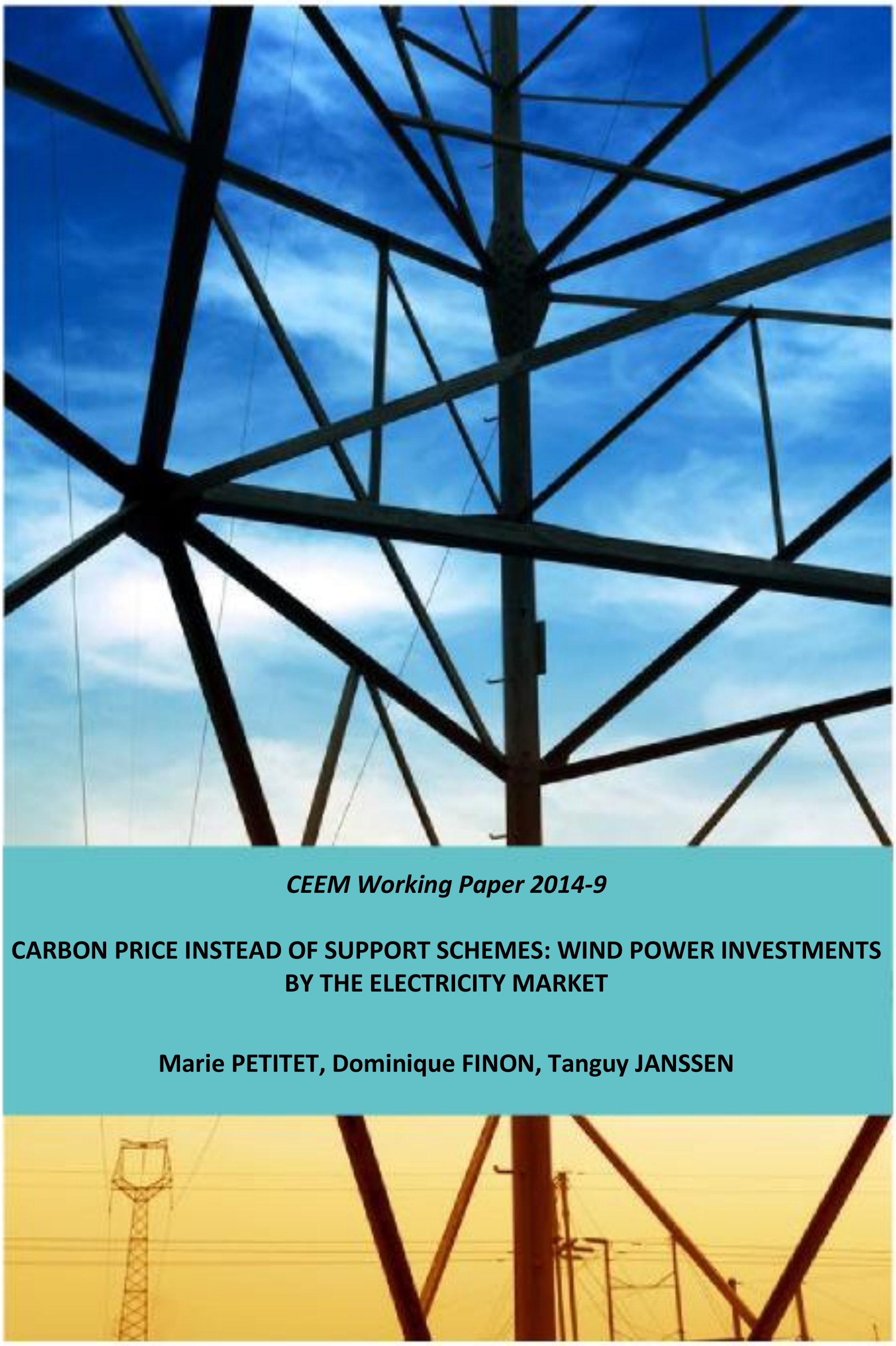
CHAIRE EUROPEAN
ELECTRICITY MARKETS
Fondation Paris-Dauphine



CEEM Working Paper 2014-9

CARBON PRICE INSTEAD OF SUPPORT SCHEMES: WIND POWER INVESTMENTS BY THE ELECTRICITY MARKET

Marie PETITET, Dominique FINON, Tanguy JANSSEN

DAUPHINE
UNIVERSITÉ PARIS

Chaire de recherche soutenue par

RTE EDF EPEXSPOT UFE

CARBON PRICE INSTEAD OF SUPPORT SCHEMES: WIND POWER INVESTMENTS BY THE ELECTRICITY MARKET

Marie Petitet[1,2,*] Dominique Finon[2,3] Tanguy Janssen[1]

For submission to the journal *Energy Policy*

October 2014

ABSTRACT

In this paper we study the development of wind power by the electricity market without any usual support scheme which is aimed at subsidizing non mature renewables, with the sole incentive of a significant carbon price. Long term electricity market and investment decisions simulation by system dynamics modelling is used to trace the electricity generation mix evolution over a 20-year period in a pure thermal system. A range of stable carbon price, as a tax could be, is tested in order to determine the value above which wind power development by market forces becomes economically possible. Not only economic competitiveness in terms of cost price, but also profitability against traditional fossil fuel technologies are necessary for a market-driven development of wind power. Results stress that wind power is really profitable for investors only if the carbon price is very significantly higher than the price required for making wind power MWh's cost price competitive with CCGT and coal-fired plants on the simplistic 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 by the preference for a stable and high carbon price rather than a fuzzy price of an emission trading scheme. Besides, results show that market-driven development of wind power would require a sky-rocketing carbon price if the initial technology mix includes a share of nuclear plants even with a moratorium on new nuclear development.

Key words: electricity generation investments, wind power, system dynamics.

Acknowledgements: This paper has benefited from the support of the Chaire European Electricity Markets of the Paris Dauphine Foundation, supported by RTE, EDF, EPEX Spot and the UFE.

[1] RTE, Markets Department, Tour Initiale, 1 Terrase Bellini - TSA 41000, 92929 La Défense Cedex, France.

[2] European Electricity Markets Chair, Paris-Dauphine University, Place du Maréchal de Lattre de Tassigny, 75775 Paris Cedex 16, France.

[3] CIRED-CNRS, 45 bis avenue de La Belle Gabrielle, 94736 Nogent sur Marne Cedex, France.

* Corresponding author: marie.petitet@rte-france.com, +33 (0)1 41 02 13 46.

1. INTRODUCTION

Climate change has received growing attention since the end of the 20th century. In 2005, the European emission trading system (EU ETS) has been launched to tackle greenhouse gas (GHG) emissions. Later on, the climate and energy package was adopted by the European union (UE) in December 2008. It defines three objectives for 2020: a 20% reduction in greenhouse gas emissions from 1990 levels, 20% share of energy from renewable resources and 20% improvement in energy efficiency. Moreover, uncertainties on long-term fuel prices and reducing energy dependence are other concerns tackled by energy policies. In that context, renewable energy sources of electricity (RES-E) are particularly relevant. But unfortunately, most of RES-E are still immature and uneconomic, except for some technologies like hydroelectricity and geothermal power that are dependent on the availability of favourable geological conditions. Among these, this article focus on on-shore wind power, one of the most mature subsidised RES-E.

Today, support mechanisms to on-shore wind power (e.g. feed-in tariffs, fixed premiums, contracts for difference, certificate obligations, etc.) strongly influence investment choices of electricity producers. While investments in conventional electricity production technologies are mainly driven by their market revenues — energy market and eventually capacity market —, future incomes of wind power plants are ensured by a specific mechanism and estimated with a low level of risk. For instance, in France, the feed-in tariff in force for on-shore wind power is € 82 per MWh for the first ten commissioning years and between € 28 and € 82 per MWh for the five following years (according to the conditions defined in the executive decision of November 17th 2008). From that perspective, investments in wind power are not linked to market signals and thus, the level of investment may not correspond to real need of the electricity system.

To ensure the large scale deployment of intermittent RES-E, the solution lies in various mechanisms that guarantee stable long-term incomes (these 15-year feed in tariffs or assimilated, or else long-term contracts with guaranteed revenue). 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) the other, a non-market regime based on these long-term arrangements providing risk management by a guaranteed price per MWh and adding, a production subsidy, for non-commercially mature technologies. At the end of the day, the growing importance of the variable RES-E capacity creates large effects on the market functioning by increasing price volatility, by lowering average daily, weekly and yearly prices because their MWh sales at zero price on the hourly markets, and by endangering the profitability of very recent gas plants and a fortiori of new investment decisions in other technologies (Finon and Roques, 2013). It was time to re-asses RES-E support schemes in place, considering that a suitable RES-E support should induce private investors to make socially efficient choices on long term in the electricity markets.

The participation of intermittent production to the energy market encourages RES-E generators to operate in a more efficient way on hourly markets and entrants to invest in relation of the anticipated situation of the markets in the long term, in particular to slow down investment in these technologies as well in other technologies in case of overcapacity. In the new guidelines on state aid adopted in April 2014 (European Commission, 2014), the European Commission supports the integration of renewable technologies to the electricity market by exposing the generators to the hourly market price, by the promotion of feed-in premium, and by auctioning contracts for getting this premium to incite them to reveal their costs. Following this trend, different European states have redefined the form of support to RES-E (electricity market reform with FIT and auctioned contracts in the United Kingdom; Spanish reform with improvement of feed-in premium; French consultation on RES-E support schemes in 2014). In Germany, the reform of the Renewable Energies Act (Erneuerbare-Energien-Gesetz, EEG) confirm this orientation to a market-driven approach for renewable technologies based on feed-in premium and auctioning.

Moreover, theoretical arguments in favour of carbon price to trigger entries in RES-E generation without the support mechanisms as soon as we are close to the commercial competitiveness are gaining in audience (Crampes, 2014). A high carbon price would significantly increase the variable cost of fossil technologies, and thus the prices on hourly electricity markets, ensuring the profitability of RES-E entries which beat fossil technologies entries. Following this trend towards more and more market-driven RES-E development, this paper focuses on investments in the most promising RES-E technology on-shore wind power within an energy-only market without any additional support mechanism, but with a credible carbon price. It is currently argued that with the present cost-price of MWh produced by the most modern wind power installations (around € 60 per MWh for a load factor of 20-25%), the carbon price to help wind power to reach competitiveness is quite low (in the range of € 30 to € 40 per ton of CO_2. But in fact the electricity markets are structured on hourly markets which do not set prices in a way that the average price or revenue per MWh on the year is aligned more or less on the average costs of new generators. So, results of an elementary optimisation approach to set the technology mix in the future with a wind power technology supposed to be competitive with the other conventional technologies should be compared to an approach which simulates the long term dynamics of an electricity market based on the investment decisions in the different technologies. We examine conditions for such a market-driven development with a system dynamics (SD) model which simulates investment decisions by private competitors based on their anticipation of hourly revenues over a 20-year period. We suppose the adoption by the government of a carbon pricing approach which allows to send a credible price signal, a carbon tax which is constant on the 20-year period, rather than an uncertain carbon price signal as it could emanate from a cap and trade mechanism as the EU ETS has been during its three first phases. Different levels of the CO_2 prices are tested in the SD model in order to highlight the capability of the carbon price to orient investors towards wind power units.

The following section 2 provides elements about the different ways to support wind power development in the electricity sector and its integration in the power markets. The system dynamics model is described in section 3. Results of the simple optimisation approach are presented in section 4. Section 5 details the results of SD simulations for different levels of carbon price and highlights differences compared to the simple optimisation. Finally, section 6 concludes and offers suggestions for further works.

2. SUPPORTING WIND POWER DEPLOYMENT: ENTRIES FROM OUT OF MARKET TO ENTRIES BY THE MARKET

In the academic literature, a carbon price is considered optimal for enabling least-cost emissions reductions, and should be the cornerstone element of a climate policy to offer the most socially efficient decarbonisation way. However, in the real world it alone is not usually sufficient because of market failures, in particular inter-temporal externalities of learning processes. Long-term costs of moving to a cleaner development path can be reduced by the development and deployment of new low carbon technologies, among which the renewables. Integrating these two policy areas therefore has the potential to reduce the cost to society of decarbonisation over the short and long term. Moreover, on electricity markets in a regulatory environment with carbon price, variability of the production of wind power creates large price risks for investors and makes fixed cost recovery more uncertain than for dispatchable technologies. The RES-E deployment by production subsidies has also dynamic effects on the wholesale price setting which amplifies risk management problems. Both problems can justify mechanisms of risks transfer on the public budget or on the consumer. That is where the dilemma lies: implementing support mechanisms or using a regulated carbon price which offers certainty but implies to define its level correctly. The second way would help market to send the right price signal to incite producers to invest in the right technologies to maintain the optimality of the technology mix including wind power units besides thermal technologies, as it was before the implementation of RES-E support. The crucial issue becomes to discover the level of the carbon price which triggers investment in wind power units and this is particularly challenging because the hourly prices on the electricity market are not uniform at all.

2.1 Wind power support schemes versus carbon price incentives

Up to now, wind power entry and more generally RES-E entry by market signal is not profitable because of the barrier raised by the learning costs and uncertainty to cover their fixed costs given that investment cost of wind power per MW is greater than most of fossil-based technologies (nuclear excluded). Besides, electricity generation of wind power depends on wind. Its load factor on a year (which is calculated by reference to the total energy produced and the total power capacity supposed to produce at full power) is between 20 to 30% while thermal technologies are available up to 85%. Hence, even if it is one of the most mature RES-E, wind power suffers from a lack of economic competitiveness compared to other traditional technologies. But, once wind power plant has been built under the incentive of a support, electricity generation is at zero variable cost and does not emit CO_2. To support that environmentally friendly technology, specific subsidy mechanisms are into force in most of European countries. The main support mechanisms are:

- Feed-in tariffs (FiT): wind farms operators receive a guaranteed price for every MWh generated for a specified period (10 to 20 years). System operator or historical operator has a purchase obligation of electricity generated.
- Contracts for difference: wind farms operators sell their electricity on the energy market and receive a payment from a public agency, corresponding to the difference between the market price and a specified value (or conversely reimburse the public agency if the market price is upper this value). The contract is concluded for a long period.
- Feed-in premiums (FiP): RES-E generators sell their electricity on the energy market and benefit from a regulated premium (paid by a public agency) for every MWh, which is defined for a period as long as for the FiT.
- Renewables obligations: electricity suppliers have the obligation to guarantee that a share of electricity is generated from RES-E by owning renewable obligation certificates (ROC) sold by

RES-E generators. Green electricity is sold on the energy market, and green certificates on a ROC market. RES-E generators' revenues correspond to market revenues plus a premium. But this premium is not fixed; it is a variable premium which is set by the ROC market.

Those support mechanisms differ in the risk wind generators are exposed to. Feed-in tariffs do not expose wind farms operators to market risks while feed-in premium do. Certificate obligation not only exposes generators to the hourly electricity market risks, but also to the ROC market risks. As capital cost of a project increases with risks, support mechanisms have different impact on the total cost of wind power projects and beyond on the RES-E policy cost paid by the consumers via a levy[4]. Consequently, support mechanisms directly influences level of investment in wind power.

Some authors advocate to phase out RES-E supports, and to substitute them by the incentive of a CO_2 price set by an increasing carbon tax or a stringent cap and trade (for instance Crampes (2003)). Fisher and Newell (2008) use a long term modelling of the electricity market with perfect information to assess efficiency of different types of energy and environmental policies focused on technologies learning, for reducing carbon emissions by a power system and show that emissions price is the most efficient option. But we should notice that they use a simplistic representation of the electricity markets and cost functions of low carbon technologies. This leads to an underestimation of the carbon price level which leads to beat any other instruments for developing low carbon technologies when the instrument are compared. When considering price-elastic electricity demand, Goulder (2003) argue that RES-E supports do not push up electricity prices as the carbon price should do: "It does not getting the electricity price up to marginal social cost [...]. It means that it does not engage the electricity conservation (energy efficiency) as a channel for reducing emissions".

Whatever it will be, RES-E capacity development in general and wind power capacity development in particular have also important side effects on the functioning of the hourly electricity markets which, in the long run, alter the function of long term price signal of the electricity market.

2.2 Difference in impacts of wind power entries on the electricity market

Literature provides a range of studies focusing on the impact of wind power capacity developed by out-of-market entries on the electricity market: effects on the net load curve, market prices and generation mix, because the de-optimisation of the overall system. Adding wind power directly impacts net electricity demand[5] to be served by thermal power plants. In practice, it does not

[4] Comparisons of different policy options are proposed by a number of papers (see for instance Menanteau et al. (2003), Palmer and Burtraw (2005), Klessmann et al. (2008)). Part of the recent literature argues for mechanisms which expose RES-E generators to market risks. It tends to overestimate the advantage of FiP or renewables obligation. For instance Klessmann et al. (2008) argue that exposing RES-E generators to market risks may eventually enhance the cost effectiveness of the system and limit the cost to society. Moreover, price competition between wind generators may have virtue to limit their costs and their eventual rent. But in the two cases, it is difficult to perceive what is at stake in terms of operational efficiency and investment efficiency.

[5] Net electricity demand (or net load curve) corresponds to the real electricity demand minus electricity generation of wind turbines.

decrease real demand by a constant value but reshapes net load curve as shown in Figure A-12: variation between peak and off-peak periods is greater for the net load curve than for real load. When the RES-E entries are “out-of market” (that is to say, pulled by production subsidies), the resulting overall technology mix cannot be the optimal one by definition. Moreover the residual non RES-E part of the generation system should have to be adapted on the long term to the artificial entries of the RES-E capacities. Optimal thermal generation mix is affected by entrance of new wind power plants, both in terms of the level of capacity needed and relative share of each technology in capacity and energy.

Entrance of large renewable generating capacity decreases the average market price by reducing net demand addressed to thermal power plants (merit-order effect). Sensfuß et al. (2008) estimated a reduction of € 7.8 per MWh on the German spot market in 2006 for a simulated renewable generation of 52.2 TWh. This entrance contributes also to reduce the hourly production of the thermal units by pushing them out of the merit order more and more frequently. These two effects makes the investment in thermal units much more risky to cover the investment cost. On the long run, if the reshaping of net load curve leads to the adaptation of fuel-based capacities, this adaptation is more than difficult. Nicolosi and Fürsch (2009) stress the increase of hourly market price volatility when renewable capacity is added and show that it results in higher peak-load capacity on the long term[6]. The same effect is obtained by Bushnell (2010) using an equilibrium model. Whatever it would be, there is few chance to arrive to an optimal mix of this residual part in any case because the result of RES-E promotion policy by FiT or any other instrument is uncertain. Last but not least, when a particular wind farm generates electricity, a large majority of the other wind farms of the same area or country also generate electricity (wind is rarely local). Combined with the merit-order effect, this results in a decrease of RES-E market revenues as installed wind capacity increases. This effect could be referred to as "cannibalisation" effect of wind power.

In a situation without RES-E support scheme, wind power entries are triggered by the profitability of investment along with investment in dispatchable thermal units, and this under the incentive of high hourly electricity market prices because of the effect of high carbon price. These different effects are endogenous to the functioning of the market. In other words, the merit order effects resulting from the RES-E capacity development – the decrease of hourly market prices, the push out the merit order when wind blows or else – are endogenous to the long term market dynamics. So even if wind power development occurs which result in energy spills, investments have been decided knowingly.

[6] Note that this long term evolution of generation mix towards higher peaking capacity and limited base-load capacity may enhance value of flexible power plants. Indeed, with high penetration of wind power, more flexibility in electricity generation is needed to balance thermal supply and electricity demand. At the same time, total cost of the system may be affected by more frequent start-ups and ramping phases.

3. THE PRESENTATION OF THE SD MODEL

The modelling adopted here focuses on the effectiveness of carbon price as a market driver to invest in renewable technologies in an energy only market. A fixed carbon price is added to the modelling of an energy-only market in order to test a carbon policy. This carbon pricing is considered in the peculiar context of hourly electricity market and its price setting (to the marginal cost of the overall system). This approach is far from the traditional price setting on average costs with the adders of mark up in commodities markets.

3.1 Overview of the model

The analysis is based on a simulation model belonging to system dynamics (SD) programming. Regarding the electricity sector, SD method has been applied[7] to study investment cycles and effects of different market designs in a randomly environment (see Teufel et al. (2013) for a review). 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 on markets. Long-run equilibrium approach (Nicolosi and Fürsch, 2009; Buschnell, 2010) is used in the literature to highlight 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 equilibrium and does not indicate if the real initial electricity system could evolve toward this equilibrium. While equilibrium approach provides the best solution, system dynamics focus on dynamic evolutions of electricity systems. Thus, it is a relevant complementary approach to equilibrium models.

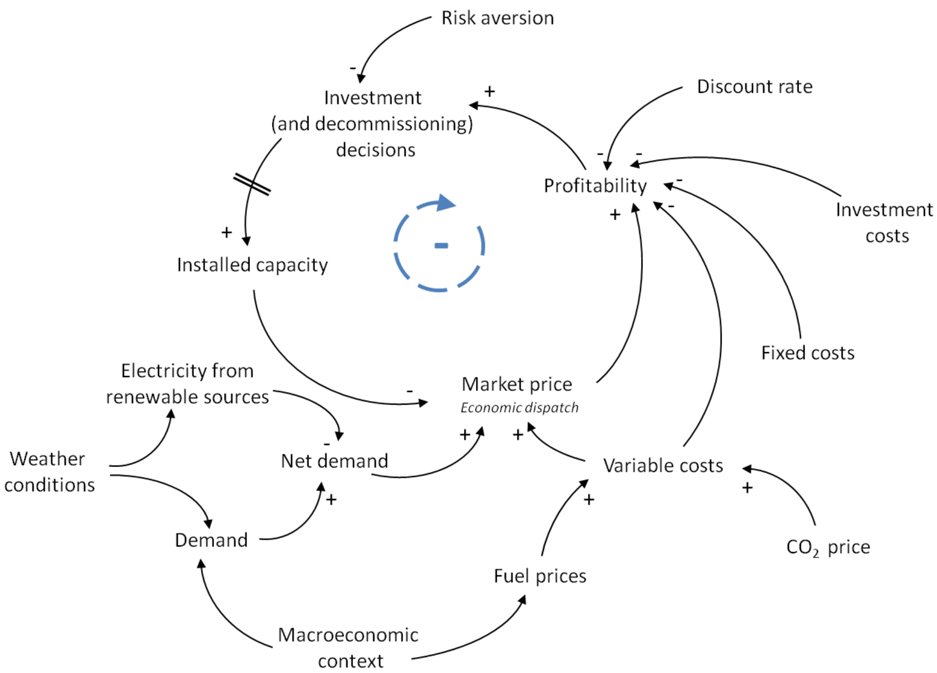
Belonging to SD programming, the model allows to simulate market evolution under investment decisions by a representative agent in a context of perfect competition in which he behaves as a price-taker. Decision process requires to anticipate future profitability of different generating technologies by modelling market evolution in a set of scenarios. Those future scenarios are obtained by historical simulation rather than by Monte Carlo simulations[8], taking into account assumptions on weather, macroeconomic growth and political orientation (through a carbon price).

---

[7] Ford (2001) was one of the pioneers in using SD to explore 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. Their analysis is based on 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. For that purpose, credit risk theory and game theory are applied together with SD modelling. In particular, they propose to differentiate among electricity companies in order to represent not only one but a range of agents in competition.

[8] Historical simulation can be considered as an alternative to Monte Carlo simulation. While Monte Carlo simulation refers to a continuous distribution, historical simulation is based on a finite historical panel data. Thus, statistical distribution of the output is estimating by testing each input scenario.

Figure 1: Causal-loop diagram of the model



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

On a year, 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 concerned equipment. Anticipations are obtained by historical simulation of a number of future scenarios on weather parameters and on the demand growth.

The representation of electricity power plants does not model each single power plant but consider 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 supposed to be available all the year. Planned maintenance and forced outages are not taken into account. Electricity grid is not represented. The assumption is a single area 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.

3.2 Modelling the electricity market

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 generated power is equal to the load demand excepted during hours of electricity outage. 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 (€ 3 000 per MWh as defined by EPEXSPOT). 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. Peak electricity prices are a crucial driver for investment. The ratio between the marginal cost of peaking units and the price cap (€ 3 000 per MWh) is in the order of 10; so that revenues during electricity outages may represent a large part of total revenues[9].

Given that 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.

3.3 Modelling investment decisions

The model considers a single representative agent acting as a price taker whose objective is to maximise its profit. Here, the modelling does not focus on agents' behaviour, as could be integration of risk aversion. Moreover, time management in investment decisions raises real dilemma 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.

3.3.1 Representation of uncertainty

Economic profitability of electricity generating projects is highly sensible to some 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 for wind turbine). The electricity market is modelled as described above. As a consequence, market price is directly related to electricity demand, fuel prices, carbon price and generation mix. Moreover, cost structures and future generation mix are supposed to be well known by the single-investor. In this version of the model, fuel prices are supposed to remain constant[10] 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 made its anticipation of the future 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 model considers 3 macroeconomic assumptions which correspond to an annual growth 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. Figure B-13 presents an example of the anticipation

[9] Note that dynamic constraints of fossil-based technologies (such as minimum up-down time, minimum production time, etc.) are not taken into account to set the market price. The underlying hypothesis is that each fossil-based power plant is capable of producing electricity for one single hour.

[10] That hypothesis was mainly undertaken for computational reasons. It decreases the number of future scenarios to be estimated during the simulation.

process of load related to the macroeconomic anticipated growth. In the short term, electricity demand is also highly sensible to weather conditions. To represent that sensibility to the weather, 12 representative demand profiles are used.

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

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

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

Carbon price
In the simulations, 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 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 investment decision, generating technologies are tested for all those scenarios.

3.3.2 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 model. However, the modelling of investment decisions depends on economic profitability of technologies and a political driver — the carbon price.

Literature on investment decisions highlights two main types of criterion:

- **Net Present Value (NPV)**: it corresponds to the sum of the discounted cash flows for all entire lifetime of the project. If the NPV of a project is positive, the project adds value to the firm and thus may be launched. Among a range of projects, an investor should select the higher NPV. Given a project, the NPV depends on the discount rate r and is expressed as:

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

where the annual net revenue $NR_{\chi}(y)$ is defined as:

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

- **Internal Rate of Return (IRR)**: it is the discount rate that makes the NPV equal to zero. A project may be carried out if its IRR is greater than the cost of capital of the firm.

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

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. Generally, both NPV and IRR led to the same selection. But in some cases, investment decision may differ according to the criterion employed.

In the model, 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 IRR is employed to select the most profitable project among a range of projects[11]. The modelling includes both computation of IRR on 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 statistical distribution of IRRs.

To be selected, IRR must be greater than 8%, corresponding to cost of capital of typical electricity producers estimated by DGEC (2008). Yearly investment decision is inferred on the basis of a recursive loop which selects the most profitable generating project at each iteration as illustrated in Figure B-14.

3.3.3 Decommissioning existing power plants

Decommissioning of existing power plant is also a key element to understand adaptation of 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, it is considered as sunk costs. Indeed, when the power plant has already been built, payment of 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.

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

In that case, profitability is estimated on the long-term for the following 5 years in order to determine if that lose 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.

3.4 Simulation data

Technical specifications of generating technologies

In the simulations, only wind turbine (WT) and thermal technologies are modelled. Three thermal technologies are considered: combined cycle gas turbine (CCGT), coal-fired power plant (Coal) and oil-fired combustion turbine (CT). Nuclear is excluded from this study but never the less, its effects on our results are presented in section 5.2.

Technical specifications are presented in Table 2. In this case study, wind power and fossil-based technologies are supposed 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 cost structures due to evolution of row material prices or due to technical developments. Moreover, fuel prices remain constant over time. However, in reality fuel prices depend on macroeconomic developments. Thus, changes in relative variable production costs may occur such as it has been the case recently for coal and gas because of introduction of shale gas in the US. This assumption of constant fuel prices decreases uncertainty of power plants' revenues and consequently it influences results of the model.

Table 2: Plant parameters used in simulations

	CCGT	Coal	CT	WT
Investment cost (€/MW)	800 000	1 400 000	590 000	1 600 000
Annual O&M cost (€/MW/year)	18 000	50 000	5 000	20 000
Nominal power capacity (MW)	480	750	175	45
Fuel variable cost (€/MWh)	64	37.5	157	0
Carbon emission factor (ton of CO_2/MWh)	0.35	0.8	0.8	0
Construction time (years)	2	4	2	2
Life time (years)	30	40	25	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 total variable generation cost is equal to the fuel variable cost plus carbon emission factor multiplied by the carbon price.

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 of the optimisation of the central planner, without wind power. This optimal thermal generation mix obtained by screening curves method (Green, 2006; Joskow, 2006) on the mean load curve and approximated to respect 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 /MWh) in the optimisation approach. Table 3 details the resulting initial generation mix of the first simulated year.

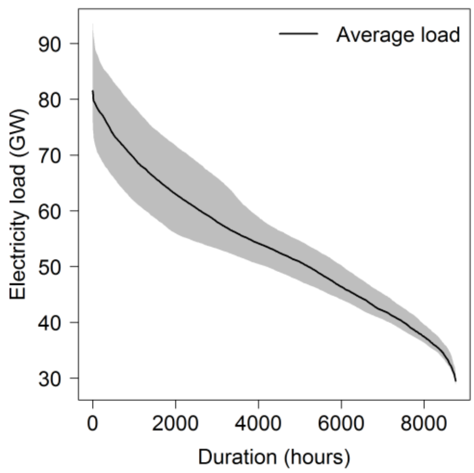
Table 3: Initial generation mix

Technology	CCGT	Coal	CT	WT
Capacity (GW)	17.76	57.75	3.50	0
Number of plants	37	77	20	0

Electricity load and wind generation

Electricity demand differs according to weather conditions on the very short term and macroeconomic evolutions which condition the demand growth on 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 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, 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 of 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 of wind turbines reshapes the net load curves. Initially, range of variation of power demand between peak and off-peak load is 59.6 MW on average over the 12 historical weather scenarios. Entrance of 45 GW of wind power increases the range of variation of net load curve to 73.6 GW on average (+23.5% compared to real electricity load). Based on this data, the dependency between load and wind generation is characterised by an average Kendall's tau correlation coefficient of 0.127. Hourly load factor of wind power varies from 0.05% to 79.5% depending on weather conditions and its mean value is 21.6%.

4. COST-PRICE COMPARISON OF FOSSIL FUEL TECHNOLOGIES AND WIND POWER

Comparison of the levelized costs of electricity (LCOE) produced by the different technologies is a rough optimisation method to determine the most economic technology at the margin of the system. This method is widely employed to assess the respective cost-prices of electricity of each generating technology. To compare them, the usual method supposes respective load factors which correspond to their position in the monotonous annual load curve when they are invest at the margin. So, CCGT is supposed to be invested as a base load plant as well as a coal plant (and what could be a nuclear plant if it will be considered as an investment option in our exercise).

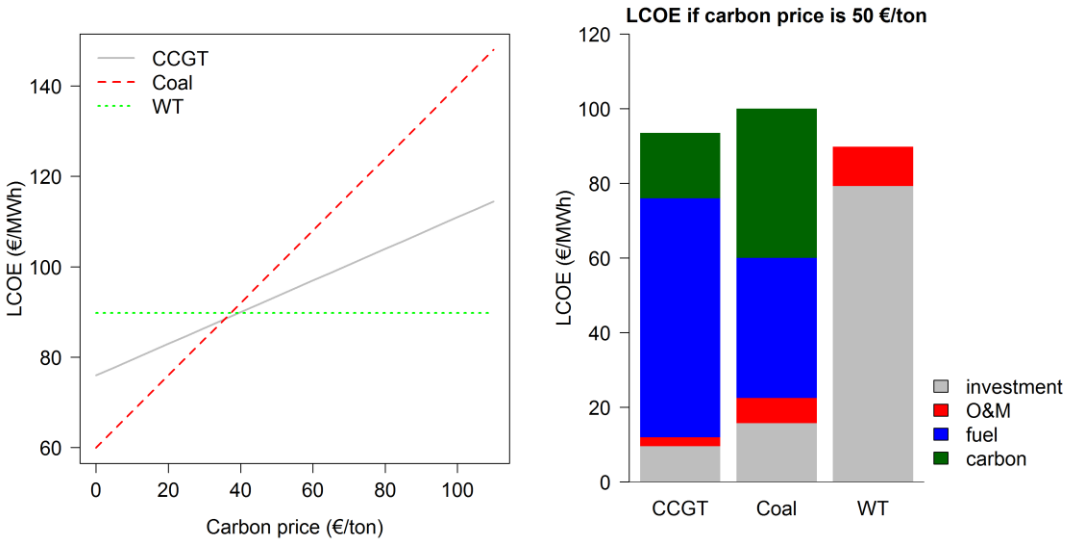
Levelized cost of electricity is the average cost of producing a MWh taking into account investment cost, O&M cost and variable generation cost which includes the carbon cost resulting from the carbon pricing. It corresponds to:

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

Comparison of LCOE with hypothesis on load factor is relevant if conducted for a same group of technologies. Here, the objective is to compare LCOE of base-load and mid-load units (coal, CCGT) which could produce at any time, with WT which is not dispatchable, but which produce randomly in any hour of the year. This comparison is possible if we suppose that the value of MWh is the same on 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 generate power during peak and extreme peak periods.

Plant parameters are those presented in Table 2. LCOE is sensible to the load factor. We consider two assumptions for thermal power plants (CCGT and Coal): (1) a load factor of coal 85% (IEA and NEA, 2010) and (2) a load factor of 100%. Wind power load factor which is computed from the data used in the simulation tool (average load factor over the 12 generation profiles) is equal to 21.6%.We use the same discounting rate of 8% than in the SD model simulation. Figure 3 presents LCOE for a carbon price between € 60 and € 100 per ton of CO_2.

Figure 3: Levelized costs of electricity as a function of carbon price



Notes: Discounting rate is equal to 8%. Thermal load factor is 85%.

On the basis of LCOE analysis, wind power is cheaper than coal and CCGT if carbon price is above € 39.5 per ton of CO_2 in the case of thermal load factor of 85% and € 44.6 per ton of CO_2 in the case of thermal load factor of 100%. But, LCOE of wind power corresponds to fixed cost (that is to say, investment cost and O&M cost) while variable costs are an important share of LCOE of fossil fuel plants which increases when the carbon price increases. Consequently fixed costs represent less than 38% of LCOE. Table 4 details LCOE and specifies fixed cost share for the two assumptions of thermal load factor (85% and 100%). This difference is crucial when looking to investment because the market price is always greater than or equal to 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 should be referred to their profitability from their anticipated revenues on the hourly markets rather than their competitiveness in terms of their respective cost-prices.

Table 4 : Levelized cost of electricity and its fixed portion for different carbon prices

Carbon tax scenario (€ per ton of CO_2)		0	50	100
CCGT	LCOE (€/MWh)	74.5 – 76.0	91.7 – 93.5	109.2 – 111.0
	Fixed cost share	13.7 – 15.7%	11.1 – 12.8%	9.3 – 10.8%
Coal	LCOE (€/MWh)	56.6 – 60.0	96.6 – 100.0	136.6 – 140.0
	Fixed cost share	33.8 – 37.5%	19.8 – 22.5%	14.0 – 16.1%
WT	LCOE (€/MWh)	89.8	89.8	89.8
	Fixed cost share	100%	100%	100%

Notes: The range of LCOEs is explained by the range of load factors which are considered.

As it has been 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 LCOEs comparison (which is a cost indicator). Investment process is much complex that a simple comparison of technologies' costs. Economic profitability of generating power plant depends on 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 maximising its value on the hourly energy markets. More precisely they allow producers to bid on the hourly markets and to produce when they are selected because they are cheaper than the marginal clearing bid. To compare roughly with wind power producers, these ones which could bid at zero price and are sure to be selected any time they anticipate in the day ahead to be able to produce (supposing that their forecasts is quasi perfect), but the moments of reliability are randomly and quite limited.

Despite wind power competitiveness in terms of cost-price when carbon price is above € 45 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.

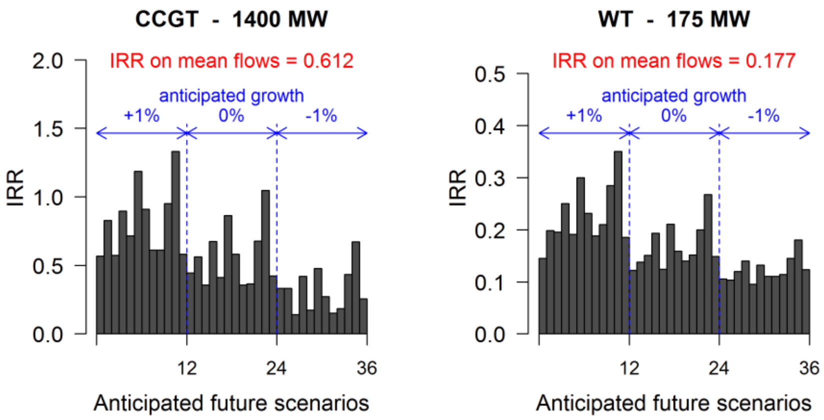
5. WIND POWER PROFITABILITY IN SD MARKET SIMULATIONS

Different market simulations are computed with different levels of constant carbon price from € 0 to € 110 per ton of CO_2. The SD simulations shown 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, which is considerably higher than the value of € 45 per ton of CO_2 making wind power competitive obtained by LCOE method. In this section, we present first the way wind power emerges as a profitable option (results of simulations with carbon price levels in the range of € 60 to € 110 per ton of CO_2) and then the dynamics of generation mix. At the end of the section, effects of the nuclear option on the profitability of wind power investment are proposed.

5.1 Profitability of wind power

This section presents 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, 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 clear the need of new capacities anticipated over the 36 simulation scenarios of future evolution of the system (see section 3.3). Figure 4 displays an example of IRRs of new CCGTs and wind turbines (WT) for the first year of the simulation with a carbon price equal to € 90 per ton of CO_2 for each of the 36 simulated scenarios.

Figure 4: IRRs of CCGT and WT projects for all future scenarios anticipated in the first year of simulation, in the case with carbon price equal to € 90 per ton of CO_2



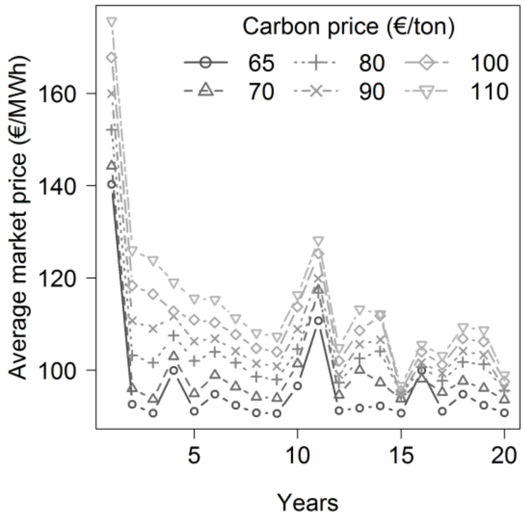
Notes: The x-axis presents the 36 anticipated scenarios for the future: the first 12 scenarios correspond to a 1% annual growth in demand, the following 12 to zero growth and the last 12 to a 1% decrease. Each group of 12 as described represents weather sensitivity given a macroeconomic assumption.

Analysis of the SD results of the simulations with the successive carbon prices shows that the IRR of wind power is generally lower than IRRs of thermal technologies projects. For all simulations, there are at first investment in peaking units (CT), followed by CCGT units and then wind power units. As defined in the modelling, when wind power is selected by the investment module, its IRR is over 8%. Out of these, two sub-cases should be distinguished:

- sub-case 1: IRRs are below 8% except for wind power. This could be referred to as "default choice of wind power".
- sub-case 2: IRR of wind power plant is greater than IRR of an other technology (in practice, CCGT).

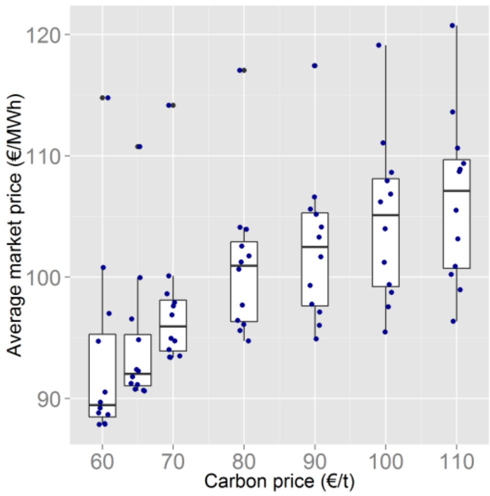
In practice, results of SD simulations show that in most cases, investment in wind power corresponds to a "default choice". But, when carbon price increases, there are more and more scenario cases in which IRR of wind power is greater than IRRs of thermal technologies. With a carbon price of € 100 per ton of CO_2, one third of investments in wind power corresponds to this later case (sub-case 2).

Figure 5: Evolution of the yearly average market price on the 20 years of the simulation for different carbon prices



Notes: First wind farms come on line in year 4 to 6 of the simulation, depending on the case considered. Year 11 of the simulation correspond to a cold year in which electricity shortage occurs.

Figure 6: Boxplot of average annual market price for generation mix at the end of the simulation



Notes: The average market price is computed for each weather scenario.

Carbon price has an effect on the electricity market price and on the respective profitability of the various generating technologies. Explanation of the increase of 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 by the Figure 5 which displays the yearly average market price for different simulation cases. The market price is influenced by:

(1) a direct effect: increase of the carbon price pushes up thermal 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: increase in wind capacity lowers the market price (because variable cost of wind power is zero).

On Figure 5, both phenomena are observed. For a given year, average market price is higher when carbon price increases, corresponding to the first movement. At the same time, given a carbon price, average market price globally decreases in time consequently to the development of wind power, corresponding to the second movement.

In addition to average market price over the whole simulations (Figure 5), ex-post analysis of average market price over weather scenarios is shown in Figure 6. The dispatch module was applied on each weather scenario for each generation mix at the end of SD simulations. It shows that average market price over weather scenarios increases with carbon price. Based on those data, average market price increases by approximately € 0.12 for each additional GW of wind power.

5.2 Dynamics of the generation mix

Electricity generation mix over time varies in relation to the carbon price. Figure 7 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 8 and detailed in Table 5, 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 and 74.2 GW over the twenty-year simulation. Then, the growth of installed wind capacity for each € 10 per ton of CO_2 slows down, corresponding to the "cannibalisation" effect of wind power (see section 2.2). Moreover, it is not common to observe that 96.7 GW in wind power capacity replace *de facto* 12.0 GW of thermal capacity between the scenario with a carbon price of € 110 per ton of CO_2 and the scenario with the price of € 60 per ton of CO_2 which do not make any wind power investment profitable for private investors.

Figure 7: Installed generation mix over time for different carbon prices

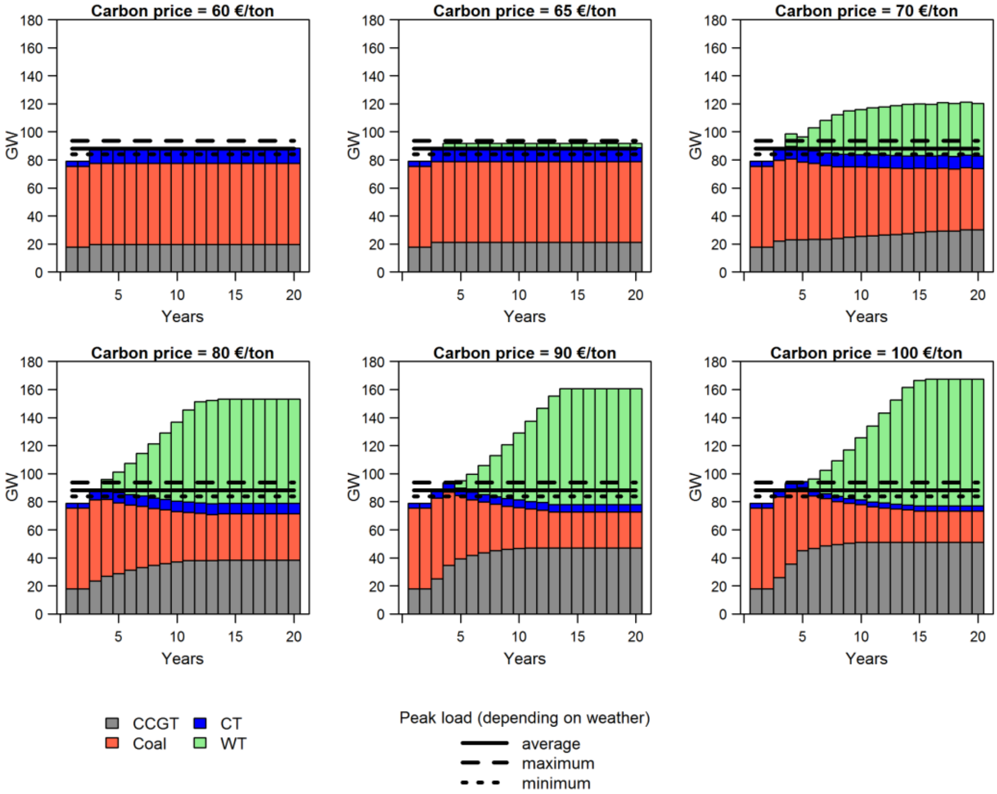


Table 5: Generation mix (expressed in MW) at the end of the simulation for different carbon prices

Carbon price (€ per ton of CO_2)	CCGT (GW)	Coal (GW)	CT (GW)	WT (GW)	Total thermal capacity (GW)
60	19.680	57.750	11.025	0	88.455
65	21.120	57.750	9.800	3.195	88.670
70	30.240	44.250	8.925	37.710	83.415
80	38.400	33.000	7.525	74.205	78.925
90	47.040	25.500	5.425	82.620	77.965
100	50.880	22.500	3.500	90.540	76.880
110	53.760	20.250	2.450	96.705	76.460

This evolution under the effect of carbon price increase comes at the expense of coal. The profitability of these 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 variable cost of CCGT and thus, CCGT becomes baseload technology. Profitability of coal-fired power plants decreases when carbon price increases. Finally, number of decommissioned coal power plants increases with carbon price (Figure 7). Consequently, as coal capacity decreases and electricity generation from wind power increases, fossil fuel use is reduced. Thus, CO_2 emissions decreases significantly as shown on Figure 9. 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 8: Installed wind capacity over time for different carbon prices

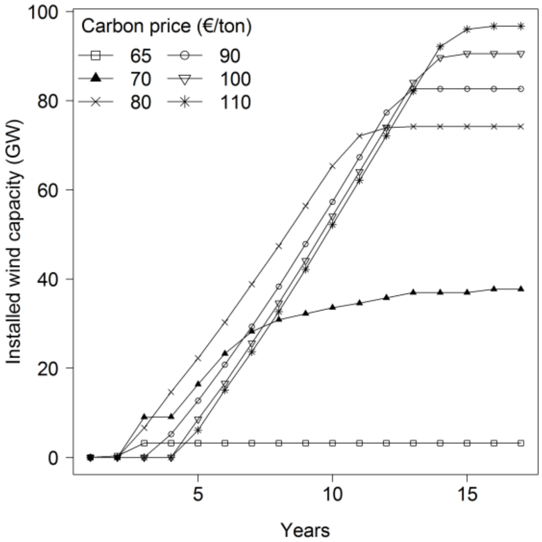
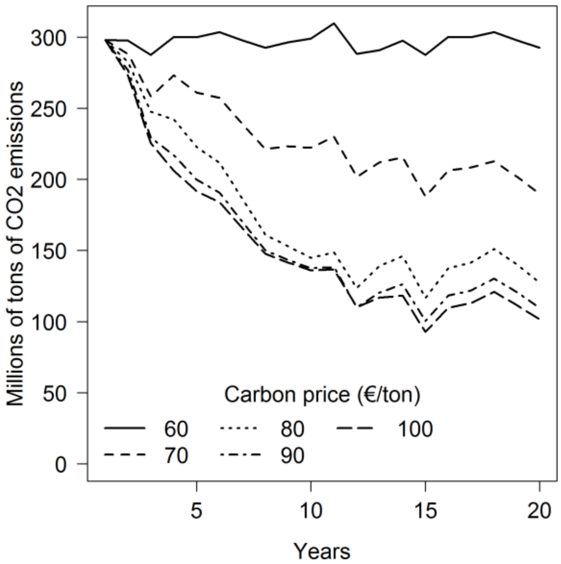


Figure 9: CO_2 emissions from electricity generation over time for different carbon prices



Notes: This does not take into account CO_2 emissions from construction of power plants.

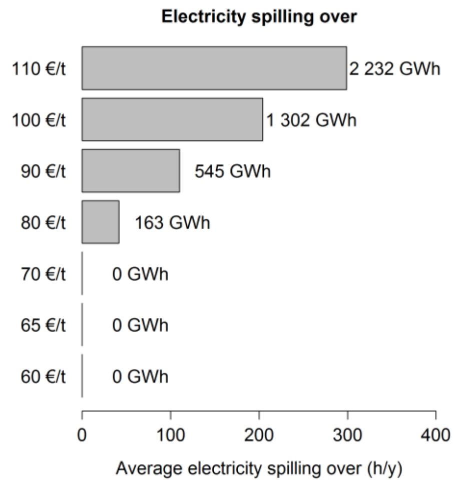
Table 6: Annual share of wind capacity and energy (mean value over the 12 weather scenarios for generation mix at the end of simulation)

Carbon price (€ / ton of CO2)	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%

Energy spills over

When wind capacity increases with carbon price, both spilling over and electricity outages occur (see Figure 10 and Figure 11), but the underlying economic problems are not the same: the first does not raise social efficiency issue while the second one does. Concerning the first one, when wind capacity increases, electricity spills over become more frequent and occur when electricity demand is low and the wind blows. Figure 10 shows average electricity spilling over (hours and volume) for generation mix at the end of the simulation, on average over the 12 weather scenarios. It underlines that above € 80 per ton of CO_2, large volumes of electricity is spilled over. But this situation is economically acceptable for investors in wind power units because investment decisions under the incentive of 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 on a significant numbers of hours. This puts forward the growing importance of inter-temporal arbitrages 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.

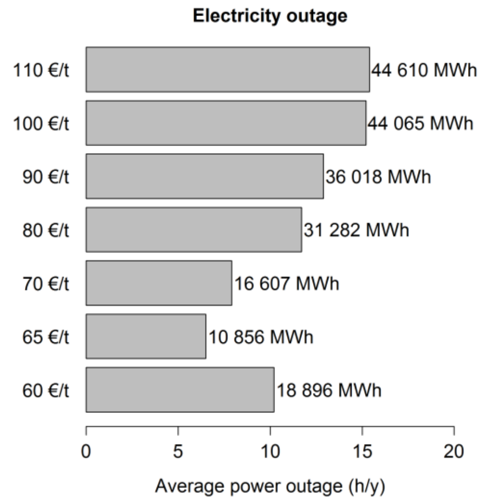
Figure 10: Average hours and volumes of electricity spilling over, over the 12 weather scenarios for different assumptions on carbon price



Power outages

Considering security of supply, when wind capacity increases with the carbon price in successive scenarios of carbon price, total thermal capacity is lower (Table 5). 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 randomly situations when electricity demand is high and wind does not blow. Figure 11 shows the increase of the average electricity outages (in number of hours and volume) on average over the 12 weather scenarios. The development of wind capacity in the succession of scenarios with higher carbon price decreases the security of supply. Behind this degradation of the security of supply and its social costs, there is 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.

Figure 11: Average hours and volumes of electricity outages, over the 12 weather scenarios for different assumptions on carbon price



Effects of nuclear option on the profitability of wind power investment

Up to now, nuclear was not considered in the study case because our first objective is to explore 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 was conducted in order to highlight impacts of nuclear[12] option on the profitability of wind power investment along the different steps of price carbon increase. Initial generation mix (Table 7) corresponds to optimal mix obtained as above by the method of screening curves on the average load curve.

Table 7: Initial generation mix (in GW) in scenarios with and without nuclear option

	CCGT	Coal	CT	WT	Nuclear
Scenario without nuclear	17.76	57.75	3.50	0	0
Scenario with nuclear	17.76	12.2	3.50	0	46.10

Two nuclear policies are tested: (Case A) the first is only to maintain existing nuclear capacity at its initial level, and (Case B) the second is to allow new nuclear development from this initial capacity.

In case A without new investments in nuclear — so that nuclear capacity remains 46.1 GW over the 20-year period — carbon price must be very high to trigger investments in wind power (Table 8). In fact, nuclear plants benefit from their low variable cost which makes them insensible to carbon pricing. In particular, nuclear remains economically relevant for investors even with a very high carbon price. So, it strongly impacts the market-driven development of wind power plants. Not only the development of wind capacity occurs to a much higher carbon price level, but this development occurs at a very slow pace and with very less span.

[12] Parameters of nuclear are the following: investment cost is € 2 900 000 per MW; annual O&M cost is € 100 000 per MW; fuel cost corresponds to € 10 per MWh; construction time is 6 years and life time is 60 years.

Table 8: Wind capacity (GW) at the end of the 20-year simulation for different carbon prices with and without existing nuclear capacities

Carbon price (€ per ton of CO2)	70	80	90	100	110	150	200	250	300
Wind capacity (GW) –Case A with existing nuclear (46.1 GW)				0	0	4.9	14.4	21.2	26.8
Wind capacity (GW) – Base-case without any existing nuclear	37.7	74.2	82.6	90.5	96.7				

In case B in which nuclear plants are politically allowed to be invested in, wind power development is still more complicated. No investment in wind power occurs below a carbon price of € 300 per ton of CO_2. This means that existing nuclear plants not only impedes profitability of wind power projects up to a high carbon price level of € 100 per ton of CO_2 (as in case A), 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 price. Consequently, market-driven investments in wind power appear to be feasible only if nuclear option is politically rejected.

6. CONCLUSION

Reduction of CO_2 emissions is one of the main objectives put forward by today's energy policies. It can be achieved by using different policy instruments as subsidies to low carbon technologies, emissions standards or carbon price. Today, both subsidies to RES-E (feed-in tariffs) and carbon price (EU-ETS) are into force in the European Union. In the context of electricity markets supposed to organise 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 was introduced in order to trigger investments in renewable energies. System dynamics modelling is employed to simulate evolutions of 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 from the LCOE analysis and the carbon price which triggers market-driven investment in wind power in the simulations of investments in electricity generation: market-driven development of wind power becomes possible if the carbon price is far higher than the threshold given by the analysis of LCOE.

This suggests that 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, given this uncertainty, and with risk adverse investment behaviours in the electricity markets, the level of CO_2 price should be significantly higher to trigger investment in wind power plants (IEA, 2007). 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 model will assess possible impacts of uncertain carbon and fossil fuels prices on the development path of wind power.

References

Bushnell, J., 2010. Building blocks: Investment in renewable and non-renewable technologies. Harnessing Renewable Energy in Electric Power Systems:“ Theory, Practice, Policy” 159.

Cepeda, M., Finon, D., 2011. Generation capacity adequacy in interdependent electricity markets. Energy Policy 39, 3128–3143. doi:10.1016/j.enpol.2011.02.063

Cepeda, M., Finon, D., 2013. How to correct long-term system externality of large scale windpower development by a capacity mechanism?

Crampes, C., 2013. EU competition policy and the three 20s. Working paper, Toulouse School of Economics.

Crampes, C., 2014. Regulation mismatch in tackling CO2 emissions, in: Analysis of Competition Policy and Sectoral Regulation. Peitz, M. and Yossi Spiegel, N. P. I. B.-D. editors, pp. 339–363.

Direction générale de l’énergie et du climat (DGEC), 2008. Synthèse publique de l’étude des coûts de référence.

European Comission, 2014. Guidelines on staite aid for environmental protection and energy 2014-2020.

Finon, D., Roques, F., 2013. European Electricity Market Reforms: The “Visible Hand” of Public Coordination. Economics of Energy & Environmental Policy 2. doi:10.5547/2160-5890.2.2.6

Fischer, C., Newell, R.G., 2008. Environmental and technology policies for climate mitigation. Journal of Environmental Economics and Management 55, 142–162. doi:10.1016/j.jeem.2007.11.001

Ford, A., 2001. Waiting for the boom: a simulation study of power plant construction in California. Energy Policy 29, 847–869.

Goulder, L.H., 2013. Climate change policy’s interactions with the tax system. Energy Economics 40, S3–S11. doi:10.1016/j.eneco.2013.09.017

Green, R., 2006. Investment and generation capacity, in: Lévêque, F. (Ed.), Competitive Electricity Markets and Sustainability. p. 21.

International Energy Agency (IEA), 2007. Climate policy uncertainty and investment risk. OECD/IEA.

International Energy Agency and Nuclear Energy Agency (IEA and NEA), 2010. Projected Costs of Generating Electricity: 2010 Edition. OECD/IEA.

Joskow, P., 2006. Competitive electricity markets and investment in new generating capacity. AEI-Brookings Joint Center Working Paper.

Joskow, P.L., 2011. Comparing the costs of intermittent and dispatchable electricity generating technologies. The American Economic Review 238–241.

Klessmann, C., Nabe, C., Burges, K., 2008. Pros and cons of exposing renewables to electricity market risks—A comparison of the market integration approaches in Germany, Spain, and the UK. Energy Policy 36, 3646–3661. doi:10.1016/j.enpol.2008.06.022

Menanteau, P., Finon, D., Lamy, M.-L., 2003. Prices versus quantities: choosing policies for promoting the development of renewable energy. Energy policy 31, 799–812.

Nicolosi, M., Fürsch, M., 2009. The impact of an increasing share of RES-E on the conventional power market—the example of Germany. Zeitschrift für Energiewirtschaft 33, 246–254.

Palmer, K., Burtraw, D., 2005. Cost-Effectiveness of Renewable Electricity Policies.

Sánchez, J.J., Barquín, J., Centeno, E., López-Pea, A., 2008. A multidisciplinary approach to model long-term investments in electricity generation: Combining system dynamics, credit risk theory and game theory, in: Power and Energy Society General Meeting-Conversion and Delivery of Electrical Energy in the 21st Century, 2008 IEEE. pp. 1–8.

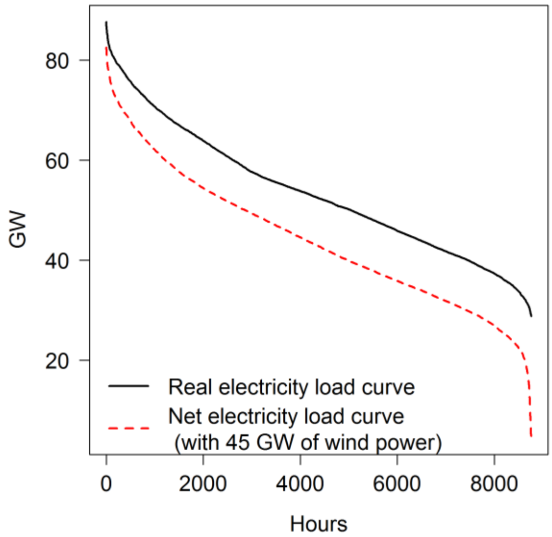
Sensfuß, F., Ragwitz, M., Genoese, M., 2008. The merit-order effect: A detailed analysis of the price effect of renewable electricity generation on spot market prices in Germany. Energy Policy 36, 3086–3094. doi:10.1016/j.enpol.2008.03.035

Teufel, F., Miller, M., Genoese, M., Fichtner, W., 2013. Review of system dynamics model for electricity market simulations.

APPENDIX A - Effect of wind power on net load curve

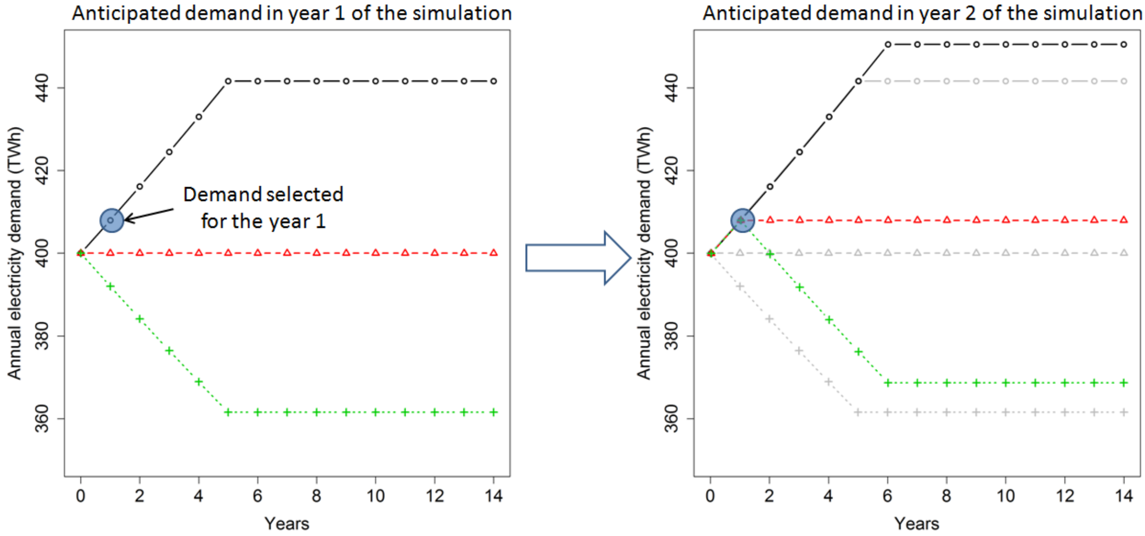
The net load curve is obtained by subtracting wind power generation to the real electricity demand on an hourly basis. Data show that this not results in a simple vertical translation of the load curve but that the shape of the load curve is affected.

Figure A-12: Typical effect of adding 45 GW of wind power on electricity load curve



APPENDIX B - Details of the model

Figure B-13: Anticipation of future load on the basis of expected macroeconomic growth



Notes: In the year 0 of the simulation, the annual electricity demand is equal to 400 TWh. Left graph of the figure represents future demands anticipated in the year 1 of the simulation. The black curve corresponds to a 2% annual growth, the red one to a constant demand and the green one to a 2% annual decrease. Note that all the curves remain constant after 5 years of evolution due to the myopic hypothesis adopted. Then, let consider that the demand selected for year 1 corresponds to a 2% growth so that it is equal to 408 TWh. On year 2, the single investors takes into account that information to anticipate electricity demand. The corresponding graph is represented on the right of the figure. Grey curves correspond to demand anticipated in year 1 and are not valid any more for year 2. It allows to compare anticipations in years 1 and 2.

Figure B-14: Investment process as modelled in the dynamic tool

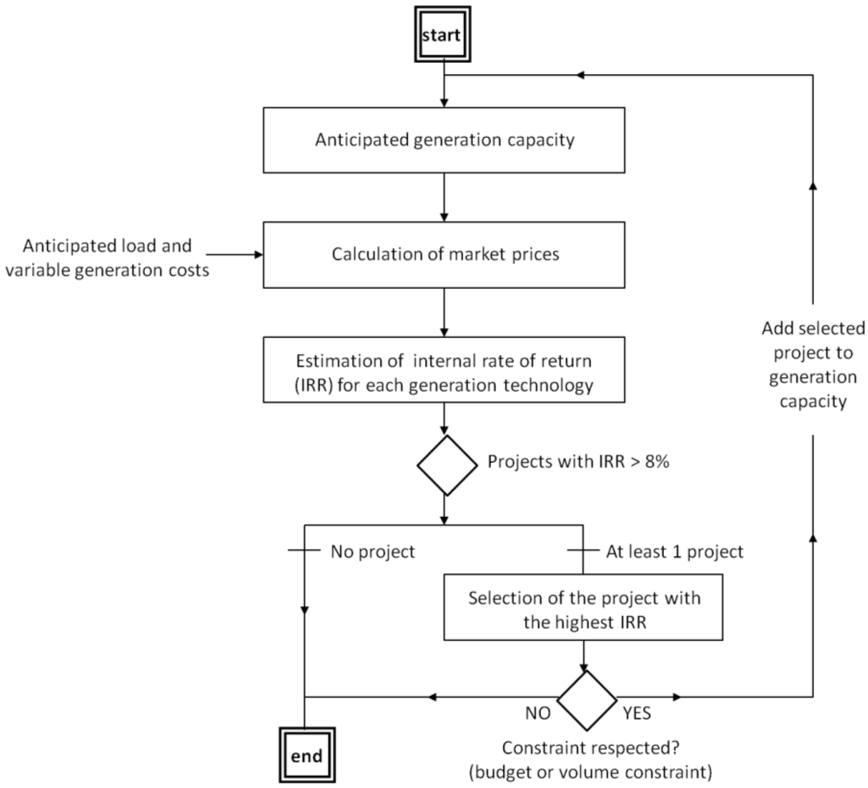


Figure B-15: Description of the modelling of decommissioning decisions