CO₂ trading and its influence on electricity markets

FINAL REPORT FOR DTE

February 2006
COB2B trading and its influence on electricity markets

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Executive summary

**Our remit**
DTe retained Frontier Economics to advise on the way that the EU ETS has affected the Dutch electricity market. In particular, we have been asked to advise on the extent to which the major generators may have accrued windfall profits as a result of the EU ETS and their free allocation of CO2 allowances.

**Our approach combines interviews with analysis**
DTe expressed the particular wish that our work should reflect our in depth understanding of the sector and the way it works, complemented by in depth interviews with the generators to understand exactly how they make their decisions.

**The EU ETS was designed to influence prices**
The EU Emissions Trading Scheme (ETS) is an economic response to the imperative of reducing CO2 emissions. Decisions in a market economy are in large part driven by prices. The trading scheme, by creating an opportunity cost of CO2, harnesses the price mechanism to achieve the behavioural changes necessary to reduce emissions. If prices in the economy do not change, the real behavioural changes necessary to bring about a reduction in emissions will be much less likely to occur.

**Grandfather allocations were made to ensure political support, not to attenuate price effects**
Any disruptive economic change has the potential to create winners and losers. Political support depends on there being few vociferous losers. The high proportion of allowances that the EC mandated should be allocated for free (95%) was driven by the need to achieve support for the ETS. Broad brush policies with few losers are likely to create winners.

Allocations were not made with an expectation that they would influence firms’ pricing decisions, which in a competitive economy should be based on opportunity costs.

**Generators behave rationally**
The four major generators have each confirmed that in all their business decisions where they take account of their costs of generation, they include the full opportunity cost of the CO2 implications of those decisions. In effect they add the relevant cost of CO2 to the fuel price.

**APX bids include CO2 cost… but only a small proportion is sold spot**
In bidding to APX all generators say that they explicitly take account of the opportunity cost of CO2. APX prices should, other things being equal reflect 100% pass through of CO2 costs.

However, only a small proportion of sales are made in the spot market. The large majority of output is sold forward, well ahead of delivery.
With respect to forward sales, generators say they are price takers… but over time forward prices may still reflect CO2 costs.

Generators describe themselves as ‘price takers’ in forward markets. As such they can only accept the market price and therefore the opportunity cost of CO2 has little or no effect.

While at face value this may seem reasonable, it is not logically consistent with the same generators saying that prices (including forward prices) have gone up because fuel costs have risen. Even in an atomistic industry where all participants are pure price takers, a cost rise affecting essentially all participants can be expected to cause the market price to rise.

Over time participants in the electricity market can be expected to arbitrage between the spot and forward markets. If APX prices rise with CO2 costs such arbitrage should in the end feed into forward prices.

Econometric analysis shows a low pass through of CO2 costs to date.

The data do not support very robust conclusions. However, it is quite clear that the rate at which CO2 costs are passed through in electricity prices is to date much less than 100%.

The rather weak econometric evidence suggests that pass through rates for sales made in 2005 for delivery in 2006, were a little less than 50% in the peak prices and just over 30% in off peak prices.

However, there is some evidence to suggest that pass through rates have been increasing over time and we think it is plausible that pass through rates in 2004 and before were substantially lower than these.

It is difficult to reconcile the empirical evidence with what generators say.

A simple inference to be drawn from what generators say would be that pass through rates should be close to 100%. Although there are several reasons why this may not be an accurate inference to draw, few of these seem likely to make a major contribution to reconciling the apparent inconsistency.

Arguing from first principles, we think it is likely that either:

- the market is not behaving as a fully competitive market would; or
- generators perceive a lower cost of carbon than the market price of allowances (for example because ETS Phase 2 allocation decisions could be perceived as depending on current behaviour).

While a crude analysis of the industry structure points to the possibility of the former, we stress that we do not have empirical evidence to confirm either of these hypotheses.

Windfall profits are difficult to define.

Windfall profits may mean different things to different people. Our measure of windfall profits can be characterised as follows:

Executive summary
• It is related solely to the generation business of the companies, e.g., it excludes any impact of the ETS on trading or retail profits.

• In order to preserve confidentiality and not confuse the analysis, it is based on a typical pattern of generator behaviour rather than a set of company-specific historic decisions.

• It is based on the difference between generator profits with and without the ETS as if they had continued to conduct business as usual and tries to exclude profits made from the way in which firms have adapted to the ETS.

### Key determinants of windfall profits are…

<table>
<thead>
<tr>
<th>Determinant</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>the timing of forward sales</strong></td>
<td>Based on interviews with the generators and our wider experience in the sector, we have assumed that 90% of sales are made evenly over the 30 months prior to the delivery year and the remaining 10% is sold during the year.</td>
</tr>
<tr>
<td><strong>the value of CO2</strong></td>
<td>The value of CO2 is easy to establish from April 2004 but only sketchy evidence is available for market expectations before then. CO2 values in 2004 were typically in the range €5-10/tonne, on average less than half those in 2005.</td>
</tr>
<tr>
<td><strong>pass through rates; and</strong></td>
<td>Furthermore, before the ETS directive was passed, it is reasonable to suppose that utilities would have discounted any effect of CO2 expectations by the probability (less than 1) of the scheme coming into being.</td>
</tr>
<tr>
<td><strong>the timing of allowance purchases</strong></td>
<td>Based on the only available but rather weak evidence for pass through rates, we have assumed average rates of 22% (peak) and 16% (off peak) to be applicable to the full 3.5 yr period over which sales of 2005 power were made.</td>
</tr>
<tr>
<td><strong>Windfall profits in 2005 were quite low… but would be likely to be very much higher in future</strong></td>
<td>While sales are predominantly forward and embody low CO2 values, we have assumed that the (notional) purchase of allowances is made at the higher prices prevailing in 2005, because earlier hedging would not have been practicable.</td>
</tr>
</tbody>
</table>
unrepresentative of windfall profits in future.

Factors which point to increased windfall profits in future are:

- Current CO2 prices are much higher than the average of those relevant to the timing of sales of 2005 output.

- Pass through rates show some signs of increasing and, even if they do not increase further, 2005 rates are 2.3 times higher than the average we estimate to be appropriate for the historic sales period for 2005 output.

- Our 2005 profit estimate is depressed by accepting high CO2 values as they pertain to costs but only low ones as they pertain to revenue. This mismatch arises from the immaturity of the CO2 market and should not persist.

While we have not modelled future windfall profits, other things being equal, they are likely to rise substantially over the next three years.
1 Introduction

1.1 GENESIS OF THE STUDY

The Dutch Ministry of Economics (MinEco) has asked the Dutch energy regulator (DTe) to gather factual information about the impact of the introduction of the European CO2 emission trading scheme (EU ETS) on the functioning of the Dutch wholesale electricity market and, in particular, to estimate the extent of windfall profits that generators may have realised as a consequence of the EU ETS. DTe has in turn appointed Frontier Economics to assist in the preparation of its advice to the Ministry.

Separately, but as a parallel task, DTe has also asked us to provide guidance on the way in which DTe should monitor the performance of the wholesale electricity market in an era of CO2 trading.

1.2 OUR REMIT

Our remit, covering both roles, comprises four tasks, which may be summarised as:

1. An assessment of the impact of the EU ETS on the Dutch wholesale electricity market;
2. A quantitative analysis of the effect of the EU ETS on the profitability of the four main power producers in the Netherlands (Essent, E.ON, Electrabel and Nuon) for 2005;
3. A quantitative analysis of existing indicators of profitability (i.e. spark spread/dark spread and Lerner index) for 2005; and
4. An assessment of how the existing indicators in the DTe monitor report of the wholesale market for electricity should be adapted to a world in which CO2 allowances are traded.

Tasks 1 and 2 address the impact of the ETS on the electricity sector and on the profitability of power producers. These are the subject of this report.

Tasks 3 and 4 are concerned with assessing whether DTe’s normal market monitoring metrics can be expected to provide them with the same insight into participants’ behaviour and the potential incidence of market power following the advent of the ETS as they did prior to the ETS. These topics will be the subject of a separate note to DTe.

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1. Ministerie van Economische Zaken

2. The concept of ‘windfall profits’ is open to interpretation. We discuss this at length in Section 4, but in summary we interpret windfall profits to be those profits that the generating businesses would have made solely owing to the implementation of the ETS, assuming they take no further actions to increase profits in the light of the ETS.
1.3 APPROACH

Our overall approach to this assignment has been built on three key planks:

- comparability with ECN’s report\(^3\) to ensure that differences between our conclusions and theirs can be understood without an involved debate, but with an increased emphasis on understanding generator behaviour and the real constraints that exist in the sector;

- in depth interviews with the four largest producers, which we have carried out jointly with DTec, and in which we were supported by Mazars Management Consultants. These were designed to understand how behaviourally the advent of the ETS has affected generators; and

- analysis of a wide variety of data, including extensive production and cost data for the year 2005\(^4\) provided by the generators to DTec.

1.4 ORGANISATION OF THE REPORT

Our report is organised as follows:

- **Section 2** describes the EU ETS, as background to the study. The section describes the institutional context, the way that the emission trading system has generally been implemented at a national level, and the way that the price of European Union Allowances (EUAs or allowances) has developed historically.

- **Section 3** describes the way in which the EU ETS has had an impact on the Dutch electricity market including:
  - the allocation of EUAs to the power sector in the Netherlands;
  - the (theoretical) impact of the EU ETS on electricity generators’ incentives;
  - evidence on generators’ behaviour gleaned from our in-depth interviews with the four major generators and visits to their trading floors by DTec and our associates, Mazars; and
  - the empirical evidence of the relationship between EUA prices and electricity prices (or spark and dark spreads)

- **Section 4** provides a conceptual framework for the estimation of windfall profits;

- **Section 5** deals with detailed assumptions that we have made and data issues we have encountered in our attempts to estimate windfall profits; and

- **Section 6** presents and discusses our estimates of windfall profits.

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3. CO2 price dynamics: The implications of EU emissions trading for the price of electricity, ECN (September 2005).

4. At the time that our draft report was prepared only 2004 production data were available. This final report is based on 2005 production data.
2 EU ETS

This section discusses the basic workings of the EU ETS and the development of the CO2 price, providing the background for our review of the impact of the EU ETS on the electricity market in the Netherlands, in Section 3.

2.1 THE EU ETS SCHEME AND THE NAPS

In December 1997, the Kyoto Protocol was signed. Following ratification, this imposed legally binding emission targets for most developed countries post-2008. The protocol committed the EU to an average cut of 8% relative to 1990 emission levels for 2008-2012. This translated into individual reduction targets for the member states through the “burden-sharing” agreement. For the Netherlands, this meant a corresponding emissions reduction of 6%.

The economy wide target for each member state was split into sector specific targets with the provision that the energy and heavy industry sectors had their target implemented by the EU ETS, an emission trading system. In order to reach their target emission levels by 2008 – 2012, member states have also imposed emission targets for the period 2005 – 2007, to be implemented through the EU ETS. Therefore, on 1st January 2005 Phase 1 of EU ETS, covering the period 2005 – 2007, began for participating sectors.

Each member state specified how many allowances each installation and hence firm would receive through its National Allocation Plan (NAP). The NAPs have been subject to approval by the European Commission (EC) which assessed the NAPs according to pre-specified criteria laid out in European Directive 2003/87/EC. Generally speaking, the criteria were to ensure that the targets implied by the allocation in Phase I would be likely to guarantee compliance with the binding Kyoto targets defined for 2008-2012, i.e. Phase II.

2.2 “CAP AND TRADE”

The EU ETS scheme establishes a mechanism for emission allowance trading within the Community. The basic idea behind the trading scheme is that:

- each EU country allocates CO2 allowances to firms in participating sectors, and each firm must surrender an allowance for every tonne of CO2 it emits;

- if a firm fails to surrender the required number of allowances, it faces a penalty charge and still has the obligation to acquire and surrender the shortfall in allowances; and

- the allowances can be traded to facilitate their efficient allocation.

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2.2.1 The effect of a cap on the level of emissions

The scheme implies that there is now a cap on the level of emissions from the relevant sectors in the economy, reducing the level of emissions relative to historic levels. As there are fewer allowances than the quantity of CO2 that the firms would naturally emit in the absence of the ETS, allowances assume a scarcity value and hence a price in the CO2 market.

The intention of the scheme is that this opportunity cost of CO2 should alter incentives through the economy. Firms in all participant sectors will be incentivised to emit less CO2 (both through fuel substitution and development of cleaner technologies) and to the extent that they continue to emit CO2 they will reflect the opportunity cost of CO2 in the prices of their output such that their consumers will face higher prices and hence consume less of such goods.

The whole purpose of the scheme is that prices should change to reflect the marginal cost of CO2. Prices influence behaviour and ultimately some element of behaviour needs to change if CO2 emissions are to be reduced. The expectations of those designing the scheme were that the price of goods/services whose provision is CO2 intensive would rise. Generally, grandfathered allowances were not made available to mitigate the effect on prices. They were made available because in their absence many companies emitting CO2 would have made a significant loss with the implementation of the EU ETS.

2.2.2 Trade – how a price for allowances is determined

In contrast to a tax, an allowance trading scheme ensures a priori that the target level of emissions is met by issuing exactly the number of allowances that meet the target. By allowing trade, a value for using the certificates for emissions is established in that

- participating firms that find it cheap to reduce emissions relative to the prevailing price of allowances will want to use fewer allowances than were allocated to them and will sell therefore be able to sell their surplus allowances; and

- firms that find it relatively costly to reduce emissions will typically want to use more allowances than were allocated to them and will therefore want to buy extra allowances.

As for other freely traded goods, the price of a CO2 allowance will be determined by the balance between supply and demand. As the available stock of allowances throughout the EU is essentially fixed by the NAPs of the 25 EU member states, the participating firms across the EU jointly determine the total abatement required. This is illustrated in the Figure 1.

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6 In practice it is possible to create additional allowances by undertaking certain types of environmentally friendly investment in developing countries and this may materially expand the number of allowances.
Figure 1: How market forces determine CO2 allowance prices

If the allocation of allowances (the vertical lines) is stringent, more abatement will be needed and relatively expensive abatement projects will be worthwhile (shown through the marginal cost of abatement across participating sectors as a whole). As a consequence, the demand for allowances (and their price) will be higher than if the governments are generous in their allocation of allowances. The point where the marginal abatement cost curve of all participating firms intersects the vertical line of the stock of allowances determines the equilibrium price of an allowance.

In economic terms, the effect of ETS is very similar to that of an appropriately designed tax: it attaches a cost to causing CO2 emissions and reduces the level of emissions to a desired target level.

2.2.3 Allocation of allowances by ‘grandfathering’

The allocation of allowances for each participating firm was based on ‘grandfathering’, meaning that past emission levels were a key, but not sole, determinant of how many allowances a participating firm would receive. In some countries, including The Netherlands, early action was explicitly rewarded. Grandfathering is the mechanism typically used in environmental protection schemes – for example, the US experience with pollution reduction schemes points to a preference for the grandfathering of emission allowances⁷.

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2.3  HISTORY OF CO2 ALLOWANCE PRICES

While the market for the trading of allowances was opened at the beginning of Phase I in January 2005, there was a grey market\(^8\) preceding this for which good price reporting has been available since ca. April 2004.

This grey market was essentially a forward or “futures” market in that it related to the allowances for 2005 – 2007, organised by brokers such Spectron and Evo Markets who bought and sold forward contracts for allowances.

As can be seen from Figure 2, CO2 clearly has a positive value in the market. The evolution of CO2 prices is notable for its steep rise when the official market began in January 2005 as well as for the volatility it has generally shown. While the grey market traded at an average of €5.80/tonne (based on Spectron data for the period April to December 2004), since the beginning of Phase I on 1\(^{st}\) January 2005, CO2 allowances rose from around this level to a peak of just over €29/tonne in July, before falling back to around €20/tonne a month later. Since then, the CO2 allowances have generally traded between €20 and €25/tonne.

The steep rise in the allowance price is likely to have stemmed from the EC enforcing tighter NAPs and the increase in the price of gas relative to coal in the Summer of 2005. Market participants would have expected gas to substitute for coal but the substantial increase in the gas price prevented this substitution. As a result, more electricity was produced from coal-fired assets than the market would have anticipated. Coal fired assets emit more CO2 per unit of electricity generated than gas-fired assets and thus the demand for CO2 allowances will have been higher than previously anticipated\(^9\). It is at least possible that the subsequent fall in the price of an allowance might in part be due to the fall in the price of gas, partially reversing this effect (not necessarily in the Netherlands but elsewhere in Europe).

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\(^8\) The grey market refers to the market which existed before the scheme formally began. Any party entering an agreement to sell an allowance was therefore relying on either receiving a grandfather allocation or being able to buy real allowances once they were issued.

\(^9\) The interdependencies between the demand for permits by generators and the prices of gas and coal will be further discussed in more detail in the next section, where we discuss the specific impact of the scheme on the Dutch electricity sector.
CO2 prices throughout 2005 have shown substantial volatility. However, as in all countries with the exception of France, CO2 allowances cannot be banked for use in the second phase of the EU ETS, volatility could increase. At the end of 2007 (or more specifically during the reconciliation period for 2007 in early 2008), allowances could either be worthless, if there are sufficient, or worth a great deal if there is even a very small shortage.

If there is any shortage at all at that stage, the price will immediately go to the penalty price plus the value of next years allowances.
The impact of the EU ETS on the Dutch electricity sector

In this section we assess how the introduction of the EU ETS and the development of the CO2 allowance price are likely to have affected the Dutch electricity generation sector. This assessment includes:

- a description of the allocation made to the sector under The Netherlands’ NAP;
- a discussion of how in principle generators’ incentives will have been changed by the advent of the EU ETS;
- a description of the way in which the four major generators say they have adapted their behaviour, and shown this in trading as inspected;
- a brief exploration of the effect of the ETS on the marginal cost supply curve for electricity and, through this, the possible effect on the opportunity that the generators might have had, to enjoy price outcomes in excess of marginal cost both with and without the EU ETS. (Please note that we do not look at whether in fact generators benefited from such price levels);
- an econometric assessment of the effect of CO2 allowance prices on Dutch electricity prices; and
- a discussion of factors which could help to reconcile the apparent inconsistency of generators’ stated behaviour with the empirical evidence.

3.1 THE SECTOR’S NAP ALLOCATION

As noted in Section 2, the burden sharing agreement defined the obligations of each EU country to reduce its emissions in the Kyoto period (2008-2012) relative to those in 1990. The Netherlands agreed to reduce their emissions by 6% relative to 1990 levels for the economy as a whole.

The Dutch NAP for the first trading period of the EU ETS stipulates that the total allowances for the participating sectors will be 95.3 million tonnes CO2 per year for each of the years 2005-2007. By comparison, emission levels for the participating sectors were 96 million tonnes in 1990 and 101.2 million tonnes in 2000. Of the 95.3 million tonnes allocated to the participating sectors in each of the years 2005-2007, ca. 34.8 million tonnes p.a. were allocated to the four largest generators in The Netherlands. Based on information provided by DTe, we estimate that, taken together the four main generators emitted approximately 37.4 million tonnes CO2 in 2004. Their allocation therefore implies a reduction of approximately 7%. Generators would either have had to make efforts to reduce their emissions or would have had to buy further allowances.

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10 All information from Ecofys „Analysis of the national allocation plans for the EU emission trading scheme“, August 2004.
3.2 IMPACT ON GENERATORS’ INCENTIVES

In this section, we explain the way in which the EU ETS changes generators’ marginal costs and therefore their business incentives.

For a generator, the EU ETS adds an additional input to the production of electricity, the quantity of which is directly related to the carbon content of the fuel in question. A generator must present a CO2 allowance for each tonne of CO2 emitted. (Emissions are subject to independent certification). Since there is a traded market for allowances, any allowance presented has an opportunity cost due to the fact that the generator has either had to purchase the allowance, or been deprived of the opportunity to sell the allowance.

Since for a given type of fuel there is a direct relationship between the number of allowances required per unit of fuel consumed, the opportunity cost of the allowance can effectively be expressed as an increase in the (opportunity) cost of the fuel. In short, the EU ETS has increased the (opportunity) cost of fuel burnt in generating power in both the Netherlands and elsewhere in Europe, such that the cost change is directly related to the market price of an allowance.

As the market price for an allowance – and therefore the opportunity cost to the generator - is determined by supply and demand conditions across the whole EU ETS, each generator may regard the price of an allowance as exogenous.

This increase in the marginal cost of using (fossil) fuel could be expected to cause generators to do one or more of the following:

- include the opportunity cost of allowances in setting prices or appraising the production that should be offered at given prices;
- schedule plant differently if the merit order is altered, ie if relative costs have changed such that a more carbon intensive technology becomes more expensive than a less carbon intensive technology (eg coal might become more expensive than gas even though in terms of the cost of the fuel alone coal is cheaper);
- reduce emissions from existing plant by investing in measures to improve the thermal efficiency or by burning biomass which is exempt from the need for CO2 allowances; and
- build any new plant with low or zero CO2 emissions (eg renewable, biomass fuelled, or nuclear plant).

The last three of these generally involve costs which would appear uneconomic if the same prices were to prevail for all inputs except CO2 and there were no EU ETS. While the generators have been unable to provide us with estimates of the extra costs they have incurred reducing CO2 emissions, we would expect, for example, the use of palm oil as a fuel to be uneconomic without the EU ETS.

Any comprehensive measure of windfall profits arising from the EU ETS should either ignore profits arising from such adapted behaviour or at the very least recognise that such costs as these may be incurred to earn in order to earn profits.
3.3 GENERATORS’ BEHAVIOUR

3.3.1 Pricing and production decisions

Generators typically want to hedge their position by selling a significant proportion of their expected production forward when prices are more predictable, reserving only a small proportion as either a hedge against unexpected plant outages or to be sold in the spot market. This means that we need to address behaviour both in selling forward and in selling close to real time (day ahead).

Day ahead

Generators participate in APX’s day ahead auction, albeit that they only sell a small proportion of their output in this way. All four generators indicated that in submitting bids to APX, whether selling residual capacity or fine tuning their make or buy decisions, they take full account of the opportunity cost of CO2. In effect they all add the cost of the carbon content in fuel to the cost of the fuel and then make decisions based on the adjusted (carbon inclusive) fuel cost. This was confirmed by inspection of short term trading activities.

Forward sales

The large majority of sales are sold forward and the effect here is rather more complex. All the generators say that in respect of forward sales they are price takers. However, that does not mean that prices at which forward sales are made do not reflect the additional opportunity cost of CO2. Even in the most atomistic market, where all participants are definitely price takers, an increase in cost suffered by all participants would normally find its way through into the market price.

While generators follow a strategy for selling forward over time, they have the ability, at least within limits, to vary volumes according to the profitability implied by current forward prices. A generator may react to the introduction of an opportunity cost of CO2 by offering fractionally less power at the ‘market price’ that he perceives. If several generators do the same thing, suppliers wishing to procure according to their normal strategy will find the market short of power. When the market is short and the prevailing price is low relative to expected costs, buyers will be willing to buy at a higher price. When the market price has moved to restore the profitability of generation, it might be reasonable to assume that the generators will then offer the quantity they originally planned to, but they are now ‘price takers’ at a higher price. Indeed, they have in this simple model never been other than price takers.
When interviewed, generators have generally indicated that although they are constrained to a hedging strategy for risk management reasons, they typically have some freedom to adapt to the profitability at the time. Furthermore, even their hedging strategy is tailored to the gradual sale of the power that they think they will find it economic to produce in due course. Their prediction of what will be economic in future will in turn depend on the opportunity costs they will face and present forward prices.

A further reason to expect the opportunity cost of CO2 to affect forward prices is the link between forward prices and spot prices. Generators are clear that their bids in the spot (day ahead) market reflect the opportunity cost of CO2. Spot market expectations can in turn be expected to affect forward prices as market participants arbitrage over time between the forward and spot markets.\(^\text{11}\)

The existence of must-run plant\(^\text{12}\) may constrain the extent to which generators will reduce output. However, by its very nature, the must-run element cannot be the element that determines the marginal cost of generation. By definition the must run loading on a plant cannot be reduced. Any upward flex in output above this is no longer must run but optional.

3.3.2 **Actions to reduce CO2 emissions**

We know that the generators have taken measures to reduce CO2 emissions. These have principally involved firing or co-firing with biomass which is exempt from the requirement for corresponding CO2 allowances. As we discuss in the next section, fuel prices have inhibited fuel substitution as a method to reduce CO2 emissions. We do not have information on any investments made to reduce emissions and this has been a consideration in choosing a definition of windfall profits (see Section 4) which does not depend on estimating profits from such investments.

3.4 **IMPACT ON MERIT ORDER AND POTENTIAL MARKET POWER**

As noted, a possible effect of the EU ETS is a change in the merit order with which plant are despatched. There are more CO2 emissions per MWh from typical coal plant than from typical gas plant. However, the merit order is determined by a combination of fuel prices /heat rates and CO2 prices and a detailed analysis of costs shows that there has been essentially no change in the Dutch merit order. Nor, importantly for forward price formation, has there been any change in the expected merit order when forward fuel prices are combined with CO2 prices. Figure 3 illustrates the robustness of the merit order by

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\(^{11}\) Please note that this linkage is not dependent on the forward market price being an unbiased estimate of the average of the relevant spot prices. Forward prices may carry a risk premium or discount but a change in expected future spot prices should still be expected to cause a concomitant change in forward prices.

\(^{12}\) An example of a ‘must run plant’ is a CHP plant that has obligations to produce heat to meet a certain profile of heat load. To do this efficiently the plant must run with a certain minimum electricity generation profile over time.
showing the (marginal cost) supply curve with and without the ETS based on average fuel and CO2 prices in the last quarter of 2005. The efficiencies of the various plant are taken from DTe’s database. The gas price used is the average TTF spot price\textsuperscript{13} for the period. The value of CO2 is the average of the mid point of Spectron’s quotations for the period.

![Figure 3: Capacity stack and variable costs of Dutch power generation](image)

**Figure 3: Capacity stack and variable costs of Dutch power generation**

Average spot fuel and EU-ETS allowance prices for fourth quarter 2005

Waste- and biomass-fired units are excluded because no data on fuel costs are available

*Source: Frontier*

The plant in the without ETS supply curve are plotted under their position in the with ETS curve. If the merit order had changed the without ETS (black dots) would not rise monotonically from left to right.

In this regard, a key point to note is that gas prices have risen much more than coal prices. Should the price of gas fall significantly relative to the price of coal, or the price of allowances rise significantly, there could be a material change in the merit order.

While we conclude that the ETS has not as yet had a material effect on the merit order, it is possible that it could still have an effect on the scope for oligopolistic market outcomes above marginal cost. The ETS will have little effect on the supply demand balance (assuming a low price elasticity) and hence on possible

\textsuperscript{13} The gas prices used in this are the spot TTF prices. We have had representations made to us to the effect that not all gas used in power generation can be assumed to have an opportunity cost related to the spot TTF market as some contracts involve gas which cannot be sold on. However, we do not have sufficient information to understand either whether such restrictions can hold legally, or if they do whether they would be such as to alter the merit order at all.
incentives to withdraw plant in times of very tight demand. However, even with the merit order unchanged, the size of the steps in the marginal cost curve can influence the profitability of strategies that involve pricing above short run marginal cost. Put simply, as demand increases and a step is approached, withdrawal of plant to bring higher cost plant on to the margin (and hence a higher price) becomes more attractive. The larger the step, the greater the withdrawal to bring on higher cost plant that may be attractive. Conversely, the smaller the step, the lower are the likely rewards from withdrawing plant.

A full analysis of potential market power in the sector is beyond the scope of this study. However, we can see from inspection of the marginal cost supply curves with and without the ETS, illustrating the merit order in Figure 3, that the size of the step moving from coal to gas plant is reduced with the ETS. This is because coal generation is a more carbon intensive technology than gas.

Therefore we conclude that, while the oligopolistic structure of the Dutch market might be a factor in outcomes with or without the ETS, we believe that impact of the introduction of the ETS will have been a reduction in the potential scope for price outcomes to exceed marginal cost.

3.5 THE RELATIONSHIP BETWEEN CO2 PRICE AND ELECTRICITY PRICES

In the preceding discussion we have explored the way in which the introduction of the EU ETS and hence an opportunity cost to CO2 emissions could have an impact on the market price. We now examine the statistical evidence for the relationship between electricity prices on the one hand and fuel and CO2 prices on the other.

To do this we start with the simplifying assumptions that:

- In peak hours gas fired plant operates on the margin and hence peak hour electricity prices are likely to relate to the gas price and the cost of CO2 in gas fired generation. We have analysed 2005 production data and we estimate that the average efficiency of the marginal plant during peak hours is approximately 35% and to estimate pass through rates we use this efficiency assumption. In contrast ECN assumed a benchmark efficiency of 42% for gas plant in peak hours. We believe that this is more likely to be representative of the average efficiency of gas plant and not the average of the marginal plant in peak hours. However, to facilitate comparisons we have also analysed results using ECN’s assumed efficiency.

- In off peak hours, coal plant generally operates on the margin and hence off peak electricity prices are likely to be related to the price of coal and the CO2 cost in coal generation. Our inspection of 2005 production data suggests that the average marginal efficiency of coal plant in off peak hours is approximately 40%. This is the same figure that ECN has assumed and therefore in this respect our results are directly comparable.
We explore in Section 3.6 potential reasons why these simplifying assumptions may not be fully valid.

In order to assess the relationship, we have chosen to look at the forwards markets in fuel and power prices. We do this to try to eliminate the effects of seasonal demand and the stochastic availability of plant which could distort spot measures. Given the distortions that time trends can create we have also chosen to focus our regressions on variables expressed in first differences. However, we have also regressed absolute levels in order to check consistency with ECN’s analysis.

We have used data from 2005 (for Calendar 06 electricity and fuel forwards and the price of 06 CO2 allowances) as this is a period in which there have been meaningful and identifiable changes in the price of CO2. The full details of the regressions including the data used are provided in Annex 1.

The key results of our regressions for 2005, based on first differences, are summarised in Table 1 below.

<table>
<thead>
<tr>
<th>Period 2005</th>
<th>Regression (Variables in first differences)</th>
<th>% pass through (95% confidence interval)</th>
<th>Adj. R²</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>CO₂ price</td>
<td>Fuel price</td>
</tr>
<tr>
<td>All 2005</td>
<td>Peak Price v. CO₂ price and gas price</td>
<td>61 (40 - 83)</td>
<td>20 (8 - 32)</td>
</tr>
<tr>
<td>January – July</td>
<td></td>
<td>47 (25 - 70)</td>
<td>20 (7 - 33)</td>
</tr>
<tr>
<td>August – December</td>
<td></td>
<td>108 (57 - 160)</td>
<td>17 (-7 - +42)</td>
</tr>
<tr>
<td>All 2005</td>
<td>Spark spread v. CO₂ price</td>
<td>18 (-9 - +46)</td>
<td>NA</td>
</tr>
<tr>
<td>January – July</td>
<td></td>
<td>4 (-26 - +35)</td>
<td>NA</td>
</tr>
<tr>
<td>August – December</td>
<td></td>
<td>66 (46 - 128)</td>
<td>NA</td>
</tr>
<tr>
<td>All 2005</td>
<td>Off-peak Price v. CO₂ price and coal price</td>
<td>34 (22 - 46)</td>
<td>-1 (-12 - +9)</td>
</tr>
<tr>
<td>January – July</td>
<td></td>
<td>32 (18 - 45)</td>
<td>-2 (-16 - +12)</td>
</tr>
<tr>
<td>August – December</td>
<td></td>
<td>39 (13 - 65)</td>
<td>-1 (-19 - +17)</td>
</tr>
<tr>
<td>All 2005</td>
<td>Dark spread v. CO₂ price</td>
<td>34 (15 - 53)</td>
<td>NA</td>
</tr>
<tr>
<td>January – July</td>
<td></td>
<td>33 (11 - 55)</td>
<td>NA</td>
</tr>
<tr>
<td>August – December</td>
<td></td>
<td>40 (0 - 80)</td>
<td>NA</td>
</tr>
</tbody>
</table>

Table 1: Summary of regression results for 2005 for the effect of CO2 prices on electricity prices/spreads.

---

14 Time trends can lead to a spurious apparent correlation between variables which are in fact unrelated. Use of first differences is a standard technique to help eliminate spurious correlation.
We find that although a relationship appears to exist, the nature of the relationship between peak electricity prices and CO2 price is statistically very uncertain. In the period January to July 2005, the electricity price regression shows a CO2 pass through of 47%. However, the confidence interval for this rate is rather broad, 25-70%. More worryingly the same regression implies that only 20% of changes in gas prices are passed through in electricity peak prices during the same period. Furthermore, applying the same specification to the rest of the year leads to a pass through estimate for CO2 of 108% which is intuitively implausible and the pass through rate for gas falls to 17%.

Following a different specification in which the peak spark spread is regressed against the CO2 price, we see pass through rates of 4% and 66% for the two periods, but with very wide confidence intervals for both estimates. In the case of the earlier period this would allow for a negative pass through rate!

The regressions to explain off peak prices/dark spreads look dubious for rather different reasons. While the pass through rates for CO2 show some stability at around 32% in the earlier part of the year and nearly 40% in the latter part of the year, this apparent result is undermined by the complete absence of an observed relationship between the electricity price and the coal price.

In summary, the statistical evidence does not provide persuasive evidence as to how CO2 prices in 2005 affect electricity prices and fuel-electricity spreads for 2006. There is prima facie evidence that pass through rates in the latter part of the year are higher than in the earlier part of the year. However, it is also plausible that as the real delivery time approaches, there are other important factors that start to influence electricity prices, for example longer term weather forecasts or more specific knowledge about the availability of plant. For the same reason that spot prices are more volatile than forward prices, forward prices close to delivery are more volatile than longer term forwards. Causal factors not represented in the model may play a more important role and bias the results. For this reason, caution should be exercised in regarding these results as truly representative of the change in pass through rates.

We have also attempted to investigate pass through rates using regressions of 2004 data (April – December) for 2005 forwards. These produce even weaker results because there is so little variation in the price of CO2 during 2004. We present the results of these regressions in Table 3.
The impact of the EU ETS on the Dutch electricity sector

<table>
<thead>
<tr>
<th>Period 2004</th>
<th>Regression</th>
<th>% pass through (95% confidence interval)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(Variables in first differences)</td>
<td>CO₂ price</td>
</tr>
<tr>
<td>April – December</td>
<td>Peak Price v. CO₂ price and gas price</td>
<td>14 (-37 - +65)</td>
</tr>
<tr>
<td>April – December</td>
<td>Spark spread v. CO₂ price</td>
<td>22 (-41 - +85)</td>
</tr>
<tr>
<td>April – December</td>
<td>Off-peak Price v. CO₂ price and coal price</td>
<td>10 (-15 - +36)</td>
</tr>
<tr>
<td>April – December</td>
<td>Dark spread v. CO₂ price</td>
<td>7 (-38 - +45)</td>
</tr>
</tbody>
</table>

Table 3. Table for 2004. Summary of regression results for effect of CO₂ prices on electricity prices / spark and dark spreads.

These regressions are based on data from April to December 2004, the part of 2004 for which we have reasonable CO₂ data. The adjusted R² and coefficient confidence levels are very poor, even for equations specified in first differences. However, such evidence as there is points to materially lower pass through rates in 2004, of the order of 14% for peak hour prices and 10% for off peak prices.

As we have no proper information on CO₂ values prior to April 2004, we cannot even attempt to estimate pass through rates that would have been applicable prior to that time. However, a cautious but intuitively plausible assumption would be that these in turn were lower than the estimated April to December 2004 pass through rates.

As we explain later in this report, pass through rates prior to 2005 are much more important for our estimate of windfall profits in 2005 than those pass through rates exhibited in 2005 with respect to sales after 2005.

3.6 RECONCILING GENERATOR BEHAVIOUR AND ECONOMETRIC EVIDENCE

A simple interpretation of the way in which generators have said that they behave would lead one to expect pass through rates of close to 100%. While the empirical evidence is at best ambiguous, it clearly does not confirm this model. This section explores various possible reasons why empirical results differ markedly from a priori expectations.

We address first peak prices. Potential reasons explaining a pass through of less than 100% are as follows:
• Prices in some peak hours may be set as the rationing price when all available plant is operating. If demand outstrips supply at the marginal cost of the most expensive plant available to the system, supply and demand can only be balanced by a rise in price which reduces or rations demand. Prices determined in this way are called rationing prices and they are decoupled from supply side costs. Owing to this decoupling they are not influenced by changes in supply side costs including the addition of a CO2 cost. Hence rationing prices would not change with CO2 prices so long as the CO2 price did not cause the marginal cost of the last plant to exceed the rationing price. It is impossible on the basis of production data alone to know exactly in how many hours this could have been the case, because there are no systematic data showing the capability of each generating set hour by hour. Plant is often partially derated. However, we believe that this reason would be unlikely to apply over anything more than a very limited number of hours.

• Some of the time the marginal fuel for the marginal plant may be a mixture of gas and biomass with emissions from the latter not requiring CO2 allowances. However, in one case at least one station we are informed that the non fossil fuel burn is fixed and therefore incremental use of the station would result solely in a change in the fossil fuel burn.

• Imports are at times marginal and for some reason they are less influenced by CO2 prices. However, as far as we can observe, during peak hours imports are not generally marginal. In off peak periods German prices may have an influence and the German allowance regime does have the effect of making the marginal cost of CO2 to generators less than the market price of an allowance. Therefore there could be some off peak effect.

• There could be some effect of a demand response to higher prices, but this is likely to be small.

• If generators believe that their future allocation of allowances will be affected by their current behaviour, they may implicitly value CO2 today at less than the market price of allowances. If this were the case, the pass through of their implicit opportunity cost would be higher than is observed by having regard to the full market price of allowances.

• Generators may have previously enjoyed market power and have now chosen not to pass through full CO2 costs, possibly to avoid the potentially high profits which full pass through could entail.

We note that neither of the last two reasons is wholly consistent with the representations made by generators to us or with DT’e’s/Mazars’ observations of current trading activity.

Two further suggestions have been put to us to explain the low observed levels of pass through:

• the first concerns the nature of indexation in certain gas costs which mean that the gas price tends to move in line with coal prices; and

• the second concerns must run plant.
We do not see any obvious way in which these factors would lead to greatly reduced rates of pass through.

The nature of gas price indexation should have not have any influence on the effect of the CO2 price. The CO2 content of burnt gas does not depend on the price of that gas and the extent to which the opportunity cost of CO2 adds to the opportunity cost of gas fired generation depends solely on the emission coefficient (tonnes of CO2/ MWh) and the value of CO2. However, we accept that gas indexation could have an effect if the opportunity cost of the fuel alone was not the same for all generators and the differences were indeed such as to change the merit order. Under these circumstances, our estimate of the average efficiency of the various plants which operate on the margin during peak hours might be less accurate.

In relation to the second issue, we understand that the overall efficiency of CHP plant (counting both electrical and useful heat output) can be very high. However, as noted in Section 3.3.1, must run plant just producing to its must run profile does not determine system marginal cost. Must run plant may be able to operate at more than its must run load. However, when it does so, we would not expect it to have an exceptionally high marginal efficiency which would be required for it to reduce significantly marginal CO2 emissions and hence reduce the effect of CO2 on system marginal cost. If it had a very high marginal efficiency it would be fully despatched and hence be unlikely to be operating on the margin.

With regard to off peak prices, variants of all but the first reasons discussed above in relation to peak prices could apply. In addition, the true marginal coal consumption of plant that is backed off over night may be significantly less than the normal short run marginal cost measure. Hence, the CO2 addition to the marginal cost of this plant may be less than simple analysis implies.
4 Windfall profits - the conceptual framework

In this section, we develop a conceptual framework for identifying windfall profits\textsuperscript{15}. By windfall profits we mean the change in profits for generators as a consequence of the EU ETS derived from their generation activity\textsuperscript{16}. In other words, conceptually we aim to estimate for each generator

\[
\text{Windfall profits} = \text{Profits with EU ETS} - \text{Profits without EU ETS}
\]

This may seem simple but is not without its complications. For example should windfall profits be measured by what would happen to the firms with and without the ETS, assuming no difference in their behaviour or should we include in windfall profits the profits that have become available to from actions that they take to respond to the ETS. As we elaborate on the concept in this section of our report, we bring out the key issues which need to be resolved to bring clarity to the definition.

In line with our brief, we focus principally on a measure of windfall profits during 2005, the first full year of the scheme’s operation.

4.1 OVERVIEW

The drivers which connect the ETS with changes in a generator’s profit are illustrated in Figure 6.

\textsuperscript{15} Throughout we refer to windfall profits, although it has to be kept in mind that these might actually be negative, and therefore losses.

\textsuperscript{16} We therefore ignore any profits from trading CO\textsubscript{2} or effect on profits in retailing electricity as these were in principle available to any party and do not arise from the allocation of permits. We also ignore profits arising from the generators’ recent efforts to reduce CO\textsubscript{2} emissions although we are not able to go back further and eliminate the effect of generators’ efforts to reduce CO\textsubscript{2} emissions over the last several years.
This framework is generic. It allows for the possibility that the ETS will have altered the merit order. If this were the case, we might expect substantial changes in the volume of generation by each plant and hence different quantities of fuels used as well as different quantise sold by each generator, with and without the ETS. However, as far as we can ascertain, the merit order has not been materially affected by the ETS and therefore in our current analysis the drivers in the shaded area may reasonably be ignored.

We now discuss the elements of this framework.

4.2 EFFECT ON REVENUE

In outline, the opportunity cost of CO2 might reasonably be expected to affect the price at which power is sold. However, to estimate this effect we need to make assumptions regarding:

- when the power delivered in 2005 was sold (or when to deem it was sold);
- what was the perception of the opportunity cost of CO2 at that time; and
- how the perceived CO2 value affected the market price of sales.

**Timing of sales**

The generators have made representations to us that the majority of power is sold forward, in advance of the year of delivery. While some of these ‘sales’ are internal, ie made to the company’s supply business, it does seem reasonable to impute to generators a reasonable forward sales hedging strategy with the timing.
of sales external to each group being the responsibility of either the retail or trading parts of the business and therefore not relevant to the effect of the ETS on generators per se. Our actual assumption for the timing of sales is detailed in Section 5.

A concomitant of this is that sales of 2006 and 2007 power, for example, will have been made during 2004 and 2005. If we were to apply mark to market concepts of profit, we would need to estimate how the 2005 year end mark to market adjustments of the value of these sales commitments would be affected by the ETS. However, we are unable within this assignment to make a full assessment of this. We note, however, that such an adjustment would probably lead to a reduction in any windfall profit estimate as the current price of CO2 exceeds its average over the relevant time periods.

**Opportunity cost of carbon**

With regard to the perception of the opportunity cost of CO2 at the time sales were made, we note that the first sales of 2005 power were probably made 2-3 years prior to the start of 2005. This was well before the EU ETS Directive was approved and it is quite likely that at least in the early period, firms had diverse views on the opportunity cost of carbon, if indeed they had any at all. However, it seems impracticable to unravel exactly what relevant parts of each firm thought at each time and in any event it might be regarded as undesirable to have a measure of windfall profit which depended on the firm’s good or bad prediction of CO2 opportunity costs rather than a measure clearly related to exogenous changes.

We therefore think it is appropriate for our present purposes to assume a value of CO2 (adjusted to reflect the probability of scheme implementation), profiled over time, that is common to all four generators. Our data and assumptions for this are set out in Section 5.

**Linkage between CO2 price and electricity prices**

This is a very problematic area as evidenced by the previous Section of our report. The way that generators describe their behaviour is rational and reasonable but is difficult to reconcile with the empirical evidence on pass through rates to date.

The discrepancy raises a semantic issue. If external factors would *aeteris paribus* give a company a windfall profit, but the company chooses to behave in such a way that it does not exploit that potential profit, is that zero windfall profit or a windfall profit matched by an equivalent give away?

We do not believe there is a right answer to this question and we therefore explore windfall profits based on two different concepts:

- the first assumes that the only measure of the effect of CO2 prices is that which is observed, albeit rather poorly, through empirical data;
- the second can be characterised as assuming that generators have behaved as they say, markets have behaved rationally and, if there has been a change in the incidence of market power or other factors decoupling price from marginal cost, it is not relevant to the definition of the windfall profit from the ETS.
4.3 EFFECTS ON COSTS

As the evidence suggests that the merit order has not changed materially, the affect on costs will be limited to:

- The need to purchase allowances over and above those allocated. If fewer allowances than were allocated were needed, the surplus would be treated as a negative cost.
- The cost of actions taken which have contained or reduced CO2 emissions, in response to the ETS.

Both of these elements raise issues.

The first issue spans the two elements and goes to the heart of what should or should not be regarded as windfall profit. In general parlance, we would expect a windfall profit to be a profit arising from a change in exogenous circumstances and which the company needs to do little to exploit. The question is ‘How little?’

**What is windfall profit?**

- If someone is walking along a road and a passer-by hands him a gold coin, that could reasonably be classed as a windfall gain.
- If someone is walking along the road and having learnt that someone on the other side of the road is handing out gold coins, he then crosses the road to take his gold coin, that too could be classed as a windfall gain.
- However, if someone learns that a gold coin is buried in a field and he hires a digger to dig up the field and subsequently finds the gold coin, has he benefited from a windfall gain or reaped the fruits of his entrepreneurial endeavour.

There is clearly no black and white distinction between a windfall gain and a gain that is earned.

Returning to the effect of the ETS, we may distinguish two extreme definitions:

- Gains which would arise even if the company did essentially nothing to respond to the scheme; and
- Gains which were made possible by the impact of the scheme and the company’s response thereto.

However, this is not the only complication. A strict definition of response could be what the company has done to reduce CO2 emissions after it knew that the ETS would definitely come into being. However, should a company that predicts the likelihood of the scheme coming into being, and acts accordingly, be judged to have made greater windfall profits than one which took the same measures just after the scheme was announced. This would seem inappropriate. A yet more difficult case would arise where a company has taken measures to produce green energy because the market pre ETS showed some willingness to pay a premium for such energy. In this case the motivation for the early move would seem to be independent of the potential ETS. Unfortunately, in practice
there may be no clear distinction as to what motivated green actions prior to the ETS, thus making it practically impossible to formulate a robust and clear concept for appropriate windfall profit.

**Net purchase/sale of allowances**

In order to value a company’s acquisition of extra allowances or cost reduction / revenue from sale of surplus, we need an assumption as to when such net sales or purchases take place or should be deemed to have taken place.

Typically companies endeavour to hedge risks by, for example, matching fuel purchases to the time at which power is sold, thus locking in the expected profit inherent in forward prices. In principle, CO2 could be treated similarly. However, there are also reasons why this might not be appropriate. First, for much of the relevant period companies did not know what their allocation through the NAP would be. Secondly, the grey market was very thin and companies could have had some difficulty adjusting their positions in accordance with a normal hedging strategy. Against this background we think it is more reasonable to deem that the adjustment of the net allowance position took place in 2005 and we have assumed that the time profile within 2005 matched the emissions profile of each company.
5 Windfall profits – detailed modelling data and assumptions

In this section we discuss how the two key components of windfall profits, changes in revenue and changes in costs, have been empirically quantified.

5.1 CHANGES IN REVENUE

We have assumed that the change in revenue arises from the changes in the price at which power is sold.

We assume that (although mixed in composite products) the difference in the effective price of the power in each hour in 2005 is related to expectations at the time that the power was sold. Specifically, the difference in effective price can be described as a multiple of the value of the marginal CO2 emissions, where that multiple is the ‘pass through rate’. Marginal emissions relate to the plant that operates on the margin during the hour in question.

Our primary analysis in this report is based on the evidence, albeit rather weak, with regard to pass through rates, that we could glean from our empirical work reported in Section 3.

To summarise we have:

- no evidence of the appropriate pass through rate to apply to 2005 forward sales made prior to April 2004, although plausible intuition suggests that they would be lower than post that date;

- evidence, albeit very weak, for pass through rates of a little less than 15% in peak prices and around 10 - 20% off peak in the period April – December 2004;

- slightly more significant evidence, but still weak, for pass through rates of 45 - 50% in peak prices and 30-35% in off peak prices, during the period January to July 2005; and

- an apparently significant, but implausibly high, estimate of the pass through rate in peak prices for the period August to December 2005 (108%), combined with a statistically insignificant estimate of a pass through rate of around 40% in off peak prices for the same period. (As noted in Section 3, the closer to real time the more likely are events not captured in this analysis to distort the results.)

As we discuss in Section 5.1.1, generators generally sell a very high proportion, perhaps typically 90%, of their expected output before the year in which that output is delivered. In choosing a representative pass through rate for our windfall profits analysis we should therefore be more concerned with the evidence, such as it is, for the pass through rates in 2002, 2003 and 2004 rather than 2005.
To arrive at representative average peak and of peak pass through rates we have assumed that pass through rates will rise gradually from close to zero at the point where sales of 2005 power are assumed to start (ie 2002, a year before the ETS Directive) to the rates indicated for 2004 by our regressions for 2004, and then continue to rise to the rates indicated by our regressions for the period January to June 2005. We discount the evidence of the August – December results as intuitively implausible and too close to real time.

Applying sales weights and CO2 values as weights to the relevant periods leads us to a crude average pass through rates of 22% for peak and 16% for off peak prices. We therefore adopt these pass through rates for our windfall profits calculation. We do, however, stress that these are subject to a great deal of uncertainty.

The value of CO2 to be used in this incremental revenue calculation is the market value of CO2 at the time the power is sold, adjusted (necessarily judgementally) to reflect the probability the participants might reasonably have attached to the scheme coming into being when this is less than 1.0. When the ETS was not certain to be implemented, one would not expect the full value of CO2, contingent on implementation, to be reflected in prices.

The extra revenue received by a generator, attributable to the ETS, in each hour is the change in effective price difference for the hour multiplied by the generator’s production in that hour.

The revenue difference over the course of the year is just the sum of the revenue changes in each hour.

To carry out these computations we need:

- the deemed pattern of sales over time to identify when 2005 delivered power was sold;
- the opportunity cost of CO2 associated with all times at which power is deemed to be sold;
- the identity of the marginal plant in each hour in 2005;
- the marginal CO2 emissions of the marginal plant; and
- the production of each generator in each hour in 2005.

We describe below the sources of our data or assumptions for each of these.

5.1.1 Generators’ trading strategy

While we are aware of the company specific trading strategies from the interviews that we and DTc have conducted, the information represents commercially valuable intelligence, which the generators have requested should remain confidential. In choosing a representative trading strategy, we therefore followed EnergieNed’s request that we should formulate a simple but reasonable strategy rather than constructing the average of the four generators or simply taking the strategy of an individual firm.
The trading strategy for 2005 delivered power that we have assumed is as follows. Generators sell:

- 90% forward prior to 2005, assuming a linear path, corresponding to 3% per month for the 30 months ending December 2004; and
- 10% on the spot market, spread over 2005.

This strategy is illustrated in Figure 4. Forward sales of 2005 generation start in July 2002. By January 2004, the generator has sold almost 60% of expected generation. By the end of 2004, 90% has been sold forward. The remaining 10% is again spread evenly over the delivery year (ie 2005).

5.1.2 Opportunity cost of CO2

A daily sequence of prices for EU-ETS allowances over the full period as determined by the trading strategy has been constructed as follows:

- From 13/04/2004 onwards, forward prices for EU ETS allowances are taken from:
  - the price for EU-CO2- Allowances (2006) as provided by Spectron; and
  - missing observations have been estimated based on the ‘European Carbon Index’ and the ‘EU-CO2- Allowances’ index provided by the EEX.

- Reliable price data are not readily available for the relevant period before this. We have therefore made the following assumptions:
  - prior to April 2004, the expected value of CO2 was as observed at the start of our data set in April 2004;
  - the market’s consensus on the probability that the scheme would come into being was 1.0 (ie 100%) from the time that the Directive was approved; and
  - the market’s consensus on the probability of the scheme coming into being rose linearly from 0.0 at the point 6 months prior to Directive approval to 1.0 at the time the Directive was approved.
The resulting probability adjusted value of CO2 over time is shown in Figure 5.

Figure 5: Carbon price expectations (2003-2005)
Source: Spectron, EEX, Frontier

5.1.3 The marginal plant in each hour and marginal CO2 emissions

To estimate the CO2 emissions of marginal units we first need to identify the generating set that is marginal in each hour.

We use a dataset provided by DTc, which contains information on 91 different generation units operated by 33 companies. Altogether, the dataset accounts for around 85% of the installed generation park in the Netherlands, as well as on imports into the Dutch market (essentially, only small-scale generation capacity such as wind power is excluded).

For each generating set, the data show generation output per hour in 2005 plus capacities, thermal efficiencies, fuel type and other relevant technical characteristics. Using this data set together with spot market fuel prices for 2005, allows estimates to be made of the variable costs per unit in each hour. Based on these calculations, we identify the marginal set in each hour of 2005 as the set with the highest variable cost, but excluding several sets during off-peak hours to reflect must-run constraints (for CHPs) or weak information on fuel prices (for waste-fired units).

Finally, once marginal units are identified for all hours of the year, their CO2 emissions have been calculated based on a factor for CO2 emissions by type of fuel used, taken from the Intergovernmental Panel on Climate Change (IPCC, www.ipcc.ch) fuel emission factors.

As noted, these calculations are based on 2005 data in contrast to our draft report, in which had to rely on 2004 generation data.

5.1.4 Production data

The production data we used to calculate the total production of each generator in each hour in 2005 came from the same data set provided by DTc.
5.2 CHANGE IN COSTS

As discussed in Section 4, we define the relevant change in cost to be the cost of acquiring the difference between the aggregate grandfather quantity allocated and the best estimate we have of emissions under a ‘business as usual scenario’.

We do not have a perfect data source for the latter and have therefore assumed that emissions under business as usual should be defined as the greater of:

- annual CO2 emissions as reported by the company for 2005; or
- the quantum of CO2 emissions estimated based on the 2004 generation profile, as given in the DTe dataset.

The implication of this procedure is that companies will not be ‘punished’ for having reduced their emissions level significantly in 2005 relative to 2004, since the higher level will be used to quantify their changes in costs. However, this necessarily simple methodology will impute higher windfall profits than might be desirable for those who invested in CO2 reduction and achieved that reduction in or before 2004.

Finally, the average price to apply to the net purchase (or sale) of allowances implied by the above is derived from 2005 CO2 prices weighted according to the emissions profile of the generator in question. In effect generators are assumed to buy their net requirement according to the profile by which they contribute to emissions.
6 Windfall profits – results

In this section we present the results of our analysis of windfall gains by the four largest Dutch generators. Other generators may also have made windfall gains (or losses) which would mean that the total position for the sector differed from the one reported here.

In summary, we base our results on the data and methodology described in Section 5 - including the empirically estimated pass through rate over the time at which 2005 power was sold, and a definition of profit which excludes profit that appears to have been derived from recent action by the firm rather than simply the exogenous change in the business environment.

We present our results in two sets of tables:

• the first set reflects better our approach; and
• the second set presents results according to the convention adopted by ECN. The difference between these two presentations relates to the choice of different building blocks to arrive at an estimate of windfall profit. Both approaches, when implemented with the same inputs, give the same value for windfall profits.

6.1 RESULTS (FRONTIER FORMAT)

<table>
<thead>
<tr>
<th></th>
<th>Revenue effect (in m€)</th>
<th>Net allowance effect (in m€)</th>
<th>Total change (in m€)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Range per firm</td>
<td>10 - 27</td>
<td>-32 - +3</td>
<td>-7 - +19</td>
</tr>
<tr>
<td>Total of four firms</td>
<td>68</td>
<td>-50</td>
<td>19</td>
</tr>
</tbody>
</table>

The nomenclature in this table is as follows:

- ‘Revenue effect’ means the increase in revenue due to the impact of the ETS on electricity prices.
- ‘Net allowance effect’ means the cost of acquiring the allowances in excess of those allocated for free, which the generator would have needed in order to continue on a business as usual basis (the greater of estimated 2004 emissions or reported 2005 emissions minus the grandfathered allocation).
6.2 RESULTS (ECN FORMAT)

<table>
<thead>
<tr>
<th></th>
<th>Price effects (in m €)</th>
<th>Free allocation (in m €)</th>
<th>Total change (in m €)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Range per firm</td>
<td>-129 -188</td>
<td>139 - 183</td>
<td>-7 -19</td>
</tr>
<tr>
<td>Total of four firms</td>
<td>-612</td>
<td>631</td>
<td>19</td>
</tr>
</tbody>
</table>

Table 3: Estimate of windfall profits, ECN format, based on 2005 dispatch data

The nomenclature in this table is as follows:

- **Price effects** includes the effects of the ETS on revenue and on full opportunity costs of production (these have opposite signs).

- **Free allocation** means the value of all the grandfathered allocation of allowances.

Please note that in this table we present the results of our methodology and assumptions in ECN’s format. This table is not the result of applying ECN’s methodology.

6.3 COMMENTARY ON RESULTS

Our results show that, at our empirically estimated pass through rate, windfall profits are small - circa €19m for the four largest generators. Indeed, if allowance is made for the uncertainty inherent in our estimate, windfall profits may well be negative. However, by the same token they could in reality be significantly higher than our estimate.

The biggest single cause of uncertainty in this estimate is the uncertainty in the pass through rates. While the data do not even support a good measure of the possible error we think that pass through rates up to 50% less or more than those estimated would not be implausible. If pass through rates were half those used aggregate profits would be negative at -€16m. If pass through rates were 50% higher than our central estimate aggregate profits would increase to €53m.

An understanding of the principal factors determining this estimate may be helpful in thinking through implications for the future. The two key ones to note are:

- Taking account of the pattern of forward sales makes a very big difference to the outcome. Based on the evidence collected, not only were expected CO2 prices much lower in years prior to 2005 but the effective pass through rates for CO2 also appear to be lower in earlier periods. Had the same calculation assumed that all sales were made uniformly in 2005 the CO2 price would have been approximately 3 times as high and the best estimate of the pass through rate would have been in the region of 2 to 3 times as high. The revenue effect element of windfall profit would then have been in the region of €300 – 500m rather than €55m.
• There is a clear but intentional mismatch between the timing of the valuation of CO2 for revenue and cost purposes. We have concluded that early low values of CO2 would have been reflected (to the extent that they were at all) in the price of electricity sold. However, under the methodology for determining windfall profit, we assume the generators incur the cost of purchasing CO2 allowances to make up the difference between their allocation and their business as usual emission requirements. We have assumed that this (notional) activity took place during 2005 when the CO2 price is relatively high. We made this assumption for two reasons: first, the companies would not have known their NAP allocations until very close to the beginning of 2005 and so they would not have known whether they were net buyers or net sellers; and, secondly, even if they did, they would not have had a CO2 market with reasonable liquidity prior to 2005 in which to adjust their CO2 positions. Had the price of CO2 in this cost effect been the same as the average for the revenue effect, the imputed extra cost would have been much lower, probably more like €20m than €50m.

Although windfall profits appear to all intents and purposes to have been non-existent in 2005, both of these points suggest that other things being equal, future windfall profits could be very much higher.

6.4 IMPACT OF WINDFALL PROFITS

DTe has asked us to comment on whether to the extent that there are windfall profits, these have been ‘paid for’ disproportionately by one consumer group rather than another.

The first point to note is that windfall profits are not borne by consumers in any meaningful sense of the phrase. Prices are a market outcome and windfall profits could be high or negative with the same market outcome. Any measure to remove windfall profit should have no impact on prices that consumers pay. There should for example be no linkage between the allocation of grandfather allowances and the price outcomes which consumers face unless generators either believe that their future allocation will be affected by their current use of allowances or their current profitability. If either of these were the case they would be mitigating not increasing the prices that consumers face.

However, we can address the different the issue of which consumers are likely to be paying relatively more than others under the ETS. Our results suggest that if there were full pass through of CO2 costs then the prices to large consumers would rise by more than prices to smaller consumers as the former tend to have a higher load factor and hence greater off peak consumption and the more carbon intensive technology, coal, operates at the margin in off peak. However, observed pass through rates are not 100% and they are not the same for peak and off peak. Peak pass through rates appear to be higher than off peak pass through rates and this tends to offset the carbon intensity effect. Therefore, on balance there is likely to be little differential impact on consumer groups. The burden of meeting the marginal environmental costs of power generation are likely to be fairly evenly spread.
Annexe:

In this annexe we describe in detail the methodological steps undertaken and the results obtained in our econometric analysis, assessing the effect of CO2 costs on electricity prices.

2005 REGRESSIONS

General Approach

In order to analyse the extent of the “pass through” of allowance costs on electricity prices after the introduction of the EU ETS regime, we have assumed that in peak hours gas fired plants operate on the margin, while in off-peak hours coal fired plants are the marginal operating plants.

We use one year forward prices for the period 2006 as of 2005 in our analysis, instead of spot prices for electricity and fuel. Spot prices are strongly affected by seasonal demand and stochastic events that cause measurement problems.

For the year 2005 analysis we regress our different specifications for all weekdays in 2005 as well as for two sub periods

- January-July 2005; and
- August-December 2005

which allow for a comparison with the findings of other studies such as ECN (2005).

Data

The data used in the year 2005 regressions reports daily prices from January 2005 to December 2005, excluding weekends and holidays, which leads to a total of 225 observations:

- **Electricity prices**: forward electricity prices (in €/Mwh of electricity) for peak and base load for delivery in year 2006, as provided by Platts.\(^\text{17}\) Off-peak prices have been derived implicitly on the basis of a total of 8,760 hours with 4,080 peak and 4,680 off-peak hours in 2005.\(^\text{18}\).

- **Gas fuel prices**: forward gas prices for delivery in year 2006 of the Title Transfer Facility (TTF) as provided by Platts.\(^\text{19}\) Prices are reported in €/MWh of power and to be comparable with electricity prices we have assumed a 35% efficiency of the relevant gas fired Dutch generation plant to turn those prices in €/MWh of electricity.

\(^{17}\) ‘NL Sys Base 1-Yr Euro’ (AADNI00) and ‘NL Sys Pk 1-Yr Euro’ (AADNK00).

\(^{18}\) Off-peak price = ((8760 * base load price) - (4080 * peak price)) / 4680

\(^{19}\) ‘Dutch TTF Eur/MWh 1st Calendar Yr’ (GTFTZ00).
- **Coal fuel prices**: we have used spot coal prices (provided by DTe). As in the data for gas fuel prices, we have transformed prices in €/MWh of electricity using a 40% efficiency of the relevant coal fired Dutch generation plant.

- **Allowance prices**: prices for EU-CO2- Allowances (2006) (originally expressed in €/tCO2) as provided by Spectron. Missing observations are estimated using the ‘European Carbon Index’ and the ‘EU-CO2- Allowances’ index provided by the EEX. The original data has been transformed according to the relevant technology (either gas or coal) in peak and off-peak hours, in price of allowances expressed in €/MWh of electricity produced using gas or coal. That transformation has assumed factor efficiencies as already mentioned and levels of emissions of 0.20196 for gas and 0.34056 for coal.

A graphical presentation of all data is given in Figure 6: and Figure 7: (in order to facilitate visual interpretation the prices of CO2 allowances are given in €/t while electricity and fuel costs are all in €/MWh of generated electricity).

![Figure 6: Electricity price (peak), gas costs and CO2 price (2005)](image)

*Source: Platts, Spectron*
Annexe:

Regressions results

In this section we extend the analysis of the regression results presented in section 3.5. All the regressions are performed by using variables expressed in first differences. The results of the regression of the peak price of electricity against the allowance price and the cost of gas are presented in Table 4:

Figure 7: Electricity price (off peak), gas costs and CO2 price (2005)

Source: Platts, Spectron
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Dependent variable (in first-differences)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Explanatory variables</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(In first-differences)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO₂ price</td>
<td>.614</td>
<td>.471</td>
<td>1.08</td>
</tr>
<tr>
<td></td>
<td>(5.55)**</td>
<td>(4.14)**</td>
<td>(4.19)**</td>
</tr>
<tr>
<td>gas cost</td>
<td>0.196</td>
<td>.20</td>
<td>.174</td>
</tr>
<tr>
<td></td>
<td>(3.21)**</td>
<td>(3.05)**</td>
<td>(1.39)</td>
</tr>
<tr>
<td>constant</td>
<td>-.003</td>
<td>-.15</td>
<td>0.78</td>
</tr>
<tr>
<td></td>
<td>(0)</td>
<td>(-0.58)</td>
<td>(0.72)</td>
</tr>
<tr>
<td>Observations</td>
<td>225</td>
<td>140</td>
<td>85</td>
</tr>
<tr>
<td>adj. R-squared</td>
<td>.193</td>
<td>.206</td>
<td>.204</td>
</tr>
<tr>
<td>Root MSE</td>
<td>.631</td>
<td>.565</td>
<td>.718</td>
</tr>
<tr>
<td>Durbin – Watson stat.</td>
<td>1.85</td>
<td>1.83</td>
<td>1.94</td>
</tr>
<tr>
<td>Correlation between permit price and coal cost</td>
<td>.300</td>
<td>.313</td>
<td>0.227</td>
</tr>
</tbody>
</table>

Table 4: Regression results – OLS regression of the peak electricity prices on CO₂ prices and gas cost (a time variable is included but not reported)

Source: Frontier Economics. Absolute value of t statistics in parentheses* significant at 5%; ** significant at 1%

Statistically, the regression points to a robust specification, as the time trend does not seem significant (the coefficient of time is not reported but non-significant in all three regressions)²⁰ and the explanatory variables together with the residuals seem uncorrelated.

However, while the coefficients for the explanatory variables are positive and significant - with the exception of the gas cost²¹ - when using the sample corresponding to the second half of the year 2005, there is again a problem in that the pass-through factor is too high at 108% in the second period of 2005.

The results of the regression of the spark-spread in first-differences are reported in Table 5. The coefficient of the allowance price is positive, although non-significant in the first period of 2005 and much higher and significant for the second period of 2005.

---

²⁰ Including a time trend in a first difference regression can be seen as a test of whether first differences really measure a statistical relationship that does not exhibit any time trend.

²¹ This can be the result of a high volatility of gas prices during that period.

Annexe:
We go through the same steps as with peak prices, attempting to estimate the effect of the allowance costs and coal fuel costs of the (assumed) marginal unit on off-peak electricity prices for the year 2005.

However, as will be seen in more detail this section, in this case, different from ECN, we are generally unable to detect any significant or meaningful relationship between off-peak prices and the coal or the allowance costs of the marginal unit. Nevertheless, we record the different specifications that have been estimated.

In Table 6 we can see the results of the regression in first-differences of the off-peak price against allowance prices and coal costs.
Table 6: Regression results – OLS regression of the off-peak electricity prices on CO₂ price and coal cost (a time variable is included but not reported)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Explanatory variables (in first-differences)</td>
<td>Dependent variable (in first-differences)</td>
<td>off-peak electricity price</td>
<td></td>
</tr>
<tr>
<td>CO₂ price</td>
<td>.337</td>
<td>.319</td>
<td>.389</td>
</tr>
<tr>
<td></td>
<td>(5.58)**</td>
<td>(4.67)**</td>
<td>(3.00)**</td>
</tr>
<tr>
<td>coal cost</td>
<td>-.027</td>
<td>-.044</td>
<td>-.017</td>
</tr>
<tr>
<td></td>
<td>(-.17)</td>
<td>(-.22)</td>
<td>(-.06)</td>
</tr>
<tr>
<td>constant</td>
<td>.017</td>
<td>-.007</td>
<td>-.33</td>
</tr>
<tr>
<td></td>
<td>(.11)**</td>
<td>(.03)</td>
<td>(-.4)</td>
</tr>
<tr>
<td>Observations</td>
<td>225</td>
<td>140</td>
<td>85</td>
</tr>
<tr>
<td>adj. R-squared</td>
<td>.11</td>
<td>.12</td>
<td>.07</td>
</tr>
<tr>
<td>Root MSE</td>
<td>.531</td>
<td>.527</td>
<td>.54</td>
</tr>
<tr>
<td>Durbin – Watson stat.</td>
<td>2.39</td>
<td>2.34</td>
<td>2.45</td>
</tr>
<tr>
<td>Correlation between the CO₂ price and coal cost</td>
<td>-.0014</td>
<td>-.0043</td>
<td>-.006</td>
</tr>
</tbody>
</table>

Source: Frontier Economics. Absolute value of t statistics in parentheses* significant at 5%; ** significant at 1%

Again, the regression in first-differences points to a substantially robust specification, as the time trend does not seem significant (the coefficient of time is not reported but non-significant in all three regressions) and the explanatory variables seem uncorrelated with the residuals.

Looking at the coefficients for the explanatory variables we find that the coal cost coefficient is not significant which, of course, in terms of the economic interpretation is highly problematic. The coefficients for the allowance price are positive, significant and constant across the three sample periods.

Finally, the results of the regression of the dark-spread in first-differences are reported in Table 7. The coefficient of the allowance price is again positive and significant and similar to the coefficients obtained in the regression of the off-peak price.
Table 7: Regression results – OLS regression of the dark-spread of off-peak price on CO₂ price (a time variable is included but not reported)

Source: Frontier Economics. Absolute value of t statistics in parentheses* significant at 5%; ** significant at 1%

2004 REGRESSIONS

Regarding the extension of the analysis by looking at year 2004 prices (from April to December), we should note that the data series used are the same as the 2005 regressions except that forward prices now relate to 2005 delivery not 2006.
### Table 8: Regression results – OLS regression of the peak price and spark spread of peak price on CO₂ price and gas cost (a time variable is included but not reported)

<table>
<thead>
<tr>
<th>Sample</th>
<th>April – December (2004)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Dependent variable (in first-differences)</td>
</tr>
<tr>
<td></td>
<td>peak price</td>
</tr>
<tr>
<td><strong>Explanatory variables (in first-differences)</strong></td>
<td></td>
</tr>
<tr>
<td>CO₂ price</td>
<td>.141</td>
</tr>
<tr>
<td></td>
<td>(.54)</td>
</tr>
<tr>
<td>gas cost</td>
<td>.191</td>
</tr>
<tr>
<td></td>
<td>(2.15)**</td>
</tr>
<tr>
<td>constant</td>
<td>.123</td>
</tr>
<tr>
<td></td>
<td>(1.86)*</td>
</tr>
<tr>
<td>Observations</td>
<td>156</td>
</tr>
<tr>
<td>adj. R-squared</td>
<td>.064</td>
</tr>
<tr>
<td>Root MSE</td>
<td>.403</td>
</tr>
<tr>
<td>Durbin – Watson stat.</td>
<td>1.95</td>
</tr>
<tr>
<td>Correlation between the CO₂ price and gas cost</td>
<td>-.0242</td>
</tr>
</tbody>
</table>

Source: Frontier Economics. Absolute value of t statistics in parentheses* significant at 5%; ** significant at 1%
<table>
<thead>
<tr>
<th>Sample</th>
<th>April – December (2004)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Dependent variable (in first-differences)</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Explanatory variables</strong></td>
<td><strong>off-peak price</strong></td>
</tr>
<tr>
<td>CO₂ price</td>
<td>.103</td>
</tr>
<tr>
<td></td>
<td>(.80)</td>
</tr>
<tr>
<td>coal cost</td>
<td>-.076</td>
</tr>
<tr>
<td></td>
<td>(-1.13)</td>
</tr>
<tr>
<td>constant</td>
<td>.035</td>
</tr>
<tr>
<td></td>
<td>(.73)</td>
</tr>
<tr>
<td>Observations</td>
<td>156</td>
</tr>
<tr>
<td>adj. R-squared</td>
<td>.014</td>
</tr>
<tr>
<td>Root MSE</td>
<td>.297</td>
</tr>
<tr>
<td>Durbin – Watson stat.</td>
<td>2.31</td>
</tr>
<tr>
<td>Correlation between the CO₂ price and gas cost</td>
<td>.037</td>
</tr>
</tbody>
</table>

Table 9: Regression results – OLS regression of the off-peak prices and dark spread of off-peak price on CO₂ price and coal cost (a time variable is included but not reported)

*Source: Frontier Economics. Absolute value of t statistics in parentheses* significant at 5%; ** significant at 1%*

As already mentioned in Section 3.5 results for the year 2004 are very poor in terms of regression fitness and overall, coefficients for the pass-through rates are smaller than those found in the year 2005.
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