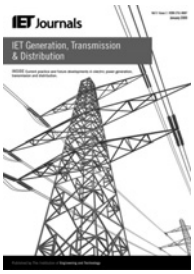
Published in IET Generation, Transmission & Distribution
Received on 27th February 2009
Revised on 14th October 2009
doi: 10.1049/iet-gtd.2009.0105

Special Issue – selected papers on Electricity Markets: Analysis & Operations



ISSN 1751-8687

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

A. Moreira[1,2] *F.S. Oliveira*[3] *J. Pereira*[1,2]

[1]*FEP.UP, Faculdade de Economia da Universidade do Porto, Rua Dr. Roberto Frias, Porto 4200-464, Portugal*
[2]*INESC Porto, Instituto de Engenharia de Sistemas e Computadores do Porto, Campus da FEUP, Rua Dr. Roberto Frias, 378, Porto 4200-465, Portugal*
[3]*ESSEC Business School, Avenue Bernard Hirsch B.P. 50105, Cergy-Pontoise Cedex 95021, France*
E-mail: jpereira@inescporto.pt

Abstract: In this study, the authors analyse 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. They 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. They 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 their analysis, they 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. The authors 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.

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 duration of 3 h

f each of the fuel type used by each considered power plant in the model – the fuel types included in the model contemplate technologies 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 was considered five owners, ranging from Endesa, Iberdrola, EDP, Unión Fenosa and others – that contemplate 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 are presented in Table 4

Variables

π global operation cost of the electrical power system's network

MC_f marginal cost (in €/MWh) of a generation unit, based on the fuel type technology 'f' used as primary resource

$GO_{g,t}$ generation output of each power plant 'g' in each of the time periods 't' considered

$OS_{g,t}$ operation status of each power plant 'g' in each of the time periods 't' considered

$LF_{l,t}$ power flow in each network connection line 'l' for each time period 't' considered

$PI_{n,t}$	power injection in each network node 'n' for each time period 't' considered
$S_{l,n}$	sensitivities matrix derived from the DC model used, binding each network connection line 'l' with each network node 'n'
θ_i	voltage phase at node i
$X_{i,k}$	reactance of branch connecting node i to node k
$F_{i,k}$	power flow in branch connecting node i to node k
P_j	active power injected at node j
$Z'_{i,j}$	impedance of branch connecting node i to node j
$\boldsymbol{A}_{i,k}$	sensitivity matrix derives the power flow in branch connecting node i to node k, accordingly to the injected power in node j
π_w	total profit for each company owner 'w'
MC_t^{high}	highest marginal cost (in €/MWh) of a generation unit in each of the time periods 't' considered
$GC_{t,w}$	generation costs of each company owner 'w' in each of the time periods 't' considered

Parameters

SuC_g	start-up cost of each power plant 'g'
SdC_g	shut-down cost of each power plant 'g'
FC_f	fuel costs (in €/MWh) of a generation unit, based on the fuel type technology 'f' used as primary resource
CO_2P	CO_2 price (in €/tonne released to the atmosphere)
EF_f	emission factor (in tonnes 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	thermal efficiency in terms of electric energy generated, depending on the primary resource used by a power plant to produce energy
G_g^{Max}	maximum available capacity for each power plant 'g'
G_g^{min}	technical minimum that a power plant 'g' must produce
H_f^{Max}	maximum number of hours that a generation unit can be producing in a single day, based on the fuel type technology 'f' used as primary resource
$D_{n,t}$	demand in each network node 'n' for each time period 't' considered
LC_l^{Max}	maximum capacity for each network connection line 'l'

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 (EU) 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 therefore requires 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 analyse 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 maximisation of social welfare is equivalent to minimisation 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 maximisation 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

IET Gener. Transm. Distrib., 2010, Vol. 4, Iss. 2, pp. 231–243
doi: 10.1049/iet-gtd.2009.0105

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 optimisation procedure that takes into account economic criteria and is subject to different types of economical, technical and security constraints (e.g. [8–10]), 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. Owing 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 despatch of centralised 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, whereas 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 parameterise the model for the MIBEL. In Section 5 we present the main results and Section 6 concludes the article.

2 European market for emissions trading

Under the Kyoto Protocol, nations that emit less than their quota of greenhouse gases (GHGs) 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), for example, [13–15] and national level (see Betz *et al.* [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 SO_2 in the 'Acid Rain Program' of 1990 in the USA [17, 18]. The EU (together with its role in the Kyoto Protocol) is 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, minimising 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 to 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, 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 analysed 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, 27], which model oligopolistic competition using a more stylised 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 minimises the system production costs, given by (1). These costs are attained by adding all power plants marginal costs, and maximise 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 (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, (3) and (4)

$$\text{Objective function:} \quad \min \pi = \sum_{f,g,t} \begin{bmatrix} (\mathrm{MC}_f \times \mathrm{GO}_{g,t}) \\ +(\mathrm{OS}_{g,t} \times (1-\mathrm{OS}_{g,t-1}) \times \mathrm{SuC}_g) \\ +((1-\mathrm{OS}_{g,t}) \times \mathrm{OS}_{g,t-1} \times \mathrm{SdC}_g) \end{bmatrix} \tag{1}$$

subject to

$$\mathrm{MC}_f = \mathrm{FC}_f + \frac{\mathrm{EF}_f}{\mathrm{TE}_f} \times \mathrm{CO_2P} \quad \forall f \tag{2}$$

$$\mathrm{GO}_{g,t} \le G_g^{\mathrm{Max}} \times \mathrm{OS}_{g,t} \quad \forall g,\ \forall t \tag{3}$$

$$\mathrm{GO}_{g,t} \ge G_g^{\min} \times \mathrm{OS}_{g,t} \quad \forall g,\ \forall t \tag{4}$$

$$\sum_t \mathrm{GO}_{g,t} = G_g^{\mathrm{Max}} \times H_f^{\mathrm{Max}} \quad \forall g \tag{5}$$

$$\sum_g \mathrm{GO}_{g,t} - \sum_n D_{n,t} = 0 \quad \forall t \tag{6}$$

$$\mathrm{LF}_{l,t} \le \mathrm{LC}_l^{\mathrm{Max}} \quad \forall t,\ \forall l \tag{7}$$

$$\mathrm{LF}_{l,t} \ge -\mathrm{LC}_l^{\mathrm{Max}} \quad \forall t,\ \forall l \tag{8}$$

$$\mathrm{PI}_{n,t} = \sum_g \mathrm{GO}_{g,t} - D_{n,t} \quad \forall t,\ \forall n \tag{9}$$

$$\mathrm{LF}_{l,t} = \sum_n (S_{l,n} \times \mathrm{PI}_{n,t}) \quad \forall t,\ \forall l \tag{10}$$

Unlike other types 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 (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 (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, (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 (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, because of the approach

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doi: 10.1049/iet-gtd.2009.0105

simplifications (branches resistance is considered zero)

$$F_{i,k} = \frac{\theta_i - \theta_k}{X_{i,k}} \tag{11}$$

Besides allowing the computation of voltage phases followed by the active power flow in each network branch, the DC model (as presented in (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]

$$F_{i,k} = \frac{\theta_i - \theta_k}{X_{i,k}} = \frac{\sum_{j \neq \mathrm{REF}} (Z'_{i,j} \times P_j) - \sum_{j \neq \mathrm{REF}} (Z'_{k,j} \times P_j)}{X_{i,k}}$$
$$= \sum_{j \neq \mathrm{REF}} \frac{Z'_{i,j} - Z'_{k,j}}{X_{i,k}} P_j = \boldsymbol{A}_{i,k} \times P_j \tag{12}$$

As presented in (12), the active power flow $P_{i,k}$ can be attained through the sensitivity matrix $\boldsymbol{A}_{i,k}$, 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 (12) for the entire network represents the DC model, (9) and (10). The model is a mixed integer non-linear problem (MINLP), solved through generic algebraic modelling system (GAMS) using the dicopt and minos solvers to reach the final solution.

4 Structure of the Iberian electricity market

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

4.1 Generation plants installed in Portugal and Spain

The data in the model include 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, the total generation capacity was about 15 GW in Portugal and 90 GW 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%, whereas 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	89 945
nuclear	–	7716
hydro power	4957	16 657
wind power	2624	15 576
other renewables	1515	12 552
thermal power	5819	37 444
→ coal	1776	11 359
→ fuel-oil	1712	4418
→ diesel/gasoil	165	–
→ combined cycle	2166	21 667

Regarding the ownership structure, described in Table 2, it is to be noticed 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	1618	25 184	39 915	8396	3898	12 552
nuclear	–	–	7716	–	–	–	–
hydro power	4957	–	–	16 657	–	–	–
wind power	2624	–	–	15 576	–	–	–
other renewables	1515	–	–	–	–	–	12 552
thermal power	4201	1618	17 468	7682	8396	3898	–
→ coal	1148	628	5298	2330	2549	1182	–
→ fuel-oil	1712	–	2062	906	1450	–	–
→ diesel/gasoil	165	–	–	–	–	–	–
→ combined cycle	1176	990	10 108	4446	4397	2716	–

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 Fig. 1.

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

The hydro system and reservoirs are dispersed in all considered equivalent zones, which are very wide areas. We have not modelled explicitly any reservoirs, instead we have considered the aggregated data of 2008 for hydro energy. For wind generation it was made an equivalent assumption: was considered the average amount of wind produced during an average day, restricted to time periods where wind is most available.

In respect to the network equivalent model, our main concern was the interconnections because of 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, because of the characteristics of the DC model implemented.

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

4.3 Scenarios for analysing load

In 2008, the peak power demand was about 9 GW in Portugal and 43 GW 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 (HDD); the second scenario corresponds to an average demand day (ADD), based on the annual energy consumptions of Portugal and Spain. For each day, we have agglutinated the hours in eight blocks of 3 h each, keeping enough detail in the model to compare the peak and off-peak hours (as

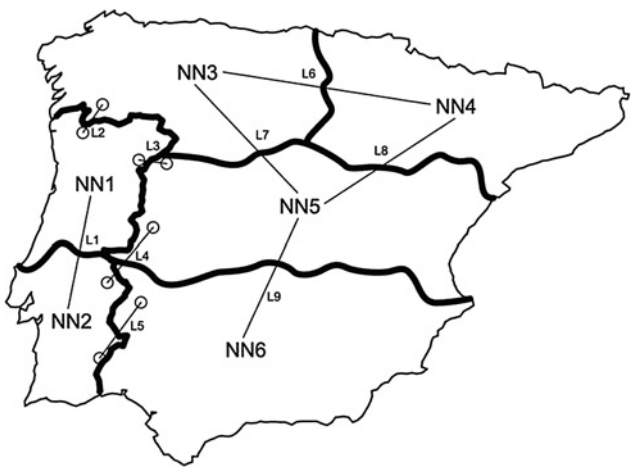

Figure 1 *Network equivalent for model proposed*

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doi: 10.1049/iet-gtd.2009.0105

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, Orense, Asturias, León, Zamora, Cantabria, Palencia, Valladolid, Burgos, Vizcaya
NN4	Guipúzcoa, Álava, La Rioja, Soria, Navarra, Zaragoza, 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, Jaén, Granada, Albacete, Murcia, Almería, Alicante

Table 4 Line capacities (in MW)

Line	nodes ($i \leftrightarrow j$)	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

presented in Table 6), and at the same time reducing its computational complexity.

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 analysed 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 in 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 Fig. 2, we present the effects of CO_2 price increases on the marginal generation costs. The marginal cost of each despatched 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 because of solely 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, for example, renewable sources or nuclear are not represented in Fig. 2.

We observe three distinct situations:

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

2. However, this mix changes when considered a price of 35 €/tCO_2eq. At this CO_2 price, plants using natural gas are despatched prior to fuel/gasoil-based units. Coal-based plants are still despatched 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.

3. 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

doi: 10.1049/iet-gtd.2009.0105

Table 5 Capacity installed in each considered equivalent node (in MW)

	Portugal		Spain			
	NN1	NN2	NN3	NN4	NN5	NN6
total installed power	6472	7119	23 596	24 402	22 476	19 471
nuclear	–	–	–	3344	4372	–
hydro power	4163	794	8994	2330	4258	1075
wind power	2020	604	8552	2492	3612	920
other renewables	289	1226	6050	3250	1788	1464
thermal power	1324	4495	–	12 986	8446	16 012
→ coal	–	1776	–	2446	4000	4913
→ fuel-oil	–	1712	–	2210	1224	984
→ diesel/gasoil	–	165	–	–	–	–
→ combined cycle	1324	842	–	8330	3222	10 115

Table 6 Demand in each considered t – time period (in MWh)

	Portugal		Spain		MIBEL	
	ADD	HDD	ADD	HDD	ADD	HDD
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

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 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 in Section 5.4.

5.2 Impact of network constraints

To analyse how network constraints influence the scheduling of electricity plants, we compare the despatch by technology, with (Fig. 3) and without (Fig. 4) capacity constraints. In this

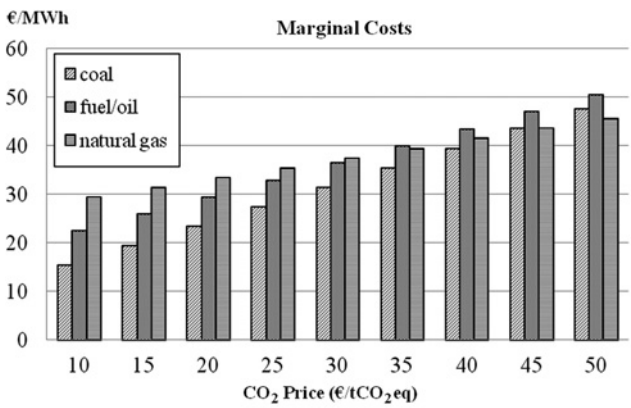

Figure 2 *Impact of CO_2 prices in technologies marginal generation costs*

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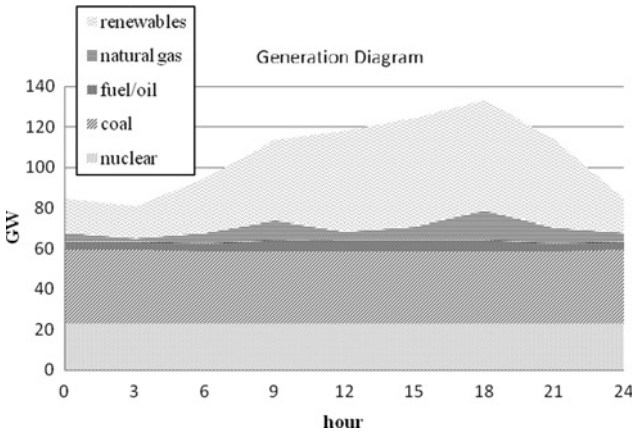

Figure 3 *Generation diagram for a typical day, considering network constraints*

comparison, we have assumed a price of 15 €/tCO_2eq, because of 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 Figs. 3 and 4. In Spain the nuclear power plants are also always producing at maximum capacity, because of their low marginal cost. (A nuclear power plant is always running near its nominal capacity and is not shut down, unless strictly necessary, because of very high shut-down costs and small ramp rates.) From the comparison of Figs. 3 and 4, it emerges that natural gas power plants are started up only when network constraints are considered.

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

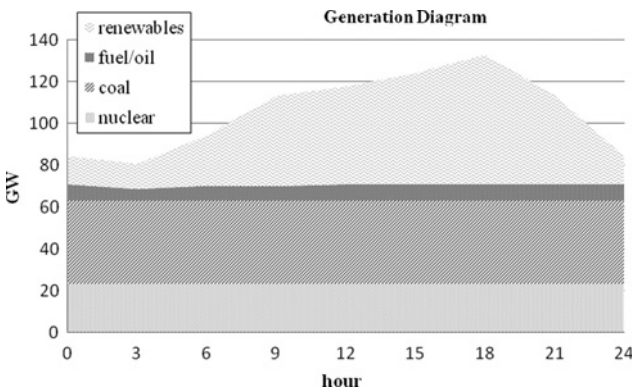

Figure 4 *Generation diagram for a typical day, not considering network constraints*

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

significant reduction of generation by coal power plants and by fuel/gasoil power plants). This behaviour reflects the difference between a purely economic despatch from centralised markets and a feasible despatch taking into account technical constraints. Network constraints lead to the despatch of expensive generators in order to meet demand, as congestion limits the access to cheaper sources of electricity.

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 summarised 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 despatched.

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 despatched.

Moreover, whereas in Table 8 both fuel/oil and natural gas power plants are despatched, in Table 7, for the typical day, natural gas power plants were not despatched. 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 despatch order follows the merit order presented in Fig. 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.

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

doi: 10.1049/iet-gtd.2009.0105

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

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 (13) (where $GC_{t,w}$ are the generation costs described by (1), for a single player), which assumes that the market price equals the highest marginal cost of the power plants running in each period

$$\pi_w = \sum_{g,t} (MC_t^{high} \times GO_{g,t}) - \sum_t GC_{t,w} \qquad (13)$$

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.

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 (e.g. 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 analyse closely to Fig. 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 Table 11 (with transmission constraints) and Table 12 (without transmission constraints).

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

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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	4.07	3.89	4.11	4.58	4.29	4.58
	Iberdrola	8.97	12.26	14.98	9.95	13.55	16.75
	EDP	2.22	2.24	2.57	2.54	2.51	2.84
	U. Fenosa	0.57	0.21	0.12	0.67	0.25	0.15
	Others	0.60	0.28	0.71	0.66	0.33	0.83

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	2.79	3.90	4.14	4.64	4.32	4.58
	Iberdrola	7.18	12.26	15.01	10.17	13.55	16.74
	EDP	1.57	2.25	2.55	2.59	2.48	2.84
	U. Fenosa	0.34	0.23	0.12	0.74	0.27	0.14
	Others	0.25	0.25	0.69	0.66	0.32	0.83

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 despatch 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 MIBEL, which includes both technical and economic factors, in order to model the energy despatch that maximises 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 difference 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 analysed 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 despatched and that natural gas plants are only despatched 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],

doi: 10.1049/iet-gtd.2009.0105

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 whereas 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, because of 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 analyse 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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