is similar to the one in (Hary et al., 2016) and (Bhagwat et al., 2017c). The auction takes place four years in advance (which is the lead time for the peak technologies considered here). The TSO assesses[42] capacity needs in four years and sets a target that corresponds to the peak load plus a security margin. This target represents the demand curve of the capacity auction (see Figure 9). As for the supply curve, it corresponds to the aggregation of agents' bids sorted in increasing order. The capacity market bids are made using a strategy that consists in balancing agents' expected revenues and their avoidable costs in year $y+4$ (considering that the auction takes place in year y).

When evaluating their expected revenues in the case of the CM, agents have to take into account the expected capacity price in year $y+4$. This price is assumed to be the same as the one in year $y+3$[43] and stay constant during the lifetime of the plant. The revenues coming from the energy market are computed exactly like they are in the case of the EOM.

Regarding avoidable costs, they vary between existing capacity and new investment: for existing capacity, they correspond to O&M costs whereas for new capacity, they also include investment costs that are still pending. The bids are constructed as follows[44]:

- For existing capacity:
    - If expected revenues from the energy market and ancillary services in year $y + 4$ cover O&M costs in that year, then the capacity market

41 This is similar to the capacity markets in PJM and the UK.

42 The TSO is assumed to know the average growth rate of the peak load, conversely to the agents who estimate it. The TSO's forecast is however not perfect since this growth rate is subject to uncertainties that the TSO cannot estimate. The TSO is assumed to be risk-neutral in the model. This assumption does not impact the main conclusions of this chapter (and the this more generally). Considering a risk averse TSO would result in higher capacity demands since the TSO would be more conservative in its forecasts.

43 Which is known because the auction already took place.

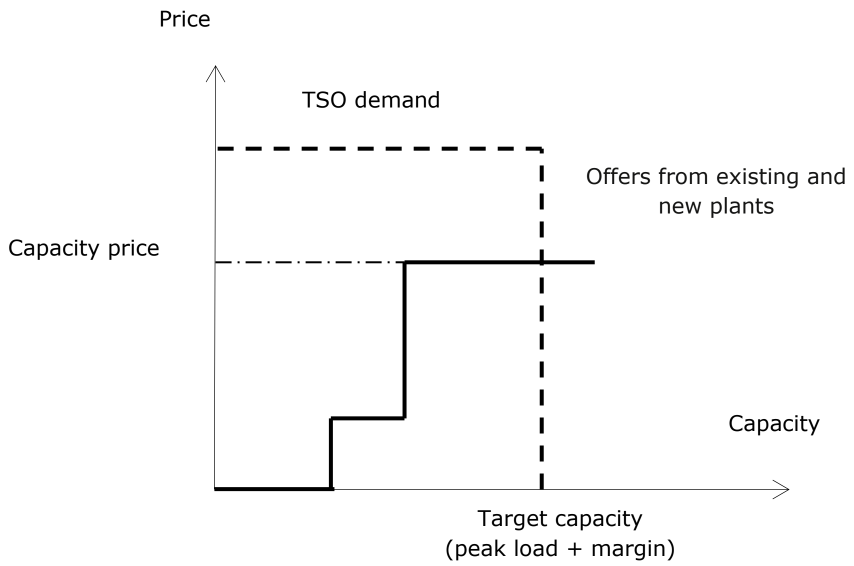
44 Strategic behaviour from agents is not considered as they make their bids only with respect to their avoidable costs.

bid is zero (no additional revenue is needed from the capacity auction to cover avoidable costs);
    - If these revenues are smaller than O&M costs, then the capacity market bid corresponds to the difference (so that avoidable costs could be recovered if the bid is accepted).
- For new capacity:
    - If the expected profitability over the lifetime of the plant (estimated NPV) computed from expected revenues from the energy market and those from the capacity auction (i.e., forecast capacity price) is positive, then the capacity market bid is zero (no additional revenue is needed from the capacity auction in order to cover avoidable costs);
    - If the expected profitability is negative (all avoidable costs are not covered), then the capacity market bid is equal to the profitability shortfall (i.e., the missing money).

Agents are assumed to bid the maximum available capacity whether it is existing or new capacity[45].

45 In the case of new capacity, the maximum capacity is determined according to Figure 8.

Figure 9. Capacity auction



In the CM, the outcome of the capacity auction determines investment and shutdown decisions. Once the bids are confronted to the capacity demand curve given by the TSO (see Figure 9), a clearing price for capacity is obtained and the accepted bids are identified. These accepted bids will translate into new investments or plants being kept active for the next year. Refused bids will lead either to plants being shut down or no investment.

2.5.3. Strategic reserve mechanism (SRM)

The strategic reserve mechanism is an alternative form of CRM. The aim of this mechanism is to ensure capacity adequacy by contracting in advance a predefined level of capacity with some existing plants that would otherwise be shut down. The reserved capacity is meant to be used only in extreme circumstances in order to deal with peak demand. The functioning of this CRM involves a central body - usually the TSO - which, based on demand forecasts, decides for a target level of strategic reserve to be purchased[46]. This is generally done through an auction. A

46 It is important to mention that there must be a limit to the total reserved capacity in order to avoid distorting the energy market. A maximum amount of reserved capacity is usually set (it can be for example defined as a percentage of the previous year installed capacity, as it is the case in the model presented here).

reserved capacity can only be activated (i.e. asked to produce electricity) upon solicitation from the TSO when the price on the short-term markets becomes higher than the maximum price it is willing to pay for energy[47]. This maximum price is most of the time equal to the price cap on the energy market. Accordingly, capacities on the energy market do not see any change in their revenues when the reserved capacities are activated because they are already selling at the price cap. This means that the revenues of the plants on the energy market can be computed using the curve illustrated on Figure 5, by simply adjusting the level of installed capacity (to subtract the reserved capacities).

An important feature of the SRM lies in the explicit distinction between the capacities in the reserve and the capacities in the energy market. Indeed, capacities are forbidden to participate in the energy market and be part of the reserve at the same time. Moreover, they are not allowed to switch from one to the other[48] (once a capacity enters the reserve, it cannot go back to the energy market). Given these restrictions, investment is likely to occur only in the energy market with unchanged incentives compared to the EOM. Therefore, the investment decision process is the same as the one presented for the EOM (only based on revenues from the energy market). Agents invest in new power plants which stay on the energy market as long as their expected revenues are high enough to cover their expected O&M costs. The distinction between the EOM and the SRM is with respect to the shutdown decisions as explained hereafter.

In the EOM, plants shut down as soon as their expected revenues do not compensate their O&M costs. In the SRM, the shutdown decision rationale is different as capacities would try to enter the reserve first, before shutting down permanently. They can do this by participating to the auction for the strategic reserve which is assumed to take place four years ahead (as for the CM). For all existing capacities on the energy market, if expected revenues are lower than

47 This is similar to the operating reserve pricing described by Stoft (2002). However, the spot market and the way the contracted reserved capacity is dispatched are not explicitly modelled here.

48 This restriction improves the credibility of the SRM and contributes to limiting the distortions in the energy market (Neuhoff et al., 2016).

projected costs, then they will bid their O&M costs[49] in the auction. As for the capacities that were already into the reserve, since they cannot go back on the energy market, their only option is to participate to the auction by bidding their O&M costs.

The supply curve of the reserve auction is thus obtained by aggregating the bids sorted from the lowest to the highest. The demand curve is modelled as a vertical curve with a reserve price cap and is determined based on the difference between the forecast peak load and the level of installed capacity in the energy market. As in the CM, an explicit target margin is set. When installed capacity on the energy market (i.e., total installed capacity minus reserved capacities) is not enough to reach the target, the TSO contracts the remaining capacities through the reserve auction. However, if installed capacity on the energy market is already larger than the target, then the TSO cannot force the excess capacity to retire. As a result, the SRM can prevent under capacity phases but can do little about overcapacity phases, as opposed to the CM which can act in both directions.

Once the auction is run, capacities with accepted bids either enter the reserve (if they are coming from the energy market) or stay in the reserve (if they were already part of it). All capacities that saw their bids rejected are permanently shut down.

49 Since capacities that are accepted in the reserve cannot participate into the energy market anymore, they need to make sure that the reserve price will cover all their O&M costs.

3. Simulations setup and indicators

3.1. Preliminary remarks on calibration and simulations

It should be noted that no back testing is carried out here, essentially because it is impossible to precisely represent historical values with this version of the model. However, the revenue curve is calibrated on historical revenues from the PJM market, although it does not provide electricity prices or other variables that can be used for back testing. Moreover, the model relies on a few exogenous curves which are partially calibrated on historical data. Furthermore, the aggregate evolution of the system margin in the model was within a realistic range, which indicates that the model performed correctly.

Another challenge in the simulations is the presentation of the results in absolute values. The model allows for the comparison of market designs without necessarily providing precise values that are consistent with a real-world system. Therefore, most of the results discussed hereafter are presented in relative levels (compared to a certain reference).

Finally, in this chapter and throughout the dissertation, although cycles are observed in the simulations, the discussion does not focus on them. This is because the issue of cycles in electricity market has already been extensively covered in the literature, so here the focus is made on other aspects that bring more added value to existing literature.

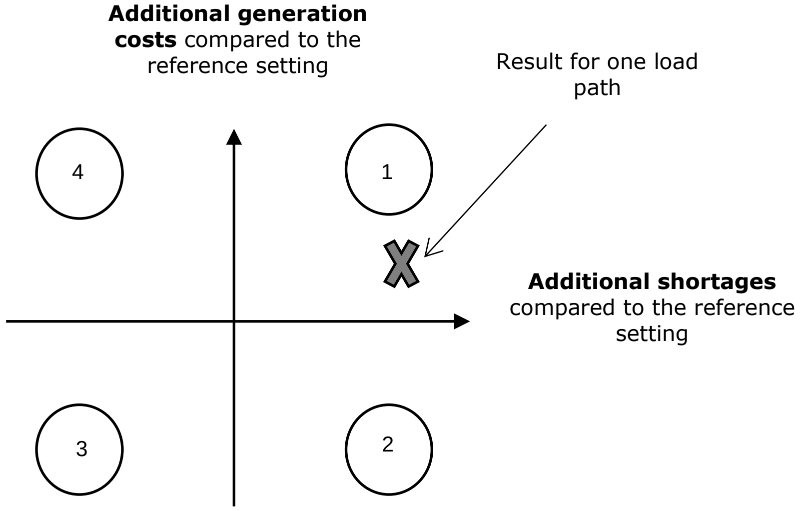
3.2. Parameters of the simulations

Simulations are run 100 times over a 40-year horizon with a randomly generated peak load path in each run. Since electricity demand is considered inelastic[50], the social welfare can be assessed through the level of shortages (proxy for reliability

50 This hypothesis may not hold in the near future with the development of smart metering and demand response. But demand response can be assimilated to a peak load capacity since adequate investments are needed for its development, despite the deployment of smart metering.

and measured as the mean curtailed demand[51] per year in % of peak load) and the total costs of generation[52] (measured in $/MW of peak load) (De Vries, 2004).

Figure 10. Interpretation of results



The results are presented on 4-quadrant graphs as illustrated on Figure 10. These graphs provide a comparison between two *settings*, each setting being defined as a combination of a specified market design (i.e., EOM, CM or SRM) and a type of agent (risk neutral or risk averse). An example of setting is: EOM with risk neutral agents.

Each cross on the graph represents the comparison of both indicators between the two settings, one of which will be chosen as a reference, for one generated load path. The X-axis shows the difference in reliability by displaying the additional[53] shortages experienced in the non-reference setting compared to the reference setting. The Y-axis displays the difference in terms of cost as the additional[54] costs

51 Shortages are considered to happen if the system margin is less than a certain threshold. This threshold is fixed to 10% in the model. Indeed, to deal with maintenance operations and outages, installed capacity has to be greater than the peak demand.

52 Both investments and maintenance costs are considered.

53 The values can be negative, indicating that the non-reference setting experiences less shortages than the reference setting.

54 The values can be negative, indicating that the non-reference setting incurs less costs than the reference setting.

incurred by the non-reference setting compared to the reference setting. To illustrate this, consider the two following settings: (A), which will be the reference, and (B). A cross in quadrant number 1 as depicted on Figure 10, means that setting (B) is less reliable and costlier than the reference setting since it leads to more shortages and generates higher costs. The main parameters and data used for the simulations are presented in Table 1.

Table 1. Variables and parameters for simulations (Chapter I)[55]

Main parameters of the model	Value
Target system margin	15% of peak load
Shortage threshold (margin below which shortages happen)	10% of peak load
Peak load growth average	1.7%
Peak load growth standard deviation	1%
Weighted Average Cost of Capital (WACC)	10%
Investments costs	$ 600 000/MW
O&M costs	See Figure 6
Risk aversion coefficient (β)	0.75
Confidence level for computation of CVaR	95 %
Forecast horizon for the peak load	4 years
Maximum capacity addition (see Figure 8)	10% (of previous year installed capacity)
NPV to reach maximum capacity addition (see Figure 8)	$ 400 000/MW
Capacity addition when NPV=0 (see Figure 8)	1.7%
Maximum capacity shutdowns	10% (of previous year installed capacity)
Price cap on capacity market	~ $ 100 000/MW (1.5X annualised cost of investment)
Price cap for reserve	~ $ 200 000/MW (3X annualised cost of investment)
Maximum amount of reserved capacity	15% (of previous year installed capacity)

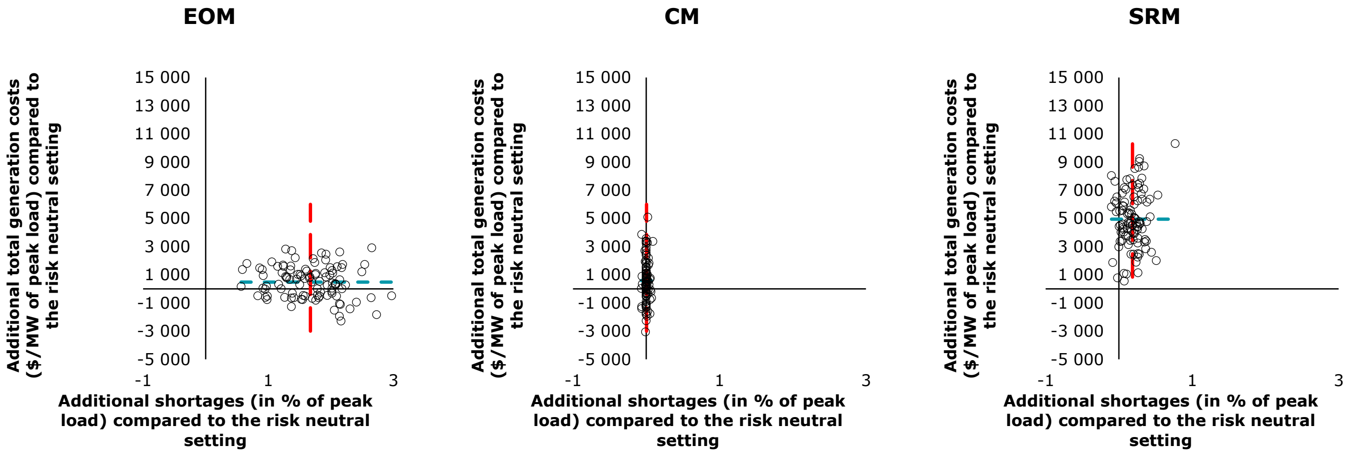
55 Some of them are based on Hary et al. (2016) and Hobbs et al. (2007).

4. Discussion on the performance of the studied market designs under different risk attitudes

4.1. Impact of risk aversion on the performances of the studied market designs

For each market design, the setting with risk aversion is compared to the one without risk aversion. The results are illustrated on Figure 11 and discussed hereafter.

Figure 11. Impact of risk aversion on the performances of the studied market designs[56]



In the case of the EOM, risk aversion tends to increase both the level of shortages[57] and generation costs, capturing two effects working in opposite directions. On the one hand, the variation in generation costs is explained by a contraction of investments related to agents' aversion. Indeed, even if the margin is tight and expected revenues on the energy market are high, the uncertainty pending on the evolution of peak load will limit or delay risk averse agents' investments, since it

[56] The red-dotted lines represent the average level of additional shortages while the blue-dotted lines correspond to the average additional generation costs.

57 On average, the system margin is lower when agents are risk averse (compared to the case where they are risk neutral).

reduces their estimated profitability. They will either invest less[58] (compared to risk neutral agents) or wait for a clearer signal (i.e., lower margin). On the other hand, since they do not invest in new plants, risk averse agents prefer keeping old and expensive power plants running. Indeed, investing in a new power plant is a more uncertain decision than keeping an existing power plant running for one more year. But O&M costs of old power plants are higher. Given the parameters used for these simulations, keeping old plants running appears to globally overweigh the reduction of investment level, resulting in a slight increase of generation costs on average.

In the CM, generation costs appear to increase slightly on average, due the explanation given above for the EOM. In a risk averse situation, bids for new investments can be higher than bids for old power plants because of a risk premium included in the bids for new investments. In that case, even if an old power plant is in effect more expensive than a new investment, it could be selected first because of its lower bid (even if it will lead to higher generation costs).

Regarding the level of shortages, the difference between the risk averse and the risk neutral cases is very small. This difference is less than 0.10% of peak load over all 100 load paths. In the CM, the target margin is almost always reached, provided that the capacity price cap is high enough[59]. This price cap could however act as a limiting factor for capacity additions if its level is too low in regard of the uncertainty faced by risk averse agents. The occurrence of such situations is the main explanation behind the difference in shortages observed between the risk averse and the risk neutral cases (as the capacity price cap is reached more often in presence of risk averse agents). It is therefore important to take this aspect into account while setting the price cap of a capacity market. According to simulations,

58 Underinvestment (compared to a risk neutral case) leads to higher prices and higher profits for electricity generators. Hence, they affect consumers in two ways: firstly, through the lack of generation adequacy and its associated social costs (costs of shortages), secondly through an increase in income transfers to the generators.

59 Risk averse agents will tend to make higher bids (compared to risk neutral agents) in the capacity auctions because of the risk premium that is taken into account when estimating the expected profitability of their investments and thus their expected shortfall. Despite these higher bids, the explicit target which is set in the auction ensures that there will be enough installed capacity, unless the bids reach the capacity price cap.

the CM appears to be less impacted by the introduction of risk aversion, compared to EOM.

Regarding the SRM, there is a noticeable increase in shortages resulting from risk aversion. This increase is rather small compared the one observed in the EOM, but higher than the one observed in the CM. The SRM seems to fall in-between the EOM and the CM in terms of resilience to risk aversion with respect to reliability, the CM being the most resilient market design. The SRM is similar to the CM in the sense that it also defines an explicit target to be reached (only for the reserved capacity). However, in a risk averse configuration, this mechanism will rely more and more on the reserve in order to restore the target margin (due to the reduced investments in the energy market).

Since there is an explicit maximum quantity of contracted reserve, this limit will impact the ability of the mechanism to reduce shortages when investments become particularly low on the energy market. Moreover, the reliability of the SRM can also be affected by its price cap on the reserve auction. As for the CM, if the price cap for contracting reserve is too low compared to the risk that is perceived by the agents (and translated in their bids), the SRM may not be effective enough (i.e., reach the target margin and thus limit shortages). According to these observations, there are two parameters that can limit the reliability of the SRM: the maximum size of the reserve and the price cap in the reserve auction. For the CM, only the price cap in the capacity auction is a limiting factor to the reliability of the mechanism. This mainly explains why the SRM appears to be less resilient than the CM with respect to reliability.

Introducing risk aversion under the SRM also leads to a significant increase in generation costs (compared to the EOM and the CM). As explained for the EOM and the CM, the overall impact of risk aversion on generation costs depends on how the decrease in investment costs (due to fewer investments) compensates the increase in O&M costs (due to older plants in the system). In the case of the SRM, the former is largely overweighed by the latter. The reason for this lies in the very functioning of the mechanism and the structure of the O&M costs. Indeed, the main aim of the SRM is to keep old power plants online, in case of extreme circumstances.

As a result, the average age of power plants under this market design is around 23 years when risk aversion is not considered and around 25 years when risk aversion is introduced[60] (the expected lifetime of power plant in the model is 20 years). In the EOM and the CM, the average age of the plants in the system varies between 20 and 22 years (depending on the risk preference assumption). Given the exponential nature of the O&M curve (see Figure 6), extending the lifetime of a power plant from 23 years to 25 induces more costs than extending it from 20 years to 22. Introducing risk aversion moves the plants of the SRM to a steeper part of the ageing curve, which explains why the additional costs of the system are higher under the SRM, compared to the EOM and the CM. It indicates that the SRM is more affected, in terms of cost, by the introduction of risk aversion[61] compared to the EOM and the CM.

4.2. Comparative analysis of the market designs in presence of risk aversion

A comparative analysis is conducted in order to confirm and complement the intuitions given by the previous observations. First, a comparison of the market designs is presented without considering risk aversion (Figure 12), then the same comparison is made but with risk averse agents this time (Figure 13).

60 The amount of reserved capacity is also higher in the risk averse situation.

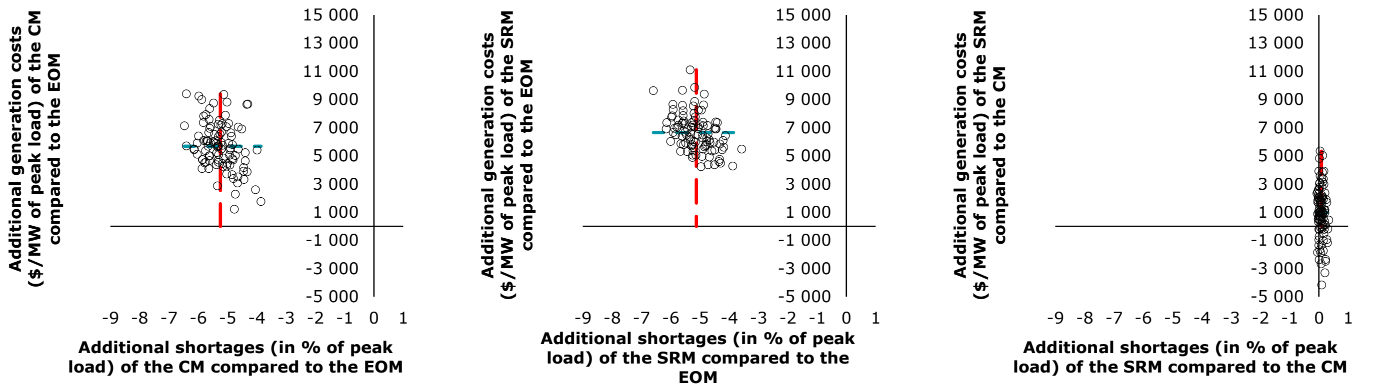
61 The magnitude of this result obviously depends on the shape of the ageing curve representing the evolution of O&M costs depending on the age of the power plants.

Figure 12. Comparative analysis of the market designs without risk aversion[62]

CM vs EOM (Agents are risk neutral in both market designs)

SRM vs EOM (Agents are risk neutral in both market designs)

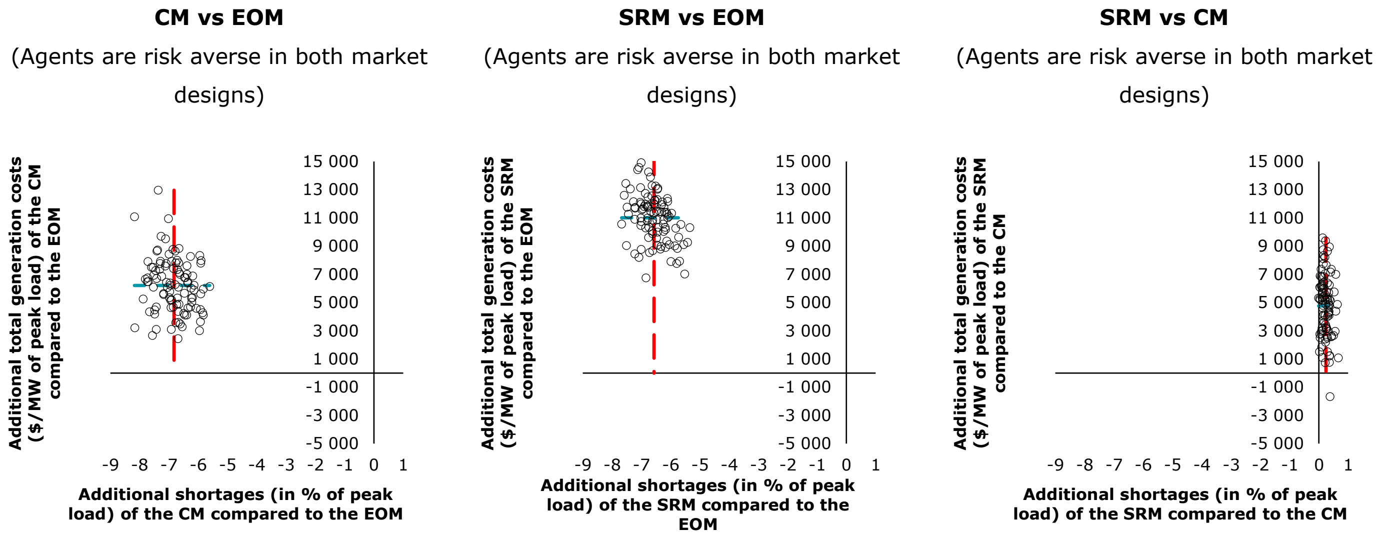
SRM vs CM (Agents are risk neutral in both market designs)



The two first graphs on the left of Figure 12 and Figure 13 show a comparison between a CM and an EOM then a SRM and an EOM. Whether risk aversion is considered or not, generation costs are higher, and shortages are significantly reduced when a CRM is implemented (be it a CM or a SRM). The second result (reduction of shortages) is the one expected as the aim of a CRM is to reduce the level of shortages. Nevertheless, the result regarding the cost of the CRMs compared to the EOM might be misleading. It is important to mention that the indicators used in this chapter do not allow for a combination of the two criteria (cost and reliability) in a unique social welfare indicator, since they are not expressed in the same units. This could be possible by assuming a level of VoLL in order to translate shortages into costs for society as it is done in the following chapters of the dissertation.

[62] The red-dotted lines represent the average level of additional shortages while the blue-dotted lines correspond to the average additional generation costs.

Figure 13. Comparative analysis of the market designs in presence of risk aversion[63]



Interestingly, the first two graphs on the left of Figure 12 and Figure 13 suggest that implementing a CRM could be even more beneficial in presence of risk averse investors, compared to a situation with risk neutral investors. Indeed, according to the simulations and the set of parameters, the gain in reliability resulting from implementing either a CM or a SRM is slightly above 5% of peak load (on average) when there is no risk aversion. If risk aversion is considered, this gain goes up to roughly 7% of the peak load (on average). As such, this can be an additional justification to the implementation of a CRM, since in a real-world environment, investors are likely to be risk averse.

The third graphs on Figure 12 and Figure 13 display a comparison between a SRM and a CM. In Figure 12 the comparison is made in a risk neutral situation. It shows that the SRM incurs slightly higher generation costs than the CM. The differences in terms of both cost and reliability between the CM and the SRM are more pronounced in the risk averse case (see Figure 13). In other words, if a CM seems preferable to a SRM in a risk neutral environment, it is even more true in a risk averse environment. These results find their explanation in the characteristics of the two CRMs.

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63 The red-dotted lines represent the average level of additional shortages while the blue-dotted lines correspond to the average additional generation costs.

As explained in the previous section, the performances of the SRM are determined by both the level of the maximum amount of reserved capacity and the price cap in the auctions for contracting reserve. As for the CM, its performances depend only on the price cap in the capacity auctions. There are therefore more chances that a SRM will fail to limit shortages compared to a CM, if their design parameters are not well defined. Moreover, in order to restore the target capacity margin, a SRM may require a lot of expensive reserved capacities which increases generation costs. In the CM, old power plants are used in a lower proportion. Therefore, the CM can reach the target margin at a lower cost, compared to the SRM which only uses old expensive plants to do so. This explains the difference of cost between the two CRMs.

5. Sensitivity analysis

In order to validate the robustness of the results presented in this chapter, a sensitivity analysis was carried out. It focuses on the parameters of the model that can have a direct impact on the results. The identified parameters are the following:

- The degree of risk aversion (β),
- The price cap on the CM,
- The price cap in the SRM,
- The maximum amount of reserved capacity,
- The lead time considered for investment and shutdown decisions,
- The maximum capacity additions and maximum shutdowns.

Table 2. Sensitivity analysis scenarios

	Degree of risk aversion (β)	Price cap on the capacity market ($/MW)	Price cap on the strategic reserve mechanism ($/MW)	Maximum amount of reserved capacity (% of previous year installed capacity)	Maximum capacity addition and maximum shutdowns (% of previous year installed capacity)	Lead time for investments and shutdowns (years)
Reference values	0.75	100 000	200 000	15%	10%	4
Alternative case 1 – Lower degree of risk aversion	**0.25**	100 000	200 000	15%	10%	4
Alternative case 2 – Higher CM price cap	0.75	**200 000**	200 000	15%	10%	4
Alternative case 3 – Higher amount of SR	0.75	100 000	200 000	**20%**	10%	4
Alternative case 4 – Higher SRM price cap	0.75	100 000	**300 000**	15%	10%	4
Alternative case 5 – Higher amount of SR and higher SRM price cap	0.75	100 000	**300 000**	**20%**	10%	4
Alternative case 6 – Shorter lead time	0.75	100 000	200 000	15%	10%	**2**
Alternative case 7 – Higher max capacity additions and shutdowns	0.75	100 000	200 000	15%	**15%**	4

Seven alternative sets of hypotheses regarding the aforementioned parameters are defined as illustrated in Table 2. The simulations are run for each market design taken individually by comparing a case with risk aversion to a case without risk aversion (as it was done in section 4.1). This is sufficient for the sensitivity analysis as the results for the individual analyses of the market designs determine the results of the comparative analyses.

Table 3. Results of the sensitivity analysis

	Market design	Mean of additional shortages due to risk aversion (% of peak load)	Standard deviation of additional shortages due to risk aversion (% of peak load)	Mean of additional generation costs due to risk aversion ($/MW of peak load)	Standard deviation of additional generation costs due to risk aversion ($/MW of peak load)
Reference values	EOM	1.583	0.448	387	1031
	CM	0.005	0.019	641	1424
	SRM	0.136	0.133	4790	1744
Alternative case 1 – Lower degree of risk aversion	EOM	0.482	0.369	157	859
	CM	0.002	0.017	324	1184
	SRM	0.050	0.084	1407	1362
Alternative case 2 – Higher CM price cap	CM	0	0.013	0	1632
Alternative case 3 – Higher amount of SR	SRM	0.043	0.094	5968	1884
Alternative case 4 – Higher SRM price cap	SRM	0.137	0.134	4989	2076
Alternative case 5 – Higher amount of SR and higher SRM price cap	SRM	0.021	0.043	6254	1991
Alternative case 6 – Shorter lead time	EOM	1.478	0.448	144	1096
	CM	0.002	0.010	341	1391
	SRM	0.814	0.556	250	1214
Alternative case 7 – Higher max capacity additions and shutdowns	EOM	1.007	0.516	- 1161	1972
	CM	0.013	0.039	- 260	2282
	SRM	0.138	0.225	1149	2616

The first row in Table 2 gives the reference values that were used in the simulations discussed in the previous sections. Alternative case 1 allows an assessment of the sensitivity to the degree of risk aversion. Alternative case 2 captures the sensitivity to the parameter of the CM, which is the price cap. Alternatives cases 3, 4 and 5 help understanding the sensitivity of the results to the two parameters of the SRM. Alternative case 6 assesses the sensitivity of the results with respect to the lead time for investment and shutdown decisions. Finally, alternative case 7 shows the influence of the maximum capacity additions (and shutdowns) on the results.

Table 3 summarises the results of the sensitivity analysis for all the alternatives cases. The sensitivity analysis globally confirms the main intuitions about the functioning of the studied market designs. It also confirms the robustness of the results discussed in section 4.

5.1. CRMs' effectiveness is constrained in face of highly risk averse agents

The first alternative case confirms the straightforward intuition that reducing the degree of risk aversion is equivalent to going towards a risk neutral situation. Indeed, for all three market designs, the additional shortages and costs related to risk aversion are significantly reduced. In the second alternative case, the impact of the price cap on the performances of the CM is very clear. By doubling this price cap (compared to its reference value in the simulations), the reliability of the market design is less impacted by the introduction of risk aversion, which is consistent with the functioning of the CM.

One can also notice that the increase in cost of the CM due to the introduction of risk aversion is less pronounced when the price cap of the capacity auction is higher. Setting the price cap of the capacity auctions at a higher level makes it possible for high bids to be accepted. Since, in a risk averse situation, these high bids generally correspond to new investments[64], this is equivalent to enabling more investments. However, building and operating a new power plant is less expensive than operating a very old one. Allowing more investments therefore contributes to reducing the total costs of generation. Thus, the impact of risk aversion on the cost of the capacity market can be reduced as well.

The three following alternative cases highlight an interesting point about the SRM. Alternative case 3 shows the clear impact of increasing the maximum amount of reserved capacity. The reliability of the mechanism is improved as it experiences

64 In the risk averse case, new investments bids might be very high because of some kind of risk premium that is included by the agents in these bids (depending on the perceived uncertainty).

less shortages. However, this comes at a higher cost of generation because more old and expensive capacities are reserved. By increasing the price cap from \$ 200 000 /MW to \$ 300 000 /MW (alternative case 4), the economic performances are barely changed. Finally, increasing both parameters of the SRM (alternative case 5) improves its reliability while increasing its cost for the same reason described above.

5.2. Lead time effects

Regarding the lead time, reducing it to two years instead of four does not change the main results of the chapter (see alternative case 6). The introduction of risk aversion still creates a negative impact on the reliability of all the studied market designs and increases the associated generation costs. Moreover, the CM is still the least impacted market design. However, the impact of risk aversion is less pronounced when the lead time is reduced. Indeed, the average levels of additional shortages and additional costs related to risk aversion are lower in the alternative case 6, compared to the reference case (in which the lead time is 4 years). With a reduced lead time, the forecast tree is narrower and thus the dispersion in the NPV distributions used in the investment procedure is reduced. The effects of risk aversion are thus mitigated since they depend on the dispersion of the NPV distributions.

5.3. Sensitivity to maximum capacity additions and maximum shutdowns

Increasing the value of the parameter related to maximum capacity additions and shutdowns from 10% to 15% (alternative case 7) means that, all things being equal, there will be more new capacities and less old capacities (as the model allows for more shutdowns). Consequently, the results regarding the impact of risk aversion on the cost of the market designs are modified according to the explanations given hereafter. Indeed, the overall impact of risk aversion on the cost of the market design depends on the difference between the reduced investment costs and the additional operation costs of older plants.

By increasing the level of maximum capacity additions, the effect of risk aversion on the level of investments is more pronounced (i.e., there will be even more investments in the risk neutral case compared to the risk averse case). Therefore, the investment costs in the risk neutral case will be even higher compared to the ones of the risk averse case. In addition to that, since the difference of age of the power plants between the risk neutral cases and the risk averse cases is smaller, the effect related to the additional operational costs is less pronounced. The combination of these two facts explains the evolution of the results regarding the costs of the market designs: the additional total generation costs due to risk aversion are less important (in the case of the EOM and CM, they even become negative, meaning that risk aversion actually leads to lower total generation costs on average).

6. Chapter conclusions

This chapter proposes an analysis of the impact of risk aversion on the performances of different capacity remuneration mechanisms (CRMs), with investors facing an uncertain peak load. Three market designs were studied for this purpose: an energy-only market (EOM), a capacity market (CM) and a strategic reserve mechanism (SRM). When comparing the three market designs, the CM seems to be the least affected by the introduction of risk aversion, both in terms of cost and reliability.

All market designs display an overall increase in generation costs when risk aversion is introduced. This increase is relatively small in the EOM and the CM, but more pronounced for the SRM. On the one hand, the introduction of risk aversion tends to limit investments and consequently reduces the associated costs. On the other hand, investors become confronted with an arbitrage between investing in a new power plant which involves a lot of uncertainties and extending the lifetime of an existing power plant which involves less uncertainty but implies higher O&M costs. They generally chose the latter. As a result, the increase in total generation costs that is observed for all three market designs can be mainly explained by the difference between the reduced investment costs and the increased O&M costs.

Regarding reliability, the results suggest that the CM and the SRM are more resilient than the EOM, with respect to risk aversion. Moreover, the CM appears to behave slightly better than the SRM, according to the simulations and the set of parameters that were used. Intuitively, this result can be explained by noticing that two parameters can limit the reliability of the SRM: the price cap and the maximum amount of reserved capacity. Even if the price cap is high enough to account for the uncertainty faced by the investors, the mechanism will fail to achieve the target margin whenever the investments in the energy-market are not sufficient enough. Indeed, the SRM does not control investments in energy market but tries to solve the capacity adequacy problem by relying only on reserved capacities. On the other hand, in the CM, the price cap is the sole parameter that may affect the reliability of the market design in situations of severe uncertainty (which lead to high bids in the capacity auction).

Looking at these results from a policy perspective, while both CRMs are able to reduce shortages, it appears, that implementing a capacity market is preferable in order to deal with the adverse effects of risk aversion. The simulations also highlight the importance of taking into account investors' behaviour in the design of the CRMs (i.e., price caps and maximum amount of reserved capacity).

Furthermore, a comparative analysis of the market designs with and without risk aversion, suggests interestingly that the benefits resulting from the implementation of a CRM are higher in presence of risk averse investors. This feature might be an additional justification to the implementation of CRMs if investors are actually risk averse. The results presented in this chapter were validated through a sensitivity analysis focusing on the most influential parameters of the model (see section 5 of this chapter).

While the model presented in this chapter is well suited to study the specific question of risk aversion and its impact on CRMs, it could be improved through the introduction of multiple technologies[65] (and not only peaking units) and a proper short-term market. The following chapter introduces these refinements. The upgraded version of the model is more suitable to tackle the research questions addressed in the next chapters. It allows a better representation of the profitability of capacity resources on energy markets through an endogenous modelling of electricity prices based on load curves and installed capacities. It therefore provides a more appropriate representation of agents' decisions and long-run dynamics.

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65 Considering several technologies with different lead times will increase the uncertainty faced by the agents, especially regarding the installed capacity, and thus their expected revenues. Since agents cannot anticipate investment decisions that have not been made yet, the technologies with the longest lead times will be more subject to forecast errors all things being equal. If this uncertainty is taken into account in the decision process of the agents, the effects of risk aversion that are highlighted in this chapter will probably be even more pronounced.

Impact of investors' risk aversion on capacity adequacy

CHAPTER II. Mothballing in power markets: conflicting private incentives and capacity adequacy objectives

Abstract

In this chapter, the potential effects of power plants mothballing on liberalised electricity systems is explored from a dynamic perspective. Mothballing consists of a temporary closure of power plants in situations of difficult economic conditions. Its main objective is to protect power plants owners against expected losses while giving them the option to reactivate their plants if market conditions improve. Therefore, it provides an interesting flexibility compared to a permanent shut down. A methodology for the integration of mothballing decisions in long-term simulation models using the System Dynamics approach is developed. Based on this methodology, two market designs are analysed: an energy-only market and a capacity market.

The chapter is composed of six sections, following a similar structure to the preceding chapter. Section 1 sets up the context and the motivation behind the research question. Section 2 presents the modelling adjustments introduced to study mothballing decisions. Section 3 describes the approach for simulations. Section 4 discusses the results for energy-only markets while section 5 covers capacity markets. Conclusions are summarised in section 6. Earlier versions of this chapter were published in two conference papers[66].

66 Abani, A.O., Hary, N., Rious, V., Saguan, M., 2017. Considering power plants mothballing in long-term simulation models for liberalized power markets, in: 2017 14th International Conference on the European Energy Market (EEM).

Abani, A., Hary, N., Saguan, M., Rious, Vincent, 2017. Effects of power plant mothballing decisions on system reliability and generation adequacy, in: 2017 15th IAEE European Conference, Heading Towards Sustainable Energy Systems: Evolution or Revolution? International Association for Energy Economics.

Résumé en français

Dans ce chapitre, les effets potentiels de la mise sous cocon de moyens de production dans les marchés libéralisés sont examinés d'un point de vue dynamique. La mise sous cocon consiste en l'arrêt temporaire de moyens de production dans un contexte de conditions économiques difficiles. Son principal objectif est de protéger les investisseurs contre d'éventuelles pertes tout en leur donnant la possibilité de réactiver leurs moyens de production si les conditions du marché s'améliorent. Par conséquent, elle offre une flexibilité intéressante par rapport à un arrêt définitif. Une méthodologie d'intégration de ces décisions dans des modèles de simulation de long terme est proposée. Sur la base de cette méthodologie, deux architectures de marché sont analysées : un marché basé uniquement sur la rémunération de l'énergie (*energy-only*) et un marché de capacité.

Le chapitre est composé de six sections, suivant une structure similaire à celle du chapitre précédent. La section 1 introduit le contexte de la question de recherche. La section 2 présente les ajustements de modélisation nécessaires à l'étude des décisions de mise sous cocon. La section 3 décrit l'approche utilisée pour les simulations. La section 4 analyse les résultats pour le marché basé uniquement sur la rémunération de l'énergie tandis que la section 5 analyse les marchés de capacité. Les conclusions sont résumées dans la section 6.

Contents of Chapter II

1. Introduction

1.1. Context and motivation

A multitude of early retirements and mothballings (i.e., temporary shutdown with possibility to re-enter the market) of thermal generation units has been observed recently in Europe (Caldecott et al., 2014). Arguing that revenues from the energy markets are not sufficient to ensure the economic viability of some of their generation assets, utilities decided to temporarily remove these assets from the market. Between 2012 and 2014, mothballing concerned more than 10 GW of installed capacity in Europe according to several reports and studies (EY, 2014; Caldecott et al., 2014; Eurelectric, 2016; Tennet, 2014; RTE, 2014; Credit Suisse, 2012). In a report dating from December 2016, EURELECTRIC (2016) estimated that the total mothballed capacity in 2015 still represented more than 7 GW, including 1 GW of oil-fired plants, 4.5 GW of gas-fired plants and 1.8 GW of coal plants.

This situation results from a combination of several factors, in particular a stagnation (and sometimes even a decrease) in the overall energy demand, a situation of overcapacity and the impact of the increasing penetration of renewable energy sources (RES). RES generation reduces even more the residual electricity demand and also decreases electricity prices due to the merit order effect (Sensfuß et al., 2008). This led to persistently low wholesale electricity prices and reduced capacity factors for thermal plants, which consequently resulted in a degraded profitability[67] of these plants.

Given such a context, it is understandable from a private perspective to shut down or mothball uneconomic assets and delay investments. In this regard, mothballing is particularly interesting for power plants owners as it enables them to limit their exposure to anticipated losses by avoiding high O&M costs which might otherwise not be covered by their revenues. Moreover, unlike a shutdown decision,

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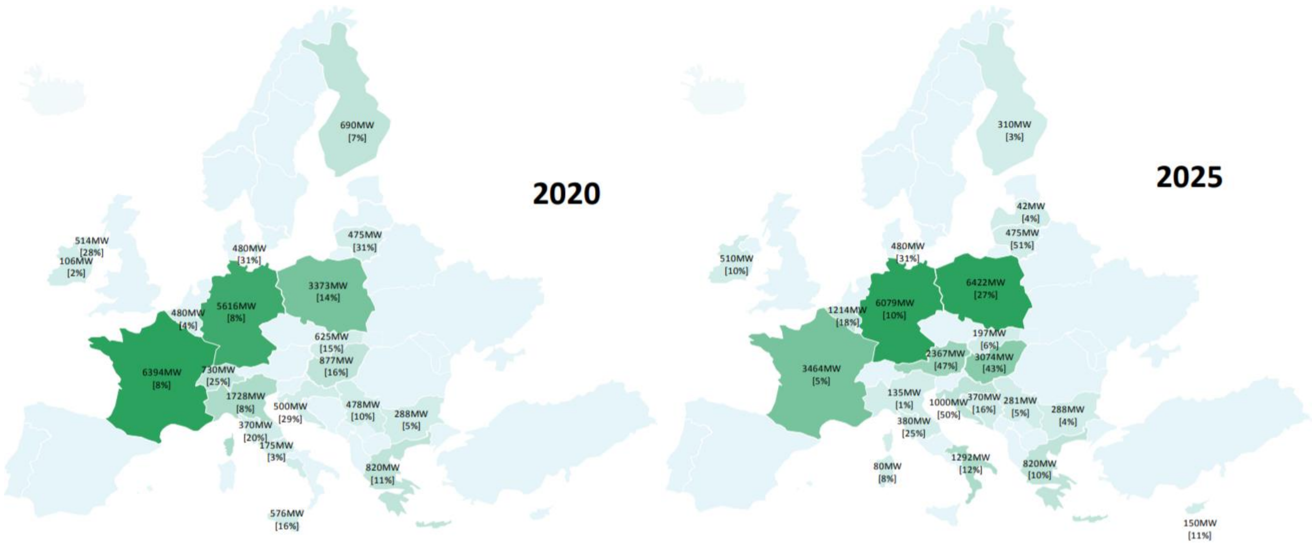
67 In some countries, part of the mothballing decisions was due to environmental restrictions. In Germany and the UK for instance, numerous highly polluting coal and lignite power plants were mothballed with plans of permanent shutdown in the future, regardless of market conditions.

mothballing allows generation assets to come back to the market if the conditions improve. The decision to mothball however entails mothballing and restart costs (in case the plant is brought back online). Therefore, this decision is a result of an arbitrage between the costs associated with mothballing and avoided losses resulting from it. There are various types of mothballing in practice, depending on the duration of the mothballing and the required measures to preserve the plant. Without getting into the technical aspects, these types can be regrouped in two categories[68]: short-term or light mothballing (3-12 months) and long-term or deep mothballing (more than 12 months).

Mothballing decisions have a direct impact in terms of security of supply. Firstly, these decisions might threaten capacity adequacy objectives because they reduce the level of available capacity. Secondly, they also affect system reliability because the plants that are being prematurely shut down or mothballed are generally some of the most flexible ones, which are much needed to cope with the variability of RES. Policymakers are concerned that the recent wave of mothballing may not be just episodical. In the future configuration of power systems with high shares of renewables, mothballing may become a recurrent phenomenon. A recent adequacy report from ENSTOE highlights this point as illustrated on Figure 14. The figure indicates the amount of capacity at risk of being mothballed in 2020 and 2025 based on forecasts from transmission system operators (TSOs). It shows that in countries like France, Germany and Poland, several gigawatts of capacities are at risk of being mothballed in the future. In Poland, almost 30% of installed capacity is at risk of being mothballed in 2025 according to the report.

68 Interested readers can find more details in Frontier Economics (2015a).

Figure 14. Generation capacity at risk of being mothballed in 2020 and 2025 according to data collected by ENTSOE[69]



Considering all types of strategies from market participants is therefore of crucial importance in adequacy assessments of future power systems. The models used for these assessments should account for potential mothballing decisions, in addition to investments and shutdowns which are traditionally examined. When mothballing decisions are not represented, models can wrongly consider that plants are either active or shut down while they might be mothballed in reality. In the first case, the model overestimates the actual system margin and in the second case, it gives a distorted investment signal. Neglecting mothballing decisions may therefore lead incorrect conclusions and/or inappropriate policy choices.

1.2. Power plant mothballing in the literature

As mentioned above, mothballing has been largely overlooked in the literature as most studies simply elude this type of decision and focus exclusively on investment and shutdown decisions. The studies addressing the topic use a variety of methods

69 Absolute MW and relative % of the 2020 (respectively 2025) total thermal generation capacity. See ENTSOE (2017) for more details.

to analyse impacts of mothballings in liberalised power markets. Here, a few studies that are particularly relevant to the research question addressed in this chapter are highlighted.

Takashima et al. (2008) analysed entry strategies into an electricity market for nuclear and thermal power plants with a real-option approach. Their results highlight the importance of mothballing in the strategies adopted for each technology. They show that the operational flexibility associated with mothballing gives gas-fired plants a competitive advantage over nuclear plants in periods of high price volatility and moderate demand growth rate.

In a similar work, Lambin (2016) develops a real-option game theoretic model to quantify the effects of mothballing from a strategic perspective. His results suggest that mothballing can be used as a predatory strategy to force competitors' early exit from the market. In his model, Lambin assumes that mothballing is not available to all firms so that those firms with the option to mothball see their value increase. In a context of continuous attrition of demand, firms which have the possibility to mothball will do so and wait until other firms which cannot mothball exit the market. The underlying rationale is that the mothballed assets represent a threat to the latter firms' potential profits because they can re-enter the market at any given point if there is an opportunity to make some profits. Since firms that cannot mothball cannot sustain losses indefinitely, they eventually exit the market.

Frontier Economics (2015b) uses an optimisation model to assess the potential developments of the Dutch electricity system from 2015 to 2035 in the context of energy transition. Their model integrates the possibility of mothballing power plants and computes the outcome of the Dutch electricity market (installed capacities, prices, etc.) when the total costs of electricity provision are minimised on a European level. Their results indicate some mothballings of conventional plants in the Netherlands in the short term (2015 to 2019).

Although the studies described above provide interesting insights on the effects of mothballing decisions, they do it from an equilibrium perspective. They do not capture the dynamic effects of mothballing which are yet important from a policy point of view. The literature on mothballing decisions in dynamic simulation models is almost non-existent. The only related studies[70] are those of Arango et al. (2013) and Harthan (2014).

Arango et al. (2013) assess the impact of mothballing decisions on a power system by using experimental economics. They consider a symmetrical Cournot model with five players and no collusive behaviour. The experiment is then run with a control group which do not have the possibility to mothball and a treatment group to whom mothballing is made available. These groups are then invited to participate in an electricity market where they make investment, shutdown and mothballing decisions (when applicable). One of their main results is that mothballing leads to higher electricity prices on average even though they dampen investment cycles.

Harthan (2014) develops a simulation model including mothballing decisions but these decisions are not associated with any costs. In his model, mothballing occurs only when fixed costs are not covered, and the technical lifetime is not reached yet. Power plants cannot decide to stay active if situations of dreary revenues appear, whereas in practice, utilities face an actual arbitrage between staying active (despite incurring losses) and mothballing their plants (which limits the operational expenditures but do not provide any revenues). Therefore, Harthan (2014) does not represent the full extent of the arbitrage utilities have to make.

1.3. Research question

This chapter of the dissertation aims at reducing the existing gap in the literature on power plant mothballing. It proposes a detailed analysis of the behaviour of an energy-only market and a capacity market in presence of mothballing decisions and highlight a number of insights that can inform policy making. The focus is made on these two market designs to represent the two main paradigms for electricity markets (i.e, an energy-only vision and a CRM vision). Strategic

70 The only other work on simulation models that mentions mothballing is the one by Petitet (2016). This study does not explicitly model mothballing decisions but provides a methodology for their consideration in the computation of the bids in a capacity market.

reserves are not covered in this chapter because they are assumed to behave like energy-only markets with respect to mothballing incentives. Indeed, since strategic reserves – in the way they are represented in this dissertation – are here only to avoid permanent shutdowns, they do not change the decision to mothball an asset, compared to an energy-only market[71].

The underlying analysis is based on a Monte Carlo approach applied to a simulation model, which endogenously represents all investment, mothballing and shutdown decisions in a liberalised electricity market. The model presented in this chapter corresponds to an extension of the one introduced in the previous chapter (using the System Dynamics framework). To properly capture the effect of mothballing, two power system settings are compared: a system in which agents cannot mothball their plants and one in which mothballing is an available strategy. These systems present identical initial conditions and differ only by the presence or absence of mothballing. All differences observed between the systems are therefore consequences of mothballing. The discussion focuses on the impact of mothballing in terms of investment/shutdown dynamics, security of supply (measured through shortages) and electricity prices[72].

This chapter contributes to the existing literature in three regards. Firstly, this study is one of the few (if not the first) to propose a simulation model based on System Dynamics, which fully endogenizes all types of decisions, including mothballing. Secondly, the discussion points out some limitations of energy-only market that are new in the literature on market designs for capacity adequacy. One particularly important caveat of energy-only markets relates to their behaviour when scarcity pricing (i.e., increasing the price cap to the VoLL) is applied in presence of mothballing. While this market architecture is argued to be a valid alternative to CRMs for the provision of long-term security of supply, it is showed that its performances can be significantly affected in a world of high uncertainty and the possibility to mothball. Thirdly, the analysis indicates that

71However, a strategic reserve mechanism will still provide a better security of supply than an energy-only market, all things being equal.

[72] Capacity prices are also analysed in the case of the capacity market.

capacity markets can realign private investors' incentives to mothball and capacity adequacy objectives.

The chapter is organised as follows: section 2 presents the modelling framework. section 3 introduces the set up for the simulations. Sections 4 and 5 discuss the results and section 6 provides a summary of the main conclusions.

2. A multi-technology model to better capture long-term dynamics

The modelling work carried out in this dissertation was done through an iterative approach as explained in the general introduction. The single technology model presented in the previous chapter is suitable enough to study the impact of risk aversion on the performance of CRMs. However, to properly capture agents' arbitrage about shutting down, mothballing or maintaining their assets online, some improvements are required. This section introduces an upgraded version of the single-technology model, considering these improvements.

The new version presents three important additional features. Firstly, the model can now accommodate multiple technologies and electricity prices are explicitly computed through a short-term market. This is a more realistic representation of the short-term market, which makes it possible to assess the profitability of each technology in order to better understand investment dynamics.

Secondly, capacity additions in the energy market are no longer dependent on a parametrised curve. They are rather determined by a stylised algorithm which endogenously determines aggregate investments based on agents' forecasts. The algorithm accounts for the lumpiness of investments, which is another refinement compared to the previous version of the model. To do so, a standard, indivisible unit size is associated to each technology based on current technology characteristics. The new version of the model can therefore capture the effects related to capacity lumpiness, which is an important aspect of the power sector industry as discussed in the general introduction.

Thirdly, mothballing decisions are now represented in addition to the traditional investment and shutdown decisions. This is the most significant change to the previous version of the model. In this chapter, a detailed rationale for mothballing decisions is developed, highlighting the arbitrage that a power plant owner may face in periods of gloomy market conditions.

For simplicity and readability, the whole modelling framework is presented, even for the modules of the model which remain unchanged. For instance, the sections related to the modelling of uncertainties, agents' forecasts and their risk preferences are similar to those outlined in the previous chapter. The reader may skim through these sections if she has already read the corresponding parts in Chapter I.

2.1. General description

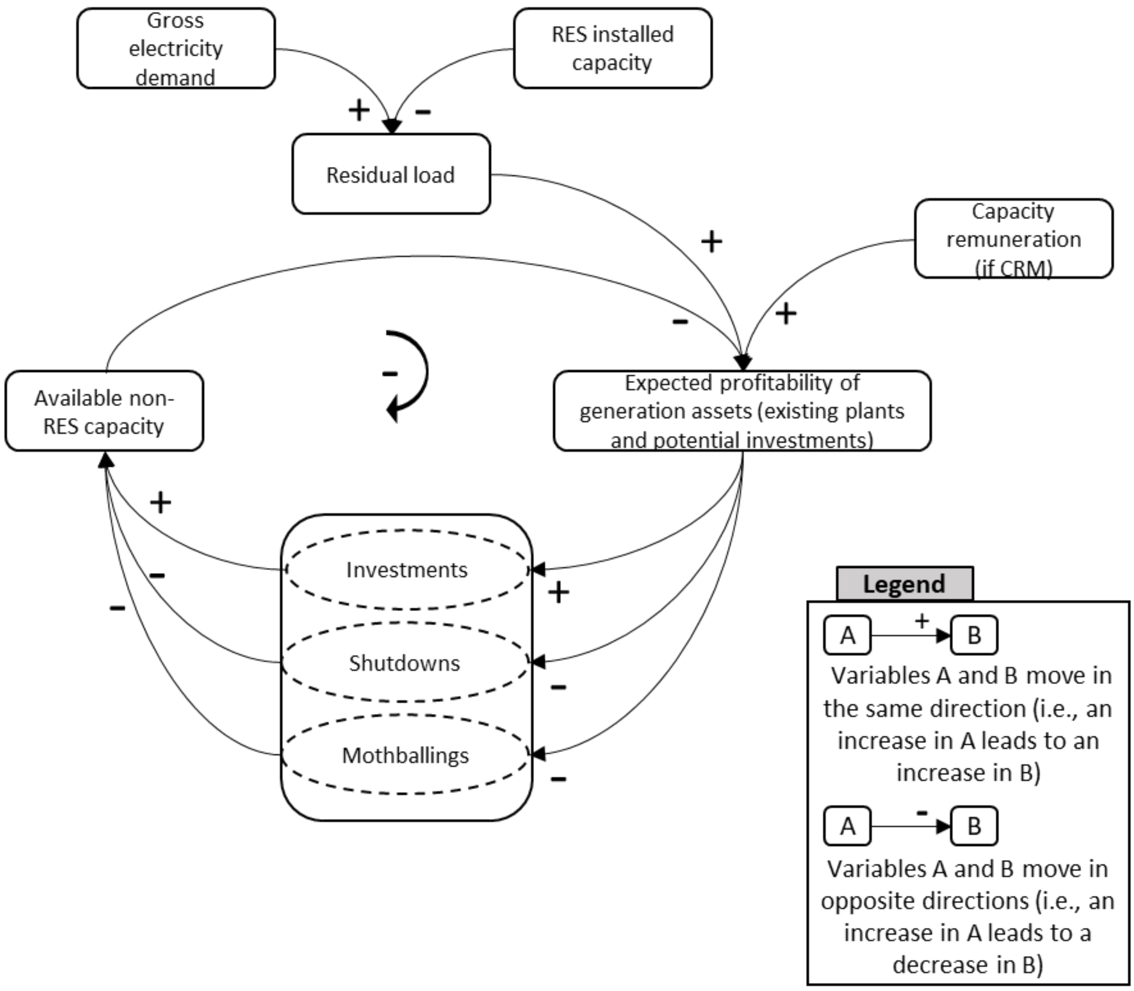
2.1.1. Structure

Figure 15 hereafter illustrates the general functioning of new version of the model by the means of a causal loop diagram. It shows the interactions between the main variables while highlighting the cyclical structure of the model illustrated though a negative feedback loop[73]. The relationship between two variables is represented by an arrow going from a variable (A) to another variable (B). The (+) and (—) symbols associated with the arrows describe the nature of the relationship between the variables. A (+) symbol means that the variables change in the same direction. For instance, an increase in the variable (A) results in an increase in the variable (B). Conversely, the symbol (—) means that the variables change in opposite directions. The model runs repeatedly on a yearly basis through the following steps:

- Agents first assess the profitability of their existing plants and potential investments based on forecasts about installed capacity and residual load;
- Depending on the anticipated profitability of the plants (existing and new), they make their mothballing, shutdown and investment decisions;
- These decisions are then used to update the available installed capacity;
- Finally, the available capacity and the residual load will determine the system margin and agents' actual profits.

73 A negative feedback loop indicates a balancing behaviour, suggesting that the system may reach an equilibrium.

Figure 15. Causal loop diagram of the model



Agents' decisions (investment, mothballing and shutdown) concern thermal generation technologies[74] such as Nuclear, Coal, CCGT and gas-fired CT. Each technology has a specific lead time for construction which is taken into account. The installed capacity of RES is determined exogenously based on existing public policies and plugged into the model. Finally, increasing O&M costs are modelled to represent the aging of power plants.

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74 The model can accommodate as many technologies as desired. For instance, even if demand response resources are not presented here, they can easily be included in the model as a technology with low investment costs and high variable costs.

2.1.2. Short-term energy market

Electricity prices are computed thanks to a dispatch algorithm, which represents the short-term market. For simplicity, no technical constraints are considered, except for plants' maximum generation capacity. Prices are thus determined, for every time step[75] in a year, by the variable cost of the last generation unit used in the merit order. During scarcity periods (i.e., when the demand for electricity exceeds the total generation capacity), prices hit the price cap of the energy market. Revenues from ancillary services are not considered because they are assumed to have little influence on plants' profitability given the technologies that are considered[76]. Moreover, electricity demand is assumed to be inelastic on the short-term market[77]. For a specific plant p, the revenue and profit from the energy market in year y can be computed using the following equations:

$$R_{p,y}^{EM} = \sum_{h} \left(p_{y,h}^{EM} - VC_{p,y}\right) * g_{p,y,h} \tag{4}$$

$$\pi_{p,y}^{EM} = R_{p,y}^{EM} - OMC_{p,y} \tag{5}$$

Where:

- $R_{p,y}^{EM}$ is the gross profit from the energy market corresponding to the difference between revenues from energy sales and variable generation costs for plant p in year y;
- $\pi_{p,y}^{EM}$ is the profit from the energy market after deduction of fixed O&M costs, for plant p in year y;
- $p_{y,h}^{EM}$ is the electricity price in hour h of year y;
- $VC_{p,y}$ is the variable cost of plant p in year y;
- $g_{p,y,h}$ is the generated electricity by plant p in hour h of the year y.

75 Each year could be decomposed in several time steps, up to an hourly resolution.

76 This may not be true for other types of technologies such as demand response or storage, which are not considered here.

77 In rigorous terms, the demand is considered perfectly inelastic (i.e. vertical) when the electricity price is lower than the VoLL and perfectly elastic (i.e., horizontal) when the electricity price reaches the VoLL.

2.1.3. Uncertainties and agents' forecasts

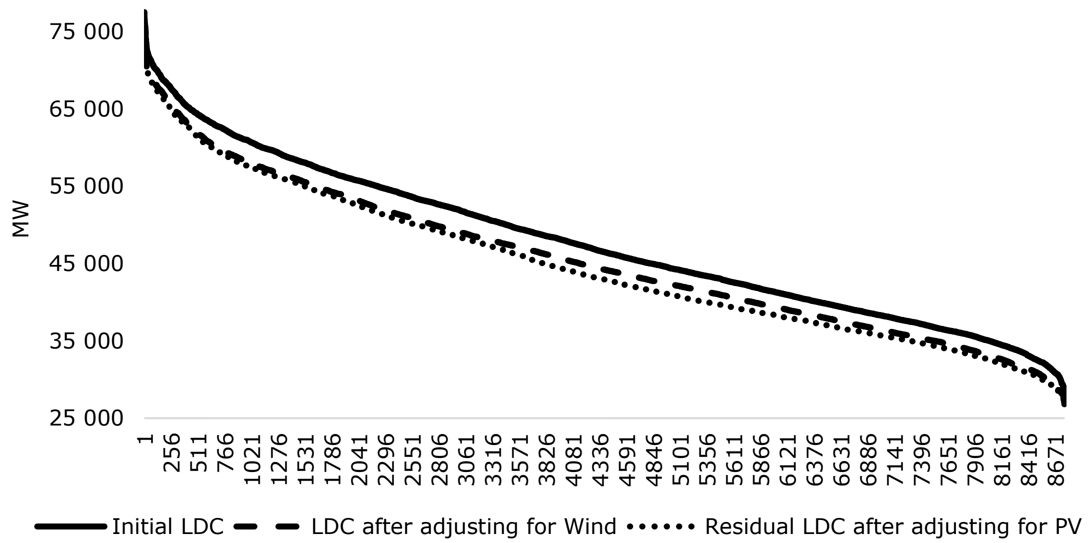
There are two sources of uncertainties in the model, namely the residual load and the installed capacity (for thermal technologies). Compared to the version presented in Chapter I, the level of installed capacity is now more uncertain because of the different lead times between technologies. Agents need to forecast both the residual load and the level of thermal capacity (by technology) in order to make their decisions. All forecasts are made over a finite horizon $h_{forecast}$ to represent a myopic foresight from agents[78]. Such an assumption is fairly consistent with real investment processes in liberalised electricity markets (De Vries and Heijnen, 2008; Hary et al., 2016; Olsina et al., 2006; Petitet et al., 2017).

In all subsequent simulations, the forecast horizon of the model is set to eight years to limit the computation time within a reasonable range while ensuring that agents do not lack to much information. The myopic foresight assumption also applies to the anticipated trajectory of RES capacity used by agents to estimate the residual load. While assessing the profitability of their assets to inform any investment, mothballing or shutdown decision, agents are only aware of the RES capacity that will be added to the system over the forecast horizon $h_{forecast}$.

The residual load is represented by a load duration curve resulting from gross electricity demand and generation from RES (wind and solar PV in this case). The peak gross demand grows at a random rate following a normal distribution representing uncertainties about economic and weather conditions (Bhagwat et al., 2017a, 2016b; De Vries and Heijnen, 2008; Hasani and Hosseini, 2011; Hobbs et al., 2007). Generation from RES is determined directly from the level of RES installed capacity and historical capacity factors of RES. Figure 16 below illustrates how the residual load is computed for a specific year.

78 Limiting the forecast horizon also improves the computational tractability of the model.

Figure 16. Impact of RES generation on residual load[79]



Agents forecast the residual load with a similar method to the one described in the previous chapter. They use a backward-looking strategy, based on the past evolution of the peak gross load over a predefined period[80] to draw a scenario tree of possible future peak load values (see Figure 17 hereafter). Every year, agents compute an evolution vector containing the average, the minimum and the maximum growth rates of the peak gross demand over the selected period. The scenario tree is constructed by exploring the possible combinations of growth rates for the years to come, up to the limit of the forecast horizon. It is computed by iteration from one year to the next one by extending each of the forecast values of the year of interest in three new values, thanks to the evolution vector. To better illustrate the forecast logic, let us consider that X is one of the forecast values of the peak load in year $y+1$. This will result in three new forecast values in year $y+2$, corresponding to a maximum, average, and minimum evolution scenario.

79 Based on load data for France in 2015. Installed capacities of wind and solar in 2015 represented about 10 GW and 6 GW respectively. Hydropower generation is deducted from all LDCs and considered constant in the model. Furthermore, cross-border exchanges are not represented.

80 For consistency, this period is the same as the forecast horizon (8 years).

Considering a technology which has a lead time of four years and assuming a forecast horizon of eight years, the scenario tree will cover the following years: four years of lead time which goes from year y (year of the decision) to year $y+4$ (first year of operation), and four additional years going from $y+5$ to $y+8$. Figure 17 depicts the forecast process for a portion of the scenario tree[81]. For years $y+1$ to $y+4$, corresponding to the considered lead time in the illustration, only the case related to a series of maximum growth rate is represented on the figure[82]. For the last years of the forecast horizon ($y+4$ to $y+8$) which correspond to the first five years of operation of the power plant, the figure shows the different peak load scenarios.

The complete load profile is obtained by scaling up the previous year's gross LDC according to the forecast scenarios of peak load and by adjusting for RES generation (given the anticipated deployment of RES capacity). To limit the computation time, the residual load forecasts are made by considering a simplified LDC composed of 10 segments[83]. In total, given the forecast horizon of 8 years, there are 6 561 possible LDC scenarios[84].

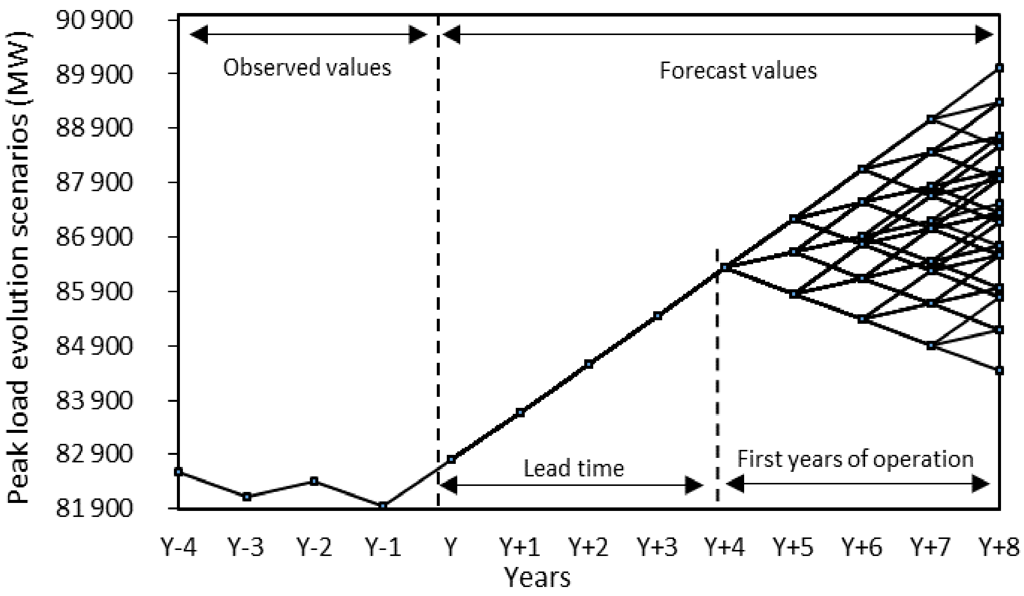
81 Only a portion of the scenario tree is represented on the figure for reasons of simplicity and readability.

82 In the model, all the combinations are computed.

83 This approach has been used in other studies such as Bhagwat et al. (2017c) or Hasani and Hosseini (2011) for example. In this model, the highest LDC segment is represented with an hourly granularity to properly capture peak load hours which are crucial for plants' profitability. An illustration of this is provided in Appendix E.

84 The number of total scenarios is $3^8 = 6561$. All the scenarios are assumed to have the same probability. In the simulations presented in sections 4 and 5, only the envelope (i.e., extreme scenarios and some in the middle) of the scenarios is considered to reduce computation time. This simplification may lead to a slight overestimation of risk but does not change the modelling conclusions.

Figure 17. Forecast of peak load scenarios

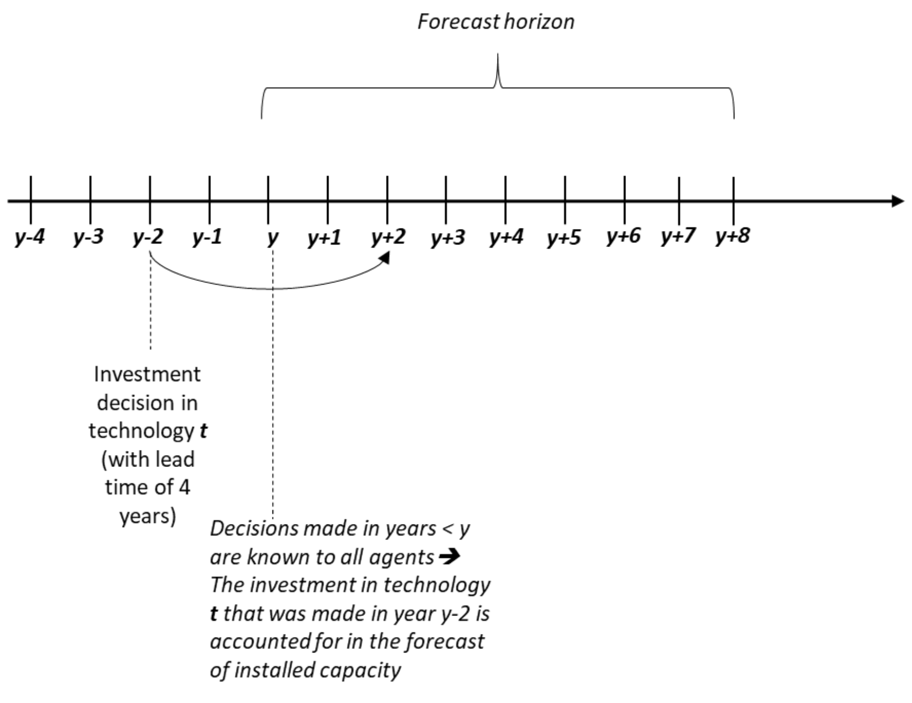


Regarding the forecast of thermal installed capacity, agents use the latest information available. The uncertainty related to this parameter is inherent to the differences in lead times among the technologies. Agents are assumed to be aware of all previous investment, mothballing and shutdown decisions that have already been made but they cannot anticipate decisions to come. They are also assumed to be conservative regarding mothballed capacities as they consider in their forecast that these capacities will come back on the market in year $y + 1$. Figure 18 illustrates the forecast procedure for installed capacity. Unlike the residual LDC, only one scenario of installed capacity is considered. However, the combination of this single scenario with those of the residual LDC provide sufficient information to apprehend the uncertainty faced by the agents.

Based on their forecasts, agents assess the profitability of their existing assets and potential investments. In order to make any investment, mothballing or shutdown decision, they have to compute the expected revenues and costs of their existing assets and potential investments. The precise computation of these revenues and costs is detailed later for each market design.

The concepts of Present Value[85] (PV) and Profitability Index (PI) are used for the profitability assessment, whether it is for potential investments or existing assets. The profitability Index is only used for investment decisions. It is defined here as the annualised NPV of an investment over the expected lifetime of the asset. Based on their forecasts, agents compute a PV distribution in which each PV corresponds to a specific residual LDC scenario (combined with the single installed capacity scenario). They will then compute an estimated PV which can be either the expected value of the PV or a risk-adjusted PV, depending on their risk preferences. The computation of these two values is described in the following section. For investment decisions, the PV is transformed in a Net Present Value (NPV) by subtracting the initial overnight investment cost.

Figure 18. Forecast of installed capacity



Finally, it should be noted that investment decisions require forecast values of cash flows (expected revenues minus costs) over the lifetime of assets, which is most of the time longer than the forecast horizon $h_{forecast}$. To deal with this, agents

85 The present value of an asset is the sum of the discounted future cash flows generated by the asset. Alternatively, the Net Present Value (NPV) is the PV minus the initial investment cost, in cases where the asset is a new plant which requires an initial investment.

assume that the system reaches a steady state beyond $h_{forecast}$. In concrete terms, it means that for each combination of residual LDC scenario and installed capacity scenario projected over $h_{forecast}$, a constant normative cash flow is considered beyond $h_{forecast}$. This normative cash flow is equal to the average of the cash flows computed over the forecast horizon $h_{forecast}$. Here, assuming myopic foresight has crucial implications for agents' anticipations regarding the deployment of RES capacities (which is used for the determination of residual LDC scenarios). Depending on the actual trajectory of RES capacity additions, agents may end up underestimating or overestimating the amount of RES in the system, which have consequences in terms of *ex post* profitability of their investments. Such behaviours have been observed over the past decade[86] and are fully captured in the model.

2.1.4. Modelling of risk preferences

As explained in the previous section, even if both risk averse and risk neutral agents make their decisions based on a PV distribution (or NPV distribution for investments[87]), they assess the profitability of the contemplated investments differently, depending on their risk preferences.

The modelling of risk preferences presented in the previous chapter is applied (see section 2.4 of chapter I). Risk aversion is modelled through the computation of the Conditional Value at Risk as illustrated on Figure 19. According to their risk preferences and based on the PV distribution, agents use the following equations to determine the estimated PV of a potential investment:

$$PV^{RN}_{estimated} = E[PV] \tag{6}$$

$$PV^{RA}_{estimated} = E[PV] - Risk_{prem} \tag{7}$$

86 Several studies show that investors and international institutions have significantly underestimated the magnitude of RES deployment in power systems around the world (Al Irsyad et al., 2019; Metayer et al., 2015).
87 The investment cost being fixed, it does not affect the shape of the distribution. In the rest of this section, the discussion is centred on the PV distribution but is equivalent for an NPV distribution.

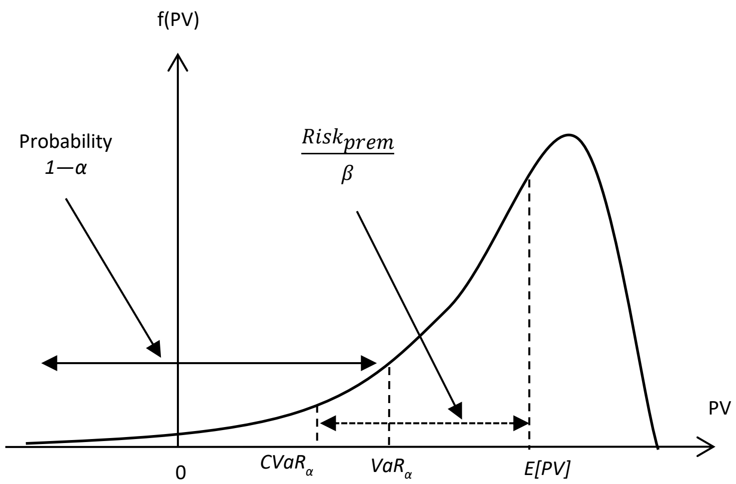
$$\text{with } Risk_{prem} = \beta * (E[PV] - CVaR_{\alpha}) \tag{8}$$

β is a dimensionless parameter which captures the relative degree of agents' aversion ($0 \leq \beta \leq 1$[88]). The difference between the expected value of the PV and the CVaR[89], multiplied by β, is defined as the risk premium. Equation (8) can also be rewritten as follows:

$$PV_{estimated}^{RA} = E[PV] * (1 - \beta) + \beta * CVaR_{\alpha} \tag{9}$$

This last equation shows that the estimated PV in the case of risk averse agents is simply a weighted average between the expected PV and the CVaR.

Figure 19. Illustration of the modelling of risk aversion



2.1.5. Modelling plant aging

As for the modelling framework described in the first chapter, O&M costs are modelled as a two-part function which is constant during the technical lifetime of

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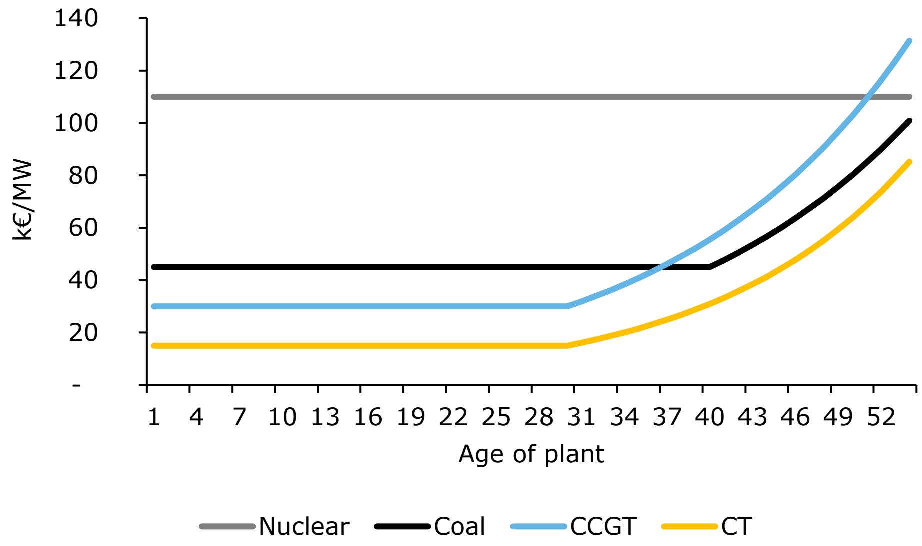
88 There is no mathematical restriction that bounds the coefficient β in the specified interval. This interval was chosen in order to reflect a behaviour of the agents which can be consistent with reality. Choosing a negative β suggests that the agents voluntarily overestimate the profitability of their investments, which is contradictory to the risk averse hypothesis. Similarly choosing a β that is higher than 1 would reflect an extremely risk averse behaviour, which is not realistic. Alternatively, the degree of risk aversion could also be adjusted through the coefficient α.

89 The procedure to compute the VaR and CVaR is detailed in Appendix C.

the plant, then start increasing up to the annualised[90] cost of investment when the age exceeds the technical lifetime by half[91]. The calibration is done to incentivize agents to make an arbitrage between keeping and old and expensive plant online or investing in a new capacity. After plants reach their technical lifetime, they might still stay in the market if agents perceive that it is less expensive for them to keep them active compared to making a potentially risky investment in a new plant. The evolution of O&M costs for each technology is represented on Figure 20.

Figure 20. **Evolution of O&M costs by technology[92]**



2.2. Energy-only market (EOM-PCap and EOM-SP)

2.2.1. Overview of the modelling

In the energy-only market (EOM), plants' profitability is solely driven by the revenues they make on the energy market. These revenues are computed using the dispatch model for each forecast scenario of LDC and installed capacity. In the

90 The annualised investment cost is computed using a discount rate of 8%.

91 This assumption is slightly different from the one made in the previous chapter but is more consistent with the calibration of the market designs studied in the current chapter and the following one (regarding the definition of the capacity price cap in particular).

92 The values of initial O&M costs and their sources are detailed in section 3.

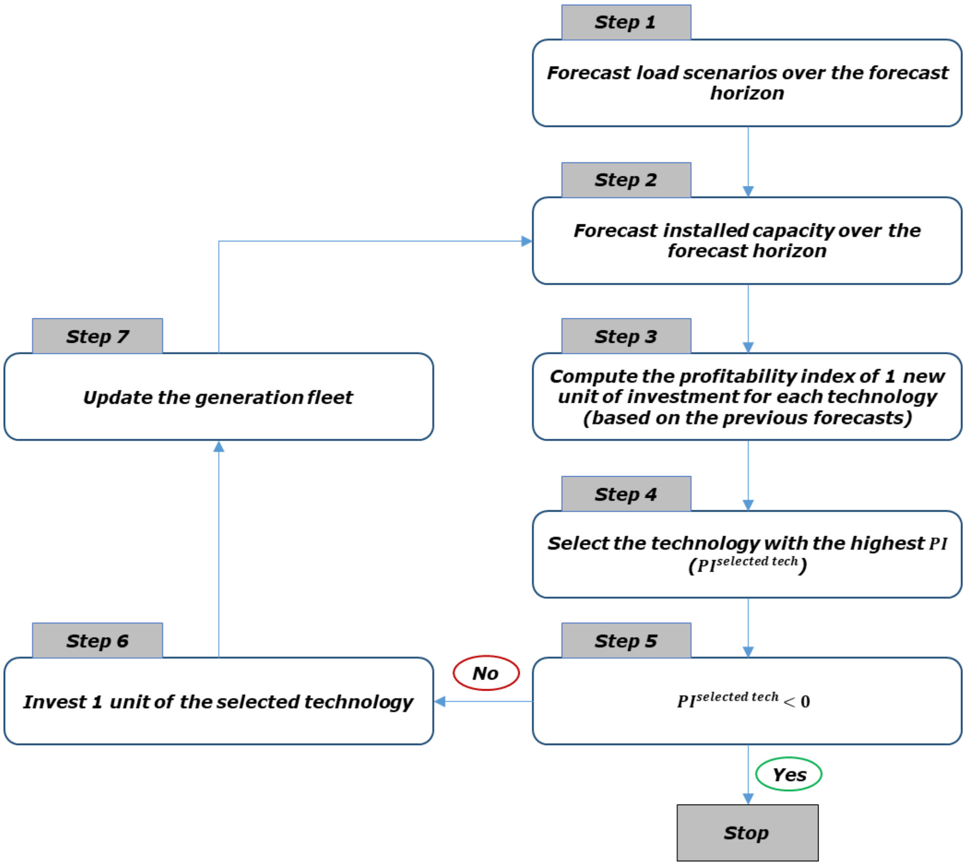
EOM-PCap, electricity prices are capped at 3 k€/MWh, whereas in the EOM-SP, they are allowed to reach the VoLL which is assumed to be 22 k€/MWh[93].

For investment decisions, agents need to identify the most profitable investment option in terms of generation technology, but also to determine how many plants they want to invest in. This is done thanks to an iterative procedure inspired from De Vries and Heijnen (2008) and Petitet et al. (2017), and described on Figure 21. First, the attractiveness of an investment in a specific technology is assessed through its profitability index PI[94], based on forecast profits from the energy market (steps 1 to 3). Agents then select the technology with the highest PI and, if the investment if profitable (i.e. $PI \geq 0$), add a unit of the selected technology into the current generation portfolio (steps 4 to 7). They repeat the previous steps, starting at step 2, until the new investment is no longer profitable (i.e., $PI < 0$). The lead times for the construction of the different technologies are accounted for in the process.

93 This VoLL is consistent with a reliability criterion of 3h/year of LOLE and the total annualised cost of a peaking unit.

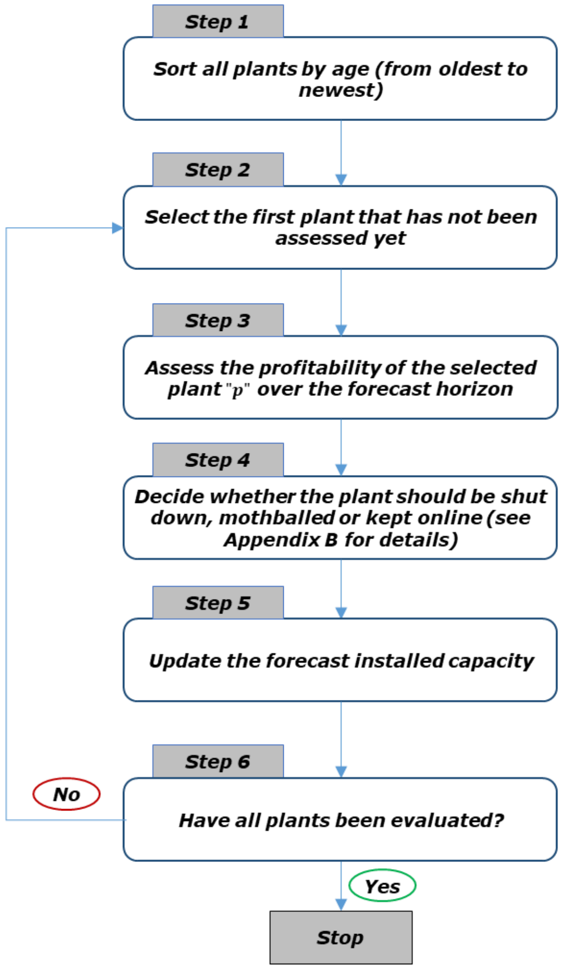
94 The PI is directly derived from the estimated NPV depending on the risk preference of the agents.

Figure 21. Investment procedure for new plants in the energy-only market



Shutdown and mothballing decisions regarding existing plants are also based on their expected profitability. Agents assess the expected profitability of operating the plant over a maximum horizon of eight years (i.e., the forecast horizon). Every year, an iterative algorithm is used to evaluate each one of the existing plants. The corresponding procedure is explained on Figure 22. The arbitrage between staying active, mothballing or shutting down depends on the expected outcomes of each strategy.

Figure 22. Shutdown/mothballing procedure for existing plants in EOM-PCap/EOM-SP



Agents start by sorting their plants depending on their age. They assess the plants from the oldest to the newest and decide whether to keep them online, mothball them or shut them down permanently. This decision is taken into account to update the forecasts about installed capacity, which in turn modifies the forecasts about the profitability of the remaining existing plants. Agents then assess the following plant and the process is repeated until all the plants are evaluated. It is important to update agents' forecasts after each decision to avoid any overestimation of the level of shutdowns/mothballings. For instance, every time agents decide to shut down a power plant, the probability of the remaining plants being profitable becomes higher, all things being equal. If the shutdown decision was not accounted for, agents might shutdown some of the remaining plants although they might be profitable.

For each year, investment on the one hand and mothballing/shutdown decisions on the other hand are made separately without any interaction. Therefore, investments that are decided in year y do not affect mothballings or shutdowns decided that same year, and *vice versa*. This avoids creating a systematic causal relationship between investment decisions and mothballing/shutdown decisions that are made in the same year. Abstracting from such interactions facilitates the interpretation of the model results.

2.2.2. Shutdown and mothballing decisions in energy-only markets

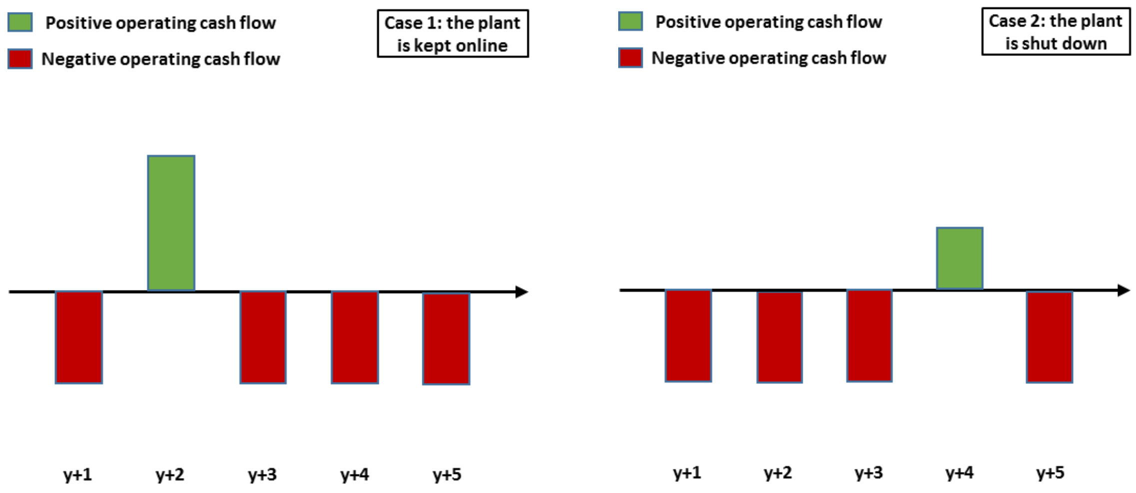
Simple shutdown decisions without mothballing

When mothballing is not an available strategy, agents can only decide whether their power plants should stay online or be shut down. For each plant, they start by assessing its profitability the following year (i.e., year $y+1$ if the current year is y): if operating the plant for one more year is profitable then it is kept online. Otherwise, the assessment horizon is extended to two years. Even if the plant is not expected to be profitable the next year, it might be rational to still keep it online if the expected operating cash flows[95] (OCF) over the following years cover the anticipated losses. As long as the maximum forecast horizon $h_{forecast}$ is not reached, the process is repeated until the algorithm finds a year in which the expected OCF is high enough to cover all the losses of the previous years (see Appendix D for a formal description of the shutdown algorithm).

Figure 23 below gives an illustration of the shutdown decisions in two stylised cases (with a forecast horizon of five years instead of eight, for readability). In the first case, the plant is kept online because the positive OCF for year $y+2$ cover the anticipated loss in $y+1$. In the second case, the forecast profits for $y+4$ are not worth incurring losses from $y+1$ to $y+3$. Consequently, the plant is shut down at the end of year y.

95 All the cash flows that are mentioned in the paper are discounted to the decision year, namely year y. Operating cash flows are defined as revenues minus operation costs.

Figure 23. Illustration of shutdown procedure (without mothballing)



The fundamental rationale of the algorithm is that making a shutdown decision based on a single year forecast might not be judicious as a shutdown decision is irreversible (conversely to the decision of staying online which implies a commitment of one year only). Shutting down a plant implies giving up on potential future revenues to amortise the initial investment cost. Therefore, before deciding to shut down a power plant, it might be interesting to consider a longer time horizon for the assessment of its expected profitability. It is assumed that this horizon can be extended up to $h_{forecast}$.

Shutdown decisions including mothballing

When mothballing is considered, the decision process becomes more complex. In addition to the two options presented before (i.e., "*shut down*" or "*stay online*"), agents now also need to consider "*mothball*" and "*restart*" options in their rationale. The decision process now depends on the current status of the plant which can be either active or mothballed. In order to choose between these options, agents compare their corresponding opportunity costs, by computing all associated avoided costs, sunk costs and foregone revenues (i.e., potential revenues from the energy market).

It should be noted that the model developed here only considers yearly mothballing. This is consistent with the timestep of the decisions made by the agents, which are on a yearly basis. However, this means that the model does not capture potential effects of mothballing that can occur due to short-term mothballing (over a few months only). Here, the focus is made on long-period mothballing decisions because they generally have a more pronounced impact on the system.

If the plant is active, the available options are staying active (for one more year), mothballing (for one year) or shutting down (permanently). Shutdown is only considered if none of the other options is profitable[96]. As such, agents first identify the least-cost option between mothballing and staying online. For that, they compare the OCF of their plants in each option, based on the expected revenues and costs as indicated in Table 4 below.

Table 4. Cash flows considered (active plant)

Options	Mothballing		Staying online	
Cash flows	**Revenues**	**Costs**	**Revenues**	**Costs**
$\boldsymbol{y+1}$		Mothballing costs	Energy market	O&M costs
$\boldsymbol{y+2}$	Energy market	Restart costs O&M costs	Energy market	O&M costs
$\boldsymbol{y+3}$ *to* $\boldsymbol{y+h_{forecast}}$	Energy market	O&M costs	Energy market	O&M costs

Between staying active and mothballing, cash flows only differ in $y+1$ and $y+2$. Beyond $y+2$, cash flows are the same since the plant is supposed to be active either ways (as mothballing is considered for one year only). Hence, the choice between the options is only based on the specific costs in $y+1$ and $y+2$; and the OCF in $y+1$ if it is negative (i.e., a loss). Once agents have selected the least-cost strategy between staying online and mothballing the plant, their next step will be to assess if the selected strategy is profitable by incrementing the assessment horizon. If the selected strategy is not profitable after the exploration of the maximum assessment horizon ($h_{forecast}$), then the plant is shut down. Otherwise, the selected least-cost strategy is applied. The corresponding algorithm is presented in Appendix D.

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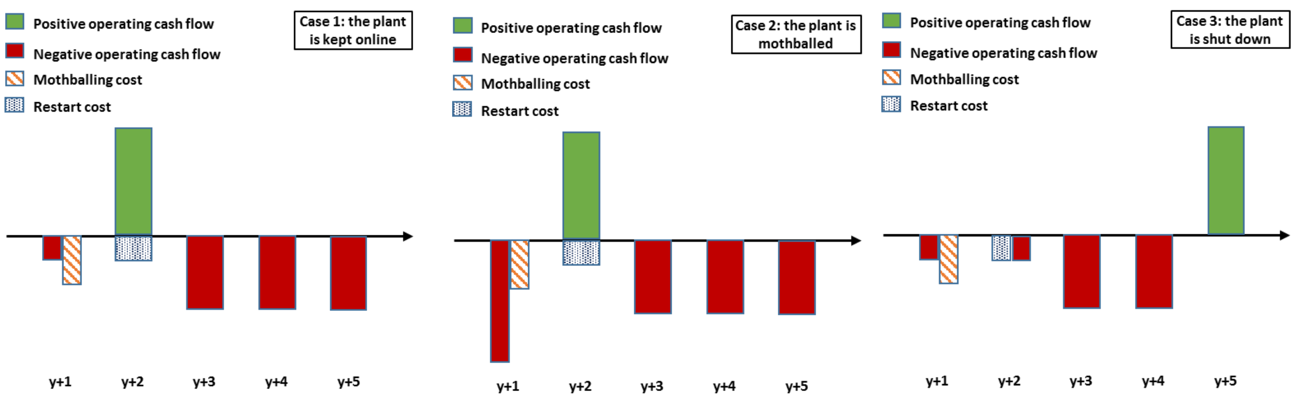
96 Shutting down a plant yields a small negative cash flow (or at best null, if the shutdown costs are covered by the resale of some parts of the plant). Therefore, it is logical to consider shutdown as the last option since the two others (mothball or stay online) may yield a positive outcome (positive net cash flow).

Three stylised cases are presented on Figure 24 to better illustrate this decision process (with a forecast horizon of five years instead of eight, for readability). In the first case, the plant is kept online because the costs of mothballing it in $y+1$ and restarting it in $y+2$ are higher than the anticipated loss in $y+1$. Moreover, this anticipated loss is compensated by the positive OCF expected in $y+2$. In the third case...

Figure 24. Illustration of shutdown procedure (with mothballing)



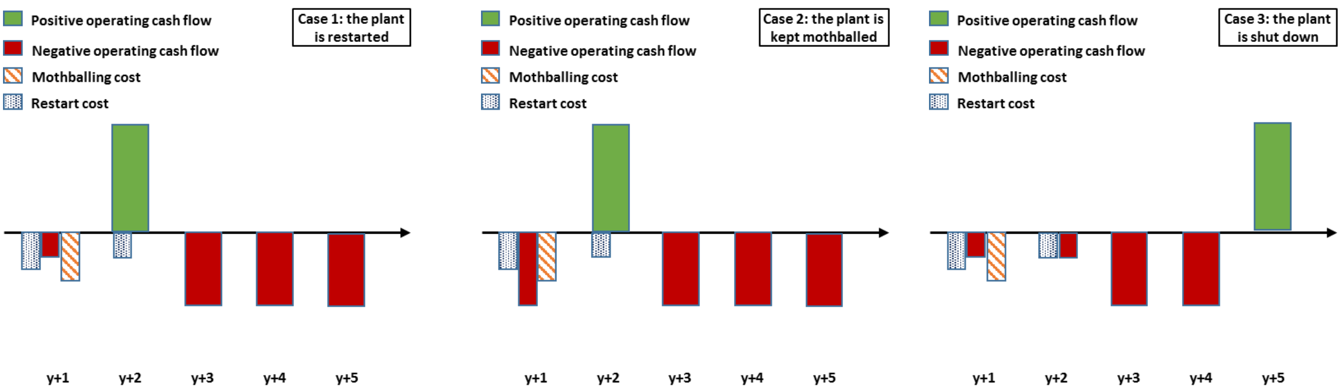
For mothballed power plants, the decision process follows the same rationale, with the sole amendment of replacing the "stay active" option by the "restart" option. Furthermore, the restart costs are also to be considered in $y+1$ for the *"restart"* option (see Table 5). Three options are available to the agents: mothball (for one more year), restart (the next year), and shut down. As explained before, shut down is only considered as a last resort. Accordingly, agents first chose between the mothball (i.e., continuation) and restart options. The algorithm of the decision process, which is very similar to the one for an active plant, is also described in Appendix D.

Table 5. Cash flows considered (mothballed plant)

Options	Mothball		Restart	
Cash flows	**Revenues**	**Costs**	**Revenues**	**Costs**
$y+1$		Mothballing costs	Energy market	Restart costs O&M costs
$y+2$	Energy market	Restart costs O&M costs	Energy market	O&M costs
$y+3$ to $y+h_{forecast}$	Energy market	O&M costs	Energy market	O&M costs

As for the case of an active plant, three illustrative cases are provided below (see Figure 25). In the first case, both the *"restart"* and the *"mothball"* options are profitable. However, the latter is less costly and thus the plant is restarted. In the second case, the scenario is reversed. In the final case, restarting or mothballing the plant is uneconomic over the considered horizon. Consequently, the plant is permanently shut down.

Figure 25. Illustration of shutdown procedure (with mothballing)



2.3. Capacity market with annual contracts (CM-AC)

The capacity market modelled in this chapter is a centralised forward capacity market with annual auctions (similar to the one presented in Chapter I). Nevertheless, the consideration of mothballing decisions requires complementary explanations to fully describe the functioning of the capacity market in this new version of the model.

Each year, a capacity auction (the CM-AC auction) is held to contract capacity to be delivered after a certain number of years ($ddelay_{CM-AC}$). There is no restriction on the plants that can participate to the auction. All existing plants and potential new investments are allowed to bid in the CM-AC auction. This feature of the CM-AC enables it to coordinate investment and shutdown or mothballing decisions, which is not the case in the EOM-PCap/EOM-SP.

The supply curve of the CM-AC auction is obtained by aggregating the bids[97] from both existing and new capacities in ascending order. New capacities' bids correspond to prospective investments while existing capacities' bids can be associated to potential shutdown or mothballing decisions (in case the bids are not accepted). For each of the previous categories the modelled bidding strategy is described below.

2.3.1. Capacity bids from new plants in CM-AC auction

In the case of new plants, the capacity bids are determined through an algorithm that is similar to the one presented in section 2.2 for the EOM-PCap/EOM-SP as presented on Figure 26 hereafter[98]. Each year, agents assess the profitability of an investment in the available technologies based on the forecast profits from the energy market and an expected capacity price (steps 1 and 2). The forecast profits from energy market are computed just as for the previous market designs.

Potential capacity revenues are also accounted for in the profitability assessment. To this end, agents use three scenarios corresponding to the average, minimum and maximum capacity price over previous years[99]. In each scenario, the capacity price is assumed to be flat (i.e., constant) over the lifetime of the assets. Since every capacity price scenario (considered over the lifetime time of an asset) corresponds to a specific present value, these present values can be used to determine a single risk adjusted present value of all capacity prices with the same

97 Strategic bidding is not considered. Perfect competition is assumed with capacity bids corresponding to agents' opportunity costs.

98 The new steps that are added compared to the case of the EOM-PCap/EOM-SP are highlighted in red boxes.

99 The number of years is set to be consistent with the forecast horizon ($h_{forecast}$).

methodology described in section 2.1.4. Agents can then compute a single expected capacity price $\boldsymbol{E}(p_y^{CM})$ by annualising[100] the estimated risk adjusted present value of all capacity price scenarios. This approach[101] enables agents to include an expected capacity price in their bids as explained below.

Using forecast energy market profits and the expected capacity price, agents select the most attractive investments (steps 3 and 4) and determine their capacity bids as follows (steps 5a, 5b, 6a and 6b):

- $\boldsymbol{E}(p_y^{CM})$, if the associated investment is expected to be profitable based on of the anticipated revenues from the energy market and the expected capacity price;
- $\boldsymbol{E}(p_y^{CM})$ plus, the annualised missing money[102] (i.e. the shortfall), if the investment is not profitable based on the forecast revenues from the energy market and the expected capacity price.

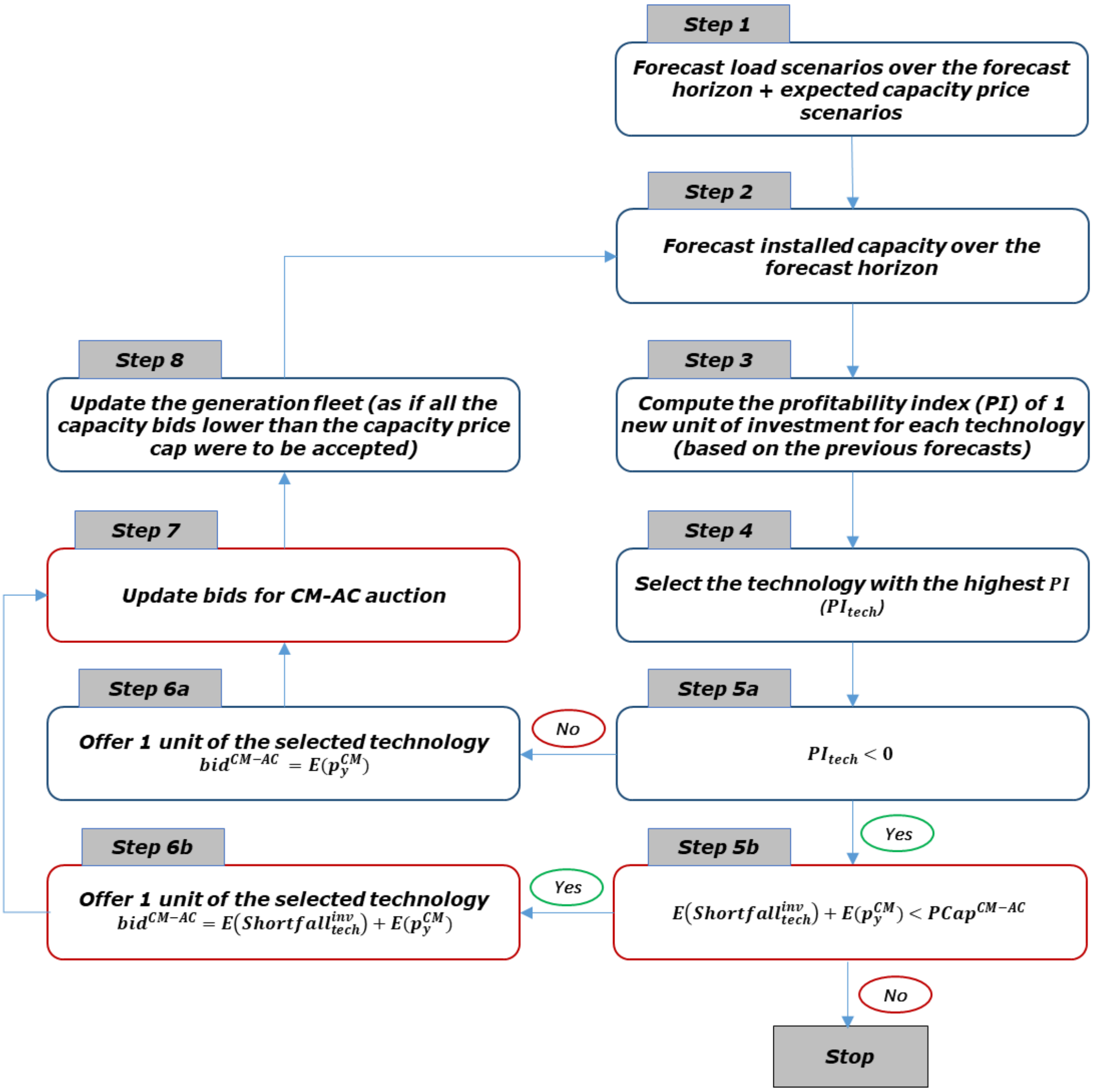
The investments corresponding to the capacity bids are used to update the installed capacity as if the capacity bids are all accepted (steps 7 and 8). Finally, agents adapt their forecasts based on the updated installed capacity (step 2) and the steps are run again. The procedure stops when the capacity revenue required for the marginal investment is higher than the capacity market price cap. Indeed, this indicates that all additional investments will have to bid higher than the capacity market price cap (which means that they will be rejected).

100 This is done using a discount rate of 8%.

101 It also facilitates the identification of the risk premium specifically related to the uncertainty associated with the capacity price.

102 The total shortfall is divided by the size of the plant to obtain a bid in €/MW.

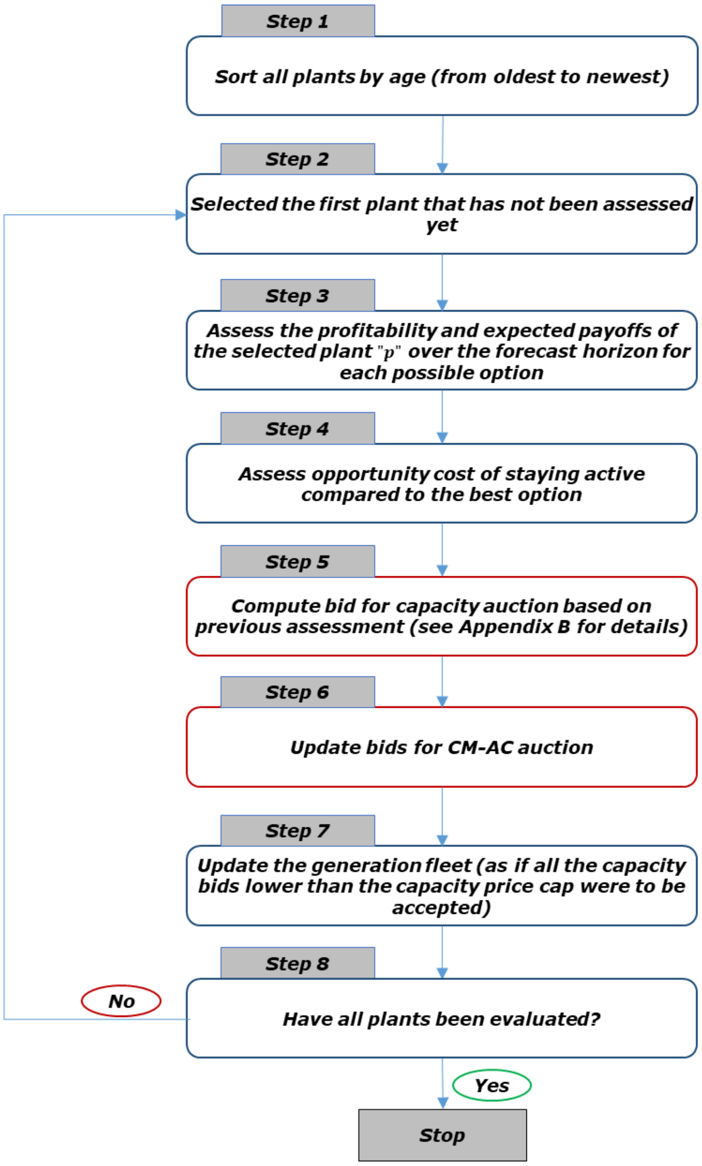
Figure 26. Investment procedure for new plants in CM-AC



2.3.2. Capacity bids from existing plants in CM-AC auction

Existing plants bid on the CM-AC auction in order to stay online. Agents assess the expected profitability of existing plants over the forecast horizon based on forecast revenues from the energy market. For each plant, they have to determine the capacity bid required to stay active but also which action to take if this capacity bid is not accepted. Consequently, the actual shutdown and mothballing decisions are dependent on the outcome of the CM-AC auction.

Figure 27. Shutdown/mothballing procedure for existing plants in CM-AC



All available options (stay active, mothball or shutdown) are considered by agents when determining their capacity bid. The bidding strategy of existing plants consist in computing their net expected payoff corresponding to every option first. Then, they identify the best option (i.e., the one with the highest expected payoff) and determine their opportunity cost associated with the decision to stay active instead of choosing their best option. Note that if the best option for the plant is to stay active, then there is no opportunity cost and the corresponding bid is zero. Figure 27 illustrates the general procedure for shutdowns/mothballings in the CM-AC. Details on bidding strategies are provided hereafter.

2.3.2.1. Bidding strategy without mothballing

When mothballing is not considered, the capacity bids of existing plants correspond to their short run missing money, which is the amount of money needed to break even if the plants remain active. The bidding strategy can be summarised as follows:

- If the expected payoff (without any additional capacity revenue) resulting from remaining active is positive, then the capacity bid is zero. The plant stays active whether the capacity bid is accepted or not[103].
- Otherwise, the capacity bid corresponds to the annualised shortfall. If the capacity bid is not accepted, then the plant is shut down since it is not expected to be profitable.

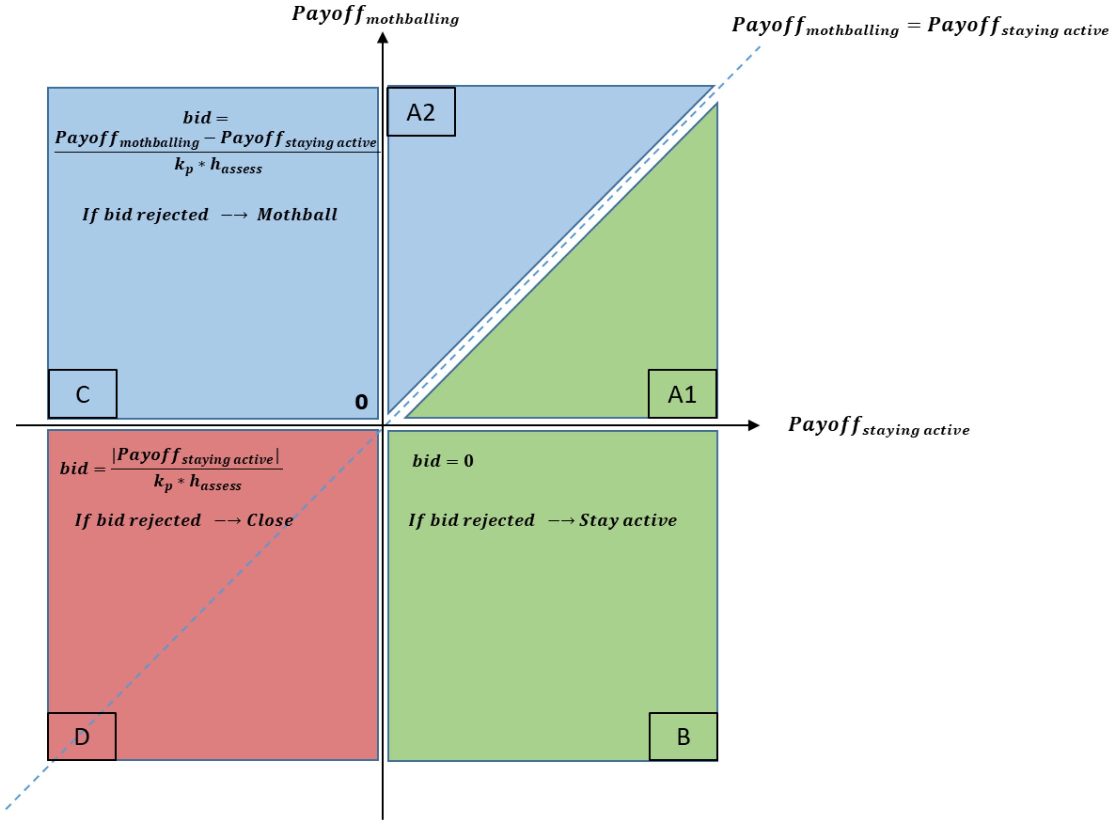
2.3.2.2. Bidding strategy with mothballing

When agents have the possibility to mothball their plant, their bidding strategy on the capacity market is less trivial. All the available options and configurations should be carefully assessed. The following explanation focuses on the case of active plants but can easily be transposed to mothballed plants.

For an active plant, based on the net expected payoffs (without an additional capacity price) corresponding to the actions of maintaining the plant active or mothballing it, five configurations are possible as presented on Figure 28. The figure gives a graphical representation of the states of the world to be considered by existing plants when computing their capacity bids. The colours correspond to states of the world in which the capacity bid and the fall-back plan (in case the bid is not accepted) are the same. The associated computation algorithm is detailed in Appendix D.

103 The TSO cannot force plants to shut down if they are expected to be profitable. In this situation, even if the capacity bid is rejected, because of an excess offer for instance, the plant will still remain active.

Figure 28. Bidding strategy in the capacity market for an active plant (when mothballing is considered)[104]



- **Configuration A** is broken down in two sub-configurations A1 and A2 depending on the relative attractiveness the two available options (mothball or stay active). In both sub-configurations, staying active and mothballing yield positive payoffs.
  - In **sub-configuration A1**, staying active yields a higher payoff than mothballing. As a result, the plant can bid zero in the capacity auction because it doesn't need an additional capacity revenue in order to be profitable. Saying active is actually its best strategy no matter what (based on the agents' expectations).
  - In **sub-configuration A2** however, the most attractive option is to mothball the plant. Indeed, even if staying active still yields a positive expected payoff, mothballing the plant yields an even higher expected payoff. In this configuration, there is an incentive to

[104] The bids are annualised over the forecast horizon.

mothball the plant, which corresponds to the difference between the expected payoffs $\boldsymbol{Payoff_{mothballing} - Payoff_{staying\ active}}$. This difference is the opportunity cost of the plant if it stays active instead of being mothballed. Therefore, for the plant to stay active, the capacity price has to be at least equal to this opportunity cost (converted in a unitary cost per megawatt). If the bid is not accepted, the best strategy is to mothball the plant.

- In **configuration B**, keeping the plant active yields a positive expected payoff, while mothballing it leads to a loss (without an additional capacity price). Given this, the rational capacity bid is zero (similar to configuration A1).

- In **configuration C**, the plant is expected to lose money by staying active whereas mothballing it results in a positive payoff. If the plant were to stay active, the capacity price would have to compensate the expected loss (negative payoff) from staying active but also the foregone positive expected payoff that would have been received by the plant if it were mothballed instead. The corresponding bid is computed as the difference in payoffs ($\boldsymbol{Payoff_{mothballing} - Payoff_{staying\ active}}$) divided by the size of the plant to obtain a price per MW. In case the capacity bid is not accepted, the best strategy is to mothball the plant since it yields a positive expected payoff. This configuration is similar to configuration A2.

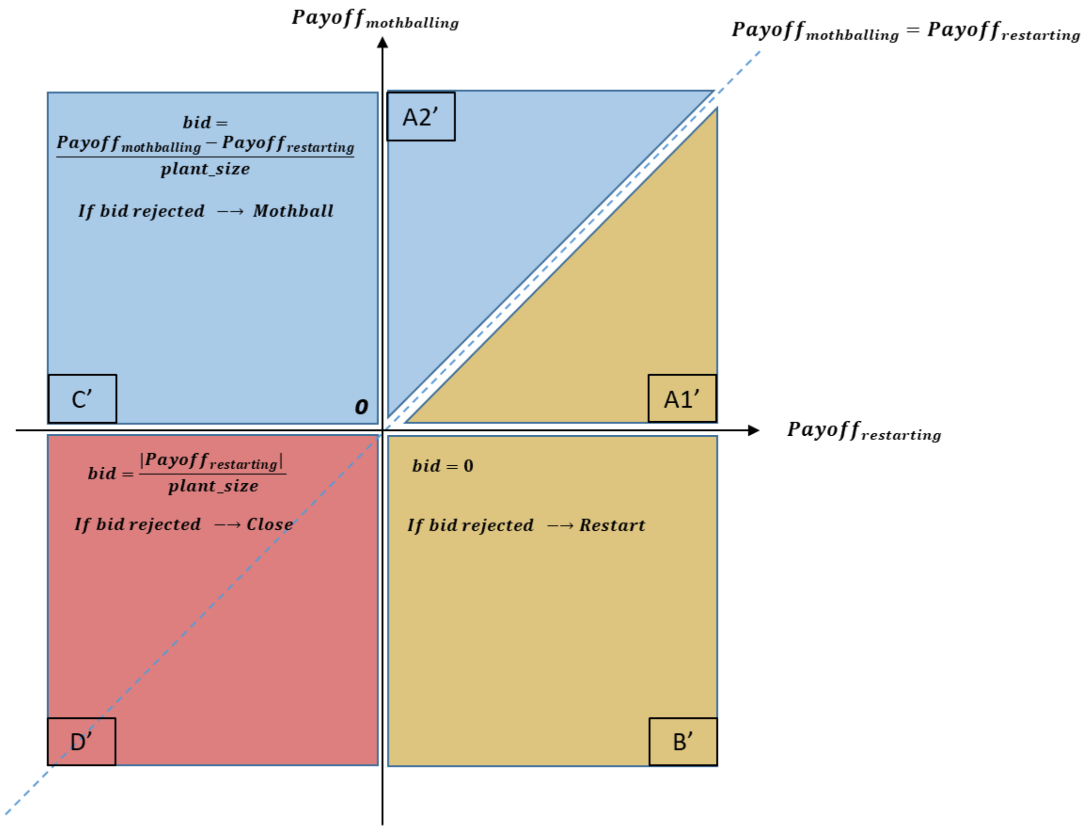
- In **configuration D**, neither keeping the plant active nor mothballing it leads to a positive expected payoff. With no additional capacity price, the plant will thus be shut down[105]. In order to stay active, the capacity price should at least compensate for its expected loss (negative expected payoff of staying active). The capacity bid is therefore determined so that the plant breaks even if it is kept active.

The bidding strategy for mothballed plants is similar to the one of active plants. The only adjustment is that, instead of choosing between staying active and

105 It is assumed that plants do now tolerate negative payoffs computed over a medium-term horizon. They can only tolerate short-term losses if they expect to be profitable over the medium-term.

mothballing, the plants have to choose between restarting and mothballing again. Hence, the same rationale can be used by replacing "staying active" by "restarting" (see Figure 29). Using the strategies described above, agents submit, for each existing plant, a capacity bid (i.e., the capacity price it needs to be active the delivery year) and the decision regarding the plant if the capacity bid is not accepted.

Figure 29. **Bidding strategy in the capacity market for a mothballed plant (when mothballing is considered)** [106]



2.3.3. Capacity demand in CM-AC auction and clearing

The demand curve of the capacity auction is determined by a central planner – generally the TSO – based on its forecasts about future electricity demand and installed capacity. The forecasts available to the TSO[107] are the same used by the agents to make their investment and shutdown decisions. The TSO determines the

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[106] The bids are annualised over the forecast horizon.

107 The TSO's forecast are thus imperfect because of uncertainties regarding the evolution of the peak load and the level of installed capacity.

capacity need for the delivery year in order to reach a certain capacity margin that is set exogenously (t_m). The TSO also accounts for the capacities under construction that will be available in the delivery year. Indeed, these capacities need not be contracted by the TSO as they are expected to be on the market for the delivery year anyway (since they have already been awarded a capacity contract in a previous auction). Therefore, the capacity demand is computed using the following formula[108]:

$$Q_{y \to y+ddelay_{CM-AC}}^{CM-AC} = max\left(0\ ;\ L_{y+ddelay_{CM-AC}}^{Fpeak} * \left(1 + tm_{y+ddelay_{CM-AC}}\right) - \sum_{a=y+1}^{a=y+ddelay_{CM-AC}} K_a^{New} \right) \tag{10}$$

Where:

- $Q_{y \to y+ddelay_{CM-AC}}^{CM-AC}$ is the capacity demand from the TSO in the CM-AC auction held in year y (for delivery in year $y + ddelay_{CM-AC}$);
- $L_{y+ddelay_{CM-AC}}^{Fpeak}$ is the forecast peak load in the delivery year;
- $tm_{y+ddelay_{CM-AC}}$ is the target margin set by the TSO for the delivery year;
- K_y^{New} is the total amount of new capacities that are expected to enter the market in year y.

The computation of the capacity demand is made under the assumption that the TSO knows exactly all the capacities under construction[109]. New capacities are also assumed to stay online at least a number of years that is consistent with $ddelay_{CM-AC}$. Keeping new capacities online at least a few years before considering shutdown is consistent with industry practices. It ensures that the capacities that are under construction when the TSO is determining the capacity demand for the

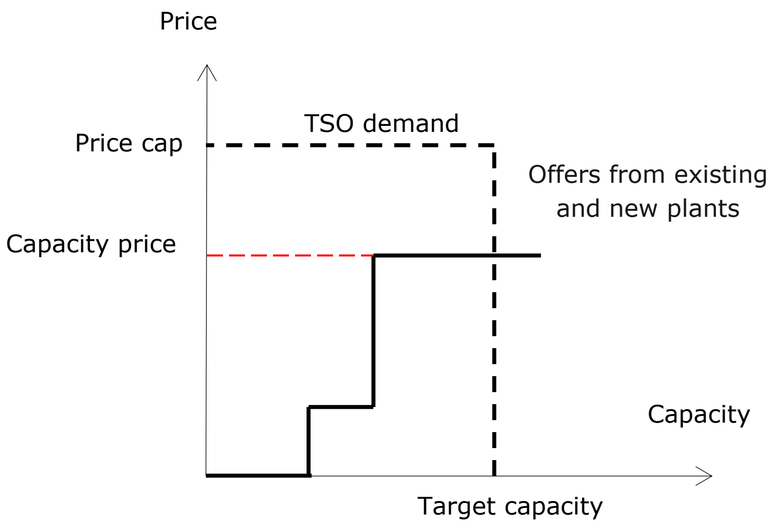
108 The equation states that the capacity demand from the TSO may be zero if the anticipated investments (K_a^{New}) are enough to ensure the reliability target. This is however unlikely to happen since the total anticipated investments for a single year would have to be close to the peak demand of the system (which is unrealistic).

109 For the sake of simplicity, capacities under construction do not participate to the capacity auctions. Although this may not be the case in real systems, it does not affect the validity of the analysis carried out here. It only leads to other capacities being accepted in the corresponding auctions.

delivery year (after $ddelay_{CM-AC}$) will in fact be available that year. Otherwise, a capacity (that is considered under construction) may come online and shutdown before the delivery year, thus creating an error in the TSO's forecast. Finally, the TSO imposes a maximum price (i.e., a capacity price cap) for the procurement of capacity. Offers that are above the price cap are automatically rejected.

The capacity auction matches the capacity demand curve with the capacity supply curve and determines a clearing price. This clearing price corresponds to the last accepted capacity bid needed to reach the target capacity (see Figure 30).

Figure 30. **Capacity market auction**



Once the capacity market is cleared, all accepted bids lead to new investments and plants staying active. Bids for new plants (prospective investments) that are rejected lead to no investment. For existing plants, rejected bids lead to plants being shut down or mothballed depending on the best fall-back strategy identified by agents in case the bids are not accepted[110]. Rare situations where plants that have bid zero are rejected can occur. This may happen if the capacity demand is lower than the capacity offered at a zero price. In these cases, the TSO cannot

110 Plants with accepted bids have an obligation to be active until the delivery year. Consequently, plants cannot be mothballed or shut down if they still have a pending capacity obligation. For instance, if a plant has an obligation to be active in year $y+4$, then even if this plant's bid is rejected in the auction held in year $y+1$, the plant cannot be closed or mothballed until $y+5$ since it has to be active in year $y+4$ (because of the capacity obligation).

force the rejected plants to exit the market if their forecasts indicate that entering the market (or staying in it) is profitable.

3. Simulations setup and indicators

3.1. Preliminary remarks on calibration and simulations

The reader should keep in mind that the level of demand uncertainty considered in the simulation (and described hereafter) is relatively high on purpose; to properly illustrate all potential effects related to mothballing. Indeed, some effects regarding long-run dynamics are only visible with high levels of demand uncertainty. However, choosing an extreme scenario of demand uncertainty to illustrate long-run effects leads to an overestimation of some short-term effects on prices and shortages. This is well explained in the discussion of the results. The reader should therefore put the results presented regarding electricity prices and shortages in perspective of the rather extreme scenario of demand uncertainty considered here.

To provide more realistic figures in terms of impact on electricity prices and shortages, many sensitivity analyses were run in this chapter, precisely to show the reader what the results would look like in a less extreme configuration. For instance, simulation results with a less uncertain demand are presented in section 4.5.2. They show that the magnitudes are more in line with what would be expected in real life.

Finally, for similar reasons to those described above, most results are presented in relative terms (compared to a reference), rather than in absolute terms. This is because absolute values would not reflect the outcome of an actual power system under normal market conditions. The indicators that are used for the analysis (see following section) are defined to show the differences between two power systems which are exposed to the similar market conditions. The important aspect of the analysis is the difference between the power systems' outcomes.

3.2. General setup and indicators

A Monte Carlo approach is used with 100 runs of the model over a horizon of 40 years to capture potential long-term effects. For each run, two settings are compared: a first one in which mothballing is not allowed (setting $SNoMoth$), and a second one in which agents have the possibility to mothball their plants (setting

$SMoth$). These settings are compared in terms of level of investments, shutdowns, shortages, electricity prices and capacity prices. The comparison is done separately for an energy-only market and a capacity market with annual contracts. Since the only difference between the settings is the presence or absence of mothballing decisions, all the differences resulting from the comparison are solely due to these decisions. These potential differences are captured through a set of indicators described below:

$$\Delta_{tech,y}^{investment} = \frac{\left(Investment_{tech,y}^{SMoth} - Investment_{tech,y}^{SNoMoth}\right)}{ICap_{initial}} \tag{11}$$

$$\Delta_{tech,y}^{shutdown} = \frac{\left(Shutdown_{tech,y}^{SMoth} - Shutdown_{tech,y}^{SNoMoth}\right)}{ICap_{initial}} \tag{12}$$

$$\Delta^{shortages} = \frac{\left(Shortages^{SMoth} - Shortages^{SNoMoth}\right)}{Shortages^{SNoMoth}} \tag{13}$$

$$\Delta^{prices} = \frac{\left(Prices_{energy/capacity}^{SMoth} - Prices_{energy/capacity}^{SNoMoth}\right)}{Prices_{energy/capacity}^{SNoMoth}} \tag{14}$$

Where:

- $ICap_{initial}$ is the total initial installed capacity (excluding RES);
- $\Delta_{tech,y}^{investment}$ measures the cumulative difference in investments between the two studied settings for technology $tech$, at year y. The difference is normalised by the total initial capacity;
- $\Delta_{tech,y}^{shutdown}$ measures the cumulative difference in shutdowns between the two studied settings for technology $tech$, at year y. The difference is normalised by the total initial capacity;
- $\Delta_{shortages}$ measures the difference in yearly average shortages (unserved energy) between the two studied settings over the whole simulation horizon;
- Δ_{prices} measures the difference in yearly average energy/capacity prices between the two studied settings over the whole simulation horizon;

- $Investment_{tech,y}^{X}$ is the cumulative level of investments in technology $tech$, at year y, in setting X ($X \in \{SMoth; SNoMoth\}$);
- $Shutdown_{tech,y}^{SMoth}$ is the cumulative level of shutdowns in technology $tech$, at year y, in setting X ($X \in \{SMoth; SNoMoth\}$);
- $Shortages^{X}$ is the average level of yearly shortages observed over the simulation horizon during a single run of the model in setting X ($X \in \{SMoth; SNoMoth\}$);
- $Prices_{energy/capacity}^{X}$ is the average level of yearly energy prices[111] or capacity prices observed over the simulation horizon in setting X ($X \in \{SMoth; SNoMoth\}$).

To complement the analysis, a social welfare indicator is also computed, based on the different system costs (i.e., generation costs, O&M costs, investment costs and the cost of shortages). As explained in Chapter I, given the assumption of an inelastic demand, a comparative analysis of social welfare can be done by assessing the level of shortages, which are included the total system costs using an assumption of VoLL (De Vries, 2004). A formal demonstration of this is provided in section 3.2 of Chapter III.

111 The yearly prices correspond to the average of the hourly prices.

Table 6. Technical and economic characteristics of thermal technologies[112]

	Nuclear[113]	Coal	CCGT	CT (gas-fired)
Investment (k€/MW)	5 200	1 700	850	500
Initial O&M costs (k€/MW/year)	110	45	30	15
Variable costs (€/MWh)	10	50	60	90
Unit capacity (MW)	1 450	750	550	150
Construction time[114] (years)	6	4	2	2
Expected lifetime (years)	60	40	30	30

All four generation technologies are considered for the simulations: Nuclear, Coal, CCGT (gas-fired) and CT (gas-fired) power plants. Their technical and economic parameters are presented in Table 6 above. Based on Frontier Economics (2015b), mothballing and restart costs are both set to 25% of annual O&M costs in the simulations[115]. Associating mothballing and restart costs to O&M enables to account for two properties: the fact that they are technology-specific and the fact that they increase with the age of the power plant (see modelling of O&M cost in section 2.1.5). Finally, to simplify the interpretation of results and properly isolate the impact of mothballing, agents are assumed to be risk neutral in the simulations. The main parameters of the simulations are summarised in Table 7.

112 These values are based on data compiled from various sources (EC Joint Research Center, 2014; International Energy Agency, 2018; International Energy Agency and OECD Nuclear Energy Agency, 2010; RTE, 2017). Values for variable costs are based on the "New Policies" scenario of the 2018 World Energy Outlook of the International Energy Agency. The underlying assumptions are the following: gas price of 8.5 $/MBtu, coal price of 82.5 $/t, CO2 price of 34 $/tCO2, efficiencies of 60%-41%-43% for CCGT-CT-Coal respectively.

113 For the simulations presented in this chapter, no nuclear investments are considered. Such investments generally include a significant political component. It is unlikely that private agents engage in nuclear investments solely based on economic considerations. Other studies such as RTE (2018) confirm this assumption.

114 The time for obtaining all the administrative authorizations and regulatory approvals is not considered.

115 To assess the sensitivity of simulation results to mothballing costs assumptions, different mothballing cost structures are tested in section 4.5.3.

Table 7. Variables and parameters for simulations (Chapter II)

	EOM-PCap	CM-AC
α Confidence level for computation of VaR and CVaR	95%	
β Risk aversion coefficient	0	
$PCap^{EOM-PCap}$ Price cap on energy market	3 k€/MWh	
$PCap^{CM-AC}$ Price cap of capacity market auctions	NA	80 k€/MW (~1.5x Net CONE[116])
tm_y Target margin set by the TSO for the delivery year	Set to reach LoLE of 3h/year[117]	
$VoLL$ Value of Lost Load	22 k€/MWh	

3.3. Electricity demand

Each run of the model is associated to a random scenario of gross electricity demand. The effective residual electricity demand observed by agents over the simulation horizon is determined on a yearly basis as a difference between gross demand and generation from renewables. The yearly evolution of peak gross demand is assumed to be flat with random deviations, representing the recent trend observed in European markets. More specifically, the growth rate of the gross demand is drawn from a zero-mean normal distribution with a standard deviation of 5%[118]. This figure aims to represent a high level of electricity demand volatility.

116 Cost of New Entry defined based on the annualised fixed cost (O&M and investment costs) of a combustion turbine, using a reference discount rate of 8% and the cost parameters presented in Table 6.

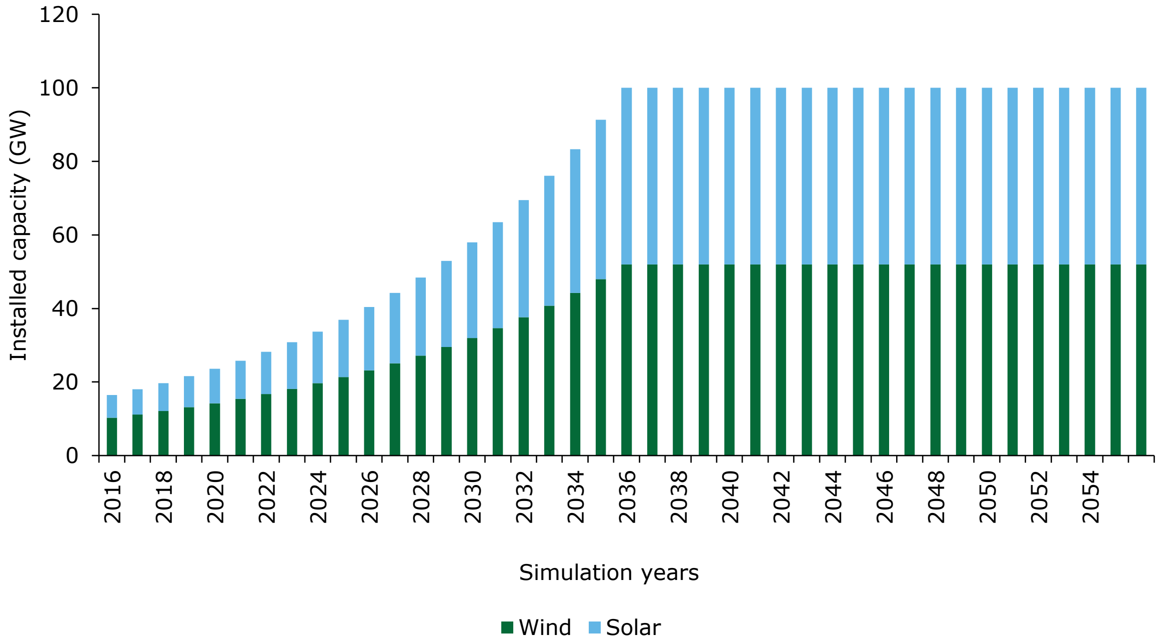
117 The Loss of Load Expectation (LoLE) of 3h/year is the reliability criterion used in France. Other European countries generally use reliability criteria ranging from 3h/year to 8h/year. In the model, the capacity needed to achieve a desired LoLE is computed using a probabilistic approach which relies on the forecast load duration curve scenarios. The load duration curve scenarios are the same as those used for agents' profitability assessments. For each load duration curve scenario, the TSO computes a corresponding level of installed capacity consistent with the reliability criterion. The target level of installed capacity (and therefore the target margin) is then determined as the expected value of all installed capacity scenarios.

118 A sensitivity analysis with an alternative value is presented in section 4.5.2.

It can be related to the variability of RES infeed in a system with high shares of renewables. The shape of this gross demand is calibrated on the 2015 load duration curve of the French system[119].

The evolution of RES capacities (wind and solar) is based on the most optimistic scenario identified in the French energy policy plan and described in (RTE, 2017). According to this scenario, wind and solar capacity are expected to grow at an average rate of 9%/year. Simulations are assumed to start in year 2016 (year 1) of simulation. Initially wind and solar PV capacities represent about 10 and 6 GW respectively. They then increase during the first 20 years of simulation from 2016 to 2035 to reach 52 GW for wind and 48 GW for solar. Afterwards, RES capacities are assumed to remain constant. The penetration trajectories of RES are presented on Figure 31 below. Generation from RES is directly derived from their installed capacity and associated generation profile[120].

Figure 31. **RES penetration scenario in case study**



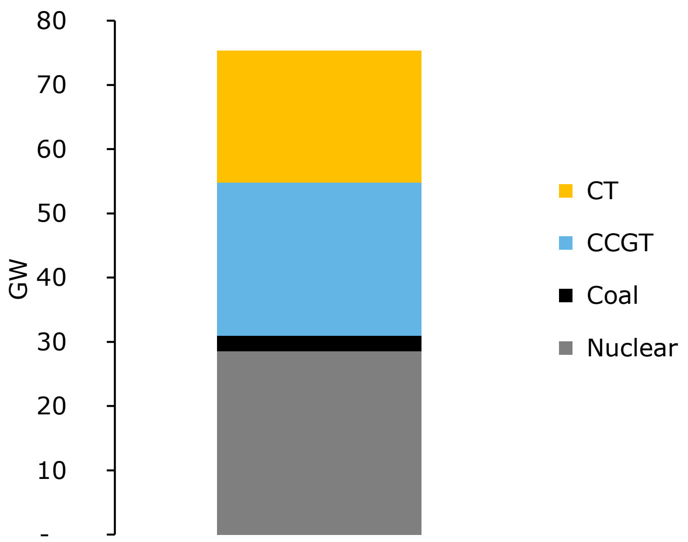
119 All hydropower generation is subtracted and assumed constant in the simulations. Cross-border exchanges are not considered.

120 The generation profile of RES is assumed to remain constant during the simulations. It is based on the actual generation profile of wind and solar in France in 2015.

3.4. Initial generation mix

Simulations start with an initial generation mix that corresponds to the optimal generation mix associated with the initial residual load curve. This mix is determined using the screening curves methodology presented by Stoft (2002). It represents the least-cost generation mix that can be used to satisfy a given load profile based on the economic characteristics of the available generation technologies (investment and operation costs) and the VoLL. A VoLL of 22 k€/MWh is assumed. Theoretically, this level of VoLL leads to 3h/year of shortages at equilibrium given the cost parameters considered in Table 6. Moreover, a discount factor of 8% is assumed, again in accordance with the existing literature (Cepeda and Finon, 2011; Hary et al., 2016; Petitet et al., 2016a). The determination of the optimal generation mix is done with the cost structure of new plants. However, plants are given different ages in the initial generation fleet to have a realistic system. The initial generation mix is presented on Figure 32.

Figure 32. Initial generation mix for simulations of chapter II



4. Analysing mothballing in energy-only markets

4.1. Understanding the long-term dynamics in presence of mothballing decisions

4.1.1. Fundamental dynamics related to mothballing

The two settings defined for the simulations are identical in terms of installed capacity until the first occurrences of mothballings in the setting with mothballing (i.e., $SMoth$). Once agents decide to mothball some of their plants, four elementary outcomes can be expected depending on what happens in the alternative setting where mothballings are not allowed (i.e., $SNoMoth$). These outcomes have different implications regarding subsequent investment and shutdown decisions as explained hereafter. The explanations are provided with graphs presenting the energy market equilibrium between inelastic demand and the merit order of variable costs of generation, as well as the resulting marginal price. The focus is made on two generation assets, one which might be mothballed (in hashed yellow) and another one (in light blue delimited by a red hashed line). Gross revenues of the latter are analysed depending on the decision to mothball the former (yellow one). If the gross revenues are higher than a profitability threshold, the blue generator is kept active, it is otherwise shutdown.

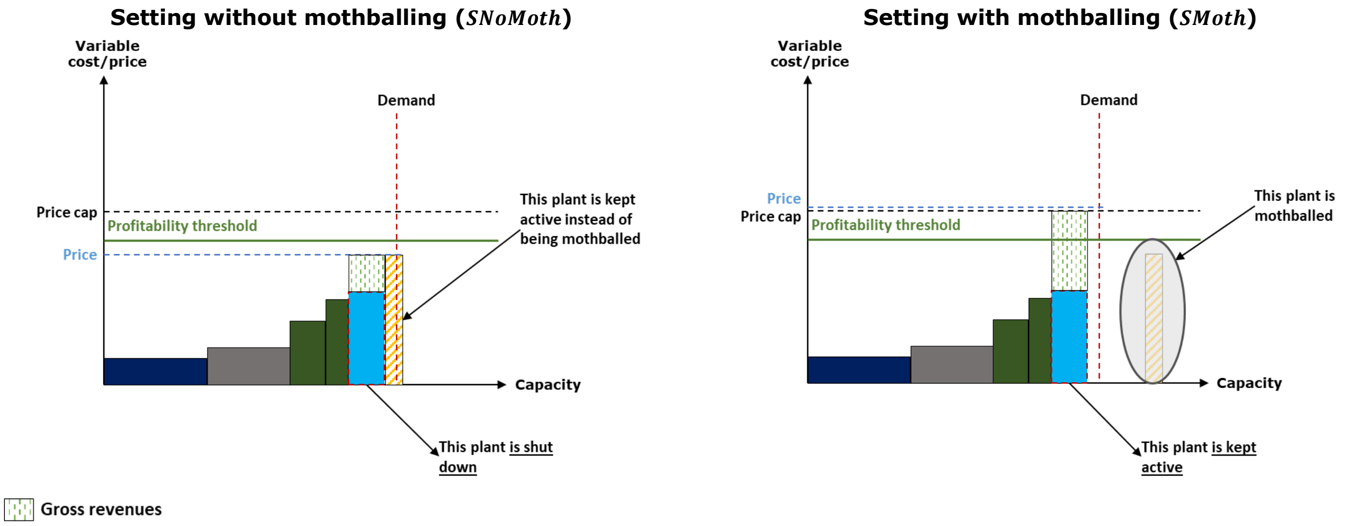
- **Expected outcome 1 ($EO1$) – mothballing leads to less shutdowns and less investments in marginal technologies**: the mothballed capacities in setting $SMoth$ are all closed instead in setting $SNoMoth$. In this case, there will be more shutdowns in the setting without mothballing, all things being equal. As a direct consequence, the potential investments (if there are) following that particular year will be lower in the setting with mothballing. Indeed, since the agents assume that the mothballed capacities will come back on the market[121], they will forecast a higher level of installed capacity and thus a lower profitability. This is the most intuitive impact as it corresponds to the stated rationale behind mothballing which is

121 This assumption reflects a cautious behaviour from investors, which can be justified in face of uncertainty. Indeed, considering that all the mothballed capacities come back online is a conservative approach as it leads to the lowest forecast revenues.

essentially a way of avoiding permanent shutdown when market conditions are temporarily bleak.

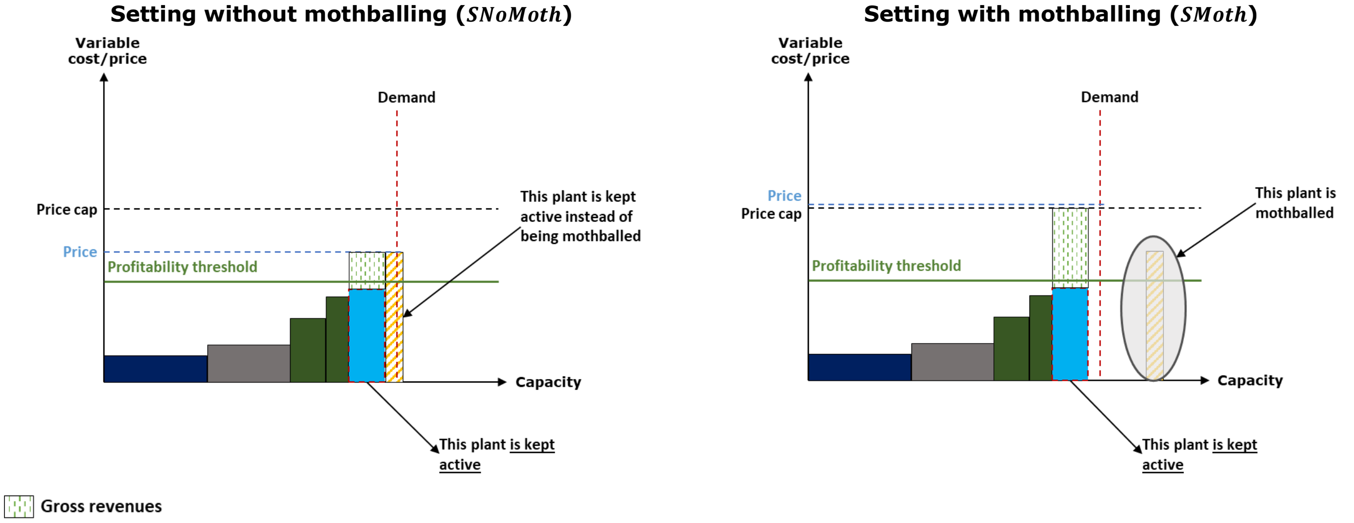
- **Expected outcome 2 ($EO2$) – mothballing leads to less shutdowns and less investments in inframarginal technologies**: the mothballed capacities in setting $SMoth$ are kept active in setting $SNoMoth$, but some other plants that are shut down in setting $SNoMoth$ are kept active instead in setting $SMoth$. This may happen when mothballing part of the plants in setting $SMoth$ creates an opportunity for other plants to stay in the market because of higher perceived revenues (while these plants exit the market in setting $SNoMoth$). The consequences of this outcome are similar to those of the first one ($EO1$): there will be less shutdowns in setting $SMoth$ and less investments compared to setting $SNoMoth$. However, this affects the generation mix differently (see Figure 33).

Figure 33. Illustration of expected outcome $EO2$ of mothballing



- **Expected outcome 3 ($EO3$) – mothballing does not affect shutdown and investment dynamics**: the mothballed capacities in setting $SMoth$ are all maintained active instead in setting $SNoMoth$. Moreover, the decision to mothball some plants in setting $SMoth$ does not affect the shutdown decisions for other plants. Here, there will be no difference in the level of shutdowns between the two settings for that particular year. Similarly, all things considered equal, investment decisions following that year will be the same in both settings as agents forecast about installed capacity will be identical (see Figure 34).

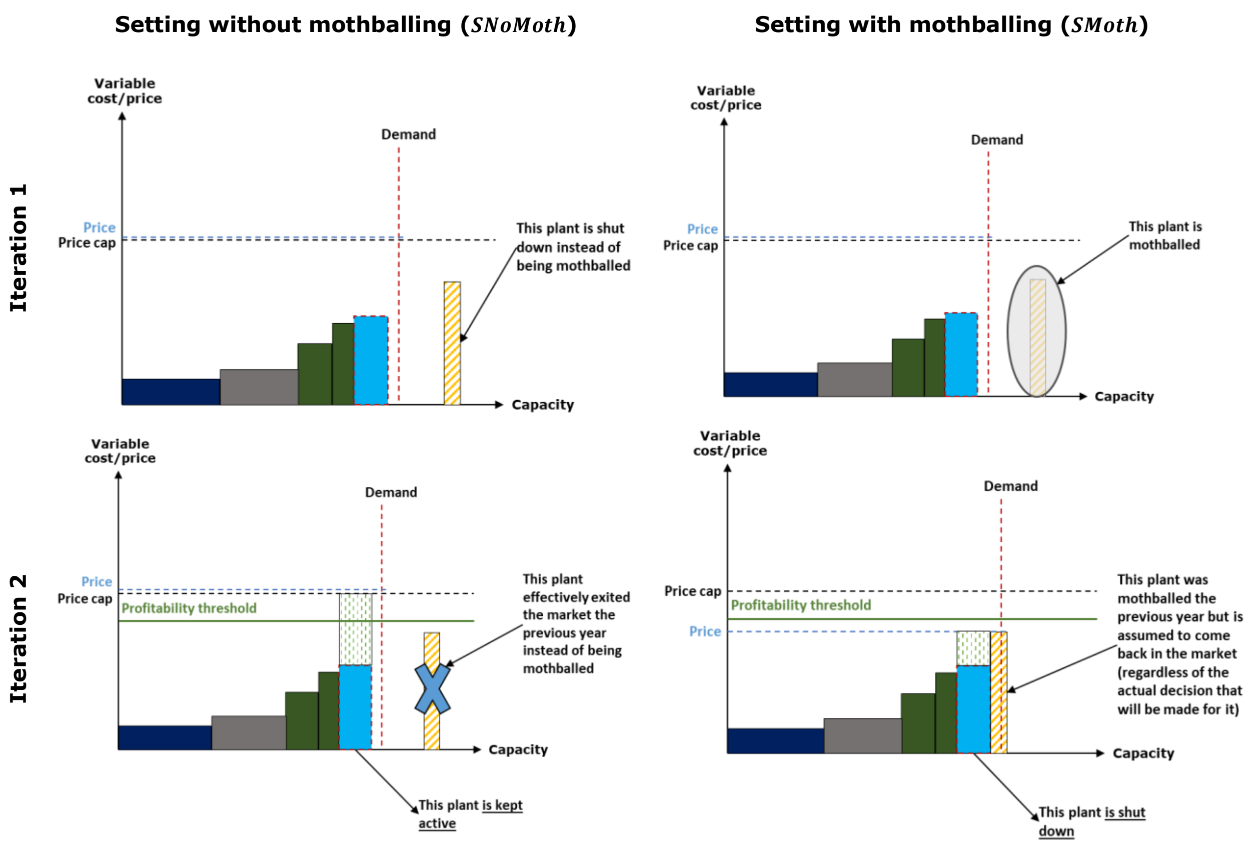
Figure 34. Illustration of expected outcome $EO3$ of mothballing



- **<u>Expected outcome 4 ($EO4$) – mothballing leads to more shutdowns and more investments</u>**: mothballed plants could also force other plants to exit prematurely as they have the possibility to come back in the market and limit other plants potential revenues. To better understand this effect, let us consider the simplistic illustration given on Figure 35. First, let us assume that both settings $SNoMoth$ and $SMoth$ are identical in year y. In each setting, agents assess their plants iteratively to determine whether they should be kept active, mothballed, or shut down permanently (as presented in section 2.2.2). Assuming the first plant which is assessed in $SNoMoth$ is shut down (iteration 1 – top left picture), the next plant to be assessed is kept online thanks to the revenues accrued from scarcity hours (iteration 2 – bottom left picture).

  Considering $SMoth$ this time, if the first plant to be assessed is mothballed instead of being shut down (iteration 1 – top right picture). When the second plant will be assessed, it is assumed (for the assessment) that the previously mothballed plant comes back on line, which automatically suppresses scarcity revenues. Therefore, the second plant could be shut down (iteration 2 – bottom right picture) rather than kept active as it was the case in $SNoMoth$. Depending on the size of the first plant in this illustration, it is possible to end up with more shutdowns in $SMoth$ compared to $SNoMoth$. Consequently, $SMoth$ could also be expected to have more subsequent investments, at least temporarily.

Figure 35. **Illustration of expected outcome $EO4$ of mothballing**

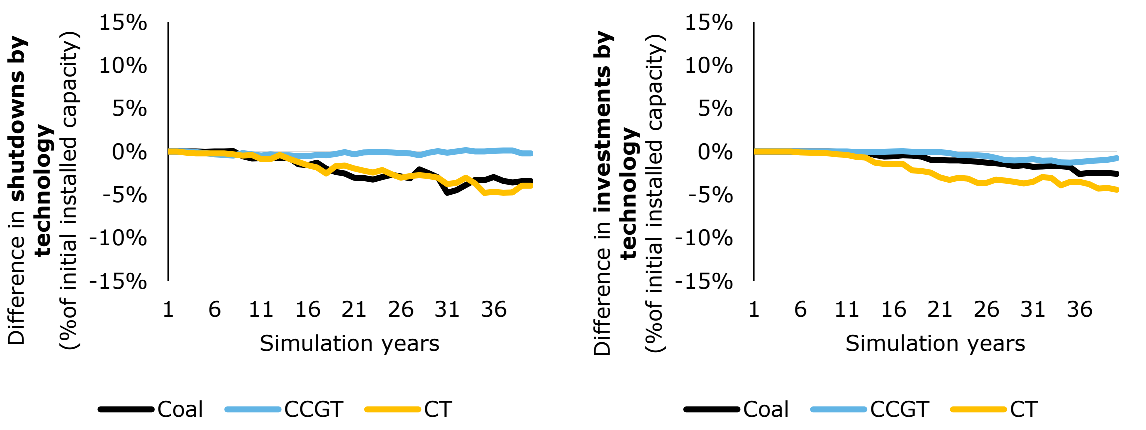


Based on the anticipated outcomes highlighted above, there is no direct conclusion that could be drawn on the potential impact of mothballing on long-run investment and shutdown decisions. The only way of assessing such effects is by the means of multiple simulations comparing the studied setting over a long-time horizon. Such an approach could help verify whether some of the anticipated effects, dominate over the others and, more importantly, whether they are persistent or not in the long run.

4.1.2. In energy-only markets, neglecting mothballing could lead to a misrepresentation of shutdowns and investments levels in a context of high demand uncertainty

To analyse long-run dynamics, the indicators $\Delta_{tech,y}^{investment}$ and $\Delta_{tech,y}^{shutdown}$ are computed for each technology through each simulation year. Figure 36 below illustrates for each technology the evolution of the average[122] differences in shutdowns and investments between the studied settings. The graphs on Figure 36 show a persistent impact of mothballing on CTs and Coal plants. CCGTs do not exhibit any significant trend as the observed deviations are random and negligible in magnitude. 95% confidence bands of the average differences in investments and shutdowns are computed for CTs and Coal. As illustrated on Figure 36, the 95% confidence bands show the effects of mothballing the investment and shutdown dynamics of these two technologies are significant[123] from a statistical point of view.

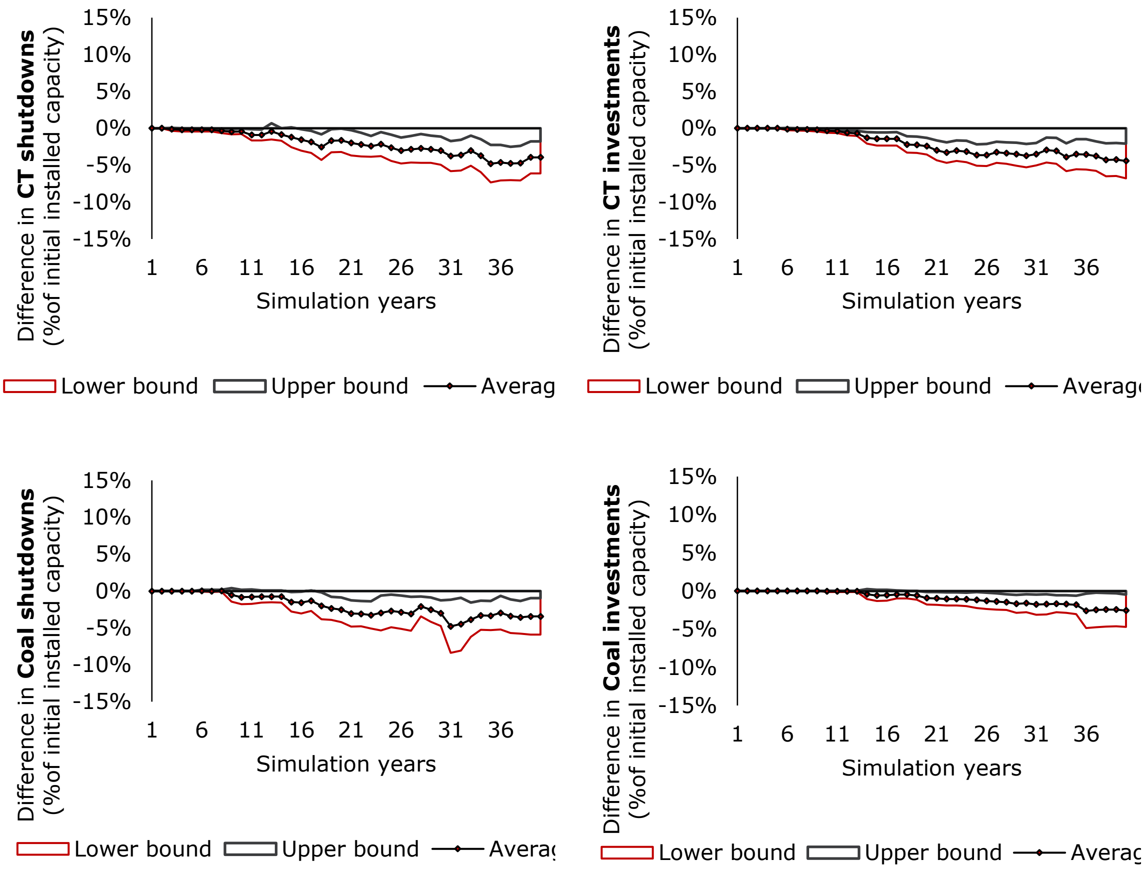
Figure 36. Impact of mothballings on shutdown and investment dynamics in energy-energy-only markets[124]



122 Average over all the 100 runs of the model.

123 Meaning that the confidence bands do not include zero, therefore rejecting the null hypothesis (the estimated effects are not random).

124 Positive values on the graphs indicate that mothballing leads to more shutdowns (respectively more investments). Conversely, negative values indicate that mothballing leads to less shutdowns (respectively investments). The lower and upper bounds correspond to a 95% confidence interval.



At the beginning of the simulations, CTs are generally the first plants to be mothballed given the volatility of their revenues and their dependence on price spikes. Around year 8, the level of CTs shutdowns in the settings start to diverge. The observed difference mainly corresponds to the anticipated outcome $EO1$ in which capacities (or part of them) that are shut down in the setting without mothballing are instead mothballed in the other setting (and thus remain in the system nonetheless). Even if after the first series of mothballing, the systems in the two studied settings are no longer rigorously comparable, the results of the simulations indicate a persistent trend of divergence regarding shutdowns.

It should be noted that at some point in the simulations, other types of outcomes (i.e., $EO2$ and $EO3$) may occur. $EO2$ for instance, explains why an infra-marginal technology such as Coal is impacted as well. By nature, $EO3$ is not observable through the indicators defined in section 3.2 as it does not create any difference in shutdowns or investments. At the end of the simulation horizon, the difference in cumulative shutdowns of CTs between the settings represents around 4% of the total initial capacity of 75 GW.

The graphs presented on Figure 36 also show the strong dependence between the dynamics of shutdown decisions and those of investment decisions. Indeed, investments' profitability mainly depend on two factors[125]: the electricity demand and the available capacity. Every shutdown decision modifies the latter, which in turn impacts the expected profitability of future investments. With that in mind, the impact of mothballings on the level of investments can be explained from the dynamics of shutdowns decisions.

As soon as shutdown decisions start to diverge between the two settings the following investment decisions are no longer the same since they are based on different forecasts. Investment incentives in setting $SNoMoth$ become mechanically stronger than those in setting $SMoth$, all things equal (because of the lower level of installed capacity perceived in $SNoMoth$). As a result, agents start investing more in setting $SNoMoth$ compared to setting $SMoth$. The final cumulative difference in CTs investments between the studied settings corresponds to 4% of the initial installed capacity of 75 GW.

To summarize, simulations results indicate that mothballing leads to chronic phases of reduced investment incentives by enabling power plants to stay longer in the market instead of exiting (as it would be the case in a market where mothballing is not allowed). Indeed, the recurrent mothballing of marginal plants (CTs in the model) delays permanent shutdown decisions for these plants and some infra-marginal plants. During this delay, agents have lower incentives to invest compared to a market where there would be no mothballing. This leads in turn to lower investment levels in the market with mothballing particularly in CTs.

Analysing investment and shutdown dynamics is also helpful in understanding how mothballing may affect security of supply. For instance, the reduced investment levels in the market with mothballing combined with the unavailability of mothballed plants suggest that, at some point, the market without mothballing may have a better security of supply than the one with mothballing. The following section discusses the potential impact of mothballing on security of supply, proxied by the level of shortages. Associated effect on electricity prices are also covered.

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125 The economic parameters of the plant have a direct impact on its profitability too.

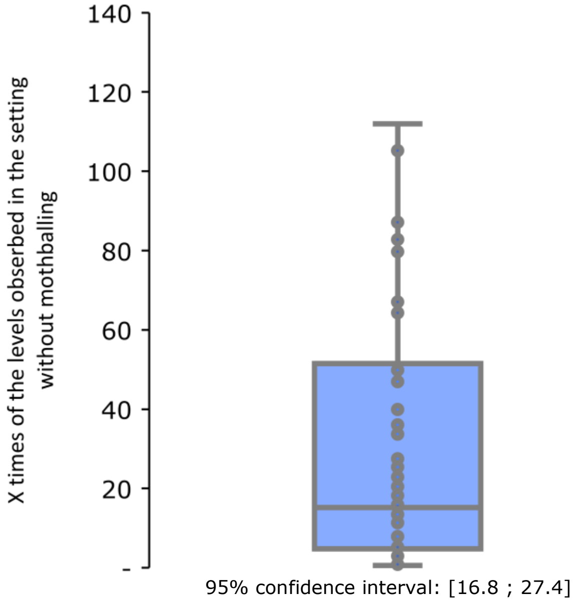
4.2. Mothballing tends to increase shortages and electricity prices

Depending on when they occur, mothballing decisions have different impacts on the level of shortages. By definition, mothballing a plant removes it temporarily from the market, thereby creating an equivalent deficit of capacity. As a result, it can be anticipated that setting $SMoth$ will experience more scarcity hours compared to setting $SNoMoth$ because of the unavailability of the mothballed plants. However, in some situations, setting $SMoth$ can actually experience less shortages than setting $SNoMoth$, at least temporarily. All things being equal, the fact that some plants can remain in the market instead of being shut down (as it is the case in setting $SNoMoth$) may improve the security of supply compared to setting $SNoMoth$ (see explanations on $EO2$). It should be noted that such situations only last about two years, before new capacities enter the market in setting $SNoMoth$ to restore a higher system margin. These successive phases are directly linked to investment and shutdown dynamics described above and occur on a recurrent basis.

The aggregate impact of mothballing on the level of shortages depends on the relative magnitude of the aforementioned effects. Figure 37 below displays the distribution of the differences in terms of unserved energy (indicator $\Delta^{shortages}$) between the setting with mothballing and the setting without mothballing. Values higher than 1 indicate that there are more shortages in setting $SMoth$ compared to setting $SNoMoth$. Conversely, values lower than 1, indicate the opposite. Figure 37 shows that mothballing has a negative impact on security of supply as it increases the level of shortages by a factor of around 20 on average (based on simulation parameters). This result is due to the fact that the deficit of capacity in setting $SMoth$ (compared to setting $SNoMoth$) induced by mothballed plants is generally higher than the excess of capacity that can be observed in setting $SMoth$ (compared to setting $SNoMoth$) once plants start being shut down in setting $SNoMoth$ but not in setting $SMoth$[126]. Moreover, new capacities quickly compensate the shutdowns in setting $SNoMoth$.

126 Recall that some of the plants in setting $SMoth$ are actually mothballed.

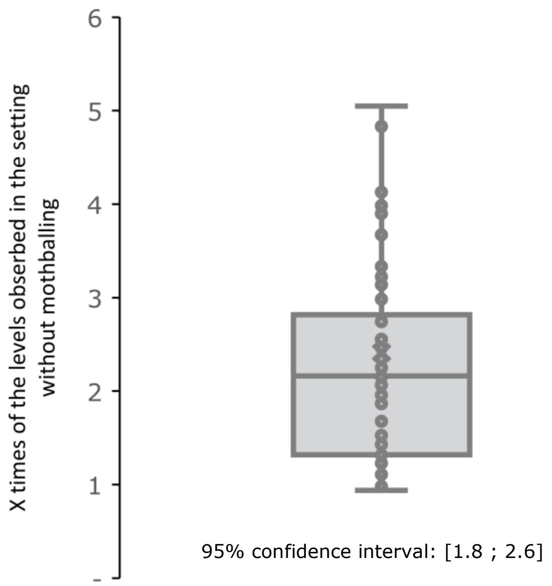
Figure 37. Impact of mothballings on shortages in energy-only market[127]



Given their direct impact on the level of available capacity, mothballing decisions are expected to have an impact on energy prices as well since they increase scarcity hours. On average, the impact of mothballing on energy prices is significant as illustrated on Figure 37, which shows the distribution of the differences in average energy prices between the two settings (indicator Δ^{prices}). Mothballing increases energy prices by more than twice on average. It should be noted that the indicator about energy prices do not capture the severity of scarcity periods as the indicator on shortages does. For instance, if there is an equivalent number of scarcity hours in the two settings, the average energy prices will also be equivalent even if the amount of unserved energy is actually higher in setting $SMoth$ compared to setting $SNoMoth$.

127 Values higher than 1 indicate that there are more shortages in setting $SMoth$ compared to setting $SNoMoth$. Conversely, values lower than 1 indicate the opposite. The segment inside the rectangle shows the median and "whiskers" above and below the box indicate the minimum and maximum points.

Figure 38. Impact of mothballings on energy prices in energy-only market[128]



The results suggest that, even in a market with no strategic behaviour, agents' incentives to mothball can be detrimental to capacity adequacy objectives. In this regard, mothballing decisions raise an important policy issue as to how to align agents' private incentives with capacity adequacy objectives. This explains why the recent wave of mothballing in Europe has been at the centre of the debates on security of supply. In some countries, it has even been one of the justifications for the implementation of capacity mechanisms (for instance in the UK). Section 5 of this chapter discusses this point precisely by analysing what outcomes to expect from a capacity market when agents' have the possibility to mothball their assets.

The results should be put in perspective of the rather extreme scenario considered for base case study. To properly illustrate all the potential effects of mothballing, a highly volatile demand was chosen on purpose (as explained in section 3.1 of the chapter). Sensitivity analyses are carried out in section 4.5.2 to show that a lower demand volatility leads to more realistic results in terms of magnitude.

128 Values higher than 1 indicate that prices are higher in setting $SMoth$ compared to setting $SNoMoth$. Conversely, values lower than 1 indicate the opposite. The segment inside the rectangle shows the median and "whiskers" above and below the box indicate the minimum and maximum points.

In addition, there are a couple of modelling assumptions (to make the model more trackable) that amplify the effects of lumpiness and ultimately those of mothballing. For each specified technology, all investments that are decided in the same year are modelled as a single plant. Also, mothballing cannot be partial (i.e., all the available capacity of the plant is mothballed). Relaxing this assumption would make the model difficult to manage in terms of size, and it would not change the direction of the results.

4.3. From a social welfare perspective, mothballing increases the need for coordination of private agents' decisions to ensure capacity adequacy

Intuitively, mothballing could be seen as an additional option in capacity provision. It gives some flexibility to private agents in their decisions as explained in section 2.2.2. However, because of the asymmetrical incentives between under procurement and over procurement of capacity for private agents, mothballing maybe detrimental to social welfare in a liberalised market.

The issue of asymmetrical incentives was discussed in the general introduction, through the lenses of investment. The same rationale holds when talking about mothballing decisions, since they can be assimilated to punctual disinvestments. When agents have the possibility to mothball their assets it is equivalent to giving them the option to disinvest temporarily at any time. Consequently, the issue of asymmetrical investment incentives appears not only at the time of the first investment decision, but also all the following years where mothballing is possible. The only difference is that the fixed costs considered in mothballing decisions are only operation and maintenance costs (conversely to an investment decision for which investment costs are also considered). This has important implications in term of social welfare.

Because private agents providing capacity do not consider the cost of shortages in their rationale for mothballing, the private value of mothballing is higher than the social cost of mothballing. From a private agent's perspective, the value of mothballing is determined by the difference between cost savings resulting from the mothballing decision and potential foregone revenues. From a social planner's perspective, the value of mothballing equals the difference between cost savings associated with the mothballing decision and potential costs of additional shortages related to the decision. In most cases, the cost of additional shortages outweighs the cost savings enabled by the mothballing decision, especially if mothballing is a year-long commitment[129].

For instance, let us consider the following situation, which is adapted from Keppler (2017). Let us assume a system in which 100 MW of mothballed peak capacity creates 10 additional hours of shortages in a year, while this capacity being kept active would result in no shortages at all. Let us also assume that there is a scarcity pricing with prices reaching the VoLL in periods of shortages. Mothballing the capacity would imply a cost of 22 M€, assuming a VoLL of 22 k€/MWh. On the other hand, given O&M costs of 15 k€/MW/year for a peaking unit, mothballing that same 100 MW would lead to cost savings of 1.5 M€ at best (assuming no mothballing and restart costs).

In the hypothetical situation described above, a social planner would rather keep the capacity active instead of mothballing it. Conversely, the private agent holding that 100 MW of capacity is better off mothballing it. By keeping the plant active, the private agent loses money since there will be no shortages and the plant will not cover its O&M costs. If the plant is mothballed instead, the agent can save part of the O&M costs and increase the profits of other plants. There is no strategic behaviour involved in this example. It is merely the outcome of a perfectly competitive market where agents seek to maximize their profits. Because of this, most optimization models which minimise total system costs (as a social planner would) without constraining the model to allow cost recovery for capacity providers would fail to capture this effect.

The results of the analysis derived from the model presented in this chapter show that mothballing tends to deteriorate social welfare by creating more shortages (see the previous section). Table 8 hereafter illustrates the negative impact of mothballing on social welfare based on the simulations carried out in this chapter.

129 As presented in the introduction of this chapter, mothballing can be decided for shorter periods such as a few months. This can reduce the magnitude of the results discussed here, without however changing the logic.

It should be noted once again that the magnitude of the results is exacerbated by some modelling assumptions regarding the indivisibility of plants[130]. While these assumptions amplify the magnitude of the results they do not change the rationale behind.

Table 8. **Impact of mothballing on system costs in an energy-only market (based on the considered simulation parameters)**

Cost components	Average increase in cost component (related to mothballing) in % of total system costs observed in the setting without mothballing
Cost of shortages[131]	166%
Generation costs	0%
O&M costs	-1%
Annualised investment costs (of installed capacity)	0%
Total additional costs	**165%**

As expected mothballing leads to operation and maintenance cost savings. In the simulations, these cost savings amount to about 1% of yearly total system costs. However, they are negligible compared to the increase in cost of shortages resulting from agents' mothballing decisions. Given the simulation parameters that are used, this increase amounts to almost 170% of yearly total system costs on average.

The results are presented in relative levels on purpose, because of the nature of the case study (extreme scenario of demand uncertainty). It does not represent an actual power system but a test case, calibrated on the French power system. Absolute values would be hard to interpret by their own. The important aspect in the discussion is the direction of the results rather than their absolute levels. More

130 To limit computation time, all investments made in the same year are assumed to represent a single plant. This may lead to plant of several gigawatts of capacity, which are indivisible in the model. This exacerbates the effect of indivisibilities. In reality, agents may be able to mothball just part of their capacity instead of the whole capacity of the plant.
131 Assuming a VoLL of 22 k€/MWh.

precisely, it is the difference between the setting without mothballing and the one with mothballing that matters for the discussion.

4.4. Remarks on the magnitude of the results and methodological limitations

It is important to underline that the magnitude of the effects presented in this section (both in terms of shortages and electricity prices) are exacerbated by a few modelling assumptions. Indeed, the volumes of shortages depend on the size of the plants that are being mothballed. In the model, agents cannot recourse to partial mothballing (i.e., mothballing only a portion of the plant's capacity). This means that capacity lumpiness is of particular importance. The larger the size of the plants, the stronger the effects are (in terms of shortages and potentially electricity prices). Since all investment decisions realised the same year (for each technology) are modelled as a single plant for tractability issues, plants can have a size of several gigawatts when peak demand is highly volatile[132].

The sensitivity analysis carried out in section 4.5.2, shows that the effects of mothballing are less pronounced with a lower demand volatility.

4.5. Sensitivity analysis

4.5.1. Higher energy price caps exacerbate the effects of mothballing on energy prices and security of supply

To complement the analysis, the same simulations are run on an energy-only market with scarcity pricing (i.e., in which the price cap is equal to the VoLL). Interestingly, the results indicate an increased occurrence of mothballing when the price cap increases. The table below summarises the effect of this increase in price cap on the intensity of mothballing through two indicators. The first one shows the frequency of mothballing as the average number of years with mothballed plants over the simulation horizon. It shows that the market with scarcity pricing experiences on average two more years of mothballing compared to the market with a price cap of 3 k€/MWh. The second indicator measures the average ratio of

132 Indeed, if agents anticipate a high increase in peak demand, they may invest a lot to capture the expected profits.

yearly mothballed capacity for CCGTs and CTs. While no significant change is observed for CTs, the average ratio of mothballed CCGTs increases from 30% to 43% as a result of a higher price cap. These observations indicate that increasing the price cap in an energy-only market tends to exacerbate the severity of mothballing.

Table 9. Intensity of mothballing with a higher energy price cap

		Energy-only market with a price cap of 3 k€/MWh	Energy-only market with a price cap of 22 k€/MWh
Frequency of mothballing (average number of years with at least one mothballed plant over the simulation horizon)		28	**30**
Severity of mothballing (average ratio of yearly mothballed capacity by technology)	**CCGT**	30%[133]	**43%**
	CT	36%[134]	**36%**

The correlation between the energy price cap and the severity of mothballing can be intuitively explained by the fact that a higher price cap implies a higher profitability during scarcity hours and thus more opportunities to recover fixed costs. Recalling that mothballing is particularly interesting when plants' revenues cover only part of their fixed costs, when potential revenues are higher, there is a better chance of plants being mothballed or kept active, all things remaining equal. The explanation is that prices become far more volatile (as explained hereafter), which makes mothballing more attractive.

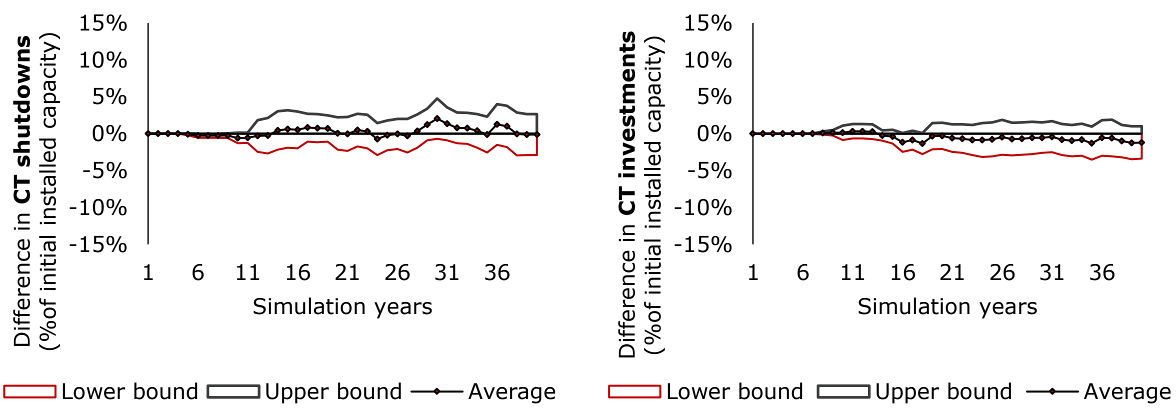
Focusing now on the different indicators designed to analyse the impact of mothballing decisions, it appears that increasing the price cap reduces the impact of mothballing on shutdown and investment dynamics. Indeed, Figure 39 shows how these dynamics are modified in presence of scarcity pricing. Unlike the results presented previously, it is difficult to conclude on the statistical significance of the

[133] This ratio is computed with respect to the technology's installed capacity. Based on the simulations, this would represent about 15% of total installed capacity.

[134] This ratio is computed with respect to the technology's installed capacity. Based on the simulations, this would represent about 15% of total installed capacity.

estimated effects in the case of a scarcity pricing since the 95% confidence bands consistently include zero. As mentioned above, when the price cap increases, there is a better chance of plants being kept active or mothballed instead of being shut down. This leads to more occurrences of the outcome $EO3$ which in turn mitigates the effects of mothballing.

Figure 39. **Impact of mothballing on shutdown and investment dynamics with a higher energy price cap (focus on CTs)**[135]



While shutdown and investment dynamics are less affected by mothballing decisions when the energy price cap is increased, effects on security of supply and shortages seem to be amplified. Table 10 highlights the impact of mothballing on shortages and average energy prices in presence of scarcity pricing. The numbers indicate a magnified effect of mothballing on both indicators compared to the case with a lower price cap. For instance, the average increase in shortages resulting from mothballing corresponds to a factor of 88 with scarcity pricing, compared to 22 with a price cap of 3 k€/MWh. Similarly, the average increase in electricity prices corresponds to a factor of 8 with scarcity pricing, while it is only a factor of 2 with a price cap of 3 k€/MWh.

135 Positive values on the graphs indicate that mothballing leads to more shutdowns (respectively more investments). Conversely, negative values indicate that mothballing leads to less shutdowns (respectively investments). The lower and upper bounds correspond to a 95% confidence interval.

Table 10. Impact of mothballing on shortages and energy prices with a higher energy price cap

		Energy-only market with a price cap of 3 k€/MWh	Energy-only market with a price cap of 22 k€/MWh
Increase in shortages (X times the level observed in the setting without mothballing)	Average	22.1	**87.8**
	Standard deviation	27.1	**113.2**
	95%-confidence interval	[16.8 ; 27.4]	**[65.6 ; 110.0]**
Increase in energy prices (X times the level observed in the setting without mothballing)	Average	2.2	**7.8**
	Standard deviation	2.0	**6.3**
	95%-confidence interval	[1.8 ; 2.6]	**[6.5 ; 9.0]**

These last results are directly related to the observations on the severity of mothballing. Indeed, more frequent and intense mothballing translate into more capacity being withheld from the market, therefore leading to more shortages and more price spikes. The behaviour of the energy-only market in a world where agents have the possibility to mothball their assets poses crucial policymaking issues, especially regarding capacity adequacy-related market design. As discussed throughout this section, the opportunity to mothball plants negatively affects security of supply in these types of markets and at the same time modifies investment and shutdown signals. Instead of reducing these effects, scarcity pricing leads in fact to even more detrimental outcomes in terms of security of supply by making mothballing more attractive.

4.5.2. Lower residual demand volatility limits the effects of mothballing

Mothballing decisions and uncertainty are intrinsically related. The more uncertain the environment, the more attractive mothballing can be for agents seeking to avoid temporary losses. In order to verify this intuition, a sensitivity analysis is run on the main source of uncertainty in the simulations, which is the electricity demand. In all previous sections, a highly uncertain demand with a standard deviation of 5% for the evolution of the peak load was considered. For the sensitivity analysis, a standard deviation of 2.5 % is considered and all other simulation parameters remain unchanged (compared to the base case simulation).

Looking at aggregate indicators on the intensity of mothballing, the first observation is that both the frequency and severity of mothballing decrease when there is less uncertainty (see Table 11). The average number of years with mothballing decreases from 28 to 25 years (over the 40 years of simulation). Nonetheless, the average proportion of mothballed capacities drops significantly, for both CCGTs and CTs. This suggests less pronounced impacts in terms of long run dynamics, shortages levels, and energy prices.

Table 11. Intensity of mothballing with lower demand uncertainty

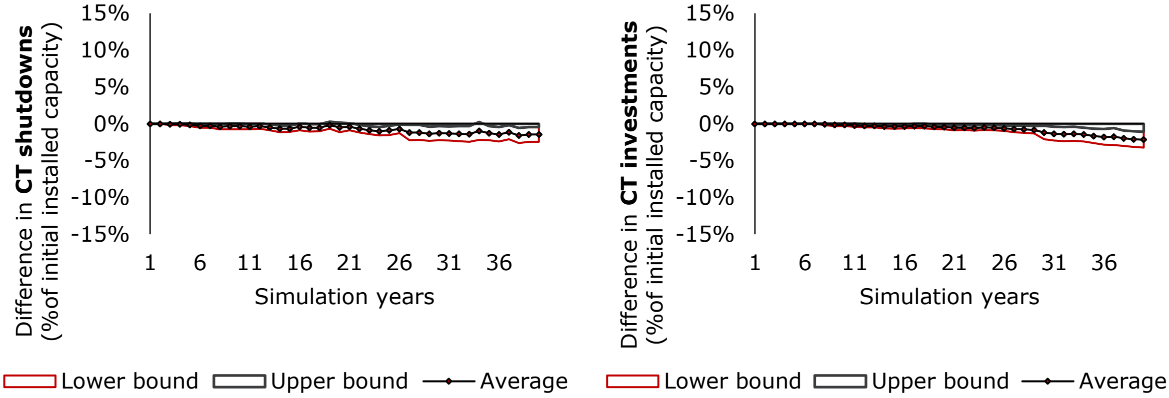
		Base case (5% standard deviation for electricity growth rate)	**Alternative case (2.5% standard deviation for electricity growth rate)**
Frequency of mothballing (average number of years with at least one mothballed plant over the simulation horizon)		28	**25**
Severity of mothballing (average ratio of yearly mothballed capacity by technology)	**CCGT**	30%[136]	**10%**
	CT	36%[137]	**19%**

As expected, a reduced intensity of mothballing leads to less interference with investment and shutdown dynamics. Figure 40 below shows that no clear trend emerges on the long run, as mothballing merely creates small deviations.

[136] This ratio is computed with respect to the technology's installed capacity. Based on the simulations, this would represent about 15% of total installed capacity.

[137] This ratio is computed with respect to the technology's installed capacity. Based on the simulations, this would represent about 15% of total installed capacity.

Figure 40. Impact of mothballing on long run dynamics with lower demand uncertainty [138]



Regarding shortages and energy prices, mitigated effects are observed, although still noteworthy (see Table 12). On average, mothballing still lead to shortages levels that are 4 times higher compared the setting without mothballing. Energy prices are also still 10% higher in the setting with mothballing on average, but this effect does not seem to be statistically significant given the corresponding confidence interval. It should be noted that these results are more in line with what would happen in an actual power system with realistic market conditions (compared to the scenario in the base case where demand is highly volatile).

138 Positive values on the graphs indicate that mothballing leads to more shutdowns (respectively more investments). Conversely, negative values indicate that mothballing leads to less shutdowns (respectively investments). The lower and upper bounds correspond to a 95% confidence interval.

Table 12. Impact of mothballing on shortages and energy prices with lower demand uncertainty

		Base case (5% standard deviation for electricity growth rate)	Alternative case (2.5% standard deviation for electricity growth rate)
Increase in shortages (X times the level observed in the setting without mothballing)	Average	22.1	**3.8**
	Standard deviation	27.1	**3.7**
	95%-confidence interval	[16.8 ; 27.4]	**[3.1 ; 4.6]**
Increase in energy prices (X times the level observed in the setting without mothballing)	Average	2.2	**1.1**
	Standard deviation	2.0	**1.1**
	95%-confidence interval	[1.8 ; 2.6]	**[0.9 ; 1.3]**

4.5.3. Variation of mothballing and restart costs

All the results presented above relied on an assumption that mothballing and restarting costs are each equivalent to 25% of annual O&M costs. This number is the only value in the existing literature (Frontier Economics, 2015b). Mothballing costs are usually strategic information that utilities do not disclose. In order to test the robustness of the simulation results (regarding mothballing intensity) presented here, a sensitivity analysis is carried out with respect to mothballing/restarting costs.

Table 13 indicates that mothballing severity (% of yearly mothballed capacity relative to the technology's installed capacity in the same year) varies depending on mothballing/restarting costs assumptions for CCGTs and CTs. The cheaper it is to mothball and restart assets (alternative case 1), the more mothballing is an attractive option for agents. This is illustrated by the increased intensity of mothballing in alternative case 1. Conversely, if mothballing becomes very expensive, then agents have a limited interest of adopting it, as highlighted by the results for alternative case 2.

Table 13. Intensity of mothballing with alternative mothballing/restart costs assumptions

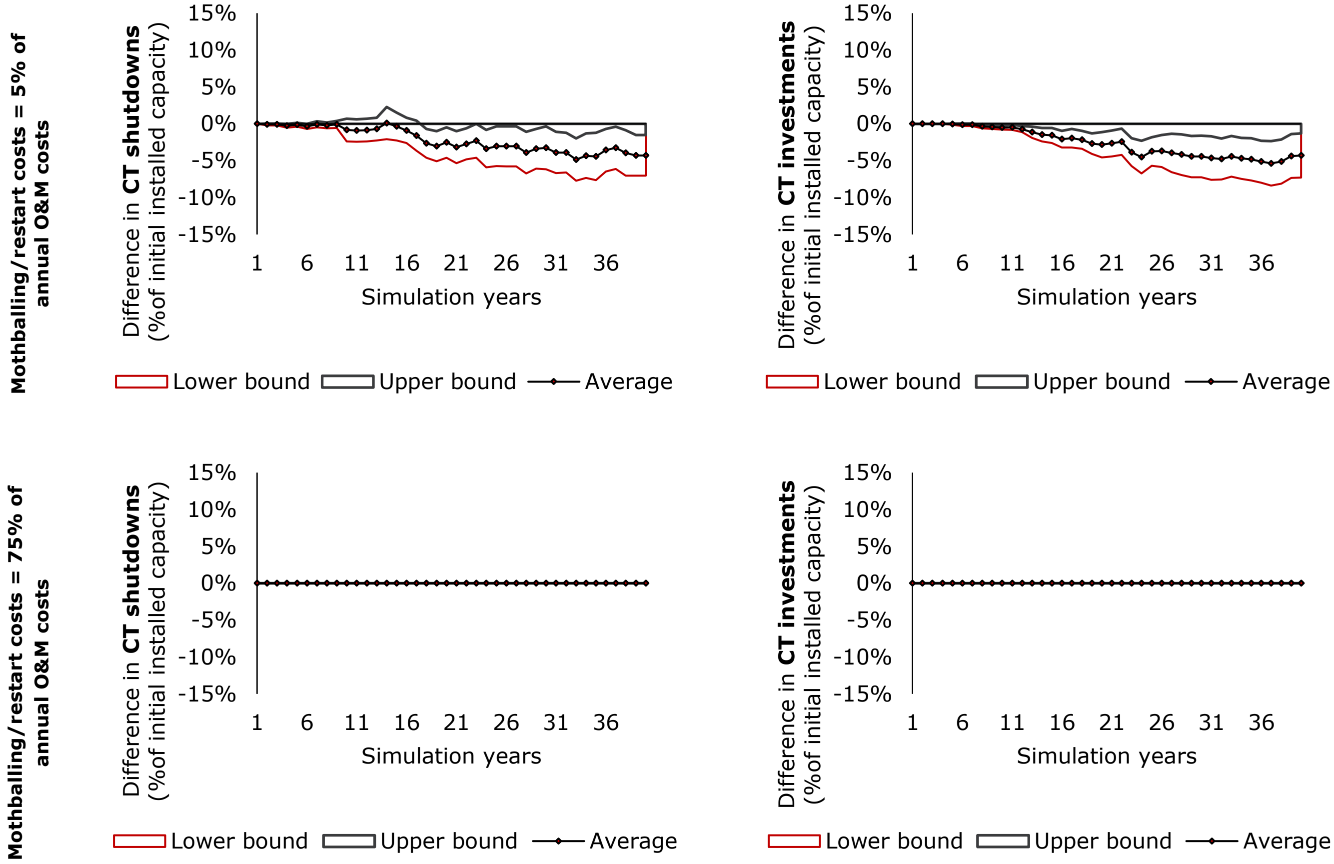
		Alternative case 1 (5% of annual O&M costs)	Base case (25% of annual O&M costs)	Alternative case 2 (75% of annual O&M costs)
Frequency of mothballing (average number of years with at least one mothballed plant over the simulation horizon)		**29**	28	**0**
Severity of mothballing (average ratio of mothballed capacity by technology)	**CCGT**	**39%**	30%[139]	**0%**
	CT	**35%**	36%[140]	**0%**

The results in terms of mothballing intensity are reflected in other dimensions of mothballing, notably regarding its impact on long-run dynamics, shortages and electricity prices. Figure 41 shows the results for long-run dynamics. Results for shortages and electricity prices are illustrated in Table 14. Overall the sensitivity analysis regarding mothballing/restarting costs confirms the expected reaction of the model in terms of changes in the mothballing/restarting cost structure and is in line with the rationale of mothballing decisions.

[139] This ratio is computed with respect to the technology's installed capacity. Based on the simulations, this would represent about 15% of total installed capacity.

[140] This ratio is computed with respect to the technology's installed capacity. Based on the simulations, this would represent about 15% of total installed capacity.

Figure 41. Impact of mothballing on long run dynamics with alternative mothballing/restart costs assumptions[141]



141 Positive values on the graphs indicate that mothballing leads to more shutdowns (respectively more investments). Conversely, negative values indicate that mothballing leads to less shutdowns (respectively investments). The lower and upper bounds correspond to a 95% confidence interval.

Table 14. **Impact of mothballing on shortages and energy prices with alternative mothballing/restart costs assumptions**

		Alternative case 1 (5% of annual O&M costs)	Base case (25% of annual O&M costs)	Alternative case 2 (75% of annual O&M costs)
Increase in shortages (X times the level observed in the setting without mothballing)	Average	**35.0**	22.1	**1**
	Standard deviation	**42.9**	27.1	**NA**
	95%-confidence interval	**[26.6 ; 43.5]**	[16.8 ; 106.7]	**NA**
Increase in energy prices (X times the level observed in the setting without mothballing)	Average	**2.4**	2.2	**1**
	Standard deviation	**2.1**	2.0	**NA**
	95%-confidence interval	**[2.0 ; 2.8]**	[1.7 ; 1.8]	**NA**

5. Analysing mothballing in capacity markets

5.1. In capacity markets, mothballing can modify the arbitrage between existing and new capacities in capacity auctions

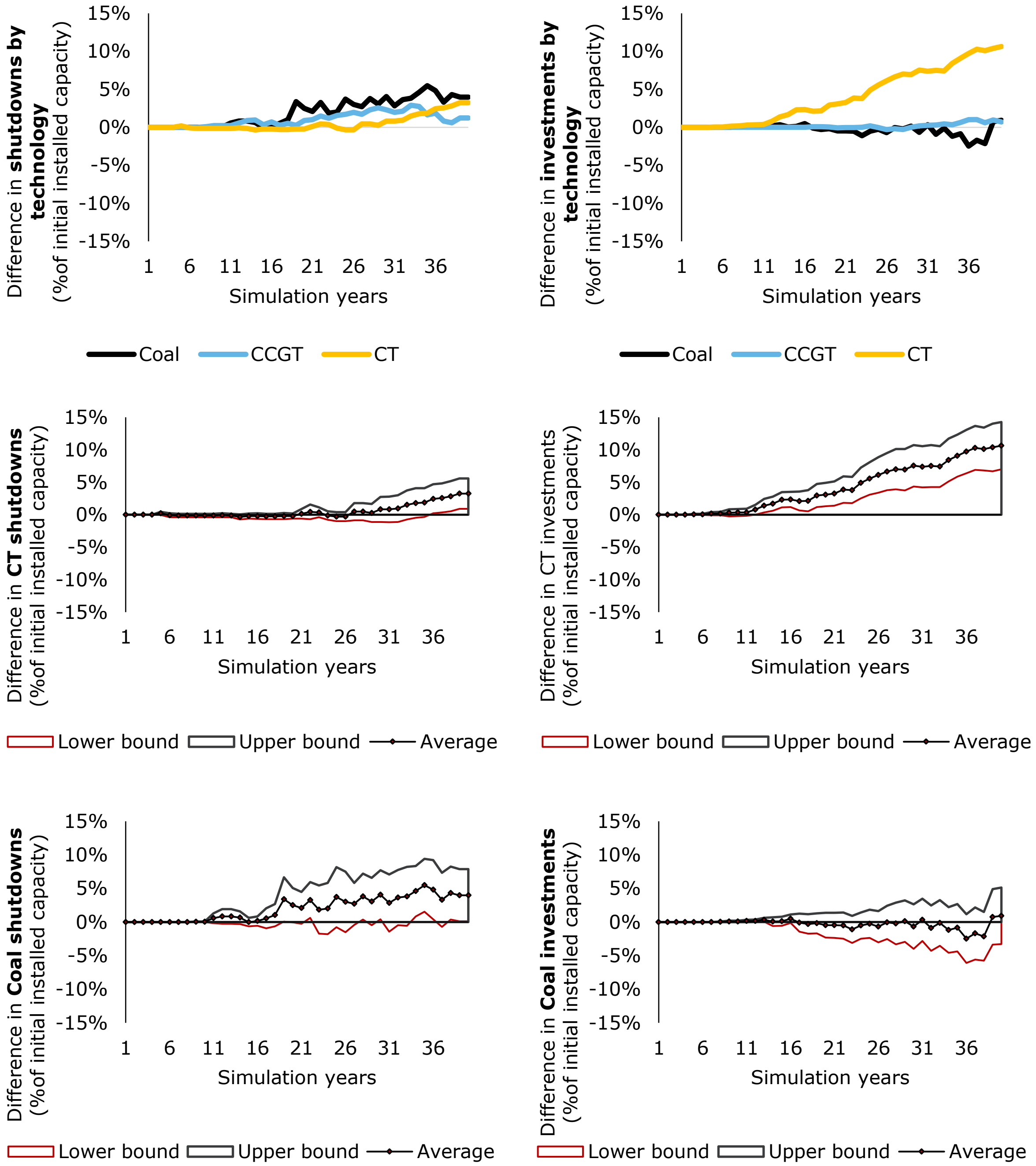
Unlike the energy-only market, shutdown and investment decisions in a capacity market are only known after the clearing of the capacity auction. Given this difference, the analysis regarding the expected effects of mothballing on investments and shutdowns presented for the energy-only market cannot be transposed here. Nonetheless, some interesting insights can be derived for capacity markets.

As presented in section 2.3, existing capacities and new capacities submit their bids for the capacity auction based on their respective anticipations. When mothballing is available, existing plants include an opportunity cost of staying active (compared to being mothballed) in their capacity bids. This increases their bids[142] to an extent that makes some existing plants (even recent ones) less attractive than a new investment. It changes the dynamics of the capacity auctions by making existing plants more expensive than what would be the case if mothballing was not available to agents.

From a long-run point of view, this translates in a preference for new capacities (and thus investments) when agents' have the possibility to mothball their assets. The graphs on Figure 42 illustrate this long-run effect through a comparison of shutdown and investment levels between the setting with mothballing ($SMoth$) and the one without mothballing ($SNoMoth$). A focus is made on CTs and coal plants which exhibit results that are partially significant (statistically).

142 The impact of mothballing capacity prices is covered more extensively in the next section.

Figure 42. Impact of mothballings on shutdown and investment dynamics in capacity markets[143]



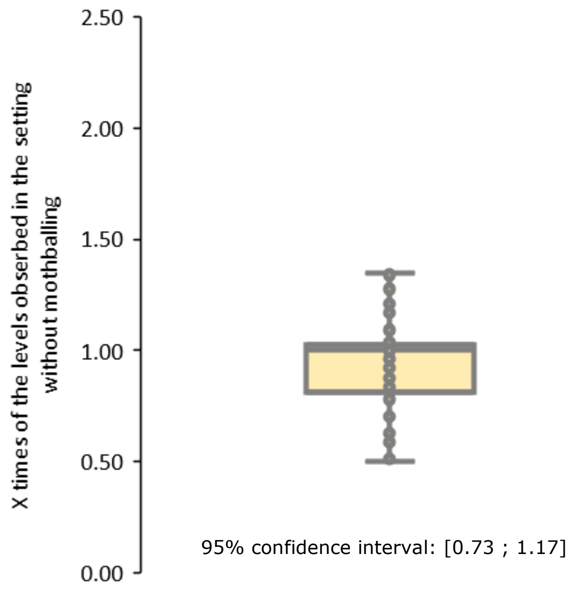
143 Positive values on the graphs indicate that mothballing leads to more shutdowns (respectively more investments). Conversely, negative values indicate that mothballing leads to less shutdowns (respectively investments). The lower and upper bounds correspond to a 95% confidence interval.

For CTs and coal, an effect on shutdown and investment dynamics is visible, although moderate in most cases. In the capacity market, mothballing tends to lead to more shutdowns as well as more investments. The curves corresponding to the upper and lower bound delimits a 95% confidence band. They show that the results are not always statistically significant for CT shutdowns since the confidence band includes the horizontal axis. For CT investments, results are statistically significant. For coal plants, the tendency is reversed. Impact on shutdowns appear to be statistically significant in some years, while impact on investments are not. These findings suggest that mothballing leads to a substitution of (existing) coal plants by (new) CTs, through the capacity auction. This is coherent with the explanations above regarding the preference for new investments compared to existing plants.

5.2. In capacity markets, mothballing has limited impact on shortages, energy prices and capacity prices

Figure 43 shows the distribution of the difference in shortages between the setting with mothballing ($SMoth$) and the one without mothballing ($SNoMoth$). As for all the distributions presented in this chapter, the differences are computed with respect to $SNoMoth$. Values higher than 1 correspond to cases where the shortages in $SMoth$ are higher than those in $SNoMoth$ and values lower than one correspond to the opposite cases. The distribution on Figure 43 indicates that in the capacity market, mothballing has no impact on shortages on average, according to simulations. The 95% confidence interval suggests that the differences in terms of shortages between the studied settings are not statistically significant. Indeed the 95% confidence interval includes the value 1 (which is equivalent to a difference in shortages of 0% between the settings).

Figure 43. **Impact of mothballings on shortages in capacity market**[144]

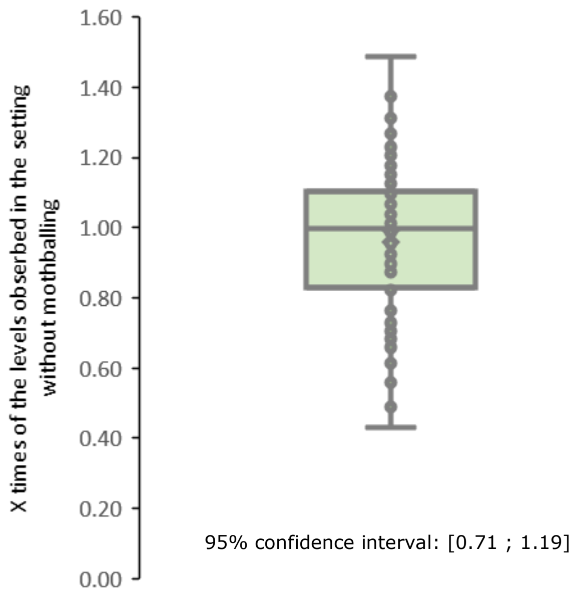


On Figure 44, differences in capacity prices between the studied settings are displayed. $SMoth$ seems to experience capacity prices that are similar to those observed in $SNoMoth$. The statistical significance test indicates that the differences between the settings are not significant[145].

144 Values higher than 1 indicate that there are more shortages in setting $SMoth$ compared to setting $SNoMoth$. Conversely, values lower than 1 indicate the opposite. The segment inside the rectangle shows the median and "whiskers" above and below the box indicate the minimum and maximum points.

145 Indeed the 95% confidence interval includes the value 1, which is equivalent to a difference in prices of 0% between the settings.

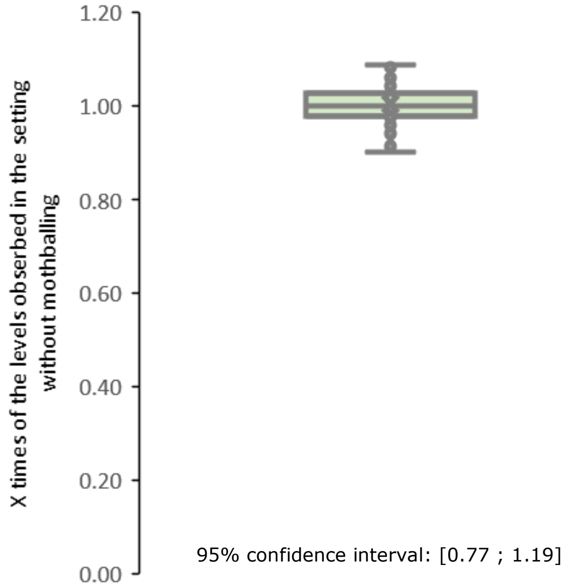
Figure 44. **Impact of mothballings on capacity prices in capacity market**[146]



Regarding energy prices, the simulation results do not highlight any clear impact either. Figure 45 indicates that energy prices are overall similar in both settings. The difference in energy prices does not seem to be statistically significant as suggested by the 95% confidence interval which includes the value 1 (i.e., a difference of 0% between the studied settings). Therefore, there is no systematic impact of mothballing on energy prices in the capacity market.

146 Values higher than 1 indicate that prices are higher in setting $SMoth$ compared to setting $SNoMoth$. Conversely, values lower than 1 indicate the opposite. The segment inside the rectangle shows the median and "whiskers" above and below the box indicate the minimum and maximum points.

Figure 45. Impact of mothballings on energy prices in capacity market[147]



5.3. From a social welfare perspective, capacity markets realign private agents' incentives with capacity adequacy objectives

The results discussed above are based on the assumption that agents behave in a perfectly rational way and always make their bids with respect to their opportunity cost. In other words, the higher bids from existing plants (induced by the possibility to mothball), are not a result of any strategic behaviour. They are due to a mismatch between private agents' interests and capacity adequacy objectives (the asymmetrical incentives between under-procurement and over-procurement of capacity). While the mismatch is related to the inelasticity of peak demand and capacity indivisibility, mothballing creates an opportunity for it to manifest (see discussion for energy-only markets in section 4.3).

Capacity markets try to realign private incentives with adequacy objectives through the capacity price but can only succeed in doing so when the capacity price cap is not a limiting factor. From a social welfare perspective, this mitigates

147 Values higher than 1 indicate that prices are higher in setting $SMoth$ compared to setting $SNoMoth$. Conversely, values lower than 1 indicate the opposite. The segment inside the rectangle shows the median and "whiskers" above and below the box indicate the minimum and maximum points.

the negative effect of mothballing associated to the higher levels of shortages it may create. Table 14 below illustrates the net effect of mothballing on social welfare in the capacity market considered for the simulations.

Table 15. Impact of mothballing on system costs in a capacity market (based on the considered simulation parameters)

Cost components	Average increase in cost component (related to mothballing) % of total system costs observed in the setting without mothballing
Cost of shortages[148]	-0.2%
Generation costs	0.1%
O&M costs	-0.1%
Annualised investment costs (of installed capacity)	-0.2%
Total additional costs	**-0.4%**

Capacity markets reduce the occurrence of mothballing and thereby the magnitude of their impact on social welfare. Overall, mothballing has a negligible impact on social welfare, according to simulations. It should be noted that the impact on shortages is not statistically significant as explained in section 5.2. The appearing reduction of costs related to shortages does not mean that mothballing reduces shortages in a capacity market. The reduction in O&M costs related to mothballing is less pronounced, as expected. A reduction in annualised investment costs is also observed due to mothballing. This comes from the substitution between coal and CTs described above. Indeed, since CTs have lower investment costs than coal, replacing coal by CTs contributes to lowering total annualised investment costs.

5.4. Sensitivity analysis

The sensitivity analysis carried out in the previous section confirmed some intuitions about the impact of demand uncertainty and mothballing/restart cost structure on mothballing. When uncertainty is lower, agents are less prone to mothball their assets. Also, mothballing becomes less attractive as it becomes

148 Assuming a VoLL of 22 k€/MWh.

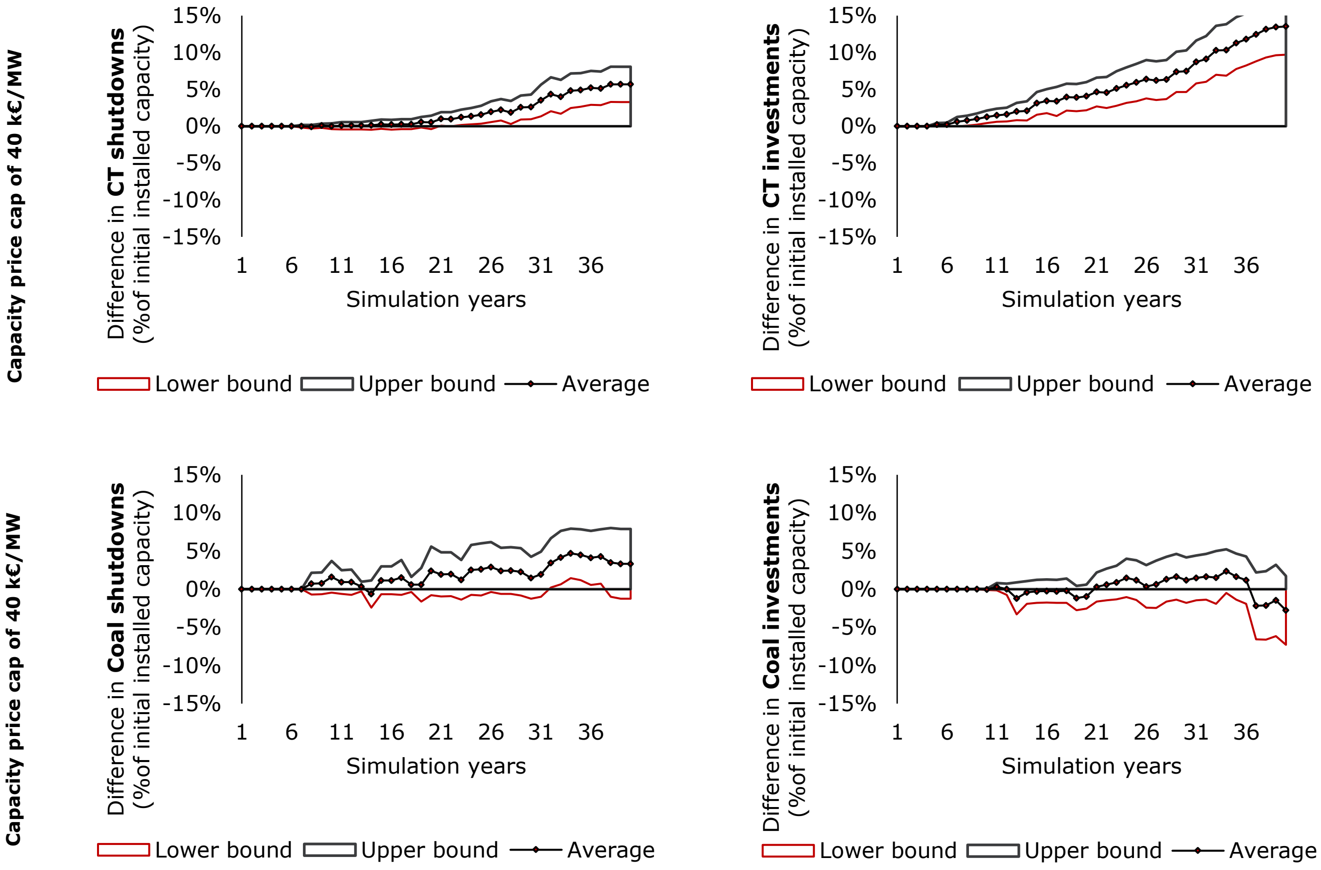
more expensive. These intuitions are also true for capacity markets. In this section, the sensitivity analysis focuses on the capacity price cap which is the new parameter (compared to the section on energy-only markets). An alternative capacity price cap of 40 k€/MW (instead of 80 k€/MW) is considered for the sensitivity analysis.

Table 16. Intensity of mothballing with lower capacity price cap

		Base case (capacity price cap at 80 k€/MW)	Alternative case (capacity price cap at 40 k€/MW)
Frequency of mothballing (average number of years with at least one mothballed plant over the simulation horizon)		3	**2**
Severity of mothballing (average ratio of yearly mothballed capacity by technology)	**CCGT**	3%	**2%**
	CT	1%	**1%**

As highlighted in Table 16, lowering the capacity price cap has little effect on mothballing intensity. The frequency and severity of mothballing remain negligible, confirming the ability of the capacity market to avoid mothballing. In terms of long-term dynamics, the main trends discussed in section 5.1 are still observed, meaning that the possibility to mothball leads to a preference for new plants instead of existing ones in capacity auctions (see Figure 46). Finally, the results regarding shortages, capacity prices and energy prices are still negligible (see Table 17), which is consistent with the results on the intensity of mothballing. Overall, the sensitivity analysis suggests that changing the capacity price cap does not affect the main results presented in this section.

Figure 46. Impact of mothballing on long run dynamics with lower capacity price cap[149]



149 Positive values on the graphs indicate that mothballing leads to more shutdowns (respectively more investments). Conversely, negative values indicate that mothballing leads to less shutdowns (respectively investments). The lower and upper bounds correspond to a 95% confidence interval.

Table 17. Impact of mothballing on shortages, capacity prices and energy prices with lower capacity price cap

		Base case (capacity price cap at 80 k€/MW)	Alternative case (capacity price cap at 40 k€/MW)
Increase in shortages (X times the level observed in the setting without mothballing)	Average	0.95	**0.95**
	Standard deviation	1.14	**1.15**
	95%-confidence interval	[0.73 ; 1.17]	**[0.72 ; 1.17]**
Increase in capacity prices (X times the level observed in the setting without mothballing)	Average	0.95	**0.96**
	Standard deviation	1.23	**1.20**
	95%-confidence interval	[0.71 ; 1.19]	**[0.72 ; 1.20]**
Increase in energy prices (X times the level observed in the setting without mothballing)	Average	0.98	**0.99**
	Standard deviation	1.08	**1.06**
	95%-confidence interval	[0.77 ; 1.19]	**[0.78 ; 1.20]**

6. Chapter conclusions

Long-time overlooked in modelling studies because of its rare occurrence, mothballing has become a more frequent practice in European markets. Most utilities have used it to preserve part of their generation assets from temporary unfavourable market conditions. While this strategy is justified from a private company's perspective, it has a direct impact on capacity adequacy since it reduces the level of available capacity. Moreover, this strategy may have unexpected long-run effects that are still not understood in the current literature. This chapter feeds onto the ongoing debates about capacity adequacy in the transforming European electricity markets. It proposes a detailed analysis of the behaviour of an energy-only market and a capacity market in presence of mothballing decisions and highlight a number of insights that can inform policy making.

The analysis is based on a Monte Carlo approach applied to a simulation model, which endogenously represents all investment, mothballing and shutdown decisions in a liberalised electricity market. This model is based on the System Dynamics methodology. To properly capture the effect of mothballing, two power systems are compared: a system in which agents cannot mothball their plants and one in which mothballing is an available strategy. These systems present identical initial conditions and differ only by the presence or absence of mothballing. All differences observed between the systems are therefore consequences of mothballing. The discussion focuses on the impact of mothballing in terms of investment/shutdown dynamics, security of supply (measured through shortages), electricity prices and capacity prices.

Simulations show that if the possibility to mothball exists, it modifies shutdown and investment signals, in a potentially persistent way depending on the system. More specifically, the results indicate that CTs and coal plants are the most affected by these changes. By mothballing part of their plants, agents defer shutdown decisions and, consequently, potential investment decisions in energy-only markets. This results in lower levels of shutdowns and investments compared to a situation where mothballing is not possible. Regarding security of supply, the results suggest a negative impact of mothballing. It also leads to prices that are higher on average (compared to a world where mothballing is not possible).

To complement the analysis, the same simulations were run on an energy-only market with scarcity pricing (i.e., the price cap is set at the VoLL). The associated results provide some additional insights regarding the impact of mothballing in an energy-only market. First, it appears that increasing the price cap in an energy-only market increases the intensity of mothballing. Indeed, a higher price cap translates into potentially higher but more volatile revenues, which makes mothballing a plant more attractive than shutting it down or keeping it active, all things equal. Interestingly, this reduces the changes in investment and shutdown dynamics induced by mothballing. However, the impacts on security of supply and electricity prices are exacerbated instead, because of the increased severity of mothballing.

In the case of capacity markets, when agents have an incentive to mothball their plants instead of keeping them active, committing to stay active through a capacity contract creates an opportunity cost for them. They may thus try to internalise this opportunity cost in their capacity bid, which, in addition to ensuring cost recovery, will also need to cover the perceived opportunity cost. Due to this, the merit-order between existing and new capacities may be modified in capacity auctions, to an extent that sometimes results in a preference for new capacities instead of existing ones. Mothballing can therefore modify investment and shutdown dynamics even in capacity markets. Notwithstanding that, capacity markets do not appear to be affected by mothballing in terms of shortages, electricity prices and capacity prices. Through the capacity price, capacity markets try to realign private incentives with adequacy objectives by remunerating private agents to keep their assets active.

The results of this analysis bring three main contributions to the current literature. Firstly, from a modelling perspective, they highlight the importance of considering mothballing in long-term simulation models of power markets. They show how models that neglect mothballing decisions might lead to misleading conclusions for energy-only and capacity markets. Secondly, these results point out some limitations of energy-only market that are new in the literature on market design for capacity adequacy. In this regard, one particularly important caveat of energy-only markets relates to their behaviour when scarcity pricing is applied in presence of mothballing. While this market architecture is argued to be a valid alternative to capacity remuneration mechanisms for the provision of long-term security of supply, it is showed that its performance can be significantly affected in a world of high uncertainty and the possibility to mothball. Thirdly, it is showed that capacity markets can realign private investors' incentives and capacity adequacy objectives through the capacity price.

To conclude, the analysis presented in this chapter could be refined by considering more granular mothballing periods for instance. Here, mothballing is only decided on a yearly basis and for a full year. In reality, agents can mothball their plants just for a few months (during the summer for instance) which allows them to exploit even more the option value of mothballing. Moreover, all the numbers resulting from the simulations remain illustrative and are not relatable to any real power system because of an absence of reliable data on actual mothballing costs. A possible extension of this work, which may help overcome this caveat would be the development of an empirical approach to estimate mothballing costs based on available market data.

Another relevant extension would be to use the model for a comprehensive comparison of the performances of market design options. The next chapter provides such an analysis by assessing the ability of several market designs to deliver long-term capacity adequacy in a context massive deployment of RES. It contributes to the current debate on security of supply in face of the ongoing energy transition.

CHAPTER III. Capacity adequacy in a context of non-increasing demand and high renewable penetration: a discussion on market design options

Abstract

This chapter provides a comprehensive comparison of several market design options for ensuring long-term capacity adequacy in the context of energy transition. It considers a system subject to a high penetration of renewables, which is consistent with the current transformation of power systems across the world, and in Europe in particular. The comparison is done from a social welfare perspective, with discussions on other specific dimensions that are relevant to policymaking: security of supply (i.e., capacity adequacy itself), costs for consumers, investment risk and profitability of capacity resources.

Five market designs are studied and compared: an energy-only market with an administrative price cap, an energy-only market with scarcity pricing where the price cap equates the VoLL, a strategic reserve mechanism, a capacity market with annual capacity contracts and a capacity market with multiannual capacity contracts for new investments. To this end, a dynamic simulation model inspired from the System Dynamics methodology, is developed to represent endogenously investment, mothballing and shutdown decisions from market participants.

The chapter includes six sections. Section 1 introduces the research question and its context. Section 2 covers the methodology, in particular the modelling of a capacity market with multiannual contracts. Section 3 describes the case study used for simulations. Section 4 provides a discussion on the simulations results. A sensitivity analysis is presented in section 5. The main takeaways of the chapter are highlighted in section 6.

Résumé en français

Ce chapitre propose une comparaison détaillée de plusieurs architectures de marché destinées à améliorer la sécurité d'approvisionnement dans le contexte de la transition énergétique. Il considère un système soumis à une forte pénétration d'énergies renouvelables, conformément à la transformation actuelle des systèmes électriques dans le monde et en Europe en particulier. La comparaison est faite du point de vue du surplus social, avec une discussion sur d'autres dimensions pertinentes pour l'élaboration des politiques publiques : la sécurité d'approvisionnement, le coût pour les consommateurs, le risque d'investissement et la rentabilité des actifs.

Cinq architectures de marché sont étudiées : un marché uniquement basé sur la rémunération de l'énergie avec un plafond de prix relativement bas, un marché basé sur la rémunération de l'énergie mais avec une tarification au coût de l'énergie non distribuée, un mécanisme de réserve stratégique, un marché de capacité avec des contrats de capacité annuels ainsi qu'un marché de capacité avec des contrats de capacité pluriannuels pour les nouveaux investissements. Pour ce faire, un modèle de simulation dynamique inspiré de la méthodologie *System Dynamics* est développé afin de représenter de manière endogène les décisions d'investissement, de mise sous cocon et de fermeture prises par les acteurs du marché.

Le chapitre comprend six sections. La section 1 présente la question de recherche et son contexte. La section 2 aborde la méthodologie, en particulier la modélisation d'un marché de capacité avec des contrats pluriannuels. La section 3 décrit l'étude de cas utilisée pour les simulations. La section 4 fournit une discussion sur les résultats des simulations. Une analyse de sensibilité est présentée dans la section 5. Enfin, les principales conclusions du chapitre sont présentées dans la section 6.

Contents of Chapter III

1. Introduction

1.1. Context and motivation

One of the crucial aspects of the ongoing energy transition in Europe is the ability of current electricity markets to accommodate the integration of high shares of renewable energy sources (RES). More precisely, questions are being raised regarding the impact of renewables on investment incentives in thermal technologies, possibly needed to cope with the variability of electricity generation from RES (Steggals et al., 2011). The recent wave of power plant mothballing[150] and investment delaying or cancelling reflect the industry's concerns regarding the profitability of those assets (Caldecott et al., 2014).

The above-mentioned issues add another layer to the long-lasting debate on the appropriate market designs to ensure capacity adequacy in electricity markets, particularly in the context of an increasing penetration of renewables. The literature on the subject has highlighted the limits of existing energy-only markets in providing optimal investment incentives. In an energy-only market, electricity generators' revenues are solely based on the energy sold and ancillary services. In theory, a well-functioning energy-only market with scarcity pricing (i.e., a market in which prices are allowed to reach the Value of Lost Load or VoLL during scarcity periods) enables generators in each type of technology to earn just enough revenues to recover their total costs, therefore inducing a socially optimal mix of capacity in the long run. However, in practice, several market failures prevent such markets from achieving this goal as explained in the general introduction of this dissertation.

First, for political, regulatory, and social considerations, prices in most electricity markets are capped at a lower level than the VoLL, thus reducing the scarcity rents of generators. This effect is even more pronounced with the penetration of

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150 Mainly Combustion Turbines (CT) and Combined Cycle Gas Turbines (CCGT). Mothballing consists in temporarily shutting down a generation asset, while taking appropriate preservation measures to ensure that the asset can be operational again when needed.

renewables (De Sisternes and Parsons, 2016; Sensfuß et al., 2008). Second, risk aversion[151] and potential herd behaviour from investors may lead to cyclical tendencies in investments and cause deviations from the optimal equilibrium (Arango and Larsen, 2011). Both these factors constitute barriers to the proper functioning of energy-only markets and can lead to sub-optimal levels of investment, resulting in more shortages than socially desirable.

Alternative market designs are being proposed and implemented in several European countries in the hopes of restoring adequate investment incentives (see Table 18 hereafter). Among these designs are capacity remuneration mechanisms (CRMs). CRMs are add-ons to the energy-only market that remunerate power plants for their installed capacity in addition to the immediate revenues they receive from energy markets. CRMs can take various forms[152] but the most widespread are the capacity market and the strategic reserve mechanism.

In a capacity market, capacity is contracted either through a centralised auction or on a decentralised basis. Both existing and new capacities are eligible to take part in capacity contracts. In a strategic reserve mechanism however, only existing capacities on the verge of being shut down can benefit from a capacity payment to stay available. These capacities are withdrawn from the energy market and called upon only during scarcity periods. France, UK and Poland have adopted the capacity market mechanism, while Finland, Germany and Sweden have implemented strategic reserve mechanisms. Another alternative to a price-capped energy-only market is an energy-only market with scarcity pricing, in which electricity prices are allowed to reach the VoLL during scarcity periods. To date, there are few European countries using a scarcity pricing system[153], although it

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151 Risk aversion alone does not raise any issue as long as there is a complete set of markets that enables investors to fully hedge their risk (De Maere d'Aertrycke et al., 2017). In the electricity sector, there is a problem of market incompleteness which, associated with risk aversion, can lead to suboptimal decisions from investors (De Maere d'Aertrycke et al., 2017; Finon, 2011; Willems and Morbee, 2010).

152 For a discussion on design options and typology of CRMs see Batlle and Pérez-Arriaga (2008) or Cramton et al. (2013).

153 An exception is the UK, which has a balancing mechanism that implements a form of scarcity pricing. When the system operator does not have enough capacity resources (generation or demand response) to balance supply and demand, it uses contingency options. During these events, the imbalance price is set at the VoLL (which was set at 3 000 £/MWh in 2018). For more details, interested readers can refer to ELEXON (2018).

seems to be the preferred option for the European Commission in its Clean Energy Package (European Commission, 2017, 2016a; Meeus and Nouicer, 2018).

Table 18. Description of market designs for generation adequacy

Market design	Description of energy market		Description of CRM	
	Description	*Important parameter(s)*	*Description*	*Important parameter(s)*
Energy-only market with administrative price cap	Generators received revenues from selling electricity on the energy market.	Electricity prices on the energy market are capped at an administrative price below the VoLL	No CRM	No CRM
Energy-only market with scarcity pricing		Electricity prices on the energy market are capped at the VoLL		
Energy-only market + Capacity market		Electricity prices on the energy market are capped at an administrative price	In addition to their revenues on the energy market, generators also receive capacity-based revenues depending on their available capacity	Prices in the capacity auction are capped at a value reflecting the annualised cost of a new plants[154]
Energy-only market + Strategic reserve mechanism			Some capacity resources (generation capacities usually) are removed from the energy market and placed in a so-called strategic reserve. These resources receive a capacity-based revenue for their availability and an energy-based revenue upon activation (when they are asked to produce electricity)	Prices in the strategic reserve auction are capped at a predetermined value The size of the strategic reserve is limited

154 The price cap of capacity auctions is generally a multiple of the Net Cost of New Entry (CONE), which represents the capacity revenue that a new peaking unit would need to cover its total annual fixed costs (including capital costs). The Net CONE is computed by subtracting expected revenues from the energy market from annual fixed costs. The multiplying factor allows the system operator to account for uncertainties about the estimated CONE but also potential risk aversion from investors. In the UK and PJM, the multiplying factor is 1.5 for instance (UK Department of Energy & Climate Change, 2014b).

From an economic point of view, the choice of a market design should be based on an assessment of its economic performance relative to the others. This assessment relies heavily on simulation models that aim to capture the characteristics and dynamics of electricity markets. Three characteristics are particularly important to consider when addressing capacity adequacy issues: (i) the cyclical tendency of electricity markets, (ii) the endogenous nature of agents' decisions and, (iii) their imperfect behaviour (such as risk aversion, herd behaviour, etc.).

As illustrated by (Arango and Larsen, 2011; Ford, 1999), electricity markets exhibit a propensity to capacity cycles leading to a succession of over and under-capacity phases. These cycles present a threat to security of supply as they increase uncertainty and distort investment signals (Green, 2006). Because of this cyclical tendency, electricity markets usually operate out of equilibrium. An analysis of electricity markets from a dynamic perspective is therefore needed to account for out-of-equilibrium phases.

Moreover, analysing capacity adequacy by the means of electricity market models requires that all agents' decisions that may affect the level of installed capacity are properly represented. Agents' decisions must therefore be endogenous with respect to their expectations. These decisions include not just investments and shutdowns, but also mothballings (Abani et al., 2017; Arango et al., 2013). In this regard, the results of Chapter II highlighted the importance of considering mothballing in the assessment of the performance of market designs. Finally, the imperfect behaviour of agents resulting from risk aversion (Meunier, 2013; Neuhoff and De Vries, 2004; Ousman Abani et al., 2018) or herd behaviour (Hary et al., 2016; Olsina et al., 2006) plays a crucial role in their decision making and ultimately on capacity adequacy. This was one of the main results of the first chapter of this dissertation. Hence, these aspects should be accounted for in the assessment of market designs.

In this chapter, emphasis is made on an additional dimension that has become crucial. It is the impact of RES deployment on investment incentives (Bhagwat et al., 2016b; Gerres et al., 2019; Llobet and Padilla, 2018; Newbery et al., 2018;

Sisternes and others, 2014; Weiss et al., 2017). Indeed, as explained above, the integration of high shares of RES affects the profitability of thermal generation technologies which are still needed to ensure security of supply in the absence of large-scale storage or highly flexible demand response. Although the literature on capacity adequacy highlights the importance of the characteristics presented above (cyclical behaviour, all types endogenous decisions, risk aversion, etc.), existing simulation models rarely take them all into account at once. The next section provides a literature review of simulation modelling studies centred on the issue of capacity adequacy in liberalised electricity markets[155].

1.2. Existing literature on market designs comparison based on modelling

The literature on simulation models can be summarised in two main categories: equilibrium-based models and non-equilibrium models[156]. The first category of models considers electricity markets in an equilibrium state, and hence make the implicit assumption that an equilibrium will be reached. This category mostly concerns optimization models trying to minimize total costs or maximize social welfare. On the contrary, non-equilibrium models do not presume that the studied markets will reach an equilibrium, and instead try to recreate as closely as possible the dynamics and characteristics of the markets. An equilibrium may emerge from market participants' interactions, but there is no guarantee that this will always be the case. This second category covers agent-based (AB) models, which explicitly represent the interactions of several market participants and system dynamics (SD) models, which analyse electricity markets from an aggregated perspective. The literature review is summarised in Table 19.

155 There is also a rich literature that addresses capacity adequacy issues through the lenses of game theory and other analytical models inspired from industrial organisation (Creti and Fabra, 2007; Fabra, 2018; Fan et al., 2012; Hary et al., 2016; Lambin and Léautier, 2018; Léautier, 2016; Llobet and Padilla, 2018; Murphy and Smeers, 2005). Although this literature provides interesting insights, it falls out of the scope of this chapter as it does not rely on simulation models.

156 For a more general taxonomy of electricity market models, see Ventosa et al. (2005). It should be noted however that the taxonomy used in this chapter is different from the one used by Ventosa et al. (2005). Here, "equilibrium-based model" should be understood as a model which assumes equilibrium, rather than an actual equilibrium model as it is presented in Ventosa et al. (2005).

1.2.1. Equilibrium-based model (optimization)

Several studies have used equilibrium-based models to study investment incentives and capacity adequacy in electricity markets. For instance, Botterud et al. (2005) use a stochastic dynamic optimization model to analyse optimal investment strategies under uncertainty. A centralised social welfare maximization approach and a decentralised profit maximizing approach are compared. Results highlight the fact that a price cap below the VoLL can have severe effects on system reliability as it contributes to investment deferrals. Furthermore, the authors show that a capacity payment helps trigger investment earlier all the while creating a risk of overinvestment in peaking units.

Mastropietro et al. (2016) build on the work of Vazquez et al. (2002) to develop a two-stage optimization model to assess the benefit of adding a penalty scheme to a CRM. Their results indicate that such schemes provide better incentives for capacity contract holders to make themselves available when needed, which in turn improves the effectiveness of CRMs.

Aghaie (2015) analyses the ability of an energy-only market to provide efficient investment signals in the presence of several uncertainties (regarding load, weather, forced outages, etc.). His analysis indicates that energy-only markets yield an efficient outcome in terms of reliability only under the provision that there is enough demand response capacity. This findings are complemented in Aghaie (2017). The author shows that risk aversion reduces investment incentives, at the same time leading to more shortages and an increased utilisation of demand response resources in an energy-only market.

An important part of the relevant literature here is comprised of studies commissioned by public authorities or other interested stakeholders. Among them are the studies by THEMA Consulting Group et al. (2013) and E3MLab (2017). Both studies use large scale optimization models to address electricity market design issues at the European level with a strong focus on the question of capacity adequacy. They point out, among other things, the importance of CRMs for long-term capacity adequacy but also highlight the risk of a free-riding effect associated with asymmetric implementation of CRMs in neighbouring and coupled countries (as the country without a CRM will benefit for free from the positive effects of the CRM implemented in the other). Gore et al. (2016) find similar results by analysing the interaction between a pure energy-only market and an energy-only market complemented with a CRM.

On a smaller scale, FTI CL - Energy (2016), RTE (2018), UFE et al. (2015), Frontier Economics and Consentec (2014), and Frontier Economics (2015) apply optimization models to assess capacity adequacy in different countries (France, Germany and the Netherlands). The first two studies carry out a quantitative analysis of market design options to ensure long-term capacity adequacy in France. Their results stress how beneficial CRMs are for restoring investment incentives, especially in an uncertain environment where investors' risk preferences affect their decisions. Frontier Economics and Consentec (2014) show more nuanced results regarding the benefits of CRMs as they argue that, based on their model and for the case of Germany, an improved energy-only market is a more appropriate option. In the same logic, Frontier Economics (2015) indicates that the Dutch energy-only market is capable of ensuring security of supply, even in the face of increasing shares of renewables.

Despite their interesting insights, all the studies presented in this section fail to account for one crucial characteristic of the considered electricity, which is their cyclical tendency. Some of them do account for several types of decisions by market participants, potential risk-averse behaviour from investor or the impact of the integration of RES. However, their omission of the cyclical nature of electricity markets leads them to ignore over and under-capacity phases, which are yet critical in the assessment of long-term security of supply.

1.2.2. Non-equilibrium models (agent-based modelling and system dynamics)

Non-equilibrium models have also been used to study capacity adequacy issues. Ford (1999), Bunn and Larsen (1992) and Bunn and Larsen (1994) conducted some of the earliest works that applied the System Dynamics (SD) methodology to study capacity adequacy in liberalised electricity markets. These studies highlight the propensity to investment cycles in such markets and illustrate how regulatory interventions in the form of a capacity remuneration or a control of plants' retirements can help stabilise markets and reduce uncertainty.

Following that, other authors have applied SD to study the dynamics of energy-only markets (Eager et al., 2012; Olsina et al., 2006). Eager et al. (2012) study investments in thermal generation in the context of high Wind penetration in the British power system. They illustrate how a lack of sufficient revenues for peaking units can affect the security of supply. Olsina et al. (2006) show that an energy-only market leads to unstable reserve margins because investments are not always made in a timely manner to compensate for plants' retirements and demand growth. They attribute this behaviour to imperfect foresight from investors as well as investment and construction delays.

A large stream of literature extends the previous one by comparing different market design options (including CRMs) to ensure capacity adequacy (Bhagwat et al., 2017a, 2017b; Cepeda and Finon, 2011; De Vries and Heijnen, 2008; Hach et al., 2016; Hary et al., 2016; Hasani and Hosseini, 2011; Petitet et al., 2017). They all provide quantitative evidence of the benefits of CRMs for securing electricity supply. Cepeda and Finon (2011) and Bhagwat et al. (2017c) on the other hand focus on the cross-border effects of CRMs. Interestingly, they both highlight similar results to those of THEMA Consulting Group et al. (2013), Gore et al. (2016), and E3MLab (2017) regarding the free-riding effect associated to an asymmetric implementation of a CRM. In addition, they show that, when a capacity market is implemented next to an energy-only market, it creates a leakage of capacity from the energy-only market to the capacity market.

Other authors have focused on the analysis of specific features of CRMs and their impact of the effectiveness of those CRMs. Hobbs et al. (2007) assess the performance of the PJM capacity market for different demand curves. They illustrate that using a sloped capacity demand curve instead of a vertical one can reduce the cost of providing a desired level of reliability. Assili et al. (2008) introduce a refined capacity mechanism with variable capacity payments which are contingent to the actual investment needs (instead of a fixed capacity payment). Their simulations results indicate that the proposed variable capacity payments are preferable to fixed capacity payments to stabilise investment cycles and achieve long-term capacity adequacy.

While the above-mentioned studies, unlike optimization models, succeed in integrating the cyclical tendency of electricity markets, they do not always allow agents' decisions to be made endogenously. For instance, some of them do not consider endogenous retirements (Assili et al., 2008; Bunn and Larsen, 1994, 1992; De Vries and Heijnen, 2008; Ford, 1999; Hasani and Hosseini, 2011; Hobbs et al., 2007; Lara-Arango et al., 2017; Olsina et al., 2006). Furthermore, none of them include mothballing decisions which have yet an impact on capacity adequacy, as demonstrated in Chapter II. These decisions might have been overlooked in the past because there was limited empirical evidence of their occurrence. However, the recent developments in the electricity sector indicate that they can no longer be ignored based on this argument.

1.3. Research question

The aim of this chapter is to provide a comprehensive comparison of several market design options for ensuring long-term security of supply in a context of growing shares RES. More precisely, five market designs are studied: an energy-only market with an administrative price cap (EOM-PCap hereafter), an energy-only market with scarcity pricing where the price cap equates the VoLL (EOM-SP hereafter), a strategic reserve mechanism (SRM hereafter), a capacity market with annual capacity contracts (CM-AC hereafter) and, at last, a capacity market with multiannual capacity contracts for new investments (CM-MAC hereafter).

To this end, the simulation model used in the previous chapter is extended to include a strategic reserve mechanism and capacity market with multiannual contracts. As explained in previous chapters, the modelling methodology is based on the System Dynamics approach. All types of private agents' decisions (investment, mothballing and shutdown) are endogenously represented. Moreover, the potential effect of risk averse behaviour from investors is taken into account. The selected market designs are compared with respect to their ability to improve social welfare. To complement the analysis, two additional dimensions are investigated, notably the effectiveness of the market designs in reducing shortages and their associated costs which concern both the total systems costs and the costs for consumers. Furthermore, impacts regarding investment risk and cost recovery are discussed.

This chapter brings two main contributions to the current literature. Firstly, the following study is one of the few to assess the performance of a capacity market with multiannual contracts, with an analysis of its impact in terms of investment risk and generation assets' profitability. Secondly, and most importantly, the results discussed in the chapter reveal the persistence of the so-called missing money problem even in capacity markets, under certain conditions related to high penetration of renewables.

The chapter is organised as follows: section 2 describes the modelling framework which builds on the model presented in Chapter II. Section 3 introduces the set up for the simulations and their underlying assumptions. Sections 4 and 5 provide a detailed discussion of the results. Finally, the main conclusions are presented in section 6.

Table 19. Summary of literature review

Study	Studied market designs				Endogenous decisions			Agents' risk profiles		RES integration	Modelling approach
	Energy-only	Strategic reserve	Capacity market (annual contracts)	Capacity market (with multiannual contracts)	Investments	Shutdowns	Mothballings	Risk neutral agents	Risk averse agents		
(Bunn and Larsen, 1992)	✓				✓			✓			Non-equilibrium models
(Bunn and Larsen, 1994)	✓		✓		✓			✓			
(Ford, 1999)	✓		✓		✓			✓			
(Olsina et al., 2006)	✓				✓	**Mentioned but not explicit**			✓		
(Hobbs et al., 2007)			✓		✓				✓		
(Assili et al., 2008)	✓		✓		✓	**Mentioned but not explicit**		✓			
(De Vries and Heijnen, 2008)	✓	✓	✓		✓			✓			
(Cepeda and Finon, 2011)	✓		✓		✓	✓		✓			
(Hasani and Hosseini, 2011)	✓		✓		✓	**Mentioned but not explicit**		✓			
(Eager et al., 2012)	✓				✓	✓		✓	✓	✓	
(Hach et al., 2016)	✓		✓		✓	✓		✓			
(Hary et al., 2016)	✓	✓	✓		✓	✓		✓			
(Bhagwat et al., 2016b)	✓	✓			✓	✓		✓		✓	
(Bhagwat et al., 2017a)	✓		✓		✓	✓		✓		✓	

Study	Studied market designs				Endogenous decisions			Agents' risk profiles		RES integration	Modelling approach
	Energy-only	Strategic reserve	Capacity market (annual contracts)	Capacity market (with multiannual contracts)	Investments	Shutdowns	Mothballings	Risk neutral agents	Risk averse agents		
(Bhagwat et al., 2017b)	✓		✓	✓	✓	✓		✓		✓	
(Bhagwat et al., 2017c)	✓	✓	✓		✓	✓		✓		✓	
(Petitet et al., 2017)	✓		✓		✓	✓		✓	✓	✓	
(Lara-Arango et al., 2017)	✓	✓	✓		✓			✓			
(Ousman Abani et al., 2018)	✓	✓	✓		✓	✓		✓	✓		
(Botterud et al., 2005)	✓	✓			✓	✓		✓	✓		Equilibrium-based models
(THEMA Consulting Group et al., 2013)	✓	✓	✓		✓	✓		✓		✓	
(Frontier Economics and Consentec, 2014)	✓	✓	✓		✓	✓	Mentioned but not explicit	✓	Mentioned but not explicit	✓	
(Aghaie, 2015) (Aghaie, 2017)	✓				✓	✓		✓	✓	✓	
(Frontier Economics, 2015b)	✓	Mentioned but not explicit	Mentioned but not explicit	Mentioned but not explicit	✓	✓	✓	✓		✓	
(UFE et al., 2015)	✓		✓		✓	✓		✓	✓	✓	
(FTI CL - Energy, 2016)	✓		✓		✓	✓	✓	✓	✓	✓	
(Gore et al., 2016)	✓		✓		✓	✓		✓		Mentioned but not explicit	
(E3MLab, 2017)	✓		✓		✓	✓		✓	✓	✓	
(RTE, 2018)	✓		✓		✓	✓	Mentioned but not explicit	✓	✓	✓	

Study	Studied market designs				Endogenous decisions			Agents' risk profiles		RES integration	Modelling approach
	Energy-only	Strategic reserve	Capacity market (annual contracts)	Capacity market (with multiannual contracts)	Investments	Shutdowns	Mothballings	Risk neutral agents	Risk averse agents		
The model presented in this dissertation	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	Non-equilibrium models

2. Model extensions for the representation of strategic reserves and capacity markets with multiannual contracts

In this chapter, the model presented in Chapter II is extended to incorporate two additional market designs: a strategic reserve mechanism and a capacity market with multiannual contracts. The modelling framework described in Chapter II is fully preserved. The two additional market designs described hereafter can be seen as complementary modules. In its most complete form, the upgraded model therefore includes five types of market designs:

i. An energy-only market with price cap (EOM-PCap);
ii. An energy-only market with scarcity pricing (EOM-SP);
iii. A strategic reserve mechanism (SRM);
iv. A capacity market with annual contracts (CM-AC);
v. A capacity market with multiannual contracts (CM-MAC).

2.1. Strategic reserve mechanism (SRM)

A SRM consists of an energy market complemented with a CRM that remunerates some plants based on their available capacity. The aim of this mechanism is to ensure capacity adequacy by contracting in advance a predefined level of capacity with some existing plants that would otherwise be shut down. The reserved capacity is meant to be used only in extreme circumstances to deal with peak demand. The functioning of this CRM involves a central body -usually the TSO- which, based on demand forecasts, decides for a target level of reserve to be purchased[157]. This is generally done through an auction. A reserved capacity can only be activated (i.e. asked to produce electricity) upon solicitation from the TSO when the price on the energy market becomes higher than the maximum price it is willing to pay for energy. This maximum price is most of the time equal to the

157 It is important to mention that there must be a limit to the total reserved capacity to avoid distorting the energy market. A maximum amount of reserved capacity is usually set (it can be for example defined as a percentage of the previous year installed capacity, as it is the case in the model presented here).

price cap on the energy market. Accordingly, capacities on the energy market do not see any change in their revenues when the reserved capacities are activated because they are already selling at the price cap.

2.1.1. Bids from existing plants in SRM auction

An important feature of the SRM lies in the explicit distinction between the capacities in the reserve and the capacities in the energy market. Capacities are forbidden to participate in the energy market and be part of the reserve at the same time. Moreover, they are not allowed to switch from one to the other (once a generation capacity enters the reserve, it cannot go back to the energy market). Given these restrictions and the fact that activation of the reserves does not impact energy prices, investments are only driven by the energy market with unchanged incentives compared to the EOM-PCap or EOM-SP. Consequently, the investment decision process is the same as the one presented for these market designs (only based on revenues from the energy market). Agents invest in new power plants which stay on the energy market as long as their expected revenues are high enough to cover their expected O&M costs.

Unlike investment decisions, shutdown and mothballing decisions are different between the SRM and the EOM-PCap or the EOM-SP (see illustration on Figure 47). In the latter, when mothballing is not an interesting option, unprofitable plants (i.e., their expected revenues do not compensate their O&M costs) are immediately shut down. In the SRM, the shutdown decision rationale is different as unprofitable capacities would try to enter the reserve first, before shutting down permanently. They can do this by participating to the SRM auction which is assumed to take place one year ahead of the delivery year. Therefore, all existing capacities on the energy market that are planned to be shut down[158] will bid their O&M costs in the auction in order to be part of the reserve instead. As for the capacities that were already in the reserve, since they cannot go back on the energy market, their only option is to participate to the auction by bidding their O&M costs as well[159]. The

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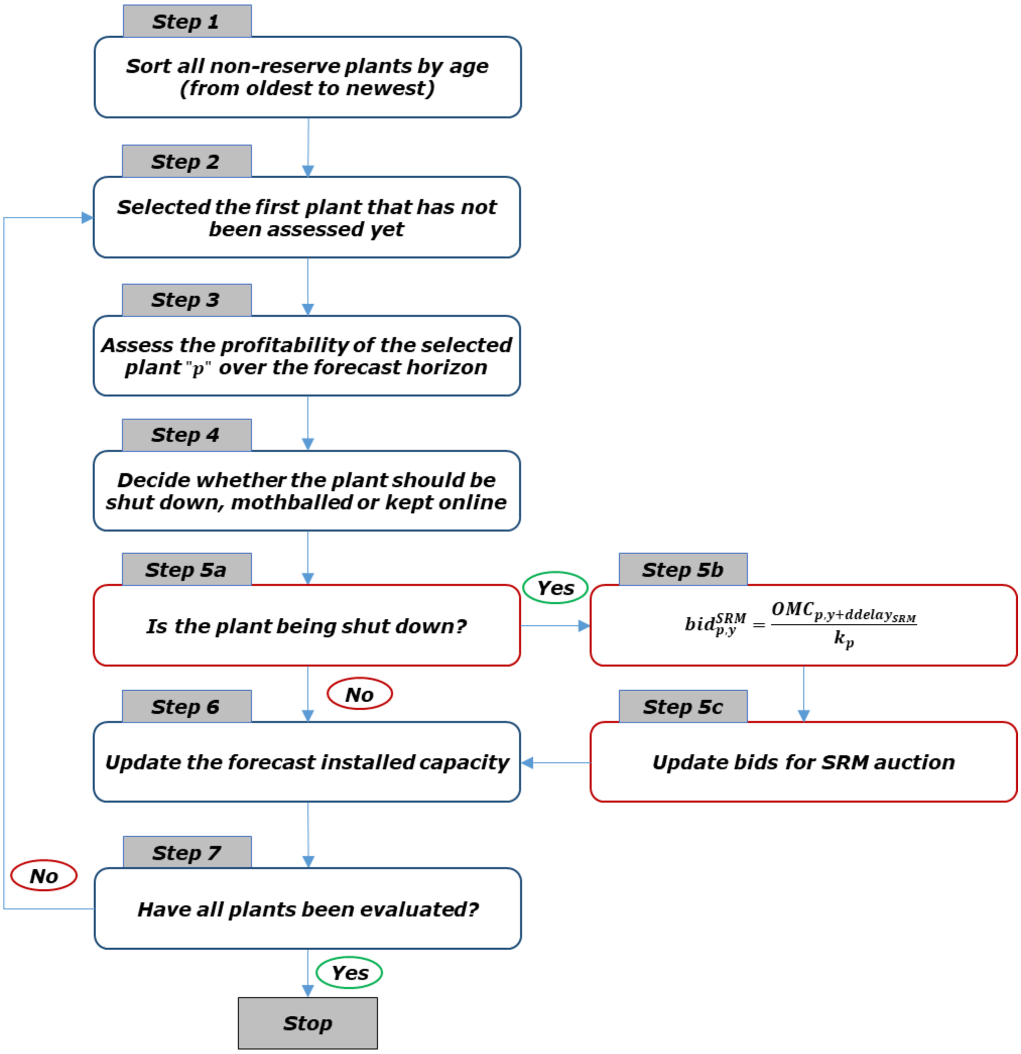
158 Note that plants that are planned to be mothballed do not participate to the SRM auction. Since, the value of the mothballing option is the possibility to come back to the market when profitability prospects improve, entering the reserve would mean losing that option. As a result, the SRM cannot prevent plants from being mothballed.

159 The shutdown and mothballing procedure in the case of the SRM is illustrated on Figure 47 below (the steps in red illustrate the differences compared to the EOM-PCap/EOM-SP).

supply curve of the SRM auction is then obtained by aggregating the submitted bids sorted in increasing order.

Figure 47. Shutdown/mothballing procedure for existing plants in SRM



2.1.2. Capacity demand in SRM auction and clearing

On the demand side of the SRM auction, the TSO expresses its capacity need in the form of an inelastic capacity demand[160]. This demand is thus modelled as a

160 In reality, TSOs may use elastic demand curves. The choice of an inelastic demand curve simplifies the modelling without altering the validity of the results since all CRM auctions are modelled with inelastic demand curves here.

vertical curve with a price cap and is determined based on the forecast peak load, an explicit target margin and the level of installed capacity in the energy market. Formally, the capacity demand for the reserve auction held in year y, can be computed using the following equation[161]:

$$Q^{SRM}_{y\rightarrow y+ddelay_{SRM}} = \min\left(Qmax^{SRM}_{y+ddelay_{SRM}}\ ;\ \max\left(0\ ;\ L^{Fpeak}_{y+ddelay_{SRM}} * \left(1+tm_{y+ddelay_{SRM}}\right) - \left(K^{Existing}_{y} + K^{New}_{y+ddelay_{SRM}}\right)\right)\right) \tag{15}$$

Where:

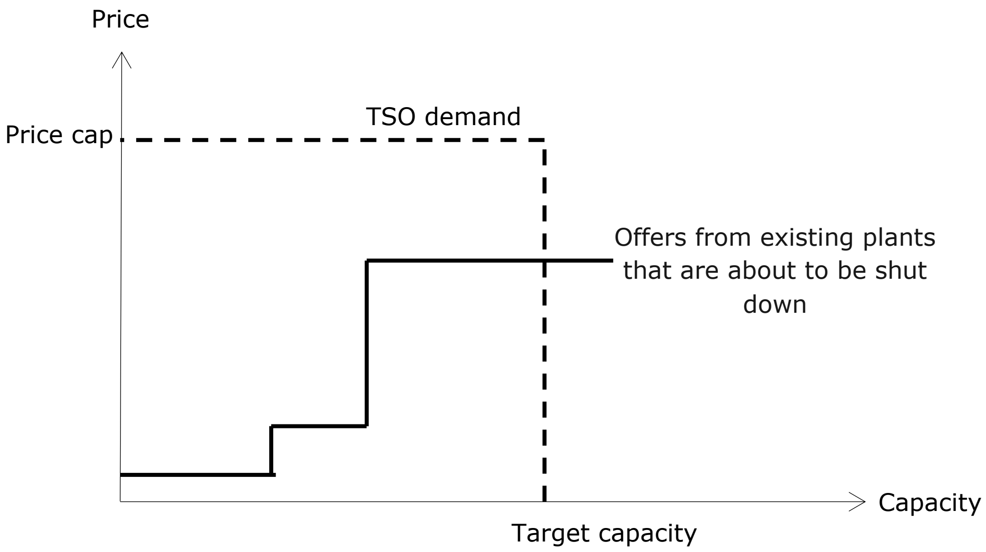
- $Q^{SRM}_{y\rightarrow y+ddelay_{SRM}}$ is the capacity demand from the TSO in the SRM auction held in year y (for delivery in year $y+\ ddelay_{SRM}$);
- $Qmax^{SRM}_{y}$ is the maximum size of the reserve in the delivery year ($Qmax^{SRM}_{y} = \tau^{SRM} * K^{Existing}_{y}$);
- $L^{Fpeak}_{y+ddelay_{SRM}}$ is the forecast peak load in the delivery year;
- $tm_{y+ddelay_{SRM}}$ is the target margin set by the TSO for the delivery year;
- $K^{Existing}_{y}$ is the total active capacity on the energy market in the delivery year (excludes capacities that are mothballed and those which are already in the reserve);
- $K^{New}_{y+ddelay_{SRM}}$ is the total amount of new capacities that are expected to enter the market in the delivery year ($y+ddelay_{SRM}$).

When the active existing capacities (those which are profitable and thus kept active for the delivery year) and the new ones resulting from previous investments are not enough to reach the capacity need, the TSO contracts the remaining capacities through the SRM auction. However, if the energy market yields a sufficient level of capacity, then the TSO does not need any capacity for the reserve. It is important to note that in case of excess capacity on the energy market (compared to the target margin), the SRM cannot force the extra capacity to exit. In addition,

161 The equation states that there is a limit to the amount of capacity that can be accepted in the reserve (this limit is $Qmax^{SRM}_{y+ddelay_{SRM}}$).

the TSO can contract capacity only to the extent of the maximum size of the reserve.

Figure 48. Strategic reserve auction



The clearing of the SRM auction is done on a pay-as-bid basis with the constraint that each plant bids to recover its fixed O&M costs[162]. This design is consistent with the rationale of the SRM which is not meant to provide plants with profit opportunities, but rather to compensate them for the losses they may incur by staying active instead of being shut down. Therefore, there is no single clearing price in the SRM auction. A simplified illustration of the auction is presented on Figure 48. Once the auction is cleared, the capacities whose bids are accepted either enter the reserve (if they are coming from the energy market) or stay in the reserve (if they were already part of it). All the capacities that saw their bids rejected are permanently shut down.

2.2. Modelling capacity markets with multiannual contracts (CM-MAC)

The CM-MAC is similar to the CM-AC in many respects. Hence the focus is made on the difference between the two market designs. The main difference between

162 It could be assumed that the regulator or the system operator requires agents to bid their actual costs.

them is that the CM-MAC distinguishes between new capacities (prospective investments) and existing capacities. Indeed, in the CM-MAC, new capacities that are accepted in the capacity auction are granted contracts with a guaranteed capacity price over several years. In return, those capacities with multiannual contracts are not allowed to participate to the capacity auction for the duration of their contract. Existing capacities that are not already under a multiannual contract can participate to the capacity auction. If their bids are accepted, they are awarded annual capacity contracts, just as in the CM-AC. This difference has two implications: first, it changes agents' rationale regarding the computation of the capacity bids for new investments and second, it modifies the TSO's demand in the capacity auctions.

Regarding the capacity bids for new investments, the possibility of multiannual contracts provides more certainty to investors as they know that the capacity price they will receive will be guaranteed for the duration of the contract (several years). As such, they take this increased certainty into account while computing their capacity bids. To this end, they consider in their forecast, a constant expected capacity price for the duration of the capacity contracts[163]. There is therefore less volatility in the forecast profits compare to the CM-AC, all things being equal. In face of risk averse agents, this will tend to lead to lower capacity bids, all things being equal.

As for the TSO's capacity demand, it is now determined by excluding all the capacities that are already under multiannual contracts. Indeed, the TSO knows that these capacities will be available no matter what. Rewriting Equation (10) and adapting it the case of the CM-MAC, the capacity demand from the TSO can be expressed as follows:

163 After the duration of the multiannual contract, they consider three scenarios of capacity price similarly to the CM-AC (average, minimum and maximum capacity price observed in a number of previous years consistent with $h_{forecast}$). An illustration is provided in Appendix E.

$$Q^{CM-MAC}_{y \to y+ddelay_{CM-LTC}} = max\left(0\ ;\ L^{Fpeak}_{y+ddelay_{CM-MAC}} * \left(1 + tm_{y+ddelay_{CM-MAC}}\right) - \left(\sum_{a=y+1}^{a=y+ddelay_{CM-MAC}} K^{New}_{a} + K^{MAC}_{y+ddelay_{CM-MAC}}\right)\right) \quad (16)$$

Where:

- $Q^{CM-AC}_{y \to y+ddelay_{CM-MAC}}$ is the capacity demand from the TSO in the CM-MAC auction held in year y (for delivery in year $y + ddelay_{CM-MAC}$);
- $L^{Fpeak}_{y+ddelay_{CM-MAC}}$ is the forecast peak load in the delivery year;
- $tm_{y+ddelay_{CM-MAC}}$ is the target margin set by the TSO for the delivery year;
- K^{New}_{y} is the total amount of new capacities[164] that are expected to enter the market in year y;
- $K^{MAC}_{y+ddelay_{CM-MAC}}$ is the total amount of capacities that are already expected to be under multiannual contracts[165], and will remain so until the delivery year.

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164 As for the CM-AC, it is assumed that capacities under construction do not participate to the capacity auctions in the CM-MAC neither.

165 This does not include the capacities that will be granted long-term contracts in the auction.

3. Case study and simulations

3.1. Preliminary remarks on the calibration and simulations

The model was validated by checking the coherence of electricity prices and generation levels for each technology. However, it is difficult to perform a precise back-testing on historical data because of some simplifications that are made in the model (for instance the absence of interconnections).

Compared to the two previous chapters, the discussion in this chapter provides more results in absolute terms, thanks to a higher level of refinement of the model. Nonetheless, for some of the results, relative values (compared to a certain reference) are still used for readability and ease of interpretation. For instance, as described in the next sections, results regarding social welfare are presented in monetary values, but as a difference with respect to some reference. Alternative ways of presenting the results regarding the differences in social welfare were considered – for instance as a percentage of the absolute of social welfare in the energy-only market or as a percentage of total industry's turnaround. However, this leads to very small values (less than 1%) which are less intuitive to interpret for the reader.

3.2. General setup and indicators

To address the research question set out in the beginning of this chapter, long-term dynamics of a liberalised power system in a context of high RES penetration are studied. A Monte Carlo approach is used, based on 100 simulation runs of the model. The setup of the simulations as well as the corresponding assumptions are detailed hereafter.

Table 20. Technical and economic characteristics of thermal technologies[166]

	Nuclear[167]	Coal	CCGT	CT (gas-fired)
Investment (k€/MW)	5 200	1 700	850	500
Initial O&M costs (k€/MW/year)	110	45	30	15
Variable costs (€/MWh)	10	50	60	90
Unit capacity (MW)	1 450	750	550	150
Construction time[168] (years)	6	4	2	2

Simulations are based on a case study of an electricity market calibrated on the French power system[169]. The model is run 100 times against a non-increasing gross electricity demand with random variations. Each run of the Monte Carlo approach corresponds to a different demand trend. In the simulations presented here, agents are considered to be risk averse and mothballing are allowed. Simulations are run over a 20-year horizon (from 2016 to 2035). Assumptions regarding the technical and economic parameters of thermal technologies are presented in Table 20 above.

The performances of the studied market designs are analysed in terms of social welfare by averaging the results of the 100 runs. Given the assumption of an inelastic demand, a comparative analysis of social welfare can be done by assessing the level of shortages and the total system costs (De Vries, 2004).

166 These values are based on data compiled from various sources (EC Joint Research Center, 2014; International Energy Agency, 2018; International Energy Agency and OECD Nuclear Energy Agency, 2010; RTE, 2017). In particular, values for variable costs are based on the "New Policies" scenario of the 2018 World Energy Outlook of the International Energy Agency. The underlying assumptions are the following: gas price of 8.5 $/MBtu, coal price of 82.5 $/t, CO_2 price of 34 $/t$CO_2$, efficiencies of 60%-41%-43% for CCGT-CT-Coal respectively.

167 For the same reasons explained in Chapter II (section 3.2), no nuclear investments are considered in the simulations. Such investments generally include a significant political component. It is unlikely that private agents engage in nuclear investments solely based on economic considerations. Other studies such as RTE (2018) confirm this assumption.

168 The time for obtaining all the administrative authorisations and regulatory approvals is not considered.

169 This case study does not attempt to represent the French electricity system. The load profile in France is used only for an illustrative purpose in order to calibrate the model on a real power system.

Indeed, if the demand is inelastic and assuming that the utility for the consumers of one megawatt hour of electricity is equal to the VoLL, the social welfare can be computed as follows[170]:

$$SW_y = \sum_h VoLL * G_{y,h} - \sum_p (\sum_h VC_{p,y} * g_{p,y,h} + OMC_{p,y} + ACC_p) \quad (17)$$

Where:

- SW_y is the social welfare in year y;
- $VoLL$ is the value of lost load;
- $G_{y,h}$ is the total generation level of all plants in hour h of year y ($G_{y,h} = \sum_p g_{p,y,h}$);
- $VC_{p,y}$ is the variable generation cost of plant p in year y;
- $g_{p,y,h}$ is generation level of plant p in hour h of year y;
- $OMC_{p,y}$ are the annual O&M costs of plant p in year y;
- ACC_p is the annualised capital cost of plant p. It includes the reference overnight investment cost (mentioned in Table 20) and a risk premium reflecting the additional financing costs related to the riskiness of the investment. A discount rate of 8% is used for the computation of annualised costs.

Equation (17) indicates that the social welfare is equal to the utility from consuming the energy that is produced minus all system costs which are generation costs, fixed O&M costs and capital costs. Rearranging Equation (17), the difference in social welfare between two market designs takes the form:

$$\Delta SW_y = VoLL * \sum_h \Delta G_{y,h} - \Delta\left(\sum_p \sum_h (VC_{p,y} * g_{p,y,h} + OMC_{p,y} + ACC_p)\right) \quad (18)$$

Where:

- ΔSW_y is the difference in social welfare in year y between market design $MD2$ and market design $MD1$ ($\Delta SW_y = SW_y^{MD2} - SW_y^{MD1}$);
- $\Delta G_{y,h}$ is the difference in generation level between market design $MD2$ and market design $MD1$;

170 The capacity provision price in CRMs is not included in the equation of the social welfare since it is just a transfer between consumers and producers. It does not impact the overall social welfare.

- $\Delta(\sum_p(\sum_h VC_{p,y} * g_{p,y,h} + OMC_{p,y} + ACC_p))$ is the difference in total system costs between market design $MD2$ and market design $MD1$.

Noting that the difference in generation level between market design $MD2$ and market design $MD1$ ($\Delta G_{y,h}$) is equal to $-\Delta ENS_{y,h}$ (the difference in energy not served or shortages), the difference in social welfare between two market designs can be rewritten according to Equation (19) below, which shows that this difference is equal to the gains from reducing shortages (energy not served) minus the cost variations between the market designs.

$$\Delta SW_y = -VoLL * \sum_h \Delta ENS_{y,h} - \Delta\left(\sum_p \sum_h (VC_{p,y} * g_{p,y,h} + OMC_{p,y} + ACC_p)\right) \tag{19}$$

Table 21. Variables and parameters for simulations (Chapter III)

	EOM-PCap	EOM-SP	SRM	CM-AC	CM-MAC
α Confidence level for computation of VaR and CVaR			95%		
β Risk aversion coefficient			0.5		
τ^{SRM} Maximum strategic reserve size (% of current installed capacity)			15%		
$PCap^{EOM-PCap/EOM-SP}$ Price cap on energy market	3 k€/MWh	22 k€/MWh	3 k€/MWh		
$PCap^{CM-AC/CM-MAC}$ Price cap of capacity market auctions	NA			80 k€/MW (~1.5x Net CONE[171])	
$PCap^{SRM}$ Price cap of strategic reserve auctions	NA		80 k€/MW (~1.5x Net CONE)	NA	

171 Cost of New Entry based on the annualised fixed cost (O&M and investment costs) of a combustion turbine, using a reference discount rate of 8% and the cost parameters presented in Table 20.

	EOM-PCap	EOM-SP	SRM	CM-AC	CM-MAC
tm_y Target margin set by the TSO for the delivery year			Set to reach LoLE of 3h/year[172]		
$VoLL$ Value of Lost Load			22 k€/MWh		
Multiannual contract duration		NA			10

In addition to analysing the social welfare variations induced by the different market designs, a set of indicators are computed to assess the performances[173] of the market designs regarding reliability targets, system costs and profitability of generation assets. The assumptions regarding the values of the parameters used for the simulations are presented in Table 21.

3.3. Electricity demand

Each run of the model is associated to a random scenario of electricity demand. The effective residual electricity demand observed by agents over the simulation horizon is determined on a yearly basis from a gross demand and generation from renewables. The peak gross demand is assumed to have a flat trajectory with random deviations, representing the recent trend observed in European markets. More specifically, the growth rate of the peak gross demand is sampled from a zero-mean normal distribution with a standard deviation of 1%[174]. The shape of this gross demand is calibrated on the 2015 load duration curve of the French system[175].

172 The Loss of Load Expectation (LoLE) of 3h/year is the reliability criterion used in France. Other European countries generally use reliability criteria ranging from 3h/year to 8h/year. In the model, the capacity needed to achieve a desired LoLE is computed using a probabilistic approach which relies on the forecast load duration curve scenarios. The load duration curve scenarios are the same as those used for agents' profitability assessments. For each load duration curve scenario, the TSO computes a corresponding level of installed capacity consistent with the reliability criterion. The target level of installed capacity (and therefore the target margin) is then determined as the expected value of all installed capacity scenarios.

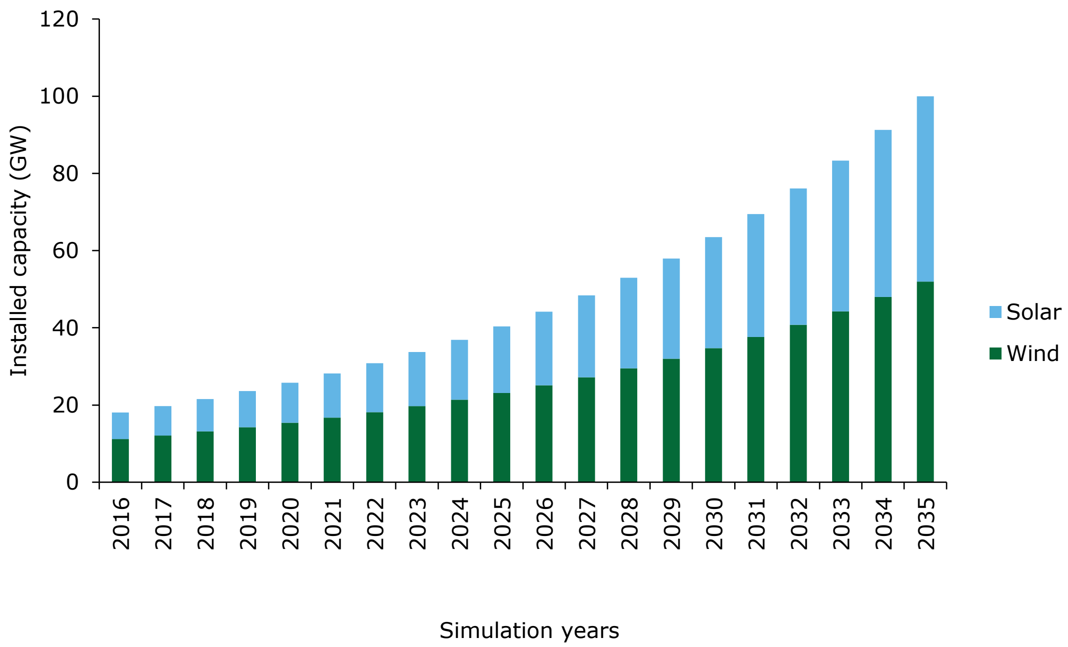
173 All indicators are computed over the last 15 years of the simulation horizon (the first years are excluded because the effects of the capacity markets are only visible after year 4 due to the delivery delay).

174 This figure is in line with the standard deviation of the peak load observed over the few past year in France.

175 All hydropower generation is subtracted and assumed constant in the simulations.

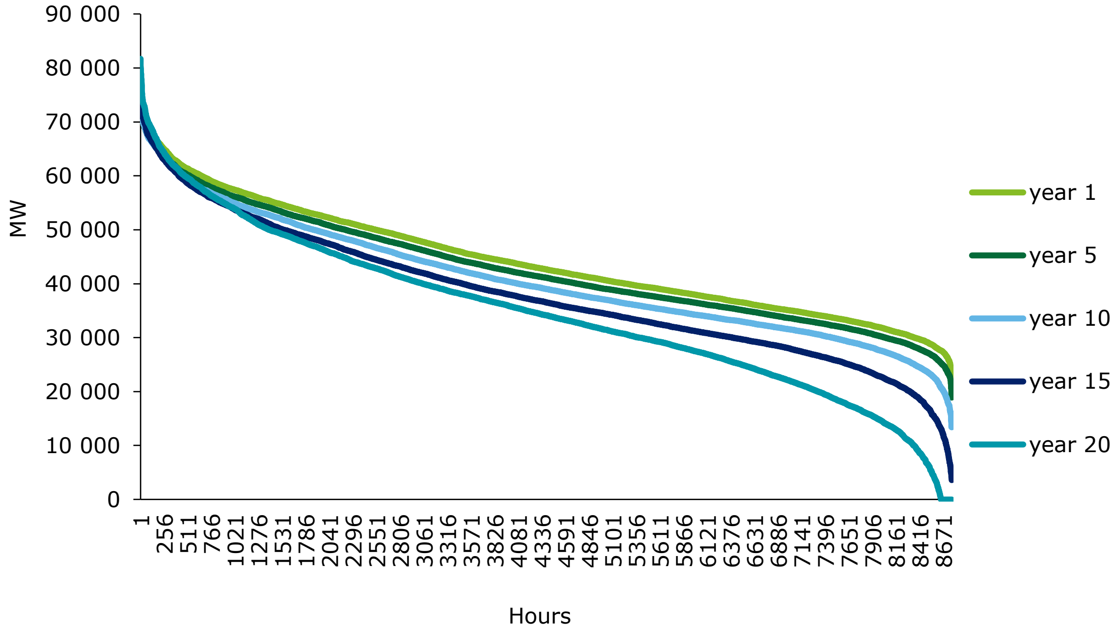
A high penetration of variable of RES based on French energy policy targets is considered. The deployment of RES capacities (wind and solar) is based on the most optimistic scenario identified by the French authorities and described in (RTE, 2017). According to this scenario, wind and solar capacity are expected to grow at an average rate of 9%/year. Initially, that is in 2015, wind and solar capacities represent about 10 GW and 6 GW respectively. They then increase from 2016 to 2035 to reach 52 GW for wind and 48 GW for solar by 2035. The penetration trajectories of RES are presented on Figure 49 below. Generation from RES is directly derived by from their installed capacity and associated generation profile[176]. Due to the increasing penetration of RES capacity, the shape of the LDC becomes more and more sloping during the simulations, as illustrated on Figure 50.

Figure 49. **RES penetration trajectory in case study**



176 The generation profile of RES is assumed to remain constant during the simulations. It is based on the actual generation profile of wind and solar in France in 2015.

Figure 50. Illustrative evolution of residual LDC during simulations

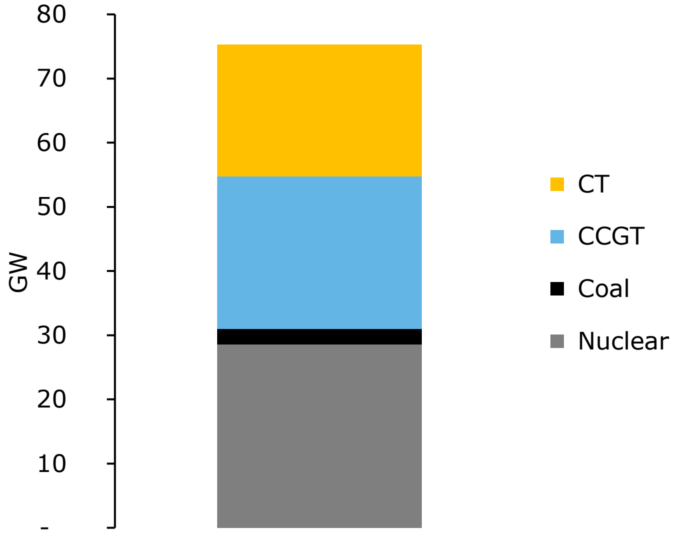


3.4. Initial generation mix

As for Chapter II, simulations start with an initial generation mix that corresponds to the optimal generation mix associated with the initial residual demand curve. This mix is determined using the screening curves methodology presented by Stoft (2002). It represents the least cost generation mix that can be used to satisfy a load profile based on the economic characteristics of available generation technologies (investment and operation costs) and the VoLL. A VoLL of 22 k€/MWh is assumed for this purpose. Theoretically, this level of VoLL leads to 3h/year of shortages at equilibrium given the cost parameters considered in Table 20. Moreover, a discount factor of 8% is assumed, in accordance with the existing literature (Cepeda and Finon, 2011; Hary et al., 2016; Petitet et al., 2017).

The determination of the optimal generation mix is done with the cost structure of new plants. However, plants are given different ages in the initial generation fleet to have a realistic system. The initial generation mix, which is exactly the same as the one in Chapter II, is presented on Figure 51.

Figure 51. Initial generation mix for simulations of chapter III



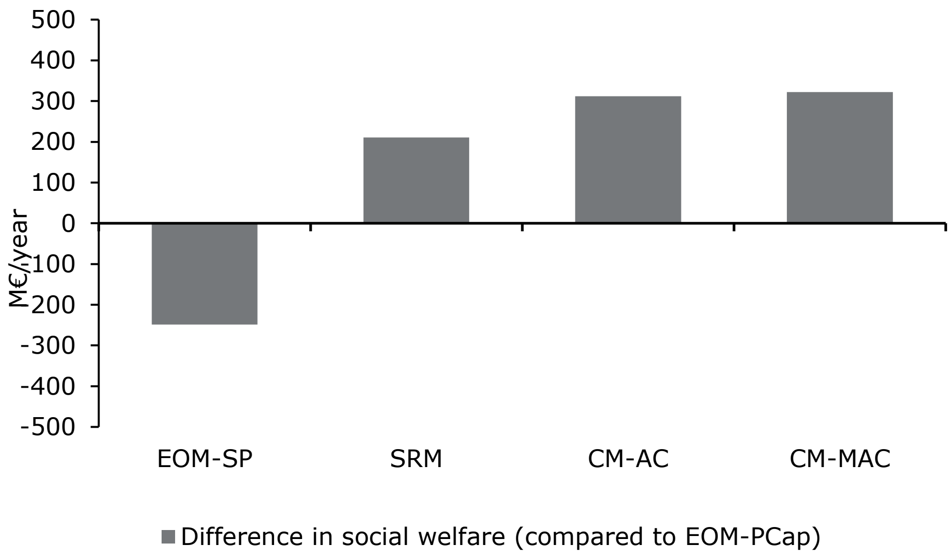
4. Performance of the studied market designs

4.1. Capacity mechanisms are superior to scarcity pricing in terms of social welfare

4.1.1. Average results over simulation horizon

Abstracting from any potential distributional effects, social welfare is usually the preferred indicator of policymakers when assessing the relevance of their choices and interventions. Here the different market designs proposed for enhancing capacity adequacy are compared with respect to their ability to increase social welfare. Using Equation (19) defined above and considering the EOM-PCap as a reference, the average variation of social welfare associated with the implementation of one of the other market designs is computed. The corresponding results are presented on Figure 52 below.

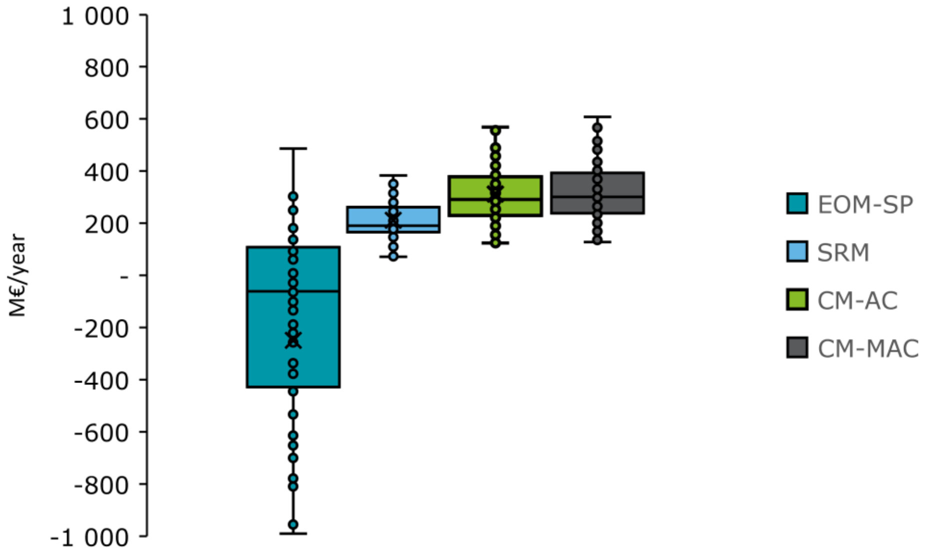
Figure 52. Comparison of market designs in terms of social welfare (average variation of social welfare compared to EOM-PCap)



At the exception of the EOM-SP, all market designs improve overall social welfare compared to the EOM-PCap. The estimated increases lie roughly between 210 M€/year and 320 M€/year, supporting the economic rationale behind policy intervention to modify the classic low-price-caped energy-only markets. However, the degree of social welfare increase is uneven between the different market designs. Figure 52 highlights the superiority of the market designs with a capacity market, especially the CM-MAC. While the SRM would generate additional welfare of 211 M€/year, a capacity market with 10-year multiannual contracts creates a social welfare increase of about 322 M€/year. The results also indicate that providing multiannual contracts to new plants in a capacity market is beneficial from a social welfare perspective, as it leads to an increase of about 10 M€/year in social welfare based on simulations (difference between the CM-MAC and the CM-AC).

One interesting result concerns the market design with scarcity pricing (EOM-SP). On average, the EOM-SP reduces social welfare by 250 M€/year compared to the EOM-PCap, based on the simulation parameters. Of course, this does not mean that scarcity pricing always impacts social welfare negatively. Figure 53 shows the distribution of the variations of social welfare for all the 100 runs. A first observation is that scarcity pricing exhibits the highest volatility in terms of social welfare variations compared to other market designs. Focusing on the EOM-SP, the distribution of social welfare variations clearly shows that scarcity pricing improves social welfare in many runs. However, the distribution is so skewed towards negative values that it results in a negative average. To put this in perspective, the median of the variations of social welfare introduced by scarcity pricing is - 61M€/year (compared to an average of - 250 M€/year). The results presented above are driven by various effects that are underlined in the next sub-section.

Figure 53. **Distribution of social welfare variations compared to EOM-PCap**[177]



4.1.2. Breakdown of the social welfare variations

To better understand the variations of social welfare presented above, a detailed analysis of the variables involved in the computation of these variations is presented in Table 22. Recalling Equation (19), social welfare variations are caused by four terms:

a. Gains (respectively losses) related to the reduction (respectively increase) of energy shortages. Gains are accounted for as a positive variation while losses are considered as a negative variation of social welfare;
b. Increases (respectively decreases) in variable generation costs. Increases (respectively decreases) in generation costs are accounted for as a negative (respectively positive) variation of social welfare.
c. Increases (respectively decreases) in total O&M costs[178]. Increases (respectively decreases) in O&M costs are accounted for as a negative (respectively positive) variation of social welfare.

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177 The rectangle of the box plot delimits the first quartile and the third quartile. The segment inside the rectangle shows the median, while "whiskers" above and below the box indicate the minimum and maximum points.
178 Including potential mothballing and restart costs.

d. Increases (respectively decreases) in total risk-adjusted capital costs. Increases (respectively decreases) in capital costs are accounted for as a negative (respectively positive) variation of social welfare.

Table 22. **Comparison of average social welfare variations between market designs (with respect to EOM-PCap)**

M€/year	EOM-SP	SRM	CM-AC	CM-MAC
Gains from reduction of shortages $[\boldsymbol{A}]$	357	319	366	366
Difference in generation costs $[\boldsymbol{B}]$	- 97	2	- 109	- 109
Difference in fixed O&M costs $[\boldsymbol{C}]$	56	30	62	62
Difference in capital costs $[\boldsymbol{D} = \boldsymbol{D}' + \boldsymbol{D}'']$	646	77	101	91
Volume/mix effect[179] [D']	**373**	**77**	**250**	**251**
Financing risk effect[180] [D'']	**273**		**- 149**	**- 160**
Variation of social welfare $[\boldsymbol{E} = \boldsymbol{A} - (\boldsymbol{B} + \boldsymbol{C} + \boldsymbol{D})]$	**- 249**	**211**	**312**	**322**

For all alternative market designs (i.e., other than the EOM-PCap), increases in social welfare are mainly due to the gains resulting from the reduction of shortages. Each avoided megawatt hour of shortage mechanically generates a social welfare increase, valued at the VoLL. The highest gains from shortage reduction are observed for the EOM-SP and the capacity markets (in similar magnitudes). The SRM also yields social welfare increase by reducing shortages, but to a lesser extent.

Reducing shortages requires additional available capacity which in turn leads to additional costs. These costs reduce social welfare since they are directly borne by electricity producers (without any transfer to consumers). Therefore, the overall variation of social welfare depends on the relative magnitude between these two

179 This is the variation of total investment costs observed in a market design, compared to EOM-PCap, by adjusting for EOM-PCap risk premiums (i.e., by considering identical risk premiums to those in EOM-PCap). Therefore, the variations directly translate the difference in investment volumes or technology mix between the market designs since the financing costs are considered constant across market designs.

180 This is the part of the variation in total investment costs related to differences in risk premiums between a market design and EOM-PCap. It is inferred from the equivalent investment costs (computed by adjusting for risk premiums in EOM-PCap) and the actual investments costs.

effects (i.e., value creation due to lower levels of shortages and cost increase related to additional capacity).

Cost variations are heterogeneous between the market designs. Table 22 shows that most market designs reduce variable generation costs, compared to the EOM-PCap (except for the SRM which barely modifies them). Conversely, O&M costs are consistently higher (compared to the EOM-PCap once again). Differences are mainly due to generation mix effects as explained in a dedicated sub-section hereafter.

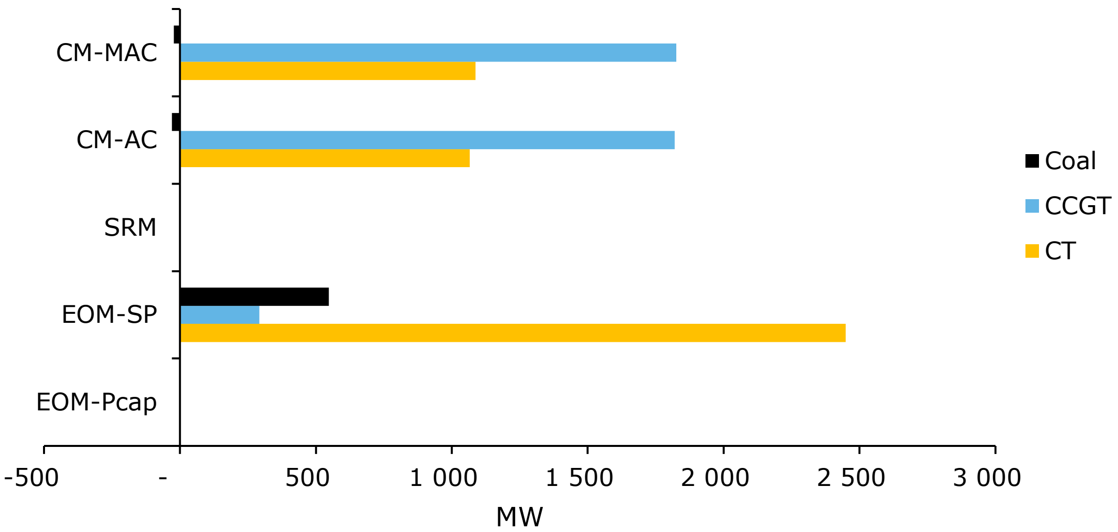
Regarding capital costs (i.e., investments), the EOM-SP stands out as the most expensive market design with a particularly high increase (more than 600 M€/year). Capacity mechanisms (SRM, CM-AC and CM-MAC) increase capital costs in similar proportions, ranging between 77 and 101 M€/year, depending on the market design. It should be noted that two effects are at play when it comes to these costs. Firstly, variations in capital costs may occur because of differences in the volume/mix of installed capacity as explained above. Secondly, even when the volume/mix is considered constant across market designs, differences in financing costs could lead to different capital costs. Interestingly, splitting these two effects highlights the impact of the studied market design on investment risk.

4.1.2.1. Volume/mix effect on capital costs

Figure 54 describes the average[181] differences in terms of investments between the reference energy-only market EOM-PCap and the alternative market designs. Cumulative investments over the simulation horizon are considered. For each technology, a positive value indicates that there are more investments in the selected market design, compared to the EOM-PCap. Conversely, negative values indicate the opposite. As illustrated on the figure, scarcity pricing is the only market design to increase investments in coal-fired capacity compared to the EOM-PCap. It also attracts more gas-fired capacity, especially CT (almost 2.5 GW more than the EOM-PCap on average).

181 Over the 100 runs of simulations.

Figure 54. **Average investments by technology over simulation horizon (compared to EOM-PCap)**



Capacity markets increase CCGT and CT capacity, but not coal. They tend to attract more CCGTs than CTs with average additional investments of about 2 GW and 1 GW respectively, compared to the EOM-PCap. As expected, the SRM does not modify investments, which is consistent with the design of the mechanism. However, it presents higher capital costs than the EOM-PCap mainly because of capacity that is kept in the reserve instead of exiting the market (as it would be the case in the EOM-PCap).

The high increase in capital costs resulting from the implementation of scarcity pricing can be partly explained by the structure of its generation mix. By bringing more coal capacity in the system, rather than just CCGTs and CTs, it relies on an even more expensive generation mix (in terms of capital costs). For capacity markets there is a natural increase of capital costs compared to the EOM-PCap, because of additional capacity. However, because they avoid coal investments, the increase of capital costs is less pronounced. Regarding O&M costs, the dynamics are similar. Scarcity pricing and capacity markets increase O&M costs compared to the EOM-PCap, because they bring more capacity[182] into the system.

Investments dynamics also explain differences in generation costs between the reference market design EOM-PCap and the others. By generating additional investments (compared to the EOM-PCap), the EOM-SP and the two capacity markets benefit from a younger generation fleet, which implies lower variable costs. Although these market designs lead to more generation in terms of energy, simulations results indicate that the lower variable costs of their generation fleet offset the impact of their higher generation level.

4.1.2.2. Investment risk effect on capital costs

Introducing a scarcity pricing in an energy-only market increases investment risk because of the higher volatility of revenues. Allowing energy prices to reach the VoLL in periods of scarcity translates into significant variations of revenues from one hour to another. For instance, the price differential between a regular hour where the price is set by a CT (90 €/MWh) and a scarcity hour (22 k€/MWh) corresponds to a ratio of 244, while this same ratio is only 33 in an energy-only market capped at 3 k€/MWh. As a result, investments are riskier in a scarcity pricing setup which is reflected in higher risk premiums (thus higher financing costs).

In comparison, capacity markets decrease financing costs by providing a fixed revenue for at least one year in the case of the CM-AC and even for 10 years in the case of the CM-MAC. While there is an intrinsic uncertainty associated with the level of the capacity price, simulations suggest that this uncertainty does not add up with the one resulting from the energy market. All things considered, capacity markets even compensate part of the uncertainty observed in EOM-PCap, which explains the lower financing costs. Finally, a strategic reserve mechanism does not have any impact on financing costs since, by design, it is not supposed to impact investment decisions.

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182 The differences in O&M costs increase between the system with scarcity pricing and capacity markets are less pronounced than those observed for capital costs. This result is mainly related to the economic characteristics of the technologies considered in the simulation.

To put these results into perspective, a comparison with the results of similar studies in the literature are provided hereafter. In order to maintain a reasonable level of comparability, only studies including a social welfare analysis and closely related to the French Power system are considered. It is important to keep in mind that despite this restriction, the selected studies still present fundamental differences in terms of methodology, parameters, and scenarios. The interest of the comparison lies in the illustration of the coherence of the results presented above, with respect to the existing literature. It does not seek to establish a rigorous comparison of the results with those of the literature.

Most of these studies have focused on comparing a scarcity pricing system with a capacity market with annual contracts. For instance, RTE (2018)[183] finds that the welfare gains associated with the implementation of a capacity market with annual contracts for the French power system would amount to about 390 M€/year, while a scarcity pricing would only deliver welfare gains of about 250 M€/year. In FTI CL - Energy (2016)[184], the difference in social welfare gains between a capacity market with annual contracts and a scarcity pricing is estimated at around 300 M€/year, at the advantage of the capacity market. Finally, Petitet et al. (2017)[185] conclude, using data from the French power system, that a capacity market with annual contracts generates welfare increases that are about 100 M€/year higher than those resulting from a scarcity pricing. The simulations results presented in this chapter are close the upper bound of these values in order of magnitude, regarding capacity mechanisms. The main differences concern welfare gains resulting from scarcity pricing, which are due to modelling methodology and simulation assumptions.

In summary, three main conclusions can be drawn for the social welfare analysis carried out in this section. Firstly, capacity markets appear to perform better

183 This is the closest study to the present one in terms of assumptions, parameters, and included factors. However, the general methodology used in RTE (2018) is an optimization approach, while the methodology in this chapter relies on a system dynamics approach. Moreover, coal investments are constrained in RTE's study, which reduces the volume/mix effect discussed in this chapter.

184 This study uses an optimization framework, but do not consider the uncertainty related to capacity price caps. Hence it underestimates the financing costs associated with investments in capacity markets.

185 Although this study considers risk aversion, it does not consider the impact of this risk aversion on financing costs and ultimately in social welfare.

overall, with a comparative advantage to the CM-MAC, which provides a better hedging to financing risks and shells the system against generation mix distortions. Secondly, although effective in improving SoS (through reduced levels of shortages), the EOM-SP induces higher capital costs (compared to all other market designs). As a result, the overall impact of the EOM-SP in terms of social welfare increase is limited compared to other market designs. Thirdly, the SRM is the least effective in terms of SoS. This is due to the constraints on maximum reserve size and price cap in the SRM auction, not mentioning the absence of additional incentives for investments (compared to the benchmark EOM-PCap).

While social welfare is one of the most comprehensive indicators used by policymakers to support their interventions (at least from an economic point of view), other factors which are only partly or not at all included in the social welfare computation may be considered also. For instance, aspects such as distributional effects, affordability for consumers or financial sustainability could also inform their decision making. In the following sections, the discussion focuses on a set of dimensions that could be of particular interest in a context of capacity adequacy in liberalised electricity markets. It covers the issues of: (i) security of supply, (ii) affordability for consumers and (iii) profitability of generation assets.

4.2. Security of supply

Security of supply is the main argument supporting the modification of existing energy-only markets or the implementation of capacity remuneration mechanisms. As mentioned before, an energy-only market with a low[186] price cap can hardly provide an adequate level of security of supply due a certain number of market failures. The market designs studied here aim at ensuring the provision of a desirable level of SoS, which is explicitly set by a target of three hours of shortages per year. It is worth noting that this target does not consider the volume of shortages, even though market designs that lead to the same duration of shortages but with different volumes of unserved energy are not equivalent. Therefore, the analysis accounts for both dimensions of SoS.

186 Compared to the VoLL.

Figure 55 and Table 23 below indicate the yearly averages of scarcity hours and volumes of unserved energy for each market design. On Figure 55, shortages are represented by the green histograms and reported on the left axis, while scarcity hours are represented by the red line and reported on the right axis.

Figure 55. Comparison of market designs in terms of security of supply

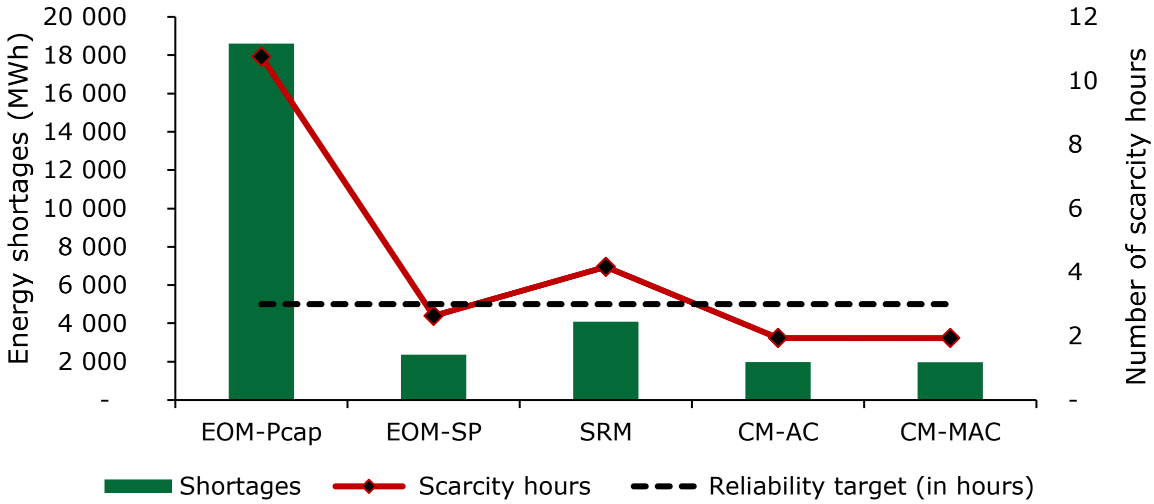
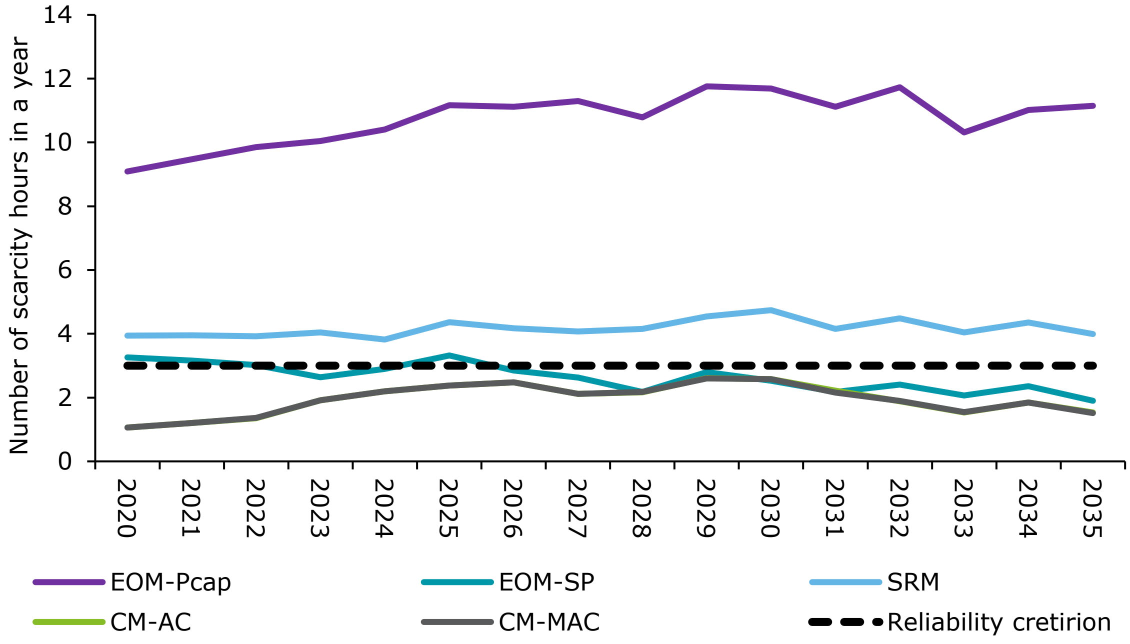


Table 23. Securtity of supply indicators in studied market designs

		EOM-PCap	EOM-SP	SRM	CM-AC	CM-MAC
Scarcity hours (#)	Average	10.75	2.64	4.17	1.94	1.94
	Standard deviation	1.62	0.77	1.25	1.10	1.09
Unserved energy (MWh)	Average	18 606	2 371	4 096	1 976	1 971
	Standard deviation	5 103	971	1 814	1 594	1 589

The results regarding SoS are in line with the analysis of social welfare variations. As explained before, these variations are partly driven by the gains resulting from an improved SoS between the alternative market designs and the benchmark market design EOM-PCap. Regarding the number of scarcity hours, all alternative market designs lead to fewer scarcity hours compared to the EOM-PCap. The EOM-SP and the two capacity markets (i.e., the CM-AC and the CM-MAC) display a very satisfactory performance as they limit shortage below the target threshold of 3 h/year. The SRM reduces scarcity hours to 4.17 h/year which is above the reliability target but still better than the the EOM-PCap.

Figure 56. Average level of scarcity hours throughout simulations



From a dynamic point of view, average levels of scarcity hours are relatively stable for all market designs as illustrated on Figure 56 above. The EOM-SP and the capacity markets stick to the imposed reliability target with some small variations around it. In accordance with the discussion above, the SRM persistently fails to reach the reliability target although it performs better than the benchmark EOM-PCap. A larger reserve size combined with a higher price cap in the SRM auctions could mitigate this limitation, but in absence of a sustained increase of electricity demand, there will still be missing incentives for additional investments. In an energy market with high shares of renewables and a continually decreasing residual demand, a strategic reserve mechanism will be less effective in providing adequate level of SoS compared to capacity markets or an energy-only market with scarcity pricing.

4.3. Costs for consumers

Measuring economic efficiency[187] through social welfare is convenient for economists because it captures an aggregate utility of the society as a whole. However, policymakers are also interested in the impact of market design on consumers' specifically (and the costs they induce for them).

Table 24 breaks down consumers' costs into three components: (i) an energy component, (ii) a capacity component for CRMs, and (iii) a component corresponding to the cost of unserved energy[188].All components are normalised to the total energy production to obtain costs in euros per megawatt hour generated. In terms of total cost, the EOM-SP appears as the least affordable market design for consumers with an average of 80 €/MWh. It is followed by the EOM-PCap and the SRM in which consumers bear a cost of 76 € and 75 € respectively for each generated megawatt hour. Finally, capacity markets lead to the lowest costs for consumers at around 73 €/MWh.

Table 24. Breakdown of consumers' total costs[189]

€/MWh	EOM-PCap	EOM-SP	SRM	CM-AC	CM-MAC
Energy component	74.62	79.46	74.75	67.74	67.73
Capacity component			0.09	5.06	4.89
Cost of unserved energy	1.27	0.16	0.28	0.13	0.13
Total cost	**75.88**	**79.62**	**75.12**	**72.93**	**72.76**

Decomposing total consumers' costs provides a better understanding of the distributional effects in each market design. Figure 57 shows the variation of the three cost components caused by alternative market designs compared to the EOM-PCap. A first observation is that the EOM-SP is the only market design to increase total costs for consumers (by about 4 €/MWh), compared to EOM-PCap. This result is explained by the higher energy cost borne by consumers (since

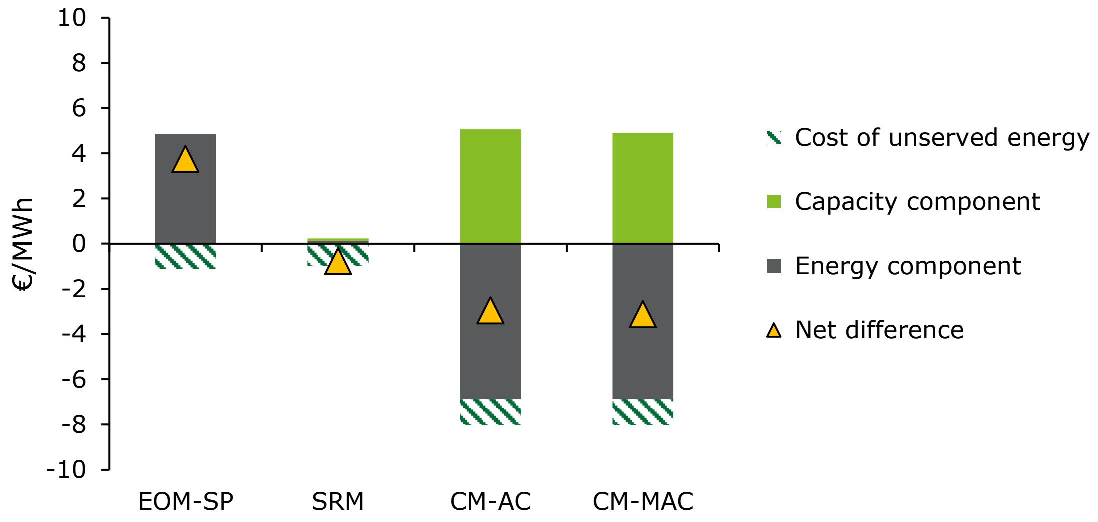
187 Here, economic efficiency is understood as both allocative and productive efficiency.

188 This cost is computed by applying the VoLL to the volume of unserved energy.

189 Generation from renewables is not taken into account. Including it would lower the energy component borne by consumers.

electricity prices are allowed to reach the VoLL). All CRMs (SRM, CM-AC and CM-MAC) reduce total costs for consumers by about 3 €/MWh compared to the EOM-PCap. These observations are in line with the results regarding social welfare.

Figure 57. Difference in consumers' total costs (compared to EOM-PCap)



4.4. Investment risk and profitability of assets

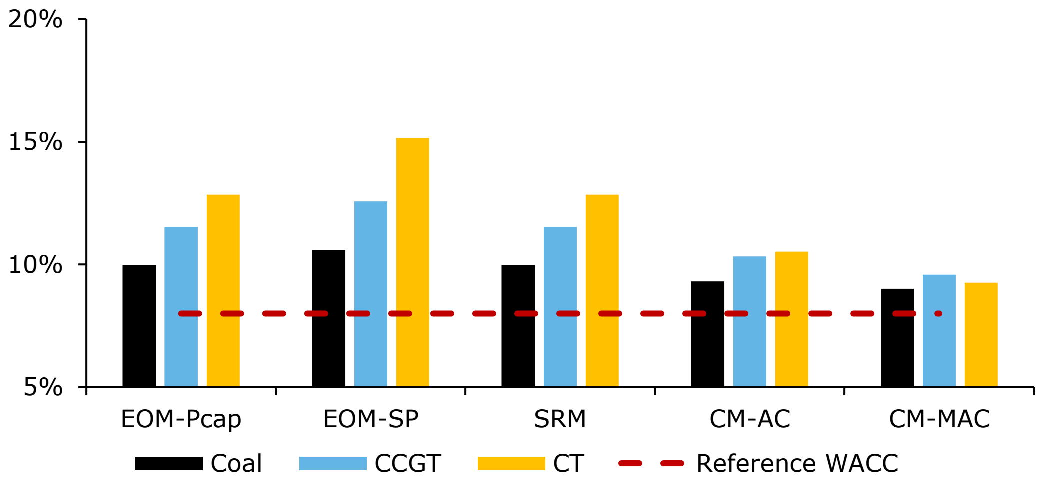
In this section, the focus of the analysis shifts towards producers and more precisely towards the intrinsic risk profile of potential investments in new generation assets. The profitability of these assets is also analysed in order to assess whether or not the studied market designs enable investors to recover their costs.

4.4.1. Investment risk

Investment risk mitigation is an important desirable feature of a market design aiming at ensuring long-term capacity adequacy. The results in terms of social welfare variations presented in section 4.1 already give some indications on the ability of each market design to reduce investment risk. For instance, they show that, given the chosen simulation parameters, capacity markets tend to reduce investment risk overall, compared to the benchmark EOM-PCap market design. Conversely, a scarcity pricing system would increase investment risk compared to the EOM-PCap as energy revenues will be more volatile. At last, there is no difference in investment risk between the SRM and the EOM-PCap since the former does not impact investment decisions in the energy market.

From a modelling and simulation perspective, investment risk is assessed through the risk premiums paid by investors on top of the reference investment costs. These risk premiums could also be translated into risk-adjusted WACC, by assuming that they represent the additional cost of financing resulting from an investment's riskiness. Figure 58 represents the average risk-adjusted WACC[190] by technology in each studied market design. The reference value of the WACC is also plotted as a benchmark (this is the base value used in simulations, without adjustment for risk premiums). As expected, the risk-adjusted WACC confirm the observations drawn from the social welfare analysis and explained above. They are also coherent with the intuition that base-load technologies are less risky than peak-load ones.

Figure 58. **Risk-adjusted weighted average cost of capital**

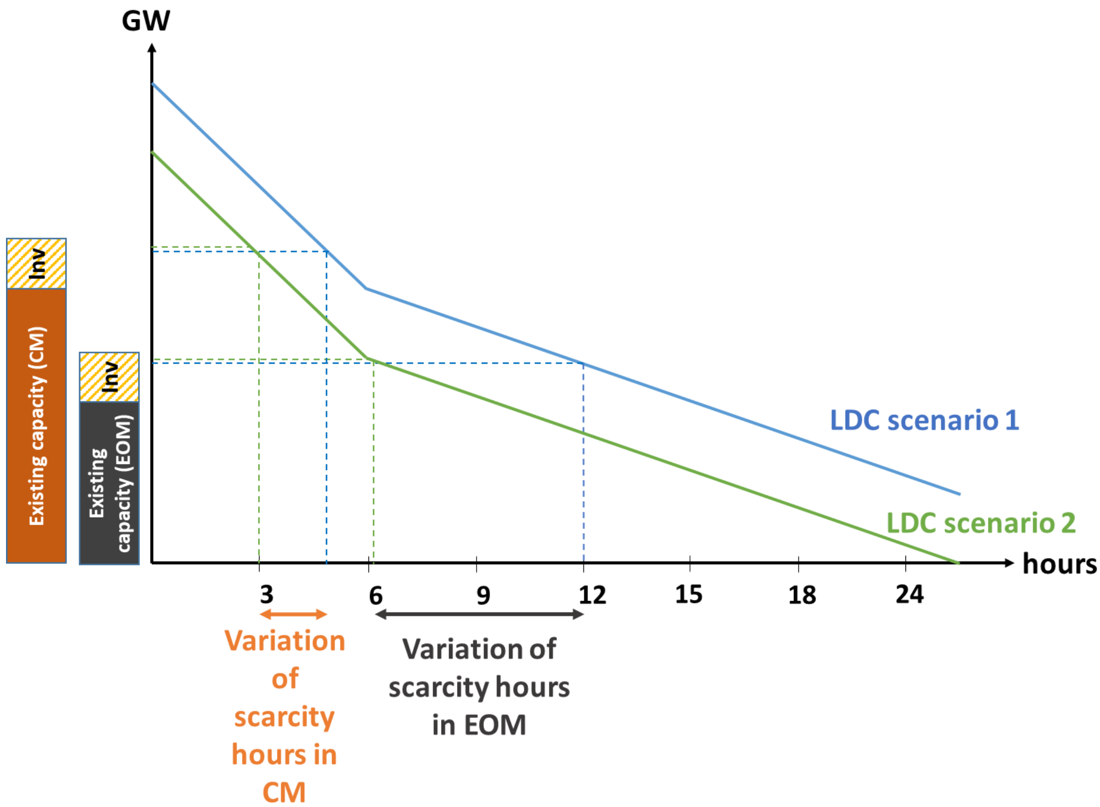


Analysing risk-adjusted costs of capital is useful for identifying market designs with risk mitigation features. However, it tells little about the fundamentals of these

190 The risk adjusted WACC is computed by considering that a risk premium in terms of investment costs could be translated into a risk premium in terms of WACC. To this end, the risk premium resulting from the CVaR computation is understood as an additional overnight investment cost, which gives a risk-adjusted overnight investment cost. By equivalence, a risk-adjusted overnight investment cost with a reference WACC of 8%, is equivalent to the reference overnight investment cost, but with a higher WACC (i.e., a risk-adjusted WACC).

features. In the case of scarcity pricing, the increase of investment risk (compared to the EOM-PCap) is intuitive, as it comes from the higher volatility if energy market revenues. For capacity markets, the beneficial effect on investment risk (again compared to the EOM-PCap) is less trivial. In fact, one may even argue that capacity markets could increase investment risk since they create an additional source of uncertainty through the capacity price. Furthermore, once a capacity contract is secured at a fixed price, it does not necessarily impact the volatility of revenues, but rather their level. The effect of capacity markets on investment risk mitigation stems from the fundamental functioning of electricity markets. Figure 59 below illustrates this effect in a simplified setting.

Figure 59. Illustration of perceived energy revenue volatility in investment appraisal in capacity markets (CM-AC/CM-MAC) and energy-only markets (EOM)



While assessing the profitability of a new generation unit, investors usually resort to expected demand curves and compute estimated revenues. Conceptually, this process can be represented by using load duration curves (LDCs), which correspond to hourly load levels sorted in decreasing order. By construction, the slope at the highest demand hours is higher than the one in the middle of the LDC. On Figure 59, a simplified example with two LDC scenarios is plotted to represent prospective load scenarios considered by an investor. The main reason why capacity markets are able to reduce investment risk is because they stabilise installed capacity at a point of lower revenue volatility on the LDCs, compared to an energy-only market.

Thanks to the explicit capacity target defined in capacity markets, the level of installed capacity will usually oscillate around a level that corresponds to the reliability target. This reliability target is always located at the high end of LDCs where the effect of additional units of capacity on the number of scarcity hours in the year is moderate. This impact is inversely proportional to the slope of the LDCs at the considered point. Conversely, energy-only markets with a low price cap will tend to stabilise installed capacity on a lower segment of the LDCs, where additional units of capacity will have a higher impact on the number of scarcity hours (translating into more revenue volatility). This difference between a capacity market and an energy-only market is well illustrated on Figure 59. Considering the two LDC scenarios and a potential investment in a peaker, the variability of scarcity hours from one LDC scenario to the other, is higher in an energy-only market, compared to a capacity market. Given the proportionality of a peaking unit's remuneration to the number of scarcity hours, investing in a peaking unit in an energy-only market will therefore involve more uncertainty than it would be the case in a capacity market.

It should be noted that the magnitude of the effect illustrated on Figure 59 depends on the shape of the LDCs. In fact, for a hypothetical LDC that would have the same slope during the highest one hundred hours of demand for instance, there would be no difference in investment risk between a capacity market and an energy-only market, from a pure energy revenue perspective. In this particular case, it is even likely that a capacity market would increase investment risk compared to an energy-only market, due to the uncertainty regarding the capacity price. Of course, a capacity market will provide a better remuneration basis and a higher profitability but that does not mean that it reduces the riskiness of investment. Furthermore, it should be noted that the analysis provided above only covers demand uncertainty. Other sources of risks such as fuel prices, climate policy or technological breakthrough are not considered. Including these could lead to different conclusions.

To summarise, there are two effects in play when a capacity market is introduced. On the one hand, a capacity market will tend to stabilise installed capacity at a point of lower energy revenue volatility (compared to an energy-only market). On the other hand, the volatility associated with the capacity price will generate an additional source of uncertainty for investors (again compared to an energy-only market). These effects work in opposite directions and the final impact on investment risk will depend on their relative magnitudes. Given the simulation parameters that are used in this chapter, the first effect seems to overweigh the second one.

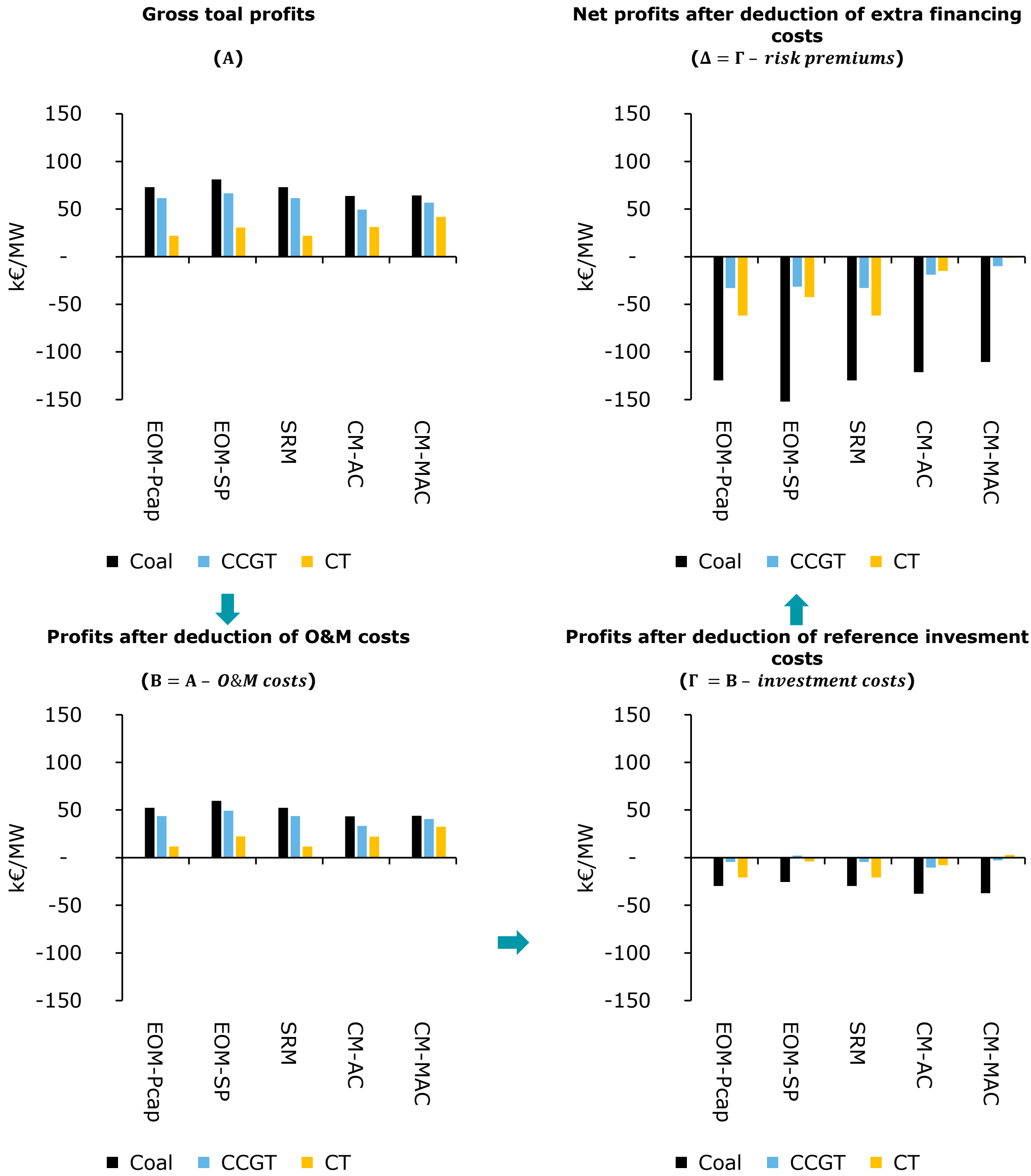
4.4.2. Profitability of assets

In addition to investment risk, market participants are also (and even more) interested in the profitability of their assets. The following paragraphs provide a detailed analysis of the profitability of generation assets and the ability for investors to recoup their capital costs. To avoid any distortions introduced by the plants from the initial generation fleet, only new plants resulting from investment decisions made over the simulation horizon are analysed. For each market design, different types of yearly profits for thermal technologies are computed. The results are highlighted on Figure 60 hereafter. Four types of profits are presented and normalised by megawatt:

a. Gross total profits corresponding to producers' gross profits from the energy market (once variable costs are deduced) plus the potential capacity payment they receive.
b. Profits after fixed O&M costs are accounted for. These are the gross total profits minus annual operation and maintenance costs.
c. Profits after deduction of investment costs, which deduce reference investment costs (without considering risk premiums) from the previous profits. Reference investment costs are the annualised reference overnight costs (without risk premium).
d. Net profits after adjusting for risk premiums (i.e., financing costs), which correspond to the previous profits minus the effective risk premiums paid by investors. These are the net profits earned by producers. In all the

discussion hereafter, capital costs should be understood as the sum of reference investment costs and risk premiums (which represent extra financing costs).

Figure 60. Decomposition of generation assets' profitability (only for new investments made over the simulation horizon)



Across all market designs profits remain positive after O&M costs are deducted (bottom-left chart). However, once annualised investment cost[191] are subtracted (bottom-right chart), a missing money phenomenon appears in most market designs, although extra financing costs (i.e., risk premiums) still have to be deducted.

The explanation for this lies in the myopic characteristic of investors. Indeed, as described in the modelling (see section 2.1 of Chapter II), agents do not have perfect forecasts about future capacity additions in thermal technologies (that have not been decided yet). Moreover, they only know the trajectory of the penetration of renewables on a horizon of eight years (i.e., the forecast horizon). Consequently, when they assess the profitability of a contemplated investment over its entire lifetime, agents tend to underestimate the effect on renewables in the long run. This is consistent with situation observed recently for gas-fired generation in Europe. Furthermore, for technologies that have long lead times such as coal, *ex post* profitability is almost systematically reduced by capacity additions in technologies that have shorter lead times (CCGT and CT). Therefore, the missing money phenomenon is even more pronounced for coal-fired plants.

Capacity markets have varied performances when it comes to recovering reference investment costs and extra financing costs. The corresponding graph (bottom-right graph) shows that, despite providing capacity revenue, the CM-AC does not lead to reference investment cost recovery (even when abstracting from risk premiums). The CM-MAC on the other hand seems to enable CCGTs and CTs to recoup their reference investment costs. In both cases, coal-fired plants do not recover their reference investment costs, due to the myopia of investors.

When revenues are adjusted for extra financing costs to factor in investment risk premiums (top right chart), the capacity market with multiannual contracts seems to be the only market design to approach full cost recovery, at least for peaking units (CTs).

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191 These investment costs are computed by considering a nominal WACC of 8% for all technologies.

The existing literature argues that capacity markets, if properly designed[192], would create adequate incentives for investments in capacity resources and provide a desirable level of SoS (Batlle and Rodilla, 2010; Cramton et al., 2013; Cramton and Stoft, 2005). While this is true from a long-run equilibrium perspective, it should be noted that the underlying assumption is that the capacity payments are determined in a way that enables investors to recover their costs. As such capacity markets only fulfil the aforementioned functions if investors have confidence that they will recoup their capital (including an appropriate remuneration for risk) over the lifetime of their assets. Any factor that can jeopardize this belief would impede on the effectiveness of capacity markets. The results presented above indicate that in the classical framework prescribed by the existing literature, there is in fact a missing money problem, even in presence of capacity markets. The next sub-section investigates why such situations of missing money may occur in capacity markets, when the dynamics of the system are considered.

4.4.3. Potential failure of capacity markets to ensure cost recovery

It is useful to recall that there are two categories of offers in capacity auctions: offers form new capacities and those from existing capacities. The difference of rationale between new and existing capacities is crucial to understand the dynamics of capacity auctions and the profitability of generation assets.

Assuming economic rationality and perfect competition, existing plants bid their annualised missing money, which is a short-term missing money only comprising fixed O&M costs, but no investment costs[193]. Holding the same assumptions, new plants (i.e., prospective investments) bid their annualised expected missing money which is an annualised long-term missing money that accounts for total capital costs (reference investment cost and risk premium). If the bid is accepted, the plant is assured to recover all costs (including annual capital costs) in the year it receives the corresponding capacity payment. The underlying logic is that the rest of the capital costs would be recovered on an annual basis through the years

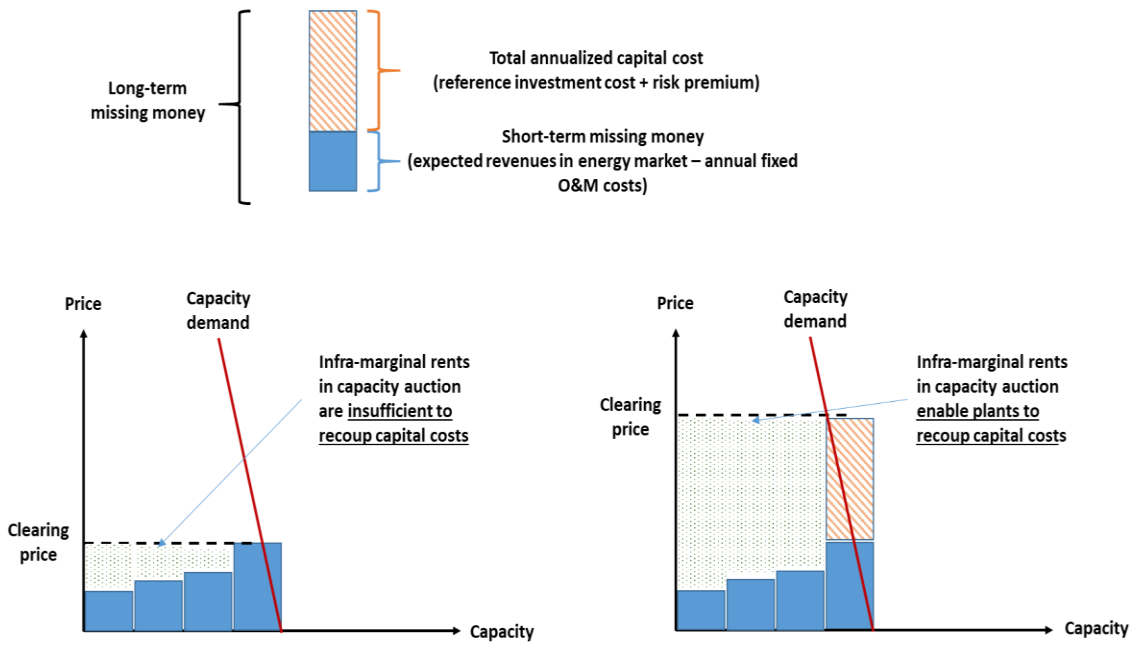
192 That is, if the capacity demand and the price cap of the auction are well defined, and there is no strategic behaviour from bidders.

193 Although existing plants may be tempted to include investments costs in their bids, this entails a higher risk of being rejected in the auction and therefore not benefiting from a capacity price at all.

thanks to infra-marginal rents in capacity auctions. A fundamental assumption in this reasoning is that the capacity auctions would frequently clear at sufficiently high prices to generate the required infra-marginal rents. However, as explained hereafter, this assumption may easily be violated depending on the needs for new capacity in the system.

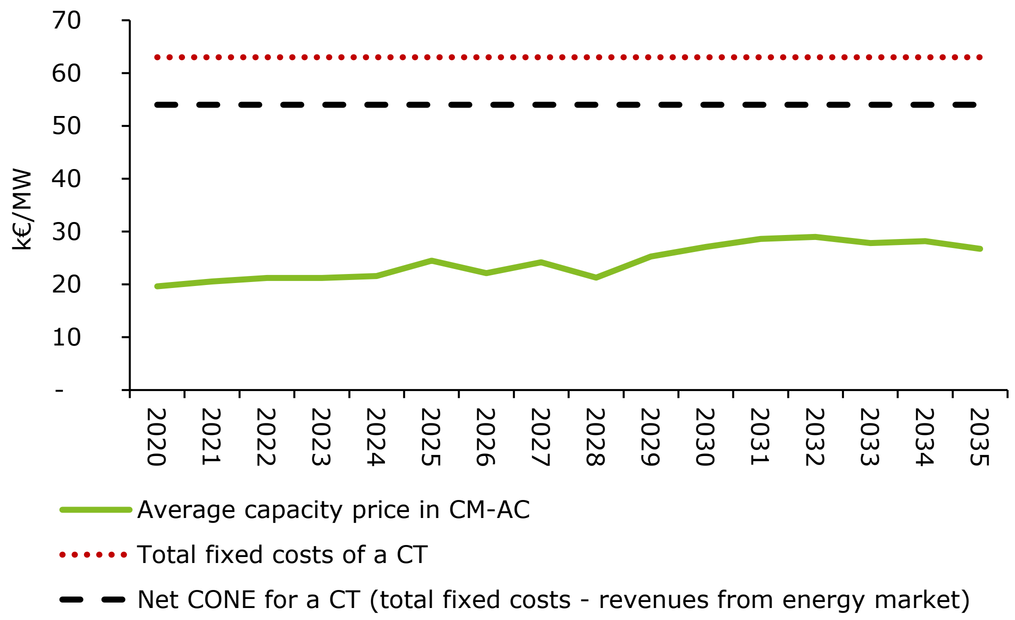
In the CM-AC where only annual capacity contracts are available, every time that the capacity auction is cleared by an existing plant, all generation assets fail to recover their annualised investment costs. In order for generation assets to recover their investment costs, the marginal bid in the capacity auction has to be one from a new plant (which includes the annualised investment cost). The profitability of generation assets in the CM-AC is therefore directly dependent on investment needs in the system. If there is a sustained need of investment, materialised by the capacity clearing price being frequently set by new plants, then all generation assets may be able to recover their capital costs on average. Conversely, in situations where investments are sparse, generation assets will only recoup their short-term missing money and part of their capital costs through the capacity price. Figure 61 below provides a simple illustration of this mechanism.

Figure 61. Illustration of cost recovery issue in capacity markets



To confirm these theoretical intuitions, a comparison of the average capacity price and the fixed costs of a new combustion turbine (CT) is displayed on Figure 62. The figure shows: the average capacity price throughout the simulation years, the total fixed costs of a CT (O&M costs and reference investment costs) and the net CONE of a CT (once expected revenues from the energy market have been accounted for). Average capacity prices are persistently lower than the net CONE, which suggests a missing money. This is consistent with the explanations above.

Figure 62. Average capacity price in CM-AC vs fixed cost of a CT



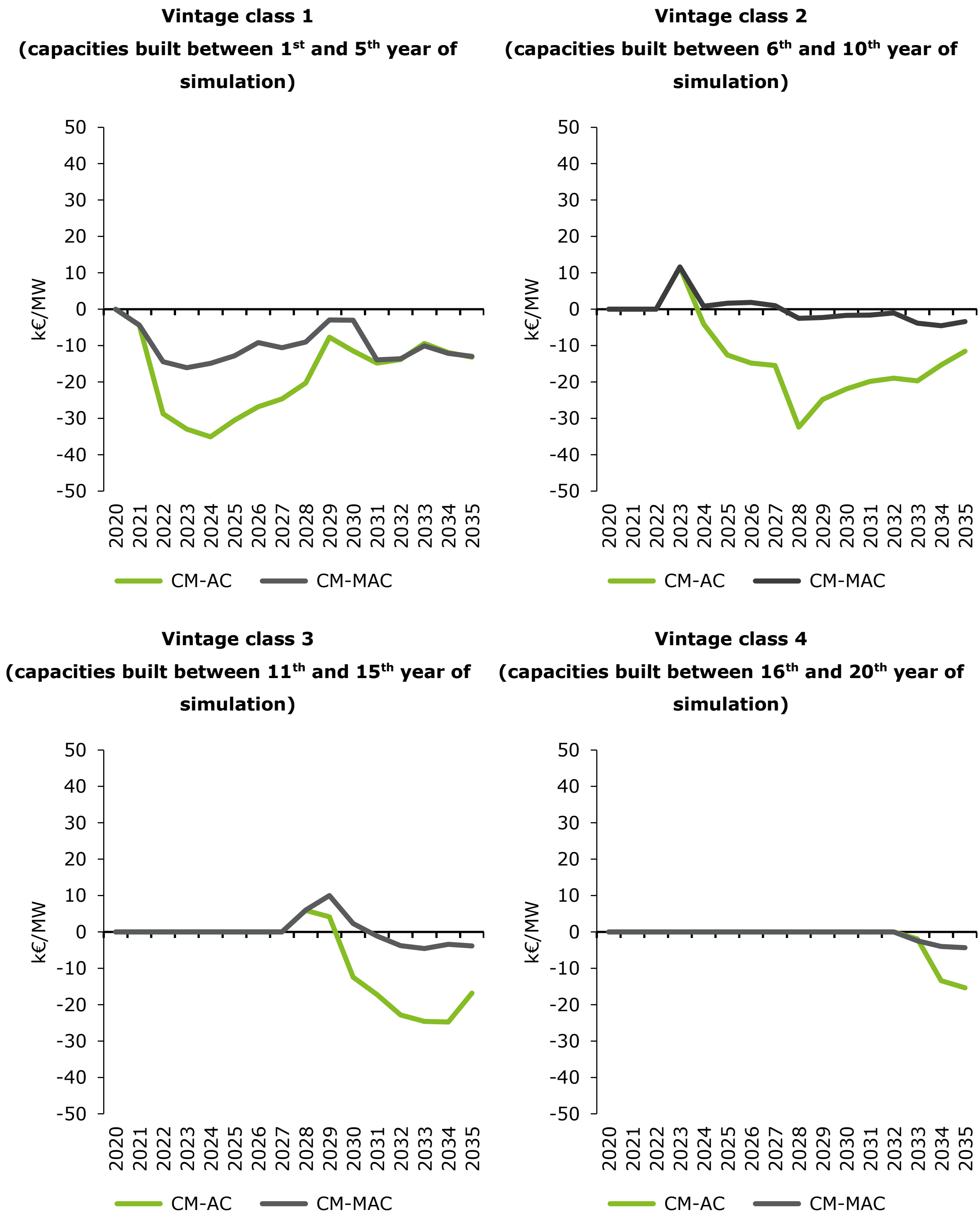
It is worth noting that the potential failure of the CM-AC to provide enough revenues for full cost recovery does not affect its effectiveness in terms of security of supply, at least not in the short run. Indeed, from an investor's perspective, the capacity price can provide a sufficient incentive to trigger needed investments and to remain active once the investment decision has already been made (and when capital costs become sunk costs). That remains true whether or not this capacity price enables the investor to fully recover engaged capital costs. However, it may be detrimental in the long run because investors may start to factor in this effect in their capacity bids for new plants.

One plausible scenario is that they may start to rely more heavily on their first capacity payment, which is essentially the economic signal that effectively triggers an investment decision. For instance, instead of spreading their capital costs over the expected lifetime of their asset and only including an annualised capital cost in their initial bid, they may decide to include a higher share of these capital costs. Two outcomes would occur in this situation: either the capacity price cap is high enough to trigger investments at significantly expensive levels, or the bids for new plants are too high to be accepted in the capacity auction. In any case, it may jeopardize the effectiveness of capacity markets in ensuring security of supply.

In capacity markets with multiannual contracts such as the CM-MAC, new plants secure a fixed capacity price for the duration of their capacity contract and are not allowed to participate to capacity auctions for delivery years covered by that period. For all subsequent delivery years, they can bid in the capacity auction similarly to all other existing plants. Holding the assumption that new plants bid their long-run missing money in their first capacity auction, a multiannual capacity contract will allow new plants to recover their capital costs for a number of years corresponding to the duration of the contract. Afterwards, the plants' ability to recover annualised capital costs will then depend on the nature of the plant setting the clearing price in the capacity auctions (as it is the case in the CM-AC). If the plant setting the price in a particular year is a new investment, then existing generation assets can recover their capital costs, whereas if it is an existing plant, they may fail to do so that year. This explains why the CM-MAC is better than the CM-AC at recovering capital costs as illustrated on Figure 60. But there is no indication that generation assets recover their entire capital costs over their expected lifetime, even in the CM-MAC.

Figure 60 only represents an average net profit over the simulation horizon for twenty years, which is shorter than the expected lifetime of all technologies. Most new plants remain under their multiannual capacity contract during the simulations. Only early investments decided in the first years come out of their initial multiannual contract by the end of the simulations. These early investments are the ones that should be tracked to properly assess the ability of the CM-MAC to enable investors to recoup their capital costs. To do so, the simulation horizon is split in four timeframes of five years each, and the net profits of the investments made in every timeframe are analysed. These investments are categorised as vintage classes and presented on Figure 63. The discussion focuses on capacity markets.

Figure 63. Evolution of net profits for new CTs by vintage class (CM-AC vs CM-MAC)



The graphs on the figure show that the CM-AC allows full capital cost recovery only punctually the first year of operation. Afterwards, the net profits are consistently negative on average. Focusing on vintage class 1 (investments made during the first five years of simulations), it appears that even the CM-MAC fails to properly remunerate invested capital (albeit during the duration of the multiannual contract). However, this is not due to the market design itself, but rather to wrong anticipations by agents because of their myopic foresight. Indeed, for investments that are decided early in the simulations, agents' forecast of installed RES capacity could be very far from reality (over the lifetime of the assets). This leads them to underestimate the capacity price required to ensure cost recovery.

Focusing on vintage 2 this time (top right graph of Figure 63), the CM-MAC provides enough revenues to remunerate invested capital, at least during the period over which their initial capacity contracts apply. A drop in net profits is observed at the end of the initial multiannual contract around year 2032. As soon as these plants no longer benefit from their initial contract, they become dependent on the bid clearing the capacity auctions in order to recoup their capital costs. Therefore, similarly to the CM-AC, the CM-MAC could also fail to ensure capital cost recovery over the entire lifetime of generation assets if investment needs are only punctual.

In theory, to ensure complete cost recovery, capacity contracts duration for new plants should match their expected lifetime, which is unrealistic in an actual electricity market because of the lock-in and windfall effects that such contracts could create. Plants that secure a long-term capacity contract would stay in the system for decades even if they are no longer cost-effective or suited to policy goals. Policymakers thus face a difficult arbitrage in the determination of capacity contracts duration. If the duration of the contracts is too long, it would create lock-in and windfall effects that may create inefficiencies. Conversely, if the duration is too short, investors could fail to recoup their capital costs, which may affect the effectiveness of the capacity market in the longer term, as explained before for the CM-AC.

In practice, the main justification behind the introduction of multiannual capacity contracts have been the reduction of financing costs by providing more certainty on the capacity price. They are expected to mitigate barriers to entry for new plants especially when they are built by small independent firms who are exposed to high financing costs. An additional argument is that providing long-term contract will limit investors' desire to load their entire capital costs in a single year contract.

This is the risk highlighted above in the discussion on the CM-AC's potential failure to ensure capital cost recovery and the subsequent impact of that failure on investors' bidding strategy.

The reduction in financing costs associated with multiannual capacity contracts is also beneficial for consumers since it leads to lower capacity bids by new entrants and thus lower costs, all things equal. These are the arguments put forward by the UK and France. UK has already implemented its multiannual contract scheme with a duration of 15 years for new eligible capacities. In France, 7-year long capacity contracts are expected to be introduced in 2019 for new investments. However, in both cases, the definition of the multiannual contract duration has been arbitrary and there is still no clear methodology proposed in the literature or by practitioners for the calibration of this parameters. Yet, a wrong calibration of the duration of multiannual capacity contracts could have detrimental effects as mentioned above.

It should be noted that the social welfare analysis carried out in section 4.1 does not account for the long-run implications of having a market design which does not ensure full cost recovery for investors. Investors' confidence is likely to be impacted in the long run as they fail to recoup their invested capital. This could in turn lead them to make higher bids in capacity auctions as a way to internalise the risk of *ex post* missing money. The possibility of such a behaviour from investors calls for special attention when designing price caps of capacity auctions, as it (the behaviour) can eventually jeopardize the performance of classic architectures of capacity markets.

5. Sensitivity analysis

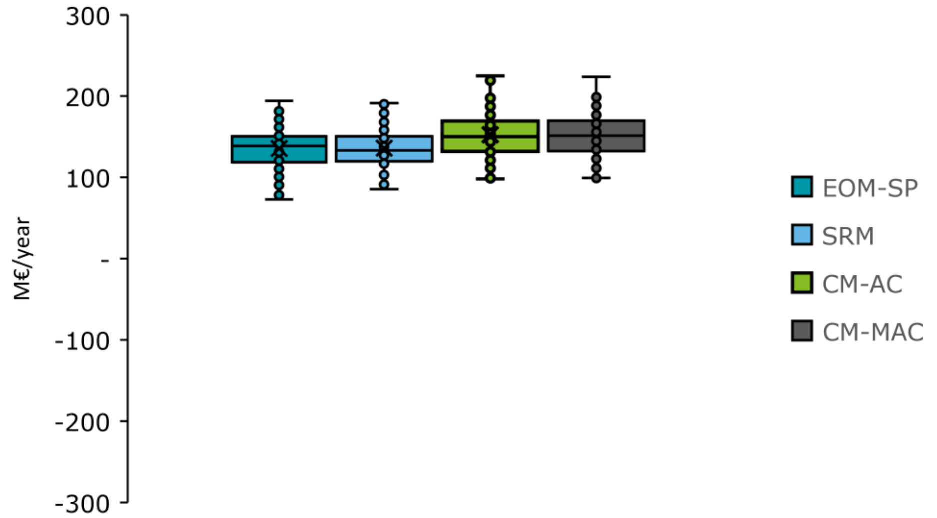
To provide some insights on the variability of the results presented in the previous section, a sensitivity analysis is carried out. It covers two of the most central factors of the simulations, which are the level of demand uncertainty and risk aversion. The focus is made on social welfare as it encompasses most of the other dimensions (except from cost recovery).

5.1. Lower demand uncertainty

An alternative value for the volatility of peak gross demand is considered in this sub-section. More precisely, the standard deviation of the normal distribution from which the evolution of the peak gross demand is sampled is changed from 1% to 0.25%. This corresponds to a relatively certain demand. The distribution of the variations of social welfare are presented on Figure 64.

Without surprise, reducing uncertainty also reduces the volatility of social welfare variations, compared to the base scenario discussed in the previous section. Another interesting observation is that the scarcity pricing performs way better this time. It Increases social welfare compared to a low-price-capped energy-only market in all 100 runs. On average, the increase of social welfare resulting from the implementation of scarcity pricing corresponds to more than 130 M€/year. The introduction of a CRM (regardless of the type), also increases social welfare between 130 and 155 M€/year on average. Capacity markets remain the best performing market designs.

Figure 64. **Distribution of the variations of social welfare compared to EOM-PCap in case of lower demand uncertainty**



These results indicate that demand uncertainty does not modify the merit order of the market designs in terms of social welfare. However, it increases the gap in performance between market designs, which is an important finding for policymaking.

Table 25 below provides a breakdown of the social welfare variations. With a less uncertain demand, all market designs reduce shortages in similar proportions. Differences in social welfare variations are therefore essentially explained by system costs (generation, fixed O&M and capital costs).

Table 25. Comparison of average social welfare variations between market designs (with respect to EOM-PCap) in case of lower demand uncertainty

M€/year	EOM-SP	SRM	CM-AC	CM-MAC
Gains from reduction of shortages $[A]$	239	233	240	240
Difference in generation costs $[B]$	- 12	1	- 39	- 39
Difference in fixed O&M costs $[C]$	31	27	35	35
Difference in capital costs $[D = D' + D'']$	85	68	92	91
Volume/mix effect[194] [D']	**73**	**68**	**103**	**103**
Financing risk effect[195] [D'']	**12**	**-**	**- 11**	**- 12**
Variation of social welfare $[E = A - (B + C + D)]$	**135**	**136**	**153**	**153**

5.2. Risk neutrality

In this sub-section, the assumption of risk averse agents is relaxed to consider risk neutrality. Social welfare variations with this new assumption are displayed on Figure 65 hereafter. Interestingly, scarcity pricing still yields a slight negative impact on social welfare on average (compared of EOM-PCap). Referring to the explanations provided in section 4.1.2 of this chapter, the only determining factor here is volume/mix (since effects on investment risks are neutralised). Once again, the merit order of the market designs is preserved, with capacity markets delivering the highest social welfare increases, compared to the EOM-PCap.

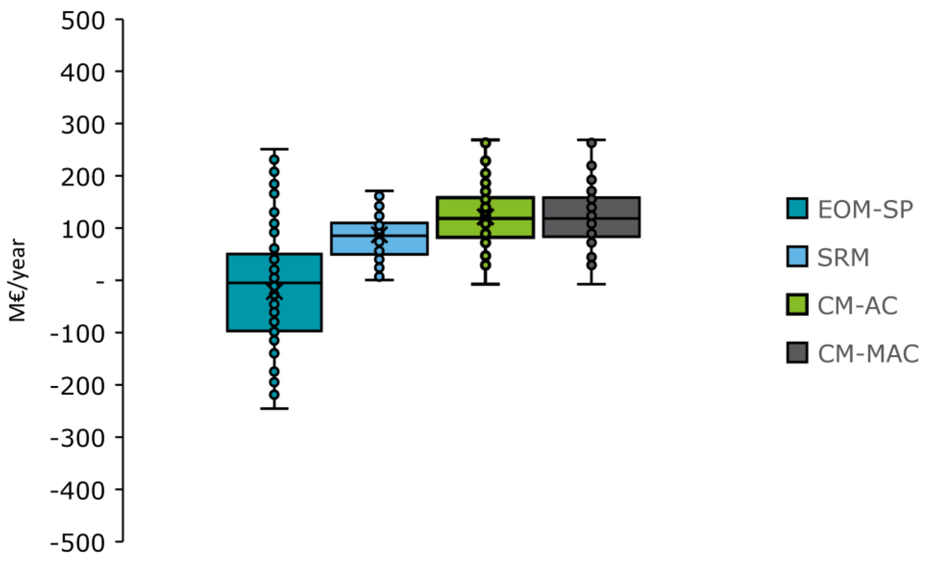
However, the benefits of implementing CRMs appear lower in case of risk neutral agents. With risk averse agents, implementing either a strategic reserve mechanism or one form of capacity market increases social welfare by 200 to 320 M€/year, while the increase is only of 80 to 120 M€/year if agents are risk

194 This is the variation of total investment costs observed in a market design, compared to EOM-PCap, by adjusting for EOM-PCap risk premiums (i.e., by considering identical risk premiums to those in EOM-PCap). Therefore, the variations directly translate the difference in investment volumes or technology mix between the market designs since the financing costs are considered constant across market designs.

195 This is the part of the variation in total investment costs related to differences in risk premiums between a market design and EOM-PCap. It is inferred from the equivalent investment costs (computed by adjusting for risk premiums in EOM-PCap) and the actual investments costs.

neutral. Recall that this result was already observed in Chapter I, using a simplified modelling framework. This brings additional confirmation to the robustness of the results obtained in Chapter I.

Figure 65. Variations of social welfare compared to EOM-PCap in case of risk neutral agents



The breakdown of average social welfare variations is highlighted in Table 26. The values do not reveal any peculiar effect. The only difference with the analysis carried out for the base case presented in the previous section is the absence of a "risk effect" in capital costs, which is consistent with the risk neutral assumption.

Table 26. Comparison of average social welfare variations between market designs (with respect to EOM-PCap) in case risk neutrality

M€/year	EOM-SP	SRM	CM-AC	CM-MAC
Gains from reduction of shortages $[\boldsymbol{A}]$	202	168	191	191
Difference in generation costs $[\boldsymbol{B}]$	- 102	1	- 65	- 65
Difference in fixed O&M costs $[\boldsymbol{C}]$	53	22	54	54
Difference in capital costs $[\boldsymbol{D} = \boldsymbol{D}' + \boldsymbol{D}'']$	272	58	79	79
Volume/mix effect[196] [D']	***272***	***58***	***79***	***79***
Financing risk effect[197] [D'']				
Variation of social welfare $[\boldsymbol{E} = \boldsymbol{A} - (\boldsymbol{B} + \boldsymbol{C} + \boldsymbol{D})]$	**- 21**	**87**	**122**	**122**

196 This is the variation of total investment costs observed in a market design, compared to EOM-PCap, by adjusting for EOM-PCap risk premiums (i.e., by considering identical risk premiums to those in EOM-PCap). Therefore, the variations directly translate the difference in investment volumes or technology mix between the market designs since the financing costs are considered constant across market designs.

197 This is the part of the variation in total investment costs related to differences in risk premiums between a market design and EOM-PCap. It is inferred from the equivalent investment costs (computed by adjusting for risk premiums in EOM-PCap) and the actual investments costs.

6. Chapter conclusions

This chapter discusses market design options to ensure long-term capacity adequacy in a context a high penetration of renewables. Five market designs are studied: an energy-only market with an administrative price cap (EOM-PCap), an energy-only market with scarcity pricing where the price cap is equal to the VoLL (EOM-SP), a strategic reserve mechanism (SRM), a capacity market with annual capacity contracts (CM-AC) and a capacity market with multiannual contracts for new investments (CM-MAC).

Based on the System Dynamics methodology, a simulation model which endogenously represents all investment, mothballing and shutdown decisions is developed. The potential effect of a risk-averse behaviour from investors is taken into account. The selected market designs are compared with respect to their ability to improve social welfare. To complement the analysis, additional dimensions are investigated, notably the effectiveness of the market designs in providing a desirable level of security of supply, their affordability for consumers and their ability to allow cost recovery for generation assets. A Monte Carlo approach consisting of 100 runs of the model with randomly generated demand trajectories is used to assess the performance of the studied market designs. Data from the French power system is used to build a concrete case study based on a real system.

Simulations results indicate that CRMs improve social welfare compared to the benchmark energy-only market with an energy price cap at 3 k€/MWh. Based on a case study calibrated on the French power system, welfare gains resulting from the introduction a CRM range from about 200 to 320 M€ per year depending on the considered market design. Capacity markets provide the highest welfare increase especially the one with multiannual contracts (CM-MAC). These welfare gains are mainly due to the reduction of shortages compared to the EOM-PCap. Despite its good performance regarding the reduction of shortages, the scarcity pricing significantly increases investment risk and financing costs, which impedes on its ability to effectively increase social welfare in a sizeable magnitude.

Regarding security of supply, only some of the studied market designs lead to desirable levels of scarcity hours as specified by the reliability target of three shortages hours per year. The scarcity pricing system and both capacity markets reach this reliability target on a consistent basis. Conversely, although it reduces scarcity hours compared to the EOM-PCap, the strategic reserve mechanism cannot meet the reliability criterion because of its intrinsic design, which does not allow it to provide additional investment incentives when necessary (compared to the EOM-PCap). A strategic reserve mechanism is primarily destined to handle punctual security of supply concerns by making old and expensive plants stay longer in the system.

In terms of costs borne by consumers (including cost of shortages), the EOM-SP is the most expensive market design mainly because of the increase of energy prices during scarcity periods. Capacity markets on the other hand yield the lowest costs for consumers. They reduce the energy component of consumers' total costs by containing scarcity periods within the range of the reliability target, which in turn also reduces the cost of unserved energy. However, this comes at the cost of a capacity charge which constitutes a direct transfer from consumers to producers. The strategic reserve mechanism lies between capacity markets and the EOM-SP. Overall, the comparison of total costs for consumers is in line with the social welfare results.

From an investor's perspective, none of the studied market designs appears to be entirely satisfying in terms of cost recovery. Even capacity markets which are meant to alleviate the missing money issue occasionally fail to provide enough remuneration to cover capital costs. In fact, the ability for investors to fully recover their capital costs is dependent of the type of capacity clearing the capacity auction on an annual basis. In case of sustained investment needs, materialised by a capacity price set by a new plant every year, then plants are indeed able to recoup their capital costs over their expected lifetime. However, if investment needs are punctual as it may be the case when electricity demand is flat or declining, then generation assets fail to recover their capital costs (each time the capacity auction is cleared by an existing plant bidding its opportunity cost).

This result is particularly important for policymakers because of its implications regarding the long run effectiveness of current capacity markets. Given the potential failure of capacity markets to appropriately remunerate invested capital, investors may start including higher risk premiums in their capacity bids as a hedging tool. Even if the introduction of multiannual contracts mitigates the missing money issue in capacity markets, it does not entirely solve it unless the contracts are calibrated to last the whole lifetime of the generation asset. This of course is not a realistic solution because of the windfall gains it could generate for investors who manage to secure capacity contracts for decades regardless of the evolution of market fundamentals. It could also create an unnecessary burden for consumers in terms of capacity charge.

Overall, capacity markets appear to be the superior solution to ensure capacity adequacy. However, their current design raises concerns about their ability to fix the missing money problem in situations of flat or decreasing electricity demand associated with a sustained deployment of renewables. The work carried out in this chapter suggests that policymakers should revisit the design of capacity markets if they want to preserve their effectiveness in the long run.

Potential extensions of the work presented in this chapter could include the consideration of an improved short-term market which takes into accounts plants' flexibility and technical constraints. This will enable to properly represent flexibility solutions such as demand response or storage and analyse how these solutions can help facilitate the integration of renewables. Short-term flexibility and long-term adequacy are intricately related and will become so even more as electricity systems welcome more renewables. The remuneration of flexibility will therefore be a crucial component of investment signals and could ultimately affect capacity adequacy.

General conclusion

The liberalisation of electricity markets around the world has revealed problems of incentives regarding long-term investments in capacity resources. The ability of energy-only markets with low price caps to provide adequate investment signals has been particularly questioned in this regard. To deal with this issue, the economic literature has proposed various alternative market designs ranging from small adjustments – consisting for instance of removing price caps – to the introduction of capacity remuneration mechanisms or CRMs, in different forms (strategic reserves, capacity markets, etc.). The choice of the market design requires for policymakers to assess and compare the economic performances of available solutions. The ongoing transition in electricity systems, partly driven by the penetration of renewables, complexifies even more this choice by raising additional concerns about investment incentives in thermal technologies and demand response.

This dissertation complements the existing literature on market design for long-term capacity adequacy by focusing on three important issues: (i) understanding how electricity markets perform under different assumptions regarding investors' risk preferences, (ii) analysing the compatibility of private agents' incentives to mothball capacity resources with security of supply objectives and (iii) assessing the economic performance of different market designs in a context of a high penetration of renewables. To this end, the System Dynamics (SD) modelling framework is mobilised to represent long-term dynamics resulting from private agents' decisions in liberalised electricity markets. The dissertation is structured around three chapters which cover key issues of market design for long-term capacity adequacy in future power systems.

The **first chapter** focuses on investors' risk aversion and its impact on capacity adequacy in liberalised markets. A dynamic simulation model focusing on peaking units is developed to address the question. Risk aversion is represented through the Conditional Value at Risk, which is a coherent risk measure. Thanks to a stylised modelling of aggregated decisions in terms of investment and shutdown decisions long-term dynamics, an energy-only market, a strategic reserve mechanism and a capacity market are analysed under different assumptions about investors' risk preferences. The analysis has focused on total generation costs and the level of shortages.

Regarding total generation costs, risk aversion is proven to increase them no matter which market design is considered. Nevertheless, the magnitude of the increase varies significantly from one market design to another. The energy-only market and the capacity market seem to be less affected than the strategic reserves mechanism. Two opposing effects drive this result. On the one hand, the introduction of risk aversion tends to limit investments and consequently reduces the associated costs. On the other hand, investors are confronted with an arbitrage between investing in new capacity which involves a lot of uncertainties and extending the lifetime of existing capacities, which involves less uncertainty but implies higher O&M costs. According to the simulations carried out in Chapter I, the increased O&M costs generally overweigh the reduction of investment costs.

Focusing on reliability (i.e., ability to reduce shortages), the results suggest that the capacity market and the strategic reserve mechanism are more resilient than the energy-only market, with respect to risk aversion. Their effectiveness in delivering capacity adequacy is only marginally affected when investors are risk averse, although the capacity market exhibits a better resilience than the strategic reserve mechanism. Furthermore, a comparative analysis of the studied market designs with and without risk aversion, suggests interestingly that the benefits resulting from the implementation of a capacity market or a strategic reserve mechanism are higher in presence of risk averse investors.

As economic intuition would suggest, the resilience of CRMs in terms of their ability to ensure capacity adequacy with risk averse investors is dependent on the calibration of their main parameters. For the strategic reserve mechanism, the auction price cap and the maximum size of the reserve act as limiting factors. However, a proper calibration of these parameters does not necessarily mean that the strategic reserve mechanism is immune to risk aversion. In fact, in its most common form, which targets mainly old capacities about to retire, this CRM cannot control investments in the energy market. This means that if investment incentives in the energy market are not sufficient and agents are risk averse, the strategic reserve mechanism could fail to deliver capacity adequacy, even with an appropriate design.

For the capacity market, the main limiting factor is the capacity price cap. Conversely to the strategic reserve mechanism, the capacity market controls and coordinates both shutdown and investment decisions. When the level of uncertainty faced by risk averse investors is correctly reflected in the capacity price cap, the effectiveness of the capacity market is preserved. In practical terms, investors use the capacity price as a de-risking instrument which allows them to transfer part of the perceived investment risk onto consumers. The capacity price cap therefore limits the amount of risk that is transferable. If this price cap is high enough, investors can transfer all their risk. This of course implies higher capacity prices compared to a situation of risk neutrality.

In the **second chapter** of the dissertation, the recent but increasingly prevalent practice of mothballing in the power sector is investigated. To study mothballing decisions and their impact in liberalised electricity markets, the model presented in Chapter I is improved to allow the representation of these decisions. A methodology is proposed to capture the underlying rationales behind these decisions and include them in a System Dynamics framework. Furthermore, the model is extended to accommodate multiple technologies. The analysis focuses on two market designs: an energy-only market and a capacity market with annual contracts, as they represent the two main paradigms for long-term capacity adequacy market design (i.e., an energy-only vision and a CRM vision).

Simulations show that the possibility to mothball assets modifies shutdown and investment dynamics in a potentially persistent way depending on the system. This result applies to both energy-only and capacity markets. In an energy-only market, mothballing leads private agents to delay shutdown and investment decisions. In capacity markets, committing to stay active through a capacity contract creates an opportunity cost for private agents who are better off by mothballing their asset instead. Therefore, they internalise this opportunity cost in their capacity bid. Due to this, the merit order between existing and new capacities may be modified in capacity auctions, to an extent that sometimes results in a preference for new capacities instead of existing ones. Mothballing can therefore modify investment and shutdown dynamics in capacity markets.

In terms of capacity adequacy, when private agents have the option to mothball, it gives them a legitimate protection against testing market conditions. However, even in a perfect competition setting with no strategic behaviour, private agents' incentives to mothball may conflict with capacity adequacy objectives. In this context, mothballing is equivalent to a decision to "disinvest", which, in case of inelastic peak demand and capacity indivisibility, leads private agents to under procure capacity. This phenomenon could be seen as another manifestation of asymmetrical incentives between over-procurement and under-procurement of capacity by private agents as discussed in section 2.3 of the general introduction. Consequently, in energy only-markets, mothballing tends to deteriorate security of supply, compared to a state of the world with no mothballing option. This tendency is exacerbated when scarcity pricing is implemented. The development of smart meters and demand response could mitigate these effects by making peak demand more elastic in the future. In capacity markets, the capacity price allows for a realignment of private agents' interests with security of supply objectives.

The **third and last chapter** builds on the previous ones to propose a comprehensive comparison of market design options for long-term capacity adequacy in future power systems. It considers a system subject to a high penetration of renewables, which is consistent with the current transformation of power systems across the world, and in Europe in particular. The comparison is done from a social welfare perspective, with discussions on other specific dimensions that are relevant to policymaking: security of supply (i.e., capacity adequacy itself), cost for consumers, investment risk and profitability of capacity resources.

Five market designs are studied: an energy-only market with an administrative price cap of 3 k€/MWh (EOM-PCap), an energy-only market with scarcity pricing where the price cap is equal to the VoLL at 22 k€/MWh (EOM-SP), a strategic reserve mechanism (SRM), a capacity market with annual capacity contracts (CM-AC) and a capacity market with multiannual contracts for new investments (CM-MAC). Based on the same modelling framework used in previous chapters, simulations are carried out to determine the performance of each market design in a context of high penetration of renewables. The performances are discussed with respect to the energy-only market with the administrative price cap of 3 k€/MWh.

Firstly, the results indicate that capacity remuneration mechanisms improve social welfare compared to the benchmark energy-only market with an energy price cap of 3 k €/MWh. Based on a case study calibrated on the French power system, welfare gains resulting from the introduction a capacity remuneration mechanism range from about 200 to 320 M€ per year depending on the considered market design. Capacity markets provide the highest welfare increase especially when they award multiannual contracts new investments (around 320 M€/year). These welfare increases are mainly due to reduced shortages compared to the reference energy-only market with a low price cap. Scarcity pricing performs well in reducing shortages, but has a limited ability to increase social welfare. This is because scarcity pricing significantly increases investment risk and financing costs for private agents, to an extent that counterbalances social welfare gains.

Secondly, regarding security of supply, the market designs that yield satisfactory outcomes are the energy-only market with scarcity pricing and the two capacity markets. The strategic reserve mechanism improves security of supply compared to the reference energy-only market but fails to meet the reliability criterion of three hours of shortages per year. As explained above, the strategic reserve mechanism is primarily destined to retain old and expensive capacities in the market for security of supply concerns. It does not provide additional investment incentives, which limits its ability to meet the reliability criterion consistently. This result was already highlighted by the simulations of the first chapter of the dissertation.

Thirdly, when it comes to cost for consumers (including the cost of shortages), capacity remuneration mechanisms are superior to both types of energy-only markets. Scarcity pricing mechanically increases the cost of energy for consumers. Overall, and despite the reduction of the cost of shortages, scarcity pricing is more expensive than the reference energy-only market. Based on the simulations results, all three CRMs reduce total costs for consumers by about 3 €/MWh (compared to the benchmark energy-only market), with the highest reduction observed for capacity markets. These results are in line with the social welfare analysis.

Finally, from a private investor’s perspective, none of the studied market designs appears to be entirely satisfying in terms of cost recovery and investment risk. As discussed above, scarcity pricing increases investment risk and financing costs. Despite high electricity prices, investors fail to recoup their fixed costs (including risk premiums). This is mainly related to the myopic behaviour of agents' who cannot correctly anticipate the states of the world (over the lifetime of their asset) in their investment appraisal. The same results apply to the strategic reserve mechanism.

An important result of the analysis of cost recovery is related to capacity markets which are supposed to alleviate the missing money issue observed in energy-only markets. Simulations show that in a context of high penetration of renewables, capacity markets with annual contracts occasionally fail to provide enough remuneration to cover power plants' fixed costs. Interestingly, the ability for investors to fully recover these costs is dependent of the type of resource which is clearing the capacity auction on an annual basis. When there is a sustained investment need, materialised by a capacity price set by a new plant every year, investors can recoup their costs over their expected lifetime. However, if investment needs are punctual as it may be the case when electricity demand is flat or declining, then generation assets fail to recover their capital costs (each time the capacity auction is cleared by an existing plant bidding its opportunity cost). This type of situation can be exacerbated by the penetration of renewables, which reduces residual electricity demand even more. This problem can be alleviated, although not entirely removed, by awarding multiannual capacity contracts. Investors are then less subject to the clearing of the capacity auction to recover their fixed costs (at least for the duration of the capacity contract).

Given the potential failure of capacity markets to appropriately remunerate invested capital, investors may start to inflate their capacity bids as a precautionary measure. Even if the introduction of multiannual contracts mitigates the missing money issue in capacity markets, it does not entirely solve it unless the contracts are calibrated to last the entire lifetime of assets. This of course is not a realistic solution. It could generate considerable windfall gains for investors who manage to secure capacity contracts for decades, regardless of the evolution of market fundamentals. It could also create an unnecessary burden for consumers in terms of capacity charge. These results suggest that policymakers should revisit the design of capacity markets if they want to preserve their effectiveness in the long run.

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The results discussed in this dissertation provide important insights for policy decisions aiming at ensuring long-term capacity adequacy, especially in the current context of energy transition. They highlight the practical difficulty that policymakers face when choosing a specific market design as they have to consider effects on consumers and investors, in addition to social welfare maximisation. By investigating central issues related to long-term capacity adequacy, this dissertation informs policymakers on the strengths and limitations of available market design options. Its findings are particularly relevant for the current discussions in Europe following the publication of the Clean Energy Package (CEP), which requires countries to justify any implementation of a capacity remuneration mechanism by a comprehensive assessment of the associated benefits and costs.

The findings of the dissertation call for a reconsideration of the benefits associated with capacity remuneration mechanisms, especially capacity markets. These findings raise questions about the stated preference for scarcity pricing in the CEP. Although this market design can deliver the required level of security of supply, it is showed that it is not the most cost-efficient solution to do so. Moreover, in case the need for a capacity remuneration mechanism is indeed demonstrated, the CEP urges for the consideration of a strategic reserve mechanism as a first option (instead of capacity markets), arguing that it introduces less distortions and is easier to remove if no longer necessary (European Commission, 2016b). Yet, the simulations carried out in this dissertation indicate that capacity markets are the superior solution to adequacy problems from a social welfare perspective.

Furthermore, simulations results suggest that a strategic reserve mechanism can only address adequacy problems when there is no need for new investments. In a system facing an increased need for new capacity, this market design may fail to perform in a satisfying way. In this regard, the ongoing discussions in Belgium for the replacement of its strategic reserve mechanism by a capacity market are very revealing. Indeed, with the decision to phase out its nuclear fleet, Belgium needs new capacity in its system. This has led policymakers to consider the introduction of a capacity market, which is expected to provide more appropriate investment incentives than the existing strategic reserve mechanism (Walstad, 2019).

Finally, the future implementation of multiannual capacity contracts in France is in line with the results discussed in the third chapter of this dissertation. They show that such contracts reduce investment risk for new capacities, lower costs for consumers and improve cost recovery for investors (compared to annual contracts).

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Future research

The work carried out in this dissertation could be extended to cover a variety of additional aspects related to capacity adequacy.

First, an immediate relevant area of future research is the consideration of other forms of mechanisms to pilot the energy transition. For instance, in light of the findings of the dissertation, options of capacity markets redesign could be investigated to ensure cost recovery for investors (see Appendix F for preliminary suggestions). Moreover, this dissertation does not address the policy-mandated phase out of some technologies such as nuclear or coal. These decisions, which are related to environmental policies, have important implications in terms of security of supply. They also have consequences for investors because they create stranded assets. Economic mechanisms to coordinate these phase outs and their impact on capacity adequacy could be studied (Llobet and Padilla, 2018).

Second, another important direction for future research is the consideration of short-term flexibility both on the demand and supply sides of power markets. With the increasing share of renewables in power systems, the need for flexibility is growing in order to ensure a reliable supply at all times (Holttinen et al., 2011; Huber et al., 2014; Newbery et al., 2018). Flexibility is therefore expected to play a crucial role in the future. Investment signals could be modified by the way flexibility will be remunerated on short-term markets, creating an even stronger link between these markets and long-term capacity adequacy. By adapting the model to refine the day-ahead market (through the consideration of technical constraints), it would be possible to explore the role that flexibility remuneration will play in steering long-term investments. Other short-term markets such as intraday market or a balancing market could also be considered to strengthen the analysis.

Third, the model could be extended to include other sources of uncertainty (beside demand). Uncertainty about CO_2 prices, renewables infeed or fuel costs are important parameters of the ongoing energy transition. They could all affect investment and shutdown/mothballing decisions in ways that are not discussed in this dissertation.

Fourth, the model could be improved by the consideration of cross-border exchanges and a broader geographical scope. This would be more suited to study the internal energy market that Europe is aiming for. It could allow to determine what are the best options in terms of market design from a European perspective, taking into account potential cross-border effects of CRMs (Bhagwat et al., 2017c; Gore et al., 2016; Lambin and Léautier, 2018).

Finally, the analysis in this dissertation relies on the assumption of perfectly competitive markets with no strategic behaviour from market participants. Relaxing this assumption could lead to interesting research questions. Market participants may be strategic in capacity auctions for instance, which impacts the effectiveness of the mechanisms (Joung et al., 2009).

Appendix A. Nomenclature

The variables and parameters of the model (in its most complete form used in chapter III) are summarized in Table 27 hereafter. Some of the variables presented in the table may not be relevant for all the chapters.

Table 27. Variables and parameters of the model

	Description
Variables	
$\pi_{p,y}^{EM}$	Profit from the energy market of plant p in year y after deduction of fixed O&M costs (k€)
ACC_p	Annualised capital cost of plant p (k€/MW.year)
$bid^{CRM}{}_{p,y}$	Capacity bid of plant p in year y (k€/MW)
$CVaR_\alpha$	Conditional Value at Risk with confidence level α (k€)
C_y^{CRM}	Total cost of capacity payment made in year y (k€)
$D_{y,h}$	Residual electricity demand in hour h of year y (MW)
$ENS_{y,h}$	Energy not served in hour h of year y (MWh)
$g_{p,y,h}$	Generation level of plant p in hour h of year y (MWh)
$G_{y,h}$	Total generation from all plants in hour h of year y ($G_{y,h} = \sum_p g_{p,y,h}$) (MWh)
h_{assess}	Current assessment horizon in shutdown and mothballing procedures (years)
k_p	Generation capacity of plant p (MW)
$K_y^{Existing}$	Total existing capacity on energy market in year y (MW)
K_y^{New}	Total new capacity on the energy market in year y (MW)
K_y^{LTC}	Total capacity under long-term contract in year y (MW)
L_y^{Fpeak}	Forecast peak load for year y (MW)
$MC_{p,y}$	Mothballing cost of plant p in year y (k€/MW.year)
$OMC_{p,y}$	Annual operation and maintenance costs of plant p in year y (k€.year)
$OC_{p,y\rightarrow y+x}$	Opportunity cost of plant p assessed over years y to $y+x$ (k€)
$OCF_{p,y}$	Net operational cash flow of plant p in year y (k€)
$p_{y,h}^{EM}$	Electricity price on energy market in hour h of year y (€/MWh)
p_y^{CM}	Capacity price[198] in year y (k€/MW))
$Payoff_{strategy}$	Net payoff of choosing a specific strategy ($strategy \in \{mothballing, restarting, staying\ active\}$) (k€)
PI_{tech}	Profitability Index of technology $tech$ ($tech \in \{Nuclear, Coal, CCGT, CT\}$) (k€/MW)

198 Only for the capacity markets CM-AC and CM-MAC.

	Description
$PV_{estimated}^{RA/RN}$	Estimated present value of investment for risk-averse/risk-neutral agents (k€)
Q_y^{CRM}	TSO's capacity demand in CRM for the auction held in year y (MW)
$Qmax_y^{SRM}$	Maximum size of the strategic reserve in year y (MW)
$R_{p,y,h}^{EM}$	Difference between revenues from the energy market and generation costs for plant p in year y (k€)
$RC_{p,y}$	Restarting cost of plant p in year y (k€/MW.year)
$Risk_{prem}$	Risk premium (k€)
SW_y	Social welfare in year y (k€)
SP_y^{Cons}	Consumers' surplus in year y (k€)
SP_y^{Prod}	Producers' surplus in year y (k€)
$Shortfall_{tech}^{inv}$	Annualised shortfall or missing money (per MW) when considering an investment in technology $tech$ ($tech \in \{Nuclear, Coal, CCGT, CT\}$) (k€/MW)
VaR_α	Value at Risk with confidence level α (k€)
$VC_{p,y}$	Variable production cost of plant p in year y (€/MWh)
Parameters	
α	Confidence level for computation of VaR and CVaR (dimensionless)
β	Risk aversion coefficient (dimensionless)
$ddelay_{CRM}$	Delivery delay for contracted capacity in CRM ($CRM \in \{SRM, CM-AC, CM-MAC\}$) (years)
$h_{forecast}$	Maximum assessment horizon for profitability forecasts[199] (years)
τ^{SRM}	Maximum reserve size in % of existing installed capacity (MW)
tm_y	Target capacity margin in year y (MW)
$PCap^{EOM-PCap/EOM-SP}$	Price cap on energy market in EOM-PCap/EOM-SP (€/MW)
$PCap^{CRM}$	Capacity price cap in CRM auction ($CRM \in \{SRM, CM-AC, CM-MAC\}$) (k€/MW)
$unit_{tech}^{New}$	Unit size of a plant for technology $tech$ ($tech \in \{Nuclear, Coal, CCGT, CT\}$) (MW)
$VoLL$	Value of Lost Load (€/MWh)

199 This is the horizon (i.e. number of years) over which agents explicitly compute the expected profitability of their plants to assess investment, shutdown and mothballing decisions. For investments, these computed values are used to extrapolate the profitability of the asset over its entire expected lifetime.

Appendix B. Formal definition of a coherent risk measure

Artzner et al. (1999) defined a set of desirable properties for a risk measure to be considered as coherent. These properties as based on four axioms outlined in their work and described hereafter: monotonicity, translation equivariance, sub-additivity, and positive homogeneity. For the definitions of the axioms below, X and Y are assumed to be random variables representing losses, $c \in \mathbb{R}$ is a scalar representing a loss, and μ is a risk measure.

i. **Monotonicity:** Higher losses mean higher risk. A risk measure μ is monotone, if for all $X, Y: X \leq Y \Rightarrow \mu(X) \leq \mu(Y)$.
ii. **Translation equivariance:** Increasing (respectively decreasing) the loss by a fixed and certain amount, increases (respectively decreases) the risk by the same amount. A risk measure μ is translation equivariant, if for all $X,\ c$: $\mu(X + c) = \mu(X) + c$.
iii. **Subadditivity:** Diversification decreases risk. A risk measure μ is sub-additive, if for all X, Y : $\mu(X + Y) \leq \mu(X) + \mu(Y)$.
iv. **Positive Homogeneity:** Doubling a portfolio's size doubles the risk. A risk measure μ is positively homogeneous, if for all $X,\ \lambda \geq 0$: $\mu(\lambda X) = \lambda . \mu(X)$.

Appendix C. Computation of VaR and CVaR

Value at Risk (VaR) is a risk measure that characterises the maximum loss exposure with a certain confidence level α (usually 95%). It can be particularly useful when facing a profit/loss distribution that depends on a range of scenarios. In this paper, PV distributions are considered in order to assess the profitability of new investments. Hence the VaR computed here is interpreted as the minimum PV that an investor can expect with the confidence level α.

The VaR gives a first idea of the riskiness of an investment but fails to account for the shape of the distribution it is applied to. Indeed, the VaR considers the minimum PV with confidence level α. It provides no information about the cases where the PV is lower than the VaR. To illustrate this, consider two distributions: one with a fat left tail and the other one with a relatively small left tail. These two distributions might very well have the same VaR even if the first one represents a riskier investment because of its fat tail. To overcome this shortfall, Rockafellar and Uryasev (2000) introduced the notion of Conditional Value at Risk or CVaR. The CVaR is a risk measure of risk which accounts for the shape of the distribution. For a given level of confidence α, the CVaR gives the expected value of the NPV if ever it is lower than the VaR.

In summary, CVaR is a more complete risk assessment tool than VaR. In a more formalised way, VaR and CVaR corresponds to the following formulas, assuming that there is a probability distribution function $f(PV)$ for the NPV ($F(PV)$ is the cumulative density function).

$$VaR_\alpha = \max\{x \; / \; F(x) \leq 1 - \alpha\} \tag{C.1}$$

$$CVaR_\alpha = \mathbb{E}\,\{PV \mid PV \leq VaR_\alpha\} \tag{C.2}$$

Here, each PV value in the distribution has the same probability. With this setting, both VaR and CVaR can be obtained by solving the following optimization problem as explained in the appendix of Conejo et al. (2008) (see also Rockafellar and Uryasev (2000) for a general implementation procedure):

$$\max_{\gamma,\psi_\omega} \quad \gamma - \frac{1}{1-\alpha}\sum_{\omega \in \Omega} \lambda_\omega \psi_\omega \tag{C.3}$$

$s.t$: $$-PV_\omega + \gamma - \psi_\omega \leq 0\,; \quad \forall\, \omega \tag{C.4}$$

$$\psi_\omega \geq 0; \quad \forall\, \omega \tag{C.5}$$

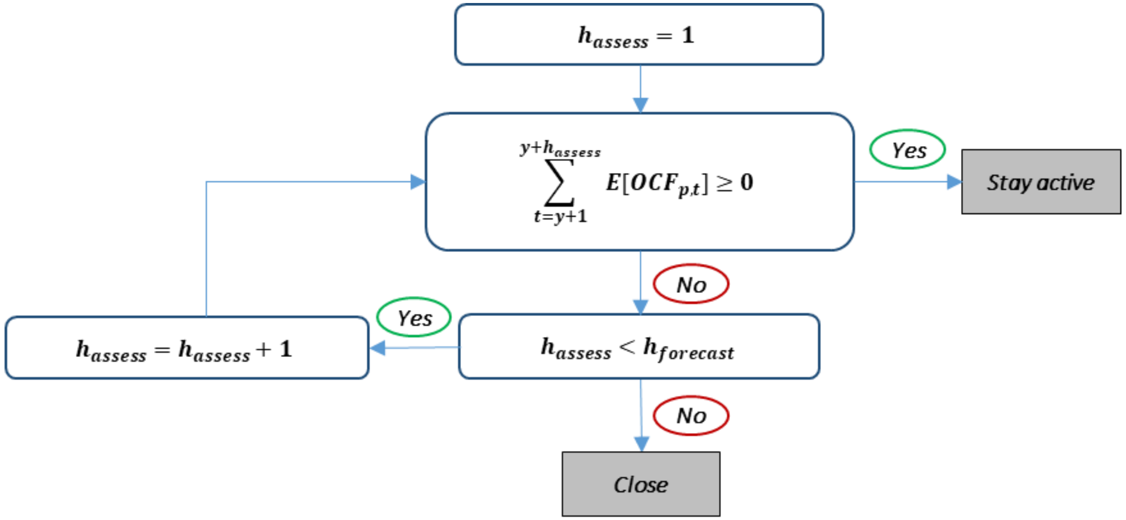
Where:

- ω represents a scenario in the set of possible scenarios Ω,
- α represents the confidence level for computation of VaR and CVaR (here 95%),
- γ is the VaR,
- PV_ω is the NPV scenario ω,
- λ_ω is the probability of scenario ω,
- ψ_ω is a variable which is equal to 0 if PV_ω is greater than the VaR. Otherwise it equals the difference between VaR and PV_ω. $\psi_\omega = min\,(0, \gamma - PV_\omega)$.

The optimal value of the objective function of the optimization problem is the CVaR, and the corresponding value of γ is the VaR.

Appendix D. Details on shutdown and mothballing rationales

Figure 66. **Shutdown algorithm in energy-only markets (when mothballing is not possible)**



h_{assess}: ***current assessment horizon***

$h_{forecast}$: ***maximum assessment horizon for profitability forecasts***

$OCF_{p,y}$: ***net operational cash flow of plant*** p ***in year*** y

Figure 67. Shutdown algorithm in energy-only markets for an active plant (when mothballing is possible)

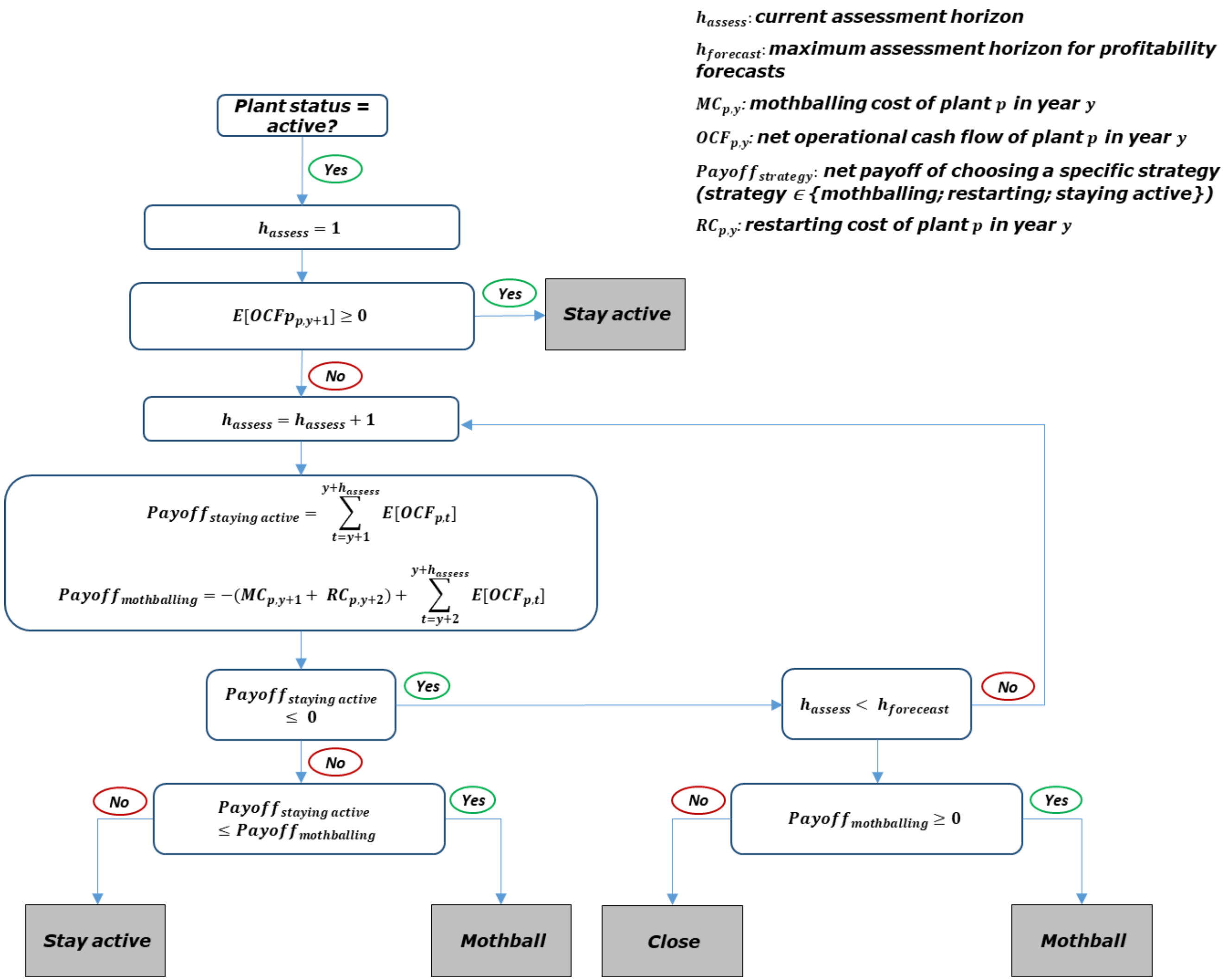


Figure 68. Shutdown algorithm for mothballed plants in energy-only markets (when mothballing is possible)

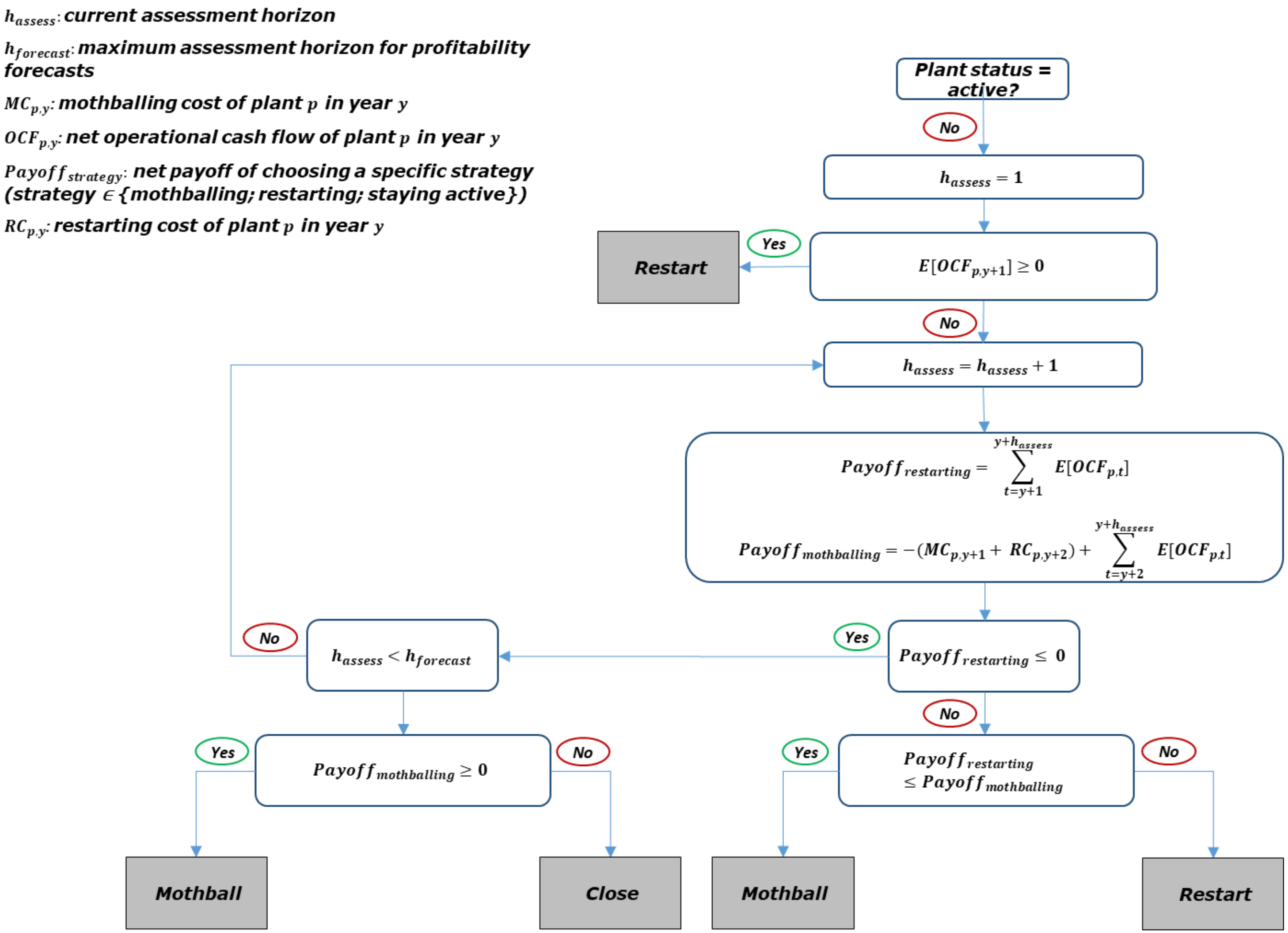


Figure 69. Computation of capacity bids for existing plants in capacity markets (when mothballing is not possible)

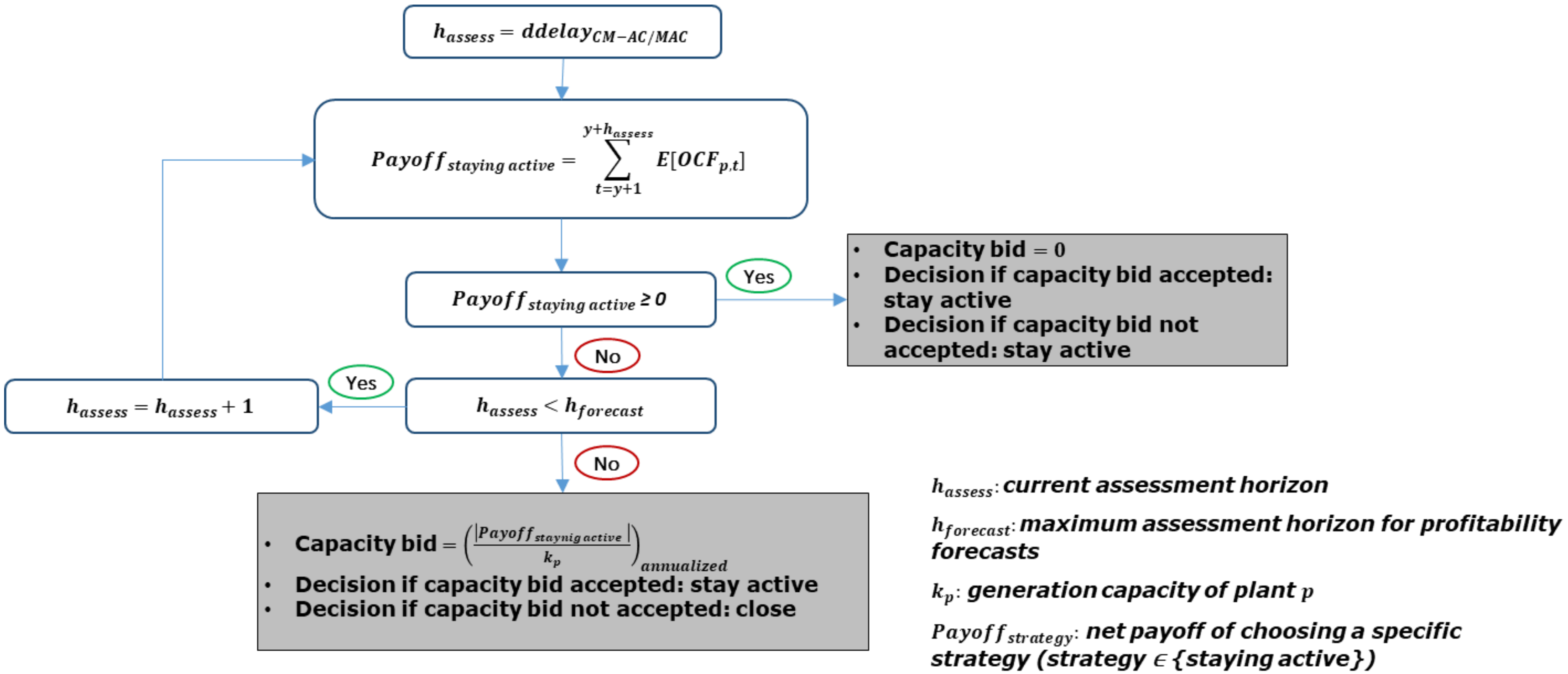


Figure 70. Computation of capacity bids for active plants in capacity markets (when mothballing is possible)

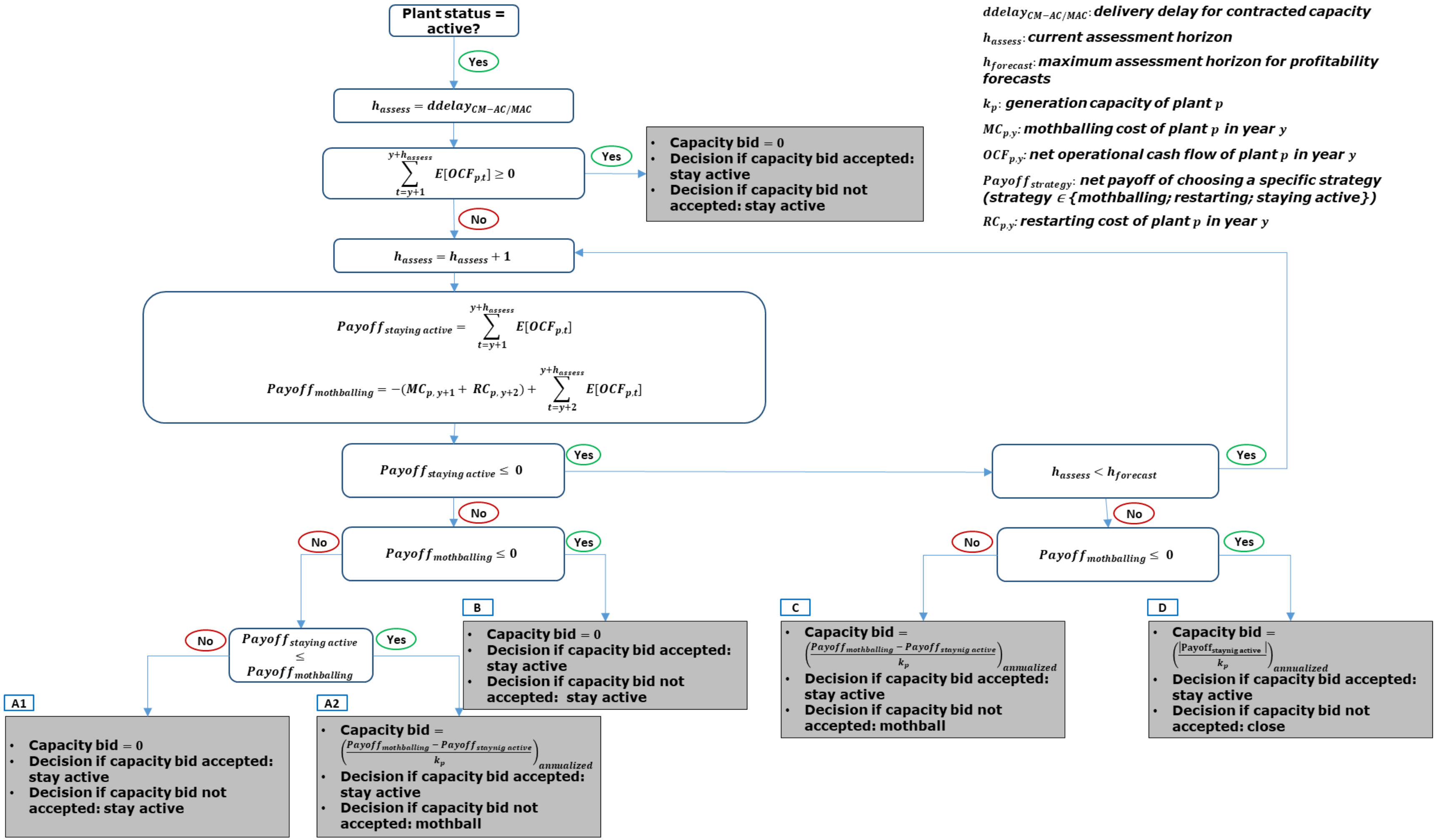
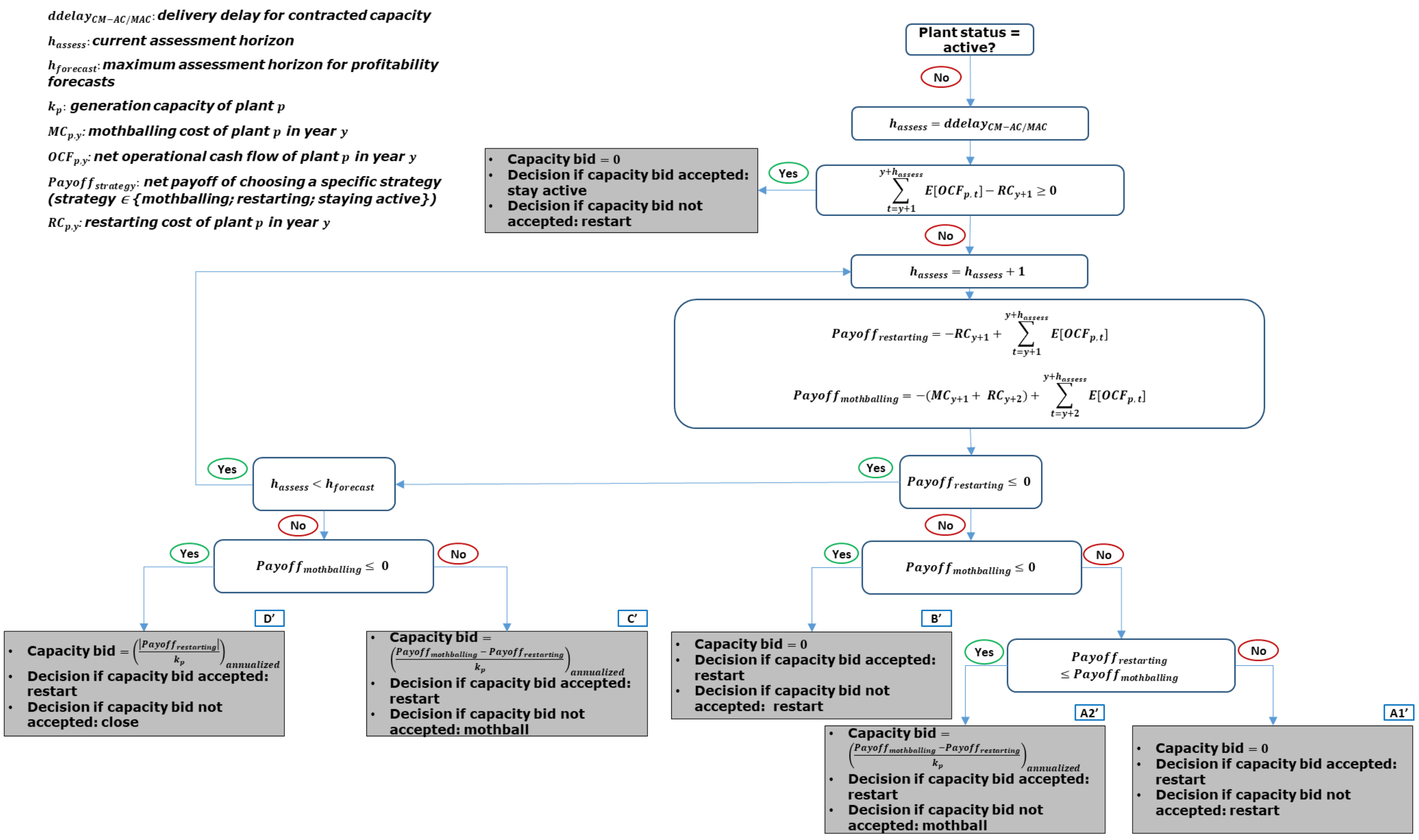


Figure 71. Computation of capacity bids for mothballed plants in capacity markets (when mothballing is possible)



Appendix E. Additional details on the model

Figure 72. Illustration of profitability scenarios computation in capacity markets with annual contracts (CM-AC)

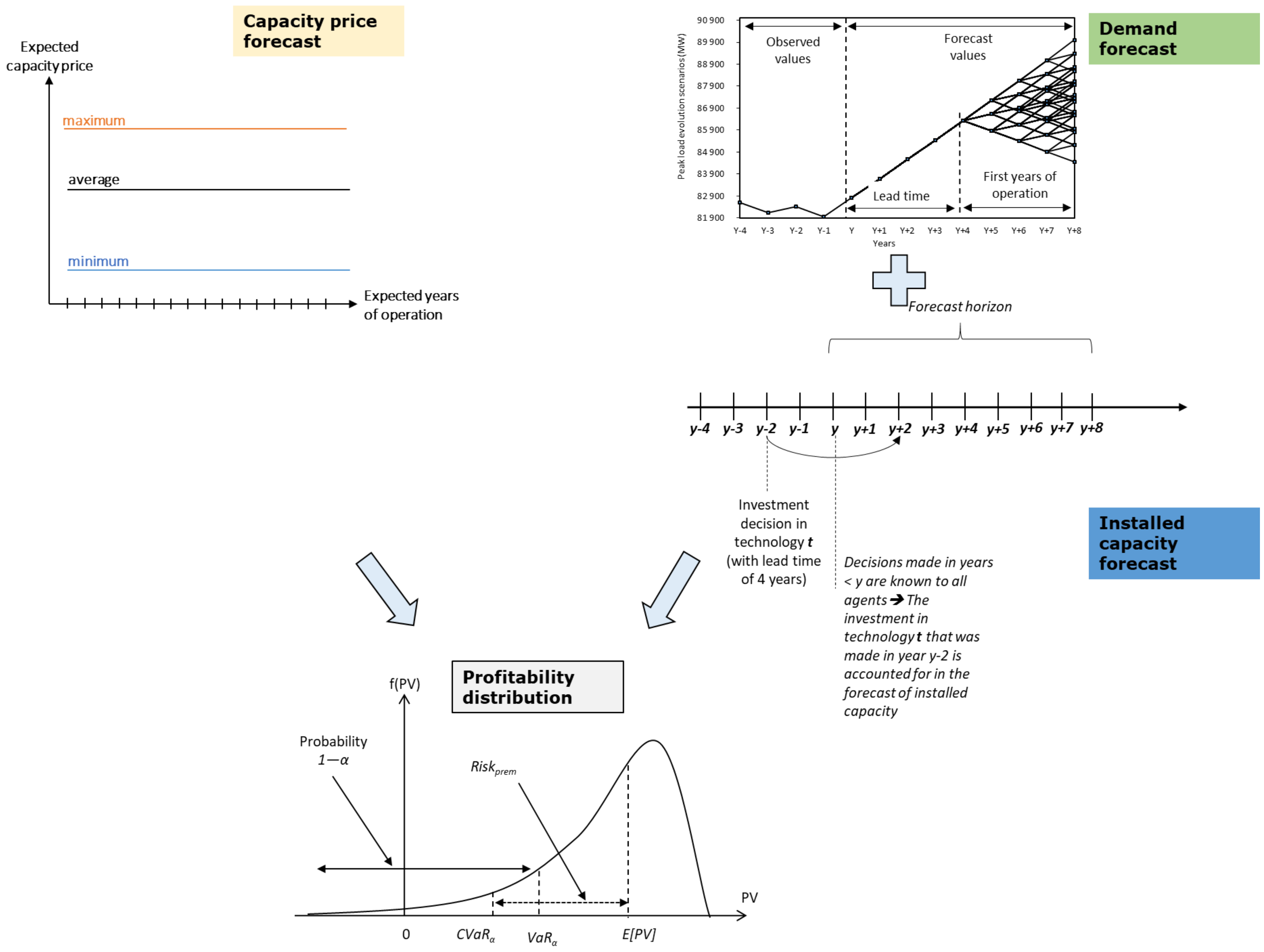


Figure 73. Illustration of profitability scenarios computation in capacity markets with multiannual contracts (CM-MAC)

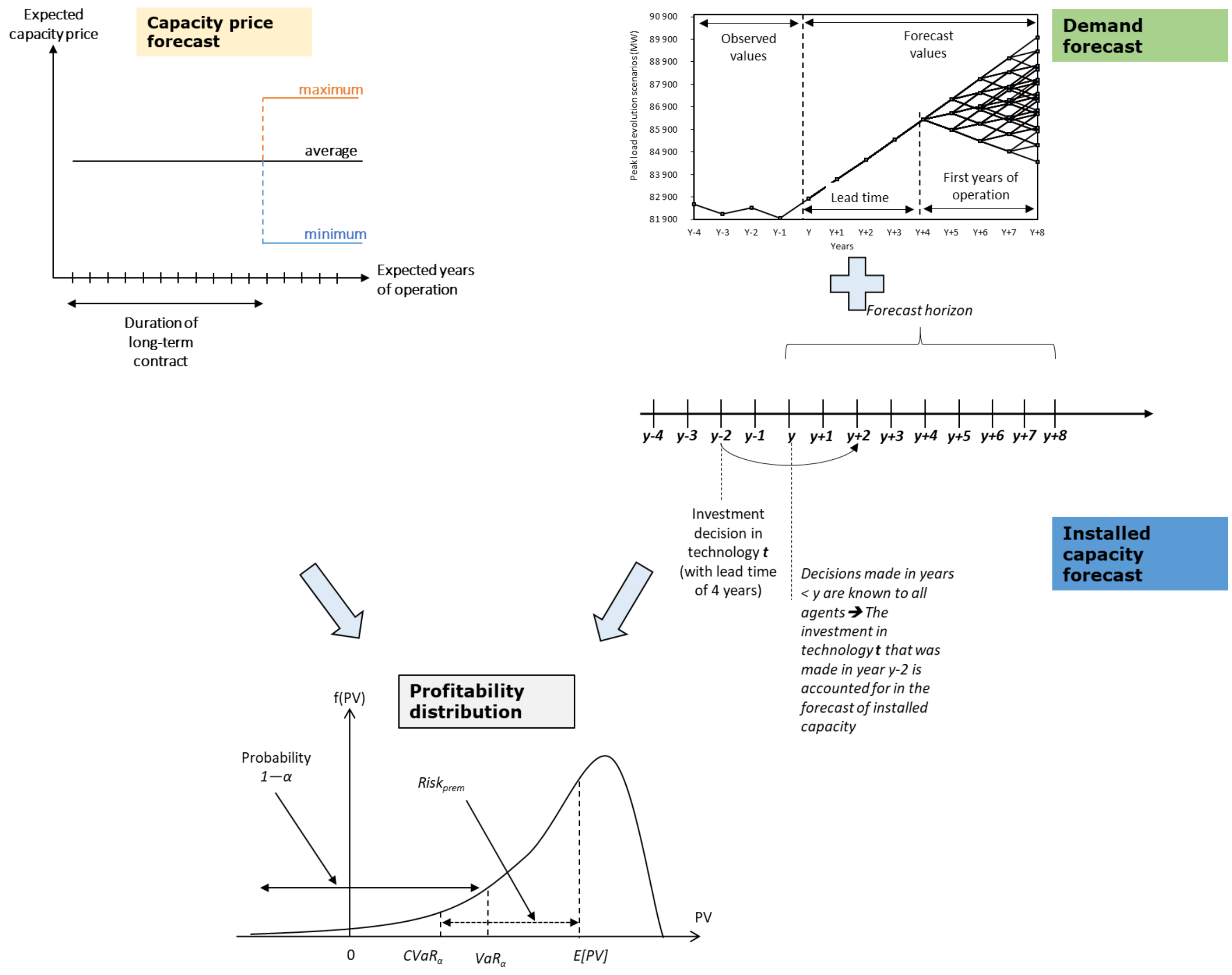
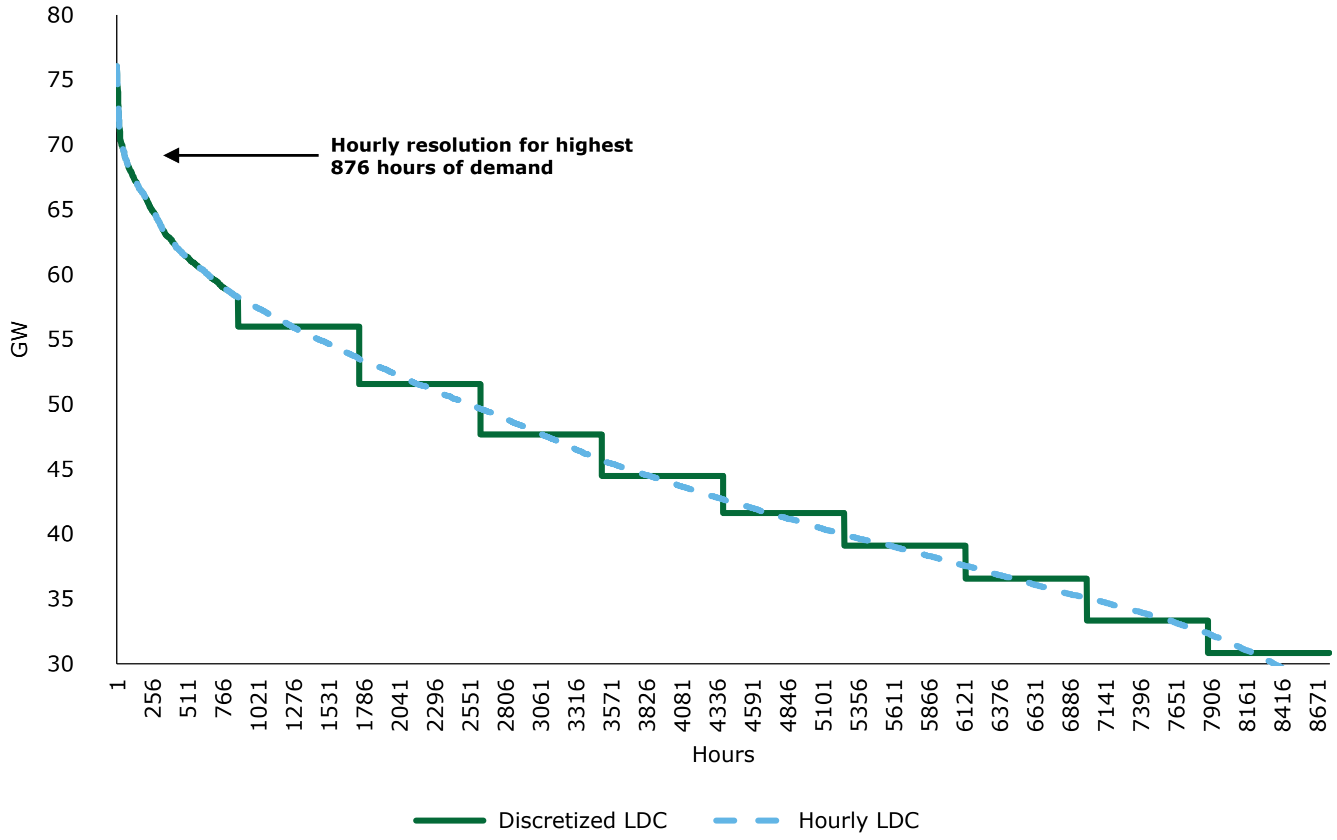


Figure 74. Discretization of LDC in forecasts in Chapters II and III



Appendix F. Suggestions for an improved design of capacity markets

F.1 Recalling the theoretical background for capacity market design

The economic rationale for the calibration of capacity markets has relied on an implicit but crucial assumption that market participants expect to recover their capital costs over the lifetime of their assets. This assumption has been widely used in the literature to establish a theoretical benchmark model that defines the relationship between the loss of load expectation (LOLE) and the price cap of electricity prices in energy-only markets. Assuming perfect competition in its broader definition[200], and abstracting from revenues derived from ancillary services, the long-term equilibrium in an energy-only market is given by a simple equation which states that the revenues earned by peaking units should be equal to their total costs[201](Stoft, 2002). This equation can be written on an annual basis using the annualised cost structure of peaking units. In a setup of homogenous peaking units, this translates into the following equation:

$$LOLE * \left(P_{cap}^{E} - VC_{peak}\right) = OMC + ACC \tag{F.1}$$

With:

$LOLE$: loss of load expectation (i.e., expected number of scarcity hours);

P_{cap}^{E}: price cap on energy market;

VC_{peak}: variable cost of peaking units;

OMC: annual fixed operation and maintenance costs;

ACC: annualised capital costs.

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[200] Atomicity of consumers and suppliers, perfect information, homogeneous products, no barriers to entry and exit, perfect factor mobility, no market power or strategic behaviour, normal profits, no externalities, well defined property rights and no transaction costs.

[201] Including an appropriate remuneration of invested capital.

The left-hand side of the equation corresponds to the expected revenue earned by a unit of peak capacity in a single year. Since peaking units are the marginal plants of the system, their net revenue is positive only during scarcity hours where the electricity price rises to the price cap. In other periods, these peaking units do not produce, or they set the electricity price, meaning that they their net revenue is zero. The right-hand side of the equation corresponds to the annual fixed costs borne by a peaker. These are both fixed operation costs and annualised capital costs (including overnight investment and financing costs). The annualised capital costs are computed based on the expected lifetime of the generation assets. This is a crucial assumption which implies that those capital costs are spread over the lifetime of the assets, or rather that investors reason as if they expect to recover their capital costs over the entire lifetime of the assets. Rewriting Equation (F.1) in more explicit terms reveals how the lifetime of the generation assets impacts the equilibrium condition.

$$LOLE * \left(P_{cap}^{E} - VC_{peak}\right) = OMC + \frac{OCC * \delta}{1 - (1 + \delta)^{-L}} \tag{F.2}$$

With:

OCC : overnight capital costs;

δ: discount factor (usually the weighted average cost of capital or WACC);

L: expected lifetime of the asset.

Equation (F.2) establishes a direct relationship between the price cap on the energy market and the LOLE. For any level of LOLE, there is a corresponding theoretical value for the energy price cap, and *vice versa*. When the price cap is set at the VoLL, representing consumers' utility from the provision of electricity, then corresponding LOLE is optimal. This means that increasing the level of shortages would reduce social welfare because part of the electricity demand could still be satisfied at a cost that is below consumers' willingness to pay. Symmetrically, reducing shortages would cost more than the benefits that consumers extract from using electricity. The scarcity pricing theory in energy-only market is based on this theoretical model. Indeed, by allowing electricity prices to reach the VoLL during scarcity periods, the expected number of scarcity hours in a year would then be optimal from a social welfare point of view.

When a CRM is introduced, generation assets receive an additional revenue in the form of a capacity price P^K. Including the capacity revenue in the equilibrium condition yields Equation (F.3) hereafter. Doing so mechanically provides a formula for the computation of the required capacity price to ensure cost-recovery. Isolating the capacity price P^K and rearranging the terms gives Equation (F.4), expressing the required capacity price as a function of the economic characteristics of peaking units, the LOLE and the energy price cap.

$$LOLE * \left(P_{cap}^{E} - VC_{peak}\right) + P^K = OMC + \frac{OCC * \delta}{1 - (1 + \delta)^{-L}} \quad \text{(F.3)}$$

$$P^K = \frac{OCC * \delta}{1 - (1 + \delta)^{-L}} + OMC - LOLE * \left(P_{cap}^{E} - VC_{peak}\right) \quad \text{(F.4)}$$

Most capacity markets in place have been designed based on this fundamental equation. The right-hand side of Equation (F.4) represents the net Cost of New Entry (CONE). It corresponds to the total annual cost of a new peaking unit minus its expected revenues on the energy market. The net CONE is the capacity remuneration needed by a new generation unit to enter the market and recover its annual total costs. The price caps in existing capacity markets are determined as a certain multiple of the net CONE, with the multiplying factor serving as an adjustment for real world conditions that do not fit the ideal perfect competition setting. For instance, policymakers need to consider investors' risk aversion, or the uncertainty related to the estimated value of the CONE. In UK and the PJM market for instance, the capacity price cap is set at 1.5 times the net CONE. In France it is expected to be progressively increased to reach to reach the net CONE in 2020.

It should be noted that there is an endogeneity problem associated with the calibration of the price caps in capacity markets. The higher the price cap, the best it can mitigate the negative effects of investors' risk aversion. At the same time, a higher price cap also means a more volatile capacity price and thus higher risk premiums that investors include in their capacity bids. If there is no strategic behaviour from investors and if they only bid their missing money, then there is an equilibrium price cap representing the lowest price cap that fully internalises the effect of risk aversion.

F.2 Enhancing capacity market design

The important distinction between new capacities and existing capacities – the double price cap framework

As explained above, this methodology and its underlying theoretical background assumes that investors behave as if they try to recover their capital costs over the entire lifetime of their generation assets. However, the discussion in Chapter III highlighted the existence of circumstances in which such an assumption would no longer be true in capacity markets. This is particularly critical if investors do not believe that the existing market design enables them to break even on annual capital costs each year. In such situations, it is more likely that investors try to recover their entire capital costs as soon as they can, during a period that is shorter than the expected lifetime of the associated asset.

In a capacity market with multiannual contracts, investors can leverage their contract to mobilise financing more easily. It is reasonable to assume that they will seek a financing structure which matches their capacity contract duration. In other terms, the existence of multiannual capacity contract with a fixed capacity price will incentivise investors:

i. First, to mobilise capital in the form of debt and/or equity which are to be serviced within the duration of the capacity contracts and;

ii. Second, to try recovering this capital over the duration of the capacity contracts.

Assuming that capacity markets are properly designed to provide such incentives, the equilibrium condition introduced in Equation (F.3) is still applicable, but this time with the consideration that there are two phases in the asset lifetime in terms of cost structure. A first phase, which last the duration of the initial multiannual capacity contract and a second phase constituted by the reminder of the asset lifetime. The difference between these phases is the presence or absence of capital costs in the equilibrium condition. Since investors are now assumed to spread the entire capital costs on the duration of their initial multiannual capacity contract, the capital costs will only intervene in the first phase of the assets' lifetime. Therefore, the following equations define the equilibrium condition for each of the aforementioned phases (Equation (F.5) for the first phase and Equation (F.6) for the second phase).

$$LOLE * \left(P_{cap}^{E} - VC_{peak}\right) + P_{1}^{K} = OMC + \frac{OCC * \delta}{1 - (1 + \delta)^{-D_{CM}}} \tag{F.5}$$

$$LOLE * \left(P_{cap}^{E} - VC_{peak}\right) + P_{2}^{K} = OMC \tag{F.6}$$

With:

$LOLE$: loss of load expectation (i.e., expected number of scarcity hours);

P_{cap}^{E}: price cap on energy market;

P_{1}^{K}: capacity price requirement during first phase of asset lifetime;

P_{2}^{K}: capacity price requirement during second phase of asset lifetime;

VC_{peak}: variable cost of peaking units;

OMC: annual fixed operation and maintenance costs;

OCC : overnight capital costs;

δ: discount factor (usually the weighted average cost of capital or WACC);

D_{CM}: duration of multiannual capacity contract.

The new equilibrium conditions indicate that the required capacity price is different for new plants which are under their initial multiannual contract and for plants which are no longer under a multiannual contract. The immediate implication is that there should be different price caps in capacity auctions to reflect the required capacity price for each phase of a generation asset's lifetime. The price caps are inferred from the previous equations as detailed hereafter. Keeping the same logic that is currently used for the calibration of capacity auctions price cap, one can distinguish a price cap (P_{1}^{K} or $P_{cap}^{K,upper}$) for new plants seeking a multiannual contract, and a price cap (P_{2}^{K} or $P_{cap}^{K,lower}$) for all existing capacities that are no longer under their initial multiannual contract, but rather under annual capacity contracts.

$$P_{cap}^{K,upper} = P_1^K = OMC + \frac{OCC * \delta}{1 - (1+\delta)^{D_{CM}}} - LOLE * \left(P_{cap}^E - VC_{peak}\right) \quad (F.7)$$

$$P_{cap}^{K,lower} = P_2^K = OMC - LOLE * \left(P_{cap}^E - VC_{peak}\right) \quad (F.8)$$

Such a double price cap system is already implemented in the UK where bidding capacities are split between *price takers* and *price makers*. Essentially, *price takers* are existing capacities which are no longer benefiting from a multiannual contract. These capacities cannot bid above a certain threshold, representing about half of the net CONE, which effectively acts as a price cap for them. Conversely, *price makers* are usually prospective investments or existing plants that are undertaking refurbishment and they can bid up to the actual price cap of the auction, which is set at 1.5 times the net CONE. The UK authorities have motivated the introduction biding limit for *price taker* by a willingness to mitigate potential strategic bidding, rather than a reflection of a result from economic theory.

In reality, there is an economic background to the introduction of a double price cap system in a capacity auction, as demonstrated above. The economic justification lies in the very nature of the capacities submitting their bids. Some of these capacities are only looking to make up for their short-run missing money while others are trying to recover their long-run missing money. In a world where there would always be a capacity of the second category that clears the auction each year, there would be no cost recovery problem as the one illustrated in Chapter III. Consequently, the difference between the two categories of capacities would not matter for the design of the capacity market. However, when electricity demand is stagnating or declining, and investment needs are punctual, this difference becomes important.

Creating appropriate conditions for a well-functioning capacity market with a double price cap framework

The system of equations expressed above (Equation (F.7) and Equation (F.8)) was constructed based on a normative assumption that all conditions exist to incentivise investors to structure their financing in accordance to the duration of multiannual capacity contracts. These conditions are still to be created by policymakers. A set of guidelines that could be used to this end is provided hereafter. The proposed guidelines described above are summarised in Table 28.

Firstly, in order to properly incentivise investors to act as desired, the design of the capacity market should enforce the idea that they can only recoup their capital costs through their initial multiannual capacity contract. The introduction of a double price cap system, with the lower price cap being set at an estimated level of short-run missing money for a peaker, is enough to provide such a signal. Indeed, as all plants which are no longer under a multiannual contract will not be able to bid above this short-run missing money threshold, investors will try to load their capital costs in their initial bid for a multiannual capacity contract. This bid is allowed to go as high as the upper price cap of the auction, which accounts for the entire capital costs of a peaker (spread or annualised over the duration of the multiannual contract).

Secondly, the design of the capacity auction should mitigate the potential exercise of market power or strategic bidding. To do so, well defined price caps for the capacity auction are usually an effective tool. The regulator and the system operator should revise the price caps frequently to account for changes in the market or technological progress. Moreover, the capacity auction rules should consider exceptional situations where existing plants may be allowed to bid higher than the lower price cap of the auction. Such situations may occur in presence of exceptional market outcomes that can affect the profitability of existing plants. It may be economically justified to allow such bids if they are competitive enough compared to some other bids. However, the regulator should monitor closely these specific bids to limit potential exercise of market power.

Table 28. Proposed design for capacity market with multiannual contracts

Type of plant	Bidding rules	Applicable price cap	Auction clearing rules
New capacity seeking multiannual capacity contract	Allowed to bid in capacity auction by submitting an offer that is under the price cap set for new plants.	Price cap is set using Equation (F.7). The actual price cap would be a multiple of $P_{cap}^{K,upper}$. The multiplying factor will allow the regulator or market operator to account for the uncertainty related to the parameters of the formula.	Bids that are below the price cap are accepted until demand is met. All accepted offers are awarded a multiannual capacity contract with a capacity price corresponding to the last accepted bid.
Existing capacity that is no longer under multiannual capacity contract	Allowed to bid in capacity auction by submitting an offer that is under the price cap set for existing plants that are no longer under a multiannual contract.	Price cap is set using Equation (F.8). The actual price cap would be a multiple of $P_{cap}^{K,lower}$. The multiplying factor will allow the regulator or market operator to account for the uncertainty related to the parameters of the formula.	Bids that are below the price cap are accepted until all bids from this category are accepted. All accepted offers are awarded an annual capacity contract with a capacity price corresponding to the last accepted offer in this category.
Existing capacity that is still under its initial multiannual capacity contract	Forbidden from participating in the capacity auctions	NA	NA

To conclude, it should be underlined that the suggestions above only apply to a simplified setting that does not include investment for refurbishments, or other types of investments. In order to account for these specific cases, the framework could be adapted by creating new categories of plants with appropriate price caps (based on their cost structure). However, this may be complex to implement, especially if there are a lot of categories. Also, the regulator would need to define a transition mechanism to cover the case of assets which have only partially recovered their fixed costs.

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RÉSUMÉ

La transition énergétique, en partie caractérisée par le déploiement massif des énergies renouvelables, a relancé un débat de longue date sur les architectures de marché fournissant les meilleures incitations aux investissements dans les marchés libéralisés de l'électricité. Ces incitations sont essentielles pour garantir la sécurité d'approvisionnement à long terme. Pour choisir l'architecture de marché adéquate, les décideurs publics doivent évaluer et comparer les performances économiques des solutions disponibles.
La présente thèse complète la littérature sur les incitations aux investissements et la sécurité d'approvisionnement en étudiant trois aspects importants : (i) le comportement des marchés de l'électricité en présence d'acteurs averses au risque, (ii) la compatibilité entre les incitations des acteurs à mettre leurs actifs sous cocon et les objectifs de sécurité d'approvisionnement et (iii) les performances économiques de différentes architectures de marché dans un contexte de forte pénétration des énergies renouvelables. Pour ce faire, une modélisation de type *System Dynamics* est utilisée pour représenter les dynamiques de long terme résultant des décisions des acteurs dans un marché libéralisé. La thèse est organisée en trois chapitres correspondant à chacun des points mentionnés ci-dessus. Les principaux résultats sont les suivants :
Premièrement, les mécanismes de capacité sont nécessaires pour faire face aux effets néfastes de l'aversion au risque des investisseurs. Ce phénomène affecte de manière significative les marchés de l'énergie de type *energy-only*, qui subissent alors une baisse des investissements et des pénuries plus importantes. Les marchés de capacité résistent mieux à l'aversion au risque des investisseurs. Cependant, cette résilience dépend du plafond des prix dans les enchères de capacité. Pour qu'une telle architecture de marché donne des résultats satisfaisants en termes de sécurité d'approvisionnement, ce plafond de prix doit tenir compte du risque d'investissement supporté par les acteurs.
Deuxièmement, si les acteurs du marché en ont la possibilité, leurs décisions de mettre leurs actifs sous cocon peuvent modifier les dynamiques d'investissement et de fermeture à long terme. En outre, dans un monde caractérisé par des actifs indivisibles, cette possibilité augmente le niveau de coordination nécessaire pour assurer la sécurité d'approvisionnement. Cela est particulièrement vrai pour les marchés de type *energy-only*, dans lesquels la mise sous cocon augmente le niveau des pénuries, au point de contrebalancer les économies de coûts qu'elle génère. En revanche, les marchés de capacité peuvent fournir la coordination nécessaire pour assurer la sécurité d'approvisionnement même lorsque les acteurs ont la possibilité de mettre leurs actifs sous cocon.
Troisièmement, parmi les architectures de marché proposées dans la littérature, les marchés de capacité apparaissent comme la meilleure solution du point de vue du surplus social. Néanmoins, du point de vue des investisseurs, et dans certaines conditions liées à une forte pénétration des énergies renouvelables, les marchés de capacité avec des contrats annuels ne suppriment pas entièrement le problème dit de « *missing money* ». Les résultats indiquent que l'attribution de contrats de capacité pluriannuels atténue le problème.

MOTS CLÉS

Sécurité d'approvisionnement – Architecture des marchés de l'électricité – Incitations aux investissements – Energies renouvelables – Modélisation *System Dynamics*

ABSTRACT

The ongoing energy transition, partly characterized by the massive deployment of renewables, has reignited a long-lasting debate on the best market design options to provide adequate investment incentives and ensure capacity adequacy in liberalised electricity markets. To choose the appropriate market design, policymakers need to assess and compare the economic performances of available solutions in terms of effectiveness and cost-efficiency.
This dissertation complements the existing literature on market design for long-term capacity adequacy by focusing on three research topics: (i) understanding how electricity markets perform under different assumptions regarding investors' risk preferences, (ii) analysing the compatibility of private agents' incentives to mothball capacity resources with security of supply objectives and (iii) assessing the economic performance of different market designs in a context of a high penetration of renewables. To this end, the System Dynamics modelling framework is applied to represent long-term dynamics resulting from private agents' decisions in liberalised electricity markets. The dissertation is organised in three chapters corresponding to each of the topics mentioned above. The main results are outlined below.
Firstly, capacity remuneration mechanisms are necessary to deal with the detrimental effects of investors' risk aversion. Energy-only markets are significantly affected by this phenomenon as they experience reduced investment incentives and higher levels of shortages. Capacity markets are more resilient to private investors' risk aversion. However, this resilience depends on the level of the price cap in the capacity auctions. For such a market design to provide satisfactory outcomes in terms of capacity adequacy, this price cap should account for the investment risk faced by market participants.
Secondly, when market participants have the possibility to mothball their capacity resources, these mothballing decisions can potentially modify investment and shutdown dynamics in the long run. Furthermore, in a world with capacity lumpiness (i.e. indivisibilities), mothballing increases the level of coordination needed to ensure capacity adequacy. This is especially true in energy-only markets, where mothballing increases the level of shortages to an extent that seems to outweigh the cost savings it generates at system level. Capacity markets can provide the required coordination to ensure capacity adequacy in a world with mothballing.
Thirdly, among proposed market designs in the literature, capacity markets appear as the preferable solution to ensure capacity adequacy from a social welfare point of view. Nevertheless, from a private investor's perspective and under certain conditions related to high penetration of renewables, capacity markets with annual contracts do not entirely remove the so-called *"missing money"* problem. The results indicate that granting multiannual capacity contracts alleviates the problem.

KEYWORDS

Capacity adequacy – Electricity market design – Investment incentives – Renewables – System Dynamics modelling