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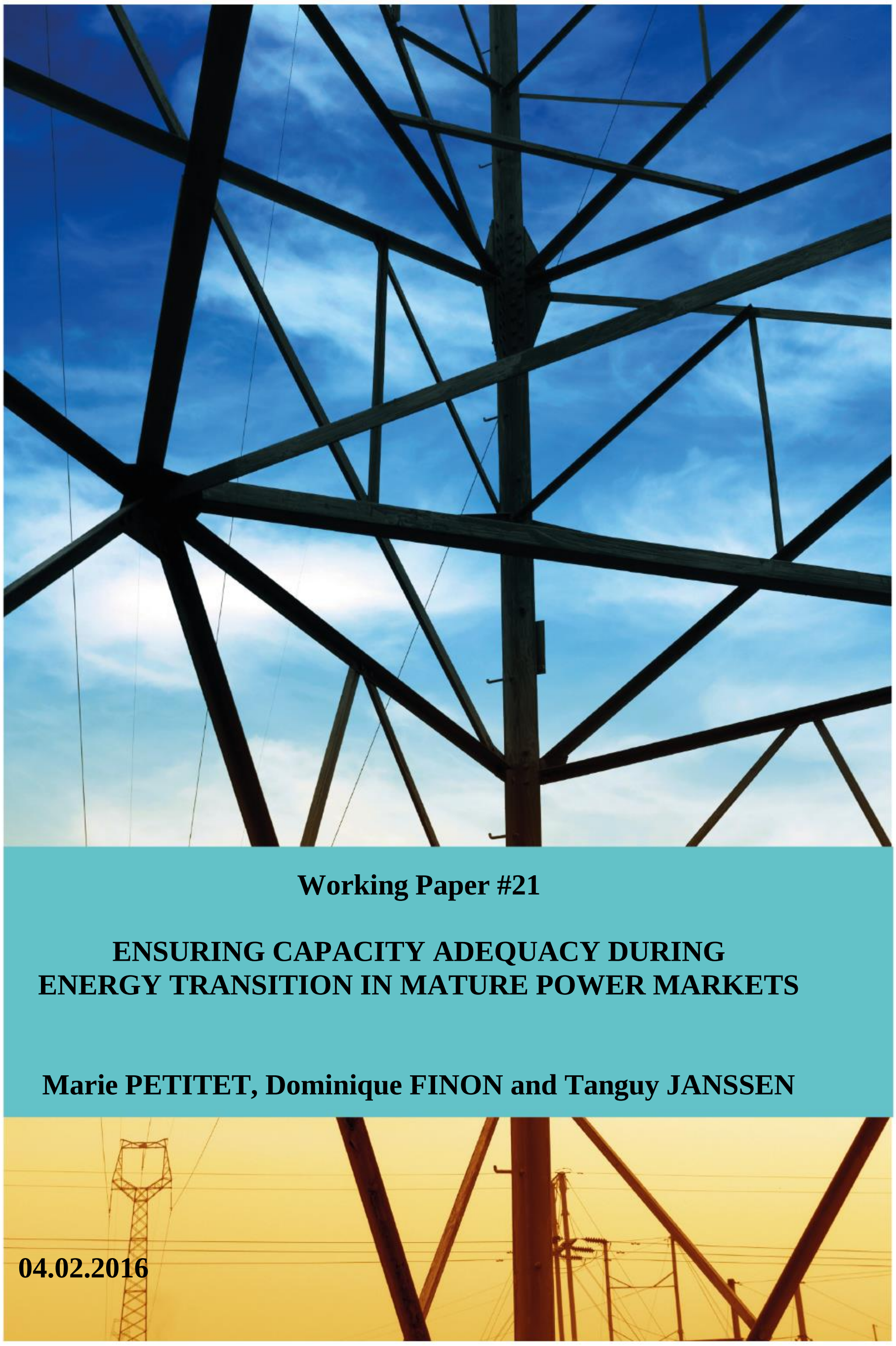

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ENSURING CAPACITY ADEQUACY DURING ENERGY TRANSITION IN MATURE POWER MARKETS

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ENSURING CAPACITY ADEQUACY DURING ENERGY TRANSITION IN MATURE POWER MARKETS: A SOCIAL EFFICIENCY COMPARISON OF SCARCITY PRICING AND CAPACITY MECHANISM

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Abstract

This paper analyses how a capacity market mechanism can address security of supply objectives in the case of an energy transition scenario which combines both high energy efficiency efforts which stabilise demand in a context of mature markets and rapid increase of renewables share. The exogenous entry of variable renewables introduces a new challenge in matter of security of supply during peak hours. To analyse this situation, power markets are simulated on the long term with a model based on System Dynamics modelling which integrates both new investment and closure decisions. This last trait is an originality of the model which is very relevant to study market maturity. The addition of a capacity mechanism in a market architecture with price cap is compared to scarcity pricing in different situations. Simulations are performed for two different cases: a case without any exogenous closure of existing power plants and a case with exogenous retirements which create a need of new investments. Under the assumption of a risk-neutral investor, the results indicate that compared to an energy-only market with price cap set at €3,000/MWh, energy-only with scarcity pricing and capacity mechanism are two efficient market designs to reach an acceptable level of loss of load. Besides, the results highlight that the advantage of one design on the other in terms of social efficiency depends on the future scenarios which are simulated. Moreover, the results illustrates that the three market designs lead to different level of risk for peaking units, suggesting that including risk aversion is a relevant further step in the modelling.

Key words

Capacity market, security of electricity supply, energy transition, mature market, System Dynamics.

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Disclaimer

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1. INTRODUCTION

In the textbooks on electricity markets, energy prices in the energy-only market design are supposed to drive investment choices in power generation in order to ensure long-term generation capacity adequacy. However, two decades after the liberalization of the European electricity sector, there are large concerns about the capability of the energy-only market to guarantee the security of electricity supply. Market failures' literature underlines that even under the assumption of risk-neutrality, the energy-only market capped at a value lower than the value of loss load fails to provide sufficient average scarcity rents for peaking units to guarantee system adequacy. This phenomenon, which is known as missing money problem, is even worsen if investors are risk adverse. However, the missing money problem can be mitigated with different approaches. This paper considers two different possible solutions: either letting the energy price reaching extremely high values during critical hours or adding a capacity mechanism.

Nevertheless, most European electricity system have benefit from a global surplus of capacity inherited from former national monopolies. Now, however, Europe faces a new situation marked by almost no electricity demand growth and the deployment of large variable renewable energy sources. This situation of mature electricity markets with no demand growth offers a radically different economical context for investors who were used to invest in a world of demand growth. Entries of renewable energy sources supported by out-of-market mechanisms further complicate this situation because energy prices tend to decrease and be more variable between hours and because anticipation of future development of those capacities is uncertain. Then, energy spot prices do not seem to assume anymore their theoretical long-term coordination function to guarantee capacity adequacy of the system.

In this context, a number of European electricity producers have announced a wave of recently built power plants mothballings and closures, while systems need more reserve capacities to handle increasing share of renewables with variable production. Moreover, a number of thermal power plants are expected to close soon in consequence of the application of the European large combustion plant directive (2001/80/EC). At the same time, investors hesitate to trigger investments in new conventional units because of a huge uncertainty on the possibility to recover their fixed costs. So, the debate on missing money has evolved towards two main topics: the issue of recovering operating fixed and variable costs for existing plants on one side, and the issue of recovering fixed costs (including capital and operating costs) to trigger investment decisions, in particular peaking units. In this respect, a capacity mechanism emerges as a solution to complement the energy market so that generation adequacy is enhanced. Today, several European countries have already set up specific capacity mechanisms and others are considering implementing one. But, scarcity pricing approach remains the theoretical benchmark solution to trigger new investments.

This paper focuses on a capacity mechanism which can be a decentralised obligation assigned to electricity suppliers, similar to the mechanism proposed in France, or a forward capacity market with auctioning by the system operator as some US mechanisms (PJM, New England). The objective is to analyse how the introduction of this capacity mechanism enhances long-term generation adequacy compared to the energy-only base case with or without price cap. To do so, evolution of electricity system is simulated over several years with a System Dynamics model. By focusing on time evolution, this approach is particularly adapted to study mature markets in which a distinction is made between economic rational of existing capacities and economic decisions for new investments.

The paper considers the case of a mature market characterized by a slow demand growth and an energy transition policy based on energy efficiency goals (which result in a stable annual electricity consumption) and renewables development. To simplify, we refer only to on-shore wind power.

Simulations are performed for two different case scenarios: (case 1) without any exogenous closure of existing power plants and (case 2) with exogenous retirement of nuclear and coal capacities. The difference lies in the combined issue of plant closures triggered by merit-order effects of renewables' entries (Sensfuß et al., 2008), and new investments. In case 1, as a consequence of both stable electricity demand due to energy efficiency and increasing renewable share, some thermal units are expected to be decommissioned endogenously. In case 2, exogenous retirements give rise to a new situation in which new investments are needed. The simulations underline how investment and decommissioning decisions are affected in the two case scenarios under three different market designs: (i) energy-only market with price cap, (ii) energy-only market with scarcity pricing and (iii) the addition of a capacity market to an energy-only market with price cap. All scenarios are simulated with the assumption that market participants are risk neutral; the validity of this assumption will be discussed based on the results of the simulations.

The following section 2 presents the rationale of introducing a capacity mechanism compared to relaxing energy price cap for allowing scarcity pricing. Section 3 details the System Dynamics model that was used in the simulations with a focus on the modelling of the capacity market. The model is used to carry out the comparison between the energy-only market with a price cap and two alternative cases: the energy-only market without price cap and the energy market with a capacity market. This analysis is conducted for two different case studies (endogenous plant closures versus exogenous closures) which are detailed in section 4. Results and their interpretation are presented in section 5. Finally, section 6 concludes.

2. CAPACITY MECHANISMS

2.1. Rationale of capacity mechanism versus scarcity pricing

The energy market is supposed to have two main coordinating functions: short-term efficiency in the use of existing capacities to serve the demand and long-term signal to ensure the right level of investments (Finon, 2013). However, since the liberalization of the European electricity sector, the long-term function of energy markets has received less attention because most of European countries have profited from over-capacity inherited from former monopolies. But today, this long term coordination of investments is at the centre of the policy debate in Europe. Indeed, there are increasing concerns about the security of electricity supply in European countries for different reasons among which ageing power plants to be replaced (e.g. in Great Britain), political and legal phase-out of nuclear and coal plants (e.g. Germany, Great Britain), increasing share of variable renewables (e.g. in Germany, Italy, Spain) or even specific peak-demand challenges (e.g. in France).

In this context, growing attention is paid to defining an appropriate market design to ensure mid-term and long-term capacity adequacy with respect to reliability preferences of consumers. In 2015, the European commission has launch a debate on market design with a particular attention to the question of scarcity pricing versus capacity mechanisms (EC, 2015). A first literature stream indicates that the benchmark design is the energy-only market with scarcity pricing, also known as peak-load pricing in the theory of marginal cost pricing of the public service monopoly (Boiteux, 1949). Under this price-based approach, the market price is equal to the marginal short-term cost of generating electricity when all demand is served; and equal to the value of loss of load when demand excesses available capacity to ensure scarcity rents for producers. When the level of capacities is optimal, marginal profit during peak periods equals marginal capital cost. Theoretically, this market design ensures social optimality and adequate level of security of supply in case of risk-neutral investors. Hogan (2005) advocates that a transparent scarcity pricing design is efficient to solve the missing money problem without disrupting the market[4]. However, the correct value of the price cap has to be defined by the regulator according to consumers' preferences and this is rather challenging. Moreover, this approach faces political acceptance issues while it increases risks faced by investors in peaking units. Indeed, when demand exceeds available capacity, not only rolling blackouts occur but also market prices jump to very high values in the magnitude of €10,000/MWh in accordance to the consumers' willingness to pay to be supplied. Moreover, a high price cap (or even no price cap at all) increases volatility of energy revenues leading to higher risks for investors. Because of those acceptance issues, only few countries has adopted scarcity pricing: ERCOT (Texas) which increased its cap from $7,000/MWh to $9,000/MWh in 2015; New Zealand with prices up to $20,000/MWh; and West Australia with a price cap set at $13,500/MWh (value adjusted annually).

In most European countries, energy markets are capped at a value which is significantly below the estimated value of loss of load and this is sometimes pointed out as a possible cause of underinvestment. However, the literature does not provide a unique analysis of the causes of underinvestment in the electricity sector. Strategic behaviour, price cap and incomplete markets (in particular the difficulties in finding long term contracts) are pinpointed as the main causes for underinvestment. On one hand, some analysts suppose that under-capacity is mostly due to strategic behaviour rather than the existence of a price cap, given that producers are perfectly informed and could benefit from adequate and complete futures markets to hedge their investment risks (Léautier, 2012). On the other hand, others (Joskow, 2006; Fabra et al., 2011) claim that underinvestment is caused by price cap which impedes the scarcity pricing and scarcity rents to be used to cover fixed costs of peaking units.

There is a wide literature about the choice for an efficient capacity mechanism in this context of imperfect regulation due to a price cap in an energy-only market. Back in the 1990's, Jaffe and Felder (1996) highlighted that capacity mechanisms (either quantity-based or price-based) allow internalizing the positive social externality of new capacities but that it should be implemented together with an improvement of the energy market functioning. Battle et al. (2014) synthesize best practises for capacity auctions from American experience and argue that a key element is the involvement of all aggregate loads in a centralised mechanism that clearly takes into account the differences between new and existing units. Cramton et al. (2013) propose to solve the adequacy problem by a forward capacity market with a reliability option which, contrary to scarcity pricing, also has the advantage of reducing market power and risk.

Keppler (2014) highlights two imperfections of the energy-only market (with or without price cap) which justify the transitory adoption of a capacity mechanism: the externalities of unreliable supply (in particular the cost of unannounced and involuntary supply interruptions) and the asymmetric incentives for agents to invest in peaking units compared to baseload technologies in a situation of inelastic demand and discrete sized units of investment. More precisely the discrete nature of the long term supply function (in other words the discontinuity of the investment function with discrete choices) combined with the inelasticity of the demand does not allow any correct anticipation of rents which could cover fixed costs of new peaking units, in the absence of appropriate hedging products which seem difficult to construct. Keppler's remarks are relevant to the question how the combined issues of the public good characteristics of adequacy and incentives to invest in peaking units (or in equivalent resources) should be dealt with in market modelling exercises concerning the issue of capacity adequacy such as this one. Indeed both security of supply externalities, as well as the impacts of asymmetric incentives for investment in peaking units are difficult to model in a relevant and transparent manner way.

[4] Stoft points out in a very relevant way that "The missing money problem is not that the market pays too little, but that it pays too little when we have the required level of reliability" (Stoft, 2002).

More precisely, the security of supply externalities escape codification almost by definition. In addition, modelling the incentives for discrete investment in different plants of specific size contributing to capacity adequacy is difficult to formalize unless a very detailed representation of the incentives and profits is undertaken at the level of the individual agent rather than at the level of the system. At the current stage, the model includes the discrete representation of investments (typical plant size are defined for each technology) and the unavailability of supply through a rate of forced outages. Future work might enhance the representation of the investment decision in peaking units. The results of the present modelling exercise must thus be put in perspective and should be discussed in detail before drawing any definite policy conclusions.

2.2. Capacity mechanism in a mature market confronted to plant closures under renewables' entries

Whatever the capacity mechanism is decentralised or not, the capacity price on a capacity market depends on the capacity that will be available at the relevant time horizon compared to the level of capacity anticipated to be required by the system operator at that time.

In the French capacity mechanism, electricity suppliers have a capacity obligation to be covered by capacity certificates. A forward capacity obligation is imposed to each supplier depending on its total load demand during peak hours. The, on an organised capacity market, annual capacity certificates are traded. In a forward capacity mechanism as the centralized reliability pricing model in PJM, existing and new generators as well as demand-response programs bid on the centralized auctioning which has a locational pricing structure. The clearing price is obtained for local areas according to the so-called variable resource requirement curves defined for each area to ensure an adequate reserve margin.

As the economic theory sets out, the price on a market corresponds to the marginal cost of the product in normal periods under the assumption of pure and perfect competition. On the energy market, the hourly energy market price reflects the marginal short-run cost of producing an additional MWh of electricity above the corresponding hourly electricity demand. Similarly, the annual capacity price reflects the cost of offering an additional certified MW (that is to say a certified "promise" to be available during critical hours) above the corresponding annual capacity obligation.

Depending on the situation, this additional certified MW comes either from postponing the closure of an existing power plant[5] or from a new power plant to be built or else by the implementation of a demand-response program. In any case, it is noteworthy that the capacity market is intrinsically in interaction with the energy market. Indeed, other things being equal, if the anticipation of energy revenues by the marginal plant which clears the capacity market decreases, a higher capacity price is needed to its cover annual fixed.

This distinction between existing and new power plants highlights the need to define the well-known "missing money" in relation to the context of the electricity system. Indeed, the missing money value is intrinsically linked to specific situations: (1) the conventional one with demand growth and no out-of-market entries of renewables, (2) the situation of stagnant demand with out-of-market entries of renewables which decrease the net demand and (3) the situation of demand decrease without or with an amplification of the decrease of net demand under the effect of out-of-market entries. So, a useful distinction should be made between:

- The missing money referring to the lack of revenue to cover annual fixed cost including both annual operation and maintenance (O&M) cost and investment cost through its annualized

[5] Almost every capacity mechanism gives a remuneration to existing plants.

value. This should be the relevant definition for new units built in the situation (1). Here, we refer to this definition as "long-term missing money".

- The missing money referring to the lack of revenue to cover annual O&M cost only. This definition should be used for existing power plants as in situations (2) and (3). Here, this is referred to as "short-term missing money".

This distinction is never made in the literature on capacity mechanism and their social efficiency because again, the (net) demand is supposed to grow. Nevertheless, the missing money is different according to the two definitions above because annual O&M costs on one hand and annual fixed costs on the other hand are significantly different in magnitude.

Theoretically, the price offered by a producer for the delivery year Y corresponds to his additional cost to forward guarantee the existence and the availability of the power plant in year Y. This price should theoretically be defined in a context of pure and perfect competition, which incites competitors to offer the lower capacity price needed to guarantee that plants will be available on critical hours of the delivering year.

As power plants remain on-line several years, generators could define their capacity bids on a multi-year sequence. But in the following, in order to simplify the model, capacity bids are formalized on a one-year basis (see sub-section 3.4).

For an existing power plant, the risk is to not covering its annual O&M cost. Then, the dilemma is to choose between shutting down the power plant, mothballing it or remaining in operation. In this situation, capacity bids by existing power plants are aligned on annual short-term missing money, which corresponds to annual O&M cost minus the possible energy revenues on the energy market. For a new power plant to be built, the bid on the capacity market is defined with respect to its annualized investment cost and O&M cost compared to its anticipated net revenues on the energy market. This form of long term missing money is the classic one in the literature.

Therefore, the presentation of aggregates producers' bids on the capacity market by a supply curve leads to a two-stepped curve of capacity certificate supply: one step with bid prices aligned on O&M fixed costs per MW for existing plants and one with bid prices aligned on annualized capital cost plus O&M fixed cost per MW for new projects (see Figure 4 below).

3. SPECIFICATIONS OF THE "SIDES" MODEL

Traditional power market equilibrium approaches, such as dispatching programming, long-term optimisation, presents two major limitations: they do not provide any elements on transition phases from one equilibrium to the next and do not indicate if the real initial electricity system could evolve toward this equilibrium. On the contrary, our approach based on System Dynamics (SD) modelling focuses on dynamic evolutions of electricity systems based on the representation of decision rules and sheds additonal light on the functionning of electricity systems.

SD modelling is increasingly used to study the electricity sector and in particular to estimate the benefits of capacity mechanisms. De Vries and Heijnen (2008) consider several types of capacity mechanism in the context of uncertain demand growth. Thanks to dynamic analysis rather than static one, they particularly highlight that energy-only market are prone to investment cycles but that cycles are reduced with capacity mechanisms. Cepeda and Finon (2011) explore the benefits of a forward capacity market for two interconnected zones and show that harmonisation between interconnected countries brings higher social efficiency.

3.1. Overview of the SIDES model

The Simulator of Investment Decisions in the Electricity Sector (SIDES) is a SD model that was developed in order to analyse the long term effects of different market designs[6]. Evolution of generation mix is obtained over several years by endogenous simulation of investment in electricity generation, decommissioning and mothballing decisions given a set of assumptions about initial generation mix, structure of the annual demand curve, energy policy and macroeconomic scenarios. The modelling considers a single representative agent acting as a price taker whose objective is to maximise his profit. This representative agent is assumed to be risk-neutral and technologically-neutral. He anticipates the future under the assumption of myopic foresight (with a 5-year time horizon). In the case of new investment decision, the myopic foresight implicitly implies that annual revenues would remain the same from the fifth anticipated year to the end of the life time of the power plant. Figure 1 illustrates the functioning of the SIDES model.

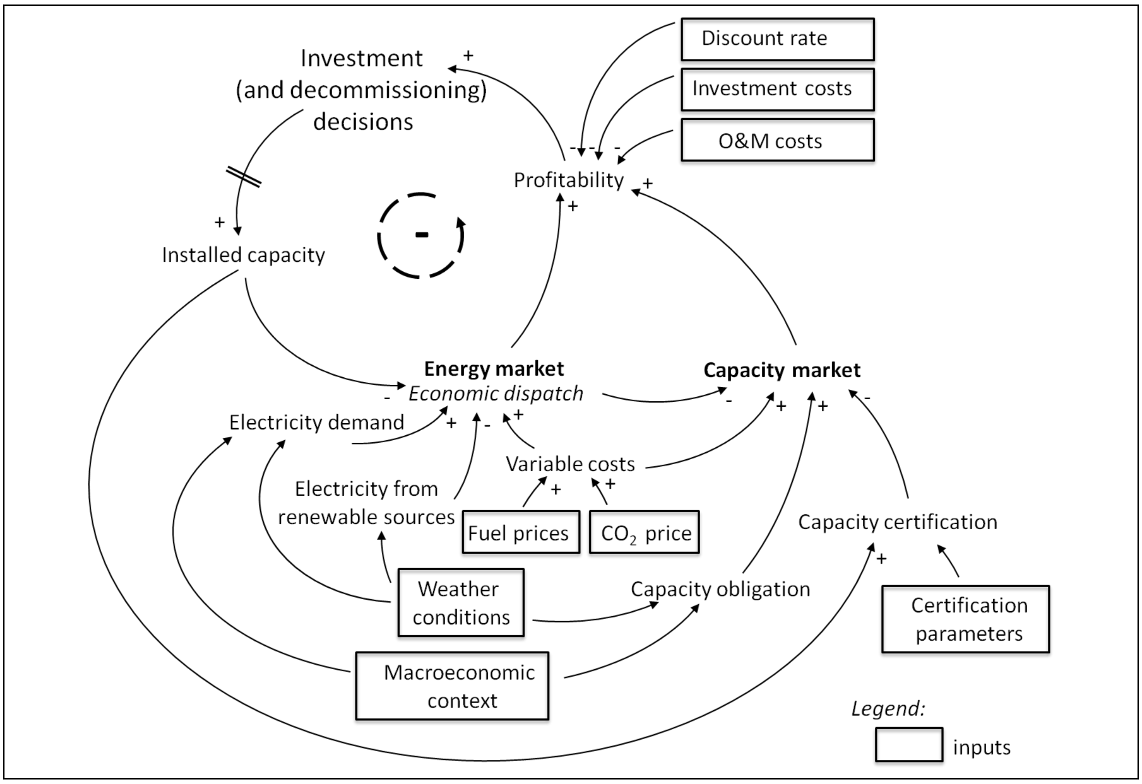

Figure 1 – Causal-loop diagram of the SIDES model, including both the energy market and a capacity mechanism.

Investors' decisions are obtained each year of the simulation on the basis of estimated profitability of various projects for a range of anticipated future patterns. The SIDES model includes both decisions of building new power plants and decommissioning existing ones. For the purpose of the study case of mature markets presented in this article, modelling decommissioning decision is a crucial point. Indeed, in a context of stable electricity demand (due to energy efficiency) and out-of-market development of renewables, thermal power plants are to be decommissioned.

Regarding the energy spot market, energy price is set on an hourly basis and is equal to the variable cost of the plant which clears the market, with respect to the merit-order principle. The energy market is represented on an hourly basis (8,760 hours per year).

[6] Its basic structure is described in Petitet et al. (2014).

The basic elements of the functioning of power plants are considered in the model. In particular, wind power production is well represented by using historical data of hourly load factors correlated to the hourly power consumption. For thermal power plants, the net generating capacity is obtained by taking into account the impact of unplanned outages through a forced outage rate, while assuming that planned outages happen when electricity demand is low and do not impact the market price.

χ	Index of the generating technology. ($1 \leq \chi \leq N$)
y	Index of the year.
h	Index of the hour. ($1 \leq h \leq 8760$)
$L(h,y)$	Electricity demand for the hour h of the year y.
κ_χ	Nominal power capacity of the technology χ.
$K_\chi(y)$	Installed capacity of the technology χ in the year y.
$y_{F,\chi}$	First commission year of the power plant
IC_χ	Investment cost of the power plant χ.
OC_χ	Annual operation and maintenance (O&M) cost of the power plant χ.
VC_χ	Fuel and carbon variable cost of the power plant χ. ($VC_1 \leq VC_2 \leq \ldots \leq VC_N$)
$p(h,y)$	Market price for the hour h of the year y.
$EP_\chi(h,y)$	Electricity production of the power plant χ for the hour h of the year y. ($0 \leq EP_\chi(h,t) \leq \kappa_\chi$)
$ENP_\chi(y)$	Estimated net profit of the power plant χ for the year t.
$MT.ENP_\chi$	Estimated net profit of the power plant χ on the mid run (typically for the years y to $y+5$).
T_χ^C	Construction time of the power plant χ.
T_χ^L	Lifetime of the power plant χ.
Lf_χ	Load factor of the technology χ.
CAP	Price cap of the energy-only market.
r	Annual discounted rate.
F_χ	Normative capacity factor of the technology χ.
$CC_\chi(y)$	Capacity certification of the technology χ in year y.

Table 1 – Nomenclature

The model considers a representative producer-investor and a representative supplier-consumer in a decentralised capacity obligation which is equivalent to a situation of perfect competition at the stage of wholesale markets with a number of competitive producers and suppliers. Consequently, the representation adopted in this analysis is also relevant for a centralised forward capacity mechanism (e.g. PJM) in which the price is defined on an annual basis. Indeed, the representative buyer of capacity certificates could also refer to the system operator who acts as a delegate of electricity consumers and uses auctions to allocate forward capacity contracts to reach the reserve margin which guarantees the security of the system in peak load and critical hours.

Market equilibrium, hourly prices on each year, decisions to invest or to close an existing plant and evolution of the generation mix are simulated over a 20-year period.

3.2. Formalization of decommissioning decisions

In the context of the energy transition, energy efficiency and exogenous development of renewables could lead to early decommissioning of existing power plants. This type of decision is formalized in the model and this represents an innovative feature compared to the state of the art. In the SIDES model, there are two causes for plant closures:

- closure imposed by the technical end-of-life of the power plant,

- early decommissioning if the power plant is not economically profitable any more.

The first case is obvious and easy to implement. The second case requires to define under which conditions an investor will consider an existing power plant as unprofitable. Because of long pay-out time of power plants, it is not sufficient to anticipate losses on the following year to decide to shut down a power plant. Indeed, a power plant can be unprofitable for one year and remain on-line because it is expected to make profit on the mid-run. So, in the model, a two-stage economic evaluation is used to simulate decommissioning decisions.

The first step consists in estimating the net profit of the different technologies for the following year. This estimation of profitability is based on energy revenues, capacity revenues and operating and maintenance costs. At this stage, investment costs are not taken into account because they are considered as sunk costs. Indeed, once the power plant has been built, payment of the investment cost is irreversible.

Estimated net profit (ENP) for the following year (noted *y+1*) corresponds to:

$$ENP_\chi(y+1) = -OC_\chi + CR_\chi(y+1) + \sum_{h=1}^{8760} max(p(h,y+1) - VC_\chi; 0).EP_\chi(h,y+1) \quad \textbf{(1)}$$

If ENP is positive, the power plant is estimated profitable at least for the next year. Therefore, the best decision is to operate the plant at least for the next year. If ENP is negative, the single investor should wonder whether to close the power plant now or to wait for better economic conditions in the mid run. In this latter case (if *ENP<0*), the second stage is carried out.

The second step consists in estimating profitability on a longer time period than one year. It is to be carried out only if the first stage shows that *ENP* is negative for a particuler power unit.

In the modeling of this second step decision, the looking period for the economic evaluation is set to 5 years. It is consistent with the myopic period of 5 years defined for new investments. The process consists in estimating annual econonomic balance for the 5 following years and computing the discounted sum. Thus, mid-term estimated net profit (*MT.ENP*) is equal to:

$$MT.ENP_\chi = \sum_{z=y+1}^{y+5} \frac{ENP_\chi(z)}{(1+\mathrm{r})^{\mathrm{z}}} \quad \textbf{(2)}$$

If both ENP and $MT.ENP$ are negative, the power plant is profitable neither on the following year nor on the mid-run and consequently, the unit is decommissioned. If ENP is negative and $MT.ENP$ is positive, the power plant remains in operation because it is expected to recover rentability over the 5 year period.

In a third step, the SIDES model also represents annual mothballing decisions of existing power plants[7].It is formalized in the following way: if MT.ENP is positive but ENP is negative, then mothballing option is tested. Economic evaluation over the five following years is estimated with mothballing and compared to the economic evaluation without mothballing. If mothballing the power plant improves its economic situation, the power plant is mothballed.

3.3. Formalization of investment decisions

Most firms base their investment decisions on economic analysis but have to select some indicators of investment profitability among the large variety proposed in economic textbooks from the well-known net present value, to real options or portfolio selection. Some academic surveys estimate which economic indicators are really used by compagnies to make their decisions. Among others, Graham and Harvey (2001) and Baker et al. (2011) highlight that net present value remain the

[7] The model does not consider short mothballing period within a year.

most common economic criterion for financial decisions. And in particular, Backer et al. (2011) find that 81% of the firms surveyed never use real options mainly because of a lack of expertise or knowledge. From this observation, the SIDES model computes the net present value of the projects. To reflect the issue raised by the high upfront investment cost of some power plants and in order to discriminate between technologies, the net present value is compared to unitary amount of capital to be spent by plant. So, in the SIDES model, new investment decisions are based on a profitability index (PI_{χ}) defined as the ratio between the net present value (NPV_{χ}) computed with a discount factor of 8% and investment cost (IC_{χ}) of the technology χ:

$$PI_{\chi} = \frac{NPV_{\chi}}{IC_{\chi}} \tag{3}$$

In order to be selected, the project must respect the two following conditions:

- its profitability index is positive,
- its estimated annual net revenu $ENP_{\chi}(y_{F,\chi})$ for the first comissioning year $y_{F,\chi}$ is positive.

The second condition is added in order to introduce a simple way of time-planning into investment decisions. Among the projects selected as just mentioned above, the SIDES model finally determines the project whose profitability index is the greatest to be invested in by the representative investor. Once a project has been chosen to be invested in, a recursive loop allows to compute if other projects are still economically interesting. For a specific simulated year, this recursive loop provides the number of plants of each technology that is invested in.

3.4. Modelling a capacity market

The SIDES model considers both a capacity mechanism and the energy-only market. It is based on the introduction of a capacity obligation assigned to electricity suppliers in relation to the consumption of their clients. Here, we focus on the electricity producer: he receives capacity certificates and sells them on the capacity market to electricity suppliers for each year. The underlying hypothesis is that the whole cost of the capacity mechanism is transferred to electricity consumers (through retail prices).

In this version of the SIDES model, the supply curve of capacity certificates is explicitly and endogenously modelled. The capacity price is obtained on an annual basis by the intersection of the supply and demand curves.

3.4.1. Adequacy target and certification of equipments

Capacity adequacy target

To contribute efficiently to security of supply, adequacy target should reflect the capacity need of the system under a normalized set of extreme conditions. Parameters are defined so that the capacity obligation corresponds to the peak power demand plus a security margin during critical hours. In the modelling, the capacity target is defined so that this level of capacity ensures a loss of load expectation of 3 hours per years in average over the weather scenarios considered.

Certification of guaranteed available power plants

Capacity certification determines the contribution of a power plant to capacity adequacy. For thermal units which are supposed to be available at all times, capacity certification (CC_{χ}) in year *y* is simply obtained through a normative capacity factor (F_{χ}) defined for each technology χ thanks to the following relation:

$$CC_{\chi}(y) = F_{\chi}.K_{\chi}(y) \tag{4}$$

where $K_{\chi}(y)$ is the level of installed capacity in year *y*. For thermal technologies, the factor *F* simply takes into account the forced outage rate of the power plants.

Certification of variable sources

The case of renewables is different. As these units are undispatchable by nature, their contribution to capacity adequacy depends on the effective production during critical hours. Hence, certification of variable energy sources is strongly related to their average availability during peak hours. This is generally referred to as "capacity credit" of renewables. This capacity credit depends on the relative share of variable renewables in the system.

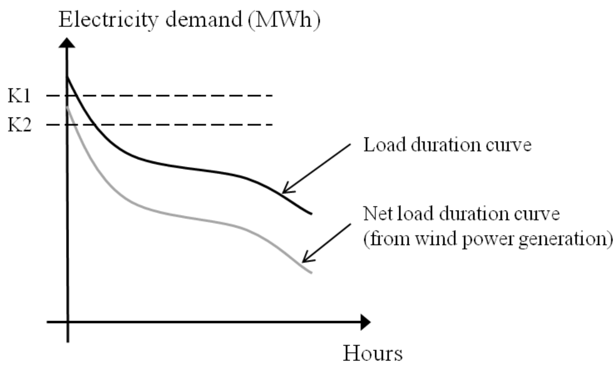

Figure 2 – Effect of wind power on net demand obligation (K1 and K2) from a load duration curve point of view.

In the SIDES model, the capacity factor of wind power is estimated each year depending on the annual load duration curve and wind production share. Figure 2 shows gross and net load duration curves. The net load duration curve is obtained by subtracting wind power generation under an assumption of installed wind capacity. K1 and K2 are respectively the obligation capacity for the gross load duration curve and the net load duration curve. The capacity credit assigned to the installed wind capacity corresponds to the difference between K1 and K2. Thus, the capacity factor of wind power is defined as the following:

$$F_{wind} = \frac{K1 - K2}{installed\ wind\ capacity} \quad \textbf{(5)}$$

This approach was applied in several studies (see for example Nicolosi and Fürsch; 2009) to estimate the contribution of renewables to capacity adequacy.

For the electricity data used in the simulations presented below, Figure 3 presents capacity factor of wind power as a function of installed capacity (from 8 GW to 70 GW). It shows that the capacity factor significantly decreases above 30 GW of wind capacity.

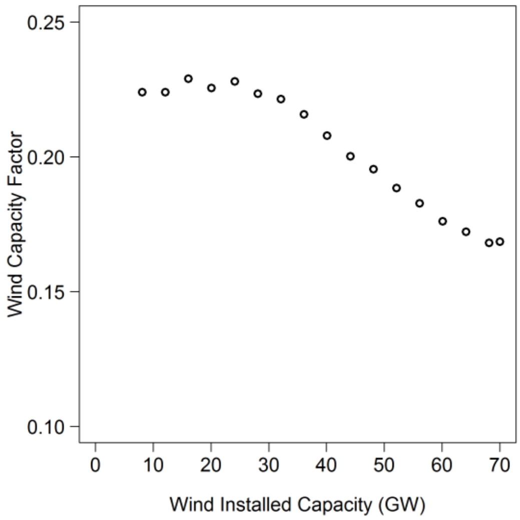

Figure 3 – Wind capacity factor as a function of installed capacity (own calculation)

3.4.2. Capacity pricing

On the capacity market, producers sell their capacity certificates to electricity suppliers that are assigned to the capacity obligation in the decentralised obligation case or to the central buyer in case of a forward capacity mechanism. The supply curve is obtained endogenously on the basis of capacity price bids, as explained above. The total volume which is bid corresponds to the capacity certificates associated to each technology and obtained by relation (4). To simplify the modelling approach, capacity demand is considered as inelastic and its level is aligned on the capacity adequacy target. Then, the clearing capacity price is determined by the intersection of the supply and demand curves as illustrated in Figure 4.

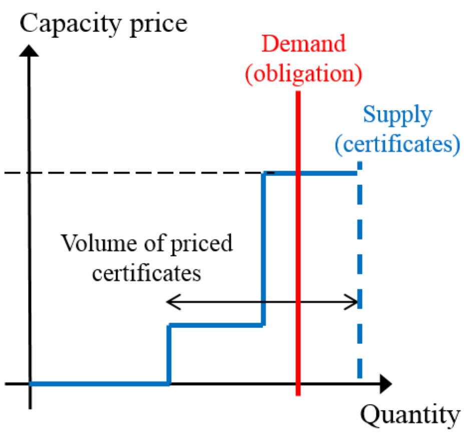

Figure 4 – Functioning of the capacity market

The price offered by a plant owner on the capacity market is a key element in the modelling of this market mechanism. In particular, its definition depends on the situation of the power plant, namely the existing power plants already installed or the plants under construction or else the ones under a forward decision to be built. The bidding strategy on the capacity market could either be defined in relation to annual considerations or in relation to inter-temporal estimations. In the SIDES model, the bidding strategy on the capacity market depends only on annual estimated profitability of power plants, whereas investment decisions are obtained based on multiannual anticipations.

For dispatchable existing units, the price offered on the capacity market is simply modelled as the difference between annual average energy revenues anticipated for the considered year and annual

O&M cost. On their side, renewable units such as wind power turbines are supposed to benefit from a specific mechanism (for example feed-in tariffs) that ensures their profitability through out-of-market supports. Thus, such renewable plants bid their capacity credits at zero price.

More precisely, to model the bidding behaviour of producers with existing capacities, the price of the capacity bids offered for a given year is assumed equal to the difference between the annual O&M cost and the estimated annual energy revenue. Thus, the capacity price CP_χ offered by an existing power plant of technology χ is defined as:

$$CP_\chi = \frac{1}{CC_\chi}\left(-OC_\chi + \sum_{h=1}^{8760} max(p(h,y) - VC_\chi; 0).EP_\chi(h,y)\right) \quad \textbf{(6)}$$

This equation represents the behaviour of producers of existing plants under pure and perfect competition conditions.

Considering new power plants, the SIDES model assumes that if existing capacities are not sufficient to cover capacity obligation, new power plant offers a price defined as the difference between anticipated energy revenues and annual fixed cost[8]. In the end, this case leads to a capacity price equal to the lower "long-term missing money", generally the one of peaking units (see section 2.2).

Moreover, in the model, the bidding strategy assumes that the capacity price drops to zero if certification of existing power plants clearly exceeds obligation with an excess of more than 1%. This is consistent with the theory of capacity requirement if there is no market power, as explained by Stoft (2002).

4. DEFINITION OF THE TWO CASE STUDIES

4.1. Definition of case studies

Two case scenarios are carried out under general assumptions corresponding to the energy transition but with an assumption of forced decommissioning in the second scenario. Energy efficiency efforts are supposed to mitigate consumption growth resulting from macroeconomic evolution, so that electricity consumption remains stable over the time period of this simulation (20 years). At the same time, exogenous wind power development is made possible by support mechanism (for example, feed-in tariff). As a consequence of those two main assumptions, net electricity demand[9] to be supplied by thermal units decreases over time. In a first set of simulations, decommissioning decisions are completely endogenous under the effect of exogenous entry of renewables which jeopardizes economic profitability of existing power plants. In a second set of simulations, some closures of coal and nuclear plants are programmed exogenously: this amounts to suppose that some units reach the end of their technical life time or that legal rules or political decisions provoke their early closure. The goal is to show differences between market designs in terms of social efficiency along these two scenarios.

4.2. Definition of the three market designs

Three different market designs are tested in each case study. Table 2 summarizes the key features of the market designs considered. The first market design ("EOM3") corresponds to the current energy-only market, with a price cap of € 3,000/MWh as it is the case on EpexSpot market in the North-Western Europe. The second one ("EOM20") is the theoretical energy-only market with scarcity pricing. In that case, the price reaches the social value of loss of load if electricity generation

[8] Annual fixed cost is the addition of annual amortization of investment cost and annual O&M cost.
[9] Net electricity demand is defined as real electricity demand (from consumers) minus electricity produced by renewable electricity sources (here, wind power).

is not sufficient to serve all electricity demand. In the simulations, this value of loss of load is estimated to be € 20,000/MWh, which is consistent with RTE (2011). Lastly, the third market design (CM) tested in the simulations corresponds to the addition of a capacity mechanism (as detailed in section 3).

Market design	"EOM3" *Energy-only market with price cap*	"EOM20" *Energy-only market with scarcity pricing*	"CM" *Capacity mechanism*
Price cap on the energy market (€/MWh)	3,000	20,000	3,000
Capacity mechanism	No	No	Yes

Table 2 – Presentation of the three market designs

4.3. Data on technologies' characteritics, costs and demand forecats

- **Power plants' characteristics**

In the simulations, four thermal generating technologies are considered: combined cycle gas turbines (CCGT), coal-fired power plants (Coal), oil-fired combustion turbines (CT) and nuclear power plants (Nuclear). Technical and cost assumptions which are detailed in Table 3 are from IEA and NEA (2010) and DGEC (2008). Wind power is included in the simulations in order to represent renewables in a simple way. Its development is fixed exogenously according to the assumptions on energy transition. Because of that, no precise cost data are needed for wind power. In further analysis, the overcost for wind power deployment to be paid by consumers via a levy is computed under the assumption of a feed-in tariff set at 80 €/MWh corresponding to present feed-in tariff level common to a number of countries.

	Combustion turbine (CT)	Combine cycle gas turbine (CCGT)	Coal plant (Coal)	Nuclear plant (Nuclear)
Investment cost (k€/MW)	500	800	1,400	3,910
Annual O&M cost (k€/MW.year)	10	20	30	75
Annualised fixed cost (k€/MW.year)*	57	91	147	391
Power capacity (MW)	175	480	750	1,400
Variable cost (€/MWh)**	162	66	42	10
Forced outage rate (%)	8	5	10	5
Construction time (years)	2	2	4	6
Life time (years)	25	30	40	60

* With a discount factor of 8%.

** The variable cost corresponds to the sum of fuel cost and carbon cost. Gas price is € 10.2 per MMBtu (€ 9.7 per GJ); coal price is € 150 per ton (€ 4.2 per GJ) and oil price is € 88.7 per barrel (€ 15.3 per GJ) according to the assumptions of IEA and NEA (2010). Carbon emission factor is supposed to be 0.35 t CO_2/MWh for CCGT and 0.8 t CO_2/MWh for coal and CT. The carbon price is set to €6 per ton of CO2 (mean value observed on the EU emissions trading system in 2014).

Table 3– Economic and technical parameters of technologies

Demand response programs could be an element of the supply resources in a long term simulation modelling but it is not considered here in order to limit the complexity of the modelling approach, while the flexibility services offered by the peaking units (gas turbines, fuel oil combustion) could be considered as quite similar in terms in flexibility value during the peaking and critical hours. However, load management aspect is taken into account exogenously through the stability of electricity demand. In that sense, only energy reduction is considered while power reduction is not represented in this case study.

- **Initial generation mix, exogenous wind power entry and exogenous retirements**

The initial mix at the beginning of the simulation correspond to the optimal thermal mix obtained by screening curves method (Green, 2006) while assuming an existing 8 GW of wind power. This initial generation mix is composed of 43 GW of nuclear, 20 GW of coal, 19 GW of CCGT and 18 GW of CT.

The total capacity of the initial generation mix is defined in order to respect 3 hours/year of loss of load expectation (LOLE) which results from the calculation by the screening curves optimisation method. These 3 hours of loss load corresponds to the reference of loss of load expectation (LOLE) which is the average value to be reached in average over the weather scenarios. It is noteworthy that this LOLE-norm of 3 hours per year should theoretically be congruent with the level of the VOLL[10] and the annualised fixed cost of the marginal peaking plant to be installed to reach this performance of security of supply, as exposed in the theory of optimal peak pricing (Boiteux, 1949). So, in theory, the loss of load probability times the VOLL should be equal to the annualised fixed cost of the peaking unit. Nevertheless, two additional remarks can be made. Firstly, power plants have typical size of several hundreds of MW which imply that reaching the exact LOLE-norm is very unlikely to happen even in simulations if the model reflects this discrete characteristic. Secondly, this theory is valid in a context of load growth but should be re-examined in the case of a decrease of the net load. Indeed, an economical decision of early retirement refers to the comparison between anticipated net revenues and annual O&M cost of the power plant (see section 3.2). Because O&M costs are significantly lower than annualised fixed costs, the LOLE with EOM20 is theoretically lower than the LOLE-norm of 3hours/per year in the context of endogenous closures due to a decrease of the net load.

With current assumptions on cost parameters, wind power is not economically viable unless the carbon price reaches a very high value (Petitet et al., 2014) and consequently it should be supported by specific mechanisms (for example, a feed-in tariff). As detailed in Figure 5, wind power installed capacity varies exogenously from 8.1 GW in 2015 to 70 GW at the end of the simulation. In terms of energy share, it represents 3.2 % in 2015 and 27.2% at the end of the simulation.

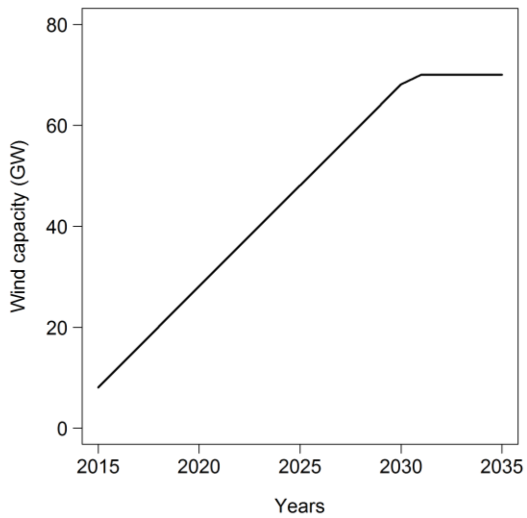

Figure 5 – Exogenous development of wind capacity (assumed for cases 1 and 2).

Concerning plant closures, while case 1 does not impose exogenously constraints on thermal power plants, case 2 is set out in coherence with the current debate about nuclear and the possible

[10] Generally, the VOLL is also a political value and in some countries it is aligned on the social preferences revealed by some polls.

effects of an EU law on polluting plants. Indeed, in Europe, Germany, Belgium and Switzerland have already planned to progressively phase out nuclear plants. The application of the European directive on large combustion plants (2001/80/EC) could also lead to closures of some large emitting plants. So, in the second set of simulation (case 2), 9.8 GW of coal (13 power plants) are exogenously closed during the period 2015-2020 and 9.8 GW of nuclear (7 power plants) between 2025 and 2030. The details are presented in Figure 6.

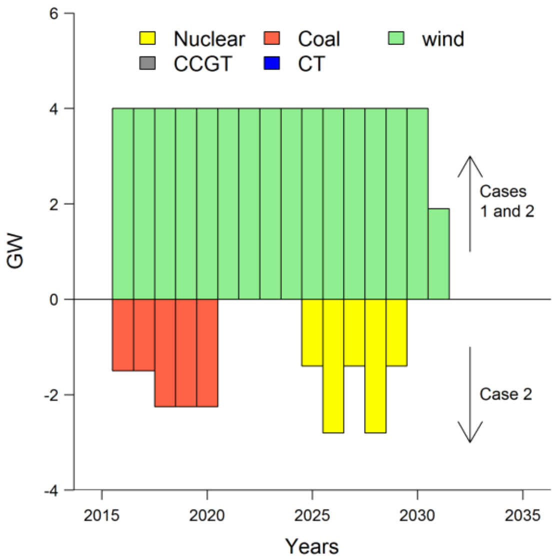

Figure 6 – Respective exogenous entries (for all cases) and closures of power plants (for case 2).

- **Electricity demand**

For its decisions, the single representative investors simulated in the SIDES model considers all the weather scenarios available to estimate future profits in the context of annual stable demand over the 20-year period. To do so, it is supposed that the evolution of the total electricity demand is perfectly anticipated by the representative investor while keeping some uncertainty about meteorological conditions represented by a unique distribution of load profiles and correlated wind power production.

The weather sensitivity of electricity demand and wind power generation is taken into account through 11 representative weather scenarios of correlated load demand and wind power generation defined on hourly basis, corresponding to the French case from 2003 to 2013 (according to open-source data available on RTE's website). Based on those data, the capacity obligation to fulfil adequacy requirement of an average of 3 hours/years of loss of load is 95.8 GW.

5. COMPARISON OF THE THREE MARKET DESIGNS IN THE TWO SCENARIOS OF ENERGY TRANSITION

This section presents the results of simulations carried out with the SIDES model for the three variants of market design in the two case scenarios. It details the evolution of the technology mix and different aspects of adequacy issues: performances in terms of loss of load, social efficiency through the addition of production costs and social cost of loss of load, and finally the cost for consumers including the energy component, the eventual capacity component and the overcost of renewables' support.

5.1. Case 1 with endogenous closure of existing power plants

This section presents the results of the case 1 in which the electricity demand remains constant over the period thanks to a restricted economic growth together with efforts on energy efficiency. Wind power development is set exogenously under the assumption that it is supported by a feed-n tariff of € 80/MWh (which only impacts the calculation of the consumers' bill). The three market designs (EOM3, EOM20 and CM) are analysed in terms of effectiveness to provide capacity adequacy at first, then in terms of social welfare and finally from in terms of consumers' bill.

5.1.1. Effectiveness in reaching the adequacy target

The capacity mix evolution over the 20-year period shows that in the three market designs, there is a decrease of non-renewable generation capacity. Plant closures have to be related to the combination of demand stagnation and exogenous wind power entries. The three market designs tested in case 1 lead to different levels of installed capacity.

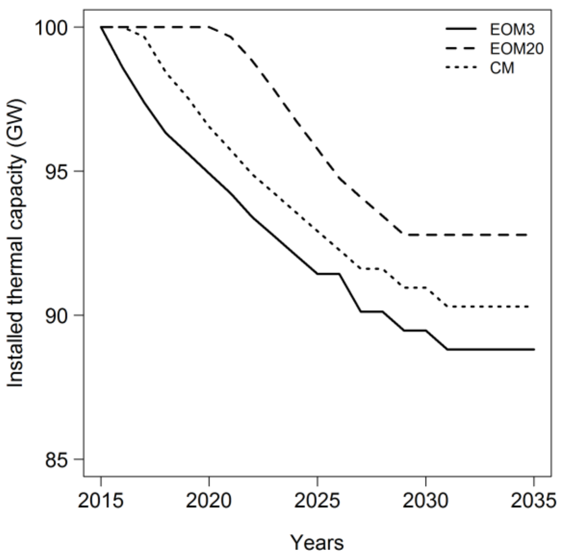

Figure 7 – [Case 1] Evolution of thermal capacity under the 3 market designs.

One aspect of these results is the decommissioning paths of thermal units which are plotted in Figure 7 for each market design. Compared to energy-only market with price cap at 3,000 €/MWh (EOM3), an additional capacity of, respectively, 4 GW and 1.5 GW remains available at the end of the simulation with scarcity pricing (EOM20) and with capacity market (CM). In the results, it appears that some CT and CCGT power plants are closed, while installed nuclear and coal capacities remain unaffected by the need to close some plants because of the massive exogenous wind power deployment and its merit-order effects. The fact than CCGT and CT rather than coal or nuclear units are closed is explained by the cost assumptions (O&M costs and variable costs). Note that in these simulations, variable generation costs of CCGT and CT are supposed higher than the ones of coal and a fortiori nuclear plants.

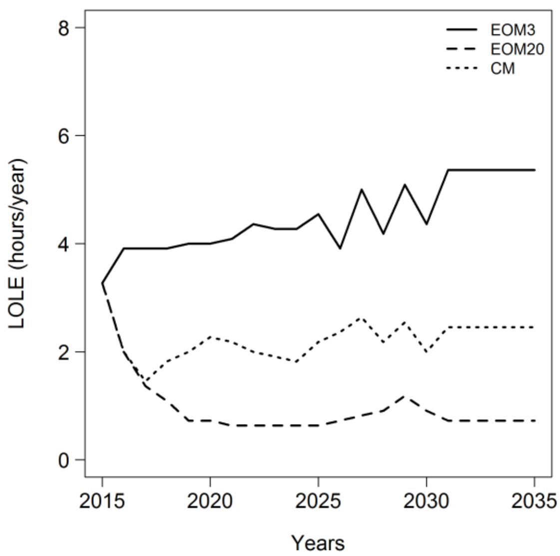

Figure 8 – [Case 1] Evolution of the LOLE (hours/year) under the different market designs.

To assess the ability of the three market design to guarantee security of supply, the loss of load expectation (LOLE) was estimated on average over the 11 weather scenarios used in the simulations. Evolution of LOLE over the 20 simulated years is presented in Figure 8 for each market design.

The results of LOLE are presented in Figure 8 and Table 4. The results underline that EOM3 clearly fails to guarantee the objective of 3 hours of loss load per year even though the system benefits from an inherited over-capacity in this context of a decreasing net demand addressed to conventional units. At the end of the simulation, LOLE is 5.36 h/y with EOM3, 0.86 h/y with EOM20 and 2.45 h/y with CM. The EOM20 and CM meet the LOLE objective of 3 hours per year but even overcome it. Indeed, in case of a decrease in the net demand addressed to thermal units, existing units will be decommissioned only if they don't get back their annual O&M cost from the energy market both on the next year and the five following years (see subsection 3.2). These results highlight that the capacity market is the best of the three simulated designs to reach the objective of 3h/y or to be closed to it. Of course, the failure of the EOM3 in terms of the LOLE-target of 3h/y was expected because no market rule give a value for the security of supply. On its side, the CM design with a capacity mechanism is the only one to internalize the objective of electricity supply, expressed as a LOLE-target, whatever the situation. But, note that the target of 3hours per year is not strictly respected in these simulations with CM because of a combination of different elements: the discrete representation of power plants of typical sizes which makes it difficult to reach the exact adequacy target, the certification excess of 1% compared to capacity demand that is needed before the capacity price drops to zero in the model and the exogenous entry of wind power which further disrupts the system.

In the scarcity pricing market design (EOM20), the profit value of peaking units is generated during critical hours with prices up to the VOLL at € 20,000 /MWh. In a context of a decrease of the net load, this profit has to be compared to the annual O&M cost of the combustion turbine which is € 10,000 /MW.year. In this context, the ratio between this annual O&M and the VOLL explains that the LOLE in EOM20 is theoretically expected to be in the range of 0.5-1 hour per year, which is lower than LOLE-norm of 3 hours per year. Finally, this comparison of annual O&M costs (which are significantly different from annualised fixed costs) and the VOLL may raise a question: in a decreasing capacity paradigm: should the LOLE-target of 3h/y be reconsidered?

Market design	EOM3	EOM20	CM
LOLE: average (h/year)	4.53	0.73	2.18
LOLE: last year (h/year)	5.36	0.86	2.45

Table 4 – [Case 1] Loss of load expectation (h/year) under the three market designs.

5.1.2. Comparison of social efficiency of scarcity pricing (EOM20) and capacity mechanism (CM)

This sub-section considers the difference in the respective increases of social welfare between the two reformed market designs EOM20 and CM, and the reference design EOM3. The social welfare (*SW*) is defined as the consumers' utility related to electricity consumption (*U*) from which are subtracted the fixed and variable operating costs of electricity generators (*GC*) and their annualized investment costs of capacities (*AIC*):

$$SW = U - GC - AIC \qquad \textbf{(7)}$$

Then, the variation of social welfare with respect to EOM20 is defined as the following:

$$\Delta SW(design\ X) = SW(design\ X) - SW(EOM3) \qquad \textbf{(8)}$$

The variation in operating generation cost (*GC*) considers both variable generation costs and annual O&M costs of power plants. When new power plants are built during the simulation, it is necessary to include investment costs in the comparison of market designs by computing annualized investment costs of power plants. The variation in consumers' utility function is defined as the difference of social costs of the non-supplied energy (NSE) which corresponds to the difference of the number of MWh not supplied, multiplied by the value of loss load (VOLL). Here, the VOLL is set at the level of €20,000/MWh which is identical to the price cap in the scarcity pricing design. Thus, the variation in consumers' utility is:

$$\Delta U(design\ X) = -\big(NSE(design\ X) - NSE(EOM3)\big) * VOLL \qquad \textbf{(9)}$$

The increases of social welfare in the two cases EOM20 and CM compared to EOM3 are presented in Table 5. EOM20 provides the highest increase of social welfare under the assumption of risk neutrality. The capacity market (design CM) with the adequacy target of 3 hours of loss load per year also increases the social welfare by € 72.4 /year on average over the 20-year period, but less than EOM20 which stands at an increase of M€ 107.7 /year on average. Indeed, with EOM20, the price cap on the energy market is set to the VOLL and consequently, the social cost of the non-supplied energy is completely internalised and leads to a LOLE which is different from the ex-ante target of 3h/y. At the end, a contradictory situation is shown in case 1: CM is clearly the best option to reach the targeted LOLE of 3h/y but it does not lead to the best social welfare. This result is a direct consequence of the difference between the adequacy target assigned to the CM and the "optimal" adequacy target in this case of a decreasing net demand. This contradictory statement suggests that the optimal capacity adequacy target could be different from the LOLE-target of 3h/y in a decreasing capacity situation. On this basis, a new simulation with CM was conducted with a capacity target set to the ratio between the annual O&M cost of CT and the value of loss load, which corresponds to a target of 0.5 hours of loss load per year. This new calibration of the CM leads to increase the social welfare improvement of CM compared to EOM3 to a value (106.9 M€/year) which is similar to the one obtained with EOM20. This confirms that the definition of the capacity target of the capacity mechanism is a key issue of its social performance.

compared to EOM3		EOM20	CM 3h	CM 0.5h
Variation of consumers' utility (M€/year)	[A]	+148.4	+89.9	159.5
Variation of generation operating cost* (M€/year)	[B]	+41.0	+17.4	52.6
Variation of annualised investment cost (M€/year)	[C]	0	0	0
Variation of social welfare under risk-neutrality (M€/year)	**[A-B-C]**	**+107.4**	**+72.4**	**+106.9**
	EOM3	EOM20	CM 3h	CM 0.5h
Relative standard deviation of CT contribution margins**	211%	306%	94%	33%

* Production cost includes variable costs and annual O&M costs.

** For each simulated year, the relative standard deviation (RSD) of CT annual contribution margins (annual gross revenues minus variable generation costs) is computed over the 11 weather assumptions. Here, the average value of RSD over the 20-year period is shown.

Table 5 – [Case 1] Comparison of social welfare improvement by implementing scarcity pricing (EOM20) or capacity market (CM) (values per year in average) and respective risk levels.

As mentioned above, the SIDES model assumes risk-neutrality of investors. Nevertheless, differences in risk level is a relevant aspect of market design. To estimate risk levels, revenues of CT were analysed for each simulated year. The relative standard deviation[11] (RSD) of the distribution of annual contribution margins on weather scenarios were computed for each year and the average value of the RSD over the 20-year period is given in Table 5. The average RSD is 211% with EOM3 whereas it increases to 306% with EOM20 but decreases to 94% with CM. This risk analysis illustrates the strong effect of CM to reduce level of risk while EOM20 tends to significantly increase it. Consequently, if investors were supposed risk-adverse, the results would change: the level of capacity would certainly decrease with EOM20 compared to the results presented here under the assumption of risk-neutrality.

5.1.3. Bill paid by consumers

In addition to the social welfare evaluation, it is relevant to evaluate the effect of the two reformed market designs (EOM20 and CM) on the consumers' electricity bill compared to the initial design EOM3.

In this calculation, consumers are supposed to have three main components in their electricity bill: a classical energy component, a capacity component if necessary (design CM) and a renewable charge which corresponds to the levy necessary to support wind power development. The energy component corresponds to the weighted average energy price of the spot energy market. When needed, the capacity component refers to the generators' total capacity revenues divided by the total electricity sales. Finally, the levy to finance wind power development is obtained as the difference between the revenue of wind power electricity sold on the spot market and a tariff guaranteed by public authorities. The total amount of subventions to wind power is then divided by the annual energy delivered to consumers. In this analysis, the feed-in tariff is supposed to be set at 80€/MWh for wind power in line with the current level of feed-in tariffs common to a number of European countries.

[11] The relative standard deviation is defined as the ratio between the standard deviation and the mean value.

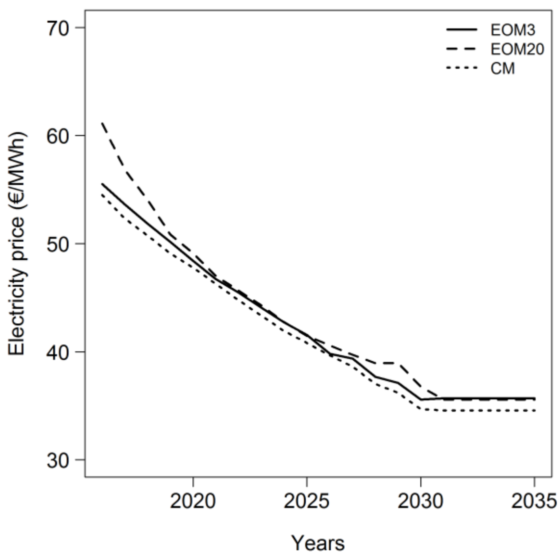

Figure 9 – [Case 1] Evolution of the energy component of the consumers' bill (the weighted average energy price) under the 3 market designs.

Figure 9 presents energy component evolution over time for each market design. Energy prices decrease over the 20 years as a consequence of exogenous wind power development. The price is generally higher with EOM20 as a consequence of much higher price cap. CM provides a lower price than EOM3 because there are less hours during which market price reaches the price cap of € 3,000/MWh (which are also the hours showing loss of load). But, in the case of CM, consumers pay the energy price plus a capacity component. The evolution of capacity price is shown in Figure 10. It shows slight fluctuations which depends on energy revenues of the different plants. The average capacity price is k€ 10.8 /MW-year over the 20 years. On average over the period, this corresponds to an additional capacity component[12] of € 2.1/MWh on the electricity bill.

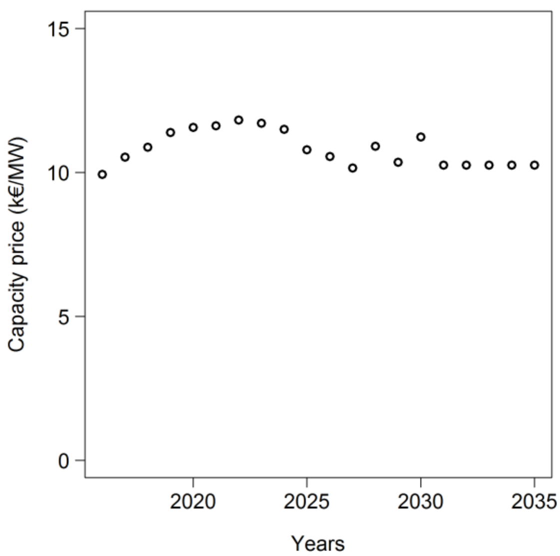

Figure 10 – [Case 1] Evolution of capacity price (in the market design CM).

[12] The capacity component to be added to the electricity bill corresponds to the total amount of capacity revenues of producers divided by the total volume of electricity delivered in a year.

Finally, the average electricity bill for consumers is detailed in Table 6. These results obtained under risk neutrality show that the electricity bill is slightly lower with EOM3 but this is achieved at the expense of more hours of loss of load. Compared to EOM3, electricity bill of household consumers increases by 1.7% with EOM20 and by 2.1% with CM. These increases of electricity bill with EOM20 and CM are limited compared to the social benefit of the improvement of the system's capacity adequacy: respectively M€ 148.4/year and M€ 89.9/year (see Table 5).

	EOM3	EOM20	CM
Energy(€/MWh)	42.4	43.3	41.5
Capacity (€/MWh)	--	--	2.1
Levy to finance wind power (€/MWh)	9.3	9.3	9.2
Total (€/MWh)	**51.7**	**52.6**	**52.8**

Table 6 – [Case 1] Electricity bill for consumer in average over the 20 simulated years

5.2. Case 2 with exogenous closures of some coal and nuclear plants

This second case study aims to analyse how adequacy target is affected when some closures are imposed exogenously, for example for political reasons. Exogenous wind power developed is the same as in the previous case but it is also supposed two "closures shocks": one of 9.8 GW of coal plants (13 units) between 2015 and 2020 and one of 9.8 GW of nuclear plants (7 units) between 2025 and 2030. These two exogenous shocks provoke a need of new conventional capacities besides entries of wind power.

This sub-section details the results for the second case scenario by following the same steps as section 5.1 and also provides elements of comparison between the two cases.

5.2.1. Effectiveness in reaching the adequacy target

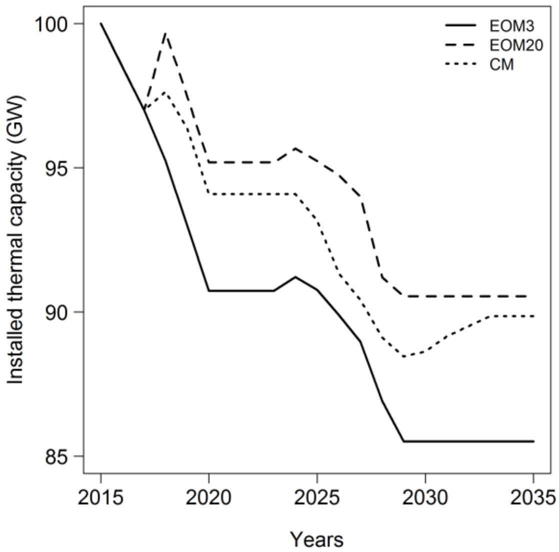

Figure 11 – [Case 2] Evolution of thermal capacity under the 3 market designs.

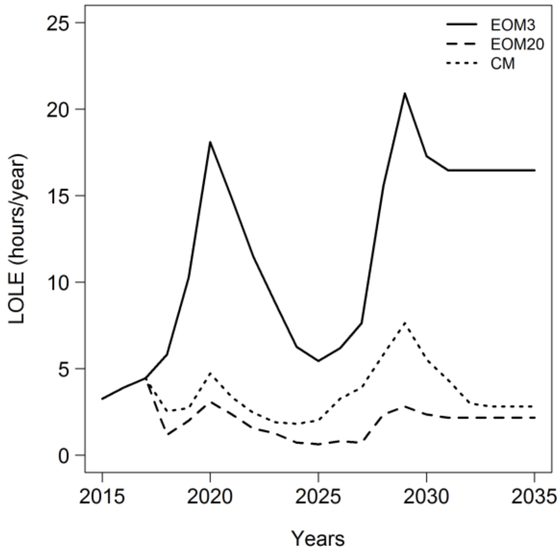

Figure 12 – [Case 2] Evolution of the loss of load expectation (hours/year) under the different market designs.

The three market designs leads to different levels of installed capacity, as shown in Figure 11 which presents nuclear and thermal capacities only. Designs EOM20 and CM provide more capacities than EOM3 thanks to the increase in power plants' revenues allowed by the very high price cap in EOM20 and the addition of capacity revenue in CM.

Market design	EOM3	EOM20	CM
LOLE: average (h/year)	11.96	2.06	3.60
LOLE: last year (h/year)	16.45	2.18	2.82

Table 7 – [Case 2] Loss of load expectation (h/year) under the three market designs.

As a consequence of this increase in physical assets compared to EOM3, the loss of load expectation is logically lower with designs EOM20 and CM, as illustrated in Figure 12 and detailed in Table 7. Results underline that EOM20 and CM are effective to ensure the LOLE target of 3 h/y whereas LOLE reaches an average value of 11.96 h/y under EOM3. Besides unacceptable average level of LOLE with EOM3, there are very large variations of the LOLE with this design. The two sharp increases in LOLE during the period 2015-2020 and 2025-2030 correspond to the exogenous closures of coal and nuclear plants respectively in the two periods. Given the price cap of 3,000 €/MWh, energy prices fail to trigger enough investments by increasing revenues. The decrease during the period 2020-2025 is mainly due to exogenous entries of wind power which improve the system's capacity adequacy because capacities of other technologies remain constant. During the period 2025-2030 when exogenous closures of nuclear plants occur, the effects of these closures on the LOLE are compensate neither by the exogenous wind power entries, nor by some endogenous entries of thermal units (mainly CCGT) that were planned during the former period between 2022 and 2025.

In this case scenario 2 in which new investments are needed, these successive closures exacerbate the failure of EOM3 to guarantee system adequacy. Indeed, in the previous case 1 under EOM3, average value of LOLE remains under 6h/y because the system benefits from over-capacity due to the exogenous development of wind power without any exogenous retirement of other units. As a closure's decision only depends on expected net profits compared to annual O&M costs (investment costs are excluded), this over-capacity remains over the simulation period so that LOLE values obtained in EOM3 in case scenario 1 are significantly lower than ones obtained with EOM3 in case 2.

Market design	Initial mix	EOM3	EOM20	CM
Nuclear (GW)	43.0	33.2	33.2	33.2
Coal (GW)	20.0	11.0	11.0	12.5
CCGT (GW)	19.0	23.3	23.8	24.8
CT (GW)	18.0	18.0	22.6	19.4
WT (GW)	8.1	70.0	70.0	70.0
Total thermal capacity (GW)	**100.0**	**85.5**	**90.6**	**89.9**

Table 8 – [Case 2] Generation mixes (in GW) at the end of simulation for the three market designs.

Concerning the differences in average LOLE related to investment incentives given by the three market designs, they are explained by the differences of evolution in thermal capacities in the case scenario 2. Table 8 details the generation mixes at the end of the simulation (year 2035) for the three different market designs in this case scenario 2. Compared to EOM3, the increase of capacity with EOM20 mainly corresponds to peaking units (CT) while with CM the additional power plants are more technologically various with CCGT, coal and CT capacities. Then, whereas EOM20 and CM provide quite close results on loss of load expectation, results on technological choices are different. However there is a systematic exceedance of the 3h-norm in the EOM20, on the opposite of the CM market design which brings to a fluctuation over and under the 3-hour standard along the simulation period. This difference is explained by the higher incentives to invest in peaking units (CT) with the market design EOM20 than with the design CM, by the profile of hourly revenues during the small number of critical hours compared to the smoothing revenues allowed by the capacity market with the design CM. When the anticipated LOLE is greater than the target of 3h/y, it is clear that all technologies benefit from higher scarcity rents in EOM20 than in the case of CM. According to the different characteristics of the technologies (costs but also construction time and life time), this can result in different choices even with the same initial mix. At the end of the day, the total capacity of coal, CCGT and CT at the end of the 20-year simulation reaches 57.4 GW (with 22.6 GW of CT) with the market design EOM20 and 56.7 GW (with 19.4 GW of CT) with the market design CM.

5.2.2. Comparison of social efficiency of scarcity pricing (EOM20) and capacity mechanism (CM)

The same methodology as in 5.1.2 is applied to estimate social welfare effects of scarcity pricing (EOM20) and capacity mechanism (CM) compared to the energy-only market with price cap (EOM3). The welfare comparison is presented in Table 9. The analysis shows that EOM20 and CM improve the social welfare compared to EOM3.

compared to EOM3		EOM20	CM
Variation of consumers' utility (M€/year)	[A]	+ 471	+ 406
Variation of generation operating cost* (M€/year)	[B]	+ 27	- 90
Variation of annualised investment cost (M€/year)	[C]	+270	+286
Variation of social welfare under risk-neutrality(M€/year)	**[A-B-C]**	**+ 174**	**+ 210**
	EOM3	EOM20	CM
Relative standard deviation of CT contribution margins**	168%	276%	72%

* Production cost includes variable costs and annual O&M costs.

** For each simulated year, the relative standard deviation (RSD) of CT annual contribution margins (annual gross revenues minus variable generation costs) is computed over the 11 weather assumptions. Here, the average value of RSD over the 20-year period is shown.

Table 9 – [Case 2] Comparison of social welfare improvement by implementing scarcity pricing (EOM20) or capacity market (CM) (values per year in average) and respective risk levels, in a situation where new investments by the market are expected.

The consumers' utility logically increases in both reformed designs because the average LOLE is significantly lower with EOM20 and CM than with EOM3. The increase in this consumers' utility is the highest with EOM20 as a consequence of the lowest average LOLE. Average generation costs are surprisingly lower with CM than with EOM3. The reason lies in a difference of technology shares because of different revenues between the three different market designs (especially when the anticipated LOLE is high) which lead to different investment decisions according to the profitability index of each technology. As detailed in Table 8, CM leads to more mid-load units (CCGT and coal) compared to EOM3, resulting in lower variable generation costs, while EOM20 show higher variable costs because it leads to build more peaking units. Here, variation in annualised investment cost is not zero as in the previous case because, as already mentioned, new investments occur to offset exogenous closures. Whereas there are more capacities invested in with EOM20 than with CM, the difference in technological choices (more peaking units with EOM20; more mid-load units in coal and CCGT technologies with CM) results in a lower annualised investment cost with EOM20 than with CM. At the end, the increase in social welfare compared to EOM3 is higher with CM than with EOM20. Note that this is a converse situation vis-à-vis the case scenario 1.

The two case scenarios lead to the same results in terms of risk levels for peaking units. As shown in Table 9, the RSD of CT annual contribution margins increases with EOM20 and decreases with CM compared to EOM3. This confirms that compared to EOM20, CM has a strong advantage in terms of risk reduction for investors.

5.2.3. Bill paid by consumers

Regarding the electricity bill paid by consumers computed with the same method as in section 5.1, the analysis considers separately the energy component, the capacity component and the charge added to finance the overcost of wind power MWhs.

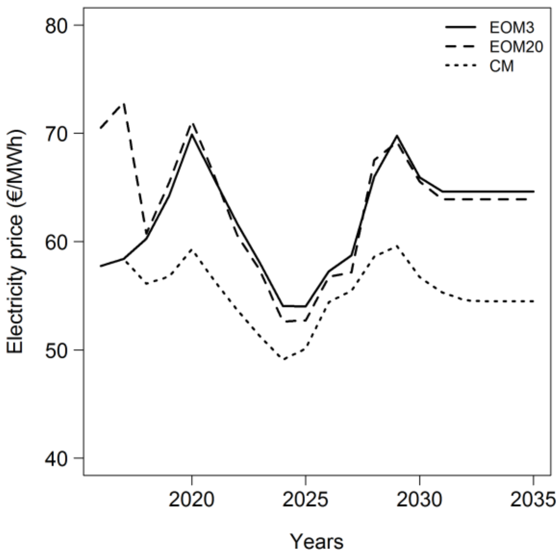

Figure 13 – [Case 2] Evolution of energy component for consumers (weighted average energy prices; capacity component and renewables charge excluded) under the 3 market designs.

The change of energy prices, which are much more variable than in case 1, is related to the exogenous changes in generation mix with the successive sequences of closures of coal and nuclear plants, which imply strong variations in technology shares.

Figure 13 presents the energy component paid by consumers defined as the weighted average value of hourly energy prices. It shows that this energy component is roughly the same with EOM3 and EOM20, except at the beginning of the period when the electricity mix evolves differently depending on the market design.

The addition of a capacity market (design CM) significantly reduces electricity prices on the energy market over the period. This is achieved through changes in generation mix towards less peaking units and more mid-load power plants as highlighted above. But, with market design CM, consumers also have to pay a capacity component (as detailed above).

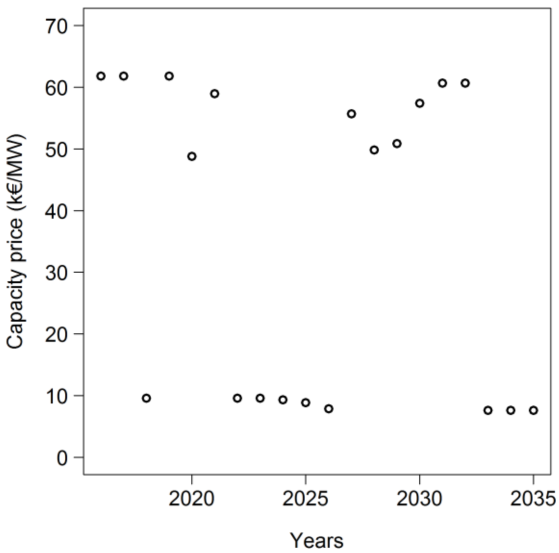

Figure 14 – [Case 2] Evolution of capacity price in the market design CM.

Figure 14 presents the evolution of capacity price over the period, expressed in k€/MW. It shows that capacity price varies between 7.6 and 61.8 k€/MW. Compared to case 1, capacity price reaches higher values and is much more variable. This variability is a consequence of the need of new investments in case 2 while in case 1, the results show no new investment but some endogenous closures of capacities in the three market designs. Expressed in € per MWh consumed, the capacity component in the design CM varies between € 1.5 and € 12.0 /MWh to be added to electricity price, with an average value of € 6.8/MWh on the simulation period.

	EOM3	EOM20	CM
Energy(€/MWh)	62.2	63.3	55.3
Capacity (€/MWh)	--	--	6.8
Levy to finance wind power (€/MWh)	6.5	6.6	6.5
Total (€/MWh)	**68.7**	**69.9**	**68.6**

Table 10 – [Case 2] Electricity bill for consumer in average over the 20 simulated years

Table 10 summarizes the situation for consumers presenting both energy and capacity components of their electricity bill in average over the simulated period 2015-2035. These results obtained under risk neutrality show that the capacity component in the design CM is offset by the decrease in energy prices so that in the end, electricity bill is roughly equal with CM and EOM3. This makes the total of energy and capacity components close to the energy component in EOM3 and EOM20 (€ 62.1/MWh with the design CM compared to € 62.2/MWh and € 63.3/MWh, see Table 10).

On the contrary, electricity bill is slightly higher with EOM20 compared to EOM3 (+1.7%). Hence, in this scenario case, the capacity market (CM) is particularly efficient because it significantly reduces the LOLE compared to EOM3 but without imposing an increase in electricity bill, while with EOM20 the improvement of capacity adequacy is obtained together with an increase of the price paid by consumers of around € 1.2/MWh in average.

5.3. Comparison of market designs and case-scenario policies

- **Comparison of scarcity pricing and capacity market in case scenarios 1 and 2**

In the two cases presented above, the energy-only market with price cap set at € 3,000/MWh (EOM3) clearly fails to maintain an acceptable capacity adequacy even in case of a decrease of the net demand addressed to conventional units (case 1). In each case, the capacity market (CM) is the closest to the LOLE target of 3h/y.

However, in terms of social welfare under risk-neutrality, the two case-scenarios show contradictory results: capacity market is the best option in terms of social welfare in the scenario case 2whereas it depends on the calibration of the capacity market in case 1. Indeed, CM presents an increase in social welfare (210 M€/year) which is higher than with EOM20 (174 M€/year). In case 1, a social welfare increase in the range of 72.9-106.9 M€/year is obtained for CM (depending on its calibration) instead of 107.4 M€/year for EOM20. The fact that CM continues to target 3 hour of loss load per year in case 1 with endogenous closures while this lead to a lower improvement of social welfare than EOM20 sheds light on the difficulty to define an optimal capacity target in case of a decreasing capacity paradigm: this is a question that need to be addressed[13]. The differences between the two cases are due to the highest need of generation investment, given exogenous closures in case 2. CM brings a sequence of more smoothed revenues, which allows a more efficient adaptation of the fleet of generation units than with EOM20.

(in M€/ year in average)	Case scenario 1	Case scenario 2
EOM20	107.4	174.0
CM	[72.4 ; 106.9]*	210.0

* The result depends on the calibration of the capacity market (see section 5.1.2 for details).

Table 11 – Comparison of social welfare improvement of scarcity pricing and capacity mechanism between case scenarios 1 and 2 (in M€/year in average), under risk-neutrality.

This analysis must be completed by an estimation a risk level which is also a key feature of market design. The two case scenarios highlight strong differences in terms of risk level for CT units. Although the SIDES model represents a risk-neutral investor, the simulations outputs were analysed in order to estimate the risk level of CT net revenues. Compared to EOM3, the two cases show that EOM20 increases the risk level for peaking units whereas CM decreases it.

	Case scenario 1	Case scenario 2
EOM3	211%	168%
EOM20	306%	276%
CM	[33% ; 94%]*	72%

* The result depends on the calibration of the capacity market (see section 5.1.2 for details).

Table 12 – Comparison of risk level for CT through the average relative standard deviation of CT annual contribution margin for the three market designs and the two case scenarios.

[13] In case 1, a complementary simulation was conducted with a different definition of the LOLE target of the CM. The LOLE objective of the CM was set to less than the norm of 3h/y because the case tested corresponds to a decrease of the net demand addressed to existing conventional capacities: it was set to the ration between the annual O&M cost of CT and the value of loss load. With this redefined target, the design CM provides a social welfare very closed to the one of EOM20.

- **Comparison of the costs of closures policies inherent to the two case scenarios with different market designs**

The two cases presented above allow the comparison of policies of endogenous closures of plants or political closures to highlight their effects on the consumers' bill. The comparison is made between the case scenario 1 without exogenous closure and the case scenario 2 with exogenous closures. It shows that the total bill paid by consumers in case 2 is higher by 32% on average over the three market designs than the one in case 2. This significant difference is explained by the exogenous closures of some coal and nuclear capacities in case 2, which impose to re-invest in conventional technologies despite the exogenous entry of wind power.

6. CONCLUSIONS

This paper focuses on capacity mechanism in a context of energy transition with demand stagnation, exogenous penetration of variable renewables and possible policies of closures of existing non-renewable plants. The SIDES model using System Dynamics was developed to simulate the evolution of electricity mix over twenty years in a context of mature markets submitted to energy transition policies. This approach represents a risk-neutral investor which makes its decisions of new investment or decommissioning based on anticipated revenues of the different technologies. Two types of conclusion are drawn.

The results obtained under risk-neutrality confirm that the energy-only with price cap (EOM3) is not sufficient to maintain an acceptable level of loss of load expectation (LOLE) because of massive decommissioning in case 1 and because of insufficient new investments in case 2. With EOM3, the LOLE increases to 5.4 h/y and 16.5 h/y in 2035 in case 1 and 2 respectively. On the contrary, the energy-only with scarcity pricing model (EOM20) and the capacity market (CM) significantly enhance the security of supply compared to EOM3 but not in the same magnitude. In case 1, the LOLE reaches 0.7h/y and 2.1 h/y in average over the period with design EOM20 and CM respectively. Similarly, in case 2, the LOLE reaches 2.1 and 3.6 hours per year with design EOM20 and CM respectively. Thus, the capacity market appears to be the best option to internalised the objective of security of supply expressed as a specified number of loss of load expectation (here, set to 3h/y).

In term of cost for consumers, electricity bill is not significantly changed when introducing a capacity market. In case 1, for both EOM20 and CM, the increase in electricity bill is lower than 3% compared to the energy-only market with price cap. In case 2, electricity bill is unaffected by the capacity market compared to the energy-only market with price cap. This is achieved through a decrease in the energy component which outweighs the addition of a capacity component to the electricity bill. Consequently, compared to the enhancement of security of supply, the increasing cost that may occur with the capacity market appears acceptable.

The two case scenarios tested show that compared to a capped energy-only market (EOM3), the social welfare is enhanced with an energy-only market with scarcity pricing (EOM20) or a capped energy-only market plus a capacity mechanism (CM). However, the comparison between the designs EOM20 and CM is dependent on the future scenario simulated. In case 1 with endogenous closures, the LOLE target defined in the CM clearly impacts the resulting social welfare. Indeed, in this case of a decrease of the net demand addressed to conventional units in which no new investments are needed, the LOLE target of the CM should be redefined in order to improve its performance in terms of social welfare. In case 2 when part of the initial generation mix is to be closed during the study period, CM leads to a higher social welfare than the two other designs. The choice of a System Dynamics model that focuses on time evolution allows to highlight the dependency of the results to the future scenario. Static optimization model (even if stochastic) cannot address this question. This underlines the potential of System Dynamics approach to address discussions on market designs.

At last but not least, the analysis of the results indicates that the level of risk for peaking units widely varies from a market design to another. More precisely, in the two case scenarios, the level of risk (measured through the relative standard deviation of CT revenues) is reduced with CM compared to EOM3 while it is significantly increased with EOM20. This element suggests that integrating risk aversion in the modelling is a relevant further work that would allow to better analyse the differences between scarcity pricing and capacity mechanisms. Indeed, as suggested by the analysis on the relative standard deviation of CT contribution margins which shows that the scarcity pricing is much more risky than the capacity market, the effects observed in the simulation could probably be different if risk aversion was taken into account in the investment decisions.

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APPENDIX

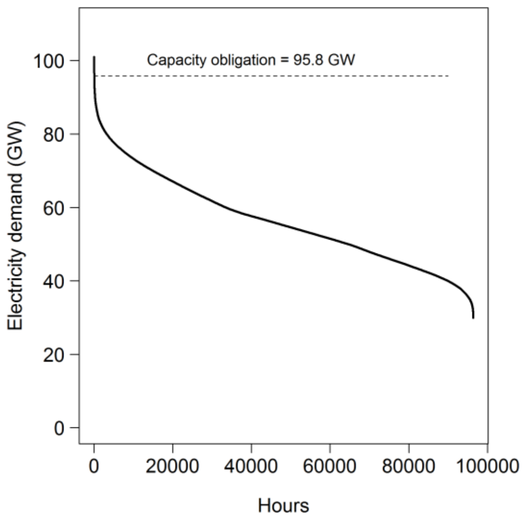

Figure – Electricity load duration curve combining the 11 annual electricity scenarios used in the simulations.

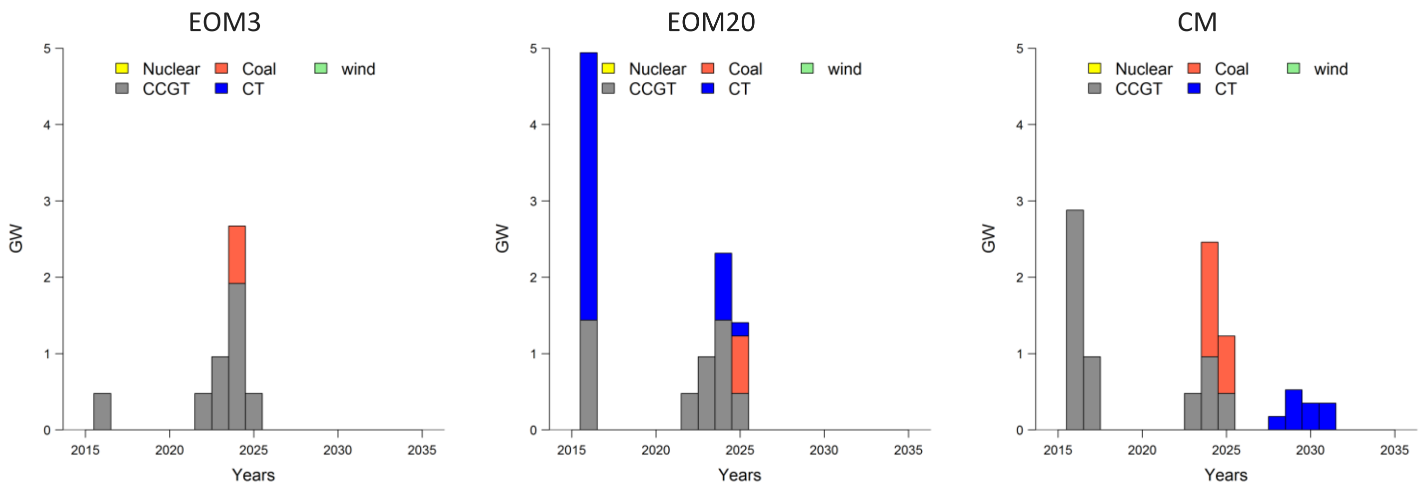

Figure – [Case 2] Investment decisions (in GW) for each simulated year for the three different market designs.