CARBON CAPTURE AND STORAGE (CCS)
Analysis of Incentives and Rules in a European Repeated Game Situation

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Executive Summary

Abstract

Two mechanisms have been created to support carbon capture and storage (CCS) technologies at the European Union-level – stimulus spending of up to €180 million for one project in selected member states and allocation of up to 45 million EU-ETS allowances (EUAs) per demonstration project from a total pot of 300 million allowances. We identify a number of key risks in designing the project selection process including the carbon price risk, the variable cost risk, technological risk and inefficiencies including asymmetric information and collusion. A Technology Category Auction (TCA) would deliver learning from diversity rather than replication, which is more appropriate for the CCS demonstration phase. To be effective, however, the TCA will require a number of demonstration projects in line with EU objectives of 10-12 plants deployed by 2015.

Policy background

In 2007, the European Union's heads of government agreed to deploy up to 12 commercial-scale integrated CO_2 capture and storage (CCS) demonstration projects across Europe by 2015. To encourage that deployment, the EU has recently agreed to two mechanisms for supporting CCS projects: (i) using 300 million emissions allowances (EUAs) set aside for CCS and innovative renewable technologies and (ii) allocating €1.05 billion of the European Economic Recovery Plan (EERP)'s stimulus spending during 2009/10 on CCS projects from a specified list of projects in seven member states, including €180 million each for projects in Germany, UK, the Netherlands, Poland and Spain, €100 million in Italy and €50 million in France. These EU-level mechanisms will interact with domestic support mechanisms such as the UK CCS Competition in determining the number and nature of the demonstrations undertaken across the entire EU. Whether explicitly or implicitly, the two EU decision processes and the domestic support mechanisms must ultimately address the question of what are the goals of demonstration, since a particular definition of demonstration will need to be enshrined in the selection process(es) and the decision criteria selected.

What should be the basis for selecting projects? There are several lists of criteria that have been assembled, but perhaps the most pertinent set from a European perspective is that of the EU Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP). ZEP launched its Flagship Programme in October 2007 and its goals included ensuring "a diverse geographical and technological spread of projects" and accelerating "cost discovery and test fundability in order to build confidence in its widescale deployment post 2020 as well as other goals such as international transport/storage element spurring action by other countries, especially large emitters. By contrast, when the ZEP published a more elaborate post-hoc justification for the commitment in 2008, the dominant rationale was that 10-12 demonstration projects would be needed to "de-risk CCS for all players within the value chain and achieve commercialisation by 2020". Although the overarching goal is simpler, ZEP then describes three layers of criteria – five eligibility, sixteen portfolio and eleven project criteria, most of which are extremely specific (i.e., hard coal versus lignite, pipelines versus ship transport). The lens adopted by the EU support mechanisms is purely a single project perspective and the EU/ZEP approach to date is entirely internally focused with little cognizance taken of the significant activities and investments being undertaken globally.

Having created not one but two separate EU funding mechanisms to support individual integrated CCS projects which operate over different time horizons, there is now a need for greater clarity on how these mechanisms should be designed to interact with each other and with the decision processes being designed at the member state level. How should the pressures to maximise the number of projects, minimise the costs while encouraging geographic and technological diversity best be reconciled?

Key questions

Following on from the discussion of criteria, perhaps the most basic question to ask is "demonstrate what?" – over what time frame, at what scale, at what cost and, most especially, to what end? Some of these questions are amenable to analysis, while others are more fundamentally in the domain of the politician and the policy-maker, but whether explicitly or not, they must still be resolved before project selection can proceed. It is impossible to resolve trade-offs and to suggest criteria for choosing one project over another before one can begin to answer these more fundamental questions. Rather than rushing into decisions on the shape of a portfolio of projects, the objectives need to be laid out with greater clarity.

One can divide objectives into speed of deployment, industrial policy, value for money, and learning potential. Valuing speed of deployment above all else implies that meeting a goal of, say, twelve plants by 2015, is more important than whether those plants are most effective in achieving longer-term objectives such as maximising the likelihood that CCS will be a widely used technology in 2030 and beyond. Speed is important, but ultimately other goals must take precedence. There are good reasons to believe that industrial policy concerns can help stimulate interest in CCS and expand geographic coverage; the need for potentially large subsidies implies that member state governments will need to think about CCS strategically. Nevertheless, although such considerations may have some role at the national level, when aggregated up to the EU level, the portfolio approach adopted largely obviates the need to consider the benefits of a specific technology or approach. Value for money is essential, particularly when CCS places a large claim on both EU and member state funding that will amount to several billion Euros. For that reason, some element of cost competition will be vital, but it is still impossible to assess value for money without a better understanding of what "value" is and, for demonstration at least, value ultimately lies in learning.

Learning can be further divided into learning from diversity and learning from replication. Given the nature of CCS technologies and the commercial scale of so-called demonstration, 'diversity' (validation of the main available technological options) should be prioritised over 'replication' of the technology (learning-by-doing). The number of replications in manufacture of CCS equipment is much smaller than for example that of wind turbines which has led to significant learning-by-doing benefits. More attention needs to be paid to the types of diversity that should be encouraged, which requires coordination (or at last greater cognizance) of projects being put forward at both the EU and global level. The principle of diversity should also be extended to the number of firms involved in the CCS demonstration projects, diversity in their industrial background and core competencies, as well as the proposed integrated capture-transport-storage solutions.

The value of learning-by-doing from almost simultaneously implemented projects may be limited. Other factors involved in conjunction with learning-by-doing are R&D and technical change, competition, and time. Since competition may be the major driver of cost savings of large-scale construction projects, it is useful to ensure that the commissioning of the envisaged demonstration projects broadens the basis and scope for future competition in the CCS market rather than offering competitive advantage to a select few companies. In the long run, all member states will benefit from the existence of a more competitive CCS market.

In the process of investigating the strategic interactions between member state and EU support schemes, we offer specific recommendations on questions of weighting of diversity versus learning-by-doing, auction design, and the design of a support scheme for both capital and operating costs.

One final question, critical in the EU context, is that of burden sharing – given the likely call on additional domestic resources, who should bear the burden of demonstration? In the Renewables Directive, an effective burden sharing solution emerged to discourage each member state separately under-supplying RD&D absent an agreement that others will contribute proportionately and fairly. The new initiatives on CCS investment thus must be seen not only as efforts to encourage development and deployment, but as a nascent effort to share burdens across member states. Clearly it is desirable that this initiative involves the widest support (to spread the burden) and encourages the most innovative and/or information-generating projects to clarify the best approach to CCS at scale, but a burden sharing arrangement must also recognize existing distribution of resources and effort in developing CCS particularly if there is hope for a rollout of demonstration projects on a rapid timescale (i.e., by the 2015 target deadline). Given a scale of activity along the lines of EU ambitions of "up to 12" demonstration projects, it should be possible to better test the hypothesis that there are learning benefits that would justify additional support (as with promising renewable technologies).

The risks

Before the CCS demonstration phase funding can be assembled and projects selected at the EU and member state level, the risks and inefficiencies involved in the design of such support mechanisms should be assessed and, where possible, mitigated. There are several concerns that emerge, some relevant to any programme of demonstration or where government subsidies are available, and others more specific to the technical and economic issues associated with a CCS demonstration programme.

One common concern is how to best address information asymmetry between a government that provides the subsidy and the firms receiving the subsidy. Another general concern is the potential for collusion among leading firms and/or the potential for a member state to engage in state aid in the guise of supporting a public good in the form of a demonstration plant. Both these concerns (and the larger objective of obtaining value for money) will be alleviated through competition and so the task is to design a competitive mechanism that simultaneously accomplishes the broader objectives with respect to learning.

With regard to the EU mechanisms themselves, the risk associated with the EERP is broadly similar to that associated with any stimulus spending although it may be especially severe for CCS demonstrations, namely that haste makes waste – the desire to expedite spending may not fit well with the project timeline of individual demonstration projects in spite of the ambitious EU deadline of 2015. More interesting is the risk associated from the other EU support mechanism, which links the fate of CCS demo funding to the ETS and specifically to allocation of EUAs based on an as-yet unspecified formula. Here, there are clear possibilities for more or less desirable outcomes depending on the design enacted.

Another more CCS-specific concern is with regard to how the higher capital and operating costs can both be addressed without worrying that firms will game the system. For example, firms might put in a bid just for capital support, and then, having received that support, come back and request additional support to operate the CCS – the game being that having spent so much money a member state government committed to decarbonising fossil generation will feel obliged to pay the modest extra amount to deliver the desired outcome. A related concern, which further justifies the need for competition, is that given the high capital costs and the uncertainty in those costs because we are at the demonstration phase, firms will need a clear signal of support before they will proceed with a project, but if all risks are removed then they will have little incentive to perform.

Proposals to mitigate the risks

A starting point would be to focus on the case of the EUA support mechanism. The present proposals would make receipt of EUAs "dependent upon the verified avoidance of CO_2 emissions", which could be interpreted as meaning that support will be in proportion to the amount of CO_2 stored or abated. Allocating these EUAs to Member States or project developers at an early date would ensure that as many EUAs as possible are allocated before 2015, to enable projects to be brought forward quickly in a way that contributes to both the capital costs and operational costs for the duration of ETS Phase III (2013-2020). It could be argued that the EUAs should not be linked solely to CO_2 abated if the aim is to stimulate rapid construction of CCS projects, which requires large amounts of up-front capital. The longer the subsidy is delayed, the higher the perceived cost to the developer, with no obvious gain in risk sharing.

As the analysis in Chapter 4 shows, the EUA price varies in sympathy with the electricity price, thereby amplifying the risk to the developer. So, a critical question is how the EUAs should be best used as this will have an impact on costs.

The arguments developed below suggest that providing support earlier rather than later and making support contingent on operational performance rather than market returns both contribute to lowering the social cost and the cost to the government of supporting CCS. Limiting bypass would both encourage the development of reliable capture facilities with a satisfactory level of availability and deliver sufficient CO_2 to test the storage reservoir at scale (i.e., ~1 million tons of CO_2 per year).

Addressing the higher operating costs of CCS is a major challenge for an effective demonstration programme since there is a danger that after major capital expenditure, the capture plant may hardly operate unless the incentives are aligned correctly. The higher the price of electricity, the greater the lost profit from operating in capture mode, as this consumes about one-quarter of the electricity that could otherwise be sold. Second, unless the avoided variable costs of switching off the CCS are low or the price of EUAs is high (above €25-30 /EUA), a CCS-enabled plant would not even cover its extra operating costs, let alone the opportunity cost of electricity. In such circumstances, the plant operator is likely to choose to run in non-capture mode without an operating subsidy, unless the subsidy was contingent on delivering a certain volume of CO_2 into storage.

The risks of EUA and electricity price volatility and of the uncertainties about the capital cost should inform the design of the support scheme to ensure that a sensible choice of CCS technology is chosen and also operated. If the EUA price is not high enough to justify capture, but the electricity and coal prices make conventional coal-fired generation profitable, then the question is whether or not the plant should be encouraged not to switch from capture to by-pass mode. Ultimately, the justification for restricting by-pass at the CCS plant is that the benefits from learning whether the CCS plant can operate reliably and continually at high load factors plus the reduction in CO_2 (which is compensated through the existing ETS but probably not to the extent needed to prevent by-pass) is sufficient to warrant the additional cost incurred.

If the uncertainty of any future contribution stream is reduced, and if the remaining extra capital costs (after crediting the NPV of these contributions) are covered by an up-front subsidy, then the main risk left with the company is delivering the investment to cost and on time – a risk that should properly be borne by the company and will be reflected in its bid, the more so the more competitive is the tender auction or selection process. One can learn useful lessons about the efficacy of risk-reducing policies from the variety of renewable electricity support schemes adopted by different member states.

With regard to auction design for allocation of EUAs, the key issues are whether there should be a first mover advantage in the structure of the auction and whether technologies and alternative configurations should compete with one another or only compete within a technology category. A first-come-first-served approach, even if restricted in scope and duration, is seen as benefiting inefficient firms seeking to avoid competition with potentially more efficient firms. Removing projects at a first stage makes competition in subsequent rounds less intense and makes it easier to sustain collusive agreements with fewer firms. Instead we propose a single-stage Technology Category Auction (TCA) at the EU level, which encourages diversity and reduces the likelihood of collusion, at least within any single category. Member states can (and will) adopt their own support mechanisms which would, of course, mean that projects selected for subsidy by the member state fare better at the EU level since they would be able to better demonstrate co-funding and financial viability.

Governments have legitimate concerns that firms have far more information on costs than the governments awarding funding and so will worry that costs submitted in proposals will be inflated. Concerns over asymmetric information helps motivate the auction format in the first place, since it provides an efficient way of extracting private information (if designed properly). In terms of firm competition, there is no clearly dominant player – several major utilities (Eon, Vattenfall, Enel, and RWE) are associated with two projects each in the EERP and there are a number of competing technology providers and other partners, so there should be the basis for effective competition if designed properly.

In considering reduction of risk to the firm versus making sure that the government is not disadvantaged, we are facing a classical principal agent/optimal risk sharing problem. The less risk the firm (agent) is exposed to, the less incentive it has to perform and the higher the expected cost to the government (principal). Reducing risk to the firm decreases the firm's incentives to perform.

Further, all technologies are not created equal and this can pose a serious threat to diversity if firms needed to bring forward all projects in a single competition. For example, although most studies find that the overall costs of pre-combustion with capture are not wildly different from the overall costs of post-combustion with capture, the base costs of pre-combustion are notably higher, which is then offset by the lower costs of capture because the CO_2 has already been separated. Similarly, oxy-combustion is generally assumed to be in the same cost range, but the uncertainty is viewed as significantly higher because there is less experience with the technology at large scale. It would be difficult, therefore, to have a competition which did not differentiate between technologies because inevitably certain technologies would be favoured over others in a single competition. Similar issues arise with respect to differentiating transport (pipelines versus ship) and storage options (saline aquifers versus depleted oil and gas fields).

For this reason, we suggest that any mechanism for awarding projects create separate categories in a TCA. Within a clearly defined technology category, however, cost should be the preferred basis for judging the winner. Such an auction could take other considerations such as local variation in costs into account, but we would argue that since it may be difficult to verify claims of local cost differences leading to problems of adverse selection where individual firms overstate local costs in order to make their bids appear less unattractive. The more categories there are (broadly construed as projects of a particular technology, nationality, geographical location etc.), the less each project is subjected to direct competition. In short, there is a trade-off between competition between projects and the degree of specificity in describing projects. There is no magic number for the number of projects in any one category since the actual competiveness will depend on the specific details of the proposals and there will be uncertainty over the number of competitors at the time a bid is submitted. We generally favour relatively few categories and conducting the process at the EU level as that would maximise the number of projects in each category since the overall number of projects is still expected to be quite limited.

One final complication is that EU CCS support plan allocates 300 million EUAs to up to 12 CCS plants plus innovative renewable energy technologies. If some level of IRT funding is made available, it would be appropriate to create a separate category for IRTs (or even for subcategories such as concentrating solar power (CSP), tidal power, etc) in the TCA since it would be difficult to judge IRTs alongside CCS.

The Scale of European Ambition

There are some important caveats that need to be introduced before the analytical conclusions are simply transferred to the policy arena. The most fundamental is one of scale – for a TCA to be effective, the number of candidate projects will need to be at least roughly in line with EU goals rather than a scenario where only one oxyfuel, one pre-combustion and one post-combustion plant come forward across the entire EU-27. Assuming that European support alone will be insufficient to finance a demonstration project in its entirety (indeed, member state co-funding is a condition of EERP support), then it is important to understand the current landscape across Europe to be able to gauge if it is more likely that there will be three projects or eight or thirteen that will ultimately emerge which affects whether the TCA proposal can be successful or whether the new entrant EUA pool will be largely untapped or oversubscribed. A sense of magnitude will help determine whether the rules should be biased in favour of encouraging more projects at the expense of a stricter set of rules that discourage collusion and emphasise value for money.

It is only a matter for conjecture as to how many countries will come forward with support, but to date, only a handful of European countries have invested in resources and activities involving the private sector, the research community and government agencies. The resulting engagement of industry and governments on the issue varies markedly from one member state to the next. Apart from the European Commission itself, seven member states plus Norway are participants in the Carbon Sequestration Leadership Forum (CSLF), the major international forum for CCS, the EERP identifies only seven in which projects might be awarded (five of which are also CSLF members) and six European countries (Norway, the UK, Netherlands, Germany, France and Italy) have joined the Australian-led Global Carbon Capture and Storage Initiative (GCCSI). Only three member states (UK, the Netherlands, and Germany) are thought to be relatively far advanced in their efforts to transpose the recent CCS Directive into national legislation. Of course, research capacity or commitment to international activity do not correlate perfectly with the ability to host and support demonstration projects, but given the abbreviated timeline of the EERP and the long lead time to get a major demonstration plant sited, permitted and financed, it is reasonable to question whether with few human resources many of the other member states will be willing or able to move quickly to put together a viable project that would be ready in the timeframe needed.

Thus, there is a real possibility that too few projects come forward in the EU because of cost uncertainties and lack of member state government support, which suggests that it may be a mistake to use concerns over state support of national champions to create a set of rules that would only discourage member states from coming forward with support for projects. The project selection process should also aim to attract as diverse a set of participants as possible regardless of ownership type.

A plausible effort to assemble up to 12 demonstration projects numbering closer to twelve than to three on what is an ambitious deployment timeline would require that at least the “leading” member states, not coincidentally those with access to storage and strong industry and government interest, would each need to support a disproportionate share, i.e., at least two flagship projects apiece. Given the logic in favour of diversity over replication at this point, those projects should demonstrate different technologies. The essential corollary is that countries willing to move forward with more than one project should have access to EU funding mechanisms such as EUA support on a project basis and that limits not be placed on access that would discourage member states from shouldering a greater share of the demonstration burden.

For a project to proceed requires a critical mass of both government support (financial and regulatory) and industry interest (including an active RD&D programme to underpin participation). EERP funding essentially requires that the project is already in a position to move forward. EUA funding and the 2015 deployment target require at least project proposals in a relatively advanced state that would need to be followed in rapid succession by an assessment of the proposed storage reservoir, a fully elaborated plan for transport, the creation of the requisite regulatory framework and member state support.

We return then to the question of what is being demonstrated and highlight the project orientation of the existing EU mechanisms for which we have offered suggestions in terms of design. By contrast, the Dutch focus on two major regional hubs (in the North and in the Rotterdam area) rather than on individual powerplant projects (echoed in the Spanish Ciuden and Yorkshire Forward proposals). Though laudable, the hub approach is not easily reconciled with the current EUA and especially the EERP support mechanisms. Support for a single plant can help cross-subsidise the infrastructure needed to make the hub a reality, but the scale of the funding proposed at the EU level is commensurate with much more limited ambitions and project-level financing.

There is a powerful case that given the existing portfolio of single projects already being assembled across the globe in the US, Australia, Canada, Norway and even China and South Africa that a major initiative designed to create a testbed for a range of technologies would be extremely attractive. Unfortunately, the potential for concentrating funding on a smaller number of large projects that would be truly groundbreaking at a global level seems implausible given the European emphasis on geographical distribution (and traditional approaches to government-industry relations in member states such as the Netherlands or Germany which favour dividing resources rather than concentrating resources, or the UK where a liberalised market acts against the planning needed for grand projects).

The future of CCS will be judged by the success of the first projects. Six white elephants built around Europe where both capital and operating costs are far higher than expected will be a major setback for the next stage which is touted as a major expansion of low-carbon fossil generation. Even if restricted to individual projects, a carefully designed EU portfolio of projects could offer a useful variation of experience in capture technology, storage medium and sectoral and geographic diversity and by simultaneously keeping costs under control could offer a solid basis for taking CCS to the commercialisation stage.

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1 Introduction[1]

Designing a support scheme appropriate for the demonstration phase of carbon capture and storage (CCS) technologies is one of the major challenges facing governments around the world. The importance of CCS technologies has been confirmed by the Intergovernmental Panel on Climate Change (IPCC), by the governments of most major economies, by leading multinationals and is even accepted by many (though not all) environmental groups. The IPCC, notably in its 2005 Special Report on CCS and 2007 Fourth Assessment Report, has shown that meeting ambitious climate targets would be far more costly if CCS technologies are not available. Many governments, including those of Australia, Canada, the United States, the Netherlands, the UK and Norway, have claimed the mantle of leadership on the subject of CCS and positioned CCS as a major low-carbon energy technology alongside renewables and nuclear power.

On one hand, CCS technologies are not especially novel from a purely technical standpoint. Separating CO2 from fossil fuels has been carried out for decades in the gas processing industry or to create pure CO2 streams used in industrial processes such as for carbonated beverages. In the western United States, hundreds of kilometres of CO2 pipeline have operated for decades, shipping CO2 from natural formations to enhanced oil recovery (EOR) projects in the Permian Basin in West Texas. Storage of CO2 in geological structures has been carried out incidentally for decades as part of those same EOR operations and intentionally in the Utsira Formation in the North Sea as a result of StatoilHydro's Sleipner project which has stored 1 million tons of CO2 per year since 1996 and at other locations around the world (In Salah, Algeria, Weyburn, Saskatchewan) on the same scale.

Yet, whereas there has been considerable experience with the individual components of the CCS value chain, there have been no large-scale, fully integrated systems that capture CO2 from power generation, transport the CO2 via pipeline and store (and monitor) the CO2 underground over time. Although there are many industrial processes from which CO2 might be captured, it is electric power generation that is the main focus of interest because of the scale of the electricity system worldwide.

Any serious policy to significantly reduce carbon dioxide emissions worldwide will have to see a disproportionate share of the reductions carried out in the power sector, because of the relative difficulty of decarbonising the transport sector in particular. The major options for the power sector are renewables, nuclear power and CCS. Although renewable generation is the most rapidly growing source of electricity, which is expected to continue for the foreseeable future, there are ultimately limits to its potential associated with intermittency,

[1] This section was written by David Reiner and David Newbery

the lack of energy storage, and physical constraints (and opportunities) from one region to the next. Nuclear power is another important source of low-carbon electricity as seen in Table 1. Nevertheless, nuclear generation is inevitably limited by concerns over waste, proliferation and political opposition that may vary enormously from one jurisdiction to the next. Fossil fuels remain the dominant source of electricity generation and they are attractive because of their costs, reliability, and the extensive experience base. The most dominant fuel is coal, which account for more generation than natural gas, nuclear power and wind combined. Reducing emissions from coal, the most polluting fuel both locally and globally, is essential to any credible effort to address climate change. The global distribution of resources is such that coal is central to the economies of many major countries including China, India, South Africa, Australia, and the United States. Coal-fired plants will have lifetimes of 40 or 50 years or longer and capacity in developing countries increases at a rate of over 100 GW per annum (dominated by China).

Table 1.1. Worldwide Electricity Generation 2006

Source	Coal	Oil	Gas	Hydro	Nuclear	Wind	Biomass
TWh	7754	1096	3806	3121	2793	130	173

Source: IEA (2009)

CCS is obviously very appealing on grounds of scale and politics, but whether CCS will be viable is ultimately dependent on the economics of CCS and the manner in which CCS is rolled out. Adding a capture unit to a power plant along with a transport system and secure storage will require upfront capital costs significantly higher than for unabated coal- (or gas-) fired generation. The energy penalty of perhaps 25%, which reduces the effective efficiency of the plant, will also result in higher operating costs and higher opportunity costs of not selling the parasitic electricity consumed. As the cost of carbon increases and the cost of CCS declines over time, CCS may eventually become economically attractive. The question is how to provide an incentive to encourage the development of CCS until that time arrives.

Another key consideration here is scale. Since CCS will need to operate on commercial coal-fired power plants, CCS technologies will operate in the 300-800 MW range rather than the 1.5 - 4 MW scale of typical wind turbines. Thus, rather than the cumulative learning curves typical of smaller scale renewables, the learning curve associated with CCS can be broken down into individually identifiable projects. The unit of analysis for any support scheme is therefore the single project since any one commercial-scale CCS project will require major government investment (of course, the emissions reductions are also commensurate with the scale involved).

There are indeed numerous examples of pilot projects for capture in the 1 MW to 30 MW range. These projects will require perhaps millions of euros in investment, but they are still small enough that individual firms can carry out these projects largely, if not entirely, on their own. Scaling up by another order of magnitude or two to the 300-800 MW range moves the project from an industry pilot to a project of a size that currently demands subsidies of a level that can only be provided by national governments or international support.

There is a good case for providing *additional* support for certain low-carbon technologies like CCS (additional to the support received for avoiding CO_2 emissions through the EU Emissions Trading System). If the low-carbon technologies are not yet mature, then their costs should fall as money is poured into their development and deployment. European heads of government have committed to up to 12 large-scale demonstration projects by 2015. Other demonstration projects have been launched in Norway, Australia, Japan, Canada, the United States, the United Arab Emirates and China. Although the original commitment was not explicitly linked to funding mechanisms, individual member states (MS) and the European Union have more recently begun to focus on how best to fund these first demonstration projects across the EU.

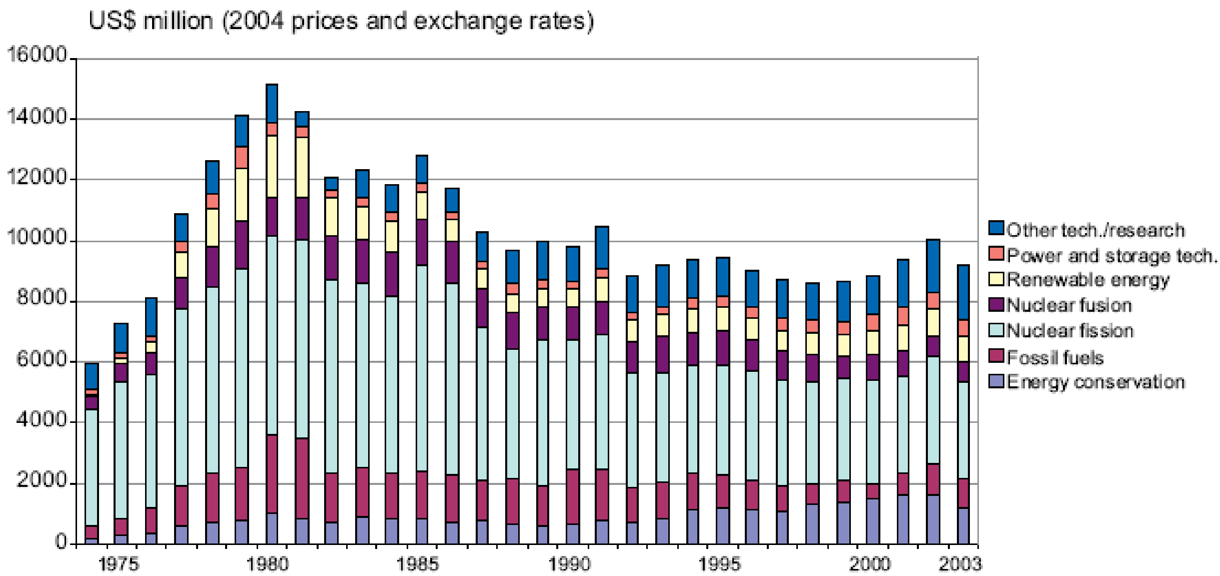

Figure 1.1 Global Energy R&D Funding 1974-2003

Source: IEA *Government Energy Technology R&D Budgets* at http://www.iea.org/Textbase/stats/rd.asp

Just as in the past, huge sums were spent developing nuclear power (see figure 1.1), and, through defence contracts, high efficiency gas turbines, which have revolutionised electricity generation, so we should now spend large sums developing CCS to the point that it becomes attractive in both developed and developing countries (once the carbon price is reflected in local electricity prices). If that happens, climate-damaging emissions will not just be reduced in the EU but in the world as a whole, helping to mitigate the impacts of climate change worldwide.

This seems to be a powerful argument, but needs scrutiny. Wind generation costs have fallen dramatically as more wind generation has been deployed, to the point that they are already competitive (on-shore) with coal and gas generation, providing the latter pay an EU carbon price of €30/tonne (its projected level). Photovoltaic (PV) panels have also seen dramatic falls in cost as chip technology driven by the IT revolution has spurred development (although they are still far too costly for most purposes). Figure 1.2 shows the results of increasing the production of various technologies, where the suggestion is that increased production (proxying for increased deployment) of these technologies results in learning by doing and with that a fall in costs.

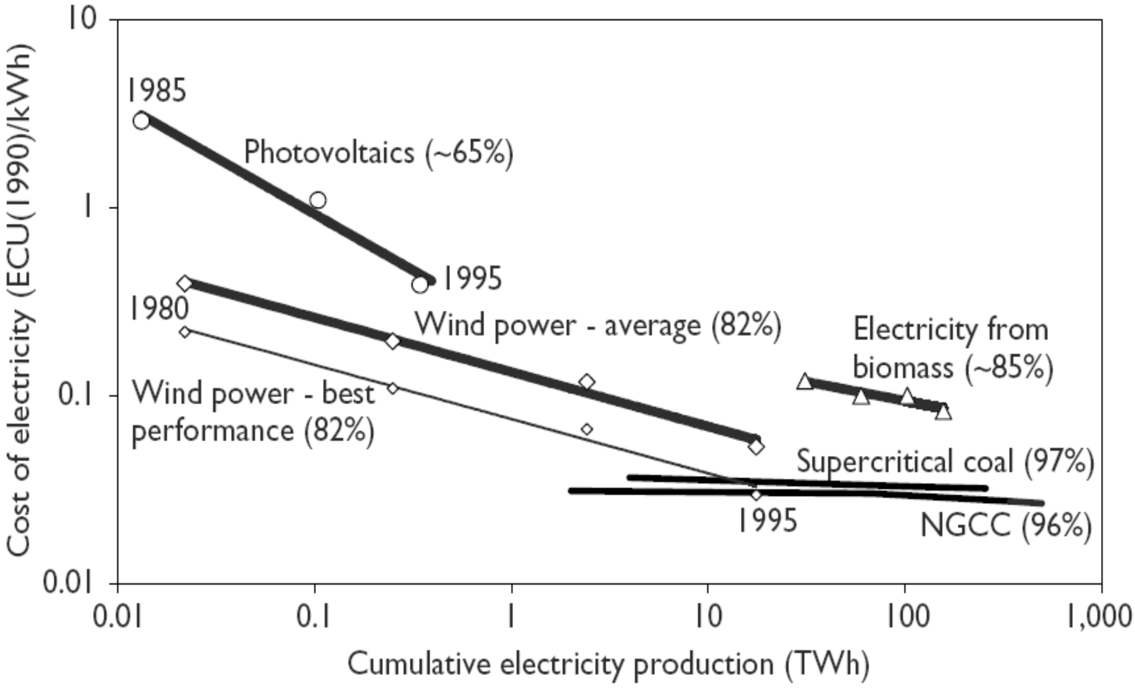

Figure 1.2 Experience curves showing cost reductions in response to learning
Source: IEA (2000)

The numbers on the graph show the costs as a percentage of the previous cost level after the scale has been doubled. Thus PV falls to 65% of its earlier cost for each doubling of output, while wind falls to 82%, or by 18% for each doubling of scale. In an IEA GHG Programme report, Prof Ed Rubin at Carnegie-Mellon University anticipates a 13-20% reduction in capital cost and 13-40% reduction in cost of capture depending on technology used, based on deployment of 100 GW of CCS plant thereby bringing the overall cost of electricity much closer to the current cost of pulverised coal generation.

It is also clear that globally we have been under-investing in low-C R&D as figure 1.1 showed. Figure 1.2 shows that once the technology has been proved in the laboratory setting, costs continue to decline with cumulative deployment, benefiting subsequent investors, and to that extent justifying public support where future investors convey a public benefit (reduced GHG emissions). We have a good example of this in the Renewables Directive, which can be seen as an effective burden-sharing solution for the collective public good of deployment support that ensures that each member state in the EU will contribute proportionately and fairly. So too the new initiatives on CCS investment are innovative attempts to encourage earlier development and deployment. Clearly it is desirable that this initiative involves the widest support (to spread the burden) and encourages the most innovative and/or information-generating projects to clarify the best approach to CCS at scale. Given a reasonable scale of activity it should be possible to better test the hypothesis that there are learning benefits that would justify additional support (as with promising renewables technologies). If, on the other hand, the technology appears to be near commercial, that will have profound implications both for the necessary carbon price and international agreements if CCS is to be widely deployed.

We believe that once the cost of the CCS technology has declined the main comparative advantage of countries will be in the implementation, including a suitable business and regulatory model/framework. The case of wind power is a good example of achieving different rates of progress and at different costs for the same relatively competitive technology. It is not too early to think about the possible business and regulatory models as part of efforts to foresee potential strategic behaviour on the part of the main actors and already there has been some noteworthy progress in the UK and Germany, particularly in the regulatory domain.

The regulatory and innovation policy lessons from other competitive energy industries may also be useful. For example, following deregulation of the electricity sector, in the US EPRI has adopted a more flexible model for collaborative R&D among the electric utilities. In the North Sea Continental Shelf the experience with competent joint ventures and operator-ship for operation and technology development and transfer in petroleum fields may offer useful lessons.

The Directive proposes a new funding mechanism, linking directly to the issuance of EU Emission Allowances. Thus, the prospects for CCS are to be even more intimately linked to the EU ETS: as both a direct funding mechanism for demonstration plants, and as a long-term incentive in which the carbon price might itself be influenced by, and reward, the cost of delivering the first few CCS units.

On top of the 300 million EUAs allocated to CCS (and innovative renewable technologies) from the new entrant reserve, the European Economic Recovery Plan (EERP) allocates just over €1 billion to CCS projects over the next two years. The EERP explicitly lists individual projects and even extends beyond the power sector (to include €50 million for removing CO_2 at the Florange steel plant in France). The list also addresses some basic concerns about ensuring the diversity of the initial projects by including an oxyfuel project in Spain and Integrated Gasification Combined Cycle (IGCC)s plants in Germany, the Netherlands and UK as well as having projects storing carbon dioxide in both saline aquifers and depleted oil and gas fields. Although there are no gas-fired projects listed, that is the primary focus of Norwegian plans for CCS deployment.

The interaction between EUA support from the new entrant reserve, the EERP stimulus and additional domestic mechanisms will ultimately determine the fate of the stated EU commitment of building up to 12 CCS demonstration projects and the speed, nature and ultimate viability of those projects. The detailed provisions will therefore be critical to ensuring learning by doing, geographic and technological diversity, and value for money.

But if governments are to provide subsidies to a select number of CCS demonstration projects, what should be the basis for selecting those projects? The first question to ask in funding demonstration projects: “what is being demonstrated?” If the funds are simply going to support the most cost-effective means of currently reducing emissions, then CCS would not be receiving any government support. Thus, the emphasis has to be on the relationship between investment today and the future potential of the technology. Chapter 2 reviews the different possible bases for choosing demonstration projects providing a global overview of different decision criteria and support mechanisms. Chapter 3 then investigates whether the goal of funding CCS demonstration projects should emphasise replication and learning-by-doing or diversity and knowledge transfer. We then provide in Chapter 4 an analysis of the risks associated with the design of the European support mechanisms, noting the importance of possible interdependencies between EU and member state support systems. We then apply game theory and auction design in Chapter 5 to justify the use of a Technology Choice Auction at the EU level as a way of fostering competition and minimising cost, subject to meeting our goals of greater diversity described in Chapter 3. Finally, we offer some conclusions in Chapter 6.

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2 Examining the Goals of Demonstration[2]

Perhaps the most basic question is: demonstrate what? In October 2007, the EU Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP) described the manifold goals of the EU flagship programme as being to: (i) Demonstrate the EU's commitment to delivering on its CO2 reduction targets and combating climate change; (ii) Kick-start the urgent wide-scale deployment of CCS in Europe; (iii) Ensure a diverse geographical and technological spread of projects; (iv) Prove that CCS works and is safe; (v) Accelerate cost discovery and test fundability in order to build confidence in its widescale deployment post 2020; (vi) accelerate projects with an international transport/storage element; and (vi) Demonstrate Europe's leading edge technology and spur action by other countries, particularly large CO2 emitters, such as India, China and the US.

Obviously, it is difficult to know if any project or set of projects could meet some of these objectives such as demonstrating "commitment" or "a leading edge". When the ZEP published a post-hoc justification for the number "up to 12", it sought instead to define the "optimal portfolio of projects necessary to cover a full range of CCS technologies and fuel sources, geographies and geologies, Europe-wide" (ZEP, 2008). They concluded that 10-12 demonstration projects were needed to "de-risk CCS for all players within the value chain and achieve commercialisation by 2020" (ZEP 2008: 5). To do so, the largely industry-led panel suggests five eligibility, sixteen portfolio and eleven project criteria (See Table 2).

Maintaining consistency in selection criteria can be elusive. The US GAO (2009) report compares the original and restructured Futuregen projects in the US, describing the very different choices taken (by the same administration) regarding technology choice, international involvement, research and development versus demonstration, single plant versus multiple sites, and the emphasis on deployment. The GAO report suggests more attention be paid to the competitive process adopted by the Clean Coal Power Initiative (CCPI), a ten-year $2 billion project initiated in 2002 intended to demonstrate advanced coal-based power generation technology at commercial scale. CCPI has taken a staged approach to funding "clean coal" technologies – the first round focused primarily on efficiency, the second on gasification and mercury control and the current Round III focuses on CCS (storing up to 300,0000 tons per year). One of the requirements of all CCPI projects is that the private sector must provide at least 50 percent of funds for the project. Phase III selection criteria include:

* Carbon capture technologies must operate at 90 percent carbon capture efficiency.
* At least 300,000 tons per year of CO_2 must be captured and sequestered or put to beneficial use.
* Projects must show significant progress toward carbon capture and sequestration with less than 10 percent increase in electricity costs.
* Projects must use domestic mined coal or coal refuse for at least 75 percent of energy input.
* Projects must produce electricity of at least 50 percent of the gross energy output.

[2] Author of this section David Reiner, Electricity Policy Research Group.

Table 2.1 ZEP Criteria for an EU Demonstration Programme

Eligibility Criteria	**Project Criteria**	**Portfolio criteria**
Each project must meet agreed information disclosure and knowledge sharing requirements	Each project should be at a scale that will allow the next project to be at commercial scale minimise any release of CO2 captured	Storage technologies: depleted oil and gas fields and deep saline aquifers, including Measurement, Monitoring and Verification (MMV)
Each project must have a good stakeholder management process defined to achieve maximum public acceptance	*If two projects are equal, a project is preferred over another if it:*	Capture technologies: pre-combustion, post-combustion and oxy-fuel
Each project must demonstrate its technical construction feasibility	has an earlier operational start date	A variety of hard coal and lignite) power plants
Each project must demonstrate safe, long-term storage by adequate, independently verifiable monitoring at CO2 storage systems	has a lower centrally managed EU contribution per tonne of CO2 stored or MWh of power delivered with CCS	International cooperation and a project in an emerging economy (if certain conditions are met – to be defined)
The obligation of delivery of an agreed project will lie with industrial sponsors subject to certain specified force majeure events; the projects will receive financial support only on the basis of actual performance (per tCO2 stored or MWh of power delivered with CCS.	contributes to the development of a large-scale transportation infrastructure in Europe	Include different capture technology variations for each of pre-combustion, post-combustion and oxy-fuel, taking into account the ZEP Technology Blocks
	allows large stationary point source emitters outside the power sector to be connected to its transport and storage system	At least one project which allows large stationary point source emitters outside the power sector to be connected to its transport and storage system
	is able to expand CO2 capture and storage in a second phase on a commercial basis	Open and structural deep saline aquifers and multiple geological settings
	has an R&D programme	Gas-fired power plant
		CCS retrofitting on an existing plant
		Power plant including CCS with improved plant-wide (or overall) efficiency
		Both onshore and offshore storage
		Co-firing biomass
		Transportation by ship
		Cross-border pipeline transport
		Explore commercial structures
		Sufficient geographical spread

In Australia, CCS projects have applied for funding through the Low Emissions Technology Demonstration Fund (LETDF), a A$500 million support scheme aimed at funding not only CCS demonstrations, but other novel forms of low-carbon energy. Thus, in addition to four fossil fuel projects (3 coal and 1 natural gas), the first round of funding also included support for a large-scale solar concentrator. There may therefore be some analogies between this project and the IRTs described in the EUA support mechanism.

Note that there is a separate Renewable Energy Fund aimed primarily at encouraging commercialisation and deployment of renewables and an Energy Innovation Fund directed at more basic energy R&D. Federal government support ranged from 7% for the Gorgon offshore gas project to 27% of the CS Energy oxyfuel project total cost. In most cases, the state government provided significant co-funding. Having met six eligibility criteria to be considered, the LETDF then imposed five "merit" criteria: i) have the potential to reduce greenhouse gas emissions over the longer term by supporting the identification and implementation of cost effective abatement opportunities and the uptake of small-scale low emission technologies ii) support the Australian Government's policy and programme initiatives iii) leverage greater non Australian Government investment (including in-kind support) in small scale low emission technologies and abatement opportunities; iv) demonstrate value for money; and v) identify and address any significant barriers or risks for the project. In the end, LETDF ended up funding five projects which displayed a significant technological diversity: one reservoir gas project (involving several oil supermajors led by Chevron), one oxy-combustion project (with Japanese partners), one integrated drying and gasification project for moist brown coals (with Chinese partners), and a project for drying brown coal to reduce CO2 emissions from unabated coal, that will be supplemented by capture on a part of the output in addition to the 154 MW solar concentrator project.

In Alberta, the goals of the phase I RFP(s) for 3-5 operating projects at a cost to the Alberta treasury of C$2B include (ecoEnergy CCS Task Force, 2008):

- A total portfolio that adds up to 5 $MtCO_2$ per year by 2015
- Minimum project threshold of 500,000 tCO_2 per year
- At least one project >1 $MTCO_2$/year
- At least one direct storage (e.g., deep saline aquifer)
- Fully integrated projects
- At least one retrofit and one new build
- At least one electric power application, at least one oil sand application and at least one 'other' application.

Thus, looking to different corners of the earth, we find a common thread of governments seeking to identify selection criteria that will encourage diversity, a finding which supports the conclusions that follow in the next chapter where diversity is favoured over replication given the nature of CCS technologies. Nevertheless, how to operationalise some of the stated goals need further consideration. How is it possible to ensure geographical diversity given differential national interest in the technology? More importantly, how is it possible to define value for money when comparing different technologies that have different costs? That is the subject of Chapter 4 on designing the mechanism for differentiating support for capital and operational costs and of Chapter 5 which introduces the concept of a Technology Choice Auction to address the need for minimising costs, but within individual technology categories.

2.1 Metrics

It is difficult to conceive of choosing projects on the basis of a single metric because of the diversity associated with the different technologies and configurations. For example, choosing between funding incremental costs and total costs (or subsidising a fraction of the total costs) would have very different implications for different technologies. Although most studies find that the overall costs of pre-combustion with capture are not wildly different from the overall costs of post-combustion with capture, the base costs of pre-combustion are notably higher, which is then offset by the lower costs of capture because the CO_2 has already been separated (IPCC, 2005: 107).

Similarly, oxy-combustion is generally assumed to be in the same cost range, but the uncertainty is viewed as significantly higher because there is less experience with the technology at large scale (IPCC, 2005: 163). It would be difficult, therefore, to have a competition which did not differentiate between technologies because inevitably certain technologies would be favoured over others in a single competition. Similar issues arise with respect to differentiating transport (pipelines versus ship) and storage options (saline aquifers versus depleted oil and gas fields).

In different guises the question of what is being optimised arises repeatedly in discussions of demonstration projects. It is common to hear support for "maximising the potential for CO_2 reductions", while at the same time advocating "least cost" solutions. Given the nature of demonstration projects, it may be advisable to move away from language implying "optimisation" and instead more explicitly describe the tradeoffs involved in alternative formulations. Some quantification of the learning and informational benefits would be helpful and if they are sufficiently robust might be included in the EC selection criteria.

Below we offer reflections on several of the criteria or considerations relevant to the design of a portfolio of projects including firm-level considerations, geographical diversity, timing and size, which extend the more technical considerations considered in the laundry list approach to selection criteria.

2.2 Firm-level considerations

Governments have legitimate concerns that firms have far more information on costs than the governments awarding funding and so will worry that costs submitted in proposals will be inflated. Concerns over asymmetric information helps motivate the auction format in the first place, since it provides an efficient way of extracting private information (if designed properly). In terms of firm competition, there is no clearly dominant player. By firm, the current EERP list includes: RWE and Vattenfall in Germany: Eon, RWE/DONG/Peel, Scottish Power (Iberdrola), and Powerfuel in the UK; Endesa (Enel) in Spain; Enel in Italy; ArcelorMittal in France; Nuon (Vattenfall) and Eon Benelux in the Netherlands; and PGE/Alstom/Dow in Poland. Thus, the distribution across firms is fairly evenly distributed with four firms (RWE, Eon, Vattenfall, and Enel) being involved in two of the projects but no one firm dominates. In addition, there are a number of competing technology providers and other partners, so there should be the basis for effective competition if designed properly.

Should governments view the repeated participation by a few utilities as problematic? In one sense it is desirable if a company gains experience with the same technology since that will reduce the costs for future plants, but one might question whether multiple countries should be providing a large 'demonstration' subsidy to the same firm to build almost identical 300 MW post-combustion capture facilities. By contrast, having eight different utilities each build a CCS plant may foster innovation but will hardly drive down costs. Since both innovation and long-term cost reduction are basic goals of the demonstration phase one might ask how to tradeoff diversity against economies of scale. One might explicitly model the benefit of a firm moving up the experience curve and reducing unit costs against the cumulative probability of breakthroughs resulting from a greater diversity of actors. These tradeoffs are discussed more explicitly in the next Chapter.

Firms at different parts of the supply chain also will have very different views on criteria regarding, for example, subsidising network infrastructure as opposed to requiring that the subsidy be directly proportional to the CO_2 stored or the benefits of life extending North Sea production via enhanced oil recovery (EOR). In addition to the electric utilities, the players which would have preferences with regard to the specific selection criteria include the major equipment manufacturers (Alstom, GE); the oil and gas supermajors (Shell, BP, Total); smaller oil and gas firms (primarily centred around and dependent on the North Sea); infrastructure, chemicals and services firms (Schlumberger, Air Products, AMEC, engineering, law firms, etc).

If one were to expand the criteria beyond environmental benefits then the employment benefits of subsidising CCS seem an obvious consideration. The wind industry, for example, partially justifies its longstanding subsidies via the link to 'green jobs'. This seems especially likely to arise for any support framed as part of the European stimulus package (EERP) or other domestic stimulus packages. To be helpful as a stimulus the projects should start as soon as possible, and that to create jobs one would ideally like jobs for which there is excess domestic supply (e.g., construction?) rather than those for which there is a scarcity (e.g., engineers, skilled off-shore workers).

2.3 Geographical Diversity

One challenge of ensuring geographical diversity is that, as currently structured, the EU support mechanisms will not be sufficient to cover the total capital and operating costs of applying CCS. Thus, national governments will need to be ready to provide some incentives above and beyond EU and private sector investment.

Theoretically, there are many European countries that have expressed an interest in CCS projects. The ZEP list of projects, which is not exhaustive, includes 9 projects from the

UK, 2 from Spain, 3 from Poland, 7 from Norway, 5 from the Netherlands, 5 from Germany, 2 in France, 1 in Finland, 2 in Denmark, 2 in the Czech Republic, and 1 in Bulgaria. However, many of these proposals are at an early stage of development.

The European countries that have shown the greatest ambitions are the UK, Germany, Norway and the Netherlands. The UK Government is now publicly committed to funding "up to 4" CCS projects, both pre- and post-combustion, which builds on the existing commitment to funding a post-combustion plant through a domestic competition. The Netherlands has two major hub flagship proposals, the Rotterdam Climate Initiative and the cluster of projects in the North of the country around Eemshaven, both of which are extremely ambitious in terms of both technological diversity and scale (aiming for ~ 10 MtCO2 storage per year). Germany's environment minister has also publicly stated his desire to see three CCS projects in Germany and discussions are underway to consider possible government support for a transport network. Norway has made the largest investments to date. It will test capture at the refinery and combined heat and power (CHP) plant at the Mongstad Test Centre from 2011 through 2014, when it is committed to full capture. The government has also committed to CCS at a new natural-gas fired power plant at Kårstø. In 2009 alone, Norwegian government investment amounts to over €100 million in Test Centre Mongstad and over €20 million at Kårstø in addition to very large funding for CCS R&D. Not coincidentally, all four countries have major fossil fuel industries and good access to storage capacity.

The next tier of countries includes France (which in many ways ranks higher because there are more domestic organisations taking the issue seriously), Spain, Poland, and Italy, which rounds out the seven member states included on the EERP list. The list itself is a proxy for those with projects that the Commission has judged could be ready in the 2009/10 timeframe of the EERP.

The willingness of countries to move forward with support, and the form that support will take, will also be related to the styles of governance. Thus, it is not surprising that the liberalisation leader UK, should immediately devise a CCS competition whereas others would prefer to simply pick a preferred option, whether that is to support a national champion or because of long-standing corporatist decision-making. Norway has largely done the latter by choosing to invest, through Gassnova, in the Mongstad and Karsto projects. Norway is already far ahead of any of the EU-27, not only because of major CO_2 storage projects at Sleipner and Snohvit, but because of major financial commitment, which in 2009 alone amounted to over €200 million. The Netherlands, which normally uses the Polder model of negotiated agreement between the government and major firms on such questions, has set up a CCS Taskforce to consider the various options. Though traditionally inclined against a tender or competitive process, the large sums for both major hub projects required will test the traditional Dutch approach or require a scaling down of ambition of both projects. Germany also has at least three major utilities committed to CCS but has not to date indicated great willingness to either subsidise capture or favour any one project over another.

Regardless of the rules adopted, will (or should) countries collude or coordinate to encourage greater diversity in technology, supplier or other specific characteristics? Some of the options available will depend on timing. For example, as a relatively early mover, the UK has signalled to others that they will adopt a competitive process and that they will require the first competition plant to be post-combustion and coal, whereas the Norwegian have clearly signalled a focus on natural gas. The independent timelines for decisions allows information to be transmitting without any explicit collusion. Seeing another member state already moving forward with post-combustion may encourage some to support other technologies even if there is no explicit agreement. As discussed in Chapter 5, we suggest that competition that takes account of technological diversity, rather than collusion will deliver technological diversity, but at lower cost.

It is only a matter for conjecture as to how many European countries will come forward with support, but to date, only a handful of EU member states have invested in resources and activities involving the private sector, the research community and government agencies. The resulting engagement of industry and governments on the issue varies markedly from one member state to the next. Apart from the European Commission itself, seven member states and Norway are participants in the Carbon Sequestration Leadership Forum (CSLF), the major international forum for CCS, the EERP identifies only seven in which projects might be awarded (five of which are also CSLF members) and six European countries (Norway, the UK, Netherlands, Germany, France and Italy) have joined the Australian-led Global Carbon Capture and Storage Initiative (GCCSI). Only three member states (UK, the Netherlands, and Germany) are thought to be relatively far advanced in their efforts to transpose the recent CCS Directive into national legislation. In their survey of over 500 European stakeholders, Shackley et al (2007) find that Norway, UK, and the Netherlands were clearly the most favourably inclined towards CCS. Of course, enthusiasm, research capacity or commitment to international activity do not correlate perfectly with the ability to host and support demonstration projects, but given the abbreviated timeline of the EERP and the long lead time to get a major demonstration plant sited, permitted and financed more generally, it is reasonable to question whether with few human resources many of the other member states will be willing or able to move quickly to put together a viable project that would be ready in the timeframe needed.

Thus, there is a real possibility that too few projects come forward in the Europe because of cost uncertainties and lack of Member State government support, which suggests that it may be a mistake to use concerns over state support of national champions to create a set of rules that would only discourage member states from coming forward with support for projects. The project selection process should also aim to attract as diverse a set of participants as possible regardless of ownership type.

A plausible effort to assemble up to 12 demonstration projects, numbering closer to twelve than to three, on what is an ambitious deployment timeline, would require that at least the "leading" member states, not coincidentally those with access to storage and strong industry interest, would each need to support a disproportionate share, i.e., at least two flagship projects apiece. Given the logic in favour of diversity over replication, at this point, those projects should demonstrate different technologies. The essential corollary is that member states willing to move forward with more than one project should have access to EU funding mechanisms such as EUA support on a project basis and that limits not be placed on access that would discourage member states from shouldering a greater share of the demonstration burden.

For a project to proceed requires a critical mass of both government support (financial and regulatory) and industry interest (including an active RD&D programme to underpin participation). EERP funding essentially requires that the project is already in a position to move forward. EUA funding and the 2015 deployment target require at least project proposals in a relatively advanced state that would need to be followed in rapid succession by an assessment of the proposed storage reservoir, a fully elaborated plan for transport, the creation of the requisite regulatory framework and member state support.

We return then to the question of what is being demonstrated and highlight the project orientation of the existing EU mechanisms for which we have offered suggestions in terms of design. By contrast, the Dutch focus on two major regional hubs (in the North and in the Rotterdam area) rather than on individual powerplant projects (echoed in the Spanish Ciuden and Yorkshire Forward proposals). Though laudable, the hub approach is not easily reconciled with the current EUA and especially the EERP support mechanisms. Support for a single plant can help cross-subsidise the infrastructure needed to make the hub a reality, but the scale of the funding proposed at the EU level is commensurate with much more limited ambitions and project-level financing.

There is a powerful case that given the existing portfolio of single projects already being assembled across the globe in the US, Australia, Canada, Norway and even China and South Africa that a major initiative designed to create a testbed for a range of technologies would be extremely attractive. Unfortunately, the potential for concentrating funding on a smaller number of large projects that would be truly groundbreaking at a global level seems implausible given the European emphasis on geographical distribution (and traditional approaches to government-industry relations in member states such as the Netherlands or Germany which favour dividing resources rather than concentrating resources, or the UK where a liberalised market acts against the planning needed for grand projects).

2.4 Timing

As indicated by the various selection efforts being launched worldwide, there is a global rush to become the first to have a fully integrated IGCC plant plus CCS or the first to have a post-combustion plant plus CCS working. Apart from several EU member states and Norway, contestants include Australia, Canada, the US, as well as Japan, UAE, and China. The "winner" is still far from obvious since all the countries and firms involved have second-guessed or hesitated in the face of technical and especially financial considerations.

Should finishing second (or seventh) affect a country's strategy? The challenge here is that, given the long lead times associated with development and deployment of CCS demonstration projects, the rules must be put in place before the winner is clear. Whether or not the EU "loses out" in this global competition, should the EU also (or alternatively) seek to encourage other firsts (e.g., first offshore EOR or first cement works) or should it be content with getting the first IGCC+CCS operational within the EU? There is in some sense less of a rush if we know that there are no other real competitors globally in one of these niche areas and so if the facility is not operational until 2016 then that is not a problem, although of course that will delay the delivery of experience to benefit the rest of the world.

2.5 Size

Currently, firms or research consortia have undertaken their own research facilities either using corporate or public research spending although the range has been in the range of 1 MW - 30 MW. There are a number of plants around the EU that are either under construction or actually in operation of up to 30 MW size including Vattenfall's Schwarze Pumpe Station in Germany and facilities in the Netherlands (Eon/CATO project) and France (Total – Lacq). Significant public support is needed for facilities much greater than 30 MW.

Many demonstration project criteria have focused on 300-400 MW as the target range, which may be related to the volume of CO_2 produced being in the range of 1-2 million tons of CO_2 per year. One might also imagine that, particularly for certain more experimental technologies (with higher unit costs and/or greater uncertainty), a smaller size, perhaps 100 MW, might be more justifiable. By contrast, some utility executives have made the case that companies should be subsidised to fit capture to the entire plant. Industry estimates place the cost of scaling up to a full scale 1.5 GW plant as roughly the same in capital cost terms as building the 300-400 MW demonstration plant, i.e., roughly four times the CO_2 could be abated for twice the subsidy and the scaling is even more dramatic for pipelines – a large pipeline is roughly twice the cost of a small one but has about 10 times the flow capacity (Read, 2009). Rather than simply dismissing larger or smaller plants it would be useful to consider seriously what the benefits of different sizes would be and whether there is a case for encouraging more smaller plants or fewer larger plants.

Similar to the discussion over timing, if Europe cannot be first, perhaps it could still be the first to fully decarbonise a major power plant. Of course, assuming a fixed level of support for CCS, support for a larger plant reduces the number of plants that can receive support. This change of tactic by a power generator may reflect a growing realisation that partial CCS will not significantly reduce opposition to the remaining unabated coal-fired capacity even though a fraction of total capacity is captured. The critical questions are whether a policy will emerge requiring all plants of less than a certain age retrofit to CCS by some future target date, and whether the extra cost of equipping a new plant with full CCS is worth the extra learning benefits relative to installing a smaller scale capture unit now and having to retrofit the rest of the plant at a later date.

3 Dynamic Considerations for CCS Demonstration Support Mechanisms in the EU[3]

The dynamics of the envisaged support scheme for demonstration of CCS technologies by the EU can be considered with a view to achieving two objectives: (1) to maximize the benefits of learning, and (2) to ensure transfer of knowledge among the actors. An important role of technology demonstration is not to allow the technology to remain in the "valley of death" between R&D and commercialisation. In addition, in the longer run, bridging the demonstration and commercialisation stages of development of the technology require a workable business and regulatory model that needs to be developed as well.

3.1 Maximizing the benefits of learning

At the demonstration stage, technological progress associated with learning is mainly related to 'validation' and 'scaling-up' of the technology. Progress in these areas will facilitate diffusion and commercialization as the subsequent stages of development of the technology. The benefits of learning from demonstration are mainly in the form of learning-by-doing.

3.1.1 Replication vs. Diversity

An important strategic consideration in allocation of resources among alternative CCS projects is the potential trade-offs between 'diversity' and 'replication' of the technology. Diversity of CCS projects can also be considered in relation to validation of the main available technological options. On the other hand 'replication' refers to learning-by-doing in the sense of benefits of manufacturing of large numbers of plants.

However, the learning-by-doing associated with the demonstration of a given technology is different from the learning that is generally associated with serial or mass production of the equipment. It is possible to distinguish between two types of learning-by-doing. The first is the learning that occurs from replication in the production of equipment and accrues to manufacturers and suppliers. The second type is the learning from operating and maintenance of plants. Equipment manufacturers that will benefit from the first type of learning-by-doing are often international players and they are limited in numbers. The operators of CCS plants benefiting from this type of learning can be domestic or international companies. The learning associated with validation and scaling up of the technology will likely benefit both the equipment manufacturers and the operators.

Given the fairly small number of demonstration plants that are to be supported by the EU, the cost savings from learning-by-doing associated with 'replication' in manufacturing or operating a total of 8 to12 CCS plants are likely to be limited. It is also unlikely that supporting a technologically diverse set of demonstration plants in different countries, which

[3] Author of this section Tooraj Jamasb, Electricity Policy Research Group.

is envisaged by the scheme, will result in significant learning-by-doing benefits. In any case, the main objective of demonstration plants is to take the technology to the next stage of development i.e. to diffusion and commercialization.

Following from the discussion above, and assuming that, due to the limited scope of learning-by-doing from a limited number of supported projects, the focus of the demonstration support scheme in the EU should be on promoting diversity rather then replication of projects. In other words, preference should be given to projects that are deemed eligible and belong to a reasonably diverse pool of technological and technical alternatives.

The EU should attempt to avoid a situation where only a limited range of similar projects are put forward by the industry and selected for support. Indeed, the process of soliciting and selection among alternative projects should be designed as a mechanism through which the industry will reveal valuable information about the range of feasible options.

This discussion is also related to the issue of how to avoid picking the winners. It is often stated that the policy making process should avoid the risk of picking the winning technologies. While in the current context of CCS support some degree of selection cannot be eliminated, the extent of this can be limited. It is better to avoid picking winners upstream already at the stage of project formulation. Instead, the demonstration support scheme should aim to make the range of technological and practical options known in order for selection among them down-stream by the EU.

The value of learning-by-doing from almost simultaneously implemented projects may be limited. Other factors involved in conjunction with learning-by-doing are R&D and technical change, competition, and time. The experience from the LNG industry suggests that installations that involve large-scale construction may yield low learning benefits. Indeed, competition may have been the major driver in cost savings (Greaker and Sagen 2008). Hence, it is useful to ensure that the commissioning of the envisaged demonstration projects broaden the basis and scope for future competition in the CCS market rather than offering competitive advantage to a select few companies. In the long run, all member countries will benefit from the existence of a more competitive CCS market.

To summarize, in a long-term and dynamic perspective, the benefits of learning-by-doing from replication are typically better achieved at the commercialization stage of development. The CCS demonstration support scheme should avoid early picking of winners in order to achieve benefits of learning-by-doing from a limited number of projects. It should rather aim to support a varied range of technical solutions. The selection process should ensure that successful projects will be diverse and will not converge on a narrow set of technological options.

3.2. Knowledge transfer

Transfer and dissemination of knowledge from the CCS support scheme must balance two opposing types of interest among the actors. One is the interest among the firms to gain know-how from their investment and effort in the CCS demonstration plants for future gains.

On the other hand, the member countries would like to see a wide dissemination of the knowledge generated to facilitate and speed up the development of the CCS technology.

The capture, transportation, and storage activities of CCS involve different sets of technologies and require specific competences. Given the lack of prior experience with integrated CCS projects, the combined necessary required competence and experience is more likely to be found in a consortia or joint-venture of several companies.

Lessons from other energy industries can shed some on light on the dynamics of knowledge generation and transfer in competitive environments. In the US the emerging deregulation of the electricity sector in the mid-1990s had important consequences for the revenues of the Electric Power Research Institute. EPRI is the US electricity industry's main vehicle for collaborative research and development activities. Collaborative research is important in industries such as energy where R&D intensity is low and the scale of required R&D can be beyond the means of most utilities. At the same time, by definition, collaborative R&D, leads to free dissemination of research findings.

One of the consequences of the deregulation of the sector was that many utilities engaged in cutting their R&D investments in order to improve their short term profitability. Another consequence of deregulation was that in the new competitive market, free sharing of R&D results and knowledge among the actors would not give the utilities any comparative advantage or competitive edge over their rivals. As a result, the contributions from member companies to collaborative R&D declined. A response from EPRI was to structure the R&D activities in such a way that individual utilities could select and contribute to selected projects. The research results from R&D projects are then shared among the participants in each project.

Likewise in the case of CCS many industrial actors see considerable benefit in gaining know how and experience that would give them comparative advantage in a new and potentially large market such as CCS. Hence, the larger the number of firms involved in CCS projects, the better it is for dissemination and transfer of knowledge. The possibilities for a similar framework can be explored for the development of CCS at EU level. This will help transform the knowledge that is created from private to public good.

3.3. Industrial policy vs. maximizing national Experience Base

Any member state can have two concurrent strategic interests in the current CCS demonstration support scheme. The first interest would be motivated by the industrial policy objective of maximizing the benefit from CCS experience to domestic operators and equipment manufacturers with a view that, in time, some of these could become world class exporters of know-how and technology. The second interest is to maximize the experience from CCS in the member state which is specific to domestic conditions. The latter objective can indeed be pursued regardless of the nationality of the actors involved.

If member states put forward projects that strongly favour their national champions, it is less likely they will receive support for several projects. On the other hand, if each country's projects represent technological diversity and involve a set of European companies they are more likely to attract support and with less regard as to where they are located.

Moreover, if several member countries act the same way, companies with international ambitions should be encouraged to seek opportunities both at home and abroad.

Here lessons from the award of field development concessions in the North Sea Continental Shelf can shed some light on an alternative mode of knowledge transfer. In Norway, a joint venture was appointed to develop and operate individual petroleum fields. The participants in the joint venture would have different shares in the projects, which often included the domestic and state-owned petroleum companies as major actors. One company is then appointed as the operator to develop and operate the field on behalf of the joint venture. While the operator does not gain any financial reward from operatorship of the field, there is competition among companies to perform this function. The main reason for this competition lies in the nature of the industry and that the experience gained from operating a field on the technological forefront is a source of comparative advantage for winning other projects elsewhere in the world.

This arrangement has had important benefits. It has maintained a high degree of competition in the sector among the relatively small number of international actors with financial and technological resources. In addition, the competition on a field to field basis also contributed to faster technological progress in the sector in general and transfer of knowledge to growing national companies in particular. By the same token, it is beneficial for the member states to maintain competition for CCS development regardless of whether the actors are domestic or international companies.

A relevant question is whether knowledge transfer in this context means dissemination of CCS technology among the firms or from these to public entities. In the absence of publicly owned energy companies, the intrinsic value of this option seems limited.

4 Analysis of Risks and Strategic Behaviour[4]

4.1 Introduction

The cost of supporting CCS plants will depend on the risk perceived by those tendering projects, as higher risks about future cost and revenue streams will translate into a higher weighted average cost of capital (WACC). As CCS is very capital intensive, any increase in the WACC will reduce the present discounted value of future profits and increase the cost of support to the government. In order to estimate the significance of these risks it is necessary to understand first the nature of the risks facing fossil generating companies in the electricity market, as these are likely to be the companies that would tender for CCS support. Second, one must estimate the *extra* risks that a generating company takes on by adding a CCS plant to its existing portfolio. Third, the economics of operating the plant in capture-mode will depend on the prices of electricity and EUAs, as well as the support scheme chosen. In addition to the impact these will have on company risk, whether or not the plant is required to always operate in capture mode, or may be able to operate in by-pass mode when electricity prices are particularly high, will affect the costs of running the plant and hence the size of the subsidy needed. It is therefore important to be clear about the operating requirements when inviting tenders for support.

The arguments developed below suggest that providing support earlier rather than later, and making these contingent on operational performance rather than market returns, both contribute to lowering the social cost and the cost to the government of supporting CCS. This simple principle has direct implications for the design of good support schemes.

In addition to designing support schemes that minimise social cost, member states will need to consider how the design of their support will influence the success of national CCS projects in the various EU competitions, and conversely how the design of the EU support schemes will impact the form and extent of member state support. These strategic issues are considered first, followed by an analysis of risks created or mitigated by the design of the support system.

4.2 Interdependencies between EU and domestic support systems

The EU has two major proposals for supporting CCS demonstration projects:

1. Setting aside 300 million EUAs from the New Entrant pot (5% of the total, or 770 m EUAs, which leaves 470 m EUAs for new entrants none of which will be from the electricity sector – and these are likely to be undersubscribed).
2. The Recovery Package of €1,050 million.

Every country will be keen to ensure that any project funded domestically will be eligible for EU support. The concern here is that if a country commits to paying for one CCS

[4] Author of this section: David Newbery, Electricity Policy Research Group.

project, the EU might deem that water under the bridge and ineligible for EU funding, in order to maximise the total amount of CCS supported. It should be easy to argue against and devise protection against this perverse outcome.

EUA price 25 October 2004-12 May 2009

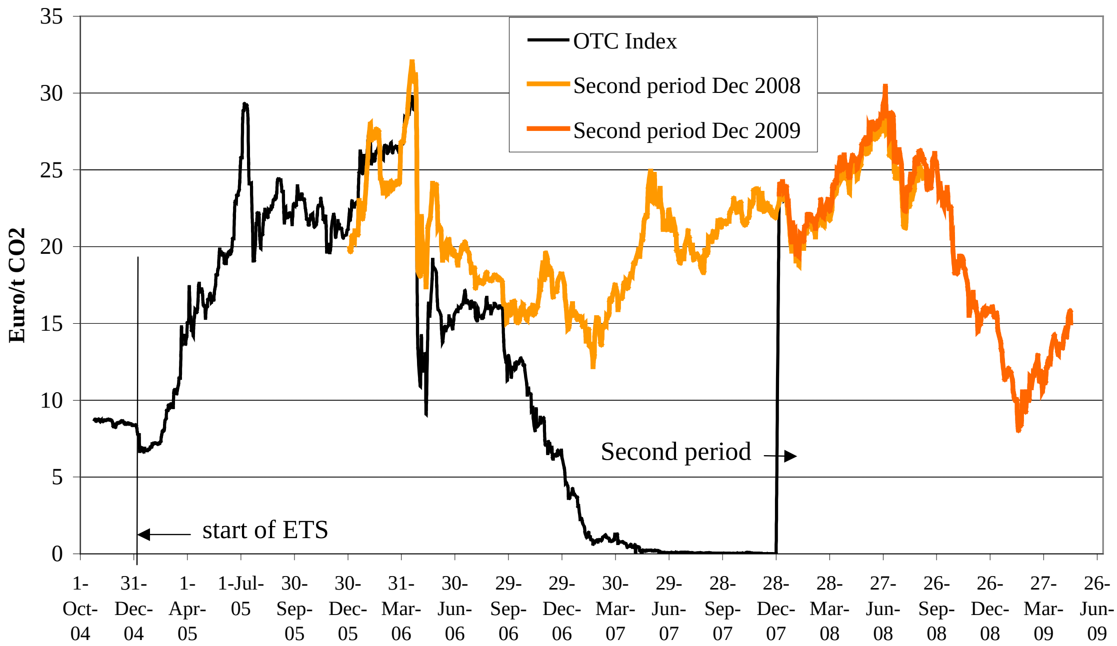

Figure 4.1 Evolution of EUA price
Source: EEX at http://www.eex.com/en/Download/Market%20Data

It is prudent to examine interdependencies between the EU mechanisms and member state policy. The consequences of not taking up the full 300 million EUAs allotted to CCS (and IRTs) is that a member state would receive a proportion of the unallocated allowances, so the cost of bidding is not zero. Note that the 300 m EUAs are worth €3.6 billion at the 2009 average price of €12/EUA but €9 billion at a target price of €30/EUA – a level reached early in the second period, as shown in Figure 4.1. Using these two prices as bookends, the European Economic Recovery Package assignment of €1,050 million would be between 14% and 40% of the value of the 300m EUAs and is to be allocated across seven member states amounting to €833-1,000/kW for projects that must be at least 300 MW capacity. On a project basis, 45 million EUAs would translate to a low of €540 million (at €12/tCO2) to €1350 million (at €30/tCO2), which is equivalent to 300% to 750% of the value of the EERP subsidy for those five member states allotted €180 million each of the EERP funding for a project.

Some issues that should be highlighted include:

- The cap per project is 15% of 300 m EUAs and up to 12 CCS projects will be selected. Clearly, not all twelve could receive 15% (it would add up to 180% of the total) but there are in any case doubts that twelve projects will be selected. 45 m EUAs might be worth between €1,800- €4,500/kW for 300 MW plants. The additional cost of equipping a generating plant with CCS might be €1,000-1,900/kW,[5] to which should be added the cost of the pipeline and the facilities for injection and storage.

- The EC intends that its support should be complemented by domestic and/or company support, and will wish to maximise the number of CCS plants (or minimise the EUA cost per plant if it wishes to also support innovative renewables). The more support is provided by national schemes and companies, the more likely the project is to be selected for EC support, at least under some allocation criteria. Thus the EC might invite bids for the extra support required over and above any domestic support.
- If in contrast the EC were to adopt another allocation mechanism such as matching domestic support, or fixing the number of EUAs per kW or per tonne sequestered, then the design of domestic support schemes would have to take that into account.

4.3 Examination of risks created or mitigated by the design of the support system

4.3.1. Introduction

The costs of supporting CCS will in part depend on the size of the risks and their allocation between the company, the EC, and the taxpayer. CCS will reduce operating costs by the amount of CO_2 saved but at the opportunity cost of delivering less electricity output from the fuel burned. The contribution that CCS makes to covering its extra fixed costs will therefore depend on future electricity and carbon prices, as well as on the form of the subsidy. If the uncertainty of this future contribution stream is reduced, and if the remaining extra capital costs (after crediting the NPV of these contributions) are covered by an up-front subsidy, then the main risk left with the company is delivering the investment to cost and on time – a risk that should properly be borne by the company and will be reflected in its bid, the more so the more competitive is the tender auction or selection process.

This section will therefore concentrate initially on the risks faced by an already commissioned CCS plant operating in an electricity wholesale market, and then work back to the overall project risks, using as an example the British electricity spot price data (reasonably representative of EU prices). This is done at several levels, as the relevant historic record since the ETS has commenced is short, and the experience of the first phase not necessarily very helpful in understanding the future. We start therefore with some theoretical considerations, informed by recent data, and then explore what might have happened if a CCS plant had been operating since the start of the ETS. The main aim is to identify the risks of operating CCS plant and how they are affected by different support mechanisms. Once that is done, one can then examine the risks to the whole investment.

[5] See the estimates on the additional capital cost per kW capacity discussed in section 4.3 below.

4.3.2. Natural hedges in the electricity and fuel markets

Existing coal and gas-fired generators would seem to face considerable risks trading in liberalised electricity markets, as the prices of fuel, electricity and CO_2 are all very volatile. However, for existing generating companies these risks are largely self-hedged, in ways that do not apply to low-carbon forms of generation, at least in the medium run. Any generating company in a liberalised electricity market faces risks that depend on its technology, as its variable costs will depend on the fuel chosen and the cost of EUAs, while the price of spot electricity will be determined by the marginal generator, possibly burning a different fuel (and with a different efficiency and other costs). If fuel and electricity prices do not move together, then the gross profit (i.e. the return to the capital) will be volatile and risky. To some extent, the ETS might be expected to reduce risk for coal and gas-fired generation, for the following reason. Suppose initially that gas-fired generation sets the marginal price, as is often the case in the UK, Italy, the Netherlands and some other EU Member States. As the price of gas increases relative to that of coal, generators will shift from now more expensive gas-fired plant to increase output from coal-fired plant, but as that releases roughly twice as much CO_2 /MWhe as gas,[6] the demand for EUAs will rise and so will their price, tending to make the cost of coal-fired generation rise in sympathy with the cost of gas-fired generation.

Fuel choices in UK electricity generation, 2000-08

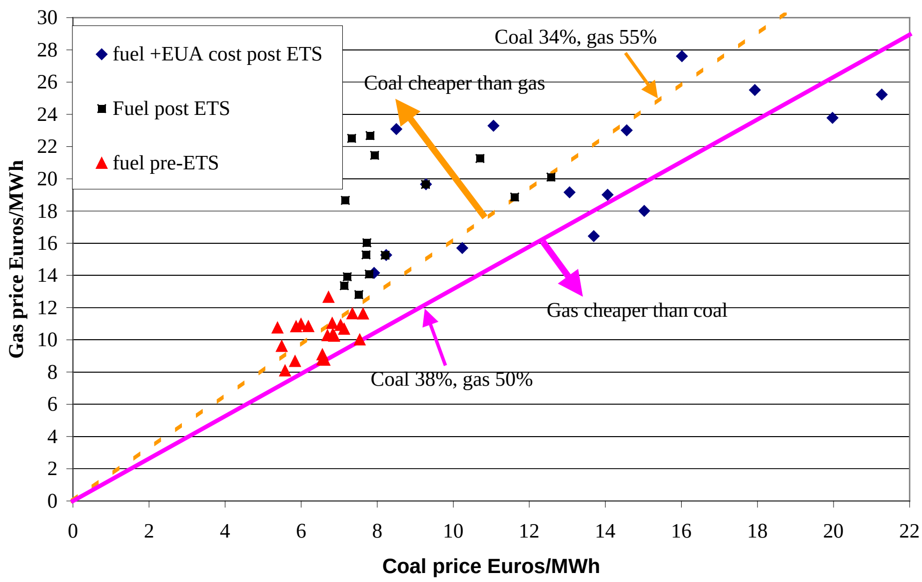

Figure 4.2: The quarterly cost of fuel in UK major generating companies

Source: UK *Quarterly Energy Prices*

To illustrate this, consider the case of the UK. In figure 4.2, each point represents the cost of generation using gas in a 50% efficient CCGT plotted against the cost of generating using coal in a 36% efficient station for various quarters. The red triangles represent the position

[6] The term MWhe is MWh of electricity produced, in contrast to MWht, which is the energy content of the fuel. If there is no indication, and the price is for fuel, it is the price per MWht.

before the ETS, the black squares are the costs of the fuels alone, and the diamonds are the costs including the EUAs required for each fuel (twice as many for coal as gas).

The two lines show the combinations of gas and coal prices (with their associated EUA price) between which coal and gas plant would have been able to compete with each other on variable cost alone (depending on the efficiencies of each, where high efficiency (55%) gas can compete against low efficiency (34%) coal at higher gas prices (dashed line) and conversely efficient coal (38%) can compete against less efficient gas (50%) for lower gas prices (continuous line). Clearly, the EUA price shifted the otherwise cheaper coal plant into this range of competition against gas – the diamonds move down and to the right compared to the squares. Thus the ETS makes both coal and gas competitive, and this should have reduced the risks associated with selling electricity from both types of power plant.

To see whether this continues to be the case, figure 4.3 shows the forward price of UK electricity for 2010 compared with the cost of the coal needed in a 35% efficient power station (ARA forward coal contracts) and the gas needed in a 50% efficient CCGT (NBP forward prices), both of which exclude the EUA costs needed to burn the fuel.[7]

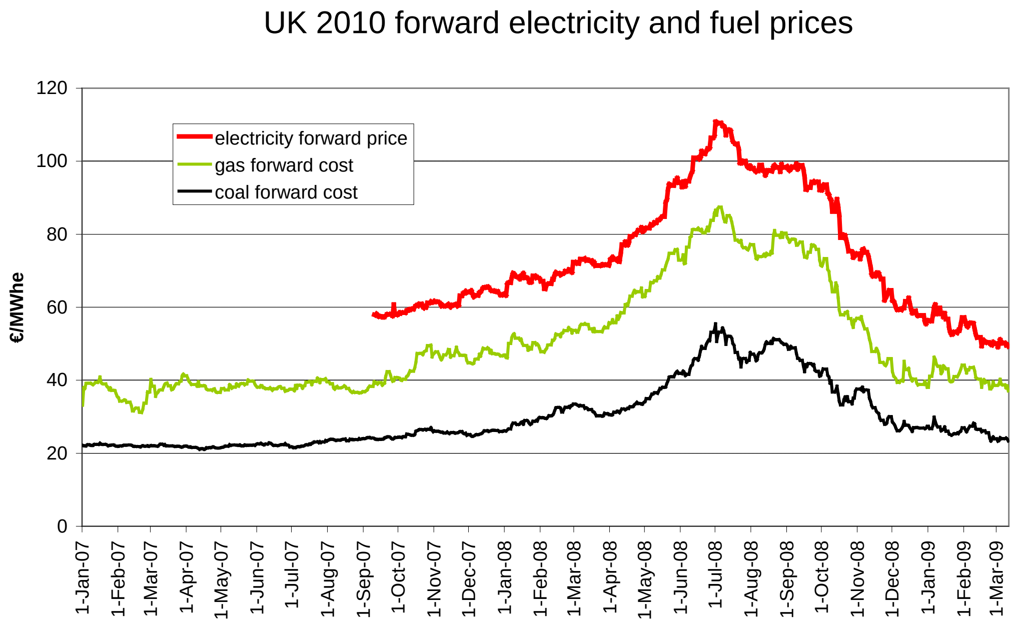

Figure 4.3 UK 2010 forward prices of electricity and fuel costs excl EUAs
Source: Bloomberg data processed

It is striking that the fuel costs move so closely together and with the electricity price. Indeed, the correlation for coal on gas prices is high (R^2=94%) and the cost of coal, p_c, in

[7] The annual forward price of electricity is taken at 50% of the summer 2010 forward price and 25% each of the adjacent winter forward prices. The figures for the UK forward electricity prices are very similar to those for France and Germany, while the Continental Zeebrugge gas price tracks the UK NBP spot price very closely, and the TTF forward price follows the NBP forward price closely, while the coal price is an EU price, so the graph should be representative of conditions in many member states.

€/MWhe is predicted to be $p_c = 0.48+0.58p_g$ where p_g is the cost of gas in €/MWhe. It is an interesting question whether the (international) coal price drives the gas price, or whether the oil price, which increasingly drives the gas price, also influences the coal price. This recent period of co-movement may reflect the recent turbulence in energy markets, and may not be a good predictor of long-term relationships.

In order to compute the costs of generation one needs to add the necessary EUA costs. This is done in figure 4.4, which shows the coal costs increasing considerably more than the gas cost (as roughly twice as many EUAs are required per MWhe), considerably reducing the profit margins. Note that the EUA price is the second period price throughout, as the forward price is for 2010, in the second period of the ETS. As there was no dramatic discontinuity in the second period EUA price, nor any dramatic change in the relationship between gas and coal costs, one cannot judge whether the earlier mechanism where the EUA price provides an automatic hedge for both fuels continues to work. The correlation of the forward coal cost *with* EUAs, P_c, on the forward gas cost *with* EUAs, P_g, is slightly higher at 96% and the equation is $P_c = 6.2+0.73P_g$, suggesting that the ETS slightly improves future fuel hedging.

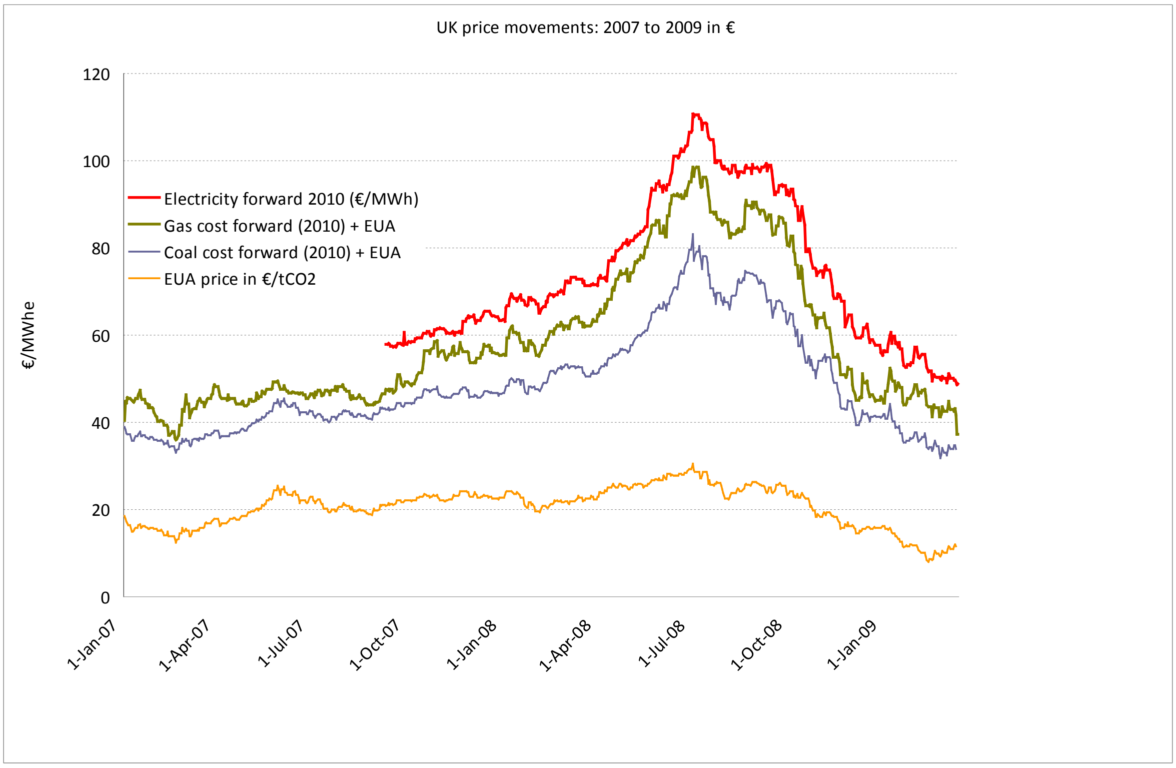

Figure 4.4 UK 2010 forward prices of electricity and generation costs

Source: Bloomberg data processed, EEX for carbon prices

The striking parallel movement in the gas and coal cost can also be seen from the corresponding forward dark green spread for the UK (the gross profit to coal fired generation) and clean spark spread (the gross profit to CCGT) in figure 4.5.

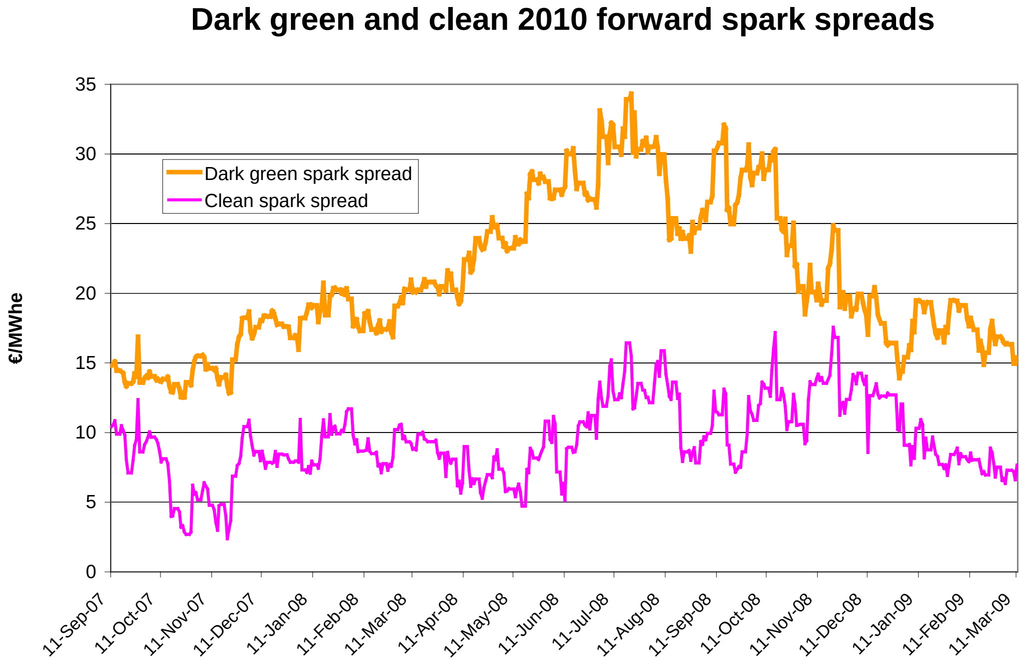

Figure 4.5: The gross profit of running coal and gas-fired stations
Source: Bloomberg data

The (forward) gross profit of coal-fired stations is higher than that for CCGT, reflecting the higher capital cost per MW (more than twice as high as a CCGT) and varies over a wider range, although the coefficient of variation of the two series is almost the same (25% for coal and 30% for gas).

Comparing figure 4.3 and figure 4.2 (the triangles and squares but not the diamonds) it would appear that the recent forward gas and coal prices are more highly correlated than the past UK fuel prices into major generating stations. The correlation of the actual gas cost on the actual coal costs in the period 2000-8 was only 46% but rises to 75% when the appropriate EUA cost is added to each fuel. The future therefore looks rather different from the past, although traders at least seem to expect future fuel costs and electricity prices to move more closely. To summarise, the current energy and EUA markets appear to hedge fossil generation (from both coal and gas) quite well, so we can now ask whether CCS is also hedged or increases risk, and how that risk depends on the support system chosen.

4.2.3. Determining the operating mode of CCS

Suppose next that the CCS plant has been successfully commissioned, the next question is to determine its costs and revenues from selling electricity and storing CO_2, and hence the profit stream that will determine its commercial attraction and hence the extent and appropriate nature of subsidy required. The first and obvious point is that CCS considerably raises the variable operating cost. The parasitic power load reduces the thermal efficiency by nearly 10 percentage points (for supercritical PC the MIT *Coal Study* shows the decline in thermal efficiency from 38.5% to 29.3%) or by roughly one-quarter. This increases the fuel cost per MWhe by an amount that depends on the cost of coal, but also increases the opportunity cost of not selling the additional electricity that could have been generated if the CCS were to be by-passed, by an amount that depends on the price of electricity. In addition there are variable costs of pumping the CO_2 to the storage site and compression costs at that site.

The *total* costs of transport and storage are estimated at $5/t$CO_2$ by Celebi and Graves (2009), while the MIT study breaks it down into the cost of transport at $1/t$CO_2$/100km and storage at $0.5-8/t$CO_2$. Eurelectric's (2008) estimate (see Appendix 1) seems high at €28/tonne CO_2= €20/MWhe. However, we should take care in using the average transport cost figures for the demonstration phase. Initially, the costs of pipelines will make up a higher fraction of the total capital costs because the pipeline will need to be sized to accommodate the long-term needs for CO_2 transport, not merely the CO_2 produced at the demonstration-scale capture facility. For example, a new coal-fired power station of 1,200-2,000 MW that eventually plans to install CCS on the whole plant, and which might also become the first element in a larger network of pipes to connect to other stations would require a pipeline many times the capacity of that for a 300 MW demonstration plant. Only a small part of the total cost should therefore be credited to the costs of the 300 MW demonstration plant.

The *variable* costs of transport are probably only 5% the total costs even for a correctly sized pipe and can almost be ignored, although the variable costs of compression for storage might be a higher proportion of its total cost. The O&M costs are also shown to be higher with CCS than without – the *additional total* costs are estimated to be €14/MWhe by Eurelectric, $8.5/MWhe = €7/MWhe by MIT, but Celebi and Graves estimate the *additional variable* O&M costs at $1.83/MWhe = €1.43/MWhe. The variable costs of a CCS plant are thus a mixture of coal-related and fixed costs, while the revenue derived will depend on the electricity price that depends on the EUA price and fuel costs, and finally the value of the proposed EU subsidy could depend on the EUA price, further amplifying the risk facing the CCS operator.

There are now several questions that can be addressed. The first is how the additional variable costs of operating CCS compare with the additional benefit of the EUA cost saved. Each MWhe generated with CCS saves 0.69 EUAs (according to Eurelectric, see Appendix 1),[8] so if the plant can switch from capture to non-capture mode and avoid these incremental costs, the value of the EUAs would need to be high enough to compensate for the extra variable costs and the lost profit from the parasitic electricity consumed. These extra costs are made up of extra fuel costs, and extra non-fuel variable costs that might range from v = €4.25-12/MWhe, or €6.2-17.4/EUA avoided. To find out the price of EUAs necessary to compensate for running in capture mode, let

P be the wholesale price of electricity,
e_c and e be the thermal efficiency with and without CCS,
f be the capture fraction,

[8] If the plant can achieve 39% efficiency in non-capture mode, and 29% in capture mode, and if only 85% of the CO_2 is captured, the CO_2 saved per MWhe generated is only 0.65 tonnes, and it would require 88% captured to achieve 0.69 tonnes.

t be the CO_2 content of coal in tonnes/MWht,[9]
p be the price of an EUA, and
v be the *additional* variable cost of generating with CCS.

We want capture to be more profitable than bypass, which requires that the variable profit/MWhe without capture, $\pi < \pi_c$, the profit with capture, i.e.

$$\pi = P\text{-}pt/e < \pi_c = (P\text{-}v)e_c/e - p(1\text{-}f)t/e_c \,, \text{ or}$$

$$p(t/e - (1\text{-}f)t/e_c) > [P(e - e_c) + v\, e_c]/e.$$

(Here e_c/e is the MWhe generated per MW capacity of the original plant that in by-pass mode can otherwise generate 1 MWhe. If e = 39% and e_c =29.25%, then e_c/e = 75%. If f = 85%, then $(1\text{-}f)t/e_c$ = 0.164 and t/e = 0.82, so $t/e - (1\text{-}f)t/e_c$ = 0.66.) This equation can be solved for the required price of EUAs, p, to make capture rather than by-pass more profitable as a function of the price of electricity, P:

$$p > 0.38P + 1.14v. \qquad (1)$$

Figure 4.6 shows the range of required EUA prices required to justify operating in capture mode if non-CCS coal-fired plant is in merit, and if there is no operating subsidy. Note that the required EUA price only depends on the price of electricity, and not directly on the cost of coal,[10] complicating the issue of how best to subsidize capture to ensure that it operates. In order to give some indication of how much of the time the electricity price might be as high as shown, figure 4.6 gives the price duration curve in €/MWhe for the UK spot market in 2008 (the inner graph gives the top 5% of prices on a larger scale). Thus for example, the spot electricity price was higher than €100/MWhe for 25% of the time, above €200/MWhe 3.1% of the time, and above €300/MWhe 0.5% of the time (or 44 hours).

[9] t = 0.32
[10] Indirectly the cost of coal is likely to affect the price of electricity by determining the marginal cost of generation and hence spot price.

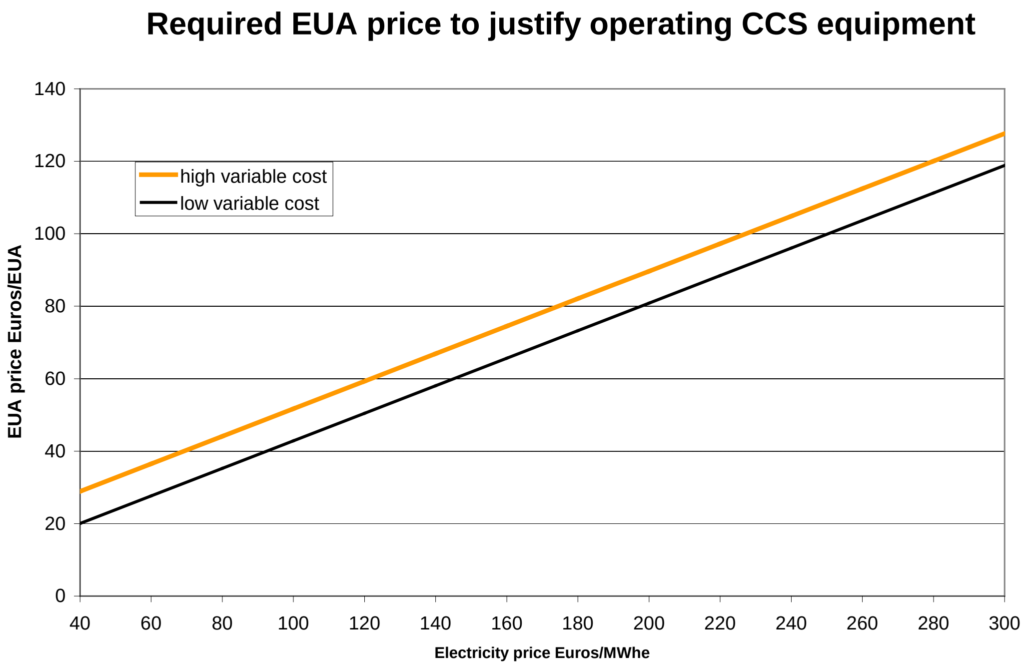

Figure 4.6 EUA price required to justify operating CCS equipment

Source: own calculations based on equation (1)

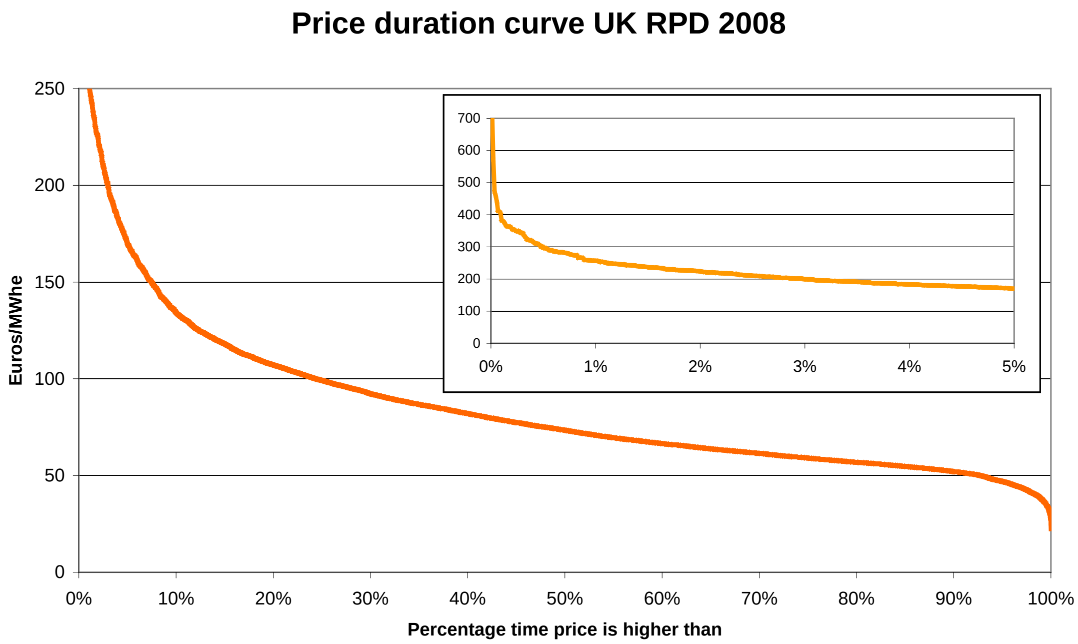

Figure 4.7 Price duration curve for UK spot market for calendar year 2008

Source: UKPX RPD data

Figure 4.8 shows the extra cost of operating CCS per MWhe generated (excluding the opportunity cost of not generating the extra electricity with by-pass) for such a plant operating in Britain at the costs of coal delivered to power stations, compared with the EUA price.

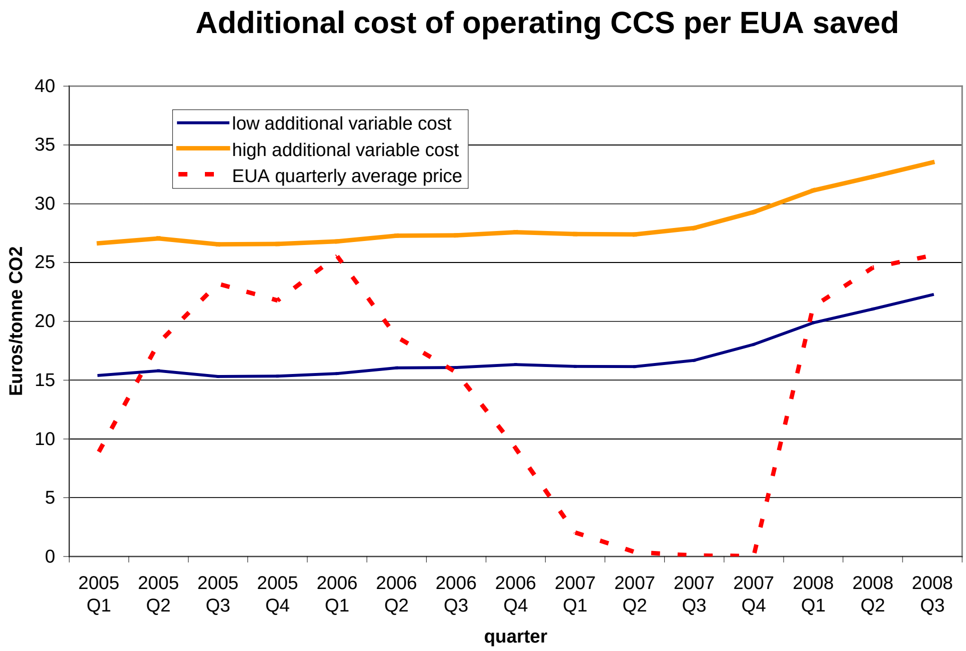

Figure 4.8 Additional costs of CCS under UK coal costs for major generators
Source: derived from UK *Quarterly Energy Prices* and EEX EUA data

The figure shows that unless the avoided variable costs of switching off the CCS are low, or the price of EUAs is high (above €25-30 /EUA) the plant would not even cover its extra operating costs, let alone the opportunity cost of electricity. It is therefore likely to choose to run in non-capture mode without an operating subsidy, unless the subsidy for winning the CCS competition were contingent on delivering CO_2 into storage (which is the preferred EC approach).

If we look back and ask how many EUAs would have been needed to make capture more profitable than by-pass in the period of reasonable EUA prices (i.e. excluding 2007) then we can simulate the evolution of profits of a supercritical station with an efficiency of 39% (i.e. the price of spot electricity less the cost of UK quarterly coal price purchase costs less the spot cost of the EUAs), and then look at the extra profit of generating only 75% of the amount of electricity per unit of capacity but reducing emissions by 0.69 t CO_2/MWhe, after allowing for the *additional* variable costs associated with CCS, taken as a rather low value of £5/MWhe).[11]

Tables 4.1 and 4.2 give the results. The load factor is the proportion of hours that the station has a positive value for the dark green spread. Table 4.2 gives the extra profit of running CCS, in the first two columns assuming no EUA credit, and in the last two columns

[11] The calculation only computes the positive values of the spreads, assuming that the station will instantly close when it is unprofitable to run that hour and reopen as soon as it is profitable. This over-estimates the profit as there will be start-up costs and ramp restrictions, but it may under-estimate profits where the station has a contract ahead of time that has a higher value (i.e. includes a risk premium) than the sport price. It also ignores O&M costs for operating in non-CCS mode in both cases but does include the additional variable non-fuel costs associated with CCS, taken as £5/MWhe.

with a subsidy of 0.6 EUAs/tonne CO_2 stored, the minimum number need to ensure profitability (except in the exception terminal year of Phase 1 of the ETS).

The first point to note is that the ETS only started on 1 January 2005 so there would have been no point in installing CCS before that date and no figures are given. The dark green spread steadily rises (with a slight fall in 2007) as the price of electricity rises with the gradual removal of excess capacity. Although the revenue from operating CCS was normally enough to cover the direct extra costs incurred, it was not enough to offset the lost profit from by-pass, and as a result the extra profit of running CCS was negative, even in years when the EUA price was reasonable (and it averaged over £11/EUA in 2005-6 and nearly £18/EUA in 2008). Using data for the UK, one can calculate the point at which a firm would be indifferent between operating in bypass mode or on capture mode. This would obviously vary for different data. If the station is granted 0.6 EUAs/tonne stored, then it becomes marginally more profitable to run CCS than by-pass averaging over the years except 2007 (and at 0.7 EUAs every year except 2007 becomes profitable). Indeed, except for 2007, over 50% of operating hours are profitable and over 60% at 0.7 EUAs/tonne CO_2 stored. The somewhat surprising finding is that the variability (measured by the SD) of this extra profit is quite low (but would be incremental to the high SD of the dark green spread).

This example is given here for illustrative purposes and it should not be concluded on the basis of this analysis that the station will operate at a profit if granted 0.6 EUAs/tonne stored.

Table 4.1 Supercritical Dark Green Spreads

Year	*LF*	*Average DGS £/MWhe*	*SD £/MWhe*	*CV*
2002	75%	4.95	3.18	64%
2003	94%	8.42	6.98	83%
2004	98%	9.87	3.44	35%
2005	86%	13.74	14.04	102%
2006	88%	14.79	15.06	102%
2007	91%	13.53	11.07	82%
2008	95%	31.60	17.28	55%

Table 4.2 CCS profit relative to by-pass

year	*Average £/MWhe 0 EUA credits*	*SD*	***Average £/MWhe 0.6 EUA credits***	***SD***
2002				
2003				
2004				
2005	-3.85	3.82	**0.72**	**4.30**
2006	-4.28	3.81	**0.36**	**4.77**
2007	-8.61	4.11	**-8.44**	**4.23**
2008	-7.84	4.17	**-0.61**	**4.18**

Source: RPD data and BERR *Quarterly Energy Prices*

If, on the other hand, the additional variable CCS costs are taken as £10 rather than £5/MWhe, then the extra profit falls by about £2.5 (less than £5 because the station operates fewer hours) but the standard deviation is hardly changed. This requires an increase in the number of EUAs/tonne from 0.6 to 1 to make CCS again profitable, again for about 60% of the hours excluding 2007. Nevertheless, providing support for operations in the form of EUAs rather than providing that support up front or in a fixed fee would certainly amplify the overall risks of the CCS investment.

Figure 4.9 plots the dark green spread and the extra profit of operating in capture mode (with no EUAs per tonne stored), as well as the cost of EUAs in the by-pass mode. It appears to show a correlation between the extra profit and the EUA price, and the coefficient of extra daily profit on the daily EUA price is 0.15 with a *t*-value of 9 (highly significant) although the R^2 is low at 0.05. The correlation of the extra daily profit on the daily electricity price is stronger at R^2 = 36% and a coefficient of –0.12 (t =-29), confirming that higher electricity prices provide a greater incentive to by-pass.

The effect of providing 0.6 EUAs/tonne stored is, unsurprisingly, to raise the correlation between the extra profit of running CCS and the EUA price to R^2 = 66% and a coefficient of 0.54, while the correlation of profit with the EUA subsidy on the average daily electricity price falls to R^2 = 2% and a coefficient of –0.04, t -value lower at -5.5. Perhaps surprisingly, the EUA subsidy reduces the correlation with the electricity price and seems therefore to not increase the risk (although the underlying risk of the station is strongly positively correlated with the electricity price, holding the coal price constant).

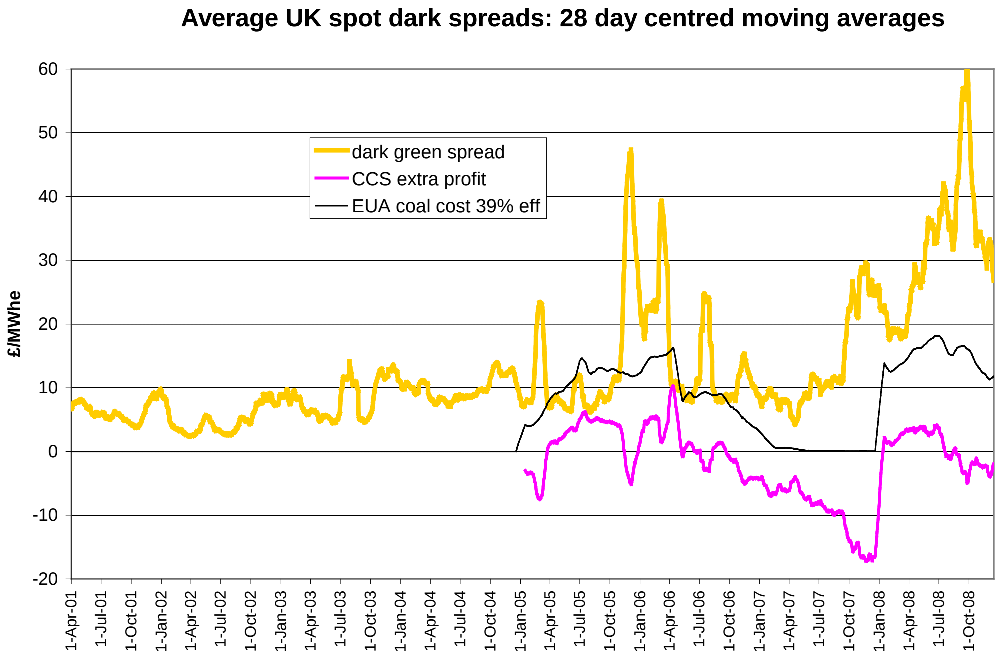

Figure 4.9 Comparison of supercritical coal-fired gross profit with and without CCS

Sources: UKPX RPD data and carbon price from EEX

There is another way to incentivise capture, and that is for the plant to store the solvent that contains the CO_2 during the periods of high electricity prices and then use cheaper off-peak electricity to release and compress the CO_2 later that day. The economics of this are studied by Chalmers et al (2008) and apparently this is profitable if the off-peak electricity price is at least £15/MWhe cheaper than peak prices. There may be a case for encouraging at least one such demonstration plant to explore the economics in greater depth.

4.3 Subsidies required for CCS

CCS plant is considerably more expensive to build than conventional coal-fired plant, although exactly how much more is unclear. Eurelectric data from *Comments on Funding*

Mechanisms for CCS Demonstration (Appendix 1) gives the additional overnight capital cost at €1,900/kW, while the MIT 2007 *Coal Study* estimated the additional cost at $810/kW, based on cost studies in 2000 and 2004 updated by the CPI to 2005. However, in early 2008, CERA published its Power Capital Costs Index showing that coal-fired plant had risen 78% since 2000, so that a plant costing $810/kW in 2000 would cost $1,442/kW in May 2008. In late 2008 CERA updated this index, noting that although the overall index had declined 3% over the six months to Q3 2008, this was due to a fall in nuclear construction costs, while coal plants had continued to experience steady cost inflation. Nevertheless, there was evidence of a flattening of the trend cost escalation, while the expected decline in power plant construction and the recent fall in commodity prices were expected to "result in lower capital costs over the near term." In response to CERA's report, the MIT group (Hamilton et al., 2008) updated their estimates and also commented on other studies. Their estimate for the cost of a supercritical plant without CCS is now $1,910 and with CCS is $3,080, suggesting that the additional cost of CCS would be $1,170/kW, an increase of 44% on its earlier estimate, but this is the cost of the *n*-th plant, not the first of a kind, which is relevant to the current study.[12]

The €/$ exchange rates are also volatile – in May 2009 the rate was 0.73€/$ (but in the last year has varied from 0.63€/$ to 0.8€/$). The revised MIT figure given this range of exchange rates would be €730-940/kW but allowing for first of a kind (FOAK) costs at 30% above long-run costs it could be as high as €950-1,200/kW. Celebi and Graves (2009) have the most recent data and estimate that the extra cost for an IGCC to be fitted with CCS would be $1,000/kW, but this is for an IGCC plant that is cheaper to upgrade with CCS.[13] Eurelectric's figure is still 60% greater than the higher of the adjusted FOAK MIT figures, perhaps reflecting a more cautious approach to FOAK estimates.

While we need not worry too much about the exact cost, as the whole purpose of a competitive tender is to elicit the current best estimate, it is useful to have a rough estimate of the additional cost in order to assess the materiality of the form of support chosen on the subsidy required. This will depend on the capital at risk and the extent to which it will be paid for out of current loans, grants or future subsidized profit streams, as discussed in the next section.

4.4 Designing the support scheme

Now that the operating risks have been identified it is possible to address the way in which these and other risks can be efficiently mitigated in order to reduce the subsidy cost. The

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[12] Barclays Capital Commodities Research June 24, 2008 suggests (near the time of the oil price peak) that the cost of coal-fired generation could be as high as $3,500/kW without CCS, so the range of uncertainty of capital values appears to remain high.

[13] It is generally assumed that the cost of a new IGCC will be considerably higher than unabated PC, but that the cost of adding capture to IGCC is lower than for post-combustion so that in the end both pre- and post-combustion with CCS do not differ too much from one another. Of course, cost estimates on unabated IGCC are considerably more speculative than for PC because there are so many fewer IGCC plants that have ever been built.

support needed will depend on the scope of the planned future CCS programme, and we can distinguish two extremes:

- a single demonstration scale project, with capture for a single 300 MW capture plant, probably using ships or lorries to transport the liquefied CO_2 to a suitable site for injection (e.g., a depleted oil or gas field or a saline aquifer);
- a pipeline and storage system for handling a large volume of CO_2 building up over time and including an ever larger fraction of all large CO_2 emitting plant in the region, of the kind envisaged in Yorkshire Forward's *A carbon capture and storage network for Yorkshire and Humber*, which envisioned storing between 60 and 270 million tonnes of CO_2 by 2030, aiming to be storing 6-22 mt CO_2 per year by 2020, which is a significant fraction of the 90 million tons produced annually in the Yorkshire and Humber region. This seems to be the dominant approach under consideration in the Netherlands as seen in the proposals for the Rotterdam Climate Initiative and for the cluster of activities around Eemshaven in the North which both include multiple point sources.

If the aim is to develop a significant pipeline infrastructure, because the distances involved to North Sea sites are quite long (200-400km), the initial cost will be also considerable (in the Yorkshire case the discounted cost of the investment to 2030 might be £725-£1,304 million at 6.5% (Yorkshire Forward, Table 9.1), and lower at higher discount rates as much of the cost is delayed until the future). The higher the volume the lower the average cost (£4.8/tonne to 2030 at the low volume case and £2.8/tonne at the high volume case, both at 6.5% discount rate). There are consequently obvious advantages in planning forward and optimizing investment, but clear problems in predicting how large a scale to plan for. Optionality implies choosing flexibility until the uncertainty is reduced or resolved, and that suggests the higher average cost but smaller scale choice, or the flexible ship rather than inflexible pipe option. A 300 MW plant operating 7,000 hours per year would capture 1.5 mt/year CO_2, which is very much at the low end of the hub proposals such as those of Yorkshire Forward and the Rotterdam Climate Initiative.

The first question to settle is then whether to be cautious and flexible or whether to consider a large-scale network investment that only makes sense if the plan is to capture a large volume of current CO_2 emissions from a range of plant (Drax, at 4,000 MW, produces 22.4 mt CO_2/yr, and as the most recent coal-fired station in the UK might continue to operate for 30-40 more years). Government support considerably in excess of EU funding would be required for the more ambitious scale. One solution might be to separate the finance of the transport an storage options and accept compressed CO_2 from the plant, either free or possibly at a location-specific price (to encourage plants to locate to minimize the total cost of capture and storage).[14] The next question is how best to provide the support, bearing in

[14] This appears to be the approach being discussed in Germany, and it has advantages if the aim is to develop a transport infrastructure, but it may raise complications in coordinating all parts of the project.

mind the risks and incentives. There are several issues here. The support mechanism may influence the type of project chosen. Assuming the objective is to encourage plants that lead to the highest amount of CO_2 abatement per unit of electricity supplied from the plant, we note that this not the same as maximizing the amount of CO_2 stored, as it might be cheaper per tonne of CO_2 to design or operate a plant with a lower fraction of CO_2 captured. The formula for abatement is:

CO_2 abated by CCS on coal plant = [Emission factor of coal / Efficiency of plant without CCS] - [(Emission factor of coal / Efficiency of CCS part) x fraction of CO_2 emitted[15]].

This would presumably require specifying the efficiency of the reference plant, presumably at least super-critical or whatever is currently the best practice for new coal-fired power stations.

The best incentive to deliver an operational CCS station would be to make the subsidy conditional on operation, but this would also maximize the risks borne by the company and require up-front borrowing by the company. In the current financial climate, there is no question that national governments are better placed to borrow than the power company, and so offering a government-guaranteed loan to finance the upfront additional cost makes sense, if the ultimate support is conditional on future output or future abatement. As noted, operating in capture mode requires a reasonable carbon price, and again the least-cost solution is an option or Contract for Difference (CfD) on the carbon price in proportion to amounts sequestered, ideally agreed as an EU instrument, failing which a government instrument.[16]

Thus one possibility would be for the winning bid to receive a loan for the full bid at a modest interest rate (close to risk-free) with the subsidy taking the form of a lump sum on commissioning the plant (effectively cancelling part of the debt), and a payment per tonne CO_2 abated for the remainder of the life of the loan, followed by a carbon option from then until some date to be determined.

To take a purely arithmetical illustration, suppose that the additional generation cost for a 300 MW plant at €1,200/kW = is €360 million,[17] and of the transport and storage is €170 million, so that the total additional capital cost is €530 million and that the extra opportunity cost of running in capture mode are covered by an EUA price of €30 (from figure 4.6 assuming a low variable cost and modest electricity price), while the actual EUA price is only €20 (requiring a net extra subsidy of €10/tonne stored). Suppose that the construction

[15] e.g. = 0.1 if the capture rate is 90%.

[16] A two-sided CfD is a contract with a specified strike price, say €30/tonne stored, entitling the holder to claim €30-EUA price for each tonne stored, and to repay the excess of the EUA price over €30/tonne for each tonne stored. A one-sided CfD with a specified strike price of €30/tonne stored, entitling the holder to claim €30-EUA price for each tonne stored, but to have no liability if the EUA price rises above €30. The latter is clearly more valuable to the holder and more costly to the government offering it.

[17] Eurelectric's more pessimistic estimate might be €1,900/kW giving a plant cost of €570m, while the McKinsey Report figures suggest a plant cost of £350m = €315, project cost of £490m = €440.

lag from the winning bid is 5 years, that funds are expended primarily in 2013 and 2014, and that the bid is settled on 1 Jan 2010 with commissioning on 1 Jan 2015, delivering 1 mt CO_2 in 2015 (operating initially at 5,000 hours per year) building up to 1.5 mt CO_2 in 2017. In calculating the required subsidy, the idea would be that the net present discounted value (NPV) of the costs and subsidies should be offsetting.

One possible loan scheme of support would be:

- 5-year loan facility at 4% nominal, drawable from 2010 at the rate of €90m/yr up to €360 m (successive tranches possibly contingent on meeting agreed milestones);
- Payment of €360 m upon commissioning of capture at the power station, €170 m upon commissioning the transport and storage facilities and first successful delivery and storage of CO_2 (cancellation of outstanding debt of that amount);
- Payment of €14/tonne CO_2 stored up to 2030 (of which €10 is to ensure no by-pass, the balance is to compensate for interest on the extra construction cost);
- Two-sided CfD with a strike price of say €20, with the right to a payment of €20-EUA price per tonne stored if the EUA is less than €20, and otherwise an obligation to pay the EUA price-€20 either for the deemed maximum volume agreed (e.g. 1.5 m tonnes), or to pay for each tonne stored.

If the WACC to the company is 8%, then this scheme would roughly compensate the company for the additional capital and operating costs incurred. The NPV of the domestic subsidy discounting at the discount rate of 3.5%[18] is €575 m (higher than the construction cost because of the continuing need to support capture to dissuade by-pass).[19]

An alternative scheme that also roughly compensates the company for the additional costs incurred at the same WACC but with a lower domestic subsidy NPV of €348m) might be

- Grants payable from 2010 (or first site work) at the rate of €90 m/yr for the first three years and a final payment of €90 upon plant completion (taken as year 5) years (successive tranches possibly contingent on meeting agreed milestones, as for the final payment here);
- Payment of €170 m upon commissioning the transport and storage facilities and first successful delivery and storage of CO_2;
- Payment of €10/tonne CO_2 stored up to 2030 (all of which is to ensure no by-pass);
- CfD support as before.

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[18] The UK Treasury rate as in the *Green Book*, representative of the correct rate to discount future CO_2 abatement benefits.

[19] If CO_2 prices rise, as they should if climate change continues to be perceived as a growing threat, then the subsidy required will be lower, and to that extent these estimates tend to exaggerate the costs.

Other combinations of up-front grants or loans and per tonne subsidies can be devised, with the trade-off being that the earlier the payments are made to the company, the less risky it is to finance the project, but the greater the risk that the cost of non-delivery will be borne by the government. This is somewhat alleviated by the payments being loans that are cancelled upon commissioning. Note that the cost to the national government is lower if the funds are made as grants rather than loans as the company can invest the cash more profitably than the public sector discount rate (or put another way, it is more costly for the company to borrow than for the national government and so they need to be paid more to compensate for this extra cost).

An additional way of reducing risk would be for the government to offer a cost-sharing scheme for some fraction of the over-run costs above some agreed level. The government might offer various combinations of a guaranteed price plus a stated cost-sharing percentage, e.g. a choice between €1,700/t.a. (t.a. = capacity to abate 1 tonne[20]) + 50% of cost over-run; or €1,800/t.a. + 30% of cost over-run; or €1,900/t/a/ + 10% of cost over-run.[21]

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[20] i.e. per unit of capacity that when operating can abate 1 tonne CO_2.

[21] These sharing rules are purely hypothetical and would require careful choice to be made operational, and would probably need to depend on the benchmarking data available.

5. Designing Selection Criteria and Mechanisms to Encourage Competition[22]

5.1. Should the first round operate on a first-come-first-served basis?

It has been suggested that the allocation of funds could be achieved through the following two-stage process: In the first round, proposed projects are supported on a first-come first-served basis; in the second round, remaining firms bid for support through some competitive process. However, we find that such a procedure might be counter-productive.

A sensible mechanism for allocating funds should, as far as possible, make firms compete against each other in order to reduce costs and increase efficiency. Furthermore, the real possibility of collusive behaviour among firms submitting bids should be taken seriously, as the potential bidders are likely to be drawn from a small pool of firms who interact repeatedly over time. Thus, there are at least two reasons why such a procedure could be counter-productive:

1. By allocating funds on a first-come first-served basis, the most inefficient firms are encouraged to rush to secure early funding and thereby avoid direct competition with potentially more efficient firms in the second round. While efficient firms may also have an incentive to avoid the competitive process in the second round, their incentives are weaker than for inefficient firms. This is because the inefficient firms may be unlikely to receive any funding at all if exposed to direct competition, while efficient firms will each have substantial chance of winning on competitive terms. In summary, under the suggested two-stage procedure it is more likely that inefficient firms will receive support.

2. Since under the proposed procedure some firms receive funds in the first round, these firms will effectively be taken out of the pool of firms that compete for funds in the second round. The reduction in the number of firms in the second round has two effects. First, competition can be expected to be less intense; firms may therefore bid less aggressively and not reduce costs as much as they otherwise would have done. Second, the fewer the number of firms who participate in the bidding process, the easier it will be to sustain collusive agreements between these firms.

In conclusion, it appears that the two-stage procedure with first-come first-served allocation followed by competition over the remaining funds could have unattractive incentive effects. A possible reason for choosing such a procedure would be to speed up the process. The perceived benefits of achieving this objective would need to be weighed against the drawbacks outlined above.

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[22] Authors of this section Richard Steinberg and Flavio Toxvaerd

5.2. Our proposed auction design

A special feature of the process of allocating funds to CCS demonstration projects is the twin goals of efficiency and diversity of technologies. In essence, diversity means that different projects are not directly comparable. This may make standard auction mechanisms less potent in reducing anticompetitive behaviour, as these are predicated on the fact that bidders compete on costs in providing a well-specified deliverable. As is known from industrial economics, when firms produce differentiated (i.e. non-homogeneous) products, each firm has some market power, enabling firms to inefficiently extract rents. In a similar fashion, bidders may use the fact that they are bidding for a shared pool of funds but are bidding both on costs and technologies. This fact may therefore increase the ease with which collusive agreements can be implemented by the firms.

In short, we are seeking an auction design that simultaneously maximises the number of different technologies proposed and minimises the possibility of collusion. This latter objective is especially important, since there is likely to be a limited number of firms bidding for support in developing relatively untested technologies, i.e. technologies whose costs are difficult to estimate. Toward that end, we propose that the bidding process be structured in a single-stage bidding process as follows, which we designate as the Technology Category Auction:

<u>Technology Category Auction (TCA)</u>

<u>First</u>, the auction authority will delimit the various *technology categories*, say, no more than six, including allowances for 'other', i.e., technologies of which it may be as yet unaware of. These categories, while based on technological factors, should not be too narrowly defined as will become clear in what follows. (In brief, projects within each category should be roughly comparable technologically in such as way that they can be ranked in terms of development costs alone).

<u>Second</u>, bids will be invited from individual firms, with an allowance for the possibility of more than one bid originating in any given member state. Each bid is then placed by the auction authority into the appropriate technology category as defined earlier.

<u>Third</u>, bids in each category are ranked by the auction authority in terms of costs, with the firm submitting the lowest (realistic) cost chosen as the leader in its technology category.

<u>Fourth</u>, the auction authority chooses the leading firm (or firms) in each technology category. If the auction authority decides to fund more than one project in any category, it will next select the project with the 2nd lowest bid, and the 3rd lowest bid, etc. in that category. Alternatively, it may decide to select, e.g., the two lowest-cost projects in each technology category.

5.2.1 How the TCA structure addresses diversity of CCS options

The argument for diversity of CCS options is to maximise the learning about the possible costs and technical barriers to as wide a range of projects as possible. By designing the auction so that there exists competition both *within* and *between* technology categories, there will be an incentive for a firm to propose a plant using a new or unusual technology, since it is likely to have less competition within its technology category.

The technology categories should be chosen to be narrow enough for competition between firms, but within categories, to be meaningful and the projects comparable. There is also competition between categories but only indirectly so, as only a number of projects will be chosen across categories.

5.2.2 How the TCA structure addresses collusion between bidding firms

As is true for all tender processes, the possibility of collusive behaviour between the bidding firms is a real concern. The construction/development of CCS fitted power plants is associated with massive uncertainty in terms of costs, development time and other specifics and there is also the potential for important informational asymmetries between the firms and the sponsoring member states.

Since in the Technology Category Auction the projects are first chosen as least cost within each technology category, even if there were to be collusion among firms within a category, the firms in this category would still need to compete with firms in other technology categories. Thus, it is not in the interest of firms using the same technology to inflate their costs, as it will be competing with firms using other technologies. It is also not in the interest for firms in different categories to inflate their costs, as they still need to compete with firms within their own technology category.

As an aside, it should be noted that it is generally true that collusive behaviour is more difficult to sustain the more potential competitors there are. This means that the bidding process should be made as simple as possible (while maintaining the right incentives) with a view to attract as many bidders as possible. In this context, it may be worthwhile considering the possibility of inviting bidders from non-EU firms or consortia.

5.2.3 How the TCA structure addresses the possibility of cost padding by member states

Individual member states may be tempted to artificially inflate (or overstate) costs of firms operating within their jurisdiction. This would especially be relevant for state owned firms. In some sense, this is no different from the firms themselves inflating their costs and is therefore already taken care of by the auction procedure outlined above.

5.2.4 A simple example

Suppose there are 9 bidders (F1-F9) and 4 different technologies (T1-T4). Each bidder submits a bid that consists of a price for the construction of a CCS fitted plant and technology specification, where the bids are placed in each of the four different classes as described above. Suppose for example that the bids are as in the following table.

Firm	Technology				Bid (100m €)
	T1	T2	T3	T4	
F1	X				8
F2			X		**10**
F3				X	4
F4	X				**7**
F5	X				11
F6				X	**3**
F7		X			14
F8				X	8
F9		X			**13**

In the table, boldfaced numbers are the lowest cost bids in their respective technology class. Based on these numbers, for technologies T1, T2, T3, T4, firms F4, F9, F2, F6 are chosen as winners, respectively, in each category. Note that incentives can be further fine-tuned by letting allocations of funds depend on the submitted bids and the different technologies of the leading bids (i.e. there is a priori no reason why all leading firms in the different categories should receive the same allocations as some technologies are inherently more expensive to develop and the EU may want to give more support to such technologies).

It should be noted that the best losing bid in technology class T1 (firm F1 with a bid of 8) is cheaper than the winning bid in technology class T3 (firm F2 with a bid of 10). This is no more than a consequence of the desire to achieve diversity which necessarily comes at a cost in terms of also selecting some (perhaps) more speculative technologies.

5.2.5 What can be done if there are too few bidders in a given technology category?

The category auction was designed with a view to achieve both efficiency and diversity, and it was recognised that there is a proper trade-off between the two. In designing any auction, an important objective is to attract as many bidders as possible in order to reap the benefits of competition. On the other hand, here one may wish to achieve not only technological but geographic diversity as well. Geographic diversity can in principle be achieved in the category auction by expanding the concept of a category to include geographic specification.

The issue is whether this is a desirable modification of the auction. It should be noted that the more specific a category is, the fewer the number of firms that will fit into it and, consequently, the less intra-category competition there will be. In the extreme, the planner will face a number of bilateral monopoly problems in which it essentially contracts one-on-one with various suppliers.

One possibility is to run the first stage of the selection process as described in the original proposal, and then merge categories that receive too few bids. For example, suppose that categories 1 and 2 each receive a single bid. In that case, one could create a new category “1-2” with the two original bids.

An important caveat is that 'category merging' might in fact be counterproductive. Specifically, the outcome of this change may be that the objective of diversity is not met as bidders either opt for popular technologies (which receive many bids) or for unpopular technologies that subsequently are merged into broader categories and lose out in direct intra-category competition against other technologies within the same broad category.

Another suggestion is to refine the existing procedure by restricting the type of bids that may win within a category. In particular, one may introduce an element of benchmarking across technologies in the following way. No project within a given category may win if it is more than x% more costly than the lowest cost bidder in another category. In this way, even if a project is alone in its category, it will have to rein in costs.

An obvious difficulty with this approach is that one has to make cost comparisons across technologies which, given the significant amount of uncertainty in developing this type of untested technologies, is a delicate thing to do.

5.3. Other issues

5.3.1 Member states subsidising national champions

National governments could be tempted to secretly subsidise national champions in order to attract projects and thereby benefit from learning by doing and increased employment. Such subsidies are already illegal under EU law and would continue to be so. However, a case can be made that in this particular instance, such subsidies are less harmful than under normal circumstances since funding demonstration projects (that the market is unwilling to fund on its own) is essentially what the EU is trying to achieve. In other words, if a member state finds it in its interest to supplement EU funds (or EUAs) with its own to a bidding firm, then it should be allowed to do so. Arguably, the EU’s restrictions on state aid are an attempt to avoid member states giving their national firms unfair advantages in market competition with other (non-subsidised) firms.

5.3.2 Possibility of 'vapourware'

It is a concern that some firms may submit bids but then fail to deliver in the hope that the allocated (and unused) funds be returned to the member states. For this to be sensible, the firm would have to be either controlled by or colluding with the national government. For this type of behaviour to be limited, some type of penalty scheme should be considered whereby firms that are allocated funds but fail to meet pre-specified milestones would be fined, thereby rendering such behaviour unprofitable. In a similar vein, all supported projects receive funds in a staged manner, made contingent on actual progress.

Another alternative would be to specify that any unused allocated resources be earmarked to specific purposes such as research into CCS technologies or some similar purpose. With such a rule, the incentive to prevent funds from being used would disappear.

6. Conclusions

The main conclusions that emerge all revolve around the central question of what benefits flow from demonstration. A more careful appreciation of the tradeoffs involved in selecting individual demonstration projects that contribute to an EU (and indeed a global) portfolio of CCS is essential in evaluating how the selection process(es) are designed and how the decision criteria are chosen.

Diversity v Replication. In considering the allocation of resources among alternative CCS projects there are tradeoffs between ‘diversity’ (validation of the main available technological options) and ‘replication’ of the technology (learning-by-doing). The scope for cost reductions from learning-by-doing associated with ‘replication’ in manufacturing or operating a total of 8 to12 CCS plants are likely to be limited given the fairly small number of demonstration plants that are to be supported by the EU, the diverse national circumstances, and concerns over competition. Diversity in itself is not unambiguously positive; clear benefits need to be generated from encouraging diversity, whether in terms of geography, technology, industry, size or level of integration. Existing technical solutions for capture, transport, and storage can be combined in a large number of ways and selection among projects should take the merits of all possible permutations into account. It is important that at this stage as many and as diverse a set of firms participate as possible. This will increase the contribution base for demonstration projects. It will also ensure more participants and hence competition in the future CCS market. We, therefore, believe that it is necessary to emphasise diversity at this stage. We believe that the process of soliciting and selection among alternative projects should be designed as a mechanism through which the industry will reveal valuable information about the range of feasible options.

Auction Design. It has been suggested that the allocation of funds could be achieved through the following two-stage process: In the first round, proposed projects are supported on a first-come first-served basis; in the second round, remaining firms bid for support through some competitive process. However, such a procedure might be counter-productive. By allocating funds on a first-come first-served basis, the most inefficient firms are encouraged to rush to secure early funding and thereby avoid direct competition with potentially more efficient firms in the second round. Further, reducing the number of firms in the second round has two effects. First, competition can be expected to be less intense; firms may therefore bid less aggressively and not reduce costs as much as they otherwise would have done. Second, the fewer the number of firms who participate in the bidding process, the easier it will be to sustain collusive agreements between these firms. A single-stage bidding round which creates a Technology Category Auction of perhaps six categories is therefore a desirable alternative since it ensures diversity while discouraging potential collusion because firms will be competing in each (or at least some) of the technology categories.

Value for Money in Demonstration? Value for money is essential when large sums are being spent in pursuit of long-term reduction of greenhouse gas emissions. When those sums might otherwise have been spent on near-term emissions reductions it is incumbent on governments funding these projects to be confident that the long-term gains are significantly larger than the immediately realizable gains from simply investing in energy efficiency or readily available supply technology such as onshore wind. Unlike energy R&D, which is expected to have relatively low costs and low probability of success, given the high costs, CCS demonstration must have both a high probability of success and importance beyond the number of tons of CO_2 abated.

The EUA allocation method. The major EU CCS support plan is to allocate 300 million EUAs to "up to 12" CCS plants plus innovative renewable energy technologies. Each project can obtain a maximum of 15% of the total or 45 million EUAs. If some level of IRT funding is made available, it would be appropriate to create a separate category for IRTs (or even for subcategories such as concentrating solar power (CSP), tidal power, etc) in the TCA since it would seem virtually impossible to judge IRTs alongside CCS.

The present proposals would make receipt of EUAs "dependent upon the verified avoidance of CO_2 emissions", which could be interpreted as meaning that support will be in proportion to the amount of CO_2 stored or abated. Allocating these EUAs to national governments or project developers at an early date would ensure that as many EUAs as possible are allocated before 2015, to enable projects to be brought forward quickly in a way that contributes to both the capital costs and operational costs for the duration of ETS Phase III (2013-2020). It could be argued that the EUAs should not be linked solely to CO_2 abated if the aim is to stimulate rapid construction of CCS projects, which requires large amounts of up-front capital. The longer the subsidy is delayed, the higher the perceived cost to the developer, with no obvious gain in risk sharing.

As the analysis in Chapter 4 shows the EUA price varies in sympathy with the electricity price amplifying the risk to the developer. So, a critical question is how the EUAs should be best used as this will have an impact on costs.

Addressing Higher Operating Costs. Once the CCS demonstration plant is built, how can incentives be structured to cover the higher operating costs associated with capturing and storing CO_2? The first point to note is that the higher the price of electricity, the greater the lost profit from operating in capture mode, as this consumes about one-quarter of the electricity that could otherwise be sold. Second, unless the avoided variable costs of switching off the CCS are low or the price of EUAs is high (above €25-30 /EUA), a CCS-enabled plant would not even cover its extra operating costs, let alone the opportunity cost of electricity. In such circumstances, the plant operator is likely to choose to run in non-capture mode without an operating subsidy, unless the subsidy was contingent on delivering a certain volume of CO_2 into storage.

A CCS project delivers two outcomes – learning about costs and technical improvements, and the know-how needed to operate the plant reliably, neither of which requires that the plant capture CO_2 every hour that the station is available. If the EUA price is not high enough to justify capture, but the electricity and coal prices make conventional coal-fired generation profitable, then the question is whether the plant should switch from capture to by-pass mode.

Without a floor price for EUAs, concern over by-pass leaves policy-makers with a decision as to how best (or whether) to ensure that the plant is run in capture mode. Ultimately, the justification for restricting by-pass at the CCS plant is that the benefits from learning whether the CCS plant can operate reliably at high load factors is sufficient to warrant the additional cost incurred.

Too Many or Too Few? The CCS projects is not just to learn what designs and configurations are best suited to various environments, but also to encourage suppliers to invest in the supply chain so that scaling up can be managed more quickly and cheaply in the future. Although there may be some concerns that there will be too many projects put forward across the EU competing for scarce resources, the more serious and likely concern for the current demonstration phase is the danger of falling far short of the goal of "up to 12" demonstration projects being put in place by 2015. At present, there seems to be a far greater likelihood that the EU will have three or four major CCS demonstrations than twelve in 2015 because of uncertainty in the level or form of the support from national governments above and beyond that currently envisioned via the ETS new entrant pool or the EERP stimulus package, combined with a liberalised electricity market. This makes signals of commitment from national governments essential if undershooting and excessive costs are to be avoided. The possibility of a significant undershoot also suggests that if there is any bias in EU-level decision criteria it should be in favour of encouraging domestic support rather than allowing concerns over state aid to national champions create a set of rules at the EU level that discourage national governments from adequately supporting CCS projects.

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Glossary

Capex:	capital costs
CCGT:	Combined Cycle Gas Turbine
CCS:	Carbon Dioxide Capture and Storage
CfD:	Contract for difference
Clean spark spread:	The price of electricity less the cost of the gas used in a CCGT of 50% efficiency to generate and the EUAs required
Dark green spread:	The price of electricity less the cost of the coal used to generate at 35% efficiency and the EUAs required
FCF:	Discounted Cash Flow
EERP:	European Economic Recovery Plan
ETS:	European Emissions Trading System
EUA:	Emission allowance: the right to emit 1 tonne of CO_2 in the EU ETS
MWhe:	Megawatt-hours of electricity generation
MWht:	Energy (thermal) content in fuel measured in Megawatt-hours
NPV:	net present discounted value
Opex:	operating costs
WACC:	weighted average cost of capital

Appendix 1

Eurelectric (2008)

Costs over a 15-year period for a "generic" CCS-plant and a 12-plant programme

Unit size MW	300
Operating hours /a	7,000
CO2 price[23]	20.00 – 30.00 €
Transport & Storage cost / MWh	20.00 €
Additional fuel cost / MWh	8.00 €
Discount rate 10%	
Additional overnight investment cost / MW -	1,900,000 €
Total additional overnight cost (300 MW plant) –	570,000,000 €
Production MWh /a	2,100,000
CO2 abated t /a	1,447,000 = 0.69 t/MWh
Avoided CO2 cost /a	28,940,000.00 € = 20€/t
Transport & Storage cost /a -	42,000,000.00 € = 28.3€/t
Extra fuel cost / a -	16,800,000.00 € = 8€/MWh
EXTRA OPEX /a -	29,860,000.00 € = 14.2€/MWh
DCF[24] for 15-year period / plant -	207,000,000.00 €
NPV[25] for 15-year period / plant -	777,000,000.00 €
Total cost of 12-plant programme (NPV) -	9,300,000,000 €
(Equivalent number of EUAs at 20€/t CO2	465 million)

Would such a plant operate if it received no variable output support in addition to the EUAs saved? The extra Opex and fuel cost are estimated at 22€/MWh or 32€/tonne CO_2 and if we take the variable transport and storage cost at only 10€/tonne the total extra cost is 42€/EUA saved, which is considerably higher than the predicted price. The conclusion is that the plant would need continuing subsidy to induce it to continue to capture the CO_2.

[23] We have assumed 20€/t for years 1-5, 25€ for years 6-10 and 30€ for years 11-15.
[24] DCF = Discounted Cash Flow
[25] NPV = Net Present Value