PART II

Empirical analyses

5. Options to address concerns regarding EU ETS–induced increases in power prices and generators’ profits: the case of carbon cost pass-through in Germany and the Netherlands

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5.1 INTRODUCTION

Power prices in EU countries have increased significantly since the European Emissions Trading Scheme (EU ETS) became effective on 1 January 2005. This suggests that these increases in power prices are due to this scheme, in particular the pass-through of the costs of EU allowances (EUAs) to cover the CO_2 emissions of eligible installations. In all sectors, however – including the power sector – eligible installations have usually received almost all of their needed allowances for free during the first phase of the EU ETS (2005–07).

In several EU countries, the coincidence of the increases in power prices and the implementation of the EU ETS has raised questions, and sometimes fierce political debate, on whether power producers have indeed passed through the costs of freely allocated CO_2 allowances to electricity prices, and to what extent the increase in these prices can be attributed to this pass-through or to other factors. In addition, it has raised discussions on whether – and to what extent – the supposed passing through of these costs has led to additional profits for power producers, that is, the so-called ‘windfall profits’ induced by the EU ETS. Finally, the supposed ETS-induced increases in power prices and generators’ profits has raised concerns affecting the legitimacy of the present EU ETS, including concerns regarding its impact on the international competitiveness of some power-intensive industries, the purchasing power of electricity end-users such as small households or, more generally, the distribution of social welfare among power producers and consumers. As a result, in several countries policy makers and stakeholders have suggested a variety of options to address these concerns, including changing the emissions trading allocation system, taxing windfall profits or controlling market prices of EU carbon allowances, electricity or both.

Against this background, the objectives of this chapter include:[1]

- To analyse empirically the trends in power prices during the 2004–06 period for two specific EU countries, that is, Germany and the Netherlands, and to assess whether and to what extent changes in these prices can be attributed to the pass-through of the costs of freely allocated EU carbon allowances or to other factors.
- To discuss the issue of windfall profits, in particular to make some qualifications to the definition and empirical estimation of windfall profits, including some rough estimates of EU ETS-induced windfall profits in the power sector of Germany and the Netherlands.
- To evaluate some policy options to address concerns regarding supposed EU ETS-induced increases in power prices and generators' profits.

The structure of the chapter is as follows. First, Section 5.2 presents some empirical analyses of price trends, cost drivers and pass-through rates (PTRs) on electricity markets in Germany and the Netherlands from 2004 to 2006. Subsequently, Section 5.3 discusses the issue of ETS-induced windfall profits in general, while providing some rough estimates of such profits in Germany and the Netherlands in particular. Next, Section 5.4 evaluates some policy options to address concerns regarding supposed EU ETS-induced increases in power prices and generators' profits. Finally, Section 5.5 gives a brief summary of the major findings, conclusions and policy implications.

5.2 EMPIRICAL ANALYSES OF PRICE TRENDS, COST DRIVERS, POWER SPREADS AND PTRs ON ELECTRICITY MARKETS

Trends in Forward Power Prices and Cost Drivers

Figure 5.1 presents trends for 2004–06 in forward (that is, year-ahead) power prices versus fuel and CO_2 emission costs to generate one MWh of electricity during the peak period in Germany, while Figure 5.2 shows similar trends during the off-peak hours in the Netherlands. These figures,

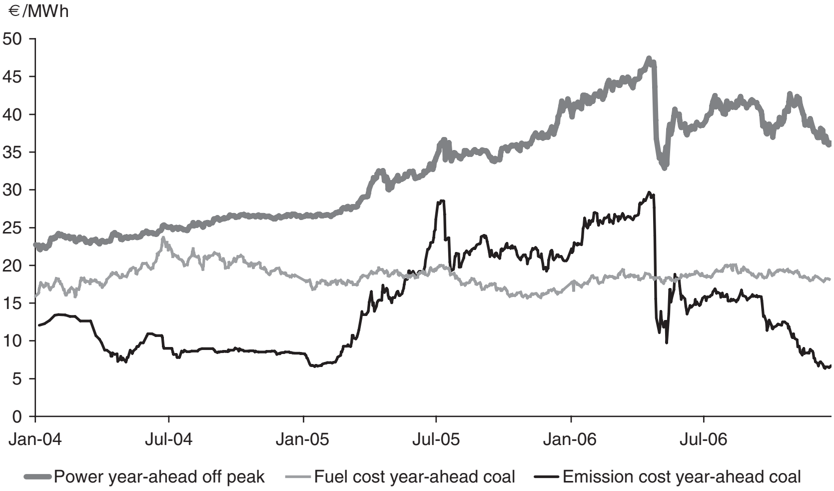

Figure 5.1 *Trends in power prices and cost drivers on forward markets in Germany during off-peak hours, 2004–2006*

and the empirical analyses outlined below, are based on the following assumptions:

1. An average fuel efficiency of 35 per cent for a coal plant and 40 per cent for an open-cycle gas turbine.
2. A related emission factor of 0.97 versus 0.51 tCO_2/MWh for coal and gas, respectively.
3. CO_2 emission costs per fuel are equal to its emission factor versus the daily price of an EUA on the forward market.[2]

Figures 5.1 and 5.2 provide a first impression of the changes in power prices in 2004–06 and the potential link with underlying fuel and carbon costs, depending on the assumed price-setting technology in the countries and load periods considered as well as the emission factors and fuel efficiencies mentioned later in Tables 5.1 and 5.2, respectively. For instance, off-peak power prices in Germany are assumed to be set by a coal-fired installation. As can be observed from Figure 5.1, these prices increased substantially from less than 30 €/MWh in early 2005 to almost 50 €/MWh in April 2006. After a sudden collapse by some 15 €/MWh in late April–early May, off-peak prices in Germany started to rise again up to the summer of 2006 but, subsequently, stabilized at a level of 30–35 €/MWh in late 2006. These significant changes in power prices cannot be explained by changes

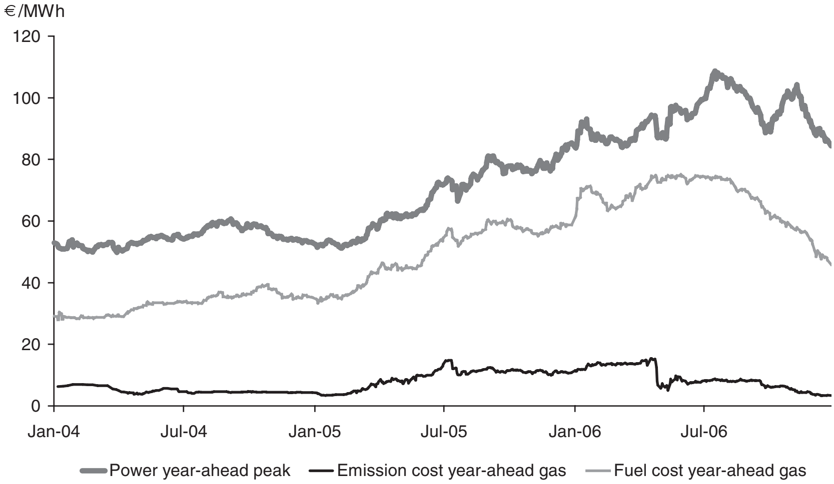

Figure 5.2 Trends in power prices and cost drivers on forward markets in the Netherlands during peak hours, 2004–2006

in coal prices, since the costs of this fuel have been rather stable at the level of 20 €/MWh over the period considered.

However, in the case of the forward off-peak power market in Germany there seems to be a close (causal) link between the prices of carbon and electricity as the changes in CO_2 emission allowance costs of coal-fired generation are more or less similar to the changes in power prices, notably during periods of major changes in the price of an EUA such as April–May 2006 (see Figure 5.1). Note, however, that the link between power prices and fuel/CO_2 cost drivers is less clear or even absent/contrary in the second half of 2006, suggesting that in this period changes in power prices have been largely affected by other factors than changes in fuel/CO_2 costs.

On the other hand, Figure 5.2 shows the trends in power prices and cost drivers on forward markets in the Netherlands during the peak period of 2004–06. For this case, power prices are assumed to be set by an open-cycle gas turbine with a fuel efficiency of 40 per cent. These prices were more or less stable during 2004, but increased rapidly from 50–55 €/MWh in early 2005 to 100–105 €/MWh in mid-2006. This increase in power prices can be largely related to rising gas prices (which, in turn, are usually related to oil-indexed prices), resulting in an increase in gas costs from 35–40 €/MWh in early 2005 to 70–75 €/MWh in mid-2006. The potential impact of gas-related CO_2 costs, however, is less substantial – rising from about 5 to 15 €/MWh between early 2005 and mid-2006 – partly due to the fact that the emission factor for gas is significantly lower than for coal.

Trends in Power Spreads on Forward Markets

In order to have a closer look and a better assessment of the potential impact of CO_2 emissions trading on forward power prices, fuel costs have been subtracted from these prices, resulting in the so-called 'power spreads'. For the present analysis, a *dark* spread is simply defined as the difference between the power price and the cost of *coal* to generate 1

BOX 5.1 DATA USED

For the empirical analyses over 2004–06, data of daily prices on forward (that is, year-ahead) markets have been used for the following commodities:

- *Power* For Germany, power prices refer to the Phelix year-ahead contracts traded at the Leipzig-based European Energy Exchange (EEX), while for the Netherlands these prices refer to similar contracts traded at the Amsterdam-based European Energy Derivates Exchange (ENDEX). Both exchanges provide price data for base-load and peak periods, while off-peak prices have been derived from these data using country-specific definitions of peak versus off-peak periods.
- *Fuels* Coal prices used for Germany and the Netherlands refer to the internationally traded commodity classified as coal ARA CIF API #2 (provided by McCloskey). Coal costs have been derived from the average of the daily bid and offer prices for yearly contracts (expressed in US$/tonne and converted to €/MWh by means of the daily dollar–euro exchange rate, the usual energy conversion factors and a fuel-efficiency rate of 35 per cent). Gas prices for Germany refer to the Bunde trading hub covering the whole period considered, that is, 2004–06 (as reported by Platts), while for the Netherlands gas prices refer to the Bunde hub during 2004–05 and to the Title Transfer Facility (TTF) hub for 2006 (provided by ENDEX).
- *CO_2 emission allowances* Carbon prices for EUAs (expressed in €/tCO_2) refer to forward prices Cal05, Cal06 and Cal07 (for delivery in December 2005, 2006 and 2007, respectively, as provided by PointCarbon and NordPool).

MWh of electricity, while a *spark* spread refers to the difference between the power price and the costs of *gas* to produce a MWh of electricity. If, subsequently, the carbon costs of power production are also subtracted, these indicators are called 'clean dark/spark spreads', respectively.[3]

Figure 5.3 and 5.4 present trends in year-ahead power spreads over 2004–06 in Germany and the Netherlands, respectively, based on the forward market trends in power prices and fuel/carbon costs discussed above. Whereas Figure 5.3 depicts trends in (clean) dark spreads for the off-peak period in Germany, Figure 5.4 shows similar trends in the (clean) spark spread during the peak hours in the Netherlands. In addition, these figures illustrate the opportunity costs of CO_2 allowances to cover the emissions per MWh produced by a coal- or gas-fired power plant, with an emission factor of 0.97 and 0.51 tCO_2/MWh, respectively.

For the off-peak hours in Germany, Figure 5.3 shows that there is a close relationship between the dark spread and the emission costs of a coal-fired power station, at least up to April–May 2006 when the year-ahead (Cal07) price of an EUA suddenly collapsed and – after a short recovery plus stabilization phase – declined steadily during the latter part of 2006. The dark spread in Germany, however, fell less in April–May 2006, and more or less stabilized during the latter part of 2006, resulting in a growing disparity between the spark spread and the emission costs of coal-generated power per MWh. This suggests either that declining carbon costs are passed through to a lesser extent (or less quickly) than rising carbon costs (that is, asymmetric pass-through) or that changes in power prices/spreads are largely due to other factors than changes in fuel/carbon costs, for instance due to growing power market scarcities and related increasing market power of electricity suppliers to set sales prices.

A similar, but even stronger picture of the delinking between the trends of the power spreads and related carbon costs – particularly since Spring 2006 – can be observed in Figure 5.4, which presents these trends during the peak period of 2004–06 in the Netherlands. While the gas-related carbon costs declined from about 15 €/MWh in April/May 2006 to approximately 5 €/MWh in late 2006, the clean spark spread improved substantially from about 30 to 45 €/MWh over this period.

In addition to the trends in power spreads, Figures 5.3 and 5.4 also provide trends in *clean* spreads over 2004–06 in Germany and the Netherlands, respectively (by subtracting the full carbon emission costs from the 'normal' spreads). If it is assumed that (i) fuel and carbon costs are passed through more or less fully and directly to power prices, and (ii) other generation costs are more or less stable during the period considered, then the trend of the clean dark spread would be represented by a straight

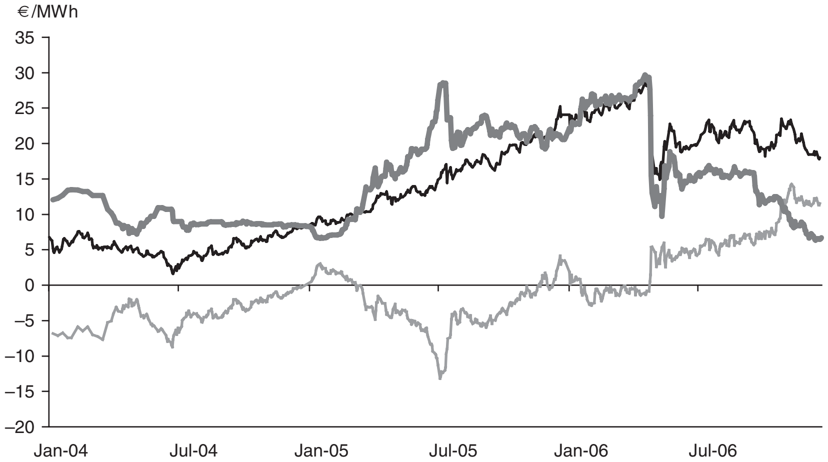

Figure 5.3 Trends in power spreads and carbon costs on forward markets in Germany during off-peak hours, 2004–2006

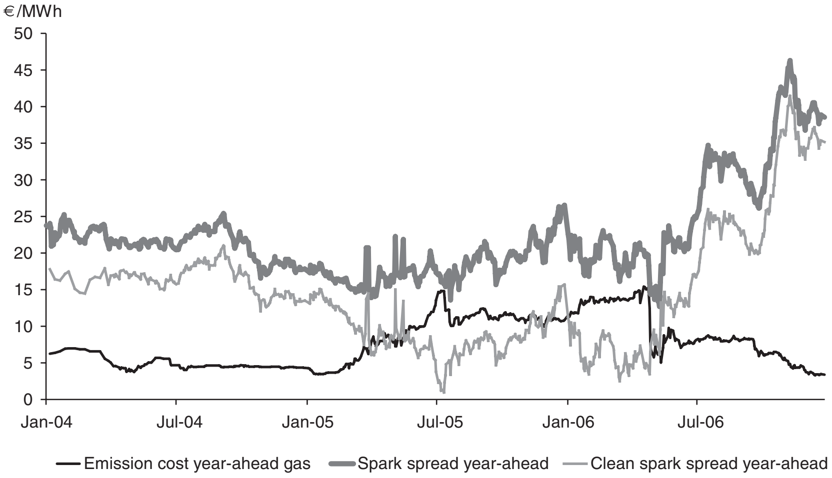

Figure 5.4 Trends in power spreads and carbon costs on forward markets in the Netherlands during peak hours, 2004–06

horizontal line at a certain level (say 10 or 20 €/MWh in order to cover the other generation costs, including profits).

Figure 5.3 and 5.4 show that, in general, clean spreads fluctuated significantly at a certain level in 2004–05, while they increased substantially during 2006. For instance, the clean spark spread during the peak hours in the Netherlands (i) was rather stable in 2004, fluctuating at a level of about 18 €/MWh, (ii) declined during the first part of 2005 (due to rising fuel/carbon costs that were not fully passed through), (iii) fluctuated at a level of approximately 15 €/MWh between mid-2005 and Spring 2006, and (iv) increased rapidly from about 10 €/MWh in April 2006 to more than 35 €/MWh in late 2006, implying that trends in peak power prices have diverged by some 25 €/MWh over this period from trends in fuel/carbon costs.

During the off-peak period, a similar but far less striking increase in clean dark spreads can be observed since April/May 2006 on the year-ahead power markets of Germany. Note, however, that these spreads are generally low, even in 2006, and that they were actually negative during most of the time in 2004 and 2005 (see Figure 5.3). The latter is surprising as it raises the question why coal operators would generate power at prices which do not even cover the opportunity costs of fuel and carbon allowances and, hence, would earn more by selling the fuel and carbon allowances straight on the market rather than using them for generating power.

The incidence of negative clean dark spreads, as observed in Figure 5.3 during the off-peak period in Germany, could be due to several reasons. First, the calculation of these spreads is based on an assumed fuel efficiency of 35 per cent for a coal station setting the price. However, if this efficiency is higher, both the fuel and carbon costs per MWh will be lower and, hence, the clean spread will be higher. Second, operators of coal stations may decide to continue power generation during off-peak hours at lower prices if it saves start-up costs for producing electricity during the peak period at more attractive prices.

Third, the calculation of the clean dark spreads is based on the assumption that off-peak prices in Germany are set by (domestic) coal plants. During certain off-peak hours, however, power prices in Germany are set by lignite plants which, overall, may have lower fuel and carbon costs (depending on the relative prices and efficiencies of the fuels and carbon used).

Finally, the observation that during certain off-peak periods the clean spreads are negative and, hence, that it would be more profitable to sell contracted fuels and (freely) obtained carbon allowances directly on the market rather than using them for generating power assumes that (i) fuel markets are liquid and, hence, contracted fuels can readily and without major costs be resold at the market, and (ii) power generators aim to maximize their profits. However, sometimes it is hardly possible or rather costly to resell contracted fuels at current market prices. Moreover, rather than maximizing profits, power generators may try to achieve other (short-term) objectives – for instance, to maintain certain market shares – or accept a certain satisfying profit margin, in particular if free allocation of carbon allowances results in a 'normal' spread that is already relatively high.

Statistical Estimates of CO_2 Cost PTRs

This subsection provides and discusses some statistical estimates of PTRs of CO_2 emission trading cost to power prices on forward wholesale markets in Germany and the Netherlands for 2005–06. The basic assumption of these estimates is that during the observation period (say 'peak 2005' or 'off-peak 2006') changes in the year-ahead power prices can be explained by variations in the fuel and carbon costs of the price-setting technology over this period. Hence, it is assumed that during this period other costs, for instance capital, operational or maintenance costs, are constant and that the market structure did not alter over this period (that is, changes in power prices cannot be attributed to changes in technology, market power, generation capacity, risks or other factors).

Based on these assumptions, the relationship between power prices (P), fuel costs (F) and CO_2 costs is expressed by equation (5.1), where superscripts c and g indicate coal and gas, respectively. Likewise, the term CO_{2t} is the CO_2 cost associated with coal and gas at time t. Thus, it is equal to the product of the CO_2 allowances price at time t and the time-invariant CO_2 emission rate of coal or gas generators. For the present analysis, fuel costs are assumed to be fully passed on to power prices. This is equivalent to fixing the coefficient β_2 at unity:

$$P_t = \alpha + \beta_1 CO2_t^{c,g} + \beta_2 F_t^{c,g} + \varepsilon_t. \tag{5.1}$$

By defining Y_t as the difference between power price and fuel cost, equation (5.2) becomes the central regression equation of which the coefficient β_1 has been estimated. In fact, Y_t represents the dark spread for coal-generated power and the spark spread for gas-generated power:

$$Y_t = (P_t - F_t^{c,g}) = \alpha + \beta_1 CO2_t^{c,g} + \varepsilon_t. \tag{5.2}$$

The first (constant) term on the right-hand side of the equation represents the fixed component of the power spread, comprising the fixed cost elements of power generation and the other, less quantifiable but stable, elements. The second term refers to the opportunity costs of the CO_2 allowances needed for the generation of power per MWh multiplied by the PTR (β_1). The last variable, the error term, represents all other non-stable components of the power spread.

In order to establish the applicability of the so-called 'ordinary least squares' (OLS) regression method to estimate the unknown variables of equation (5.2), the stationarity of the relevant data time series has to be determined. In the case of the relevant power spreads and carbon costs, all series appeared to be non-stationary. After first differencing of the data, stationarity was established and, thus, all series were found to be integrated of order one. None of the relevant series, however, appeared to be co-integrated. Therefore, by differencing the relevant time series the OLS method was applied to the following regression equation:

$$\Delta Y_t = \Delta(P_t - F_t^{c,g}) = \beta_1 \, \Delta CO_{2t}^{c,g} + u_t \tag{5.3}$$

where Δ refers to the difference between sequential data observations and u_t represents the error term.

Table 5.1 presents the results of the estimated regression equation, notably of the estimated PTRs of carbon costs to electricity prices on the year-ahead power markets of Germany (DE) and the Netherlands (NL) during the peak and off-peak periods in 2005–06. The major findings of this table include:

- In those cases where the price-setting technology is assumed to be coal (DE-peak, DE-off peak and NL-off-peak), the estimated PTRs vary between 40 and 60 per cent, while in the gas-fired production case (NL-peak), the estimated PTRs are slightly above 1, that is, 1.3 in 2005 and 1.1 in 2006. These estimates seem to suggest that in the latter (gas) case the PTRs are substantially higher than in the former (coal) cases, although in an absolute sense the emission factor and, hence, the carbon costs of gas are significantly lower compared to coal.
- All estimated PTRs are statistically significant at the 1 per cent level with, in general, small confidence intervals. However, the indicator for the 'goodness of fit' of the estimated regression equation (R^2) is generally low (although far from bad for a single variable equation), implying that only a small part – about 30 per cent – of the changes in power prices/spreads can be attributed to changes in carbon costs.

These findings, however, have to be interpreted with some caution due to the following considerations.

First, as noted, the estimated PTRs are based on the fundamental assumption that changes in power prices are predominantly caused by changes in the underlying costs of fuels and CO_2 emission allowances, and that all other generation costs and factors affecting power prices are more

*Table 5.1 Empirical estimates of carbon cost PTRs on year-ahead power markets in Germany and the Netherlands, 2005–2006**

		DE		NL	
		Peak	Off-peak	Peak	Off-peak
	Price-setting technology	Coal	Coal	Gas	Coal
	Fuel efficiency (%)	35	35	40	35
2005	PTR	0.60	0.41	1.34	0.40
	Interval (Δ)	±0.06	±0.04	±0.14	±0.04
	R^2	0.29	0.32	0.28	0.34
2006	PTR	0.57	0.64	1.10	0.38
	Interval (Δ)	±0.05	±0.04	±0.14	±0.03
	R^2	0.36	0.38	0.20	0.38

Note: Based on a first-difference regression of power spreads versus carbon costs. All estimated PTRs are statistically significant at the 1% level.

or less fixed during the observation period (that is, for instance, the peak period in 2005 or the off-peak period in 2006). However, as observed in the previous two subsections, this assumption seems to hold for certain periods (for example, the off-peak 2005) but not for others (notably during the peak period of the second half of 2006). The other generation costs and factors refer not only to maintenance or fixed costs, but also to items such as changes in scarcity of generation capacity, market power, risks and so on. Due to a lack of data, however, it is not possible to account quantitatively for the impact of these other changes in power prices, which may lead to biased results of the estimated PTRs.

Second, the estimated PTRs are based on the assumption that during the observation period, power prices are set by a single (marginal) technology with a fixed, generic fuel efficiency. In practice, however, peak or off-peak prices during a particular year (or even a particular month, week or day) may be set by a variety of technologies (with different or changing fuel efficiencies), depending on the specific load hour, the maintenance or outage schedule of the generation park, daily changes in relative fuel/carbon prices and so on. Once again, due to a lack of data, it is not possible to account quantitatively for these technological factors, which may lead to (additional) biases in the estimated PTRs.

Third, the estimated PTRs depend on (that is, are sensitive to) the assumed generic (fixed, average) fuel efficiency rates, which in all relevant cases amount to 35 and 40 per cent for coal and gas, respectively. However, for specific cases, for example, NL-off-peak, these rates may be too low. As indicated by Sijm et al. (2005), the estimated PTR increases significantly if a higher fuel efficiency rate is assumed, notably when the fuel costs of the marginal technology account for a major share of the power price and, hence, for a relatively low power spread.[4]

Finally, the estimated PTRs are based on the use of daily price data for fuels traded on (inter)national, rather liquid markets, assuming that these data reflect the changes in the opportunity costs of the fuels used by the marginal, price-setting technology in either Germany or the Netherlands (for details, see Box 5.1). In practice, however, power generators may use another (or adjusted) fuel price indicator for their operational and bidding strategies as they usually rely on long-term fuel supply contracts with specific marketing and pricing conditions. Moreover, in particular the gas market is often less liquid and, hence, the ‘opportunity costs’ of gas becomes a dubious concept as power companies are less flexible in trading gas surpluses or shortages due to contract fines and other, high balancing costs of trading gas flexibly. Therefore, the estimated PTRs depend on the assumptions made with regard to the fuel price data.

Nevertheless, although the exact value of the estimated PTRs is hard to determine, there is sufficient (both theoretical and empirical) support for the conclusion that in liberalized power markets, such as in Germany and the Netherlands, generators include the opportunity costs of (freely allocated) CO_2 emission allowances in their pricing strategies. In addition to the empirical analyses outlined above – as well as in several other studies – this support includes interviews, presentations and other statements by representatives of the power sector confirming that they do indeed incorporate these costs in their wholesale price bidding and other operational decisions.[5]

Power producers, however, are not able simply to set wholesale power prices in liberalized, competitive markets or to pass through carbon costs to these prices as price setting and cost pass-through in the power sector are determined by a complex set of wholesale market forces. In general, it is hard to assess the impact of CO_2 allowance costs on power prices as these prices are set by a large variety of factors, including fuel prices, the €/US$ exchange rate, available production capacity, investment costs, imports, weather conditions, heat demand (‘must runs’), fuel contract inflexibilities, risks, expectations and sentiments of market players, and so on. Moreover, the extent to which CO_2 costs are passed through to power prices depends on factors such as power market structure, demand responsiveness, changes in the merit order or specific (free) allocation provisions (Sijm et al., 2008).

Therefore, although in liberalized, competitive markets power producers include the opportunity costs of (free) CO_2 emission allowances in their price bidding and other operational decisions, due to a large variety of factors affecting power prices and carbon cost pass-through it is hard to determine empirically the exact PTR and, hence, the exact impact of emissions trading costs on electricity prices.

Carbon Cost Pass-through on Retail Power Markets

In the previous sections, the analysis focused on the impact of CO_2 emissions trading on (year-ahead) *wholesale* power prices in Germany and the Netherlands over the 2005–06 period. This raises the question whether and to what extent there is already some empirical evidence on the pass-through of carbon allowances costs to *retail* power prices in these countries during this period. In order to address this question, data have been gathered from Eurostat on average, semi-annual power prices for two categories of electricity end-users:

- households, with an annual consumption of 3.5 MWh (of which 1.3 MWh at night); and
- industry, in particular large industrial end-users with an annual consumption of 24,000 MWh (maximum demand 4 MW and 6,000 annual load hours).

Figure 5.5 presents the changes in the average, annual electricity prices for these two categories of power consumers in Germany and the Netherlands over 2004–06. It shows that retail power prices in Germany and the Netherlands have increased significantly for both households and industrial consumers. For instance, including taxes, power prices for large industrial end-users in Germany rose from 86 €/MWh in 2004 to 105 €/MWh in 2006 (+21 per cent), while household electricity prices in the Netherlands increased from 183 to 211 €/MWh over this period (+15 per cent). To some extent, these changes in retail prices are affected by changes in energy taxes (including value-added taxes). Between 2004 and 2006, for instance, taxes on industrial power prices in Germany were raised from 24 to 27 €/MWh, resulting in an increase in these prices, excluding taxes, from 62 to 78 €/MWh (+25 per cent), while taxes on household power prices in the Netherlands were raised from 80 to 89 €/MWh, leading to an increase in these prices, excluding taxes, from 103 to 122 €/MWh (+18 per cent). Hence, whereas changes in energy taxes can explain a major part (about one-third) of the increase in household power prices in the Netherlands over 2004–06, they are less important (about one-sixth) in accounting for differences in industrial power prices in Germany during this period.

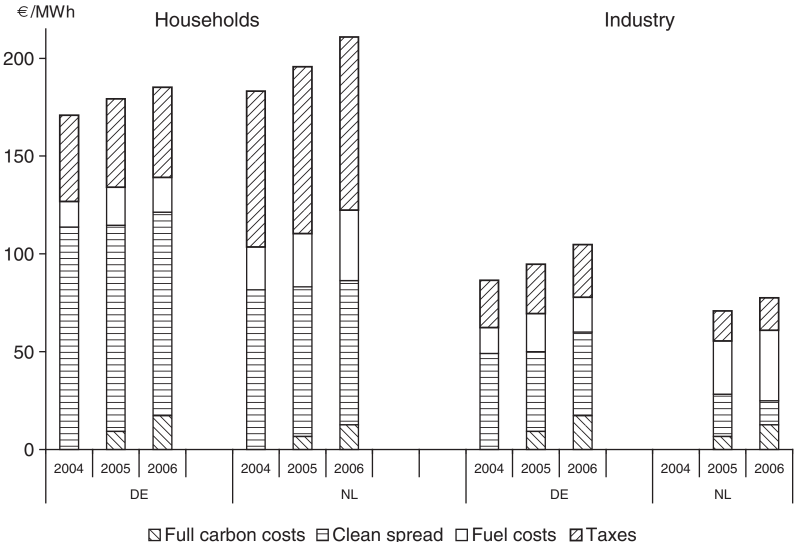

Figure 5.5 Changes in cost components of electricity prices for households and industry in Germany and the Netherlands, 2004–2006

In order to assess the possible impact of CO_2 emissions trading on (changes in) retail power prices in Germany and the Netherlands during 2005–06, the carbon costs passed through on the retail power markets have been estimated according to three different methodologies:

1. Estimation of the carbon costs passed through based on the change in the so-called 'retail power spread' (defined as the difference between the average, annual power price, excluding taxes, and the average, annual fuel costs of power generation per MWh). This approach assumes that changes in this spread can be solely attributed to changes in carbon costs passed through on the retail market (and, hence, that changes in retail power prices can be explained by changes in these carbon costs, fuel costs and taxes), while other costs or determinants of retail power prices are fixed over this period (2004–06). According to this approach, the estimated carbon costs passed through are assumed to be equal to the difference in the average, annual retail power spread during a certain year after emissions trading (2005 or 2006) and the year before emissions trading (that is, 2004).[6]
2. Estimation of the carbon costs passed through on retail markets based on the estimated PTRs on related wholesale power markets. This approach assumes that for each specific case (say Germany in 2005) the

same rate (or amount) of carbon costs is passed through on both the wholesale and retail power markets. According to this approach, the estimated carbon costs passed through on the retail market are assumed to be equal to the weighted average of the estimated CO_2 costs passed through on the wholesale market during the peak and off-peak periods.

3. Estimation of the carbon costs passed through on retail markets based on the so-called 'full carbon costs' of the marginal technologies setting the power price. This approach assumes that the costs of these technologies are fully passed through on the retail markets. According to this approach, for each specific case, the estimated carbon costs passed through are assumed to be equal to the weighted average of the CO_2 emission costs of the marginal technologies setting the power price during the peak and off-peak periods.

The results of the three methodologies outlined above are summarized in Table 5.2, where the three approaches are briefly denoted as 'retail', 'wholesale' and 'full carbon costs', respectively.[7] First, the upper part of this table shows the estimated amounts of carbon costs passed through according to these three methodologies. For instance, following the first approach (retail), the amounts of carbon costs passed through to households in Germany are estimated at 1.0 €/MWh in 2005 and 7.7 €/MWh in 2006, while for the large industrial users these costs amount to 0.9 and 11.0 €/MWh, respectively. However, according to the second methodology (wholesale), the estimated amounts are significantly higher for both German households and industrial users, that is, 4.8 and 9.0 €/MWh in 2005 and 2006, respectively. These amounts are even higher if it is assumed that the carbon costs of the price-setting technologies are fully passed on to these consumers (that is, following the third, full carbon costs approach). Note that, in general, the estimated amounts of carbon costs passed through to retail power prices are substantially higher in 2006 than in 2005. This is due to the fact that, while the estimates for 2005 are based on year-ahead prices of CO_2 emission allowances in 2004 (to be delivered in 2005) and estimates for 2006 on year-ahead carbon prices in 2005, these prices have been, on average, significantly higher in 2005 than in 2004.

Table 5.2 then presents the estimated PTRs according to the three different methodologies (where the PTR is defined as the estimated amount of carbon costs passed through divided by the full carbon costs of the price-setting technologies, as discussed above). Following the 'retail' approach, the PTRs are estimated at 11 per cent in 2005 and 44 per cent in 2006 in the case of German households, at 24 and 38 per cent, respectively, for German industry, and at 10 and 63 per cent, respectively,

Table 5.2 *Summary of estimated carbon cost PTRs on retail power markets in Germany and the Netherlands, 2005–2006*

Approach	Households				Industry			
	DE		NL		DE		NL	
	2005	2006	2005	2006	2005	2006	2005	2006
Estimated amount of carbon costs passed through in (€/MWh)								
Retail	1.0	7.7	1.6	4.8	0.9	11.0	N.A.	N.A.
Wholesale	4.8	9.0	5.2	9.9	4.8	9.0	5.2	9.9
Full carbon costs	9.2	17.4	6.7	12.6	9.2	17.4	6.7	12.6
PTR (% of full carbon costs)								
Retail	11	44	24	38	10	63	N.A.	N.A.
Wholesale	52	52	78	78	52	52	78	78
Full carbon costs	100	100	100	100	100	100	100	100
Share of carbon costs passed through (% of retail power prices, including taxes)								
Retail	1	4	1	2	1	10	N.A.	N.A.
Wholesale	3	5	3	5	5	9	7	13
Full carbon costs	5	9	3	6	10	17	9	16
Share of carbon costs passed through (% of change in retail power prices, including taxes, compared to 2004)								
Retail	12	52	13	18	9	60	N.A.	N.A.
Wholesale	58	62	42	35	63	49	N.A.	N.A.
Full carbon costs	111	120	53	45	121	95	N.A.	N.A.

Note: Some estimates for Dutch industry are not available (N.A.) since Eurostat data on power prices for large industrial power consumers in the Netherlands are missing prior to 2004. All estimated PTRs are statistically significant at the 1% level.

for Dutch households (while similar estimates for Dutch industry are not available since data on power prices for large industrial end-users in the Netherlands are lacking up to 2004). On the other hand, assuming that the PTRs on the retail markets would be similar to the estimated PTRs on the wholesale markets, these rates amount to 52 per cent in Germany and 78 per cent in the Netherlands for both consumer groups in both 2005 and 2006.[8]

The results following from the retail approach suggest that the pass-through of CO_2 emission costs on the retail markets in Germany and the Netherlands was rather low in 2005, but increased substantially in 2006. The low figures for 2005 may be due to time lags in retail price setting or other (marketing) constraints in passing through carbon costs fully or immediately to retail power consumers. The estimated PTRs according to this approach, however, have to be interpreted with due care as they are based on the assumption that changes in retail power spreads result only from changes in carbon costs passed through – and, hence, both changes are equal – but not from changes in other price determinants (besides taxes, fuel costs and carbon costs) such as distribution or marketing costs or growing market scarcities.

Finally, in order to get an indication of the relevance of carbon costs passed through for both the absolute levels of the retail prices and the changes of these prices in Germany and the Netherlands during 2005–06, the lower part of Table 5.2 presents these costs as a share or percentage of both these absolute levels and price changes. In general, the table shows:

- as the carbon costs passed through on the retail market according to the retail approach are generally much lower compared to either the wholesale or – even stronger – the full carbon costs approach, the shares of these costs in (changes of) retail power prices are consequently much lower for the retail approach than the other two methodologies;
- as the retail prices are usually much higher for households than for industrial power consumers, the shares of carbon costs passed through to these prices are consequently much lower for households than for industrial users;
- as the estimated carbon costs passed through on retail markets are generally much higher for 2006 than for 2005, the shares of these costs in (changes of) retail prices are consequently much higher in 2006 than in 2005; and
- as short-term changes in retail power prices are usually a minor part of the total or absolute levels of these prices, the shares of carbon costs passed through on retail markets are consequently much higher when expressed as a percentage of the changes in retail prices rather than as a share of the absolute levels of these prices.[9]

More specifically, Table 5.2 shows that when the carbon costs passed through are estimated according to the retail approach, the share of these costs in total retail prices is relatively low in 2005–06, that is, in general less than 4 per cent. The only exception concerns the case of German industry in 2006, where the carbon costs passed through account for about 10 per cent of the retail power price concerned. Even if one assumes that the full carbon costs are passed through to retail power prices, these costs account generally for only a small part of these prices, although in the case of the large industrial power users in both Germany and the Netherlands the share of the full carbon costs in the electricity prices for these consumers amounted to about 16–17 per cent in 2006.

On the other hand, when the (estimated or assumed) carbon costs passed through are expressed as a percentage of the changes in retail power prices, these rates are generally much more significant. For instance, if it is assumed that the changes in the retail power spreads are solely due to the pass-through of carbon costs (that is, the retail approach), the shares of these costs in the changes of the retail prices in 2005–06 (compared to 2004) range from 13–18 per cent for Dutch households, 12–52 per cent for German households, and 9–60 per cent for German industry (where the first percentage mentioned refers to 2005 and the second to 2006, see Table 5.2). This implies that the remaining shares of the price changes in these cases can be attributed to changes in fuel costs and/or energy taxes.

However, if it is assumed that the carbon costs passed through on the retail market are similar to either the carbon costs passed through on the wholesale market (that is, the wholesale approach) or the full carbon costs of the price-setting technologies (that is, the full carbon costs approach), Table 5.2 shows that the shares of these costs in the retail price changes are usually much higher.

To conclude, if it is assumed that over the 2004–06 period changes in the retail power spreads – defined as retail power prices excluding taxes and fuel costs – are solely due to carbon costs passed through, the impact of the EU ETS on (changes in) retail power prices was still relatively low in 2005 due to relatively low year-ahead carbon prices in 2004 and, perhaps, some time lags or other (marketing) constraints in passing through these costs to retail prices. In 2006, however, this impact seems to be already more significant, notably in Germany, due to relatively higher forward carbon prices in 2005 and, presumably, an increasing share of carbon costs passed through. Moreover, if it is assumed that the carbon costs passed through on the retail market are similar to either the carbon costs passed through on the wholesale market or the full carbon costs of the price-setting technologies, the impact of these costs – and, hence, of the EU ETS – on retail power prices becomes generally even more significant. These findings, however, have to be treated with due care as, to some extent, they depend on the assumptions made to estimate the carbon costs passed through, in particular the assumption that the changes in the retail power prices over the 2004–06 period are solely due to changes in taxes, fuel costs and carbon costs and, therefore, that other determinants of these prices – such as distribution/ marketing costs or the incidence of market scarcity/power – have been stable over this period.

5.3 THE ISSUE OF WINDFALL PROFITS

The pass-through of the opportunity costs of EUAs to power prices has raised the issue of the so-called 'windfall profits'. As power companies receive most of the allowances to cover their emissions for free during the first and second trading periods (2005–12), the value of these free allowances cannot be considered as truly paid costs but rather as the transfer of a lump-sum subsidy (or 'economic rent') enhancing the profitability of these companies (depending on the output price and sales volume effects of passing through the opportunity costs of the EUAs). In addition, even if companies have to pay fully for all allowances needed, some infra-marginal producers may benefit (or lose) from emissions trading, depending on the ETS-induced increase in power prices set by the marginal producer versus the EUA costs of the infra-marginal producer (where both the marginal and the infra-marginal producers can be either a high-, low- or non-CO_2 emitter).

Estimates of the incidence of windfall profits due to the EU ETS vary widely, depending on the countries or companies considered and the underlying assumptions made.[10] For instance, based on an EUA price of 20 €/tCO_2, estimates of windfall profits accruing to power producers in Germany are estimated at €4–8 billion per annum, that is, about 8–17 €/MWh produced, depending on whether either a gas or coal station is assumed to set the power price (WWF, 2006).[11] Similar estimates for the Netherlands vary from €19 million (Frontier Economics, 2006), €250–600 million (Sijm et al., 2006b) or even more than €1 billion per annum (Kesisoglou, 2007), depending primarily on the assumptions/estimates with regard to the PTRs and the shares of allowances obtained for free versus those purchased at the market by power producers. With an annual production of about 100 TWh in the Netherlands, these estimates imply an average pass-through amounting to 0.2, 2.5–6 and 10 €/MWh, respectively.

Several qualifications, however, can be added to the issue of EU ETS-induced windfall profits in the power sector. First, the term 'windfall profits' is often poorly defined and understood, notably in the context of emissions trading in the power sector. Literally (or originally), the term seems to refer to the fruit that falls from the tree due to the wind. Hence, it relates to something one gets for free, that is, an extra bonus without having to make an additional effort and which, usually, one did not expect to receive. Therefore, in the context of EU emissions trading in the power sector, the term defined broadly refers to the changes in generators' profits (either positive or negative) due to the implementation of the EU ETS which these generators had not expected once they made their investment decisions. Consequently, windfall profits have a bearing only on existing installations – that is, 'incumbents' or, more precisely, on investments made before the policy decision to introduce (or change the fundamental conditions) of emissions trading – but not on new investments as the level and kind of these investments (including those in more expensive, but low- or non-CO_2-emitting installations) are based on the new policy conditions and the attendant profit expectations.

Moreover, as indicated above, changes in incumbents' profits due to policy decisions on the fundamentals of emissions trading (that is, windfall profits, defined broadly) can or should be distinguished into the following two categories:

A. *Changes in incumbents' profits due to ET-induced changes in production costs, power prices and sales volumes* This category of profit changes (denoted as 'windfall A') occurs irrespective of whether eligible companies have to purchase all their allowances at an auction or market or receive them for free. The impact of changes in generation costs, power prices and sales volumes on incumbents' profits can vary significantly among companies (or even countries) and can be positive or negative, depending on the fuel generation mix of these companies (or countries), the price of an emission allowance, and the ETS-induced changes in power prices set by the marginal installation versus the ETS-induced changes in generation costs and sales volumes of both marginal and infra-marginal operators (where these operators can be either a high-, low- or non-CO_2 emitter). For instance, if the power price is set by a coal (high-emitting) installation, an operator of such a plant may either break even – if the change in carbon and other generation costs is passed fully to the power price, while sales volumes do not change – or make a loss if price changes are lower than cost changes or if sales volumes drop due to (i) lower, price-responsive demand levels or (ii) lower load hours resulting from a loss of competitiveness and an attendant change in the merit order of power supply. However, in such a situation, infra-marginal operators of a low or non-CO_2-emitting station may benefit from a higher profit margin and higher load hours (that is, sales volumes) due to gains in competitiveness. On the other hand, if the power price is set by a gas (low-emitting) or nuclear (non-emitting) plant, the operator of such an installation may more or less break even, whereas infra-marginal producers operating a higher-emitting station will make a loss as the increase in their carbon cost is not covered by a similar increase in power revenues.[12]

B. *Changes in incumbents' profits due to the free allocation of emission allowances* This category of profit changes (denoted as 'windfall B')

> is an addition to or compensation for the first category of windfall profits/losses to the extent to which allowances are obtained for free – rather than purchased – by eligible companies. These changes in incumbents' profits are usually positive, but can vary significantly among companies (or even countries), depending on the fuel generation mix of their installations, the price of an emission allowance, the amount of free allowances received, and the impact of specific free allocation provisions on the power price.[13] For instance, if carbon prices are high and emissions are covered largely by allowances allocated for free in a fuel-specific way (that is, high polluters such as coal or lignite plants get more free allowances), companies – or countries – with a relative high share of high-emitting installations in their generation mix benefit most, in an absolute sense, while low- or non-CO_2-emitting installations will profit less or not at all from free allocation.

The distinction between the two categories of windfall profits is relevant not only to indicate the differences in the underlying causes or mechanisms of these profits (or in differences in the incidence of these profits at the installation, sectoral or national level) but also to discuss the differences of these two categories in terms of investment incentives and policy implications. Whereas the first category (windfall A) encourages investments in especially low- or non-CO_2-emitting installations, the second category (windfall B) induces investments in particularly high-emitting technologies (provided that allowances are allocated for free to both incumbents and new entrants, in particular in a fuel- or technology-specific way, it implies a capacity subsidy that benefits and, hence, promotes notably more carbon-intensive generation plants). In addition, if for one reason or another one wants to tackle the incidence of generators' windfall profits due to the EU ETS, one has to make a distinction between the two categories of these profits as some policy options affect only the first category but not the second, or vice versa (as discussed in Section 5.4, below).

Third, the term, 'windfall profits' has a negative connotation, mainly because it is associated with either 'unfair' or 'unjustified' practices resulting in higher power prices for small and less-benevolent end-users and, hence, in a transfer of wealth from these end-users (or the public sector) to privileged stakeholders of large, private power companies filling their pockets. However, the pass-through of the opportunity costs of (free) emission allowances into power prices is a rational and intended effect from both a business economics and an environmental policy perspective. If someone is to blame for the resulting windfall profits one should primarily look at the policy makers who decide to allocate these allowances for free (rather than at the power producers whose actions act as could be expected are governed by rational, profit-maximizing motives). Moreover, a major part of the windfall profits in the power sector accrues to public hands, as these profits are subject to public taxation while, in addition, in several EU countries a large number of the power companies are still owned by the public sector (including municipalities, provinces or federal states). Finally, if one wants to avoid the negative connotation of windfall profits, one could use the term ‘changes in generators’ profits’ or, even better, ‘changes in producer surplus’.

A fourth and last qualification is that estimates of windfall profits have to be treated with due care since it is very hard to estimate these profits empirically in an exact and reliable way, in particular at the company level or in the long run. Most estimates of windfall profits are based on estimates (or sometimes even on assumptions) of the EUA cost PTR on a certain market during a certain period (for example, the wholesale forward market in Germany during the peak or off-peak period in 2006). As outlined above, however, it is very difficult to estimate these PTRs empirically, not only on forward markets but even more on spot markets as power prices on these markets are affected by a large variety of factors besides fuel/carbon costs (Sijm et al., 2008). Hence, in practice, it is very hard to estimate what the power price would have been without emissions trading. It is even more difficult to estimate changes in generators’ profits due to emissions trading as, besides changes in power prices, these profits are affected by changes in carbon or other generation costs and changes in sales volumes (due to lower, price-responsive power demand and carbon price-induced changes in the merit order or other abatement measures). Moreover, ET-induced changes in sales volumes – or other variables affecting profits – may vary significantly at the company level, depending on their fuel generation mix, making it even more complicated to estimate the incidence of windfall profits at the company level.

In addition, in the long run, the price elasticity or responsiveness of power demand to ET-induced increases in power prices may become more significant (that is, reducing windfall profits) while ET-induced investments in new capacity will further affect changes in power prices, cost structures, sales volumes and, hence, generators’ (windfall) profits. Another complicating factor is that estimates of windfall profits are usually based on transactions and PTRs on the wholesale power market, while at the retail level transactions, PTRs and other factors influencing profits of (integrated) power companies are often affected by the incidence of time lags, long-term contracts or other considerations besides maximizing short-term profit such as maintaining or reaching a certain market share. Hence, due to all these factors and changes it is hard to make a reliable, empirical estimate of windfall profits, notably of the first category ('windfall A') at the company level or in the long run.

At first sight, it seems easier to estimate the second category of windfall profits (B), since this can be done quite straightforwardly through multiplying the amount of allowances obtained for free by their (average) price, resulting in their market value or 'economic rent'. However, in the case of specific free allocation provisions – such as (i) updating, (ii) closure rules or (iii) free allocation to new entrants – this category is also rather hard to estimate empirically, notably in the long run, as these provisions have contrary, long-term effects on power prices on the one side (that is, reducing the ET-induced increases in these prices) and on carbon prices on the other (that is, raising these prices and, hence, the carbon cost passed through to power prices). Therefore, these provisions have contrary, indeterminate effects on changes in generators (windfall) profits, which are, hence, difficult to estimate empirically.

Nevertheless, despite all the qualifications and complications involved, rough/conservative estimates of ETS-induced windfall profits in the power sector can be made in order to get a feeling of the order of magnitude concerned. For instance, at an (average) price of 15 €/tCO$_2$, the market value or economic rent of the allowances allocated for free during 2005–06 is equal to some €700 million per annum in the Netherlands and approximately €5 billion in Germany (and at least €15 billion in the EU ETS as a whole). Or, assuming an ET-induced increase in (average) power prices of only 3 €/MWh in 2005–06 (while average generation costs and sales volumes are supposed to be more or less similar to 2004), windfall profits in the power sector due to the EU ETS amount to about €300 million per annum in the Netherlands and almost €2 billion in Germany (and more than €9 billion in the EU ETS as a whole). For the short run, these are rough but rather conservative estimates, implying that they may be significantly higher if the (average) carbon price or the (average) pass-through is higher. However, even conservative estimates of windfall profits raise questions on the socio-political acceptability of the EU ETS, in particular if this system does not lead to significant emission reductions or if it results in higher electricity prices for small households and power-intensive industries which may not always be able to pass on these higher energy costs to their customers. These questions will be addressed further in the next section, including policy implications and options to deal with the incidence of windfall profits and other concerns regarding the pass-through of the opportunity costs of EU emission allowances.

5.4 POLICY OPTIONS AND IMPLICATIONS

As supported by economic theory and empirical evidence, power producers in competitive, unregulated electricity markets pass through (part of) the opportunity cost of CO_2 emissions trading, even if they receive carbon allowances for free. From a climate policy perspective, internalizing the costs of CO_2 emissions is a rational and intended effect, enhancing the efficiency of emissions trading by incentivizing end-users to reduce their consumption of carbon-intensive goods. Hence, from such a perspective, the pass-through of these costs should be supported and promoted rather than discouraged – even if the allowances are granted for free – by creating conditions for competitive power markets and avoiding measures or threats to regulate price formation or carbon cost pass-through on these markets.

Nevertheless, as indicated above, the pass-through of CO_2 emissions costs – notably in the case of free allocations – may raise certain questions or concerns affecting the socio-political acceptability of the EU ETS. In particular, these questions or concerns refer to:

- *Windfall profits – that is, more surpluses – for power producers* As noted, the pass-through of carbon costs to electricity prices results in windfall profits for power producers, which may be quite substantial even in the case where all allowances have to be purchased at an auction or a market. To some extent, windfall profits – and losses–for (infra-)marginal producers due to ETS-induced changes in power prices, generation costs and sales volumes ('windfall A') can be accepted as the outcome of normal, everyday changes in economic conditions (which in the case of policy-induced losses can justify some free allocations or other – temporary – compensation measures). However, in countries with a large share of nuclear/hydro installations as base-load capacity (such as France or Sweden), this category of windfall may not only be substantial but also raise questions and concerns about these profits: why should end-users such as small households or power-intensive industries pay more for their electricity consumption, resulting in additional profits for (well-to-do) stakeholders who often made their nuclear/hydro investment decisions a few decades ago when these profits did not lead to significant CO_2 reductions, for instance due to all kinds of constraints limiting the further expansion of non-CO_2 power generation? Similar questions and concerns are raised even more outspokenly in the case of windfall profits due to free allocations ('windfall B'), in particular (i) if these profits – or the EU ETS as a whole – do not lead to significant carbon abatements in the power sector or, through fuel-specific free allocation provisions to new entrants, even encourage investments in CO_2-intensive power generation, and (ii) if these profits actually imply a wealth transfer from the public sector or (private, less benevolent) electricity end-users to (private, privileged) stakeholders of power companies, raising income distributional or equity concerns (see also next point below).

- *Higher prices – that is, fewer surpluses – for electricity consumers* The pass-through of CO_2 emission costs of power generation leads to higher prices for electricity end-users, regardless of whether the carbon allowances are allocated for free or not. As noted, this is a rational, intended/expected effect of emissions trading enhancing the carbon abatement efficiency of the EU ETS and, therefore, it can be regarded as an acceptable, necessary or unavoidable effect. In some particular cases, however, the ETS-induced increases in end-user electricity prices raises questions and concerns from either a competitiveness or equity point of view. For instance, some industrial end-users face higher power prices but, in turn, are not able to (fully) pass on these higher costs themselves due to outside competition or relatively high price responsiveness of demand for their output products, resulting in a loss of competitiveness, market shares, sales volumes or profits. Although this issue has sometimes been exaggerated, notably by some business associations, there are indeed some power-intensive industries or specific products that are disadvantaged by this effect (such as the aluminium industry or the production of copper). In addition, higher electricity prices have a negative purchasing-power effect and a regressive income-distribution effect as they affect notably low-income households which spend a relatively high share of their budget on power consumption. These effects may be particularly relevant for some EU countries, for instance in Eastern Europe, where the incidence of low-income households is relatively higher and which may have other, more attractive options to meet their mitigation commitments than reducing power-related emissions through higher end-user prices. Moreover, in some countries – for instance, the Netherlands – households already pay a substantial amount of environmental levies on their electricity consumption, which may lead to 'double taxation' of these households once the costs of emissions trading are passed through to the end-user prices. Finally, it should be noted that the above-mentioned concerns with regard to the potential adverse effects of higher power prices on industrial competitiveness, household income and equity would be even stronger if (i) the future prices – and, hence the cost pass-through – of carbon allowances

> were significantly higher, (ii) the abatement effect of the EU ETS was modest, notably the price-induced demand effect on power-related emissions, and (iii) the windfall profits for power producers were high due to, in particular, free allocations and a high pass-through of carbon costs.

In order to address the (either putative or real) concerns outlined above, policy makers, analysts, industrial stakeholders or other interest groups have suggested a wide variety of options, including options to change the allocation system, both inside and outside the EU ETS. More specifically the suggested options include:

1. auctioning;
2. allocating free allowances to power consumers;
3. benchmarking;
4. reducing carbon prices;
5. regulating power prices;
6. encouraging competitive power markets; and
7. taxing windfall profits.

These options are evaluated briefly below in terms of (i) their impact on power prices, (ii) their impact on windfall profits in the power sector, distinguished between ‘windfall A’ and ‘windfall B’ categories, (iii) their impact on the competitiveness of power-intensive industries, (iv) some other major effects (or advantages and disadvantages) of these options, and (v) the overall performance of these options in terms of socio-political acceptability, feasibility and addressing the concerns related to carbon cost pass-through outlined above.

Auctioning

The first and most widely suggested option to address in particular the EU ETS-induced windfall profits is to sell the CO_2 emission allowances at an auction (or market) rather than allocating them for free. In the two ideal (or textbook) types of allocation, that is, auctioning versus perfect free allocation (based on either grandfathering or benchmarking), both types have the same effects in terms of environmental effectiveness, economic efficiency, cost pass-through and output prices. The only difference concerns the distribution of the market value or ‘economic rent’ of the CO_2 emission allowances in the sense that this value accrues to the auctioneer (or public sector) in the case of auctioning and that it is transferred as a kind of lump-sum subsidy to eligible companies in the case of free allocations, thereby enhancing the profits of these companies (compared to a situation of emissions trading with auctioning). Therefore, in the ideal situation, auctioning eliminates only the windfall profits due to the free allocations of emission allowances (windfall B) by abolishing the transfer of the market value of these allowances to eligible companies. It should be noted, however, that auctioning in itself does not reduce, let alone eliminate, the windfall profits due to the ETS-induced changes in power prices, generation costs and sales volumes (windfall A).

In addition, the present system of free allocations in the EU ETS does not meet the ideal type of perfect grandfathering or perfect benchmarking as it is characterized by some specific free allocation provisions called 'updating' as a result of periodic allocation decisions, instead of more permanent provisions, including the loss of free allowances in the case of plant closures and the allocation of free allowances to new entrants. The implication of these provisions is that they have a depressing effect on power prices (and, hence, on generator profits), which may vary not only by country but also in the short, medium or long term, depending on (i) the scope and force of these provisions in the countries concerned, (ii) the impact of these provisions on the present and future (fuel mix of) generation capacities or on the relevant opportunity costs of emission allowances for participating producers (which influences the impact on power prices in the short, medium or long run), and (iii) the demand responsiveness of electricity consumers to changes in power prices, the technology or fuel-specific character of the free allocation provisions, and the EU ETS cap versus the limits on the inflow of joint implementation and clean development mechanism (JI/CDM) credits (which influences the impact of these provisions on total CO_2 emissions and, hence, the demand for carbon allowances, the price of these allowances, the opportunity costs of the allowances passed through and, ultimately, the resulting changes in power prices and generators' profits).[14]

The outcome or balance of these contrary effects on power prices and generators' profits is an (unknown) empirical issue, depending on the factors mentioned above. In a closed ETS with a fixed CO_2 budget (that is, with a fixed cap and a binding limit – or strict ban – of JI/CDM and other offset credits), the depressing effects of the specific free allocation provisions on power prices may largely cancel out, implying that – on balance or over time – these prices hardly change if the allocation system changes. However, in a more open ETS with a flexible CO_2 budget (for instance, with a flexible, price-dependent inflow of offset credits), the specific free allocation provisions – notably for new entrants – have a depressing impact on power prices in the long run which is not cancelled out by a similar upward-pressing effect on EU carbon prices (due to the inflow of offset credits).

This implies that in the case of auctioning – that is, abolishing these provisions and effects – power prices and related (windfall) profits may be higher in the long run.

Similarly, empirical estimates of carbon cost PTRs on power markets are often less than 1.0 in the short run, but little is known about the actual reasons why these rates are less than 100 per cent (let alone the values and determinants of these PTRs in the medium or long term). For instance, is the value of these estimates influenced by the effects of the specific free allocation provisions and, if yes, what is – on balance – the impact of these provisions (or abolishing these provisions by means of auctioning) on the power prices and generators profits in the long run? Moreover, the pass-through of the opportunity costs of carbon allowances is based on the assumption that power producers try to maximize their profits. However, in the case of free allocation, producers may perhaps sacrifice some of the resulting windfall profits – by reducing the amount of carbon cost pass-through – in order to achieve other short-term objectives such as reaching or maintaining a certain (retail) market share. In the case of auctioning, however, producers lack these windfall resources and, hence, they may increase the amount of carbon cost pass-through. Therefore, in these examples, shifting from free allocation to auctioning not merely abolishes the windfall profits due to the economic rent of allocating allowances, but may also affect (that is, increase) power prices and, hence, windfall profits due to other factors than transferring economic rents of free allocations.

To conclude, shifting from perfect free allocation to auctioning implies that windfall profits due to the transfer of economic rents will disappear, but it will have no impact on electricity prices or other factors affecting generators' profits, including windfall profits due to ETS-induced changes in these prices and other factors (assuming that power producers try to maximize their profits). However, if emissions trading is characterized by specific free allocation provisions (such as updating, plant closure rules or free allocation to new entrants) a shift towards auctioning may imply that, in the long term, power prices – and, hence, related windfall profits – may be higher, notably when additional emissions due to these provisions result in an extra inflow of JI/CDM credits rather than an increase in the price of an EU carbon allowance and a corresponding pass-through of the allowance costs into power prices.

Other effects of auctioning

In addition, auctioning of emission allowances has some other effects.[15] A major advantage of auctioning is that it raises revenues which can be used (i) to finance public expenditures on carbon abatement or other useful, social objectives, (ii) to reduce taxation and related efficiency distortions ('double dividend'), or (iii) to compensate power-intensive industries and other electricity consumers for the ETS-induced increases in power prices. Recycling of auction revenues, however, raises all kinds of new allocation issues (Sijm et al., 2006b). For instance, if these revenues are recycled by reducing income and business taxation in a general way, it may particularly benefit better off households and firms which are affected relatively less by the ETS-induced increases in power prices.[16] On the other hand, if auction revenues are recycled in a specific, targeted way in order to compensate consumers for the ETS-induced increases in power prices, it may lead to an overcompensation of some industrial end-users (that is, those able to pass on the higher power costs into higher output prices) or all kinds of perverse effects on CO_2-related power consumption (similar to the distortive effects of specific free allocation provisions on CO_2-related power production).[17]

The main disadvantage of auctioning is that it raises the (true, actual) costs for eligible firms which reduces their competitiveness, profitability, sales volumes and/or market shares if these costs cannot be fully passed on to their output prices due to the fact that (i) eligible firms face competition from outsiders not subject to similar carbon costs, (ii) infra-marginal generators face higher carbon costs than marginal, price-setting producers, or (iii) companies are faced by a significant demand response to ETS-induced price increases (notably in the medium or long run).[18] To some extent, however, these issues can be relieved by (a) restricting auctioning to those eligible firms that are unlikely to face outside competition (such as power companies), while applying free allocations to other, 'exposed' participants, (b) limiting or differentiating the extent of auctioning (say 70 or 90 per cent of allowances needed) for firms facing issue ii or iii, and (c) recycling auction revenues to improve industrial competitiveness in general or to (partly) compensate firms affected by auctioning (while observing the qualifications made above on the recycling of auction revenues). With regard to the power sector, however, one may question whether limiting the extent of auctioning or recycling auction revenues can be justified after 2012 since, by that time, it has already benefited, in general, from generous free allocations and ETS-induced increases for more than eight years (2005–12).

Overall, to conclude, auctioning of emission allowances seems to be a proper option for the power sector after 2012 in order to address the issue of windfall profits due to free allocations up to 2012 and the efficiency distortions of some specific free allocation provisions. Eliminating these provisions, however, may lead to some increases in power prices and related windfall profits. Moreover, auction revenues from the power sector could be used to finance expenditure for useful, social objectives or to reduce taxation in order to improve industrial competitiveness in general or to compensate certain consumer groups in particular for ETS-induced increases in power prices.

Allocating Free Allowances to Power Consumers

Rather than allocating free allowances directly to power producers, these allowances could be allocated indirectly to power consumers while power producers are still obliged to cover their emissions by submitting allowances to the emission authority. This would imply that these consumers could sell these allowances while the producers have to buy them.

Basically, the option has the same effects as auctioning in terms of abolishing the windfall profits of power producers due to free allocations and, if present, eliminating the effects of specific free allocation provisions on power prices and related generators' surplus. The major difference is that electricity consumers are compensated directly for the ETS-induced increases in power prices (rather than the auction revenues accruing to the public sector).

However, if allocation of allowances to individual power consumers depends on their decisions on the quantities of electricity purchased, it may have a perverse, that is, stimulating effect on power consumption and related CO_2 emissions (similar to the effects of recycling auction revenues in a direct, targeted way as discussed above). In addition, it may lead easily to an overcompensation of at least some of the consumers, in particular those able to pass on higher power costs into higher output prices. Moreover, besides an adjustment of the present EU ETS directive and current practice of allocating allowances directly to power producers, it may imply a significant increase in transaction costs if allowances have to be allocated to hundreds of millions of end-users and, subsequently, sold on the market.

To some extent, the problems or disadvantages outlined above can be relieved by restricting allocations to end-users who cannot pass on the costs of higher electricity prices, or by allocating allowances to local distribution companies or to an independent trustee who could sell the allowances to power producers and use the revenues to rebate consumers on a per capita or household basis independent of the quantities of electricity purchased by each consumer.[19] Nevertheless, although this option may at first sight seem attractive, its overall performance seems to be low compared to the first option of auctioning discussed above and using the auction revenues in more general ways (including appropriate means to compensate end-users who actually need it without having an adverse effect on their power consumption decisions).

Benchmarking

Benchmarking implies allocating emission allowances for free based on a standard emission factor (that is, the benchmark) multiplied by a certain quantity or activity level (for instance, a certain input, output or capacity level). While the benchmark itself is usually fixed *ex ante* (but can vary per activity, technology, country or period considered), the quantity or activity level can be either fixed *ex ante* (that is, before the actual operational decisions are taken, resulting in a fixed cap-and-trade system) or adjusted *ex post* (that is, after the actual activity level is realized, resulting in a relative cap-and-trade system).

If a similar amount of free allowances is allocated in a benchmarking system with a similar fixed cap as in a grandfathering system, it has the same performance in terms of environmental effectiveness, economic efficiency, carbon prices, cost pass-through, output prices and overall (windfall) profits. However, in terms of distributing the economic rent of the free allocations – and, hence, the related windfall profits – it may result in a different outcome among the sectors or installations involved, depending on the specifics of the benchmarking system. This applies in particular to a ‘perfect’ benchmarking system (compared to a ‘perfect’ grandfathering system), that is a free allocation system with a fixed cap and no updating – including no specific free allocation provisions for new entrants or plant closures – but also to a benchmarking system with a fixed cap and updating provisions (compared to a similar, less perfect grandfathering system).

On the other hand, in a benchmarking system with a relative (*ex post*) cap, the allocation of free allowances acts as a production subsidy which reduces the opportunity costs of emissions trading and, hence, reduces the amount of these costs passed through and the related windfall profits proportionally (compared to a situation of perfect free allocation – either grandfathering or benchmarking – with no updating). Depending on the level (stringency) of the benchmark and the actual emissions of the price-setting technology, the opportunity costs passed through and the resulting changes in power prices and windfall profits for marginal producers may even reduce to zero. Infra-marginal generators, on the contrary, may realize either windfall profits or losses depending on any possible change in output prices and sales volumes, as well as on the balance between their actual emissions and the allowances received for free (that is, the balance of allowances to be bought or sold on the market).

The main disadvantage of benchmarking with a relative cap, however, is that it also reduces the environmental effectiveness and/or economic efficiency of the ETS as the implicit output subsidy (and the resulting lower output prices) lead to more (price-responsive) demand, more production, less carbon efficiency, more emissions, extra demand for emission allowances, higher allowance prices and/or higher inflows of JI/CDM credits. For exposed sectors (that is, those facing outside competitors without similar carbon costs) benchmarking with a relative cap could to some extent be considered as a possible option, depending on weighing the trade-off in the performance of such a benchmarking system versus the performance of an alternative allocation system with a fixed cap (either auctioning or free allocation). However, for the power and other sheltered sectors (that is, those lacking outside competitors) benchmarking with a relative cap is not an attractive option from an efficient climate policy perspective as it results in more emissions, higher abatement costs or both. Moreover, besides uncertainty on meeting the overall emission target of the EU ETS (and, hence, of the EU mitigation commitments), a relative cap system is fundamentally different from the present fixed system, requiring a basic change of the EU ETS, which is not a politically feasible or acceptable option for the European Commission.

Reducing the Price of an Emission Allowance

In addition to changing the allocation system, there are some other options for addressing concerns related to the ETS-induced increases in power prices and generators' profits, for instance by reducing the price of an emission allowance. In theory, this carbon price reduction can be achieved by (i) increasing the EU ETS cap, (ii) setting a binding maximum carbon price, (iii) increasing the inflow of JI/CDM and other offset credits, (iv) implementing other policies besides emissions trading that reduce emissions of the ETS sectors, and (v) encouraging carbon-saving technologies.

In general, by lowering the price of an allowance, and, hence, the amount of carbon costs passed through, these options do indeed reduce the ETS-induced increases in power prices and both categories of windfall profits (A and B), at least in an absolute sense. For a variety of reasons, however, these options have some restrictions or other drawbacks, which make them either less attractive or feasible from an efficient carbon policy point of view.

For instance, increasing the EU ETS cap is not possible within a current trading period, while probably neither carbon efficient nor politically acceptable as it implies that the EU will not reach its mitigation objectives or, most likely, that the non-ETS sector would have to abate at higher overall costs. Similarly, setting a binding maximum carbon price is also not a politically acceptable, feasible option partly because it is a kind of market regulation which is nowadays unpopular among both policy makers and private traders, and partly because it has implications in terms of mitigation targets and abatement costs similar to the option of increasing the EU

ETS cap outlined above. Moreover, although there may be some rational considerations for introducing a maximum ETS price (‘safety valve’), one may question whether addressing concerns related to ETS-induced increases in power prices and windfall profits is an appropriate justification for such a safety valve.

Increasing the inflow of offset credits (JI/CDM), on the contrary, could be a rational and attractive option to reduce EUA prices. It should be noted, however, that such a strategy only makes sense when there is no equilibrium between EUA and carbon offset prices or, more precisely, when the differential between these prices is significantly higher than the difference in risks and transaction costs between these alternative options to cover emissions of EU ETS installations. Moreover, the supply of these credits may be hard to increase due to a variety of political, technical, socio-economic and other project-related constraints in the home countries concerned. In addition, the EU prefers to limit the inflow of these credits into its ETS to ensure that a major part of the mitigation commitments are met domestically and to maintain a certain EUA price level that furthers domestic innovation purposes.

Implementing other climate or energy policies besides emissions trading – for instance, policies to promote renewables or energy saving – may lead to fewer emissions in the ETS sectors and, hence, to lower EUA prices. If these policies are implemented largely for other reasons than mitigation objectives – for instance, to enhance energy security – attendant outcomes in terms of lower ETS emissions or EUA prices could be welcomed (although it would probably make more sense to lower the ETS cap according to the lower ETS sector emissions due to these policies). On the other hand, if these policies are implemented solely to reduce ETS sector emissions or EUA prices, they can be questioned from a socially efficient climate policy perspective as, if effective, they generally replace cheaper abatement options (induced by emissions trading) by more expensive options (Sorrell and Sijm, 2003).

Finally, encouraging, carbon-saving technologies to reduce the price of a CO_2 emission allowance can be a sensible option, depending on the time perspective considered and the means applied to achieve this objective. If such (existing) technologies are subsidized heavily from public resources just to reduce short-term carbon prices for private operators, it does not seem to make sense from a socially efficient climate policy perspective. On the other hand, if certain market imperfections in the R&D stages of new carbon-saving technologies are overcome by adequate public support in a socially optimum way, it can be a highly justified option to keep carbon prices affordable in a process of growing mitigation ambitions. However, this option, if successful, will only control carbon prices in the long run rather than reducing them in the short term.

Regulating Power Prices

Another option to reduce ETS-induced increases in power prices and generators' profits due to free allocation is to have these prices regulated by an external authority, for instance the national transmission system operator (TSO) or the energy market surveillance authority. In practice, this option would imply that power producers are allowed to pass through only the (average) costs of carbon allowances bought on an auction or market (and the abatement costs of reducing power-related CO_2 emissions, or other changes in generation costs due to emissions trading) but not the opportunity costs of the allowances obtained for free. Besides limiting increases in electricity prices in favour of end-users, including small firms and low-income households, a related advantage of this option is that it reduces the deterioration of the international competitiveness of some power-intensive industries.

Regulating power prices, however, has some serious drawbacks. First, this option is nowadays not popular among EU policy makers as it does not fit in the current process of market liberalization, privatization and deregulation in order to achieve competitive, efficient power markets. Second, it may be hard and administratively demanding to determine (*ex ante*) the (average) costs of purchasing the necessary allowances over a certain trading period or the abatement costs (and other changes in generation costs) due to emissions trading, notably in the case of setting wholesale spot or forward prices.

Third, if effective, and assuming power demand to be price responsible – notably in the medium and long terms – this option implies higher power production, and, hence, higher sector-related emissions, thereby forfeiting an efficient strategy to meet future mitigation commitments. Moreover, lower power prices imply fewer incentives for investments in more-expensive, but carbon-saving technologies such as renewables.

Finally, one may question the effectiveness of this option to reduce power prices. As noted above, if effective, this option would result in more power demand, fewer carbon-saving technologies and, hence, more power production by CO_2-intensive plants. However, as operators of these plants are not allowed to pass through the opportunity costs of allowances obtained for free, they are inclined to reduce their production and sell the allowances on the market, resulting in serious power market scarcities and induced higher (rather than lower) electricity prices. Therefore, for a variety of reasons, regulating power prices does not seem to be a cost-effective or politically attractive option to reduce ETS-induced increases in electricity prices or generators' profits due to free allocations of allowances.

Encouraging Competition in the Power Sector

It is sometimes suggested that the ETS-induced increases in power prices and windfall profits resulting from free allocations are due to a lack of competition in the power sector and, hence, that encouraging this competition would reduce these increases in prices and profits. However, although encouraging power market competition may increase sector efficiency or reduce the incidence of market power – and, hence, reduce power prices – one may question whether this option is effective in reducing ETS-induced increases in power prices and generators' profits due to free allocations.

First, as supported by economic theory and empirical evidence, in competitive markets power producers also pass through the opportunity costs of carbon allowances into their price bids (even up to 100 per cent), regardless of whether they have purchased these allowances or obtained them for free. Moreover, depending on the specific characteristics of non-competitive market structures and power demand (that is, a constant elasticity or linear demand curve), the carbon cost PTR on a monopolistic or oligopolistic market may be either significantly higher or lower than 100 per cent (Sijm et al., 2008). Therefore, encouraging competition in the power sector will not eliminate ETS-induced increases in power prices and windfall profits due to free allocation (on the contrary), but may even result in a higher carbon cost PTR and, hence, to even higher increases in these prices and profits.

In addition, a similar or related suggestion is that free allocations to new entrants lead to earlier investments in additional generation capacity and, perhaps, even in more power producers actively supplying on the market, resulting in less market scarcity, less market power or more competition and, therefore, in reducing or compensating the ETS-induced increases in power and windfall profits due to free allocation to existing producers. However, although to some extent these effects may occur, several qualifications can be made to free allocations to new entrants (in addition to the qualifications made above with regard to the impact of market competition on cost pass-through and power prices).

First, this option is only effective if it indeed leads to additional, earlier investments in generation capacity, which in the power sector may take at least take several years to implement. Second, due to a variety of technical, economic and other constraints, investments in new generation capacity are usually conducted by existing firms rather than by newcomers. Third, as already noted for similar options reducing power prices, if effective, and assuming power demand to be price-responsive, this option implies higher power production and, hence, higher sector-related emissions, thereby giving up an efficient strategy to meet mitigation targets. Moreover, lower power prices imply less incentive for investments in more-expensive, but carbon-saving technologies such as renewables. This applies particularly if free allowances to new entrants are allocated in a fuel-specific or technology-biased way (that is, high polluters get more, while non-CO_2 emitters receive nothing), thereby undermining the ETS incentive structure towards carbon-saving investments. Finally, if one is interested in increasing generation capacity or power market competition, there are most likely more socially efficient measures than free allocations to new entrants, such as introducing capacity markets or direct capacity payments to power producers, including newcomers, or separating power network structures from production and marketing activities. Therefore, for a variety of reasons, encouraging competition in the power sector – notably by allocating allowances for free to new entrants – is highly questionable as a cost-effective option to reduce ETS-induced increases in power prices and windfall profits.

Taxing Windfall Profits

Another major, final option to address the issue of windfall profits due to the EU ETS is skimming these profits through taxation, either fully or partially. Compared to auctioning, a major advantage of taxation is that it can address both categories of windfall profits, that is, not only category B but also category A. Another advantage of taxing windfall profits is that it raises revenues that can be either recycled or used to finance public expenditures (although recycling tax revenues raises similar problems as recycling auction revenues, discussed above).

The major problem of taxing windfall profits is that, in practice, it is hard to estimate them reliably just as it is rather difficult to estimate empirically exact, reliable PTRs and, hence, to estimate what power prices (or sales volumes, generation costs, and so on) would have been without emissions trading (as discussed in Section 5.3). This applies in particular to estimating windfall profits at the individual company level, or to estimating such profits when free allocation provisions such as updating or free allocations to new entrants reduce ETS-induced increases in power prices and windfall profits in the medium or long run. An additional complicating issue is whether only ETS-induced windfall profits in the power sector should be taxed or also similar profits in other sectors, and how to determine these profits in a fiscal–juridical correct way (and what about any possible windfall losses due to emissions trading)?

Another, related problem concerns the definition of windfall profits, notably whether they refer to category A or B, or both categories, and whether they are related only to existing producers or also to new entrants (see Section 5.3). While in some EU ETS countries the issue of windfall profits in the power sector refers almost solely to category B (that is, windfall profits due to free allocations), in other countries it is related primarily to category A (that is, windfall profits due to ETS-induced changes in power prices, sales volumes and generation costs).

In addition, while some observers refer the issue of windfall profits to both existing and new producers, others relate it solely to incumbents, arguing that new entrants have based their investment decisions on profit expectations *after* the policy decision to introduce emissions trading. Moreover, taxing windfall category A to new entrants would imply that the incentive to invest in carbon-saving technologies would be reduced. On the other hand, however, taxing windfall category B accruing to new entrants would mean that the incentive to invest in CO_2-intensive technologies and the distortive effects on output prices and abatement efficiency would be reduced, notably if the free allocation to new entrants is applied in a fuel-specific or technology-biased way.

To some extent, the dilemmas outlined above could be relieved by restricting taxation to the full or partial (average) market value of the allowances allocated for free to both incumbents and new entrants in the power and other sheltered sectors of the EU ETS. However, a similar and, perhaps, even simpler solution would be to auction the corresponding amount of allowances to these sectors. In addition, a problem of full, that is, 100 per cent, taxation (or auctioning) is that it may lead to ‘overtaxation’ of windfall profits due to free allocations – depending on the actual PTR and the ETS-induced changes in sales volumes – while, as noted, it is hard to estimate the right tax rate to break even, notably at the company level or in the long run. Moreover, taxing only windfall category B would not solve the issue of windfall category A, which is not only more important in some EU ETS countries but, in addition, would deny these countries the potential revenues to address some concerns related to the ETS-induced increases in electricity prices such as losses in purchasing power of low-income households or losses in international competitiveness of some exposed, power-intensive industries.

Another option would be no taxation but auctioning of carbon allowances to all power operators (and other sheltered producers) and, as far as category A of windfall profits to existing, private companies is a relevant problem in some countries, these profits can be taxed by these countries – based on a conservative, prudent estimate of the size of windfall A – while the revenues can be used at their own discretion.

5.5 CONCLUSION

Power prices on forward (that is, year-ahead) wholesale markets in Germany and the Netherlands have generally increased substantially between early 2005 and mid-2006. In those cases where these prices have been set predominantly by coal-fired stations, notably during the off-peak period, this increase cannot be ascribed to the impact of fuel costs – as coal prices were rather stable over this period – whereas there seems to be a close relationship between the price and carbon costs of coal-generated power. However, in the case of gas setting (peak) power prices, the increase in these prices is mainly due to rising fuel costs, while the impact of gas-related carbon costs is less significant. Moreover, after the collapse of the carbon price in April/May 2006 and, particularly, during the latter part of 2006 (when both carbon and gas prices declined steadily), the link between power prices and fuel/carbon costs is far less clear, suggesting that other factors – such as growing capacity scarcities or market power – have become more important in affecting power prices.

Empirical estimates of carbon cost PTRs on forward wholesale power markets in Germany and the Netherlands vary from 0.4 to more than 1.0 in 2005–06. These estimates have to be interpreted with due care as, to some extent, they depend on (shortcomings of) the data and the methodologies used or the assumptions made, in particular that during the observation period power prices are set by a single (marginal) technology with a fixed, generic fuel efficiency, or that changes in power prices are predominantly caused by changes in the underlying costs of fuels and CO_2 emission allowances, and that all other generation costs and factors affecting power prices are more or less fixed.

Power prices on retail markets for either households or industrial users in Germany and the Netherlands have also increased significantly in 2004–06. However, since retail electricity prices in these countries are generally 2–4 times higher than wholesale power prices – due to high energy taxes, in particular for households, and high distribution or other marketing costs – the role of carbon costs passed through seems to be less relevant to account for (changes in) power prices on retail markets in Germany and the Netherlands in 2005–06.

More specifically, if it is assumed that over the 2004–06 period changes in the retail power spreads – defined as retail power prices excluding taxes and fuel costs – are solely due to carbon costs passed through, the impact of the EU ETS on (changes in) retail power prices was still relatively low in 2005 due to relatively low year-ahead carbon prices in 2004 and, perhaps, some time lags or other (marketing) constraints in passing through these costs to retail prices. In 2006, however, this impact seems to be already more significant, notably in Germany, due to relatively higher forward carbon prices in 2005 and, presumably, an increasing share of carbon costs passed through. Moreover, if it is assumed that the carbon costs passed through on the retail market are similar to those passed through on the wholesale market, the impact of these costs – and, hence, of the EU ETS – on retail power prices becomes generally even more significant. These findings, however, have to be treated cautiously as, to some extent, they depend on the assumptions made to estimate the carbon costs passed through.

For 2005–06, empirical estimates of windfall profits in the power sector of Germany and the Netherlands vary from, on average, 0.2 to 17 €/MWh or, in total, from €20–1000 million for the Netherlands and €4–8 billion in Germany. Similarly to the above-mentioned findings on carbon cost pass-through on wholesale and retail power markets, however, these estimates have to be treated with caution as EU ETS-induced windfall profits are hard to estimate precisely, depending on the time period considered and the assumptions made, including the definition of windfall profits.

Passing through the opportunity costs of (freely allocated) CO_2 emission allowances to power end-user prices is a rational and intended effect from an efficient carbon abatement policy perspective, while generators' windfall profits may result from free allocations and/or increases in these prices set by marginal fossil-fuelled stations (which also or mainly benefit infra-marginal, less-carbon-intensive plant operators). Nevertheless, the supposed ETS-induced increases in power prices and generators' profits have raised questions and concerns affecting the legitimacy or acceptability of the present EU ETS, including concerns regarding its impact on the international competitiveness of some power-intensive industries, the purchasing power of electricity end-users such as small households or, more generally, the distribution of social welfare among power producers and consumers. As a result, in several countries – including Germany and the Netherlands – policy makers and stakeholders of industrial or other interest groups have suggested a variety of options to address these concerns, including changing the emissions trading allocation system, taxing windfall profits or controlling market prices of EU carbon allowances, electricity or both. A summary of the performance of the major options suggested to address the above-mentioned concerns is provided in Table 5.3. The table shows that the performance of options to control or reduce carbon/power prices – either directly or indirectly – is generally low to medium, partly depending on the means to achieve these objectives, because either they barely address the ETS-related concerns mentioned above or they have certain disadvantages or other side-effects which make these options not attractive or acceptable to policy makers.

Table 5.3 Performance of options to address concerns regarding ETS-induced increases in output prices and windfall profits in the power sector

Option	Impact on power prices	Impact on windfall profits		Impact on competitiveness of power-intensive industries	Other main effects (including major advantages and disadvantages)	Overall performance
		A	B			
1. Auctioning	0/+ ?	0/+ ?	–	0/–?	Raising auction revenues May reduce competitiveness of specific firms	High
2. Allocation to power consumers	0/+ ?	0/+ ?	–	0/–?	Direct compensation Perverse consumption effect Overcompensation of sheltered industries	Medium
3. Benchmarking:						
• *Fixed (ex ante) cap*	0	0	0	0	Effects are similar to grandfathering with fixed cap	Low
• *Variable (ex post) cap*	–/0?	–/0?	–	+ /0?	Losses of economic efficiency and environmental effectiveness	Low
4. Reducing EUA price by:						
• *Increasing ETS cap*	–	–	–	+	Overall, lower CO_2 reductions and/or higher costs	Low
• *Setting maximum price*	–	–	–	+	Idem + interferes with free market	Low
• *Increasing JI/CDM credits*		–	–	+	Technical, socio-economic and/or political limitations	Medium
• *Other carbon-reducing policies*	–	–	–	+	Neither abatement effective nor efficient	Low

• *Encouraging carbon-saving technologies*	–	–	–	+	Mainly effective in the long run	Medium/ high
5. Regulating power prices	–	–	–	+	Interferes with liberalization of competitive markets More demand/emissions Fewer carbon-saving investments More market scarcities	Low
6. Encouraging market competition	–/+ ?	–/+ ?	–/+ ?	+ /–?	Effects depend mainly on level of PTR of more vs. less competition	Medium
• *By free allocation to new entrants*	–/0?	–/0?	–/0?	+ /0?	Abatement inefficiency Undermines EU ETS incentives	Low
7. Taxing windfall profits	0	–	–	0	Windfall profits are hard to define or to estimate precisely in a fiscal–juridical way	Medium

Note: '+' indicates that prices or profits increase (or competitiveness improves), while – indicates that prices or profits decrease (or competitiveness deteriorates) due to the policy option.

For similar reasons, the overall performance is also low to medium for free allocation-related options such as free allocation of allowances to power consumers or free allocation based on benchmarking with either a fixed (*ex ante*) or a flexible (*ex post*) cap. On the other hand, the overall performance of auctioning allowances to power producers is considered to be rather high as it enhances the carbon efficiency of the EU ETS, eliminates the windfall profits due to free allocations, while it raises revenues that can be used (i) to finance public expenditures on carbon abatement or other useful, social objectives, (ii) to reduce taxation and related efficiency distortions ('double dividend'), or (iii) to compensate power-intensive industries and other electricity consumers for the ETS-induced increases in power prices.

Auctioning, however, does not reduce generators' windfall profits due to ETS-induced increases in power prices – in particular for infra-marginal, less-carbon-intensive plant operators – and may even result in an increase in such profits (notably when it implies the termination of free allocation to new entrants, leading to higher power prices in the medium or long run). As far as such profits are a major point of concern in some EU countries, these profits can be taxed by these countries, while the revenues can be used at their own discretion (similar to recycling auction revenues).

NOTES

1. This chapter is largely based on a study conducted by the Energy research Centre of the Netherlands (ECN) on behalf of the European Commission (see Sijm et al., 2008). It should be emphasized, however, that the views expressed here are those of the authors and do not necessarily reflect those of the European Commission.
2. Unless stated otherwise, the forward market refers to the year-ahead market where, for instance, electricity or fuel delivered in 2006 is traded during every day of 2005. (For a discussion of the data used for the empirical analyses, see Box 5.1.)
3. These spreads are indicators for the coverage of other (non-fuel/carbon) costs of generating electricity, including profits. For the present analysis, however, these other costs (for instance, maintenance or capital costs) are ignored as they are assumed to be constant for the period considered (although they may vary for the different country/load periods analysed) and, hence, they are assumed to not affect the PTRs of carbon costs estimated below in Section 6.2.
4. For instance, for the Netherlands over the period from January to July 2005, Sijm et al. (2005) show that if the assumed *gas* efficiency rate is raised from 40–45 per cent, the estimated PTR in the peak hours jumps from 0.27 to 0.55 while, if the assumed *coal* efficiency rate is raised from 35 to 40 per cent, the estimated PTR in the off-peak period increased from 0.47 to 0.55.
5. For a detailed discussion of the theoretical and empirical support for the pass-through of the opportunity costs of emissions trading to power prices, see Sijm et al. (2008).
6. For more details on the methodologies applied, see Sijm et al. (2008).
7. See also Figure 5.5, which presents a decomposition of the retail power prices into (a) energy taxes, (b) fuel costs, (c) full carbon costs, and (d) clean spreads, defined as the difference between the 'normal' (or 'dirty') retail power spreads and the full carbon costs

of the technologies setting power prices. Hence, by adding the full carbon costs to the clean spreads presented in Figure 5.5, one gets an indication of the absolute levels of these (normal/dirty) spreads in 2004–06 and the changes of these spreads over this period.

8. Note that the estimated PTRs according to the 'wholesale' approach vary by country but are similar in both 2005 and 2006 for both consumer groups in each country. This is due to the assumptions of this approach, notably that (i) for each country, the estimated carbon costs passed through on the wholesale market are equal to those passed through on the retail market, regardless of whether the electricity is sold to households or industrial consumers, and (ii) the PTRs for the year-ahead wholesale markets in 2004 (that is, power produced/consumed in 2005) are equal to the PTRs estimated for the forward markets in 2005 (as estimates of year-ahead PTRs for 2004 are lacking). In addition, note that the estimated PTRs according to the 'wholesale' approach for Germany and the Netherlands in 2006 (as recorded in Table 5.2) are actually the averages of the estimated PTRs of these countries on the year-ahead power markets during the peak and off-peak periods in 2005 (weighted by the shares of each period in total annual power sales), as recorded in Table 5.1. This follows from the assumption that the carbon costs passed through on the wholesale year-ahead markets in 2005 (with delivery in 2006) are subsequently passed through on the retail markets in 2006.
9. Note that in some cases of the 'full carbon costs' approach, the share of carbon costs passed through as a percentage of the changes in retail power price is more than 100 per cent. This may be due to the fact that (i) the carbon costs passed through are actually overestimated by the 'full carbon costs' approach, and/or (ii) the net change in retail power prices is small compared to the carbon costs passed through because (the increase in) these costs are compensated by a decrease in fuel costs or energy taxes.
10. See Sijm et al. (2008) for a review and discussion of estimates of windfall profits due to EU emissions trading.
11. VIK (2005) has made a similar estimate of EU ETS-induced windfall profits for the German power sector amounting to €5 billion per year, that is, approximately 10 €/MWh generated.
12. Note that these changes in profits of (infra-)marginal producers due to changes in relative carbon costs are similar to profit changes resulting from changes in fuel or other generation costs.
13. See Sijm et al. (2008) for a discussion of the power price impact of specific free allocation provisions, including (i) upgrading of free allocation, (ii) free allocation contingent on minimum production levels ('plant closures'), and (iii) free allocation to new entrants.
14. For a more detailed discussion of the effects of free allocation provisions on power prices, see Sijm et al. (2008).
15. For a broader discussion including design options, advantages and disadvantages of auctioning emission allowances, see Hepburn et al. (2006), Burtraw et al. (2007), Matthes and Neuhoff (2007) and Harrison et al. (2007).
16. In countries where end-users already pay relatively high environmental levies or value-added taxes on their power consumption, auction revenues could be used to reduce these levies/taxes or, perhaps even better, to reduce the taxes on those environmentally friendly commodities consumed by small households and firms in order to compensate them for the regressive income distribution effect of ETS-induced increases in retail power prices.
17. These perverse effects can be avoided if power users are compensated by a fixed, lump-sum amount which is independent of their current or future consumption decisions, but as soon as updating – including 'firm closures' and 'new entrants' – is included in the compensation scheme, it has a perverse effect on these decisions.
18. Another 'disadvantage' of auctioning is that governments cannot use free allocations to achieve other objectives besides carbon abatement efficiency, such as promoting security of supply or certain technological innovations (Harrison et al., 2007). However, such objectives can also – or even better – be achieved by using auction revenues accordingly.
19. For a further discussion of these approaches, see Burtraw and Palmer (2006).

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