

EU Emission Trading Scheme and the Effect on the Price of Electricity

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ECON Analysis

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Foreword

The Electricity Market Working Group and the Climate Change Policy Working Group of the Nordic Council of Ministers, has commissioned ECON Analysis to prepare this report "*EU Emission Trading Scheme and the effect on the price of electricity*". The report analyses the demand and supply of GHG emission allowances and the price of emission allowances for the periods 2005-2007 and 2008-2012 and the effect on the electricity price in the Nordic electricity market.

The demand for emissions allowances has then been estimated for different scenarios, with different assumption on burden sharing between sectors and international participation and the supply of emission allowances is determined by the marginal abatement costs. Based on available information on abatement costs the supply of allowances is then estimated. The market balance between the demand and supply for allowances then determines the price of emission allowances.

The effect on the electricity price is simulated with ECON's model for the Nordic power market to quantitatively estimate the effect from emissions trading on the electricity price, production, consumption, trade, etc.

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 and the effect on the electricity price in the Nordic electricity market.

Stockholm, August 2004

Helsinki, August 2004

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Sammanfattning

Från den 1 januari 2005 kommer Europeiska Unionen att införa ett system för handel med utsläppsrätter för växthusgaser. Under den första handelsperioden, 2005 – 2007, omfattar systemet endast CO₂ och det finns inga internationella åtaganden att reducera utsläppen av växthusgaser. Under den andra perioden, 2008 – 2012, har Europeiska Unionen åtagit sig att reducera utsläppen av växthusgaser med 8 % jämfört med 1990 års nivåer.

Handel med utsläppsrätter kommer att medföra en kostnad för CO₂-utsläpp och öka marginalkostnaden för att producera elektricitet i fossileldade kraftverk. Detta kommer att medföra en höjning av elpriset.

För perioden 2005 – 2007 uppskattas det sannolika prisintervallet för utsläppsrätter inom EU vara € 1-5/ton CO₂ och för 2008 – 2012 € 8-13/ton CO₂. Effekten på elpriset på den nordiska elmarknaden analyseras med utgångspunkt i dessa uppskattningar. På kort sikt är prishöjningarna i de nordiska länderna, förutom på Jylland, något lägre än höjningen av marginalkostnaden för koleldade kraftverk. På något längre sikt (2012) är prishöjningen ungefär samma som höjningen i marginalkostnad för ny gaseldade kraftverk.

Bakgrund

Den Europeiska Unionen (EU) har beslutat att införa ett system för handel med utsläppsrätter (EU ETS) från den 1 januari 2005. Under den första perioden, 2005 – 2007, omfattar handeln endast koldioxid (CO₂) från stora industriella anläggningar inom energiintensiv industri. För den perioden finns inte heller några internationella åtaganden att reducera utsläppen av växthusgaser, och följaktligen har tilldelningen av utsläppsrätter inte varit väldigt restriktiv. För perioden 2008 – 2012 kan systemet komma att utökas och även omfatta ytterligare sektorer och andra växthusgaser vid sidan om CO₂. Vidare är den perioden också den första åtagandeperioden under Kyotoprotokollet för att reducera globala utsläpp av växthusgaser.

EU ETS innebär att ett pris sätts på utsläpp av CO₂ för alla företag som omfattas av systemet, inklusive elproducenter. En viktig fråga för elproducenter och konsumenter är därför vilken effekt som EU ETS kommer att få på framtida elpriser.

Problem och metod

ECON har på uppdrag av Nordiska ministerrådet analyserat följande:

- Utbud och efterfrågan på utsläppsrätter för växthusgaser och priset på utsläppsrätter för perioderna 2005 – 2007 och 2008 – 2012 och
- Effekten på elpriset på den nordiska elmarknaden.

För den första delen har information från de nationella allokeringsplanerna (NAP) och annan tillgänglig information använts för att estimerar den sannolika nettoefterfrågan på utsläppsrätter för perioden 2005 – 2007. För perioden 2008 – 2012 har reduktionskraven för EU beräknats utifrån business-as-usual framskrivningar och utsläppsmålen enligt Kyotoprotokollet. Efterfrågan på utsläppsrätter har sedan

estimerats för olika scenarier med olika antaganden om bördefördelning mellan sektorer och internationellt deltagande.

Utbudet på utsläppsrätter bestäms av den marginella reduktionskostnaden. Baserat på tillgänglig information om reduktionskostnader har utbudet på utsläppsrätter sedan estimerats.

Marknadsjämvikten mellan utbud och efterfrågan på utsläppsrätter bestämmer sedan priset på utsläppsrätterna.

Effekten på elpriset har sedan simulerats med ECONS modell för den nordiska elmarknaden för att kvantitativt estimerat effekten av handel med utsläppsrätter på elpriset, produktion, konsumtion, handel, etc.

Slutsatser

I rapporten har vi analyserat utbud och efterfrågan på utsläppsrätter inom EUs system för handel med utsläppsrätter. Baserat på detta har vi estimerat sannolika priser på utsläppsrätterna.

Utbudet av utsläppsrätter baseras på tillgängliga estimat avseende den marginella reduktionskostnaden inom EU. Samma estimat används för hela perioden, dvs. vi har inte tagit hänsyn till någon teknisk utveckling.

Efterfrågan på utsläppsrätter för den första handelsperioden baseras på information i från de nationella allokeringsplanerna som fanns tillgängliga i juni 2004 och viss komplimenterande information. Som förväntat visar de nationella allokeringsplanerna att incitamenten för en restriktiv fördelning under den första perioden är svaga och som en följd av detta har medlemsstaterna inte varit särskilt restriktiva. Detta återspeglas i låga förväntade priser på utsläppsrätter och för perioden 2005 – 2007 innebär våra estimat ett sannolikt prisintervall på € 1 – 5/ton CO₂. Osäkerhet kvarstår dock om tilldelningsnivåer såväl i planer som ännu inte lämnats till Kommissionen som revisioner av planerna efter Kommissionens granskning. Granskningen av de första åtta planerna medförde emellertid enbart mindre förändringar.

För den första åtagandeperioden enligt Kyotoprotokollet, 2008 – 2012, ska Kyotomålen uppfyllas. För EU-15 innebär detta en reduktion med 8 % jämfört med basårsutsläppen, eller 7,5% jämfört med utsläpp år 2010 enligt *business-as-usual* framskrivningar. Med rimliga antagande om bördefördelning mellan ETS-sektorer och icke-handlande sektorer kan reduktionen inom ETS-sektorerna mötas till en relativt låg kostnad. Vårt intervall för sannolika priser är € 8 – 13/ton CO₂. Ryskt deltagande skulle öka utbudet och sänka priserna på utsläppsrätter. Ett substantiellt utbud av JI- och CDM-krediter skulle också reducera priset på utsläppsrätter.

Baserat på analysen ovan har effekten av handel med utsläppsrätter på elpriset analyserats med hjälp av ECONS nordiska kraftmarknadsmodell. Simuleringar har gjorts för tre olika scenarier med olika pris på utsläppsrätter (låg, medel, hög) för tre olika år. Priserna på utsläppsrätter har antagits vara 1, 5 och 8 €/ton CO₂ år 2006 och 5, 8 och 15 €/ton CO₂ för åren 2008 och 2012.

Simuleringarna visar att elpriset kommer att öka till följd av handel med utsläppsrätter. På kort sikt (2006 och 2008) är prishöjningen i de nordiska länderna, förutom Jylland, något lägre än höjningen i marginalkostnad för kolkraftverk. För Jylland och kontinentländerna inkluderade i modellen är prishöjningen ungefär densamma som

höjningen i marginalkostnad för kolkraftverk år 2006 och nära höjningen i marginalkostnad för moderna gaseldade kraftverk år 2008. På något längre sikt (2012) bestäm effekten på elpriset för samtliga områden i modellen av förändringen i marginalkostnad för moderna gaseldade kraftverk, eftersom dessa kommer att bli prissättande på marknaden.

I modell finns endogena investeringar i gaseldad produktion, vilket innebär att investeringar görs när de är lönsamma. I Norge har en exogen begränsning på mängden gaseldad produktion lagts in, vilket innebär kapaciteten begränsas till vad som för närvarande har givits koncession (1660 MW). Detta tak är endast bindande i situationen utan handel med utsläppsrätter, eller då priset på utsläppsrätter är lika med noll. Med ett positivt pris på utsläppsrätter minskar investeringarna och norsk gaskraft minskar när priset på utsläppsrätter stiger. Detta innebär att investeringar utöver vad som för närvarande har givits koncession inte är lönsamma.

1 Summary

Starting from 1st January 2005 the European Union will implement a scheme for trading with greenhouse gas (GHG) emission allowances. During the first trading period, 2005 – 2007, the scheme covers only CO₂, and there is no international commitment to reduce the emission of GHG. During the second period, 2008 – 2012 the European Union has committed to reduce their emissions of GHG by 8% compared to 1990 levels.

Emissions trading will create a cost of CO₂ emissions, and increase the marginal cost of producing electricity in fossil fuelled plants. This will result in an increase in the electricity price.

For the period 2005 – 2007 the likely range of allowance prices in the EU is estimated to be € 1-5/tonne CO₂ and for 2008 – 2012 € 8-13/tonne CO₂. Based on these estimates the effect on the price of electricity is analysed. In the short run the price increases in the Nordic countries, except Jutland, is less than the increase in marginal cost for coal plants. In the somewhat longer run (2012) the price increase is approximately the same as the increase in the marginal cost of modern gas-fired plants.

Background

The European Union (EU) has decided to implement a system with tradable emissions allowances, the European Union Emission Trading Scheme (EU ETS) from 1st January 2005. During the first period, 2005 – 2007, the trade covers only carbon dioxide (CO₂) at large industrial installations within energy intensive industries. For that period there is no international commitment to reduce the emission of greenhouse gases (GHG), and consequently the allocation of emission allowances to participating companies will most likely not be very restrictive. For the period 2008 – 2012 the system may be extended to cover further sectors and other GHGs besides CO₂. Furthermore, and even more important, that period is also the first commitment period in the Kyoto protocol to reduce global emissions of greenhouse gases.

The EU ETS implies that a price is placed on CO₂-emissions of all participating companies including electricity generators. A central question for electricity generators as well as power consumers is what impact the EU ETS may have on future electricity prices.

Problem statement and method

ECON has been commissioned by the Nordic Council of ministers to analyse the following:

- The demand and supply of GHG emission allowances and the price of emission allowances for the periods 2005-2007 and 2008-2012 and
- The effect on the electricity price in the Nordic electricity market.

For the first part information from National Allocation Plans (NAPs) and other available information has been used to estimate the likely net demand for allowances for the period 2005 – 2007. For the period 2008 – 2012 the reduction requirement for the

EU has been calculated using projected business-as-usual emissions and the Kyoto emission targets. The demand for emissions allowances has then been estimated for different scenarios, with different assumption on burden sharing between sectors and international participation.

The supply of emission allowances is determined by the marginal abatement costs. Based on available information on abatement costs the supply of allowances is then estimated.

The market balance between the demand and supply for allowances then determines the price of emission allowances.

The effect on the electricity price is simulated with ECON's model for the Nordic power market to quantitatively estimate the effect from emissions trading on the electricity price, production, consumption, trade, etc.

Conclusion

In the report we have analysed the supply and demand for emission allowances within the EU emissions trading scheme. Based on this we have made estimates of likely prices of emission allowances.

The supply of emission allowances are based on available estimates of the marginal abatement costs within the European Union. The same estimates are used for the entire analysed period, i.e., we do not take into account any technological development.

Demand for emission allowances for the first trading period is based on information available from the national allocation plans (NAP) as of June 2004 and supplementary information. As expected the NAPs show that incentives for a restrictive allocation for the first trading period has been weak, and consequently the Member States have not been very restrictive. This is reflected in a low expected price on emission allowances, and for 2005 – 2007 our estimate indicate a likely price range of € 1 – 5/tonne CO₂. Uncertainty remains however on the allocation levels of NAPs still to be submitted to the Commission as well as any revisions to NAPs following Commission review of Member States plans. The review of the first eight plans, however, only resulted in minor changes.

For the first Kyoto commitment period, 2008 – 2012, the Kyoto targets should be met. For EU-15 this implies a reduction of 8 per cent compared with the base year emissions, or 7.5 per cent compared with projected business-as-usual emissions in 2010. However, with reasonable assumptions on the burden sharing between the ETS and NTS sectors, the implied reduction within the ETS sector can be met at a fairly low cost. Our likely price range is € 8 – 13/tonne CO₂. Russian participation would increase the supply and decrease the price of emission allowances. A substantial supply of JI- and CDM-credits would also reduce the price on emission allowances.

Based on the above analysis on likely prices of emission allowances the effect of emissions trading on the price of electricity has been analysed using ECON's Nordic power market model. Assuming three different scenarios for allowance price (low, medium and high prices) simulations of the effects are made for three different years. The assumed allowance prices are 1, 5 and 8 €/tonne CO₂ in the year 2006 and 5, 8 and 15 €/tonne CO₂ in the years 2008 and 2012.

The simulations made show that the electricity price will increase due to emissions trading. In the short run (2006 and 2008) the price increase in the Nordic countries, except Jutland, will be somewhat less than the increase in marginal cost of coal plants. For Jutland and the continental countries included in the model the price increase will be approximately the same as the increase in the marginal cost of coal production for 2006 and close to the increase in marginal cost of modern gas-fired plants in 2008. In the somewhat longer run (2012) the price effect for all included areas is determined by the change in marginal cost for modern gas-fired plants, since that technology will set the price in the market.

In the model there is endogenous investments in gas-fired production, which means that investments are made when they are profitable. In Norway an exogenous constraint on the total amount of gas-fired production has been added, which is set equal to the capacity that currently has been granted concessions (1660 MW). This exogenous constraint is only binding when there is no trade with emission allowances, or when the price of allowances is equal to zero. With a positive price on allowances the investments in Norwegian gas production decreases with the price of allowances for the price intervals considered here. The interpretation is that investments beyond current concessions are not profitable.

2 Introduction

The European Union (EU) has decided to implement a system with tradable emissions allowances, the European Union Emission Trading Scheme (EU ETS) from 1st January 2005. During the first period, 2005-2007, the trade covers only carbon dioxide (CO₂) at large industrial installations within energy intensive industries. For that period there is no international commitment to reduce the emission of greenhouse gases (GHG), and consequently the allocation of emission allowances to participating companies will most likely not be very restrictive. For the period 2008-2012 the system may be extended to cover further sectors and other GHGs besides CO₂. Furthermore, and even more important, that period is also the first commitment period in the Kyoto protocol to reduce global emissions of greenhouse gases.

The EU ETS implies that a price is placed on CO₂-emissions of all participating companies including electricity generators. A central question for electricity generators as well as power consumers is what impact the EU ETS may have on future electricity prices.

The Nordic Council of Ministers has commissioned ECON to estimate the prices of emission allowances during the periods 2005-2007 and 2008-2012 respectively and estimate the price effect for the northern European power markets.

Background

The European Union as party to the Kyoto Protocol has made a commitment to reduce emissions of GHGs by 8 per cent from the base year 1990 to the commitment period 2008-2012. This commitment covers the 15 existing Member States, which have agreed the internal burden sharing as shown in table 2.1. The 10 new Member States acceding the EU 1st of May 2004 have separate targets under the Kyoto Protocol as shown in the table.

The EU ETS is the most notable measure employed by European countries to meet their commitments under the Kyoto Protocol. In addition to the EU ETS and domestic policies and measures Member States is allowed to meet commitments by acquiring emission allowance and credits abroad through the Kyoto mechanisms, including Joint Implementation (JI) and Clean Development Mechanism (CDM), under the Kyoto Protocol. In addition European governments have also allowed companies to comply with their commitments under the EU ETS by using JI and CDM.

Non-EU parties to the Kyoto Protocol have the same opportunity, which can impact the demand for JI and CDM credits and consequently prices. Especially participation by the US could have substantial impact on the JI and CDM market. Presently, it seems highly unlikely that the USA will ratify the Kyoto protocol and throughout this analysis it is assumed that the US not will ratify the protocol and take part in an international emissions trading scheme.

Without US ratification of the Kyoto Protocol, Russian ratification is key to entry-into-force of the Protocol. The EU ETS will enter into force whether Russia ratifies or not, but Russian ratification is of importance for the international carbon market and prices

in general. Russia's ratification is still uncertain even though Russia most likely will be a net seller of emission allowances (or JI- credits). Linking Russia's ratification to other political negotiations such as Russia's full membership in the World Trade Organization (WTO), as was done at the EU-Russia meeting in May, provide further incentive for Russia to ratify.

Table 2.1 Kyoto targets of EU countries

EU-15 Member States	%	Accession countries	%
Austria	-13	Czech Republic	-8
Belgium	-7.5	Estonia	-8
Denmark	-21	Hungary	-6
Finland	0	Latvia	-8
France	0	Lithuania	-8
Germany	-21	Poland	-6
Greece	+25	Slovakia	-8
Ireland	+13	Slovenia	-8
Italy	-6.5	Cyprus	No commitment
Luxembourg	-28	Malta	No commitment
Netherlands	-6		
Portugal	+27		
Spain	+15		
Sweden	+4		
UK	-12.5		
European Community	-8		

Content

The report documents the analysis of both the estimates of allowance prices and effect on the spot price of electricity at the north European power markets.

In section 3 we estimate the demand for emission allowances in the EU ETS. This is based on Member States projections of future GHG emissions and the national plans for allocating emission allowances to participants in the EU ETS.

As of 31st March 2004, all the EU member states should have submitted their national allocation plans (NAP) for the period 2005-2007 to the Commission. The process of submitting NAPs and Commission evaluation of the plans has been delayed.

Consequently the analysis is based on the 14 plans available as of June 2004 and drafts from additional four Member States. During the summer five more plans have been submitted and the European Commission have concluded evaluation of eight plans.

Since NAPs are now becoming available it is possible to better estimate the total allocation of emission allowances and thereby what demand of allowances that can be expected during the first period. However, since all Member States have not handed in their NAPs yet and changes may occur during the evaluation by the Commission, there

are still some uncertainties regarding the total allocation. For the commitment period 2008-12 the information regarding the allocation of emission allowances is still very limited. Therefore, the analysis is based on likely scenarios, which both can contribute to reducing the uncertainty but also prepare for different outcomes.

Provided that there is a shortage of allowances among participants the costs of freeing allowances by reducing emissions will be a determinant of allowance prices. Given the estimated demand for allowances in the EU ETS we estimate in section 4 the likely price level of allowances based on existing estimates of the cost of reducing emissions in Europe. The section also discusses the potential impact of importing JI and CDM emission credits to the EU ETS.

Based on the estimates of allowance prices an analysis of the effect from emissions trading on the electricity price at the north European power markets is made in section 5. As a tool ECON's Nordic electricity market model is used to simulate the price effect. In these simulations assumptions regarding the development in production capacity provided by the client have been used.

3 Demand for allowances

Under the emission trading scheme (ETS) Member States in the EU will allocate emission allowances to companies covered by the scheme. Companies will be required to hold a number of allowances equivalent to their emission levels. If their allocation level is expected to fall short of emissions, companies have a choice to either limit emissions or alternatively buy more emission allowances on the market.

Comparing expected business-as-usual emissions to allowance allocation levels gives an estimate of demand for allowances. This comparison can be done on the basis of allocation decisions in Member States (or assumptions on decisions to be taken) and national emission projections. The resulting demand estimate shows that the number of allowances allocated to the ETS-sectors in each Member State may fall short of or be in excess compared to the expected emission levels.

Actual demand from companies falling short of their allocation in one Member State may be higher than this demand estimate, if other companies in the same country have a surplus of allowances. The demand we estimate in this section is thus a net demand for emission allowances.

For the first period (2005-2007) of the EU ETS a considerable amount of information on allocation decisions is available, although final allocation levels still remains to be settled in some Member States. For the second period the total reduction requirement for each country and the EU can be calculated from the projected business-as-usual emissions and the Kyoto target. However, the burden sharing between the ETS-sectors and non-trading sectors (NTS) is uncertain and thus are the requirements on the ETS sector uncertain. There are also a number of additional factors, which cause uncertainty. The net demand for allowances is thus much more uncertain for this period compared with 2005-2007.

3.1 Allocation of allowances 2005 – 2007

EU Member States are required to produce a National Allocation Plan (NAP) specifying the number of allowances it intends to allocate and the method for allocating allowances between participating companies. The NAP needs to be notified to the European Commission, which may reject the plan that does not comply with provisions of the EU directive.

After the first NAPs have been made public, net demand for allowances in the first period across the EU-25 region seem to be very modest. Participants with a shortage of allowances seem to a large degree to be offset by surplus allocation to other participants. The need to reduce emissions below business-as-usual seem to be limited.

We have estimated the requirement for emission reductions – or the net demand – in the EU ETS based on the emission caps provided in the first NAPs and projected business-as-usual emissions provided in NAPs or national communications submitted to the United Nations Framework Convention on Climate Change (UNFCCC). For countries that have not yet published a NAP, we have made assumptions on sharing the national

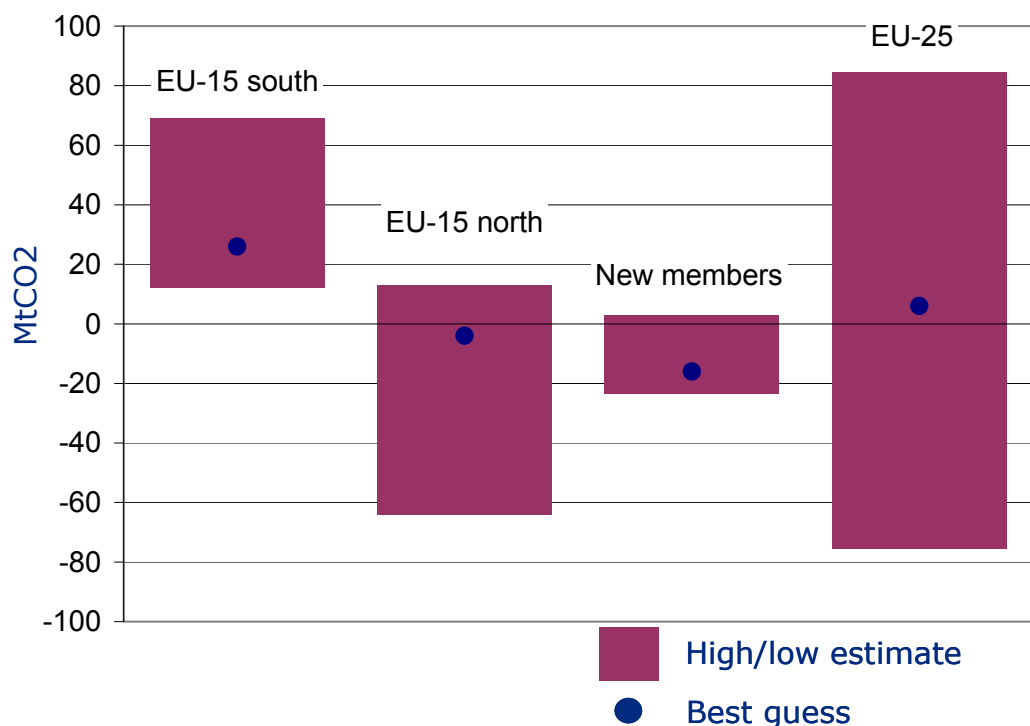
Kyoto gap among sectors. Comparing for each country the cap to business-as-usual emissions provides an estimate of the possible shortages of emission allowances at the national level or in other words the demand for emission reductions. Adding estimates for all countries provides an indication of the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

For the EU-25 region as a whole we estimate a maximum net demand (shortages of EU allowances) of 84 Million tonne CO₂. There could however also be a net surplus of allowances as high as 76 Million tonne CO₂. The northern part of EU-15 (Germany, UK, Ireland, the Netherlands, Denmark, Sweden and Finland) and the new member countries especially contribute to the expected low net demand – new members due to their surplus under the Kyoto Protocol and northern European countries due to allocations in their NAPs that are not very restrictive.

For the northern part of EU-15 the low estimate result in particular from uncertainty about emission developments in Germany. Projections included in the 3rd national communication show continuously decreasing emissions in the ETS sector, which would result in a substantial surplus of allowances under the proposed allocation. This projection may well be too optimistic and our best guess is thus closer to the high demand estimate.

The higher estimated demand in southern Europe (Spain, Portugal, France, Italy, Greece, Austria and Belgium) primarily reflects the high Kyoto gap in some of these countries. Allocations in these countries may in fact prove far more generous - which first national drafts seem to support - and decrease net demand even further. Our best guess is thus close to the low demand estimate.

Figure 3.1 Net demand for emission reductions in the EU ETS after the first NAPs



High and low estimates in the figure are calculated reflecting uncertainty on a number of issues:

- Emission caps in Member States that have not submitted NAPs during this analysis is uncertain and Commission approval may result in changes to existing NAPs
- There is uncertainty around the projections of business-as-usual emission developments. The fact that Some Member States have produced new projections that differ from those included in their national communication illustrate this.
- Not all allowances allocated in a country might eventually be available to the market. Reserves to new entrants will only be issued if there are in fact new entrants eligible to receive allowances. Most Member States are expected to sell excess allowances on the market, while others like Germany will cancel any excess allowances.

The allocation levels of the NAPs used in above estimates are shown in table 3.1. Allocation levels compared to historical emissions reported by Member States in their NAPs are in most cases allowing industry to increase CO₂ emissions.

Table 3.1 Allocation levels in first NAPs, MtCO₂ per year

	Average base year emissions ¹⁾	Average annual allocation
Austria	30,2	33,2
Denmark	30,9	33,5
Finland	36,7	45,5
Germany	501,0	499,0
Ireland	20,9	22,5
Italy	256,6	279,1
Netherlands ²⁾	97,2	98,3
Portugal	36,5	40,8
Sweden	20,2	22,9
UK	245,9	245,3
Latvia	4,2	4,6
Lithuania	9,3	14,2

Source: Member States NAPs as submitted to the Commission as of June 2004 except for Italy where the numbers originates from first draft in national consultation.

Note:

- 1) Member States have chosen different base year periods for allocating allowances. Base year emissions in the table are thus shown as average annual emission in the chosen period. In some cases base period is further differentiated among sub-sectors subject to the EU ETS and based on preliminary emission estimates. These cases are not reflected in the table.
- 2) Base year emissions for the Netherlands include adjustments for future growth and energy efficiency. Actual base year emission should be expected to be lower than indicated in the table. During the review by the European Commission in July 2004 the Dutch allocation was reduced by 3 million tonne of CO₂ below the level indicated in the table.

For the remaining countries¹ indicative allocation levels based on proportional allocation of the Kyoto gap (or surplus)² are shown in table 3.2. These are used as a low estimate of the emission reduction requirement (i.e. low net demand). As a high estimate it is assumed that allocation to the ETS sector is settled at half of the Kyoto gap. In case the country expects a surplus under the Kyoto commitment, the high estimate assumes that industry will not be allocated any of the surplus emission allowances.

¹ Luxembourg, Slovenia, Cyprus and Malta are not included. Malta and Cyprus are excluded since they do not have commitments under the Kyoto Protocol and Luxembourg and Slovenia due to their modest size compared to the whole market.

² A straight line from historical emissions to projected 2010 emissions is assumed in calculating a gap for the 2005 to 2007 period.

Table 3.2 Proportional allocation levels in remaining Member States, MtCO₂ per year

	2000	Proportional allocation	Half of Kyoto gap
Belgium	51.3	46.6	42.9
France	106.6	108.1	102.5
Greece	67.4	67.7	67.6
Spain	149.1	135.0	131.9
Czech Rep.	77.4	86.6	71.3
Hungary	29.7	35.6	31.6
Estonia	14.7	23.7	14.3
Slovakia	22.9	27.9	24.0
Poland	210.0	232.3	218.2

Source: National inventories and national communications to the UNFCCC

Note: The calculated allocation is based on proportional burden sharing of the Kyoto gap between sectors included in the EU ETS and sectors outside the scheme. As an alternative is calculated an allocation where half of the Kyoto gap is placed with the ETS sector. For the 2005-2007 the gap (or surplus) to be divided is assumed to be reduced according to a straight line from 2000 to 2010.

3.2 Allocation of allowances 2008 – 2012

The uncertainty about the net demand is higher for the second period of EU ETS. Although the Kyoto targets are well known for all countries there are a number of important factors that will have large impact on the requirements both within a EU trading system and globally.

Within the EU there are two primary factors of uncertainty. The first one relates to the burden sharing between the trading sectors (ETS sectors) and the non-trading sectors (NTS sectors) of the economy. The second one relates to the allocation of the surplus that most of the new member states have. These surplus allowances can either be allocated to the ETS sector to allow for further growth in emissions, be used for covering emission increases in NTS sectors or alternatively be banked by the government to future commitment periods. To which extent this surplus is allocated as emission allowances in the EU ETS will have a large impact on net demand.

Furthermore, there are two uncertain factors with global reach. The first aspect is the supply of credits from JI and CDM projects to be used within the EU ETS, which is still very unclear. First of all the volume of such projects is uncertain. Secondly, the competition from other countries and from NTS sectors (represented by governments) is not clear.

Finally, Russia has not ratified the Kyoto protocol, which is required for the protocol to enter into force. It is uncertain what impact continued non-ratification will have on the market.

3.2.1 Emission projections and emission reduction requirements

According to the Kyoto protocol the industrialised countries (Annex I countries) shall during the first commitment period (2008-2012) reduce their emissions of greenhouse gases by on average 5.2 per cent compared with the 1990 level. For developing countries (non Annex I-countries) there are no targets on emission reductions. As of April 2004, 32 Annex I-countries had approved the Kyoto protocol while five countries had not.³

EU-15 has committed to reduce its emissions of greenhouse gases by on average eight per cent compared with the base year (1990). The member states have agreed on a burden sharing, which sets country specific reductions targets varying from an allowed increase of emissions by 27 per cent (Portugal) to a reduction requirement of 28 per cent (Luxembourg). The full list of EU countries commitments under the Kyoto Protocol is included in section 2.

In the absence of specific policy measures GHG emissions are projected to decrease only slightly and a gap remains of 7.5 per cent or approximately 300 million tons of CO₂e (GHG emission expressed in carbon dioxide equivalents) for the EU-15 countries, see figure 3.2. Consequently, the so-called Kyoto gap will need to be closed by further climate policy measures such as the EU emissions trading scheme to achieve the Kyoto target.

The Kyoto gap will vary between countries because emissions in the absence of any further measures (business-as-usual emissions) will develop differently and because obligations to reduce emissions differ according to the internal burden sharing agreement. The national gaps are shown in figure 3.2. Even though Spain under the burden sharing agreement has been allowed to increase emissions by 15 per cent, emission are expected to increase even more. At the other end of the scale UK are expecting to over-achieve the commitment to reduce emissions by 12.5 per cent.

Besides Spain especially Denmark, Ireland, Austria and Belgium will have to make substantial effort to further reduce emissions or alternatively acquire emission allowances and credits under the Kyoto Protocol.

Quite the opposite is the case for the new EU member states, which all - except Slovenia - expects to over-achieve their targets and have a surplus under the Kyoto Protocol, see figure 3.3.

³ By approved is here meant ratification, acceptance, approval or accession. The Annex I countries that have approved the protocol are Austria, Belgium, Bulgaria, Canada, Czech republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Lithuania, Luxembourg, Netherlands, New Zealand, Norway, Poland, Portugal, Rumania, Slovakia, Slovenia, Sweden, Switzerland, Ukraine and United Kingdom. The Annex I countries that not have approved the protocol are: Australia, Liechtenstein, Monaco, Russia and USA. The Kyoto protocol enters into force when 55 parties (fulfilled), and Annex I countries responsible for at least 55 per cent of the emissions (not fulfilled – at the moment approximately 44%) have approved it. Source: UNFCCC's web page <http://unfccc.int> and list of status of ratification (<http://unfccc.int/resource/kpstats.pdf>).

Figure 3.2 Gap between projections based on existing policies and measures and 2010 targets in EU-15 (percentages of 1990 emissions)

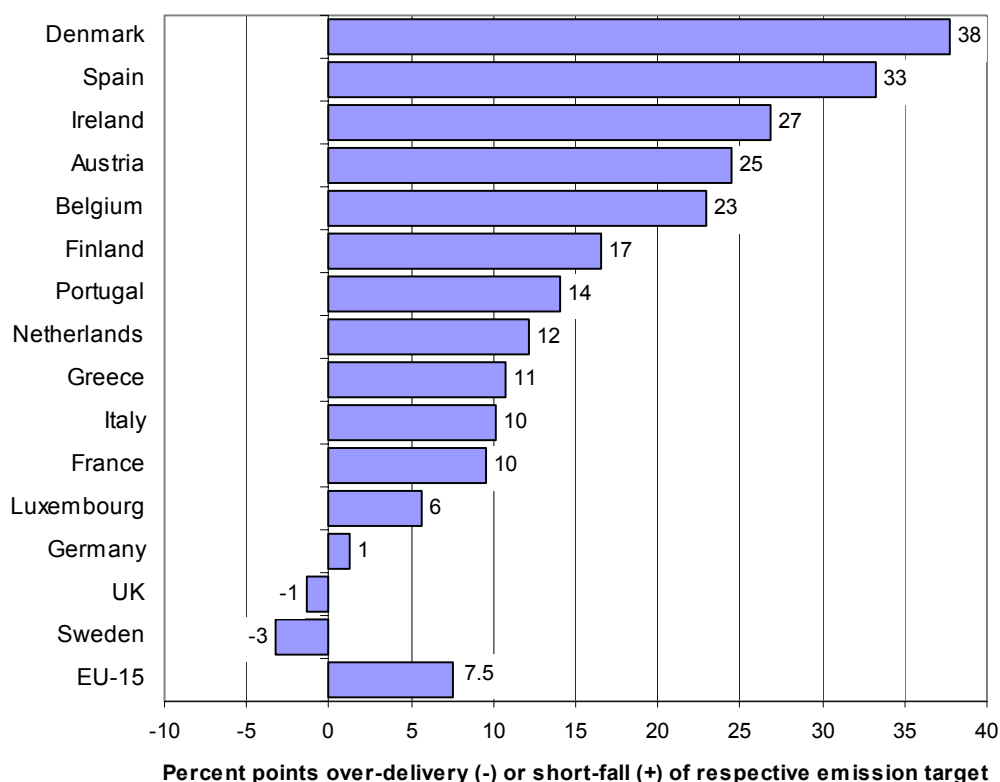
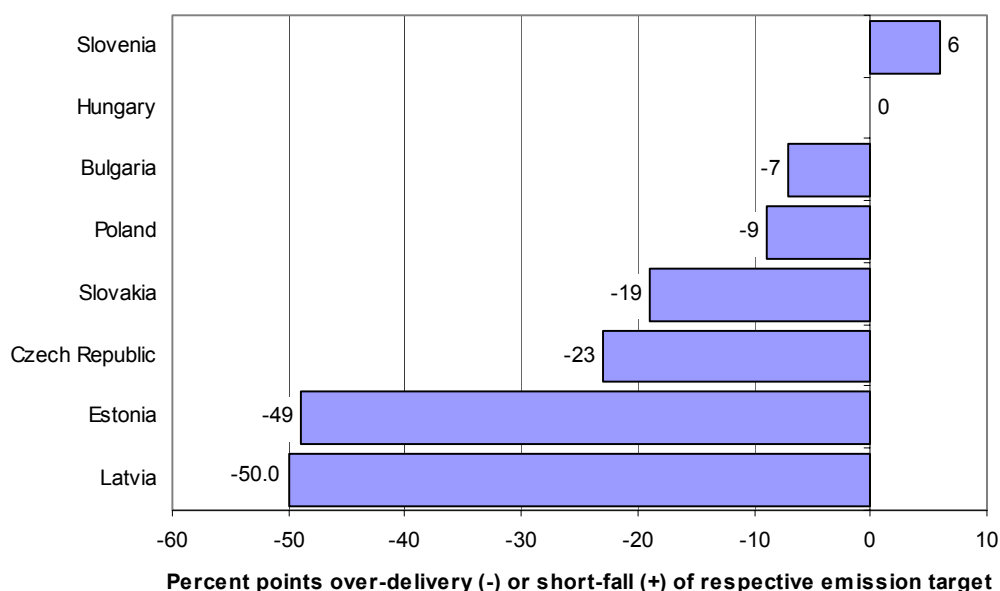


Figure 3.3 Gap between projections based on existing policies and measures and 2010 targets in accession countries (percentages of 1990 emissions)



The economic restructuring in Eastern Europe in the 1990's has resulted in a substantial decrease in emissions. Most of the surplus originates from Poland and the Czech Republic. Emissions in both countries are expected to increase rapidly, but the surplus

remains relatively high even so, due to the size of these two countries. The surplus could increase considerably if economic restructuring turns out to be slower than expected or growth is less intensive in GHG emissions.

The compilation of reduction requirements for the EU is summarised numerically in Table 3.3. The compilation is based on national emission projections made by the individual member states and the Kyoto/EU burden sharing targets.

Table 3.3 Emissions and reduction requirements in the EU

Country	Base year emissions, M tonne CO₂e	Kyoto and EUs burden sharing target, M tonne CO₂e	Emission projection (with current measures), M tonne CO₂e	Reduction requirement, M tonne CO₂e
Austria	77.2	67.2	86.1	18.9
Belgium	145.0	134.1	167.4	33.3
Denmark	69.5	54.9	81.2	26.3
Finland	77.2	77.2	89.9	12.7
France	542.7	542.7	594.3	51.6
Germany	1 218.2	962.4	977.8	15.4
Greece	107.0	133.8	145.2	11.4
Ireland	53.8	60.7	75.2	14.5
Italy	521.0	487.1	540.1	53
Luxembourg	12.7	9.2	9.9	0.7
Netherlands	212.0	199.3	225	25.7
Portugal	64.9	82.4	91.5	9.1
Spain	207.0	238.1	307	68.9
Sweden	70.4	73.2	70.9	-2.3
UK	744.7	651.6	640.9	-10.7
EU-15	4 123.3	3 773.9	4 102.4	328.5
Cyprus	N.A.	N.A.	N.A.	N.A.
Czech rep	192.1	176.7	131.7	-45.0
Estonia	43.5	40.0	18.9	-21.1
Hungary	102.6	96.4	95.6	-0.8
Latvia	29.0	26.7	12.8	-13.9
Lithuania	51.5	47.4	27.3	-20.1
Malta	N.A.	N.A.	N.A.	N.A.
Poland	565.3	531.4	394	-137.4
Slovakia	72.2	66.4	53.2	-13.2
Slovenia	19.9	18.3	22.1	3.8
EU-25	5 199.4	4 777.3	4 858.0	80.7

Source: Report from the Commission, COM(2003) 735 final, 28.11.2003, table 2

In Table 3.4 reduction requirements for the remaining Annex I countries that have approved the Kyoto protocol are displayed. The total reduction requirement from these countries is approximately 365 million tonne CO₂e.

Table 3.4 Emissions and reduction requirements in remaining Annex I countries that have approved the Kyoto protocol

Country	Base year emissions, M tonne CO ₂ e	Kyoto and EUs burden sharing target, M tonne CO ₂ e	Emission projection (with current measures), M tonne CO ₂ e	Reduction requirement, M tonne CO ₂ e
Bulgaria	157.7	145.1	133.7	-11.4
Canada	607.0	570.6	770.0	199.4
Iceland	2.8	3.1	3.0	-0.1
Japan	1 229.0	1155.3	1 317.0	161.7
New Zealand	73.1	73.1	N.A.	10 ⁴
Norway	52.0	52.5	63.2	10.7
Romania	264.8	243.6	284.4	40.7
Switzerland	52.0	47.8	48.2	0.4
Ukraine	255.2	255.2	209.3	-45.9
Total	2 693.6	2 546.2	2 828.8	365.6

Source: National Communications to UNFCCC where not otherwise stated

Among the Annex I countries that have not ratified the Kyoto protocol particular Russia is of interest. In Table 3.5 estimates of the emission reduction requirement for Russia are displayed. If 1990 is used as the base year Russia will have an excess of allowed emissions compared with projected emissions between approximately 600 and 760 million tonne CO₂e. These estimates are based on figures from Russia's third national communication to the UNFCCC. There they present three scenarios with estimated CO₂-emission up until 2020. The two scenarios with the smallest growth in CO₂-emissions project CO₂-emission at about 75 – 80 per cent of the 1990 level. These growth figures are used for all the greenhouse gas emissions to form an estimate of the total emissions in 2010.

⁴ New Zealand projects itself to have a shortfall of 50 million tonnes for the first commitment period (2008-12). The countris sinks credits are estimated to 105 million tonnes, which would generate a surplus of 55 million tonnes. Here the sinks are not taken into account. Source: Climate Change, The Government's Preferred Policy Package – A Discussion Document, New Zealand Climate Change Project, April 2002

Table 3.5 *Emissions and reductions requirements in Russia*

Country	Base year emissions, M tonne CO ₂ e	Kyoto and EUs burden sharing target, M tonne CO ₂ e	Emission projection (with current measures), M tonne CO ₂ e	Reduction requirement, M tonne CO ₂ e
Russia	3 050.0	3 050.0	2 287.5 – 2 452.2	-762.5 – -597.8

Source: National Communication to UNFCCC

In Table 3.6 the estimates presented above are summarized. The total reduction requirement compared with the business-as-usual scenario (with measures) is according to these estimates somewhere in the range between 1076 to 1241 million tonne CO₂e. Without US and Australia, but with Russian, participation there would however be room for increased emissions with between 151 and 316 million tonne CO₂e. This is however based on an assumption that the countries with excess room for emissions between their Kyoto target and their business-as-usual projection will let these be used so that other countries can meet their target without in-country emission reductions. That assumption is perhaps not the most likely one, and below we will discuss some different scenarios for allocation of emission allowances.

Table 3.6 *Summary of reduction requirements for Annex I countries*

Country	Base year emissions, M tonne CO ₂ e	Kyoto and EUs burden sharing target, M tonne CO ₂ e	Emission projection (with current measures), M tonne CO ₂ e	Reduction requirement, M tonne CO ₂ e
EU-15	4 123.3	3 773.9	4 102.4	328.5
EU-25	5 199.4	4 777.3	4 858.0	80.7
All annex I-countries that have approved the Kyoto Protocol	7 893.0	7 323.5	7 686.8	446.4
All approving annex I countries + Russia	10 943.0	10 373.5	10 163.4	-316.1 – -151.4
All annex I countries	17 484.4	16 532.6	17 715.4	1 076.8 – 1241.5

3.2.2 Scenarios for the availability and allocation of emission allowances

The basic assumptions behind the scenarios presented here is that the EU fulfils its commitments according to the Kyoto protocol. That does, however, not eliminate the uncertainties when it comes to the total reduction requirements, the allocation to the ETS-sectors and thus the price of allowances.

Within EU ETS the two main uncertainties are the 1) ETS-sectors share of the total emissions reductions and 2) the allocation of surplus allowances from the new Member States to the ETS-sector. We have made two different scenarios:

1. Proportional allocation of reductions: According to the first scenario the ETS-sectors are assumed to reduce its emissions proportionally to these sectors share of total emissions as shown in Table 3.7 ETS-sectors share of total emissions in EU-15. The ETS sector in the new Member States is allocated a share of the surplus corresponding to their share of total emissions.
2. Full burden to the ETS sector: According to the second scenario the ETS-sector are assumed to stand for all emission reductions needed while NTS sectors will be allowed business-as-usual emission levels. Carbon sinks in forestry and land-use sectors and expected government purchases of CDM/JI-credits will contribute to meeting commitments and reduce the burden of the ETS sector to ca. 2/3 of total reduction requirements.⁵ New Member States allocate emission allowances according to their business-as-usual projections, which implies that the ETS sector receive no surplus emission allowances. The second scenario represents a maximum demand situation in the EU ETS.

Table 3.7 ETS-sectors share of total emissions in EU-15

Country	Total GHG emissions in 2001, MtCO ₂ e	CO ₂ emissions in ETS sectors, MtCO ₂	ETS-sectors share of total emissions
Austria	85.2	34.4	0.40
Belgium	150.4	67.5	0.45
Denmark	69.4	33.7	0.49
Finland	80.8	41.7	0.52
France	566.1	156.1	0.28
Germany	990.2	500.4	0.51
Greece	132.2	74.0	0.56
Ireland	70.0	23.7	0.34
Italy	544.6	252.4	0.46
Netherlands	219.4	105.8	0.48
Portugal	83.8	37.7	0.45
Spain	382.6	177.6	0.46
Sweden	70.4	26.8	0.38
UK	658.7	299.8	0.46
Total EU-15	4106.5	1834.3	0.45

Note: Estimates are based on 2003 GHG inventory submitted to the UNFCCC. Due to the definitions of installations included in the EU ETS, the estimated shares may differ from actual coverage of the EU ETS in the individual Member States. The shares may also change in the second phase of the scheme if it is decided to extend the scheme to other sectors or greenhouse gases.

⁵ For EU-15 it is thus assumed that carbon sinks and government JI and CDM programmes will deliver emission reductions in total of approximately 100 MtCO₂e per year in the 2008-2012 period.

3.2.3 Net demand in EU ETS

Estimates of net demand in the 2008-2012 period are presented in Table 3.8. The reduction requirements for the ETS sector within EU-15 would amount to 143 million tonne CO₂ with a proportional burden sharing between the ETS- and NTS-sectors and 219 million tonne with full burden on the ETS sector. As mentioned, a majority of the new Member States have a surplus, or “negative reduction requirement”, and can thus increase their emissions compared to 2010 business-as-usual projections and still meet their Kyoto targets. If part of this surplus were allocated as allowances in the EU ETS as assumed in the proportional allocation scenario, the net demand for EU-25 would be reduced considerably to a level of 8 million tonne CO₂. In the full burden scenario with no surplus allocation in the new member states, the net demand would remain at 219 million tonne of CO₂.

Both scenarios represent extremes and the actual burden placed on industry should be expected to be somewhat between these extreme levels. On the one hand new member states could be expected to bank surplus allowances for future commitment periods instead of allowing increasing emissions in industry. The Commission may also prevent allocating an extensive amount of surplus allowances on account that it will represent illegal state aid in the internal market. On the other hand it may prove difficult for the Commission to prove all cases of excess allocation and it may also be political difficult in existing member states to place as high a burden on industry as indicated in the full burden scenario (2/3 of the Kyoto gap placed on the ETS sector).

A mid-point estimate of emission reduction requirement in 2010 at approximately 100 million tonnes CO₂ would thus not be unlikely.

Table 3.8 Reductions requirements for ETS-sectors in EU year 2010, MtCO₂

Country	Total reduction requirements	Reduction requirements of ETS sectors in full burden scenario	Reduction requirements of ETS sectors with proportional burden sharing *
Austria	18.9	12.6	7.6
Belgium	33.3	22.2	14.9
Denmark	26.3	17.5	12.8
Finland	12.7	8.5	6.5
France	51.6	34.4	14.2
Germany	15.4	10.3	7.8
Greece	11.4	7.6	6.4
Ireland	14.5	9.7	4.9
Italy	53	35.3	24.6
Luxembourg	0.7	0.5	0.3
Netherlands	25.7	17.1	12.4
Portugal	9.1	6.1	4.1
Spain	68.9	45.9	32.0
Sweden	-2.3	-1.5	-0.9
UK	-10.7	-7.1	-4.9
EU-15	328.5	219.0	142.8
Cyprus	N.A.	N.A.	N.A.
Czech rep	-45.0	0	-23.6
Estonia	-21.1	0	-15.7
Hungary	-0.8	0	-0,4
Latvia	-13.9	0	-4.3
Lithuania	-20.1	0	-8.3
Malta	N.A.	N.A.	N.A.
Poland	-137.4	0	-78,0
Slovakia	-13.2	0	-6.2
Slovenia	3.8	0	1,6
EU-25	80.7	219.0	7.8

* Based on the ETS-sectors' share of projected emissions 2010 as presented in table 2.7.

4 Market balance and the price on emission allowances

Comparing the estimates of demand with supply of emission allowances provides an indication of the possible market balance and prices at the European emissions trading market. Demand estimates as outlined in the previous section represent the net of sellers and buyers before any emission reductions occur. Against their emissions one group of participants will fall short of allowances while other participants will have a surplus. Gross demand for allowances will thus be far higher.

4.1 Supply of emission reductions

In a perfect European carbon market the supply of EU allowances will be determined by the marginal cost of reducing CO₂ emissions across the enlarged Europe in the sectors participating in the ETS. EU allowances can be traded freely within the enlarged EU and shortage of allowances in one country can be supplied by reducing CO₂ emissions in another part of the Community where the costs of emission reductions are lower. The market mechanism will give incentive to utilise the emission reduction options with the lowest costs regardless of their geographical location in the enlarged EU.

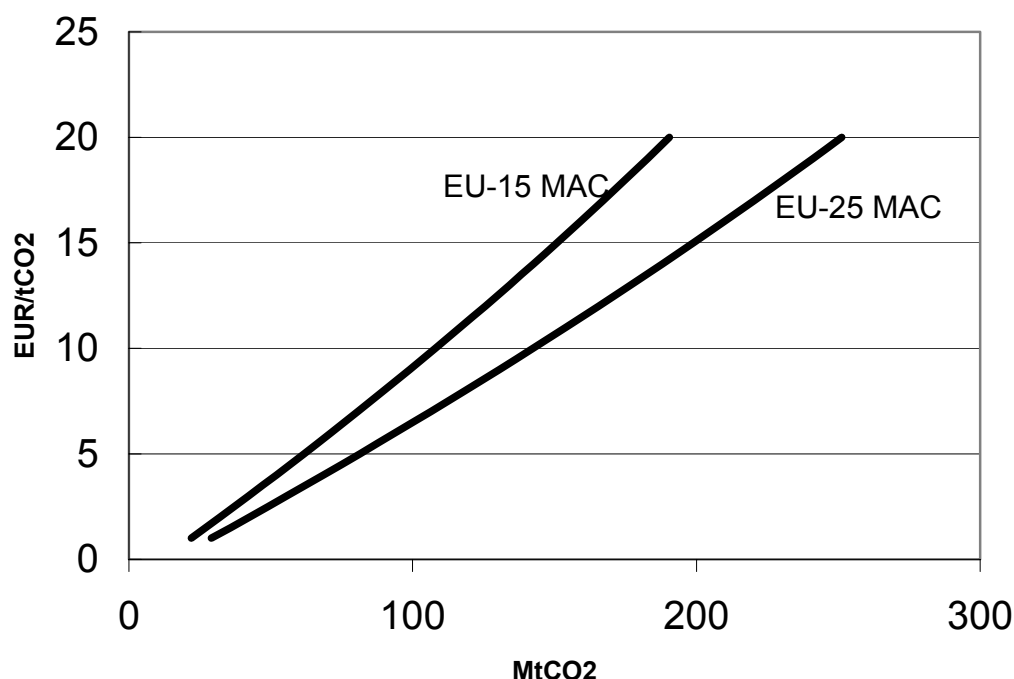
4.1.1 EU supply

Similar to demand estimates the supply of emission reductions represents the supply of allowances net of any surplus allowances allocated by governments.

The marginal abatement cost curves shown in figure 4.1 are based on an EU study⁶, which model the energy system in the EU-15 on a country-by-country basis. By gradually increasing the cost of CO₂ emission, the model estimates indicate that emissions in ETS sectors by 2010 can be reduced with costs as shown in the marginal abatement cost (MAC) curve to the left in the figure. This curve is the aggregated marginal abatement cost curve for all 15 countries and is thus summarising the model results for each of the countries. The estimate implies that more than 100 million tonne CO₂ could be reduced in the EU ETS with costs below € 10 per tonne CO₂.

⁶ Economic Evaluation of Sectoral Emission Reduction Objectives for Climate Change, Ecofys and National University of Athens (2001)

Figure 4.1 Supply of emission reductions in the EU ETS



Estimates at this level are supported by a recent study by Credit Suisse First Boston (CSFB).⁷ Here it is found that emission reductions of more than 100 million tonne CO₂ can be achieved at costs below € 10 per tonne CO₂ by switching power production from coal-fired power plants to existing natural gas fired generators and CHP plants. This is merely by switching the load factor on existing power plants and increasing the utilisation of existing low carbon power generators. The study indicates that even rather large CO₂-reductions can be achieved without large-scale investments in new low carbon production capacity and thus can be effectuated within a short time period by the right price signal. Increasing the cost of CO₂-emission will contribute to this switch, but will also depend crucially on the relative fuel prices.

The EU-15 MAC does not include potential emission reductions in the new Member States and we use the curve as a low estimate of the potential supply of emission reductions in the EU ETS in the enlarged Europe. Several of the new member countries have a very emission intensive energy supply and are generally acknowledged to have high potential for low cost emission reductions. To reflect this we assume that ETS participants in the new member countries can achieve 25 per cent more CO₂ reductions than EU-15 participants at the same price.⁸ At a cost of € 10 this adds another ca. 40 million tonne CO₂ of emission reductions as shown in the curve to the right.

⁷ CSFB, European carbon trading – utilities to get a boost, Sector Review European Utilities, 8 October 2003

⁸ If a company in the EU-15 can reduce 10 MtCO₂ to 8 MtCO₂ at a given cost, a company in one of the new Member States is assumed to reduce emissions to 7.5 MtCO₂.

The potentials and associated costs of reducing emissions are quite uncertain and rely on a range of assumptions on future economic development, relative fuel prices, technological development and regulatory framework on energy markets.

As mentioned we also make the simplifying assumption that the European carbon market is perfect. We assume that the cheapest emission reductions will be pursued regardless of their location in the enlarged EU. Most likely there will be barriers preventing a perfect market solution, which will increase the costs of emission reductions and the price of EU allowances. Different tax treatment of allowances and transactions across borders is one notable example that will change the actual cost of supplying an EU allowance as well as the willingness to pay. Tax issues are the prerogative of Member States and not likely to be harmonised at least in the short term.

4.1.2 JI and CDM supply

The so-called Linking Directive was adopted by the European Parliament 20th April 2004. The directive allows participants in the EU ETS to use carbon credits from Joint Implementation (JI) and the Clean Development Mechanism (CDM) projects to meet their obligations.⁹

Participants in the EU ETS will be able to use CDM credits (CERs) from the launch of the EU market, while JI credits (ERUs) will be eligible only from 2008 and onwards. CERs purchased before 2008 can be banked to the 2008-2012 period, if they have not been used to meet emission limits.

The Linking Directive also determines that Member States are not required to limit the use of CDM credits in the first period, but will be required to fix limits for JI and CDM in the 2nd period according to the supplementarity provisions of the Kyoto Protocol.¹⁰

JI and CDM credits from a large range of project types are eligible. Emission reductions in any sectors and greenhouse gases covered by the Kyoto Protocol (CO₂, CH₄, N₂O, HFCs, PFCs and SF₆) can be used. Exceptions are projects that enhance biological CO₂ sequestration (e.g. from forestry projects) and projects relying on nuclear energy.

Imports from JI and CDM will add to the supply function in the EU market. Since the potential supply of JI and CDM credits in the 2008 – 2012 period is expected to be more substantial than prior to 2008 the Linking Directive is generally assumed to have any significant impact on prices only in the second period of EU carbon market. In the short term, impact on prices is more unlikely due to limited supply.

On the one hand the supply may be constrained by lead-time needed to develop projects and receive the required international approval. It takes 2 – 4 years to develop a CDM-

⁹ JI and CDM are mechanisms under the Kyoto Protocol whereby a project activity that reduce GHG emissions in one country can be awarded carbon credits (in tonnes of CO₂e) and transferred to another country. JI credits (Emission Reduction Units, ERUs) refer to projects carried out in countries with commitments under the Kyoto Protocol, in particular Russia, Ukraine and Eastern European countries. CDM credits (or Certified Emission Reductions, CERs) refer on the other hand to projects in developing countries, which have no commitments under the Kyoto Protocol.

¹⁰ This provision limits the possibility to fulfil commitments through the Kyoto mechanisms. UN provisions settle qualitative limits and not quantitative limits on the use of Kyoto mechanisms.

project. Supply of credits in the 2005 – 2007 period will thus largely have to come from projects already in preparation. Governments, or carbon funds funded primarily by governments, have contracted most of the credits expected from projects being pursued today. Supply in the short term will thus be very limited. Even if projects are to supply credits in 2008 – 2012 they need to be initiated shortly.

Furthermore the capacity of the approval process for projects at the national and UN level will be a limiting factor for the number of projects that can generate credits in the 2008 – 2012 period. Both JI and CDM projects need to be approved by governments, and CDM projects in addition need to be approved by the UN. Next to this uncertainty about future climate change commitments internationally is preventing projects that need to rely on carbon revenue from credits generated beyond 2012. In practice this means that the opportunity to pursue especially CDM projects, but to some extent also JI projects for the 2008-2012 period will deteriorate significantly in the next couple of years.

On the other hand repetition of similar projects may turn out to reduce these market constraints. Recent transactions of large-scale CDM projects within manufacturing facilities producing fluorinating greenhouse gases indicate that a small number of projects may in fact be able to provide a substantial base load supply to the EU market. Some carbon brokers thus expect that there will not be any major supply constraint on JI and CDM. Ratification of the Kyoto Protocol by Russia and launch of international negotiations on future climate change commitments will furthermore increase the possible supply of JI and CDM credits.

If project development is not increased significantly it is thus unlikely that there will be a large enough supply of credits to stabilise European carbon prices. The linking directive provides increasing incentives for private sector CDM activity by allowing CERs to be used in the 2005-2007 period. Contrary to EU allowances CERs will be bankable to the Kyoto period, which will increase the value of CERs in the carbon portfolio of companies. So far companies have however been reluctant to consider purchases of CERs.

4.2 Market balance in 2005 – 2007

Comparing demand and supply estimates of the previous sections provides a picture of the market balance and likely allowance prices in the first period of the EU ETS.

The net demand estimate for the 2005 – 2007 period is shown together with the net supply from the previous section in Figure 4.2. Our best guess is a net demand just slightly above zero. The supply estimate indicates that a demand at this level can be supplied at a zero allowance price.

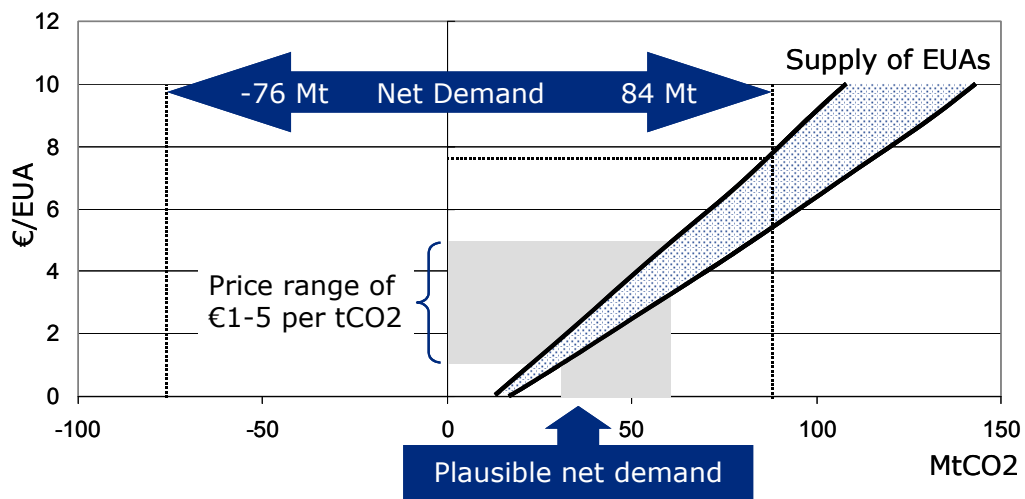
We do however not find allowance prices close to zero very likely. If allowance prices stay very low, participants with surplus allowances might stay out of the market. Transaction costs will in this case be high compared to the benefits of engaging in the market. In addition participants might keep a higher reserve of allowances for balancing their accounts at the end of the period rather than using resources on closely monitoring emissions and the carbon market. A net demand of 30 – 60 million tonne CO₂ could thus be plausible and result in prices between € 1 and € 5 in the first period. This price

interval reflects a likely range of demand for allowances and the uncertainty in costs of emission reductions and thus supply of EU allowances.

The maximum demand for allowances of 80 million tonne CO₂ identified in section 3.1 indicate that prices of EU allowances substantially above € 8 for the first period of the EU ETS seem quite unlikely. Emission reductions at this level could be delivered at abatement costs below € 8 even in the case of low estimate for supply of EU allowances.

CDM is not included in these estimates and any supply of CDM credits (CERs) will add to the supply side. As mentioned in the previous sub-section any supply from CDM in the short term should be expected to be limited. There are only a limited number of projects currently being developed and for these projects a large share of the resulting carbon credits have already been contracted by governments and multilateral organisations, which are not likely to offer these credits for sale. Furthermore CDM credits might turn out to be priced higher than EU allowances, since they can be banked to the 2nd period from 2008 to 2012 contrary to EU allowances. It is thus not clear that linking to CDM will be able to have any significant impact on prices of EU allowances in the first period.

Figure 4.2 Market balance in first phase of the EU ETS



Source: ECON

4.3 Market balance in 2008 – 2012

In Figure 4.3 the estimated abatement costs and reduction requirements within EU ETS for the period 2008 – 2012 are displayed. In the “full burden” scenario in which the new member states allocate emission allowances according to their projected business-as-usual emissions in 2010, the net demand would be up to 219 million tonne CO₂, if governments provide industry with tight allocations in the second period. An allocation based on proportional burden sharing between sectors in the EU-15 would reduce this to 143 million tonne CO₂. Allocation of surplus allowances in the new member states will reduce this amount further, potentially to a very low level of 8 million tonne CO₂. The

equilibrium price would with a demand of 120-140 million tonne CO₂ be somewhere in the range € 8 – 13/tonne CO₂.

With a more generous allocation of emission allowances to the ETS-sectors from the new member states, or with a large supply of JI and CDM-credits, or Russia's participation this price is could drop to € 5 or even lower.

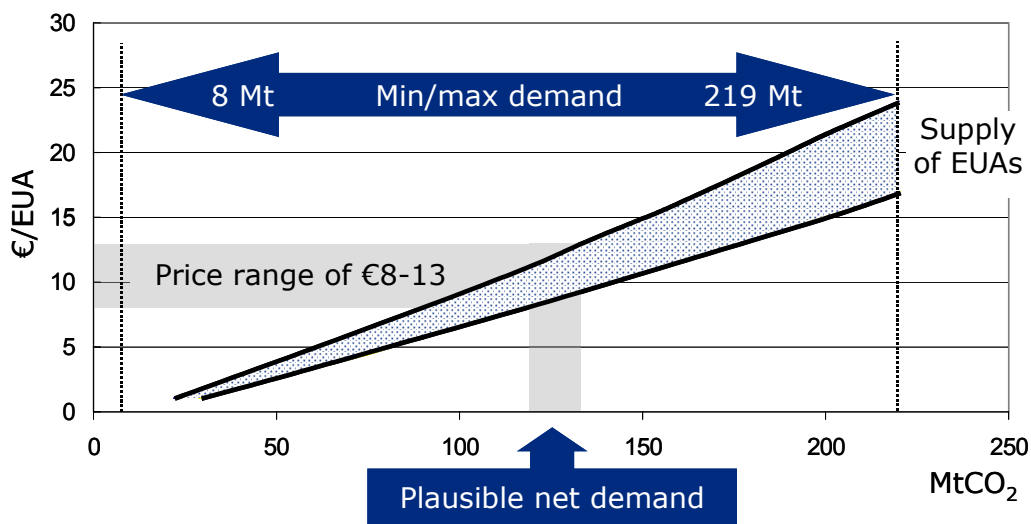


Figure 4.3 Market balance in the period 2008-12

Source: ECON

Other studies

Even if it is uncertain whether JI and CDM supply constraints will be significant or not, it seems clear that credits most likely will put a downward pressure on the price of EU allowances. Other studies seem to support this observation.

In the *KPI Technical Report* from May 2003 the effect of linking under different assumption is analysed. That analysis is based on model simulations. These simulations yield an emission allowance price in the EU-25 without linking of € 26/tonne CO₂. The description of the modelling done there is rather brief, and it is therefore hard to evaluate their estimate or to compare it with our result. The most important difference does however seem to be the projected reduction requirements. Their baseline reference emissions in 2010 are substantially above the projections used in this report. The analysis presented in the *KPI Technical Report* is however primarily focused on the impacts of linking and the baseline may therefore be of less interest. If the EU ETS is opened to JI and CDM credits, but without competition for credits from other parties, the price of allowances would according to their analysis drop to € 4.8 - € 12 per tonne CO₂ depending on the level of competition from other purchasers of credits. According to this analysis, linking thus results in a substantial reduction of the price of emission allowances. The result is sensitive to the level of JI and CDM supply and possible constraints on this supply.

We feel less confident about the high prices suggested in the KPI Report for the case of no linking (i.e. € 26). This would seem to require a substantial burden to be carried by the ETS-sectors, which would hardly seem political feasible.

In a report by *Credit Suisse First Boston (CSFB)* from October 2003¹¹ the likely price of emission allowances is analysed. The analysis is focused on utilities (electricity production) and indicates a value of emission allowances of € 9.2/tonne CO₂ for EU-15 in 2010. In EU-15 + candidate countries (i.e. enlarged EU) the value of carbon would drop to € 6.9/tonne CO₂. If the effect of JI and CDM credits is added the value of carbon drops further to € 3.2/tonne CO₂. These results hinges on that most important electricity markets in the EU have enough flexibility in terms of switching between technologies so that a 10 per cent carbon shortfall can be offset (at a cost of € 0-14/tonne). If the shortfall is larger it has to be met by building new CCGT plants, which according to CSFB would result in a sharp increase in the value of carbon to € 26.9/tonne CO₂.

Simulation results reported in *Bergman and Radetzki (2003)*¹² indicate a price of emission allowances of € 15.3/tonne CO₂ for the case with trade in EU and other Annex I countries (except USA). Trade only within EU-15 would result in a price of € 35.9/tonne CO₂. This analysis is however based on a computable general equilibrium (CGE) model, which basically covers the entire economy. The trade does thus not only take place within the EU ETS-sectors, but also with non-trading sectors of the economy including for instance transport. The resulting high prices might thus depend on higher abatement costs in other sectors, and a comparison with the estimates for the ETS-sectors is hard to make.

4.4 Caveats and comments

The European carbon market is emerging, but still in its very early stages. Estimating prices of emissions allowances is thus essentially very uncertain and a number of caveats and comments mentioned in the previous sections should be summarised.

Separate first period

Banking of allowances in the EU ETS from the first to the second period will generally not be allowed by member states. The first phase will thus be distinct from the second and prices largely independent.

Since participants in the first two years will receive allowances for two years before they need to surrender allowances for last year's emissions, most participants will be able to postpone purchases of allowances. A shortage will not necessarily show in the market until a very late stage of the first period and prices in the first years will to a large extent be determined by participants expectations of prices in the last year. Prices in the first period may therefore fluctuate substantially and can potentially turn out to be very low.

¹¹ CSFB, European carbon trading – utilities to get a boost, Sector Review European Utilities, 8 October 2003

¹² Lars Bergman and Marian Radetzki, "The Continue Project – Global climate policy and implications for the energy sector in a small open economy: the case of Sweden", 2003

In the second period the ETS directive allows banking to subsequent periods and prices will depend not only on the current period, but also expectations about future climate change commitments and allocation decisions to be taken on the basis of these commitments. Prices in the second period could increase especially if international negotiations were concluded that tightens member states commitments.

Snapshot of NAPs

Our estimate of possible prices in the first period of the EU ETS is sensitive to the further development of NAPs. We have used a snapshot of NAPs as of June 2004 and a number of Member States still remained to submit their NAP to the Commission. The allocation plans of these Member States may turn out to be different than our estimates. Furthermore the Commission has to review Member States allocation plans and ensure that they comply with the criteria established in the directive. The review of the first eight plans carried out by the Commission in July lead only to minor changes to those plans, but it is still uncertain whether the remaining plans will be changed during the review.

Business-as-usual development

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

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

On the other hand most member states projects have been produced before the final decision to introduce the emissions trading scheme in the EU. Many projections are thus based on a situation without any CO₂ tax on industry and the price of CO₂ in the EU ETS now introduced should be expected to reduce the expected future emission level of industry. Most projections have also been produced before the recent increases in energy prices, which also will contribute to limit emissions.

5 Analysis of the effect on electricity price

In the Nordic electricity market the wholesale price is primarily set based on the marginal cost of the most expensive power plant used, i.e., the plant in use with the highest marginal cost.¹³ The primary exception to this principle comes if market power is exploited resulting in prices above the relevant marginal cost. During considerable parts of the time fossil fuel based plants, primarily coal-fired plants, provide the marginal production in the Nordic (and northern European) power market. The introduction of emission allowance trading will increase the marginal cost of these plants, which then will be reflected in higher power prices at times when fossil fuel plants are setting the price.

In this section the effect of emissions trading on the price of electricity is analysed. ECON's Nordic power market model has been used to simulate the price response in the Nordic power market.

With the model we have simulated the market equilibrium in a normal, wet and dry year as defined below. The model simulates the market equilibrium based on a number of underlying assumptions about developments in demand, production capacities and the political framework (see Appendix B). The different scenarios used in the simulations are presented in section 5.1 and are then followed by the simulation results in section 5.2.

5.1 Scenarios

The baseline scenario is basically a business-as-usual scenario in which current policies are continued, but no additional measures are taken to reduce GHG emissions.¹⁴

The effect of the emission trading is analysed for three different levels of allowance prices for each of the three years 2006, 2008 and 2012.

Based on the analysis in the previous sections we have used three different levels of the price of emission allowances for each year. For the first period the likely price range for emission allowances is 1 – 5 €/tonne CO₂ and we find it highly unlikely that the price will exceed 8 €/tonne CO₂. Based on this we have chosen to use 1, 5 and 8 €/tonne CO₂ as low, medium and high estimates in the simulations for the period 2005-2007.

For the period 2008-2012 the price of allowances is likely to be higher since the Kyoto commitments should be met. The likely price range within the EU ETS is estimated to

¹³ In a hydro-based system the water value might set the price. Although the water value is not a measure of the direct production cost it is a measure of the opportunity cost of producing electricity from a hydro power plant in a particular hour and should thus be regarded as the relevant marginal cost of the hydro plant.

¹⁴ The Danish CO₂-taxes have been removed in the baseline scenario.

be 8 – 13 €/tonne CO₂e. With Russian participation or a large supply of JI/CDM credits the price might be reduced. A tighter allocation of allowances to the ETS-sectors can naturally result in a higher price, but our belief is that it is not very likely that the price will exceed 15 €/tonne CO₂. Therefore we have chosen allowance prices of 5, 8 and 15 €/tonne CO₂ as low, medium and high estimates in the simulations for 2008 and 2012.

These scenarios should not be interpreted as extreme boundaries of possible prices on emission allowances, but as low and high scenarios that have a reasonable possibility of occurring.

Table 5.1 Summary of assumed prices of emission allowances used in simulations, €/tonne CO₂

	Low	Medium	High
2005 – 2007	1	5	8
2008 – 2012	5	8	15

For each of these scenarios (3 years and 3 different emission allowance prices) simulations are made for three different assumptions on precipitation; normal, wet and dry year. This results in a total of 27 simulations in addition to the baseline scenario.

5.2 Results from model simulations

In this section the results from the simulations using ECON's Nordic power market model for years for with normal precipitation are presented and discussed. We first present the results for the reference scenario in a normal year, and then continue with a discussion of the main results regarding the effect of emissions trading including a discussion on how differences in coal prices changes the effect of emission trading. Finally we present a more detailed description of the results for each scenario. The results for extreme wet and dry year are presented in Appendix A.

5.2.1 Results for the reference scenario

The model simulates a price level slightly above 23 øre/kWh in 2006 for Norway, Sweden, Zealand and Finland and about 1-2 øre/kWh lower for Jutland, Germany and Netherlands (see Table 5.2).¹⁵ For Poland the price in the reference scenario will be around 4 øre/kWh below the price in the Nordic countries. Between 2006 and 2008 the simulation results suggest a price decrease with almost 2 øre/kWh for the Nordic countries. The reason is an assumption that the coal prices will stay at today's unusual high level until 2006, but decrease to a much lower, long run level in 2008. This more than outweighs a general tightening of the market. From 2008 to 2012 the prices increase and end approximately 1.5 øre/kWh above the level in 2006. With a constant coal price the price increase over time would be larger.

The picture with slightly higher prices in Norway, Sweden, Zealand and Finland in 2006 is reversed in 2008 and even more so in 2012 with Germany and Netherlands

¹⁵ All prices are in 2004-Norwegian kronor (or øre) if not stated otherwise.

having prices 4 – 5 øre/kWh higher than the Nordic countries. It is driven by the fact that the model generates very high prices during high load periods in the northern continental countries (70 – 80 øre/kWh). In the model investments in peak load capacity is endogenous and the peak load prices is thus determined by the expected costs of adding new peak load capacity. Since the average price to such high degree is determined by these high load prices, that particular result should be interpreted with some caution. The important result is however that the high load prices are higher in the continental countries than in the Nordic countries such that the transmission interconnectors are fully used for export to the continent.

Poland is an exception with significantly lower prices than all the other countries in 2008, but slightly above the Nordic countries in 2012.

In all the years Norway, Sweden and Finland has a negative net export, i.e., are net importers. For Sweden this net import increases from 2006 to 2012 while for Norway it decreases due to new gas fired plants. The Finnish net import increases between 2006 and 2008 and then decreases, which is explained by the new Finnish nuclear power plant.

Poland has a low electricity price in 2006 and 2008, but can see a rather sharp price increase until 2012. In the longer run Jutland will have the lowest average price, benefiting from the low Nordic high load prices and the low German low load prices.

Table 5.2 Electricity price (NOK øre/kWh), production (TWh) and net export (TWh), normal year 2006-12 in reference scenario

		Norway	Sweden	Jutland	Zealand	Finland	Germany	Nether-lands	Poland
Electricity price	2006	23.2	23.2	21.2	23.2	23.2	22.0	22.6	19.6
	2008	21.5	21.5	18.8	21.5	21.5	23.4	24.4	13.5
	2012	24.7	24.7	22.7	24.6	24.6	29.4	28.6	25.4
Production	2006	119	143	32	20	79	547	99	137
	2008	121	148	32	18	80	575	81	160
	2012	135	154	33	20	94	568	145	160
Net export	2006	-89	-7	11	45	-15	-5	-14	176
	2008	-7	-7	9	2	-18	4	-35	30
	2012	-4	-13	9	4	-112	-44	18	21

Source: ECON model simulation

Production capacity is changed according to known plans and our estimates on fulfilment of political goals. These changes are the same for all scenarios and are documented in Appendix B. In addition to these we assume that new CCGT plants and peak load capacity will be built when it is profitable. As requested by the client, investments in gas fired power plants in Norway is however limited by the exogenous assumption that no more gas fired plants will be build than currently has been granted concessions. Since prices and production costs vary between scenarios so will the

amount of endogenous investments do. No investments other than planned are found to be profitable before 2012. That is valid for all countries and all scenarios. The amount found to be profitable is presented in Table 5.3 and Table 5.4. The bulk of the investments will be carried out as base load gas fired plants in the Netherlands and as peak load gas fired plants in Germany. Uncertainty around the use of existing interconnectors between the two countries does however imply a corresponding uncertainty around the localization between the two countries.

Table 5.3 Amount of profitable investments in CCGT in 2012, MW.

Emission allowance price	Norway	Germany	Netherlands	Poland
0 €/tonne CO _{2e}	1660	997	5132	0
5 €/tonne CO _{2e}	1368	669	5611	0
8 €/tonne CO _{2e}	1196	734	5445	0
15 €/tonne CO _{2e}	664	919	5519	0

Source: ECON model simulations

Table 5.4 Amount of profitable investments in peak power plant in 2012, MW.

Emission allowance price	Norway	Germany	Netherlands	Poland
0 €/tonne CO _{2e}	0	8100	1532	327
5 €/tonne CO _{2e}	0	7515	1516	245
8 €/tonne CO _{2e}	0	7522	1479	54
15 €/tonne CO _{2e}	0	7478	791	0

Source: ECON model simulation

These results confirm our previous study (ECON, 2004) showing that the investments in gas-fired power plants are reduced with the price of emission allowances. In ECON (2004) we did however find that a further increase in the price of emission allowances (to 20 €/tonne CO₂) triggered investments in gas fired power plants. It is possible that a similar effect would occur here, but that the assumed CO₂-prices have not been high enough to trigger those larger investments.

5.2.2 Effects of trade with emission allowances

The effect on the electricity price is driven by the fact that trading with emission allowances effects (increases) the marginal production cost of CO₂-emitting power plants. It may also change the merit order, i.e., change the ordering of the marginal cost of different technologies and thus in which order different technologies are taken into use.

Table 5.5 displays the changes in marginal production cost of different technologies (fuels) from the introduction of emissions trading, assuming different prices on the emission allowances. The differences in the effect on the marginal cost between

different countries for a particular technology (fuel) depends in this calculation on the efficiency differences between different power plants (primarily new vs. older plants). In the table the effect on the marginal cost is calculated for currently existing plants. The mix will change during the studied period as older, and more inefficient, plants are faced out and possibly newer plants are built.

The effect on the average electricity price is determined primarily by two factors. One is the change in the systems marginal cost, i.e., the marginal cost of the marginal plant. That determines the effect on the price within one particular hour (assuming perfect competition). The other important factor is the number of hours during which different technologies are setting the price in the market.

This assumes that the demand is perfectly inelastic, i.e., not responding to the price at all. With some price sensitivity a price increase will lead to a reduction in equilibrium demand and in some cases the effect will be that a cheaper technology becomes marginal. The price effect will then be smaller. Figure 5.1 gives a schematic illustration of such an occurrence.

Figure 5.1 Schematic illustration of the effect on the price of electricity from emissions trading

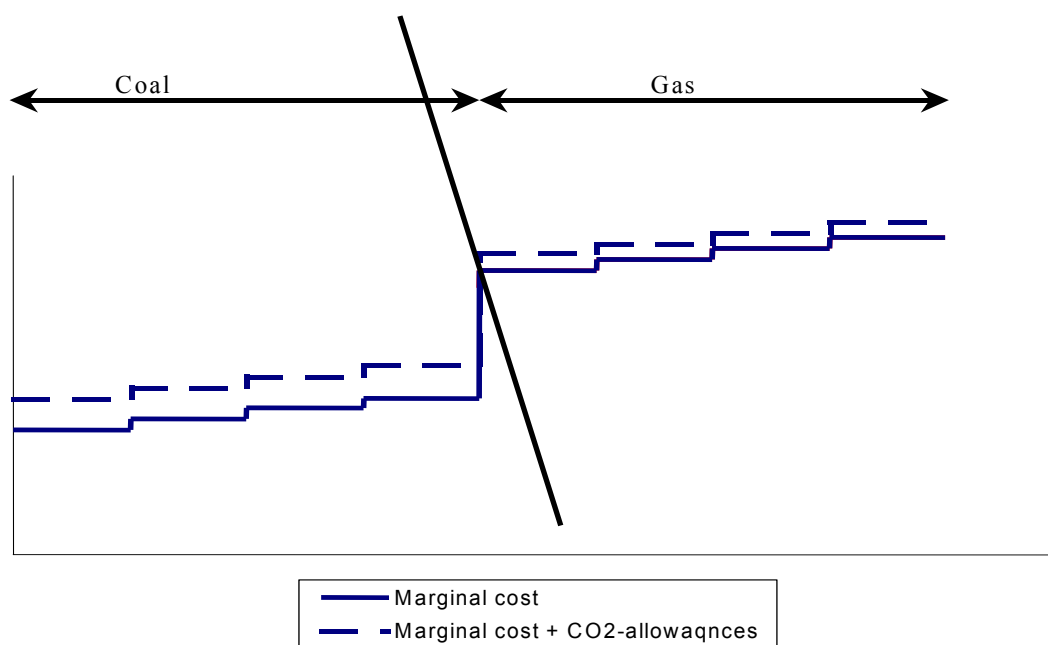


Table 5.5 *Effects on the marginal production cost from emission trading*

	Emission of CO ₂	1 €/tonne	5 €/tonne	8 €/tonne	15 €/tonne
Sweden	kg/kWh	Norwegian øre/kWh			
Coal	0.63	0.54	2.70	4.32	8.09
CCGT new	0.35	0.30	1.48	2.37	4.45
Norway					
CCGT new	0.35	0.30	1.48	2.37	4.45
Zealand					
Coal	0.81 – 0.88	0.69 - 0.75	3.47 - 3.74	5.55 - 5.98	10.41 - 11.21
Peak load gas and oil	0.85	0.73	3.64	5.83	10.93
SCGT	0.88	0.75	3.73	5.98	11.20
CCGT new	0.35	0.30	1.48	2.37	4.45
CCGT old	0.92	0.79	3.94	6.30	11.81
Lignite	0.76	0.65	3.25	5.20	9.75
Jutland					
Coal	0.49 – 0.80	0.62 - 0.69	3.10 - 3.43	4.96 - 5.48	9.31 - 10.28
Peak load gas and oil	0.64	0.55	2.74	4.38	8.21
CCGT new	0.35	0.30	1.48	2.37	4.45
Finland					
CCGT new	0.35	0.30	1.48	2.37	4.45
Germany					
Coal	0.95 – 1.00	0.81 - 0.85	4.03 - 4.24	6.45 - 6.79	12.10 - 12.73
Peak load gas and oil	0.79	0.67	3.35	5.35	10.04
SCGT	0.59	0.50	2.51	4.01	7.52
CCGT new	0.35	0.30	1.48	2.37	4.45
CCGT old	0.39	0.33	1.66	2.66	4.98
Oil	0.80	0.68	3.41	5.45	10.22
Lignite	0.98	0.83	4.16	6.66	12.49
Netherlands					
Coal	0.68 – 0.96	0.58 - 0.82	2.91 - 4.11	4.66 - 6.58	8.74 - 12.33
Peak load gas and oil	0.98	0.84	4.18	6.69	12.54
SCGT	0.74	0.63	3.15	5.05	9.46
CCGT new	0.35	0.30	1.48	2.37	4.45
CCGT old	0.58	0.49	2.47	3.96	7.42
Oil	0.42	0.36	1.81	2.90	5.43
Lignite	0.51	0.44	2.19	3.50	6.57

Source: ECON

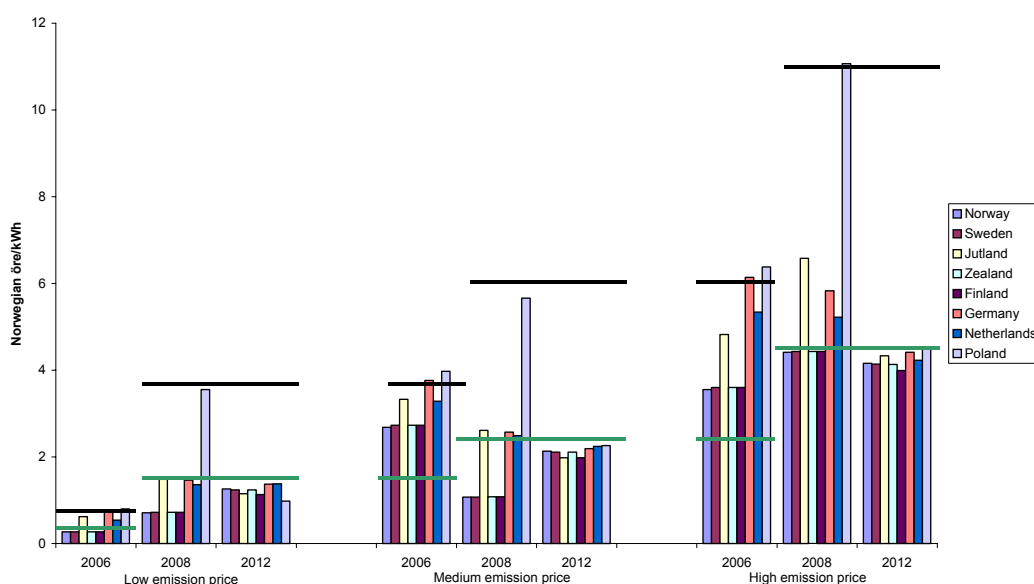
Table 5.5, continued

Poland					
Coal	0.94 - 0.993	0.80 -0.84	-4.01 - 4.2	-13.13	12.02 - 12.60
Peak load gas and oil	0.98	0.84	4.18	6.69	12.54
SCGT	1.00	0.85	4.27	6.84	12.82
CCGT new	0.35	0.30	1.48	2.37	4.45
Lignite	0.85	0.73	3.64	5.83	10.93

Source: ECON

In Figure 5.2 the effect on the price of electricity according to the model simulation are shown for each of the emission price scenarios and each country. A more detailed description and discussion of the results for each scenario is provided below. In addition the effect on the marginal cost for two different technologies are displayed. For each scenario and year there are two lines. The lower of these show the effect on the marginal cost in new CCGT plants, and the upper line show the effect on the marginal cost in coal fired plants.¹⁶

Figure 5.2 Effect on marginal cost and electricity price



Source: ECON

From this two things are clear. In the very short run (2006) the effect on the electricity price in the Nordic countries, except Jutland, is below the increase in marginal cost for coal fired plants, which are often price setting in the Nordic market. However, since they are not setting the price in every hour the average effect on the electricity price will be lower than the increase in marginal cost. For Jutland, Germany, the Netherlands and

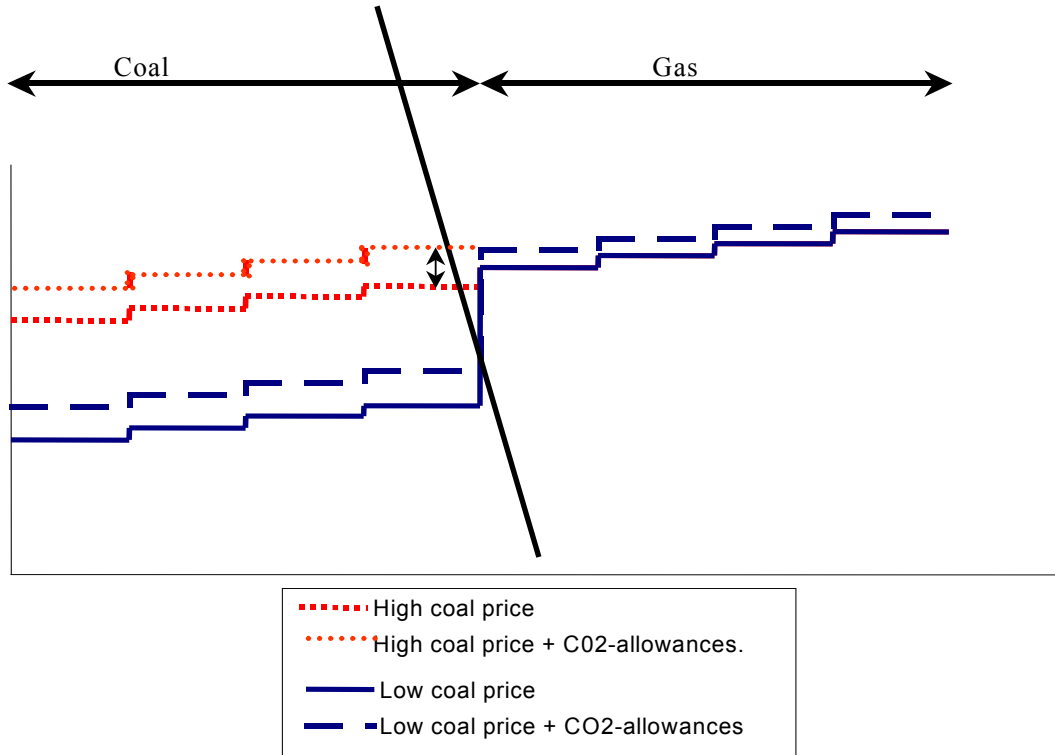
¹⁶ Both of these are based on the average of the smallest and largest effect for coal plants in Zealand in Table 5.5.

Poland the increase in the electricity price in 2006 is approximately the same as the increase in the marginal cost of coal production. The price increase is larger in these countries both because coal fired power plants are marginal more frequently and because there are coal fired plants with lower efficiency and hence higher increase in marginal cost. The latter fact explains why Poland and Germany get a higher price increase than the indicated increase in marginal cost for coal fired power plants.

For all the emissions price scenarios we can observe that the price increases are smaller compared to the increase in marginal costs in 2008 than in 2006. The explanation lies with the discontinuities in the supply curve for the electricity market. In the simulations, with the low coal price in 2008, the demand curve hits the supply curve in the vertical step between the most expensive coal production and the cheapest gas production during a considerable share of the year, as illustrated in Figure 5.3. When emission trading is introduced the equilibrium price in these time periods is already above the marginal cost of coal production including the price of emission allowances. In the example provided in the figure emissions trading has no effect on the price of electricity.

With the higher coal price in 2006 the demand curve hits the supply curve in a horizontal coal segment. The price of electricity will be equal to the marginal cost of most expensive coal production. When emission trading is introduced the marginal cost of coal production increases and the price of electricity is increased by a similar amount.

Figure 5.3 Schematic illustration of the effect of emissions trading with different coal prices



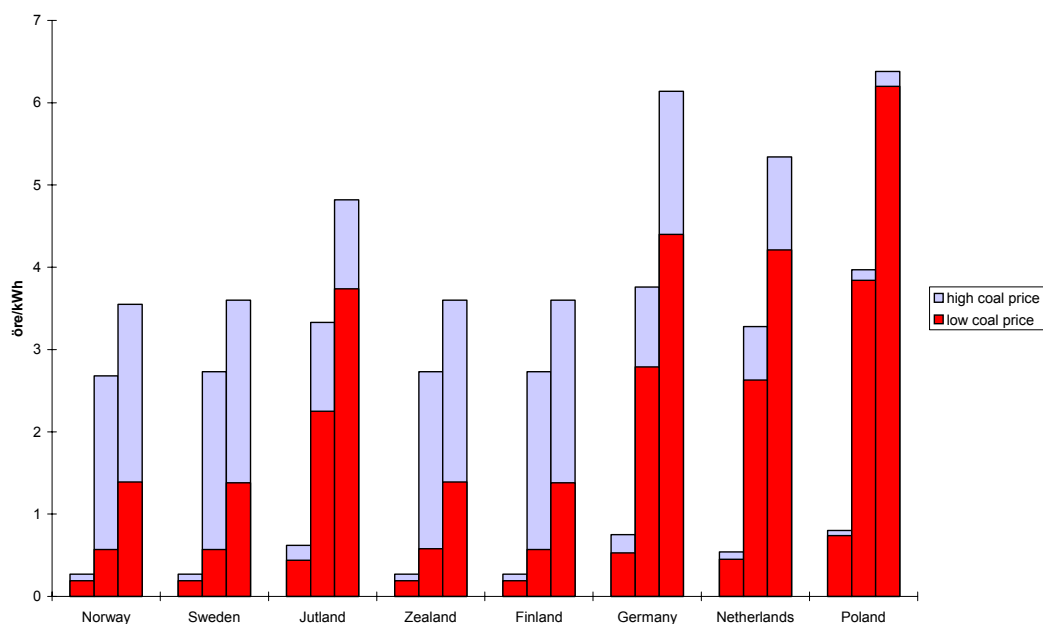
In the somewhat longer run (2012), the effect on the electricity price is approximately the same as the increase in marginal cost of new CCGT in all countries. One would expect the price increase to be (almost) identical to the increase in long run marginal cost for gas-fired power plants, at least in Norway where new power plants are built according to long run marginal cost. The reason for the smaller price increase in the investment cap of 1660 MW. As this cap is binding in the baseline scenario, the price is above the long run marginal cost of a new gas-fired power plant. Hence the price increase is smaller than the increase in long run marginal cost since the investment cap is no longer binding in any of the three scenarios with emissions prices. For the continental countries, the reason for the difference between price increase and increase in long run marginal cost of gas-fired power plants is the change in price structure. A different price structure may give a different change in fixed costs/kWh and hence an additional change in long run marginal costs which is not shown in the figure.

5.2.3 Effect of different coal prices

Currently the coal price is unusually high, but it is expected to fall in the future. Our baseline assumption regarding the coal price in 2006 is 58.75 \$/tonne. The coal price has an obvious effect on the price level for electricity, but may also have an impact on the effect of emissions trading. This explained the difference between 2006 and 2008. To study the effect of coal price without disturbance from changes in other parameters, a sensitivity analysis simulations for 2006 using the assumed long run equilibrium price of 35 \$/tonne has been made. The results of these simulations show that the effect of the coal price is substantial.

In Figure 5.4 the results from the simulations for 2006 using a high coal price (58.75 \$/tonne) and a low coal price (35 \$/tonne) for each country and each assumed price of emission allowances are displayed. For each country the assumed price of allowances are 1, 5 and 8 €/tonne CO₂. Especially in the Nordic countries and with medium or high allowance prices there are large effects from a high coal price on the effect of emissions trading. With the medium price on emission allowances the effect of emissions trading for the Nordic countries (except Jutland) are about 4.7 times higher with the high coal price compared with the low coal price. With a high allowance price the effect is about 2.5 times higher with the high coal price. For Jutland, the Netherlands and Germany the effect on emissions trading increases with a factor between 1.25 and 1.5 for the medium and high allowance price scenarios. For Poland the coal price has almost no effect.

Figure 5.4 *Effect on the electricity price from emissions trading in 2006 depending on assumed coal prices*



Source: ECON model simulations

5.2.4 More results from the scenarios with emission trading

This section presents the market equilibriums found for the three scenarios with emission trading.

Low price scenario

In the low price scenario the price of emission allowances will be very low (1 €/tonne CO₂ in 2006 and 5 €/tonne CO₂ in 2008) and thus the effect on electricity prices, production and trade will also be limited.

The results for the low emission allowance price scenario are displayed in Table 5.6. The effect on the electricity price in 2006 will be an increase of below 0.3 øre/kWh in Norway, Sweden, Zealand and Finland. In Jutland and the northern continental countries the price increase will be double or more than that. The production and the net export will quite naturally be only moderately affected.

For 2008 and 2012 we expect that the price of emission allowances will be higher than in 2006, which is reflected in the scenarios. This primarily drives the larger effect on the electricity price in 2008 compared with 2006. Still the price increases in the Nordic countries (except Jutland) will only be around 0.7 øre/kWh in 2006 and 1.5 øre/kWh in the continental countries (except Poland). However, the effect on the electricity price is also larger in 2012 than in 2008 for the Nordic countries (except Jutland), while the price effect decreases in the northern continental countries.

As shown in Table 5.3 and Table 5.4 the investments (in 2012) in Norway, Germany and Poland decreases due to the introduction of emissions trading in Norway, Germany and Poland. Only in the Netherlands are the investments increased. The exogenous

assumption that limits gas fired capacity in Norway to 1660 MW is not binding when emission trading is introduced.

Table 5.6 Difference in electricity price (NOK øre/kWh), production (TWh) and net export (TWh) between reference scenario and low emission price scenario, normal year 2006-2012

		Norway	Sweden	Jutland	Zealand	Finland	Germany	Nether-lands	Poland
Electricity price	2006	0.3	0.3	0.6	0.3	0.3	0.8	0.5	0.8
	2008	0.7	0.7	1.5	0.7	0.7	1.5	1.4	3.6
	2012	1.3	1.2	1.2	1.2	1.1	1.4	1.4	1.0
Production	2006	0	0	0	0	0	-0.9	-0.6	-1.0
	2008	0	0	-0.2	0	0	-7.8	0.2	-5.5
	2012	-2.2	0	-0.1	0	0	-3.8	0.2	-0.8
Net export	2006	0.2	0.2	0.1	0	0.1	0.3	-0.4	-0.4
	2008	0.6	0.6	0	0.0	0.3	0	0.7	-2.1
	2012	-1.2	1.1	0.1	0.1	0.4	-1.4	0.7	0.4

Source: ECON model simulation

Medium price scenario

Also in the medium price emission price scenario the effect on the electricity price in 2006 will be about 2.7 øre/kWh in Norway, Sweden, Zealand and Finland and 0.5 – 1 øre/kWh more in the other modelled areas, as shown in Table 5.7. Comparing the effects between years we see that the price increase is smaller in 2008 than in 2006 in spite of the fact that the emission allowance price is assumed to increase. One explanation for this is the different assumptions regarding the coal price (see section 5.2.3 for a discussion). Between 2008 and 2012 the effect on electricity prices increases for Norway, Sweden, Zealand and Finland from a little more than 1 øre/kWh in 2008 to around 2 øre/kWh in 2012. For the continental countries we, again, see the opposite effect of a decreasing price effect over time and in 2012 the effect on the electricity price is approximately the same in all the modelled areas.

The production also decreases. For the Nordic countries this decrease primarily takes place in Norway (in 2012) due to less new gas fired production compared with the reference scenario

As mentioned above, in the medium emission price scenario the capacity expansion is lower in 2012 compared with the reference scenario. In Norway investments in base load gas fired plants are reduced even further compared with the reference and the low emission price scenarios, and the exogenous restriction on gas fired capacity is thus not binding in this scenario either. In Germany investments in both base and peak load gas fired plants are reduced. In the Netherlands the investments in base load gas fired capacity increases, while the investments in peak load gas fired capacity decreases resulting in a net increase of capacity between the two scenarios.

Table 5.7 Difference in electricity price (NOK øre/kWh), production (TWh) and net export (TWh) between reference scenario and medium emission price scenario, normal year 2006-2012

		Norway	Sweden	Jutland	Zealand	Finland	Germany	Nether-lands	Poland
Electricity price	2006	2.7	2.7	3.3	2.7	2.7	3.8	3.3	4.0
	2008	1.1	1.1	2.6	1.1	1.1	2.6	2.5	5.7
	2012	2.1	2.1	2.0	2.1	2.0	2.2	2.2	2.3
Production	2006	5.3	0	0.1	-0.9	-4.0	-21.5	11.5	-5.5
	2008	0	0	-0.1	0	0	-13.5	0.7	-7.7
	2012	-3.5	0	-0.3	0	0	-4.4	-1.5	-2.4
Net export	2006	7.1	2.2	0.4	-0.7	-3.1	-15.9	12.7	-2.7
	2008	0.8	0.9	0.1	0.0	0.4	-1.2	1.7	-2.6
	2012	-1.9	1.8	-0.1	0.1	0.7	-0.2	-0.7	0.3

Source: ECON model simulation

High price scenario

The results for the high price scenario are displayed in Table 5.8. In the high emission price scenario the price of electricity increases with about 3.6 øre/kWh in the Nordic countries (except Jutland) in 2006. The effect is a little more than 1 øre/kWh larger in Jutland and an additional 0.5 – 1.5 øre/kWh larger in the continental countries.

The high emission price scenario for 2008 and 2012 implies a price on allowances of 15 €/tonne CO₂. It should be remembered that the high price scenario should not be regarded as an extreme and highly unlikely scenario, but being in the upper end of rather likely scenarios.

Once again, in 2008 the effect on the electricity price is lower in the Nordic countries (except Jutland), compared with the continental countries. Especially Poland is hit with a large price increase.

For 2012 the price effect decreases in all countries, but much more so in the continental countries and Jutland, which result in a convergence in the price effect between different areas. In 2012 the increase in the electricity price will be 4 – 4.5 øre/kWh in all areas, if the price of emission allowances is 15 €/tonne CO₂. This means that the price of electricity will be about 5 øre/kWh higher in Germany and the Netherlands compared with the Nordic countries.

Table 5.8 Difference in electricity price (NOK øre/kWh), production (TWh) and net export (TWh) between reference scenario and high emission price scenario, normal year 2006-2012

		Norway	Sweden	Jutland	Zealand	Finland	Germany	Nether-lands	Poland
Electricity price	2006	3.6	3.6	4.8	3.6	3.6	6.1	5.3	6.4
	2008	4.4	4.4	6.6	4.4	4.4	5.8	5.2	11.1
	2012	4.2	4.1	4.3	4.1	4.0	4.4	4.2	4.5
Production	2006	5.8	0	0.1	-0.9	-4.0	-26.4	11.7	-9.3
	2008	0	-0.6	0.5	-0.4	0	-36.5	22.1	-22.5
	2012	-7.5	0	-0.2	0	0	-13.9	8.2	-10.8
Net export	2006	8.2	2.8	0.5	-0.6	-2.9	-16.7	13.6	-5.0
	2008	3.1	3.1	1.1	-0.1	1.4	-19.4	24.2	-13.5
	2012	-4.4	3.4	0.2	0.2	1.4	-4.3	9.8	-6.2

Source: ECON model simulation

6 Conclusions

In the report we have analysed the supply and demand for emission allowances within the EU emissions trading scheme. Based on this we have made estimates of likely prices of emission allowances.

The supply of emission allowances are based on available estimates of the marginal abatement costs within the European Union. The same estimates are used for the entire analysed period, i.e., we do not take into account any technological development.

Demand for emission allowances for the first trading period is based on information available from the national allocation plans (NAP), where available, and some supplementary information. As expected the NAPs show that the incentives for a restrictive allocation for the first trading period are weak, and consequently the member states have in general not been very restrictive. This is reflected in a low expected price on emission allowances, and for 2005 – 2007 our belief is that the likely price range is € 1 – 5/tonne CO₂.

For the first Kyoto commitment period, 2008-2012, the Kyoto targets should be met. For EU-15 this implies a reduction of 8 per cent compared with the base year emissions, or 7.5 per cent compared with projected business-as-usual emissions in 2010. However, with reasonable assumptions on the burden sharing between the ETS- and NTS-sectors, the implied reduction within the ETS-sectors can be met at a fairly low cost. Our likely price range is € 8 – 13/tonne CO₂e. Russian participation would increase the supply and decrease the price on emission allowances. A substantial supply of JI- and CDM-credits would also reduce the price on emission allowances.

The estimated prices on emission allowances are then used in simulations of the effect on the electricity price in the Nordic power market. Three levels of allowance prices have been analysed for three different years.

The simulations made show that the electricity price will increase due to emissions trading. In the short run (2006 and 2008) the price increase in the Nordic countries, except Jutland, will be somewhat less than the increase in marginal cost of coal plants. For Jutland and the continental countries included in the model the price increase will be approximately the same as the increase in the marginal cost of coal production for 2006 and close to the increase in marginal cost of modern gas-fired plants in 2008. In the somewhat longer run (2012) the price effect for all included areas is determined by the change in marginal cost for modern gas-fired plants, since that technology will set the price in the market.

In the model there are endogenous investments in gas-fired production, which means that investments are made when they are profitable. In Norway an exogenous constraint on the total amount of gas-fired production has been added, which is set equal to the capacity that currently has been granted concessions (1660 MW). This exogenous constraint is only binding when there is no trade with emission allowances, or when the price of allowances is equal to zero. With a positive price on allowances the investments in Norwegian gas production decreases with the price of allowances for the

price intervals considered here. The interpretation is that no more investments than what currently has been granted concessions are profitable.

7 References

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8 Appendix A: Simulation results for wet and dry years

The Nordic electricity system is highly dependent on hydro power and consequently the price of electricity varies with the precipitation. In addition to the simulation results for a year with normal precipitation simulations have also been made for extreme wet and dry years.¹⁷

8.1 Results for a wet year

Table 8.1 show the average electricity price in the reference scenario during an extreme wet year. Comparing with a normal year we see that there is a substantial price decrease in the Nordic areas, but only a minor effect for the continental countries (see Table 8.2).

Table 8.1 Electricity price (NOK øre/kWh), production (TWh) and net export (TWh), extreme wet year 2006-12 in the reference scenario

		Norway	Sweden	Jutland	Zealand	Finland	Germany	Nether-lands	Poland
Electricity price	2006	19.0	19.0	18.9	19.0	19.1	21.9	22.4	19.6
	2008	14.8	14.8	14.3	14.8	14.8	22.5	23.6	13.1
	2012	19.1	19.2	19.1	19.2	19.2	29.0	28.3	24.9
Production	2006	139	154	32	16	75	538	98	134
	2008	140	158	31	17	80	574	74	160
	2012	155	165	33	19	94	561	138	160
Net export	2006	7.3	-0.4	10.4	0.4	-20.2	-14.0	-15.4	13.3
	2008	6.4	-2.8	7.7	1	-20.0	0.4	-43.2	29.1
	2012	10.7	-7.2	8.9	1.5	-13.9	-52.4	11.0	20.0

Source: ECON model simulation

¹⁷ The extreme wet and dry years are defined such that the probability of getting a year as wet or wetter, respectively as dry or dryer, is 5 %.

Table 8.2 *Difference in electricity price (NOK øre/kWh), production (TWh) and net export (TWh) between wet and normal year in the reference scenario, 2006-12*

		Norway	Sweden	Jutland	Zealand	Finland	Germany	Nether-lands	Poland
Electricity price	2006	-4.2	-4.2	-2.3	-4.2	-4.14	-0.2	-0.1	-0.0
	2008	-6.9	-6.7	-4.4	-6.7	-6.7	-0.9	-0.8	-0.4
	2012	-5.6	-5.5	-3.6	-5.5	-5.4	-0.4	-0.3	-0.5
Production	2006	19.3	10.4	-0.2	-4.0	-4.0	-8.3	-1.3	-3.2
	2008	19.4	9.9	-1.0	-0.8	0	-1.1	-7.5	-0.2
	2012	19.4	10.6	-0.3	-1.9	0	-6.7	-7.1	-0.2
Net export	2006	16.2	7.0	-0.4	-4.3	-5.3	-8.6	-1.4	-3.2
	2008	13.7	3.8	-1.4	-1.2	-2.5	-3.9	-7.8	-0.6
	2012	14.8	5.9	-0.6	-2.2	-2.0	-8.1	-7.2	-0.6

Source: ECON model simulation

8.1.1 Effects of trade with emission allowances

Low price scenario

In the low price scenario the effect on electricity prices in the Nordic countries from emissions trading is somewhat larger than in a normal year, especially for 2006 and 2008 (*Table 8.3*). It is rather contra intuitive that we see a larger price effect in periods when there is less dependence on CO₂-emitting production. This has the same basic explanation as the effect of different coal prices. In a normal year the demand curve hit the vertical step between different technologies relatively often. The effect on the electricity price from emission trading will in those periods be fairly limited. With more water the supply schedule is moved outwards, which has the consequence that the demand curve hits a horizontal segment of the supply curve more often and the electricity price will in those periods rise by approximately the same amount as the increase in marginal cost.

Table 8.3 *Difference in electricity price (NOK øre/kWh), production (TWh) and net export (TWH) between reference scenario and low emission price scenario, wet year 2006-2012*

		Norway	Sweden	Jutland	Zealand	Finland	Germany	Nether-lands	Poland
Electricity price	2006	0.8	0.8	0.8	0.8	0.8	0.7	0.5	0.8
	2008	2.8	2.8	3.0	2.9	2.9	2.0	1.9	3.6
	2012	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.1
Production	2006	0	0	0	0	0	-2.5	-0.1	-0.8
	2008	0	0	-0.1	-1.4	-3.6	-9.8	1.1	-7.4
	2012	-2.2	0	-1.4	0	0	-3.0	-0.1	-1.1
Net export	2006	0.6	0.6	0.1	0	0.2	-1.4	0.1	-0.2
	2008	2.6	2.8	0.2	-1.2	-2.5	0.2	1.8	-3.9
	2012	-1.0	1.2	-1.3	0.1	0.5	-0.3	0.5	0.4

Source: ECON model simulation

Medium price scenario

With the medium price scenario the effect on the electricity price in 2006 is approximately the same in a wet and normal year. In 2008 we again have a much larger effect in the wet year than a normal year, which again has the same basic explanation as above. In 2012 the effect in a wet an normal year is again approximately the same.

Table 8.4 *Difference in electricity price (NOK øre/kWh), production (TWh) and net export (TWH) between reference scenario and medium emission price scenario, wet year 2006-2012*

		Norway	Sweden	Jutland	Zealand	Finland	Germany	Nether-lands	Poland
Electricity price	2006	2.5	2.6	2.5	2.6	2.6	3.8	3.3	4.0
	2008	4.2	4.3	4.7	4.3	4.3	3.3	3.1	6.0
	2012	2.3	2.3	2.3	2.3	2.3	2.3	2.4	2.5
Production	2006	5.3	0	-0.1	-2.8	-0.1	-22.5	12.6	-7.5
	2008	0	0	-0.1	-1.4	-3.8	-14.8	2.1	-12.8
	2012	-3.5	-0.6	-1.5	-0.8	0	-3.5	-1.8	-2.4
Net export	2006	7.2	2.2	0.1	-2.7	0.8	-16.8	13.9	-4.7
	2008	3.7	4.1	0.4	-1.2	-2.1	-0.7	3.3	-7.4
	2012	-1.4	1.6	-1.2	-0.7	0.9	1.1	-0.9	0.5

Source: ECON model simulation

High price scenario

In the high price scenario the effect on the electricity price in the Nordic countries (except Jutland) in 2006 is somewhat less than 1 øre/kWh higher in a wet year than in a normal year. For the continental countries the effect is roughly unchanged.

In 2008 the effect in a wet year is about twice as high in a wet year than in a normal year for the Nordic countries, while it is smaller in the continental countries. Again the same explanation as before applies. For 2012 the effect is somewhat higher in a wet year than a normal year for the Nordic countries, while approximately unchanged in the continental countries.

Table 8.5 *Difference in electricity price (NOK øre/kWh), production (TWh) and net export (TWh) between reference scenario and high emission price scenario, wet year 2006-2012*

		Norway	Sweden	Jutland	Zealand	Finland	Germany	Nether-lands	Poland
Electricity price	2006	4.4	4.4	4.4	4.4	4.3	6.2	5.4	6.4
	2008	8.2	8.2	8.6	8.2	8.2	6.7	6.0	11.4
	2012	5.6	5.6	5.7	5.6	5.6	4.6	4.4	4.8
Production	2006	5.8	0.0	-4.0	-2.8	-0.1	-27.8	12.9	-9.3
	2008	0.0	0.0	-0.1	-3.2	-4.0	-44.3	29.3	-27.7
	2012	-7.5	-0.6	0.0	-2.2	-3.6	-16.5	15.2	-14.5
Net export	2006	9.1	3.7	-3.6	-2.6	1.4	-18.0	14.8	-4.9
	2008	6.8	7.4	0.8	-2.7	-1.0	-24.6	31.8	-18.4
	2012	-2.8	4.4	0.6	-1.9	-1.5	-6.0	16.8	-9.6

Source: ECON model simulation

8.2 Results for a dry year

In an extreme dry year the prices in the Nordic countries, except Jutland, rises dramatically as shown by Table 8.6 and Table 8.7. The prices in the thermal based continental countries are not affected at all, while we see a moderate price increase in the Jutland prices. This is easily explained by the fact that the Nordic area, not counting Jutland, is a net importer even in a normal year. The possibilities to counter a dry year with increased import are thus limited, which explains the large price effect in the Nordic areas and the absence of effects in the continental areas.

Table 8.6 *Electricity price (NOK øre/kWh), production (TWh) and net export (TWh), extreme dry year 2006-12 in the reference scenario*

		Norway	Sweden	Jutland	Zealand	Finland	Germany	Nether-lands	Poland
Electricity price	2006	32.5	32.5	22.8	32.4	32.4	22.2	22.8	19.6
	2008	30.1	30.0	20.8	30.0	30.0	23.6	24.5	13.7
	2012	33.3	33.2	25.6	33.2	31.7	29.9	29.0	25.9
Production	2006	103	136	33	20	84	552	99	137
	2008	104	141	32	20	82	579	85	160
	2012	118	146	34	20	98	572	147	160
Net export	2006	-20	-8	11	5	-7	-3	-14	17
	2008	-18	-7	10	5	-13	5	-32	30
	2012	-15	-14	10	4	-5	-43	21	21

Source: ECON model simulation

Table 8.7 *Difference in electricity price (NOK øre/kWh), production (TWh) and net export (TWh) between dry and normal year in the reference scenario, 2006-12*

		Norway	Sweden	Jutland	Zealand	Finland	Germany	Nether-lands	Poland
Electricity price	2006	9.3	9.2	1.5	9.2	9.2	0.2	0.2	0.0
	2008	8.5	8.5	2.0	8.5	8.5	0.1	0.1	0.1
	2012	8.6	8.6	2.9	8.6	7.1	0.4	0.4	0.5
Production	2006	-16.8	-6.9	0.2	0.0	4.7	5.2	0.1	0.5
	2008	-16.8	-7.5	0.3	2.1	1.9	4.0	3.7	-0.1
	2012	-16.8	-7.6	0.4	0.0	4.1	4.5	2.3	0.1
Net export	2006	-11.0	-0.2	0.3	0.5	7.4	2.4	0.1	0.5
	2008	-11.1	-0.9	0.5	2.6	4.6	0.6	3.8	0.0
	2012	-10.8	-0.9	0.7	0.5	6.6	1.1	2.5	0.4

Source: ECON model simulation

8.2.1 Effects of trade with emission allowances

Low price scenario

In the low price scenario (see Table 8.8) the price of electricity is not affected at all in Norway, Sweden, Zealand and Finland in 2006, since the average price is primarily determined by the energy constrain. In Jutland and the continental countries the price effect is almost identical to that in a normal year.

In 2008 the effect on the average electricity price from the emissions trading is larger in a dry year compared with a normal year for the Nordic areas, and approximately the same as in a normal year for the continental countries. The extreme dry year prices will however be lower in 2008 than in 2006 in the reference scenario. This means that the electricity prices in the low price scenario will still be lower in 2008 than in 2006, even though the effect from emission trading is stronger in 2008.

Table 8.8 Difference in electricity price (NOK øre/kWh), production (TWh) and net export (TWh) between reference scenario and low emission price scenario, dry year 2006-2012

		Norway	Sweden	Jutland	Zealand	Finland	Germany	Nether-lands	Poland
Electricity price	2006	0.0	0.0	0.7	0.0	0.0	0.8	0.6	0.8
	2008	1.2	1.2	2.0	1.2	1.2	1.6	1.5	3.5
	2012	1.2	1.2	1.2	1.2	1.7	1.4	1.4	1.0
Production	2006	0.0	0.0	0.0	0.0	0.0	-1.1	0.0	-1.0
	2008	0.0	0.0	-0.1	0.0	-1.9	-5.9	0.0	-4.2
	2012	-2.2	0.0	-0.1	0.0	-0.1	-3.7	0.8	-0.7
Net export	2006	0.0	0.0	0.1	0.0	0.0	0.2	0.2	-0.4
	2008	0.7	0.8	0.0	0.1	-1.6	0.3	0.5	-0.9
	2012	-1.5	0.8	0.0	0.1	0.4	-1.6	1.3	0.5

Source: ECON model simulation

Medium price scenario

In the medium price scenario the effect from emissions trading in a dry year is smaller than in a normal year in the Nordic countries (except Jutland) for 2006 and 2008.

In 2008 the effect from emissions trading is about twice as high in the dry year compared with a normal year in the Nordic areas (except Jutland), which implies a difference with approximately 1.2 øre/kWh. In Jutland the effect is almost 1 øre/kWh larger in the dry year compared with the normal year and in the continental countries the differences between dry and normal year are very small. The explanation lies with the step-wise supply function and that the prices in the Nordic areas are affected by the energy constraint and import possibilities and set above marginal cost. An increase in the marginal cost of production has a limited effect on the price in the market.

In 2012 the effect of emissions trading is slightly higher in a dry year compared with a normal year. The primary explanation is the expansion of new thermal capacity, which makes the Nordic countries less sensitive to the precipitation. To a lesser extent will import possibilities and the energy constraint determine the prices and more often will the system operate on a horizontal segment of the supply schedule.

Table 8.9 Difference in electricity price (NOK øre/kWh), production (TWh) and net export (TWh) between reference scenario and medium emission price scenario, dry year 2006-2012

		Norway	Sweden	Jutland	Zealand	Finland	Germany	Nether-lands	Poland
Electricity price	2006	0.3	0.3	3.2	0.3	0.3	3.8	3.4	4.0
	2008	2.3	2.3	3.5	2.3	2.3	2.8	2.7	5.6
	2012	2.7	2.6	2.3	2.6	3.3	2.2	2.2	2.4
Production	2006	5.3	-0.1	0.1	0.0	-4.7	-18.5	11.5	-5.5
	2008	0.0	-1.7	-0.1	0.0	-1.9	-11.4	1.5	-7.5
	2012	-3.5	0.0	-0.1	0.0	-1.3	-4.0	-1.0	-2.1
Net export	2006	5.4	0.1	0.4	0.0	-4.7	-11.3	12.8	-2.8
	2008	1.3	-0.2	0.2	0.1	-1.3	-0.2	2.5	-2.5
	2012	-1.9	1.8	0.1	0.1	-0.3	-0.3	-0.2	0.7

Source: ECON model simulation

High price scenario

Also in the high price scenario we the effect on the electricity price is smaller in a dry year compared with a normal year, except for 2012. The same explanation as before applies.

Table 8.10 Difference in electricity price (NOK øre/kWh), production (TWh) and net export (TWh) between reference scenario and high emission price scenario, dry year 2006-2012

		Norway	Sweden	Jutland	Zealand	Finland	Germany	Nether-lands	Poland
Electricity price	2006	0.3	0.3	3.2	0.3	0.3	3.8	3.4	4.0
	2008	2.3	2.3	3.5	2.3	2.3	2.8	2.7	5.6
	2012	2.7	2.6	2.3	2.6	3.3	2.2	2.2	2.4
Production	2006	5.3	-0.1	0.1	0.0	-4.7	-18.5	11.5	-5.5
	2008	0.0	-1.7	-0.1	0.0	-1.9	-11.4	1.5	-7.5
	2012	-3.5	0.0	-0.1	0.0	-1.3	-4.0	-1.0	-2.1
Net export	2006	5.4	0.1	0.4	0.0	-4.7	-11.3	12.8	-2.8
	2008	1.3	-0.2	0.2	0.1	-1.3	-0.2	2.5	-2.5
	2012	-1.9	1.8	0.1	0.1	-0.3	-0.3	-0.2	0.7

Source: ECON model simulation

9 Appendix B: Model assumptions

The price forecast and estimates of the effects of trade with emission allowances are based on model simulations of the market equilibrium in years with normal precipitation levels and in extreme wet and dry years. The wet and dry years are defined such that the probability of getting a year as wet or wetter, respectively as dry and dryer, is 5 % based on historical observations.

Our price forecasts are built on model calculations of the market equilibrium in a year with normal water inflow levels. Model simulations have been carried out for 2006, 2008 and 2012. Furthermore, we assume a highly competitive market with exchange rates equal to those currently observed in the market.

All prices are given in NOK value for 2004. Prices, consumption, production and trade are determined simultaneously in the Nordic countries as well as in Germany, Poland and the Netherlands.

9.1 Demand

The underlying growth of an economy is an important catalyst behind changes in general electricity consumption. Expected GDP growth rates in the Nordic countries are based on official estimates and ECON's own forecasts, and are presented in the table below.

Table 9.1 Annual GDP growth. Percent

	Norway	Sweden	Finland	Denmark
2004	2.2	2.6	3.0	2.0
2005	2.6	2.7	3.6	2.6
2006	2.2	2.2	2.9	2.2
2007-2015	2.0	2.0	2.5	2.0

Electricity consumption in the energy intensive industry is exogenously determined because it is driven by world market developments rather than national growth rates. In our base forecast we have assumed a relatively strong growth rate in 2004 and 2005, especially in Norway. This is based on decided capacity expansions. We have assumed that Hydro Aluminium not will rebuild the old Söderberg-ovens that for environmental reasons have to be shut down in 2007 and 2008. This will in total make 3.3 TWh of energy available. In Sweden and Finland the growth is related to free production capacity that is expected to be used. In the longer run we expect an annual growth rate of 2%. In the model analysis some efficiency improvements in the use of electricity is expected, such that the growth in power consumption is less than the growth in production. Note that the expected growth rates in energy intensive industry is for electricity prices in years with normal precipitation levels.

In addition to the clear positive correlation between growth rates and electricity usage, the development in end-user electricity prices is also an important factor. We have made the following assumptions:

- The Green certificate market in Sweden will imply increased costs for Swedish consumers, which will increase with the strictness of certificate requirements.
- Otherwise unchanged consumption taxes.

9.2 Capacity developments

As a basis in the analysis we have put in capacity expansions that are already planned or seen to be likely. Some of these are based on assumptions provided by the client. The same is true for decommissioning of capacity.

Norway

- Endogenous investments in gas power, but limited to the capacity which currently has been granted concessions, i.e., 1660 MW (on request of the client).
- Hydropower production in normal years increases to 0,8 TWh by 2006, with an additional 0.2 TWh by 2008 and another 0.7 TWh by 2012.
- Wind power production increases gradually to 2.5 TWh in 2012.

Sweden

- The nuclear station Barsebäck 2 is closed by 2006
- Remaining nuclear power is maintained. Annual production in these plants is expected to increase by 2.8 TWh from 2004 to 2012.
- Existing fossil fuel capacity is maintained.
- New gas fired CHP in Gothenburg from 2006 (275 MW and 1.2 TWh/year).
- The market for Green Certificates stimulates capacity building of a total of 9.8 TWh new green electricity by 2012.

Denmark

On request from the client we have used the following assumptions on production from renewable sources (wind and bio-fuelled CHP).

Table 9.2 Power production from renewable sources

2006	2008	2012
8.5 TWh	9.5 TWh	10.5 TWh

Finland

- Some minor investments in hydropower generating capacity.
- Increased capacity in district heating and industrial CHP.
- A fifth nuclear power station is built between 2008 and 2012 (1 600 MW).

Germany

- Nuclear power is phased out in accordance with the nuclear compromise. The effect is to reduce nuclear power capacity from around 20 000 MW in 2002 to around 14 000 MW in 2012.
- Coal power plants are phased out according to age and a few new lignite power plants are constructed.
- Renewable energy provides an estimated (net) 600 MW in new thermal CHP plants and 15 000 MW in wind power up until 2012.
- A substantial amount of oil fuelled capacity and peak load capacity is phased out according to plans
- New gas fired peak load capacity is build as it is profitable, i.e., when the peak load prices reaches 70 – 80 øre/kWh.

In addition to the above, we have assumed optimal investment behaviour in the market in the long run. This implies that new capacity will be built if it is seen to be profitable. We assume that CCGT is the cheapest technology for new capacity, and that investments will be undertaken when average prices are high enough to cover the full costs (see section below). The exception is that an exogenous restriction on CCGT in Norway is imposed (on request of the client).

Production taxes

- The current CO₂-quota system in Denmark and the gas tax in Germany are replaced by the common CO₂-quota system.

Fuel prices

- Oil prices are expected to be fluctuate around a long run level of 25 \$/barrel.
- The long run equilibrium coal price level is expected to fall from 70 \$/tonne in 2004 towards a long run normal level of 35 \$/tonne in 2008. For 2006 we have assumed a coal price of 58.75 \$/tonne. Until 2006 this is in line with future prices on coal.
- Gas prices in Emden are assumed to be 90 øre/sm³. Behind this is an assumption of some decoupling from oil prices, but that the competition in the gas market will be far from perfect.

Costs for new gas fired plants

Gas-fired power plants in Norway pay a gas price equal to the Emden price *minus* transport costs from the terminal in Norway to Emden. We assume that transport costs will decline, and fall to 10 øre/sm³ from 2008 onwards. In other countries the cost of gas for the gas-fired power plants will be higher because they have to pay for the Emden-price *plus* the transport cost. On request from the client we have used fairly high gas prices as documented in Table 9.23.

Table 9.3 Gas prices in the Nordic countries and Germany, NOK øre/sm³.

	Norway	Sweden	Finland	Denmark	Germany
Gas price øre/sm ³	94	129	111	129	123

The long-term electricity price level also depends on other costs for gas-fired power, which are not expected to vary between countries. In addition to fuel costs, the plants have variable costs including for instance costs of CO₂ and. Constant production-dependent costs make up 1 øre/kWh and include grid feed-in tariffs.

Capital costs are estimated using an investment cost of USD 600/kW, a required rate of return of 10% (real before tax), a 2 year building period, a payback period of 20 years and 7500 hours of production hours/year. We have assumed a dollar exchange rate of DKK 6,14 (January 2004).

9.3 Trade

Transmission capacity in the Nordic region

Most of the planned expansion of transmission capacities within the Nordic area will be carried out before 2005. This increases the transmission capacity between Norway and Sweden, between Sweden and Finland and between Sweden and Jutland.

Trade with the rest of the world

We have assumed that a 600 MW cable between Norway and Netherlands will be built between 2008 and 2012.

Import capacity from Russia to Finland will be fully utilized and will be around 11 TWh per year in the whole period. An interconnector between Finland and Estonia with a capacity of 300 MW will be built within 2008. There is substantial excess capacity in the Baltic area, and we assume that the interconnector will yield full imports to Finland during the whole period we are analysing.

We have also assumed that trade with the Continent is expected to become more effective than today, but will still require a price differential before trade will be triggered.

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