





# Update on the Latest Developments in the EU Emission Trading Scheme

## **Update on the Latest Developments in the EU Emission Trading Scheme**

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# Summary

## Abstract

*Based on an analysis of BAU-scenarios for CO<sub>2</sub>-emissions, National Allocation Plans and abatement costs, we forecast a price for CO<sub>2</sub>-emissions in the first period of EU ETS of approximately € 2-5/tonne CO<sub>2</sub>. The Russian ratification of the Kyoto protocol does not influence this estimate since JI credits cannot be used before 2008 and since prices in the first and second period of EU ETS are largely independent. Our price forecast for CO<sub>2</sub>-emission allowances is much lower than the observed prices in the market, which have been between € 6-13/tonne CO<sub>2</sub>. This difference may be due to a risk premium, misperception by the participants, or to imprecision in our analysis. With our best guess for prices on emission allowances for CO<sub>2</sub>, we forecast an increase of power prices of approximately 1-4 øre/kWh for the Nordic countries.*

## Background

EU has established a system for trade with CO<sub>2</sub>-emission allowances, EU Emission Trading Scheme (ETS). Each year, all participants within the ETS-sectors must hand in CO<sub>2</sub>-emission allowances equal to their total CO<sub>2</sub>-emissions. Allowances can be saved for later years within the first period, 2005-2007, but not for later periods. Since allowances for the coming year are allocated before the allowances for last year's emissions have to be handed in, allowances can in practice also be borrowed from later years within the first trading period.

EU ETS started on 1<sup>st</sup> of January 2005 so there are hence a few months of experience with the system already. It is however not until the end of the first period of EU ETS, which is the beginning of 2008, that the market balance and hence "correct price" will be revealed. Today's prices are based on the participants' expectations of the uncertain future as well their risk aversion.

## Problem Statement and Method

*What will the price of an allowance to emit 1 tonne of CO<sub>2</sub> be worth at the end of the first period? And how will the price of CO<sub>2</sub>-allowances influence the European power prices? We have analysed fundamental*

*aspects that determine the price for emission allowances and compared our forecast with the prices observed in the market.*

The results presented in this memo rest on the same methodology as in a previous report from September 2004 (ECON, 2004b), and update the analysis with respect to new information. Since the previous report more national allocation plans (NAPs) has become available, and currently the European Commission has approved all but three NAPs.

The emission caps given by the NAPs and projections on business-as-usual emission levels provide a basis for estimating the total reduction requirements and thus the net demand for emission allowances. The supply of emission allowances is then determined by the marginal abatement costs for achieving emission reductions. The market clearing of the estimated net demand and supply for emission allowances provides a base estimate of the price for the allowances.

The effect of emissions trading on electricity prices is then assessed. Based on previous simulations with ECON's Nordic power market model the effect on the Nordic and Northern European electricity markets are analysed and discussed. The effects on other European electricity markets are also discussed, based on the characteristics of the different markets.

## Conclusions

Our analysis indicates a low net demand for emission allowances of approximately 10 million tonne. We thus forecast a low price for CO<sub>2</sub>-emissions, € 2-5/tonne CO<sub>2</sub>, in the first period of the EU ETS. This forecast is not influenced by the Russian ratification of the Kyoto protocol since we find it very unrealistic that Russian CO<sub>2</sub>-allowances will be available in the EU ETS before 2008. Our forecast is much lower than the price observed in the market.

The effect on electricity prices is estimated to be in the range of 1-4 øre/kWh in the Nordic countries, given our estimates of the price of emission allowances. With the existing higher prices on allowances the effect on electricity prices may be 4 øre/kWh or more.

In other European countries the effect on electricity prices may be larger due to higher carbon intensity in the marginal production plant. In some cases it may also be lower due to substantial degree of market power or price regulation.

This memo was finalised in mid-March 2005 and is based on the developments until the end of February 2005. A brief comment on important changes between the finalisation of this memo and June 2005 is provided initially.

# 1. Comments to the Memo

This memo was finalised in mid-March updating on the events until the end of February 2005. The developments since then have showed significantly higher prices on emission allowances than suggested in this memo. There are two main reasons for this. Firstly, it is important to realise that we estimated our best-guess for the *most probable* price *at the end* of the trading period. Secondly, as we pointed out, there were large uncertainties around several parameters. Two of these aspects have turned out significantly different than anticipated and both have contributed to higher prices for CO<sub>2</sub> emissions. We shortly discuss both aspects below.

The memo also discussed the influence of CO<sub>2</sub> emission trading period on the power price. We predicted an increase in power price equal to the increase in the marginal production cost, which reflect the marginal carbon intensity of the power market. Price formation so far has proven to reflect this principle as shown section 0.

## 1.1 Most Probable Price at the end of the Period

We estimated what we found to be the most likely value of a CO<sub>2</sub> emission quota at the end of the trading period. There is however a large uncertainty about this value. Since the most likely price was very low and much closer to zero than to the upper limit, it is rational for participants in the market to trade quotas at higher prices in the beginning of the trading period. That is because there is a possibility of much higher prices (than the most likely outcome) at the end of the trading period, but no possibility of a much lower price. With the very low price that we estimated to be the most likely value at the end of the period, we would hence expect a decrease in the price over time.

## 1.2 Revealed Uncertainty

As pointed out in the memo there are several sources for uncertainty. As already mentioned, two of these aspects have turned out quite differently than we anticipated and have both contributed to an increase in our estimate for the most likely end value of CO<sub>2</sub> emission price. The two parameters are Italian NAPs and gas price.

### 1.2.1 Italian NAPs

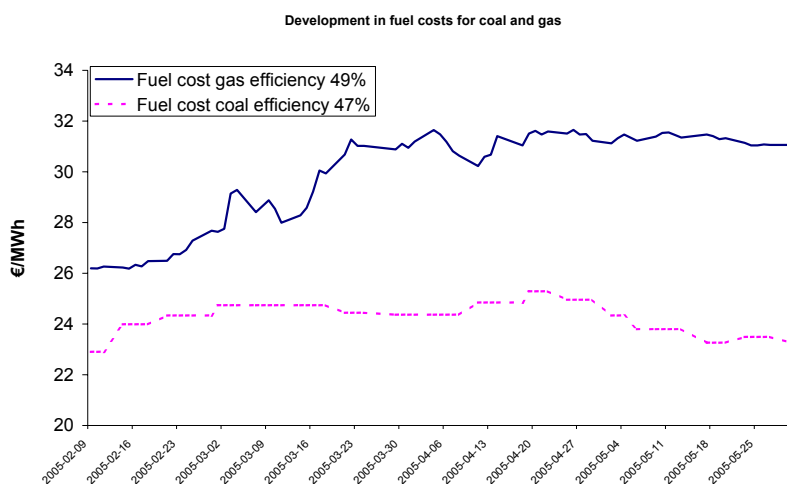
At the time of writing the memo there were uncertainties about the allocation of allowances, which now to a large extent have been resolved. The decision by the Commission on the Italian NAP provided the most important uncertainty in this respect. Our best guess estimate included a cut of approximately 10 million tonne CO<sub>2</sub> per year in the Italian NAP, and the final outcome was a cut of 23 million tonne. That would thus increase our net demand estimate with 13 million tonne per year.

### 1.2.2 Gas Prices

Gas prices are important since fuel switching from coal to gas fired power plants is one of the most important abatement possibilities in the short run. Increased gas prices relative to coal prices means that a higher carbon price is needed to trigger fuel switching.

Figure 1.1 shows the development in fuel costs for coal and gas fired power plants in the period February to May 2005. From the graph it is clear that increases in gas prices have increased the fuel costs for gas fired power plants significantly over a few months, while the fuel costs for coal fired power plants have been roughly unchanged seen over the entire period.

Figure 1.1 Development in fuel cost for coal and gas fired power plants, February - May 2005



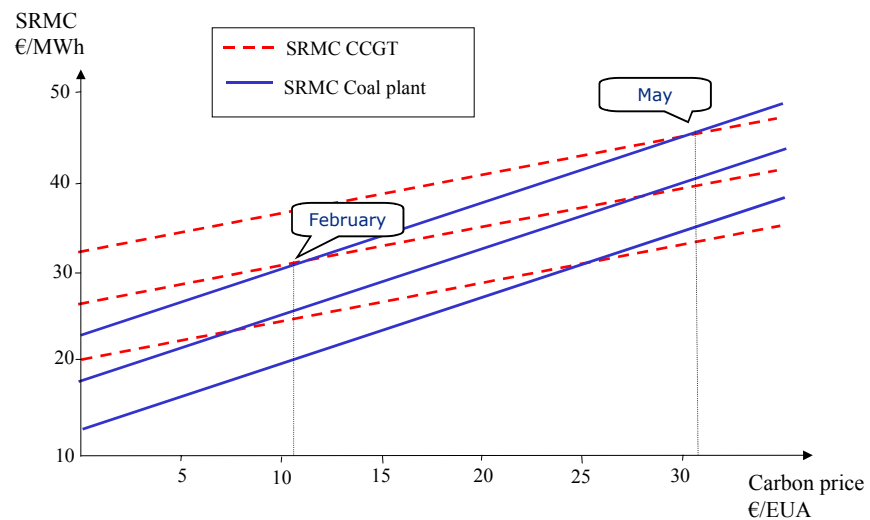
Source: Fuel costs for gas power plants have been calculated using Endex TTF Reference price for gas delivered in Q3-05 and fuel costs for coal power plants have been calculated using coal prices for coal delivered in Q3-05 from global-coal.com.<sup>1</sup>

<sup>1</sup> Using different sources may affect the absolute numbers, but the qualitative implications remain.

Gas fired plants are normally more expensive than coal fired plants due to more expensive fuel. Coal fired plants do however emit more CO<sub>2</sub> and emissions trading may thus make gas fired plants cheaper and fuel switching profitable. The price level for CO<sub>2</sub> emission quotas necessary for a profitable fuel switch depends on the relative fuel costs (as well as efficiency levels etc). This is illustrated with an example in Figure 1.2. The dotted lines illustrate the SRMC (defined as fuel costs + carbon costs) for a gas-fired plant at different gas prices and the full lines illustrates the SRMC for a coal-fired plant at different coal prices.

In February the coal and gas prices were such that the carbon price needed for fuel switching, i.e. to make gas fired production as cheap as coal fired production, was slightly above 10 €/EUA. The increase in gas prices over the period meant that in May a carbon price above 30 €/EUA was needed to trigger fuel switching. This shows the dramatic effect that the fuel price development has had on the short-run abatement possibilities through fuel switching.

Figure 1.2 Carbon prices necessary for triggering fuel switching



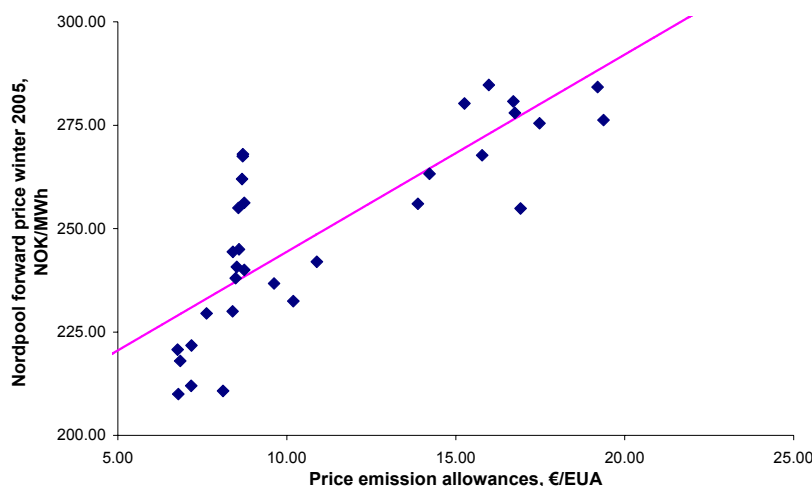
Source: ECON's calculations

### 1.3 Relationship Between Electricity and Carbon Prices

In the report it was concluded that emissions trading would affect Nordic power prices through its effect on system marginal costs. This in turn will be determined by the marginal carbon intensity in the power sector and the carbon prices. Model simulations numerically supported this.

Figure 1.3 shows the relationship between the price on emission allowances and the price for a forward contract on Nord Pool delivered in the winter 2005. The graph indicates a clear relationship. The regression line inserted has a slope parameter that is close to, but a bit below, the effect that emissions trading has on the marginal cost for a coal fired power plant. The relationship between carbon prices and power prices is similar when looking at German power prices, although the effect on power prices is then slightly stronger.

*Figure 1.3 Relationship between Nordic power prices and carbon prices*



Source: Nordpool and EEX

## 2. Introduction

During the first period of the Kyoto protocol, EU has committed to reduce their emissions of greenhouse gases (GHG) by 8% compared to 1990 levels. Emission trading is one of the so-called flexible mechanisms in the Kyoto protocol, and the purpose is to achieve the emission reduction targets at the lowest possible cost for society. Emission trading will put a cost on CO<sub>2</sub>-emissions, and will thus affect many industries. The electricity industry will be affected through an increase in the marginal cost of producing electricity in fossil fuelled plants. Prices in the wholesale electricity market are primarily determined by the marginal cost of the marginal plant, i.e. by the marginal cost of the most expensive plant in use in the relevant time period.

On 1<sup>st</sup> January 2005 the European Union (EU) implemented a scheme for trading with emission allowances. During the first trading period 2005-2007 the EU Emission Trading Scheme (EU ETS) covers only CO<sub>2</sub> and there is no international commitment to reduce the emissions. The second trading period for EU ETS parallels the first period of the Kyoto protocol, 2008-2012.

ECON has previously been commissioned by the Nordic Council of Ministers to analyse supply and demand to make a price forecast for these emission allowances in the EU ETS and its likely effect on the price of electricity in the Nordic power market (ECON, 2004b).

The analysis in that report was based on the 14 National allocation plans (NAP) that were available as of June 2004 and drafts from additional four member states. ECON has now been commissioned by the Nordic Council of Ministers to make an updated analysis based on new information. More specifically the assignment included the following tasks:

- An update of the status for NAPs for all EU member states, including changes caused by the Commissions approval of the plans.
- An estimate of the effect on prices of emission allowances due to these changes.
- A comparison between observed prices on emission allowances and our forecast including a discussion of the reasons for possible differences.
- An analysis of the effect on electricity prices in the Nordic countries and in other European Union member states.
- A discussion of the effects of the Russian ratification of the Kyoto protocol.

In the above-mentioned previous ECON report, results of model simulation using ECON's Nordic power market model were reported. This assignment does not include new model simulations, but based primarily on previous simulations an assessment of the likely short- and long-term effects on the electricity price in the Nordic countries is made. Furthermore a comparison with other European electricity markets, mainly those with dominant fossil fuelled power generation, should be conducted.

## Outline of the Memo

The remainder of this memo is organised in five sections. First we present our analysis of the net demand for emission allowances (section 3). Secondly, we compare the demand estimates with the supply of emission allowances to provide an indication of the possible market balance and prices of the allowances and compare with observed prices on emission allowances (section 4). We then continue with a discussion of the possible effects of Russia's ratification of the Kyoto protocol (section 5). Finally we discuss which effects that the emissions trading will have on electricity prices (section 6).

In this memo the results from the updated analysis are presented. For a more detailed description of background and methods we refer to the previous ECON report (ECON 2004b).

## 3. Net Demand for Allowances

All member states of the EU will allocate emission allowances for CO<sub>2</sub> during the first EU ETS period. By comparing these allocations with expected emissions in Business As Usual (BAU) scenarios for CO<sub>2</sub>-emissions, we get a net demand for emission allowances in the various countries.

Assessment on the basis of additional information now available does not change the fundamental conclusion in our previous report (ECON, 2004b). Estimates of net demand for allowances across the EU-25 region in the first trading period remain modest. Participants with a shortage of allowances seem to a large degree to be offset by surplus allocation to other participants and the need to reduce emissions below business-as-usual levels seem to be limited.

### 3.1 Status of NAPs

The allocation process in the EU ETS has almost been finalised. All Member States have submitted their NAPs to the European Commission and most of these NAPs have been reviewed and approved by the Commission. Exceptions are NAPs of the Czech Republic, Italy and Greece, which have not yet been approved.

During review the Commission have demanded cuts in proposed allocation levels of several countries, in particular among the new member states. The NAPs have in all these cases failed to fulfil one of the key criteria for approval, that NAPs must not allocate more allowances than projected emissions. The Commission have assessed the emission growth implied by the proposed allocation level and deemed this excessive compared to reasonable business-as-usual developments. Table 3.1 shows the cuts resulting from the Commission reviews undertaken so far.

**Table 3.1 Allocation cuts during Commission review**

|             | Required cut, Mt CO <sub>2</sub><br>per year | In pct. of proposed<br>allocation level |
|-------------|----------------------------------------------|-----------------------------------------|
| Poland      | 47.1                                         | 16.5%                                   |
| Lithuania   | 1.3                                          | 9.6%                                    |
| Belgium     | 0.7                                          | 1.1%                                    |
| Estonia     | 2.7                                          | 12.5%                                   |
| France      | 1.5                                          | 0.9%                                    |
| Latvia      | 1.9                                          | 29.0%                                   |
| Luxembourg  | 0.2                                          | 4.4%                                    |
| Portugal    | 0.7                                          | 1.8%                                    |
| Slovakia    | 5.0                                          | 14.0%                                   |
| Austria     | 0.1                                          | 0.3%                                    |
| Ireland     | 0.2                                          | 0.7%                                    |
| Netherlands | 3.0                                          | 3.2%                                    |

Source: European Commission press releases

The largest cut is clearly in the Polish NAP. Poland is discontent with the cut, which was concluded 8 March 2005, and immediately announced that it intends to try the issue in the European Court. Whether this will actually be carried through or is just a show for the domestic audience remains to be seen.

After Commission review the UK has announced that it intends to increase its allocation level during the first trading period by 19.6 MtCO<sub>2</sub>. This naturally requires Commission acceptance. It is currently uncertain whether the Commission will accept this. One reason for this is that other countries might follow suit and wish to increase their allocation level. Slovakia has already been mentioned as one such country.

Based on the information presently available, about 2.200 MtCO<sub>2</sub> will be allocated annually in the EU ETS. The allocation levels of individual countries are shown in table 3.2. Allocation levels compared to historical emissions reported by Member States in their NAPs are in most cases allowing industry to increase CO<sub>2</sub> emissions.

**Table 3.2 Allocation levels in NAPs, Mt CO<sub>2</sub> per year**

|             | Base year emissions <sup>1)</sup> | Total allocation | Reserves |
|-------------|-----------------------------------|------------------|----------|
| Austria     | 30,2                              | 33,0             | 1,0      |
| Belgium     | 59,3                              | 62,9             | 3,0      |
| Denmark     | 30,9                              | 33,5             | 2,6      |
| Finland     | 41,2                              | 45,5             | 0,8      |
| France      | 138,7                             | 156,5            | 5,7      |
| Germany     | 501,0                             | 499,0            | 4,5      |
| Greece      | 70,9                              | 74,4             | 3,2      |
| Ireland     | 20,9                              | 22,3             | 0,7      |
| Italy       | 224,0                             | 240,7            | 38,9     |
| Netherlands | 95,9                              | 95,5             | 2,5      |
| Portugal    | 36,6                              | 38,2             | 3,1      |
| Spain       | 174,5                             | 172,3            | 6,3      |
| Sweden      | 20,2                              | 22,9             | 1,8      |
| UK          | 245,9                             | 252,0            | 16,6     |
| Czech Rep.  | 89,0                              | 107,7            | 4,0      |
| Hungary     | 29,4                              | 29,9             | 1,3      |
| Estonia     | 15,9                              | 19,0             | 0,6      |
| Latvia      | 4,2                               | 4,6              | 0,5      |
| Lithuania   | 8,5                               | 12,3             | 0,8      |
| Slovakia    | 26,7                              | 30,5             | 0,7      |
| Poland      | 219,8                             | 239,1            | 8,8      |
| Total       | 2 083,7                           | 2191,7           | 107,4    |

Source: Member States NAPs as submitted and adjusted during assessment by the European Commission as of 11 March 2005

Note:

1) Member States have chosen different reference periods for allocating allowances. Base year emissions in the table are thus shown as average annual emission in the chosen period or as emissions in a single year. In some cases figures include emissions from installations below 20 MW and thus overestimates emission levels or rely on secondary sources.

2) Due to their modest size in the market, Cyprus, Malta, Slovenia and Luxembourg are not considered

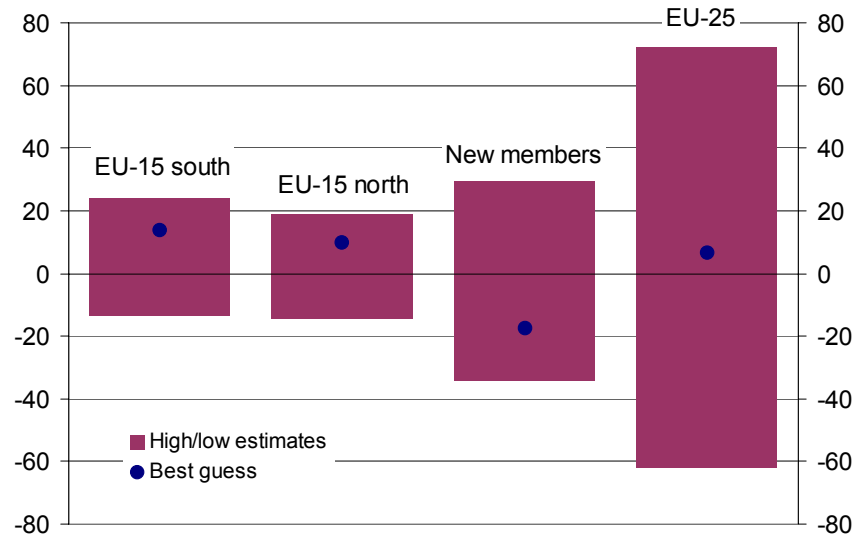
### 3.2 Net Demand

We have estimated the requirement for emission reductions – or the net demand – in the EU ETS based on emission caps provided in NAPs and projected business-as-usual emissions provided either in NAPs or in national communications submitted to the United Nations Framework Convention on Climate Change (UNFCCC). More specifically we have used projections in the national communications to identify expected emission growth rates for the energy and industry sectors. These growth rates are applied to the base year emissions shown in table 3.2 to generate an alternative business-as-usual emission development for the ETS sectors. In cases where countries have provided new projections in their NAP, we thus have two business-as-usual emission developments, which are used as high and low estimates.

Comparisons for each country of the volume of NAPs cap to business-as-usual emissions, provides an estimate of the possible shortages of emission allowances at the national level. In other words, we estimate the net demand for emission reductions. Adding estimates for all countries provides an indication of the overall requirement to reduce emissions in the ETS sector in the enlarged EU. Estimates aggregated on major areas of the EU are shown in figure 3.1. A positive number implies that there is a shortage of allowances and emissions either need to be reduced or additional allowances bought on the market.

For the EU-25 region as a whole we estimate a maximum net demand (shortages of EU allowances) of 72 million tonne CO<sub>2</sub>. There could however also be a net surplus of allowances as high as 62 million tonne CO<sub>2</sub>.

We assume that Commission review of the remaining NAPs will result in allocation cuts of 20 million tonne CO<sub>2</sub> per year. It is further assumed that the UK will not be allowed to increase its allocation level by 6.5 million tonnes CO<sub>2</sub> per year. Our best guess is a net demand of 10 million tonnes CO<sub>2</sub> i.e. close to zero for the first period of the EU ETS. This represents a modest increase compared to the previous study. This reflects that NAPs in EU-15 countries are not very restrictive and any net demand could for a large part be covered by a surplus in the new member countries.

Figure 3.1 Net demand for emission reductions in the EU ETS, annual demand in Mt CO<sub>2</sub>

Source: ECON

Note: EU-15 south include Spain, Portugal, France, Italy, Greece, Austria and Belgium; EU-15 north include Germany, UK, Ireland, the Netherlands, Denmark, Sweden and Finland; new members include Czech Republic, Hungary, Estonia, Latvia, Lithuania, Slovak Republic and Poland. Cyprus, Malta, Slovenia and Luxembourg are not included due to their limit size.

### *Changes from Previous Study*

Compared to our previous report (ECON, 2004b) estimates for the regions have changed for a number of reasons.

#### EU-15 South:

- Actual allocation levels have, as we regarded as very likely in the previous report, proved to be higher than the calculated levels in the previous report. Demand thus tends to be reduced, and both the high and low demand estimates are lower now. Our best guess is also reduced, but the region remains the largest net demander of allowances.

#### EU-15 North:

- Required cuts in allocation levels during Commission review and new emission projections in the UK have resulted in a small increase to the high demand estimate.
- The low estimate is substantially increased due to German emission projections. Our previous estimates included emission growth rates from the 3<sup>rd</sup> national communication that show continuously decreasing emissions in the ETS sector. We now find this projection too optimistic, since emissions in the ETS sectors have been more or

less at the same level in the last 5 years. We have thus chosen to exclude this projection altogether from the assessment.

- Our best guess has as a consequence increased from a small surplus allocation to a small demand.

New member countries:

- Emission projections in the NAPs are generally higher than provided in the national communications. High demand estimates are thus increased and reflects uncertainty as to the level of growth after full membership to the EU.
- Even though Commission review has resulted in cuts, the allocation levels of the NAPs are larger than our previous assessment. The low demand estimate is thus reduced, which reflect a potentially higher surplus of allowances.

### 3.3 Uncertainty

There is considerable uncertainty about our estimates for both NAPs and BAU-forecasts.

#### *NAPs*

The process of determining allocation levels in the first trading period is coming to a close. This reduces the uncertainty about the fundamental basis for demand in the first trading period of the EU ETS. Uncertainty, as reflected by the high and low estimates in figure 3.1, does however remain high for several reasons:

- It is uncertain whether Commission review of the remaining three NAPs will result in allocation cuts as we have assumed. Furthermore, acceptance of the additional allocation that the UK intends to undertake may result in additional allocations in other countries as well. Similarly, legal challenges to Commission decisions by e.g. Poland can potentially result in adjustments to allocation levels.
- There is uncertainty around the projections of business-as-usual emission developments. The fact that some Member States have produced new projections that differ from those included in their national communication illustrate this. It is in particular uncertain whether emission growth rates in the new member countries will increase as expected domestically or will continue at a more modest level.
- Not all allowances allocated in a country might eventually be available to the market. Reserves to new entrants will only be issued if there are in fact new entrants eligible to receive allowances. Most

Member States are expected to sell excess allowances on the market, while others like Germany will cancel any excess allowances.

#### *Business-as-usual Development*

There is a considerable uncertainty about the development of emissions in ETS sectors. Member States projections, which we have based our estimates on, can in some instances be viewed as political wish thinking, overestimating the effect of policies and measures. The impact of mitigation efforts can in some cases reflect the political intentions and agreements rather than an objective assessment of expected emission reductions that can be achieved from the decided measures. Development of economic growth, energy prices and technologies may also turn out to deviate from expected levels and increase future emissions.

If projections are too optimistic, more emission reductions will be required by industry than indicated by our estimates and this will result in higher prices of EU allowances.

On the other hand most member states projections have been produced before the final decision to introduce the emissions trading scheme in the EU. Many projections are thus based on a situation without any cost on CO<sub>2</sub> emissions in industry. The price of CO<sub>2</sub> emissions introduced by the EU ETS should be expected to reduce emission levels in industry. Most projections have also been produced before recent increases in energy prices, which also will contribute to limit emissions.



## 4. Market Balance and the Price on Emission Allowances

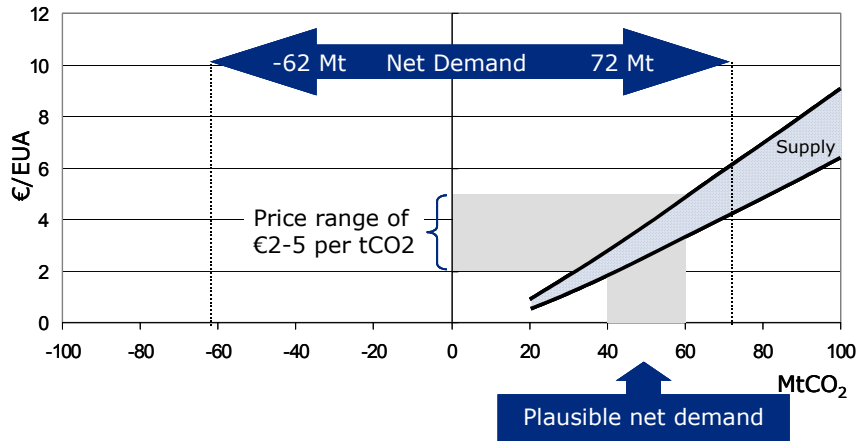
To get the market balance and price on emission allowances *at the end of the first period of EU ETS*, we combine the net demand found in the previous section with our estimates of the supply curve. Banking of allowances in the EU ETS from the first to the second period will generally not be allowed by member states. The first phase will thus be distinct from the second and prices largely independent. We hence do not need to consider the second phase when forecasting the emissions price in the first period.

The updated demand relationship of the previous section provides only minor adjustments to the price of emission allowances estimated at €1-5 per tonne CO<sub>2</sub> in our previous report (ECON, 2004b).

### 4.1 Price of Allowances

The updated demand estimate for the 2005 – 2007 period is shown in figure 4.1 together with the same supply curve as used in the previous study. The supply curve is equal to an ordering of the abatement costs from the possible emission reductions. As in the previous report, CDM is not included and any supply of CDM credits (CERs) will add to the supply side. Even though developments of CDM projects have progressed since summer, progress is still rather slow. It remains the case that only a limited number of projects exist in the pipeline and only 2 projects have reached final registration in the CDM executive board. Furthermore, a large share of the resulting carbon credits of existing projects have already been contracted by governments and multilateral organisations, which are not likely to offer these credits for sale. Furthermore CDM credits might turn out to be priced higher than EU allowances, since they can be banked to the 2<sup>nd</sup> period from 2008 to 2012 contrary to EU allowances. It is thus not clear that linking to CDM will be able to have any significant impact on prices of EU allowances in the first period.

Figure 4.1 Market balance in first trading period of the EU ETS



Source: ECON

With a net demand of 10 million tonne CO<sub>2</sub>, the price will be close to zero. We do however not find this very likely for two reasons:

- Our estimate on 10 MtCO<sub>2</sub> is *net* demand. *Gross* demand will however be much larger since some participants will be short (need to buy emission allowances) and others will be long (can sell emission allowances). With very low prices, transaction costs will not be neglectable compared to the potential income from sales of a small volume of allowances. Combined with the fact that not all participants will know exactly their total emissions, this may lead some of the participants to have an excess of allowances at the end of the period. These emission allowances will not enter into the market.
- The reserves kept for new entrants by authorities might hold excess allowance at the end of the period. According to NAPs most governments intend to sell any surplus, but some may for political reasons refrain from this option, especially if the market tend to be flooded by allowances.

Our estimates of net demand do not take capture such behavioural aspects and imperfections. A net demand of 40 – 60 million tonne CO<sub>2</sub> could thus be plausible and result in an eventual price level between € 2 and € 5 per tonne CO<sub>2</sub> in the first period.

## 4.2 Uncertainty

We will however emphasize the uncertainty in our estimate. In addition to the uncertainties about NAPs and the Business As Usual scenario, there are several other uncertain aspects.

*Costs of Emission Reductions*

The supply curve for emission allowances is the same as applied in our previous report. The potentials and associated costs of reducing emissions are as mentioned in the report quite uncertain and rely on a range of assumptions on future economic development, relative fuel prices, technological development and regulatory framework on energy markets.

We also assume that the European carbon market is perfect so that the cheapest emission reductions will be pursued regardless of their location in the enlarged EU. There will be barriers preventing a perfect market solution, which will increase the costs of emission reductions and the price of EU allowances. Differences across borders in the way allowances and transactions are treated is one notable example that will change the actual cost of supplying an EU allowance as well as the willingness to pay.

*Disincentives to reduce emissions*

There are uncertainties concerning the allocation plans for the first Kyoto commitment period, 2008-2012. One issue that might have implications on the EUA prices in the current period is the possible use of grandfathering in the first commitment period. If, for example, the allocation is based on the participants' emission levels until 2006, there are lower incentives for "early" emission reductions, and therefore an increased (decreased) demand (supply) for EAUs during these years. This would result in higher EUA prices.

### 4.3 Comparison with Observed Prices on Emission Allowances

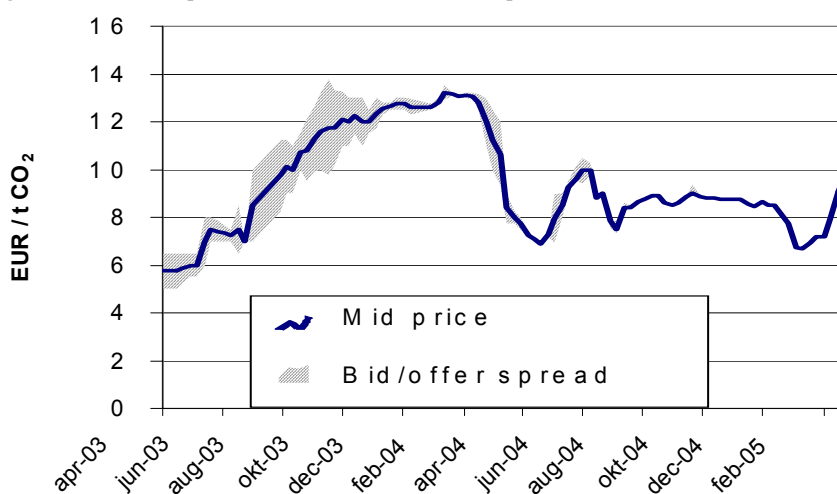
Emission allowances have been traded through brokers (over-the-counter or OTC) for about two years, expecting the EU ETS to come into force. On 11<sup>th</sup> February 2005, NordPool launched exchange trading and clearing of emission allowances. NordPool currently offers trade with forwards for physical delivery in December 2005, 2006 and 2007.

In Figure 4.2 historical prices on emission allowances from April 2003 to the beginning of March 2005 are provided. The prices in the figure are based on information from PointCarbon, which is a company specialized in market intelligence for the emerging carbon market. It is a volume-weighted assessment based on a combination of OTC brokered trades and volumes traded on the exchanges. So far traded volumes are rather low. Most participants have not started active trading yet. The market is still very much in a learning phase, and the trades usually involve rather small volumes (a few trades a day each in the size of 5000 –

20000 EUA<sup>2</sup>). However, the bid/offer spread is now very low indicating a fairly well functioning market.

During the autumn of 2004 prices varied between approximately € 8.5 and 9 per tonne CO<sub>2</sub>. When the EU ETS were implemented we saw a sharp decline in the prices from about € 8.5 in the end of December 2004 to below € 7 in the middle of January 2005. During February 2005 prices started to increase again and towards beginning/mid of March a sharp increase was observed with prices above 10 per tonne CO<sub>2</sub> (on 9<sup>th</sup> March the price was € 10.75).

Figure 4.2 Observed prices on emission allowances, April 2003 – March 2005, €/tCO<sub>2</sub>



Source: Pointcarbon

Our estimate for a likely price interval is thus clearly below observed prices. The observed prices are currently about twice as high as the upper bound in our “best-guess” interval and at the level, which we in our analysis concluded to be “unlikely”. When comparing our results with the observed prices it is important to note that there are good reasons for the market price to develop over time.

Our price estimates relates to the final market clearing in April 2008 and the price pattern until then is highly uncertain. Each year, no later than the 30<sup>th</sup> April, the participants have to hand in the right amount of emission allowances, i.e., the amount corresponding to the emission levels during the previous year. Since the allocation of new allowances should be made no later than the 28<sup>th</sup> February each year the participants can borrow from the coming year to meet last years obligations. This means that the final market clearing for the period 2005-2007 does not have to take place until April 2008. As already pointed out, there is a large uncertainty about net demand and supply as well as possible strate-

<sup>2</sup> European Union Allowance (EUA)

gic behaviour of the participants when it comes to emissions reductions. This uncertainty is also relevant for the participants. They do not know the value of an emission allowance at the end of the period. The price may hence fluctuate as the expectations vary (incorrectly or due to new information) over time.

Uncertainty gives rise to a risk premium, i.e. the price in the market equals the expected value *plus a risk premium*. The risk premium may be either positive or negative. It depends on the relative risk aversion between the sellers and buyers of emissions allowances. With low expected price it is however reasonable to assume that the risk premium is positive since the price of an allowance cannot be negative, but can be much higher than €2-5/MtCO<sub>2</sub>. We hence find it reasonable that the observed price level is above our best guess.



## 5. Effect of Russia's Ratification

With Russia's decision to ratify the Kyoto Protocol in November 2004, the Protocol finally entered into force in February 2005, seven years after agreement in the UN. Of primary importance for prices in the EU ETS, Russia's ratification imply that there will be a larger supply available at the international carbon market, which potentially can support lower prices than would otherwise be the case. The impact on the EU ETS will depend on how Russia is able to access the EU market and what level of constraints could be expected on the supply/demand relationship.

### *Reduced Risk*

A first observation is that Russia's ratification has removed the single most important risk element in the carbon market overall. Countries will in fact be bound by their commitments under the Protocol, and demand in the international carbon market is reinforced. Ratification additionally removes any remaining uncertainty on the need for the EU to maintain the emission trading scheme post 2008.

Even though risk has been reduced, this did not have any impact on forward prices in the EU market. They remained stable around the time of ratification in Russia. One reason could be that market participants had already factored in a positive ratification decision. More likely is it though that Russia's ratification is far more significant to long-term developments and hardly will have any impact on the first trading period of the EU ETS.

### *No Impact in the First Period of EU ETS*

The lack of impact relates to the fact that Russia will not change the short-term supply in the EU market.

The Linking Directive that was approved in the fall allows CDM credits to be imported and used in the EU ETS in the first trading period. It is however not an option to get Russian emission allowances since, according to the linking directive, JI credits will not carry any validity before 2008. This is consistent with Kyoto Protocol, where JI projects cannot earn credits before 2008. Projects in Russia will thus not be able provide any additional supply in the short term.

Any supply into the EU would have to be through linking to a domestic Russian emissions trading scheme. This would require that a scheme be established in Russia and conclusion of an agreement whereby allow-

ances would be mutually recognized in each scheme. With less than three years left of the first trading scheme this is highly unlikely.

Since Russia will not be able to affect supply in the first trading period of the EU ETS, no major impact on prices should be expected. The fact that prices in the first period of the EU ETS will be distinct from prices in the Kyoto period from 2008 to 2012 only reiterate this point.

### *Russian Supply Post 2008*

It is commonly accepted that Russia both has a significant potential for cost efficient emission reductions and has a surplus allowances under the Kyoto Protocol commitments. The World Bank has conservatively estimated a Russian supply of 200 million tonne CO<sub>2</sub> per year in the international carbon market. The figure is uncertain and could potentially be substantially higher and sufficient to satisfy all international demand.

There are three different ways for Russian supply to enter into the EU market and the extent to which these are brought into play are largely uncertain at this moment. The three ways are:

- Participants in the EU ETS can import JI credits for compliance purposes, which they are allowed to under the Linking Directive
- Increased allowance allocations in the 2<sup>nd</sup> period made possible through Government acquisition of the Russian assigned amount units (AAUs) or JI credits
- Direct linking of a domestic Russian ETS with the EU scheme

### *JI Credits*

Under the first option the Linking Directive requires national authorities to approve the credits for compliance purposes and thus to approve the underlying project from which the credits originate. The Directive furthermore requires that Member States determine quantitative limits on the amount of JI and CDM credits to be imported in each country. The limits will be determined in NAPs for the 2<sup>nd</sup> trading period and will thus remain uncertain for at least another year. During negotiations of the Directive limits between 6-8% were discussed. Applying this across all countries would result in a maximum demand of 130-180 million tonne CO<sub>2</sub> per year. Demand will be further constrained if some EU countries decide to apply lower limits. Constraints in demand will prevent price equalization and result in higher prices in the EU.

Secondly, it is difficult to see that JI should be able to support a supply of the magnitude indicated by the World Bank magnitude. With an average project size of 0.5 to 1 million tonnes CO<sub>2</sub> over the 2008-2012 period this would require development and approval of 1,000-2,000 JI projects in Russia within the next 2½ years. Project development activi-

ties at this level seem unrealistic in the current situation where Russian criteria and procedures for JI approval are not yet put into place.

#### *Government Acquisitions of the Russian Assigned Amount units (AAUs)*

The second option with government purchases does not imply any immediate constraints on Russian supply. The Kyoto Protocol requires the use of Kyoto mechanisms to be supplemental to domestic action, but strict quantitative limits have not been agreed upon. It is however uncertain to what extent EU governments will turn to this option in their 2<sup>nd</sup> period NAPs instead of putting tougher burdens on industry and whether government spending will be allowed for purchasing surplus Russian allowances ("hot air"). Indications are that many EU governments will in fact not wish to purchase surplus allowances, but only rely on JI credits. The Russian government has furthermore indicated that it will not bring large amounts of surplus allowances to the market. Government officials have indicated a supply of 2-3% of all Russian allowances equivalent to 60-90 million tonnes CO<sub>2</sub> per year.

Neither does it seem likely that supply will be unconstrained since Russia does not have an interest in driving down carbon prices. Economic analysis indicates that Russia will get maximum revenue under the Kyoto Protocol by constraining their supply.

#### *Direct Linking of a Domestic Russian ETS with the EU Scheme*

Direct linking to a domestic Russian emission trading schemes or green investment scheme seem to be the only way that unconstrained demand in the EU and full cost equalization can really be realized. This will however require that Russia establish a domestic ETS, which in the EU is viewed as credible and resulting in real emission reductions below business-as-usual emission developments and also that Russia meets extra criteria in the Kyoto protocol. There is an interest among Russian industries and in the government to pursue this option, but it is not clear that industry will accept a design with sufficient compatibility to EU priorities. Even if this should be the case it will take time, possibly two to three years, to put in place a domestic scheme in Russia and additional time to conclude an agreement on mutual recognition of allowances with the EU. At best a direct link could thus be established from 2008-2009 and possibly not until the post 2012 period.

*Conclusion*

The Russian ratification does not have any impact on prices in the first period of the EU ETS. It will however affect prices in the second period. Supply constraints will result in increased competition for JI and CDM credits among purchasers, which besides operators in the EU ETS include EU governments as well as Japanese and Canadian purchasers. Constraints will put an upward pressure on prices.

## 6. Effect on Electricity Prices

The previous study included an analysis of the impact of on power prices in the North European market based on simulations with ECON's power market model. Before recollecting the main results, we present some general theory and comments about the way emissions prices are transferred to power prices.

### 6.1 Theory

#### *Marginal vs. Average Carbon Intensity*

The first important determinant for the effect of emissions trading on European electricity prices is the carbon intensity of the production technologies used in different market areas. It is however important to note that the effect on electricity prices should not be determined by the average carbon intensity in the electricity sector, but by the marginal carbon intensity. This means that countries with a very large proportion of non-carbon emitting production technologies (e.g. the NordPool area and France), but were the marginal production stem from carbon emitting facilities the price increase might be substantial.

#### *Short Run vs. Long Run Costs*

Secondly, price determinants may differ between different market areas. In over-supplied and fragmented markets short-run marginal cost pricing should be the primary determinant. One such example is UK. In under-supplied areas the pricing is, or will eventually be, determined by the cost of new entry. Iberia is one such market. The NordPool area is at least moving towards a situation of under-supply. So far prices are not primarily set by the cost of new entry, but will most likely do so in the future. Some market areas may, for instance due to lacking competition, be in between these two cases, with prices above short-run marginal cost but below the cost of new entry.

#### *Perfect Competition vs. Market Power*

The degree of marginal cost pass-through into higher electricity prices can be affected by the market structure and the degree of market power. In a perfect competitive market marginal cost increases should be directly pass-through into higher prices. With market power the link is less direct.

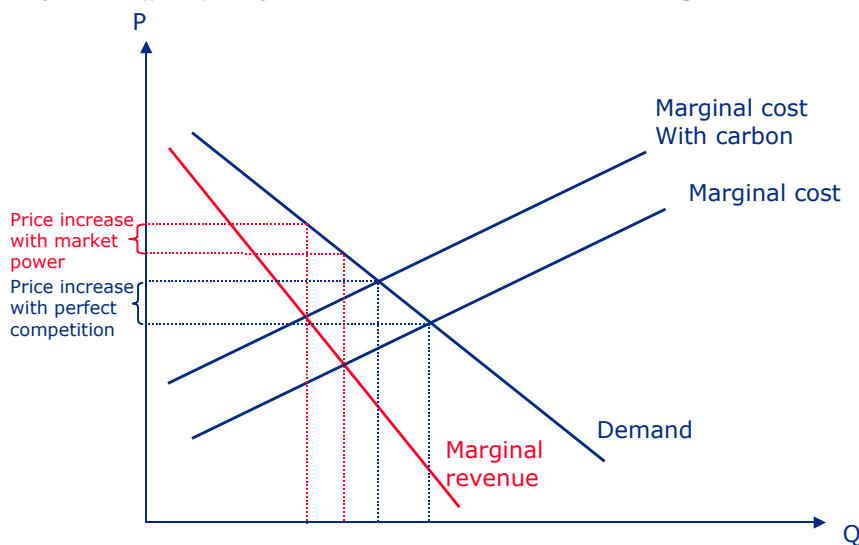
In the case where current prices are above marginal cost but below the cost of new entry there might not be any effect on prices at all.

In more general terms, disregarding any effects from new entry, full marginal cost pass-through may not be consistent with profit maximizing behaviour of firms with market power. This is illustrated with an example. In perfect competition a profit-maximizing firm sets its price (or choose its quantity) such that the price equals the firm's marginal cost. A change in marginal cost thus leads to a reduction in produced quantity and an increase in the price so that this equality still holds.

With market power the marginal revenue of a firm no longer equals the price of the product. This is due to the fact that an increase in the quantity produced will be accompanied with lower price -- as long as there is some demand elasticity. The profit-maximizing quantity is now chosen so that the firm's marginal revenue equals its marginal cost, and it is this equality that should be restored after a change in the marginal cost. In the example showed here the price effect is lower with market power than without. If market power is an important factor in the market it is thus harder to predict the actual pass-through into higher prices.

One may argue that there is no price elasticity in the power market. In the very short run this may be true for some of the power markets (but not for the Nordic market where industry reduces its consumption with high prices). Producers with market power will however probably also look at the longer run price elasticity. Even if consumption is not reduced immediately when prices are increased, the price increase may in the longer run for instance increase the users' effort to save electricity.

Figure 6.1 *Effect of marginal cost increase with and without market power*



### *Regulated vs. Market Based Prices*

Deregulation in Europe is furthermore an ongoing process, where different countries are in very different stages. The effect of differences in the regulation of the industry might also have an effect, especially on the pass-through into retail prices. The regulatory response might also be affected by the initial allocation of the allowances.<sup>3</sup>

## 6.2 Simulation of the North European Power Market

The previous ECON report (ECON, 2004b) included an analysis of the possible effects on the price of electricity based on model simulations using ECON's Nordic power market model. We formulated three different scenarios for the price of emission allowances (see Table 6.1) and conducted simulations for three different years 2006, 2008 and 2012.

**Table 6.1 Scenarios for emission prices, €/tonne CO<sub>2</sub>**

|           | Low price scenario | Medium price scenario | High price scenario |
|-----------|--------------------|-----------------------|---------------------|
| 2005-2007 | 1                  | 5                     | 8                   |
| 2008-2012 | 5                  | 8                     | 15                  |

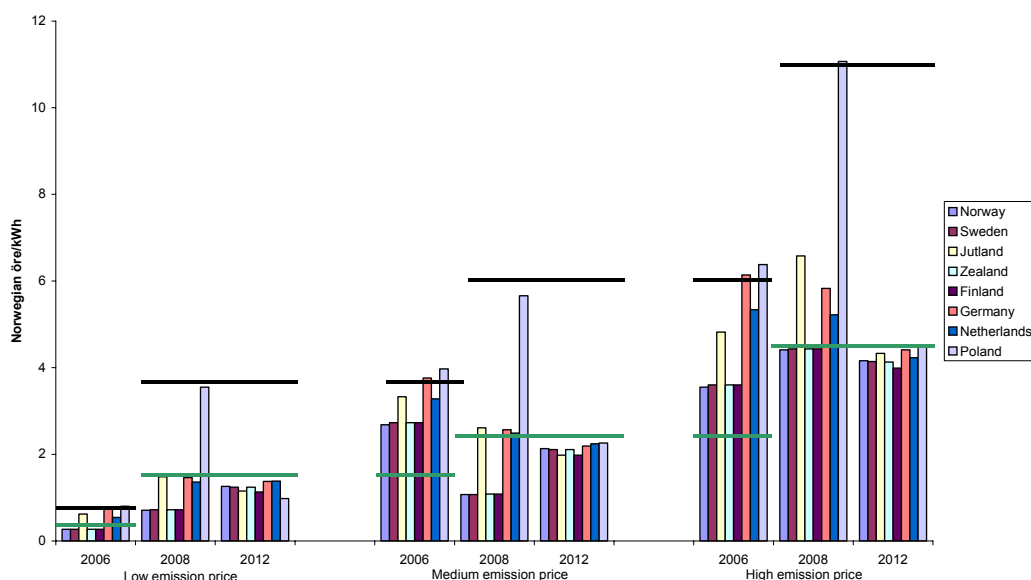
The scenarios for emission allowance prices were based on the supply-demand analysis of the European allowance market. Our “best-guess” estimate of the prices were then in the range € 1-5 per tonne CO<sub>2</sub> for the period 2005-2007 and we concluded that prices higher than € 8 per tonne were unlikely during the first trading period.

Our updated analysis indicates a likely price range of € 2-5 per tonne CO<sub>2</sub>. While the lowest possible price level has been increased as outlined in section 4, the upper bound is unchanged compared to the previous analysis. That would indicate that the medium price scenario is the most relevant scenario for the period 2005-2007. Given normal precipitation levels the effect on electricity prices in 2006 in the medium price scenario is according to the model simulations 2.7 Norwegian øre/kWh in the Nordic countries, except Jutland. In Jutland the price effect according to the simulations will be 3.3 øre/kWh.

In Figure 6.2 the simulation results regarding the effect on electricity price in 2006, 2008 and 2012 given the three emission price scenarios are presented. In addition the figure contains horizontal lines that indicate the increase in marginal costs for modern CCGT plants (the lower line of each pair) and coal-fired plants (the upper line of each pair).

<sup>3</sup> In general the initial allocation can affect the investments in the sector, but should not affect the short-term profit maximization. It has been speculated that the initial allocation might affect the urgency with which generators seek to raise prices. That should however at maximum be a temporary effect.

Figure 6.2 Effect on marginal cost and electricity price from emissions trading, Norwegian øre/kWh



Source: ECON

The model simulations presented above show that the price increase is substantially higher in the thermal based areas of Jutland, Germany, Poland and the Netherlands. These model simulations are based on an assumption of perfectly competitive markets and as long as the market is not capacity constrained prices are determined by the system marginal cost. Basically this leads to full marginal cost pass-through into higher wholesale prices.<sup>4</sup>

In the longer run the price effect of emissions trading is, according to the simulations, similar in all the countries included in the analysis. The reason is that prices eventually will be determined by the cost of CCGT in all the areas (new entry).

#### *Other Model Results from the Previous Study*

The simulations results above are for a so-called normal year, i.e., a year with normal precipitation levels and temperatures. Simulations were also made for extreme wet and dry years. The results showed similar effects in a wet year, except for Jutland where the price effect was lower in a wet year compared with a normal year. The simulations for an extreme dry year showed the interesting, but perhaps surprising, result that the effect on electricity prices in the Nordic countries (except Jutland) from emissions trading is almost negligible in an extreme dry year, according to the simulations. The main explanation is that prices increase a lot in an ex-

<sup>4</sup> In reality we do not always see a full pass-through primarily due to the step-wise supply curve that characterizes the electricity market. This was discussed in ECON (2004b).

treme dry year and primarily are determined by the energy constraint. This means that electricity prices without emissions trading already are above the marginal costs and an increase in marginal costs of fossil fuelled power plants have almost no effect on prices. As discussed above the emission allowances are currently traded at a much higher level than our analysis suggests, which makes it relevant to also discuss the price effect in the high emission price scenario. In the high allowance price scenario (€ 8 per tonne CO<sub>2</sub> in 2005-2007) the model simulations suggest a price increase of 3.6 øre/kWh in the Nordic countries, except Jutland and 4.8 øre/kWh in Jutland. In an earlier study even higher prices on emission allowances were used (ECON, 2004a). The effect on electricity prices in 2006 with a price of € 10 per tonne CO<sub>2</sub> was in that study 6.2–6.4 Swedish öre/kWh (approximately 5.6–5.8 Norwegian øre/kWh) given normal precipitation levels. In that study the effect on prices were highest in a normal year, and lower both in a wet and dry year.

### 6.3 Can Price Increases Be Observed?

Trying to identify actual price changes caused by the implementation of the EU ETS is not an easy task. An important factor complicating any such analysis is the large amount of hydropower in the Nordic power system, which introduces a dynamic element in the supply curves.

A hydropower producer is not directly affected by the introduction of emission allowances, since it does not need any allowances for its production. The direct marginal cost of the hydropower producer is thus unaffected. However, the relevant cost measure for a hydro producer with a reservoir is not the operational costs, but the opportunity costs of giving up production in another time period.

If a hydropower producer expects prices to rise at a later time it is rational for that producer to hold back production. With all hydropower producers acting this way the current power price will be pushed up and the price in the future will be reduced. There is equilibrium when current prices equal expectations of future prices plus a risk premium. It is hence no reason to expect prices to have any sharp increase when EU ETS came into force. Rather we would expect to see a continuous increase in price as the probability of the EU ETS increased.

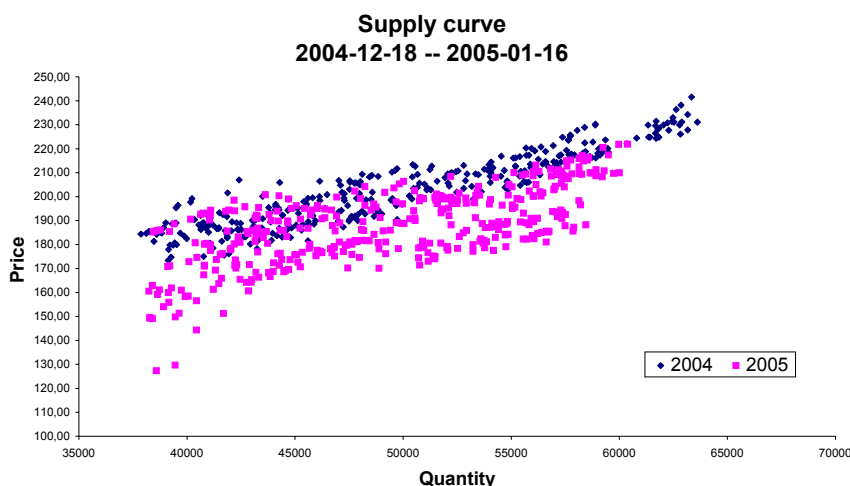
There are however limitations to which extent the production can be shifted from one period to another. First of all the storage capacity in the hydro reservoirs might make it impossible to store as much water as the producer ideally would like to. It is therefore not possible to study the price development over a longer time period.

Furthermore, changes in expectations regarding reservoir levels may change the relevant marginal cost (measured as opportunity cost) quite drastically even over only a short period of time. To identify shifts in the

supply curve due to the introduction of emissions trading we would need bid data for the carbon emitting plants. We do not have access to such data.

In Figure 6.3 the total production levels in Denmark, Finland, Norway and Sweden and the system price on NordPool for each hour during the period 18<sup>th</sup> December 2004 to 16<sup>th</sup> January 2005 are plotted. This can be seen as supply curves for that period. As expected it is not possible from this plot to identify an upward shift in the supply curve between the latter half of December 2004 and the first half of January 2005. On the contrary it seems like the supply curve has shifted downwards from 2004 to 2005, which can be explained by the improved hydrological situation.

Figure 6.3 Supply curve in the Nordic power market, 2004-12-18--2005-01-16



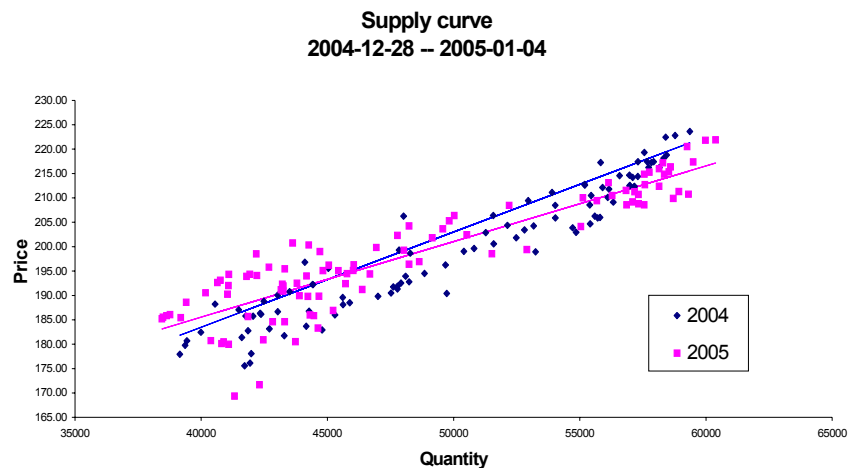
Source: NordPool

Around the turn of the year 2004/05 the reservoir situation improved, which should have affected the water values and pushed prices downwards. This is a likely explanation to the apparent downward shift in the supply curve. Therefore we have also studied the prices and quantities for an even shorter time period, which is shown in Figure 6.4. During that short time period the effect on the water values should have been limited, and the spread in prices is also smaller. For low quantities the supply curve seem to have shifted somewhat upwards between 2004 and 2005, but there is no such indication when demand is higher. The change is however small and it is quite hard to find an explanation for such a change based on the implementation of emissions trading. The hydro producer will try to shift as much production as possible from the low load to higher load segments, and that behaviour should not have been affected by possible higher high load prices.

One additional problem with trying to identify price effects at that particular point of time is that the water reservoir levels were quite high and

demand fairly low due to relative high temperatures. This meant that there was little coal power production, the technology for which the possibilities to identify supply curve shifts are the best.

Figure 6.4 Supply curve in the Nordic power market, 2004-12-28 -- 2005-01-04



Source: NordPool

## 6.4 Other Studies of Price Effects

We know that the both the deregulation process and the market structure varies quite a lot between different European countries, which is might give raise to differences in marginal cost pass-through. Also other companies have analysed the effect of carbon trading.

### 6.4.1 ILEX

In a study made on behalf of the UK Department of Trade and Industry (ILEX, July 2004) the issue of pass-through in different European countries are discussed. It is concluded that in the NordPool area, Germany, France, the Netherlands, UK and Ireland<sup>5</sup> there will be 100% cost pass-through into higher wholesale prices. In the case of France this is primarily caused by the link to German prices. In the two other countries included in the study the pass-through the wholesale prices is estimated to be 0% in Italy and 8% in Spain. The motivation is that regulatory intervention will prevent prices from increasing more than actual average cost increases. Cost pass-through into retail prices is believed to be very limited in France (only average cost pass-through of 2.5%) and small also in Ireland (23%).

<sup>5</sup> In the case of Ireland it is suggested that 100% pass-through might first occur in 2006.

#### 6.4.2 CSFB

The supply conditions and the effect from emissions trading on electricity prices in a number of European electricity markets (UK, Scandinavia, Central Europe, Iberia, Italy and Greece) are analysed in a study by CSFB (2003). Estimates are made on the proportion of different fuels setting the prices in different markets. The estimates made for the UK suggests that prices is set by CCGT in 45% of the time, by coal in 45% of the time and by oil/gas in 10% of the time. The corresponding numbers for Scandinavia was 60% by nuclear and hydro, 30% by coal and 10% by oil and gas.<sup>6</sup> In these two market areas short-run marginal cost was seen as the most important determinant for prices. Areas such as Iberia and Italy are seen as areas where the cost of new entry set prices, implying that the cost of CCGT determines prices 100% of the time. Finally, in the Central European countries (e.g. France and Germany) are seen as hybrid markets where neither the short-run marginal cost nor the cost of new entry sets the price. Prices are above the short-run marginal cost but below the cost of new entry.

The implication of the analysis made by CSFB is that in the UK and Scandinavia electricity prices will increase with the change in marginal cost, implying an electricity price increase by 6 €/MWh in the UK and by 3.1 €/MWh in Scandinavia given an value of carbon on 9.2 \$/tonne CO<sub>2</sub>.<sup>7</sup>

In the Central European countries the introduction of carbon trading will, according to CSFB, not lift the marginal cost above current prices. Their conclusion is thus that prices will not be affected at all in the short run. In Iberia prices will increase with between 1.0 and 3.7 €/MWh (given a price on carbon of 9.2 €/tonne). The upper bound on this range is determined by the cost increase for new entry. However, regulations on plants built before 1998 (all but new CCGT) may limit the increase. The special stranded-cost tariffs are valid until 2011, and after full cost pass-through should occur. Finally in Italy prices are determined by the cost of new entry, so the price increase will be 3.7 €/MWh.

### 6.5 Conclusions on Electricity Prices

According to ECON's opinion prices in the NordPool area will in the long run be determined by the cost of new entry, which primarily should be new CCGT. Also in the Northern European thermal based systems older plants will be replaced by CCGT and that will determine prices.

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<sup>6</sup> In ECON's opinion the estimation that nuclear and hydro sets prices in 60% of the time in the Scandinavian market seems like a clear exaggeration, and that fossil fuel production is price setting during a larger share of the year.

<sup>7</sup> CSFB estimates the carbon value for EU-15 only of 9.2 €/tonne CO<sub>2</sub>.

Thus, at least in a few years time the Northern and Central European countries should experience similar price effect due to emissions trading.

In the UK substantial amounts of CCGT base load capacity have been added during the last decade. No substantial additions will be made during the coming years and prices will thus be determined the marginal cost of existing plants. The effect of emissions trading will thus depend on the increase in marginal cost for CCGT and coal fired power plants.

In the short-run the effects may differ more. If current prices in some countries are pushed above the short-run marginal cost due to market power of incumbent producers, these countries may experience smaller price increases compared with today's prices. Furthermore, the deregulation process is in different stages in different areas. Regulatory issues may therefore have an effect. This should however primarily relate to the retail market, and less to the wholesale market.



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