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The Impact of Fuel and CO_2 Prices on Electricity Power Plans*

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Abstract:

The increasing uncertainty surrounding the electricity generating sector has implications on the forecasting accuracy and makes sensitivity analysis an essential tool for electricity power planning. The fuel price volatility and the emissions trading schemes represent major sources of uncertainty, as the relative economic interest of thermo power plants and of renewable energy sources largely depends on these two factors. In this paper, an electricity planning model will be used to analyse both these aspects, identifying the relative importance and sensitiveness of the optimal electricity power plans to changes on these parameters.

Key Words: *Electricity planning, Uncertainty, Sensitivity analysis*

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1. Introduction

Electricity planning involves the determination of the type of electricity generation technologies and their utilisation ratios that will best meet the goals of society. Energy decisions are complex by nature and require awareness of the economic, environmental and social contexts within which the projects will take place. As Bruckner et al. (2005) note this is an ever changing field, depending on aspects like policy issues, advances in computer sciences and developments in economics, engineering and sociology. Ferreira (2008) review some recent papers proposing different approaches to energy planning and give a broad overview of the planning tools most frequently used, their advantages and drawbacks and fields of application.

This paper deals with the economic and environmental dimensions of the electricity power planning problem, assessing the impact that fuel and CO_2 market prices may have on long term power decisions. The problem under analysis was described by mathematical expressions, allowing for the use of optimisation procedures. Based on the developed model, simulations were conducted in order to evaluate the robustness of the proposed scenarios to changes on the assumed parameters.

The structure of the paper is as follows. Section 2 addresses the uncertainties of the energy markets, namely the fossil fuel prices and EU CO_2 allowances cost. Section 3 presents a brief description of the Portuguese electricity sector. In Section 4 the formulation of the model is described along with the base case scenario results. Section 5 contains the sensitivity study analysing the impact that different fuel prices and CO_2 allowances costs will have on long range electricity power plans. The main conclusions are summarised at the end.

2. The Uncertainties of the Energy Markets

Since the 19(80)s power systems have been moving away from command-and- control planning solutions to price-based solutions. The basic reason for liberalization was to create a more efficient system by avoiding capacity surplus which was most common in monopolies. Thus, more efficient investment should be a consequence of market liberalization and competition.

However, liberalisation does not necessarily result in lower market prices. Competition is but one of the factors influencing electricity prices. End-user prices are the outcome of different price drivers: regulation, competition, supply and demand characteristics. Among the factors affecting supply are fuel prices. Both fuel prices and CO_2 prices are also price risks directly affecting power investments Cash Flows.

Although European Union (EU) is a key player in the international energy market, accounting for 14% to 15% of total energy consumption, its influence on world price formation remains extremely small or even it doesn't exist. Neverthless, this does not necessarily mean that EU-27 (plus Switzerland and Norway) must remain as vulnerable to energy shocks or disruptions as it was in the (19)70's. Indeed, vulnerability is a multi-dimensional concept, which can be applied at different aggregation levels, and it depends on a variety of indicators such as: energy dependency, costs of energy imports, price volatility, technology, storage capacity, energy transport facilities, international relationships, exchange rates, among many others. Thus, inter-linking concepts and actions such as energy supply security, foreign policy and political solidarity among European countries is essential to build a coherent energy policy.

The EU vulnerability to fossil fuels price volatility and political events involving energy imports (oil shocks, Russia-Ukraine gas and Russia-Belarus oil crises in December 2005 and January 2007, respectively) is well known. About 80% of the EU-27 primary energy consumption comes from natural gas, oil and coal. Half of the EU-27 energy needs is imported. The European reserves are small, accounting for less than 1% for oil, 2% for gas and 4% for coal of world reserves.

The energy dependence has been steadily increasing since 1990. Russia, Norway, the Middle East and North Africa are the largest suppliers of EU-27. Russia became the largest single energy supplier both for natural gas and oil and the second –after South Africa – for coal (Kavalov and Peteves, 2007). About a third of EU natural gas imports come from Russia (Von Hirschhausen, et al., 2005) which has emerged as a growing concern of the European foreign policy.

2.1. Fossil Fuel Markets: Where do we stand?

The power generation sector is by far the largest coal user. Since coal is the most carbon-intensive fossil fuel, its use for electricity generation is heavily dependent on future GHG-reduction policies. Actually, electricity and heat production generate 27% of total greenhouse gas emissions (EEA, 2008).

Electricity supply in the EU-25 is mainly based on nuclear (32%), followed by coal (30%), hydro (15%) and natural gas (17%) (EEA, 2008). For the EU-27, the coal share in power generation is about 30% and even higher than 50% for some of the Member-States.

The current phase of the international hard coal trade started with the 1973 oil shock. Oil price sharp increase became a strong incentive to convert power stations from oil to coal and even to build new coal-fired plants. The second oil shock in 1979 reinforced this trend. The share of coal in power generation will also depend on its relative price namely the price of natural gas, the main competitor of coal in power generation. The biggest factors in coal's price surge in the last decade have been the China together with India increasing demand of coal for power generation and steel-making process aided by rising costs for oil and natural gas. The increasing power generation capacity and higher utilisation rates in Asia are expected to sustain that trend, at least until 2025.

Sustained demand for thermal coal is also forecasted for Europe, despite a tighter emissions regulation, carbon trading and natural gas competition. Indeed, on a long-time perspective and even with the EU energy efficiency targets, all estimates assume that the electricity demand will increase in EU in the next 25 years (Kavalov and Peteves, 2007).

The last two years of global economic recession deserve a careful analysis in what concerns energy prices as it can help us to have a better understanding of global energy markets. Notwithstanding the worst global economic contraction since World War II, 2008 was a year of high volatility, although OECD countries and former Soviet Union suffered a decrease of the demand for oil, natural gas and nuclear power and a stabilization of thermal coal consumption. Only hydroelectric output and other renewable forms of energy increased in 2009. The main point is that, since 2003, these countries had experienced the fastest economic growth ever, dominating the global energy demand and playing a pivotal role on energy prices (Rühl and Nerurkai, 2010).

In 2008, for the first time, non-OECD energy consumption exceeded OECD energy consumption. The demand pressure on fossil fuels international markets has contributed to that unexpected rise on prices, helping to explain not only prices behaviour but eventually its contribution to the worsening of the economic crisis. This was reflected on the evolution of prices on the second half of 2008 showing declining prices (BP, 2010).

However, the worsening of the economic crisis in the second half of 2008 is not sufficient to explain fuel price behaviour, as their trajectories are not similar. This is particularly important for oil, where the structure of supply remains highly concentrated.

2.2. The European CO_2 Market

According to the first Kyoto Protocol commitment period (2008-2012) EU is required to make an 8% cut in emissions compared to 1990. Furthermore, EU energy-environment targets for 2020 were set as follows:

- 20% cut in greenhouse gas emissions by 2020, compared with 1990 levels
- 20% increase in use of renewable energy by 2020
- 20% cut in energy consumption through improved energy efficiency by 2020

The European Union Emission Trading Scheme (EU ETS), a market-based mechanism (cap and trade) to incentivize the reduction of greenhouse gas (GHG), is an essential part of the European Climate Change Program (ECCP) which main purpose is to identify and develop an European strategy to implement the Kyoto Protocol. The EU ETS started on January 2005 and it is the world's largest greenhouse gas trading program involving all the 27 Member-States, operating through the allocation and trade of CO_2 emissions allowances[4].

Allocation plans for emission allowances are decided periodically: the EU ETS is divided into three commitment phases (Phase I: 2005-2007, Phase II 2008-2012, Phase III: 2013-2020. While Phase I (2005-2007) included only CO_2, Phase II comprehends other Greenhouse Gases (methane, nitrous oxide, sulfur hexafluoride, HFCs, and PFCs. Also penalties imposed on excess emissions were increased: from €40 to €100 per ton of CO_2

The EU ETS is substantially larger and by far more complex than the pioneering US acid rain program, a successful cap and trade system which produced a 50% reduction in emissions. Under the EU ETS, companies/installations are allocated the right to emit up to a specified amount of carbon dioxide, known as a cap. The units of allowable emissions are EUAs, and each one accounts for one ton of carbon dioxide. These units can then be purchased or sold through the EU ETS as companies/installations either have a deficit or a surplus of EUAs for their requirements.

While in Phase I allowances (EUA) were based on estimates of emissions, for Phase II EUA were based on real data. From 2012 onwards, the European Commission will change the EU ETS in order to reduce corporate influence over permits. Moreover, the auctioning of 100% of the credits is planned.

Apparently, the EUA over-allocation in Phase I[5] explain the price crash as well as EU recession has caused reductions in the output of energy intensive industries like steel, paper, cement and glass, leading to a sell-off of carbon credits. This is clearly seen by the price evolution from July 2008, with carbon prices falling sharply[6]. This decline followed the price of oil and other commodities.

3. The Portuguese Electricity Sector

At present, the Portuguese electricity generating system is basically a mixed hydrothermal system. The total installed power reached in 2011 about 18901 MW, distributed between thermal power plants (coal, fuel oil, natural gas and gas oil), hydro power plants and Special Regime Producers. In addition, the Portuguese system is interconnected with Spain. In 2011, the total electricity consumption reached 50503 GWh (REN, 2011). Figure 1 presents the general characteristics of the Portuguese electricity system in 2011 and the expected ones for 2022.

The move towards renewable energy technologies is strongly stressed in the government policy for the sector and the response of the industry has been positive,

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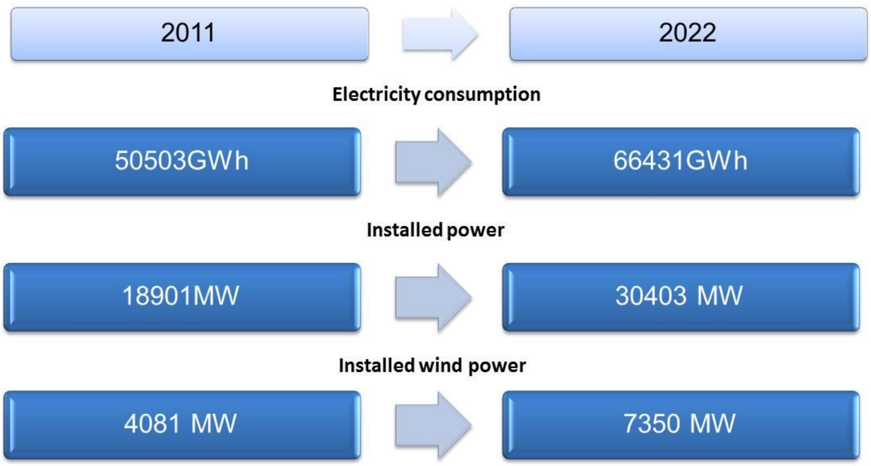
4 One allowance represents one ton of carbon dioxide equivalent.

5 According to Derwent (2008) some of the "over-allocation" argument is over-done: new research shows 2005 and 2006 emissions lower than baseline projections by 50-100mt.

6 See http://www.eea.europa.eu/data-and-maps/figures/eu-ets-future-contract-prices-200520132009

in particular in regard to wind power. During the next decade, the structure of power generation is expected to change significantly in favour of renewables. Large hydro is still the dominant renewable energy resource in Portugal but wind power is closely following it and the renewable energy sources (RES) development is mainly driven by the high growth rates of wind energy. At the end of 2011, the total wind power capacity reached a value close to 4 100 MW, placing Portugal amongst the top European wind power producers. Forecasts for the sector clearly indicate that this trend will continue, with the installed power in Portugal expected to overcome the current Danish values within a decade[7].

Figure 1. The Portuguese electricity system in 2011 and 2022



Sources: Own elaboration from REN (2011 a and b)

The specific characteristics of the Portuguese electricity system give rise to considerable challenges to the planner. Aspects such as a high dependency of the system on rainfall, the management of a diversified mix of technologies presently operating in the system, the expected impacts of the RES development, the increase in energy demand, and the regulatory environmental policies must be taken into consideration.

[7] A detailed description of the wind power sector in Portugal may be found in Ferreira et al. (2007).

4. Electricity Power Planning Model

The aim of the electricity planning models is to determine the type of electricity generation technologies and their utilisation ratios that will best meet the goals of society. The model used in this research deals with the cost and environmental dimensions of the electricity planning problem. The cost objective may be described and included in the models by a function representing the present value of total cost of the electricity generation plan, including the investment cost, fixed operation and maintenance (O&M), variable O&M, fuel and CO_2 emission allowances. The model is built in an incrementally and centrally planned perspective. The present characteristics of the system under analysis are included and represent the starting point of the problem. The optimisation is conducted evaluating the alternative's cost and benefits by its effect on the entire system's operating costs. A large number of constraints ensuring the reliability of the electricity system and its legal, technical and environmental requirements are also included. In this study, for the environmental impact, total CO_2 emissions were selected as a proxy measure.

The developed model was applied to the Portuguese electricity sector for a 10 years planning period as described in Ferreira (2008). The existing Portuguese electricity system was modelled taking into account the technologies currently being used, including: special regime producers (SRP), coal, natural gas, fueloil and large hydro power plants. According to the expected future characteristics of the Portuguese system, the new technologies considered for addition included wind, coal and natural gas.

The problem resulted in a mixed integer non linear model, where the impact of the increasing wind power on the performance of the thermal power plants is incorporated. The model was written in a GAMS code and uses a Branch and Bound algorithm, calling SBB upon to solve the problem. The interested reader may refer to Ferreira (2008) and Ferreira et al. (2007) for a description of the optimisation models and the considered assumptions. The aim of the present work is to use the model, to analyse to what extent changes on the assumed fuel prices and CO_2 emissions allowances pieces may affect the overall results and consequently how they would affect the decision making process.

4.1. Base Case

Table 1 presents the results of the optimisation process, where S0 is the least costly solution and S1 is the optimal cost solution, constrained by the average CO_2 limit of 20Mton/year for the analysed period.

Table 1. Configuration of the electricity system in 10 years for the optimal solution

		S0	S1			S0	S1
Total installed power (MW)	Coal (new)	4500		Contribution to electricity supply (%)	Coal (new)	44	0
	Coal (existing)	1820	1820		Coal (existing)	13	10
	Gas (new)	330	5040		Gas (new)	3	49
	Gas (existing)	2916*	2916*		Gas (existing)	1	1
	Wind (new)	3848	3225		Wind (total)	14	13
	Wind (existing)	1515	1515		Large hydro	14	16
	Large hydro	5805	5805		NWSRP	11	11
	NWSRP(1)	3245	3245				
	Total	23979	23566		Total	100	100
Share of RES (%)(2)		39	40	External dependency (%) (3)		65	64

*Includes 750 MW SCGT.
(1) NWSRP- Non wind special regime producers. Includes the production from cogeneration and renewable sources except wind and large hydro.
(2) Share of electricity consumption from renewable energy sources (RES). Large and small hydro power share corrected by the HPI (equal to 1.22) of the base year of Directive 2001/77/EC (1997).
(3) Proportion of energy used in meeting the demand for electricity that comes from imports.

From these results it can be concluded that the least costly solution (S0) assumes investments mainly in new coal power plants. According to this solution, in ten years:

- The electricity supply would come mainly from new and old coal power plants.
- CCGT (combined cycle gas turbine) would also be operating but representing only about 4% of the electricity supply.
- The remaining electricity would come from non large thermal power stations namely, wind power (about 14%), large hydro (about 14%) and NWSRP (about 11%).
- The electricity consumption from renewable energy sources would represent 39 % of the total electricity demand (meeting but not exceeding the renewable Directive).
- About 65% of the electricity consumption would come from imported primary energy sources (mainly coal).

Solution S1 proposes no more investments on new coal, but electricity generation from existing coal power plants still represents 10% of the total electricity supplied. The integration of new CCGT into the system compensates this reduction and ensures the imposed CO_2 limit, even with a reduction of the wind power production. In ten years, the electricity consumption from renewable energy sources represents 39% of the total demand and, the share of electricity consumption obtained from imported primary energy sources is about 65%. Under these solutions, the thermal power mix relies mainly on natural gas which reduces the possibility of diversification of primary energy suppliers and makes the electricity system highly vulnerable to the international prices of natural gas.

5. Sensitivity Analysis: Fuel and CO_2 Prices Changes

As seen in previous section 2, the increasing uncertainty surrounding the electricity generating sector makes the sensitivity analysis an essential tool to long term planning. The fuel price volatility and the emissions trading schemes, probably represent the major sources of uncertainty, since the relative economic interest of thermo power plants and of renewable energy sources largely depends on these two factors. In this section, both these aspects will be analysed.

5.1. Fuel Costs

For the sensitivity analysis two possible annual average growth rates for natural gas were analysed: moderate growth rate (4% per year) and high growth rate (7% per year). Table 2 summarises the main results of the sensitivity run. According to the results, the rising trend of the natural gas price may result in a different optimal configuration of the electricity system. Even when imposing emission limits, coal will have an important role in particular in the later years of the planning period. According to solution S1, the CO_2 limits would be achieved mainly by combining coal power electricity production (especially from new plants) and wind power generation.

However, it is also important to analyse the simultaneous increase of both natural gas and coal prices. Table 3 summarises the main results of the sensitivity run combining an annual growth rate of 4% for natural gas with an annual growth rate 2.6% for coal.

Table 2. Results of the natural gas price sensitivity in 10 years

		Moderate gas price growth rate (4%)		High gas price growth rate (7%)	
		S0	**S1**	**S0**	**S1**
Total installed power (MW)	Coal (new)	4800	4300	4800	4500
	Coal (existing)	1820	1821	1820	1821
	Natural gas (new)		2190	330	1790
	Natural gas (existing)	2916	2916	2916	2916
	Wind (new)	4102	7034	4102	7500
	Wind (existing)	1515	1515	1515	1515
	Large hydro	5805	5805	5805	5805
	NWSRP	3245	3245	3245	3245
	Total	24203	28826	24533	29092
Contribution to electricity supply (%)	Coal (new)	47	40	47	41
	Coal (existing)	10	9	10	6
	Natural gas (new)	0	3	3	3
	Natural gas (existing)	3	0	0	0
	Wind	15	23	15	24
	Large hydro	14	14	14	15
	NWSRP	11	11	11	11
	Total	100	100	100	100
Cost (M€)		16878	19502	17069	20223
CO_2 (Mton)		316	200	316	200
Cost (€/MWh)		32.026	37.005	32.387	38.373
CO_2 (ton/MWh)		0.600	0.379	0.600	0.379

Table 3. Results of the natural gas and coal prices sensitivity run in 10 years

		Moderate coal and gas prices growth rate	
		S0	**S1**
Total installed power (MW)	Coal (new)	4800	4200
	Coal (existing)	1820	1821
	Natural gas (new)		2190
	Natural gas (existing)	2916	2916
	Wind (new)	4096	7500
	Wind (existing)	1515	1515
	Large hydro	5805	5805
	NWSRP	3245	3245
	Total	24197	29192
Contribution to electricity supply (%)	Coal (new)	46	39
	Coal (existing)	11	8
	Natural gas (new)	0	4
	Natural gas (existing)	3	0
	Wind	15	24
	Large hydro	14	14
	NWSRP	11	11
	Total	100	100
Cost (M€)		17725	19970
CO_2 (Mton)		316	200
Cost (€/MWh)		33.633	37.892
CO_2 (ton/MWh)		0.599	0.379

The results are not much different from the previous runs testing natural gas price increases individually. Electricity production from coal power plants would still represent an important share of the total electricity production in ten years, even for scenarios with environmental restrictions. In the same way, the least costly solution for the S1 scenario points to the maximisation of the wind power electricity generation combined with a high share of electricity from existing and new coal power plants. These results are dependent on the cost structure of the analysed technologies and reflect the high sensitivity of CCGT to fuel price changes and the less sensitivity of coal power plants to changes in variable costs.

5.2. CO_2 Allowances Cost

The base case scenario assumed that the price of EU allowances (CO_2 emission cost) would remain stable and close to 22 €/t. Taking into consideration a possible downward trend, two possible scenarios for the CO_2 emission cost were considered for the sensitivity analysis: the moderate price scenario (10 €/t CO2) and the zero price scenario (0 €/t CO_2). Table 5 summarises the main results of the sensitivity runs for the proposed model.

Table 4. Results of the CO2 emission cost sensitive run in 10 years

		Zero CO_2 price (0 €/ton)		Moderate CO_2 price (10 €/ton)	
		S0	**S1**	**S0**	**S1**
Total installed power (MW)	Coal (new)	4900		4600	0
	Coal (existing)	1820	1821	1820	1821
	Gas (new)		4950	400	5040
	Gas (existing)	2916	2916	2916	2916
	Wind (new)	3678	3326	3811	3225
	Wind (existing)	1515	1515	1515	1515
	Large hydro	5805	5805	5805	5805
	NWSRP	3245	3245	3245	3245
	Total	23879	23578	24112	23567
Contribution to electricity supply (%)	Coal (new)	47	0	45	0
	Coal (existing)	10	0	12	1
	Gas (new)	0	48	3	48
	Gas (existing)	3	13	1	11
	Wind	14	13	14	13
	Large hydro	15	15	14	16
	NWSRP	11	11	11	11
	Total	100	100	100	100
Cost (M€)		11364	14315	13769	15865
CO_2 (Mton)		316	200	316	200
Cost (€/MWh)		21.563	27.162	26.127	30.104
CO_2 (ton/MWh)		0.600	0.379	0.600	0.379

For the optimal cost solution (S0), in respect for the share of each electricity generation technology, the CO_2 price reduction does not seem to affect the results significantly even when a zero value is assigned to the emissions. The reduction of the CO_2 prices reinforces the position of coal as the least expensive electricity generation plants. For environmentally constrained solutions (S1), gas fired production maintains a dominant role.

The reduction of CO_2 price will favour CCGT in particular. The average generation costs of coal power plants would also be reduced for these scenarios, but it seems that the combination of CCGT with wind power becomes economically more interesting. This way, although the increase of wind power affects CCGT performance, the reduction of the CO_2 prices brings economic advantages to both existing and new CCGT allowing increasing their electricity production even in the presence of large wind power scenarios.

6. Conclusions

Long range energy planning involves forecasting parameters like fuel and CO2 prices, which is not an easy and straightforward task. The energy market is extremely volatile and highly sensitive to external problems, politics, government regulation and technological developments. As Hobbs (1995) states "no one resource plan will be the best under all possible futures". The sensitivity analysis showed that the planning process is very responsive to variations on the parameters, and the recent developments of the market clearly demonstrate that a 10 year period involves a lot of uncertainty: the relationship between fuel prices may change, the CO_2 prices may contribute to this change or become a major cost source and the legal environment will certainly suffer modifications.

The presented sensitivity analysis demonstrated that natural gas price increase is particularly relevant for the decision process and if a general increasing trend was foreseen for the next years, the combination of coal with large wind power scenarios might become the economically more interesting option even for environmentally constrained scenarios.

In fact, the sensitivity analysis indicates that the results strongly depend on highly volatile elements, being particularly sensitive to natural gas price forecasts. The cost of the CCGT plants depends mainly on their operational costs while for coal power plants the investment cost is much more relevant than the operational costs. This makes CCGT much more sensitive to variations on the variable costs (fuel and CO_2) and coal power plants much more sensitive to variations on the discount rate. The effect of these sensitivity simulations on installed wind power, although visible, is in large extent levelled out by the minimal RES requirements imposed to the model by Directive 2011/77/EC.

The research in now proceeding with the development of new models able to combine short and long term optimisation in order to avoid the use of average operating conditions to describe the power plant performance. Instead, the expected performance of each power plant under each scenario will be considered, along with the implications on fuel consumption, emissions and costs. This of course increases deeply the complexity of traditional models, but it will be particularly useful for a system with high share of RES for electricity generation, as is the case of Portugal. It will allow making long term defensible decisions and more reliable cost and emissions projections for the future, recognising the interaction between all the elements in the electricity system.

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