Modelling CO_2 price pass-through in imperfectly competitive power markets

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Abstract. *In line with economic theory, carbon ETS determines a rise in marginal cost equal to the carbon opportunity cost regardless of whether carbon allowances are allocated free of charge or not. Hence, common sense would suggest that firms in imperfectly competitive markets will pass-through into electricity prices only a part of the increase in cost. Instead, by using the load duration curve approach and the dominant firm with competitive fringe model, the analysis proposed in this paper shows that the result is ambiguous. The increase in price can be either lower or higher than the marginal CO_2 cost depending on several structural factors: the degree of market concentration, the available capacity (whether there is excess capacity or not) and the power plant mix in the market; the allowance price and the power demand level (peak vs. off-peak hours). The empirical analysis of the Italian context (an emblematic case of imperfectly competitive market), which can be split in four sub-markets with different structural features, confirms the model predictions. Market power, therefore, can determine a significant deviation from the "full pass-through" rule but we can not know which is the sign of this deviation, a priori, i.e. whithout before carefully accounting for the structural features of the power market.*

Keywords: emissions trading, power pricing, imperfect competition

1. Introduction

Power generation is the largest industry sector covered by the European Union CO_2 emissions trading scheme (EU ETS)[1]. Therefore, on the one hand, the performance of the ETS largely depends on its efficacy in inducing power industry to significantly reduce

[1] The EU ETS started in 2005. In the period 2005-2007, each European country allocates allowances to eligible firms. At least 95% of the total amount of allowances are allocated free of charge and firms can use or trade them. At the end of each calendar year each eligible firm must deliver a number of allowances

CO_2 emissions. On the other hand, the ETS might have a sensible impact on power prices and, consequently, on social welfare.

This study focuses on this latter issue, attempting to understand how a CO_2 price could impact on power pricing when electricity markets are imperfectly competitive[2]. Studies aimed at exploring this issue do exist but they provide a very controversial framework.

On the theoretical side, Sijm et al. (2005) and Wals and Rijkers (2003) find that the electricity price in a competitive scenario increases more than under market power, on both percentage and absolute basis[3]. They attribute this result to the assumption of linear demand function they adopt. Surprisingly, however, Lise (2005) achieves the opposite result (electricity price increases more under market power) even though the author use the same model. Reinaud (2003), relying on price competition, and Newbery (2005), by assuming constant price elasticity, states that electricity prices are likely to increase more under market power.

On the empirical side, there are not specific studies aimed at measuring the impact of market power. Most analyses try to check whether CO_2 costs are fully passed through into electricity prices or not and generically attribute the "deviation" from this "rule" to various factors among which the exercise of market power in the output markets.

In this paper, we specifically attempt to assess the impact of market power by using a simple theoretical model and subsequently checking its robustness by means of an empirical analysis.

Concerning the theoretical issues, we have to be aware that results significantly depends on the choice of the competition model[4].

corresponding to his total emissions in that year. At the beginning of 2008 a new ETS starts and the old allowances become worthless.

[2] Many authors deal with the link between market structure and environmental issues. For a survey, see also Requate (2005).

[3] The aurhors use a game theoretical simulation model based on the theory of Cournot competition and Conjecture Supply Funcions, the COMPETES model. For details on this model, see Day et al. (2002), Hobbs and Rijkers (2004a; 2004b).

[4] In particular, price elasticity choice is very important in simulating the impact of the ETS and can undermine the effectiveness of a model. For example, the existence of Nash equilibria within the Cournot model requires substantial negative price elasticity. This is the case, for example, of the COMPETES model cited above. Whereas completely inelastic demand seems to be more appropriate for the power industry, at least in the short-run. Moreover, Bolle (1992) proves that in this latter case no equilibrium exists in the supply-function model.

In the present work we will follow the suggestion of authors who argue in favour of adopting the "auction" approach (von der Fehr and Harbord, 1993, 1998). In fact, several electricity spot markets have characteristics which make standard models not well-suited to their analysis. In particular in these markets pricing mechanism is a uniform, first price auction.

In addition, to simulate market power in electricity markets we use a dominant firm facing a competitive fringe model rather than the usual dupolistic-oligopolistic framework. This choice is due to several reasons, either methodological or practical. On the methodological side, the attraction of this characterization is that it avoids the implausible extreme of perfect competition and pure monopoly, at the same time escaping the difficulties of characterizing an oligopolistic equilibrium[5]. On the practical side, it is well suited to simulate the structural features of the Italian market which is the empirical case analysed in this paper[6].

The article proceeds as follows. Section 2 focuses on the theoretical analysis. Firstly we will carry out a model which will be used in order to derive the price equilibria and the marginal pass-through rates. We will discuss various possible scenarios depending on the following factors: (1) the leader's share of the total capacity in the market (degree of market concentration); (2) the plant mix operated by either the dominant firm or the competitive fringe; (3) the allowance price (lower or higher than the so-called "switching price"); (4) the available capacity in the market (whether there is excess capacity or not). Section 3 sets out the empirical analysis. The Italian power market, an emblematic case of imperfect competition, will be analysed in order to check the robustness of the model

[5]In particular, this model allows us to overcome the problem of possible inexistent equilibria in pure strategy. In their article on spot market competition in the UK electricity industry, using a typical duopolistic framework, von der Fehr and Harbord (1993) demonstrate that under variable-demands period (i.e. when the range of possible demands exceeds the capacity of the largest generator) there does not exist an equilibruim in pure strategy. Instead, there exist a unique mixed-strategy Nash equilibrium.

[6]Indeed, the dominant firm-competitive fringe model is useful to represent the reality of several power markets. We especially refer to those markets emerging from restructuring processes where the incumbent is obliged to sell a portion of his capacity to different firms and new independent producers meet the rise in power demand over time. This is the case of Italy where Enel was obliged to sell 15,000 MW to three different buyers and now holds around 50% of the total power capacity installed in Italy (including imported power). The wholesale spot market started in 2004 and during the first year the power firms other than Enel behave as a competitive fringe. In fact, their bid prices were very close to marginal cost (or, in some circumstances, nil).

predictions. Finally, section 4 summarizes the main results of the article.

2. Theoretical analysis

2.1. The model: basic assumptions. This subsection describes the structure of the model detailing the main assumptions on the regulation of the electricity and emissions allowance markets.

Concerning power demand, consistently with most contributions on this topic, we assume power demand is inelastic[7], predictable with certainty and given by a typical load duration curve $D = K(H)$, where $H = K^{-1}(K)$ is the number of hours (the reference time unit adopted here) in the reference time period (e.g. the year) that demand is equal to or higher than K $(K(H) \geq K)$, where $0 \leq H \leq H_L$. $K_L = K(H_L)$ is the base-load demand (the minimum level) and $K_H = K(0)$ is the peak-load demand (the maximum level).

With regard to power supply, we model technologies by means of two distinctive elements: variable costs (essentially, fuel costs) and CO_2 emission rates (emissions per unit of electricity generated).

In particular, CO_2 emission rate is $e \geq 0$ and variable cost of production is $v \geq 0$ for production levels less than capacity, while production above capacity is impossible (i.e. infinitely costly).

Since we simulate a uniform, first price auction, it suffices focusing on technologies which have a positive probability of becoming the marginal operating unit. This allows us to neglect, without loss of generality, those technologies suited to meet the base-load demand (i.e. nuclear and large hydropower plants, renewable technologies, cogeneration plants and so on) or which are inelastically supplied.

Given these premises, we restrict the analysis to two groups of plants, a and b, and assume that each group includes a very large number n of homogeneous generating units[8] such that

$$K_j = \sum_{i=1,2..n} k_j^i = nk_j,\ j = a, b \text{ and } v_j^i = v_j; e_j^i = e_j, \forall i, j$$

[7] The majority of consumers purchase electricity under regulated tariffs which are independent of the prices negotiated in the wholesale market, at least in the short run. This can justifies the assumption of price-inelastic demand. See Wolak and Patrick (1997).

[8] Assuming that each group includes the same number n of units implies that k_j depends on K_j. This is an arbitrary assumption which does not undermine, however, the significance of the analysis.

where $v_j^i = v_j > 0$ and $k_j^i = k_j > 0$ are the variable cost and the capacity of the i-th unit belonging to the group j, respectively. Thus K_a and K_b are the installed capacity of groups a and b, respectively.

Furthermore, we assume $v_a < v_b$ and $K_a + K_b = K_H$, i.e. the units of kind a and b are sufficient to meet the peak demand, and consider two scenarios: Scenario 1 in which there is trade-off between variable costs and emission rates (hereafter "trade-off in the plant mix"), i.e. the technology with lower variable cost is the worse polluter ($v_a < v_b$ and $e_a > e_b$, a typical relevant example is given by coal plants (a) versus CCGT -combined cycle gas turbine- technologies (b)); Scenario 2 in which there is not such a trade-off, i.e. the technology with lower variable cost is also the cleaner technology ($v_a < v_b$ but $e_a < e_b$, a typical relevant example is given by CCGT plants (a) versus steam cycle plants (b)). These two scenarios are well suited to represent the Italian market which is the context used for the empirical analysis.

Emission abatement is supposed to be impossible or, equivalently, abatement cost infinitely costly. This hypothesis is consistent with the time horizon of the analysis (short term analysis of the ETS impact).

Concerning the wholesale market, we assume a typical day ahead market. Before the actual opening of the market (e.g. the day ahead) the generators simultaneously submit bid prices for each of their units on hourly basis. We neglect the existence of technical constraints such as start-up costs. The auctioneer (generally the so-called market operator) collects and ranks the bids by applying the merit order rule. The bids are ordered by increasing bid prices and form the basis upon which a market supply curve is carried out.

If called upon to supply, generators are paid according to the market-clearing spot price (the system marginal price, equal to the highest bid price accepted). All players are assumed to be risk neutral and to act in order to maximize their expected payoff (profit). Production costs, emission rates as well as plants' installed capacity are common knowledge.

Given the regulatory framework described above, it is straightforward that price equilibria will depend on the power demand level. Since this latter continuously varies over time, an useful way of representing the price schedule is carrying out the so-called price duration curve $p(H)$ where H is the number of hours in the year that the power price is equal to or higher than p.

With regard to the allowance market, we suppose this market is very large (consistently with the extent of the European ETS) and that firms are price takers. Therefore, the allowance price, p^{tp}, is given exogenously. Carbon emissions allowances are allocated free of charge and on the basis of the amounts emitted in a base period, generally a year in the past (typical grandfathering) or the present year or on the basis of the expected emissions in the future[9].

Finally, we assume that firm's offer prices are constrained to be below some threshold level, $\widehat{p}$, which can be interpreted in several ways.

It may be a (regulated) maximum price, $\overline{p}$, as officially introduced by the regulator or we can suppose that it is not introduced officially but simply perceived by the generators, i.e. firms believe that the regulator will introduce price regulation if the price rises above the threshold. This latter interpretation is well-suited to the topic analysed here. In fact, firms might decide to bring bid prices down not only to avoid regulation in the wholesale electricity market but also to avoid a change in the allowance allocation method, e.g. from freely allocation to auctioning[10]. For these reasons we think that it is acceptable assuming the price cap is insensitive to the CO_2 price.

Alternatively, we can suppose that there is so much generation that price never is above the marginal cost of a peaker. In order to simulate this situation, we introduce a third technology, c, such that $v_c > \max[v_a,\ v_b]$ and whose capacity is great enough, $K_c = \overline{K}_c$, that the dominant firm does not try to let it all run and drive the price up to the price cap. Instead, $K_c = 0$, is useful to simulate the situation in which there is not excess capacity in the market and prices can reach the price cap, $\overline{p}$. Finally, we assume that $e_a > e_c > e_b$ in the Scenario 1 and $e_c > e_b > e_a$ in the Scenario 2. These choices are crucial for our analysis but not arbitrary. Technoogy c, in fact, can be interpreted as a typical peaking technology (in the Italian market, old oil-fired plants or gas turbine plants) whose electrical efficiency is generally much lower than that of the CCGT. Furthermore, this technology is generally more polluting than CCGT (or gas-fired steam cycle plants)

[9] For a comparative analysis of the different allocation methods, see Harrison and Radov (2002) and Burtraw et al. (2001).

[10] For instance, in Germany, where there is a controversial debate on this topic, Eon, one of the leading power firms, argues that "there is no scope to remove windfall profits from the EU-ETS, only redistribute them, so efforts should be focused on bringing the electricity price down".

but cleaner than coal plants.

In brief, we will consider two scenarios (Scenario 1 and Scenario 2, with and without "trade-off in the plant mix", respectively) and, for each of them, two cases of available capacity in the market, excess capacity ($K_c = \overline{K}_c$) and scarcity of generation capacity ($K_c = 0$).

2.2. Price duration curves. In order to derive price equilibria in the form of price duration curves, we have to start from how the ETS impacts on marginal production costs. Given that an emission allowance represents an opportunity cost, the marginal cost of production is expected to include the full carbon opportunity cost, regardless of whether allowances are allocated free of charge or not. Formally,

$$MC_j^i = v_j^i + p^{tp} e_j^i \tag{1}$$

where MC_j^i is the marginal cost of the i-th unit belonging to the group j of plants and $p^{tp} e_j^i$ is the corresponding carbon opportunity cost.

Given equation (1) and for the purpose of this analysis, the generating units belonging to the group j of plants are the most (least) efficient units if their marginal cost (including the carbon opportunity cost) is lower (higher) than that of the units belonging to the other group i.

Furthermore, looking at the Scenario 1 ("trade-off in the plant mix"), there exists an allowance price, the "switching price" $p^{tp*} = (v_b - v_a)(e_a - e_b)$, such that the marginal cost of the plants of the group a, MC_a, is equal to that of the plants of the group b, MC_b. Allowance prices are defined as low if $p^{tp} \leq p^{tp*}$ and high if $p^{tp} > p^{tp*}$.

Finally, the marginal carbon opportunity cost is the price of the CO_2 emissions allowance multiplied by the emission rate of the marginal production unit.

Given these definitions, the change (due to the ETS) in marginal production cost of the marginal unit is given by

$$\Delta MC = \begin{cases} \overline{MC} - v_b & \forall K \in \left]K_H; \underline{K}\right] \\ \underline{MC} - v_a & \forall K \in \left]\underline{K}; K_L\right] \end{cases}$$

where

$\overline{MC} = \max\{MC_a = v_a + p^{tp} e_a; MC_b = v_b + p^{tp} e_b\}$

$\underline{MC} = \min\{MC_a = v_a + p^{tp} e_a; MC_b = v_b + p^{tp} e_b\}$

$$\text{and } \underline{K} = \begin{cases} \begin{cases} K_a & \text{if } p^{tp} \leq p^{tp*} \\ K_b & \text{if } p^{tp} > p^{tp*} \end{cases} & \text{when } v_a < v_b \text{ and } e_a > e_b \\ K_a \;\; \forall p^{tp} & \text{when } v_a < v_b \text{ and } e_a < e_b \end{cases}$$

Notice that ΔMC is equal to the impact of the ETS under perfect competition. In this case, in fact, prices equal the marginal cost of the marginal unit regardless of the power demand level.

We are now able to simulate the impact of market power on power pricing. For this purpose, as previously pointed out, we adopt a dominant firm facing a competitive fringe model. The general formulation of the model assumes that the dominant firm owns and operates $z \in [0; 2n]$ units of both group a and b while the remaining units are operated by $2n - z$ firms behaving as a competitive fringe. Obviously, $z = 0$ corresponds to the case of pure competition while $z = 2n$ to that of pure monopoly.

In order to derive the price schedule in the form of a price duration curve, we introduce the following parameters.

The first parameter is $\delta \in [0; 1]$ representing the share of the total power capacity in the market operated by the dominant firm. Complementary, the competitive fringe operates a share $(1 - \delta)$ of the total power capacity. Thus, δ can be interpreted as a measure of the degree of market concentration.

The other parameters are $\underline{\mu}^d \in [0; 1]$ and $\underline{\mu}^f \in [0; 1]$ representing the share of power capacity the strategic operator and the competitive fringe get in most efficient plants, respectively. By complement, $\overline{\mu}^d = (1 - \underline{\mu}^d)$ and $\overline{\mu}^f = (1 - \underline{\mu}^f)$ are the same in the least efficient ones.

By facing the competitive fringe, the dominant firm has two alternative strategies: (1) bidding the price threshold $(\widehat{p})$ so accommodating the maximum production by the fringe or (2) competing *à la Bertrand* with the rivals in order to maximize his market share.

Let $\underline{K}^f$ be the installed capacity in most efficient plants operated by the competitive fringe. Thus $\underline{K}^f = \underline{\mu}^f (1 - \delta) K_H$, and $\underline{H}^f = K^{-1}(\underline{K}^f)$.

Similarly, let $\overline{K} = K_H - \overline{K}^d$ be the peak demand minus the dominant firm's capacity in least efficient plants $(\overline{K}^d)$. Thus $\overline{K} = \left(1 - \delta \overline{\mu}^d\right) K_H$, and $\overline{H} = K^{-1}(\overline{K})$.

Finally, $\underline{K} = \left[\underline{\mu}^d \delta + \underline{\mu}^f (1 - \delta)\right] K_H$ is the total capacity in most efficient plants, al-

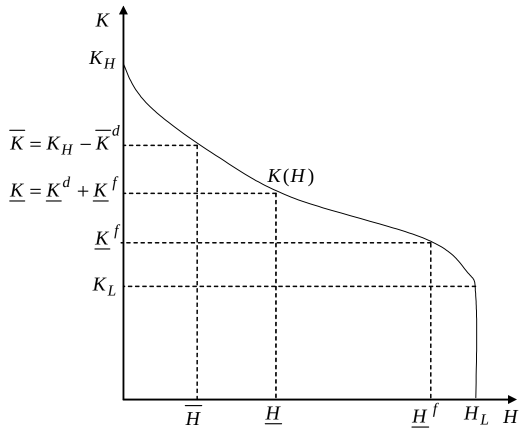

Figure 1: An example of supply configuration

ready introduced in the previous section.

It is important to note that δ determines not only the degree of market concentration but also the total share of most efficient plants in the market, $\underline{K}$. In particular, increasing δ implies increasing $\underline{K}$ if $\underline{\mu}^d > \underline{\mu}^f$, and vice versa if $\underline{\mu}^d < \underline{\mu}^f$.

Figure 1 shows an (generic) example of possible power supply configuration.

The following Lemma describes the shape of the price duration curve.

Lemma 1. *There exists $\widehat{K} \in \left]\overline{K}; \underline{K}^f\right]$ such that the system marginal prices equal the price threshold $\widehat{p}$ when $K \geq \widehat{K}$ and the marginal cost of the least efficient plants $(\overline{MC})$ when $K < \widehat{K}$. When $K < \underline{K}^f$, pure Bertrand equilibria (first marginal cost pricing) arise and prices equals the marginal cost of the most efficient plants $(\underline{MC})$, where*

$$\widehat{K} = \begin{cases} \widetilde{K}\left(\delta, \underline{\mu}^d, \zeta\right) = \left[\underline{\mu}^d \delta\zeta + (1-\delta)\right] K_H & \text{for } \widehat{K} > \underline{K} \\ \widetilde{\widetilde{K}}\left(\delta, \underline{\mu}^f, \zeta\right) = (1-\delta)\left[\dfrac{(1-\underline{\mu}^f)}{(1-\zeta)} + \underline{\mu}^f\right] K_H & \text{for } \widehat{K} \leq \underline{K} \end{cases}$$

and $\zeta = \dfrac{\left(\overline{MC} - \underline{MC}\right)}{\widehat{p} - \underline{MC}}$ with $\widehat{p} = \begin{cases} \overline{p} & \text{for } K_c = 0 \\ MC_c & \text{for } K_c = \overline{K}_c \end{cases}$

Proof. See the Appendix. ■

Therefore, two possible price duration curves are possible depending on whether the discontinuity is at $\widetilde{H} = K^{-1}(\widetilde{K})$ or $\widetilde{\widetilde{H}} = K^{-1}(\widetilde{\widetilde{K}})$. The following Proposition identifies the critical value of δ which discriminates between these two cases.

Proposition 1. *Under market power, there exists* $\underline{\delta}(\underline{\mu}^d, \underline{\mu}^f, v_j, e_j, p^{tp})$ *such that*

$$p = \begin{cases} \widehat{p} & \forall K \in \left[0; \widehat{K}\right] \\ \overline{MC} & \forall K \in \left]\widehat{K}; \underline{K}^f\right] \\ \underline{MC} & \forall K \in \left]\underline{K}^f; K_L\right] \end{cases}$$

$$\text{where: } \widehat{p} = \begin{cases} \overline{p} & \text{for } K_c = 0 \\ MC_c & \text{for } K_c = \overline{K}_c \end{cases} ; \widehat{K} = \begin{cases} \widetilde{K} & \text{if } \delta < \underline{\delta} \\ \widetilde{\widetilde{K}} & \text{if } \delta \geq \underline{\delta} \end{cases} \text{ and } \underline{\delta} = \frac{\underline{\mu}^f - 1}{\underline{\mu}^f - 1 + \underline{\mu}^d(\zeta - 1)}$$

Proof. See the Appendix. ■

By differentiating $\widetilde{K}$ and $\widetilde{\widetilde{K}}$ with respect to $\underline{\mu}^d$, $\underline{\mu}^f$, we find that the degree of market power (which decreases in $\widehat{K}$) is an increasing function of $\underline{\mu}^f$, when $\delta > \underline{\delta}$, and a decreasing function of $\underline{\mu}^d$, when $\delta < \underline{\delta}$ (see the Appendix).

Understanding how market power depends on the allowance price (i.e. how the ETS impacts on market power) is a little bit more complex. The following corollary describes this kind of correlation under low allowance prices[11] (the most relevant case for the empirical analysis of this paper).

Corollary 1. *Under low allowance prices, the ETS determines an increase in market power ($\widehat{K}$ decreases in p^{tp}) if $(\overline{e} - e_a)/(\overline{v} - v_a) > (e_b - e_a)/(v_b - v_a)$, where: $\overline{e} = e_c$ and $\overline{v} = v_c$, under excess capacity; $\overline{e} = 0$ and $\overline{v} = \overline{p}$, without excess capacity.*

Proof. For the formal proof, see the Appendix. Intuitively, the ETS can increase market power when the change in the cost structure between the technologies makes more profitable bidding the price threshold rather than the marginal cost of the least efficient plants, i.e. when $(\overline{e} - e_a)/(\overline{v} - v_a) > (e_b - e_a)/(v_b - v_a)$. This condition always (never) is satisfied if "trade-off in the plant mix" combines with excess capacity (without both "trade-off in the plant mix" and excess capacity). Otherwise, it is satisfied only under certain values of v_j and e_j. ■

[11] When allowance prices are high the framework is even more complex. Since understanding how the ETS impacts on market power under all conditions is beyond the scope of this paper, we neglect the formal analysis of what can occur under high allowance prices.

2.3. Marginal pass-through rate. Since we intend to consider the overall change in marginal prices due the ETS, an useful way of proceeding is evaluating the marginal pass-through rate defined as follows.

Definition 1. *The marginal pass-through rate (MPTR) is the change in power prices, $\triangle p$, divided by the change in marginal production costs of the marginal unit, ΔMC, due to the ETS.*

Notice that the MPTR is always equal to 1 under perfect competition. In this case, in fact, prices equal the marginal cost of the marginal unit regardless of the power demand level.

Table 1: Parameter expressions before and after the ETS

	Before ETS	Scenario 1		Scenario 2
	$p^{tp}=0$	$p^{tp} \leq p^{tp*}$	$p^{tp} > p^{tp*}$	$\forall p^{tp}$
MC_c	v_c	MC_c	MC_c	MC_c
$\overline{MC}$	v_b	MC_b	MC_a	MC_b
$\underline{MC}$	v_a	MC_a	MC_b	MC_a
$\underline{\mu}^d$	μ_a^d	μ_a^d	μ_b^d	μ_a^d
$\underline{\mu}^f$	μ_a^f	μ_a^f	μ_b^f	μ_a^f

In order to carry out the MPTR curve (i.e. how the MPTR is distributed over time), we have to depict the price and marginal cost (of the marginal unit) duration curves before and after the ETS distinguishing between low ($0 < p^{tp} \leq p^{tp*}$) and high ($p^{tp} > p^{tp*}$) allowance prices (only for the Scenario 1). Table 1 shows the different expressions of MC_c, $\overline{MC}$, $\underline{MC}$, $\underline{\mu}^d$, $\underline{\mu}^f$ corresponding to the situations after and before the ETS. We will use the superscript star (*) in order to address the critical threshold of K, H, and δ when $p^{tp} \neq 0$ (i.e. the situation after the ETS).

In what follows, we will present some relevant examples of marginal pass-through rate curves corresponding to different scenarios in terms of available capacity, market concentration and plant mix. For the sake of simplicity, we will illustrate only the outcome under low allowance prices while that under high allowance prices is reported in the Appendix.

Scenario 1 ("trade-off in the plant mix"): low allowance prices. In this case, $\widehat{K}$ always decreases in p^{tp} under excess capacity whereas may either decrease or increase under scarcity of generation capacity (see proof of Corollary 1). We refer to increasing market power because this is the most likely situation given the plausible plant mix in the market: coal plants (a), CCGT (b) and oil-fired plants (c). In fact, by using the emission rates and variable costs of these technologies (tab. 4 in the Appendix), we get $(\overline{e}-e_a)/(\overline{v}-v_a) > (e_b-e_a)/(v_b-v_a)$, regardless of the available capacity in the market. Thus, three relevant configurations (corresponding to three possible values of market concentration) have to be analysed (see Lemma 1 and Proposition 1): $\widetilde{K} > \widetilde{K}^* > \underline{K}$ $(\delta < \underline{\delta}^* < \underline{\delta})$; $\widetilde{K} > \underline{K} > \widetilde{\widetilde{K}}^*$ $(\underline{\delta}^* < \delta < \underline{\delta})$; $\underline{K} > \widetilde{\widetilde{K}} > \widetilde{\widetilde{K}}^*$ $(\underline{\delta}^* < \underline{\delta} < \delta)$.

Figures 2 and 3 illustrate the MPTR curves obtained by deviding the change in prices by the change in marginal production cost of the marginal unit[12]. For the sake of simplicity and without loss of generality, we assume that the dominant firm and the competitive fringe operate the same share of most efficient plants ($\underline{\mu}^d = \underline{\mu}^f$).

Figures clearly show that results largely depends on the power demand level (peak vs. off-peak hours) and the available capacity in the market.

In the peak hours, there would not be any CO_2 cost pass-through under scarcity of generation capacity (provided that δ is enough high) whereas, under excess capacity, the MPTR would be more than 1.

In the off-peak hours power prices can include the full marginal carbon cost but even much less if the share of most polluting plant in the market is enough high[13]. This is more likely to occur under excess capacity than under scarcity of generation capacity.

Scenario 2 (without "trade-off in the plant mix"): low allowance prices. In this case, as pointed out before (proof of Corollary 1), under excess capacity both $\widehat{K} > \widehat{K}^*$ and $\widehat{K}^* > \widehat{K}$ are possible whereas under scarcity of generation capacity market power always decreases in p^{tp} $(\widehat{K}^* > \widehat{K})$, regardless of v_j and e_j. This time a, b and c may be CCGT, gas-fired steam cycle plants and oil-fired steam cycle plants, respectively (plausible plant mix).

[12] Curves are carried out by assuming 20 €/tonCO_2, which is consistent with the range of varibility during 2005 and 2006.

[13] In fact, a rise in $\underline{\mu}^f$ determines decreasing $\underline{H}$ and $\underline{H}^f$ while $\widetilde{H}$ and $\widetilde{H}^*$ do not vary. At the same time, to the extent to $\underline{\mu}^d$ decreases, $\underline{H}$ moves slowly towards the low-load together with $\widetilde{H}$ and $\widetilde{H}^*$. The range of hours in which the MPTR is less than 1 will tend therefore to disappear.

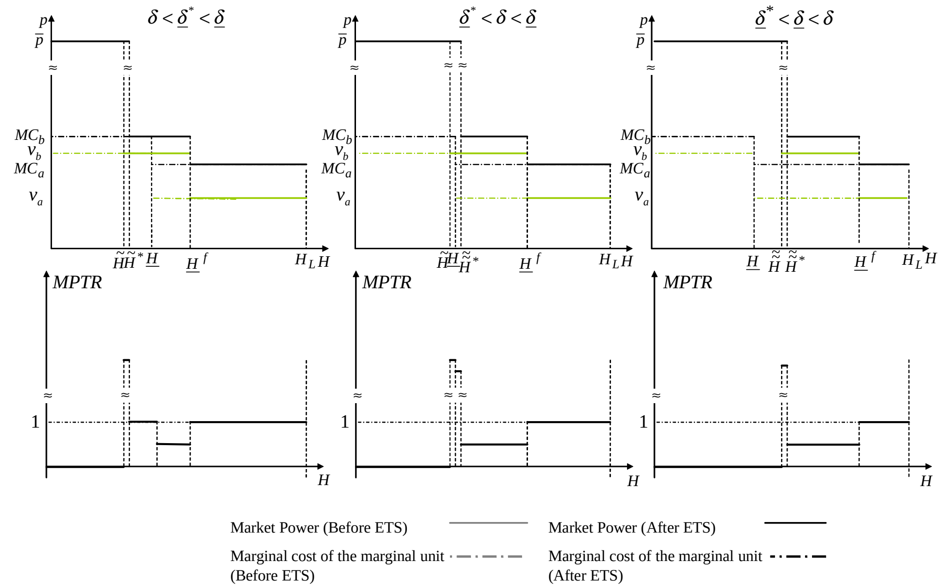

Figure 2: Marginal pass-through rate (MPTR) curve (Scenario 1): low allowance prices and without excess capacity ($\underline{\mu}^d = \underline{\mu}^f$)

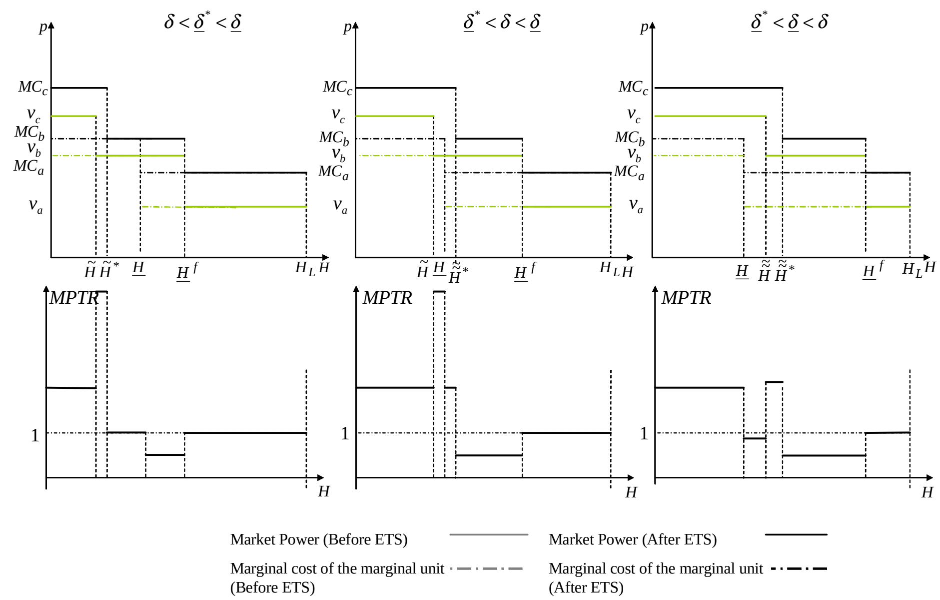

Figure 3: Marginal pass-through rate (MPTR) curve (Scenario 1): low allowance prices and excess capacity ($\underline{\mu}^d = \underline{\mu}^f$)

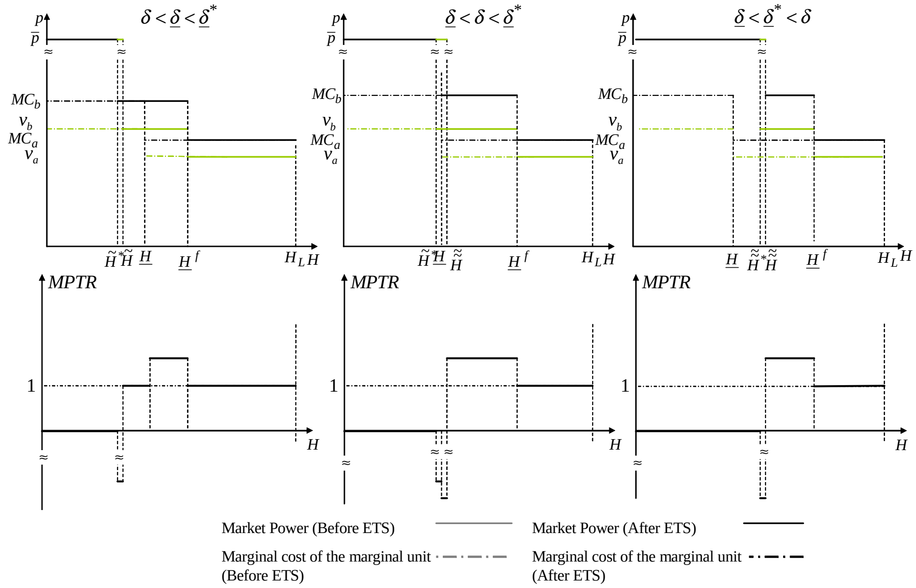

Figure 4: Marginal pass-through rate (MPTR) curve (Scenario 2): low allowance prices and without excess capacity ($\underline{\mu}^d = \underline{\mu}^f$)

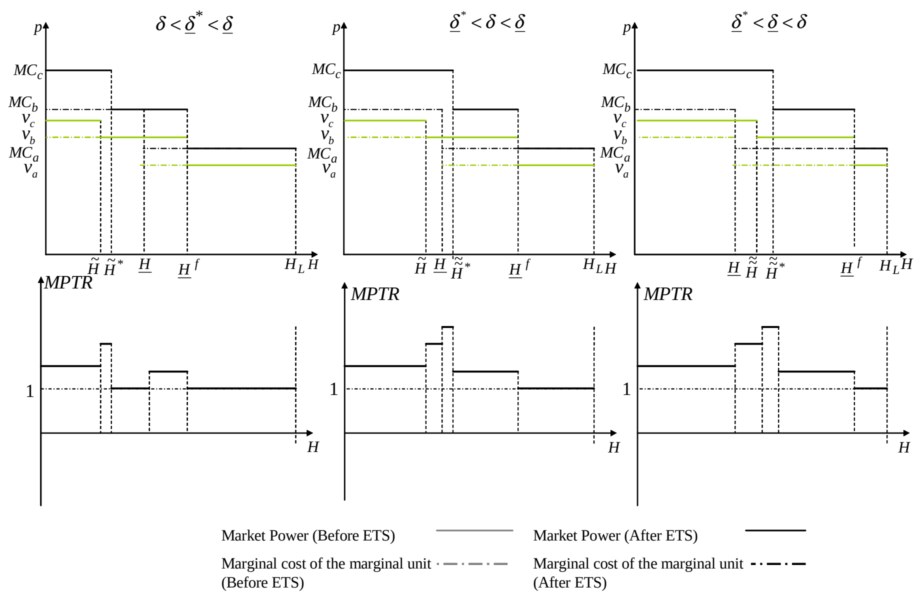

Figure 5: Marginal pass-through rate (MPTR) curve (Scenario 2): low allowance prices and excess capacity ($\underline{\mu}^d = \underline{\mu}^f$)

By using the emission rates and variable costs of these technologies (table 4 in the Appendix), we get $(\overline{e} - e_a)/(\overline{v} - v_a) > (e_b - e_a)/(v_b - v_a)$, under excess capacity (i.e. increasing market power), and $(\overline{e} - e_a)/(\overline{v} - v_a) < (e_b - e_a)/(v_b - v_a)$, without excess capacity (i.e. decreasing market power).

Therefore, the following configurations have to be analysed: $\widetilde{K} > \widetilde{K}^* > \underline{K}$ ($\delta < \underline{\delta}^* < \underline{\delta}$), $\widetilde{K} > \underline{K} > \widetilde{\widetilde{K}}^*$ ($\underline{\delta}^* < \delta < \underline{\delta}$), $\underline{K} > \widetilde{\widetilde{K}} > \widetilde{\widetilde{K}}^*$ ($\underline{\delta}^* < \underline{\delta} < \delta$), under excess capacity; $\widetilde{K}^* > \widetilde{K} > \underline{K}$ ($\delta < \underline{\delta} < \underline{\delta}^*$), $\widetilde{K}^* > \underline{K} > \widetilde{\widetilde{K}}$ ($\underline{\delta} < \delta < \underline{\delta}^*$), $\underline{K} > \widetilde{\widetilde{K}}^* > \widetilde{\widetilde{K}}$ ($\underline{\delta} < \underline{\delta}^* < \delta$), under scarcity of generation capacity.

In the peak hours (figs. 4 and 5), the results are similar to those emerging from the Scenario 1 (MPTR more than 1, under excess capacity, and less than 1, under scarcity of generation capacity).

In the off-peak hours, instead, the outcome is substantially different. This time power prices fully include the marginal carbon opportunity (and even much more in the mid-merit hours), regardless of the share of most (least) polluting plants in the market.

3. Empirical analysis

With regard to the impact of the ETS on power prices, the empirical literature provides a controversial framework. Some authors argue in favour of a full (or almost full) pass-through[14]. Others find that the CO_2 costs seem to have not (yet) been fully passed into power prices[15] or that there is limited evidence that CO_2 is factored in wholesale price[16]. This controversial framework arises even though authors analyse the same set of markets.

Therefore, we are not able to check the robustness of our model on the basis of the

[14] For instance, by analyzing the spark spread (the difference between the power price and the cost of gas to produce a MWh of electricity) in Germany, the Netherland and United Kingdom, Newbery (2005), relying on visual interpretation, states that "most if not all of the EUA (EU Emission Allowance) opportunity cost has been passed through into the wholesale price" and ".... possibly more in the presence of market power". Sijm et al. (2006) argue in favour of a full pass-through, especially in Germany. Honkatukia et al. (2006) find that "on average, about 75% to 95% of a price change in EU ETS is passed on to the Finnish NoordPool spot price".

[15] This is the case, for example, of Sijm et al. (2005) who analyze the German and Dutch markets. The authors calculate the dark spread (the difference between the power price and the cost of coal to produce a MWh of electricity) in the peak and off-peak hours in the case of Germany and the spark spread in the case of the Netherland. They find that that the pass through rates are higher in Germany (where there is a large share of coal plants) and lower in the Netherland (where there is a large share of gas-fired plants).

[16] See Levy (2005). The author bases his analysis on the correlation between wholesale prices, fuel costs and CO_2 prices in the case of France, Germany, Spain and UK.

current literature, not only because of the (significant) disparities in (and possible limits of) the methodologies and the uncertainty and immaturity of the CO_2 market but also because these studies do not focus on the problem of measuring the effect of market power. Thus, the need of carrying out a specific empirical analysis arises.

For this purpose, we examine the Italian context which is a highly concentrated market where Enel, the dominant firm (holding around 50% of the total power capacity in the market) is able to exert a high degree of market power. Furthermore, this context is interesting for another reason. Because of the features of the electricity transport grid, the Italian wholesale power market can be split into four sub-markets (North, macro-South, macro-Sicilia and Sardegna).

Table 2: Structural features of the Italian sub-markets (2005)

	North	macro-South	macro-Sicilia	Sardegna
Peak demand (MW)	28,800	18,000	3800	1900
Available installed capacity$^{(1)}$ (MW)	37,000	18,500	6400	2800
Share of capacity operated by the first company (%)	40	70	50	39
Share of capacity operated by the second company (%)	14	14	23	24

Source: our estimations and AEEG (2005)

(1) including imported power

Table 2 shows the main structural features of these sub-markets in terms of maximum power demand, available capacity and market concentration. As can be noted, Sardegna and macro-Sicilia sub-markets are tyipical duopolies (Sardegna more than macro-Sicilia) whereas the North and macro-South sub-markets are well-suited to be described by a dominant firm facing a competitive fringe model. In addition, in the North of Italy the degree of market concentration is relatively low and there is excess of generation capacity whereas in the South the degree of market concentration is very high and there are problems of scarcity of generation capacity[17]. Analysing separately these sub-markets,

[17] Generally, security of supply needs a reserve margin in peaking technologies around 5-10% of the total installed capacity. Conventionally, above (below) this threshold we face excess capacity (scarcity of capacity).

therefore, might allow us to check the robustness of the theoretical analysis with respect to the combined effect of the different structural factors of the power market.

In the emprical literature generally two approach are used in order to estimate the rates of passing through CO_2 opportunity costs[18]. One approach, the most used, relies on the forward markets. The pass-through rates are estimated by assessing the extent to which changes in forward power prices can be explained by changes in underlying forward prices for fuel and CO_2 allowances. The other approach relies on spot markets by comparing hourly electricity prices for the period after the ETS with the corresponding hourly electricity prices in the period before the ETS (generally the year 2004).

Since in Italy currently there are not forward markets, we are obliged to use the second approach which implicitily assumes that factors other than CO_2 and fuel costs do not change from 2004 to the subsequent years (2005 and 2006). According to this, the difference in the electricity price during a specific hour after the introduction of the ETS and the corresponding hour in 2004 would be explained by the difference in fuel prices during the hours concerned, the impact of the CO_2 price and by an error term[19].

Adopting this approach would imply that we should calculate the relevant spread (i.e. the difference between the electricity price and the cost of fuel to produce an unit of electricity of the marginal plant) in the peak and off-peak hours (or in a particular hour of the day) in every day of 2005 and 2006 and compare it with the corresponding spread in 2004.

Nevertheless we think this way of proceeding might not be well-suited to our case, for the following reason. It is based on the comparison of prices and spreads corresponding to the same hour (or set of hours) in each day in different years under the implicit assumption that the marginal technology (i.e. technology setting prices) does not vary from a year to another on hourly basis. This hypothesis might be acceptable only if the demand level in each hour does not change substantially from a year to another or if the power generating system is characterised by low technological heterogeneity[20] (i.e. a situation in which only one kind of technology has a positive probability to become the marginal unit in most

[18]See Sijm et al. (2006).

[19]See Sijm et al. (2006).

[20]This method is well suited to study markets where generation is mostly based on the use of a specific fuel (like in Germany where power generation is mostly based on coal plants).

hours, regardless of the power demand level).

Since this is very unlikely to occur, the time series approach (without appropriate and complicated elaborations) may lead to incorrect interpretation. Consequently, it seems more appropriate (and simple) reasoning in terms of load duration curves instead of time series, i.e. directly comparing prices corresponding to similar levels of power demand in different years. This approach, moreover, is consistent with the theoretical analysis presented above.

Table 3: Tecnology mix in the Italian sub-markets (2005)

	Enegy supply by technology		Number of hours in which each technology sets prices	
	North	South	North	South
Gas turbine	2%	1%	1%	1%
Hydro	18%	9%	39%	3%
Oil-fired steam cycle	8%	20%	4%	43%
Gas-fired steam cycle	12%	19%	16%	43%
CCGT	45%	33%	37%	5%
Coal	13%	12%	2%	4%
Other	2%	6%	1%	1%
Total	100%	100%	100%	100%

Source: Italian Market Operator (GME) and our estimates

Furthermore, since the Italian market is the combination of (almost) separated sub-markets (with different features in terms of market power and available capacity), the analysis of this market as a whole might be misleading[21]. To avoid this problem, it is better analysing each sub-market separately, focusing on the North and the macro-South sub-markets, for the reasons already explained.

The approach consists of the following steps. Firstly, it is necessary to carry out the load duration curve and the corresponding price, fuel cost and CO_2 cost curves, by

[21] For example, since the national price (PUN) is the zonal (sub-market) weighted average price, we might find a full pass-through which might be the combination of a marginal pass-through rate higher than 1 in a sub-market and lower than 1 in another sub-market, i.e. a situation in which the overall result is due to a trade-off between complementary regional results.

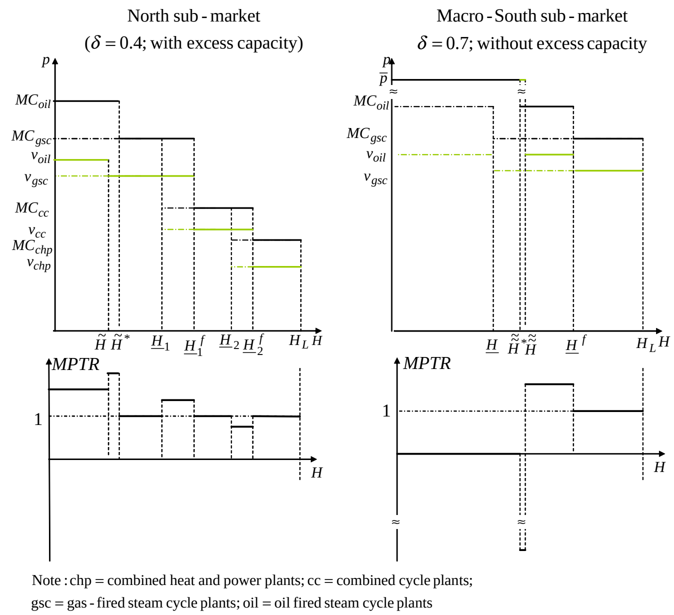

Figure 6: MPTR curves: model simulation (2006 vs. 2005)

ordering power prices, fuel cost and CO_2 cost by decreasing level of demand. Secondly, the spread curve, obtained by subtracting the fuel cost curve from the price curve, is compared to the CO_2 cost curve.

The fuel and CO_2 costs[22] are calculated by accounting for the real plant mix in each sub-market (tab. 3), i.e. by estimating which kind of technology is able to set prices in each hour. In particular, in the North sub-market it is very likely that hydro plants (in Italy, mainly storage and pumped storage hydro plants) could be the marginal units in the peak hours, the CCGT plants in the peak and mid-merit hours and the cogeneration plants (based on the CCGT technology) in the (very) off-peak hours. In the macro-South sub-market, instead, oil-fired and gas-fired steam cycle plants set prices in almost all hours in the year (tab. 3).

Before proceeding it is necessary showing what the model predicts by using the real plants mix and degree of market concentration of each sub-market. The simulation as-

[22] With regard to fuel prices dynamic we use data provided by the Italian Energy Authority for each months in the year. For the CO_2 price, we use the the carbon index of EEX (European Energy Exchange) market. The other European carbon markets show very similar prices.

sumes 20 € per tonne of CO_2 (thus, below the "switching price" between coal and CCGT plants), which is consistent with the range of variability during the period covered by this analysis (2005 and 2006).

Figure 6 shows that in the North of Italy, where there is excess capacity and relatively low degree of market concentration, the electricity prices should include more than the CO_2 cost (MPTR more than 1) in a relativley limited number of peak hours whereas the MPTR should converge to 1 (or just above or below) in the remaining hours[23]. This outcome is obtained by assuming that storage hydro plants bid prices equal to the marginal cost of the gas-fired steam cycle plants[24].

In the South of Italy, where there is not excess capacity and the degree of market concentration is high, power firms should not pass through any CO_2 cost in a large number of peak hours whereas the MPTR should be sensibly more than 1 in the mid-merit hours before converging to 1 in the (very) off-peak hours.

Are the model estimates confirmed by the emprical analysis? In order to answer this question we begin from comparing year 2005 to 2004. The results are illustated in figures 7 and 8.

As can be noted, in both macro-South and North sub-markets the change in spread is almost everywhere negative, legitimating us to say that it is unlikely that power prices included the CO_2 cost in 2005. This result may be explained by the fact that in Italy the CO_2 emission allowances have been allocated only at the beginning of 2006. Consequently, it is presumable that power firms began to pass through the CO_2 cost only in that year, i.e. they decided to do not pass through the CO_2 cost during 2005 (before the allocation)

[23] In the (very) off-peak hours prices are set by the CHP-CCGT plants which are CCGT plants providing combined heat and power generation. The overall efficiency (heat plus power devided by the fuel consumption) of these plants is around 70-80%. Their marginal cost of power production is generally calculated by sharing the total cost between power and heat, on the basis of the energy or the exergy content (or by subtracting the revenue from heat from the total cost). Thus the marginal cost of power production is lower than that of the simple CCGT. With regard to the CO_2 cost the procedure is quite different. In fact, the public authority allocates the allowances on the basis of the total CO_2 emissions without sharing between power and heat. Since the amount of emissions from CHP-CCGT plants is larger than that from a simple CCGT, the CO_2 cost (per unit of electricity) will be significantly higher.

[24] The variable cost of hydro plants is virtually zero. However, because of the scarcity of the water supplies a shadow price, which can be viewed as variable cost, arises. In fact, generating one megawatt-hour in a given hour implies not being able to generate one megawatt-hour in some future hour, so determining an opportunity cost.

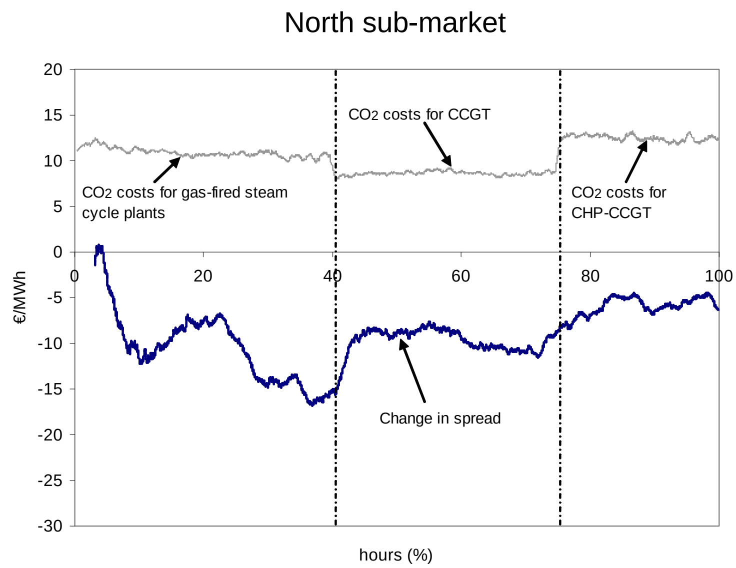

Figure 7: Marginal carbon cost (50-hour moving average) and change in spread (400-hour moving average) curves (2005 vs. 2004)

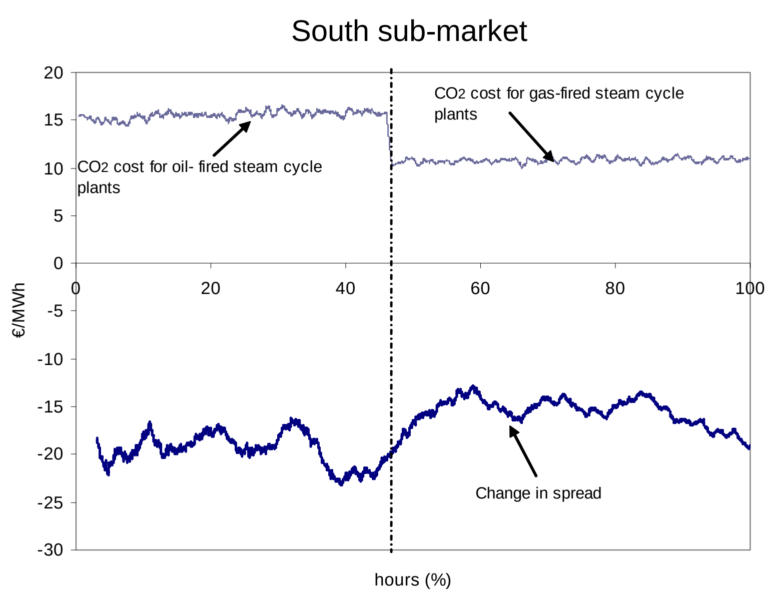

Figure 8: Marginal carbon cost (50-hour moving average) and change in spread (400-hour moving average) curves (2005 vs. 2004)

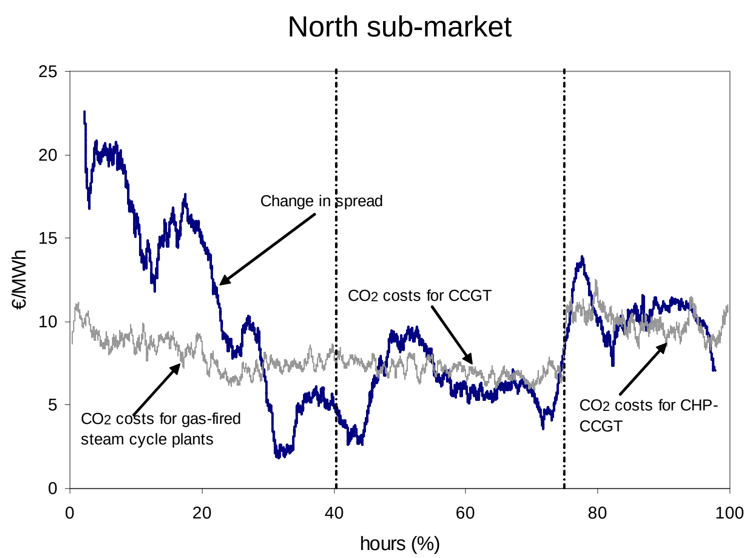

Figure 9: Marginal carbon cost (50-hour moving average) and change in spread (400-hour moving average) curves (2006 vs. 2005)

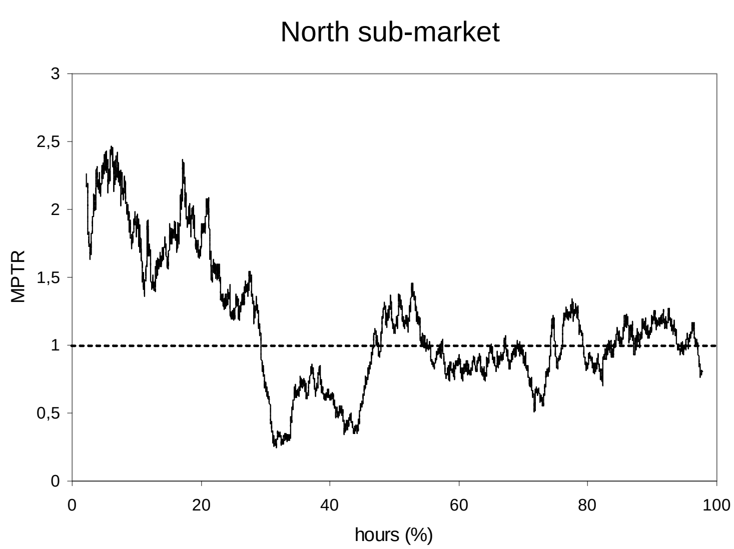

Figure 10: Marginal pass-through rate (MPTR) curve (2006 vs. 2005)

also (perhaps) in order to avoid more restrictive regulation (allowance under-allocation).

The empirical analysis supports this latter hypothesis providing a framework confirming the model predictions. In the North sub-market (fig. 9), the change in spread (2006 vs. 2005) is much higher than the CO_2 cost (close to the carbon cost of a typical peaking technology, i.e. a gas turbine plant or an oil-fired plant) in a relatively limited number of hours (up to 1700, i.e. up to 20% on perecentage basis) in the peak period. In the remaining hours the change in spread is more or less equal to the CO_2 cost for the CCGT and for CHP-CCGT. The shape of the MPTR curve, therefore, is enough similar to that predicted by the model (fig. 10), except for the interval between 2200 and 4000 hours (between 25% and 45% on pecentage basis). In this range, in fact, the model seems to overestimate the pass-through rate[25].

In the South of the country, the change in spread (fig. 11) is much lower than the CO_2 cost (and even negative) in a large number of hours (up to 4000, around 40% on percentage basis) according to model simulation, while converges to the CO_2 cost for gas-fired steam cycle plants only in the (very) off-peak hours. Instead, in between 45% and 60%, it is sensibly more than the CO_2 cost for gas-fired steam cycle plants. According to the model estimates, in this period the dominant firm would set prices by bidding the marginal cost of the oil-fired plants (second marginal cost pricing). Overall, the shape of the empirical MPTR curve (fig. 12) is very close to that predicted by the model which, however, does not explain what occurs in the (very) peak hours (up to 15%) where it seems to sensibly underestimate the MPTR[26].

In conclusion, looking at the overall picture suggests that the results of the simulation model are enough robust. Thanks to the possibility of splitting the Italian market

[25] A partial explaination of this difference might be that in imperfectly competitive market strategic firms find it optimal to move hydro production from hours with high demand to those with lower demand (Bushnell, 2002). Looking at our specific case, this implies that, in a certain range of peak hours (presumably those with lower demand), the increase in prices due to ETS under imperfect competition might equal the CO_2 cost for CCGT whereas, under perfect competition, this increase would equal the CO_2 cost for gas-fired steam cycle plants. Consequetly, the MPTR might be significantly less than 1.

[26] This might be due to a particular event occurred in the beginning of 2006 in Italy. From January to April 2006, in fact, there was a shortage of gas importation from Russia. In order to partly save natural gas storage, public authorities allow power firms to increase the use of heavy fuel oil (higly polluting and costly, given the very low electrical efficiency of the old oil-fired power plants)). This might lead to a change (increase) in the perceived price cap.

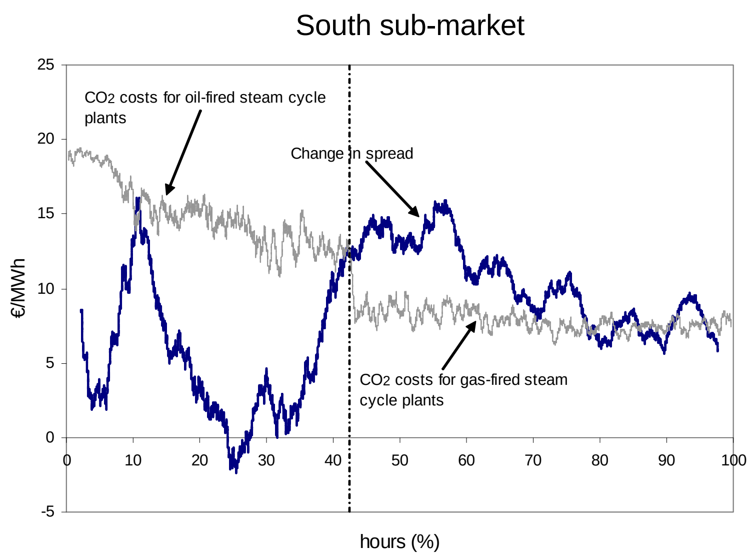

Figure 11: Marginal carbon cost (50-hour moving average) and change in spread (400-hour moving average) curves (2006 vs. 2005)

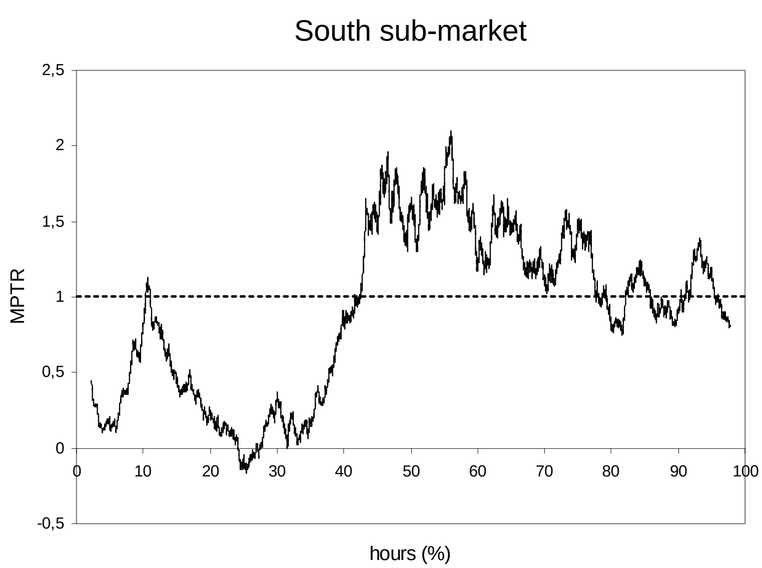

Figure 12: Marginal pass-through rate (MPTR) curve (2006 vs. 2005)

into different sub-markets, the empirical analysis seems to confirm what the model predicts about how the CO_2 price pass-through depends on the combined effect of market concentration, plant mix and available capacity in the market.

4. CONCLUSIONS

In line with economic theory, carbon ETS is expected to determine a rise in marginal cost equal to the carbon opportunity cost regardless of whether carbon allowances are allocated free of charge or not. Hence, common sense would suggest that firms in imperfectly competitive markets will pass-through into electricity prices only a part of the increase in cost.

Instead, the theoretical analysis carried out in this paper shows that the result is ambiguous. The increase in price can be, in fact, either lower or higher than the marginal CO_2 cost depending on several factors: (1) the degree of market concentration, (2) the plant mix operated by either the dominant firm or the competitive fringe, (3) the price of the CO_2 emissions allowances; (4) the available capacity in the market (whether there is excess capacity or not). Furthermore the outcome substantially depends on the power demand level, i.e. if we look at the peak or off-peak hours.

In the peak hours, the marginal pass-through rate (MPTR) is certainly less than 1 under scarcity of generation capacity whereas, under excess capacity, power prices include the full marginal carbon opportunity cost (and even more).

In the off-peak hours the MPTR may be less than 1 only when there is "trade-off in the plant mix" (i.e. the technology with lower variable cost is the worse polluter, such as in the case of coal plants vs. CCGT) and the share of most polluting plants is enough high (regardless of whether there is excess capacity or not).

In order to check the robustness of the model estimates we have carried out an empirical analysis of the Italian market, which is an emblematic case of imperfectly competitive market. However, market power is asimmetrically distributed across the country. It is relativley low in the North where, moreover, there are excess capacity and "trade-off in the plant mix". It is high in the South where, instead, there is scarcity of generation capacity but not "trade-off in the plants mix" (i.e. the technology with lower variable cost is also the cleaner technology, such as in the case of gas fired vs. oil-fired steam cycle plants).

By analysing separately these two sub-markets, we find results confirming the model predictions. In particular, in the North sub-market power prices include more than the marginal CO_2 cost in a relatively limited number of peak hours (up to the dominant firm prefers to use his relatively low market power). In the off-peak hours, the MPTR is equal to 1 (or just below). In the macro-South sub-market, the marginal pass-through rate is much lower than 1 (and even nil) for almost all the peak hours whereas power prices include much more than the CO_2 cost in off-peak hours (converging to the CO_2 cost in the very off-peak hours).

An overall picture, therefore, which seems to support the model simulations and suggests the following consideration. Market power can really determines a deviation from the "full pass-through" rule but we can not know which is the sign of this deviation, *a priori,* i.e. without before carefully taking into account the structural features of the power market.

5. Appendix

Proof of Lemma 1. It is immediately intuitive that when $K \geq \overline{K}$ the system marginal price equals $\overline{p}$ (for $K_c = 0$) or MC_c (for $K_c = \overline{K}_c$). When $K < \underline{K}^f$, pure Bertrand equilibria (first marginal cost pricing) arise and prices equals the marginal cost of the most efficient plants ($\underline{MC}$). In fact, on the one hand, whenever the demand is so high that both leader's and fringe's least efficient units can enter the market, the dominant firm would not gain any advantage by competing *à la Bertrand,* i.e. by attempting to undercut the rivals. Therefore, he will maximize his profit by bidding the price threshold[27]. On the other hand, whenever the power demand is lower than the fringe's power capacity in most efficient plants, competing *à la Bertrand* is the only leader's available strategy in order to have a positive probability of being dispatched. In consequence prices will converge to the marginal cost of the most efficient plants.

It remains to identify the leader's optimal choice on $K \in \left]\overline{K};\underline{K}^f\right]$[28]. Under the assumptions of the model, each generator in the competitive fringe has a unique dominant strategy whatever is the market demand: bidding according to its own marginal cost of production (which, after the implementation of the ETS, includes the carbon opportunity

[27]Strictly speaking, only offer prices of units that may become the marginal units (i.e. units belonging to the group b) need equal the price cap or the backstop price.

[28]Note that assuming a dominant firm with competitive fringe model, rather than an oligopolistic framework, assures that equilibria in pure-strategy do exist. For an explanation of why equilibria in pure strategies do not exist in the case of oligopolistic competition, see von der Fehr and Harbord (1993).

cost). By converse the best choice of the dominant firm might consist in (1) bidding the price cap ($\overline{p}$, if there is not excess capacity, i.e. $K_c = 0$) or the backstop price (MC_c, if there is excess capacity, i.e. $K_c = \overline{K}_c$) or in (2) bidding $\overline{MC}$[29].

Let π_1^d and π_2^d be the profits corresponding to the first and second strategies above, respectively. Whenever the least efficient units could enter the market (i.e. $K(H) > \underline{K}$), the profit the dominant firm earns by choosing the first strategy (i.e. $\forall H \in \left]\overline{H}; \underline{H}\right]$) is

$$\pi_1^d = (\widehat{p} - \underline{MC}) \left[K(H) - K_H (1-\delta)\right] - \sum\nolimits_{i=1}^{z} \sum\nolimits_{j=a,b} \left(k_j^i f_j^i - p^{tp} \overline{E}_j^i\right) \tag{A1}$$

where f_j^i is the capital cost per unit of installed capacity of the unit i-th unit belonging to the group j of plants and $\overline{E}_j^i$ the amount of allowance allocated (free of charge) to the generic plant i belonging to the group j.

If the dominant firm chooses the second strategy, he earns

$$\pi_2^d = \left(\overline{MC} - \underline{MC}\right) \underline{\mu}^d \delta K_H - \sum\nolimits_{i=1}^{z} \sum\nolimits_{j=a,b} \left(k_j^i f_j^i - p^{tp} \overline{E}_j^i\right) \tag{A2}$$

where $\widehat{p} = \begin{cases} \overline{p} & \text{for } K_c = 0 \\ MC_c & \text{for } K_c = \overline{K}_c \end{cases}$

Therefore the leader's optimal strategy is bidding $\widehat{p}$ if and only if $\pi_1^d \geq \pi_2^d$, i.e. if and only if

$$K \geq \left[\underline{\mu}^d \delta\zeta + (1-\delta)\right] K_H = \widetilde{K}(\delta, \underline{\mu}^d, \zeta) \tag{A3}$$

where $\zeta = \dfrac{\left(\overline{MC} - \underline{MC}\right)}{\widehat{p} - \underline{MC}}$

When $K \in \left]\underline{K}; \underline{K}^f\right]$ (i.e. $H \in \left]\underline{H}; \underline{H}^f\right]$) the profit the dominant firm earns by choosing the first strategy is

$$\pi_3^d = (\widehat{p} - \underline{MC}) \left[K(H) - K_H (1-\delta)\right] - \sum\nolimits_{i=1}^{z} \sum\nolimits_{j=a,b} \left(k_j^i f_j^i - p^{tp} \overline{E}_j^i\right) \tag{A4}$$

and by choosing the second strategy, the profit is

$$\pi_4^d = \left(\overline{MC} - \underline{MC}\right) \left[K(H) - K_H \underline{\mu}^f (1-\delta)\right] - \sum\nolimits_{i=1}^{z} \sum\nolimits_{j=a,b} \left(k_j^i f_j^i - p^{tp} \overline{E}_j^i\right) \tag{A5}$$

[29]Strictly speaking, bidding $\overline{MC}$ for units of kind b and $p \leq \overline{MC} - \epsilon$ (where $\epsilon \simeq 0^+$) for units of kind a.

Thus the dominant firm will choose the first strategy (bidding the price cap or the backstop price) if and only if $\pi_3^d \geq \pi_4^d$, i.e. if and only if

$$K \geq (1-\delta)\left[\frac{(1-\underline{\mu}^f)}{(1-\zeta)} + \underline{\mu}^f\right] K_H = \tilde{\tilde{K}}(\delta, \underline{\mu}^f, \zeta) \tag{A6}$$

Therefore the leader's best reply is a function of power demand. We still have to demonstrate that the two critical values $\widetilde{K}$ and $\tilde{\tilde{K}}$ never work together, i.e. if $\widetilde{K} \in \left]\overline{K}; \underline{K}\right[$ then $\tilde{\tilde{K}} \notin \left]\underline{K}; \underline{K}^f\right[$ and vice versa.

Given that $\overline{K}^f = (1-\underline{\mu}^f)(1-\delta)K_H$, $\underline{K}^d = \underline{\mu}^d \delta K_H, K^f = (1-\delta)K_H$ and $\underline{K} = \left[\underline{\mu}^d \delta + \underline{\mu}^f(1-\delta)\right] K_H$, equation (A3) can be rewritten as

$$K(H) \geq \widetilde{K}(\delta, \underline{\mu}^d, \zeta) = \zeta \underline{K}^d + K^f \tag{A7}$$

and equation (A6) as

$$K(H) \geq \tilde{\tilde{K}}(\delta, \underline{\mu}^f, \zeta) = \frac{\overline{K}^f}{1-\zeta} + \underline{K}^f \tag{A8}$$

Assume for instance $\widetilde{K} > \underline{K}$. From (A7) $\dfrac{\overline{K}^f}{(1-\zeta)} > \underline{K}^d$ and from (A8) $\tilde{\tilde{K}} > \underline{K}$. Thus, $\tilde{\tilde{K}} \notin \left]\underline{K}; \underline{K}^f\right[$.

Similarly suppose $\tilde{\tilde{K}} < \underline{K}$. From (A8) $\underline{K}^d > \dfrac{\overline{K}^f}{1-\zeta}$ and from (A7) $\widetilde{K} < \underline{K}$. Thus, $\widetilde{K} \notin \left]\overline{K}; \underline{K}\right[$.

In addition, from (A7) and (A8), if $\widetilde{K} = \underline{K}$ then $\tilde{\tilde{K}} = \underline{K}$ and vice versa.

Finally, note that $\widetilde{K} < \overline{K}$ and $\tilde{\tilde{K}} > \underline{K}^f$.

Last some comparative statics,

$$\frac{\partial \widetilde{K}}{\partial \underline{\mu}^d} = \delta \zeta K_H > 0; \; \frac{\partial \tilde{\tilde{K}}}{\partial \underline{\mu}^f} = -(1-\delta)\frac{\zeta}{1-\zeta} K_H < 0$$

In fact, when $\delta > \underline{\delta}$, increasing fringe's share of most efficient plants implies that bidding the marginal cost of the least efficient plants becomes less profitable for the dominant firm compared to bidding the price cap or the backstop price (π_4^d in equation (A5) decreases whereas π_3^d in equation (A4) does not depend on $\underline{\mu}^f$). Inversely when we look at the case of $\delta < \underline{\delta}$ and at the rise of $\underline{\mu}^d$. This time increasing leader's share of most efficient plants implies that bidding the marginal cost of the least efficient plants becomes more convenient for the dominant firm (π_2^d in equation (A2) increases whereas π_1^d in equation (A1) does not depend on $\underline{\mu}^d$). Furthermore,

$$\frac{\partial \widetilde{K}}{\partial \zeta} = \underline{\mu}^d \delta K_H > 0; \; \frac{\partial \widetilde{\widetilde{K}}}{\partial \zeta} = \frac{(1-\delta)(1-\underline{\mu}^f)}{(1-\zeta)^2} K_H > 0$$

Thus, market power is a decreasing function of ζ.

5.1. Proof of Proposition 1. This proposition follows directly from Lemma 1. Since $\widetilde{K}$ and $\widetilde{\widetilde{K}}$ never work together and provided that when $\widetilde{K} = \underline{K}$ then $\widetilde{\widetilde{K}} = \underline{K}$ (see the proof of Lemma 1 above), in order to identify the critical value of δ it suffices carrying out the locus of points of δ ($\underline{\widetilde{\delta}}$) that $\widetilde{K} = \underline{K}$ which is equal to the locus of points of δ ($\underline{\widetilde{\widetilde{\delta}}}$) that $\widetilde{\widetilde{K}} = \underline{K}$

$$\underline{\widetilde{\delta}} = \underline{\widetilde{\widetilde{\delta}}} = \underline{\delta} = \frac{\underline{\mu}^f - 1}{\underline{\mu}^f - 1 + \underline{\mu}^d(\zeta - 1)}$$

Furthermore, note that $\widetilde{K} < \overline{K}$ and $\widetilde{\widetilde{K}} > \underline{K}^f$.

5.2. Proof of Corollary 1. By differentiating ζ with respect to p^{tp} we get

$$\frac{\partial \zeta}{\partial p^{tp}} = \begin{cases} \dfrac{(e_b - e_a)(v_c - v_a) - (e_c - e_a)(v_b - v_a)}{[(v_c - v_a) - p^{tp}(e_c - e_a)]^2} & \text{under excess capacity} \\ \dfrac{(e_b - e_a)(\overline{p} - v_a) + e_a(v_b - v_a)}{(\overline{p} - v_a - p^{tp} e_a)^2} & \text{without excess capacity} \end{cases}$$

$$\text{Consequently, } \frac{\partial \zeta}{\partial p^{tp}} < 0 \text{ when} \begin{cases} \dfrac{(e_c - e_a)}{(v_c - v_a)} > \dfrac{(e_b - e_a)}{(v_b - v_a)} & \text{under excess capacity} \\ \dfrac{-e_a}{(\overline{p} - v_a)} > \dfrac{(e_b - e_a)}{(v_b - v_a)} & \text{without excess capacity} \end{cases}$$

This condition always (never) is satisfied when "trade-off in the plant mix" combines with excess capacity (without both "trade-off in the plant mix" and excess capacity).

Since $\widetilde{K}$ and $\widetilde{\widetilde{K}}$ are increasing functions of ζ (see comparative statics in proof of Lemma 1 above), market power surely increases (decreases) in p^{tp} when "trade-off in the plant mix" combines with excess capacity (without both "trade-off in the plant mix" and excess capacity). Otherwise, the ETS can determine either a rise or a decrease in market power depending on the relative values of variable costs and emission rates of the different kinds of technologies.

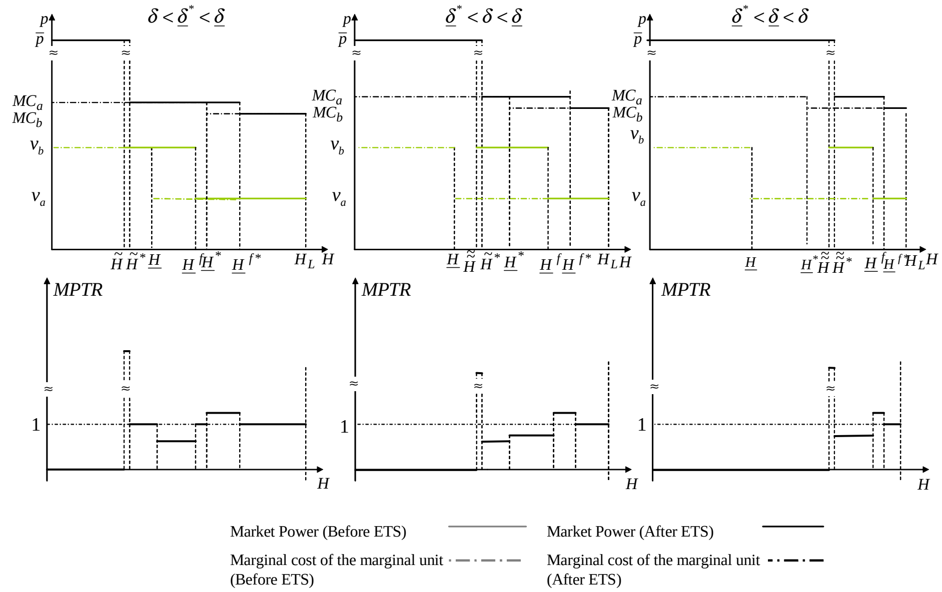

Figure 13: Marginal pass-through rate (MPTR) curve (Scenario1): high allowance prices and without excess capacity ($\underline{\mu}^d = \underline{\mu}^f$)

5.3. High allowance prices. For the sake of simplicity, we report only examples referring to the Scenario 1. Figures 13 and 14 refer to an allowance price around 43 €/tonCO$_2$, just above the "switching price" between coal and CCGT plants. As can be noted, the outcome is very similar to that under low allowance prices (see subsection 2.3.)[30]. This time, however, it is more likely that the MPTR could be less than 1 in the off-peak hours.

5.4. Technical parameters of power plants. Table 4 reports variable costs, emission rates and energy efficiencies of power generating technologies adopted throughout the paper.

[30]As pointed out in note 11, explaining how the ETS can impact on market power under high allowance prices is beyond the scope of this paper. However, it is possible to demontsrate that $\widehat{K} > \widehat{K}^*$ if the allowance price is not very high (even if above the "switching price). This is the case simulated in figs A1 and A2.

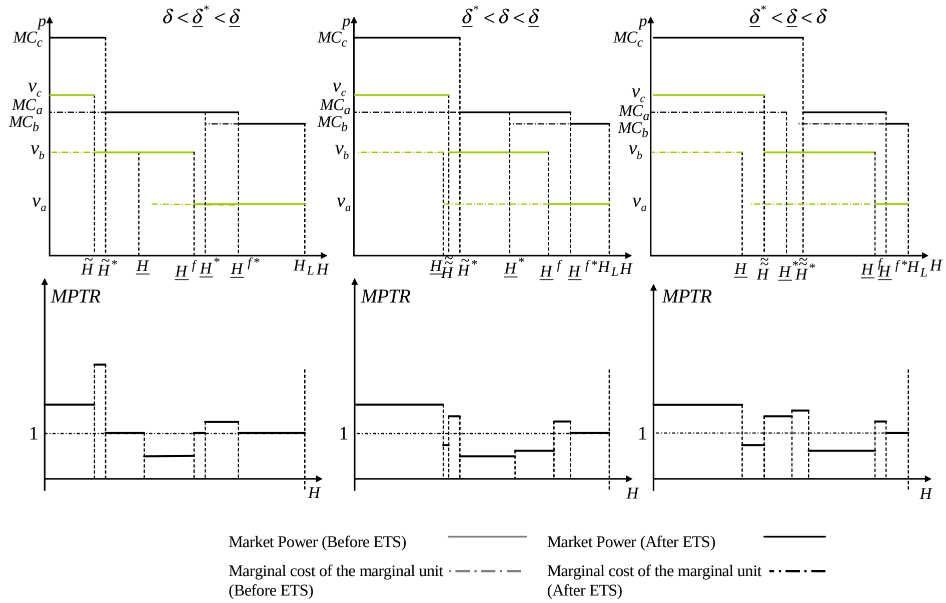

Figure 14: Marginal pass-through rate (MPTR) curve (Scenario 1): high allowance prices and excess capacity ($\underline{\mu}^d = \underline{\mu}^f$)

Table 4: Technical parameters of the power generating plants

	Oil-fired steam cycle	Gas-fired steam cycle	CCGT	Coal plant	CHP-CCGT
Variable cost (v), €/MWh	60	56	42	25	33
CO_2 emission rate (e), kg/MWh	750	500	400	800	550
Efficiency (η)	0.35	0.40	0.50	0.40	0.70(1)

(1) Including heat (i.e. useful heat plus power divided by fuel consumption)

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