The implications of free allocation versus auctioning of EU ETS allowances for the power sector in the Netherlands

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Abstract
The main objective of the present study is to analyse the implications of shifting from free allocation to auctioning of EU ETS allowances (EUAs) for the power sector in the Netherlands. In order to achieve this objective, this study has used three methodological approaches, including theoretical, empirical and model analyses of the impact of free allocations versus auctioning of EUAs on the power sector, notably in the Netherlands. In addition, as Combined Heat and Power (CHP) plays a major role in the electricity sector of the Netherlands, the present study also pays some particular attention to the implications of shifting from free allocation to EUA auctioning for the CHP sector in the Netherlands.

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The major findings of the analytical approaches are summarised below.

Theoretical approach

According to economic theory, power producers pass through the opportunity costs of emissions trading to electricity prices regardless of whether the allowances have been auctioned or allocated for free. In the ideal or reference cases of auctioning versus perfect free allocation, the impact of emissions trading on abatement efficiency and power prices is similar in both cases. In practice, however, emissions trading schemes may contain some specific free allocation provisions which distort the outcomes of these ideal cases in terms of carbon efficiency and power prices. These provisions include in particular (i) updating baselines of free allocation to incumbents, based on their output, (ii) contingent free allocation to plant closures (i.e., loosing freely obtained allowances if plants close), and (iii) free allocation to new entrants.

The main effect of these specific free allocation provisions is that they reduce the carbon efficiency of the ETS, i.e., they result in less CO_2 emission reduction - if the carbon budget of the system is not fixed - and/or in higher abatement costs. This applies in particular for so-called protected industries, such as the power sector, which do not face competition from outside the scheme. In addition, the specific provisions may reduce the ETS-induced increases in power prices in the medium or long term, depending on whether the carbon budget is fixed or not.[1]

Empirical approach

Empirical analyses of the impact of the EU ETS on electricity prices and generators' profits in the Netherlands during the years 2005-2006 including the impact of free allocation show that power producers include the EUA costs of generating electricity in their bidding prices and, hence, pass-through these costs to wholesale and retail electricity prices, resulting in additional ('windfall') profits for operators of both fossil and non-fossil fuelled plants.

Based on these empirical results and the theoretical findings outlined above, the major implications of shifting from free allocation to auctioning for the power sector in the Netherlands during the third phase of the EU ETS can be summarised as follows:

- The implications of shifting from free allocation to auctioning will be mainly restricted to reducing (windfall) profits of fossil fuel operators while other power sector variables prices, investments, sales volumes, emissions, etc. will be hardly affected if it is assumed that either (i) free allocations during the first and second trading periods largely meet the ideal,

[1] The carbon budget of an ETS refers to the total amount of carbon allowances allocated to eligible installations (i.e., the cap) and, if allowed, the use of offset credits such as JI or CDM credits to cover the emissions of these installations. According to the January 2008 proposals of the European Commission, the cap of the EU ETS is fixed far beyond 2020 while the use of JI/CDM is limited up to 2020. Therefore, the carbon budget of the EU ETS is fixed at least up to 2020 (although it is not certain whether in all cases the available JI/CDM limit will be fully used). More importantly, according to these proposals, carbon allowances will be auctioned to the power sector starting from 2013, implying that the impact of free allocation provisions on power prices if any will be eliminated.

textbook type of perfect free allocations, or (ii) the impact of the specific free allocation provisions has been small in the short term or will be compensated by induced higher carbon prices due to a fixed overall CO_2 budget of the EU ETS in the long run.

- On the other hand, the implications of moving from free allocation to auctioning will be quite the opposite if it is assumed that (i) free allocations during the first and second trading periods do not meet the ideal, textbook type of perfect free allocations, and (ii) the impact of the specific free allocation provisions will be substantial notably in the long run due to a flexible CO_2 budget of the EU ETS. In that case, profits will remain more or less the same for marginal, fossil fuel operators but increase for infra-marginal, non-fossil generators, while it will also affect most other power sector variables: increase power prices, reduce sales volumes, improve carbon efficiency of new investments, reduce power sector emissions, etc.

Model approach

The implications of shifting from free allocation to EUA auctioning have also been analysed by means of the so-called COMPETES model. The analyses are based on several model scenarios, distinguishing different wholesale power market structures i.e. perfect versus oligopolistic competition and different levels of demand responsiveness to changes in electricity prices. In addition, three different price levels of CO_2 emission allowances are considered, i.e. 0, 20 and 40 €/tCO_2, where (i) 0 €/tCO_2 refers to a situation of no emissions trading - e.g. the period before the introduction of the EU ETS (ii) 20 €/tCO_2 to the (average) price of a carbon allowance during the first years of the EU ETS, notably 2005-2006, and (iii) 40 €/tCO_2 to the (expected, average) price of an EUA by the end of the third trading period of the EU ETS (2013-2020).

Emissions trading in the COMPETES model is actually based on the assumption of full auctioning of emission allowances, but it can simulate the impact of free allocations on generators' profits by simply adding the value of free allocations to these profits. However, the model is not able to analyse the impact of the specific free allocation provisions of the EU ETS on the power sector. Nevertheless, some of its major findings in the context of the present study include:

- The estimated pass-through rates (PTRs) of carbon costs to electricity prices in the Netherlands under various COMPETES model scenarios vary between 0.84 and 1.10 at an allowance price of 20 €/tCO_2 and between 0.75 and 0.83 at 40 €/tCO_2, while the empirically estimated PTRs for the years 2005-2006 at an average allowance price of 20 €/tCO_2 vary from 0.38-0.40 in the off-peak period (when coal is assumed to set the electricity price) to 1.10-1.34 in the peak period (when gas is assumed to be the marginal technology). This seems to suggest that (i) the PTR will be lower if the carbon price is higher (which may be due to carbon price induced changes in the merit order), and (ii) at the same carbon price, the model estimated PTRs are, on average, somewhat higher than the empirically estimated PTRs. Both types of PTRs, however, have to be treated with due care because of their different sets of underlying assumptions and data used.
- Emissions trading and the resulting pass-through of carbon cost to electricity prices may reduce CO_2 emissions significantly by affecting not only producers decisions - through a redispatch or change in the merit order of generation technologies - but also consumer decisions, i.e. through reducing power demand in response to ETS induced increases in electricity prices.
- In general, total power generators' profits increase significantly due to emissions trading, notably under free allocation but even under full auctioning. Whereas non-fossil generators benefit from ETS induced increases in electricity prices (under both auctioning and free allocation), fossil fuel operators generally benefit mainly from the free allocation effect on their profits. Hence, these operators will lose these (windfall) profits if the ETS shifts from free allocation to auctioning. Moreover, compared to the situation before (or no) emissions trading, some individual power companies and even the total power sector of some individual countries may face less profits due to emissions trading with auctioning, notably if these companies are more carbon intensive than their (price-setting) competitors and/or their sales vol-

umes decline substantially due to a loss of competitiveness and/or a significant responsiveness of power demand to ETS induced increases in power prices.

Implications for CHP in the Netherlands

Combined Heat and Power (CHP) plays a major role in the electricity sector of the Netherlands, accounting for approximately 50% of available generation capacity and electricity production in 2006. In general, the implications of shifting from free allocation to auctioning for the CHP subsector are similar to those for the power sector as a whole, as outlined above. However, there are some differences in terms of implications for the CHP sector versus the power sector as whole, including:

- CHP produces not only power but also heat. Whereas EUA costs of power are (assumed to be) passed-through to electricity prices regardless of the allocation method, the EUA costs of heat production are assumed to be passed through under auctioning but not under free allocation. This implies that under free allocation CHP benefits from additional (windfall) profits due to ETS induced increases in electricity prices (which are forgone again if the ETS shifts towards auctioning), whereas the profits from heat production more or less break even under both free allocation and auctioning.
- CHP in the Netherlands used to be supported by the Dutch government, depending on the 'financial gap' or 'lack of profitability'- of CHP operations/investments. This implied that both positive and negative changes in this gap due to the EU ETS used to be (partially) compensated by the amount of support to CHP. In 2008, however, the Dutch government decided to abolish the operational support to existing CHP installations, while for new installations the potential subsidy will be considered again in 2009, depending on actual and expected trends in costs and benefits of CHP operations for new entrants.

In general, however, the competitiveness and/or profitability of CHP in the Netherlands should improve due to the EU ETS - even with auctioning - as it is more carbon efficient than most of its (price-setting) competitors.

1. Introduction

Background and objective of present study
During the first and second trading period, 2005-2012, the EU Emissions Trading Scheme (ETS) has relied primarily on the free allocation of EU emission allowances (EUAs). In January 2008, however, the European Commission has proposed that, starting from the third phase (2013-2020), free allocation to the power sector will be abolished and replaced by auctioning of EUAs.[2]

Against this background, the main objective of the present study is to analyse the implications of shifting from free allocation to auctioning of EU ETS allowances for the power sector in the Netherlands. In order to achieve this objective, this study has used three methodological approaches, including theoretical, empirical and model analyses of the impact of free allocations versus auctioning of EUAs on the power sector, notably in the Netherlands.

Analytical perspectives
Beforehand, it has to be noted that the free allocations of EUAs during the first and second trading period of the EU ETS do not meet the ideal, standard type of free allocation outlined in the theoretical literature, but are characterised by some distortions or so-called 'specific free allocation provisions' such as the contingent allocation of free allowances to plant closures or the free allocation of EUAs to new entrants. Therefore, the implications of moving from free allocation to auctioning have to be analysed not (only) from the perspective of the ideal textbook notion of free allocation, but (also) from the perspective of the actual practice of free allocation by the EU ETS, including the incidence of these specific provisions.

Moreover, in order to analyse the implications of EUA auctioning in a proper way, these implications e.g. the impact on power generators' profits are analysed not only compared to a situation of free allocation but also to a situation of no emissions trading at all (i.e. before the introduction of the EU ETS). Finally, as Combined Heat and Power (CHP) plays a major role in the electricity sector of the Netherlands, the present study also pays some particular attention to the implications of shifting from free allocation to EUA auctioning for the CHP sector in the Netherlands.

Report structure
The structure of the present study runs as follows. Firstly, Chapter 2 analyses the implications of different EU ETS allocation methods for the power sector in general from a theoretical point of view, notably the implications of EUA auctioning versus free allocations, including the incidence of the specific free allocation provisions. Subsequently, Chapter 3 addresses the implications of free allocation versus auctioning of EU ETS allowances for the power sector in the Netherlands, based on an empirical approach, while Chapter 4 considers these implications by means of using the so-called COMPETES model for the wholesale power sector in the Netherlands and for comparative reasons some of its neighbouring, competing countries (notably Belgium, France and Germany). Finally, Chapter 5 pays some particular attention to the implications of EUA auctioning versus free allocation for the CHP sector in the Netherlands.

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[2] In mid-December 2008, both the European Council and the European Parliament agreed to 100% auctioning for the power sector, starting from 2013. For existing installations in some (mainly East-European) countries, however, it was decided that the auctioning rate in 2013 will be at least 30% and will be progressively raised to 100% no later than 2020.

2. The implications of EU ETS allocation for the power sector - a theoretical approach

The impact of CO_2 emissions trading on the power sector in general and electricity prices in particular depends on a variety of factors, notably (i) the price of a CO_2 emission allowance, (ii) the carbon intensity of the power sector, especially of the generation technologies setting the electricity price at different levels of power demand, and (iii) the structure of the power market, including the level of market concentration or competitiveness, the shape of the power demand and supply curves, and the level of market liberalisation versus regulation.[3] In addition, this impact may depend on the allocation system, i.e. the way in which the emission allowances are allocated to the participants of the trading scheme, for instance by auctioning or by free allocation.

This chapter aims to analyse from a theoretical point of view the implications of the allocation system - notably of the EU ETS - on the power sector in general and electricity prices in particular. First of all, Section 2.1 discusses the link between allocation and pass-through of the so-called *opportunity costs* of CO_2 emission allowances to power prices. Subsequently, Section 2.2 considers two reference or base cases of allocating emission allowances, i.e. auctioning versus perfect free allocation, and their implications for the performance of the power sector. During the first and second trading periods (2005-2012), the EU ETS has been based largely on free allocation but it has not met the conditions of the 'ideal type' of perfect free allocation as it has been characterised by some specific free allocation provisions, including (i) updating baselines of free allocations to incumbents, (ii) contingent free allocation to plant closures, and (iii) free allocation to new entrants. The primary and secondary effects of these specific free allocation provisions are discussed in Sections 2.3 and 2.4, respectively. Finally, Section 2.5 presents a summary and conclusion of this chapter.

2.1 The opportunity costs of CO_2 emission allowances

In an emissions trading system, a CO_2 allowance is a scarce and, therefore, a valuable commodity that can be traded on the market at a certain price. A producer, such as a power generator, who owns a certain amount of carbon allowances can either use these allowances to cover the CO_2 emissions resulting from the production of electricity or sell them on the market to other participants who need additional allowances. Hence, for a producer, using emission allowances represents a so-called 'opportunity cost' - i.e. the cost of *not* selling the allowance - regardless of whether the allowances have been allocated for free or purchased at an auction or market. Therefore, in line with economic theory on optimal market behaviour and the efficiency of emissions trading, power generators who aim at profit maximization are expected to include the opportunity costs of a CO_2 allowance into their operational decisions and to pass-through these costs into their price bids on the electricity wholesale market, even if the allowances are granted for free.[4]

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3 See Chapter 2 of Sijm *et al.* (2008a) for an extensive, theoretical explanation of the impact of market structure on the pass-through of carbon costs to electricity prices.

4 The concept of opportunity costs is fundamental to economics and not restricted to the analysis of using free emission allowances but also accepted in other respects. For instance, if a power company has acquired the right to coal or gas at some contract prices, it is nevertheless expected that the current market price of fuels dictates the price setting of electricity, provided the company could otherwise sell the fuel to someone else at the current market price, including transaction costs (Radov and Klevnas, 2007). It should be noted that the concept of opportunity costs applies not only to allowances obtained for free but also to allowances auctioned or bought. Hence, regardless of whether allowances have been obtained for free or bought on an auction or market, current operational decisions are based on the current opportunity cost - i.e. the current market price - while the difference between the current market price of an allowance and what has been paid for it in the past - if any - is accounted for as a loss or profit due to storage or other operational transactions.

Including the opportunity costs of carbon allowances to the other, variable costs of power generation and internalising these costs into the price setting of electricity is an important condition for achieving the environmental target of CO_2 emissions trading at least costs, notably by the following means:

- It provides an incentive to power producers - both incumbents and new entrants - to reduce their emissions by switching or investing towards technologies with lower emissions, including more efficient gas-fired plants, nuclear, renewables, carbon capture and storage or other abatement options.
- It provides an incentive to power consumers - both households and industrial users - to reduce their demand for carbon-generated electricity, notably in the medium and long term by means of increasing their energy efficiency - i.e. electricity saving - or switching to less CO_2 intensive generated electricity.

By equalizing the marginal abatement costs of all mitigation options throughout the system to the price of a CO_2 allowance, emissions trading results in the least costs to achieve its environmental target. However, if power prices do not internalise the opportunity costs of carbon allowances, least cost abatement options from low-emission generation and energy saving will not be encouraged. For a fixed emission target, abatement will therefore have to be achieved by other, more expensive options. This will increase the price of a CO_2 allowance and, hence, the overall costs of the trading scheme (Radov and Klevnas, 2007).

2.2 The reference cases: auctioning versus perfect free allocation

In order to illustrate the impact of allocation on passing through carbon costs in the power sector, two reference or base cases of allocating emission allowances are considered, i.e. auctioning versus perfect free allocation. In an auctioning system, allowances are initially allocated by selling them at an auction (or market). On the other hand, the ideal (textbook) type of perfect free allocation is characterized by:

- A one-off initial allocation of free allowances to existing installations (incumbents), usually for a long time frame, based on (i) a fixed baseline or historic reference period of actual emissions at the installation level ('grandfathering'), or (ii) a standard emission factor multiplied by an ex-ante fixed quantity or activity level, for instance a certain input, output or capacity level ('benchmarking' with an absolute or fixed cap).[5]
- At closure, installations retain their allowances.
- New entrants do not receive allowances for free, but have to buy them on the market.

As the initial allocation of emission allowances in a perfect free allocation system is independent of operation, closure and investment decisions, it creates the same set of conditions for abatement efficiency as an auctioning system (Harrison et al., 2007). Hence, both allocation system result in the same level or choice of abatement, the same level of the allowance price, and the same (optimal) efficiency of emissions trading, including the same level of passing through of carbon allowance costs to power prices (as illustrated below).[6] The only difference between auctioning and perfect free allocation concerns the transfer of economic rent due to the initial allocation of emission allowances. Whereas this rent accrues to the government or public sector in case of auctioning, it is transferred to the recipients of allowances in case of perfect free allocation (Neuhoff et al., 2005b and 2006).

[5] If the quantity or activity level is determined ex-post - i.e. after the actual company's decisions or activity level realised - the allocation system is called benchmarking with a relative cap.

[6] It is important to note that, in addition to the conditions of the 'ideal' types of auctioning and perfect free allocation, these 'idealised' results hold only when certain other conditions hold as well, including negligible transaction costs, perfect competition in product and emissions markets, and a low cost of emissions relative to other costs and the overall value of economic activity (Harrison et al., 2007).

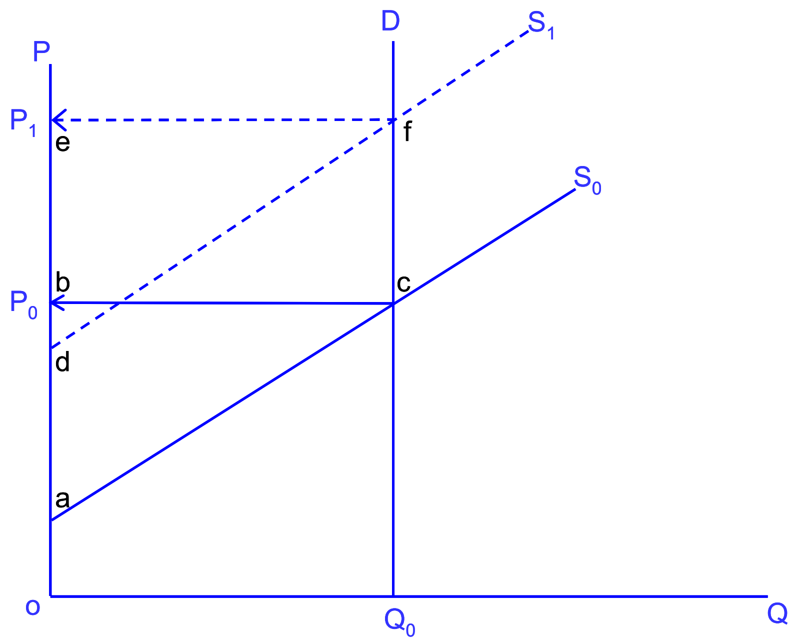

Figure 2.1 *Pass-through of carbon costs to power prices*
Note: S_0 is the supply curve excluding carbon costs, while S_1 includes carbon costs.

The pass-through of the opportunity costs of carbon allowances to power prices can be illustrated by means of Figure 2.1 representing the reference case of either auctioning or perfect free allocation, while assuming perfect competition, an inelastic demand curve (D), and a straight, upward sloping supply curve with constant carbon intensities of the generation technologies concerned (S_o). When emissions trading is introduced, the opportunity costs of carbon allowances are included to the other (variable) production costs, resulting in supply curve S_1. Under the conditions of the reference case, this results in the following implications:

- The power price increases from P_0 to P_1. Hence, the pass-through rate is 100% since the change in power price is equal to the change in marginal production costs.
- The producer surplus before emissions trading is equal to the triangle *abc*, i.e. the difference between total revenues (Q_o0bc) and total variable costs (Q_oOac). In a competitive situation, this surplus covers the fixed (investment) costs of power production, including some normal generators' profits. After emissions trading, in case of auctioning, the producer surplus is equal to *def*. Since it can be shown that the size of *def* is equal to *abc*, it implies that in this case there is no change in the overall producer surplus due to emissions trading. The total emissions costs are equal to the quadrangle *adfc*, which are fully passed on to the power consumers by means of higher electricity prices, resulting in a similar loss of their consumer surplus.[7] In case of perfect free allocation, however, the producers get the allowances for free, while still passing on the opportunity costs of these allowances to the consumers, resulting in an increase in their producer surplus by the quadrangle *adfc*. This increase in producer surplus due to emissions trading is commonly defined as the 'windfall profits' resulting from grandfathering.

Due to a variety of reasons, however, the conditions or assumptions underlying the simple reference case outlined above may not be met, resulting in different rates of CO_2 cost pass-through and/or different changes in producer or consumer surpluses. While the implications of alternative allocation conditions are discussed in the sections below, the impact of different power market assumptions on the pass-through of carbon costs is addressed by Sijm *et al*. (2008a).

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[7] Note that the quadrangle *adfc* also represents the economic rent of allocating carbon allowances, which in case of auctioning accrues to the public sector.

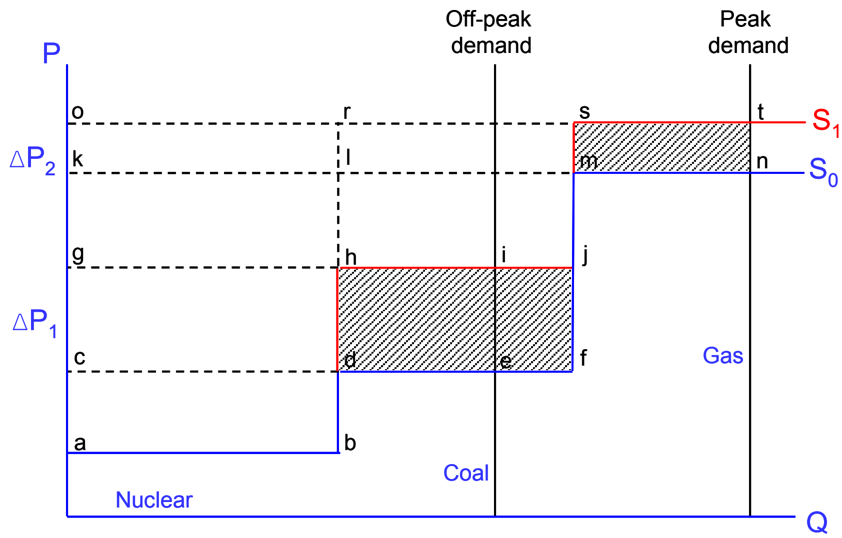

Figure 2.2 *Change in power prices and generators' profits due to emissions trading for different load periods and production technologies*

Note: The blue line S_0 represents the supply curve before emissions trading, while the red line S_1 includes the carbon costs due to emissions trading. The shaded areas represent the CO_2 opportunity costs of a fossil-fuel technology when it becomes the marginal unit (which in case of free allocation implies a transfer of economic rent enhancing generators' profits).

The reference cases: an alternative illustration

A slightly more realistic (and more complicated) situation is depicted by Figure 2.2, which shows the change in power prices and generators' profits due to emissions trading for different load periods and production technologies with different emission rates. During the off-peak period, the power price is set by the marginal technology, i.e. coal, while during the peak period it is set by gas. Assuming no change in the merit order and power demand, emissions trading results in a change of power prices equal to ΔP1 during the off-peak and ΔP_2 during the peak period, where $\Delta P_1 > \Delta P_2$ since the emission factor per unit produced is significantly higher for coal than gas.[8]

Table 2.1 *Change in profitability of power generation due to emissions trading for different technologies and load periods*

Technology	Load period	Profits before ET	Profits after ET Auctioning	Profits after ET Perfect free allocation	Change in profits Auctioning	Change in profits Perfect free allocation
Nuclear	Off-peak	abcd	abgh	abgh	cdgh	cdgh
	Peak	abkl	abor	abor	klor	klor
Coal	Off-peak	0	0	dehi	0	dehi
	Peak	dflm	hjrs	dfrs	lmrs-dfhj	lmrs
Gas	Off-peak	0	0	0	0	0
	Peak	0	0	mnst	0	mnst

Note: The symbols in this table refer to Figure 2.2.

Changes in generators' profits due to emission trading can also be derived from Figure 2.2 (see also Table 2.1 for an overview of these changes in profits for different production technologies and load periods, distinguishing between auctioning and free allocation of carbon allowances).

[8] The implications of emissions trading for power prices and generators profit under changes in the merit order and/or power demand are analysed in Sijm et al. (2008a).

For instance, during the off-peak period, profits for the marginal technology (coal) are 0 before emissions trading (as the cost per unit is equal to the power price), while after passing through the costs of emissions trading they remain 0 in case of auctioning but increase by the rectangle *dehi* if all allowances are granted for free. On the other hand, for an infra-marginal technology such as nuclear (which has no CO_2 emissions), the profitability of power generation during the off-peak period increases by the rectangle *cdgh*, regardless of whether the allowances are auctioned or allocated for free as in both cases nuclear benefits from the ETS induced increase in the off-peak price while its costs do not change.

During the peak period, Figure 2.2 shows that the price is set by the gas-fired technology. Due to emissions trading, the peak generators' profits for gas remain 0 in case of auctioning while they increase by *mnst* in case of free allocation. For an infra-marginal, non-CO_2 technology such as nuclear or hydro, these profits increase by *klor* in both cases. On the other hand, for an infra-marginal, fossil-fuel technology such as coal (which has an emission factor higher than gas), emissions trading during the peak period results in a loss of producer surplus ('windfall losses') in case of auctioning as the increase in total costs (*dfhj*) is larger than the increase in total revenues (*lmrs*). However, when carbon allowances are allocated for free, coal-fired generation during the peak period benefits by the amount *lmrs*.

A major observation of Figure 2.2 and Table 2.1 is that the allocation method (i.e. auctioning versus perfect free allocation) does not affect the impact of passing through the CO_2 opportunity costs on power prices and, hence, on the price-induced changes in the profits of both fossil and non-fossil generators. In fact, the issue of auctioning versus perfect free allocation only affects the distribution of the economic rent of carbon allowances in the sense that in case of perfect free allocation this rent is transferred to incumbents in the form of a lump-sum subsidy that enhances their producer surplus (compared to auctioning where this rent accrues to the authority allocating the allowances).

2.3 Primary effects of free allocation provisions on power prices

During the first and second trading phase (2005-2012), the EU ETS is based almost fully on a free allocation system of emissions allowances.[9] This system, however, does not meet the conditions of the ideal type of perfect free allocation mentioned above, but is rather characterised by the following free specific provisions or distortions of this ideal type:

1. Updating free allocation to incumbents.
2. Contingent allocation to plant closures.
3. Free allocation to new entrants.

This section discusses the main implications of these specific free allocation provisions, in particular their primary effect effects on power prices, while their potential secondary effects on CO_2 emissions, allowance prices, carbon costs pass-through and power prices are treated subsequently in Section 2.4 below.

[9] The share of auctioning in total allowances allocated is less than 1% during the first phase of the EU ETS and about 3% during its second phase. The major reasons for the high shares of free allocation include (i) to facilitate the acceptability of the EU ETS among eligible firms and, hence, the introduction and implementation of this scheme, (ii) to compensate firms which face external competition (or price-responsive demand) and, hence, are not able to fully pass on the costs of buying allowances on an auction or market, and (iii) to avoid distortions of the internal market (i.e. an unequal level playing field) due to a lack of harmonisation of allowances among Member States, resulting in the so-called 'prisoners dilemma' or 'race-to-the-bottom' effect regarding the rate of auctioning.

Updating free allocation to incumbents

As noted above, a major characteristic of perfect free allocation is the one-off initial allocation of allowances to existing installations (incumbents), usually for a long time frame, based on either grandfathering or benchmarking,. The major implication of this feature is that operational decisions of incumbents are affected by the CO_2 price (or carbon opportunity costs) of emission allowances but not by the allocation of these allowances at the installation level as the latter is fixed ex-ante, i.e. before these decisions are made. In contrast, however, the baseline or reference period of free allocations to incumbents can also be regularly updated, for instance allocation in the next trading period can depend on their emissions, production or other activity level of the current period and, hence, decisions on current activity levels are affected by the prospects or expectations of future allocations.[10]

The major reason for updating the baseline or reference period for allocating allowances is that in a dynamic economy with major future uncertainties and large (unknown) differences in growth patterns among sectors and installations - including plant closures and new entrants - it may be hard to allocate allowances for a long time frame based on a fixed reference period. Hence, updating can serve to avoid a lot of special provisions and maintain the allocation provisions of the ETS as simple as possible (Matthes et al., 2005).[11]

The major implication of updating is that the operational decisions of incumbents are affected by the allocation system as their current production or emission level influences their future allocations. As a result, incumbents will incorporate the value of these allocations in their production decisions, implying a lowering of their internal opportunity costs of emission allowances, a lower level of carbon cost pass-through and, hence, a lower increase in power prices (compared to perfect free allocation).[12]

Actually, whereas emission trading acts as a tax on CO_2 based production - increasing its variable (marginal) costs - updating essentially provides an output subsidy that reduces (the increase in) these costs and, hence, creates an incentive to increase current output (Fischer, 2001; Keats and Neuhoff, 2005).

Although the allocation periods for the EU ETS have been relatively short, it is unclear to what extent updating is a relevant factor for the EU ETS. Up to now, there have only been two allocation rounds, i.e. the first period (2005-2007) and the second period (2008-2012). Allocation to incumbents over the periods has varied significantly among the Member States with varying, often moving allocation reference years from the first to the second allocation plans. Consequently, companies might have expected or assumed a kind of updating for the third period (or beyond) and may, therefore, have incorporated this in their operational decisions, in particular passing through lower opportunity costs to their output prices. However, the European Commission's proposal of 23 January 2008 to amend the EU ETS provides that the (EU-wide harmonised) allocation rules shall not give incentives to increase production.[13] This clearly argues against updating. In addition, the Commission rejects extreme versions of updating such as ex-post allocation or relative target systems in which allocation is based on current production.

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[10] Allocation in the current trading period can even be based on current production or emissions at the installation level. This kind of 'extreme updating' (or ex-post allocation) results in a trading system with a relative cap during the current period (rather than a fixed cap in an ex-ante allocation system).

[11] In addition, updating could provide an option for addressing the problem of free allocation to plant closures (Ahman et al., 2006). Moreover, if allowances are freely allocated to new entrants (based on expected or updated activity levels) it becomes increasingly harder in equity terms to justify free allocations to incumbents on emissions or activity levels in the remote past.

[12] Updating also results in less generators' profits during the current period but this is offset by the prospect of additional profits by future (higher) allocations (NERA, 2005).

[13] See EC (2008), notably COM (2008) 16 final, Article 10a(1).

Contingent allocation to plant closures

Another feature of perfect free allocation is that, at closure, installations retain their allowances (allocated one-off for a long-time frame). As evidenced during the first and second trading periods of the EU ETS, however, allocation to installations in almost all Member States is contingent on their operational status in the sense that the allocation of allowances during the next period requires that the installation remains open or active for a minimum number of hours during the present period.

The main reason for such closure provisions is that authorities want to avoid that plants close - or even move to other countries - because their operations become unprofitable due to emissions trading (carbon leakage), while the operators benefit from selling large amounts of allowances allocated for free. Other reasons for closure rules refer to reaching other objectives besides abatement efficiency such as national energy security or industrial policy aims (e.g., to protect a diversity of key energy resources and industries) or just to maintain a level playing field for domestic industries as neighbouring, competitive countries are applying similar closure rules.

Compared to perfect free allocation, allocation to incumbent installations contingent on their operational status distorts the closure decisions of these installations. If power operators forgo free allowances when they close, they regard the value of these allowances as an annual or periodical subsidy covering the fixed costs or losses of upholding production capacity. While the opportunity costs of emissions trading are passed through to power prices, the subsidy provides an incentive to keep more capacity operational compared to an ETS with perfect free allocation or auctioning. This implies that older, carbon-inefficient power stations will stay on line. As a result, there is more power supply, particularly during the peak period, putting initially a downward pressure on electricity prices during this period (thereby eroding the ETS induced upward pressure on power prices due to the pass-through of the carbon opportunity costs).

The impact of contingent allocation on power prices depends on the expected (net present) value of the free allowances forgone if the operator fails to meet the conditions of the plant closure rule. This value or subsidy to keep power capacity open, is equal to the value of the (expected) amount of allowances involved multiplied by the (expected, net present) price of an allowance. If this value is large enough to cover at least the losses of keeping inefficient capacity operational it acts to reduce power prices by preventing these prices to increase in markets with scarce capacity. While the amount of inefficient generation depends on the specific, minimum conditions of the closure rule, this amount is most likely produced during the peak hours when prices are highest and, hence, the output losses are minimised. To the extent that (peak) power prices depend on the margin of capacity, contingent allocation to incumbents can offset some of the impact of emissions trading on plant's variable costs, thereby limiting the overall implications of emissions trading on (average) power prices (Green, 2007).

Free allocation to new entrants

A final characteristic of perfect free allocation is that emission allowances are allocated for free to incumbents, but not to new entrants. In the EU ETS, however, the first and second set of National Allocation Plans (NAPs I and II) of all Member States included provisions for a so-called New Entrants Reserve (NER) in order to allocate allowances for free to new installations.

The major reasons for these new entrants provisions include (i) to compensate for distortions due to closure conditions (notably delaying the shift towards new efficient investments), (ii) to create 'fairness' among existing and new facilities (if incumbents receive allowances for free, so should new facilities) and (iii) to reduce carbon leakage and other adverse competitiveness effects (in case of external competitors not subject to similar carbon costs), (iv) to encourage new investments in certain technologies or, more precisely, to compensate the disincentive effects of emissions trading on investments in certain technologies, and (v) to reduce market power and, hence, increase competition by reducing barriers to entry for new operators, notably by improving their liquidity or access to capital as free allocations to new entrants avoid or compensate the additional costs of emissions trading (Neuhoff et al., 2006; Ahman and Holmgren, 2006; Ahman et al., 2007; Harrison et al., 2007). [14]

Compared to emissions trading based on perfect free allocation (or auctioning), free allocation to new entrants distorts the investment decisions of power operators and, hence, can have important effects on the performance of the power sector, including electricity prices. If emissions trading is based on free allocation to new installations, this can be regarded as a subsidy towards their fixed costs, coupled with a tax on their variable costs. While the tax is passed through to power prices, the subsidy gives an incentive to invest in additional capacity. Normally, the electricity price in an underinvested market increases until it reaches the long-run marginal costs (LRMC) of a new power plant (where the LRMC includes both variable and fixed costs). Since free allocation to new entrants lowers the LRMC of the next power plant, investments in additional capacity are moved forward in time at a lower electricity price. To the extent that (peak) power prices depend on the margin of capacity, this effect can offset some of the impact of emissions trading on a plant's variable costs, thereby limiting the overall implications of emissions trading on (average) power prices in the long run (Green, 2007; Lindboe et al., 2007). Therefore, free allocation to new entrants can (largely) mitigate the increase in power prices due to the pass-through of carbon opportunity costs.

Some qualifications

As outlined above, power producers pass through the opportunity costs of emissions trading to electricity prices regardless of whether the allowances have been auctioned or allocated for free. In the ideal or reference cases of auctioning versus perfect free allocation, the impact of emissions trading on abatement efficiency and power prices is similar in both cases. In practice, however, emissions trading schemes - such as the EU ETS - are often characterised by some specific free allocation provisions which distort the outcomes of these cases in terms of carbon efficiency and power prices. These provisions include in particular (i) updating baselines of free allocation to incumbents, (ii) contingent free allocation to plant closures, and (iii) free allocation to new entrants. Although the mechanisms and significance of these provisions may differ, they all have a similar primary effect on power prices, i.e. they reduce the increase in power prices due to the pass-through of emissions trading costs.

It is important, however, to make some qualifications to the primary, output price-reducing effect of the specific free allocation provisions.[15]

Firstly, and most importantly, although the specific free allocation provisions may have some advantages or further some objectives (such as lower power prices for end-users, lower windfall profits for power producers, or less carbon leakage and other adverse competitiveness effects for exposed, power-intensive industries), compared to auctioning or perfect free allocation they erode the abatement efficiency of the ETS by (i) encouraging production of carbon intensive output, (ii) discouraging investments in more expensive, but less carbon intensive technologies such as renewables, (iii) stimulating price-responsive demand for carbon intensive products, and (iv) maintaining capacity or even promoting new investments in carbon intensive technologies, in particular when free allocations are fuel- or technology specific. Notably free, technology-specific allocations to new entrants imply a serious erosion of the incentive framework of an ETS towards investments in less carbon intensive technologies in the long run (Matthes et al., 2005; Neuhoff et al., 2006; Harrison et al., 2007).

Secondly, in addition to the abatement inefficiencies mentioned above, the specific free allocation provisions result in other inefficiencies or distortions at the inter-sectoral, international or

[14] Neuhoff et al. (2006) note correctly that the expression 'new entrant allocation' seems a bit misleading as most new projects in the power sector are initiated by existing utilities and, this expression could perhaps be better replaced by 'new project allocation'.

[15] For additional qualifications, in particular with regard to the free allocation to new entrants, see Sijm et al. (2008a).

inter-temporal level if they are not applied in a uniform, harmonised way but differentiated among sectors, countries or trading periods (Neuhoff et al., 2005a and 2005b; Sijm et al., 2008a).

Thirdly, the effectiveness of reducing power prices by means of free allocations to new entrants in the power sector is limited by several factors, including:

a) Free allocation to new entrants is only effective in reducing power prices if generation capacity is indeed scarce and if, subsequently, the capacity scarcity is actually relieved by the implementation of new investments becoming operational (in the power sector it may at least take 4-5 years before new capacity investments are implemented and become productive).
b) It is only effective if the New Entrants Reserve is large enough to cover the needs for allowances of all new entrants, in particular the last, marginal new entrant setting power prices in the long run.
c) The effectiveness of free allocations to new entrants in reducing power prices is limited by (i) policy uncertainties or risks about future allocations of free allowances, and (ii) higher investment costs due to the increased demand for new generation capacity resulting from the subsidy effect of free allocations.[16]

Finally, the primary effects of the specific free allocation provisions - i.e. reducing power prices - may be compensated by their secondary effects, in particular their possible upward pressure on carbon prices. These secondary effects are discussed in the next section.

2.4 Secondary effects of free allocation provisions on carbon and power prices

In addition to the primary, price-reducing effects of the specific free allocation provisions on the power market, these provisions may also have other effects, in particular on the price of carbon on the (EU) allowance market, which - in turn - may have additional, secondary effects on power prices. As noted, compared to perfect free allocation (or auctioning), the free allocation provisions exert an upward pressure on total emissions of eligible installations as they tend to enhance the (price-responsive) demand for carbon intensive products and to encourage output supply by maintaining or even expanding generation capacity of CO_2 inefficient plants, in particular if free allocations are fuel-specific or biased towards more carbon intensive technologies.[17] Extra emissions imply an additional demand for CO_2 allowances which, in case of a fixed supply, result in higher carbon prices on the allowance market and, subsequently, in a pass-through of higher carbon opportunity costs and, finally, in higher power prices. Therefore, the primary effects of the specific free allocation provisions - i.e. decreasing power prices - may be either partially or fully compensated by their secondary effects, i.e. increasing CO_2 allowance prices, resulting in increasing carbon opportunity costs passed through and, hence, increasing power prices.[18]

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[16] Matthes and Neuhoff (2007) note that in 2006 the German government had initially envisaged in its national allocation plan for phase II of the EU ETS that power stations which start operation in phase II will receive free allowances for more than a decade. The German power industry did attribute a high probability to this promise, resulting in a surge in demand for coal power plants to be commissioned by 2012 and correspondingly high prices in the option contracts for the construction of such plants.

[17] Ellerman (2006) notes that the effect of free allocation to new entrants on emissions is ambiguous, in particular if demand is inelastic and free allocations are technology neutral, as the effect depends on the extent to which production from other units is displaced and on the emission characteristics of the units displacing and being displaced. However, if demand is price-responsive or free allocations are technology biased (i.e. higher emitters get more allowances for free while non-emitters get nothing), free allocations to new entrants results most likely in an upward pressure on emissions. Moreover, the effect of the other two specific free allocation provisions on emissions seems to less ambiguous, i.e. they usually increase emissions.

[18] Under specific conditions, the primary effects of the specific free allocation provisions may be fully or exactly nullified by their secondary effects, resulting in similar power prices as under the reference cases of auctioning and perfect free allocation. These conditions include in particular a fixed CO_2 budget of emission allowances and

More specifically, the incidence or extent to which the secondary effects of the free allocation provisions may take place depends in particular on the following three factors:
- The price responsiveness of power demand.
- The technology bias of free allocations.
- The flexibility to the CO_2 budget.

These factors are discussed briefly below.

The price responsiveness of power demand
In general, power demand is rather price-inelastic in the short run, but more responsive to price changes in the medium and long term. This implies that if the specific free allocation provision indeed result in lower power prices (compared to the reference cases of auctioning and perfect free allocations), they also lead to a higher power demand and, hence, an upward pressure on CO_2 emissions, notably in the medium and long run.

The technology bias of free allocations
Free allocations can be either technology neutral or technology specific. If free allocations are technology neutral, the same benchmark or emission standard is applied to all power generating technologies, including non-CO_2 technologies such as nuclear or renewables. On the other hand, if free allocations are technology (or fuel) specific, high-emitting plants receive more free allowances than low-emitting stations while non-emitting installations get nothing. Although more carbon intensive plants also need more allowances to cover their emissions (similar to a system based on auctioning or perfect free allocation), technology-specific free allocation provisions reduce the incentive to switch producer decisions towards cleaner technologies and, hence, affect the choice of technology in favour of higher emitting plants (Green, 2007). Hence, the secondary effects of the free allocation provisions - on emissions, etc. - are more significant if these provisions are more technology specific.

The flexibility to the CO_2 budget
The CO_2 budget of an ETS refers to the total amount of carbon allowances allocated to eligible installations (i.e. the cap) including, if allowed, offset credits - such as JI or CDM credits - to cover the emissions of these installations. This budget can be either fixed or variable, i.e. the cap of the total allowances allocated can be either fixed or variable, while the use of offset credits can be either fully forbidden, fully free or allowed under certain quantitative or qualitative restrictions.[19] If the CO_2 budget is fixed, additional emissions due to free allocation provisions result in increasing carbon prices and, hence, the primary effects of these provisions on power prices are compensated by these secondary effects, including the pass-through of higher carbon costs to power prices. On the other hand, if the CO_2 budget is variable, additional emissions of eligible installations are covered by extra allowances or credits and, hence, the carbon price hardly changes, implying that the secondary, price-increasing effects of the free allocation provisions on the power market are negligible (while the primary, price-decreasing effects may be substantial). Therefore, these secondary effects depend ultimately on the flexibility of the CO_2 budget of the ETS.

The EU ETS is characterised by a fixed cap of carbon allowances, but in order to cover their emissions eligible installations are also allowed to use JI/CDM credits to a certain limit. This implies that the secondary, power price-increasing effects of the free allocation provisions of this system depends on whether these installations have already reached their limit of JI/CDM

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offset credits, as well as a uniform application of the free allocation provisions throughout all sectors, countries and trading periods of the scheme (Keats and Neuhoff, 2005; and Neuhoff et al., 2005a).

19 In addition, the inter-temporal allocation of the CO_2 budget, i.e. between different trading periods, depends on the incidence of banking and borrowing of emission allowances and offset credits (if allowed). For a detailed discussion of the inter-temporal implications of free allocation provisions, see Neuhoff et al. (2005a, 2005b and 2006).

credits and, if not, whether the additional demand for JI/CDM credits results in higher prices for these credits and, subsequently, higher (related) prices for EU carbon allowances.

2.5 Summary and conclusion

According to economic theory, power producers pass through the opportunity costs of emissions trading to electricity prices regardless of whether the allowances have been auctioned or allocated for free. In the ideal or reference cases of auctioning versus perfect free allocation, the impact of emissions trading on abatement efficiency and power prices is similar in both cases. In practice, however, emissions trading schemes are often characterised by some specific free allocation provisions which distort the outcomes of these ideal cases in terms of carbon efficiency and power prices. These provisions include in particular (i) updating baselines of free allocation to incumbents, (ii) contingent free allocation to plant closures, and (iii) free allocation to new entrants. Although the mechanisms and significance of these provisions may differ, they all have a similar primary effect on power prices, i.e. they may mitigate the ETS-induced increase in power prices resulting from the pass-through of carbon costs.

In addition, however, free allocation provisions erode the overall abatement efficiency of an ETS, while they lead to additional inefficiencies and distortions if they are applied differently across sectors, countries or trading periods. Moreover, the effectiveness of these provisions - in particular the free allocation to new entrants - is often limited in actually offsetting the ETS-induced increase in power prices. Finally, the primary, price-decreasing effects of these provisions on the power market may be either partially or fully offset by their secondary effects on CO_2 emissions of eligible installations, the price of these emissions and, hence, the pass-through of resulting carbon costs of power generation to electricity prices. The size or strength of these second, price-increasing effects on the power market depends particularly on (i) the price responsiveness of power demand, (ii) the technology bias of free allocation and, above all, (iii) the flexibility of the CO_2 budget of an ETS, including the potential use of JI/CDM or other offset credits to cover emissions of eligible installations.

A major policy implication is that if one moves from a perfect free allocation system to auctioning, there is no specific allocation effect on power prices or carbon efficiency. However, if the free allocation system is not perfect, for instance due to updating or free allocations to new entrants, moving towards auctioning may have an upward pressure on power prices in the long run, depending on whether the carbon budget of the ETS - including the inflow of offset credits - is fixed or not. Therefore, the ultimate impact of emissions trading in general and its allocation system in particular is largely an empirical issue as it depends highly on the specifics of this system, including the incidence of specific free allocation provisions and the flexibility of its total carbon budget.

3. The implications of EU ETS allocation for the power sector in the Netherlands an empirical approach

This chapter analyses the implications of free allocation versus auctioning of EU ETS allowances for the power sector based on an empirical approach. More specifically, it presents first of all a summary of the major empirical results of analysing the impact of allocating EU allowances (EUAs) for free on power prices and generators' profits over 2005-2006 in Section 3.1. Subsequently, based on these results and the theoretical reflections of the previous chapter Section 3.2 considers the potential implications of shifting from free allocations (up to 2012) towards auctioning EUAs (starting from 2013).

3.1 The impact of free allocations during the first phase of the EU ETS

During the first phase of the EU ETS (2005-2007), the power sector in the Netherlands has received almost all of its necessary EUAs for free in order to cover its actual emissions over this period.[20] The sections below present a summary of the major results of some empirical analyses of the impact of the EU ETS on the forward power market in the Netherlands over 2004-2006.[21]

3.1.1 Trends in forward power prices and cost drivers

For the years 2004-2006, Figure 3.1 presents trends in forward (i.e. year-ahead) power prices versus fuel and CO_2 emission costs to generate one MWh of electricity during the off-peak period in the Netherlands, while Figure 3.2 shows similar trends during the peak. These figures, and the empirical analyses outlined below, are based on the following assumptions:

1. In the Netherlands, the power price is set by a coal-fired unit during the off-peak period and a gas-fired plant during the peak period.
2. An average fuel efficiency of 35% for a coal plant and 40% for an open cycle gas turbine.
3. A related emission factor of 0.97 versus 0.51 tCO_2/MWh for coal and gas, respectively.
4. CO_2 emission costs per fuel are equal to its emission factor times the daily price of an EU emission allowance on the forward market.[22]

Figures 3.1 and 3.2 provide a first impression of the changes in power prices over 2004-2006 and the potential link with underlying fuel and carbon costs, based on the assumptions mentioned above. For instance, off-peak power prices in the Netherlands are assumed to be set by a coal-fired installation. As can be observed from Figure 3.1, 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 started to rise again up to the summer of 2006 but, subsequently, stabilised at a level of 30-35 €/MWh in late 2006. These significant changes in power prices can not be explained by changes in coal prices since the costs of this fuel have been rather stable at the level of 20 €/MWh over the period considered.

[20] In 2005, the verified CO_2 emissions power and heat sector in the Netherlands amounted to some 42 $MtCO_2$, while the free allocations amounted to about 39 Mt CO_2, i.e. a shortage of approximately 7% (Kettner et al., 2007).

[21] For a more extensive discussion of these analyses including empirical results for other countries and power markets see Sijm et al. (2005, 2006a, 2006b, 2008a and 2008b).

[22] 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 3.1).

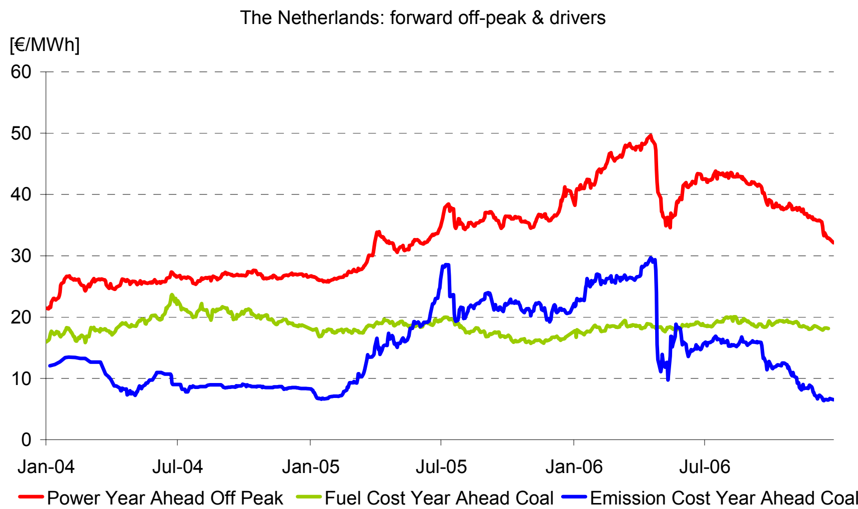

Figure 3.1 *Trends in power prices and cost drivers on forward markets in the Netherlands during off-peak hours in 2004-2006*

However, in case of the forward off-peak power market there seems to be a close (casual) 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 EU emission allowance (EUA) such as April-May 2006 (see Figure 3.1). Note, however, that the link between power prices and fuel/CO_2 cost drivers is less clear 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.

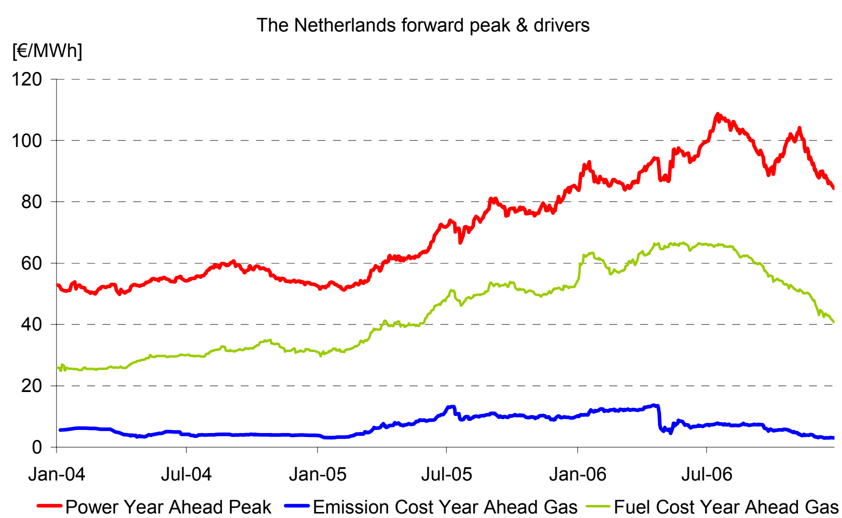

Figure 3.2 *Trends in power prices and cost drivers on forward markets in the Netherlands during peak hours in 2004-2006*

On the other hand, Figure 3.2 shows the trends in power prices and cost drivers on forward markets in the Netherlands during the peak period of 2004-2006. For this case, power prices are assumed to be set by an open cycle gas turbine with a fuel efficiency of 40%. 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.

Box 3.1 *Data used*

For the empirical analyses over 2004-2006, data of daily prices on forward (i.e. year-ahead) markets have been used for the following commodities:

- *Power*: Electricity prices refer to year-ahead contracts traded at the Amsterdam-based European Energy Derivates Exchange (ENDEX). This exchange provides price data for base load and peak periods, while off-peak prices have been derived from these data using the definition of peak versus off-peak periods in the Netherlands.
- *Fuels:* Coal prices 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 transferred to €/MWh by means of the daily dollar-euro exchange rate, the usual energy conversion factors and a fuel efficiency rate of 35%). Gas prices refer to the Bunde hub during the years 2004-2005 (as reported by Platts) and to the Title Transfer Facility (TTF) hub for the year 2006 (provided by ENDEX).
- *CO_2 emission allowances*: Carbon prices for EU allowances (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).

3.1.2 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 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.[23]

Figure 3.3 and Figure 3.4 present trends in year-ahead power spreads in the Netherlands over 2004-2006, based on the forward market trends in power prices and fuel/carbon costs discussed above. Whereas Figure 3.3 depicts trends in (clean) dark spreads for the off-peak period, Figure 3.4 shows similar trends in the (clean) spark spread during the peak hours. 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, Figure 3.3 shows that there is a rather 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 stabilisation phase - declined steadily during the latter part of 2006. The dark spread, however, fell less in April-May 2006, and more or less stabilised 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 that either declining carbon costs are passed-through to a lesser extent (or less quickly) than rising carbon costs (i.e. asymmetric pass-through) or that changes

23 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.

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.

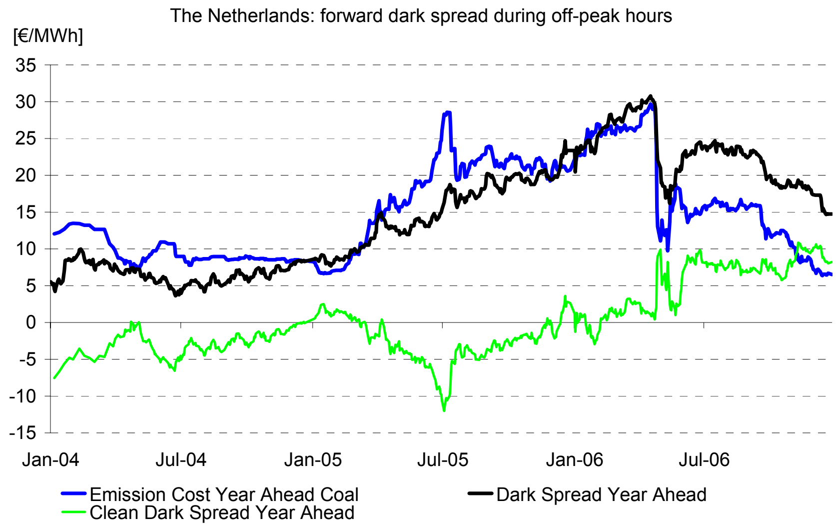

Figure 3.3 *Trends in power spreads and carbon costs on forward markets in the Netherlands during off-peak hours in 2004-2006*

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 3.4, which presents these trends during the peak period of 2004-2006 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.

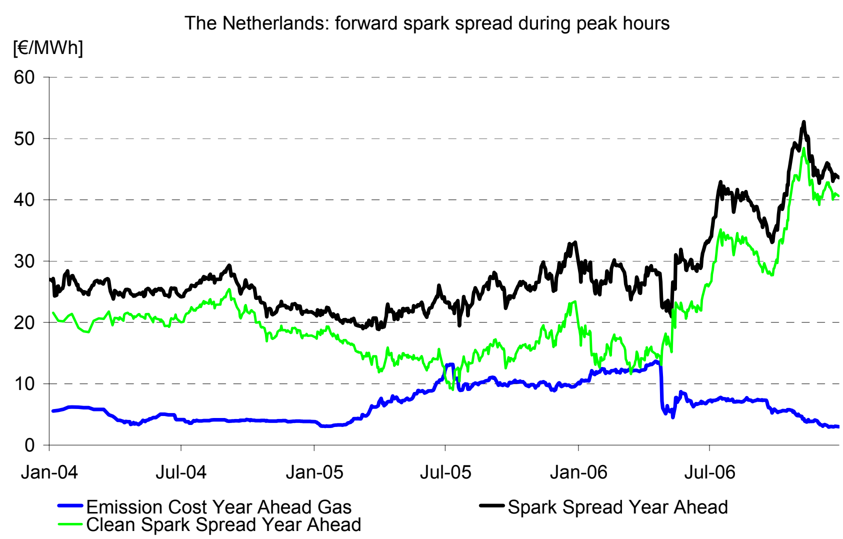

Figure 3.4 *Trends in power spreads and carbon costs on forward markets in the Netherlands during peak hours in 2004-2006*

In addition to the trends in power spreads, Figure 3.3 and Figure 3.4 also provide trends in *clean* spreads over 2004-2006 (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 horizontal line at a certain level (say 10 or 20 €/MWh in order to cover the other generation costs, including profits).

Figures 3.3 and 3.4 show that, in general, clean spreads fluctuated significantly at a certain level in the years 2004-2005, 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 diverted by some 25 €/MWh over this period from trends in fuel/carbon costs.

3.1.3 Statistical estimates of CO_2 cost-pass through rates

This section presents some statistical estimates of pass-through rates of CO_2 emissions trading cost to power prices on forward wholesale markets in the Netherlands for the years 2005-2006. 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 (i.e. changes in power prices can not be attributed to changes in technology, market power, generation capacity, risks or other factors).[24]

Table 3.1 shows the results of the estimated pass-through rates (PTRs) of carbon costs to electricity prices on the year-ahead power markets in the Netherlands during the peak and off-peak periods in 2005-2006. The major findings of this table include:

- In the off-peak period of 2005 and 2006, when coal is assumed to set the power price, the PTRs are estimated at approximately 40%. For the peak period, however, (when gas is assumed to be price-setting), the estimated PTRs are more than 100%, i.e. 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 difference in terms of €/MWh passed through is less significant as the emission factor is about twice as high for coal compared to gas.
- The PTRs are statistically significant at the 1% 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% - of the changes in power prices/spreads can be attributed to changes in carbon costs.

[24] For a further discussion of the methodology and underlying assumptions to estimate pass-through rates of carbon costs to power prices, see Sijm et al. (2008a).

Table 3.1 *Empirical estimates of carbon cost pass-through rates on year-ahead power markets in the Netherlands, 2005-2006*

		Peak	Off-peak
	Price-setting technology	Gas	Coal
	Fuel efficiency [%]	40	35
2005	Pass-through rate	1.34	0.40
	Interval [Δ]	±0.14	±0.04
	R^2	0.28	0.34
2006	Pass-through rate	1.10	0.38
	Interval [Δ]	±0.14	±0.03
	R^2	0.20	0.38

Note: All estimated pass-through rates (PTRs) are statistically significant at the 1% level.

The above findings, however, have to be interpreted with some discretion due to the following considerations.

Firstly, as noted, the estimated PTRs are based of 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 or less fixed during the observation period (i.e., for instance, the peak period in 2005 or the off-peak period in 2006). However, as observed in the previous sections, this assumption seems to hold for certain periods (e.g. 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, etc. Due to a lack of data, however, it is not possible to account quantitatively for the impact of these other factors changes in power prices in an adequate way, which may lead to biased results of the estimated PTRs.

Secondly, 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, etc. Due to a lack of data, it is not possible to account quantitatively for these technological factors in an adequate way, which may lead to (additional) biases in the estimated PTRs.

Thirdly, the estimated PTRs depend on - i.e. are sensitive to - the assumed fuel efficiency rates, which amount to 35 and 40% for coal and gas, respectively. However, as indicated by Sijm et al. (2005), the estimated PTRs may change significantly if only a small change in the fuel efficiency is assumed.

Finally, the estimated PTR 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 the Netherlands (for details, see Box 3.1). 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.

3.1.4 Carbon cost pass-through on retail power markets

In the previous sections, the analysis was focused on the impact of CO_2 emissions trading on (year-ahead) *wholesale* power prices in the Netherlands over the period 2004-2006. This raises the question whether and to what extent there is empirical evidence on the pass-through of EUA costs to *retail* power prices 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).
- Industry, in particular large industrial end-users with an annual consumption of 24,000 MWh (maximum demand 4 MW and 6000 annual load hours).

Figure 3.5 presents the changes in the average, annual electricity prices for these two categories of power consumers in the Netherlands over 2004-2006.[25] It shows that retail power prices have increased significantly for households over 2004-2006. For instance, including taxes, household power prices rose from 183 €/MWh in 2004 to 211 €/MWh in 2006 (+15). 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 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%). Hence, changes in energy taxes can explain a major part (about one-third) of the increase in household power prices in the Netherlands over 2004-2006.

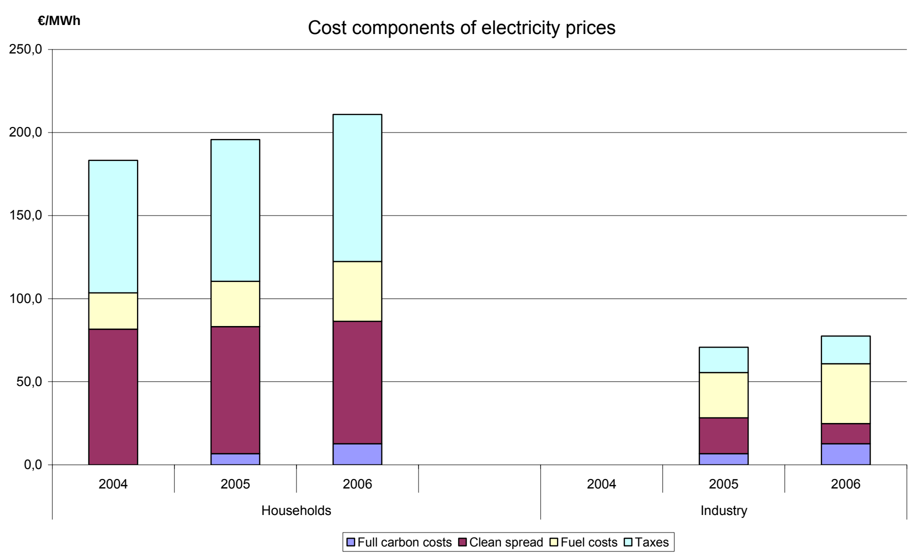

Figure 3.5 *Cost components of electricity prices for households and industry in the Netherlands (2004-2006)*

In addition, changes in retail power prices can be attributed also to changes in fuel costs. For instance, between 2004 and 2006, the average annual fuel costs rose from almost 22 €/MWh in 2004 to 36 €/MWh in 2006, i.e. an increase by approximately 14 €/MWh or about half the increase in the household electricity price over this period.[26]

[25] Unfortunately, however, Eurostat data on retail power prices for large industrial consumers in the Netherlands are lacking up to 2004 and are only available starting from 2005.

[26] Fuel costs of power sold on retail markets during a specific year (say 2006) are assumed to be equal to the annual average fuel costs of power traded on year-ahead wholesale markets during the peak and off-peak periods of the previous year (2005) weighted by the power sales volumes during these periods.

Table 3.2 *Cost components of electricity prices for households and industry in the Netherlands, 2004-2006 [€/MWh]*

	Absolute levels						Annual changes compared to:[a]		
							2004		2005
	Households			Industry			Households		Industry
	2004	2005	2006	2004	2005	2006	2005	2006	2006
Full carbon costs	0.0	6.7	12.6	n.a.	6.7	12.6	6.7	12.6	5.9
Clean retail spread	81.6	76.5	73.7	n.a.	21.6	12.3	-5.1	-7.9	-9.3
Fuel costs	21.9	27.3	36.0	n.a.	27.3	36.0	5.3	14.1	8.8
Taxes	79.7	85.3	88.5	n.a.	15.3	16.7	5.6	8.8	1.4
Total power price	183.2	195.8	210.9	n.a.	70.8	77.6	12.6	27.7	6.8
PM: 'dirty' retail spread[b]	81.6	83.2	86.3	n.a.	28.3	24.9	1.6	4.8	-3.4

a) Since industry data are not available (n.a.) for 2004, annual changes in cost components of electricity prices for industry have been calculated only for 2006 compared to 2004.

b) The dirty retail spread is the difference between the power price excluding taxes and the fuel costs. Actually, it is equal to the sum of the clean retail spread and the full carbon costs.

In order to assess the possible impact of CO_2 emissions trading on (changes in) retail power prices in the Netherlands during 2005-2006, 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 (2004-2006). 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 (i.e. 2004).
2. Estimation of the carbon costs passed through on retail markets based on the estimated pass-through rates on related wholesale power markets. This approach assumes that for a specific case (say the Netherlands 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 during a specific year (for instance, 2006) are assumed to be equal to the annual average of the estimated CO_2 costs passed through on the wholesale market during the peak and off-peak periods of the previous year (2005) weighted by the power sales volumes during these 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 on the retail market during a specific year (e.g., 2006) are assumed to be equal to the annual average of the CO_2 emissions costs of the marginal technologies setting the power price on the wholesale market during the peak and off-peak periods of the previous year (2005) weighted by the power sales volumes of these periods.

The results of the three methodologies outlined above are summarised in Table 3.3, where the three approaches are briefly denoted as 'Retail', 'Wholesale' and 'Full carbon costs', respectively.[27] First of all, the upper part of this table shows the estimated amounts of carbon costs

27 See also Figure 3.5, 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

passed through according to these three methodologies. For instance, following the first approach ('Retail'), the amounts of carbon costs passed through to households are estimated at 1.6 €/MWh in 2005 and 4.8 €/MWh in 2006. According to the second methodology ('Wholesale'), the estimated amounts are significantly higher, i.e. 5.2 and 9.9 €/MWh in 2005 and 2006, respectively. If it is assumed that the carbon costs of the price-setting technologies are fully passed on to these consumers (i.e. following the third, 'full carbon costs' approach), these amounts are even higher: 6.7 and 12.6 €/MWh in 2005 and 2006, respectively. Note that, in general, the estimated amounts of carbon costs passed through to retail power prices are substantially higher in 2006 than 2005. This is due to the fact that 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, while these prices have been, on average, significantly higher in 2005 than 2004.

Table 3.3 *Summary of estimated carbon cost pass-through on retail power markets in the Netherlands, 2005-2006*

	Households		Industry	
	2005	2006	2005	2006
	Estimated amount of carbon costs passed-through [in €/MWh]			
Approach:				
Retail	1.6	4.8	N.A.	N.A.
Wholesale	5.2	9.9	5.2	9.9
Full carbon costs	6.7	12.6	6.7	12.6
	Pass-through rate [in % of full carbon costs]			
Approach:				
Retail	24	38	N.A.	N.A.
Wholesale	78	78	78	78
Full carbon costs	100	100	100	100
	Share of carbon costs passed-through [in % of retail power prices, including taxes]			
Approach:				
Retail	1	2	N.A.	N.A.
Wholesale	3	5	7	13
Full carbon costs	3	6	9	16
	Share of carbon costs passed-through [in % of change in retail power prices, including taxes, compared to 2004]			
Approach:				
Retail	13	18	N.A.	N.A.
Wholesale	42	35	N.A.	N.A.
Full carbon costs	53	45	N.A.	N.A.

a) Some estimates for the Dutch industry are not available since Eurostat data on power prices for large industrial power consumers in the Netherlands are lacking up to 2004.

Subsequently, Table 3.3 presents the estimated pass-through rates (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 24% in 2005 and 38% in 2006 in case of the Dutch households. 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 78% for both households and industry in both 2005 and 2006.[28]

to the clean spreads presented in Figure 3.5, one gets an indication of the absolute levels of these (normal/dirty) spreads in the years 2004-2006 and the changes of these spreads over this period.

[28] Note that the estimated PTRs according to the 'wholesale' approach are similar in both 2005 and 2006 for both consumer groups. This is due to the assumptions of this approach, notably that (i) the estimated amount of carbon costs passed through on the wholesale market is equal to the amount of carbon costs passed through on the retail

The above-mentioned results following from the ‘retail’ approach suggest that the pass-through of CO_2 emissions cost on the retail markets in the Netherlands was rather low in 2005, but somewhat higher in 2006. These relatively low PTRs 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 either the absolute levels of the retail prices or the changes of these prices in the Netherlands during the years 2005-2006, the lower part of Table 3.3 presents these costs as a share or percentage of 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’ approach 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 the year 2006 than 2005, the shares of these costs in (changes of) retail prices are consequently much higher in 2006 than 2005.
- 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.

More specifically, Table 3.3 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 2005-2006, i.e. in general less than 3%. Even if one assumes that the full carbon costs are passed through to retail power prices, these costs account generally only for a small part of these prices, although in case of the large industrial power users in the Netherlands the share of the full carbon costs in the electricity prices for these consumers amounted to some 16% 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 (i.e. the ‘retail’ approach), the shares of these costs in the changes of the retail prices in 2005-2006 (compared to 2004) range from 13 to 18% for Dutch households (where the first percentage mentioned refers to 2005 and the second to 2006, see Table 3.3). 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 (i.e. the ‘wholesale’ approach) or the full carbon costs of the price-setting technologies (i.e. the ‘full carbon costs’ approach), Table 3.3 shows that the shares of these costs in the retail price changes are usually much higher.

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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 (i.e. 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).

To conclude, if it is assumed that over the period 2004-2006 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, 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 period 2004-2006 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.

3.1.5 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 period (2005-2012), 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 infra-marginal producer can be either a high-, low- or non-CO_2 emitter).

Empirical estimates of EU ETS induced windfall profits in the power sector of the Netherlands amount to, on average, 300-400 million per annum during the first trading period, based on an average EUA price of 20 €/tCO_2 and a pass-through rate of 50% (Sijm et al., 2006b).[29] With an annual production of about 100 TWh in the Netherlands, these estimates imply an average pass-through amounting to 3-4 €/MWh, respectively.[30]

3.2 The impact of EUA auctioning during the third phase of the EU ETS

Based on the theoretical framework presented in Chapter 2 and the empirical results with regard to the impact of the EU ETS on the power sector in the Netherlands during the first phase of the EU ETS outlined in the previous sections, some qualitative assessments of the potential implications of auctioning EUAs during the third phase of the EU ETS are outlined below (whereas more specific, quantitative assessments based on model analyses are presented in the next chapter). These qualitative assessments are based on an assumed average carbon price during this period similar to the actual average EUA price in 2005-2006, i.e. some 20 €tCO_2 (while the impact of auctioning EUAs at a carbon price of both 20 and 40 €tCO_2 is discussed as part of the quantitative model analyses presented in the next chapter).

[29] Based on an EUA price of 20 €/t CO_2, alternative estimates of EU ETS induced windfall profits in the Dutch power sector vary from € 19 million in 2005 (Frontier Economics, 2006) to more than € 1 billion per annum during the first phase of the trading scheme (Kesisoglou, 2007).

[30] For some qualifications to the issue of ETS induced ‘windfall profits’ in general and the methodology to estimate such profits in particular, see Sijm et al. (2008b).

In the sections below, the implications of EUA auctioning during the third trading period is compared to both the situation of perfect free allocation and the incidence of distorting, specific free allocation provisions, assuming that the overall CO_2 budget of the EU ETS is either fixed or flexible (for instance, because the actual inflow of JI/CDM offset credits depends on the demand for EUAs and, hence, their price). In addition, these implications are compared the situation before the first phase of the EU ETS, i.e. a situation with no emissions trading or similar CO_2 mitigation policies.

The implications of EUA auctioning are discussed below under the following headings:
- Power sector investments and generation capacity
- Power prices
- Power demand and supply
- Power trade and competitiveness
- Power sector profits and cash flows
- Power sector EUA expenditures, auction revenues and other fiscal issues

3.2.1 Power sector investments and generation capacity

In the long run, the main impact of auctioning EUAs on the power sector compared to either no emissions trading at all or emissions trading with specific free allocation provisions to plant closures and new entrants lies most likely in the field of the size and type of new investments in generation capacity. As explained in Chapter 2, compared to auctioning or perfect free allocation these provisions tend to increase the size of total generation capacity, either by preventing or retarding the closure of old, carbon intensive capacity or by accelerating new capacity investments through lowering the long-run marginal costs of these investments (thereby reducing long-run electricity prices and, hence, enhancing power demand and related emissions).

Moreover, if these free allocation provisions are technology biased i.e. higher carbon emitters get more allowances per unit output they further undermine the incentive structure of the ETS towards replacing old, carbon intensive generation capacity by new, more carbon efficient investments. Therefore, by shifting from these free allocation provisions towards auctioning, these adverse effects on the carbon efficiency of the power generation capacity are more or less nullified.

One may question, however, to what extent the free allocation provisions of the EU ETS already have exerted their adverse effects on new capacity investments. Although EUAs have been allocated for free to new entrants in the power sector during the first and second trading periods usually biased toward more carbon intensive technologies these periods have probably been too short to have a major impact on new investments, in particular as the European Commission has launched its proposal to fully auction EUAs for the power sector starting from the third period already in early 2008 (while new entrants had most likely expected less free allocations beyond 2012 amply before 2008).

Moreover, the average carbon price during the first phase including future price expectations was generally modest, while other factors such as expected trends in future power demand and fuel costs are often more important for decisions in new generation investments than current or expected carbon prices. Hence, although contingent free allocations to plant closures during the initial phases of the EU ETS may have had some impact on maintaining carbon-inefficient capacity in operation, the adverse effect of free allocations on new generation investments has most likely been rather small or even absent.

Nevertheless, if the EU had decided to continue the practice of free allocation provisions to plant closures and new entrants indefinitely, it would likely have exerted a much stronger adverse effect on the carbon efficiency of the trading scheme in the long run. Therefore, probably the most important effect of shifting towards full auctioning in the power sector is that - depending on the future carbon and fuel prices it encourages the closure (or less deployment) of old, carbon intensive plants and the investment in new, more carbon efficient generation capacity, including investments in renewables, nuclear or in carbon capture and storage (CCS).

3.2.2 Power prices

The impact of auctioning EUAs on electricity prices during the third phase of the EU ETS depends on the perspective one takes, i.e. whether this impact is compared to a situation of:

1. No emissions trading or similar carbon price policies at all,
2. Perfect free allocation,
3. The incidence of distorting, free allocation provisions during the first phase, or
4. The (assumed) continued incidence of these provisions during the third phase of the EU ETS (and beyond).

Moreover, in case of the latter two perspectives, it also depends on the CO_2 budget of the EU ETS, i.e. whether this budget including both the cap of EUAs and the inflow of JI/CDM credits is fixed or not. Finally, in case of the latter two perspectives, it also depends on whether the pass-through rate of EUA costs to power prices during the first (free allocation) phase is more or less similar to the third (auctioning) phase.

These different perspectives are illustrated below.

As outlined in Chapter 2, compared to a situation of no emissions trading, the impact of auctioning EUAs on wholesale power prices is similar to the impact of perfect free allocation. In both cases, the opportunity costs of the required EUAs are included in the bid prices of the power producers. Moreover, in both cases, the CO_2 pass-through rate i.e. the extent to which carbon costs are ultimately passed on to (equilibrium) electricity prices on the wholesale market - depends not on the allocation method but solely on the structure of the power market, in particular (i) the level of market concentration or competitiveness, (ii) the shapes of the power demand and supply curves, including carbon price induced changes in the merit order to the supply curve, and (iii) other market factors such as producers' market strategy or the incidence of market imperfections and regulations (Sijm et al., 2008a).

As noted, however, the first (and second) period of the EU ETS has not been characterised by perfect free allocation but rather by the incidence of distorting, free allocation provisions to both incumbents, plant closures and new entrants. It is, however, hard to determine whether and to what extent these provisions have already exerted a (reducing) effect on power prices during the first phase. Hence, it is also hard to assess whether auctioning during the third phase will have an additional (increasing) effect on electricity prices (compared to the first or second phase). As argued in the previous section on power sector investments, although the contingent free allocations to plant closures may already have exerted a small, downward effect on power prices during the first ETS phase, the prospect of the free allocation provisions to incumbents and new entrants has probably been too short and too uncertain to have exerted any significant (reducing) effect on power prices in the long run. Therefore, the impact of auctioning EUAs on power prices during the third ETS phase is likely small or even absent compared to its first phase.

If it is assumed, however, that the incidence of the specific free allocation provisions would have been continued in the third phase (and beyond), the impact of these provisions and, hence, the impact of shifting towards auctioning on power prices after 2012 might have been much more significant, depending on the overall carbon budget of the EU ETS. If this budget is fixed - including the use of JI/CDM credits the downward effect of these provisions on the pass-through rate of carbon costs to power prices are compensated by their upward effects on carbon prices.[31] Therefore, in this case, the impact of auctioning versus free allocation including the distorting provisions on power prices is probably small or even absent.

On the other hand, if the CO_2 budget is not fixed in the long run for instance, because the actual use of JI/CDM credits may depend on the price of these credits relative to the price of EUAs the incidence of the free allocation provisions may have a significant downward effect on passing through CO_2 costs of power generators to electricity prices (which is not or hardly compensated by an equivalent upward effect on carbon prices). Therefore, in this case, shifting from free allocation towards auctioning may imply a significant increase in power prices in the long run.

Another perspective: estimated, empirical CO_2 pass-through rates

The discussion above on the potential impact of auctioning EUAs on power prices can also be considered from another point of view, i.e. from the perspective of estimated, empirical CO_2 pass-through rates (PTRs). As presented in Section 3.1.3, the empirical evidence shows that these PTRs are often significantly below 1.0.[32] For instance, according to Table 3.1 of this section, the PTR on the wholesale market in the Netherlands during the off-peak period of 2005 is estimated at 0.40. Does this imply, as is sometimes suggested, that free allocations have resulted in passing-through only 40% of the EUA costs to generate power while the other 60% will follow once auctioning is introduced? Most likely not, as a PTR < 1.0 can be due to a variety of factors, including:

- Shortcomings in the data and methodology used.
- Market structure
- The incidence of specific free allocation provisions
- Time lags
- Regulatory threat

These factors are discussed below.

Shortcomings in the data and methodology used

The PTRs are obtained by means of an estimation method based on certain assumptions and data used. Some of the major assumptions include in particular:

- The electricity price during a certain observation period say ‘peak 2005’ or ‘off-peak 2006’ is set by the marginal fuel and carbon costs of generating power by a single technology with a fixed, average fuel efficiency.
- All other costs or factors affecting power prices are fixed and, hence, do not explain observed changes in these prices.
- The daily fuel prices at certain (inter)national markets provide a good indicator for the daily fluctuations in the true (opportunity) costs of fuel used by price-setting generators.

In practice, however, these assumptions are not always met, for instance:

- The electricity price during a certain observation period may be set by a variety of generation technologies with differences and changes in fuel efficiencies depending on shifts in power demand, plant outages, etc.
- Changes in power prices do not only result from changes in marginal (fuel and carbon) costs but also from a variety of other factors, including changes in market power, market scarcities, weather conditions, risks, etc.
- Fuel market prices do not always adequately represent the true opportunity fuel costs due to market illiquidity, specific fuel contract conditions, other market imperfections, start-up costs of plants or other adjustment and transaction costs.

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[31] Note that the upward effect of the free allocation provisions on carbon prices and, hence, on the pass-through of carbon costs to electricity prices is due to their impact on increasing CO_2 emissions and, therefore, on increase de demand for EUAs/offset credits (see Chapter 2).

[32] See also Sijm et al. (2008a) which besides own estimates of PTRs across a variety of power markets in EU Member States provides an overview of empirical studies on carbon cost pass-through to power prices.

In addition, the method or data used may show all kinds of statistical or econometric shortcomings. Therefore, in absolute terms, the exactness of the estimated PTRs may be questioned. Perhaps the most important meaning of these PTRs lies in whether they confirm or reject the null hypothesis that power producers include carbon costs in their price bids while a variety of factors see also below may explain why the PTR is smaller (or larger) than 1.0.

Market structure
PTRs may be significantly lower (or higher) than 1.0 due to the structure of the power market, notably (i) the level of market concentration or competitiveness, (ii) the shape of the supply and demand curves, including changes in the merit order, and (iii) other factors such as the incidence of market imperfections or differences in market strategies among power producers (Sijm et al., 2008b). Therefore, since the structure of the power market is highly independent from the method of allocation, this factor in itself does not change the CO_2 pass-through rate if one shifts from free allocation to auctioning.

The incidence of specific free allocation provisions
Due to the incidence of specific free allocation provisions, the CO_2 PTR may be lower than 1.0, implying that this rate and, hence, the resulting power prices may be higher if one moves from free allocation to auctioning. As argued above, however, the impact of this factor has probably been small or even absent in the short term, i.e. during the first phase of the EU ETS, while in the long run its impact on power prices depends primarily on the flexibility of the CO_2 budget of the EU ETS and, therefore, on its long-term impact on EUA carbon prices.

Time lags
The passing through of the full carbon costs of power generation to electricity prices in particular to end-users on retail markets may be due to time lags resulting from, for instance, medium or long-term contract provisions or producers' strategies to maintain or reach certain market shares (rather than to maximise short-term profits). Although this factor is probably largely independent from the method of allocation, it may imply that the carbon costs of a certain period (characterised by free allocations) are passed through in a later period (when the allocation has shifted towards auctioning).

Regulatory threat
Passing through the opportunity costs of freely allocated EUAs to electricity prices results in additional ('windfall') profits for power producers. In response particularly when these profits are substantial policy makers may react by either regulating power prices, taxing windfall profits or reducing free allocations to power producers in the next allocation phase. In order to avoid this response, power producers may be hesitant to pass on the full EUA costs. It is hard to say, however, whether and to what extent this factor has played any role in power price setting in the Netherlands during the first (and second) phase of the EU ETS. If it has, it implies that power prices will go up to the same extent if one shifts from free allocation to auctioning of EUA during the third phase of the EU ETS.

To conclude, in liberalised power markets such as in the Netherlands a shift from free allocation to auctioning of EUAs will most likely have no significant additional impact on (wholesale) electricity prices (assuming a similar EUA price under both allocation systems). Due to factors such as time lags or regulatory threat, however, (retail) electricity prices may become higher if one shifts from free allocation in the initial periods of the EU ERS towards auctioning in the next periods. Moreover, due to the incidence of specific free allocation provisions, the CO_2 PTR may be lower than 1.0, implying that this rate and, hence, the resulting power prices may be higher if one moves from free allocation to auctioning. However, the impact of this factor has probably been small or even absent in the short term, i.e. during the first phase of the EU ETS, while in the long run its impact on power prices depends primarily on the flexibility of the CO_2 budget of the EU ETS and, therefore, on its long-term impact on EUA carbon prices.

3.2.3 Power demand and supply

Power demand depends primarily on structural factors in particular on the structure and level of economic development but to some extent also on electricity prices. Although the responsiveness of power demand to electricity prices is usually low in the short run, it is generally rather significant in the medium or long term. Since power can hardly be stored, in market equilibrium power supply has to meet demand and, hence, supply depends on the same factors as power demand, although supply costs determine not only the source or technology of power generation but also electricity prices and, hence, power demand as well.

Hence, both the carbon price i.e. the level of EUA costs to generate power and the extent to which these costs are passed on to electricity prices affect power demand and supply, including the structure or composition of power supply, but in the short term these factors are independent of the allocation method. As outlined above, however, differences in allocation method only affect total power supply and demand to the extent in which auctioning versus the specific free allocation provisions has any impact on electricity prices.

3.2.4 Power trade and competitiveness

Emissions trading affects the competitiveness of power plants and firms, depending on their relative carbon intensiveness. Moreover, it may also affect the competitiveness and, hence, power trade between countries, depending not only on the relative carbon intensities of power generation in these countries but also on the availability of unconstrained transmission capacities between these countries.[33] In case of auctioning or perfect free allocation, however, the competitiveness of power plants, firms or countries is affected by the opportunity costs of emissions trading but not by the method of allocating allowances. Hence, depending on these costs, more carbon intensive power plants, firms or countries may loose competitiveness and, hence, output production to the benefit of less carbon intensive plants, firms or countries, regardless of the method of allocation.[34]

On the other hand, the incidence of the specific free allocation provisions during the initial phases of the EU ETS in general and the technology bias of these provisions in particular i.e. the number of free EUAs depends on the carbon intensity of the generation technology - undermines or even nullifies the loss of competitiveness of carbon intensive technologies to generate power. Hence, regarded from this perspective, abolishing these provisions by shifting towards auctioning implies that allocation has a significant impact on the competitiveness of power plant technologies, firms and countries.

It should be added, however, that the competitiveness of new entrants i.e. new investments, for instance in carbon mitigation technologies such as renewables or CCS depends not only on the carbon price or the incidence of technology-biased, specific free allocating provisions, but also on other factors such as differences in fuel or investment costs, including national or geographical differences between countries. For instance, due to its geographical conditions the Netherlands may have a comparative disadvantage for certain renewables (solar, biomass) while owing to its harbour facilities, cool water reserves and (empty, former) gas fields it may have a comparative advantage for coal/gas-fired power generation with CCS (Seebregts and Daniëls, 2008).

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[33] As far as countries have different currencies, the competitiveness between these countries depends also on (changes in) the exchange rate between these countries.

[34] For instance, before the start of the EU ETS (i.e. before 2005), the Netherlands which relies heavily on gas-fired power generation used to be a major importer of electricity, mainly form Germany where power is largely produced by coal-fired stations. However, depending on the EUA price (among others), the Netherlands will most likely switch to a major exporter of electricity in particular to Germany by the end of the third phase of the EU ETS (i.e. 2020; see Özdemir et al., 2008; and Seebregts and Daniëls, 2008).

Therefore, due to these differences, abolishing free allocation provisions by shifting towards auctioning may imply that in a particular country some carbon saving technologies become competitive while others do not (whereas for another country the reverse may apply).

3.2.5 Power sector profits and cash flows

In case of emissions trading with free allocations, resulting changes in profits of existing producers ('incumbents') can be distinguished into two categories according to two different causes of these profit changes:

- *Changes in incumbents' profits due to ETS induced changes in production costs, power prices and sales volumes.* This category of profit changes (denoted as 'windfall A') occurs irrespective whether eligible companies receive all their allowances for free or have to purchase them at an auction or market. The impact of changes in generation costs (including the opportunity costs of EUAs), 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 on 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).
- *Changes in incumbents' profits due to the free allocation of emission allowances.* This category of profit changes (denoted as 'windfall B') is an addition or compensation of the first category of windfall profits/losses to the extent in 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.

During the first and second phase of the EU ETS, carbon emission allowances have been largely allocated for free to existing power producers in the Netherlands and other countries based on grandfathering (with some correction factors). As a result, high-emitting incumbents have generally received relatively large amounts of EUAs for free while non-emitting generators have received nothing. As power production in the Netherlands is predominantly fossil fuel-based with coal/gas-fired plants setting wholesale electricity prices this implies that during the initial phase of the EU ETS Dutch incumbents have benefited mainly from the second category of windfall profits and to a lesser extent or even suffered from the first category. In contrast, in other countries such as France or Sweden, where power generation is largely nuclear/hydro-based, companies have benefited mainly from the first category of profit changes and less or hardly from the second category.

On the other hand, if allocation to power producers is shifted towards full auctioning, it implies that fossil fuel-based incumbents in the Netherlands and other countries lose the second category of (windfall) profit changes, while they may still benefit or suffer from the second category depending on (i) their carbon efficiency compared to the carbon efficiency of the power generator setting the electricity prices, and (ii) their changes in sales volumes due to both ETS induced changes in electricity prices and the resulting responsiveness of power demand by end-users. For instance, if a fossil-fuel producer sets the power price, he will break even in case of auctioning, provided his carbon costs are passed through fully to the power price and his sales volume does not change.[35] In this case, however, a less carbon efficient producer will lose (due to higher carbon costs not met by similar increases in power prices, resulting in a loss of profitabil-

[35] It will be obvious that the power producer will lose if his carbon costs are not fully passed through and/or his sales volume decreases due to the ETS induced increase in electricity prices and the resulting response of lower power demand.

ity/competitiveness, including a loss of sales volume), whereas a more carbon efficient producer will benefit (due to opposite reasons).[36]

To summarise, compared to a situation of (perfect) free allocation, the profits of fossil fuel-based incumbents will always decrease in case of auctioning, equivalent to the value or 'economic rent' of the free EUAs forgone. Compared to the situation of no EU ETS, however, the profits of fossil fuel-based incumbents may either increase, decrease or break even depending mainly on (i) the carbon efficiency of these incumbents relative to the price-setting producer, (ii) the pass-through rate of EUA costs to power prices, and (iii) the responsiveness of power demand and individual sales volumes to changes in end-user prices and producers' costs. In contrast, the profits of non-fossil producers will normally always increase due to the EU ETS regardless of the allocation method as they will benefit from an improved competitiveness, resulting in either a higher profit margin per unit output and/or higher sales volumes.

Some qualifications, however, have to be added to the conclusions outlined above.

Estimates of profit changes
Firstly, it is very hard or even impossible to estimate empirically (notably ex ante) what the exact impact of changing the allocation method of the EU ETS will be on the profits of the power sector during the period 2013-2020 in the Netherlands in general and individual firms in particular as it depends on a large variety of factors. These factors include, among others, (i) the EUA price, (ii) the number of EUAs allocated for free before 2013, (iii) the carbon efficiency of power producers, (iv) the pass-through rate of EUA costs to electricity prices, (v) the competitive structure of the power market, (vi) the incidence of the specific free allocation provisions and their possible effect on carbon prices, and (vii) the responsiveness of power demand and individual sales volumes to changes in end-user prices and producers' costs.

The next chapter, however, presents some model estimates of the impact of auctioning versus (perfect) free allocation on the profits of the power sector and some major individual power companies in the Netherlands - compared to some other countries and foreign-based companies - for different model scenarios combining different carbon prices, different market structures and/or different price elasticities of power demand.

Free allocation provisions
The above-mentioned observations and conclusions on the impact of allocation on power firms' profits are largely based on comparing auctioning versus perfect free allocations. As noted, however, the initial phases of the EU ETS have been characterised by the incidence of distorting specific free allocations rather than perfect free allocation. These provisions may result in lower electricity prices - notably in the medium or long run - and, hence, to lower profits for all producers (both fossil and non-fossil fuel based generators). In an extreme case this would imply that due to the incidence of these provisions the economic rent of free allocations would be fully transferred from power producers to consumers through lower electricity prices (compared to a situation of free allocation). In addition, it would imply that by shifting towards auctioning - and, hence, abolishing the incidence and impact of the free allocation provisions - generators' profits would either increase, decrease or break even, depending on the rise of power revenues versus the costs of purchasing EUAs. On the other hand, power consumers would face an increase in electricity prices and a shift or transfer of the economic rent of the EUAs towards the public sector.

Competitiveness versus profitability
In general, the profitability of a firm depends on its (operational) competitiveness but not vice versa. Compared to a loss-making or less profitable firm, however, a highly profitable company

[36] If the EUA costs of an infra-marginal, carbon efficient producer are not met by an equivalent increase in the power price due to a pass-through rate smaller than 1.0 the profits of such a producer will decrease in case of auctioning.

has easy access to own equity resources or to external capital at favourable terms. This provides this company a strategic or competitive advantage to finance new investments - including taking over other companies and maintaining or expanding market shares - thereby enforcing its operational competitiveness. This implies that the operational competitiveness of non-fossil producers in countries such as France or Sweden does not only benefit from the introduction of the EU ETS - as it enhances the generation costs of fossil-fuel based producers - but also from the shift towards auctioning - as it enhances their relative profitability - at the detriment of fossil-fuel based producers in countries such as Germany or the Netherlands.

Changes in power profits and cash flows

Auctioning of EUAs also has an impact on the cash flows of power companies as it implies higher cost expenditures compared to a situation of either no ETS or an ETS with free allocations. During the third phase of the EU ETS, these expenditures are equal to the actual, verified emissions of the power sector times the price of an EUA, regardless of whether the EUAs are purchased at an auction or (secondary) market).[37]

However, as the EU ETS also incurs changes in power revenues - through changes in power prices and/or changes in sales volumes - the cash flow effect of auctioning is actually similar in size to its profit effect (compared to a situation of either no ETS or an ETS with free allocation). Hence, if the profit effect of auctioning is positive or negative, its cash flow effect is also positive or negative.

The main difference between the cash flow and profit effects is a matter of timing in the sense that expenditures for purchasing EUAs might have to be paid earlier than the receipt of additional power revenues due to ETS induced higher electricity prices.[38] In general, power companies should be able to address this timing issue by taking recourse to either internal or external financing. For each of these options, however, some costs are involved. Although these costs can be regarded as additional EUA costs, the opportunity to pass on these costs to electricity end-users may be limited. This implies that, depending on the extent to which these costs can be passed through, power sector profits will decrease accordingly.

3.2.6 Power sector EUA expenditures, auction revenues and other fiscal issues

It is important to note that in case of full auctioning to the Dutch power sector, the EUA expenditures of this sector to cover its verified emissions in a certain year (say 2020) is most likely not similar to the auction revenues of the power sector-related auction revenues received by the Dutch government in that year. Apart from potential differences in timing or accounting issues, this is mainly due to the following reasons:

- According to the January 2008 proposals of the European Commission with regard to the new EU ETS directive beyond 2012, auction revenues for the Dutch government depends on (i) the EUA price, (ii) the amount of EUAs auctioned to both the power and other ETS sectors, (iii) the share of the Netherlands in the 2005 verified emissions of the EU ETS, and (iv) the redistribution of 10% of the auction revenues from rich Member States such as the Netherlands to poorer Member States such as Romania or Bulgaria (EC, 2008a). This implies that the auction revenues of power sector related EUAs received by the Dutch government in the

[37] For an estimate of these expenditures, see the section below on EUA expenditures and auction revenues. It should be noted that during the first phase of the EU ETS the Dutch power sector already had to buy a small amount of its required EUAs at the market, while during the second phase an additional amount was subtracted from the free allocations to the power sector and sold at an auction. Therefore, compared to the first or second phase, the additional cash flow effect of full auctioning during the third phase - in terms of additional EUA cost expenditures - is less than the total amount of EUAs purchased by the power sector during the third period.

[38] Since the price elasticity of power demand is far less than 1.0, total revenues for the power sector increase if the electricity prices go up. Due to a loss of competitiveness, however, power revenues of some individual, carbon intensive companies may decrease due to the EU ETS.

year 2020 are estimated at approximately € 1150 million, based on (a) an assumed EUA price of 40 €/tCO_2 in 2020, (b) an assumed quota of EUAs to be auctioned to the Dutch power and heat sector, equivalent to 32 MtCO_2 in 2020, based on a level of verified emissions by this sector of some 42 MtCO_2 in 2005 and a mitigation target equal to the overall decline of the ETS cap between 2005 and 2020, i.e. minus 1.75% per annum, and (c) a reduction of the Dutch auction revenues by 10% to be redistributed among poorer Member States.[39]
- As noted, the verified emissions of the Dutch power and heat sector in 2005 amounted to approximately 42 MtCO_2 (Kettner et al., 2007). Depending on (i) the growth rate of this sector up to 2020 (including a shift from less power imports to more domestic production), (ii) the achievements of the Dutch renewables targets, (iii) the carbon price and, hence, (iv) the additional, realized mitigations options, these emissions may increase, decrease or stabilize. Assuming an emission level of about 40 MtCO_2 in 2020 and an EUA price of 40 €/tCO_2, this implies that the total EUA expenditures by the power and heat sector will amount to some € 1600 million in 2020, regardless of whether the EUAs are purchased at a (Dutch) auction or not.

Hence, based on the above-mentioned assumptions - notably a carbon price of 40 €/tCO_2 in 2020 - the auction revenues of the power sector related EUAs received by the Dutch government are estimated at some € 1150 million in 2020, while the EUA cost expenditures by this sector are estimated substantially higher, i.e. at approximately € 1600 million. Besides the reduction of the auction revenues to the Dutch government - to be redistributed to other, poorer Member States - this difference is mainly due to the amount of EUAs allocated to the Dutch government presumed to be auctioned to the Dutch power sector and the assumed (higher) amount of actual emissions by the Dutch power sector in 2020 to be covered by EUA purchases at a (Dutch) auction or elsewhere.[40]

In addition to the auction revenues, there are some other fiscal issues related to the allocation method of the EU ETS affecting the power sector and the treasury in the Netherlands. Since the tax on business profits amounts to some 25% in the Netherlands, this implies that ETS induced changes in gross business profits in the Netherlands will affect net profits and fiscal revenues accordingly. Moreover, since the value added tax on household expenditures on electricity use amounts to 6%, this implies that ETS induced changes in power expenditures by households affect these expenditures and fiscal revenues accordingly.

Finally, power production by renewables or new CHP installations in the Netherlands may be subsidised by the Dutch government depending on their lack of profitability compared to less carbon efficient, price-setting technologies. However, this lack of profitability - and, hence, the amount of support - is affected by the EU ETS, for instance by the ETS induced changes in power prices or by the profits resulting from the (over)allocation of free EUAs to the CHP sector (see Chapter 5). Therefore, the EU ETS in general and (changes in) its allocation system in

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[39] 40 €/tCO_2 * 32 MtCO_2 * 0.9 = € 1150 million. It should be noted that (i) the verified emissions of approximately 42 MtCO_2 in 2005 refer to both the power and heat sector, based on data provided by Kettner et al. (2007); (ii) although the heat sector may still receive some free allocations to cover its emissions in 2013 and beyond, according to the proposals by the EC the heat sector will also be subject to full auctioning by 2020, and (iii) besides auctioning revenues from the power and heat sector, the Dutch government will also receive auction revenues from other (industrial) sectors as the sheltered ETS industries will also be subject to full auctioning in 2020. It should be emphasized, however, that in practice the Dutch government will only be allocated an overall amount of EUAs to be auctioned, without any further distinction or specification to which sectors these EUAs have to - or will - be auctioned. To estimate the power sector related auction revenues, however, it is assumed that the amount of EUAs auctioned by the Dutch government to the power sector is equal to the verified emissions of the Dutch power sector in 2005 reduced by the overall mitigation target for the ETS cap over the period 2005-2020, i.e. 1.75% per annum.

[40] Or, to put it differently, the potential difference between the power sector related auction revenues for the Dutch government and the EUA expenditures by the Dutch power sector in 2020 is due to the fact that, besides the redistribution issue, the EUA expenditures by the Dutch power sector are related to its actual, verified emissions in 2020 while the auction revenues for the Dutch government are not.

particular affect not only the performance of the power sector in the Netherlands - including its end-users - but also the fiscal performance of the Dutch government.

4. The implications of EU ETS allocation for the power sector in the Netherlands a model approach

This chapter analyses the implications of emissions trading including the allocation of emission allowances for the performance of the power sector by means of the so-called COMPETES model. Although the present study is mainly interested in the implications of emission trading and allocation issues for the power sector in the Netherlands, in order to put the performance of this sector in perspective these implications are also presented for the power sector in neighbouring, competing countries i.e. Belgium, France and Germany as well as for the group of 20 European countries covered by the model (EU-20).

The analyses are based on several model scenarios, distinguishing different wholesale power market structures i.e. perfect versus oligopolistic competition and different levels of demand responsiveness to changes in electricity prices. In addition, three different price levels of CO_2 emission allowances are considered, i.e. 0, 20 and 40 €/tCO_2, where (i) 0 €/tCO_2 refers to a situation of no emissions trading - e.g. the period before the introduction of the EU ETS (ii) 20 €/tCO_2 to the (average) price of a carbon allowance during the first years of the EU ETS, notably 2005-2006, and (iii) 40 €/tCO_2 to the (expected, average) price of an EUA by the end of the third trading period of the EU ETS (2013-2020).

The analyses of the implications of emissions trading and allocation issues for the power sector in the countries mentioned above covers the following topics:

- Power prices
- Carbon cost pass-through
- Power sales
- Power trade
- Carbon emissions
- Power generators' profits

The structure of the present chapter runs as follows. First of all, Section 4.1 provides a brief description of the COMPETES model (whereas a more detailed description is included in Appendix A). Subsequently, Section 4.2 discusses the major characteristics of the COMPETES model scenarios distinguished for the present study. Finally, Section 4.3 presents the major results with regard to the topics mentioned above.

4.1 Brief description of the COMPETES model

In order to analyse the performance of wholesale electricity markets in European countries, ECN has developed the so-called COMPETES model.[41] The present version of the model covers twenty European countries, i.e. Austria, Belgium, the Czech Republic, Denmark, Finland, France, Germany, Hungary, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, and the United Kingdom.

In the COMPETES model, the representation of the electricity network is aggregated into one node per country, except for Germany and Luxembourg, which are joined into one nod, while Denmark is divided into two nods belonging to two different, non-synchronised networks (i.e. Eastern versus Western Denmark). Virtually all individual power companies and generation

[41] COMPETES stands for COmprehensive Market Power in Electricity Transmission and Energy Simulator. This model has been developed by ECN in cooperation with Benjamin F. Hobbs, Professor in the Whiting School of Engineering of The Johns Hopkins University. For a more extensive description of this model, see Appendix A of the present report.

units in the 20 countries including CHP plants owned by industries or energy suppliers - are covered by the input data of the model and assigned to one of these nodes. The user can specify which generation companies are assumed to behave strategically and which companies are assumed to behave competitively (i.e. the price takers). The latter subset of companies is assigned to a single entity per node indicated as the 'competitive fringe'.

The COMPETES model is able to simulate the effects of differences in producer behaviour and wholesale market structures, including perfect versus oligopolistic competition. The model calculates the optimal behaviour of the generators by assuming that they simultaneously try to maximise their profits. Profits are determined as the income of power sales (market prices multiplied by total sales) minus the costs of generation and if sale is not at the node of generation transmission. Costs of generation are calculated by using the short-run marginal cost (i.e. fuel and other variable costs). Start-up costs and fixed operating costs are not taken into account since these costs have less effect on the bidding behaviour of suppliers on the wholesale market in the time horizon considered by the COMPETES model.

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

4.2 Definition of model scenarios

In order to analyse the implications of CO_2 emissions trading for electricity prices under different assumptions regarding power market structure and price responsiveness of electricity demand, different scenarios have been assessed by means of the COMPETES model. The acronyms and assumptions of each scenario are summarised in Table 4.1.

The reference scenario (REF) concerns an assumed situation of perfect competition and fixed power demand on the wholesale markets of European countries. It is based on a carbon price of 20 €/tCO_2 (comparable to the average EUA price in 2005-2006). The reference scenario has been calibrated to the level of power demand in 2006, while model outcomes in terms of wholesale prices and carbon emissions are quite close to actual realisations in 2006 (see Sijm et al., 2008a).

To assess the influence of market structure on CO_2 cost pass-through, two stylistic ('extreme') cases are considered, namely perfect competition (indicated by the acronym PC) and oligopolistic competition (indicated by OC) where the French company Electricité de France (EdF) is assumed not to be able to exercise market power in France due to regulatory threat, whereas all other non-fringe firms fully exercise market power in all markets in which they operate.

To analyse the impact of demand response to the CO_2 cost-induced changes in power prices, different levels of demand elasticity have been assumed. For most scenarios, a price elasticity of 0.2 has been taken (indicated by e0.2 in the acronyms of the scenarios).[42] This may be justified

[42] It is acknowledged that the sign of the price elasticity of power demand is usually negative (e.g. -0.1 or -0.2). For convenience, however, price elasticities in this chapter are expressed in their absolute values (i.e. as 0.1 or 0.2).

as the demand response in the medium or long term.[43] For the short term, however, a price elasticity of 0.2 may be considered too high because it is usually hard to reduce power consumption in the short run. Hence, some scenarios with lower elasticities or zero elasticities have been considered as well, namely 0.1 for the oligopolistic competition scenarios (indicated by e0.1 in the acronyms of the scenarios) and 0 - i.e. fixed load demand - for the perfect competition scenarios (indicated by e0 in the acronyms of the scenarios).

To study the implications of emissions trading for power prices, an exogenously fixed CO_2 price has been considered at three different levels: 0, 20 and 40 €/tCO_2 (indicated by c0, c20 and c40 in the acronyms of the scenarios). The COMPETES model has not yet been extended to include CO_2 costs endogenously. This model feature of an exogenously fixed carbon price implies that power producers are assumed to be price takers on the EU CO_2 allowance market, i.e. they are assumed to be unable to influence the price of an EUA.

Table 4.1 *Summary of scenarios in COMPETES*

Scenario acronym	CO_2 price [€/t]	Elasticity	Description
REF	20	0.0	Reference scenario: Perfect competition with fixed demand
OCe0.1c20	20	0.1	Oligopolistic competition with EdF price taker in France
OCe0.2c20	20	0.2	Oligopolistic competition with EdF price taker in France
PCe0c0	0	0.0	Perfect competition with fixed demand at REF level
PCe0.2c0	0	0.2	Perfect competition
OCe0.1c0	0	0.1	Oligopolistic competition with EdF price taker in France
OCe0.2c0	0	0.2	Oligopolistic competition with EdF price taker in France
PCe0c40	40	0.0	Perfect competition with fixed demand at REF level
PCe0.2c40	40	0.2	Perfect competition
OCe0.1c40	40	0.1	Oligopolistic competition with EdF price taker in France
OCe0.2c40	40	0.2	Oligopolistic competition with EdF price taker in France

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

Based on the REF scenario, four additional perfect competition (PC) scenarios are derived by setting the carbon costs at 0 and 40 €/tCO_2 and by assuming either fixed demand or a demand elasticity of 0.2. In addition, six oligopolistic (OC) scenarios are derived by assuming a carbon cost of 0, 20, and 40 €/tCO_2, combined with a demand elasticity of either 0.1 or 0.2.

The results of the COMPETES model analyses are presented not only in an absolute sense for each scenario separately but also by providing the difference between two scenarios. More specifically, to gain insight in the effect of the CO_2 allowance costs on power market performance,

[43] Note that COMPETES covers the wholesale power market only. In response to a price increase, certain power-intensive users may shift to self-production, which reduces demand/supply on the wholesale market.

the difference in outcome between the scenario with and without CO_2 allowance cost is studied for the same market structure (perfect or oligopolistic competition) and price elasticity of power demand. These differences between these scenarios are indicated by acronyms such as PCe0Δ20 or OCe0.2Δ40, where for instance PCe0Δ20 refers to the difference in outcome between the perfect competition scenarios with and without a carbon price of 20 €/tCO_2, assuming fixed demand, i.e. a price elasticity of 0 in both scenarios.

The COMPETES analyses focus on the extent to which the opportunity costs of CO_2 allowances affect power prices (and related issues such as power demand and carbon emissions). By comparing the results of the scenarios, the impact of emissions trading on power prices (and related issues) has been analysed under different assumptions of market structure, demand response and CO_2 prices (including resulting changes in the merit order of the power supply curve). These results are discussed in Sections 4.3 below.

4.3 Model results

In the sections below, the major results of the COMPETES model analyses of the implications of CO_2 emissions trading for the power sector are discussed, in particular the effects of the EU ETS on wholesale power prices, sales, trade, carbon emissions and generators' profits. These effects are assessed at two different EUA price levels, i.e. 20 and 40 €/tCO_2.[44] The results are presented for the Netherlands compared to its major power trading/competing countries i.e. Belgium, France and Germany as well as the EU-20 as a whole.[45]

Beforehand, however, some model characteristics should be mentioned (see also Appendix A). Firstly, COMPETES is a static, medium-term model and hence, it is not able to assess dynamic changes - i.e. new investments - in generation capacity in the long run. Secondly, COMPETES is based on the assumption that power producers include the (full) opportunity costs of emissions trading in their bidding prices, regardless of the allocation method. Moreover, while COMPETES is able to assess quantitatively the implications of either auctioning or perfect free allocations at different EUA prices, it is not able to analyse the effects of specific free allocation provisions such as updating free allocation baselines of incumbents or contingent free allocations to plant closures. Therefore, at a certain carbon price level, the COMPETES model results are similar in terms of the impact of the EU ETS on the power sector, regardless of the allocation method. The major exception concerns the impact on generators' profits, as illustrated below.

4.3.1 Power prices

For all scenarios considered, Table 4.2 presents estimates of the impact of CO_2 emissions trading on power prices in Belgium, France, Germany, the Netherlands and the EU-20 as a whole, while Table 4.3 and Table 4.4 show the absolute and relative changes in these prices (in €/MWh and %, respectively). By comparing these scenarios, the most striking results recorded by these tables include:

- For a given carbon price and demand elasticity, electricity prices are significantly higher under the oligopolistic competition (OC) scenarios than under the perfect competition (PC) scenarios. The major exception concerns France for which it is assumed that in the OC scenarios, the dominant company Electricité de France (EdF) is a price taker in its home coun-

[44] The price level of 20 €/tCO_2 is representative for the average EUA price during the first years of the EU ETS (2005-2006), while the level of 40 €/tCO_2 is representative for the expected EUA price during the (end of) the third phase.

[45] Results for the other individual countries of the EU-20 are presented in Sijm et al., 2008a. It is acknowledged that Norway and Switzerland are not part of the European Union (EU). Nevertheless, for convenient reasons, the expression EU-20 is used to indicate the total of 20 countries included in the COMPETES model.

try, i.e. due to regulatory threat it is not able to exercise market power in order to raise electricity prices in France.

- For a given carbon price and power market structure, electricity prices are substantially higher under lower demand elasticity scenarios, notably in case of oligopolistic competition, demonstrating the relation between price elasticity of power demand and the ability to exercise market power to increase electricity prices.
- In the perfect competition scenarios before emissions trading (PCc0), electricity prices are generally lowest in France and Germany while highest in Belgium and the Netherlands. Since prices in these scenarios are set by marginal (fuel) costs, this is due to differences in fuel mix in these countries. Whereas electricity prices are set largely by nuclear in France or coal in Germany, they are set by gas in the Netherlands (and Belgium) during a major part of the year, in particular during the peak period.
- In the oligopolistic competition scenarios before emissions trading (OCc0), electricity prices are generally lowest in France and highest in Belgium. Since prices in these scenarios are determined largely by the incidence of market power, this is due to differences in market structure and (assumed) producer behaviour in these countries. Whereas the level of market concentration i.e. the potential to exercise market power is relatively high in Belgium, it is assumed that in France EdF is not able to raise electricity prices by using market power (due to regulatory threat).
- In all comparable scenarios i.e. those with a similar demand elasticity and market structure power prices increase significantly due to emissions trading. Under perfect competition (PC), the price increases in absolute terms i.e. in €/MWh are generally highest in Germany and lowest in France. For instance, depending on the assumed demand elasticity, the increase in power prices due to an EUA price of 20 €/tCO_2 ranges between 14-15 €/MWh in Germany and between 7-11 €/MWh in France, while at a carbon price of 40 €/tCO_2 these price increases vary between 29-31 and 16-22 €/MWh, respectively (Table 4.3). For the Netherlands, the comparable changes in power prices due to emissions trading at EUA prices of 20 and 40 €/tCO_2 amount to some 10-11 and 23-25 €/MWh, respectively. These differences in ETS induced price increases among countries are due to differences in carbon intensity of the (existing) price-setting generation units in these countries. It implies that due to emissions trading and given the existing fuel mix of generation capacities the competitive position of the power sector in the Netherlands deteriorates compared to France but improves relative to Germany.[46]
- Under oligopolistic scenarios, however, the absolute increases in power prices due to emissions trading are generally lower than comparable perfect competition scenarios, notably in Belgium (see Table 4.3). Given the COMPETES model assumption of linear, downward sloping demand curves, this results from the (expected) lower pass-through rate of carbon costs to power prices under these market conditions (i.e. oligopolistic competition with linear, elastic demand; see also next section as well as Sijm et al., 2008a).[47] Note, however, that despite generally higher price increases due to emissions trading under PC, power prices affected by emissions trading are still far lower in absolute terms under PC than OC (Table 4.2).
- In relative terms, the differences in power price increases due to emissions trading are even larger between comparable PC and OC scenarios. For instance, under PC and an EUA price

[46] In the medium to long run, the competitive position of the power sector among countries depends also on the (ETS induced) new investments in generation capacity in these countries. Moreover, whether and to what extent changes in the competitive position of the power sector among countries result also in changes in power trade depends on (changes in) transmission capacities between these countries. Nevertheless, as discussed in the previous chapter, depending on the relative fuel and carbon prices and induced dynamic changes in generation capacity the power trade position of the Netherlands versus Germany may change due to the EU ETS from a net importer to a net exporter (Özdemir et al., 2008; Seebregts and Daniëls, 2008).

[47] In addition, it may result from the fact that power demand is generally lower under OC than PC due to the responsiveness to higher prices under OC. This lower demand may be met by either a higher or a lower carbon intensive plant setting the power price (compared to a situation of PC). Therefore, the resulting difference in carbon cost pass-through due to this factor may either enhance or (over)compensate the effect of the lower pass-through rate under OC discussed in the main text.

of 40 €/tCO_2, these increases range depending on the assumed demand elasticity - between 40-46% for Belgium and the Netherlands, and between 66-74% for Germany. On the other hand, under OC and a similar carbon price, these ranges in relative price increases amount to only 3-7% for Belgium, 15-19% for the Netherlands, and 31-38% for Germany (see Table 4.4).[48] These differences in relative power price increases between PC and OC scenarios are partly due to the (slightly) lower absolute amounts of carbon costs passed through under OC market conditions (as discussed above) but mainly due to the higher absolute power prices under OC before emissions trading (to which the lower pass-through amounts are related).

- As expected, in all comparable scenarios i.e. those with a similar carbon price and market structure wholesale electricity prices are generally lower in scenarios with a higher price elasticity of power demand (Table 4.2). Moreover, in comparable PC scenarios with relatively higher demand elasticity, increases in power prices due to emissions trading are also lower in both absolute and relative terms (Table 4.3 and Table 4.4). In comparable OC scenarios with relatively higher demand elasticity, however, these increases may be either higher or lower in absolute/relative terms.[49]

Table 4.2 *Wholesale power prices in EU countries under various COMPETES model scenarios [€/MWh]*

Scenarios: CO_2 price [€/tCO_2]	Demand elasticity	Scenario acronym[a]	Countries/results: Belgium	France	Germany	The Netherlands	EU-20
Perfect competition (PC)							
0	0.0	PCe0.0c0	54.3	38.4	42.2	54.2	45.6
0	0.2	PCe0.2c0	55.7	42.1	43.5	55.4	47.9
20	n/a	Reference	65.4	49.1	57.3	65.5	58.8
40	0.0	PCe0.0c40	79.1	60.1	73.5	79.4	73.0
40	0.2	PCe0.2c40	77.7	57.6	72.1	78.0	71.1
Oligopolistic competition (OC)							
0	0.1	OCe0.1c0	220.9	42.3	87.4	126.6	85.6
0	0.2	OCe0.2c0	132.8	40.8	66.1	92.3	65.8
20	0.1	OCe0.1c20	225.1	51.0	100.8	136.2	95.9
20	0.2	OCe0.2c20	138.6	48.4	78.8	101.1	75.9
40	0.1	OCe0.1c40	227.2	58.4	114.4	145.4	106.1
40	0.2	OCe0.2c40	141.5	55.9	91.5	109.7	86.4

a) PC and OC refer to Perfect Competition and Oligopolistic Competition, respectively, e.0.X to the demand elasticity, and cX to the CO_2 price.

[48] Note that these relative changes refer to wholesale power prices. As retail power prices are generally 2-3 times higher than wholesale prices while the amount of carbon cost passed through is assumed to be more or less similar in the long run the relative increase in retail power prices is evidently proportionally lower.

[49] The latter case is due to the fact that sometimes the ETS induced increase in power prices i.e. the numerator of the equation in OC scenarios with higher demand elasticity are relatively larger than the related power price before emissions trading (i.e. the denominator of the equation). In addition, it is occasionally due to the fact that the ETS induced increases in power prices are higher in OC scenarios with relatively higher demand elasticities (as explained in note 46).

Table 4.3 *ETS induced changes in wholesale power prices in EU countries under various COMPETES model scenarios [€/MWh]*

Scenarios:			Countries/results:				
ΔCO_2 price [€/tCO_2]	Demand elasticity	Scenario acronym[a]	Belgium	France	Germany	The Netherlands	EU-20
Perfect competition (PC)							
20	0.0	PCe0.0cΔ20	11.1	10.7	15.1	11.3	13.2
20	0.2	PCe0.2cΔ20	9.8	7.0	13.9	10.1	10.9
40	0.0	PCe0.0cΔ40	24.9	21.7	31.3	25.2	27.4
40	0.2	PCe0.2cΔ40	22.1	15.5	28.6	22.7	23.3
Oligopolistic competition (OC)							
20	0.1	OCe0.1cΔ20	4.2	8.7	13.4	9.6	10.3
20	0.2	OCe0.2cΔ20	5.8	7.6	12.7	8.8	10.1
40	0.1	OCe0.1cΔ40	6.3	16.1	27.1	18.9	20.5
40	0.2	OCe0.2cΔ40	8.8	15.1	25.3	17.4	20.7

a) PC and OC refer to Perfect Competition and Oligopolistic Competition, respectively, e.0.X to the demand elasticity, and cΔX to the change in the CO_2 price (while the other parameters of the model scenario are constant).

Table 4.4 *ETS induced changes in wholesale power prices in EU countries under various COMPETES model scenarios [%]*

Scenarios:			Countries/results:				
ΔCO_2 price [€/tCO_2]	Demand elasticity	Scenario acronym[a]	Belgium	France	Germany	The Netherlands	EU-20
Perfect competition (PC)							
20	0.0	PCe0.0cΔ20	21	28	36	21	29
20	0.2	PCe0.2cΔ20	18	17	32	18	23
40	0.0	PCe0.0cΔ40	46	56	74	46	60
40	0.2	PCe0.2cΔ40	40	37	66	41	49
Oligopolistic competition (OC)							
20	0.1	OCe0.1cΔ20	2	21	15	8	12
20	0.2	OCe0.2cΔ20	4	19	19	9	15
40	0.1	OCe0.1cΔ40	3	38	31	15	24
40	0.2	OCe0.2cΔ40	7	37	38	19	31

a) PC and OC refer to Perfect Competition and Oligopolistic Competition, respectively, e.0.X to the demand elasticity, and cΔX to the change in the CO_2 price (while the other parameters of the model scenario are constant).

4.3.2 Carbon cost pass-through

Table 4.5 provides estimates of the marginal CO_2 costs of power generation due to emissions trading in some EU countries under various COMPETES model scenarios. Four major observations can be noted:

- For the countries considered, the marginal carbon costs of power production are generally highest in Germany, lowest in Belgium - except under PC with a carbon price of 40 €/tCO_2 when these costs are lowest in France - while the Netherlands take a medium position. These differences between countries are due to differences in the carbon intensities of the generation units setting the price during the various load periods considered in COMPETES.
- For all countries considered, the marginal carbon costs of comparable cases - i.e. scenarios with similar market structures and demand elasticities - are higher if the allowance price per tonne CO_2 is higher. At first sight, this link between higher CO_2 prices and higher marginal carbon costs seems logic, but is not necessarily so: if the CO_2 price increases, power demand may decrease or the merit order of the supply curve may shift, resulting in another unit set-

ting the price. If this unit is less carbon intensive, the marginal carbon costs may decrease - or even become 0 - if the CO_2 price rises.

- For a certain carbon price, however, the marginal carbon costs may be either higher or lower for comparable cases, i.e. cases with similar market structures or with similar demand elasticities (for instance, 0.2 under both PC and OC). This is due to ETS induced changes in the merit order and/or differences in power demand under similar market structures.[50]

Table 4.5 *ETS induced changes in marginal CO_2 costs of power generation in EU countries under various COMPETES model scenarios [€/MWh]*

Scenarios: ΔCO_2 price [€/tCO_2]	Demand elasticity	Scenario acronym[a]	Countries/results: Belgium	France	Germany	The Netherlands	EU-20
Perfect competition (PC)							
20	0.0	PCe0.0cΔ20	10.60	12.56	16.03	10.84	14.07
20	0.2	PCe0.2cΔ20	10.60	12.56	16.03	10.84	14.07
40	0.0	PCe0.0cΔ40	28.73	22.83	33.50	28.71	29.34
40	0.2	PCe0.2cΔ40	30.86	23.28	34.62	30.38	29.52
Oligopolistic competition (OC)							
20	0.1	OCe0.1cΔ20	9.50	16.99	20.04	10.71	13.85
20	0.2	OCe0.2cΔ20	12.86	16.81	16.47	10.88	13.92
40	0.1	OCe0.1cΔ40	7.13	20.97	40.00	23.02	24.76
40	0.2	OCe0.2cΔ40	12.72	19.98	38.46	21.98	28.29

a) PC and OC refer to Perfect Competition and Oligopolistic Competition, respectively, e.0.X to the demand elasticity, and cΔX to the change in the CO_2 price (while the other parameters of the model scenario are constant).

In addition, Table 4.6 presents estimates of the marginal carbon cost pass-through rate (PTR) under various COMPETES model scenarios. This rate is defined as the ETS induced change in power price relative to the CO_2 allowance costs of the marginal generation unit setting the power price:

$$PTR = \Delta \text{ power price} / \Delta \text{ marginal } CO_2 \text{ allowance costs} \qquad (4.1)$$

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

The absolute values of the numerator and denominator for the various scenarios and countries considered have been recorded in Table 4.3 and Table 4.5, respectively. Hence, the relative values or pass-through rates (PTRs) of Table 4.6 have been obtained by dividing these respective absolute values.

[50] Note that for each country the marginal costs are similar in the cases PCe0.0cΔ20 and PCe0.0cΔ40 (see Table 4.5). This is due to the fact that in the reference scenario (PC with fixed demand and a carbon price of 20 €/tCO_2) the marginal units setting the price of electricity and, hence, the marginal costs of power generation are similar, while in the PC scenarios without emissions trading the carbon costs are also similar - i.e. equal to 0 - regardless of the units setting the price.

Table 4.6 *Estimates of pass-through rates of carbon costs to power prices in EU countries under various COMPETES model scenarios*

Scenarios: ΔCO_2 price [€/tCO_2]	Demand elasticity	Scenario acronym[a]	Countries/results: Belgium	France	Germany	The Netherlands	EU-20
Perfect competition (PC)							
20	0.0	PCe0.0cΔ20	1.18	0.97	0.87	1.10	0.93
20	0.2	PCe0.2cΔ20	0.99	0.65	0.75	0.99	0.75
40	0.0	PCe0.0cΔ40	0.89	1.07	0.89	0.88	0.94
40	0.2	PCe0.2cΔ40	0.71	0.73	0.77	0.75	0.78
Oligopolistic competition (OC)							
20	0.1	OCe0.1cΔ20	0.54	0.58	0.67	0.95	0.75
20	0.2	OCe0.2cΔ20	0.51	0.46	0.76	0.84	0.71
40	0.1	OCe0.1cΔ40	1.09	0.87	0.68	0.83	0.83
40	0.2	OCe0.2cΔ40	0.80	0.78	0.65	0.81	0.71

a) PC and OC refer to Perfect Competition and Oligopolistic Competition, respectively, e.0.X to the demand elasticity, and cΔX to the change in the CO_2 price (while the other parameters of the model scenario are constant).

Some of the major observations from Table 4.6 include:

- For all cases considered, most PTRs range between 0.75 and 0.95, while some vary between 0.5 and 1.2. For the Netherlands, most PTRs range between 0.8 and 1.0 (with one observation amounting to 1.1). For all cases, however, the COMPETES model assumes that the opportunity costs of emissions trading are included (fully) in the bidding prices - and other operational decisions - of power producers, regardless of the allocation method. Hence, differences in PTRs are due solely to differences in market structures, differences in demand elasticities and/or ETS induced changes in the merit order of the marginal units setting the price in various load periods distinguished by COMPETES.
- According to economic theory, the PTR in case of PC and fixed demand should be 1.0, while in case of OC with linear responsive demand it should be lower than 1.0. Table 4.6, however, shows that in all PC cases with demand elasticity 0.0 - i.e. all countries considered under PC with either 20 or 40 €/tCO_2 - the PTR deviates from 1.0, while it is higher than 1.0 in Belgium under the OCe0.1cΔ40 scenario. The reason for these deviations is that in case of an ETS induced change in the merit order the PTR may be either higher or lower than 1.0, even under PC with fixed demand, depending on whether the price setting technology shifts from either a high-CO_2 to a low-CO_2 marginal unit or vice versa (Sijm et al., 2008a). Hence, the deviations mentioned above indicate that at least during one of the load periods considered by COMPETES the merit order has shifted due to a change in the carbon price.[51]
- As predicted by basic economic theory, in case of linear price responsive power demand, PTRs are usually lower under OC than PC scenarios with similar carbon prices and demand elasticities (Sijm et al., 2008a). In addition, as predicted, under scenarios with similar carbon prices and market structures, PTRs are lower if demand elasticities are higher (Sijm et al., 2008a). Table 4.6, however, shows that there are some exceptions to these general, basic statements (e.g., for Belgium or France, the PTR is higher under OCe0.2cΔ40 than PCe0.2cΔ40, while for Germany the PTR is higher under OCe0.2cΔ20 than under OCe0.1cΔ20). The reason for these exceptions is a shift in the merit order during at least one of the load periods considered by COMPETES.
- The estimated pass-through rates (PTRs) of carbon costs to electricity prices in the Netherlands under various COMPETES model scenarios vary between 0.84 and 1.10 at an allowance price of 20 €/tCO_2 and between 0.75 and 0.88 at 40 €/tCO_2, while the empirically estimated PTRs for the years 2005-2006 at an average allowance price of 20 €/tCO_2 vary from

[51] It should be noted, however, that although most PTRs in Table 4.6 meet the expected or predicted values, they may still be affected by an ETS induced change in the merit order during at least one of the demand periods considered by COMPETES.

0.38-0.40 in the off-peak period (when coal is assumed to set the electricity price) to 1.10-1.34 in the peak period (when gas is assumed to be the marginal technology). This seems to suggest that (i) the PTR will be lower if the carbon price is higher (which may be due to carbon price induced changes in the merit order), and (ii) at the same carbon price, the model estimated PTRs are, on average, somewhat higher than the empirically estimated PTRs. Both types of PTRs, however, have to be treated with due care because of their different sets of underlying assumptions and data used.

Table 4.7 *Total power sales in EU countries under various COMPETES model scenarios [TWh]*

Scenarios:			Countries/results:				
CO_2 price [€/tCO_2]	Demand elasticity	Scenario acronym[a]	Belgium	France	Germany	The Netherlands	EU-20
Perfect competition (PC)							
0	0.0	PCe0.0c0	[illegible]	478	566	116	3016
0	0.2	PCe0.2c0	[illegible]	490	594	120	3129
20	n/a	Reference	[illegible]	478	566	116	3016
40	0.0	PCe0.0c40	[illegible]	478	566	116	3016
40	0.2	PCe0.2c40	[illegible]	463	535	111	2881
Oligopolistic competition (OC)							
0	0.1	OCe0.1c0	[illegible]	485	537	105	2886
0	0.2	OCe0.2c0	[illegible]	493	549	107	2948
20	0.1	OCe0.1c20	[illegible]	477	523	104	2832
20	0.2	OCe0.2c20	[illegible]	480	523	104	2842
40	0.1	OCe0.1c40	[illegible]	471	510	102	2778
40	0.2	OCe0.2c40	[illegible]	467	498	100	2730

a) PC and OC refer to Perfect Competition and Oligopolistic Competition, respectively, e.0.X to the demand elasticity, and cX to the CO_2 price.

Table 4.8 *ETS induced changes in power sales in EU countries under various COMPETES model scenarios [%]*

Scenarios:			Countries/results:				
ΔCO_2 price [€/tCO_2]	Demand elasticity	Scenario acronym[a]	Belgium	France	Germany	The Netherlands	EU-20
Perfect competition (PC)							
20	0.0	PCe0.0cΔ20	0	0	0	0	0
20	0.2	PCe0.2cΔ20	-3.2	-2.4	-4.7	-3.3	-3.6
40	0.0	PCe0.0cΔ40	0	0	0	0	0
40	0.2	PCe0.2cΔ40	-7.5	-5.5	-9.9	-7.5	-7.9
Oligopolistic competition (OC)							
20	0.1	OCe0.1cΔ20	-1.4	-1.6	-2.6	-1.0	-1.9
20	0.2	OCe0.2cΔ20	-1.4	-2.6	-4.7	-2.8	-3.6
40	0.1	OCe0.1cΔ40	-1.4	-2.9	-5.0	-2.9	-3.7
40	0.2	OCe0.2cΔ40	-2.8	-5.3	-9.3	-6.5	-7.4

a) PC and OC refer to Perfect Competition and Oligopolistic Competition, respectively, e.0.X to the demand elasticity, and cΔX to the change in the CO_2 price (while the other parameters of the model scenario are constant).

4.3.3 Power sales

Table 4.7 and 4.8 provide data on total power sales under various COMPETES model scenarios for the Netherlands compared to Belgium, France, Germany and the EU-20 as a whole. Under perfect competition (PC) total power sales remain fixed at the same level if the price elasticity of power demand is 0 (i.e. fixed demand), regardless of the level of the CO_2 price and its impact on electricity prices. On the other hand, if power demand responds to changes in electricity prices under either PC or OC scenarios total power sales decline when increases in the carbon price are passed through to electricity prices.

In addition, however, the following observations and qualifications can be made by comparing the results for individual scenarios and countries recorded in Table 4.7 and Table 4.8:

- As expected, under price responsive scenarios with similar market structures (i.e. either PC or OC), the decrease in power sales is higher if the carbon price is higher and/or the price elasticity of power demand is higher. Moreover, under price responsive scenarios with similar demand elasticities e.g. 0.1 under both PC and OC and similar carbon prices, i.e. either 20 or 40 €/tCO_2, the decline in power sales is usually higher under PC than OC. This is due to the fact that under linear, price-responsive demand, the pass-through of carbon costs to electricity prices is generally higher under PC as explained above while power prices before emissions trading are significantly lower under PC. This results in substantially higher proportional (%) increases in power prices due to emissions trading under PC at similar carbon prices and, hence, in significantly higher decreases in power sales under PC than OC (at similar demand elasticities).[52]
- Under similar scenarios, there might be significant differences between countries in terms of changes in power sales due to (ETS induced) changes in electricity prices. For instance, in the OC scenario with a carbon price of 40 €/tCO_2 and a demand elasticity of 0.2, the decline in power sales due to emissions trading amounts to 2.8% for Belgium, 5.3% for France, 9.3% for Germany and 6.5% for the Netherlands (Table 4.8). These differences are due to (i) differences in carbon intensity of power units setting the electricity prices in these countries, resulting in different *amounts* of carbon costs of power output, and (ii) differences in market concentration in these countries or, in particular in case of France, different assumptions regarding producer behaviour, resulting in differences in exercising market power in these countries and, hence, in different *rates* of carbon costs passed through to electricity prices. Consequently, despite similar carbon prices and demand elasticities, electricity prices may increase faster in some countries than others. As a result, power sales decrease more in countries with higher ETS induced increases in power prices due to both lower domestic power sales and a loss of trade competitiveness resulting in less power exports or more power imports. On the other hand, power sales decrease less or may even increase in countries with lower ETS induced increases in power prices due to a smaller decline in domestic power sales and an improvement in trade competitiveness, leading to more exports or less imports of electricity (see also next section). Similarly, even within one country, power sales of individual companies (or units) may decline less than other companies or even increase depending on their carbon intensity and, hence, the change in their competitive position due to emissions trading (see also Section 4.3.6).

[52] Note that power prices under OC are generally significantly higher than under PC and, hence, that the absolute levels of total power sales are lower under OC than PC (at similar carbon prices and demand elasticities). In specific, individual cases, however, total power sales of a particular country may be higher under OC than PC at similar prices and demand elasticities. For instance, at a carbon prices of 40 €/tCO_2 and a demand elasticity of 0.2, total power sales in Belgium, Germany, the Netherlands or the EU-20 as a whole are significantly lower under OC than PC, but slightly higher in France. This is to some extent due to the fact that it is assumed that in France EdF is not able to exercise market power (because of regulatory threat) and, hence, power prices under OC increase less in France than in de other countries considered and, therefore, power sales in France decline less. In addition, it is also due to the fact that power generation is, on average, less carbon intensive in France and, therefore, less carbon costs are passed through to power prices in France. This further improves the competitive position of power companies in France versus neighbouring, competing countries and, therefore enables these companies to maintain or even increase their power sales including power trade to other countries compared to their foreign companies (see also next bullet point in the main text, as well as the section below on power trade).

Table 4.9 *Power generation, domestic sales, net trade flows and major trading partners of EU countries in the reference scenario [TWh]*

	Generation	Sales	Net trade	Major trading partner
Belgium	75.2	89.9	-14.7	France, the Netherlands
France	535.4	478.4	57.1	Switzerland, Italy, Germany, Belgium (the Netherlands)
Germany	566.3	565.7	0.7	Exports: the Netherlands Imports: the Czech Republic, France
Netherlands	95.9	116.1	-20.2	Germany, Belgium (France)
EU-20	3016.0	3016.0	0.0	

Table 4.10 *Net power trade of EU countries under various COMPETES model scenarios [TWh]*

Scenarios:			Countries/results:				
CO_2 price [€/tCO_2]	Demand elasticity	Scenario acronym[a]	Belgium	France	Germany	The Netherlands	EU-20
Perfect competition (PC)							
0	0.0	PCe0.0c0	-15	57	2	-20	0
0	0.2	PCe0.2c0	-15	54	11	-19	0
20	n/a	Reference	-15	57	1	-20	0
40	0.0	PCe0.0c40	-7	57	-11	-14	0
40	0.2	PCe0.2c40	-6	59	-20	-12	0
Oligopolistic competition (OC)							
0	0.1	OCe0.1c0	-10	42	-8	-1	0
0	0.2	OCe0.2c0	-8	41	-7	-1	0
20	0.1	OCe0.1c20	-10	46	-11	-1	0
20	0.2	OCe0.2c20	-9	44	-10	-1	0
40	0.1	OCe0.1c40	-10	49	-16	-0	0
40	0.2	OCe0.2c40	-9	52	-19	-1	0

a) PC and OC refer to Perfect Competition and Oligopolistic Competition, respectively, e.0.X to the demand elasticity, and cX to the CO_2 price.

4.3.4 Power trade

Table 4.9 shows the amounts of power generation, domestic sales, net trade flows and major trading partners of some EU countries in the reference scenario of the COMPETES model. In this scenario, France and Germany are both the main power producers and the main power traders in terms of gross trade flows.[53] For instance, in the COMPETES reference scenario, France generates some 535 TWh of electricity. A major part of this production is sold and consumed at home (478 TWh), while the rest is exported to Switzerland, Italy or indirectly i.e. via Belgium/Germany to the Netherlands.

Similarly, in the reference scenario, Germany produces some 566 TWh of electricity, which is more or less equal to its domestic sales. In addition, however, Germany imports major amounts of power from countries such as France or the Czech Republic whereas it exports more or less similar amounts to the Netherlands, resulting in a net trade position of 0.7 TWh in the reference scenario.

[53] Gross trade flows refer to the sum of power exports and imports of an individual country, while net trade flows concern the balance of its power exports minus imports.

On the other hand, in the reference scenario, the Netherlands is the second main net importer of power (after Italy). Whereas the domestic power consumption of the Netherlands amounts to 116 TWh, its domestic production reaches only 96 TWh, resulting in major power imports of more than 20 TWh (i.e. almost one-sixth of total domestic sales). These imports are obtained either directly or indirectly from Belgium, France and Germany.

Table 4.10 presents the net power trade position of some EU countries under various COMPETES model scenarios, including the reference scenario. It shows that in all scenarios considered, France remains a main net exporter of power while Belgium is a major net importer. However, in PC scenarios - notably when the demand elasticity is 0.2 - Germany shifts from a net power exporter if the carbon price is relatively low (i.e. 0-20 €/tCO_2) to a net power importer if this price becomes relatively high (i.e. 40 €/tCO_2 or higher), while in the OC scenarios Germany imports already a significant amount of power before emissions trading. This amount tends to increase once emissions trading is introduced and the carbon price starts to rise. On the other hand, in the PC scenarios, the Netherlands tends to decrease its substantial net power imports when the carbon price increases, while under OC its net imports hardly change at a rather low level.[54]

These differences and changes in power trade positions among countries are due to differences and ETS induced changes in power demand and competitive position - i.e. relative power prices - among countries, resulting from their market structure as well from their fuel mix and carbon intensity of their generation capacities.

4.3.5 Carbon emissions

Table 4.11 presents the total CO_2 emissions of the power sector under various COMPETES model scenarios for Belgium, France, Germany, the Netherlands and the EU-20 as a whole. It shows that, in general, these emissions go down if the carbon price goes up, notably in the scenarios where power demand is more responsive to ETS induced changes in electricity prices. For instance, if the carbon price increases from 0 to 40 €/tCO_2, the carbon emissions of the EU-20 decreases from 1234 to 1069 MtCO_2 (-15%) in the PC scenario with fixed demand, while they decline from 1317 to 954 MtCO_2 (-33%) in the PC scenario with a demand responsiveness of 0.2. These figures illustrate that emissions trading and the resulting pass-through of carbon cost to electricity prices may reduce CO_2 emissions significantly by affecting not only producers decisions - through a re-dispatch or change in the merit order of generation technologies - but also consumer decisions, i.e. through reducing power demand in response to ETS induced increases in electricity prices.

Note from Table 4.11 that if the carbon price increases (in scenarios with similar market structures and demand elasticities), the proportional decrease in CO_2 emissions may vary significantly between individual countries, and that in specific cases the CO_2 emissions of an individual country may even slightly rise if the carbon price goes up (see, for instance, the Netherlands in the PC scenario with fixed demand: CO_2 emissions go up if the carbon price rises from 20 to 40 €/tCO_2). This is due to differences between these countries in the fuel mix or carbon intensity of their generation units, the opportunities for fuel switch or re-dispatch of the merit order, and the resulting ETS induced changes in electricity prices, competitive (trade) positions and, hence, total power sales of individual countries.

Finally, Table 4.11 also shows that at similar carbon prices and demand elasticities, CO_2 emissions are generally much lower under OC than PC. This is due to the higher electricity prices and, hence, lower power sales under OC, thereby illustrating once again the trade-off between

[54] As noted, under PC, the trade position of the Netherlands - particularly with regard to Germany - may change from a net importer to a net exporter of power, notably when the carbon price becomes relatively high (Özdemir et al., 2008; Seebregts and Daniëls, 2008).

the short-term interest of the consumer (low prices, high sales) and the long-term interests of the environment (high prices, less emissions). Note, however, that - in similar cases - the CO_2 emissions in the Netherlands are considerably higher under OC than PC. The explanation for this result is that coal units in the competitive fringe (exerting no market power under OC) change from being a marginal unit in the PC scenarios (operating at partial or no capacity) to a largely base load unit in the OC scenarios (operating at full capacity).

Table 4.11 *Total CO_2 emissions of the power sector in EU countries under various COMPETES model scenarios [$MtCO_2$]*

Scenarios:			Countries/results:				
CO_2 price [€/tCO_2]	Demand elasticity	Scenario acronym[a]	Belgium	France	Germany	The Netherlands	EU-20
Perfect competition (PC)							
0	0.0	PCe0.0c0	23.8	45.6	327.8	58.4	1234.2
0	0.2	PCe0.2c0	25.1	52.7	357.1	60.8	1316.6
20	n/a	Reference	22.6	44.5	306.1	53.3	1101.5
40	0.0	PCe0.0c40	22.6	43.2	294.5	54.4	1069.5
40	0.2	PCe0.2c40	21.1	32.2	258.6	53.2	953.7
Oligopolistic competition (OC)							
0	0.1	OCe0.1c0	10.3	42.9	269.6	67.0	1103.9
0	0.2	OCe0.2c0	12.1	47.5	284.8	64.7	1138.0
20	0.1	OCe0.1c20	9.7	36.0	245.8	58.6	991.8
20	0.2	OCe0.2c20	10.3	35.4	250.0	58.2	974.9
40	0.1	OCe0.1c40	8.8	31.9	218.0	56.9	892.6
40	0.2	OCe0.2c40	8.7	30.2	208.3	56.0	817.1

a) PC and OC refer to Perfect Competition and Oligopolistic Competition, respectively, e.0.X to the demand elasticity, and cX to the CO_2 price.

4.3.6 Power generators' profits

Profits of power producers are affected by emissions trading in general and its allocation method in particular. As mentioned in Sections 3.1.5 and 3.2.5, in case of emissions trading with free allocations, resulting changes in profits of existing producers ('incumbents') can be distinguished into two categories according to two different causes of these profit changes:

- *Changes in incumbents' profits due to ETS induced changes in production costs, power prices and sales volumes.* This category of profit changes (denoted as 'windfall A') occurs irrespective whether eligible companies receive all their allowances for free or have to purchase them at an auction or market. This impact on power generators' profits is called the 'emissions trading' (ET) effect as this impact occurs regardless of the allocation method.
- *Changes in incumbents' profits due to the free allocation of emission allowances.* This category of profit changes (denoted as 'windfall B') is an addition or compensation of the first category of windfall profits/losses to the extent in which allowances are obtained for free rather than purchased by eligible companies. This impact on power generators' profits is called the 'free allocation' effect as this impact is solely due to transferring the value or economic rent of the allowances allocated for free.

Table 4.12 *ETS induced changes in power generators' profits at the country level under various COMPETES model scenarios [%]*

	Perfect competition (PC)				Oligopolistic competition (OC)			
		Δ Profits due to: [a]				Δ Profits due to: [a]		
	CO_2 rate [b]	ET effect	Free allocation[c]	Total	CO_2 rate [b]	ET effect	Free allocation[c]	Total
	At a carbon price of 20 €/tCO_2 and a demand elasticity of 0.2							
Belgium	*251*	11.6	17.0	28.6	*147*	1.2	5.1	6.4
France	*93*	15.5	10.3	25.9	*74*	21.1	7.1	28.2
Germany	*541*	16.7	43.9	60.6	*478*	5.3	18.7	24.0
Netherlands	*459*	4.3	32.9	37.2	*560*	-8.4	16.2	7.9
EU-20	*365*	10.4	25.1	35.4	*343*	5.9	15.1	20.9
	At a carbon price of 40 €/tCO_2 and a demand elasticity of 0.2							
Belgium	*245*	14.1	29.7	43.8	*126*	-1.2	9.6	8.4
France	*70*	39.1	16.4	55.5	*65*	41.8	11.6	53.4
Germany	*483*	49.8	74.9	124.8	*418*	15.0	32.9	47.9
Netherlands	*479*	-0.3	59.5	59.2	*560*	-14.4	29.1	14.7
EU-20	*331*	29.9	43.4	73.3	*299*	14.9	25.2	40.1

a) These figures refer to scenario model results, not to facts of life.
b) Average, sales-weighted CO2 emission rate [kg CO_2/MWh].
c) Assuming that 90% of the emissions and, hence, 90% of the required allowances are covered by free allocations.

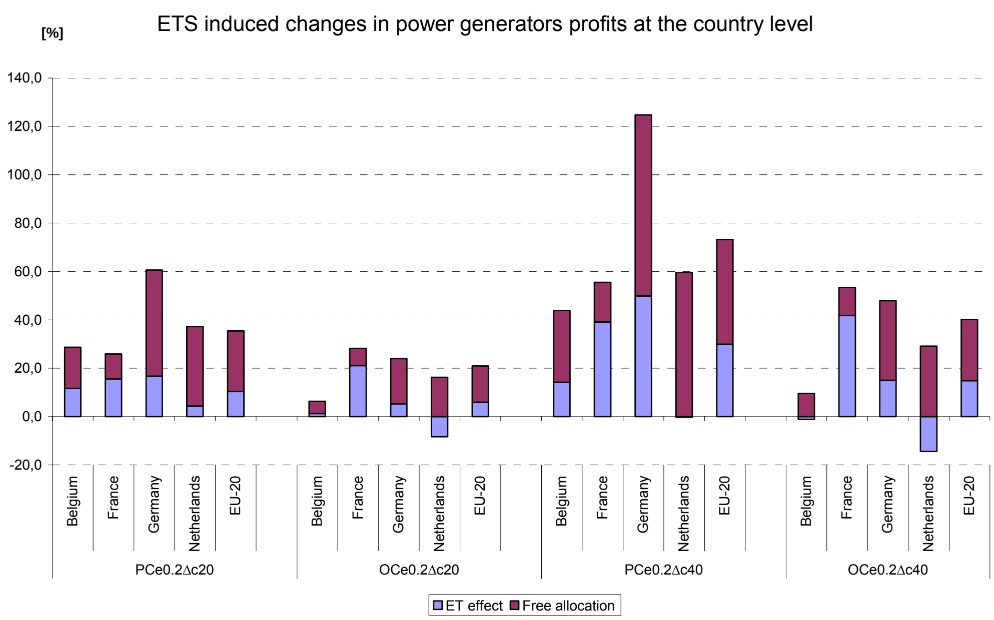

Figure 4.1 *ETS induced changes in generators' profits at the country level under various COMPETES model scenarios*

Table 4.12 presents estimates of proportional changes in generators' profits at the country level due to emissions trading under various COMPETES model scenarios, including the distinction between the two types - or causes - of profit changes mentioned above (see also Figure 4.1). This table is based on the assumption that 90% of the CO_2 emissions of each power producer - and, hence 90% of its required allowances - are covered by free allocations, while the remaining 10% has to be bought on an auction or market. Moreover, the scenarios included in this table are all based on the assumption of a similar price elasticity of power demand equal to 0.2.

In the COMPETES model, power generators' profits are determined as the income of power sales (market prices multiplied by total sales) minus the costs of generation and if sale is not at the node of generation transmission. Costs of generation are calculated by using the short-run marginal costs (i.e. fuel and other variable costs). Other costs such as start-up costs or fixed (operational/investments) costs are not taken into account. Hence, the (operational) generators' profits have to cover these other costs as well as the net 'normal' profit needs of producers (after taxes).

The most important observations of Table 4.12 and Figure 4.1 are discussed below.

In all cases considered of emissions trading with (90%) free allocations, total generators' profits increase substantially compared to similar cases without emissions trading (i.e. with similar market structures and demand elasticities). For instance, due to emissions trading with free allocations, total generators' profits in the EU-20 increase by 21% in the OC scenario with a carbon price of 20 €/tCO_2 and even by 73% in the PC scenario at 40 €/tCO_2 (and a demand elasticity of 0.2 in both scenarios). For individual countries, total generators' profits also increase significantly due to emissions trading with free allocations but the proportional profit changes of individual countries vary not only widely between the scenarios considered but also between these countries within one scenario. For instance, in the OC scenario at 20 €/tCO_2, total profits rise by approximately 6% in Belgium, 28% in France, 24% in Germany and 8% in the Netherlands, while in the PC scenario at 40 €/tCO_2 they increase by about 44% (Belgium), 56% (France), 125% (Germany) and 59% (the Netherlands), respectively. These differences between scenarios and countries are due to differences in carbon prices and market structures but also to differences in fuel mix and carbon intensity of price-setting technologies and, hence, to differences in carbon cost passed through, sales volumes, CO_2 emissions and carbon allowances received for free.

In addition to major differences between scenarios and countries with regard to the proportional changes in total generators' profits, there are also major differences between the scenarios and countries concerning the size and mutual importance of the two underlying causes of these profit changes. For instance, in the OC-40 €/tCO_2 scenario, total generators' profits in France increase by 53%, which can be attributed mainly to the so-called ET effect (+42%) and to a lesser extent to the effect of free allocation (+12%). On the other hand, total generators' profits in the Netherlands rise only by 15% in this scenario, which results from the net balance of a positive free allocation effect (+29%) and a negative ET effect (-14%).

Differences in proportional profit changes due to the free allocation effect between countries within a single scenario result mainly from differences in the average carbon intensity of total power output in these countries (as indicated in the second and sixth columns of Table 4.12).[55] Since free allocations are based on (90% of) power-related emissions, countries - or companies - which emit relatively more thus benefit relatively more from free allocations. Between scenarios, however, these differences in proportional profit changes result from differences in carbon prices and/or differences in market structures and related differences in (ETS induced changes in) electricity prices, merit orders, sales volumes, carbon emissions and, hence, in differences in free allocations.[56]

In addition, although not recorded in Table 4.12, differences between scenarios in proportional profit changes due to free allocation result also from differences in demand elasticities (leading

[55] In addition, as Table 4.12 records proportional changes, these differences may also result from differences in absolute profit levels between countries before emissions trading.

[56] Moreover, as Table 4.12 records proportional profit changes, differences in these changes between scenarios with different market structures result also from the fact that absolute profit levels before emissions trading are significantly higher under OC than PC and, hence, the proportional profit changes due to the free allocation (and/or ET) effect are substantially lower under OC than PC. Therefore, although these changes are generally lower under OC than PC, the absolute profit levels after emissions trading are usually higher under OC than PC.

to differences in sales volumes, carbon emissions and, hence, free allocations between scenarios with similar market structures and carbon prices). Finally, it will be clear that the proportional profit changes owing to the free allocation effect will be higher (lower) if the free allocation rate is higher (lower) than the 90% assumed in Table 4.12.

Differences in proportional profit changes due to the emissions trading effect between countries within a single scenario result mainly from the fuel generation mix of these countries or, more particularly, from the ETS induced changes in power prices set by the marginal unit versus the ETS induced changes in both sales volumes and generation costs - including the opportunity costs of emissions trading - of both marginal and infra-marginal operators (where these operators can be either a high-, low- or non-CO_2 emitter). Between scenarios, however, these differences in proportional profit changes result from differences in carbon prices and/or differences in market structures and related differences in (ETS induced changes in) electricity prices, merit orders, sales volumes, carbon emissions and, hence, in differences in free allocations.

Moreover, as the ETS induced changes in both electricity prices and sales volumes are sensitive to the price responsiveness of power demand, differences in ETS induced changes in generators' profits result also from differences in demand elasticities. More specifically, the proportional profit changes due to emissions trading - as well as to free allocations - are generally higher (lower) if the demand elasticity is lower (higher). As the price responsiveness of power demand is usually higher in the long run (than in the short term), it implies that the profit changes due to emissions trading/free allocations are lower - or, in some cases, even negative - in the long run.[57]

In Table 4.12 (and Figure 4.1), the profit changes due to emissions trading are based on the assumption that the opportunity costs of emissions trading are actual costs, while the profit changes due to free allocation correct for this assumption if emission allowances are allocated for free (by including the economic rent of the free allowances to power generators' profits). Therefore, the profit changes due to free allocations actually represent the loss in profits if one moves from free allocations to full auctioning, while the profit changes due to the ET effect actually represent the balance of profit changes in case of full auctioning (compared to the situation before emissions trading).

Table 4.12 shows that the profit changes due to free allocation - and, hence, the losses if one moves to full auctioning - can be very substantial.[58] In addition, however, it shows that the balance of profit changes under full auctioning - compared to the situation before emissions trading - is still significantly positive in most cases, notably in those countries where:

- a major part of power production is generated from non-carbon resources (nuclear, renewables),
- electricity prices are set by carbon intensive technologies while the infra-marginal producers are less carbon intensive,
- the pass-through rate of carbon costs to electricity prices is high, and/or
- the price elasticity of power demand - or the loss in trade competitiveness - and, hence, the reduction in sales volumes is low.

In a few cases, however, a shift towards full auctioning results in an overall reduction of generators' profits (compared to a situation before emissions trading). This applies notably for the Netherlands, in particular in the PC scenario with a carbon price of 40 €/tCO_2 and, more signifi-

[57] In addition, in the medium to long run, ETS induced increases in generators' profits lead to extra investments in new production capacity, which reduces increases in power prices and, hence, reduces increases in generators' profits.

[58] Note that Table 4.12 does not include the impact of the specific free allocation provisions - e.g. to new entrants - on generators' profits. As discussed, these provisions may reduce ETS induced increases in power prices and, hence, generators' profits in the long run. Shifting towards full auctioning, however, abolishes these provisions and, therefore, their possible impact on generators' profits.

cantly, in both OC scenarios considered in Table 4.12. The reduction in generators' profits in the Netherlands is largely due to:

- the vast share of fossil fuels in total power generation,
- the fact that the electricity price during a major part of the year is set by less carbon intensive, gas-fuelled plants while a large part of the infra-marginal producers consists of more carbon intensive, coal-fuelled stations who are not able to meet their carbon costs by equally rising electricity prices,
- the carbon cost pass-through rate for the marginal producer is less than 1.0 because of the (oligopolistic) market structure of power supply and/or the price responsiveness of power demand, and
- the decline in sales volumes resulting from the ETS induced increase in electricity prices and the elasticity of power demand.[59]

Table 4.13 *ETS induced changes in power generators' profits at the firm level under various COMPETES model scenarios [%]*

		Perfect competition (PC)			Oligopolistic competition (OC)		
		Δ Profits due to: [a]			Δ Profits due to: [a]		
	CO_2 rate [b]	ET effect	Free allocation[c]	Total	ET effect	Free allocation[c]	Total
		At a carbon price of 20 €/tCO_2 and a demand elasticity of 0.2					
Comp_BE[d]	*530*	0.0	41.4	41.4	-5.6	11.4	5.8
Comp_DE	*651*	9.0	42.2	51.3	0.8	31.7	32.5
Comp_FR	*561*	-4.9	31.3	26.4	2.6	26.8	29.5
Comp_NL	*521*	2.4	43.9	46.4	-4.0	21.3	17.3
E.ON	*524*	14.2	29.4	43.6	9.3	4.2	13.5
ELECTRABEL	*442*	11.8	23.4	35.2	-0.5	4.7	4.2
EdF	*212*	18.0	7.8	25.9	19.4	3.5	22.9
ENBW	*403*	24.3	21.6	45.8	8.5	10.5	19.0
ESSENT	*690*	-10.1	51.6	41.4	-8.9	24.1	15.1
NUON	*959*	-11.9	42.5	30.3	-11.2	19.4	8.2
RWE	*692*	-4.2	58.7	54.5	-6.2	16.0	9.8
VATTENFALL	*579*	2.4	42.3	44.7	-8.4	23.3	14.9

a) These figures refer to scenario model results, not to facts of life.
b) Average, capacity-weighted CO2 emission rate of total power sales (in g CO2/MWh).
c) Assuming that 90% of the emissions and, hence, 90% of the required allowances are covered by free allocations.
d) Comp_BE refers to the power producers in Belgium who belong to the so-called competitive fringe.

In addition, Table 4.13 presents the ETS induced changes in power generators' profits at the *firm* level under two COMPETES model scenarios, i.e. a PC versus OC scenario at a carbon price of 20 €/tCO_2 and a demand elasticity of 0.2 (see also Figure 4.2). The table includes the main power companies operating in Belgium, Germany, France and the Netherlands as well as the so-called 'competitive fringe' in these countries (denoted by Comp_BE, Comp_DE, Comp_FR and Comp_NL, respectively).

Table 4.13 shows some major differences between the PC and OC scenario with regard to both the ET effect, the free allocation effect and the total profit effect (which can be similarly explained as discussed above concerning the differences observed in Table 4.12). In addition, the table presents some interesting differences regarding these effects between individual companies within one scenario. For instance, under the PC scenario, the ETS induced total profit

[59] Recall that the assumed demand elasticity in Table 4.12 is 0.2. This implies that generators' profits in the Netherlands would decrease less (or even increase) if this elasticity is lower - e.g. in the short run - but decrease more if the demand responsiveness to price changes is higher (in the long run). On the other hand, in the long term generators' profits may improve due to ETS induced dynamic changes in carbon saving technologies.

change is significantly positive for all individual firms but ranges from 26% for EdF to 55% for RWE. The free allocation effect is also positive for all firms but varies even stronger under the PC scenario from 8% for EdF to 59% for RWE.

On the other hand, the so-called 'emissions trading' (ET) effect excluding free allocations is positive for some individual firms but negative for others. For instance, due to this effect (at 20 €/tCO_2) generators' profits under the PC scenario increase by 18% for (French-based) EdF and even by 24% for (German-based) ENBW, while they decrease by some 10-12% for (Dutch-based) companies such as ESSENT and NUON.

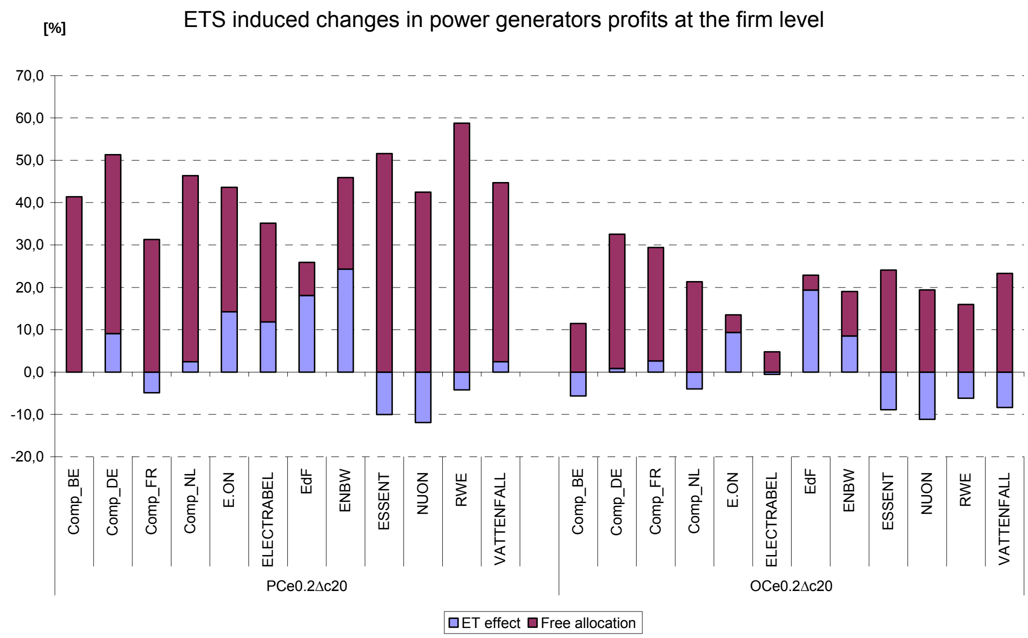

Figure 4.2 *ETS induced changes in generators' profits at the firm level under two COMPETES model scenari*

The differences between the ETS induced profit effects at the firm level can be explained mainly by the carbon intensity of individual companies as indicated in the second column of Table 4.13 compared to the carbon intensity of the marginal unit setting the electricity price during the respective load periods and countries considered. For instance, Dutch-based companies such as ESSENT and NUON are, on average, relatively carbon intensive, while the power price in the Netherlands is set by less carbon intensive, gas-fuelled stations during major (peak) periods of the year, implying that coal-generated power becomes less profitable in case of emissions trading without grandfathering (i.e. free allocations based on historic, fuel-specific emissions).[60] On the other hand, EdF relies heavily on nuclear, while the power price in France or in neighbouring, trading countries is set by fossil-fuelled plants during major periods of the year, implying that nuclear based power becomes more profitable in case of emissions trading.[61]

Moreover, due to emissions trading total sales volumes may decline (if power demand is responsive), while some carbon intensive firms may lose competitiveness and, hence, their power

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[60] This is particularly the case when the pass-through rate of carbon costs to electricity prices is less than 1.0, e.g. when power demand is price responsive or under oligopolistic market structures with linear, downward sloping demand.

[61] Note that both the competitiveness and profitability of nuclear based companies usually benefit from emissions trading regardless of the allocation method, but that in case of shifting from free allocations to auctioning their profitability improves relatively, i.e. compared to the profitability of fossil-fuel based companies.

sales may decrease relatively more, while others may gain competitive strength and, thus, their sales may decrease less (or even increase). Therefore, to conclude, whereas the profits of carbon intensive companies such as ESSENT, NUON or RWE benefit largely from emissions trading based on fuel-specific free allocations i.e. grandfathering they suffer from emissions trading based solely on auctioning (depending on the carbon efficiency of the marginal producer and the price responsiveness of power demand). On the other hand, profits of nuclear based companies such as EdF increase absolutely due to emissions trading in general and relatively i.e. compared to their fossil-fuel based competitors from auctioning in particular.

5. The implications of auctioning EU ETS allowances for the Combined Heat and Power (CHP) sector in the Netherlands

This chapter pays some particular attention to the implications of free allocation versus auctioning of EUAs for the Combined Heat and Power (CHP) sector in the Netherlands.[62] First of all, Section 5.1 provides some background information on the role of CHP in the Netherlands, including the support to CHP in the years 2001-2008. Subsequently, Section 5.2 discusses briefly the implications of free allocation for CHP installations in the Netherlands during the initial phases of the EU ETS (2005-2012), while Section 5.3 analyses the specific implications of moving from free allocation to auctioning for these installations beyond 2012. Finally, Section 5.4 addresses in some detail the link between the EU ETS and government support to CHP in the Netherlands, including some policy conclusions on this issue.

5.1 The role of CHP in the Netherlands

CHP plays an important role in the power sector of the Netherlands. Out of 99 TWh of electricity from Dutch generators in 2006, some 56 TWh was produced by CHP installations. In addition, out of the 23 GW_e of installed capacity, as reported by the Central Bureau of Statistics (CBS) for the year 2006, some 11.5 GW_e involves CHP installations. Some 5.4 GW_e thereof concerns centralized CHP installations.[63] Out of the remaining 6.1 GW_e of decentralized installations, some 3.2 GW_e is installed in the industry, whereas the remaining 2.9 GW_e is installed in other sectors such as services or horticulture.

A large share of the CHP installations has a thermal capacity above 20 MW_{th}. Only the gas engines and the smaller gas turbines representing roughly 2.4 GW_e, which is mainly installed in services and horticulture have lower thermal capacities. Moreover, many CHP plants are so-called "must-run facilities", which operate permanently due to a constant heat demand and, hence, can not be simply switched on or off during peak or off-peak hours depending on the electricity price and, hence, the profitability of power generation by these facilities during these periods. The full load hours per year can differ significantly per application (ten Donkelaar, et al., 2004). Typically CHP plants in industry, which need to run more or less permanently because of process heat production, show full load hours per year ranging from 5000-7000h. On the other hand, installations in horticulture or in services typically show some 3000 to 4000 full load hours per year.

During the 1990s, a strong growth of installed capacity of CHP was realised in the Netherlands. This growth resulted from the introduction of an effective support mechanism for CHP, based on a system of fixed tariffs for CHP generated electricity. With the introduction of a liberalised electricity market in the Netherlands in 1999, however, the tariff-based support scheme was abandoned and replaced by a market-based pricing system. Although CHP generally has a competitive advantage over conventional thermal technologies due to the relatively high overall efficiency, its position was compromised by competitive pressure from coal-fired technologies. Particularly the price of electricity in the off-peak period, mainly set by the relatively low-cost coal-fired facilities, was too low to cover for the marginal production costs of the generally gas-fired CHP facilities. As many CHP-facilities were designed to produce on a continuous basis, in order to fulfil local heat demand, many installations faced losses during the off-peak. As a result, although most existing CHP units remained in operation often at less load hours, however -

[62] The focus of this chapter is on the CHP installations participating in the EU ETS. It should be noted, however, that small CHP installations outside the EU ETS may benefit significantly from the ETS-induced increase in power prices and, hence, increase their capacity and output accordingly.

[63] Centralized CHP installations are defined as installations connected to the national high-voltage grid.

the rapid increase in installed CHP capacity observed during the 1990s practically came to a standstill.

CHP support (2001-2008)
By January 2001, a subsidization scheme was introduced in order to support CHP installations. Originally, the subsidy involved an exemption of taxes on electricity production generated by CHP for the national grid. By mid-2003, this tax exemption was replaced by the so-called MEP subsidy scheme for CHP. The MEP-CHP subsidy was granted on a year-by-year basis. From 2004 onward, the MEP scheme provided a reward for the avoided CO_2 emissions due to CHP-based power production, compared to separate production of heat and power by means of a gas-fired boiler and a CCGT installation, respectively.[64]

From 2006, the subsidy to CHP was based on the so-called 'financial gap' calculations, differentiated for several specific types of CHP installations. This financial gap (or 'lack of profitability') is defined as the support per unit output e.g. 40 €/MWh which is needed in order that the net present value (NPV) of the costs and benefits of operating a CHP installation breaks even.[65]

In the course of 2008, however, the Dutch government decided to abolish the operational support to existing CHP installations, while for new installations the potential subsidy would be considered again in 2009, depending on actual and expected trends in costs and benefits of CHP operations for new entrants. As the prospects for new CHP installations in 2008 were considered to be rather favourable, the Dutch government decided to provide no (operational) support to new CHP entrants in that year.[66]

5.2 The implications of the EU ETS for CHP

From the 1st of January 2005, CHP installations with a thermal output above 20 MW participate in the EU ETS. This scheme has major consequences for both the competitiveness of CHP-based (electricity) production and the profitability of CHP installations.

Generally speaking, production of electricity and heat by deployment of CHP installations is more efficient than production through deployment of both an electricity production facility and a boiler. In principle, CHP installations need less primary fuel for the production of a specified amount of electricity and heat than separate production. As CO_2 emissions relate linearly to fuel consumption, CHP installations emit less CO_2 than separate gas-fired production of heat and electricity. The resulting competitive advantage applies primarily to the peak hours as gas-fired facilities are generally considered to be the marginal technology for the peak periods in the Netherlands. For off-peak hours, coal-fired facilities are generally considered to be the marginal technology in the Dutch market. Although coal-fired facilities are faced with higher cost-increases due to the introduction of the EU ETS than gas-fired (CHP) facilities, the marginal costs of coal-fired facilities may still be significantly lower than the marginal costs of gas-fired CHP installations.

Costs and benefits due to the EU ETS
The impact of the EU ETS on the profitability of CHP installations requires a closer analysis of the additional costs and benefits due to the introduction of the scheme. The ETS induced costs

[64] The MEP-CHP subsidy scheme between 2004 and 2006 is explained in some detail in Appendix C of Sijm et al. (2006b).

[65] The financial gap is calculated as the (annuity) capital costs + operation costs revenues (from electricity + heat + CO_2 allowances). A positive outcome here means that there is a certain financial gap. For more details and illustrative examples of the financial gap methodology, see Appendix C of Sijm et al. (2006b) and, more recently, Hers et al. (2008a and 2008b).

[66] It should be noted that new investments in CHP can still benefit from favourable investment tax schemes in the Netherlands.

refer to the costs of deploying EUAs for the purpose of producing electricity and/or heat. In case of production of electricity and heat, these costs may be recovered by passing them through to the end-user prices. On the other hand, the allocation of EUAs during the first two trading periods of the EU ETS was based on grandfathering and, hence, free of charge. The freely allocated EUAs thus represent a benefit owing to the EU ETS.

As far as pass-through of the costs of EUAs to electricity pricing is concerned, prices are generally set by marginal cost of generating electricity. In case the cost increase of the producer at hand is higher than the cost increase of competitors, the relative competitiveness of this producer deteriorates. If, on the other hand, the cost increase of the producer at hand is lower than the cost increase of competitors, the relative competitiveness of the producer improves. The latter situation applies to owners of CHP installations, both during peak hours when CHP installations compete with gas-fired installations, and even more during off-peak hours when CHP installations compete with coal-fired facilities.

Analyses of electricity prices since the introduction of the EU ETS in the Netherlands and other EU countries supports the view that costs of EUAs are accounted for in the electricity prices (see Chapter 3). In case of the Netherlands, the off-peak prices show a significant correlation with the increase in the marginal costs of coal-fired facilities due to the opportunity costs of the EUAs, whereas the increase in the peak prices corresponds with the increase in opportunity costs for gas-fired CCGT. In other words, costs of EUAs for power generation by CHP installations, which are generally less carbon intensive than both coal-fired facilities and CCGTs, are covered largely by the ETS induced increases in power prices.

The price of heat from CHP, on the contrary, is not based on a market price but rather on the basis of the cost of avoided heat generation. Assuming a third party can either choose to install a boiler or purchase heat from a CHP owner, this third party will pay at most the cost of production for deployment of a boiler. It is, therefore, generally assumed that the price of CHP heat output in practice is set by the cost of heat generation through deployment of a reference boiler, possibly at a small discount.[67]

Hence, in case the reference boiler would participate in the EU ETS, the costs of EUAs should be accounted for in the heat price accordingly. However, it can be assumed that a third party would install a new boiler and this party would receive the required allowances for free during the first and second allocation period of the EU ETS. Since the time for a new investment in a boiler to become operative is relatively short (compared to a power plant), this implies that the increase in operational costs due to the EU ETS is nullified by the investment subsidy due to the free allocation to new entrants and, hence, that on balance the heat price hardly changes. Therefore, in this case, the third party would in effect face the choice between the costs of heat delivery from a CHP versus the costs of heat generation by means of a boiler, including free allocation of the necessary EUAs. The CHP owner can, hence, not charge the third party for the cost of EUAs, as the third party in that case would simply choose to install a new boiler. Note that in case allocation of EUAs for boilers in the Netherlands would be based on auctioning or there is no free allocation to newly installed boilers, this argumentation no longer applies and heat would be priced on the basis of the costs of both the fuel and the EUAs needed for deployment of a new boiler (see Section 5.3 below).

Under the current allocation scheme in the Netherlands, which is based on grandfathering, all participants in the EU ETS receive EUAs for free. For new installations, allocation is based on projected CO_2 emissions. For existing installations, the volume is based on historical emissions, including some corrections. Most importantly, individual assignments for existing installations are corrected for the national emission cap by application of the so-called correction factor. The correction factor is based on the ratio between expected emissions and the total volume of avail-

[67] Information on bilateral heat pricing is not readily available as it is confined to undisclosed bilateral agreements.

able EUAs for the Netherlands. It is applied as a multiplier to all individual assignments of EUAs in order to meet the national cap. For the first period this correction factor was 0.9 whereas it is 0.785 for the second.

The allocation of emission allowances to CHP plants is following the guidelines laid down in the national allocation plan (SenterNovem, 2004; 2008). Both for the first and the second trading period, the allocation for CHP is based on the emissions associated with separate generation of power and heat. Therefore CHP installations, being more energy efficient than the benchmark, receive more CO_2 emission allowances than needed. Calculations made by ECN based on actual gas consumption of a number of standardized CHP plants (CCGT units and gas turbines) compared to the benchmark efficiencies of electricity and heat production showed that these CHP plants are 12% to 20% more efficient than the benchmark. However, according to the guidelines, the over-allocation for energy efficiency measures like CHP is maximized at 10% (in accordance with the so-called *10% rule*). Over-allocation of EUAs for CHP installations is therefore capped at 10% of the expected yearly CO_2 emission. In addition the correction factor applies to existing facilities. Application of the correction factor for the first trading period resulted in some 7% over-allocation for the CHP sector. For the second trading period virtually no over-allocation, and in some cases even under-allocation, resulted from the calculations for the standardized CHP cases.

5.3 The implications of moving from free allocation to auctioning

This section discusses the implications of shifting from free allocation to auctioning of EUAs for the CHP sector in the Netherlands. In mid-December 2008, both the European Council and the European Parliament agreed to 100% auctioning for the power sector, starting from 2013.[68] For heat production, the allocation rules beyond 2012 are similar to those agreed for the industrial sectors. Electricity generators may receive free allowances for district heating and for heat produced through high efficiency cogeneration as defined by Directive 2004/8/EC in the event that such heat produced by installations in other sectors were to be given free allocations.[69]

The shift from free allocation to auctioning will affect above all the profitability of CHP installations. In particular, the benefits due to free allocations - including the over-allocations to CHP installations - will come to an end. On the other hand, under auctioning costs of using EUAs for production purposes remain equivalent to the opportunity cost of selling free EUAs, assuming that the net effect of possible updatings of free allocations on carbon costs is low or even absent (see Chapter 2). Therefore, nothing would change with respect to the carbon costs due to the EU ETS, regardless of the allocation method. For power production, the pass-through of EUA costs to electricity prices under auctioning is presumed to be similar under free allocation and, hence, the power price is assumed to hardly change when moving from free allocation to auctioning (as discussed in Chapters 2 to 4).

For heat production, however, auctioning implies that the implicit subsidy of free allocations to new investments in boilers will be abolished and, hence, that the heat price will rise accordingly, i.e. similar to the EUA costs of heat production by a boiler (as discussed in the previous section). Therefore, moving from free allocation to auctioning will significantly reduce the profitability of power generation by CHP installations, whereas it will hardly change the profitability of heat production by these installations. As noted, however, power produced by CHP plants has

[68] For existing installations in some (mainly East-European) countries, however, it was decided that the auctioning rate in 2013 will be at least 30% and will be progressively raised to 100% no later than 2020.

[69] For the so-called non-exposed industrial sectors, the auctioning rate is set at 20% in 2013, increasing to 70% in 2020, with a view to reaching 100% in 2027. For the industrial sectors exposed to outside EU competition, free allocation may be up to 100% during the third trading period (in case of no international climate policy agreement beyond 2012). Free allocations to industrial installations, including heat production, will be based on EU-wide (uniform) benchmarks regardless the actual emissions of specific installations (and, hence, more carbon efficient installations will benefit accordingly).

benefited from free (over)allocations and the pass-through of EUA costs to electricity prices during the initial phases of the EU ETS. Hence, compared to the situation before the EU ETS, the profitability of CHP installations will either increase, decrease or break-even depending on the factors discussed in the previous chapter such as the carbon efficiency of CHP installations compared to the price-setting units, the structure of the power market or the price responsiveness of power demand (see particularly Section 4.3.6). In general, however, the competitiveness and/or profitability of CHP in the Netherlands should improve due to the EU ETS - even with auctioning - as it is more carbon efficient than most of its (price-setting) competitors.

5.4 The link between the EU ETS and CHP support in the Netherlands

As explained in Section 5.1 above, the support to CHP installations in the Netherlands used to be based on the so-called 'financial gap' calculations, differentiated for some types of CHP installations. These calculations include the expected (EUA) costs and benefits - free allocations, induced higher output prices - due to the EU ETS. Hence, there used to be a close link between the EU ETS and the Dutch support to CHP in the sense that changes in the (expected) financial gap of CHP installations due to the EU ETS affect the support to these installations.

In case of shifting from allocation to auctioning of EUAs, there are some implications for calculating the expected financial gap of CHP installations. In summary, these implications include:

- The opportunity costs of EUAs are included in the CHP support calculations regardless of the allocation method. Hence, these costs do not affect the financial gap of CHP installations when moving from free allocation to auctioning.
- The value of the free (over)allocations, however, affect the financial gap calculations as, for obvious reasons, it is regarded as benefits under free allocation but not under auctioning.
- With regard to the revenues from power production, it is assumed that the ETS induced increase in electricity prices - due to the pass-through of EUA costs - is more or less similar regardless of the allocation method. Therefore, this factor has no implications for calculating the financial gap of CHP plants when shifting from free allocation to auctioning.
- The price of heat, however, depends on the allocation method (as explained in the previous sections). If the shift from free allocation to (full) auctioning refers also to new investments in boilers (at least by the year 2020), it implies that under auctioning the revenue from heat production in the support calculations for CHP is expected to increase similar to the auctioning induced increase in the cost/price of heat produced by a boiler. Therefore, this factor would compensate for the loss of benefits related to the free allocations forgone, although it will most likely cover this loss only partially.[70]

To conclude, a shift from free allocation to auctioning affects the financial gap - or lack of profitability - of CHP plants in the sense that it nullifies the benefits from the freely (over)allocated EUAs, which is only partially compensated by the expected, auctioning-induced increase in the price of heat (while all other costs and benefits of CHP operations - including the ETS induced increase in electricity prices - are expected to be similar regardless of the allocation method). Therefore, such a shift implies a significant net loss of profitability of operating CHP plants.

For the year 2008 the Dutch government has decided that no support is granted to CHP - including both existing and new installations - as the operations of most types of CHP plants are expected to be (nearly) profitable in 2008 (partly due to the EU ETS). Granting no support implies that in case of a loss of CHP profitability due to changes in the EU ETS - including a change in

[70] For example, assuming that the CHP installation operates with a thermal efficiency of 35%, it generates 0.35 GJth heat out of 1.00 GJ of natural gas. A boiler running at 90% efficiency would produce 0.35 GJth heat out of 0.39 GJ of natural gas. Therefore, the CHP owner should be able to recover the EUA costs associated with 0.39 GJ of natural gas, for each GJ of natural gas it transforms into electricity and heat. In other words, in case of moving from free allocation to auctioning the CHP owner should be able to recover some 40% of the costs of EUAs.

the allocation method - nothing of this loss will be compensated by higher state aid (up to the point where the ETS induced loss in CHP profitability results in a financial gap for CHP once again and in a decision to resume support to CHP).

Finally, as concluded above, a shift from free allocation to auctioning reduces the profitability of CHP. During the first and second phase of the EU ETS, however, CHP has benefited from emissions trading in general and its allocation method in particular through induced higher electricity prices and free (over)allocations of EUAs.[71] Therefore, one should compare the profitability of CHP not only under auctioning versus free allocation but also under auctioning versus the situation of no ETS (or before the ETS started to operate). As discussed, the net profit effect of emissions trading with auctioning - compared to no ET at all - is hard to determine for specific categories of (CHP) power installations as it depends on a large variety of factors, which may even vary over time, such as the carbon efficiency of these installations - compared to the marginal unit - the structure of the power market or the price responsiveness of power demand. In general, however, the competitiveness and/or profitability of CHP in the Netherlands should improve due to the EU ETS - even with auctioning - as it is more carbon efficient than most of its (price-setting) competitors.

[71] Moreover, due to the incidence of the specific free allocation provisions (or other reasons), the rate of passing through carbon costs to electricity prices may be higher under auctioning than free allocation. This implies that the loss of CHP profitability will be lower if one moves from free allocation to auctioning.

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Appendix A The COMPETES model

In order to analyse the performance of wholesale electricity markets in European countries, ECN has developed the so-called COMPETES model.[72] The present version of the model covers twenty European countries, i.e. Austria, Belgium, the Czech Republic, Denmark, Finland, France, Germany, Hungary, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, and the United Kingdom.

In the COMPETES model, the representation of the electricity network is aggregated into one node per country, except for Germany and Luxembourg, which are joined into one nod, while Denmark is divided into two nods belonging to two different, non-synchronised networks (i.e. Eastern versus Western Denmark, see Figure A.1). Virtually all individual power companies and generation units in the 20 countries including CHP plants owned by industries or energy suppliers - are covered by the input data of the model and assigned to one of these nodes. The user can specify which generation companies are assumed to behave strategically and which companies are assumed to behave competitively (i.e. the price takers). The latter subset of companies is assigned to a single entity per node indicated as the 'competitive fringe'.

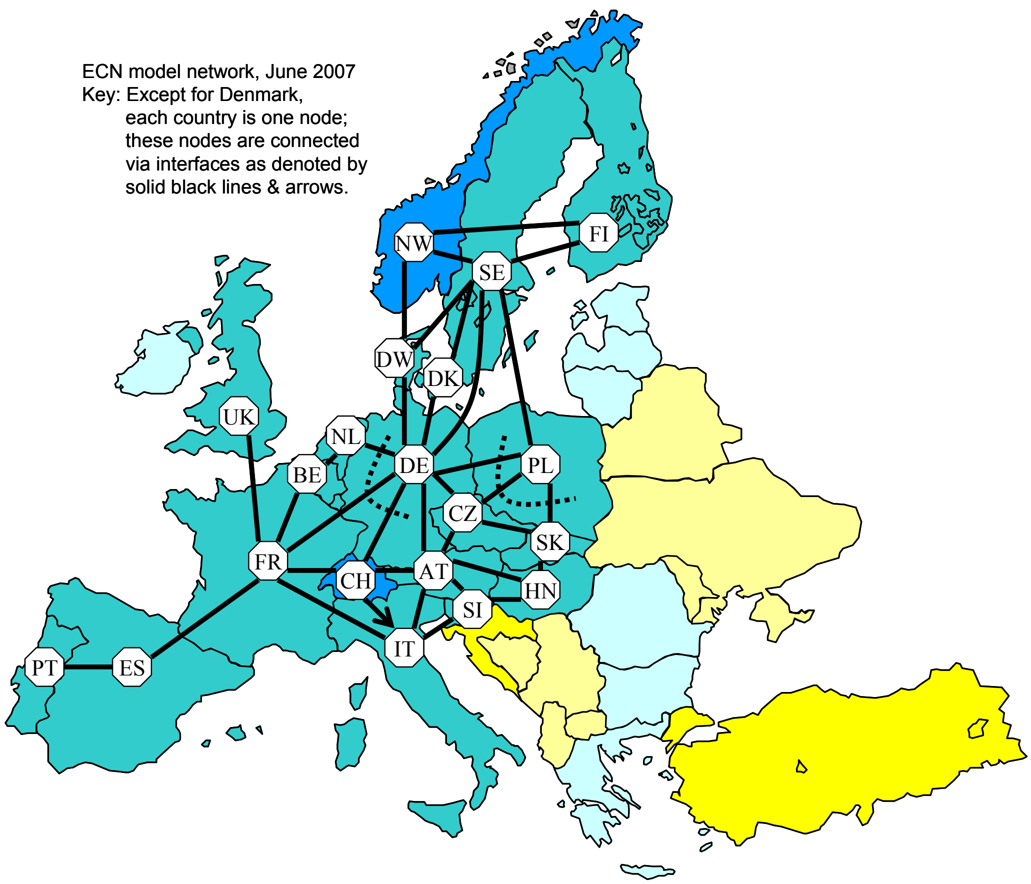

Figure A.1 *Physical and path-based representation of the electricity network in COMPETES*

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[72] COMPETES stands for COmprehensive Market Power in Electricity Transmission and Energy Simulator. This model has been developed by ECN in cooperation with Benjamin F. Hobbs, Professor in the Whiting School of Engineering of The Johns Hopkins University.

Producer behaviour

The COMPETES model is able to simulate the effects of differences in producer behaviour and wholesale market structures, including perfect versus oligopolistic competition. In addition, it is able to simulate the effects of electricity trade and transmission constraints between countries. Simulating oligopolistic (or strategic) behaviour of power producers is based on the theory of Cournot competition and so-called 'Conjectured Supply Functions' (CSF) on electric power networks.[73]

Strategic behaviour of generation companies is reflected in the conjectures each company holds regarding the supply response of rival companies. These response functions simulate each company's expectations concerning how rivals will change their electricity sales when power prices change in response to the company's actions. These expectations determine the perceived profitability of capacity withholding and other strategies.

Cournot's theory of oligopolistic competition represents one possible conjecture, i.e. rivals will not change their outputs. COMPETES can also simulate the other extreme: company's actions will not change the power price (i.e. price taking behaviour or perfect competition). CSFs can be used to represent conjectures between these two extremes. COMPETES can also represent different systems of transmission pricing, among them fixed transmission tariffs, congestion-based pricing of physical transmission, netting restrictions, and auction pricing of interface capacity between countries.

The model calculates the optimal behaviour of the generators by assuming that they simultaneously try to maximise their profits. Profits are determined as the income of power sales (market prices multiplied by total sales) minus the costs of generation and if sale is not at the node of generation transmission. Costs of generation are calculated by using the short-run marginal costs (i.e. fuel and other variable costs). Start-up costs and fixed operating costs are not taken into account since these costs have less effect on the bidding behaviour of suppliers on the wholesale market in the time horizon considered by the COMPETES model.

Power demand and consumer behaviour

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

Transmission system operator

The electricity network covering the 20 countries is represented by a direct current (DC) load flow approximation. This approximation is a linear system that accounts only for real power flows and is a simplification of the alternating current (AC) power flow model. However, the approximation ensures that both the current law and the voltage law of Kirchhoff are respected.

[73] The basic transmission-constrained Cournot formulation underlying COMPETES was first presented in Hobbs (2001), while the conjectured supply function generalization appeared first in Day et al. (2002). COMPETES itself, including alternative transmission pricing formulations, is presented and applied in Hobbs et al. (2004a and 2004b). COMPETES has been used to analyse issues such as effects of proposed mergers among power companies (Scheepers et al., 2003), market coupling (Hobbs et al., 2005), market power (Lise et al., 2008), electricity prices and power trade (Özdemir et al., 2008), and the EU Emissions Trading System (Chen et al., 2008; and Sijm et al. 2005 and 2008a).

Using these two laws, the flows within the electricity network can be uniquely identified using the net input of power at each node, i.e., where supply is subtracted from demand.[74] Besides the physical network, path-based constraints are defined using the net transmission capacities (NTC) between the 20 countries. In the current application, these NTCs are set equal to the capacities that are available for the trade on the interconnections between the countries.

In the model, generators or traders will buy network capacity when they want to transport power from one region to another. The total amount of transportation between two nodes can be limited due to physical transmission constraints (such as thermal or security limits) or due to the limited availability of interconnection capacity between countries due to regulation (see Figure A.1). It is assumed that there is no netting for any of the interconnections. In other words, a power flow from, for example, Belgium to the Netherlands will not increase the available interconnection capacity from the Netherlands to Belgium.

In addition to the bilateral interconnection capacities between two countries in the path-based representation of COMPETES, there are also two multilateral interconnection capacities, namely Germany versus France, the Netherlands and Switzerland; and Poland versus the Czech Republic, Germany and Slovakia. Hence, the total flow between Germany (Poland) and the three indicated countries is also restricted contractually. This is indicated in Figure A.1 with two dotted curvy lines. There is also an arrow running from Switzerland to Italy indicating that power is only possible in one direction.

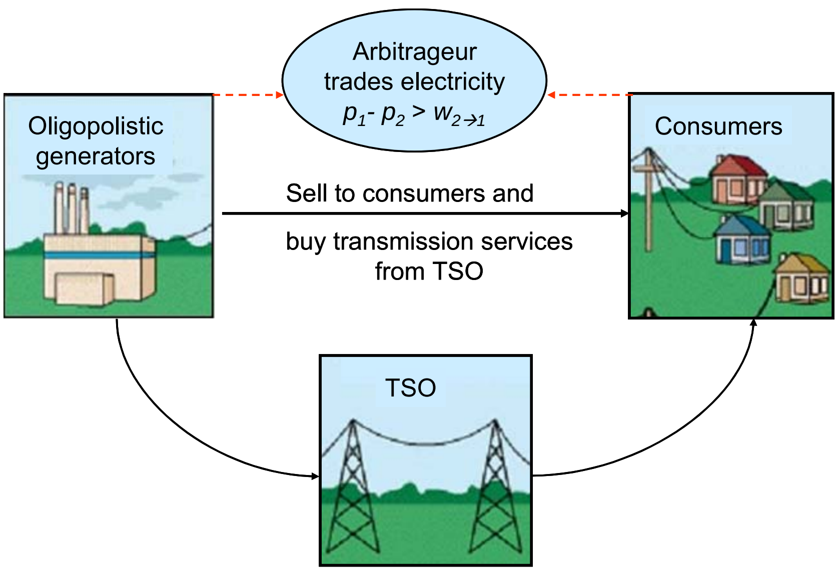

Figure A.2 *Model structure of COMPETES showing the relevant actors*

Traders' behaviour

Between countries and nodes it can be assumed that arbitrageurs are active (see Figure A.2). An arbitrageur (or trader) is assumed to maximise its profits by buying electricity at a low price node and selling it to a high price node as long as the price differences between these nodes is higher than the cost for transporting the power between these nodes. This is equivalent to a TSO running a 'market splitting' type of auction in which the TSO automatically moves power from low-price locations to high-price locations. The model scenarios do not allow for arbitrage that has not yet been realised, and full arbitrage indeed may not be realised because of many institutional barriers.

[74] The DC load flow representation is done through power transmission distribution factors (PTDFs), which are based on a detailed study of the UCTE region by Zhou and Bialek (2005).

Limitations and legitimacy of the model

- Power consumers are modelled as being price sensitive. In reality, in the short-term demand response is probably small. On longer time scales, however, elasticity will be substantially higher. The output of the model is a static equilibrium situation in which the optimal price, profit and production is calculated. This can be seen as a medium-term situation, which justifies a small price elasticity.
- COMPETES is a static model. This implies that it does not integrate new investments endogenously. Currently, the situation in the year 2006 is represented. The inputs are based on the situation in 2006, taking into account new power plants that will be taken into operation until 2006, the demand situation that prevails in 2006 and the available transmission capacity in 2006.
- In their bidding strategy, generators do not take into account the start-up costs of their power plants. Integrating start-up costs in the bidding curves would not have a large impact on the fuel mix (i.e. the choice between gas-fired versus coal-fired plants) because coal-fired plants are generally already more profitable to run during the base load hours as they have lower marginal costs. Some switching to gas-fired power plants may be possible after adding a substantial CO_2 tax to the marginal costs.
- Strategic behaviour of generators is modelled by using the Cournot assumption: All generators maximise their profits by choosing a certain level of production under the somewhat naive assumption that their competitors will not change the level of output. 'Naive' because when a generator changes its output and the market price increases as a result, competitors would have an incentive to anticipate and increase their outputs. The CSF theory is actually developed in order to reckon with this effect, so it is possible to model this in COMPETES.
- In reality the electricity wholesale market consists of a number of markets (day-ahead market, OTC market, balance market). The COMPETES model assumes an efficient arbitrage between these markets. A real market is characterised by several inefficiencies and irrational behaviour of participants, which is not covered by this model, based on efficient and rational behaviour. An important example of inefficiency in the real market is the time lag between the market clearing of the spot market and the daily auction of the interconnection capacity on the Dutch borders. The existing inefficiencies are, however, assumed to have a similar effect on the different scenarios that will be calculated. Therefore, it does not harm the comparisons of scenarios and variants.

Input data

The most relevant input data used for the model that influence the output data are:

- The fuel prices assumed for each country.
- The availability and efficiency per generation technology. Availability during peak seasons is limited by forced outage rates, while availability during off-peak seasons also accounts for maintenance outages.
- The demand load per season and period within each country.

The fuel prices and the generating unit characteristics are based upon a comparison among various data sources, namely IEA, Eurostat, etc. The generating units are taken from the WEPP database (UDI, 2004) and ownership relations are retrieved from the annual reports of the energy companies. The remaining capacities are assigned to price taking competitive fringes.

Technology mix of power generation

Figure A.3 presents the technology mix of power generation in 20 European countries under the COMPETES model reference scenario. It shows that there is a large variety in generation technologies. For instance, Norway is highly specialised in hydro, Poland in coal, France in nuclear and the Netherlands in gas.

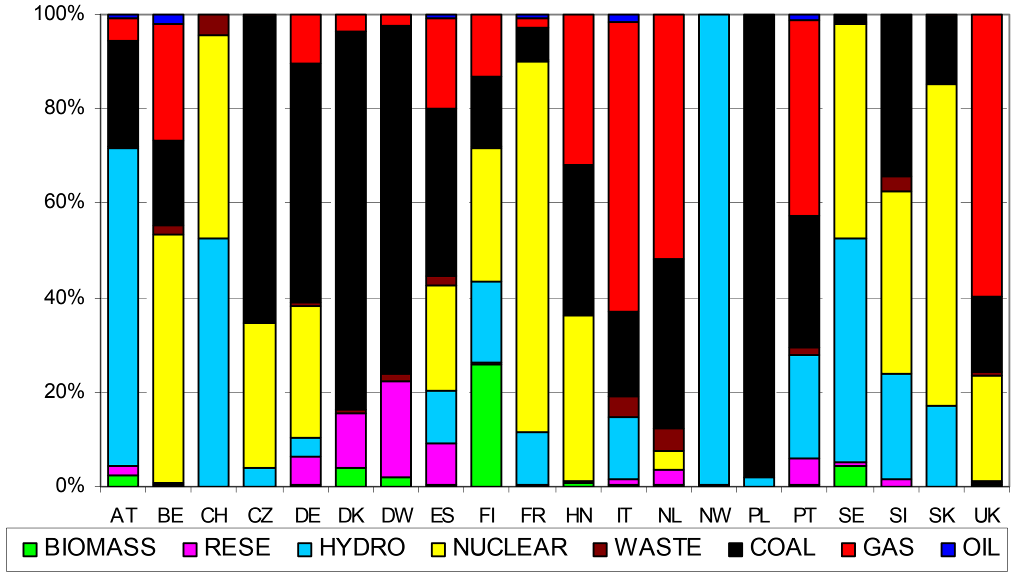

Figure A.3 *Technology mix of power generation in 20 European countries under the COMPETES model reference scenario*

In addition to the technology mix, it is also important to consider the level of market concentration, because this is an important determining factor in market power. Table A.1 shows the market shares of the firms that can exercise market power. In each market, the competitive fringe is represented by a single entity, aggregating the price-taking companies, and indicated with the prefix ‘‘Comp’’. Note that power markets in Poland, Slovenia and Switzerland are relatively competitive, as a result of the presence of large competitive fringes in those countries, representing 86% of generation capacity in Poland and 100% of generation capacity in Slovenia and Switzerland (see Table A.1).

To solve the model, it is assumed that the competitive fringes can only sell in the market where they are located. Large firms can sell in the market where they are located and all countries to which they are directly connected. For instance, EdF can sell in almost all countries, except Norway, Finland and Portugal. Table A.2 shows the assumptions concerning market access. Alternative assumptions could be made, such as all firms having access to all countries. In theory, the EU Directive allows for such freedom of trade, but due to not yet fully liberalised markets and regulatory rules, access may be limited.

Finally, active cross-border ownership is assumed so that a single firm owning generation plants in various countries optimises over its full portfolio. This assumption may somewhat overestimate the ability of firms to use market power, because due to a number of organisational and technical reasons, firms may, in practice, optimise their behaviour only within single markets.

Table A.1 *Generation capacity and market shares of power companies in EU countries*

		Total [MW]	Share [%]
Austria			
Comp_AT	AT	9844	57%
VERBUND-AUSTRIAN HYDRO POWER	AT	7418	43%
ESSENT ENERGIE PRODUCTIE BV	AT	28	0%
Belgium			
ELECTRABEL SA	BE	13083	85%
Comp_BE	BE	2215	14%
UNION ELECTRICA FENOSA SA	BE	51	0%
ESSENT ENERGIE PRODUCTIE BV	BE	19	0%
Switzerland			
Comp_CH	CH	8417	49%
GRANDE DIXENCE SA	CH	1998	12%
KERNKRAFTWERK LEIBSTADT AG	CH	1220	7%
AXPO HOLDING AG	CH	1025	6%
KKW GOESGEN DAENIKEN	CH	1020	6%
MAGGIA UND BLENIO KRAFTWERKE	CH	1004	6%
KRAFTWERKE OBERHASLI AG (KWO)	CH	976	6%
ENERGIE OUEST SUISSE (EOS)	CH	750	4%
KRAFTWERKE HINTERRHEIN AG	CH	640	4%
E.ON ENERGIE AG	CH	103	1%
ELECTRICITE DE FRANCE	CH	25	0%
ENBW	CH	21	0%
Czech Republic			
CEZ AS	CZ	12735	84%
Comp_CZ	CZ	2407	16%
ELECTRICITE DE FRANCE	CZ	48	0%
RWE POWER	CZ	17	0%
Germany			
Comp_DE	DE	36279	30%
E.ON ENERGIE AG	DE	28030	23%
RWE POWER	DE	27384	23%
VATTENFALL AB	DE	17034	14%
ENBW	DE	10192	8%
ELECTRICITE DE FRANCE	DE	1035	1%
ESSENT ENERGIE PRODUCTIE BV	DE	695	1%
ELECTRABEL SA	DE	422	0%
NUON NV	DE	57	0%
Denmark East			
ENERGI E2 A/S	DK	3905	91%
Comp_DK	DK	398	9%
Denmark West			
ELSAM A/S	DW	4266	75%
Comp_DW	DW	1439	25%
Spain			
Comp_ES	ES	24984	38%
ENDESA GENERACION	ES	17967	27%
IBERDROLA SA	ES	16268	25%
UNION ELECTRICA FENOSA SA	ES	4865	7%
ENBW	ES	847	1%
RWE POWER	ES	423	1%
ENEL SPA	ES	129	0%
CIA PORTUGESA PRODUCAO ELEC	ES	124	0%
Finland			
Comp_FI	FI	10706	72%
FORTUM POWER & HEAT	FI	4069	27%
E.ON ENERGIE AG	FI	165	1%
France			
ELECTRICITE DE FRANCE	FR	92628	83%
Comp_FR	FR	13820	12%
ELECTRABEL SA	FR	4828	4%
ENBW	FR	49	0%
RWE POWER	FR	26	0%
Hungary			
Comp_HN	HN	3383	38%
ELECTRABEL SA	HN	2154	24%
PAKSI ATOMEROMU RT	HN	1866	21%
RWE POWER	HN	655	7%
ELECTRICITE DE FRANCE	HN	428	5%
ENBW	HN	240	3%
E.ON ENERGIE AG	HN	95	1%
Italy			
ENEL SPA	IT	43577	50%
Comp_IT	IT	25686	30%
EDISON SPA	IT	8871	10%
ENDESA GENERACION	IT	6907	8%
ELECTRABEL SA	IT	1615	2%
RWE POWER	IT	15	0%
Netherlands			
ELECTRABEL SA	NL	4917	24%
Comp_NL	NL	4893	24%
ESSENT ENERGIE PRODUCTIE BV	NL	4696	23%
NUON NV	NL	4110	20%
E.ON ENERGIE AG	NL	1889	9%
Norway			
Comp_NW	NW	19028	67%
STATKRAFT SF	NW	9403	33%
ELSAM A/S	NW	124	0%
Poland			
Comp_PL	PL	30937	86%
ELECTRICITE DE FRANCE	PL	2557	7%
ELECTRABEL SA	PL	1800	5%
VATTENFALL AB	PL	615	2%
Portugal			
CIA PORTUGESA PRODUCAO ELEC	PT	7794	60%
Comp_PT (Portugal)	PT	4250	33%
RWE POWER	PT	1017	8%
Sweden			
Comp_SE	SE	12959	42%
VATTENFALL AB	SE	12906	42%
FORTUM POWER & HEAT	SE	2556	8%
E.ON ENERGIE AG	SE	2224	7%
Slovania			
Comp_SI	SI	1576	52%
TERMOELEKTRARNA SOSTANJ PO	SI	745	25%
NUKLEARNA ELEKTRARNA KRSKO	SI	707	23%
Slovakia			
SLOVENSKE ELEKTRARNE AS (SE)	SK	3531	47%
ELECTRICITE DE FRANCE	SK	3422	46%
Comp_SK	SK	481	6%
E.ON ENERGIE AG	SK	76	1%
United Kingdom			
Comp_UK	UK	44539	54%
BRITISH ENERGY PLC	UK	15804	19%
E.ON ENERGIE AG	UK	8462	10%
RWE POWER	UK	8163	10%
ELECTRICITE DE FRANCE	UK	4764	6%
ELECTRABEL SA	UK	248	0%

Table A.2 *Large firms included in the COMPETES model and countries where they can sell electricity*

	AT	BE	CH	CZ	DE	DK	DW	ES	FI	FR	HN	IT	NL	NW	PL	PT	SE	SI	SK	UK
AXPO HOLDING AG	√		√		√					√		√								
BRITISH ENERGY PLC										√										√
CEZ AS	√			√	√										√				√	
CIA PORTUGESA PRODUCAO ELEC								√		√						√				
E.ON ENERGIE AG	√	√	√	√	√	√	√		√	√	√	√	√	√	√		√	√	√	√
EDISON SPA	√									√		√						√		
ELECTRABEL SA	√	√	√	√	√	√	√	√		√	√	√	√		√		√	√	√	√
ELECTRICITE DE FRANCE	√	√	√	√	√	√	√	√		√	√	√	√		√		√	√	√	√
ELSAM A/S					√		√		√					√			√			
ENDESA GENERACION	√							√		√		√				√		√		
ENEL SPA	√							√		√		√				√		√		
ENERGI E2 A/S					√	√											√			
ENERGIE BADEN-WURTTEMBERG ENBW	√	√	√	√	√	√	√	√		√	√	√	√		√	√	√	√	√	√
ENERGIE OUEST SUISSE (EOS)	√		√		√					√		√								
ESSENT ENERGIE PRODUCTIE BV	√	√	√	√	√	√	√			√	√	√	√		√		√	√		
FORTUM POWER & HEAT					√	√	√		√					√	√		√			
GRANDE DIXENCE SA	√		√		√					√		√								
IBERDROLA SA								√		√						√				
KERNKRAFTWERK LEIBSTADT AG	√		√		√					√		√								
KKW GOESGEN DAENIKEN	√		√		√					√		√								
KRAFTWERKE HINTERRHEIN AG	√		√		√					√		√								
KRAFTWERKE OBERHASLI AG (KWO)	√		√		√					√		√								
MAGGIA UND BLENIO KRAFTWERKE	√		√		√					√		√								
NUKLEARNA ELEKTRARNA KRSKO	√										√	√						√		
NUON NV	√	√	√	√	√	√	√			√			√		√		√			
PAKSI ATOMEROMU RT	√										√							√	√	
RWE POWER	√	√	√	√	√	√	√	√		√	√	√	√		√	√	√	√	√	√
SLOVENSKE ELEKTRARNE AS (SE)				√							√				√				√	
STATKRAFT SF							√		√					√			√			
TERMOELEKTRARNA SOSTANJ PO	√										√	√						√		
UNION ELECTRICA FENOSA SA		√						√		√			√			√				
VATTENFALL AB	√		√	√	√	√	√		√	√			√	√	√		√		√	
VERBUND-AUSTRIAN HYDRO POWER	√		√	√	√						√	√						√		