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Capacity adequacy in power markets facing energy transition: A comparison of scarcity pricing and capacity mechanism

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ABSTRACT

This article analyses how a capacity mechanism can address security of supply objectives in a power market undergoing an energy transition that combines energy efficiency efforts to stabilise demand and a rapid increase in the proportion of renewables. To analyse this situation, power markets are simulated over the long term with a System Dynamics model integrating new investment and closure decisions. This last trait is relevant to studying investment in power generation in mature markets undergoing policy shocks. The energy-only market design with a price cap, with and without a capacity mechanism, is compared to scarcity pricing in two investment behaviour scenarios with and without risk aversion. The results show that the three market designs lead to different levels of risk for peaking unit investment and results thus differ according to which risk aversion hypothesis is adopted. Assuming a risk-neutral investor, the results indicate that compared to an energy-only market with a price cap at 3 000 €/MWh, an energy-only market with scarcity pricing and the market design with a capacity mechanism are two efficient options to reach similar levels of load loss. But under the hypothesis of risk aversion, the results highlight the advantage of the capacity mechanism over scarcity pricing.

1. Introduction

In the European Union, an important debate has emerged around the issue of capacity adequacy in power markets. Concerns about short and long term functioning of power markets are reinforced by the significant deployment of variable renewable electricity sources (RES) supported by long term production subsidies (feed-in tariffs, etc.). According to the electricity market textbooks, in the energy-only market design, energy prices are supposed to drive power generation investment choices in order to ensure long-term generation capacity adequacy in parallel with optimal mix development. Essential conditions for ensuring that electricity markets send the right price signals to reach adequate levels of capacity are (i) allowing prices to reflect scarcity during demand peaks and (ii) making sure that investors trust the long-term price signals from the day-ahead market.

However, for many reasons, ranging from system operator rules during critical periods and operational price caps to the political unacceptability of very high prices, power prices rarely reach the theoretical value of lost load (VOLL) in practice, leading to a chronic shortage of revenue for plant operators. This so called "missing money" issue is widely dealt with in the academic literature (Jaffe and Felder, 1996; Hogan, 2005; Joskow and Tirole, 2007; Joskow, 2008, Cramton and Soft, 2008, Fabra et al., 2011). Proponents of the unfettered energy-only market denounce system operators' procedures and the introduction of price caps as the most important barriers to efficient scarcity pricing, which should in fact be an important element in future market design. To those who say that more volatile prices could lead to a risk of political acceptance issues or abuse of market power, the authors reply that these risks can be avoided by hedging against volatility while assuming complete markets. The 2015 European Commission Communication on market design reforms (EC, 2015) develops this position:

> "Allowing wholesale prices to rise when demand peaks or generation is scarce does not necessarily mean that customers are exposed to higher or more volatile prices. Well-functioning longer-term markets will allow suppliers and producers to manage price swings on spot markets – where generators effectively can sell insurance to suppliers and consumers against the impact of price swings and also improve the long term investment signals. […] This is why it is

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critical both to allow for price fluctuations in short-term markets and link them to long-term markets".

Given the specific characteristics of power markets, such hedging products are unlikely to emerge due to the misalignment of investors' and suppliers' interests (Chao et al., 2008). Thus, the focus should be placed on market failures in an energy-only market without a price cap. Whereas price peaks constitute a significant percentage of generators' revenues and are thus an important signal for any decision, the frequency and the level of these price peaks are hardly predictable. Under such conditions, it is difficult to anticipate the level of capacity – including peak capacity – that will emerge spontaneously from stakeholders in the market and therefore to predict the occurrence of load shedding and outage situations. In other words, scarcity prices are highly uncertain and intrinsically volatile and, most importantly, there is no guarantee that adequacy standards set at a political level will be achieved. The missing money problem becomes even worse if investors are risk averse, which they could be given the uncertainty of revenues during peak periods. The inclusion of a capacity mechanism thus contributes to improving the social efficiency of the electricity markets (Oren, 2003; Joskow, 2008, Cramton and Soft, 2008, De Vries and Heijnen, 2008, Cramton et al., 2013).

In an original analysis of market failures in terms of capacity adequacy, Keppler (2014) highlights two imperfections of the energy-only market which justify the transitory adoption of a capacity mechanism: (i) the high social cost of unreliable supply – in particular the cost of unannounced and involuntary supply interruptions, and (ii) the asymmetric incentives for agents to invest in peaking units – as opposed to baseload technologies – in a situation of inelastic demand and fixed-unit-size generation units. More precisely, the discrete nature of the long term supply function due to the nominal power capacity of each technology, combined with the inelasticity of demand, prevents correct anticipation of rents which could cover the fixed costs of new peaking units in the absence of appropriate hedging products to trigger investment decisions. This invites an analysis of the issue of investment in generation with fixed-unit-size representation of plant capacities and a hypothesis of risk-averse behaviour.

The issue of capacity adequacy is reinforced by the growing proportion of RES generation that is directly dependent on weather conditions. Indeed, mature electricity markets, such as those in the EU, combined with very active promotion of renewables offer a radically different economic context for existing generators and investors who were used to investing in a world of demand growth. The appearance of RES supported by out-of-market mechanisms further complicates the situation for at least three reasons: (i) in the short-term, generation by RES tends to alter the pricing on the day-ahead markets and to decrease the revenues of existing and new conventional plants by the so-called "merit order effects" (Sensfuß et al., 2008); (ii) energy prices become more variable hour-by-hour and price risk increases for investors; and (iii) future development of RES capacity and its influence on prices compared to the contribution of RES to overall production is unpredictable (Nicolosi and Fürsch, 2009). In consequence, energy spot prices no longer perform their theoretical long-term coordination function of guaranteeing capacity adequacy of the system in parallel with the development of an optimal mix. This situation affects both new projects for conventional units – because of huge uncertainty over the possibility of recovering their fixed costs – and existing power plants because of the difficulties of recovering operating costs in the short term, as evidenced by the wave of mothballing or closure of recently built gas power plants announced by a number of European electricity producers. At the same time, electricity systems need greater reserve capacities to deal with the increasing proportion of renewables with variable production. Thus, the debate about missing money has evolved to address a new issue: recovery of existing plants' operating costs besides the traditional issue of recovering fixed costs of new units to trigger investment decisions, the latter being amplified by the price variability resulting from the high proportion of variable production. In this respect, the motives for introducing a capacity mechanism are reinforced as a solution to complement the market design so that generation adequacy is preserved and enhanced. Thus, in 2015–2016, several European countries are setting up specific capacity mechanisms and others are considering implementing them, despite the reluctance of the European Commission for which the scarcity pricing approach remains the theoretical benchmark solution to trigger new investments.[1]

To inform this debate, this article focuses on a capacity mechanism which can be a decentralised obligation imposed upon electricity suppliers, similar to the mechanism proposed in France, or a forward capacity market with auctioning by the system operator as in some US mechanisms such as those used by PJM or in New England (Finon and Pignon, 2008). The objective is to analyse how the introduction of this capacity mechanism enhances long-term generation adequacy compared to the energy-only market, with or without a price cap in the case of mature markets characterized by a stable electricity demand and an increasing proportion of RES, as is the case in a number of European member states. To carry out this analysis, changes in the electricity market are simulated over several years with a System Dynamics model. By focusing on change over time, this approach is particularly well-adapted to studying mature markets in which a distinction is made between the economic rationale for retiring existing plants and economic decisions for new investment. Moreover, the model includes both new investment and closure decisions, an originality that is relevant to the study of mature markets prone to RES policy shocks. The second originality of the approach is that it compares scarcity pricing to capacity mechanisms under different hypotheses of investment behaviour in terms of risk aversion.

The simulations underline how investment and retirement decisions are affected under three different market designs: (i) energy-only market with a price cap, (ii) energy-only market with scarcity pricing and (iii) the addition of a capacity mechanism to an energy-only market with a price cap. These three market designs are simulated with two different hypotheses of investor behaviour: risk neutrality and risk aversion. As a consequence of assumptions on electricity demand and renewables development, some thermal electricity generation units are expected to be decommissioned endogenously.

The following Section (2) details the System Dynamics model that was used in the simulations with a focus on the modelling of the capacity market. The case study and data are described in Section 3. Section 4 presents and discusses the results. Finally, Section 5 concludes and highlights policy implications.

2. Specifications of the SIDES model

Traditional power market equilibrium approaches, such as dispatching programming and long-term optimisation, present two major limitations: (i) they do not provide any information about transition phases from one equilibrium state to the next and (ii) they do not indicate whether the real initial electricity system could move towards this equilibrium. On the other hand our approach, based on System Dynamics (SD) modelling, focuses on dynamic changes in electricity systems based on the representation of decision rules and sheds additional light on the functioning of electricity systems. Sterman

[1] The position of the European Commission is hinted at in its Communication on New Energy Market Design (EC, 2015): "Closer integration of markets across national borders and the development of short- and long-term markets with effective price formation – notably reflecting the need for new capacity – should deliver the right investment signals to allow new generation sources to come onto the market and, where overcapacity exists, signals for decommissioning." … "While capacity mechanisms might be warranted under certain circumstances, they may be costly and distort the market. Furthermore, they may contradict the objective of phasing out environmentally harmful subsidies including for fossil fuels."

(2000) provides details of System Dynamics modelling.

SD modelling has been increasingly used to study the electricity sector since the 1990's, and in particular to estimate the benefits of capacity mechanisms. At the beginning, SD models were mainly introduced to analyse investment cycles in electricity generation by focusing on investments in peaking plants (Ford, 1983; Bunn and Larsen, 1992, 1994; Olsina et al., 2006). This approach has then been employed to analyse the impacts of different market designs, ranging from renewable support schemes (Tan et al., 2010; Vogstad, 2005; Ford et al., 2007; Cepeda and Finon, 2013; Fagiani et al., 2013) to capacity mechanisms (Ford, 1999; Hobbs et al., 2007; De Vries and Heijnen, 2008; Hary et al., 2016). More specifically, De Vries and Heijnen (2008) and Assili et al. (2008) consider several types of capacity mechanism in the context of uncertain demand growth. By using a dynamic analysis rather than a static one, they particularly highlight the fact that energy-only markets are prone to investment cycles, but that these cycles are reduced when capacity mechanisms are added. 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. Cepeda and Finon (2013) investigate the effects of a capacity mechanism on the endogenous entry of RES, compared to a scenario of out-of-market entry of RES by production subsidies.

When modelling electricity markets using the SD approach, three main trends can be identified (Teufel et al., 2013): (i) SD models that include other methods, for example genetic algorithms, decision trees or real options, (ii) SD models with a representation of different risks and (iii) SD models for the analysis of new market designs. The simulation framework developed in this article follows these trends completely by including elements of investment decisions and risk aversion theory, together with a representation of long-term demand risks and short-term weather risks, in order to assess the effectiveness of different market designs.

2.1. Overview of the SIDES model

The Simulator of Investment Decisions in the Electricity Sector (SIDES) is an SD model that was developed in order to analyse the long term effects of different market designs.[2] Changes in the generation mix over several years are obtained by endogenous simulation of investment in electricity generation, decommissioning and mothballing decisions on the basis of a set of assumptions about the initial generation mix, structure of the annual demand curve, energy policy and macroeconomic scenarios. The model considers a single representative agent acting as a price taker whose objective is to maximise his profit. This representative agent is assumed to be technology-neutral. He anticipates the future using the assumption of myopic foresight (with a 5-year time horizon). In the case of decisions about new investment, myopic foresight inherently implies that annual revenues would remain the same from the fifth anticipated year to the end of the lifetime of the power plant. Fig. 1 illustrates the functioning of the SIDES model and Table 1 details abbreviations and nomenclature used hereafter. Appendix A provides more details on the SIDES model.

For each year of the simulation, investors' decisions are obtained on the basis of the estimated profitability of various projects for a range of anticipated future patterns. The SIDES model includes decisions both to build new power plants and to decommission existing ones. For the purpose of the mature markets scenario presented in this article, modelling of decommissioning decisions is a crucial point.

The energy spot market is represented on an hourly basis (8760 h per year) and is equal to the variable cost of the plant that clears the market on the basis of the merit-order principle.

The basic elements of power plant operation are considered in the model. In particular, wind power production is represented by using historical data of hourly load factors correlated with the hourly power consumption (data for France available on the RTE website). 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.

The model considers a representative producer-investor and a representative supplier-consumer in a state of 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 to 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 under peak load and at critical hours.

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

2.2. Formalization of investment decisions

Most firms base their investment decisions on economic analysis but have to select some indicators of investment profitability from the large variety proposed in economic textbooks including the well-known net present value, real options or portfolio selection. Some academic surveys have estimated which economic indicators are really used by companies to make their decisions. Among others, Graham and Harvey (2001) and Baker et al. (2011) highlight the fact that net present value remains the most common economic criterion for financial decisions. And in particular, Baker et al. (2011) find that 81% of the firms surveyed never use real options, mainly because of a lack of expertise or knowledge. Based on this observation, the SIDES model computes the net present value of the projects. To deal with 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 the unitary amount of capital to be spent per plant. Thus, 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 the investment cost (IC_χ) of the technology χ:

$$PI_\chi = \frac{NPV_\chi}{IC_\chi} \tag{1}$$

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

- a positive profitability index,
- a positive estimated annual net revenue $ENP_\chi(y_{F,\chi})$ for the first commissioning year $y_{F,\chi}$.

The second condition is added in order to introduce a simple means of time-planning into investment decisions. Among the projects selected as described above, the SIDES model finally determines which project will have the greatest profitability index and will thus be selected by the representative investor. Once a project has been chosen for investment, a recursive loop computes whether other projects are still economically interesting. For a specific simulated year, this recursive loop provides the number of plants using each technology in which investment will be made.

[2] Its basic structure is described in Petitet et al. (2016).

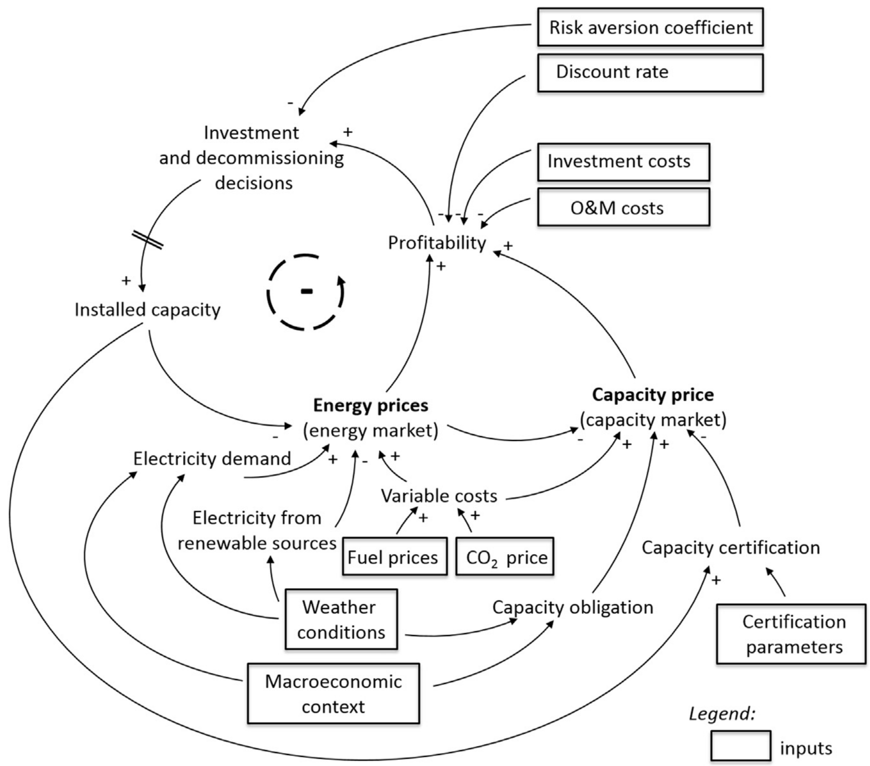

Fig. 1. Causal-loop diagram of the SIDES model, including both an energy market and a capacity market.

2.3. Introducing risk aversion into the modelling of investment decisions

There are several approaches to represent risk aversion in investment decisions. The most common methods are (i) risk-adjusted discount factor, (ii) mean-variance analysis and (iii) concave utility functions. In some cases, models also propose empirical relationships between the value of the project and the level of investment to be made, for example Hobbs et al. (2007).

In the SIDES model, risk aversion is represented through the use of a concave utility function. Instead of making its decision on the average value of the project, as is the case for risk neutrality, the investor makes its decision on the basis of the project's utility function. The utility function employed in the SIDES model corresponds to an exponential function normalized by the mean value, as defined in (2) where x is the net present value in the case of new investment or the net profit in the case of closure, α is the risk aversion coefficient and μ is the mean of the distribution of x. The case where $\alpha = 0$ corresponds to zero risk aversion.

$$U(x) = \begin{cases} -\exp\left(-\frac{\alpha x}{|\mu|}\right) & for\ \alpha > 0 \\ x & for\ \alpha = 0 \end{cases} \tag{2}$$

As shown in Babcock et al. (1993), the calibration of the risk aversion coefficient (α) in a classical constant absolute risk aversion function depends on the gamble size of the variable x. To remove this ambiguity, the variable x is normalized by the mean value of its distribution, thus giving it properties similar to constant relative risk aversion utility functions. This choice was motivated by the fact that the SIDES model uses the same utility function for both new investments and decommissioning decisions for which the values are not of the same magnitude.

The decision concerning new investment or early retirement is made on the certainty equivalent of the distribution. In the case of new investment, the distribution of net present values (NPV) is inferred for the different future scenarios that are anticipated by the single investor. In the case of early closures of existing power plants, the net revenues are obtained for the different future scenarios. In both cases, once the distribution is obtained, the expected utility EU is defined as the average value of the utility function computed on the distribution of revenues or NPV. The certainty equivalent (CE) is then the value that provides the same utility as the expected utility of the distribution as described in (3).

$$U(CE) = EU \tag{3}$$

For concave utility functions – which is the case here – the certainty equivalent is lower than the mean value of the distribution in order to represent risk aversion.

2.4. 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 originality of the SIDES model as detailed in Petitet et al. (2016), which has been improved to consider revenues from a capacity mechanism. In the SIDES model, there are two possible causes for plant closure:

- closure imposed by the technical end-of-life of the power plant,
- early decommissioning if the power plant is no longer profitable.

The first case is obvious and easy to implement. The second case requires the definition of the conditions under which an investor will consider an existing power plant to be unprofitable.[3] As described in Petitet et al. (2016), in the SIDES model, a two-stage economic evaluation is used to simulate decommissioning decisions.

[3] Because of the long pay-back time of the initial investment, the decision to close a power plant cannot be taken simply on the basis of anticipated losses in the following year. Indeed, a power plant can be unprofitable for one year and remain on-line because it is expected to make a profit in the medium term.

Table 1
Abbreviations and nomenclature.

Abbreviations	
CCGT	Combined Cycle Gas Turbines
CM	Capacity Mechanism
CT	Oil-fired Combustion Turbines
EOM	Energy-Only Market
LOLE	Loss Of Load Expectation
NPV	Net Present Value
NSE	Non-Supplied Energy
O & M	Operation and Maintenance
RES	Renewable Electricity Sources
SD	System Dynamics
SIDES	Simulator of Investment Decisions in the Electricity Sector
RSD	Relative Standard Deviation
VOLL	Value of Lost Load
Nomenclature	
α	Level of investors' risk aversion.
χ	Generating technology index. ($1 \le \chi \le N$)
AIC	Annualised investment cost of existing capacities, for a given simulation.
CAP	Price cap of the energy-only market.
$CC_\chi(y)$	Capacity certification of technology χ in year y.
CE	Certainty equivalent (of a given distribution)
$CR_\chi(y)$	Capacity revenue of technology χ in year y.
CU	Consumers' utility related to electricity consumption.
$EP_\chi(h, y)$	Electricity production of power plant χ for hour h of year y. ($0 \le EP_\chi(h, t) \le \kappa_\chi$)
$ENP_\chi(y)$	Estimated net profit of power plant χ for year y.
EU	Expected utility (of a given distribution)
F_χ	Normative capacity factor of technology χ.
GC	Generation cost including fixed and variable costs, for a given simulation.
h	Hour index. ($1 \le h \le 8760$)
IC_χ	Investment cost of power plant χ.
κ_χ	Nominal power capacity of technology χ.
$K_\chi(y)$	Installed capacity of technology χ in year y.
$L(h, y)$	Electricity demand for hour h of year y.
Lf_χ	Load factor of technology χ.
$MT.\,ENP_\chi$	Estimated net profit of power plant χ on the mid run (typically for years y to y+5).
NPV_χ	Net present value of technology χ.
NSE	Volume of non-supplied energy, for a given simulation.
OC_χ	Annual operation and maintenance (O & M) cost of power plant χ.
$p(h, y)$	Market price for hour h of year y.
PI_χ	Profitability index of technology χ.
r	Annual discounted rate.
SW	Social welfare for a given simulation.
T_χ^C	Construction time of power plant χ.
T_χ^L	Lifetime of power plant χ.
U	Utility function used to represent investors' risk aversion.
VC_χ	Fuel and carbon variable cost of power plant χ. ($VC_1 \le VC_2 \le \ldots \le VC_N$)
$VOLL$	Value of lost load, set to 20 000 €/MWh.
y	Year index.
$y_{F,\chi}$	Year in which power plant first commissioned.

The first step consists of 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. More specifically, estimated net profit (*ENP*) for the following year (denoted *y+1*) corresponds to the difference between the annual operating and maintenance (O & M) cost and the annual revenues from the energy and capacity markets, as detailed in Eq. (4).

$$ENP_\chi(y+1) = -OC_\chi + CR_\chi(y+1) + \sum_{h=1}^{8760} (p(h, y+1) - VC_\chi).\ EP_\chi(h, y+1) \tag{4}$$

In Eq. (4), $EP_\chi(h, y + 1)$ is equal to zero for a given hour h if $p(h, y + 1) \le VC_\chi$.

If *ENP* is positive, the power plant is estimated to be 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 medium term. In the latter case (if $ENP < 0$), the second stage consists of estimating profitability over a longer time period than one year.

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

$$MT.\,ENP_\chi = \sum_{z=1}^{5} \frac{ENP_\chi(y+z)}{(1 + r)^z} \tag{5}$$

If both *ENP* and *MT. ENP* are negative, the power plant is profitable neither in the following year nor in the medium term and consequently, the unit should be decommissioned. If *ENP* is negative and *MT. ENP* is positive, the power plant remains in operation because it is expected to recover profitability over the 5-year period.

In a third step, the SIDES model also represents decisions concerning annual mothballing of existing power plants.[4] It is formalized in the following way: if MT.ENP is positive but ENP is negative, then the mothballing option is tested. The economic performance over the next five years is estimated with and without mothballing. If mothballing the power plant improves its economic performance, it is mothballed for one year. Each year, the mothballing option is tested and the power plant remains mothballed if economically relevant.

2.5. Modelling the capacity mechanism

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 their clients' consumption. Here, the model focuses on electricity producers who receive capacity certificates and sell them each year to electricity suppliers on the capacity market. The annual capacity price is obtained from the intersection of the supply and demand curves.

2.5.1. Adequacy target and certification of equipment

2.5.1.1. Capacity adequacy target. To contribute efficiently to security of supply, the adequacy target should reflect the capacity requirements of the system under a normalized set of extreme conditions. Parameters are defined so that the capacity obligation corresponds to peak power demand plus a safety margin during critical hours. In the model, the capacity target is defined so that this level of capacity ensures an average loss-of-load expectation[5] (LOLE) of 3 h per year for the weather scenarios considered.

2.5.1.2. 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 using the following equation:

[4] The model does not consider mothballing periods of less than a year.

[5] The loss of load expectation (LOLE) corresponds to the number of hours during which the installed generating capacity is not sufficient to meet the electricity demand.

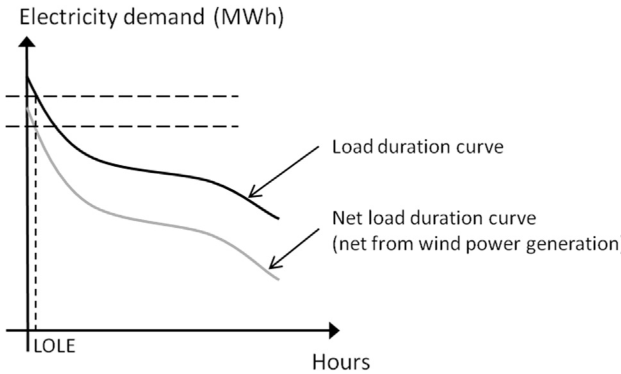

Fig. 2. Effect of wind power on net demand obligation (K1 and K2) from a load duration curve point of view (illustrative figure).

$$CC_{\chi}(y) = F_{\chi} \cdot K_{\chi}(y) \tag{6}$$

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.

2.5.1.3. Certification of variable sources. The case of renewables is different. By their nature, these technologies cannot be dispatched, so 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 the "capacity credit" of renewables. This capacity credit depends on the relative proportion of variable renewables in the system.

In the SIDES model, the capacity factor of wind power is estimated each year depending on the annual load duration curve and the contribution made by wind energy production. Fig. 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 represent the capacity obligation[6] for the gross load duration curve and the net load duration curve respectively. 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 follows:

$$F_{wind} = \frac{K1 - K2}{Installed\ wind\ capacity} \tag{7}$$

This approach has been 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, Fig. 3 presents the capacity factor[7] 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.

2.5.2. Capacity pricing

On the capacity market, producers sell their capacity certificates either (i) to electricity suppliers that are assigned to the capacity obligation in the case of decentralised obligation or (ii) to the central buyer in the case of a forward capacity mechanism. The supply curve is

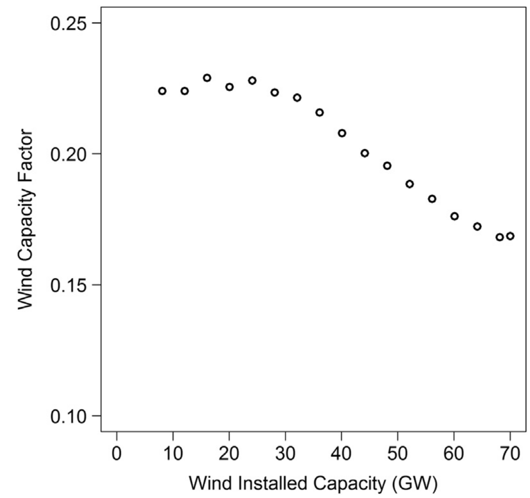

Fig. 3. Wind capacity factor as a function of installed capacity (own calculation).

obtained endogenously on the basis of capacity price bids as detailed below. The total volume which is bid corresponds to the capacity certificates associated with each technology. To simplify the modelling approach, capacity demand is considered as inelastic and its level is aligned with the capacity adequacy target. The clearing capacity price is then determined by the intersection of the supply and demand curves as illustrated in Fig. 4.

Theoretically, the price offered by a producer on the capacity market corresponds to his additional cost (which is detailed below) to guarantee the existence and the availability of the power plant during the delivery year. This price should theoretically be defined in a context of pure and perfect competition, which incites competitors to offer the lowest capacity price needed to guarantee that plants will be available during critical hours. As power plants remain on-line for several years, generators could define their capacity bids for a multi-year sequence. But in order to simplify the model, the SIDES model supposes that capacity bids are formalized on a one-year basis whereas investment decisions are made on the basis of predictions over five years.

The reference to a mature market with the exogenous entry of renewables requires that the missing money problem should distinguish between existing and new power plants. Indeed, in the context of a decrease in the net demand addressed to conventional technologies, a capacity mechanism is more likely to delay the closing of existing plants rather than trigger new investments, on the assumption that existing plants have the same operating costs as new ones. The underlying economic dilemma is very different for existing plants and new ones. For an existing power plant, the dilemma is to choose between shutting down the power plant, mothballing it or remaining in operation based on the risk of not covering its annual O & M cost, while the investment cost should be considered as a sunk cost to be paid whatever the situation. For new power plants, the dilemma is to decide whether to invest or not, according to whether the total costs – including investment costs – can be recovered.

It would thus be useful to make the distinction between the missing money for triggering investment decisions and the missing money for avoiding the early retirement of existing plants. In this respect, two types of missing money can be defined[8]: (i) "long-term missing money" which refers to the lack of revenue to cover annual fixed costs including both annual O & M cost and the annualised value of the investment cost and (ii) "short-term missing money" which corresponds to the lack of revenue to cover annual O & M cost only.

[6] More specifically, K1 and K2 correspond to the capacity required to ensure a mean LOLE of 3h/y (or 0.5h/y in the case of CM0.5) with respect to the gross and the net load duration curves respectively.

[7] Overall, wind power's capacity factor decreases with installed wind capacity. However, it can be non-monotonic, especially for low installed wind capacity depending on production from wind turbines during peak hours and depending on the way hours are reordered.

[8] This distinction is never made in the literature about capacity mechanisms and their social efficiency because (net) demand is generally supposed to grow.

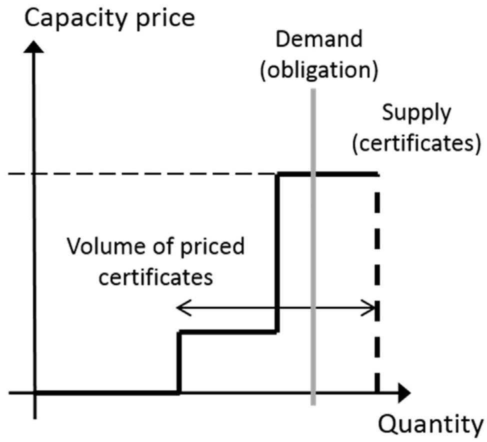

Fig. 4. Functioning of the capacity market.

The supply curve representing aggregated producers' bids on the capacity market therefore leads to a three-zone curve of capacity certificate supply: (i) one zone corresponding to renewables offering their certificates at zero price, (ii) one zone with bid prices corresponding to the lack of revenues compared to O & M fixed costs per MW for existing dispatchable plants and (iii) one zone with bid prices corresponding to the lack of revenues compared to annualised fixed cost[9] per MW for new dispatchable projects.

3. Definition of the three market design cases

This section details the different market designs and the energy transition scenario considered in the simulations. For the sake of clarity, it is important to stress that assumptions on electricity demand and wind power development imply that net electricity demand[10] to be supplied by thermal units decreases over time. Decommissioning decisions are completely endogenous under the effect of exogenous entry of renewables which jeopardizes the economic profitability of existing power plants. The goal is to show the differences in terms of social efficiency between market designs.

3.1. Definition of the three market designs

Three market designs are tested for different levels of risk aversion. 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 is the case for the EpexSpot market in north-west Europe. The second ("EOM20″) is the theoretical energy-only market with scarcity pricing. In this case, the price reaches the social value of loss of load if electricity generation is insufficient to meet total electricity demand. In the simulations, this value of loss of load is estimated to be20 000 €/MWh. The third market design (CM) tested in the simulations corresponds to the addition of a capacity mechanism (as detailed in Section 2). The case study presented in this article allows us to re-examine the definition of the capacity target in a capacity mechanism. To this end, simulations are conducted for two different targets expressed as the LOLE in mean hours per year, as detailed in Table 2. The first one ("CM3″) corresponds to a LOLE of 3 h/y as is the norm in France. The second ("CM0.5″) corresponds to a target of 0.5 h/y applied to a decreasing net demand as 0.5 is the ratio between (i) the annual O & M cost of peaking plants (10 000 € per MW per year) and (ii) the VOLL (20 000 €/MWh).

Table 2
Presentation of the three market designs.

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 (CM3 or CM0.5)

3.2. Data on characteristics of technologies, costs and demand forecasts

3.2.1. Power plant 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). The technical and cost assumptions 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[11] according to the assumptions for the energy transition that we have considered.

Demand response programmes could be an element of the supply resources in long-term simulation modelling but they are not considered here in order to limit the complexity of the model. However, in order to conform with the energy transition policy which is the background of our scenario, the annual electricity demand and the peak load demand remain constant over the 20-year period despite the context of economic growth, which means that this policy includes a component of energy efficiency measures that affect electricity consumption by demand-side management. Incidentally, this also means that we do not explicitly consider price elasticity of the load demand for the same reasons of simplification.

3.2.2. Initial generation mix, exogenous entry of wind power and exogenous retirements

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

The total capacity of the initial generation mix is defined in order to conform to the 3 h/year loss of load expectation. These 3 h of lost load correspond to the standard for LOLE which is the average value to be reached for the weather scenarios. It is noteworthy that this LOLE norm of 3 h per year should theoretically be congruent with the level of the VOLL[12] and the annualised fixed cost of the marginal peaking plant to be installed to reach this level of security of supply, as shown in the theory of optimal peak pricing (Boiteux, 1949). So, in theory, the loss of load probability multiplied by the VOLL should be equal to the annualised fixed cost of the peaking unit. Nevertheless, two additional remarks can be made. First, power plants typically have a capacity of several hundred MW which implies that the exact LOLE norm is very unlikely to be reached even in simulations if the model reflects this characteristic of substantial, fixed unit size for power plants. Second, this theory is valid in a context of load growth but should be re-

[9] Annual fixed cost is the sum of the annual O & M cost and the annual amortization of the investment cost.

[10] Net electricity demand is defined as real electricity demand (from consumers) minus electricity produced by renewable electricity sources (here, wind power).

[11] This exogenous representation of wind power development explains the fact that no precise cost data are needed for wind power. Moreover, the results presented in this article do not require the social cost of wind power development to be defined. Indeed, we show relative values between simulations (characterized by different market architectures) in which the exogenous development of wind power is assumed to be identical.

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

Table 3
Economic and technical parameters of technologies.

	Combustion turbine (CT)	Combine cycle gas turbine (CCGT)	Coal plant (Coal)	Nuclear plant (Nuclear)
Investment cost (k€ per MW)	500	800	1 400	3 910
Annual O & M cost (k€ per MW per year)	10	20	30	75
Annualised fixed cost (k€ per MW per 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 assumed 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).

examined in the case of a decrease in the net load. Indeed, an economic decision relating to early retirement refers to the comparison between the anticipated net revenue and the annual O & M cost of the power plant. Because O & M costs are significantly lower than annualised fixed costs, the LOLE with EOM20 is theoretically lower than the LOLE norm of 3 h/per year in the context of endogenous closures due to a decrease in the net load.

In this case study, it is supposed that investment in on-shore wind power results from specific support mechanisms. Indeed, as pointed out in Petitet et al. (2016), market-based investments in wind power are unlikely to occur unless the carbon price reaches a very high value. In this case study, on-shore wind power capacity thus varies exogenously from 8 GW to 70 GW, as illustrated in Fig. 5. In terms of proportion of total energy production, it represents 3.2% in 2015 and 27.2% at the end of the simulation.

3.2.3. Electricity demand

In order to reach decisions, the single representative investor 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 this, it is assumed that changes in total electricity demand are perfectly anticipated by the representative investor while maintaining some uncertainty about meteorological conditions represented by a unique distribution of load profiles and correlated wind power production. In this case study, the simulation is conducted with a constant electricity demand over the period due to restricted electricity demand growth together with energy efficiency measures.

The sensitivity of electricity demand and wind power generation to weather is taken into account through 11 representative weather scenarios of correlated load demand and wind power generation defined on an hourly basis, corresponding to the situation in France from 2003 to 2013 (according to open-source data available on RTE's website). Based on these data, the capacity obligation to meet a mean adequacy requirement of 3 h/year loss of load is 95.8 GW.

4. Results and discussion: comparison of the performances of three market designs with and without risk aversion

This section presents the results of simulations carried out with the SIDES model for the three market designs. It details the changes in 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. The results are presented first using the assumption that investors are risk neutral and then the analysis is conducted for different levels of risk aversion.

4.1. Detailed analysis of the risk-neutral case

4.1.1. Effectiveness in reaching the adequacy target

In the three market designs, some thermal generation capacities are endogenously closed by the representative investor due to the combination of demand stagnation and exogenous wind power entry. The three market designs tested in this risk-neutral case lead to different levels of installed capacity resulting from different decommissioning paths of thermal units, plotted in Fig. 6.

Compared to the energy-only market with a price cap at 3 000 €/MWh (EOM3), an additional capacity of respectively 4 GW and

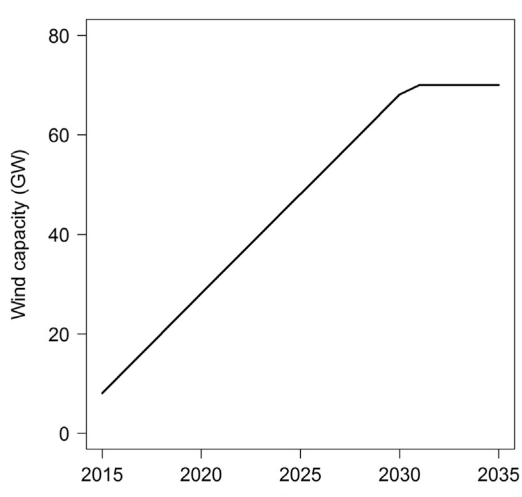

Fig. 5. Exogenous entry of wind capacity.

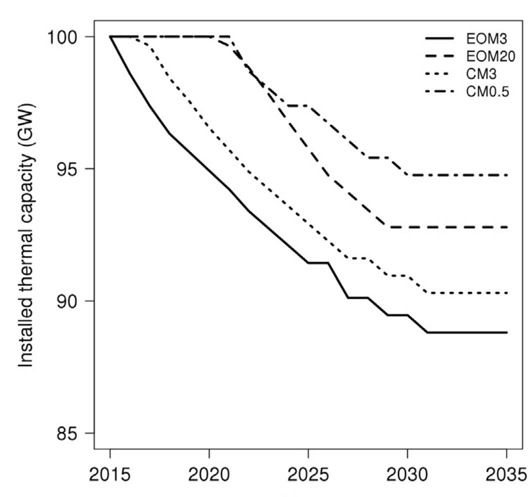

Fig. 6. [$\alpha = 0$] Changes in thermal capacity under the different market designs.

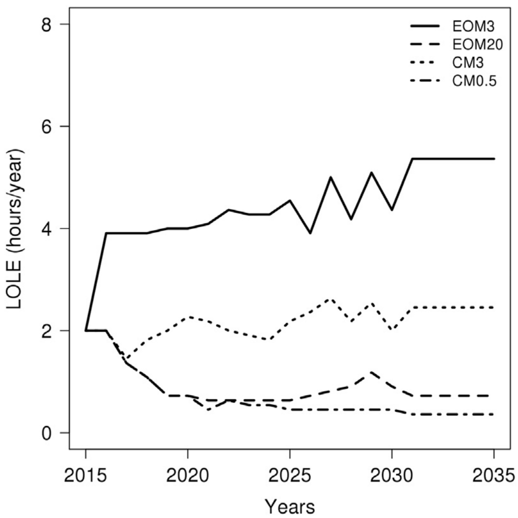

Fig. 7. [$\alpha = 0$] Changes in the LOLE (hours/year) under the different market designs.

1.5 GW remains available at the end of the simulation with scarcity pricing (EOM20) and with a capacity market (CM3). In the results, it appears that some CT and CCGT power plants are closed, while installed nuclear and coal capacities remain unaffected. The fact that 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 to be higher than those of coal and, a fortiori, nuclear plants.

To assess the ability of the three market designs to guarantee security of supply, the average LOLE was estimated for the 11 weather scenarios used in the simulations. Changes in LOLE over the simulated period are presented in Fig. 7 and Table 4 for each market design under risk-neutrality. The results underline the fact that EOM3 clearly fails to guarantee the objective of 3 h of lost load per year even though the system benefits from an inherited over-capacity in this context of decreasing net demand addressed to conventional units. At the end of the simulation, LOLE is 5.4 h/y with EOM3, 0.7 h/y with EOM20 and 2.5 h/y with CM3. EOM20 and CM3 meet the LOLE objective of 3 h per year, even exceeding it. Indeed, in the case of a decrease in the net demand addressed to thermal units, existing units will be decommissioned only if they fail to recover their annual O & M cost from the energy market both in the next year and the five following years. These results highlight the fact that, of the three simulated designs, the capacity market (CM3) succeeds best in reaching the objective of 3 h/y or coming close to it. Of course, the failure of EOM3 in terms of the LOLE target of 3 h/y may be expected because this design gives no value to security of supply. For its part, the CM3 design with a capacity mechanism is the only one to internalise the objective of electricity supply, expressed as a LOLE target, whatever the situation. However, it should be noted that the target of 3 h/y is not strictly respected in these simulations with a CM for two reasons: the representation of power plants of typical sizes as discrete units, making it difficult to reach the exact adequacy target, and the exogenous entry of wind power that 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 in the net load, this profit has to be compared to the annual O & M cost of the combustion turbine which is 10 000 € per MW per year. In this context, the ratio between this annual O & M cost and the VOLL explains that the LOLE in EOM20 is theoretically expected to be in the range of 0.5–1 h per year, which is lower than the LOLE norm of 3 h/y. Finally, this comparison of annual O & M costs (which are significantly different from annualised fixed costs) and the VOLL raises a question: in a decreasing capacity paradigm, should the LOLE target of 3 h/y be reconsidered? To this end, simulations were also conducted for a CM with a target of 0.5 h/y: the results in terms of LOLE are very close to those of EOM20 (see Table 4).

Table 4
[$\alpha = 0$] Loss of load expectation (h/year) under the three market designs.

Market design	EOM3	EOM20	CM3	CM0.5
LOLE: average (h/year)	4.4	0.9	2.2	0.7
LOLE: last year (h/year)	5.4	0.7	2.5	0.4

4.1.2. Comparison of the social efficiency of scarcity pricing (EOM20) and capacity mechanisms (CM)

This sub-section considers the difference in the respective increases of social welfare between the different market designs compared to the reference design EOM3 under risk-neutrality. Social welfare (SW) is defined as the consumers' utility related to electricity consumption (CU) (or in other words, their surplus) from which are subtracted the fixed and variable operating costs of electricity generators (GC) and the annualised investment cost of existing capacities (AIC):

$$SW = CU - GC - AIC \tag{8}$$

The variation of social welfare with respect to EOM3 is then defined as follows:

$$\Delta SW(designX) = SW(designX) - SW(EOM3) \tag{9}$$

The variation in generation operating costs (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 annualised investment costs of power plants. The variation in the consumers' utility[13] (ΔCU) is defined as the difference in 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 lost 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:

$$\Delta CU(designX) = -(NSE(designX) - NSE(EOM3)) * VOLL \tag{10}$$

The increases in social welfare in the reformed market designs compared to EOM3 are presented in Table 5. The capacity market with the adequacy target of 3 h/y (CM3) provides a higher social welfare than EOM3 by 69 M€/year on average over the period. This is less than EOM20 or CM0.5 which show an increase of 102 M€/year on average compared to EOM3. 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 3 h/y. In fact, there is a contradictory situation shown here: CM3 is clearly an effective option to reach the targeted LOLE of 3 h/y but it does not lead to optimum social welfare. This result is a direct consequence of the difference between the adequacy target assigned to the CM3 and the "optimal" adequacy target in this case of decreasing net demand. This confirms that the optimal capacity adequacy target in terms of the LOLE target should be re-examined in the context of an energy transition. The new calibration of the capacity market with a target of 0.5 h/y (CM0.5) leads to increased social welfare compared to EOM3 with a value similar to that obtained with EOM20. Thus, defining the capacity target of a capacity mechanism is a key criterion of its social performance and may

[13] In the model, electricity demand is assumed to be inelastic. In that case, additional assumptions can be required to accurately define the surplus that consumers obtain from the electricity consumption. For this reason, we prefer to provide changes in social welfare or consumers' utility rather than absolute values. Given the definition of ΔCU, the underlying assumption is that the electricity demand is capped at the VOLL.

Table 5
[$\alpha = 0$] Comparison of social welfare improvement by implementing scarcity pricing (EOM20) or capacity market (CM) (values per year on average over the simulation period) and respective risk levels.

compared to EOM3		EOM20	CM3	CM0.5
Variation of consumers' utility (M€/year)	[A]	+141	+86	+152
Variation of generation operating cost* (M €/year)	[B]	+39	+17	+50
Variation of annualised investment cost (M €/year)	[C]	0	0	0
Variation of social welfare under risk-neutrality (M€/year)	[A-B-C]	+102	+69	+102

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

depend on the characteristics of power systems.

The results presented in this section assume risk-neutrality of investors. Nevertheless, allowing for differences in risk level is a relevant aspect of market design. In particular, as pointed out in the literature on missing money, peaking plants can face significant risks because a large share of their energy revenue depends on critical hours with high prices. To estimate risk levels, CT revenues were analysed for each simulated year by computing the relative standard deviation (RSD) of the annual contribution margins.[14] The average RSD of CT plants is 211% with EOM3, whereas it increases to 306% with EOM20 but decreases to 94% with CM3 and 33% with CM0.5. This risk analysis shows that the level of risk is very different from a market design to another. In particular, compared to the benchmark EOM3, EOM20 implies a higher level of risk, whereas the two CM designs imply lower levels of risk. Consequently, the results are expected to change if investors are assumed to be risk-averse.

4.2. Effects of risk aversion

4.2.1. Effects of risk aversion in an energy-only market

When risk aversion increases, the generation mix is affected both in terms of total capacity and in the contribution of each technology. This section presents the results for the energy-only market with a price cap set at 3 000 €/MWh (design EOM3).

As illustrated in Fig. 8, the total thermal capacity decreases over time as a consequence of stable electricity demand and exogenous entry of wind power. The level of endogenous retirement of thermal plants is clearly affected by the coefficient of risk aversion defined in the exponential utility function. In the case of risk neutrality ($\alpha = 0$), 11.2 GW of thermal plants are closed. In the case of high risk aversion ($\alpha = 3$), the capacity adequacy of the system is significantly worsened and 12.7 GW are decommissioned.

The endogenous closures observed in these simulations with an energy-only market with a price cap at 3 000 €/MWh concern combined cycle gas turbines (CCGT) and oil-fired combustion turbines (CT) while nuclear and coal capacities remain constant over the 20-year period. In the case of risk neutrality ($\alpha = 0$), 3.8 GW of CCGT and 7.4 GW of CT are closed. In case of high risk aversion ($\alpha = 3$), 4.8 GW of CCGT and 7.9 GW of CT are closed.

As a consequence of these differences in the power-generation mix, capacity adequacy differs according to the level of risk aversion. To evaluate capacity adequacy, the average LOLE is computed for the 11 weather scenarios of the year being considered. With EOM3, the results show that the LOLE clearly increases when the level of risk aversion increases, from an average of 4.4 h/y over the 20 years (5.4 h/y for the last simulated year) with no risk aversion to an average of 13.3 h/y

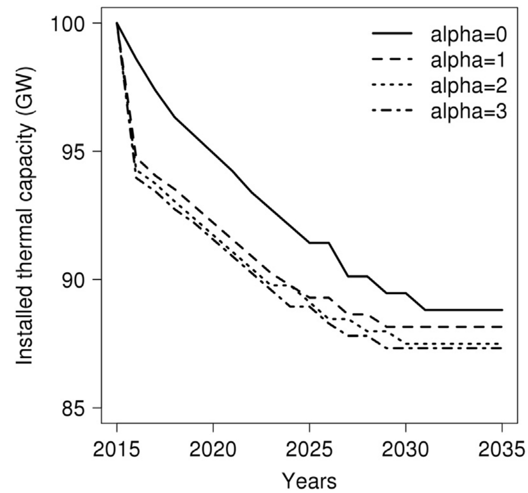

Fig. 8. Changes in total thermal capacity under design EOM3 for different levels of risk aversion.

(10.3 h/y for the last simulated year) with the highest risk aversion tested here ($\alpha = 3$).

Therefore, it is clear that the energy-only market with a price cap set at 3 000 €/MWh fails to maintain an acceptable level of capacity adequacy even in the case of an energy transition characterized by stable electricity consumption and significant entry of renewables.

4.2.2. Comparison of market designs

This subsection presents the simulations conducted for the three market designs presented in Table 2 and for different levels of risk aversion.

Globally, the results obtained for the EOM20 design follow the same pattern as those already presented for EOM3: when risk aversion increases, the installed capacity is reduced and the capacity adequacy evaluated by the LOLE is worse. The values of LOLE obtained for each simulation (on average over the period and at the end of the simulation) are presented in Table 6. As in the EOM3 design, the LOLE obtained with EOM20 is significantly sensitive to the level of risk aversion: it increases from 0.9 h/y on average under risk neutrality to 3.6 h/y with the highest level of risk aversion ($\alpha = 3$). On the contrary, the LOLE remains globally the same with CM3 or CM0.5 whatever the level of risk aversion.

These results show that the capacity mechanism (CM3 or CM0.5) is significantly less sensitive to the level of risk aversion than EOM3 and EOM20. This is explained by the fact that this capacity mechanism is quantity-based and allows producers to receive a capacity remuneration that suits their risk aversion because the clearing price depends on their bids. On the contrary, with an energy-only market, whatever the price cap, the remuneration of the power plants depends only on electricity demand and the variable costs of the generation units: revenues are thus not dependent on the level of risk aversion.

A comparison of social welfare has been conducted using the same methodology as that presented above. The analysis of social welfare is presented in Fig. 9 and detailed in Table 7. It shows that the social welfare of EOM3 significantly decreases when risk aversion increases. The reformed market EOM20 and CM improve the social welfare compared to EOM3 but their sensitivity to the risk aversion coefficient is not the same: CM is clearly less sensitive to the level of risk aversion. In that sense, the social welfare obtained with CM is only weakly dependent on the assumption concerning the level of risk aversion while this assumption significantly affects the results of the two other designs EOM3 and EOM20.

Finally, this case study highlights the fact that taking risk aversion into account can significantly change the conclusion of a market design comparison. The results presented here clearly show that CM is far less

[14] The RSD is defined as the ratio between the standard deviation and the mean value of the considered distribution. Specifically, for each year of the simulation, the annual contribution margin (defined as annual gross revenues minus variable generation costs) is computed for each weather scenario, and then the RSD is computed.

Table 6
Loss of load expectation (hours/year) on average over the simulation and at the end of the simulation, for the three market designs EOM3, EOM20 and CM, with different levels of risk aversion.

		EOM3	EOM20	CM3	CM0.5
$\alpha = 0$	LOLE average	4.4	0.9	2.2	0.7
	LOLE last year	5.4	0.7	2.5	0.4
$\alpha = 1$	LOLE average	10.0	2.4	2.6	0.9
	LOLE last year	7.1	1.6	2.7	0.5
$\alpha = 2$	LOLE average	12.1	3.3	2.5	0.8
	LOLE last year	9.6	2.3	2.8	0.5
$\alpha = 3$	LOLE average	13.3	3.6	2.4	0.7
	LOLE last year	10.3	2.3	2.4	0.5

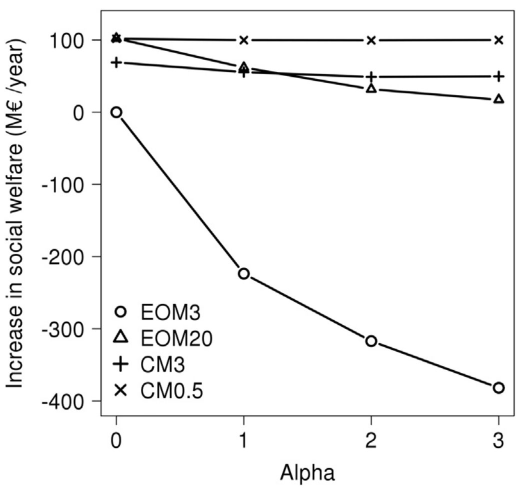

Fig. 9. Variation in social welfare compared to the design EOM3 with no risk aversion ($\alpha = 0$).

influenced by the level of risk aversion than energy-only designs (EOM3 or EOM20).

5. Conclusion and policy implications

This paper focuses on the capacity mechanism in a context of energy transition with demand stagnation, exogenous penetration of renewables having variable production levels and possible retirement of existing non-renewable plants. The SIDES model, which uses System Dynamics, has been developed to simulate investment and retirement decisions resulting in changes in the electricity mix over several decades. More precisely, the model simulates an investor making its decisions on the basis of anticipated revenues for different technologies. The results are analysed first for a risk neutral investor and then for different levels of risk aversion.

Three types of conclusion are drawn from the risk neutral approach. First, the energy-only design with a price cap (EOM3) is not sufficient to maintain an acceptable level of LOLE because of massive decommissioning. With EOM3, the LOLE reaches 4.4 h/y in 2035 on average over the period studied. The energy-only with scarcity pricing model (EOM20) and the capacity market (CM3 or CM0.5) significantly enhance the security of supply compared to EOM3 but not by the same magnitude. Although the capacity market appears to be the best option to internalise the objective of security of supply expressed as a specified loss of load expectation (here, set to 3 h/y or 0.5 h/y), its

Table 7
Variation of social welfare (in M€/year on average over the period) compared to the reference risk-neutral case EOM3.

	EOM3	EOM20	CM3	CM0.5
α=0	0.0	102.3	69.0	101.8
α=1	−223.7	61.9	55.5	99.9
α=2	−317.2	31.9	48.9	99.6
α=3	−381.8	17.2	49.7	100.0

performance clearly depends on the definition of the capacity target. In particular, the CM design with a LOLE target of 0.5 h/y leads to the same performance as the scarcity pricing design in terms of capacity adequacy. Second, the tests show that, compared to a capped energy-only market (EOM3), social welfare is enhanced with an energy-only market with scarcity pricing (EOM20) or with a capped energy-only market plus a capacity mechanism (CM). In this case of decrease in the net demand addressed to conventional units in which no new investments are needed, the CM with an adapted LOLE target is as efficient as a scarcity pricing design. Last but not least, the analysis indicates that the level of risk for peaking units widely varies from one market design to another. More precisely, the level of risk measured through the relative standard deviation of CT revenues is reduced with CM3 or CM0.5 compared to EOM3 while it is significantly increased with EOM20. In other words, scarcity pricing creates a riskier environment for investors than the capacity market. So, when risk aversion is taken into account in investment decisions, the effects of the different market designs observed in the simulation are different.

The case study with risk aversion highlights how the latter affects the hierarchy of market designs and decisions about the early retirement of conventional plants. First, the results show that energy-only markets with or without a price cap (scarcity pricing) are very sensitive to the level of risk aversion. Second, when comparing different market designs in terms of social efficiency, the relative ranking is affected by the level of risk aversion. Thus, it is important to consider risk aversion when policy makers have to decide between scarcity pricing and capacity mechanisms. Third, a capacity market that is well designed, in particular in terms of the definition of the capacity target, appears to be the best choice whatever the level of risk aversion ("least regret" choice). This market design is not really sensitive to the level of risk aversion either in terms of loss of load expectation or social welfare. This is a strong advantage for policy makers as its effectiveness would remain the same whatever the degree of risk aversion of the investors.

Finally, it is worth noting that results presented in this article may depend on economic and policy scenarios being tested, and on technologies' parameters. First, decommissioning decisions observed in this scenario inherently depend on O & M and variable costs' assumptions, but they do not depend on investment costs. Indeed, decommissioning process are based on the comparison between O & M costs and revenues which are influenced by variable costs. Rather, in a context of significant net demand growth, new investments would occur, and thus results would also depend on investment cost' assumptions compared to market revenues. However, comparing the three market designs in a scenario of net demand growth would lead to the same conclusion. Second, as the model already includes the representation of variable RES with short-term uncertainties, it could be refined to replicate the detailed functioning of real electricity systems with large share of RES. Specifically, depending on the considered system, more accurate results would be obtained by including additional characteristics of each technology (for example start-up and ramping constraints) together with short-term market design options (in order to obtain new revenue sources for flexible units), and by including a wider variety of technologies being considered.

Disclaimer

The views and opinions expressed in this article are those of the authors and do not necessarily reflect neither those of the partners of the CEEM, nor the official policy or position of RTE (Réseau de Transport d'Electricité).

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Appendix A. Details of the SIDES model

See Appendix Figs. A-1 and A-2.

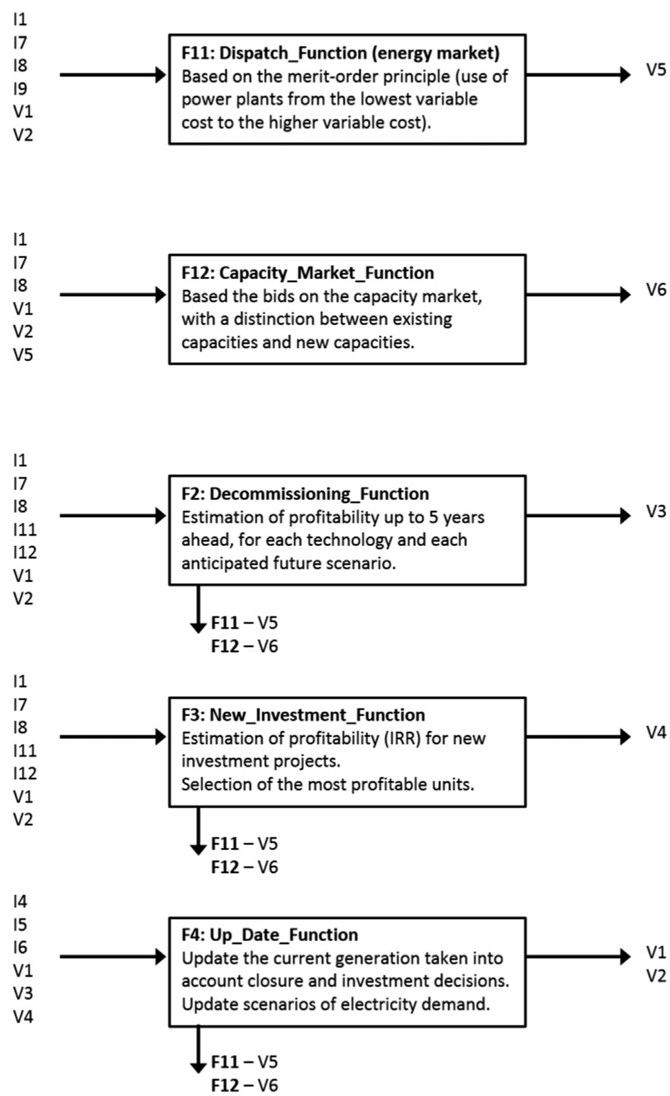

Fig. A-1. Description of the main functions.

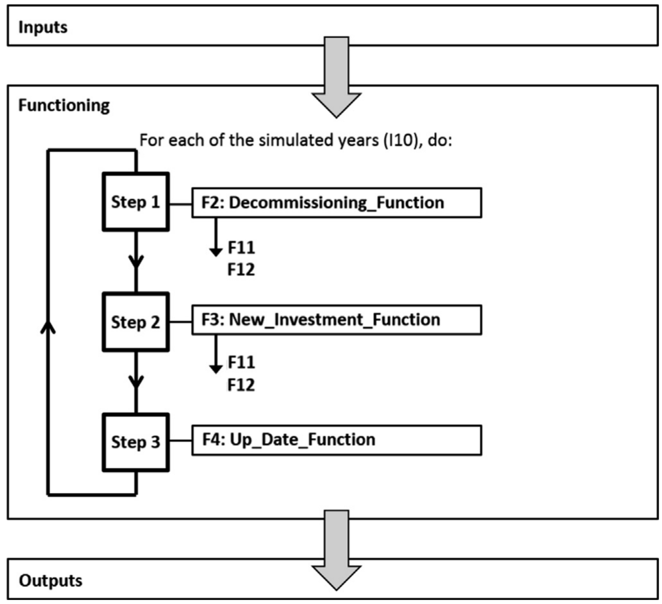

Fig. A-2. Description of the functioning of the SIDES model (corresponding to the main script).

See Appendix Table A-1.

Table A-1
Main inputs, variables and outputs of the SIDES model.

Inputs
- I1: Plants' parameters (costs, life time, construction time, carbon emission factor)
- I2: Anticipation on evolution of total electricity demand
- I3: Weather scenario of electricity demand and production from wind power (annual data in hourly steps)
- I4: Realised weather and demand growth for each year of the simulation
- I5: Generation mix (at the beginning of the simulation)
- I6: Forced evolution of certain capacities - if needed
- I7: Fuel prices (constant)
- I8: Carbon price (constant)
- I9: Price cap on the energy market
- I10: Number of year to be simulated
- I11: Discount rate
- I12: Level of risk aversion

Variables
- V1: Current generation mix
- V2: Electricity demand scenario (in hourly steps)
- V3: Decommissioning decision
- V4: New investment decision
- V5: Hourly prices on the energy market
- V6: Annual capacity price on the capacity market

Simple Relations
- V1 = function(I5, I6, V3, V4)
- V2 = function(I2, I3)

Outputs
- O1: Evolution of the generation mix over the simulated period
- For each year of the simulation:
- O2: Hourly energy prices
- O3: Hourly production of each technology
- O4: Hourly volume of electricity outages
- O5: Hourly volume of electricity spill-overs (from wind power)
- O6: Annual capacity price

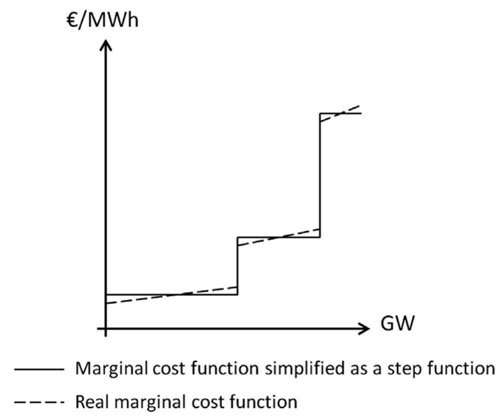

Fig. A-3. Simulated marginal cost function and real marginal cost function.

The Simulator of Investment Decisions in the Electricity Sector (SIDES) model used in this article is implemented with the open-source software R (see http://www.r-project.org for more details about this software environment). The SIDES model belongs to System Dynamics programming. For a complete description of System Dynamics methodology, one should refer to Sterman (2000). A description of the SIDES model without capacity mechanism and under the risk-neutral assumption is presented in Petitet et al. (2016). This appendix aims at providing a detailed and technical description of the SIDES model, up-dated with the representation of the capacity market and with the proposed representation of risk aversion. Scenario building is presented in Section A.1 and the pseudo code of the SIDES model is provided in Section A.2.

The main features of the SIDES model are (i) an endogenous representation of electricity prices, (ii) a deterministic representation of risks by using historic-based scenarios and (iii) a representation of several years with a dynamic view. Besides, the SIDES model embeds the basic elements of the functioning of power systems. In particular:

- **Discrete size of power units**: Power units are characterized by their typical nominal power capacity. The investment and decommissioning processes are discrete events: an investment or a decommissioning decision affects an integer multiple of the nominal power capacity of the considered technology.
- **Investment lag**: For each technology, the time required to build the power plant is taken into account by imposing a delay between the time when the investment decision is undertaken and the time when the power plant is commissioned. However, the model assumes that the decommissioning of an existing power plant occurs immediately in the same year when the decommissioning decision is taken (when decided before the end of the power plant's life time).
- **Correlation between electricity demand and generation from renewables**: Undispatchable electricity generation from variable renewables is defined by the use of hourly load factors which are correlated to the hourly electricity demand based on historical data.

A.1 Scenario building in the SIDES model

For a given year of simulation, the private investor represented in the SIDES model should anticipate the future evolution of the system before estimating the economic value of various projects. The SIDES model considers a dynamic representation of future scenarios: for each simulated year, the anticipated future scenarios are updated.

In the SIDES model, the representative investor anticipates the future on a limited number of years and then, considers that all the future years will be the same (steady state). This assumption of myopic foresight is fairly consistent with real investment processes. Besides, bounded rationality is a common assumption of System Dynamics models which can be represented by backward looking and extrapolation and combined with a limited widow of foresight (Olsina et al., 2006; Hobbs et al., 2007; Assili et al., 2008; De Vries and Heijnen, 2008; Hary et al., 2016).

In the modelling, the representative investor is assumed to benefit from perfect information on the generation mix. More specifically, the representative investor knows (i) the installed capacity of each technology for the present year, (ii) the age of each plant and (iii) his own past decisions including new investments and early closures. Thus, the investor represented in the SIDES model perfectly anticipates the evolution of the generation mix in the following years. In practice, power plants may face risks from different sources. In the SIDES model, the risks that may occur on the costs of the power plants are not represented. However, as the volume risks can be significant, the electricity demand is represented in detail and subject to risks. More specifically, risks affecting the electricity demand are modelled through two parameters:

– the long-term risk: the demand profile is inflated with respect to the anticipated electricity demand growth;
– the short-term risk: the demand profile depends on weather conditions represented by a set of historical data.

Thus, each year of the simulation, the anticipated demand scenarios result from the combination of the long-term risk and the short-term risk. In the simulations presented in this article, only one constant electricity demand growth is used to build the investor's anticipations of the future. The short-term risk is represented by a set of 11 equiprobable representative years (electricity demand and load factors of on-shore wind turbines) which are based on French historical data for the period 2003–2013.

A.2 Pseudo code of the SIDES model

The pseudo code of the SIDES model is provided below.

**** Main Script ****
READ all the input data.
FOR each year which is simulated, do
CALL Decommissioning_Function.
COMPUTE the up-dated generation mix by taking into account the decommissioning decision.
CALL New_Investment_Function.
CALL Up_Date_Function with the decommissioning and new investment decisions.
END FOR

**** Dispatch_Function (F11) ****
READ the installed capacity of each technology and the marginal generation costs.
READ the demand scenario and its correlated wind production profile.
COMPUTE the hourly production from wind power which is equal to the hourly production factor times the installed capacity of wind power.
COMPUTE the net demand which corresponds to the hourly electricity demand minus the hourly production from wind power. Negative net demand is not permitted. Negative values are set to zero.
COMPUTE the hourly price considering only thermal units and net demand. The hourly price is equal to the marginal generation cost of the more expensive unit to run. If the total generation thermal capacity is lower than net demand, the price is equal to the price cap of the market. SeeFig. A–3.
RETURN hourly prices.

In the SIDES model, all units of a given technology are supposed to have the same marginal generation cost. In that sense, there is no difference between new and old units. Consequently, the corresponding supply function is a step function as shown in Fig. A-3 (solid line). But in reality, marginal cost of new units is generally lower than the one of old units, as illustrated by the dashed line in Fig. A-3. Then, if new power plants have slightly lower marginal costs than old ones, considering the real marginal cost function would incentivise to build more new power plants; but this effect is not taken into account in the SIDES model. Our intuition is that this underestimation of new units' revenues is not crucial for the results presented in this article.

**** Capacity_Market_Function (F12) ****
READ the installed capacity of each technology and their technical parameters.
READ the capacity obligation.
READ the revenues from the energy market for the different anticipated scenarios.
FOR each technology (existing capacities)
COMPUTE the distribution of the balance between the annual O & M cost and the energy revenue (negative values are set to zero).
COMPUTE the bid on the capacity market, which is defined as the certainty equivalent of the distribution obtained in line 4, divided by the volume of certified capacity.
END FOR
FOR each technology (new capacities)
COMPUTE the distribution of the balance between the annualised cost* and the energy revenue (negative values are set to zero).
COMPUTE the bid on the capacity market, which is defined as the certainty equivalent of the distribution obtained in line 10, divided by the volume of certified capacity.
END FOR
COMPUTE the capacity price (capacity bid which clears the capacity market).
COMPUTE the capacity remuneration for each technology.
RETURN capacity price and capacity remunerations.
* The annualised cost includes both the annualised equivalent of the investment cost and the annual O & M cost.

**** Decommissioning_Function (F2) ****
READ the data corresponding to the current status of generation mix and general parameters (current installed capacity of each technology, technologies' specifications and discount factor).
For the next year:
READ the data corresponding to the anticipations (demand scenarios and correlated wind generation factors, fuels prices, carbon price).
FOR each set of anticipation for the next year, do
COMPUTE the variable costs of each technology given fuels prices, carbon prices and emissions factors.
CALL Dispatch_Function.
COMPUTE the net profit for each technology. It corresponds to the sum of hourly market price times the production ratio, minus variable generation cost, minus annual operation and maintenance cost.
END FOR
CALL Capacity_Market_Function
COMPUTE the certainty equivalent of the distribution of net profits for the anticipated scenarios, for each technology.
SELECT the technology indices for which the certainty equivalenton the next year is negative.
FOR the technology selected above, do
FOR each year of the 5 following years, do
COMPUTE the variable costs of each technology given fuels prices, carbon prices and emissions factors.

CALL Dispatch_Function.
COMPUTE the net profit for each technology. It corresponds to the sum of hourly market price times the production ratio, minus variable generation cost, minus annual operation and maintenance cost.
END FOR
CALL Capacity_Market_Function
COMPUTE the net profit for each technology including capacity remuneration.
END FOR
COMPUTE the certainty equivalent of the distribution of net profits for the anticipated 5-year scenarios for each selected technology. The 5-year net profit corresponds to the discounted sum of annual net profits, using the discount factor.
Among this tested subset of technologies, SELECT the technologies for which the certainty equivalent of the 5-year net profits is negative and DEFINE the capacity of the selected technology to the current value minus the typical size of capacity. STORE in memory the decommissioning decisions.
REPEAT from line 16 UNTIL there is no decommissioning of existing power plant.
RETURN the number of units (of typical size) to be decommissioned for each technology.

**** New_Investment_Function (F3) ****
READ the data corresponding to the current status of generation mix and general parameters (current installed capacity of each technology and its future evolution, technologies' specifications and discount factor).
FOR each technology, do
COMPUTE the generation mix to be tested by adding one unit of typical size of the technology considered to the current generation mix. Update the evolution of the generation mix over years taking that into account.
FOR each future year, up to 5 years ahead, do
SELECT the generation mix corresponding to this future year.
FOR each anticipated scenarios of the year, do:
CALL Dispatch_Function.
COMPUTE the market revenue of the unit considered. It corresponds to
$\sum_{year} \max(market\ \ price - variable\ \ \cos t).\ production$
END FOR
CALL Capacity_Market_Function. END FOR
COMPUTE the net profit on each future year, on average over the future scenarios. The net profit corresponds to the revenues from the energy market and from the capacity market, minus the annual operation and maintenance cost.
COMPUTE the net present value (NPV) for each anticipated future year, under the assumption of myopic foresight.
COMPUTE the certainty equivalent of the distribution of NPVs.
COMPUTE the Profitability Index (PI), defined as the ratio between the certainty equivalents of the NPVs and the up-front investment cost.
END FOR
SELECT the technology with the highest PI, within the technologies with PI≥1. For the selected technology, a unit of typical size is added to the current mix (and the decision is saved for outputs). The current mix is up-dated, taking into account the construction time.
REPEAT from line 4 UNTIL no more investment is selected or until the volume constraint (a maximum of 10 GW of new units) is reached.
RETURN investment decision, corresponding to the capacity to be installed for each technology.

**** Up_Date_Function (F4) ****
READ the data corresponding to the current status of generation mix and general parameters (current installed capacity of each technology and its future evolution, technologies' specifications).
READ the decommissioning and new investment decisions.
COMPUTE the up-dated evolution matrix of the generation mix given the decisions. New units appear in the generation mix after the construction time. Decommissioning decision is effective immediately from the current year.
FOR all weather scenario of the current year, do
CALL Dispatch_Function.
STORE results as output.
END FOR
CALL Capacity_Market_Function.
READ the scenario realised for the current year (defined in inputs).
COMPUTE new demand scenarios given the realised macroeconomic growth. The new weather scenarios correspond to the previous ones multiplied by the realised macroeconomic evolution of the system.
RETURN up-dated data

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