Flexible operation of coal-fired power plant with CO_2 capture

Hannah Chalmers*

CCC/160

January 2010

ISBN 978-92-9029-480-1

Abstract

This report reviews possible operating requirements for coal-fired power plants with carbon dioxide (CO_2) capture in current and future electricity systems. It also outlines a range of operating options that may be available to plant operators to meet these requirements. It is expected that flexible operation of coal-fired power plants with CO_2 capture will be required in many electricity systems. Current knowledge of potential approaches for flexible operation of power plants with CO_2 capture in the public literature is limited. A review is, however, used to inform an initial technical evaluation of potential operating modes for coal-fired power plants with CO_2 capture. It is also necessary to identify suitable techniques for economic analysis of possible operating approaches. A range of factors that could be considered are outlined and should be taken into account in further work to develop robust analytical methods. If these methods can be successfully developed and implemented then they should improve decisions made by investors, policy-makers and other stakeholders.

* This report is a revised and extended version of a thesis submitted for examination for a Diploma of Imperial College (DIC). It is based on work carried out at Imperial College London from October 2006 to September 2007 and then subsequently at the University of Surrey, within an interdisciplinary PhD study in this area funded by the UK Energy Research Centre.

Acronyms and abbreviations

CCS	carbon dioxide capture and storage
CO_2	carbon dioxide
G8	Group of Eight (Canada, France, Germany, Italy, Japan, Russia, UK and USA)
IEA	International Energy Agency
IEA GHG	International Energy Agency Greenhouse Gas Research and Development Programme
IEEE	Institute of Electrical and Electronic Engineers
IGCC	Integrated Gasification Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
LHV	lower heating value
MEA	monoethanolamine
MWh	megawatt hour (unit of energy)
R&D	Research and Development
SRMC	short run marginal cost
UK	United Kingdom
USA	United States of America

Contents

1 Introduction

In recent years, carbon dioxide capture and storage (CCS) has been identified as a potentially important technology to include within an international approach to mitigating the risk of dangerous climate change. The Intergovernmental Panel on Climate Change published a special report on CCS in 2005 (IPCC, 2005). The International Energy Agency has also suggested that CCS could play an important role if global action is taken to significantly reduce carbon dioxide (CO_2) emissions, including within its 2008 Energy Technology Perspectives study (IEA, 2008a). In 2008, leaders of the G8 nations continued to recognise a potentially significant role for CCS globally. In their summit declaration (G8 leaders, 2008) they included a specific reference to CCS, stating:

'*We strongly support the launching of 20 large-scale CCS demonstration projects globally by 2010, taking into account various national circumstances, with a view to beginning broad deployment of CCS by 2020.*'

CCS is a family of technologies that can be used to reduce CO_2 emissions from fossil fuel use significantly. In a typical CCS project, CO_2 would be captured where it is produced, rather than being released to the atmosphere. Once it has been collected, the captured CO_2 is then transported to safe storage typically in deep geological formations. Levels of CO_2 emission reduction will vary between CCS projects, but it is generally expected that at least 90% of the CO_2 produced by a coal-fired power plant could be captured and stored using CCS. Critically, CCS projects allow continued use of fossil fuels, even if low greenhouse gas emissions are required from electricity generation and other energy use. This is important since a number of countries have large, indigenous fossil fuel reserves that they are likely to want to use.

Initial commercial-scale integrated CCS projects including power plants are beginning to progress towards deployment (*see* Section 2.3). It is, therefore, timely to review key gaps in knowledge and understanding that may be important to enable successful implementation and operation of these projects. In some cases, this pre-deployment review could identify additional considerations that should be included in project designs. It is also likely that some questions will be identified that cannot be fully answered until relevant experience has been gained with real plants. In this second case, reviews carried out at this stage should aim to identify research and testing programmes. These programmes should ensure that relevant data can be gathered to inform future improvements. This could include identifying upgrades for existing plants, as well as developments in new-build designs.

The aim of this report is to review operating options for coal-fired power plants with CO_2 capture from a technical and economic perspective. As outlined in Chapter 3, a number of operating requirements must be considered. Although the focus of this report is on coal-fired power plants, it should be noted that most of the discussion included in this report is also relevant to power plants burning other fossil fuels or biomass.

A range of relatively detailed engineering studies of CO_2 capture have been carried out, including a series of studies for the IEA Greenhouse Gas R&D Programme summarised by Davison (2007). This is accompanied by techno-economic literature on CO_2 capture at power plants including contributions from academics and industry, such as Allinson and others (2006), Jakobsen and others (2005) and Bergerson and Lave (2007). There has, however, been very limited analysis that extends to cover a range of possible operating situations for power plants fitted with CO_2 capture technology. Instead, engineering studies in the public domain typically focus on optimum plant design for rated output at maximum fuel input. Similarly, most analysis of economic performance will then assume that if a plant is operated it will be supplying its rated output to the electricity network. Most studies also assume relatively high load factors (so also very frequent use of the plant at rated output) throughout the economic life of the investment being considered. Some useful insights can be gained from these studies. It is necessary, however, to relax some of the assumptions framing the analysis for a more complete understanding of likely real power plant performance with CO_2 capture to be established. In this context a number of questions are addressed in this report including:

- What additional factors should be considered in plant design if requirements for operating flexibility are taken into account?
- What research and test programmes should be considered for demonstration plants and during initial deployment to provide a better basis for future designs?
- What additional analytical methods could/should be considered to help inform decisions made on the points above?

After providing an overview of CO_2 capture technologies (Chapter 2) and operating requirements for coal-fired power plants in electricity networks (Chapter 3), this report aims to respond to these questions from both a technical (Chapter 4) and economic (Chapters 5 and 6) perspective.

2 CCS overview

A number of technologies can be used in CCS projects, but in all cases three stages are required: capture, transport and storage (or use) of CO_2. The literature includes a number of detailed introductions to CCS, including a 2005 special report of the Intergovernmental Panel on Climate Change (IPCC, 2005). This chapter, therefore, provides only a brief overview of CO_2 capture, transport and storage. An outline of possible timelines and some announced plans for commercial-scale integrated demonstration and deployment is also included. This overview of the context for CCS development and deployment is important since it introduces factors that influence both technical and economic considerations for operating power plants with CO_2 capture. Since there are regular announcements of new projects and changes to existing plans, the current status of CCS deployment is continually evolving. Some organisations are, however, maintaining databases that attempt to track this activity (for example, Scottish Centre for Carbon Storage, 2009; Turner, 2009).

2.1 CO_2 capture and coal-fired power plants

Figure 1 illustrates three approaches to CO_2 capture that are the most developed for commercial-scale deployment of CO_2 capture at coal-fired power plants. Each of these options is outlined in this section and further details are included in Chapter 4.

The majority of coal-fired power plants operating today burn pulverised coal in air in a boiler. Water circulates through the power plant in a closed cycle. It is heated in the boiler to generate steam that is passed through turbines to generate electricity before being returned to the boiler. The flue (waste) gases from the boiler will typically contain nitrogen, CO_2 and other components such as particulates and oxides of nitrogen and sulphur. In many jurisdictions, there are limits on the allowable emissions of a number of 'conventional pollutants' to the atmosphere, including particulates and oxides of nitrogen and sulphur. Measures are, therefore, taken to limit their production or remove them from flue gases after combustion. Typical examples include the use of low NOx burners to reduce formation of oxides of nitrogen and the use of flue gas desulphurisation to remove oxides of sulphur from flue gases in a post-combustion cleaning process.

In post-combustion capture, CO_2 is removed from flue gas after a normal combustion process at a pulverised coal fired

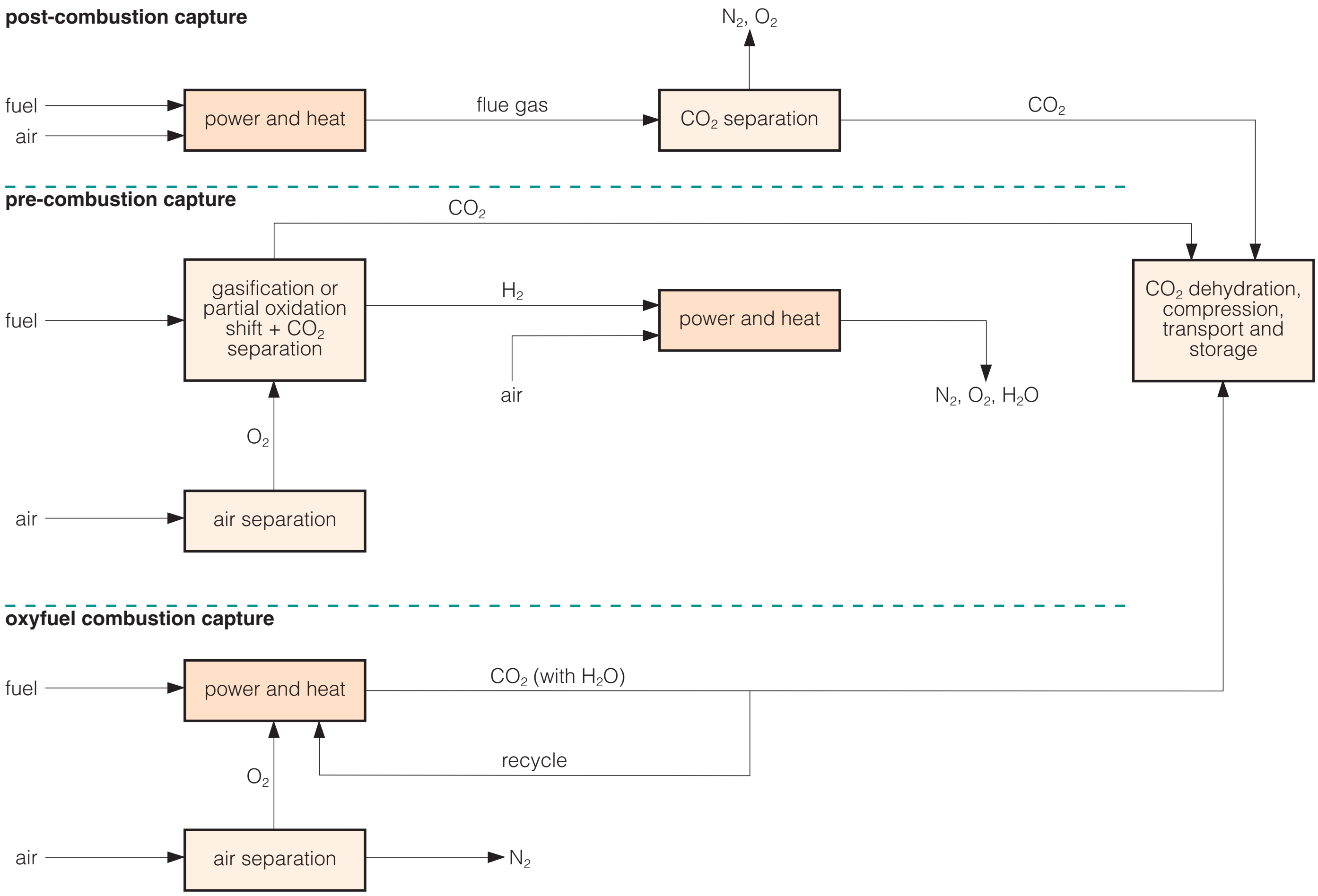


Figure 1 Schematic illustrations of CO_2 capture technologies closest to commercial deployment at coal-fired power plants (Jordal and others, 2004)

power plant (or other large source of CO_2). Typically after conventional pollutant removal, the flue gas is passed through a slightly alkaline solution based on chemicals such as ammonia or amines. Since CO_2 is slightly acidic, it is absorbed into the alkaline solution. In a second step, the chemicals loaded with CO_2 are heated to reverse the reaction and release the CO_2. The released CO_2 is collected, dried and compressed so that it is suitable to put into a CO_2 transport system. The alkaline chemical is reused.

Since relatively few modifications are required to an industry standard pulverised coal plant it can be relatively easy to retrofit post-combustion capture options to existing plants. This, of course, requires that certain basic requirements such as sufficient space for capture equipment and access to suitable geological storage are met. It is also necessary that appropriate access to install CO_2 capture equipment is available. For plants that are not yet built, a number of measures can be taken to ensure that CCS retrofit is possible in the future, as discussed in a detailed study commissioned by the IEA Greenhouse Gas R&D Programme on behalf of the G8 (IEA GHG, 2007).

Another option for power generation with coal involves the use of an integrated gasification combined cycle approach. This combines coal gasification with a combined cycle power plant. A few commercial-scale integrated gasification combined cycle plants have been operating for several years in Europe and the USA, but they are not widespread. In this approach, coal is gasified and not combusted. This produces a synthesis gas consisting mainly of carbon monoxide and hydrogen. For power generation without CO_2 capture, the synthesis gas is then used as the fuel for the combined cycle power plant.

The most widely discussed option for pre-combustion capture of CO_2 from coal-fired power plants uses an integrated gasification combined cycle as the base power plant. The main difference between integrated gasification combined cycle plants with and without CO_2 capture is that a hydrogen-rich gas is used in the combined cycle power plant for a plant with CO_2 capture, rather than the synthesis gas. The synthesis gas is converted to this hydrogen-rich gas by a shift reaction. In this reaction, water or steam is added to synthesis gas so that carbon monoxide is converted to CO_2 and more hydrogen. CO_2 is then separated from hydrogen, typically using a physical solvent.

Pre-combustion CO_2 capture is generally more difficult to retrofit than post-combustion capture. For example, at integrated gasification combined cycle power plants it is not straightforward to integrate the plant well both before and after a CO_2 capture retrofit. Retrofitting a gasifier to a natural gas combined cycle plant has, however, been suggested as a potentially attractive option in some locations (IEA GHG, 2005a). This latter approach is likely to have less challenging integration on suitable sites. This is because the retrofitted gasifier can be sized appropriately for the previously installed gas turbines. It is necessary, however, for the turbines to be designed (or retrofitted) to be suitable for burning a different fuel since they would now receive a hydrogen-rich gas rather than natural gas (or a standard synthesis gas).

The third approach to CO_2 capture illustrated in Figure 1 uses oxyfuel combustion. In this case, oxygen is separated from air and the fuel is then combusted in an oxygen-rich atmosphere. It is necessary to moderate flame temperatures due to materials constraints. One typical approach for this is to recycle some CO_2-rich flue gas with the oxygen that will be used for combustion to reduce peak flame temperatures. Although energy is required for separation of oxygen from air, the subsequent use of oxygen in the combustion process significantly increases the CO_2 concentration in the flue gas. This allows the chemical CO_2 separation process required for post-combustion capture to be avoided, although some CO_2 clean-up, including drying, will still be required during the CO_2 compression process.

A number of different power plant designs using an oxyfuel combustion process can be envisaged. The literature is currently dominated by approaches that would result in power plants that are similar to an industry-standard pulverised coal fired power plant (*see* Section 4.3). Water/steam would still circulate in a closed loop where it is heated in a boiler and then used to generate power in turbines. There are, however, some significant differences in the boiler island due to the oxyfuel combustion process outlined above. Leading boiler manufacturers have been developing oxyfuel technology for many years and full-scale oxyfuel burner tests are now being undertaken.

It has been suggested that oxyfuel technology could be retrofitted to existing plants, but it is not yet clear whether this will be a technically viable option for typical units. For the air-like oxyfuel system discussed above, it would be necessary for boiler manufacturers to identify methods that would reduce air leaking in to the existing system, unless that system was completely replaced. The majority of air-fired plants operate with the combustion system at slightly negative pressure. This means that atmospheric air will leak in to the system if there is not a perfect seal between the combustion air and the surrounding air. This significantly reduces the risk that hot combustion air could leak out of the combustion system. It would not, however, be expected as a normal operating mode for a typical oxyfuel combustion system where levels of nitrogen and other (non-oxygen) components in air are kept to a minimum, partly by ensuring a tight seal between the combustion system and the atmosphere.

For coal-fired electricity generation there is currently no clear winner between the three general approaches to CO_2 capture illustrated in Figure 1. It is quite likely that different approaches will be best suited to different sites and jurisdictions. Also the technologies are not static. Even with the present limited market for CCS technologies there is extensive activity directed towards improving the performance and reducing the costs of CO_2 capture. This includes continuing incremental improvements that can build up to significant developments, as well as more radical possible step changes. For example, a review undertaken by the IEA Clean Coal Centre (Davidson, 2007) highlights research in post-combustion capture that includes improvements to relatively well-established amine based processes and ongoing development work for ammonia processes. Fundamental research into other processes for separating CO_2 from flue gases is also under way. This includes the US Department of Energy's Carbon Sequestration Program investment in the development of a portfolio of 'innovative concepts' including metal organic frameworks, ionic liquids, and enzyme-based systems (Figueroa and others, 2008).

2.2 CO_2 transport and storage

Once CO_2 has been captured and compressed it must be transported to a site where it can be safely stored (or used). For the volumes involved for commercial-scale CCS projects, it is expected that pipelines will often be the best option. It is possible, however, that a ship may be more cost-effective in some niche applications including for transport over very long distances. Onshore CO_2 pipeline transport is generally considered proven (IPCC, 2005), but there is limited experience of transporting CO_2 offshore (Race and others, 2007). There is a large, existing onshore network for enhanced oil recovery operations in the USA, particularly in the Permian Basin in Texas. A dedicated pipeline is also used to transport CO_2 from North Dakota to Weyburn within one of the longest running CCS demonstration projects in the world (US Department of Energy, 2008).

It will be necessary, however, to ensure that engineers and operators gain a good understanding of any significant differences between existing networks and those that would be built for widespread rollout of CCS. For example, current networks are dominated by natural sources of CO_2 servicing enhanced oil recovery operations. More heterogeneous networks would be expected for CCS. Variable quality CO_2 might be delivered from different plants capturing CO_2. It is also likely that non-steady flow of CO_2 into transport networks would become more common for CCS infrastructure than is currently occurs. This is discussed in later chapters of this report for the example of power plants. Additionally, a wider range of geological facilities are envisaged for CO_2 storage than are used for current hydrocarbon production activities.

Given current levels of experience and capacity in CO_2 transport infrastructure, it will be important that preparations for potentially widespread deployment of CCS carefully consider CO_2 transport infrastructure. In some jurisdictions, new legislation will be required. This will need to take account of a number of factors, including those discussed above. Some legislators will also need to consider whether additional safety requirements should be enforced for CO_2 to be transported through areas that are more densely populated than current typical pipeline routes. Another important decision is whether the transport infrastructure for initial projects should be deliberately oversized due to potential longer-term benefits associated with establishing a network that is able to accommodate CO_2 produced at later projects. For example, Pöyry Energy Consulting (2007) considered possible transport networks for the UK in the context of work commissioned by UK Government on cost supply curves for CCS. Additionally, Element Energy and others (2007) analysed how a CO_2 transport and storage network might develop for the North Sea basin for the North Sea Basin Taskforce.

Safe storage of CO_2 in geological formations includes a number of different phases such as site selection, CO_2 injection and site closure. A range of different geological formations could be used to store CO_2 including saline formations and depleted oil and gas reservoirs (IPCC, 2005). Storage capacity estimates typically suggest that saline formations will provide the most significant contribution to global CO_2 storage capacity. It is important to note, however, that further work is required to check whether the potential storage capacity identified in initial basin-wide assessments is viable once more detailed information is considered. Additional criteria, including non-technical aspects such as economics, must also be taken into account. For example, Holloway (2009) reported capacity estimates for CO_2 storage in the UK continental shelf and concluded that:

'The real challenge for studies of aquifer CO_2 storage capacity in the UK is perhaps not to estimate the total theoretical CO_2 storage capacity, as this is not a particularly meaningful number. Rather it is to thoroughly investigate selected reservoirs perceived to have good storage potential to a standard where there is scientific consensus that the resulting storage capacity estimates are realistic.'

One important aspect of all CO_2 storage activities is expected to be appropriate monitoring during all phases of CO_2 storage. This will need to continue after CO_2 injection has stopped and sites have been closed. Many of the technologies required can be adapted from existing oil and gas activities, although some new approaches may be necessary for CCS applications. Ongoing work is considering lower cost approaches to monitoring. Techniques for remediating any serious leaks from CO_2 storage sites are also being developed (World Resources Institute, 2008).

The development of regulations for CO_2 storage could be critically important in determining how projects can be operated. Dixon (2009) provided a useful review of regulatory developments relevant to CCS, including a commentary on the processes for amending two international treaties to allow geological storage of CO_2 underneath the seabed. Although significant progress has been made, a number of detailed legal issues are still to be resolved in most jurisdictions. Some general principles are, however, emerging in the literature and as real regulations are implemented to allow initial CCS projects to proceed. For example, one of the underpinning assumptions of an interim report of the multidisciplinary CCSReg project (CCSReg Project, 2009) based at Carnegie Mellon University in the USA is that:

'because it will be impossible to know with certainty the specific behavior of large volumes of CO_2 injected at great depth before injection begins, an effective regulatory approach must involve an adaptive, performance-based approach for any given project.'

2.3 Commercial-scale demonstration and deployment plans

A number of energy systems studies, including work undertaken by the International Energy Agency such as

IEA (2008a), assume that CCS will be available for widespread deployment from around 2020. The aims of a 'flagship programme' of commercial-scale integrated CCS demonstration in Europe proposed by the European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP, 2008) suggest that this is a challenging, but achievable, view. This section will review possible timescales and opportunities for commercial-scale demonstration and initial widespread deployment of CCS. This context is important for developing a good understanding of some likely constraints and operating options for power plants with CO_2 capture, at least during the first decade or so of their lives.

Gibbins and Chalmers (2008) suggested a 'two-tranche' model for demonstration and initial deployment to facilitate widespread implementation of CCS from around 2020, as illustrated in Figure 2. The 'second tranche' of plants after initial commercial-scale projects are deployed is an important component of this model. This could be critical in providing a fleet of reference plant designs to underpin widespread commercial deployment. It might also be necessary for developing the skilled workforce and supply chains needed to support the challenging growth rates for CCS deployment proposed by many analysts.

Another key component of these proposed timescales for CCS development is that rapid progress is needed on a first tranche of commercial-scale, integrated CCS projects. There have been relatively large-scale demonstrations of CO_2 storage operating successfully for over ten years (Statoil, no date; PTRC, 2009) but, at the time of writing, there are no commercial-scale integrated CCS projects involving CO_2 capture at power plants. The potential for CCS to make a significant contribution to mitigating the risk of dangerous climate has, however, been increasingly recognised and accepted in the past decade. This has led to a number of initiatives and projects to encourage initial commercial deployment of CCS in integrated commercial-scale projects and some of these are discussed below.

As noted in the introduction to this report, in 2008 G8 leaders supported the 'launching' of 20 large-scale integrated CCS projects by 2010 (G8 leaders, 2008). This could be a significant milestone since their decision was based on a detailed assessment of CCS carried out as part of a range of studies initiated by the 2005 G8 summit in Gleneagles, Scotland. The G8 leaders did not, however, announce any financing mechanisms to support these projects. In this context, another potentially significant decision in 2008 was European agreement to support up to 10–12 projects using an incentive mechanism funded by allowances from the EU Emissions Trading Scheme (New Energy Focus, 2008; European Parliament, 2008). The Australian Government also announced its intention to establish a Global CCS Institute (Modern Power Systems, 2008; Australian Government, 2009) to support global co-operation to accelerate commercialisation of CCS.

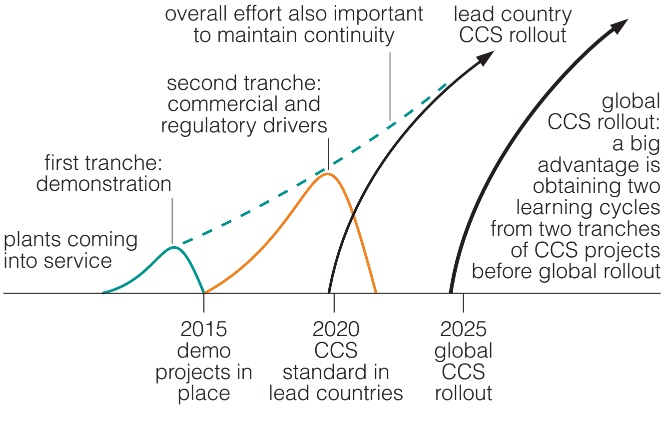


Figure 2 A two-tranche model for CCS development with new build plants (Gibbins and Chalmers, 2008)

It is important to note, however, that structured demonstration programmes can require significant set-up and tendering phases before the projects to receive funding are identified and, hence, able to proceed. Some fast-track projects could be encouraged by stimulus funding provided in response to difficult global economic conditions in 2008 and 2009. At the time of writing, the most significant stimulus funding for CCS has been announced in the USA (US Government, 2009). $1 billion of the $3.4 billion funds allocated for CCS within the American Recovery and Reinvestment Act are to be used by the Futuregen Alliance (US Department of Energy, 2009a). An integrated gasification combined cycle project in Kern County, California being developed by Hydrogen Energy and a post-combustion capture project that would deploy Powerspan's ammonia scrubbing option at the Antelope Valley power station in North Dakota have also been allocated funds set aside in this Act (US Department of Energy, 2009b).

Within Europe, a number of CCS projects are at different stages of development including a broad range identified by the European Technology Platform for Zero Emission Fossil Fuel Power Plants in their proposal for a flagship fast track demonstration/deployment programme (ZEP, 2008). For example, in the UK, the Government launched a competition in 2007 for funding for a 300 MWe post-combustion capture (or oxyfuel) demonstration project at a pulverised coal fired power plant (BERR, 2007). Three projects are in the second phase of bidding for support at the time of writing. A number of pre-combustion projects have also been proposed in the UK including two projects at new integrated gasification combined cycle power plants led by Progressive Energy (CCSA, 2008) and Powerfuel (Shell, 2007). Although these latter projects are not eligible for support from the initial UK Government CCS competition they are still progressing. They could be supported by further incentives announced by UK Government in April 2009 (DECC, 2009) and are also expected to be eligible for support within European programmes.

Other countries have also been making good progress with developing CCS projects. For example, the GreenGen project in China (GreenGen, 2006) has the potential to be among the first commercial-scale power plants constructed with CCS. Meanwhile, Japanese companies have formed the Japanese CCS Company. This initiative is intended to drive progress from research to demonstration of CCS in Japan, partly by facilitating integration of technologies owned by different shareholders in the company (Japan CCS Co Ltd, 2008). In

Canada, both Alberta and Saskatchewan have committed funds to significant CCS activities such as proposals by SaskPower (no date).

Although many of the projects discussed above require construction of new build power plants, there may be significant value in carrying out some demonstration projects as retrofits to existing power plants (Chalmers and others, 2009a). At the time of writing, both SaskPower and one of the UK competition bidders are proposing retrofits to pulverised coal power plants (SaskPower, no date; ScottishPower, 2009). Such projects could significantly decrease the time taken to prove at least one CO_2 capture option (post-combustion capture) sufficiently well for policy-makers, industry and other stakeholders to be convinced that CCS is able to make a significant contribution to global emissions reductions, as illustrated in Figure 3.

Anecdotal evidence suggests that some key players in global negotiations on action to mitigate the risk of dangerous climate change are likely to find it difficult to agree to likely required greenhouse gas emissions cuts if they were not allowed to use, often significant, indigenous coal reserves. This potential option for fast-track development of CCS could, therefore, be important to allow progress in these negotiations at the rate which may be required for an effective response to current assessments of likely required CO_2 emissions trajectories to mitigate the risk of dangerous climate change (for example, IPCC, 2007; Committee on Climate Change, 2008).

2.4 Summary

This chapter has provided an overview of CCS technology and potential timelines for commercial-scale demonstration and deployment of CCS at coal-fired power plants. The three main approaches to CO_2 capture that are closest to commercial deployment were introduced: post-combustion, pre-combustion and oxyfuel combustion. There is currently no clear winner between these technologies in terms of efficiency or cost of power generation with coal. In fact, it seems likely that the best choice of technology could vary depending on the particular site considered.

It will be important for power plant developers and owners to track developments in CO_2 transport and storage since they may have direct impacts on decisions related to investment and operation of power plants with CO_2 capture. Additionally, successful development of CO_2 transport networks and safe operation of CO_2 storage sites will be critical for rapid development and deployment of CCS generally. Regulation in this area is currently incomplete; although there is a sufficient framework in place for initial commercial-scale demonstration projects to progress in some jurisdictions.

Understanding operating options available to power plants with CO_2 capture also requires some appreciation of the general timeline for CCS development and deployment. Timing of initial projects will determine when opportunities to begin learning from commercial-scale projects begin. The funding arrangements for early projects could also be important, including any conditions attached to financial (or other) support provided to these projects. It is possible that arrangements could place constraints on plant operations. Any requirements for knowledge sharing might also affect how quickly any lessons learned at one demonstration project are available in the public domain.

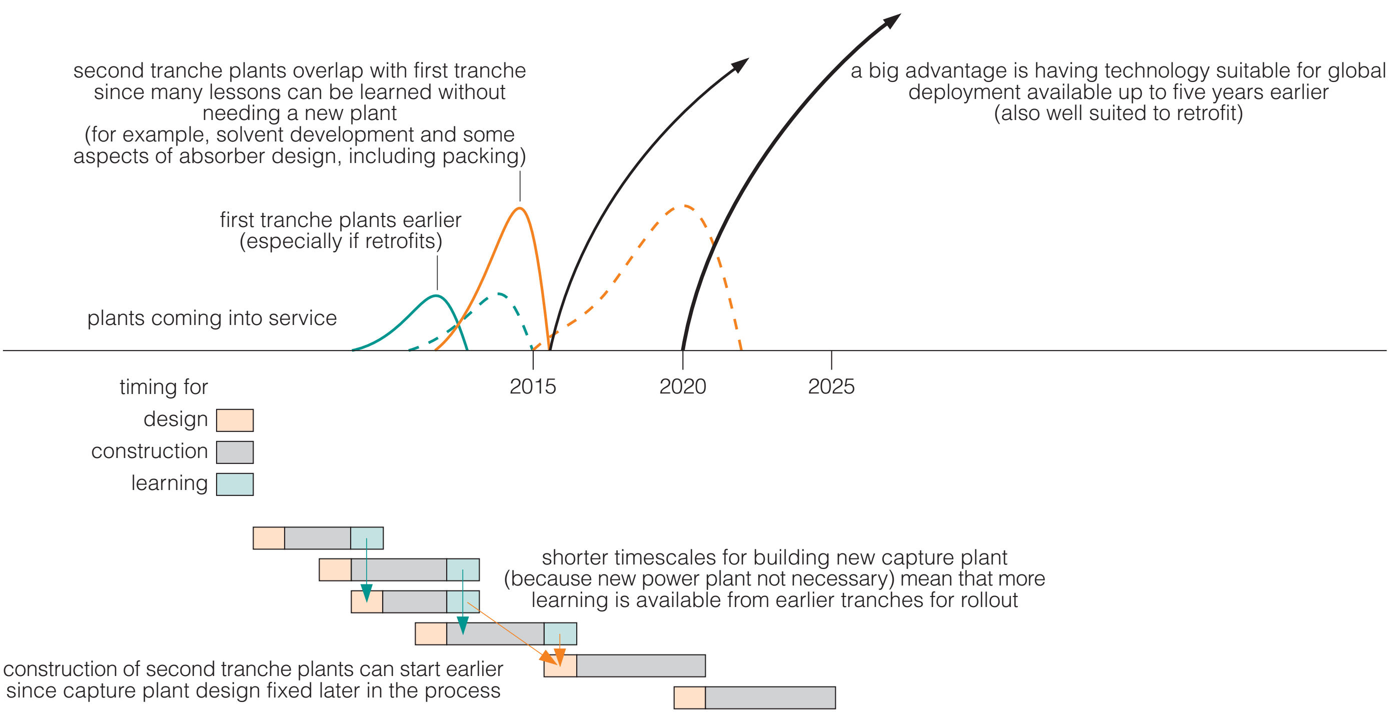


Figure 3 A two-tranche model for CCS adapted for fast-track development using post-combustion capture (Gibbins and Chalmers, 2008)

3 Operating requirements in electricity networks

Before exploring the operating options available for power plants with CO_2 capture, it is useful to understand typical roles played by coal-fired power plants in electricity networks and how these may change in the future. This chapter, therefore, reviews current typical operating patterns for coal-fired power plants in electricity networks. It also explores some possible network developments. These may shape the value of different operating options available to power plant operators in the future. An outline of some characteristics that are likely to be important to consider in determining which roles a plant is able to fulfil within an electricity network is also included.

3.1 Typical roles for coal-fired power plants

Interconnected electricity networks are well established as an effective way to connect electricity generators to users through a transmission and distribution system. The UK Parliamentary Office of Science and Technology (2001) provides a useful overview of the UK electricity system, highlighting some benefits of these interconnected networks, including:

- Cost-effective provision of electricity services, since the cheapest generators can be selected to serve users regardless of their physical location within the network (except for possible physical constraints of the transmission and distribution system);
- Security of supply should be improved since, depending on the generating capacity available and the transmission and distribution network design, if one part of the system fails then demand can be met through another route;
- Reduced frequency response since system frequency depends on the balance between supply and demand and 'interconnection allows the frequency of the system to be controlled without each separate system having to maintain its own frequency'.

A number of different methods can be used to determine which power plants will be operated to meet demand. In most cases, a network operator will be responsible for ensuring that supply meets demand on various timescales from seconds to hours and, sometimes, longer. In many regions systems have been liberalised and privatised, and a market structure of some form is used to determine which plants are used to meet demand. A detailed review of these market structures is beyond the scope of this report, but some general features can be identified and are discussed in this chapter.

In most, if not all, interconnected electricity networks a number of different roles for power plants can be identified. Some of these roles are illustrated in Figure 4, which shows typical demand patterns for an example system where demand is higher in summer than in winter. This could be because heating is required in the winter, but air conditioning is not required in the summer. Table 1 outlines the purpose of each role indicated on Figure 4 and identifies the typical use of current coal-fired plants without CO_2 capture in each of these roles.

There can be variations between the methods that different jurisdictions use to determine which power plants are operated at any given time. In many cases, a first approximation of the role that a particular plant takes can be determined by its position within the 'merit order' of power

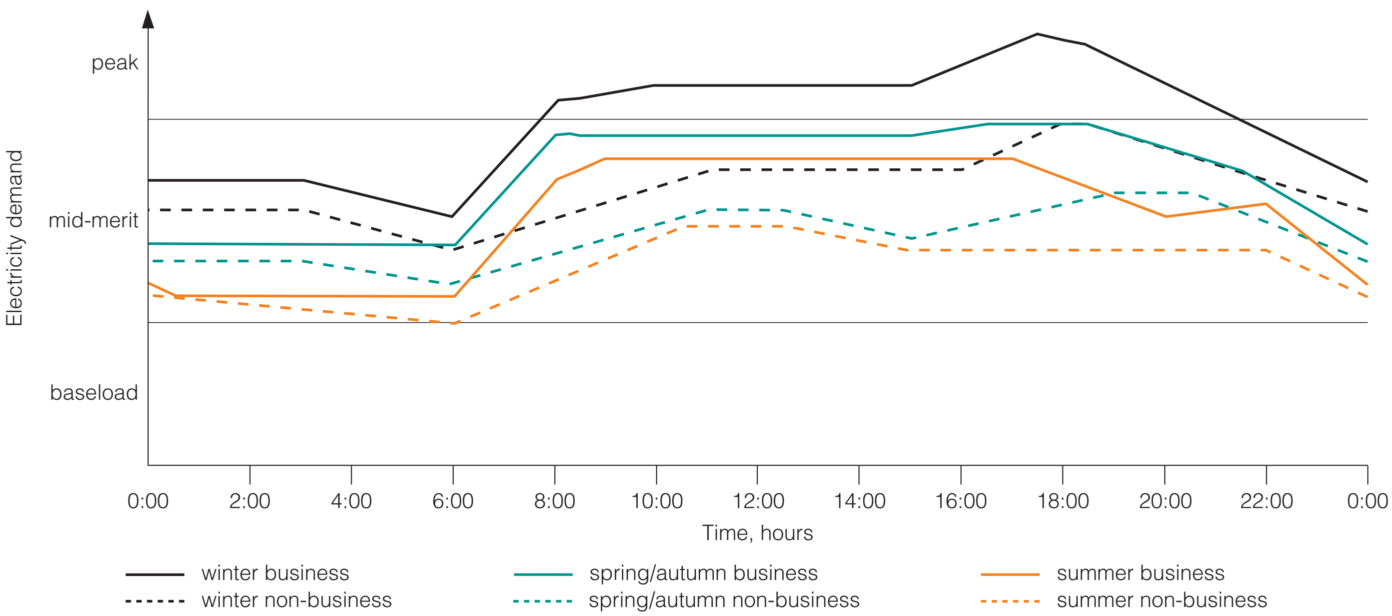


Figure 4 Schematic split of power generator roles in an interconnected grid (Chalmers and Gibbins, 2006; ILEX Energy Consulting and Strbac, 2002)

Table 1 Summary of plant roles and use of coal-fired power plants without CO_2 capture (Chalmers and others, 2007a)

Plant role	Purpose/characteristics	Use of coal-fired plants without CO_2 capture
Baseload	Continuous operation at full load to provide enough power to meet minimum demand. Low operating costs but often high capital cost (paid back since steady income stream is obtained by baseload operation).	Varies between systems. Contribution depends on a number of factors including coal/gas price ratio, any cost for emitting CO_2 and the availability of other options with lower short-run marginal costs such as nuclear and many renewables.
Mid-merit	Varying operation with capacity used, turned off or reduced to part load, depending on changes in demand. Typically mid-range capital and operating costs.	In many jurisdictions, current pulverised coal fired plants will operate as mid-merit plants, particularly towards the end of their operating lives. Also, note that mid-merit plants will often provide some ancillary services.
Peaking plant	Infrequent operation since only used at times of very high demand. Likely to have low capital cost and often high operating costs. Typical examples are pumped storage hydro and open-cycle gas turbine plants.	Limited contribution, although some extra output capacity can be obtained (with an efficiency and, hence, cost penalty) by changing plant operations, for example by reducing condensate heating.

plants. Merit order principles are well established in the literature (for example Turvey, 1968). In short, power plants within an electricity network can be ranked depending on their short run marginal, or 'avoidable', costs. These are the costs that are incurred by running a plant given that it is has already been built. The lowest cost plant is ranked highest in the order. The network operator will normally try to minimise the costs of providing the electricity required to meet demand. This means that they should dispatch electricity first from the plants which are highest in the merit order.

In a well functioning market it would be expected that the selling price of electricity would be closely related to the cost of generation for the marginal plant – that is the most expensive plant which is required to operate to meet demand. Of course, operating a real electricity network is more complicated than this, since other considerations must also be taken into account and real markets are imperfect. For example, bilateral trading between suppliers and consumers can co-exist alongside wholesale markets (Herguera, 2000). Thus, although merit order principles and categories are still relevant, they may not be observed explicitly within the electricity system at all times.

The merit order should change in response to the costs associated with plant operation including fuel price and, in an increasing number of jurisdictions, the cost of emitting CO_2. Some of the assumptions which lead to these changes are outlined in a short article by Brown (2005). He explores a number of the difficulties associated with using fundamental principles to determine merit orders and plant operation, particularly when carbon pricing is included in the market price of electricity.

Another common feature of all electricity systems is that a range of support services, often known as 'ancillary services', are required to maintain the security and quality of electricity supplied to consumers within the network. Making arrangements to provide ancillary services is one reason that real electricity systems typically don't fully conform to basic merit order principles. This is because these ancillary services might be provided by plants which have a higher marginal cost for electricity generation than other capacity which is available for dispatching electrical energy, but that is not able to provide the required ancillary service. Table 2 provides a summary of some of the ancillary services identified in a study carried out by the UK Energy Research Centre (Gross and others, 2006). Although this does not provide an exhaustive list, it does give a thorough overview of key services and identifies those which can have different names in different markets.

For both electricity generation and ancillary service provision, one important factor in determining how plants in interconnected electricity systems operate is often the mix of other generating plants available for use. Whether other technologies can provide flexibility in the electricity network is likely to have some significant implications for which operating options may be valuable or necessary for power plants firing fossil fuels, with or without CCS. One typical example is that large-scale hydro projects can often provide additional supply to the network very quickly. In countries where large-scale hydro is not available (for example, because the geography is not suitable) flexible generation is typically still required to maintain the security and quality of supply, but other technologies must be used.

In most jurisdictions some measures are required to ensure that sufficient ancillary services are provided, although the 'natural' characteristics of the least cost mix to match supply with projected demand based on merit order principles will often provide some flexible supply. These measures can include additional markets to pay for ancillary service provision and bilateral contracts between the network operator and power plants providing ancillary services. The provision of many of these services implies that the electricity

Table 2 Examples of ancillary services (Chalmers and others, 2007a)

Ancillary service	Purpose	Typical service provision on supply side
Frequency control through primary response (including some 'spinning reserve')	Very quick response (up to a few minutes) to add or remove power from the system to maintain system frequency following a sudden change in supply or demand. Is able to respond more quickly than other response/reserve measures, but in some cases the change in output obtained can only be maintained for short periods. This allows time for secondary response (below) to react.	Predominantly plants providing this service would be generating some electricity and be fully synchronised with the system frequency – that is plants operated at less than their rated capacity and able to ramp output up or down rapidly. Generating plants will typically be set-up to respond automatically to control signals defining required changes when they are providing this service.
Frequency control through secondary response (including some 'spinning reserve')	Relatively quick response (typically able to change output within a few minutes to less than half an hour) to provide extra capacity when demand or supply changes. Slower than primary response, but critical that it is available so that primary response can be replaced and, therefore, be ready to respond to future changes in supply/demand matching.	Plants providing this service might be generating some electricity and fully synchronised with the system frequency. Plants with fast start-up capability can also be used here. For example, open-cycle gas-turbine stations and standby diesel engines can be synchronised in minutes after an instruction to operate.
Standing reserve	Plant which are available with some hours notice to replace generating plant that are unavailable (or secondary response that has been used to replace unavailable capacity).	Various options are available here. One example is thermal plants, such as pulverised coal plants, which are deliberately kept warm (that is maintained at operating temperature) to allow relatively rapid start-up, but that do not generate electricity.
Voltage control	Electricity networks are expected to provide electricity within a narrow frequency and voltage range. Thus, it is necessary to provide voltage control as well as frequency control.	Frequency should be maintained by matching supply and demand of electrical energy. For voltage control, some plants are contracted to provide reactive power.
Black-start capacity	Many power plants require input from the electricity network to be able to start-up. Black-start facilities can start-up without this external electricity supply to facilitate network recovery after any (highly unusual) total system collapse.	Some plants within a network should have black-start capability (for example, appropriately-sized diesel generators). Within liberalised markets, generators will be contracted to provide this capability to the network, with contracts normally awarded after a competitive tendering process.

network should contain a 'capacity margin'. This is because some plants which could generate electricity should not operate at full load continuously, even during periods of very high demand, if the network is to include the range of ancillary service provision identified above. This capacity margin is also necessary to accommodate planned and unplanned outages at power plants which imply that all installed capacity is unlikely to be available to meet demand at any given time.

The characteristics of electricity demand are also important in determining which operating options could be important and valuable for power plant operators, including whether significant 'demand side management' is possible. Demand-side measures could provide significant flexibility in electricity systems (Heffner and others, 2007). For example, if there is a sudden increase in demand or reduction in supply, it can be more cost-effective to disconnect (or shed) loads deliberately according to pre-arranged contracts rather than increasing supply rapidly. Ancillary services requirements are also partially determined by the characteristics of electricity demand within the system.

3.2 Possible future developments in electricity networks

It is, of course, important to remember that many power plants with CO_2 capture will operate in future electricity networks that could have very different characteristics than current networks. It is likely that widespread deployment of CCS will occur alongside the rollout of other measures to significantly reduce global CO_2 emissions. There are many studies exploring how significant, and probably rapid, decarbonisation of energy generation and supply could be achieved. They typically indicate that both renewable and, in some jurisdictions, nuclear electricity generation could have a significant role. It has also been suggested that greater use of decentralised energy generation could be an important element of future networks with associated changes in network management (for example, Watson and others, 2008).

It is not yet clear how real electricity networks will evolve (or possibly change radically) in the coming decades. One key point discussed in many studies is, however, variability in electricity supply from some renewable sources. In particular, is it expected that new approaches to managing electricity networks will be required as these variable sources make a larger contribution in future electricity generation mixes. A review of the impacts of wind intermittency for the Great British electricity system, if it is not significantly reconfigured, was carried out by the UK Energy Research Centre in 2006 (Gross and others, 2006). It drew on a broad range of international literature. One important conclusion was that increasing the proportion of electricity generated by intermittent renewables up to 20% of supply could be accommodated in the UK system without compromising the reliability of electricity supply. It also noted that one impact of increased use of electricity generated by wind is likely to be that:

'the output of fossil fuel-plant needs to be adjusted more frequently, to cope with fluctuations in output. Some power stations will be operated below their maximum output to facilitate this, and extra system balancing reserves will be needed. Efficiency may be reduced as a result.'

It is important to note that the likely pattern of electricity generation from renewables and its potential impact on a particular electricity system will depend on a number of factors. For example, if individual generators can be dispersed geographically or rely on different energy resources then this can help to reduce the overall variability of electricity capacity from renewable sources available in the system (Sinden, 2007).

Also, much higher targets for introducing renewable electricity generation are now being discussed and implemented in some jurisdictions including in response to a European Renewables Directive (European Parliament, 2009). Continuing with the Great British example, Pöyry Energy Consulting (2009) summarises a comprehensive, year-long study they undertook to explore the potential impacts of introducing up to 40 GW of wind-powered electricity generating capacity into Great Britain's system by 2030. To put this in context, peak demand within the system is expected to be around 70 GW in 2030 in the scenario results reported. They concluded that further work is needed to 'properly' model the behaviour of electricity systems with this level of variable renewables included in the energy mix. They suggest that it is technically feasible for the system to include this proportion of variable electricity generation, but express concern over the ability of current electricity market structures to deliver a system that works effectively and with reasonable electricity costs for consumers in this scenario.

The costs of responding to renewable intermittency and specific requirements for coal-fired power plants will depend on a number of factors including: the size of the electricity network; any interconnection with neighbouring systems; and whether other technologies in the electricity network are able to provide flexible responses to changes in renewable electricity supply. For example, nuclear power plants are generally expected to have a relatively inflexible output. They also normally have very low marginal operating costs which will typically undercut those of coal-fired plants. This means that significant penetration of nuclear power generation is likely to lead to more challenging requirements for operators of coal-fired power plants. If demand side response measures are available these could balance variable supply from renewables. Commercially viable energy storage options would also be expected provide an alternative to flexible operation of coal-fired power plants if they can be developed and deployed successfully.

It is also possible that changes in the broader energy system could lead to changes in operating options that are necessary or valuable for coal-fired power plants. For example, there is increasing interest in approaches to reduce CO_2 emissions from road transport. The introduction of vehicles powered by electricity or hydrogen has been proposed (HM Treasury, 2007). If battery electric vehicles become widely available this could significantly change both the average demand for electricity and the typical variation of demand between day and night, or in different seasons. One possible change would be 'valley-filling', where excess electricity generating capacity during periods of otherwise low demand is used for the majority of vehicle battery charging (Kintner-Meyer and others, 2006). This could significantly reduce the difference between day and night electricity demand. One implication of that change could be that fewer coal-fired plants would be required to 'two shift' (that is significantly reduce their output overnight as electricity generation follows the pattern of demand, such as that illustrated in Figure 4 in Section 3.1).

It is also possible, however, that fast charging could happen during the day with the potential to increase electricity demand during periods where it is already likely to be high. Thus, appropriate demand management techniques will be required or additional peaking capacity would need to be available (Koyanagi and Uriu, 1997). Of course, fast charging facilities that included energy storage could themselves also provide load-levelling to some extent depending on how they were used. The vehicle-to-grid (V2G) concept is attracting interest and could lead to valley-filling. This is where batteries in battery electric vehicles are deliberately used as storage capacity that can supply power back to the network during periods of high demand, as in Kempton and Letendre (1997). In this situation, it is possible that battery electric vehicles could provide additional storage capacity that would reduce the need for flexible operation of coal-fired power plants.

3.3 Characteristics for plants in different roles

It is useful to develop a set of assessment criteria to be able to review the suitability of different power plants to fulfil the requirements of different roles within the network. Table 3 outlines some technical measures of power plant flexibility that could be suitable for this purpose and explains their relevance for characterising ability to undertake certain roles in the generating mix. In addition to the broad range of roles that coal-fired power plants can have in an electricity network, it is also possible that the role of a particular plant will change during its life. Many plants that operate in the baseload initially could be mid-merit or peaking plants later in their lives, as they are displaced from baseload generation by newer plants. This can occur for a number of reasons including the use of improved technology at new plants and

Table 3 Some technical measures for power plant flexibility (Chalmers and others, 2007a)

Technical measure of plant flexibility	Relevance for characterising plant role in the generating mix
Start-up/shut-down time	Standing reserve and capacity used for peak shaving must be able to start-up quickly. Also advantageous for mid-merit plant. In this latter case, being able to start-up and shut-down cheaply allows plants to operate for shorter periods. Operators can turn plants off during periods of low demand when they would make an operating loss due to relatively low electricity prices, but without excessive costs for shutting down and restarting the plant.
The rate at which plant output can vary as it is changed (ramp rate)	Particularly important for spinning reserve. It must have a fast ramp rate so that it is able to increase load rapidly when required.
Plant efficiency when operated at less than full output (part load)	Important for plants providing response services, since the plant will be required to operate at part load before reserve is called upon. Plant efficiency tends to be lower when it is operated below full load. The higher part load efficiency is, the less the increase in marginal cost of electricity.
Grid rated capacity and maximum output	The maximum output from a power plant can be above the output obtained with maximum fuel input. This is particularly relevant during periods of very high demand where generating options with high marginal costs will be required unless alternative options can be identified. For example, stopping feedwater heating at a coal-fired power plant can increase plant output, but will reduce efficiency. The increased costs associated with that reduced efficiency could, however, lead to a lower cost of electricity than the use of a separate plant for providing extra capacity.
Minimum stable generation (the minimum steady output that a plant can operate at, based on physical constraints such as flame stability in a coal-fired boiler)	This is particularly relevant during periods of low demand when flexible plants are not included within the electricity generating mix selected by applying merit order principles alone. The lower minimum stable generation for a coal-fired plant operated to provide ancillary services is, the more electricity can be supplied by cheaper, but less controllable, capacity such as nuclear and intermittent renewables.
Variety of fuels	If power plants are able to use different fuels then this can reduce their exposure to fuel price volatility since supply can be switched, for example the ability to run gas-fired plants on distillate is useful for energy security. Also, the use of non-fossil fuels to replace some fossil fuel input can effectively reduce CO2 emissions from a particular plant. Biomass cofiring at pulverised coal fired plants is now common in markets where this is economically viable.
Variety of products	Especially for integrated combined cycle plants, it is possible that different products can be produced which may provide a revenue stream which is at least as important as electricity sold to the network. Combined heat and power (CHP) is also important in some jurisdictions. In some cases, producing a non-electricity product may restrict flexibility of electricity generation (such as CHP where matching heat demand is typically prioritised), but this would not be the case for all products.
Ability to respond to ambient conditions	In many jurisdictions a range of ambient conditions (such as temperature and humidity) will be observed. Plant operators must understand how performance is likely to change across this range of conditions. This is particularly the case for extreme weather events that can be accompanied by unusual electricity system demands.

increases in operating costs for existing plants that can often occur as they become older.

Many of the characteristics highlighted in Table 3 may have a range of values depending on the operating state of the plant under consideration. For example, start-up times will normally be quicker for a 'hot' plant that was shut down relatively recently (maybe within the last eight hours) than a 'cold' plant which has been off-line for more than 48 hours (Gostling, 2002). Additionally, ramp rates can vary depending on the starting and finishing load required partly since the plant may be operated in different modes depending on the fuel input. It is also important to note that changes in these technical parameters can be relevant to some non-technical aspects of plant performance. Kruger and others (2004) illustrated this point in their explanation of the reasons for 'high demand' for reducing start-up and shut-down costs in European thermal power plants. Although this is partly driven by the requirements of the network operators in deregulated systems, other factors are also relevant, including power plant environmental performance.

3.4 Summary

This chapter has reviewed operating requirements for coal-fired power plants in typical electricity networks. In many systems, plant operators can be paid for providing electricity (electrical energy) or ancillary (support) services to the electricity network. Electricity network operators will typically aim to minimise the cost of meeting electricity demand, but will also need to take in to account that appropriate ancillary services must be provided. The choice of power plants for dispatch to provide electrical energy can be broadly linked to a ‘merit order’. Plants with the lowest short run marginal, or avoidable, costs will typically be selected first for providing electricity. Alterations to the generating mix will then be required in many jurisdictions to ensure that sufficient ancillary services are also supplied.

Power plants that normally operate at full output when they are available are typically considered to be baseload power plants. Mid-merit plants typically change their output relatively frequently and a third category of plants are used infrequently to meet peaks in demand. As many systems increase the use of variable renewable energy sources these broad categories may be less applicable. The technical and economic consequences of increased penetration of renewable sources are not yet fully understood, but one likely result is more frequent, flexible operation of coal-fired power plants in many jurisdictions. Other changes in the energy system could also affect which operating modes are necessary or valuable for coal-fired power plants. This includes the potential introduction of battery electric vehicles. Depending on what battery charging patterns are adopted, widespread use of battery electric vehicles could lead to more or less need for flexible operation of coal-fired power plants (and other electricity generating sources).

An overview of technical measures that can be used to characterise the ability of power plants to provide different ancillary services is included in the final section of this chapter. In many jurisdictions, the typical role of a coal-fired power plant will vary during its life. Currently, new coal-fired power plants will often run as baseload plants for a number of years allowing the capital investment required to build the plant to be paid back. Later in life, coal-fired power plants tend to be displaced from the baseload in some jurisdictions. They might then operate as mid-merit plants with a potentially significant proportion of their revenue resulting from ancillary service provision.

4 Technical potential for flexible operation

Having established typical roles for coal-fired power plants within current and future electricity systems, a review of different operating options that could improve or constrain the ability of power plants to fulfil these roles can be undertaken. This chapter outlines a range of options for flexible operation of pulverised coal fired power plants, with post-combustion or oxyfuel capture, and integrated gasification combined cycle plants with pre-combustion capture. As outlined above, these options are chosen since they are closest to widespread commercial deployment. The previous chapter has highlighted the importance of power plants using fossil fuels being able to change output rapidly and provide ancillary (support) services within the network. Much of the focus in this chapter is, therefore, on different modes of operation that could provide this flexibility for a plant operator.

4.1 Overview of options

A detailed, quantitative assessment of power plant performance is beyond the scope of this report. Instead, the general areas of power plant performance that may be changed by adding CO_2 capture are considered. Full-scale CO_2 capture has not yet been applied at a power plant, but the technologies which are closest to commercial deployment are understood well enough for some possible impacts on power plant operating options to be identified. Before reviewing specific technologies, it is useful to outline considerations and options which are expected to be relevant, as shown in Table 4.

Experience with pilot or full-scale plants, that are larger than the units already in-service at the time of writing, is likely to be required to allow a full assessment of impacts of CO_2 capture on power plant flexibility. There is also limited public domain data in this area. For example, a 2008 scoping study on operating flexibility of power plants with CO_2 capture commissioned by the IEA Greenhouse Gas R&D Programme (IEA GHG, 2008) concluded that:

'*extensive gaps exist in the consideration of the important operability issues with respect to power plants with CCS. No definitive assessment of the operability of the individual technologies is available and it is certainly not possible to comment on the relative operabilities of post-, pre-, or oxy-combustion.*'

It is clear, however, that it is very likely that different CO_2 capture technologies will have different impacts on plant performance. For example, some approaches to CO_2 capture include additional integration between units that must be included for successful operation of the power plant. This may tend to reduce flexibility. This is not the case for all CO_2 capture options though. In some cases integration between different units within the plant can be useful to improve plant efficiency (or some other aspect of plant performance), but is not necessary for operation. With these latter approaches it is possible that plant operators may then have additional operating options available to them.

It is also important to note that changes in particular aspects of power plant performance could be constrained by limitations imposed by non-capture elements of the system. For example, additional potential capacity that may be obtained by bypassing the capture unit or delaying energy intensive aspects of the CO_2 capture process can only be delivered into the electricity network if the generator and grid connection are large enough. For plants where capture is retrofitted, it is expected that the 'balance of plant' would often be appropriately sized for the additional output that can be generated without capture, since these items would be appropriate for the initial plant before capture was fitted. It is not yet clear, however, whether investment to provide this flexibility at a plant built with CO_2 capture from the beginning of its operations would be justified by the potential value of that flexibility.

In addition to the various aspects of power plant operation noted in Table 4, it is also important to understand the requirements of the systems downstream of the power plant. For example, CO_2 quality requirements for transport and storage systems should be defined and understood. Further work is also required for a more detailed, fundamental understanding of the dynamic performance of CO_2 compression, transport and storage systems to be developed. The current evidence base suggests that no show-stoppers to flexible operation of power plants due to compression, transport and storage system constraints are inevitable, but some care may be required in designing systems downstream of the CO_2 capture unit to handle variable flows.

4.2 Post-combustion capture

Post-combustion capture involves the addition of a unit to remove CO_2 from power plant flue gases after a normal combustion process. A thorough review of some post-combustion capture options closest to commercial deployment is provided in a previous IEA Clean Coal Centre study (Davidson, 2007). A range of more detailed studies are also available in the literature including in work commissioned by the IEA Greenhouse Gas R&D Programme (IEA GHG, 2004) and a study completed as part of the UK Government's cleaner coal research programme (Panesar and others, 2007).

As shown in Figure 5, in the CO_2 capture unit flue gases are passed through chemical solvents (typically amines or ammonia) which remove or 'scrub' the CO_2 from the flue gas in the absorber column. The 'rich' solvent is then transferred to a second column which includes a reboiler where solvent is heated using steam taken from the power plant steam cycle to release the captured CO_2. The CO_2 is then dried, compressed and transported to safe geological storage (or, in a few cases, it may be used). 'Lean' regenerated solvent is returned to the absorber column for reuse.

Depending on the solvent chosen, it may also be necessary to

Table 4 Some potential changes to power plant flexibility when CO_2 capture is added (Chalmers and others, 2007a)

Flexibility option or consideration	Relevance/impact on plant performance
Likely changes in start-up and shut-down procedures	Further work required to understand these using models and real operating experience. Start-up and shut-down times and costs can be important in determining what role plants can play within the electricity network, with implications for plant economic performance.
Potential to change ramp rates for load following – could be faster or slower	Plant ramp rates are critical in determining whether a plant is suitable to provide response capacity. Changes in these could affect the services that could be offered to the electricity network by a power plant. Further work is required to understand the performance of various components of capture schemes and how their interactions with the base plant could alter ramp rates.
Part-load efficiency for power plants with CO_2 capture is not fully understood	Some coal-fired plants are often operated at part load to offer response capacity to the electricity network. It is important to establish how CO_2 capture affects power plant efficiency across the full range of outputs. Operating experience and integrated plant models are likely to be needed to improve understanding in this area.
Can change plant efficiency by changing capture plant operation – increased capacity at times of high demand, depending on overall plant constraints	If plant efficiency can be increased by reducing CO_2 capture levels (or delaying energy intensive aspects of the CO_2 capture process) then extra capacity can be made available to the electricity network, possibly very quickly. This will partly depend on balance-of-plant constraints (see further discussion in the main text of this section). This could be a response/reserve service that would not require off-design operation for that service to be available to the network operator.
Can change plant efficiency by changing capture plant operation – reduced minimum stable generation at times of low demand	If energy intensive aspects of the CO_2 capture process are delayed (as above) then this will lead to a reduction in plant efficiency when additional energy intensive activities are needed. Power plant output during times when these postponed energy intensive processes are undertaken later will also be reduced. At times of low demand this could be useful for the system operator. It would reduce the minimum stable generation of the plant, leaving more capacity in the electricity system able to be provided by other plants with lower marginal costs, but without compromising the security and quality of electricity supply.
Fuel flexibility could affect CO_2 savings associated with the power plant and negative emissions might be possible	The importance of fuel flexibility is not expected to change, but adding CO_2 capture introduces the potential for negative emissions if biomass is burned. Biomass removes CO_2 from the atmosphere as it grows. This would be permanently removed if the CO_2 re-released at combustion (or gasification) was captured and stored, rather than being emitted to the atmosphere.
Variety of products produced may be important, but need to be aware of changes to climate benefit for some products	Some of the most important modes of flexibility available to plant operators with pre-combustion capture systems may involve providing products other than electricity such as hydrogen or feedstocks for chemicals. It should be noted that if carbon-containing products are produced then this may reduce the percentage of fossil carbon that is captured, unless the CO_2 formed when the product is used is also captured.
Variation in ambient conditions	Changes in ambient conditions can cause significant variation in plant performance in some jurisdictions. Further work is required to understand if there are significant differences in sensitivity to different likely changes in ambient conditions for power plants with CO_2 capture, when compared to variation without CO_2 capture considerations.

apply a flue gas desulphurisation process to significantly reduce the levels of sulphur compounds in the flue gases. This would be needed to avoid unacceptably high levels of solvent degradation since heat stable salts could be formed by sulphur-based compounds reacting irreversibly with the chemical solvent. For example, for the Fluor Daniel Econamine FG process, a maximum of 10 ppm SO_2 content is a likely requirement, although some other solvents can be used with higher levels of sulphur compounds remaining in the flue gas (IPCC, 2005).

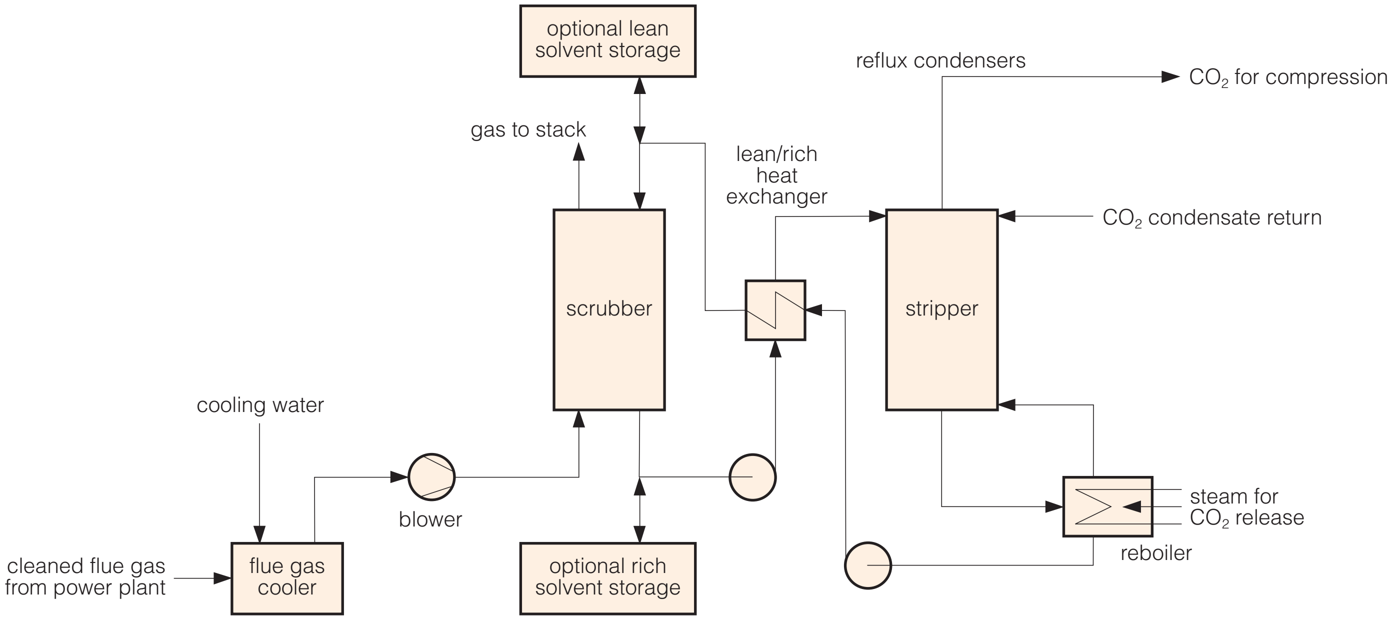


Figure 5 Schematic diagram of a post-combustion capture process added at a pulverised coal power plant (Chalmers and Gibbins, 2007)

As discussed in Table 5, since post-combustion capture processes require relatively limited changes to the base power cycle, it should be technically feasible to design plants so that the whole capture system can be bypassed. In fact, it is likely that this bypass would be a requirement for some utilities for reliability, availability, maintainability and operability (sometimes referred to as RAMO) reasons. As discussed in the previous section it is possible that additional electrical output could be generated when a capture plant is bypassed. In this case, steam used in the capture process would be diverted back to the power plant steam cycle to generate electricity. Critical areas of 'balance of plant' that must be appropriately sized to allow additional electricity to be generated and exported to the electricity network include the low pressure turbine, generator and switchgear. If this mode of flexibility is available then it could allow power plants with CO_2 capture to provide a number of services to the electricity network. These include peaking capacity and at least some response to changes in supply or demand elsewhere in the network.

Speed of response is likely to vary between plants depending on a number of factors. For example, Lucquiaud and Gibbins (2009a,b) suggested that different response times could be possible for different steam cycle configurations for post-combustion CO_2 capture. If a low pressure turbine is unclutched when a plant is operated with CO_2 capture, it can be maintained so that it can be brought back into service if the capture unit is bypassed leading to extra steam being available to generate power. In this case, it is expected that 20–30 minutes would be required to start, synchronise and reclutch the turbine. Other options that use valves to redirect steam between the steam cycle and the capture unit have significantly improved dynamic response. If the pressure is allowed to float where steam is taken out of the steam cycle, typically from the crossover between the intermediate and low pressure turbines, then response would be expected to take tens of seconds to a few minutes since there will be some temperature changes within the steam cycle as flows change. It is also possible to use throttling to control steam flows and pressures. Although this latter approach can incur an efficiency penalty of the order of 0.5 percentage points, it is expected to allow very fast response. This is because there are then no significant temperature changes within the intermediate pressure and low pressure steam turbines as steam extraction rates are changed.

Although it seems likely that there could be electricity system benefits associated with bypassing a post-combustion capture system, one disadvantage of this approach is the associated increase in CO_2 emissions at the plant. This would not, however, lead to a global increase in CO_2 emissions if the plant is operating in a jurisdiction with a cap on CO_2 emissions or emissions performance standard including that plant. It could, however, be undesirable from an economic perspective or be disallowed under particular legislation. Some legislators may be inclined to introduce legislation that limits CO_2 emissions from individual plants over short timescales, with no allowance for averaging emissions. It should be noted, however, that CO_2 is a long-lived pollutant with global effects (Hansen and others, 2007) so this approach is likely to be inappropriate. Current typical schemes for trading of allowances for CO_2 emissions recognise this since they allow plants to comply with CO_2 emissions limit requirements on an annual basis. This is different to pollutants that have local effects (for example, oxides of nitrogen and sulphur) where limits for individual plants or within geographical regions that have limited or no scope for time-averaging of emissions are more likely to be appropriate, at least in some cases (Sorrel and Skea, 1999).

One option that could be used to improve operating flexibility with little or no increase in CO_2 emissions at the plant is solvent storage. Solvent storage takes advantage of the fact

Table 5 Some potential changes to power plant flexibility for post-combustion capture (Chalmers and others, 2007a)

Flexibility option or consideration	Description	Relevance to ancillary service provision and other aspects of plant behaviour
Start-up/shut-down time of CO_2 capture/compression equipment	A detailed understanding of changes to start-up and shut-down of plant is not yet included in the literature. It has been argued that power plant start-up/shut-down times should not be affected by the capture/compression system since they are not integral to the power generation process. It might, therefore, be possible for the base power plant to be fully operational and dispatching power before the capture system was available.	Might have some impact on plant ability to provide ancillary services. Additional start-up costs for extra plant components plus any payments for CO_2 emissions may also affect the generator's marginal costs enough to change their position in the merit order. This could alter operating decisions, particularly when costs are close to the market price for selling electricity.
Ramp rate of CO_2 capture/compression equipment when changing load	A detailed understanding of changes to ramp rates of plant is not yet included in the literature. Again it is possible that this need not constrain overall plant operation, as long as appropriate control systems are in place. Could also have improvements in ramp rates resulting from ability to divert steam taken to reboiler back into the steam cycle (or vice-versa).	Changes in ramp rate are relevant to plant ability to provide response capacity. If ramp rates can be improved by moving steam between the capture plant and the steam cycle, this could provide a low cost primary reserve measure. The rate of change of output would be expected to be similar to the rate at which valves were opened/closed, depending on the steam cycle design chosen and the impact of changes in steam flow on reboiler operation.
Part load operation of CO_2 capture/compression equipment	A detailed understanding of changes to part load operation of plant is not yet included in the literature. *See* Lucquiaud and others (2007) and Linnenberg and Kather (2009) for some initial work in this area.	Part load operation is relevant to ability to offer response services, due to costs associated with changes in efficiency compared with full load operation. Transport and storage systems must also be designed to accommodate part load operation, as with other modes of flexibility that affect CO_2 output.
Bypassing CO_2 capture unit	CO_2 is not captured but is instead emitted to the atmosphere. The vast majority of the capture energy penalty should be avoided since the energy-intensive solvent regeneration and CO_2 compression processes are no longer required.	Significant extra capacity could be made available to the network operator, depending on balance-of-plant constraints. As such, this could provide reserve capacity without requiring part-load operation of plants. Rapid shut-down and restart of a capture unit is, however, likely to be more challenging than part load operation.
Storing rich solvent, with associated additional regeneration later	CO_2 is removed from the flue gas as it is produced, but solvent regeneration and CO_2 compression are left until later. Most of the capture energy penalty is avoided when regeneration/compression is delayed. This energy penalty is then applied when additional solvent is regenerated (and the produced CO_2 is compressed) later.	As with bypassing the capture unit, when the capture penalty is avoided extra capacity can be made available to the network operator, depending on balance-of-plant constraints. When the capture penalty is increased during additional regeneration the minimum stable generation will be reduced which can have system benefits in some cases (*see* Table 4).
Fuel flexibility	Since combustion processes are not changed, it is expected that fuel flexibility will not be affected by adding post-combustion capture. Appropriate flue gas treatment will be required to remove any combustion products produced that might degrade the solvent.	As outlined in Tables 3 and 4, fuel flexibility can be important for energy security and, in some cases, plant risk management. Thus, it is useful if this is maintained when CO_2 capture is added. Also, there is potential for overall negative CO_2 emissions if biomass is used.
Variation in ambient conditions	Changes in ambient conditions can lead to relatively significant changes in power plant behaviour and performance.	Since there has been very limited work in this area, it is not yet clear whether any significant changes can be expected, when compared to current variations for power plants without CO_2 capture.

that in most, if not all, post-combustion capture processes the majority of the energy penalty is associated with processes that are not necessarily required to operate at the same time as power is generated and CO_2 is produced. CO_2 is still removed from power plant flue gases in the absorber, but rich solvent is sent to a storage tank rather than being regenerated immediately. Once additional electricity output is less valuable (for example, overnight) the stored solvent can be regenerated in addition to rich solvent being generated by current operations.

Gibbins and Crane (2004), Chalmers and Gibbins (2007) and Haines and Davison (2009) discussed this approach, but further work is required to develop detailed engineering designs, provide robust cost estimates for installing solvent storage tanks and optimise operating regimes for solvent storage systems. It may be also useful or necessary to develop approaches for continuing to have a minimal steam flow sent to the reboiler even when rich solvent is being stored, so that the system is kept warm. This could also be useful during bypass of a post-combustion capture system depending on the dynamic performance required by the electricity network operator or desired by the power plant operator. Other critical points to consider include whether degradation of stored solvent might be a particular problem and whether the capital cost for installing solvent storage tanks would be justified by expected revenues. Any changes to environmental permitting requirements for larger solvent inventories held on-site and the implications of additional solvent inventory for supply chains should also be checked.

Capture plant bypass or solvent storage could both be useful approaches to respond to peaks in electricity demand. In, at least, some jurisdictions it is likely that there will also be periods when coal-fired power plants with CO_2 capture are operated solely to provide back-up for other plants in the system that are not able to provide sufficient flexibility to the electricity network operator. These relatively inflexible plants will typically have much lower incremental costs of electricity generation. In this situation, it is likely to be valuable to the system operator to reduce the output from the power plant using fossil fuels so that maximum delivery of energy (electricity) from the generation options with lowest incremental costs is possible. As noted in Table 4, in this context the reduction in coal-fired power plant output associated with additional solvent regeneration could be helpful, at least from an electricity system perspective, since it effectively reduces the minimum stable generation of the plant. This reduced output can lead to more energy being dispatched by inflexible sources without compromising the provision of sufficient flexible generation to provide necessary ancillary services.

There is limited literature in the public domain on the performance of power plants with CO_2 capture operated significantly below their design capacity. Some initial results have, however, been published for a test unit operating on a slipstream taken from a pulverised coal fired unit at Esbjerg power plant. The CO_2 capture unit is able to produce 1 t/h of CO_2 when operating at full load. Feron and others (2007) reported results from deliberate part load operation of this CO_2 capture plant carried out during early plant operation. They demonstrated that their desired linear relationship between gas and solvent flow could be obtained. They found that CO_2 recovery increased at part load, although at very low loads CO_2 recovery is slightly lower (although still higher than at full load). Their explanation for this behaviour is that:

'In general a longer residence time of the gas and liquid in the column will improve CO_2-recovery. At very low gas and liquid flow rates, it is likely that maldistribution of the solvent will result in a reduction of the CO_2-recovery. The pilot plant might also not have achieved equilibrium conditions at low gas and liquid flow rates. In the stripper the increased residence times will lead to a deeper regeneration of the solvent and the lean loading decreases at lower liquid flow rates to a level of 0.2 mol CO_2/mol MEA.'

This suggests a number of areas where future work may be useful. Although the operators in this case chose to vary solvent flow rate in direct proportion to gas flow rate this need not be the case. Solvent flow rate could be deliberately maintained at high enough levels to avoid maldistribution in the column. It is then necessary to consider how this may affect the CO_2 recovery rate and capture plant energy requirements. For example, Linnenberg and Kather (2009) show that specific reboiler heat duty (measured in terms of energy required per tCO_2) varies according to the liquid to gas ratio (L/G) and that the minimum reboiler duty generally occurs at different L/G ratios for part load operation. Of course, part load performance of the steam cycle should also be considered for an overall assessment of plant performance. For example, Lucquiaud and others (2007) presented steam cycle analysis for fuel inputs in the range 70–100% of full design load for a range of cases.

Additionally, Knudsen and others (2007) reported selected results from the second 1000-hour trial at the pilot-scale unit at Esbjerg which was carried out from December 2006 through February 2007 using a standard 30wt% monoethanolamine (MEA) solution. During this trial, one test involved almost continuous running of the pilot plant for a total period of 550 running hours (from 15 January to 7 February) with the base power plant frequently changing load. This allowed information to be gathered on solvent consumption, build-up of degradation products and process stability. The pilot plant did not have an active control loop, so CO_2 capture levels fluctuated as flue gas composition changed, as a result of changes in load at the power plant. There were, however, 'no incidents or malfunctions' during the test period.

Finally, a relatively new but developing literature has also begun to emerge that uses dynamic modelling to explore the performance of post-combustion capture units. Kvamsdal and others (2009) and Lawal and others (2009) report dynamic models of absorbers operating on gas and pulverised coal flue gas respectively. Ziaii and others (2009a,b) present a dynamic stripper model for a coal-fired power plant. The author is not aware, however, of any dynamic models in the public domain that include a full capture plant (both absorber and stripper columns). Further work is also required to integrate capture plant models with CO_2 compression and the power plant steam cycle. More complete models are, however, often included as areas for further work in papers focusing on work on individual capture plant components.

4.3 Oxyfuel capture

In the most widely discussed approach involving oxyfuel capture, pulverised coal is burned in a mixture of pure oxygen and recycled flue gas, as shown in Figure 6. The discussion in this section will focus on air-like oxyfuel plant designs, although it is possible that alternative designs with very different operating characteristics will be developed for successful commercial deployment in the future. This could include plant designs that combine oxy-firing with fluidised bed combustion. As with post-combustion capture, a number of reasonably detailed studies of plant design options are available in the literature. These include work commissioned by the International Energy Agency Greenhouse Gas R&D Programme (IEA GHG, 2005b) and a study completed within a programme of research that was part-funded by UK Government (Panesar and others, 2007). For near-term deployment, it is generally expected that oxygen will be produced using a cryogenic air separation unit. Research to develop high temperature ion transport membranes for separating oxygen from air is also under way. This could significantly reduce the energy penalty associated with air separation (IPCC, 2005; Allam, 2009).

As nitrogen is not present, the flue gas from an oxyfuel boiler has a significantly higher CO_2 content than flue gas from an air-fired boiler. Thus, the treatment of flue gases after the combustion processes does not require chemical solvents. Instead, impurities in the CO_2 stream can be removed during the compression and drying process. Flue gas recycle is required (in typical current 'air-like' oxyfuel concept designs) to moderate flame temperatures in the boiler due to material constraints and also to entrain pulverised coal in the mills and transport it to the burners. As with other plants, safety is critical in determining acceptable modes of operation for oxyfuel power plants. One particular concern for these plants is identifying appropriate measures to ensure that mixtures with high oxygen concentrations, which could lead to explosions, do not accumulate including during start-up, shut-down and load changes.

For typical air-like oxyfuel concepts it is generally accepted that start-up on air will be the standard operating procedure. Once combustion is stable, the boiler will then switch to firing oxygen. Initial burner tests have suggested that mass flows of air, oxidant and flue gas could be stable within 20–30 minutes of the start of the switchover process (Kluger and others, 2009). It is likely, however, that some flue gas species will take longer to reach steady levels. New burner concepts are also under development that could significantly reduce the time taken to switch from air to oxy-firing. For example, University of Stuttgart and ALSTOM are developing a new burner which is expected to allow an air to oxygen switch to occur in less than 15 minutes (Grathwohl and others, 2009). Plant operators will need to include the costs associated with emitting CO_2 to the atmosphere within their decision-making processes, as discussed in the previous section considering post-combustion capture.

One significant difference between post-combustion and oxyfuel capture is that bypassing all of the components of an oxyfuel system that have a significant energy penalty requires changes upstream of the capture unit. This is because the air separation unit makes a significant contribution to the energy

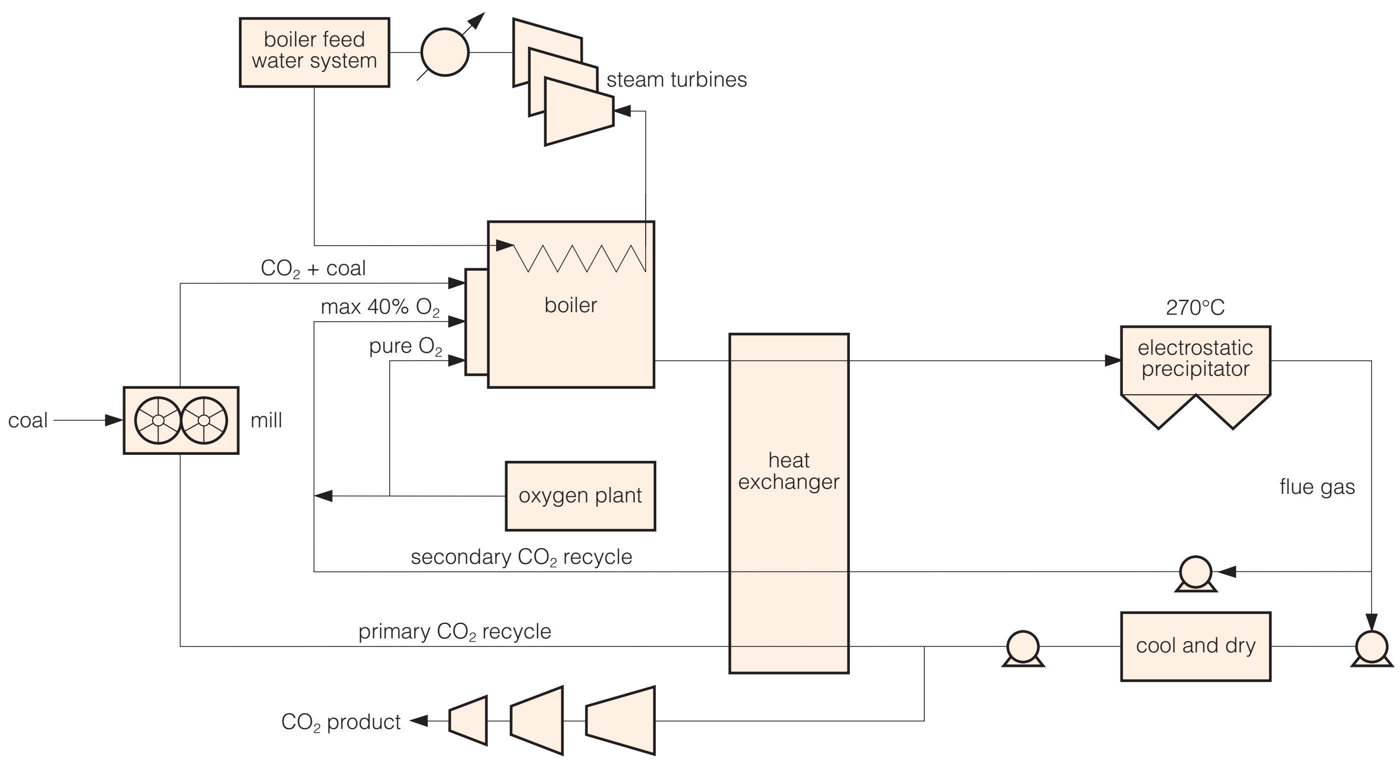


Figure 6 Schematic diagram of an oxyfuel process at a pulverised coal power plant (IEA GHG, 2005b)

penalty for oxyfuel capture. A scoping study on operating flexibility of power plants with CO_2 capture commissioned by the IEA Greenhouse Gas R&D Programme (IEA GHG, 2008) cites Sarofim's (2007) analysis that roughly twice as much of the original plant output could be recovered by substituting air for O_2, compared with only bypassing the CO_2 compression system. It has, therefore, been suggested that it is highly unlikely that power plant operators would find it economically attractive to bypass the CO_2 compression system alone (Santos, 2009). Another practical consideration for bypassing CO_2 compression only would be ensuring safe release of the flue gas stream produced by the oxy-combustion process. It would be necessary to address any safety concerns associated with releasing a CO_2-rich gas to the atmosphere, unless an appropriate approach to diluting the CO_2 concentration of the flue gas or ensuring plume buoyancy could be identified.

Further work is needed to improve understanding of plant start-up times and likely ramp rates (that is time taken for power plant output to change between two steady-state outputs). Current typical applications for air separation units and CO_2 compression have much less demanding specifications for these parameters than could be seen for coal-fired power plants in future electricity markets. Vendors are, however, exploring methods to reduce or remove any constraints that might be imposed on base power plant (that is boiler and turbine island) performance by additional components associated with oxyfuel power production. For example, White and others (2009) reported that a typical air separation unit ramp rate is around 1% per minute, but this can be increased to 3% per minute if this is included in the design specification supplied by a particular customer.

White and others (2009) also suggest that liquid oxygen storage could be used to further improve ramp rates available from air separation units. It is, of course, necessary to generate liquid oxygen that has been stored to be used later. This means the energy penalty associated with the period of generating liquid oxygen that is stored for later must be appropriately considered when the attractiveness of this option is analysed. It is possible, however, that this approach may be necessary for plant start-up times for oxyfuel plants to match air-fired pulverised coal units (Panesar and others, 2007). It has also been suggested that gaseous oxygen storage will be possible and that this approach would be more energy efficient than storing liquid oxygen (Santos, 2009).

For both liquid and gaseous oxygen storage, there are some obvious analogies between solvent storage for post-combustion capture and oxygen storage for oxyfuel plants (and integrated gasification combined cycle plants, *see* Section 4.4). A smaller change in output is possible with oxygen storage alone than with solvent storage for post-combustion capture since the CO_2 compressor load is not automatically avoided for oxygen storage, but it is for solvent storage. As with solvent storage for post-combustion capture, further work is required to develop the engineering details of this system, including addressing concerns that non-continuous operation of the air separation unit may be problematic (Haines and Davison, 2009).

As with post-combustion capture, a limited literature reporting dynamic modelling of plant performance is available in the public domain. A scoping study on power plant operating flexibility with CO_2 capture commissioned by the IEA Greenhouse Gas R&D programme (IEA GHG, 2008) identified studies reported by Yamada and others (1999) and Imsland (2006). Yamada and others provide an illustration of trade-offs that can be important in making power plant operating decisions. They suggest that there may be occasions where more air separation units may be run than are needed to meet current oxygen demand to avoid costly start-ups. This operating approach might also be considered to improve other aspects of plant flexibility. Further work is, however, required to consider how intelligent use of oxygen storage may affect the results obtained.

Finally, it is also relevant to consider fuel flexibility for power plants with oxyfuel capture. Fundamental work to understand oxyfuel combustion is ongoing, but it is also clear that a much broader range of oxidant concentrations will be possible for oxyfuel combustion than for air combustion (Kluger and others, 2009). This might, therefore, allow oxyfuel power plants to burn a broader range of fuels than air-fired plants. Cofiring of biomass with coal should also be a possibility, as with air-fired combustion. If a high enough proportion of the fuel mix is biomass it could, therefore, be possible for an oxyfuel power plant to have 'negative emissions'. In this case, the amount of CO_2 removed from the atmosphere as biomass grows would be greater than the CO_2 released to atmosphere by generating power with CO_2 capture.

4.4 IGCC with pre-combustion capture

The most developed pre-combustion CO_2 capture option for coal-fired power generation is the use of physical solvents at an integrated gasification combined cycle (IGCC) plant, so this option will be the focus of this section. As illustrated in Figure 7 (Provost and others, 2008) IGCC plants use gas generated from coal gasification to fuel a combined cycle power plant. Coal gasification produces a synthesis gas which is a mixture of carbon monoxide and hydrogen. When CO_2 capture is used, the carbon monoxide in the synthesis gas is converted to CO_2 and more hydrogen in a shift reaction. CO_2 is then separated from hydrogen using a physical solvent. The produced CO_2 is cleaned and compressed for transport to safe storage. Hydrogen can then be used for power generation, or for some other purpose.

A scoping study on operating flexibility if power plants with CO_2 capture commissioned by the IEA Greenhouse Gas R&D Programme (IEA GHG, 2008) reported 'no mention having been found relating to the operability of pre-combustion capture' in their literature review. There could be a number of possible reasons for this gap. Since a very limited number of IGCC plants have been constructed, there has been little opportunity or motivation to develop an understanding of base power plant operating characteristics in this case, although there is some literature in this area.

A number of choices must be made by investors in IGCC

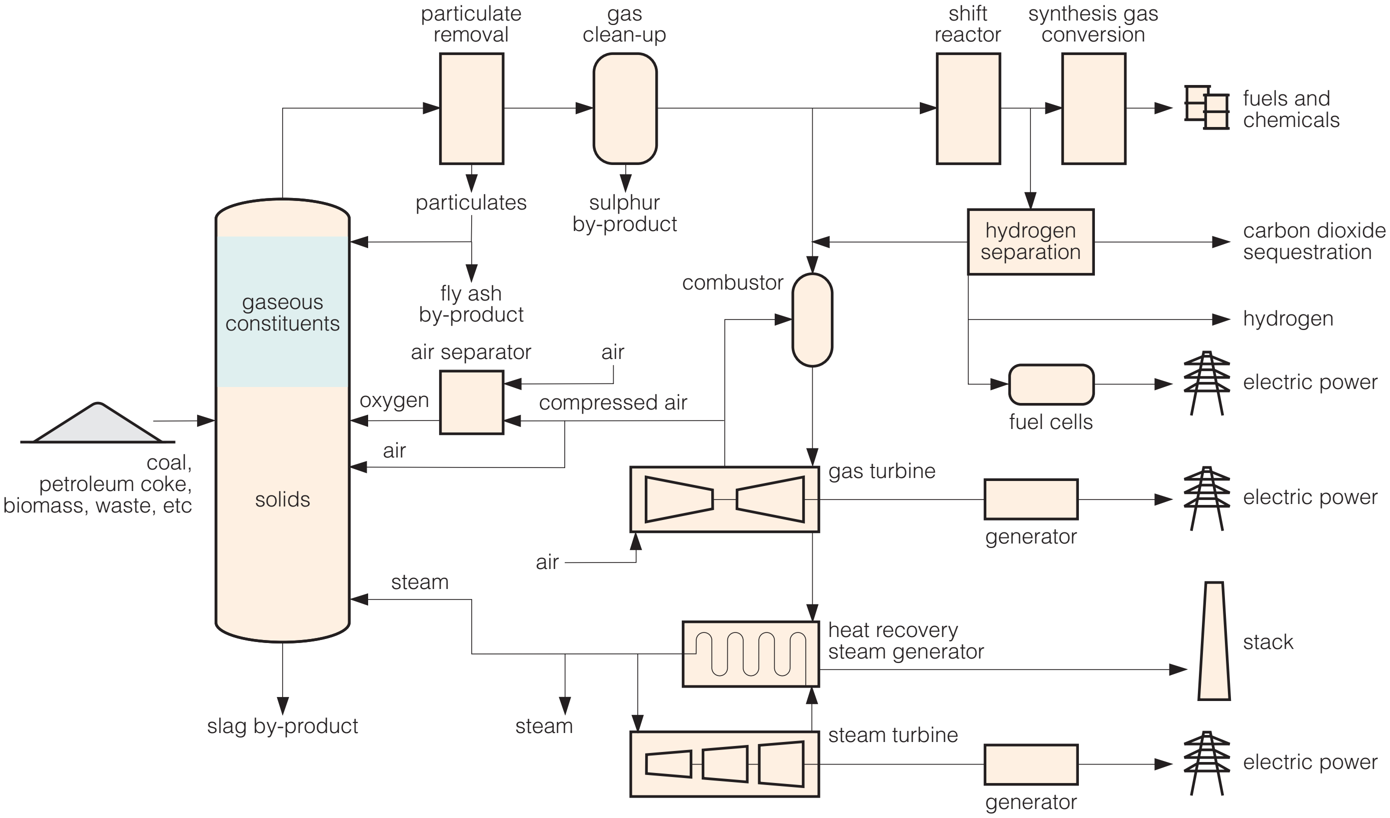


Figure 7 Schematic diagram of an IGCC process with pre-combustion capture (Provost and others, 2008)

plants, including which gasification technology they wish to use and how tightly integrated different plant components will be. For example, Norris and others (2004) reported results from a techno-economic evaluation of IGCC without CO_2 capture. They analysed cases with three levels of integration between the gasifier and the gas turbine. They also considered options for hydrogen production to keep the gasifier warm during periods when the gas turbine is not producing electricity.

For the cases they considered, Norris and others (2004) concluded that full integration between the gasifier and gas turbine was the preferred case in terms of operating income. They noted, however, that this approach reduced operating flexibility and argued that:

'The higher the efficiency of the plant, the less relevant operational flexibility becomes, since high efficiency plant will run base load more often and for longer than lower efficiency plant (if all other factors are equal, such as fuel price, etc). The higher efficiencies of highly integrated IGCCs can offset the cost associated with the longer start up times of the gasifier, due to the increased likelihood of base load running).'

Since this report has written, typical projections for future electricity mixes have changed. As discussed in Chapter 3, it seems likely that there will be increasingly limited opportunities for power plants firing fossil fuels to operate in the baseload. Instead, other low carbon electricity generating costs are expected to operate whenever they are available. In some, and possibly many jurisdictions, this could leave all coal-fired power plants with a requirement to operate flexibly or not at all.

The potential to use interim storage of syngas or hydrogen appears to be a promising approach to provide variable output from IGCC plants, but without any need for flexible operation of the gasifier. Newcomer and Apt (2007) assessed the value of syngas storage for an IGCC without capture and concluded that it is profitable to store syngas overnight and build an additional turbine to generate additional electricity during the day when electricity prices are higher. A study commissioned by the IEA Greenhouse Gas R&D Programme (IEA GHG, 2007) reported work considering the potential value associated with co-production of hydrogen and electricity for IGCC with CO_2 capture which concluded that:

'Hydrogen and electricity can be readily co-produced in gasification plants. Simple modifications to the plant design enable the hydrogen:electricity ratio to be varied between 1.3:1 and 3.1:1 on an energy basis, while continuing to operate the coal gasifiers at full load.'

This approach was explored further by Davison (2009) who focused particularly on the use of gasification-based hydrogen production with storage to balance variable electricity output from wind. He concluded that the use of coal gasification for hydrogen production, coupled with underground buffer storage of hydrogen and independent combined cycle power generation could provide 'substantial advantages' when compared to other approaches for generating electricity from fossil fuels to complement electricity generation from wind. He noted, however, that further work is required to establish where appropriate geological storage for hydrogen is available. Alternative methods for hydrogen storage are also an active area for research and development.

Davison (2009) also notes that the use of coal gasification for hydrogen production could be a useful option to significantly reduce the use of natural gas for power generation. One related option that could be of interest in some jurisdictions is to deliberately locate an IGCC plant near a natural gas combined cycle power plant. If both combined cycle plants are operated at part load during periods of low electricity demand then they could both be fuelled by the gasifier while they are operating at part load, assuming that a dual-fuel turbine is installed at the natural gas combined cycle plant. This would minimise the use of natural gas and also avoid its use during periods when sometimes relatively significant energy penalties are observed due to part load operation.

Another alternative could be to provide some flexibility in IGCC electrical output could be to use oxygen storage. This would follow similar principles to those discussed in the previous section for oxyfuel plants. This will only be possible, however, if the degree of integration between the gasifier and gas turbine at the plant allows this. Since IGCC plants typically use much less oxygen per unit of electricity than oxyfuel plants, this approach would provide a significantly smaller relative change in output than could occur if oxygen storage is used at an oxyfuel plant.

Some flexibility in syngas production from gasifiers is also possible, especially if engineers are asked to consider this within plant design. If syngas production cannot be varied quickly enough to match the required changes within the electricity network then it may be possible to use natural gas to supplement the rate of change of hydrogen production, in addition to the potential use of interim storage. Manufacturers will typically develop site-specific guidance on allowable mixes of fuels for a particular combustor based on a number of factors, including the design fuel. Existing IGCC plants are able to fire both natural gas and syngas, although the majority of operating hours with natural gas firing are typically due to forced outages elsewhere in the plant, including as outlined by Garcia Pena and Coca (2009). Burners for firing multiple fuels are also currently less advanced than those typically used at modern natural gas combined cycle power plants.

Additionally, it should be noted that gasifiers are often considered to have good flexibility in fuel feed. It is important, however, to consider differences in feed equipment and fuel handling which may limit the range of fuels that could be used by any particular gasifier. Fuel changes can, of course, also be expected to lead to changes in the useful energy available in the syngas produced by the gasifier.

One important activity to complement techno-economic desk-based studies and reviewing experience at real IGCC plants is the development of simulations that allow more operating options to be considered. Provost and others (2008) present a generic process design model with associated control strategies for an IGCC plant with CO_2 capture. It is intended that the simulator developed in this project led by the US Department of Energy National Energy Technology Laboratory can be used for operator training and research and development activities exploring different plant configurations and equipment options. Bhattacharyya and others (2009) report some challenges and initial results from the simulator with further work likely to include transient analysis and a study on controllability.

Overall, since there has been very limited experience with IGCC power plants, even without CO_2 capture, it is not yet clear what base plant operating flexibility could be obtained. For IGCC plants with CO_2 capture it seems likely that the most frequently used modes of flexible operation could involve storing or changing the use of hydrogen-rich fuel gas, possibly including supplying the gas to a non-power generating application. Oxygen storage might also be feasible for oxygen-fired IGCC plants but would be expected to have a smaller impact on overall plant performance than is observed with oxyfuel plants since significantly less oxygen is required.

It is not yet clear how differences in operating modes to be considered for different CO_2 capture technologies will affect their relative operating performance in technical or economic terms. One obvious difference to consider, however, is that optimum operating choices for IGCC plants might require a good understanding of both hydrogen and electricity prices (for providing energy and ancillary services). Although some plants burning pulverised coal may be able to sell by-products such as ash into niche markets, they do not have a potentially significant revenue stream from selling hydrogen to take into account.

4.5 Summary

This chapter has provided an overview of technical factors to consider when characterising power plant operating flexibility with CO_2 capture. It has also outlined current knowledge of likely operating options for each of the three CO_2 capture technologies closest to commercial deployment at coal-fired power plants: post-combustion capture with aqueous solvents, pre-combustion with physical solvents, and 'air-like' oxyfuel combustion. CO_2 compression, transport and storage are not discussed in detail. It is expected, however, that there would be no barriers to flexible operation of power plants due to compression, transport and storage systems, although some care may be required in designing systems downstream of the CO_2 capture unit to handle variable flows.

Post-combustion capture with aqueous solvents can be undertaken with relatively few changes to an industry-standard pulverised coal fired power plant with air combustion. Typical designs include heat integration between the power plant steam cycle and CO_2 capture and compression. This is not, however, required for electrical energy to be generated and delivered to the electricity network. Two operating modes that could be used to provide additional capacity to the network are bypass of the capture unit and temporary storage of 'rich' solvent for regeneration at another time. Depending on any 'balance of plant' constraints, these approaches could make a significant contribution to peaking capacity within some electricity systems. Further work is required to determine whether the costs associated with making many of these options available would be outweighed by the benefits. Further work is also required to establish the transient behaviour of power plants with post-combustion capture. Depending on the choice of steam cycle design, it is possible that relatively fast response could be available.

For oxyfuel power plants, it is important to ensure that all operating modes do not allow accumulation of oxygen. It is, therefore, expected that ‘air-like’ oxyfuel plants that are closest to commercial deployment will always start in air-firing mode. Once stable combustion is achieved, the plant would then switch to oxygen firing. Initial burner testing suggests that switchover between air and oxygen firing can be achieved in less than an hour, with further work aiming to reduce switchover times to 15 minutes. An important operating option for oxyfuel power plants could be storage of oxygen in liquid or gaseous form. This interim storage option could be important to improve plant ramp rates by supplementing changes in oxygen production that are possible with an air separation unit alone. The use of oxygen storage would, however, provide a smaller change in output than would be expected for solvent storage at a power plant with post-combustion capture. In the oxyfuel case, a penalty associated with CO_2 compression would still be incurred while oxygen was stored. This would be avoided during periods when rich solvent was stored.

Pre-combustion capture using physical solvents at an integrated gasification combined cycle plant has very different characteristics to the options based on pulverised coal combustion discussed above. It seems likely that the most practical options for providing operating flexibility at these plants will involve interim storage of hydrogen (or syngas in cases where CO_2 capture is not used). This allows continuous operation of the gasifier, while taking advantage of the flexibility of the combined cycle power plant. It will be necessary, however, for investors to consider trade-offs between operating flexibility and efficiency. It is expected that increased integration could improve efficiency, but would reduce flexibility. Additionally, gasifiers are often considered to have good fuel flexibility. For a single gasifier to be able to use a range of fuels effectively it will be necessary to design appropriate fuel handling and feed equipment.

5 Economic analysis of flexible operation

Both investment and operating decisions take a broad range of factors into account once key technical constraints have been established. This chapter, therefore, outlines some critical issues for economic analysis of power plants with CO_2 capture. It begins by reviewing some factors affecting the cost and value of electricity. Key questions to consider in economic analysis for investment decisions and analytical techniques that may be relevant are then introduced. Finally, some additional considerations related to investment risk are outlined. Although no quantitative results are reported in this chapter, some illustrative examples are included in the next chapter.

5.1 Factors affecting cost and value of electricity

One obvious consideration when making an investment decision is the cost of the options available including initial capital, decommissioning, operations and maintenance. When factors affecting power plant costs are identified, it is useful to consider two distinct groups that affect investment decisions. These are (i) factors that can make it impossible to use a particular technology regardless of how much the investor wishes to pay and (ii) factors that vary from site to site, but that do not tend to lead to obvious, absolute constraints on which technology can be deployed. A summary of some key considerations is given in Table 6 for coal-fired power plants built with and without consideration of CO_2 capture.

A comprehensive discussion of the range of impacts that variations in the factors identified in Table 6 can have on ultimate plant costs is beyond the scope of this report. As an illustrative example, one plant performance parameter that is often discussed when site-specific variations are considered is the condenser pressure, with its associated implications for power plant efficiency. This can be affected by both ambient conditions and any constraints on the plant cooling system, such as limited water availability. Henderson (2007) reported results for a series of case studies carried out by the IEA Clean Coal Centre which illustrate this. This includes Majuba which is a subcritical plant burning high ash bituminous coal in an area of water shortage in South Africa. Units 1–3 use dry cooling, but units 4–6 have wet cooling. The difference in performance between the two sets of units is significant. Units 1–3 have a design condenser pressure of 16.6 kPa and a design LHV efficiency of 35% net. This can be compared to 6 kPa design condenser pressure and 37% net design efficiency for units 4–6. Another typical difference between sites is the availability of lower temperature cooling water at coastal plants, with an associated decrease in condenser pressure and increased plant efficiency, as illustrated in Figure 8.

Many engineering studies concentrate on establishing costs of electricity generation. Real investment and operating decisions will also consider a number of other factors. For example, a review of investment in electricity generation undertaken by the UK Energy Research Centre highlighted

Table 6 Summary of some key considerations for determining power plant cost and technology choice (Chalmers and others, 2007b)

	Factors that can restrict options available (regardless of how much an investor could pay) as well as changing cost	Factors that change cost of electricity sold but that are unlikely to lead to a particular plant design option being technically impossible
Coal-fired power plant with no CO_2 capture considerations	• Type of coal available • Water availability • Availability of raw materials for any required pollution control measures • Planning (and other) regulations • Lack of infrastructure (and not able to build it) • Appropriate land available for reasonable plant layout	• Labour availability/cost • Cost of commodities and components (for construction and operation) • Financial factors, including tax regime and interest rates • Ambient conditions, particularly temperatures • Policy factors, including support mechanisms
Coal-fired power plant with CO_2 capture considerations (including capture-ready plants that do not have capture installed on day 1, but are planned to be suitable for retrofit)	• Access to viable route for CO_2 transport to safe geological storage (or use) • Availability of additional raw materials for CO_2 capture • Larger land area required, including allowance for capture plant and access for undertaking retrofit for capture-ready designs	• As above, but costs likely to have different sensitivity to external changes. For example, more components to construct and run, with more commodities likely to be involved. Also possible that different project risks might lead to a different financial structure.

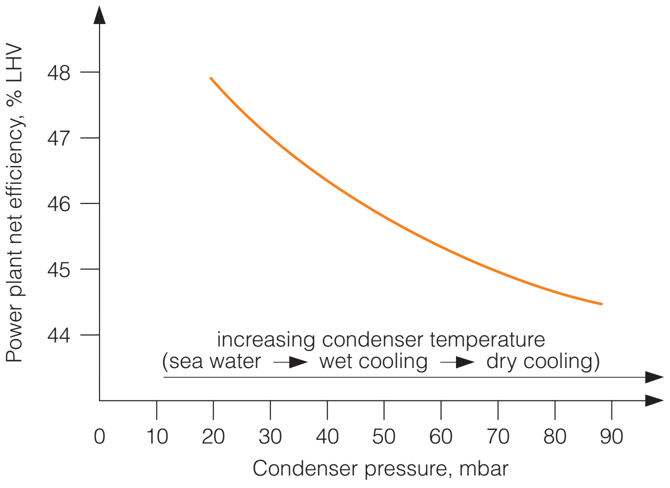


Figure 8 Variation in plant (LHV) efficiency with condenser pressure for an ultra-supercritical coal-fired power plant (Kjaer, 1993)

the need to consider risk and expected return on an investment (Gross and others, 2007). This is obvious when a financial investment decision is understood at its most basic level: as a decision to spend money now with the aim of receiving future cash flows. Table 7 summarises some key factors affecting power plant revenues and uncertainties associated with them. Methods for including risk in economic analysis are discussed in Section 5.3.

Most of the factors identified in Table 7 are interrelated. As with the costs identified in Table 6, a detailed discussion of their impacts on power plant revenue and investment decisions is beyond the scope of this report. It is useful, however, to briefly consider results obtained in other work that has considered the impact of uncertainty and risk in power plant revenue. For example, in May 2007, the Technology and Policy Assessment function of the UK Energy Research Centre published a report that reviewed the literature available on the role of costs, incentives and risks in investment in electricity generation (Gross and others, 2007). This study concluded that market conditions and structure were both important factors in determining electricity price volatility and related price risk.

In a working paper supporting the main report, Blyth (2006) explores the costs and net present value of different technologies for a range of scenarios based on assumptions used in a UK Government review of energy policy (DTI,

Table 7 Summary of some key factors and associated uncertainties in determining power plant revenue and investment decisions (Chalmers and others, 2007b)

Factor	Some sources of uncertainty and impact on revenue
Price variations in electricity selling price and by-product selling/disposal price*	Price variations in various, relevant commodities and services can be expected. Sometimes companies will avoid this risk by using long-term contracts, although this will have associated contractual risk. Changes in price will ultimately be seen as a change in plant revenue as cash inflows (or outflows for cost changes) will change.
Local, national and international policy and regulation	Various forms of policy and regulation can affect both costs and revenues of power plants. This can include taxation and limits on plant operating procedures, for example. Due to typical policy-making processes, changes can be very difficult to predict so represent a significant uncertainty in power plant investment (and other) decisions.
Electricity market structure	Methods for arranging financing for power plants and paying for their operation vary significantly between and within some countries. The uncertainties and risks associated with changes in power plant operations are held by different stakeholders in different jurisdictions so plant revenue uncertainty (and expected profits) will also vary.
Electricity network physical structure	The physical network connecting power generators to consumers can also affect power plant revenue. For example, transmission constraints can have a significant effect in determining which power plants are used to supply demand at a particular time. This has implications for power plant operating pattern and utilisation factor, with revenue (and cost) impacts.
Construction time	The construction time and, hence, time between initial capital investment and the beginning of revenue generation can have a marked impact on power plant economic performance when whole life revenue and profits are analysed, as in the sensitivity analysis of Roques and others (2006).
Portfolio diversity within an individual company	Often power plant operators will have more than one plant generating electricity within an electricity network. Since revenues tend to vary differently in response to different changes in many of the factors outlined above, operating companies will tend to invest in a range of technologies to reduce their overall exposure to risk and uncertainty.

* Also, similar uncertainty for variation in power generation cost associated with commodity price variations

2006). He concludes that revenue uncertainty makes a significant contribution to the expected value of an investment. In competitive markets, some power generation options (generally gas or coal, depending on local market conditions) will have a significant role in setting the selling price of electricity. Other plants will then have to 'take' the price set by those 'marginal' plants within the electricity generating mix. For the UK scenarios considered by Blyth, gas power plants were price setters for the majority of cases with coal plants setting the price in around 1/3 of the cases considered. As a result, he concluded that 'gas prices are to a large extent incorporated into the [UK] electricity price'. Thus, possibly counter-intuitively, gas-fired plants in the UK have relatively low risk associated with changes in gas price since their gross margin (the difference between revenue and cost) does not vary significantly with changes in gas price. Other plants that must take the price set by the gas plant are, however, exposed to gas price risk.

5.2 Evaluation of flexibility of power plants

Economic evaluation of flexibility of power plants requires a reasonable understanding of options that can be translated into income for plant operators (or some other relevant factor depending on the purpose of the analysis, such as operating costs/savings for network operators). In some cases, flexible operation may be valuable since plant operators are able to respond to changes in the wholesale electricity price received for produced electricity. For example, if a supercritical coal-fired plant with post-combustion capture is able to bypass the CO_2 capture unit then this may be an economically attractive option when electricity prices expressed in \$/MWh are around 2-3 times higher than CO_2 prices expressed in \$/tCO_2 (Gibbins and Crane, 2004; Chalmers and Gibbins, 2007). This analysis was based on cases where only electricity selling prices affect operating decisions and there are no balance of plant constraints restricting plant output when the capture plant is bypassed. For example, if CO_2 prices are 40 \$/tCO_2 then it is likely that bypass could be valuable for wholesale electricity prices of 80–120 \$/MWh or higher.

In many networks it seems likely that any value associated with providing ancillary services could be a significant factor in determining the economic worth of flexible operation. A detailed exploration of the various methods used to determine the costs for providing ancillary services in electricity networks and markets is beyond the scope of this report. This information and some understanding of the various methods that can be used by network operators to pay for these services is, however, required to determine the likely value of being able to provide an ancillary service in any particular network. Instead, this chapter focuses on identifying some areas that should be considered in developing a better understanding of potential impacts of CO_2 capture on power plant operation and revenue, and particularly power plant flexibility when providing ancillary services. Table 8

Table 8 Some potential economic impacts of ancillary service provision (Chalmers and others, 2007a)

Some features of ancillary services with direct financial consequences	Some potential financial consequences
Reduced efficiency associated with part load generation	Particularly relevant for spinning reserve, this implies increased fuel cost (and CO_2 emissions, possibly with associated costs).
Reduction of component life and/or increase in maintenance requirements (could be relevant for off-design operation for spinning reserve or increased frequency of start-up/shut-down for standing reserve)	This implies increased plant lifetime costs to cover early replacement of affected components and/or additional maintenance. In an extreme case, plant operating life might be reduced if component replacement or additional maintenance is not economically viable. However, when plant remains online to provide ancillary services when it would otherwise have stopped operating, this represents a potential benefit to the plant owner since a shut-down/start-up cycle is avoided.
Plant operation is sub-optimal based on merit order considerations alone	This could be reduced output (as happens during part-load operation) when a plant would otherwise be operating at full load. This could lead to lost profit for the plant operator. Another example is when a plant operates to provide ancillary services, but would not be used otherwise. This could lead to an increased selling price of electricity, depending on the electricity network that the plant is operating within.
Changes in frequency of start-up/shut-down, with associated costs	In addition to the potential reduction in component life discussed above, start-up and shut-down have particular costs associated with them. These include the requirement to burn fuel in sub-optimal conditions with associated increases in costs and emissions.

identifies some costs to plant operators which could be experienced by plant operators when they offer ancillary services to an electricity network. Some questions for further analysis, and techniques that could be used to address them, are then outlined.

For the purposes of some analyses, it is also important to consider how services which are not given their full value by markets or other payments made to power plant operators can be included. Such analysis may consider a range of power plant options from differing viewpoints (that is not just a power plant operator perspective in a competitive market that is expected to seek maximum value within the market(s) considered). One classic example of this is the cost of emitting CO_2. Although a market value has been assigned to CO_2 emissions for some operating environments, many would argue that this significantly underestimates the 'social cost' of CO_2. The social cost might be appropriate to use for a study considering the environmental impacts of power plant operation from a societal perspective (AEA Technology, 2005).

Understanding the economic value and cost of potential changes to power plant behaviour when CO_2 capture is added will be crucial in developing a better understanding of the impacts of capture on power plant performance and operations. Some particular questions which should be explored are:

- How does CO_2 capture affect the operation and economic viability of power plants (and how does this compare to other options for power generation using fossil fuels)?
- Is the capital expenditure required to provide solvent or liquid oxygen storage justified by potential revenues?
- Is the optimum timing for retrofit of CO_2 capture to capture-ready power plants affected by the revenue streams that could be generated by flexible operation of the retrofitted plant?
- How valuable would the option to bypass the CO_2 capture unit be under different market conditions?
- How does the flexibility offered by coal-fired plants compare with other options for flexible generation or use of electricity?
- How is the value of flexible operation to provide ancillary services changed when the mix of technologies included within the network varies?

Many questions such as these can be identified relatively easily. Appropriate techniques for economic analysis to provide answers which reflect real market behaviour accurately enough to provide useful insights may be more difficult to identify. For example, further work is needed to develop reliable estimates of the costs and benefits associated with different changes to power plant behaviour. Accurate estimation of potential capital expenditure to improve plant flexibility is also difficult. Detailed engineering studies are typically required if uncertainty in an estimate is to be minimised. If a relatively low uncertainty is obtained this will, however, tend to indicate that the estimate has limited validity in terms of the sites it is applicable to and the time period that the cost is likely to be accurate or guaranteed for. A brief review of some techniques that could be useful to handle uncertainty in analysis of power plant economic performance with CO_2 capture is included in Chalmers and others (2009b).

One key challenge in economic analysis is to include sufficient detail to model the impact of short-term operating decisions in the context of a typical 20–30 year investment life. For example, models that simulate the merit order or economic dispatch of power plants within a particular electricity system are typically able to provide useful insights into hour-by-hour operating decisions (for example, Cohen and others, 2008; Wise and Dooley, 2009). They are, however, generally run for no more than a few years since it can be difficult to determine the relatively detailed input data required for longer periods. CCS has also been included in some larger whole systems studies that are run for the entire economic life of a power plant (*see* Gerlagh, 2006). The modelling techniques that are typically used in these studies are generally not well-suited to including detailed consideration of hour-by-hour operating choices. Some modelling approaches, however, aim to include short-run detail over an investment lifecycle. For example, Caselles-Moncho and others (2006) use a dynamic simulation approach to look at economics of coal plant with FGD in the Spanish market. In addition, a number of specialist electricity investment planning tools have also been developed, such as WASP (Kellas, 2000).

It is also likely that techniques that have been developed in other disciplines could be useful in this context. Two possibilities are Monte Carlo Analysis and portfolio theory. Monte Carlo analysis is a well-established approach for quantitative risk assessment (Vose, 2000). Portfolio theory has been developed in financial economics (Awerbuch and Berger, 2003). The author is not aware of any studies using either of these approaches to assess CCS operating economics. There are, however, some studies that focus on other electricity generation options that may provide some useful insights. For example, Allan and others (1998) propose a Monte Carlo simulation approach for modelling scheduling of hydro pumped (electricity) storage. Doege and others (2006) consider the valuation of flexible operation within the context of risk management of power portfolios, also using the example of dispatch of a hydro pumped storage plant.

5.3 Considering risk in investment decisions

This chapter has outlined a number of factors affecting power plant cost and revenue. Analysis of investment decisions also needs to consider a number of other issues, including the risks associated with any particular investment. A number of areas can be identified that should be explored in trying to understand the risk profile of a CO_2 capture project (or portfolio of projects). For example, if CO_2 capture systems can be operated flexibly in response to CO_2 price signals, these plants could be significantly less exposed to risks associated with carbon price volatility. Similarly, for plants that are able to have CO_2 capture retrofitted, it is expected that some of the risks associated with potential changes in policy to reduce CO_2 emissions from power plants should be mitigated since the plant could be retrofitted in response to increased carbon price (IEA, 2007). This reduces the risk that the plant will become a 'stranded asset' that is unable to generate any income as climate change policy develops. For analysis of CO_2 capture within portfolios, it will also be important to understand how plants operating with different CO_2 capture techniques respond in similar situations. This is needed to explore whether choosing to deploy a range of CO_2 capture technologies across a power plant fleet could help to diversify risk.

Different stakeholders involved in deployment of power plants with CCS will be exposed to different costs, benefits and risks. They will, therefore, have different views of what is valuable and what investment should be undertaken. The discussion here will focus on the investor perspective. Obvious areas for further consideration include exploring how policy-makers and regulators may use or adapt the techniques highlighted here. In particular, additional considerations are likely to be required in any analysis that is intended to inform actions that are designed to alter investor choices so that they reflect wider societal priorities, such as controlling environmental damage and ensuring security of supply.

When a company decides whether it wishes to make an investment and how capital could be raised to finance it, it is likely to consider a number of factors in its analysis. These will normally include what return it wants on capital invested and what level of risk it is willing to accept for a potential return. Regardless of the required return and acceptable risk, all companies must choose an appraisal metric (or several metrics, if appropriate) to determine how capital should be deployed. Although the ultimate decision should always rest with human decision makers, a number of quantitative metrics can be used. Table 9 summarises four of the most commonly discussed approaches.

Lumby and Jones (1999) conclude that payback period and return on capital employed may be useful for initial screening of projects and for evaluating short, small projects. They also suggest, however, that they are not sufficient to provide good quality, quantitative information for large investment decisions such as those being considered in this report. Additionally, they argue that the theoretical and practical difficulties associated with using internal rate of return to inform investment decisions are significantly greater than any problems associated with net present value.

In particular, they suggest that calculations involving net present value automatically include an accurate representation of a capital market investment that could be made instead of a

Table 9 Four common quantitative metrics to support investment decisions (Chalmers and others, 2007b; Lumby and Jones, 1999)

Metric	Summary	Some key strengths and weaknesses
Payback period	Time taken for capital deployed to be repaid by cash flow generated. A shorter payback period indicates a less risky investment.	Quick, simple and avoids needing to forecast cash flows beyond the initial period required for payback. Does not consider payments outside the payback period so could miss important information.
Return on capital employed (ROCE)	Ratio of accounting profit to capital outlay as a percentage. A higher ROCE indicates a better investment.	Projects are evaluated based on profitability and using a % concept which is familiar to managers. Accounting profit (not cash flow) is used so not giving true picture of project operation, and difficult to incorporate a time value of money*.
Net present value (NPV)	Return/loss expected as a result of making an investment. Calculated based on discounted cash flows* for the whole project. A positive NPV indicates an investment worth making, if funds are not scarce.	Obvious logic with a decision rule which holds when projects to be compared are very different in character (including in magnitude or duration). Requires an accurate discount rate and cash flow model to give an accurate result. Also need to carefully consider the size of investment required for a particular NPV to be obtained since this can affect the project risk profile.
Internal rate of return (IRR)	The rate of discount* which produces an NPV of zero when applied to the project cash flows. An IRR which is higher than the cost of capital† for the project indicates an investment worth making if funds are not scarce.	In many ways, an arithmetic result based on an NPV calculation, so retains some of the strengths and weaknesses of NPV. But, there are significant theoretical and practical difficulties in determining how IRR should be applied which are not a problem for NPV methods.

* Both NPV and IRR are examples of discounted cash flow analysis. In these cases, it is assumed that money in the future is worth less than money now, so the value of money in the future is discounted compared to money now to allow the total value of the project in today's money to be calculated.

† The cost of capital is a specific measure of how much a company has to spend to obtain cash to be used for a particular investment. See Lumby and Jones (1999) or other standard economics textbooks for definition and discussion.

project investment. In contrast when an internal rate of return is calculated, the focus is on whether an investment in a certain project is expected to give a return that is greater or lesser than an investment in capital markets. The internal rate of return does not, however, give a reliable indication of how much better (or worse) a project investment would be than a capital market alternative. It is possible to extend analysis based on internal rate of return to allow an indication of relative value of different projects to be obtained, but Lumby and Jones (1999) conclude that this approach is 'excessively complex and unwieldy' if compared to options for using net present value (NPV) to obtain similar information for decision-making. They, therefore, conclude that 'only NPV remains as an investment appraisal technique which will give consistently reliable advice leading to shareholder wealth maximization'.

Although net present value approaches offer a significant improvement over the other techniques discussed above, it is important to note that the standard net present value approach is also imperfect. For example, uncertainties in future cashflows are generally not taken into account in a particular model run. Some scenario-based analysis can, however, give some indication of the range of outcomes possible. Stochastic versions of net present value can also be used, such as the Stochastic Energy Deployment System (SEDS) model discussed by Short and others (2006).

If a power plant is able to operate flexibly then it is likely to be able to respond to a variety of risks. These include decisions made by other investors and volatility in prices of traded commodities which affect plant costs and value such as fuel and, in at least some markets, CO_2. It is clear that flexibility to operate assets in different modes as circumstances change could significantly reduce the exposure of an investment to variations in the operating environment. This can include significant 'one-off' events such as changes to regulations which impact on plant operating requirements and economic performance. Day-to-day flexibility to react to changes in plant use in response to fluctuations in the electricity market can also be valuable, as discussed in more detail in the next chapter.

It seems reasonable to expect that investors would place some value on this flexibility. One useful approach to this problem might be to consider the applicability of real options analysis. This technique has evolved from the use of options in financial markets. Trigeorgis (1993) provides a useful introduction, highlighting that it expands on standard net present value techniques to evaluate total value of a project as:

Expanded (strategic) net present value
= Static (passive) net present value of expected cash flows
+ value of options from active management

This analytical framework represents an improvement on valuations which consider only static net present values, although it still has some limitations. It is often not simple to calculate the value of options and it can be difficult to determine what expected cash flows should be assumed. It is also important to note that real options analysis typically includes the use of Monte Carlo simulation to allow probability distributions of costs and benefits to be used.

A few applications of real options analysis to CCS have been completed and published. For example, Blyth and others (2007) considered the impact of climate policy uncertainty and investment risk and included CCS in the cases considered in a real options analysis. One key conclusion of their work was that the availability of a CCS retrofit option acts as a 'hedge' against uncertain CO_2 prices and that this should accelerate investment in coal-fired power plants. As with most other real options studies in the literature that consider CCS (such as Liang and others, 2009; Reinelt and Keith, 2007; Sekar, 2005), this study considered an aspect of managerial flexibility. In this case it was timing of investment in a coal-fired power plant and in an associated CO_2 capture scheme for that plant. It did not include a valuation of operating flexibility. It should also be noted that investors have a wide range investment opportunities to consider including the potential for incremental upgrades to base power plants and the CO_2 capture plant, once installed.

There has been very limited treatment of operating flexibility of CCS in papers applying methods developed in financial economics in the public domain. One study has, however, been carried out by Patiño-Echeverri and others (2007). They considered possible future allowance prices for multiple pollutants (oxides of sulphur and nitrogen, mercury and CO_2) and the potential for CCS for pulverised coal and integrated gasification combined cycle plants, both as a retrofit and new build option. They suggested that an emissions control device should have an option value since it effectively provides insurance to plant operators. Once fitted, if an emissions control device can be bypassed when the plant operator wishes, the exposure of the plant operator to an emissions penalty is limited to the operating cost of the that device. It should be noted a number of factors affect whether bypass of an emissions control device is possible, including regulations on allowable emissions of the pollutant. For example, emissions of sulphur oxides in the USA (where Patiño-Echeverri and others are based) have been regulated using trading mechanisms that could allow this operating approach. This approach would not, however, be allowed for many parts of Europe since regulations have tended to focus on emissions limit values defined by the Large Combustion Plant Directive (LCPD; *see* Official Journal of the European Communities, 2001).

As noted in the last section, portfolio analysis is another method from financial economics that could provide useful insights into power plant investment decisions. It can be closely linked to real options analysis. Portfolio analysis is potentially important since the risk associated with a group of dissimilar investments is normally not a simple summation of the risk associated with each individual investment. If the value of one investment tends to increase at the same time as another investment decreases in value then the expected return of the two assets combined is less risky than either investment individually. Elton and others (2007) provided a detailed introduction to modern portfolio theory for investment analysis and note that 'option pricing has important implications for generating the inputs to portfolio analysis'. Awerbuch and Berger (2003) provided a thorough introduction to the application of mean variance portfolio theory for electricity planning. He reminded readers that portfolio analysis cannot prescribe a single best combination. Instead a range of ‘efficient choices’ that show the trade-off between best available return with minimum portfolio risk are found.

Although real options analysis and portfolio analysis can offer more robust insights to inform investment decisions, they can also be time consuming and difficult to use. Lumby and Jones (1999) and other standard texts outline alternative approaches, that specifically include risk and uncertainty but that are closer to the net present value approach. One example is the Capital Asset Pricing Model (typically referred to as CAPM). In this model, the return that should be expected from an investment is modelled as the risk-free return plus a risk premium. The risk premium is determined by the market price of systematic risk and the level of systematic risk involved in the project. Systematic risk is the risk that cannot be diversified by investing in a portfolio of projects. One key output from the Capital Asset Pricing Model is a discount rate that can be used in a net present value calculation (or some other form of discounted cash flow analysis) to take account of risk.

As noted at the end of Section 5.2, a number of other analytical methods can be considered for analysing economic performance of CCS projects over a period of 20–30 years. In some cases, these could also be used to give some indication of the quantitative value of risk associated with a particular project or portfolio of projects. Any potential analyst, regardless of perspective, should review the methods available and pick an approach or suite of approaches that is most suitable for their particular questions. In their introduction to dealing with uncertainty in quantitative risk and policy analysis, Morgan and Henrion (1990) summarise this by highlighting the need to always ‘let the problem drive the analysis’.

5.4 Summary

This chapter has reviewed some key principles for economic analysis of power plant operating and investment decisions. A number of factors affecting the cost of generating electricity at coal-fired power plants, both with and without CCS, have been identified. These can be split into two categories. Some considerations, such as the type of fuel available and local regulations, can make it impossible to use particular technologies at a given site. Other considerations are likely to change the relative attractiveness of different technology options, but are less likely to make any particular electricity generation option impossible. This second category includes local labour costs and ambient conditions. Some factors that affect power plant costs also affect revenues. A range of additional factors must also be taken into account when determining power plant income. These include the physical structure of the electricity network and the market (or other) structure used for buying and selling electricity.

When a power plant is operated flexibly within an electricity system, a number of factors could be important in determining costs and revenue obtained. In particular, costs associated with any off-design operation need to be identified and can include additional fuel costs for part-load operation and changes to maintenance costs. In this latter case, power plant owners might benefit if a plant is able to avoid shut-downs and start-ups by providing ancillary (support) services within the electricity network. It is, of course, also possible that flexible operation could lead to increased maintenance costs and reduced component life. Similarly, a broad range of revenue streams might be available and should be included in analysis, where appropriate. This can include selling by-products and the value of providing ancillary (support) services within the electricity network.

A range of methods can be considered for evaluating power plant economic performance with flexible operation. There is currently limited literature in this area. Further work is, therefore, needed to apply existing techniques to many core questions for power plant operators and investors. In some cases, it may also be necessary to revise existing methods or identify new analytical approaches for a robust analysis to be completed. One particular challenge will be accurately characterising risk and uncertainty. Insights from financial economics could be important to help improve the quality of analysis in this area.

6 Examples of operating options for post-combustion capture

As noted in the previous chapter, there is very limited quantitative analysis of the possible value of operating flexibility in the literature, but some initial illustrative work has been completed. This chapter will focus on key results from work carried out by the author focusing on steady-state analysis of options for post-combustion capture that may be of interest to power plant operators. The trends illustrated in this chapter are expected to be reasonably robust in a range of potential real futures. There is significant uncertainty, however, in absolute values of costs and revenues associated with CO_2 capture from power plants including within the analysis presented here. Significant caution is also needed in converting results reported in different currencies and from different years due to significant fluctuations in key data, including construction and commodity costs.

Although the author is not aware of any detailed, quantitative analysis of dynamic performance of power plants with CO_2 capture in the public domain, some initial work for post-combustion is reported by Lucquiaud and Gibbins (2009b). This suggests that very fast response is possible, but depends on the steam cycle design strategy chosen (*see* Section 4.2). Additionally, a qualitative review of coal-fired transient performance with post-combustion capture is provided by Chalmers and others (2009d). Some other contributions to the literature on operating options for power plants with CO_2 capture that are not covered in this chapter include an initial study of the value of operating flexibility within the IEEE reliability test system (IEEE Reliability System Taskforce, 1999) carried out at the University of Waterloo (Alie and others, 2006) and more recent work on the Texas electricity market at University of Texas at Austin (for example, Cohen and others, 2008, 2009).

6.1 Part load performance

Power plants using fossil fuels typically operate with a lower efficiency when they are operated at part load. An initial indication of possible part load performance for a supercritical coal-fired power plant with post-combustion capture is included in Figure 9, based on Chalmers and Gibbins (2007). The part load curve without capture is based on data reported by the UK Government Department of Trade and Industry (DTI, 1999) and Sakai and others (1999). The energy penalty for a post-combustion capture process can be expressed as a constant percentage point reduction in plant net efficiency for a given fuel. This assumes that reasonable plant integration can be achieved, since the energy penalty is generally directly proportional to the CO_2 to be processed and, therefore, the power plant fuel input. For the base case with CO_2 capture plant reported in Figure 9, a constant energy penalty of 9% points is incurred across the full power plant output range, corresponding to a constant energy requirement per tonne of CO_2 captured. This is expected to be conservative compared to the potential performance of current and future state-of-the-art solvents. It was argued that, in the absence of plant-specific data, the inherent improvements in absorber performance at lower throughputs would tend to offset other components achieving poorer performance at part load. A possible exception to this, which was examined, is a limited efficient turn-down for the CO_2 compressors, as shown in Figure 9 and discussed below.

In reality, it is not yet clear whether the overall impact of changes in key operating parameters, including steam turbine efficiency and heat required per unit CO_2 captured, will lead to an overall increase or decrease in the energy penalty. It is, therefore, possible that different part load performance will be observed. One factor that could lead to an increased energy penalty at lower loads is any requirement to operate CO_2 compressors below around 75% of their full load (Chalmers and Gibbins, 2007 based on White, 2006). In the base case, it is assumed that a CO_2 capture unit is operating at a multiple unit site with several CO_2 compression trains. In this case, it is likely that it would be feasible to turn off some CO_2 compressors when the power plant is operating at part load so that any operating compressors have a throughput at or above 75% of their full load.

It is possible, however, that in some cases compressor shut-down would be avoided to improve dynamic performance or that the use of multiple compression trains will not be possible for some other reason. In this case, it is necessary to recirculate CO_2 flow when power plant output is below around 75% of full load to maintain steady operation. This leads to reduced power plant net efficiency at part load since a constant MW energy penalty is incurred below the limiting load at which steady, efficient operation is possible. The

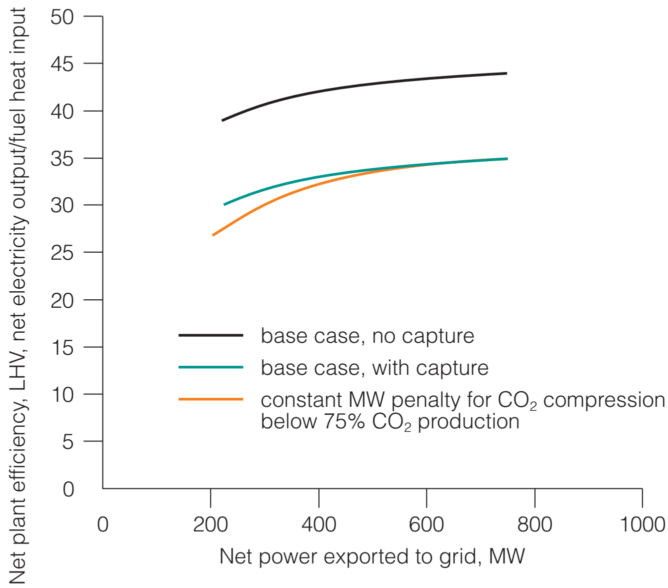


Figure 9 Possible part load efficiency curves for a supercritical coal-fired power plant without CO_2 capture and using an amine-based post-combustion capture process (Chalmers and Gibbins, 2007)

energy penalty associated with aspects of CO_2 capture that have a constant MW penalty below a limiting load can be expressed as:

$$\eta_{CCS} = \eta_{noCCS} - [\%penalty_{load1} \times (heat\ in_{load1}/heat\ in_{load2})]$$

Where η_{CCS} is the net plant efficiency for a given fuel input with CCS operating
η_{noCCS} is the net plant efficiency for a given fuel input without CCS operating
$\%penalty_{load1}$ is the energy penalty associated with adding capture at the limiting load
load1 is the limiting load (minimum load at which efficient part load operation occurs)
load2 is the lower load at which efficiency is being calculated.

Further work has been undertaken using more detailed power plant models to consider part load performance across a range of fuel inputs. For example, Lucquiaud and others (2007) reported results for 70-100% load, including a range of operating options, as discussed below. Linnenberg and Kather (2009) combined two simulation tools (EBSILONProfessional® and Aspen Plus®) to assess part load operation from 40-100% of a supercritical reference plant. They suggested that greater energy penalties can be expected at part load for the case they analysed once a range of factors are taken into account. These included reduced CO_2 concentration in the flue gas if air ratio is increased in the boiler at part load and an increase in specific power duty (in power required per unit mass of CO_2 processed) for the CO_2 capture unit at lower loads. Further work is, however, required to consider whether alternative operating strategies could be used to avoid this poor performance. For example, Linnenburg and Kather (2009) suggested that flue gas recycling could be considered to increase CO_2 concentration in flue gas delivered to the CO_2 capture system. Variable flow fans and blowers could also be considered to avoid or, at least reduce, the increase in specific power duty at part load.

6.2 Bypassing CO_2 capture plant and short run marginal cost sensitivities

Section 4.2 outlined the potential for plant operators to choose to bypass a post-combustion capture unit during periods of high electricity prices and low CO_2 prices. Whether this option is available will depend on a number of factors including local environmental regulations and power plant design choices. If a power plant is operating within a 'cap and trade' scheme it is expected that bypassing should be environmentally acceptable. Since CO_2 is a global pollutant that is long-lived in the atmosphere, the precise time and place of CO_2 emissions do not matter (Hansen and co-authors, 2007). Within the trading scheme it is expected that total CO_2 emissions will be at the level of the cap. CO_2 emissions during a period when a capture unit is bypassed will, therefore, be balanced by reduced CO_2 emissions at another time or place.

Figure 10, after Chalmers and Gibbins (2007), illustrates some options available to a power plant operator when full design fuel input is assumed. This could occur during a period of high electricity demand when maximum output from the plant is likely to be wanted by the electricity system operator. It is assumed that the operating decision is made based on short run operating costs and electricity (energy) sales revenue alone, that there are no 'balance of plant' constraints on power plant output when the capture plant is bypassed and the whole of the energy penalty with capture can be avoided. The result reported here agrees with previous work by Gibbins and Crane (2004) which suggested that bypassing post-combustion capture could be economically attractive when £/MWh wholesale electricity prices are 2-3 times higher than £/tCO_2 costs for emitting CO_2 (or equivalently that $/MWh wholesale electricity prices are 2-3 times higher than $/t$CO_2$ costs). More detailed sensitivity analysis to determine whether changes to the input assumptions used for the illustrative example reported here would have significant impacts on operating decisions is, however, required.

The location of the size of the different regions on a decision diagram will vary depending on a number of factors. A detailed exploration is beyond the scope of this report. One important consideration in identifying priorities for future analysis is understanding which factors are most important in determining short run marginal costs. Some analysis of changes to these costs caused by varying a range of input

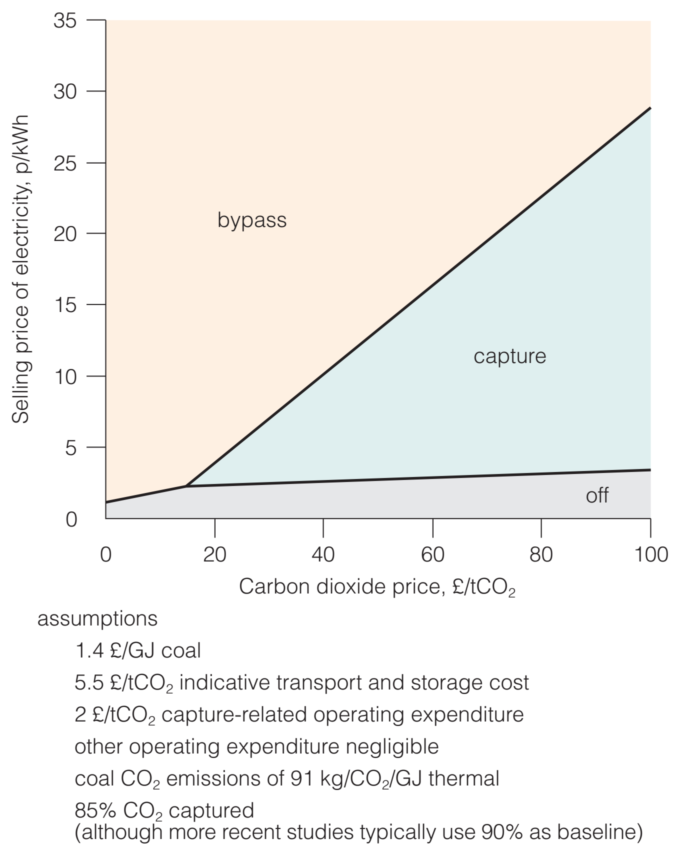


Figure 10 Decision diagram for a choice between operating plant with and without CO_2 capture assuming maximum fuel input and no balance of plant constraint (Chalmers and Gibbins, 2007)

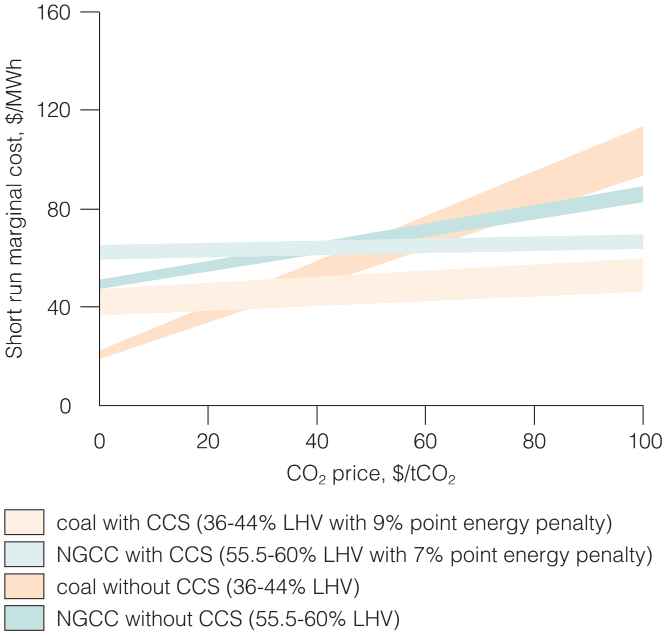


Figure 11 Short run marginal cost for power generation with fossil-fired power plants with 2.2 $/GJ coal and 7.8 $/GJ gas (Chalmers and others, 2009c)

assumptions is reported in Chalmers and others (2009d). Figure 11 illustrates the range of short run marginal costs observed for typical ranges of base plant efficiency for power plants with post-combustion capture. Plant characteristics follow Davison (2007), where possible, and are reported in the Appendix.

Figure 12, also from Chalmers and others (2009c), illustrates the change in short run marginal costs for a range of changes in factors that can affect short run marginal cost with a fixed fuel price of 2.2 $/GJ coal and 7.8 $/GJ gas. Although a change in base plant efficiency is relatively important, a doubling or halving of costs associated with CO_2 capture (expenditure for capture plant operating expenditure plus CO_2 transport/storage costs) is more important for these fuel prices. All of the sensitivities illustrated in Figure 12 are, however, less significant than a plausible change in fuel prices. For example, a doubling in coal price to 4.4 $/GJ leads to an increase in short run marginal costs for the supercritical and subcritical plants with CO_2 capture considered here of nearly 23 $/MWh and 30 $/MWh respectively.

6.3 Solvent storage

It is likely that there will be a limited range of occasions when bypassing a CO_2 capture unit makes economic sense. For example, Haines and Davison (2009) concluded that the potential value of bypass is 'quite small' for their analysis of the UK electricity market. It is also possible that capture plant bypass may be disallowed by environmental policy, even if it would make economic sense. One approach that could allow plant operators to have a range of operating options available that is, at least, similar to capture plant bypass is to install storage tanks for interim storage of amine.

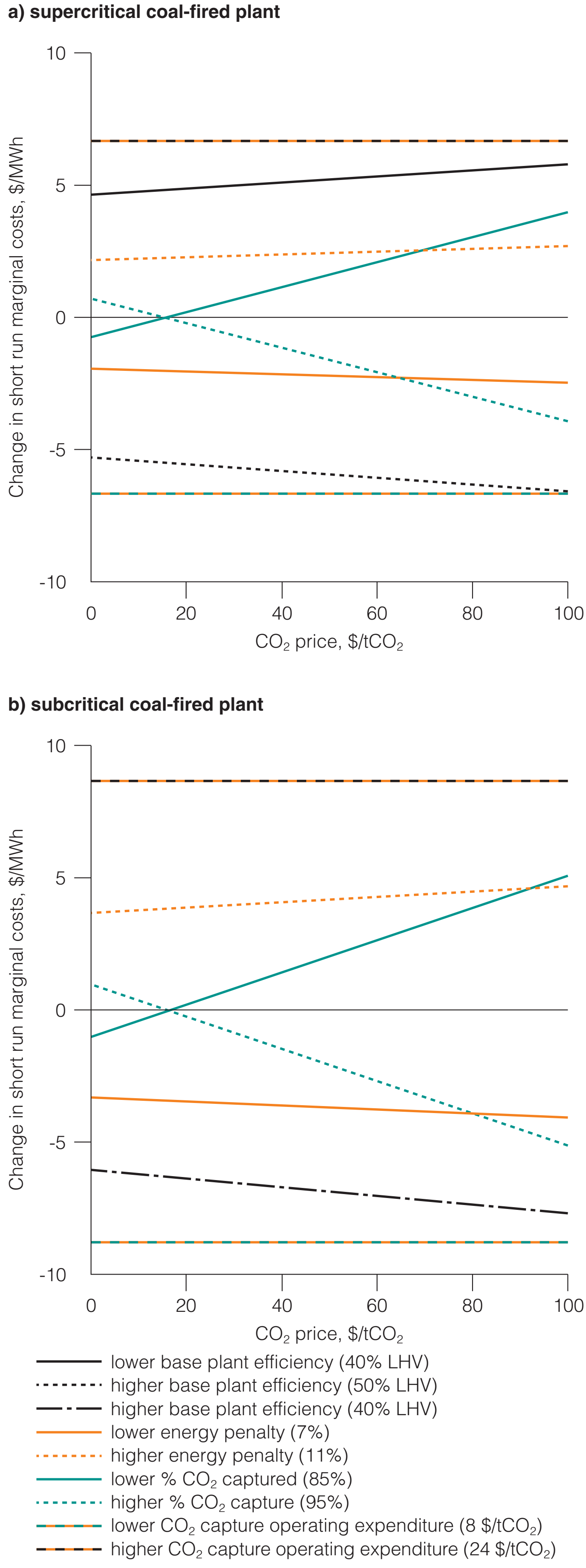


Figure 12 Change in short run marginal costs for changes in input assumptions for two coal-fired power plants (Chalmers and others, 2009c)

This concept is introduced in Section 4.2 and in Gibbins and Crane (2004).

Figures 13 and 14, based on Chalmers and Gibbins (2007) and Lucquiaud and others (2007) respectively, illustrate power plant net LHV efficiency for illustrative operating options for supercritical coal-fired power plants with solvent storage installed within a post-combustion capture scheme. The simple cases illustrated in Figure 12 do not consider possible limits on steam extraction from the power plant cycle, although this is illustrated in Case 5 in Figure 13.

Figure 13 does, however, illustrate possible changes in capacity available for dispatch for plants with and without CO_2 capture installed. For the plant shown here, it is assumed that the plant with capture has no balance of plant constraints and, hence, a reduction in energy penalty associated with CO_2 capture is translated into an increase in power delivered to the electricity network. Additionally, the fuel input for the base case plant with capture is higher than the base case without capture, so that both plants have a rated capacity at full load of 750 MWe for 'normal' full load operation. As already noted, one potentially significant factor here is that the minimum stable generation of a plant can be reduced while stored solvent is regenerated which should allow additional energy to be dispatched from other plants within the electricity network with lower short run marginal costs, such as intermittent renewables, without compromising security and quality of electricity supply.

Some illustrative analysis to compare the short run economics for solvent storage with CO_2 capture plant bypass is reported

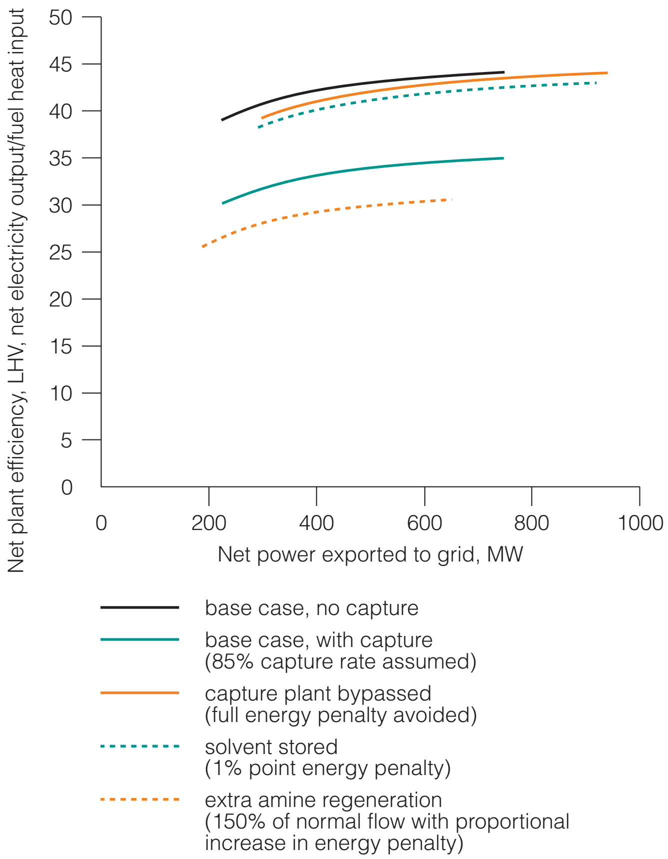
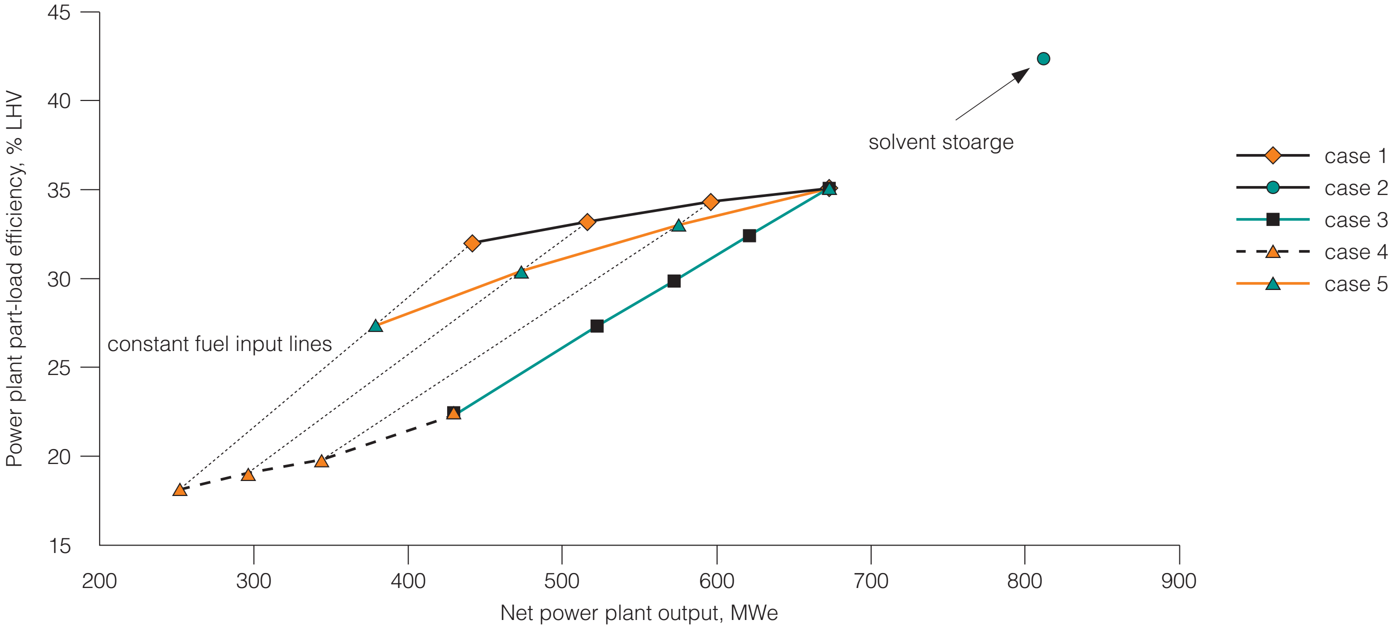


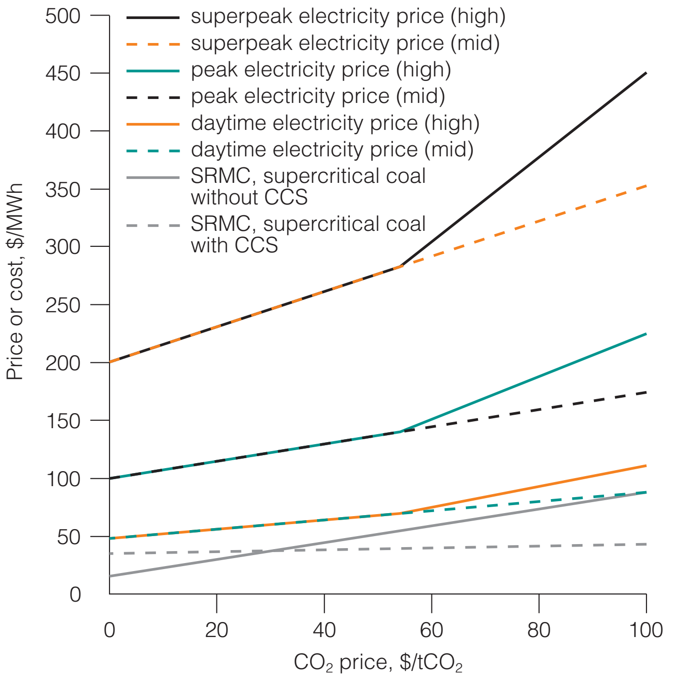
Figure 13 Possible part load efficiency curves for a supercritical coal-fired power plant without CO_2 capture and using an amine-based post-combustion capture process including solvent storage options (Chalmers and Gibbins, 2007)



case 1 'normal' capture plant operations, 70-100% load
case 2 solvent stored at full load
case 3 additional regeneration rate for stored solvent varied from 0% to 100% of normal regeneration rate added to normal flow for 100% fuel input
case 4 100% additional regeneration, or maximum possible where this is not technically feasible, for same range of fuel inputs as case 1
case 5 additional regeneration rate varied to achieve constant CO_2 production for same range of fuel inputs as case 1

Figure 14 Power plant part load performance for a range of operating options including solvent storage and additional regeneration of stored solvent (Lucquiaud and others, 2007)

a) short run marginal costs (SRMC) and electricity prices



b) increase in short run profit for an illustrative solvent storage cycle

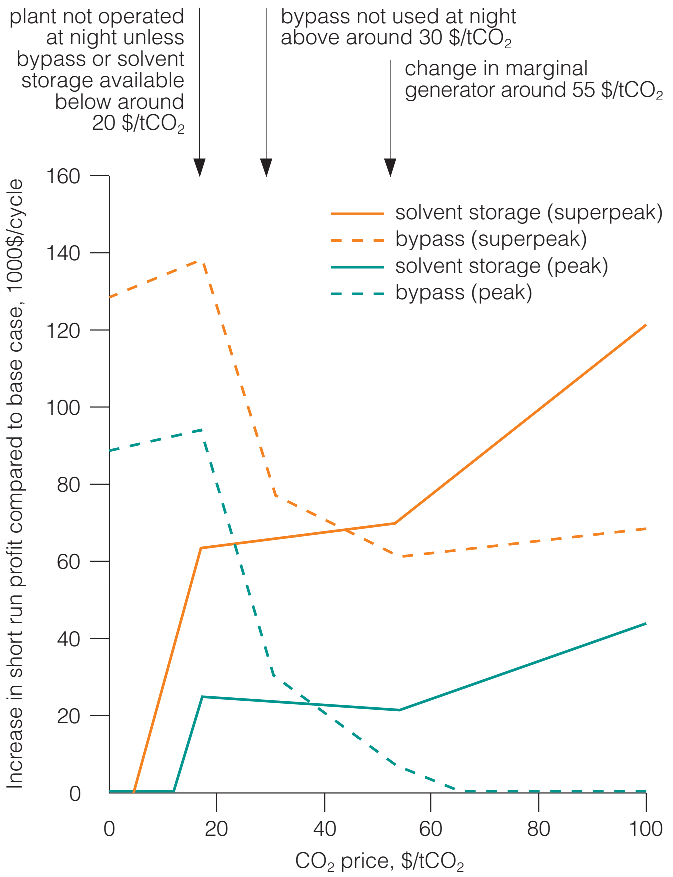


Figure 15 Illustrative short run economics for CO_2 capture plant bypass and solvent storage for a supercritical coal-fired power plant (Chalmers and others, 2009b) *key assumptions are included in the Appendix*

in Chalmers and others (2009c), as shown in Figure 15. Related input assumptions are given in Appendix A. Two illustrative electricity price scenarios are considered. In the 'high' case, the electricity price is set by higher of two short run marginal costs; subcritical coal without CO_2 capture or natural gas combined cycle without CO_2 capture. The 'mid' case considers an alternative situation where subcritical coal plants have CO_2 capture available, but natural gas combined cycle plants still operate without CO_2 capture. The price of electricity is still set by the short run marginal plant in this second case. The electricity selling price is, however, reduced at higher CO_2 prices since the availability of CO_2 capture at the subcritical plant reduces the short run marginal cost of generating electricity for that plant.

Increases in short run operating profit (that is before capital payback is considered) for the 750 MWe supercritical plant is illustrated in Figure 15b. This suggests that in systems with regular peaks in electricity prices, the investment required for solvent storage to be available could be justified. Of course, this will depend on the capital costs associated with solvent storage. Chalmers and others (2009d) and Haines and Davison (2009) provided initial analysis of possible costs. Haines and Davison (2009) suggested that an increase in revenue during the highest peak periods of 15% or higher could be obtained depending on the number of hours of storage available and the operating strategy chosen in a UK example. This reduced on days with the lowest peak prices. They concluded that:

'The potential extra revenue increases with available storage until there is insufficient capacity to perform the catch up regeneration at which point further increases in peak output time start to drastically reduce revenue because overall daily output starts to fall . . . Cursory inspection of these curves [of possible changes in operating revenue for different solvent storage scenarios] would suggest that around 4 hours storage would be worth considering if the costs of providing it are not out of line with the gains.'

It is also worth noting that, provided space is available somewhere on the site, and that other requirements for chemical storage can be met, solvent storage could be added or extended relatively quickly in response to market conditions.

Chalmers and Gibbins (2007) also considered what the optimum operating approach for a plant with solvent storage might be. An adjusted short run marginal cost of electricity production is proposed to facilitate this analysis. This adjusted cost represents the minimum electricity selling price that would be required during periods of additional solvent regeneration to allow the whole cycle of solvent storage and additional regeneration to break-even and can be expressed as:

$$\text{adjusted SMRC}_{regen} = \frac{\text{opcost}_{regen} - \text{profit}_{storage}}{\text{load}_{regen} \text{ x time}_{regen}}$$

Where adjusted SMRC_{regen} is the adjusted SRMC for the period when solvent is regenerated at a given plant output and regeneration rate

Table 10 Breakdown of costs for analysis of different power plant operating patterns (Chalmers and Gibbins, 2007)

Quantity	Without solvent storage and 150% regeneration	Without solvent storage
Capacity available for dispatch with maximum fuel input during storage operations	920 MWe	750 MWe
SRMC during storage operations	1.59 p/kWh	2.39 p/kWh
Net revenue* during 1-hour storage period†	£16,950	£7,492
Net plant output during 1-hour storage period†	920 MWh	750 MWh
Capacity available for dispatch with maximum fuel input during regeneration operations	652 MWe	750 MWe
Basic SRMC during regeneration operations	3.00 p/kWh	2.39 p/kWh
Net revenue* during 2-hour period required for full additional solvent regeneration†	–£7,894	£0‡
Net plant output during 2-hour period required for full additional solvent regeneration†	1304 MWh	1500 MWh
Average SRMC for solvent/regeneration cycle§	2.41 p/kWh	2.39 p/kWh
Net profit for solvent/regeneration cycle	£8694	£7492
Adjusted SRMC for regeneration¶	1.72 p/kWh	1.89 p/kWh

* Plant income from electricity sales not required to cover operating costs for electricity price 3.39 p/kWh during solvent storage and 2.39 p/kWh during solvent regeneration.
† For simplicity, only data for full fuel input and with a single electricity price assumed for each operating period is reported in these illustrations.
‡ Note that this selling price is the short-run break-even point for the plant under the assumptions used in this study. Thus, further analysis taking more costs into account may indicate that this plant would not run during the period when a plant with solvent storage would still running to regenerate additional solvent. However, this would not change the later conclusions reported here.
§ Defined as total costs for operation divided by total electricity dispatched.
¶ As defined by the equation in Section 6.2.

$load_{regen}$ is the selected output capacity in MW (or GW etc) from the plant during the period of solvent regeneration
$time_{regen}$ is the time required to allow for regeneration of all the stored solvent at a selected $load_{regen}$
$opcost_{regen}$ is the basic cost of operation for $time_{regen}$ in \$ (or € etc) given the plant operating conditions (eg rate of solvent regeneration)
$profit_{storage}$ is the profit obtained during the period while solvent is stored for later regeneration in \$ (or € etc), with this period when the solvent is stored considered in isolation for the purposes of analysis

Table 10 provides an illustrative example of the breakdown of costs for different power plant operating patterns with solvent storage. The adjusted short run marginal costs for a broader range of cases are reported in Figure 16. A lower adjusted short run marginal cost indicates a more profitable solvent storage operating option. Lower costs are, therefore, observed for plants with higher income during periods of solvent storage. Another trend in the results reported here (from Chalmers and Gibbins, 2007) is that faster regeneration of stored solvent is expected to give improved short run economic performance. It is necessary, however, to consider whether this faster regeneration rate is feasible at lower loads. The capital costs for additional equipment for this faster regeneration rate must also be considered since additional investment would be required for sufficient capacity to be available to allow this more rapid regeneration to occur.

6.4 Summary

This section has introduced some illustrative analysis of pulverised power plant operating costs and profits with post-combustion capture. It draws on previous work by the author, although other initial analysis is also available in the literature (including Alie and others, 2006; Cohen and others, 2008, 2009). Possible performance curves for part load operation are also presented.

Perhaps the simplest option for flexible operation of a power plant with post-combustion capture is to bypass the capture unit. A decision diagram can be constructed to provide a quick guide to whether it is economically favourable to bypass the CO_2 capture plant. This could be particularly useful in cases where it can be assumed that full fuel input is favourable, such as during peaks in electricity demand, and relatively few operating modes need to be considered.

Further work is required to analyse key sensitivities in determining the boundaries of the different regions included on this diagram. An important first step is understanding key factors determining short run marginal costs of electricity. For the initial analysis reported in this chapter, fuel price is the dominant factor. The next most important factor for the fuel

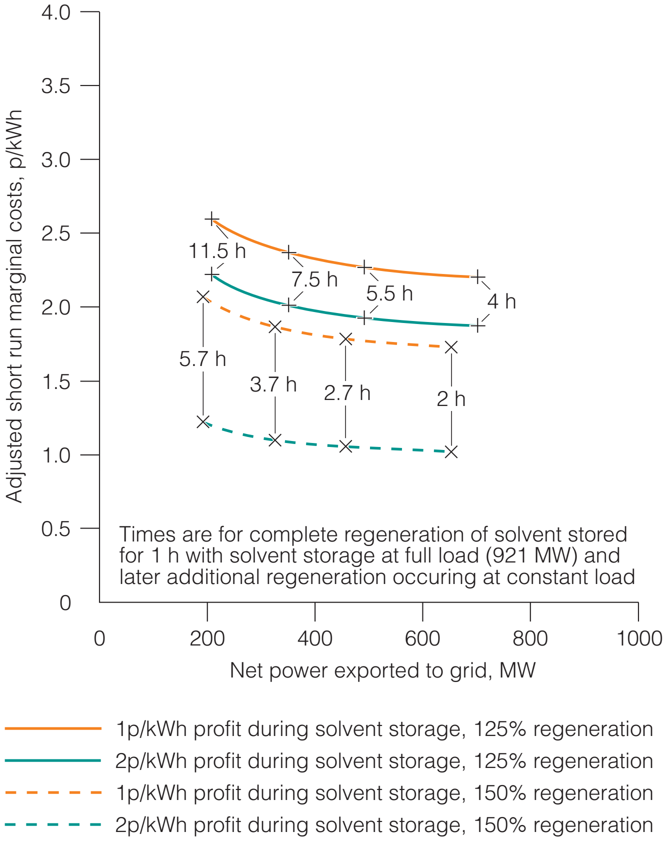


Figure 16 Adjusted short run marginal cost for plants with different solvent storage operating patterns, but identical fuel inputs (Chalmers and Gibbins, 2007)

prices considered here was a doubling or halving of costs associated with CO_2 capture (expenditure for capture plant operating expenditure plus CO_2 transport/storage costs).

Although bypassing the CO_2 capture unit could be a valuable option in some situations, it is likely that other operating options will be more important in many jurisdictions under likely electricity and CO_2 price combinations. Solvent storage could be a useful approach to provide flexibility similar to bypass during periods of peak electricity demand. In this case, the energy penalty associated with solvent regeneration and CO_2 compression is shifted rather than avoided. It is important to identify appropriate methods for valuing a whole solvent storage cycle (storage plus regeneration) when an operating decision is made. An 'adjusted short run marginal cost' of electricity generation concept was, therefore, outlined. Since additional capital expenditure is required for solvent storage to be available, the costs of relevant investment must be included for a complete analysis of whether this is an economically attractive operating option to be undertaken.

7 Conclusions and recommendations for further work

This report has reviewed likely requirements for flexible operation of power plants with CO_2 capture and how these could be included in engineering design and economic analysis. In particular, it aimed to review the evidence base related to three questions:

- What additional factors should be considered in plant design if requirements for operating flexibility are taken into account?
- What research and test programmes should be considered for demonstration plants and during initial deployment to provide a better basis for future designs?
- What additional analytical methods could/should be considered to help inform decisions made on the points above?

Chapter 3 of this report reviewed typical roles of fossil fuel-fired power plants in electricity networks and some implications of possible future developments in electricity systems. It seems likely that flexible operation of power plants with CO_2 capture will be helpful or necessary in many jurisdictions. They should complement other sources of electricity that are less well suited to providing variable output as the supply/demand balance in the electricity network changes. A number of characteristics to consider in determining the suitability of different plants for fulfilling various roles can be identified, including those highlighted in Table 3. These include both steady-state characteristics, such as part load performance, and transient characteristics, such as the ramp rate (that is rate of change of output) that can be achieved between two steady-state loads.

A review of coal-fired power plant operating options with a particular focus on flexibility forms Chapter 4 of this report. This highlights a range of changes to power plant flexibility that could be expected when CO_2 capture is added. An indication of a range of areas where further work is required to gain a better understanding of plant technical performance is also included. Further studies and analogies to existing systems in other applications are likely to provide some useful information, including continued developments in dynamic modelling. It is likely, however, that many of the uncertainties in technical performance that are not already resolved will require some operating experience for a deeper understanding to be developed. In many cases, this will need to be gathered from larger-scale capture plants operating at power stations than are available at the time of writing.

Some important information that cannot be verified without data gathered from a demonstration plant of reasonable scale includes verification of modelling predictions of steady-state performance, including heat requirements for solvent regeneration with implications for overall plant efficiency. Testing dynamic performance is also important. This includes checking what ramp rates are possible with different operating approaches and measurement of CO_2 emissions and other performance parameters during start-up, shut-down and load changes. Where limits in dynamic performance are identified, it is likely to be valuable to experiment with a range of modifications that may be able to improve performance, possibly including (although certainly not limited to) the use of surge tanks and alterations to control system design. If reliable dynamic models can be developed they could provide a useful tool to test multiple plant configurations relatively rapidly so that a limited set of promising options can be identified for tests at pilot projects or as part of commercial-scale demonstrations, as appropriate.

Finally, Chapters 5 and 6 of this report considered the economic potential for flexible operation of power plants with CO_2 capture. Available techniques for economic analysis of operating flexibility are reviewed, including some discussion of tools that may be suitable for considering the risks associated with investment in CCS projects. A broad range of analytical options are available. It is likely that different approaches will be used by different stakeholders and at different stages in project development. These include calculation of the net present value for a project based on simulated project cashflow and real options analysis. Although real options analysis is more complex, it may be applied in some cases since it is able to include a value for investment and operating options that mitigate risks. These option values are typically not considered adequately in net present value calculations. Portfolio analysis to gain a better understanding of possible economic performance of a group of projects, such as the fleet of a particular electric utility or the whole system, is also likely to be a powerful tool in some cases. Perhaps the most important point here is that it is crucial that when any analyst decides which modelling approaches they are planning to use they should 'let the problem drive the analysis' (Morgan and Henrion, 1990).

A number of areas for further work are beyond the scope of this report. At the time of writing, initial commercial-scale integrated CCS projects are making progress with securing finance to form a first tranche of plants that could be operating by no later than 2015. Future developments in policy for mitigating the risk of dangerous climate change will play a critical role in determining if and when CCS projects can be commercially viable without project-specific support. It is also possible that policies to encourage innovation in and initial deployment of CCS could be introduced, at least in some jurisdictions. It can be expected that any policy could affect operating (and investment) decisions, although some are likely to have more impact than others. It will be necessary for investors, policy-makers and other stakeholders to understand how the evolving policy environment affects how power plants with CO_2 capture are allowed to be operated and also what operating choices plant operators might make within the operating envelope available to them.

Some potential priorities for further qualitative or quantitative analysis can be identified. One likely priority for quantitative analysis is establishing baseline expectations for likely technical performance characteristics for a range of CO_2 capture plant configurations and control strategies. This should consider both steady-state and dynamic performance, including part-load performance. This is necessary to gain a better understanding of which services to the electricity network are likely to be able to be provided by power plants with CO_2 capture and where significant uncertainties exist. A complementary analysis to gain a better understanding of whether key likely technical variations could lead to significant changes in plant economic performance should also be carried out. This would serve to inform decisions on priorities for more detailed, engineering development work, as well as contributing to policy-relevant analysis.

8 References

Adams D (2009) *Efficiency upgrades and partial capture technologies for existing coal-fired power plants.* London, UK, IEA Clean Coal Centre, forthcoming

AEA Technology (2005) *Methodological Approaches for Using SCC Estimates in Policy Assessment.* London, UK, Department of Environment, Food and Rural Affairs, 124 pp (Dec 2005)

Alie C, Douglas P, Croiset E (2006) A generalized framework for evaluating the performance of CO_2 capture processes. In: *Proceedings of the 8th International Conference on Greenhouse Gas Control Technologies: GHGT-8*, Trondheim, Norway, 19-22 June 2006. Oxford, UK, Elsevier Science Ltd

Allam R (2009) Improved oxygen production technologies. *Energy Procedia*; **1** (1), 461-470

Allan R N, Li R, Elkateb M M (1998) Modelling of pumped-storage generation in sequential Monte Carlo production simulation. Generation, Transmission and Distribution, *IEE Proceedings*; **145**, 611-615

Allinson G, Ho M T, Neal P R, Wiley D E (2006) The methodology used for estimating the costs of CCS. In: *Proceedings of the 8th International Conference on Greenhouse Gas Control Technologies: GHGT-8*, Trondheim, Norway, 19-22 June 2006. Oxford, UK, Elsevier Science Ltd

Australian Government (2009) *Global Carbon Capture and Storage Institute (GCCSI)* Australian Government Department of Resource, Energy and Tourism. http://www.ret.gov.au/resources/gccsi/Pages/default.aspx

Awerbuch S, Berger M (2003) *Applying Portfolio Theory to EU Electricity Planning and Policy-Making*. IEA/EET Working Paper, Report No.: EET/2003/03. Paris, France, OECD/IEA, 72 pp (Feb 2003) http://www.iea.org/textbase/papers/2003/port.pdf

Bergerson J A, Lave L B (2007) Baseload coal investment decisions under uncertain carbon legislation. *Environmental Science and Technology*; **41** (10); 3431-3436 (May 2007)

BERR (2007) *Competition for a Carbon Dioxide Capture and Storage Project: Project Information Memorandum.* London, UK, Department for Business, Enterprise and Regulatory Reform, 48 pp (Nov 2007) http://www.berr.gov.uk/files/file42478.pdf

Bhattacharyya D, Turton R, Zitney S E (2009) Plant-wide Dynamic Simulation of an Integrated Gasification Combined Cycle (IGCC) Plant with CO2 Capture. 2009 *AspenTech Worldwide User Conference*, Houston, Texas, USA, 4-7 May 2009

Blyth W (2006) *Factoring Risk Into Investment Decisions*. UK Energy Research Centre Technology and Policy Assessment Function Working Paper. London, UK, UK Energy Research Centre, 14 pp (Nov 2006) http://www.ukerc.ac.uk/Downloads/PDF/07/0706_TPA_Factoring_Risk.pdf

Blyth W, Yang M, Bradley R (2007) *Climate Policy Uncertainty and Investment Risk*. Paris, France, OECD/IEA, 144 pp, http://www.iea.org/textbase/nppdf/free/2007/Climate_Policy_Uncertainty.pdf

Brown M (2005) The problem with carbon. *Power UK*, **138**; 2-4 (Aug 2005) http://www.ilexenergy.com/Pages/Documents/Reports/Carbon/TheProblemWithCarbon.pdf

Caselles-Moncho A, Ferrandiz-Serrano L, Peris-Mora E. (2006) Dynamic simulation model of a coal thermoelectric plant with a flue gas desulphurisation system. *Energy Policy*; **34** (18); 3812-3826 (Dec 2006)

CCSA (2008) Progressive Energy Ltd (Jan 2008) http://www.ccsassociation.org/our_members/profiles/progressive.html#

CCSReg Project (2009) *Carbon Capture and Sequestration: Framing the Issues for Regulation*. An Interim Report from the CCSReg Project (Jan 2009). http://www.ccsreg.org/pdf/CCSReg_3_9.pdf

Chalmers H, Gibbins J (2006) Potential for Synergy Between Renewables and Carbon Capture and Storage. In: *Proceedings of the 29th IAEE International Conference*, Potsdam, Berlin, Germany, 7-10 June 2006. Cleveland, Ohio, USA, International Association of Energy Economics

Chalmers H, Gibbins J (2007) Initial Evaluation of the Impact of Post-combustion Capture of Carbon Dioxide on Supercritical Pulverised Coal Power Plant Part Load Performance *Fuel*; **86** (14); 2109-2123 (Sep 2007)

Chalmers H, Gibbins J (2009) Carbon capture and storage - the ten year challenge *Proceedings of the Institution of Mechanical Engineers Part C – Journal of Mechanical Engineering Science*, in-press

Chalmers H, Gibbins J, Leach M (2007a) Initial Assessment of Flexibility of Pulverised Coal-Fired Power Plants with CO_2 Capture. In: *Proceedings of Third International Conference on Clean Coal Technologies for our Future*, Sardinia, Italy, 15-17 May 2007

Chalmers H, Gibbins J, Leach M (2007b) Site Specific Considerations for Investments in New Coal-Fired Power Plants with CO_2 Capture. In: *Proceedings of 24th Annual International Pittsburgh Coal Conference*, Johannesburg, South Africa, 10-14 September 2007

Chalmers H, Gibbins J, Lucquiaud M (2009a) Retrofitting CO_2 capture to existing power plants as a fast track climate mitigation strategy In: *Proceedings of the ASME 3rd international conference on energy sustainability (ES2009)*, San Francisco, USA, 19-23 July 2009

Chalmers H, Leach M, Lucquiaud M, Gibbins J (2009b) Valuing flexible operation of coal-fired power plants with CO_2 capture. *Energy Procedia*; **1** (1), 4289-4296

Chalmers H, Leach M, Lucquiaud M, Gibbins J (2009c) Drivers and challenges for flexible operation of pulverised coal power plants with CCS. In: *Proceedings of the 4th international conference on clean coal technologies (CCT2009)*, Dresden, Germany, 18-21 May 2009

Chalmers H, Lucquiaud M, Gibbins J, Leach M (2009d) Flexible Operation of Coal Fired Power Plants with Post Combustion Capture of Carbon Dioxide *American Society of Civil Engineers: Journal of Environmental Engineering*; **135** (6), 449-458

Cohen S M, Rochelle G T, Webber M E (2008) Turning CO_2 capture on & off in response to electric grid demand: a baseline analysis of emissions and economics. In: *Proceedings of ASME 2nd International Conference on Energy Sustainability: ES2008.* Jacksonville, Florida, USA, 10-14 August 2008. American Society of Mechanical Engineers

Cohen S M, Fyffe J, Rochelle G T, Webber M E (2009) The effect of fossil fuel prices on flexible CO_2 capture operation. In: *Proceedings of ASME 3rd International Conference on Energy Sustainability: ES2009.* San Francisco, California, 19-23 July 2009. American Society of Mechanical Engineers

Committee on Climate Change (2008) *Building a low-carbon economy – the UK's contribution to tackling climate change.* 1st report of the Committee on Climate Change. London, UK. TSO (The Stationery Office), 511pp (Dec 2008) http://hmccc.s3.amazonaws.com/pdf/TSO-ClimateChange.pdf

Davidson R M (2007) *Post combustion carbon capture from coal fired plants – solvent scrubbing.* Report CCC/125. London, UK, IEA Clean Coal Centre, 58pp (Jul 2007) http://bookshop.iea-coal.org/reports/ccc-125/81794

Davison J (2007) Performance and costs of power plants with capture and storage of CO_2, *Energy*, **32** (7); 1163-1176 (Jul 2007)

Davison J (2009) Electricity systems with near-zero emissions of CO_2 based on wind energy and coal gasification with CCS and hydrogen storage, *International Journal of Greenhouse Gas Control*, in-press (available online Sep 2009)

DECC (2009) *Building a low carbon economy: a framework for the development of clean coal*, UK Government Department for Energy and Climate Change, London, UK, 10p, Available from http://www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/ccs/ccs.aspx

Dixon T (2009) International legal and regulatory developments for carbon dioxide capture and storage: from the London Convention to the Clean Development Mechanism. *Proceedings of the Institution of Mechanical Engineers Part A – Journal of Power and Energy*; **223** (3); 293-297 (Apr 2009)

Doege J, Schiltknecht P, Luthi H J (2006) Risk management of power portfolios and valuation of flexibility. Or Spectrum 28, 267-87

DTI (1999) *Technology status report 009: supercritical steam cycles for power generation applications*, TSR009, UK Government Department of Trade and Industry, London, UK, 13p, http://www.berr.gov.uk/files/file18320.pdf

DTI (2006) *The Energy Challenge.* Report URN No 06/1576x. London, UK, TSO (The Stationery Office), 218 pp (Jul 2006) http://www.berr.gov.uk/files/file31890.pdf

Element Energy, Pöyry Energy and British Geological Survey (2007) *Development of a CO_2 transport and storage network in the North Sea: Report to the North Sea Basin Task Force.* London, UK, Department for Business, Enterprise and Regulatory Reform (BERR). 52 p, www.nsbtf.org/documents/file42476.pdf

Elton E J, Gruber M J, Brown S J, Goetzmann W N (2007) *Modern Portfolio Theory and Investment Analysis*. 7th ed. USA: John Wiley & Sons Inc

European Parliament (2008) *Position of the European Parliament adopted at first reading on 17 December 2008 with a view to the adoption of Directive 2009/.../EC of the European Parliament and of the Council amending Directive 2003/87/EC so as to improve and extend the greenhouse gas emission allowance trading system of the Community.* European Parliament (Dec 2008)

European Parliament (2009) *European Parliament legislative resolution of 17 December 2008 on the proposal for a directive of the European Parliament and of the Council on the promotion of the use of energy from renewable sources.* European Parliament (last updated 22 Sep 2009) http://www.europarl.europa.eu/sides/getDoc.do?pubRef=-//EP//TEXT+TA+P6-TA-2008-0609+0+DOC+XML+V0//EN&language=EN

Feron P H M, Abu-Zahra M R M, Alix P, Biede O, Broutin P, de Jong H, and others. (2007) Development of post-combustion capture of CO_2 within the CASTOR Integrated Project: Results from pilot plant operation using MEA. In: *Proceedings of Third International Conference on Clean Coal Technologies for our Future*, Sardinia, Italy, 15-17 May 2007

Figueroa J D, Fout T, Plasynski S, McIlvried H, Srivastava RD (2008) Advances in CO_2 capture technology—The U.S. Department of Energy's Carbon Sequestration Program. *International Journal of Greenhouse Gas Control Technologies*; **2** (1); 9-20 (Jan 2008)

G8 leaders (2008) G8 *Hokkaido Toyako Summit Leaders Declaration* (Jul 2008) http://www.mofa.go.jp/policy/economy/summit/2008/doc/doc080714__en.html

Garcia Pena F, Coca P ELCOGAS: R&D activities forwards zero emissions IGCC plants. In: *Proceedings of the 4th international conference on clean coal technologies (CCT2009)*, Dresden, Germany, 18-21 May 2009

Gerlagh R (2006) ITC in a global growth-climate model with CCS: The value of induced technical change for climate stabilization. *Energy Journal*; **Sp. Iss. 1**; 223-240

Gibbins J, Chalmers H (2008) Preparing for global rollout: A 'developed country first' demonstration programme for rapid CCS deployment. *Energy Policy*; **36** (2); 501-507 (Feb 2008)

Gibbins J R, Crane R I (2004) Scope for reductions in the cost of CO_2 capture using flue gas scrubbing with amine solvents. *Proceedings of the Institution of Mechanical Engineers Part A – Journal of Power and Energy*; **218** (4); 231-239 (Jun 2004)

Gostling J (2002) Two Shifting of Power Plant: Damage to Power Plant Due to Cycling – A brief overview *OMMI*; **1** (1); 1-9. http://www.ommi.co.uk/PDF/Articles/35.pdf

Grathwohl S, Lemp O, Schnell U, Maier J, Scheffknecht Ga, Kluger F and others (2009) Highly Flexible Burner Concept for Oxyfuel Combustion. In: Proceedings of *1st International Oxyfuel Combustion Conference*, Cottbus, Germany, 7-11 September 2009

GreenGen (2006) *General goals of the GreenGen project.* http://greengen.com.cn/en/aboutgreengenproject.htm

Gross R, Heptonstall P, Anderson D, Green T, Leach M, Skea J (2006) *The Costs and Impacts of Intermittency: An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network Technology and Policy Assessment Report*. London, UK, UK Energy Research Centre, 112 pp (Mar 2006) http://www.ukerc.ac.uk/Downloads/PDF/06/0604Intermittency/0604IntermittencyReport.pdf

Haines M R, Davison J E (2009) Designing carbon capture power plants to assist in meeting peak power demand. *Energy Procedia* **1** (1), 1457-1464

Hansen J and 46 co-authors (2007) Dangerous human-made interference with climate: a GISS modelE study.

Atmospheric Chemistry and Physics; **7** (9); 2287–2312

Heffner G, Goldman C, Kirby B, Kintner-Meyer M (2007) *Loads Providing Ancillary Services: Review of International Experience*. Report LBNL –62701. Ernest Orlando Lawrence Berkeley National Laboratory, 64 pp (May 2007) http://www.oe.energy.gov/DocumentsandMedia/Loads_providing_Ancillary_Services_main_report_62701.pdf

Henderson C (2007) Case studies on recently constructed fossil-fired plants In: *Proceedings of Third International Conference on Clean Coal Technologies for our Future*, Sardinia, Italy, 15-17 May 2007

Herguera I (2000) Bilateral contracts and the spot market for electricity: some observations on the British and the NordPool experiences. *Utilities Policy*; **9** (2); 73-80. (Jun 2000)

HM Treasury (2007) *The King Review of low-carbon cars, Part I: the potential for CO_2 reduction* London, UK, HM Treasury, Crown Copyright (Oct 2007) http://www.hm-treasury.gov.uk/d/pbr_csr07_king840.pdf

Holloway S (2009) Storage capacity and containment issues for carbon dioxide capture and geological storage on the UK continental shelf. *Proceedings of the Institution of Mechanical Engineers Part A – Journal of Power and Energy*; **223** (3); 239-248 (Apr 2009)

IEA (2007) *Climate Policy Uncertainty and Investment Risk*. International Energy Agency, Paris, France, OECD/IEA, http://www.iea.org/textbase/nppdf/free/2007/Climate_Policy_Uncertainty.pdf

IEA (2008a) *Energy Technology Perspectives 2008*, International Energy Agency, Paris, France, OECD/IEA

IEA (2008b) *World Energy Outlook 2008*, International Energy Agency, Paris, France, OECD/IEA

IEA GHG (2004) *Improvement in power generation with post combustion capture of CO_2.* Report PH4/33. International Energy Agency Greenhouse Gas R&D Programme**,** Cheltenham, UK, 272 pp (Nov 2004)

IEA GHG (2005a) *Retrofit of CO_2 capture to natural gas combined cycle power plants.* Report 2005/1. International Energy Agency Greenhouse Gas R&D Programme**,** Cheltenham, UK, 247 pp (Jan 2005)

IEA GHG (2005b) *Oxy Combustion Processes for CO_2 Capture from Power Plant.* Report 2005/9. International Energy Agency Greenhouse Gas R&D Programme**,** Cheltenham, UK, 212 pp (Jul 2005)

IEA GHG (2007) *CO_2 Capture Ready Power Plants.* Report 2007/4. International Energy Agency Greenhouse Gas R&D Programme**,** Cheltenham, UK, 127 pp (May 2007)

IEA GHG (2008) *Scoping Study on Operating Flexibility of Power Plants with CO_2 Capture.* Report 2008/TR1. International Energy Agency Greenhouse Gas R&D Programme**,** Cheltenham, UK, 86 pp (Sep 2008)

IEEE Reliability System Taskforce (1999) *The IEEE Reliability Test System – 1996* IEEE Transactions on Power Systems; **14** (3); 1010-1020 (Aug 2009)

ILEX Energy Consulting and Strbac G (2002) *Quantifying the System Costs of Additional Renewables in 2020*. London, UK, Department of Trade and Industry. (Oct 2002) http://www.berr.gov.uk/files/file21352.pdf

Imsland L (2006) On the dynamics and control of two oxyfuel power cycles for CO_2 capture. In: *Proceedings of the 8th International Conference on Greenhouse Gas Control Technologies: GHGT-8*, Trondheim, Norway, 19-22 June 2006. Oxford, UK, Elsevier Science Ltd

IPCC (2005) *IPCC Special Report on Carbon Dioxide Capture and Storage.* Prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz B, Davidson O, de Coninck HC, Loos M, Meyer LA (eds.)].United Kingdom and New York, USA, Cambridge University Press, 442 pp, http://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf

IPCC (2007) *Climate Change 2007: Synthesis Report. Contribution of Working Groups I, II and III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* [Core Writing Team, Pachauri, R.K and Reisinger, A. (eds.)]. Geneva, Switzerland, IPCC, 104 pp http://www.ipcc.ch/publications_and_data/publications_ipcc_fourth_assessment_report_synthesis_report.htm

Jakobsen VE, Hauge F, Holm M, Kristiansen B (2005) Environment and value creation: CO_2 for EOR on the Norwegian shelf – a case study. Bellona, 108 pp (Aug 2005) http://www.bellona.org/filearchive/fil_CO2_report_English_Ver_1B-06022006.pdf

Japan CCS Co Ltd (2008) Japan CCS has embarked upon a full-scale enterprise. *RITE CCS Workshop 2008*, 26 September 2008, http://www.rite.or.jp/Japanese/labo/choryu/ccsws/ccsws2008tokyo/6.pdf

Jordal K, Anheden M, Yan J, Stromberg L (2004) Oxyfuel Combustion for Coal-fired Power Generation with CO_2 Capture – Opportunities and Challenges. In: *Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies: GHGT-7*, Vancouver, Canada, 5-9 September 2004. Oxford, UK, Elsevier Science Ltd

Kellas A (2000) The Use of WASP model and the Generation System Development in Cyprus. In: *Proceedings of 10th Mediterranean Electrotechnical Conference, 2000. MELECON 2000*, Lemesos, Cyprus, 29-31 May 2000; vol **3**; 1036-1038

Kempton W, Letendre S (1997) Electric Vehicles as a New Source of Power for Electric Utilities. *Transportation Research Part D – Transport and Environment*; **2** (3); 157-175 (Sep 1997)

Kintner-Meyer M, Schneider K, Pratt R (2006) *Impacts Assessment of Plug-in Hybrid Vehicles on Electric Utilities and Regional U.S. Power Grids (Part 1: Technical Analysis).* Pacific Northwest National Laboratory, Richland, Washington, USA. http://www.ferc.gov/about/com-mem/wellinghoff/5-24-07-technical-analy-wellinghoff.pdf

Kjaer S (1993) *Die zukunftingen 400-MW-ELSAM-Block in Aalborg und Skaerbaek*, ELSAM report number EP93-02, VGB Conference, Kolding, 16-18 June 2003

Kluger F, Mönckert P, Krohmer B, Stramatelopoulos G-N, Jacoby J and Burchhardt U (2009) Oxyfuel Pulverized Coal Steam Generator Development 30MWth Pilot Steam Generator Commissioning and Testing. In: Proceedings of *1st International Oxyfuel Combustion Conference*, Cottbus, Germany, 7-11 September 2009

Knudsen J N, Jensen J N, Vilhelmsen P J, Biede O (2007) Second year operation experience with a 1 t/h CO_2 absorption pilot plant at Esbjerg coal-fired power station in Denmark. In: *Proceedings of 24th Annual International Pittsburgh Coal Conference*, Johannesburg, South Africa, 10-14 September 2007

Koyanagi F, Uriu Y (1997) Modeling power consumption by electric vehicles and its impact on power demand. *Electrical*

Engineering in Japan; **120** (4); 40-47 (Sep 1997). Translated from Denki Gakki Ronbunshi; 117-B (1); 41-46; Jan 1997
Kruger K, Franke R, Rode M (2004) Optimization of boiler start-up using a nonlinear boiler model and hard constraints. *Energy*; **29** (12-15); 2239-2251.
Kvamsdal H M, Jakobsen J P, Hoff K A (2009) Dynamic modeling and simulation of a CO_2 absorber column for post-combustion CO_2 capture, *Chem. Eng. Proc*; **48**, 135–144
Lawal A, Wang M, Stephenson P, Yeung H, (2009) Dynamic modelling of CO_2 absorption for post combustion capture in coal-fired power plants. *Fuel*; in-press. DOI:10.1016/j.fuel.2008.11.009
Liang X, Reiner D, Gibbins J, Li J Assessing the value of CO_2 capture ready in new-build coal-fired power plants in China. *Energy Procedia*; **1** (1); 4363-4370
Linnenberg S, Kather A (2009) Evaluation of an Integrated Post-Combustion CO_2 Capture Process for Varying Loads in a Coal-Fired Power Plant using Monoethanolamine. In: *Proceedings of the 4th international conference on clean coal technologies (CCT2009)*, Dresden, Germany, 18-21 May 2009
Lucquiaud M, Gibbins J (2009a) Retrofitting CO_2 capture ready fossil plants with post-combustion capture. Part 1: requirements for supercritical pulverized coal plants using solvent-based flue gas scrubbing. *Proceedings of the Institution of Mechanical Engineers Part A – Journal of Power and Energy*; **223** (3); 213-226 (Apr 2009)
Lucquiaud M, Gibbins J (2009b) Steam turbines for post-combustion capture. In: *Proceedings of the 8th Annual Conference on Carbon Capture & Sequestration*, Pittsburgh, USA, 4-7 May 2009
Lucquiaud M, Chalmers H, Gibbins J (2007) Potential for flexible operation of pulverised coal power plants with CO_2 capture. *Energy Materials*; **2** (3); 175-180
Lumby S, Jones C (1999) *Investment appraisal and financial decisions.* 6th Ed, London, UK, International Thomson and Business Press, 647 pp
Modern Power Systems (2008) *Global CCS Institute receives strong support*. Modern Power Systems (1 Dec 2008) http://www.modernpowersystems.com/story.asp?sectionCode=131&storyCode=2051601
Morgan M G, Henrion M (1990) *Uncertainty: A Guide to Dealing with Uncertainty in Quantitative Risk and Policy Analysis*. Cambridge, UK and USA, Cambridge University Press
New Energy Focus (2008) *European leaders agree 2020 climate change targets.* New Energy Focus. (12 Dec 2008) http://www.newenergyfocus.com/do/ecco.py/view_item?listid=1&listcatid=109&listitemid=2031
Newcomer A, Apt J (2007) Storing syngas lowers the carbon price for profitable coal gasification. *Environ. Sci. Technol.*; **41**, 7974–7979
Norris D P, Tabberer R J, Dimou E, Zhang N (2004) *Techno-Economic Evaluation – Cleaner Coal Plant Operability*. Report No. COAL R238, DTI/Pub URN 04/698. (Nov 2004)
Official Journal of the European Communities (2001) Directive 2001/80/EC of the European Parliament and of the Council of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants. (27 Nov 2001) http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2001:309:0001:0021:EN:PDF
Panesar R S, Lord M R, Simpson S T, White V, Gibbins J, Reddy S (2007) *Coal-fired advanced supercritical retrofit with CO_2 capture.* Final Report. Technology Strategy Board: Emerging Energy Technologies – Project Report, Contract Number C/08/00393/00/00, 83 pp (Dec 2007)
Parliamentary Office of Science and Technology (POST), (2001) *UK Electricity Networks.* POSTnote No.163, London, UK, POST, Parliamentary Copyright. (Oct 2001) http://www.parliament.uk/post/pn163.pdf
Patino-Echeverri D, Morel B, Apt J, Chen C (2007) Should a coal-fired power plant be replaced or retrofitted? *Environmental Science and Technology*; **41** (23); 7980-7986. (Oct 2007)
PTRC (2009) Weyburn-Midale CO_2 project. Petroleum Technology Research Centre, http://www.ptrc.ca/weyburn_overview.php
Pöyry Energy Consulting (2007) *Analysis of Carbon Capture and Storage Cost-Supply Curves for the UK.* Oxford, UK, Pöyry Energy (for UK Department of Trade and Industry), 34 pp, http://www.berr.gov.uk/files/file36782.pdf
Pöyry Energy Consulting (2009) Impact of Intermittency: How Wind Variability Could Change the Shape of the British and Irish Electricity Markets, 30 pp http://www.ilexenergy.com/pages/documents/reports/renewables/Intermittency%20Public%20Report%202_0.pdf
Provost G T, Erbes M R, Stone H P, Zitney S E, Turton R, Phillips J and others (2008) Generic Process Design and Control Strategies Used to Develop a Dynamic Model and Training Software for an IGCC Plant with CO_2 Sequestration. *Proceedings of 25th Annual International Pittsburgh Coal Conference*, Pittsburgh, Pennsylvania, USA, 29 September – 2 October 2008
Race J M, Seevam P N, Downie M J (2007) Challenges for offshore transport of anthropogenic carbon dioxide. In: *Proceedings of 26th International Conference on Offshore Mechanics and Arctic Engineering*, San Diego, USA, 10-15 June 2007. American Society of Mechanical Engineers
Reinelt P S, Keith D W (2007) Carbon capture retrofits and the cost of regulatory uncertainty. *Energy Journal*; **28** (4); 101-27
Roques F A, Nuttall W J, Newbery D M (2006) Using Monte Carlo simulation to assess the impact of risks and managerial flexibility on different generation technologies In: *Proceedings of the 26th USAEE/IAEE North American Conference*, Ann Arbor, USA, 24-27 September 2006. Cleveland, Ohio, USA, International Association of Energy Economics
Sakai K, Morita S, Sato T (1999) State-of-the-art technologies for the 1000-MW 24.5-MPa/600°C/600°C coal-fired boiler. *Hitachi Review* 1999; **48** (5); 273–276. http://www.hitachi.com/rev/1999/revoct99/r5_104.pdf
Santos S (2009) Cheltenham, UK, International Energy Agency Greenhouse Gas R&D Programme personal communication (Aug 2009)
Sarofim A (2007) *Oxy-fuel combustion: progress and remaining issues*. Presentation to 2nd workshop of the International Oxy-Combustion Research Network
SaskPower (no date) Clean Coal Project http://www.saskpower.com/cleancoal/index.html
ScottishPower (2009) ScottishPower Ready To Kick-Start Central North Sea Carbon Storage Industry Within Five Years http://www.scottishpower.com/PressReleases_1864.htm

Scottish Centre for Carbon Storage (2009) *Where is CO_2 storage taking place?* http://www.geos.ed.ac.uk/sccs/storage/storageSitesFree.html

Sekar RC (2005) *Carbon Dioxide Capture from Coal-Fired Power Plants: A Real Options Analysis.* Report Number MIT LFEE 2005-002 RP, Cambridge, Massachusetts, USA, MIT Laboratory for Energy and the Environment. (May 2005) http://sequestration.mit.edu/pdf/LFEE_2005-002_RP.pdf

Shell (2007) *Powerfuel and Shell Sign Agreement for Coal Gasification*. Press release. (17 Apr 2007) http://www.shell.co.uk/home/content/gbr/aboutshell/media_centre/news_and_media_releases/2007/news/powerfuel_agreement_170407.html

Short W, Ferguson T, Leifman M (2006) Modeling of Uncertainties in Major Drivers in U.S. Electricity Markets In: *Proceedings of the 26th USAEE/IAEE North American Conference*, Ann Arbor, USA, 24-27 September 2006. Cleveland, Ohio, USA, International Association of Energy Economics

Sinden G (2007) Characteristics of the UK wind resource: Long-term patterns and relationship to electricity demand. *Energy Policy*; **35** (1); 112-127. (Jan 2007)

Sorrell S, Skea J (1999) *Pollution for sale: emissions trading and joint implementation*, International Studies in Environmental Policy Making, Cheltenham, UK, Edward Elgar Publishing, 390 pp

Statoil (no date) *CO_2 storage 1,000m down*. http://www.statoil.com/statoilcom/svg00990.nsf/web/sleipneren?opendocument

Trigeorgis L (2003) Real Options and Interactions with Financial Flexibility. *Financial Management*; **22** (3); 202-224

Turner G (2009) European and Global CCS: the Current Status and Future Need. Presentation to *CCSA CCS Implementation Workshop*, Brussels, 29 April 2009. http://www.ccsassociation.org/docs/2009/Guy%20Turner%20CCS%20EP%20workshop%20290409.pdf

Turvey R (1968) *Optimal pricing and investment in electricity supply: an essay in applied welfare economics.* London, UK, George Allen and Unwin Ltd, 124 pp

US Department of Energy (2008) Weyburn Carbon Dioxide Sequestration Project. Project facts series. Pittsburgh, USA, US Department of Energy Office of Fossil Energy National Energy Technology Laboratory, 4 pp, April 2008, http://www.netl.doe.gov/publications/factsheets/project/Proj282.pdf

US Department of Energy (2009a) FutureGen Clean Coal Project (14 Jul 2009) http://fossil.energy.gov/programs/powersystems/futuregen/

US Department of Energy (2009b) Secretary Chu Announces Two New Projects to Reduce Emissions from Coal Plants (1 Jul 2009). http://www.fossil.energy.gov/news/techlines/2009/09043-DOE_Announces_CCPI_Projects.html

US Government (2009) American Recovery and Reinvestment Act of 2009. Washington DC, USA. http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=111_cong_bills&docid=f:h1enr.pdf

Vose D (2000) *Risk Analysis: A Quantitative Guide.* 2nd ed. Chichester, UK, John Wiley & Sons Ltd, 430 pp

Watson J, Sauter R, Bahaj B, James P, Myers, L, Wing R (2008) Domestic micro-generation: Economic, regulatory and policy issues for the UK. *Energy Policy*; **36** (8); 3095-3106

White V (2006) Hersham, UK, Air Products *personal communication*. (Dec 2006)

White V, Armstrong P, Fogash K (2009) Oxygen Supply for Oxyfuel CO_2 Capture. In: Proceedings of *1st International Oxyfuel Combustion Conference*, Cottbus, Germany, 7-11 September 2009

Wise M A, Dooley J J (2009) The value of post-combustion carbon dioxide capture and storage technologies in a world with uncertain greenhouse gas emissions constraints. *International Journal of Greenhouse Gas Control Technologies*; **3**, 39-48

World Resources Institute (WRI), (2008) *CCS Guidelines: Guidelines for Carbon Dioxide Capture, Transport, and Storage.* Washington DC, USA. http://www.wri.org/publication/ccs-guidelines

Yamada T, Kiga T, Fujita N, Inoue T, Okawa M, Murata Y, Arai K, Seo Y (1999) Development of the dynamic plant simulation in CO_2-recovery type pulverized-coal fired power plant applied oxygen/recycled flue gas combustion. In: *Joint Power Generation Conference*, **1**, 557-522, ASME

ZEP (2008) EU Demonstration Programme for CO2 Capture and Storage (CCS) ZEP's Proposal. European Technology Platform for Zero Emissions Power Plants, (Nov 2008) http://www.zero-emissionplatform.eu/website/docs/ETP%20ZEP/EU%20Demonstration%20Programme%20for%20CCS%20-%20ZEP%27s%20Proposal.pdf

Ziaii S, Cohen S, Rochelle GT, Edgar T F, Webber M E, (2009a) Dynamic operation of amine scrubbing in response to electricity demand and pricing. *Energy Procedia*; **1**, 4047-4053

Ziaii S, Rochelle G T, Edgar T F (2009b) Dynamic Modeling to Minimize Energy Use for CO_2 Capture in Power Plants by Aqueous Monoethanolamine. *Ind. Eng. Chem. Res.*; in press. DOI: 10.1021/ie801385q

(All web references last visited 29 September 2009)

9 Appendix – key input assumptions for Figures 11,12,14 and 15

Figures 11 and 12

In most cases, assumptions given here follow Davison (2007).

Base plant performance
Specific CO_2 emissions from coal: 91 $kgCO_2$/GJ burned
Specific CO_2 emissions from gas: 58.5 $kgCO_2$/GJ burned
CO_2 captured when capture plant operated: 90% of CO_2 produced
CO_2 captured when capture plant bypassed: none
Supercritical coal-fired plant efficiency without capture at maximum output (LHV): 44%
Subcritical coal-fired plant efficiency without capture at maximum output (LHV): 36%
Coal energy capture penalty (LHV): 9 percentage points
NGCC plant efficiency without capture at maximum output (LHV): 55.5%
NGCC energy capture penalty (LHV): 7 percentage points

Input prices and costs
Coal price: 2.2 $/GJ (and 4.4 $/GJ sensitivity)
Natural gas price: 7.8 $/GJ (and 15.6 $/GJ sensitivity)
Variable costs for non-capture operations: negligible
Variable costs for capture, transport and storage: 11 $/t$CO_2$ captured and stored
CO_2 price: various, as reported in results
Illustrative mark-up on SRMC for electricity selling price: 2 $/MWh

Figure 14

Summary of assumptions used for preliminary study	
CO_2 produced from fuel	Coal: 91 $kgCO_2$/GJ burned (estimated based on IEA GHG PH4/33 report base case)
Boiler efficiency across the range of load	94% Boiler efficiency changes down to 70% load can be neglected. Increased radiation and air leakage losses will tend to be offset by reduced flue gas exit temperatures and possibl improved combustion at lower mill throughputs
Generator efficiency across the range of load	Generator efficiency is constant between 70% and 100% load
Steam turbines	Operated by sliding pressure Reheat temperature is aintained across the range considered Constant turbine efficiencies. HP: 87.5%, IP: 93%, LP: 94%
Capture plant	CO_2 capture efficiency of 85% Constant solvent regeneration temperature of 120°C. Constant heat of regeneration across the range of load. Solvent reboiler requirement of 490.4 MW for 1913 MW of fuel input
Ancillary power	Constant across the range of load Boiler and turbine island: 81 MW Capture plant: 20 MW (based on IEA GHG PH4/33 base case)
Compression power	60 MW at base load Proportional to CO_2 regenerated in solvent reboiler. Low grade heat available for feedwater heating is determined by the CO_2 compressor outlet temperature. (Condensate temperature at the outlet of heat recovery exchanger based on IEA GHG PH4/33 base case.) The plant has extra compression capacity for additional solvent regeneration

Figure 15

Where possible, assumptions are taken from Davison (2007) or Chalmers and Gibbins (2007).

Summary of efficiency and CO_2 emitted at full load for power plants		
Plant type	Efficiency, %, LHV	CO_2 emitted, g/kWhe
New supercritical coal (no CCS)	44	743
New supercritical coal with CCS (90% capture)	35	93
Subcritical coal (no CCS)	36	908
Subcritical coal retrofitted with CCS (90% capture)	27	121
NGCC (no CCS)	55.5	379
For all operating modes, assume no balance of plant constraints for exporting power produced etc		

Basic plant costs
Net plant output without CCS (at full load): 750 MW
Coal price: 2.2 $/GJ
Gas price: 7.8 $/GJ
Marginal costs for solvent: 5 $/t$CO_2$
Nominal cost for CO_2 transport and storage: 11 $/t$CO_2$
Other marginal operating costs: negligible

Electricity price assumptions
'High' daytime electricity price: short run marginal cost of maximum of subcritical coal or NGCC (both without CO_2 capture)
'Mid' daytime electricity price: short run marginal cost of maximum of subcritical coal (with CO_2 capture installed) or NGCC (without CO_2 capture)
Night electricity price: short run marginal cost of minimum of subcritical coal or NGCC (both without CO_2 capture)
Peak electricity price: 2x or 4x daytime electricity price (high case used for solvent storage illustrative case)
Length of peak price assumed for solvent storage cycle economic calculations: 2 h

Performance with solvent storage
Energy penalty during solvent storage: 1% of fuel LHV
Solvent flow during regeneration: 125% of normal solvent flow
Regeneration time for 125% flowrate: 4 h for each hour of solvent storage
Energy penalty during solvent regeneration: Increase in direct proportion to solvent flow rate (125% of energy penalty with additional regeneration for 125% flowrate)