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The Impact of the EU ETS on Prices, Profits and Emissions in the Power Sector: Simulation Results with the COMPETES EU20 Model

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Abstract This paper analyses the impact of the EU Emissions Trading Scheme (ETS) on electricity prices, in particular on wholesale power markets across the EU. To study this impact, this paper discusses the major results of a bottom-up modelling analysis of the implications of emissions trading for the performance of the wholesale power market in 20 European countries. The analyses show that a significant part of the costs of (freely allocated) CO_2 emission allowances is passed through to power prices, resulting in higher electricity prices for consumers and additional ('windfall') profits for power producers, even in cases of full auctioning. In addition, they show that the ETS-induced increases in power prices depend not only on the level of CO_2 prices but also on the structure of the power market, i.e., the incidence of market power, and the price responsiveness of power demand. Finally, the analyses show that the internalization and pass-through of carbon costs are crucial elements in a policy regime to reduce CO_2 emissions by both changing the mix of power generation technologies and lowering total electricity demand.

Keywords Electricity market · Carbon cost pass-through · Power sector modelling · Europe, EU ETS · Windfall profits · CO_2 reduction · Cournot competition

JEL Classification C7 · D2 · Q4 · R3

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1 Introduction

Power prices in EU countries have increased significantly since the EU emissions trading scheme (ETS) became effective on the 1st of January 2005. 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 opportunity costs of EU allowances (EUAs) to cover the CO_2 emissions of eligible installations. This pass-through occurs even though eligible electric generators have received most of their needed allowances for free during the first phase of the EU ETS (2005–2007).

In several EU countries the coincidence of the increases in power prices and the implementation of the EU ETS has raised questions on whether power producers have indeed passed through the costs of freely allocated CO_2 allowances to electricity prices, and to what extent the increase in these prices can be attributed to this pass-through or to other factors. In addition, it has raised questions on whether—and to what extent—the supposed passing through of these costs has led to additional profits for power producers, i.e., the so-called 'windfall profits'. Finally, the supposed ETS-induced increases in power prices and generators' profits have raised concerns regarding the scheme's impact on the international competitiveness of some power-intensive industries, the purchasing power of electricity end-users such as small households or, more generally, the distribution of economic surplus among power producers and consumers. As a result, policy makers and stakeholders of industrial or other interest groups in several countries have suggested a variety of options to address these concerns, including improving the EU ETS allocation system (notably increasing the share of auctioning), taxing windfall profits or controlling market prices of either EU carbon allowances, electricity or both.

In the literature, various modelling studies based on bottom-up (engineering economic) approaches can be found that analyse the implications of the EU ETS for the power sector in general and for electricity prices in particular. Bottom-up models use optimization-based approaches to compute market equilibria and build in considerable technical detail on generation and transmission (Neuhoff et al. 2005; Ventosa et al. 2005). IPA (2005) uses the dynamic models ECLIPSE and EPSYM to estimate the impact of the EU ETS on power prices over 2005–2020 according to different carbon price scenarios. Dynamic models allow for long run modification of the generation mix, whereas static models hold the capacity fixed. The cost of carbon is expected to add a direct uplift of 5–16 €/MWh to wholesale power prices in the UK over the forecast period to 2020, assuming carbon prices of €15, €20 and €25/t in Phases I, II and III.

Kara et al. (2008) have analysed the likely impacts of the EU ETS on power plant operators, energy-intensive industries and other consumer groups, specifically in Finland as well as, more generally, in the other Nordic countries. They project that large windfall profits will accrue to power producers in the Nordic area. In Finland, on the other hand, metal industry and private consumers are estimated to be highly affected by the EU ETS-induced increases in power prices.

In order to assess the impact of the EU ETS on the Spanish electricity sector, Linares et al. (2006) apply a model called ESPAM. This is a technology-detailed, oligopolistic market model of the Spanish power system which simulates expansion of generation capacity and endogenously determines CO_2 allowance prices. To some extent, the rise in power prices is, in the long run, mitigated by the EU ETS-induced fuel switching and expansion of generation capacity towards Combined Cycle Gas Turbines (CCGTs). Nevertheless, due to the pass-through of CO_2 costs to power prices, large windfall profits are estimated to accrue to power generators.

Table 1 Overview of modeling studies on the impact of the EU ETS on power prices

Study	Country	Model	CO_2 price (in €/t)	ETS-induced increase in power price (in €/MWh)
IPA (2005)	UK	Dynamic	15–25	5–16
Kara et al. (2008)	Finland	Static	20	15
Linares et al. (2006)	Spain	Dynamic	7–15	3–5
Oranen (2006)[a]	Nordic area	Static	20	1–8
Chen et al. (2008)[a]	Belgium	Static	20	10–14
	France			2–5
	Germany			15–19
	Netherlands			9–11

[a] For comparative reasons, only the perfect competition scenario results of these studies have been included in this table

Oranen (2006) aims to find out how dominant firms in Nord Pool—i.e., the relatively highly integrated and liberalised Nordic power market—will react to the EU ETS and how this will affect the price of electricity in the Nordic countries. To achieve this objective, she uses a Cournot oligopolistic market model based on a Nordic merit order[1] supply curve and a constant elasticity demand function. The results show that the demand level and the price elasticity of demand significantly affect the dominant firms' possibilities for exercising market power and passing through carbon costs.

In order to analyse the implications of EU emissions trading for the price of electricity, Sijm et al. (2005) have applied a variety of methodological approaches, including the use of the model COMPETES for the Netherlands–Belgium–French–German markets (see also Chen et al. 2008). For these four EU countries, the increase in power prices is estimated at 2–19 €/MWh, i.e., an increase varying between 10 and 66% compared to the national power prices before emissions trading.

Table 1 presents a comparative overview of the above modelling studies on the impact of the EU ETS on power prices. More specifically, these studies have all estimated the ETS-induced increase in power prices in absolute terms (i.e., in €/MWh). Table 1 shows that the estimates of this increase vary between 1 and 19 €/MWh (at a carbon price of, in general, 20 €/t). These differences result mainly from differences in the technology mix between countries or, more specifically, from differences between countries in the carbon efficiency—or carbon costs—of the marginal generation technology setting the power price.

In addition to bottom-up modelling analyses, there have also been econometric studies of the linkages between CO2, fuel, and electricity prices (Bauer and Zink 2005; Bunn and Fezzi 2007; Chernyavs'ka and Gulli 2008; Frontier Economics 2006; Honkatukia et al. 2006; Levy 2005, and Sijm et al. 2005, 2006). These studies have usually estimated pass-through rates varying from (less than) 0 to more than 1. This variety of outcomes results mainly from differences in (i) definitions of the pass-through rate or regression variable estimated, (ii) coverage of the countries, power markets and observation periods analyzed, and (iii) data and methodologies used.

[1] The "merit" or "dispatch" order of a set of power plants is a ranking in order of variable cost. In general, because of differences in emissions rates among generating units, a change in emissions allowance prices can change this order, which in turn will determine the extent of use of each unit and, ultimately, the total cost and emissions of the system (see also Figs. 6 and 7, *infra.*).

The aim of this paper is to analyse the impact of CO_2 emissions trading on the power markets of EU countries—in particular to determine the pass-through rate of the CO_2 allowance costs of power generation to wholesale electricity prices—by employing a thoroughly tested model of the European power market, COMPETES EU20. This paper builds on Chen et al. (2008) and extends their analyses from four to 20 countries and a wider range of CO_2 costs (20–40 €/t). The geographic expansion is needed because the EU is now a continental power market, and the ETS could appreciably affect the already significant power exchanges between the four original countries and the other sixteen. We also consider fuel prices and generation capacities for a more recent year, 2006, when the EU ETS was already in place. The analysis is undertaken using a bottom-up market simulation model, applying different assumptions on market power and demand elasticity within an interlinked, but transmission-limited European power system. In addition to assessing this impact for a large variety of 20 European countries, the paper analyses the implications of CO_2 costs pass-through for carbon mitigation—distinguished between lower power consumption versus supply re-dispatch effects—as well as for generators' profits, divided between rents from free allocation versus other emissions trading effects.

The outline of this paper is as follows. Section 2 introduces the features and assumptions of the COMPETES EU20 model which is employed for analysing the effect of the EU ETS on power prices. Consequently, Sect. 3 introduces the eleven scenarios in which we vary the ability to exercise market power, demand elasticity, and the CO_2 cost. Section 4 presents and discusses four sets of results: power prices, rates of pass-through of CO_2 costs to power prices, CO_2 emissions, and profits. These effects are assessed at two different EUA price levels, i.e., 20 and 40 €/t. The fifth section presents conclusions.

2 Model

In order to analyse the performance of wholesale electricity markets in European countries, this paper applies the so-called COmprehensive Market Power in Electricity Transmission and Energy Simulator (COMPETES) model.[2] The present version of the model covers twenty European countries, i.e., Austria, Belgium, the Czech Republic, Denmark, Finland, France, Germany, Hungary, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, and the United Kingdom[3] (see Fig. 1, which also displays the intercountry transmission linkages).[4]

In the COMPETES model, the representation of the electricity network is aggregated into one node per country, except for Germany and Luxembourg, which are joined into one node, while Denmark is divided into two nodes (East and West Denmark) belonging to two different, non-synchronised networks. Virtually all individual power companies and generation units in the 20 countries—including combined heat and power plants owned by industries or

[2] The basic transmission-constrained Cournot formulation underlying COMPETES was first presented in Hobbs (2001). COMPETES itself, including alternative transmission pricing formulations, is presented and applied in Hobbs et al. (2004). COMPETES has been used to analyse issues such as effects of proposed mergers among power companies (Scheepers et al. 2003), market coupling (Hobbs et al. 2005), market power, trade and droughts (Lise et al. 2008), and future power exchanges in Europe (Özdemir et al. 2008), as well as the subject of this paper, the EU ETS (Chen et al. 2008; and Sijm et al. 2005, 2008a and Sijm et al. 2008b).

[3] The data for the UK in addition to Wales, England and Scotland, also includes Northern Ireland both installed capacity and demand, in order to cover all CO_2 emissions in the UK, even though Northern Ireland is in a separate market

[4] Although Norway and Switzerland are not part of the European Union (EU), for convenience we use the expression EU-20 to indicate the total of 20 countries included in the COMPETES model.

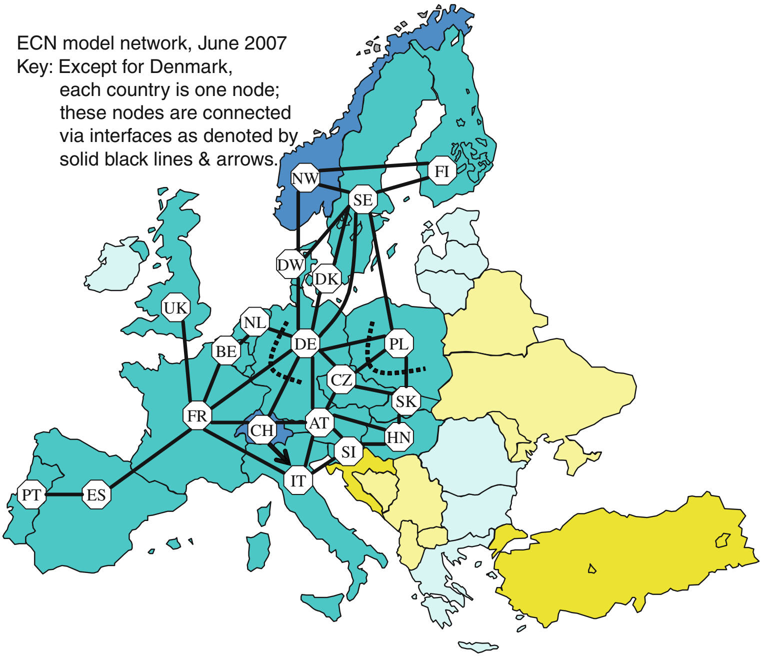

Fig. 1 Representation of the electricity network in COMPETES (*dashed lines* represent constraints on the sum of flows on the links shown)

energy suppliers—are covered by the input data of the model and assigned to one of these nodes. The user can specify which generation companies are assumed to behave strategically and which companies are assumed to behave competitively (i.e., the price takers). The latter subset of companies is assigned to a single entity per node indicated as the 'competitive fringe.'

The COMPETES model is able to simulate the effects of differences in producer behaviour and wholesale market structures, including perfect versus oligopolistic competition. The model calculates the optimal behaviour of the generators by assuming that they simultaneously try to maximise their profits. Profits are determined as the income of power sales (market prices multiplied by total sales) minus the short-run variable costs of generation and—if sales are not at the node of generation—transmission. Short-run costs include fuel and other variable costs; thus, what we call "profits" actually represent gross margins. Start-up costs and fixed operating costs are not taken into account since these costs have less effect on the bidding behaviour of suppliers on the wholesale market in the time horizon considered by the COMPETES model. Our disregarding of fixed capital costs does not affect the differences in profits between different solutions.

The oligopolistic scenarios in this paper are simulated using a Cournot-Nash framework in which the strategic variables for each large generating company (which may own facilities in several countries) are its sales to each country's market within the EU20 area. Smaller generating companies are assumed to be part of a price-taking competitive fringe. Generators pay transmission charges to the transmission system operator (TSO) in order to move power from power plants to customers. The TSO sets the price of transmission to clear the implicit markets for transmission capacity; i.e., so that the market for transmission capacity between countries clears (implicit demand for transmission capacity is less than or equal to supply). Generators are assumed to be price-taking relative to prices of transmission services.

This Cournot-Nash equilibrium is actually an extreme bounding case because it simulates a situation without long-term (multiyear) forward contracts (i.e., pure spot market) and without implicit regulatory threats. As is well known, the pre-existence of forward contracts significantly dampens the motivation of large firms to raise prices (Green et al. 1999). Furthermore, tacit agreements or tacit regulatory threats in other countries could also act to limit the unilateral market power of large companies operating in those markets. In the oligopolistic scenarios of this paper, however, we assume that such a threat constrains firm behaviour only in one extreme situation. This is the case of EdF, the dominant player in France, where it owns nine-tenths of the capacity and is modelled as a price-taking rather than strategic firm.

The model considers 12 different periods or levels of power demand, based on the typical demand during three seasons (winter, summer and autumn/spring) and four time periods (super peak, peak, shoulder and off-peak). The 'super peak' period covers 240 h per annum, consisting of the 120 h with the highest sum of power loads for the 20 considered countries during spring/fall and 60 h each in winter and summer. The other three periods represent the rest of the seasonal load duration curve covering equal numbers of hours during each period and season. Altogether, the 12 periods include all 8760 h of a year. Power consumers are assumed to be price sensitive through use of linear demand curves.[5] The number and duration of periods and the price elasticity of power demand in different periods are user-specified parameters.

The transmission system was modelled using path-based constraints. These constraints simulate market rules that dictate which interfaces that transactions between different countries need to purchase, whether or not the physical power flows actually travel along those paths. Some of the path constraints limit total flows between one country and a neighbouring set of countries, as indicated by dashed arcs on Fig. 1.[6]

Some characteristics of the model are as follows. First, COMPETES is a static, medium-term model and hence, it is not able to assess dynamic changes—i.e., new investments—in generation capacity in the long run. Second, COMPETES is based on the assumption of profit maximization, so that power producers consider the (full) opportunity costs of emissions trading in their bidding prices, regardless of how allowances are allocated. Moreover, while COMPETES is able to assess quantitatively the implications of either auctioning or perfect free allocations at different EUA prices, it does not endogenously calculate the effects of specific free allocation provisions upon plant closures or new entry. Therefore, given a certain carbon price level, the power prices yielded by COMPETES are unaffected by the allowance allocation method. In contrast, in the long-run, allowance allocation procedures can affect retirement and entry decisions, which feed back to prices (e.g., Zhang et al. 2009); thus, ours is a short-run analysis. However, COMPETES can be used to show how alternative allocation methods impact generators' profits (Sect. 4.5).

[5] Note that this assumption is made for modeling convenience, as the version of COMPETES with linear demand is much easier to solve. The results in terms of pass-though rates could be different if constant elasticity of supply (CES) demand curves would have been used (Chen et al. 2008).

[6] Alternatively, but not used in this paper, the COMPETES model could also consider physical transmission constraints (based on power transmission distribution factors derived from a linearized DC load flow representation and thermal transmission limits) (Hobbs et al. 2004). Linearized DC load flows simulate the flow of real (but not reactive) power along parallel paths between sources and sinks, and so are approximations of more complex AC load flows. In addition, controllable DC lines can be represented that connect the non-synchronized Nordpool and UCTE (continental Europe) systems (Hobbs et al. 2008).

Table 2 Summary of COMPETES model scenarios

Scenario acronym	CO_2 price [€/t]	Elasticity	Description
REF	20	0	Reference scenario: Perfect competition with fixed demand[a]
OCe0.1c20	20	0.1	Oligopolistic competition with EdF price taker in France
OCe0.2c20	20	0.2	Oligopolistic competition with EdF price taker in France
PCe0c0	0	0	Perfect competition with fixed demand at REF level
PCe0.2c0	0	0.2	Perfect competition
OCe0.1c0	0	0.1	Oligopolistic competition with EdF price taker in France
OCe0.2c0	0	0.2	Oligopolistic competition with EdF price taker in France
PCe0c40	40	0	Perfect competition with fixed demand at REF level
PCe0.2c40	40	0.2	Perfect competition
OCe0.1c40	40	0.1	Oligopolistic competition with EdF price taker in France
OCe0.2c40	40	0.2	Oligopolistic competition with EdF price taker in France

[a] Because of the demand calibration procedure used, this scenario does not depend on the price elasticity, and so is also equivalent to the PCe0.1c20 and PCe0.2c20 scenarios

Fuel cost, generator efficiency and capacity, demand, and transmission capacity assumptions are obtained from various sources (Lise et al. 2008). The model is not calibrated to 2006 power prices, so the comparison between actual and simulated prices in that year (Sect. 4.1) is an appropriate test of COMPETES' validity.

However, it should be emphasised that our estimates of impacts upon power generators' profits and other market outcomes should be interpreted cautiously. These figures are derived from a model that was designed to simulate strategic behaviour on the wholesale market. Nevertheless, the model offers some useful insights with regard to the impact of emissions trading on electricity prices, generators' profits and carbon emissions of the power sector. For instance, it can estimate the impact of different CO_2 price levels, different market structures and different demand elasticities on the extent to which carbon costs are passed through to power prices. In addition, it can assess the order of magnitude of the impact of emissions trading on operational profits at the sector and firm levels. If interpreted prudently, the results can even be helpful in considering the policy implications of emissions trading and allocation methods for the power sector (see, for instance, Sijm et al. 2008a and Sijm et al. 2008b).

3 Scenarios

In order to analyse the implications of CO_2 emissions trading for electricity prices under different assumptions regarding power market structure and price responsiveness of electricity demand, different scenarios have been assessed by means of the COMPETES model. The acronyms and assumptions of each scenario are summarised in Table 2.

The reference scenario (REF) concerns an assumed situation of perfect competition and fixed power demand on the wholesale markets of European countries. It is based on 2006 fuel prices and a carbon price of 20 €/t (comparable to the average EUA price in 2005–2006). The reference scenario has been calibrated to the level of power demand in 2006. A comparison of model outcomes in terms of wholesale prices and carbon emissions shows that these outcomes are generally quite close to actual realisations in 2006 (see Lise et al. 2008; Sijm et al. 2008b).

To assess the influence of market structures on CO_2 cost pass-through, two stylistic ('extreme') cases are considered, namely perfect competition (indicated by the acronym PC) and oligopolistic competition (indicated by OC) where the French company Electricité de France (EdF) is assumed not to be able to exercise market power in France due to an implicit regulatory threat, whereas all other non-fringe firms fully exercise market power in all markets in which they operate. Consistent with our use of OC as a bounding case, we assume that exercise of market power is unconstrained by existence of forward contracts or vertical integration, which results in higher prices than if such contracts or integration is present.[7]

To analyse the impact of demand response to the CO_2 cost-induced changes in power prices, different levels of demand elasticity have been assumed. For most scenarios, a price elasticity of 0.2 has been taken (indicated by e0.2 in the acronyms of the scenarios).[8] This may be justified as the demand response in the medium or long term.[9] For the short term, however, a price elasticity of 0.2 may be considered too high because it is usually difficult to reduce power consumption in the short run. Hence, some scenarios with lower elasticities or zero elasticities have been considered as well, namely 0.1 for the oligopolistic competition scenarios (indicated by e0.1 in the acronyms of the scenarios) and 0—i.e., fixed load demand—for the perfect competition scenarios (indicated by e0 in the acronyms of the scenarios).

To study the implications of emissions trading for power prices, an exogenously fixed CO_2 price has been considered at three different levels: 0, 20 and 40 €/t (indicated by c0, c20 and c40 in the acronyms of the scenarios). The COMPETES model has not yet been extended to include CO_2 costs endogenously. This model feature of an exogenously fixed carbon price implies that power producers are assumed to be price takers on the EU CO_2 allowance market, i.e., they are assumed to be unable to influence the price of an EUA.

In addition, because the power producers are profit maximizers, they regard the costs of CO_2 allowances as 'opportunity costs', regardless of whether they purchase the allowances or get them for free. Hence, they add these costs to their other marginal costs when making production or trading decisions (following economic theory and sound business principles). Therefore, the pass-through rate in the sense of the extent to which carbon costs are considered in calculating the marginal costs of power generation is by definition (or default) 100% in the COMPETES model. However, the extent to which CO_2 allowances costs ultimately affect power market prices may differ from 100% due to a variety of reasons such as a change in the merit order, demand response, market structure, etc.

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[7] This is equivalent also to a so-called 'open loop' Nash-Cournot equilibrium in which oligopolistic producers assume that long run contracts would be renewed at prices consistent with spot prices, and the producers make forward contracting and spot decisions simultaneously. Other Nash-Cournot assumptions, such as the Allaz and Vila (1993) closed loop forward contracting model or exogenous fixed forward contracts, yield lower prices.

[8] Although the sign of price elasticity of power demand is usually negative (−0.2), for simplicity we express them as absolute values (i.e., as 0.2). Price elasticity is nonconstant for linear demand curves, so our elasticity assumption applies to the point on each country's demand curve corresponding to the perfect competition / zero carbon cost scenario.

[9] Note that COMPETES covers the wholesale power market only. We assume that wholesale price increases are passed on to retail rates. In response to a price increase, certain power-intensive users may shift to self-production, which reduces demand/supply on the wholesale market. Econometric estimates of long-run price elasticities for retail sales are often over 0.5 (Abrate 2003), but since wholesale generation costs make up approximately half of retail costs, the equivalent elasticity for wholesale sales is roughly halved. In the short run, elasticities are typically on the order of 0.1.

Based on the REF scenario, four additional perfect competition (PC) scenarios are derived by setting the carbon costs at 0 and 40 €/t and by assuming either fixed demand or a demand elasticity of 0.2. In addition, six oligopolistic (OC) scenarios are derived by assuming a carbon cost of 0, 20, and 40 €/t, combined with a demand elasticity of either 0.1 or 0.2.

The results of the COMPETES model analyses are presented not only in an absolute sense for each scenario separately but also by providing the difference between two scenarios. More specifically, to gain insight in the effect of the CO_2 allowance costs on power market performance, the difference in outcome between the scenario with and without CO_2 allowance cost is studied for the same market structure (perfect or oligopolistic competition) and price elasticity of power demand. These differences between these scenarios are indicated by acronyms such as PCe0Δ20 or OCe0.2Δ40, where—for instance—PCe0Δ20 refers to the difference in outcome between the perfect competition scenarios with and without a carbon price of 20 €/t, assuming fixed demand, i.e., a price elasticity of 0 in both scenarios.

The COMPETES analyses focus on the extent to which the opportunity costs of CO_2 allowances affect power prices (and related issues such as power demand and carbon emissions). By comparing the results of the scenarios, the impact of emissions trading on power prices (and related issues) has been analysed under different assumptions of market structure, demand response and CO_2 prices (including resulting changes in the merit order of the power supply curve).

4 Results and Discussion

4.1 Power Prices

Figure 2 presents average (quantity-weighted) actual spot prices in 2006 in nine countries for which historical spot price data are reported, and compares them to simulated prices for the reference case REF (0.2 elasticity, 20 €/t, perfect competition) and oligopoly case (same elasticity and emissions price). The reference case prices are decomposed into marginal energy and CO_2 costs, based on the marginal sources of power in each region.

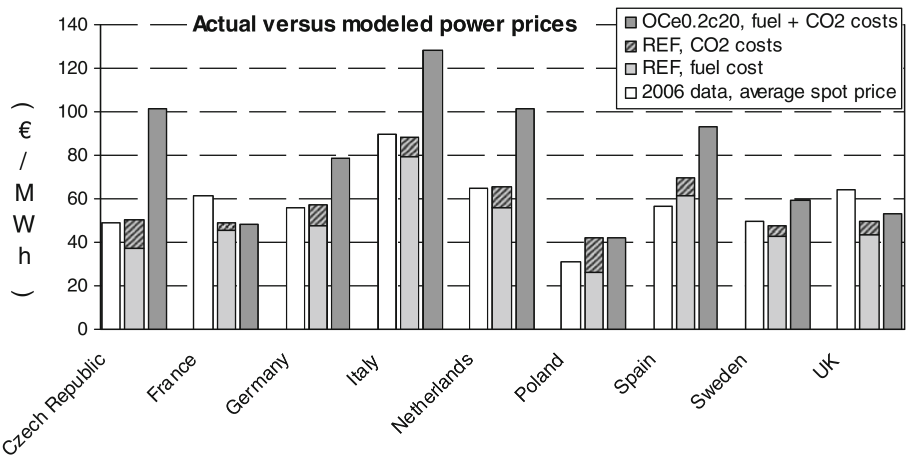

Fig. 2 A comparison of COMPETES model power prices (reference competitive case and oligopoly case) with actual, average spot prices in 2006 for selected EU countries

Figure 2 indicates that in terms of power prices, the model reference outcomes under perfect competition compare generally well to the actual realisations in 2006. For five of the nine countries the price difference is less than 5%, for France[10] and the UK the REF prices are about 10 €/MWh lower than average spot prices, whereas for Poland and Spain the REF prices are about 10 €/MWh higher. An explanation for these deviations is that the model reference scenario assumes liberalised electricity markets with no market power, no regulation and free trade among countries within their transmission constraints. In reality, however, EU power markets in 2006 were to some extent still characterised by the incidence of market power, regulation and trade restrictions affecting power prices.

From Fig. 2 we can make the following observations. For a given carbon price and demand elasticity, electricity prices are significantly higher under the oligopolistic competition (OC) scenarios than under the perfect competition (PC) scenarios. The major exception concerns France for which it is assumed that in the OC scenarios, the dominant company—Electricité de France (EdF)—is a price taker in its home country, i.e., due to regulatory threat it is not able to exercise market power in order to raise electricity prices in France.

In the perfect competition scenario with emissions trading (REF), electricity prices are generally lowest in Poland (42 €/MWh) while highest in Italy (88 €/MWh). Since this is a short-run model, prices in these scenarios are set by marginal (fuel) costs and price differences reflect the different fuel mixes in these countries. Whereas electricity prices are set largely by coal in Poland, they are set by gas in Italy during a major part of the year, in particular during the peak period.

In the oligopolistic competition scenario with emissions trading (OCe0.2c20), electricity prices are generally lowest in Poland (0% increase due to market power) and highest in Belgium, namely 139 €/MWh (112% increase due to market power). Since prices in these scenarios are determined largely by the incidence of market power, this is due to differences in market structure and (assumed) producer behaviour in these countries. Whereas the level of market concentration—i.e., the potential to exercise market power—is relatively high in Belgium (where one company—i.e., Electrabel—owns about 85% of total generation capacity) and transmission constraints severely limit imports, it is relatively low in Poland due to the relatively high share of the competitive fringe in Poland (86%). Note, however, that in reality, prices could not reach such levels for two reasons. One is that because they would provoke regulatory intervention, and the second is the existence of extensive forward contracting. However, the OC case is nevertheless a useful bounding case for examining how the presence of a carbon price could interact with oligopolistic behavior in the power market.

Comparing the prices in Fig. 2 to the results of scenarios with lower elasticities (not shown), the effect of smaller elasticities is to increase oligopolistic prices further. This confirms the expected relation between price elasticity of power demand and the ability to exercise market power to increase electricity prices.[11]

[10] Actual French prices are higher than the modeled prices because we have modeled EDF as a price taker. The actual prices suggest that EDF may be exercising market power, although not nearly as much as it would if it was a Cournot player (and thus a near monopolist in its home market). It is possible to model EDF market power as being between the competitive and Cournot extremes by, for example, using a conjectural variation parameter in the model whose absolute value is between zero and one, as in Centeno et al. (2007).

[11] A higher elasticity also increases competitive prices under a 0 €/t price, but this is an artefact of the calibration procedure which passes the demand curve through a REF case based on perfect competition and a 20 €/t price. As a result, the lower marginal costs under the 0 €/t price result in a great expansion of quantity demanded in the higher elasticity case, increasing the equilibrium prices. By definition of the calibration procedure, the competitive prices are unaffected by elasticity at a price of 20 €/t as the industry moved up its supply curve.

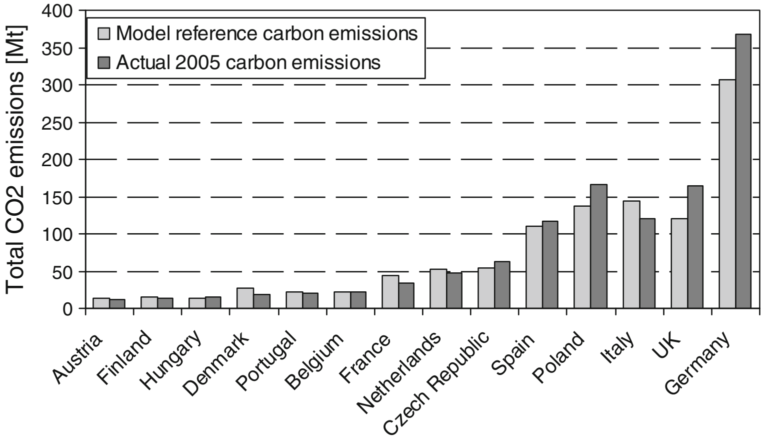

Fig. 3 Actual versus model CO_2 emissions of the power sector

Figure 3 compares the estimated CO_2 emissions of the COMPETES reference scenario to the actual emissions of the power sector for 15 countries in 2005. These countries represent 82% of the total CO_2 emissions in the power sector of the 20 European countries covered by COMPETES and, hence, are quite representative to test the model calibration in terms of CO_2 emissions.

Figure 3 indicates that for most countries the COMPETES reference scenario emissions compare relatively well to the actual emissions in 2005. For Germany and the UK, the reference emissions are respectively 17 and 27% lower than the actual 2005 emissions, while in Italy the model emissions are about 19% higher.

The deviations between model estimates and actual emissions can be due to specific assumptions regarding the reference scenario such as the assumption of (fully) liberalised, competitive electricity markets across the EU (as discussed above). Another explanation for these deviations refers to the assumed (fixed, annual average) relative fuel prices affecting fuel switch and, hence, related emissions in the power sector, notably in a country where the opportunities for fuel switch are relatively large and depend critically on (daily) changes in these prices, such as in Germany or the UK.

Figure 4 presents how the prices increase as a result of introducing emissions trading at CO_2 costs of 20 and 40 €/t, respectively, under various elasticity and competition scenarios. Neighbouring countries are largely grouped together to show how country level prices change relative to their neighbours.

In all comparable scenarios—i.e., those with a similar demand elasticity and market structure—power prices increase significantly due to emissions trading. Under perfect competition (PC), the price increases in absolute terms—i.e., in €/MWh —are generally highest in Poland and lowest in France and Hungary. For instance, depending on the assumed demand elasticity, the increase in power prices due to an EUA price of 20 €/t amounts to about 19 €/MWh in Poland and to some 9 €/MWh in Hungary. These differences in ETS-induced price increases among countries arise because of the combined effect of transmission constraints, differences in carbon intensity of the (existing) price-setting generation units in these countries (coal in Poland, nuclear in France), and ETS-induced shifts in the merit order of the power generation technologies.

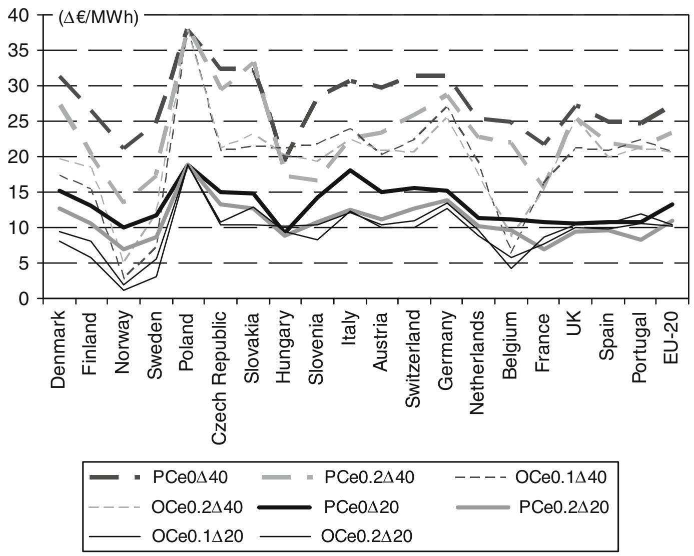

Fig. 4 Changes in wholesale power prices in EU countries due to emissions trading under various COMPETES scenarios (compared to the same scenarios without emissions trading, i.e., with a CO_2 price of 0 €/t)

Under oligopolistic scenarios, however, the absolute increases in power prices due to emissions trading are generally lower than the increases that occur in the comparable perfect competition scenarios, notably in Belgium and Scandinavian countries such as Finland, Norway or Sweden. This results from the COMPETES model assumption of linear, downward sloping demand curves, which is consistent with the general result that pass-through rates for input cost increases are lower under oligopoly (Chen et al. 2008). Constant elasticity demand curves would yield the opposite result. Note, however, that despite generally higher price increases due to emissions trading under PC, power prices under a carbon trading regime are still far lower in absolute terms under PC than OC.

Comparing these results to the earlier EU4 (Netherlands–France–Belgium–Germany) simulations by Chen et al. (2008) results; we see broadly similar patterns in the results for those countries, but some differences. Prices are generally 15 €/MWh or so higher in the EU20 simulations, which is primarily due to the updated (and higher) natural gas and fuel oil costs used in our model. French prices in the EU20 scenarios are higher because of exports from France to the Iberian Peninsula and Italy, which were not considered by Chen et al.. For the same reason French prices are affected to a greater extent by CO_2 trading than in the EU4 case, because they are affected by prices in the markets that France exports to. In the other three countries in the EU4, the effect of a carbon price of 20 €/M upon power prices is broadly the same (in the range of 5–15 €/MWh), with the greatest impact in Germany. The market power scenarios in both cases show that Belgium is the most vulnerable of the four countries to strategic behaviour, although France would also show high market power if EdF had not been assumed to be a price taker.

4.2 Pass-Through Rates

Figure 5 presents estimates of the marginal carbon cost pass-through rate (PTR) under various COMPETES model scenarios.

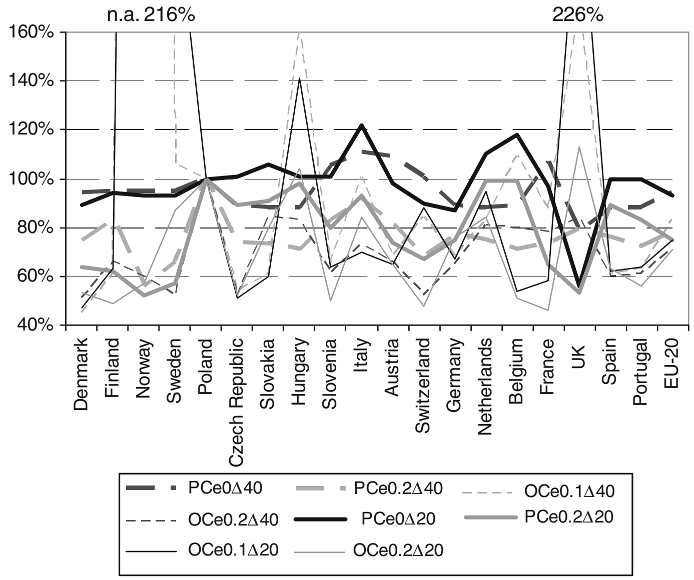

Fig. 5 Estimates of pass-through rates of CO_2 costs to power prices in EU countries under various COMPETES scenarios (measured as the ratio of power price difference to the carbon component of marginal generation cost in each country)

This rate is defined as the ETS-induced change in power price relative to the CO_2 allowance costs of the marginal generation unit setting the power price:

$$\text{PTR} = \Delta\text{power price}/\Delta\text{marginal } CO_2 \text{ allowance costs} \tag{1}$$

The numerator, Δ power price, is the power price differential between the scenarios with and without emissions trading. The denominator, on the other hand, refers to the change in CO_2 allowance costs per MWh of the marginal production unit setting the power price (where the allowance costs are zero in the case without emissions trading).[12]

For all cases considered, most PTRs range between 0.5 and 1.0. The estimates of the PTRs are based on the assumption that the opportunity cost to companies of allowances is the same (the price of allowances) whether they have to purchase allowances or own excess allowances they can sell, so that the marginal cost of allowances is independent of allocation method. Hence, differences in PTRs are due solely to differences in market structure, differences in demand elasticities, and ETS-induced changes in the merit order of the marginal units setting the price in various load periods distinguished by COMPETES.

[12] As discussed in Chen et al. (2008), the identification of the marginal source of power at a particular location in a linearized DC transmission network, even in the perfect competition case, can be challenging. This is because the nature of electricity flow constraints can mean that a marginal MWh of demand at a location might optimally be met by changing several sources, one or more of which might even be decreased as demand increases in order to make more transmission capacity available. The problem is even more challenging in the oligopolistic case, because under Cournot competition, firms of different sizes will have different marginal costs in equilibrium, and so the choice of a marginal plant depends upon which firm is considered. Because of that reason this paper only considers path-based constraints. This simplifies the procedure of finding the marginal unit considerably. In the PC scenarios, there is always a single marginal unit, which can be deduced from the power flows. However, in the OC scenarios, there can be multiple marginal units with different price characteristics; of these the generation weighted average CO_2 costs are taken into consideration in the analysis.

According to economic theory, in the simple case of linear marginal costs of production that are uniformly shifted upwards by emissions trading, the PTR in the case of PC and fixed demand will be 1.0, while in the case of OC with linear responsive demand it will be lower than 1.0 (Chen et al. 2008). Figure 5, however, tells a more complex story. In some situations, the results accord exactly with theory. Poland, for instance, is an exporting country with an elastic supply provided by price-taking producers using mainly a single technology (coal-fired production); as a result, the PTR equals the expected competitive value of 1.0, even in the oligopolistic case. However, in most countries in the PC cases with fixed demand, the PTR deviates from 1.0, while in some OC cases the PTR is (significantly) higher than 1.0. The reason for these deviations from the simple model predictions is that in the case of an ETS-induced change in the merit order, the PTR may be either higher or lower than 1.0, even under PC with fixed demand, depending on whether the price setting technology shifts from either a high-CO_2 to a low-CO_2 marginal unit or vice versa. This shift can be caused by changes of merit order within a country, or changes in congestion patterns that alter the marginal source of power.

The PTR values as found in the modelling exercise can deviate from the theoretical value due to the ability of the model to account for merit order changes, a phenomenon that is excluded from the simple theoretical reasoning. For example, changes in the merit order can be caused by network constraints or increased economic attractiveness of cleaner natural gas under a carbon price. In that case, the denominator of the PTR will be determined by the carbon cost of the marginal (price-setting) technology after adding allowance costs, but this technology will differ from the marginal technology in the case of no carbon costs. If the new marginal technology has lower emissions than the old one (e.g., switching from oil to gas), then its carbon cost difference (the denominator) will be smaller than the old technology's carbon cost, and the denominator of the PTR could be much lower than the numerator (the price difference), yielding a PTR value well beyond 1. The same reasoning can be followed for other merit order changes; for instance, a switch the other way around (the marginal technology changing from gas to coal) could yield a PTR substantially below 1 (Sijm et al. 2009).

Consistent with the predictions of single market models with linear supply and demand functions (Chen et al. 2008), PTRs are usually lower under OC than PC scenarios with similar carbon prices and demand elasticities. Also consistent with this theory, for scenarios with the same carbon prices and market structures, PTRs are lower if demand elasticities are higher.

If we compare these results to those of Chen et al. (2008) for the EU4, there are close similarities in outcomes, but also significant differences due to the greater geographic scope of the EU20 model. For instance, coal-dependent Germany saw lesser PTR rates than the other countries, and France's PTR rates were more variable among scenarios largely because the denominator of the PTR (the marginal carbon emissions rate) was much smaller than for other countries.

4.3 Total and National Distributions of Carbon Emissions

Figure 6 shows the total emissions for each of the scenarios, as well as its distribution among countries. In general, total emissions go down if the carbon price goes up, with greater decreases in the scenarios where power demand is more elastic. For instance, if the carbon price increases from 0 to 40 €/t, the carbon emissions of the EU-20 decline from 1234 to 1069 Mt (−15%) in the PC scenario with fixed demand, while they fall more than twice as much (from 1317 to 954 Mt, −33%) in the PC scenario with a demand elasticity of −0.2.

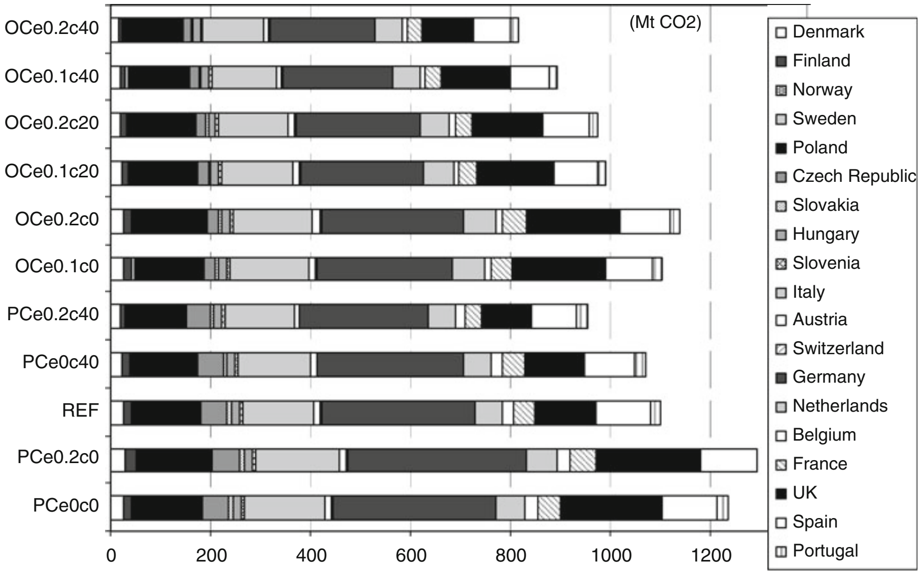

Fig. 6 Total CO_2 emissions of the power sector in the EU-20 under various COMPETES model scenarios (REF case is equivalent to PCe0c20 and PCe0.2c20.)

Note that the total emissions are much less under the oligopoly cases due to the demand response to higher prices due to market power. If indeed there was such a demand response, allowance prices would actually be lower than assumed, as the effective demand curve for allowances would have shifted to the left. However, because we have not modelled the non-power sector demands for allowances, we limit our analyses to a price scenario approach.

Figure 6 also shows that emissions decrease by different percentages across the 20 countries. For instance, UK and Czech emissions vary by a factor of two among the scenarios, while Spanish and Polish emissions vary by a much lesser proportion. This occurs mainly for the reason of marginal generation cost differences. For instance, because Polish plants are relatively inexpensive even with the imposition of carbon taxes, their output changes less than higher cost coal plants further west.

4.4 Supply-Side versus Demand-Side Responses

The greater CO_2 reductions in the more elastic cases demonstrate that reductions can result not only from a supply response, as occurs in the zero elasticity case, but also from demand reduction due to price increases. The supply response results from changes in the merit order, resulting in gas-fired generation displacing some coal-based generation. In Table 3, the impact of emissions trading upon CO_2 emissions is decomposed into these two effects under different scenarios.

The decomposition of Table 3 is accomplished as follows. Under perfect competition with fixed demand (PCe0), emission reductions due to (ETS-induced) demand response must be zero. The total carbon abatement of 133 Mt in PCe0Δ20 is, hence, fully due to re-dispatch. Assuming that this is a good approximation of the amount of CO_2 reduction due to re-dispatch in all other cases as well, the additional reduction in the latter case can be credited

Table 3 Decomposition of ETS-induced reductions in total CO_2 emissions of the power sector in the EU-20 countries under various COMPETES model scenarios [Mt]

	PCe0 Δ20	PCe0.2 Δ20	PCe0 Δ40	PCe0.2 Δ40	OCe0.1 Δ20	OCe0.2 Δ20	OCe0.1 Δ40	OCe0.2 Δ40
Demand response	0	82	32	230	-21	30	78	188
Re-dispatch	133	133	133	133	133	133	133	133
Total reduction	133	215	165	363	112	163	211	321
As % of reference emissions	12%	20%	15%	33%	10%	15%	19%	29%

to demand response. Thus, as the total carbon abatement under this scenario is 215 Mt, the CO_2 reduction due to demand response amounts to 82 Mt.

Table 3 illustrates that emissions trading and the resulting pass-through of carbon cost to electricity prices may reduce CO_2 emissions significantly by affecting not only producer decisions—through a re-dispatch or change in the merit order of generation technologies—but also consumer decisions, i.e., through reducing power demand in response to ETS-induced increases in electricity prices. Therefore, if power demand is price responsive (notably in the medium or long run), the pass-through of carbon costs to higher electricity prices for end-users is an important means of reducing CO_2 emissions in the medium term, as well as the long term. Indeed, the relative proportion of emissions decreases to be credited to demand response is seen to increase at higher levels of reduction.

Thus, an effort to "protect" energy consumers from ETS-induced price increases (either through regulation or subsidies) will actually increase the social cost (as measured by consumer and producer surplus in the electricity markets) of achieving a given CO_2 decrease by eliminating the demand-side as a source of CO_2 reductions. The greater surplus would imply that exists, in theory, an income redistribution scheme that could leave consumers better off and producers no worse off compared a situation where consumers are insulated from electricity price changes.

ETS-induced changes in the merit order at carbon prices of 20 or 40 €/t are illustrated in Figs. 7 and 8, each showing three sets of marginal production costs for the mix of power generation technologies at the EU-20 level. These sets include:

- The merit order or ranking of the supply technologies based on their marginal (fuel) production costs before emissions trading at zero carbon costs (black line). Labels describe which plants are associated with which points.
- A curve showing the marginal (fuel + carbon) costs after emissions trading, i.e., at either 20 or 40 €/t (Figs. 7 and 8 respectively), but shown in the original merit order or ranking of generation technologies before emissions trading (grey line).
- A curve illustrating the marginal (fuel + carbon) costs after emissions trading, based on the reordering of generation technologies according to the new costs (dashed black line).

Figures 7 and 8 show that, due to emissions trading, the marginal production costs of carbon-inefficient technologies—notably coal or lignite—increase substantially, whereas carbon-efficient technologies—notably CCGT—decrease substantially (grey line) and that, subsequently, the merit order may change significantly—especially at higher carbon prices—in the sense that less carbon efficient technologies (coal) shift to the right in the merit order while more carbon efficient units (CCGT) move to the left (resulting in the dashed black

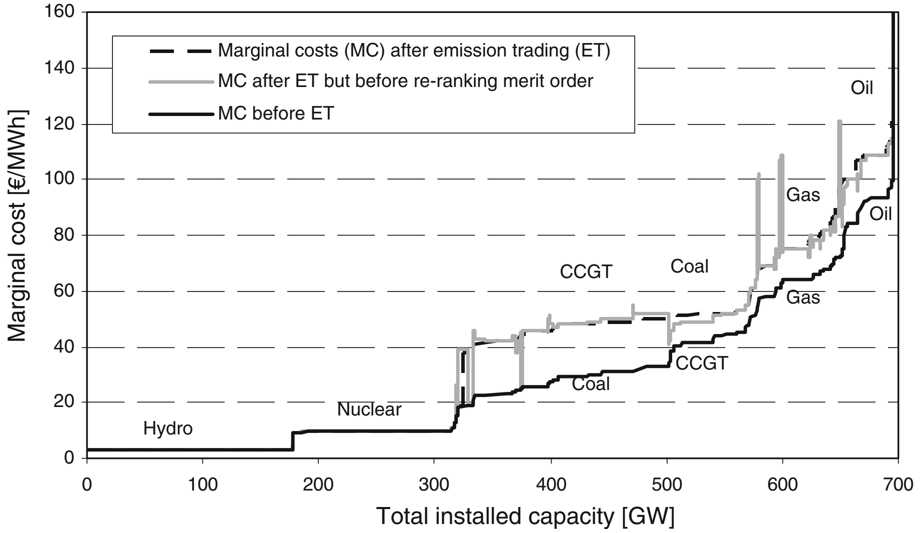

Fig. 7 ETS-induced changes in the EU-20 merit order at 20 €/t and 2006 fuel prices

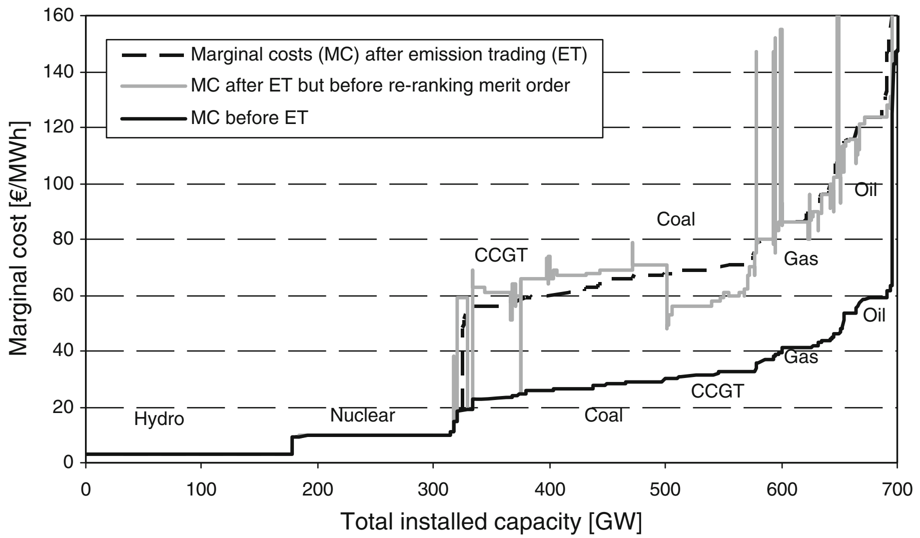

Fig. 8 ETS-induced changes in the EU-20 merit order at 40 €/t and 2006 fuel prices

line).[13] Since technologies on the right of the merit order run fewer load hours—or may even close due to a lack of demand/profitability—the carbon emissions of the technologies decline accordingly (i.e., the re-dispatch effect on carbon emissions discussed above). The decline in carbon emissions is further enhanced if power demand decreases in response to ETS-induced increases in electricity prices, resulting in even fewer operating hours for (more) carbon emitting technologies (i.e., the demand response effect, also outlined above).

[13] Some plants in the 300–400 GW installed capacity range are biomass-fired power plants with zero CO_2 emissions, whereas the spikes at around 600 GW represent some blast furnace gas fired power plants.

For illustrative purposes, Figs. 7 and 8 present shifts in the merit order of all generation technologies at the EU-20 level. But in practice (and in the COMPETES simulations), those plants are not dispatched in strict merit order because of transmission constraints. As a result, there are a variety of differentiated and (partially) integrated power markets across the EU-20 with different marginal technologies setting different levels of power prices in these markets, depending on the level of power demand, the mix of generation technologies and the transmission capacity of the countries involved. Consequently, shifts in merit order might not alter the actual dispatch because transmission limits might not allow the now-cheaper plants to expand production. Nevertheless, the figures showing merit orders at the EU-20 level are useful for illustrating the general significance of a shift in the merit order.

Whether a shift in the merit order occurs in particular markets or countries depends not only on the carbon price—or the relative fuel prices—but also on differences in the fuel mix—and carbon efficiency—of generation technologies within these markets or countries. At a carbon price of 20 or 40 €/t, the COMPETES model observes hardly any technology switching in Finland, Hungary, Portugal, Slovenia, Sweden and Switzerland. On the other hand, significant shifts in generation technologies occur in Germany and the UK, i.e., countries with a major share of both coal and CCGT technologies and, where at 2006 fuel prices, CCGT is nearly competitive compared to coal. In particular, the sum of fuel and CO_2 variable costs for CCGT fall below that for a significant amount of coal capacity, even at the lower CO_2 price of 20 €/t.

4.5 Changes in Profit

Table 4 presents estimates of ETS-induced changes in power generators' profits under various COMPETES model scenarios for the EU-20 as a whole.[14] Gross margins, the difference between power revenues and variable costs, are shown for each of the scenarios. Profit equals gross margin minus fixed costs, and is not estimated here since fixed cost estimates are not available. However, because short run changes in gross margin equal short run changes in profits, we can report profit differences among scenarios.

The table is based on the assumption that 90% of the CO_2 emissions of each power producer—and, hence 90% of its required allowances—are covered by free allocations, while the remaining 10% has to be bought on an auction or market. This distribution is generally consistent with Phase I allocation rules; however, post-2012, all allowances will be auctioned for most but not all countries, whereas Poland lobbied for exemptions.

Table 4 shows that, as expected, for scenarios with similar market structures and demand elasticities, generators' profits are higher when carbon prices are higher. Further, the table divides ETS-induced changes in power generators' profits into two effects:

- *The free allocation (FA) effect.* This effect on total firm profits results from the free allocation of emission allowances to power producers. It is equal to the economic rent of these allowances, i.e., the number of allowances received for free multiplied by the CO_2 price of these allowances.
- *The electricity price (EP) effect.* This effect on total firm profits results from ETS-induced changes in electricity prices, sales volumes and production costs—including abatement costs—assuming that all required allowances are bought at an auction or market. This effect is usually (highly) positive for low- or non-CO_2 producers

[14] For a discussion of ETS-induced changes in power generators' profits at the national and firm level under various COMPETES scenarios, see Sijm et al. (2008b).

Table 4 ETS-induced changes in total generators' profits at the EU-20 level under various COMPETES model scenarios

	Total gross margin estimated by COMPETES[a] [B€]	ΔGross margin (=ΔProfit) due to:			Percentage changes in gross margin due to:		
		EP effect [B€]	FA effect[a] [B€]	Total effect [B€]	EP effect [%]	FA effect[a] [%]	Total effect [%]
PCe0c0	72						
REF/PCc20	107	16	20	35	21.7	27.6	49.3
PCe0c40	147	37	39	75	50.9	53.7	104.6
PCe0.2c0	79						
REF/PCc20	107	8	20	28	10.4	25.0	35.4
PCe0.2c40	137	24	34	58	30.3	43.0	73.3
OCe0.1c0	163						
OCe0.1c20	188	7	18	25	4.5	11.0	15.5
OCe0.1c40	211	16	32	49	10.1	19.9	30.1
OCe0.2c0	117						
OCe0.2c20	141	7	18	24	5.9	15.0	20.9
OCe0.2c40	163	17	29	47	15.0	25.3	40.3

[a] Assuming that 90% of the emissions and, hence, 90% of the required allowances are covered by free allocations. This equals 0.9 times the emissions times the assumed price

who benefit from ETS-induced increases in power prices who expand their sales and earn greater gross margins on their production. On the other hand, this effect can be (substantially) negative for high CO_2 emitters who suffer from higher production costs that are not fully compensated for by increases in power prices—and whose output becomes less competitive.

Table 4 shows, for instance, that total power generators' profits in the EU-20 have been estimated by COMPETES to increase by 75 billion Euro (B€) (147 minus 72) in the perfect competition scenario with fixed demand and emissions trading at 40 €/t (PCe0c40) compared to a similar scenario without emissions trading (PCe0c0). Almost half of this increase is due to the introduction of emissions trading, regardless of the allocation method, while the remainder is due to the free allocation of CO_2 allowances.

In all scenarios with emissions trading—either including or excluding (90%) free allocations—operational profits of power generators in the EU-20 as a whole increase significantly compared to similar scenarios without emissions trading (i.e., scenarios with similar market structures and demand elasticities, but no carbon costs). Depending on the specific scenario considered, the percentage increase in gross margin due to the electricity price effect varies between 5 and 51%, while gross margin increases by an additional 11–54% owing to the free allocation effect. Half to two-thirds of the overall profit increase result from free allowances. However, even if all allowances were auctioned and none given away, generator gross margins at the EU-20 level still grow by 5–51%.

For scenarios with similar carbon prices and demand elasticities, increases in generators' profits are somewhat higher under perfect competition (PC) than oligopolistic competition (OC). This is due to two reasons. First, the COMPETES model assumes linear demand functions, implying that the pass-through rate of carbon costs to electricity prices is lower under OC than PC and, hence, the EP effect is smaller under OC. Second, since electricity prices are higher under OC (than PC), power demand is lower under OC (in the case of price responsive demand). This implies that power related emissions are also lower and, hence, that the size of the free allocation effect is smaller as well. In relative or proportional terms, the differences in profit changes between comparable PC and OC scenarios are even larger as the profits before emissions trading—i.e., the denominator of the equation—is usually much higher under OC than PC.

For scenarios with similar carbon prices and market structures, changes in generators' profits are generally higher under scenarios with lower demand elasticities. Once again, this is due to two reasons, similar to those outlined above: if the demand elasticity is lower, (i) the pass-through rate is higher (i.e., a stronger EP effect), and (ii) power demand is higher, due to a lower ability to reduce demand, resulting in more emissions and, hence, a higher level of free allocation (i.e., a stronger free allocation effect). The second effect would be modified if instead COMPETES was used to simulate a market in which a fixed number of allowances were allocated, trade was allowed with non-power sectors, and the allowance price was endogenous. In that case, instead of greater FA rents arising from more allowances being allocated under competition (as implicitly assumed here), greater rents from free allocation would occur because the allowance price would likely be higher because of the greater effective demand for allowances under PC compared to OC.

5 Conclusions

COMPETES EU20 is a bottom-up model to simulate and analyse the impact of strategic behaviour of large power producers on the wholesale power market in 20 European countries under different market structures. These structures vary from perfect competition to Cournot oligopolistic market conditions, as well as different price elasticities. Because of its detailed representation of generation plant capacities and fuel costs, COMPETES can be used to analyse the implications of emissions trading on the market. Here, we have considered the effects of different carbon prices scenarios upon power prices, CO_2 emissions, and generator profits in 20 European countries.

Our major findings include:

- Wholesale power prices increase significantly due to CO_2 emissions trading under all scenarios considered. In the case of a CO_2 price of 20 €/t, these increases are generally highest in coal-intensive Poland (19 €/MWh, assuming that producers recognized the opportunity cost of allowances when bidding and making operating decisions) and lowest in hydro-intensive Norway (1–10 €/MWh). For the EU-20 countries, on average, the increase in wholesale power prices is estimated at 10–13 €/MWh, i.e., an increase of about 12–27% compared to wholesale power prices before emissions trading.
- Estimates of the pass-through rates (PTRs) are generally high. Most of these rates vary between 70 and 90%, depending on the country, market structure, and demand elasticity considered. In general, the PTR is lower in scenarios with a higher price elasticity and higher in scenarios characterised by perfect competition, consistent with the results for simple single-market models with linear demand and supply in which carbon trading causes a constant upward shift in marginal costs (Chen et al. 2008).
- Emissions trading and the resulting pass-through of carbon cost to electricity prices reduce CO_2 emissions significantly by affecting not only producers' decisions—through a re-dispatch or change in the merit order of generation technologies—but also consumer decisions, i.e., through reducing power demand in response to ETS-induced increases

in electricity prices. For instance, under perfect competition and a price elasticity of demand of 0.2, a carbon price of 20 €/t leads to an emission reduction of more than 210 Mt, of which more than 80 Mt is due to demand response and the rest to re-dispatch. At a carbon price of 40 €/t, total abatement grows to 363 Mt, of which almost 230 Mt is attributed to demand response. Therefore, if power demand is price responsive (notably in the medium or long run), the pass-through of carbon costs to higher electricity prices for end-users can be a major contributor to the goal of reducing CO_2 emissions in the medium or long term.

- In all scenarios with emissions trading—either including or excluding free allocations—operational profits of power generators in the EU-20 as a whole increase significantly compared to similar scenarios without emissions trading. This implies that even if all allowances were auctioned (or, equivalently, a tax equal to our assumed allowances price was imposed), power operators' profits would still improve at the EU-20 level. However, individual firms ay see decreases in profits because of variations in carbon intensity of their generators.

An area of future research would be to extend the COMPETES model with endogenous CO_2 prices, where firms may also exercise market power to influence the price setting in the EU ETS. This extension would also open the way to study more closely the impact of auctioning CO_2 permits on the performance of the EU power sector. Nevertheless, we hope that this paper has added to an understanding of the influence of adding a CO_2 cost to pricing in the power market.

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