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ORIGINAL ARTICLE

Implications of CO_2 emissions trading for short-run electricity market outcomes in northwest Europe

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Abstract We examine the short-run implications of CO_2 trading for power production, prices, emissions, and generator profits in northwest Europe in 2005. Simulation results from a transmission-constrained oligopoly model are compared with theoretical analyses to quantify price increases and windfall profits earned by generators. The analyses indicate that the rates at which CO_2 costs are passed through to wholesale prices are affected by market competitiveness, merit order changes, and elasticities of demand and supply. Emissions trading results in large windfall profits, much but not all of which is due to free allocation of allowances. Profits also increase for some generators because their generation mix has low emissions, and so they benefit from electricity price increases. Most emission reductions appear to be due to demand response, not generation redispatch.

Keywords Electric power markets · Emissions trading · Carbon dioxide emissions · European Union Emissions Trading System · Cap-and-trade programs

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1 Introduction

In an effort to achieve the Kyoto Protocol emission reduction targets, the European Union (EU) implemented a CO_2 Emissions Trading Scheme (ETS) in January 2005 (Parker 2006). In the ETS, which is similar to the US SO_2 trading program, facilities in power or other energy-intensive sectors in 27 EU countries must hold sufficient permits to cover their annual emissions. Each member state allocates a fixed number of allowances among installations based on their respective National Allocation Plans (NAPs). The underlying assumption is that the ETS will enable firms with high costs for reducing CO_2 emissions to purchase allowances from lower cost firms with excess allowances, benefiting both buyers and sellers. In theory, such cap-and-trade programs will minimize the cost of achieving a given emission reduction target (Stavins 1995; Newell and Stavins 2003).

Under the current EU Directive, CO_2 allowances are, for the most part, given at no cost to covered installations (EC 2003). Nevertheless, in theory, the CO_2 costs will be treated as opportunity costs when calculating short-run production costs, since unused allowances can be sold. This opportunity cost would therefore affect power prices even when allowances are allocated gratis to generators (Burtraw et al. 2002).[1,2] Two important questions concern the extent to which CO_2 costs would be passed on to power prices, and second, the effect of those price changes on generator profits.[3]

A number of studies examined the effect of the EU ETS on the EU power sector (Wals and Rijkers 2003; Sijm 2004; Linares et al. 2006; Lise and Kryseman 2007). Linares et al. (2006) develop an oligopoly electricity market model with capacity expansion to assess the impacts of the ETS on the Spanish electricity sector over 2005–2014. This model determines endogenously allowance prices using a residual (non-power sector) demand curve for allowances. Linares et al. conclude that power prices could increase by 20% and substantial windfall profits would be earned by power generators, especially for inframarginal producers owning low CO_2 capacity. In contrast, our paper focuses on determining the factors that affect the level of CO_2

[1] However, under a regulated cost-plus pricing regime, retail electricity tariffs are designed to cover all capital, fuel and other operating expenditures plus a predetermined return to capital (Keats and Neuhoff 2005). In that case, the opportunity cost of free allowances would not be a recoverable part of production costs, since it is not a cash expenditure.

[2] The extent to which emissions costs will be added to power prices is less of an issue for other emission trading programs, such as the US SO_2 trading program (USEPA 2006a) and NO_x under the State Implementation Plan (SIP) Call program (USEPA 2006b). This is, in part, because SO_2 emission rates for typical peaking marginal units, such as natural gas combustion turbines, are relatively low; hence, the impact of emissions costs on power prices would be relatively small, at least during high demand periods. However, when coal plants with high SO_2 and NO_x emissions rates clear the markets during off-peak periods, significant SO_2 and NO_x costs could pass through to power prices.

[3] While the conventional meaning of windfall profits refers to just the value of economic rent from some fixed asset such as free allowances (always non-negative), this paper uses a broader definition that also includes any changes in profit due to changes in production costs and sales revenue (either positive or negative).

cost pass-through in the short-run, considering interactions of the ETS with transmission constraints. Further, we examine differences in how firms with various generation mixes respond to EU ETS; Linares et al. (2006) instead emphasize aggregate electricity effects under various allowances allocation schemes in the long-run without considering transmission.

In another study, Lise and Kryseman (2007) investigate the long-run implications of the EU ETS in relation to various pollutants under competitive and oligopoly markets using a recursive dynamic model for the northwest European electricity market. Simulation results indicate that both consumers and the environment can benefit from a competitive market compared to an oligopoly market because of lower power prices and lower SO_2 and NO_x emissions. This is mainly due to the earlier installation of gas-based technologies.

Our study focuses instead on short-run (fixed capacity) market outcomes. Two previous studies explore the potential impacts of the EU ETS on short-run electricity prices (Wals and Rijkers 2003; Sijm 2004). (Newcomer et al. 2008 report a similar analysis for US power markets.) The first ETS study uses the COMPETES model (Comprehensive Market Power in Electricity Transmission and Energy Simulator) to estimate the magnitude of ETS-induced power price increases using 2002 data (Wals and Rijkers 2003). The analysis concludes that the response of power prices to ETS is positively associated with carbon intensity in the generation mixes. The highest impact would occur in coal-intensive German markets and the least in nuclear-intensive France.[4] However, fuel costs and ownership have changed significantly since 2002. The second study (Sijm 2004) identifies factors that would affect electricity prices under emissions trading. This study concludes that the three most important factors in determining the magnitude of the increase in power prices are the level of the ETS allowance price, the CO_2 emission rate of marginal sources of power, and the degree to which producers will pass on marginal CO_2 costs to power prices.

More recently, Bonacina and Guilli (2007) present a theoretical auction model to examine power pricing under ETS, assuming a dominant firm and a competitive fringe. They consider three types of generating technologies: coal, combined-cycled gas turbine, and combustion turbine. Their findings are consistent with our prediction that CO_2 costs would be completely passed on to electricity prices when the market is competitive. When markets are less competitive, the pass-through could exceed 100% when there is excess capacity of non-coal plants and the market share of the most polluting plants (i.e., coal) is sufficiently low. This model was not calibrated to actual EU supply and demand conditions, however, and did not consider transmission.

The present paper addresses three broad issues. First, we explore possible reasons for the power price increases that were actually experienced after the introduction

[4] Although the number of studies on the impact of the EU ETS on the power sector has grown rapidly over the past 2 years, except for a few studies, empirical evidence on the impact of the EU ETS on electricity prices is still limited (e.g., Levy 2005; Honkatukia et al. 2006; Sijm et al. 2006a). Levy (2005) found that CO_2-induced effects increased wholesale power prices by 1–11 and 1–7 €/MWh for French and German markets, respectively. Sijm et al. (2006a) concluded that approximately 60–100% of CO_2 costs have been passed on to German and Dutch wholesale power markets in 2005. Honkatukia et al. (2006) examined the first 16 months of the EU ETS, and found that on average 75–95% of CO_2 costs were passed on to the Finnish Nord Pool day-ahead wholesale prices.

of the EU ETS. To do so, we use two approaches. In the first, we develop simple models to consider how market competitiveness along with elasticities of demand and supply affect cost pass-through. In the second approach, the COMPETES model calibrated with recent supply and demand data is used to examine how factors that cannot be considered in simple models—namely heterogeneous generation mixes and emissions rates, transmission congestion, and changes in merit order[5]—could interact in the northwest European market and influence CO_2 cost pass-through rates in 2005. Since COMPETES covers the power sector in only 4 out of 27 participating countries (see Sects. 4.1–4.2), the CO_2 allowances price is modeled as an exogenous input with a fixed price.[6] The model is used to estimate CO_2 pass-through rates, and examine the reasons why generators with different carbon intensity and pricing strategies (price-taking or oligopoly) respond to emissions trading differently. In particular, the Cournot assumption serves as a bounding case in the oligopoly scenarios.

The second issue addressed by this paper concerns the amount of ETS-induced windfall profits that could be earned by generating companies in northwest Europe, and the contribution of allowances rents to those profits. This is analyzed using COMPETES. The third and final issue concerns the sources of ETS-induced emission reductions. Using COMPETES, we decompose those reductions into those that are due to shifts in the generators' merit order as a result of changes in their marginal cost and those due to elasticity-induced reductions in power consumption.

The rest of this paper is organized as follows. In Sect. 2, background is provided on the EU ETS. In Sect. 3, theoretical analyses concerning CO_2 pass-through rates are undertaken with simple models. In Sects. 4 and 5, we analyze ETS-induced effects on power prices, CO_2 emissions, and generators' profits and average emissions rates using the COMPETES model for the northwest European electricity market. The model is summarized in Sect. 4.1. Background information on the electricity market simulated is presented in Sect. 4.2. Pass-through rates are defined in Sect. 4.3, followed by a summary of assumptions of the model runs in Sect. 4.4. Section 5 presents the estimates of the CO_2 pass-through rates and other COMPETES results. The latter include the effect of market structure, demand elasticities, and emissions trading on power prices, profits, consumption and CO_2 emissions, as well as a decomposition of the sources of emissions reductions. Conclusions are presented in Sect. 6.

[5] The production merit order is an ordering of a set of generators based on their marginal production costs. If there is neither market power nor any constraints except market clearing and generator capacity limits, the least-cost production involves first dispatching the generator with lowest marginal cost, followed by the next lowest generator in the merit order and so forth until the demand is met (Stoft 2000). Out-of-order dispatch occurs in real power systems because of market power as well as transmission and unit commitment considerations, such as ramp rate limits and start-up costs.

[6] An alternative approach would be to endogenously solve for the price using a power market model covering all 27 participants in the EU ETS, as well as accounting for opportunities to trade credits with other economic sectors of the EU ETS and with JI/CDM countries outside the EU ETS. Such an analysis is beyond the scope of the COMPETES model and the present paper.

2 Background on the EU ETS

The goal of the EU ETS is to reduce EU CO_2 emissions to 8% below 1990 levels by 2012. The ETS is implemented in two phases: 2005–2007 and 2008–2012, where the second phase is the commitment period of the Kyoto Protocol. The EU ETS covers 27 countries with about 12,000 installations, including energy-production facilities such as power utilities and oil refineries as well as energy-intensive industries such as iron, steel, paper and minerals. In particular, generators with a rated thermal capacity greater than 20 MW (except hazardous or municipal waste installations) fall under the cap. The total emissions covered are roughly 2.2 Gtons/year of CO_2. For the EU as a whole, allowances to the power sector account for approximately 55% of total allowances in the first phase (McKinsey and Ecofys 2006; Levy 2005). In the first phase, approximately 95% of allowances were distributed to installations for free, while the remaining were sold by auction. The amount of allowances to be auctioned is to be increased to 10% in the second phase (Parker 2006). In 2005, the EU ETS reported 362 million tons of allowance trading (or 14.5% of the total allowance allocation) with a financial value of 7.2B€ (Bellemare 2006).

In addition, Emission Reduction Units (ERUs) and Certified Emission Reductions (CERs) generated from the Kyoto Joint Implementation (JI) and Clean Development Mechanism (CDM) are also alternative sources of allowances under the EU Linkage Directive. While member states can convert CERs into ETS allowances in 2005–2007, the conversion of the ERUs associated with JI projects will not be allowed until the second phase of the EU ETS (2008–2012). The maximum number of credits that can be imported from ERUs and CERs is up to the member governments to determine. At the time of writing, transactions associated with ERUs play only a small role in overall compliance (Hasselknippe and Ronie 2006).

3 Theoretical relationships of CO_2 costs to short-run power prices

In theory, the magnitude of changes in short-run power prices as a result of emissions trading depends on various factors, including marginal emissions rates, demand elasticity, and market structure. If the CO_2 emission rate of the marginal source of power is zero, the power price will remain unchanged if the market is perfectly competitive, even if inframarginal generating units incur CO_2 costs. On the other hand, if the marginal units have the highest emission rates, then power prices can rise by more than the average cost per MWh of allowances. As for demand response, it will suppress power consumption if prices rise, resulting in net price increases that only partially reflect the cost of emissions allowances to marginal generation sources.

This section examines the level of CO_2 pass-through analytically. Pass-through is defined as the ratio of the changes in the price of power to the changes in marginal costs due to emissions trading. In particular, we consider power demand and supply curves with constant elasticities—ε and $1/b$ respectively, where both ε and b are greater than zero. We also consider the effect of relaxing the constant-elasticity assumption by allowing either or both linear supply and/or demand. The competitiveness of a market is characterized by the number of symmetric firms in the market (N). The

Table 1 Cost pass-through under constant and linear curve assumptions: theoretical results

	Both constant-elasticity (CE)	CE demand, linear supply[a]	Linear demand, CE supply	Both linear
Demand elasticity (ε)	−	−	−	−
Supply elasticity ($1/b$)	+	+	+	+
Number of firms (N)	−	−	+	+

[a] $N\varepsilon > 1$; if $N\varepsilon \leq 1$, there is no finite price equilibrium, as demand becomes so inelastic that firms would push prices to infinity

result of emissions trading is simulated by an infinitesimal change in production cost ΔC €/MWh (= emissions rate [ton/MWh]×allowance price [€/tCO_2]).

Table 1 summarizes our theoretical results concerning the level of CO_2 cost pass-through under linear and constant-elasticity curves. Proofs are in the appendices. A plus + (minus −) sign indicates that CO_2 cost pass-through increases (decreases) with an increase in the given factor.

In general, whereas increases in demand elasticity (ε) would reduce the level of cost pass-through, a higher supply elasticity (b) has the opposite effect. However, the effect of the number of firms (N) depends on whether linear or constant elasticity demand is assumed. This ambiguous result arises because increasing N under linear demand leads to lower prices, which shifts the solution to a less elastic region of the demand curve, which in turn increases the pass-through rate. In other words, the effect of a lower demand elasticity more than offsets the pure effect of a lower N.

Some special cases of linear demand/supply cases are summarized as follows. First, given fixed demand (i.e., zero elasticity), the pass-through is 100% when market is perfectly competitive ($N = \infty$). Second, when the supply is perfectly elastic (i.e., flat line), the pass-through is again 100%. Third, when demand is constant-elastic but supply is linear, the level of cost pass-through is $\Delta CN\varepsilon/(N\varepsilon - 1)$ for an infinitesimal ΔC, and pass-through is >100%—i.e., price rises by more than the cost of CO_2 (Appendix A.2). Fourth, if demand is linear and supply is perfectly elastic, the cost that is passed on to price is $\Delta CN/(N + 1)$ for a small ΔC (Appendix A.4).[7]

To provide some insight on these results, we graphically examine the linear supply and demand case (i.e., last column) under the polar cases of competition and monopoly in Figs. 1 and 2, respectively. We continue to assume that the ETS leads to a ΔC €/MWh increase in marginal cost, and there is no change in the merit order. For comparison purposes, this graphical analysis assumes the same pre-emissions trading equilibrium for all demand elasticities. Thus, the demand curves intersect the original supply curve at the same point, and the effect of changing the elasticity assumption is to rotate the demand curve around the original equilibrium point.

[7] Kate and Niles (2005) look at pass-on of costs savings as a consequence of mergers. They derived a similar result using a framework that allows for asymmetric firms, quadratic cost functions and convex demand curves. They find that if cost-savings are industry-wide, the savings passed-through are proportional to $N/(N+1)$. This finding is consistent with our constant-elastic supply/linear demand result, but for more general conditions.

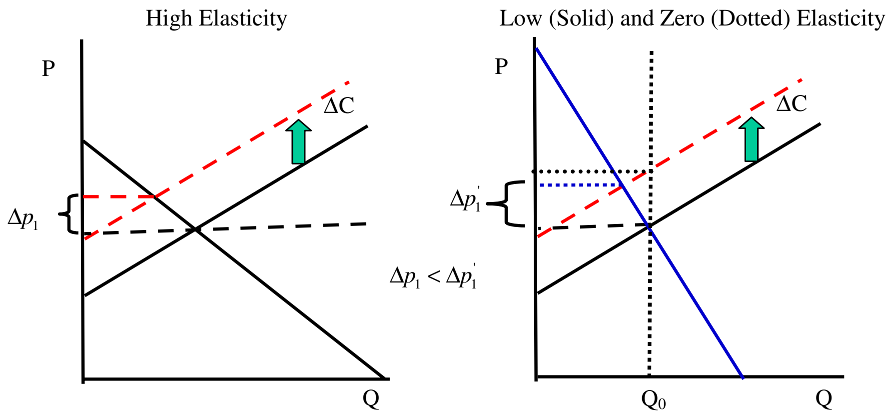

Fig. 1 Effect of demand elasticity on pass-through rate under perfect competition

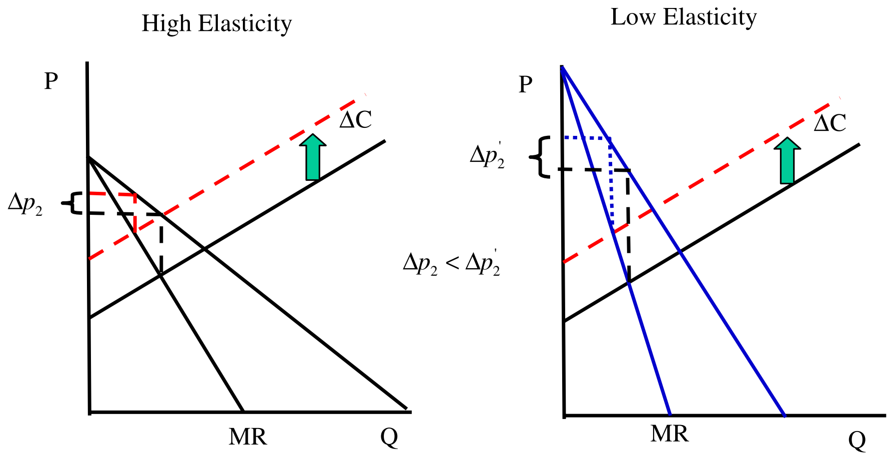

Fig. 2 Effect of demand elasticity on pass-through rate under monopoly case

Figures 1, 2 suggest that a low demand elasticity is associated with a higher pass-through rate regardless of market structure (i.e., $\Delta C > \Delta p_1' > \Delta p_1$ in Figs. 1 and 2 for the competitive and monopoly cases, respectively, where the prime indicates a less elastic demand curve). As an extreme case when demand is fixed under competition (Fig. 1, right), $\Delta p = \Delta C$, and all ETS-induced economic rents ($= Q_0 \times \Delta C$, because allowances are free) are earned by generators at the expense of consumers. The same conclusions are reached when examining the pass-through of taxes to prices under constant elastic demand (Varian 1999).

The results in Table 1 are based on a set of restrictive assumptions. The analysis does not account for other crucial factors in electricity markets, such as transmission congestion between regions with different fuel mixes and costs or emission cost-induced changes in the "merit order" (see footnote 5, *supra*). In theory, when transmission lines connecting two regions are fully used, each region will have its own marginal source of power supply and its own power price; thus, the amount of emissions costs added on to power prices could differ over space. As for merit order, if emissions costs are high enough, the marginal generating unit could change, even if the quantity demanded is unaltered. The price increase could then be much more, or much less than, the allowances cost for the marginal units. Thus, the extent to which CO_2 costs will be passed on to electricity prices is the result of a complex interplay of a number of factors, which we turn to next.

4 Analysis using COMPETES model: background and assumptions

4.1 Summary of COMPETES

COMPETES is a computational equilibrium model that simulates short-run (i.e., fuel and variable costs) competition in the electricity market.[8] The suppliers can be modeled as price takers or strategic producers that exercise market power *a la* Cournot.[9] However, regarding the price of transmission, all suppliers behave as price takers. COMPETES embeds two types of transmission schemes: a path-based system (in which interfaces between countries are priced and sold) and nodal pricing which considers parallel flows that result from a linearized DC network based on Kirchhoff's laws (Hobbs and Rijkers 2004). Because the path-based system is the most binding constraint in the study area, our analysis considers only that form of congestion pricing. An independent system operator (ISO) is modeled who is assumed to allocate interface and transmission capacity efficiently. This conforms with the competitive market environment in northwest Europe. The consumers in the model are represented by linear demand curves. Annual load is represented by 12 demand periods, with four periods for each of three seasons, i.e., Fall/Spring, Winter and Summer.

The formulation of COMPETES is based on deriving a market equilibrium using the first-order conditions for the maximization problems for the transmission system operator and each of the suppliers, and combining them with market clearing conditions (Hobbs and Rijkers 2004). The conditions under which this type of model yields a unique solution have been proven elsewhere (Metzler et al. 2003). COMPETES has previously been used to assess the interactions of transmission and electricity markets (Hobbs et al. 2004) and benefits of market coupling (Hobbs et al. 2005).

The model was first calibrated using 2002 data (Hobbs et al. 2004) and later updated to 2005. In particular, fuel costs by type of generation and by countries are based on various public and proprietary sources, including the International Energy Agency,

[8] For more details on the COMPETES model, see Sijm et al. (2005) and Hobbs and Rijkers (2004).

[9] Various forms of Nash games have been assumed in simulating strategic behaviors in electricity markets: Cournot (i.e., quantity as the strategic variable), Bertrand (i.e., price) and supply function equilibrium (i.e., both quantity and price in the form of bid functions). There is considerable debate in the literature over which game better describes strategic behavior in those markets. Perfect competition and Cournot assumptions provide the most and least competitive market conditions, respectively, and have been commonly used to estimate the lower and upper bounds of possible power prices (Bushnell et al. 2008). Therefore, we adopt the Cournot model as bounding case for the effects of strategic behavior. The final advantage of the Cournot methodology is computational convenience, which has made it the most common oligopoly model for network-constrained power markets (e.g., Yao et al. 2008).

Eurostat, and Platts. Generating characteristics are obtained from Utility Data Institute data. Ownership data are updated to 2005 based upon company annual reports. Hourly demands used to construct inverse demand curves are based on information from Union for the Coordination of Transmission of Electricity. The transmission capacity between countries is from the European Transmission System Operators.

4.2 Northwestern EU electricity market

COMPETES simulates the northwest continental European wholesale power markets, including Belgium, France, Germany and the Netherlands. These four countries each have power exchanges that serve as the platforms for electricity trades (e.g., APX for the Netherlands, EEX for Germany). When interfaces between countries are not congested, all four countries should be economically equivalent to a single market since transmission does not limit electricity trade. In contrast, if interfaces into a country are congested, its power exchange is a market by itself and isolated from other countries. That is, external suppliers cannot increase their net supply to that isolated market in response to prices changes. For instance, while the Belgian-Dutch interface is rarely congested, the Dutch import interfaces with Germany and the Belgian import interfaces with France are congested more than 90% of the time. Consequently, the Low Countries are isolated from French and German prices at least 90% of the time, and those countries often behave as a single and isolated market.

The total market is relatively concentrated with a Herfindahl-Hirschman Index of more than 1900 if measured by capacity ownership. This is due to the dominant role of Electricité de France (EdF). Given that transmission constraints among these four countries often limit trade (Harris et al. 2003), the effective concentration in local markets is much larger in France and Belgium and lower elsewhere (Moselle et al. 2006).

Table 2 summarizes the ownership of generation and the respective capacity-weighted CO_2 emission rates in the study region in 2005. The total generation capacity is almost 260 GW. Based on ownership data, the regional power market comprises 11 major firms with capacity shares between 1% and 39%. Other, smaller generating companies in each country are collectively represented in COMPETES by a single "competitive fringe". Market structure varies by country, with France the most concentrated and Germany the least. Because of significant between-country transmission constraints, market power could possibly occur in small, relatively concentrated markets such as the Netherlands and Belgium (Harris et al. 2003; Scheepers et al. 2003; EC 2007).

The capacity-weighted CO_2 emission rate varies between 0 and 970 kg/MWh among the generating companies, reflecting their diverse generation mixes. Nationale Du Rhone has the lowest rate since all its capacity is hydropower, while the highest is STEAG AG, with 99% of its capacity being coal-fired. The overall average is 410 kg/MWh.

4.3 Definitions of pass-through rates

Here, pass-through rate measures the degree to which the incurred CO_2 costs are passed on to power prices. Various definitions of pass-through rate have been proposed. For

Table 2 Generation capacity, market shares and capacity-weighted CO_2 emission rates of companies included in COMPETES

Firm	Capacity (MW)	Market share in the four countries (%)	Capacity-weighted emission rate (kg/MWh)
Competitive Fringe Belgium	1,930	1	379
Competitive Fringe France	9,307	4	598
Competitive Fringe Germany	21,195	8	758
Competitive Fringe Netherlands	1,977	1	759
E.ON Energie AG	29,905	12	466
Electrabel SA	17,797	7	399
Electricité de France	99,659	39	118
Energie Baden-Wurttemberg ENBW	10,671	4	360
Essent Energie Productie BV	6,129	2	676
Nationale Du Rhone	3,377	1	0
NUON NV	3,766	1	920
RWE Power	27,586	11	675
SOC Production D'Elec (SPE)	1,530	1	520
STEAG AG	4,169	2	970
Vattenfall Europe AG	16,904	7	785
Total/Average	255,901	100	410

instance, an absolute pass-through rate has been defined as the ratio of the change in the power price to the change in the marginal cost of the marginal power source (Kate and Niles 2005), consistent with the definition used in the simple models of Sect. 3. On the other hand, Stennek and Verboven (2001) define a relative pass-through rate as the percentage change in the power price divided by the percentage change in the marginal costs. Below, we define two types of rates, where the definition of the marginal pass-through rate conforms to the absolute pass-through rate of Kate and Niles (2005):

$$\text{Average pass-through rate (APR)} = \frac{\overline{P}_1 - \overline{P}_0}{\overline{C}} \tag{1}$$

$$\text{Marginal pass-through rate (MPR)} = \frac{\overline{P}_1 - \overline{P}_0}{\overline{MC}_1} \tag{2}$$

APR (1) is the ratio of the average increase in power prices ($\overline{P}_1 - \overline{P}_0$) to the average CO_2 cost per MWh ($\overline{C}$), where $\overline{P}_1$ ($= \sum_{t \in T} s_{1t} p_{1t} / \sum_{t \in T} s_{1t}$) and $\overline{P}_0$ ($= \sum_{t \in T} s_{0t} p_{0t} / \sum_{t \in T} s_{0t}$) are the sale-weighted power prices with and without ETS, respectively. The subscript t refers to the 12 demand periods simulated in COMPETES. Each country or the EU4 as a whole (including Belgium, the Netherlands, France and Germany) can have its own pass-through rate when congestion causes prices to separate between markets. The term s_{1t} (s_{0t}) is the total power sales in period t with (without) emissions trading. The term $\overline{C}$ in €/MWh is the output-weighted average CO_2 cost, equaling the product of output-weighted average CO_2 emission rate [ton/MWh] and CO_2 allowances price [€/ton CO_2]. This also equals the total value of emissions allowances in € divided by total power production in MWh.

The APR (1) is useful for assessing the distribution of economic rents associated with (free) allocation of allowances. These rents equal the price of allowances times the quantity of allocated allowances. If all allowances are given away to generating plants, and if APR equals unity, then these rents are entirely retained by generators (if the quantity demanded does not change). An APR less than one means that some rents are passed on to consumers, as the price increase does not reflect the entire opportunity cost of allowances. Meanwhile, APR > 1 means that prices increase by more than the value of the rents, so generator profits increase even if they have to pay for allowances.

In contrast, the MPR (2) measures the marginal effect of CO_2 cost on power prices, where the term $\overline{MC}_1$ $(= \sum_{t \in T} s_{1t} MC_{1t} / \sum_{t \in T} s_{1t})$ is the sales-weighted marginal CO_2 cost. If it is assumed that the market is competitive (price = marginal cost) and supply is perfectly elastic or demand is perfectly inelastic, then, as in Sect. 3, the marginal pass-through rate would be equal to one.

Two aspects of network-constrained markets complicate the calculation of pass-through rates. First, estimation of total country-by-country CO_2 emissions becomes arbitrary because the source of imported energy, and thus its CO_2 emissions, cannot be determined unambiguously. For simplicity, we assume that the emissions rate of energy imported by a given country is the output-weighted emissions rates of the neighboring countries with a direct transmission linkage.

Second, imperfect competition makes identification of marginal power sources, and thus marginal costs, nontrivial. In principle, a marginal source must be a "basic" generation unit (i.e., one operating strictly between its lower and upper capacity bounds).[10] When there is no transmission congestion and the market is competitive, there would be only one marginal unit that determines power prices for the entire region, save for the unlikely case in which two units have exactly the same marginal cost and are marginal. But when there is market separation due to network congestion or when markets are oligopolistic, there could be multiple marginal units that are not operated at their full capacity, and thus affect power prices. If a marginal unit is owned by a strategic firm, then the power price will exceed its marginal cost by the amount of markup. The marginal unit for a market could also be located in elsewhere if the interface connecting two regions is uncongested.

4.4 Scenario assumptions

We use 17 scenarios to quantify how the elasticity and competitiveness factors analyzed in Sect. 3 affect CO_2 cost pass-through rates in northwestern Europe (Table 3). In particular, the COMPETES analysis simulates three values of demand elasticity (i.e., 0.0, 0.1 and 0.2),[11] three possible CO_2 allowance prices (*i.e.*, 0, 10 and 20 €/tCO_2), and three market structures. Our assumptions concerning short-run elasticity are within

[10] Theoretically, if N transmission constraints are binding, at most $N + 1$ units are basic (marginal) in a competitive market, but even more are possible in oligopoly markets. Thus, when two or more marginal units are associated with a given price in an oligopoly market, the overall marginal cost associated with this price is obtained as the average of those units' marginal costs, weighed by the generation of those units.

[11] Note that this is the elasticity measured for wholesale prices; given a fixed markup for distribution costs, this translates into larger elasticities for retail prices. This is the elasticity at the competitive equilibrium.

Table 3 Summary of scenarios assumptions in COMPETES simulations

Scenarios	CO_2 price [€/tCO_2]	Elasticity	Description
PC0-0.2	0	0.2	Perfect competition (By definition, the same as PC0-0.1)
PC10-0.2	10	0.2	Perfect competition
PC20-0.2	20	0.2	Perfect competition
SA0-0.1	0	0.1	Oligopoly, EdF a price taker in France
SA10-0.1	10	0.1	Oligopoly, EdF a price taker in France
SA20-0.1	20	0.1	Oligopoly, EdF a price taker in France
SA0-0.2	0	0.2	Oligopoly, EdF a price taker in France
SA10-0.2	10	0.2	Oligopoly, EdF a price taker in France
SA20-0.2	20	0.2	Oligopoly, EdF a price taker in France
ST0-0.1	0	0.1	Oligopoly, EdF exercises market power in France
ST10-0.1	10	0.1	Oligopoly, EdF exercises market power in France
ST20-0.1	20	0.1	Oligopoly, EdF exercises market power in France
ST0-0.2	0	0.2	Oligopoly, EdF exercises market power in France
ST10-0.2	10	0.2	Oligopoly, EdF exercises market power in France
ST20-0.2	20	0.2	Oligopoly, EdF exercises market power in France
LP10	10	0.0	Perfect competition, demand fixed at PC0 level
LP20	20	0.0	Perfect competition, demand fixed at PC0 level

the range of empirical estimates, such as −0.2 (Bohi and Zimmerman 1984), −0.05 (Crowley and Joutz 2005) and −0.28 (Espey and Espey 2004). Likewise, the levels of allowance costs are also within the range of actual prices experienced in 2005:8–30 €/tCO_2 (Convery and Redmond 2007). Prices have fallen since then, but that is because of the expectations of a surplus of allowances through the end of Phase I (2007); the earlier, higher prices are anticipated to be more representative of prices that are likely to be experienced in the future.

The competitive scenarios are labeled in the results tables as scenarios "PC$p-\varepsilon$", where "p" is the assumed price of allowances and "ε" is the assumed price elasticity of demand. The two oligopoly scenarios differ in the assumptions about the behavior of Electricité de France (EdF) in the French market. We assume that although EdF is a near-monopoly in France, its electricity price is de facto limited by an implicit threat of regulation from the French government so that it cannot exercise all the market power it possesses in the local electricity market (Hobbs et al. 2004). Thus, this analysis models EdF as a price taker under the first set of oligopoly scenarios, designated as "SA$p-\varepsilon$ " in the results tables (again, "p" is the allowance price and "ε" the demand elasticity). As a comparison, we also examine EdF's potential impact on power prices and pass-through rate by allowing it to become a strategic player in the French market in the second set of oligopoly scenarios, designated as scenarios "ST$p-\varepsilon$." Two additional runs, LP10 and LP20, are formulated as linear programs (LPs) with fixed nodal demand at the PC0-0.2 level. These runs allow us to quantify the amount of CO_2 reduction due just to generator redispatch under CO_2 allowances

Footnote 11 continued
Since linear demand is assumed in COMPETES, the elasticity is greater under the higher prices resulting from the oligopoly solutions.

prices of 10 and 20 €/tCO2, respectively. Finally, there is no scenario combining zero elasticity with strategic behavior, because that would lead to infinite prices under the Cournot assumption.

In summary, a total of 17 scenarios are analyzed in which five scenarios represent perfect competition (two assume demand is fixed, the others elastic demand) and 12 scenarios represent oligopoly conditions (EdF is a price taker in 6 of these scenarios, behaving *a la* Cournot in the other 6.)

5 Results of COMPETES simulations

5.1 Effects of demand elasticity, market structure, and emissions trading on power prices, consumption, and CO_2 emissions

5.1.1 Effects of demand elasticity and market structure on power prices

Less elastic demand enhances the ability of Cournot firms to raise power prices above competitive levels.[12] For instance, power prices increase by 27.8, 46.3, 17.5 and 40.9 €/MWh (36, 56, 36 and 69%) under ST10-0.1 compared to ST10-0.2 for the Dutch, Belgian, German and French markets, respectively. As for market structure, when markets are modeled competitively, power prices are generally the highest in the Netherlands and lowest in France. In contrast, under the oligopoly scenarios (i.e., SA and ST), power prices are generally highest in the concentrated Belgian market and lowest in Germany.

5.1.2 Effects of emissions trading on power prices

Emissions trading significantly increases power prices under each scenario. The highest impact is in Germany and the lowest in France, partly reflecting the fact that those countries have relatively high and low CO_2 emission rates, respectively. For instance, under a CO_2 cost of 20 €/tCO_2 and an elasticity of 0.2, French power prices increase by only 1.8 €/MWh (9.6%), 1.2 €/MWh (6.7%) and 1.3 €/MWh (2.2%) for scenarios PC, SA and ST, respectively, since nuclear or hydro plants are often on the margin there. In contrast, for the German market, the increases are 14.7 €/MWh (52.1%), 13.4 €/MWh (31.5%), and 13.5 €/MWh (31.4%), respectively, as coal is often that market's marginal power source. The Belgian and Dutch price effects lie between these extremes. Qualitatively, similar conclusions about relative effects across countries also hold for the 0.1 demand elasticity scenarios.

Consistent with results from the simple models of Sect. 3 (Table 1), ETS-induced electricity price increases (at a constant CO_2 price) are higher under perfect competition than oligopoly. For instance, in Belgium, the level of power price increase is 6.1

[12] Except of an under-prediction of power prices in French market, power and allowances prices under PC20-0.2 are to some extent consistent with the empirical spot prices experienced in 2005. For instance, the reported average spot price for Belgium, the Netherlands and Germany is 47, 47 and 46 €/MWh, respectively. The reason is that COMPETES simulates competition based on short-run marginal cost, while in reality, a price market-up is required in France to cover nuclear plants' fixed cost.

€/MWh for PC10-0.2, compared to 2.6 and 3.1 €/MWh for SA10-0.2 and ST10-0.2, respectively. The results of Sect. 3 suggest that the higher pass-through under competition may be an artifact of the linear demand assumption, since lower pass-through rates would instead result if demand was of the constant elasticity form.

One exception to the greater pass-through rates under competition is the Dutch market, where the ETS-induced increase in power prices under oligopoly is similar to that under competition, ranging between 4.4 and 4.8 €/MWh when allowances cost 10 €/tCO_2. This could be the result of factors that are not considered in Sect. 3, including merit order changes and network congestion.

The difference in power prices between countries is an indicator of the level of transmission congestion in the market. Whether the implementation of EU ETS would result in more or less congestion is an empirical question, depending on level of electricity demand, generators' locations, their relative CO_2 emissions rates, network topology, and allowance prices. In our simulations, results were ambiguous. On one hand, under higher allowances prices, congestion decreases on the German-Dutch interface, as measured by the difference in their prices. This is because the incremental CO_2 cost for the cheap German exporters increases more than the Dutch CO_2 costs. The difference in the electricity prices between two countries under PC10-0.2 and PC20-0.2 declines to 11.9 and 8.2 €/MWh, respectively, from 14.2€/MWh in PC0-0.2. In contrast, congestion between France and the Low Countries would be worsened since the increase in CO_2 costs in the importing country (e.g., Netherlands) is more than that for the exporting country. As a result, the price difference increases with allowances prices, adding 3 and 7 €/MWh to the original (PC0-0.2) 23.9 €/MWh price difference for PC10-0.2 and PC20-0.2, respectively. These ambiguous results indicate that emissions trading does not clearly increase or decrease congestion.

5.1.3 Effects of emissions trading on power consumption and CO_2 emissions

Total power sales and CO_2 emissions are reported in Table 5 for each country and the EU4 region. Except for perfect competition with zero elasticity (the LP scenarios), ETS-induced price increases cause loads to decrease. Comparison of the scenarios shows how strategic reduction of output in the oligopoly cases interacts with CO_2 allowance costs and demand elasticity. The changes in total CO_2 emissions closely correlate with reductions in power sales.

5.2 Sources of CO_2 emission reductions under the EU ETS

The ETS-induced CO_2 emission reductions can be attributed to two causes: demand response and changes in generator merit order. Whereas less CO_2 is emitted when higher power prices suppress power demand and, thus, power generation, changes in merit order yield less CO_2-intense generation mixes for a given level of output.

Two additional runs (i.e., LP10 and LP20) are designed to decompose the total CO_2 reductions in the competitive cases into these two effects. In particular, the nodal demands in these two runs are fixed at the level of PC0. Thus, the difference in the total emissions between LP10 (LP20) and PC0 is the emission reductions due to the redispatch of generators in response to a CO_2 allowance price of 10 (20) €/tCO_2. These runs indicate that the changes in the merit order contribute 19 and 23 Mtons of CO_2 reductions in the EU4 at prices of 10 and 20 €/tCO_2, respectively. The rest of the emissions reductions of 38 (67%) and 75 Mtons (77%) are due to demand response. Thus, increasing the allowances price from 10 to 20 €/tCO_2 only yields 4 Mtons more emissions reductions due to changes in generator merit order. Even under the low demand elasticity assumption, the effect of demand response outweighs emissions reductions due to redispatch.[13]

One goal of the ETS in the short run is to reduce the operations of CO_2-intensive generating units and improve average emission rates. When the allowance price increases, operating CO_2-intensive units becomes less economically desirable, all else being equal.[14] These and other COMPETES results suggest that when allowance prices are no more than 20 €/tCO_2, merit order changes are minor; however, runs with more than 30 €/tCO_2 would cause significant changes in the production merit order. These changes primarily involve increased output from gas-fueled or wood-burned technologies with low emission rates at the expense of output from German lignite-burned coal plants with relatively high emission rates (Sijm et al. 2005, p. 83). In reality, coal prices were relatively stable over the simulated period, while CO_2 and gas prices fluctuated considerably. Had coal prices also increased over time, gas would have been more competitive compared to coal and changes of merit order would occur for lower CO_2 costs (i.e., <30 €/tCO_2).

Another way to compare the effect of the changes in the merit order relative to demand response is to examine average emission rates. The average CO_2 emissions rate under each scenario can be calculated by dividing total emissions by total power sales in Table 4. The average emission rate for the entire market declines from 370 (PC0-0.2) to 337 (PC10-0.2) and finally to 313 kg/MWh under PC20-0.2. Meanwhile, the average emissions rate for LP10 and LP20 is 355 and 352 kg/MWh, respectively. Thus, the effect of changes in merit order when CO_2 cost equals 20 €/MWh leads to a reduction of average emissions rate from 370 to 352 kg/MWh (PC0-0.2 vs. LP20), while demand response further reduces the emissions rate to 313 kg/MWh (PC20).

The demand response under ETS forces marginal high-cost units, which also happen to be high emitting units, to cease operating. The average emissions rate for these units is approximately 864 and 903 kg/MWh based on a comparison of PC10-0.2 to LP10 and PC20-0.2 to LP20, respectively.[15] Thus, implementation of the ETS would nudge

[13] However, since equilibrium power prices are higher than the price at which the reference elasticity (0.1 or 0.2) is calculated, the linear demand curve used here is more elastic in that region than the reference value. Therefore, we would expect that if instead constant elasticity demand was assumed, the demand response would have been less than calculated here, and less emissions reduction would be due to demand response than in the linear demand case.

[14] Of course, merit order changes depend upon assumed fuel costs (Keats and Neuhoff 2005). Fuel prices in COMPETES vary by country, range from 2.38–2.95 €/GJ for coal, 3.46–4.15 €/GJ for gas, to 13.41–15.0 €/GJ for diesel oil.

[15] For the case where the allowances price equals 10 €/MWh, this is calculated as ((444–406) [Mtons]/(1250–1206) [TWh]) $\times 10^{-9}$ [kg/Mtons] $\times 10^{6}$ [TWh/MWh] = 864 [kg/MWh].

Table 4 Power prices at country level [€/MWh]

	Netherlands	Belgium	Germany	France	EU4
Capacity-weighted average emissions rate (kg/MWh)	679	381	635	148	409
PC0-0.2	42.5	37.1	28.2	18.6	25.9
PC10-0.2	47.0	43.2	35.2	20.1	30.2
PC20-0.2	51.1	47.0	42.9	20.4	33.9
SA0-0.2	72.2	78.6	42.6	17.9	35.7
SA10-0.2	76.7	81.2	49.2	18.8	39.0
SA20-0.2	80.9	82.8	56.0	19.1	41.9
ST0-0.2	71.8	79.1	43.0	59.3	53.5
ST10-0.2	76.6	82.2	49.7	59.5	57.8
ST20-0.2	80.7	85.1	56.5	60.6	62.3
LP10–0	47.9	43.9	37.9	21.0	32.0
LP20–0	53.1	50.9	46.7	23.3	37.7
SA0-0.1	100.7	126.3	59.0	17.8	47.3
SA10-0.1	105.1	127.4	65.7	18.8	50.7
SA20-0.1	110.0	129.1	72.5	19.3	53.9
ST0-0.1	99.8	127.7	59.2	99.4	81.0
ST10-0.1	104.4	128.5	66.7	100.4	85.9
ST20-0.1	109.2	129.5	74.1	100.6	90.4

the region's power system towards a generation mix with slightly lower emissions rates.[16]

5.3 Estimated pass-through rates for ETS CO_2 costs

CO_2 cost pass-through rates are reported in Table 5, based on average and marginal emissions rates (Eqs. 1 and 2, respectively).

5.3.1 Marginal pass-through rates

The marginal pass-through rate measures the marginal effect of emissions trading on power prices by relating changes in these prices to changes in CO_2 allowance costs of the marginal production unit. The simulated results using COMPETES in Table 6 are to some extent consistent with the theoretical analysis of Sect. 3 with respect to demand elasticities and market competitiveness.

For perfect competition (e.g., the PC and LP solutions), the marginal pass-through rate is generally higher than for imperfect competition. For most non-competitive cases, the marginal pass-through rate is <1, consistent with the results of the simple

[16] In contrast, changes in dispatch order can have much larger effects in SO_2 and NO_x emissions trading systems (see (Heslin and Hobbs 1989) and (Leppitsch and Hobbs 1996)), and such emissions dispatch is an important component of emissions reductions strategies that also include fuel changes, emissions control retrofits, and demand reduction. The reason is that, at least in US experience, there is a diversity of SO_2 and NO_x emissions rates even among units with similar fuels and, thus, fuel costs. As a result, it is possible to change dispatch orders at relatively low cost.

Table 5 Annual power sales (TWh) and CO_2 emissions (Mtons) at country level

Scenarios	Netherlands		Belgium		Germany		France		EU4	
	Sales	CO_2	Sales	CO_2	Sales	CO_2	Sales	CO_2	Sales	CO_2
PC0-0.2	96	76	89	25	542	345	523	17	1,250	463
PC10-0.2	94	62	86	20	510	312	516	12	1,206	406
PC20-0.2	93	59	84	18	474	277	516	11	1,167	365
SA0-0.2	83	68	69	15	480	281	522	19	1,154	383
SA10-0.2	80	55	67	11	452	250	518	12	1,117	328
SA20-0.2	79	52	66	10	425	219	517	11	1,087	292
ST0-0.2	83	68	68	12	477	284	307	26	935	390
ST10-0.2	80	55	67	10	449	253	306	24	902	342
ST20-0.2	79	52	65	9	421	220	300	17	865	298
LP10–0	96	63	89	23	542	342	523	16	1,250	444
LP20–0	96	60	89	22	542	342	523	16	1,250	440
SA0-0.1	83	64	68	17	478	275	522	22	1,151	378
SA10-0.1	82	55	67	14	464	254	520	15	1,133	338
SA20-0.1	81	52	67	13	450	237	518	12	1,116	314
ST0-0.1	83	64	67	14	477	276	310	35	937	389
ST10-0.1	82	55	67	11	462	257	307	31	918	354
ST20-0.1	81	52	66	11	446	240	306	29	899	332

Table 6 Marginal and average pass-through rates at country level

Scenarios	Netherlands		Belgium		Germany		France		EU4	
	MPR[a]	APR[b]	MPR	APR	MPR	APR	MPR	APR	MPR	APR
PC10-0.2	0.98	0.82	0.83	2.53	0.80	1.13	0.74	6.82	0.79	1.33
PC20-0.2	0.70	0.82	0.80	2.27	0.80	1.25	0.43	4.21	0.71	1.33
SA10-0.2	0.60	0.73	1.26	1.38	0.67	1.21	1.11	3.89	0.66	1.18
SA20-0.2	0.96	0.71	1.86	1.22	0.68	1.32	0.43	2.83	0.63	1.20
ST10-0.2	0.64	0.75	0.69	2.10	0.68	1.19	n.a.	0.21	0.73	1.13
ST20-0.2	0.96	0.72	0.51	2.17	0.69	1.29	10.83	1.08	0.78	1.28
LP10-0	0.91	0.94	0.99	2.54	0.92	1.53	0.71	7.80	0.88	1.78
LP20-0	1.04	0.97	1.07	2.68	1.18	1.47	1.15	7.69	1.16	1.73
SA10-0.1	0.64	0.66	0.74	0.50	0.70	1.25	0.61	3.62	0.65	1.18
SA20-0.1	1.04	0.72	0.96	0.64	0.68	1.31	0.34	3.34	0.60	1.21
ST10-0.1	0.67	0.68	0.54	0.50	0.75	1.35	n.a.	0.99	0.85	1.25
ST20-0.1	1.03	0.73	0.62	0.54	0.74	1.38	n.a.	0.63	0.86	1.26

[a] Marginal pass-through rates, Eq. 1
[b] Average pass-through rates, Eq. 2
Note that pass-through rates, by definition, do not exist for the 0 €/tCO_2 scenarios

linear demand models of Sect. 3. But the difference in marginal pass-through rates among countries cannot be entirely explained by the level of competitiveness. For instance, given that the electricity market is less competitive in France and Belgium, one would expect the marginal pass-through rates to be lower in these two countries. Yet, in several cases (e.g., ST20-0.2 in France), the marginal pass-through rate in those countries is actually higher than elsewhere. This could partly be attributed to interactions among network congestion, merit order changes, and differences in generation mixes such that when nuclear generators are the marginal sources in most periods, any slight increase in power prices will result in a large marginal pass-through rate. Overall, the marginal pass-through rate for the EU4 under oligopoly scenarios varies between 0.6 and 0.9, lower than in the competitive runs.

As for the effect of demand elasticity, higher elasticity (0.2 vs. 0.1) results in lower pass-through rates in the oligopoly scenarios. For instance, the respective marginal pass-through rates in the Netherlands are 1.03 and 0.64 for SA20-0.1 and SA10-0.1, exceeding their corresponding cases under 0.2 elasticity (0.96 and 0.60) for CO_2 costs equal to 20 and 10 €/tCO_2, respectively. One exception is in Belgium, where the marginal pass-through rate under a 0.2 elasticity (i.e., SA20 and SA10) is considerably higher than that under 0.1. This is in part because in a number of off-peak periods in these scenarios, the prices in Belgium are determined by French nuclear generators with zero emissions rates. This amplifies the calculation of marginal pass-through rates since the denominator in (2) in these periods is small.

Several marginal pass-through rates are marked as "n.a." (Not Applicable), notably in France under the ST scenarios. The reason is that French prices under these scenarios are determined by zero-emission nuclear units. Thus, the denominators become zero in (2), and marginal pass-through rates are undefined. Thus, the transmission network complicates the calculation of the marginal pass-through rates, and results could be not compared with the theoretical predictions in Table 1.

5.3.2 Average pass-through rates

Depending on the emissions rate of inframarginal and marginal generators, average pass-through rates at the country level can be grouped into two categories. When the emissions rate for marginal plants is substantially lower than the average rate (including inframarginal plants), the change in the power price (the numerator in (1)) is likely to be much less than the average CO_2 allowances cost (the denominator of (1)), yielding lower average pass-through rates. On the other hand, if marginal emission rates exceed inframarginal emission rates, then the average pass-through rate could be much higher. The Dutch markets are an example of the former case, where power prices are mostly determined by low-emitting but expensive gas-fired generators that are the marginal source of power. Thus, their average pass-through rates are less than 1.0 (Table 5). In contrast, the French market is an example of the latter case in which the inframarginal units are nuclear plants with zero emissions, while marginal units are often high emission fossil-fuel generators. There, average pass-through rates are much greater, being as high as 7.8. Belgium and Germany are between these extremes, with most average rates lying above 1.0.

However, some exceptions occur to this pattern of average pass-on rates. For instance, in France when EdF acts strategically (scenarios ST10-0.1, ST20-0.1 and ST10-0.2), APRs have values of 0.99 or lower. A reason for these exceptions is that this is a simplified classification, abstracting from a number of complications such as transmission congestion and load levels (e.g., peak, shoulder and off-peak periods). For instance, during periods when EdF withholds output, nuclear is the marginal source that determines power prices, and average pass-through rates would fall.

5.4 ETS-induced changes in firms' CO_2 emissions rates, output and profits

5.4.1 Changes in firms' CO_2 emissions rates

When facing CO_2 constraints, rearrangement of the merit order means that the average output-weighted CO_2 emissions rates will decrease for a given level of total generation. Meanwhile, decreases in total generation could increase or decrease average emission rates, depending on the emission rates of marginal generators relative to average rates. Figure 3 presents a scatter plot of the ETS-induced changes in generating firms' output (relative to the scenarios with a zero allowance price) against their output-weighted CO_2 emission rates for various scenarios. We divide the generators owned by each firm into three subsets for each scenario: those that decrease production, those that increase production, and those that do not change production. The total output and output-weighted emissions rate for each of the first two subsets is then plotted in Fig. 3 for each firm under each scenario.[17] There are a total of 268 points, representing alternative combinations of firms, scenarios, and whether the point represents generators that have increased output or decreased output. The downward-sloped trend in the scatter plot shows that changes in output are inversely related to emission rates: CO_2 trading results in increased generation from low emission generators and decreased generation from high emission plants.

This seemingly simple relationship is actually the consequence of complicated interactions among several factors. In general, increases in generation must be due to changed dispatch orders, while decreases in generation could be due either to changes in dispatch order, or to decreases in load, which in turn would lower output from marginal facilities. However, the interactions of strategic behavior, transmission limits, and other factors complicate the picture. For instance, the output of a number of firms with high output-weighted emission rates (e.g., 1500–2000 kg/MWh) declines only marginally as a result of emissions trading. Most of these firms are modeled as price takers. The downward pressure on generation output created by the firms' CO_2 emissions costs is neutralized to some degree by the upward incentive associated with higher power prices caused by the exercise of market power by strategic players as well as the pass-through of CO_2 costs. This implies that the relationship between changes in output and emissions rates in Fig. 3 could be stronger under perfect competition. As an extreme case, one CO_2-intensive unit with an emissions rate of 1,987 kg/MWh reduces its output by 0.62 TWh per year (9%) under trading (PC10) relative to PC0. However,

[17] The change in output by generating unit h owned by company f is $\Delta g_{fh} = g_{fh1} - g_{fh0}$ [MW], where subscript 1 indicates cases with emissions trading and 0 gives cases without trading. Then, the x-axis or output-weighted CO_2 emissions rate is $\sum_{h \in H^{+}(f)} \Delta g_{fh} E_{fh}^{CO_2} / \sum_{h \in H^{+}(f)} \Delta g_{fh}$, where $H^{+}(f)$ indicates the subset of generators owned by firm f that increase their output under emissions trading; and the y-axis is $(\sum_{h \in H^{+}(f)} \Delta g_{fh})/(\sum_{h \in H^{+}(f)} g_{fh0})$ in percentage terms. Likewise, the relative change in output and the output-weighted emissions rate for the subset of generators owned by firm f (i.e., $H^{-}(f)$) that decreases their output can be calculated in the same way. Each firm under one scenario (compared to its corresponding reference case) can have at most two points: one for the subset of generators that increase their output and one for those that decrease their output. In contrast, if no generator owned by firm f changes its output, there will be no point in Fig. 3 associated with firm f. Thus, given 12 scenarios with positive allowances prices and 15 firms in the market, the maximal number of points in Fig. 3 is 360 $(= 12 \times 15 \times 2)$.

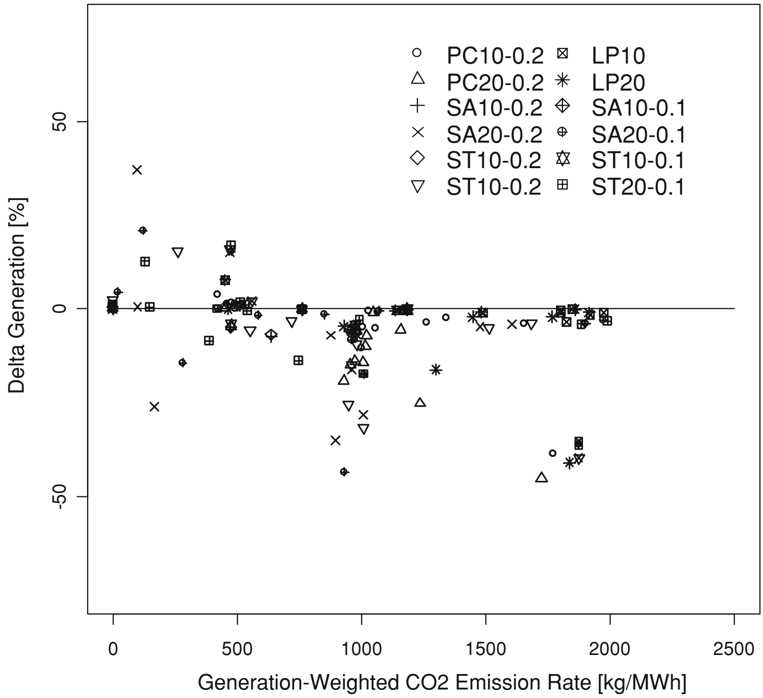

Fig. 3 Scatter plot of ETS-induced changes in output level of the subsets of firms' generators that alter their output (with separate subsets for those increasing and decreasing output) against their generation-weighted CO_2 emissions rate under various model scenarios

it actually increases its output by 1.52 TWh/year (21%) under SA10-0.1 compared to PC0 (not shown in Fig. 3). Its increase under SA10-0.1 compared to SA0-0.1 is small but positive. Thus, high power prices due to market power can make it economical for CO_2-intensive units owned by small companies to expand their output.

5.4.2 Changes in firms' profits

This section examines whether companies with a low or even moderate capacity-weighted emissions rate would benefit disproportionately from CO_2 emissions trading. We first analyze the scenarios assuming that all allowances consumed by generators are grandfathered based on allocations in the 2005 NAPs,[18] followed by a comparison with

[18] In the absence of firm-specific data on allowance allocations, this analysis assumes that the number of allowances allocated to a firm is proportional to its emissions under PC0. For instance, the amount of allowances available to the power sector in the Netherlands, Belgium, Germany and France based on the 2005 NAPs is approximately 41, 16, 286, and 33 Mtons, respectively (Cunningham et al. 2006). If generators owned by a firm in Germany emit 10% of that country's power sector CO_2 emissions in the COMPETES PC0 run, then we allocate 28.6 Mtons of allowances to this generating company. This is consistent with the way in which the initial allocation is made in the German NAP that is based on historical emissions without emissions trading (Federal Ministry 2006). We keep the number of allowances available to each firm at this level in all runs. The total number of allowances distributed is 378 Mtons. When comparing

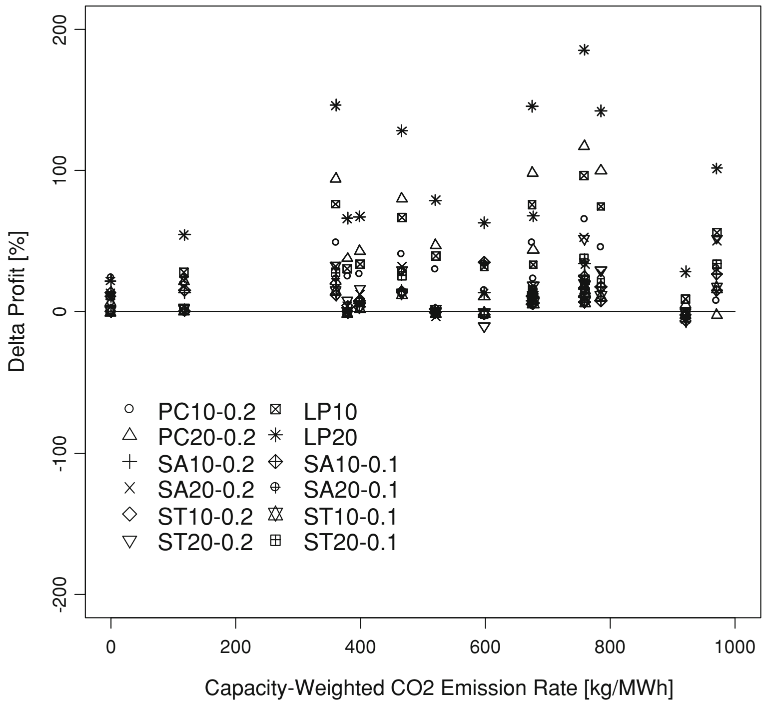

Fig. 4 Scatter plot of the ETS-induced changes in firms' profit (including estimated allowance rents from 2005 NAPs allowances) against their capacity-weighted CO_2 emissions rate under various model scenarios

the alternative (and less realistic) assumption that allowances are entirely purchased by firms through auctions.

Figure 4 presents a scatter plot of ETS-induced changes in firms' profits (including allowance rents = emissions [tons] × allowance price [€/tCO_2]) against their capacity-weighted CO_2 emissions rate under various scenarios. Each point in the plot is one firm under one scenario compared to its counterpart without ETS. Thus, given 12 scenarios with non-zero allowance costs and 15 firms, there are a total of 180 points. Since firms' capacity-weighted emissions rates do not vary with their generation among different scenarios, all points associated with a particular firm are situated at the same location along the x-axis, while being spread along the y-axis for different scenarios.

Figure 4 indicates that the ETS benefits most firms if allowances are grandfathered. Whereas firms with lower emissions rates have already profited from emission trading even in the absence of profits from free allowances (Fig. 5), grandfathered allowances provide additional (and generous) compensation to firms with high emission rates.

Footnote 18 continued
a country's initial CO_2 allowances allocation to estimated emissions under various scenarios in Table 5, COMPETES predicts an allowances deficit in the Netherlands but a surplus in the French power sector. The number for Germany and Belgium markets could be either more or less than initial allocation, depending on the scenario: shortages under perfect competition (i.e., more generation and more emissions) yet a surplus under oligopoly.

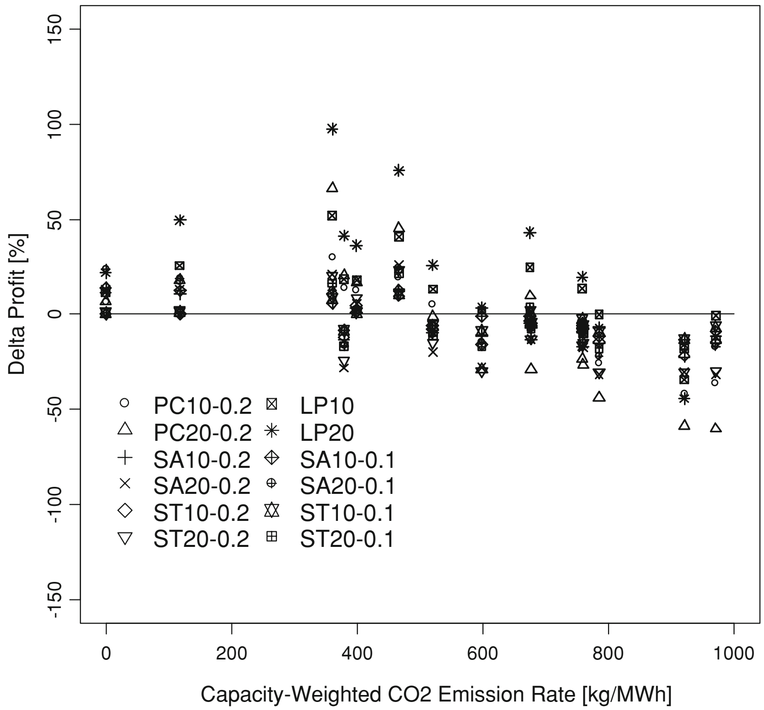

Fig. 5 Scatter plot of ETS-induced changes in firms' profit (assuming allowances are paid for) against their capacity-weighted CO_2 emissions rate under various model scenarios

As a result, nearly all firms, including the highest emitters, earn increased profits when revenue from free allowances is taken into consideration. Companies that experience lower profits even when allowance rents are included are small fossil fuel-based firms with intermediate emissions rates (these are Competitive Belgium, SOC Production D'Elec, and Competitive Fringe France). In those cases, profit loss results when changes in power sales, prices, and production costs together cannot be made up by allowance rents.

In contrast, Fig. 5 displays the changes in the profits against capacity-weighted CO_2 emissions rates, assuming that the consumed CO_2 allowances, like fuel costs and other inputs for electricity production, need to be purchased from the markets. Essentially, what this does is to subtract economic rents associated with free allowances from firms' profits, shifting downward all the points in Fig. 4 by that amount. Thus, firms on the right side of Fig. 4 are moved further down since they are likely to have been given more allowances in a grandfathering system, given their high capacity-weighted emissions rates. Figure 5 suggests that emissions trading generally favors firms with a lower capacity-weighted emissions rate due to ETS-induced changes in electricity prices and sales. However, it is surprising that some firms with a relatively high emissions rate, say for example 750 kg/MWh, can also benefit from emissions trading under certain scenarios even when allowances have to be paid for by these firms. Overall, firms with a capacity-weighted emissions rate less than 500 kg/MWh

Table 7 Decomposition of EU4 windfall profits

Scenarios	Total operating profit (M€)[a]	Profit changes (excluding allowance rents)[b] (M€)	Allowance rents[c] (M€)	Total windfall profits[d] (M€)	Fraction due to gen. and sales (%)	Fraction due to allowances rents (%)
PC0-0.2	13,919	n.a.	0	n.a.	n.a.	n.a.
PC10-0.2	14,963	1,044	3,773	4,817	21.7	78.3
PC20-0.2	15,631	1,712	7,546	9,258	18.5	81.5
SA0-0.2	22,063	n.a.	0	n.a.	n.a.	n.a.
SA10-0.2	22,140	77	3,773	3,850	2.0	98.0
SA20-0.2	22,097	34	7,546	7,580	0.4	99.6
ST0-0.2	32,015	n.a.	0	n.a.	n.a.	n.a.
ST10-0.2	31,488	−527	3,773	3,246	−16.2	116.2
ST20-0.2	31,473	−542	7,546	7,004	−7.7	107.7
LP10-0	17,099	3,180	3,773	6,953	45.7	54.3
LP20-0	19,821	5,902	7,546	13,448	43.9	56.1
SA0-0.1	32,424	n.a.	0	n.a	n.a.	n.a.
SA10-0.1	32,715	291	3,773	4,064	7.2	92.8
SA20-0.1	33,028	604	7,546	8,150	7.4	92.6
ST0-0.1	53,656	n.a.	0	n.a.	n.a.	n.a.
ST10-0.1	53,635	−21	3,773	3,752	−0.6	100.6
ST20-0.1	53,574	−82	7,546	7,464	−1.1	101.1

[a] Gross margin (revenue minus variable costs), not considering fixed costs
[b] Profit changes exclude allowance rents (i.e., assume allowances are paid for by generators) and are calculated relative to the corresponding zero allowance price case (PC, SA, or ST), except for the LP cases, which are compared to PC0-0.2
[c] Allowance rents equal the number allowances allocated to EU4 multiplied by the scenario allowances price
[d] Total windfall profits = change in operating profits (i.e., revenue minus variable generation costs) + allowance rents
n.a.—Not applicable

generally benefit from EU ETS, regardless of market structure assumptions and the value of the free allowances they are allocated.

5.5 Decomposition of EU4's per MWh profit change and windfall profits

Table 7 decomposes aggregate EU4 profit changes into changes due to shifts in power sales and production costs (i.e., Generation and Sales Column) and allowance rents. Except for the ST scenarios, the ETS induces a positive increase in profits, even when excluding allowance rents. Yet the negative change in the net revenue under ST scenarios is still more than made up by the allowance rents. Thus, under the ST scenarios, the relative contribution of allowance rents to total windfall profits for EU4 exceeds 100%. Overall, the contribution of allowance rents to total windfall profits account for 92–98% (higher under a 0.2 elasticity) under ETS, compared to 70–80% for the competitive cases, and 50–60% under a zero elasticity for the LP scenarios.

6 Conclusions

This paper uses simple analytical models and the COMPETES model to examine how implementation of the EU Emissions Trading Scheme affects generators' profits and to estimate the extent to which CO_2 costs would be passed on to electricity prices. Two definitions of pass-through rates are used. The average pass-through rate indicates whether the average increase in generator revenue per MWh exceeds or falls short of the average opportunity cost of CO_2 allowances per MWh. In contrast, the marginal pass-through rate is defined as the ratio of the increase in power price to the marginal generator's CO_2 cost. The analytical models predict that the level of CO_2 pass-through is positively associated with supply elasticity, but inversely related to demand elasticity. The impact of market competitiveness depends on the functional form of demand and supply curves. When demand is of the constant-elasticity form, the pass-through rate decreases with the number of firms in the market. By contrast if demand is linear, a more competitive market yields higher pass-through rates. However, these analytic models do not account for the complicating factors of transmission congestion, heterogeneity in capacity mixes among firms, and time varying demand. These factors are addressed using COMPETES, a model that includes detail on transmission capacities and the spatial distribution of demand, generation types, and fuel costs.

The COMPETES results show that average pass-through rates are likely to be greatest in France and lowest in the Netherlands. In contrast, marginal pass-through rates are higher in Belgium and the Netherlands, and lower in France, except in scenarios where nuclear power is the marginal power source. The marginal pass-through rates are usually higher in more competitive markets, consistent with the prediction by analytical models that share COMPETES' assumption of linear demand. Yet in several cases, these rates are lower under competition. This is due in part to the interplay of market competition, changes in the merit order, and transmission congestion.

Sijm et al. (2006b) estimate marginal pass-through rates using empirical data from forward energy and fuel markets, and conclude that these pass-through rates are approximately 60–80% and 60–120% for the Netherlands and Germany, respectively. In contrast, COMPETES estimates that the marginal pass-through rates are 60–100% for Dutch markets and 60–80% for German markets. Thus, COMPETES' modeling results may overestimate pass-through rates in the Netherlands, but fall within the empirical range for Germany.

Since emissions allowances received by generators are for the most part free under the current EU ETS, the passing-through of the opportunity costs of these allowances increases their profits. The analyses concerning changes in profits due to the ETS show that substantial economic rents arising from grandfathered allowances are likely to be earned by generators. Even if no such rents were earned (i.e., allowances are allocated by auctions), some generators would still significantly profit from the power price increases caused by emissions trading (Fig. 5) because their average emissions costs are well below the emissions costs of marginal production units. As a result, generators' energy revenues are likely to increase more than their average production costs. The estimates of windfall profits in this study could be a lower bound to the actual profits, owing to our assumptions concerning demand. While short-run electricity demand is nearly perfectly inelastic, the COMPETES model is based on elastic linear inverse demand curves. As shown by simple analyses in Sect. 3, the ETS-induced economic rents would go completely to producers (at the expense of consumers) when demand is perfectly inelastic (fixed) and pure competition is assumed. The profitability of firms under elastic cases would be less than that under fixed demand in general.

Preliminary reports on our results stimulated debate in the European parliaments as well as media coverage concerning the contribution of the EU ETS to power price increases and the reasons for cost pass-through in 2005–2006 (e.g., Newvalues Community (2005); The European Council for an Energy Efficient Economy (2005); Point Carbon (2005, 2006)). A number of Member States responded by proposing alternatives such as auctions for distributing allowances in the second phase of the EU ETS (2008–2012). Our analysis shows, however, that if allowances are fully auctioned off, the power sector as a whole and most generators could still benefit from emission trading under most scenarios. The power sector's strong opposition to the auctioning of allowances on the grounds that they would then be worse off under the ETS (relative to a no-ETS scenario) is misleading for many firms, as Fig. 5 shows.

In sum, implementation of the EU ETS has likely altered generation mixes due to changes in power production costs; increased power prices; and redistributed economic rents among generators and consumers. The portion of emission costs that are passed through to consumers in the form of price increases depends on demand elasticity, market structure, and allowance prices. As for generators, when allowances are freely granted, nearly all generating companies earn significant windfall profits (Fig. 4). Even if allowances were to instead be auctioned off, the majority of firms would still benefit from EU ETS, especially if the market is competitive.

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Appendix

A.1 Proof of pass-through under constant elasticity demand and supply curves

The constant-elastic demand curve is assumed to be $Q = Q_o(p/P_o)^{-\varepsilon}$, where Q is quantity, p is price, $-\varepsilon$ is demand elasticity ($\varepsilon > 0$), and Q_o and P_0 are a reference quantity-price pair (where supply and demand are assumed to intersect under perfect competition and no emissions trading). Thus, the inverse demand function can be written as $p = P_0(Q/Q_0)^{-1/\varepsilon}$. The constant-elastic supply function is $MC = P_0(Q/Q_0)^b$, where $1/b > 0$ is the supply elasticity. Then the marginal cost for firm f is $MC_f = P_0(Nq_f/Q_0)^b$, where N is number of symmetric firms in the market and q_f is output from firm f.

Assume that marginal cost increases by ΔC as a result of emissions trading, then the marginal cost for firm f is as follows:

$$MC_f = P_0\left(\frac{Nq_f}{Q_0}\right)^b + \Delta C \tag{1}$$

Thus, assuming Cournot competition, the first-order profit maximization condition $MR = MC$ and symmetry among firms yield the following equilibrium condition for firm f:

$$p\left(1-\frac{1}{N\varepsilon}\right)-P_0\left(\frac{Q}{Q_0}\right)^b-\Delta C=0 \tag{2}$$

To investigate cost pass-through (the change in the price p with respective to the change in the marginal cost ΔC), we take the total derivative dp/d(ΔC) of (2), defined as F for convenience:

$$F=\frac{\mathrm{d}p}{\mathrm{d}(\Delta C)}=\frac{1}{1-\frac{1}{N\varepsilon}+b\varepsilon P_0^{\varepsilon b+1}p^{-\varepsilon b-1}} \tag{3}$$

We then evaluate $\mathrm{d}p/\mathrm{d}(\Delta C)$ at $\Delta C=0$ by substituting p in terms of N, ε and b into (3) using (2):

$$F=\frac{\mathrm{d}p}{\mathrm{d}(\Delta C)}=\frac{1}{(1-\frac{1}{N\varepsilon})(1+b\varepsilon)} \tag{4}$$

Note that if the price elasticity of supply is much higher than the demand elasticity (so that $1+b\varepsilon$ is close to 1), then the pass-through rate can exceed 1. To examine the effect of demand elasticity ε, supply elasticity 1/b, and number of firms N on F, we need the sign of the partial derivative with respective to ε, b and N(i.e., $\partial F/\partial\varepsilon$, $\partial F/\partial b$, and $\partial F/\partial N$, respectively). We discuss each in turn.

A.1.1 Demand elasticity ε

When $N\varepsilon>1$, then $\mathrm{d}p/\mathrm{d}(\Delta C)=F>0$. The term $1/(1+b\varepsilon)$ in (4) is unaffected by ε if $b=0$, and is decreasing in ε if $b>0$. The term $1/(1-1/(N\varepsilon))$ is unaffected by ε if N is infinite and is otherwise decreasing in ε. Thus, if $b>0$ and N is finite, then F is positive and decreasing in demand elasticity ε (i.e., $\partial F/\partial\varepsilon=-((1-1/(N\varepsilon)(1+b\varepsilon))^{-2}((N\varepsilon)^{-2}N(1+b\varepsilon)+(1-1/(N\varepsilon)b)<0$. That is, more elastic demand means less pass-through.

A.1.2 Supply elasticity b

When $N\varepsilon>1$, both terms $1/(1+b\varepsilon)$ and $1/(1-1/(N\varepsilon))$ in (4) are positive, and $1/(1+b\varepsilon)$ is decreasing in b given that supply elasticity $\varepsilon>0$. Thus, $F=\mathrm{d}p/\mathrm{d}(\Delta C)>0$ and is decreasing in b (i.e., $\partial F/\partial b=-((1-1/(N\varepsilon)(1+b\varepsilon))^{-2}(1-1/(N\varepsilon)\varepsilon<0)$.) In the limiting cases of perfectly inelastic and elastic supply ($b=\infty$, 0, respectively), there is no pass-through and pass-through of $1/(1-1/(N\varepsilon))$, respectively. Less elastic supply (i.e., higher b) means less pass-through.

A.1.3 Number of firms N

As noted, both terms $1/(1+b\varepsilon)$ and $1/(1-1/(N\varepsilon))$ in (4) are positive; further, $1/(1+b\varepsilon)$ is not affected by N and $1/(1-1/(N\varepsilon))$ is decreasing in N, given that demand elasticity $\varepsilon>0$ and $N\varepsilon>1$ (i.e., $\partial F/\partial N=-((1-1/(N\varepsilon)(1+b\varepsilon))^{-2}(1+b\varepsilon)\varepsilon\ (N\varepsilon)^{-2}<0$.) As an extreme case, if $1+b\varepsilon$ is close to 1, then the pass-through rate approaches 1 from above as N increases. Thus, more competitive markets mean less pass-through.

A.2 Proof of pass-through under constant-elastic demand and linear supply curves

This is a special case when $b = 0$ in (4), which reduces to the following:

$$F = \frac{\mathrm{d}p}{\mathrm{d}(\Delta C)} = \frac{1}{1 - 1/(N\varepsilon)} \tag{5}$$

Thus, when marginal cost increases from by ΔC due to emissions trading, the equilibrium price increases by $\Delta C N\varepsilon/(N\varepsilon - 1)$.

A.3 Proof of pass-through under linear demand and constant-elasticity supply

Under linear demand, the inverse demand curve is parameterized as Eq. 6 so that the competitive equilibrium with no carbon trading passes through (Q_0, P_0) and has elasticity ε at that point:

$$p = P_0\left(1 + \frac{1}{\varepsilon}\right) - \left(\frac{P_0}{Q_0\varepsilon}\right)Q. \tag{6}$$

For N symmetric firms, the individual firm's marginal cost is $P_0(Nq_f/Q_0)^b$, as in Sect. A.1. For an individual Cournot firm, the first-order condition MR=MC under emission cost equal to ΔC is:

$$p - \left(\frac{1}{\varepsilon N}\right)\left(\frac{P_0}{Q_0}\right)Q - P_0\left(\frac{Q}{Q_0}\right)^b - \Delta C = 0. \tag{7}$$

We evaluate the total derivative $\frac{\mathrm{d}p}{\mathrm{d}(\Delta C)}$ at $\Delta C = 0$ using $\frac{\mathrm{d}Q}{\mathrm{d}p} = -\varepsilon\left(\frac{Q_0}{P_0}\right)$ derived from Eq. 6:

$$F = \frac{\mathrm{d}p}{\mathrm{d}(\Delta C)} = \frac{1}{1 + \frac{1}{N} + \varepsilon b\left(\frac{Q}{Q_0}\right)^{b-1}}. \tag{8}$$

We then substitute p from (6) into (7) and derive $\frac{\partial Q}{\partial N}$, $\frac{\partial Q}{\partial \varepsilon}$ and $\frac{\partial Q}{\partial b}$ as a function of N, b, ε and Q:

$$\frac{\partial F}{\partial N} = \frac{-\left(\frac{-1}{N^2} + \frac{\varepsilon b(b-1)}{Q_0}\left(\frac{Q}{Q_0}\right)^{b-2}\frac{\partial Q}{\partial N}\right)}{\left(1 + \frac{1}{N} + \varepsilon b\left(\frac{Q}{Q_0}\right)^{b-1}\right)^2} \tag{9}$$

$$\frac{\partial F}{\partial \varepsilon}=\frac{-\left(b\left(\frac{Q}{Q_0}\right)^{b-1}+\frac{\varepsilon b(b-1)}{Q_0}\left(\frac{Q}{Q_0}\right)^{b-2}\frac{\partial Q}{\partial \varepsilon}\right)}{\left(1+\frac{1}{N}+\varepsilon b\left(\frac{Q}{Q_0}\right)^{b-1}\right)^2} \tag{10}$$

$$\frac{\partial F}{\partial b}=\frac{-\left(\varepsilon\left(\frac{Q}{Q_0}\right)^{b-1}\left(1+b\left(\ln\frac{Q}{Q_0}\right)\right)+\frac{\varepsilon b(b-1)}{Q_0}\left(\frac{Q}{Q_0}\right)^{b-2}\frac{\partial Q}{\partial b}\right)}{\left(1+\frac{1}{N}+\varepsilon b\left(\frac{Q}{Q_0}\right)^{b-1}\right)^2}. \tag{11}$$

Substitute $\frac{\partial Q}{\partial N}=\frac{1}{\varepsilon N^2\left(\frac{b-1}{Q_0}\left(\frac{Q}{Q_0}\right)^{b-2}+\frac{Q_0}{(1+\varepsilon)Q^2}\right)}$ into Eq. 9 and rearrange the terms. If $b>1$, it implies that $\frac{\partial F}{\partial N}>0$. Thus, the cost pass-through is positively associated with the number of firms N in the market.

Equation 10 is <0 given $b>1$ and $\frac{\partial Q}{\partial \varepsilon}>0$ (because decrease in elasticity ε would lead to higher price with smaller equilibrium quantity Q.) Thus, the cost pass-through is negatively associated with demand elasticity.

Finally, the cost pass-through is expected to be positively associated with supply elasticity $1/b$, if $b>1$ and $\ln\frac{Q}{Q_0}>-\frac{1}{b}$ (Eq. 11). That is, the equilibrium quantity relative to the reference Q_0 is bounded by exponential of negative supply elasticity.

A.4 Proof of pass-through under linear demand and constant marginal costs

For simplicity, we assume linear demand curve is $p=1-Q$, where p is price and Q ($\sum_{f=1,\ldots,F} q_f$) is total quantity consumed. Without loss of generality, the marginal cost for firm f is assumed to be zero and ETS increases marginal cost by ΔC. Given that MC is zero, q_f will always be positive. Then this yields the first-order profit maximization condition $MR=MC$ as follows:

$$(1-Q)-q_f-\Delta C=0 \tag{12}$$

Next, we impose the symmetry assumption (i.e., $Q=Nq_f$) in to (12) and solve for q_f and price:

$$q_f=\frac{1-\Delta C}{N+1},\ \text{and} \tag{13}$$

$$p=\frac{1+N\Delta C}{N+1}. \tag{14}$$

Comparing Eqs. 13 and 14, power price increases by $(N\Delta C)/(1+N)$ and market output decreases by $\Delta C/(N+1)$ when marginal cost increase by ΔC. Thus, as N becomes large, the pass-through of ΔC approaches 1. Thus, the CO_2 costs will be fully passed on to power prices in the limiting case of perfect competition.

The calculation of equilibrium prices, pass-through and output under perfect, monopoly, duopoly, and oligopoly competition are summarized in Table A1.

Table A1 Effects of imposing CO_2 trading as a function of number of firms in the market

Case	N	Price (€/MWh)	Pass-through of CO_2 costs (%)	Individual firm's output (MWh)	Total output (MWh)
Perfect	∞	ΔC	100	n.a.	$-\Delta C$
Monopoly	1	$\Delta C/2$	50	$-\Delta C/2$	$-\Delta C/2$
Duopoly	2	$2\Delta C/3$	67	$-\Delta C/3$	$-2\Delta C/3$
Oligopoly	$2 \leq N < \infty$	$N\Delta C/(N+1)$	$100N/(N+1)$	$-\Delta C/(N+1)$	$-N\Delta C/(N+1)$

n.a.—Not applicable

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