Carbon Price instead of Support Schemes: Wind Power Investments by the Electricity Market

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ABSTRACT

This paper studies wind power development within electricity markets with a significant carbon price as the sole incentive. Simulation of electricity market and investment decisions by System Dynamics modelling is used to trace the evolution of the electricity generation mix over a 20-year period from an initially thermal system. A range of carbon prices is tested to determine the value above which market-driven development of wind power becomes economically possible. This requires not only economic competitiveness in terms of cost-price, but also profitability versus traditional fossil-fuel technologies. Results stress that wind power is profitable for investors only if the carbon price is significantly higher than the price required for making wind power MWh's cost-price competitive on the basis of levelized costs. In this context, the market-driven development of wind power seems only possible if there is a strong commitment to climate policy, reflected in a stable and high carbon price. Moreover, market-driven development of wind power becomes more challenging if nuclear is part of investment options.

Keywords: Electricity market, Renewables, Investment, Carbon price, System dynamics modelling.

1. INTRODUCTION

After the oil shocks, energy policies have focused on the reduction of energy dependence and exhaustible resource conservation including a component of R&D and promotion of renewables justified by the social gains associated to these collective goods and the remedies to the market failure in the capture of intertemporal externalites of technological learnings. After 1990, renewables promotion policies received the backing of climate change activists based on the rationale of reducing carbon externalities. In the electricity sector, renewable energy sources of electricity (RES-E) have received particular attention in the OECD countries with special support policies mostly based on long term production subsidies, despite the launching of carbon pricing policies based on emissions trading systems, and sometimes on carbon taxes. The design of RES-E promotion policy is central to the current European enegy debate and has been questioned in a number of academic works (see for instance Menanteau et al., 2003; Palmer and Burtraw, 2005; Klessmann et al., 2008).

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Today, RES-E support mechanisms – feed-in tariffs (FIT), fixed premiums (FIP),[1] auctioning for fixed-price contracts, certificate obligations – strongly influence the investment choices of electricity producers. While investments in conventional electricity production technologies are mostly driven by anticipations of their market revenues on day-ahead markets,[2] which present important price-risk and volume-risk, the future incomes of RES-E projects are ensured by specific mechanisms which guarantee long term revenues and so, are estimated with a low level of risk. This leads to two investment regimes: (1) one based on anticipations of market prices, sums of discounted net hourly revenues and criteria of risk management and (2) an out-of-market regime based on these long-term arrangements providing both a production subsidy to non-commercially mature technologies and risk transfer to consumers via the levy financing the cost overruns of the RES-E promotion policy.

Regarding the literature about the impacts of out-of-market RES-E entries on the electricity market, it mainly focuses on the effects on the market prices, residual load curve and generation mix. More recently, academic works also focus on defining an optimal system for a set of characteristics of variable generation technologies and on the market value of a MWh generated by RES taking into account their integration costs. Firstly, the increasing RES-E capacity significantly alters market functioning by increasing price volatility and lowering average prices, thus endangering the profitability of new investments in complementary thermal technologies for mid-load and peak-load. Indeed, two merit order effects are classicaly described in the literature : (1) a high level of entry by RES-E producers decreases the average market price by reducing the net demand addressed to thermal power plants (Sensfuß et al., 2008) and (2) this entrance contributes also to reduce hourly production of thermal units by pushing them out of the merit order more and more frequently. These two effects not only make new investment in thermal units much more risky and threaten coverage of investment cost but also make some of the existing thermal capacities obsolete. Moreover, with sufficient RES-E capacities, hourly market prices are significantly reduced during periods of wind or sun thus a lower market value of RES-E output (Green and Vasilakos, 2011; Hirth, 2013). Secondly, the residual part of the generation system has to adapt itself in the long term to these artificial entries which reshape the residual load (Holtinen, 2005; Nicolosi & Fürsch, 2009; Bushnell, 2010). To facilitate the optimal adaptation of non-RES capacities, result of RES-E promotion policies should be certain at a forward horizon while in practice, it is intrinsically uncertain due to the use of a price-instrument (FIT or FIP) rather than a quantity-instrument (obligation of green certificates, etc.). Thirdly, RES-E variability strongly alters short-term mechanisms such as operating reserves. Indeed, system costs (including plant-level and grid-level costs) resulting from the variability of wind power and photovoltaic increase more than linearly with the cumulative RES-E capacity (Keppler and Cometto, 2013). However, given the difficulties encountered with current RES-E supports, it is time to challenge their existence. The dilemma is between implementing

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1. The feed-in tariff mechanism (FIT) relies on the obligation of the transmission system operator or the historical supplier to purchase RES-E electricity at a guaranteed price for every MWh generated for a specified period (10 to 15 or 20 years). With the feed-in premium (FIP), the RES-E generators sell their electricity on the energy market and benefit from a flexible regulated premium paid by a public agency for every MWh which each month is adapted in a way to guarantee the same total revenue as with the FIT, and for a period as long as for the FIT.

2. More precisely investors anticipate expected revenues on hourly power markets, net of their variable operating costs and estimate if their fixed costs (capital and O&M) could be recovered with a reasonable pay-back time and rate of return, under a dominant perspective of risk management (Roques et al., 2008). That being said, it is noteworthy that some non-RES plants also benefit from government supports. In particular, new nuclear power plants built after market reforms are largely developed thanks to government guarantees or large sized public companies able to bear large risks.

support mechanisms which guarantee long term revenues to RES-E producers or implementing a regulated carbon price to internalize environmental damages. In the new guidelines on state aids in environmental protection and energy adopted in April 2014 (European Commission, 2014), the European Commission supports the integration of renewable technologies into the electricity market by exposing generators to hourly market prices, by the promotion of feed-in premiums instead of feed-in tariffs and by auctioning contracts for getting this premium and inciting entrants to reveal their costs. In the same trend, different European states have redefined the form of their support for RES-E (electricity market reform in the United Kingdom; Spanish reform; reform of the Renewable Energies Act in Germany; French consultation on RES-E support schemes in 2014, etc.).

Yet, theoretical arguments in favour of carbon price to trigger entries in RES-E generation without support mechanisms as soon as we are close to the commercial competitiveness are gaining in audience (Crampes, 2014). On the broader level of reducing CO_2 emissions, it is also argued that carbon pricing (through carbon tax or cap and trade system) is the best option to mitigate climate change (Gollier and Tirole, 2015). Concerning the electricity sector, Fisher and Newell (2008) use a long term modelling of the electricity market with perfect information to assess the efficiency of different types of energy and climate policies and show that the carbon price is the most efficient option compared to various other types of RES-E support. But, the use of a simplistic representation of electricity markets and cost functions of low carbon technologies leads to an underestimation of the carbon price equivalent to the RES-E supports which are compared with.

In this article, we consider that wind power[3] entries are triggered by its profitability compared to investment in dispatchable thermal units under the incentive of higher hourly electricity market prices which include a high and stable carbon price. The market-based development of wind power is assessed using the Simulator of Investment Decisions in the Electricity Sector (SIDES) which is a System Dynamics (SD) model of an electricity market (see Sterman (2000) for details on System Dynamics). The method allows to endogenously reproduce three important effects of wind power development: (1) the negative correlation between hourly wind power production and hourly price in opposition to dispatchable plants; (2) the gradual decrease of the average annual price with the development of new RES-E capacities, both of which make fixed costs recovery more difficult and (3) the feedback loop consisting in the "self-cannibalisation" of wind power competitiveness by its own development and leading to an endogenous limit of wind power capacities. This latter effect does not exist in the case of out-of-market entries of wind power (under the incentive of feed-in tariff or feed-in premium).

In the following approach, endogenous evolution of the technology mix is simulated by the formalisation of investment decision-making based on a long-term anticipation of hourly market prices and hourly net revenues (the so-called "infra-marginal rents") that each new plant could generate on the energy market during pay-back period. The model considers an energy-only market without any additional RES-E support mechanisms, but with a credible carbon price constant over a 20-year period rather than an uncertain carbon price signal (as that which emanated from the EU-ETS during its three first phases). In that sense, wind power is invested in under the same regime of other thermal power plants. The carbon price is supposed to be known and constant so that issues raised by its uncertain level are evacuated. The development of wind power when the carbon price is sufficiently high exacerbates capacity adequacy issues. One answer, which is not

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3. Because of its closeness to the competitive threshold, on-shore wind power was used as an illustrative case to explore the conditions of market-driven RES-E entry through the incentive of a constant carbon price. Nevertheless, variability profiles of other RES-E technologies (as solar) are quite different from wind profile.

represented in the SIDES model, is to implement a capacity mechanism with capacity credit allocation differentiated by technologies. In such a case, RES-E units with variable production are inevitably penalized by their low capacity credit and consequently their development is reduced (Cepeda and Finon, 2013).

Finally, this study also adresses the argument that with the present cost-price of MWh produced by the last state-of-the-art wind power technology, the carbon price needed to reach competitiveness of wind power is quite low (for instance in the range of €30 to €40 per ton of CO_2 as in IEA and NEA (2010)). In fact, as our purpose is to take into account the market value of wind power output, the SD simulations presented herein suggest that the carbon price needed for wind power development is much higher than the one estimated by a comparison of levelized costs of electricity (LCOEs). In section 2 which follows, the SIDES (Simulator of Investment Decisions in the Electricity Sector) model is described. Section 3 details the results of the simulations for different levels of carbon price in two policy contexts: one without opened nuclear option and one with the nuclear technology acting as a low carbon competitor of wind power. Then, the results are discussed and compared to the simple cost-price approach of wind power competitiveness in section 4. Finally, section 5 concludes and offers suggestions for further work.

2. METHODS

The modelling adopted here focuses on the effectiveness of carbon price as a market driver for investment in renewable technologies in an energy only market. A fixed carbon price is added to the model of an energy-only market in order to test carbon policies. This carbon pricing is considered in the particular context of hourly electricity markets and their price setting linked to the marginal cost of the overall system. This approach is far from the traditional price setting on average costs with the addition of mark-up as in classic commodity markets.

2.1 Overview of the Model SIDES (Simulator of Investment Decisions in the Electricity Sector)

The Simulator of Investment Decisions in the Electricity Sectior (SIDES) is a simulation model belonging to System Dynamics (SD) programming. Regarding the electricity sector, the SD method has been applied to study investment cycles and the effects of different market designs in a random environment (Teufel et al., 2013). Ford (2001) was one of the pioneers in using SD to explore the development of generating capacities in deregulated electricity markets. Cepeda and Finon (2011) examine investments in generating capacities in two interlinked electricity markets with or without capacity mechanisms, using a long-term SD market model and Monte Carlo simulation of future scenarios. Sánchez et al. (2008) also study long-term evolution of electricity markets with a SD model but in the context of imperfect competition.

The SD approach differs widely from traditional approaches (dispatching programming, long-term optimisation, etc.) because it does not focus on market equilibrium. The objective of SD is to obtain temporal evolution by modelling dynamic relations between entities. As a consequence, SD is a relevant methodology to explore transition effects and business cycles in markets. The long-run equilibrium approach (Nicolosi and Fürsch, 2009; Bushnell, 2010) is used in the literature to highlight the long-term effects of wind power development. But this equilibrium approach presents two main limitations: it does not provide any elements on transition phases from one equilibrium to the next and does not indicate if the real initial electricity system could evolve toward this equilibrium. While the equilibrium approach provides the best solution, SD focuses on dynamic

evolutions of electricity systems. Thus, it is a relevant complementary approach to equilibrium models.

The SD programming model makes it possible to simulate market evolution under investment decisions by a representative agent in a context of perfect competition in which he behaves as a price-taker. The decision process requires us to anticipate the future profitability of different generating technologies by modelling market evolution in a set of scenarios. These future scenarios are obtained by historical simulation (based on finite historical panel data) rather than by Monte Carlo simulations, taking into account assumptions on weather, macroeconomic growth and political orientation (through a carbon price).

Given assumptions about the initial generation mix, the annual structure of hourly electricity demand, the level of the constant carbon price and macroeconomic scenarios, the evolution of the generation mix is obtained over several years by endogenous simulation of decisions on investment in the different technologies and (this is an original feature of our SD model) on decommissioning decisions. Figure 1 represents the dynamic process of the simulation for each year. The causal relationships between two system variables are indicated by arrows and the + (respectively −) symbol specifies positively (respectively negatively) related effect. A curved arrow indicates a feedback loop. Here, it is a negative feedback loop (represented by the − sign). The negative loop is self-correcting.

Figure 1: Causal-loop Diagram of the SIDES Model
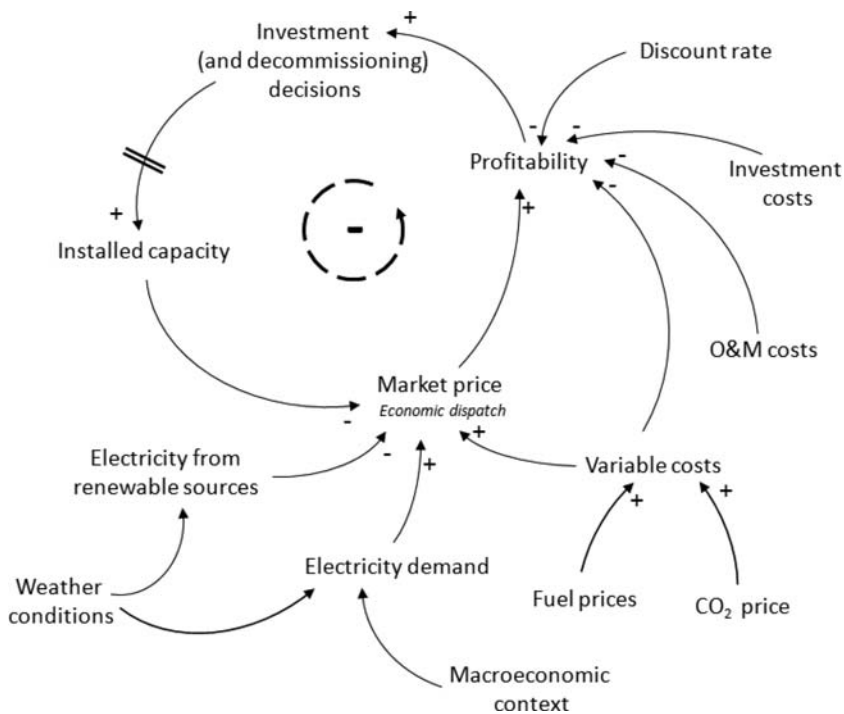
For each year, the investment decision is obtained by selecting the most economically profitable electricity generating projects. The profitability is estimated for each type of generating technologies on the basis of anticipated incomes on the hourly markets of the successive years of the lifetime of the equipment. Anticipations are obtained by historical simulation of a number of future scenarios of weather parameters and demand growth.

The representation of electricity power plants does not model each single power plant but considers a number of representative groups of technologies. Generating technologies are divided into N representative clusters. A cluster is defined by its nominal power capacity (MW), fuel, costs (investment cost, fuel cost, annual operating and maintenance cost) and CO_2 emission factor. As a simplification, fossil-based power plants are assumed to be available all the year. Planned maintenance and forced outages are not taken into account. The electricity grid is not represented. The assumption is that a single area is considered as a "copper plate," which means that there is no grid congestion.

The following sections present the formalisation of the electricity market and the investment decision process.

Table 1: Nomenclature

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.
IC_χ	Investment cost of the power plant χ.
OC_χ	Annual operation and maintenance 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. ($0 \leq EP_\chi(h,t) \leq \kappa_\chi$)
$NR_\chi(t)$	Annual net revenue of the power plant χ for the year t.
$ENP_\chi(y)$	Estimated net profit of the power plant χ for the year t.
$LT.ENP_\chi$	Estimated net profit of the power plant χ on the long run (typically for the years t to $t+5$).
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.

2.2 Modelling the Electricity Market

The hourly market price is set to the variable cost of the marginal unit which clears the market. Following the merit order principle, generating technologies are selected from the one with the lower variable cost to the one with the higher variable cost. The hourly amount of generated power is equal to the load demand except during electricity outages. If instant electricity demand is higher than total generating capacity, a part of the demand remains unserved and the market price is fixed by the price cap. For each hour h of the year y, the market price is defined by:

$$p(h,y) = \begin{cases} VC_\chi \text{ if } \sum_{1 \leq x \leq \chi-1} K_x(y) < L(h,y) \leq \sum_{1 \leq x \leq \chi} K_x(y) \\ CAP \text{ if } L(h,y) > \sum_{\chi=1}^{N} K_\chi(y) \end{cases}$$

This representation of the electricity market corresponds to a perfect spot market: electricity producers bid their marginal cost. Here, operational constraints of power plants (ramping, minimum up-time and down-time, etc.) and grid congestion are not part of the modelling. In reality, it could increase variable costs of thermal plants depending on the share of wind power in the system. This simplification (as the assumption of constant fuel prices and carbon price) allows to keep a simple formalisation of the system operation and to have a clear view of the sole effect of the carbon price on wind power development.

Peak electricity prices are a crucial driver for investment. The ratio between the marginal cost of peaking units and the price cap is of an order of 10; so that revenues during electricity outages may represent a large part of total revenues.

Given that the variable generation cost of wind power is equal to zero, wind power is always the cheapest generating technology when available. When the wind is blowing, wind turbine generation is automatically sold at market price. If wind electricity generation exceeds load, the wind generator is not paid for its surplus generation, contrary to the case of the present support mechanisms.

Finally, as the SIDES model focus on long-term issues, short-term balancing mechanisms are not represented. In that sense, wind power doesn't bear the costs related to the difference between forecasted and actual electricity generation.

2.3 Modelling Investment Decisions

The SIDES model considers a single representative agent acting as a price taker whose objective is to maximise his profit. Here, the modelling does not focus on agents' behaviour, as there could be integration of risk aversion. Moreover, time management in investment decisions raises real dilemmas for investors when considering uncertainties (Green, 2006). Actually, postponing investment decisions can add value to a project because it increases information available for the future. This alternative is not taken into account in the modelling.

2.3.1 Representation of uncertainty

The economic profitability of electricity generating projects is highly sensitive to parameters such as investment cost, market price, electricity demand, fuel prices, carbon price, electricity generation from RES-E and regulatory constraints on power or technologies (and electricity production from wind turbines). The electricity market is modelled as described above. As a consequence, the market price is directly related to electricity demand, fuel prices, carbon price and generation mix. Moreover, cost structures and future generation mix are assumed to be well known by the single-investor. In this version of the SIDES model, fuel prices remain constant during the whole simulation. Finally, only electricity demand, electricity generation from RES-E and carbon price are considered as uncertain in the modelling.

The modelled investor makes his anticipation of the future for up to 5 years and then considers that all the future years will be the same. That myopic foresight is fairly consistent with real investment processes.

Electricity demand and electricity generation from wind power

The total annual energy demand in the future depends on macroeconomic anticipations. The SIDES model considers 3 macroeconomic assumptions which correspond to an annual growth rate of 1%, an annual decrease of 1% and no evolution. Each year of the simulation, annual demand anticipations are adapted to the level selected for the year before. In the short term, electricity demand is also highly sensitive to weather conditions. To represent that sensitivity to the weather, 12 representative demand profiles are used.

Hence, uncertainty of electricity demand is represented by two factors:

- long-term uncertainty: translation of the demand profile with respect to anticipated macroeconomic growth
- short-term uncertainty: the demand profile depends on weather conditions

As with electricity demand, the electricity generation of wind turbines varies significantly with weather conditions. The modelling considers a perfect correlation between electricity demand and electricity generation of wind turbines. The 12 wind generation profiles correspond to the 12 demand profiles. Finally, there are 12 correlated demand-wind generation scenarios.

Carbon price

In the simulations, the carbon price is fixed over the entire period and known by the economic agent. This corresponds to a carbon tax which remains constant over the period. Here, we do not consider an increasing carbon tax which would be a solution to make it socially acceptable in the real world.

Number of scenarios to be considered

In the case where carbon price and fuel prices are fixed and constant over time, the number of future scenarios to be estimated for investment decisions is determined by multiplying the number of macroeconomic assumptions by the number of short-term weather profiles. Each step of the investment decisions and each generating technology are tested for all scenarios.

2.3.2 Investments in new generating capacities

In the real world, investment decisions are very complex because they are driven not only by economic reasons but also by political considerations. In practice, an investor may choose to invest in a power plant not because it is the most profitable project but because it diversifies his portfolio of generating technologies. This eventuality is not taken into account in the SIDES model. However, the modelling of investment decisions depends on the economic profitability of technologies and a political driver—the carbon price.

The literature on investment decisions highlights two main types of criterion: the net present value (NPV) and the internal rate of return (IRR). In practice, economic agents are sensitive to both NPV and IRR. Investment decisions are based on the selection of the project whose criterion (NPV or IRR) is the highest. In some cases, investment decisions may differ according to the criterion employed.

Portfolio approach is also employed for investment decisions. It consists in considering together different projects (for example, investing in wind power together with a thermal plant or a solar pannels) in order to reduce risks. At this stage, risk aversion is not considered in the SIDES model however it would be an interesting further development. In this version of the SIDES model, the IRR is employed to select the most profitable project among a range of projects.[4] IRR is defined as the discount rate that makes the NPV equal to zero:

$$NPV_\chi(IRR) = 0$$

where the NPV is

$$NPV_\chi(r) = -\kappa_\chi.IC_\chi + \sum_{y=T_\chi^{C}}^{T_\chi^{C}+T_\chi^{L}} \frac{NR_\chi(y)}{(1+r)^y}$$

4. Simulations were conducted for two investment criteria: IRR and NPV divided by investment cost. Results are not significantly different.

and the annual net revenue $NR_\chi(y)$ is

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

In the SIDES model, the economic assessment takes into account incomes from the energy-only market, investment cost and operating costs. Other costs such as settlement for imbalances are neglected. The modelling includes both the computation of IRR for each anticipated future scenario and IRR on mean cash flows (mean value over all anticipated future scenarios). For the present risk-neutral model, only IRR on mean cash flows is transferred to the investment decisions module. But further developments could include risk-aversion based on the statistical distribution of IRRs.

To be selected, the IRR must be greater than 8%, which corresponds to the cost of capital of typical electricity producers as estimated by DGEC (2008). The yearly investment decision is inferred on the basis of a recursive loop which selects the most profitable generating project at each iteration.

2.3.3 Decommissioning existing power plants

Decommissioning of existing power plant is also a key element in understanding the adaptation of the generation mix. Plant closures are modelled endogenously. There are two causes for plant closures:

- closure is automatically imposed at the end-of-life time of the power plant
- early decommissioning occurs if the power plant is not economically profitable any more

The modelling of early decommissioning requires a method to detect unprofitable units within installed power plants. For that purpose, existing power plants' profitability is estimated in two stages. The first step consists in estimating the net profit of the different technologies for the following year. That estimation of profitability is based on energy revenues and operating and maintenance costs. Investment costs are not taken into account because at that stage, they are considered as sunk costs. Indeed, once the power plant has been built, payment of the investment cost is irreversible. Thus, estimated net profit (*ENP*) corresponds to:

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

If *ENP* is positive, the power plant is profitable at least for the next year. Therefore, the single investor prefers 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 economic conditions to improve. In that case, profitability is estimated on the long-term for the following 5 years in order to determine if that loss of profit seems temporary or lasting. Long-term estimated net profit (LT.ENP) is equal to:

$$LT.ENP_\chi = \sum_{z=y}^{y+4} ENP_\chi(z)$$

If both *ENP* and *LT.ENP* are negative, the single investor decides to decommission the power plant. If *ENP* is negative and *LT.ENP* is positive, it seems better not to close the power plant and wait for economic conditions to improve. In that case, mothballing could occur but it is not modelled in detail here.

2.4 Simulation Data

2.4.1 Technical specifications of generating technologies

In the simulations, four conventional technologies are considered besides wind turbines (WT): combined cycle gas turbines (CCGT), coal-fired power plants (Coal), oil-fired combustion turbines (CT) and nuclear power plants (Nuclear). Two cases are considered in the simulations: case A is a pure thermal mix without nuclear and case B is a mixed system with nuclear. Two assumptions on nuclear investment cost are considered: a low value of €2,900/kW (median case of IEA and NEA, 2010, page 103) and a high value of €5,000/kW (synthesis EC / DG Energy, 2013).

Table 2: Plant Parameters Used in Simulations

	CCGT	Coal	CT	Nuclear	WT
Investment cost (k€/MW)	800	1,400	590	2,900 | 5,000	1,600
Annual O&M cost (k€/MW/year)	18	50	5	100	20
Annualised fixed cost* (k€/MW/year)	89	167	60	334 | 504	170
Nominal power capacity (MW)	480	750	175	1,400	45
Fuel variable cost (€/MWh)	64	37.5	157	10	0
Carbon emission factor (ton of CO_2/MWh)	0.35	0.8	0.8	0	0
Construction time (years)	2	4	2	6	2
Life time (years)	30	40	25	60	25

Notes: Data is from IEA and NEA (2010) and DGEC (2008). Assumptions on fuel prices: 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).
* The annualised fixed cost is computed with annual discount rate of 8%.

Technical specifications are presented in Table 2. In this case study, wind power and fossil-based technologies are assumed to be mature so that their costs (investment cost and annual O&M cost) are constant over the whole 20-year period. Hence, the study does not consider changes in investment costs or in variable costs, due to the evolution of raw material prices or new technical developments.

The total variable generation cost is equal to the fuel variable cost plus the carbon emission factor multiplied by the carbon price. In the simulations, fuel prices and carbon price remain constant over time in order to facilitate understanding and interpretation of the results. However, in reality fuel prices depend on uncertain economic developments. Thus, changes in relative variable production costs may occur as has been the case recently for coal and gas because of the introduction of shale gas in the U.S. This assumption of constant fuel prices decreases the uncertainty of power plants' revenues and consequently it influences the results of the model. This point is addressed in the following discussion of the results. In the simulations, the capital cost is expressed in constant money and the discount rate is set to 8%, corresponding to a precautionary approach of investment risk.

In this case study, we do not consider pre-existing wind power capacity which could have been developed under the incentive of a wind power support scheme. We consider an initial generation mix resulting from the optimisation of the central planner on the time-weighted average load curve of the different weather scenarios, without wind power. This thermal generation mix is obtained by the screening curves method (Green, 2006; Joskow, 2006) on the time-weighted average load curve and approximated to respect the nominal power capacity of each technology. The value of lost load (VoLL) of the screening curves method is set equal to the price cap of the simulation (€3,000 per MWh as defined by EPEXSPOT) in the screening curves method. Table 3 details the resulting initial generation mix of the first simulated year for both cases A and B. Because the initial mix is set on the time-weighted average load curve, there is still a need of investments at the

beginning of the simulations, triggered by the variability in electricity demand due to weather conditions.

Table 3: Initial Generation Mix (Cases A and B)

Technology	CCGT	Coal	CT	Nuclear	WT
Capacity in case A (GW)	17.76	57.75	3.50	0	0
Capacity in case B (GW)	17.76	12.2	3.50	46.10	0

2.4.2 Electricity load and wind generation

Electricity demand differs according to weather conditions in the very short term and macroeconomic evolutions which condition the demand growth in the long term. Weather sensitivity of electricity demand is obtained by using 12 different historical demand profiles whose range of variation is shown in Figure 2. Over those 12 scenarios, hourly electricity load varies between 28.7 GW and 93.6 GW and its mean value is 53.5 GW. Macroeconomic sensitivity of electricity demand is represented by a vertical translation of the load duration curve. In this case study, 3 macroeconomic assumptions are used to define anticipated future scenarios, corresponding to +1%, 0% and −1% of annual growth. Thus considering only one assumption on carbon price, each year, investment decisions are taken on the basis of 36 anticipated future scenarios. In simulations, the realized evolution of electricity demand is set to no economic growth and varies only because of its weather sensitivity.

Figure 2: Average Electricity Demand and its Weather Sensitivity (shaded area)
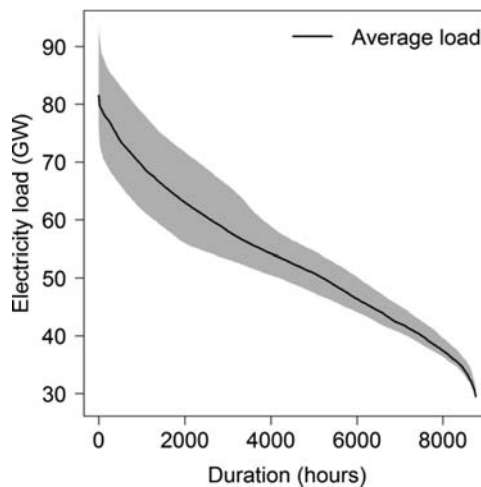
Electricity generation from wind power is correlated to electricity load for each hourly time-step. 12 different wind generation profiles are used, corresponding to the 12 demand profiles. Electricity generation from wind turbines reshapes the net load curves. Initially, the range of variation of power demand between peak and off-peak load is 59.6 MW on average over the 12 historical weather scenarios. The entrance of 45 GW of wind power increases the range of variation of the net load curve to 73.6 GW on average (+23.5% compared to real electricity load). The hourly load factor of wind power varies from 0.05% to 79.5% depending on weather conditions and its mean value is 21.6%.

3. RESULTS

Different market simulations are computed with different levels of constant carbon price from €0 to €300 per ton of CO_2 in two scenarios of initial systems and a scope of technology options, the generic one with a pure fossil-fuel based system without nuclear and the diversified one with a system with a mix of fossil-fuel and nuclear plants.

3.1 Wind Power in an Initial Pure Fossil-fuel Based System

3.1.1 Dynamics of the generation mix

Figure 3: Installed Capacities (GW) Over Time for Different Carbon Prices [Case A]
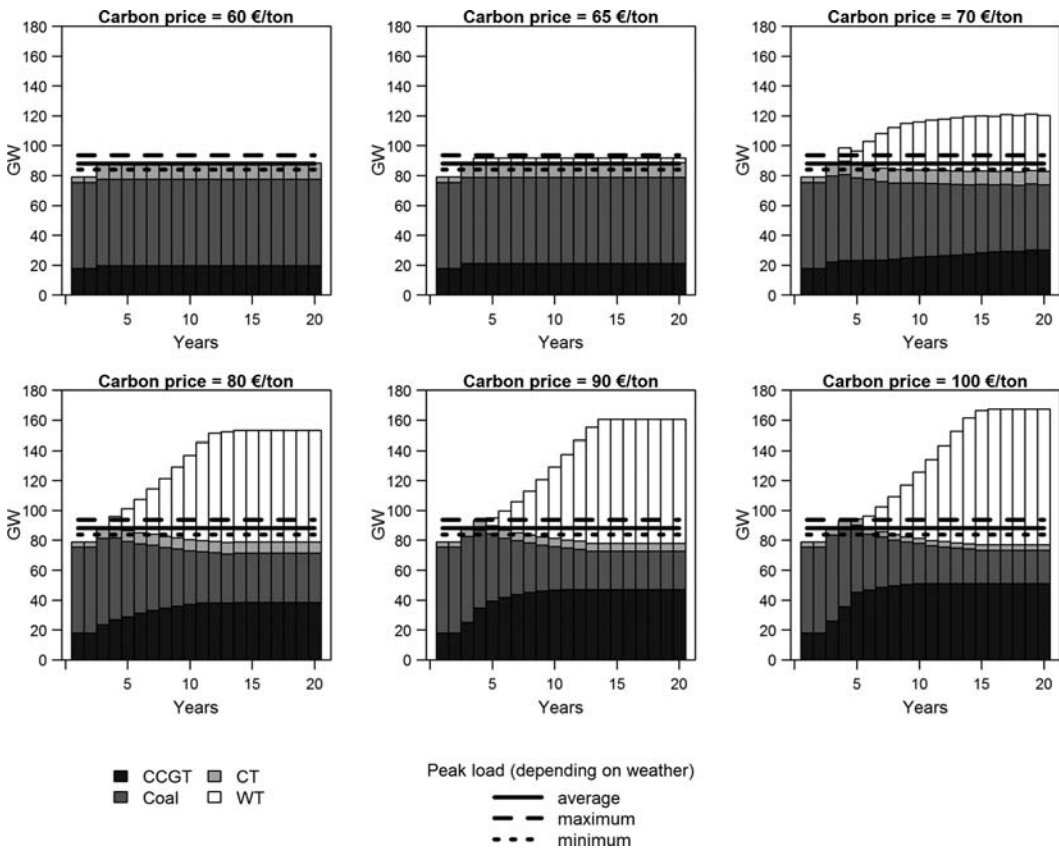
The SD simulations show that the threshold value of the carbon price beyond which wind power is selected by the representative investor is €70 per ton of CO_2. The electricity generation mix over time varies in relation to the carbon price. Figure 3 shows in each simulation the evolution of the technology mix. Below €65 per ton of CO_2, no wind power appears in the generation mix. With this value, only a marginal wind capacity of 3.2 GW is installed during the twenty years of the simulation. As shown in Figure 4 and detailed in Table 4, as the carbon price jumps to €70 per ton of CO_2 and above €80 per ton of CO_2, capacity development of wind turbines increases sharply and reaches respectively 37.7 GW (15.3% of the annual production) and 74.2 GW (30.0% of the annual production) over the twenty-year simulation. In this case, the growth of installed wind

Figure 4: Installed Wind Capacity Over Time for Different Carbon Prices [Case A]
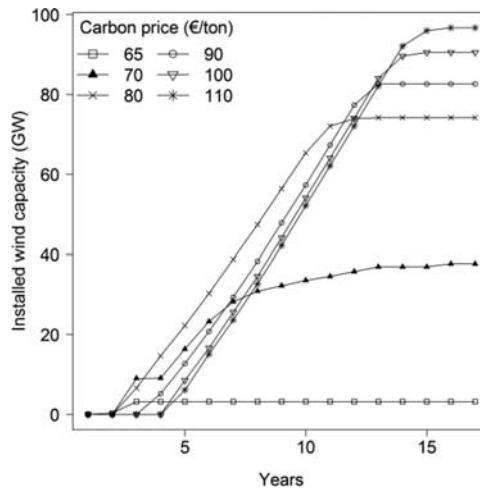
Figure 5: Share of Electricity Production from Thermal and Wind Power at the End of the Simulation (on average over the 12 weather scenario) for Different Carbon Prices [Case A]
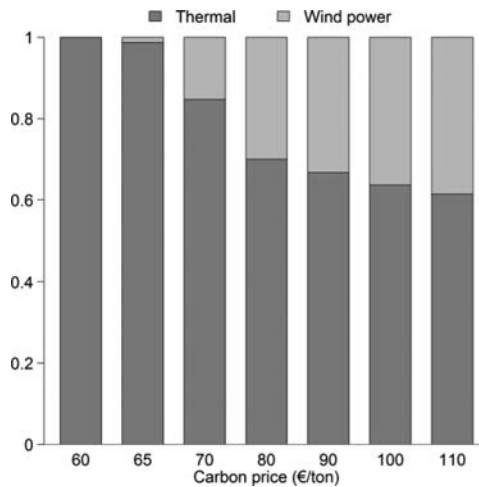
capacity for each €10 per ton of CO_2 slows down, corresponding to the "cannibalisation" effect of wind power development on its competitiveness. Moreover, it is not common to observe that 96.7 GW in wind power capacity replace *de facto* 12.0 GW of thermal capacity in the scenario with a carbon price of €110 per ton of CO_2 versus the scenario with the price of €60 per ton of CO_2 which does not make any wind power investment profitable for private investors.

This evolution under the effect of carbon price increases comes at the expense of coal. The profitability of coal plants decreases rapidly and more than the new CCGT's profitability when carbon price increases. Below €60 per ton of CO_2, coal is the baseload technology of the system. Above this value, its variable cost is higher than the variable cost of CCGT and thus, CCGT becomes the baseload technology. The profitability of coal-fired power plants decreases when the carbon

Table 4: Generation Mixes at the End of the Simulation for Different Carbon Prices [Case A]

Carbon price (€ /tCO$_2$)	CCGT (GW)	Coal (GW)	CT (GW)	WT (GW)	Total thermal capacity (GW)
60	19.7	57.8	11.0	0	88.5
65	21.1	57.8	9.8	3.2	88.7
70	30.2	44.3	8.9	37.7	83.4
80	38.4	33.0	7.5	74.2	78.9
90	47.0	25.5	5.4	82.6	78.0
100	50.9	22.5	3.5	90.5	76.9
110	53.8	20.3	2.5	96.7	76.5

Table 5: Annual Share of Wind Capacity and Energy (mean value over the 12 weather scenarios for the generation mix at the end of simulation) [Case A]

Carbon price (€/ ton of CO$_2$)	65	70	80	90	100	110
Share of wind capacity	3.5%	31.1%	48.5%	51.4%	54.1%	55.8%
Share of wind energy	1.3%	15.3%	30.0%	33.3%	36.3%	38.6%

Figure 6: CO$_2$ Emissions from Electricity Generation Over Time for Different Carbon Prices (average values for weather scenarios) [Case A]
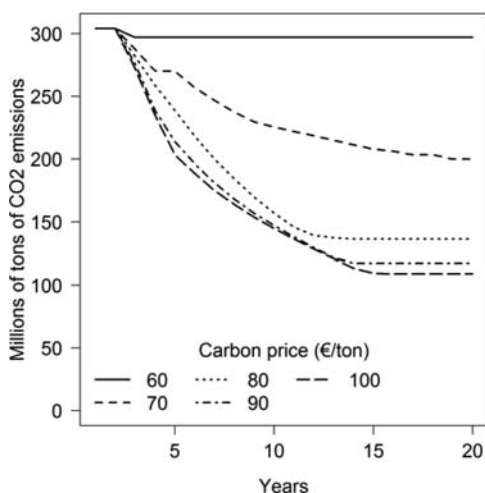
Notes: This does not take into account CO$_2$ emissions from the construction of power plants.

price increases. Finally, the number of decommissioned coal power plants increases with the carbon price (Figure 3). Consequently, as coal capacity decreases and electricity generation from wind power increases, fossil-fuel use is reduced. Thus, CO$_2$ emissions decrease significantly as shown on Figure 6. A carbon price of €70 per ton of CO$_2$ decreases CO$_2$ emissions by 22% over the twenty years of the simulation, compared to the case of €60 per ton of CO$_2$ with no development of wind power.

Figure 7: Evolution of the Yearly Average Market Price on the 20 Years of the Simulation for Different Carbon Prices (average values for weather scenarios) [Case A]
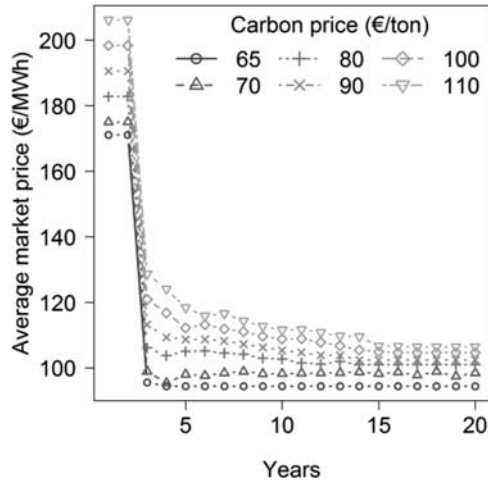

Notes: The first wind farms come on line in years 4 to 6 of the simulation, depending on the case considered.

In Figure 7, for a given year, the average market price is higher when carbon price increases. At the same time, for a given a carbon price, the average market price globally decreases in time consequent to the development of wind power.

3.1.2 Energy spill-overs

When wind capacity increases, electricity spill-overs become more frequent and occur when electricity demand is low and the wind blows. Figure 8 shows the average amount of electricity spill-over (hours and volume) for generation mix at the end of the simulation, on average over the

Figure 8: Average Hours and Volumes of Electricity Spill-overs, Over the 12 Weather Scenarios for Different Assumptions on Carbon Price [Case A]
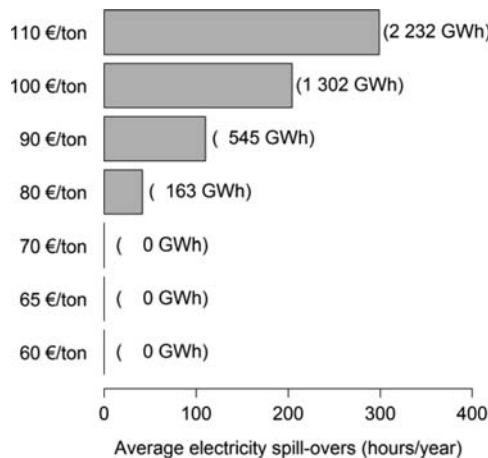
12 weather scenarios. It underlines that above €80 per ton of CO_2, large volumes of electricity are spilled over.

3.1.3 Power outages

One of the majors concerns about the development of RES-E is the increase of electricity outages when production from wind power is low. In order to quantify this effect, hours and volumes of electricity outages was computed on the 12 weather scenarios for the generation mix obtained at the end of the 20-year simulation for each carbon price (Figure 9). When the carbon price is € 60 /ton with no wind power development, there is an average of 10 hours of electricity outage per year. This value could seem to be high but it is explained by the assumption on the price cap (€3,000 per MWh) considered in the simulations.

When wind capacity increases with the carbon price in successive scenarios of carbon price, total thermal capacity is lower (Table 4). This effect threatens the security of supply of the electricity system because the total thermal capacity is not sufficient to serve all the electricity demand in random situations when electricity demand is high and wind does not blow. Figure 9 shows the increase of the average electricity outages (in number of hours and volume) on average over the 12 weather scenarios. Figure 9 also underlines that when few wind capacities are being installed (for a carbon price of €65 to €70 per ton of CO_2), electricity outages are slightly reduced because a relatively small volume of thermal capacity is closed due to the development of wind power. For higher carbon prices, the development of wind capacity in the succession of scenarios with higher carbon price decreases the security of supply.

3.2 Wind Power in a System with the Nuclear Option Open

In the previous sub-section, nuclear was not considered in the generic case in which wind power plants are compared to fossil-fuel technologies. But what if nuclear technology is an acceptable option in a country? Another set of simulations is conducted in order to highlight the impact of a nuclear option on the profitability of wind power investment along the different steps of carbon price increase. Two nuclear policies are tested: case B-1 is to maintain only the existing

Figure 9: Average Hours and Volumes of Electricity Outages (in average over the 12 weather scenarios) for Different Assumptions of Carbon Price [Case A]
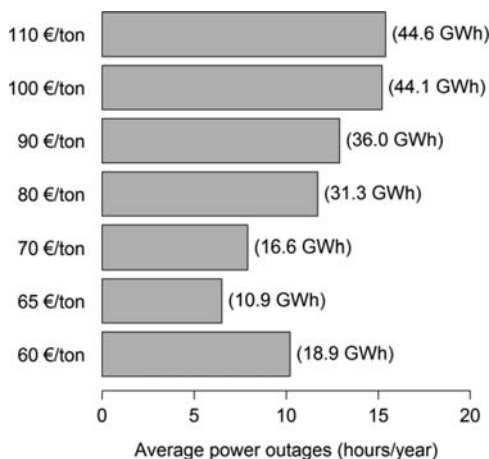
Notes: The price cap on the energy market is €3,000 per MWh.

nuclear capacity at its initial level (moratorium on new nuclear investment), and case B-2 is to allow new nuclear development from this initial capacity. For this latter case, two constrasted hypothesis on nuclear investment cost are tested: €2,900 / kW in case B-2/H1 and €5,000 / kW in case B-2/H2.

For the simulations, investment cost of nuclear is supposed to be €2,900 /kW as proposed in the median case of the report of IEA and NEA (IEA and NEA, 2010, page 103). Details on nuclear assumptions are presented in Table 2. An alternative assumption on nuclear cost was also tested and is presented below. Details are presented in Table 2. The initial generation mix with nuclear (Table 3) corresponds to the optimal mix obtained as above by the method of screening curves on the average load curve, with an intial nuclear capacity of 46 GW for a maximum load of 89 GW.

In case B-1 without new investments in nuclear—so that nuclear capacity remains 46 GW over the 20-year period—the carbon price must be very high to trigger investments in wind power (Table 6). In fact, nuclear plants are insensitive to carbon pricing because they benefit from their low variable cost together with the fact that this source of electricity does not emit CO_2. In particular, nuclear remains more economically relevant for investors than wind power even with any high level of carbon price. So, nuclear strongly impacts the market-driven development of wind power plants. Not only does the development of wind capacity occur at a much higher carbon price level, but this development occurs at a very slow pace and with a much narrower span.

In case B-2/H1 and B-2/H2 in which nuclear plants are politically allowed for investment, wind power development is still more slowed down. With the low assumption of €2,900 /kW (case B-2/H1), simulations were conducted for a range of carbon price from €0 to €500 per ton of CO_2. Even with the value of €500 per ton of CO_2, no wind power appears in the generation mix. With the high nuclear investment cost of €5,000 / kW (case B-2/H2), wind power capacities are invested in if the carbon price reaches €300 per ton of CO_2. But it remains at an anecdotal level: only 2 GW of wind power with this value and 13 GW with a carbon price of €500 per ton of CO_2.

These results suggest that existing nuclear plants not only impede profitability of wind power projects up to a high carbon price level of €100 per ton of CO_2 (as in case B-1), but with the phase-in of new nuclear, it appears that new nuclear investment could be the most profitable option of non-carbon power development under the incentive of higher and higher carbon prices Consequently, market-driven investments in wind power appear to be feasible only if the nuclear option is politically rejected.

4. DISCUSSION

4.1 Cost-price Comparison of Fossil-fuel Technologies and Wind Power

This section proposes a comparison between the results obtained by SD simulations and a cost-price analysis based on the levelized cost of electricity (LCOE). It underlines that the carbon price estimated by simulations is higher than the one suggested by LCOE analysis. This difference

Table 6: Wind Capacity at the End of Simulation for Different Carbon Prices With and Without Existing Nuclear Capacities [Cases A and B-1]

Carbon price (€/tCO$_2$)	70	80	90	100	110	150	200	250	300
Wind capacity (GW) – Case A without any nuclear	37.7	74.2	82.6	90.5	96.7	119	140	159	175
Wind capacity (GW) –Case B-1 with existing nuclear (46.1 GW)	0	0	0	0	0	4.9	14.4	21.2	26.8

is due to the cost inherent to non-dispatchable generation which suffers from weather uncertainty (as exposed in the following) and consequently, it should not be seen as a market failure.

The levelized cost of electricity is the average cost of producing a MWh taking into account investment cost, O&M cost and variable generation cost which includes the carbon cost resulting from the carbon pricing. It corresponds to:

$$LCOE_{\chi} = \left(OC_{\chi} + \frac{IC_{\chi}.r}{1-(1+r)^{-T_{\chi}^{L}}} \right) \frac{1}{8760.Lf_{\chi}} + VC_{\chi}$$

LCOE is widely employed to assess the respective cost-prices of electricity of each generating technology and to determine the most economic technology at the margin of the system. However, comparison of LCOEs with hypotheses on load factor is relevant if conducted for a same group of technologies. Here, the objective is to compare the LCOEs of base-load and mid-load units (coal, CCGT) which could produce at any time, with WT which is not dispatchable, but which produces randomly at any hour of the year. This comparison is valid if we suppose that the value of a MWh is the same at any hour of the year on the electricity market. We do not consider peaking units (high variable cost but low investment cost) because they are dedicated to generating power during peak and extreme peak periods.

Plant parameters are those presented in Table 2. LCOE is sensitive to the load factor. For thermal power plants (CCGT and Coal), we consider a load factor of 85% (IEA and NEA, 2010). The wind power load factor computed from the data used in the simulation tool (average load factor over the 12 generation profiles) is equal to 21.6%. Figure 10 presents the evolution of LCOEs at different carbon prices.

On the basis of LCOE analysis, wind power is cheaper than coal and CCGT if the carbon price is above €39.5 per ton of CO_2. But, the LCOE of wind power corresponds to fixed costs (that is to say, investment cost and O&M cost) while variable costs are an important share of the LCOEs

Figure 10: Levelized Cost of Electricity as a Function of Carbon Price
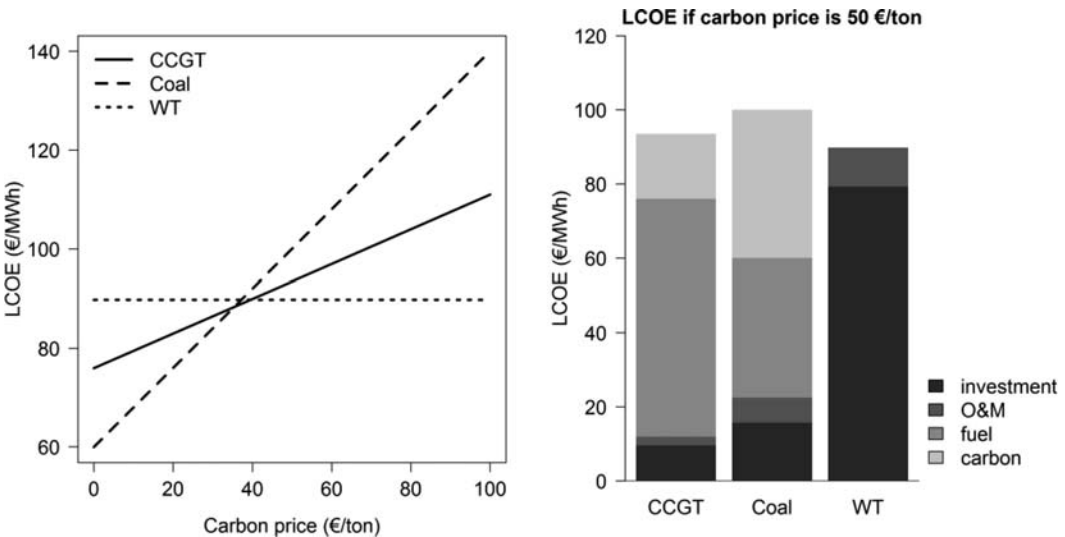
Notes: The discount rate is equal to 8%. The thermal load factor is 85%.

Table 7: Levelized Cost and Fixed Cost Ratio for Different Carbon Prices

Carbon tax scenario (€ per ton of CO_2)		0	50	100
CCGT	LCOE (€/MWh)	76.0	93.5	111.0
	Fixed cost share	15.7%	12.8%	10.8%
Coal	LCOE (€/MWh)	60.0	100.0	140.0
	Fixed cost share	37.5%	22.5%	16.1%
Nuclear	LCOE (€/MWh)	54.9	54.9	54.9
	Fixed cost share	81.8%	81.8%	81.8%
WT	LCOE (€/MWh)	89.8	89.8	89.8
	Fixed cost share	100%	100%	100%

of fossil-fuel plants which increase when the carbon price increases. Consequently fixed costs represent less than 38% of LCOE. Table 7 details LCOE and specifies the fixed cost share. This difference is crucial when looking at investments because the market price is always greater than or equal to the variable cost of plants that produce electricity at the time, given that it is aligned on the marginal cost of the costlier fossil-fuel plants which clear the hourly market. The recovery of fixed costs of the wind power units with their infra-marginal surplus on hourly markets will be much more uncertain than the same fixed cost recovery of the fossil-fuel units. So the selection of technologies by the investors is done with reference to their profitability from their anticipated revenues on the hourly markets rather than their competitiveness in terms of their respective cost-prices.

As underlined by Joskow (2011), LCOE comparison considers that electric energy is "a homogeneous product governed by the law of one price" which makes the comparison of LCOE for renewable electricity sources and conventional technologies not economically relevant. But in fact, the value of a MWh varies with hours of day, week and season on the year when the MWh is generated. Triggering investment cannot be easily deduced from LCOE comparison (which is a cost indicator). The investment process is much more complex that a simple comparison of technologies' costs. The economic profitability of a generating power plant depends on its investment cost compared to the gap between variable cost and market price on each hourly market during the economic lifetime of the equipment, rather than total generation cost.

In fact, dispatchable generating technologies allow producers to choose when their power plants generate electricity and thus maximise their value on the hourly energy markets. More precisely, producers bid on the hourly markets and then, produce electricity only if their bid is cheaper than (or equal to) the marginal clearing one. On the contrary, wind power producers cannot decide whether or not their plants generate electricity. Their moments of reliability are random and quite limited. Consequently, if we suppose that their forecasts is quasi perfect, wind power producers could bid at zero price when they anticipate to be able to generate electricity and are sure to be selected. But, they cannot maximise their profits by producing when the market price is the highest.

To illustrate this difference between dispatchable and non-dispatchable units, Figure 11 shows the time-weighted average price and the wind-profile-weighted[5] average price in the simu-

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5. Whereas the time-weighted average price is the classical mean value of hourly prices (thus it is the mean price received by a base-load producer), the wind-profile weighted average price corresponds to the mean price received by a wind power generator having the average wind profile.

Figure 11: Time-weighted and Wind-weighted[6] Average Price Over Years for the Simulation with a Carbon Price of €100 per Ton of CO_2 (for each year, in average over the 12 weather scenarios)
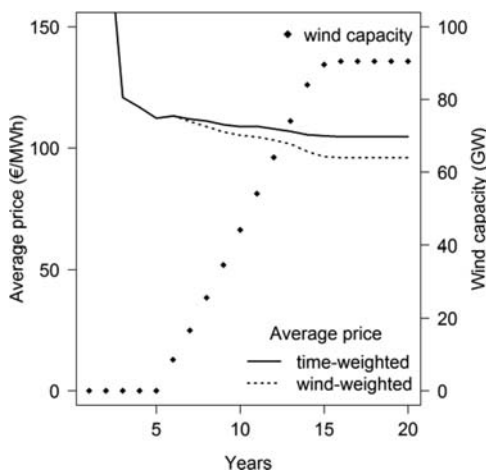
lation with a carbon price of €100 per ton of CO_2. The graph clearly underlines that when wind capacity increases, wind-weighted average price becomes significantly lower than time-weighted average price. In this illustrative case, the market value of wind power is 0.92 of time-weighted average price for an installed wind capacity of 90.5 GW corresponding to 36.3% of electricity generated by wind power. Hirth (2013) estimates a lower market value of wind power, in the range of 0.5–0.8 at a market share of 30%. Green and Vasilakos (2011) also highlight this effect of lower market prices when wind power produces and estimate its magnitude for Denmark. Despite wind power's competitiveness in terms of cost-price when the carbon price is above €40 per ton of CO_2, wind power is weakened by its non-dispatchable nature and the share of fixed cost to be recovered by revenues on quite volatile hourly markers, compared to fossil-fuel technologies. SD simulations support this intuitive difference. Indeed, the threshold value of €70 per ton of CO_2 given by SD simulations is considerably higher than the value of €40 per ton of CO_2 for wind power competitivity obtained by the LCOE method. This shows clearly that the hourly electricity markets do not give an economic value to the MWh coming from variable wind generators in the same way as those of dispatchable plants.

4.2 Profitability of Wind Power

This section discusses how and when wind power begins to be selected and then emerges as a central option for investors. With the market-based selection of investment in the different technologies, the investment process in new power plants is based on the calculation of the internal rate of return (IRR) of every possible project of each technology. Then, investments are obtained by selecting projects from those with the highest IRR and going down to the one which clears the need for new capacity (section 2.3.2).

Carbon price has an effect on the electricity market price and on the respective profitability of the various generating technologies. The explanation of the increase in the IRRs of the wind power stays in the combination of two opposite effects of the higher level of carbon price from one SD simulation to the next one as shown in Figure 7 which displays the yearly average market price

for different simulation cases. Indeed, the market price is influenced by two effects (observed in Figure 7):

(1) a direct effect: an increase in the carbon price pushes up the variable costs of thermal units and consequently, this increases hourly market prices. In other words, the thermal units do not make more profit while the wind power units show better hourly revenues.
(2) an indirect effect: an increase in wind capacity lowers the market price (because the variable cost of wind power is zero).

4.3 Energy Spill-overs and Power Outages

When wind capacity increases with carbon price, both spilling over and electricity outages occur (Figures 8 and 9), but the underlying economic problems are not the same: the first does not raise social efficiency issues while the second one does.

The increase in energy spill-overs is economically acceptable for investors in wind power units because investment decisions under the incentive of a higher carbon price have been made after having assessed the profitability of these new units, even with a share of their production which could not be physically absorbed by the system load demand over a significant number of hours. This puts forward the growing importance of inter-temporal arbitrage with RES-E development, including electricity storage and electricity demand side management. Inter-temporal arbitrages are crucial to deal with wind intermittency and improve the security of supply of the electricity system.

On the contrary, the degradation of the security of supply and its social costs raises an issue of regulatory imperfection. This problem of security of supply related to wind power deployment is created by the low price cap at €3,000 per MWh which does not reflect the social disutility of not being supplied. The price cap impedes price spikes of sufficient magnitude to generate a sufficient scarcity rent and encourage investment in peaking units.

4.4 Sensitivity of the Results to Plant Parameters and Market Design

In this last part of the discussion, some assumptions and their implications on results are discussed.

4.4.1 Plant parameters: fuel prices and investment costs

As mentioned previously, fuel prices and cost assumptions for both thermal an wind power plants remain constant over the 20-year simulations. However, it will obsviously not be the case in reality. Nevertheless, this assumption is necessary to simplify the analysis of the results. Our objective is to assess the influence of carbon price on market-driven investments in wind power and to highligh the difference between the carbon price needed for wind power development obtained by LCOE analysis and SD simulations. The latter is not affected by a change in fuel prices.

To assess the sensitivity of the results to the investment cost of wind power, another series of simulations was conducted with a lower value of the investment cost of wind turbines of €1,200/kW instead of €1,600/kW. This second assumption corresponds to a decrease of 25% of WT investment cost. Except this assumption on the investment cost of wind power, others parameters of

Table 8: Wind Capacity in Case A and Sensitivity to Investment Cost of Wind Power

Carbon price ($€/tCO_2$)	20	30	40	50	60	70	80	90
Wind capacity (GW)— Case A	0	0	0	0	0	37.7	74.2	82.6
Wind capacity (GW)— WT investment cost of €1,200/kW	0	3.6	17.7	91.2	109	120	127	132

the simulations are the same as in case A. The results confirm this significant gap between the carbon price which could make the WT competitive with CCGT in terms of LCOE and the one which allows sufficient profitability to wind power. Table 8 presents the wind capacity obtained at the end of simulations for different carbon price with the assumptions of case A and with the low assumption on WT investment cost (€1,200/kW). The results in relative terms are quite the same. On one hand, LCOE analysis suggests a carbon price of €17 per ton of CO_2 to make wind power competitive with thermal power plants. On the other hand, system dynamics simulations show that a carbon price of €30 per ton of CO_2 is needed to see market-driven investments in wind power. With this value of €30 per ton of CO_2, 3.6 GW of wind power are installed and 91.2GW with €50 per ton of CO_2. In the two cases of wind power investment cost, the gap of carbon prices between LCOE analysis and SD simulations is very significant: a difference of $€23/tCO_2$ with wind power investment cost of €1,200 / kW and a difference of €30 / tCO_2 with wind power investment cost of €1,500 / kW.

Finally, this analysis on the sensitivity of the results to the investment cost of wind power confirms that SD simulations lead to a carbon price needed for wind power development much higher than the one estimated by LCOE analysis.

4.4.2 Level of the energy price cap

In the simulations, the energy market is capped at €3,000 per MWh. This value is the current price cap on EPEX SPOT which applies in France. The price cap influences the level of capacities installed because the peak units should cover their cost during period of electricity outages (scarcity rent). In the reality, setting the price cap is quite challenging: regulators want to ensure security of supply (favourable to high energy price cap) and limit the price for consumers (favourable to a low energy price cap).

With our assumption on the energy price cap (€3,000 per MWh), electricity outages occur approximately 10 hours per year. This value is relatively high compare to the acceptable level for consumers (for example, the French objective of electricity of supply is to limit electricity outages to 3 hours per year). In such a situation, real investors could anticipate that regulators would take actions to limit these periods of electricity outages (by increasing the energy price cap or introducting a capacity mechanism). This aspect is not represented in the modelling. However, another set of simulation was carried out in order to estimate the sentivity of the results to the price cap. All the simulation parameters are identical to case A exept the energy price cap that is fixed to €20,000 per MWh instead of €3,000.

The results on wind capacity (see Table 9) obtained with an energy price cap of €20,000/ MWh are quite close to case A. The development of wind power appears approximately for the same range of carbon price. With €60 per ton of CO_2, only 0.3 GW of wind power is installed;

Table 9: Wind Capacity in Case A and Sensitivity to the Energy Price Cap

Carbon price (€/tCO$_2$)		50	60	70	80
Case A with price cap of €3,000/MWh	Wind capacity (GW)	0	0	37.7	74.2
	Thermal capacity (GW)	88.3	88.5	83.4	78.9
Case with price cap of €20,000/MWh	Wind capacity (GW)	0	0.27	32.7	72.6
	Thermal capacity (GW)	93.5	93.3	88.6	84.7

with a value of €70, wind capacity reaches 32.7 GW. These two sets of simulations only differ in terms of outages: instead of roughly 10 hours, there is less than one hour of electricity outages per year as a consequence of the higher energy price cap which allows a larger capacity of peak power plants (this could be observed by the difference in thermal capacities with case A). Finally, these simulations with an alternative value of the price cap show that the main results in terms of wind power deployment are not really affected by this assumption.

5. CONCLUSIONS

Reduction of CO$_2$ emissions is one of the main objectives put forward by today's energy policies. Different policy instruments like subsidies to low carbon technologies, emissions standards or carbon price can be used to achieve this objective. Today, both subsidies to RES-E (feed-in tariffs) and carbon price (EU-ETS) are in force in the European Union. In the context of electricity markets which are supposed to organise the long term coordination of decentralized market players on the basis of hourly prices equal to short term marginal costs, this article explores the possible development of wind power within an energy-only market without any support scheme. A carbon price is introduced in order to trigger investments in renewable energies. SD modelling is employed to simulate evolutions in the generation mix over a 20-year period for different values of carbon price. Results confirm that not only economic competitiveness in terms of LCOEs, but also profitability against traditional fossil-fuel technologies are necessary for a market-driven development of wind power.

The study highlights a very significant gap between the carbon price which makes wind power competitive in LCOE analysis and the carbon price which triggers market-driven investments in wind power in the simulations of investments in electricity generation. Market-driven development of wind power only becomes possible if the carbon price is far higher than the threshold given by the analysis of LCOE. In this way, this paper strongly illustrates that LCOE approach is a poor way of assessing what carbon price would be necessary to achieve substantial market-driven development of wind power. Besides, if we keep the nuclear option open as a low carbon technology, results show that market-driven development of wind power is not possible. In the case of an important existing nuclear capacity, wind power investments require a moratorium on new nuclear development and a sky-rocketing carbon price.

This suggests that the transition to full market integration of on-shore wind power and more generally variable RES-E should be gradual and supported by strong political commitments reflected by a high and stable carbon price. Indeed, the assumption of a policy based on a fixed and high carbon price requires strong political commitments that may not arise in reality. Moreover, as shown by the IEA report (IEA, 2007), the level of CO$_2$ price should be significantly higher to trigger investment in wind power plants if uncertainty on carbon price and risk adverse investment

behaviours in the electricity markets are taken into account. Thus, as the carbon price emanating from the EU ETS is likely to remain uncertain in the future despite the envisaged reforms, further developments of the present SIDES model will assess possible impacts of uncertain carbon and -fuels prices on the development path of wind power. Moreover, in the context of the current debate about security of supply, a number of countries have implemented (or will implement) a capacity mechanism in addition to the energy market. In this perspective, the analysis of market-driven developement of RES-E presented here could be extended to integrate revenues from a capacity mechanism.

ACKNOWLEDGEMENTS

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APPENDIX A: FUNCTIONNING OF THE SIDES (SIMULATOR OF INVESTMENT DECISIONS IN THE ELECTRICITY SECTOR) MODEL

The SIDES model presented in this article was implemented with the open-source software R (see http://www.r-project.org/ for more details about this software environment). It belongs to System Dynamics programming. For a complete description of System Dynamics methodology, one should refer to Sterman (2000).

Principles of the SIDES model are described in section 2 of the article. This appendix aims at providing a more detailed and technical description of the SIDES model.

Table A-1: Inputs, variable 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 *(here, −1% / 0% / + 1% per year)*
- I3: Weather scenario of electricity demand and production from wind power (annual data in hourly steps)
- I4: Realized 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 *(here, it was not used)*
- 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

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

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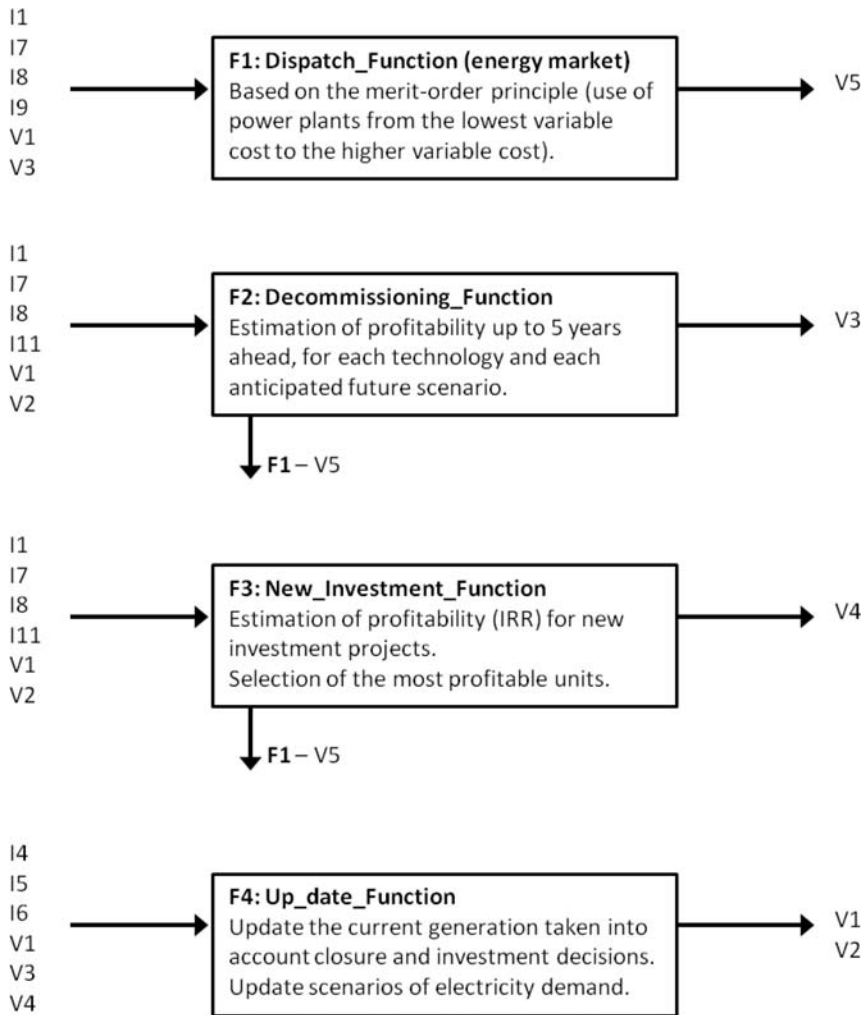- V1 = function(I5, I6, V3, V4)
- V2 = function(I2, I3)

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)

Figure A-1: Description of the Main Functions

I1
I7
I8
I9
V1
V3

F1: Dispatch_Function (energy market)
Based on the merit-order principle (use of power plants from the lowest variable cost to the higher variable cost).

→ V5

I1
I7
I8
I11
V1
V2

F2: Decommissioning_Function
Estimation of profitability up to 5 years ahead, for each technology and each anticipated future scenario.

→ V3

↓ **F1 – V5**

I1
I7
I8
I11
V1
V2

F3: New_Investment_Function
Estimation of profitability (IRR) for new investment projects.
Selection of the most profitable units.

→ V4

↓ **F1 – V5**

I4
I5
I6
V1
V3
V4

F4: Up_date_Function
Update the current generation taken into account closure and investment decisions.
Update scenarios of electricity demand.

→ V1
V2

Figure A-2: Description of the Functioning of the SIDES Model (corresponding to the main script)
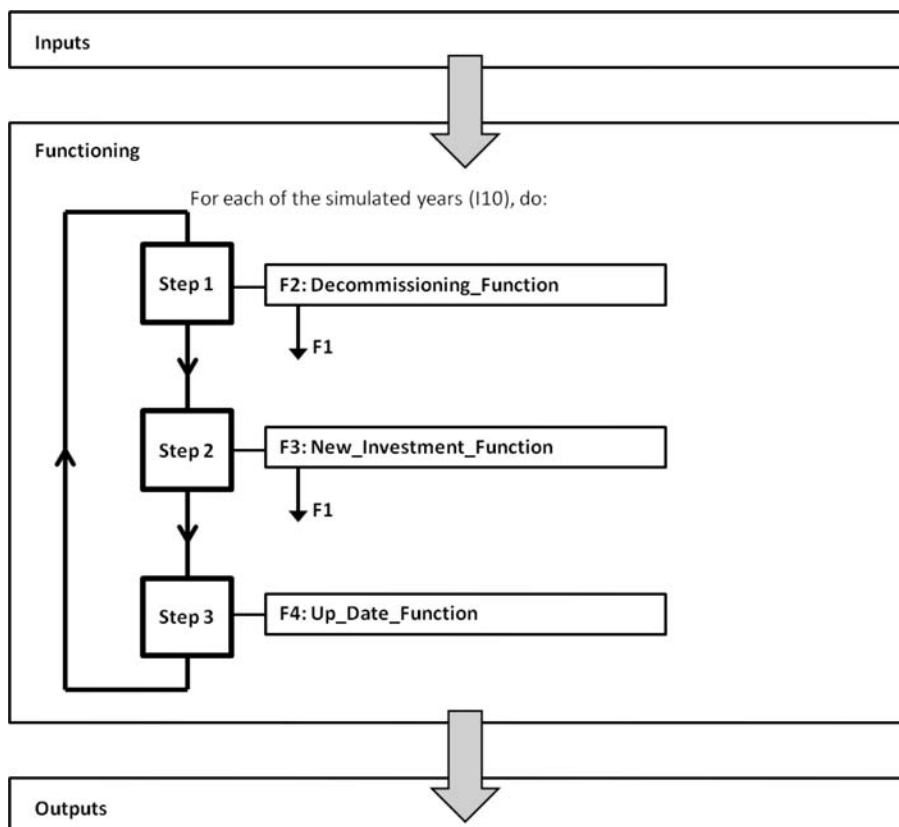
The pseudo code of the SIDES model is provided below.

**** Main Script ****

1   READ all the input data.
2   FOR each year which is simulated, do
3   CALL Decommissioning_Function.
4   COMPUTE the up-dated generation mix by taking into account the decommissioning decision.
5   CALL New_Investment_Function.
6   CALL Up_Date_Function with the decommissioning and new investment decisions.
7   END FOR

** Dispatch_Function (F1) **

1   READ the installed capacity of each technology and the marginal generation costs.

2   READ the demand scenario and its correlated wind production profile.

3   COMPUTE the hourly production from wind power which is equal to the hourly production factor times
4   the installed capacity of wind power.

5   COMPUTE the net demand which corresponds to the hourly electricity demand minus the hourly
6   production from wind power. Negative net demand is not permitted. Negative values are set to zero.

7   COMPUTE the hourly price considering only thermal units and net demand. The hourly price is equal to
8   the marginal generation cost of the more expensive unit to run. If the total generation thermal capacity
9   is lower than net demand, the price is equal to the price cap of the market. See figure A-3.

10   RETURN hourly prices.

      In the SIDES model, all units of a technology are supposed to have the same marginal generation cost. In that sense, there is no difference between new and old units among a technology. Consequently, the corresponding supply function is a step function as shown in Figure A-3 (solid line). But in reality, marginal cost of new units is generally lower than the one of old units. The real function is as illustrated in dashed line in Figure A-3. Then, if new power plants have slightly lower marginal costs than old ones, considering the real marginal cost function leads to higher incentive to build new power plants which 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 here.

Figure A-3: Simulated Marginal Cost Dunction and Real Marginal Cost Function

€/MWh

GW

―――― Marginal cost function simplified as a step function

― ― ― · Real marginal cost function
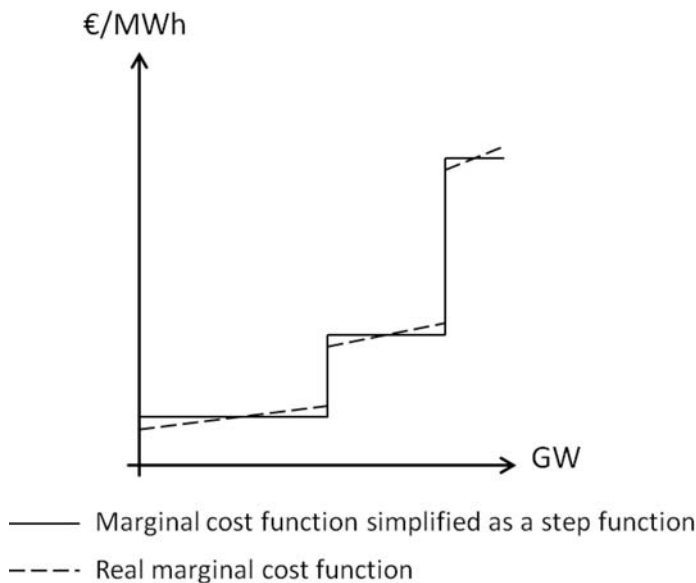
** Decommissioning_Function   (F2) **

1 READ the data corresponding to the current status of generation mix and general parameters (current
2 installed capacity of each technology, technologies' specifications and discount factor).

3 For the next year:

4 READ the data corresponding to the anticipations (demand scenarios and correlated wind generation
5 factors, fuels prices, carbon price).

6 FOR each set of anticipation for the next year, do

7   COMPUTE the variable costs of each technology given fuels prices, carbon prices and emissions
8   factors.

9   CALL Dispatch_Function.

10   COMPUTE the net profit for each technology. It corresponds to the sum of hourly market price
11   times the production ratio, minus variable generation cost, minus annual operation and
12   maintenance cost.

13 END FOR

14 COMPUTE the average net profit for the anticipated scenarios, for each technology.

15 SELECT the technology indices for which the average net profit on the next year is negative.

16 FOR the technology selected above, do

17   FOR each year of the 5 following years, do

18   COMPUTE the variable costs of each technology given fuels prices, carbon prices and
19   emissions factors.

20   CALL Dispatch_Function.

21   COMPUTE the net profit for each technology. It corresponds to the sum of hourly market
22   price times the production ratio, minus variable generation cost, minus annual operation
23   and maintenance cost.

24   END FOR

25 END FOR

26 COMPUTE the average net profit for the anticipated 5-year scenarios for each selected technology. The
27 5-year net profit corresponds to the discounted sum of annual net profits, using the discount factor.

28 Among this tested subset of technologies, SELECT the technologies for which the 5-year average net
29 profit is negative and DEFINE the capacity of the selected technology to the current value minus the
30 typical size of capacity. STORE in memory the decommissioning decisions.

31 REPEAT from line 16 UNTIL there is no decommissioning of existing power plant.

32 RETURN the number of units (of typical size) to be decommissioned for each technology.

** New_Investment_Function   (F3)**

1 READ the data corresponding to the current status of generation mix and general parameters (current
2 installed capacity of each technology and its future evolution, technologies' specifications and discount
3 factor).

4 FOR each technology, do

5 COMPUTE the generation mix to be tested by adding one unit of typical size of the technology
6 considered to the current generation mix. Update the evolution of the generation mix over years
7 taking that into account.

8 FOR each future year, up to 5 years ahead, do

9 SELECT the generation mix corresponding to this future year.

10 FOR each anticipated scenarios of the year, do:

11 CALL Dispacth_Function.

12 COMPUTE the market revenue of the unit considered. It corresponds to

13 $$\sum_{year} \max(market\ price - variable\ cost; 0). production$$

14 END FOR

15 COMPUTE the average revenue for the anticipated scenarios of the year.

16 END FOR

17 COMPUTE the net profit on each future year, on average over the future scenarios. The net profit
18 corresponds to the average revenue from the energy market, minus the annual operation and
19 maintenance cost.

20 COMPUTE the Internal Rate of Return (IRR) based on the investment cost of the technology and
21 the average net profits for each future year, under the assumption of myopic foresight.

22 END FOR

23 SELECT the technology with the highest IRR.

24 IF the IRR of the selected technology is above 8%, a unit of typical size of this technology is added to the
25 current mix (and the decision is saved for outputs). The current mix is up-dated, taking into account the
26 construction time.

27 END IF

28 REPEAT from line 4 UNTIL no more investment is selected or until the volume constraint (a maximum of
29 10GW of new units) is reached.

30 RETURN investment decision, corresponding to the capacity to be installed for each technology.

** Up_Date_Function   (F4) **

1 READ the data corresponding to the current status of generation mix and general parameters (current
2 installed capacity of each technology and its future evolution, technologies' specifications).

3 READ the decommissioning and new investment decisions.

4 COMPUTE the up-dated evolution matrix of the generation mix given the decisions. New units appear in
5 the generation mix after the construction time. Decommissioning decision is effective immediately from
6 the current year.

7 FOR all weather scenario of the current year, do

8   CALL Dispatch_Function.

9   STORE results as output.

10 END FOR

11 READ the scenario realised for the current year (defined in inputs).

12 COMPUTE new demand scenarios given the realised macroeconomic growth. The new weather scenarios
13 correspond to the previous ones multiplied by the realised macroeconomic evolution of the system.

14 RETURN up-dated data

15