REPORT

The Brattle Group

ALSTOM

March 2009

Authors:

Serena Hesmondhalgh
Principal

Toby Brown
Senior Associate

David Robinson
Principal

The Brattle Group *provides consulting and expert testimony in economics, finance and regulation to corporations, law firms and governments around the world.*

For more information please visit ***www.brattle.com****.*

ALSTOM Power Systems *is a global leader in equipment and services for power generation and rail transport. The Group is present in more than 70 countries worldwide.*

For more information please visit ***www.alstom.com.***

EU Climate and Energy Policy to 2030 and the Implications for Carbon Capture and Storage

A Report for ALSTOM Power Systems

Contents

Introduction and Executive Summary

This report examines the prospects for carbon capture and storage (CCS) technology in the EU, in the light of current and forecast carbon prices. It adopts the basic premise of recent International Energy Agency (IEA) studies: that coal-based generation will continue to grow worldwide; that CO_2 emissions from coal plants will pose a significant environmental policy challenge; and that CCS is the only currently available technology to directly cap coal-based CO_2 emissions.

First, the report argues that CCS is central to key EU energy policy goals concerning carbon reduction and security of supply. We show that to meet its self-imposed 2020 greenhouse gas emissions reduction target of 20% below 1990 levels, the EU requires CCS unless it *both* relies on meeting its highly ambitious targets on renewable energy and energy efficiency, *and* is also willing to accept a significant increase in gas imports from Russia, the Middle East and Africa. The report also examines the interaction of the emissions target with other energy policy instruments, for instance showing how even apparently small under-achievement of the EU's efficiency or renewable targets could make it significantly more difficult to reach the target. For example, a 1% underachievement of the energy efficiency target would imply that emissions reductions would have to be over 3% higher. For a 1% under-achievement of the renewables target there would either have to be a 5% decrease in generation emissions or a 10% decrease in the average emissions per unit of electricity (see Appendix I).

If 2030 targets are set in line with the EU's longer-term ambitions for greenhouse gas emission reductions, it seems likely that the EU may struggle to meet the targets unless CCS can be part of the low-carbon repertoire, even on the most optimistic scenarios for nuclear and renewables ramp up. With regards to security of supply, there is a perceived EU need for fuel diversity (including coal) both to provide security of supply and to enable the EU to react to changing fuel market conditions; CCS is one way of achieving this objective.

Second, the report examines whether carbon prices are sufficient to stimulate private investment in CCS. Even before the recent (early 2009) collapse in EU Emissions Trading Scheme (ETS) allowance prices, from 25 €/t CO_2 to 11 €/t CO_2, carbon prices[1] were below the levels required to make CCS economic. Estimates of the costs of CCS vary widely, but, over the wide range of recent fuel price levels, carbon prices would have to be significantly above the levels that have been seen to justify investment. Given the unlimited banking between Phase II (2008-12) and Phase III (2013-2020), carbon prices today should provide some indication of the market's view of prices until the end of Phase III in 2020 (subject to the caveat in the next paragraph). We conclude that markets alone are unlikely to bring forward investment in CCS before 2020, particularly given the volatility that carbon prices have displayed.

Third, although the current carbon spot price is market participants' best expectation of what the carbon price will be in the future, there is still significant uncertainty about what the carbon price will actually turn out to be. We assess the potential magnitude of some of the most important sources of uncertainty, with correspondingly major implications for investment in CCS. As a starting point, the report identifies the key determinants of carbon prices. It focuses on the role played by the electricity sector, and in particular the role of coal and gas, given that substitution between coal and gas will be the main tool for reducing generation emissions at least through 2020, and moreover is likely to be the "marginal" source of abatement. The relative prices of coal and gas are, therefore, key determinants of the price for carbon. For example, if coal becomes more expensive relative to gas, the price of carbon in the EU ETS will fall as it becomes cheaper to generate using gas, which produces less CO_2. Conversely, lower than anticipated economic growth will mean that the emissions target can be more easily met, a particularly relevant consideration given the widespread effects of the economic downturn produced by the "credit crunch". A key implication is that potential investors in CCS face significant price uncertainty, some of which is linked to policy instruments.

1. We use carbon price and CO_2 price interchangeably in this report, but all prices are reported in units of €/t CO_2.

Factors influencing the carbon price

The European Commission has estimated that carbon prices in Phase III could be around 30 €/t CO_2, assuming that there is no agreement among other developed countries on reducing emissions post-2012.[2] Other forecasts, primarily from banks, suggest that the 25 €/t CO_2 level of Phase II carbon prices seen during most of 2008 (*i.e.*, before the credit crunch led to declining demand for allowances and a slump in carbon prices), could be up to 10 €/t CO_2 lower than might rationally be expected on the basis of the underlying fundamental determinants of the carbon price.

Our own analysis presented in this report comes to a similar conclusion: carbon was under-priced even at 2008 levels. Various explanations have been put forward to explain why this has occurred. The general view appears to be that the market has not sufficiently taken into account the effects of unlimited banking of allowances between Phases II and III, which should raise the price in Phase II since there is a clear economic incentive to bank Phase II allowances so as to meet the more stringent Phase III caps.

Table 1 summarises the main factors that might move carbon prices up or down from these levels.

Table 1 Potential Influences on CO_2 Prices

Factor	Effect on CO_2 prices
Higher than expected economic growth	*Upward* — increased demand for allowances
Coal prices fall relative to gas prices	*Upward* — increased demand for allowances
International agreement on abatement post-2012	*Upward* — EU will tighten cap on emissions but not allow additional JI/CDM credits fully to compensate
Failure to meet renewables and/or energy efficiency targets	*Upward* — increased demand for allowances
Overall fuel prices	*Uncertain* — lower prices may increase energy demand but will mitigate effect of fuel price differentials and vice versa for higher prices
Economic downturn	*Downward* — reduced demand for allowances
Coal prices rise relative to gas prices	*Downward* — reduced demand for allowances
Trading of Renewables Guarantees of Origin to meet national renewables targets	*Downward* — theoretically more chance of renewables target being met but also the risk of less political support for generous national feed-in tariffs for renewables

Recent variability in carbon prices

Over the past year, the price of emission allowances for 2010 has risen from 20 €/t CO_2 (February 2008) to over 30 €/t CO_2 (in July 2008) and then fallen to 8 €/t CO_2 (early February 2009). As Table 1 suggests, part of this variability may be traceable to the dramatic changes in the levels of gas and coal prices over the past months. When carbon prices were at their peak, the relative levels of forward gas and coal prices for 2010 (44 €/MWh for gas, 130 €/t for coal) meant that there was unlikely to have been an expectation of significant switching from existing coal to existing gas-fired plants. Recent (February 2009) forward prices for 2010 (21 €/MWh for gas, 69 €/t for coal, 11 €/t CO_2) mean that switching between existing plants in 2010 should be more likely. However, in both situations, the carbon prices should have been sufficient to encourage more rapid investment in new, more efficient, gas-fired capacity, which would substitute for older coal-fired plants.

2. Table 15 of Commission Staff Working Document "Annex to the Impact Assessment," European Commission, February 2008.

Required investments in low-carbon technologies

A large part of the emissions reductions required by EU targets can be achieved without investing in new low-carbon technologies, as a result of factors including the Large Combustion Plant Directive (LCPD) and the use of Joint Implementation (JI) and Clean Development Mechanism (CDM) credits.[3] The LCPD requires around 60 GW of the existing 250 GW of coal plant to close by 2015 in lieu of fitting expensive sulphur abatement equipment. This is likely to result in an "automatic" reduction of CO_2 emissions of up to 100 Mt CO_2 per year, from 2016 onwards.

Unused JI/CDM credits from Phase II can be carried over into Phase III, but no new credits will be allowed unless there is wider international agreement on the need for carbon abatement and the EU moves to a 30% reduction target, in which case half of the additional savings in the ETS can be covered by new JI/CDM credits. However, the JI/CDM limits in Phase II are quite generous, and the European Commission expects the credits to be significantly cheaper than ETS allowances. Use of JI/CDM may cover around 160–180 Mt CO_2 per year during Phase III.

However, even taking both these factors fully into account, emissions reductions of around 130 Mt in 2020 will still need to be found if the 20% reduction cap is to be met. If all of this reduction had to be met by the electricity sector, it would broadly correspond to replacing 20 GW of baseload coal plant with zero emissions, assuming there are no other changes to the plant mix and no growth in demand. A further 16 GW of new zero emissions plants will be required if the early closure nuclear programmes in Germany and Belgium are maintained.

Looking further out to 2030, the required level of emissions reductions will increase — although, at this stage, it is unclear by how much more than for 2020. A 2030 target of 30–40% reductions in GHG emissions from 1990 levels might require a radical transformation of the generation sector relative to today. All coal plants without CCS could be closed, being replaced with some new gas capacity plus at least 61 GW of new zero carbon generation. Alternatively, if newer coal plants remain on the system, around 100 GW of new zero carbon capacity would be required, displacing older coal- and gas-fired plant.

Implications for CCS

Under such circumstances, CCS could play an important, possibly vital, role, but only if the technology has been developed to a commercial stage well before 2030. However, our analysis shows that the level of carbon prices required to make CCS competitive on purely commercial terms appears to be higher than seems likely to be the case before 2020. A second possible problem for CCS is that if coal prices are very high (as they were in 2008), even plants built for demonstration purposes may be unable to run without making operating losses. Moreover, the volatility of carbon prices that has been apparent in Phase II points to a further difficulty: namely that it is difficult for potential investors to have sufficient certainty about CO_2 prices to justify additional capital investment to reduce emissions.

In terms of support options for CCS, the EU has adopted the policy of allocating up to 300 million allowances from the EU ETS New Entrants Reserve to CCS projects. In addition, the European Commission has proposed that up to five CCS pilot projects will each be able to receive €180 million of development aid under the "Economic Recovery Plan". Some individual Member States are also providing support at national level. Whether this support will be sufficient to fund the development of CCS plants will depend crucially on the carbon price. There are, however, at least three other support mechanisms that could be used to encourage CCS, although they would involve coordinated political decisions. The first option would be to impose a requirement to use revenues from the auctioning of emissions allowances to support demonstration CCS schemes. At a carbon price of 30 €/t CO_2, this could generate around €22 billion per year in 2020. Whilst we are not suggesting that all these revenues would or should be

3. JI and CDM are mechanisms that enable revenues to be paid to specific projects that reduce emissions and, in return, the emissions reductions can be counted as credits towards meeting emissions allowances.

allocated to CCS, the calculation demonstrates that, in principle, very significant support for CCS could be provided via this route. The second option would involve issuing free emission allowances to CCS projects in respect of the CO_2 that is put into storage. More sophisticated versions of this approach could involve using an "exchange rate" to reduce the number of allowances granted to CCS projects per tonne of CO_2 put into storage and/or capping the total number of allowances that could be issued. The final option would be to link the EU ETS to other carbon trading schemes that are being developed, particularly in the U.S. Such linkages would reduce volatility in carbon prices due to local effects.

Other Reasons to Build CCS

Carbon prices sufficient to make CCS attractive could well also make building new nuclear plants an attractive option. Whilst many EU countries have historically been unwilling to contemplate building new nuclear plants, the situation is now changing due to concerns about security of supply and the difficulty of relying heavily on renewables to meet CO_2 reduction targets. There are, however, other compelling arguments for supporting CCS. First, within the EU there is a perceived need for fuel diversity (including coal) both to provide security of supply and to enable the EU to react to changing fuel market conditions and CCS is one way of achieving this. Second, the rapid expansion of coal-fired generating capacity in China and India means that any hope of achieving significant global reductions in emissions must involve measures to slash the production of greenhouse gases from these plants and CCS is currently the only option available. Third, even on the most optimistic scenarios for nuclear and renewables ramp up by 2030, it seems likely the EU may struggle to deliver the desired level of abatement of CO_2 emissions unless CCS can be part of the low-carbon repertoire.

Structure of the report

Following on from this summary, this report covers the current and proposed policy framework for the European Union's Emissions Trading Scheme (EU ETS) and other energy and climate polices. We consider the way in which the ETS targets for Phase III (2013-2020) might be met and what implications this might have for security of supply. We go on to explain what we consider to be the key drivers of carbon prices and what these imply for the viability of CCS. We then extend our analysis to what might happen under Phase IV (2021-2030). Finally, we outline several policy options that could be used to provide further support to CCS, if this was considered necessary or desirable.

The report is structured as follows. Chapter 1 describes the details of the EU ETS whilst Chapter 2 provides an overview of other EU climate and energy change policies that are likely to interact with the ETS in the coming years. Both of these chapters are largely informational in nature but we turn, in Chapter 3, to analysis of how the 2020 emissions reductions might be achieved. From this analysis, we go on, in Chapter 4, to consider how coal-gas switching is likely to be a key determinant of carbon prices and what this implies for CCS. Although the report concentrates on Phase III, we extend our analysis in Chapter 5 to examine some scenarios for Phase IV (2020 to 2030). Finally, Chapter 6 considers at a high level some additional policy options that would help support CCS.

Chapter 1 | THE EU EMISSIONS TRADING SCHEME

The European Union has ambitious targets for reducing greenhouse gas emissions: in 2007, the European Council agreed that by 2020 EU greenhouse gas emissions should be 20% below 1990 levels or 30% below these levels if other developed countries agree to take action. In December 2008 these targets were reflected in a final agreement on new legislation on renewables and emissions trading. In the longer term, the EU has the aspiration that emissions should be reduced by 60–80% by 2050.[4] In this chapter, we describe the main policy instrument that the EU is using to achieve its greenhouse gas emission targets — the Emissions Trading Scheme or "ETS".

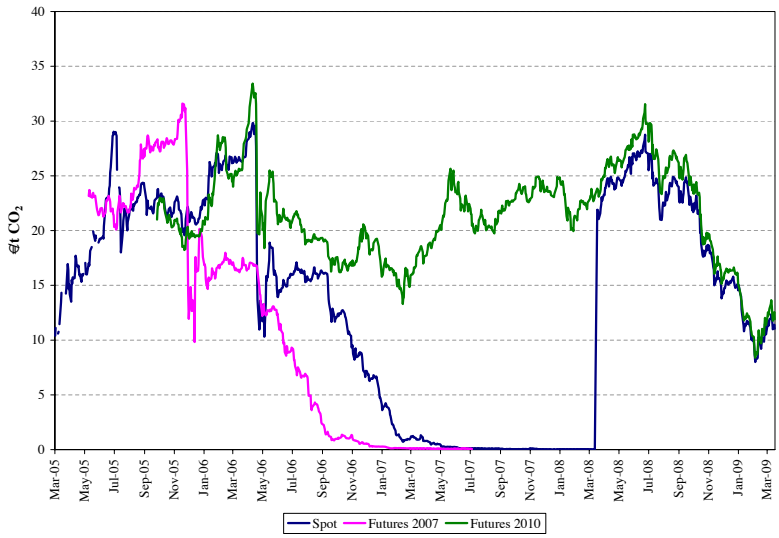
The EU Emissions Trading Scheme began in 2005: Phase I ran from 2005 to the end of 2007, and Phase II runs from 2008 until 2012. Large emitters of carbon dioxide in the sectors covered by the scheme must submit allowances for each tonne of CO_2 they emit. Member States issue allowances to each installation under rules and subject to overall caps reviewed and, in some cases, amended by the European Commission. Installations are able to trade allowances throughout the EU, and, subject to certain limits, to purchase allowances from outside the EU through JI/CDM.

1.1 Phases I and II of the ETS

1.1.1 Phase I

Phase I of the EU ETS is best regarded as a "trial run", whose objective was to set the scheme in motion and develop the necessary institutions and monitoring/auditing arrangements. Reducing emissions was probably of secondary importance. Phase I ran for only three years (2005 to 2007) and the scheme's designers were careful to ensure that there was no possibility for banking allowances between Phases I and II. As it turned out, the Phase I cap (number of allowances issued) was not particularly tight, and emissions in the first part of the period were lower than had been expected. As a result, prices from mid 2006 started to fall, and were essentially zero for the whole of 2007. However, because Phase I allowances could not be banked for use in Phase II, the fall in value of Phase I allowances had no effect on the value of Phase II allowances, which traded at between 20 €/t CO_2 and 25 €/t CO_2 until autumn 2008. Phase II prices then fell sharply to a minimum of 8 €/t CO_2 in early February 2009. Figure 1 illustrates this, and the Pew Center report[5] provides a good and detailed account of how the ETS worked in Phase I.

Figure 1 Prices for Phase I and Phase II ETS Allowances Over Time



4. "Developed countries should continue to take the lead by committing to collectively reducing their emissions of greenhouse gases in the order of 30% by 2020 compared to 1990. They should do so also with a view to collectively reducing their emissions by 60% to 80% by 2050 compared to 1990." European Council, March 2007.

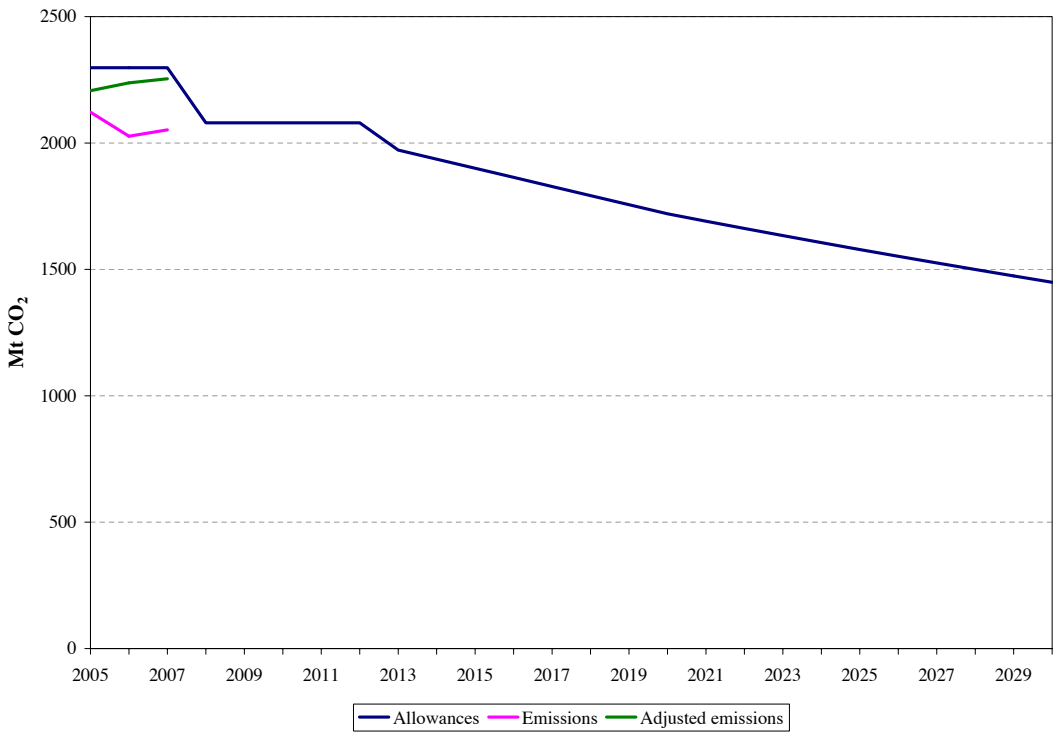
5. A. D. Ellerman and P. L. Joskow, *The European Union's Emissions Trading System in Perspective*, The Pew Center on Global Climate Change, May 2008.

1.1.2 Phase II

The most significant design difference between Phases I and II is that Phase II allowances are bankable, and can be used in later Phases. The cap in Phase II is tighter than in Phase I: although the Phase II cap was proposed by the Member States, the European Commission reviewed and in many cases tightened the Member State proposals because they did not meet the criteria set out in the legislation. Member States had proposed national allocations that in aggregate would have resulted in Phase II allowances approximately equal to the Phase I level, but after the Commission's review the final aggregate amount for Phase II is about 10% below Phase I.[6] Although they have fallen dramatically in the wake of the current recession, prices for Phase II allowances are still well above the low levels seen in the second half of Phase I, reflecting the tighter caps in Phases II and III (the option to bank allowances into Phase III means that a tighter Phase III cap feeds back into higher Phase II prices).

Various opt outs were allowed under Phase I of the ETS so that the reported emissions are not directly comparable with the emissions cap for Phase III. Deutsche Bank has reported "adjusted" emissions to take account of these opt outs. If the adjustment is correct, it indicates that 2007 emissions were just less than 160 Mt above the cap for 2008. Figure 2 below shows the past, current and proposed ETS emission allowances and also the actual and "adjusted" emissions from the sectors covered by the ETS.

Figure 2 ETS Emission Allowances (Actual and Proposed) and Actual Emissions



6. All on an annual average basis: the Phase I average cap was 2,298 Mt CO_2 and the Phase II cap (before inclusion of aviation) is 2,091 Mt CO_2 (figures taken from *Carbon Emissions — Aviation Deviation: EU Parliament Sends Bullish Signal for Phase 3*, Deutsche Bank, 2007).

1.2 Phase III

In December 2008 the EU agreed to the terms of a Directive setting out the rules for Phase III of the EU ETS, which will run from 2013 to 2020.[7] This Directive is intended to deliver reductions in emissions from the sectors currently covered by the ETS of 15% relative to 2005, over the 2013-20 period.[8] The ETS is expected to achieve 60% of the savings required to meet the overall greenhouse gas target, but around one third of the savings within the ETS may come from JI/CDM credits purchased from outside the EU.[9] The electricity generation sector is expected to deliver a significant proportion of the necessary savings within the ETS.[10]

There are a number of important changes between Phase III and Phases I and II of the ETS:

- *the European Commission, rather than Member States, will be responsible for issuing allowances (in Phases I and II the Commission had the power to review Member State allocations), and there will be fully harmonised rules for allocating free allowances;*
- *the allowances issued each year will decrease linearly over time at a rate of 1.74% of the total allowances;*
- *new sectors and gases are to be included (CO_2 from emissions from petrochemicals, ammonia and aluminium production, N_2O from the production of nitric, adipic and glyoxylic acids, and perfluorocarbons from aluminium production, in addition to aviation which is due to join during Phase II);*
- *allowances from Phase II can be banked and used in Phase III (without limit);*
- *Norway, Lichtenstein and Switzerland are to join; and*
- *about 60% of overall allowances and 100% of allowances for the power sector (subject to a few minor exceptions) will be auctioned, rather than being given away for free. However, industrial sectors subject to carbon leakage will receive 100% free allowances based on the benchmark of the best available technology.[11] The auctions will be carried out by the Member States, and the Member States will keep the auction payments.*

1.2.1 Credits From Outside the EU

Emission reduction credits from projects in countries outside the EU (operating under the "flexible mechanisms" of the Kyoto Protocol: the Clean Development Mechanism (CDM) and Joint Implementation (JI)) can be used within the EU ETS, up to the limits imposed by Member States in their National Allocation Plans for Phase II.[12] No further use of CDM/JI credits will be allowed in Phase III unless the EU moves to a 30% overall target. The European Commission expects that, as a result of using the credits allowed in Phase II, around one third of the required emissions savings in Phase III will come from this source. The European Commission also expects that JI/CDM credits will be relatively cheap (significantly less expensive than emissions reductions within the EU ETS).

1.2.2 Impact of International Negotiations

The overall greenhouse gas emissions proposals for Phase III are, to some extent, contingent on what happens in respect of international negotiations on emissions reductions post-2012. If there is an

7. Although the Directive has yet to be formally adopted, and so in that sense is a "draft" Directive, its terms have been agreed by the European Council of Ministers and the European Parliament. Consequently, we simply refer to it as a Directive.
8. See *Questions and Answers on the Commission's proposal to revise the EU Emissions Trading System* (MEMO/08/35), European Commission 2008.
9. See *Impact Assessment: Document accompanying the Package of Implementation measures for the EU's objectives on climate change and renewable energy for 2020* (SEC(2008) 85/3), European Commission 2008.
10. "This division, with about 60% of reductions to be achieved in EU ETS sectors, reflects the larger cost-effective potential in particular in the electricity sector compared to non ETS sectors." *Ibid.*, p. 8.
11. Industrial sectors not exposed to carbon leakage will receive 80% of their allowance for free in 2013 but their free allocations will fall to 30% by 2020.
12. Subject also to an EU level agreement on the overall level of JI/CDM credits.

international agreement, the EU ETS would be adjusted in two respects. First, the overall number of allowances issued would be reduced in proportion to the "extra" reductions[13] needed by the EU agreeing to go beyond a 20% cut. Second, the amount of JI/CDM credits that can be used within the ETS would rise, such that half of the "extra" reductions within the ETS could be covered by JI/CDM. Since not all the extra reductions could be met by increased JI/CDM credits (even assuming that enough were available to reach the increased limit), the result of tightening the overall cap would be to put upward pressure on carbon prices.

There is unlimited banking of allowances from Phase II into Phase III. In principle, this means that today's price for Phase II allowances should already represent market participants' expectations for the price in Phase III. However, as we discuss in sections 4.1.1. and 4.3.1. below, a number of forecasts of carbon prices suggest that the market may not have fully taken account of potential developments in the ETS and associated policies.

The European Commission will play a more central role in Phase III than it has in the ETS to date. However, each Member States will be able to determine how 80% of its auction revenues are used. The remaining twenty percent of the revenues must be used for one or more of the following purposes:

- *reduce greenhouse gas emissions to adapt to the impacts of climate change and to fund research and development for reducing emissions;*
- *help meet the 20% renewables and energy efficiency targets;*
- *support carbon capture and sequestration;*
- *support measures to avoid deforestation, in particular in Least Developed Countries;*
- *facilitate developing countries' adaptation to the impacts of climate change;*
- *address impacts on lower and middle income households; or*
- *cover the administrative expenses of the management of the ETS.*

The European Commission will bring forward a Regulation governing the conduct of the auctions, which are to be carried out by the Member States, in order to ensure that the auctions are coordinated and efficient.

1.2.3 Other Targets and Figures

In determining that Phase III of the EU ETS will deliver a 21% reduction in CO_2 emissions[14] relative to 2005, the EU has adopted a "burden sharing" position that fixes a target for sectors outside the EU ETS to reduce emissions by 10% relative to 2005 in each Member State. The 10% reduction in emissions from outside the ETS is necessary for the EU to meet its overall goal of reducing greenhouse gas emissions by 20% from 1990 levels, but it is not attached directly to mechanisms for delivering the required reduction.

1.3 Phase IV

Post 2020, the Directive envisages that the annual cap on emissions allowances would continue to fall at the same annual rate as during Phase III (1.7% in the current proposals, assuming an overall 20% greenhouse gas emissions reduction target for 2020). The European Commission has said that this would be reviewed no later than 2025.

13. For example, if the EU were to agree a 25% reduction rather than a 20% reduction, the total allowed emissions would fall by 5% of 1990 emissions. This number would be multiplied by the proportion of total reductions being achieved in the EU ETS (*i.e.*, 5% times 60% = 3% of 1990 emissions). The result is the amount by which the total Phase III ETS allowances would be reduced.
14. For specific industries, further greenhouse gases will also be covered by the ETS.

Chapter 2 | OTHER EU CLIMATE AND ENERGY POLICIES

In addition to the overall target relating to greenhouse gas emissions, there are a number of component targets and objectives, some of which are, or will be, legally-binding targets, while others are ambitions or signals of how policy makers expect to see the overall greenhouse gas target delivered. For example, the EU has also agreed that renewable energy should make up 20% of energy consumption by 2020 and that 10% of transport fuel should come from biofuels.[15]

2.1 Renewables

The EU has agreed to the terms of a Directive that will oblige Member States to meet legally binding renewable energy targets: each Member State has an individual target for renewables as a proportion of total energy consumption, and all Member States must meet a 10% biofuel target.[16] The combined effect of the individual renewable energy targets is that the EU as a whole would achieve the 20% target agreed by the European Council. The European Commission has not explicitly stated what the 20% target means for renewable generation, but it has said that more than half of the target will be met by renewable generation, and it is clear that a very large increase in installed capacity will be required. In recent years, about 8.5% of the EU's energy is renewable,[17] and about 14% of electricity is renewable.[18] The PRIMES scenarios, which seem to underpin much of the European Commission's analysis, suggest that the 20% renewables target corresponds to renewables producing around 42% of electricity generation (by output).[19] Table 2 shows the breakdown of renewable generation in 2006 by country.

Table 2 Renewable Generation as a Percentage of Electricity Consumption in 2006

Austria	56.6%	Germany	12.0%
Sweden	48.2%	Bulgaria	11.2%
Latvia	37.7%	Ireland	8.5%
Romania	31.4%	Netherlands	7.9%
Portugal	29.4%	Czech Republic	4.9%
Denmark	25.9%	UK	4.6%
Slovenia	24.4%	Belgium	3.9%
Finland	24.0%	Hungary	3.7%
Spain	17.7%	Lithuania	3.6%
Slovakia	16.6%	Luxembourg	3.4%
Italy	14.5%	Poland	2.9%
France	12.5%	Estonia	1.4%
Greece	12.1%		
EU average 14.3%			

Source
EU Energy in Figures 2009, European Commission

15. There has been considerable recent opposition to the biofuels target on environmental and other grounds.
16. Page 15 of Commission Staff Working Document, *Annex to the Impact Assessment*, European Commission, February 2008.
17. The figure is for 2006.
18. The figure relates to 2007.
19. The PRIMES scenario which corresponds to meeting the 2020 targets is the "high renewables and efficiency" scenario. See *European Energy and Transport, scenarios on energy efficiency and renewables*, European Commission, 2006.

2.2 Energy Efficiency

In a 2005 Green Paper on energy efficiency, the European Commission's assessment was that it would be possible and economic to save 20% of projected "business as usual" 2020 energy use through improved energy efficiency. The 20% reduction in projected energy use is one of the targets in the European Commission's "20 20 20"[20] policy paper. It is a clear policy goal, but it is not directly attached to a mechanism for achieving the goal, as is the case for the ETS, and it does not have legal force.[21] Nevertheless, energy efficiency is a very important part of the overall climate package. As discussed below, the other targets under the climate strategy have been set on the basis of forecasts which assume that the energy efficiency target is met: in the relevant PRIMES scenario, total energy use *decreases* in absolute terms by 0.7% per annum from 2010 to 2020, and electricity demand is almost flat — it increases at 0.1% per annum from 2010 to 2020.[22]

European legislation on end use energy efficiency requires Member States to develop "National Action Plans" on end use energy efficiency, and to adopt non-binding targets of saving 9% of average annual energy consumption compared to the "business as usual" scenario within nine years, *i.e.*, by 2015.[23]

2.3 Large Combustion Plant Directive

The Large Combustion Plant Directive (LCPD) is a European Union Directive that aims to reduce acidification, ground level ozone and particulates by controlling the emissions of sulphur dioxide, oxides of nitrogen and dust from large (>50 MW) combustion plant. New plants (those built after 1987) must comply with stringent emission limit values (ELVs), which means that new coal- and oil-fired plants must fit flue gas desulphurisation (FGD) equipment. Existing plants (those built before 1987) can either comply with the LCPD through installing FGD equipment or 'opt-out' of the Directive. An existing plant that chooses to 'opt-out' is restricted to operating for no more than 20,000 hours after 2007 and must close by the end of 2015.

The likely effect of the LCPD will be a swathe of plant closures between 2012 and 2015, as those plants that have opted out of the LCPD close. These plants will typically be old and inefficient, so CO_2 emissions should fall as a result of these plant closures since their output will be replaced by electricity from power stations with lower CO_2 emissions levels. However, the impact of the closures on CO_2 emissions will be limited by the fact that, typically, these old plants do not operate at high load factors.[24]

2.4 Support for CCS

The European Council and the European Commission have endorsed Carbon Capture and Sequestration (CCS) as an important technology for delivering future emission reductions. The EU has agreed to a Directive to remove legal barriers to CCS and to regulate site permitting, third party access to CO_2 transportation infrastructure, and other relevant matters. In addition, the European Commission has proposed that up to five CCS pilot projects will each be able to receive €180 million of development aid. This proposal will be discussed in a co-decision procedure by the European Council and the European Parliament.

20. ***20%*** renewables and ***20%*** energy efficiency savings by 20***20***.
21. Moreover, since it is expressed in terms of projected energy use, it is really an ambition to reduce energy consumption from what it would otherwise be rather than to reduce energy consumption in absolute terms.
22. See "high renewables and efficiency" scenario in *European Energy and Transport, scenarios on energy efficiency and renewables*, European Commission, 2006.
23. *Official Journal of the European Union*, Issue L114 - *Directive 2006/32/EC on Energy End-Use Efficiency and Energy Services and Repealing Council Directive 93/76/EEC*, April 2006, Page 75.
24. Some relaxation of the LCPD rules is being discussed but no decision has yet been reached.

The Directive on Phase III of the EU ETS makes it clear that allowances will not have to be surrendered in respect of CO_2 that goes into storage, and also lists CCS as one of the things on which Member States can spend the 20% of auction revenues that the ETS Directive requires to be spent on listed items (there are no restrictions on how the other 80% may be spent). In addition, up to 300 million permits from the EU ETS New Entrants Reserve will be allocated to CCS plants, with individual schemes receiving a maximum of 45 million allowances.[25]

Chapter 3 | ACHIEVING THE EMISSIONS REDUCTIONS REQUIRED BY 2020

As with any cap and trade system, the EU ETS achieves its goal of reducing emissions by ensuring that there is a scarcity of emission rights: as a result of the mismatch between supply and demand for rights, emitters bid up the price of allowances until the point at which the marginal cost of abatement equals the price for allowances. In the case of the EU ETS Phase III, there will be 15% fewer allowances issued than would have been required to cover 2005 emissions.[26] Since, even allowing for efficiency gains, underlying electricity and energy demand are likely to grow,[27] the overall "scarcity" of allowances relative to business as usual will be more than 15%. Table 3 shows an estimate of what the 2020 targets might mean in terms of ETS allowance scarcity.

Table 3 Breakdown of the 2020 ETS Target

Emissions (Mt CO_2)		Source	
5,621	EU-27 in 1990	[1]	EEA states that 2005 emissions were 7.9% below baseline
4,497	Target for 2020	[2]	80% of 1990 figure
1,124	Reduction needed by 2020	[3]	[4]-[2]
5,177	EU-27 in 2005	[4]	European environment agency
444	Reduction already achieved	[5]	[1]-[4]
680	Further reduction needed to meet 2020 target	[6]	[4]-[2]
408	Reduction from 2005 required in ETS	[7]	60% of [6]

The table shows that the Phase III target requires about 408 Mt CO_2/yr to be saved relative to 2005 ETS emissions by 2020. In the rest of this chapter we discuss how this might be achieved.

3.1 JI / CDM

The European Commission's proposals for Phase III essentially allow all CDM credits permitted in Phase II to be carried over into Phase III. According to the European Commission Impact Assessment, this means that "more than one third" of the reductions to be made in the ETS by 2020 can be made using CDM credits, assuming that none of the credits are used for compliance in Phase II. This translates into the equivalent of approximately 160 Mt CO_2. As a check of this assumption, we have added up the figures in Member State Phase II National Allocation Plans: Phase II CDM credits are equivalent to about 180 Mt CO_2 per year in Phase III, which is broadly consistent with the Impact Assessment assumption.

The European Commission assumes that CDM credits will be cheaper than the carbon price in the EU ETS on the grounds that it should be less expensive to reduce emissions in less developed countries, where

25. *Texts Adopted at the Sitting of Wednesday 17 December 2008 – Provisional Edition*, P.E. 417.801, December 2008, Pages 98-99.
26. The average ETS emissions during 2012–20 must be about 15% below 2005 emissions. Assuming a linear rate of reduction, this equates to 21% below by 2020. See *Questions and Answers on the Commission's proposal to revise the EU Emissions Trading System* (MEMO/08/35), European Commission, 2008.
27. Note that the European Commission's PRIMES scenario under which its energy efficiency goal and renewables targets are met implies electricity consumption rising at only 0.1% per year from 2010 to 2020, and that energy use overall will fall by 0.7% per annum. In contrast, for example, UCTE forecasts an annual increase in electricity consumption of 1.5% per year (*System Adequacy Forecast*, UCTE, 2008).

no abatement or efficiency measures are yet in place, than it is in the EU where emissions controls have been in place for some time. Current CER (CDM credit) prices are around 8 €/t CO_2.

Even if there is a post-2012 international agreement on emissions abatement, and the EU allows more JI/CDM credits to be taken into account, it is by no means certain that all of the increased allowances will be readily available. Already, a large share of the available credits is purchased by governments both inside the EU and more broadly, *e.g.*, Japan. Any international agreement on abatement is only likely to increase the extent to which other governments and, indeed, companies, wish to make use of these credits. In addition, the cost of the credits is likely to rise as the demand for them grows and more expensive projects have to be undertaken. We discuss what overall impact a post-2012 agreement might have in section 3.5 below.

3.2 Large Combustion Plant Directive

The LCPD should force out many of the older, less efficient coal- and oil-fired plants that are currently operating, by 2015 at the latest. We estimate, in Table 4, that around 60 GW of currently operating coal-fired plants will have to close by 2015. Making the assumptions that the average efficiency of these plants is 33% and that they operate at a load factor of 30% (*i.e.*, they generate for the equivalent of 30% of the year operating at full output) we estimate that these opted out plants currently produce around 156 Mt of CO_2. Note that if these plants burn lignite, which many of them do, or they are less efficient than we assume, this total could be significantly higher so that our calculation of CO_2 emissions is relatively conservative. If we further assume that the output from these plants is replaced by output from new state of the art coal plants (43% efficiency) then this would result in savings of 37 Mt, or around 2% of the intended annual allocation of emission allowances during Phase III. This is demonstrated in the bottom section of the column labelled "coal" in Table 4. On the other hand, if the replacement electricity came from new gas-fired plants, the emission savings would be nearly three times as much, at nearly 100 Mt or 6% of the Phase III allowances (see below the section of column labelled "gas"). These facts, or at least the basis for them, are generally well known and so it is reasonable to assume that they are already factored into forward carbon prices.

Table 4 Potential Impact of LCPD on Power Sector CO_2 Emissions

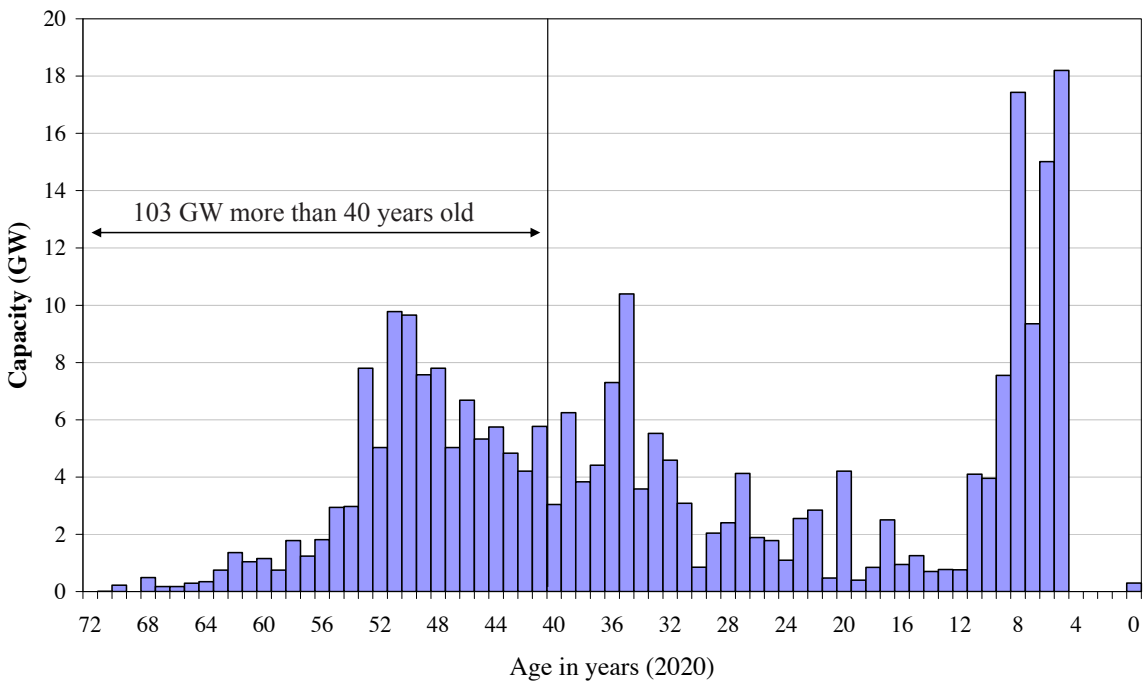
			Coal	Gas
Emissions data				
kg C/t coal or gross MMBTU gas	[1]	Assumed	627	15.4
t coalnet /GJ or gross MMBTU/net GJ	[2]	Assumed	25.13	0.948
kg C/Net GJ	[3]	[1]/[2]	24.95	16.24
t C/Net GJ	[4]	[3]/1000	0.025	0.016
Net GJ/MWh	[5]	Assumed	3.6	3.6
t C/MWh in	[6]	[4]x[5]	0.090	0.058
t CO_2/MWh in	[7]	[6]x44/12	0.329	0.214
Estimated emissions from plants without FGD				
Installed capacity (GW)	[8]		59.8	
Load factor	[9]	Assumed	30%	
Efficiency	[10]	Assumed	33%	
GWh out	[11]	[8] x [9] x 8,760	157,147	
GWh in	[12]	[11]/[10]	476,202	
CO_2 emissions (Mt CO_2)	[13]	[12]x[7]/1,000	156.8	
Estimated emissions from replacement plants				
Efficiency - new plant	[14]	Assumed	43%	59%
GWh in for replacement	[15]	[11]/[14]	365,457	266,350
CO_2 emissions (Mt CO_2)	[16]	[15]x[7]/1,000	120.4	57.1
Estimated emissions savings (Mt CO_2)	[17]	[13]-[16]	36.5	99.7

Whilst the terms of the LCPD have been agreed for some time, in early 2009 some Member States have begun lobbying for derogations from its terms. Their argument is that their electricity generation is dominated by coal-fired plants and the costs of fitting emissions reduction equipment to them or replacing them with new plants will be prohibitive, particularly given the economic downturn resulting from the "credit crunch". No decisions have yet been reached on whether to grant derogations, but allowing old, inefficient coal plants to continue operating would clearly increase carbon emissions, all other things being equal.

3.3 Other Coal Plant Closures

In addition to the coal-fired plants that have opted out of the LCPD, there are also many other coal-fired plants that have been operating for over thirty years. Figure 3 shows what the age profile of existing and currently planned coal plants will be in 2020. Whilst coal plants can, in principle, be kept operating almost indefinitely (since each individual component can be replaced), a "typical" lifetime is often taken to be 40 years. Of the nearly 250 GW of existing and planned coal-fired plants, around 103 GW will be more than 40 years old in 2020. This 103 GW includes the approximately 60 GW of plants that have opted out of the LCPD, suggesting that another 40 GW of coal-fired plants might close between now and 2020.

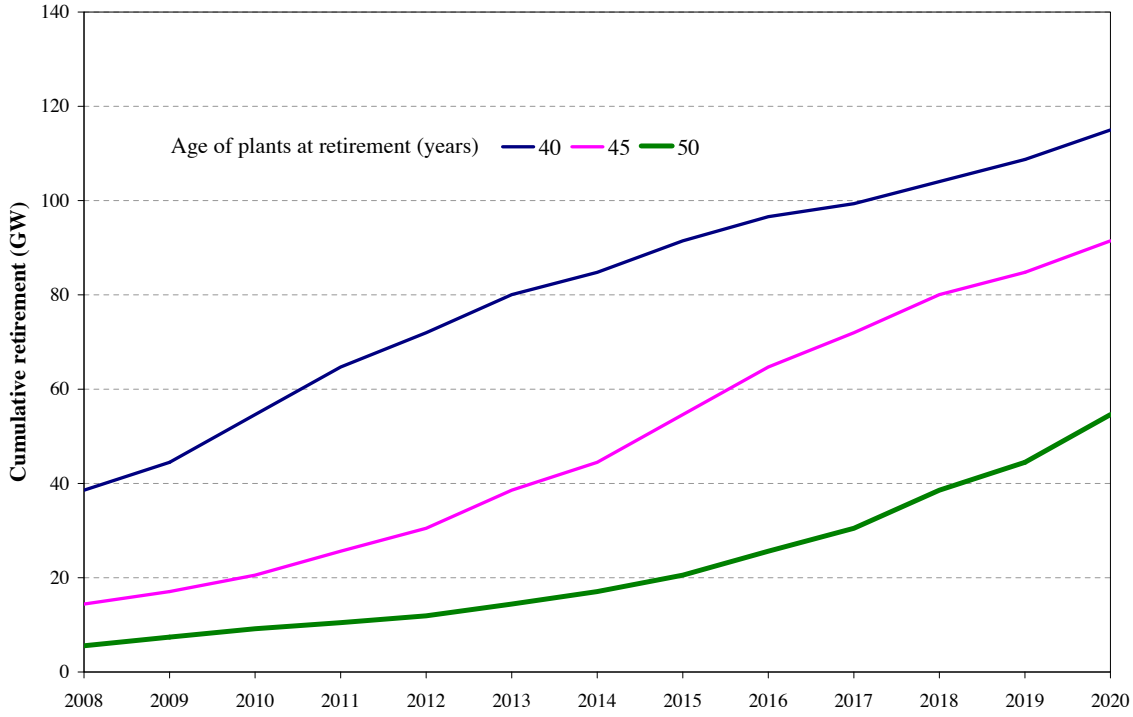
Figure 3 Age Profile of EU Coal Plants in 2020[28]



If anything like this level of closures were to take place, and the plants were replaced by less polluting plants, then there could be a further reduction of emissions by 2020 of between 25 Mt and 46 Mt, depending on whether the plants were replaced by new coal or gas plants. On the other hand, if coal plants remained on the system until they were 50 years old, then, as shown in Figure 4, there might be no closures beyond those required by the LCPD Directive.

28. Based on the Q4 2008 *Powervision* database (Platts). Note that it is unlikely that all the plants due to come on-line in 2012 (and hence be 8 years old in 2020) will be commissioned in that year so that this graph should only be considered to be illustrative of general trends.

Figure 4 Possible Retirement Profiles of Coal Plants for Different Lifetimes



The other interesting point to note from Table 5 is that there are plans to bring on over 75 GW of new coal plants between now and 2020. Whilst Germany accounts for the bulk of the new coal plants, twelve other countries have plans to bring on at least 1 GW of new coal plants and five (Italy, Poland, UK, Netherlands and Greece) have plans to bring on at least 3 GW. It is highly unlikely that all these plants will be built, but nonetheless it provides some assurance that coal is perceived as a viable option for new plants.

Table 5 Planned New Coal Plants 2009 — 2020

Country	*Capacity (MW)*
Germany	27,760
Poland	11,237
United Kingdom	10,336
Netherlands	5,100
Italy	4,820
Greece	3,100
Czech Republic	2,595
Bulgaria	1,891
Slovakia	1,664
France	1,500
Spain	1,237
Belgium	1,100
Romania	1,000
Austria	800
Hungary	640
Slovenia	600
Finland	200
Denmark	80
Latvia	20
Total	**75,680**

3.4 Interactions Between the Targets For Emissions, Renewables and Efficiency

Any market that is influenced by government policy is subject to uncertainty since policies can change. In the case of the EU ETS, even if we take EU policy over the period 2012 to 2020 as fixed,[29] significant uncertainty remains because of the inter-dependency among various policies. Here we describe two specific examples: the interaction between the EU ETS and energy efficiency, and between the EU ETS and renewables. We illustrate the examples by reference to a simple breakdown of emissions and energy use (see Appendix I for further details).

3.4.1 Energy Efficiency and the EU ETS

The EU has an ambitious target for energy efficiency: namely a 20% reduction from the level of consumption under a "business as usual" scenario in 2020. (Note that this target relates to overall energy consumption — not consumption within the ETS sectors.) If this target is not met, demand for energy, including electricity, will be higher than the Commission's forecasts underpinning the Phase III ETS proposals. It would also mean that it was harder for the renewables target to be met, since this is measured in terms of the percentage of energy consumption met by renewables.

The total number of allowances to be issued for Phase III will be fixed: it will not depend on outturn energy demand. Hence, if electricity demand turns out higher than expected, demand for ETS allowances will also be higher than it would have been otherwise. Since the generation sector is supposed to do much of the "work" in reducing emissions, any extra demand is likely to require even greater coal to gas fuel switching in generation. A very simple calculation suggests that missing the energy efficiency target by 1% requires generation emissions to be 3.4% below where they would have been if the target had been met (assuming that all of the additional reduction comes from generation).

This finding is based on the following logic. Suppose that the efficiency target is missed by 1%, *i.e.*, instead of a 20% reduction in energy use (compared to business as usual) only a 19% reduction is achieved. Energy consumption increases, but the renewables and GHG targets are still met. We assume that emissions from the non-generation sectors go up in line with the increased energy demand; however, total emissions are the same because the overall emissions target is still met. As a result, emissions from generation must go down. In addition to the fact that generation emissions must fall in absolute terms, the overall level of generation has to rise to cater to the increased demand due to missing the energy efficiency target.

There is one important factor to note in relation to these energy demand calculations: the impact of final energy demand on the EU ETS operates automatically without any kind of policy intervention.

3.4.2 Renewables and the EU ETS

The EU also has an ambitious renewable energy target. If this target is not met, additional emissions reductions would have to be achieved in order for the overall greenhouse gas target to be met. We have considered two scenarios under which the renewables target might be missed by 1%, *i.e.*, renewables only account for 19% of final energy consumption in 2020. In Scenario 1, we assume that the fact that the renewables target is missed is entirely due to non-generation sectors; whereas Scenario 2 shows the results when the target is missed because of insufficient wind generation.

If we assume that all of the additional reduction has to come from the generation sector, then we can estimate what would have to happen for the greenhouse gas target to be met. Under Scenario 1, generation emissions would have to fall by 4.7% from where they would have been if the target had been met. If the 20% renewables target is missed by 1% because of reduced uptake of wind generation

29. Eight years seems relatively long compared to the "policy cycle", but it is only a small fraction of the economic lifetime of a power station.

(Scenario 2), additional non-renewable generation would be needed to meet electricity demand. As a result, further emissions reductions would be required from the generation sector on a per kWh basis, so that the extra output could be produced without producing additional emissions. Average emissions per unit of electricity, *i.e.*, the carbon intensity of generation, would have to be 9.7% lower than it would otherwise have been.

Note that Scenario 2 operates to reduce the availability of EU ETS allowances automatically: if the "missing" renewables are within the ETS, the extra emissions also have to be saved within the ETS — there is no need for policy intervention to ensure that the overall emissions do not rise. However, in Scenario 1, emissions outside the ETS would rise as a result of missing the renewables target. In order to "make up" for the extra emissions, the ETS targets would have to be adjusted accordingly.

3.4.3 Trading of Guarantees of Origin Certificates and the Renewables Target

Member States are obliged to issue Guarantees of Origin (GoO) certificates for electricity produced by renewable energy. There have been suggestions that Member States should be allowed to use GoO certificates from other Member States as a means of meeting their renewables obligation. In principle, this would allow renewables growth to be concentrated where it is easiest to achieve and make it more likely that the renewables target is met (or even exceeded). This, in turn, would make it easier to achieve the emissions cap.

However, such an outcome is likely to be strongly resisted for a number of reasons. First, there is no standard specification for GoOs, and across the EU there are differences in the size of the GoOs, their validity period and how frequently they are issued. These differences would make trading very difficult, but standardising the GoOs would be costly. Second, different Member States support renewables via different mechanisms, *e.g.*, feed-in tariffs, supplier obligations, etc., which means that the level of support varies. There is, therefore, likely to be significant resistance to the idea that renewable generators in one state could benefit from the support mechanism in that state but sell their GoOs to another state. Of course, this latter problem could be overcome if the renewable generator received its subsidy from the state in which it sold its GoO. Such a solution might, however, necessitate changes to the way in which Member States choose to support renewables which in turn might increase the risks faced by existing renewable generators and hence their costs.

3.5 Carbon Abatement Outside the EU

If the EU adopts a tighter greenhouse gas emissions target, the European Commission proposes that the ETS cap should be tightened proportionally, and that half of the reduction in the ETS cap would be eligible to be met with CDM/JI credits. Moving from a 20% to a 30% target would mean that reductions during 2020 would have to be approximately 560 Mt CO_2 greater than would otherwise be the case.[30] If 60% of this comes from the ETS sector (consistent with the EU's statement that the ETS would only have to do the same share of the work towards the additional reductions as it would under the 20% reduction proposals), and half can be met from CDM/JI, around 170 Mt CO_2 more savings would have to be made within the ETS than under the 20% reduction proposals.

These additional savings would approximately double the emissions savings that would otherwise be required in 2020. If all of the additional savings had to be met by the electricity sector, this would require very significant changes in the plant mix, *e.g.*, a further 26 GW of baseload coal plants replaced with zero carbon generation. Under such circumstances, the need for CCS plants might become acute since it is unlikely that renewables could fill the gap — it would, for example, require nearly 70 GW of wind plants, allowing for their lower load factors. It also seems highly unlikely that new nuclear plants could be built at the required rate. We note, however, that between 2010 and 2020, nearly 16 GW of nuclear

30. The 20% target corresponds to emissions of 4,497 Mt (=0.8 x 5,621, see Table 3) and the equivalent 30% target is 3,935 Mt (=0.7 x 5,621). The difference is 562 Mt.

plants are due to be closed under accelerated decommissioning programmes in Germany and Belgium. If these plants were to remain on-line, then this would make a significant contribution to achieving the additional savings. Since the alternative to keeping the plants open might be sharply rising carbon prices and hence higher fuel and electricity costs to consumers, it does not seem implausible that the necessary changes in government policy might occur.

If carbon abatement measures were adopted outside the EU, particularly in the U.S., it seems likely that this would increase carbon prices over time within the EU even if the tighter target were not to be implemented. Not only does it seem unlikely that the mistakes of the Phase I ETS would be repeated, *i.e.*, there would be a better match between the demand and supply of allowances, but, over time, we would expect a shortage of allowances to develop, just as is meant to happen in Phase III of the ETS. Such a shortage would naturally put upward pressure on European carbon prices through greater competition, and thus higher prices, for CDM/JI projects. (We discuss the possibility of trading of allowances between different schemes in Section 6.3.)

The position taken by the U.S. is key to what might happen in the sense that it may create a domino effect. If emissions abatement is enforced at a federal level (instead of by a few states, such as California and the Northeastern states, as is happening now), then Canada would almost certainly feel obliged to follow suit so as to avoid disrupting the North America Free Trade Agreement. It is also possible, for the same reasons, that Mexico would implement some form of emissions abatement policy. Longer term, the U.S. might seek to impose taxes on imports from countries without emissions control and this would have implications for what might happen globally.

3.6 Implications for the Security of Gas Supplies

In sections 3.2 and 3.3 we discussed possible closure of existing coal plants, as well as the prospects for new coal plants. An accelerated switch from coal-fired to gas-fired generation would reduce emissions but would further increase the volume of gas consumed in the EU, most of which will need to be imported by 2020. Import dependence is already seen by many as a significant security of supply issue: about 45% of EU gas supplies came from outside Europe in 2005. We can illustrate the significance of the trade-off between meeting emissions targets and gas import dependence as follows. Assume that apart from JI/CDM credits of 180 Mt CO_2 all the remaining emissions reductions (228 Mt CO_2) have to come from fuel switching and that:

- *about 60 GW of coal plants close because of the LCPD (as in section 3.2) and are replaced by new coal capacity; and*
- *all coal plants now older than 30 years (i.e., older than 40 years in 2020) close by 2020 and are replaced by gas.*

The impact on emissions and on gas demand is shown in Table 6 below.

Table 6 Impact of Switching from Coal to Gas

	Capacity (GW)	Emissions removed	Emissions from new plant	Emissions savings	Additional gas demand (bcm)
LCPD closures	60	157	121	37	
Replace plants over 40 years old	44	167	75	92	38
Replace plants over 30 years old	52	188	89	99	41
Total	156			227	79

Notes
LCPD plants are assumed to be replaced with new coal.
This is equivalent to assuming that about half of the currently-announced coal plant is built.

Meeting the cap in this way implies a significant additional gas demand of about 80 bcm/yr by 2020, all of which would probably have to be met by increased gas imports. If Russian imports were to be the only source of additional gas volumes, then this would be equivalent to an increase of over 60% in Russian gas imports from their 2007 levels.

Even after removing almost 160 GW of existing coal capacity in this way, there would still be about 50 GW of new and recent coal-fired capacity. If all these plants were also to be replaced, a tighter emissions target could be reached entirely on the basis of coal to gas fuel switching in generation. A very approximate calculation suggests that a further 130 Mt CO_2 could be saved in this way. This is equivalent to a revised EU ETS 2020 target of 28% below 1990 levels (*i.e.*, an additional 8%), but the required additional gas imports would then be 134 bcm/yr. This is approximately equivalent to an additional doubling Russian gas imports from 2007 levels.

3.7 Conclusions

We have shown that at least a 408 Mt CO_2 reduction in emissions must be delivered by the ETS:

- *180 Mt CO_2 are likely to be provided by JI/CDM credits;*
- *36-100 Mt CO_2 could be achieved "automatically" due to the LCPD; and*
- *a further 26-46 Mt CO_2 reductions might result from further coal plant closures.*

This leaves between 80 Mt CO_2 and 170 Mt CO_2 reductions to be found from other sources. If these savings had to be achieved from the generation sector then this would require significant further changes in the generation mix. For example, if 130 Mt of savings in 2020 had to be achieved, this would require:

- *replacing around 35 GW of baseload coal with baseload natural gas; or*
- *replacing around 20 GW of baseload coal plants with around 75 GW of wind generation; or*
- *replacing around 20 GW of baseload coal with 20 GW of zero carbon baseload generation (nuclear, CCS).*

The required ETS emissions reductions would rise to 744 Mt CO_2 if an international agreement on emissions is reached for the period after 2012 and the EU emissions target is tightened to a 30% reduction. However, further JI/CDM credits would be expected to account for around half of the additional reductions, leaving a further 170 Mt CO_2 to be found within the EU.

Many of the sectors covered by the ETS produce products for which demand elasticity is rather low: for example, if the price of electricity rises, consumption does not fall significantly, at least over the short-to-medium term. In this respect, therefore, the role of the demand side in delivering emissions reductions is likely to be relatively small. On the other hand, the number of allowances that is released under each Phase of the ETS is based on assumptions regarding the demand for allowances, which in turn reflects views on the development of industrial output, the demand for power and transport and other macro-economic variables. If these forecasts turn out to be incorrect, then the supply of allowances will no longer be appropriate. An economic downturn will reduce the demand for allowances and make it easier to meet the target, assuming that a subsequent boom does not mean that the overall demand for allowances across Phase II remains unchanged. Conversely, higher than anticipated growth will increase the demand for allowances and make it more difficult to meet the target than would otherwise be the case.

The interactions between the targets for emissions, renewables and energy efficiency will also influence how difficult it is likely to be to reach the emissions target. A failure to meet either the renewables or the energy efficiency target by even 1% would increase the emissions reductions the ETS would have to deliver by between 3% and 5%. The likelihood that the ambitious renewables target will be met may depend, at least to some extent, on whether trading of Guarantees of Origin certificates is allowed.

Finally, meeting the emissions target is likely to have significant implications for the security of gas supplies if most of the ETS reductions are met by switching from coal-fired to gas-fired generation. At worst, gas imports might have to rise by 80 bcm/yr to meet the 20% emissions reduction target, which would correspond to a 60% increase in Russian imports if all the additional volumes had to come from there.

Chapter 4 | CARBON PRICES AND THE PROSPECTS FOR CCS

In the preceding chapter, we have discussed various ways in which the Phase III emissions target might be met. Most of these involve fuel switching in one way or another, and in this chapter we explore how such switching is likely to influence the carbon price. We discuss how our views align with carbon price forecasts produced by a range of banks and the analytical basis underlying the Phase III targets. We end by considering what implications this linkage is likely to have for the development of CCS projects.

4.1 Gas–Coal Fuel Switching Sets the Carbon Price

Fuel switching in electricity generation (both in the power sector and industrial cogeneration) is likely to produce a significant proportion of these carbon savings required under the ETS, although the industry more generally will obviously have a role to play. Both fuels account for significant shares of the generation mix (in terms of installed capacity) and the two kinds of power stations compete with each other. Unless there is no further possibility for substitution (*i.e.*, the gas plants are all running flat out), it will always be possible for one gas plant to run slightly more, and one coal plant slightly less, thus producing further emissions savings.

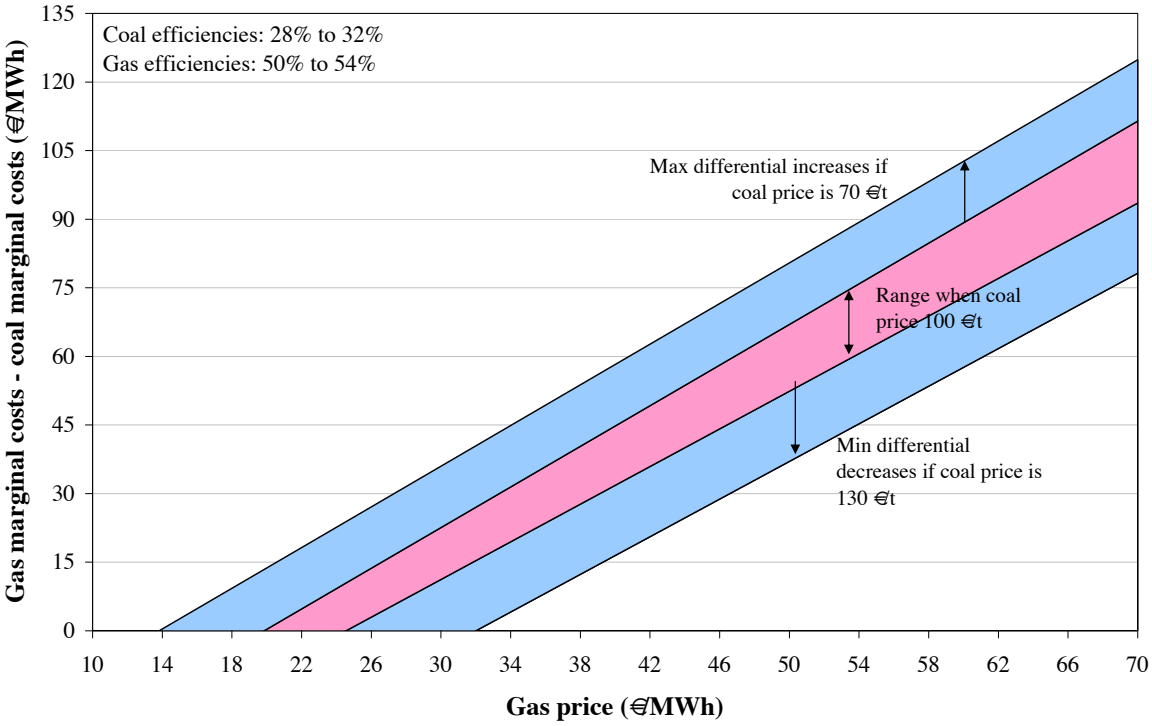
Under this logic, the relative prices of coal and gas together set the price for carbon: if coal becomes more expensive relative to gas (*e.g.*, due to increased demand from China or India), the price of carbon in the ETS will fall as it becomes cheaper to generate using lower-carbon gas. Conversely, if the price of gas in Europe rises relative to coal, the price of carbon would rise, because there would be increased demand for emission allowances.

4.1.1 Illustrative Calculations of the Impact of Fuel Prices

We can illustrate the cost of carbon consistent with fuel switching in generation by calculating the carbon prices that make the marginal costs of a combined cycle gas turbine (CCGT) and a coal plant equal. Our starting point is that the marginal generation costs of coal are generally much lower than those for gas-fired plants. This is illustrated in Figure 5, which shows how the differential between gas and coal marginal costs varies with gas price taking account of the likely range of efficiencies for existing coal and gas plants. For example, at a gas price of 50 €/MWh, the marginal cost of a gas plant will be between 52 €/MWh and 67 €/MWh higher than the marginal cost of a coal plant when the price of coal is 100 €/t. The range in marginal cost differentials reflects the fact that the outcome depends on the efficiencies of the plants being compared.[31] The higher marginal cost differential is based on comparing the costs of a relatively efficient coal plant (32%) to a relatively inefficient gas plant (50%). If, however, a relatively inefficient coal plant (28%) is compared to a relatively efficient gas plant (54%) then this yields the lower marginal cost differential.

31. All efficiencies in this report are quoted in lower heating value (LHV) terms.

Figure 5 Marginal Cost Differentials, Ignoring Carbon Costs

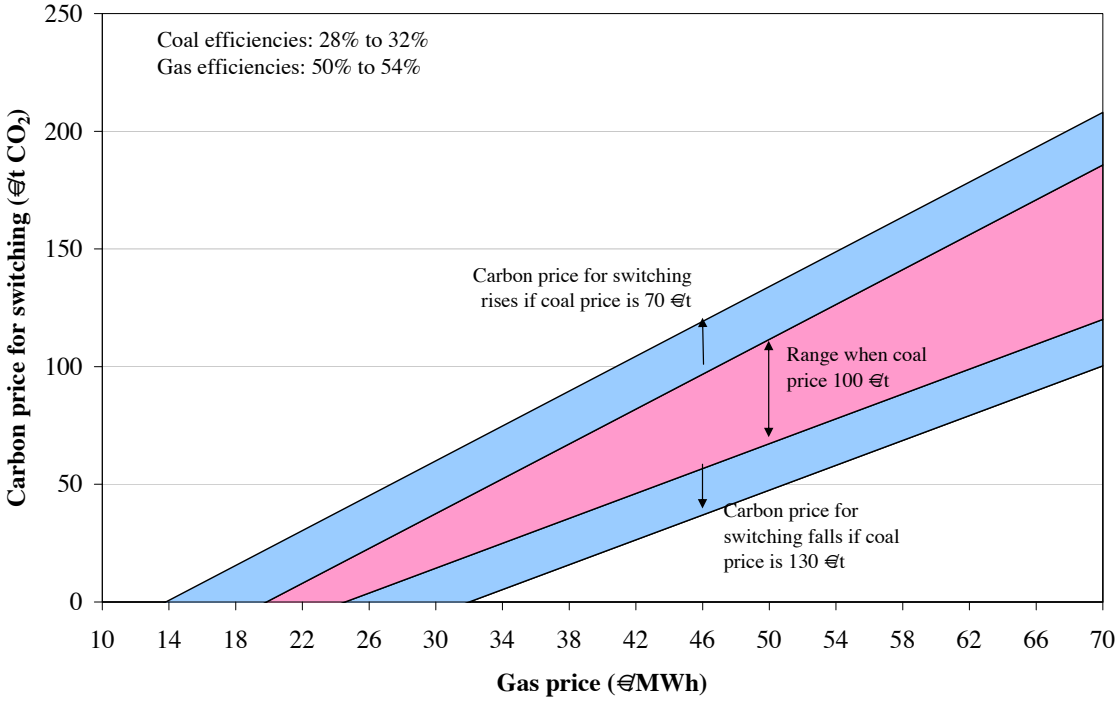


To encourage switching from coal to gas, the carbon price has to be sufficient to equalise the marginal costs of generation for the two plants, taking into account the different carbon intensities of coal and gas. On this basis, we show in Figure 6 the carbon prices required to encourage switching that are consistent with the marginal cost differentials shown above. Again, there is a range of outcomes depending on the efficiencies of the switching plants. Within each band, the higher carbon prices relate to switching from a relatively efficient coal plant (32%) to a relatively inefficient gas plant (50%). Conversely, the lower carbon prices relate to switching from a relatively inefficient coal plant (28%) to a relatively efficient gas plant (54%).

By way of reference, the maximum forward (2010) prices in 2008[32] were around 130 €/t for coal and 44 €/MWh for gas[33] but now (early February 2009), they are around 69 €/t for coal and 21 €/MWh for gas.

32. These occurred in July and August 2008.
33. Prices are for ARA coal and NBP gas, from EEX and Platts respectively.

Figure 6 Switching Carbon Prices as a Function of Gas and Coal Prices

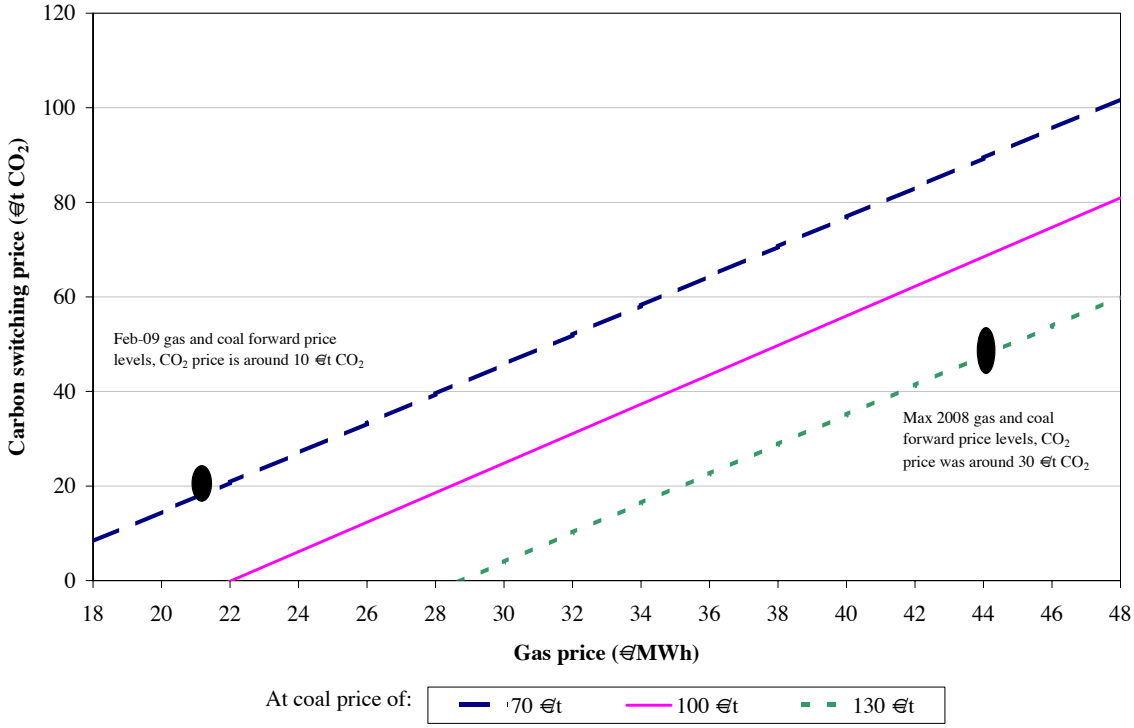


Our calculations suggest that when forward fuel prices reached their maximum in 2008[34] carbon prices would have had to reach around 50 €/t CO_2 for a CCGT with 52% thermal efficiency to replace the output of a coal plant with a 30% thermal efficiency. By early February 2009, fuel price and exchange rate movements meant that the equivalent figures had fallen to around 18 €/t CO_2. This is demonstrated in Figure 7.

Note, however, that the carbon prices required to induce switching between a 28% efficient coal plant and a 54% efficient CCGT are significantly lower: 32 €/t CO_2 at the maximum fuel prices and 10 €/t CO_2 in early February 2009.

34. This occurred in early July 2009 for coal and gas prices.

Figure 7 Switching Carbon Prices for 30% Coal and 52% Gas Plants



In both August 2008 and February 2009 carbon prices for 2010 were at levels that suggested only more efficient gas plants would be competitive with coal, and then only with rather inefficient coal plants (say around 30% efficiency or less). Nonetheless, the magnitude of the change in carbon prices is broadly consistent with our view of the importance of coal-gas price relativities in setting carbon prices, especially when the effect of a change in the demand for allowances is taken into account.

These results suggest that Phase II carbon prices have been consistently below a sustainable level for the medium-term since they would be unlikely to result in sufficient fuel switching for the 2020 target to be met. As explained below in the discussion of the impacts of banking, the current carbon price should, in principle, reflect market expectations about switching costs from now until 2020. Some of the disparity may relate to unpublished longer-term views on fuel prices since forward fuel price curves do not extend much beyond 2014.

4.1.2 Illustrative Calculations of the Impact of Thermal Efficiency

As noted above, the marginal cost differentials between coal and gas depend on the relative efficiencies of the two types of plants. Consequently, the carbon price required to induce fuel switching depends on the thermal efficiencies of the plant concerned as well as the relative prices of coal and gas. We illustrate this point in Figure 8, which shows the variation in switching cost with the thermal efficiency of the coal plant. A similar result comes from varying the efficiency of the gas plant.

Figure 8 Switching Costs as a Function of Gas Price and Coal Thermal Efficiency

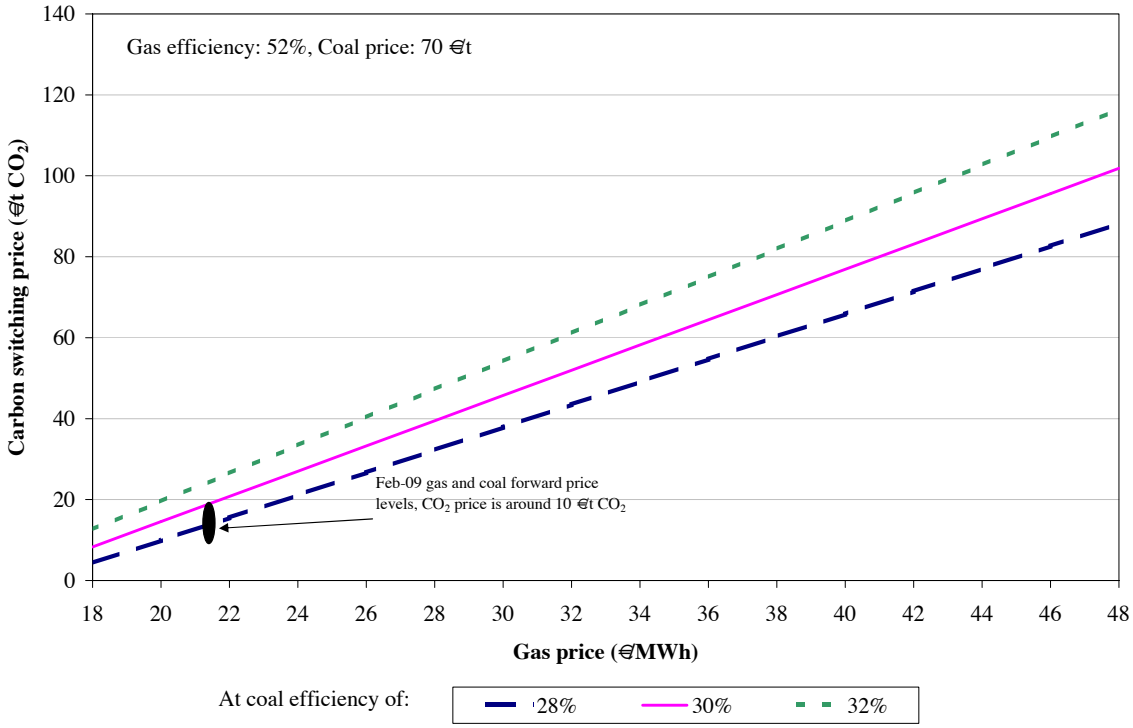
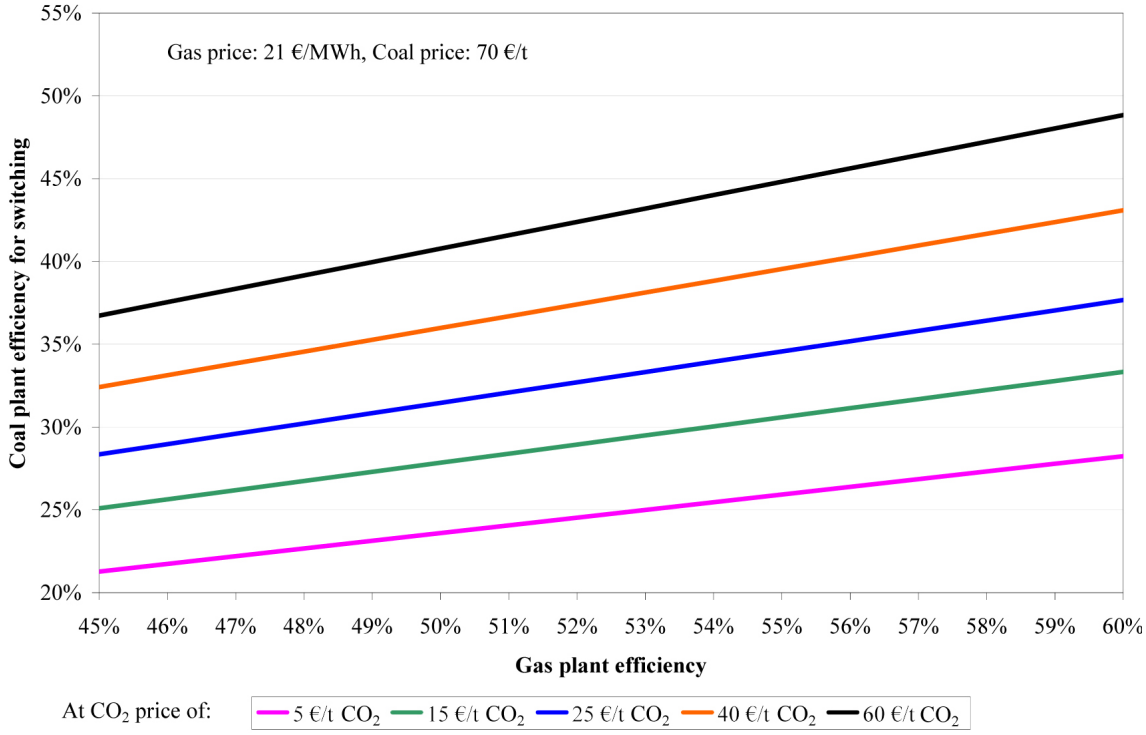


Figure 9 shows how the switching cost depends on the efficiencies of the pair of gas and coal plants delivering the marginal emissions savings through switching their output. Each line shows the combination of gas and coal plant efficiencies at which their marginal costs equalise (and so switching from coal to gas becomes possible) for a given carbon price. For a fixed gas plant efficiency, as the carbon price increases, so does the coal plant efficiency at which switching will occur. Equally, for a given carbon price, the coal plant efficiency at which switching should occur increases as the efficiency of the gas plant replacing its output increases.

Figure 9 Marginal CCGT and Coal Plant Efficiencies and Switching Costs



4.1.3 Impact of Banking Allowances

The unlimited banking of carbon allowances between Phase II and Phase III means that it is market participants' expectations about gas and coal prices throughout both phases that should influence the carbon price, rather than the current gas and coal prices. Note that there should be no predictable trend in the price of carbon over time, because allowances can be used in any of the 12 years of Phases II or III. Unlike gas, coal, or electricity, allowances can effectively be "stored" for free. Thus, the current market price for allowances should already measure market participants' expectations about future prices.[35] Hence, unlike for fuel prices, the "forward curve" for carbon should always be flat. The price will move over time as market views of supply and demand change, but the forward price for all future years should always be the same as the spot price.[36] As an example, the price for 2015 allowances should always be the same as the spot price for current-year allowances.

4.1.4 Fuel Prices

It is important to emphasise that we are not suggesting that carbon prices cannot move but only that there should be little shape to the forward curve: prices should be the same (allowing for the time value of money) all the way along the curve. The absolute level of the curve is, of course, not fixed. It depends on the current relativities in fuel prices and future expectations as to how this might change. These expectations can vary from day to day as the forward curves for the individual fuels adjust. Figure 10 illustrates how the price of a contract to purchase gas for a year from October 2007 to September 2008 (the 2007 gas year) at the NBP varied over the course of 2007.

35. With the minor caveat that there is no borrowing between Phase III and Phase II, so current prices could be above market participants' expectations of Phase III prices. Given the rate at which the cap is due to tighten over time, this possibility can be discounted.

36. In practice, of course, the time value of money will mean that the forward price should be higher than the spot price but the point is that the real value should be constant.

Figure 10 Movements in the Forward Price for the Annual Contract for the 2007 Gas Year

Even ignoring the price spike (to over 80 p/th) that occurred in March 2007, the price for this contract varied from 30.45 p/th to 43.05 p/th, which is 41% higher than 30.45 p/th. For the carbon price to have stayed the same, the forward price for coal would have had to follow precisely the same path would the ratio between coal and gas prices have been constant. Under all other circumstances, the carbon price would have varied in line with the changing ratio between coal and gas prices.

As Table 7 shows, over the past year the forward curves for fuel prices have generally suggested that the market expects the ratio of coal to gas prices to remain broadly constant, at least until 2014 (the end of the forward curve — although there is very little if any trading beyond 2011 in coal and gas, which is why the forward prices are the same thereafter). Historically, there has been a strong linkage between gas and oil prices,[37] but it is interesting to speculate whether the flatness of the coal forward curve is entirely due to supply-demand fundamentals or may also, to some extent, reflect the linkage to gas prices through the carbon price. Comparing figures for May 2008 with those for February 2009, Table 7 shows both that the ratio of gas to coal prices along the curve (columns 5 and 6) changes less than do the gas and coal prices in columns 1–4, and that the price ratio along the curve is constant (increasing by 6% from 2010 to 2014 in both cases).

37. For example, the increase in oil prices between 2010 and 2014 is similar to the increase in gas prices over the same period in both May 2008 and February 2009.

Table 7 Forward Prices

Year	Coal (€/MWh in)		Gas (€/MWh in)		Ratio gas to coal prices	
	May-08 [1]	Feb-09 [2]	May-08 [3]	Feb-09 [4]	May-08 [5]	Feb-09 [6]
2009	14.5		38.8		2.67	
2010	13.9	9.1	38.7	21.7	2.79	2.38
2011	13.0	9.8	38.3	24.7	2.96	2.53
2012	13.0	10.3	38.3	26.3	2.96	2.55
2013	13.0	10.4	38.3	26.3	2.96	2.52
2014	13.0	10.4	38.3	26.3	2.96	2.52
2015						
2016						
2014/2010	0.93	1.14	0.99	1.21	1.06	1.06

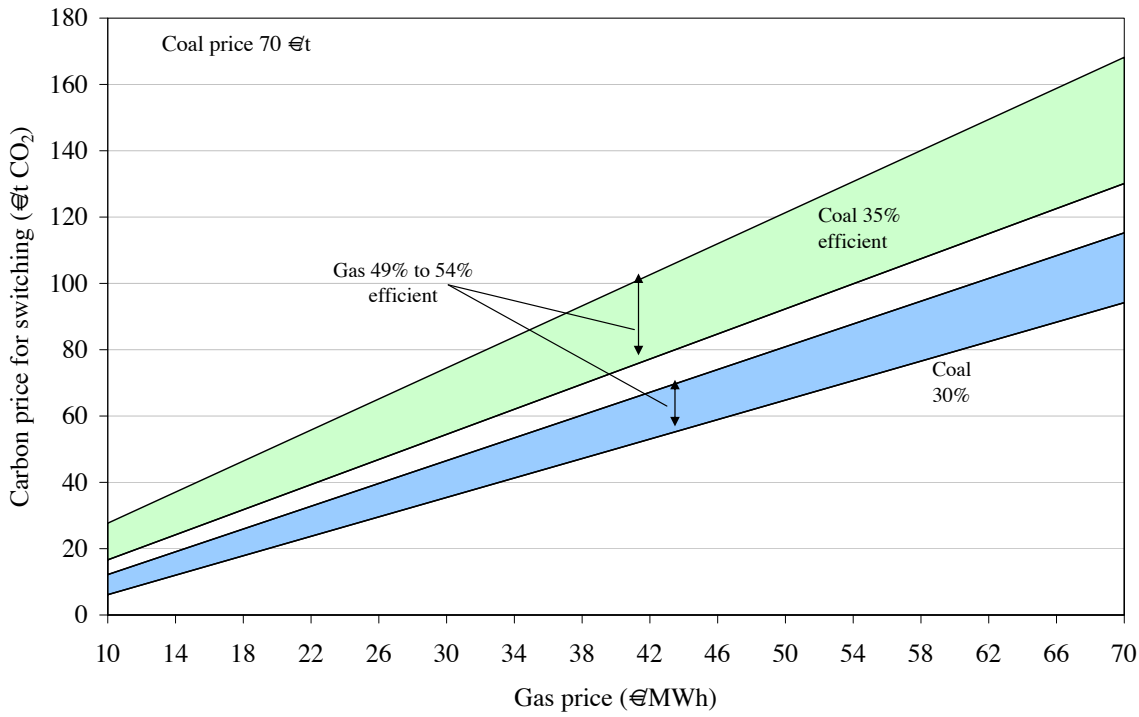
Notes:
Coal: ARA from EEX
Gas: BEB from EEX
Oil: Light sweet crude from Nymex

4.1.5 Impact of Market Tightness

A tight electricity market, where supply and maximum demand are close together, is likely to generate higher carbon prices than an over-supplied market. With a low capacity margin, more of the plants on the system will be required to generate in order to meet demand, regardless of the emissions they produce. Consequently, the opportunities for coal to gas fuel switching are reduced and, to some extent, emissions from the generation sector are fixed. This implies that any required savings will have to be provided from other sectors, where the costs of abatement are generally higher than for power stations, and so the price of carbon will rise.

Even if some coal to gas switching is still possible, it is likely that the carbon price will be pushed up from what it otherwise would be. This is illustrated in Figure 11 below, where the blue coloured area represents the carbon prices at which switching would occur under a tighter capacity margin and the green coloured area indicates what the switching price might be in a more over-supplied market. The point is that more coal to gas switching will be required if the capacity margin is tight, because more plant have to operate. Consequently, switching will have to involve more efficient coal plants than might otherwise be the case (and a range of gas plant efficiencies) and this leads to higher carbon prices being required to make switching economic. (A more efficient coal plant has lower marginal costs, so the carbon price has to be higher in order to match a given gas-fired plant's marginal costs.)

Figure 11 Switching Prices for Different Combinations of Plant Efficiencies



4.2 Investment Influences the Cost of Fuel Switching

As explained above, the relative cost of gas- and coal-fired plants is likely to be a key determinant of the carbon price. However, expectations about future investment in power station capacity are also important: if there is significant investment in highly efficient new gas plants, the price-setting plant is more likely to be a newer, higher efficiency gas plant displacing an older, low efficiency coal plant. If there is less investment in new gas plants, it is more likely that the price-setting plants will be a different pair in the merit order: an older, less efficient gas plant displacing a newer coal plant. Effectively, it will be harder to make sufficient emissions savings because sometimes it will be necessary to operate some high-carbon plants (gas or coal) in order to meet electricity demand.

Note that investment in new coal plants might actually result in the displacement of some existing gas plants because the high thermal efficiency of the new coal plants might lead it to have lower marginal costs.

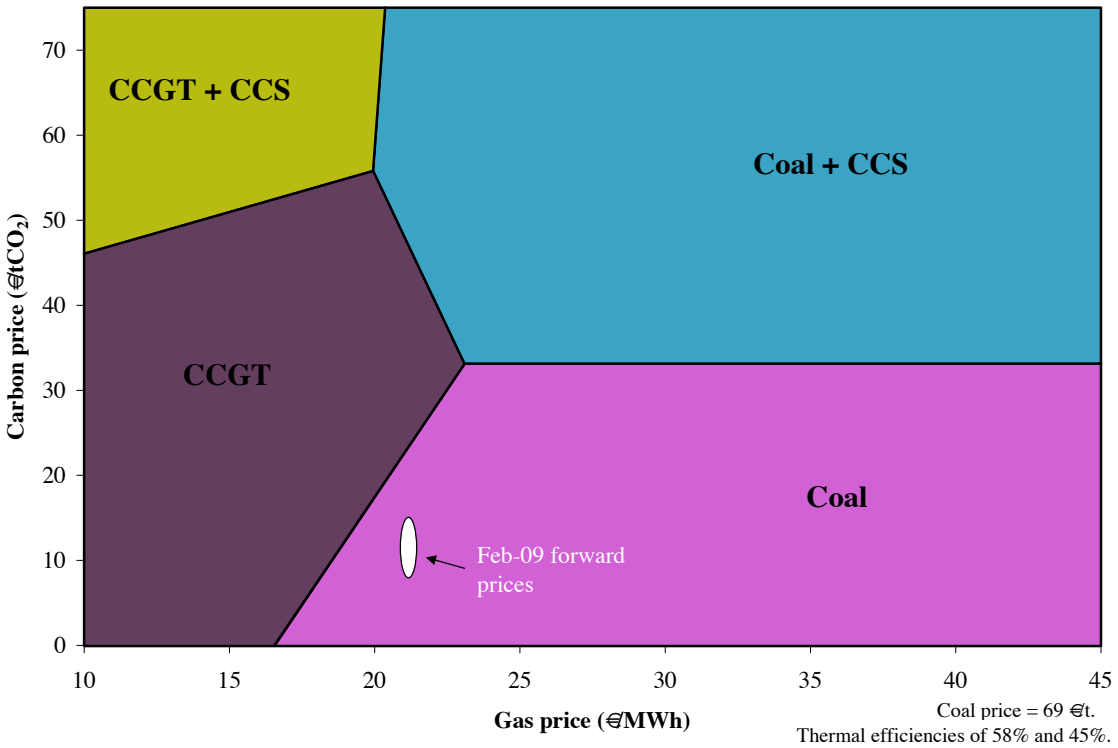
In thinking about new investment and fuel choice, it is relevant to look at total costs: investors presumably expect to be able to recover their investment cost as well as their operating costs when giving the go-ahead for new investment. The analysis above suggests that, at least for some pairs of gas and coal thermal efficiencies, the ETS and the carbon market tend to equalise the expected marginal cost of a gas and a coal plant.

The traditional wisdom used to be that since gas plants have lower capital costs than coal plants, investment in new coal plants could only be justified by special circumstances (*e.g.*, access to coal at below market rates, or electricity demand in a region to which it is difficult to import gas or electricity). The reasoning was that if electricity prices are expected to be high enough to allow a coal plant to recover its (relatively high) capital costs, they must be more than high enough to allow a gas plant to do so. Investors should therefore prefer the gas plant. This view reflected the fact that, historically, international coal prices had not been low enough compared to gas prices to overcome the capital cost disadvantage.

However, this view may no longer be correct. We illustrate this point by calculating which generating technology has the lowest total costs (Figure 12) and marginal costs (Figure 13) as a function of gas and carbon prices, based on recent (February 2009) coal prices. We show both figures because it is only when a technology is the least cost option on both a marginal and a total cost basis that it will be the preferred option. Marginal costs are generally considered the relevant benchmark when deciding whether or not to operate a plant — if it can at least cover its marginal costs it will be able to make a contribution to fixed costs and so it is worth running the plant. If a technology is not the cheapest option on a marginal cost basis then it is unlikely to achieve the baseload load factor assumed in the total cost analysis. Hence, it is irrelevant whether or not the technology appears to be the cheapest total cost option if it is not also cheap on a marginal cost basis. Equally, if a technology is the cheapest marginal cost option but is expensive with regard to its total costs, it may operate at a high load factor but be unable fully to recover its fixed and capital costs.

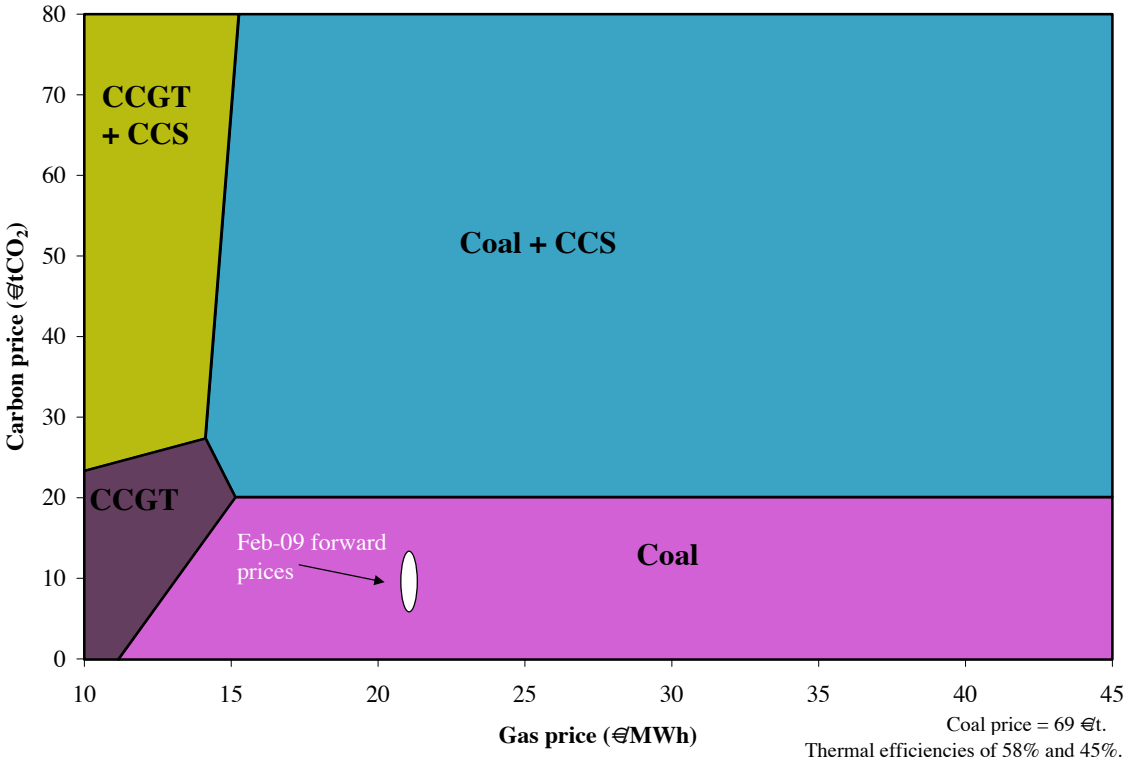
The figures demonstrate that at recent gas prices (21 €/MWh) and carbon prices (10 €/t CO_2), coal is the cheapest new build option in both marginal cost and total cost terms. The figures illustrate a further distinguishing feature between coal- and gas-fired plants. The lower emissions from normal gas-fired plants, *i.e.*, CCGTs, mean that the carbon price at which it is economic to fit CCS is much higher (over 46 €/t CO_2 on a total cost basis) than the carbon price at which it becomes economic to fit CCS to coal-fired plants (roughly 33 €/t CO_2 on a total cost basis).

Figure 12 **Least *Total* Cost Generating Technology at February 2009 Coal Prices as a Function of Gas and Carbon Prices**[38]



38. Generation costs are from *Dynamics of GB Electricity Generation Investment*, a paper by EES and Redpoint for the DTI, 2007; *The Future of Coal, an interdisciplinary MIT study*, MIT, 2007; and *Analysis of Carbon Capture and Storage Cost—supply curves for the UK*, a report by Pöyry for the DTI, 2007.

Figure 13 **Least *Marginal* Cost Generating Technology at February 2009 Coal Prices as a Function of Gas and Carbon Prices**

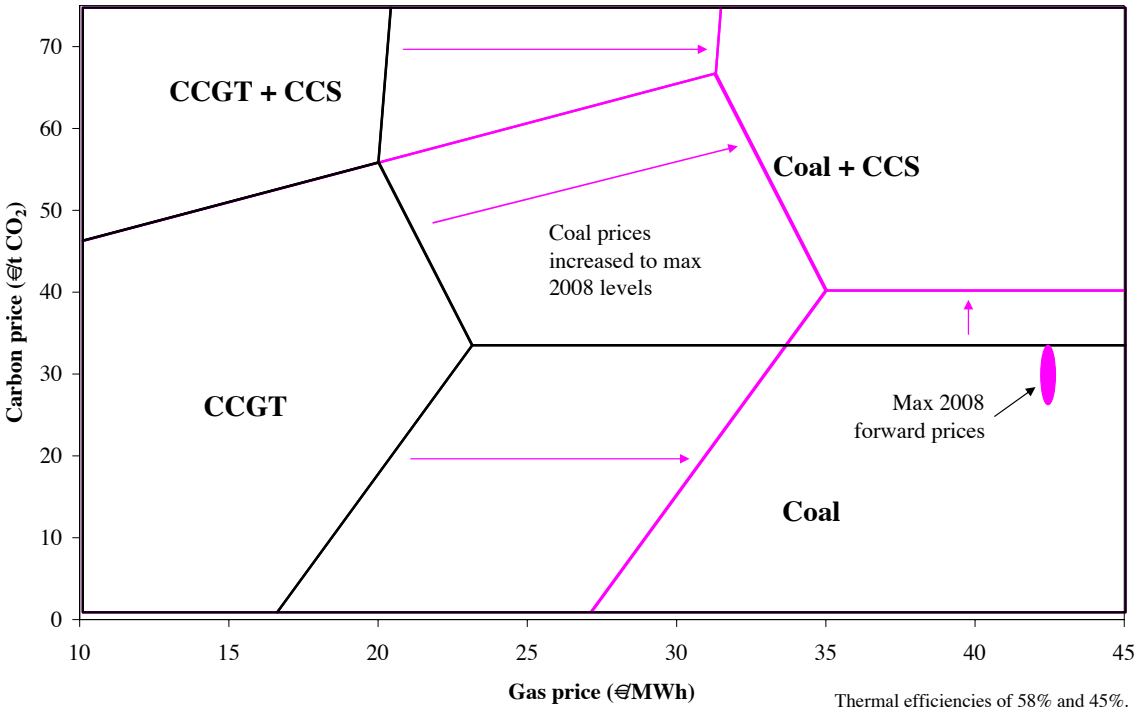


These results are not just specific to current forward prices but depend on the coal-gas price relativity. When coal and gas prices were at their peak in July 2008, coal was also the best option because the relativity between their prices was the same as it is now. This is demonstrated in Figure 14, which also illustrates the impact of essentially doubling both coal and gas prices on the choice of least cost technology.[39]

However, it is unclear whether this position is sustainable. In an efficient market, the marginal costs of coal and gas should equalise for those plants which are setting prices. The carbon price and the efficiency pair, *i.e.*, the combination of coal plant and gas plant efficiencies, at which this occurs will depend on how tight the emission target is perceived to be. If the efficiency pair corresponds to new gas plants and new coal plants then the capital cost disadvantage of coal will mean that gas plants are built. It is only when the efficiency pair is new gas versus old coal that it may be economic to build new coal-fired plants. It appears likely that it is a combination of the perceived current "looseness" of the emissions targets and the fact that, as discussed earlier, carbon prices last year were below the level that market fundamentals would suggest, which is leading to new coal appearing to be the least cost option.

39. The figure shows total costs because if coal is the least cost option on a total cost basis then it generally follows that it will also be the best choice on a marginal cost basis since, as Figure 5 above illustrated, coal marginal costs are generally below gas marginal costs..

Figure 14 **Least *Total* Cost Generating Technologies: A Comparison Between the Situation Based on February 2009 Fuel Prices and That Using the Maximum Fuel Prices in 2008**



The carbon/gas price pairs at which different fuels and technologies become the best option do, of course, depend on the efficiency assumptions that are made. Figure 15 and Figure 16 illustrate the impact of increasing the assumed efficiencies of the gas plants by 5% on the least cost total and marginal cost technologies respectively. In both instances, the gas price at which coal becomes more cost effective increases but there is relatively little change in the carbon price at which CCS becomes competitive. (There is, obviously, no effect at all on the carbon price at which coal with CCS becomes competitive with coal without CCS.) Figure 17 illustrates that the effect of changing efficiencies is broadly symmetric — increasing the coal plant efficiencies by 5% roughly decreases the gas price at which coal becomes competitive by the same amount that the gas price has to increase when the gas plant efficiencies are increased.

Figure 15 Impact on Least *Total* Cost Technology Choices of Increasing the Gas Plant Efficiency by 5%

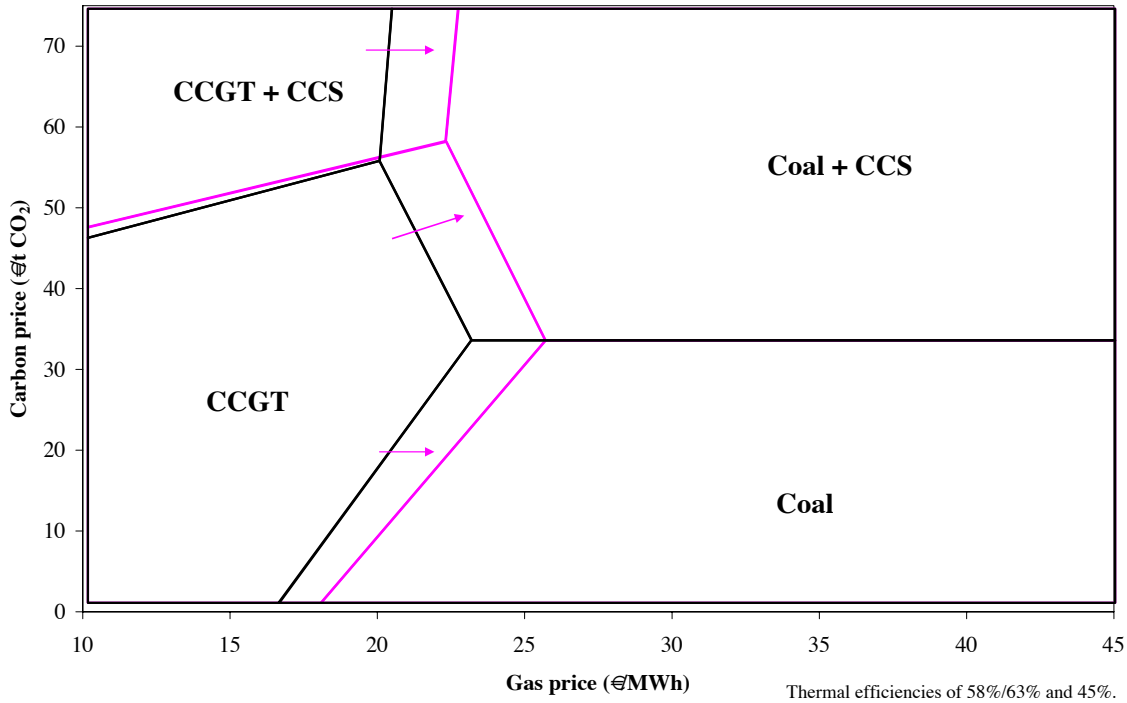


Figure 16 Impact on Least *Marginal* Cost Technology Choices of Increasing the Gas Plant Efficiency by 5%

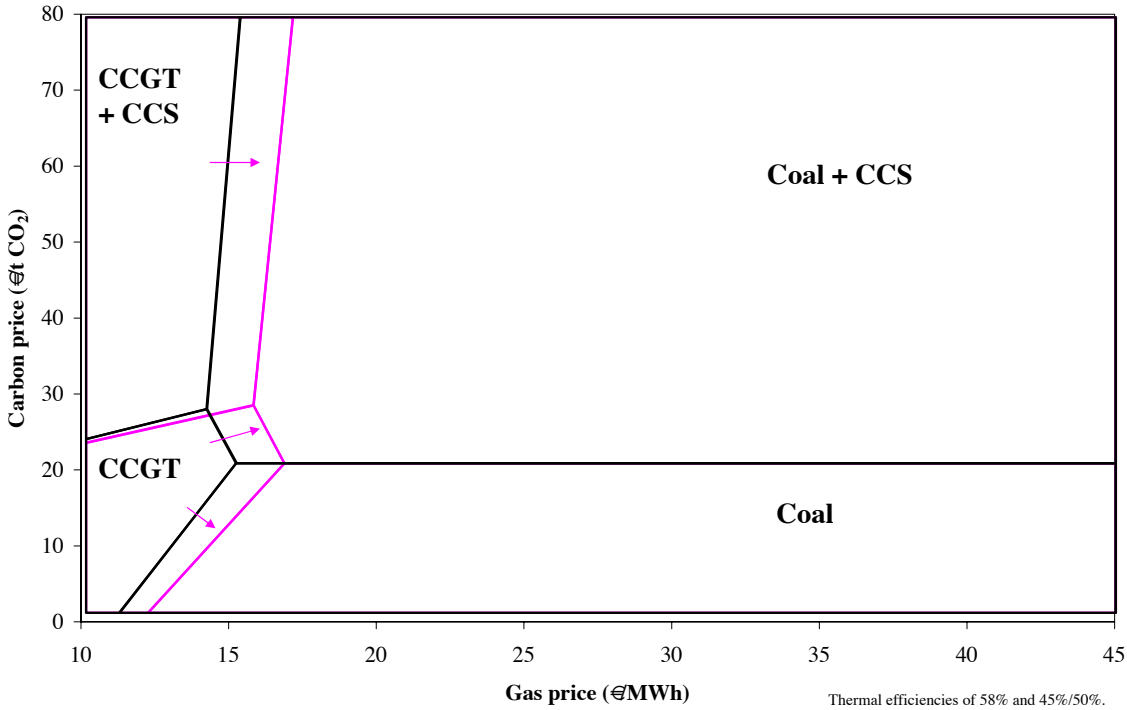
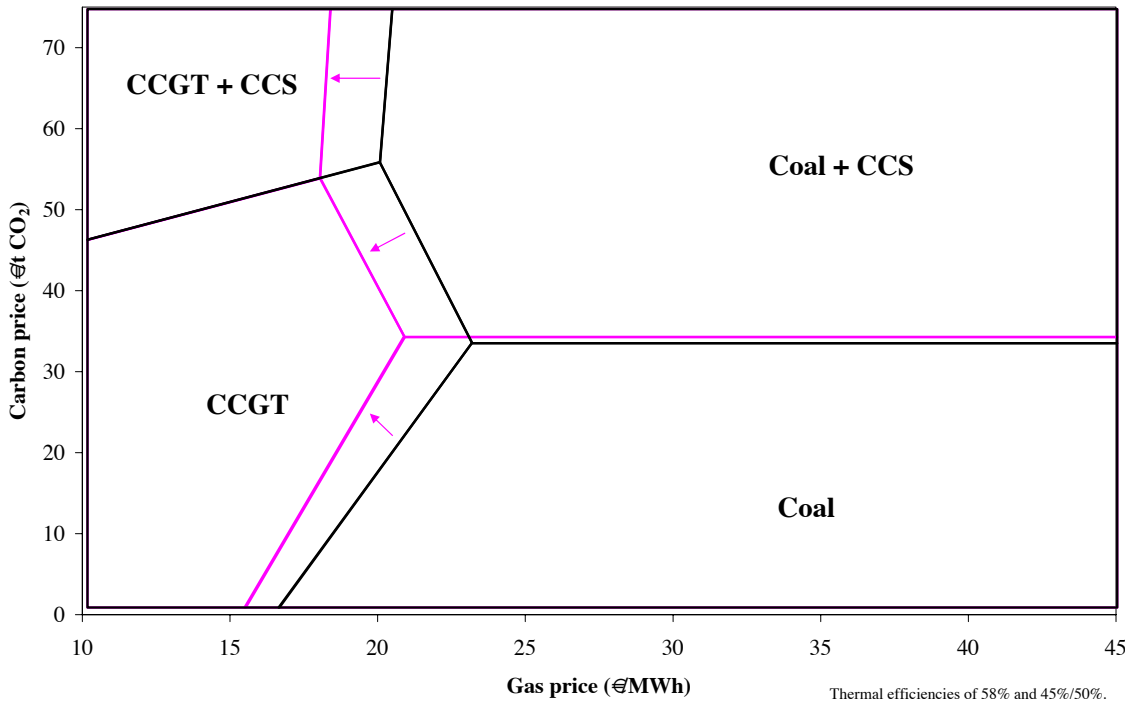


Figure 17 Impact on Least *Total* Cost Technology Choices of Increasing the Coal Plant Efficiency by 5%



4.3 Carbon Price Forecasts

4.3.1 Survey Results

Most published carbon price forecasts are relatively short-term in nature, focusing on Phase II prices. An April 2008 Reuters survey found that many major banks considered that then current prices (around 25 €/t CO_2) were well below the rational long-term price that might be expected, as shown in Table 8. In other words, these forecasts are consistent with our view that carbon prices have been at unsustainably low levels over the past year (see section 4.1.1.).

Table 8 Long-Term Carbon Price Forecasts (€/t CO_2)

Source	Price (€/tCO_2)
Deutsche Bank	35
Pointcarbon	30
Fortis	35
SocGen	31
NCF	28
UBS	25

Source
Reuters (*EU carbon price boost from 2007 emissions data, 4 April 2008*).

4.3.2 Analytical Basis of the Commission's Decisions

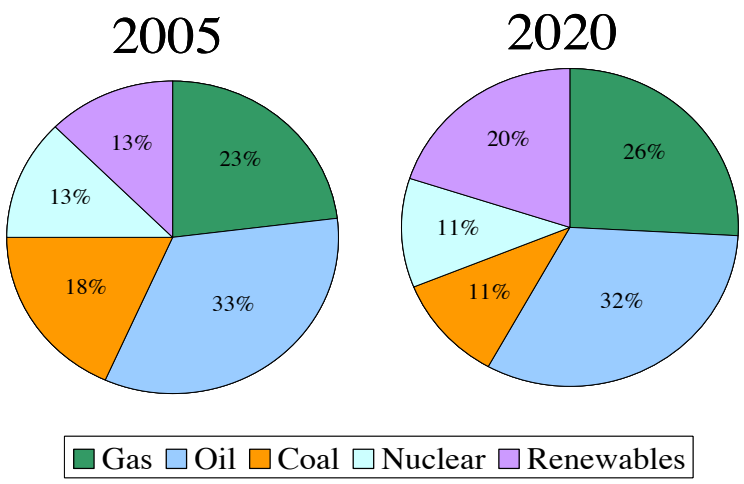
In the impact assessment that accompanied the EU's Phase III proposals, information was provided on the assumptions underlying the decisions that had been made. The "business as usual" case, against which changes were measured, was taken from the PRIMES scenarios. The fuel price assumptions on which these scenarios were based are shown in Table 9.

Table 9 EU Fuel Price Assumptions (2005 Money)

Fuel	2005	2020	2020 high oil price scenarios	
Oil	54.5	61.1	100	
Gas	34.6	46.0	77	59
Coal	14.8	14.7	24	23

With these fuel price assumptions, and assuming the energy efficiency and renewables targets are met, the EU foresaw relatively little change in the energy mix derived from different fuels, as can be seen from Figure 18. The most notable point is that the share of coal falls by 7 percentage points, largely as a result of the rise of renewables and, to a lesser extent, gas.

Figure 18 EU Assumptions on Breakdown of Energy Consumption in 2005 and 2020



Based on all these assumptions, the EU projects that the Phase III carbon price might be around 30 €/t CO_2. Under its high oil price scenario, which may be more realistic, the EU anticipates that the carbon price would be lower, possible by around 4-5 €/t CO_2. The rationale behind the lower carbon price appears to be that higher oil prices will (a) encourage more renewables and energy efficiency and (b) reduce economic growth. Both these effects should reduce the demand and hence the price for emissions allowances.

However, the relationship between oil and carbon prices is complex. For example, the price for 2008 allowances fell by 2 €/t CO_2 to 20 €/t CO_2 in February 2008 on fears that high oil prices would stifle economic growth and reduce the demand for energy. On the other hand, there is another potential effect from rising oil prices that the EU does not appear to have considered — namely that gas prices are more closely linked to oil prices than coal prices so that a rise in oil prices will tend to increase the carbon price, since the carbon price required to force switching from coal to gas will rise.[40] To take another example, in late May/early June 2008 the price for 2008 allowances rose by 2 €/t CO_2 as oil prices climbed by 20 $/bbl — allegedly because power producers were switching from gas to coal. Consequently, it is not particularly obvious which factor will prove more important over the medium-term since there are likely to be limits to both effects.

4.4 Volatility of Carbon Prices

Under cap and trade schemes, such as the ETS, carbon prices adjust to reflect changing expectations of the demand for allowances. This has, for example, been very obvious over the past six months. The disadvantage of this price responsiveness is that it can dilute the effectiveness of the investment signals that are provided. Potential investors, particularly in new power plants, will face a situation in which the economic attractiveness of different options may depend crucially on highly uncertain carbon prices. Consequently, they may choose to "play it safe", particularly in regard to options that entail high capital investments. So, for example, they may be unwilling to invest in a coal plant with CCS even if their forecasts suggest it is likely to be the least cost option.[41]

4.5 Carbon Capture and Sequestration

4.5.1 As a Demonstration Project

Figure 12 shows that CCS plants are expensive compared to other conventional generation in that carbon costs have to be above 35 €/t CO_2 to be the least cost technology, on the basis of total costs. This figure relates to coal CCS plants, it is higher still for gas CCS plants (see below). It is anticipated that coal CCS capital costs will be 50% or more above those of a conventional coal plant, their thermal efficiency will be lower by eight percentage points or more, and the technology has significant operating costs (on-site energy demand to run the scrubbers and CO_2 compressors and pumps). It is likely that CCS plants will initially be built as demonstration projects, and, as such, will not have to be economic/commercial as stand-alone private investments: they are more likely to be subsidised directly with public funds, or supported by private sponsors as development projects. Nevertheless, even as demonstration projects, it seems reasonable to suppose that a CCS plant must run baseload, in order to help meet as much of its high capital costs as possible.

CCS plants can only run at baseload if the carbon price is sufficient to make them competitive with conventional plant on a *marginal cost* basis. The large area labelled "Coal + CCS" in Figure 13 show that CCS plants can run baseload over a wide range of gas prices if the coal price is 69 €/t (the gas price must be more than around 15 €/MWh, and the carbon price must be over 20 €/t CO_2). Nonetheless, at recent (early February 2009) fuel and carbon prices, CCS plants would not run at baseload. However, at a coal price of 130 €/t, *i.e.*, the maximum level reached in 2008, the gas price only has to be 25 €/MWh and the carbon price 25 €/t CO_2 for CCS to be competitive. In other words, for a short period in 2008, CCS might have been a competitive baseload option.

40. In this report, when we discuss switching of this kind it should be understood that we refer to one kind (say gas-fired) of generator increasing its output and the other kind (coal-fired) decreasing its output. We are not referring to any individual plants changing from using one kind of fuel to another.
41. See, for example, the *Brattle* report "Carbon Fees vs Cap and Trade," February 2007.

Moreover, since CO_2 pumping costs are both marginal costs and non-negligible, a higher carbon price would be required for a demonstration plant located far from a storage site, and a lower price if it were located very close by (the illustrative figures we use are for a post-combustion technology for a plant at Aberthaw (Wales), pumping CO_2 for storage in the North Sea, a distance of about 450 km).[42]

A CCGT fitted with CCS would require a higher carbon price to run baseload, although at low coal and gas prices, the differential is not great. As discussed previously, this simply reflects the fact that gas-fired plants have much lower greenhouse gas emissions than coal plants so it is only when the carbon price is high that the lower efficiency of the CCS option can be fully offset by avoided carbon costs.

4.5.2 Commercially-Viable CCS

To make commercial sense, like any other plant a CCS plant would need to cover both its operating and capital costs. As noted above, Figure 12, which takes account of capital and fixed operating costs in addition to marginal generation costs, suggests that much higher carbon prices are needed for this: in the region of 35 €/t CO_2, but increasing sharply to about 50 €/t CO_2 or more if gas is cheaper than about 20 €/MWh.

Capital cost estimates for a nuclear plant from a year ago are similar to those for a coal plant with CCS. Since the marginal generating costs of nuclear plants are typically assumed to be relatively low, the total cost of nuclear power could be significantly lower than coal plus CCS.[43] However, recent difficulties and costs overruns with the nuclear plants under construction in Finland and France suggest that the published cost estimates may be over-optimistic. Moreover, there would likely be supply chain constraints (including a shortage of nuclear engineers) if a significant programme of nuclear plant construction was undertaken in the near future. Whilst there might also be supply chain constraints if a large CCS programme were undertaken, they are unlikely to be as severe as for coal plants since the engineering expertise required is less specialised.

It can also be argued that CCS plants are competing with renewables as a source of zero carbon generation. This comparison shows CCS in a more favourable light, as Table 10 demonstrates. This table shows some recent estimates of the costs of various different technologies (assumed to be installed in the UK) both currently and in 2020 (allowing for cost reductions as technologies mature). Whilst hydro, co-firing, by-product gas plants and onshore wind farms in favourable locations are all cheaper than CCS at recent fuel prices, all the remaining technologies may be more expensive. It is also, of course, the case that co-firing and by-product gas plants are not true zero carbon technologies.

42. *See Analysis of Carbon Capture and Storage Cost — supply curves for the UK*, a report by Pöyry for the DTI, 2007.
43. Decommissioning costs obviously push up the total costs of nuclear plants but since these only occur 40 years into the future, their annuitised effect is relatively small.

Table 10 Estimated Total Costs of Various Renewable Options (2006 Prices)

Technology	Levelised costs (£/MWh) 2006	2020
Sewage gas	38	38
Landfill gas	48	48
Co-firing regular	51	49
Onshore wind - large - high wind	62	61
Hydro - large	63	63
Co-firing energy crop	67	64
Hydro - small	71	71
Onshore wind - small - high wind	72	70
Onshore wind - large - low wind	74	72
Energy from waste CHP	79	79
Onshore wind - small - low wind	86	83
Biomass - regular	90	95
Offshore wind	91	85
Anaerobic digester CHP	107	143
Biomass - energy crop	122	116
Gasification/pyrolysis	127	160
Biomss - CHP	135	139
Tidal	181	137
Wave	199	151
Solar PV	635	444

CCS could be cheaper at current (2009) fuel prices

Source: Ernst & Young
Impact of banding the Renewables Obligation - costs of electricity production, April 2007

4.6 Conclusions

In this chapter, we have explained the likely linkage between carbon prices and the relative prices of coal and gas. For each combination of coal and gas prices, the carbon price at which switching will occur depends on the efficiencies of the plants between which switching might occur. Lower carbon prices are required to induce switching between older, inefficient coal plants and gas plants than between newer, more efficient coal plants. Conversely, for a given gas price, the carbon price at which switching occurs falls as the coal price rises.

Across the wide range of fuel prices seen over the past year, the carbon price has only been sufficient to encourage switching between old coal plants and gas plants. Switching of this type is unlikely to deliver sufficient emissions reductions for the 2020 target to be met.

We have also examined the interaction between carbon prices and investment decisions, including building new plants fitted with CCS. We have shown that new coal plants would have appeared attractive for much of this time but that carbon prices have been insufficient to support plants with CCS.

Carbon prices sufficient to support CCS, based on current capital costs, might also make nuclear an attractive option but there are likely to be constraints (physical, political and financial) on the rate at which new nuclear plants can be built. Moreover, if CCS as a zero carbon option is compared to a wide range of renewable generation possibilities, it is a cheaper option. Under these circumstances, providing support to CCS is an economically rational choice.

Chapter 5 | POST 2020 (PHASE IV)

5.1 Post 2020 Targets

The analysis presented up to this point has considered only the period up to 2020. However, policy-makers have recognised that emissions post 2020 will have to be even further reduced. The European Council has acknowledged that cuts of 60%–80% will be needed by 2050, and the concrete proposals already announced for the EU ETS specify that Phase IV of the scheme (2020–2028) will see EU ETS emissions continue to fall at the same rate in Phase IV as in Phase III. However, what this rate will be will depend on whether or not an international agreement leads to the stricter 2020 target being imposed. Since the final level of required reductions is still very uncertain, we consider below two scenarios for further reductions in emissions beyond 2020. In the illustrative analysis which follows, our estimates are based on the assumption that all EU ETS reductions take place in the generation sector, and that there are no changes in energy demand over time. Whilst the requirement for all emissions reductions to come from the generation sector may be unduly harsh, this is, at least to some extent, counterbalanced by the assumption that energy demand remains constant.

5.2 Scenarios for 2030 ETS Targets

5.2.1 Scenario A: 30% by 2030

Scenario A is based on the proposals for Phase IV of the EU ETS. Assuming that the annual cap in the EU ETS continues to fall at 1.74% per year during both Phase III and IV, the overall EU-wide GHG target could be around 30% below 1990 levels. This is consistent with what the European Commission has already proposed: 60% of the "effort" to come from EU ETS sectors, and no additional use of CDM/JI credits. Scenario A implies EU ETS emissions in 2030 being cut by a further 337 Mt CO_2 from the 20% 2020 target.

5.2.2 Scenario B: 40% by 2030

Scenario B assumes that there is a post-Kyoto agreement and that the EU adopts a 30% target for 2020. If the longer-term ambition were a 60% cut by 2050, a simple linear interpolation would imply a 40% cut by 2030. Assuming the more generous treatment of CDM/JI credits already announced,[44] this is equivalent to EU ETS emissions 397 Mt CO_2 below the 2030 target in Scenario A, *i.e.*, a reduction of 734 Mt CO_2 below the 20% 2020 target.

The assumptions underlying the two scenarios are described in Table 11 below.

Table 11 Scenarios for 2030 Targets (Mt CO_2)

	GHG emissions reductions from 1990 [A]	[B]	Reductions from 2005 [C]	ETS reductions from 2005 [D]	Number of ETS allowances [E]	ETS reductions from 2005 net of CDM/JI [F]	ETS emissions [G]
Scenario A							
2020	20%	1,124	680	408	1,720	228	1,900
2030	30%	1,686	1,242	745	1,383	565	1,563
Scenario B							
2020	30%	1,686	1,242	745	1,383	397	1,731
2030	40%	2,248	1,804	1,083	1,045	734	1,394

Notes
All figures in $MtCO_2$, based on the scope of the EU ETS at the end of Phase II.
[A] assumed, based on discussion in the text of the report.
[B] = [A] x (EU-27 1990 emissions, European Environment Agency).
[C] = [B] – (fall in EU-27 emissions from 1990 to 2005, European Environment Agency).
[D] = [C] x % (proportion of effort from EU ETS, European Commission).
[E] = (2005 ETS allowances) – [D].
[F] (Scenario A) = [D] – (Deutsche Bank estimate of CDM/JI credits carried over from Phase II).
[F] (Scenario A) = [D] – (assumed volume of CDM/JI credits allowed, see discussion in the text of the report).
[G] = (2005 ETS allowances) – [F].

44. The European Commission has said that if a 30% target is agreed for 2020, half of the additional savings in the ETS can be met by additional CDM/JI credits.

5.3 Impact of Coal Plant Closures[45]

We discussed above (sections 3.2 and 3.3) how emissions reductions are likely to be achieved as a result of closing older coal plants (either because of the LCPD or because the plants have reached the end of their economic lives). Around 230 Mt CO_2 would be saved by 2030 if all coal plant older than 40 years closes (leaving about 50 GW of newer coal on the system).[46] After taking these savings into account, the additional required reductions from other measures are shown below.

Table 12 EU ETS Reductions (Mt CO_2)

Scenario		A	B
2030 reduction	[1]	565	734
Impact of coal plant closures	[2]	227	227
Remaining reductions required	[3]	338	507

Notes
[3] = [1] – [2].

If all coal plants were closed, *i.e.*, the 50 GW of newer coal plants were also shut, around a further 130 Mt CO_2 might be saved. Hence the targets shown in Table 12 certainly require significant investment in non-fossil generation or CCS. Thus, although the savings shown in Table 12 are based on switching significant quantities of coal-fired generation (without CCS) to gas, so much additional zero carbon generation is also required that overall gas consumption would start to fall because gas-fired plants would also have to close. Assuming that fitting CCS to gas-fired plants is less likely than to coal-fired plants, there would be less gas-fired generation in both scenarios than required to meet the 2020 targets, and for Scenario B there would be less gas-fired generation than currently exists.

5.4 Implications for Low-Carbon Investment

In earlier sections of this report we estimated how much low-carbon generation, *i.e.*, gas-fired plants, would have to displace higher carbon generation, *i.e.*, coal-fired plants followed by inefficient gas plants, to achieve various levels of emission savings. However, it is important to note that as the targets get tighter, the impact on emissions of additional investment in low-carbon generation falls because the plants being displaced will be even newer and hence more efficient and so the savings will be reduced. For example, 1 GW of a newer baseload coal plant emits about 5.8 Mt CO_2 per year (compared to 6.5–7.5 Mt CO_2 for an old coal-fired plant), whilst 1 GW of a baseload gas plant emits about 3.2 Mt CO_2/yr.[47] On the basis of this simple assumption, we calculate illustrative figures for the quantity of zero carbon generation that would be required to meet the targets in Scenarios A and B. Note that these figures are illustrative only: at these levels of (hypothetical) investment, the EU's electricity system would need to be totally transformed.

45. In this and following sub-sections, we refer to capacity changes relative to current levels unless otherwise stated.
46. These assumptions are equivalent to assuming all plants over 30 years old in 2020 close, as discussed in Section 3.3.
47. Based on: 85% load factor, efficiency of 42% for coal and 50% for gas, carbon content of 0.33 t CO_2/MWh input (coal) and 0.21 t CO_2/MWh.

Table 13 Meeting the 2030 Targets by Investing in Zero Carbon Generation

Scenario		*A*	*B*
Total reduction required (Mt CO_2)	[1]	565	734
Meet target with zero coal generation			
Savings from switching older coal plants to gas (Mt CO_2)	[2]	227	227
Savings from switching newer coal plants to nuclear/wind (Mt CO_2)	[3]	292	292
Savings from switching older gas plants to nuclear/wind (Mt CO_2)	[4]	46	215
Total zero-carbon baseload capacity required (GW)	[5]	61	111
Net change in gas-fired capacity from 2005 (GW)	[6]	42	-11
Meet target with some coal generation			
Savings from switching older coal plants to gas (Mt CO_2)	[7]	227	227
Savings from switching older gas plants to nuclear/wind (Mt CO_2)	[8]	338	507
Total zero-carbon capacity required	[9]	100	150
Net change in gas-fired capacity from 2005 (GW)	[10]	-49	-102

Notes
Based on emissions savings per GW displaced of 5.8 and 3.2 Mt CO_2/yr for coal and gas respectively.
Assuming baseload zero carbon capacity has a load factor of 90% and 85% for fossil-based capacity.
[1], [2]. [7] from preceding table.
[3] assuming that 50 GW of coal plants is displaced.
[4] = [1] – [2] – [3].
[5] = { [3] / 5.8 + [4] / 3.2 } x 90% / 85%.
[8] = [1] – [7].
[9] = { [8] / 5.8 } x 90% / 85%.

5.5 Conclusions on 2030 Targets

The high-level analysis above suggests that meeting plausible 2030 targets could require a complete transformation of the generation sector. It will certainly require significant investment in zero carbon generation (at least 61 GW of baseload capacity). In addition, it will be necessary to require all coal-fired generation (without CCS) to close or to build an additional 39 GW[48] of baseload zero carbon capacity (displacing gas) or some combination of the two approaches. This is the minimum based on our scenarios. The more stringent 2030 target we have examined (Scenario B — a 2030 target that is consistent with the longer-term ambitions of 60% cuts in emissions by 2050) could only be achieved by closing all coal plants without CCS and replacing some existing gas plants with zero carbon generation (necessitating an investment in a total of 111 GW of new baseload plants).

Achieving such a transformation would, of course, be extremely challenging. The option of using CCS as part of the zero carbon mix should make the challenge more achievable. However, CCS would have to have reached commercial scale well before 2030 if it were to make a significant contribution to meeting the target.

We showed above (section 3.6) that the 2020 target could be met with much less radical change: all coal plants older than 30 years would be replaced with gas plants, but otherwise no investment in zero carbon generation would be required, provided the EU meets its renewable and energy efficiency targets. Even this has its challenges — notably increased gas dependency. The more ambitious 2030 targets cannot be met in this way, principally because no more "conventional" savings from switching coal to gas are available once there are no more coal plants. It is unclear whether EU politicians have fully appreciated the likely considerable costs of the transformation of the energy sector that would be required to meet the EU's longer-term (post-2020) emission reduction ambitions. Nonetheless, CCS is likely to have a key role to play in meeting any realistic 2030 targets. For this reason, it is important that early consideration is given to understanding how best to use the policy tools available to encour-

48. 100 GW with some coal burn, 61 GW without (figures taken from Table 13).

Chapter 6 | POLICY OPTIONS THAT WOULD SUPPORT CCS

age its development, namely regulation, financial incentives and market-based instruments.
Overall, the problem for CCS is that the level of carbon prices required to make it competitive on purely commercial terms appears to be higher than the range of prices forecast out to 2020. This problem may only be a temporary feature: experience from other emerging technologies suggests that capital costs typically fall substantially as the technology matures and economies of scale become possible. However, given current CCS capital costs, carbon prices sufficient to make CCS attractive could make building new nuclear plants an attractive option. Whilst many EU countries are not at present willing to contemplate building new nuclear plants, the situation is changing due to concerns about security of supply and the difficulty of relying heavily on renewables to meet CO_2 reduction targets.

There are, however, other compelling arguments for supporting CCS. First, within the EU there is a perceived need for fuel diversity (including coal) both to provide security of supply and to enable the EU to react to changing fuel market conditions, and CCS is one way of achieving this. Second, the rapid expansion of coal-fired generating capacity in China and India means that any hope of achieving significant global reductions in emissions must involve measures to slash their production of greenhouse gases and CCS is currently the only option. Third, as we have just demonstrated, even in the most optimistic scenarios for nuclear and renewables ramp up by 2030, it seems likely that the EU may struggle to deliver the desired level of abatement of CO_2 emissions unless CCS can be part of the low-carbon repertoire.

In terms of support for CCS, the EU has decided to allocate up to 300 million allowances from the fund for new entrants to CCS projects, with a limit on the allowances that an individual project can receive of 45 million. The European Commission has also proposed around €180m of development aid under its "Economic Recovery Plan" to each of five CCS pilot projects. Some individual Member States are also providing support at the national level. Whether this support will be sufficient to fund the development of CCS plants will depend crucially on the carbon price. Below, we describe additional possible policy approaches that could be used to support the introduction of CCS. Note that all of these additional approaches link CCS subsidies to the carbon price so if the problem is that the carbon price is too low then they might not be effective.

6.1 Auction Revenues

As explained earlier, the current Phase III proposals stipulate that 20% of the revenues earned from auctioning allowances must be used by Member States for one of a defined list of purposes, which includes support for CCS. However, there is no absolute requirement to support CCS. There is an argument to suggest that it could be more cost effective to support CCS than some of the more expensive renewable technologies (such as tidal or wave power), particularly because of the global benefits that could accrue from having commercial CCS solutions that could be retrofitted to the coal plants springing up in China and, to a lesser extent, India. Consequently, seeking to amend the provisions, for example, to require auction revenues from the electricity sector to be dedicated to CCS (perhaps only in countries which rely heavily on coal-fired plants) would be an obvious route to guaranteeing support for CCS.

To estimate the magnitude of the support that might be available, we have used the PRIMES scenario, which assumes energy efficiency and renewables targets are met. This projects emissions from the power sector of 760 Mt CO_2 in 2020. At a price of around 30 €/t CO_2, as assumed by the EU in its impact assessment (see section 4.3.2), this would equate to revenues of around €22 billion per year.[49] Whilst we are not suggesting that all these revenues would or should be allocated to CCS, the calculation demonstrates that, in principle, very significant support for CCS could be provided via this route.

49. This seems consistent with the impact assessment which, for the same carbon price, estimates revenues from auctioning allowances for the aviation plus power sectors at nearly €39 billion.

6.2 Allowances For Sequestered Carbon

Whilst CCS demonstration plants will receive up to 300m EU ETS allowances (up to 45m per project), it would also be possible to go one stage further and move from an implicit subsidy for CCS to an explicit subsidy by issuing allowances in respect of the carbon savings from CCS, *i.e.*, for every tonne of CO_2 that goes into storage, the plant operator would receive an emissions allowance that it could sell. The logic would be that CCS was delivering emissions reductions that would otherwise not be achieved. There could also be variants of this scheme, with a multiple or fraction of allowances per tonne of CO_2 stored. In addition, a cap could be put on the total number of allowances that would be released in this way.

6.3 Linked Trading Schemes

As discussed above, it seems possible that the U.S., Canada and Australia might introduce their own cap and trade schemes. If this were to occur, then given the global nature of the CO_2 problem, there would be advantages in linking these systems together in some way. In other words, allowances issued under one scheme could be used in any of the linked systems, possibly with some exchange rate applying between different emissions allowances, *i.e.*, one EU allowance might be worth more or less than one allowance in another scheme.

Linking schemes in this way would have much the same effect as creating one larger scheme. Hence, it would be likely to reduce the volatility in carbon prices due to the larger pool of affected installations.

Whether or not linkage would increase carbon prices in the EU beyond those that would result from increasing the 2020 emissions reduction target to 30% would depend on the strictness of the emissions targets in the other linked markets. Moreover, if one of the linked regions is able to reduce emissions more cheaply than the others, carbon prices will rise in this region relative to what they would have been for an isolated scheme, but prices in the other markets will be lower with linkage.

Introducing a linking between schemes is not necessarily straightforward. Different approaches to issues such as the banking of allowances, penalty buyout prices, and the coverage of the scheme could all cause problems. Nonetheless, there could be considerable benefits from such a development as investors would be able to seek out the most economically efficient mitigation opportunities on an international rather than a local basis.

Appendix — Analysis Underpinning Our Renewables and Energy Efficiency Calculations

Table 14 shows the starting point of our analysis. The top section of the table simply shows that we assume the three 20% targets are met. The second section shows the illustrative values we give to emissions and energy consumption — all values for emissions are based on 2020 emissions being 100 (notional units) if the targeted 20% reduction in GHG since 1990 is met. The third section shows a number of assumptions based on the European Commission's PRIMES scenarios. The last panel calculates the implied drop in emissions, and the change in emissions per unit of energy generated. The 42% reduction in generation emissions is simply the percentage fall in emissions from 1990 to 2020, *i.e.*, (46.2–26.7)/46.2. The 56% reduction in carbon intensity is calculated in a similar way.

Table 14 Emissions and Energy Use if the Targets Are Met[50]

	1990	2020
Efficiency savings		20%
Renewable energy		20%
Emissions reduction		20%
CO_2 emissions	125	100
Energy consumption	-	100
Non-renewable energy consumption	-	80
Total generation	100	132
Thermal generation	58	72
CO_2 emissions excluding generation	78.8	73.3
CO_2 emissions from generation	46.2	26.7
Carbon intensity (emissions/generation)	0.46	0.20
Reduction from 1990 levels of:		
Generation emissions		42%
Carbon intensity of generation		56%

50. Based on PRIMES figures.

Based on this analysis, Table 15 shows what happens if the energy efficiency target is missed by 1%. The second part of the table shows that energy consumption increases from the base case by 1 notional unit, and so more thermal generation is required (3rd panel) and the carbon intensity of thermal generation increases (4th panel) if there is no change in fuel mix. Consequently, further reductions in generation sector emissions are required to meet the emissions target.

Table 15 Emissions and Energy Use if the Efficiency Target Is Missed

	1990	2020 Target met	2020 Target missed
Efficiency savings		20%	19%
Renewable energy		20%	20%
Emissions reduction		20%	20%
CO_2 emissions	125	100	100
Energy consumption	-	100	101
Non-renewable energy consumption	-	80	81
Total generation	100	132	134
Thermal generation	58	72	73
CO_2 emissions excluding generation	78.8	73.3	74.2
CO_2 emissions from generation	46.2	26.7	25.8
Carbon intensity (emissions/generation)	0.46	0.20	0.19
Reduction from 1990 levels of:			
Generation emissions		42%	44%
Carbon intensity of thermal generation		38%	41%
Change in 2020 generation emissions because of missing efficiency target			-3.4%

Table 16 repeats the analysis shown in Table 15 under the assumption that the renewables target is missed by 1%. We explore two different scenarios. Under Scenario 1, the renewables target is missed entirely due to non-generation sectors; whereas in Scenario 2, the target is missed because of insufficient wind generation.

Table 16 Emissions and Energy Use if the Renewables Target Is Missed

	1990	2020 Target met	2020 Target missed Scenario 1	2020 Target missed Scenario 2
Efficiency savings		20%	20%	20%
Renewable energy		20%	19%	19%
Emissions reduction		20%	20%	20%
CO_2 emissions	125	100	100	100
Energy consumption	-	100	100	100
Non-renewable energy consumption	-	80	81	81
Total generation	100	132	132	132
Thermal generation	58	72	72	80
CO_2 emissions excluding generation	78.8	73.3	74.5	73.3
CO_2 emissions from generation	46.2	26.7	25.5	26.7
Carbon intensity (emissions/generation)	0.46	0.20	0.19	0.20
Reduction from 1990 levels of:				
Generation emissions		42%	45%	42%
Carbon intensity of generation		56%	58%	56%
Carbon intensity of thermal generation		54%	56%	58%
Change due to missing renewables target in 2020 in				
Generation emissions			-4.7%	0.0%
Carbon intensity of thermal generation			-4.7%	-9.7%

Notes
In Scenario 1 the renewables target is missed because biodiesel uptake is less than forecast.
In Scenario 2 the renewables target is missed because there is less wind generation than forecast.
For simplicity we ignore the use of non-renewable energy in producing biomass-derived renewables.