LONG-TERM CAPACITY ADEQUACY IN ELECTRICITY MARKETS: RELIABILITY CONTRACTS VS CAPACITY OBLIGATIONS

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ABSTRACT

In this paper, we study the problem of long-term capacity adequacy in electricity markets. Two investment incentive mechanisms - Capacity obligations and Reliability contracts - are analyzed and compared to the benchmark design, the energy-only market. We use the dynamic programming method and real option theory to develop two dynamic models that enable one to assess the optimal market design for ensuring sufficient generation capacity to meet future demand at efficient cost (the deterministic model) and to analyze the optimal timing of investments when uncertainties in future load and fuel prices are considered (the stochastic model). The effects of different factors on investment strategies, such as the pricing of CO2 and differences between construction delays and cost structures of the new technologies, are also analyzed. The numerical results show that: (1) the reliability contract scheme would be the more cost-efficient mechanism, ensuring the long term system adequacy and encouraging earlier and adequate new investments in the system, compared to the capacity obligation method which would result in over-investment and price manipulations; (2) short lead time technology would be preferred with the capacity obligation design, while cost competitive technology would be chosen with the reliability contract scheme; (3) the pricing of CO2 and the taking into account of uncertainties would affect investment strategies but would have no impact on the effectiveness of the reliability contracts scheme.

Keywords: Electricity markets, generation capacity adequacy, real options, dynamic programming.

JEL Classifications: C61, L51, O14, O21

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1. INTRODUCTION

Operation and planning in electrical power systems prior to deregulation was usually characterized by a high degree of centralization. The typical organization of the industry was based on vertically-integrated companies, incorporating all functions of production, system operation, transmission and distribution. The vertically-integrated firms had monopolies in their own areas, and because of this, prices were regulated. They built capacity to serve their own consumers, and had to build enough to serve them all, at all times. However, the ongoing restructuring of the electric power industry has resulted in decentralized decision-making and in the future, investments by competitive producers will be controlled by the need for cost effectiveness in a risky environment, rather than the need to cover demand in a captive market. It was thought that in this environment competition would result in competitive prices, and therefore consumers would expect to enjoy low prices, reliable service, and the opportunity to benefit from any value-added services that may become available.

Instead, deregulation has brought wildly volatile wholesale prices and undermined the reliability of the electricity supply. The California crisis in the summer of 2000 was considered the first failure of deregulation. It was characterized by extraordinarily high spot market prices, up to 10 times historical levels, and shortages and subsequent rolling blackouts within the state. The basic problems underlying the crisis were, firstly, a fundamental imbalance between the steadily growing demand for power and the limited increases, due to the lack of investments, in generation capacities during the 1990s; and secondly, the market power exercised by existing generators. The crisis had a chilling effect on deregulation and reform in the rest of the United States and in many other places in the world. In this study, we show why the energy-only market[1], the type of market in existence in California during the crisis, could not give good signals for new capacity additions, and why an implementation of an additional incentive mechanism is needed to guarantee the availability of all generators and to attract new investment.

In theory, the energy-only market design requires the elimination of any price cap, allows full participation of demand, and leaves each market agent to fully experience the volatility of market prices. Moreover, in critical periods scarcity rents would give good signals for new entrants to invest in the system and for end users to reduce their consumption. However, it fails to guarantee the availability of generation and to ensure sufficient generation capacity, since it ignores the existence of failure in actual markets. Failure may be caused by several factors. One is the presence of uncertainties in future demand, supply, and fuel prices, which reduces the effectiveness of market signals. In the presence of uncertainty market signals could be imperfectly interpreted, due to the risk-averse behavior of potential investors. This is especially so for the peaking unit, which produces only a few hours a year when electricity prices are higher; consequently, investors in it would receive no remuneration most of the time. The high volatility of income makes the investment very risky, therefore the firm will reject the opportunity to invest. The

[1] Coupled to serious market design flaws and other circumstances, has resulted in serious shortages of generation.

second factor concerns the consumer. Ideally, consumers seeking greater reliability would sign long-term contracts to hedge against higher prices. However, in most cases, regulated tariffs isolate consumers from spot prices, so consumers do not feel the need to protect themselves from spike prices. The lack of maturity results in a malfunctioning of the long-term market and causes a lack of generation investment. The third factor is that generators can use their market power to increase electricity prices by withholding capacity, since no commitment is imposed on them. Several studies suggest that capacity withholding in the California spot market during the summer of 2000 explains the observed price increases.

The experience with the energy-only market shows the need for end users to purchase ex-ante the availability of generators and to commit them to be available, especially in scarcity situations. This is done by introducing an additional incentive mechanism, which works in addition to the energy market. It provides, on one hand, additional revenues for all generators in exchange for their ex-ante availability, and on the other hand gives good signals for new entrants to invest in the system.

In this paper, we seek to find the optimal investment incentive mechanism that would ensure earlier new investments in the system, sufficient available generation capacity to meet future demand at efficient cost, and that would reduce price manipulations. The optimal market design is found by comparing two incentive mechanisms, [1] and [2], that differ in their characteristics, implementations and motivations. The first one is the capacity obligation mechanism[2]. It ensures generation adequacy by imposing an installed capacity obligation on load serving entities (LSEs: large consumers, retailers, etc.). The LSEs are required, every year, to have or to contract enough firm generation capacity above their peak load to cover their expected peak load plus a regulated margin. This leads to the creation of a capacity market, in addition to the energy market, that allows trading of capacity obligations among the LSEs and the generators. The capacity markets prompted by the obligation provide generators with the opportunity to collect extra revenue for their generation capacities and provide incentives for the building of reserves beyond the reserves that meet the short term needs for ancillary services.

The second incentive mechanism is the reliability contract scheme (Call Option). It has the same objective as the first one, where the availability of generation has to be bought ex-ante, but it differs in its organization. Here, the system operator (SO) proposes a system of options to protect electricity buyers against to high prices on the spot market. Energy producers are rewarded for the insurance they provide and punished when they fail to supply the energy they have contracted upon. The options are marketed by the SO through yearly uniform price auctions. The SO determines in advance, firstly, the strike price for the auction, which acts as a price cap for demand, and secondly, the time horizon, which is typically the peak period, during which the generator is required to generate the committed energy at any time. The SO will exercise his option whenever the energy price exceeds the strike price. The generators submit one or several bids to the auction, expressing quantity (the committed energy) and price (the required premium). Finally, the market is cleared as a simple auction and all of the accepted bids receive the premium that was solicited by the marginal bid. The call is represented as follows: consumers pay a premium to acquire the right to buy energy

[2] It has been implemented in the eastern pools in the US including PJM, NYPP and New England.

at the exercise price rather than the spot price and generators receive the premium for abandoning the right to sell at the spot price and for committing to sell at the exercise price whenever consumers exercise the option. On one hand, this method stabilizes the income of generators, who exchange an uncertain and volatile income (the energy price above the strike price) for a certain one (the premium from the auction); on the other hand, it represents a market-based mechanism to hedge demand against the occurrence of high market prices (since the energy price is capped by the strike price). It really commits the generators to be available when the system needs them because of scarcity of supply [3]. The differences between the characteristics of the two mechanisms are presented in table 1.

Table 1:
Characteristics of reliability contracts and capacity obligations mechanisms

	Capacity obligations	**Reliability contracts**
Organization	-SO determines: Q= expected peak lead + reserve margin -LSe required to purchase Q	-SO sets the strike price and the volume of reliability contracts (Q)
Market setting	-Transactions between LSe and generators via the capacity market - Capacity price (CP) is determined	-Generators bid quantity and price (Premium) - Market is cleared as a simple auction (Call option) -SO exerts the option whenever the energy price exceeds the strike price
Generator revenues	-CP from the capacity market and energy price from the energy market.	-The premium from the auction and the energy price (capped by the strike price)
Adequacy	-Commitment by the agents to purchase and to sell (otherwise, penalties) -Identifiable commercial product (capacity) -Guarantee a regulated generation adequacy level -Extra revenue for generators -Consumers remain fully exposed to high prices in the energy market (if no price cap is applied in the spot market)	-Generators committed to produce whenever they are called (otherwise, penalties) -Guarantee a regulated generation adequacy level - Extra revenue for generators -Consumers are fully protected from high prices in the energy market

This paper compares these two incentive mechanisms in terms of long-term system adequacy and optimal timing of investments. This approach is all the more relevant as there has been almost no previous research on how reliability contracts can deal with such problems in the long term. In other words, do such instruments (principally reliability contracts) solve the problem of supply adequacy? If so, at what cost? By long-term system adequacy we mean the existence, in peak periods, of sufficient installed available capacity, of the appropriate characteristics, to be able to meet the estimated peak demand at efficient cost. Indeed, the problem of capacity adequacy concerns only peak periods when demand and prices increase considerably and generation entails high production costs. Experience with existing energy-only markets shows the difficulty of installed capacity to meet the high and volatile demand within this period, inducing high prices and negative capacity balances in most cases. Thus the implementation of an incentive mechanism that encourages new and earlier investments and ensures sufficient and adequate capacities during the peak period is crucial. For the rest of the year, capacity adequacy is assured in a straightforward manner by base technologies that generally entail low variable costs, while demand and prices generally vary within normal levels.

The literature proposes other mechanisms for assuring adequate supply of capacity in the system. For instance, with the capacity subscription method [4], consumers have the freedom to choose their level of reliability through the amount of maximum capacity to which they subscribe. With the capacity payment mechanism[3], generators are given in peak periods an additional capacity payment based on their availability (whether they get dispatched or not) or based on generated energy as an addition to the energy market clearing price.

Different methods have been used for modeling the effect of investment incentive mechanisms on optimal investment strategies. For instance, based on a system dynamic model, it is shown in [5] that, firstly, without incentives, construction cycles would occur frequently and the industry would face repeated periods of undersupply, and secondly, the introduction of a constant capacity payment could diminish considerably the occurrence of these cycles. In a risky environment, the stochastic dynamic programming method is used for handling uncertainties in generation expansion problems, [6] and [7]. The model presented in [8] looks at the question of long-term generation capacity adequacy in restructured and competitive power systems where future demand is represented as a stochastic process. The results clearly show that a dynamic capacity payment is more likely to maintain an adequate level of installed capacity if demand grows faster or slower than expected. The model presented in [9] calculates optimal investment strategies under both centralized social welfare and decentralized profit objectives. It is shown, firstly, that a price cap below the value of lost load or monopolistic investment conditions will contribute to postponing investment decisions further, and secondly, that a capacity payment will help trigger earlier investments, but can also result in too much investment in peaking units.

Our study is derived from the one of [8] and [9], but it differs in several points. Firstly, the long-term system adequacy is for peak periods only and is calculated according to the capacity margin evolution as well as the cost effectiveness of the

[3] It has been implemented in the UK (before the new trading arrangements (NETA)), Spain and several Latin American countries.

mechanism, rather than only the timing of investments. Secondly, electricity prices are determined relative to the investor's available declared capacities rather than his installed capacity. This will enable the investigation of the possibility of price manipulations. Thirdly, the two incentive mechanisms modeled here have the advantage of imposing an obligation for generators to make available their declared capacity whenever they are called upon to produce, while with the capacity payment method studied in [8], no commitment is imposed and therefore the level of adequacy cannot be guaranteed. In addition, quantities and prices in the reliability contracts scheme are determined via market-based mechanisms (organized auctions) rather than settled administratively as in the capacity payment scheme. Fourthly, we investigate how differences in technologies, in terms of cost structures and construction lead times, would affect the optimal technology choices and in turn, the system adequacy. Two technologies are modeled which differ in their investment costs, operating costs and construction periods. Construction periods would significantly affect the long-term planning of investment as well as the capacity adequacy in the system, since the response time of generation investment to an increase in demand depends on the construction period of the new technology. The shorter the construction period, the earlier availability is assured and the more the system can avoid critical situations and better satisfy volatile demand. In the literature, there has been almost no research on how the choice between different production technologies unfolds in a dynamic context. An exception is in [10], where it is shown that small-scale technology may be chosen in equilibrium and assuming risk neutrality, the effect of uncertainty on technology choices is found small. Also, we analyze how the pricing of CO2 would affect investment strategies (technology choices, capacity expansions), the effectiveness of the incentive mechanism and in turn the long-term system adequacy. The pricing of CO_2 can be of great importance for the revenue base for new power plant projects, and a big question is how CO_2 allowance prices will develop in the future, including how they will affect electricity and heating prices[4]. Finally, uncertainties in future load and fuel prices are considered, while only future load is modeled as a stochastic variable in [8] and [9]. Indeed, the evolution of future fuel prices is highly reliant on economic and political factors, and would evolve stochastically, thus disturbing the profitability of the new investment project, especially for thermal units.

We therefore develop two one-agent dynamic optimization models, where the new investor is assumed to have an exclusive right to invest in the system. He maximizes his total expected profit over the planning period and, relative to the adopted market design, optimal expansion decisions as well as optimal declared capacities are found for each time step. Dynamic programming and real option theory are used for the resolution of the models.

The main finding of this study is that reliability contracts would be the more cost-efficient mechanism for assuring long-term system adequacy and encouraging earlier and adequate new investments in the system. We also find that prices in the electricity market and the capacity market are manipulated when applying the capacity obligation mechanism. Moreover, we show that short lead time technologies are preferred when applying the capacity obligation design, while with

[4] Fuel prices could also be affected indirectly by the CO_2 allowance price.

the reliability contracts scheme, technologies with competitive costs are chosen. In addition, the change in framework conditions and the taking into account of uncertainties would affect investment strategies, but without influencing the effectiveness of the reliability contracts scheme. Finally, we find that the dynamic valuation of the investment problem, compared to the static assessment, would contribute to further postpone investment decisions.

The remainder of the paper is organized as follows. Section 2 outlines the proposed dynamic investment model formulations. Section 3 presents the empirical analysis and the results from the application of our model to the French electricity sector. Section 4 summarizes and concludes.

2. Dynamic models for optimal investments

In this section we describe two dynamic optimization models for optimal investments in new generation assets in a deregulated power market. We focus on modeling aggregate power generation investments under deterministic and stochastic investment criteria. In the first study, we use the deterministic dynamic programming method to find the optimal market design that could ensure sufficient generation capacity to meet future peak demand at efficient cost. Two market designs—capacity obligations and reliability contracts—are studied and compared to the energy-only market in terms of long-term system adequacy. The dynamic investment model assesses optimal market design when different factors that affect the realizations of the socially optimal level of investment are considered, such as the consequence of the pricing of CO2 and the difference between construction leads times and cost structures of new technologies. In the second study, we introduce uncertainties in future load and fuel prices and we analyze the optimal timing of investment relative to the adopted market design. Real options theory is employed to develop the investment model, which optimizes the participant's timing of investment in new power plant, while the stochastic dynamic programming method is used for the resolution.

2.1 Model A: Deterministic Dynamic Investment Model

Dynamic programming[5] [11] is an approach developed to solve sequential, or multi-stage, decision problems. It divides the problem to be solved into a number of sub-problems and then solves each sub-problem in such a way that the overall solution is optimal relative to the original problem. The essence of dynamic programming is Bellman's principle of optimality[6]. It is therefore often solved stepwise, starting either from the beginning or the end of the period under consideration. This technique is used here to solve the dynamic investment model.

The investor is assumed to have an exclusive right to invest in the system and acts as a new entrant[7]. He can choose to invest in two peaking technologies, which

5 The theory of dynamic programming can be found in Bertsekas (2000).

6 Bellman's principle of optimality states that: "An optimal policy has the property that, whatever the initial action, the remaining choices constitute an optimal policy with the respect to the sub problem starting at the state that result from the initial action"

7 For simplicity, we use a one-agent optimization model. However, competition among new investors could be modelled by using game theory methods.

differ in their investment costs, operational costs and construction periods. We suppose also that if an expansion decision is made, additional investments cannot be made until the ongoing construction period is finalized. The effect of the strategies of other generators (capacity additions) and the phasing out of existing capacities are represented in the model by a fixed variation in the initial peak capacity over the planning period, which in turn affects the evolution of peak spot prices. So, the interaction between investors' decisions and competitors' choices is represented in an exogenous manner, and concerns only the electricity price evolution. Finally, we assume that the new investor can manipulate prices by declaring available only capacities that maximize his profit from energy sales and additional incentive mechanisms.

The investment problem is described as follows:

$$J_0 = \max_{u_{k,i}, x_{availb,k,i}} \left[\sum_{k=0}^{T} (1+r)^{-k} . g_k \left(x_k, x_{availb,k,i}, l_k, n_k, u_{k,i}, P_k, VC_{k,i}, C_{inv,k,i}, R_{j,k} \right) \right] \tag{1}$$

$$x_{(k+1)} = x_k + u_{(k-lt_i+1)} \tag{2}$$

$$0 \le x_{availb,k,i} \le x_{k,i} \tag{3}$$

$$x_k \in \Omega_{x_k}, u_{k,\mathrm{i}} \in \Omega_{u_{k,\mathrm{i}}} \tag{4}$$

Where,

J_0	Max expected payoff over the planning horizon T (MEuro)
g_k	Payoff function in the peak period, time step k (MEuro)
l_k	Demand in the peak period, time step k (MW)
n_k	Fuel price in the peak period, time step k ($)
P_k	Average peak spot price, time step k (Euro/MWh)
$VC_{k,i}$	Variable cost, technology i (Euro/MWh)
$C_{invt,k,i}$	Adjusted investment cost, technology i, time step k (Euro/MW)
$R_{j,k}$	Additional revenue from the incentive mechanism j, time step k (MEuro)
$x_{\mathrm{k}} = \sum_{i=1}^{2} x_{\mathrm{k,i}}$	Sum of investor's installed capacities in the peak period, time step k (MW)
$x_{availb,k,i}$	Declared capacity, technology i, time step k (MW)
$\mathrm{u}_{\mathrm{k,i}}$	Investment decisions, technology i, time step k (MW)
r	Real risk-adjusted discount rate

lt_i Construction period for technology i (years)

$i = [1, 2]$ Technology 1 and Technology 2

$j = [1, 2, 3]$ 1 for Energy-only Market, 2 for Reliability Contracts and 3 for Capacity Obligations

k Time step

The objective function, which is to be maximized, J_0, is the sum of discounted expected payoffs from energy sales and additional incomes from incentive mechanisms in the peak period of the year, g_k. The algorithm calculates optimal expansion decisions, $u_{k,i}$, (the optimal investment path) and optimal declared capacities, $x_{availb,k,i}$, i.e. for each period, the model finds the optimal solution which indicates whether it is optimal to invest in technology 1 or technology 2 or no as well as how much capacity will be declared. The maximal expected profit, J^*_0 is also calculated.

Three simplified sub-models representing the electricity spot price, the variable cost and the investment cost are introduced to best represent the investor's profit from electricity sales in the market.

Electricity prices

In order to evaluate the possibility of prices manipulations by the new investor, an exponential function is used to express the relationship between electricity prices in the peak period and the availability of generation represented by the load factor, which is the fraction of average peak load to average available capacity over the peak period [8]. The new entrant can therefore exercise market power by withholding capacity and in turn increases peak prices. The mathematical description of the peak spot price is:

$$P_k = a * b^{\wedge LF_k} \tag{5}$$

Where

$$LF_k = \frac{l_k}{x_{init,k} + \sum x_{avail,k,i}}$$ Load factor in the peak period, time step k

$x_{init,k}$ Initial available capacity of existing generators in peak period k (MW)

$x_{avail,k}$ Investor's total declared capacities, peak period k (MW)

a, b Constants to be estimated from historical data

Variable costs

While the variable cost of technology 1 is assumed to be constant and modestly dependant on fuel prices, we assume that it is highly reliant on fuel prices for technology 2. The relationship is expressed by a linear function, which is described as follows:

$$VC_{k,2} = d.n_k - c \tag{6}$$

Where

c, d Constants defining the relationship between variable cost and fuel prices

Investment costs

The investment cost is calculated by the sum of all fixed costs connected to the specific investment, from the period when the investment decision is made to the end of the planning period. To do so, we first calculate the constant annuity computed from the total investment cost that would be paid over the life time of the plant (7), and then the adjusted investment cost is determined by the sum of the discounted constant annuity within the remaining part of the planning horizon.

$$Ann_{TIC_i} = \frac{TIC_i}{\sum_{j=1}^{nt_i} (1+r)^{-j}} \tag{7}$$

$$C_{invt,k,i}(u_k) = Ann_{TIC_i} \cdot \sum_{s=1}^{N-K} (1+r)^{-j} \tag{8}$$

Where,

Ann_{TIC_i} Fixed annuity for all time step in the planning period (Euro/MW)

TIC_i Total investment cost, technology i (Euro/MW)

nt_i Life time for technology i (years)

After developing the three sub-models for peak spot prices, variable costs and investment costs, we can calculate the investor's profit from energy sales in the spot market. However, the payoff function of the investor in each period also depends on the additional revenues received from the incentive mechanism. So, three payoff functions will be developed relative to the applied design.

2.1.1 Payoff function with "energy-only market"

In this scenario, the payoff function will depend entirely on the investor's sales in the spot market. Here, no commitment of generation is imposed on generators and the profit is calculated on the assumption that the investor can easily stop the generation when the spot price falls below operating cost. In addition, the investor can manipulate electricity prices by declaring only capacity that maximizes his payoff in the year. The description of the payoff function is shown in (9).

$$g_k(R_{1,k}) = \sum_{i=1}^{2} \mathrm{hf}_i . \mathrm{L}_k \; x_{\mathrm{availb},k,i}\left(P_k\left(x_k, l_k\right) - \mathrm{V}C_{k,i}(n_k)\right) - u_{k,i} . C_{inv,k,i} \qquad (9)$$

Where

hf_i Expected availability of the new technology i

L_k Duration of the peak period (hours)

2.1.2 Payoff function with Reliability Contracts

Here, an organized market is established prior to the energy market, where the regulator requires the system operator to purchase a prescribed volume of energy from generators on behalf of all the demand. The aims of this mechanism are to ensure an ex-ante availability of generation as well as to give investment signals for new entrants by providing additional and stable revenues for their available capacities. Moreover, it enables the hedging of end users against high and volatile market prices. The method is based on financial call options and an auction procedure. In our study, we make the following assumptions for the realization of the auction [12]:

- The auction is organized a few months ahead of real time (peak period k).
- The quantity purchased by the system operator equals the expected peak load plus a reserve margin.
- The system operator sets the strike price[8] S, a function of the expected efficient price[9]. When the electricity price exceeds S, the system operator exercises his option and commits the generator to produce and to sell his committed energy at the strike price.
- The time horizon: the peak period of the year.
- The existing generators submit one or several bids to the auction, expressing quantity (the committed energy) and price (the required premium). For the investor, he submits all his available capacity.
- The market is cleared as a simple auction and all of the accepted bids receive the premium that was requested by the marginal bid.
- We suppose that the price of the contract is equal to the marginal bid offered by the new investor when his bid is accepted. An economically rational investor should calculate his desired premium fee by incorporating two terms. The first would represent the income that he will forego from the spot market price as a consequence of his option, since for him the market price has a maximum value S. The second term would reflect his need to recover his investment cost (a share of the investment cost of his expensive technology), so that the investment is attractive. Thus, we can expect that investor's bid would be the highest. Otherwise, the premium equals the highest bid of existing generators, which only corresponds to the income from the spot market that has been given up. The premium fee function is described as follows:

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[8] It acts as a price cap for demand.

[9] It corresponds to the situation where the investor declares his total installed capacity.

$$P_{rem,k} = \begin{cases} \int_{P>S} (P(k) - S_k) dk & \text{if } Q_k \le hf.x_{\text{init, k}} \quad (10a) \\ \int_{P>S} (P(k) - S_k) dk + a.\max\left\{Ann_{TIC_1 / if\ x_{1,k}>0}, Ann_{TIC_2 / if\ x_{2,k}>0}\right\} & \text{if } Q_k > hf.x_{\text{init, k}} \quad (10b) \end{cases}$$

Where

$P_{rem,k}$ The premium fee required by the marginal bid (Euro/MW)

$Q_k = f.l_k$ The quantity purchased in the auction, fixed by the system operator and corresponding to the peak load in the period plus a reserve margin (MW)

S The strike price (Euro/MWh)

a The share of the investment cost to be covered by the premium

The price of the contract depends on whether or not the investor's offer is accepted. If the quantity required by the operator, Q_k, is below the capacity of existing generators, the investor's offer will be rejected and all quantities will be largely satisfied by existing generators (10a). However, when existing capacities cannot satisfy Q_k, the remaining quantity will be provided by the investor's accepted quantity and his bid will determine the price of the contract (10b).

On the other hand, to calculate the investor payoff function in the period, we have to distinguish between three situations:

✓ When the investor's bid is rejected by the auction, his payoff function will depend entirely on his sales in the spot market:

$$g_k(R_{2,k}) = \sum_{i=1}^{2} \text{hf}_i . L_k . x_{\text{availbk,i}} \left(P_k(x_k, l_k) - VC_{k,i}(n_k) \right) - u_{k,i} . C_{inv,k,i} \tag{11}$$

If,

$$Q_k \le hf..x_{init,k}$$

✓ If only a share of the investor's total declared capacities is accepted, and assuming the divisibility in different blocks of investor's plants, the payoff function will be:

$$g_k(R_{2,k}) = \int_{P<S} \left[\sum_{i=1}^{2} \text{hf}_i . x_{\text{i,RC,k}} . (P(k) - VC_{i,k}) \right] .dk + \int_{P>S} \left[\sum_{i=1}^{2} \text{hf}_i . x_{\text{i,RC,k}} . (S_k - VC_{i,k}) \right] .dk$$
$$+ P_{rem,k} . \sum_{i=1}^{2} \text{hf}_i . x_{\text{i,RC,k}} + \sum_{i=1}^{2} \text{hf}_i . L_k . x_{\text{i,EM,k}} . (P_k - VC_{i,k}) - u_{k,i} C_{\text{inv,k,i}} \tag{12}$$

If,

$$0 < Q_k - \text{hf}.x_{init,k} < \sum_{i=1}^{2} \text{hf}_i . x_{\text{availb,i,k}}$$

$$x_{\text{i,RC,k}} + x_{\text{i,EM,k}} = x_{\text{availb,i,k}}$$

$x_{i,RC,k}$ Investor's declared capacity i, offered and accepted by the auction, time step k

$x_{i,EM,k}$ Investor's capacity rejected by the auction and sold in the spot market.

The first term in (12) represents the income that the investor will receive from his committed energy (accepted by the auction) sold in the spot market, since the market price is below the strike price. The second term represents his income when the spot price exceeds the strike price, so the system operator exercises his option and makes a commitment to ensure the availability of the generator and the sale of the committed energy at the strike price. The third term represents the total premium earned from the auction. The fourth term shows the income received from his remaining energy (quantity rejected by the auction) sold in the spot market.

✓ If all the investor's declared capacities are accepted, his payoff function will be:

$$g_k\left(R_{2,k}\right)=\int_{P<S}\left[\sum_{i=1}^{2}\mathrm{hf}_i\,.\,x_{\mathrm{availb},i,k}\,.\left(P(k)-VC_{i,k}\right)\right].dk + \int_{P>S}\left[\sum_{i=1}^{2}\mathrm{hf}_i\,.\,x_{\mathrm{availb},i,k}\,.\left(\mathrm{S}_k-\mathrm{VC}_{i,k}\right)\right].dk + \mathrm{P}_{\mathrm{rem},k}\,.\sum_{i=1}^{2}\mathrm{hf}_i\,.\,x_{\mathrm{availb},i,k} - \mathrm{u}_{k,i}\,.\,\mathrm{C}_{\mathrm{inv},k,i} \tag{13}$$

If,

$$Q_k - \mathrm{hf}.\ x_{init,k} \geq \sum_{i=1}^{2}\mathrm{hf}_i\ .\ x_{\mathrm{availb},i,k}$$

2.1.3 Payoff function with Capacity Obligation

As in the reliability contract scheme, the implementation of a capacity obligation mechanism ensures generation adequacy by imposing an installed capacity obligation on load serving entities, LSEs (large consumers, retailers, etc.). Particularly, the LSEs are required, in peak periods, to contract enough firm generation capacity (and not energy as in the reliability contracts scheme) to cover their expected peak load plus a regulated margin. This leads to a creation of a capacity market, which works in addition to the electricity market. This mechanism is implemented in our model in order to study its effect on investment attractiveness and system adequacy.

The practical implementation of the approach is similar to the capacity payment mechanism modeled in [8] and is presented as follows:

- The system operator sets the level of contract coverage of firm generation capacity to all LSEs. As in the reliability contracts scheme, the quantity will be the estimated peak load plus a reserve margin, and the availability of generation will be bought ex-ante.
- The capacity market is organized few months ahead of real time (peak period k).
- The investor sells his total declared capacity in the capacity market.
- The LSEs are committed to participate and required to purchase the adequate capacity imposed by the system operator, Q_k. Generators will earn additional revenue for each MW sold in the market, and the committed capacity has to

be available at the time of delivery. The mathematical description of the generator revenues from the capacity market is described in (14):

$$P_{CO,k} = d_1 . e^{\wedge}\left(\frac{d_2}{CF_k}\right) \text{ if } CF_k \leq CF_{\lim it} \tag{14}$$

Where,

$P_{CO,k}$ Revenue in the capacity market (Euro/MW)

$CF_k = \dfrac{x_{init,k} + \sum_{i=1}^{2} x_{\text{availb,k,i}}}{l_k}$ System capacity factor, peak period k

CF_{limit} Capacity factor limit

An exponential function is used to express the functional relationship between the generator's payment from the capacity market and the capacity factor in the peak period (figure 1). This function reflects the market's demand for capacity, where the payment increases as the capacity factor decreases, so there is more incentive to invest when the expected CF_k is low. We also note that, when the expected CF_k exceeds CF_{limit}, reflecting an overcapacity situation, the capacity price will be zero.

In addition, we suppose that the investor can also manipulate prices in the capacity market by making available only capacities that yield to reduce the capacity factor and in turn, increase the revenue from the capacity market.

When applying this mechanism, the investor's payoff function in the peak period k will be:

$$g_k(R_{3,k}) = \sum_{i=1}^{2} \text{hf}_i \, . \, \text{x}_{\text{availb,k,i}} \left(P_{CO,k} + \text{L}_k . \left(P_k - \text{V}C_{\text{k,i}}\right)\right) - \text{u}_{\text{k,i}} . C_{inv,k,i} \tag{15}$$

Figure 1: Relationship between P_{CO} and CF

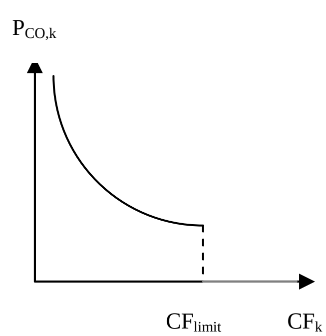
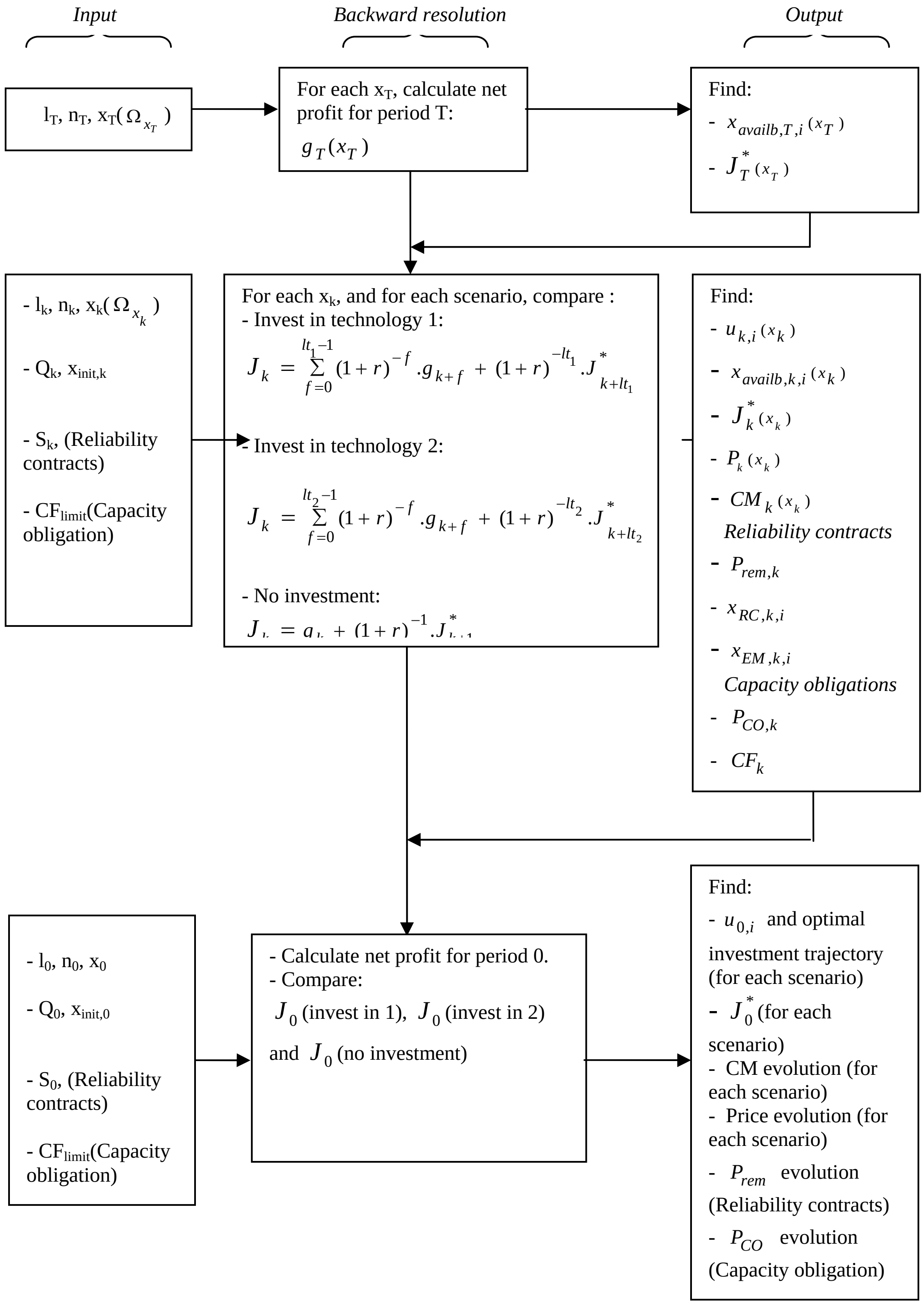


Figure 2: Flow chart for the resolution of the investment problem based on the backward dynamic programming method and used for the three market designs.



2.1.4 Flow chart for the resolution of the investment model

A backward dynamic programming algorithm is used in order to find a solution to the investment problem. Based on Bellman's principle of optimality, as shown in (16), and for each market design j, the resolution runs from the end to the beginning of the planning period, and at each time step k, the algorithm calculates the optimal expansion decision and the optimal declared capacity given the state variable ($x_k \in \Omega_{x_k}$) at that period, and then the expected total profit from year k and throughout the planning period, $J_k(x_k)$, is found.

$$J_k(x_k) = \max\left(\sum_{f=0}^{F-1}(1+r)^{-f}.g_{k+f}(x_k) + (1+r)^{-F}.J^*_{k+F}(x_k + u_{k,i})\right) \qquad (16)$$

Where,

$F = [1, lt_i]$ 1: no investment, lt_i: invest in technology i

In the initial period, the algorithm determines the maximal expected total profit over the planning horizon, J_0. We then deduce the optimal paths of capacity expansions as well as declared capacities and the simulated electricity prices, capacity margins (17) and incentive costs (P_{rem} and P_{CO} for the reliability contract and the capacity obligation designs, respectively) are also found. A further description of the backward resolution is shown in figure 2.

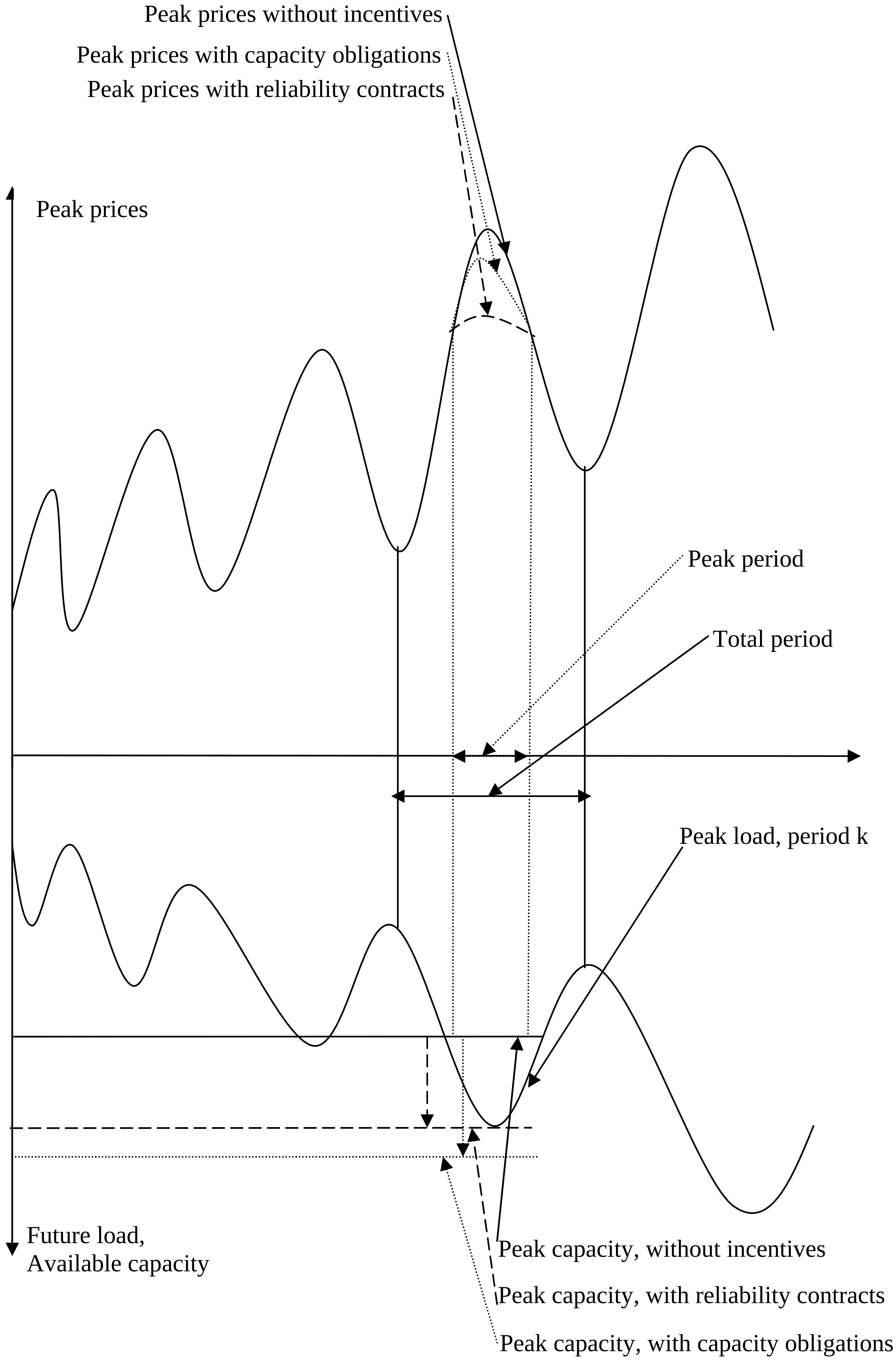
$$CM_k = \frac{x_{init,k} + \sum_{i=1}^{2} x_{k,i} - l_k}{l_k} \qquad (17)$$

2.1.5 Comparison between incentive mechanisms

The objective of this first study is to find the optimal market design that could assure long-term system adequacy at efficient cost and reduce price manipulations. The main differences between the two investment incentive mechanisms modeled here concern the future evolution of the additional payment and the main decision variable on which the mechanism acts. While the reliability contracts scheme provides stable revenue for generators and acts both on electricity prices by imposing a strike price and on capacity addition by making investments more attractive, the capacity obligation mechanism assures a volatile additional payment for available capacity, which is very high in critical periods, and acts mainly on capacity additions. This is shown in figure 3 where, all other things being equal, the reliability contracts scheme would reduce prices in peak periods, due to the strike price imposed by the system operator, while capacity obligation mechanisms would assure more installed capacity, due to the double remuneration of available capacities. We can suggest that the assessment of the two incentive mechanisms has to consider the situation in the market and its needs in term of capacity additions, as well as the requirements in term of total costs paid by end users.

To do so, two criteria are used in this study to evaluate the different market designs. The first one is the evolution of peak capacity margins within the planning period. The second is the evolution of average peak prices and total incentive costs paid by end users for each incentive mechanism.

Figure 3: Long-term effect of the two incentive mechanisms on future peak prices and peak capacity in the system



2.2 Model B: The stochastic dynamic investment model

In this model, two assumptions are added to the first analysis:

- Load and fuel prices are represented as stochastic variables. Additionally, we assume that they are correlated.
- The investor can only invest in technology 2 and only one investment in the planning period is allowed.

Due to the presence of uncertainty in the state variables of the model, the best method for evaluating the investment project is one that uses real options theory (RO). This technique captures the value of managerial flexibility in adapting decisions in response to unexpected market developments. It allows management to characterize and communicate the strategic value of an investment project. Traditional methods (e.g. net present value, NPV) fail to accurately capture the economic value of investments in an environment of widespread uncertainty and rapid change. In contrast to the NPV rule that a project should be carried out only when the sum of discounted cash flows is positive, in a real options valuation investment projects are considered as options and the decision-maker has the choice of postponing the investment decision and then investing later in the event of favorable investment conditions. Thus, the optimal timing of an investment does not occur until the value of the project itself (NPV) equals the value of the option to invest in the future (RO) [8]. RO valuation is based on stochastic dynamic optimization, where the flexible and the dynamic timing of investments are considered and uncertainties are taken into account as stochastic processes.

In this study, we use the backward stochastic dynamic programming method to solve the investment problem that corresponds to real options valuations. The objective function is based on the expected sum of discounted profits over a planning horizon of T years. The investor maximizes the objective function based on the recursive Bellman's principle (as in the first analysis, but here, 2 state variables (future load and fuel prices) are stochastic). The mathematical formulation of the investment problem is described as follows:

$$J_k(x_k,l_k,n_k)=\max_{u_k,x_{availb,k}}\left[\underset{l_k}{E}\left[\underset{n_k/l_k}{E}\left(\sum_{f=0}^{F-1}(1+r)^{-f}.g_{k+f}\left(x_k,l_{(k+f)},n_{(k+f)},R_{j,(k+f)}\right)+(1+r)^{-F}.J_{k+F}\right)\right]\right] \tag{18}$$

$$x_{(k+1)}=x_k+u_{(k-lt+1)} \tag{19}$$

$$l_{(k+1)}=l_k+w_{l,k} \tag{20}$$

$$n_{(k+1)}=n_k+v_{n,k} \tag{21}$$

$$x_k\in\Omega_{x_k},u_k\in\Omega_{u_k},l_k\in\Omega_{l_k},n_k\in\Omega_{n_k} \tag{22}$$

Where,

J_k	Max expected payoff in period k (MEuro)
u_k	Investment decisions, technology 2, time step k (MW)
$w_{l,k}$	Long term uncertainty in demand level, time step k
$v_{n,k}$	Long term uncertainty in fuel prices, time step k

The model describes the connection between time of investment decisions, length of construction period, and uncertainties in energy demand and fuel price variables. The stochastic variables are modeled by Markov chains (Figure 4). Due to the correlation between them, the probability of change in energy demand together with change in fuel price is modeled as a two-dimensional discrete probability distribution and the two independent Markov chains are replaced with one Markov chain.

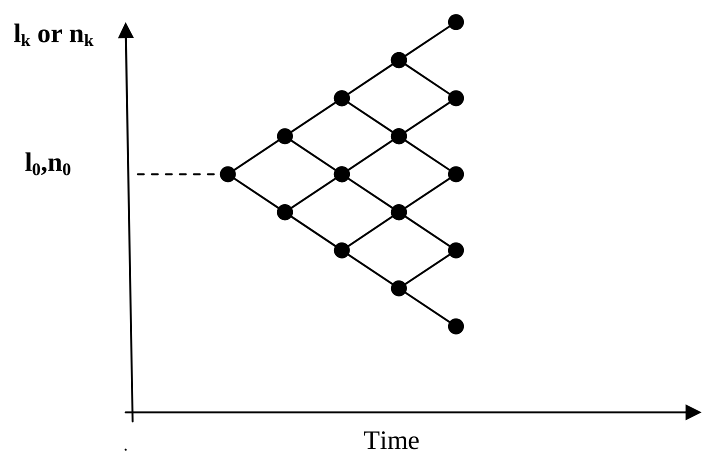


Fig 4: Tree description of a discrete Markov chain for uncertainty variables

The decision rule gives the yearly decisions that depend on the information available when the decisions have to be made. The recursive solution of (18) gives a strategy for decisions that depend on the actual values of the uncertain variables. The resolution of the model is quite similar to the chart flow in the first analysis (Figure 2), but due to uncertainties in state variables, we cannot calculate the optimal future investment for each period, as the optimal investment strategy depends on the realization of the stochastic variables. But, by varying the initial values of the stochastic state variables (k=0), we can identify state variable threshold levels, at which it becomes optimal to invest, i.e. the value of the project itself (J_0 calculated by the static NPV) equals the value of the option to invest in the future (J_0 calculated by the recursive solution of (18)), so there is no incentive to delay the investment decision. The model then determines both the optimal first-stage investment decision u^*_0 for the optimal combination of initial values of the stochastic state variables and the maximum expected profit in the initial period J^*_0.

The investor's profit from energy sales in each time step is represented as in the first analysis with the same description of the sub-models of electricity spot prices, variable costs and investment costs. The single difference concerns x_k, which here depends only on investment in technology 2.

The investor's payoff function in each period also depends on additional revenues received from incentive mechanisms. But due to the uncertainties, a number of assumptions are added to the first analysis.

2.2.1 Reliability contracts design

Now, the mechanism is reformulated as a two-stage problem. First, we assume that the auction is organized before the realization of the stochastic variables and given the expected peak demand, $Q_{max,k}$, the investor decides both the energy level to be sold in the auction[10], $x_{RC,k}$ and the required premium (23). Second, after the realization of the stochastic variables, he can adjust his available capacity by declaring more where it is profitable, $x_{EM,k}(l_k, n_k)$. The investor's payoff function for each combination of the state variables in period k (x_k, l_k, n_k) is described in (24).

$$P_{rem,k} = \begin{cases} \mathrm{E}\left(\int\limits_{P>S} \left(P(k) - \mathrm{S_k}\right).dk \right) & \text{if } \mathrm{Q_{max,k}} \le hf.x_{\mathrm{init,k}} \\ \mathrm{E}\left(\int\limits_{P>S} \left(P(k) - \mathrm{S_k}\right).dk \right) + a.\max\left\{Ann_{TIC_2 / if\ \mathrm{x_{2,k}}>0}\right\} & \text{if } \mathrm{Q_{max,k}} > hf.x_{\mathrm{init,k}} \end{cases} \tag{23}$$

Where,

$Q_{max,k}$ Max expected peak load in period k plus a reserve margin.

E Mathematical operator that evaluates the future income of the generator, taking into account the uncertainty in future load and the risks involved.

With this representation of the premium function, the investor has the possibility of exchanging an uncertain and volatile income (energy price above the strike price) for a certain income (the premium from the auction).

10 As in the deterministic analysis, the determination of this quantity depends on whether or not the investor's offer is accepted.

$$g_k\left(x_k, l_k, n_k\right) = \int_{p<s}\left[\mathrm{hf}\,.\,x_{\mathrm{RC,k}}\left(P\left(l_k\right) - VC_k\left(n_k\right)\right)\right]dk + \int_{p>s}\left[\mathrm{hf}\,.\,x_{\mathrm{RC,k}}\left(\mathrm{S} - \mathrm{VC_k}\left(n_k\right)\right)\right]dk \quad (24)$$
$$+\ P_{rem,k}.\mathrm{hf}\,.\,x_{\mathrm{RC,k}} + \sum_{\mathrm{i=1}}^{2}\mathrm{hf.L_k}\,.\,x_{\mathrm{EM,k}}\left(l_k, n_k\right)\left(P_{\mathrm{k}}\left(l_k\right) - VC_k\left(n_k\right)\right) - \mathrm{u_k C_{inv,k}}$$

Where,

$$x_{\mathrm{availb,k}}\left(l_k, n_k\right) = x_{\mathrm{RC,k}} + x_{\mathrm{EM,k}}\left(l_k, n_k\right)$$

2.2.2 Capacity obligations design

Here, the method is also reformulated as a two-stage problem. The investor first decides (before the realization of stochastic variables) the capacity to be sold in the capacity market, $x_{\mathrm{CO,k}}$ and second, after the realization of the stochastic variables, he can adjust his available capacity. The capacity factor that determines the capacity price in the capacity market is calculated according to the maximal expected peak load in the period, $l_{\max,k}$ and the available capacities declared at the first stage.

$CF_k = \dfrac{x_{init,k} + x_{\mathrm{CO,k}}}{l_{\max,k}}$	System capacity factor, peak period k
$x_{\mathrm{CO,k}}$	Investor declared capacity in the first stage, period k
$l_{\max,k}$	Max expected peak load in period k

The payoff function for each combination of the state variables is described as follows:

$$g_k(x_k, l_k, n_k) = \mathrm{hf}\ .\mathrm{L}_{\mathrm{k}}.\mathrm{x}_{\mathrm{availb,k}}.\left(P_k - \mathrm{VC_k}\right) + P_{CO,k}.\mathrm{hf.x}_{\mathrm{CO,k}} - \mathrm{u_k}.C_{inv,k} \quad (25)$$

Where,

$$\mathrm{x_{CO,k}} \leq \mathrm{x_{availb,k}}\left(l_k, n_k\right) \leq \mathrm{x_k}\left(l_k, n_k\right)$$

2.2.1 Comparison between incentive mechanisms

The model identifies at which load and fuel price levels it is optimal to invest in a new power plant. The analysis is repeated for the three market designs, i.e. the energy-only market, capacity obligations and reliability contracts. The valuation of the capacity mechanisms will be done by comparing the optimal timing of investment (optimal demand threshold and optimal fuel price threshold) found for the three market designs.

3. CASE STUDY

3.1. General input data

The parameters in the models are estimated based on historical data for the French electricity market[11], and found in [13], [14], [15] and [16]. Table 1 shows the main parameters used in the model.

The introduction of CO2 tax will only affect the variable cost of technology 2, due to its higher dependence on fuel prices, by adding a supplementary cost of 4 €/MWh.

Table 2: Initial input parameters for the investment models

NAME IN THE MODELS	VALUE
$x_{init,0}$	69300 MW
l_0/ n_0	60200 MW / 4,5 $
l_{growth}/ n_{growth}	1000 MW / 0,1 $
$w_{l,k}$	600 or 1500 MW
$v_{n,k}$	-0,2 or 0,4 $
$u_{k,1}$ / $u_{k,2}$	1500 MW / 750 MW
TIC_1/TIC_2	350000€/MW / 150000€/MW
$VC_{k,1}$ /$VC_{k,2}$	16,5€/MWh / (8,577 n_k – 0,683)/MWh
Tax-Co2	0 or 4€/MWh
lt_1 / lt_2	7 years / 3 years
nt_1 / nt_2	60 years / 30 years
f	1,05
CF_{limit}	1,05
r	0,08
L_k	1300 hours
Af_i	0,9

[11] The opening of the French electricity market was achieved with the creation of Powernext SA in 2001. We have referred to monthly historical data for load and electricity price in Powernext to estimate the parameters in the spot price model.

3.2 Results: Deterministic analysis

This section is concerned with identifying optimal investment decisions and studying, under deterministic investment criteria, how investment incentives, i.e. reliability contracts and capacity obligations, could ensure long-term system adequacy. The capacity adequacy level is calculated using the capacity margin in the peak period. Optimal capacity adequacy is assured when the capacity margin is up to 5% of the peak load in the period and is at least positive. The best mechanism will be the one that both assures the optimal adequacy level and efficient costs for end users and reduces the possibility of price manipulations. We also investigate the consequences on investment strategies if the pricing of CO2 is taken into account, and how the difference between construction delays and cost structures of the new power plants could affect optimal investment decisions.

A planning horizon of 18 years is used for the case study and the six different scenarios analyzed here are shown in table 2.

Table 3: Definition of scenarios in the case study

Scenarios	
EOM	Energy-only market
RC	Reliability contracts
CO	Capacity obligations
EOM1	Energy-only market with tax-Co2
RC1	Reliability contracts with tax-Co2
CO1	Capacity obligations with tax-Co2

For reliability contracts scenarios (RC and RC1), the premium fee earned by the investor in the auction is assumed to cover 60% of the yearly investment cost of the expensive technology plus the income that he will forego from the spot market as a consequence of his option. We represent load and spot prices with daily distributions in order to compare daily prices and the administrative strike price, which is set at 80% of the expected efficient price. The time horizon of the auction is the peak period of the year. The capacity obligations scenarios (CO and CO1) are modeled as explained in section 2.1.3 with a CF_{limit} of 1.05[12].

Result 1: Long term capacity adequacy in the system is assured when introducing incentive mechanisms

We can see from figure 5 that when introducing incentive mechanisms (RC and CO), the optimal capacity margin is assured from T8 to the end of the planning period, while with no incentives, the system needs to rely on imports in order to meet the total peak demand in the last four periods. This result confirms the theoretical predictions, which assume that economic signals of incentive mechanisms would intend to augment the volume of installed and available capacity and the reliability of the system would be enhanced. However, it is shown in the figure that the capacity margin can be higher than required in scenario CO (T12 and

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12 We note that the parameters used for modeling incentive mechanisms (RC and CO) give the same additional payment for a threshold capacity factor of 1.05.

T13), yielding overcapacity periods. This is proved in figure 6, where the added capacity in the system is at all times higher in scenario CO compared to scenario RC.

As we expected, since available capacities are doubly compensated when applying the capacity obligation mechanism, the new investor has more incentive to invest in the system in order to profit from this higher revenue, and the capacity additions would increase slightly, yielding overcapacity situations. However, the extra revenue provided by scenario RC only corresponds to the part of the investment cost to be covered by the auction, and moreover, the electricity price is capped by the strike price, so the incentives for new investments are given with adequate manner and the prescribed capacity adequacy level is attained.

Figure 5: Capacity margin evolution in the planning period for the three market designs.

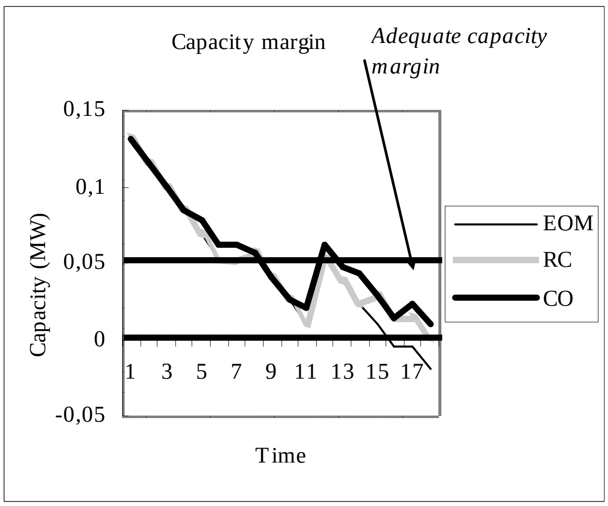
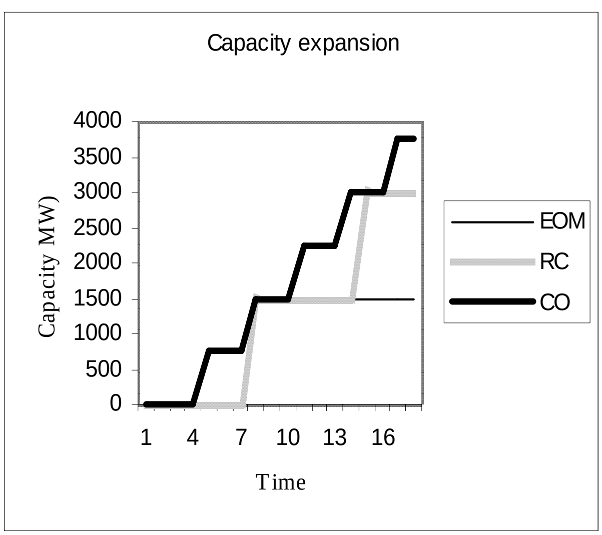


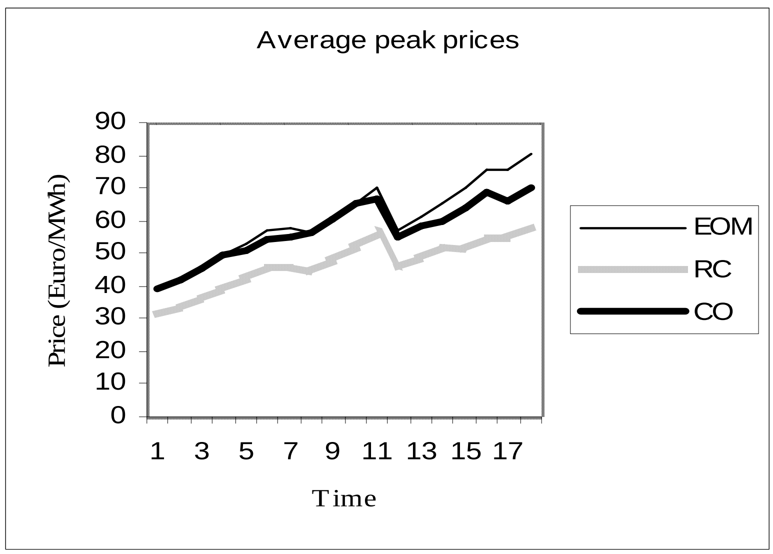
Figure 6: Capacity expansions in the planning period for the three market designs



Result 2: In the reliability contracts scheme, expected peak prices are lower and consumers' surplus from price reductions are much greater compared to capacity obligation mechanism.

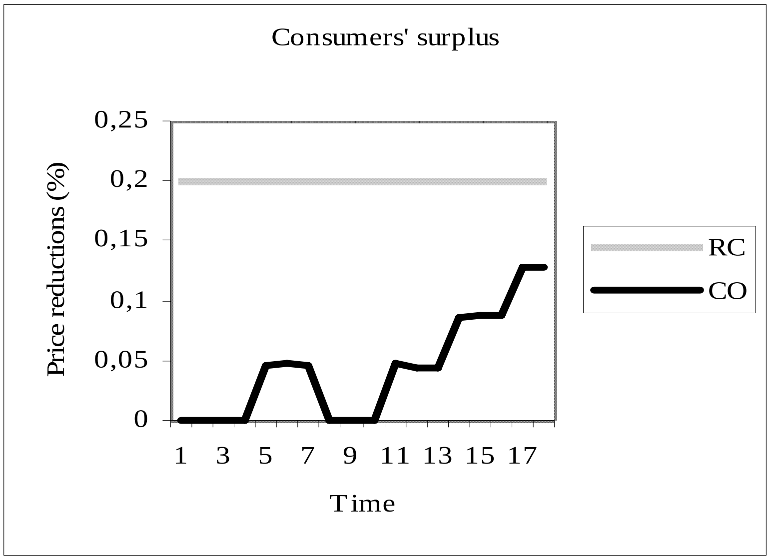
From figure 7, we can see that peak prices are lower with incentive mechanisms (RC and CO), compared to the first design (EOM) and especially at the end of the planning period, due to the undesirable capacity adequacy level in this scenario and the lack of new investments, which involve prices that will not stay within a socially acceptable range. When introducing incentive mechanisms, prices decrease significantly, mainly in scenario RC where the strike price imposed by the system operator acts as a price cap by preventing peak prices from reaching high levels, and thus consumers are fully protected from high prices in the energy market. With this method, consumers receive something (a maximum-price hedge) in exchange for all the capacity they are contracting.

Figure 7:
Expected peak prices in the planning period for the three market designs.



Furthermore, it is shown in figure 8 that consumers' surpluses in terms of price reductions when introducing incentive mechanisms are largely higher in scenario RC compared to scenario CO. An important weak point of the capacity obligation design is that consumers remain fully exposed to the potential high prices in the energy market, and they generally argue that they are paying a capacity charge and receive nothing in return. So, we can suggest that an application of a price cap in the energy market is necessary.

Figure 8: Consumers' surplus from price reductions for the incentive mechanisms: reliability contracts and capacity obligations



Result 3: The reliability contracts scheme is the more cost efficient mechanism and leads to a stabilization of consumers' payments.

From results 1 and 2, we can suggest that the EOM scenario would not give good signals for new capacity additions and would lead to high prices and insufficient capacity adequacy, especially at the end of the planning period, so the implementation of an additional incentive mechanism is needed. To best evaluate the two incentive mechanisms, we calculate the cost paid by consumers for all the capacity they contract. We distinguish between the specific incentive cost paid for assuring the optimal adequacy level and the total cost paid for each MWh bought from the market, including the energy price and incentive cost. Figure 9 illustrates the evolution of the specific incentive cost. It is stable and close to 20 €/MWh over all periods in scenario RC, while it is volatile and high and reaches great levels, up to almost 60€/MWh, at the end of the planning period in scenario CO. Indeed, in this scenario, specific incentive costs are largely dependent on the capacity factor in the system and the more the capacity factor decreases (demand is rationed), the more the additional payment increases, so the investor chooses to wait before investing until the system is close to rationing. However, with call options, the premium is set via a market-based mechanism, with a limited amount of regulatory intervention, giving a stable income for generators on one hand and hedging consumers from the occurrence of high prices and high additional incentive costs on the other hand.

For the total costs paid by consumers, figure 10 also shows a stable and low payment over the planning period in scenario RC, a total cost which varies between 50€/MWh and 70€/MWh. However, the implementation of a capacity obligation mechanism involves increasing costs which attain 130€/MWh at the end of the planning period. The reliability contracts scheme can be seen as a market-compatible price cap where the problem of discouraging investments, induced by this price cap, is eliminated thanks to the incentive economic signal given by the stabilizing effects of the contract on the generators' revenues. Also, consumers would obtain, in exchange for a stable payment, a satisfactory guarantee that there will be enough available generation capacity whenever it is needed.

Figure 9:
Specific incentive cost evolution for the two incentive mechanisms

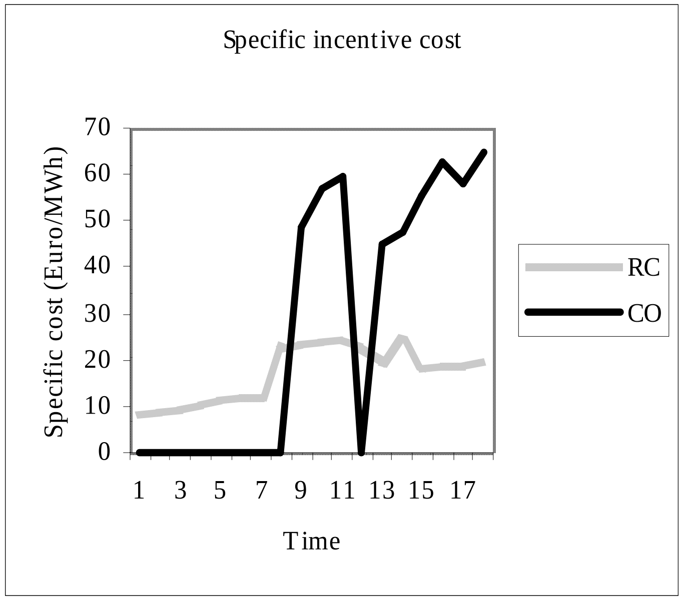
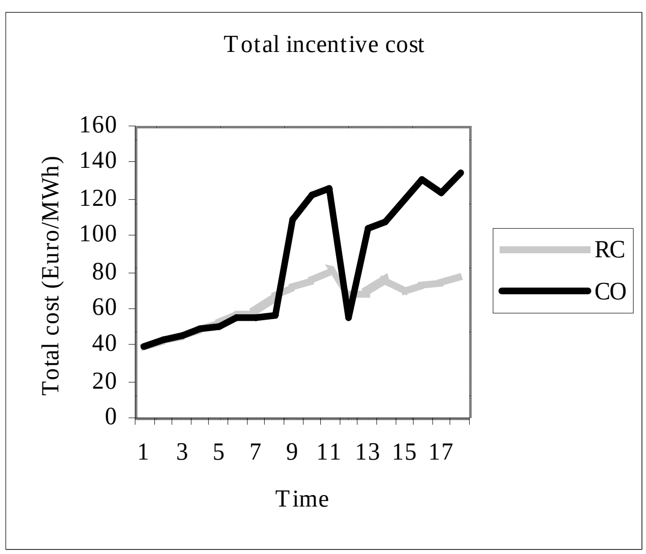


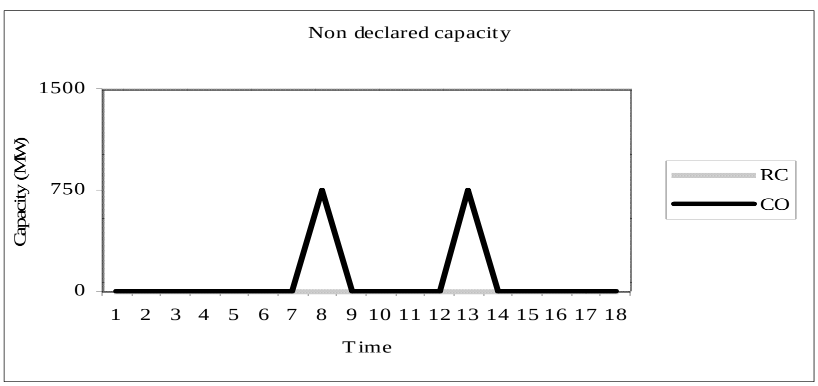
Figure 10:
Total incentive cost paid by end users for the two incentive mechanisms



Result 4: With the capacity obligation mechanism, prices in the electricity market and the capacity market are manipulated by the new generator.

We now study how the new generator can manipulate electricity prices and revenues from incentive mechanisms by declaring only capacities maximizing his total payoff in the period. From figure 12, we see that in scenario CO, the capacity declared by the new generator in T8 and T12 is lower than his total installed capacity. This result is explained by the fact that the expected capacity factors in these two periods are almost above 1.05, so the generator expects to earn no revenue from the capacity market, and thus he prefers to declare only a share of his installed capacity in order to reduce the capacity factor in the system to almost 1.04, and to increase his revenue from the capacity market and from the energy market (by increasing the load factor and in turn the electricity price). The main shortcoming of this mechanism is the volatility of the income earned from the capacity market and its dependence on the capacity factor in the system. This revenue tends to be high when rationing is more likely, therefore it would be profitable for a rational generator to manipulate the situation. Consequently, the system will often be close to rationing. However, in scenario RC, the extra revenue is stable over the planning period and electricity prices are capped by the strike price, so they are not subject to manipulations, and thereafter, at all times, the new generator chooses to declare his total installed capacity.

Figure 11:
The non-declared capacity for each incentive mechanism



Result 5: The capacity obligation mechanism stimulates more investments in short lead time technology, while, with reliability contracts, only differences between costs structures of new technologies are crucial in optimal technology choices.

We now study optimal technology choices for the two incentive mechanisms. Figures 12 shows optimal choices between technology 1, requiring long construction lead time, high investment cost and low variable cost, and technology 2, characterized by its short construction lead time but largely dependent on fuel prices. It is shown in scenario CO that only technology 2 is chosen. However, in scenario RC, the investor prefers technology 1. This can be explained by two factors. Firstly, with the capacity obligations mechanism, the generator expects the perfect operation of the capacity market, so the earlier he has available capacity, the more he can profit from the double remuneration of his capacity, and thus the short lead time technology is chosen.

Secondly, when applying the reliability contracts scheme, the premium earned by the participant in the auction covers a large part of the investment cost of the new capacity, so the investor prefers the low operating cost technology in order to profit from its cost competitiveness (lower variable cost).

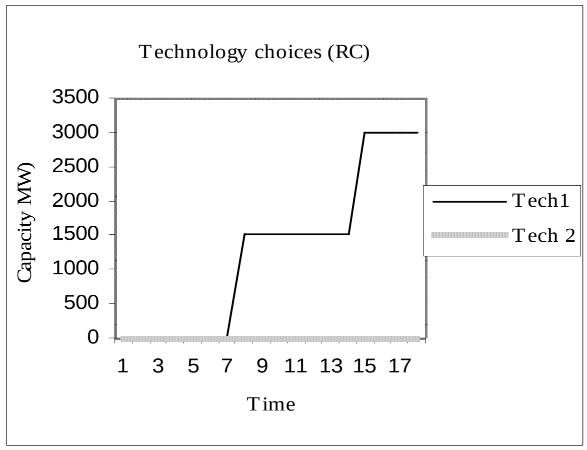
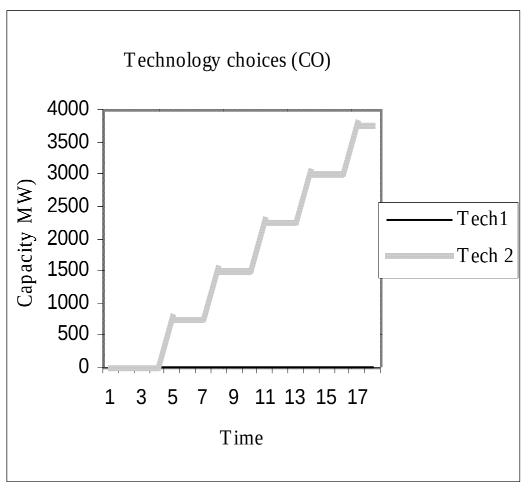


Figure 12:
Technology choices in the two market designs:
reliability contracts and capacity obligations



Result 6: The implementation of a Tax-Co2 would change the optimal technology choices without affecting the effectiveness of the reliability contracts scheme.

We now study the effect of the pricing of CO2 on optimal technology choices and in turn, on the capacity adequacy in the system. The Tax-Co2 will only affect the variable cost of technology 2, due to its high dependence on fuel prices, by adding a supplementary cost of 4 €/MWh. The results in figure 13 show a shift in optimal choices and the investor now chooses to invest in both technology 1 and technology 2 in scenario CO1, profiting on one hand from the cost effectiveness of technology 1 and on the other hand from the shorter construction lead time of technology 2. However, in scenario RC1, the introduction of Tax-Co2 does not affect the optimal technology choices and the investment path concerns only technology 1. As in the case without tax-Co2, the reliability contracts scheme stimulates more investments in technology 1, due to its cost effectiveness and to the possibility of covering a large part of the investment cost of the plant when bidding in the auction.

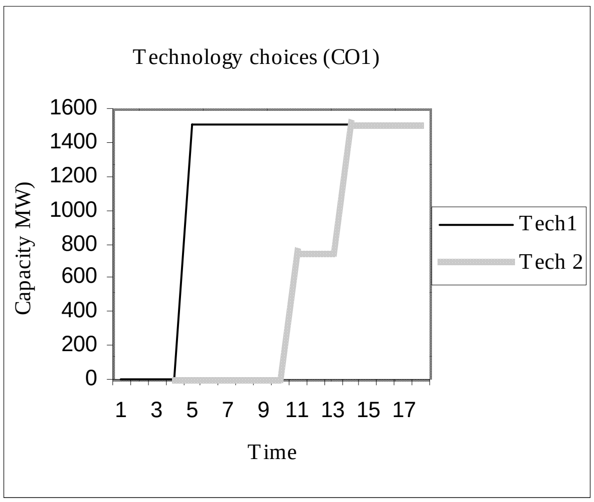
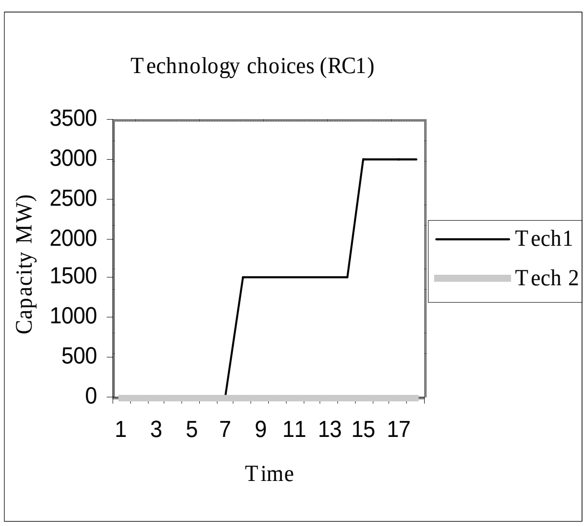


Figure 13:
Technology choices in the two market designs with Tax-Co2: reliability contracts and capacity obligations



This change in optimal technology choices did not affect the system adequacy, and it is shown in figure 14 that the two incentive mechanisms still assure the adequate level of capacity margins, which move in similar fashion, especially at the end of the planning period.

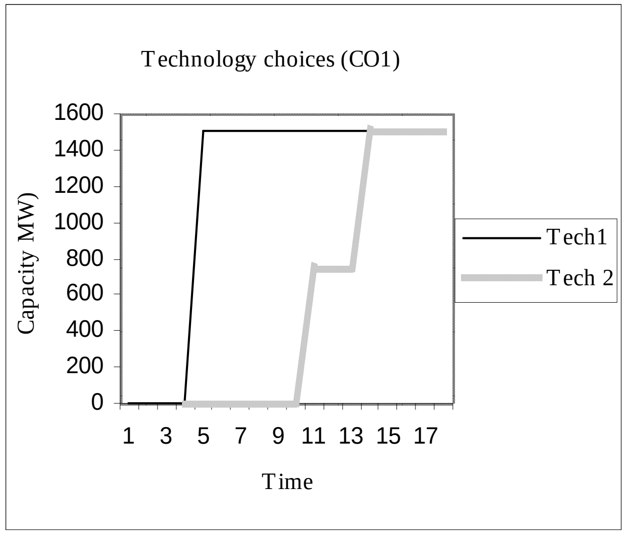


Figure 14:
Capacity margin evolution in the planning period for the three market designs with Tax-Co2.

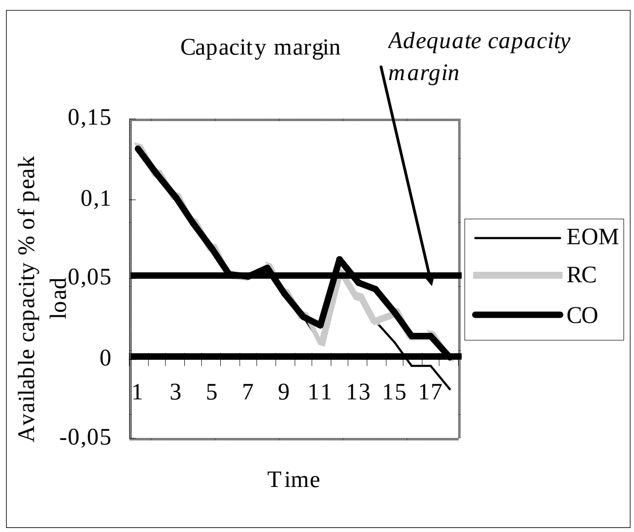


Figure 15:
Total incentive cost paid by end users for the two incentive mechanisms with Tax-Co2

An interesting result here is that the tax-Co2 implementation has reduced the levels of new capacity additions in scenario CO1 and brought it back down to the levels found in scenario RC1. However, the total cost paid by consumers for each market design over the planning period (Figure 15) evolves in similar fashion to the pattern found in scenarios without Tax-Co2, with a stable and low payment in scenario RC1 and increasing and higher costs in scenario CO1.

3.2 Results: Stochastic analysis

Here, future load and fuel prices are taken into account as uncertain variables. We compare the same scenarios studied in the deterministic analysis, but the criterion is the optimal timing of investments, rather than future capacity margins. The main aims of this analysis are threefold: (1) to identify the mechanism that could ensure earlier and adequate investments in the system; (2) to study the effect of the introduction of uncertainties on the assessment of the investment project; (3) to study the effectiveness of the incentive mechanism compared to the deterministic evaluation. A planning horizon of 10 years is used for the case study.

Result 7: The reliability contract scheme assures earlier new investment in the system and the lowest cost for end users.

Table 4 shows the investor's profit and optimal load thresholds for which it has become optimal to invest immediately in the new power plant with static and dynamic assessments for the three market designs. If we use a static assessment of the project, we know that the investor should invest as soon as the NPV is positive, i.e. average load level equal to 63,800MW (EOM scenario). However, by not investing the investor keeps the opportunity to invest open, and when applying a dynamic assessment of the investment project, we see consequently that investment should be made if the average load level reaches 99,000 MW (EOM scenario). This is when the profit from investing immediately exceeds the profit from postponing the investment. The reason is that there is an underlying load growth in the system, which gives rise to an option value of waiting for higher future prices, and thereby increased profits for the power plant. When going from static to dynamic assessment, we see an increase in the load level threshold, resulting in a higher expected profit over the planning period.

The electricity price in this scenario will not stay within a socially acceptable range, so we need a proactive measure in the form of a mandatory hedge or insurance such as capacity obligations or reliability contracts schemes.

To do so, we extend the analysis from the first scenarios to include the effect of introducing the reliability contract mechanism as an incentive for earlier investments in new power generation and more security in the system. The reliability contracts scheme is modeled as explained in section 2.2.1. The results show a huge reduction in the investment threshold for a load with almost 34%. This method stimulates earlier investment compared to the energy-only market scenario, and it stabilizes the income of the generators with a minimum of regulatory intervention.

We repeat the analysis with a capacity obligation mechanism (CO). The capacity factor limit, CFlimit is set at 1.05. We see that a higher level of load (79200MW), which is increased by 22% compared to the reliability contracts scenario, is now required to trigger the new investment. The expected profit is also increased considerably at the optimal investment threshold compared to scenario RC. Here, the additional revenue earned from the capacity market is an uncertain income, this gives an additional incentive for the investor to postpone the investment decision, in order to wait for the capacity factor to fall and so the revenue from the capacity market to grow before carrying out an irreversible investment action. This factor increases the option value of postponing the investment and explains the significant shift in investment thresholds when going from static to dynamic assessments in scenario CO.

We see also from Table 4 that, as in the deterministic analysis, the total costs paid by consumers are very low when applying the reliability contract scheme compared to scenario CO. The taking into account of uncertainties in this analysis had no impact on the effectiveness of the reliability contract scheme. It still efficiently assures system adequacy, by providing an incentive to invest in a timely fashion. However, uncertainties have made the capacity payment in the capacity market more uncertain, so investment decisions are further postponed and they are made only when the system fails (high level of demand and critical capacity factor), to profit from high prices in this situation.

t is also shown that an adequate level of capacity factor when the new capacity is added in the system is assured in scenario RC (1.038), however, critical levels are found for scenario EOM and scenario CO, with almost 0.69 and 0.85 respectively.

Scenarios	Investment thresholds for load		Cost of incentive M€	Capacity factor
	Dynamic (SDP)	Static (NPV)		
EOM	99000 MW	63800 MW	2338	0.69
RC	64900 MW	63910 MW	17,975	1.038
CO	79200 MW	64350 MW	750,629	0.85

Table 4: Optimal investment results for each scenario

Result 8: With the reliability contract scheme, there is no option value in postponing the investment decisions to profit from favorable change in fuel prices.

We now calculate fuel price thresholds for which new investments are triggered. Table 5 shows, similarly to result 7, that new investments are started for a high level of fuel prices when applying the reliability contracts scheme compared to the CO and EOM scenarios, where investors have to wait for a decrease in fuel prices before investing. So in scenario RC, there is no need to wait in order to take advantage of favorable changes in fuel prices. Whereas the fuel price threshold for optimal investment is high ($4.30), the premium earned from the auction would cover largely the high variable cost of the capacity and in turn, motivate the new investor to be available even in bad market conditions.

When going from static to dynamic assessment, we see a decrease in optimal fuel price levels in scenarios EOM and CO. This is because the underlying fuel price variations in the system give rise to an option value in waiting for a drop in production costs and thereby an increase in the expected profit. Waiting has a value for the additional information obtained by observing fuel prices during the additional waiting time, before carrying out an irreversible investment action. Except for the RC scenario, optimal levels are the same with static and dynamic valuations.

Scenarios	Investment thresholds for fuel prices	
	Dynamic (SDP)	Static (NPV)
EOM	$0.5	$4.1
RC	$4.3	$4.3
CO	$3.08	$4.4

.Table 5: Optimal fuel price thresholds

Result 9: The advantage of applying the reliability contracts scheme compared to the capacity obligation mechanism is insensitive to the levels of the strike price and the capacity factor limit.

In order to study the sensitivity of our results to the strike price in scenario RC, we repeated the analysis by reducing the strike price to 60% of the expected efficient price. In practice, this would not have a major effect since the investor would increase his required premium, which includes the difference between the expected spot price and the strike price fixed by the operator. Not surprisingly, the results in scenario RCa (Table 6) show modest variations in investment thresholds for load and fuel prices. However, the expected profit is practically double, due to the higher premium required by the new investor in this scenario. For the sensitivity of our results to CF_{limit} in scenario CO, we have set the capacity factor limit at 1.03 and 1.1, in scenario COa and COb respectively. In practice, this means that there is less (more) incentive to invest since it would reduce (increase) the opportunity of earning non-zero price from the capacity market. However, our results show that there is not a significant difference in optimal thresholds. In fact, when reducing the capacity factor limit, the investment thresholds for load is modestly augmented by 330MW, and in the other case it is still stable.

Scenario	Investment threshold: Load	Investment threshold: Fuel prices
RCa	64800 MW	$4.24
COa	79530 MW	$4.35
COb	79200 MW	$4.30

Table 6: Optimal investment thresholds in scenarios RCa, COa and COb

4. CONCLUSION

In this paper, we have illustrated, based on the dynamic programming method and real option theory, two dynamic investment models for addressing the problem of long-term capacity adequacy in electricity markets. Two investment incentive mechanisms, reliability contracts and capacity obligations, are analyzed and compared to the benchmark design, the energy-only market, in order to find the optimal market design that could ensure earlier new investments in the system (uncertain environment) and sufficient generation capacity to meet future peak demand at efficient cost. The effects of different factors on investment strategies, such as the pricing of CO2 and differences between construction lead times and cost structures of the new technologies, have also been analyzed.

The main finding of this study is that the reliability contracts scheme would efficiently assure the long term system adequacy and encourage earlier investments, and appears to be a more cost-efficient incentive mechanism compared to the capacity obligations scheme, which would result in over-investment. We also found that prices in the electricity market and the capacity market are manipulated when applying the capacity obligation mechanism. In addition, it is shown that the taking into account of uncertainties would not have any effect on the effectiveness of the reliability contract scheme, while in the capacity obligation scenario, uncertainties would make the capacity payment from the capacity market more uncertain, and investment decisions would be further postponed and would occur only when the system fails. It is also illustrated that the short lead time technology is preferred when applying the capacity obligation design, while with the reliability contracts scheme, technology with competitive costs is chosen. Finally, we found that the pricing of CO2 would affect investment strategies but would have no impact on the effectiveness of the reliability contracts scheme.

This analysis could be extended in several ways. Firstly, we could study the effect of other mechanisms such as capacity payments and capacity subscriptions. Secondly, the feedback of the demand side to the implementation of an incentive mechanism could also be analyzed. Finally, game theory methods could be used to study the effect of competition among market participants on the long-term system adequacy.

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