Relationship between CO₂,
fuel and electricity prices
and the effect on Green
House Gas (GHG)
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Preface

The European Union emissions trading scheme (EU ETS) has reached the end of the first phase (2005 to 2007) and the market has moved on to the next phase, which runs from 2008 to 2012. This report is divided into two main parts. The part first looks back at the evidence to date to assess what effect the EU ETS has had on power prices and emission levels in the Nordic region. The report provides a description of the EU ETS and shows how the Nordic countries have fared so far in terms of their emission levels relative to their allocations.

The report looks at the level of pass-through of CO₂ costs into power prices, the price drivers and price levels in the Nordic region as well as the effect on the level of emissions from the sectors covered by the EU ETS due to both weather and fuel price considerations. The first part is concluded by looking at the key lessons learned from phase 1, which inform the modelling and forecasts described in the second part of the report.

The second part of the report looks at phase 2 and provides information on the market fundamentals and key price drivers. We present several carbon price scenarios using our proprietary Carbon Price Forecaster model and use these scenarios within our mid-term Nordic power model to examine the impact of CO₂/fuel prices and hydro inflow levels on NordPool system prices, level of power flows between countries, generation levels and emissions.

The report has been prepared by Point Carbon. The opinions contained in this report are those of Point Carbon. While Point Carbon considers that the information contained, analysis presented and opinions expressed are all sound, all parties must rely on their own judgement when using the information contained in this report. Point Carbon makes no representations or warranty, expressed or implied, as to the accuracy or completeness of such information. Point Carbon will not assume any liability to any party for loss or damage arising out of the provision of this report.

The Electricity Market Working Group and the Climate Change Policy Working Group does not necessarily share the views and conclusions of the report, but looks at it as a contribution to our knowledge about the EU Emission Trading Scheme.

Oslo, March 2008

Jon Engebretsen

Chairman Chairman

Climate Change Policy

Working Group

Copenhagen, March 2008

Flemming G. Nielsen

Electricity Market Working Group

Summary

The EU Emissions Trading Scheme (EU ETS) has moved from the first phase (2005–7), which has really been a trial or learning period, to the second phase (2008–12), which runs in parallel with the first Kyoto commitment period. This is therefore an appropriate time to look back and assess the impacts of the EU ETS on Nordic power prices and emissions, and to use these findings to forecast what is likely to occur during phase 2.

The EU allowance (EUA) price has been volatile during the three years of the first phase with prices between 30 euros per tonne and 3 euro cents. The market went from a perception of being short to actually turning out to be significantly long (as witnessed in the verified emissions in 2005 and 2006), which has led to low prices towards the end of the phase.

The Nordic countries covered by the EU ETS in phase 1 (Sweden, Denmark and Finland) have had higher allocations than emissions, which is in line with the overall picture in EU27. The exception is Denmark, in which 2006 emissions from EU ETS sectors were some 20 per cent higher than 2005 emissions. This shows how sensitive Danish emissions are to weather and the hydrological situation in Norway and Sweden.

The power sector is the most important sector within the EU ETS as this is the largest sector, with around 60% of allowances, and also it is the most dynamic in terms of its trading and optimising behaviour – essentially basing generation output levels on prevailing fuel, CO₂ and power prices. This has, at times, led to strong correlations between CO₂ prices and fuel prices, particularly during 2005, when the market perceived that it was fundamentally short and that fuel switching from coal to gas plants was required to reduce emission levels.

Analysis of the correlations shows that near-term gas and coal prices have only had periodic and limited effect on the CO₂ price to date. There has, however, been a much higher correlation between oil and CO₂ prices, as European gas prices are indexed to oil-based products. Although this correlation broke down towards the end of the first phase, we expect that this will be an important CO₂ price driver during the second phase.

Weather impacts on the power sector by affecting by demand but also the supply (level of renewable generation). Weather had a much higher correlation to changes in the EUA price at the beginning of the scheme, when the market perceived it was short. Like fuels, we no longer see weather necessarily being a key driving factor of the EUA price for the remainder of the first phase. We do expect that it will become important again in the second phase of the EU ETS, especially during the winter periods.

Power prices

The introduction of the EU ETS has had a significant impact on power prices across Europe. The cost of CO₂ is added to the marginal production cost of thermal power plants, which feeds through into electricity prices. In most power systems, the marginal price is usually set by coal or gas plant, and this means that all plants (including non-emitting plants) will benefit from increased power prices. This increases the relative competitiveness of low-emitting generation such as nuclear, renewables and plants with carbon capture and sequestration.

Analysis of forward spreads (the difference between fuel cost and power prices) is a useful way of examining the level of pass-through of CO₂ costs into power prices. The NordPool region is a complex system to assess using this form of analysis as underlying forward spreads are strongly influenced by expectations of hydro generation. However, it is evident that the underlying forward spreads in Nordpool have followed the lead of the German market, responding slowly to the introduction of the scheme but now passing through a reasonably high level of the CO₂ price into the forward prices. This suggests that the main impact of the EU ETS on Nordpool has been through the trade with Germany – which often is seen as setting the marginal value of water in this system. German forward prices appear to be pricing in the full cost of the CO₂ price into the forward prices, whilst the NordPool region has lower levels of around 50% (due to the very high level of non-thermal generation and the important impact this has on power prices).

The level of total energy reservoir is a key price driver in the Nord-Pool market. Since 2005, there has been a change in the relationship between these variables (see figure below). Initially there was a break in the high correlation, although this has since been re-established. The correlations between the two factors are still present currently but the spot price level has remained at a high level in 2005–7, well above the level predicted if the historic relationship between total energy reservoir and NordPool spot price had persisted. This clearly demonstrates the effect of higher priced thermal power imports from Denmark and Germany (in periods of low energy reservoir levels) due to the onset of carbon pricing.

NordPool spot prices (€/MWh) and energy reservoir levels (TWh; deviation below normal)

Volatility has also increased in the European power markets as both power and CO₂ prices react to some of the same fundamentals. This is evident to a large extent in the NordPool market although it is not possible to isolate the effect of the EU ETS compared to other fuel-price effects.

Emissions variability

The level of emissions in the Nordic power sector is also volatile, which is primarily due to the level of energy reservoir in the Nordic region (see figure below). The average annual emissions over the period 1990 to 2006 are 56 Mt. The highest emission levels over this same period are 78 Mt (in 1996), which gives a surge in Nordic power emissions of 22 Mt in one year of low rainfall. Denmark has the highest average emissions and the highest level of variability.

Power sector emission levels and energy reservoir levels (deviation below normal)

As well as hydro levels, temperature also affects emissions through the consumption of power, which is particularly evident in Sweden, Norway and Finland with high power consumption for domestic heating. There is

quite a low potential for fuel switching in Nordic countries and so the effect of changing fuel prices on emissions is limited. The main effects of changing fuel prices will be through the relative change in power generating costs and the level of imports from neighbouring countries.

Phase 2

Phase 2 of the EU ETS runs from 2008 to 2012, and is closely linked with the international carbon market. One key change between the first and second phase is that banking of allowances is allowed in phase 2, which means that price signals post-2012 will have an impact on prices during phase 2.

We present several carbon price scenarios using our proprietary Carbon Price Forecaster model and use these scenarios within our mid-term Nordic power model to examine the impact of CO₂/fuel prices and hydro inflow levels on NordPool system prices, level of power flows between countries, generation levels and emissions.

The model that we have used to forecast prices and emission levels is ideal for the hydro-dominated Nordic system, as this allows us to examine the impact both from fuel/CO₂ prices and hydrological conditions (which are used in the model to calculate the water values with optimisation under uncertainty).

The fuel and carbon price scenarios used are shown in the figure below. Our central assumption for CO₂ prices in phase 2 is currently €25/tonne (average price over the five year period). The high and the low scenarios assume that the oil price is increased or decreased, respectively, by 25%, whilst the coal price is kept constant so that the relativity between coal and oil/gas prices can be explored. The "central – high CO₂" scenario uses the same fuel prices as the central scenario, but assumes a post-2012 price of €35/tonne (consistent with a situation of increased global participation in the carbon market with tight targets) that gives rise to an increase phase 2 price of €32/tonne.

Fuel and carbon price scenarios (2008 to 2009)

Scenario	Central	Central - High CO ₂	High	Low
CO ₂ price (€/t)	25	32	32	17
Coal price (\$/t)	81.3	81.3	81.3	81.3
Oil price (\$/bbl)*	72	72	90	54

* Gas prices and HFO prices are linked to the oil price

Model results – power prices

The average annual forecast NordPool system price in 2008 for the central scenario is €46.3/MWh. This result is based on the average of all the 150 inflow scenarios for this model run. The impact of the inflow level on system prices is significant with a decrease of 40 TWh hydro genera-

tion in 2008 increasing the annual average price by €2.80/MWh, and an increase of 40 TWh decreasing prices by €3.60/MWh.

Average annual system prices for all scenarios (€/MWh)

Scenario	2008	2009
Central	46.3	47.3
- 10% inflow	49.1	51.7
- 90% inflow	42.7	43.7
Low	39.2	42.4
High	51.8	53.1
Central – high CO₂	50.9	53.2

Both the "central – high CO₂" and "high" scenario have a higher CO₂ price (€32/tonne) than in the central scenario (€25/tonne) but the high scenario also has an oil price that is 25% higher. The system prices for these two scenarios are very close together, which suggests that the effect of increased CO₂ prices is the main driver of power prices and that oil prices do not have that much of an effect on Nordic prices. This is due to the fact that the majority of gas plants run as CHP and that power output is not a function of the cost of production, but rather the level of heat output required. Also, coal prices set the marginal power price in Germany and so it is the increased CO₂ cost on top of coal prices that increases German power prices, hence pulling up the Nordic prices.

Increasing the CO₂ price by €/tonne in the central scenario, increases power prices by around €5.6/MWh, which represents a very high level of pass-through into Nordic power prices (90%). With the same fuel and CO₂ prices, but using a higher inflow level, the apparent level of CO₂ cost pass-through into Nordic prices is much lower (30%). This shows that the cost of CO₂ is passed through to a high degree into Nordic power prices but that this increase can be offset by healthy hydrological conditions, which exert a bearish impact on power prices. This demonstrates that Nordic power prices cannot be analysed just on the basis of either the CO₂ price influence or hydrological conditions – these must be considered together. This is particularly important for regulators to bear in mind when setting the level of allocations within the power sector.

Higher prices post-2012 will have an effect on phase 2 EUA prices due to the ability to bank allowances between phases. This effectively raises the "floor" price in phase 2 as operators will seek to optimise their position through time. This in turn means that power prices in the EU, including the NordPool region, will increase as the CO₂ price increases. So if there is a bullish signal for phase 3 prices, based on the anticipation of tighter supply/demand fundamentals in the post-Kyoto period, this could have a direct effect now on increasing Nordic power prices, through raising the phase 2 CO₂ price.

Model results – Nordic power sector emissions

It is not that clear cut in terms of how a high EUA price would affect Nordic power sector emissions. A higher CO₂ price should also serve to lower emissions, through switching generation from coal to gas, but there is not much switching potential in the Nordic region, which means that changes in hydro generation and the level of imports have a greater impact on the level of emissions.

In the central scenario, when hydro generation in 2008 decreases by around 18%, emissions increase by around 12% (from 47 to 53 Mt). Conversely, with a high inflow scenario and increased hydro production of 19%, emissions decrease by around 12%. The range of emissions variability between the low and high inflow scenario is even greater (17.5 Mt) in 2009, due to the lower energy reservoir level.

With changes in fuel/CO₂ prices in the other scenarios, the effect on emissions is limited. In years with high energy reservoir levels, the effect of fuel price changes is limited to within a narrow range of 2 Mt/year, although again this depends on both the level of hydro generation but also the level of net imports from countries interconnected to the Nordic region.

When the level of hydro generation varies from year to year, the emissions from gas and HFO plants are relatively constant under the different inflow scenarios and, within the Nordic region, it is the coal-based emissions that change, reflecting the fact that coal plants respond to the change in level of hydro generation. This emissions increase is noticed mostly in Denmark, which has the highest amount of coal plant, and to a lesser extent in Finland too. We note that any additional net imports to the Nordic region will also result in increased emissions in neighbouring interconnected due to lower hydro imports from the Nordic region and more thermal exports.

Summary of power sector emissions in Nordic region for all scenarios (Mt/year)

Scenario	2008	2009
Central	47.1	48.0
- 10% inflow	52.8	57.8
- 90% inflow	41.4	40.3
Low	46.3	52.7
High	46.0	49.1
Central – high CO₂	45.1	49.8

1. EU ETS phase 1 (2005–2007)

1.1 Structure of the EU ETS

The 15 Member States that made up the EU until its enlargement to 25 countries on 1 May 2004 are committed to reducing their combined emissions of greenhouse gases by 8% from 1990 levels by the end of the Kyoto Protocol's first commitment period 2008–12. This overall target has been translated into differentiated emission reduction or limitation targets for each Member State under a 'burden sharing' agreement. The 10 new Member States are not covered by the EU target but have their own reduction target of 6% or 8% under the protocol, except for Cyprus and Malta which have no targets. However, all Member States are full participants in the EU trading scheme.

Basic Features

The ETS has been established through binding legislation proposed by the European Commission and approved by the EU Member States and the European Parliament. The scheme is based on six fundamental principles:

- It is a 'cap-and-trade' system;
- Its initial focus is on CO₂ from big industrial emitters;
- Implementation is taking place in phases, with periodic reviews and opportunities for expansion to other gases and sectors;
- Allocation plans for emission allowances are decided periodically;
- It includes a strong compliance framework;
- The market is EU-wide but taps emission reduction opportunities in the rest of the world through the link to the Kyoto Protocol's Clean Development Mechanism (CDM) and Joint Implementation (JI), and provides for links with compatible schemes in third countries.

Emission Allowances

At the heart of the ETS is the common trading 'currency' of emission allowances. One allowance (EUA) represents the right to emit one tonne of CO₂. Member States have drawn up national allocation plans for 2005–07 which give each installation in the scheme a certain number of allowances free of charge, thus allowing it to emit the corresponding amount of CO₂ without any cost. Decisions on the allocations are made public.

The limit or 'cap' on the number of allowances allocated creates the scarcity needed for a trading market to emerge. Companies that keep their emissions below the level of their allowances are able to sell their excess allowances at a price determined by supply and demand at that time. Those facing difficulty in remaining within their emissions limit have a choice between

taking measures to reduce their emissions, such as investing in more efficient technology or using a less carbon-intensive energy source, buying the extra allowances they need at the market rate, or a combination of the two, whichever is cheapest. Theoretically, this ensures that emissions are reduced in the most cost-effective way.

Most allowances are allocated to installations free of charge – at least 95% during the initial phase and at least 90% in the second phase from 2008 to 2012.

A key aspect of the EU scheme is that it allows companies to use credits from Kyoto's project-based mechanisms, joint implementation (JI) and the clean development mechanism (CDM), to help them comply with their obligations under the scheme. This means the system not only provides a cost-effective means for EU-based industries to cut their emissions but also creates additional incentives for businesses to invest in emission-reduction projects elsewhere, for example in Russia and developing countries.

Coverage

While emissions trading has the potential to involve many sectors of the economy and all the greenhouse gases controlled by the Kyoto Protocol (CO₂, methane, nitrous oxide, hydro-fluorocarbons, perfluorocarbons and sulphur hexafluoride), the scope of the ETS is intentionally limited during its initial phase while experience of emissions trading is built up.

Consequently, during the first trading period from 2005 to 2007, the ETS covers only CO₂ emissions from large emitters in the power and heat generation industry and in selected energy-intensive industrial sectors: combustion plants, oil refineries, coke ovens, iron and steel plants and factories making cement, glass, lime, bricks, ceramics, pulp and paper. A size threshold based on production capacity or output determines which plants in these sectors are included in the scheme.

Even with this limited scope, close to 11 500 installations in the 25 Member States are covered, accounting for around 45% of the EU's total CO₂ emissions or about 30% of its overall greenhouse gas emissions. By early 2008, the Commission is due to present a report reviewing the functioning of the scheme. The review will allow fine-tuning it in the light of the experience gained and to consider whether it should be extended to additional sectors and more greenhouse gases.

National allocation plans

Member States' national allocation plans (NAP's) have to be based on objective and transparent criteria, including a set of common rules that are laid down in the legislative framework establishing the ETS. The most important of these rules are listed below.

- An allocation plan has to reflect a Member State's Kyoto target as well as its actual and projected progress towards meeting it. The total quantity of allowances allocated is key in this regard. Allocating too many allowances would mean that greater efforts to cut emissions would have to be taken in economic sectors not covered by the scheme, in potentially less cost-effective ways than trading;
- Allocations to installations must take account of their potential for reducing emissions from each of their activities, and must not be higher than the installations are likely to need;
- Where Member States intend to use JI and CDM credits to help them reach their national emission target – thereby giving their companies more scope to emit – these plans must be substantiated, for example through budgetary provisions.

The European Commission has issued specific guidance on how these rules are to be applied by Member States. The Commission assesses NAP's on the basis of these rules, as well as EU rules on State aid and competition, and has the power to require changes or even to reject a plan altogether. Once it approves a plan, the total quantity of allowances cannot be changed; nor can the number of allowances per installation following the final allocation by the Member State.

The National Allocation Plans (NAPs), developed by each member state and approved by the Commission, set the overall structure of EU ETS by outlining the upper level of allowances to be issued (the caps) and how these are allocated to sectors and individual installations within in each Member State (MS). The EU Commission (EC) has approved in total 6.3 billion allowances to be issued for the period 2005–2007, excluding allowances set aside to new installations, resulting in an average of 2.1 billion allowances to be distributed each year. However, MS' initial applications were for even more. The EC ended up cutting almost 300 Mt of allowances, or more than 4% of the total volume, from the initial volumes of allowances as submitted in the draft NAP's.

The annual average cap is distributed among the MS's as shown in Figure 1 Germany is by far the MS with highest number of allowances (488 Mt/year), followed by Italy, Poland and the UK pending around 250 Mt each for the first trading period, and France and Spain around 150 Mt. Together, these six countries constitute 71% of the total allowances in the market.

Figure 1. EU member states with more than 100 Mt in aggregated allocations for the 2005–2007 period. Emissions in ETS sectors in 1990, 2003 and allocated in 2005, in Mt CO₂

Within each MS the allowances are allocated to existing installations in five main sectors. Figure 2 illustrates the distribution of allowances between these. The power & heat sector is by far the largest sector, accounting for 55% of all allowances in the system, making the EU ETS primarily dependant on activities and changes within this sector.

Figure 2. Total EU ETS allocations on sector level, aggregate for 2005–2007 period, in Mt CO₂

Source: Point Carbon

Compliance control

At the end of April each year, installations must surrender a number of allowances equivalent to their verified CO₂ emissions in the previous calendar year. These allowances are then cancelled so they cannot be used again. Those installations with allowances left over can sell them or save them for next year (generally within Phase 1 only). Those that have not produced enough allowances to cover their emissions will have to pay a dissuasive fine for each excess tonne emitted. In the initial phase the penalty is EUR 40 per tonne, but from 2008 it will rise to EUR 100. Operators also have to obtain allowances to make up the shortfall in the following year, and they will be publicly named by Member States.

There have already been two verification and “true-up” period in May 2006 and 2007, when the results from the previous year were made public. There is one further “true-up” period during Phase 1, which will occur in May 2008.

True-ups

The EU ETS market is a function of the actual *emissions* from the ETS sectors and the *cap* which determines the number of ETS allowances available for the sectors covered by the trading scheme. The overall cap can be separated into two main parts, allocation to existing installations and the reserves of allowances (NER) needed for new installations or for auctions.

The equation *emissions* minus *cap* represents the estimated CO₂ emissions across all countries and sectors less the total quantity of allowances allocated to installations (includes the initial allocation to existing installations and the volumes contained in the various reserves). A positive value for this “emissions-to-cap”-figure signifies a shortage of the EU ETS (emissions higher than the cap), whilst a negative value signifies that the EU ETS is long, see text box below.

Emissions-to-cap (E-t-C)

The statistic “emissions-to-cap” (E-t-C) is found for any given unit – be that an installation, sector or country – by calculating its total emissions minus its total cap. The cap is given as the sum of EU allowances (EUAs) allocated to the unit in a given year. A positive E-t-C number, as seen for example in the short power and heat sector, thus means a greater amount of emissions than the number of allowances allocated for the year. Conversely, negative numbers, as seen in the other sectors, means that an entity has a surplus of allowances, which may then be sold.

The 2005 true-ups, where member states published verified emissions for the first trading year, nevertheless revealed that the EC had been too generous in setting the caps for phase 1, resulting in a market that is fundamentally long for the whole period, as seen in the negative emissions-to-cap values see Table 1.

2005 and 2006 data represent verified emission figures downloaded from the Community Independent Transaction Log (CITL) where available. Point Carbon's proprietary emission forecasting model is used to estimate and forecast emissions 2007.

Table 1. Emission-to cap for phase 1 of the EU ETS

	E-t-C, Mt CO ₂
2005	- 96,1
2006	- 60,6
2007 (forecast)	- 88,2
Total 2005-7 (forecast)	- 244,9

The 2006 true-ups showed an increase of 22 million tonnes of CO₂ emissions from 2006 Mt in 2005 to 288 Mt in 2006. The emission increase of 1.1 per cent can mainly be attributed to three main factors:

- Increased power demand and production;
- Increased industrial production; and
- Lower hydro production in the Nordic region.

At the same time, power sector emissions fell in France and Iberia, particularly in Spain, amid favourable hydro levels. Power production in the EU area was up by 1.5 per cent and industrial production also grew more than industrial emissions, as carbon emission intensity improved across the board. Despite the intensity improvement, the increased emissions across the board demonstrate that significant internal abatement has yet to happen in the EU ETS.

Obviously, over-supply of allowances in phase 1 means there is little incentive to reduce emissions. Nevertheless, a survey conducted by Point Carbon suggests that abatement activities have been initiated in a significant number of installations. Representatives for 1020 installations responded to the survey, accounting for around ten per cent of EU ETS emissions (212 Mt). More than half of these said they had started abatement projects, particularly through energy efficiency and fuel switching. While internal abatement is in its infancy, greater reductions in phase 2 may have a significant impact on the balance between emissions and allowances.

The implications for EUA-prices of over-supply of allowances in Phase 1 are discussed further in section 2.2.

1.2 EU ETS in Nordic countries

As members of the EU, Denmark, Finland and Sweden have been covered by the EU Emissions trading scheme from the outset, while Norway and Iceland have not. Following a lengthy negotiation process among Norway, Iceland and Lichtenstein (as members of the European Economic Area, EEA) and between EEA and the European Commission, it now seems clear that the directive will cover these countries as well in the

second phase of the trading scheme. In Norway, however, a national emissions trading scheme with quite similar provisions as the EU ETS has been in force since 1st January 2005.

The overall picture for the Nordic countries is very much in line with the general tendencies for phase 1 throughout the EU. As discussed before, phase 1 is structurally long, and for the three Nordic countries covered by the EU ETS, allocations outstrip emissions in the 2005–7 period, giving negative emissions-to-cap values.

This is also true for all countries in the individual years within the period as shown in Figure 3, with the exception of Denmark in 2006, where emissions from the traded sector were some 20 per cent higher than both 2005 emissions and the emissions expected for 2007. This shows how sensitive Danish emissions are to weather and the hydrological situation in Norway and Sweden.

Figure 3. Emissions-to-cap in the Nordic countries covered by the EU ETS, 2005 and 2006

Source: Emissions-to-cap = emissions minus cap

Broken down to sector level, the general picture in the EU ETS is that industry sectors have been allocated a more than sufficient number of allowances to cover their emissions, while installations in the power and heat sectors have had to purchase allowances in order to be in compliance.

Figure 4 and Figure 5 show sector wise emissions-to-cap numbers in the Nordic countries for 2005 and 2006 respectively. The most evident feature looking at trends for the Nordic countries is the change in power sector positions from 2005 to 2006. While the power sector is overall long in 2005 (with the exception of Sweden), verified numbers for 2006 show an overall short position for this sector. This is most evident for Denmark, and can again be explained by the fact that emissions were higher in 2006 due to the below-average hydro situation that year.

Figure 4. Sectoral emissions-to-cap numbers for Nordic countries covered by the EU ETS, 2005

Figure 5. Sectoral emissions-to-cap numbers for Nordic countries covered by the EU ETS, 2006

1.3 Carbon price developments

In the EU ETS, as in every commodity market, the price is determined by the relationship between supply and demand. In this case, the demand for allowances is determined by the relationship between CO₂ emissions and the cap. Greater distance between these indicates a higher demand. The supply is determined by the amounts of EU allowances (EUAs) and Certified Emission Reductions (CERs) from CDM projects brought to the market. In addition to the EUAs already allocated to existing installations through the NAP process, allowances issued to new entrants and/or through auction of NER surplus will increase the supply.

The price drivers for the EU ETS are discussed further in section 2.2 in relation to phase 2.

1.3.1 Prices to date

Figure 6. Price of EU Allowances (EUA 07) from December 04 up to November 06

Source: Piont Carbon

Since the introduction of the EU ETS, EUA prices have traded showing a number of different trends:

- Pre-EU ETS introduction: prices traded in a very tight range with almost no volatility. Prices stayed firmly in the range of 8–9 €/tonne for the six month's leading up to the introduction of the scheme on the back of expectations on expected length of the market. Considerable uncertainty at this time with outstanding decisions on some key NAPs (notably Poland, Italy and the Czech Republic).
- First six months 2005: after a brief period where the prices fell (on the back of unseasonably warm winter weather across Northern Europe), prices began a strong and consistent upward trend from a base of 7 €/tonne that included a speculative bubble in July 2005. During that bubble, prices steeply rose to almost 30 €/tonne before industrial selling brought prices back down to levels around 20 €/tonne.
- Second six months 2005: the EUA price settled into a band between 20 and 25 €/tonne. Trading within that period showed some trending, with upward and downward trends periodically replacing each other.
- First four months of 2006: prices broke out of the 20–25 €/tonne band and rose quickly to 27 €/tonne. Afterwards, prices settled into a more gentle trend increase, gradually going upwards to around 29 €/tonne. Again a rapid increase occurred to take the market over the 30 €/tonne threshold.
- Post May 2005: The market suddenly changed when news of verified emissions for 2005 began to be leaked from a number of countries. A

significant market correction then happened with considerable long positions being closed out quickly and prices collapsing below 10 €/tonne. Following the correction, prices bounced back and subsequently traded at above 15 €/tonne until mid-September.

- Mid-September until present: prices have declined from above 15 €/tonne to below 0.1 €/tonne due to power hedging mainly complete for year-ahead, increased volume from industrial players as well as mild and wet weather conditions throughout Europe.

A simple measure of price variability is given in Figure 7 where the highest and lowest OTC prices for the December 2006 contract are given for each month. Note that the months with the most variability are January, April, May and September 2006. Prices in 2007 have gradually dropped towards to towards around €0.08/tonne by the end of October.

Figure 7. Monthly price variations throughout 2006

1.4 Fuel price developments

1.4.1 Brent Crude

Since 2004, the global oil market has seen fundamental changes in how future price formation is viewed. Until that time, there was a broad consensus among oil market analysts that the long-term cost of bringing additional oil to the market was such to sustain prices for oil in the 20–25 \$/barrel region. The global oil market then would trade in such a way that longer-term priced future oil would be in that range, regardless of what prices were doing in the more near-term contracts.

In 2004, a number of events changed this consensus, including:

- A much tighter prompt market than previous seen, driven largely by a sharp increase in demand from Asia;

- Emerging evidence that the cost of new supply projects (from exploration through to development) was higher than previously seen and in excess of the 20–25 \$/barrel previously assumed;
- A more proactive role by public national oil companies and growing difficulty for private international oil companies to access reserves in the large producing regions such as Russia and Venezuela; and
- Greater credence being given to peak oil theory suggesting that future supplies of oil will be harder to develop.

As a result of these developments, analysts and traders views on future pricing began to be re-valued with no clear evidence emerging about what represents the long-term equilibrium price.

Over the span of phase 1, crude oil prices have continued to grow rapidly. Having broken in 2004 the historical nominal record, they have recently come very close to breaking the all time high price in real terms as well (the real price record was attained during the 1979–80 oil crisis – around \$101/barrel in 2007 prices, depending on the deflator used).

At present, there are two main views over the drivers that are sustaining the oil price at current levels:

- On the one hand is what can be called the “OPEC View”, which maintains that the market is adequately supplied and that speculative capital from hedge funds, investment banks and other large financial players is to blame for the high prices observed in the market. This trend would appear to be growing, as capital moves away from other investment vehicles and into commodity markets.
- The alternative view is the “fundamentals view”, that argues that a new demand paradigm, arising mainly from ballooning consumption in China, India and other fast developing economies, is keeping the supply demand balance very tight.

In reality, it is likely that a combination of these two factors – with possibly a stronger influence from the former than from the latter – is supporting the rising price of the commodity.

Figure 8 illustrates these developments by showing the progression of prices seen in the market for the longer-term delivery of oil (for a month-ahead, year ahead [Y+1] and three years ahead [Y+3]).

Figure 8. History of forward curves for oil (Brent crude)

From this figure, we see that:

- The prompt month price has moved from a price around 30 \$/bbl, to trade consistently around the 60–70 \$/bbl level, reflecting a tight immediate market for crude;
- The price for delivery in three-years has moved upwards each year, from levels of 25 \$/bbl to nearing 70 \$/bbl. During this period, the curve has undergone a number of parallel shifts, with the full curve following the prompt upwards. The curve was previously in backwardation, reflecting greater current concerns than those associated with future delivery. This changed in 2007 with the curve moving into contango, suggesting concerns about meeting future demands becoming greater than those associated with the prompt.

1.4.2 Coal

Like the global oil market, the global steam coal market has recently seen fundamental changes in how future price formation is viewed. Until that time, there was a clear consensus among coal market analysts that the long-term cost of bringing additional coal to the market was low – reflecting continued efficiencies in mining and a long period of reasonably benign prices – particularly in North West Europe.

In 2004, a number of events changed this consensus, including:

- A much tighter prompt market than previous seen, driven largely by a sharp increase in demand from Asia. This sharp increase was initially particularly acute in the freight market, driving CIF (cost including freight) prices high, and then increasingly tight in the underlying commodity (FOB or free on board) prices; and

- Emerging evidence that the cost of new supply projects (from mine-head through to port berthing) was higher than previously seen, due in combination to a shortage of skilled workers and significant price increases for increasingly scarce equipment.

As a result of these developments, analysts' and traders' views on future pricing began to be re-valued, with no clear evidence emerging about what represents the long-term equilibrium price. The forward curves then started to behave much like their counterparts in the oil market – shifting upwards or downwards in line with what is driving the prompt.

Contrary to the oil market however, there is broad consensus among market observers that the rapidly growing Asian economies (mainly from India and China) are the main responsible for tightening the global coal supply-demand balance. The effects of such growth have been felt throughout the entire coal supply chain:

- Rising Asian demand for iron ore and other raw commodities – including steam and coking coal – has tightened the dry bulk shipping market as total vessel capacity has failed to keep up with demand. This has augmented the transport component of delivered coal costs (as well as that of other dry bulk commodities).
- The levels of coal demand from Asian buyers were underestimated by most global producers, resulting in production bottlenecks at nearly every major production site across the world. Port and rail bottlenecks, which have generated long queues of ships waiting to load in Australian ports –one of the world's largest steam coal exporters– have further added to the tightness in the freight market. A similar situation has taken place at iron ore and coking coal export sites.
- The gradual passing of China from a net coal exporter to a net coal importer, which reduced the volumes available for global trade, thus further exacerbating the coal supply-demand imbalance.

Figure 9. Front month (API2) coal price time series (\$/tonne)

1.4.3 Gas

Natural gas has had a different evolutionary path than either oil or coal, in that it has not been predominantly driven in the last few years by developments in Asia. It also has had a different experience with regards to price formation with much of the gas sold on the global market being priced with some relationship to oil. This relationship to oil is due to either:

- Gas supply contracts having direct indexation to oil (either crude or products – such as low sulphur fuel oil or gas oil). This was done historically to ensure that gas would always be lower priced fuel than oil, and this helped encourage the uptake of gas in new markets. To account for the transformation of crude into products, contracts that are directly indexed to crude oil are indexed to crude spot prices with a three to six-month lag (the latter being more common). Oil indexation remains one of the main price-setting drivers for gas in Europe and for much LNG sold into Asia; or
- Gas traded in more liberalised markets retaining an underlying correlation with movements in the oil price. In particular, gas at the US Henry Hub has shown a long-term correlation of 94% with the US crude oil benchmark (WTI) – this being the correlation of annual average prices of the two fuels from 1989 to 2005. Potential explanations for this long-term correlation are:
 - Substitution at the burner tip which means gas producers feel they can price on average up to the price of oil before they begin to lose market share; or
 - Gas and oil are driven by the same primary forces – which appears on the face of it largely unconvincing due to the difference in use between the two fuels; or
 - Gas traders take their positioning from the deeper and more liquid oil markets in making their price decisions on gas.

Regardless of the reason, much price formation in gas markets has been related to developments in the crude oil market. An implication of this is that much of the development of gas markets has been done with prices not providing a significant signal about the state of supply and demand in the gas markets, except during extreme events.

Figure 10. Spot (day ahead) North-European gas price history vs. Lagged crude prices

From the figure we see that:

- Gas prices have remained relatively stable around the 20 €/MWh in nominal terms;
- The price exhibits the seasonality typical of gas prices, with (generally) higher price levels observed during the high demand winter periods and lower prices observed during the lower demand summer.
- Exceptional peaks and troughs in prices tend to appear every so often, usually reflecting supply infrastructure problems, such as outages of storage facilities, compressor station failures or shutdown of major transport pipelines.
- The relatively good correlation to 6-month lagged oil prices (i.e. the oil price six months before the date of the quoted gas price), indicating that prices on liquidly traded markets also follow oil prices to remain competitive with the long term oil indexed gas contracts.

1.5 Observation of correlations

In order to monitor and interrelations between the carbon price and the effect of fuel prices and weather, Point Carbon has developed a unique set of models that provide continuous updates and forecasts of CO₂ production for all sectors in each of the countries covered by the EU ETS. The models draw upon a wide variety of input data and structural information, including for instance detailed information about installations in the power and heat sectors (e.g., installed capacity (MW), efficiency, and availability). This allows us to examine both the correlation of the EUA price with fuel prices but also with the effect that these have on emission levels in the aggregate EU region.

Relative fuel costs

The relative cost of input fuels into power generation will determine which plant is most economical to run at any given time.

The two fuels that are most important in European power markets are gas and coal – and the spot prices of these two commodities (and the CO₂ price) will determine which generation plant will be used and what ultimately will be emissions from the sector. In general, nuclear and most renewable sources of generation (hydro, wind) will operate whenever they are available. Since there is more available generation than demand at any time (as there has to be a margin above peak demand), this means that gas-fired and coal-fired plant will compete for the remainder of the baseload section of the curve.

As both gas and coal have different relative carbon intensities, the CO₂ price may rise to a level to make lower carbon gas-fired generation more competitive than higher carbon coal-fired generation. This will encourage greater use of gas and thereby reduce emissions from the power sector against what they otherwise would have been.

The UK power market is interesting to examine as there is roughly an equal amount of coal and gas-fired generation and there is spare capacity to switch between these depending on the prevailing fuel and carbon prices. Figure 11 shows the costs of generating power using coal against the costs of generating power using gas in the UK – taking into account the fuel and carbon costs of each fuel type as well as average UK plant efficiencies. As this figure shows the cost of coal-fired generation less that of gas-fired generation, a negative number means coal plant is more competitive and a positive number means gas is more competitive.

Figure 11. Costs of UK coal-fired generation against the costs of gas-fired generation

Source: The figure uses ARA coal and NBP (UK) gas prices; coal plant efficiency = 36%; gas plant efficiency = 50%

From this figure, we see that the CO₂ price has been at a level that was, on average:

- Insufficient to encourage generators to switch from using coal-fired plant to using gas-fired plant during the winter months (January–March; October–December) in 2005;
- Sufficient to encourage fuel switching from coal to gas in the summer (April–September) 2005;
- Insufficient to encourage fuel switching from coal to gas throughout 2006;

Possible explanations for this behaviour are that:

- The greatest possibility for fuel switching in the power sector is in the summer as power demand levels are lowest and excess capacity is therefore greatest. As such, the market only priced CO₂ to achieve summer month's fuel switching;
- The market did not see the UK power market as the source of marginal emissions reductions and therefore did not have to follow UK gas prices upwards during the winter months. Rather, the lower continental oil-indexed prices – which sets the summer gas price in the UK – was what the market was pricing itself against throughout the year; or,
- The supply of allowances in the market was sufficient to ensure that the price of CO₂ never needed to rise to levels to ensure fuel switching against market fuel prices in all periods.
- In 2007, coal prices have increased relative to gas, which means that gas-fired generation has been more competitive than coal-fired generation even with a low carbon price.

Brent crude and the CO₂ market

Analysing the correlation of coal and gas prices with CO₂ prices shows that the interaction between markets has only been a periodic driver of the CO₂ price during the first phase. This is because there are specific factors to both gas and coal markets that are driving those markets. There has, however, been a much higher correlation between oil and CO₂ prices. Figure 12 shows how the CO₂ market has traded with the front month oil curve.

Figure 12. Brent crude price and CO₂ price

From this figure, we see that:

- During the initial five month period, participants' view of the scheme was one of increasing tightness with the EC making decisions on some key NAP's and taking almost 60 Mt/CO₂ out of the phase. As the scheme seemed to go from expected length to expected shortness, the EUA price continued to rise and price movements were closely correlated with Brent prices by June 2005;
- After this initial period, the EUA price traded closely with the Brent price, showing very similar trading trends until late April 2006. The measured correlation between the scheme to date is 0.76 – showing the highest consistent correlation between any energy price and the EUA price that we have assessed;
- Since late April 2006, the correlation has broken down as the expectation for the scheme has gone from one of shortness of allowances to one of length. As such, the market no longer trades with any consideration that it may need marginal emissions reductions from the power sector to occur. The measured correlation in May 2006 between the fuels was -0.65 which although reasonably strong, is completely counter-intuitive and simply reflects that while the oil market traded downwards throughout May, the CO₂ market was bouncing back from the strong correction that occurred in late April following the leaking of verified emissions numbers.

An interesting feature of the high correlation between front period Brent and EUAs that occurred prior to late April 2006 is that this has occurred even though there is little oil used by the sectors covered by the EU ETS. Given this, the likely reason for the importance of this as an indicator for the EUA price is that:

- Most long-term contracts for European gas supply include pricing that is directly indexed to either Brent oil prices or to oil-product prices (gas oil and fuel oil). As such, the crude price is seen as a key determinant of future gas prices across Europe. Many traders that will have been trading CO₂ will have been more familiar with oil markets than gas markets (as the only well established market in Europe is the NBP/Zeebrugge market) and thus may have felt more comfortable trading CO₂ in relation to oil;
- In the longer term, as European gas prices decouple from oil prices, we would expect a closer correlation between the CO₂ and gas prices, as this is the actual fuel burnt in power plants.

Key points:

- The CO₂ price has not been high enough to encourage fuel switching from coal to gas in 2006;
- Gas and coal prices have only had periodic and limited effect on the CO₂ price to date;
- There has been a much higher correlation between oil and CO₂ prices;
- The correlation of oil and the CO₂ price has now been broken for the remainder of the first phase of the EU ETS but we expect a correlation to persist for phase 2.

Effect of CO₂ price on fuel prices

Having described the effect that fuel prices have on the CO₂ price, the reverse effect should also be mentioned. In the short-term, the CO₂ price does not influence coal, oil or gas prices as:

- these are driven by their own demand and supply factors; and
- these demand and supply factors are global, which means that the impact of a European CO₂ market does not exert a significant impact on the overall supply/demand balance.

For instance, a lower CO₂ price is likely to make coal generation more competitive relative to gas, which would increase the demand for coal. However, the increase is very small compared to total global coal demand and will not therefore impact prices.

In the longer term, a more structural shift in, say, coal demand could influence prices, especially if other regions outside Europe are also constrained by a CO₂ price.

Gas prices may be more affected by CO₂ prices, especially if prices are based on more local demand and supply factors. In the UK, which has a high potential for fuel-switching, the change in CO₂ price can cause short-term shifts in gas demand as generators optimise their portfolios in

line with running costs. This change in gas demand can have some impact on prices if the demand change is significant with respect to the UK gas market supply/demand fundamentals.

Weather

As well as being sensitive to the relative price of fuels, emissions from the power sector are also sensitive to changes in weather patterns. Weather impacts on the power sector by affecting:

- Demand – with hotter weather driving an increase in the use of air-conditioning load and colder weather driving an increase in heating load; and
- Supply – with hot and dry conditions affecting the availability of hydro and nuclear power generation and wind levels affecting the amount of wind fired generation. As the availability of these types of generation fall, the greater the call on thermal generation.

Point Carbon looks at an aggregate weather variable for all of Europe and combines all of these factors into a single variable. In

Figure 13 Figure we show the rolling 30 day correlation between this aggregated weather variable and the EUA price throughout 2005.

Figure 13. Combined weather variable correlated with the EUA price (2005)

From this chart we see that:

- Changes in weather had a much higher correlation to changes in the EUA price at the beginning of the scheme. Over the first six months of 2005, weather maintained correlations of over 0.8, with particular high correlations throughout the first winter period and in the very hot June period.
- This close relationship began to break-down towards the end of the energy summer and the correlation dropped to below 0.5 from the beginning of the next energy winter (October).

Weather-related effects on emissions were also well correlated with EUA price movements during the winter 06/07 period although this correlation has again decreased during the rest of 2007. Again, like fuels, we no longer see weather necessarily being a key driving factor of the EUA price for the remainder of the first phase. We do expect that it will become important again in the second phase of the EU ETS, especially during the winter periods.

1.6 Analysis of carbon cost pass through into power prices

The introduction of the EU ETS has had a significant impact on power prices across Europe. The theoretical background for this is that in a competitive environment where producers are maximising their profit, the cost of CO₂ should be factored into emitter's generation plans. The carbon cost can be regarded as an opportunity cost; it reflects the forgone value of the allowances used for generation that otherwise could have been sold. This is true irrespective of whether allowances have been provided for free or need to be purchased¹.

The cost of CO₂ is added to the marginal production cost of thermal power plants, which feeds through into electricity prices. In most power systems, the marginal price is usually set by coal or gas plant, and this means that all plants (including non-emitting plants) will benefit from increased power prices. This increases the relative competitiveness of low-emitting generation such as nuclear, renewables and plants with carbon capture and sequestration.

For a thermal power plant, the full CO₂ cost is added to the marginal production cost, thus the CO₂ price comes in addition to the cost of fuel and operation/maintenance (O & M). The EUA cost in €/MWh depends on the plant efficiency rate and the fuel emission factor used at the power plant. Efficiency rates for power plants vary, but in the example in Figure 14 we have used 39% and 55% as representative efficiencies for coal power plants and CCGTs, respectively. These plants emit around 0.87 tonne CO₂/MWh (coal) and 0.38 tonnes CO₂/MWh (CCGT).

¹ Further details on the theory of how cost pass-through affects power prices are included in Appendix

The introduction of EU ETS influences the electricity production costs in EU and also the merit order of the different production technologies. In this example we have used a delivered gas price of €22/MWh and delivered coal price of \$80/tonne. The coal power plant in the example is the cheapest technology if the CO₂ cost is disregarded. With an EUA price of €20/t included, the coal power plant is still more economic to run than CCGT plant, however if the EUA price reaches €35/t, the CCGT plant will become the cheapest technology.

Figure 14. Short run marginal cost (in €/MWh) for a coal and gas fired power plant, EUA price of €20 and €35/t. Delivered fuel prices: gas = €22/MWh and coal = \$80/tonne

Key points:

- The CO₂ cost is regarded as an opportunity cost and is added to the marginal production cost of thermal power plants, which feeds through to wholesale power prices;
- The introduction of EU ETS has influenced the electricity production costs in EU and also the merit order of the different production technologies.

1.7 Level of cost pass-through

In this section we look at evidence of how the power markets important to the NordPool region have responded to date to the introduction of CO₂ pricing:

- The *European Continental market* using the German baseload price as the basis price for this market. The market encompasses Germany, France, Austria and Switzerland which all have prices that have high levels of convergence. This market is characterised by having considerable coal capacity (around 70% of installed thermal capacity in Germany is coal fired) sitting alongside non-CO₂ emitting forms of generation such as nuclear, hydro and wind;

- The *Nordpool market* which brings together the markets of Norway, Sweden, Finland and Denmark. This market is characterised as being dominated by non-CO₂ emitting forms of generation (predominantly hydro). Nordpool does have interconnectors with Continental markets (Germany, Poland) and operates as swing supply in response to hydro availability. As of 2008, a new interconnector between Norway and the Netherlands will become operational.

In looking at the evidence, we focus on looking at power spreads, which take out of the power price the impact of changes in variable (fuel) costs. We look at the coal spreads in the German and Nordpool markets:

- *Dark spread* – the power price less the price of coal adjusted for the efficiency of the coal-fired generation plant; and
- *Dark clean spread* – the dark spread less the price of CO₂ adjusted for the carbon intensity of coal-fired generation.

Spot prices

In general, we expect underlying spreads on a spot basis (price for immediate delivery) to show some variability year-to-year as they depend on the actual marginal price setting plant needed to meet demand and that will be influenced by factors such as the actual number of supply outages, availability of plant such as hydro and nuclear, levels of demand – and many of these are influenced by non-constant factors such as the weather. Given all of things that influence spot prices and spreads, it is more difficult to make definitive conclusions just looking at spot price data. Table 2 shows the spot dark and dark clean spreads in Germany and NordPool.

Table 2. Average annual spot spreads for Germany and NordPool

	All figures €/MWh	2004	2005	2006
Germany	Dark spreads	4.6	31.3	37.5
Germany	Dark Clean spreads		14.9	17.2
Nordpool	Dark spreads	5.0	9.4	25.1
Nordpool	Dark Clean spreads		-7.0	4.8

The very low dark spreads seen throughout 2004 in Germany were quickly replaced with much higher dark spreads – around an average 25 €/MWh impact on the spread. The main drivers of this large increase in underlying coal spreads include:

- 2005 having a number of periods of extreme system stress where average German power prices were driven up high on the back of extreme weather. In the first, at the end of February and beginning of March 2005, severe winter weather caused a huge surge in the marginal price of gas and this pushed up the price of the marginal

peak therm (which is often gas in Germany despite it being largely a coal based system). In the second, in June, unseasonable hot weather reduced hydro availability and again pushed prices up as it required more expensive thermal plant to meet demand. In the third event, in November, extreme winter storms collapsed part of RWE's distribution network and again caused a sustained spike in prices. If we control for the prices associated with these three events (by excluding the 45 days associated with these three events when prices were over 60 €/MWh), this removes around 7 €/MWh from the average dark spread;

- General increase in gas prices between 2004 and 2005. While gas is not always the price setting plant (it is more commonly coal) in this system, the coal spreads will have benefited from the periods gas was being called upon to set prices. We estimate that the increase in the underlying oil indexed contract price was in the order of 30% year-on-year and this will have affected prices in certain periods;
- The CO₂ price. We see that with 100% pass through, this would account for around half of the increase in spreads or around 16 €/MWh.

For the Nordic market, the low dark spreads of 2004 were replaced with only slightly higher average spreads in 2005. With negative average dark clean spreads, this suggests that if CO₂ was influencing spot prices, it was only doing so at a very limited pass-through level. We note that 2005 was a very wet with high hydro reservoir levels, which meant that hydro was setting the marginal price more than in a normal year. The step increase in 2006 dark spreads (and dark-clean spreads) may suggest that a higher proportion of CO₂ prices are being priced into the spot market.

From this discussion, we conclude that for Continental spot prices, there does appear to be convincing evidence that a high level of CO₂ pass-through is occurring. We can draw no firm conclusions about the level of CO₂ price pass through into the low-CO₂ emitting Nordpool market by looking at spot prices as hydro conditions (in addition to other short term factors like demand and transmission flows between regions) mask the CO₂ impact.

Forward prices

Instead we look at forward prices (future delivery) as these have less year-to-year variability. Forward spreads more reflect participants expectations of average future outcomes (as this influences their willingness to pay for a hedge) and these tend to be more constant. Indeed, these are more influenced by expected changes in annual demand and supply patterns and these only change gradually year to year. In undertaking the analysis, we looked at how the year-ahead (Y+1) spread traded in the previous year (e.g. how price for power delivered in 2005 traded through 2004) to see how the forward markets reacted to the introduction of the

EU ETS. We then adjusted the spreads to see what the level of CO₂ pass-through is that would keep average spreads at a level consistent with those seen in previous years.

Continental power – Germany

In Figure 15 we present the relevant spreads for German year-ahead (Y+1) power prices.

Figure 15. Dark and Dark-clean spreads for Continental power year-ahead (Y+1) contacts (2004–2007)

Note: We assume average efficiency of coal plant in Germany = 37%, Dark clean spread is with 100% pass-through of CO₂ costs, Adjusted Dark clean spread is with 50% pass-through of CO₂ costs

From this figure we see that the contract for delivery of power in:

- 2004 (pre-ETS) showed forward dark spreads in the German market of between 10–15 €/MWh. This is at levels about half of that required to support new build coal plant and reflects a relatively comfortable peak margin (installed capacity/peak demand) in the region;
- 2005 (as traded through 2004) showed no significant change in underlying dark spread, with spreads consistently trading around 10 €/MWh. The lack of many fundamental developments in the market (demand growth less than 1%, no new thermal capacity) suggest strongly that the forward market did not price EUAs into the 2005 contract as it traded. It seems clear that the forward prices for German power prior to the introduction of the ETS did not take account of the introduction of the EU ETS.
- 2006 (as traded through 2005) showed trend increasing dark spreads that were consistent with an increasing level of CO₂ price being passed-through to the forward power price. However, the market did not look as if it was passing through 100% of the CO₂ price into the power price as dark clean spreads remained low and at times went negative. Rather, the first seven months of the year looking looked

like the market was passing through around 50% of the prevailing CO₂ price (to give an adjusted dark clean spread of 10 €/MWh). However, the full dark clean spreads started to increase and by December 2005, these spreads were then trading around the 10 €/MWh level.

- 2007 (as trading through the first 6 months of 2006) showed dark spreads that continued to increase trading consistently above 30 €/MWh and then rapidly fall, in line with the pattern of underlying CO₂ prices. Up until the readjustment of the CO₂ price in late-April 2005, it appeared that German forwards were pricing in 100% of the EUA price into the forward power prices – with dark clean spreads remaining at around the 10 €/tonne level.

From this, we can conclude that despite a slow start to recognising the likely impact of the EU ETS on the market, German forward power prices now appear to be pricing CO₂ fully into the price of power for future delivery. This has had the effect of increasing dark spreads by anywhere between 10–30 €/MWh depending on the prevailing CO₂ price.

Nordic power

The most complex system to assess using this form of analysis is the Nordpool system which has underlying forward spreads that will be influenced by expectations of hydro generation. That is, when reservoir levels look high, then there is less need for thermal plant and imported power and forward spread fall. In dry years, reservoir levels remain low and more thermal plant is needed and spreads increase. Keeping this in mind, Figure 16 presents the spread analysis for Nordpool, looking at coal spreads given the trading link with continental Europe.

Figure 16. Dark and dark clean spreads for Nordpool power year-ahead (Y+1) contracts

Note: We assume average efficiency of coal plant in NordPool region = 39%, Dark clean spread is with 100% pass-through of CO₂ costs, Adjusted Dark clean spread is with 50% pass-through of CO₂ costs

From this figure, we see that the contract for delivery of power in:

- 2004 (pre-EU ETS) was such the dark-spread traded between 13 and 18 €/MWh, across what was a dry year (2003) for most of Europe;
- 2005 traded with a dark spread that was reasonably constant around the 9 €/MWh level, reflecting increasing reservoir levels throughout 2004. Given the persistent negative dark clean spreads throughout the period, we conclude that the CO₂ price had no impact on forward power prices throughout this period;
- 2006 showed a similar pattern to that seen in German prices, with the dark spread continuously increasing in line with the CO₂ price. As with Germany, the forward prices did not seem at any point in that year to be fully pricing in 100% of the CO₂ price with the second half of the year having relatively constant spreads with the previous year with a 50% pass-through level.
- 2007 again follow closely on the behaviour of the German market, with spread levels increasing and remaining sticky at a high level following the CO₂ readjustments of prices.

We see that the underlying forward spreads in Nordpool have followed the lead of the German market and behaved in a similar manner – responding slowly to the introduction of the scheme but now passing through a reasonably high level of the CO₂ price into the forward prices. This suggests that the main impact of the EU ETS on Nordpool has been through the trade with Germany – which often is seen as setting the marginal value of water in this system. This is explored further in the following section.

1.8 Carbon effects on power prices in the Nordic region

The supply side in the Nord Pool market consists of around 51% hydro power, 13% nuclear power, 31% thermal power and 5% wind power/other renewables (assuming normal hydrology situation). This means that no more than 31% of the total installed capacity is exposed to the EU ETS market directly. Included in the 31% are also Combined Heat and Power producers (CHP), where electricity is essentially a bi-product of the production of district heating and so the production is relatively insensitive to fuel and power prices. (We note that this is not exclusively the case as in Denmark CHP plants produce electricity as the primary product and heat is the bi-product).

Figure 17 shows the annual spot prices in the Nord Pool market and Germany (EEX) from 2005 and until 2007. The prices in the forward market for 2008 to 2010 are also presented. As explained in section 1.7, the rise in the EEX spot prices in 2005 can to a large extent be attributed

to the introduction of the EU ETS and also extreme weather events that pushed gas prices up. The Nord Pool spot prices in 2005 seem to have been less affected by the EU ETS market. 2006 Nord Prices were higher in 2006 due to low hydro levels and increased fuel-costs (including CO₂ costs), which explains the increase in EEX spot prices to around €50/MWh. Spot prices in 2007 decreased in both EEX and more significantly for Nord Pool, giving rise to a wide differential between these regions. Forward contracts for EEX are high at around €80/MWh reflecting the surge in coal prices during the second half of 2007. This section of the report explains some of the main price drivers in the Nordic power markets and the effect that CO₂ has.

Figure 17. Average annual NordPool and EEX spot prices and forward contracts (25/10/07)

Energy reservoir

The hydrological resources for hydro producers in the NordPool area can be defined as Total Energy Reservoir. This is the sum of water reservoirs and snow reservoirs in Norway and Sweden. Official water reservoir numbers are released weekly by the Norwegian Water Resources and Energy Directorate (NVE) in Norway and Svensk Energi in Sweden. Snow reservoirs are estimated during the winter season.

Normal water reservoir levels and snow reservoir levels are estimated by using 30 years of statistical data. The correlation between total energy reservoir, deviation from normal, and spot prices is 0.85 in the period 1996–2004. Water and snow reservoirs below normal levels result in high prices, while the opposite is true when energy reservoirs are higher than the seasonal normal. In Figure 19 below we have plotted the 52 weeks rolling correlation between the two quantities. The rolling correlation is between 0.6 and 0.95 from 1996–2004. For the period 2004–2005 the correlation dropped to 0.5 which means that there were other significant drivers of spot prices such as fuel prices and the introduction of CO₂ pricing. The correlation increased again during the first half of 2005 back to

historic levels and has remained high from the second half of 2005 until the third quarter of 2007.

Figure 18, shows the weekly average NordPool spot price (left axis) and the deviation of the total energy reservoir from the normal (right axis), from 1996 until week 15 in 2007. Negative numbers on the right axis imply energy reservoirs below normal. When the NP spot price peaked in week 2 2003 at around €100/MWh, the energy reservoir was 38 TWh lower than the seasonal normal, according to Point Carbon's models.

Towards the end of 2004 we witnessed a break in the historic levels and correlations between the power prices and the energy reservoir levels. The correlations between the two factors are still present currently but the spot price level has remained at a high level in 2005–7, well above the level predicted if the historic relationship between total energy reservoir and NP spot price had persisted. This clearly demonstrates the effect of higher priced thermal power imports from Denmark and Germany (in periods of low energy reservoir levels) due to the onset of carbon pricing. It is important to note that the CO₂ market has not altered the fundamental importance of hydro in the Nordic system but has merely shifted the price level upwards.

The correlation between total energy reservoir, deviation from normal, and spot prices is 0.85 in the period 1996–2004. Water and snow reservoirs below normal levels result in high prices, while the opposite is true when energy reservoirs are higher than the seasonal normal. In Figure 19 below we have plotted the 52 weeks rolling correlation between the two quantities. The rolling correlation is between 0.6 and 0.95 from 1996–2004. For the period 2004–2005 the correlation dropped to 0.5 which means that there were other significant drivers of spot prices such as fuel prices and the introduction of CO₂ pricing. The correlation increased again during the first half of 2005 back to historic levels and has remained high from the second half of 2005 until the third quarter of 2007.

Figure 18. NordPool spot prices and energy reservoir levels (below normal)

Figure 19. 52 weeks rolling correlation between NP spot price and Total energy reservoir (deviation from Normal)

Generation costs

Figure 20 shows NordPool spot prices and coal-fired generation levels from 2003 up to October 2007. The Danish region (DK1) spot price is closely correlated with the German EEX spot price, due to the high-level of coal-fired generation. The Swedish spot price (SE) is mainly driven by the levels of hydro generation. We note that bottlenecks in the transmission network can also lead to differences in spot prices between the regions in the Nordic market.

It can be seen that the spot price (especially in Denmark) closely follows the short run marginal cost (SRMC) for coal-fired power production. In the beginning of 2005, SRMC was around €30/MWh for a typical coal power plant with efficiency rate of 39% (including fuel cost, CO₂ allowance and operating and maintenance costs). During the summer of 2005, SRMC reached a peak of €50/MWh, due to rapidly increasing CO₂ allowance prices.

During 2005, the Swedish spot price was below the DK1 spot price as it was a year with high levels of hydro generation. The situation reversed in 2006 due to lower levels of hydro generation and an increase of thermal generation and imports. 2007 has seen a softening of prices in Sweden due to increased hydro levels, which has also contributed to lower prices in Denmark.

It is clear from the analysis is that the Danish (DK1) spot price closely follows the coal-fired generation cost with the cost of CO₂ fully incorporated into this price.

Figure 20. NordPool spot prices and thermal generation costs

Volatility

The introduction of a pan-European CO₂ price component into power prices has also led to stronger correlations between the various power markets. As well as this, CO₂ costs have also had an effect on the volatility of power prices. This is because both power and CO₂ prices react to some of the same fundamentals. For example, warm winters lead to lower power demand and hence less emissions, thus lower CO₂ prices. As a result, power prices will experience a double downturn effect directly and indirectly through the CO₂ pricing component.

The most liquid product in the Nord Pool financial market is the nearest seasonal forward contract. Long-term forward contracts tend to be strongly correlated, but with higher volatility for front products, i.e. contracts for the nearest quarters and years. In 2007 from January to October, the ENOYR-08 contract (this is the annual 2008 contract) had a 71% correlation with the ENOYR-09 contract, although as seen in Figure 21 the 08 contract was much more volatile than the 09 contract.

Figure 21. Historical volatility of yearly forward contracts 2007

It is interesting to examine whether the volatility has increased in the NordPool region since the introduction of the EU ETS. Figure 22 shows the volatility of the year-ahead contracts as traded in 2004 and 2007 (for year-ahead 05 and 08 contracts respectively). It is clear that there has been a dramatic increase in the volatility of the year-ahead contract in 2007 compared to 2004. There are a number of components that will be driving this including the volatility of the fuel prices but it is likely that the introduction of the EU ETS has contributed to this.

Figure 22. Volatility of 05 and 08 year-ahead contracts as traded in 2004 and 2007

1.9 Effect on emissions

1.9.1 Level of emissions in Nordic region

Historic emission levels in the Nordic countries are displayed in Figure 23, and show a rather stable trend seen over the 15 year period.

Looking briefly at the specifics of each country, the *Danish* emissions profile has shown a downward trend for the last decade, due mainly to a shift in the fuel mix from coal to gas in many power stations. A particular

feature for the Danish emissions profile is that fluctuation in emissions from year to year can be large due to trade in electricity with other countries, mainly the Nordic countries. From 1990 to date, five particular years have shown a peak in emissions due to large electricity exports (1991, 1994, 1996, 2003 and 2006).

Figure 23. Emissions trends in the Nordic countries, 1990–2005, MtCO₂eq.

Source: National Inventory Reports 2007, Submissions to UNFCCC

In 2005 *Finland's* greenhouse gas emissions totalled 69.3 Mt CO₂ eq., which is a decrease by 2.7 per cent from 1990-levels. The 2005 emissions decreased by nearly 15 per cent compared to the emissions of previous year, showing the flux in emissions also in Finland.

Total greenhouse gas emissions in *Norway* were 54.2 million tons of CO₂ equivalents in 2005. Emissions have increased by 4.4 million tons between 1990 and 2005, or by about 9 per cent.

GHG and CO₂-emissions in *Sweden* show a downward trend, and total GHG-emissions decreased by over 7 per cent between 1990 and 2005, and emissions per capita were lower in 2003 than in 1990, showing a decoupling from economic growth. Energy sector emissions account for under half of the emissions, given the high level of hydro and nuclear power production.

As illustrated in Table 3, Sweden is the only of the Nordic countries set to meet its Kyoto target without additional policies and measures. Denmark and Norway face the largest challenges in terms of reaching their targets, with a requirement to reduce emissions by respectively 24.4 and 18.6 per cent from a business-as-usual scenario, while Finland needs to bring its emissions down by 9.4 per cent from projected 2010 emissions.

The EU ETS is the main vehicle towards reaching the Kyoto targets, and covers large parts of GHG-emissions in most Nordic countries, as seen in Figure 24. The reason why coverage is significantly lower in Norway than in the other countries, is that the large petroleum sector is not included in the first phase of the Norwegian trading scheme, and there are

very low emissions in the electricity sector. In Norway, during phase 2 the offshore sector will be included and the ETS coverage will reach the same levels as most Member States from 2008–12, averaging around 46% of total GHG emissions.

Table 3. The Kyoto challenge: Base year, Kyoto target, current status and emissions forecast, Mt CO₂eq.

Country	1990	Kyoto target	2005	2010 (BAU)
Denmark	70.5	54.8	62.5	72.5
Finland	71.1	71.1	69.3	78.5
Norway	49.8	50.3	54.9	61.8
Sweden	72.3	75.2	69.7	71.5

Source: UNFCCC and Point Carbon

Figure 24. ETS share of total GHG emissions, 2005

Source UNFCCC and Point Carbon

1.9.2 Effect of weather

In general, CO₂ production depends on a number of factors, such as weather data (temperature, rainfall, and wind speed), fuel prices, carbon prices and economic growth. Among these factors, weather has a double effect; firstly, cold weather increases energy consumption and CO₂ emissions through power and heat generation. Secondly, rainfall and wind speeds will affect the share of power generated by non-emitting sources and thus emission levels. This is of course particularly important for countries and regions relying on hydro- and/or wind power to any significant extent.

During dry years in the Nordic Power Exchange area, CO₂ emissions tend to soar along with the price of power, with Norway and Sweden drawing power from the pool at higher levels and coal-fired generation in Denmark and Finland ramping up, along with increased level of imports from Germany. The Danish emissions profile is thus a good litmus test for the impact of weather.

As shown in Figure 25, annual emissions from power and heat generation in Denmark during the period 1990–2005 fluctuated from a low of about 24 MtCO₂ in 1990 to a high of 42 MtCO₂ in 1996, an exceptionally dry year, representing a swing of about 70% from the lowest to the highest level.

Figure 25. Danish power exports (left axis – bars) and emissions from the power and heat sector (right axis – line) for the period 1990–2005

Source: Point Carbon (www.pointcarbon.com) and Energistyrelsen (www.ens.dk)

By far the most important weather factor in the Nordic region is the level of precipitation and the corresponding level of the hydrological energy reservoir. Figure 26 looks emission levels in the power sector in Nordic countries with thermal generation and compares this to the average deviation from normal energy reservoir levels.

It is clear that there is high correlation between emissions and hydro levels. The correlation between 1996 and 2006 is 0.87. 1996 was a year with low rainfall and this is manifested in the high level of emissions in all three countries, due to an increase in the output of thermal generation.

The average annual emissions over the period 1990 to 2006 are 56 Mt. The highest emission levels over this same period are 78 Mt (in 1996), which gives a surge in Nordic power emissions of 22 Mt in one year of low rainfall. Figure 27 shows how the emission variability looks at country level. Denmark has the highest average emissions and the highest level of variability.

Figure 26. Power sector emission levels and energy reservoir levels shown as deviation below normal

Figure 27. Power sector emission range over the period 1990 to 2006

Effect of temperature

Whilst rainfall affects the level of emissions on the supply side by determining the level of non-emitting generation, the primary effect of temperature is on the demand side. Temperature affects the level of power demand (and hence emissions), which in Northern Europe is negatively correlated to temperature as when the weather is cold the requirement for heating increases. We note that in Norway most domestic heating is provided by electricity. Electricity has quite a high share of the heating demand in Sweden and Finland too but this is much lower in Denmark.

Figure 28 shows the demand patterns for these countries over a three year period. The pattern in Sweden, Norway and Finland is similar with the highest level of demand coming in the coldest first quarter. Denmark has a flatter profile due to relatively milder winters and less electricity based heating demand.

Figure 28. Quarterly demand patterns in Nordic countries (GWh)

Source: NordPool

We observe that in all countries, there has been only a very moderate level of electricity demand growth. The average level of growth between 2004 and 2006 is around 1.1% per year.

Table 4. Level of consumption and growth rates in Denmark, Sweden, Norway and Finland

Country	2004 (TWh)	2005 relative to 2004 (%)	2006 relative to 2005 (%)	2007 relative to 2006 (%)
Q1	112.5	1.3	5.4	-5.4
Q2	84.8	-0.1	5.7	-1.1
Q3	78.0	3.7	-1.6	3.7
Q4	106.8	-0.5	-4.7	
Total	382.1	1.0	1.2	

To look at the isolated effect of temperature on the level of emissions it is necessary to look at the consumption. If we look at the emission levels directly, which we calculate for each country's power sector on a daily basis, we include the effects of fuel prices and rainfall that in turn affects the type and emission intensity of generation.

Figure 29. Example of correlation between temperature and consumption. Data from Sweden from October 2003 up to October 2007

In Figure 29 above, there is a good correlation (R-squared value of 0.83) between the daily consumption and temperature. This is to be expected in a Northern European country, although this does not hold true for countries with more mild climates.

Table 5. Relationship between temperature and consumption as well as approximate emission variability

Country	Correlation between temp and consumption (R-squared)	Consumption change per degree decrease (MWh/degree)	Heating days in year (average 04-06)	Average emission of thermal generation (t/MWh)	Emission variability per degree per year (Mt/degree)
Finland	66%	3,268	331	0.6	0.65
Norway	87%	8,600	346	0.6	1.79
Sweden	83%	9,400	336	0.6	1.90

Table 5 shows the correlation between temperature and consumption for Finland, Norway and Sweden. It also shows how the daily consumption changes with each change in degree. So in the case of Finland, one degree decrease will on average give rise to an increase of 3,268 MWh consumption for a particular (and average) day. Interestingly, an examination of the correlation between the daily change in temperature and consumption did not reveal any strong correlation. So the change of weather from one day to the next is much less of an effect than the absolute temperature level itself. One possible explanation of this could be lag effect of temperature on consumption with temperature changes affecting consumption for several consecutive days.

The heating day measure is used in the estimation of the energy needs for heating. It is calculated as the absolute difference between the daily mean temperature and a reference temperature, usually 18 degrees Cel-

sus. The table shows the number of heating days in each country as these could be days in which additional heating (in these countries assumed to be from electricity) demand is required. The generation that will need to be run to cover this additional demand (from colder temperatures) would come from thermal generation, rather than non-thermal generation like hydro and nuclear, which more generally runs baseload.

If we take an average thermal emission factor in the Nordic region of 0.6 tCO₂/MWh then we can convert the consumption variability into an approximate emission variability. The variability ranges from about 0.7 Mt/year/degree in Finland (around 2% of its EU ETS emissions in 2005) to about 1.8 Mt/year/degree in Sweden and Norway. However, we note that:

- There is uncertainty in these figures based on using one regression for the full year rather than for different seasons. In winter the effect of temperature will be greater than in summer, when consumption is generally lower;
- Considerable share of total heat consumption in the Nordic region is from biomass (wood stoves, district heating etc) and so the assumption that conventional thermal generation will be needed to meet the extra consumption demand is likely to lead to an over-estimate of the emissions increase;
- The emission variability is not symmetric – i.e. if temperatures are higher than normal for large periods of the year, this will not decrease emissions as much as emissions would increase due to colder weather;
- Even though Norway does not have any thermal generation, the consumption increase is likely to come from thermal-based imports. There is no way of saying which country this would be from but this could be from Denmark.

There is also a secondary effect that temperature can have on emission levels and this is through the level of snow and snow-melt during the year. If there is a mild period, especially during the spring time, this can give rise to high melting rates of the snow pack. This can affect the hydro production in two ways:

- Water is lost through spilling – this is essentially wasted hydro production, which could lead to higher level of emissions; or
- Determine when hydro is used – high melt levels would mean that hydro needs to be used (or water would be spilled) or low melt levels would mean that reservoirs would be at higher levels later on during the year. These effects could lead to emission levels changing (possibly between seasons or years) based on how much hydro power is generated.

1.9.3 Effect of fuel prices

The effect of fuel prices on emissions in the Nordic area is limited as such a high proportion of the generation comes from non-thermal sources. The main way that fuel prices will affect the level of emissions in the Nordic region is through fuel switching between coal plant to gas plant. Over a longer period, fuel prices can affect levels of demand but this is not considered within the scope of this report.

For fuel-switching to occur, it is necessary to have both coal plant and spare capacity of gas plant. There may also be other physical constraints such as contractual obligations, locational grid constraints and grid flexibility issues (ramping rates/costs) that would inhibit the amount of fuel switching in a particular power system.

In any case, as can be seen in Figure 30, there is limited scope for fuel switching between coal and gas plant, except perhaps in Denmark. Even here though, there is still a relatively small percentage of installed gas capacity and the variability in gas and coal generation is not that great.

Figure 31 shows the source of electricity generation in Denmark over the previous six years. The amount of generation from oil has decreased, whilst the level of renewables has increased – mainly from wind and biomass. The level of generation from gas-fired plants is pretty constant and it is clear that coal-fired generation is the marginal plant type, which responds to the change in electricity demand (including that of exports). For example, the increase in generation in 2003 due to the poor Nordic hydro conditions came entirely from additional coal-fired generation. The main reason for this is that almost all of the gas-fired generation is combined heat and power, which means that the level of electricity generation essentially follows the level of heat production. Heat demand is more temperature driven and so the level of electricity generation is generally insensitive to the fuel and power prices.

Figure 30. Relative installed capacity in 2005 (MW)

Source: Platts

Figure 31. Electricity produced by different sources in Denmark

Source: Energistyrelsen (Denmark)

1.10 Market distortions and disparities

This section looks at some of the market distortions and disparities in the EU ETS during phase 1. One of the main issues has been that of the level of free allocations to installations, in particular within the power sector.

The key mechanisms that are used for the allocation of emissions allowances in Europe are:

- *Grandfathering* – in which allowances are provided to the installation on the basis of either historical or expected future requirement for such allowances by the installation;
- *Benchmarking* – in which allowances are provided to the installation on the basis of a specific benchmark installation's requirement for such allowances;
- *Auctioning* – in which allowances are provided to the installation on the basis of prices that the installation is willing to pay in an auction.

It is not explicitly a choice of only one option, as it is possible that different mechanisms could be applied as part of an allocation strategy, for example applying different mechanisms between sectors. In phase 1 of the EU ETS, most Member States have used grandfathering allocation methodologies for most sectors, with a few countries using benchmarking, particularly for the power sector. In phase 1 there was a limited amount of auctioning used.

Under all of the different allocation mechanisms, it is the size of the cap that will eventually determine the ultimate degree of scarcity under the scheme. It is the determination of the emissions reduction target that

will have a big influence on both the eventual market price of carbon and on how individual installations will be treated under the allocation mechanisms.

Differences in targets between Member States can lead to differences in how individual installations are treated between countries (size of initial allocation) and this can have undesirable impacts on relative competitiveness.

Even within Member States, the methodology chosen can give a wide range of allocation outcome for different plant types and this can have a large impact on the relative competitiveness of installations and companies.

It is the free nature of the allocation of allowances that has been particularly problematic politically in phase 1 of the EU ETS. More specifically, it has been the pass-through of the opportunity cost of carbon into the power price *given free allowances* that has been controversial. While we believe that this pass-through is part of basic power plant optimisation (see Appendix 3), it remains the fact that the resulting provision of “wind-fall” profits to utilities has been one of the more important issues surrounding the operation of the EU ETS in phase 1.

The choice of allocation mechanism will certainly influence, but not necessarily determine, investment decisions on new power plants, based on the compliance costs that plants will face. By having full auctioning, this would be most favourable to the lowest-emitting plants.

Closure rules

Providing free allowances has given rise to plant closure rules, in which allowances allocated to an installation are removed if the installation closes down. The main rationale for this is that if allowances are provided free of charge, then they should be returned if the installation no longer needs them. Unfortunately, such reasoning may distort the scheme as, in theory at least, emissions trading should encourage the environmentally least efficient plant to close (if the value from not emitting is greater than the value from producing). Allowing installations to keep the value of the foregone carbon emissions may be crucial in making the decision to close the plant.

The absence of installation closure rules may also bring their own distortions. Particularly if keeping an installation open for another few years means it will then qualify for a long-term (5 to 10 year) allocation which could then be traded once into a new phase. This could result in delayed closure of some of the least energy efficient installations.

New entrants rules

The allocation mechanisms should be able to accommodate entry, within the phase, of new plant, although there is no requirement to provide new plant with a primary allocation. New plant tends to be more efficient, and therefore, likely to produce less emissions than existing plant.

It can be argued that the failure to provide such plant with a primary allowance (through an initial allocation) will effectively penalise new plant by exposing them to a much higher degree of carbon costs than existing plant, and this is perverse. The longer phases are for, the greater the issue as it becomes increasingly difficult to foresee the pattern of new entry as you progress further away from the present.

In phase 1 of the EU ETS, most Member States addressed this by creating a new entrant reserve (NER) that explicitly looked to provide a fund of allowances that could be drawn on by installations that were not allocated allowances at the start of the phase. We expect that regardless of the mechanism, any scheme with long-term allocations in it will need to provide access to primary allocations to new entrants. Otherwise, the scheme will be biased against new entrants as the only participants without some access to primary allocations.

A number of issues exist with the creation of a NER including:

- Size of the NER to be set aside;
- Rules/provisions for replenishing a NER if it is exhausted; and
- Rules for releasing or cancelling unallocated allowances in the NER.

Summary

The fact that Member States create their national allocation plans themselves, with only the total level of allocation controlled by the European Commission, means that there are large differences between plans, not least regarding the level of allocation. Comparing power sector installation allocations across Member States shows that there are clear differences between the burdens faced by different utilities in Europe as a result of the EU ETS.

There is a large variation in the allocation methodologies for existing plants used across Member States. Grandfathering is still the most common method, although benchmarking has been adopted in several countries. The type and choice of benchmarks varies considerably, and consequently the effects on the relative competitiveness between fuel-types and technologies can be significant.

The choice of allocation impacts the compliance costs for different technologies, and this can influence, although not necessarily determine, investment decisions in the power sector. For example, moving to full-auctioning would benefit lower-emitting plants, but could lead to investment in a particular technology type (gas over coal plant, for instance), which may have implications for diversity of supply. The choice of allocation therefore has an important impact on the level of emissions in the longer term.

Harmonisation and choice of allocation methodologies is an important issue that the review of the EU ETS Directive will examine, and it will be important for policy makers to maintain a balance between harmonising methodologies to reduce the differences between countries and allowing Member States to tailor the allocation methods based on their energy policy objectives (including considerations of diversity of supply).

1.11 Lessons learned

The key lessons learned can be summarised as follows:

- The Nordic countries covered by the EU ETS in phase 1 have had higher allocations than emissions, which is in line with the overall picture in EU27;
- While the power sectors were overall long in 2005 (with the exception of Sweden), verified numbers for 2006 show an overall short position for the Nordic power sector in total. This is most evident for Denmark, and can again be explained by the fact that *emissions were higher in 2006 due to the below-average hydro situation that year*.
- The CO₂ price has been volatile in the first phase with prices between 30 euros per tonne and 3 euro cents.
- Gas and coal prices have only had periodic and limited effect on the CO₂ price to date but there has been a much *higher correlation between oil and CO₂ prices*;
- The correlation of oil and the CO₂ price has now been broken for the remainder of the first phase of the EU ETS, as the market is long, but we expect a correlation to persist for phase 2;
- *Weather impacts on the power sector* by affecting by demand but also the supply (level of renewable generation);
- Weather had a much higher correlation to changes in the EUA price at the beginning of the scheme, when the market perceived it was short.
- Like fuels, we no longer see weather necessarily being a key driving factor of the EUA price for the remainder of the first phase. We do expect that it will become important again in the second phase of the EU ETS, especially during the winter periods.

Power prices

- Underlying forward spreads in Nordpool have followed the lead of the German market and behaved in a similar manner – responding slowly to the introduction of the scheme but now passing through a reasonably high level of the CO₂ price into the forward prices. This suggests that *the main impact of the EU ETS on Nordpool has been through the trade with Germany* – which often is seen as setting the marginal value of water in this system;

- German forward prices appear to be pricing in the full cost of the CO₂ price into the forward prices, whilst the NordPool region has lower levels of around 50% (due to the very high level of non-thermal generation and the important impact this has on power prices);
- The level of total energy reservoir is a key price driver in the NordPool market. Since 2005, there has been a change in the relationship between these variables. Initially there was a break in the high correlation, although this has since been re-established. The correlations between the two factors are still present currently but the spot price level has remained at a high level in 2005–7, well above the level predicted if the historic relationship between total energy reservoir and NordPool spot price had persisted. This clearly demonstrates the effect of higher priced thermal power imports from Denmark and Germany (in periods of low energy reservoir levels) due to the onset of carbon pricing.
- Volatility has increased in the European power markets as both power and CO₂ prices react to some of the same fundamentals. This is evident to a large extent in the NordPool market although it is not possible to isolate the effect of the EU ETS and other fuel-price effects;

Emissions variability

- The average annual emissions for the power sector in Denmark, Sweden and Finland over the period 1990 to 2006 was 56 Mt. The highest emission levels over this same period was 78 Mt (in 1996), which gives a surge in Nordic power emissions of 22 Mt in one year of low hydro output;
- Temperature affects emissions through the consumption of power, which is particularly evident in Sweden, Norway and Finland with high power consumption for domestic heating;
- There is quite a low potential for fuel switching in Nordic countries and so the effect of changing fuel prices on emissions is limited, especially relative to the change in emissions due to weather-related factors.

2. EU ETS phase 2 (2008–12)

Phase 2 of the EU ETS runs from 2008 to 2012, and is closely linked with the international market. Before going into details about phase 2 of the EU ETS, it is worth outlining the main structure of the international carbon market.

The Kyoto protocol relies significantly on the power of market actors and market mechanisms for obtaining global reductions of GHG emissions. Three mechanisms are identified through the Kyoto Protocol, all with their own tradable credits or allowances:

- International Emission Trading (IET)
- Clean development mechanism (CDM)
- Joint implementation (JI)

All countries with targets under the Kyoto Protocol (Annex B countries) will be issued with Assigned Amount Units (AAUs) that can be used in IET under the Kyoto Protocol. The main supply of AAUs is expected to come from economies in transition (EIT) in Eastern Europe, and Russia and Ukraine in particular, as these countries have actual emissions far below their Kyoto target (their assigned amount). Thus, they can sell the surplus to countries or companies that are in short positions and can use the allowances for compliance.

In addition to this are two project-based mechanisms. Certified Emissions Reduction (CERs) from CDM and Emission Reduction Units (ERUs) from JI are issued based on actual projects with proven emissions reductions in non-Annex B countries, i.e. countries without emissions targets, and in Annex B countries, principally in Eastern Europe, respectively. Figure 32 displays the structure of the carbon market in the 2008–2012 periode. The market consists of governments and private entities, and the rules governing their trading relationships.

Figure 32. Theoretical structure of the Kyoto market

The left side of the figure displays the governments specified in the Kyoto Protocol's Annex B. The demand side will manifest itself mainly in the EU15, Japan, Canada, and New Zealand. The supply side will be concentrated in Eastern Europe.

Governments with demand for allowances in the Kyoto period can also forward parts of their compliance to the private sector through emissions trading schemes or other measures. The largest operational regional trading scheme is the EU ETS but there is also demand from the Japanese private sector, where industry has taken on ambitious commitments to reduce emissions, and potential demand from other emissions trading schemes that are being planned in other countries.

The common factor for all different market segments is their link to CDM and JI. Governments and companies alike, in all regions of the world, will be able to use CERs and ERUs for compliance. Thus, these project based credits will act as the carbon market's interconnector, ensuring that there is at least indirect price linkage between the systems, as the stream of credits will in theory go to the system with the highest price.

This means that the market in phase 2 of the EU ETS needs to be considered within a more global perspective. The price drivers will include global macro-economic and political factors as well the key driver relating to the supply-demand balance of CER and ERU credits.

2.1 Main features of EU ETS phase 2

Phase 1 of the EU ETS must be understood as learning period, in which governments, business and the EC alike have been preparing for phase 2 and the Kyoto period. The EU ETS Directive consequently lays down different rules for the two trading periods. The main differences are summarised in Table 6 below.

Table 6. Principle rules for EU ETS for phase 1 and 2

Compliance period	2005-2007	2008-2012
Auctioning	Up to 5%	Up to 10%
Penalty	€40/tonne	€100/tonne
Participation	Opt out/opt in	Opt in
Banking to next phase	No	Yes
CDM/JI	CDM	CDM/JI

The key differences are that the level of auctioning allowed by Member States has increased to 10%, although few have made use of this. The penalty price for non-compliance increases from €40 to €100/tonne, and it should be noted that this penalty is in addition to companies needing to make up the shortfall the following year (or the penalty is applied again if installations are short). It is no longer possible for installations or sectors to opt out of the EU ETS, which was provisioned for in phase 1 as some installations were covered by other GHG reduction legislation or domestic emissions trading schemes.

It is possible to bank allowances from phase 2 into the subsequent phase and this has important price implications as discussed later in this chapter. Finally, it is possible to use credits from JI projects as well as CDM projects, as the JI scheme starts its crediting period in 2008.

2.2 Critical drivers in phase 2

CO₂ is no different to other commodities in that the price is determined by the supply and demand balance. What makes the carbon market distinctive from other commodities is that the supply-side is not fundamentally driven (such as in power markets) but instead is determined by regulation. Whilst the level of supply is set before the next commitment period starts, supply is not decided beyond this, which makes the CO₂ price subject to significant regulatory uncertainty in a long-term perspective.

2.2.1 Supply side

National Allocation Plans

Phase 2 of the EU ETS begins next year and already the market is focusing on this period (and beyond), given the collapse of prices in phase 1. One of the key lessons learnt from the EU ETS Phase 1 is the importance of avoiding an overall long market. Therefore, it is hard to overestimate the

significance of the allocation of EU allowances through NAP decisions to the Phase 2 market. The European Commission has now commented on all 27 NAPs and cut the allocations by around 230 Mt/year compared. Figure 33 shows the cuts at country level in absolute and percentage terms. The total cap for the EU27 is now set at 2080 Mt/year during Phase 2.

The largest absolute cut to the NAPs was in Poland, with a cut back of around 70 Mt/year. Many of the largest cuts in percentage terms were from the new Member States. There are currently several legal procedures against the EC taken by some of these countries who claim that economic growth rates used by the EC are not realistic. The outcome of these legal disputes is likely to take several years.

Figure 33. Cuts to individual NAPs

Once the allocation is set, the main picture of EU allowances available for the market is by and large known. There are, however, uncertainties related to how much of the reserves that will be available for the market and what will happen to the allowances allocated to existing installations that are closed down during Phase 2.

Reserves are split into new entrants reserves (NER), auction volume and JI reserve (essentially put in place to avoid double counting for companies carrying out JI projects in eastern European countries). Based on Point Carbon's estimates and information in NAPs, countries will have a total reserve of some 1,030 Mt in total for Phase 2. Key uncertainties include:

- When allowances set aside for auctioning come to market;
- The rate that NERs are depleted and refilled;
- The likelihood of an "NER buffer", i.e. countries setting their NER higher than actual requirements in order to safeguard investments;
- Whether a surplus (if there is one) from the NER will come to market;
- The extent that cancelled allowances due to closures is transferred to NERs.

In Phase 1 a large percentage of the reserves have not been sold to the market, which is partly due to the collapse in prices and the political sensitivity of selling surpluses into an already long market. It is likely, however, that there will still be some slack and therefore not all of this volume will reach the market by the end of Phase 2.

There may also be a further delay in the volume coming to market, particularly with the auctions as Member States decide on how to carry these out. In total, 11 Member States have set aside a share of their total allocation for auctioning in Phase 2. This suggests that the total volume of auction will be about 80 Mt/year, or about 2% of the total allocation.

Certified Emission Reductions (CERs) and Emission Reduction Units (ERUs)

The supply of offset credits from the Clean Development Mechanism (CDM) and Joint Implementation (JI) is also determined through a regulatory process. At the time of writing, Point Carbon's risk-adjusted estimate is that some 2,100 Mt of CERs and ERUs will be issued up and until 2012. However there is a large uncertainty around this figure due to:

- The rate at which projects move through the regulatory process of getting approved by the UNFCCC;
- The performance of projects – how many credits the projects actually deliver compared to expectations;
- The volume of new projects that get initiated – this is in turn due to which project methodologies are approved by the UN regulatory body, the carbon price, and the amount of equity that investors are willing to put into these projects;
- The nature of a post-2012 agreement and the impact/signals for the future carbon price.

There are also other sources of demand for CER/ERU credits outside of the EU ETS. Governments with Kyoto targets have so far pledged to buy some 710 Mt in during the Kyoto Commitment period (2008–12). In addition to this, it is necessary to take into account the private sector demand in non-EU countries, including companies in Japan procuring credits for compliance with voluntary or mandatory targets and possibly companies in Canada and the US. Acknowledging the lack of substantive data, we currently estimate non-EU demand of 200 Mt for Phase 2 (40 Mt/year), which admittedly is conservative in view of the Kyoto gaps in Canada and Japan. This leaves around 1,190 Mt available for the EU ETS. The estimated supply of CERs/ERUs to Phase 2 is shown below in Figure 34.

Figure 34. Supply of CER/ERU credits in Phase 2

The estimated supply in 2008 is larger than in 2009 due to the issued credits being rolled-over from previous years coming into the market in 2008. The supply from 2009 then increases towards 2012 due to the larger number of projects online that will be generating credits.

Limits on the use of CER/ERU credits in the EU ETS

As well as addressing the total level of allocation within the National Allocation Plans, the European Commission has also established a standardised methodology for the credit limit that is the maximum volume of credits from CDM and JI projects that can be used for compliance by EU ETS installations in Phase 2.

The Commission's assessment of the NAPs has resulted in reduced credit limits in eight Member States. In total, the Commission has reduced the potential to use CERs/ERUs for compliance by around 74 Mt per year, corresponding to a 22 per cent cut compared to the limits proposed in the NAPs. As shown in Figure 35, the largest cuts have taken place in Spain (46 Mt), Poland (31 Mt) and Italy (20 Mt). In relative terms, the credit limits have also been reduced significantly in the smaller countries, with a 56 per cent cut in Ireland and a 50 per cent cut in both Austria and Sweden.

Figure 35. Changes to the limits on use of CER/ERUs

The total credit import limit of CER/ERUs for the EU27 is just over 1,400 Mt for the 5 year period, which is around 13% of the total cap.

2.2.2 Demand side

On the other side is the demand for allowances. This is based on the level of emissions compared to the amount allocated, which is in turn dependent on demand (shaped by economic activity), weather (affecting both demand and supply of renewable-type generation) and commodity prices.

Figure 36 displays the CO₂ price drivers and the interaction of CO₂ with other fuels and electricity prices.

$P = \text{price}$

Figure 36. CO₂ price drivers

For industrial sectors, emissions are primarily related to levels of production and energy efficiency. The same factors apply to the power sector

but in addition it is this sector that gives rise to linkages with fuel prices as the relative cost of input fuels into power generation determines which plant is most economical to run at any given time.

Weather too is another important short-term consideration as this not only influences power demand but also the level of non-emitting renewable generation such as wind and hydropower. For instance, weather may increase emissions in the EU27 by up to 60 Mt/year compared to a normal year.

We observe that the construction of new plants and also other legislation, such as the EU Large Combustion Plant Directive (capping SO₂ emissions) and nuclear phase-out plans in Germany, will have an effect on emission levels in the longer-term perspective.

Given fuel price assumptions, normal weather patterns and a demand growth for conventional power of 1.5% per year, Point Carbon currently forecasts that the CO₂ emissions in Phase 2 will be close to 11,500 Mt (averaging 2,300 Mt/year). We note that this is not a business-as-usual forecast as this forecast includes a carbon price (taken at around €22/tonne at the start of October 2007) and so we inherently include a certain level of abatement within our demand forecast.

2.2.3 Phase 2 market balance

Figure 37 shows the overall market balance for the five years in Phase 2. The total short position over the five years without including the volume from CER/ERU credits is roughly 1,100 Mt. On average this is equivalent to a shortfall of 220 Mt/year, although the volume from reserves is likely to increase throughout the period, which leads to a larger short position in early years.

The total volume of credits that will be available to the EU ETS is forecast to be 1,190 Mt, which is within the maximum import limit of credits imposed by the European Commission (circa 1,400 Mt). As with the reserves, the supply of credits will increase throughout the period. Including the credit supply, the short position in 2008 is around 210 Mt but by 2012 the supply from reserves and credits (including those issued in the first quarter of 2013) will exceed the demand by over 300 Mt.

The net position of the EU ETS market over the entire phase, including the supply of CER/ERU credits, is roughly balanced however the key uncertainties that could swing the market out of balance in either direction include:

- the percentage of reserves that will reach the market;
- the supply of CER/ERU credits; and
- the level of demand for EUAs (the expected emissions over the 5 years).

Figure 37. Yearly market balance in Phase 2

Banking and borrowing

The fact that the EU ETS market may be fundamentally short in the early years but balanced or long towards 2012 means that one key price driver is the ability and willingness of companies to borrow allocation from future years to cover short positions early on in Phase 2. The ability to borrow comes about through the fact that installations receive their second year's allocation before they need to submit their allowances (equal to the previous year's emissions). Essentially, this means that it is possible to bring forward future allocations to cover current emissions. This would be particularly useful for companies with a contracted inflow of CER/ERU credits coming later in the period.

Key barriers to borrowing include:

- Industry positions are generally balanced and so borrowing is not required. Borrowing allocation from future years to sell to utilities is taking a speculative position and this may not be possible;
- Utilities are governed by stricter risk limits in the post-Enron era and this may prevent them from taking larger open positions in future years. However, some utilities may treat their five year allocation as one large pool and allocate this internally across the years according to their forward sales of power;
- Accounting rules may also prevent some companies from booking future allocations into accounts in earlier years.

However, higher prices in early years are more of a concern to the industrials than utilities, who can recoup their costs through increased power prices. Financial institutions are also encouraging industry players to “unlock” their allowances by offering industrials contracts whereby allowances are purchased now and sold back at a later date with fees that are more attractive than current interest rates.

While banking from Phase 1 to 2 was left to Member States' discretion (although in practice disallowed), article 13(3) of the EU ETS Directive states that "Member States shall issue allowances [...] to replace any allowances [...] which are cancelled".

The opportunity to bank would ensure a smooth transition of prices across commitment periods and avoid disruptions such as the "2007 wall". In principle, the extent to which allowances will be banked depends on Phase 3 prices. There is currently no clear market signal for post-2012 prices as a lot of uncertainty exists regarding the structure and components of a global carbon market. We expect a clearer signal on post-2012 prices over the next few years and this will certainly affect phase 2 prices towards the back-end of the period.

Utilities versus Industry

It is clear in Phase 1 that the market dynamics is underpinned by the fact that utilities are short and industry players are balanced or long. This means that utilities, which are actively trading and balancing their portfolios according to fuel price movements, create the demand in the market according to their hedging requirements. Industrials, on the other hand, have been more risk averse and have generally only come into the market at the end of the year when final positions are known. Moreover, a significant amount of industrial length never came to market as it was split amongst so many small installations.

Whilst there is less over-allocation in Phase 2, industry sectors are mostly balanced whilst the utilities are shorter than in the previous Phase. The dynamics in Phase 2 will be affected by the willingness of industry participants to trade more dynamically throughout the year – this would require resources to follow the market more closely.

CER/ERU credit limits

There is a limit in place on the volume of CER/ERU credits that companies in the EU ETS can use for compliance. These limits are generally applied at installation level but as stated before, many industrial installations are not short and therefore do not need to use CER/ERU credits for compliance, nor would they wish to enter this market. Conversely, utilities that are facing the most stringent reduction targets are keen to purchase large volumes of credits (and have already contracted significant volumes from the primary market i.e. project development) in order to reduce their compliance costs.

In order for them to use these credits, they will need to swap CERs/ERUs for EUAs with companies in industry sectors to ensure that the limit is fully utilised. The extent to which this happens (and the timing) is an important price driver in that it determines the level of abatement from external credits. If insufficient CER/ERU credits are available to meet the shortfall in the power sector then fuel-switching will be required.

2.3 Scenario price analysis

The methodology used to produce our fair price assessments is described fully in Appendix 2. Essentially the principle is that there are two pricing regimes depending on the market balance taking into account the inflow of CER/ERU credits.

On the one hand, if the supply of CERs/ERUs and reserves are sufficient to cover the entire market shortfall, EUAs should approach the price of CERs/ERUs which defines a price floor. We set this value at €8/t as this is level below which the Chinese authorities will not approve CDM projects. The majority of CER credits are expected to originate from China in Phase 2 and so the floor price is representative for the total inflow of CER credits.

On the other hand, in case domestic reductions are needed, EUAs should be priced against the cost of switching to less carbon-intensive fuels in the power and heat sector, which in turn defines a ceiling for EUA prices². The cost of fuel switching varies from country to country (depending on the type and characteristics of generation plant) and fuel prices (essentially the relativity between oil/gas and coal).

For our fuel-price assumptions, we have taken forward curves for oil, coal, gasoil and NBP gas and we extend the last year of the forward curve out to 2012 if there is no forward price going this far. The prices shown in Table 7 below are averages over the five year period. We also include transportation and taxation costs when calculating the cost of generation at different plants.

The inputs to our scenario price calculation are summarised in Table 7. To capture the uncertainty in the input variables, we run our Carbon Price Forecaster model stochastically and apply standard deviations to each input. We are able to calculate the likelihood that internal abatement will be required and the mean value from the model runs, which is our fair price assessment.

Given our central assumptions discussed in the report so far about fuel prices and supply/demand fundamentals, we see €25/t as a fair price for Phase 2 EUAs. Note that this is an average price for the whole 5 year period.

² An absolute price ceiling is the penalty level of €100/t + the price of Phase 3 allowances needed to cover the shortfall

Table 7. Central assumptions for fair price assessment

	Mean Value (2008-12)	Standard deviation
Cap including reserves	10,400 Mt	40 Mt
Oil price (Brent)	\$72/bbl	30%
Coal price (API#2)	\$81.3/t	20%
NBP price	41 p/Th	30%
Demand growth conventional power	1.6%/year	0.5%
Price floor	€8/t	-
Switching price	€30.5/t	
X = likelihood of switching required	75%	
Fair price Phase 2 EUAs	€25/t	€16/t

The analysis finds a 75 per cent probability that domestic reductions will be needed – i.e. 75% of the 10,000 scenarios run calculated a short market after taking into account the credit supply. The switching price is found to be €30.5/t, representing the average switching price in all simulation outcomes where domestic reductions are needed.

The fair price assessment presented above is for the full 5 years and inherently assume that long and short positions across years are netted-off i.e. borrowing from future years is possible. If borrowing was not permitted, then carbon prices of around €50/t would be required to clear the short positions in 2008 and 2009. However, such high prices are likely to trigger demand-side responses, additional CER/ERU credits and borrowing. These responses would therefore counteract any significant price increases. Changing assumptions on borrowing behaviour gives a wide range of price forecasts in our models, but it is more a psychological question of what price the market can accept. Given Phase 1 prices did trade in the early €30's/t, it is probable that these prices could occur again. There would likely be more resistance towards the €40/t level.

In conclusion, the lack of borrowing would certainly present an upside risk to prices in early years although it is likely that the market would arbitrage part of any price difference between current and future years (i.e. if the EUA forward curve was in backwardation).

2.3.1 Sensitivities

Several sensitivities to this central price assumption are presented by changing key parameters. These are summarised in Table 8 below.

Table 8. Key sensitivities to fair price assumption

	Change to value	Fair price (€/t)
Main scenario	-	25
Oil sensitivity	+25%	32
	-25%	17

The price of oil is a key driver of carbon prices due to the importance of oil-linked gas as a power generating fuel. There has been significant volatility in the oil markets over the past few years and the main trend during this time has been upwards. In this analysis we apply a sensitivity of +/- 25%, which corresponds to an oil price of \$90 and \$54/bbl respectively. We note that the carbon price is reasonably sensitive to these oil price sensitivities changing the carbon price by +€/t and -€/t respectively.

Finally, by making an assumption on phase 3 prices, we assume that prices in phase 2 do not go below this as companies would arbitrage the price differential by banking EUAs into the next phase given any surplus. Making the assumption of a €20/t phase 3 price increases our central fair price assessment to €29/t.

2.4 Effects of post-2012 uncertainty

As discussed in section 2.2.3, the possibility to bank from phase 2 to phase 3 means that there should be a smooth price transition between the two phases. Currently, there is no clear signal for what post-2012 prices should be. Looking further ahead, there are three long-term processes that are ongoing that should provide further clarity on the post-2012 situation:

- The first is the review of the EU ETS Directive, which will determine the nature of the scheme in phase 3, including what new sectors to involve. The EC has produced a legislative document but this now needs to be implemented into law and there may some amendments before this is passed;
- Secondly, the EU member states will further discuss the new targets for 2020 – reducing CO₂ levels by 20% (or 30% if there is equivalent effort from other developed countries) compared to 1990 levels. The key question is how the reduction burden is apportioned between countries, but also between the traded sectors (EU ETS) and non-traded sectors (those outside of the scope of the EU ETS such as agriculture).
- Thirdly, the negotiations under the UNFCCC will address the global issue of finding a successor to the Kyoto Protocol. Meetings,

including the COP/MOP in Poland (2008) and Copenhagen (2009), will give important signals regarding the nature of any post-2012 agreement.

Strong signals post-2012 will provide a bullish signal for the Phase 2 period both fundamentally (due to the fact that EUAs can be banked into the next period) and psychologically (as market actors factor in a tighter scheme in the future).

When a clear post-2012 price signal is evident in the market, this should set a floor price for the EUA price in phase 2 because any players with a long position will be able to take advantage of any arbitrage between the prices in both phases. In our modelling of phase 2 prices we use a stochastic approach with several thousand scenarios by flexing key variables. By setting in a price in our model for the post-2012 period we effectively set all scenarios in which the price is less than the post-2012 price to the post-2012 price. This has the effect of increasing our fair price upwards – even if the post-2012 price used is below the average phase 2 price.

Modelling post-2012 prices requires consideration of the political framework (i.e. which countries take on targets), the level of future emissions (determined by factors such as economic growth and fuel prices), and the cost of reducing emissions (including the price dependency of credits from the Clean Development Mechanism). The range of prices is large given the uncertainty around many of the variables.

In our central phase 2 price scenario, we do not assume any phase 3 price. But in Table 9 we examine the effect of including a phase 3 price and the impact that this has on the phase 2 price.

This report does not include any detailed modelling of phase 3 prices but instead uses indicative price levels based on two different (but realistic) political outcomes. The first scenario is that at start of the post-2012 period there is no global agreement reached on reduction targets and it is the EU that goes it alone, using the CDM as offset mechanism. Under this scenario we assume a phase 3 price of €20/tonne, which increases the phase 2 price from €25/tonne to €29/tonne.

The second scenario assumes that there is a more global agreement on emission reduction targets, which means the EU ETS is set more stringent targets and there is more competition for the supply of CDM credits. This results in a higher carbon price than the first scenario, which we assume is 35 €/t. This increases the phase 2 price to €31/tonne.

Table 9. Effect on phase 2 prices from the introduction of a phase 3 price

Scenario description	Indicative phase 3 price (€/t)	Phase 2 price (€/t)
Central phase 2 scenario	No phase 3 price assumed	25
Continuation of EU ETS post-2012 although no global agreement on GHG reduction targets, which leads less ambitious reduction targets for EU ETS	20	29
Existing Kyoto signatories and major emitters (including the US) sign up to new targets, albeit weak targets for new countries initially. This gives rise to more challenging EU ETS targets and more competition for offset credits.	35	31

2.5 Market view

Figure 38 show the development of EUA 2008 prices since the start of the 2007. At the start of the year there was little news on NAPs and prices followed the development of fuel and power prices (German Cal-08 contract). At the start of March, carbon prices began to increase based on the strict NAP decisions combined with the overall rise in energy prices, particularly the German power price. At the start of April, there was an early release of the 2006 emissions data. The emissions event led to an immediate fall in the EUA-08 price, even though 2006 emissions came in around 1 percent higher than in 2005. The price drop reflected early news reports failing to take into account the data released in the CITL were incomplete. Prices began to increase again the week after this and continued to increase steadily until a peak at the end of May. This increase was due mainly to further cuts in allocation plans and the market perception of a tight market early on in phase 2.

Following the three month bull-run, in which the EUA Dec 08 contract gained almost €8/t, the contract lost €2.9/t in June. During the month, volatility was high and the EU ETS had a record volume of allowances traded. An important factor for explaining the price decline, from a fundamental point of view, is the strong coal prices. Coal prices for 2008 ARA delivery increased from \$75.8/t on 1 June to

\$81/t on 24 June. Some of the decline can be explained by softening power prices and profit taking from speculative positions.

At the end of July, prices broke below the €20/tonne mark partly due to the emerging swap market of EUAs and CERs. But there was support at around €19/tonne and prices rebounded above the €20/t mark again. With the NAPs now settled, the main price drivers are energy prices, speculative position taking, CER hedging and CER/ERU supply signals. The price movements during August to October have been primarily based on the movement of the energy complex, with a decrease in the aftermath of the US credit crisis, followed by an increase in October with record high prices in both oil and coal.

Figure 38. Dec08 EUA price from Jan 2007 to Oct 2007

Figure 39 and 40 show how the EUA08 price has been correlated to German EEX calendar 08 baseload prices as well as crude oil and coal prices. As can be seen from both figures, the EUA price has been highly correlated with the Cal 08 EEX price for most of the period between February and October 2007. This can be explained by the following points:

- The German power market is the most significant market segment in the EU ETS in terms of emissions and trading activity and so movements in this commodity have a large effect on EUA prices;
- Power companies sell power forward contracts and lock-in the dark spread when they do so. This means that when prices go up and there is a favourable dark spread, power companies will lock-in the coal and carbon components. This in turn means that the demand for EUAs increases, which causes a price increase;
- The EUA price also affects the EEX price as the full cost of carbon is included in the generation costs and so is passed through into the power prices;
- Part of the correlation can also be attributed to market psychology as it is the power traders that often trade EUAs as well and so movements

in the energy complex often result in corresponding EUA price movements.

As Figure 40 shows, there is sometimes a high correlation between the EUA price and oil and coal prices although this does not occur all the time as there are other drivers in each of the markets. It is interesting to observe that coal and oil are correlated in the same direction i.e. EUA prices increase when oil and coal prices increase. The EUA price could be expected to decrease when coal prices increase as this would require a lower carbon price in order to switch from coal to gas-fired generation. But it can be explained by the fact that increased coal prices push the German power price up, and it is this that leads to the positive correlation with the EUA price.

Figure 39. German EEX Cal 08 prices and EUA 08

40. Correlation (rolling 30 day) with EUA 2008

2.6 Effect on Figure Nordic power and emissions

In this section of the report we use the carbon price forecasts described above, along with the main conclusions on how the power market has responded to the EU ETS to date, to model the effect on Nordic power prices and emissions during the first few years of phase 2.

Whilst the absolute results of power prices and emission levels are of interest, the main purpose of this modelling exercise is to assess the impact of changes in the carbon price on power prices, emissions and flows of power between countries.

2.6.1 Description of the SDDP model

SDDP is a mid-term hydrothermal dispatch model with representation of the transmission network. The model calculates the least-cost stochastic operating policy of a hydrothermal system using Stochastic Dual Dynamic Programming. The model solution represents a market equilibrium conditions obtained under assumption of perfect competition, where hydro power producers are optimizing their production given uncertainty regarding future inflow levels.

The essential advantage of using SDDP in hydrothermal systems is that it is possible to incorporate water values calculated with optimisation under uncertainty – i.e. future inflows are uncertain and this needs to be reflected in the system optimisation of the water value calculations. Many stack-based power models calculate the water values of hydro power given the knowledge of future prices (i.e. under certainty) but this can lead to under-estimated prices, due to the asymmetry in the relationship between hydro balance and price.

Since this is a market equilibrium type of model, output includes for example:

- System spot area prices;
- Water values for each hydro region;
- CO₂ emissions/power production/fuel consumption;
- Power transmission flows.

2.6.2 Price scenarios

The scenarios were run for the time period between 2008 and 2009, which is a realistic timescale for the assessment of how fuel and carbon prices affect power prices and emission levels in the Nordic region. The fuel and carbon price scenarios used are taken from section 2.3.

Table 10. Fuel and carbon price scenarios (2008 to 2009)

Scenario	Central	Central - High CO ₂	High	Low
CO ₂ price (€/t)	25	32	32	17
Coal price (\$/t)	81.3	81.3	81.3	81.3
Oil price (\$/bbl)*	72	72	90	54
* Gas prices and HFO prices are linked to the oil price				

The central scenario assumes a carbon price of 25 €/t and a crude oil price of \$72/bbl. We then include a sensitivity on just the carbon price without adjusting any of the fuel prices. This central oil, high CO₂ (central – high CO₂) scenario is representative of including a phase 3 price (35€/t), which serves to increase the phase 2 price to 31 €/t (see section 2.4).

We then look at two further scenarios in which the oil price is increased and decreased by 25% to \$90 and \$54/bbl respectively. This changes the CO₂ price to 32 €/t and 17 €/t.

Consumption does not differ between the scenarios, but there is a slight growth in consumption from 2008 to 2009.

2.6.3 Model setup

The model is set up as four countries (Norway, Sweden, Finland and Denmark) that are interconnected and modelled as a combination of thermal stack with twelve hydrological regions, covering the period between 2008 and 2009.

The initial water reservoir content is set at levels witnessed at the end of October 2007, which we note are higher than the normal. The model thus has good foresight of water levels at the start of 2008 but uncertainty is greater further out, giving rise to wider distributions of reservoir levels.

Inflow scenarios are generated from autoregressive models estimated from historical inflow data spanning from 1931 to 2005. The original data for Norway consists of water flow levels of 105 rivers which have been aggregated to 11 hydrological regions; 8 regions in price area NO1, 1 region in NO2 and 2 regions in NO3. The Swedish inflow model is based on data spanning from 1980 to 2005. Reservoir levels in each hydrological region are restricted by “soft constraints” adding a penalty if reservoirs go below a certain threshold level (alert storage) or if water is spilled.

Other types of power plants than hydro are represented with unit specific data for fuel efficiency and operation and maintenance cost. Based on profit maximization, a specific plant will run when the short-run marginal cost is lower than the market prices in the area. For combined heat and power plants, however, generation depends on temperature, not price. The available generation capacity is restricted according to maintenance

plans for different types of plants (coal plants, gas plants, nuclear plants, etc), based on historical outage patterns.

The model has a weekly resolution, but within the week, the load differs between four levels corresponding to off-peak I (weekdays 00:00–07:59), peak (weekdays 08:00–19:59), off-peak II (weekdays 20:00–23:59) and weekend (Saturday and Sunday). Demand is assumed fully inelastic in the short-run. Load is determined using the 1981–2005 temperature normal and historical growth levels in consumption.

Exchange between Nordpool price areas follows differences in the regional prices, but is of course restricted by transmission capacities (see Figure 41). We model power markets that are interconnected to the Nordic region exogenously. Germany is the most important country both in terms of size of cross-border power flows and the responsiveness to price differences. We also model the cross-border flows between the Netherlands and Norway through the NordNed interconnector that will be operational at the start of 2008:

- Germany/Netherlands: power prices in these regions are modelled based on the fuel and carbon price inputs used in the various scenarios. Quarterly price forecasts are derived taking the assumption that the recent level of spreads witnessed in peak and baseload contracts persist in 2008 and 2009;
- Russia/Poland: we use a fixed price to model the relatively constant imports of power into Sweden and Finland,

Figure 41. Overview of existing major power market linkages in/out of the Nordic region (Maximum Net Transfer Capacity capacities in MW)

Source: NordPool³

Source: There will be a link between Norway and the Netherlands (NordNed Interconnector) that will be operational from the start of 2008

³http://www.nordpoolspot.com/upload/Capacities/Maximum%20NTC%20Capacities_100MW%20tolerance.pdf

Based on the inflow model, 150 inflow scenarios are generated and the market equilibrium solution is obtained for each of these scenarios. The Nordpool system price is calculated using a weighted average of regional prices that the model produces.

Figure 42 shows a schematic of the distribution of different inflow scenarios. We note that the actual distribution is not normal and differs for the various seasons. In modelling power prices, generation levels and emissions in the SDDP model, we generally take the average of all inflow scenarios. However, in order to capture the effects of different hydro inflow levels, we also examine the 10% and 90% confidence intervals, which represent lower and higher than average inflow scenarios.

Figure 42. Schematic of distribution of model hydro inflow levels

2.6.4 Model results – NordPool system price forecasts

Figure 43 shows the forecast (spot) prices for the central scenario. We run the SDDP model using 150 different inflow scenarios (based on historic data) and the single line is the price outcome using the average of all of these inflow scenarios. In order to assess the effect on the price arising from higher or lower inflows, we show the price envelope taking the 10% and 90% interval inflow scenarios (represented by the blue area in the chart).

Figure 43. NordPool system price forecast (central scenario) based on average inflow scenarios and the 10 and 90% interval

From the figure we observe that:

- The quarterly prices display the profile common in the Nordic region with the highest prices occurring during the first quarter (Q1) due to the highest demand (we note that prices would be higher in the event of lower than normal temperatures);
- The annual 2009 price is around €/MWh higher than 2008 with the largest increase observed in the Q1 price. Fuel prices used in the scenario are the same across both years and the difference in prices is due to slightly lower levels of hydro production in 2009, leading to increased levels of thermal generation;
- With lower reservoir levels in 2009, there is lower hydro generation, which leads to higher system prices. Figure 44 shows the level of hydro generation under the different inflow scenarios. The relationship is asymmetric in this case in that a decrease of 40 TWh hydro generation in 2008 increases the annual average price by €/MWh, whereas an increase of 40 TWh decreases prices by €/MWh. The asymmetry may be in the other direction in periods with lower reservoir levels.

Figure 44. Quarterly level of hydro generation under different inflow scenarios

Figure 45 shows the system price forecasts for all the fuel and CO₂ price scenarios. For comparison purposes, we also show the actual trading range of forward prices settled between January and October 2007. Table 11 displays the average annual prices for all the scenarios.

Figure 45. NordPool system price forecasts for all scenarios (€/MWh)

Table 11. Average annual system prices for all scenarios (€/MWh)

Scenario	2008	2009
Central	46.3	47.3
- 10% inflow	49.1	51.7
- 90% inflow	42.7	43.7
Low	39.2	42.4
High	51.8	53.1
Central – high CO₂	50.9	53.2

We observe the following points:

- All the scenarios follow the same quarterly shape as the central scenario although the price levels vary according to fuel and CO₂ prices;
- The central scenario (with oil price of \$72/bbl and CO₂ price of €25/tonne) has average annual prices of €46.3/MWh and €47.3/MWh in 2008 and 2009 respectively;
- The high scenario (with oil price of \$90/bbl and CO₂ price of €32/tonne) has higher average annual prices of €5.50 and €5.80/MWh in 2008 and 2009 respectively compared to the central scenario. This is mainly due to higher prices of continental imports from Germany and Netherlands (with full pass-through of CO₂ costs), as well as increased generation costs in the Nordic region;
- The central high CO₂ case (with oil price of \$72/bbl and CO₂ price of €32/tonne) is representative of a scenario in which a post-2012 price signal increases the phase 2 CO₂ price, although the oil and oil-linked gas prices are the same as in the central scenario. In this scenario, NordPool system prices are very close to the high scenario, which suggests that the effect of increased CO₂ prices is the main driver of power prices and that oil prices do not have that much of an effect on Nordic prices. This is due to the fact that the majority of gas plants run

as CHP and that power output is not a function of the cost of production, but rather the level of heat output required. Also, coal prices set the marginal power price in Germany and so it is the increased CO₂ cost on top of coal prices that increases German power prices, hence pulling up the Nordic prices;

- An increase of €/tonne to the CO₂ price, increases power prices by around €5.6/MWh, which represents a very high level of pass-through into Nordic power prices (90%). Note that this assumes normal weather and also uses an average of all inflow scenarios. If we increase the CO₂ price by €/tonne but use the higher inflow case (90% confidence interval) then the power price increase is lower (average increase of €1.7/MWh for 08/09) and the apparent level of CO₂ cost pass-through into Nordic prices is much lower (30%). This shows that the cost of CO₂ is passed through to a high degree into Nordic power prices but that this increase can be offset by healthy hydrological conditions, which exert a bearish impact on power prices. This demonstrates that Nordic power prices cannot be analysed just on the basis of either the CO₂ price influence or hydrological conditions – these must be considered together;
- Higher prices post-2012 will have an effect on phase 2 EUA prices due to the ability to bank allowances between phases. This effectively raises the “floor” price in phase 2 as operators will seek to optimise their position through time. This in turn means that power prices in the EU, including the NordPool region, will increase as the CO₂ price increases;
- The low scenario (with oil price of \$54/bbl and CO₂ price of €7/tonne) has average annual prices that are, respectively, €7.10 and €4.90/MWh lower in 2008 and 2009 compared to the central scenario. This is due to the lower cost of generation both in the Nordic region and also in continental Europe. In this scenario, the 2009 annual price is higher than in 2008, and the percentage increase between years is significantly higher than in the central scenario. This is due to the fact that it is more profitable for hydro generators to run more in 2008, which leads to lower reservoir levels (and hydro production) in 2009.

2.6.5 Model results – Generation and emissions forecasts

Figure 46. Level of power sector emissions in Nordic region

Figure 46 shows the forecast level of emissions in 2008 and 2009 in the Nordic power sector, as well as the verified emissions for the power sector covered by the EU ETS in 2005 and 2006. As described in section 1.9.1, emission levels in the Nordic region can vary widely due to the hydrological conditions, in this case increasing by around 20 Mt CO₂ between 2005 and 2006. The emissions forecast in the central scenario in 2008 and 2009 are positioned in between the levels of 2005/6 emissions at around 47 Mt.

Figure 47 shows that:

- when hydro generation in 2008 decreases by around 18% compared to our central case, emissions increase by around 12% (from 47 to 53 Mt). Conversely, with a high inflow scenario and increased hydro production of 19%, emissions decrease by around 12%;
- the difference in emission levels between the low inflow and high inflow case in 2008 is significant at 11.5 Mt. This difference is even greater in 2009, at 17.5 Mt, due to the lower energy reservoir levels in 2009;
- the emissions from gas and HFO plants are relatively constant under the different inflow scenarios and it is the coal-based emissions that change, reflecting the fact that coal plants respond to the change in level of hydro generation. This emissions increase is noticed mostly in Denmark, which has the highest amount of coal plant, and to a lesser extent in Finland too.

We also note that in the case of lower hydro inflow (central – 10%), the generation and emissions increase in the Nordic region but there is also a large increase in the *net* level of imports into the region, which will increase the emissions in interconnected countries, as less hydro is imported from the Nordic region and more thermal generation is exported to

the Nordic region. In the central scenario (with average inflows) we observe a *net* import of 2 TWh into the Nordic region but this increases to over 30 TWh in the case of the lower inflow scenario.

Figure 47. Level of emissions by fuel type in the central scenario with different levels of hydro generation

Figure 48 shows the change in emissions for the various fuel and CO₂ price scenarios modelled in this study compared to the central scenario. Emission levels change due to changes in the level of coal, gas, and hydro generation, along with the level of net imports into the Nordic region. We note the following points:

- In 2008, emission levels decrease relative to the central scenario in all the other scenarios;
- For the central – high CO₂ scenario, the higher CO₂ price reduces the level of coal generation and some of this is shifted to increased gas production;
- For the high scenario (with higher gas and CO₂ prices), emissions decrease slightly (ca. 1 Mt) even though there is a slight increase in coal generation. Gas generation decreases, as would be expected with higher gas prices, but there is a significant increase in the level of net imports into the region;
- Emissions also decrease in the low scenario, with the primary driver being the lower gas price, which increases gas generation. Hydro and net import levels also increase at the expense of coal generation;
- The range of emissions across all scenarios in 2008 is only around 2 Mt;
- In 2009, which is a year with lower energy reservoir levels than 2008, emissions increase in all the other scenarios as hydro generation decreases;
- The range of emissions across all scenarios in 2009 is around 5 Mt, which is wider than in 2008 and predominantly driven by the change in hydro production levels

2008: Generation and emission levels relative to central scenario

2009: Generation and emission levels relative to central scenario

Figure 48. Change in generation levels and emissions relative to the central scenario in 2008 and 2009

From Figure 47 and Figure 49 it is apparent that the hydrological conditions have a more substantial impact on the level of emissions than fuel prices. One consequence of this is that allocations to power plants in the Nordic region should not be based only on one reference year as emissions are highly dependent on hydrological conditions, which exhibit significant annual variance. During the phase 2 NAP process, Finland was able to argue for a higher cap as the European Commission based its judgement using reference emissions in 2005, which was an unusually wet year.

We note though that for the next round of NAP discussions, which will need to be finalised before 2013, there will be a much longer history of verified emissions to use, should the EC wish to base their allocation methodology on historic data.

Within this modelling framework, we treat CO₂ prices as exogenous inputs into the model, although we note that a change in emissions will have a feedback effect on the CO₂ price. In a Nordic context, higher or lower than normal inflow can affect the emissions levels significantly (with 20 Mt annual variations observed historically), which would cer-

tainly have some influence on the CO₂ price. However, there are numerous other CO₂ price drivers that also come into play including temperature, hydro conditions in other parts of Europe (Iberia and the Alpine region), fuel prices, CER/ERU supply, etc, which taken together would influence CO₂ prices much more than just the Nordic hydro conditions.

Table 12. Summary of power sector emissions in Nordic region for all scenarios (Mt/year)

Scenario	2008	2009
Central	47.1	48.0
- 10% inflow	52.8	57.8
- 90% inflow	41.4	40.3
Low	46.3	52.7
High	46.0	49.1
Central – high CO₂	45.1	49.8

2.6.6 Model results – Power flows

Figure 49 displays the flow of power between two regions: Norway (NO1), which is a hydro dominated area, and Denmark, which is thermally dominated. This serves as an example to show the effect of the different scenarios on cross-border power flows. The figure shows a familiar overall pattern of flows with thermal imports from Denmark to Norway highest during the winter months and hydro exports from Norway to Denmark, which are highest during the summer months. There are, however, flows both ways across the year reflecting the difference between peak and off-peak prices in the different systems.

Figure 49. Weekly imports and exports of power between Norway (NO1 region) and Denmark for central scenario (2008)

Figure 50 shows the annual flows between these regions for the different scenarios. In 2008, which has a higher energy reservoir level than normal, there is a high level of export from Norway to Denmark and this increases in the high and central (high CO₂) scenarios, as the generation

costs in Denmark increase. It is interesting to observe that imports from Denmark to Norway also increase with higher CO₂ prices, as it more advantageous for hydro producers in Norway to sell their power into Denmark during peak periods and import power for off-peak periods.

A more comprehensive examination of the cross-border flows between countries would need to cover all of the regions (not just one border) and also would need to model the German and Dutch power markets endogenously to capture the effect of relative prices on flow volumes and directions.

Figure 50. Annual imports and exports of power between Norway (NOI region) and Denmark for all scenarios (2008)

2.7 Conclusions

The model that we have used to forecast prices and emission levels is ideal for the hydro-dominated Nordic system, as this allows us to examine the impact both from fuel/CO₂ prices and hydrological conditions (which are used in the model to calculate the water values with optimisation under uncertainty).

The average annual forecast NordPool system price in 2008 for the central scenario is €46.3/MWh. This result is based on the average of all the 150 inflow scenarios for this model run. The impact of the inflow level on system prices is significant with a decrease of 40 TWh hydro generation in 2008 increasing the annual average price by €2.80/MWh, and an increase of 40 TWh decreasing prices by €3.60/MWh.

Both the "central – high CO₂" and "high" scenario have a higher CO₂ price (€32/tonne) than in the central scenario (€25/tonne) but the high scenario also has an oil price that is 25% higher. The system prices for these two scenarios are very close together, which suggests that the effect of increased CO₂ prices is the main driver of power prices and that oil prices do not have that much of an effect on Nordic prices. This is due to the fact that the majority of gas plants run as CHP and that power output is not a function of the cost of production, but rather the level of heat

output required. Also, coal prices set the marginal power price in Germany and so it is the increased CO₂ cost on top of coal prices that increases German power prices, hence pulling up the Nordic prices.

Increasing the CO₂ price by €/tonne in the central scenario, increases power prices by around €5.6/MWh, this represents a very high level of pass-through into Nordic power prices (90%). With the same fuel and CO₂ prices, but using a higher inflow level, the apparent level of CO₂ cost pass-through into Nordic prices is much lower (30%). This shows that the cost of CO₂ is passed through to a high degree into Nordic power prices but that this increase can be offset by healthy hydrological conditions, which exert a bearish impact on power prices. This demonstrates that Nordic power prices cannot be analysed just on the basis of either the CO₂ price influence or hydrological conditions – these must be considered together.

Higher prices post-2012 will have an effect on phase 2 EUA prices due to the ability to bank allowances between phases. This effectively raises the “floor” price in phase 2 as operators will seek to optimise their position through time. This in turn means that power prices in the EU, including the NordPool region, will increase as the CO₂ price increases. So if there is a bullish signal for phase 3 prices, based on the anticipation of tighter supply/demand fundamentals in the post-Kyoto period, this could have a direct effect now on increasing Nordic power prices, through raising the phase 2 CO₂ price.

It is not that clear cut in terms of how a high EUA price would affect Nordic power sector emissions. A higher CO₂ price should also serve to lower emissions, through switching generation from coal to gas, but there is not much switching potential in the Nordic region, which means that changes in hydro generation and the level of imports have a greater impact on the level of emissions.

In the central scenario, when hydro generation in 2008 decreases by around 18%, emissions increase by around 12% (from 47 to 53 Mt). Conversely, with a high inflow scenario and increased hydro production of 19%, emissions decrease by around 12%. The range of emissions variability between the low and high inflow scenario is even greater (17.5 Mt) in 2009, due to the lower energy reservoir level.

With changes in fuel/CO₂ prices in the other scenarios, the effect on emissions is limited. In years with high energy reservoir levels, the effect of fuel price changes is limited to within a narrow range of 2 Mt/year, although again this depends on both the level of hydro generation but also the level of net imports from countries interconnected to the Nordic region.

When the level of hydro generation varies from year to year, the emissions from gas and HFO plants are relatively constant under the different inflow scenarios and, within the Nordic region, it is the coal-based emissions that change, reflecting the fact that coal plants respond to the change in level of hydro generation. This emissions increase is noticed

mostly in Denmark, which has the highest amount of coal plant, and to a lesser extent in Finland too. We note that any additional net imports to the Nordic region will also result in increased emissions in neighbouring interconnected due to lower hydro imports from the Nordic region and more thermal exports.

Within this modelling framework, we treat CO₂ prices as exogenous inputs into the model, although we observe that a change in emissions will have a feedback effect on the CO₂ price. In a Nordic context, higher or lower than normal inflow can affect the emissions levels significantly (with 20 Mt annual variations observed historically), which would certainly have some influence on the CO₂ price. However, there are numerous other CO₂ price drivers that also come into play including temperature, hydro conditions in other parts of Europe (Iberia and the Alpine region), fuel prices, CER/ERU supply, etc, which taken together would influence CO₂ prices much more than just the Nordic hydro conditions.

Sammendrag

EUs kvotesystem (EU ETS) har nå gått over fra sin første fase (2005–7), en læringsfase, til andre fase (2008–12), som sammenfaller med Kyoto-protokollens første forpliktelsesperiode. Det er derfor et hensiktsmessig tidspunkt å vurdere i hvilken grad EU ETS har påvirket nordiske kraftpriser og utslipp i den første fasen, og anvende disse funnene til å se på forholdet mellom disse faktorene i fase 2.

Prisen på kvotene i EUs kvotesystem (kalt EUA) har vært volatil i de tre første årene med kvotehandel og har variert mellom 30 Euro per tonn ned til 3 euro cent per tonn. Markedet hadde en initiell forventning om knapphet på kvoter. Publisering av de verifiserte utslippsdataene for 2005 og 2006 viste imidlertid at det var et overskudd av kvoter, noe som førte til lave priser mot slutten av den første fasen.

De nordiske landene som var dekket av EU ETS i fase 1 (Sverige, Danmark og Finland) hadde høyere allokering enn utslipp i denne fasen, i likhet med EU27 som helhet. Unntaket er Danmark der utslippene i 2006 var om lag 20 prosent høyere enn utslippene i 2005. Dette vitner om at utslipp i Danmark (og andre Nordiske land) er svært sensitive for metrologiske og hydrologiske forhold i Skandinavia, særlig den hydrologiske balansen i Norge og Sverige, men også for temperatur og vind.

Kraftsektoren er den største og viktigste sektoren i EUs kvotesystem, med rundt 60 prosent av kvotene. Bedriftene i kraftsektoren er også de mest dynamiske aktørene i kvotemarkedet. Dette har tidvis ført til høy korrelasjon mellom CO₂-priser og brenselpriser, spesielt i 2005 da markedet ennå trodde det var knapphet på kvoter og at det ville være nødvendig med tiltak – feks kjøring av gasskraftverk istedet for kullkraftverk – for å overholde utslippsgrensene.

Vår analyse av disse korrelasjonene viser at gass- og kullpriser kun har hatt begrenset effekt på CO₂-prisen, og kun i visse perioder. Korrelasjonen mellom oljepris og CO₂-pris har vært mye sterkere, noe som henger sammen med at gassprisene i Europa er indeksert med oljebaserte produkter (med noe tidsforsinkelse). Selv om denne korrelasjonen ikke var tilstede mot slutten av første fase da det var klart at det var overskudd av kvoter, antar vi at oljeprisen igjen vil være en viktig prisdriver for CO₂-prisen i fase 2 av EU ETS.

Vannkraft utgjør bortimot 100 % av kraftproduksjonen i Norge og omlag 50 % i Sverige. Derfor er det naturlig at vær-situasjonen påvirker utslippsnivåene. Som ventet finner vi mye sterkere korrelasjon mellom endringer i EUA-prisen og værforhold tidlig i fase 1, da markedet ennå trodde at det var knapphet på kvoter, enn sent i fasen. Vi antar at denne korrelasjonen vil bli sterkere igjen i fase 2, spesielt i vinterhalvåret.

Kraftpriser

Innføringen av EUs kvotesystem i 2005 har hatt betydelig innvirkning på kraft-prisene i Europa. Kostnadene ved CO₂ legges til den marginale produksjons-kostnaden i termisk kraftproduksjon, og kommer til syne i form av høyere kraftpriser. Bortsett fra i svært våte eller tørre perioder bestemmes norske kraftpriser av marginalkostnaden på kull- eller gasskraftverk. Høyere kraftpriser som følge av kvotepriser vil øke den relative konkurranse-kraften til produsenter med lave utslipp, slik som atomkraftverk, kraftverk basert på fornybare energikilder og kraftverk med fangst- og lagring av CO₂.

En analyse av forskjellen mellom brenselkostnader og kraftpriser er nyttig for å vurdere i hvilken grad CO₂-kostnader blir lagt til som et påslag på kraftprisen. Det er utfordrende å analysere NordPool-regionen i dette henseende, siden den underliggende forskjellen mellom brenselkostnader og kraftpriser vil være avhengig av forventet vannkraftproduksjon i regionen. Vi ser imidlertid at NordPool-markedet har fulgt tendensene i det tyske markedet, ved at markedet sakte men sikkert har tatt innover seg kvotesystemet, og at en rimelig stor andel av CO₂ kostnaden nå prises inn i forward-prisene. Dette er en indikasjon på EU ETS har påvirket NordPool-markedet delvis via handel med Tyskland. Mens tyske forward-priser på kraft ser ut til å prise inn hele CO₂-kostnaden i sine priser, priser NordPool-regionen inn om lag halvparten av kostnaden (noe som skyldes den store andelen av fornybar kraftproduksjon og virkningen dette har på kraftprisen).

Vann- og snømagasinene er den viktigste prisdriveren innenfor NordPool-markedet. Figuren under viser at det har vært en endring i forholdet mellom den hydrologiske balansen (avvik mellom faktisk energireservoar og normalt energireservoar) og pris siden 2005. Vi ser fortsatt en sterk korrelasjonen mellom de to faktorene, men nivået på spot-prisen i perioden 2005–7 har vært godt over hva en kunne forventet utfra den historiske sammenhengen mellom hydrologisk balanse og spot-prisen i NordPool-systemet, som følge av at kostnaden ved CO₂ er priset inn i kraftprisen. Dette illustrerer effekten av integrasjonen mellom det hydrobaserte norske og svenske kraftsystemet og de termisk dominerte systemene i Danmark og Tyskland.

Spot priser i NordPool (€/MWh) og hydrologisk balanse (TWh)

Europeiske kraftmarkeder har generelt blitt mer volatile som følge av at både kraft og CO₂-priser påvirkes av de samme grunnleggende faktorer. Dette ser vi også i Nordpool-markedet. Det er imidlertid vanskelig å isolere effekten av EU ETS fra andre faktorer knyttet til brenselprisen.

Utslippsnivå

Utslippsnivået i den nordiske kraftsektoren har variert mye, noe som i hovedsak skyldes variasjoner i energireservoarer i denne regionen (se figuren under). Gjennomsnittlig årlig utslipp i perioden 1990 til 2006 var 56 Mt. Det høyeste utslippsnivået i denne perioden var 78 Mt (1996) – noe som var en økning fra året før på 22 Mt som følge av svært lite nedbør dette året. Danmark har de høyeste gjennomsnittlige utslippene og også høyest variasjon i utslippsnivå fra år til år.

Utslippsnivå fra kraftsektoren og nivå i energibeholdningen (avvik fra normalt)

Temperatur er en annen faktor som påvirker utslippsnivå via kraftforbruket. Dette er særlig tydelig i Sverige, Norge og Finland der mye av varmebehovet dekkes av elektrisitet (og varmesystemer basert på fossile brensler). Effekten av svingninger i brenselpriser er begrenset i det nordiske markedet siden potensialet for å skifte mellom brensler til kraftpro-

duksjon er begrenset, særlig sammenlignet med effektene vi observerer fra endringer i værrelaterte faktorer.

Fase 2 av EU ETS

Fase 2 av EU ETS (2008–12) er linket til det internasjonale karbonmarkedet. En viktig endring fra fase 1 til fase 2 er at det i motsetning til tidligere nå er lov til å overføre kvoter til påfølgende fase, noe som betyr at prissignaler for perioden post-2012 vil påvirke prisdannelsen i fase 2.

I vår analyse presenterer vi ulike karbonpris-scenarier basert på vår beskyttede *Carbon Price Forecaster* modell. Vi bruker deretter disse scenariene i vår nordiske kraftmodell for å se på virkningen av CO₂-priser, kraftpriser og vanntilførsel på NordPool priser, nivå av kraftoverføring mellom land, kraftproduksjon og utslipp.

Modellen vi bruker til å forutsi priser og utslippsnivåer er spesialtilpasset det vannkraft-dominerte nordiske systemet og gir oss muligheten til både å undersøke effekten av brensler/CO₂-priser og vannressurssituasjonen.

Figuren under viser brensel- og karbonprisscenariene vi har brukt. Vår hovedantakelse (central) for CO₂-pris er per idag €25/tonn (gjennomsnittlig pris over femårsperioden). I høy- og lav- scenariene forventer vi at oljeprisen henholdsvis øker eller synker med 25 %. Kullprisen er holdt konstant slik at vi kan analysere den relative påvirkningen fra kull og olje/gass. I ”central-high CO₂”- scenariet bruker vi de samme brenselprisene som i vårt hovedscenario, men antar en post-2012-pris på €35/tonn CO₂, noe som gir en gjennomsnittlig fase 2 pris på €32/tonn. (Post-2012-prisen på €35/tonn fremkommer i et scenario med økt deltakelse og strenge målsetninger i det globale klimaregimet).

Brensel- og karbonprisscenarier (2008 to 2009)

Scenario	Central	Central - High CO ₂	High	Low
CO ₂ price (€/t)	25	32	32	17
Coal price (\$/t)	81.3	81.3	81.3	81.3
Oil price (\$/bbl)*	72	72	90	54

* Gas prices and HFO prices are linked to the oil price

Resultater – kraftpriser

Den gjennomsnittlige NordPool prisen i 2008 er i vårt hovedscenario €46.3/MWh. Dette resultatet har fremkommet som et gjennomsnitt av 150 scenarier for tilsig til kraftmagasinene som er kjørt i modellen. Virkningen av ulike tilsigsscenarier er betydelig; vi finner at en nedgang på 40 TWh vannkraftproduksjon i 2008 vil øke den årlige gjennomsnittsprisen med €2.80/MWh, og en tilsvarende økning på 40 TWh vil føre til at prisene synker med €3.60/MWh i gjennomsnitt.

Årlige gjennomsnittspriser for alle scenarier (€/MWh)

Scenario	2008	2009
Central	46.3	47.3
- 10% inflow	49.1	51.7
- 90% inflow	42.7	43.7
Low	39.2	42.4
High	51.8	53.1
Central – high CO₂	50.9	53.2

Både "central-high CO₂"-scenariet og "high"-scenariet (€32/tonn) har en høyere CO₂-pris enn i hovedscenariet ("central") ((€25/tonn). I tillegg har "high"-scenariet en oljepris som er 25 % høyere. Prisene i "central-high CO₂" og "high" ligger tett opptil hverandre, noe som indikerer at effekten av økte CO₂-priser er hoveddriveren bak kraftprisene og at oljeprisen har en relativt liten effekt på Nordiske kraftpriser. Dette skyldes at de fleste gasskraftverkene er kraft-varme verk (CHP) og at kraftproduksjonen avhenger av det rådende varmebehovet, ikke av produksjonskostnader. Samtidig settes den marginale kraftprisen i Tyskland av kullprisen. Dermed vil det være påslaget av CO₂-kostnaden på toppen av kullprisen som skaper økte kraftpriser i Tyskland, og som i sin tur bidrar til økte priser i det nordiske systemet.

Ved å øke CO₂-prisen med €/tonn i hovedscenariet, øker kraftprisene med rundt €5.6/MWh. Dette innebærer at CO₂-prisen i svært stor grad reflekteres i økte kraftpriser i Norden (90 %). Ved å bruke de samme brensel- og CO₂-priser, men øke tilsiget til vannmagasinene, vil imidlertid CO₂-kostnaden overføres til kraftprisen i betydelig mindre grad (30 %). Selvom CO₂-prisen i stor grad reflekteres i kraftprisen, vil dette altså kunne oppveies av mye nedbør og høyt energitilsig. Dette viser tydelig at det ikke er mulig å analysere nordiske kraftpriser ved utelukkende å se på CO₂-priser eller hydrologiske forhold – de ulike faktorene må sees i sammenheng. Myndighetene i de nordiske landene bør ha dette i bakhodet i forbindelse med beslutninger om allokering av kvoter til kraftsektoren.

Høyere priser post-2012 vil ha en effekt på EUA-prisene i fase 2 av EU ETS fordi det nå er anledning til å overføre kvoter fra fase 2 til senere faser. Dette vil øke "bunnprisen" i fase 2 idet operatørene i EU ETS-markedet vil søke å optimalisere sine posisjoner. Dette betyr igjen at kraftprisene i EU, inkludert i NordPool-regionen, vil øke som følge av økt CO₂-pris. Hvis signalet for fase 3-priser er "bullish" (dvs. prisen skal opp), basert på en forventning om et strammere forhold mellom tilbud/etterspørsel av kvoter, kan dette, gjennom at CO₂-prisen for fase 2 øker, få en direkte effekt på dagens nordiske kraftpriser.

Resultater – Utslipp fra kraftsektoren i Norden

Det er ikke trivielt å analysere sammenhengene mellom EUA-priser og utslipp fra kraftsektoren i Norden. En høyere CO₂-pris burde teoretisk føre til lavere utslipp, gjennom skifte fra kullbasert- til gassbasert kraftproduksjon. Men siden det er relativt lite potensial for slikt skifte i det nordiske kraftmarkedet, betyr det at endringer i vannkraftproduksjon og grad av kraftimport fra andre regioner har en større effekt på utslippsnivåene i denne regionen. Det må legges til at høyere kraftpriser som følge av utslippskvoter på litt sikt vil redusere kraftforbruket og dermed utslippene. Vi kan også forvente en langsiktig effekt på tilbudssiden i kraftmarkedet siden høye kvotepriser gjør investeringer i utslippsfrie teknologier mer attraktive.

Hvis vi ser på et tilfelle med lavt tilsig i vårt hovedscenario (central), der vannkraftproduksjonen i 2008 synker med rundt 18 %, øker utslippene med rundt 12 % (fra 47 til 53 Mt). I motsatt fall vil et tilsigsscenario med 19 % høyere tilsig enn "normaltilsiget" føre til 12 % lavere utslipp. Gapet mellom scenariene med høyt eller lavt vanntilsig er ennå større i 2009 (17,5 Mt) som følge av noe lavere gjennomsnittlige reservoarnivå.

I følge modellresultatene er utslippseffekten av endrede brensel/CO₂-priser begrenset. I år med stor energibeholdning, finner vi at effektene av brenselsprisendringene vi har forutsatt ikke er mer enn 2 Mt/år. Merk imidlertid at dette også er avhengig av både nivå av vannkraftproduksjon og kraftimport fra land som er koplet sammen med det nordiske kraftmarkedet.

Til tross for variasjoner i årlig vannkraftproduksjon, vil utslippsnivået fra gasskraftverk og oljefyrte kraftverk være relativt konstant. Når det gjelder utslippene fra kullkraftverk ser vi imidlertid endringer som følge av at kullkraftproduksjonen påvirkes av endringer i nivået på vannkraftproduksjonen. Økningen i utslipp kommer tydeligst frem i Danmark, som har størst andel kullkraftverk, og til en viss grad også i Finland. Vi ser også at økt kraftimport til det nordiske markedet resulterer i økte utslipp i naboland som er koplet til det nordiske kraftmarkedet – på grunn av lavere import av vannkraft fra det nordiske markedet og høyere eksport av kull/gasskraft.

Sammendrag av utslipp fra kraftsektoren i Norden for alle scenariene (Mt/år)

Scenario	2008	2009
Central	47.1	48.0
- 10% inflow	52.8	57.8
- 90% inflow	41.4	40.3
Low	46.3	52.7
High	46.0	49.1
Central – high CO₂	45.1	49.8

Appendices

Glossary of terms

Annex B Countries	Annex B countries are the 39 emissions-capped countries listed in Annex B of the Kyoto Protocol.
Annex I Countries	Annex I countries are the 36 countries and economies in transition listed in Annex I of the UNFCCC. Belarus and Turkey are listed in Annex I but not Annex B; and Croatia, Liechtenstein, Monaco and Slovenia are listed in Annex B but not Annex I. In practice, however, Annex I of the UNFCCC and Annex B of the Kyoto Protocol are often used interchangeably.
Annex II Countries	Annex II of the UNFCCC includes all original OECD member countries plus the European Union.
Assigned Amount (AA) and Assigned Amount Units (AAUs)	The assigned amount is the total amount of greenhouse gas that each Annex B country is allowed to emit during the first commitment period (see explanation below) of the Kyoto Protocol. An Assigned Amount Unit (AAU) is a tradable unit of 1 tCO ₂ e.
Auctioning	Allocation mechanism in which allowances are provided to the installation on the basis of prices that the installation is willing to pay in an auction
Baseline and Baseline Scenario	The baseline represents forecasted emissions under a business-as-usual (BAU) scenario, often referred to as the 'baseline scenario' i.e. expected emissions if the emission reduction activities were not implemented.
BAT	Best available technology
Benchmarking	Allocation mechanism in which allowances are provided to the installation on the basis of a specific benchmark installation's requirement for such allowances
Business As Usual Scenario (BAU)	A business as usual scenario is a policy neutral reference case of future emissions, i.e. projections of future emission levels in the absence of changes in current policies, economics and technology.
Cap and Trade	A Cap and Trade system is an emissions trading system, where total emissions are limited or 'capped'. The Kyoto Protocol is a cap and trade system in the sense that emissions from Annex B countries are capped and that excess permits might be traded. However, normally cap and trade systems will not include mechanisms such as the CDM, which will allow for more permits to enter the system, i.e. beyond the cap.
Carbon Dioxide Equivalent (CO ₂ e)	This is a measurement unit used to indicate the global warming potential (GWP) of greenhouse gases. Carbon dioxide is the reference gas against which other greenhouse gases are measured.
Carbon Market Forecaster	This model provides the foundation for the estimation of the present value of carbon permits. Carbon Market Forecaster uses input data from a large number of sources: historical trends, various top-down models, bottom-up studies, expert group surveys and forecasts. The model is highly flexible and is updated continuously.
Carbon Net Present Value	<p>This is the carbon-associated segment of an installation's cash-flow that is discounted. This discounted cash-flow is the sum of the:</p> <p>Compliance costs from the scheme, which is a function of allocation mechanism, the price of carbon and the actual level of plant dispatch;</p> <p>Carbon revenue from the scheme that is a function of the price</p>

	of carbon, the level of CO ₂ pass-through into power prices and the level of plant dispatch.
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage – technology for capturing CO ₂ from large point sources such as power plants and storing this in suitable storage sites (often deep geological structures including saline formations and exhausted gas fields),
Certification	The certification process is the phase of a CDM or JI project when permits are issued on the basis of calculated emissions reductions and verification, possibly by a third party.
Certified Emission Reductions (CERs)	CERs are permits generated through the CDM.
CHP	Combined heat and power
Clean Development Mechanism (CDM)	The CDM is a mechanism for project-based emission reduction activities in developing countries. Certificates will be generated through the CDM from projects that lead to certifiable emissions reductions that would otherwise not occur.
CNPV	See Carbon Net Present Value
Commitment Period	The five-year Kyoto Protocol Commitment Period is scheduled to run from calendar year 2008 to calendar year-end 2012.
Economies in Transition (EIT)	Countries that are in the transition from a planned economy to a market-based economy, i.e. the Central and East European countries, Russia, and the former republics of the Soviet Union.
Dark clean spread	The dark spread less the price of CO ₂ adjusted for the carbon intensity of coal-fired generation
Dark spread	The power price less the price of coal adjusted for the efficiency of the coal-fired generation plant
EC	European Commission
Emission Reduction Unit (ERU)	Permits achieved through a Joint Implementation project.
ERU	Emission Reduction Unit
EUA	EU Allowance
EU ETS	European Union Emissions Trading System
EU27	27 members of European Union (EU25 including Bulgaria and Romania)
Grandfathering	Method for allocation of emissions, where permits are allocated, usually free of charge, to emitters and firms on the basis of historical emissions.
Greenhouse gases (GHGs)	Greenhouse gases (GHGs) are trace gases that control energy flows in the Earth's atmosphere by absorbing infra-red radiation. Some GHGs occur naturally in the atmosphere, while others result from human activities. There are six GHGs covered under the Kyoto Protocol – carbon dioxide (CO ₂), methane (CH ₄), nitrous oxide (N ₂ O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulphur hexafluoride (SF ₆).
Clean spark spread	The spark spread less the price of CO ₂ adjusted for the carbon intensity of gas-fired generation
Host Country	A host country is the country where a JI or CDM project is physically located.
Hot Air	Excess permits that have occurred due to economic collapse or declined production for reasons not directly related to intentional efforts to curb emissions.
International Emissions Trading (IET)	Emissions Trading allows for transfer of AAUs across international borders or emission allowances between companies covered by a Cap and Trade scheme. However, it is a general term often used for the three Kyoto mechanisms: JI, CDM and emissions trading.
Joint Implementation (JI)	Joint Implementation is a mechanism for transfer of emissions permits from one Annex B country to another. JI generates ERUs on the basis of emission reduction projects leading to quantifiable emissions reductions.

Kyoto Protocol	The Kyoto Protocol originated at COP-3 to the UNFCCC in Kyoto, Japan, December 1997. It specifies emission obligations for the Annex B countries and defines the three so-called Kyoto mechanisms: JI, CDM and emissions trading. It entered into force on 16 February 2005.
Leakage	Decrease or increase of greenhouse gas-related benefits outside the boundaries set for defining a project's net greenhouse gas impacts that result from project activities.
Marginal Abatement Cost (MAC)	The marginal abatement cost is the cost of reducing emissions with one additional unit. Aggregated marginal costs over a number of projects or activities define the marginal abatement cost curve.
NAP	National Allocation Plan – plan submitted by each EU Member State with details of allocations at national, sector and installation level.
NER	New entrant reserve – allowances set aside for new installations that are not included in an initial allocation
Non-Annex I countries	Annex I is an Annex in the UNFCCC listing those countries that are signatories to the Convention and committed to emission reductions. The Non-Annex I countries are developing countries, and they have no emission reduction targets.
Spark spread	The power price less the price of gas adjusted for the efficiency of gas-fired generation plant
SRMC	Short run marginal cost
UNFCCC	United Nations Framework Convention on Climate Change. The UNFCCC was established 1992 at the Rio Earth Summit. It is the overall framework guiding the international climate negotiations. Its main objective is "stabilisation of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic (man-made) interference with the climate system".
Verification	In order for AIJ, CDM and JI projects to have a formalised validation of an emission reduction stream, a recognised independent third party must confirm that claimed emissions reduction activity has occurred.

2. Point Carbon's CO₂ fair price methodology

(Fair price methodology from October 2007)

Point Carbon has introduced a framework for estimating a “fair” price for Phase 2 EUAs based on three main elements:

- CER/ERU prices from the primary project market⁴ define a price floor for EUAs;
- The cost of switching to less carbon-intensive fuels defines a price ceiling;
- The extent to which EUAs should be priced against the floor or ceiling is determined by the probability (X) that domestic reductions will be needed to cover the entire shortage.

⁴ Note that we differentiate between CER/ERU prices from the primary market, which involves purchasing credits from projects directly, and the secondary market, which involves purchasing credits from another counterparty (i.e. the credit is disassociated from a particular project)

Importantly, Phase 2 prices should not drop to zero – as seen in Phase 1 – due to the opportunity to bank allowances into Phase 3. This in effect leaves us with two competing sources of demand for Phase 2.

On the one hand, if the supply of CERs/ERUs and reserves are sufficient to cover the entire shortfall, EUAs should approach the price of CERs/ERUs which defines a price floor. On the other hand, in case domestic reductions are needed, EUAs should be priced against the cost of switching to less carbon-intensive fuels in the power and heat sector, which in turn defines a ceiling for EUA prices (an absolute price ceiling is of course the penalty level of €100/t + the price of Phase 3 allowances needed to cover the shortfall).

Having established a view on CER/ERU and switching prices, the question is how to determine the extent to which EUAs should be priced against CERs/ERUs (floor) or switching prices (ceiling)?

Acknowledging inherent uncertainties about supply and demand, the following formula is employed:

$$\text{Fair price} = X * \text{Switching price} + (1-X) * \text{CER/ERU price}$$

Here X denotes the probability that domestic reductions will be required to cover the shortfall, Switching price is the cost of switching to less carbon-intensive fuels in the power and heat sector (ceiling) and CER/ERU price is the price of credits from CDM (CER) and JI (ERU) projects (floor).

The probability X is in effect a “weighting” factor that expresses the extent to which EUAs should be priced according to CERs/ERUs or

switching prices as illustrated in the figure below.

Point Carbon's fair price assessment

Schematic showing Point Carbon's probabilistic approach to determining a fair price for Phase 2 EUAs

In general, X is defined as the share of events or outcomes (%) where domestic reductions are needed. Hence, if X=50% there is an equal number of outcomes or events where domestic reductions are needed as events where supply of CERs/ERUs and reserves is sufficient to cover the entire shortage.

In practice, X can be determined from Monte Carlo simulations by assigning mean values and statistical distributions for key input parameters. Even though determining mean values and distributions for all key parameters is a complex exercise, the following figure provides an outline of how this is done using a combination of quantitative and qualitative methods.

Schematic showing how to estimate the probability that domestic reductions will be needed in Phase 2

Floor price

In order to establish a Phase 2 price floor based on CER/ERU prices there are several key elements one could consider including:

- i) marginal development cost for CDM/JI projects; and
- ii) price floor communicated by developing country project developers.

i. It is well documented that there are CDM and JI projects with development costs around and even below the €1/t mark. However, as the technical potential for some of these projects (e.g., HFC) is close to being fully utilised, a more relevant question is what the marginal development cost would be for a portfolio of projects that could cover the entire shortage in the EU ETS. There is currently not enough information to calculate this given the uncertainty in the level and type of supply from CDM/JI projects.

ii. China has introduced a “price floor”, according to which they will not sell CERs below a level of €8–9/t. As this level applies even to projects where the seller does not commit to or guarantee delivery, one should in principle add a risk premium and costs representing third-party margins.

Considering these elements, we firstly recognise the importance of China which is expected to provide up to 70% of volumes in Phase 2 and in our view is unlikely to lower its price floor of €8–9/t. On the other hand, one could see increased competition from project developers in other countries which may offer projects below the Chinese price floor. Finally, technological innovation could also forward low-cost abatement opportunities below the current “Chinese price floor”. Overall, the balance of evidence suggests a price floor of €8/t.

Price ceiling – Switching price

Owing to the diversity of installations covered by the EU ETS, abatement costs will range from a few to several hundred euros. In practice, however, a time horizon of 5 years is generally limited in comparison with the life-time of investing in more energy efficient production technologies for, say, cement and steel production. Hence, it is reasonable to assume that the bulk of reductions in Phase 2 will be provided by switching to less carbon-intensive fuels in the power and heat sector.

In general, the switching price is a function of fuel prices and efficiencies and will thus differ across time and geography. The figure below provides a schematic illustration of UK switching prices based on a range of plant efficiencies to represent a “high” and “low” switching price.

Illustration of UK switching prices

3. Theory – impact of CO₂ on power prices

At its most basic level, power prices in the market are a function of:

- the short-run variable or marginal costs (SRMC) of the power plant that is needed to meet demand at any given time. As power demand increases, plants with higher marginal costs are needed to meet that demand and the power price increases; and
- the level of fixed costs that can be recovered depends on the capacity of plant that is available to generate compared with the demand level and the level of market power that exists. Where the merit order is most competitive, in the off-peak when the level of demand is lowest compared to the amount of capacity, prices may be bid down to SRMC. In other periods when demand is higher, there is less competition to generate and some additional degree of fixed cost recovery is likely to occur.

If there is considerable market power (such as one firm owning a large amount of the installed capacity in a given market segment), then a firm could ensure that it recovers all of its fixed costs over the year and possibly considerable additional profits. If one firm has enough market power, then it can affect prices in all hours of the day.

The process that we describe above is illustrated in that uses a schematic price duration curve (a curve that shows how long certain price levels in a market exist).

Price duration – setting electricity prices in a market

In looking at the impact of CO₂ on these market dynamics, it is important to realise that the proportion of the CO₂ price provided for free (through the allocation plan) will have a role to play. However, from an economic optimisation standpoint it is incorrect to assume that if all of the CO₂ allowances are provided free to the operator, then the CO₂ price will not subsequently influence power pricing. This is because the traded CO₂ price becomes an opportunity cost for the generator that it must take into account in deciding to generate.

CO₂ price as an opportunity cost

The CO₂ price is an opportunity cost because in deciding to generate, a power producer will use up both its fuel and the CO₂ allowances required to off-set the emissions from that generation. In most power markets, generators will only generate electricity therefore if the revenue from selling electricity exceeds the revenue that they could earn from selling their fuel and CO₂ permits in the respective spot markets. This will influence power prices as the electricity market needs to provide a higher level of remuneration for generators to secure the same volume of electricity.

However, this does not necessarily mean that the CO₂ price will influence the electricity price in every hour.

As an opportunity cost, the combined opportunity costs of fuel and CO₂ must exceed the power price for the power price to adjust to secure the given level of generation. If the power price exceeds these short-run opportunity costs, for instance, because it is recovering some fixed costs, then the market price has no need to adjust. That is, since the costs are not incurred and are simply opportunity, the level of fixed cost recovery is not impacted and therefore it is more economic to generate even without changing the bid price.

As the off-peak power market is the most competitive, we would expect that this is when the CO₂ price will have its biggest impact on power prices. In periods when the power price is likely to exceed short-run marginal costs (fuel and CO₂), then generators do not need any additional incentive to produce generation to meet demand and prices should remain unaffected. Any significant market power – or indeed even an expectation that the market will price this in – could mean that prices would nevertheless be affected.

CO₂ as an incurred cost

In addition to being opportunity costs, some cost of the EU ETS will have been incurred for this sector as power generation in aggregate was short allowances in 2005. Generators will want to recover any costs associated with the allowances they need to purchase on the market to off-set their generation. As this increasingly becomes the case (less free allocation and more incurred cost), then we expect that the impact on the power price will increase to all periods as this then does start to impact on the level of fixed costs that are recovered.

The net impact of CO₂

Returning to our schematic of how prices are formed, we see the impact of the EU ETS in theory being to:

- Cause a shift upwards in electricity prices at times when power prices are pushed down to short-run marginal costs; and
- Slightly reduce peak prices as the upward shift in off-peak prices increases total revenue while the level of incurred costs only slightly rises. As such, the total amount of fixed costs that need to be recovered in peak periods could only change marginally or even reduce (since there is more fixed cost recovery in off-peak periods).

The impact of the CO₂ price on power prices

The net effect of these two impacts is to:

- Increase the average (or baseload) level of power prices; and
- Reduce the margin between peak and baseload contracts (depending on how much was incurred).

4. German power prices – input to model

Historic price spreads for German power market (2007 YTD)

Forecast German power prices used in model (€/MWh)