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Social welfare analysis of the Iberian electricity market accounting for carbon emission prices.

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A Social Welfare Analysis of the Iberian Electricity Market Accounting for Carbon Emissions Prices

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ABSTRACT

In this paper we analyze the social welfare impact of the integration of Portugal and Spain in the Iberian electricity market (MIBEL), taking into account the CO_2 price for emissions trading. We model the impact of emissions trading on the daily clearing prices and generation scheduling, and its effects on the benefits of integration as a whole. We compare the impact of market integration in Portugal and Spain and show that the welfare impact of the MIBEL is dependent on the CO_2 prices. From our analysis we conclude high CO_2 prices lead to a change in the merit order. Moreover, natural gas is the generation technology that most benefits from transmission constraints and from high CO_2 prices, as in the base case it is mainly used as a peak technology. We have also found that increases in the CO_2 prices do not lead to higher profits. Overall, the introduction of the MIBEL will increase social welfare by reducing generation costs and prices.

KEYWORDS: Carbon Prices, Electricity Markets, Electric Network Constraints, Simulation, Mixed Integer Non-linear Programming.

1. Introduction

An important factor to determine the short-term efficiency of electricity markets is the specific market structure and trading rules, such as regulation, applied in each specific market [1]. Within the European Union's policy for developing a single market for electricity, the Portuguese (in which competition was almost non-existent) and Spanish (which was very concentrated and lacked competition, [2]) electricity markets have been merged into the Iberian Electricity Market (MIBEL). The creation of the MIBEL has involved complex negotiations between the two countries, which included regulation and the operation of the joint market [3]. Nonetheless, it seems that the MIBEL still shows limited levels of market efficiency [4].

The Iberian electricity system operates almost as an island (with the two markets already very interrelated [5]) in Europe given that the degree of interconnection of Spain with France is very small (when compared with the demand) and the interconnection with Morocco is negligible, and therefore it can be studied as a separate market. It is therefore required coordination on grid operation and growth in interconnections (which is very important for social welfare, as we shall see), in order to ensure the system's security and stability [5]. In this context, electric energy transport grids have a crucial role in assuring proper interconnections to MIBEL's implementation.

In this paper we analyze the impact of the MIBEL on social welfare (i.e., the total consumer plus generators surplus), taking into account the impact of CO_2 emission prices. This same problem has been addressed by Reneses and Centeno [6], who have modelled the impact of the Kyoto protocol in the Iberian market using an oligopoly model, concluding that energy policies and the prices of CO_2 emissions are crucial for the Iberian market to adapt to the

Kyoto protocol. Our method differs from theirs as we assume that the market will work near the social optimum, and we ignore the issues with market power, which Reneses and Centeno [6] capture in their model. It should be noted that in a market with inelastic demand (as it is arguably the case of electricity markets and as considered in our model) the maximization of social welfare is equivalent to minimization of production costs: as demand is inelastic the total demand (and production) do not change; a change in the electricity price has no impact on social welfare, as there is just a symmetrical change in the surpluses of generators and consumers; therefore, the only way to increase social welfare is by improving the schedule of plants.

We look at the maximization of social welfare for several reasons: first this option is justified by the presence of regulation in the market, which suggests that oligopoly models fail to capture the actions of regulation and both prices and generation closer to the social optimum then it would be predicted by oligopoly model, as discussed by Bunn and Oliveira [7]. Second, this option allows us to better capture the technicalities of electricity production, such as, capacity constraints and start-up costs, the constraints associated with Hydro-based production and to model the electricity network. Nonetheless, we recognise that models of oligopoly, such as the one presented by Reneses and Centeno [6] can explain why the market equilibrium may deviate from the social optimum in the short-term.

Our model is based on the solution of the unit commitment problem, determining the operating schedule of the power units for the considered period. When multiple sources of energy exist, the main objective of unit commitment is to determine the combination of production sources and units that will supply the demand of electricity in each period of the planning horizon. This combination is the result of an optimization procedure that takes into account economic criteria and is subject to different types of economical, technical and security constraints (e.g. [8], [9], [10]), such as marginal generation costs, start-up costs and ramp rates. We have taken into account the impact of the transmission grid operation and, therefore, taken into consideration both the economic and technical issues of the industry. Due to economic and environmental infeasibility of installing several energy transmission grids in the same geographical area it is necessary to assure their proper management in a way that suitable levels of quality, confidence and security of the system are guaranteed [11]. For this reason, it is necessary to adjust the economic dispatch of centralized markets until a solution to technically explore the system can be found.

We show that the CO_2 prices have impact on the merit order (and electricity prices) of the markets for high level of prices (above 35 €/tCO_2eq), this more than double the price identified by Reneses and Centeno in [6], which was 15 €/tCO_2eq. Overall, our experiments show that the benefits from market merger are different for different levels of CO_2 prices and for the different firms. We conclude that big Spanish firms benefit from market integration, most especially if the CO_2 prices are high, whilst EDP, the biggest Portuguese firm, less competitive, will lose with market integration.

The article proceeds by introducing the European market for emissions, section 2. In section 3 we describe our model and in section 4 we parameterize the model for the MIBEL. In section 5 we present the main results and section 6 concludes the article.

2. The European Market for Emissions Trading

Under the Kyoto Protocol, nations that emit less than their quota of greenhouse gases are able to sell emission permits to polluting nations [12]. The Protocol also allows emissions trading schemes to be established at regional level, such as the one in the European Union Emission

Trading Scheme (EU ETS), e.g., [13], [14], [15], and national level (see, Betz [16] for an analysis of the national allocation plans of the EU emissions trading mechanism). Under such schemes, governments set emission caps to be met by the participants, and enable them to trade carbon dioxide emissions: it is a cap-and-trade scheme, based on the one used for SO2 in the "Acid Rain Program" of 1990 in the USA, [17], [18]. The European Union (together with its role in the Kyoto Protocol) as one of the front runners in the new green economy

The main purpose of the ETS is to allocate the emission cutting efforts where they are less expensive, minimizing all costs of compliance. The scheme should be a cheaper alternative to achieve the CO_2 goal, stimulating emissions reduction innovations, and creating all other kinds of incentives to reduce GHGs emissions. Nonetheless, Anger [19] has estimated, using numerical simulations on a multi-country equilibrium model, that the ETS would induce only minor economic benefits as trading was restricted to energy-intensive companies who were assigned high initial emissions. Both Anger [19] and Loreta et al. [20] agree that an enlarged carbon market would increase the benefits of the trading scheme. In regard to the electric sector, power prices in EU countries have increased significantly since the EU ETS became effective. Besides other factors, these increases in power prices may – at least in part – be due to this scheme, in particular due the pass-through of the costs of EU allowances (EUAs) to cover the CO_2 emissions which are in a significant part of the emissions costs are passed to the consumer and generation profits increased, as discussed in [21] and [22], who suggest that an increase in nuclear power capacity would mitigate this effect.

The ETS has important implications for the risk management of firms, as the participants in the energy market have to deal with the increased risk associated with the complexity and high price uncertain of carbon allowances, [23], [24]. The ETS has also implications for the operations of electricity firms, which need to consider the direct and indirect costs of compliance. Direct costs emerge from investing in cleaner production methods, switching to alternative production methods and buying emission units allowances (EUAs). Indirect costs arise from higher electricity prices reflecting the EUA price. It is, therefore, necessary to combine detailed power systems operation with ETS [25], to capture its impact on the investment in renewable technologies, using a conjectural-variations model of the Spanish electricity market. They conclude that the ETS promotes the expansion of gas and wind technologies but, overall, it does not increase investment in renewable energies. Nonetheless, as noted by Matos et al. [26], the need to reduce CO_2 emissions, together with a deliberate policy by the governments, will most probably lead to an increase in production of renewable energy, which makes the management of the electricity systems more complex.

On this same issue, Chen et al. in [27] have analyzed the emissions trading mechanism, using an oligopolistic model, concluding that the generation profits increase, but the rate by which CO_2 emissions costs are passed to consumers depend on the competitive structure of the industry, on elasticity of demand and supply and merit order changes. This conclusion is also supported by Veith et al. [28] who showed that stock returns of the larger power generation firms are positively correlated with rising prices for emissions rights.

3. Description of the Model

In order to compute the scheduling of plants social optimum we need to solve the unit commitment problem, which must ultimately satisfy generation unit constraints as well as transmission and other relevant system constraints, while meeting system load requirements [29]. The presented work assesses the short-run implications of CO_2 trading for power production, prices, emissions and generator profits considering different scenarios of CO_2

emission prices, demand, fuel prices and renewable generation. We model an inelastic demand, taking also into account start-up costs and the technical constraints faced by the different generation technologies, such as Hydro and Wind power plants. We present a social welfare analysis of the problem of integration of two markets taking into account emissions trading. For these reasons our approach differs from [6] and [27], which model oligopolistic competition using a more stylized representation of electricity markets.

The short-term resource scheduling problem is one of the critical issues in the economics of the operation of power systems. Given the initial status of generating units, the solution to the resource scheduling problem is to find the unit commitment schedule, and the associated generation schedule, that minimizes the system production costs, given by Equation 1. These costs are attained by adding all power plants marginal costs, and maximize social welfare, with start-up and (or) shut-down costs of the respective power plants.

In our model, the marginal cost of a generation unit is based on the fuel type used as primary resource to produce energy, which includes fossil fuel costs, thermal efficiency and emission factors of a determined technology used to produce electric energy and CO_2 emission costs, given by Equation 2. The CO_2 emission costs reflect the CO_2 market price and thus the emissions trading influence on the optimal planning of resource scheduling. Each power plant must comply with the technical restrictions on maximum and minimum amount of energy that can be generated at any given time, Equation 3 and Equation 4.

$$\text{Objective Function: } \min \pi = \sum_{f,g,t} \begin{bmatrix} \left(MC_f \times GO_{g,t}\right) + \\ +\left(OS_{g,t} \times \left(1 - OS_{g,t-1}\right) \times SuC_g\right) + \\ +\left(\left(1 - OS_{g,t}\right) \times OS_{g,t-1} \times SdC_g\right) \end{bmatrix} \qquad \text{Equation 1}$$

Subject to:

$$MC_f = FC_f + \frac{EF_f}{TE_f} \times CO_2P \ \ \forall f$$ Equation 2

$$GO_{g,t} \leq G_g^{Max} \times OS_{g,t} \ \ \forall g, \forall t$$ Equation 3

$$GO_{g,t} \geq G_g^{min} \times OS_{g,t} \ \ \forall g, \forall t$$ Equation 4

$$\sum_t GO_{g,t} = G_g^{Max} \times H_f^{Max}, \forall g$$ Equation 5

$$\sum_g GO_{g,t} - \sum_n D_{n,t} = 0, \forall t$$ Equation 6

$$LF_{l,t} \leq LC_n^{Max}, \forall t, \forall l$$ Equation 7

$$LF_{l,t} \geq -LC_l^{Max}, \forall t, \forall l$$ Equation 8

$$PI_{n,t} = \sum_g GO_{g,t} - D_{n,t}, \forall t, \forall n$$ Equation 9

$$LF_{l,t} = \sum_n \left(S_{l,n} \times PI_{n,t}\right), \forall t, \forall l$$ Equation 10

Unlike other type of generation, hydroelectric plant has a limited amount of fuel it can use, restricted by the reservoir size. A similar constraint is also applicable to wind generation, as the electricity generated by a wind turbine, at any given day, depends on wind on that day. These constraints are considered in Equation 5, which limits the maximum generation output, at any given day, for these types of plant.

As we are interested in modelling daily behaviour of demand, and as in practice the short-term electricity demand does not respond to price, we have assumed an inelastic demand. In Equation 6 we represent the equilibrium condition of the model: the total amount of generation equals total demand, at any given time. As this demand, and the generation plant, are distributed in the space of the Iberian Peninsula, and as there are transmission constraints that may restrict the ability of the market to attain the social optimum, we have also incorporated grid constraints, Equations 7 and 8. These constraints limit the maximum amount of energy that can be transported from one node to another. As in [30], we have modelled a DC network for two main reasons: a) the full model of the Iberian market is very computational intensive; b) it is known that the results of the DC model approximate very well the exact solution of the full AC model [31]. In the classic DC approach, the power flows are given by Equation 11, where, $\theta_i - \theta_k$ represent the voltage phase difference between two connected buses *i* and *k* by a single branch of $X_{i,k}$ reactance, and $F_{i,k}$ is the active power flow. Voltage magnitudes are supposed to be 1 p.u. (per unit) and reactive power flow is null, due to the approach simplifications (branches resistance is considered zero).

$$F_{i,k} = \frac{\theta_i - \theta_k}{X_{i,k}} \qquad \text{Equation 11}$$

Besides allowing the computation of voltage phases followed by the active power flow in each network branch, the DC model (as presented in Equation 12) allows to associate the active power flow in each branch with the injected active power in each bus, by using a sensitivity matrix, without requiring the calculation of the voltage phases calculation, as in [32].

$$F_{i,k} = \frac{\theta_i - \theta_k}{X_{i,k}} = \frac{\sum_{j \neq REF} Z'_{i,j} P_j - \sum_{j \neq REF} Z'_{k,j} P_j}{X_{i,k}} = \sum_{j \neq REF} \frac{Z'_{i,j} - Z'_{k,j}}{X_{i,k}} P_j = A_{i,k} P_j \qquad \text{Equation 12}$$

As presented in Equation 12, the active power flow $P_{i,k}$ can be attained through the sensitivity matrix, $A_{i,k}$, which allows the calculation of the power flow in each branch accordingly to the injected power P_j in each bus. The sensitivity matrix changes depending on the considered reference bus, a characteristic of the DC model implemented (nonetheless, the final results do not change). The consideration of all expressions in Equation 12 for the entire network represents the DC model, Equations 9 and 10. The model is a mixed integer non linear problem (MINLP), solved through GAMS (Generic Algebraic Modelling System) using the *dicopt* and *minos* solvers to reach the final solution.

4. The Structure of the Iberian Electricity Market

In this section we parameterize the model for the MIBEL, including the technical details for generation, for the network and for demand.

4.1. The Generation Plants Installed in Portugal and Spain

The data in the model includes 103 Spanish power plant groups, respective capacities and owners (grouped in four large companies, plus EDP and the rest of independent power producers). It also includes 29 Portuguese power plants, respective capacities and owners (grouped as EDP and the independent power producers). The parameters used to describe the power plants considered the differences between technology type and the generation capacity of each plant.

By the end of 2008, had a total generation was about 15 TW in Portugal and 90 TW in Spain, with a total capacity by technology as represented in Table 1. In Portugal the renewable share of generation (including hydro, wind, biomass, waves and photovoltaic) was about 61%, while in Spain nuclear power plants represent 8.5% of installed capacity, the renewable represent 49.8%, and the thermal plants represented 41.6% of installed capacity. The Portuguese government made a commitment towards the European Commission to increase the renewable share to 45% of the supplied energy by 2010. In this scope, the wind park stations in December 2008 already presenting a significant share in installed capacity (2624 MW), are planned to increase to 3500 MW by 2010.

Table 1 – Capacity Installed in the Portuguese and Spanish Generation System (in MW).

	Portugal	Spain
Total Installed Power	14 915	89945
Nuclear	-	7716
Hydro Power	4 957	16657
Wind Power	2 624	15576
Other Renewables	1 515	12552
Thermal Power	5 819	37 444
→ Coal	1 776	11359
→ Fuel-Oil	1 712	4418
→ Diesel/Gasoil	165	-
→ Combined Cycle	2 166	21667

Regarding the ownership structure, described in Table 2, to notice that "EDP – Energies of Portugal" owns almost all power plants installed. Only "Pego Power Plant" (coal – 628 MW), and "Tapada do Outeiro Power Plant" (natural gas – 990 MW) are owned by TejoEnergia and Turbogás, respectively. This represents an ownership structure where EDP possesses more than 90% of installed capacity in Portugal.

Three large companies (Endesa, Iberdrola and Unión Fenosa) dominate the Spanish electricity sector. Regarding the ownership structure of the generation capacity in Spain: Endesa owns about 30% of installed capacity in coal, fuel/gasoil, natural gas and nuclear power plants; Iberdrola possesses an average of 40% of total installed capacity – about 20% of Iberdrola generation groups are based on coal, fuel/gasoil, natural gas and nuclear power technologies and the remaining generation groups are composed of wind and large hydro stations; 10% of total installed capacity in coal, fuel/gasoil and natural gas power plants belong to Unión Fenosa; and EPD owns about 5% of total installed capacity in coal and natural gas power plants. The remaining 15% of total installed capacity belong to small independent producers.

Table 2 – Capacity Installed of each Considered Owner (in MW).

	Portugal		Spain				
	EDP	***Others***	***Endesa***	***Iberdrola***	***U. F.***	***EDP***	***Others***
Total Installed Power	13 297	1 618	25 184	39 915	8 396	3 898	12 552
Nuclear	-	-	7 716	-	-	-	-
Hydro Power	4 957	-	-	16 657	-	-	-
Wind Power	2 624	-	-	15 576	-	-	-
Other Renewables	1 515	-	-	-	-	-	12 552
Thermal Power	4 201	1 618	17 468	7 682	8 396	3 898	-
→ Coal	1 148	628	5 298	2 330	2 549	1 182	-
→ Fuel-Oil	1 712	-	2 062	906	1 450	-	-
→ Diesel/Gasoil	165	-	-	-	-	-	-
→ Combined Cycle	1 176	990	10 108	4 446	4 397	2 716	-

4.2. Describing the Network

We have represented the transmission constraints in the MIBEL by grouping the different regions in six large areas (nodes) of the transmission grid, taking into account the most important transmission constraints in the market, and including nine equivalent lines connecting these nodes, as presented in Figure 1.

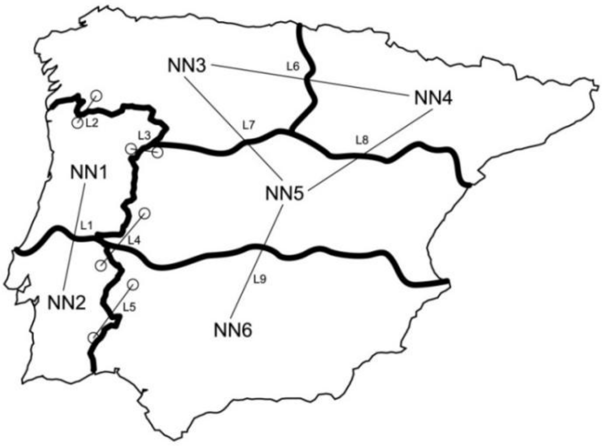

Figure 1– Network equivalent for model proposed.

Portugal was divided into two equivalent nodes and Spain into four equivalent nodes, as presented in Table 3.

Table 3 – Portuguese districts and Spanish provinces included in each node

nodes	region included (District / Province)
NN1	Viana do Castelo, Braga, Porto, Vila Real, Bragança, Aveiro, Viseu, Guarda, Coimbra, Castelo Branco, Leiria.
NN2	Lisboa, Santarém, Setúbal, Beja, Faro, Évora, Portalegre
NN3	La Coruña, Pontevedra, Lugo, Asturias, León, Zamora, Cantabria, Palencia, Villadolid, Burgos, Vizcaya.
NN4	Guipúzcoa, Álava, La Rioja, Soria, Navarra, Zaragoça, Huesca, Lérida, Tarragona, Barcelona, Gerona.
NN5	Salamanca, Cáceres, Ávila, Segovia, Madrid, Toledo, Guadalajara, Cuenca, Teruel, Castéllon, Valencia.
NN6	Badajoz, Huelva, Sevilla, Cádiz, Córdoba, Málaga, Ciudad Real, Jaón, Granada, Albacete, Murcia, Almería, Alcante.

The hydro system and reservoirs are dispersed in all considered equivalent zones, which are very wide areas. So, it was considered the data of hydro generation in GWh for 2008 and it were not modelled any reservoirs and how they are connected. For the wind generation it was made an equivalent procedure. It was considered the average amount of wind produced during an average day, restricted to time periods were wind is most available.

In respect to the network equivalent model, our main concern was the interconnections due to the market impact of congestions. The line capacities used for simulations are presented in Table 4. The capacities considered for interconnections were based on data of capacity for importation / exportation of electric energy by 2008. The connection limits between equivalent nodes of the same country were estimated based on the considered area and estimated power capacity for each zone. In the case of Spain this was 5600 MW per line and in the Portuguese case 1160 MW per line (which corresponds to about 13% of peak power demand).

For each line of the transmission grid we have assumed a reactance in the inverse proportion of considered capacity in each zone, presented in Table 4, and no resistance, due to the characteristics of the DC model implemented.

Table 4 – Line capacities (in MW)

line	nodes (i↔j)	capacity (MW)	impedance (p.u.)	interconnection?
L1	NN1↔NN2	1160	0.03	no
L2	NN1↔NN3	560	0.05	yes
L3	NN1↔NN5	440	0.06	yes
L4	NN2↔NN5	290	0.10	yes
L5	NN2↔NN6	310	0.09	yes
L6	NN3↔NN4	5600	0.02	no
L7	NN3↔NN5	5600	0.02	no
L8	NN4↔NN5	5600	0.02	no
L9	NN4↔NN6	5600	0.02	no

The installed capacity in each of the equivalent nodes *nn* is presented in Table 5.

Table 5 – Capacity Installed in each Considered Equivalent Node (in MW).

	Portugal		Spain			
	NN1	*NN2*	*NN3*	*NN4*	*NN5*	*NN6*
Total Installed Power	6 472	7 119	23 596	24 402	22 476	19 471
Nuclear	-	-	-	3 344	4 372	-
Hydro Power	4 163	794	8 994	2 330	4 258	1 075
Wind Power	2 020	604	8 552	2 492	3 612	920
Other Renewables	289	1 226	6 050	3 250	1 788	1 464
Thermal Power	1 324	4 495	-	12 986	8 446	16 012
→ Coal	-	1 776	-	2 446	4 000	4 913
→ Fuel-Oil	-	1 712	-	2 210	1 224	984
→ Diesel/Gasoil	-	165	-	-	-	-
→ Combined Cycle	1 324	842	-	8 330	3 222	10 115

4.3. Scenarios for Analysing Load

In 2008, the peak power demand was about 9 TW in Portugal and 43 TW in Spain, and total generation was about 51 TWh in Portugal and 264 TWh in Spain. In our model, we have considered two scenarios for electricity demand in 2008, in Portugal and Spain. The first scenario corresponds to a high demand day (H.D.D.); the second scenario corresponds to an average demand day (A.D.D.), based on the annual energy consumptions of Portugal and Spain. For each day, we have agglutinated the hours in eight blocks of three hours each, keeping enough detailed in the model to compare the peak and off-peak hours (as presented in Table 6), and at the same time reducing its computational complexity.

Table 6 – Demand in each Considered *tp* – time period (in MWh).

	Portugal		Spain		MIBEL	
	A.D.D.	*H.D.D.*	*A.D.D.*	*H.D.D.*	*A.D.D.*	*H.D.D.*
TP1	13 574	16 080	70 812	84 307	84 386	100 387
TP2	12 967	15 360	67 641	80 532	80 608	95 892
TP3	15 178	17 980	79 179	94 269	94 357	112 249
TP4	18 251	21 620	95 209	113 353	113 460	134 973
TP5	18 969	22 470	98 952	117 809	117 920	140 279
TP6	19 990	23 680	104 280	124 153	124 270	147 833
TP7	21 417	25 370	111 723	133 014	133 139	158 384
TP8	18 285	21 660	95 385	113 563	113 670	135 223

5. Numerical Results on the Welfare Analysis of the MIBEL

We have analysed different scenarios for the CO_2 prices, in order to evaluate the impact of these prices on the technologies' merit order and on the players' profits, in the MIBEL. We have also analyzed the possible impact of network constraints on social welfare.

5.1. Effects of CO_2 Prices on the Merit Order

CO_2 prices affect fossil fuel combustion. With the rise of CO_2 prices and with natural gas being a less pollutant technology, it gradually replaces more pollutant technologies such as coal and fuel/gasoil powered units.

In Figure 2 we present the effects of CO_2 price increases on the marginal generation costs. The marginal cost of each dispatched unit, calculated accordingly with the fuel type used as primary source of energy, does not change with demand variation. In addition, network constraints do not change these costs either. For these reasons, it is possible to infer how the merit order changes due solely to the impact of CO_2 emissions on the marginal cost of the different technologies. The marginal costs not affected by the CO_2 emission prices, e.g., renewable sources or nuclear, are not represented in Figure 2.

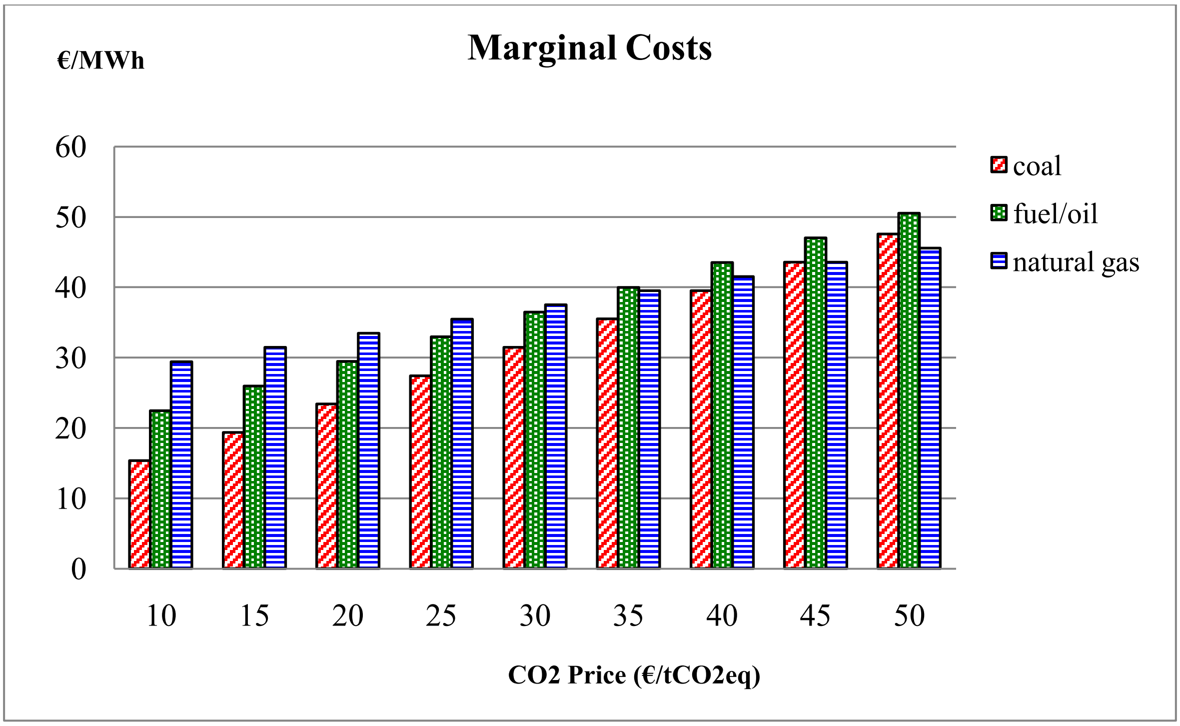

Figure 2– Impact of CO_2 prices in technologies marginal generation costs.

We observe three distinct situations:

a) Between 10€ and 30€ /tCO_2eq, the generation-mix does not change. Coal groups are dispatched first, followed by fuel/gasoil and natural gas units, at last.

b) However, this mix changes when considered a price of 35 €/tCO_2eq. At this CO_2 price, plants using natural gas are dispatched prior to fuel/gasoil based units. Coal based plants are still dispatched first and the merit order changes between fuel/gasoil and natural gas because the latter, although more expensive, has lower emission factors. Consequently, the marginal cost is lower in natural gas power plants than in fuel/gasoil power plants, at a CO_2 price of 35 €/tCO_2eq.

c) Above 45 €/tCO_2eq the generation-mix changes once again. Coal power plants are replaced by natural gas power plants. The coal power plants are less efficient because their emission factors are the highest (this reflects the importance of emission factors for high CO_2 prices.)

In conclusion, when CO_2 prices rise the generation is relocated from the more to the least polluting technologies in terms of emission factors. Moreover, as the CO_2 prices rise (in the considered range from 10€/tCO_2eq to 50 €/tCO_2eq), the difference between the maximum and minimum marginal costs of the different technologies tends to decrease. This fact has repercussions on the firms' profits, as analysed on section 5.4.

5.2. Impact of Network Constraints

To analyze how network constraints influence the scheduling of electricity plants, we compare the dispatch by technology, with (Figure 3) and without (Figure 4) capacity constraints. In this comparison we have assumed a price of 15 €/tCO_2eq, due to the actual CO_2 price for Kyoto Phase II that seems to be around 14 €.

At all times, biomass power plants are permanently working. Wind and Hydro power plants also produce energy at total daily maximum allowed, based on a percentage of total capacity that reflects forecasted availability of the wind and water, respectively. These types of power plant contribute to the renewable layer presented in Figures 3 and 4. In Spain the nuclear power plants are also always producing at maximum capacity, due to their low marginal cost. (A nuclear power plant is always running near its nominal capacity and is not shut down, unless strictly necessary, due to very high shutdown costs and small ramp rates.) From the comparison of Figures 3 and 4, it emerges that natural gas power plants are started up only when network constraints are considered.

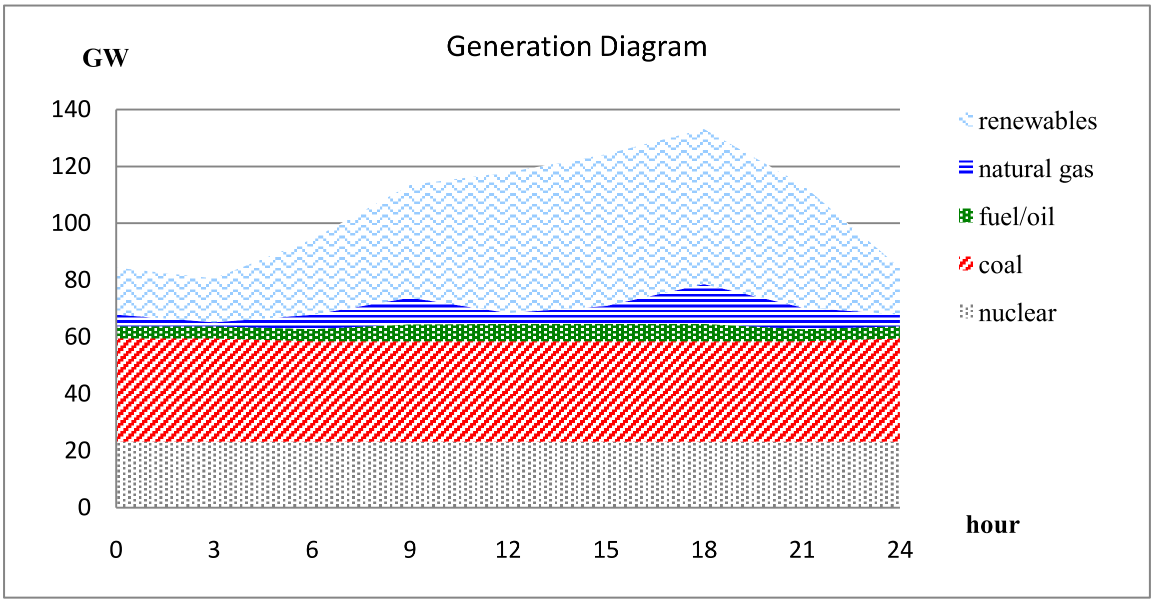

Figure 3 – Generation Diagram for a typical day, considering network constraints.

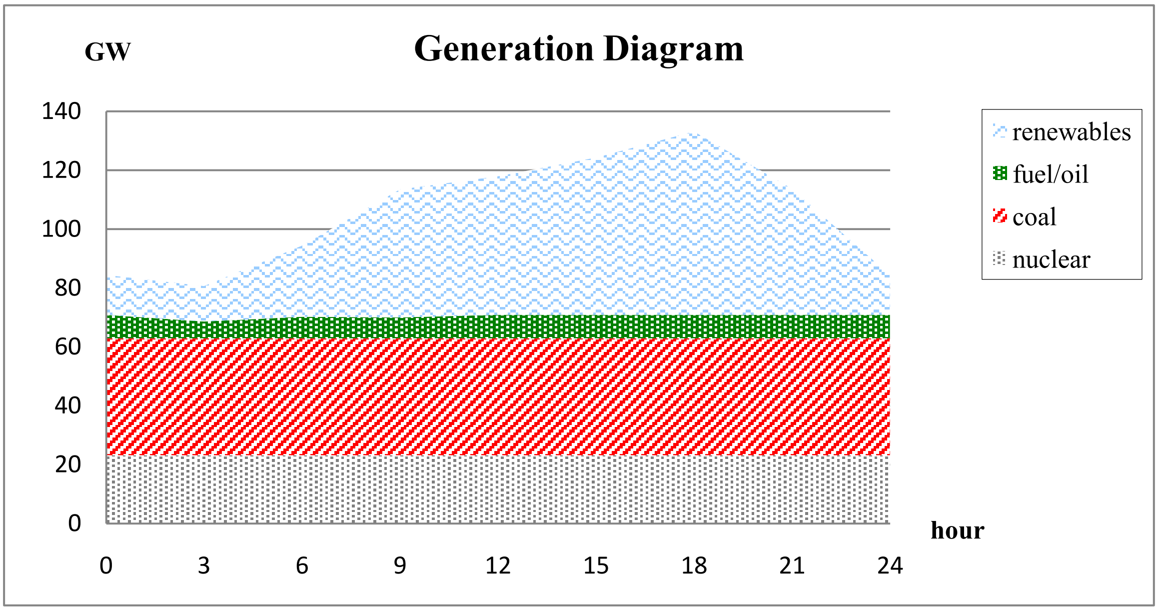

Figure 4 – Generation Diagram for a typical day, not considering network constraints.

In Table 7 we compare the generation of the fossil fuel based power plants, with and without considering transmission constraints. It illustrates how the introduction of transmission constraints increases electricity production from gas power plants (which is compensated by a very significant reduction of generation by coal power plants and by fuel/gasoil power plants). This behaviour reflects the difference between a purely economic dispatch from centralized markets and a feasible dispatch taking into account technical constraints. Network constraints lead to the dispatch of expensive generators in order to meet demand, as congestion limits the access to cheaper sources of electricity.

Table 7 – Total Generation of fossil fuel based power plants, for a typical day.

	Total Generation (GWh)		
	natural gas	fuel/gasoil	coal
without network constraints	0	60	318
with network constraints	52	42	284

5.3. Impact of Demand

To illustrate how demand affects a power system we have considered the scenario with the high load demand and, as before, we assumed a CO_2 price of 15 €/tCO_2eq. The results are summarized in Table 8, which does not include nuclear power plants and power plants using renewable sources to produce energy, as in both cases (with and without constraints) they are fully dispatched.

Comparing Tables 7 and 8, in the case where there are no transmission constraints, we observe that in both cases coal power plants are fully dispatched.

Table 8 – Total Generation of fossil fuel based power plants, for a high demand day.

	Total Generation (GWh)		
	natural gas	fuel/gasoil	coal
without network constraints	38	185	318
with network constraints	98	125	318

Moreover, while in Table 8 both fuel/oil and natural gas power plants are dispatched, in Table 7, for the typical day, natural gas power plants were not dispatch. This implies that the level of demand has a direct impact on the electric system operation costs and on the value of the generation technologies. Notice that, in both cases, the dispatch order follows the merit order presented in Figure 2 for a CO_2 price of 15 €/tCO_2eq, which was expected because demand variation does not change the marginal costs of the different technologies.

The impact of the level of demand on the scheduling of plant is affected by the presence of transmission constraints; these tend to favour generation by natural gas plants, which benefit as much from the presence of high demand as from transmission constraints.

5.4. Determinates of Firms' Profits

In this section we compute the firms' profits using Equation 13 (where GC_{tp} are the generation costs described by Equation 1, for a single player), which assumes that the market price equals the highest marginal cost of the power plants running in each period.

$$P_w = \sum\nolimits_{g,f,t} \left(MC_f^{high} \times GO_{g,t} \right) - \sum\nolimits_t GC_t \qquad \text{Equation 13}$$

We present the firms' profits both for average and high demand days, for the firms in Portugal, assuming it is an independent market (Table 9), for the firms in Spain, assuming that it is an autarkic market (Table 10), and for all the firms in the MIBEL, after integration of both markets (Table 11). In all these simulations we have included transmission constraints, with the parameters presented in Table 4.

Table 9 – Profits attained by all considered companies in Portugal (only).

		Average day			*High Demand day*		
		CO_2 Price			**CO_2 Price**		
		15	**40**	**50**	**15**	**40**	**50**
Profits (M €)	**EDP**	2.5	6.4	6.1	7.9	6.6	6.3
	Others	0.2	0.3	0.2	0.8	0.5	0.2

Table 10 – Profits attained by all considered companies in Spain (only).

		Average day			*High Demand day*		
		CO_2 Price			**CO_2 Price**		
		15	**40**	**50**	**15**	**40**	**50**
Profits (M €)	**Endesa**	18.1	17.7	17.7	20.2	18.0	17.8
	Iberdrola	24.7	21.9	20.9	25.8	22.6	20.9
	EDP	1.3	0.54	0.03	1.3	0.54	0.20
	U. Fenosa	1.8	0.74	0.06	2.1	0.85	0.35
	Others	1.4	0.42	0.49	1.6	0.82	0.74

Table 11 – Profits attained by all considered companies in MIBEL, with network constraints.

		Average day			*High Demand day*		
		CO_2 Price			**CO_2 Price**		
		15	**40**	**50**	**15**	**40**	**50**
Profits (M €)	**Endesa**	7.9	8.7	9.6	8.7	8.8	9.7
	Iberdrola	6.4	9.5	10.1	8.2	9.6	10.4
	EDP	2.6	2.8	2.9	2.8	2.9	3.0
	U. Fenosa	0.48	0.17	0.04	0.63	0.23	0.06
	Others	0.60	0.23	0.17	0.60	0.31	0.35

Our analysis shows that an increase in CO_2 prices does not always lead to a rise in profits. Since an increase in CO_2 prices implies a raise in marginal cost (that sets price) each company has higher costs for generating electricity. However, if for some firms this results in a price increase and a higher profit (for example if the firm owns wind farms or nuclear power plants) for others, owning for example coal power plants, profits can decrease as the higher price does not compensate for increased generation costs. If firms do not have market power they cannot pass all the increase in their costs to consumers (only part will be passed) which means that some firms will lose from higher CO_2 emission prices. Another limitation to the ability of firms to pass the cost to consumers is the possible line congestion that reduces the ability of firms to benefit from higher prices. It should be noted that firms tend to benefit from transmission constraints but they benefit less from these constraints when CO_2 emission prices are higher.

This result is at odds with the conclusion of Chen et al. [27] and the evidence from Veith et al. [28], both of which defend that firms will profit from the emissions markets by passing the costs to consumers. Our result suggests that this is only possible if the firms have market power, otherwise, using a marginal cost pricing, not all firms can pass their increased production cost to consumers. From a social welfare perspective the firms are not able to pass such a large proportion of the cost increase to consumers and, therefore, they have lower profits.

If we analyze closely to Figure 2, when the CO_2 price increases the marginal costs between technologies become more levelled. This means the gap between the higher marginal cost and the lower marginal cost diminishes, which implies less profit. This finding suggests that it is important for firms to own different technologies in order to shift production between technology types to attain higher profits.

Moreover, the market integration reduces the companies' profits, as the market integration allows the exchange of energy between the two countries, Portugal and Spain, in order to assure demand at lower prices by allowing Portugal to gain access to cheaper energy from Spain and vice-versa. In order to understand the impact of network constraints on the companies' profits, we can compare Tables 11 (with transmission constraints) and 12 (without transmission constraints).

Table 12 – Profits attained by all considered companies in MIBEL, without network constraints.

		Average day				*High Demand day*		
		CO_2 Price				**CO_2 Price**		
		15	**40**	**50**		**15**	**40**	**50**
Profits (M €)	**Endesa**	5.2	8.3	9.6		6.6	8.8	9.7
	Iberdrola	6.0	8.7	10.1		7.1	9.2	10.2
	EDP	1.9	2.6	2.9		2.6	2.9	2.9
	U. Fenosa	3.4	0.1	0.0		0.6	0.2	0.1
	Others	2.5	0.1	0.2		0.5	0.3	0.3

Without transmission constraints the companies' profits are lower. This is due to the fact that without transmission constraints the marginal cost that sets remuneration is the lowest. This result illustrates the typical impact of the network constraints on social welfare. The electric grid has losses and sometimes congestions in some lines, which leads to the dispatch of the generation with higher marginal costs, and therefore it leads to higher companies' profits.

6. Conclusions

In this paper we have developed a model of the Iberian Electricity Market which includes both technical and economic factors, in order to model the energy dispatch that maximizes social welfare taking into account the impact of CO_2 prices on the generation costs. Additionally, as the study does not include any income from free allocation of allowances, it assumes that all of these allowances are bought at market prices.

First, we have looked at the impact of CO_2 prices on generation costs and concluded that only for high CO_2 prices (above 35€/tCO_2eq) will the merit order change. (This result is much more demanding on the increase of the CO_2 price than reported in [6], in which the threshold is about 15€/tCO_2eq: the different is justified by the assumptions about market power and, demand elasticity. In this case, the most pollutant technology is replaced by natural gas (that is the least pollutant). All the non-pollutant technologies (wind, hydro, and biomass) are fully used in generation.

Second, we have analyzed the impact of different levels of demand (typical days) on plant scheduling (for the CO_2 emissions price of 15 €/tCO_2eq used in the experiments), concluding that: if there are no transmission constraints coal power plants are fully dispatched and that natural gas plants are only dispatched for a day with very high demand.; the transmission constraints interact with the level of demand to favour generation by natural gas power plants.

Third, we have compared the influence of network constraints on the scheduling of the different technologies. We concluded that biomass, wind, hydro and nuclear power plants produce energy at total daily maximum. However, natural gas plants (for the CO_2 emissions price of 15 €/tCO_2eq used in the experiments) are only used when including network constraints that increase considerably generation accompanied by a significant reduction of generation by coal plants and fuel/gasoil plants.

Furthermore, we have found that an increase in CO_2 emission prices does not imply an increase in profit (although it leads to higher marginal generation costs and prices, as in Reneses and Centeno [6]). This result is at odds with the results in Chen et al. [27] and Veith et al. [28], suggesting that market power is the reason why, in their analysis, generation firms profit from CO_2 emissions trading. Moreover, the presence of transmission constraints cannot be explored to the full by firms when CO_2 emission prices increase. Our result suggests that firms may own different technologies in order to shift production between technology types and achieve higher profits.

Moreover, the creation of the MIBEL, even with transmission grid constrains, improves the efficiency of generation at the Iberian level, reducing production costs and increasing consumer surplus (as prices are lower). For this reason, the MIBEL reduces the companies' profits. Another important point is that firms benefit from transmission congestion, which shows that the investment in transmission is important for consumers and social welfare but it goes against the interests of generation firms (even of the more efficient ones).

Finally, our results suggest that while the biggest Spanish firms benefit from the MIBEL, especially if CO_2 prices are high, the biggest Portuguese firm (EDP) loses with market integration.

As a point of discussion, it is interesting to notice that some of the main qualitative results from Reneses and Centeno's [6] oligopoly model still hold in our welfare analysis. The question we would ask is: when is it advantageous to model the oligopoly as a game? Can a social welfare analysis capture the same qualitative results? And, in the presence of a regulator, which one of these approaches represents better reality?

Finally, due to the complexity of the problem addressed, all the results in this paper are numerical as we have not provided any closed form solution to the research questions. This limits the validity of the results which are only valid in the instances of the problem studied in the paper. Nonetheless, these computational results allow us to analyze the impact of market merger on the social optimum taking into account the details of the electricity market, within a scenario for the parameters that we have considered a good representation of the real world problem. This issue is always present when computational simulations and numerical approaches are used in the analysis of large scale, complex problems.

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Appendix: Nomenclature

Indexes

g	each of the considered generation groups in the model – it were considered 132 power plants total and respective capacities, fuel type and owner.
t	each of the time periods considered during a day – for the presented model, each time period has a duration of three hours.
f	each of the fuel type used by each considered power plant in the model – the fuel types included in the model contemplate tecnologies like: wind, hydro and biomass, as part of the renewable generation mix; coal, fuel/gasoil and combined cycle (that runs on natural gas), as part of the thermal generation mix; and nuclear power reactors, available in the Spanish generation mix.
w	each of the considered companies' owners. It were considered five owners, ranging from: Endesa, Iberdrola, EDP, Unión Fenosa and others – that comtemplate small independent producers companies.
n	each of the considered Iberian network equivalent nodes – considered regions of each node are presented in Table 3
l	each of the considered Iberian network equivalent lines – capacities of each considered line is presented in Table 4

Variables:

$A_{i,k}$	sensitivity matrix derives the power flow in branch connecting node i to node k, accordingly to the injected power in node j
MC_f	represents the highest marginal cost (in €/MWh) of a generation unit, based on the fuel type technology *"f"* used as primary resource;
$GO_{g,t}$	represents the generation output of each power plant *"g"* in each of the time periods *"t"* considered;

$OS_{g,t}$ represents the operation status of each power plant *"g"* in each of the time periods *"t"* considered;

$F_{i,k}$ power flow in branch connecting node i to node k

$LF_{l,t}$ represents the power flow in each network connection line *"l"* for each time period *"t"* considered;

$PI_{n,t}$ represents the power injection in each network node *"n"* for each time period *"t"* considered;

P_j active power injected at node j

$S_{l,n}$ represents the sensitivities matrix derived from the DC model used, binding each network connection line *"l"* with each network node *"n"*.

$X_{i,k}$ reactance of branch connecting node i to node k

$Z'_{i,j}$ impedance of branch connecting node i to node j

π represents the global operation cost of the electrical Power System's network;

θ_i voltage phase at node i

θ_k voltage phase at node j

Parameters:

SuC_g represents the startup cost of each power plant *"g"*;

SdC_g represents the shutdown cost of each power plant *"g"*;

FC_f represents the fuel costs (in €/MWh) of a generation unit, based on the fuel type technology *"f"* used as primary resource;

CO_2P represents the CO_2 price (in €/ton released to the atmosphere);

EF_f represents the emission factor (in ton of CO_2 per MW of energy produced) of a generation unit, based on the fuel type technology *"f"* used as primary resource;

TE_f represents the thermal efficiency in terms of electric energy generated, depending on the primary resource used by a power plant to produce energy;

${G_g}^{Max}$ represents the maximum available capaticity for each power plant *"g"*;

${G_g}^{min}$ represents the tecnical minimum that a power plant *"g"* must produce;

${H_f}^{Max}$ represents the maximum number of hours that a generation unit can be producing in a sigle day, based on the fuel type technology *"f"* used as primary resource;

$D_{n,t}$ represents the demand in each network node *"n"* for each time period *"t"* considered;

${LC_l}^{Max}$ represents the maximum line capacity of each network connection line *"l"*.