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Abstract

The introduction of renewable energies target and CO_2 emissions trading systems make the investment decision more difficult and add an additional flow of expenditure for electricity producers. This challenge represents a double advantage for biomass, which is a renewable alternative to fossil fuels, whose use in thermal coal can now reduce emissions of greenhouse gases. Whereas renewable energy sources (RES-E) are now supported by various economic tools such as feed-in tariffs and call for tender, the use of biomass is also enhanced by the CO_2 emission price. However, the price evolution of emission allowance is uncertain. Taking into account these incentives, the scope of this work is to study the penetration of green electricity production from biomass and its impacts on the future electricity generation mix for France incorporating different scenarios of emission allowance prices. While the use of the power plant is organized according to their growing running costs in the short-term approach, in the long-term approach capacity expansion planning should be determined by using several optimization methods. So, we develop a model based on a linear dynamic programming approach for supporting the electricity generation management in which renewable energies, climate and energy policies are modeled. We apply the model to the French power market under consideration of the neighboring countries. We present the results of the initialization and the electricity price and production tests. Then the expected demands of fuel over 2020 are presented for different CO_2 prices as an example to illustrate how the model can be put to use in different contexts.

Keywords: Electricity production, biomass, bioenergies, optimization.

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Introduction

The introduction of environmental constraints - such as the reduction of greenhouse gases emissions by Directive 2009/28/EC and penetration targets for Renewable Energy (REC) in the joint production of electricity announced by the Grenelle of Environment- added additional constraints that have complicated the production planning of electricity. Thus, renewable energies and CO_2 emissions trading systems make the investment decision more difficult and add an additional flow of expenditure for electricity producers. This challenge represents a double advantage for biomass, which is a renewable alternative to fossil fuels, whose use in thermal coal can now reduce emissions of greenhouse gases. Whereas renewable energy sources (RES-E) are now supported by various economic tools such as feed-in tariffs and call for tender, the use of biomass is also enhanced by the CO_2 emission price. However, the price evolution of emission allowance is uncertain. The objective of this work is to study the penetration of green electricity production from biomass in the French electricity production system, by incorporating different scenarios of emission allowance prices.

All the potential benefits are complex functions of factors such as the price of coal and biomass, government policies, capital investments, and the carbon market. In this context, the present study aims to develop a model for supporting the electricity generation management taking these factors into account. Moreover, to meet the requirements of long-term analysis for this sector, we develop a model based on a linear dynamic programming approach in which the two main following constraints are taken into consideration. First, an essential characteristic of electricity is that it cannot be stored. The immediate consequence is that the electricity supply needs to be adjusted to meet demand. Some equipment could only be used a limited number of hours during the year to meet demand when it is at its highest level. Thus, the cost of a kilowatt hour (kWh) can vary in a ratio of 1 to 10 according to the period of the day (during off-peak hours or not). Second, there is a time constraint that penalizes the electricy system. This constraint takes the form of delays in construction equipment production rates (two to seven years) and the lifetime of this equipement is very long (20 to 50 years).

After a short review of the literature, we present the modeling of the electrical system in the form of a linear dynamic programming model. In this paper we study how to integrate environmental constraints in the formalization of the problem. The third part is devoted to the parameters used for the French case. The incentives for biomass use in the renewable energies mix are described in part four. Finally, in part four we highlight the results of a 'base case' and projections for 2020. We analyze the evolution of marginal costs, fuel use and investment needed for different types of power plants based on the price of CO_2 allowances.

1 Literature review

The topic of our paper is related to four strands of literature which are briefly discussed below.

A first strand of literature considers power generation modeling. The issue of the optimum electricity generating mix was first introduced by Bar-Lev & Katz (1976). Secondly Awerbuch & Berger (2003); Awerbuch (2006) have more recently extended the analysis to various power mixes. Fortin et al. (2008); Roques et al. (2008); Huisman & Kort (2009); Huang & Wu (2009) have also applied mean-variance portfolio techniques in various papers to also present risk measures. The energy portfolios management and the future optimum power generation mix are problems usually dealt by two main approaches that we can be observed in the literature. The first approach concerns works focusing on maximizing the Net Present Value (NPV) of the electricity generation sector. The NPV is composed of the objective function of an optimization problem, which is subject to a set of constraints, depending on the issue. With the optimization of the problem, we get the power generation mix for which the NPV system is maximized. The optimum point could indicate the optimum investing timing, such as in Madlener et al. (2005); Kumbaroglu et al. (2008). Thanks to this approach we can forecast the future electricity prices. The second main approach aims at minimizing the electricity generation cost (Porat et al., 1997). In this case, assumption over the future electricity prices does not have to be made. Focusing on minimum generation cost implies minimizing the cost to be passed on to the final consumers, irrespective of the electricity price. This method has the advantage of studying the agent behavior when faced with a mix of different types of constraints: economic, technical, and environmental constraints. Our approach is similar in the way that we develop a linear dynamic model where the total costs are minimized.

A second strand of literature is related to the study of biomass use in the power sector. Jäger-Waldau & Ossenbrink (2004) consider that biomass is the only other known naturally available, energy-containing carbon resource that is large enough to be used as a substitute for fossil fuels. Moreover, for various technical and economic reasons the use of solid biofuels is seen to be one of the most promising options for a more environmentaly responsible energy systems in the future (Hartmann & Kaltschmitt, 1999; European Parliament and Council of the European Union, 2009; Al-Mansour & Zuwala, 2010): without major changes, biomass is suitable as a substitute for fossil fuels in the energy conversion chain. Few biomass conversion technologies exist and can be employed to obtain electricity (Jäger-Waldau & Ossenbrink, 2004). However, the introduction into the existing energy system should be managed with the necessary political support. Indeed, for Gan & Smith (2006), economic competitiveness remains the major barrier. We study this aspect in our paper.

Presently available options for generating electricity from biomass are small- and medium-sized biomass-fired power plants, and Combined Heat and Power plants (CHP), and co-firing biomass with fossil fuels in large power boilers. The co-firing option is the least expensive of these. So, the biomass will play an important role via co-firing with coal. Different studies have been done on this topic: Hartmann & Kaltschmitt (1999) do an analyse based on a Life Cycle Analysis of the environmental effects of electricity production from hard coal in existing power plants in comparison to electricity production in similar plants based on a co-combustion of hard coal and biomass. Biomass co-firing experience worldwide have been also reviewed and compared by Al-Mansour & Zuwala (2010).Basu et al. (2011) discuss the influence of factors such as the coal and biomass prices, policies, capital investment and the carbon market on the viability of different technical co-firing options in coal-fired power plants. An analysis of the economic aspects of different co-firing options in Canada is performed. Our approach is similar but the difference is that we develop a model over the period 2015-2030 to analyze the French case in the long term.

Then, our paper is related to a third strand of literature which deals with the co-firing option in power generation models. Different kinds of model have been used to investigate the cost competitiveness of woody biomass for electricity production. They can be distinguished by the scale of the study (international, national, regional) and the modelled technologies using biomass. There are bottom-up and top-down models. Santisirisomboon et al. (2001) use the least cost approach for the power generation expansion planning in Thaïland as Berggren et al. (2008) for the Polish case. The difference is in the number of technology modelled. Their work focuses entirely on the co-firing option and, consequently, the modeling does not compare co-firing to other RES-E technologies (such as biomass-based CHP, hydraulic, wind, solar...). At a national level, Rentizelas et al. (2010) model the Greek national electricity generation system for long-term analysis and an optimization method is applied, to determine the optimal generating mix that minimizes the electricity generation cost. The renewable energy generation targets are taken into consideration as a constraint of the system. So the methodology used in this paper is close to our approach but import and export are not modelled and the co-firing is not taken into account. Biomass is supposed to be used in a dedicated unit. More recently, Levin et al. (2011) have developed a state-scale version of the MARKAL energy optimization model to address the impacts of a renewable electricity standard (RES) and a carbon tax in one southeastern state, Georgia. MARKAL is a bottom-up, dynamic, mostly linear programming (LP) model which was developed by the Energy Technology Systems Analysis Programme (ETSAP) (Loulou, 2004). MARKAL considers both the supply and demand side economics of an energy system.

At the European and Amercian levels, we have found two papers in the literature. First, Skytte et al. (2006) developed a dynamic year-by-year market simulation in which national RES-E supply curves are matched with policy-based demand curves. This model is a part of the ADMIRE-REBUS project under the EU research program. They also compare two ways to achieve renewable energies target compliance - either with the import of biomass from countries outside the EU or without. The major finding of the study is that increased imports of low-cost biomass will significantly reduce the cost of target compliance. Secondly, Gan & Smith (2006) use the CGE model called Global Trade Analysis Project (GTAP) to study biomass use in the American power system under alternative CO2 emission reductions and taxes but, contrary to our paper, no co-firing system was considered. Our paper is different to this literature in the sense that we consider a partial equilibrium model where all the French technologies of production are modeled including the balance of the exchanges, the different electricity production support schemes and the CO_2 price. Our work also contributes to the established literature on the power generation modeling with a comparison of the co-firing with other RES-E technologies.

Finally, our paper is related to a fourth strand of the literature which deals with impacts of European and national policies on biomass use. Skytte et al. (2006) underline that although it is widely recognized that biomass can be a major contributor to securing compliance with the indicative targets for 2010, biomass may not play the role expected by the European Commission in the 1997 white paper for renewable energy. This indicates that the targets - and, in particular, the expectations of development within the use of biomass in CHP plants - at that time were ambitious. It can also indicate a lack of development in the desired direction since the publishing of the white paper. The Skytte et al. (2006) study indicates that additional subsidies are needed if the deployment target for biomass-based CHP plants is to be reached. Kautto et al. (2011) examine interactions of the EU Emissions Trading System (EU ETS) with the main national climate policy instruments and identify the influence of these on biomass use. The work draws experiences from seven EU countries (France is not included). The analysis explores the effects of policy interactions and is based on an examination of the literature, and interviews with biomass experts in research, industry and policy spheres. Our conclusion will draw on their results.

2 Modeling of the power sector: cost minimization under load constraint and merit order

Electricity generation should be provided by a large set of power plants which are characterized by different technologies associated to a very large spectrum of fixed and running costs. Consequently, this leads to optimal usage and the investments to reach the demand. Optimizing the overall electricity cost of production by the different types of plants enables us to 'hierarchism' of the production means. Indeed, when electricity demand increases and the power available in the lowest cost category is not enough, then it must implement the means of production whose cost category is immediately above.

In the short-term approach, the use of the power plant is organized according to their growing running cost (merit order). In the long-term approach, capacity expansion are allowed and should be determined by using several optimization methods (linear programming techniques, dynamic programming). Here, our modeling approach is based on a linear dynamic programming approach. The other methods are out of the scope of this paper; they can be found in the literature review of Weber (2004); Rentizelas et al. (2010).

Because the different generation modes are more or less competitive according to their call time, it is then necessary to define the stack of the power generation means. Optimal management assumes that the modes of production reach saturation capacity when, for the remaining call duration to cover, they are not profitable anymore. Subsequently, the fuel needed to produce electricity are derived from the use of power plants. This should be affected by the fuel prices as well as environmental policies. In this context, we allow fuel switches, especially between coal and biomass.

The following paragraphs are dedicated to the model description.

2.1 The long-term static model

The static model is designed to meet the demand of a horizon year at minimum cost. It determines the production level and the fuel consumption of each power plant, and the investments. Futhermore, the marginal costs associated with each hour-seasonnal post are derived from the shadow values related to the demand equations.

In our model, the variables are the levels of production, the need of fuels, the CO_2 emissions and the expansion of capacity. The parameters are the coefficients for the fixed and running costs, the different yields of production, the existing production capacities, the feed-in-tariffs and the demand.

2.1.1 The objective function

The utility function we need to optimize is a cost function. This approach is justified in a market context (Weber, 2004) when this one is efficient and the demand is price unelastic. Three terms are introduced in the objective function:

- proportional costs of production which include operating costs , fuel costs and CO_2 emissions;
- imports and exports costs;
- the fixed and the investment costs of equipment to install. If it is a static model, the cost considered is an annual cost including depreciation economy.

The model simulates the power production problem, taking into account several power demand according to a probability distribution. The objective function of the static model is the minimization of the expected total cost (TC) of production.

2.1.2 The constraints

The power system, as previously described, should be represented through the following set of constraints:

- Capacity constraints: for each sub-period, the power provided by each production unit must not exceed the potential power of this equipment. This potential power depends on both the capacity level and the availability of the equipment. This availability is affected by the maintenance plan for all the units, the availability of wind or solar radiation for photovoltaic, and wind energies, etc;
- Demand constraints which ensure that during each time period, the total power produced by the various units available is sufficient to meet the power demand. Because several levels of the demand should be considered for the horizon year t, a probability distribution associated to the electricity demand has been introduced in the model (objective function). So, an alea is introduced regarding the demand. Furthermore, the electricity grid is not represented and, consequently, there is no transmission constraint and the demand considered in this model is a gross demand (net demand and losses on the grid).
- Constraints of fuel needs: the fuel consumption of each unit is derived from the process yields; then, when several fuels could be used, the fuel selection is based on the fuel availability (other constraint) and the fuel prices (in the objective function).

2.1.3 Mathematical formulations

From the previous description of the objective function and the constraints, we obtain the following model for the horizon year t:

$$\min E[TC] = \sum_a pr_a * (\sum_{u,\tau,s}(l_{\tau,s} * vc_u * P_{u,\tau,s,a,t} + \sum_f (p_f + p_{CO_2} * e_f) * X_{f,u,\tau,s,a,t} +$$
$$(p^{imp}_{\tau,s,a} + p_{CO_2}) * Imp_{\tau,s,a,t} - p^{exp}_{\tau,s,a} * Exp_{u_1,\tau,s,a,t})) +$$
$$\sum_u (fc_u + ic_u) * Cap_{u,t}$$
$$s.t.\ capi_u + Inv_u = Cap_u$$
$$\frac{1}{disp_{u,s}} * P_{u,\tau,s,a,t} \leq Cap_{u,t}\ \forall \{u, \tau, s, a\}$$
$$\sum_u P_{u,\tau,s,a,t} + Imp_{\tau,s,a,t} \geq dem_{\tau,s,a,t} - AP_t + \sum_u Exp_{u,\tau,s,a,t}$$
$$\sum_f \eta_{u,f} * X_{f,u,\tau,s,a,t} = l_{\tau,s} * P_{u,\tau,s,a,t}\ \forall \{u, \tau, s, a\}$$
$$\sum_{u,\tau} X_{f,u,\tau,s,a,t} \leq fuelav_{f,s}$$

With the variables:

- $P_{u,\tau,s,a,t}$, power loaded on the grid by each equipment of type u at sub-period τ, the season s and the demand related to the random event a in year t (MW);
- $X_{f,u,\tau,s,a,t}$, the fuel energy input f demanded by the unit u at sub-period τ, the season s and the demand related to the random event a in year t (MWh);
- $Cap_{u,t}$, the capacity of the equipment of type u in year t (MW);
- AP_t, must-run supply (MW);
- $Imp_{\tau,s,a,t}$ and $Exp_{u,\tau,s,a,t}$, imports and exports;

and with the parameters:

- pr_a: probability associated to the random event a of the demand with a $\in \{1, 2, 3\}$;
- $l_{\tau,s}$, length of the sub-period τ in seaon s (hours);
- vc_u, variable cost of production of each equipment u (euros/MWh);
- e_f, the emission factor of CO_2 per fuel f (t_{CO_2}/MWh);
- p_f and p_{CO_2}, price of the fuel f and emission price of CO_2;

- fc_u and ic_u, fixed costs and investment annuities of each unit of production (euros/MW);
- $dem_{\tau,s,a,t}$, called power on the grid for the sub-period τ, season s and random event a (MW);
- $disp_{u,s}$, coefficient of availability in each season for each equipment u;
- $\eta_{u,f}$, the technology efficiency of unit u for fuel f;
- $fuelav_{f,s}$, the availability of fuel f at season s (ton).

$AP = \sum_{u1} P_{u1,\tau,s,a,t}$ is the sum of must-run supply from the units, u_1, with $u_1 \subset u$. Futhermore, some other constraints have been added.

2.1.4 Policies instruments

We examine two different policy instruments: emission price and feed-in tariffs (FIT). Emission price is a climate policy instrument, and FIT is a renewable electricity (RES-E) policy instrument. The FIT is a specific price that is paid for RES-E production by electricity distributors (for more details see part 4.2.2). If the power production of the unit u is subject to FIT, we consider that it will be deduced from the variable cost, $vcost_u$. The variable cost for plants in the case of FIT, $p_{fit,u}$, is also:

$$vc_u = vcost_u - \max\{0, p_{fit,u}\}$$

The climate policy, i.e., emission price is targeted at the fossil fuel used in co-firing and at the fossil-fueled single power plants. We measure the CO_2 emitted by the different units of the power sector thanks to the emission factors. The emission price is paid for every unit of CO_2 emissions originating from energy production. The renewable fuel is accounted for as carbon neutral in the climate policy considerations.

2.1.5 Modeling hydro-power generation

The hydraulics power units generation requires a particular modeling approach because the specificity of hydraulics is that in dams or reservoirs, water can accumulate for some time before being used to generate electricity. Thus, the stock of water should be considered as a stock of energy. Futhermore, in specific case, a lake could be refilled by a pumping station which allows a regulatory role for such units. Hydraulic equipment must satisfy the constraints of the power system, namely the constraints of meeting demand and capacity constraints, as well as the thermal equipment. The demand constraint does not pose particular difficulties since the hydraulic equipment is simply a means of further production to meet the demand. The particularity of hydraulics is therefore the formulation of a capacity constraint different from thermal equipment. However, once a certain amount of water is discharged from the dam for the production, the reservoir capacity is reduced by the same amount of water. Consequently, power that may provide hydraulic equipment during a number of usage hours cannot exceed capacity (variable) tank. For any season s and random event a, the capacity constraint for the hydraulic equipment can be defined as :

$$\sum_{i=0}^{\tau_j} P_{HY,\tau_i,s,a,t} * l_{\tau_i,s} \leq \omega_{\tau_j,s,a,t} \tag{1}$$

where HY is the hydraulic equipment. The second part of the equation, $\omega_{\tau_j,s,a,t}$, represents the cumulated energy which varies according to period τ_j, namely according to substraction intensity (extreme peak, peak, semi-peak or off-peak hours).

The cumulated energy functions Hydraulic energy is concentrated on the first τ_j periods of a season s, that is to say, until the hydraulic equipment is needed, the potential energy is accumulated in reservoirs. The second member $\omega_{\tau_j,s,a,t}$ directly follows the function $\omega_{s,a,t}(\chi_j)$ for the duration of the first τ_j periods of the season with $\chi_j = \sum_i^{\tau_j} l_{\tau_i,s}$. You have two different functions depending on the number of hours used, χ_j, is less than or greater than a certain number of hours in the season, h_s.

- If $\chi_j < h_s$, cumulated energy is equal to the maximum power, denoted $PM_{HY,s,a,t}$ that can supply hydraulic equipment for the number of hours required during the season s. Such as:
  $\omega_{s,a,t}(\chi_j) = PM_{HY,s,a,t} * h_s$ if $\chi_j < h_s$;
- If $\chi_j > l_s$, cumulated energy function is given by:
  $\omega_{s,a,t}(\chi_j) = PM_{HY,s,a,t} * h_s + AP_HY(\chi_j - h_s)$ if $\chi_j > h_s$ where AP_HY is the must-run power.

Therefore, it produces at maximum power during h_s hours. Then, hydro power is provided by the must-run power during the number of called hours still unmet in the season.

While the use of the power plant is organized according to their growing running costs in the short-term approach, capacity expansion planning should be determined by using several optimization methods in the long-term approach. So, we develop a model based on a linear dynamic programming approach.

2.2 The linear dynamic model

Dynamic modeling of the electrical system is designed to consider the temporal evolution of different parameters (demand, costs, ...) to determine the dynamic of the variables (production capacity of equipment). Interest in modeling exercises does not rely only on the determination of the economic situation in the final period but also on the analysis of situations in different intermediate periods. The relevance of dynamic modeling in the case of the electrical system is justified, particularly through the following problems and questions:

- We need to know the structure of marginal costs by the final year of study to get an idea of the likely evolution of electricity prices that follow the principle of 'marginal cost pricing'.

- Moreover, the electrical system requires an analysis of the long-term taking into account the time of making and commissioning of facilities because of the importance of investment needs, duration of construction, and life of the equipment.

In order to introduce residual values at the end of the period, we consider an infinite period of the last period with an infinite renewal of the same facilities. Investment costs introduced into the economic function also include the cost of replacement to the same. Moreover, in a multi-period model, the time can be reduced as desired. However, we must introduce the following hypothesis: the final period will be of infinite length so as not to have the problem of estimating the residual value of the equipment which are not decommissioned at the end of the period. We call this hypothesis the permanent regime (sale price stability, negligible effect of technical progress). In the following model description, we consider a set of sub-periods $t = \{1, ..., T\}$.

2.2.1 The objective function

The economic function of the dynamic model becomes the minimization of the discounted sum of fixed costs and the expected cost management according to the demand and the available capacity:

$$\min \sum_{t} [pr_a * (\sum_{u,s,\tau,a} (\gamma_t * l_{\tau,s} * vc_{u,m(t)}) * P_{u,\tau,s,a,m(t)} + \sum_{f} (p_f + p_{CO_2} * e_f)) * X_{f,u,\tau,s,a,m(t)} +$$
$$(p^{imp}_{\tau,s,a} + p_{CO_2}) * Imp_{\tau,s,a,m(t)} - p^{exp}_{\tau,s,a} * Exp_{u_1,\tau,s,a,m(t)}$$
$$\sum_{u} \varphi_t (fc_{u,m(t)} + ic_{u,m(t)}) * (Cap_{u,m(t)} + C_{u,t})]$$

With:

- t, the period;

- $m(t)$, representative year of the period t;

- $n(t)$, number of year during the period t;

- $ic_{u,m(t)}$, investment annuity for the unit u in the representative year $m(t)$ of the period t (euro/kW)

- $C_{u,t}$, capacity to built the equipement u at the period t;

- γ_t and φ_t are the discount factors such as:

$$\gamma_t = \frac{1}{(1+r)^{b(t)}} \sum_{k=1}^{n(t)} \frac{1}{(1+r)^k}$$
$$\varphi_t = \frac{1}{(1+r)^{b(t)}}$$

with r, the discount rate and $b(t) = \sum n_k$, number of years before the period t.

The electricity generating cost is calculated for each year and each technology using the levelized lifetime cost estimation methodology (International Energy Agency, 2005). According to this methodology, the levelized lifetime cost per unit of electricity generated is the ratio of total lifetime expenses versus total expected outputs, both expressed in terms of Present Value equivalent. This methodology has been chosen instead of traditional Net Present Value analysis, as it transforms the investments and the time series of expenditures and incomes during the lifetime of the investment to equal annuities, discounted in Present Value. Therefore, it allows fair comparison of the electricity generation cost even for power plants installed in years close to the boundary of the time-period examined, where traditional NPV analysis would fail to provide reliable results, as only part of the lifetime of the power plant would be included in the calculations (Rentizelas et al., 2010).

The investment cost is calculated as a series of equal annuities, spread over the entire lifetime of the unit u, in order to be able to perform reliable calculations also for the years t where the operational lifetime of a specific technology is longer than the remaining time period for examination. This way, only the annuities ($ic_{u,m(t)}$) corresponding to the time span under investigation are taken into account.

We apply a different discount factor for the variable cost and investment annuities. Indeed, the variable cost is different every year and the discount factor varies also every year. On the contrary, the discount factor corresponding to a future investment is more simple since, by convention, we invest in the first year of sub-period, but payment of annuities is done throughout all the period.

2.2.2 Demand and supply constraints

As before, there are for each period, supply (or capacity) and demand constraints :

- Capacity constraints:

$$\frac{1}{disp_{u,s}} * P_{u,\tau,s,a,m(t)} \leq \sum_u \alpha_{u,q(t)} Cap_{u,m(q)} \tag{2}$$

with $\alpha_{u,q(t)}$, coefficient of availability of the equipment u, in year q, activated in year t. It measures the capacity reductions that occur after the construction of a plant.

- Constraints to meeting demand: the sum of equipment must provide the power required on an hourly basis for consumers and this, for each random event a such as: $\sum_u P_{u,\tau,s,a,m(t)} \geq dem_{\tau,s,a,m(t)}$

- Constraints of fuel needs;

Evolution of the demand over time The fact that the demand has a random distribution puts a strain on the load curve, and therefore it may have significant distortions on the load curve in the future. Therefore, we must examine more specifically the components of the electricity demand in order to envisage several possible scenarios and thus see the effect on marginal costs and prices. In addition, electricity demand is not independent of prices since the user behavior is sensitive to price changes.

The uncertainties on the demand are also significant. With changes in job organization and the development of electric heating, the seasonality of demand has sharply increased in recent years. Accordingly, the sensitivity of the load curve to the random event (and more particularly, to temperature that affects more its level than its form) also increases.

Finally, we must take into account the forecast demand and changes in user behavior. Thus, even though the winters of the last decade were more forgiving, households have tended to increase the average temperature of their homes which, of course, has resulted in additional power demand.

2.2.3 Equation between sub-periods

Schematically, we can duplicate the static model defined above as many times as periods. Finally, the connection between each of these sub-models is done by equations that describe the evolution of the system of power generation equipment. If $Cap_{u,t}$ and $Cap_{u,t-1}$ represent the capacity of equipment u during two consecutive years, and $U_{u,t}$, the commissioning of this equipment in year t, we can then write the following relation of the electric park evolution:

$$Cap_{u,t} = Cap_{u,t-1} + U_{u,t} \text{ with } U_{u,t} \geq 0$$

In addition, we assume that the second members of the equalities related to the initial year are the capacities existing at the starting point, U_0. To better reflect reality, we should modify this equation by integrating on the one hand, the decommissioning of obsolete units (decisions are optimized for the decommissioning of old structures, but we maintain the same renewal assumption of the future equipment) and on the other hand, the 'teething problem' of thermal equipment that result in additional allowances on the production capacities of these facilities during the first years just after commissioning.

We get the following equations:

$$Cap_{u,t} - \sum_{u} \alpha_{u,k,t} U_{u,k,t} = \alpha_{u,0,t} U_{u,0} \tag{3}$$

with:

- $Cap_{u,t}$, capacity available of the equipment u at the period t,
- $U_{u,0}$, capacity (given) existing at the beginning of the period studied ,

- $U_{u,k,t}$, capacity of the equipment u built in year k of the period t,
- $\alpha_{u,k,t}$, coefficient of availability in year k for the equipment u built in period t.

We are now going to apply our model to the French case.

3 Application to the French case

The structure of the numerical application follows the French electricity market. In this section we define the parameters.

3.1 The demand

We have seen that the most important feature of the electrical system is that electricity is not storable. This implies that production must adjust instantaneously to the consumer and ensure that equipment is functioning at full capacity at the time of peak demand, and even at extreme peaks. Therefore, the load curve, which represents the continuing evolution of the power demand over time, is one of the fundamental elements of the optimization model.

3.1.1 The French load curve over the last decade

The share of electricity in the national balance sheet has grown significantly in recent years and it is likely that this trend continues for a few years with the development of electric cars. While the level of petroleum product consumption has stagnated since the 1980s in slightly more than 71 Mtoe, there was a sharp increase in electricity consumption. It now represents 22.4% of final consumption of primary energy. Thus, it is the power which has the highest average annual growth rate in parallel with natural gas: 2.1 and 2.4% per year between 1990 and 2007, respectively, (Commissariat Général au Développement Durable, 2009). By sector, too, the share of electricity is important (except in transportation where it obviously remains marginal): 36.4% of the energy consumption is electricity in the industry and electricity represents 64.3% in the residential/commercial with the highest growth rate. On the contrary, in the transport sector, electricity consumption remains low, with less than 2.8% of consumption in this sector (IEA, 2009).

The demand per period was determined from historical data for the French sector, from 1996 to 2009 furnished by the French electric network of transport, RTE [1] (cf. figure (1)).

Description of the load curve Electricity consumption in France corresponds to that of a temperate country. The load curve has the same shape almost every year except during the extreme peak hours of demand (see figure (1)). Indeed, development of electric heating in recent years has led the consumption of electricity to have the highest average annual growth rate. The spikes in electricity demand therefore occur only in winter (first part of

[1] http://www.rte-france.com/fr/nous-connaitre/qui-sommes-nous/information-in-english

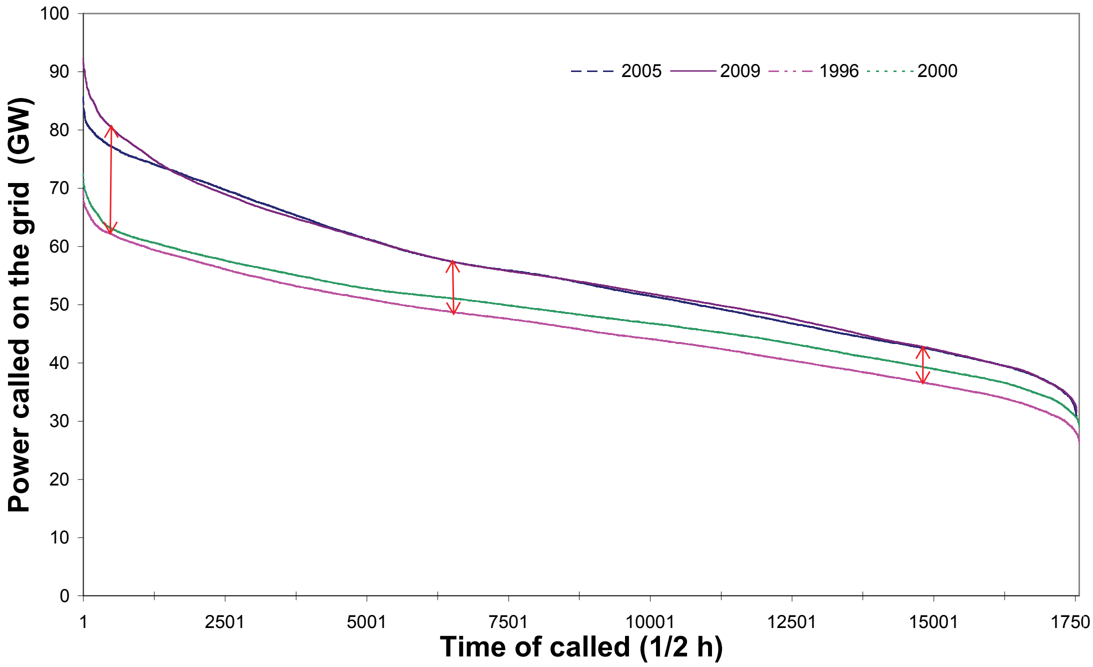

Figure 1: Power loaded on the grid (net demand) as a function of time (8 760 hours)

the curve). The air-conditioning market is still not well developed because the periods of hot weather in France are generally too short to justify the deployment of air-conditioning at the household level. Other uses of electricity, hot water, and cooking do not really depend on a climate hazard. So we can think that consumption is perfectly predictable since it depends on the number of subscribers and the power they require throughout the year. However, hot water and cooking do not represent the majority of electricity consumption. Lighting is really the only captive usage of the electricity and its function is based on climate due to relatively long nights. Furthermore, consumption of lighting is 'pumped' by the winter hours system in France and also the summer hours. Therefore the demand is based on the climate, which is entirely random. Moreover, the load curve is very volatile, not only during the seasons but also in the weeks and even days.

The level of the French demand For the need of modeling, we propose three different demands representing years with different climate conditions as observed in figure (2). We distinguish between a hot-summer and a cold-winter year (as in 2009 where the power demand was high), a year with a low consumption of electricity during the base and the semi-base hours (as in 2007) and a year with a mean consumption (as in 2005, 2006 and 2008). So we have a climate uncertainty wich impacts the power demand in three ways.

So we index the alea a_y with $y \in \{1, 2, 3\}$. The index characterizes the climate conditions during the year. A probability is associated to each random event a of the demand.

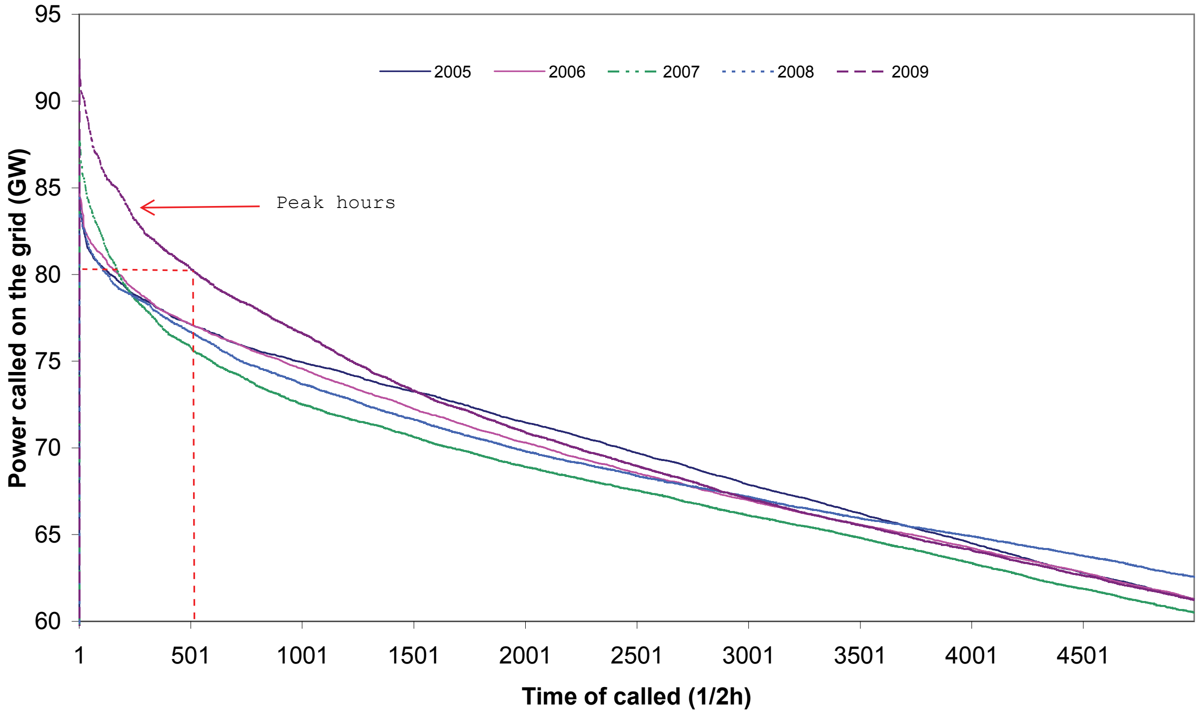

Figure 2: The three different types of power demand in France

3.1.2 The decomposition into seasons and hours

Even if we can get a very fine level of disaggregation of the order of hour, it will not really be necessary for the model. Therefore, since electricity consumption fluctuates in part due to the pace of climate, the first cut on the application is made by the seasons and the second by hours. For a relatively detailed model, it seemed preferable to split the year into four 'seasons' and four 'hours'. The four seasons are: winter (S1), the half-season (S2), spring (S3) and July and August(S4). In France, the periods when electricity demand is lowest corresponds to S4. Futhermore, four seasons have been considered as we have seen that the demand varies depending on time of day. The four hours are: the extreme peak,τ_0 (the hours for which the demand is the highest); the peak, τ_1, (four hours per day, Monday through Friday, excluding holidays and the like, throughout the winter. The morning peak is set from 9 am to 11 am and evening from 18 pm to 20 pm); the peak,τ_2 (six hours per day, Monday through Friday and Saturdays, Sundays, public holidays and also all the months of

July and August); the off-peak, τ_3 (all other hours). In France, in general, peaks in demand are realized in the morning and evening. We also consume differently depending on the day, and in particular, demand for electricity is lower during the weekend. However, daily cutting can be integrated into the cutting zone (hours).

Demand corresponding to each combination of time and season will be the demand to be met. So we combine the seasons and times for hour-seasonal posts we used for the model. In France, the peak hours always occur in winter; demand will be zero for sub-periods $\tau_0 S_2$,$\tau_0 S_3$, $\tau_0 S_4$, $\tau_1 S_2$, $\tau_1 S_3$,$\tau_1 S_4$, $\tau_2 S_4$. The demand requested to the producers during the season 4 (July-August) with the lowest consumption will be considered as a part of the off-peak only and will be equal to zero for other positions. A certain demand corresponds to each of these positions : it is expressed in MW. When powers are ranked in order of their call, we call this curve, the load curve.

Electricity is the only energy source whose use is expected to grow by 2020 (from 45.3 Mtoe in 2005 to 46.9 Mtoe in 2020), the main causes are the increased use of electronic assets and emergence of new uses such as electric cars and heat pumps. Taking into account these evolutions, we define demand projections for our prospective.

3.1.3 Demand projections

For this case study, we have made projections of total energy demand in France through 2030 following IEA fuel prices projections. An analysis of end-use electricity demand in France was performed in each of the five sectors, residential, commercial, industrial, transport, and agriculture based on historical data from 2001 to 2008, and three different growth scenarios are presented: low, reference, and high. Our scenarios of demand follow the above-mentioned projections. We assume that the shape of the load curve remains the same as in 2008 and demand is not disaggregated by end-use for the purposes of this model. These projections do not anticipate any gains in energy efficiency that deviate from business-as-usual demand growth, as they are all based on historical data.

3.2 Generation utility means

The optimization of power generation can 'prioritize' the means of production. By this we mean that it is of course preferable to use first and maximum units with the lowest cost of production. In our model, nuclear power stations will therefore be used as a base. When electricity demand increases, the power available in the category of low cost is no longer enough. We must then implement in priority the means of production whose cost category is immediately above. There exists a merit order of different equipment that depends on the operating costs which allowed us to define in the first part the 'stack' of various equipment on the monotonous annual charge.

3.2.1 Present capacities

Currently, electricity production is divided between thermal equipment (87%) and hydraulic equipment (11%) and other renewable facilities (2%). Moreover, the French electricity production system is characterized by a fleet of hydro-power plants which is saturated because all the places that are naturally friendly for hydro-power production have all been equipped and are currently being used. Moreover, nuclear equipment is in overproduction because of the French energy policy to reduce oil supplies and energy dependency rate since the 70s. One major consequence of this over-capacity of equipment is the amount of electricity generated and the significant development of exports for 10-year period. In 2007, electricity exports accounted for about 68 TWh of the 560 TWh generated while they were only 12 TWh in 1980 for a production of 250 TWh. Exports increased from 5% of production in 1980 to almost 12% of production in 2007.

Total present capacity of each generation technology was obtained from RTE[2](Réseau de transport d'électricité) which published public data on all generating facilities for 2008. Wind power and photovoltaic capacities stand for 2010. We define the different equipment in the following section:

The thermal equipment Their operating principle is as follows: combustion or nuclear reaction can heat a fluid which produces, in a turbine, mechanical energy converted into electrical energy by a generator. There are five main types of thermal equipment:

- gas turbine whose exhausted gases produce directly on the work required to drive the alternator. Performance of this mode of production is relatively low (15 to 30% depending on power) and operating costs, for fuel consumption, are very important.
- combined cycle, which consists of installing a gas turbine and a counter-pressure (steam turbine), maximizes the production of electricity.
- units of combined heat and power (also known as cogeneration), simultaneously supply electricity and heat from one or sometimes multiple pieces of equipment generators.
- conventional thermal power stations with two versions: thermal oil and thermal coal.
- thermal nuclear power plant which includes several types depending on the type of fuel and coolant used and also the nature of the nuclear reaction. In 2007, about 58 units had been installed since 1971, 54 of which were PWRs (pressurized water reactor using uranium as a fuel, enriched up to 3%).

Hydraulic equipment: an adjustable source of electrical power We rank the hydraulic equipment in four broad categories: there are 'run of river' plants whose reserves are practically nil, lock group plants that can accumulate water for a few days and lake plants that can store water for several months. These first three items are the so-called 'gravity

[2]RTE is a French company with public capital and has been subsidiary of EDF since 2005.

plants'. The fourth category is different from the previous ones. These are pumping plants called STEP(pumping energy transfer stations) that do not exploit any natural resource, in other words they do not provide energy, they simply provide a transfer in time, at some cost. The principle of using STEP is to share the same water between two basins of the same capacity (natural or artificial) located at different altitudes. Water is pumped from the lower basin at the time of off-peak consumption usually at night. The water accumulated in the upper basin is injected to the turbines when energy is scarce during demand peaks.

The existence of these pumping stations in the production utility means can have an important impact on the structure of marginal costs. Indeed, they can reduce overall production costs by storing energy when its marginal cost of production is low (the tank is full) to restore it when it is high. This helps minimize the differences between the marginal costs of production during off-peak and peak hours. In addition, a pumping station is not only intended to convert the energy of 'off-peak' to the energy of 'peak' since its reserve of power is renewable and may be implemented in a very short time. It is therefore the ideal remedy when one of the thermal production equipment is faulty.

Wind turbines and photovoltaic equipment

- Electricity generation by solar energy (PV)
  Photovoltaic effect converts sunlight directly into electricity. Electricity generation by photovoltaic generators is related to the intensity and duration of sunshine as well as the panel orientation toward the sun.

- Electricity generation through wind energy
  Just like water and solar energy, wind energy is clean and renewable indefinitely. Electricity generation by wind depends primarily on the quality of sites. Only a preliminary study of local weather data and a long period of field measurements can be used to assess the real interest of a proposed site for the construction of wind, in terms of wind exposure, frequency, and wind speed in average.

3.2.2 Potential capacities

Regarding potential capacities, certain generation technologies such as gas, wind, solar and hydroelectric (MINEFI, 2006) have maximum potential generation capacities, which are constrained by resources. Data on maximum wind generation capacity and hydroelectric potential were obtained from (DGEMP-OE, 2008). Similar data for average solar resource are presented by EREC[3] (European Renewable Energy Council) and OPTRES[4]. Biomass generation capacity is limited by the availability of biomass feedstock, which will be discussed in more detail.

According to the baseline scenario of the RTE model, the coal thermal power plant could not be developed without authorization. Only the 600 MW-units will remain in 2030. For

[3]http://www.erec.org/
[4]http://www.optres.fhg.de/

the same reasons, the thermal power plant (others than CTP) will be shut down between 2020 and 2030 (DGEMP-OE, 2008). Futhermore, new thermal generation utility means will be installed from 2020 to 2030 to face the increasing demand of electricity during the peak and semi-peak hours.

The optimization model of electricity supply will help the investments planning and will help downgrade (merit-order) the means of production in the long term.

3.3 Costs of production and fuel availability

3.3.1 Investment and operating costs

The data of capital and operation and maintenance costs come from EDF[5], MIT[6], the DGEC[7] and Farnoosh (2011)[8].

We also incorporate a technology learning curve into our model so that the real costs of the technologies decrease over time. The rates of technology learning are proportional to those estimated for the technologies under the assumptions of the Annual Energy Outlook 2009, a document published by the (EIA, 2009). Technology learning leads to an average annual real cost decrease of approximately 1.1 % for coal, 1.4% for combined natural gas turbine, 1.5% for nuclear power plants and 2.1% for dedicated biomass. Costs for hydroelectric generation were obtained from (RTE, 2010). We assume technology learning leads to a reduction in real cost by 1.0% per year for hydroelectric generation technologies, which is comparable to those of other mature technologies such as coal. Estimates for the costs of renewable generation were obtained from (IAE-NEA, 2010) and EDF. Technologies considered include onshore wind (off-shore units are not modeled), solar photovoltaic, cogeneration from wastes and wood.

The assumption to the AEO (EIA, 2009) also provides an estimate of the costs of modifying a coal-fired generation unit to allow biomass co-firing. As Levin et al. (2011), we assume a conversion cost in the middle of the range and following Hansson et al. (2009), we allows up to 15% of current coal generation capacity to be converted to biomass co-firing. We also consider the possibility of generating electricty with waste or low-cost biomass used as a fuel in cogeneration units. We assume technology learning leads to decrease the real costs by 1% per year for both biomass co-firing conversion and waste or low-cost biomass.

3.3.2 Fuel costs

Costs for delivered fossil fuel to the power sector are obtained from DGEMP. Cost estimates for nuclear fuel have been made by DGEMP sources. Our base scenario assumes a cost of 4.4 €/MWh in 2008 with a real cost increase of 0.5% per year (Levin et al., 2011). According to the European Commission simulations (European Commission, 2008), the reference crude

[5]http://france.edf.com/france-45634.html
[6]http://web.mit.edu/
[7]http://www.developpement-durable.gouv.fr/-Energies-et-Climat-.html
[8] For more details about our data, please contact the authors.

oil price which is considered in the model raises up to 105.9 dollars_{2008}/baril in 2030. We also determine the coal and gas price over the twenty next years. Complete fossil fuel and uranium cost projections for the base case scenario are presented in table(1).

Table 1: Crude oil (Brent), coal, gas and uranium prices (base 100=2008)

	Source	Unit	2015	2020	2025	2030
Brent price CIF (1)	DG-Trend,2010	dollars/b	74.6	82.2	90.2	98.3
Coal price CIF, (2)		dollars/t	60.3	80.2	98.7	113.5
Gas price CIF	IEA (2009)	dollars/Mbtu	10.5	12.1	13.1	14.0
Uranium, in 2008 prices		euro/MWh	4.4	4.4	4.5	4.5

(1) CIF: Cost, Insurance and Freight.
(2) Coal prices correlated to Brent price.

3.3.3 Biomass costs and availability

We use the figures from the literature to characterize the different sources of biomass. The resource data on volumes are from the French project REGIX (Unified references, methods and experiences to enable a better assessment of potential agricultural and forestry ligno-cellulosic resources for bioenergy in France) and MEEDDM (2010); RENEW (2008, 2004). MEEDDM (2010) estimates a total of approximately 30 million dry tons of woody biomass available annually for energy in France in the form of harvesting residues unmerchantable timber. Mill residues, urban wood waste and paper mill sludge are all considered to be feedstock for biomass cogeneration units (denoted COO2, see table(5) for notations). We present the potential available for energy utilization in table (2).

Our results are highly sensitive to the costs of biomass. We assume a delivered price range of 18-33 euro/MWh for wood chips (REGIX, 2010).

4 The incentives for biomass use in the renewable energies mix

The French generation park contains nuclear and hydroelectric power plants that makes it one of the less greenhouse gases emitters in the world. However, the multiannual investment program power (electricity PPI) presented in 2009 holds a substantial increase in the share of renewable electricity produced in 2020 (7 073 ktoe in 2010 against 12 729 ktoe in 2020). It was done in order to cope with the increased consumption and to place France as the leader in renewable energy (see table (3)). Near-future options available to reach this target are the co-firing of biomass in large coal-fired power boilers, wind power, hydropower, biogas plants, and biomass-fuelled power plants.

Table 2: French biomass potential

Type of biomass	Humidity	Calorific power	Quantity of biomass available for energy purpose			
	%	MJ/kg	2010	2015	2020	2025 and 2030[1]
WOOD	40	19.75	23.76	28.91-31.66	31.36 - 37.5	31.36 - 37.5
Wood industrial coproducts	0	19	0.3	1.5	2.7	2.7
Straw	15	16.5	1.228	1.25	2.5	2.5
SRCA (2)	25	18.12	-	-	2	2
SRCF (3)	50	19.75	-	-	3.5	3.5

(1) For this last period, the same available quantities than in 2025 has been assumed;
(2) SRCA : Short Rotation Crops from the Agriculture sector;
(3) SRCF : Short Rotation Crops from the Forest sector;
Source: MEEDDM (2010); RENEW (2008, 2004).

Table 3: Projection of final electricity consumption produced from renewable energy (ktoe)

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Consumption	7 073	7 386	7791	8 297	8 836	9 407	10 008	10 641	11 306	12 002	12 729

4.1 Biomass position in the development of renewable electricity

Biomass could play a considerable role in fulfilling the RES-E target for the European Union, as demonstrated by (Skytte et al., 2006). By allowing importation of biomass, the corresponding technologies would play an even larger role in the fulfilment of the target. We first present the advantages and drawbacks that biomass represent for the power sector.

4.1.1 Advantages and drawbacks

Presently available options for generating electricity from biomass are small -and medium-sized biomass-fired power plants and combined heat and power plants and co-firing biomass with fossil fuels in large power boilers. The co-firing option is the least expensive of these. So, the biomass will play an important role via co-firing with coal. Indeed, this renewable resource presents advantages in comparison with the other renewable energies. Hartmann & Kaltschmitt (1999) show with a Life Cycle Analysis of electricity production from various renewable and fossil energy carriers that the use of biomass is very promising in terms of non-renewable energy resource consumption (in MWh_{prim}/GWh_{el}), CO_2 emission-equivalents and SO_2 emission-equivalents per GWh_{el} produced in comparison to other possibilities for the provision of electricity from renewable sources of energy like wind and photovoltaics[9]. Moreover, the fact that most renewable energy sources cannot be dispatched when required, as they strongly depend on weather conditions, prevents them from constituting a reliable base-load solution in the long term (Rentizelas et al., 2010). Contrary to the photovoltaïc and wind powers, the technology based on biomass is not faced to the problem of generation intermittency. Despite their short setup periods and zero fuel requirements, they often suffer from resource unavailability. Thus biomass could play a leading role in buffering the energy needs during times when seasonal and time variable energy sources, like wind or PV, have a low performance (Jäger-Waldau & Ossenbrink, 2004). The resource can be stored and used during the peak hours. In addition, it can be used via co-firing with coal in the existing thermic facilities. In this case, new investment will not be required.

There is currently no developed market for biomass in France. This creates uncertainty with respect to supply and price, but implementation of co-firing should therefore be a comparatively low-risk path for power-generating companies (utilities), as they can then still rely on the use of fossil fuel as a base fuel in case of disturbances on the biomass supply side.

The biomass conversion efficiency is ranged from 30–38% (higher-heating value basis) (Baxter, 2005).

4.1.2 Power plant co-firing potential

As observed in Sweden, the share of biomass in co-firing is highly dependent on the driving force (i.e., policy/economic and legislation) for using biomass in electricity production. We

[9]The use of hydro power could, however, be more environmentally friendly in some cases.

present the different support schemes proposed by the French government in the following section.

4.2 Bioenergy position in the support schemes to promote the use of renewable energy

4.2.1 The regulation

For each generation mean, Multi-Annual Program of Investment in electricity holds some objectives to be achieved. However, these targets are there in order to create incentives and it is not compulsory. Thus, electricity suppliers do not have to include, for instance, a minimum share of renewable energy in their bids. Similarly, there is no regional or municipal constraint on use or regarding the renewable energy production.

4.2.2 Support-schemes

Feed-in tariffs The renewable energy production benefits from the arrangements in the purchase-obligation defined by the 10th Article of the law approved on February 10, 2000. Therefore, any renewable energy generation under this mechanism is sold, transported, and distributed, subject to the imperatives of safety and maintenance, except when this production (because of its intermittent nature) undermines the security of the network. Through the purchase obligation, the renewable facilities are not dependent on market conditions. Electricity distributors (EDF and the local distribution companies) are the agencies responsible for the purchase obligation. They buy electricity generated by producers of renewable electricity and sell it for the best value on the market. The difference between the sale price on the market and the purchase price will be compensated through the CSPE (contribution to public power service)[10]. Table (4) below summarizes the main characteristics of purchase price. Details of eligibility criteria are contained in tariff orders.

We assume that feed-in tariffs are not given for power generated from biomass in co-firing. Indeed, this is currently the case currently in France. Furthurmore, technologies under purchase-obligation regime generate winter-periods production. The obligation to purchase electricity for power plants under 12 MW represents an essential element of French political support. However, call for tenders are used for higher capacities.

Call for tenders The investigation of call for tenders is managed by the Commission of Energy Regulation (CRE) and the monitoring of projects is carried out by the Ministry of Energy. Calls for national projects launched since 2003 have concerned:

- 2003 and 2005: construction of biomass units (200 MW from biomass and 50 MW from biogas);
- 2005: construction of wind farm on-shore;

[10] In French, CSPE means 'contribution au service public de l'électricité'.

Table 4: Feed-in-tariffs per generation utility means (MEEDDAT, 2010)

Power	Date of the tariffs orders	Length of contracts	Feed-in-tariffs for facilities put in service at the date of issuance of Orders
Hydraulic	March 1, 2007	20 years	- 6.07 c€/kWh + premium which varies between 0.5 et 2.5 c€/kWh for small plants + premium of 0 to 1.68 c€/kWh in winter - 15 c€/kWh for off-shore hydro-electricity, tidal barrage, stream system, lagoon and marine current stream generators
	June 25, 2001	20 years	- 5,49 à 6,1 c€/kWh according the power premium which varies between 0 and 1.52 c€/kWh in winter
Wind Power	November 17, 2008		- on-shore : 8.2 c€/kWh during 10 years,then between 2.8 and 8.2 c€/kWh during 5 years depending on the sites. - off-shore : 13 c€/kWh during 10 years, then between 3 and 13 c€/kWh during 10 years depending on the sites.
	June 8, 2001	15 years	8.38 c€/kWh during 5 years, then 3.05 to 8.38 c€/kWh during 10 years depending on the sites
Cogeneration	July 31, 2001	12 years	6.1 to 9.15 c€/kWh in function of the gas price, the length of production and the power
Combustion of biomass	December 28,2009	20 years	4.5 c€/kWh + optional premium between 8 and 13 c€/kWh depending on the power, the ressources used and the efficiency
	April 16 ,2002	15 years	4.9 c€/kWh + energy efficiency premium between 0 and 1.2 c€/kWh
Photovoltaic	January 15, 2010	20 years	from 31.4 c€/kWh to 58 c€/kWh depending on the integration in the building of the cells DOM, Mayotte and Continent: the tariff varies between + 0% to 20% according to the shining ratio
Power	July 10, 2006	20 years	-Continent : 30 c€/kWh + premium for plants depending on the integration in the building 25 c€/kWh - Corse, DOM, Mayotte : 40 c€/kWh + premium for plants integrated to the building 15 c€/kWh
	March 13, 2002	20 years	- 15.25 c€/kWh in France and 30.5 in Corse and DOM
Biogas	July 10, 2006	15 years	from 7.5 and 9 c€/kWh in function the power + energy efficiency premium which varies between 0 and 3 c€/kWh
	October 3, 2001	15 years	4.5 to 5.72 c€/kWh according to the power + energy efficiency premium which varies between 0 and 0.3 c€/kWh (valuable for the biogas from waste only)

- 2006: construction of biomass cogeneration unit (300 MW of cogeneration with 80 MW for units between 5 and 9 MW and 220 MW for facilities of more than 9 MW);
- 2009: construction of biomass cogeneration units, and construction of photvoltaic units in each French region (total of the power: 300 MW).

Other calls for tenders are being prepared, including the construction of biomass plants (call for projects proposed every year) and offshore wind farms. The case of biomass illustrates the potential of call for tenders in terms of performance requirement. In fact, every call for tenders is an opportunity to specify new performance criteria to be met. The call for the 2011 projects has highlighted the security for using heat, which maximizes energy efficiency projects, and a biomass supply plan. It is planned annually to renew the call for tenders for the construction of biomass power by adjusting the specifications to technological advances, the maturity of the industry and the biomass sources availability.

The green certificates The RECS (Renewable Energy Certificate System) is a harmonized European system of traceability and certification of renewable electricity. It is a subset of the 'European Energy Certificate System' (EECS) from a private initiative which aims to draw electricity in Europe. The RECS is administered in each country (geographical area) by a single bank of issue (Observ'ER in France). After opening an account with the issuing institution, the producer sends a certificate request to the central bank no later than three months after the production of electricity subject to the certification request. In France, according to Observ'ER, the application must be accompanied by proof of the production realized by the manager of transmission or distribution. The statements are verified by Observ'ER. Once the application is approved, Observ'ER will give credits to the producers of green electricity. Facilities under obligation to purchase at fixed feed-in tariffs can enhance the electricity generated by issuing RECS certificates. Actually, this system is the basis of the 'green tender' made by some suppliers of electricity to individual and industrial customers. Directive 2009/28/EC (European Parliament and Council of the European Union, 2009) imposes conditions on systems' evolution to guarantee that the electricity comes from renewable sources. It is about finding a solution to avoid duplication emissions (the national guarantee of origin and certificates RECS) and articulates the certification of electricity with 'feed-in tariffs'.

In addition to these financial supports, we also have in France: tax credit for sustainable development, eco-zero interest loan, tax exemptions and accelerated or exceptional depreciation. Systems to ensure the production of electricity from renewable sources also cover: the system of guarantee of origin, the Fund of demonstration, the reduced VAT (value-added tax) rate, aid for electricity generation from off-grid renewable systems and Energy Performance Plan of farms (EPP).

In conclusion, a large panel of support schemes have been put in place in France to promote the use of renewable energy. However, arbitration between different renewable energy technologies will meet the objectives of optimizing the generation of electricity under the 'merit-order structure' of the means of production. The next section presents the result of the optimization.

5 Results

In this part, we present the results of the optimization model obtained under the programming language GAMS and using the Cplex solver. The model is run over the 20-year period from 2010 to 2030, within five year increments. All inputs and results are reported in constant 2005 dollars.

5.1 Initial scenario

The base scenario will correspond to the year $t = 0$ of our model.

5.1.1 Results of the initialization

In the base scenario, additional demand (during peak hours) for the year is largely met through hydraulic (HWP), combined cycle gas turbines (CCG), conventional thermal power plants with coal and fuel (CTP and THF). We represent with figure (3) the optimal mix of technologies which represents the continuing evolution of the power demand over time for the year 2007 (a_2). The different modeled technologies are defined in table(5). At the beginning, the model authorizes the usage of different fuel per plant. In the result, we sum up the fuel consumptions of the different plants allowed to use it all over the period.

Table 5: Modeled technologies and fuel use

Technology	Notation	Fuel used
Nuclear power plant	NPP	Uranium
Coal Thermal Power Plant	THC	Biomass and Coal
Fuel Oil Thermal Power Plant	THF	Heavy fuel Oil
Combustion Turbine Power Plant	CTP	Domestic oil and Gas
Combined Cycle Gas Turbine Power Plant	CCG	Gas
Combined Heat and Power Plant with gas	COG	Gas and Biogas
Combined Heat and Power Plant with coal	COC	Coal and biomass
Combined Heat and Power Plant with fuel	COF	Heavy oil and Domestic oil
Combined Heat and Power Plant with waste	COO1	Wood industrial coproducts
Combined Heat and Power Plant	COO2	Others(waste)
Wind Power	WPO	Wind
Photovoltaics power	PVP	Sun
Hydraulic water-flow station	HYW	Water
Hydraulic lock station	HLO	Water
Hydraulic lake station	HLA	Water
Hydraulic pumping station	HWP	Water

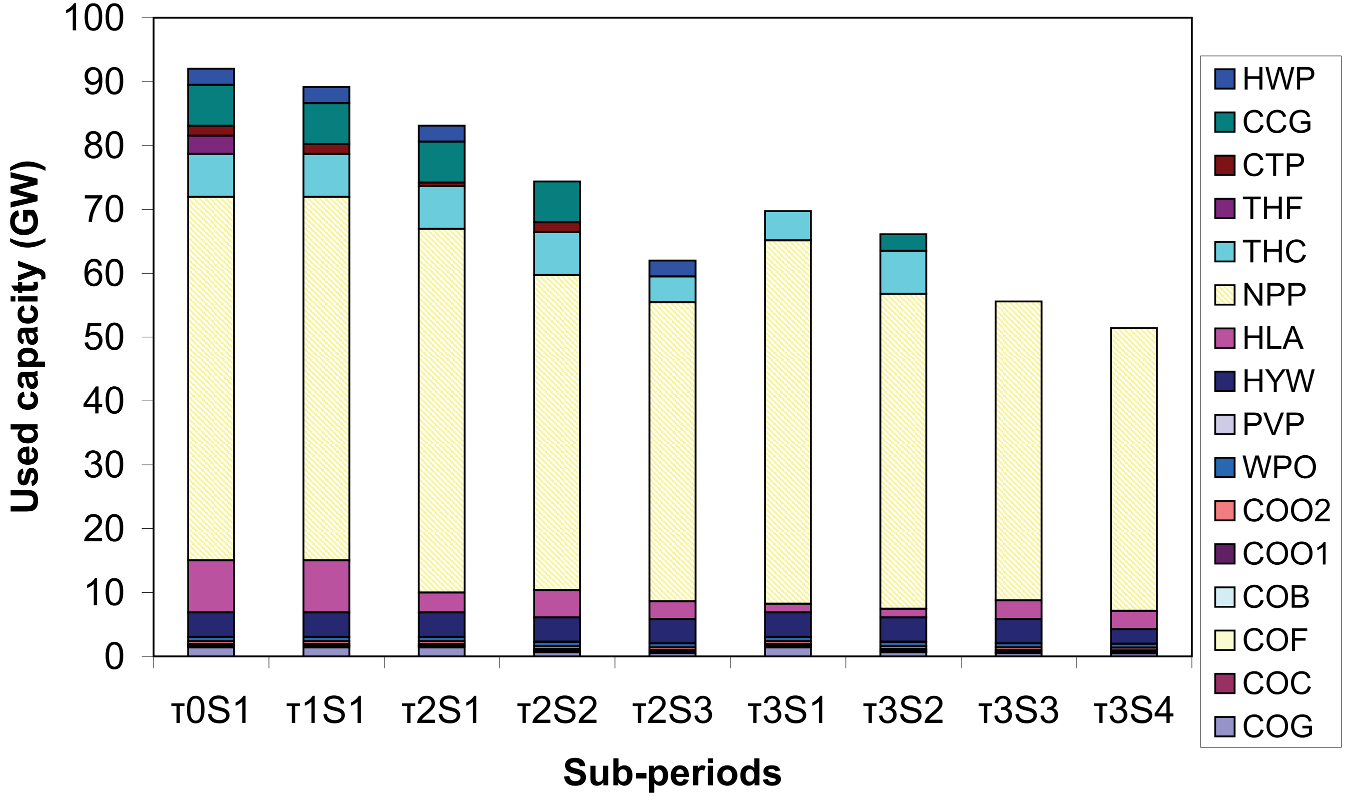

Figure 3: Optimal mix of technology for the base case results (a_3)

5.1.2 The electricity production test

We compare our results with the data from IEA/OECD Electricity statistics in order to verify the initialization of our model. The shares of production per energy source are presented in table (6) with the errors. The fuel consumptions are summarized in table(7) with the errors. These results correspond to the demand a_2 which represents the demand for the year 2007.

First, the errors calculated are not significant for both production and fuel use because they are inferior to 5%. Then we test our expected distribution for a_1, a_2 and a_3 with Chi-square tests[11]. We have four degrees of freedom: one observation per random event a and per fossil fuel (Coal, Heavy fuel oil and Domestic fuel oil, Gas) or renewable solid fuel (Wood industrial coproducts, Waste, Biogas). Our results show that we can reject the null hypothesis where there is no relationship between data simulated and expected. The model results tell us there is a relationship between the model results and the data observed from 2005 to 2009.

Table 6: Validation of the model's base case results for 2007: electricity production per energy source

Type of power	Model	Reference (IEA/OECD)	Difference	Error
Nuclear	431.8	418.6	13.27	2.44 %
Hydraulic	61.38	63.3	1.91	0.35%
Solar	0.055	0.0	0.05	0.01%
Wind	5.60	4.1	1.50	0.28%
Combustible fuels	48.19	55.1	6.90	1.26%
Coal	26.60	28.2	1.59	0.29%
Oil	1.46	4.9	3.43	0.63%
Gas	20.13	22.0	1.87	0.34%
Combustion Renewable and Waste	5.87	3.7	2.17	0.40%
Average error	553.00	544.5	8.20	1.51%

Table 7: Validation of the base case results for 2007: fuel consumption

Fuel use	Unit	Model	Reference	Difference	Error
Oil	Mtoe/y	0.659	0.888	.228	3.31%
Coal	Mt/y	8.73	9.3	0.52	$\prec$ 0.01%
Gas	TBtu/y	151.08	134.12	16.95	0.25%
Wood	GWh/y	1913	1914	0.81	$\prec$ 0.01%
Waste	GWh/y	3885.24	3891	5.76	0.08 %
Biogas	GWh/y	78.84	83	4.16	$\prec$ 0.06%
Average error					2.91%

[11] $\sum_i^m \frac{(O_i - E_i)^2}{E_i}$ with O_i the observed value and E_i the estimated value of the class i.

Even if the coal, oil, and gas consumptions obtained with the optimization model are respectively lower and higher than ones observed in 2007 (table(7), the error percentages of power production from these fossil fuels are lower than 1%. The wood, waste and biogas consumptions are closed to the data for the year 2007.

5.1.3 The electricity price test

The shadow values associated to the power demand at each sub-period correspond to the marginal value of the last megawatt per hour produced. We can notice for the representative year, a_3, which corresponds to a cold-winter and hot-summer year like 2009, that the marginal cost of electricity production is around 90 euros/MWh during one hour of the first 62 hours of the period 0 and season 1. During the off-peak hours of season 2 (March, November) $\tau 3s2$ which lasts 719 hours, the marginal cost is equal to around 43.07 euros/MWh. Finally, the off-peak hours are the less expensive one as the marginal cost is around 30 euros/MWh in July and August (season 4).

5.2 Biomass usages and influence of the CO_2 price

We consider the feed-in tariffs proposed by MEEDDM (2010) and summed up in table(4), the fuel costs, the biomass availability and the expected demand previously defined.

5.2.1 The expected use of biomass

We analyze a scenario in which there is no strict renewable electricity standard in place, but a tax on carbon emissions has been instituted instead. The tax is modeled as a fixed price from 0 to 90 euros/tCO_2 within ten euros increments. The emission cost is considered in the objective function. This analysis helps to identify tipping points where certain generation technologies become more cost favorable than others. We remind that we allows up to 15% of current coal generation capacity to be converted to biomass co-firing.

Thus, we analyse the effect of CO_2 price on the biomass fuel usage in the French power generation park. The aim is to determine the breakeven for which the power producer switches to biomass when co-firing is allowed in coal thermal power plants. Figure (4) represents the fuel use in TWh per year in function of a increasing CO_2 price.

The use of raw biomass (no pretreated) starts for a cost of CO_2 higher than 35 euros per ton. The carbon tax scenarii also show a decrease in coal generation in favor of less carbon intensive natural gas and domestic fuel generations for a tax inferior to 35 euros/tCO_2. After 40 euros/tCO_2, the decrease in coal usage is not only provided by gas power plant but also biofuel system will play an important role. For a CO_2 price which lies between 60 and 70 euros/t, we observe investment in CCG units. This investment explains the increase of gas use to the disadvantage of raw biomass for co-firing, domestic fuel and coal. Solar power does not generally seem to be able to compete with the other RES in cost terms. These findings are in accordance with results from the literature. Rentizelas et al. (2010) show that

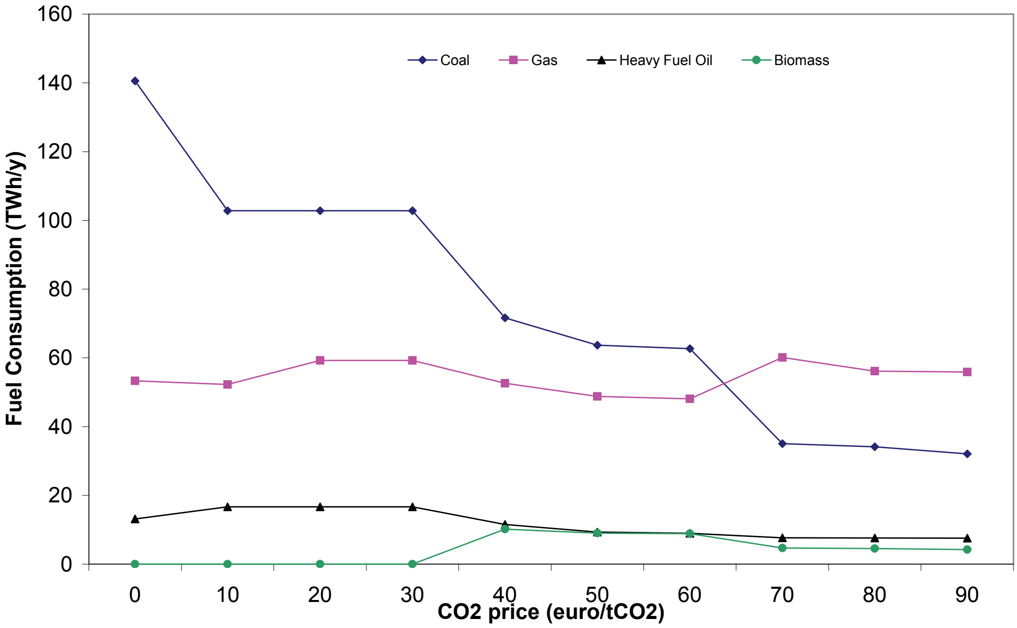

Figure 4: Sensitivity analysis of the fuel consumption with respect to the CO_2 prices for 2020

biomass is used in very small amounts with zero or low CO_2 cost and is used extensively after 2020 with high CO_2 price.

5.2.2 CO_2 tax pass-through effect over biomass use

We analyze the results of the dual problem to explain the CO_2 tax pass-through effect over the biomass use for co-firing biomass and coal in a coal thermal power plant[12](THC). The results are summed up in the table(8). Reading along the second column called 'Reduced cost related to the fuel variable *Biomass*', we notice a decreasing value as a function of CO_2 price until 40 euros/t_{CO_2} which is the break-even price for co-firing. For the event a_1 (for instance), we note that a 5 euro CO_2 tax increase leads to an increase of biomass use interest of 4.75 euros for the thermal power plant. Indeed, while the thermal power plant does not use biomass, the difference (Δ) between the two dual values related to the biomass demand equation is equal to 0.94 which results in a value of 4.75 when it is divided by the thermal

[12]That is the only plant for which the co-firing coal and biomass is allowed for this analysis.

power plant yield with biomass (given a probability of a_1 occurrence of 0.6). We get this result back from the dual values associated to the equation of fuel yield. The difference between the two shadow values is equal to 2.85, which (given a probability of a_1 occurrence of 0.6) results in a value of 4.75. The pass-through rate of CO_2 price on the cost reduction of biomass use should be equal to 100%. However, the effective pass-through rate on the THC plant is inferior. Indeed, as proved by Sijm & Chen (2006), the effective pass-through rate on electricity market depends on the demand elasticity and the change in merit order due to CO_2 cost. It also depends on the fuel yield.

Table 8: Dual values related to the primal biomass use problem

CO_2 price	Reduced cost related to the fuel variable *Biomass*	Δ(1)	Shadow value related to equation of fuel yield	Δ
euros/tCO_2				
25	2.166	0.94	26.411	2.85
30	1.225	0.94	29.261	2.85
35	0.295	0.94	32.11	2.85
40	0.	0.295	34.732	2.621
45	0.	0.	37.254	2.522
50	0.	0.	39.775	2.521

(1) In absolute value.

6 Conclusion

In this paper, we present a study of the future bioenergies usages in the electricity generation park, taking into account long-term investment planning. The partial equilibrium model used is based on linear dynamic programming to define the future national electricity generation mix up to the year 2030 and the biomass demand function. We minimize the electricity generation cost under several constraints, such as demand, reliability, availability of biomass and CO_2 emission cost. The combination of model theory and detailed demand and supply analysis provides the groundwork for the development and the implementation of the model. The modeling framework used is the Cplex[13] optimization code. We apply our model to the French case where renewable energy policies are designed to promote the development of renewable electricity. The incentives are modeled. The idea behind the optimization performed is that we can identify the most promising fuels and technologies for each level of CO_2 emission price. This information could be equally useful for state authorities and private investors as investor in biomass supply chain.

The model results show the CO_2 break-even price for which biomass can be introduced in the power sector and the consequences of this introduction on the French park. Moreover the biomass use in the French park seems to impede the investment in natural gas generation. Under cost minimization and CO_2 price constraints, the co-firing option delays the switch from coal-fired generation to gas-fired generation to the disadvantage of emissions abatement. From the results of the dual problem we can also explain the CO_2 tax pass-through effect over the biomass use for co-firing in coal thermal power plant.

In conclusion, the co-firing of coal with biomass is a relatively low-cost option but the potential is limited to approximately 15% for a high CO_2 price. The technical limit of incorporation is due to a lower calorific power value of biomass than coal, while a high level of emission allowance price is necessary to compensate a part of the biomass cost and modify the merit order. In further research, we propose to study the enhancement of pre-treated biomass based bioenergies in the French power system. Indeed, the pre-treatment could be a way to densify the biomass and increase its calorific power. The feedstock prices can also fluctuate over the time. This variability could have a consequence on the equilibrium price between the supplier and the power sector, and then modify the mix of fuel and technologies. Thus, different biomass price scenarios should be also taken into account.

[13]The Cplex Optimizer was named for the simplex method as implemented in the C programming language. Today it provides additional methods for mathematical programming and offers interfaces other than just C. It was originally developed by Robert E. Bixby and was offered commercially starting in 1988 by CPLEX Optimization Inc. The Cplex Optimizer is accessible through independent modeling systems such as GAMS (General Algebraic Modeling System).

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