Strategic Electricity Planning Decisions*

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Abstract

Sustainable electricity power planning involves trade-offs between multiple goals. The different attributes of each technology or generation portfolio in terms of the attainment of society goals must be assessed and included in the planning models. Optimization models always played an important role for supporting complex planning decision making, from which the particular case of the electricity industry stands out. This study addresses energy policy and strategic central decisions, presenting a long-term model for electricity planning. A MILP problem is described, which addresses a mixed hydro-thermal-wind power system close to the Portuguese electricity case. Through scenario analysis, the expected impacts in terms of costs, CO_2 emissions and external energy dependence are evaluated for a 10 years planning period. Based on the assumed cost information and on the imposed technical restrictions, the obtained results put in evidence the importance of coal power plants combined with new hydro power investments for minimum cost scenarios.

1 INTRODUCTION

During the past years, society adopted new concerns and objectives mainly because of the increasing environmental concerns joint with the important economic goals. European 20-20-20 targets are an example of how objectives changed, envisaging now to combat climate changes, and to increase the European Union energy security and competitiveness. Besides that, European 20-20-20 targets also aim to contribute to reach a high energy-efficient and a low carbon

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economy at the European level. New and clean energy technologies are emerging as major contributors for the achievement of these set of goals. Energy efficiency combined with renewable energy sources (RES) is then a key strategy for a sustainable future.

Usually, decision making takes place in complex systems, characterized by uncertainty, the involvement of mutually dependent organizations, social interaction, unpredictability, divergent problems definitions and lack of knowledge [15]. The electricity sector is not different. The decision makers responsibility, due to the high investments that characterize this sector and also because of the environmental concerns increase, make the work of decision maker more difficult.

Generation expansion planning aims to determine the best solution for future generation utilities, taking into consideration that a minimum mistake may result in a loss of a large amount of money and that society welfare concerns must be taken into account, in the way that demand must be met to avoid social costs [9]. The main concern of generation expansion planning is frequently defined as to find the least cost expansion plan according to the characteristics of each electricity system [16]. Optimization models are often used for generation expansion planning with the objective of minimizing cost and/or emissions, taking into account a set of restrictions that characterize the system under consideration. The complexity of these models largely result from the diversity of technologies available to systems expansion, the temporal and/or spatial evolution of parameters included in the model, and the environmental and social arguments that need to be integrated [8].

Although a great importance is given to the economic aspect of generation expansion planning, it is interesting to observe an increase of environmental concerns along with the social arguments over the last years. To Li *et al.* [8], beside the economical aspect, optimization tool can be extremely useful to solve decision maker's problems where environmental issues are considered. Also Diakoulaki *et al.* [3] encompass on their study both the importance of the economic dimension of the energy decisions and the minimization of environmental impacts. Cai *et al.* [1] enhance the environmental aspects latent on the electricity decision making. In their study, these concerns and others like fossil fuel increasing prices, reliability and security of supply are seen as on-going challenges faced by decision makers around the entire world.

The increase of renewable technologies, characterized by low emissions factor and frequently by variable output, is changing the paradigm of electricity power generation. Optimization models remain as a fundamental tools for strategic decision making, being able to include technical, economic, environmental and system restrictions.

This study proposes an optimization model for electricity power planning. The model is applied to the Portuguese electricity sector strongly based on hydro, wind and thermal power plants. In particular, the impact of CO_2 emissions allowance costs and fuel prices on the production of each generation technology is evaluated, based on a sensitivity analysis.

The remaining sections of this paper are structured as follows: Section 2 details the model, including the description of the Portuguese electricity system, the dataset used and mathematical formulation. Section 3 describes and analyses the results of this study and finally, section 4 presents the conclusions.

2 MODEL DESCRIPTION

We start with an overview of the Portuguese electricity system that will be used as a case study for the proposed optimization model. The remaining of the section will be used to present the mathematical description of the model, already adapted for the case study under consideration.

2.1 Case Study: Portuguese Electricity Sector

Portuguese Decree-Law n^{o} 29/2006 of March 15 established the organization and operation of the Portuguese electricity sector. The electricity production activities may be classified in two different regimes: special regime production (SRP) and the the ordinary regime production (ORP). The special regime corresponds to the production of electricity based on cogeneration and endogenous, and renewable energy sources supported by feed–in tariffs. On the other hand, the ordinary regime corresponds to the traditional centralized power plants such as the large thermal and hydro power groups. In 2010, ordinary regime production contributed to about 62% of total production. From ordinary regime almost half of it (46%) was provided from hydro power, and the remaining 54% come from traditional large thermal power plants [14]. Special regime production, strongly based on wind power, is increasing and reached a share of 34% of total production in 2010.

According the Portuguese national electricity network (REN) 2008 report [12], until 2019 an average 4.4% annual increase of the electricity demand is expected. However, a recent REN report showed that between 2009 and 2010, the consumption increased 4.7% from 49873 to 52205 GWh demonstrating the importance of the power generation system reinforcement [14].

The Portuguese electricity system still relies strongly on thermal power plants, and, therefore, it is strongly dependent on fossil fuels importations, making it strongly affected by the volatility of coal and gas fuel prices. The total installed thermal power, at the beginning of 2011, reached 7407 MW. Thermal based electricity was provided essentially by coal and gas, each one with specific operating characteristics. Coal power plants, presenting reduced flexibility and relatively low operational cost, tend to be the major source of electricity production, operating mainly as base load security. On the other hand, combined cycle gas turbines, despite the higher fuel costs, are characterized by low emissions and high flexibility, and as so are frequently used to cover peak load situations [4].

The importance and increase of hydropower over the years is depicted in Figure 1. Presently, the total installed hydro power is close to 4578 MW. Electricity generation from, hydropower increased 88% between 2009 and 2010, contributing to 28% of total electricity consumption in 2010. This significant production increase is explained by an high Hydraulic Productivity Index (HPI) with a value close to 1.2 in 2010. This increase was particularly due to a rainy year (HPI greater than 1) with this index reaching an unseen value since 2003, as it is possible to see in Figure 2 [14]. This allowed to almost double the hydro power production, which combined with an increase of the wind power generation, largely explains the reduction of the thermal power share for this year. A thermal power reduction of 27% was seen from 2009 to 2010, where electricity generation from fuel oil and coal was the most affected, with a reduction of 88% and 45%, respectively, while electricity generated from gas presented a reduction of 7%. These

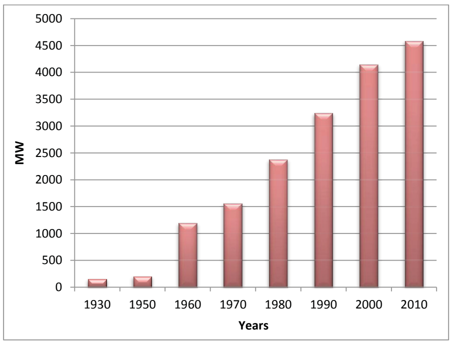

Figure 1: Hydropower in Portugal 1930 – 2010 (REN [11]).

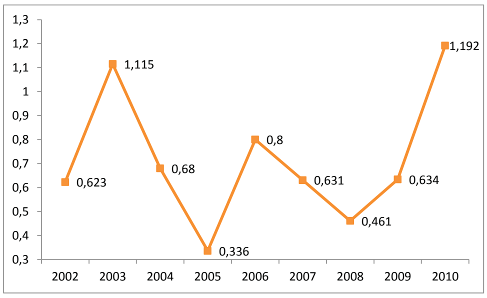

Figure 2: Hydraulic Productivity Index in Portugal 2002 – 2010 (REN [14]).

reductions are also partially explained by the need to mitigate greenhouse gas emissions (GHG), where a strong investment in new and clean energy sources and the decommissioning of the oldest and more pollutant units are seen as an effective alternative.

To take advantage of the still non-explored hydro potential, in 2007 a national plan for dams with high hydraulic potential [6] was elaborated. Among others measures, reinforcement of existing hydropower units, as well as, the investment in new ones is considered. Until 2020, a total of 7000 MW of installed hydropower, is expected to be operational. The proposed objectives correspond to 70% of the Portuguese hydraulic potential and an increase of approximately 53% with respect to present values.

In 2010, about half of total SRP was provided from wind power plants, and the total installed wind power was 3702 MW. The growth of the wind power share is shown in Figure 3, presenting both the installed wind power and wind based electricity generation [14]. Until 2020, this increasing trend is foreseen and a total installed power of 8500 MW[1] is expected, taking into consideration a set of factors as power demand evolution, and technical and economic viability

[1]Information drawn from: `www.min-economia.pt/innerPage.aspx?idCat=51\&idMasterCat=13\&idLang=1`

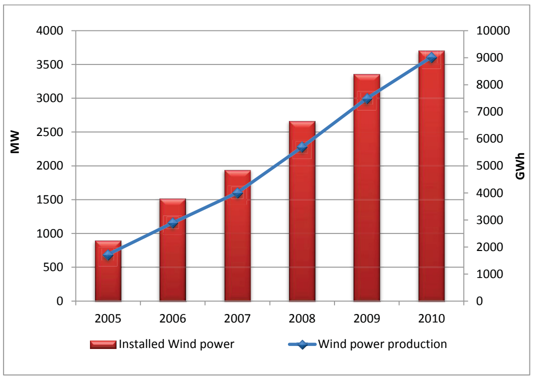

Figure 3: Installed wind power and wind based electricity generation in Portugal 2005-2010 (REN [13]).

of offshore technology.

In addition to the need to mitigate GHG emissions, the overall objectives of reducing external energy dependency, as well as, contributing to the country economic boost, are seen as other fundamental reasons to invest in new and clean technologies based on endogenous resources.

2.2 OPTIMIZATION MODEL

2.2.1 Objective functions

The proposed model formulation takes into account both the economic and environmental cost, originating two independent objective functions to be considered. The first objective function considers the economic cost measured in € and is defined by:

$$\sum_{t\in T}\sum_{n\in N}\left[\left(Ic_n\frac{j(1+j)^{lt_n}}{(1+j)^{lt_n}-1}+CFOM_n\right)Ip_{n,t}(1+j)^{-t}\right]+ \\ \sum_{t\in T}\sum_{m\in M}\sum_{i\in I}\left[(CVOM_i+F_i+Cp_i+EC\times CO_{2_i})P_{i,m,t}\Delta_m(1+j)^{-t}\right], \quad (1)$$

where T is a set of the time period (in years) considered in the model, N is a set of the new power plants to be included in the system, M is the set of months per year of planning, I is the set of all power plants, Ic_n is the n new power plant investment cost (€/MW), j is the annual discount rate, lt_n is the n new power plant lifetime (years), $CFOM_n$ is the Operation and Management (O&M) fixed cost of the n type of power plant (€/MW), $Ip_{n,t}$ is the installed power of plant n in year t (MW), $CVOM_i$ is the variable O&M costs for each i type of power plant (€/MWh), Cp_i is the cost of pumping for each i type of power plant (€/MWh), F_i is the fuel cost for each i type of power plant (€/MWh), EC is the CO_2 emission allowance cost (€/ton), CO_{2_i} is the CO_2 emission factor of type i power plant (ton/MWh), $P_{i,m,t}$ is the power output from power plant i in month m of year t (MW), and Δ_m is the number of hours for month m.

This objective function is set up by the sum between fixed and variable costs. The fixed costs are related with the investment cost applied to the new power plants and also with all fixed O&M costs. The capital investment cost is obtained through the sum of annuities over the planning period, assuming the uniform distribution of the investment cost during the plant lifetime. In what concerns to variable costs, those encompass the variable O&M costs, the fuel and pumping cost, and CO_2 emission allowance costs for each power plant.

The second objective function considers the environmental cost, measured in tons of CO_2 emission of the system. The objective is defined by

$$\sum_{t\in T}\sum_{m\in M}\sum_{i\in I} CO_{2_i} P_{i,m,t}\Delta_m. \tag{2}$$

This objective function is described as the sum of the total CO_2 emissions released from all power plants during the entire planning period. However, for this particular case study and for the achievement of our goals, this objective function will not be considered as such but as a constraint.

2.2.2 Constraints

The set of adopted constraints for the electricity sector planning problem usually includes constraints derived from physical processes, demand requirements, capacity limitations and legal/policy impositions. These constraints are equations that impose conditions to the model formulation, defining values of the decision variables that are feasible [5].

Equation (3) represents the total power generation from all power units that must meet by the system load demand at each month of each year of the planning period, including the pumping consumption.

$$D_{m,t} - PSRP_{m,t} \leq \left[\sum_{s\in S} P_{s,m,t} - \sum_{p\in Pump} P_{p,m,t}\right]\Delta_m, \qquad \forall m\in M, \forall t\in T, \tag{3}$$

where $D_{m,t}$ is the demand in month m of year t (MWh), $PSRP_{m,t}$ is the production of other renewable power plants (non-large hydro and non-wind) and co-generation (SRP - special regime production) in month m of year t (MW), S is the set of all power plants except pumping units, and $Pump$ is a set of all pumping power units.

For each month of each year during the entire planning period, the power output of each thermal power plant must be less or equal to the installed power availability. These constraints represent the power capacity of each power unit and are presented in equation 4 for existing power units and equation 5 for new power units. The available factor of thermal power plants were assumed as constant for each month during all the years considered in the planning. This factor ranges from 92% for coal and fuel oil power plants, to 94% for CCGT power plants [7]. The first one is related to existing power units and is defined by:

$$P_{e,m,t} \leq \varphi_{e,m} \times Ip_{e,t} \qquad \forall e\in T\_E, \tag{4}$$

where $\varphi_{e,m}$ is the availability factor of power unit e on month m, $Ip_{e,t}$ is the installed power of unit e on year t, T_E is the set of all existent thermal power plants;

$$P_{n,m,t} \leq \varphi_{n,m} \times Ip_{n,t} \qquad \forall n \in T\_N, \tag{5}$$

where T_N is the set of all new thermal power plants.

Renewable constraint enforce the model to ensure at least a pre-defined minimum level of electricity generation from renewable energy sources. The mathematical formulation of this constraint is given by Equation (6).

$$\begin{aligned} \sum_{m\in M} \Bigg[dp \times PSRP_{m,t} + \sum_{e\in E\_Wind} P_{e,m,t} \times \Delta_m + \sum_{n\in N\_Wind} P_{n,m,t} \times \Delta_m + \\ \sum_{e\in E\_Hydropower} P_{e,m,t} \times \Delta_m + \sum_{n\in N\_Hydropower} P_{n,m,t} \times \Delta_m \Bigg] \\ \geq share_r \times \sum_{m\in M} D_{m,t} \qquad \forall t \in T, \end{aligned} \tag{6}$$

where dp is the share of renewable SRP, $share_r$ is the goal for renewable energies, and N_Wind and E_Wind are the sets of the new and existent wind power plants, respectively.

Unlike thermal power plants, wind power plants are not subject to dispatch and so, all power generation has priority in grid access. By this way, Equation (7) and (8) ensure wind power generation capacity to be equal to the total installed power taking into account the wind availability. It is also necessary to ensure that wind power potential will be kept between proper values. This potential is ensured throw Equation (9) and (10).

$$P_{n,m,t} = \varphi_{n,m} \times Ip_{n,t} \qquad \forall t \in T, \quad \forall m \in M, \quad \forall n \in N\_Wind \tag{7}$$

and

$$P_{e,m,t} = \varphi_{e,m} \times Ip_{e,t} \qquad \forall t \in T, \quad \forall m \in M, \quad \forall e \in E\_Wind. \tag{8}$$

$$Ip_{n,t} \leq ONV \qquad \forall t \in T, \quad \forall n \in N\_Onshore \tag{9}$$

where $N\_Onshore$ is the set of wind onshore power plants, ONV is the maximum onshore wind potential value (MW), and

$$Ip_{n,t} \leq OFV \qquad \forall t \in T, \quad \forall n \in N\_Offshore, \tag{10}$$

where $N\_Offshore$ is the set of wind offshore power plants and OFV is the maximum offshore wind potential value (MW).

In what concerns hydro power plants, the model has considered both large hydropower units with reservoir and pumping and run-of-river power units. Equation (11) and (12) are refereed to large hydropower units and equation (12) was used due to the transition between December and January months of consecutive years. For the run-of-river power units, and like wind power units, due to it lower storage capacity, the production of these units is equal to their installed power multiplied by an availability factor. Equations (13) and (14) present these constraints. Additional constraints were used in this model for hydro power units such as, upper and lower bounds to define maximum and minimum reservoir levels, pumping constraints, minimum share of run-of-river units, between others, but due to the length of model a detailed description is presented and can be seen in [10].

$$\begin{aligned} reserve_{1,t} = reserve_{12,t-1} + Inflows_{1,t} - \\ \left(\sum_{n \in N\_Hydroreserve} P_{n,1,t} + \sum_{e \in E\_Hydroreserve} P_{e,1,t} \right) \times \Delta_1 + \\ \sum_{p \in Pump} P_{p,1,t} \times \Delta_1 \qquad \forall t \in T \setminus \{1\}, \end{aligned} \tag{11}$$

where $reserve_{m,t}$ is the reservoir level on month m of the year t, $Inflows_{m,t}$ is the hydro inflow on month m of the year t, $N\_Hydroreserve$ are all new hydropower units with reservoir and $E\_Hydroreserve$ are all existing hydropower units with reservoir.

$$\begin{aligned} reserve_{m,t} = reserve_{m-1,t} + Inflows_{m,t} - \\ \left(\sum_{n \in N\_Hydroreserve} P_{n,m,t} + \sum_{e \in E\_Hydroreserve} P_{e,m,t} \right) \times \Delta_m + \\ \sum_{p \in Pump} P_{p,m,t} \times \Delta_m \qquad \forall t \in T, \forall m \in M \setminus \{1\}. \end{aligned} \tag{12}$$

$$P_{n,m,t} = \varphi_{n,m} \times Ip_{n,t} \qquad \forall t \in T, \forall m \in M, \forall n \in N\_Hydrorr, \tag{13}$$

where $N\_Hydrorr$ is the set of new run-of-river hydropower plants.

$$P_{e,m,t} = \varphi_{e,m} \times Ip_{e,t} \qquad \forall t \in T, \forall m \in M, \forall e \in E\_Hydrorr, \tag{14}$$

where $E\_Hydrorr$ is the set of existing run-of-river hydropower plants.

To ensure a minimum security of the system, a reserve constraint taking into account the non-usable capacity that may not be always available to be scheduled due to temporary reasons is used. Equation (15) present this constraint. (for a detailed description refer to [2]).

$$\begin{aligned} RM \left(\sum_{n \in I\_N} Ip_{n,t} + \sum_{e \in I\_E} Ip_{e,t} + IPsrp_t \right) \leq \sum_{n \in I\_N} Ip_{n,t} + \sum_{e \in I\_E} Ip_{e,t} + IPsrp_t - \\ (LW \times (\sum_{n \in N\_Wind} Ip_{n,t} + \sum_{e \in E\_Wind} Ip_{e,t}) + LH \times (\sum_{n \in N\_Hydropower} Ip_{n,t} + \sum_{e \in E\_Hydropower} Ip_{e,t}) + \\ LSRP \times IPsrp_t + LBHG + LBTG - Pl_t) \qquad \forall t \in T \end{aligned} \tag{15}$$

Table 1: Optimal solution.

	Cost (€/MWh)		CO_2 (ton/MWh)	
Optimal cost solution	29.847		0.398	
	Coal	Gas	Wind	Hydro
Electricity production in 2020 (TWh)	46	0.0408	9.13	21.2

where I_N and I_E are the set of all new and existent power units respectively, RM is the set reserve margin of system, $IPsrt_t$ is the installed power of SRP in year t, LW is the potential reduction of wind power due to the lack of wind, LH is the potential reduction of hydropower due to a dry regime, $LSRP$ is the potential loss of SRP due to an unfavorable regime and $LBHG$ and $LBTG$ represent the lost of biggest hydro and thermal power groups. Pl_t is the system peak load in year t.

In the next section, the results of power planning case study will be presented and discussed.

3 Results

Table 1 shows the optimal solution to the base case scenario, characterized by no impositions on fuel prices and CO_2 emissions allowance. The cost objective function defined in (1) is considered for this scenario, and no constraint on the CO_2 emissions is included. The results show that electricity production from coal power plants stands out mostly because of the low operating costs and because no limit on CO_2 emissions was imposed. The electricity production from RES seen on Table 1 is essentially due to the contribution of existing units and few additional hydropower plants added to the system .

A sensitivity analysis to these results was conducted assuming the possibility of different scenarios of growth rates per year for both coal and gas fuel prices and also for CO_2 emissions allowance price. The simulated growth rate scenarios ranged from 5% increase per year to 35% for all the parameters. Table 2 presents the results for the assumed scenarios under both coal and natural gas cost increase. Significant changes comparatively to the base case scenario began to be particularly notorious for fuel prices growth rates higher than 15%. The increase of fuel prices would lead to a reduction of thermal power production that would be compensated by both a significant amount of new onshore wind power, reaching the estimated potential for this sector, and by an also increase on hydroelectricity generation due to the investment on new units. For lower growth rates few changes on the structure of the production system seems to occur but an overall increase of the production cost is evident, essentially due to the increase on fuel prices. Figure 4 visually helps to conclude that thermal power plants are replaced by RES power plants, when higher growth rates of fossil fuel prices are considered. Natural gas power plants present a low electricity production share because of their assumed high production costs, even for the base case scenario. The wind power generation from offshore plants is only proposed for the extreme fossil fuel growth rate scenarios, when the offshore wind power becomes competitive.

Table 2: Power units production and average costs for increasing coal and gas fuel prices.

	Cost (€/MWh)	CO_2 (ton/MWh)	Total production (TWh)			
			Coal	Gas	Wind	Hydro
5%	31.103	0.398	46.0	0.0408	9.13	21.2
10%	32.733	0.398	45.7	0	9.26	21.3
15%	34.666	0.358	30.2	0	20.4	25.1
20%	36.763	0.336	29.8	0	20.4	25.1
25%	39.208	0.316	28.8	0	20.5	25.2
30%	42.079	0.304	25.7	0	23.3	25.6
35%	45.482	0.294	25.7	0	23.3	25.6

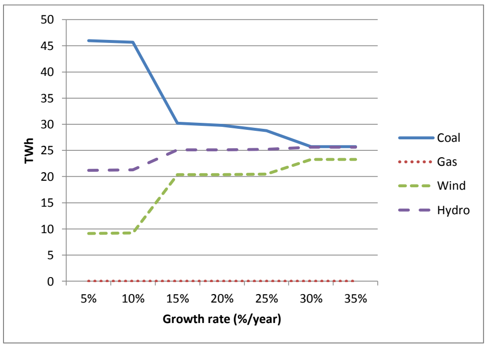

Figure 4: Power production evolution for increasing coal and gas fuel prices.

Table 3: Power units production and average costs for increasing CO_2 emission allowance costs.

	Cost (€/MWh)	CO_2 (ton/MWh)	Total production (TWh)			
			Coal	Gas	Wind	Hydro
5%	29.847	0.398	46	0.0408	9.13	21.2
10%	30.409	0.362	30.3	3.5	20.4	22.1
15%	31.434	0.312	15.7	14.6	20.4	25.6
20%	33.213	0.240	0	30.6	20.4	25.3
25%	34.378	0.193	0	30.5	20.4	25.4
30%	34.681	0.183	0	27.8	23.3	25.3

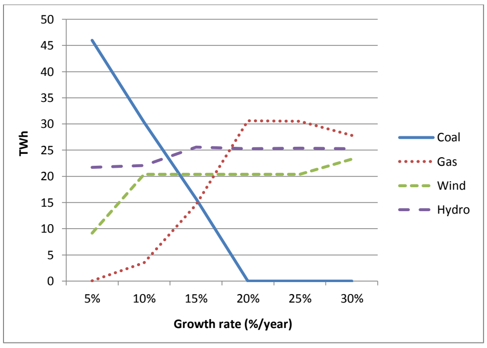

Figure 5: Power production evolution for increasing CO_2 emission allowance costs.

Table 3 presents the results for the same scenarios previously considered, but in this case under a CO_2 emissions allowance cost increase. Comparing both Tables 1 and 3, and for a small increase on emission cost allowance of 5%, only an increase of overall cost of the system was observed. Unlike gas power units, coal power plants present high levels of CO_2 emissions. As so, for an increase cost of emissions allowance, the decrease seen on coal power production at the assumed growth rate increases, is perfectly understandable. As visually shown in Figure 5 the reduction of electricity generation from coal power plants would be compensated by an increase of gas, wind, and hydro power units production. However, for higher growth rate scenarios the inclusion of offshore wind power generation would be replacing part of the gas power productions.

For all the scenarios, and comparing Table 2 and 3 to Table 1, an overall production cost increase is observed while the CO_2 emissions tend to decline. This is notorious on both tables and is basically explained by the investment on more expensive, however more clean, power units reducing the fossil fuel dependency of the electricity system.

4 Conclusions

This paper addresses the use of optimization models for electricity planning. A deterministic programming model was presented aiming to support the long term strategic decision. A case study close to the Portuguese electricity system was considered, characterized mainly by a mixed hydro-thermal power system with increasing importance of on wind power technologies. The results describe possible electricity scenarios in a 10 years planning horizon, firstly under a base case scenario, and secondly assuming the increase of coal and gas fuel prices and of CO_2 emissions allowance costs.

The results of this study indicate that the increase of fuel and emissions allowance prices will lead to the investment in new and clean energy technologies despite its high investment costs. This is seen mainly for high growth rate scenarios. This prices increase would turn thermal power plants less competitive, and would drive the market to invest on clean technologies.

Despite this trend to a reduction of production by thermal power plants, this reduction will present different decrease rates. For an increase on fuel prices, the maximum potential of renewables is achieved only for an increase of fossil fuel prices of 35% per year and the electricity system would be mainly based on coal, wind and hydropower

On the other hand, for an increase of CO_2 emissions allowance prices, the maximum renewables potential is achieved for a growth of 30% per year. CCGT power plants will be largely used, with coal power units production tending to 0, due to its higher emissions factors. The results demonstrate that, even without regulation imposing a RES share or a limit to CO_2 emissions of the sector, an efficient and costly CO_2 market may drive the market to investment on clean energy sources but may also increase significantly electricity costs.

For future research, a new short-term model for operations management of the electricity system problem will be proposed. The objective is to use it to support the definition of the best combination of units for electricity production, for the economic dispatch and unit commitment. Once again it will be applied to the Portuguese case considering restrictions similar to those considered in the model with long-term and technical constraints associated with the operation of power plants.

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