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Sector Comment

UBS Investment Research

European Emissions Trading Scheme

ETS: Bonanza or bust?

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Vincent Gilles
+44-20-7568 1799
vincent.gilles@ubs.com

Andrew Wright
+44-20-7568 4585
andrew.wright@ubs.com

Luis Amusategui
+44-20-7568 4084
luis.amusategui@ubs.com

Marco Cipelletti
+39 02 7210 0256
marco.cipelletti@ubs.com

- **Emission trading scheme: A reality in 15 months**
  The EU adopted the 'CO_2 Directive' during the summer, putting the introduction of CO_2 emissions trading firmly on track. The next step is the allocation of permits at the national level, which is scheduled to take place by the end of March 2004. The scheme is due to take effect from 1 January 2005.

- **A windfall for all utilities?**
  Our scenario-based analysis by country indicates that the introduction of ETS could result in a windfall for utilities. We expect wholesale prices to rise by as much as 63% across Europe. In several countries, we see some risk of governments using the permit allocation process as a tool of energy policy or taxation.

- **SSE, Iberdrola and E.ON should benefit the most**
  Our risk/reward model identifies Scottish and Southern Energy, Iberdrola and E.ON as the three 'winners'. We have incorporated the benefits of ETS into our price targets for SSE (PT from 600p to 665p, Neutral 1 unchanged), E.ON (PT from 53.3 to 54.7, Buy 2 unchanged) and Iberdrola (PT from 16.6 to 18, upgraded from Neutral 1 to Buy 1).

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Vincent Gilles
vincent.gilles@ubs.com
+44 20 7568 1799

Andrew Wright
andrew.wright@ubs.com
+44 20 7568 4585

Luis Amusategui
luis.amusategui@ubs.com
+44 20 7568 4084

Marco Cipelletti
marco.cipelletti@ubs.com
+39 02 7210 0256

George-Wilson Ocran
george.ocran@ubs.com
+44-20-7568 4493

Raimundo Fernandez-Cuesta Laborde
raimundo.fernandez-cuesta@ubs.com
+44 20 7568 3975

Malgosia Suligowska
malgosia.suligowska@ubs.com
+44 20 7568 8067

Alasdair Cummings
alasdair.cummings@ubs.com
+44-20-7568 8060

Richard Gray
richard.gray@ubs.com
+44 20 7568 1958

Daniel Woodbridge
daniel.woodbridge@ubs.com
+44 20 7568 8830

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We would like to thank Per Lekander and Antonio Volpin from McKinsey & Co for a fruitful exchange of ideas and perspectives on the future shape of the CO_2 market and, in particular, on permit pricing and the changes in merit order at the pan-European level.

ETS: Bonanza or bust?

We published our first report addressing the issue of carbon dioxide (CO_2) in May 2003 (*The greening of UK electricity*, 63pp). In this new report, we:

We take another look at the CO_2 Directive, now that it has become law and is on its way to being implemented

(1) update investors on the most recent developments and their potential impact on the economics of the companies under our coverage; and

(2) shed light on the very complex national issues and suggest core scenarios for each country. We believe this is key to understanding the impact of the coming changes on the valuation of each individual company.

In this report we focus on German, Italian, Spanish and British utilities. We have excluded Belgium and Portugal from this report as the scarcity of information made drawing conclusions too uncertain.

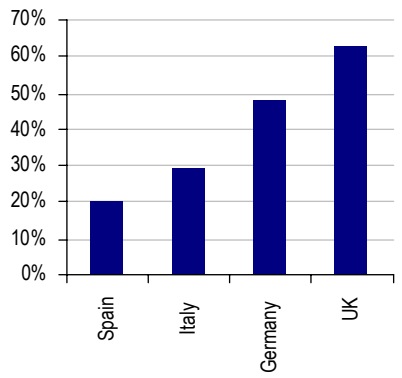
During the summer of 2003, the EU council adopted a directive regulating the introduction of CO_2 trading schemes across the current and future members of the EU. It is now up to the EU member states to implement the scheme. They have to define their National Allocation Plans (NAPs) by the end of March 2004. Issuing the Directive and setting well-meaning principles was the easy bit; defining the NAPs will be very complex and politically challenging.

Domestic governments now face the tough decisions

The windfall is potentially large in most cases

They probably did not realise it at the time, but when European countries committed themselves to reducing collective emissions by 8% in 2008-12 (relative to 1990 levels) they transferred a potential net windfall that we value at €27.6 billion for the companies we study in this report (c10% of their EV). This is largely because we expect that the cost of emissions will drive wholesale market prices higher (see Chart 1) and the ability of companies to pass this rise further on their final customers. Whatever happened to the principle of 'polluter pays'?

Chart 1: Wholesale price rise, 2012 vs 2002



Source: UBS estimates

Our country-based scenario approach is relatively simple: each analyst was asked to define what he or she thought could be disaster, black sky, central and blue sky scenarios. Each analyst has given his or her country sensitivities. Through this approach, we have largely been able to identify a 'value at risk' linked to the coming changes as much as tentative conclusions on the impact on valuations.

Our scenario approach helps us define a 'value at risk' as well as the potential winners and losers from the coming changes

Chart 2 shows the estimated impact of emissions trading on our European utility valuations:

- In most cases, we expect the introduction of ETS to result in a positive impact on equity valuations under our 'central' scenario. No single company shows an implied negative impact on the central scenario and only three out of 10 show a (limited) loss of value in the black sky scenario.

- Eight out of 10 companies would in theory suffer from falls in their equity value under the disaster scenario, but none would get into financial trouble like British Energy.

- Only one company wins under all four scenarios (Scottish and Southern Energy).

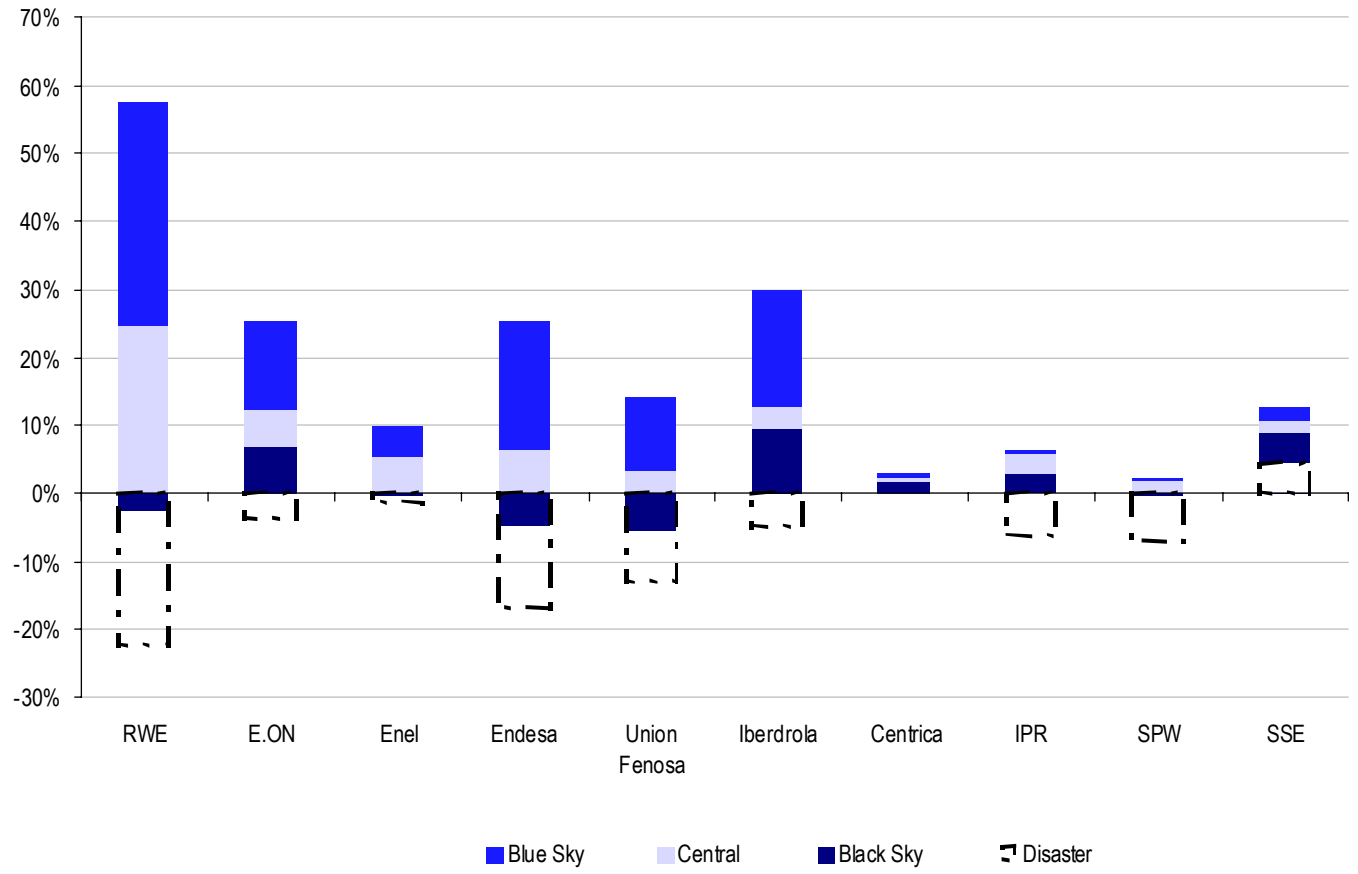
SSE should benefit the most – followed by Iberdrola and E.ON

- A number of companies seem to be relatively 'safe'. E.ON, Iberdrola, and to a lesser extent ScottishPower and International Power would suffer a serious hit in value only under the disaster scenario. Counter-intuitively perhaps, we do not believe that Enel will be hit by the introduction of ETS. This is because we believe Enel will be less CO_2-intensive in the future.

Some uncertainty on Endesa, RWE and Union Fenosa

- Three companies out of 10 (Endesa, Union Fenosa, RWE) would only experience significant swings in their equity depending on our choice of scenario. This is due to their exposure to coal generation and, in the case of RWE, to coal mining as well. In our view, this implies that the equity risk premiums of these three stocks should increase in the next few months.

Chart 2: Potential impact of ETS on share prices of some European utilities



Source: UBS estimates

Take the example of RWE in the chart above. First, 0% change represents the current share price of the stock. The range of possible changes in the stock price is from –22% to +57% depending on our four scenarios. The central scenario would add 24% to the current share price level, while the black sky scenario would take 3% off the share price. Another stock of particular interest is SSE – even in our 'disaster' scenario, the share price should rise.

But will companies be able to keep this windfall?

The size of the windfall itself makes it vulnerable to a form of clawback, be it at the level of permit allocation (the main tool for most countries) or at the level of regulation (by limiting the capacity of the companies to pass the rise in wholesale prices on to their final customers). There is a distinct possibility that in a period of large public deficits, a number of European countries will realise that they can find a way to transfer the windfall back to their own coffers. At the very least, we believe it is probably reasonable to assume that France, Italy, and possibly Spain and Germany will use the allowance allocation as a tool of industrial policy.

Which shares benefit in this analysis?

Stocks do not seem to have moved so far…but we think this will take place sooner rather than later

Probably the first question to be asked is whether it is yet time for investors to trade on this theme. Despite the enormity of the coming changes, we believe that the share prices of European utilities have not yet started reflecting the introduction of ETS. In our view, this is due to both the large uncertainty surrounding NAPs and the difficulty for the market to identify the adequate risk premium to be associated with the coming changes. In addition, we would expect there to be no impact on profitability before 2005, making multiples-based valuations difficult.

However, with newsflow on permit allocations swelling in the next few weeks and months, we believe that stocks where we can identify an impact on the share price should start reflecting the changes in value.

SSE the 'clearest' winner but not a cheap stock. E.ON and Iberdrola are on balance more favourably geared to this issue

There is only European stock that benefits under all four of our scenarios: Scottish and Southern Energy. As noted above, even the disaster scenario would have a positive effect on SSE's value.

We would also argue that E.ON and Iberdrola have risk profiles skewed towards the upside and could benefit from this theme. As a result, we have incorporated an element of the benefits of the introduction of ETS in the price targets of SSE, Iberdrola and E.ON. This is based on the risk/reward approach described in the next two tables.

RWE, Endesa and Union Fenosa: strong winners under our optimistic scenario

Beyond this, the choice is more complex because either the scope of the potential impacts is too narrow (Centrica, ScottishPower, Enel) or because the volatility implied by the 'value at risk' identified appears to be too large, in our view (RWE, Endesa, Union Fenosa). We have not included any change in the valuation of these stocks. However, we would take the view that these three stocks would benefit if anything like our blue sky scenario turned out to be true.

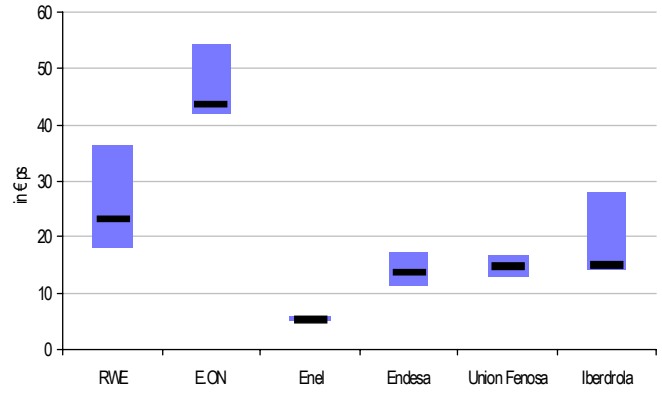
Table 1: 'Winners and losers' under various scenarios

	Disaster	Black sky	Central	Blue sky
Benefits	SSE	Iberdrola, SSE, E.ON	RWE, Iberdrola	RWE, Endesa, Fenosa, Iberdrola, EON
No impact	Centrica	Enel	Enel, Fenosa	SPW, Centrica
Hurt	RWE, Endesa, Fenosa, IPR	RWE	/	/

Source: UBS estimates

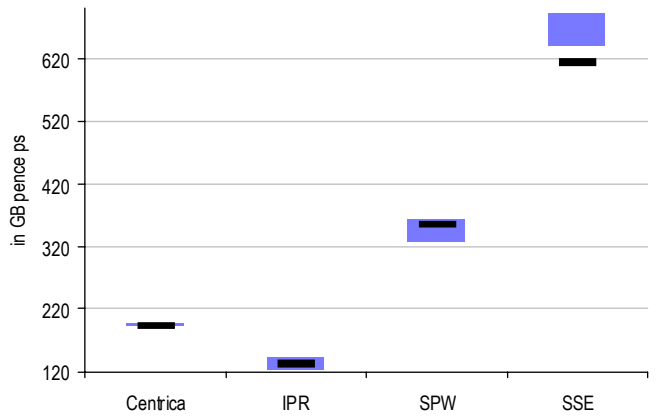
The following charts show the impact of our scenario approach on the equity valuations of the stocks mentioned shown versus the absolute level of the share price, potentially highlighting to what extent the share price may have recognised the CO_2 issue.

Chart 3: Potential impact on European utilities of ETS



Source: UBS estimates

Chart 4: Potential impact on UK utilities of ETS



Source: UBS estimates

In our view, the best way investors can try to include ETS in their investment decisions is by running a risk/reward analysis, as shown in the following table.

SSE, E.ON and Iberdrola price targets upgraded

Based on this analysis, we are raising our price targets on three European utilities: Scottish and Southern Energy (from 600p to 665p), E.ON (from €53.3 to €54.7) and Iberdrola (from €16.6 to €18.0). On the back of our price target increase for Iberdrola, we upgrade our rating from Neutral 1 to Buy 1.

Table 2: ETS – Impact on UBS utility share price targets

Company	Price target	Risk / reward balance	Winner / loser
Centrica	230p	Risks: retail margins Rewards: value of gas assets and renewable investments	Small winner
ScottishPower	420p	Risks: Retail margins Rewards: higher power prices, renewable energy investments	Small winner
International Power	140p	Risks: coal plant valuation Rewards: increased value of CCGT and higher gas prices	Small winner
Scottish and Southern En.	**From 600p to 665p**	**Risks: Retail margins** **Rewards: No downside, higher power prices, low carbon generation mix**	**The only winner in Europe under all four scenarios**
RWE	€23	Risks: Value of coal mining and generation assets, regulation, worse hit if no free allocation to German utilities, UK risks through Innogy Rewards: High power prices, biggest winner of all in blue sky scenario	We would avoid playing RWE on the ETS theme, as we would expect the shares to be volatile
E.ON	**From €53.3 to €54.7**	**Risks: Regulation and allocation – but to a controllable extent** **Rewards: higher power prices, rising value of Ruhrgas**	**Winner but carries greater risks than SSE and Iberdrola in our view. Our third-favourite play after SSE and Iberdrola.**
ENEL	€5.5	Risks: regulation, exposure to coal generation Rewards: our biggest surprise of the report was probably that risks are limited	Little gearing to the issue with regulatory risks
Endesa	€14.3	Risks: heavy on coal generation and coal mines, needs a favourable political decision to be a winner Rewards: Like RWE, the dark horse – third biggest upside to rosy outcome.	We would avoid playing Endesa on the ETS theme, as we would expect the shares to be volatile
Iberdrola	**From €16.6 to €18**	**Risks: Limited – Only downside in Disaster scenario** **Rewards: Hydro and nuclear generation capture the highest margins that is kept at the retail level**	**Our favourite to play the ETS theme in Southern Europe**
Union Fenosa	€12.6	Risks: similar to Endesa compounded by absence of cash to renew assets, downside in black scenario only – needs blue sky to raise value Rewards: Like Endesa but less gearing to successful outcome	Little upside with some downside

Source: UBS estimates

Long-term consequence for the sector

In our report on ROIC in European utilities that we jointly published with Deloitte on 25 September 2003 (*Will value destruction continue forever?*, 95 pp), we highlighted our concern that the sector in Europe only changes its course as a result of external shocks. We take the view that the introduction of ETS will be one of them. In the following paragraphs, we review some of the potential consequences.

- **Business models: the great return of generation assets?** The last few years have seen a flight out of generation in many European countries. This was because liberalisation processes were largely asymmetrical, resulting in declining wholesale markets but stable and potentially increasing transmission and retail margins. The introduction of ETS transfers value back to the generation business. Obviously not all generation assets will be worth more in the next few years. One of the key goals of ETS is to incentivise generators to cut coal and promote clean(er) generation sources. We highlight in this piece that the value of gas plants strongly rises across Europe (by more than 70% in the UK and Germany on the back of the rises in wholesale markets), whereas coal plants are only worth a fraction of their

past value if anything. On balance, gas, nuclear and hydro generation is now worth much more than in the past whereas the value of the other businesses in vertically integrated companies is not necessarily negatively impacted. It is probably safe to assume that British Energy would have benefited from the introduction of ETS.

- **A coming M&A bubble?** Some companies will be worth more, either because of the intrinsic value of their assets or the value of the permits that they will be allocated. Investors will be well inspired in the future to check the portfolio position of European utilities, as unused permits will carry a very tangible value. It is probably safe to assume a rise in the value of many Eastern European generation assets on the basis of their potential permit allocation (see the concept of 'hot air', starting on page 16). Given the rise in wholesale market prices, pure supply and retailers may also be interested in hedging themselves 'upward' with generation assets – an interesting change in comparison with the last few years.

- **Increased regulatory risk?** As we said earlier in this introduction, we feel that the politicians who agreed to the ETS scheme did not fully realise the consequences of their actions. In our view, they will gradually wake up to the fact that utilities will benefit from the Kyoto Protocol. In a period of large budget deficits and because the allocation of permits comes at a time where governments and regulators have little influence left on the sector, we fear that the legal application of ETS will become the 'Alamo' of regulation. We mentioned earlier in this report the risks linked to a taxation of the 'CO_2 windfall'.

- **Renewables: still necessarily the future in all of Europe?** Many European countries have devised schemes that favoured power generation based on renewable energy over the past few years. The conjunction of those schemes and ETS will potentially compound the rise in prices we expect (particularly in the UK), creating a very complex legal situation (several countries have several, largely contradictory, emissions targets). Given the political importance of hitting Kyoto targets, we would argue that countries like Germany may reform their renewable policies – potentially cutting some of the benefits enjoyed by cogeneration and other renewable energy sources.

- **A different equity risk premium?** As value in the sector moves back to generation, investors will potentially face: (1) higher earnings volatility; and (2) a different level of equity risk premium due to changes in regulation and valuation.

- **Will nuclear come back?** The Kyoto Protocol was signed by many European governments in response to the growing wave of green sentiment in the 1990s. Many large European countries had or have governments involving Green parties (France, Germany, Belgium). Those governments are in charge of allocating permits and will face the fundamental question of how to treat nuclear plants – one of the only two CO_2 emission-free sources of baseload generation in Europe. In some 'green' countries, the idea of maintaining nuclear capacity in the long term is politically contentious.

Germany introduced a programme of nuclear pull out by 2026 in 2000. Belgium has a similar scheme (at least officially). At the same time, Spain and France are quietly working on extending the useful life of their plants. Finland has launched a new nuclear tranche. We would expect some heated debate on nuclear energy in the next few years and, possibly, a change in consensus. This is particularly relevant if countries are really determined to hit the 'long-term' target of a 70% reduction in greenhouse gas emissions.

- **Rising fuel costs and rising energy prices**. The rise in gas-based generation should result in a significant rise in gas prices across Europe. McKinsey suggests that the introduction of CO_2 emissions trading would result in consumption of an additional 56 bcm (likely imported) by 2010, in addition to the 46 bcm that the rise in gas demand from power generation should lead to in Western Europe. McKinsey also concludes that gas prices at the border could rise by 15% by 2010 as a result of the additional demand suggested above (from US$3.2/Mbtu to US$3.67/Mbtu). This would have consequences on utilities' costs (which we believe we have correctly taken into account in our models) and the prices of electricity across Europe. Those who doubted the strategic relevance of the Ruhrgas acquisition by E.ON will be given plenty of evidence in the medium term. We could also identify Centrica, Suez (because of its interest in Distrigaz) and potentially Gas Natural in Spain as potential beneficiaries of the rise in gas volumes being exchanged. An increase in the value of gas could also marginally benefit Centrica. As mentioned earlier, RWE (because of Rheinbraun) could be negatively impacted by the potential decline in the value of coal mines.

Looking beyond utilities

This second study of the impact of the introduction of ETS in Europe has strengthened our view that many other European industrial activities will be impacted in the near future. We make the following two assumptions:

- The rise in power prices will depress the bottom lines of many industrial companies. Power prices account for more than a third of the controllable costs of an aluminium smelter, for example. The introduction of ETS cannot and will not be neutral on some European heavy industries, impacting their relative competitiveness.

- Fuel suppliers will be impacted. It is probably safe to assume that gas suppliers and transmitters will benefit from the coming changes in the shape of generation in Europe. Conversely, coal producers could be seen as negatively impacted.

EU emissions trading scheme

In this section, we provide an update to the background on the EU emission-trading scheme, covering:

- **Progress on implementation**
- **A reminder of the theory behind EU emission trading**
- **A revised view of the market in permits, based on analysis by McKinsey & Co**

Progress on implementation

The emission trading Directive

The European Parliament agreed the EU Emission Allowance Trading Directive on 22 July this year. This Directive, designed to ensure the delivery of the EU's commitments under the Kyoto Protocol, will now come into force on 1 January 2005.

EU Directive requires member states to impose cap on CO_2 emissions

The Directive requires that European member states impose a cap on carbon dioxide emissions from installations covered by the scheme – which includes all but the smallest fossil-fired power generation facilities – through issuing emission allowances. These allowances can be traded between installations in any of the EU member states.

A summary of the key points in the Directive can be found in Appendix 1. The Directive has not yet been published by the European Union, but an unofficial version of the final text can be found on the European Commission website (http://europa.eu.int/comm/environment/climat/emission.htm).

With the Directive passing into law, the initiative now passes to the member states who are required to pass relevant legislation in each country and to implement most of the administrative framework, including

- Setting the cap on emissions
- The allocation and distribution of allowances
- Establishing a register of allowances
- Monitoring and reporting emissions covered by the scheme

Timetable

The key dates for the implementation of the Directive are as follows:

- **31 December 2003:** All member states are expected to have passed relevant legislation. However, we believe there may be some flexibility on this given the short timeframe.
- **31 March 2004:** Deadline for all member states to submit their National Allocation Plans to the European Commission for approval.

- **30 September 2004:** Final decision on the allocation of allowances to installations for 2005-07 must be made, having agreed a plan with the Commission.

- **1 January 2005:** The scheme comes into effect.

- **28 February 2005:** Deadline for allocating allowances to installations.

The 'projects' Directive

The EU is also progressing a second Directive, which will supplement the emission trading Directive, which links the EU scheme to the various project-based mechanisms in the Kyoto Protocol for transferring credit for greenhouse gas (GHG) emission reductions achieved outside the European Union into the EU scheme. There are two principle mechanisms:

- The 'Joint Implementation' (JI) mechanism – covering greenhouse gas reductions in Eastern Europe

- The 'Clean Development Mechanism' (CDM) – covering projects in developing countries

GHG reductions under these schemes will be allowable against emissions within the EU up to at least 6% of total allowance allocations. However, the projects will have to be approved for suitability before they qualify as credits.

As we expect JI and CDM mechanisms to have only a peripheral impact on the EU scheme, we do not consider it useful to examine the Directive in more detail.

Emission trading economics – a refresher

We introduced the key concepts behind our analysis of the impact of the EU emission trading scheme (ETS) in our May report on the impact of environmental initiatives on the UK (*The greening of UK electricity*, May 2003). In this section we set out some of the key concepts again – updated for recent development and fresh information.

Delivering on Kyoto

Aim of the emissions trading scheme is to meet Kyoto targets

The initial objective of the EU ETS is to meet the EU's commitments under the Kyoto Protocol. Under that agreement, the EU committed to reducing total GHG emissions from 1990 levels by 8% by 2008-2012. This commitment has been dividend into individual targets for member states under the EU 'burden sharing' agreement, depending on the expected levels of economic growth and the scope to reduce emissions. Targets range from an allowed increase of 27% for Portugal to required reductions of 21% for Germany and Denmark.

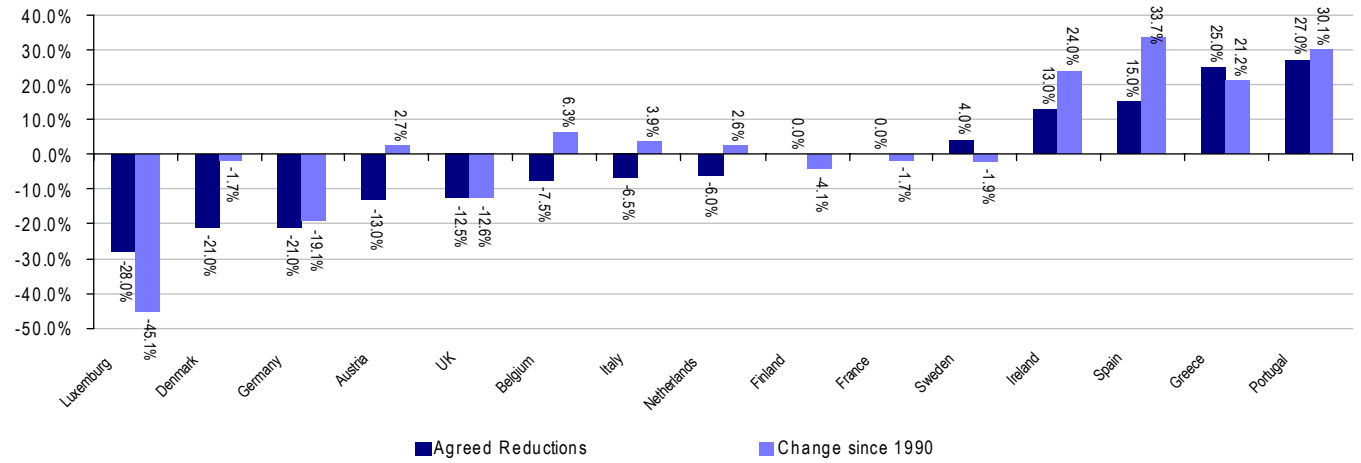
By 2001, the EU had already delivered GHG reductions of around 2.3%, suggesting reasonable progress towards its target. However, complacency would be a mistake, as most of this reduction occurred due to one-off factors in just two countries – Germany and the UK – and is unlikely to be repeated.

— In Germany, the collapse of the East German industry after unification led to material reductions in emissions.

— In the UK, the liberalisation of the power market combined with the availability of plentiful, low-cost gas produced a large increase in gas-fired power generation (the so-called 'dash for gas').

Many other countries, including Spain and Italy, are a very long way from meeting their required emission targets and would be very unlikely to do so without specific action. The chart below shows the progress each country has made towards its Kyoto target over the period 1990-2000.

Chart 5: Progress towards GHG emission reduction targets by EU countries (1990-2000)



Source: EU position paper on emissions trading, July 2000, EEA, 2002 after McKinsey & Co.

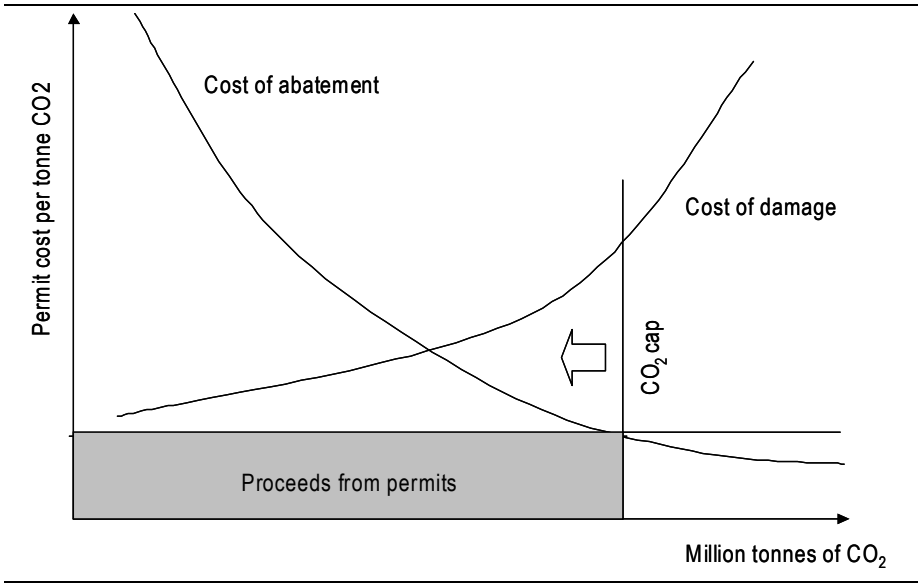
Emission allowances will have value

In the absence of an emission trading scheme, we would expect GHG emissions in the European Union to rise to significantly above current levels and well above the commitments under the Kyoto Protocol. Therefore, if emissions are capped under the EU ETS, the tradable emission allowances will have a material value.

In order for GHG emission reductions to stay within the cap, it will be necessary to incur costs, either through switching to more expensive, lower-emission alternatives or investing in lower-emission capacity.

The price of allowances will settle at the marginal cost of abatement at the cap. If this price is correctly reflected in the price of products (power, cement) to consumers, they will be incentivised to reduce consumption if their value of consumption is less than the higher price of power. This is illustrated in the supply and demand curves shown below.

Figure 1: Supply and demand curves for carbon dioxide emissions trading

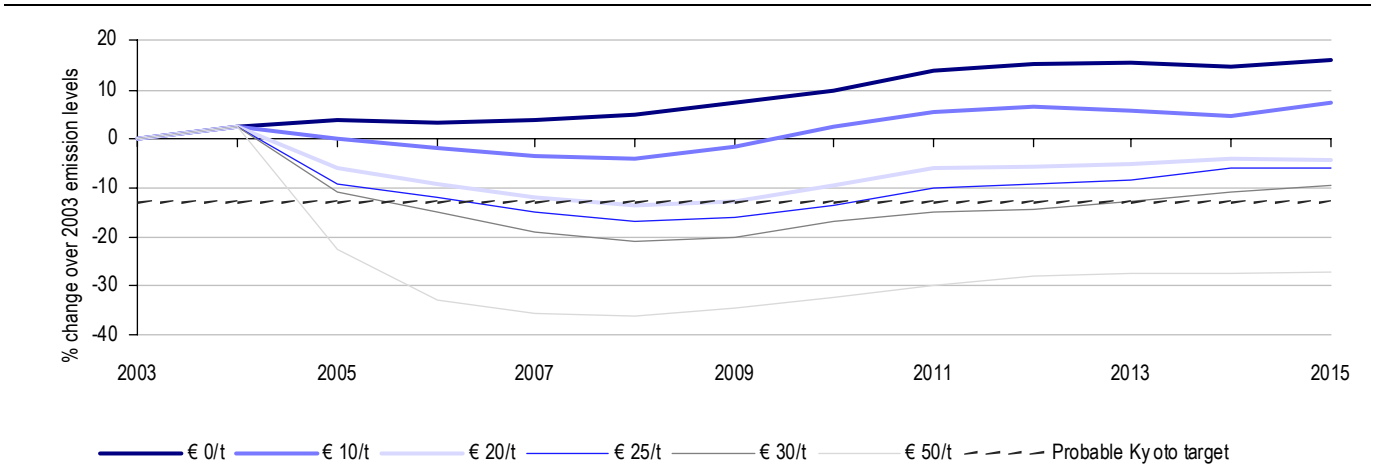


Source: UBS estimates

Emissions fall as the cost of allowances rise

The higher the price of allowances, the lower the emissions of carbon dioxide. The chart below summarises the impact of a range of different levels of permit costs on carbon emissions in continental European countries.

Chart 6: European carbon emissions under different scenarios for the price of carbon emission rights



Source: McKinsey & Company

Without any carbon emission costs, McKinsey estimates that CO_2 emissions would rise by around 12% from 2003 levels over the next 12 years. It can be seen that to achieve the Kyoto target, the price of emission rights needs to rise to around €25 per tonne. This is not surprising, given that at around €25 per tonne it becomes more profitable to build and run a new CCGT rather than to continue to operate existing higher-emission coal capacity.

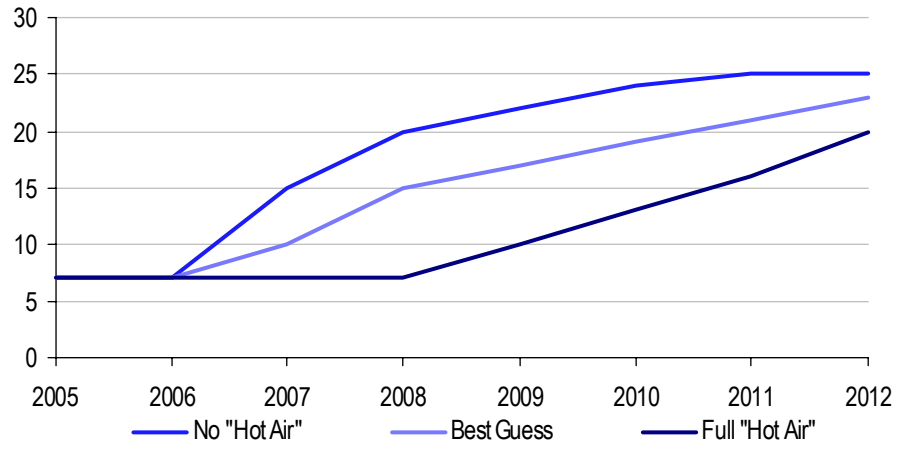
The revised McKinsey projections for the price of allowances

The chart below shows McKinsey's projection for the price of emission rights in Europe based on the objective of reaching the EU's Kyoto target by 2008-2012. The forecasts are slightly different than in our May report, reflecting the impact of the JI and CDM mechanisms in the early years of the scheme and, later, the differentials in new entrant gas plant costs in different countries across Europe.

- Initially, McKinsey sees the price settling at around €7 per tonne. This is because the required carbon reductions up to 2006 can be achieved by increasing the output from existing generation capacity.

- The price of rights is projected to rise to around €25 per tonne over the following five to six years, by which time the cost of emissions should be sufficient to stimulate substitution of existing coal plant by gas in larger markets such as the UK and Germany.

Chart 7: McKinsey's projections of the price of emission allowances



Source: McKinsey and Company

The two main sensitivities impacting the price of permits are:

(1) The so-called 'hot air' issue – how much of the headroom from the new entrant countries in Eastern Europe will be available for trading in the EU scheme after the EU expands from 15 to 25 countries in 2004.

(2) The price of fuel – the eventual value of allowances depends on the cost of gas and coal at equilibrium. If gas prices rise, or coal prices fall, allowances would have to be more expensive to stimulate new build.

'Hot air'

We expect new EU entrants to participate in ETS from the start

In 2004, the EU will expand to 10 new countries. In terms of carbon emissions, the larger countries of Eastern Europe – Poland, the Czech Republic and Hungary – dominate these new entrants. We expect these countries to participate in the EU ETS from the start.

Like eastern Germany, the former communist countries of Eastern Europe experienced a major industrial contraction the early 1990s, leading to falling

carbon dioxide emissions. As a result, these countries have around 200 million tonnes of headroom to their combined Kyoto targets.

Under the EU scheme, it is not easy to issue allowances to installations in excess of historical requirements. This may constitute a form of state aid. Therefore, the excess allowances of these countries would only come onto the market as their domestic emissions increased.

However, there are provisions under the Kyoto Protocol – outside of the EU scheme – for trading of allowances at a country level. It remains to be seen whether countries within the EU will be able to gain access to these allowances through the Kyoto provisions or some other mechanism. These potential additional allowances are commonly termed 'hot air'.

McKinsey's 'hot air' sensitivities are shown on the chart above. The top line shows the projection without any of the Eastern Europe excess ('no hot air'). In this scenario, prices rise quickly to the equilibrium level (by 2006). The lowest line shows the projection assuming full 'hot air' – prices remain low until 2008, when emissions are expected to rise to the point where excess allowances are used up. There will be some small positive value (McKinsey assumes €5 per tonne), reflecting an incentive for Eastern European countries to trade, rather than bank, allowances.

Fuel price sensitivities

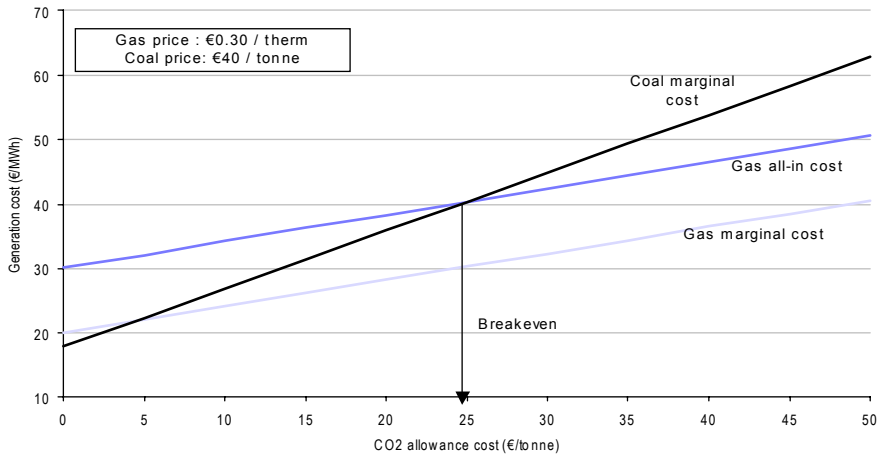
The second key sensitivity is the impact of fuel costs on the substitution between coal and gas technology – and in particular the price at which emission trading stimulates new entry by gas plant.

An emission allowance price set at €25 per tonne should stimulate construction of new gas plant

The chart below indicates that an emission allowance price of around €25 per tonne should stimulate new entry by gas plant. It shows the way the marginal cost of gas and coal plant changes as the price of emission allowances change. Also shown is the all-in cost of a gas plant, including the repayment of fixed operating costs and capital costs.

As the carbon dioxide emissions per MWh of gas generation are less than half that of coal generation, the variable cost of coal generation increases faster then gas. Eventually the marginal cost of coal exceeds the all in cost of a gas plant, and at this point we would expect new capacity to be built. The chart shows that for typical fuel cost assumptions (gas at €0.30 per therm and coal at €40 per tonne), the emission price that stimulates new entry is €25 per tonne of carbon dioxide.

Chart 8: Determining the equilibrium price for the permit prices

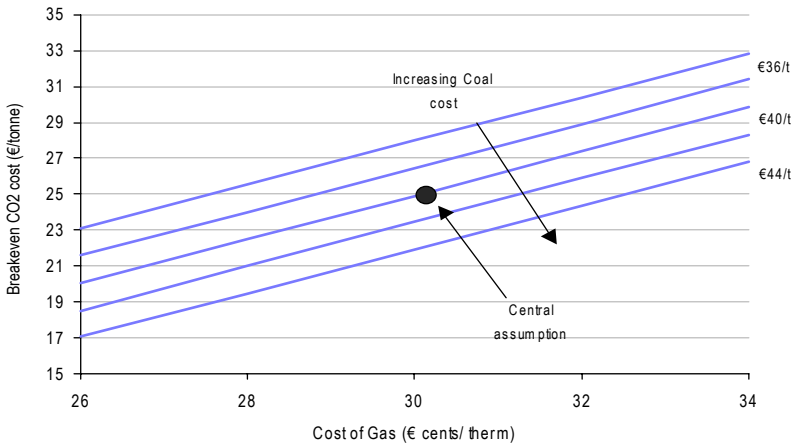


Source: UBS

However, gas and coal prices have varied widely. Emission trading in the EU is itself expected to lead to higher gas prices and, possibly, lower coal prices in Europe. As a result, the eventual equilibrium price may be different.

The chart below shows how the equilibrium price of emission allowances varies with gas and coal prices. The large black dot is our central assumption of a €25 breakeven price.

Chart 9: Equilibrium allowance cost as a function of gas and coal prices



Source: UBS

This analysis shows that a reasonable range for the equilibrium price of emission allowances is between €17 and €31 per tonne – this reflects a range of gas prices between €0.26 and €0.34 per therm and coal prices between €36 and €44 per tonne. Given the volatility of fuel markets, the range of outcomes could be greater.

Implications for power markets

Windfalls all around?

ETS creates a large potential windfall for utilities…

The advent of emission trading in the EU will have profound effects on the electricity markets. We believe the following changes will take place:

- Our analysis shows carbon emission trading leading to very significant increases in wholesale power prices in the medium term in every EU country. Even if allowances are issued free of charge, generators will require extra income to offset the *opportunity cost* of selling a valuable emission allowance.
- Prices for industrial and commercial customers will increase in each European country. Retail prices may also increase, depending on the degree of integration of each company and the form of retail price regulation.
- Higher gas demand through changes in the merit order (due to increased utilisation of CCGTs) are likely to lead to higher gas prices and snowball into even greater increases in power prices.

All things being equal, we expect the increase in utilities' revenues to exceed the rise in costs, creating a potential windfall for utilities. Unfortunately, this is largely at the expense of substantial price increases for consumers.

Welcome to the real world…

…which we think would be politically unacceptable

In our view, the asymmetry between the benefits for the utilities (ultimately the polluters) and the additional costs for their customers is too large. It is likely that the increase in prices will be seen as very poor value for money, given the low proportion that will be applied to reducing the environmental impact of power generation.

Moreover, we do not believe that windfall profits to utilities will be tolerated in an environment where industrial and residential customers face big price increases. So why does a market-based system appear to be so inequitable and inefficient in delivering the desired environmental benefits?

The reason is that, until now, the cost of the carbon emissions has been externalised – paid for by all in terms of environmental damage rather than internalised in the price of electricity. By limiting the issuance of carbon emission permits, the EU will be implicitly attributing value to this environmental damage. We must assume that the cost of environmental damage exceeds the cost of reducing carbon emissions to the new cap; otherwise it would be cheaper to address the consequences of carbon emission rather than reduce emissions. However, there are weaknesses at the heart of the EU proposals:

- Although the economic cost of pollution is now internalised, the cost is not being borne by the generators. The carbon permits are to be issued free of charge. As a result, although the consumer pays a premium price for power, this is realised as windfall profits rather than being applied to addressing the cost of pollution. This violation of the 'polluter pays' principle is the main reason for the surprisingly positive outcome for utilities from the imposition of emission trading.

- Electricity demand is not price elastic. Therefore, increased prices generally lead to increased revenues for the industry rather than a fresh equilibrium between price, supply and demand, which could lead to lower or higher revenues.

- The increased profitability of carbon-free sources such as nuclear power is an inevitable but economically sound consequence of carbon emission trading. Although this appears to deliver no benefit to the environment in the short term at substantial cost to the consumer, it is important for ensuring that correct incremental investment decisions are made in the future – for example, extending plant lives or improving availability. However, it is equally important to ensure that all other environmental costs of carbon-free technologies are also properly internalised, including the cost of nuclear waste management and the visual impact of wind farms.

What can governments and regulators do?

We believe there are several tools that EU member states have at their disposal to limit the windfall and restrict the redistributive effects of the scheme:

- **Charging for allowances:** We believe EU governments will tend to make frequent use of their ability to auction allowances up to the cap set by the Directive (5% up to 2007, 10% between 2008 and 2012). We would prudently assume that all allowances are auctioned after 2012.

- **Limiting end-user price impacts:** Where possible, we expect governments and regulators to seek ways of preventing the rise in wholesale prices being reflected in end-user tariffs.

- **Skewing allocations away from the power sector:** We expect the power sector to be last in the queue when it comes to allocating allowances. Preference will tend to be given to industrial consumers – even to the extent of giving them allowances to cover indirect emissions implied by their electricity use.

- **Clawing back value elsewhere:** Where there is room to do so, regulators may seek to claw back the windfall through reductions in remuneration elsewhere in the value chain, such as in distribution prices and stranded cost recovery. The 'nuclear option' is some form of utility windfall tax, such as that imposed in the UK in 1995.

Our approach to analysis

The rest of the report is a country-by-country analysis of the impact of emission trading. The distinguishing characteristic of our approach to analysing these issues is as follows:

(1) The country angle is key

Emission allowances will be traded on a pan-EU basis and have a uniform value across Europe. However, the impact of emission trading in each country is likely to vary widely, depending on the structure of the market, the mix of plant, the political and regulatory background and the supply-demand fundamentals in

each country. Therefore, each of our country analysts has analysed Germany, the UK, Spain and Italy in turn, focusing on the important features that influence the impact on each company.

(2) The potential utility windfall is a big issue

We believe the potential windfall for generators throughout Europe is a key issue that will affect the implementation and consequences of the scheme. We believe governments will seek ways to limit price rises to customers. Therefore, the political and regulatory background in each country is central to our view.

(3) Allocations are the big unknown

In all countries, the approach to allocating allowances is the largest uncertainty in judging the impact of the scheme. Therefore, we consider a wide range of sensitivities to different allocation approaches. In general, we characterise these as 'blue sky', 'base case', 'black sky' and 'disaster' scenarios – the last being a description of the worst possible combination of decisions, however unlikely.

(4) In some cases we know enough to change our price targets

Despite the uncertainties, we now know the EU ETS will be implemented, we know the fundamental drivers of the economics of the scheme and we can make some assessment of the political and regulatory framework. The allocation of allowances remains uncertain, but we believe it is possible to incorporate the likely impact into our stock valuations and price targets.

Germany

ETS in Germany

Summary and conclusion

- As of 2001, Germany had reduced its GHG emissions by 18% from 1990 levels (the target is a 21% reduction by 2008-12). German utilities have reduced their emissions by c15.6% over the period, but we assume that they will 'outperform' with a 22.5% reduction by 2008, whereas we expect Germany as a whole to miss its target.

- We expect wholesale prices to rise by 48% as a result of the introduction of a CO_2 trading scheme in Germany. In any scenario except a very negative one, the rise in prices should significantly exceed the rise in costs, creating a windfall for utilities of €12.5 billion in our central scenario.

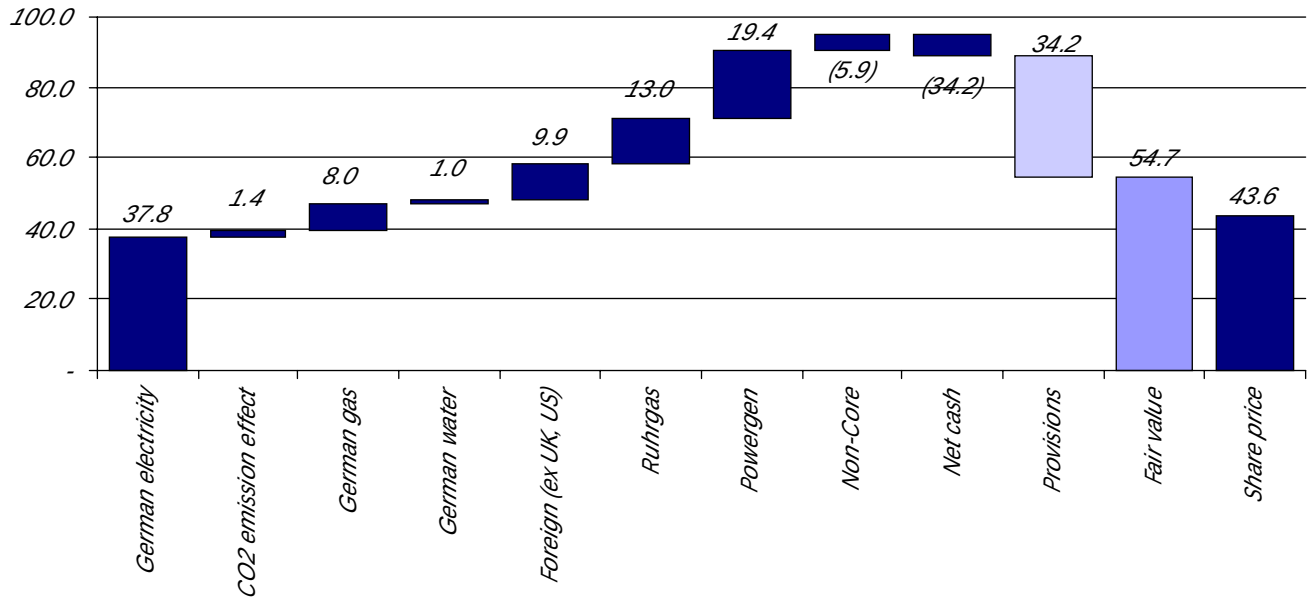
- The allocation of permits will be a highly politicised process in Germany. We believe that it is likely that the government will mix 'political and economic' views and 'push' coal (hard coal and lignite to a lesser extent) out of the merit order, while at the same time using part of the windfall to pay for the social cost of this.

- Our model suggests that the introduction of ETS could result in an increase in value ranging from €3.5 billion to €8.9 billion (3.9% to 13.7% of the current EV) for E.ON and from nil change to €7.9 billion (0.2% to 14.4% of EV) for RWE, after including the rise in value of Powergen and Innogy we expect in our UK central scenario.

- We believe that it is unlikely that E.ON and RWE will be able to keep the entire potential positive impact we have unveiled. We believe that there is a substantial risk of 'windfall taxation' that could hit them either for social reasons or simply as one of the few ways the German government can keep its budget deficit under control.

- We have raised our valuation of E.ON from €53.3 to €54.7. This increase is based on the assumption that E.ON would keep 50% of the benefits of the 'black sky' scenario. We have taken this very cautious stance in order to reflect in our price target the balance of risks and rewards faced by the stock. The main elements of our sum of the parts for E.ON are shown in the following chart.

Chart 10: E.ON – UBS SOTP (€)



Source: UBS

*share price as at 23 September 2003

Germany and Kyoto targets

Below we distinguish between CO_2 and greenhouse gases (of which CO_2 is but one) in general.

- According to data from the EU (European Environment Agency), Germany reduced its emissions of GHG by 18% between 1990 and 2001 (the last year of EU published figures). These statistics are important given that they are likely to be used as the basis for the calculation of NAPs. Germany's commitment under Kyoto is a 21% reduction of emissions of GHG by 2008-12. The reduction in GHG over 1990-2001 was largely driven by a reduction of other gases, particularly CH_4 (–48.4%) and NO_2 (–31.5%).

- CO_2 emissions account for roughly 80% of all GHG emissions in Germany and were reduced by 14.2% over 1990-2001. The transport industry saw the biggest increase in emissions of CO_2 (+10% over the period).

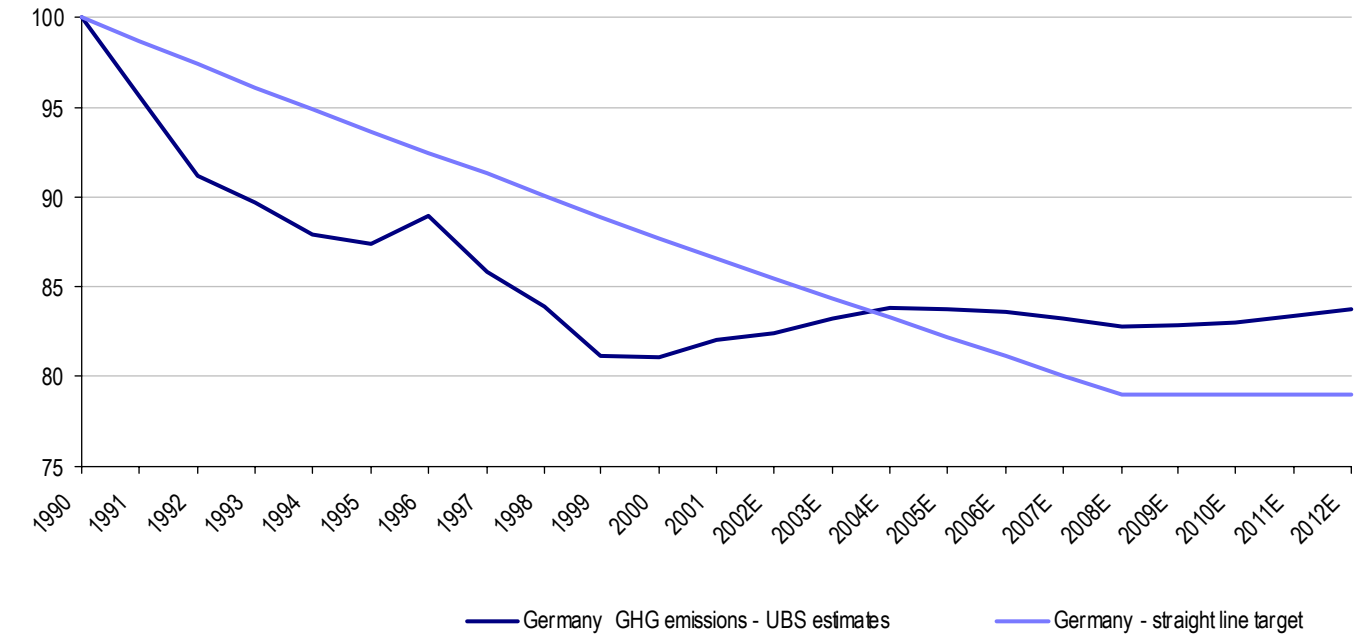
- Those achievements are impressive but they need to be reviewed in detail. A large proportion of the reduction in German GHG levels is due to the collapse of East German industry since unification. The EEA suggests in its July 2002 update that 50 % of this reduction – c80 million tonnes – came from the former Eastern Germany of which 40 million tonnes was a result from the modernisation of the power plants.

Under the Kyoto Protocol, Germany has committed to a 21% reduction in total GHG emissions by 2008-2012…

Chart 11 describes our core scenario of the future development of GHG emissions in Germany. We do not expect Germany to meet its targets for GHG emissions by 2008-2012. According to our calculation, GHG emissions in Germany should rise by 0.1% pa to 2008; that is, emissions should be broadly

stable over the coming decade based on 1% nominal GDP growth pa over the period to 2012. As a result we expect Germany to miss its target by 4% or c46 million tonnes – reaching 1,015 million tonnes in 2012 (of which 891 million tonnes of CO_2). One of the best studies publicly available on emissions in Germany (RWI – July 2003) mentions total emissions of an estimated 979 million tonnes.

Chart 11: Germany – GHG emissions – past and anticipated future performance (1990 = 100)

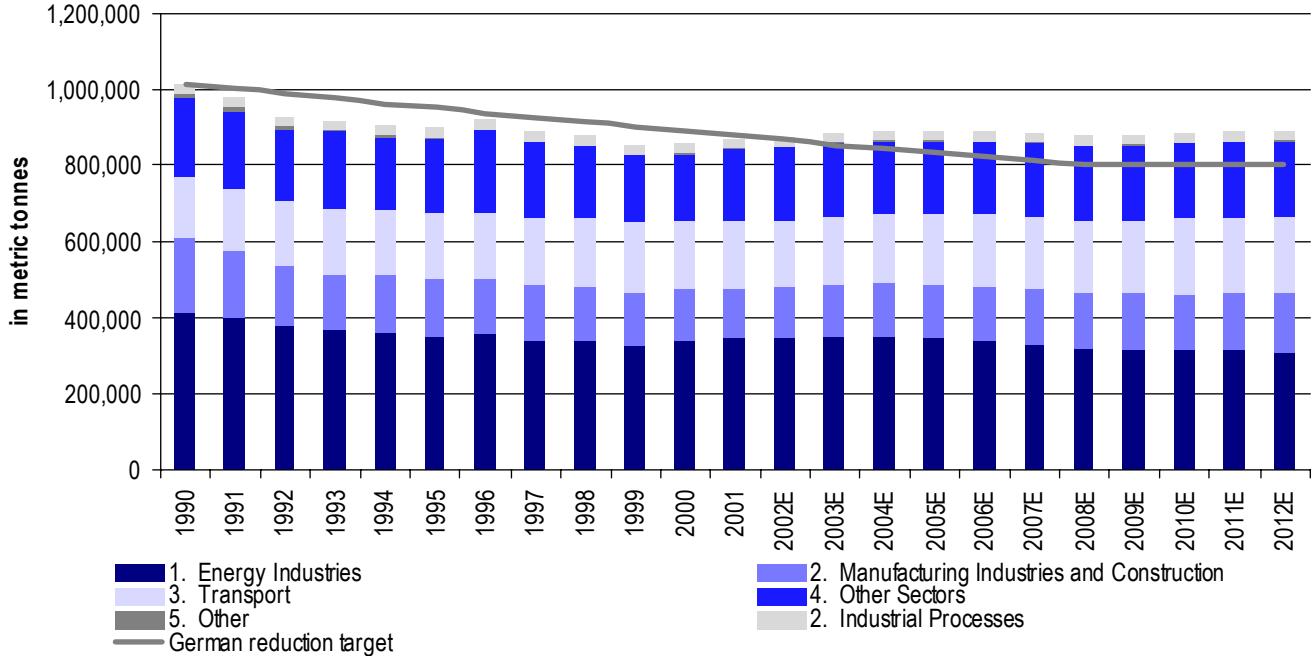


Source: EEA, UBS estimates

Chart 12 highlights why we think Germany is unlikely to meet its target. Whereas those sectors that are included in the Kyoto Protocol should be able to hit the 21% target, we believe that emissions from the 'non-Kyoto' sectors will continue to rise. We assume that transport emissions rise by 1.2% pa post 2001, versus 0.9% pa in 1990-2001.

…a target we think is unlikely to be met due to the 'non-Kyoto' sectors, such as transport

Chart 12: Breakdown of GHG emissions in Germany (in million tonnes)



Source: UBS estimates

Germany has not yet indicated how it intends to set reduction targets by industry or sector, but like other European countries it is expected to do so by the end of March 2004. For the sake of simplicity, we have assumed that the 21% reduction applies equally to all sectors.

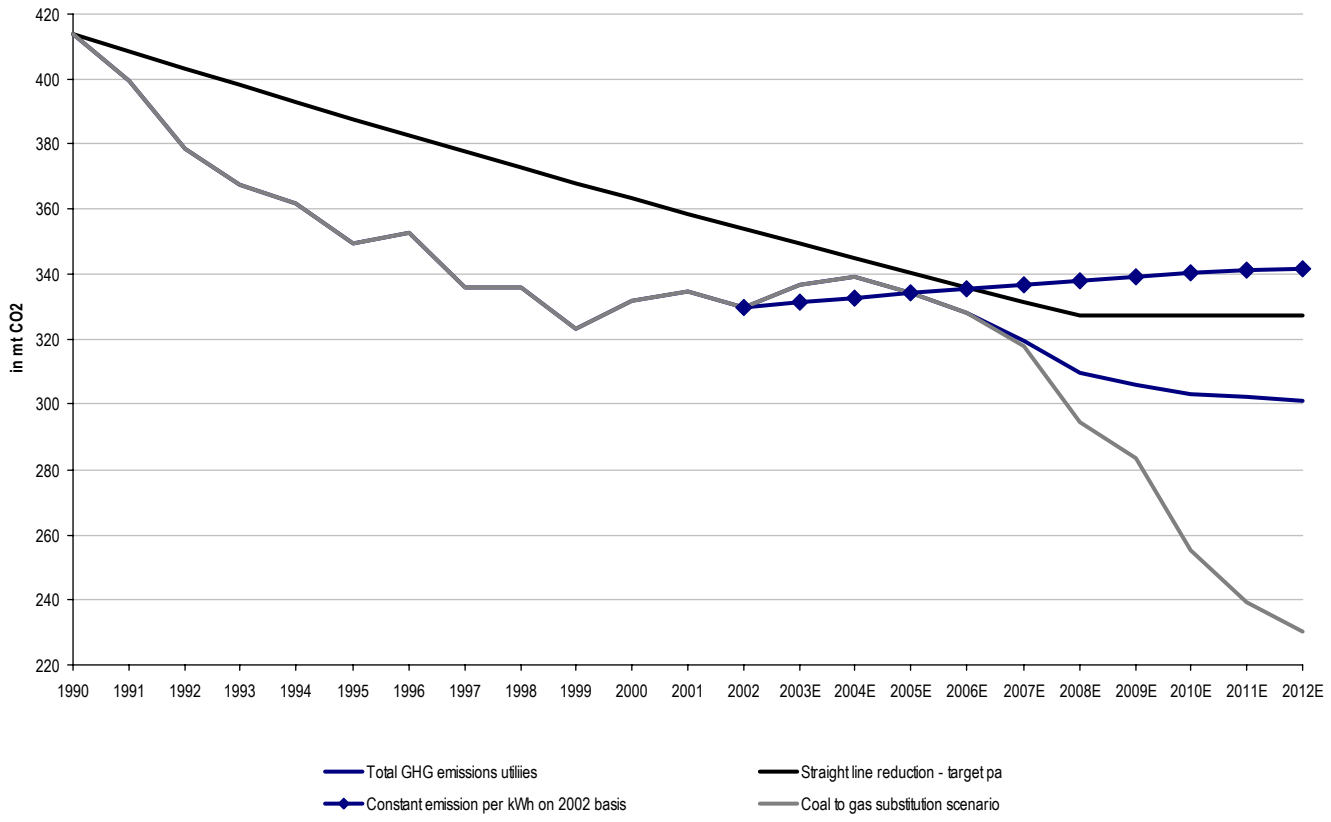
German utilities and GHG

German utilities' CO_2 emissions have fallen 16% from 1990 to 2001

According to the EU, over 1990-2001 German energy companies (a classification that includes oil refineries) have reduced their emissions of CO_2 by 16.4% (from 414 to 345 million tonnes). We estimate that power utilities reduced their total GHG emissions from 414 to 301 million tonnes, of which CO_2 from 370 to 309.2 million tonnes over the same period – also a 16.4% drop.

In Chart 13, the straight line shows a linear reduction of GHG emissions of German utilities over the period 1990-2008, assuming that utilities are assigned a 21% reduction target to 327 million tonnes in 2008.

Chart 13: German utilities – GHG emissions – past performance and future estimates



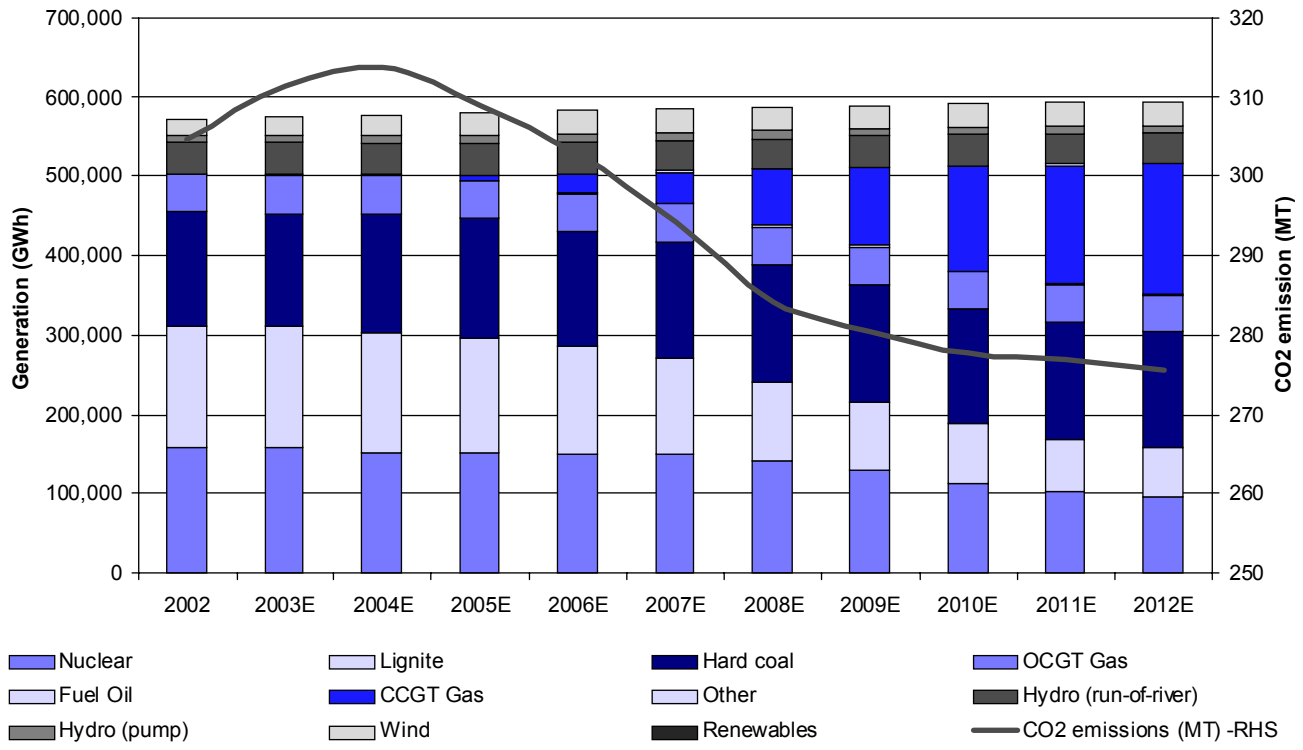
Source: UBS estimates – CO_2 emissions based on the assumption of 400kg/MWh for CCGT, 800kg/MWh for fuel oil, 1,100kg/MWh for lignite and 850kg/MWh for hard coal, no emissions for nuclear and hydro. We made no assumption of difference in emissions as a function of the age of the plant and its efficiency.

For both the country as a whole and the utility sector, GHG emissions reached their lowest point in 1999 but rose in subsequent years, as shown in Chart 12. The small drop in 2002 emissions can be traced to a very mild winter and slow economic activity. In 2003, the combination of a cold winter and a heat wave during a period of a tighter supply/demand balance is likely to have pushed coal generation and emissions up.

Gradual retirement of older plants and construction of new gas-fired capacity expected to boost utilities' total CO_2 reductions to 22.5% by 2008

Chart 13 highlights our assumption that German utilities will have reduced emissions by 22.5% in 2008, suggesting that they will find themselves c17 million tonnes under the implied target of 327 million tonnes. This figure is based on our core German pricing scenario, in which we anticipate the gradual retirement of older plants and the building of 23.4GW of new gas-based capacity by 2012 (mainly used as base load). At the same time a very large proportion of lignite and coal plants will have been retired.

Chart 14: German utilities CO_2 emissions – UBS fuel mix estimates



Source: UBS estimates

Alternative scenarios for ETS

Chart 13 highlighted two alternative scenarios for the emissions of German utilities. We detail them in the next following paragraphs.

(1) No change in emission pattern

We calculate that German utilities emitted a weighted average of 553kg of CO_2 per MWh in 2001. We built a scenario with fixed emissions per MWh. We calculate that total utility GHG emissions would be 338 million tonnes in 2008, or 9% above our estimate.

(2) Perfect substitution from coal to gas

The main aim of introducing CO_2 trading schemes is to reduce if not completely eliminate coal-based energy generation and to substantially cut lignite generation. We have built a scenario where the price of permits move within three years to the level of substitution between coal and gas, leading German utilities to totally switch away from coal and into gas by 2013.

In our model we assume that all German coal plants (a total of 49.4GW in 2006) are replaced by the end of 2013 by new CCGT plants run with a load factor of 65% from 2007 onwards (and 55% thermal efficiency). This is arguably optimistic, as it would imply that German utilities make such important investment decisions as early as 2004 – that is, as soon as details on CO_2 emissions trading emerge in Germany (assuming there are no delays).

In this model, implied CO_2 emissions would amount to 168 million tonnes in 2012 versus 276 million tonnes in linear reduction model. This would enable Germany to 'free' up to 108 million permits that could be 'exported' to those countries that need permits. This in turn could depress the value of permits across Europe and slow the process of substitution to gas from coal in other countries heavily dependent on coal.

This scenario of perfect substitution is probably unrealistic, given that the introduction of ETS is only one of the many uncertainties surrounding the economics of German utilities at the current stage. In our view, the heads of RWE and E.ON are unlikely to embrace CO2 trading wholeheartedly at the outset.

Political background and domestic issues

Traditional allocation

Allocation of emission rights

- **2005-08**

There are two main issues in this period. What is the basis of calculation for the permits? Will allocation be full or partial? We assume that emission permits will be allocated, one way or another, on the basis of historical emissions over a pre-determined period (probably 2000-2002). There is no guarantee that the government will use 'grandfathering' as the basis for its emissions allowances in the first place. However, grandfathering provides an easy and understandable basis to our calculations, and we have kept it as a reference in building our scenarios.

Allocation of permits likely to be determined on the basis of historical CO_2 emissions

The EU Directive requests that during the first phase (January 2005 to January 2008), countries allocate 'at least 95%' of the certificates for free. It is important to understand that the issue of the payment is separate from the issue of the number of permits that the various plants of a generator may be allocated.

- **2008-12**

The EU Directive stipulates that during this period 'at least 90%' of the certificates could be allocated for free. In other words, 10% of the permits could be auctioned. This is our core assumption.

We believe CO_2 permits will become a form of taxation in Germany

- **Post 2012**

We assume 100% auctioning of the permits.

The trade-off between power utilities and all other industries

As shown in Charts 13 and 14, Germany as a whole is unlikely to hit its target but German utilities should. In this case, the German government would have to find ways to encourage more drastic reductions of GHG emissions across the country.

We believe that it is very possible that utilities will be asked to contribute to the elimination of the potential surplus. This could be done by 'under-allocating' permits to utilities.

Trading permits for newcomers

There is no specific information regarding the intentions of the German government. We believe that the most 'logical' approach would be to 'reserve' some permits for newcomers – in effect any new plant – given that permits will be allocated plant, not by company.

Issues specific to Germany

When the German government establishes its NAP, it will have to balance several very complex issues. Below we discuss four of the trickiest factors.

CO_2 reduction and nuclear phase-out

Dilemma #1: Germany wants to encourage a reduction in CO_2 emissions but at the same time wants to get rid of one of the few source of power that does not emit CO_2

In June 2000, Germany decided to phase out nuclear generation by 2026. Over the last few years, nuclear power has accounted for roughly a third of German power generation, and we calculate that this generation helped 'reduce' CO_2 emissions by c60 million tonnes pa – roughly a fifth of total CO_2 emissions in 2001 – compared to the same level of generation based on gas. Note that a CCGT plant still emits c400kg of CO_2 per MWh, versus none for a nuclear plant and close to 900kg for a coal plant. On the basis of the already mentioned €25 per tonne CO_2, the price of this 'avoided cost' would be close to €1.5 billion.

Nuclear generators should receive the biggest windfall (higher prices, but no change in costs irrespective of the allocation process). However, if the nuclear phase-out is actually carried out, generators will have to replace their nuclear capacity with (presumably) gas plants.

EON and RWE will probably try hard to get 'nuclear' permits, but we think they are unlikely to get them

In order to 'secure' their potential windfall, both E.ON and RWE probably intend to lobby the government with a view to being allocated 'virtual' CO_2 emissions permits corresponding to the emissions that would have come from gas plants. In other words, those free permits could be a form of partial stranded cost payment for the phase-out of nuclear generation. We see the rationale behind the request, and the German press is reporting that the government is listening to it. However, we would argue that most nuclear plants in Germany will be shutting down after 2012, when all permits have to be paid for. As a result, there is probably a case to be made that all companies would be on a level playing field. Also, the size of the windfall enjoyed by German utilities in most scenarios would make it difficult for them to argue for 'more'.

How will Germany mitigate the (social) impact of phasing out coal?

CO_2 schemes provide a clear incentive to generators to phase out coal generation. In Germany – probably more than in any other European country – the coal industry (mining and generation) continues to be a large provider of jobs. Germany subsidises its steam coal industry by €3.3 billion pa. This scheme is slated to end in 2005, but it can be envisaged that some form of subsidy will remain in place. Lignite is not subsidised. The biggest lignite producer, Rheinbraun, is a 100% subsidiary of RWE. We estimate that c55,000 jobs are

still directly linked to the coal mining industry in Germany (of which 80% are in the subsidised part of the business).

Dilemma #2: Some 55,000 jobs would go if coal became uncompetitive overnight…is this socially acceptable?

EU rules prohibit direct subsidies and state aid. Yet politicians will be under pressure to soften the blow from their decisions. One possibility could be to 'tweak' the criteria of permit allocation in favour of coal-based generators. We think this is unlikely, however, as it could be problematic from a legal standpoint. We believe that it is more likely that the government will consider that the 'windfall' profit from CO_2 should help pay for the final closure of all German coalmines over a period of time. The UK windfall tax in 1998 provides a striking example of profits being regulated away. In our view, it would not be hard for the German government to justify a form of 'windfall tax' for the sake of the environment. As we said earlier, in our view, CO_2 permits will largely be treated as a form of taxation by all European governments. Given the level of the budget deficit in Germany, we believe it is safe to assume that any potential revenue source will be considered .

Managing the rise in gas consumption

Dilemma #3: CO_2 trading will encourage the use of gas…but Germany has virtually no domestic gas and depends on imports through pipelines

In addition to more plants being built, CO_2 schemes should also result in new and existing gas-fired plants being run harder. The main issues arising from the growth of gas generation in Germany are linked to: (1) security of supply and (2) the level of gas prices.

Security of supply: Germany imported more than 80% of its gas needs in 2000 through a series of long-term contracts. Our understanding is that a large proportion of these contracts are take or pay with flexible prices. Power generation accounts for only 10bcm pa of consumption on average versus total consumption of 88.3bcm in 2000. Before the introduction of ETS had become part of our core scenario in Germany, we suggested that there could be a rise of 30% to 40% in gas consumption to 2010, essentially led by the growth in gas-based generation (see *The future of gas in Europe*, 146pp, April 2002).

We assume a 15% nominal rise in gas prices during the 2005-2015 period due to ETS

Impact on gas prices? As mentioned in the introduction of this report, we expect gas prices to rise across Europe, including Germany. This is the result not of scarcity of supply but of the rise in the long-term marginal cost of the fields that will help meet the surplus demand. In our gas price assumptions for Germany –essential for the definition of a new entry price – we assume additional gas price rises of 15% in nominal terms (cumulative) as a result of ETS over the period 2005 to 2015.

Other renewable energy issues in Germany

Germany has two schemes in place for renewable energy.

(1) The renewable energy law requires all regional utilities to buy renewable power (including wind) at a premium price of €8.8/MWh (a degressive tariff over five years that can be extended to 20 years). The additional costs resulting from the renewable obligations are to be passed on in full to the supplying companies through an equalisation scheme applicable across Germany.

(2) The co-generation protection law is intended to help reduce CO_2 by encouraging CHP generation. Originally the German government planned to impose a quota of CHP-based generation with the aim of reducing CO_2 emissions by 23 million tonnes by 2010. In its second incarnation, this law has created a very complex set of bonus payments for CHP generation, with local network operators being allowed to pass on the additional costs to their customers in full. In their negotiations with the government regarding some changes in this law in 2001, utilities argued that the new system could result in 'voluntary' CO_2 emission reductions of 45 million tonnes to 2010.

As a follow up to the 1992 Rio conference on the environment, Germany had committed itself to a 25% reduction in CO_2 emissions by 2005. It is unclear whether the German government is still sticking to this target. It has not been mentioned publicly for a long period of time now but could re-emerge to justify setting 'tougher' emissions targets in the run-up to 2008.

It remains unclear to us whether the introduction of ETS will lead the government to adopt changes to this complex legislation; the government consider the cogeneration law and the Kyoto targets to be one and the same thing. Industrial lobbies are currently strongly arguing in favour of this, as they take the view that this could help reduce industrial prices.

Impact on regulation

Generation prices set by market forces in Germany, while to some extent grid fees and retail tariffs are regulated

Our analysis of the economics of CO_2 in Germany indicates a potential bonanza for the utilities. We mentioned earlier that this could be regulated away in the form of taxation, but it could also have an impact on regulation itself. In the German electricity market, only generation business prices are entirely set by market forces. Grid fees and retail tariffs are regulated to various degrees. There is no evidence of any debate in government circles linking the two issues at the current stage. However, it seems increasingly clear to us that the authorities are gradually realising that the introduction of CO_2 trading schemes will be beneficial to the utilities. We believe this will probably increase the regulatory risk.

A Catch-22 for German utilities?

If CO_2 trading schemes turn out to be the bonanza that many believe it will be, German utilities are in a Catch-22. On the one hand, potential regulatory pressure on the grid should lead them to 'hide' their grid returns by spreading the margins more evenly between generation and transmission of power. At the same time, the introduction of trading schemes will probably prompt them to 'hide' their recovering generation profitability. 'Pushing' the margin into the retail business is virtually impossible because of regulation, but also because neither RWE nor EON fully control all their retail business.

Decision-making process: who is in charge?

Allocation of CO_2 emission permits likely to be a complex process

Reaching a decision regarding the allocation of CO_2 emission permits will be devilishly complex in Germany. We mentioned earlier all the social issues raised by the introduction of the schemes. In addition, the German government will have to define its CO_2 plants concomitantly with the introduction of a regulator and a rapidly tightening of demand and supply. We will soon publish a

report that reviews the current price situation in Germany and introduces our new pricing model.

Our understanding is that Chancellor Schroeder, Economics Minister Clement and Environment Minister Trittin will be involved in the decision-making process. Mr Clement is also the former premier of North Rhine Westphalia, one of the core areas of the German coal industry. Mr Trittin is a member of the Green Party and is the minister who worked out the nuclear exit strategy agreed in 2000. Trade unions and various industry representatives are also to be included in the talks. Formally, decisions will be taken by the Environment Agency.

We understand that German utilities plan to argue that the allocation should recognise the extent of the reductions achieved in the early 1990s. Given our view that this reduction was largely the product of an external shock (the demise of eastern Germany as an industrial centre), we believe that this argument will not prevail.

We think the government will consider it a top priority to meet the Kyoto targets

We would argue that given (1) the narrow timeframe of the decision making process on CO_2 as opposed to the 'longer term' nuclear exit, and (2) the political risk for the Greens associated with not being tough on CO_2, the government will consider hitting the Kyoto targets as its core priority, particularly as the allowance of CO_2 permits will largely be a form of taxation in a period of large budget deficits. We noted earlier that there are ways for Germany to soften the social impact of the demise of the coal industry. Our view seems to be borne out by the snippets emerging from the recent meeting between utilities and the government, where Mr Trittin's reiteration of the Kyoto targets and the general objective of GHG reduction in Germany was positively greeted by the heads of utilities.

In theory, Germany should come to its allocation plan by the end of March 2004. However, given the extreme complexity of getting together all the necessary legislation, we would not rule out the possibility of delays.

As this report goes to press, newspapers in Germany report that at the recent summit between the government and the utilities, the government reiterated the voluntary agreement of a 45 million tonne GHG reduction (a 22% reduction versus 1990, or 1% in excess of the Kyoto target) and that the shut-down of nuclear plants would result in a form of compensation. In short, a blend of the central and blue sky scenarios could be envisaged on the basis of this. Please note that there has been no official confirmation of this from the government.

Other political considerations

We would expect a tough debate in Germany on the merits of buying permits from abroad, particularly from neighbouring Eastern European countries. We would doubt that the Green party would agree to this.

Will nuclear generation make a comeback?

There is little room for us to consider a potential reversal of the German government's stated decision to pull out of nuclear generation any time soon – it is unlikely under this government. This said, we would argue that the debate will

be reopened soon in Germany, particularly as France and Finland, for example, are due make decisions on the next generation of plants.

Allowance scenarios for Germany

In our view, the introduction of a CO_2 emissions trading scheme in Germany, in theory, should result in:

- A rise in wholesale prices. We calculate a potential 48% rise in wholesale market prices in Germany versus our 'non-CO_2' scenario in 2010. This rise in prices should significantly exceed the rise in costs. Nuclear and hydro generators would benefit strongly, as in theory they are in a better position than coal generators once permits have to be paid for.

- Our model suggests that the introduction of ETS could result in a rise of value ranging from €3.5 billion to €8.9 billion (or 3.9% to 13.7% of the current EV) for E.ON and from nil change to €7.9 billion (0.2% to 14.4% of EV) for RWE, after including the rise in value of Powergen and Innogy that we expect.

- We do not believe that German utilities will be allowed to keep the entire benefit of the windfall. In our view, equity investors should consider the risk of CO_2 emissions as a form of indirect taxation and adjust their equity risk premium accordingly.

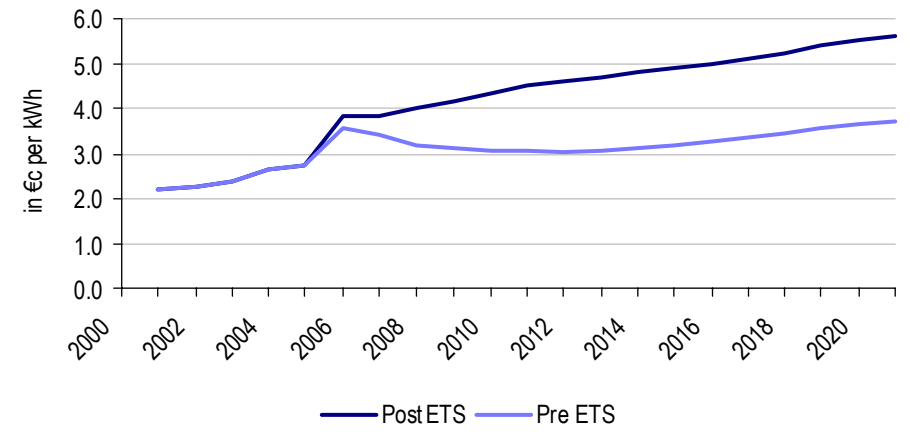
- However, in order to put our money where our mouth is, we have added €1.4 to our previous €53.3 price target for E.ON. This increase is derived from taking 50% of the impact of our 'black–sky' scenario. In taking 50%, we have tried to continue using a risk/reward approach and balancing the potential positive impact with the potential negatives. Please note that we will soon publish a report on the German electricity market as a whole.

Impact on the economics of the sector in Germany

Impact of CO_2 emissions trading on wholesale market

Our German pricing model suggests a rise in wholesale prices of close to 48% versus a 'pre-CO_2' market in 2010, as shown in the chart below.

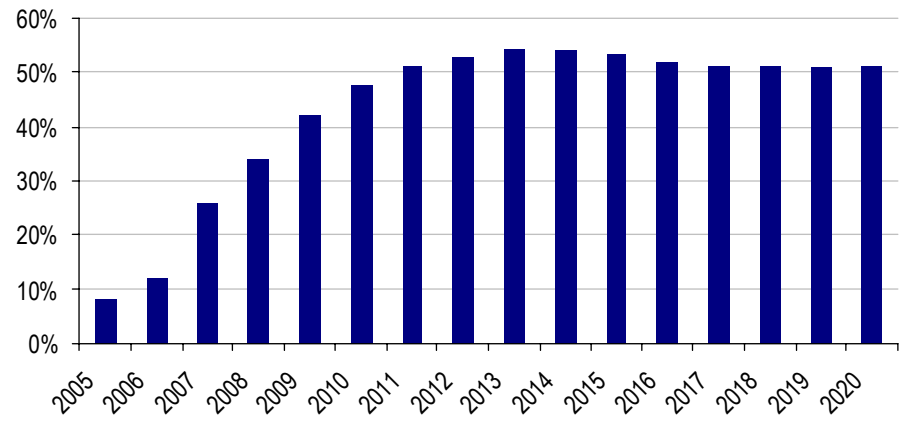
Chart 15: German wholesale price post introduction of CO_2 trading permits



Source: UBS

Chart 16 shows the expected rise from the perspective of the rising differential between prices pre-ETS and post-ETS from 2005 onwards.

Chart 16: Difference in wholesale prices scenario pre- and post-ETS

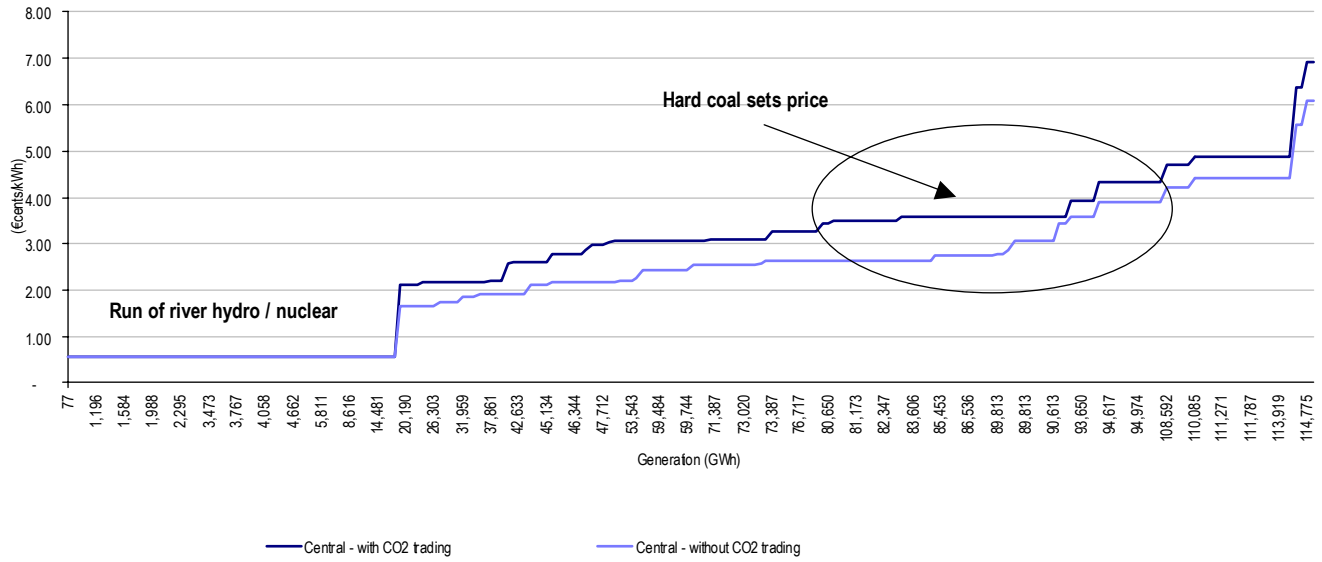


Source: UBS estimates

This rise in prices is the result of

- The rise in the costs incurred by companies – a fairly straightforward calculation.
- The change in the merit order resulting from the introduction of the scheme. The following chart shows the current merit order in Germany for the next few years.

Chart 17: German supply curve pre- and post-introduction of CO_2 emission scheme



Source: UBS estimates

A full pass-through? Economic theory suggests that the rise in wholesale prices will result directly from the rise in the cash cost of the marginal generator due to the introduction of the scheme. In Germany, hard coal is the marginal generator for a sufficient period during the year for us to consider that hard coal could drive the prices. However, as the supply situation gets tighter – resulting in the construction of capacity and the value of the permit gradually rising to €25 per tonne – it can be envisaged that the full costs of new gas plant could set the price soon after 2008.

Despite the tight supply/demand balance, wholesale prices have not yet fully reflected the cash price of marginal generation

A key issue, however, is whether German utilities behave entirely rationally during the next few years and read the signals sent by the ETS allowance price to switch out of coal. One quandary of the current situation is that despite the increasingly tight supply/demand balance, wholesale prices have not yet fully reflected the cash price of the marginal generator in the market and are still hovering somewhere between marginal and cash costs. This could be largely explained by the vertical integration of those businesses that, to some extent, 'spread' the necessary coverage of the full cash costs of the plants over the entire value chain.

It is not clear at present whether the forward wholesale market in Germany is already reflecting the introduction of ETS in 2005. The spread between the 2005 and the 2004 contract was close to €1/MWh only last week in the EEX market, suggesting that the spread will widen during the course of 2004.

Impact on industrial and retail prices

Will power utilities be able to pass on the full extent of the price rise to their customers? As mentioned earlier in this document, we envisage a rise in the wholesale price of close to 48%.

- **Industrial prices**: Any potential rise would be a function of the ability of energy companies to pass on the rise in wholesale prices and costs to their

industrial customers. Our model is based on the assumption of 60% pass-through, leading to a rise of 29% in average end industrial prices post introduction of CO_2 schemes (relative to pre-CO_2 schemes). We believe that industrial customers could turn to cheaper external suppliers such as EdF to cut their bills (assuming fluid grid access).

- **Retail price** rises have to be approved by local authorities in Germany. We assume that utilities will try to pass part or all of the potential rise in costs due to CO_2 on to retail customers. According to our calculation, generation accounts for c28% of the final (post-tax) price to retail customers. We assume that a level of 20% pass-through would be acceptable. In other words, the rise in the average bill of retail customers would be in the region of 8%. This does not seem to be excessive from an acceptance point of view – rises due to various ecological taxes have previously been accepted by the public.

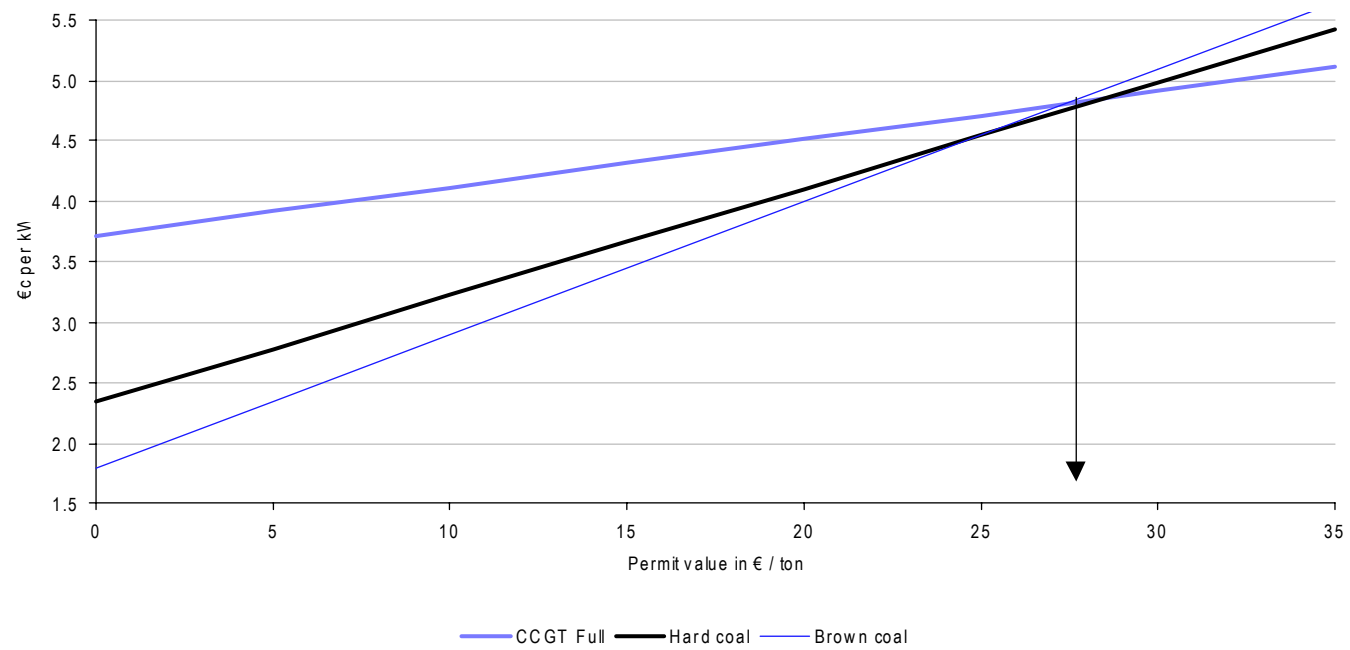
What theoretical value do the permits have?

At what level of permit prices do generators start building CCGT in Germany?

In theory, CO_2 trading permits should clear at the marginal cost of abatement at the cap. This should be the level where generators start substituting coal plants (based on their marginal costs) with new gas plants (based on their full costs).

Chart 18 plots the costs of coal- and gas-based generation versus the price of the permits in the German market only. This suggests: (1) a substitution level that is higher than the level we expect in most European countries; and (2) no significant difference between hard coal and lignite. The point of substitution between coal and gas is higher in Germany than in most other European countries due to both the absolute level of fuel prices and the expected relative prices of gas versus coal going forward.

Chart 18: Theoretical value of permit

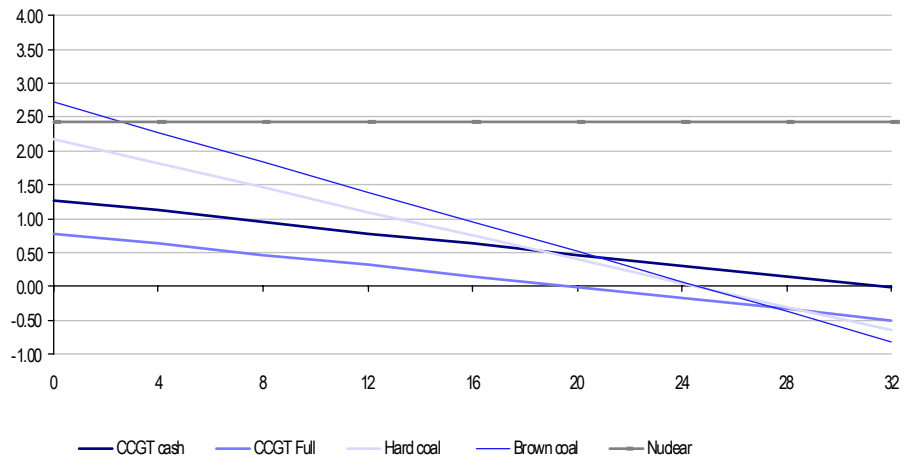


Source: UBS estimates

Generating or selling the permit?

Another way to look at the economics of the permit is to estimate the level at which generators would stop generating and sell the permit. Basically, the substitution point should be at the level where the EBITDA of each plant falls below the value of the permit. Chart 19 plots the EBITDA per kWh of each fuel type and suggests that a German generator would sell the permit at around €26/tonne. However interesting this may be, it is important to remember that German utilities are vertically integrated – we have long suspected that they have been 'hoarding' their revenues into the grid business by virtue of artificially low generation prices. We believe that the introduction of CO_2 emission trading will lead to a rebalancing of this situation over the next few years.

Chart 19: EBITDA per kWh (€) based on fuel type



Source: UBS estimates

Impact on earnings and valuations

Scenario analysis

In order to assess the impact of the introduction of ETS on the value of E.ON and RWE, we have constructed three scenarios. Our three core scenarios are described in the following table.

Table 3: CO_2 scenarios for Germany (to be updated if necessary)

	Black sky	Central	Blue sky
Allocation vs. average 2000-02	Irrelevant	95%	100%
From 2005 to 2008, auctioning of	100%	5%	0%
From 2008 to 2012, auctioning of	100%	10%	0.0%
Share of utilities for German wide deficit	40%	30.0%	0.0%

Source: UBS estimates. Reminder: post 2012, we envisage 100% auctioning.

Central scenario: Compromise between political and economical considerations

In our **central scenario**, we assume that the government will try to get the power industry to pay for part of the failure of the country at large to deliver on its targets, probably by under-allocating permits to the utilities. In this scenario, we assume that utilities are forced to purchase 'only' 40% of the estimated 66 million permits in 2010. As noted earlier, we believe that from a political standpoint, it would be easy for the government to 'sell' this as a form of windfall taxation for nuclear generators.

We assume that the government will try to accelerate the transition to gas and renewable by auctioning the maximum possible of 10% of the available permits over the period 2008-12.

Black sky scenario: A triumph of pure economics

In our **black sky scenario**, we try to measure the maximum impact of the introduction of ETS on both German utilities. In this scenario, the government accelerates the transition of the power industry out of coal and into gas, regardless of the social and economics consequences. By definition, this scenario would be very negative for the coal generators and would imply that the government has decided to go much further than stipulated by the Kyoto Protocol.

Blue sky scenario: A triumph for the coal industry

Our **blue sky** scenario corresponds to a highly political scenario in which the government decides to use its power to steer permit allocation to smooth the transition to a 'coal-light' power industry and keep the utilities happy (perhaps in exchange for other commitments).

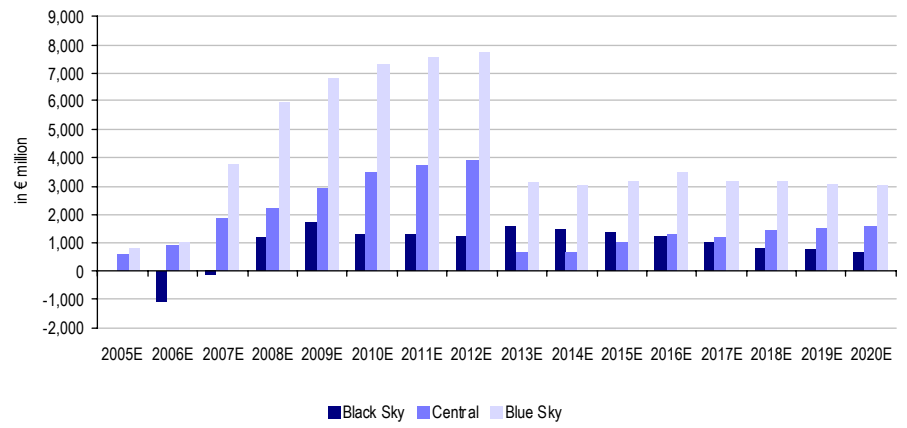
Impact on profitability

We believe ETS will have a positive impact on the economics of the sector, even under our black sky scenario

Our model suggests a positive impact on the economics of the sector in the three scenarios we have envisaged, as shown in the following chart. Even in our black sky scenario, the rise in costs incurred by the full auctioning of the permits from 2005 onwards (which is not a genuine possibility from the legal standpoint) hardly exceeds the positive impact of the rise in sales. Conversely, the extent of the benefit in the blue sky scenario shows that such a scenario is hardly viable from political or regulatory points of view.

The total positive impact of the ETS on the total NOPLAT of the sector in our model is very substantial and is largely front-end-loaded – at least until 2012, when we believe that 100% of allowances would be traded. The most striking feature of these figures is that they fundamentally change the economics of the sector, providing in our view a largely unjustified bonanza to the utilities.

Chart 20: EBITDA impact of UBS ETS scenarios for German utilities



Source: UBS estimates

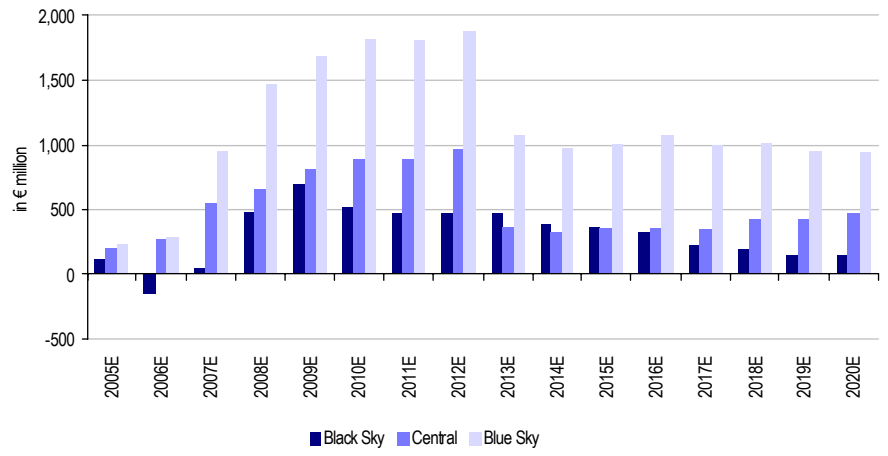
E.ON

With no brown coal in its generation mix, E.ON benefits under all three scenarios

E.ON seems to 'win' in almost all circumstances – with the exception of a total clawback scenario. This is due to the absence of brown coal in E.ON's generation mix as well as the capacity of the company to ramp up its own generation to cover its needs – note that at the current stage E.ON only generated 60% of its total deliveries in Germany in 2002 – largely the result of a deliberate procurement policy.

Looking at the positive impact of ETS on E.ON, it becomes apparent that nuclear generators will find it hard to convince the government that they deserve to see their lack of CO_2 emissions recognised in any form of allocations or allowances. We calculate that CCGT moves from nil contribution to the company's fuel mix to 44% in 2011. This is admittedly a very strong rise that can be justified by E.ON's ownership of Ruhrgas.

Chart 21: EBITDA impact on E.ON of introduction of ETS



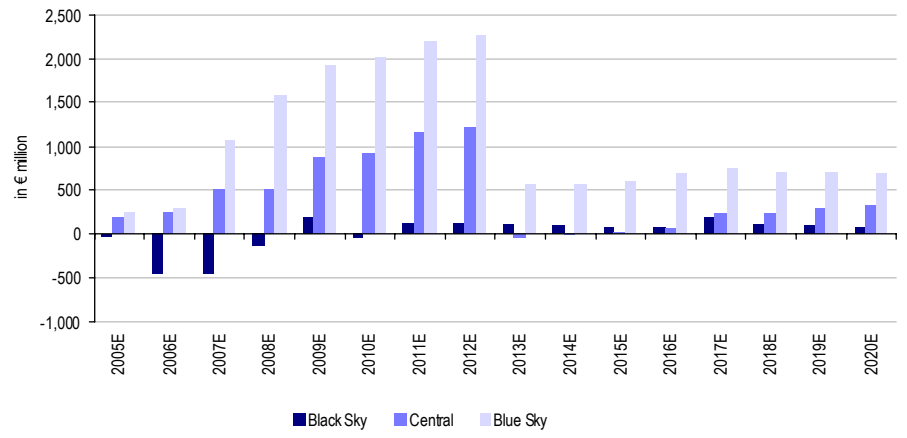
Source: UBS estimates

RWE

...while RWE suffers under our black sky scenario

As expected, given the relative weights of brown coal and hard coal in RWE's generation mix, the company suffers under our black sky scenario, with the net EBITDA impact negative in virtually every year to 2020. Conversely, the impact is very positive in the blue sky scenario given that the company benefits from the rise in prices without hardly any rise in costs. In terms of fuel mix for RWE, we assume that lignite and hard coal – which made up more than 50% of the company's generation in 2002 – will account for 37% only in 2011. Conversely, we expect CCGT to move from nil in 2002 to 33% over the same period. We have made no assumption regarding the earnings of the mining operations of Rheinbraun – RWE's power generation and brown coal mining subsidiary – as we assume that the changes in margins would be passed through within the company and would therefore be a 'one off'.

Chart 22: EBITDA impact on RWE of introduction of ETS



Source: UBS estimates

Valuation impact on E.ON and RWE

We have calculated the impact of the introduction of ETS on the value of companies by discounting the NOPLAT we estimate in each scenario on the basis of EBITDA taxed at 35% and discounted at 10% to 2020. For the sake of simplicity, we have assumed no change in other costs and no terminal value.

As suggested by our comments on the EBITDA impact of ETS, the companies and the sector in general appear to be net beneficiaries. However, while the black sky scenario suggests a loss of value for the sector and RWE, it seems to hardly impact the value of E.ON at all. The impact of both central and blue sky scenarios is significantly positive as shown in Charts 23 to 25.

ETS likely to have a greater positive impact on E.ON – will the government address this discrepancy?

The model suggests a very positive impact on the value of E.ON. This raises the question of whether a different treatment in allowances between E.ON and RWE could be envisaged, typically with a view to the government trying to 'rebalance' the situation between the two major utilities in Germany. Again, this is not a scenario we would favour, given that it creates myriad possibilities – making all analysis irrelevant before the NAP is published – and also because we would argue that the legal position of such a bias would be weak, opening the door to litigation.

Calculations on the impact of ETS on the value of the sector and the companies should be considered with a degree of caution; we see this as more of an exercise in identifying value at risk (a fairly positive one in this instance) rather than a final calculation. In our view, any potential impact on EPS is largely irrelevant at the current stage, given the level of uncertainty regarding the application of the scheme.

UK impact (Innogy and Powergen)

On the basis of the changes in our UK valuations post ETS, the valuation of both Innogy and Powergen are altered.

- **Powergen:** The value of the park of power plants rises by €737 million but the value of customers is lowered by €572 million – a net positive of €165 million only or €0.2 per E.ON share.

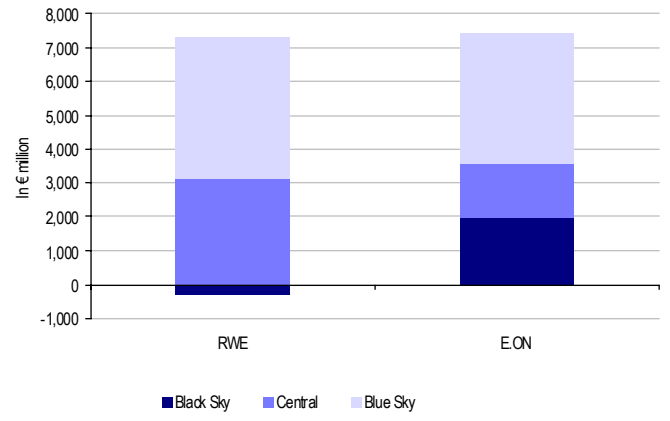
- **Innogy:** The value of the park of power plants is €875 million higher but the value of the customer base goes down by €437 million resulting in a net rise of €438 million or €0.8 per RWE share.

Note that in other parts this report we refer to 'disaster' scenarios. In the case of RWE and E.ON, this refers to the case in which none of the UK utilities are allocated any permits.

Conclusion on valuation

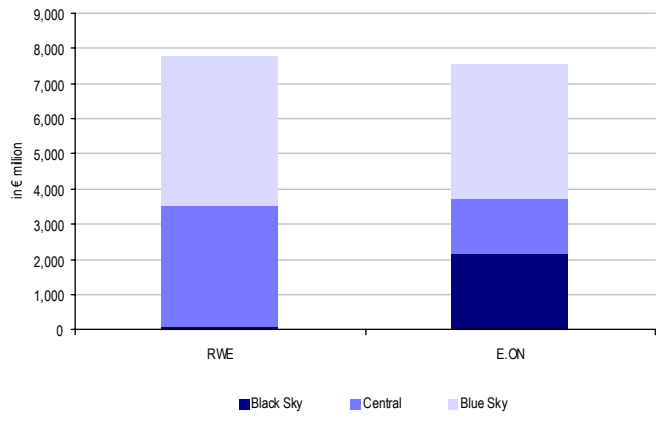
Our modelling approach suggests potentially very large rises in the valuations of RWE and E.ON. In the following charts, we present the assumed impact in terms of absolute value (Germany only and at the group level) and relative terms (the rises as a proportion of current EV).

Chart 23: Potential ETS impact on valuation – Germany only



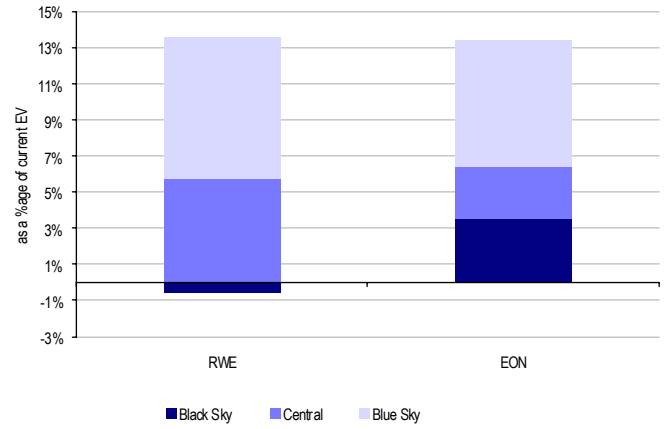
Source: UBS estimates

Chart 24: Potential ETS impact on valuation – group level



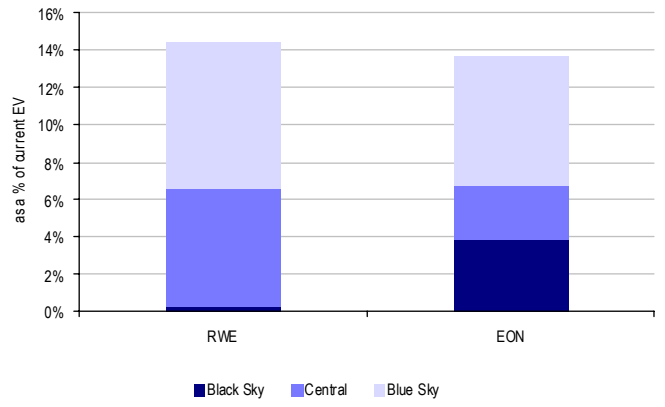
Source: UBS estimates

Chart 25: Potential ETS impact on EV – Germany only



Source: UBS estimates

Chart 26: Potential ETS impact on EV – group level



Source: UBS estimates

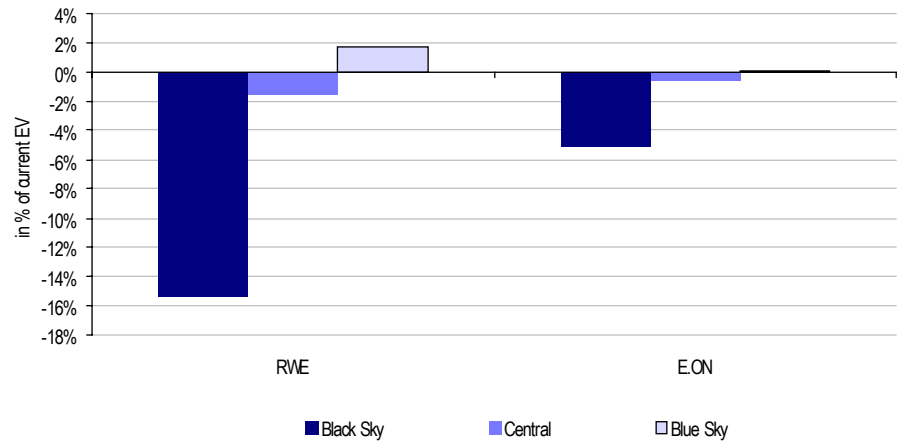
For RWE, we think it is important to keep in mind that we have made no assumption regarding the implicit value of the Rheinbraun mining operation except in the 'disaster' scenario.

Sensitivity analysis

What if utilities enjoy no revenue growth in Germany?

As noted previously, these tentative valuations are based on the assumption of positive revenue growth due to the introduction of ETS. In a scenario with no revenue compensation for the additional costs, our model suggests that RWE would suffer significantly more than E.ON. In the following chart, we present as an example the NPV of the NOPLAT impact. We believe that extending beyond the period where we anticipate full auctioning makes little sense, as by definition costs will converge to the full value of the EV. Going beyond 2012 would also implicitly assume that companies do not adapt their business models to the new trading conditions, which is unrealistic.

Chart 27: NPV of additional costs in Germany, 2005-2012



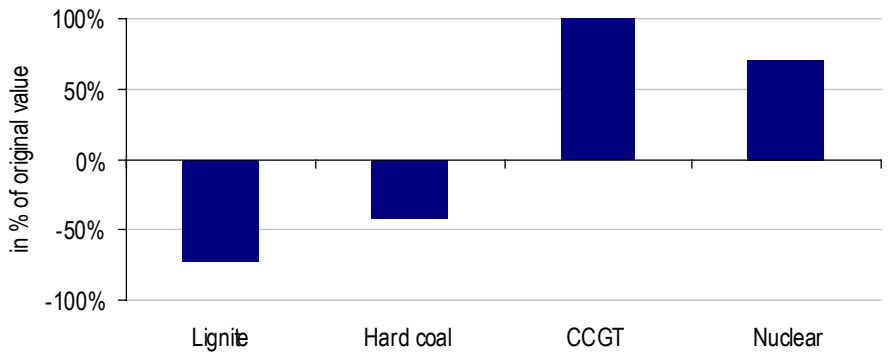
Source: UBS estimates

Where is the shift in valuation?

In theory, the introduction of ETS affects the value of plants only. While valuing plants is a relatively easy business in Spain and the UK, we view it is much more difficult in Germany, as: (1) companies are vertically integrated; and (2) there is still no actual market price in the transfer of power between the generation business and the supply business, making changes in plant valuation as a measure of value creation or destruction broadly irrelevant in Germany. That said, the impact of such an external shock to the system would be significant, as shown in the following chart. Particularly noteworthy are:

- The rise in the value of the nuclear plants, despite our assumption that all plants are shut down by 2026; that is, there is no terminal value in our model;
- The swing from negative value to positive value for CCGT;
- The reduction in the value of brown coal (gradually pushed out of base load by gas) and hard coal (where the rise in costs is partly mitigated by hard coal becoming the marginal price setter for a period of time, enabling coal plants to get a higher level of revenue per kWh).

Chart 28: Potential change in value of plants in Germany



Source: UBS estimates

We have deliberately not shown the absolute value per plant, as we are in the process of publishing a new pricing scenario for Germany.

We explained earlier that a potential consequence of the introduction of ETS is a shift in the profitability of each section of the business amongst German utilities. In other words, the shift in valuation due to the introduction of ETS will probably be spread across the various divisions of the companies and not in the value of the generation business only – even if the bulk of the change is concentrated there.

United Kingdom

ETS in the United Kingdom

- **As the most liberalised electricity market in Europe, UK regulators and politicians will, in our view, face the greatest difficulties in preventing a windfall benefit to utilities.**

- **With coal generation driving the marginal cost of power, we forecast wholesale power prices to rise by 63% from 2004 to 2012, despite recent increases in the forward price.**

- **As the UK is already close to its Kyoto target, it will be difficult to avoid a high proportion of the allocation of free allowances going to the power sector. This will exacerbate sector windfalls, in our view.**

- **We believe Scottish and Southern Energy is a clear beneficiary from the EU ETS under all scenarios. We have raised our price target from 600p to 665p to reflect this. With 9% potential upside, our rating remains Neutral 1.**

Summary and conclusion

- The United Kingdom has reduced its total GHG emissions by around 12% between 1990 and 2001, although CO_2 reductions were lower at 6%. Its total target under the Kyoto 'burden sharing' agreement is a reduction of 12.5%.

- The power sector has reduced CO_2 emissions by around 16% since 1990 as new combined cycle gas plant has replaced coal generation. However, this has been offset by increases elsewhere in the economy.

Power sector has reduced CO_2 emissions by around 16% since 1990, offset by increases elsewhere

- After incorporating the impact of emission trading we expect the wholesale power price to rise by 63% in real terms to 2012 from current year-ahead prices. This is on top of the 15% rise we have seen in 2004 prices since May this year. This sharp increase reflects the role of coal as the main driver of wholesale prices.

After incorporating impact of emission trading, we expect wholesale power price to rise 63% in real terms to 2012

- With few regulatory levers available to OFGEM or the government, we expect the allocation of permits to be used as a way of limiting the windfall to UK generators. As a result, we expect maximum use of auctioning and minimum free allocation to the sector within the scope of the Directive.

Allocation of permits a way to limit windfall to UK generators?

- The estimated value impact on the competitors in the UK reflects the underlying impact on generation values (negative for coal, positive for all others), the value of allocations (scenario dependent), the impact on retail margins (generally negative) and the impact on upstream gas asset values (generally positive).

- All UK utilities benefit from the ETS under all scenarios (other than the highly unlikely prospect of zero free allocations), in our view. However, we believe Scottish and Southern emerges as the clearest winner, with a base case impact of more than 10% from today's share price. The positive impact on other stocks is 5% or less.

While all UK utilities benefit under ETS, we expect Scottish and Southern to emerge as a winner

- We have raised our price target on Scottish and Southern (SSE) to 665p from 600p to reflect our base case allocation scenario. With 9% potential upside, our rating remains Neutral 1. The upside on Centrica, International Power and ScottishPower is too diluted by other business to justify a price target upgrade.

Raised our price target for Scottish and Southern to 665p from 600p, our rating remains Neutral 1

Table 4: SSE – revised valuation

	Revised		Previous	
	(£m)	(p/share)	(£m)	(p/share)
Power networks	2,771	**322**	2,771	**322**
Value of retail customers	1,321	**153**	1,490	**173**
Generation asset values	2,164	**251**	1,434	**166**
Other businesses	685	**80**	685	**80**
Enterprise Valuation	6,940	**805**	6,379	**740**
Net Debt	(1,207)	**(140)**	(1,207)	**(140)**
Market Valuation	(522)	**665**	(522)	**600**

Source: UBS estimates

- It is difficult to envisage downside for the UK electricity sector from the EU ETS. With liberalised markets, the sector does not need to rely on regulators to pass extra costs to the market. It is not dependent on free allocations to prevent serious downside.

We find it hard to envisage downside for the UK electricity sector from the EU ETS

- However, political unpopularity may lead to adverse consequences in future political or regulatory decisions affecting the sector. We believe the risk of a direct windfall tax is small.

The greening of UK electricity

In May we published a report on the impact of environmental issues, including carbon trading, on the UK electricity companies (*The greening of UK electricity*, May 2003). The main conclusions of this report were:

- Carbon trading is likely to lead to a large increase in the marginal cost of fossil fired power generation, which will drive the wholesale price of power higher. UK wholesale power prices could rise by around 80% up to 2010E from the prices prevailing at the time of the report.

- Nuclear, renewable and gas plant are likely to experience increased profitability as the impact of higher prices and output will outweigh the cost of permits. Coal generators will face higher costs and a reduced market share.

- Allowances are to be allocated largely free of charge, which could enhance the upside for gas and nuclear and more than compensate for the downside on coal generation.

- UK retail prices are unregulated, so the only explicit restraint on passing wholesale price rises on to consumers will be competitive considerations.

However, we believe the implicit risk of regulatory intervention is likely to lead to some of the increased cost being absorbed in retail margins.

- The combination of these factors means that it is likely that prices to retail customers will rise by substantially more than the additional cost to the industry leading to potential windfall gains for generators.

- However, we questioned the political acceptability of windfall gains for generators at the expense of higher prices for customers – particularly at a time of environmental cost pressure.

What has changed?

Despite the relatively short time since our previous publication, we have seen a number of important changes, both at the EU level and in the UK. The EU-wide developments have been covered in an earlier section. In the UK:

UK government issued initial consultation document on implementation of EU ETS

- The UK government has issued an initial consultation document on the implementation of the EU ETS, focussing specifically on the implementation of the National Allocation Plan (NAP). Draft proposals will be published before the end of the calendar year, followed by a further period of consultation. Final proposals are due in February or March 2004, in time for the EU deadline for the submission of National Allocation Plans.

UK wholesale power prices and gas prices have risen, altering the competitive landscape

- UK wholesale power prices and gas prices have risen, altering the competitive landscape in the UK. In our view, at least some of the increase evident in calendar year 2005 and beyond is a reflection of the impact of emission trading.

The UK consultation document

The UK consultation document on the implementation of the EU ETS was published in August 2003. The document gives few clues as to the choices the UK government is likely to make, but sets out the key issues, including:

- What method (or methods) should be used to allocate the UK's overall cap of allowances to individual installations?

- How should new entrants and plant closures be treated?

- Should the UK make use of its ability to auction up to 5% of allowances?

- How should 'early action' (ie, emission reductions prior to 2005) be taken into account?

The UK government defines its aim in this process to be to 'ensure that the EU ETS is implemented on an efficient and equitable basis' (page 4).

Consultants report on allocation alternatives brings some key ideas into the public domain

Greater insight into the potential process has been given in a consultants report attached as an appendix to the document. This report goes into greater depth on the range of allocation alternatives. The report goes through the obvious key parameters (allocation metric, which years etc) and identifies some of the

consequences of the various choices. The report brings some key ideas into the public domain.

- The report highlights the likelihood of a '**windfall gain**' for power generators because they will receive higher prices for power while receiving allowances for free.

Likelihood of a 'windfall gain' for power generators

- The consultants suggest one solution to this might be to allocate allowances to energy users based on **indirect emissions** – including emissions they are indirectly responsible for through their use of electricity. This would have the effect of transferring allocations from electricity generators to end-users. However, under the EU Directive such 'indirect' allocations would only be possible to installations covered by the EU ETS.

Allowances to energy users based on indirect emissions a possibility?

- Another key issue highlighted is the extent to which the **allocation to sectors** can take account of the differences in scope for emission reduction in each sector and government policies and projections for future emission levels. It is quite possible that the power sector will have to bear the brunt of other sectors in the ETS falling short of the overall Kyoto target.

To what extent does the allocation to sectors takes account of differences in scope for emission reduction?

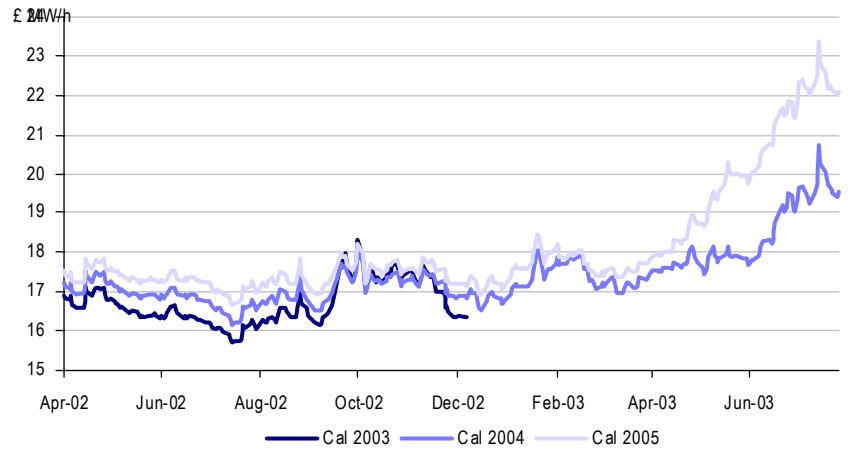
In short, we believe it is clear that the UK is considering the widest possible range of allocation options and it would be premature to assume a simple emission based allocation approach was inevitable.

We believe the UK is considering widest possible range of allocation options – premature to assume simple emission-based allocation approach inevitable?

Rising wholesale power prices

Since we published our previous research on emission trading in May, wholesale power prices for calendar year 2004 have risen by around 15% and for 2005 by around 30%, as can be seen in the chart below.

Chart 29: UK baseload wholesale power prices since April 2002

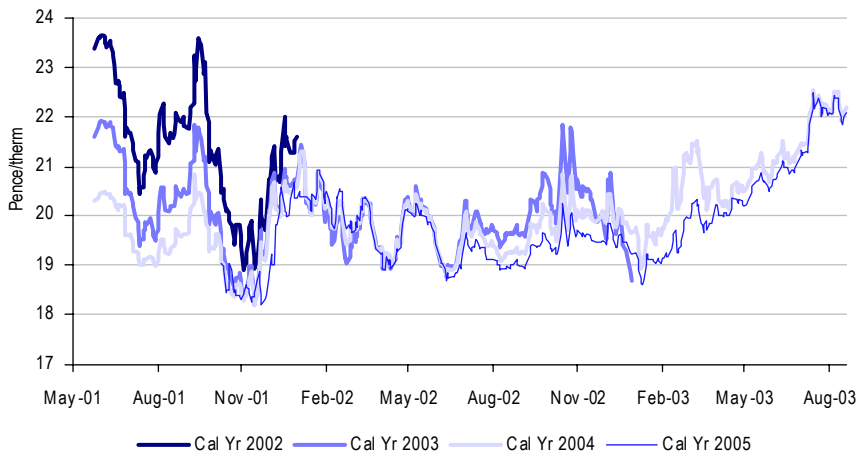


Source: Innogy

Part of the explanation for this can be found in the increase in the wholesale gas price over the same period, as can be seen in chart below. Spark spreads for 2004 will have barely changed. However, the widening spread in power prices between 2004 and 2005 is not apparent in gas prices.

Wholesale gas price have increased over the period…

Chart 30: UK wholesale gas prices



Source: UBS estimates

...as have coal prices

In addition, coal prices have increased over the last four months. Since May, winter 2003/04 prices have risen from US$37.50 per tonne to around US$44 per tonne (ARA delivered price) – which is also an increase of around 15%. The price increase for delivery in later years has been closer to 10%.

We believe the increasing spread between 2004 and 2005 power prices reflects the expected increase in wholesale power prices following the advent of emission trading. The difference between the two years is around £2.50/MWh – equivalent to an allowance value of €6.50 per tonne. We believe this is a reasonably cautious reflection of the likely impact of ETS, given the remaining uncertainties.

Revised power market projections

We have adjusted our forecasts for UK power prices, taking account of gas and coal price increases and slightly adjusted emission allowance forecasts

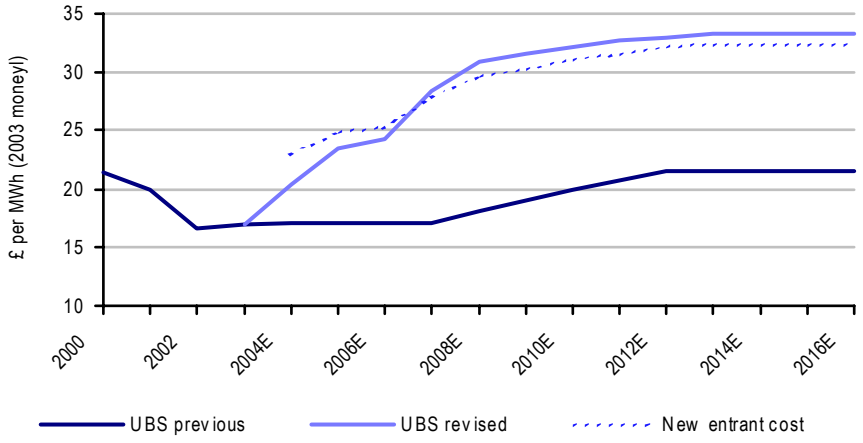
We have adjusted our forecasts for UK power prices to take account of the increase in gas and coal prices over the last year and our slightly adjusted forecast of the value of emission allowances. Our forecasts incorporating the impact of emissions trading will now be adopted as our base case UK scenario.

Annual average forward UK gas price is flat for 2004-07, with seasonal differences widening substantially

The average annual forward price for gas in the UK is flat from 2004-07E – the latest data we have for the forward price. However, the seasonal difference between summer and winter has widened substantially. Since May, we have seen little change in 'off peak' prices, which remain around 18p per therm. However, since May the winter peak price has risen from 26p to 30p per therm.

The chart below shows our revised forecasts for wholesale prices compared with our forecast of new entry costs and our previous forecasts (ex emissions trading).

Chart 31: UBS revised wholesale power price forecasts for the UK



Source: UBS

We forecast a 63% increase in prices from the current April 2004 annual forward price of £20.50/MWh, or a 90% increase from the late 2002 low – although some of this increase is the result of higher gas and coal prices over the last year.

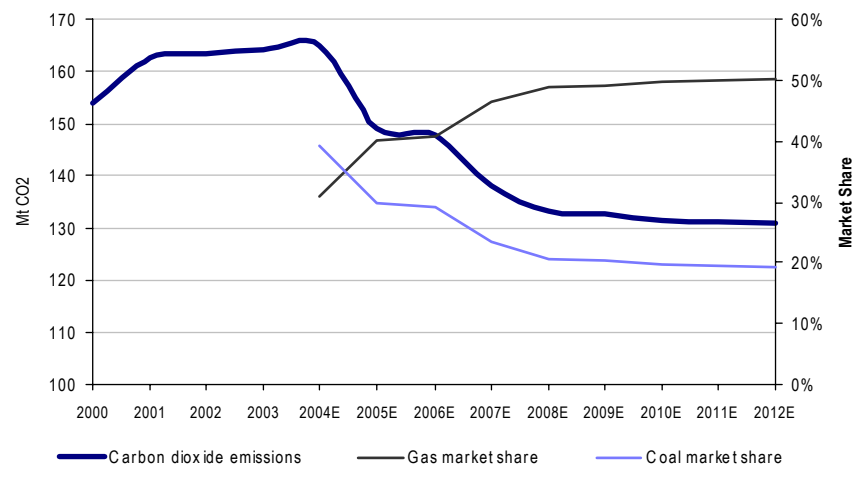
We forecast a 63% increase in prices from the current April 2004 annual forward price £20.50/MWh

Our forecast for 2005 and 2006, the first years of emissions trading, is in line with the current forward curve for power. The new entrant cost for a CCGT running at an 80% load factor is also shown. The forecast price rises above new entrant costs in 2008, suggesting that we may get new CCGT plant build beyond this date.

As the price of allowances increases, market share shifts from coal to gas. This will, in turn, lead to lower carbon dioxide emissions. The chart below shows the development of gas and coal market share and industry carbon dioxide emissions to 2012.

As price of allowances increases, market share shifts from coal to gas, with lower carbon dioxide emissions

Chart 32: Carbon dioxide trends and market shares in the UK power sector



Source: UBS

Our projections show:

- Carbon dioxide emissions from the UK power sector falling from around 165 million tonnes today to around 130 million tonnes by 2012 – entirely as a result of substitution in existing capacity.
- The market share of coal capacity falling from around 38% today to just below 20% in 2012. Coal plant load factors would fall from just under 50% to around 25%.
- The market share of gas capacity rising from 31% today to 50% by 2012E. Load factors would increase from 53% to near full utilisation at 85%.

A windfall for generators?

Profound increase in revenues for generation industry implied by price increases – especially those that increase market share

A 63% increase in wholesale power prices, on top of the 15% increase we have already seen from 2002 prices to the forward price for 2004, implies a profound increase in revenues for the generation industry as a whole – and particularly for gas generators who are also likely to experience an increased market share.

An increase in revenues

The table below shows our projected increase in revenues per kW (in 2003 money) for the three main types of generating capacity – gas, coal and nuclear. As can be seen, the increase in wholesale prices for coal capacity beyond 2004 is more than offset by the fall in market share, resulting in a fall in revenues of around 26%. For gas plant, in contrast, CCGT market share increases, so the impact on revenues is amplified. We forecast a more than doubling of revenues to 2012. Nuclear capacity also benefits in exact proportion to the increase in prices.

Table 5: Revenues per kW by plant type incorporating emission trading (£/kW)

	2002	2004	2012	Increase 2004-12	Increase (percent)
Coal	91	108	80	-28	-26%
CCGT	84	95	246	151	160%
Nuclear	120	139	226	86	62%

Source: UBS. Note: 2003 prices throughout.

An increase in EBITDA

Increasing revenues only part of the story, increasing costs will also impact EBITDA

However, increasing revenues are only part of the story. Increasing fuel costs between 2002 and 2004E will impact EBITDA, as will the cost of emission allowances (prior to any free allocations). Also, we assume an increase in gas prices resulting from higher gas demand across Europe. The table below shows the impact of higher costs on the EBITDA per kW of generating capacity. We assume all allowances have to be paid for at full market price.

Table 6: Increase in revenues, costs and EBITDA per kW, 2004 – 2012E

£/kW	Revenues	Fuel	Allowances	Other	EBITDA
Coal	-28	34	-34	5	-24
CCGT	151	-61	-53	-3	34
Nuclear	86	0	0	0	86

Source: UBS. Note: 2003 prices throughout.

Power generators still likely to have a materially beneficial impact from EU ETS, but coal will be negatively impacted while gas and nuclear benefit

The conclusion of this calculation is that – even if generators have to pay the full cost of emission allowances – the EU ETS is likely to have a materially beneficial impact on the EBITDA of power generators as a whole. However, coal stations are negatively impacted, while gas, coal and nuclear stations benefit. In the short term, power and fuel contracts will have a material impact on actual EBITDA. However, by 2012, most of these contracts will have ended.

Free allowances – the 'icing on the cake']

A substantial part of the increase in costs for generators is the cost of emission allowances. Under the EU ETS, at least 95% of allocations in the first phase (2005-07) must be allocated free of charge to installations in the ETS. Therefore it is highly likely that most allowances required for power generators will be allocated free of charge.

The table below shows the impact of free allocations based on 2002 emissions on the EBITDA of each type of generating capacity. We assume percentage allocations from zero to 100% (we consider the issue of allocations in detail in the next section).

Table 7: Impact of free allowance allocations on EBITDA/kW

	Allowance allocation as a percent of 2001 emissions				
£/kW	0%	25%	50%	75%	100%
Coal	-24	-6	11	28	45
CCGT	34	42	51	60	68
Nuclear	86	86	86	86	86

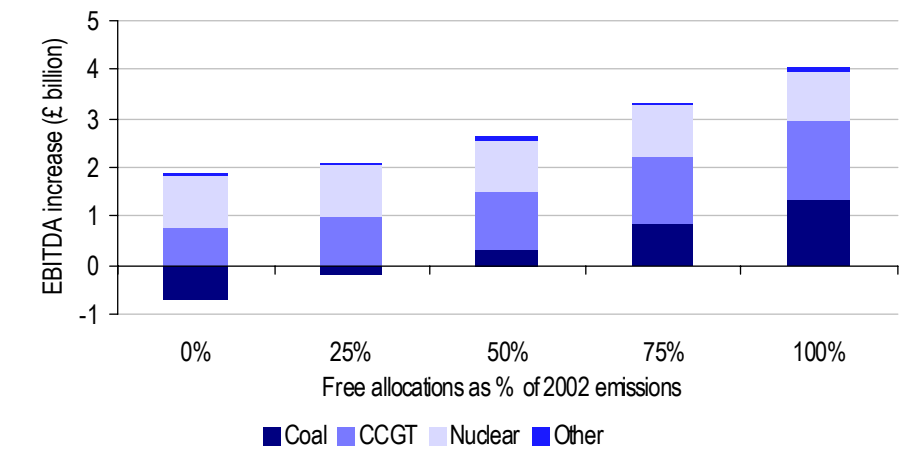
Source: UBS Note: 2003 Money

It can be seen that gas and nuclear capacity benefits regardless of the level of carbon emissions. Coal capacity, however, requires some allowances (greater than 34% of 2002 emissions) to benefit from emission trading. Otherwise, the impact of higher costs and lower market share outweighs the benefit of higher prices.

The scale of the windfall

These £/kW indicators do not give an indication of the full scale of the impact of emission trading on the sector. This is shown in the chart below.

Chart 33: The scale of the windfall to UK power generation.



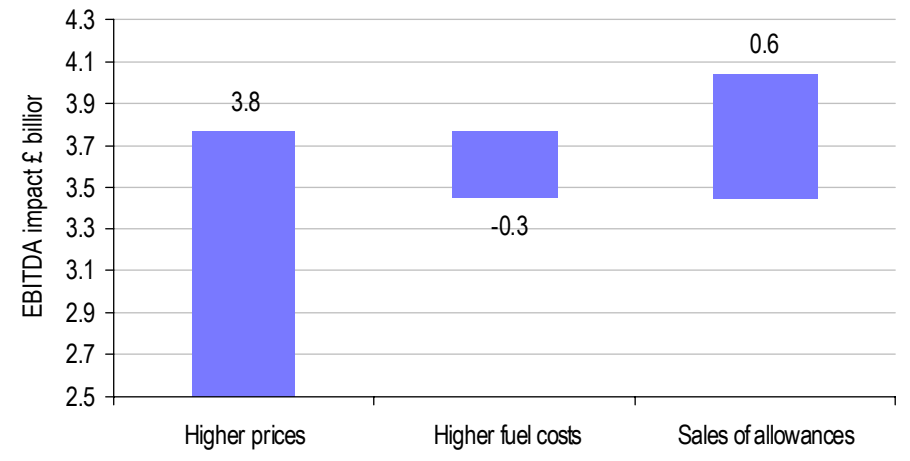
Source: UBS

If the UK generators are given allowances in respect of their full 2002 carbon emissions, we estimate the total pre-tax windfall will exceed £4 billion per annum. Even without any free allocations, we forecast an EBITDA benefit of £1.2 billion. The difference (£2.8 billion) represents the value of 165 million tonnes of free emission allocations (2002 emissions) at £17.50 (roughly €25) per tonne.

If UK generators are given full allowances, we estimate the pre-tax windfall will exceed £4 billion pa

This windfall is paid for by both increased revenues from further down the value chain (energy retailers or customers) (£3.8 billion) and the proceeds of the sale of excess allowances to other sectors or countries (£0.6 billion). This is offset by just over £300 million of additional fuel costs.

Chart 34: EBITDA impact of higher revenues, fuel costs and the sale of allowances



Source: UBS

Our view on allocations

The four main goals of UK energy policy, expressed in the White Paper ('*Our Energy Future: Creating a Low Carbon Economy*', Department of Trade and Industry, February 2002) are:

- **To reduce carbon emissions**
- **To maintain the reliability of energy supplies**
- **To promote competitive energy markets**
- **To ensure that every home is adequately and affordably heated**

Achieving these four goals simultaneously, within the context of the EU ETS, will be a major challenge.

The windfall problem – the number one allocation issue

The two biggest issues facing the UK government are closely intertwined related. They are:

(3) How to avoid windfalls in the power generation sector

(4) How to avoid substantially higher prices to customers

Allocating the windfall is more problematic in the UK, as the government has relinquished control over both wholesale and retail pricing

The UK faces a greater problem than other countries in this respect because, as a part of the process of liberalisation, it has abandoned the usual controls governments have over the pricing of electricity – either in the wholesale or retail market. Most other EU countries retain at least some control over residential retail prices.

As we have already shown, wholesale power prices in the UK are likely to rise by around 63% over the next five to seven years as the marginal cost of power rises to reflect the increasing cost of emission allowances. As retail markets are wholly liberalised, there is no regulation of end-user prices. Retailers are free to pass through higher prices to customers if the market can bear it. If the rising cost of wholesale power is passed through in full, residential prices would rise by around 23%.

A windfall profit for utilities together with higher retail prices would likely be politically unacceptable

The retail market in the UK is, by and large, vertically integrated. Therefore, there is a risk that the same companies that are making windfall profits in generation will be raising prices sharply to end customers. As these same consumers are likely to be bearing the additional cost of the renewables obligation, the energy efficiency initiative and the increased distribution costs to accommodate embedded generation, we do not believe a windfall profit for electricity utilities at the expense of higher prices to customers will be politically acceptable. But what can the UK government do about it?

Options for tackling the windfall

One possible solution to the problem is to re-impose controls over either wholesale or retail markets. Such a retreat from the UK's position as the most liberalised power market in Europe is, in our view, highly unlikely. For that reason we believe the UK government has three levers from which it can impact on the scale of windfall.

(5) The government could use the **allocation process** to skew the distributive benefits of the EU ETS away from the power sector and towards other sectors. However, the government's options are limited here because:

- At least 95% of allowances have to be allocated free of charge
- Allowances can only be granted to installations in the EU ETS – not to third parties such as large consumers outside the scheme
- Over-allocations to the non-power sectors much not breach EU state aid rules

For this reason we believe the government will find it difficult to avoid allocating a substantial share of free allowances to the power sector.

(6) The government and/or regulators could apply **subtle pressure** on retailers not to pass increased costs through to end users – particularly given the high level of retail margins in the residential and SME sector at present. The threat of action under the Competition Act or a potential Competition Commission referral may be enough to encourage restraint on behalf of retailers. We believe there are limits to how far retail margins can fall. If margins are forced to fall to uneconomic levels, this will be seen a barrier to entry for non-vertically integrated new entrants.

(7) The government could seek ways of **clawing back the windfall**, through taxation or additional obligations on companies. The UK windfall tax of 1998 sets some sort of precedent, although the government was adamant that the tax was not to be repeated.

In our view, a direct windfall tax is unlikely. It should be remembered that around £1 billion of the windfall accrues to nuclear generators (British Energy and BNFL). BNFL is state-owned and a large part of any increase in revenues for British Energy will accrue to either BNFL or the UK government, who, after restructuring, will receive most of British Energy's free cash flow to pay for nuclear liabilities adopted by the state. An indirect windfall tax already exists.

We think the government will limit the size of any windfall through the allocation process and by applying subtle pressure on retailers

We believe the government will use a combination of the allocation process and subtle pressure on retailers to limit the scale of any windfall. Therefore, our default assumption is that allocations to the UK power sector will be scaled back wherever the government can do so within the framework of the EU ETS Directive and the existing regulatory controls in the UK.

Our three UK allocation scenarios

There are three dimensions to the allocation of allowances in the UK:

(8) The overall level of allowances allocated to the ETS sectors

(9) The allocation of allowances to the sectors within the ETS

(10) The allocation of allowances to installations within the electricity sector

We have proposed three allocation scenarios,

- **Blue sky:** Based on full allocation to the power sector and allocations based on historical emissions (we use 2002 as the basis for allocations).

- **Base case:** We assume full auctioning of permits; the power sector takes the 'balance' of allowances after full allocations to other sectors and a 3% set-aside for new entrants.

- **Black sky:** As above, except industrial allocations are made on the basis of 'indirect emissions', including the implied share of allowances from electricity consumption. This further reduces electricity sector allocations.

We believe there may be scope for the UK government to be tougher than our 'black sky' case. For example, the UK could sell a proportion of its allowances to another country under the Kyoto Protocol – effectively increasing the UK Kyoto target beyond the current 12.5% reduction. The extent to which this is allowed by the EU still needs to be clarified – it is a key factor impacting the extent to which the Eastern European new entrants to the EU can get excess allowances into the EU ETS.

UK government could allocate allowances based on its tougher 'national goal' rather than the Kyoto target

Also, the UK has its own 'national goal' of reducing carbon dioxide emissions (rather than all GHGs) by 20% from 1990 levels by 2010. As carbon dioxide is currently less than 6% below 1990 levels (compared to over 12% for all GHGs), this is a materially tougher target than the Kyoto protocol. It is possible that the UK government will allocate allowances based on this tougher target rather than the more easily achievable Kyoto target. The difference could either sold to another country or simply not allocated.

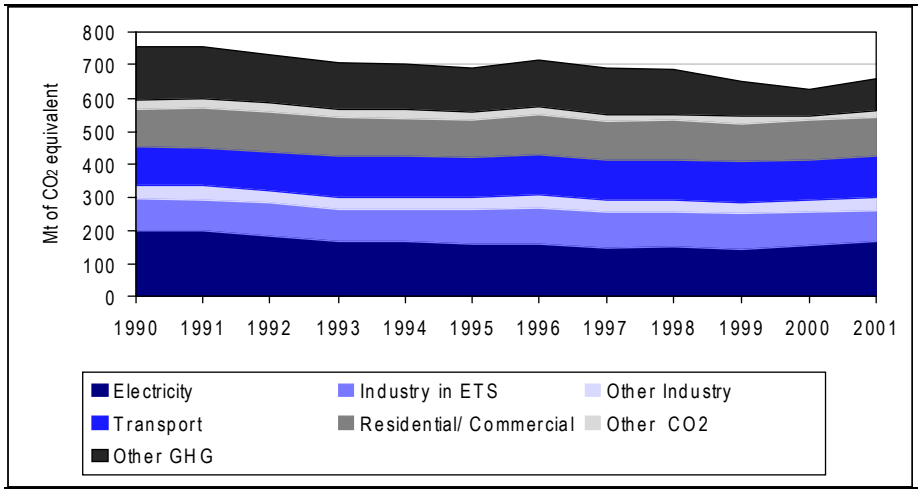
In our later analysis we consider a 'disaster' scenario in which the UK power sector receives no free allocations at all.

Allocation background

Total greenhouse gas emissions have fallen 12% from 1990 to 2001…

The trend in GHG emissions since 1990 provides the backdrop to considering UK allocations of emission allowances. As the EU ETS covers 45% of all CO_2 emissions and just 39% of all GHG emissions, another important consideration is the likely trend in emissions in sectors outside the ETS over the period to 2012. The chart below shows GHG emissions for each year from 1990 to 2001 in the UK, based on data provided by the UK government to the EU.

Chart 35: GHG emissions in the UK by sector (1990-2001)



Source: European Commission

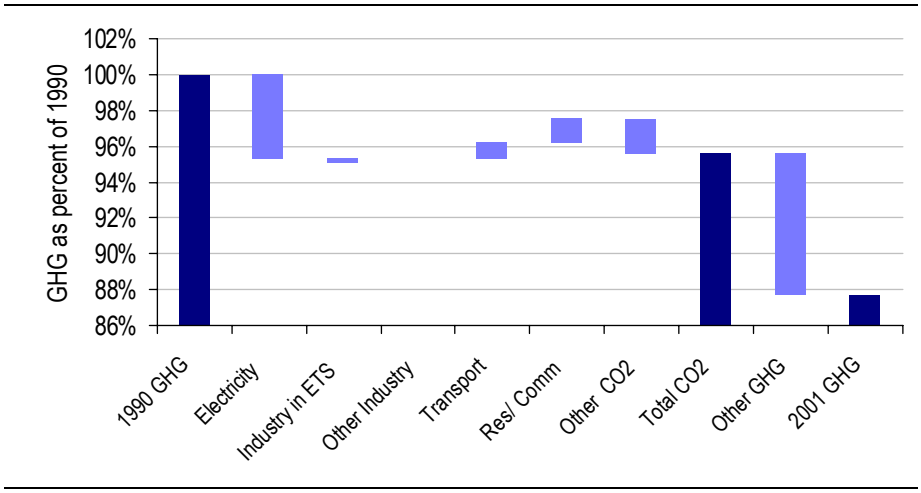
Total GHG emissions over this period have fallen 12.3%, from 753 to 661 million tonnes. However, much of this is due to a one-third reduction in other GHGs (mainly methane and nitrous oxides) over the period. Carbon dioxide emissions alone have fallen by just 5.6%.

...but much of this is due to GHGs other than CO_2

Most of the reduction in CO_2 has arisen because of the 18% reduction in emission from the power generation sector. Emissions in the rest of industry are almost unchanged. However, rising trends in the transport sector (mainly road transport) and the residential and commercial sectors (mainly space heating) have offset this. Emissions in these sectors have increase by around 1% per annum since 1990. The chart below shows the contributors to the trend in GHG gas emissions in the UK over the period 1990-2001.

Lower CO_2 emissions from generators has been offset by transport, residential and commercial sectors

Chart 36: Contributors to the UK's reduction in GHG (1990-2001)



Source: UBS, EC

Blue sky and base case allocations

Our blue sky allocations assume that the UK electricity sector receives allocations in line with actual 2001 emissions. This (optimistically, in our view)

assumes that trends in emissions outside of the power sector are consistent with the UK hitting its Kyoto target

Our base case assumes that the power sector is used as the balancing sector, reflecting the relative ease of reducing emission and the absence of competition with production from outside the EU. In determining the level of allocations available to the ETS sectors in general and the electricity sector in particular we assume:

- Transport and residential energy use continue to increase at the same rate as in the last decade;
- Other non-ETS sectors, including other GHGs, remain unchanged from 2001 levels;
- The industrial sectors in the ETS receive full allocations at 2001 levels, with electricity receiving the balance;
- The UK government auctions the maximum of 5% of allocations in the first period (2005-07) and 10% in the second period (2008-12). A further 2% of allowances are allocated to new entrants.

The table below shows our projections on this allocation basis. In can be seen that allocations to the UK power sector in 2005 start at 14% below 2001 levels but fall by a further 14% or c21 million tonnes by 2012 to accommodate growth in emissions elsewhere and increased auctioning. By 2012, allocations under this scenario to the power sector would be 72% of 2002 levels.

Table 8: Projected allocations to consistent with meeting Kyoto obligations – base case

Mt CO_2eq	2001	2002E	2003E	2004E	2005E	2006E	2007E	2008E	2009E	2010E	2011E	2012E
Electricity	162.6	163.4	164.2	165.0	139.2	138.1	137.0	122.2	121.2	120.1	119.0	117.9
Other ETS	97.6	97.6	97.6	97.6	97.6	97.6	97.6	97.6	97.6	97.6	97.6	97.6
Set aside	0.0	0.0	0.0	0.0	17.8	17.7	17.7	30.0	29.8	29.7	29.5	29.4
Non ETS	400.2	401.8	402.9	404.1	405.3	406.5	407.7	409.0	410.2	411.4	412.6	413.9
	660.5	**662.8**	**664.8**	**666.8**	**660.0**	**660.0**	**660.0**	**658.8**	**658.8**	**658.8**	**658.8**	**658.8**

Source: UBS. Note: Data before 2005 reflects actual or projected emissions rather than allocations.

Black sky allocations

Our 'black sky' scenario assumes that allowances for 'indirect emissions' are allocated to industrial consumers in the ETS rather than to the electricity sector. The electricity generators would have to purchase these allocations back from the industrial sectors in order to generate.

According to the consultant's report published with the UK consultation paper on allocations, the use of 'indirect' emissions would reduce the emissions base for the electricity sector by 22%. We think this is an overestimate, because it includes redistribution to some sectors outside the initial ETS, such as chemicals and food. We assume, therefore, a more cautious 20% redistribution.

The projected allocations under this scenario are shown below. We calculate a shift of around 33 million tonnes in 2005-07 and around 30 million tonnes in 2008-12 (because of lower carbon intensity in the power sector). The resulting allocation to the power sector falls from 65% in 2005E to 55% in 2012E.

Table 9: Projected allocations to consistent with meeting Kyoto obligations – black sky

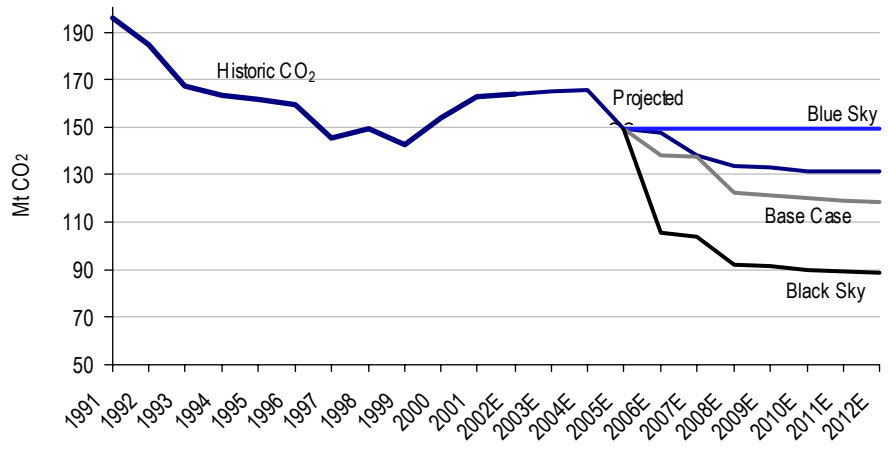
Mt CO_2eq	2001	2002E	2003E	2004E	2005E	2006E	2007E	2008E	2009E	2010E	2011E	2012E
Electricity	162.6	163.4	164.2	165.0	106.2	105.1	104.0	92.4	91.3	90.3	89.2	88.1
Other ETS	97.6	97.6	97.6	97.6	130.7	130.7	130.7	127.5	127.5	127.5	127.5	127.5
Set aside	0.0	0.0	0.0	0.0	17.8	17.7	17.7	30.0	29.8	29.7	29.5	29.4
Non ETS	400.2	401.8	402.9	404.1	405.3	406.5	407.7	409.0	410.2	411.4	412.6	413.9
	660.5	**662.8**	**664.8**	**666.8**	**660.0**	**660.0**	**660.0**	**658.8**	**658.8**	**658.8**	**658.8**	**658.8**

Source: UBS. Note: Data before 2005 reflects actual or projected emissions rather than allocations.

Surpluses and shortfalls

The chart below shows our projected CO_2 emissions from the UK power sector (which should be independent of allocations) set against projected allocations under each of our scenarios. It can be seen that there is only a surplus of permits under the blue sky scenario. Under the base case and black sky scenarios, permits would have to be bought – either from the government through auctions or from other sectors and countries. As we have already suggested, under the black sky scenario, we would expect the power sector to purchase the 'indirect' allocations from industrial users.

Chart 37: UK power sector: CO_2 emissions and projected allocation scenarios



Source: UBS

Power station values

The large changes in EBITDA indicated in the analysis of the 'windfall' above are likely to have a material impact on the values of power stations in the UK.

Large changes in EBITDA will have a material impact on values…

We believe it most useful to consider the value of installations as comprising two elements:

- The value of the underlying plant; and
- The value of the associated allowance allocations. The underlying value should be independent of the allocations scenario.

Our simple valuation model is based on a DCF valuation. Our terminal value projections assume prices and costs remain the constant in real terms to the end of the station life.

Combined-cycle gas turbine (CCGT) plant

CCGTs benefit from higher prices and higher load factors, offset by the extra cost of permits and higher gas prices.

CCGTs remain the preferred new-entry plant after the EU ETS is introduced. As prices converge on the new entry price by 2008, we would expect the value of a new plant to converge to the capital cost of a new station by that stage. Older plant will be depreciated, reflecting shorter remaining asset lives and lower thermal efficiency.

...though on CCGT values the impact is less than one might expect...

The impact on CCGT values is less than might be expected. We would expect power prices to converge on the new entry price in any case – just not as soon. Our previous base case assumed new entry prices were realised in 2012.

The table below shows our DCF valuation of a CCGT as a function of the remaining plant life and the discount rate (real, post tax). The oldest capacity in the UK is around 12-13 years old and has 13-14 years of remaining life. Using a discount rate of 6%, this implies a valuation of between £175-300/kW for existing CCGT.

Table 10: CCGT plant value (£/kW)

		Remaining plant life (years)				
		5	10	15	20	25
Real discount rate	4.5%	76	177	258	323	375
	5.0%	74	172	248	308	355
	5.5%	73	167	239	293	335
	6.0%	72	162	230	280	318
	6.5%	71	158	221	267	301
	7.0%	69	153	213	256	286
	7.5%	68	149	205	244	272

Source: UBS

...at around £75-90/kW

A similar analysis based on our previous gas and power price scenarios implies a valuation of £100-210/kW – implying an enhancement in underlying value resulting from emission trading and recent price increases of around £75-90/kW.

However, our current standard valuation used in our sum-of-the-parts valuations is £200-250/kW, depending on the age of the plant. This seems a little generous in the light of this fresh analysis. As a result, excluding the benefit from free allowance allocations, the increase to our valuations will not be great.

Coal-fired capacity

Despite higher electricity prices, coal capacity loses out from both loss of market share and the cost of allowances. Coal will be the marginal plant on the system at peak times. As a result, before the value of allocations we would expect the least profitable coal station to be just cash flow breakeven. The price of power will adjust to ensure that the contribution to fixed cash costs is sufficient to remunerate such marginal plant.

We believe this state of affairs is unlikely to improve until all coal stations are closed – which would, after all, be a successful outcome for carbon emissions trading. A premium for shortage of capacity – allowing a premium return for the marginal capacity – may arise before new CCGT capacity is built. However, we believe that this would be a short-lived benefit and that it is more likely that new CCGTs will be built to lower CO_2 emissions before there is a strict need for new capacity to meet demand.

Underlying value of coal plant is close to zero

For these reasons we believe the underlying value of coal plant to be close to zero. Cash flows are likely to be sufficiently positive to incentivise the plant to remain on the system. We propose a valuation of £25/kW to reflect this residual value. Our analysis shows the most efficient and longest-lived capacity, such as Drax, may have an underlying value as high as £50/kW.

Our previous research has typically used a valuation of £100-125/kW for coal plant without flue gas desulphurisation (FGD), suggesting a reduction in underlying value of £75-100/kW. This is broadly consistent with a DCF valuation using the same methodology.

Nuclear and renewable capacity

Values of nuclear and renewable rise dramatically

Nuclear and renewable capacity benefit from higher prices without losing out from an accompanying increase in costs. As a result the value of both types of capacity has risen dramatically.

- Our DCF valuation of a nuclear plant with 20 years of remaining life has risen from £140 to £680/kW.
- The implied value of a new nuclear station with 40 years remaining life is £945/kW – still not high enough to justify new build.
- Our DCF valuation of new wind capacity with an assumed 25 years asset life has risen from £278 to £563/kW prior to the value of renewable obligation certificates (ROCs). This compares with a construction cost of around £800/kW.
- If the value of ROCs is included, the value of wind capacity rises to £1,445/kW under our revised view of power prices. Previously this valuation was £1,159/kW.
- We believe this valuation of wind capacity is overoptimistic because it is possible that there will be some adjustment in the ROC system in the longer

term to reflect the benefit of carbon trading to renewables. To do otherwise would imply a double subsidy.

The value of allowance allocations

Our input assumptions for the valuation of allowance allocations are:

- The overall free allocation to the power sector is as described above in our three allocation scenarios (blue sky, base case, black sky).
- There are no free allocations after 2012.
- Allocations are made to each type of plant as a fixed percentage of 2002 CO_2 emissions.

Allocations to coal plants will depend on historical load factors – which depend on whether FGD is fitted

The table below shows the results of our analysis, assuming a discount rate of 6% real post tax. The allocations for a coal plant will depend strongly on its historical load factor. One of the main determinants is whether or not the plant has FGD fitted. Without FGD, the cap on its sulphur dioxide emissions limits a coal station's output. We assume FGD plant has a historical load factor of 65% and non-FGD plant 40%.

Table 11: NPV of emission allowances by plant type and scenario (£/kW)

Scenario	CCGT	Coal (FGD)	Coal (other)
Blue sky	95	257	196
Base case	73	197	150
Black sky	55	149	113

Source: UBS

Plant value summary

The table below summarises our plant value analysis. We also show our proposed revised valuation benchmarks for generation capacity in the UK based on our analysis. This incorporates the underlying value of the capacity plus the value of allowance allocations under our base case.

Table 12: Summary of power plant valuation analysis (£/kW)

		Value of allowances (£/kW)			Valuation benchmarks (£/kW)	
Scenario	Underlying value	Blue sky	Base case	Black sky	Revised	Previous
CCGT	230	95	73	55	**300**	200
Coal (FGD)	50	257	197	149	**250**	200
Coal (other)	10	55	149	113	**160**	125
Nuclear	682	0	0	0	**N/A**	N/A
Wind	1445	0	0	0	**1,000**	800

Source: UBS

Our benchmark valuations are merely a guide for use in our sum-of-the-parts analysis. We have incorporated these benchmarks into our revised valuations, having made some specific adjustments for age of plant. Our revised valuations are discussed below.

Retail market impact

Prices are bound to be affected by political and regulatory considerations...

Retail electricity prices in the UK are not directly price regulated. However, given the immaturity of the competitive market, the still dominant position of regional incumbents and the recently increased consolidation, it would be wrong, in our view, to presume that retail prices will be unaffected by political or regulatory considerations.

We believe it appropriate to divide the retail energy market into two distinct sectors:

- **Large industrial and commercial consumers.** These customers are highly price-sensitive and typically renegotiate prices for electricity supply annually. Margins for these customers are already very low and prices tend to follow wholesale prices closely, with minimal lag.

- **Residential and SME customers.** These are smaller, less price-sensitive customers who switch supplier rarely, if ever. Loyalty to incumbent brands is high. Prices to these customers have fallen little in recent years.

...and high retail margins are likely to come under pressure

We believe that retail margins in electricity will contract under pressure from rising wholesale prices. In our view, margins are above long-run sustainable levels and rising wholesale prices will accelerate the process of return to equilibrium.

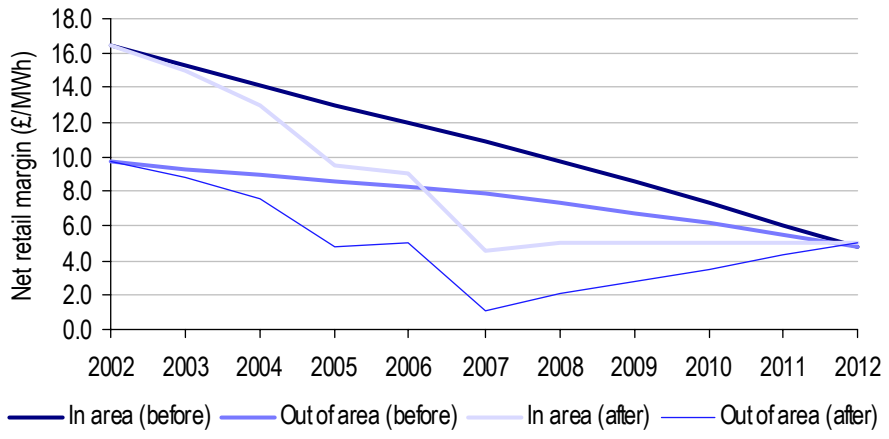
This process will, in our view, be reinforced by the political and regulatory scrutiny that the retail market is under. Companies passing wholesale price increases through to customers without any reduction in margins will risk action under the Competition Act, referral to the Competition Commission or, at the least, opprobrium from industry watchdogs and politicians.

Revised assumptions

Currently we assume a gradual decline in retail margins to equilibrium levels over an extended period to 2012 (by which time we assume wholesale prices will have risen to new entrant costs). Under our revised assumptions we assume retailers absorb price increases until gross margins return to the equilibrium absolute level – our view of a stable gross margin. Based on last year's base-load wholesale price of around £17/MWH, we believe retail margins were around 40%. We expect this to fall to around 20% based on today's retail price.

The chart below shows the retail net margin (after operating costs) both before and after the impact of emissions trading on the wholesale power price. As can be seen, net retail margins converge on the same absolute level of £5/MWh.

Chart 38: Net retail electricity margins in the UK (£/MWh)



Source: UBS estimates

The key features are:

- Before emissions trading, the retail margin falls steadily due to lower real prices and, later, higher costs, eventually converging on the equilibrium retail margin by 2012

- After emissions trading, the retail margin falls more quickly in the early years, but stabilises later to reach the same equilibrium end-point in 2012E. Our basic thesis is that in the long run retail margins are independent of wholesale prices.

We have valued this stream of net margins by discounting their post-tax value and assuming a stable real value after 2012. The table below shows the impact on the valuation per customer.

Table 13: Impact of emission trading on retail customer values (£/customer)

	Revised valuation	Previous valuation	Change
In area	247	290	-43
Out-of-area	195	244	-49
Average	231	276	-45

Source: UBS estimates

We predict c£45 fall in average customer value to £231 after emission trading begins

Our projected impact is a reduction in average customer value of around £45, from £276 before emission trading to £231 after. Our calculations show the impact on out-of-area customers to be slightly greater than in-area. However, the difference is arbitrary. In fact, it could be argued that rising prices would lead to a more rapid decay of the incumbent price premium.

In calculating the impact on companies we assume a standard reduction in electricity customer values of £45 per account. In our sum-of-the-parts valuations we use a range of average customer values between £200 (Centrica) and £300 (Scottish and Southern) at present, reflecting the differences in the

proportion of in-area to out-of-area and differences in cost-to-serve. We assume these differences are unaffected by emission trading.

Other valuation impacts

Emission trading will have an impact on other aspect of utility valuations, in particular:

- Emission trading will lead to an increase in gas demand across Europe. There will therefore be an increase in the value of upstream gas assets as a result of higher gas prices. The major gas assets owned by UK utilities are the upstream gas fields owned by Centrica and the gas storage assets owned by Centrica, Scottish and Southern, and ScottishPower.

- Emission trading will also impact on the economics of gas retailing. However, we expect the increase in gas prices to be steady and manageable within the bounds of politically acceptable price increases. Unlike electricity, retail gross margins in gas are still below our view of the long-run sustainable level. Therefore we assume no impact on gas customer valuations.

- Finally, emission trading will boost the value of renewable energy ventures under the UK's renewable obligation. As the 'buy-out' for the obligation is fixed at £30/MWh (2002/03 money) and there is no mechanism for remunerating excess renewable capacity, the profitability of renewable schemes built by the retailers will increase. However, we believe there is a possibility of the ROC scheme being adjusted in future years to reflect the more favourable economics.

Upstream gas valuation impacts

We have calculated the impact of 15% higher gas prices in 2012 on the value of UK gas assets:

- The value of Centrica's Morecambe Bay increases by just £55 million, or 5%. This reflects the front-end weighted production profile. We assume the impact on gas prices in the early years is modest. The impact on the other gas fields is around £35 million – or around 10% of our current valuation.

- We assume the impact on gas storage asset value is pro rata to the increase in the spread between summer and winter gas prices. As most of the increase in UK gas demand will be in the winter, we believe most of the price impact will also be then. Therefore we forecast that a 15% increase in power prices will drive an increase in the summer/winter price spread of around one-third (from about 8p today to 12p in the future).

- Therefore the value of Centrica's Rough gas asset will increase by around £100 million, Scottish and Southern's storage asset by £40 million and ScottishPower's by £15 million.

Company-by-company impact

We have calculated the net impact of emission trading on the four impacted UK quoted companies (Centrica, International Power, ScottishPower, and Scottish and Southern) as well as the UK subsidiaries of RWE (Innogy) and E.ON (Powergen).

The factors we consider are:

- The underlying impact on generation assets (excluding allowances)
- The value of allowances under each scenario
- The impact on electricity retail customer valuations
- The impact of higher gas prices on upstream assets

The impact on underlying generation asset values

The table below shows our assessment of the impact of emission trading on generation asset values for each company.

We have based the calculation on the change from our previous benchmark valuations rather than the absolute impact using the same methodology. This particularly impacts CCGT capacity, where our new methodology suggests our benchmark of £200/kW was too high by around £50/kW.

We calculate changes from our previous benchmark valuations

Table 14: Impact of emission trading on underlying generation asset values (£m)

	Coal	Coal FGD	Gas	Hydro	Wind	Total impact	Impact per share
Change in value (£/kW)	**-115**	**-159**	**30**	**250**	**200**	**£m**	**(local currency)**
Centrica	0	0	75	0	0	**75**	2
Innogy	-508	0	75	13	29	**-392**	-1.0
International Power	-115	0	15	0	0	**-100**	-8
Powergen	-339	-323	65	13	21	**-563**	-1.2
ScottishPower	-397	0	29	31	26	**-312**	-17
Scottish and Southern	0	0	139	271	0	**409**	47

Source: UBS Note: Powergen and Innogy per share impact is in € per share of E.ON and RWE respectively

It can be seen that:

- Scottish and Southern, and Centrica, both show a positive impact because they have no exposure to coal capacity.
- Scottish and Southern has the largest impact per share because it has the lowest carbon mix of generation, and UK generation is a larger proportion of its business.
- For all other capacity the negative impact on coal valuations outweighs the positive impact from gas – although the net impact on the share prices is not large.

The value of emission allowances

The chart below shows the impact on generation values incorporating the value of allowance allocations under our three scenarios.

Table 15: Impact of emission trading on generation values (incorporating allowances)

	£ million				p per share			
	Underlying	Blue	Base	Black	Underlying	Blue	Base	Black
Centrica	75	313	**257**	212	2	7	**6**	5
Innogy	-392	507	**452**	245	-1.0	1.3	**1.2**	0.6
International Power	-100	98	**87**	41	-8	8	**7**	3
Powergen	-563	610	**439**	192	-1.2	1.3	**0.9**	0.4
ScottishPower	-312	298	**277**	132	-17	16	**15**	7
Scottish and Southern	409	850	**746**	664	47	99	**87**	77

Source: UBS Note: Powergen and Innogy per share impact is in € per share of E.ON and RWE respectively

It can be seen that the impact on generation assets values is positive under all scenarios and for all companies. Once again, the largest per share impact is on Scottish and Southern.

Powergen has the greatest sensitivity to allocations

Powergen's exposure to coal (particularly Ratcliffe) means that it has the greatest sensitivity to allocations. Under the base case its allowances are worth, on our estimates, almost exactly £1 billion.

Overall impact

The chart below shows the overall impact on valuations for the base case, incorporating the impact on retail valuations and upstream gas assets.

Table 16: Overall impact of emission trading on valuations (base case) – £ million

	Underlying generation	Value of allocations	Retail customer values	Upstream gas valuations	Total impact (£ million)	Per share (local currency
Centrica	75	182	-270	190	**177**	**4**
Innogy	-392	844	-189	0	**263**	**0.7**
International Power	-100	187	0	0	**87**	**7**
Powergen	-563	1,002	-243	0	**196**	**0.4**
ScottishPower	-312	589	-171	15	**121**	**7**
Scottish and Southern	409	337	-225	40	**561**	**65**

Source: UBS Note: Powergen and Innogy per share impact is in € per share of E.ON and RWE respectively

The only material valuation impact is on Scottish and Southern Energy…

It can be seen that, out of the UK companies, the only material impact is on Scottish and Southern Energy, where we estimate a net positive impact on valuation of 65p per share, or almost 11% of the current share price. The next most important impact is on International Power, where the increase in value represents around 5% of the current share price. Centrica and ScottishPower both show minimal increases in value (around 2%).

However, the base case is just one scenario, and the allocation of free allowances remains a major uncertainty. The table below shows the impact on

valuations under our three scenarios, as well as the underlying impact excluding any free allocations.

Table 17: Impact of emission trading on company valuations (by scenario)

	Total impact (£ million)				Per share impact (local currency of parent)			
Allocation scenario	**Zero**	**Blue**	**Base**	**Black**	**Zero**	**Blue**	**Base**	**Black**
Centrica	-5	233	177	132	0	6	4	3
Innogy	-581	318	263	56	-1.5	0.8	0.7	0.1
International Power	-100	98	87	41	-8	8	7	3
Powergen	-806	367	196	-51	-1.7	0.8	0.4	-0.1
ScottishPower	-468	142	121	-24	-26	8	7	-1
Scottish and Southern	224	665	561	479	26	77	65	56

Source: UBS. Note: Powergen and Innogy per share impact is in € per share of E.ON and RWE respectively

Investment consequences for UK stocks

Scottish and Southern Energy price target raised to 665p

Of the UK quoted companies, only Scottish and Southern Energy shows any substantial increase as a result of the EU emission trading scheme. We estimate a base case increase in valuation of 65p per share, worth around 11% of our price target.

Moreover, the company is unique in Europe in showing upside under all scenarios – even the unlikely 'disaster' scenario of zero free allocations. The range of upsides is from 26p per share to 77p under the 'blue sky' case.

...for which we increase our price target accordingly

Therefore we are proposing an increase in the price target for Scottish and Southern Energy from 600p to 665p to reflect this analysis. The increase in generation asset and gas storage values of £746 million is offset by a reduction in the retail business value of £225 million.

The revised sum-of-the-parts valuation is shown below.

Table 18: SSE – revised valuation

	Revised		Previous	
	(£m)	(p/share)	(£m)	(p/share)
Power networks	2,771	322	2,771	
Value of retail customers	1,321	153	1,490	
Generation asset values	2,164	251	1,434	
Other businesses	685	80	685	
Net Debt	(1,207)	(140)	(1,207)	

Source: UBS estimates

Impact on other UK stocks is minimal

We are not altering our price targets for other UK stocks

The net impact on the other three UK quoted stocks(Centrica, ScottishPower and International Power) is too small to be considered significant within the context of overall uncertainties in our valuations. Therefore we are not altering our price targets for them. We will aim to include the consequences of emission trading on these stocks at our next routine update.

However, it is worth noting that the impact on all companies is positive under all of our main scenarios, and so we do not see emission trading as a material risk for any company. Only under the extreme case of zero free allocations would we see downsides for ScottishPower and International Power

Innogy and Powergen incorporated in RWE and E.ON analysis

The outcome of our analysis for Innogy and Powergen is incorporated in our valuation assessment of RWE and E.ON respectively. Broadly, these subsidiaries follow the pattern of other UK companies with neutral to positive outcomes under all but the 'zero allocations' case.

Powergen is the most sensitive to an allocation policy

Powergen is the most sensitive to the allocation policy of the UK government because of its high proportion of coal plant and the (relatively) high load factor of its FGD fitted coal station, Ratcliffe.

Spain

ETS in Spain

Summary and conclusions

- The Kyoto Protocol in general, and the implementation of the Emission Trading Scheme (ETS) in particular, should in our view have major implications for the Spanish electricity sector, and should be the most important change to the sector since liberalisation in 1998.

- Spain has tough targets to meet, and the electricity sector may be asked to carry more than its fair share of such targets as it has greater technological potential to reduce emissions than other sectors (eg transport). It also has the ability to purchase additional allowances under the ETS scheme.

- The cost of allowances should ultimately be reflected in the wholesale generation price, which in our view should increase by more than 20%. This should benefit generation technologies that do not produce emissions (nuclear and hydro). Our base case scenario contemplates an increase in nuclear and hydro valuations of 40% and 11% respectively.

- However, we think coal and fuel oil generation should suffer as plants become more expensive to operate and lose competitiveness against new gas-fired plants. We estimate coal and fuel oil generation to decline by c65% and c70% respectively by 2012 from 2001 levels. We estimate a potential reduction in our valuations of coal and fuel oil plants in the region of 50% and 80% respectively. We also expect that the government will partially compensate for this value destruction via the allocation of free emission allowances. We assume a 65% compensation rate in our base case scenario.

- The ultimate impact of ETS should depend on the details of implementation, though our base case indicates a positive impact for Spain overall, partly because there is a transfer of value from costs of transition to competition (CTCs) to increased prices, and we conservatively do not include future CTCs in our stock valuations.

- Iberdrola stands in our view as a winner vis-à-vis its peers due to its relatively low exposure to thermal generation and its high exposure to hydro and nuclear generation. We therefore upgrade our price target to €18.0 from €16.6 and our rating to Buy 1 from Neutral 1.

Table 19: Impact of ETS on valuations of Spanish electricity companies

	Endesa			Iberdrola			Fenosa		
	€m	€/share	% of PT	€m	€/share	% of PT	€m	€/share	% of PT
Blue Sky	3,652	3.4	24.1%	4,002	4.4	26.7%	638	2.1	16.6%
Central	**920**	**0.9**	**6.1%**	**1,684**	**1.9**	**11.3%**	**144**	**0.5**	**3.8%**
Black Sky	(680)	(0.6)	-4.5%	1,261	1.4	8.4%	(243)	(0.8)	-6.3%
Disaster	(2,461)	(2.3)	-16.3%	(651)	(0.7)	-4.4%	(595)	(2.0)	-15.5%

Source: UBS estimates

Emission targets

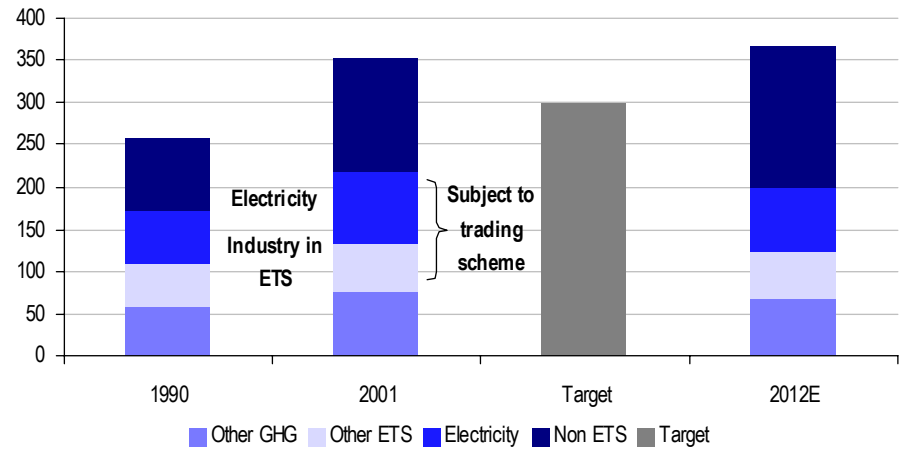
Country targets

Target for emission cuts may place high demands on electricity sector...

Under the Kyoto Protocol, Spain pledged to limit total emissions to 15% above the 1990 level (from 258 million tonnes in 1990 to 297 million tonnes pa in 2008-12). In the meantime, total emissions (including other greenhouse gases (GHGs)) have increased by 37% to 354 million tonnes, and so now need to be reduced by 16%. The problem is that the Emissions Trading Scheme (ETS) aims to accomplish this by controlling CO_2 emissions of facilities subject to the trading scheme, which account for only 40% of total emissions. This will be extended when other GHGs are included in the trading scheme, but even then it will cover only 60% of total emissions. So the reduction required from the electricity sector (or at least the allocations of allowances granted to them) may very well be more demanding.

The following chart illustrates this. Note that 2012E figures assume that electricity, industry in ETS, and other GHGs meet their target of no more than a 15% increase on 1990, but that non-ETS sectors continue to grow emissions at half of the CAGR over 1990-2001.

Chart 39: Total GHG emissions in Spain (million tonnes)



Source: Spanish Ministry of environment, UBS estimates.

The key problem in Spain is that, even if CO_2 emissions under the ETS and other GHGs can meet their target, non ETS CO_2 emissions are likely to overshoot significantly, producing some 70 million tonnes more of emissions than its 'fair share'. These include transport (c66%), industry (c25%), residential and commercial, net of the positive impact from land absorption.

...but Kyoto Protocol offers alternatives to strictly meeting targets

Unless there is a significant focus on reducing emissions from these areas, Spain is likely to miss its Kyoto targets (even if the electricity sector comes under pressure to meet the targets). However, under the Kyoto Protocol the targets do not have to be met literally. Each country can take alternative measures to actual emission reductions, such as buying additional allowances under the EU ETS (or, in future, in other approved ETS programmes) or via the Clean Development Mechanism, developing emission-reducing projects in other countries.

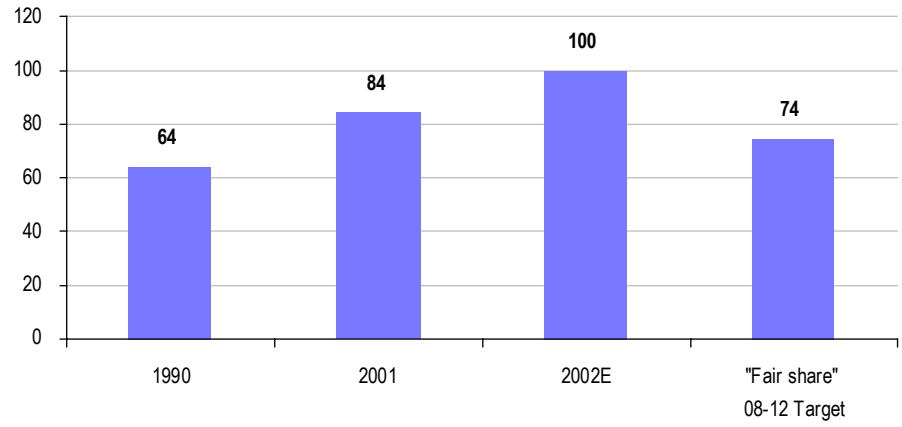
So the Spanish government may reduce the allowances it gives to facilities under the ETS so that a significant share of Spain's emissions can be offset by allowances purchased from other countries.

Electricity sector target

If non-ETS sectors overshoot their emission targets, electricity sector will not get its 'fair share' of the 15% increase allowed it…

Spain's electricity sector produced some 64 million tonnes of CO_2 emissions. in 1990 By 2001 this had increased by 30% to 84 million tonnes, and by 2002 by an additional 15% to 100 million tonnes (partly due to very dry weather). Spain pledged to increase emissions between 1990 and the 2008-12 period by only 15%. Assuming that the electricity sector takes its 'fair share' of this 15% increase, its emissions will need to be reduced by 26% from their 2002 level by 2008-12. As we explain later, this target is achievable in our view. However, we also believe that the non-ETS sectors could increase their emissions by some 70 million tonnes, and in our view these will need to be offset by smaller allowances to the electricity sector and external purchases of allowances. Under our base case scenario we estimate that the electricity sector may get only some 23 million tonnes of allowances rather than its 74 million tonnes 'fair share' (see page 77 section on our 'Abraham' scenario), and hence contributing by an extra 50 million tonnes (the quantity of allowances purchased) to meeting Kyoto targets.

Chart 40: Spanish CO_2 emissions and Kyoto target (million tonnes)

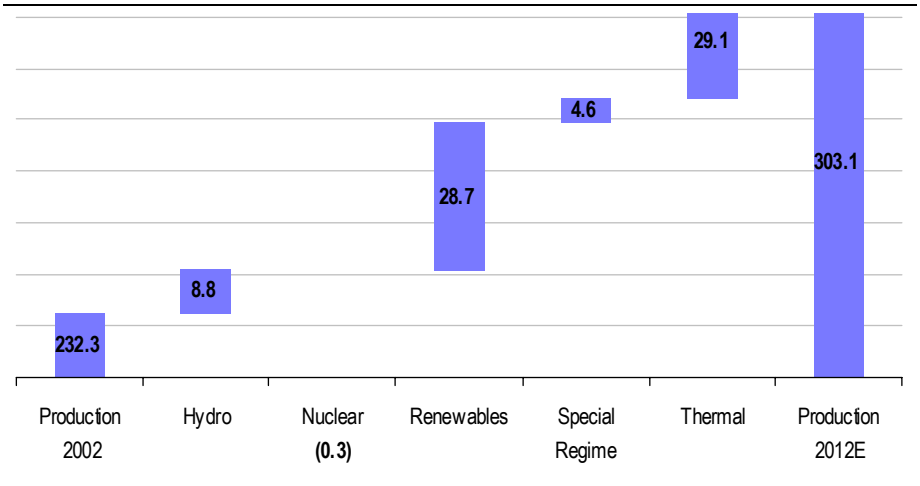


Source: UBS estimates, Iberdrola analyst presentation

…and growing electricity demand makes its targets all the more challenging

Furthermore, these reductions need to be achieved in an environment of growing electricity demand. The Spanish energy plan for 2002-11 estimates yearly demand growth of 3.4% on average. We are slightly more conservative at 3.0%. Even so, we estimate that thermal generation will increase by 26% from 113TWh in 2002 to 142TWh in 2012.

Chart 41: Electricity demand coverage in Spain (TWh)

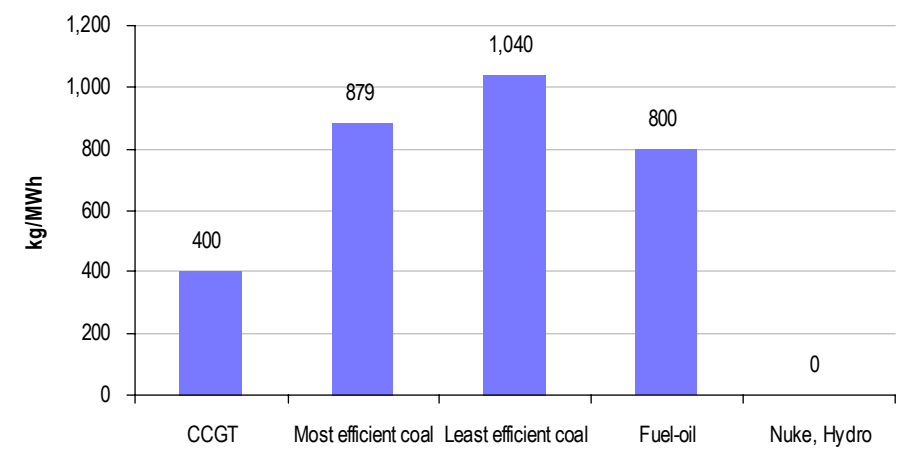


Source: REE, UBS estimates

So the electricity sector needs to accomplish a reduction of 26% in emissions in spite of an increase of 26% in thermal generation. In our view this can be achieved only by substitution of high-emission coal and fuel oil power stations with low-emission gas-fired power stations.

Low-emission gas power stations will have to replace high-emission coal and fuel oil

Chart 42: Emission levels by technology (kg/MWh)



Source: CNE, UBS estimates

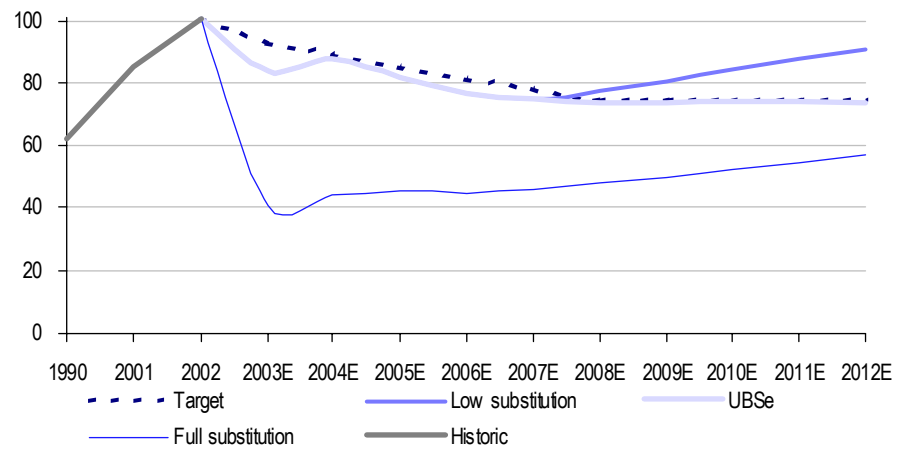
The level of emissions by the sector will depend on the level of substitution achieved. We have constructed three scenarios:

- **Low substitution:** Under this scenario gas-fired plants partly replace coal and fuel oil plants. Initially the substitution is significant, partially driven by the new entry of CCGTs to ensure security of supply. This scenario would result in a significant overshoot of the 74 million tonne emission target at 77 million tonnes in 2008 and 91 million tonnes in 2012.

- **Target substitution:** This scenario assumes that the substitution rate is enough to meet the Kyoto Protocol targets. The sector would then meet its emission levels.

- **Full substitution:** This scenario shows the theoretical path of emissions under full substitution of coal and fuel oil power stations by gas-fired plants. We do not believe it will be implemented. However, we believe that this scenario will be a benchmark for policymakers in looking at country-wide emission levels, helping them to assess the capability of the electricity sector to achieve more than its fair share of emission reductions.

Chart 43: Emission level scenarios (million tonnes of CO_2)



Source: UBS estimates (historical data from EEA)

Meeting the Kyoto Protocol targets

The ETS: A market-driven mechanism

The EU's Emission Allowance Trading Directive proposes a market-based approach (the ETS) to resolve a policy-driven issue (reducing emissions). The level of emissions for the sectors covered by the ETS is capped at the EU level by granting allowances for each country that are consistent with meeting the Kyoto targets.

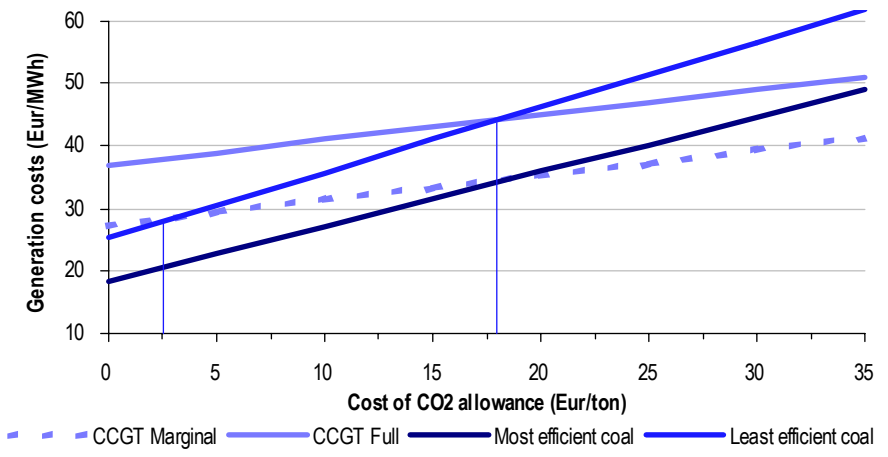
EU emissions target allows for trading of allowances between member countries

However, the sectors covered by the ETS in each country do not necessarily have to meet those targets; they just need to ensure that their total allowances equal their actual emission levels by buying any allowances they may need or selling any they do not need. From an economic perspective the market ensures that emission reductions are made where they are least costly.

The prices of allowances should therefore depend on supply and demand at an EU-wide level. In each country, the level of substitution of coal and fuel oil plants by gas fired ones would depend on the cost of allowances. McKinsey & Co estimates that the price of allowances will initially be around €7/tonne, but will increase to €25/tonne by 2012.

The following chart compares the costs of a CCGT plant in Spain (marginal and full) with the cost range of a coal power station (depending on its overall efficiency in terms of fuel costs and emissions produced). Note that the cost of a fuel oil power station is some €64/MWh before accounting for the cost of allowances. So we believe fuel oil's role in generation will be limited to small peak-time plants.

Chart 44: Spanish generation costs depending on cost of CO_2 allowances



Source: UBS estimates

This chart indicates that gas-fired plants become cheaper to run than the least efficient coal plants provided allowances trade above €2/tonne, and their full costs are below those of the least efficient coal plants if allowances trade above some €17/tonne. Under such a scenario the least efficient coal capacity would cease to operate, but the most efficient ones would continue to compete against CCGTs.

The higher the cost of allowances, the lower the running costs of CCGTs versus coal plants

Spain's policy-driven electricity sector

Spain's generation is not currently completely liberalised, as it is distorted by several mechanisms:

- **Wholesale price cap:** Current legislation sets a price cap of €36/MWh on capacity operating before 1998, under the methodology for recovering the stranded costs allowance – the cost of transition to competition (CTC). This excludes CCGT plants, which started to come on stream only in 2002. It also excludes Special Regime generation (renewable and co-generation) because this energy does not compete in the pool and is not linked to CTCs.

- **All-in tariffs:** Spanish consumers still have the choice between going to the liberalised market and paying an all-in tariff that includes all electricity costs, including generation. A miscalculation by the government could result in a tariff deficit (as occurred in 2002). This deficit will be recovered over 2003-10.

- **Average price caps:** Spanish legislation stipulates that the average electricity tariff should not grow by more than 2% (nominal) during the 2003-10 period.

The current environment leads us to believe that the Spanish government may not necessarily take a fully market-driven approach to meeting Kyoto targets. In our view it will aim for the following:

Spain may not take a fully market-driven approach to Kyoto targets

- **To meet physical targets,** or at least limiting the degree of overshoot. This would in our view put particular pressure on the electricity sector, given its technological capability to reduce physical emission levels.

- **To maintain price stability**, which was a key objective of the most recent regulatory review completed in December 2002. There has been a big political effort to ensure that average electricity prices will not be allowed to rise more than 2% per annum. In our view the government will want to keep this cap if at all possible.

- **To mitigate negative impact on companies:** The transition to a lower-emission generation mix should, in our view, have a negative impact on the owners of coal and fuel oil power stations. We believe that the government will aim to mitigate this economic impact. It could do this by granting owners free allowances. The precedent for this would be the transition to a 'liberalised' environment in 1998, when the impact of transition was offset by the implementation of a scheme to repay CTCs. The government then estimated that the sector would be able to recover 65% of the losses generated by this transition.

Overall, we believe that the government's approach will be mainly policy-driven, but that it cannot ignore the underlying economics.

The ETS under the current regulatory environment

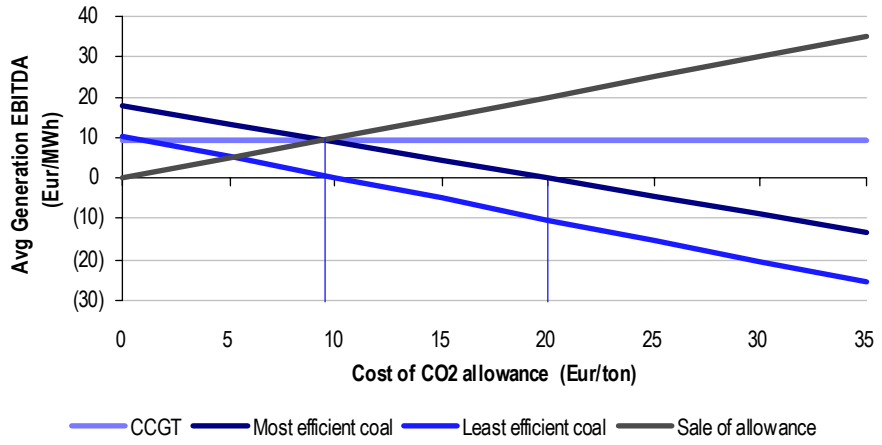
ETS would not necessarily work under the current regulatory environment…

In our view, the ETS would not necessarily work under the current regulatory environment. Under the €36/MWh average price cap on generation, it could be argued that coal and fuel oil plants would not be able to pass on the cost of emissions to customers. In contrast, CCGTs are not subject to this price cap. For instance, the 2003 tariff already contemplates a price of €43/MWh for these plants (however, detailed legislation in relation to this has yet to be passed, and Endesa and Iberdrola differ significantly in their views of the existing legislation on this point).

…as only CCGTs would be allowed to pass on emission costs to consumers

In our view the existing legislation would allow CCGTs to pass on the cost of emission allowances to the consumer. This could alter the marginal price in the system, but in theory any extra amount received by other generators would be deducted from the CTC to be received. This essentially implies that if coal plants had to pay for their permits, their EBITDA would decrease as the costs of these permits increased, while CCGTs' EBITDA would remain constant. This is illustrated in the following chart.

Chart 45: Average generation EBITDA by technology by allowance cost (€/MWh)



Source: UBS estimates

This scenario would probably become too harsh for coal generation and would force a full exit of coal plants from the system. For instance, the most efficient coal plants would become less competitive than CCGTs at an allowance cost of €10/tonne, and would become EBITDA negative at an allowance cost of €20/tonne.

Current regulations must be changed to avoid extreme scenarios

So we believe that it will be necessary to implement changes to the current regulations in order to avoid extreme scenarios. Changes would, in our view, involve likely increases in the wholesale price cap (from its current €36/MWh), possibly offset by a reduction in the value of outstanding CTCs. Depending on the actual outcome, the 2% tariff cap could be difficult to maintain in some years.

Theoretically, any changes need to be introduced before the end of this year. However, we find it difficult to believe that any legislation will be changed before the government presents its proposals for allocating tariffs (which should be before 31 March 2004) or publishes the actual detailed allocations (by 30 September 2004).

If the government decided to implement a market-driven approach, the changes would need to be greater, in our view. Such an approach would require the elimination of all price caps and tariffs, which would make it difficult to ensure stable electricity prices.

Allocations of allowances – a compensation mechanism

Allocation of allowances has no bearing on the cost of producing emissions

In our view the allocation of allowances among sectors should not change the way they behave, at least in theory. This may sound counterintuitive, but the fact is that the cost of producing emissions for a given plant does not depend on whether it has a free allowance. The cost is the same, whether it is an actual cost (buying the allowance) or an opportunity cost (what the allowance would have realised if it had been sold instead of used).

So any free allowances received by a facility can be seen as compensation to offset increasing costs and/or decreasing volumes – even though it might either be used to generate or be sold at its market price. Note that the price of allowances will depend on pan-European supply and demand for such 'instruments'.

A free allowance can be used to compensate for either higher costs or lower volumes

According to the EU directive, 'the total quantity of allowances to be allocated shall be consistent with assessments of actual and projected progress towards fulfilling the Member States' contribution to the Community's commitments' and 'shall be consistent with the potential, including the technological potential, of activities covered by this scheme to reduce emissions.'

These extracts support our view that the technological capability of the electricity sector will result in it receiving less than its 'fair share' of allocations.

Another question is whether governments will be able to link allocations of allowances to levels of emissions – in which case allowances could be used as a tool to direct the generation mix. For instance, a government might provide a company with a level of allowance consistent with a theoretical production mix. If the company then decided to ignore such a mix, the government could reduce its emission allowance for the following allocation period. Such a scenario would be inconsistent with the market-driven logic of the ETS, but we do not believe it can be ruled out. It would make another tool available to governments that adopt a more policy-driven approach.

Governments might be able to allocate allowances to direct the generation mix

Two possible scenarios: 'Abraham' and 'Adam'

The range of potential outcomes of the changes to come is endless, in our view. However, in our initial assessment of the situation we have configured two concrete scenarios:

- **The 'Abraham' scenario:** This scenario envisages a policy-driven approach, and so we have named it after a politician (Abraham Lincoln).
- **The 'Adam' scenario**: This scenario envisages a market-driven approach, and so we have named it after an economist (Adam Smith).

As we explain in this section, we believe that the current regulatory structure will make it very difficult to move straight away to a market-driven scenario. We believe that the initial approach towards meeting the Kyoto targets will be policy-driven. In the longer term we would not rule out a move towards 'Adam', but we believe that current investment decisions should focus on 'Abraham'.

Initial approach to meeting Kyoto targets is likely to be driven by policy, not markets

The 'Abraham' scenario

The government's aims

Our base case scenario assumes that the main aims of the government are:

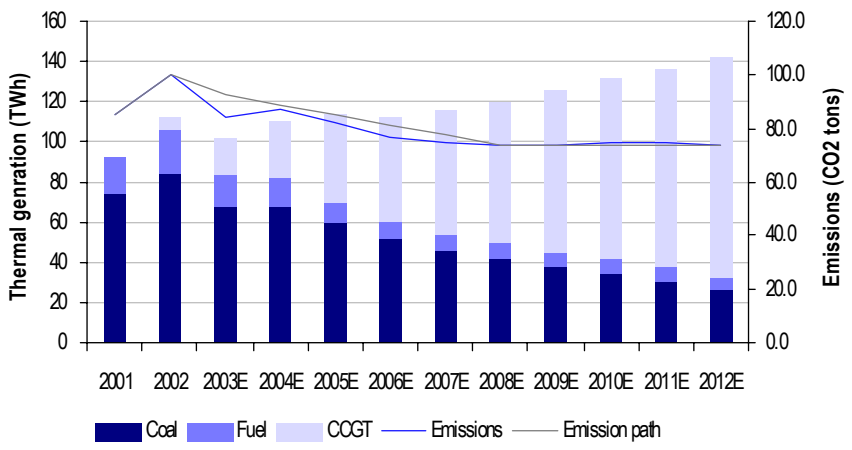
- **To meet physical targets:** In our view a policy-driven scenario is likely to be tilted towards meeting Kyoto's physical targets. In our view this is particularly true of the electricity sector in Spain, given that it has the technological potential to significantly reduce emissions.

- **To limit the impact on consumers:** In our view the Spanish government will aim at maintaining overall electricity price stability, and thus at maintaining its current target of capping overall electricity price growth at 2% pa. This would create an environment that would aim to avoid delivering unnecessary revenue windfalls.

- **To compensate generators for losses in value:** In our view the ETS should result in a significant change in generation mix, probably even greater than the change to a 'liberalised' market on 1 January 1998. At that time the government agreed to pay a CTC to utilities to compensate them for 65% of losses in value generated by the change. In our view this time the government will be able to use allocations of free allowances as a compensation mechanism. We have assumed that the government will again aim to compensate for 65% of any losses.

The following chart shows our estimates of thermal generation mix under such a scenario.

Chart 46: Spain's thermal generation 2001-12E (TWh) – 'Abraham' scenario



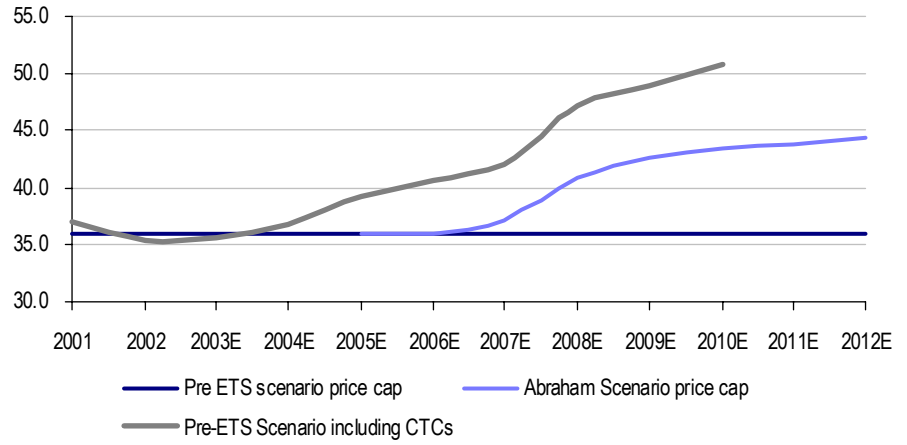
Source: REE, UBS estimates. Note: Thermal generation excludes nuclear generation and co-generation

Characteristics of the 'Abraham' scenario

The 'Abraham' scenario has the following characteristics:

- **Increase in wholesale price cap:** We estimate that the current price cap of €36/MWh will need to be increased to €44/MWh as a result of the increased cost of the base load coal generation.

Chart 47: Spanish generation price cap – 'Abraham' scenario (€/MWh)



Source: UBS estimates

- **Reduction in CTCs:** The level of CTCs outstanding at the end of 2002 was some €5.2 billion. We estimate that under the existing framework some €6.5 billion will be directed towards repayment of CTCs and interest accrued. However, under 'Abraham' the increase in the price cap would be offset by a reduction in CTCs repaid to €4.5 billion. In essence, value would be transferred from CTCs to the windfall. This is a net positive in our valuation framework, as we include no value for CTCs in our price targets.

- **Maintaining 2% tariff growth cap:** Our calculations suggests that the stated 2% pa tariff growth could be maintained under the 'Abraham' scenario. After 2010 the tariff in Spain will decline once CTCs are repaid. Under 'Abraham', such a decline would not be so sharp, recognising that the increase in the price cap is permanent and does not depend on CTCs.

- **Allocations:** Given the political drivers of the 'Abraham' scenario, we would expect allocations to be used to meet two objectives: to compensate coal and fuel oil capacity owners and to incentivise potential new entrants. In this scenario we will address only the 'compensation' allocations. Even though we believe new CCGTs may indeed receive allocations of allowances (as is clearly contemplated in the EU directive), in our view the total amount would be linked to the mechanisms used to set the price. We estimate the loss in value of thermal plants at €5.3 billion, requiring total compensation of €3.4 billion, assuming a 65% compensation rate. We estimate that to fund such compensation (in NPV terms) the government would need to allocate some 23 million tonnes of allowances per annum, equivalent to c30% of the total target emissions under a 'fair share' scenario.

Impact on value of generation capacity

The following table summarises our views of the impact of the 'Abraham' scenario on the value of generation capacity.

Table 20: 'Abraham' impact on generation values, before free allowances (€/kW)

	Valuation	(€/kW)		
Type of plant	**Before**	**After**	**Change**	**Comment**
Fuel	250	50	-80%	Sharp decline in volumes and tighter margins force values down
Coal	600	274	-54%	Sharp decline in volumes and tighter margins force values down
Hydro	700	780	11%	Favoured by increase in price cap, partly offset by lower peak price
Nuclear	900	1,270	41%	Favoured by overall increase in average price
CCGT	450	450	0%	Values are likely to depend on aggressiveness of new entrants
Extrapeninsular:				
Fuel	700	400	-43%	For extrapeninsular activities we assume that 65% of the increase in costs
Coal	525	380	-43%	is passed on to customers – also substantial substitution
CTCs	0	0		We continue to assume a zero value for future CTCs

Source: UBS estimates

Impact on company valuations

We have used the values in Table 20 to estimate the impact of the 'Abraham' scenario on the valuations of Spanish electricity companies. We have done the following calculations:

- **Impact of declines in thermal generation values:** We have updated our valuations of thermal generation to reflect lower coal and fuel values.
- **Impact of increases in hydro and nuclear generation values:** We add the increases in the values of hydro and nuclear generation as a result of the increase in the wholesale price cap.
- **Value of free allowances:** In estimating the level of free allowances to be received by utilities we have taken a pragmatic approach, assuming that allowances paid to electricity companies will be high enough to mitigate the negative impact of the loss in value of their coal and fuel plants. We have assumed a 65% recovery of this loss. This is based on the rate of compensation that the government adopted back in 1998 when the market was liberalised.

Table 21: 'Abraham' impact on valuations by company

	Endesa			Iberdrola			Fenosa		
	€m	**€/share**	**% of PT**	**€m**	**€/share**	**% of PT**	**€m**	**€/share**	**% of PT**
A. Change in thermal generation	(2,461)	(2.3)	-16.3%	(651)	(0.7)	-4.4%	(595)	(2.0)	-15.5%
B. Change in hydro/nuclear generation	1,781	1.7	11.8%	1,912	2.1	12.8%	352	1.2	9.2%
C = (A+B). Change in valuation	**(680)**	**(0.6)**	**-4.5%**	**1,261**	**1.4**	**8.4%**	**(243)**	**(0.8)**	**-6.3%**
Value of allowances (65% of A)	1,600	1.5	10.6%	423	0.5	2.8%	387	1.3	10.1%
Net impact on UBS valuation	**920**	**0.9**	**6.1%**	**1,684**	**1.9**	**11.3%**	**144**	**0.5**	**3.8%**
Reduction in future CTCs (38%)	(1,018)	(1.0)	-6.7%	(391)	(0.4)	-2.6%	(301)	(0.3)	-2.0%
Impact net of CTCs	(98)	(0.1)	-0.6%	1,293	1.2	8.5%	(157)	(0.1)	-1.0%

Source: UBS estimates

Conclusion

'Abraham' scenario gives a good indication of the potential impact of the ETS

Even though we believe that it is still too early to define with any clarity the potential impact of the ETS, we believe that the 'Abraham' scenario gives a good indication of what is to come, exposing the 'value at risk' in thermal plants, the potential windfalls in nuclear and hydro generation, and the mitigating factor to be derived from the allocation of free allowances.

We believe our calculations are realistic, notwithstanding the surrounding uncertainties. We also believe that they lead to reasonable conclusions:

- **Thermal generation stands to lose:** Even before we made any calculations, it appeared to us logical that in a climate of concern over GHG emissions, nuclear and hydro capacity should gain relative to coal and fuel capacity. Our calculations support this view.

- **Value is transferred from CTCs to windfalls:** The above calculations show that value generated by windfalls is to a substantial degree offset by a reduction in CTCs to be recovered. This is a net positive in our valuations, which do not include recovery of CTCs.

- **We are unsure about CCGTs:** We have maintained our construction cost valuation for CCGTs (€450/kW). On the one hand, CCGT improves its competitive position relative to coal generation, which should be positive for its valuation. However, the flattening of the price curve as a result of the decline in fuel oil-based generation may often result in CCGT becoming the marginal plant on which it is more difficult to recover full costs. We believe the values of CCGTs will depend mainly on the aggressiveness of new entrants.

- **Allowances will be the key to defining value:** The loss of value in some generation types may be quite substantial. We believe that the allocation of free allowances will act as a compensation mechanism.

- **Iberdrola stands better than its peers with upgraded valuation and rating:** In our view Iberdrola is favoured by a generation mix that is more exposed to nuclear and hydro capacity, and as a result it stands out as the relative winner in the run-up to implementation of the ETS. In order to highlight the better outlook of Iberdrola vs its peers, we believe that it makes sense to reflect the €1.9/share potential positive impact in our stock valuation. We have upgraded our valuation from €16.6/share to a rounded €18.0/share. As a result of this upgrade, our rating moves from Neutral 1 to Buy 1.

Table 22: Iberdrola SOTP valuation, including ETS effect

Division	€m	€/share	Weight	Methodology
Core domestic business	**20,850**	**23.1**	**81%**	
Generation	11,080	12.3	43%	Benchmarks by technology
Distribution & supply	7,541	8.4	29%	€900 per customer, excl HV sale
Other core business	2,228	2.5	9%	Wind at €1,050/kW
International	**2,254**	**2.5**	**9%**	**Local benchmarks**
Other	**2,721**	**3.0**	**10%**	**Various**
EV	**25,824**	**28.6**	**100%**	
Net debt, provisions, minorities	(10,872)	-12.1		
Equity valuation	14,952	16.6		
ETS impact	1,684	1.9		
Post ETS valuation	16,637	18.5		
Revised target		**18.0**		

Source: UBS estimates

The 'Adam' scenario

The main aims

An alternative scenario to 'Abraham'

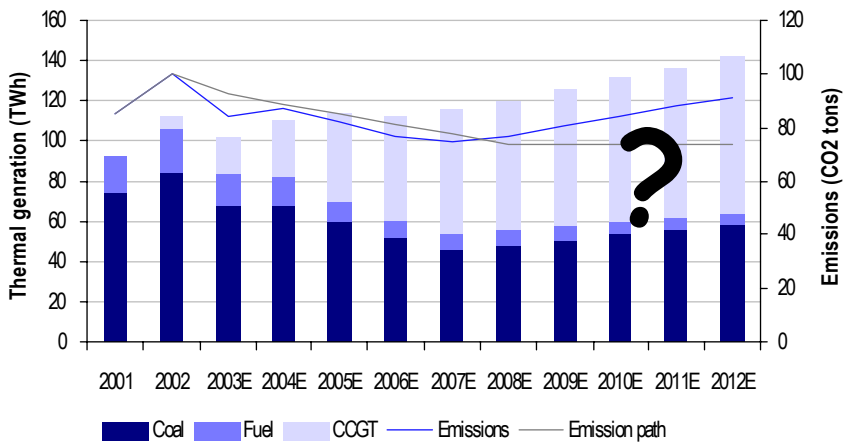
Even though we believe our 'Abraham' scenario is more illustrative of the potential impact of ETS in the Spanish electricity sector, we have developed an alternative scenario. The main aims of the 'Adam' scenario would be:

- **Let the market run:** We assume that the electricity sector would be moved purely by market forces. So the aim is just to put the mechanisms in place to get the ETS running; the market will do the rest in order to meet the Kyoto Protocol.

- **No physical targets:** We assume that the electricity sector will produce emissions substantially above its 'fair share' target, but that it will simply purchase enough allowances to meet the targets.

The following chart shows our estimates of the thermal generation mix under such a scenario.

Chart 48: Spain's thermal generation 2001-12E (TWh) – 'Adam' scenario



Source: REE, UBS estimates. Note: Thermal generation excludes nuclear generation and co-generation

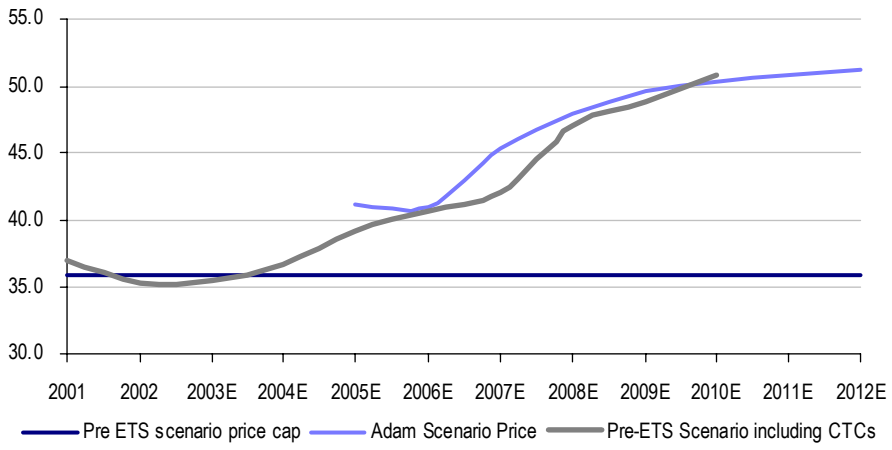
Characteristics of the 'Adam' scenario

The 'Adam' scenario has the following characteristics:

- **No price caps or CTCs:** In our view all price caps would need to be removed under a market-driven approach. We estimate that the current price cap of €36/MWh would need to be replaced by a market price, which would reach some €51/MWh. CTCs would also need to be removed under a market-driven scenario, and so would any tariff growth cap. This would not have a negative impact on our valuations as we include no value for CTCs in our price targets.

- **No cap on annual price growth:** Under our calculations growth in prices would likely overshoot the 2% annual maximum targeted by the government, leading to windfall revenues for nuclear and hydro generation.

Chart 49: Spanish generation price cap – 'Adam' scenario (€/MWh)



Source: UBS estimates

- **Lower allocations:** Higher increases in prices would result in smaller losses for coal and fuel oil generation, requiring less compensation and thus lower

allocations of free allowances. We have estimated that some 16 million tonnes of allowances pa (c20% of 'fair share' levels) will be required to compensate for 65% of losses in value.

Impact on value of generation capacity

The following table summarises our views of the impact of the 'Adam' scenario on the value of generation capacity.

Table 23: 'Adam' impact on generation values, before free allowances (€/kW)

	Valuation	(€/kW)		
Type of plant	**Before**	**After**	**Change**	**Comment**
Fuel	250	50	-80%	Sharp decline in volumes and tighter margins force values down
Coal	600	404	-33%	Sharp decline in volumes and tighter margins force values down
Hydro	700	780	11%	Favoured by increase in price cap, partly offset by lower peak price
Nuclear	900	1,950	117%	Favoured by overall increase in average price
CCGT	450	450	0%	Values are likely to depend on aggressiveness of new entrants
Extrapeninsular				
Fuel	700	400	-43%	For extrapeninsular activities we have assumed that 65% of the increase in costs
Coal	525	300	-43%	is passed on to customers
CTCs	0	0		We continue to assume a zero value for future CTCs

Source: UBS estimates

Impact on company valuations

We have used the values in Table 23 to estimate the impact of the 'Adam' scenario on the valuations of Spanish electricity companies, using the same methodology as described on page 80.

Table 24: 'Adam' impact on valuations by company

	Endesa			Iberdrola			Fenosa		
	€m	€/share	% of PT	€m	€/ share	% of PT	€m	€/share	% of PT
A. Change in thermal generation	(1,713)	(1.6)	-11.3%	(489)	(0.5)	-3.3%	(328)	(1.1)	-8.5%
B. Change in hydro/nuclear generation	4,251	4.0	28.1%	4,173	4.6	27.9%	753	2.5	19.6%
C = (A+B). Change in valuation	**2,538**	**2.4**	**16.8%**	**3,684**	**4.1**	**24.6%**	**425**	**1.4**	**11.1%**
Value of allowances (65% of A)	1,113	1.1	7.4%	318	0.4	2.1%	213	0.7	5.5%
Net impact on valuation	**3,652**	**3.4**	**24.1%**	**4,002**	**4.4**	**26.7%**	**638**	**2.1**	**16.6%**
Reduction in future CTCs (100%)	(2,678)	(2.5)	-17.7%	(391)	(0.4)	-2.6%	(301)	(1.0)	-7.8%
Impact net of CTCs	**974**	**0.9**	**6.4%**	**3,611**	**4.0**	**24.1%**	**337**	**1.1**	**8.8%**

Source: UBS estimates

Conclusion

Windfall revenues and need for regulation make 'Adam' look an unrealistic scenario

Unlike 'Abraham', 'Adam' would likely bring windfall revenues to the electricity sector as a whole and would require a complete reshaping of the regulatory environment. In our view these are key reasons for believing that this scenario is unrealistic.

Notwithstanding this, we note that under this scenario, nuclear and hydro generation would remain in a significantly better position than thermal

generation, and as a result Iberdrola would still be better placed than its peers, particularly before any compensation via allowances.

'Abraham' and 'Adam' vs other scenarios

Reconciling 'Abraham' and 'Adam' with other scenarios

In the introduction to this note we discuss several scenarios by country from a pan-European perspective. The reconciliation between those definitions and the Spanish scenarios shown in this section are as follows:

- **Blue sky scenario:** The outcome of our 'Adam' scenario, which contemplates sizeable windfalls.
- **Central case scenario:** The net impact on our valuations derived under the 'Abraham' scenario.
- **Black sky scenario:** The same as the central scenario but assuming no allocations of allowances.
- **Disaster scenario:** Based on the negative impact on thermal generation derived under the 'Abraham' scenario, without taking into account potential windfalls or allocations.

Table 25: Impact of ETS on Spanish electricity companies

	Endesa			Iberdrola			Fenosa		
	€m	€/share	% of PT	€m	€/share	% of PT	€m	€/share	% of PT
Blue Sky	3,652	3.4	24.1%	4,002	4.4	26.7%	638	2.1	16.6%
Central	**920**	**0.9**	**6.1%**	**1,684**	**1.9**	**11.3%**	**144**	**0.5**	**3.8%**
Black sky	(680)	(0.6)	-4.5%	1,261	1.4	8.4%	(243)	(0.8)	-6.3%
Disaster	(2,461)	(2.3)	-16.3%	(651)	(0.7)	-4.4%	(595)	(2.0)	-15.5%

Source: UBS estimates

Italy

ETS in Italy

Summary and conclusions

- **Emission history and targets:** Italy agreed a 6.5% reduction in total GHG emissions by 2012 versus 1990, implying -13% versus 2001. CO_2 emissions rose slightly faster than total GHGs in 1990-01; so our assumed target CO_2 reduction by 2012 is 7.5% versus 1990 and 14% versus 2001.

- **Electricity sector may face tougher targets:** Electricity represents roughly one-third of total CO_2 emissions. We assume that transport is allowed to continue to grow emissions (albeit at a slower rate than in the past) and that this is offset by a decline in other sectors. On this basis, electricity would be asked to contribute most of the net reduction in CO_2 for the country, implying a 31% reduction for electricity by 2012 versus 2001.

- **'Fit to target' and substitution:** After the initial 'cushion' (2005-07) of the planned new CCGT capacity, we estimate that the sector will miss its CO_2 emission target by c50 million tonnes (c50%) in 2012. As an extreme illustration, to meet the target the system would need either to double its production from renewables, or to add a further 8GW of CCGT by 2010 (and even more thereafter) on top of what we assume. This seems unrealistic to us as it would imply almost total displacement of coal and fuel oil.

- **Value of allowances and impact on generation costs:** Based on our falling oil price forecast, we estimate that €25/tonne is the value of emission allowances at which the marginal cost of coal equals the full cost of CCGT. With a higher oil price, this level moves to €30/tonne.

- **'Marginal cost' scenario:** With a gradual rise in the price of allowances to €25/tonne and 90-95% free allocations, we estimate that wholesale prices rise by up to €13/MWh over time, creating extra profits for companies, as the additional cost of CO_2 allowances is less than additional revenues. In our simulation this windfall would, paradoxically, be biggest for Enel: Enel has been very CO_2-intensive so far, but our assumed fall in its load factor relative to the sector implies a proportionately lower additional cost. We have simulated that the potential positive valuation impact for Enel under this scenario is €3.2-5.0 billion, or €0.52-0.82/share.

- **'Political' scenario:** Should the government seek to sterilise the benefit of higher prices, we have simulated that the annual net loss for the electricity sector from the introduction of an ETS rises gradually to c€1.4 billion in 2012, of which c€0.3 billion is borne by Enel. The negative valuation impact in our simulation is limited to c€0.1/share.

- **Reality lies somewhere in between:** Given Italy's high wholesale prices, some political interference seems inevitable, but putting the entire CO_2 onus on companies would be against the concept of an unregulated electricity pool. So a hybrid scenario is more likely, implying, for example, a low proportion of 'free' allocations of emission allowances (eg 50%). Under this scenario the valuation benefit for Enel would be €0.3-0.48/share.

Existing legislation on renewable sources

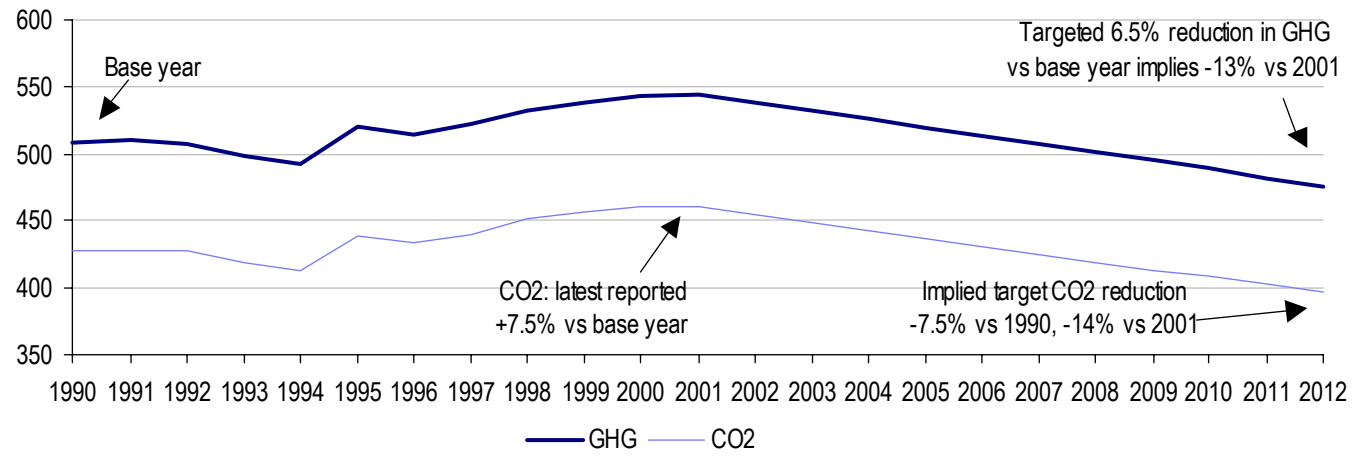
Italy's Electricity Act of 1999 introduced so-called 'green certificates', an obligation for all power producers to have a minimum of 2% of their annual output from 'new' renewable sources, ie renewable energy plants built after April 1999. Companies failing to meet this target have to purchase 'green certificates' from either the grid operator or other producers (ie those having a surplus of new renewable electricity beyond the 2% threshold). Based on our information, the value of 'green certificates' is currently around €80/MWh, which, as a function of the 2% obligation, implies an additional cost of c€1.6/MWh for a company having no new renewable electricity production.

'Green certificates' add c€1.6/MWh to costs of companies with no new renewable electricity capacity

Total emission levels, targets to 2012

Italy has agreed a 6.5% overall reduction in total GHG emissions versus the 1990 level of 509 million tonnes. As of 2001, total emissions had actually risen by 7% from the 1990 level; the 2012 target therefore implies a 13% reduction versus the 2001 emission level. CO_2 emissions rose by 7.5% over the same period. Assuming other types of emissions follow the same trend seen in the past, the implied target reduction in CO_2 emissions by 2012E is 7.5% versus the 1990 level and 14% versus the 2001 level.

Chart 50: Italy – total GHG and CO_2 emissions in 1990-01 (m tonnes) and simulated straight-line target reduction to 2012E



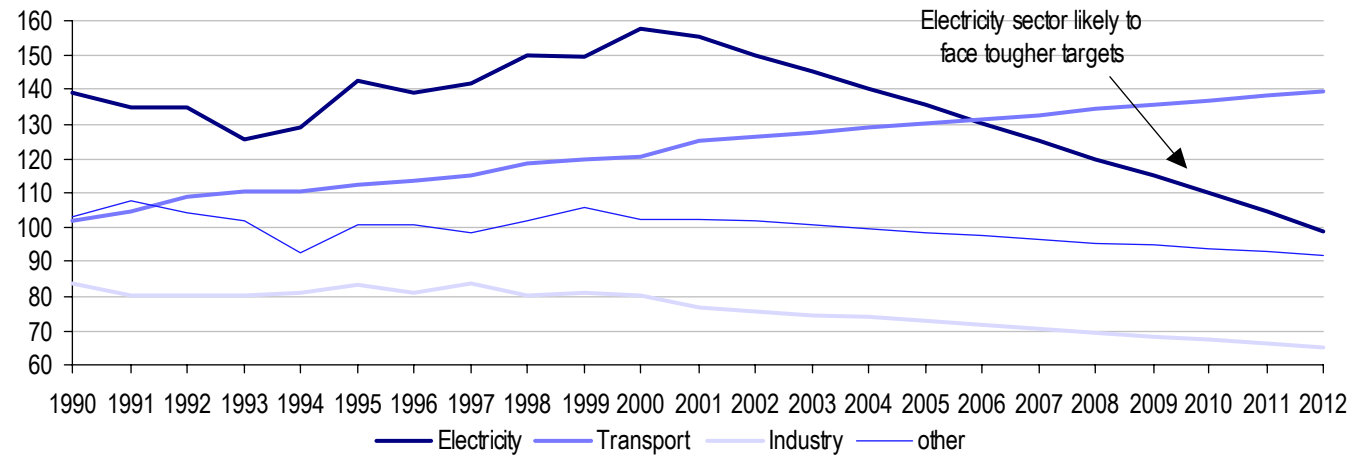
Source: European Environment Agency

Electricity sector emission targets likely to be tougher

The electricity sector represented 34% of total CO_2 emissions in 2001, and increased emissions by 12% from 1990 to 2001 (1.0% CAGR). Emissions in the transport sector rose by 2.0% CAGR while industry CO_2 fell by 0.8% CAGR and the rest was flat. We assume that due to traffic growth CO_2 emissions in the transport segment continue to grow, albeit at a much slower rate (0.5% pa), and that this is broadly compensated by a decline in industry and the other sectors. On this basis the electricity sector would need to be asked to contribute most of the net reduction in CO_2 emissions for the country, ie c23% by 2012 versus the 1990 level and 31% versus the 2001 level.

Electricity sector would be asked to contribute most of Italy's CO_2 net emission cuts

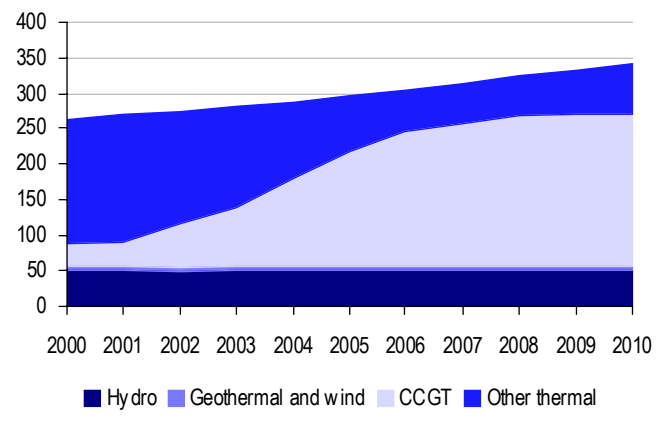
Chart 51: Italy – Electricity sector total CO_2 emissions in 1990-01 (m tonne) and simulated straight-line target reduction to 2012E



Source: European Environment Agency

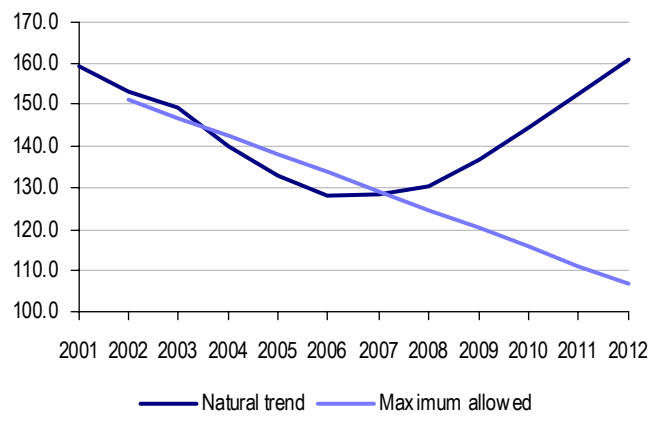
Based on our current Italian electricity market model, we have projected our estimated natural evolution of the sector's emission levels, compared with the assumed required reduction to 2012, expressed as a straight line.

Chart 52: Electricity generation – output mix (TWh)



Source: UBS estimates

Chart 53: Electricity sector CO_2 emissions (m tonnes)



Source: UBS estimates

Italy looks like overshooting 2012 emission target by c50 million tonnes

The trend in our projected CO_2 emissions in the electricity sector (Chart 53) is strongly influenced by our assumptions on the generation capacity mix (Chart 52). Our model already assumes a heavy move towards CCGT, ie 11GW of new capacity and 13GW of conversions by 2010, the bulk of it within 2007. This is in line with consensus, and the replacement of high-emission fuel oil production – given that new CCGT would run as base load – implies a reduction in CO_2 emissions in the next few years, allowing the sector to stay within the target at least until 2007. However, based on our earlier assumptions, a big problem would materialise in the longer term once our model stops incorporating new CCGT capacity and electricity demand growth leads to increased emissions. Given the above assumptions, our model implies that Italy will overshoot the required emission level for 2012 by c50 million tonnes. Any delays in the CCGT projects or changes in the load factor assumptions post-2007 would change the shape of the curve in Chart 53.

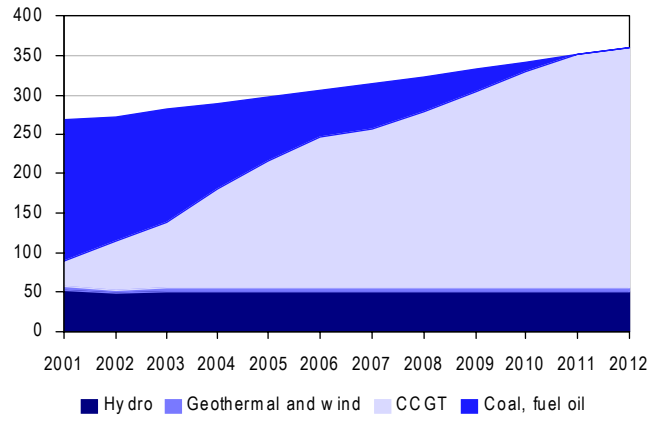
Simulating an extreme, 'fit to target' scenario

'Fit to target' scenario seems unrealistic as it implies almost total displacement of fuel oil and coal

As an illustration, Chart 54 shows how Italy's generation mix has to change towards the end of the decade, assuming that the sector is required to match the target level of emissions. Assuming a stable contribution from hydro and renewables, this scenario implies an even more drastic move to CCGT, adding further new capacity post-2007, than under our base assumptions. This scenario requires up to 8GW of additional CCGT by 2010 and further new capacity thereafter, on top of what we already assume until 2007. This seems unrealistic to us, as it implies an almost total displacement of fuel oil and coal. Current plans of both Enel and Endesa Italia to convert some capacity from fuel oil to coal would then face the prospect of a very low load factor.

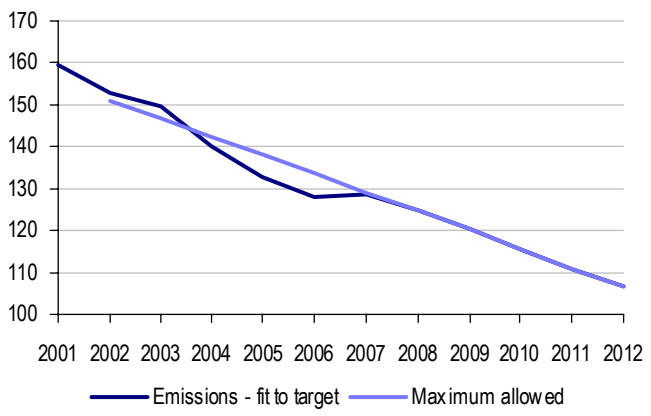
Alternatively, Italy could pursue the renewable energy option. Based on our estimated overshooting in emissions, Italy would need to double its current production from renewable sources by 2012, which does not sound realistically achievable. Equally, we would exclude for the time being the possibility that Italy would reconsider the nuclear option, which was banned following a referendum back in 1987. The only possible buffer would be a significant increase in import capacity from the current c6GW: Apart from environmental issues (new wires crossing the Alps), the recent tightness of European electricity markets argues against increasing Italy's dependence on imports even further.

Chart 54: Generation output (TWh) – extreme 'fit to target' mix



Source: UBS estimate

Chart 55: CO_2 emissions (m tonnes) – 'fit to target' scenario

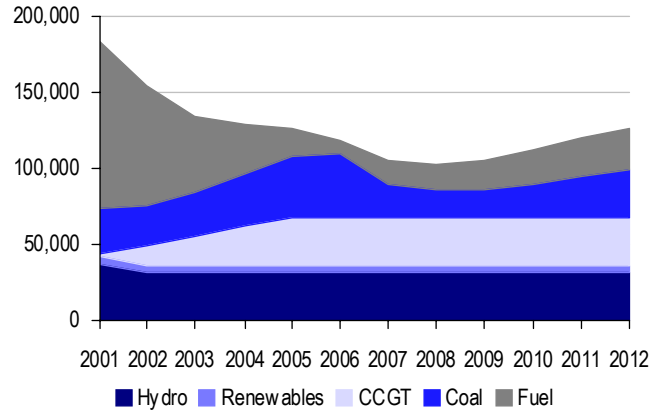


Source: UBS estimate

Enel's production and emissions

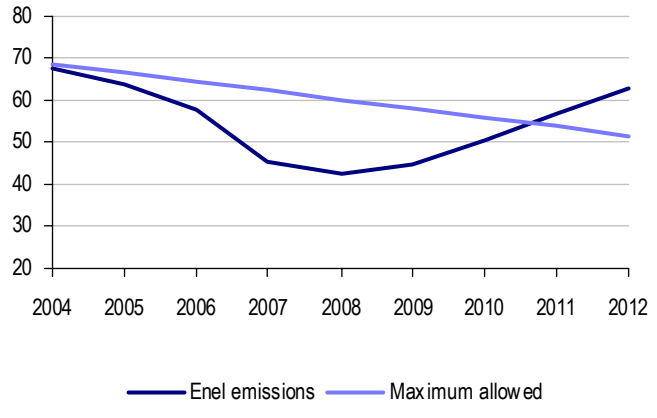
We have replicated the above base case analysis to the case of Enel. Following the disposal of the three gencos, we estimate that Enel will represent 48% of Italian electricity production in 2003.

Chart 56: Enel – estimated output mix (GWh)



Source: UBS estimates. Note: Enel sold 15 GW of capacity in 2001-02.

Chart 57: Enel – estimated CO_2 emissions (m tonnes)

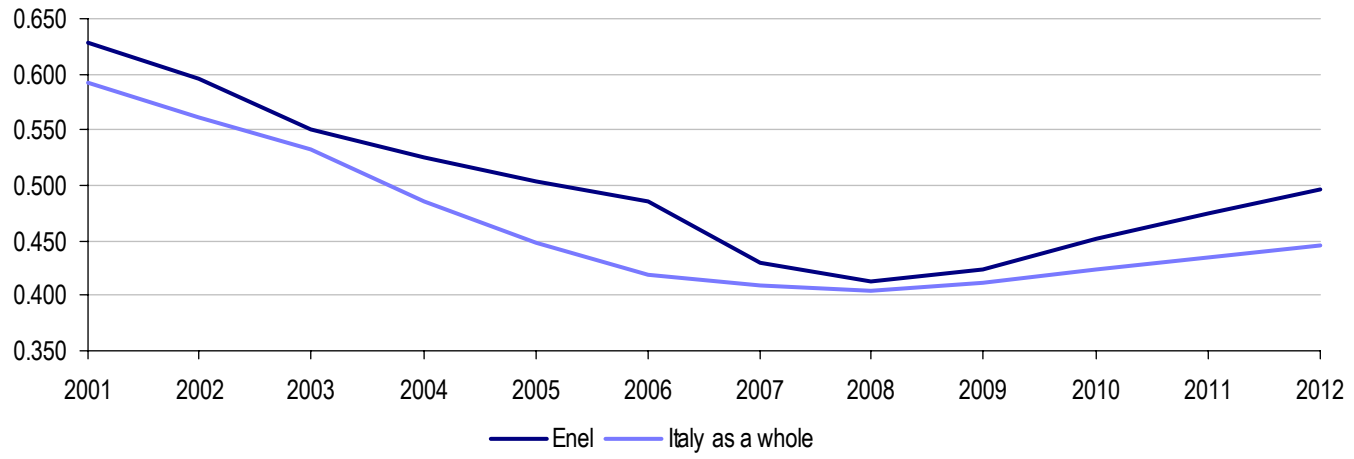


Source: UBS estimates

In the next few years our model is already harsh as it implies that Enel's share of total production will fall further, to some 35%, due to new CCGT coming on board from other producers (Enel is restricted by the Electricity Act from adding new net capacity). As a result of this, and of Enel's own conversions to CCGT, the group's CO_2 emissions should fall faster than those of the sector as a whole, as the much reduced fuel oil production will be mostly from Enel's plants. Enel's emissions would pick up strongly after 2007, when our model stops assuming new capacity in the system. Assuming that the target reduction in CO_2 emissions is allocated to Enel proportionately versus the sector, as a function of historical emissions (adjusted for disposals), Enel would – paradoxically – find itself in a less challenging position than the rest of the sector (ie actual emissions falling faster than the target).

Enel's CO_2 emissions could fall faster than those of the sector as a whole

Chart 58: Emissions (tonne/MWh) – Enel versus Italian average



Source: UBS estimates

Impact of allowances on generation costs

By end-March 2004 the Italian government is required to submit to the European Commission the plan for the allocation of emission allowances to each sector. At the start, it expected that almost all allowances (95%) would be given

for free. However, as soon as carbon emission limits are restricted below natural levels, the permits will begin to have a value.

Logic of EU directive is that cross-border trading will determine the value of allowances at EU level

The value of $C0_2$ emission permits will essentially depend on (1) the gap between target levels of emissions versus the level that the sector would naturally produce without CO_2 restrictions; and (2) The percentage of allowances granted for free, and its evolution over time. But according to the EU directive's logic of cross-border CO_2 emission trading, the value of allowances will tend to be determined at EU level.

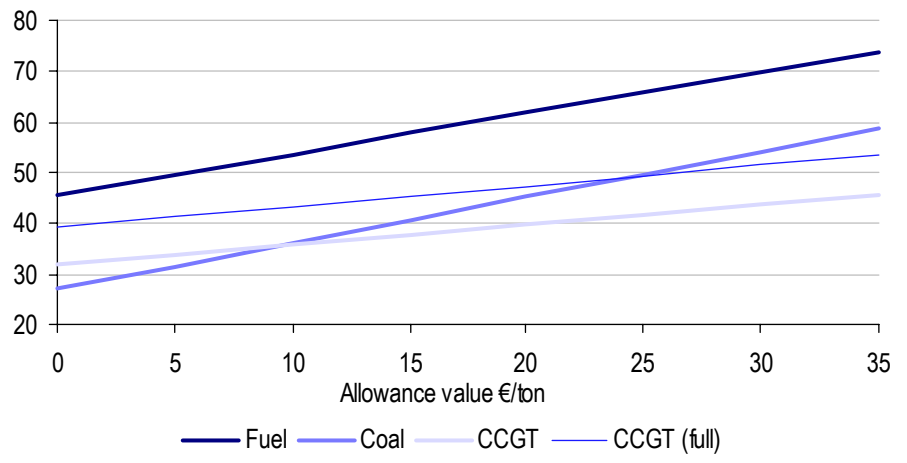
In order to simulate the impact on generation costs for the various types of plant, we have used a range of €0-25/tonne of emissions as an assumption for the value of allowances, in accordance with the rest of this report. In the illustrations below we have considered a specific feature of Italy, which is its high dependence on the oil price. Therefore our simulations show the varying impact of different values of CO_2 allowances on the total estimated cost of each type of generation in both a low oil price and a high oil price scenario.

Low oil price

At $22 Brent, new CCGT capacity can compete with coal with allowances at €25/tonne

The following chart shows our estimated production costs for each type of plant, based on the assumption of Brent at $22, with varying levels of allowance costs. In this environment we estimate that building new CCGT becomes competitive versus coal with allowances at c€25/tonne.

Chart 59: Total cash costs (€/MWh) – low oil price

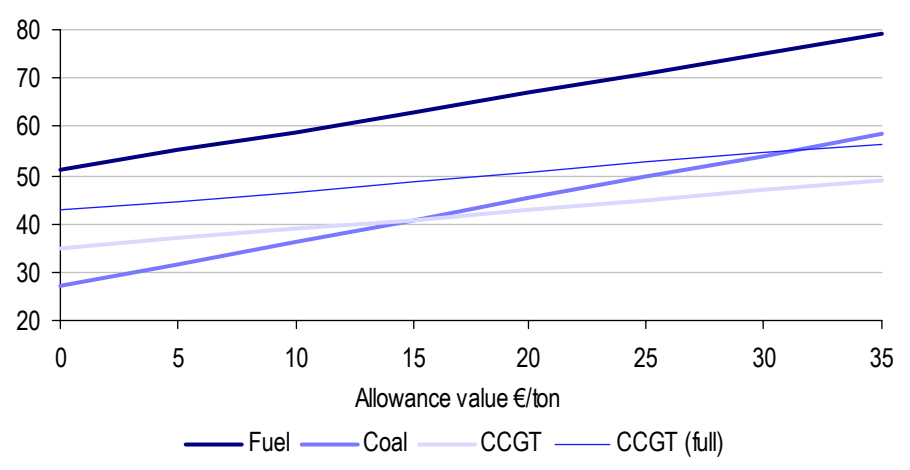


Source: UBS estimates

High oil price

In a higher oil price environment ($25/barrel), assuming that the variable cost of coal would be unchanged, total cash costs of coal plants would only match the full cost of a new CCGT with allowances at c€30/tonne.

Chart 60: Total cash costs (€/MWh) – high oil price



Source: UBS estimates

Less significant impact on merit order than in the UK

New CCGT capacity would be base load, so change in merit order would be less significant than in the UK

UBS's analysis of the UK electricity market (*The greening of UK electricity*, May 2003) shows that the introduction of CO_2 permits could heavily alter the merit order of plants. As gas prices are highly seasonal in the UK, gas generation tends to run ahead of coal for only about 60% of the year. The disproportionate impact of CO_2 allowances on the two types of plant therefore changes the load factors significantly. In Italy, however, given the structure of generation capacity, the new CCGT will tend to be base load, and therefore we would argue that the change in the merit order would be less significant: a high price of allowances would more simply accentuate the natural downtrend in the load factor of fuel oil and reduce the load factor of coal.

Who bears the cost?

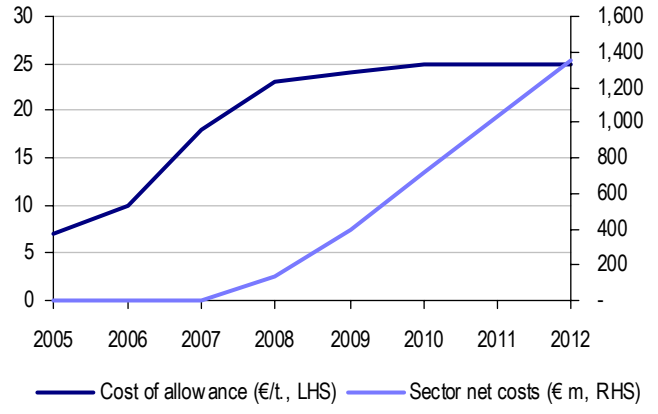
'Political' scenario: Costs borne by companies

The current level of wholesale prices in Italy (c€60/MWh) is roughly double the European average. We estimate it to fall to some €45/MWh by 2007, mostly driven by a lower oil price, but even this level would maintain a significant gap with the rest of Europe as Italy has yet to see the first signs of competition in the electricity sector. On this basis we think it is likely that the government will seek to sterilise the impact of a further increase in prices driven by CO_2 allowances.

Under 'extreme' scenario, companies would be charged for overshooting emission targets

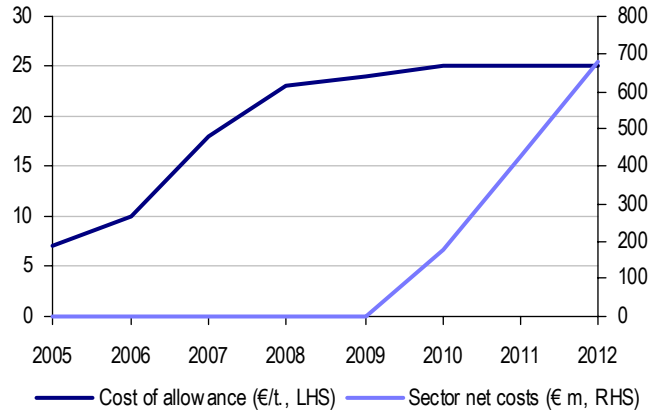
In an 'extreme' scenario we simplistically assume that the natural increase in wholesale prices led by the cost of CO_2 allowances would be offset by a contribution charged to companies (ie allocations would not be free). In this scenario we would simulate the net cost for companies as a function of the 'overshooting' of emissions versus the sector's target. The following charts illustrate this scenario with two alternative cases: one with electricity treated as other sectors, ie allocated its 'fair share' of target emissions, the other with electricity asked to contribute more than the rest.

Chart 61: Net cost for electricity sector – tough CO_2 targets



Source: UBS estimates

Chart 62: Net cost for electricity companies – 'fair share'



Source: UBS estimates

'Marginal cost' scenario: Costs borne by customers

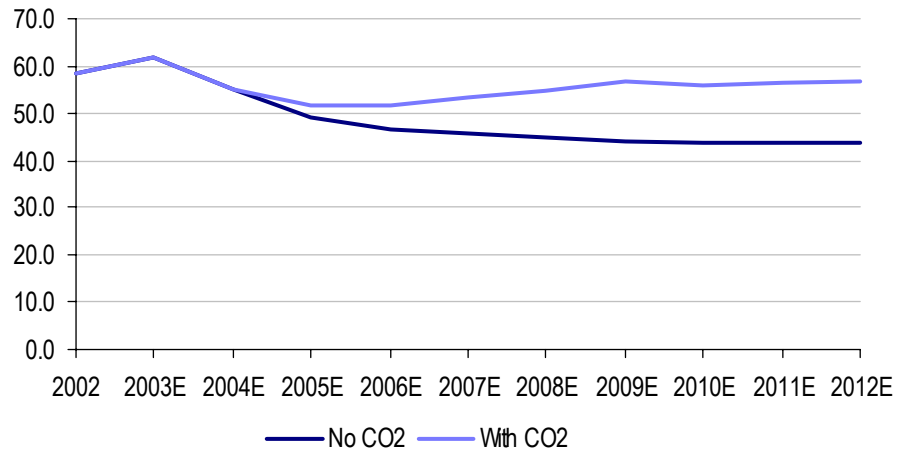
But if government did not interfere with pricing, wholesale prices would rise in line with additional generation costs…

An opposite approach is to assume no government interference in the mechanism of formation of prices. In this scenario wholesale electricity prices would rise as a function of the additional generation costs due to the price of CO_2 allowances, as shown previously. In this scenario electricity companies would benefit, as the higher cost of the marginal plant would imply a higher price for all generators, in excess of the cost borne on average to pay for the shortfall in allowances.

Effect on wholesale prices

The next chart simulates the potential impact of CO_2 trading on wholesale prices, assuming that the value of allowances rises over time following the same trend shown in Charts 62 and 63, settling in the long run at €25/tonne. At this level we estimate that the impact on wholesale prices would be an increase of up to €13/MWh.

Chart 63: Wholesale price (€/MWh) with introduction of CO_2 trading



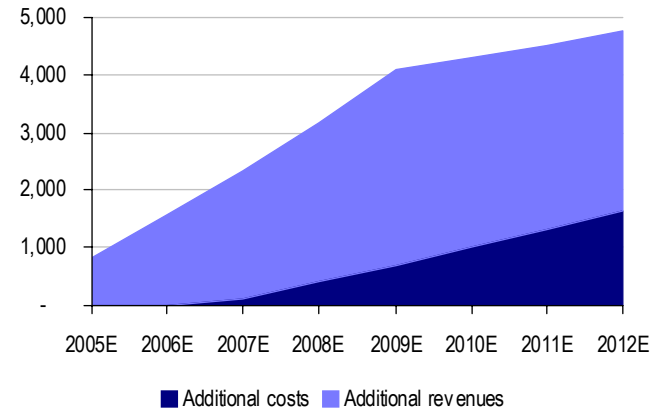
Source: UBS estimates

Effect on profitability

...and sector EBITDA would be boosted by c€3 billion pa in 2008-12E

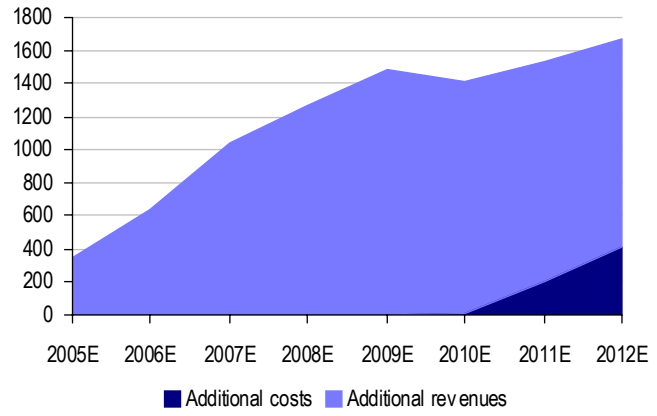
In this scenario electricity generation companies would enjoy a net benefit, which we have simulated as a function of the difference between additional revenues (due to a higher wholesale price) and additional costs due to the payment for the allowances not allocated for free. We have assumed that 95% of allowances in 2005-07 are granted for free based on the emission levels of 2001-02, and 90% in 2008-10. We continue to use the unit value of allowances as an input in the calculation, in accordance with the rest of this report, implying a gradual rise to €25/tonne. In this simulation, the whole sector would gain an additional c€3 billion EBITDA per annum in 2008-12E, peaking in 2009 and presumably falling after 2012 in the absence of new capacity in the system.

Chart 64: Impact on EBITDA (€m) – whole sector



Source: UBS estimates

Chart 65: Impact on EBITDA (€m) – Enel



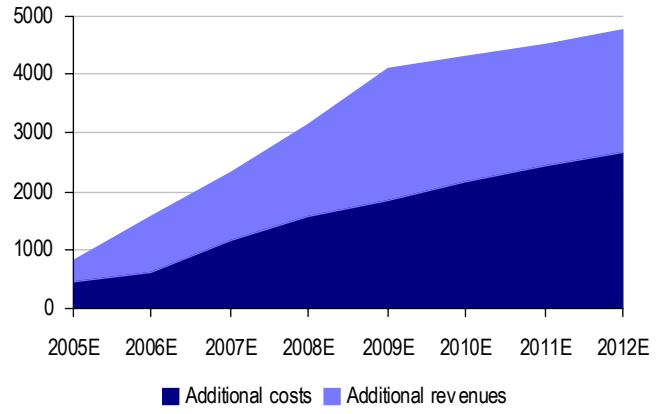
Source: UBS estimates

'Intermediate' scenario

Under 'moderate' scenario, sector EBITDA might still benefit by c€2 billion pa

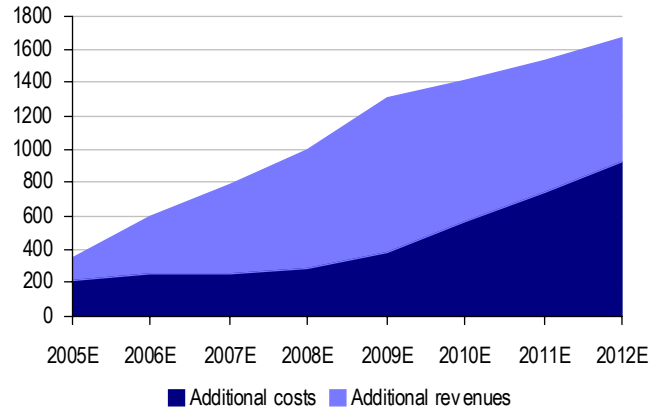
Given the extent of the extra profits that would occur in the 'marginal cost' scenario, one can envisage a hybrid scenario based on an increase in wholesale prices as shown above but also simulating a degree of government interference, imposing a lower proportion of 'free' allowances. To illustrate the impact, the charts below simulate for simplicity a 50% share of allocations auctioned, versus 90-95% in the previous scenario. In this case the sector's overall additional EBITDA gain would be reduced to c€2 billion of per annum over the period.

Chart 66: Impact on EBITDA (€m) – sector



Source: UBS estimates

Chart 67: Impact on EBITDA (€m) – Enel



Source: UBS estimates

The paradox: Could Enel be a winner?

Our model implies Enel's production share goes down, so its emissions fall faster than sector average – hence the paradox of Enel seeming better off

The above charts suggest that Enel might be better off than the Italian sector average. This seems counterintuitive if one looks at Enel's production mix of the past few years – heavily biased towards fuel oil and thus CO_2 intensive. In fact, our simulations are heavily influenced by the assumptions in our electricity market model, where Enel's load factor is significantly reduced, until 2006-07, by new CCGT capacity coming on stream from other producers. In addition, Enel's own industrial plan implies the substitution of most fuel oil production with CCGT and coal: the management plans to produce only 5% of total from fuel oil and low-merit gas in 2007, down from 45% in 2002. Our model implies that Enel's share of total production will fall from c48% of Italy's total in 2003 to c34% in 2007, which implies that the group's CO_2 emissions should fall faster than those of the sector in this period. In our simulations, as Enel gets allocations in proportion to historical emissions, it bears a smaller cost burden than the rest of the sector, relative to the benefit of additional revenues. Enel's emissions would pick up strongly after 2007, when our model stops assuming new capacity in the system.

So Enel's prospects look good in medium term, but less so after 2012 in our view

In conclusion, we believe Enel's picture looks good in the medium term because our model already implies a big hit on Enel's output, but things might turn negative beyond 2012. Assuming no additional capacity in the system, Enel's high-emission plants would have to run with a higher load factor, leading to a squeeze in the above spread between additional revenues and additional costs.

Simulating the potential valuation impact for Enel

We have tried to turn the above scenario analysis into a range of potential valuation impacts for Enel. For each scenario we have calculated the net present value of our simulated EBITDA impact (after tax) in 2005-12, discounted at 7.5%, which is the rate we apply to our valuation of Enel's generation business. Our big caveat is that, with a high degree of uncertainty on the period to 2012, the post-2012 outlook is even less clear. So we have simulated the valuation impact in each scenario both without terminal value and with a prudent terminal value assumption (5x post-tax). Finally, we have provided a sensitivity table to varying discount rates, given the very low visibility of these cash flow effects.

Table 26: Impact on Enel's valuation

NPV at 7.5% (2005-12)	Political scenario	Worst case	Bull case (marginal cost)	Hybrid scenario
Impact with no terminal value (€m)	-106	-422	3,173	1,808
Per share (€)	-0.02	-0.07	0.52	0.30
Impact with terminal value at 5x (€m)	-516	-1,191	4,994	2,881
Per share (€)	-0.09	-0.20	0.82	0.48

Source: UBS estimates

Bear case versus worst case

In what we call the 'political' scenario we have simulated the net cost for Enel as a function of the 'overshooting' of the emissions target, the latter being based on Enel's historical emissions. This implies a relatively small cost for Enel in our calculation, owing to the significant reduction in the company's emissions in the 2001-05 period, in accordance with the reduction in fuel oil production.

If Enel has to reduce emissions in line with the sector after 2005, its costs could rise sharply

If instead we simulate that Enel is required to reduce emissions at the same pace as the sector after 2005, a criterion that would ignore Enel's reduction in emissions in 2001-05, then Enel's total net cost would rise as per what we call worst case. Again, the caveat here is that we have tried to ring-fence the sensitivity of the valuation to the terminal value, given that there is no visibility on what could happen after 2012.

If we were to use more aggressive terminal value assumptions versus our simplistic multiple of 5x, obviously the range in the table below would widen.

Table 27: Impact on Enel's valuation – sensitivity to discount rate (€/share)

	Bull case		Central case		Bear case	
Discount rate	With TV	No TV	With TV	No TV	With TV	No TV
6.0%	0.92	0.58	0.53	0.33	-0.10	-0.02
6.5%	0.89	0.56	0.51	0.32	-0.09	-0.02
7.0%	0.86	0.54	0.49	0.31	-0.09	-0.02
7.5%	**0.82**	**0.52**	**0.48**	**0.30**	**-0.09**	**-0.02**
8.0%	0.79	0.51	0.46	0.29	-0.08	-0.02
8.5%	0.77	0.49	0.44	0.28	-0.08	-0.02
9.0%	0.74	0.48	0.42	0.27	-0.07	-0.02
9.5%	0.71	0.46	0.41	0.26	-0.07	-0.01
10.0%	0.69	0.45	0.39	0.25	-0.07	-0.01

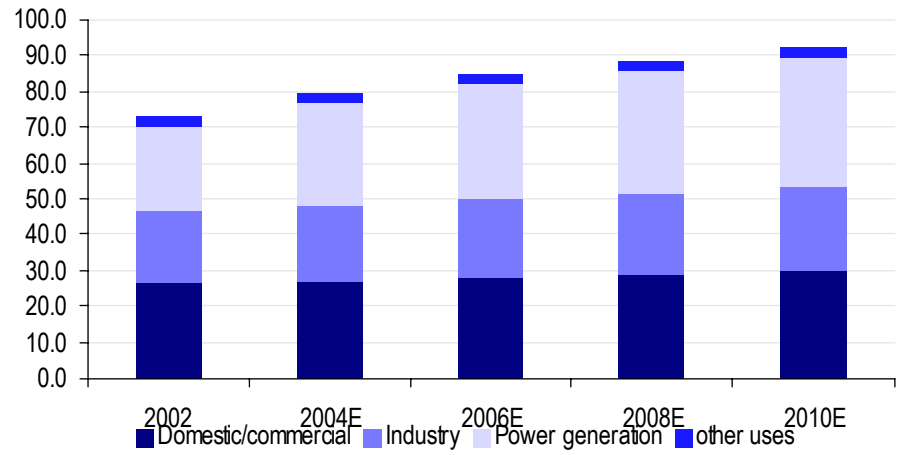
Source: UBS estimates

Effect on gas demand and gas prices

Power generation to be major driver of gas demand growth to 2010

As we argued earlier, our electricity market model already incorporates a fairly heavy move to CCGT production, as a result of both new capacity and conversions from fuel oil. Based on our Italian gas demand forecasts, we believe power generation should rise from 32% of total in 2002 to 39% in 2010, and be the major driver of a c3% CAGR in total gas demand over the same period.

Chart 68: Italian gas demand (bcm, 2002-10E)



Source: UBS estimates

McKinsey: CO_2 permits could lead to higher gas demand and higher prices

Our Enel model is simplistic in that it assumes that gas prices remain pegged to the oil price and remain broadly flat in 2005-10, since we project no change in the oil price post 2005. McKinsey & Co, however, estimates that the introduction of CO_2 permits could lead to an increase in gas demand CAGR from 2.7% to 3.8%, leading to an increase in gas prices of up to 15% by 2010.

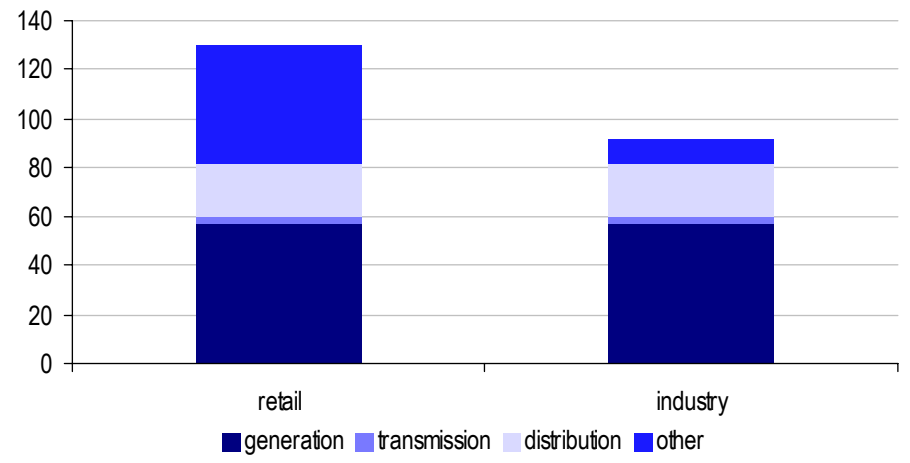
Final prices to the customer

This is another unclear subject as the retail portion of the Italian electricity market has yet to open to competition. We expect full opening in mid-2007 in accordance with EU requirements. About 80% of the retail market is still supplied by Enel as an integrated operator. We find it impossible at this stage to anticipate the extent with which an increase in generation cost, led by the introduction of CO_2 allowances, could be passed on to retail customers. But in broad terms we would expect a high, if not full, proportion of any additional cost to be passed on to retail customers, and a lower proportion to industrial customers.

20% rise in wholesale price implies retail prices up 9% and prices to industrial users up 135

We estimate that generation represented c45% of the average €130/MWh pre-tax price paid by retail customers in 2002, and 60% of the average €92/MWh paid by industrial users. Therefore, an increase of €12/MWh in wholesale prices, or c20% versus current levels, implies a 9% hit on the final retail price (pre-tax), and a 13% impact on industrial users.

Chart 69: Split of pre-tax electricity prices (€/MWh, January 2002)



Source: Autorità' per l'energia e per il gas, UBS estimates

Appendix 1: The EU Directive

The EU Directive

Scope

- The scheme initially covers carbon dioxide emissions from the following sectors:
  - Power, refineries and coke ovens
  - Cement, glass, ceramics, bricks
  - Pulp and paper
- The EU may extend the scheme to cover other industries and greenhouse gases in the second period from 2008. Member states can also unilaterally extend the scope from 2008.
- In the first phase (to 2007), countries can exempt individual installations, provided it can be shown that there is a scheme to reduce emissions in place that will achieve a similar objective.

Permits

- After 1 January 2005, Installations in these sectors can only emit greenhouse gases if they have been issued with a permit.
- This permit obliges the operator to comply with reporting requirements and submit emission allowances equal to the total emissions for the installation within *four months* of the end of each calendar year.
- Emitting greenhouse gases without a permit will incur penalties.

National Allocation Plan

- Each member state has to submit a National Allocation Plan to the European Commission by 31 March 2004, covering:
  - The total quantity of allowances to be issued in the three-year period from 2005 to 2007 inclusive
  - The method for allocating these allowances between installations
- For subsequent five-year periods, the plan should be published 18 months before the start of the period. So, for 2008-2012, the allocation plans for the second phase will be published by 30 June 2006.
- The Commission has three months to reject all or part of the plan, and has to give reasons why. Final allocations have to be notified at least three months before the start of first period and 12 months before the start of any subsequent period.
- The National Allocation Plans should be drawn up according to the following criteria:

- The total quantity of allowances will be determined by each member state and approved by the Commission as a part of the National Allocation Plan.

- The total quantity of allowances to be allocated shall be consistent with a path towards 'achieving or overachieving' each country's obligation under the Kyoto Protocol.

- The quantity of allowances should take into account the proportion of emissions covered by the sectors and gases covered by the scheme, national energy plans and the national climate change programme.

- The distribution of allowances between sectors may take account of the carbon intensity of each sector and the scope for reducing emissions in the future. The impact of competition from outside the EU may also be taken into account.

- The allocation plans should not discriminate between companies or sectors and should not constitute state aid.

- The allocation plans should address the treatment of new entrants (defined as installations not included in the original allocation for each period).

- At least 95% of allocations will be issued free of charge in the first period (2005-2007) and 90% for the second period (2008-2012).

How the scheme will work

- Out of the total allocation of allowances for each three- or five-year period, a proportion will be allocated in each year on or before 28 February.

- Once allocated, these allowances can be transferred (traded).

- By 30 April each year, each installation needs to surrender sufficient allowances to cover emissions during the previous calendar year. Failure to submit allowances will result in a fine of €100 per tonne (€40 in the first period). This is not a 'buy-out' – operators will still be required to submit allowances to cover these emissions in the following year.

- Allowances for a given three- or five-year period can be used for any emissions during than period. As there is an overlap, next year's allocation of allowances can be used for last year's emissions and vice versa.

- Unused allowances valid for the first period will be cancelled. However, member states have the option of replacing these permits with allowances for the second period. In subsequent period, member states are required to replace any unused allowances from previous periods with new allowances.

Administration

- Member states have to pass legislation to comply with the Directive by 31 December 2003 (article 31 of the latest public Directive draft).

- Each member state is responsible for maintaining a register of allowances, monitoring, reporting and verifying emissions and providing reports to the commission.

- There will also be a central administrator maintaining an independent register of allowances as a cross-check on member state registries.

Linking with the CDM and JI

- The so called 'project based mechanisms' of the Kyoto Protocol includes the Clean Development Mechanism (CDM), which applies to developing countries, and the Joint Implementation (JI), which applies to other countries. Proposals to link to these mechanisms to the EU trading scheme are being developed separately and are intended to apply in parallel with the emissions trading Directive.

Major review in 2006

- Before 30 June 2006, the Commission will draw up a report on the trading scheme covering:

  — The possible extension of the scheme to other sectors and greenhouse gases (chemicals, aluminium and transport are specifically mentioned);

  — The relationship of the EU scheme with the international trading scheme due to start in 2008;

  — Possible further harmonisation of allocation plans, including possible auctioning after 2012;

  — The use of credits from project mechanisms (CDM, JI);

  — The possibility of a single EU registry of allowances;

  — How to adapt the scheme to the enlarged European Union.

Appendix 2: Glossary of terms

Glossary of terms

This is a condensed version of the glossary found on **www.co2e.com**. We have selected the terms that we believe are the most relevant to our readers.

A

Abatement

Abatement is the reduction in the quantity or intensity of **greenhouse gas emissions.**

Additionality

According to the Kyoto Protocol Articles on Joint Implementation and the Clean Development Mechanism, **Emissions Reduction Units** (ERUs) will be awarded to project-based activities provided that the projects achieve reductions that are 'additional to those that otherwise would occur'. A distinction is made between environmental additionality and economic/financial additionality.

Financial additionality means projects will only earn credit if funds additional to existing ODA commitments are specifically committed to achieve the greenhouse gas reductions.

Environmental additionality requires that emission reductions represent a physical reduction or avoidance of emissions over what would have occurred under a business as usual scenario.

Allocation

Allocation is the number of credit or allowance permits provided to an emissions source (e.g. a company with net emissions) by a jurisdictional regulatory body during a specific compliance period. Allocation of permits occurs primarily through **grandfathering** or **auctioning.**

Allowance

Allowances are the unit of trade under closed systems. Allowances grant the holder the right to emit a specific quantity of pollution once (e.g. one tonne). The total quantity of allowances issued by regulators dictates the total quantity of emissions possible under the system. At the end of each compliance period each source must surrender sufficient allowances to cover their emissions during that period.

Assigned amount (AA) and assigned amount units (AAUs)

The assigned amount is the total amount of **greenhouse gas** that each country is allowed to emit during the **first commitment period** of the **Kyoto Protocol.** This total amount is then broken down into measurable units.

Auctioning

Auctioning is a method for issuing emission **permits** to emitters and firms in a domestic emissions trading regime based on a willingness to pay for the permits. This method of allocation may be combined with **grandfathering.**

Avoided emissions

Avoided emissions would have been emitted under a **business as usual scenario** but were avoided due to the implementation of an emission reduction project.

B

Banking

Within the Kyoto Protocol, emission permits not used in one **commitment period** can be saved or 'banked' for future use in a subsequent compliance period.

Baseline and baseline scenario

The baseline represents the forecast emissions of a company, business unit or project, using a **business as usual scenario,** often referred to as the 'baseline scenario', i.e. expected emissions if the firm did not implement emission reduction activities. This forecast incorporates the economic, financial, technological, regulatory and political circumstances within which a firm operates.

Binding targets

Binding targets are agreed or mandated emission limits on an entity that are to be met at a specific point of time or period.

Bubble

A bubble is a regulatory concept whereby two or more emission sources are treated as if they were a single emission source. This creates flexibility to apply pollution control technologies to whichever source under the bubble has the most cost effective pollution control options, while ensuring the total amount of emissions under the bubble meets the environmental requirements for the entity. Bubbles are closed systems. Article 4 of the **Kyoto Protocol** allows a bubble to be formed between **Annex B** countries, for example the European Union nations.

Business As Usual scenario (BAU)

Estimate of a company's future and current emissions under normal operating circumstances. Depending on the scope of the business as usual scenario this may incorporate some emission reduction regulatory controls including carbon taxes etc.

C

Cap and trade

The cap and trade system involves trading of emission allowances, where the total allowance is strictly limited or 'capped'. A regulatory authority established the cap, which is usually considerably lower (50% to 85%) than the historic level of emissions. Allowances are created to account for the total allowed emissions (an allowance is a unit of measurement referred to as AAU). Trading occurs when an entity has excess allowances, either through actions taken or improvements made, and sells them to an entity requiring allowances because of growth in emissions or an inability to make cost-effective reductions. Cap and trade programmes are closed systems, but can be modified to allow the creations of new permits by non-capped sources in the manner of credit-based systems.

Carbon dioxide equivalent (CO_2eq)

Is the universal unit of measurement used to indicate the **global warming potential** (GWP) of each of the six greenhouse gases. It is used to evaluate the impacts of releasing (or avoiding the release of) different greenhouse gases.

Carbon dioxide or CO_2

A naturally occurring gas that is a by-product of burning fossil fuels and biomass, land use changes and other industrial processes. Carbon dioxide is the reference gas against which other **greenhouse gases** are measured.

Carbon offsets

See **Offsets**

Carbon sink

A carbon sink is a reservoir that can absorb or 'sequester' carbon dioxide from the atmosphere. Forests are the most common form of sink, as well as soils, peat, permafrost, ocean water and carbonate deposits in the deep ocean.

Chlorofluorocarbons (CFCs)

CFCs are organic compounds that contain carbon, chlorine, and fluorine atoms. They are widely used as coolants in refrigeration and air conditioners, as solvents in cleaners, and as propellants in aerosols.

CFCs are the main cause of stratospheric ozone depletion. One kilogram of the most commonly used CFCs may have a direct effect on climate thousands of times greater than that of one kilogram of CO_2. However, because CFCs also destroy ozone – itself a greenhouse gas – the actual effect on the climate is unclear.

Clean Development Mechanism (CDM)

The CDM is a mechanism established by Article 12 of the **Kyoto Protocol** for project-based emission reduction activities in developing countries. The CDM is designed to meet two main objectives: to address the **sustainable development** needs of the **host country**, and to increase the opportunities available to Parties to meet their reduction commitments.

A coal bed methane emission reduction project captures methane released from coal bed seams during the mining process for flaring or energy use.

Cogeneration

This process involves the use of waste heat from electric generation, such as exhaust from gas turbines, for industrial purposes or district heating.

Credit for early action

Within the **Kyoto Protocol,** Annex B governments cannot receive credits before the first **commitment period** (2008-12) towards their emission obligation, except under the **Clean Development Mechanism**. However some governments have suggested giving credit for early action taken before 2008 with the intent to stimulate investment in their emission abatement projects.

D
E

Early action

The action of reducing emissions, investing in **Clean Development Mechanism** projects, **Joint Implementation** or trading emissions before the start for the **Kyoto Commitment Period.**

Eligibility Criteria

The **Kyoto Protocol** and jurisdictional criteria that must be met by an emissions reduction project to produce reductions that can be banked, traded or offset against emissions.

Emission allowance

Emission allowances are the total emissions allowed to be released by an emission source (often a net emitting firm) within a given period of time. Emission allowances are created by a regulating entity and distributed to emitters by grant, auction, or a combination of the two.

Emission cap (or cap)

A regulatory device that sets a ceiling on emissions that can be released into the atmosphere within a designated timeframe. Within the **Kyoto Protocol** Annex B countries agreed to caps on emissions within the 2008-2012 timeframe in reference to 1990 emissions levels. Caps are effectively the same as 'Allowances', but caps more often refer to national emission limitations and allowances to individual emitters.

Emissions trading

Emissions trading is a general term used for the three **Kyoto Protocol** flexibility mechanisms. It is a market-based system that allows firms the flexibility to select cost-effective solutions to achieve established environmental goals. With emissions trading, firms can meet established emission goals by: (a) reducing emissions from a discrete emissions unit; (b) reducing emissions from another place within the facility; (c) securing emission reductions from another facility, or (d) securing emission reductions from the marketplace. Emissions trading encourages compliance and financial managers to pursue cost-effective emission reduction strategies and provides incentives to emitters to develop the means by which emissions can inexpensively be reduced.

EU bubble

Under the **Kyoto Protocol**, the individual countries that comprise the European Union have aggregated their emissions and accepted an aggregated emissions reduction target. This has been reallocated back to the individual countries to allow differentiation of national reduction programs. The arrangement allows the target to be shared among all countries within the bubble.

F

Flexibility mechanisms

The **Kyoto Protocol** has provisions that allow for flexibility in how, where, and when emissions reductions are made via three mechanisms: the **Clean**

Development Mechanism, International Emission Trading and **Joint Implementation**. These mechanisms have been established to increase flexibility and hence reduce the costs of reducing emissions.

G

Global warming

The continuous gradual rise of the earth's surface temperature thought to be caused by the greenhouse effect and responsible for changes in global climate patterns.

Global warming potential (GWP)

The **GWP** is an index that compares the relative potential of the six **greenhouse gases** to contribute to global warming, i.e. the additional heat/energy which is retained in the earth's ecosystem through the release of this gas into the atmosphere. The additional heat/energy impact of all other greenhouse gases are compared with the impacts of **carbon dioxide** (CO_2) and referred to in terms of a **CO_2 equivalent** (CO_2eq). **Carbon dioxide** has been designated a GWP of 1, while **methane** has a GWP of 23. The latest officially released GWP figures are available from the **IPCC** in their publication *Climate Change 2001: The Scientific Basis*.

Grandfathering

Method for issuing emission permits to emitters and firms in a domestic emission trading scheme according to their historical emissions. This method of allocation may be combined with **auctioning.**

Greenhouse effect

The impact of human activities that cause certain gases to be released and trapped in to the earth's atmosphere. They then absorb the sun's energy and cause the earth to warm at a faster rate than usual. It is named after the phenomena of glass trapping heat in a greenhouse.

Greenhouse gas reduction or emission reduction

A reduction in emissions intended to slow down the process of global warming and climate change. Greenhouse gas reductions are often measured in tonnes of carbon-dioxide-equivalent (CO_2eq), which is calculated according to the **GWP** of a gas.

Greenhouse gases (GHGs)

The greenhouse gases in most contexts are the six gases regulated under the Kyoto Protocol, determined to be the main contributors to the **greenhouse effect.** The three principle gases are

- **carbon dioxide** (CO_2)
- **methane** (CH_4)
- **nitrous oxide** (N_2O)

In addition to these three GHGs, there are other gases that are engineered chemicals which occur on a very limited basis in nature:

- **Hydrofluorocarbons** (HFCs)
- **Perfluorocarbons** (PFCs)
- **Sulphur hexafluoride** (SF_6)

Although they are more potent greenhouse gases and tend to have comparatively high GWPs, they are emitted in such small quantities that their overall impact is currently small.

H

Hot air

Reductions of greenhouse gases that have occurred due to economic collapse or declined production for reasons not directly related to intentional efforts to curb emissions.

Hydrofluorocarbons

Hydrofluorocarbons (HFCs) are being developed to replace chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs) for use primarily in refrigeration and air conditioning equipment. These gases also are inadvertently emitted during some manufacturing processes.

I

Intergovernmental Panel on Climate Change (IPCC)

The World Meteorological Organisation (WMO) and the United Nations Environment Programme (UNEP) formed the Intergovernmental Panel on Climate Change (IPCC) in 1988. The IPCC represents the collective work of more than 2,000 scientists, principally in the atmospheric sciences, but also comprising social, economic and other environmental components potentially impacted by climate change. Between its three Working Groups, the IPCC assesses the scientific and socioeconomic aspects of human-induced climate change, as well as options for greenhouse gas reduction and other forms of climate change mitigation. Its Task Force on National Greenhouse Gas Inventories is responsible for overseeing the National Greenhouse Gas Inventories Programme (NGGIP).

The IPCC neither conducts original research nor monitors climate-related data, but its periodic assessment reports and technical papers play a very important role in the creation of climate change policies worldwide. The IPCC was instrumental in establishing the Intergovernmental Negotiating Committee for the United Nations Framework Convention on Climate Change (UNFCCC, or the Convention) in 1992.

Internal trading

An intra-company emissions trading system allowing the trade of emission permits among a firm's own business units with the objective of maximising cost-effective internal emission abatement opportunities.

International emissions trading (IET)

IET is a flexibility mechanism of the Kyoto Protocol which allows the trade of **assigned amount units (AAUs)** among Annex B countries. It is expected that this activity will be delegated by national governments to entities within their jurisdictions so that international trading between entities will occur. This will adjust each nation's 'pool' of AAUs.

J

Joint Implementation (JI)

Joint Implementation refers to emission reduction projects jointly implemented by entities within different industrial nations JI is an extension of the concept developed in the Activities Implemented Jointly pilot that ends in 2000.

Kyoto commitment period (or compliance period)

The Kyoto commitment period is the period in which Annex B countries have committed to reduce their collective emissions of greenhouse gases by an average of 5.2%. There are currently no emissions targets after the commitment period specified in the **Kyoto Protocol** from 2008 to 2012. These targets, if the United Nations Framework Convention on Climate Change (UNFCCC or the Convention) process continues in its present form, will be negotiated closer to the expiration of the first commitment period. It is expected that the current model of five-year periods of commitment will be maintained. Major questions regarding future commitment periods include the level of allowed emissions among capped (Annex I) countries and the extent to which additional countries take on caps (that is, developing country participation).

Kyoto Protocol

The Kyoto Protocol originated at the 3rd COP to the United Nations Convention on Climate Change held in Kyoto, Japan in December 1997. It specifies the level of emission reductions, the deadlines and methodologies that signatory countries (i.e. countries who have signed the Kyoto Protocol) are to achieve.

K
L
M

Marginal abatement cost (MAC)

The cost of reducing emissions by one tonne of CO_2eq. An aggregation of these costs against total tonnes abated creates a firm's marginal abatement cost curve. The lower the MAC curve, the more effective the firm's emission reduction strategies

Monitoring

Monitoring relates to the regular measurement, assessment and recording of emissions and emission reductions by an emitting firm or an emission reduction project. For example, emitting firms may monitor the actual level of emissions reduction achieved as a result of internal abatement programs.

N

National self-determination

Self-determination is the process of a nation (or a firm) deciding its own framework for emission control, measurement and monitoring methodologies, without reference to the wishes of any other nation, firm or agency.

O

Operational entity

Operational entity is an entity authorised by the CDM Executive Board to be able to approve output from CDM projects.

P

Permit

Permits are certificates of operation that allow the holder to operate a facility provided they do not exceed a specified rate (e.g. kilograms/tonnes per day). Permits are often designated as an upper limit. Because few systems operate at 100% of capacity at all times, actual emissions are usually a fraction of the theoretical upper limit of allowed emissions. However, as new permits become harder to obtain, existing operations are motivated to increase their level of operations under their existing permits (e.g. adding a second shift, thereby legally increasing the overall quantity of emissions).

Polluter pays

Principle that pollution (specifically greenhouse gas emissions) creating entities should pay compensation to third parties for pollution damages. This equates to polluters paying for the environmental externalities created by pollution.

R

Reference Year

The reference year is the benchmark year on which emission reduction targets are established. The Kyoto protocol uses 1990 as the reference year against which Annex I nations are required to control their emissions.

Renewable energy

Renewable Energy is included in the project **Class** under the **Energy Use** Category on the CO_2e Trading Floor (Abb: Renew). Renewable energy is electricity that is generated using renewable energy sources (solar, photovoltaic, wind, geothermal, biomass, and hydroelectric technologies) and which adhere to sustainable development practices.

Renewable energy certificates (RECs)

A renewable energy certificate represents a unit of electricity generated from renewable energy with low net greenhouse gas emissions. One REC represents 1 megawatt-hour (1000 kilowatt-hours). A REC is the unit referred to in the Australian mandatory scheme, and also in the voluntary European scheme.

Renewable obligation certificates (ROCs)

An ROC represents a unit of electricity generated from renewable energy in the UK. One ROC is issued for each megawatt-hour (1000 kilowatt-hours) of renewable electricity generated. Suppliers can purchase ROCs with the power either from a generator, or they can buy them on the market separately from the power, to meet their mandatory targets for renewable energy in the UK.

S
T

Tradable emission permits

A permit is an authorisation allowing an emitter to emit a specified number of tonnes of emission. Once those tonnes have been emitted, the permit expires. The total number of permits in any tradable market equals the desired level of emissions sought by the regulating authorities. Tradable permits allow emitters to determine the most economic manner to cover their emissions – by buying permits to cover emissions, taking actions to reduce emissions and selling excess permits, or a combination of those activities.

■ Statement of Risk

The assumptions made in this document are based on publicly available information from EEA . The adoption of Emissions Trading Schemes is both a EU and domestic process and many of the assumptions made in this report are exposed to a risk.

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Global ratings: Definitions and allocations

UBS rating	Definition	UBS rating	Definition	Rating category[1]	Coverage[2]	IB services[3]
Buy 1	Excess return potential > 15%, smaller range around price target	**Buy 2**	Excess return potential > 15%, larger range around price target	**Buy**	34%	43%
Neutral 1	Excess return potential between -15% and 15%, smaller range around price target	**Neutral 2**	Excess return potential between -15% and 15%, larger range around price target	**Hold/Neutral**	57%	41%
Reduce 1	Excess return potential < -15%, smaller range around price target	**Reduce 2**	Excess return potential < -15%, larger range around price target	**Sell**	9%	38%

Excess return: Target price / current price - 1 + gross dividend yield - 12-month interest rate. The 12-month interest rate used is that of the company's country of incorporation, in the same currency as the predicted return.
US Closed-End Fund ratings and definitions are: Buy: Higher stability of principal and higher stability of dividends; Neutral: Potential loss of principal, stability of dividend; Reduce: High potential for loss of principal and dividend risk.
UK and European Investment Fund ratings and definitions are: Buy: Positive on factors such as structure, management, performance record, discount; Neutral: Neutral on factors such as structure, management, performance record, discount; Reduce: Negative on factors such as structure, management, performance record, discount.
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2: Percentage of companies under coverage globally within this rating category.
3: Percentage of companies within this rating category for which investment banking (IB) services were provided within the past 12 months.

Source: UBS; as of 30 June 2003.

Companies mentioned

Company Name	Reuters	Rating	Price*
Centrica	CNA.L	Buy 2	185p
E.ON[10a,12]	EONG.DE	Buy 2	€42.65
Endesa[10b,12]	ELE.MC	Neutral 2	€13.41
Enel[10a,12]	ENEI.MI	Neutral 2	€5.39
Iberdrola[10a,12]	IBE.MC	Buy 1	€14.66
International Power[7]	IPR.L	Neutral 2	134p
RWE[3a,10a]	RWEG.DE	Neutral 2	€23.32
Scottish & Southern[10a,12]	SSE.L	Neutral 1	610p
ScottishPower[3b,3a,8,10a]	SPW.L	Buy 1	356p
Suez[3b,3a,9,10a,12]	LYOE.PA	Neutral 2	€13.99
Union Fenosa	UNF.MC	Neutral 2	€14.42

* As of 26 September 2003. Source: UBS.

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