CO_2 price dynamics:

The implications of EU emissions trading for the price of electricity

J.P.M. Sijm

S.J.A. Bakker

Y. Chen*

H.W. Harmsen

W. Lise

*** The Johns Hopkins University (Baltimore)**

ECN-C--05-081 September 2005

Acknowledgement/Preface

The present study has been financed by the Ministry of Economic Affairs in the Netherlands as part of its annual support to the Energy research Centre of the Netherlands (ECN). Although the study has benefited from comments by a Steering Committee of the Ministry, the responsibility for the contents of the report lies fully at ECN.

Prof. B.F. Hobbs of the Johns Hopkins University (Baltimore) contributed significantly to this report, notably to the discussion on the relationship between grandfathering emission allowances and power prices, including modelling analyses to explore this relationship. His stimulating ideas and enthusiasm for the project are highly appreciated. In addition, Prof. Hobbs has given support to one of his Ph.D.-students, Yihsu Chen, who joined the team while he was staying at ECN Amsterdam. Besides valuable contributions to the theoretical parts of the project, Yihsu has put great value to the project by means of his participation in the COMPETES modelling work as well as to the empirical and statistical analyses.

The project team would also like to thank the staff members of power companies and industrial electricity users who have been interviewed as part of the present study. Some of them have in addition been very helpful in answering specific questions by mail or phone, providing information, or by commenting on specific parts of this report.

This project is registered at ECN under number 7.7651. For information on the project you can contact Jos Sijm by email (sijm@ecn.nl) or by telephone (+31 224 568255).

Abstract

The present study analyses the relationship between EU emissions trading and power prices, notably the implications of free allocation of emissions allowances for the price of electricity in countries of North-western Europe. To study this impact, it uses a variety of analytical approaches, including interviews with stakeholders, empirical and statistical analyses, theoretical explorations, and analyses by means of the COMPETES model. The study shows that a significant part of the costs of freely allocated allowances is passed through to power prices and discusses its implications in terms of higher electricity prices for consumers and windfall profits for producers. It concludes that free allocation of emission allowances is a highly questionable policy option for a variety of reasons and suggests that auctioning might offer a better perspective.

29 September 2005

Contents

List of tables

List of figures

Summary

Since January 2005, the EU Emissions Trading Scheme (EU ETS) has been in force. A major point of controversy and political sensitivity concerns the potential impact of free allocation of emissions allowances on the price of electricity and the resulting implications for power producers, consumers and policy makers as illustrated by ongoing discussions throughout the EU in professional journals, popular media and political arenas. In addition, in 2006, Member States and the European Commission have to decide on this allocation of emission allowances for the second trading period (2008-12), including the option to auction a part of these allowances. Overall, some 10 billion emission allowances of 1 tonne CO_2 each will be allocated for this period. At current prices, this represents a social value of more than 200 billion Euros, about half of which will be allocated to the power sector.

Against this background, the key objectives of the present study include:
- To present a structured overview and qualitative analysis of the underlying, major factors determining the impact of EU emissions trading on the price of electricity.
- To assess the extent of passing through CO_2 costs of freely allocated emission allowances to power prices in Germany and the Netherlands by means of empirical and statistical analyses.
- To provide a quantitative analysis of the potential implications of the EU ETS for power prices in the countries of continental North-Western Europe (Belgium, France, Germany and the Netherlands) by means of the so-called COMPETES model.
- To indicate the socio-economic implications of passing through carbon costs of emissions trading to the price of electricity for major power producers and consumers, including options and strategies for policy makers to address potential adverse implications.

In order to achieve these objectives, the present study has followed a broad approach, including four analytical methodologies:
- Interviews with stakeholders in the power sector of the Netherlands, including major power producers and large industrial consumers of electricity.
- Empirical and statistical analyses of trends in prices of fuels, CO_2 and electricity in Germany and the Netherlands over the period January-July 2005.
- Analyses by means of the COMPETES model of the implications of emissions trading on power prices, generators' profits and other issues related to the wholesale power market in four countries of continental North-Western Europe (Belgium, France, Germany and the Netherlands).
- A survey of the theoretical and empirical literature, notably on the determinants of the impact of emissions trading on the price of electricity.

The major results of these analytical approaches and their policy implications are discussed below.

Interviews with stakeholders
Overall, ten interviews were held in June-July 2005 with staff members of major power producers and large industrial consumers of electricity in the Netherlands. Some interesting findings of these interviews are:
- Power companies try to maximise their profits by optimising their production and trading decisions. In that respect, costs of freely allocated CO_2 allowances are regarded as opportunity costs, which are included when power companies make their production and trading decisions.

- Power producers are not able to simply set power prices or simply pass through costs to these prices as they are primarily determined by a complex set of wholesale market forces. In general, it is hard to assess the impact of CO_2 allowances costs on power prices as these prices are determined by a large variety of factors, including fuel prices, the Euro/US$ exchange rate, available production capacity, investment costs, imports, weather conditions, heat demand ('must runs'), gas contract inflexibilities, expectations and sentiments of market players, etc. Moreover, the extent to which CO_2 costs are passed through to power prices varies by market, load factor and country considered.
- Major industrial power consumers in the Netherlands estimate that in June 2005 the forward prices of coal-generated electricity during the off-peak/base-load hours have increased by approximately 7-9 €/MWh due to the partly passing through - i.e. about 65 percent - of CO_2 allowances costs.
- The impact of higher power prices is very significant for power-intensive industries, especially for the aluminium and iron & steel industries. The options to avoid or mitigate the impact of higher power prices for these industries are limited.

Empirical and statistical analyses

Trends in prices of electricity, fuels and CO_2 emission allowances have been analysed for Germany and the Netherlands over the period January-July 2005. Based on these trends, rates of passing through CO_2 costs in power prices have been analysed for four cases (see Table S.1). They have been selected as they are regarded as the most representative cases for the load period and countries considered. Three methods have been used to estimate the rates of passing through CO_2 costs in power prices. These include two statistical regression approaches, called the Ordinary Least Squares (OLS) method and the more sophisticated Prais-Winston (PW) method, as well as a simple regression-line approach developed by ECN. The major results of these estimation methods are summarised in the table below.

Table S.1 *Comparison of estimated pass-through rates in Germany and the Netherlands over the period January-July 2005*

Country	Period	Fuel (efficiency)	OLS[a]	PW[a]	ECN	
			[%]	[%]	[%]	[€/MWh]
Germany	Peak load	Coal (40%)	72	69	73	9.5
	Off-peak	Coal (40%)	42	42	46	5.9
NL	Peak load	Gas (42%)	40	44	39	2.8
	Off-peak	Coal (40%)	53	47	55	7.2

[a] All regression estimates are statistically significant at the 1% level.

The major findings of the empirical and statistical estimates of the pass-through rates in Germany and the Netherlands include:

- Given the (autoregressive) character of the power price data, the Prais-Winston method provides most likely better estimates of the pass-through rates than the OLS approach. For the Netherlands, the PW estimates vary between 44 and 47 percent and for Germany between 42 and 69 percent.
- By means of a simple regression-line method ECN has estimated pass-through rates varying from 46 to 73 percent for Germany and from 39 to 55 percent for the Netherlands.
- In addition, ECN has estimated the absolute amounts of CO_2 costs passed through to power prices, based on an average price on the EU ETS market of 15.3 €/MWh over the period January-July 2005. For Germany, these amounts vary from 5.9 €/MWh during the off-peak period to 9.5 €/MWh during the peak load hours (both coal-based cases). For the Netherlands, these amounts vary from 2.8 €/MWh during the peak load period (gas-based case) to 7.2 €/MWh during the off-peak hours (coal-based case). The amount for the gas-based case in the Netherlands is relatively low because the carbon intensity of gas-generated power is

much lower (about half) than coal-generated power, while the passing-through rate for gas is relatively low (probably because the gas prices have been very volatile and rapidly rising during the period considered, while coal prices have been rather stable). Moreover, the passing through rate for gas during the peak hours in the Netherlands is likely underestimated due to the underlying assumptions used.

It should be emphasised, however, that these rates and amounts of passing through CO_2 costs do not necessarily apply to all installations during all load periods considered. On the contrary, notably in the Netherlands there is a major share of gas installations that must run during off-peak hours, even if it is not profitable, as seems to be the case under forward 2006 price conditions. Under these conditions, such price-following installations are not able to cover the opportunity costs of grandfathered allowances, let alone to realise 'windfall profits' due to emissions trading. On the other hand, it should be recognised that - besides potential revenues from heat production - these installations may earn significant profits during peak load hours (when prices are relatively high) and that without emissions trading power prices might have been lower during the off-peak hours given the average pass-through rates and the average high CO_2 prices considered.

COMPETES model findings
COMPETES is basically a model to simulate and analyse the impact of strategic behaviour of large producers on the wholesale market under different market structure scenarios (varying from perfect competition to oligopolistic and monopolistic market conditions). As part of the present study, it has been used to analyse the implications of emissions trading for power prices, firm profits and other issues related to the wholesale power market in four countries of continental North-western Europe (i.e. Belgium, France, Germany and the Netherlands).

The major findings of the COMPETES model analyses include:
- Power prices increase significantly due to CO_2 emissions trading under all scenarios considered. In case of a CO_2 price of 20 €/tonne, these increases are generally highest in Germany (13-19 €/MWh) and lowest in France (1-5 €/MWh), with an intermediate position for Belgium (2-14 €/MWh) and the Netherlands (9-11 €/MWh). For these EU4 countries, on average, the increase in power prices is estimated at 6-12 €/MWh, i.e. an increase of about 13-39 percent compared to the power prices before emissions trading.
- Estimates of the pass-through rates are generally high. Most of these rates vary between 60 and 80 percent, depending on the country, market structure, demand elasticity and CO_2 price considered.
- Emissions trading in general and the free allocation of emission allowances have a major impact on business profits of major power companies. Even if it is assumed that these companies have to buy all their CO_2 emission allowances on the market, profits increase significantly under most scenarios (mainly due to the fact that carbon-extensive generators benefit from higher power prices set by carbon-intensive generators). However, power companies receive most of their emission allowances free of charge while part of the opportunity costs of these allowances are passed through into higher power prices, leading to so-called 'windfall profits'. As a result, total business profits increase by some 6-98 percent, depending on the scenario and CO_2 price considered. These figures, however, have to be treated with due care as they refer to model scenario analyses rather than facts of life.

Determinants of the impact of emissions trading on power prices
The impact of EU emissions trading on the price of electricity is determined by three major factors:
- the price of carbon in the EU ETS market,
- the carbon intensity of power production,
- the level of passing through carbon costs.

With regard to the third factor, the so-called ‘pass-through rate’, a distinction should be made between the extent to which producers add on the opportunity costs of CO_2 emission allowances to their other, marginal costs when making production or trading decisions (‘add-on rate’) and the extent to which CO_2 allowances costs ultimately work on power prices that are determined by a complex set of market forces (‘work-on rate’). Even if the add-on rate is 100 percent, the work-on rate may be (far) less than 100 percent due to a variety of reasons. In general, these reasons include:

- A change in the merit order of the power supply curve due to rising CO_2 costs.
- A change in power demand due to higher ETS-induced power prices.
- The incidence of market power by monopolistic or oligopolistic generators.
- A decline in the gross margin to cover fixed investment costs and/or a decline in oligopolistic mark-ups due to the free allocation of emission allowances.
- A restriction in ETS-induced power price increases by means of regulation or voluntary agreement.
- The incidence of outside competition, for instance by non-fossil generators.
- The development and adoption of carbon-saving technologies induced by changes in carbon prices.
- Other reasons or factors such as the updating of National Allocation Plans or the incidence of non-optimal behaviour among power producers, market imperfections, time lags or other constraints, including (i) the incidence of risks, uncertainties, lack of information, and the immaturity or lack of transparency of the carbon market (ii) the incidence of rapidly rising CO_2/fuel (i.e. gas) prices, and (iii) the incidence of other production constraints, such as a lack of a flexible and liquid gas market.

Policy implications

The EU ETS is a cap and trade system based primarily on a free allocation of a fixed amount of emission allowances, often denoted as *grandfathering.* If applied equally to existing and new fossil-fuel installations, however, such an allocation system may have two opposite effects on power prices with significant different implications for power producers, consumers and policy makers:

- A price increasing effect due to the passing through of the opportunity costs of grandfathering.
- A price compensating or neutralising effect of grandfathering due to its subsidisation of fixed investment costs.

The first grandfathering effect implies that profit maximising producers pass through (‘add-on’) the opportunity costs of CO_2 emission allowances to their other (short-term) marginal costs when taking production or trading decisions. If this would be the only effect of grandfathering, this would mean that these costs would be passed-through (‘work-on’) to power prices. As a result costs of CO_2 emissions would be internalised by higher power prices, leading to a more efficient or more optimal situation from a social welfare point of view, including less CO_2 emissions due to (i) less power sales, if power demand is price elastic, and/or (ii) a change in the merit order, if the costs are high enough to effectuate such a change.

In addition, however, passing through of opportunity costs of grandfathering would imply higher power prices for all consumers, including households, small firms, power-intensive industries and other major electricity users. If power-intensive industries are hardly able to pass through the higher costs into their outlet prices - due to outside competition or high elastic demand response - it would imply that these industries are faced by less profits, less production, less employment and a shift in investment, production and trade opportunities to locations outside the EU ETS (including ‘carbon leakage’). Finally, a free allocation of emission allowances implies a transfer of wealth from consumers to producers (called ‘economic rent’ or ‘windfall profits’).

On the other hand, the second grandfathering effect implies a lump-sum subsidy to an installation that lowers the fixed investment costs of power generation, which - under certain conditions - results in a neutralisation of the increase in power prices due to the passing through of the opportunity costs of CO_2 emission allowances. If fully effective, it would mean that power prices, on balance, would not change and, hence, that certain potential adverse effects of higher power prices would not occur. However, it would also imply that external costs of CO_2 emissions would not be internalised through higher prices, leading to a less efficient situation from a social welfare point of view. This means that total CO_2 emissions by the power sector are not significantly decreased through lower demand or by large changes in the generation mix since neither output prices nor the total average costs of generation technologies would change significantly. As a result, emission reductions elsewhere have to be increased to meet overall environmental targets.

In fact, if grandfathering is applied equally to existing and new investments it leads, on the one hand, to an internalisation of external CO_2 emission costs due to the passing through of these costs into higher power prices, on the other hand, this effect may be nullified by the implicit lump-sum subsidy to fixed investment costs due to grandfathering, with the subsidy being higher if the investment is more carbon-intensive. Hence, the impact of grandfathering on emissions reduction may be small, while it encourages investments in carbon intensive generation capacity. Such a contradictory - or even perverse approach may be questioned from a consistent and cost-effective environmental policy point of view.

The impact of the second effect of grandfathering will only be effective up to a certain CO_2 price level and in a (long-term equilibrium) situation in which generation capacity is scarce and actually enlarged by investment in new capacity. However, regardless whether and to which extent the first effect of grandfathering will be fully or partially neutralised by the second effect, there will always be a trade-off between these effects with regard to their implications for power producers, consumers and society at large. Either the second effect will not or only partly neutralise the first effect, meaning that - on balance - power prices will increase, leading to beneficial implications on the one side (less CO_2 emissions by the power sector) and to adverse implications on the other (higher costs to power-intensive industries and other consumers; windfall profits to generators). Or the second effect will fully neutralise the first effect, meaning that - on balance - power prices will not increase, thereby avoiding not only the adverse implications of higher power prices but also the beneficial implications mentioned above.

In order to address the adverse implications of grandfathering, the present study discusses a wide variety of power options and strategies. These options and strategies include:

- indirect allocation of emission allowances
- auctioning
- regulation
- benchmarking with ex-post allocation adjustments
- limiting the price level of a CO_2 emission allowance
- encouraging competition in the power sector
- abolishing grandfathering to new investments
- taxation
- state aid
- other long-term options such as broadening the climate coalition or encouraging carbon-saving technologies in the power sector
- strategies at the level of power consuming industries such as energy saving, stringent power contract negotiations, or self-generation of electricity.

However, there seems to be no ideal option or package of options to address these implications as each option has its specific pros and contras. Overall, auctioning seems to be a better option than grandfathering or an ex-post benchmarking system. While auctioning would raise power prices by the costs of the CO_2 allowances, it would have several beneficial effects, including (i) avoiding windfall profits among producers, (ii) enhancing environmental-economic efficiencies by internalising the external costs of CO_2 emissions into the power price, (iii) raising public revenues that could be used to mitigate potential drawbacks of rising power prices, and (iv) treating incumbents and newcomers equally while avoiding potential distortions of new investment decisions.

In the end, however, allocation of economic rents is a political issue belonging to the world of policy makers.

1. Introduction

1.1 Background and objectives

Since January 2005, the EU Emissions Trading Scheme (EU ETS) has been in force. A major point of controversy and political sensitivity concerns the potential impact of free allocation of emissions allowances on the price of electricity and the resulting implications for power producers, consumers and policy makers as illustrated by ongoing discussions throughout the EU in professional journals, popular media and political arenas. In addition, in 2006, Member States and the European Commission have to decide on this allocation of emission allowances for the second trading period (2008-12), including the option to auction a part of these allowances. Overall, some 10 billion emission allowances of 1 tonne CO_2 each will be allocated for this period. At current prices, this represents a social value of more than 200 billion Euros, about half of which will be allocated to the power sector.

Against this background, the key objectives of the present report can be stated as follows:

- To present a structured overview and qualitative analysis of the underlying, major factors determining the impact of emissions trading on the price of electricity in EU countries.
- To assess the extent of passing through CO_2 costs of freely allocated emission allowances to power prices in Germany and the Netherlands by means of empirical and statistical analyses.
- To provide a quantitative analysis of the potential implications of the EU ETS for power prices in the countries of North-Western Europe (Belgium, France, Germany and the Netherlands) by means of the so-called COMPETES model.
- To indicate the socio-economic implications of passing through carbon costs of emissions trading to the price of electricity for major power producers and consumers, including options for policy makers to address potential adverse implications.

1.2 Major determinants of the impact of the EU ETS on power prices

Basically, the impact of EU emissions trading on the price of electricity is determined by three major factors:

- the price of carbon in the EU ETS market,
- the carbon intensity of power production,
- the level of passing through carbon costs.

Or, to put it in a formula:

$$\Delta P_e = C * I * L$$

where

ΔP_e	=	the change in the price of electricity (expressed in €/MWh),
C	=	the price of carbon in the EU ETS market (in €/tCO_2),
I	=	the carbon intensity of power production (in tCO_2/MWh),
L	=	the level of passing through carbon cost (in %).

For instance, if C is equal to € 10/tCO_2, I is equal to 0.8 tCO_2/MWh, and L to 50 percent, than the change in the price of electricity (ΔP_e) due to the EU ETS can be calculated as follows:

$$€\ 4/MWh = €\ 10/tCO_2 * 0.8\ tCO_2/MWh * 0.5$$

However, whereas the price of carbon is more or less the same throughout the EU ETS, the other two determinants of the price impact of emissions trading are likely to vary widely among the countries of the EU ETS, depending on differences in the major characteristics of the power sector of these countries, notably differences in the structure of their power markets and the mix of their power generating technologies. Moreover, the role of the three determinants (including the carbon price) in affecting the price of electricity will most likely change over time as these determinants depend in turn on other, underlying factors which may change over time. The present report will analyse these factors and national characteristics of the power sector in order to account for differences in the impact of emissions trading on the price of electricity in EU countries and for changes in this impact over time.

1.3 Report structure

The structure of the present report runs as follows:

- Chapters 2 to 4 analyse the three major determinants of the impact of emissions trading on the price of electricity (including the underlying factors accounting for differences in this impact over time and among EU countries): the price of carbon in the EU ETS market (Chapter 2), the carbon intensity of power production (Chapter 3), and the level of passing through carbon costs (Chapter 4).
- Chapter 5 presents the major findings of interviews with stakeholders in the electricity sector of the Netherlands (i.e. major power producers and large-scale electricity consumers) regarding their perception on the implications of the EU ETS for the price of electricity.
- Chapter 6 discusses the major results of some empirical and statistical analyses of trends in power prices and costs (including fuel and CO_2 costs), as well as estimated rates of passing through CO_2 costs into power prices in Germany and the Netherlands for the period January-July 2005.
- Chapter 7 presents the major results of the COMPETES model analyses with regard to the implications of EU emissions trading for power prices (and other, related variables) in four countries of North-Western Europe: Belgium, France, Germany and the Netherlands.
- Finally, Chapter 8 discusses the socio-economic implications of allocating CO_2 allowances for free and passing through the costs of these allowances to the price of electricity for power producers and consumers, including options for policy makers to address potential adverse implications.

2. The price of carbon in the EU ETS market

This chapter deals with the first factor in the equation determining the impact of the EU ETS on electricity prices: the price of CO_2. Firstly, Section 2.1 provides a brief overview of the main features of the EU ETS. Subsequently, Section 2.2 discusses the major determining factors of the carbon price in the EU ETS. Finally, Section 2.3 presents some price projections for CO_2 emission allowances in the EU ETS published in the literature concerned.

2.1 The EU Emissions Trading Scheme

The EU ETS is a corner stone of the European Climate Change Programme aimed at achieving the Kyoto target of the EU (i.e. reducing aggregate greenhouse gas emission by 8% in 2008-2012 compared to 1990). Till date, it is the largest emissions trading scheme in the world, covering over 12,000 installations in the EU-25.

Main features

The EU ETS is a so-called *cap and trade system* in which a fixed amount of CO_2 emission allowances is allocated among a set of participating installations that can use or trade these allowances in order to cover their emissions. As stated in Annex III of the Directive 2003/87/CE, all combustion installations with a rated thermal input exceeding 20 MW (except hazardous or municipal waste installations) fall under the directive of the EU ETS (CEC, 2003a). This means that basically all major power and heat generators are covered by the scheme. In addition, the EU ETS covers all oil refineries, coke ovens and installations that meet a certain output threshold level in specific industries (cement clinkers, ferrous metals, pulp and paper, glass and ceramics).

The interaction of the EU ETS with the Kyoto Mechanisms, notably JI and CDM, is laid down in the so-called *Linking Directive* (European Commission, 2004). According to this Directive, installations covered by the EU ETS may convert credits from JI and CDM projects into EU Allowances (EUAs) in order to fulfil their obligations under the EU ETS. Credits from CDM projects, called Certified Emission Reductions (CERs), can already be converted into EUAs during the first trading period of the EU ETS (2005-07), while credits from JI projects, called Emission Reduction Units (ERUs), can only be transferred into the EU ETS starting from its second trading period (2008-12). The Linking Directive leaves it up to Member States to set a maximum for this transfer of credits.

At the start of the ETS, there are no links with other emissions trading systems. The Directive explicitly specifies, however, that such a link is a possibility in future trading periods. Several countries have expressed their possible interest in linking their (intended) trading systems to the EU ETS: Canada, Norway, Switzerland and Japan.

Allocation of allowances

The process of allocating allowances to installations by each Member State has been one of political gaming between companies, national governments and the European Commission. The total CO_2 emission budget in the National Allocation Plans is based for most countries on a matching of, on the one hand, a bottom-up analysis of emission projections for the covered installations and, on the other hand, a top-down analysis regarding a country's commitment to meet its Kyoto target and a sharing of this commitment between covered and non-covered activities. In most countries, a correction factor has been applied to the bottom-up projections in order to align them with the top-down sectoral targets and, hence, with the overall Kyoto commitments.

Recent market developments
The EU ETS market is picking up quickly since 2004. In this year, approximately 8 million tonnes of CO_2 was traded (Point Carbon, 2004). In 2005, 1 million tonnes of CO_2 traded per day is no exception. Most transactions thus far refer to so-called forward trades delivered by the end of each year during the first trading period (i.e. December 2005, 2006 or 2007). Incidentally, forward trades for the second ETS period occur. In addition, spot trading in CO_2 emission allowances takes place on exchanges such as Nordpool, the European Energy Exchange (EEX) or the European Climate Exchange (ECX). Besides the brokers and traders, the major players on the market are currently the power producers from various countries, notably Germany, UK, Spain and the Netherlands.

Figure 2.1 presents the trend in CO_2 forward 2005 prices on the EU ETS market between mid 2003 and mid 2005. It can be noticed that CO_2 prices have been quite volatile over this period, with a strong increase in CO_2 prices during the period February-July 2005, followed by a significant decline and, subsequently, a stabilisation up to mid September 2005. The major determinants of this development in CO_2 prices on the EUA market will be discussed in the next section.

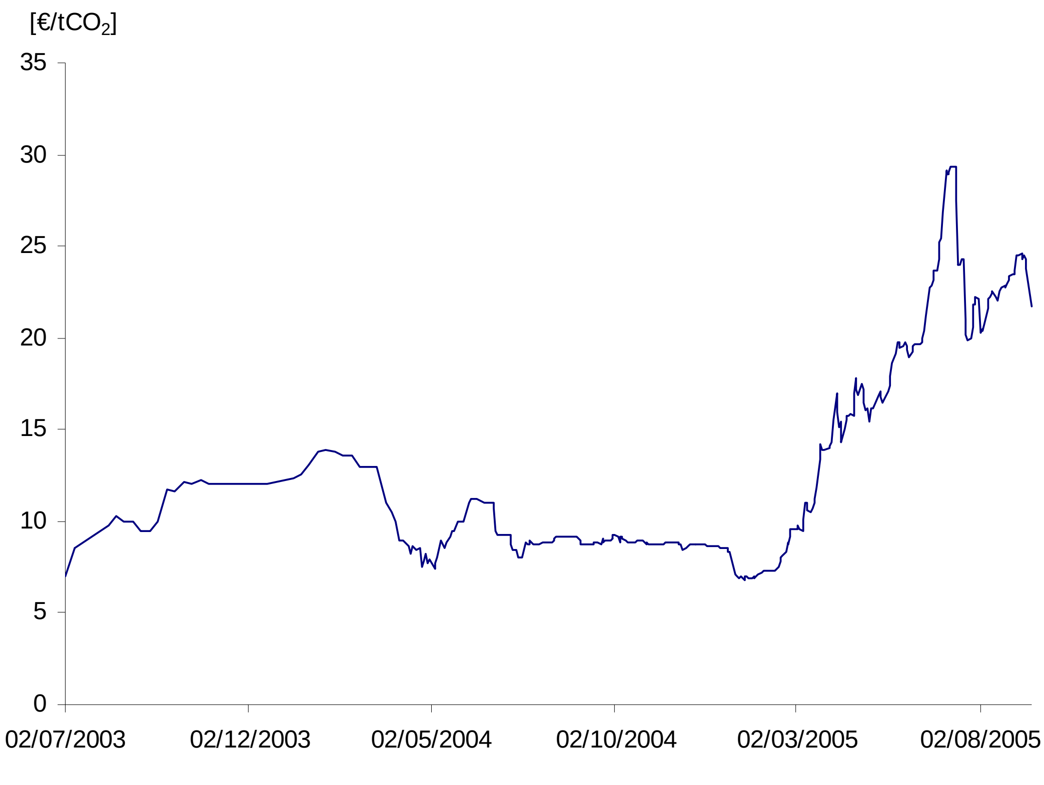

Figure 2.1 *Forward CO_2 prices on the EUA market (Calender 2005)*

2.2 CO_2 price determinants

Determinants of the CO_2 price on the EUA market can be distinguished by three categories:
- supply factors
- demand factors
- factors related to market structure, regulation and intervention.

These factors will be considered in the sections below.

2.2.1 Supply factors

The supply of CO_2 emission allowances during the first trading period of the EU ETS is basically determined by four factors:

- allocation of EU allowances (EUAs),
- supply and conversion of CDM credits (CERs) into EUAs,
- possibility of borrowing EUAs,
- possibility of banking EUAs.

Allocation of EU allowances (EUAs)

The total amount of EUAs is laid down in the National Allocation Plans (NAPs) as designed by each Member State and approved by the European Commission. In principle, this total amount fixes the cap of the aggregated CO_2 emissions of the 12,000 participating installations.[1] This amount is approximately equal to 2.2 $GtCO_2$ per annum in 2005-07.

Figure 2.2 shows that changes in CO_2 prices since late 2004 can be highly related to political decisions regarding the cap in the NAPs. However, the market was immature during these decisions and, hence, the psychological effect of these decisions has affected CO_2 prices as well, notably in the short term (but may level out in the longer term).

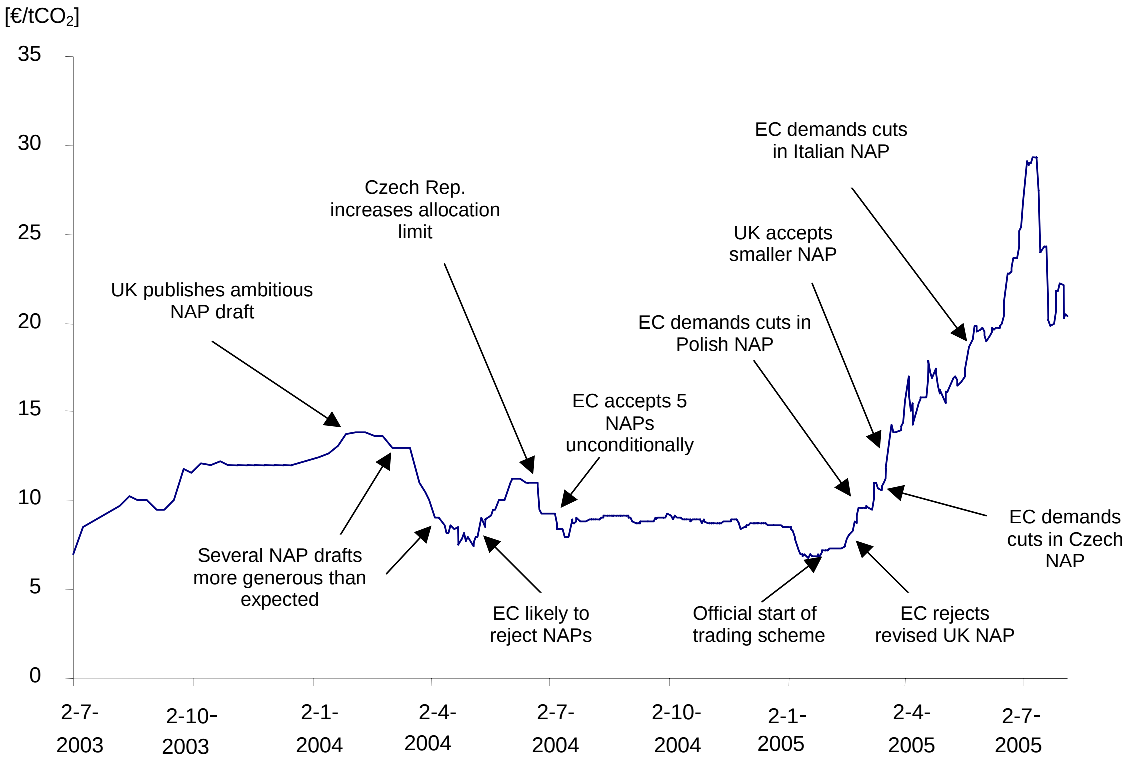

Figure 2.2 *CO_2 prices on EUA market (forward 2005; June 2003 – September 2005)*
Source: Beyers (2005)

Carbon credits from CDM

As noted, the Linking Directive allows conversion of CERs into EUAs. As CERs are in general cheaper than EUAs, this linking of carbon markets is likely to have a downward effect on the

[1] However, supply of CDM/JI credits may in effect increase the emission ceiling. On the other hand, countries may cancel unused new entrants reserves, which (if applicable) basically lowers total emission rights.

EUA carbon price. However, the CDM market is surrounded by large uncertainties over future supply of credits and, hence, by risk premiums into CER prices.

Borrowing of allowances
The possibility of 'borrowing' emission allowances from the second trading period (2008-2012) would create an option to increase the emission budget for the first period. Such borrowing is however not allowed, thereby limiting the amount of EUAs in the first period. Borrowing between the three years of the first trading period is allowed.

Banking of allowances
'Banking' refers to the opposite of borrowing: transferring EUAs from the first period to the second. This is also not allowed. On the other hand, banking of CERs is allowed, which may be interesting if the carbon price is expected to be higher in the second phase of the EU ETS.

2.2.2 Demand factors

The basic determinant of the total demand for EUAs is either projected emissions (ex-ante) or actual emissions (ex-post) of the installations covered by the EU ETS. However, as installations receive allowances for free, the net demand for EUAs on the market is determined by the difference between their emissions and the amount of allowances received for free (called 'Emissions-to-Cap' or EtC).

Figure 2.3 shows how different sectors in the EU ETS are likely to be long (EtC>0) or short (EtC<0) of EUAs. Based on projected emissions and sectoral allocations of allowances, the power and heat sector is expected to be a major demander of EUAs at the market (about 300 $MtCO_2$ over the period 2005-07), while the other sectors are projected to become major suppliers of EUAs on the market.

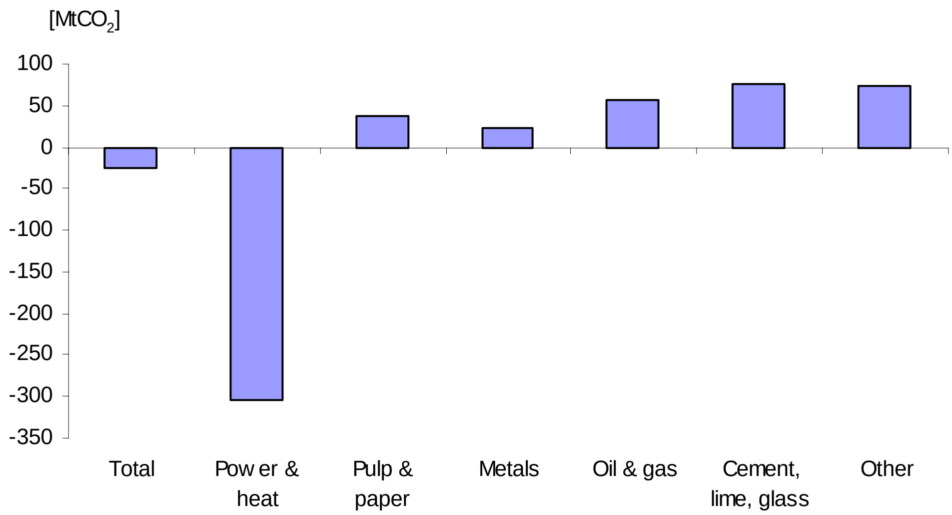

Figure 2.3 *Sectoral projected Emissions-to-Cap (EtC) for the period 2005-07*
Note: Projections are based on business-as-usual scenarios, while caps include new entrants reserves.
Source: Christiansen, et al. (2005).

Projected or actual emissions at the installation level are determined by a number of factors, including economic growth, weather, abatement options and market sentiments. These factors are discussed below.

Economic growth
Projected emissions in 2005-07 are based on a range of assumptions, the most important of which is economic growth. The relation between baseline CO_2 emissions and economic growth appears to be rather well known (and stable for most individual countries). Economic growth itself, however, is difficult to predict exactly across a time period of three years. Therefore, a change in the (projected) growth will have a major impact on emissions. For example, if economic growth in 2007 is significantly lower than anticipated, the market as a whole may be long, even though a considerable shortfall of allowances was expected. The opposite may of course also occur although this is somewhat less likely to happen, as projected emissions and EUA allocations are probably based on optimistic economic scenarios.

Weather
Temperature and rainfall both have a major impact on emissions of the covered installations. A cold winter increases demand for heating by electricity or fuels, whereas a warm summer puts power demand for air-conditioning on the rise. Winter 2005 shows a clear increase in energy requirements and therefore a rise in emissions. It is widely acknowledged that this is an important factor determining the CO_2 price rise in early 2005.

Rainfall is a major factor in hydropower output in a range of European countries. Any shortage in hydropower needs to be compensated for by fossil fuel based power (nuclear and wind are base-load) and consequently triggers emissions increases, as illustrated by recent developments in Spanish power and heat emissions versus hydropower output. Compared to 2001, hydropower output dropped by approximately 12 TWh in 2002 (25 percent) while CO_2 emissions increased by 15 Mt. In 2003 hydropower increased again to the 2001 level and emissions decreased by about 7 Mt.

Energy prices (gas, oil, coal)
One of the factors most quoted as having a significant impact on the demand for EUAs and, hence, on the CO_2 price of these EUAs are fuel prices (Karmali, 2004; Rowland, 2004, Beyers, 2005). Most relevant are gas prices - which follow oil prices - as they may affect the fuel switch in power generation (see Chapter 3).

Abatement options
Basically, every installation has options to reduce its on-site emissions by implementing CO_2 abatement measures. The choice whether or not to implement such measures depends on several factors. Cost of the option compared to the CO_2 price of a EUA is likely to be the most important, i.e. installations will reduce their emissions if this is cheaper than buying allowances, but also information about options, experience with CO_2 abatement and company policy determine such decisions.

Market sentiments
The still young EUA market is often quoted as being ‘sentiment-driven’. This refers to factors such as uncertainty on whether the prices are going to rise or decrease, on short or long positions or on future policy decisions. Changes in CO_2 prices have occurred in anticipation of EC decisions on NAPs. For instance CO_2 prices began to rise days before the actual decision on the Czech NAP was published (with no change after this decision was taken, as the cut demanded was as expected). It should be noted, however, that sentiments may play a significant role particularly in an immature market such as the present EU ETS.

2.2.3 Market structure, regulation and intervention

In addition to supply and demand factors, CO_2 prices on the EUA market are determined by other factors such as market structure, regulation and intervention. Market structure refers particularly to the number of parties active in the market and the ability of these parties to affect market prices by means of strategic behaviour. Although the number of parties active in the EUA market has increased rapidly during 2005, carbon trading has often been dominated by a small group of large buyers or sellers. It is hard to assess, however, whether these buyers or sellers have actually affected or even manipulated CO_2 prices on the EUA market by means of strategic behaviour. It is expected that potential market power will decrease over time when the EUA market becomes more mature and more liquid, as no party will probably control enough allowances to manipulate CO_2 prices.

Market regulation or intervention refers particularly to policy decision-making that affects CO_2 prices on the EUA market directly or indirectly (i.e. by changing the rules of the system). Examples include decisions regarding maximum or penalty prices, coverage of the EU ETS by greenhouse gasses, sectors and installations, linking with JI, CDM or ET schemes of other countries, rules regarding banking and borrowing or EUAs, allocation methodology, determination of future caps and emissions reduction commitments, etc. All of these factors indicate the considerable influence of policy decisions - including expectations regarding future decisions - on trading and pricing in the EU ETS.

2.2.4 Summary of CO_2 price determinants

Table 2.1 presents a brief overview of the factors determining the CO_2 price. The column 'variability' refers to the relative likeliness of major fluctuations in the factor concerned. 'CO_2 price impact' indicates the qualitative impact when the factor increases (+ or -) and 'relation' is a semi-quantitative elasticity factor.

Table 2.1 *Summary of CO_2 price determinants*

Factor	Variability	CO_2 price impact[a]	Relation	Remarks
Economic growth	Medium	+	Strong	
Gas-to-coal price	Large	+	Strong	Christiansen (2004) has estimated a CO_2 price sensitivity of 4 €/tCO_2 at a 20% gas price increase, and 3 €/tCO_2 at 20% coal price decrease
Oil price	Medium	+	Strong	Strong due to gas price impact
Temperature summer	Large	+	Medium	
Temperature winter	Large	-	Strong	
Rainfall	Large	-	Strong	
Market uncertainty	Medium	+	Strong	Currently larger variability, but more market certainty expected in mid-term
Info on abatement	Low	-	Weak	
Allocation	Low	-	Strong	Fixed after NAP approval
(expected) CER supply	Large	-	Strong	Christiansen (2004) estimated 3 €/tCO_2 increase at 20 Mt less CER supply
Market power	Medium	+	Medium/-strong	Role expected to decrease with maturing market

a) Impact when factor increases.

2.3 Projections of CO_2 prices on EUA market

Table 2.2 provides some projections and expectations of CO_2 prices on the EUA market for the first and second trading period, derived from different studies published in the years 2003-05.

Most of these studies expect or predict a price for a EUA between 5-10 €/tCO_2 for the period 2005-07 and between 10-25 €/tCO_2 for the period 2008-12. To compare: over the period January-July 2005, the actual CO_2 price on the EUA market fluctuated between 6 and 30 €/tCO_2, while the average price over this period amounted to about 15.3€/tCO_2 (see Chapter 6 for a further analysis of the trend in CO_2 prices on the EUA market).

Table 2.2 *Projections and expectations of CO_2 prices on the EUA market, 2005-2012, derived from different studies*

[€/tCO_2]	Phase 1: 2005-07			Phase 2: 2008-12		
Study	Low	Central	High	Low	Central	High
ICF (03/2003)	2	5	10	4	10	20
PointCarbon (04/2003)[a]	15	5	40	2	7	45
DKW (10/2003)		15			25	
JP Morgan (11/2003)		6			28	
ILEX (12/2003)	5-7		15-18	5-7		19-25
Oxera (06/2004)	5	10	15	5	10	25
Enviros (2004)		6-20			10-25	
ECON (2004b)	1	5	8	5	8	15

a) Based on a sounding among market specialists (PointCarbon, 25 April 2003).

3. The carbon intensity of power production

In addition to the price of carbon, the impact of emissions trading on the price of electricity depends also on the carbon intensity of the marginal technology of power production. This intensity, however, depends in turn on the carbon intensity of the fuel used and the thermal efficiency of burning the fuel. For instance, at a theoretical 100 percent thermal efficiency, the generation of 1 MWh of electricity by means of coal will emit about 0.341 tCO_2, while its emission will be some 0.202 tCO_2 if natural gas is used. At an average thermal efficiency of 35 percent, a coal station will produce 0.97 tCO_2/MWh, while a gas station operating at 53 percent will produce 0.38 tCO_2/MWh (Doyle, 2005). If the price of carbon is € 10/tCO_2, this implies that the carbon costs added to power production are € 9.7/MWh for coal-fired generation and € 3.8/MWh for gas-fired generation.

However, whereas the price of carbon is more or less the same throughout the EU ETS, the carbon intensity of the marginal generation technology varies widely throughout the EU electricity system, depending on the fuel use and thermal efficiency of this technology in national or regional sub-systems. Moreover, the marginal production technology may differ between the base load and (super) peak load periods of power production and, hence, the resulting carbon costs of generating electricity may also differ between these periods. In addition, the carbon intensity of the marginal production technology may change over time - in the short and/or long term - partly due to exogenous factors (‘autonomous technological change’), and partly due to a change in endogenous factors such as a change in relative fuel prices or a change in the price of carbon (‘induced technological change’). These factors will be considered in some detail in the sections below.

3.1 Generation mix and carbon intensity

Table 3.1 presents the generation mix and carbon intensity of power production in the EU-15 countries for the year 2002. It shows that the generation mix varies widely among these countries. In Sweden, for instance, the share of coal and oil in electricity production amounted to only 2 and 1 percent, respectively, while more than 96 percent of power generation was accounted for by non-fossil fuels such as nuclear, hydro or other renewables. In Greece, on the other hand, the share of coal and oil in electricity production amounted to 64 and 17 percent, respectively, while non-fossil fuels accounted for some 8 percent (see also Figure 3.1).

In addition, Table 3.1 shows that the carbon intensity of power production in 2002 varies widely between the EU-15 countries, both for individual fossil fuels and for the generation mix as a whole (due to differences in both thermal efficiencies per fuel and generation mix per country). For instance, the carbon intensity of coal-fired generation ranges from 520 $kgCO_2$/MWh in Denmark to 1092 $kgCO_2$/MWh in Belgium, and for gas-fired generation from 204 $kgCO_2$/MWh in Luxembourg to 505 $kgCO_2$/MWh in Greece. Overall, the average carbon intensity of total power production in 2002 varies from 16 $kgCO_2$/MWh in Sweden to 807 $kgCO_2$/MWh in Greece (see also Figure 3.2).

However, assuming that the price of electricity is primarily determined by the costs of the marginal generation technology, it is important to identify this technology - and the associated carbon intensity - for each national or regional power market, distinguished between base load and peak periods. For instance, the Dutch market is dominated by gas-fired plants, which are used as peak plants (gas fired) and base load plants (combined cycles). In contrast, the dominant/marginal production technology in Germany during both the base load and peak periods is coal-fired generation (with gas/oil-fired generation during the super peak period), while in France the overall dominant/marginal technology is nuclear (Scheepers et al., 2003).

Table 3.1 *Fuel generation mix and carbon intensity of power production in EU-15 countries (2002)*

Country	Electricity generation [TWh]	Fuel share in power production [%]				Carbon intensity of power production [$kgCO_2/MWh$]			
		Coal	Oil	Gas	Non-fossil fuels	Coal	Oil	Gas	Total (fossil and non-fossil)
Austria	60.3	11.1	3.3	13.0	72.6	886	401	292	150
Belgium	82.7	19.4	1.0	19.3	60.3	1092	733	335	284
Denmark	36.2	46.0	12.2	24.3	17.5	520	597	250	373
France	535.8	5.8	1.4	2.1	90.7	544	324	238	41
Finland	70.0	18.9	0.9	14.4	65.8	1056	526	337	253
Germany	567.1	52.7	0.8	9.3	37.2	821	440	345	468
Greece	53.4	64.2	16.6	11.1	8.1	979	736	505	807
Ireland	23.7	36.3	19.6	39.1	5.0	971	701	460	670
Italy	269.9	11.3	31.8	37.5	19.4	1058	706	431	506
Luxembourg	0.4	0.0	0.0	53.1	46.9	-	-	204	108
Netherlands	89.6	28.4	3.5	57.7	10.4	951	528	304	464
Portugal	43.4	33.9	19.4	16.5	30.2	865	574	383	468
Spain	221.7	36.5	10.2	9.1	44.2	900	634	303	421
Sweden	145.9	2.1	1.2	0.3	96.4	578	311	208	16
UK	372.2	33.4	1.5	39.4	25.7	918	554	385	467
EU 15 Average	2572.3	28.6	8.8	23.1	39.5	808	518	332	353

Source: IEA (2002).

3.2 Changes in carbon intensity

As noted above, the carbon intensity of the marginal technology to produce power may change over time for instance due to a change of carbon costs, resulting in a change of the competitiveness (or merit order) of power plant technologies, including fuel switch or a change in thermal efficiency.

Figure 3.3 illustrates a change in the merit order (or competitiveness) of three installed power plant technologies due to the inclusion of carbon costs.[2] In the left part of Figure 3.3, excluding carbon costs, the merit order consists of nuclear (cheapest technology), coal (medium cost option) and, lastly, gas-fired generation (the most expensive technology). If carbon costs are included, however, coal-fired power production becomes more expensive than gas-fired generation and, hence, the merit order changes into nuclear, gas and, lastly, coal (see right part of Figure 3.3). Therefore, assuming that the price of electricity is primarily determined by the costs of the marginal generation technology, the impact of emissions trading on this price depends also on the possible change of the marginal production technology in the short/long term and its associated costs (including carbon).

[2] The merit order refers to the ranking of generation technologies from those with the lowest costs to those with the highest.

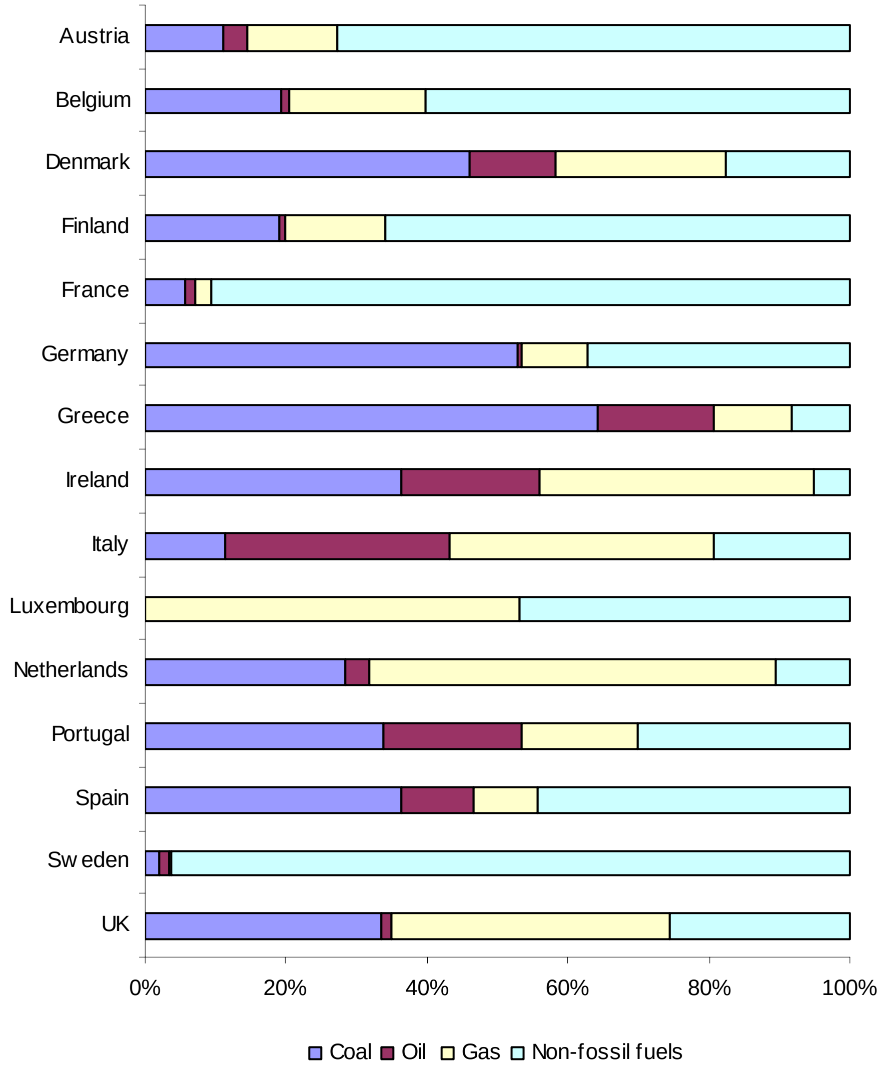

Figure 3.1 *Fuel mix of power production in EU-15 countries (2002)*
Source: Table 3.1.

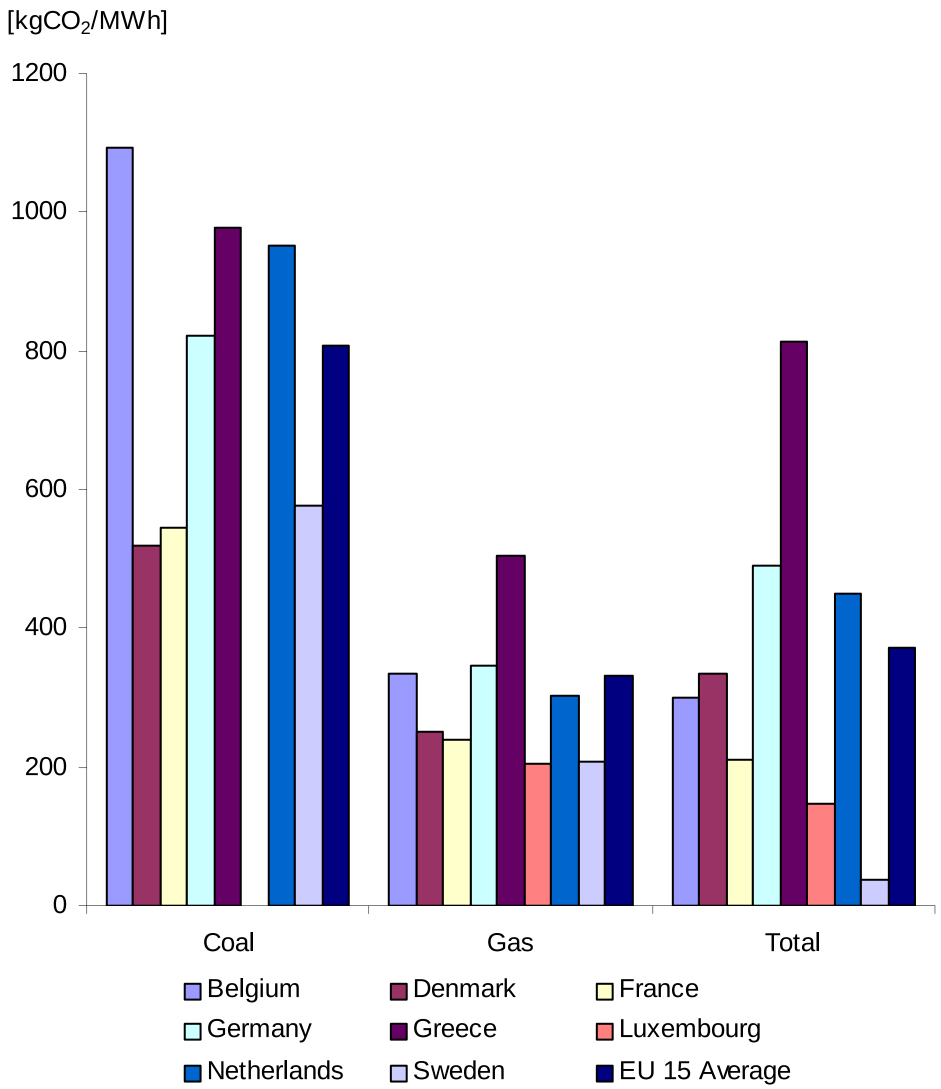

Figure 3.2 *Carbon intensity of power production in EU-15 countries (2002)*
Source: Table 3.1.

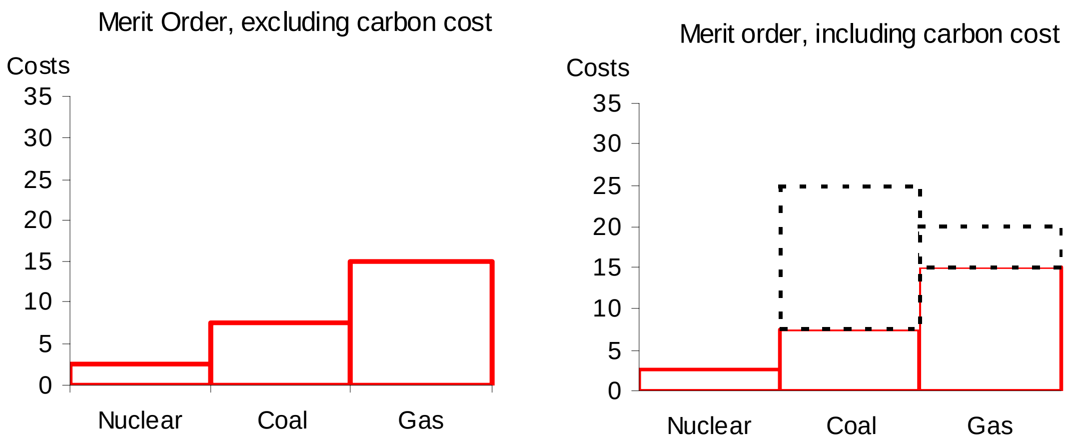

Figure 3.3 *Change in merit order of power plant technology due to the inclusion of carbon costs*

The short-term impact on operational decisions

For the short term, a change in the competitiveness between installed technologies can also be illustrated by means of Table 3.2, which provides short term cost assumptions for combined cycle gas turbine (CCGT) and coal-fired power plants based on historic, representative data for the EU.[3] It shows that, in the short run, an installed CCGT plant is not competitive compared to an installed coal-fired power plant if carbon costs are excluded (or relatively low), while it is attractive to switch fuel technology from existing coal-fired plants to existing CCGT plants if a carbon cost of € 20/tCO_2 is included (provided that idle capacity of CCGT plants is available).

Table 3.2 *Short run marginal cost (SRMC) assumptions for combined cycle gas turbine (CCGT) and coal fired power plants*

	Unit	CCGT	Coal
Fuel price at plant	[€/GJ]	3,5	1,5
Thermal efficiency	[%]	49	37
Fuel costs	[€/MWh]	25,7	14,5
Variable O&M costs	[€/MWh]	1,5	3,3
Short-run marginal cost (SRMC)	*[€/MWh]*	*27,2*	*17,9*
CO_2 cost	[€/t]	20	20
CO_2	[t/MWh]	0,412	0,918
CO_2 cost	[€/MWh]	8,2	18,4
SRMC with carbon	*[€/MWh]*	*35,4*	*36,3*

Source: NEA/IEA (2005).

The point or CO_2 price that makes CCGT plants equally attractive in terms of marginal costs is usually called the 'switching point' or 'breakeven price'. Figure 3.4 shows that this point can be determined at the intersection of the short-run marginal cost (SRMC) curves for existing coal-fired and CCGT plants at varying CO_2 prices, assuming that plant efficiencies, fuel prices and other cost factors are given (as specified in Table 3.2). More specifically, it can be calculated that the resulting breakeven price of CO_2 amounts to € 18.5/t.

This breakeven price between an existing coal-fired plant and an existing CCGT plant is clearly sensitive to a number of the assumptions made, notably (Reinaud, 2003; NEA/IEA, 2005):

[3] These data have been gathered and analysed by NEA/IEA (2005). See also Reinaud (2003).

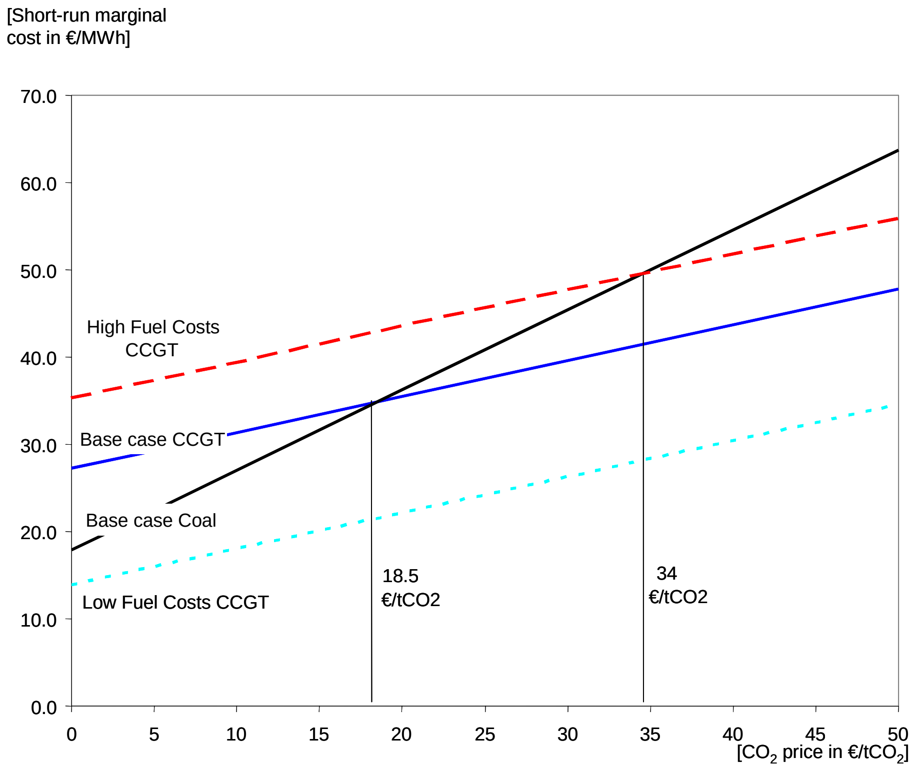

Figure 3.4 *Comparison and sensitivity of the competitiveness between existing coal-fired and combined cycle gas turbine (CCGT) plants*
Source: NEA/IEA (2005).

- *Fuel prices.* A higher gas price (or a lower coal price) than specified in Table 3.2 will result in a significantly higher CO_2 breakeven price. For instance, if the gas price increases to € 4.59/GJ, the carbon price would have to rise to € 34/tCO_2 to equalise the competitiveness of coal and gas. In this case, a 40 percent change in gas prices leads to an 84 percent change in the breakeven price. The relative competitiveness of coal and gas is twice as sensitive to the gas price differential as it is to the price of carbon.[4]
- *Plant efficiency.* A higher thermal efficiency for CCGT plants (or a lower efficiency for coal-fired plants) than specified in Table 3.2 will result in a significantly lower CO_2 breakeven price. For instance, if the CCGT plant's efficiency rate reaches 62 percent, the fuel costs decline by 22 percent, the SRMC by 20 percent, and the CO_2 breakeven price by 65 percent to € 6.5/tCO_2.[5]
- *Other cost factors.* If the variable operating and maintenance costs for coal-fired (or CCGT) plants are higher or lower than specified in Table 3.2 - for instance due to additional, other environmental policies - it will lead to a proportional change in the CO_2 breakeven price.

[4] In Figure 3.4, the sensitivity of the CO_2 breakeven price to a change in the gas price can be determined by a corresponding shift upwards or downwards of the SRMC curve for CCGT as illustrated by Reinaud (2003) and NEA/IEA (2005). A similar shift of the SRMC curve for coal-fired plants can be used to account for the sensitivity of the CO_2 breakeven price to a change in the coal price.

[5] In Figure 3.4, the sensitivity of the CO_2 breakeven price to a change in the efficiency rate of a CCGT plant can be determined by a corresponding shift upwards or downwards of the SRMC curve for CCGT as illustrated by Reinaud (2003) and NEA/IEA (2005). A similar shift of the SRMC curve for coal-fired plants can be used to account for the sensitivity of the CO_2 breakeven price to a change in the efficiency of such plants.

In reality, there will not be one unique breakeven price that applies throughout the whole EU ETS but a series of local breakeven prices, depending on actual local conditions such as local relative fuel prices, local plant efficiencies and other local cost factors involved. Hence, whereas a fuel switch between existing plants may occur in certain locations at relatively low CO_2 prices (say € 10/tCO_2 or less), it may happen in other locations at only relatively high CO_2 prices (say € 50/tCO_2 or more). Moreover, in the short run, the shift from existing coal-fired plants to existing CCGT plants depends on the availability of idle installed capacity of CCGT plants (or vice versa), whereas in the long run a shift towards CCGT by means of investments in new capacity depends on the long-run competitiveness of CCGT (as discussed below).

The long-term impact on investment decisions

To encourage investments in new capacity, expected wholesale power prices have to cover the future long-run marginal costs (LRMC) of generation. Besides fuel and other operational costs, the LRMC includes capital costs for new capacity. Table 3.3 provides LRMC assumptions of new coal-fired and CCGT plants, based on representative data for the EU (NEA/IEA, 2005). It shows that a new CCGT plant is competitive compared to a new coal-fired plant, even excluding carbon costs. Including these costs to the LRMC further enhances the competitiveness of a new CCGT plant compared to a new coal-fired plant (see also Figure 3.5, which provides the LRMC curves for new coal-fired and CCGT plants at varying CO_2 prices, based on the LRMC assumptions of Table 3.3).

Table 3.3 *Long-run marginal cost (LRMC) assumptions for new combined cycle gas turbine (CCGT) and coal plants*

	Unit	CCGT	Coal
Plant capacity	[MW]	600	750
Capital costs	[€ million]	300	825
Economic plant life	[Yrs]	25	30
Capacity factor	[%]	80	80
Fuel price	[€/GJ][a]	3,00	1,66
Fuel costs	[€/MWh]	19,6	14,93
Cost of capital	[€/MWh]	5,75	12,65
Variable O&M costs	[€/MWh]	1,50	3,33
Fixed O&M costs	[€/MWh]	2,33	3,50
Thermal efficiency	[%]	55	40
Pretax return	[%]	8,06	8,06
Depreciation	[€/MWh]	2,85	5,23
Long-run marginal cost (LRMC)	*[€/MWh]*	*29,18*	*34,41*
CO_2 cost	[€/t]	20	20
Carbon emitted	[t/MWh]	0,367	0,85
CO_2 cost	[€/MWh]	7,344	17,028
LRMC with carbon	*[€/MWh]*	*36,95*	*51,43*

Source: NEA/IEA (2005).

Comparing SRMC with LRMC shows at which level it is more profitable to continue operating an existing power plant rather than build a new one. Figure 3.5 illustrates which technology is more competitive in relation to a varying carbon price, based on the cost assumptions of Tables 3.2 and 3.3. Actually, three different carbon price zones can be distinguished (Reinaud, 2003; NEA/IEA, 2005):

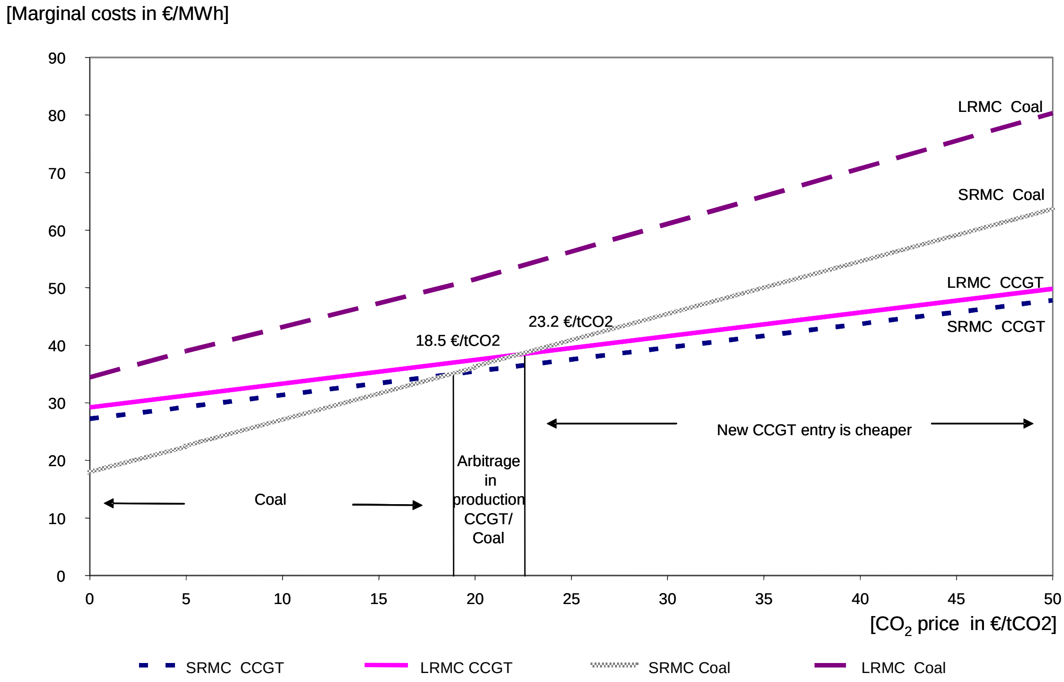

Figure 3.5 *Comparison of the competitiveness between existing and new combined cycle gas turbine (CCGT) and coal-fired plants*
Source: NEA/IEA (2005).

- *Between € 0 and € 18.5 per tonne CO_2.* As discussed above, up to € 18.5/tCO_2, it is more competitive to operate an existing coal-fired plant than an existing CCGT plant. The break-even price of € 18.5/tCO_2, however, is very sensitive to the underlying assumptions. Hence, in reality, this price may vary widely throughout the EU ETS, depending on local plant conditions.
- *Between € 18.5 and € 23.2 per tonne CO_2.* Above € 18.5/tCO_2, it is attractive to switch power generation from existing coal-fired plants to existing CCGT plants, provided that idle capacity of the latter is available. If this capacity is lacking, installed coal-fired plants will continue to operate up to the breakeven price of 23.2/tCO_2 where the SRMC of an existing coal-fired plant is equal to the LRMC of a new CCGT plant.
- *Above € 23.2 per tonne CO_2.* Above € 23.2/tCO_2, it is more profitable for companies to build modern CCGT plants and to shut down their existing coal-fired plants. It will be clear that this CO_2 breakeven price is also very sensitive to the underlying assumptions made and, hence, that in reality this price may vary widely throughout the EU ETS, depending on local conditions.

In addition to comparing the competitiveness of (existing/new) coal-fired plants with CCGT plants under varying carbon prices, it is also possible to compare the competitiveness of operating existing coal-fired plants with investments in such plants in order to reduce their carbon intensity, for instance by means of replacing coal in existing boilers partly by biomass (co-combustion) or by refiring/refurbishing existing coal stations with new gas-fired technologies (Innovest, 2003). Moreover, it is also possible to compare the competitiveness of fossil-fuel plants with renewables under varying carbon prices, although the switching point between these alternative generation technologies is often still high, notably between non-hydro renewables and fossil-fuel stations (with in reality a wide range of CO_2 breakeven prices throughout the EU ETS, depending on local conditions and the renewable technology considered). The key issue, however, is that from a certain point, rising CO_2 prices will encourage the deployment of carbon-saving technologies to generate electricity.

Therefore, when assessing the impact of EU emissions trading on the price of electricity, the effect of the carbon price on the carbon intensity of the marginal generation technology has to be accounted for.

3.3 Second order effects

In addition to the effects outlined above, there may be substantial feedback or second order effects of emissions trading on the price of electricity. Probably the most important of these feedback effects is the impact of emissions trading on relative fuel prices, particularly of coal versus gas. As explained in Section 3.2, the incidence of carbon costs will most likely encourage the switch from coal-fired power plants to gas-fired (CCGT) stations, thereby accelerating the tendency for gas to become the preferred fuel in power production (BCG, 2003). Therefore, in order to make additional investments in new (more expensive) gas sources profitable, gas prices are likely to rise. This will in turn increase wholesale power prices, adding to the increase of this price due to the primary effect of passing through carbon costs of emissions trading.[6]

Another reason why gas prices may increase due to the EU ETS is related to the way these prices are fixed in long-term contracts. In Continental Europe, gas is mostly supplied under long-term contracts, which set a base price and a formula for adjusting that price at regular intervals, for instance by means of oil-price indexation. With the introduction of ETS-induced carbon costs, gas-fired stations become the preferred technology which gives additional value to gas as the carbon intensity of gas is significantly lower compared to other fossil fuels (see Table 3.1 and Figure 3.2). Therefore, gas suppliers might be inclined to include at least part of this additional carbon fuel in their gas contracts, thereby shifting away from oil-price indexation and increasing their gas prices (Reinaud, 2003; Doyle, 2005; Halstead, 2005).

Overall, long-term gas prices are likely to increase due to the introduction of the EU ETS. McKinsey (2003) estimates that the EU gas border price in 2014 will be 15 percent higher due to CO_2 regulation. As a result, wholesale power prices will rise by about 10 percent in addition to an increase of these prices by 30 percent due to the passing-through of carbon costs at €25/tCO_2. Hence, according to these estimates, the second order effects of the EU ETS are about one-third of the first order effects of this emissions trading system.

[6] It should be noted that when the price of gas rises relative to the coal price, the CO_2 breakeven price or switching point of gas-fired plants versus coal-fired plants becomes higher, thereby mitigating the switch from coal-fired plants to gas-fired plants (as explained in Section 3.2).

4. The level of passing through carbon costs

Besides the price of carbon and the carbon intensity of the marginal generation technology, the third factor that determines the impact of emissions trading on the price of electricity concerns the extent to which the carbon costs of power production will be passed through to electricity prices. This chapter analyses this complex issue, largely from a theoretical perspective, by discussing the major factors that affect the rate of passing through carbon costs to power prices. These factors will be discussed under the following headings:

- the opportunity costs of grandfathering,
- grandfathering as a subsidy of fixed costs,
- grandfathering as a mechanism to reduce mark-ups,
- market structure,
- outside competition,
- market regulation and voluntary agreement,
- demand response,
- change in merit order,
- carbon-saving innovations,
- updating of EUA allocations,
- non-optimal behaviour, market imperfections, time lags and other constraints.

When discussing the factors that affect the so-called ‘pass-through rate’ a distinction should be made between the extent to which producers *add on* the opportunity costs of CO_2 emission allowances to their other, marginal costs when making production or trading decisions (‘*add-on rate*’) and the extent to which CO_2 allowances costs ultimately *work on* power prices that are determined by a complex set of market forces (‘*work-on rate*’). Even if the add-on rate is 100 percent, the work-on rate may be (far) less than 100 percent due to a variety of reasons, as discussed and illustrated in the sections below.

4.1 The opportunity costs of grandfathering

The EU ETS is a cap and trade system based primarily on a free allocation of a fixed amount of emission allowances to a set of covered installations that are allowed to trade these allowances among each other. This free allocation of emission allowances is often denoted as *grandfathering*.[7] In addition, each Member State is allowed to auction, at the maximum, 5 percent of its allowances during the first trading period (2005-07) and 10 percent during the second (2008-12). For the first trading period, however, almost all Member States have opted to allocate the full amount of their emission allowances for free.

The major implication of this political choice is that almost all installations covered by the EU ETS receive most or all CO_2 emission allowances for free. Companies can either use these allowances to cover the emissions resulting from the production of these installations or sell them on the market (to other companies that need additional allowances). Hence, for a company an emission allowance represents an opportunity cost, regardless whether the allowances are allocated for free or purchased at an auction or market (Sorrell, 2002; Reinaud, 2003; ECON, 2004a). Therefore, in principle and in line with economic theory, a company adds the full costs

7 It should be noted that the term *grandfathering* originally referred only to the free allocation of a fixed amount of allowances to installations based on historic emissions, i.e. on the basis of emissions in a reference year or an average over several years in the past. Nowadays, the term is often used in a much wider meaning, referring to all kinds of free allocation (even in relative terms), including allocation based on future, projected emissions or based on a (fixed) emission factor or Performance Standard Rate (PSR) multiplied by a fixed (projected) input or output level (KPMG, 2002; Harrison and Radov, 2002).

of CO_2 emission allowances to its other marginal (variable) costs when it is making (short-term) production or trading decisions, even if the allowances are granted for free.

The passing through of the opportunity costs of grandfathering to power prices can be illustrated by means of Figure 4.1 representing a simple reference case characterised by perfect competition, an inelastic demand curve (D) and a straight, upward sloping supply curve with constant carbon intensities of the generation technologies concerned (S_0). When emissions trading is introduced, the opportunity costs of grandfathering are added to the other marginal production costs, resulting in supply curve S_1. Under the conditions of the reference case, this implies that (i) power prices increase from P_0 to P_1, (ii) the pass-through rate is 100 percent in terms of both the add-on rate and the work-on rate, (iii) the so-called '*windfall profit*' (i.e. the transfer of wealth from power consumers to producers due to grandfathering) per unit output is equal to the change in power price (P_1 - P_0) and (iv) total windfall profits are equal to the change in power price (P_1 - P_0) multiplied by total output (Q_0). Due to a variety of reasons, however, the conditions or assumptions underlying the simple reference case may not be met. As a result, even if the add-on rate is 100 percent, the work-on rate may be far less than 100 percent. These reasons will be discussed in the sections below.

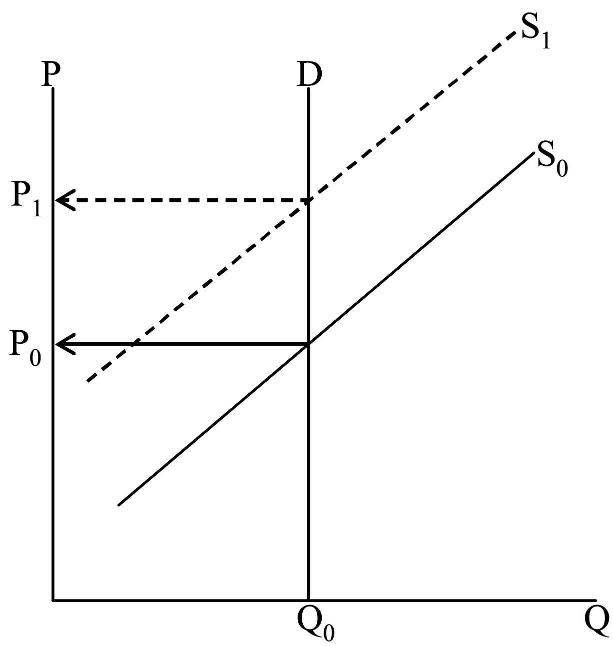

Figure 4.1 *Passing through of carbon costs to power prices*
Note: S_0 is the supply curve excluding carbon cost, while S_1 includes carbon cost.

4.2 Grandfathering as a subsidy of fixed costs

Besides its effect on the variable or marginal costs, grandfathering can also affect the margin to cover the fixed investment costs of power production, as argued by Mannaerts and Mulder (2003).[8] According to this view, grandfathering can be regarded as a lump-sum transfer of

[8] Mannaerts and Mulder (2003) have used the term 'mark-up' in order to indicate the fixed cost margin of power production. Although this term is often used in different meanings, the present report prefers to follow the standard international literature when using the concept 'mark-up', defined as the difference between the marginal costs and the actual price in a monopolistic or oligopolistic situation (see, for instance, Stoft 2002). Hence, in this meaning, this concept is only used for situations of imperfect competition where producers exercise market power in order to raise prices of electricity above its marginal costs, for instance by withholding capacity output. In contrast, the term 'fixed cost margin' is defined as the amount of investment cost that has to be recovered from the gross margin earned in the energy market, where the gross margin is defined as total revenue minus total variable cost including the opportunity cost of allowances.

wealth (or fixed subsidy, independent of future production), which firms could use to reduce the net fixed costs that have to be covered by gross margins from power sales.

Whether the fixed cost margin will actually be reduced depends on the treatment of new entrants in the emissions trading scheme. When new entrants have to buy the allowances, while incumbents receive them for free, the fixed cost margin of power prices will not be reduced as new entrants are not able to supply against a price that does not pay for the allowances and, hence, entry will not drive down prices and the resulting contributions to fixed costs. However, when incumbents and new entrants both receive allowances free of charge, the net fixed cost of entry is less and entry is more attractive; this additional entry can drive down electricity prices and the resulting gross margins earned by incumbent firms. Or, to put it slightly different, grandfathering can have two opposite effects on power prices: on the one hand, power prices can increase due to power producers adding the opportunity costs of grandfathered emission allowances to their marginal (variable) generation costs while, on the other hand, this price increase can be partially or completely offset by the subsidisation and, hence, reduction of the average fixed costs of power production if both incumbents and newcomers receive their allowances for free.

The argument by Mannaerts and Mulder (2003) that grandfathering to incumbents and newcomers can be regarded as a lump-sum subsidy to an installation that lowers the fixed investment costs of power generation and, hence, can lead to a neutralisation in the increase in power prices due to the passing-through of the opportunity costs of CO_2 emission allowances is in theory correct. Nevertheless, some major qualifications can be added to this argument as outlined below.[9]

Only effective if capacity scarcity is actually reduced

The price-neutralising effect of grandfathering will only be effective in a (long-term equilibrium) situation in which generation capacity is scarce and actually enlarged by investments in new capacity. If production capacity is amply available, the scarcity rent will be nearly zero and power prices will be determined almost exclusively by short-term marginal costs, at least in competitive markets. In such a situation, grandfathering will not act as a mechanism to reduce power prices through a lowering of the scarcity rent or margin to cover the fixed investment costs. Moreover, if generation capacity is indeed scarce, this rent or margin will only be reduced if it is actually enlarged by investments in new capacity. In the power sector, this may take some time, perhaps several years, particularly if new producers want to enter the power market, if the power market is characterised by imperfect competition (as is often the case), and/or if the enlargement of the generation capacity is faced by a variety of other constraints. During this time, power prices will increase due to the passing through of the opportunity costs of CO_2 emission allowances, resulting in welfare transfers ('windfall profits') from electricity consumers to producers. Simulations performed by Resources for the Future indicate that it can take many years before the price-reducing effect of entry induced by free allowances is significant.[10]

Only effective up to a certain CO_2 price level

The price-neutralising effect of grandfathering is only effective up to a certain CO_2 price level as no producer will sell power at a price below the opportunity costs of the fuels and CO_2 allowances used. Otherwise it is more profitable to sell the fuels and CO_2 allowances directly on the market. Or, in other words, the price-neutralising effect of grandfathering is only effective up to the point where the scarcity rent or margin to cover fixed investment costs is reduced to zero as

9 These qualifications are based on a lively e-mail discussion with Prof. Ben Hobbs (Johns Hopkins University, Baltimore) on the relationship between grandfathering and power prices, including some model runs by Prof. Hobbs.

10 Recent simulations by Burtraw and Palmer (2005) have used the HAIKU dynamic power industry model to assess the effects of different allowance allocation rules. They have found that giving free allowances to entrants results in a partial but not complete offsetting of CO_2 opportunity costs over a twenty year time horizon.

a result of the full subsidisation of these costs and the consequent abundance of production capacity due to this subsidisation of new capacity investments.

To illustrate this issue, suppose that the average fixed costs of a gas-fuelled plant amount to 10 €/MWh, while its emission factor is 0.5 tCO_2/MWh. This implies that up to a price level of 20 €/CO_2 (i.e. 10 €/MWh divided by 0.5 tCO_2/MWh) the price-neutralising effect of grandfathering may be effective, but beyond this point it will become ineffective and power prices will increase due to the passing through of the opportunity costs of the CO_2 allowances as no producer will sell power at a price below the opportunity costs of the allowances and fuels used.

In principle, the situation of high CO_2 prices being passed through can be relieved by enlarging the amount of emission allowances. In practice, however, this will not be a viable option since the EU ETS is characterised by an absolute cap (with limited new entrants' reserves), while governments are not able or willing to raise this cap as it would imply they have to meet their Kyoto emissions reductions somewhere else where it might be more difficult or more expensive to achieve. Therefore, beyond a certain CO_2 price level, increases in power prices will no longer be neutralised by the mechanism of subsidizing and lowering fixed investment costs, resulting in a lasting situation of windfall profits, even in a fully competitive situation.[11]

If effective, it reduces the internalisation of external costs

On the other hand, if the price-neutralising effect of grandfathering is fully effective, it implies that the external costs of CO_2 emissions are not internalised through higher power prices, resulting in a less efficient situation from a social welfare point of view. In particular, there will be too much consumption and production relative to a welfare-maximizing solution that maximizes the sum of consumer and producer surplus subject to an emissions constraint. In order to meet the CO_2 cap while producing more electricity, the generation mix would be further oriented towards more expensive cleaner technologies so that, on balance, emissions still meet the cap. Thus, the social cost of power production (the real investment and fuel costs of producing electricity) will increase relative to the social welfare maximizing solution.[12] In sum, emission reductions elsewhere have to be increased to meet overall environmental targets.

In fact, if the price-neutralising effect is effective, emissions trading based on grandfathering leads, on the one hand, to an internalisation of external CO_2 emission costs due to the passing through of these costs into higher power prices while, on the other hand, this effect is nullified by the implicit lump-sum subsidy to fixed investment costs owing to the free allocation of emission allowances, with the subsidy being higher if the investment is more carbon-intensive. Such a contradictory - or even perverse approach may be questioned from a consistent and cost-effective environmental policy point of view.

Moreover, the price-neutralising effect of grandfathering would, in principle, apply not only to the power sector but also to all other sectors and activities covered by the EU ETS. Hence, if giving free allowances to new investments is effective in lowering power prices, this would imply that one or the other will occur:

- One possibility is that total CO_2 emissions of all sectors covered by the EU ETS are not significantly decreased through lower demand nor by large changes in the generation mix. If costs to power consumers are indeed not increased significantly and subsidies are main-

11 Note that as long as the oil prices remain high and, hence, the gas prices, the CO_2 prices will also remain high in order to effectuate a required fuel switch in the power sector (see Chapter 3). Moreover, a more stringent cap during the second trading period of the EU ETS may result in average CO_2 prices beyond 20 or 30 €/tCO_2. Hence, up to 2012 - i.e. the period in which the EU ETS will be largely based on grandfathering - there is a fair chance that the scheme will lead to higher power prices and significant, lasting windfall profits.

12 Due to grandfathering, the average variable costs of fossil-fuel technologies increase –resulting from the passing through of the CO_2 costs – while the average fixed cost decrease, owing to the lump-sum subsidy of these costs. Under very restrictive conditions, the second effect of grandfathering neutralises the first effect, implying that neither the total average generation costs of these technologies nor the long-run supply curve will change.

tained in the form of free emissions allowances to investments in high-carbon intensity generation technologies, emissions decreases will become much more difficult to achieve in the electricity sector. This would question the rationale of the system as it implies that a scheme to reduce emissions is set up - with all its administrative and transaction costs involved - but that in the end it contributes nothing to its overall environmental target. It would mean that its reduction objectives would have to be achieved outside the system, i.e. by means of its linking to JI/CDM projects and the resulting conversion of JI/CDM credits into additional EUAs. However, the generation and conversion of these credits may be restricted due to a variety of constraints, including several project-related barriers, or a policy-induced restriction on the maximum amount of JI/CDM credits that can be converted into EUAs (as proposed by the Dutch government).
- Or, the prices of a EUA would be pushed beyond the level that would make the price-neutralising effect of grandfathering ineffective (as discussed above), implying that CO_2 prices, generation costs (including carbon opportunity costs) and power prices would rise until the required emission reductions are realised through a lower demand and/or a switch in technology within the system.

Therefore, if effective, the price-neutralising effect of grandfathering could lead to large inefficiencies and several contradictory or even perverse environmental policy effects.

If effective, it leads to distortions of investment decisions.
As a basic principle for designing markets, it can be argued that the allocation of property rights - such as CO_2 emission allowances - should not be a function of future decisions, because of the risk of distorting these decisions. For instance, free allocation of CO_2 emission allowances to new investments can lead to inefficiencies and other distortions such as investments in carbon-intensive technologies, investments in unnecessary, unreliable production capacity or investments in ‘rent-capturing activities’ (‘how do I get the most allowances’) rather than investments in efficient, low-carbon and truly needed expansions of generation capacity. This is particularly the case when CO_2 prices are relatively high, leading to high levels of subsidizing fixed investment costs of fossil-fuel generators. The result will be higher social cost to achieve the desired emission reductions. Hence, even if the grandfathering of allowances to new investments is effective in lowering electricity prices, such grandfathering to new investments may be questioned because of these distortions.

To conclude, the price-neutralising effect of grandfathering can be questioned on the following grounds. Either it is only effective up to a certain CO_2 price level, provided there is a generation capacity scarcity that is actually reduced by new investments. Or, if it is effective, it leads to distortions of investment decisions, other social inefficiencies and contradictory or even perverse policy effects. If policy makers are interested in encouraging competition or enlarging generation capacity in the power sector, and in ensuring that allowance rents are not entirely captured by producers, there are likely less questionable instruments than grandfathering.

4.3 Grandfathering as a mechanism to reduce mark-ups

Under imperfect competition, such as a monopoly or oligopoly, power producers may exercise strategic behaviour (or market power) in order to increase the price of electricity above its marginal costs, for instance by withholding production capacity (see also Chapter 7). The mark-up is a measurement of the degree to which a firm can exercise such market power. It is defined either in absolute terms as (P - MC) or in relative terms as (P - MC)/P, where P is the price of a commodity in market equilibrium and MC is its corresponding marginal cost.[13]

[13] In relative terms, the mark-up is usually indicated as the so-called ‘Lerner Index’.

Mark-ups in the market may decline as a result of grandfathering. If CO_2 allowances are allocated for free to incumbents and newcomers, it may encourage newcomers to indeed invest in new production capacity and to enter the market, resulting in more competition (i.e. less concentrated markets) and a reduction of oligopolistic mark-ups. Under certain conditions, it may be possible for grandfathering to even lead to a reduction of power prices, i.e. the impact of emissions trading on power prices may become negative.

For example, suppose that in an oligopolistic situation before emissions trading the marginal or variable (fuel) costs of power production are 20 €/MWh, average fixed costs are 8 €/MWh and the mark-up is 13 €/MWh. Hence, the power price before emissions trading is 33 €/MWh and the oligopolistic profits are 5 €/MWh. Suppose further that the opportunity costs of grandfathered CO_2 emission allowances amount to 10 €/MWh. If these costs are passed through and demand is ineleastic, the resulting power price becomes 43 €/MWh and producers will make a windfall profit of 10 €/MWh besides the mark-up of 13 €/MWh. However, grandfathering may encourage competition through entry, reducing the mark-up from 13 to 5 €/MWh, so that the power price becomes 35 €/MWh (for instance, entrants might find their fixed costs reduced to zero, once the value of allowances is netted out). Further entry could lead to even more competition and a decline of the mark-up to zero. As a result, the power price becomes 30 €/MWh, i.e. lower than before emissions trading, while producers still make a windfall profit of 2 €/MWh.

This scenario must be qualified in several respects. Firstly, in practice, it may be hard and take several years (if ever) for newcomers to enter an oligopolistic market as major incumbents may (i) try to deter newcomers by means of strategic pricing and trading behaviour, (ii) benefit from economies of scale in their production and trading operations, and (iii) possess certain scarce resources, i.e. own the best power plant sites in terms of available land, interconnections with the grid or gas pipelines, etc.

Secondly, even if newcomers succeed in entering an oligopolistic market, it may take many years before they have built up a substantial market share, leading to less concentrated markets and a resulting decline in the mark-up.

Finally, as outlined in the previous section, grandfathering may lead to distortions of new investment decisions, in particular inefficient amounts or mixes of new investments. Hence, although grandfathering could, in principle, lead to a reduction of mark-ups and, hence, of power prices, it may take many year (if ever) to become effective. Meanwhile, it may result in significant windfall profits and distortions of new investment decisions. Therefore, if policy makers are interested in increasing competition and reducing mark-ups, there are likely better instruments than grandfathering.

4.4 Market structure

The extent to which carbon costs due to the EU ETS will be passed through to electricity prices depends on the competitive structure of the power market in EU countries, including:

- The level of market concentration, i.e. the number of active market parties (notably on the supply side), including the level of horizontal and vertical integration of the market, the level of excess generation capacity in the market, the entry of newcomers on the market, etc. The market structure may vary from perfect (free and full) competition among a large number of suppliers - in which each supplier adjusts his production or trade volume until his marginal costs is equal to given market prices - to one of imperfect (monopolistic or oligopolistic) competition in which only one or a few (vertically integrated) companies dominate the market (DKW, 2003; Scheepers et al., 2003; DG TREN, 2004-05).
- The transparency and trading arrangements of the power market, varying from transparent power exchanges - where electricity is traded, characterised by standardised contracts, price disclosure, liquidity and a large number of participants - to opaque 'over-the-counter'

(OTC) markets where electricity is traded through bilateral (long-term) contracts between large-scale consumers and producers, usually based on historical relationships (Scheepers et al., 2003; ECON, 2004a; DG TREN 2004-05).

It should be acknowledged, however, that despite the ongoing liberalisation process of the electricity sector a single EU power market does not exist at present due to remaining grid restrictions and other barriers that limit international trade in electricity. In fact, based on the present availability of international transmission lines and actual international trade in electricity, the EU power sector is fragmented in six regional wholesale markets (DG TREN, 2004-05):

1. the North-western Continental market (Germany, France, Belgium, Luxemburg and the Netherlands)
2. the Nordic market (Norway, Sweden, Finland and Denmark)
3. the Iberian market (Spain and Portugal)
4. the Italian market
5. the UK market
6. the Central and Eastern market (Czech Republic, Poland, Hungary, Slovakia and Slovenia).

The level of competition varies widely between these regional markets. For instance, whereas the number of power producers dominating the market is relatively low in the Italian, Iberian and West Continental markets, it is relatively high in the other markets. On the other hand, while present excess generation capacity is tight in the Nordic and Italian markets, it is more comfortable or even large in the other regional markets (DG TREN, 2004-05).

Due to remaining internal trade barriers and other restrictions, however, even within one regional market there may still be significant differences in market competition in terms of number of dominant participants, level of vertical integration, strategic behaviour, and trading arrangements, resulting in different price effects in regional sub-markets for different categories of electricity users.[14] Therefore, the differences in market structure between and within the regional power markets of the EU have to be accounted for when assessing the level to which carbon costs of emissions trading will be passed through to wholesale and retail end-user prices.[15]

The relationship between various market structures and the extent to which CO_2 costs of emissions trading will be passed through to power prices is explained theoretically and illustrated graphically in Appendix A of the present report. This appendix shows that under certain conditions (no outside competition - see Section 4.5 below - and, most notably, a linear demand curve), the extent to which carbon costs are passed through to power prices is given by the formula N/(N+1), where N is the number of identical power generators operating in the market.

The implications of this formula are somewhat counterintuitive: a monopoly (where N=1) passes through half of any increase in carbon costs. However, if a sector is more competitive (i.e. the number of firms increases), the level of cost pass-through rises until it is close to 100 percent. In general, the greater the degree of market concentration, the smaller the proportion of the CO_2 costs will be passed on. Or, in other words, the more competitive the industry, the greater the cost pass-through (Oxera, 2004; see also ILEX, 2004; CEPS, 2005, Varian, 1984, as well as Appendix A of the present report).

This apparently paradoxical and counterintuitive result can be explained by the fact that as an industry becomes more competitive, prices become more aligned with costs. In competitive markets, where producers are assumed to maximise their profits, marginal costs are equal to marginal revenues (i.e. market prices). Hence, *ceteris paribus*, carbon costs will be fully trans-

---

14 For an analysis of the similarities and differences in the competitive position of large power producers in the countries of North-western Europe, see Scheepers et al., 2003.

15 For instance, although ILEX (2004) expects that carbon costs will be fully passed through on the wholesale markets of Germany and France, on the retail market the level of pass-through is expected to vary between 2.5 percent in France and 100 percent in Germany.

mitted into higher prices. On the other hand, in less competitive markets - where producers are also assumed to maximise profits and where prices are already relatively high due to the mark-up above marginal costs - less than 100 percent of the change in carbon costs is actually transmitted into higher power prices as these equilibrium prices are set under imperfect market conditions (with a sloped marginal revenue curve), resulting in a reduction of the mark-up as carbon costs increases (see Appendix A, notably Figure A.5, as well as Section 7.3, Figure 7.3, dealing with different market structures in the COMPETES model).

4.5 Outside competition

The level of passing through carbon cost into power prices depends also on the level of outside competition, which is closely related to the issue of market structure outlined in the previous section. In fact, in the previous section, the formula on cost pass-through was based on the assumption of no outside competition.[16] However, with regard to the coverage of the power sector in the EU ETS, three different kinds of outside competition can be distinguished.

- Competition from foreign companies outside the EU ETS. For the power sector within the EU ETS, this is not a relevant factor as hardly any power is imported from outside the borders of the EU. However, for other sectors or activities covered by the EU ETS, for instance basic metals, this may be a relevant factor explaining why they are hardly able to pass through carbon costs into their outlet prices as these prices are largely set by world markets and foreign competition.
- Competition from power installations below the participation threshold level of 20 MWh_{th}. In general, this is also not a relevant factor as the market share of these installations is small, while they are usually not the price-setting (marginal) units. However, depending on the incidence of alternative carbon policy constraints to these installations, their market share may increase in the long run in an attempt of power producers to avoid the restrictions of the EU ETS by operating below the threshold level.[17]
- Competition from non-fossil installations. This factor may be relevant in those countries where the share of non-fossil generated electricity is high, particularly where such installations are the price-setting units during a certain load period (for instance, nuclear plants in France or hydro installations in Sweden). In these cases, fossil fuel plants are not able to pass through their carbon costs. Moreover, this factor may become even more relevant in the coming decades as the competitiveness and, hence, the share of non-fossil power is likely to improve owing to the climate policies of EU countries.

[16] If outside competition is present, the formula for cost pass-through becomes X/(N+1), where X is the number of companies affected by the cost change and N is the total number of identical companies operating in the market (or, more precisely, N is the number of firms within the industry that remain profitable in the long run, after the cost increase, although for the short run it may be assumed that N is equal to the initial number of firms in the industry). The most important conditions or assumptions underlying this formula are a linear demand fuction and identical companies operating in the market (Oxera, 2004).

[17] Such an attempt, however, seems not very likely given the opportunity for power producers to make windfall profits due to the EU ETS.

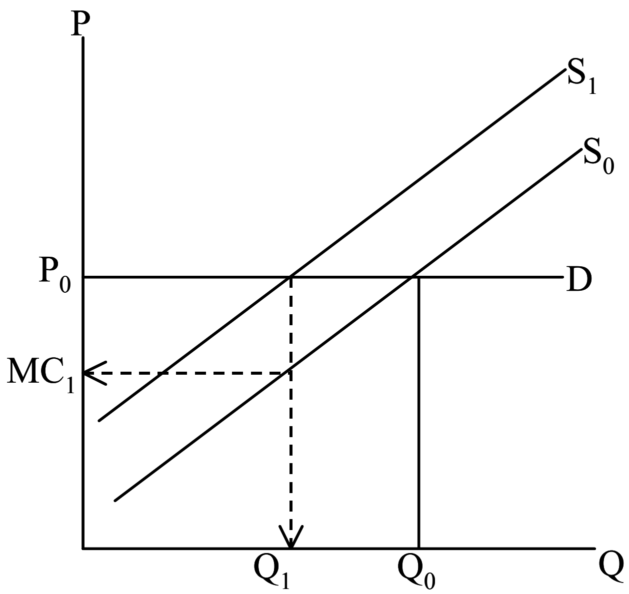

Figure 4.2 *Passing through of carbon costs when power price is given*
Note: S_0 is the supply curve excluding carbon costs while S_1 includes carbon costs.

The impact of outside competition on the passing through of carbon costs to power prices can be illustrated by Figure 4.2 representing a case of perfect competition where the power price is given for individual generators (corresponding to a situation in which the demand curve is fully elastic). When emissions trading is introduced, the opportunity costs of allowances are added to the other marginal costs, resulting in a shift of the supply curve from S_0 to S_1. Under these conditions, the power price remains the same (P_0), but generators will still equate their total marginal costs (including the opportunity costs of grandfathering) to this given price. As a result, this implies that (i) generators will reduce their output from Q_0 to Q_1, (ii) generators will still pass on the opportunity costs of grandfathering (i.e. the add-on rate is 100 percent) although the power price remains the same (i.e. the work-on rate is 0 percent), (iii) the windfall profits per unit output is equal to the difference between the power price and the corresponding marginal production costs, excluding the opportunity costs of grandfathering (P_0 - MC_1), and (iv) total windfall profits are equal to Q_1*(P_0 - MC_1).[18] The observation that power producers still pass on the full amount of the opportunity costs of grandfathering (and, hence, realise a corresponding windfall profit per unit output) while the power price remains the same is explained by the fact that the other marginal production costs are reduced due to the decrease in output up to the point where total marginal costs, including the opportunity costs of grandfathering, are equal to the power price. Hence, even if the work-on rate is zero, power producers may still make a windfall profit due to grandfathering.

4.6 Market regulation and voluntary agreement

The level of cost pass-through depends also on the incidence of market regulation and government intervention in EU member states. This applies particularly for countries such as Ireland, Italy and Spain (ILEX, 2004; Reinaud, 2004; Doyle 2005). In Ireland, for instance, the government announced in April 2004 that it might use adjustments in transmission and distribution charges - especially for Irish state-owned companies - in order to ensure that the full pass-through of carbon costs into wholesale electricity prices does not feed through into retail prices for consumers and to prevent ‘windfall profits’ for these companies arising from freely allocated emission allowances (ILEX, 2004). In Spain, the government decided in July 2004 not to allow electricity companies to raise prices to cover the costs of emissions trading. Moreover, any in-

[18] Note, however, that ‘normal profits’ are likely to decline due to the decrease in output production.

crease in wholesale prices would be offset in lower stranded cost compensation to generators until the expiration in stranded costs (Reinaud, 2004).

The implications of market or price regulation can be illustrated by the left part of Figure 4.3, where S_0 is the supply curve excluding carbon cost while S_1 includes carbon cost. Emissions trading without price regulation results in an increase in power prices from P_0 to P_1 and a decrease in power production from Q_0 to Q_1. However, if the price is regulated at P_r, generators will reduce their production (and sell their surplus of grandfathered allowances on the market) until the marginal costs of power output (including the full opportunity costs of power output) is equal to the regulated price (at point Q^s).[19] Hence, while the price impact of grandfathering is restricted (i.e. the work-on rate will be reduced), producers still pass through the full amount of the opportunity costs of emission allowances (i.e. the add-on rate is still 100 percent). The major effect of price regulation is that it reduces the quantity supplied (Q^s) and, hence, reduces the other marginal production costs (S_0, excluding carbon costs) but it does not reduce the amount of CO_2 cost passed through. Therefore, from a point of view of restricting the add-on rate and, hence, reducing the incidence of windfall profits, price regulation is ineffective.

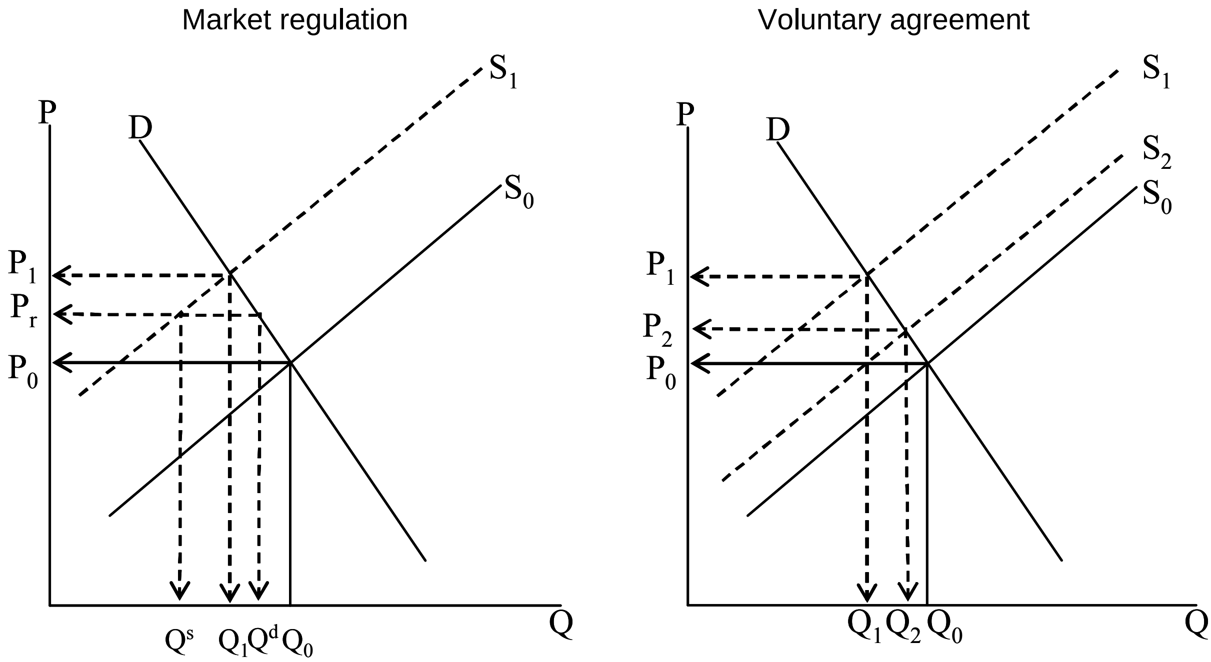

Figure 4.3 *Implications of market regulation and voluntary agreement for power prices, production and passing through carbon costs*

In addition, price restrictions will enhance power demand (Q^d), while reducing power supply, resulting in unmet official demand and non-price rationing of supply. This leads to the creation of informal markets - where uncontrolled, unofficial prices are higher - and/or to investments in so-called rent-seeking activities among consumers ('how do I get access to scarce, but cheap resources') rather than investments in efficient production opportunities among power generators. As a result, price regulation is hardly effective in controlling prices or reducing the level of passing through opportunity costs of emissions trading ('add-on rate').

A specific form of regulation or 'voluntary agreement' concerns the proposal launched by some organisations representing European power-intensive industries (see, for instance, ECON, 2004a; Reinaud, 2004; or CEPS, 2005). In short, this proposal includes that power producers are either forced or 'voluntary agree' to pass through only the average 'true' costs of the emission

[19] In practice, however, it is hard to imagine that such a situation will occur in the power market. Most likely, (informal) rents or subsidies to producers will increase in order to induce additional supply.

allowances actually bought rather than the full marginal, opportunity costs of the allowances allocated for free. The implications of this kind of regulation or 'voluntary agreement' can be illustrated by the right part of Figure 4.3, where S_2 represents the supply curve including the average 'true' costs of the emission allowances actually bought on the market. If producers agree to accept S_2 as their supply curve, the resulting power price becomes P_2 while the level of production amounts to Q_2. As a result, the level of passing through carbon cost is limited to the average 'true' costs of allowances bought on the market and, hence, the incidence of windfall profits is avoided.[20]

4.7 Market demand response

In addition, the extent to which carbon costs will result in higher power prices depends on the response or sensitivity of electricity demand to price changes, as measured by the so-called 'own-price elasticity of demand'. This elasticity is generally low for households and other small-scale consumers of electricity, but may be more significant for major end-users such as the power-intensive industries. Moreover, the price elasticity of demand is usually higher in the long term than in the short run (for instance, because of the diffusion of power-saving technologies or because power-intensive industries decide to generate electricity for themselves). Finally, the price elasticity of demand for an individual supplier will be higher if consumers have the opportunity and willingness to switch to another supplier. Hence, these potential differences in market response have to be accounted for when assessing the extent to which carbon costs of emissions trading will be transmitted in higher prices on various markets in EU countries.

Figure 4.4 shows the impact of elastic versus inelastic demand response on passing through carbon costs to the price of electricity under perfect market conditions. If the power demand is inelastic, the change in power price (P_1 - P_0) is equal to the change in marginal costs due to emissions trading (S_1 - S_0, i.e. the carbon costs) and, hence, the 'work-on rate' is equal to the 'add-on rate' (100 percent, similar to Figure 4.1 of Section 4.1). If the power demand is elastic, however, the change in power price is smaller than the change in marginal costs due to emissions trading. While the work-on rate will, hence, be lower than 100 percent, the add-on rate will remain 100 percent and, therefore, in case of grandfathering, the incidence of windfall profits does not change per unit output (although the volume of output sales is reduced).[21]

[20] Note, however, that regulation or voluntary agreements on price restrictions may also have some adverse effects and policy implications (see Chapter 8).

[21] Note though that if Q is less, then the implied demand curve for allowances shifts to the left, which will lower the price of allowances. As a result, the total allowance rent would likely decrease.

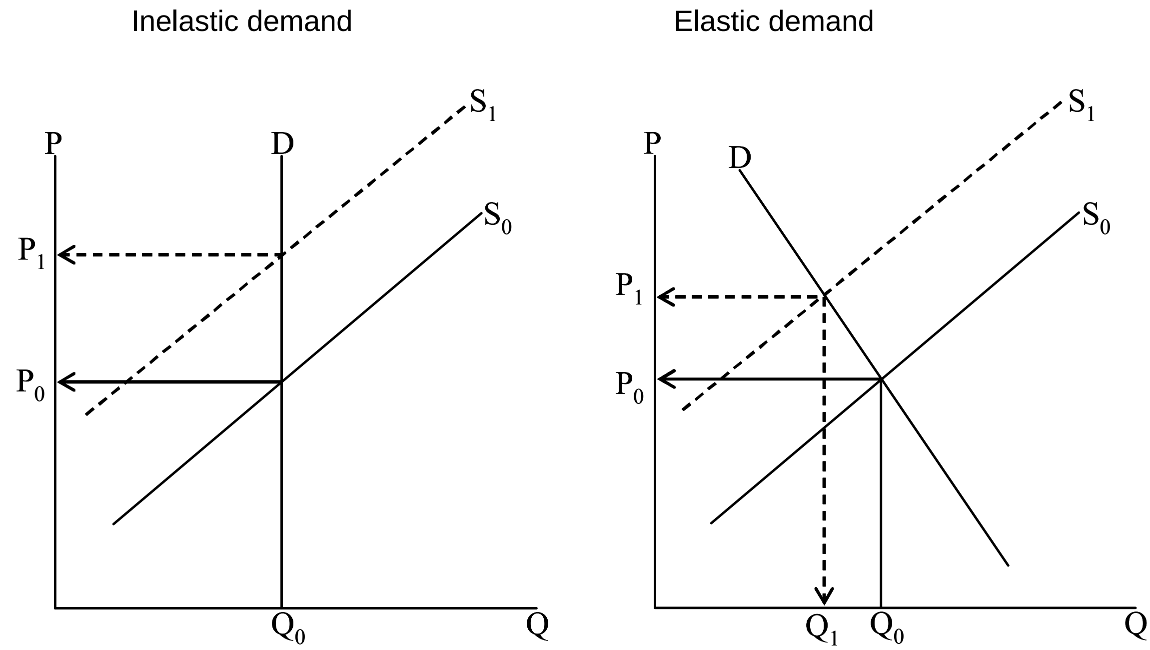

Figure 4.4 *Impact of market demand response on passing through carbon cost to power price*
Note: S_0 is the supply curve excluding carbon cost, while S_1 includes carbon cost.

4.8 Changes in merit order

The extent to which carbon costs are passed through to power prices depends also on changes in the merit order of the supply curve due to emissions trading (as discussed in Section 3.2). This can be illustrated by Figure 4.5, where the supply curve is characterised by a step function with two types of technologies - A and B. The fixed demand is indicated by the vertical dash line. In the left part of Figure 4.5, when there is no change in the merit order, the change in the power price (Δp_2) will always be equal to the marginal CO_2 allowances costs of the marginal generation technology B. The resulting pass-through rate will always be unity (in terms of both the add-on rate and the work-on rate). However, when there is a switch in the merit order - as displayed in the right part of Figure 4.5, the situation becomes different. In this case, the marginal technology is A with CO_2 allowances costs equal to Δp_3 while the change in the power price is Δp_4. Therefore, the work-on rate $\Delta p_4 / \Delta p_3$, will be less than 1 since $\Delta p_4 < \Delta p_3$. However, the add-on rate for the marginal production technology A is 100 percent and, hence, in case of grandfathering the incidence of windfall profits per unit output does not change.

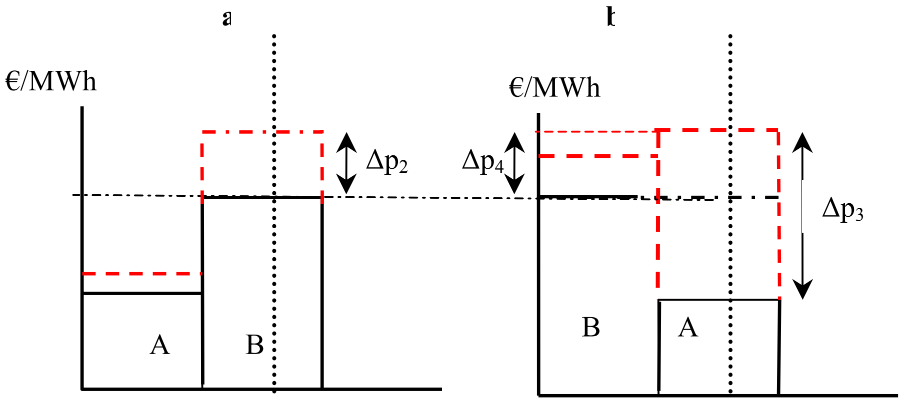

Figure 4.5 *Pass-through rates under changes in the merit order*

4.9 Carbon-saving innovations

Besides (short-term) changes in the merit order of production technologies due to emissions trading, the rate of passing through CO_2 costs depends also on the generation and diffusion of carbon-saving innovations, which - to some extent - are induced by changes in the costs of emissions trading. However, induced technological change is a cumbersome, long-term process that may become only fully effective if changes in carbon costs are supplemented by a package of policy measures to address the variety of market imperfections in the field of carbon-saving innovations (Sijm et al., 2004).

4.10 Updating of EUA allocations

Updating - or rebasing - implies that the historical basis for allocating allowances freely is updated periodically. Such an allocation method exerts a downward effect on the level of cost pass-through in rebasing years. If the allocation for the second phase of the EU ETS depends on emissions during the first phase, this creates a perverse incentive to higher emissions during the first phase in order to gain additional allowances in the second phase. This implies that the internal opportunity costs of selling emission allowances will be lower than the CO_2 market price and, consequently, companies will be inclined to pass through a lower level of carbon costs and, hence, to raise prices less, resulting in more power production and associated emissions in rebasing periods (ILEX, 2003 and 2004).

For most member states, the allocation method for the second phase of the EU ETS is yet not known. Moreover, the European Commission has already indicated that it will not accept an updating approach for this period (Vis, 2005; Point Carbon, 2005). Therefore, it is unlikely that this allocation option might have an impact on the level of passing carbon costs during the first phase of the EU ETS.

4.11 Non-optimal behaviour, market imperfections, time lags and other constraints

Economic theory and power sector models are usually based on the assumption that producers maximise their profits under (largely) perfect market conditions such as full information, no risks or uncertainties, low adjustment costs, hardly any time lags, etc. Under such conditions,

CO_2 costs of freely allocated allowances will be regarded as true opportunity costs that will be fully and immediately passed on to consumers. In daily practice, however, power production, trading, pricing and other decisions may deviate significantly from optimal outcomes due to a variety of reasons, namely (i) trade or risk managers pursue sometimes other objectives besides profit maximisation, (ii) the incidence of risks, uncertainties or lack of information, (iii) the incidence of other production constraints, such as a lack of a flexible and liquid gas market, resulting in a lack of production flexibility and high costs of short-term production adjustments.[22] In addition, during periods of volatile or rapidly rising CO_2/fuel prices, it may take some time before these costs are fully covered by proportionally rising power prices. Therefore, due to all these reasons, CO_2 costs may not always be fully or immediately passed on to power prices. However, the intent and likely ultimate effect of electricity market liberalisation is to increase the incentive for generators to adapt more quickly and effectively to changes in cost, demand, and technology conditions, so adjustments to rising CO_2 and costs might occur more rapidly in the future than they would have in the past.

4.12 Summary and conclusion

In principle, power producers will always pass on the full opportunity costs of freely allocated emission allowances in the sense that they will add these costs to their other marginal production costs (i.e. the so-called add-on rate is, in principle, 100 percent). Producers, however, can not simply set power prices as these are determined by a complex set of market forces. Hence, due to a variety of reasons, the work-on rate (i.e. the extent to which CO_2 allowances costs ultimately work on power prices) may be significantly lower than the add-on rate (i.e. the extent to which producers add on the opportunity costs of grandfathered emission allowances to their other, marginal costs when making production or trading decisions). These reasons refer to the incidence of (i) outside competition, (ii) a change in the merit order (iii) demand response (iv) the incidence of market regulation, (v) market power, (vi) carbon saving innovations (vii) updating of EUA allocations, (viii) a decline in so-called 'mark-ups' and 'fixed cost margins' of power prices due to grandfathering and the dynamics of new investments, and (ix) the incidence of non-optimal behaviour, market imperfections, time lags and other constraints. The relevance and timing of these reasons to explain the pass-through rate of carbon costs in a particular situation is largely an empirical question requiring further (long-term) research. However, even if the power price remains the same (i.e. the work-on rate is zero), power producers may still pass on the full opportunity costs of freely allocated emission allowances and, hence, realise a windfall profit as their other marginal production costs may decline due to some of the reasons mentioned above.

[22] It is striking that during the interviews with power producers in the Netherlands (see Chapter 5), they mentioned particularly these reasons to explain why the actual pass-through rate in the Netherlands might be less than 100 percent (rather than the other reasons outlined in the previous sections).

5. Major findings of stakeholders interviews

5.1 Introduction

This chapter includes a summary of the major findings of interviews with stakeholders in the Dutch electricity sector, including major power producers/suppliers and major power-intensive, industrial users in the Netherlands. The main purposes of these interviews were (i) to hear the point of view of these stakeholders on the potential impact of EU emissions trading on the price of electricity, and (ii) to enhance the practical knowledge of the interviewers on this issue, notably the testing of some (theoretical) ideas on the behaviour of power producers/suppliers, the extent to which CO_2 costs are passed on to electricity prices, and the implications of such a potential pass-through for the major power-consuming industries.

Overall, ten interviews were held in the period 15-06-2005 to 14-07-2005. Interviews with staff members of power producers/suppliers included the following companies: Electrabel, ENECO, E.ON, ESSENT and NUON. In addition, interviews were held with four major power-consuming industries - i.e. Corus (iron and steel), Pechiney (aluminium), Philips (electronics) and DSM (chemicals) - as well as with staff members of the Dutch Association for business users of Energy and Water (VEMW).

Anonymous summaries of the major findings of the interviews with staff members of the power companies and, subsequently, major power-consuming industries are presented in Sections 5.2 and 5.3, respectively. It should be emphasised, however, that the views expressed in these sections are those of the stakeholders interviewed, and not necessarily those of the interviewers (i.e. the authors of the present report).[23] Moreover, it has to be stressed that although the sections below provide summaries of the views expressed by the stakeholders interviewed, this does not necessarily imply that they are (fully) shared by each individual stakeholder concerned for which he/she or the company involved can be accounted for.

5.2 Views expressed by power companies

The major findings of the interviews with staff members of the major power companies in the Netherlands can be summarised as follows:

Pricing and market behaviour

- In general, power companies try to maximise their profits by optimising their production and trading ('make-or-buy') decisions. In that respect - following economic theory and sound business principles - costs of freely allocated CO_2 allowances are regarded as opportunity costs, which are included when power companies make their production and trading decisions. Hence, based on these principles, one would expect CO_2 costs of emission allowances to be passed on to power prices.
- Power prices are determined on the wholesale market. On this market, power companies are purely interested in maximising their profits through business optimisation, and not in reaching a certain market share.
- Power prices on the retail market are derived from those on the wholesale market. On the retail market, power suppliers are interested in market shares, but the price margin for competition on this market is usually small and, hence, competition on the retail market is to a major extent based on cost components such as marketing, call centres, back-offices or other services.

[23] The views of the authors - if any - are expressed in others parts of the report, particularly in Chapters 6 and 8.

The extent of passing through CO_2 costs

- Although power companies may affect power prices by means of their strategic behaviour, this does not imply that they are able to simply set these prices or simply pass through costs to power prices ('cost-plus-adding') as these prices are primarily determined by wholesale market forces.
- In general, it is hard to assess the impact of CO_2 allowances costs on power prices as these prices are determined by a large variety of factors, including fuel prices, the Euro/US$ exchange rate, available production capacity, investment costs, imports, weather conditions, heat demand ('must runs'), gas contract inflexibilities, expectations and sentiments of market players, etc.
- The extent to which CO_2 costs are passed through to power prices varies by market, load factor and country considered. In general, the pass-through rate seems to be higher on the spot market than the forward market (probably because on the spot market, prices are primarily determined by short-term marginal costs - including CO_2 allowances costs - while on the forward market other, additional factors also play a role). Overall, however, price differences between different markets are mitigated by price arbitrage. A direct effect of emissions trading is that it creates a bottom or minimum price on the spot market (as suppliers will not sell power in this market below the opportunity costs of CO_2 allowances). An exception to this rule concerns the so-called 'must-run' hours in which prices can sometimes be rather low as certain (CHP) installations have to run regardless the demand for electricity.
- In addition, the extent to which CO_2 allowances costs are passed on to base load prices seems to be higher in Germany (40-50 percent) than in the Netherlands (20-25 percent). However, as the off-peak load prices in the Netherlands are largely determined by coal-generated power imports from Germany, the pass-through rate with regard to Dutch off-peak prices is also estimated at about 40-50 percent for coal-generated power.
- Analyses of spark spreads in the Netherlands (and Belgium) show that these spreads - i.e. the difference between power prices and fuel/gas costs, including CO_2 costs - have declined significantly during recent periods of high CO_2 prices, sometimes to very low or even unremunerative levels. According to the power companies, this indicates that there is no relationship between the prices of power and CO_2 in the sense that CO_2 allowances costs are not or hardly passed on to power prices.

Explanations for the relatively low pass-through rate of CO_2 costs

- Based on economic theory and sound business principles, one would expect full or at least a high rate of passing through CO_2 costs to power prices, but in practice this rate seems to be relatively low, at least in the Netherlands. According to the power companies, this relatively low rate can be attributed to the following reasons:
  - The relatively high incidence of so-called 'must-runs' installations (i.e. mainly CHP plants) in the Netherlands, which causes a lack of flexibility as well as a depressing effect on power prices and spark spreads, particularly during the off-peak hours.
  - The CO_2 market is still young and immature, i.e. characterised by ignorance, uncertainty, illiquidity, volatility and lack of transparency.
  - The incidence of a variety of other reasons and distorting factors such as (i) the presence of market sentiments and expectations, (ii) the incidence of risks, uncertainties or lack of information on the power/CO_2 market, (iii) the incidence of uneconomic or non-optimal behaviour of trade and risk managers who sometimes pursue other objectives besides profit maximisation, and (iv) the incidence of other production constraints, including a lack of a flexible and liquid gas market, resulting in a lack of production flexibility and high costs of short-term production adjustments.

5.3 Views expressed by major power-consuming industries

The major findings of the interviews with staff members of some major power-consuming companies in the Netherlands can be summarised as follows:

Power use and contracts

- Power consumption by the industrial end-users interviewed is generally high, varying between 600 to 3400 GWh per annum (for the plants located in the Netherlands). Most of the electricity used is bought from the (wholesale) market - i.e. not self-produced - by means of a variety of long-term contracts with a variety of power suppliers (both domestic and foreign, with a term of usually 1-2 years). The power price in these contracts is either fixed (based on current forward prices) or based on an index of energy prices.

Impact of CO_2 allowances cost on power prices.

- For power-intensive users, it is often hard to assess exactly the impact of CO_2 emissions trading on power prices as the transparency of power markets and pricing is often limited, while power suppliers are not willing to hand over so-called ‘cost-plus’ contracts.
- Nevertheless, based on their available information, major power-consuming industries estimate that in June 2005 forward base load prices (Cal 2006) have increased by approximately 7-9 €/MWh due to the (partly) passing through of CO_2 allowances costs. For the off-peak hours in the Netherlands, the extent to which CO_2 costs are passed on to (coal-generated) power prices (Cal 2006) is estimated at 65 percent during the first part of 2005.
- One respondent reported that the percentage of passing through the CO_2 costs in the electricity price is not the fundamental issue. In his opinion, CO_2 costs are taken 100 percent into account in the business optimisation process. This phenomenon is caused by the nature of the current allocation rules (cap and trade). But the outcome on the electricity prices is low or even zero in percentage terms at low CO_2 prices and high in percentage terms at high CO_2 prices.

Impact of higher power prices

- The impact of higher power prices is very significant for power-intensive industries, especially for the aluminium and iron & steel industries. In general, power consumption is a significant (5-10 percent, up to 30-40 percent) of the cost structure of some products of these industries, while they are not able to pass these (higher power) costs on to their outlet prices as these are usually determined by world market forces (including outside competitors who are not faced by similar increases in power prices due to CO_2 emissions trading).

Options to avoid or mitigate the impact of higher power prices

- *Self-production*. For most of the major power-consuming industries self-production is not a real option for a variety of reasons: “it is not our business”, high initial investment costs, long-term and sometimes cumbersome license and investment project procedures, capacity/imbalance problems, including the problem of the required back-up installation, etc. In addition, it was mentioned that self-production could never be a structural solution for buyers of electricity. It would only mean that they have to charge the higher market price to their internal customers (or to themselves) because they have the opportunity to sell the electricity on the market at the higher power prices.
- *Energy saving*. Options for saving power are rather limited for the industries interviewed as they are already highly energy efficient and meet high international benchmarks regarding power intensities.
- *Stringent contract/price negotiations*. To a certain degree, power-intensive industries consider using their (limited) countervailing market power to negotiate power price contracts that reduce the CO_2 impact, but up to now this has not led to concrete results.
- According to one respondent, the root cause of the problem is the system of allocation; the amount of allowances is decoupled from the amount of production of electricity. Structural

solutions must address this root cause. For example, an allocation just below the EU-average of the emission per unit of output (tonne CO_2/MWh) would address the root cause. When coal-fired electricity is marginal, prices will marginally increase and when gas-fired electricity is marginal the opposite will occur. This could mitigate undesired windfall profits caused by the opportunity-cost principle.

6. Empirical analyses of price trends and pass-through rates

This chapter discusses the major results of some empirical and statistical analyses of price trends and pass-through rates in the electricity sector of Germany (DE) and the Netherlands (NL), notably for the period January-July 2005. Firstly, Section 6.1 shows some trends in prices of electricity, fuels and CO_2 allowances, and discusses whether there is any relationship between these trends. Subsequently, Section 6.2 presents trends in so-called dark and spark spreads of power production as well as the results of a simple regression-line method to estimate rates of passing-through CO_2 costs in power prices, based on these trends in dark and spark spreads. Finally, Section 6.3 discusses the results of some statistical regression analyses to estimate pass-through rates.

6.1 Trends in prices of electricity, fuels and CO_2 allowances

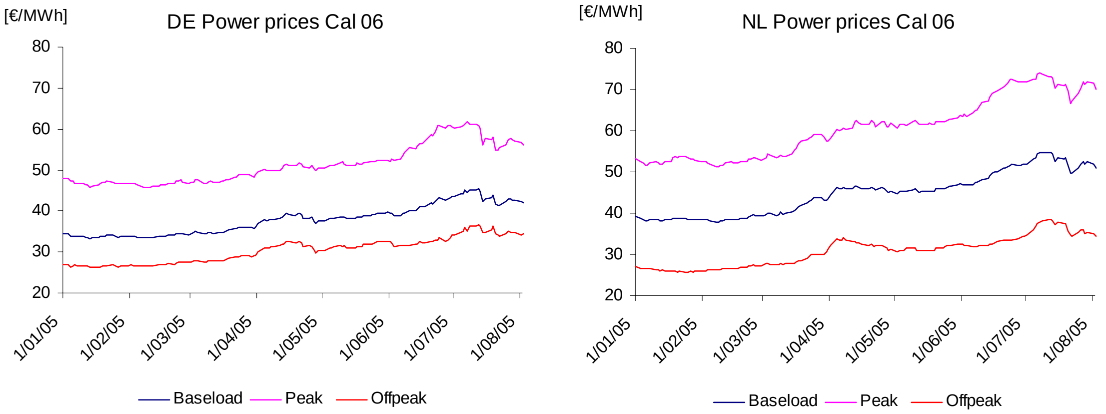

Figure 6.1 *Power prices in Germany and the Netherlands (Forward Cal 2006, January-July 2005)*

Figure 6.1 shows the trends in forward power prices (Calendar 2006) in Germany and the Netherlands over the period January-July 2005 for base load, peak load and off-peak hours.[24] In general, these prices have increased significantly over this period, particularly up to the first week of July followed by a small decline in power prices during the remaining weeks of July. For instance, peak load prices in the Netherlands have risen from about 52 €/MWh in early January 2005 to approximately 72 €/MWh in early July 2005 and, subsequently, declined slightly to some 70 €/MWh in late July 2005. This development fits into or, more accurately, accelerates a longer-term trend of steadily rising power prices in the Netherlands as exemplified by the Dutch peak load prices which have increased from about 43 €/MWh in early 2001 to approximately 52 €/MWh in late 2004 (DTe, 2005).

[24] In the Netherlands, peak hours run from 7:00 up to 23:00h each working day, i.e. excluding weekends and public holidays. Assuming 255 working days per year, this implies a total number of 255 * 16 = 4080 peak hours per year. All other hours in the year are considered as off-peak hours, i.e. 8760 - 4080 = 4680 hours per year. The power price for off-peak hours ($O_{ff\text{-}peak}$) has been calculated as follows: $O_{ff\text{-}peak} = ((8760 * P_{baseload}) - (4080 * P_{peak}))/4680$ (DTe, 2005). For Germany, peakload hours are defined from 8:00 to 20:00h for each working day, regardless whether it is a holiday or not. Assuming 260 working days per year, this implies a total number of 260 * 12 = 3120 peak hours per year. Hence, for Germany, the off-peak power price has been calculated as follows: $O_{ff\text{-}peak} = ((8760 * P_{baseload}) - (3120 * P_{peak}))/5640$ (RWE, personal communication).

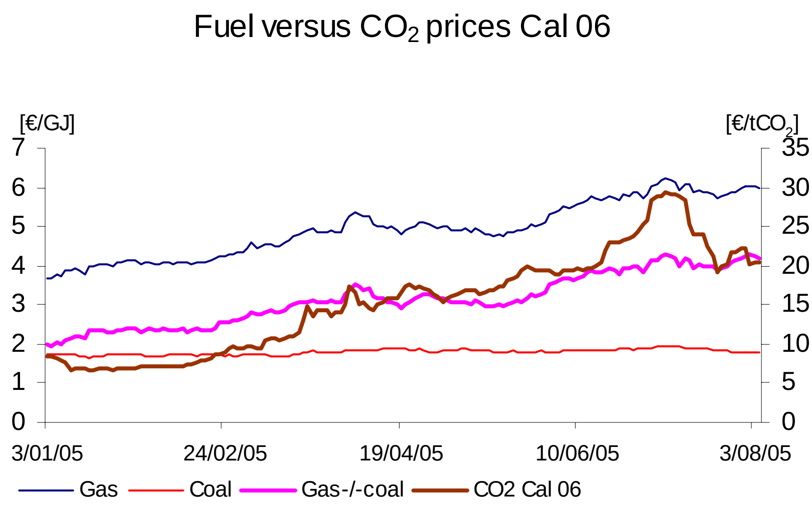

Figure 6.2 *Fuel versus CO_2 prices (Forward Cal 2006, January-July 2005)*

Figure 6.2 presents trends of forward prices for CO_2 allowances on the EUA market (Delivery December 2006) and internationally traded fuels such as coal and gas (Calendar 2006).[25] It can be observed that whereas coal prices have been more or less stable at a level of 1.8 €/GJ over the period considered (January-July 2005), gas prices have increased strongly from less than 4.0 €/GJ in early January to approximately 6.0 €/GJ in late July. This difference in price trends between coal and gas is caused largely by the fact that wholesale gas prices are linked to the international oil prices - which have increased significantly since 2004 - while coal prices are not. As a result, the price differential between gas and coal has been more than doubled from less than 2 €/GJ in early January to more than 4 €/GJ in late July.

The rising price differential between gas and coal has been one of the major factors determining the increase in CO_2 prices on the EUA market from less than 10 €/tCO_2 in January to almost 30 €/tCO_2 in early July (due to the switch from gas to coal and the resulting increase in the demand for EUAs, as explained in Chapters 2 and 3). This is supported by Figure 6.2, which shows both a rising gas-/-coal price differential (expressed on the left-hand Y-axis) and an increasing CO_2 price on the EUA market (expressed on the right-hand Y-axis).

Figure 6.3 shows the relationship between power and CO_2 prices in Germany and the Netherlands during the first seven months of 2005. At first sight, the figure suggests a close (almost one-to-one) correlation between these prices. Although illustrative, the figure is a bit suggestive - not to say 'manipulative' - as the Y-axes of this figure have been adjusted to fit a close relationship between power and CO_2 prices. Such figures are sometimes used not only to suggest a close correlation between power and CO_2 prices, but also a full passing through of CO_2 costs into power prices.[26] However, even if there is a close correlation between power and CO_2 prices, this is no conclusive evidence on the extent to which CO_2 costs may be passed on to power prices (as even with a minor pass-through there might be a high level of correlation between power and CO_2 prices).

[25] Throughout this chapter, coal refers to the internationally traded commodity classified as coal ARA CIF API#2, while gas refers to the high caloric gas (35,17) from the Dutch Gas Union Trade & Supply (GUTS).

[26] See, for instance d'Adda (2005).

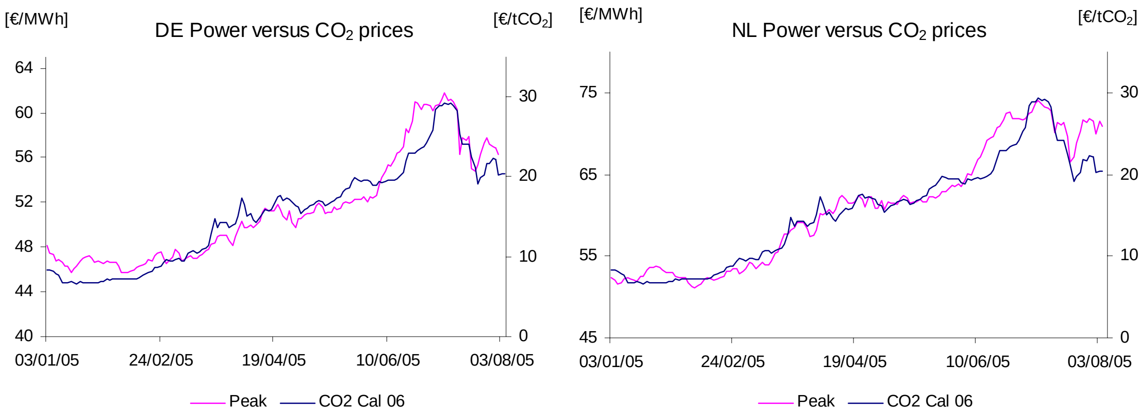

Figure 6.3 *Power versus CO_2 prices in Germany and the Netherlands (Forward Cal 2006, January-July 2005)*

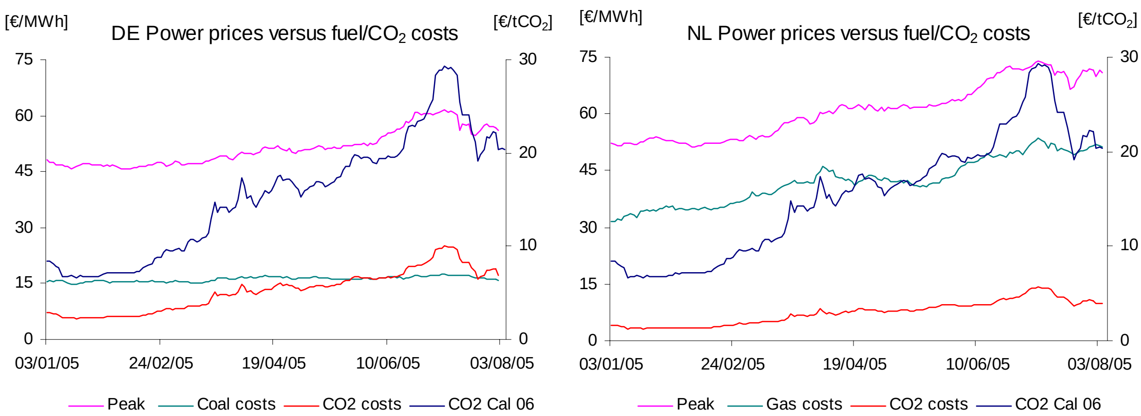

Figure 6.4 *Power and CO_2 prices versus fuel/CO_2 costs in Germany and the Netherlands (Foward Cal 2006, January-July 2005)*

Less suggestive - and more informative - is Figure 6.4, which shows not only power and CO_2 prices along unadjusted Y-axes but also fuel and CO_2 costs to generate a MWh of power (assuming a fuel efficiency of 40 percent for coal and 42 percent for gas, a related emission factor of 0.85 and 0.48 tCO_2/MWh for coal and gas, respectively, and full 'opportunity' costs for generating electricity by either coal or gas). The left-hand side of the figure covers the case of coal-generated peak load power in Germany, while the right-hand side presents the case of gas-generated peak load power in the Netherlands.

The German case shows that the fuel (i.e. coal) costs to generate power have been more or less stable at a level of about 16 €/MWh during the period January-July 2005 (which comes at no surprise because - as noted above - coal prices have been rather stable over this period). CO_2 costs of coal-generated power, however, have been significant and approximately trebled over this period - from about 6 €/MWh in January to some 18 €/MWh in July - which is due to the rising CO_2 prices and the high - but constant - emission factor of coal-generated power). This suggest, therefore, that the increasing peak load prices in Germany over this period - from 47 to 57 €/MWh - have been caused primarily by the rising CO_2 prices, although the CO_2 costs seem to have not (yet) been fully passed on into the peak load power prices.[27]

[27] These figures suggest that about (10 - 0)/12 = 83 percent of the CO_2 costs of coal-generated power has been passed through to German peak load prices.

On the other hand, the Dutch case illustrates that the fuel (i.e. gas) costs to produce electricity has risen substantially from some 33 €/MWh in early January 2005 to about 50 €/MWh in late July. CO_2 costs of gas-generated power have also increased over this period, but less dramatically, i.e. from 4 to 10 €/MWh (partly due to the relatively low - but constant - emission factor of gas-generated electricity). This suggests, hence, that the rising peak load prices in the Netherlands over this period - from about 52 to 72 €/MWh - have been predominantly caused by the rising gas prices, while the (less rising) CO_2 costs seem to have been only partly passed through into the peak load prices.[28]

6.2 Estimates of dark/spark spreads and pass-through rates

The method presented below to estimate the extent to which CO_2 costs are passed on to power prices is based on an analysis of the trend in so-called dark/spark spreads over a certain period, both excluding and including CO_2 costs. For the present analysis, a *dark* spread is simply defined at the difference between the power price and the cost of *coal* to generate a 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 the costs of CO_2 are included, these indicators are called '*clean dark/spark spreads'* or '*carbon compensated dark/spark spreads*'.[29]

The method used to estimate pass-through rates can be explained by means of Figure 6.5, which presents estimates of dark/spark spreads - assuming different pass-through rates - over the period January-July 2005 during the peak load hours. The left-hand side of this figure refers to the case of coal-generated power in Germany, while the right-hand side covers the case of gas-generated power in the Netherlands (assuming a fuel efficiency rate of 40 percent for coal and 42 percent for gas). For each case, four sub-figures are distinguished:

1. The first two (top) sub-figures present the trend in dark/spark spreads assuming 0 percent pass-through of carbon costs to power prices. It can be observed that in both the German (peak load-coal) case as the Dutch (peak load-gas) case the trend line of the dark/spark spreads moves upwards, indicating that CO_2 costs are to some extent included in the power price (based on the assumption that without including these costs, the trend line would be a straight horizontal line, as discussed below). This is confirmed by the correlation coefficient (R^2 = 0.81/0.30), indicating that the change in dark/spark spreads can be explained to a high extent by the factor time. The upward sloping trend of the spark/dark spreads can be attributed to the assumed fact that a growing amount of CO_2 costs is included in the spreads (creating a positive relationship between these spreads and the factor time). Hence, the assumption of 0 percent pass-through of carbon costs to power prices has to be rejected, i.e. the pass-through rate is larger than zero.

2. The next two sub-figures illustrate the trend in dark/spark spreads assuming 100 percent pass-through of carbon costs to power prices. It can be noticed that in both the German and Dutch cases the trend line of these spreads moves downwards, suggesting that CO_2 opportunity costs are not fully included in the power price (based on the assumption that by including the full CO_2 opportunity costs, the trend line would be horizontal). This is confirmed by the correlation coefficient (R^2 = 0.42/0.54), indicating that the change in dark/spark spreads can be explained to some extent by the factor time. This downward sloping trend of the spark/dark spreads can be attributed to the fact that a too high amount of

[28] These figures suggest that about (20-17)/6 = 50 percent of the CO_2 costs of gas-generated power has been passed through to Dutch peakload prices.

[29] These spreads are indicators for the coverage of other (non-fuel/CO_2) costs of generating electricity, including profits. For the present analysis, however, these other costs - for instance investment, maintenance or operating costs - are ignored as, for each specific case, they are assumed to be constant for the (short-term) period considered - although they may vary per case considered - and, hence, they do not affect the estimated pass-through rates.

CO_2 has been excluded from these spreads (creating a negative relationship between these spreads and the factor time). Hence, the assumption of 100 percent pass-through of carbon costs to power prices has to be rejected, i.e. the pass-through rate is smaller than unity.

3. The following two sub-figures present the trend of the dark/spark spreads - based on the assumption that the trend line of these spreads should be horizontal when including the CO_2 costs - and provide estimates of the corresponding spreads and pass-through rates in order to meet that condition. As indicated, these rates are estimated at 73 percent for the German (base load-coal) case and 39 percent for the Dutch (peak load-gas) case. The R^2 values of the resulting trend lines of the spark/dark spreads are extremely low (3E-06 for the German case and IE-05 for the Dutch case), indicating that these lines are indeed flat and the corresponding spreads constant over time, and that the remaining, observed variations of these spreads can be attributed to random variables (u_t), with an expected value of zero, i.e. $E(u_t) = 0$.[30]

4. Finally, the last two (bottom) sub-figures show the cost components (or built-up) of the power prices in the two cases considered, assuming that CO_2 costs are passed through according to the rates estimated above (resulting in a 'partly carbon compensated' dark/spark spread that fluctuates around a horizontal trend line at a certain level). For instance, as observed in Section 6.1, the fuel (i.e. coal) costs of generating power remain more or less stable at a level of 16 €/MWh, while the (partly) passed-through CO_2 costs increase from less than 4 €/MWh in early January to more than 16 €/MWh in early July 2005. On average, the amount of CO_2 costs passed through in Germany peak load prices is estimated at about 9.5 €/MWh over the period January-July 2005 (i.e. about 73 percent of the full CO_2 opportunity costs). The resulting (partly) carbon compensated dark spread fluctuates around an average level for this period of 26 €/MWh (i.e. the height of the horizontal trend line). On the other hand, in the Dutch case, the fuel (i.e. gas) costs of generating power have increased substantially from about 32 €/MWh in early January to some 50 €/MWh in late July, while the (partly) passed-through CO_2 costs increase from 1.4 to 4.0 €/MWh over this period. On average, the amount of CO_2 costs passed through into Dutch peak load prices is estimated at approximately 2.8 €/MWh over the period considered (i.e. about 39 percent of the full CO_2 opportunity costs). The resulting (partly) carbon compensated spark spread fluctuates between 11.1 and 19.6 €/MWh around an average level for this period of 16 €/MWh (i.e. the height of the horizontal trend line).

30 It should be emphasised that the recorded R^2 values refer to the significance between the spark/dark spreads and the factor time and, hence, to the significance of the assumption that these spreads include a certain amount of CO_2 costs that changes over time. However, the R^2 values do not say anything about the (statistical) significance of the estimated pass-through rates, except that these rates have been estimated correctly if they lead to a flat trend line with a corresponding low R^2 value.

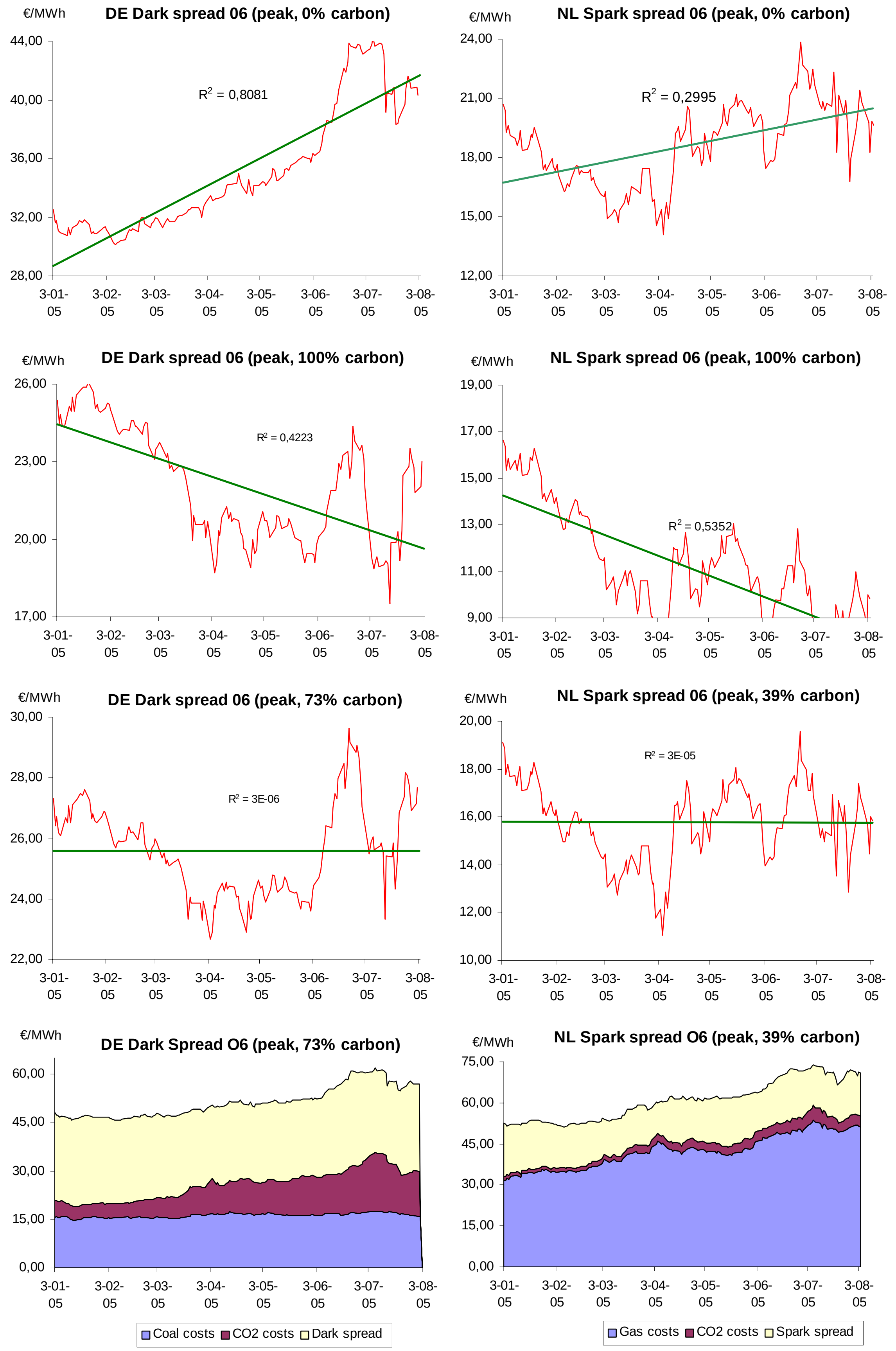

Figure 6.5 *Estimates of dark/spark spreads and CO_2 pass-through rates in Germany and the Netherlands (efficiency coal: 40% and gas 42%, forward Cal 2006, January-July 2005)*

In addition to the two cases discussed above, two other cases have been analysed, including coal-generated power during the off-peak hours in Germany and the Netherlands. These two additional cases are based on a coal efficiency rate of 40 percent. They have been selected as they are regarded as the most representative cases for the off-peak period and countries considered. The two additional cases are illustrated in Figure 6.6, while a summary of the major characteristics and results of all four cases considered is provided in Table 6.1. It shows that the estimated rates of passing-through CO_2 costs vary significantly among the cases considered. For Germany, these rates range from 46 percent for off-peak power to 73 percent for peak load electricity (both cases refer to coal-generated power). For the Netherlands, the variation in pass-through rates is smaller, i.e. from 39 percent for peak load electricity (42% efficiency gas-generated), to 55 percent for off-peak electricity (the latter case refers to coal-generated power). Given the fact that the emission factor for gas is lower that for coal, the variation in absolute figures – i.e. the amount of CO_2 costs passed on to power prices – varies in the Netherlands from 2.8 €/MWh for gas-generated power during peak-load hours to 7.2 €/MWh for coal-generated off-peak electricity. For Germany, the estimated amounts passed through vary between 6 and 10 €/MWh (all coal-generated).

It should be emphasised, however, that these rates and amounts of passing through CO_2 costs do not necessarily apply to all installations during all load periods considered. On the contrary, notably in the Netherlands there is a major share of gas installations that must run during off-peak hours, even if it is not profitable, as seems to be the case under forward 2006 price conditions. Under these conditions, such price-following installations are not able to cover the opportunity costs of grandfathered allowances, let alone to realise 'windfall profits' due to emissions trading. On the other hand, it should be recognised that - besides potential revenues from heat production - these installations may earn significant profits during peak load hours (when prices are relatively high) and that without emissions trading power prices might have been lower during the off-peak hours given the average pass-through rates and the average high CO_2 prices considered.

In addition, it should be stressed that the estimated rates and amounts of passing through CO_2 costs are sensitive so some (methodological) assumptions, notably:
1. The assumed trend line
2. The period considered
3. The fuel efficiency rate assumed
4. The fuel price considered

These issues will be discussed below.

The assumed trend line
As noted, the estimate of the pass-through rate is based on the assumption of a straight horizontal trend line for the (average) level of the (partly) carbon compensated dark/spark spread over time. One could argue, however, that besides a certain evolution over time - resulting from a variety of factors affecting the level and development of dark/spark spreads over a number of years - there might also be a seasonal pattern in the trend of these spreads within a year. For instance, one could argue that dark/spark spreads are highest during winter - because of higher power demand, resulting in a higher plant capacity used and, hence, more favourable power prices/spreads - and lowest during summer. If correct, this would imply that the trend line of spark/dark spreads moves downwards over the period January-July and upwards during the months July-January. If, for instance, the spark spread for gas-generated peak load power in the Netherlands would normally be 2 €/MWh lower in July than in January and the trend line would slope downwards accordingly over this period, the estimated pass-through rate would have been about 51 percent (compared to the estimated 39 percent, based on the assumption of a straight horizontal trend line).

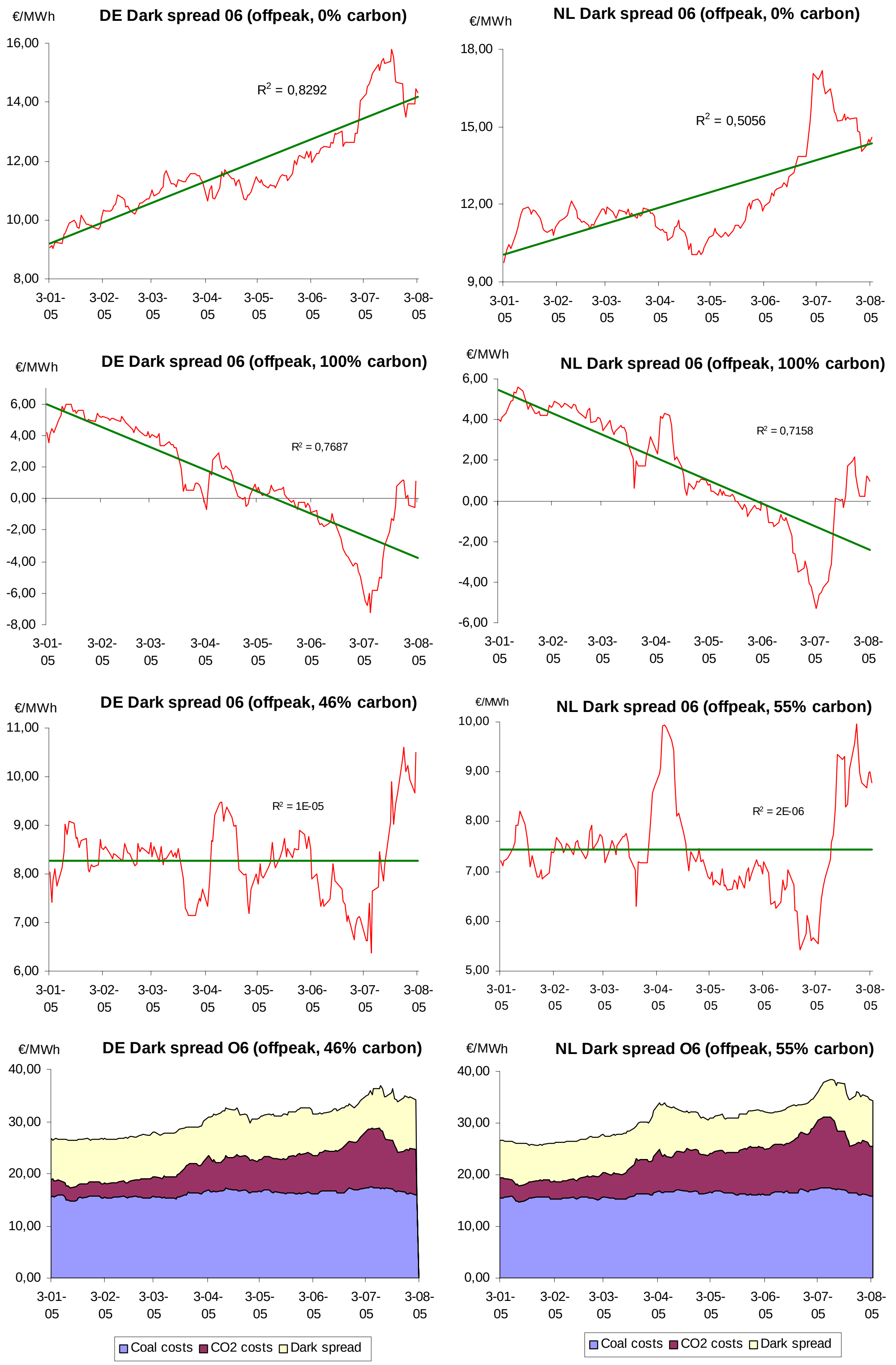

Figure 6.6 *Estimates of dark spreads and CO_2 pass-through rates in Germany and the Netherlands (40% fuel efficiency, forward Cal 2006, January-July 2005)*

Table 6.1 *Summary of major characteristics and results of different cases to estimate CO_2 pass-through rates in Germany and the Netherlands (January-July 2005)*

	Unit	Germany Peak-load	Germany Off-peak	Netherlands Peak-load	Netherlands Off-peak
Fuel used		Coal	Coal	Gas	Coal
Fuel efficiency	[%]	40	40	42	40
Emisson factor	[tCO_2/MWh]	0.85	0.85	0.48	0.85
Pass-through:					
• Rate	[%]	73	46	39	55
• Amount	[€/MWh]	9.5	5.9	2.8	7.2
Av. CO_2 price (Cal 06)	[€/tCO_2]	15.3	15.3	15.3	15.3
Av. CO_2 opportunity costs (i.e. 100% pass-though)	[€/MWh]	13.0	13.0	7.4	13.0
Av. power price	[€/MWh]	51.3	30.4	60.8	30.8
Av. fuel costs (Cal 06)	[€/MWh]	16.2	16.2	42.2	16.2
Av. CO_2 costs (based on estimated pass-through rate)	[€/MWh]	9.5	5.9	2.8	7.2
Av. dark/spark spread	[€/MWh]	25.6	8.3	15.8	7.4

Moreover for gas-generated power in this specific period (January-July 2005), there is an additional reason to question the assumption of a straight horizontal trend line. In this specific period, namely, gas prices have increased rapidly to almost unprecedented levels. It has been assumed that these rapidly increasing prices have always been fully passed through into (or covered by) higher power price, without any consequence for the trend or normal level of the spark spread. One could argue, however, that during periods of rapidly rising gas prices, the spark spread would come under pressure and move downwards (and move upwards again once gas prices are stabilising or decreasing). If correct and accounted for this effect, this would imply that the appropriately estimated pass-through rate would have been higher accordingly.

The period considered

The estimated pass-through rate depends on the period considered or, more accurately, on whether the uncompensated carbon dark/spark spreads - as shown in the upper parts of Figures 6.5 and 6.6 - move more or less in the same direction, i.e. either upwards or downwards over the period considered. Actually, the method illustrated to estimate the CO_2 pass-through rate is only (and most) appropriate if these spreads move indeed more or less in the same direction over the period considered. If, for instance, the trend of the spark/dark spreads moves more or less upwards during four months (say, in line with rising CO_2 prices), followed by a downward trend during the next four months (in line with declining CO_2 prices), it is not appropriate to draw a trend line for the whole period and estimate a corresponding pass-through rate. Rather, for each period of four months, a trend line should be drawn separately and a pass-through rate estimated accordingly. For instance, if the period considered for estimating a pass-through rate is restricted to the period February-July 2005 the estimated pass-through rate increases to 61 percent.

The fuel efficiency rate assumed

For coal and gas, a fuel efficiency rate has been assumed of 40 and 42 percent, respectively. If, for instance, a fuel efficiency of 45 percent is assumed for the Dutch gas-peak load case, the estimated pass-through rate increases from 39 to 55 percent. With a fuel efficiency of 40 percent, the pass-through rate in the Dutch gas-peak load case becomes 27 percent. On the other hand, if

- for instance - a fuel efficiency of 35 percent is taken for the Dutch coal-base load case, the estimate pass-through rate decreases from 55 to 47 percent.[31]

The fuel price considered
In order to estimate the pass-through rate, the coal price for the internationally traded commodity API#2 has been taken for all coal cases, while in the Dutch gas-peak load case the fuel price refers to gas sold by the Dutch Gas Union Trade & Supply (GUTS). However, whereas the price of API#2 is generally acknowledged and used as an adequate price indicator for coal, the GUTS price may be questioned as an adequate indicator for the fuel price of Dutch gas-generated plants. The GUTS price is based on an index of fuel oil and gas oil prices and, hence, has increased significantly over the period January-July 2005 due to the internationally rising oil prices since 2004.

However, although gas contracts are generally not open to the public, there seem to be long-term contracts in the Netherlands in which the gas price paid by power producers is based on an index of fuel oil and coal prices.[32] As the coal price has been more or less stable over the period January-July 2005, while the price of gas oil has increased significantly, this implies that a gas price based on an index of fuel oil and coal prices increases less significantly than when based on an index of fuel and gas oil prices. Hence, the trend line of the spark spread based on the fuel oil/coal price index will become steeper than when based on the fuel/gas oil price index and, therefore, the estimated pass-through rate will be higher in the former than latter case.[33]

Two qualifications, however, can be added to the reasoning above. Firstly, several power companies have denied the existence of such ‘favourable’ gas contracts and emphasize that most of their gas is bought at current, forward prices on the gas market (personal communications).[34] Secondly, even if power companies possess ‘favourable’ long-term gas contracts they still use current, forward market prices as the ‘opportunity costs’ for their make-or-buy decisions as, in principle, they can (re)sell contracted gas on the market.[35] Nevertheless, regardless of all these remarks and qualifications, the central issue is that the estimated pass-through rate is sensitive to the fuel price considered.

6.3 Statistical analyses of pass-through rates

In addition to the graphical (‘regression-line’) approach of the previous section, the present section discusses the estimation of pass-through rates by two statistical regression approaches, called the Ordinary Least Squares (OLS) method and the Prais-Winston (PW) method, by using the same data base for the six cases included in Table 6.1.

The basic assumption of the regression analyses of the present section is that the dynamics of the power prices in Germany and the Netherlands over the period January-July 2005 (see Figure 6.1) can be fully explained by the variations in the fuel and CO_2 costs over this period (see Fig-

31 The reason why the estimated pass-through rate in the Dutch gas case seems to be more sensitive to the assumed fuel efficiency rate than in the Dutch coal case is probably due to the fact that gas prices have been higher and increased significantly over the period considered, while coal prices have remained more or less stable.

32 Note that in case of the NUON Intergen auctions of virtual power plant capacities, a similar index or formula of fuel oil and coal prices was used to determine the variable/marginal costs of the Intergen power plant (NMa, 2004; DTe, 2005; ABN-AMRO, personal communication).

33 Based on the Intergen price formula (and data provided by ABN-AMRO), an alternative series of spark spreads has been calculated for peak load plants in the Netherlands over the period January-July 2005 that leads to a pass-through rate of approximately 100 percent.

34 Note that a long-term contract with a gas price based on an index of fuel oil and coal prices (rather than an index of fuel oil and gas oil prices) is only favourable during periods in which gas oil prices increase faster than coal prices, but that such a contract becomes unfavourable if fuel oil prices become relatively lower than coal prices.

35 In practice, however, the gas market in the Netherlands is less liquid and, hence, the ‘opportunity costs’ of gas (and CO_2 allowances) becomes a dubious concept as power companies are less flexible in trading gas surpluses or shortages due to fines and other, high balancing cost of trading gas flexibly.

ure 6.4). Hence, it is assumed that during this period other costs, for instance operational or maintenance costs, are constant - i.e. do not change - 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 or other supply-demand relationships).

Based on these assumptions, the relationship between power prices (P), fuel costs (F) and CO_2 costs is expressed by equation (1), where superscripts *c* and *g* indicate coal and gas, respectively. Likewise, the term $CO2_t$ is the CO_2 cost associated with coal and gas at time *t*. It is assumed that the fuel costs are fully passed on to power prices. This is equivalent to fixing the coefficient β_2 at unity.

$$P_t = \alpha + \beta_1 CO2_t^{c,g} + \beta_2 F_t^{c,g} + \varepsilon_t \qquad (1)$$

By defining Y_t as the difference between power price and fuel cost, equation (2) becomes the central regression equation of which the coefficient β_1 has been estimated. In fact, Y_t represents the dark spread for coal-generated power and the spark spread for gas-generated power.

$$Y_t = (P_t - F_t^{c,g}) = \alpha + \beta_1 CO2_t^{c,g} + \varepsilon_t \qquad (2)$$

Finally, given the nature of power price data, it is assumed that the error term ε_t is characterised by a so-called first-order autoregressive process, AR (1).[36] See equation (3), where u_t is a purely random variable with an expected value of zero, i.e. $E(u_t) = 0$, and a constant variance over time, i.e. $Var(u_t) = \sigma^2$. If the error terms are indeed autocorrelated, estimates by means of the relatively simple regression method OLS could be biased, while estimates of a more sophisticated approach, such as the Prais-Winston method, would be more correct.

$$\varepsilon_t = \rho \varepsilon_{t-1} + u_t \qquad (3)$$

Table 6.2 *Comparison of estimated pass-through rates in Germany and the Netherlands over the period January-July 2005 (in %)*

Country	Period	Fuel (efficiency)	OLS[a]	PW[a]	Table 6.1
Germany	Peak load	Coal (40%)	72	69	73
	Off-peak	Coal (40%)	42	42	46
NL	Peak load	Gas (42%)	40	44	39
	Off-peak	Coal (40%)	53	47	55

[a] All regression estimates are statistically significant at the 1% level.

Table 6.2 presents the results of the estimated pass-through rates of CO_2 costs into power prices for the same cases covered by Table 6.1, using either the OLS or PW method. For comparative reasons, the estimates of the pass-through rates based on the regression-line method of Section 6.2 are included in the last column of Table 6.2. The major findings of the statistical regression estimates of the pass-through rates recorded in Table 6.2 can be summarised as follows:

- For the Netherlands, the estimated pass-through rates according to the OLS method vary between 40 percent for the gas peak case to 53 percent for the coal off-peak case. For Germany, the variance of the OLS estimates is larger, i.e. ranging from 42 percent for off-peak coal to 72 percent for peak load coal.

[36] AR (1) is an econometrical concept that stands for autoregression or autocorrelation among the error terms with one period of lag [Stewart and Wallis, 1981]. It indicates a process of correlation frequently experienced in every day's life. For instance, if the ambient temperature was high yesterday and there are no major changes in the weather conditions, the temperature today should be more or less similar. In a case, the temperature today provides a prior belief from which tomorrow's temperature can be inferred.

- When regressing the OLS predicted residual ($\hat{\varepsilon}_t$) with its one-period lag ($\hat{\varepsilon}_{t-1}$), the ρ are all statistically significantly different than (less than) unity. This indicates the existence of a serial correlated structure in the error terms, implying that the Prais-Winston method most likely provides better estimates of the pass-through rates than the OLS approach. For the Netherlands, the PW estimates vary between 44 and 47 percent and for Germany between 42 and 69 percent.
- In general, the estimated pass-through rates of the 'advanced' statistical regression methods OLS and PW correspond surprisingly well with the estimated rates by the 'simple' regression-line method outlined in Section 6.2.

Why are the estimated pass-through rates less than 100 percent?
An intriguing issue of Table 6.2 is that all estimated pass-through rates are (far) less than 100 percent although, at first sight - based on economic theory and the praxis of producer behaviour expressed during the interviews (see Chapter 5) - one would expect a full pass-through of CO_2 allowances costs into power prices, even if the allowances are allocated for free. As outlined above, the estimated pass-through rates are sensitive to some underlying (methodological) assumptions and, hence, they may be underestimates (notably in the Dutch gas-peak load case). Moreover, as outlined in Chapter 4, there might be a variety of reasons why the estimated pass-through rates are less than 100 percent, including (i) the incidence of outside competition, (ii) a change in the merit order, (iii) demand response, (iv) the incidence of market regulation, (v) market power, (vi) carbon saving innovations, (vii) updating of EUA allocations, (viii) a decline in so-called 'mark-ups' and 'fixed cost margins' of power prices due to grandfathering, and (ix) the incidence of non-optimal behaviour, market imperfections, time lags and other constraints (see Sections 4.2 up to 4.11). Most of these reasons, however, have a long-term character or seem to be less relevant for the short term cases analysed in the present chapter. Of particular interest for these cases seems to be the last (ix) category of reasons notably uncertainty and immaturity of the CO_2 market, or the presumed time lag between high or rising CO_2/gas prices and pass-through rates - implying that these rates (and the resulting power prices) may become higher over time. On the other hand, the impact of other categories of reasons indicated above may become more important over time - particularly changes in merit order or market power/elastic demand effects - implying that pass-through rates (and resulting power prices) may become lower over time. Which of these reasons and effects will dominate over time is, as said, an empirical issue requiring additional research over time.

7. Major results of the COMPETES model analyses

This chapter discusses the major results of the COMPETES model, which has been used to analyse the implications of emissions trading for power prices, firm profits and other issues related to the wholesale power market in four countries of continental North-western Europe (i.e. Belgium, France, Germany and the Netherlands). First of all, Section 7.1 provides a brief description of this model. Subsequently, some central concepts and scenario assumptions applied in the model analyses are discussed in Section 7.2. Next, Section 7.3 highlights the overall results of the model analyses at the market (or country) level while, finally, Section 7.4 presents some specific results at the level of the major individual, power-generating companies included in the COMPETES model.

7.1 Brief model description

The model COMPETES - which stands for COmprehensive Market Power in Electricity Transmission and Energy Simulator - covers the wholesale electricity market in Belgium, France, Germany and the Netherlands.[37] It can simulate different market structures depending on firms' abilities to exercise market power (Lise, 2005). The two extreme cases are, on the one hand, perfect (or price) competition where firms do not exercise market power (also referred to as Bertrand equilibrium) and, on the other hand, oligopolistic competition (or 'strategic behaviour') where firms fully exercise market power in order to raise electricity prices and maximise their profits (also referred to as Cournot equilibrium).

The oligopolistic competition case, which analyses particularly firms' strategic behaviour, is based on the theory of Cournot competition and Conjectured Supply Functions (CSFs). This behaviour, such as capacity withholding or price setting, is reflected in the conjectures each power company holds regarding the supply response of rival companies. By parametrically changing the slope of the conjectured rival supply functions, different degrees of competitive intensity can be modelled, ranging from Bertrand-perfect competition (characterised by a very large supply response by rivals to price increases) to Cournot-oligopolistic competition (characterised by zero response, i.e. all oligopolistic power producers maximise their profits by choosing or withholding a certain level of production capacity under the assumption that their rivals do not change their output level). Positively sloped CSFs represent different degrees of competitive intensity between these two extreme cases (Neuhoff, et al., 2004).

Virtually all generation companies in the four countries are covered by the input data of the model. The user can specify which generation companies are assumed to behave strategically and which companies will be allocated to the so-called 'competitive fringe' (i.e. the price takers). The model calculates the optimal behaviour of the generators - and the resulting outcomes - by assuming that they simultaneously try to maximise their profits.

With regard to consumer behaviour, the model considers 12 different levels of 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 in each season consists of the 200 hours with the highest sum of the loads for the four considered countries. The three other periods have equal numbers of hours and represent the rest of the seasonal load dura-

[37] The COMPETES model has been developed by ECN in cooperation with Benjamin F. Hobbs, Professor in the Whiting School of Engineering of The Johns Hopkins University (Department of Geography and Environmental Engineering, Baltimore, Maryland, USA). For more details on this model, see Appendix B, and references cited there, as well as website http://www.electricitymarkets.info.

tion curve. Altogether, the twelve periods represent all 8760 hours of a year. The consumers are assumed to be price sensitive by using decreasing linear demand curves depending on price.

7.2 Definition of central concepts and scenario assumptions

7.2.1 Mark-ups

As explained in Section 4.3, the mark-up is a measurement of the degree to which a firm in a market can exercise market power. It is defined either in absolute terms as (P - MC) or in relative terms as (P-MC)/P, where P is the price of a commodity in market equilibrium and MC is the marginal cost. Figure 7.1 is a plot of a pair of simplified supply and demand curves. The plot in the left represents equilibrium under perfect competition while the one on the right represents monopolistic competition. The mark-up in Figure 7.1-a is zero since power is priced by marginal cost in perfect competition (P=MC). On the other hand, when the market is monopolistic, see Figure 7.1-b, the resulting mark-up becomes positive (Ξ).

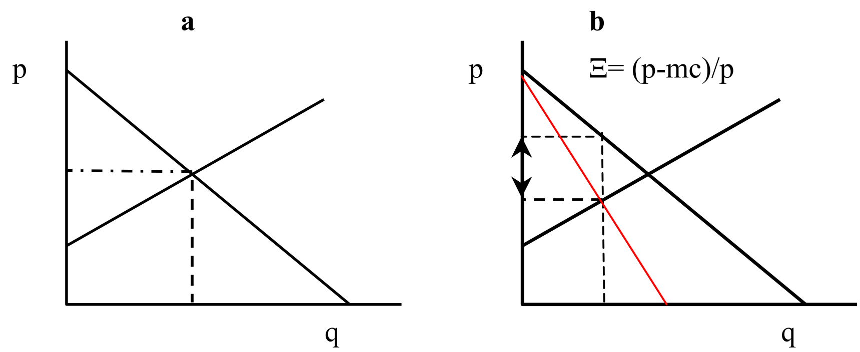

Figure 7.1 *A simple mark-up analysis under perfect competition and monopoly*

The scale and complexity of the COMPETES model (in particular multiple periods, regions and transmission networks) make it less straightforward to estimate mark-up. A major task in estimating mark-up is to identify the set of marginal units that determine the power price in market equilibrium.[38] Then, each power price is associated with a set of marginal units. For example, assuming a three-node system with three distinct prices (P_1, P_2 and P_3), three marginal units with marginal cost MC_1, MC_2 and MC_3, each determines a power price. The total sale at each node is S_1, S_2 and S_3. The overall market sale-weighted mark-up can then be estimated by $\sum_i\{(P_i\text{-}MC_i)/P_i\}S_i$. In COMPETES, the estimation needs to be weighted by periods, since there are twelve periods in the model.

7.2.2 Pass-through rate

As part of the COMPETES analyses, two types of pass-through rates have been defined and estimated. One type concerns the *average* pass-through rate while the other type is called the *marginal* pass-through rate.

[38] In principle, under perfect competition, if there are N distinct markets with N different prices, there will be N marginal units. However, there could be more than N marginal units in the oligopolistic cases.

Average pass-through rate
The average pass-through rate (PTR), which measures the change in power prices relative to the average costs associated with CO_2 allowances, can be expressed by means of equation (1):

Average PTR = Δ power price (in €/MWh)/average CO_2 allowance cost (in €/MWh) *(1)*

The numerator, Δ power price, is the power price differential between the current scenario and the reference scenario (where the reference scenario is generally the one with zero CO_2 costs, see Section 7.2.3 below). The denominator, the average CO_2 allowance cost, is the average cost of the CO_2 allowances to cover a MWh of power. In order to calculate the average CO_2 allowance cost, two approaches have been followed:
1. Relating total CO_2 costs to fossil fuel-generated power only. This approach leads to the so-called 'average fossil-fuel pass-through rate', indicated as 'average PTR [I]'.
2. Relating total CO_2 costs to both non-fossil and fossil fuel-generated power. This approach leads to the so-called 'average overall pass-through rate', indicated as 'average PTR [II]'.

This distinction is particularly relevant to compare countries with different fuel generation mixes. For instance, Table 3.1 of Section 3.1 shows that the share of non-fossil fuels (nuclear, renewables) in power generation is high in France (91 percent), but low in the Netherlands (10 percent). Using the second approach mentioned above implies that the average PTR for France will be high (as the denominator will be low), while the reverse applies to the Netherlands. Using the first approach enhances the comparability of the average PTR between such countries.

Since COMPETES is a multi-period model covering several countries, with each of them represented by one or more nodes, the overall (or country-specific) CO_2 allowances cost has to be weighted by nodal sales at each period.[39]

Table 7.1 summarizes the parameters/variables and indices used to develop the average fossil fuel pass-through rate. To correctly take into account the CO_2 allowances costs associated with importing electricity, the fossil-fuel imported-adjusted CO_2 emission rate for country *c* in period *p* is a convex combination of the domestic emission rate and the importing emission rate. Mathematically, this can be represented by equation (2):

$$IMCO_2(c,p) = SR(c,p) * OCO2(c,p) + (1 - SR(c,p)) * CCO2(c,p) \qquad (2)$$

where the term *SR(c,p)* is the self-sufficiency power supply ratio (= MIN(*Gen(c,p)/D(c, p),* **1**)); the parameter $OCO_2(c,p)$ is the average fossil-fuel generation-weighted CO_2 emission rate of country *c* in period *p*; the term $CCO_2(c, p)$ is the average fossil-fuel generation-weighted CO_2 emission rate for countries other than *c* in period *p*. For a country *c* that entirely relies on importing power in period *p*, the term *SR(c,p)* is zero; in contrast, for an exporting country in the period *p*, the term *SR(c, p)* becomes one.

The average CO_2 allowances cost is then calculated by multiplying sales-weighted import-adjusted CO_2 emission rate in country *c* and period *p* (term within brackets) with allowances price P^{CO2}, as expressed by equation (3):

$$CO_2 \text{ allowance costs} = \left\{ \frac{\sum_p IMCO_2(c,p) * D(c,p)}{\sum_p D(c,p)} \right\} P^{CO_2} \qquad (3)$$

[39] A node is a spatial representation of a market in the electricity network. For an illustration of the nodal network in COMPETES, see Appendix B.

Table 7.1 *Parameters and indices for calculating average pass-through rates*

Parameter	Unit	Description
C		Country {Netherlands, Belgium, France and Germany}
P		Period
D(c, p)	[MWh]	Demand for country *c* in period *p*
Gen(c, p)	[MWh]	Generation for country *c* in period *p*
$OCO_2(c, p)$	[kg/MWh]	Owned generation-weighted CO_2 emission rate for country *c* in period *p*
$CCO_2(c, p)$	[kg/MWh]	Complement generation-weighted CO_2 emission rate for country other than *c* in period *p*; for example, the set of the complement countries for the Netherlands are Belgium, France and Germany;
SR(c,p)	Unit-less	Self-supply ratio of country *c* at period *p*
$IMCO_2(c,p)$	[kg/MWh]	Import-adjusted CO_2 emission rate
P^{CO2}	[€/ton]	CO_2 allowance price

The following hypothetical example will be used to analyse the relationship between the relative CO_2 emission rates of the base load and peak load units and the average pass-through rate. In Figure 7.2, there are two graphs, where Figure 7.2-a expresses the situation in which the CO_2 emission rate of a more expensive unit (technology B) is greater than the rate of a cheaper base load unit (technology A). Such a relationship is reversed in companion Figure 7.2-b. To simplify the analysis, the following assumptions are made: (i) the emission rate of A = emission rate D (and likewise for technologies B and C); (ii) capacity for each technology = 1 MW; and (iii) total demand is fixed at 2 MW. At market equilibrium, the difference in power price before and after implementation of CO_2 trading for Figures 7.2-a and 7.2-b is ΔP_1 and ΔP_2, respectively, where $\Delta P_1 > \Delta P_2$. The costs associated with CO_2 allowances will be the same in Figures 7.2-a and 7.2-b given assumptions (i)-(iii). Consequently, the average pass-through rate for Figure 7.2-a will be higher than that of Figure 7.2-b. Based on these principles, the four countries simulated in COMPETES can be roughly grouped, with Belgium, Germany and the Netherlands belonging to Figure 7.2-b-type, while only France is associated with Figure 7.2-a -type.

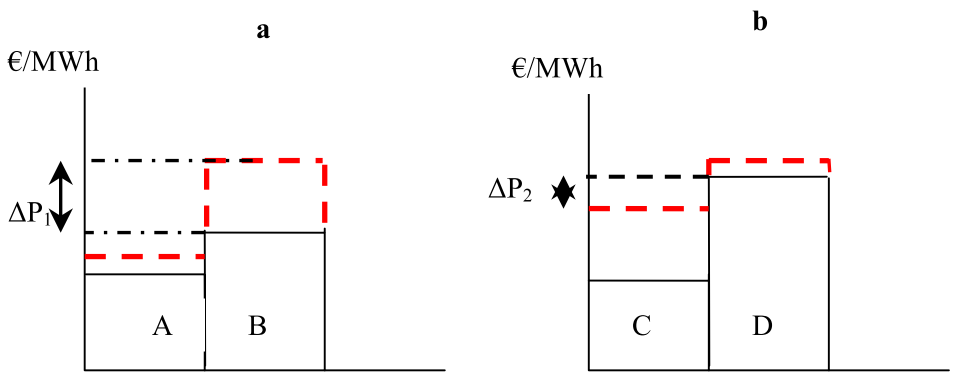

Figure 7.2 *A simplified example for estimating average pass-through rate*

Marginal pass-through rate

In addition to the two average PTRs discussed above, two versions of the *marginal* pass-through rates have been defined and estimated. The first version, called marginal PTR [I] is defined by equation (4):

Marginal PTR [I] = Δ power price (in €/MWh)/Δ marginal production cost (in €/MWh) (4)

The numerator remains the same as the difference in power price between the reference case and comparing case. The denominator, however, becomes the difference in marginal production cost between the marginal units with and without the implementation of CO_2 trading.

An alternative and equivalent approach of calculating marginal PTR [I] is based on the estimation of the mark-up. As discussed in Section 7.2.1, the mark-up is calculated by *(P-MC)/P*. Assuming that the mark-up for the reference case is Ξ_0 ($=(P_0-MC_0)/P_0$) and mark-up for the comparing case is Ξ_1 ($=(P_1-MC_1)/P_1$), the marginal PTR [I] can be approximated by $\Delta p/(p_1(1-\Xi_1)-p_0(1-\Xi_0))$.

The second version, called 'marginal PTR [II]', is defined by equation (5):

Marginal PTR [II] = Δ power price (in €/MWh)/marginal allowance costs (in €/MWh) (5)

In this definition, the denominator becomes the CO_2 allowances costs per MWh of the marginal production unit (i.e. the price of a CO_2 allowance in €/tCO_2 multiplied by the emission factor - in tCO_2/MWh - of the marginal production unit).[40]

Both definitions in equations (4) and (5) will provide proper estimates of marginal pass-through rate. However, they are actually quite different in their theoretical properties. To understand the theoretical properties of marginal pass-through rate [I], Figure 7.3 illustrates two equilibria under perfect competition (Figure 7.3-a) and monopolistic competition (Figure 7.3-b), respectively, where S_0 is the supply curve without CO_2 costs and S_1 is with CO_2 costs.

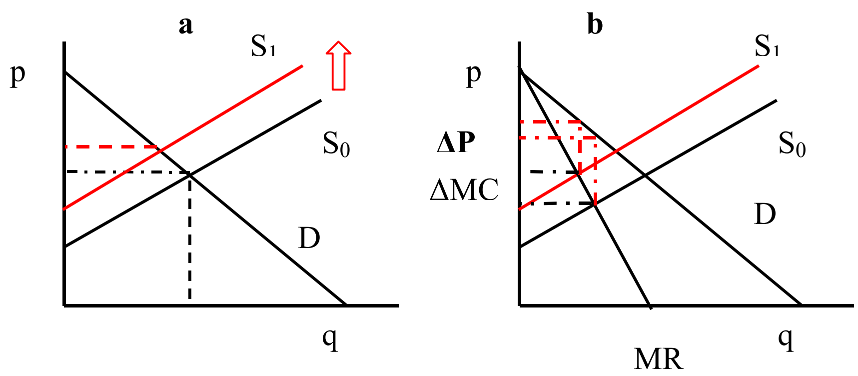

Figure 7.3 *Pass through under perfect and monopolistic competition*

For simplicity, in Figures 7.3-a and 7.3-b a uniform CO_2 emission rate applied to each unit in the curve is assumed. In reality, the emission rate could be different and changes in merit order could occur. In Figure 7.3-a, since power is priced at marginal cost, by default, the marginal pass-through rate for the perfect competition case is equal to one. In the monopolistic case, however, the output quantity is determined by the intersection of the marginal revenue curve (MR) and supply curve (S_0 or S_1). The resulting increase in the power price (ΔP) is less than the increase in the marginal cost (ΔMC). Hence, to conclude, the marginal pass-through rate would be equal to 1 under perfect competition and less than 1 under oligopolistic competition.

---

[40] The definition of marginal PTR [II] conforms probably most to the common sense definition of the pass-through rate, although the definition ofmarginal PTR [I] seems to be more correct and appropriate from a theoretical point of view since it does not only cover the change in CO_2 allowances costs but also the change in other marginal production costs due to CO_2 emissions trading.

7.2.3 Scenario assumptions

In order to analyse the implications of CO_2 emissions trading for power prices under different assumptions of demand response, market structure and behaviour, 17 different scenarios have been studied by means of the COMPETES model. The acronyms and assumptions of each scenario are summarised in Table 7.2.

To assess the influence of market power, three stylistic ('extreme') cases are considered, namely perfect competition (indicated by the acronym PC) and two Cournot-oligopolistic competition scenarios: one where the French company Electricité de France (EdF) can not exercise market power in France (indicated by SA) and one where EdF can (ST).

To analyse the impact of demand response to 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. This may be justified as the demand response in the medium or long term.[41] 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 (denoted by 'le') or zero elasticities (denoted by 'ze') have been considered as well, namely 0.1 for the oligopolistic competition scenarios and 0.0 - i.e. fixed load demand - for the perfect competition scenarios.

To study the implications of emissions trading for power prices, three exogenously fixed CO_2 prices have been considered: 0, 10 and 20 €/tCO_2 (indicated by 0, 10 or 20 in the acronyms of the scenarios). As a result of considering the price of an emission allowance as exogenously fixed, it is assumed that power producers are price takers on the EUA market, i.e. they are assumed to be unable to influence the price of a CO_2 allowance on this market.

Moreover, note that in all scenarios fuel costs are fixed at the levels of 2004 (the most recent year for which the model has been calibrated). Hence, although fuel prices could be changed, the model does not account for the dynamics of rising fuel (and CO_2) prices as witnessed, for instance, in the first part of 2005 (and as analysed in Chapters 2, 3 and 6).

In addition, it is assumed that power producers regard the cost of CO_2 allowances as true ('opportunity') costs - even if they get the allowances for free - and, hence, add these costs to their other marginal costs when making production or trading decisions (following economic theory and sound business principles, supported by the views expressed by power producers during the stakeholders interviews, as outlined in Chapter 5). Therefore, the pass-through rate in the sense of the so-called 'add-on rate' is by definition (or default) 100 percent in the COMPETES model. However, as explained in the last part of Chapter 4, the extent to which CO_2 allowances costs ultimately work-on power prices that are determined by a complex set of market forces (the so-called 'work-on rate') may be (far) less than 100 percent due to a variety of reasons such as a change in the merit order, demand response, market power, regulation, non-optimal behaviour, etc.

The COMPETES analyses have been focussed on the extent to which CO_2 allowances costs work on power prices (and other related issues), including the reasons why the estimated 'work-on rates' have often been less than unity. By comparing the results of the 17 scenarios, the impact of emissions trading on power prices (and other related issues) has been analysed under different assumptions of market structure and behaviour, demand response and CO_2 prices (including resulting changes in the merit order of the power supply curve). The comparison and analyses of these results are discussed in Sections 7.3 and 7.4 below.

[41] 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.

Table 7.2 *Summary of scenarios assumptions in COMPETES*

Scenario	CO_2 price [€/ton]	Elasticity	Description
PC0	0	0.2	Perfect competition
PC10	10	0.2	Perfect competition
PC20	20	0.2	Perfect competition
SA0	0	0.2	Oligopolistic competition w/ EdF as a price taker in France
SA10	10	0.2	Oligopolistic competition w/ EdF as a price taker in France
SA20	20	0.2	Oligopolistic competition w/ EdF as a price taker in France
ST0	0	0.2	Oligopolistic competition w/ EdF as a monopoly in France
ST10	10	0.2	Oligopolistic competition w/ EdF as a monopoly in France
ST20	20	0.2	Oligopolistic competition w/ EdF as a monopoly in France
PC10-ze	10	0.0	Perfect competition w/ nodal demand fixed at PC0 level
PC20-ze	20	0.0	Perfect competition w/ nodal demand fixed at PC0 level
SA0-le	0	0.1	Oligopolistic competition w/ EdF as a price taker in France
SA10-le	10	0.1	Oligopolistic competition w/ EdF as a price taker in France
SA20-le	20	0.1	Oligopolistic competition w/ EdF as a price taker in France
ST0-le	0	0.1	Oligopolistic competition w/ EdF as a monopoly in France
ST10-le	10	0.1	Oligopolistic competition w/ EdF as a monopoly in France
ST20-le	20	0.1	Oligopolistic competition w/ EdF as a monopoly in France

7.3 Overall results at the country level

In the sections below, the major results of the COMPETES model analyses with regard to the implications of CO_2 emissions trading at the country level will be discussed, notably with regard to the impact on power prices, mark-ups, pass-through rates, power sales, and CO_2 emissions.

Table 7.3 *Changes in power prices and mark-ups due to CO_2 emissions trading (0.2 elasticity scenarios)*

	PC0	PC10	PC20	SA0	SA10	SA20	ST0	ST10	ST20
				Power prices [€/MWh]					
Netherlands	42.5	47.0	51.1	72.2	76.7	80.9	71.8	76.6	80.7
Belgium	37.1	43.2	47.0	78.6	81.2	82.8	79.1	82.2	85.1
Germany	28.2	35.2	42.9	42.6	49.2	56.0	43.0	49.7	56.5
France	18.6	20.1	20.4	17.9	18.8	19.1	59.3	59.5	60.6
EU4	25.9	30.2	33.9	35.7	39.0	41.9	53.5	57.8	62.3
				Changes in power prices [€/MWh]					
Netherlands	-.-	4.5	8.6	-.-	4.5	8.7	-.-	4.8	8.9
Belgium	-.-	6.1	9.9	-.-	2.6	4.2	-.-	3.1	6.0
Germany	-.-	7.0	14.7	-.-	6.6	13.4	-.-	6.7	13.5
France	-.-	1.5	1.8	-.-	0.9	1.2	-.-	0.2	1.3
EU4	-.-	4.3	8.0	-.-	3.3	6.2	-.-	4.3	8.8
				Changes in power prices [%]					
Netherlands	-.-	10.6	18.3	-.-	6.2	11.3	-.-	6.7	11.6
Belgium	-.-	16.4	22.9	-.-	3.3	5.2	-.-	3.9	7.3
Germany	-.-	24.8	41.8	-.-	15.5	27.2	-.-	15.6	27.2
France	-.-	8.1	9.0	-.-	5.0	6.4	-.-	0.3	2.2
EU4	-.-	16.6	26.5	-.-	9.2	15.9	-.-	8.0	15.2
				Market mark-ups (as a share of power price)					
Netherlands	0	0	0	0.36	0.38	0.36	0.40	0.38	0.35
Belgium	0	0	0	0.80	0.74	0.73	0.79	0.67	0.57
Germany	0	0	0	0.54	0.42	0.32	0.54	0.42	0.32
France	0	0	0	0	0	0	0.83	0.83	0.83
EU4	0	0	0	0.43	0.36	0.3	0.65	0.58	0.52
				Market mark-ups [€/MWh]					
Netherlands	0	0	0	26.0	29.1	29.1	28.7	29.9	29.1
Belgium	0	0	0	58.2	60.1	61.3	60.1	60.0	48.5
Germany	0	0	0	22.2	20.7	17.9	22.4	20.9	18.6
France	0	0	0	0.0	0.0	0.0	49.2	49.4	50.3
EU4	0	0	0	14.6	14.0	12.6	34.2	33.5	30.5

7.3.1 Power prices

Table 7.3 presents estimates of the influence of CO_2 emissions trading on power prices in four EU countries (Belgium, France, Germany and the Netherlands) for all 0.2 elasticity scenarios, while Table 7.4 provides similar estimates for the so-called low or zero elasticity scenarios. By comparing these scenarios, the most striking results include:

- Power prices are significantly higher under the oligopolistic scenarios (SAx and STx) than under the perfect competition scenarios (PCx).
- Power prices are substantially higher under the low/zero elasticity scenarios than under the 0.2 elasticity scenarios.
- In the perfect competition scenarios, power prices are generally highest in the Netherlands and lowest in France, while under the oligopolistic scenarios with EdF as a monopoly in France (STx) power prices are usually highest in Belgium and lowest in Germany.
- Power prices increase significantly due to CO_2 emissions trading under all scenarios. These increases are generally highest in Germany and lowest in France (in both absolute - i.e. €/MWh - and relative - % - terms).

- In the low and zero elasticity scenarios, price increases due to CO_2 emissions trading are highest under perfect competition and lowest under oligopolistic competition, both in relative and absolute terms (in accordance with economic theory, as outlined in Section 4.2 and Appendix A). For the 0.2 elasticity scenarios, the picture is a bit mixed in absolute terms, but in relative terms price changes due to CO_2 emissions trading are lowest under oligopolistic scenarios. Note, however, that despite generally higher price increases due to emissions trading under perfect competition, power prices in an absolute sense are still far lower under perfect competition than under oligopolistic competition, even if the price of CO_2 is relatively high (20 €/tCO_2).

Table 7.4 *Changes in power prices and mark-ups due to CO_2 emissions trading (low and zero elasticity scenarios)*

	PC0	PC10-ze	PC20-ze	SA0-le	SA10-le	SA20-le	ST0-le	ST10-le	ST20-le
	Power prices [€/MWh]								
Netherlands	42.5	47.9	53.1	100.7	105.1	110.0	99.8	104.4	109.2
Belgium	37.1	43.9	50.9	126.3	127.4	129.1	127.7	128.5	129.5
Germany	28.2	37.9	46.7	59.0	65.7	72.5	59.2	66.7	74.1
France	18.6	21.0	23.3	17.8	18.8	19.3	99.4	100.4	100.6
EU4	25.9	32.0	37.7	47.3	50.7	53.9	81.0	85.9	90.4
	Changes in power prices [€/MWh]								
Netherlands	-.-	5.4	10.6	-.-	4.4	9.3	-.-	4.6	9.4
Belgium	-.-	6.8	13.8	-.-	1.1	2.8	-.-	0.8	1.8
Germany	-.-	9.7	18.5	-.-	6.7	13.5	-.-	7.5	14.9
France	-.-	2.4	4.7	-.-	1.0	1.5	-.-	1.0	1.2
EU4	-.-	6.1	11.8	-.-	3.4	6.6	-.-	4.9	9.4
	Changes in power prices [%]								
Netherlands	-.-	12.7	22.1	-.-	4.4	8.8	-.-	4.6	9.0
Belgium	-.-	18.3	31.4	-.-	0.9	2.2	-.-	0.6	1.4
Germany	-.-	34.4	48.8	-.-	11.4	20.5	-.-	12.7	22.3
France	-.-	12.9	22.4	-.-	5.6	8.0	-.-	1.0	1.2
EU4	-.-	23.6	36.9	-.-	7.2	13.0	-.-	6.0	10.9
	Market mark-ups (as a share of power price)								
Netherlands	0	0	0	0.59	0.55	0.54	0.58	0.55	0.53
Belgium	0	0	0	0.89	0.88	0.87	0.9	0.88	0.87
Germany	0	0	0	0.72	0.6	0.49	0.71	0.59	0.5
France	0	0	0	0	0	0	0.90	0.90	0.90
EU4	0	0	0	0.59	0.55	0.54	0.58	0.55	0.53
	Market mark-ups [MWh]								
Netherlands	0	0	0	59.4	57.8	60.5	58.9	57.4	57.9
Belgium	0	0	0	112.4	110.8	109.7	114.9	110.5	115.3
Germany	0	0	0	42.5	37.4	35.5	42.0	36.7	37.1
France	0	0	0	0.0	0.0	0.0	89.5	91.4	90.5
EU4	0	0	0	27.4	26.9	25.3	62.4	55.8	53.3

Note: A price elasticity of power demand has been assumed of 0.1 for all oligopolistic scenarios (SAx and STx), and 0.0 for the perfect competitive scenarios PC10-ze and PC20-ze.

7.3.2 Mark-ups

Tables 7.3 and 7.4 also present estimates of the mark-ups, i.e. the extent to which power companies exert market power in a specific country. In competitive cases, power is priced at marginal cost (P=MC) and the mark-up is zero. In other scenarios, the results of mark-up reflect the model assumptions concerning generators behaviour, demand elasticity and the level of CO_2 costs. By comparing the different scenarios, the major significant results regarding mark-ups include:

- The highest mark-ups are reported in Belgium and Germany, except the scenarios in which France is allowed to exercise market power (STx). In the latter scenarios, i.e. when EdF is a monopoly in the French market, its mark-ups vary between 0.83 and 0.90 (which is the highest among all cases considered in Tables 7.3 and 7.4).
- In most cases, when the CO_2 price increases, the mark-ups decrease, not only as a share of power prices but also in absolute terms, particularly under low elasticity and least competitive cases. This indicates that CO_2 trading - when all allowances have to be bought - puts stress on firms' profits in uncompetitive markets, aggravated by less total sales, but it ignores the fact that about 85-95 percent of the allowances have been allocated for free (see Section 7.4 below).

7.3.3 Pass-through rates

Average pass-through rates

In Section 7.2.2, two different - but related - types of average pass-through rates have been defined, namely 'average PTR [I] and 'average PTR [II]'. Whereas the average PTR [I] relates the change in power price to the average CO_2 allowance costs of fossil-fuel generated power only, the average TPR [II] relates it to the average CO_2 allowance costs of total (fossil-fuel and non-fossil) generated power (per MWh). Table 7.5 provides estimates of the average PTR [I], while Table 7.6 presents estimates for average PTR [II].

Table 7.5 *Estimates of average pass-through rates [I]*

	PC10	PC20	SA10	SA20	ST10	ST20
Netherlands	0.59	0.57	0.60	0.60	0.63	0.63
Belgium	0.74	0.61	0.38	0.31	0.48	0.47
Germany	0.73	0.77	0.71	0.73	0.71	0.73
France	0.18	0.10	0.10	0.07	0.02	0.08
EU4	0.47	0.44	0.38	0.36	0.48	0.51
	PC10-ze	PC20-ze	SA10-le	SA20-le	ST10-le	ST20-le
Netherlands	0.72	0.73	0.62	0.68	0.64	0.69
Belgium	0.81	0.82	0.16	0.20	0.13	0.14
Germany	1.01	0.97	0.73	0.74	0.81	0.81
France	0.27	0.27	0.12	0.09	0.13	0.08
EU4	0.67	0.65	0.40	0.39	0.57	0.56

Note: Average PTR [I] = Δ in power price (in €/MWh) / average CO_2 allowance cost (in €/MWh) of fossil-fuel generated power only (see Section 7.2.2).

As the average fossil-fuel generated CO_2 emission rate varies only slightly between the countries considered (as discussed in Section 7.3.5 below,), the denominator of the average PTR [I] varies also slightly.[42] As a result, the variation in average PTRs [I] reported in Table 7.5 reflects largely the variation in the nominator, i.e. the change in power prices, as discussed in Section 7.3.1 above.

The most striking finding of Table 7.5, however, is that all the recorded PTRs are smaller than 1 (except for Germany in the PC10-ze case, where it is 1.01). This implies that if all CO_2 allowances have to be bought on the market, the average costs of these allowances for a fossil-fuel

[42] It should be acknowledged, however, that the denominator of the average PTR [I] has been corrected for power imports, while the average fossil-fuel generated CO_2 emission rates discussed in Section 7.3.5 - Tables 7.9 and 7.10 - have not.

generated MWh of power are not fully (and often only partly) covered by the average increase in power prices.

However, under the present EU Emissions Trading System, almost all allowances are granted for free, although for the power sector the freely allocated allowances are most likely not sufficient to cover their emissions. Assuming that the power sector has to buy additional allowances on the market to cover, say, 10 percent of its emissions, the estimated PTRs [I] in Table 7.5 have to be multiplied by a factor 10 to represent the 'true' costs. In that case, all the reported PTRs become larger than 1 (except for France under certain scenarios). This implies that the average costs of CO_2 allowances for a fossil-fuel generated MWh of power are more than fully covered by the average increase in power prices and, hence, result in a profit.

Moreover, the countries considered produce not only fossil-fuel generated power but also non-fossil power that does not occur CO_2 costs but benefits from the CO_2-induced higher power prices. As noted, however, the share of non-fossil power in the total generation mix varies widely between the countries considered from about 10 percent in the Netherlands to some 90 percent in France (Table 3.1). This implies that the average overall emission rate - covering both fossil-fuel and non-fossil power - varies also widely (see Section 7.3.5 below). As a result, the denominator of the average PTR [II] i.e. the average allowance costs of total generated power, becomes rather small for a country such as France whereas it hardly changes for a country such as the Netherlands (compared to the denominator of average PTR [I], i.e. average allowance costs of fossil-fuel generated power only). The consequence is that (compared to the estimated average PTRs [I] of Table 7.5), the estimated average PTRs [II] recorded in Table 7.6 increase significantly for a country such as France, while they hardly change for a country such as the Netherlands.

Table 7.6 *Estimates of average pass-through rates [II]*

	PC10	PC20	SA10	SA20	ST10	ST20
Netherlands	0.82	0.82	0.73	0.71	0.75	0.72
Belgium	2.53	2.27	1.38	1.22	2.10	2.17
Germany	1.13	1.25	1.21	1.32	1.19	1.29
France	6.82	4.21	3.89	2.83	0.21	1.08
EU4	1.33	1.33	1.18	1.20	1.13	1.28
	PC10-ze	PC20-ze	SA10-le	SA20-le	ST10-le	ST20-le
Netherlands	0.94	0.97	0.66	0.72	0.68	0.73
Belgium	2.54	2.68	0.50	0.64	0.50	0.54
Germany	1.53	1.47	1.25	1.31	1.35	1.38
France	7.80	7.69	3.62	3.34	0.99	0.63
EU4	1.78	1.73	1.18	1.21	1.25	1.26

Note: Average PTR [I] = Δ power price (in €/MWh) / average CO_2 allowance cost (in €/MWh), of both fossil-fuel and non-fossil generated power (see Section 7.2.2.

The most striking result of Table 7.6 is that in most cases the presented PTRs are higher than one, except for the Netherlands under all scenarios, for Belgium under the low elastic-oligopolistic scenarios, and for France under most of the STx scenarios. However, assuming that only, say, 10 percent of the required allowances have to be bought on the market, the estimated average PTRs [II] in Table 7.6 have to be multiplied by a factor 10 to represent the 'true' costs. In that case, all the recorded PTRs become larger than 1, varying from 2.1 for France under the ST10 scenario to 78 - also for France - under the PC10-ze scenario. This indicates that, overall emissions trading seems to be quite profitable for the power companies (see also Section 7.4 below).

Marginal pass-through rates

In addition, two different - but related - types of marginal passing-through rates have been defined and estimated, namely 'marginal PTR [I]' and 'marginal PTR [II]'. Whereas the marginal PTR [I] relates the change in power price to the change in (total) marginal production costs, the marginal PTR [II] relates it to the CO_2 allowance costs of the marginal unit to produce a MWh of power. Table 7.7 provides estimate of the marginal PTR [I], while estimates of the average PTR [II] are presented in Table 7.8.

Table 7.7 *Estimates of marginal pass-through rates [I]*

	PC10	PC20	SA10	SA20	ST10	ST20
Netherlands	1.00	1.00	3.26	1.62	1.06	0.95
Belgium	1.00	1.00	0.48	0.63	0.29	0.29
Germany	1.00	1.00	0.73	0.72	0.76	0.74
France	1.00	1.00	1.00	1.00	N/A	8.13
EU4	1.00	1.00	0.74	0.72	0.78	0.78
	PC10-ze	PC20-ze	SA10-le	SA20-le	ST10-le	ST20-le
Netherlands	1.00	1.00	0.81	1.01	0.84	0.95
Belgium	1.00	1.00	0.51	0.95	0.30	0.53
Germany	1.00	1.00	0.70	0.67	0.75	0.76
France	1.00	1.00	0.96	0.96	N/A	N/A
EU4	1.00	1.00	0.69	0.68	0.85	0.86

Note: Marginal PTR [I] = Δ power price (in €/MWh) / Δ in marginal production cost (in €/MWh; see Section 7.2.2). It is assumed that CO_2 allowance costs are 'true' costs (i.e. all allowances are bought on the market).

Table 7.8 *Estimates of marginal pass-through rates [II]*

	PC10	PC20	SA10	SA20	ST10	ST20
Netherlands	0.98	0.70	0.60	0.96	0.64	0.96
Belgium	0.83	0.80	1.26	1.86	0.69	0.51
Germany	0.80	0.80	0.67	0.68	0.68	0.69
France	0.74	0.43	1.11	0.43	N/A	10.83
EU4	0.79	0.71	0.66	0.63	0.73	0.78
	PC10-ze	PC20-ze	SA10-le	SA20-le	ST10-le	ST20-le
Netherlands	0.91	1.04	0.64	1.04	0.67	1.03
Belgium	0.99	1.07	0.74	0.96	0.54	0.62
Germany	0.92	1.18	0.70	0.68	0.75	0.74
France	0.71	1.15	0.61	0.34	N/A	N/A
EU4	0.88	1.16	0.65	0.60	0.85	0.86

Note: Marginal PTR [II] = Δ power price (in €/MWh) / marginal CO_2 allowance cost (in €/MWh; see Section 7.2.2

Table 7.7 shows that the marginal PTRs-[I] are 1 in all competitive cases, as predicted by economic theory. Moreover, most of the marginal PTRs-[I] in the non-competitive cases are smaller than 1. In general, the marginal PTRs-[I] are smallest for Belgium and highest for France and the Netherlands, with an intermediate position for Germany. On average, the marginal PTR-[I] of the EU4 in the uncompetitive cases varies between 0.7 and 0.9.

It should be noted, that in a few cases the marginal PTR-[I] is larger than 1 (see particularly the Netherlands in the cases SA10, SA20 and ST10). At first sight, this seems to be in conflict with economic theory as outlined in Appendix A of the present report (which says that the marginal PTR-[I] should be less than 1 under uncompetitive markets). However, this theoretical analysis of Appendix A is based on some strict conditions and assumptions, notably linear demand, a uniform emission rate across technologies, and identical operators in terms of market shares, market behaviour, technologies used, etc. Whereas COMPETES meets the condition of linear demand, it does not comply with the other assumptions as (conform to reality) it includes generators who differ in market size, technologies used, and strategic behaviour in the sense that some generators are price-takers while others are strategic players. For price-takers, the marginal costs are equal to the given market price, but for strategic players the marginal costs are usually significantly lower than the power price (resulting in a mark-up). Whereas the production unit of the price-taker may be the marginal unit setting the price before emissions trading, thereafter the strategic player may set the price. This may lead to a price increase, while the marginal costs of the strategic player may be lower than those of the price-taker, resulting in a negative marginal PTR-[I] (in conflict with economic theory, at least at first sight). As the recorded marginal PTRs-[I] in Table 7.7 are all averages over twelve periods (3 seasons * 4 load periods), a shift in a marginal unit from a price-taker to a strategic player may lead to a decline in marginal costs and, hence, to a lowering of the average denominator of the marginal PTR-[I] and, hence, in an marginal PTR-[I] > 1.[43]

In addition, Table 7.7 shows a few estimates of the marginal PTR-[I] that are 'not applicable' (NA), notably for France in the STx scenarios. This is due to the fact that in these cases the marginal unit in all runs is the same nuclear generator owned by France. Since the marginal costs of this non-fossil plant do not change as carbon costs increase, the denominator of the marginal PTR-[I] formula is zero.

Table 7.8 presents estimates of the so-called marginal PTR-[II] (defined as: Δ power price/marginal CO_2 allowance cost). This definition conforms to the estimated rates for the pass-through rates, averaging peak and off-peak periods, resulting from the statistical and empirical analyses as discussed in Chapter 6. It can be observed from Table 7.8 that the recorded marginal PTRs-[II] are generally high. For instance, in the competitive case PC10, the marginal PTR-[II] varies from 0.74 for France to 0.98 in the Netherlands, while the average for the EU4 is 0.79.

Note that some marginal PTRs-[II] recorded in Table 7.8 have a value higher than 1. At first sight this seems remarkable, but can be explained simply by the fact that a unit with low carbon emissions but high other production costs may become the marginal unit if CO_2 prices increase. As a result, the nominator of the marginal PTR-[II] formula may be substantially larger than the denominator, leading to a marginal PTR-[II] > 1.

7.3.4 Total power sales

The upper part of Tables 7.9 and 7.10 provide some information on total power sales under different scenarios. Except in the perfect competitive cases with zero elasticity (PC10-ze and PC20-ze), total sales decline when CO_2 prices increase. Besides the price elasticity assumed, the level of total power sales depends particularly on the competitiveness of the scenarios considered, i.e. under similar price elasticities, total sales are lower in less competitive scenarios. This finding is consistent with oligopoly theory: strategic generators contract their output in order to push up power prices (Tirole, 1998).

[43] For instance, comparing SA0 and SA10 in the Dutch market, the period (m, off peak) is cleared by a *competitive* generator in the Netherlands at € 60.11/MWh for SA0. The marginal cost (MC_0) in this case is equal to price (P_0, where the subscript 0 and 1 represent the reference and compared run, respectively). However, the price in the same period (m, off peak) for the compared SA10, on the other hand, is cleared by a *strategic* generator at € 64.72/MWh. Since it is a strategic generator, its marginal cost (MC_1) is substantially lower than the power price (P_1), i.e., $MC_1 < P_1$. The difference is the markup (= 64.72-45.55= € 19.17/MWh). The net impact is the exaggeration of mPTR (I) since the difference in marginal cost (MC_1-MC_0) appears in the denominator of the mPTR (I) formula.

Table 7.9 *Total power sales and CO_2 emissions (0.2 elasticity scenarios)*

	PC0	PC10	PC20	SA0	SA10	SA20	ST0	ST10	ST20
	Total power sales [TWh]								
Netherlands	96	94	93	83	80	79	83	80	79
Belgium	89	86	84	69	67	66	68	67	65
Germany	542	510	474	480	452	425	477	449	421
France	523	516	516	522	518	517	307	306	300
EU4	1251	1206	1166	1154	1118	1087	935	902	865
	Total CO_2 emissions [Mt]								
Netherlands	76	62	59	68	55	52	68	55	52
Belgium	25	20	18	15	11	10	12	10	9
Germany	345	312	277	281	250	219	284	253	220
France	17	12	11	19	12	11	26	24	17
EU4	445	389	349	370	318	282	388	342	295
	Average overall CO_2 emission rate [kg/MWh]								
Netherlands	794	664	637	815	687	659	815	684	652
Belgium	276	234	209	215	170	156	178	147	138
Germany	636	611	585	586	552	516	596	563	522
France	33	23	21	36	23	22	85	79	57
EU4	355	323	299	321	284	259	415	379	341
	Average fossil CO_2 emission rate [kg/MWh]								
Netherlands	844	709	682	867	732	702	867	728	693
Belgium	879	822	805	630	656	649	631	648	645
Germany	961	954	953	950	936	923	953	939	925
France	916	867	869	922	894	891	845	836	803
EU4	938	908	901	921	887	867	918	885	860

Note: Average CO_2 emission rate of both fossil-fuel and non-fossil generators; b: Average CO_2 emission rate of fossil-fuel generators only.

7.3.5 Total CO_2 emissions

Tables 7.9 and 7.10 present also data for total CO_2 emissions under different scenarios. They show that total CO_2 emissions go down if the price of CO_2 goes up in all cases considered, notably in the more price elastic scenarios. Moreover, they illustrate that, under similar (0.2) elasticities, these emissions are generally highest under the most competitive scenarios (PCx). This indicates a trade-off between the interests of the consumer (low prices, high sales) and those of the environment (high prices, less emissions).[44]

Interestingly, however, despite lower sales, total CO_2 emissions are higher under the STx scenarios (where EdF acts as a monopoly in France) than under the SAx scenarios (where EdF acts as price taker). This suggests that a major part of the nuclear capacity withhold by EdF in the STx scenarios is replaced by fossil-fuel generators of the so-called ‘competitive fringe’ in France itself, but also in Germany in order to substitute for less imports from France.

A reduction in total CO_2 emissions by the power sector, however, may result not only from a demand response (i.e. less total power sales) but also from a change in technology (i.e. a re-dispatch or change in the merit order). In Table 7.11, a decomposition of these two effects is provided for the impact of emissions trading on emissions reduction under different scenarios. This decomposition is based on the fact that under the zero-elasticity scenarios, the estimated CO_2 reduction is fully due to a change in the merit order since total demand is fixed. Table 7.11

[44] For different views on this issue, see Lise (2005) and Lise, et al. (forthcoming).

shows that, under fixed demand, the reduction in CO_2 emissions due to re-dispatch is equal to 15 and 19 Mt if the price of CO_2 is 10 and 20 €/tonne, respectively. Assuming that a similar reduction occurs in all other scenarios due to re-dispatch, the remaining part of the emission reduction estimated is attributed to lower demand.[45] As a result, Table 7.11 shows clearly that, as expected, under high elasticity scenarios, emissions trading results in more emissions reduction due to demand response.

Table 7.10 *Total power sales and CO_2 emissions (0.2 elasticity scenarios)*

	PC0	PC10-ze	PC20-ze	SA0-le	SA10-le	SA20-le	ST0-le	ST10-le	ST20-le
				Total power sales [TWh]					
Netherlands	96	96	96	83	82	81	83	82	81
Belgium	89	89	89	68	67	67	67	67	66
Germany	542	542	542	478	464	450	477	462	446
France	523	523	523	522	520	518	310	307	306
EU4	1251	1251	1251	1150	1133	1116	937	917	899
				Total CO_2 emissions [Mt]					
Netherlands	76	63	60	64	55	52	64	55	52
Belgium	25	23	22	17	14	13	14	11	11
Germany	345	342	342	275	254	237	276	257	240
France	17	16	16	22	15	12	35	31	29
EU4	445	430	426	368	329	306	390	354	333
				Average overall CO_2 emission rate [kg/MWh]					
Netherlands	794	651	626	774	674	646	772	672	644
Belgium	276	262	248	250	203	200	203	166	162
Germany	636	630	630	575	547	528	579	556	538
France	33	31	31	42	29	23	112	100	96
EU4	355	343	340	320	291	274	416	387	370
				Average fossil CO_2 emission rate [kg/MWh]					
Netherlands	844	691	665	816	711	682	813	709	680
Belgium	879	844	830	616	648	648	616	647	648
Germany	961	955	954	938	922	912	941	924	914
France	916	893	882	922	901	894	751	760	752
EU4	938	908	903	897	866	851	883	856	842

Note: Average CO_2 emission rate of both fossil-fuel and non-fossil generators; b: Average CO_2 emission rate of fossil-fuel generators only.

[45] This assumption ignores the fact that the re-dispatch effect is lower when total demand decreases.

Table 7.11 *Decomposition of total CO_2 emission reductions (Mt)*

	PC10	PC20	SA10	SA20	ST10	ST20
Demand response	40	77	37	69	32	75
Re-dispatch	15	19	15	19	15	19
Total reduction	55	96	52	88	47	94
As % of reference emissions	12	22	14	24	12	24
	PC10-ze	PC20-ze	SA10-le	SA20-le	ST10-le	ST20-le
Demand response	0	0	24	44	20	38
Re-dispatch	15	19	15	19	15	19
Total reduction	15	19	39	62	35	57
As % of reference emissions	3	4	11	17	9	15

7.3.6 Average CO_2 emission rate

Finally, the lower part of Tables 7.9 and 7.10 provide data on average emissions rates under different scenarios. A distinction is made between the (sales-weighted) average rate of the fossil-fuel generators only, called 'average fossil CO_2 emission rate', versus the 'average overall CO_2 emission rate' of all (both fossil-fuel and non-fossil) generators. It can be observed from these tables that in most cases both indicators of average CO_2 emissions decline if CO_2 prices increase and that, under similar conditions, they are generally lowest in the SAx scenarios.

However, while the impact on total emissions due to the reduction in demand is relatively straightforward, i.e. total emissions decline if CO_2 costs increase, the effect of this increase on the average fossil-fuel emission rate is rather complicated and sometimes counterintuitive. In particular, the average fossil fuel emission rate can actually change in either direction, depending on the merit order in the supply function. For instance, if the reduction in output is from units with low emission rate (but with higher variable costs, that is why they are at the margin), the average fossil fuel emission rate will increase. On the other hand, if the output reduction is related to the high emission rate units, it will lead to a reduction in de average fossil fuel emission rate.

Interestingly, while in all scenarios the EU4 average fossil fuel emission rate declines as the CO_2 costs go up, the average fossil fuel emission rate at the country level may actually increase with higher CO_2 costs. In particular, in all oligopolistic runs, the average fossil fuel emission rate of Belgium actually increased with higher CO_2 costs levels. For instance, the average fossil fuel emission rate for Belgium in SA0-SA20 is 630, 656 and 648 kg/MWh, respectively. This counterintuitive outcome in the average fossil fuel emission rate partly explains the low average fossil fuel pass-through rate, (due to big denominator), observed in Belgium in several scenarios: SAx, STx, SAx-le and STx-le (see Section 7.3.3 above).

7.4 Detailed results at the company level

7.4.1 Capacity-weighted CO_2 emissions rate

In COMPETES, there are 15 firms in the market. Among these 15 firms, four firms are the so-called 'competitive fringes', which are the collection of smaller firms in each country. Their capacity is relatively smaller such that their ability to exercise market power is limited. The model treats them as price takers in the power market. Except Comp Nationale du Rhone (which owns only hydro units and, hence, has no emissions), the firm's capacity-weighted CO_2 emission rate ranges from 120 kg/MWh to 970 kg/MWh, with the lowest for Electricite de France and the highest for Steag AG. The overall market capacity-average is 410 kg/MWh. Figure 7.4 shows cumulative capacity against CO_2 emission rate for 5 selected firms included in COMPETES. If the majority of capacity owned by a firm is associated with low-emission technologies, it could benefit from high CO_2 prices; in contrast, owning a set of CO_2-intensive generators will incur substantial costs under the same conditions. Abstracting from behaviour assumptions, Figure 7.4 indicates that EdF potentially will profit by its low-emission capacity while RWE Power possibly will suffer profit losses due to higher CO_2 costs. In general, an increase of the CO_2 emission price will reduce the output from high-polluted generating units. The sources of substitutive supply are dependent on the relative production cost (considering CO_2 costs) and the availability of the transmission network.

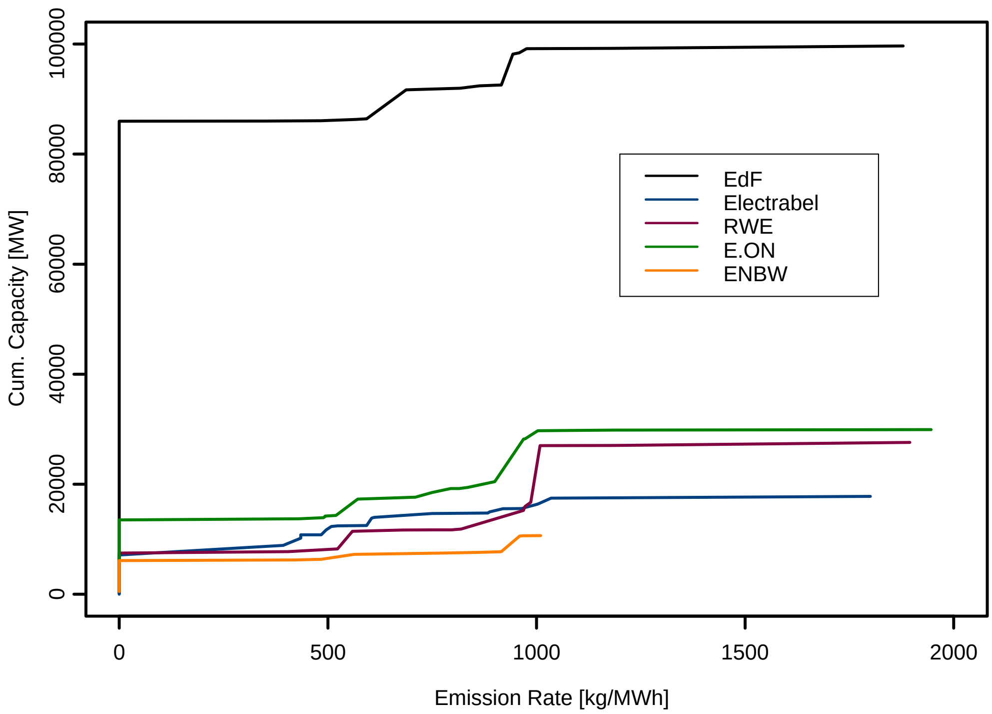

Figure 7.4 *CO_2 emission rate vs. cumulative capacity for 5 selected firms in COMPETES*

7.4.2 Changes in firms generation and CO_2 emissions

Appendix Tables C1 and C2 summarize the total emissions and power generation for each firm under different scenarios. An increase in CO_2 costs puts an upward pressure on the production costs for CO_2-intensive generators. This encourages firms to reduce output from these generating units. Therefore, if CO_2 cost goes up, a reduction of the output by firms having a higher emission rate can be expected. To see this, Figure 7.5 shows the changes in the total output versus the capacity-weighted emission rate. Each point in the plot represents the changes in output of a generating firm under a scenario relative to the reference case. A total of 180 points (12 points for each firm) are displayed. Figure 7.5 shows a nearly decreasing trend, implying that high-emission firms are more likely to reduce their output when facing increases in CO_2 costs. However, a more informative approach is to study the set of generating units (owned by the same firm) that changed their output levels during different runs.

Figure 7.6 presents the average CO_2 emission rate (weighted by the output changes)[46] for the set of units owned by the same firm that changed their output during two runs against the percentage change in firms' output. Figure 7.6 clearly shows that the set of generators that experienced

[46] Output change adjusted CO_2emission rate is calculated by $\sum_i \Delta g_i E_i / \sum_i \Delta g_i$, where Δg_i is the change in output by generator i and E_i is CO_2 emission rate for unit i.

reduction in output is generally associated with high emission rates (the right and lower half of Figure 7.6). The shortage is then supplied by the set of generating units having a low emission rate (the left upper corner of Figure 7.6).

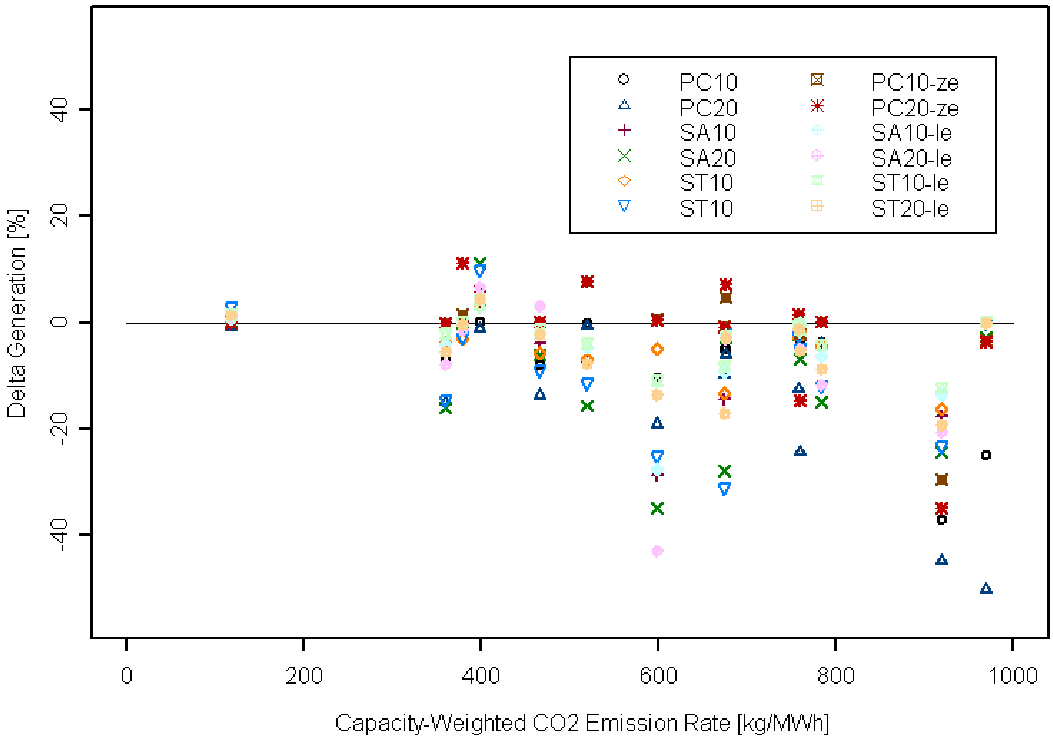

Figure 7.5 *Generation changes in percentage (relative to reference case) against firm capacity-weighted CO_2 emission*

Note: The cluster from left to right is Comp Nationale Du Rhone, Electricite De France, Energie Baden-Wurttemberg Enbw, Comp_Belgium, Electrabel Sa, E.On Energie AG, Soc Production D'Elec (SPE), Comp_France, RWE Power, Essent Energie Productie BV, Comp_Germany, Vattenfall Europe AG, Nuon NV and STEAG AG).

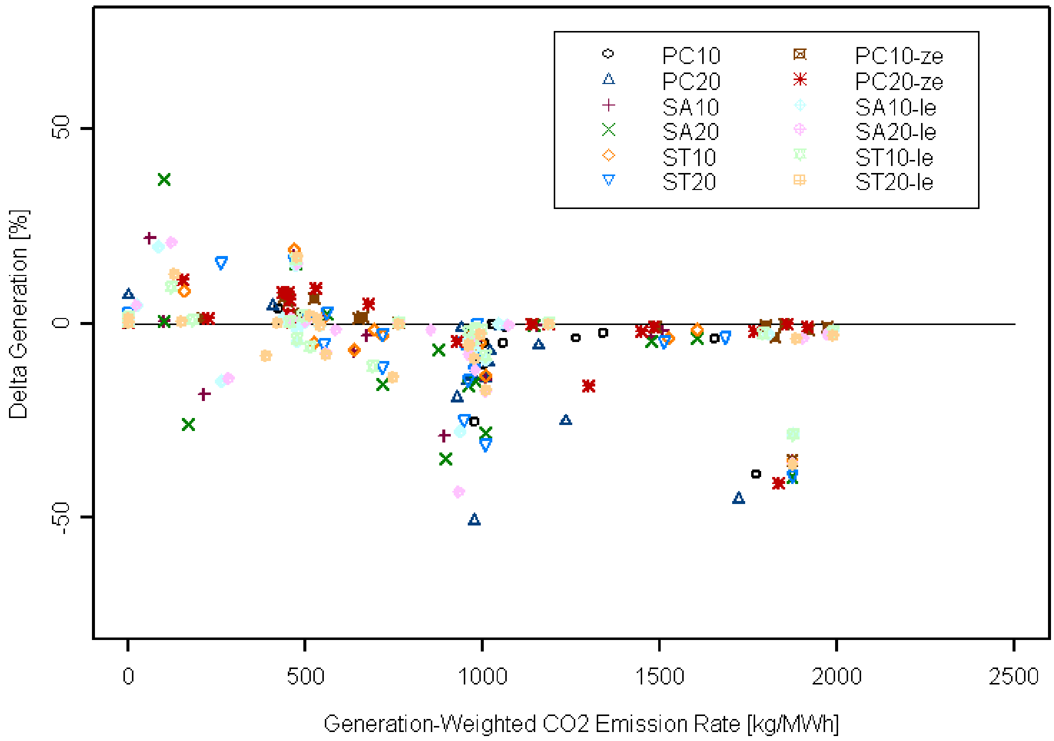

Figure 7.6 P*ercentage change in output against generation-weighted CO_2 emission rate*

One would expect EdF with substantial nuclear capacity to be the perfect substitute energy supplier as CO_2-intensitve generating units withdraw their output in response to higher CO_2 costs. In many of the runs, it turns out not to be the case. This is because the ability of EdF to export its power to neighbouring regions is limited by the interface transmission capacity. This is validated by the fact that the French market has a different power price compared with its neighbouring regions in most runs.

Two companion runs - PC10-ze and PC20-ze - provide valuable information on changes in merit order under different values of CO_2 costs. Aside from market structure and behaviour assumptions, two factors that affect the degree of pass-through and total CO_2 emissions are demand response and re-dispatch of generation due to the change in the merit order. Figure 7.7 is the plot of the generation rank without CO_2 costs (X-axis) against the cases with CO_2 costs (Y-axis). If the rank is completely unchanged, each point would lie on the 45° line. A point far off the 45° line implies a significant change in the merit order. If a point falls on the upper half of 45° line it indicates a drop in the generation rank as the unit becomes relatively expensive to operate due to the higher emission rate. Figure 7.7 implies that CO_2 costs introduce significant changes in the merit order when its value is above 20 €/tonne.

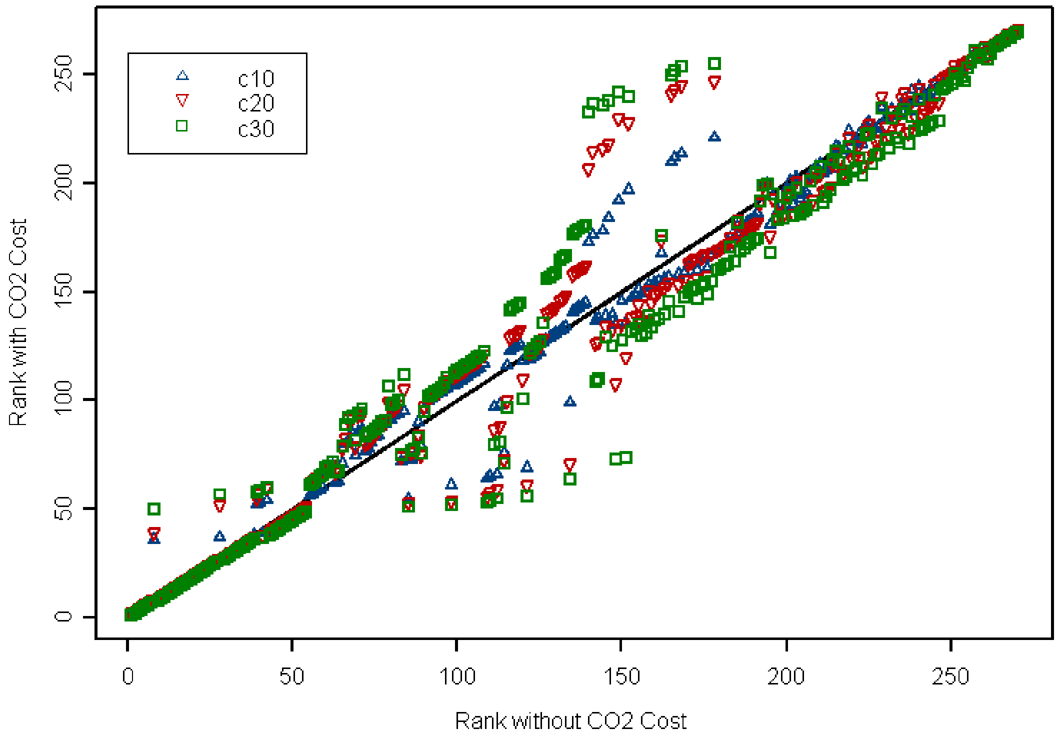

Figure 7.7 *The change of generation merit order under different values of CO_2 costs*

7.4.3 Changes in firms profits

Annex Tables C.3-C.6 present detailed data on changes in firms' profits due to emissions trading To present data differently, Figure 7.8 shows changes in firms' profits (relative to reference cases) against firms' capacity-weighted CO_2 emission rate (similar to Figure 7.5). Each point in the plot represents the profit changes of a generating firm under a scenario relative to the reference case. A total of 180 points (12 points for each firm) are displayed in Figure 7.8. An apparent downward-sloped trend indicates that a firm with a low capacity-weighted CO_2 emission rate generally is better off than others which have a higher capacity-weighted emission rate.

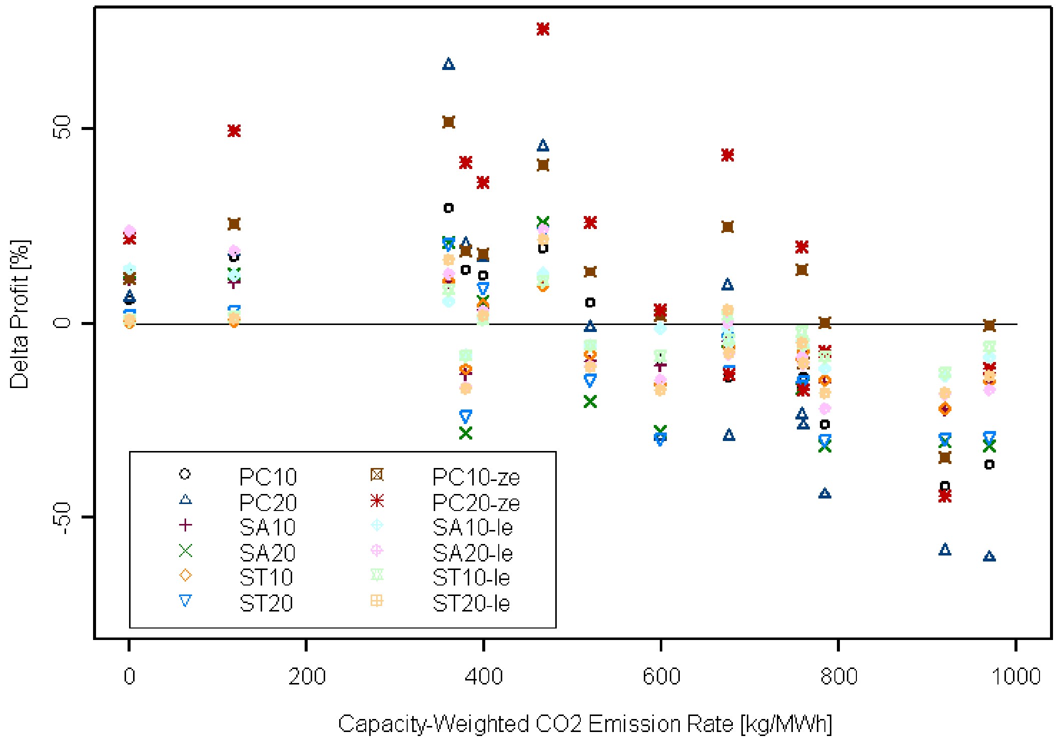

Figure 7.8 *Profit changes (relative to reference case) against firm capacity-weighted CO_2 emission rate*

Note: The cluster from left to right is Comp Nationale Du Rhone, Electricite De France, Energie Baden-Wurttemberg Enbw, Comp_Belgium, Electrabel Sa, E.On Energie AG, Soc Production D'Elec (SPE), Comp_France, RWE Power, Essent Energie Productie BV, Comp_Germany, Vattenfall Europe AG, Nuon NV and STEAG AG).

Table 7.12 presents a summary of the changes in total firms' profits due to emissions trading under different scenarios. These ET-induced profit changes can be distinguished into two categories:

1. Changes in profits due to ET-induced changes in production costs and power prices.
2. Changes in profits due to the free allocation of emission allowances.

Although both categories of profit changes are due to emissions trading, there are some major differences between these categories:

- The first category of 'windfall profits' is caused by the fact that carbon-extensive generators benefit from higher power prices set by carbon-intensive generators, while the second category is due to the fact that allowances are allocated for free (i.e. a transfer of wealth or 'economic rent').
- Whereas the second category is always positive ('windfall profits'), the second category may also be negative ('windfall losses') due to the fact that (i) the carbon intensity of power production of a firm may be higher than the carbon intensity of the marginal unit setting the price, and (ii) total sales – and, hence, profits – may decline due to ET-induced increases in production costs and/or consumer prices.
- The size of the first category of windfall profits is primarily determined by the difference between the change in power price and the change in the average production costs of a specific firm multiplied by its production volume, while the size of the second category is de-

termined by the (average) price of a CO_2 allowance multiplied by the total amount of allowances grandfathered to a specific firm.

- The size of the first category of windfall profits is estimated by the COMPETES model, while the second category is, in principle, determined outside the COMPETES model (since, as stated above, it is determined by the – average – price of a CO_2 allowance multiplied by the total amount of allowances grandfathered to a specific firm).
- The first category of windfall profits encourages ‘positive’ (i.e. carbon-extensive) investments, while the second category stimulates ‘negative’ or ‘perverse’ (i.e. carbon-intensive) investments.
- While the size of the first category of windfall profits may decline over time due to new (ET-induced) investments in generation capacity (if it leads to lower power prices), the second category may increase due to new (ET-induced) investments (if it leads to more emissions and, hence, to a higher amount of freely allocated allowances and/or a higher price per CO_2 emission allowance).

In the left part of Table 7.12, it is assumed that all firms have to buy all their emissions allowances on the market, i.e. there are no windfall profits due to grandfathering. Even under this condition, total firm profits increase under most scenarios (except STx where total profits decline). This results from the fact that, on average, power prices are set by marginal units with relatively high carbon intensities that pass their relatively high carbon costs through to these prices. Intra-marginal units with relatively low carbon intensities are not faced by these high carbon costs but benefit from the higher power prices on the market. Overall, profits increase due to emissions trading. In general, the rate of passing through is higher in competitive markets than non-competitive markets (as predicted by economic theory). This explains why the total profits increase particularly under the competitive scenarios, whereas they decrease in the non-competitive scenarios. Moreover, under scenarios with a low price elasticity, the increase in profits due to emissions trading is generally higher, mainly because rates of passing through are higher when demand is less elastic.

Under the present EU ETS, however, companies do not have to buy their emission allowances on the market but receive them largely for free. This implies that they are able to realise windfall profits due to grandfathering as they still pass on the carbon costs of grandfathered emission allowances. The fifth column of Table 7.12 shows estimates of these profits, based on the total firms CO_2 emissions (Appendix Table C.2) and the assumption that power companies receive, on average, 90 percent of the allowances to cover their emissions for free.[47] These windfall profits vary between € 3 and 8 billion, depending on the price of carbon and the scenario considered. As total production and total emissions are generally higher under the competitive scenarios, the total windfall profits are also higher under these scenarios.

If windfall profits due to grandfathering are included, total profits rise significantly under all scenarios (including STx), but they increase most under the PC scenarios. For instance, under PC20, firm profits increase from almost € 14 billion without emissions trading to almost € 20 million with emissions trading at a cost of 20 €/tonne (including windfall profits due to the price

[47] This assumption is based on the expectation that, *on average,* 90 percent of the projected emissions by the power sector during the period 2005-07 is covered by freely allocated emissions allowances. This assumption has been used rather than the actual allocations as laid down in the National Allocation Plans for this period, mainly for two reasons. Firstly, using the actual allocation data for the non-competitive scenarios (SAx and STx) would result in a large surplus of emission allowances since total production and, hence, total emissions in these scenarios are substantially lower than actual production and emissions data on which the actual allocation of allowances is based. As a result, it would lead to an exaggeration of the estimated windfall profits (since it is realistic to assume that under the non-competitive scenario firms would have received less allowances than the actual allocations, based on actual production and emissions data). Secondly, using actual allocation data may lead to confusion and misinterpretation as they suggest that the estimated changes in profits due to emissions trading are ‘actual’, ‘real’ changes in firms profits (which is not the case as they are partly based on estimates by the COMPETES model).

effects of emissions trading, but excluding windfall profits due to grandfathering). Overall, if both categories of windfall profits are included, total firms' profits in the PC20 scenario almost double from € 14 billion to € 27 million.

Table 7.12 *Changes in power firms' profits due to CO_2 emissions trading*

	Total profits	Change in profits due to ET-induced price effects		Change in profits due to grandfathering	Total profits	Total change in profits due to emissions trading	
	[M€]	[M€]	[%]	[M€]	[M€]	[M€]	[%]
PC0	13919				13919		
PC10	14963	1044	7.5	3506	18469	4549	32.7
PC20	15631	1712	12.3	6272	21904	7984	57.4
SA0	22063				22063		
SA10	22140	76	0.3	2859	24999	2936	13.3
SA20	22097	34	0.2	5074	27172	5108	23.2
ST0	32015				32015		
ST10	31488	-527	-1.6	3075	34563	2549	8.0
ST20	31473	-542	-1.7	5308	36782	4767	14.9
PC0	13919				13919		
PC10-ze	17099	3180	22.8	3865	20605	6686	48.0
PC20-ze	19821	5902	42.4	7666	26093	12174	87.5
SA0-le	32424				32424		
SA10-le	32715	291	0.9	2962	35574	3150	9.7
SA20-le	33028	604	1.9	5513	38102	5678	17.5
ST0-le	53656				53656		
ST10-le	53635	-22	0.0	3189	56710	3054	5.7
ST20-le	53574	-82	-0.2	5996	58883	5227	9.7

Under other scenarios, however, the increase in profits due to emissions trading is less spectacular. For instance, under the high elasticity ST20 scenario, profits decline due to emissions trading by almost € 500 million if it is assumed that firms have to buy all their emissions allowances on the market. Lifting this assumption implies the creation of a windfall profit due to grandfathering of € 3.1 billion when the price of an allowance is 10 €/tCO_2 and of € 5.3 billion when the price becomes 20 €tCO_2. As a result, total power profits under the high elasticity ST10 and ST20 scenarios increase by € 2.5 and 4.8 billion, respectively, i.e. about 8 and 15 percent of the business profits before emissions trading.

There are major differences, however, in profit performance due to emissions trading at the individual level, as can be noticed from the detailed tables of Appendix C as well as from Table 7.13 that presents changes in profits of individual firms due to emissions trading under the two scenarios mentioned above (ST20 and PC20).[48] In general, when excluding windfall profits, companies such as F seem to benefit most from emissions trading, especially from the increase in power prices due to the pass-through of carbon costs. This is not surprising given the high share of nuclear production in total generation by F. On the other hand, some companies make a loss due to emissions trading when they have to buy their emissions allowances, even under the

[48] Because of the sensitivity of publishing data on individual firms' profits, these data have been recorded anonymously.

PC20 scenario. These are particularly the companies J and K. Once the windfall profits are accounted for, however, all companies realise additional profits due to emissions trading under the PC20 scenario.

Table 7.13 *Changes in profits of individual firms due to emissions trading under two different scenarios (in M€)*

	ST0	ST20	Change in profits due to: Price effects	Free allocation	ST20 (Incl. free allocation)	Total change in profits
A	425	433	8	0	433	8
B	250	190	-60	80	269	20
C	1576	1105	-472	317	1422	-155
D	1972	1653	-319	1344	2997	1025
E	392	333	-59	136	469	77
F	3269	4027	757	199	4226	956
G	2775	3021	245	199	3220	445
H	12287	12610	323	98	12709	422
I	1646	1977	330	205	2182	536
J	775	676	-99	247	923	147
K	650	454	-195	166	620	-29
L	2896	2777	-119	468	3245	349
M	339	288	-51	60	348	9
N	658	462	-196	539	1001	343
O	2103	1467	-636	1251	2718	615
Total	32015	31473	-542	5308	36782	4767

	PC0	PC20	Change in profits due to: Price effects	Free allocation	PC20 (Incl. free allocation)	Total change in profits
A	127	154	28	0	154	28
B	204	289	84	51	340	135
C	200	207	7	119	326	126
D	743	890	147	1230	2119	1376
E	128	106	-22	66	172	44
F	2007	3524	1517	1051	4575	2568
G	1722	2347	625	536	2883	1161
H	4405	6582	2178	225	6807	2402
I	768	1517	748	373	1890	1122
J	319	277	-42	257	535	216
K	204	114	-90	148	261	57
L	1861	2663	802	1902	4565	2704
M	52	65	13	27	92	41
N	217	192	-25	245	438	220
O	962	893	-69	1436	2329	1367
Total	13919	19821	5902	7666	27487	13567

It should be emphasised, however, that the figures on (windfall) profits mentioned above and recorded in the tables should be treated with due care. These figures are derived from a model that aims to simulate strategic behaviour on the wholesale market. Although the model is quite detailed and based on recently calibrated data, it does not pretend to give a full realistic picture of the power sector. The scenarios of this model are ‘extreme’ scenarios aimed at analysing the impact of market structure on variables such as power prices, firm profits and output production. As a result, total power sales, including the associated emissions - and, hence, the grandfathered allowances and windfall profits - vary largely between these scenarios and, especially, at the firm level.

Nevertheless, the model offers some useful insights, also with regard to the impact of emissions trading on power prices and firm profits. For instance, it can estimate the impact of different CO_2 price levels on the extent to which carbon costs are passed through to power prices. Or it can assess the order of magnitude of the impact of emissions trading on business operations at the firm level. If interpreted prudently, the results can even be helpful in analysing and supporting the discussion on the policy implications of emissions trading for the power sector, a subject that will be treated more extensively in the next chapter.

8. Implications for power producers, consumers and policy makers

This final chapter will first of all summarise briefly the major implications of EU emissions trading for power prices and discuss the potential problems related to these implications. Subsequently, it will discuss a variety of potential options and strategies to address these implications.

8.1 Implications of grandfathering: what's the problem?

The EU ETS is a cap and trade system based primarily on a free allocation of fixed amounts of emission allowances, often denoted as *grandfathering.* In addition, a Member State is allowed to auction, at the maximum, 5 percent of its allowances during the first trading period (2005-07) and 10 percent during the second (2008-12). For the first trading period, however, almost all Member States have opted to allocate the full amount of their emission allowances for free.

The major implication of this political choice is that most installations covered by the EU ETS receive CO_2 emission allowances for free. Companies can either use these allowances to cover the emissions resulting from the production of these installations or sell them on the market (to other companies that need additional allowances). Hence, for a company an emission allowance represents an opportunity cost, even if it is granted for free. Therefore, in line with basic economic theory and sound business principles, it is logic and normal that a company adds this cost fully to its other (marginal) costs when it is making (short-term) production or trading decisions. Such a practice fits well into an economic market system based on marginal cost pricing and profit maximising behaviour, resulting in a social efficient or optimal situation provided the full costs of production - including the environmental and other external costs - are reflected in output prices. This applies equally to power producers and non-power producers, either large or small.

If grandfathering is applied equally to existing and new fossil-fuel installations, it may have two opposite effects on power prices with significant different implications for power producers, consumers and policy makers:

- A price increasing effect due to the passing through of the opportunity costs of grandfathering.
- A price compensating or neutralising effect of grandfathering due to its subsidisation of fixed investment costs.

These effects and their implications are discussed below.

The price increasing effect of grandfathering

The first grandfathering effect implies that profit maximising producers pass through ('add-on') the opportunity costs of CO_2 emission allowances to their other (short-term) marginal costs when taking production or trading decisions. If this would be the only effect of grandfathering, this would mean that these costs would be passed-through ('work-on') to power prices. As a result costs of CO_2 emissions would be internalised by higher power prices, leading to a more efficient or more optimal situation from a social welfare point of view, including less CO_2 emissions due to (i) less power sales, if power demand is price elastic, and/or (ii) a change in the merit order, if the costs are high enough to effectuate such a change. The previous chapter has shown that these CO_2 emission reductions due to demand response and re-dispatch can be very significant, depending on the level of CO_2 prices, the extent to which CO_2 costs are passed through to power prices, and the price elasticity of power demand. In general, significant CO_2 reductions in the power sector can be relatively easy or cheaply achieved, implying that more difficult or expensive CO_2 emission reductions in other sectors can be avoided in order to meet the cap or overall national target.

In addition, however, passing through of opportunity costs of grandfathering would imply higher power prices for all consumers, including households, small firms, power-intensive industries and other major electricity users. If households and small firms already pay relatively high energy/carbon taxes on their electricity use, such as the Energy Tax (EB) in the Netherlands, this would mean that they are taxed double from an energy/environmental point of view. If power-intensive industries are hardly able to pass through the higher costs into their outlet prices it would imply that these industries are faced by less profits, less production, less employment and a possible shift in investment, production and trade opportunities to locations outside the EU ETS (including 'carbon leakage'). Finally, a free allocation of emission allowances implies a transfer of wealth from consumers to producers (called 'economic rent' or 'windfall profits').

The price compensating effect of grandfathering

On the other hand, the second grandfathering effect implies a lump-sum subsidy to an installation that lowers the fixed investment costs of power generation, which - under certain conditions - results in a neutralisation of the increase in power prices due to the passing through of the opportunity costs of CO_2 emission allowances. If fully effective, it would mean that power prices, on balance, would not change and, hence, that certain potential adverse effects of higher power prices would not occur (for instance, no 'double taxation' of small consumers, no higher electricity cost for power-intensive industries, no carbon leakage, no windfall profits, etc.). However, it would also imply that external costs of CO_2 emissions would not be internalised through higher prices, leading to a less efficient situation from a social welfare point of view. This means that total CO_2 emissions by the power sector are not significantly decreased through lower demand or by large changes in the generation mix since neither output prices nor the total average costs of generation technologies would change significantly. As a result, emission reductions elsewhere have to be increased to meet overall environmental targets.

In fact, if grandfathering is applied equally to existing and new investments it leads, on the one hand, to an internalisation of external CO_2 emission costs due to the passing through of these costs into higher power prices, on the other hand, this effect may be nullified by the implicit lump-sum subsidy to fixed investment costs due to grandfathering, with the subsidy being higher if the investment is more carbon-intensive. Hence, the impact of grandfathering on emissions reduction may be small, while it encourages investments in carbon intensive generation capacity. Such a contradictory - or even perverse approach may be questioned from a consistent and cost-effective environmental policy point of view.

As outlined in Chapter 4, the impact of the second effect of grandfathering will only be effective up to a certain CO_2 price level and in a (long-term equilibrium) situation in which generation capacity is scarce and actually enlarged by investment in new capacity. However, regardless whether and to which extent the first effect of grandfathering will be fully or partially neutralised by the second effect, there will always be a trade-off between these effects with regard to their implications for power producers, consumers and society at large. Either the second effect will not or only partly neutralise the first effect, meaning that - on balance - power prices will increase, leading to beneficial implications on the one side (less CO_2 emissions by the power sector) and to 'adverse' implications on the other (higher costs to power-intensive industries and other consumers; windfall profits to generators). Or the second effect – resulting from the implicit subsidisation of carbon-intensive investments – will fully neutralise the first effect, meaning that - on balance - power prices will not increase, thereby avoiding not only the adverse implications of higher power prices but also the beneficial implications mentioned above.

To compare, auctioning will (*ceteris paribus)* always lead to higher power prices since the variable costs of the CO_2 allowance will be passed through while the fixed costs do not change. As a result, auctioning will have beneficial implications on the one hand (induced less CO_2 emissions by the power sector) and some adverse effects on the other (higher costs to power-intensive industries and small-scale consumers). However, auctioning prevents the incidence of windfall profits among producers as the economic rent of CO_2 allowances accrues to society at large by means of the auction revenues, which can be used to address the adverse effects of higher power prices mentioned above.

It should be noted, however, that the trade-off between the opposite effects of grandfathering on output prices does not apply only to the power sector but also to other sectors, companies or installations covered by the EU ETS (although these effects are usually much smaller, depending on the carbon-intensity of the output of these installations). Hence, these sectors are also faced by a trade-off between the beneficial and adverse price effects of grandfathering, i.e. a trade-off between environmental and social efficiency on the one hand, and higher outlet prices for consumers and resulting windfall profits for producers on the other. Therefore, although these effects fall beyond the scope of the present study, they will be included in the considerations below, dealing with options and strategies to address the potential adverse implications due to grandfathering while trying to preserve its potential positive effects.

8.2 Options to address adverse implications of passing through CO_2 costs

8.2.1 Indirect allocation of emission allowances

In an indirect system of grandfathering, electricity *users* receive emission allowances for free, while power *generators* are responsible for surrendering allowances according to their emissions. Since electricity users do not need the allowances for themselves, the end result will be that they will sell them to the power generators [Harrison and Radov, 2003; Mannaerts and Mulder, 2003; Sijm, 2003).

In short, the major advantages of this option are that (i) it forces power producers to buy their allowances on the market and, hence, encourages them to pass through the full external costs of CO_2 emissions to their end-users, thereby promoting energy/environmental efficiency, (ii) it reduces the potential windfall profits of the power producers, and (iii) the revenues from selling allowances compensate electricity users for the increases in electricity prices induced by emissions trading.

On the other hand, this option has some drawbacks. First of all, if the indirect system covers all electricity users - including millions of households and small firms - it might lead to high administrative demands and transaction costs. However, if it covers only major industrial users of electricity, households and small firms are not compensated for higher electricity prices while power producers still may reap substantial windfall profits. Moreover, as noted above, the issue of passing through the opportunity costs of freely allocated emission allowances (and, hence, of realising windfall profits) may not be restricted to the power sector only and, therefore, an extension of the indirect system to other sectors might have to be considered from an equity point of view (thereby complicating the administrative demands and transaction costs of the system).

In addition, another drawback from a distributional perspective concerns the opportunity that a power-intensive facility may be in a position to pass-through the cost increase due to higher electricity prices, while it has already been compensated financially for these costs via the sale of indirectly, freely allocated allowances (Reinaud, 2004). The basic problem with grandfathering - either direct or indirect - is that it concerns a system of allocating economic rents that may result in windfall profits (if opportunity costs are passed through) or social inefficiencies (if it does not result in the internalisation of external costs). Therefore, rather than grandfathering indirectly, it may be less complicated to auction allowances or to tax the carbon emissions of the power (and other) sectors and, subsequently recycle the revenues among the users of electricity and other carbon-intensive producers covered by the EU ETS.

8.2.2 Auctioning

Auctioning has been advocated by policy analysts as the preferred option for allocating allowances, based on the following arguments (KPMG, 2002; SER, 2002; Sijm and Van Dril, 2003):

- All participants, including new entrants, are treated in the same, equal and fair way. Companies that have reduced their emissions in the past need to buy fewer allowances and, hence, are rewarded for this 'early action'. Moreover, an auction avoids both competitive disadvantages to new market entrants as well as windfall profits - or capital transfers - due to the (over) allocation of free allowances to (incumbent) participants.
- Auctioning is preferable from an efficiency point of view as, compared to free allocation, it provides the best reflection of the polluter-pays principle and, hence, the best incentive for technological innovations and cost-effective adjustments in existing production and consumption patterns, notably for carbon-intensive goods.
- Auctioning generates revenues for the public sector, which may be used to finance government expenditures, to reduce existing market distortions such as taxes on labour or capital, or to compensate users of carbon-intensive products for the higher prices of these products due to the passing through of the CO_2 allowances costs.

The main disadvantage of auctioning, however, is that it raises the costs of participating industries (comparable to a carbon tax). If applied to the EU ETS only, this would deteriorate the competitiveness of EU industries, resulting in a loss of economic growth, income and employment. Although recycling the auction revenues to these industries can to some extent lift these adverse effects, it raises the problem of how the auction revenues can be recycled in the most optimal way. For instance, it may be administratively complicated to exactly compensate only energy-intensive industries for the total amount of the ETS-induced increase in their electricity bill. A possible solution to this problem is to compensate industrial (and other) end-users of electricity in more general terms for ETS-induced increases in electricity prices, for instance by recycling auction revenues through lowering the overall level of taxation and social premiums. This solution is administratively less complicating, while it has the least distortive impact on the overall competitiveness of the industrial sectors (although it causes a shift in competitive advantage from the energy-intensive to the energy-extensive industries).

A temporary limittion of auctioning is that, according to the EU Directive, Member States shall allocate at least 95 per cent of the allowances free of charge during the first phase of the EU ETS (2005-2007) and at least 90 per cent of the allowances free of charge during the second phase (2008-2012). Hence, up to 2012 Member States have the opportunity to auction only a small part of their allowances and, if applied by an individual Member State only, it will affect the competitive position of covered installations compared to those of other Member States. However, after the second trading phase of the EU ETS, the share of total allowances to be auctioned can be raised and made mandatory to all Member States.

A final drawback of auctioning is that it may be politically hard to accept, notably by the power producers but also by other, carbon-intensive industries covered by the scheme and even by the (non-covered) power-intensive industries since they will be faced by higher costs for their emissions (as they have to buy their emission allowances rather than getting them for free) and/or by higher costs for their electricity used (as the rate of passing through CO_2 costs may be higher under auctioning than grandfathering). Only if affected industries are sure that they will be lastingly compensated through the recycling of auction revenues, the political resistance may dwindle but, as indicated above, it may be hard to design such a recycling system and guarantee its durable character.

To some degree, political resistance to auctioning by non-power industries can be relieved by restricting auctioning of emission allowances to the power sector only. However, apart from the risk of potential competitive distortions between sectors or industries, the issues related to grandfathering (i.e. passing through CO_2 costs and transferring wealth or windfall profits to producers) are not restricted to the power sector only but concerns, in principle, all activities covered by the EU ETS.

8.2.3 Regulation

An option to restrict power price increases due to the passing through of the opportunity costs of grandfathered emission allowances is regulation, i.e. setting and controlling (increases in) power prices by an external authority, for instance the national Transmission System Operator (TSO). Besides limiting price increases in favour of electricity users, including households and small firms, the major advantage of this option is that it reduces the deterioration of the international competitiveness of power-intensive industries.

However, as explained in Chapter 4, restricting power prices has some adverse side effects. Firstly, in response to a price restriction, power generators will reduce their production (and sell their surplus of grandfathered allowances on the market) until the marginal costs of power output (including the full opportunity costs of power output) is equal to the regulated price. Hence, while the price impact of grandfathering is restricted (i.e. the work-on rate is less than 100 percent), producers still pass through the full amount of the opportunity costs of emission allowances (i.e. the add-on rate is still 100 percent). Therefore, from a point of view of restricting the add-on rate and, hence, reducing the incidence of windfall profits, price regulation is ineffective.

In addition, price restrictions will enhance power demand, while reducing power supply, resulting in unmet official demand and non-price rationing of supply. This leads to the creation of informal markets - where uncontrolled, unofficial prices are higher - and/or to investments in so-called rent-seeking activities among consumers ('how do I get access to scarce, but cheap resources') rather than investments in efficient production opportunities among power generators. As a result, price regulation is only partly effective, while it hardly fits with an efficient, liberalised power market.

A specific form of regulation or 'voluntary agreement' concerns the proposal launched by some organisations representing European power-intensive industries (see, for instance, ECON, 2004a; Reinaud, 2004; or CEPS, 2005). In short, this proposal includes that power producers are forced or 'voluntary agree' to pass through only the average 'true' costs of the emission allowances actually bought rather than the full marginal, opportunity costs of the allowances allocated for free. As discussed in Chapter 4, if the proposal could or would be implemented effectively, it would have some of the advantages of price regulation mentioned above (notably restricting increases in power prices for end-users and, hence, reducing the deterioration of the international competitiveness of power-intensive industries). In addition, it would eliminate windfall profits, as producers would only pass through the real, average costs of emissions trading.

On the other hand, it would also have some of the adverse effects of price regulation, resulting particularly in inefficiencies regarding power production, consumption and investment decisions. In addition, since the external costs of CO_2 emissions are only partly internalised by higher power prices, total demand and supply of power will be higher. This leads to higher emissions and - given the overall system or national cap - the need to meet additional CO_2 reductions in other sectors and, hence, to further social inefficiencies since abatement costs are likely to be higher in these sectors.

Moreover, the proposal mentioned above does not account for the fact that emissions trading may also affect other marginal production costs besides allowances cost, for instance due to a change in power demand or a change in the merit order, thereby affecting company profits (most likely in a negative sense). Accounting for these changes in other marginal costs would put additional demands on cost data and administrative controls to implement the proposal adequately. Finally, even abstracting from the latter administrative requirements, the proposal would most likely be hard to implement in practice and does not fit with an efficient, liberalised power market based on marginal pricing and producers seeking to optimise their production and maximising their profits.

8.2.4 Benchmarking with ex-post allocation adjustments

An alternative allocation system, besides auctioning and grandfathering under a (fixed, absolute) cap and trade system, is a system of free allocation of emission allowances based on a relative quota or Performance Standard Rate (PSRs) such as an energy/carbon efficiency benchmark per unit input or output. These PSRs or benchmark could be multiplied by the *expected* output (or input) volume during a certain trading period in order to determine ex-ante, i.e. before the trading period commences, the total fixed amount of allowances allocated at the installation, national and system levels, as allowed by the European Commission and recommended by the Social Economic Council of the Netherlands (CEC, 2003; SER, 2002).

Alternatively, these benchmarks could be multiplied by the *realised* output volume during certain periods in order to determine ex-post, i.e. after the trading period has ended, the variable total amount of allowances - varying by ex-post, realised production - allocated at the installation, national and system levels, as proposed by organisations and representatives of industrial stakeholders (see, for instance, Schyns and Berends, 2003a and 2003b; and Schyns, 2004).

The major advantages of an ex-post system are that it rewards (early) action on enhancing energy/carbon efficiency and that it is popular among industrial stakeholders since it is less restrictive on economic growth. Moreover, depending on the level at which the benchmark is set, it may reduce the increase in output (power) prices and the incidence of windfall profits.[49]

On the other hand, a relative quota or ex-post PSR system has some drawbacks, including:

- A relative quota system is less efficient because it is a combination of a price on emissions and a production subsidy. Consequently, production will exceed the optimal output level, and allowance price and abatement costs need to be higher in order to meet the same emission target as in an efficient system with an absolute quota (Koutstaal, et al., 2002; Koutstaal, 2002).
- A relative quota system does not provide certainty with regard to the environmental effectiveness of an ETS and may lead to an overrun of international commitments on carbon mitigation or the need to take additional (more expensive, short-term) measures to meet these commitments. To some extent, this problem can be controlled by a regular adjustment of the PSR, but this creates uncertainty in the carbon and products markets.
- A relative quota system does not fit into the present Directive (and political consensus) on the EU ETS - opting for a fixed cap and trade system, at least up to 2012 - and, hence, it may take years (if ever) to change the fundamentals of the EU ETS.
- A relative quota system may imply high information and other transaction costs, notably if a large number of PSRs has to be determined and regularly updated for a large number of firms and/or products, including process emissions. It may be cumbersome and time-consuming to determine EU-wide PSRs or to find a political consensus on what an acceptable, average EU benchmark should be (Reinaud, 2004; CEPS, 2005). Moreover, even if a relative quota system based on EU-wide PSRs could be developed and agreed on, it still may distort the competitiveness among firms (Jansen, 2002; Elzenga and Oude Lohuis, 2003).

---

49 For a full discussion of the pros and contras of different allocation systems, see Sijm and Van Dril (2003), and references cited there.

- A relative quota system is faced by the same trade-off as a grandfathering system depending on whether it leads to the full internalisation of external costs in outlet prices or not, i.e. a trade-off between environmental and social efficiency on the one hand and higher prices for consumers and resulting windfall profits for producers on the other hand.

8.2.5 Limiting the price of a CO_2 emission allowance

The implications of the EU ETS for power prices and, hence, power-intensive industries can be reduced by limiting the CO_2 prices on the EUA market. This could be achieved by relaxing the overall cap, for instance during the second budget period (2008-12), or encouraging the influx of Emission Reduction Units (ERUs)/Certified Emission Reductions (CERs) from JI/CDM projects as part of the Linking Directive to the EU ETS. Relaxing the overall cap, however, implies that - given the overall Kyoto target - emissions reductions elsewhere have to be increased (which may be more expensive) while it may be hard to increase the flux of ERUs/CERs due to a variety of political, technical, socio-economic and other, project-related constraints.

Another option to limit the CO_2 price in the EUA market and, hence, its potential impact on power prices is to set a maximum price on a carbon allowance, i.e. below the already determined penalty price of 40 and 100 €/t CO_2 for the first and second trading period, respectively. Besides the penalty price, however, the present EU ETS Directive does not enable the setting of such maximum prices, while changing the Directive in this sense might take some time given the required EU-wide political consensus to do so. Moreover, setting a maximum price implies that the environmental objective of the EU ETS will not be met and that, as stated before, additional - perhaps more expensive - emission reductions have to be achieved elsewhere to meet the Kyoto commitments.

8.2.6 Encouraging competition in the power sector

An option to reduce or even neutralise the increase in power prices due to grandfathering is to encourage competition in the power sector, notably by means of an equal treatment of grandfathering between incumbent and new producers, resulting in a reduction of the fixed cost margin and/or mark-up of power prices. Although encouraging sound competition in the power sector in general, and treating incumbents and newcomers equally in particular, can be justified to some extent, this option can nevertheless be questioned on the following grounds (as discussed in Chapter 4):

- The option will be effective only in a (long-term equilibrium) situation in which generation capacity is scarce and actually enlarged by investments in new capacity. In the power sector, this may take some time, perhaps years, particularly if new producers want to enter the power market and/or if the power market is characterised by imperfect competition (as is often the case). During this time, power prices will increase due to the passing through of the opportunity costs of CO_2 emission allowances, resulting in welfare transfers ('windfall profits') from electricity consumers to producers.
- The option will only be effective up to a certain CO_2 price level - say 16-20 €/tCO_2 - since beyond this level the fixed cost margin (and/or mark-up) can not be further reduced because no producer will ever sell power at a price below the opportunity costs of the fuels and CO_2 allowances used.
- On the other hand, if the option is effective, it implies that the external costs of CO_2 emissions are not internalised in the power prices, resulting in an inefficient or sub-optimal situation from an environmental-economic or welfare point of view.
- As a basic principle for designing markets, it can be argued that the allocation of property rights - such as CO_2 emission allowances - should not be a function of future decisions, because of the risk of distorting these decisions. For instance, free allocation of CO_2 emission allowances to new investments can lead to inefficiencies and other distortions such as investments in carbon-intensive technologies, investments in unnecessary, unreliable produc-

tion capacity or investments in 'rent-capturing activities' ("how do I get the most allowances") rather than investments in efficient, low-carbon and truly needed expansions of generation capacity. Hence, even if the option is effective, grandfathering to new investments may be questioned because of these distortions.

To conclude, the option of reducing power price increases by means of grandfathering to both incumbents and newcomers can be questioned on the following grounds: (i) it may result in substantial welfare transfers from power producers to consumers during some (long) time since the mechanism of neutralising power price increases through encouraging investments in new capacities is either not or partly effective, (ii) on the other hand, as far as it is effective, it implies that CO_2 costs are not internalised in the power price, resulting in welfare inefficiencies, and (iii) it may result in all kinds of distortions regarding new investment decisions. If policy makers are interested in encouraging competition or enhancing generation capacity in the power sector, and in ensuring that allowance rents are not entirely captured by producers, there are likely less questionable instruments than grandfathering CO_2 allowances to both incumbents and newcomers.

8.2.7 Abolishing grandfathering to new investments

As outlined above, a free allocation of emission allowances to new investments in generation capacity implies a lump-sum subsidy to the fixed costs of particularly fossil-fuel power production, leading to negative or perverse capacity and production outcomes from an environmental or social efficiency point of view. These outcomes can be avoided by abolishing grandfathering to new investments. This would also abolish the price-neutralising effect of grandfathering, which may enlarge the net first effect of passing through carbon costs to power prices and, hence, augment the internalisation of external costs and the resulting environmental efficiency of emissions trading.

On the other hand, enlarging the net price-increasing effect of grandfathering implies that windfall profits due to ET-induced price changes may be higher while windfall profits due to free allocated allowances remain the same. Therefore, abolishing grandfathering to new investments addresses the problem of encouraging perverse investments in generation capacity, but it does not deal with the issue of windfall profits (while it may even enlarge these profits).

8.2.8 Taxation

In the field of taxation, there are at least two options to address potential negative implications of emissions trading on power prices:[50]

- *Taxing windfall profits.* In principle, windfall profits accruing to power companies could be skimmed by partly or fully taxing these profits. In practice, however, it may be hard to distinguish the tax base of these profits from changes in 'normal profits' since the latter are affected not only be the value of the freely allocated allowances but also by changes in other marginal production costs and changes in trade volumes due to emissions trading. If taxing is restricted to the full or partial value of the feely allocated allowances, a similar option would be to simply auction the corresponding amount of allowances. A complicating issue, however, is whether potential windfall profits due to emissions trading in other sectors have to be taxed as well (and how to determine these profits in a fiscal-juridical correct way).
- *Tax relief to consumers.* In order to compensate electricity consumers for ETS-induced increases in power prices, taxation of these consumers could be relieved, either in a general way - for instance by reducing income or business taxes - or in a specific way, for instance by lowering specific energy taxes. In the Netherlands, for instance, households and small firms may be double taxed by the interaction of the regulatory energy tax (REB) for small-

[50] A more fundamental option with regard to taxation is the introduction of a widespread, uniform carbon tax (in stead of emissions trading based on grandfathering or auctioning), but this option falls beyond the scope of the present study.

scale users and the higher power prices due to the internalisation of CO_2 costs by the EU ETS (Sijm and Van Dril, 2003). This double taxation can be relieved by reducing the REB for these small scale users. The major problem of this option, however, is that governments generally lack funds to finance such a tax relief. Only if they auction the emission allowances to the power sector, they acquire resources to finance this option.

8.2.9 State aid

Under certain conditions, the power price effect of emissions trading could be addressed by providing state aid to heavily affected companies that can not pass through higher electricity costs into their outlet prices. A precondition is that Member States are willing to grant state aid and that such action would be compatible with EC state aid rules (CEPS, 2005). Major drawbacks of such state aid are that it may (i) take a permanent character (unless timing conditions are specified to prevent so), (ii) lead to other, new competitive distortions if not implemented and targeted correctly, and (iii) lead to higher taxation or less resources for other public expenditures.

8.2.10 Other, long-term policy options

Other, long-term options to relieve the potential negative implications of emissions trading for power prices include (Sijm et al., 2004):

- *Broadening the climate coalition.* If the present climate coalition of Annex I countries - i.e. countries accepting emission limits as part of the Kyoto Protocol - would be broadened by including other countries, notably the US, Australia, China, India, Brazil, etc. - it would enhance the opportunity for power-intensive industries affected by the EU ETS to pass-through their higher power costs, leading to less losses in terms of profits, income, employment and carbon leakage by these industries. However, the broadening of such a coalition may be a long-term issue.
- *Encouraging carbon saving technologies in the power sector.* By promoting the development and adoption of carbon-saving technologies in the power sector, costs of CO_2 emissions will be reduced, resulting in less high power prices in the long run. Similar to broadening the climate coalition, encouraging carbon saving technology is also a long-term option before it will become significantly effective. Moreover, markets for ‘green technologies’ are characterised by a variety of imperfections and distortions, requiring a balanced package of various policy interventions to make this option truly effective (Sijm et al., 2004).

8.2.11 Strategies for power-intensive industries

In addition to the national or EU policy options discussed above, there are some strategies that power-intensive companies could follow to address potentially negative effects of passing through CO_2 costs into power prices. These strategies include:

- *Energy saving.* In general, cost-effective options for saving power among major industrial users are limited since they are usually already highly energy efficient and often meet high international benchmarks regarding power intensities. However, if the prices of carbon and, hence, fossil-generated electricity remain high, some investments or innovations resulting in power savings may become commercially attractive.
- *Stringent contract/price negotiations.* Large industrial electricity consumers may consider using their countervailing market power to negotiate long-term delivery contracts that reduce the impact of emissions trading on the price of electricity they have to pay. In general, however, the scope and impact of this strategy will likely be limited since electricity suppliers (i) follow similar practices with regard to power pricing, including the costs of CO_2 allowances, (ii) are not inclined to provide more transparency with regard to the cost structure of their power deliveries, and (iii) are usually not inclined to sign contracts based on other

terms than (given) wholesale prices. Therefore, even for large industrial electricity users it may be hard to negotiate contracts that mitigate the CO_2 impact on power prices.

- *Self-generation.* For some power-intensive industries, own production of electricity becomes a more attractive option due to the EU ETS, particularly if the resulting CO_2-induced power prices are considered to remain at a high level. However, as mentioned in Chapter 6, for most large-scale power users, self-generation is not a real option for a variety of reasons: it is not the core business of these industries to produce power, high initial investment costs, long-term and sometimes cumbersome license and investment project procedures, capacity/imbalance problems, including the problem of the required back-up installation, etc.

To conclude, there is a large variety of policy options and company strategies to deal with the negative implications of grandfathering on power prices. There seems to be no ideal option or package of options to address these implications as each option has its specific pros and contras. Overall, auctioning seems to be a better option than grandfathering or an ex-post benchmarking system. While auctioning would raise power prices by the costs of the CO_2 allowances, it would have several beneficial effects, including (i) avoiding windfall profits among producers, (ii) enhancing environmental-economic efficiencies by internalising the external costs of CO_2 emissions into the power price, (iii) raising public revenues that could be used to mitigate potential drawbacks of rising power prices, and (iv) treating incumbents and newcomers equally while avoiding potential distortions of new investment decisions.

In the end, however, allocation of economic rents is a political issue belonging to the world of policy makers.

Appendix A Impact of power market structure on the degree of CO_2 costs passing through to power prices

This appendix offers an analysis of the relationship between market structure and the degree to which CO_2 allowance prices will be passed on to electricity prices. Aspects of market structure include market concentration and elasticities of demand and supply. The sections below analyse various market structures (i.e., competitive, monopolistic, duopolistic, and oligopolistic markets), starting from the assumption that marginal cost of electricity production is zero, followed by the assumption that the marginal cost rises to ΔC €/MWh, reflecting the incurred cost of carbon allowance and, finally, derives the change in power price (ΔP) prior and post introduction of carbon allowance (see, for instance, Figure A.1).

Competitive market

a. In a competitive market, the price of electricity is equal to its marginal cost (P=MC). In the absence of a CO_2 policy, MC is assumed to be zero, total Q is 1 MWh and the price is 0 €/MWh.
b. Introducing an exogenous carbon allowance cost (ΔC, in €/MWh) increases total marginal cost to ΔC €/MWh. To maintain P=MC, the price will increase from zero to ΔC €/MWh, and quantity reduces from Q to 1-ΔC MWh.
c. Therefore, in a competitive market with horizontal (perfectly elastic) supply, the incurred carbon cost will be fully passed on to the power price.
d. This is not true if supply is not perfectly elastic. In a competitive market, the degree to which CO_2 costs are passed through to power prices depends on the relative elasticities (slopes) of supply and demand (Figure A.2) In the extreme case of perfectly elastic demand, any upward sloping supply curve will result in none of the costs of CO_2 being passed on (Figure A.3). On the other hand, in the extreme case of perfectly inelastic demand, CO_2 costs are fully passed through to power prices (Figure A.4).

Monopolistic market

a. In a monopolistic market, the output level is determined by the intersection of the marginal cost and marginal revenue (MR) curve. Consequently, in the absence of a CO_2 policy, total output level is 1/2 MWh and price is also 1/2 €/MWh.
b. Introducing an exogenous carbon allowance cost (ΔC, in €/MWh) increases total marginal cost to ΔC €/MWh. The resulting output level will be 1/2- ΔC/2 MWh. Hence, the price of power will be 1/2+ ΔC/2 €/MWh.
c. Therefore, allowance price is partially passed on to the power price.
d. In a more general case with upward sloping MC curves, the amount of CO_2 cost that is passed on depends on the relative elasticities. In general, however, less is passed on by a monopolist than in a competitive market. This is, in part, because the marginal revenue (MR) curve of a monopolist - who can affect prices - is steeper than the comparative demand curve for a producer on a competitive market where prices are given (Figure A.5).

Duopolistic Market

a. In a duopolistic market with identical generators, the resulting output level for each individual generator will be 1/3 MWh; and total output will be 2/3 MWh. The price of power will be 1/3 €/MWh.
b. Having carbon allowance cost will decrease output level from 1/3 to 1/3-ΔC/3 MWh. The price increases from 1/3 to 1/3+ 2ΔC/3 €/MWh.
c. Therefore, only 2/3 of carbon allowance price is passed on to the power price. This is an intermediate case between the monopoly and competitive cases.
d. As above, in a more general case with upward sloping MC curves, the amount of CO_2 cost that is passed on depends on the relative elasticities of demand and supply. In general, how-

ever, less is passed on in a duopolistic market than in a competitive market, but more than in a monopolistic market.

Oligopolistic market

a. In the oligopolistic market structure, it is assumed that there are N identical generators having the same marginal cost equal to zero. The resulting output level for each generator is 1/(N+1) MWh and total output will be N/(N+1) MWh. The price of power becomes 1/(N+1) €/MWh.
b. In case of an exogenous carbon allowance, the output of each generator shrinks by 1/(N+1)ΔC MWh; and total output decreases by N/(N+1)ΔC MWh. The power price increases by N/(N+1)ΔC €/MWh.
c. Therefore, the fraction N/(N+1) of the carbon allowance price is passed through to the power price if supply is perfectly elastic and demand is downward sloping.
d. As above, the case is more complex if both demand and supply are elastic. In general, however, it can be predicted that the greater the degree of concentration, the smaller the proportion of the CO_2 cost will be passed on.

Tables A.1 and A.2 summarise the discussion of the impact of market structure on the degree to which CO_2 costs will be passed on to power prices. In general, given the simplified assumptions, in particular, the linear demand function and the constant marginal cost, less concentrated markets (i.e., larger number of firms) will pass most of the CO_2 costs to power prices. In addition, the more elastic demand is, the smaller the proportion of the CO_2 cost will be passed on to consumers.

Table A.1 *Summary of carbon allowance analysis with perfectly elastic supply and linear downward sloping demand: base case*

	Price [€/MWh]	Firm's output [MWh]	Total output [MWh]
Competitive	0	NA	1
Monopolistic	$\frac{1}{2}$	$\frac{1}{2}$	$\frac{1}{2}$
Duopolistic	$\frac{1}{3}$	$\frac{1}{3}$	$\frac{2}{3}$
Oligopolistic	$\frac{1}{N+1}$	$\frac{1}{N+1}$	$\frac{N}{N+1}$

Table A.2 *Summary of carbon allowance analysis with perfectly elastic supply and linear downward sloping demand: CO_2 costs case*

	Price [€/MWh]	Firm's output MWh]	Total output [MWh]
Competitive	ΔC	NA	$1-\Delta C$
Monopolistic	$\frac{1}{2}+\frac{\Delta C}{2}$	$\frac{1}{2}-\frac{\Delta C}{2}$	$\frac{1}{2}-\frac{\Delta C}{2}$
Duopolistic	$\frac{1}{3}+\frac{2\Delta C}{3}$	$\frac{1}{3}-\frac{\Delta C}{3}$	$\frac{2}{3}-\frac{2\Delta C}{3}$
Oligopolistic	$\frac{1}{N+1}+\frac{N\Delta C}{N+1}$	$\frac{1}{N+1}-\frac{\Delta C}{N+1}$	$\frac{N}{N+1}-\frac{N\Delta C}{N+1}$

Factors determining the degree to which CO_2 costs are passed through power prices
In the case of CO_2 costs, there are essentially two counteracting forces affecting the equilibrium of power prices: (a) an upward shift of the supply curve due to CO_2 costs, with different shifts for different plants reflecting their relative efficiencies and fuel sources along with possible changes in plant merit orders; and (b) a reduction in demand when price of power increases.

The upward shift of the supply curve due to CO_2 costs depends on the marginal emission rates of the units. The operating order of plants might shift if the CO_2 costs of units with cheaper fuels increase faster than lower emission rate units that have higher fuel costs (in contrast, the preceding analysis assumes a uniform emission rate to each generator.) If the operating order does not change, then the change of power price (ΔP) will reflect the change in ΔC of the marginal unit ($\Delta C^{marginal}$).

If the base load units are coal plants, a substantial upward lift in the lower segment of the supply curve is expected when emissions trading is introduced (Figure A.6). On the other hand, if the base load is supplied by nuclear or hydro plants, hardly any increase in marginal cost associated with the lower segment of the of the supply curve is observed (Figure A.7). Changes in operating order would further complicate the analysis.[51] Meanwhile, the reduction of demand in response to price increase is dependent on demand elasticity. A market with highly elastic demand will see lower total power consumption if prices are increased due to rising CO_2 costs. The largest price increase might be in off peak periods if coal plants provide base load power. Therefore, the new equilibrium is a result of these two counteracting factors.

When demand is inelastic, the increase in power price is a function of the emission rate of the marginal units and possible changes in the merit order. The higher the emission rate of a marginal unit, the larger increase in power price. When demand is elastic (Figure A.3), there is no general observation about equilibrium, and a modelling approach is required.

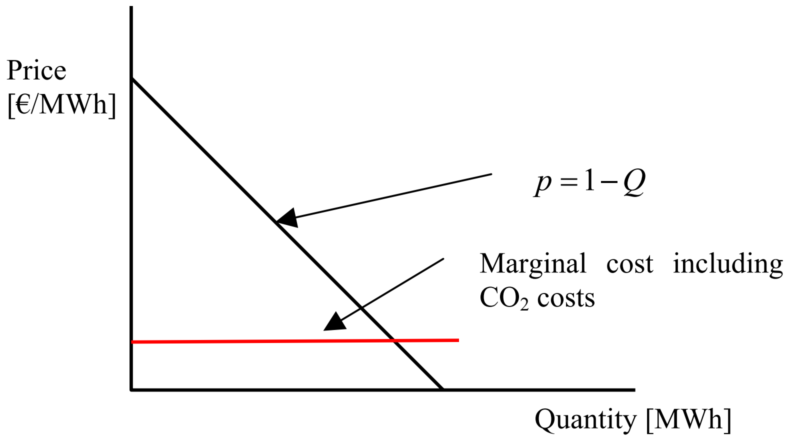

Figure A.1 *Constant supply and marginal cost curves with and without CO_2 costs*

[51] Note that changes in merit order between coal and natural gas plants are unlikely, unless CO_2 allowance prices are very high. It could change the ordering of efficient units with high coal prices and inefficient units burning low cost coal.

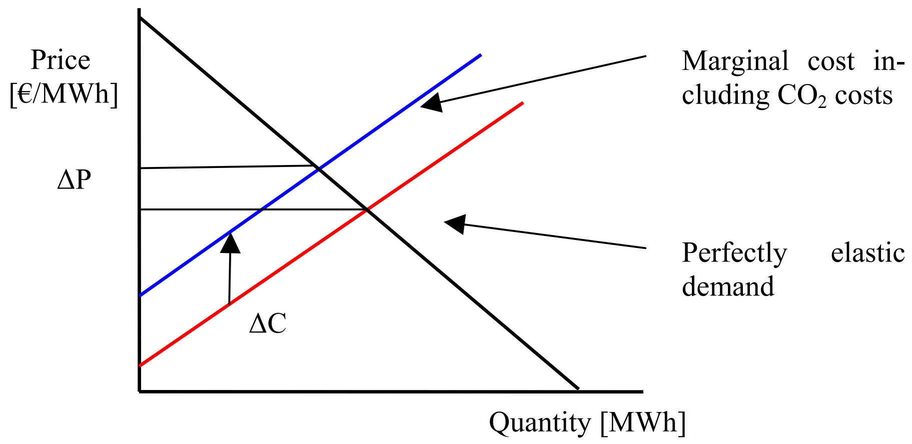

Figure A.2 *Equilibrium of power prices with sloped supply and demand curve, competitive case, showing that not all of CO_2 costs are passed on to customers*

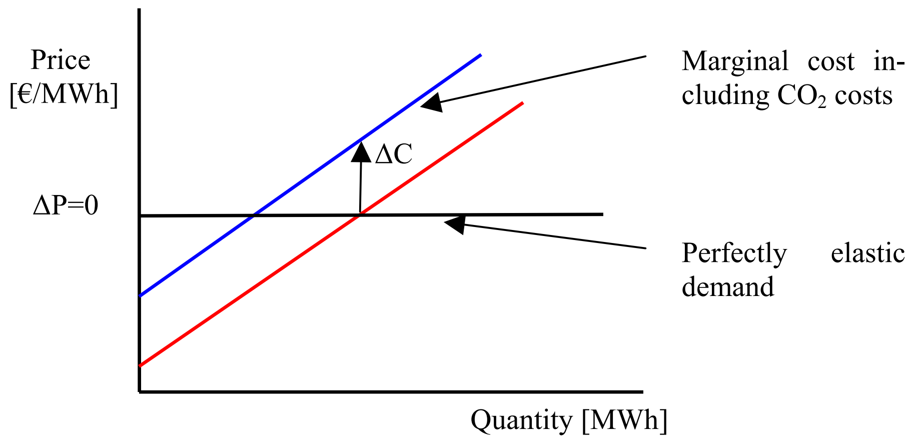

Figure A.3 *Equilibrium of power prices with elastic supply and 'perfectly' elastic demand: no change in power price*

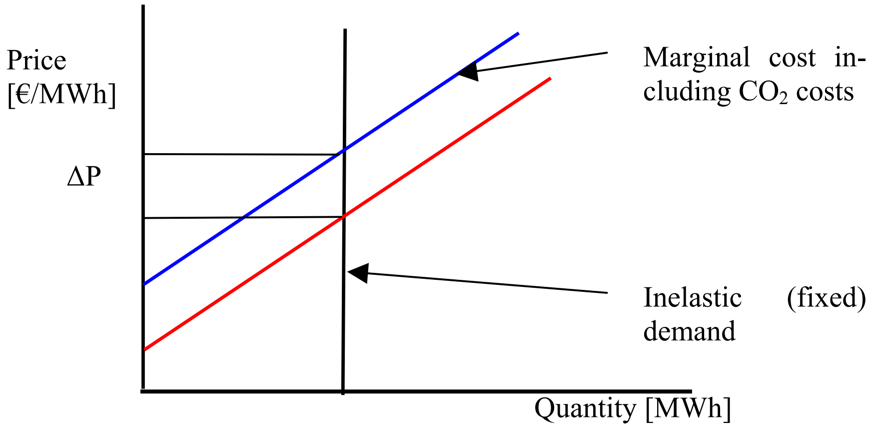

Figure A.4 *Equilibrium of power prices with elastic supply and 'inelastic' (fixed) demand: CO_2 costs are fully passed on to consumers*

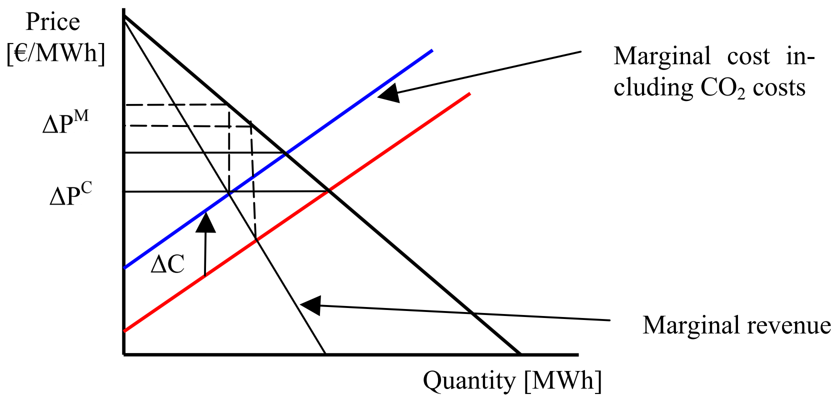

Figure A.5 *Equilibrium power prices under competitive and monopolistic market structure, Sloped demand and supply*

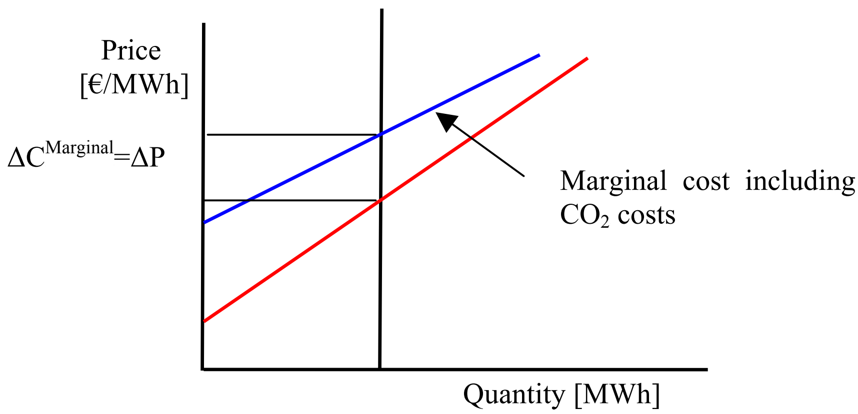

Figure A.6 *Equilibrium of power prices with fixed demand and increasing marginal emission rate: Perfectly inelastic demand case*

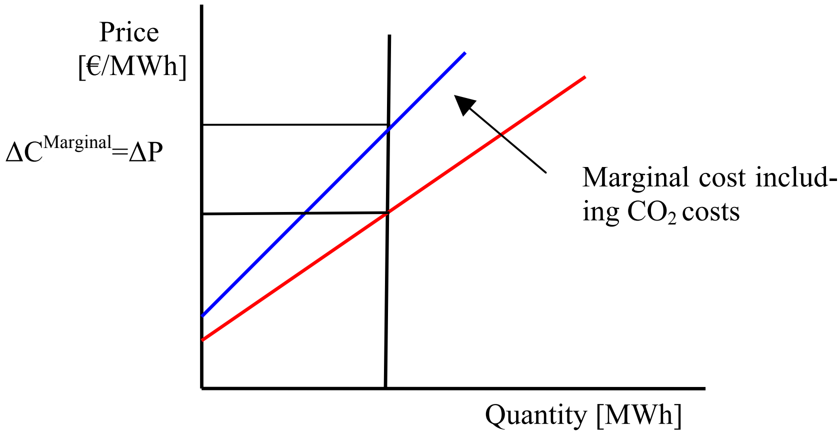

Figure A.7 *Equilibrium of power prices with fixed demand and decreasing marginal emission rate: Perfectly inelastic demand case*

Appendix B Summary of the COMPETES model

General introduction

COMPETES[52] covers the Northwest European electricity markets (the Netherlands, Belgium, France and Germany). It simulates strategic behaviour (oligopolistic competition) among the larger electricity generation companies. This strategic behaviour is based on the theory of Cournot and Conjectured Supply Functions (CSF) on electric power networks. These theories and their relation towards other theoretical approaches are discussed by Day et al. (2002). The specific theoretical approach and application within COMPETES is described more in-depth in the papers by Hobbs and Rijkers (2004) and Hobbs, et al. (2004), as well as – more recently – in Neuhoff et al. (2005) and Hobbs et al. (2005).

The strategic behaviour of the generation companies is reflected in the conjectures each company holds regarding the supply response of rival companies. These response functions simulate expectations concerning how rivals will change their electricity sales when prices change; these expectations determine the perceived profitability of capacity withholding and other strategies. COMPETES can also represent different systems of transmission pricing, among them fixed transmission tariffs, congestion-based pricing of physical transmission, and auction pricing of interface capacity between countries.

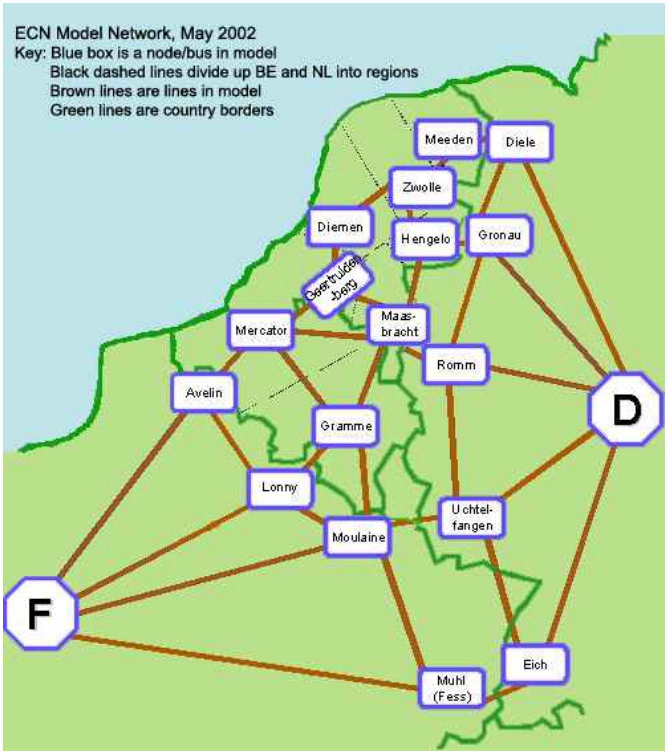

Figure B.1 *Physical representation of the electricity network in COMPETES*

Geographic scope of the model

The model covers the electricity markets in the Netherlands, Belgium, France and Germany. The representation of the electricity network in the model is aggregated to a few nodes per

[52] COMPETES stands for COmprehensive Market Power in Electricity Transmission and Energy Simulator. This model is based on the theory of Cournot and Conjectured Supply Functions (CSF) competition on electric power networks, and is developed in cooperation with Benjamin F. Hobbs, Professor in the Whiting School of Engineering of The Johns Hopkins University.

country (see Figure B.1). The Dutch network is aggregated to five different nodes; France and Germany are both modelled by only one node. All individual generation units in the four countries are allocated to one of these nodes. Information on generation units, type of units and the corresponding capacities is mainly based on the WEPP database[53], updated with public available information. Assumptions concerning generator availabilities and thermal efficiencies are estimated using ECN publications.

Generators behaviour
Virtually all generation companies in the four countries are covered by the input data. Also CHP plants owned by energy suppliers and industrial CHP plants are included. The user can specify which generation companies are assumed to behave strategically and which companies will be allocated to the competitive fringe (i.e. the price takers). 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 sales (market prices multiplied by total sales) minus costs of transmission (if sale is not at the node of generation) minus the cost of generation. Cost of generation is calculated by using the short run marginal cost (operation and fuel costs). Start-up costs and fixed costs are not taken into account since these costs have no significant effect on the bidding behaviour of suppliers on the wholesale market.

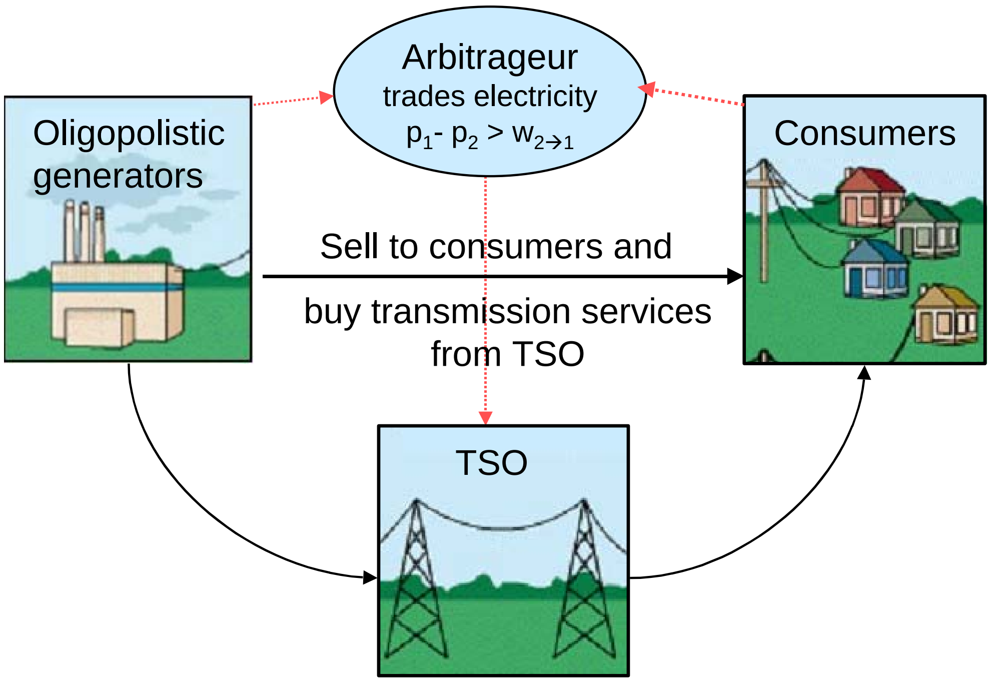

Figure B.2 *Model structure of COMPETES showing the relevant actors*

Consumer behaviour
The model considers 12 different levels of 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 in each season consists of the 200 hours with the highest sum of the loads for the four considered countries. The three other periods have equal numbers of hours and represent the rest of the seasonal load duration curve. Altogether, the twelve periods represent all 8760 hours of a year. The consumers are assumed to be price sensitive by using decreasing linear demand curves depending on price. The model includes demand curves representing net wholesale loads on the high voltage grid for six network nodes in the Netherlands, two in Belgium, and one each in France and Germany (Figure B.1). In addition, the Netherlands values include an estimate of the load served by decentralized sources, whose

[53] World Electric Power Plants database of 2001, UDI (2001).

erlands values include an estimate of the load served by decentralized sources, whose capacities are included in the model.

Transmission system operator
The electricity network covering the four countries is represented by a DC load flow approximation. This approximation is a linear system that accounts only for the real power flows (not for reactive power) and is a simplification of the AC power flow model. Within this system both the current law and the voltage law of Kirchhoff apply. 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. supply minus demand. Besides the physical network path-based constraints are defined using the available transmission capabilities (ATC) between the four countries. In the current application these ATCs 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 the physical constraint or due to the limited availability of interconnection capacity between countries (see Figure B.3). For the interconnectors it can be assumed that netting is or is not applied (anticipating that a power flow from, for example, Belgium to the Netherlands will increase the available interconnection capacity from Netherlands to Belgium).

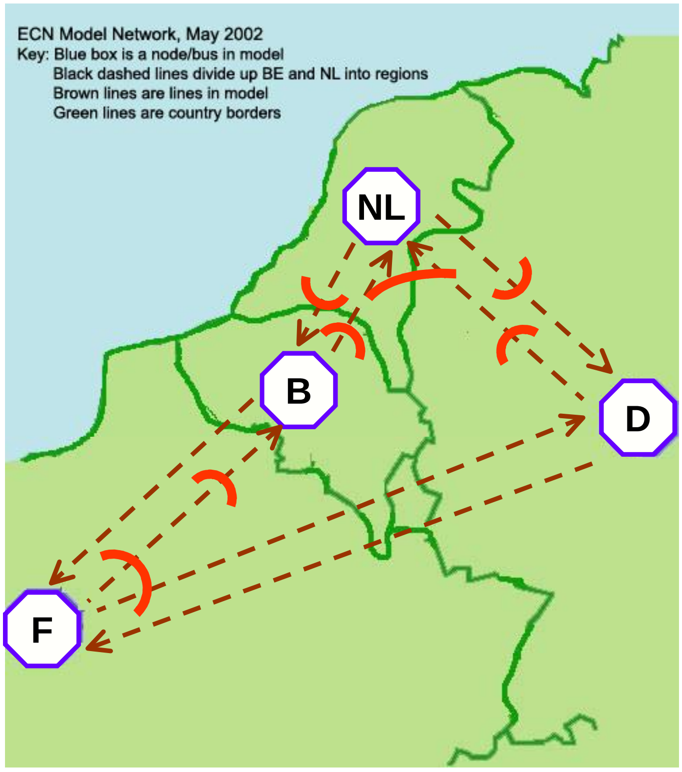

Figure B.3 *Representation of path-based network in COMPETES*

Traders' behaviour
Between countries and nodes it can be assumed that arbitrageurs are active (see Figure B.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.

Limitations and legitimacy of the model

- The consumers are modelled as being price sensitive. In reality, in the short-term demand response is probably substantially smaller. On longer time scales however elasticity will be somewhat increased. 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.
- The model is a static model. This implies that it does not integrate new investments endogenously. Currently, the situation in the year 2004 is represented. The inputs are based on the situation in 2004, taking into account new power plants that will be taken into operation until 2004.
- 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 final output (i.e. the choice between gas-fired versus coal-fired plants) since coal-fired plants are already more profitable to run during the base load hours since they have lower marginal costs.
- Strategic behaviour of the generators will be modelled by using the Cournot assumption: All generators maximise their profits by choosing a certain level of production under the somewhat naïve assumption that their competitors will not change the level of output. 'Naïve' 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 will influence the output data are the

1. fuel prices assumed per country,
2. availability and efficiency per power plant for each generator,
3. demand load per season and period within each country.

The fuel prices and the generating unit characteristics are based upon a study by ECN for DTe (Boots et al. 2005). The generating units are taken from the WEPP database of UDI (Utility Data Institute, 2004), while ownership relations are retrieved from the annual reports of the energy companies.

Appendix C Detailed tables of specific results at the firm level

Table C.1 *Detailed model results of firms' electricity generation (TWh)*

Firm\Scenario	Emission Rate[1] [kg/MWh]	PC0	PC10	PC20	SA0	ST10	SA20	ST0	ST10	ST20
A	0	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
B	379	9.7	9.6	9.7	5.1	5.1	5.1	5.3	5.1	5.1
C	598	13.0	11.6	10.5	16.2	11.5	10.5	35.7	33.9	26.7
D	758	81.0	80.6	71.0	94.9	92.7	92.6	95.2	92.7	92.6
E	759	6.6	6.4	5.0	11.6	11.2	10.8	11.4	11.2	10.8
F	466	148.9	137.0	128.4	107.6	103.3	101.0	111.4	104.8	101.1
G	399	89.7	89.9	88.7	52.3	54.3	58.2	63.8	66.0	69.9
H	118	533.8	529.8	529.4	532.2	533.3	533.1	270.5	271.4	277.5
I	360	62.7	58.5	53.4	61.4	58.0	51.5	62.2	59.7	52.9
J	676	19.1	18.2	18.0	20.0	19.7	19.4	19.9	19.7	19.4
K	920	19.0	12.0	10.5	18.9	15.6	14.3	18.8	15.8	14.4
L	675	159.0	151.1	143.4	105.3	90.2	75.9	112.8	97.8	77.4
M	520	3.0	3.0	3.0	7.5	6.9	6.3	7.5	7.0	6.6
N	970	14.7	11.0	7.3	31.0	31.0	30.2	31.0	31.0	30.9
O	785	82.6	79.6	79.5	81.7	77.4	69.5	81.9	78.3	71.9
Total/Average	410	1250.8	1206.4	1165.8	1153.6	1118.3	1086.5	935.4	902.4	865.1
		PC0	**PC10-ze**	**PC20-ze**	**SA0-le**	**SA10-le**	**SA20-le**	**ST0-le**	**ST10-le**	**ST20-le**
A	0	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
B	379	9.7	9.8	10.8	5.9	5.9	5.8	5.9	5.9	5.9
C	598	13.0	13.1	13.0	20.3	14.7	11.5	51.0	45.2	44.0
D	758	81.0	82.2	82.2	110.6	109.8	108.9	111.1	110.3	109.7
E	759	6.6	6.5	5.6	14.6	14.6	13.9	14.6	14.4	13.8
F	466	148.9	149.2	149.2	97.4	100.3	100.4	103.4	102.1	101.0
G	399	89.7	94.8	94.9	53.6	56.2	57.2	66.1	68.0	69.0
H	118	533.8	533.4	533.8	527.6	530.9	533.1	258.2	261.1	261.7
I	360	62.7	62.7	62.7	61.7	59.2	56.9	61.8	60.3	58.4
J	676	19.1	20.0	20.4	21.1	20.5	20.4	21.1	20.6	20.5
K	920	19.0	13.4	12.4	20.8	17.9	16.5	20.6	18.0	16.6
L	675	159.0	157.7	157.7	88.5	80.2	73.3	94.4	86.4	78.3
M	520	3.0	3.3	3.3	9.6	9.2	8.9	9.7	9.2	8.9
N	970	14.7	14.1	14.1	31.0	31.0	31.0	31.0	31.0	31.0
O	785	82.6	82.6	82.7	79.2	74.3	69.9	79.6	76.0	72.5
Total	410	1250.8	1250.8	1250.8	1150.1	1132.7	1115.8	936.5	916.7	899.4

1: Capacity Weighted CO_2 Emission Rate

Note: These figures refer to scenario model results, not to facts of life.

Table C.2 *Detailed model results of firms CO_2 emissions (Mt)*

Firm\Scenario	Emission Rate[1] [kg/MWh]	PC0	PC10	PC20	SA0	ST10	SA20	ST0	ST10	ST20
A	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
B	379	2.7	2.6	2.0	4.4	4.4	4.4	4.6	4.4	4.4
C	598	6.7	5.4	4.4	9.8	5.7	4.8	26.2	24.4	17.6
D	758	68.9	67.1	58.0	80.0	75.7	74.7	80.7	75.7	74.7
E	759	5.0	4.6	3.0	8.3	8.0	7.6	8.1	8.0	7.6
F	466	58.6	46.8	38.7	18.0	13.2	11.0	21.2	14.7	11.1
G	399	29.4	26.7	25.3	10.5	9.1	10.1	10.5	9.7	11.1
H	118	13.5	9.2	8.3	15.3	12.6	12.4	5.5	5.5	5.5
I	360	20.7	16.7	11.9	19.6	16.4	10.1	20.3	18.0	11.4
J	676	14.1	13.1	13.0	14.9	14.3	13.7	14.8	14.3	13.7
K	920	22.0	9.1	7.2	21.8	10.9	9.2	21.8	11.0	9.2
L	675	107.7	99.3	91.8	54.3	38.9	24.5	61.8	46.6	26.0
M	520	1.4	1.4	1.4	3.9	3.6	3.1	3.9	3.6	3.3
N	970	14.2	10.6	7.0	30.1	30.1	29.3	30.1	30.1	29.9
O	785	79.7	76.8	76.7	79.1	74.9	67.1	79.2	75.7	69.5
Total/Average	410	444.5	389.5	348.5	369.8	317.7	281.9	388.7	341.7	294.9
		PC0	PC10-ze	PC20-ze	SA0-le	SA10-le	SA20-le	ST0-le	ST10-le	ST20-le
A	0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
B	379	2,7	2,8	2,8	5,0	5,0	4,9	5,0	5,0	5,0
C	598	6,7	6,7	6,6	13,8	8,6	5,7	34,7	30,8	29,5
D	758	68,9	68,4	68,3	92,2	88,7	86,7	93,1	89,0	87,3
E	759	5,0	4,6	3,6	10,9	10,9	10,2	10,9	10,7	10,2
F	466	58,6	58,4	58,4	11,4	10,8	10,2	13,5	11,6	10,6
G	399	29,4	30,5	29,8	12,4	11,2	11,6	12,7	11,4	11,7
H	118	13,5	12,7	12,5	14,9	12,8	12,7	5,6	5,6	5,6
I	360	20,7	20,7	20,7	19,9	17,4	15,1	19,9	18,5	16,6
J	676	14,1	14,1	14,3	16,1	15,1	14,7	16,2	15,1	14,7
K	920	22,0	9,9	8,2	22,7	13,1	10,2	22,6	13,1	10,3
L	675	107,7	105,7	105,7	37,3	28,9	21,9	43,2	35,1	26,9
M	520	1,4	1,5	1,5	5,1	4,9	4,7	5,1	4,9	4,7
N	970	14,2	13,7	13,6	30,1	30,1	30,1	30,1	30,1	30,1
O	785	79,7	79,7	79,8	76,7	71,8	67,5	77,1	73,5	70,1
Total	410	NA	7.5	12.3	NA	0.3	0.2	NA	-1.6	-1.7

1; Capacity Weighted CO_2 Emission Rate
Note: These figures refer to scenario model results, not to facts of life.

Table C.3 *Detailed model results of firms profits, excluding 'windfall profits' due to free allocation of CO_2 allowances (0.2 elasticity scenarios, in M€)*

Firm\Scenario	Emission Rate[1] [kg/MWh]	PC0	PC10	PC20	SA0	SA10	SA20	ST0	ST10	ST20
A	0	127	135	135	137	152	155	425	426	433
B	379	204	232	246	248	215	179	250	220	190
C	598	200	182	142	208	185	150	1576	1328	1105
D	758	743	623	568	1932	1753	1612	1972	1794	1653
E	759	128	111	95	396	367	335	392	365	333
F	466	2007	2396	2916	3259	3650	4110	3269	3589	4027
G	399	1722	1938	2012	2748	2844	2903	2775	2899	3021
H	118	4405	5163	5210	4186	4629	4724	12287	12332	12610
I	360	768	997	1277	1605	1774	1939	1646	1823	1977
J	676	319	275	226	781	731	679	775	729	676
K	920	204	119	85	658	511	458	650	508	454
L	675	1861	1885	2041	2859	2727	2729	2896	2806	2777
M	520	52	54	51	338	305	271	339	312	288
N	970	217	139	87	644	545	442	658	561	462
O	785	962	714	541	2064	1752	1413	2103	1797	1467
Total/Average	410	13919	14963	15631	22063	22140	22097	32015	31488	31473

% Change Relative to the Reference Case		PC0	PC10	PC20	SA0	SA10	SA20	ST0	ST10	ST20
A	0	NA	6.2	6.7	NA	11.2	13.0	NA	0.1	1.8
B	379	NA	13.7	20.3	NA	-13.2	-28.1	NA	-11.8	-24.0
C	598	NA	-9.1	-29.1	NA	-10.9	-27.9	NA	-15.8	-29.9
D	758	NA	-16.1	-23.5	NA	-9.3	-16.6	NA	-9.0	-16.2
E	759	NA	-13.9	-26.3	NA	-7.5	-15.5	NA	-7.0	-15.1
F	466	NA	19.4	45.3	NA	12.0	26.1	NA	9.8	23.2
G	399	NA	12.5	16.8	NA	3.5	5.6	NA	4.5	8.8
H	118	NA	17.2	18.3	NA	10.6	12.8	NA	0.4	2.6
I	360	NA	29.7	66.3	NA	10.5	20.8	NA	10.7	20.1
J	676	NA	-13.7	-29.0	NA	-6.4	-13.1	NA	-6.0	-12.8
K	920	NA	-41.7	-58.4	NA	-22.3	-30.3	NA	-21.8	-30.1
L	675	NA	1.3	9.7	NA	-4.6	-4.5	NA	-3.1	-4.1
M	520	NA	5.3	-1.0	NA	-9.7	-19.9	NA	-7.9	-15.0
N	970	NA	-36.1	-60.1	NA	-15.3	-31.3	NA	-14.8	-29.7
O	785	NA	-25.8	-43.8	NA	-15.1	-31.6	NA	-14.6	-30.2
Total	410	NA	7.5	12.3	NA	0.3	0.2	NA	-1.6	-1.7

1: Capacity Weighted CO_2 Emission Rate

Note: These figures refer to scenario model results, not to facts of life.

Table C.4 *Detailed model results of firms profits, excluding 'windfall profits' due to free allocation of CO_2 allowances (0.1 and zero elasticity scenarios, M€)*

Firm\Scenario	Emission Rate[1] [kg/MWh]	PC0	PC10-le	PC20-le	SA0-le	SA10-le	SA20-le	ST0-le	ST10-le	ST20-le
A	0	127	141	154	144	164	178	744	749	750
B	379	204	242	289	531	486	444	536	491	446
C	598	200	204	207	212	210	182	3519	3212	2921
D	758	743	845	890	3669	3496	3358	3698	3607	3519
E	759	128	115	106	780	736	699	767	725	689
F	466	2007	2825	3524	4645	5231	5768	4598	5086	5593
G	399	1722	2031	2347	4244	4294	4374	4324	4361	4417
H	118	4405	5536	6582	4222	4745	5005	21391	21650	21704
I	360	768	1166	1517	2585	2737	2915	2612	2832	3040
J	676	319	299	277	1243	1183	1144	1228	1172	1135
K	920	204	134	114	1051	912	861	1033	899	847
L	675	1861	2322	2663	3847	3804	3849	3906	3971	4048
M	520	52	58	65	822	774	734	831	782	737
N	970	217	216	192	1140	1040	946	1148	1073	995
O	785	962	963	893	3289	2904	2571	3321	3025	2734
Total/Average	410	13919	17099	19821	32424	32715	33028	53656	53635	53574

% Change Relative to the Reference Case		PC0	PC10-ze	PC20-ze	SA0-le	SA10-le	SA20-le	ST0-le	ST10-le	ST20-le
A	0	NA	11.6	21.9	NA	14.0	23.9	NA	0.7	0.8
B	379	NA	18.5	41.3	NA	-8.4	-16.3	NA	-8.5	-16.8
C	598	NA	2.2	3.6	NA	-1.1	-14.4	NA	-8.7	-17.0
D	758	NA	13.8	19.7	NA	-4.7	-8.5	NA	-2.5	-4.8
E	759	NA	-10.1	-17.1	NA	-5.7	-10.4	NA	-5.5	-10.2
F	466	NA	40.8	75.6	NA	12.6	24.2	NA	10.6	21.6
G	399	NA	17.9	36.3	NA	1.2	3.0	NA	0.9	2.1
H	118	NA	25.7	49.4	NA	12.4	18.6	NA	1.2	1.5
I	360	NA	51.8	97.4	NA	5.9	12.8	NA	8.4	16.4
J	676	NA	-6.3	-13.1	NA	-4.9	-8.0	NA	-4.6	-7.6
K	920	NA	-34.3	-44.2	NA	-13.3	-18.1	NA	-13.0	-18.0
L	675	NA	24.8	43.1	NA	-1.1	0.0	NA	1.7	3.6
M	520	NA	13.2	25.9	NA	-5.8	-10.7	NA	-5.9	-11.3
N	970	NA	-0.6	-11.5	NA	-8.7	-17.0	NA	-6.5	-13.3
O	785	NA	0.1	-7.2	NA	-11.7	-21.8	NA	-8.9	-17.7
Total	410	NA	22.8	42.4	NA	0.9	1.9	NA	0.0	-0.2

1: Capacity Weighted CO_2 Emission Rate Note: These figures refer to scenario model results, not to facts of life.

Table C.5 *Detailed model results of firms profits, including 'windfall profits' due to free allocation of CO_2 allowances (0.2 elasticity scenarios, in M€)*[1]

Firm\Scenario	Emission Rate[2] [kg/MWh]	PC0	PC10	PC20	SA0	SA10	SA20	ST0	ST10	ST20
A	0	127	135	135	137	152	155	425	426	433
B	379	204	256	281	248	255	258	250	260	269
C	598	200	230	221	208	236	235	1576	1547	1422
D	758	743	1228	1611	1932	2434	2956	1972	2476	2997
E	759	128	152	148	396	439	471	392	437	469
F	466	2007	2818	3612	3259	3768	4308	3269	3721	4226
G	399	1722	2179	2467	2748	2926	3085	2775	2987	3220
H	118	4405	5246	5360	4186	4742	4947	12287	12381	12709
I	360	768	1147	1491	1605	1921	2121	1646	1984	2182
J	676	319	393	459	781	860	925	775	858	923
K	920	204	201	214	658	610	624	650	608	620
L	675	1861	2779	3694	2859	3077	3171	2896	3225	3245
M	520	52	67	76	338	337	326	339	345	348
N	970	217	234	213	644	816	969	658	831	1001
O	785	962	1405	1921	2064	2426	2620	2103	2478	2718
Total/Average	410	13919	18469	21904	22063	24999	27172	32015	34563	36782
% Change Relative to the Reference Case		PC0	PC10	PC20	SA0	SA10	SA20	ST0	ST10	ST20
A	0	NA	6.2	6.7	NA	11.2	13.0	NA	0.1	1.8
B	379	NA	25.3	37.6	NA	2.8	4.0	NA	4.2	7.9
C	598	NA	15.1	10.8	NA	13.6	13.4	NA	-1.8	-9.8
D	758	NA	65.2	116.9	NA	26.0	53.0	NA	25.5	52.0
E	759	NA	18.2	15.1	NA	10.7	18.8	NA	11.4	19.5
F	466	NA	40.4	80.0	NA	15.6	32.2	NA	13.8	29.3
G	399	NA	26.5	43.2	NA	6.5	12.3	NA	7.6	16.0
H	118	NA	19.1	21.7	NA	13.3	18.2	NA	0.8	3.4
I	360	NA	49.2	94.1	NA	19.7	32.1	NA	20.5	32.5
J	676	NA	23.3	44.0	NA	10.1	18.5	NA	10.6	19.0
K	920	NA	-1.5	5.1	NA	-7.3	-5.2	NA	-6.5	-4.5
L	675	NA	49.3	98.5	NA	7.6	10.9	NA	11.3	12.0
M	520	NA	29.9	47.4	NA	-0.2	-3.5	NA	1.7	2.6
N	970	NA	7.9	-2.1	NA	26.7	50.5	NA	26.4	52.2
O	785	NA	46.0	99.6	NA	17.5	26.9	NA	17.9	29.3
Total	410	NA	32.7	57.4	NA	13.3	23.2	NA	8.0	14.9

1: Based on the assumption that 90 percent of the required allowances is allocated for free.
2: Capacity Weighted CO_2 Emission Rate
Note: These figures refer to scenario model results, not to facts of life.

Table C.6 *Detailed model results of firms profits, including 'windfall profits' due to free allocation of CO_2 allowances (0.1 and zero elasticity scenarios, M€)*

Firm\Scenario	Emission Rate[1] [kg/MWh]	PC0	PC10-le	PC20-le	SA0-le	SA10-le	SA20-le	ST0-le	ST10-le	ST20-le
A	0	127	141	154	144	164	178	744	749	750
B	379	204	267	340	531	531	533	536	536	536
C	598	200	265	326	212	287	284	3519	3489	3452
D	758	743	1461	2119	3669	4294	4919	3698	4408	5090
E	759	128	157	172	780	834	883	767	821	872
F	466	2007	3351	4575	4645	5328	5952	4598	5190	5784
G	399	1722	2306	2883	4244	4394	4583	4324	4463	4626
H	118	4405	5651	6807	4222	4860	5234	21391	21700	21804
I	360	768	1353	1890	2585	2894	3187	2612	2998	3339
J	676	319	426	535	1243	1319	1408	1228	1308	1400
K	920	204	223	261	1051	1029	1045	1033	1017	1032
L	675	1861	3274	4565	3847	4064	4242	3906	4287	4533
M	520	52	72	92	822	818	818	831	826	821
N	970	217	339	438	1140	1311	1487	1148	1344	1536
O	785	962	1680	2329	3289	3550	3787	3321	3686	3996
Total/Average	410	13919	20964	27487	32424	35676	38540	53656	56823	59570

% Change Relative to the Reference Case		PC0	PC10-ze	PC20-ze	SA0-le	SA10-le	SA20-le	ST0-le	ST10-le	ST20-le
A	0	NA	11.6	21.9	NA	14.0	23.9	NA	0.7	0.8
B	379	NA	30.6	66.2	NA	0.0	0.5	NA	-0.1	-0.1
C	598	NA	32.4	63.1	NA	35.3	33.8	NA	-0.8	-1.9
D	758	NA	96.6	185.3	NA	17.0	34.1	NA	19.2	37.6
E	759	NA	22.3	34.0	NA	6.9	13.2	NA	7.0	13.6
F	466	NA	67.0	128.0	NA	14.7	28.1	NA	12.9	25.8
G	399	NA	33.9	67.4	NA	3.5	8.0	NA	3.2	7.0
H	118	NA	28.3	54.5	NA	15.1	24.0	NA	1.4	1.9
I	360	NA	76.1	146.0	NA	11.9	23.3	NA	14.8	27.8
J	676	NA	33.4	67.6	NA	6.1	13.3	NA	6.5	14.0
K	920	NA	9.3	28.2	NA	-2.1	-0.6	NA	-1.5	-0.1
L	675	NA	75.9	145.3	NA	5.6	10.3	NA	9.8	16.0
M	520	NA	39.7	78.9	NA	-0.5	-0.5	NA	-0.6	-1.2
N	970	NA	56.0	101.4	NA	15.0	30.5	NA	17.1	33.8
O	785	NA	74.6	142.0	NA	7.9	15.1	NA	11.0	20.3

Note: These figures refer to scenario model results, not to facts of life.

References

BCG (2003): *Keeping the Lights On* - Navigating Choices in European Power Generation, The Boston Consulting Group, Boston.

Betz, R., W. Eichhammer, J. Schleich (2004): *'Designing National Allocation Plans for EU emissions trading. A first Analysis'.* Energy & Environment, Vol. 15, No. 3, July 2004, pp 375-425.

Boogert, A., and D. Dupont (2005): *'On the Effectiveness of the Ant-Gaming Policy between the Day-Ahead and Real-Time Electricity Markets in The Netherlands'.* Energy Economics*,* Vol. 27, No. 5, pp. 752-770.

Boots, M., and M. Scheepers (2004): *Modelling Concentration on the Electricity Market*. Paper for the 6th IAEE European Conference 'Modelling in Energy Economics and Policy', 1-3 September 2004, Zurich, Switzerland.

Boots, M., W. Lise, M. Scheepers, F. Boisseleau, T. Kristiansen, K. Petrov, and W. van der Veen (2005): *Effects of Regulatory Measures on the Dutch Wholesale Electricity Market.* Report ECN-CX-05-016, Energy research Centre of the Netherlands (ECN), Petten/Amsterdam.

Bovenberg, L., and L. Goulder (2000): *Neutralizing the Adverse Industry Impacts of CO_2 Abatement Policies: What Does it Cost?* NBER Working Paper No. 7654, National Bureau of Economic Research, Cambridge, Massachusetts.

Butraw, D., K. Palmer, and D. Kahn (2005): *Allocation of CO_2 Emissions Allowances in the Regional Greenhouse Gas Cap-and-Trade Program.* Resources for the Future, Discussion Paper 05-25, Washington, D.C.

Byers, C. (2005): *Prices Drivers in the EUA Market.* Fortis Carbon Banking, Presentation at the Environmental Finance Conference EU Emissions Trading 2005, Brussels 11-12 July 2005.

Carbon Trust (2004): *The European Emissions Trading Scheme: Implications for Industrial Competitiveness.* London.

CEC (2003a): *Directive 2003/87/EC of the European Parliament and of the Council of 13 October 2003 establishing a scheme for greenhouse gas emission allowance trading within the Community and amending Council Directive 96/61/EC.* Brussels.

CEC (2003b): *The EU Emissions Trading Scheme: How to develop a National Allocation Plan.* Non-Paper, 2nd meeting of Working Group 3 Monitoring Mechanism Committee, Directorate-General Environment, Brussels, April 1, 2003.

CEPS (2005): *Business Consequences of the EU Emissions Trading Scheme.* CEPS Task Force Report No. 53, Centre for European Policy Studies, Brussels.

Chandell, J. (2004): *Reduction of CO_2 Emissions in the EU.* Presentation by the CEMBUREAU Chief Executive, 25 May 2004.

Christiansen, A. (2004): *Overview and Update of the EU ETS.* Presentation at the 4th Annual Emissions Trading Conference, Euromoney, London, 22-23 November 2004.

Christiansen, A., A. Damsiora, and A. Skogen (2005): *Presentation at workshop on 'Carbon Fundamentals & Price Forecasting'.* Market Insights Conference, Amsterdam, 1-3 March 2005.

D'Adda, F. (2005): *EU Emissions Trading - Competitive Implications and Policy Challenges.*

UNICE, Presentation at the Environmental Finance Conference EU Emissions Trading 2005, Brussels 11-12 July 2005.

Damme, E. van (2005): *'Liberalizing the Dutch Electricity Market: 1998-2004'*, The Energy Journal, Special Issue on European Energy Liberalisation, pp. 155-179.

Day, C., B. Hobbs, and J.-S. Pang (2002): *'Oligopolistic Competition in Power Networks: A Conjectured Supply Function Approach'*. IEEE Transactions on Power Systems, Vol. 27, No. 3, pp. 597-607.

DG TREN (2004-05): *Quarterly Review of European Electricity and Gas Prices.* DG Energy and Transport, European Commission, Brussels.

DKW (2003): *Emission Trading - Carbon Derby Part II.* Dresder Kleinwort Wasserstein Securities Limited, UK.

Doyle, G. (2005): *Impact of EU ETS on Energy Sector.* Presentation at workshop 'Carbon Costs & Power Prices', Carbon Market Insights Conference, Amsterdam, 1-3 March 2005.

Dril, T. van, and H. Elzenga (2005): *Referentieraming Energie en Emissies 2005-2020.* ECN-C-05-018, Energy research Centre of the Netherlands (ECN), Petten.

DTe (2004): *Onderzoek Ontwikkeling Liquiditeit Elektriciteitsmarkt 2003-2004 - Constateringen en Aanbevelingen.* Dienst Uitvoering en Toezicht Energie (DTe), Den Haag.

DTe (2005), *Marktmonitor, Ontwikkeling van de Groothandelsmarkt voor Elektriciteit 2004-2005 - Resultaten en Aanbevelingen.* Directie Toezicht Energie (DTe), Den Haag.

DTe (2005): *Informatie- en Consultatiedocument ten behoeve van het Advies van DTe aan het Ministerie van Economische Zaken (EZ) inzake Virtual Power veilingen voor de Nederlandse Groothandelsmarkt.* Dienst Uitvoering en Toezicht Energie (DTe), Den Haag.

ECN (2001): *Energy Market Trends.* Energy research Centre of the Netherlands (ECN), Petten/Amsterdam.

Ecofys (2004): *Analysis of the National Allocation Plans for the EU Emissions Trading Scheme.* August 2004.

ECON (2004a): *Emissions Trading and Power Prices.* ECON Report 2004-020, Stockholm.

ECON (2004b): *EU Emissions Trading Scheme and the Effect on the Price of Electricity.* ECON Report 2004-081, Stockholm.

EDF (2005): *CO_2 Impact on Prices and Dispatching.* Presentation at Carbon Market Insights Conference, Amsterdam, 1-3 March 2005.

Elzenga, H., and J. Oude Lohuis (2002): *'Prestatienorm geeft ongelijk speelveld'.* Economisch Statistische Berichten, 6-12-02, pp. 883-885.

Emanuel, J. (2004): *Emissions Trading So Far, Lessons Learned and How Best to Utilise the Market.* Presentation at the 4th Annual Emissions Trading Conference, Euromoney, London, 22-23 November 2004.

Enviros (2004): *European Emissions Trading Scheme: Executive Briefing Two.* August, Environs Consulting, London.

Green, R. (2005): *'Electricity and Markets'.* Oxford Review of Economic Policy, Vol. 21, No. 1, pp. 67-87.

Grobbel, C. (2005a): *Impact of EU ETS on Industry Competitiveness.* McKinsey & Company, Conference Presentation, Cologne, May 12, 2005.

Grobbel, C. (2005b): *EU Carbon Market and Key Drivers.* McKinsey & Company, Conference Presentation, Cologne, May 13, 2005.

Grubb, M. (2004): *Implications of EU ETS for Competitiveness of Energy-intensive Industry.* Presentation at IEA/IETA/EPRI workshop on Greenhouse Gas Emissions Trading, Paris, 4-5 October 2004.

Halstead, G. (2005): *Impacts on Fuel Prices.* Presentation at Carbon Market Insights Conference, Amsterdam, 1-3 March 2005.

Harrison, D., and D. Radov (2002): *Evaluation of Alternative Initial Allocation Mechanisms in a European Union Greenhouse Gas Emissions Trading Scheme.* National Economic Research Associates (NERA).

Hasselknippe (2005): *Carbon prices to 2020*. Presentation at Carbon Market Insights conference, Amsterdam, March 2, 2005.

Hobbs, B. and F. Rijkers (2004): *'Strategic Generation with Conjectured Transmission Price Responses in a Mixed Transmission System I: Formulation'*, IEEE Transactions on Power Systems, Vol. 19, No. 2, pp. 707-717

Hobbs, B., F. Rijkers, and A. Wals (2004): *'Strategic Generation with Conjectured Transmission Price Responses in a Mixed Transmission System II: Application'.* IEEE Transactions on Power Systems, Vol. 19, No. 2, pp. 872-878.

Hobbs, B., F. Rijkers, and M. Boots (2005): *'The More Cooperation, The More Competition? A Cournot Analysis of the Benefits of Electric Market Coupling'.* The Energy Journal, Vol. 26, No. 4, pp. 1-30.

ICF (2003): *EU Power Markets and CO_2 Emissions Trading - A Detailed Analysis of the Competitive Implications of the Proposed EU Emissions Trading Scheme and Allowance Allocation on EU Power Markets.* ICF Consulting, Fairfax, VA.

IEA (2002): *CO_2 Emissions from Fuel Combustion.* OECD/International Energy Agency, Paris.

IFIEC (2004): *Emissions Trading to hit Electricity Price and Industry's Competitiveness.* International Federation of Industrial Energy Consumers, IFIEC Europe, Brussels.

ILEX (2003): *A Review of Cost-Effectiveness and Carbon Saving Data for the UK Climate Change Programme.* December, Ilex Energy Consulting, Oxford.

ILEX (2003): *Implications of the EU ETS for the Power Sector.* A report to DTI, DEFRA and OFGEM, ILEX Energy Consulting Limited, Oxford.

ILEX (2004): *Impact of the EU ETS on European Electricity Prices.* A report to DTI (UK), ILEX Energy Consulting Limited, Oxford.

Innovest/WWF (2003): *Power Switch: Impacts of Climate Policy on the Global Power Sector.* Innovest/World Wildlife Fund (WWF).

Jakobsen, A. (2004): *Impact of Emissions Trading on the Northern European Electricity Markets.* Presentation at the 4th Annual Emissions Trading Conference, Euromoney, London, 22-23 November 2004.

Jansen, J. (2002): *Emissions Trading in the Netherlands - a Market in the Making.* Energy research Centre of the Netherlands (ECN), Petten/Amsterdam.

Jeekel, R. (2005): *The ETS Impact on the Power Prices and Markets.* European Association of Metals, Presentation at the Environmental Finance Conference EU Emissions Trading 2005, Brussels 11-12 July 2005.

JPMorgan (2003): *CO_2 emissions: no windfall for European utilities.* Global Equity Research, London.

Judisch, S. (2005): *The Power Markets in Europe are Converging….or: Germany is not an Island.* Presentation by the Managing Director RWE Trading GmbH, May 2005.

Karmali, A. (2004): *State of the Carbon Markets.* Presentation at the 4th Annual Emissions

Trading Conference, Euromoney, London, 22-23 November 2004.

Karmali, A., and N. Cornelis (2003): *'Winning in the European Greenhouse Gas Emissions Trading Scheme: Insights for Power Generators'*. World Power*,* pp. 1-3.

Koster, P. (2005): *Emissions Trading: Creating a Central Marketplace in Europe.* European Climate Exchange, Presentation at the Environmental Finance Conference EU Emissions Trading 2005, Brussels 11-12 July 2005.

Koutstaal, P. (2002): *'Emissions Trading with Relative and Absolute Targets'.* Change, No. 63, pp. 5-7

Koutstaal, P. A. Gielen, and H. Vollebergh (2002): *A Comparison between Emissions Trading with Absolute and Relative Targets.* Paper presented at CATEP workshop, University College, London.

Leyva, E. de, and P.A. Lekander (2003), *'Climate Change for Europe's Utilities'*. The McKinsey Quarterly, No. 1.

Linares, P., F. Javier Santos, M. Ventosa, and L. Lapiedra (2006): *'Impacts of the European Emissions Trading Scheme and Permit Assignment Methods on the Spanish Electricity Sector'.* The Energy Journal*,* Vol. 27, No. 1, pp. 79-98.

Lise, W. (2005): *The European Electricity Market - What Are the Effects of Market Power on Prices and the Environment?.* Energy research Centre of the Netherlands (ECN), Petten/Amsterdam.

Lise, W., V. Linderhof, O. Kuik, C. Kemfert, R. Ostling, and T. Heinzow (forthcoming): *'A Game Theoretic Model of the North-western European Electricity Market - Market Power and the Environment'.* Energy Policy*,* (in press).

Maeda, A. (2003): *'The Emerge of Market Power in Emission Rights Markets: The Role of Initial Permit Distribution'.* Journal of Regulatory Economics*,* Vol. 24, No. 3, pp. 293-314.

Mannaerts, H., and M. Mulder (2003): *Emissions Trading and the European Electricity Market – Consequences of emissions trading on prices of electricity and competitiveness of basic industries.* CPB Memorandum, CPB Netherlands' Bureau for Economic Policy Analysis, The Hague.

Martinez, K. (2004): *'Electricity Prices - What to Look out for?'.* Carbon Finance*,* March 2004.

Martinez, K., and K. Neuhoff (2004): *Allocation of Carbon Emission Certificates in the Power Sector: How generators profit from grandfathered rights.* Cambridge Working Papers in Economics CWPE 0444, Massachusetts Institute of Technology (MIT), Center for Energy and Environmental Policy Research, Cambridge, Massachusetts.

McIntyre, R. (2004): *Price Dynamics of Emissions in the Weather and the Energy Complex.* Presentation at the 4th Annual Emissions Trading Conference, Euromoney, London, 22-23 November 2004.

McKinsey (2003): '*Power producers should pay close attention to a European Commission proposal to curb greenhouse gas emissions. It could have paradoxical effects'. McKinsey Quarterly,* No. 1, Paris.

NEA/IEA (2005): *Project Costs of Generating Electricity - 2005 Update.* Nuclear Energy Agency and International Energy Agency, Paris.

Neuhoff, K., J. Barquin, M. Boots, A. Ehrenmann, B. Hobbs, and F. Rijkers (2004): *Network-constrained Models of Liberalized Electricity Markets: The Devil is in the Details.* Internal Report, Energy research Centre of the Netherlands (ECN), Petten/Amsterdam.

NMa (2004): *Besluit,* Besluit van de Directeur-Generaal van de Nederlandse

Mededingingsautoriteit als Bedoeld in Artikel 41, vierde lid, van de Mededingingswet, Betreft zaak: 3386/Nuon - Reliant Energy Europe, Den Haag.

OFGEM (2005): *Emissions Trading: Impacts on Electricity Consumers.* London.

Oxera (2004): *CO_2 Emissions Trading: How will it affect UK Industry?*. Report prepared for The Carbon Trust, Oxera, Oxford.

Point Carbon (2003-2005): *Carbon Market Europe*, weekly, Oslo.

Point Carbon (2004): *Carbon Market Analyst.* Special issue - What determines the price of carbon? October 14, 2004.

Point Carbon (2005), *Carbon Market Daily.* Oslo.

Reinaud, J. (2003): *Emissions Trading and its Possible Effects on Investment Decisions in the Power Sector.* IEA, Paris.

Reinaud, J. (2004): *Industrial Competitiveness under the European Union Emissions Trading Scheme.* IEA, Paris.

Rowland, C. (2004): *Working in a Carbon Constrained Europe.* Presentation at the 4th Annual Emissions Trading Conference, Euromoney, London, 22-23 November 2004.

Scheepers, M., A. Wals, and F. Rijkers (2003): *Position of Large Power Producers in Electricity Markets of North Western Europe.* Report for the Dutch Energy Council on the Electricity Markets in Belgium, France, Germany and the Netherlands, ECN-C--03-003, Energy research Centre of the Netherlands (ECN), Petten.

Schyns, V. (2005): *Climate Change Challenges and the Search for a Sustainable Policy.* DSM, the Netherlands.

Schyns, V., and J. Berends (2003a): *Greenhouse Gas Emissions Trading between Companies - A Comparative Analysis of Allocation Systems.* DSM, Geleen, The Netherlands.

Schyns, V., and J. Berends (2003b): *The Conversion of Energy Efficiency to CO_2 when Using the PSR-method.* Geleen, The Netherlands

Seebregts, A., M. Scheepers, and H. de Vries (2004): *Base load Elektriciteitsprijzen en Brandstofprijzen 2005 tot en met 2020.* ECN-I-04-002, Energy research Centre of the Netherlands (ECN), Petten.

SER (2002): *Nationale CO_2-emissiehandel in Europees Perspectief.* Advies inzake het Eindrapport van de Commissie CO_2-emissiehandel, Sociaal-Economische Raad, The Hague.

Sijm, J. (2003): *'The Impact of the EU Emissions Trading System on the Price of Electricity'*, in: Ros, A.P. en H.R.J. Vollebergh (eds.), *Ontwikkeling en Overheid,* Sdu Uitgevers, Den Haag (also published as ECN reprint report RX--04-015).

Sijm, J., O. Kuik, M. Patel, V. Oikonomou, E. Worrell, P. Lako, E. Annevelink, G. Nabuurs, H. Elbersen (2004): *Spillover of Climate Policy – An Assessment of the Incidence of Carbon Leakage and Induced Technological Change due to CO_2 Abatement Measures.* Netherlands Research Programme on Climate Change, Scientific Assessment and Policy Analysis, Report 500036 002, RIVM, Bilthoven.

Sijm, J., and A. van Dril (2003): *The Interaction between the EU Emissions Trading Scheme and Energy Policy Instruments in the Netherlands - Implications of the EU Directive for Dutch Climate Policies.* ECN-I--03-060, Energy research Centre of the Netherlands (ECN), Petten/Amsterdam.

Sikorski, T. (2003): *'EU Emissions Trading: What does it Mean for an Electricity Generator?'.* Commodities Now*,* December, pp. 2-5.

Sorrell, S. (2002): *The Climate Confusion: Implications of the EU Emissions Trading Scheme for the UK Climate Change Levy and Climate Change Agreements.* SPRU (Science and Technology Policy), University of Sussex, Brighton.

Sorrell, S., and J. Sijm (2003): *'Carbon Trading in the Policy Mix'.* Oxford Review of Economic Policy, Vol. 19. No. 3, pp. 420-437.

Stewart, M., and K. Wallis (1981): *Introductory Econometrics.* Second Edition, Basil Blackwell, Oxford.

Stoft, S. (2002): *Power System Economics - Designing Markets for Electricity.* IEEE/Wiley Interscience Press, John Wiley & Sons, Inc.

Tangen (2005) *Managing Carbon in a Risky World.* Presentation at Carbon Market Insights conference, Amsterdam, March 1, 2005.

Tirole, J. (1998): *The Theory of Industrial Organization.* MIT Press, Cambridge, Massachusetts.

UBS (2005): *CO_2 - The Windfall Has Arrived.* UBS Investment Research, UBS Limited, London.

Utility Data Institute (2004): *Word Electric Power Plants Database.* Utility Data Institute, July 2004, Washington.

Varian, H. (1984): *Microeconomic Analysis.* Second Edition, Norton & Company, New York.

Vis (2005): *Status & Lessons Learned.* Presentation at Carbon Market Insights Conference, Amsterdam, 1-3 March 2005.

Wals, A., and F. Rijkers (2003): *How will a CO_2 Price affect the Playing Field in the Northwest European Power Sector?.* Paper presented at the Research Symposium on European Electricity Markets, The Hague, September 2003.

Wold, P-O, and G. Doyle (2005): *Carbon Costs & Power Prices.* Workshop presentations at Carbon Market Insights Conference, Amsterdam, 1-3 March 2005.