Systems analysis of the techno-economic investment required for coal generation with carbon capture and storage

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Declaration

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Abstract

This thesis uses an engineering systems approach to assess the technical and economic investment required for coal with carbon capture and storage (CCS) to make a contribution to electricity generation in the UK.

The thesis begins by presenting the wider case for deployment of CCS at the global level and the UK level. It is shown that from a policy perspective, the deployment of coal with CCS is necessary to ensure emissions targets can be met, as apart from nuclear, it is the only technology that will allow existing fossil fuel reserves to be used- something that will certainly happen. However, questions remain over the technical feasibility and the commercial case for the adoption of CCS technology. Therefore, the remainder of the thesis presents a detailed technology assessment and financial analysis to derive the market case for deploying coal with CCS.

The technology assessment extends previous work in this area by comparing sub system performance across all capture technologies in detail. The combination of current and future technical developments for CCS along with the use of technology and system readiness levels is a novel approach to technology assessment and extends previous work in the area by presenting a systems framework under which CCS technology can be evaluated. The conclusion of the technology assessment is that pulverised-coal plant with post combustion capture is the closest CCS technology to deployment.

The second part of this thesis concerns the investment case for CCS. The analysis involves a derivation of costs for carbon capture technologies. The financial characteristics of CCS are identified using sensitivity analysis to compare to both the original plant and incumbent choice for new generation (gas fired CCGT), and implications for policy and investors are drawn out. Investment in a CCS plant is then valued as a perpetual American call option, while the expected time to investment is evaluated using mean time to absorption calculus. This approach of combining the American call option with the mean time to absorption method is a novel way to assess the expected timeframe over which investment in CCS could take place and extends previous work in this area.

Recently, real options analysis has been used in engineering systems analysis. Although not as advanced as in business and economic investigations, real options analysis has begun to be used to recognise the value of flexibility in system design. The intellectual and practical contribution of this thesis to the field of engineering systems lies in the derivation of a framework for the consistent analysis of current and future power generation technologies, coupled with real options analysis of an American call option with the mean time to absorption to evaluate the investment case for coal CCS.

The relevance of adopting a systems approach for real world application of this research has been proved by the project commissioned during the course of this research for ATCO Power (Canada) Ltd concerning

evaluation of the most promising options for carbon capture and storage and technology and investment case for future business strategy, which included material from Chapters 4 and 5 of the thesis.

NOMENCLATURE

Abbreviations

ASU	air separation unit	MEA	Monoethanolamine
AZEP	advanced zero emission power plant	MOFC	molten oxide fuel cell
BCM	billion cubic meter	Mtoe	million tonnes oil equivalent
CAPEX	capital expenditure	MWe	electric power output (MW)
CCGT	combined cycle gas turbine	OTM	oxygen transport membrane
CCS	carbon capture and storage	PC	pulverised-coal fired power plant
CLC	chemical looping combustion	Ppmv	parts per million by volume
COE	cost of electricity	PPP	plant performance parameter
CO_2	carbon dioxide	PVAm	Polyvinylamine
CV	calorific value	PSA	pressure swing adsorption
ECBM	enhanced coal bed methane	R&D	research and development
EGR	enhanced gas recovery	SCR	selective catalytic reduction
EOR	enhanced oil recovery	SOFC	solid oxide fuel cell
ESP	electrostatic precipitator	SOX	sulphur oxides
EU	European Union	SPP	system performance parameter
FGD	flue gas desulphurisation	SWOT	strengths, weaknesses, opportunities and threats
HHV	higher heating value	Syngas	synthesis gas
HRSG	heat recovery steam generation	TPC	total plant cost
IGCC	integrated gasification combined cycle	TPP	technical performance parameters
IGFCCC	integrated gasification fuel cell combined cycle	TRL	technology readiness level
IPCC	intergovernmental panel on climate change	USC	ultra super critical
LCPD	large combustion plant directive	WGS	water gas shift reaction
LHV	lower heating value	WSOI	wider system of interest
LP	low pressure cycle		

Symbols

C_g	cost of generation (£/MWh)
$C_cA(t,r)$	annuity payable on the capital cost; r is the interest rate, t is the loan period (£/year)
C_{O+M}	fixed annual operation and maintenance costs (£/year)
$C_dB(t,r)$	annual payment to a decommissioning fund (£/year)
C_f	fuel cost (£/MWh)
U_t	average annual load factor of a plant (%)
P_c	plant capacity (MW)
C_E	cost of emissions (£/MWh)
NPV	net present value (£)
$\varDelta$	capital recovery factor (%)
R	revenue (£)
C_c	capital cost (£)
C_o	annual operations costs (incl. O+M and fuel costs) (£/year)
E	proportion of capital provided by equity (%)
D	proportion of capital provided by debt (%)
R	interest rate (%)
T	Time
C_d	capital investment for decommissioning funds (£)
K	return required on equity in perpetuity (%)
$\varLambda$	rate of interest on decommissioning saving fund (%)
Cv	calorific value of fuel (GJ/t)
C_{carbon}	cost of carbon on the market (£/tonne)
η	efficiency of a process (dmnl)
e.f.	emissions factor of a process
m_f	rate at which fuel is burnt (t/MWh)
$C_{avoided}$	cost of CO_2 avoided (£/tonne)
E_{coal}	emissions from coal plant (tonnes/year)
E_{coal_CCS}	emissions from CCS plant (tonnes/year)
E_{CO2}	emissions of CO_2 (t/hour)
C(t)	price of a call option
$\varPhi$	cumulative standard normal distribution
M	Drift
$\varSigma$	Volatility
Dz	Weiner process having a drift of zero and variance of 1
S	price of the asset
R	annual revenue (£/year)
P_e	price of electricity (£/MWh)
$\varOmega$	option value
B	constant (function of δ and σ)

1 Introduction

This thesis has been written to assess the technical and economic investment required for coal with carbon capture to make a contribution to the electricity generation in the UK.

Carbon capture and storage (CCS) is a process that can be applied to fossil fuel power stations (or industrial processes) to significantly reduce emissions of carbon dioxide. Carbon dioxide is separated as part of the overall generation process and compressed. It is then transported to a suitable location to be stored in isolation from the atmosphere.

The sub-objectives of this thesis are to:

I. Evaluate the need for the deployment of coal with carbon capture and storage at the UK level by identifying and assessing global and UK environmental, political and economic drivers;
II. Evaluate the entire carbon capture and storage chain for technical feasibility;
III. Identify the leading carbon capture technology given current and future performance potential;
IV. Compare and evaluate the economic characteristics and sensitivities of coal/gas with CCS compared to a standard coal/gas plant;
V. Evaluate the expected timeframe over which coal CCS plant could be expected to become a viable generation choice in the UK market under revenue uncertainty.

Chapter 1 partially answers sub-objective I by assessing the global need for CCS. The global trends provide environmental and political incentives for the uptake of coal CCS.

Chapter 2 provides the remaining answer to sub-objective I through an evaluation of the potential need for coal CCS at the UK level.

Chapter 3 presents the systems framework used in the analysis of coal CCS. A process chart of the methodology is shown in Figure 1-1.
Chapter 4 answers thesis sub-objectives II and III through the use of systems technology assessment to investigate the viability of the CCS system and leading coal CCS technology. The analysis framework developed in Chapter 3 is applied to the prospective CCS technologies to evaluate which process is best, both from a current and potential technology performance point of view, individual system characteristics and technology readiness i.e. proximity to commercial deployment. The combination of current and future technical developments for CCS along with the use of technology readiness levels is a novel approach to technology assessment.

Chapter 5 answers thesis sub-objective IV by presenting the results of investment analysis performed to understand the economic characteristics and sensitivities of coal/gas with CCS compared to a standard coal/gas plant. Chapter 5 also assesses the cost profiles of the different generation technologies to understand the economic conditions under which investment in CCS plant will become preferable to investment in a CCGT plant.

Chapter 6 answers thesis sub-objective V. This is done by applying the mean time to absorption calculus to augment the American call option on a new coal CCS plant. The method of augmenting the American call option valuation with the mean time to absorption is novel and aids the investment decision in new plant by plotting the probability that the critical price required to invest in coal CCS is reached as a function of time.

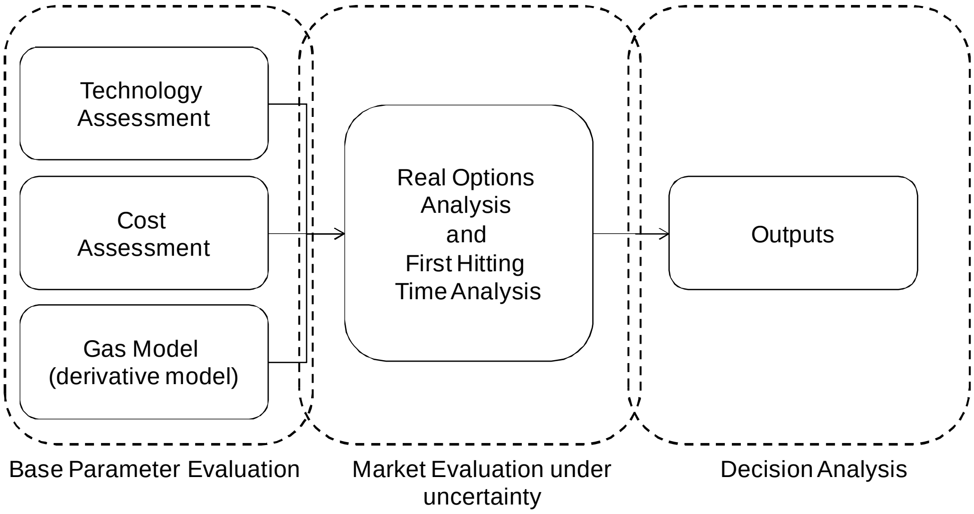

Figure 1-1: Overview of research methodology

Chapter 7 presents the conclusions of the thesis and areas for future work. It also reiterates the objective function of the thesis and evaluates the answers to the stated objectives.

1.1 Global need for carbon capture and storage

Chapter 1 illustrates the global need for coal with CCS by assessing the fundamental drivers and constraints that will necessitate the deployment of the CCS technology and thereby provide part of the need for the UK to deploy CCS technology.

The projected increase in global energy demand is the fundamental driver of the need for coal with CCS. Fossil fuels dominate the current global energy mix. Rising global energy demand will drive an increase in demand for fossil fuels and in particular, due to its abundant nature, coal. Consequently, emissions of carbon dioxide will increase and current environmental targets will not be met. Fitting coal plant with CCS is the only way to allow coal to be used as an energy source while meeting environmental constraints. Moreover, the pathway for global deployment of CCS requires the UK (along with other countries) to develop commercial technology before deployment to non OECD countries which are expected to account for the majority of coal use.

1.2 Global energy demand

The International Energy Agency estimates that world primary energy demand will grow 45% by 2030 (IEA, 2008c) (primary energy refers to the energy contained in raw fuels in their natural form). The rate of growth in energy demand will differ between OECD and non-OECD countries. It is projected that non-OECD countries will account for 87% of the increase in global energy demand to 2030, with China and India accounting for the majority of this (IEA, 2008c). This is because megatrends such as the rate of population growth, urbanisation and economic development, which are the main driving factors for energy demand, will be highest in non-OECD countries and more specifically in China and India. OECD countries are expected to see a modest increase in energy demand, although it should be noted that OECD countries have a far higher energy intensity than non OECD countries' at present (IEA, 2006). To meet rising energy demand, consumption of primary energy sources (especially fossil fuels) is projected to increase Figure 1-2.

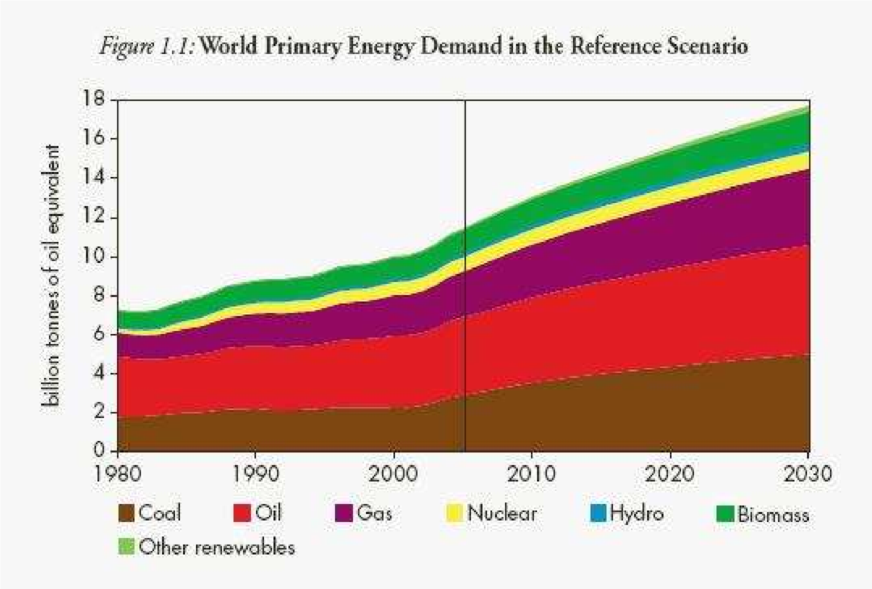

Figure 1-2: Projection of global primary energy demand

Demand for primary energy is derived from four sectors: electricity, transport, industrial and other. Electricity is the largest of the sectors, accounting for 50% of total primary energy demand (IEA, 2007). Moreover, the rate of increase in electricity demand is projected to be greater than the rate of increase in demand for primary energy. As this thesis is written to assess the contribution CCS can make to electricity generation, the next question to ask is: which primary energy sources will be used for electricity generation?

1.3 Distribution and reserves of fossil fuels

The previous Section outlined projections for global primary energy demand. This Section shows that coal will be one of the main fuel sources used to meet primary energy demand, both in the present and into the future, due to its relative abundance and wide distribution.

The first attraction of coal as a primary energy source is its abundance. Calculations based on verified reserves and present consumption rates show that oil production is projected to peak around 2020 (IEA, 2008c), while proven gas reserves are expected to last for 64 years (IEA, 2006). In comparison, proven coal reserves are estimated to last for 164 years (IEA, 2006)[1].

The second attraction of coal is that it is dispersed throughout the world, unlike gas or oil reserves, which are concentrated in politically unstable areas such as the Middle East and Russia (BP, 2007). Moreover, significant coal reserves are found in countries where demand for primary energy is forecast to grow most. Table 1-1 shows that nearly 50% of coal reserves are found in 5, non-OECD, countries. Given that energy demand in these countries (especially in China and India) is projected increase at a high rate, it can be concluded that these countries will use coal reserves to meet primary energy demand (IEA, 2007). This trend can already be seen in the rate at which China is building coal fired power stations (35GW of new coal plant capacity was commissioned in 2009[2]).

Table 1-1: Coal reserves by country (data source: (BP, 2007))

	Total proven reserves (% of global)	Total reserves of anthracite and bituminous coal (% of global)	Country classification
USA	27	23	OECD
Russian Federation	17	10	Non-OECD
China	13	13	Non-OECD
India	10	19	Non-OECD
Australia	9	8	OECD
South Africa	5	10	Non-OECD
Ukraine	4	3	Non-OECD
Other	15	14	N/A

1.4 Environmental constraint

There is a general agreement among scientists that climate change is caused by the release of greenhouse gases due to human activities (IPCC, 2007). The consequences of irreversible climate change are sufficient to motivate world policy makers to call for a cap to world greenhouse gas emissions. However, meeting increasing energy demand by use of unabated fossil fuels will cause emissions of greenhouse gases to increase significantly.

Greenhouse gases (GHG's) are a bundle of chemical species that all have a positive radiative forcing effect on the atmosphere. Of all greenhouse gases, CO_2 is the most prominent because of the scale on

[1] There is much uncertainty and speculation surrounding fossil fuel reserves. Key uncertainties are lack of geological knowledge and uncertainties due to political or economic interest.
[2] http://www.instituteforenergyresearch.org/2010/09/01/some-coal-fired-power-plants-were-built-last-year-is-this-the-start-of-a-new-trend-or-are-new-coal-plants-dead/

which it is emitted. Figure 1-3 shows that emissions of CO_2 by sector: the power generation sector will require the most energy and will produce the most CO_2 emissions, more than double those of transport (IEA, 2007). Figure 1-3 also shows the impact non-OECD countries will have on global emissions – in the legend, 'transition economies' refers to economies from the old Soviet Union, while developing countries refers to other non-OECD countries.

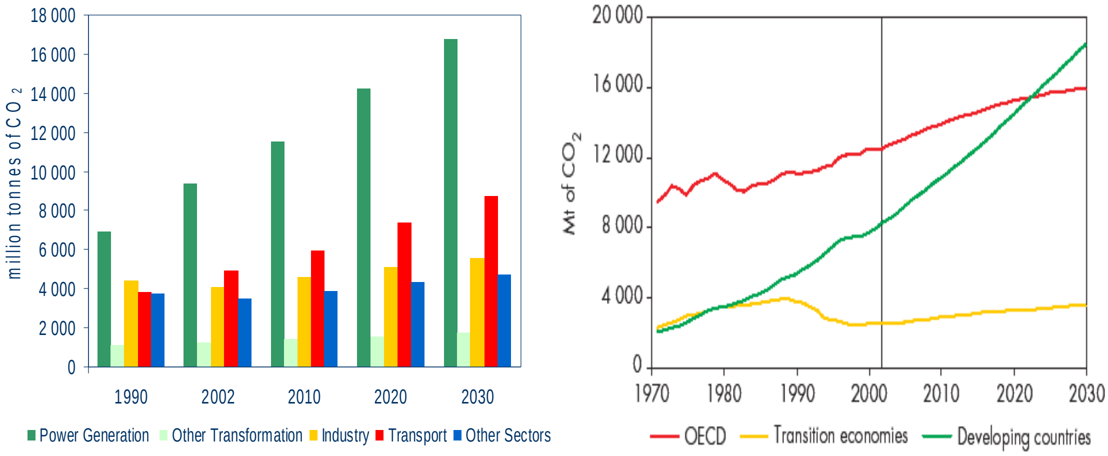

Figure 1-3: Emissions by sector and region (Source: (IEA, 2007))

Figure 1-3 shows that by 2020, emissions from non-OECD countries, primarily driven by China and India, (China and India will account for 80% of the increase in coal demand to 2030 (EIA, 2007)) will surpass the emissions from OECD countries. Non-OECD countries will become the major emitters of GHG's due to meeting increasing energy demand resulting from increasing wealth and population.

Combustion of coal accounted for 41% of CO_2 emissions in 2005 and is projected to continue to be the leading source of CO_2 emissions in all IEA growth scenarios (IEA, 2007). Therefore the combustion of coal for electricity generation is expected to account for the majority of CO_2 emissions in all future global energy scenarios.

1.5 Emissions legislation and mitigation options

Concerns over the effects of climate change and global warming have driven intergovernmental organisations to place caps (targets) on the atmospheric concentration of CO_2. The Kyoto Protocol came into force in 2005 and legally binds 37 industrialised countries (excluding the United States) to reduce emissions of greenhouse gases to an average of 5.2% below 1990 levels. In addition, the European Commission has passed legislation requiring 20% of electricity to come from renewable sources by 2020 with even more stringent prospects for legislation likely.

A number of possibilities have been put forward to mitigate CO_2 emissions, while meeting growth in energy demand (Pacala and Socolow, 2004) including:

- Reduce average energy demand by increasing energy efficiency from both automobiles and dwellings;
- Reduce deforestation and promote afforrestation;
- Increase the use of renewable energy;
- Increase the use of nuclear energy (fission);
- Shift towards less carbon intense fuels e.g. coal to natural gas;
- Capture and store carbon dioxide emissions from fossil fuel power stations.

Improvements in energy efficiency are necessary, but not sufficient to address the increase in carbon emissions that will be produced from new generation capacity at the global scale (Deutch and Moniz, 2007). Moreover, the speed and extent to which energy efficiency can be improved and other energy sources can be implemented is questionable (IPCC., 2001). Nuclear energy, although deployable in the OECD countries, is complicated by worries over proliferation of nuclear weapons, waste disposal and public opinion. In addition, the prospect of commercial nuclear fusion still seems distant. The amount of renewable energy that can be deployed is ultimately limited by cost, performance and technology availability. Using less carbon intensive fuels would reduce emissions, but entail switching from coal to gas, which would increase prices and decrease energy security. In addition, the emissions savings would not be enough to offset emissions from new build to a satisfactory degree. CCS has a large potential application because it allows an abundant fossil fuel to be used to meet energy demand while emitting acceptable quantities of CO_2.

The overarching conclusion is that there is no single silver bullet to mitigate all emissions from meeting energy demand. CCS can be seen as one of the mitigation options in a portfolio of CO_2 mitigation technologies. The scale of the challenge is illustrated in Figure 1-4. The image on the left is a graph of carbon emissions over time that is projected into the future. The dotted line marks the business as usual line, while the solid line shows the trajectory required for mitigation of carbon emissions over the next 50 years. The diagram on the right shows the cumulative amount of carbon that needs to be mitigated broken down into seven “wedges”. One wedge is the equivalent of 800GW of coal power stations with CCS. One wedge is also equivalent to doubling the world’s nuclear capacity (Pacala and Socolow, 2004). It should be stated that these example technologies are indicative and there are others available that could also meet one “wedge” of demand e.g. wind. Ultimately, it is most likely that a variety of technologies will need to be deployed to provide low carbon generation. However, it should also be noted that mitigation options involving: i). A switch from coal to gas and/or nuclear or; ii). An expansion into CCS; would result in a faster depletion rate of global fossil fuel reserves.

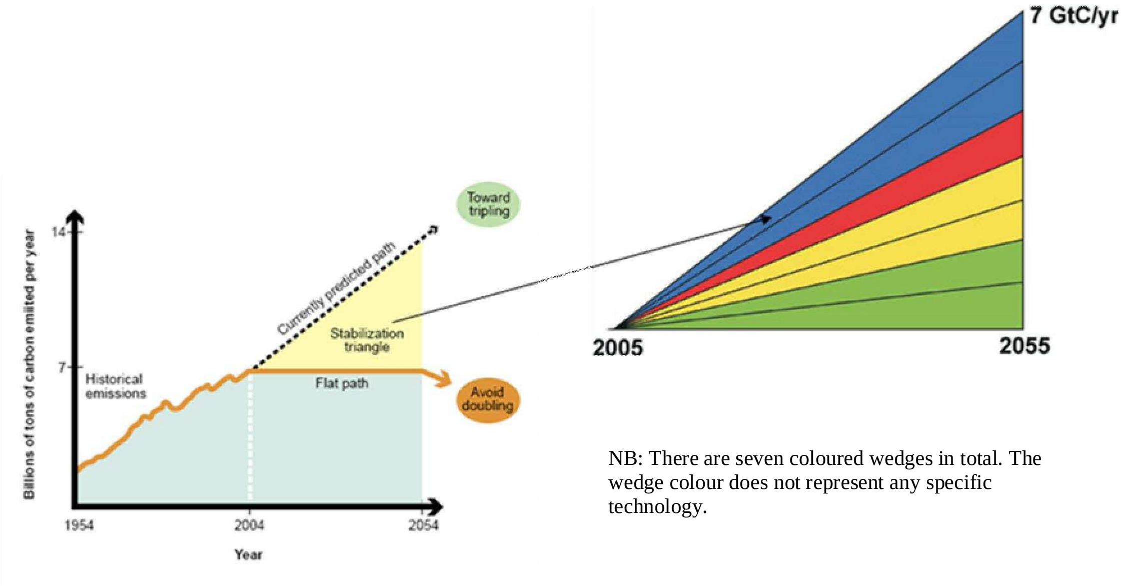

Figure 1-4: Carbon Wedge concept (Source: Carbon Mitigation Initiative, Princeton University)

In order to meet targets on levels of atmospheric CO_2 – set at 450ppmv by the IPCC (IPCC, 2007)- the rate at which CO_2 emissions are released into the atmosphere also needs to be capped. Recent studies have shown that the concentration of CO_2 in the atmosphere is rising by at least 2ppmv per year and is expected to increase in line with energy demand unless mitigation measures are adopted (King, 2005). This implies that targets for global CO_2 levels will be reached sooner than the current rate suggests. In addition, the delay in the Earths' carbon cycle means that even if CO_2 emissions were to stop now, atmospheric CO_2 concentrations would still increase (Sterman and Sweeney, 2002), (King, 2005). Both of these latter points convey the need to take action to reduce CO_2 emissions (by whatever method) sooner rather than later.

Taking action to mitigate emissions in the near term also appears sensible from an economic point of view: the Stern report found that taking action to stabilise emissions at 500ppmv today would cost 1% of global GDP compared to an equivalent cost of between 5 and 20% of GDP per year if action is delayed (Stern, 2006).

1.5.1 Current power generation system architecture

At present, the generation of electricity on a global scale is dominated by fossil fuels (66.6%), followed by hydro (16.4%), nuclear (14.7%), combustible renewables and waste (1.3%) and geothermal, solar and wind along with other renewables which account for 1.1% (IEA, 2008b).

Disaggregating the data into the OECD and non OECD countries, fossil fuels contribute 63% of electricity from OECD countries, while non-OECD countries derive 74% of their electricity from fossil fuels. Coal plants dominate both the OECD and non-OECD countries providing 30% and 55% of total generation capacity respectively (IEA, 2008b).

The system architecture of the electricity generation industry lends itself to the reduction of emissions. Large point sources of carbon intensive emissions can be targeted (and regulated) much more easily than emissions from small sources (e.g. transport). Therefore the power generation sector has the ability to help compensate for other areas of the economy where it is more difficult to reduce emissions.

The average age of OECD power plants is greater than that of non-OECD plants. Therefore OECD countries are replacing aging fleet and non-OECD countries are investing to meet increasing demand. This implies that in the coming years there will be a significant requirement for new generation on a global scale.

1.5.2 Future power generation system architecture

The objective of the future power generation system will be to meet demand in a reliable and economic manner using low carbon technologies. New low carbon forms of generation are required but it is likely that the transition will be incremental as barriers to implementation need to be overcome (Criqui et al., 2007). The main barriers to the deployment of low carbon generation are cost, technical performance and system inertia.

Figure 1-5 illustrates the low economic competitiveness of low carbon generation technologies. Most of the current generation mix is in the top left hand corner. The target is the bottom left hand corner- low carbon emissions and a competitive cost of generation. Fossil fuel generation is relatively low in price compared to renewable energy. For renewable energy to be adopted on a global scale, much of the additional cost associated with low carbon generation will need to be met by government. The trend in Europe is to use tariffs or price emissions that can be traded; however, it is not clear how non OECD countries are expected to adopt more expensive generation technologies. Current low carbon- low cost generation is currently not achievable without some form of subsidy to make low carbon generation cost competitive.

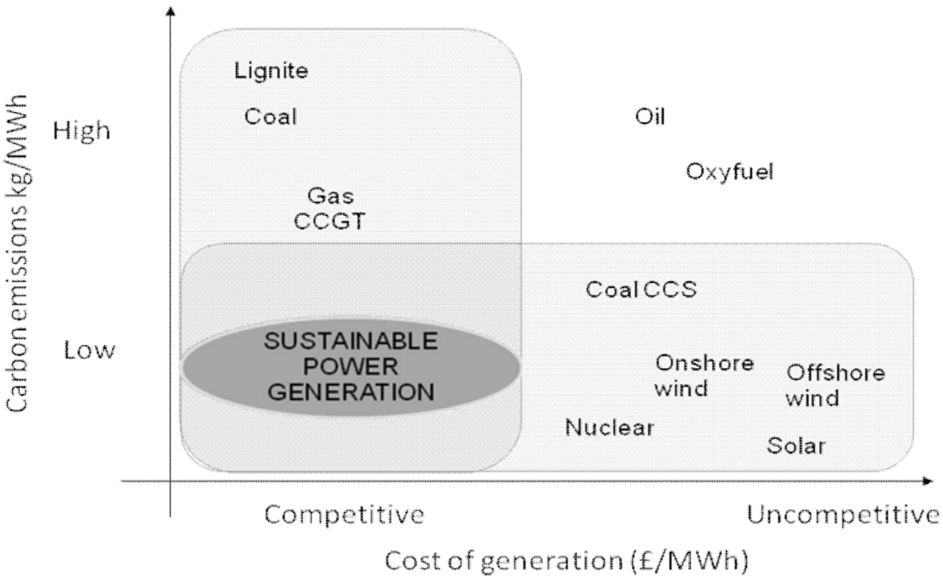

Figure 1-5: Characterisation of generation technologies by cost and carbon emissions

The second barrier is the technical performance of some low carbon generation technologies. The effect of large amounts of wind generation on grid stability is a notorious example, requiring fossil fuel stations to operate as backup plant (Gross et al., 2006). Other types of low carbon generation, such as solar, are limited by geographical location. Finally, some low carbon technologies are fairly new developments and have not been proven at commercial scale.

The third barrier is the inertia in the composition of the current generation system. Infrastructure and control systems have been constructed to meet the needs of centralised fossil fuel generation instead of highly variable output and control (e.g. smart grids). In addition, a coal fired plant built today will operate for the next 40 years, while a CCGT will operate for 25 years. These factors imply a certain amount of technological lock in for fossil fuel generation that is currently being built.

The high cost of low carbon generation, technical performance and system inertia implies that OECD and non OECD countries are likely to develop power generation systems in a different way. OECD countries have the wealth and technical knowledge to adopt significant amounts of low carbon in the near term, given appropriate government intervention and a public willingness to pay. Non-OECD countries will meet the majority of demand through the use of fossil fuels, as these are the least cost generation option. The effect of this is compounded by the expected rate of demand growth in non OECD countries; predictions from the IEA state that fossil fuels will provide the bulk of power generation to 2030 (IEA, 2007).

The transition to low carbon generation in non-OECD countries will be a result of the advances in technical performance and reduction in capital costs through learning by doing as low carbon generation is deployed in the OECD.

In conclusion, future global power generation capacity will be greater than today, and is likely to be fossil fuel dominated to at least 2030, followed by a transition to low carbon generation. The dominant driver is electricity demand, which will grow at a rate that exceeds that of primary energy demand itself. This demand will be primarily met via fossil fuel combustion, with some low carbon generation in OECD countries. Non OECD countries, in particular China and India will drive the increase in fossil fuel generation. Due to its abundant nature, the dominant fossil fuel for global electricity production will be coal, which if not mitigated will cause emissions to rise to unsustainable levels.

1.6 Achieving global CCS deployment

To achieve technology transition from the OECD to non OECD countries, there must be some form of economic incentive in place to make up for the additional cost of low carbon generation. The European Union has linked its cap and trade emission trading scheme to the Kyoto Protocol's offset mechanism since 2004, thereby providing a means for signatory countries to receive credits for financing emissions reductions programmes in non-signatory countries. Given the projected rate of build for new coal plant in non-signatory countries, there is a vast potential market for CCS to be fitted to plant in non-signatory countries, once it has been commercially deployed in OECD countries. The clean development mechanism is one example of the type of mechanism required for the global deployment of carbon capture and storage.

1.7 Chapter conclusion

This Chapter evaluated the drivers of the global generation system to present the broad context for CCS at the global level. Energy demand will increase, primarily driven by non-OECD countries. In the near term, new plant will be fossil fuel based due to the current generation infrastructure and technology readiness and additional cost of low carbon technology. In particular, coal is likely to provide the dominant form of primary energy for electricity generation[3]. This is expected to lead to unsustainable levels of greenhouse gas emissions. In addition to other measures to reduce emissions, CCS provides a means to limit emissions from fossil fuel power generation, and can be retrofitted to existing plants. As a result it appears that CCS could be applied to help mitigate global emissions, which could potentially benefit UK industry- the next Chapter, and the rest of the thesis, examines the case for adoption of CCS at the UK level.

[3]Globally, coal has been the fastest growing primary fuel source for the last six years BP (2009) BP Statistical Review of World Energy June 2009, BP plc.

2 UK need for carbon capture and storage

The increasing use of coal as a primary energy source coupled with environmental constraints drives the need for global deployment of carbon capture and storage. This Chapter establishes the need for CCS to be deployed as part of the UK generation system from a policy perspective.

The two main influences on the UK generation mix are energy policy and the investment decision of private investors. The UK faces a significant power generation challenge. As one of the signatory parties to the Kyoto protocol, it has pledged to cut its emissions of CO_2 by 20% by 2020 and (unilaterally) 80% by 2050 based on 1990 levels. However, this must be traded off against the other attributes of energy policy: economics and energy security. This Chapter shows that there is a specific need for the UK to deploy CCS to meet energy policy goals.

2.1 UK generation system

The UK electricity generation and distribution system is based on large centralised production of electricity. This is a result of historical events and the economies of scale associated with large scale power production.

As a result of privatization in the 1990's, the majority of UK generation capacity is now controlled by six power generation companies. It should be noted that these companies are essentially private entities whose first priority is shareholder value (Appenix B). The effect of liberalisation on the generation mix of the UK has been profound. In 1990, the generation mix constituted 47% coal, 17% oil, 15% nuclear and 5% gas, with renewables, pumped storage and imports making up the remaining 16% (Watson, 2004). After privatisation, gas was allowed as a fuel for power generation which led to advances in CCGT efficiency, accelerating technology uptake and reducing capital costs (Watson, 2004). In addition, CCGT plants were easily able to meet emissions limits on NOx and SOx; coal plants required additional (expensive) processes to enable emissions limits to be met (Watson, 2004). The reduction in plant cost and decent emissions performance coupled with a period of cheap natural gas, and a desire to diversify sources of electricity generation from new entrants. This meant that CCGT's became base load plants, displacing coal generation (Gross et al., 2007). By 2002, 34% of electricity was generated from gas-fired plant, 32% from coal, 23% from nuclear, 3% from renewables, and 4% from oil and other sources (DTI, 2002). In 2008 gas accounted for 45%, coal 32%, nuclear 13%, oil 2%, renewables 5%, other 3% (BERR, 2009).

2.2 Outlook for the UK generation system

The UK will require significant investment in new generation capacity before 2030. The drivers for this requirement are the increasing demand for electricity, the retirement of existing coal plant due to the Large Combustion Plant Directive and the retirement of nuclear plant that is coming to the end of its design life. Of the three drivers, the retirement of coal and nuclear plant will create the most significant need for new generation capacity.

The enforcement of the LCPD means that 12GW of coal plant will shut down by 2016 at the latest (see Appendix B.i). Retirement of nuclear plant means that in addition, 7.4GW of plant will be decommissioned by 2020 and a further 9.8GW will be decommissioned by 2023 (BERR, 2007).

Meanwhile, demand is projected to increase. In 1990 demand was 302TWh, rising to 355TWh in 2008. Projections as part of the Supergen project UK electricity demand to between 415TWh (66GW peak) and 360TWh (60GW peak) by 2020, depending on economic growth assumptions (Ault et al., 2006). Latest government projections indicate that total demand in 2020 will be 348TWh, due to a combination of demand reduction measures and CHP (DECC, 2008b).

The result of retirements and increasing demand for electricity is that the UK will require 23GW of new generation capacity by 2020 and between 30 and 35GW of capacity by 2030 (BERR, 2007). In general, the elements of the new generation mix must be:

- Compatible with UK energy policy;
- A viable market option (i.e. enable merchant generators to return value to shareholders).

These two objectives are potentially contradictory as low carbon generation is usually too expensive to be a viable market option without some form of government support. The remainder of this Chapter establishes the need for CCS from a political perspective (answering the first point). The second criterion is answered in later Chapters of this thesis. In establish the political viability of CCS, it is necessary to understand the political, economic and social drivers behind the UK generation system (Hughes, 1983).

2.3 Energy policy for the UK power generation system

Energy policy is means by which the UK government seeks to direct energy market to achieve the emergent characteristics it desires. The interaction between emergent characteristics is complex as these are sometimes in direct conflict with each other, and the goals of energy policy vary over time.

The government intervenes in the market for social, environmental, market, competitiveness reasons. For example, it can provide incentives for citizens to improve the energy efficiency of their homes, or legislation to reduce the number of households in fuel poverty. The government can also choose to intervene in the market to incentivise the adoption of economically uncompetitive low-carbon generating technologies via feed in tariffs or renewable certificate schemes. However, the willingness of the public and industry to pay for these types of intervention is limited and so places a cap on the extent of renewable generation and incentives for energy efficiency measures. The objectives of energy policy change over time. The old UK energy policy of the 1980's and 1990's focused on privatisation, liberalisation and competition, primarily due to excess supply of fossil fuels and low energy prices (Helm, 2005).

There are three pillars of energy policy: energy security, environmental constraints, and economics. These emergent properties are the result of a combination of macro-drivers e.g. global energy demand and emissions targets, and micro drivers that are UK specific e.g. fuel poverty.

2.3.1 Energy security

Energy security refers to the reliability of primary energy supply to a country and the political, economic and social implications that supply disruption would have. A secure generation mix will have energy from a variety of suppliers and have a diverse generation mix (Wicks, 2009).

The two fundamental drivers of energy security are the geographical dispersion and total reserves of energy resources. The unequal dispersion of global energy reserves implies that some countries must import primary energy in order to meet domestic demand, thus driving concerns over security of energy supply.

Energy security, or the absence of energy shortages, can be split into two categories: shortages due to supply disruptions and shortages of energy due to market behaviour (economics).

Disruptions in supply arise for two reasons: temporary supply and demand imbalances or deliberate action. Temporary supply and demand issues can result from prolonged periods of high demand (e.g. because of prolonged low temperatures) or for force majeure reasons. Deliberate disruptions in primary energy supply have historically been the result of over reliance on a single country for energy, which can lead to both actual shortages of supply and economic shortages of supply. An example would be a country that is willing to manipulate the market price or supply of energy due to its dominant position as a single supplier in order to meet political goals or express dissatisfaction with other states behaviour, as happened in the Russia-Ukraine energy dispute in 2006. The flip side of the argument is that the supplier of energy depends on the consumer for income as much as the consumer depends on the supplier for energy. However, there is still the potential for the supplier to take action if it desires and this potential is enough for some parties to call for reduced dependence on certain fuels.

Relying on one energy source which comes from a number of suppliers is a different matter. The main risk here is that a country is prone to the effects of fuel price volatility and price increases as fossil fuels are traded on global markets. Due to supply and demand, increasing global demand for a finite resource (fossil fuels) will lead to increases in commodity prices which influence energy security and economic concerns in the long term. However, in the shorter term, it is likely that imbalance between demand and supply will result in exposure to price volatility.

Two trends can be seen in Figure 1-4, which shows global primary energy dispersion. Firstly, coal is the most abundant primary energy source. Secondly, coal reserves exist in every continent and with exception of South America, make up the largest source of primary energy in each continent. In contrast over 70% of world oil and gas reserves are in the Middle East, a politically unstable region. Both of these points add to the attraction of coal from an energy security perspective.

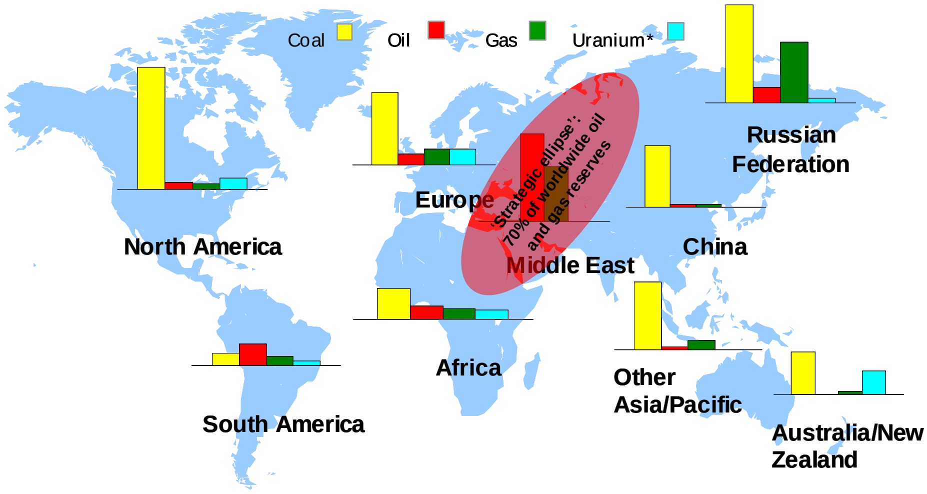

Figure 2-1: Global energy stocks and dispersion (source: (Jackenhovel, 2007))

The decline in production of North Sea gas and oil, along with the earlier closure of indigenous coal mines has led the UK to become a net importer of energy. In 2008 the UK imported 26% of its energy (BERR, 2009). Government projections in 2006 suggested that up to 80% of energy supplies will be imported (BERR, 2007). As a net energy importer, and given the requirement for energy in the UK, issues of energy security are increasingly prominent in UK Energy Policy (Wicks, 2009).

The impact of political instability on oil and gas prices causes oil and gas to be significantly more volatile than coal. The current trend in the UK is to increase the use of natural gas; however, this has implications as the UK is now beginning to have a generation mix dominated by gas. An expansion into coal would benefit the UK generation mix due to the dispersed, relatively abundant nature of coal and the existence of UK domestic reserves. Therefore coal is an appealing energy source from an energy security point of view as the UK can import coal from stable regions such as Europe, America, and Australia, while avoiding relying on politically unstable regions such as the Middle East for fuel supplies.

2.3.2 Environment

Environmental constraints have recently gained an increasingly strong position in the formulation of UK Energy Policy. The main environmental drivers behind current UK energy policy are greenhouse gas emissions (mainly CO_2) and others such as NO_x and SO_x that damage local air quality and cause acidification.

The implementation of the European large combustion plant directive (LCPD) is a result of local and international environmental problems. This legislation limits the amount of NO_x and SO_x emissions from fossil fuel fired power stations, which are mainly coal fired plant.

Some environmental constraints are linked to the global situation: in order to mitigate climate change, global emissions targets need to be met. This means action needs to be taken on a local or national level, as this is where emissions sources are located. As seen in the previous Chapter, global drivers relate the macro effects of greenhouse gas emissions to action at the state level. In order for international targets to be met, intergovernmental organisations such as the EU have set targets and caps for member states to meet. In November 2008 the UK has also passed legislation (The Climate Change Bill) to legally bind emissions reductions by 26% by 2020 and 80% by 2050 on a 1990 baseline. It should be noted that in the short term the UK benefits switching from a high carbon intensity fuel (coal) to a low-carbon intensity fuel (gas) and this has influenced some of the ambitious government targets.

The UK government does intervene in the electricity system on environmental grounds; this can be seen with the prohibition of new coal plant to be built in the UK unless it can demonstrate it is capture ready. The main reason for intervention is that environmental protection takes place at increased cost, and government usually must incentivise it, forcing technology adoption via taxes or cap and trade schemes.

2.3.3 Economics

The third strand of energy policy is to have affordable energy for economic reasons. The electricity generation system affects the economy via the price of industrial electricity and via the price of domestic electricity. The price of electricity paid by industry translates into economic competitiveness at the national and international level. The price of electricity for domestic consumers must be affordable to avoid the possibility of fuel poverty. The government is particularly sensitive to the needs of domestic customers, especially high- risk, low income groups such as the elderly.

2.3.4 Discussion

The goal of current UK energy policy is to provide low carbon growth. Delivering this goal involves a trade-off between the three aspects of energy policy.

Total UK emissions for all sectors in 1990 were 591.8 $MtCO_{2e}$. Given government targets to reduce emissions by 20% by 2020, UK emissions must fall to 473$MtCO_{2e}$ (DECC, 2008a), a reduction of 119$MtCO_{2e}$. The latest projections from DECC indicate that UK emissions will be 440$MtCO_{2e}$ by 2020 (DECC, 2008b). However, this figure includes emissions allowances external to the UK purchased from the EU-ETS (and so have been deducted); actual emissions are projected to be 482$MtCO_{2e}$, equating to a reduction of 110$MtCO_{2e}$. Emissions from the power sector in 1990 amounted to 204$MtCO_2$ (DTI, 2006b). Projections for 2020 indicate emissions of 144$MtCO_2$ for power generation, equivalent to 60$MtCO_2$ reduction in power generation emissions and more than half of UK emissions reductions (DECC, 2008b).

It has been projected that gas-generated electricity could reach 70% of the total (Laughton, 2003), as planned renewable energy sources will not satisfy the predicted shortfall in capacity due to plant retirements (Hughes C D, 2006). A Parliamentary Office of Science and Technology note (POST, 2004) acknowledged that in 2006 the UK became a net importer of gas and that by 2020 80% of gas would be imported. With this and with 70% of power generation relying on gas, the UK economy could become vulnerable to gas-price volatility and uncertain availability (Gittus, 2004).

As a result of liberalisation, the UK government has left it to the market to decide which technology to invest in. The paradigm shift in energy policy towards less polluting, and more secure forms of energy has created problems for the power generation industry in the UK operating in a liberalised energy market, as they are faced with uncertainty over future policy direction whilst trying to deliver shareholder value. Investors generally back a project based on the likelihood of return on investment, and government policy sets the investment environment through its energy policy (IEA, 2007). In particular, true value in the sense of energy policy is not shareholder value, but stakeholder value. At the moment it appears that a non-intervention policy will not deliver the low-carbon growth that the government policy requires. A large part of this is due to the misalignment between government energy policy and power generator values. It has also been noted by others that the UK government appears to be ill equipped to deal with the new power generation challenge (Helm, 2002).

Government intervention will be required in order to enforce the transfer to low carbon generation. A necessary but insufficient step has been taken through the introduction of the European emissions trading scheme (EU-ETS), which charges generators based on their CO_2 emissions, which enables European governments to set the price of carbon emissions to drive the uptake of low carbon generation technology.

Given that the goal of current UK energy policy is to have low-carbon electricity generation that is secure and enables economic growth, how can the UK power generation system meet the challenge imposed by external drivers discussed in this Section? A vast overhaul of the UK generation system is required to bring it into meet the low-carbon growth objective of the government. Section 2.4 describes the power generation challenge for the UK and examines the role that CCS could play.

2.4 The Power Generation Challenge

This Section sets out the challenge for UK power generation to meet if the goals of energy policy are to be realised.

The first step would be to meet demand. Some of the demand requirement may be mitigated through energy efficiency, but significant investment in new capacity will be required in the near term and beyond as existing plant retires. Demand for electricity could increase if transport was to decarbonise via electrification of cars, or the electricity generation system could play a pivotal role as a hydrogen provider in a hydrogen economy.

Given the average planning and construction time of nuclear and coal plant, the first gap which will occur between now and 2016 is likely to be filled by natural gas and wind. The second gap, which will emerge beyond 2016, could provide an opportunity for coal with CCS to make a material contribution to the UK generation mix (CCC, 2009).

The future generation mix will determine the emergent properties of the power generation system in terms of security of supply, economics and environmental performance. In order to meet the goal of energy policy, investment in alternative forms of power generation will need to take place.

Table 2-1: Characteristics of alternative power plants

	Energy Security	Economics	Carbon Targets
Gas (CCGT)	-	X	-
Coal (PC, IGCC)	X	X	-
Nuclear	X	?	X
Renewables (Wind, Solar etc)	X/?	-	X
Gas CCS (CCGT)	-	?	X
Coal CCS (PC, IGCC, Oxyfuel)	X	?	X

Table 2-1 shows the attributes of the various generation types ranked against the three pillars of energy policy. An X means that the technology meets the criterion, a dash means it does not, while a question mark means the outcome is uncertain. The first thing to note is that none of the technologies listed appears to satisfy all criteria. This drives the need for a diverse generation mix.

Any combination of nuclear, renewables and coal or gas with CCS could contribute to diversity of supply and help meet carbon targets. The question mark next to energy security for renewables relates to issues surrounding the intermittent nature of certain renewable energy sources (e.g. wind); intermittency could be a limiting factor for large-scale renewable generation deployment (over 10GW), which the government will need to adopt to meet its renewable energy target of 20% by 2020 (Gross et al., 2006). A discussion and investigation into the exact effect of intermittent generation sources on the electricity generation system is outside the scope of this thesis. The simple assumption is that these forms of generation save fuel and emissions, but are expensive and do not provide firm capacity to the system.

Of the remaining options, nuclear and coal with CCS are the only technologies deployable on a large-scale that can meet demand while enabling environmental targets to be met. Nuclear power could provide a significant proportion of generation capacity, although doubts exist whether this could take place without government intervention, due to the dominance of CCGT plants (Roques et al., 2006). In addition, long term solutions for decommissioning and nuclear waste storage will need to be found. A repository for nuclear waste is currently being developed in Scandinavia, but for geological reasons this storage method is not applicable to the UK (Powell et al., 2010).

2.4.1 A role for coal CCS?

The only way to mitigate emissions on a significant scale from fossil fuels is CCS, and fossil fuel plants will be built in the UK in the future. CCS is also applicable to industrial users of energy (cement, aluminium works etc). As industrial plant is also required to cut emissions, developing CCS for UK power generation could enable UK heavy industry to decarbonise. Therefore at worst, CCS can act as a stop gap until the transfer to a more sustainable energy system can take place. The key question that needs answering is: what role can coal with CCS play?

Assuming that coal with CCS reduces CO_2 emissions by 90% from coal fired power stations, 10% generation from CCS would equate to 3.4 GW of coal with CCS and would emit 5MtCO_2 per annum instead of 31MtCO_2 per annum from normal coal plant, a saving of 26MtCO_2 and provide one third of the CO_2 reduction target for the power generation sector. Additional savings could be made by increasing nuclear generation (to 10GW) and increasing the amount of renewable generation (mainly wind and biomass). The contribution of coal with CCS can be seen in the tables in Appendix B; 10% CCS implies that gas generation accounts for 35% of total generation rather than 45% in current DECC projections. The amount of captured CO_2 to be stored from 3.4GW of coal would equate to 20MtCO_2 per annum[4]. The CO_2 savings at the national level would be of the order of 11Mt CO_2 per annum compared to the unabated CCGT baseline (Table B-3).

2.5 Chapter conclusion: CCS as a mitigation option

CCS has a number of advantages over other low carbon generation technologies for the UK. Firstly, it allows the use of fossil fuels to continue. Power plants can operate as part of the existing grid network, with modifications. CCS will enable UK industry to gain expertise in a technology that will need to be deployed on a global scale. Moreover, in the future, CCS could also be applied to energy intensive industrial processes. Coal with CCS could provide an important means by which to diversify electricity generation and help meet low-carbon generation targets. Therefore coal CCS has the potential to help the UK to achieve low-carbon growth while still using fossil fuels and thereby adding to fuel mix diversity.

In order to become a viable option for generation, coal with CCS needs to be seen as a robust commercial choice. It is clear that the UK government is firmly behind the technology as it is supporting a large scale demonstration competition for a subsidised plant to be operational by 2014 (DECC, 2009). The key questions that remain are to assess the technical and economic viability of CCS as part of the UK mix[5].

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[4] CO2 stored (t/yr) = capacity (3400MW) * availability factor (0.85, dmnl) * 8760 (hrs/yr) * sequestration factor (0.819tCO2/MWh)

[5] This chapter presents the preliminary conclusion that coal with CCS could make a substantial contribution to the future UK energy mix. This is affirmed by current UK government policy.
Since the start of this research in 2005, coal with CCS has steadily grown into a key component of the UK government's strategy for moving to a low-carbon economy. This is confirmed in the latest government document "The UK Low-carbon Transition Plan: National Strategy for Climate & Energy" DECC (2009) The UK Low Carbon Transition Plan: National Strategy for Climate & Energy. Department of Energy and Climate Change, TSO. which states that by 2020 there will be at least 4 operational CCS plants in the UK.

3 System analysis of power plants

Coal CCS can make a viable contribution to deliver UK energy policy; however, a question still remains over the market viability of the technology. This Chapter explains why an engineering systems approach is required and presents a framework to analyse coal-fired CCS plant and compare it to other forms of power generation to understand the case for coal CCS as a viable market option.

To place the framework into context, this Chapter gives a brief overview of engineering systems followed by its application to analysis of power generation. The research framework is then presented. Desirable performance parameters of engineering systems are introduced in order to aid the technology analysis in Chapter 4. The final Section provides an important restatement of the research problem based on the systems theory that is presented in this Chapter.

3.1 Origins of engineering systems

There are four related, but separate fields that influence engineering systems: systems analysis, operational research, systems engineering and system dynamics (Moses, 2004). All four fields are highly quantitative and stress the importance of whole system performance over that of its individual components (see Appendix C).

Engineering systems draws from all of the fields mentioned above and as the name implies is concerned with the design and performance of systems. The key difference between systems engineering and engineering systems is that the latter are at a significantly larger scale, and have more complex interactions with wider systems and/or its environment. Therefore an engineering system may be defined as a man-made system that has significant interaction with its wider-environment including at the level of government policy, society, interaction with the natural-environment and the economy. This is an interpretation of the definition made in a symposium on Engineering Systems at MIT in 2004 (Moses, 2004). Power generation technologies fit into this category as they are man-made systems that have significant interactions with society, policy and economics. For the engineering system to be successful, it must satisfy constraints from all elements of the wider system and/or its environment. An example of this can be seen in the refusal of the UK government to grant planning permission to new coal plant unless it has the ability to be retrofitted with carbon capture and storage. The interactions between policy, economics, the natural environment and technology imply that an engineering systems approach is used in this research.

3.2 Systems theory

Systems theory underpins all of the four sub fields that constitute engineering systems. This Section introduces three fundamental systems concepts in order to aid the creation of a framework for the analysis of coal plant with CCS and to place the research problem in a systems context: system, hierarchy and emergence.

A system may be defined as a set of interacting, inter-related components regarded as a unity (Finkelstein, 2006). In general, a system is viewed globally, rather than in terms of the detail of its sub-systems, however, the behaviour of the system is determined by the properties of its sub-systems and the nature of the interaction between them.

System hierarchy implies that any system is contained within another, wider system and also contains smaller systems (Hitchins, 1992). Figure 3-1 shows this representation, but an obvious question arises: how is the system boundary defined? In order to answer this question, the concept of emergent properties needs to be defined.

Emergent properties relate the behaviour of a system to its components. Whole entities exhibit properties that are meaningful only when attributed to the whole and not its constituents (Hitchins, 1992). In the context of the UK power generation system, the case is as follows: the power generation system exhibits the emergent properties: energy security, economics and environmental performance. The whole system behaviour is a product of the constituent parts of the power generation system: the power plants, transmission grid etc. However, the emergent properties of the power generation system cannot be reduced to the behaviour of its constituent parts. Therefore it is the collective effect of gas, coal, nuclear and renewables that give the UK generation system its emergent properties in terms of security of supply, the environment and economics, and the contribution each of these methods of generation makes to the whole also determines emergent properties (this is shown in diagrammatic form in Appendix B.iii).

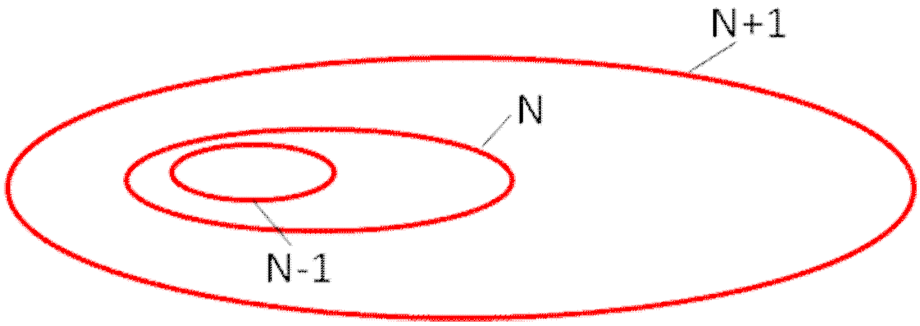


Figure 3-1: System hierarchy

The emergent properties of a system denote a sub-system boundary and the boundaries make up a hierarchy i.e. a system of systems (SoS). Just as power plants are sub-systems of the UK generation system, the UK generation system sits within the UK economic system and the EU generation system and to a certain extent the global power generation system which itself sits in the global system and so on. It is at the global system level that the effects of CO_2 emissions will manifest themselves, although the consequences will probably be felt at the national level (e.g. floods in Bangladesh).

Emergent properties denote levels in the systems hierarchy: the emergent properties of the sub systems of the (generation) system define the generation system. Emergent properties are not always known. This is sometimes due to the nature of the system itself i.e. its complexity. Some emergent properties of complex systems only become visible once the problem has occurred. For example, it could be argued that one of the emergent properties of industrialisation has been an increase in CO_2 emissions that has the potential, via complex interactions with the earth's environmental system, to raise temperatures on earth to unsustainable levels.

In conclusion, emergent properties are properties exhibited by systems of systems. When considering a system designed with a purpose, certain emergent properties can be thought of as required parameters i.e. a parameter that a system must have in order to fulfil its purpose. When the system must compete against other engineered systems, one such parameter could be the monetary cost of the process per unit of output. Other emergent properties exist: sometimes these are known about and sometimes they are unknown. If emergent properties are known, systems can be designed to meet them. The problem with unknown emergent properties is that sometimes an unknown emergent property has critical consequences. The scope of this thesis extends to an examination of the interactions between the wider systems that drive the UK generation system and the interactions and constraints that are imposed on the system of interest: coal with CCS.

3.3 Engineering systems and the power generation system

The electricity generation system is likely to have been, along with the railways and the telephone, one of the first technological entities to require the explicit acknowledgment of systems concepts such as emergence and hierarchy (Hughes, 1983), (Mindell, 2002). This is due to its complexity and central place in the economy.

3.3.1 The UK generation system

The electricity generation infrastructure in the UK can be split into three sub systems; the generation, the transmission network (400kV/275kV) and the distribution network (132kV to 415/215V). The objective of the subsystems is straightforward; the generation system produces electricity to meet consumer demand which is transported through the regions in a high voltage network in order to reduce losses, before being stepped down at transfer stations and routed through regional distribution networks to end users at a voltage and current suitable for domestic and light industrial requirements. The UK generation system includes the generation infrastructure and the infrastructure required to transport primary energy to the UK.

Section 2.1, showed that most of the sources of generation are "point sources" i.e. large entities that take advantage of the economies of scale associated with generating large amounts of electricity. The power output from these plants typically range from 100MW to the coal fired power station, Drax which outputs 4,000MW. Most of the UK grid was built in the 50's and 60's- a period when large coal fired power plants were constructed. As a result there are substantial high voltage networks around former coal mining regions. This is one barrier to the deployment of renewable energy, as the areas that would need to be developed e.g. North West Scotland, would require an extension of the existing grid infrastructure. This is a current issue, with many wind farm developers citing transmission access as one of the key concerns when deciding on the location of a new wind farm. In contrast, coal with CCS could fit in to the existing grid network relatively easily by displacing plants that are closing due to the LCPD and therefore would not require additional infrastructure from a grid connection point of view.

3.4 Modelling framework

This Section presents the framework that will be used for analysing coal with CCS. Although specific techniques will be used for the technical and economic analysis establishing a global architecture will allow a structured and methodologically sound analysis of coal with CCS to take place. As shown in Chapter 2, current value systems are aligned with specific properties of the generation system not only at the national level, but also at the global level; it is the emergent properties at the national level that constrain CCS deployment in the UK.

As a starting point, it is necessary to define the system of interest (SOI). This is the system that the analysis will focus on, and for the purposes of the thesis it is the coal CCS system. Next it is necessary to define the boundary of the SOI. The boundary of the SOI is the interface with the wider system of interest (WSOI). For the purposes of this thesis, the WSOI is the UK generation system. The first thing to note is that the WSOI (the generation system) constrains the SOI (the coal CCS system), Figure 3-2. If the SOI cannot meet the constraints of the WSOI, it ceases to be a viable system. An example of this would be the application of SO_x limits through the LCPD: a coal fired plant that did not have flue gas desulphurisation process technology would not be a viable system beyond 2015 (when the directive is implemented). One key constraint that the WSOI places on the SOI is the cost of generation, meaning that a power plant must be able to generate electricity for a certain price/unit output- usually £/MWh. The WSOI, in this case the UK generation system, is constrained by a wider system too; the UK economy and ultimately the environment. As such, there is a direct link between the levels of the systems hierarchy and the implementation of environmental goals on the global scale.

Figure 3-2: Representation of the SOI and WSOI for the generation system

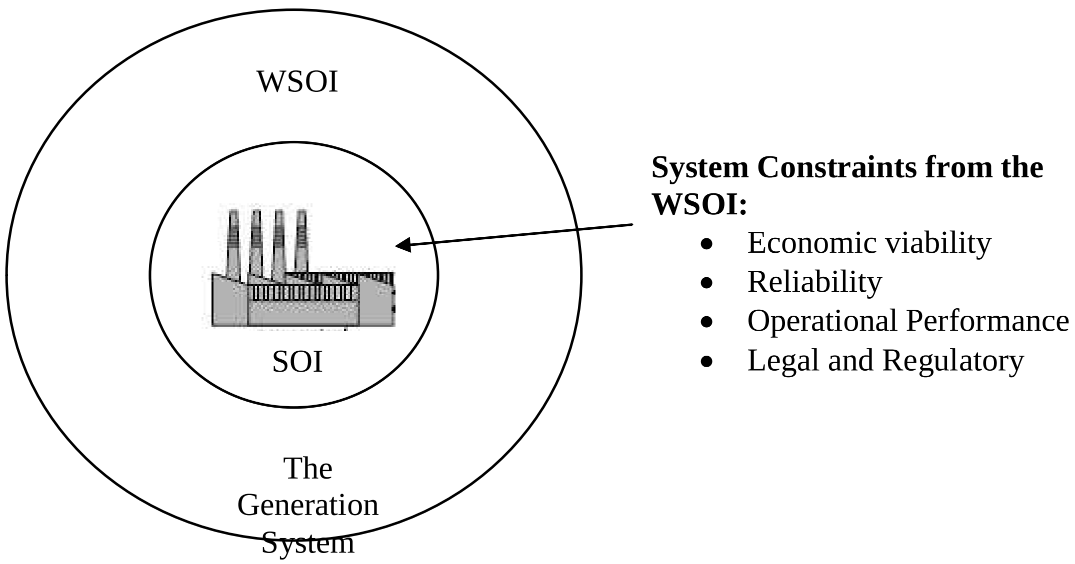


Figure 3-3 illustrates the conflicting systems that are influencing the choice of power generation. The first is the power generation system, which produces electricity at a cost constrained by the second system: the economic system. The power generation system also currently releases CO_2 and other greenhouse gases into the third system; the environmental system. Current understanding indicates that the environmental system cannot accept much more greenhouse gas without altering its state. Therefore the environmental system is now constraining the power generation system.

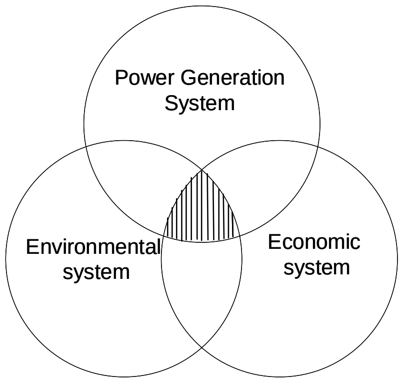


Figure 3-3: Illustration of overlapping systems influencing the power generation system

The main options to meet these constraints are to wholly adopt renewable generation, nuclear power or CCS or some combination of all three. At present, the cost of generation from each of these technologies is greater than that for fossil fuels and, the environmental system is not sufficiently constraining the economic system to promote the adoption of low carbon.

Evidence from previous Chapters allow us to frame the system of interest (coal with CCS) in terms of constraints from the wider system of interest (the UK generation system). It has also been shown that in many ways the WSOI constrains the SOI in terms of acceptable performance. In this thesis these constraints are the system performance parameters, and are the parameters required for the CCS system to become viable. The value or range that the system performance parameter must have is set by the WSOI. System performance parameters include: cost of generation, environmental performance, reliability etc. An example of a system performance parameter is: cost of generation must be less than £50/MWh.

Just as systems can be broken down into sub-systems, system performance parameters can be broken down further into sub system performance parameters. The sub systems of the CCS system are the plant and capture process, the CO_2 transportation process and the storage process. Just as the WSOI constrains the system, so the system constrains the sub system performance e.g. capture process must have an efficiency penalty of less than 10%.

In the same way that the SOI helps to determine the behaviour of the WSOI, so the behaviour of the SOI is determined by its sub systems. Figure 3-4 shows the hierarchical nature of system performance broken down into the process level and sub process level using a pulverised coal (PC) plant with CCS as an example. Just as the combined behaviour of all entities within the generation system define the system, so the behaviour or attributes of all sub-systems within the coal with CCS system define the emergent properties of the coal with CCS system. Therefore in order to understand the system, the sub-processes that form it must be understood and in addition, the sensitivity of emergent properties to sub-processes will allow the identification of critical process performance.

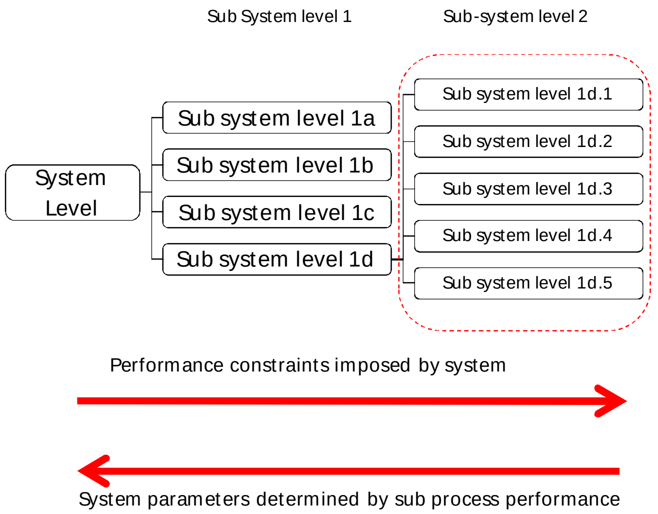


Figure 3-4: Hierarchical nature of system performance

As a significant part of the research involves the identification of the best CCS plant, it is necessary to compare alternative power plants. Figure 3-5 illustrates that comparisons between systems in terms of performance can only be done at the system level.

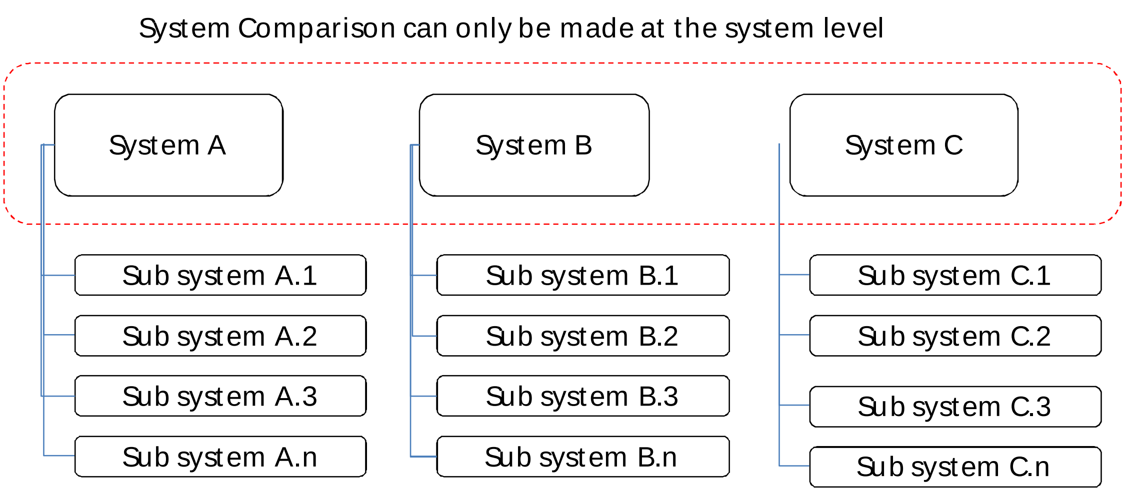


Figure 3-5: Illustration to show that system comparison can only be made at the system level

Figure 3-5 illustrates that if the objective of an analysis was to compare systems, this would need to be done at the appropriate system level. Ultimately sub system characteristics manifest themselves in the plant performance parameters e.g. cost of generation, reliability etc; as shown previously (Figure 3-4), whilst performance constraints are imposed by the system, performance characteristics are determined by the sub systems.

As it is within the scope of this thesis to compare alternative CCS systems with one another and with other methods of power generation and to compare alternative sub processes of alternative CCS systems, it is necessary to differentiate between two fundamental questions:

1. How is system performance determined?
2. How can sub system or system alternatives be compared?

System performance is determined as a product of collective sub system performance; hence alternative plants can be compared at the system level. Sub systems can be compared against each other as long as sub process performance parameters are abstracted to a sufficient level so that tradeoffs between characteristics of the process can be taken into account.

3.4.1 Desirable system parameters

As part of the analysis to show the viability of the CCS system, it is necessary to set out the performance parameters and characteristics that the system will be measured against in order to compare the systems against one another.

Table 3-1, adapted from Moses (Moses, 2004) gives an outline of the typical goals and characteristics that are important for engineering systems in general.

Table 3-1: System Characteristics (Adapted from (Moses, 2004))

Goals		Characteristics
Traditional Properties	Non-Traditional Properties	
Function	Flexibility	Complexity
Performance	Robustness	Uncertainty
Cost	Scalability	Emergence
	Safety	Systems Architecture
	Durability	
	Sustainability	
	Reliability	
	Recyclability	
	Maintainability	
	Quality	

The inclusion of all characteristics in the table lies outside the scope of the thesis. The first two Chapters set out the current challenge facing the power generation system. It was also noted that the power generation system in the UK can be thought of as undergoing a paradigm change, primarily caused by a shift in government energy policy. The new energy paradigm replaced the old liberalisation paradigm with minimum market interference in the space of 15-20 years. It is quite possible that energy policy will change again in another 15-20 years and this situation marks the first instance of a wider system characteristic, namely: uncertainty. Uncertainty can be mitigated through the desirable system property: flexibility.

The generation system can be seen to be in a state of transition. The effect of this on generators is two-fold: firstly it creates uncertainty in new power infrastructure investments. Secondly, the problem is compounded by the long lifetime of power plants; building a coal plant now would result in an operational plant for the next 40 years. Therefore there is a degree of lock-in associated with new plants i.e. unless these plants have the ability to be retrofitted with carbon capture and storage, carbon emissions will be produced over the plants operational lifetime. In addition, there is also a case to be made on whether or not existing plants' that are only partly through their lifetime should be retrofitted with CCS technology. There is also a certain amount of instability and uncertainty in energy policy and the external factors that determine energy policy. This results in an uncertain environment in which a power plant must exist. Given that large capital costs are involved, flexibility to switch operational regimes and adapt to emerging external constraints is valuable.

Flexibility implies that the change is known about and has been designed for. The flexibility of a system relates to a systems ability to switch from one regime to another e.g. to retrofit a "capture ready" power plant with CCS. Usually, incorporating flexibility into system design incurs additional cost, while it often takes time for the system to change regime. In the example case, the power plant has been designed with the flexibility required to change from non-capture to capture status. If this can be done in a week, rather than a month, the system is more flexible. In addition, if the change in regime can be made at a competitive additional cost, the system is also more flexible. Adaptability is slightly different, in that the plant can be adapted to meet a new requirement.

The next undesirable system characteristic is complexity. Complexity is defined by the degree of interdependence and hence interaction between the system, sub-systems and components. Complexity not only gives rise to emergent properties that cannot be foreseen, but complex systems are more difficult to maintain and if something does go wrong, the cause can be more difficult to isolate.

The specific tools to be used in order to value attributes in these fields are a subject of ongoing research, and some are easier to quantify than others. This thesis is limited in scope to determine the potential of CCS as part of the generation system. Therefore, although CCS will be investigated, direct modelling of the emergent properties of the generation system, and its associated architecture in detail is out of the scope. The expected emergent properties of the CCS system and their effect on the generation system as a whole have been used to form part of the argument for deployment of CCS at the global (Chapter 1) and the national (Chapter 2) scale.

3.4.2 Analysis framework

Chapter 4 contains analysis that compares alternative technologies at the system level to assess the viability of coal with CCS. The primary method of comparison is the cost of generation and technical performance of the system. In addition, Chapters 5 and 6 will assess the variation of the cost of generation over time at the system level.

There is a need to establish a benchmark for CCS plants to enable a system comparison to take place. At present there are at least three alternative types of plant available that could be deployed as part of the CCS system. Therefore, in order to choose the most viable baseline plant, Chapter 4 addresses the different alternatives for CCS power plants. In addition, Chapter 4 seeks to categorise the alternative technologies against the desirable system parameters that were brought forward. Therefore, Chapter 4 assesses the various aspects of the CCS system, viz; power plant with capture technology, the transport system and the storage system. Particular emphasis is placed on the plant technology; specifically the potential of CCS plant which allows data collection for input into the investment model in Chapter 5 and an assessment to be made as to the most viable CCS plant.

3.5 Reaffirmation of the research problem from a systems perspective

This Section restates the research problem and objective from a systems perspective. Now is a suitable point because the global and local issues have been brought out and this enables us to reformulate the problem now that all the sub systems and emergent behaviours and drivers are known. The introduction of engineering systems has provided a framework into which the problem can be meaningfully stated.

It is widely accepted that the increasing concentration of greenhouse gases in the Earth’s atmosphere is due to human activity. Although the climate mechanism is complex, it is generally accepted that an increase in the concentration of greenhouse gases will lead to climate change, the effects of which are expected to be severe.

Chapter 1 showed that the main cause of global emissions is power generation which is a result of energy demand. Chapter 1 also showed that over the coming years, global energy demand will increase significantly, primarily due to the energy demand from developing countries such as China. Moreover, the most abundant fuel in China and India is coal, which has the largest amount of CO_2 per unit of energy produced of any fossil fuel.

The goal of global energy policy is to meet energy demand (in an economically efficient manner) while meeting global emissions targets. This is a significant challenge given: i). The scale of the problem; ii). The high cost and immaturity of low-carbon generation technology. The scale of the problem has been illustrated by using wedges to break the problem into manageable segments with coal CCS highlighted as one potential enabling technology.

Coal with CCS could provide an opportunity for non-OECD countries to use indigenous natural coal resources while emitting little CO_2. However, the development and deployment of CCS technology is likely to be expensive, and non-OECD countries are unlikely to sacrifice economic growth for low carbon generation. Therefore it seems unlikely that countries such as China will develop CCS technology alone. This implies that there is a need for OECD countries to develop and deploy CCS technology before non-OECD countries – the cost associated with developing CCS could be regained by selling expertise in CCS technology. From a global perspective, it is also necessary that CCS can be retrofitted to existing or under construction plant in non OECD countries which already account for globally significant levels of CO_2 emissions (Davison, 2007).

The emergent properties of the UK generation system can be split into the following categories: economics, environment and energy security. The current objective of the generation mix is to meet constraints in all of these categories in the most efficient (least cost) manner.

The UK requires significant new generation capacity to meet demand and compensate for plant closures. In order to meet government targets, at least some of the new build will be renewable energy, but the amount expected to be deployed will not be enough to cover the generation gap. Nuclear power has the potential to make a significant contribution, but the long planning times, issues with waste and decommissioning and public opinion mean that market penetration by 2015 is unlikely. There appears to be a significant gap to be filled, and if this is not to be taken by natural gas then it could be by coal with CCS. As an OECD country, the UK has a role in developing low-carbon technologies, both from a commercial point of view (due to the size of the potential global market) and an environmental perspective. In addition, coal with CCS will bring benefits in terms of energy security (moving away from dependency on the Middle East). However, the UK generation system is market based, and not centrally planned. Therefore the existing system is based on minimising cost rather than providing energy security or satisfying environmental constraints. For coal with CCS to be deployed commercially, the technology must prove both technically feasible and economically viable. Otherwise, the government must legislate for coal with CCS to make up a fixed proportion of the UK generation systems which, at present, seems unlikely.

3.5.1 Chapter conclusion

The case for deployment of coal with CCS plant has been made in Chapters 1 and 2, in terms of global need and UK need. The remaining question to be answered is:

Is Coal with CCS technically and economically viable?

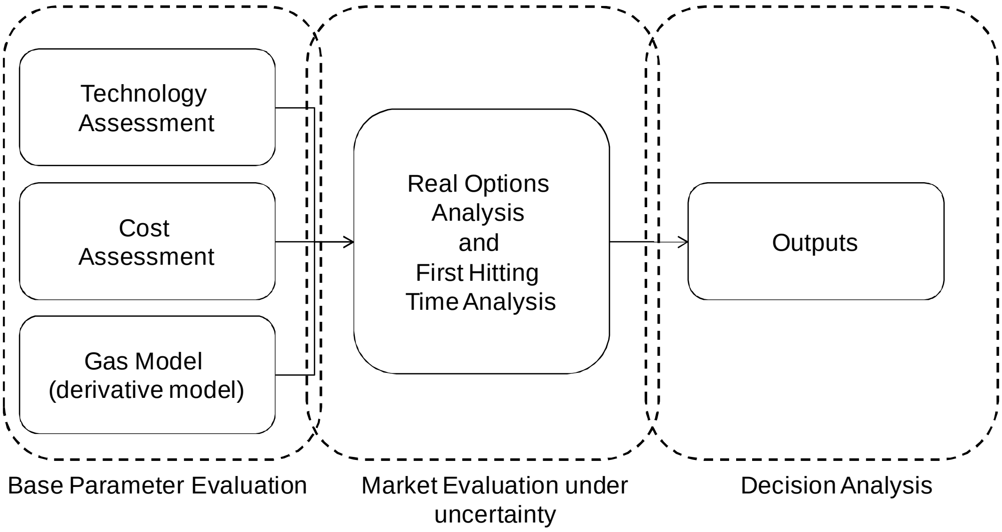


Figure 3-6: Research methodology

Chapter 3 has set out the framework in which this analysis will take place and in particular has outlined the systems hierarchy that is necessary to conduct the analysis in a logical manner. Important systems characteristics have been defined against which the alternative CCS plant technologies will be measured. The goal of Chapter 4 is to assess the technical viability of the CCS system and in particular to rank the alternative coal plants in order to determine the most viable plant to be used in Chapters 5 and 6, which analyses the system from an economic viewpoint.

4 System technology assessment and evaluation

Concern over carbon emissions is forcing governments and companies to consider energy efficient processes and low carbon generation. For fossil fuel power generation, consideration must be given to new combustion technologies together with carbon capture and storage. To date a number of first generation capture technologies have been developed; however, key performance parameters are distributed widely throughout the literature, making a comprehensive technical assessment difficult. Furthermore, a plethora of second-generation capture technologies are being researched. These novel capture technologies are at different stages of development and there is a clear need to identify and categorise them against a common benchmark.

The objective of Chapter 4 is to:

- Evaluate the entire carbon capture and storage chain for technical feasibility;
- Identify the leading carbon capture technology given current and future performance potential.

The three types of coal-fired plant considered in this Chapter are: Oxyfuel, Integrated Gasification Combined Cycle (IGCC) and pulverised-coal combustion (PC).

This Chapter applies a systematic framework to identify the most promising capture technology. The analysis framework is based on the concept of system hierarchy. Section 4.2 presents an examination and evaluation of base plant and related sub processes; Section 4.3 presents an examination and evaluation of the CO_2 capture process by plant, transport process and storage process; and Section 4.4 an examination and evaluation of potential novel capture processes for each plant type. Section 4.5 brings the analysis of the previous Sections together to perform a technology assessment that uses technology readiness levels, system readiness levels, and SWOT analysis to identify the leading option for coal CCS given current and future performance potential.

4.1 Analysis framework

This Section presents a systematic framework, to evaluate coal with CCS plant, based on systems concepts discussed in Chapter 3. The framework provides a consistent means to derive system performance from sub-system performance. The following figures illustrate the system concepts defined in the previous Chapter as applied to the analysis of generation plant, namely; hierarchy, emergent properties and comparison level.

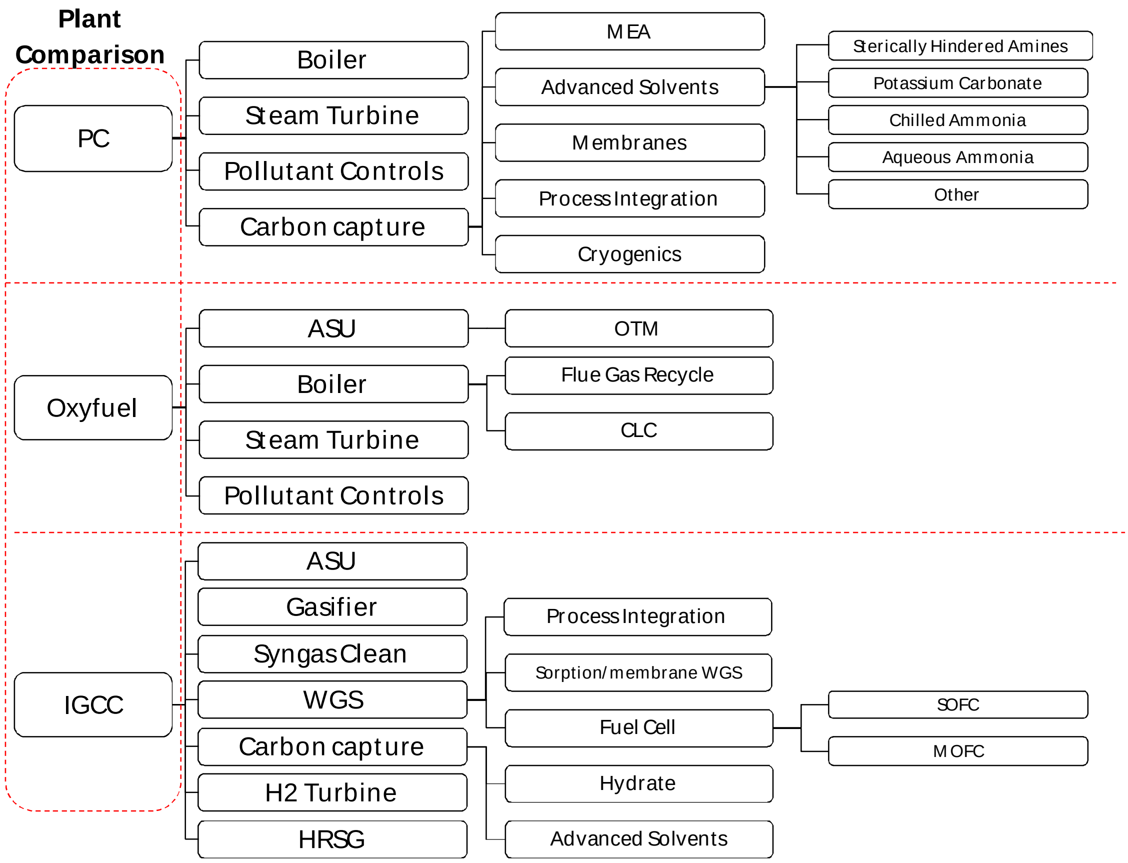


Figure 4-1: Hierarchical nature of plant performance

As the objective of this Chapter is to identify the best plant suited to CCS, Figure 4-1 presents a map of the three different plants under investigation along with the main process and sub-processes that make-up the plant. Moving to the right shows the main constituent processes, which are the subject of investigation in Sections 4.2 (underlying plant technology) and 4.3 (carbon capture technology). The final two segments detail the alternative carbon capture sub-processes which are assessed in Section 4.4.

Figure 4.1 also illustrates how overall plant performance is based on the performance of plant sub-processes but that a comparison between different plants in terms of plant performance can only be done at the plant level. Although this appears obvious, it is surprising how many studies compare sub processes in terms of performance without taking the parameters up to the next level. A typical example, using information presented later in this Chapter, would be a comparison between the performance penalties of carbon capture processes for IGCC plant and a PC plant: on initial inspection, the IGCC plant suffers less of a performance penalty from the addition of CCS and there is less additional cost to fit the capture process (Section 4.3.10). This would lead to the selection of the IGCC plant as the preferable plant. However, IGCC plant has a poor reliability record due to its relative immaturity and costs substantially more than a PC plant to build (see Section 4.3.10). The additional cost of the IGCC plant more than compensates for the savings from the installed capture process meaning that from a whole system perspective, the PC plant is more competitive (see Section 4.3.10).

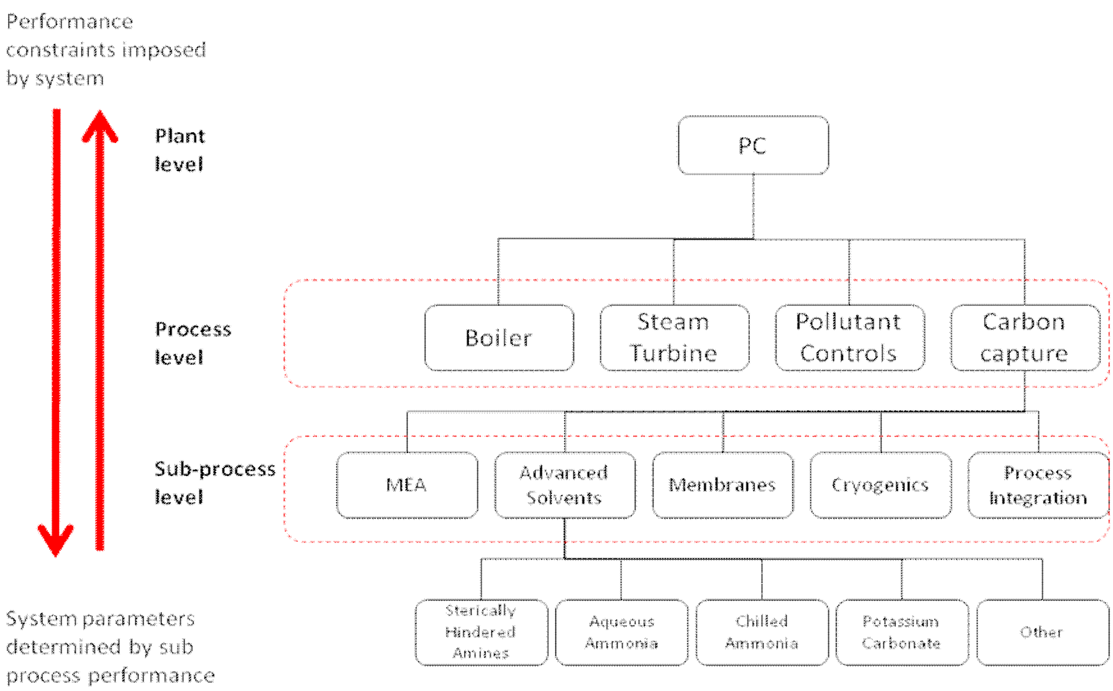


Figure 4-2: Illustration to show that system comparison can only be made at the system level

Figure 4-2 uses an example of a PC plant with CCS to illustrate two points. The first is that performance constraints are imposed by the wider system of interest e.g. cost of generation to be competitive in the market place. To be viable, the system meets these external constraints through the performance of its constituent parts i.e. together, the performance of processes and sub-processes defines the performance of the overall system. In the case of Figure 4-2, the collective performance of the 'process level' and 'sub-process level' components define performance at the 'plant level' e.g. cost of generation, reliability etc. Therefore the reason why this thesis investigates sub-processes should be clear: plant performance is determined by the sub systems.

In systems engineering, key system performance parameters are known as technical performance measures (TPM's), which can be decomposed into design dependent parameters (DDP's) i.e. specific quantitative parameters that a process must have to enable the system to meet its objective (TPM). For coal with CCS a TPM might be to have a cost of generation of less than £45/MWh, while the corresponding DDP would be to have a capture efficiency penalty of less than 5%. This DDP would then become a constraint for any proposed capture sub-system. This last point illustrates the power of the systems approach: a top down constraint (cost of generation to be competitive) can be transposed into a design constraint and if all design dependent parameters are met, the system will be successful.

The second point to be taken from Figure 4-2 is that a comparison of separate sub processes for the same plant can be done at the process level, but not at the sub process level. Otherwise the analysis would not take into account the trade-off between the efficiency penalty due to capture and any additional cost incurred due to the attribute. Mistakes can be made when comparing processes if emergent properties are incorrectly defined. For example, a solvent that has a large carrying capacity, degrades slowly but has a high cost can be compared to a solvent that is cheaper, has the same carrying capacity but degrades quickly in terms of individual parameters. However, it is not possible to identify the better solvent without taking into account the whole system performance of the solvents .i.e. do some parameters more than compensate for others? This error of reporting is commonplace in the literature, as will be shown in Chapter 4 and makes an objective analysis of capture technologies difficult.

4.2 Evaluation of standard coal plant technology

This Section evaluates plant processes and identifies key plant performance parameters to enable a comparison of alternative plant technologies Analysis of the standard coal plant enables an understanding of key processes and the impact they have on plant performance parameters. Base plant performance without CO_2 capture contributes a significant proportion of the generation cost, a key emergent property of the power plant, even when CCS is included. Other key properties include environmental performance, reliability and availability. Technology availability and future performance parameters are also assessed as improvements in plant efficiency result in lower specific emissions output.

4.2.1 Pulverised-coal plant

4.2.1.1 Overview

This Section presents an overview of the key processes that make up a standard PC plant, the efficiency of the plant, operational parameters such as reliability, pollutant controls, the state of technology deployment and future technology developments.

4.2.1.2 Plant process

The basic PC plant follows the cycle in Figure 4-3. The principle is to raise steam in order to drive a turbine to generate electricity.

PC is blown into the combustion chamber of a boiler. The pulverised coal is entrained in air and blown into the boiler where it is burnt. Pulverisation increases the surface area of the coal, allowing for a quicker rate of reaction (burning). Inside the boiler there is a primary network of pipes containing water. The water in the pipes is heated by the hot combustion products produced by combustion of the pulverised-coal. The water changes phase to steam and as part of a Rankine cycle it is fed into the turbine. The turbine drives a generator while steam exits the turbine via a condenser and is then pumped back to the boiler to be heated. The combustion products, commonly referred to as flue gas, are treated to meet emissions constraints and vented to atmosphere.

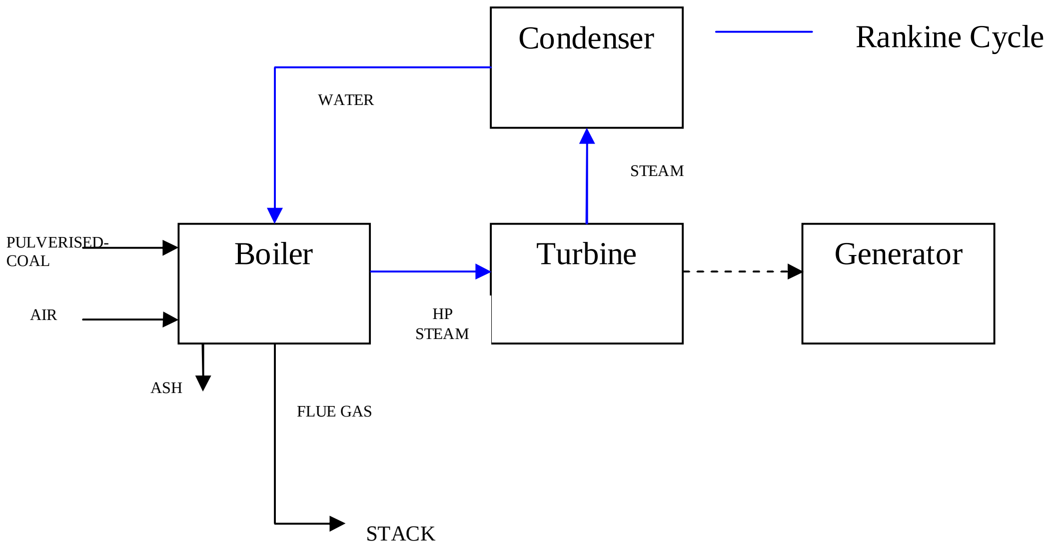


Figure 4-3: Process diagram of a PC power plant

The emergent properties of the base plant process are the plant performance parameters which include efficiency, operational reliability, maintenance and availability, electrical output, pollutants (environmental performance) and by-products, capital and operational costs, fuel costs and carbon costs. Together, these factors determine the cost of generation (COG), and hence the economic performance of the plant.

4.2.1.2.1 Plant efficiency

Aside from adopting carbon capture technology, improving plant efficiency is the best way to reduce specific CO_2 emissions and reduce the cost of generation. However, in order to reduce global emissions levels to those required to meet CO_2 targets, CCS must be deployed.

The efficiency of the Rankine cycle is governed by the temperatures at which heat is accepted to and rejected from the cycle. In the case of a PC plant these are:

- Maximum steam temperature entering the turbine;
- Temperature at which exit steam is condensed (exit temperature);
- Maximum theoretical efficiency.

Maximum steam temperature can be increased by raising the furnace temperature or increasing the boiler pressure to heat the water to sub-critical, supercritical or ultra-supercritical temperatures. Table 4-1 shows operating conditions for the three classes of plant.

Table 4-1: Operating temperatures and pressures of different PC plant classes. (Source: (Davison, 2007))

	Temperature (^{o}C)	Pressure (MPa)
Sub-critical	538	16.7
Super-critical	540-566	25.0
Ultra-super-critical	580-620	27.0-28.5

The critical point of water occurs when water vapour and water liquid are indistinguishable from one another, implying no change of state if the liquid is heated above the critical point. As a result, no energy is wasted in the phase change, meaning a more efficient heating process.

Process efficiency may be further enhanced by introducing a low-pressure turbine and a reheat cycle. These measures are shown in Figure 4-4. In addition, it is desirable to preheat the air before it enters the furnace. This is done by letting the air intake pipe to be heated via low-grade steam. Water from the condenser is preheated in the same manner.

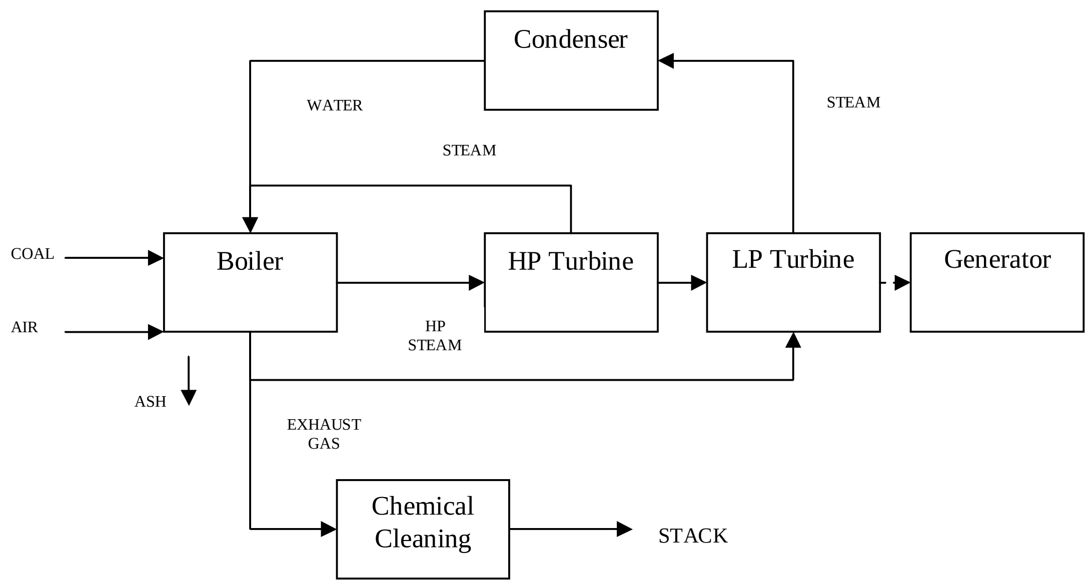


Figure 4-4: PC fired power plant with reheat cycle

In order to further increase the efficiency of the plant, the following processes can be added:

- Increase the number of reheat cycles;
- Type of condensing cycle;
- Water temperature;
- Size of plant;
- Elevation of site.

While sources of losses to minimise include:

- Mechanical Losses;
- Electrical Losses;
- Power Consumption within the plant (e.g. pumps etc).

It is a moot point whether the increase in capital, operating costs (also known as Capex and Opex) and complexity when using higher operating temperatures and multiple reheat cycles is more than compensated for by reductions in the cost of generation (due to greater plant efficiency) and better environmental performance. Generally, legislation must be introduced to incentivise the adoption of less polluting technologies.

The extreme environment in supercritical and ultra-supercritical plant means that materials used for boiler construction need to be resistant to the high operating temperatures. The unavailability of new materials limits ultra-supercritical cycles to 600-610°C. The EU sponsored project, AD700, includes ultra supercritical steam cycles that operate at 700 °C, further increasing efficiency, reducing fuel consumption and reducing CO_2 emissions (a reduction of 30% in CO_2 emissions is expected compared to standard plant). Table 4-2 reflects the current state of the art based on a number of plants located around the world.

Table 4-2: State of the art PC plant worldwide. (Source (DTI, 2006a))

Plant	Working Fluid Conditions (Mpa/°C/°C)	Net Thermal Efficiency %		Capacity (MWe) Net (gross)
		HHV	LHV	
Tachibanawan (Japan)	24.1/600/610	42.1	44	1050
Tanners Creek (USA)	24.1/538/552/566	39.8	42	580
Nordjyllandsværket 3 (Denmark)	29.0/582/580/580	45	47	411
Niederaussen K (Germany)	27.5/580/600	42-43	45.2	965

4.2.1.2.2 Operational reliability, maintenance and availability

The availability of a plant influences the cost of generation and is a consequence of the plants reliability and expected downtime for routine maintenance. Different definitions of availability mean that some figures quoted can be misleading; for example, the availability of plant at Nordjyllandsværket 3 in Denmark, which since start-up in 1998 has had an availability of 98% (BWE), however this is actually the boiler island availability when the plant is called on. For the purposes of this thesis, the availability is the amount of time per year, expressed as a percentage that a power station is producing electricity. In general a figure of around 85% is accurate for standard coal fired plant according to NERC GADS database.

4.2.1.3 Pollutants and by-products

There are two reasons to examine pollutant control in power plants; firstly, modern power plants must comply with laws that prohibit the emission of harmful particulates and gases that make up combustion products. Secondly, certain carbon capture processes are sensitive to impurities and other exhaust gases.

Modern power plants are more than capable of meeting the emissions restrictions imposed on them. The point is that the emission reduction technology costs money to install and therefore legislation has to be in place so that companies install the technology. This style of incentive is epitomised by the LCPD.

Pollutant control typically involves selective catalytic reduction (SCR) to reduce NO_x, flue gas desulphurisation (FGD) to remove sulphur dioxide and particulate removal with an electrostatic precipitator (ESP). The Large Combustion Plant Directive requires all new and existing coal plants to meet strict emissions criteria by the beginning of 2016.

Table 4-3: Emission levels for supercritical plant (Source: (DTI, 2006a)

Emissions (@6% Oxygen dry vol basis)	EU LCPD limit – existing plant (mg/NM^3)	EU-LCPD limit – new plant (mg/NM^3)	Levels currently offered for new plant (mg/NM^3)
NO_x	500	200	38
SO_2	400	200	100
Particulates	50	30	20
PM10	-		20
Mercury	-		4.5 x 10^{-6} Kg/MWh
VOC	-		38
CO	-		11
H_2SO_4	-		3.75

Table 4-3 shows the LCPD emission limits for current plants, new plants (which have stricter emissions limits) and potential of current technology; it can be seen that new plant can easily meet the requirements of the LCPD. Older plant may have to be retrofitted with the appropriate technology or can be closed by 2016, subject to capped running hours. The presence of SO_x affects the performance of the solvent used in carbon capture processes and increases the rate of solvent degradation (analysed in Section 4.2.1). In addition, the transport system for CO_2 also imposes constraints on pollutants (Section 4.3.6).

4.2.1.3.1 Pollutant control measures

The main pollutants controlled under legislation; sulphur dioxide, nitrogen oxide, particulates are removed from the exhaust gas of the plant using a variety of methods.

Sulphur dioxide may be removed from the flue gas by in-furnace technologies, dry sorbent injection FGD, semi dry FGD, or wet FGD. The most popular removal technique is wet FGD, which dominates the global FGD market (WCI, 2003). The FGD unit can be added to the plant as a retrofit measure with the capacity of the equipment being scaled to the boiler size. It is claimed that current FGD technology will remove in excess of 90% of sulphur dioxide emissions (DTI, 2003). The penalty incurred as a result of FGD is a reduction in thermal efficiency of the plant and the increase in capital costs incurred.

The formation of NO_x in power plants is represented by three mechanisms: thermal NO_x, fuel NO_x and prompt NO_x. Thermal and prompt NO_x are a result of combustion conditions in the boiler while fuel NO_x is a function of the nitrogen content of coal. The options for reducing NO_x emissions are:

- Combustion modifications
    - minimisation of excess air;
    - alter fuel/air staging;
- Low NO_x burners;
- Re-burning (addition of fuel after the main combustion stage to reduce NO_x to N_2);
- Flue gas recirculation (replace air with flue gas);
- Flue gas treatment- selective catalytic reduction (SCR) and selective non catalytic reduction (SNCR).

Table 4-4: Effect of NO_x reduction technologies on NO_x reduction (Source:(IEACCCc)

NO_x Reduction Technique	% NO_x Reduction
SCR	80-90
SCNR	30-50
Burner Optimisation	39
Flue Gas Recirculation	<20
Fuel Staging	10

More than one NO_x reduction technology tends to be installed on modern PC plant. The technologies can be divided into primary (modifications to boiler/combustion chamber) and secondary (flue gas treatment) measures (IEACCCa, IEACCCc). Primary and secondary measures can be combined to deliver further reductions but as there is a cost penalty, the choice is usually forced on the generator by legislation such as the LCPD.

Particulate matter is removed from flue gas using electrostatic precipitators (ESP). The ESP is effective, removing 99% of particulates sized 0.01- >100 µm (IEACCCa). As an example, the flue gas of Tachibana-Wan has the following emissions levels:

Table 4-5: Emissions from reference plant (Tachibana-Wan) (Source: IEA CCC)

Pollutant	Emissions (mg/Nm3)
NO_x	90
SO_2	140
Dust/ Particulates	10

The reduction of plant efficiency due to pollutant removal is dependent on the process used to remove the pollutant. Graus and Worrell (Graus et al., 2007) report that a coal-fired plant suffers a 1% reduction in gross efficiency due to typical pollutant reduction measures (the pollutant removal add-ons are: SCR, combustion modification and wet FGD).

Some by-products of coal combustion provide a source of revenue. Bottom ash and fly ash can be used as aggregates for concrete and soil stabilisation. However, the addition of advanced pollutant removal processes, such as SCR to reduce NO_x emissions, can cause ammonia to become entrained with the ash, which then has to be separated out. One caveat to note is that in the USA a low cost of landfill has stopped ash being used as an aggregate (Power, 2002).

4.2.1.4 Technology deployment

PC power plants account for over 90% of the world's power generated from coal and have been in use for over a century (Yeh and Rubin, 2007). Given the technology status of oxyfuel and IGCC plant it is likely that PC will remain the standard generating technology in the near future, especially in developing Asian economies such as India and China.

4.2.1.5 Future technology developments

Future technology developments for PC plant follow two tracks: reducing specific emissions and reducing the cost of generation. Specific emissions relate to the emissions of CO_2, particulates, NO_x and SO_x produced per MWh of electricity. CO_2 emissions can be reduced by co-firing coal with biomass or organic waste, advanced versions of NO_x removal, while FGD and ESP will reduce particulates and gaseous emissions. Improvements in plant efficiency reduce specific emissions, as the same amount of fuel is used to produce more energy.

Increasing plant efficiency may result in a lower cost of generation. The relationship between steam temperature and generating efficiency means that new alloys need to be developed to withstand higher operating temperatures in steam turbines, pipe work and boilers. Therefore the rate at which efficiency increases will be dependent on the increase in performance of alloys. In addition, improvements in design should reduce capital costs, further reducing the cost of generation, although the cost of using the new alloys will offset some of the efficiency benefits.

Figure 4-5 shows a projection of future PC plant efficiency; it is notable that the rate of efficiency improvement is projected to decrease in both cases post 2010. This suggests that improvements in plant efficiency will be small and incremental rather than step changes in the future. The difference between the high and low scenarios is dependent on R&D spending from both the private and public sectors (Lako, 2004).

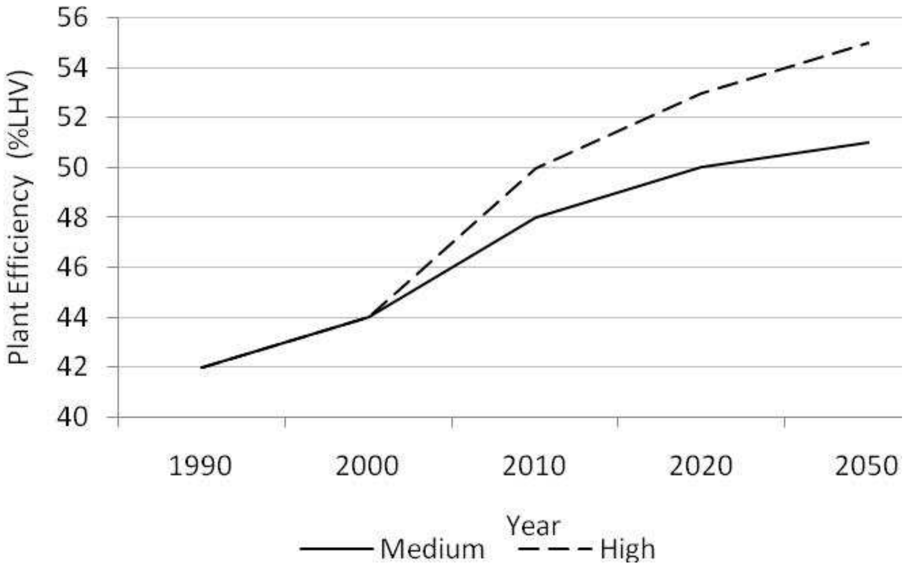


Figure 4-5: Future efficiency of PC plant. (Data source (Lako, 2004))

4.2.1.6 Conclusion

PC plant is the dominant technology used to produce electricity from coal. It is efficient, cost effective, proven and reliable, but is also mature and therefore improvements in plant efficiency will be refinements rather than step changes. In addition, as a mature technology, the reduction in capital cost experienced from learning by doing will not be as great for PC plant as for other plant technologies.

Although advanced PC plant is capable of meeting future NO_x, SO_x and particulate emissions constraints, improvements in process performance will not more than compensate for emissions of CO_2 from new plants on a global scale: the only way to achieve this is through the integration of CCS.

4.2.2 Oxyfuel plant

4.2.2.1 Overview

Oxyfuel plant refers a process in which coal combustion takes place in an environment with high O_2 concentration. The oxygen is produced from ambient air using cryogenic processes to separate air into O_2 and N_2. Apart from flue gas recycling, the process is otherwise very similar to that of an advanced PC plant.

Oxyfuel technology has been used in the glass and metal industries to improve combustion efficiency and because it improves product quality (Anheden et al., 2005). No full scale plant has been built for power generation as the process is not economically viable; the technology is expensive to build and inefficient when the cost of separating air into oxygen and other constituents is taken into account.

Oxyfuel plant is saved as a rational option for coal fired power generation as CO_2 capture is much easier than from standard PC plant: the volume of flue gas is much smaller, and has a high concentration of CO_2 – avoiding the need for a separate capture process. The small volume of flue gas is mainly due to flue gas recirculation, which is required in order to maintain flame stability and a low temperature.

4.2.2.2 Plant process

The thermodynamic principle of an oxyfuel plant is similar to a PC plant: coal is combusted to produce heat to drive a Rankine cycle and hence produce electricity. The main difference is that flue gas is recycled and the coal is burnt in N_2 free O_2 provided by an air separation unit and combustion products from the flue gas recirculation process. A schematic of an oxyfuel power plant is shown in Figure 4-6.

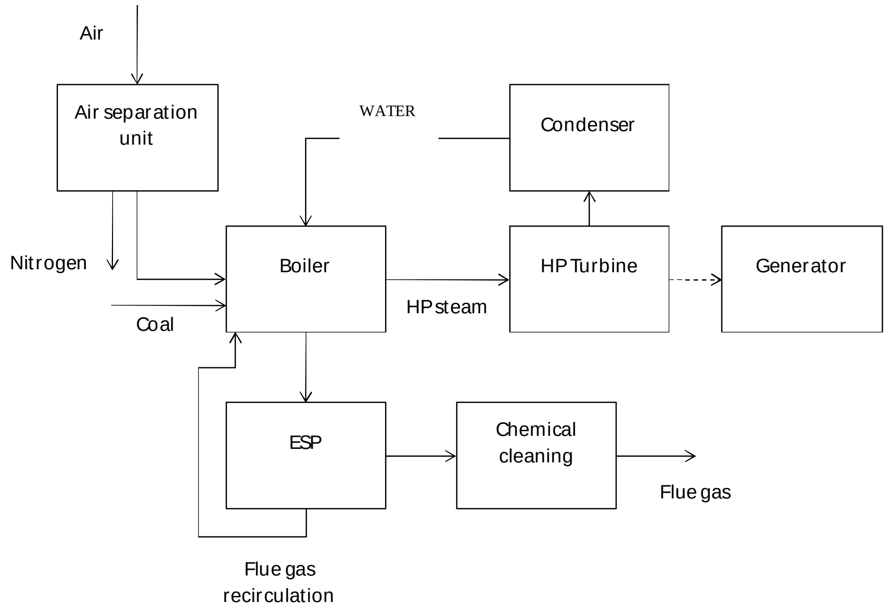


Figure 4-6: Schematic of Oxyfuel combustion process

Firstly the intake air is separated into oxygen and nitrogen in a cryogenic air separation plant. The resulting air pumped into the boiler is 95% pure oxygen (Buhre et al., 2005). Therefore combustion products contain no nitrogen- only CO_2, water and trace gases as well as particulates. Particulates are removed by an ESP. Around 60-80% of the flue gas is recycled i.e. mixed with the pure oxygen (Jordal et al., 2005). This is done to maintain temperature and heat flux profiles in the boiler (Buhre et al., 2005) i.e. control flame temperature and stability in the boiler by creating similar burning conditions to air. There are two types of flue gas recirculation: internal and external. External flue gas recirculation is the current process applied to power generation. Internal flue gas recycling originates in the steel industry and results in the so called oxyfuel flameless regime which has better emissions performance (Villermaux et al., 2009). However, this would need full redesign of the furnace to be applicable to oxyfuel power plants (Villermaux et al., 2009).

The flue gas that is not re-circulated has high CO_2 and water vapour concentration, along with other minor constituents. After desulphurisation, the main constituents are CO_2 and water vapour, which are easily separated.

4.2.2.2.1 Plant efficiency

Section 4.2.1.2.1 discussed improvements that could be made to the Rankine cycle to become more efficient. The same applies to oxyfuel. Therefore it is best to concentrate on the components of oxyfuel plant that differ significantly from standard PC plant, namely; the air separation unit (ASU) and flue gas recirculation.

The ASU separates air into oxygen and nitrogen with high purity. Cryogenic ASU is a widely used technology in other industries and for other processes (e.g. gasification). Air is first filtered, compressed and cooled to remove water vapour before being passed through micro filters to remove CO_2 and any remaining water vapour. This process is required as otherwise the CO_2 and water would freeze and form a deposit on the inside of the distillation tower. After this has been achieved the gas is cooled to -185^{o}C. The air is then sent to the distillation column where any nitrogen leaves from the top of the column and oxygen from the bottom of the column. Cryogenic air separation is a mature technology with patents being filed by Linde in 1895 for cryogenic air separation and 1902 for oxygen production (Linde, (2007)). Oxygen can be produced at between 95-99% purity, depending on the cost requirement.

As stated at the start of the Section, oxyfuel combustion suffers from cost and efficiency penalties because of the need to install and operate the ASU. The ASU has the biggest impact on reducing overall plant efficiency. Jordal et al (Jordal et al., 2005) state that the ASU may account for up to 20% of the gross power output of the plant, equating to a 6.4% reduction in efficiency (Deutch and Moniz, 2007). Therefore there is definitely a need for a cheaper and less energy intensive process to produce pure oxygen.

The next substantially different process in the oxyfuel plant is flue gas recirculation, which is used to control flame temperature and stability. It is necessary to reduce flame temperature to reduce thermal NO_x formation (Jordal et al., 2005) and protect boiler materials. There are two different classes of flue gas recirculation: external and internal. Internal recirculation involves the use of high momentum oxygen jets to induce recirculation in the boiler, a method primarily used in the glass and steel industry (Buhre et al., 2005). During external flue gas recirculation, the flue gas is piped back into the boiler after undergoing particulate removal in the ESP. The current method proposed for oxyfuel combustion is external flue gas recirculation.

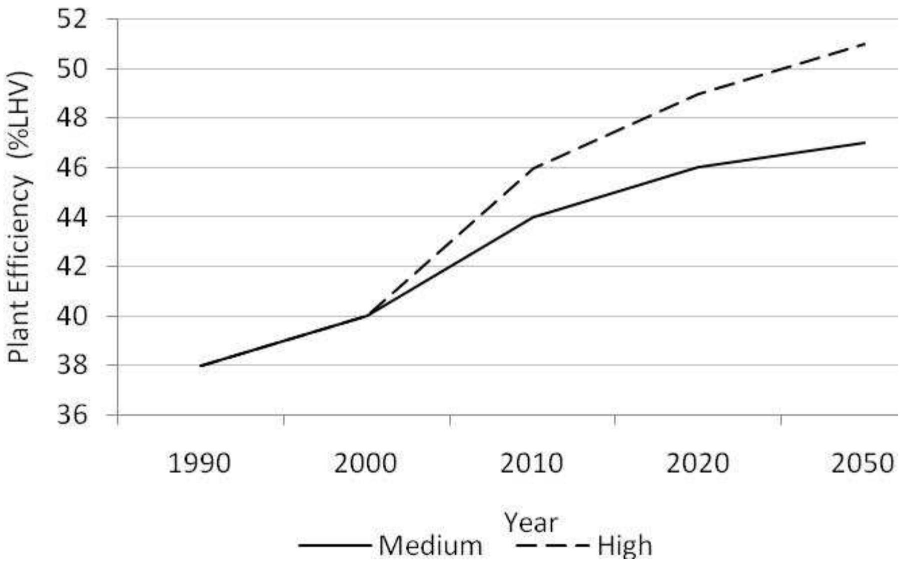


Figure 4-7: Projected Oxyfuel plant efficiency (data source: (Lako, 2004))

As previously stated, the main reduction in plant efficiency is a result of ASU operation. The standard supercritical oxyfuel cycle is estimated to be around 38.5% efficient with a slight increase in efficiency (3%) due to improvements in boiler efficiency and reduced energy usage in the FGD stage compared to a standard plant but the ASU reduces efficiency by 6.4% (Deutch and Moniz, 2007). Therefore the overall efficiency of an oxyfuel power station is expected to be 35.1%, approximately equivalent to a subcritical PC plant.

4.2.2.2.2 Reliability and O&M

As no oxyfuel power plants have been built for commercial power generation, it is difficult to give an accurate estimate of potential reliability and O&M issues. Two issues enable a forecast of reliability and O&M issues to be made. Firstly, oxyfuel combustion has been used in the glass and steel industries for several years. Secondly, laboratory experiments and test rigs suggest that there should be little difference between PC and oxyfuel plant reliability and O&M issues, although it is noted that for a true assessment of availability full scale demonstration plants are required (Buhre et al., 2005).

Buhre et al (Buhre et al., 2005) report on a study carried out at the Energy and Environmental Research Corporation (EERC) on a 3MW pilot reactor which found no operational difficulties with oxyfuel technology. The issue of high concentrations of sulphur dioxide in the combustion chamber as flue gas is re-circulated before FGD takes place was also a concern, although there is evidence to suggest that oxyfuel combustion certainly produces less NO_x, and perhaps even less SO_2 than standard PC combustion (Buhre et al., 2005).

Jordal et al (Jordal et al., 2005) state that due to the high concentrations of CO_2 in the flue gas, high temperature corrosion is more likely due to greater heat flux to the walls and super heaters. This is due to the thermal properties of CO_2 (it is also the reason why CO_2 is considered a greenhouse gas).

4.2.2.3 Technology deployment

The Swedish utility company Vattenfall are building a 30MW pilot power plant in Germany that was commissioned in 2008 (IEAGHG, 2007) which will be useful in providing technology proof of concept. In addition, a 40MW demonstration plant has also been opened in July 2009 by Doosan Babcock in Renfrew, Scotland (Babcock, 2009)[6].

4.2.2.4 Future technology developments

Future technology developments in oxyfuel plant design will focus on a more efficient method of separating air into oxygen and nitrogen because at present such a large loss in efficiency is experienced. Jordal et al (Jordal et al., 2005) state that the EU funded project, ENCAP, is investigating methods of oxygen separation including: membrane separation, ceramic thermal auto recovery and chemical looping combustion.

Jordel et al suggest that future plant will be subject to process integration so that waste heat can be used more effectively e.g. liquid N_2 could be used to cool water or for flue gas condensation (Jordal et al., 2005).

4.2.2.5 Conclusion

The current state of the art oxyfuel plant is cryogenic ASU with flue gas recirculation. Although oxyfuel combustion is not competitive with PC plant without carbon capture, it will be shown in Section 4.3.3 that in the case of CO_2 removal, oxyfuel suffers less performance penalties than PC plant. Therefore when considering carbon capture, oxyfuel is a viable option- competitive with PC in terms of cost of electricity and total plant cost. Due to the lack of commercial deployment, no costs for oxyfuel plant exist. Operational parameters such as the ability to load-follow are also unreported.

The oxyfuel plant has a number of advantages including improved heat transfer in the boiler, low flue gas volume output and the increase in efficiency that comes about as a result of flue gas recirculation. The main disadvantages are that oxyfuel combustion requires a large quantity of energy to separate oxygen- although this is an ongoing research area, and that the technology is relatively immature (30MW test plant).

Apart from improvements in the air separation process, it appears that improvements of oxyfuel plant efficiency are related to the improved performance of PC plant which itself is dependent on the use of new alloys. Hence, the overall performance of an oxyfuel plant would be expected to follow that of a PC plant albeit with possible step changes due to new methods of oxygen separation.

[6] http://www.doosanbabcock.com/live/dynamic/News2ShowArticle.asp?article_id={56FB5815-644D-44B8-95A8-FC7BAC057D61}&cmetemplate=dynamic/pressreleaseslist.tmp

4.2.3 Integrated gasification combined cycle (IGCC)

4.2.3.1 Overview

The IGCC plant operates much like a combined cycle gas turbine plant, but instead of natural gas being combusted, syngas produced from coal gasification is used. The combination of two cycles results in a higher plant efficiency than currently achievable in a PC plant. IGCC also offers distinct advantages for carbon capture which will be discussed in Section 4.3.4. Deutch and Moniz (Deutch and Moniz, 2007) state that there are four 275MW-300MW IGCC plants in Europe and the US although none have CO_2 capture installed and that these plants have been built as a result of government funding. The plants in Europe are part of the THERMIE project, but many gasification plants have been built for use in the chemical industry.

4.2.3.2 Plant process

The IGCC plant first converts coal into synthesis gas (syngas) which is combusted and drives a gas turbine (Brayton Cycle). The hot exhaust gases are then used to heat water as part of a Rankine cycle (like a combined cycle gas turbine (CCGT) plant). In order to obtain the high temperatures required in the gasifier, pure oxygen from an ASU is blown into the gasifier (Maurstad et al., 2006). The plant process is shown in Figure 4-8.

Gasification of coal takes place in a shortage of oxygen to produce synthesis gas (also known as syngas or fuel gas) at high temperature (1700^{o}C in an entrained flow gasifier) and pressure[7]. Syngas is composed primarily of carbon monoxide (CO) and hydrogen (H_2). The syngas is then cooled before being cleaned to remove slag particles, different trace elements, sulphur and, if required, CO_2 (Maurstad, 2005). Once this has been done, the syngas is combusted and drives the gas turbine to produce electricity. The exhaust gases heat water as part of a Rankine cycle. The steam cycle is essentially similar to that in a PC plant except that a lower temperature and pressure is used.

[7] An alternative method involves gasifying with air to produce a lower quality product gas.

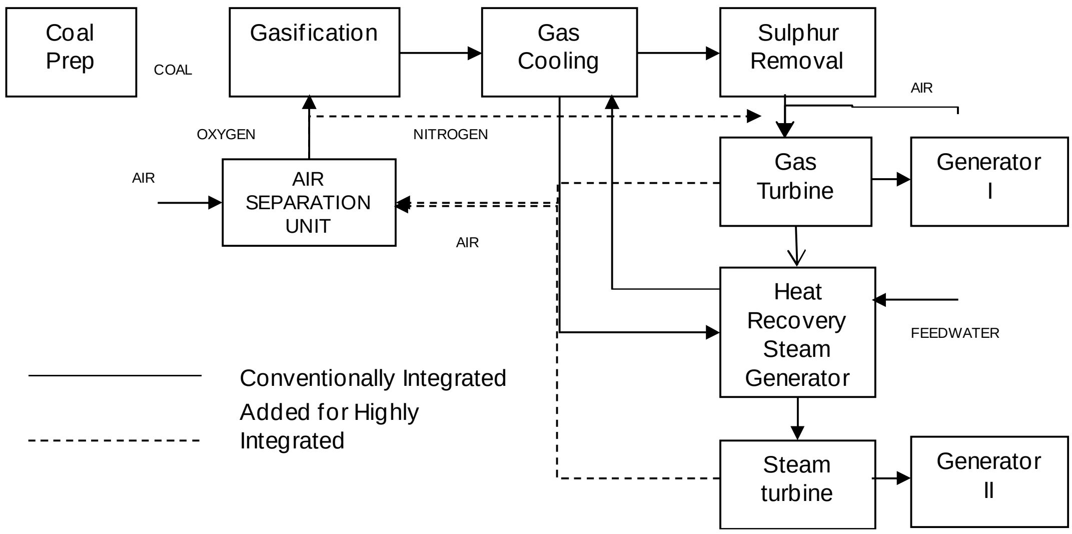


Figure 4-8: Process diagram of the IGCC system (adapted from: Holt (2001))

There are three types of gasifier; entrained flow, fluidised bed and moving bed. The gasifiers differ in the characteristics of the zone where the reaction between coal, air/oxygen and steam occurs. Gasification consists of two processes acting in parallel: combustion and pyrolysis. Combustion is the rapid oxidation of fuel accompanied by the release of large quantities of heat. Pyrolysis is the thermal degradation of solid fuel into a variety of simple gases and organic vapours and liquids. Pyrolysis is an endothermic process, and hence the heat released by the combustion process drives pyrolysis. The type of gasifier used also depends upon the type of coal to be gasified for different levels of grindability.

Table 4-6: Coal feed properties for various types of gasifier (Source IEA CCC (2007))

Gasifier Type	Coal Input
Moving Bed	Lumped Coal
Fluidised Bed	3-6mm
Entrained Flow	25–200 μm

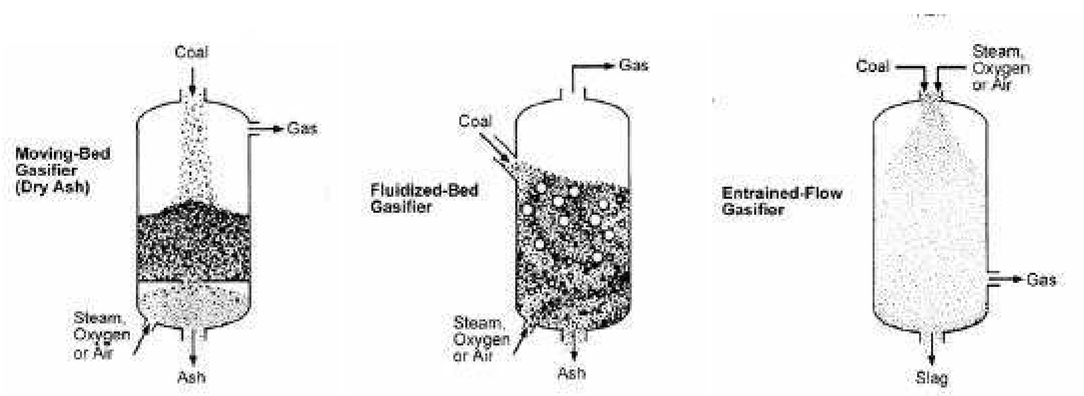


Figure 4-9: Types of gasifier- moving bed, fluidised bed and entrained flow (Source: Phillips, 2007)

In the moving bed gasifier, the coal is fed in from the top while steam and oxygen are blown in through the bottom of the gasifier. When the two flows come into contact with one another the stages of gasification take place. Ash falls through the grate at the bottom of the gasifier and is collected. The moving bed gasifier is produced by Lurgi AG and used by the South African company, Sasol, to produce electricity (van Dyk et al., 2004). In the fluidised bed gasifier steam and oxygen are injected at such a rate that the coal in the gasifier reaches a fluidised regime. Holt (Holt et al., 2001) states that this process is primarily used to gasify low quality coal. In the entrained flow gasifier, both coal and oxygen are fed in from the top of the gasifier. The entrained flow gasifier is used by GE Energy, Conoco-Phillips, Shell, and Siemens for industrial and IGCC applications because of the high rate of gasification i.e. the gasifier can provide enough syngas for commercial applications (Holt et al., 2001). Although fluidised bed gasifiers can produce the same quantity of gas in a similar timescale, a larger gasifier is required thereby increasing the capital cost.

4.2.3.2.1 Plant efficiency

The IEA Clean Coal Centre (IEACCCb) give Puertollano IGCC plant (300 MWe) as a recommended reference plant. The efficiency of the plant is 42%, making it comparable to advanced PC plants (IEACCCb).

As the more efficient gasifiers are pressure vessels, they cannot be fabricated on site in the same way that PC boilers can. Large gasifiers are difficult to transport, simply because of their weight and size. This could restrict their use for plant above 300 MW (IEACCCb) and have implications for economies of scale.

4.2.3.2.2 Reliability and O&M

IGCC plants are capital intensive meaning high availability is required to keep the cost of electricity low. IGCC plant does not have a good record for availability because many plants have been one of a kind without the benefits of standardisation and learning over time. As IGCC plants are relatively novel and complex, considerable O&M is required. However, if operated correctly high reliability and availability are achievable.

4.2.3.3 Pollutant control measures

One of the strengths of an IGCC plant is that it has excellent emissions performance compared to other plants (Table 4-7). Emissions from IGCC compare very well to emissions form the latest PC plant with SCR, although more NO_x is produced, levels are within LCPD limits and SO_2 emissions are substantially lower (see Table 4-3 for PC plant emissions).

Table 4-7: Emissions from Puertollano 300MW IGCC plant (Source: IEA CCC)

Pollutant	Emissions (mg/Nm3)
NO_x	150
SO_2	25
Dust/ Particulates	8

It is not expected that IGCC plant will have problems meeting future emissions constraints. Table 4-8 gives IEA CCC predictions of the potential emissions from an IGCC plant. The figures take into account advances in technology and represent an improvement on current plant emissions.

Table 4-8: Potential Emissions from IGCC plant (Source: (IEACCCb, IEACCCa))

Pollutant	Emissions (mg/Nm^3)
NO_x	<100
SO_2	<20
Dust/ Particulates	<2

4.2.3.4 Technology deployment

There are four operational gasification plants worldwide that produce power and run on hard coal or a mixture of petcoke and lignite. Many other gasification plants exist, but do not use coal as a feedstock or do not produce electricity commercially.

IGCC plant can handle a variety of fuels including all types of coal, biomass and residuals. However, it is not clear how much scope there is for changing fuel once the plant has been designed to operate on a specific feedstock, even if it is a mixture of feedstock such as sub bituminous coal and petcoke (as is Puertollano). IGCC plants benefit from fuels that have a homogeneous consistency such as petcoke; that is why gasification plants have sometimes been located near to refineries.

4.2.3.5 Future technology developments

Future improvements in IGCC plant performance should increase in plant efficiency, reduction of specific emissions, reduce capital and operational costs and improve reliability.

Increases in plant efficiency should be achieved through the installation of high efficiency gas turbines, and high temperature FGD. At present, gas cleaning stages for particulates and sulphur removal have to be undertaken at low temperatures, the gas inlet temperature to the gas turbine is low. If the inlet temperature can be raised, IGCC plant could achieve thermal efficiencies seen in modern Combined Cycle Gas Turbine (CCGT) plants (>50%). This is a problem of the coal gasification process not the CCGT process per se: advances in CCGT technology could be transposed onto IGCC plants, albeit with some performance penalty due to feedstock processing, air separation and flue gas cleaning. Essentially, the (comparatively) lower CV and hence large volume of syngas affects the “CCGT” performance

Capital costs are expected to decrease reasonably quickly as the technology is relatively novel although this is dependent upon the level of RD&D. Reliability will only improve through further process development and the construction of new plants. IGCC has better NO_x and SO_x performance than PC plant.

Figure 4-10 shows the difference between the high and low scenarios for efficiency. Improvement is related to continued investment in R&D from the public and private sectors.

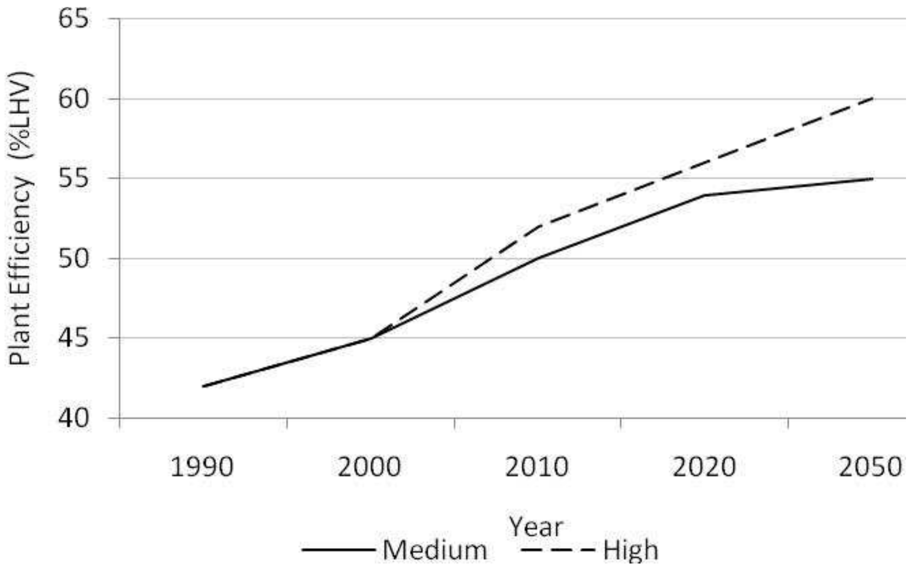


Figure 4-10: Projected efficiency of IGCC plant (Data Source (Lako, 2004))

Modified IGCC plants may produce hydrogen as a by-product of the process. However, there is no clear market for large scale hydrogen production at the moment (DECC projections for the introduction of hydrogen vehicles are post 2030). Therefore, although potentially valuable, hydrogen production from IGCC plants appears to be an issue for post 2030 plants.

4.2.3.6 Conclusion

This Section reviewed the IGCC plant. IGCC plants have good emissions performance, while plant efficiency and potential achievable efficiency is greater than that of PC and Oxyfuel plant.

Disadvantages include the high level of complexity, low operational flexibility and high capital investment cost; while IGCC plant needs to be designed for a specific fuel (i.e. cannot easily be converted co-fire with biomass). As the process is relatively novel, there appears to be significant potential for reduction in capital cost. In addition, the high level of complexity does not mean that the process cannot be reliable; the deployment of additional plants should provide the opportunity to increase process robustness.

If IGCC is to have a future as a competitive generating technology, it must become more efficient, cheaper and more reliable. Table 4-7 showed that IGCC plant has the potential to meet future emissions limits, but it is likely that utility companies will want to see improved reliability figures before committing to investment.

As will be shown in Section 4.3, IGCC has great potential as a carbon capture ready power plant and pre combustion capture of CO_2 is viable and may have advantages over PC.

The ability to produce hydrogen is a significant attribute for the IGCC plant. Although the time-frame over which a transition to a hydrogen economy is long-term, investment in R&D for IGCC hydrogen production plants could drive the technology development needed to eventually establish IGCC as a competitive commercial power plant.

4.2.3.7 Section discussion and conclusions

Standard coal plant performance is important as improvements in the underlying sub-processes could help compensate for the penalty incurred by operating CCS process. This Section compared three plant technologies: IGCC, PC and oxyfuel. Sub processes have been evaluated and base plant performance parameters identified.

PC plant is the most developed, reliable, available plant, and is efficient, although the limited number of IGCC plants that have been deployed means that a comparison is difficult to make. PC plant also benefits from being the dominant technology at present, with more than 2000 plants in operation worldwide (Yeh and Rubin, 2007).

One of the key plant performance parameters is plant efficiency, which determines fuel cost, specific emissions, and hence has a significant impact on cost of generation.

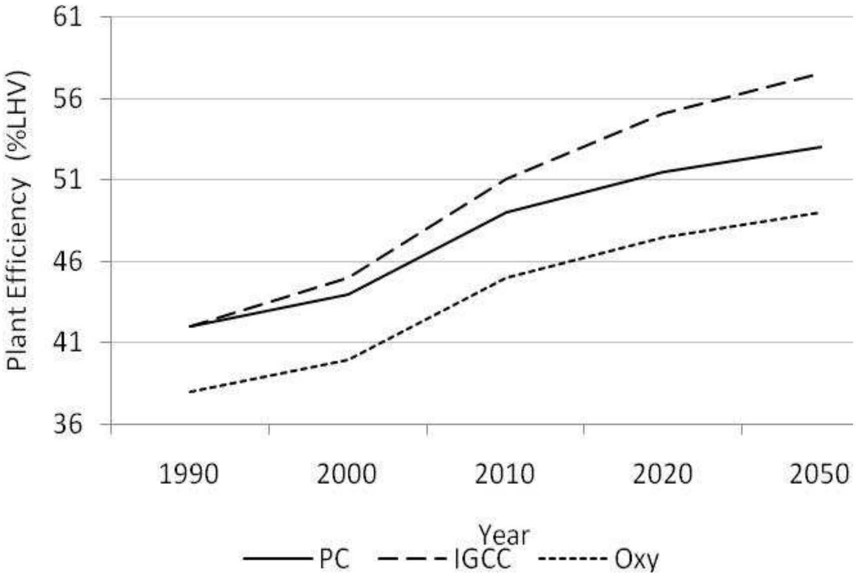


Figure 4-11: Projection of median efficiencies of power plants

Figure 4-11 shows projections of the median efficiency of plants until 2050. IGCC plant is regarded as having the greatest potential efficiency; the rate of increase in efficiency up until 2050 is much greaterfor IGCC than for a PC plant. However, this does not mean that IGCC will become the dominant technology of choice in the near future. Firstly, the projections depend upon sufficient investment in R&D. At present, it could be argued that PC plant has more R&D spent on it than IGCC; for example the Eon AD700 project. If this is the case the rate of improvement in PC plant will be faster than IGCC, suggesting that the upper estimate should be used. Assuming that the lower estimate of IGCC performance takes place, the two efficiencies would not cross until 2010 (according to data from (Lako, 2004)) and would still be within 1% of each other at 2020, and the same at 2050. Therefore, the amount of investment of RD&D for IGCC plant is critical if it is to overcome the market position of PC plant as the preferred method of generation. Secondly, the key question that remains is: does the efficiency increase in IGCC more than compensate for additional cost and reliability issues? The rate of improvement in an IGCC plant could be more than compensated for by inconsistencies in plant performance coupled with inexperience in plant operation. Utility companies value reliability and competitiveness highly and therefore the current IGCC plant suffers when compared to PC plant. Given the amount of money a generator will lose if the plant closes down, it is difficult not to see reliability as a central requirement of the generators value system.

If future PC plants will have efficiencies matching the upper end of the projections and availability factors in excess of 85%, as now, then PC will be a formidable opponent to IGCC in terms of investment. Projections for oxyfuel plant efficiency are taken from those for PC plant with a reduction in performance ascribed to the ASU. Oxyfuel offers an interesting variation on PC plant, although this plant has not been commercially demonstrated at full scale due to the uneconomic nature of the process. However, oxyfuel offers significant advantages when carbon is to be captured; this could explain why Vattenfall have decided to research the oxyfuel technology that can be retrofitted to standard PC plant (Ciferno et al., 2009).

Emissions performance is another important plant performance parameter; IGCC has superior emissions performance relating to SO_x and NO_x, at present and into the future. PC plant cost increases the more stringent the environmental limits are i.e. it will cost more for PC plant to meet future emissions laws than for an IGCC plant to do so.

All coal plants can integrate into the generation system fairly easily; connection to the national grid can take place and is facilitated if new plants are built on the sites of older plants that are due to retire as a result o the LCPD. This contrasts with large-scale renewable generation, where new connections to the grid are required.

In terms of cost of base plant, IGCC will remain more expensive in terms of cost per MWh than a PC plant. The cost of generation also illustrates the viability of the hierarchy set out in Section 3.4: the cost of generation calculation incorporates the trade-off parameters of a high capital cost but low fuel cost process with one that is cheaper but more fuel intensive.

The reason that IGCC and oxyfuel plants are being researched is because they have sufficient capability to surpass PC plant as the de facto generation method for coal plant, especially when considering carbon capture. Therefore, in conclusion, the result of the literature review for standard plants suggests that in the short to medium term, PC plant will remain the dominant plant technology. However, ultimately, the selection of plant is site and fuel specific.

Finally, the improvement in plant efficiency will offset some but not all emissions from a new coal plant. An improvement of 1% in coal plant efficiency reduces CO_2 emissions by between 2 and 3%. This means that an additional 15MW capacity of coal plant could be built without increasing overall emissions (relative to the original inefficient plant). On the other hand, an (optimistic) increase in efficiency of 8% would offset an additional 85MW of coal plant capacity (at the higher efficiency, but the same load factor i.e. 0.8TWh of additional generation) without increasing overall CO_2 emissions. Therefore from the wider generation system perspective, CCGT plants are a better option to reduce CO_2 emissions as the plant is more efficient and the fuel has less carbon content. In addition, CCGT pant can easily meet NO_x and SO_x regulations. The only way coal plant can have lower emissions than a CCGT is to install CCS.

4.3 Evaluation of the carbon capture and storage system

The objective of this Section is to analyse the process of carbon-capture and storage as an applicable technology to current coal fired plant.

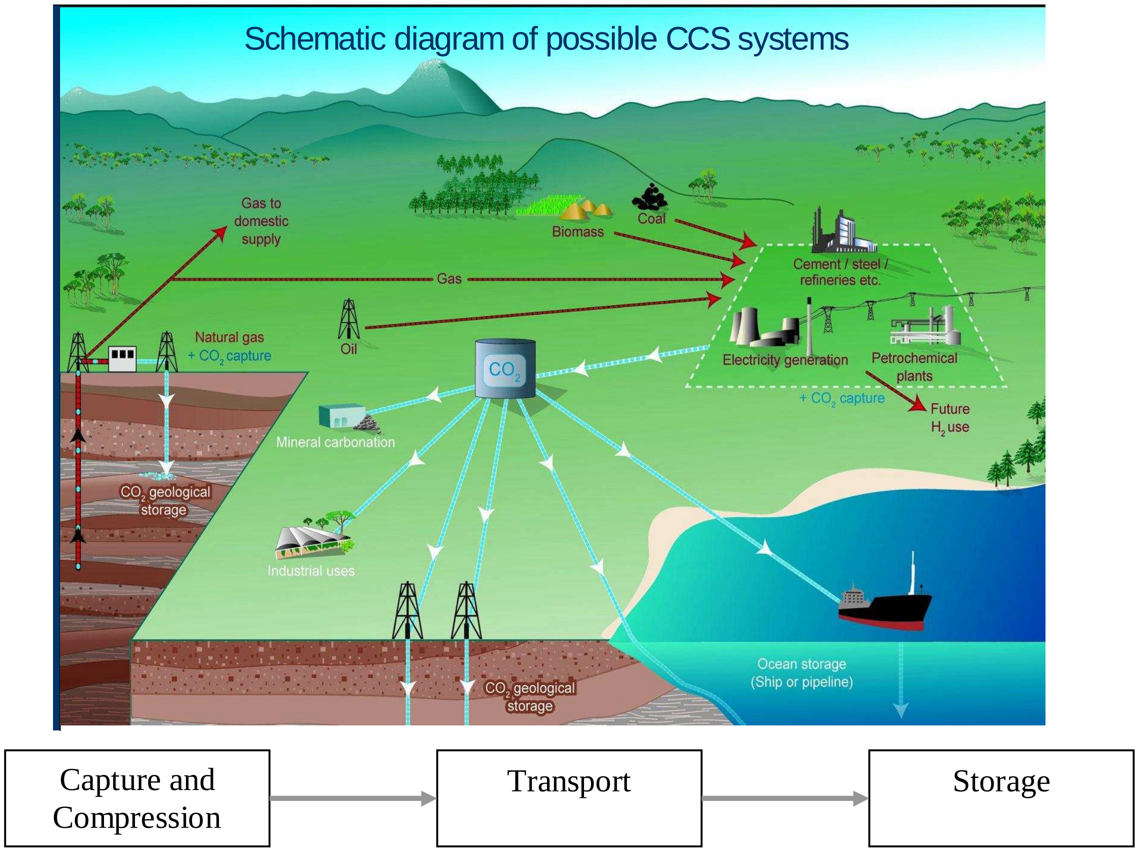


Figure 4-12: Schematic of possible CCS system (Source (IPCC, 2005))

The CCS system consists of the original power station, modified to include sub-processes required for separation of CO_2 from the exhaust gas, compression equipment for liquefaction of CO_2, transport and storage (as shown in Figure 4-12). Capture processes differ according to the type of plant under investigation, while compression is fairly generic. Transport and storage are location specific, but otherwise are also generic and have a different set of constraints as they must serve the entire generation system rather than an individual plant. Therefore this Section analyses the state of the art capture processes for the alternative plant configurations analysed in the previous Section. Capture processes are examined and the effects on plant performance parameters are given along with technology availability. In addition, the impact of compression, transport and storage is also evaluated in terms of system performance and cost of generation.

Implementation of CCS alters the performance parameters of the system and plant in a negative manner, adding complexity and cost to the system. In addition, the stages of the CCS system constrain one another i.e. storage and transport stages constrain the capture and compression stages.

4.3.1 Carbon capture

The objective of the capture process is to separate carbon dioxide from other flue gas components such that it is suitable for compression, transport and sequestration. This Section will investigate the effect of carbon capture on plant efficiency and cost. The penalty of installing carbon capture process is particularly high compared to other forms of emissions control due to the volume of emissions to be captured: a 500MW coal fired plant will produce approximately 3 million tonnes of CO_2 per year (Deutch and Moniz, 2007).

This Section assesses new build plant with capture facilities integrated but it will be shown that there is an important contribution that could be made from retrofitting technology to existing plant and enhancing plant performance by allowing flexible capture systems to be installed which give the plant the ability to "load follow" i.e. increase and decrease electrical output in order to meet market demand for electricity.

4.3.2 Carbon capture at PC plant

Post combustion carbon capture is carried out at approximately twelve institutions around the world (Herzog and Golomb, 2004), but none of these plants produce electricity commercially at full scale; most CO_2 is used for enhanced oil recovery (EOR) or to produce food grade CO_2.

The capture of carbon dioxide from PC power stations usually takes place after flue gas cleaning. A schematic of the plant process is shown in Figure 4-13.

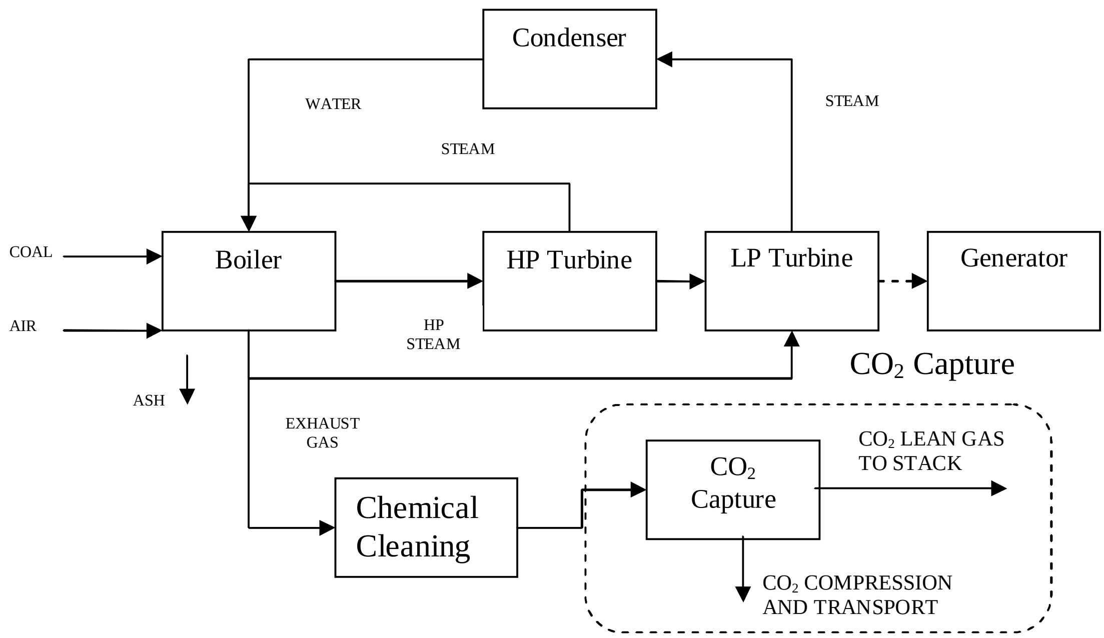


Figure 4-13: Schematic of a standard PC Plant with CO_2 capture

The scale of CO_2 capture equipment can be illustrated with a comparison to other emissions from a coal-fired plant. Deutch & Moniz (Deutch and Moniz, 2007) calculate the emissions of a 500MW supercritical plant burning Illinois coal with an efficiency of 35%. The plant emits 2.7million kg/hr flue gas. The makeup of the flue gas is broken down into constituent emissions in Table 4-9.

Table 4-9: Typical emissions from a 500 MW supercritical plant (Deutch & Moniz 2007)

Pollutant	Mass kg/hr
CO_2	463000
SO_2	12700
NO_x	1900

Although CO_2 makes up less than 20% of the total flue gas volume, there is more than 3.5 times the volume of CO_2 in the flue gas than the other controlled emissions presented in Section 4.2.1.3. This implies that CO_2 capture equipment will be substantially larger, require more power to operate and be more costly than traditional emissions controls.

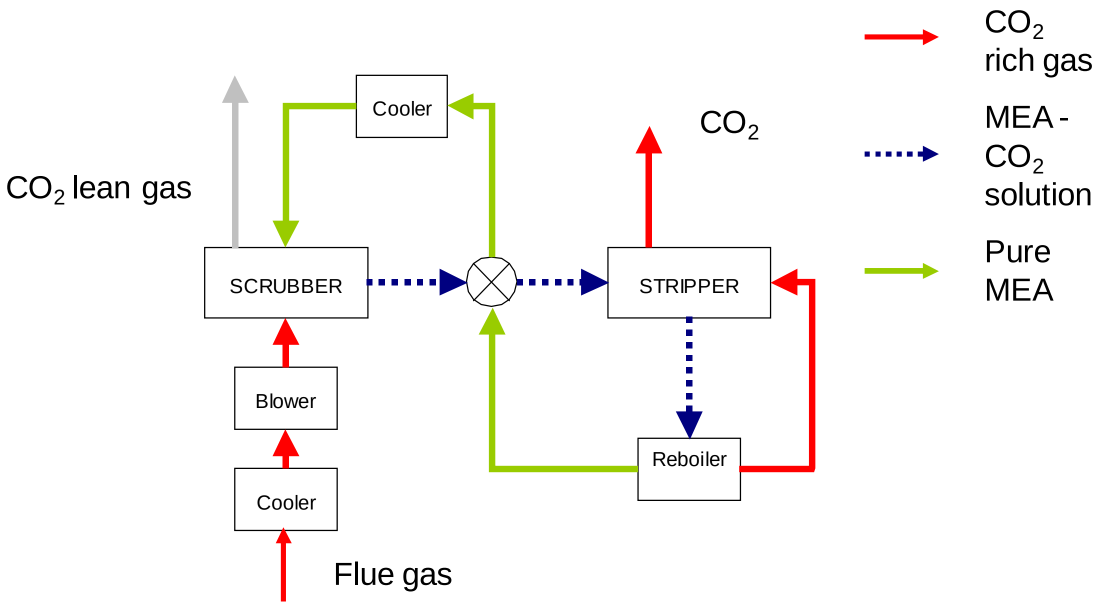


Figure 4-14: Schematic of carbon capture process

A schematic of the process for carbon capture from a PC plant is shown in Figure 4-14. The state of the art process is based on chemical absorption. Clean flue gas is cooled to around 40- 60^{o}C and then pressurised in the compressor (sometimes referred to as a blower), as there are pressure losses in the scrubber or absorber (IPCC, 2005), before being sent to the absorber (scrubber) which is a packed tray or column, the height of which is dependent upon the rate of absorption and the quantity of CO_2 that can be absorbed. In the absorber, the cool flue gas mixes with a solution containing monoethanolamine (MEA). Due to the slightly acidic nature of CO_2 and the slightly basic nature of MEA, the CO_2 in the flue gas forms a weak bond with the MEA to form a CO_2-MEA solution. The remaining flue gas is vented to atmosphere. The CO_2-MEA solution, carbamate, passes through a heat exchanger which removes heat from the lean solvent and is piped into the regenerator or stripper. The stripper separates CO_2 from the MEA. Latent heat is introduced from LP steam cycle (extracted from the last expansion stage in the steam turbine) into the reboiler, which heats the solution. The weak bond between the CO_2 and MEA is broken leaving a pure stream of CO_2 and hot MEA. The hot MEA is passed through the heat exchanger to heat the CO_2 MEA solution and is then cooled further. Not all MEA is recovered by the heating process and so additional MEA is added to replace that lost. The MEA is then piped into the absorber/scrubber to capture more CO_2. The hot CO_2 is cooled and pressurised, ready to be transported for disposal.

The governing reactions for the process are:

CO_2 Absorption:

$$\begin{aligned} 2HO-CH_2-CH_2-NH_2 + CO_2 \rightarrow\ & HO-CH_2-CH_2-NH_3 + \\ & +HO-CH_2-CH_2-NH-COO \end{aligned} \tag{4.1}$$

MEA Regeneration

$$\begin{aligned} HO\text{-}CH_2\text{-}CH_2\text{-}NH\text{-}COO + HO\text{-}CH_2\text{-}CH_2\text{-}NH_3 \rightarrow\ & CO_2 + \\ & + 2\ HO\text{-}CH_2\text{-}CH_2\text{-}NH_2 \end{aligned} \tag{4.2}$$

Carbon capture technology must integrate into the overall plant layout. The capture method for PC plant is fairly easy to install and can be thought of as a "bolt on solution"- constraints on the concentration of other flue gases demand that post combustion capture apparatus are installed after other pollutant controls. The properties of the process and gas are given in Figure 4-10.

Table 4-10: Key data for the PC removal process (Data: (Bailey and Feron, 2005)

Characteristic	
Heat of absorption	50-80KJ/mole CO_2
Absorption Temperature	40-60 C
Regeneration Temperature	100-140C
Pressure	Atmospheric

4.3.2.1 Capture consequences

Capture of CO_2 from a PC power plant requires significant amounts of energy. In order to drive the capture process, electricity is diverted from the plant output to run coolers, compressors etc. In addition, steam is diverted from the LP cycle to heat the carbamate solution to break the weak bond formed between MEA and CO_2. The overall plant efficiency penalty due to capture from a PC plant has been estimated to be 9.2% (Deutch and Moniz, 2007). The contributions to the overall factors from individual processes are shown below:

Table 4-11: Source of overall plant efficiency loss due to carbon capture in PF combustion (Data: Deutch & Moniz (2007))

Process	CO_2 Capture Penalty (%)
CO_2 Recovery	-5
CO_2 Compressor	-3.5
CO_2 Recovery (Power)	-0.7

It can be observed that the bulk of energy is lost during the CO_2 recovery and compression for transport. There is also a substantial cost penalty involved in installing the CO_2 capture and compression technology. This added cost is not just limited to capital cost but to operations and maintenance costs as well. In addition a low Sulphur dioxide concentration of between 1-10 ppmv is required in order not to damage solvent performance. Therefore there is a constraint imposed on emissions of SO_x and NO_x which dictates the performance of the emissions controls.

4.3.2.2 Manufacturers offering MEA capture process

There are two commercial manufacturers of capture equipment based on MEA: Fluor and ABB (Chapel et al., 1999), (Alstom, 2001).

Table 4-12: Manufacturer and process name for MEA capture process providers

Manufacturer	Process
Fluor	Econoamine
Fluor	Econoamine +
ABB	Lummus Global Tech

4.3.2.3 Future developments

New technological developments for carbon focus on minimising the cost and performance penalty of the capture process. Gibbins et al (Gibbins, 2004) propose six rules that should be followed to produce optimal post combustion capture performance. The rules cover steam entry and exit temperatures, process integration and interestingly the flexibility that the post combustion process offers. This focus is a consequence of the efficiency loss breakdown in Table 4-11 and the economic loss incurred. These developments are assessed in Section 4.4.2.

4.3.3 Carbon capture at oxyfuel plant

After chemical cleaning, the flue gas of an oxyfuel plant is mostly CO_2 and water vapour. Cooling the flue gas means that the water vapour changes phase and precipitates out leaving a relatively pure stream of carbon dioxide that can be compressed. This places the oxyfuel plant in an advantageous position compared to the PC plant, as no additional chemical process is required to remove CO_2 and it is why the oxyfuel option has been included in the report. Drying and flash systems then compress and purify CO_2. There is around 80% less flue gas, at a higher density, as a consequence of flue gas recycling so CO_2 purification equipment is smaller in volume and hence less costly. Flue gas recirculation is important to maintain combustion temperatures that are within the design tolerances of the boiler – the furnace exit temperature in an oxyfuel plant is approximately 1150^{o}C (Wilmsdorf et al., 2009).

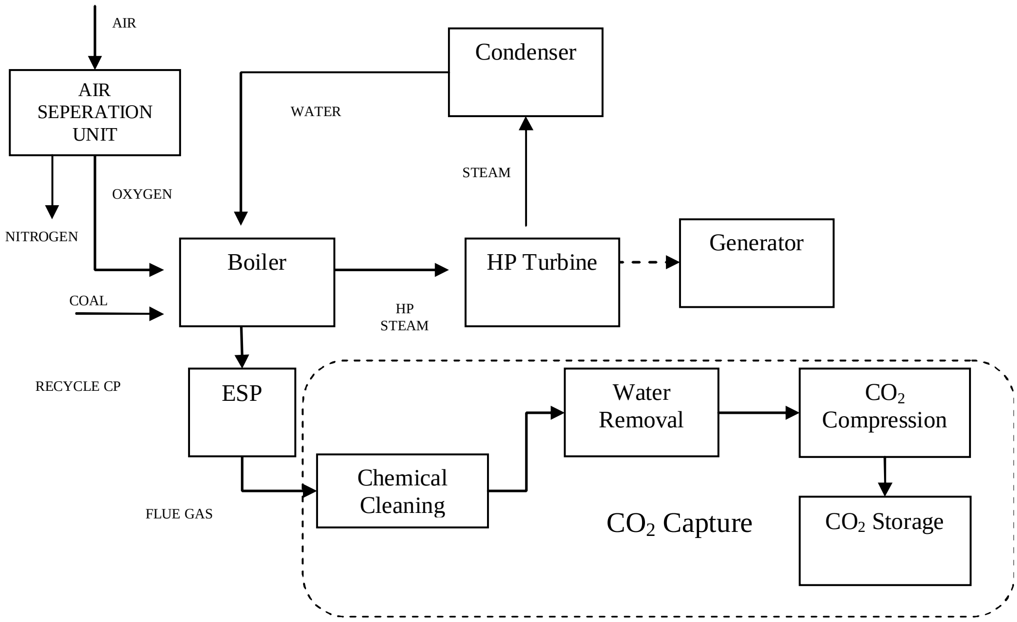


Figure 4-15: Schematic of oxyfuel plant with carbon capture

4.3.3.1 Capture consequences

Although a relatively pure stream of CO_2 is produced, the gas still needs compressing and cleaning before transport. A total efficiency penalty for carbon capture from an oxyfuel plant is approximately -4%- this is on top of the penalty associated for running the ASU as the table only describes additional processes required for CCS. The efficiency penalty is broken down into constituents in Table 4-13. In addition, it should be noted that the oxyfuel process already incurs a substantial efficiency penalty for operating the ASU as shown in 4.2.2.2.1.

Table 4-13: Source of overall plant efficiency loss due to carbon capture: Oxyfuel (Data: Deutch & Moniz (2007))

Process	CO_2 Capture Penalty (%)
CO_2 Compressor	-3.5
Other	-0.7

The bulk of efficiency is lost during CO_2 compression for transport. “Other” refers to the energy requirements of the CO_2 cleaning system.

The penalty cost for installing the CO_2 compressor technology should be less for an oxyfuel plant than for a PC plant because the volume of flue gas is 75% lower. Therefore the cost of the capture equipment should be significantly lower than for a normal PC plant. Further, there is no need for a chemical removal process; however, it is still worthwhile to remember that the oxygen has to be produced in an ASU, which incurs a performance penalty of around 4%.

4.3.4 Carbon capture at IGCC plant

In order to capture carbon dioxide from an IGCC plant, fundamental changes must be made to the plant design. These changes add complexity and capital cost to a class of plant that already struggles to compete against PC plant in the current market.

Figure 4-16 shows the layout of an IGCC plant with carbon capture installed.

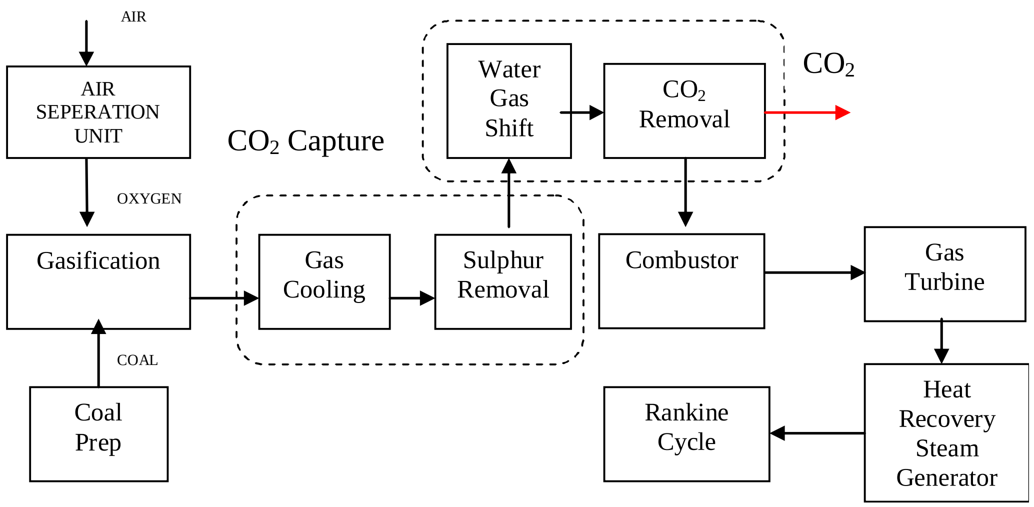


Figure 4-16: Schematic layout of IGCC plant with pre-combustion capture

It is more economic and efficient to capture CO_2 from a modified IGCC plant than from a PC plant because the CO_2 stream is more concentrated and at a high partial pressure compared to the CO_2 stream in a PC plant. Hence a weak solvent (Selexol) can be used which is inexpensive and requires little energy input to break the chemical bond between itself and CO_2

To facilitate the removal of CO_2 from the IGCC plant, a water-gas shift reactor is installed between gas cooling and sulphur removal by separating the syngas into CO_2 and H_2. There are two possible plant arrangements for CCS removal from IGCC plants; a process where both CO_2 and H_2S are removed together "sour shift" and a process where H_2S is removed followed by a shift reaction and CO_2 removal "clean shift". The "sour shift" process suffers a smaller efficiency penalty when installed (1.5% less) (IEA GHG (2003)), and will be used in this study.

The main reaction that takes place in the water gas shift reactor is between carbon monoxide (the primary constituent of syngas) and water vapour:

$$CO + H_2O_{(g)} \rightleftharpoons H_2 + CO_2 \tag{4.3}$$

After this reaction has taken place, the CO_2 and H_2 are separated by using a chemical adsorption or physical absorption process. The solvent is Selexol or Rectisol and removes both the CO_2 and the H_2S. The remaining H_2 is then combusted in the gas turbine. The CO_2-selexol solution at high pressure is sent to a flash tank to reduce the pressure and most of the CO_2 desorbs. To capture the remaining CO_2 a further flash stage is introduced, the CO_2 desorbs and is compressed and rejoins the main CO_2 stream that is compressed, ready for transport.

4.3.4.1 Capture consequences

IGCC plant with carbon capture is more complicated and costly than the standard plant, but the IGCC process with carbon capture installed incurs a lower performance penalty than the PC plant- a total loss of 7.2% (2% less than PC plant). Table 4-14 shows the sources of efficiency losses. The ASU is not included as it is required in the normal plant configuration.

Table 4-14: Sources of overall plant efficiency losses due to carbon capture: IGCC (Data Source: (Deutch and Moniz, 2007))

Process	Efficiency Penalty (%)
Water/Gas Shift & Other	-4.2
CO_2 Compression	-2.1
CO_2 Recovery	-0.9

The water gas shift reaction requires steam to function and this is drawn off from standard plant configuration. Compression of CO_2 accounts for a partial, but significant loss of performance, but removes 1.5% less efficiency than the PC capture process, primarily because of the higher pressure of carbon dioxide. Recovery of CO_2 accounts for around 14% of the efficiency penalty. The addition of a complex CO_2 removal process could compound reliability problems already experienced by the first generation of IGCC plants.

4.3.4.2 Possible future developments

As the largest efficiency penalty encountered is due to the water gas shift reactor, most research concentrates on improving the efficiency of this process. Alternative methods to increase efficiency include: pressure swing absorption/adsorption (Alternative solvents), membrane enhanced water gas shift reaction, and fuel cell systems.

It is not clear whether or not the plant would need to shut down if the carbon capture process were to go offline. There is no option to bypass the water gas shift reactor as all downstream plant is designed for CO_2 free operation. The sulphur cleanup system would face different operating conditions and the gas turbine could have flame stability problems (Alie et al., 2005).

4.3.5 CO_2 compression

The objective of the CO_2 compression process is to pressurise the separated CO_2 for transport to sequestration sites. Transmission companies set CO_2 quality specifications that must be met by the capture process (IPCC, 2005). A final pressure of between 110 and 140 bar[8] is required before CO_2

[8] This is equivalent to between 11MPa and 14MPa respectively.

transport can commence. CO_2 compression takes place in 5 stages, with cooling taking place in between each stage to 40 C (Oexmann et al., 2008). A compressor is used for the initial stages before a pump once the gas becomes dense/liquid. Once CO_2 is at a pressure of above 10MPa, the gas is either in the dense phase or a liquid phase, depending on the temperature which lowers transport costs.

The CO_2 compression process requires a significant amount of energy for all processes under review- of the data presented for all plants; compression of CO_2 typically reduces performance by between 2.1 and 3.5 penalty points depending on the pressure of the exhaust gas.

4.3.6 CO_2 transport

The idea of transporting carbon dioxide from power stations to sink sites is not a new one- more than 50Mt of CO_2 are transported through a network of 2500km of pipeline in the western USA, primarily for enhanced oil recovery (EOR) (IPCC, 2005). There are three methods to transport CO_2 to a storage site: tanker, onshore pipeline and offshore pipeline. The carbon transport system constrains the capture process in the plant in terms of pollutant or other species that are allowed and pressure that the liquid must be at. Canyon Reef, the first large CO_2 pipeline in the USA, has provided the following specification for transporting CO_2 (IPCC, 2005):

- Carbon Dioxide purity- 95%;
- No free water and tolerances on water in vapour phase;
- Hydrogen sulphide: less than 1500ppm;
- Total sulphur: Less than 1450ppm;
- Temperature not greater than 48.9^{o}C;
- No more than 4% nitrogen;
- No more than 5% hydrocarbons;
- Not more than 10ppm oxygen.

The reason for putting limits on nitrogen, oxygen and hydrocarbons is so that a single-phase flow can be achieved. The limits on hydrogen sulphide and water vapour are to stop corrosion problems. Other sources (Jordal et al., 2005) state that in order to transport CO_2, the CO_2 stream must not contain non-condensable gases (Argon, O_2, N_2) and water vapour (corrosion) and must be pressurised to 110atm.

4.3.6.1 Transport costs

Transport costs for CO_2 are a function of transport method, distance from the power plant to the storage location and the mass flow rate of carbon dioxide (if applicable). Figure 4-17 shows transport costs (£/tCO_2) as a function of distance from source to storage location for the three different transportation methods.

Jordal at al (Jordal et al., 2005) note that the requirements for CO_2 purification differ according to the final disposal method- enhanced oil recovery (EOR) or storage. The question that emerges is one of acceptability; is it acceptable to sequester SO_2 and NO_x along with CO_2? If it is acceptable, some processes such as flue gas desulphurisation may be removed from the process providing economic and efficiency benefits.

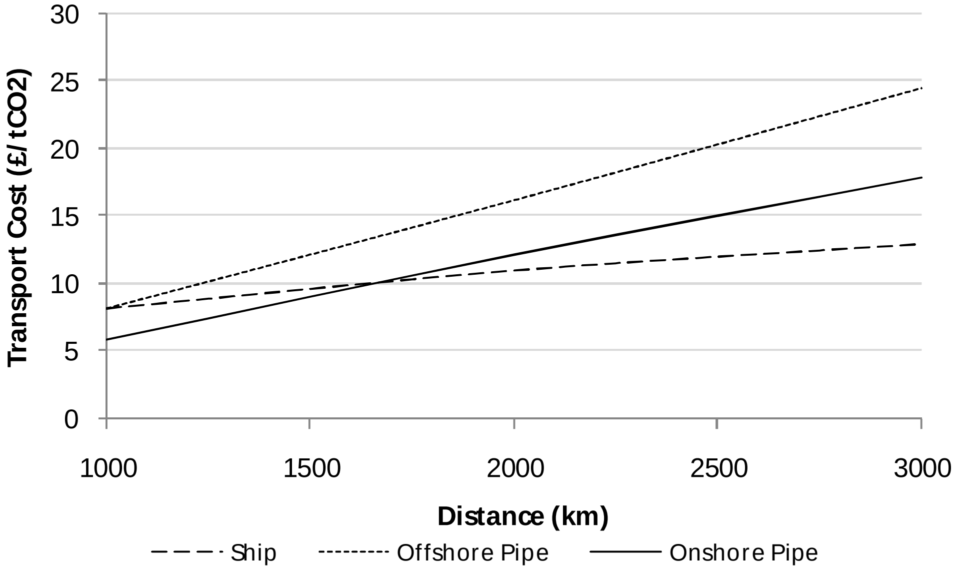


Figure 4-17: Transportation costs for CO_2 as a function of distance for various transport methods (Data Source: (IPCC, 2005))

The costs of pipeline transport can be broken down into construction cost, operations and maintenance costs and other costs (e.g. right of way) (IPCC, 2005). It should also be noted that Figure 4-17 represents total costs for transport, including the cost incurred in building liquefaction plant prior to transport etc. Detailed costs of transport that informed the IPCC report are given in Hendriks et al (Hendricks et al., 2004). For the purposes of this thesis, CO_2 will be transported 500km by offshore pipe, as the storage sites for the UK are offshore (Element et al., 2007).

Key factors of the carbon transport system include scale, complexity and optimisation of the transport network to cope with a number of emissions sources. This is essentially a question of where to situate the hubs if a hub and spoke transport network[9] is to be used and the matching of sinks (storage sites) to sources (power stations). In addition, regulatory factors are also important: for example, who is liable for emissions if CO_2 is transported across national borders?

[9] In a hub and spoke network traffic moves along spokes connected to a hub at the centre. For a CO_2 transport network, the hub would be where all CO_2 passed through on route to storage. The opposite of a hub and spoke network is a point to point network. Hub and spoke networks are the model used by the existing natural gas network, which has stong parallels with a CO_2 network (same process but in reverse).

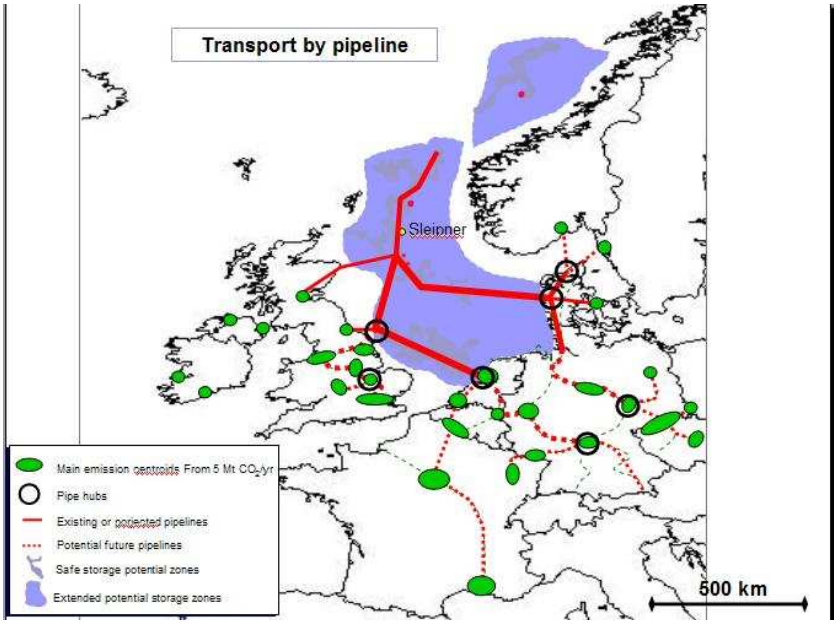


Figure 4-18: Example of a hub and spoke network for North West Europe (IEA Summer School, Kloster Seeon 2007)

4.3.7 Carbon storage

It is generally acknowledged that carbon storage can take place in any of the following:

- Depleted oil and gas fields;
- Partially depleted oil fields (EOR);
- Unmineable coal layers (ECBM);
- Deep saline formations/aquifers.

Deep saline formations are rocks with pore spaces filled with water of a significant salt content (brine) (IEA GHG (2007)). The rock type exists throughout the world, but high quality sites are not equally dispersed (IPCC, 2005). This has implications for the cost of carbon dioxide transport, if CCS is to be deployed worldwide, which is a function of distance between source and sink.

There are currently at least eight CO_2 storage projects in operation throughout the world with another nineteen projects using CO_2 for enhanced oil recovery (IEA GHG (2007)). The largest injection projects are at Sleipner off the coast of Norway (1Mt of CO_2 injected per year), In-Salah in Algeria (1.2Mt CO_2/year) and Weyburn in Canada (2MtCO_2/year).

There appears to be plenty of capacity for CO_2 storage at the global level: Hendricks et al (Hendricks et al., 2004) estimate that the potential for worldwide CO_2 storage is a minimum of 1660Gt CO_2 with a high estimate of 6000Gt CO_2. This is equivalent[10] to storage capacity for 80 years worth of world CO_2 emissions in the former case and would enable approximately 250 years of CO_2 emissions to be stored in

[10] Authors calculations based on global emissions in 2004 HENDRICKS, C. A., GRAUS, W. H. J. & VAN BERGEN, F. (2004) Global Carbon Dioxide Potential and Costs. Ecofys in Cooperation with TNO.

the later case, but the authors note that if the requirements for storage were relaxed (i.e. a lower quality aquifer) then the amount of available space would increase significantly.

There are a number of stages before storage capacity can be considered firm or valid (Holloway et al., 2006). The three stages of classification are:

- Theoretical (speculative, poorly quantified potential);
- Realistic (meets a range of engineering and geological criteria and therefore can be quantified with a fair degree of confidence);
- Valid capacity (meet additional criteria to allow an estimate of annual injection capacity).

Together, the three stages form a pyramid, as in general valid capacity is far less than theoretical capacity. Only once all geological studies have been completed is the capacity valid.

A recent report, based on empirical data of water from oil and gas fields, has suggested that the principal mechanism by which CO_2 is trapped in saline aquifers is by dissolution in water (Gilfillan et al., 2009). As the reservoirs that were investigated have contained dissolved CO_2 for millions of years, this implies that the majority of injected CO_2 can be expected to be stable (Gilfillan et al., 2009).

The elements required to deliver successful CO_2 storage are: site selection, regulatory framework, monitoring and liability. In addition to site selection, barriers to the commercial operation of CCS storage relate to the classification of carbon emissions as waste and the liability and ownership of CO_2 once it has been injected into a storage site.

If CO_2 is classified as waste, then it could be subject to EU waste directives, which ban the injection of liquid waste into landfill sites (Tysoe, 2008). The EU CCS directive attempts to re-classify CO_2, so that it can be injected onshore, but time is required for amendments to be implemented. There is some public concern, fuelled by speculation form NGOs, that this reclassification of CO_2 has safety implications i.e. the risk and consequences CO_2 of leakage (Rochon et al., 2009). However, academic research has shown that such events are extremely unlikely given monitoring regimes and the geological mechanisms by which CO_2 is stored (Condor et al., 2009). In addition, offshore storage of CO_2 requires policies such as the London Convention and the OSPAR convention to be altered in order to allow CO_2 storage in offshore aquifers. The liability associated with CO_2 leaks is a significant issue because of the timescale over which leakage could occur; CO_2 could escape centuries after it has been first injected. Due to the large timescale involved, which could exceed the lifetime of a company; it appears to be inevitable that some form of liability transfer to national governments will be required. As a result, the necessary legal framework to facilitate this transfer will have to be passed into law, adding time until commercial storage of CO_2 emissions can begin. Risk analysis tools for CO_2 storage also need to be further developed and standardised (Condor et al., 2009).

4.3.7.1 Carbon storage costs

The cost of CO_2 storage is predominantly due to cost incurred during drilling wells and operational costs (Hendricks et al., 2004). Therefore the number of wells and the depth of drilling influences the overall cost incurred as does the estimated operational lifetime.
If the storage is to be offshore, an injection platform must also be built. Hendricks et al (Hendricks et al., 2004) note that the costs incurred for enhanced oil recovery (EOR) and enhanced coal bed methane (ECBM) storage complicate the cost model considerably due to the stochastic price of commodities. Table 4-15 gives costs for CO_2 storage, taken from the IPCC report (IPCC, 2005).

Table 4-15: Estimates of CO_2 transport and storage costs (Data Source: (IPCC, 2005))

Option	Representative cost range (£/tonne CO_2 stored)
Geological storage	0.3-5.1
Geological monitoring	0.1-0.2
Ocean storage, CO_2 transported by pipeline	3.8-19.8
Ocean storage, CO_2 transported by ship	7.7-10.2
Mineral carbonation	31.9-63.9

4.3.7.2 Carbon transportation and storage in the UK

It is relatively simple to calculate amount of storage required for the UK using some high level assumptions. The largest saline aquifer is the southern north sea basin which it is estimated can store in excess of 14Gt of CO_2 (Holloway et al., 2006), although other sea basins still need to be analysed. Given that the UK emissions of CO_2 in 2008 totalled 550Mt of CO_2, of which 177MtCO_2 came from power stations (DECC, 2008a), this means that there is enough offshore storage potential to sequester CO_2 emissions from power stations for at least 80 years in the Southern North Sea basin alone. Some reports state that there is enough storage for up to 300 years[11]. The study by the British Geological Survey also estimates that there is sufficient capacity in all current gas and oil fields to capture emissions for between 13 and 38 years (Holloway et al., 2006).

4.3.8 Capture ready and capture flexible plant

There has been research into strategies a generator can adopt to reduce its exposure to future carbon price uncertainty. Capture ready plants and capture flexible plants have been investigated.

Capture ready is an attribute that allows a plant to switch from non-CCS operations to CCS-enabled operations at some point in the future. Capture ready is hard to define accurately but at the minimum it is a set of pre-investments that enable plants to be retrofitted with CCS (Chalmers and Gibbins, 2007), (Sekar et al., 2007), (Bohm et al., 2007) and (IEAGHG, 2007). Although the potential of carbon “lock-in” is avoided (Gibbins and Chalmers, 2008), plants will continue to emit carbon dioxide until they choose to exercise such options; a sufficient carbon price will provide the trigger to do so. Carbon “lock-

[11] “North Sea’s new bonanza”, The Sunday Times, 16.08.2009

in" refers to the hypothetical situation in which new coal plants were built without CCS or the ability to retrofit CCS at some point in the future. Such inflexibility in operations would result in the plant emitting CO_2 when operating regardless of the external environment, as such the plant would be "locked in" to emitting CO_2. The effect of several new coal plants being "locked in" to carbon emissions is not desirable from a political, environmental and arguably an economic point of view.

Enabling parameters for a capture ready plant are that the other elements of the CCS system must be in place, and that sufficient space should be left for the installation of the capture processes (although this varies according to technology). In addition, the penalties associated with capture ready plant should be more than compensated for by the value of flexibility associated with the capture ready characteristic, e.g. efficiency penalty, increase in capex and fuel costs.

Capture flexible plants have the ability to adjust the proportion of CO_2 captured depending on external conditions (high electricity price or low-carbon price) or operational demands such as startup, shutdown and load-following (Chalmers and Gibbins, 2007). In deciding to switch the capture facility off, the plant gains efficiency, as the carbon capture process is not operated. This would allow the operators to receive additional income from a spike in electricity prices that would more than compensate for the carbon penalty incurred by venting CO_2. If this practice was deemed to be politically unacceptable, legislation that limited CO_2 emissions on an absolute basis i.e. t/MWh could be put in place (rather than on an average t/MWh basis).

4.3.9 Coal plant economic performance data

A wide variety of sources have been consulted in order to estimate the expected cost of generation for the various plants under investigation, and therefore it has been necessary to use an exchange rate from dollars to pounds (Officer and Williamson, 2008). The raw data tables are in Appendix D.iv.

This Section provides cost data for the various CCS technologies under investigation. Absolute costs will be dependent on site selection, local planning, permitting process and component development, brown-field or green-field build and feedback from demo projects. There will also be a difference in costs if a plant is retrofitted or built as new. Table 4-16 gives the data inputs used for the comparison of the various forms of coal plant. The levelised cost in Table 4-16 has been derived using the methodology in Chapter 5.

Table 4-16: Data used for case study comparison (source: Chapter 5)

	PC	IGCC	Oxyfuel	PC_CCS	IGCC_CCS	Oxyfuel_CCS
Capex (£/kW)	900	1000	9500	1350	1530	1400
Opex (£/kW)	24	48	35	40	63	40
Efficiency (%)	44	44	40	35	37	36
Fuel Cost (£/GJ)	1.32	1.32	1.32	1.32	1.32	1.32
Carbon Cost(£/tonne)	16.5	16.5	16.5	16.5	16.5	16.5
Total (£/MWh)	40.24	43.96	44.10	46.21	50.75	46.14

4.3.10 Discussion and conclusion of CCS system evaluation

The CCS system has not been demonstrated at a commercial scale anywhere in the world. In order for the CCS system to be viable, and to remove uncertainty surrounding costs and regulation, large-scale demonstration of CCS is required. Full scale commercial demonstration would also clear uncertainty regarding how well capture-enabled plant can follow load demand. In addition, system integration is also a key driver: all three elements need to be in place before CCS can be successfully implemented.

The three phases of the CCS system have different problems associated with them, for example, although the contribution of costs per MWh is small (Section 5.5.6), the complexity of the transport network is high, as is the cost for this additional infrastructure. The storage of CO_2 is technically viable, but there are significant legal impediments that need to be overcome, particularly with regard to ownership and liability associated with long term CO_2 storage.

The effect of CCS system on plant and system performance parameters has been evaluated. The result is an increase in the cost of generation, primarily due to impact on plant performance. The method used to capture carbon dioxide is dependent upon the type of plant in use; PC, oxyfuel or IGCC. Whichever method is used, the overall efficiency of the plant decreases, the capital cost and operations and maintenance cost also increase. When the cost of transporting and storing CO_2 is added, the total penalty is that the price of electricity from a power plant with CCS is significantly higher than electricity produced from a plant without CO_2 capture and storage.

Reliability is an essential system performance parameter, although it should be noted that in terms of breakdown of the CO_2 capture process, PC and oxyfuel have a definite advantage over IGCC as the capture process is not integral to the plant process. Therefore in the event of equipment malfunction, the flue gas is simply vented to atmosphere from a PC plant whilst an IGCC plant would have to shut down completely.

There is no clear “best” capture technology. IGCC plants are the most capital intensive plants, but have a more efficient capture process. However, IGCC plant is a relatively new technology with reliability problems. The additional capture penalty for an oxyfuel plant is low but when the efficiency penalty from operating the ASU is taken into account, oxyfuel plant has a similar efficiency to IGCC plant. In addition, although an oxyfuel plant uses many of the same components as a PC plant, the oxyfuel process has not yet been deployed on a commercial scale which means there could be reliability issues. Capturing CO_2 from a PC plant has the largest performance penalty. However, PC technology is the world standard at present and there are no problems with availability.

Capture ready is an important source of flexibility. It allows a coal fired power plant to be built with the option to upgrade to capture carbon dioxide later i.e. once CCS system processes, transport and storage, are in place and economic incentives are sufficient for capture to be implemented. Additional potential for PC plant with the capture process added, but dormant, to take advantage of future improvements in solvent technology by integrating it into the plant when the capture option is ready to be exercised, subject to operational constraints.

Capture flexible plant has operational flexibility to switch the capture process off and increase output during times of high demand. This operational flexibility would add value if performance penalties incurred from installing but not operating a capture process were more than compensated for by the revenue gained from higher plant efficiency.

The high concentration and pressure of the shifted-syngas gas in an IGCC plant results in favourable conditions for CO_2 capture. The expected trend in future performance (efficiency) for IGCC plant and the associated capture penalty are greater than and less than, respectively, those of a PC plant. The additional investment cost for an IGCC plant is less than that required for a PC plant. However, when CCS is used the complexity of the IGCC process increases, which could impact on operational and reliability parameters.

Oxyfuel benefits from having no separate chemical capture process- the nature of the exhaust gases means that after FGD and water removal, the flue gas can be compressed for transport. The air separation unit is a well-proven technology and although no oxyfuel boilers have been built for power generation, there is a significant amount of transitional experience from standard PC boilers. Flue gas recirculation limits the combustion temperature in O_2 enriched gas mixture to similar temperatures achieved with combustion in air and there is ongoing research into new alloys that can withstand high furnace temperatures.
The market for a PC plant appears to be largest in the near term, with orders for new plant being bolstered by demand from China and India. In addition, although IGCC could be the superior technology in terms of emissions performance, the capital cost of a PC plant is expected to remain lower than IGCC in the future (Figure D-1).

In conclusion, it is difficult to see how the CCS system will be deployed at a national/ international scale without some kind of incentive in place. Breakdown of costs show that the bulk of additional cost associated with CCS system operation lies in the operation of the capture process, but significant barriers to the implementation of the other two elements of the CCS are legal and regulatory frameworks that need to be in place in order to facilitate the allocation of responsibility for long term carbon storage from operator to national governments.

Moreover, based on the technology literature reviewed so far, it is difficult to reach a firm conclusion as to which plant process (IGCC, oxyfuel or PC) is best suited to perform CO_2 capture. The main reason for this is that the research community and equipment manufacturers realise that the current performance penalty imposed by operating the carbon capture process results in uncompetitive cost of generation (under the current carbon price). Therefore, a significant body of research, design and development is progressing with novel capture technologies to reduce the performance penalty associated with capturing CO_2 from the power plant. In order to make a more robust comparison between the alternative CCS plants from a technology perspective, the next Section examines the alternative capture processes in detail. This allows the full technology assessment to be conducted on a more robust basis in Section 4.5. This more detailed examination of advanced capture technologies is also in line with the framework set out in Chapter 3 i.e. comparing the impact of alternative sub-processes on plant performance.

4.4 Evaluation of advanced carbon capture technology

Section 4.3 showed that the cost of generating electricity from a plant with operational carbon capture is prohibitive in a commercial market due to additional capital costs, operational costs and performance penalties; predominantly caused by the operation of the capture process rather than CO_2 transport and storage costs.

In order to reduce the cost penalty associated with carbon capture, a plethora of novel technologies for capture are under research and development. Novel capture technologies each have different advantages and disadvantages and are at different stages of development. If one of the three types of plant investigated so far (IGCC, PC or Oxyfuel) has significantly better near-term potential for reducing the performance penalty associated with carbon capture through novel capture processes, this could influence the conclusion of the technology analysis. Therefore, Section 4.4 applies a systematic framework to allow an objective comparison of novel CO_2 capture technologies for PC, Oxyfuel and IGCC plant using system performance parameters. In addition, synergies between technologies are identified as this will allow a process to be upgraded in the future. This Section sits within the overall analysis framework presented in Section 4.1, by comparing alternative technologies at the sub-process level, as shown in Figure 4-1 and Figure 4-2.

An evaluation of advanced capture processes is hampered by a number of factors. Firstly, the sheer number of alternative capture processes being investigated. This is due to two reasons: the process conditions and the potential market for the technologies. The process conditions for CO_2 capture are different for IGCC, PC and Oxyfuel plants, which necessitates alternative capture processes for the different plant types. This is compounded by the size of the potential market for these technologies, which drives significant investment into research in alternative process technologies for carbon capture.

In general, the nature of the CO_2 rich gas (i.e. pre-capture) dictates the type of capture process best suited to a particular plant. Table 4-17 shows the general rule for matching plant types and CO_2 capture processes.

Table 4-17: Table matching CO_2 rich gas characteristics to capture processes

	CO_2 rich gas pressure	CO_2 concentration	Capture stage	Standard capture process
PC	Atmospheric	12-15%[12]	Post Combustion	Chemical absorption
IGCC	Pressurised	~39%[13]	Pre Combustion	Physical absorption/ adsorption, membranes
Oxyfuel	Atmospheric/Pressure		Post Combustion	N/A (compression of exhaust gas)

For example, the low pressure of exhaust gas from a PC plant means that without treatment of the exhaust gas, physical absorption is not a viable capture process as its main driving force is the partial pressure of the gas. Therefore physical absorption is better suited to capture from processes where the gas is at high pressure, such as IGCC.

There are exceptions to the general rule; for example, contact membranes are being developed for PC capture. However, it may be necessary to compress the gas prior to membrane contact in order to achieve a reasonable rate of reaction. In this case the key question becomes: do the benefits of the alternative capture method outweigh additional costs required for their implementation?

4.4.1 Overview of novel capture processes

Novel capture processes attempt to address the shortcomings of the state of the art capture processes. To date, a number of advanced technologies have been put forward. For the sake of brevity, this Section only assesses those technologies that are either close to or at system development stage – these are shown in Table 4-18. Data is taken from (Eide et al., 2005), (Figueroa et al., 2008), and (Yang et al., 2008).

In general, there are two routes to increase the performance of the capture process: Improving the capture process related to the existing technology or introducing new capture technology. The key questions that each novel process or technology needs to be evaluated against are:

- What are the performance benefits/ disadvantages in relation to current technologies?
- What are the cost benefits/disadvantages in relation to current technologies?

Table 4-18: Improvements to the carbon capture process by plant type

[12] Data from BAILEY, D. W. & FERON, P. H. M. (2005) Post Combustion DeCarbonisation Processes. Oil & Gas Science and Technology – Rev. IFP,, 60**,** 461-471.

[13] Data from GRAINGER, D. & HÄGG, M.-B. (2008) Techno-economic evaluation of a PVAm CO2-selective membrane in an IGCC power plant with CO2 capture. Fuel, 87**,** 14-24.

Type of improvement	PC	Oxyfuel	IGCC
Process improvements	Amine solvents	Cryogenic oxygen	Physical absorption / adsorption with alternative solvents
	Advanced amine-solvents	Oxygen transport-membrane (OTM)	
	Process integration	Internal flue gas-recirculation	
New sub-processes	Membrane systems	Chemical looping-combustion	Sorption/ membrane-enhanced WGS
	Cryogenics		Separation via hydrate formation
			Fuel cell

4.4.2 Advanced technologies for post combustion capture

Adding carbon-capture to a PC plant increases capital cost, O&M cost, and reduces plant efficiency. In addition, complexity is increased as new processes are integrated into existing plant. Therefore, cost of electricity increases while reliability (usually a function of plant complexity) could possibly decrease. In order to be considered as viable technical options, advanced technologies for carbon capture on a PC plant need to have benefits compared to MEA i.e. lower performance penalty and/or cost. This focus is a consequence of the efficiency loss breakdown as shown in Figure 4-19 where 54% of the energy penalty is associated with CO_2 recovery, and the economic loss incurred due to increased capital and operational costs. Processes that reduce the heat required for CO_2 recovery (traditionally provided in the form of steam) are advanced solvents. A description of the types of solvents currently under investigation can be found in IPCC (IPCC, 2005).

Two other methods for reducing the overall efficiency loss of the process include the utilisation of a cryogenic process to cool a heat exchanger below the freezing point of CO_2 so that CO_2 precipitates out of the flue gas. When enough CO_2 has been collected, the precipitate is heated to form a pure stream of CO_2 ready for compression and transportation. The cryogenic process is described in Eide et al (Eide and Bailey, 2005). The second method is process integration. Process integration refers to changes in networks within plants to reduce energy costs without changing the absorbent. It is reported that heat consumption can be reduced by between 1/2 to 1/3 of that used with conventional flow sheets (Leites et al., 2003). Although new technology can reduce costs, new solvents are not clearly better than MEA on an economic or efficiency basis and none have been proved at a commercial scale.

4.4.2.1 Capture consequences

As shown in 4.3.2.1, the installation and operation of capture technology results in significant performance penalty. Figure 4-19 presents a breakdown of the performance penalty associated with carbon capture.

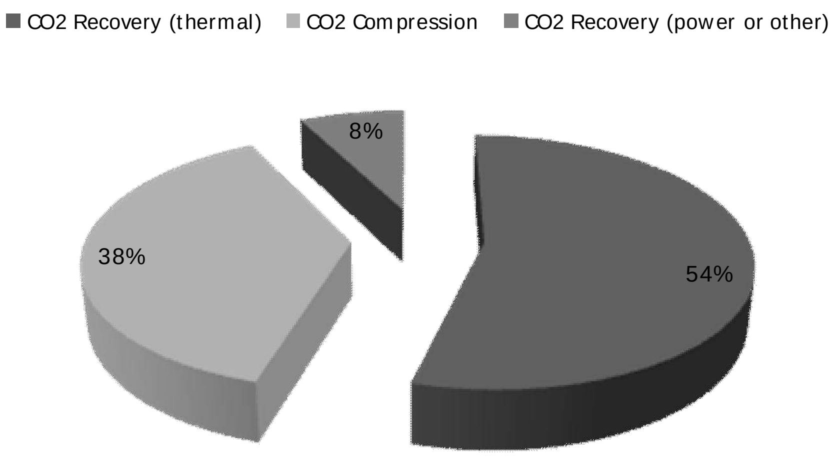


Figure 4-19: Proportional representation of energy penalty associated with installation of carbon capture on a PC plant (data source: (Deutch and Moniz, 2007))

As shown in Figure 4-19, the energy required for CO_2 capture in PC plant can be split into:

- Thermal energy that is required to separate the CO_2 from the amine solution ('CO2 recovery (thermal)' in Figure 4-19);
- Energy required to compress the CO_2 prior to transportation;
- Any other energy required for CO2 recovery (e.g. running auxiliary processes).

The CO_2 content of flue gas from a PC plant is typically 12-15% of the total flue gas, in addition the flue gas is at atmospheric pressure and because of this, removal techniques based on high partial pressures (physical solvents or membranes) may not be efficiently applicable for capture. Chemical solvents show enough absorption capacity to be applicable to capture (Oexmann et al., 2008). The main characteristics of post combustion exhaust gas are given below, along with other factors which influence the performance penalty of carbon capture at a PC plant:

- Low pressure flue gas with dilute CO_2;
- Steam requirement for thermal regeneration (amines);
- High compression costs and low loads due to CO_2 produced at low pressure;
- Flue gas contaminants influence solvent degradation (Eide et al., 2005);
- Corrosion problems.

4.4.2.2 Chemical absorption with advanced solvents

Chemical absorption for capture of CO_2 from a PC plant consists of the following sub processes: cooling, absorption, heat exchange, regeneration and compression. The cooling requirement is a function of the solvent activation temperature. The rate of absorption determines the size of the absorber and hence the capital expenditure. The heat exchange is the process whereby heat is transferred between lean and rich CO_2 solvents. Regeneration temperature is the energy required to separate the solvent rich solution and is a function of solvent properties. The energy required for CO_2 compression is a function of the exhaust gas pressure.

The complete process is broadly the same for all of the alternative solvents. Advanced solvents attempt to improve upon the performance of MEA by offering better overall performance. The obvious question is: What defines the performance of a chemical solvent? As a result of the literature review, it became clear that a number of technical performance parameters (TPP's) determine the performance of a chemical solvent for absorption. The TPP's are:

- **Heat of absorption/regeneration.** A solvent with low heat of absorption requires less energy during regeneration and hence less energy (in the form of steam) is required from the LP plant cycle leading to a lower efficiency penalty. (Alie et al., 2005, Alstom, 2001), (Mimura et al., 2000).
- **CO_2 absorption rate.** A solvent with a high absorption rate minimises the absorber size, pressure drop across the absorber and associated pumping costs. Alternatively, with the same size of absorber/desorber, the energy requirement becomes lower (Yagi et al., 2006).
- **CO_2 absorption/desorption capacity.** A high absorption capacity allows more efficient operation and can reduce solvent volume requirements and equipment size. When defining the CO_2 loading capacity, it is necessary to relate the difference between the CO_2 loading in the absorber and the CO2 loading in the stripper. This is because not all CO_2 that is absorbed in the scrubber is released in the stripper. Therefore the difference between the CO_2 loading at the exit of the scrubber and exit of the stripper, is the actual amount of CO_2 captured (Yagi et al., 2006).
- **Resistance to degradation/impurities.** Solvents with a high resistance to degradation reduce solvent make up costs and can reduce gas clean up costs in the stages prior to the absorption system (Oexmann et al., 2008), (Mimura et al., 2000).
- **Corrosion.** Corrosive solvents are undesirable because they shorten the life of process equipment (Oexmann et al., 2008).
- **Volatility.** A volatile solvent can escape with the flue gas and cause environmental issues.

In addition, the IPCC (IPCC, 2005) defines the following as key characteristics that determine the technical and economic performance of a flue gas capture system:

- **Flue Gas flow rate.** Determines the size of the absorber, which then determines capital expenditure.
- **CO_2 content of flue gas.** Low concentration of CO_2 in flue gas encourages use of chemical absorption processes.
- **CO_2 removal.** The amount of CO_2 to be removed: typically 80-95%. The higher the % removed, the greater the cost in terms of capital and energy penalty.
- **Solvent flow rate.** The solvent flow rate is one of the determinants of the rate of absorption of CO_2.
- **Energy requirement.** The sum of all of the energy required to: a). operate ancillary equipment and b). the thermal energy required for solvent regeneration.

- **Cooling requirement.** The flue gas needs to be cooled in order for the absorption process to work.

The chemical solvents that were identified in the literature review as the most promising and advanced are presented in the sub-sections and compared against the list of parameters given above. In addition, key questions are raised and the current technology status is given.

4.4.2.3 Sterically hindered amines

Mitsubishi Heavy Industries (MHI) along with Kansai Electric Power have been developing an alternative chemical solvent to MEA since 1990 (Iijima et al., 2004). The Kansai-Mitsubishi proprietary carbon dioxide recovery process (KM-CDR), uses a process similar to that used by MEA (Iijima et al., 2004), but with different solvent, KS-1, KS-2 and KS-3, which are sterically hindered amines. MHI has published a considerable amount of information on the process: (Muramatsu and Iijima, 2002), (Iijima et al., 2004), (Imai and Ishida, 2004), (Yagi et al., 2004), (Ohishi et al., 2006), and (Yagi et al., 2006).

According to MHI, the KM-CDR has a number of benefits over capture using MEA:

- Higher CO_2 absorption capacity (CO_2 loading)
- 20% lower heat of regeneration, mainly due to the low temperature of solvent regeneration (110 C-120 C) (Iijima et al., 2004) which requires less steam from the low pressure turbine.
- More resistant to degradation (Muramatsu and Iijima, 2002)
- More resistant to corrosion (Muramatsu and Iijima, 2002)
- Higher CO_2 absorption rate than MEA (Yagi et al., 2006)
- No data on local environmental effects of the solvent.
- No data on the rate of reaction

The result is smaller solvent flows and pumping costs, smaller diameter absorbers and strippers. The solvent is also resistant to degradation by oxidation and corrosion (Mimura et al., 2000). One possible disadvantage is that the KS-1 solvent is more costly than MEA (IEAGHG, 2004). Of course, if the solvent does not have severe degradation problems, there will be an overlap between initial cost of solvent and maintenance cost (cost required due to degradation).

Much of the work undertaken by MHI has focused on investigating the effect of impurities (NO_x and SO_2 and their effect on process performance (Iijima et al., 2004), (Yagi et al., 2006). They found that a sulphur level of 30ppm accelerated the degradation of KS-1 due to the formation of heat stable salts, which then needed to be removed. Hence MHI recommend a limit of SO_x that needed to be removed upstream of the CO_2 removal process (10ppm). One of the most useful aspects of the work undertaken by MHI is that they openly compare the results of experiments involving KS-1 with other chemical solvents (MEA). As a result, the information has a more authentic base to it.

MHI have provided the process for use in urea production (160tCO_2/day) (Iijima et al., 2004), and market a 6000tCO_2/day removal process (Yagi et al., 2004). In addition MHI have done much work on process integration in order to maximize the effectiveness of steam use etc (Iijima et al., 2004). MHI have been testing the process on flue gas from an existing coal fired plant at the rate of 10t CO_2/day for 3000 hours (Ohishi et al., 2006). At present, the technology appears to be as advanced as MEA i.e. ready for full-scale demonstration. The evaluation criteria not answered in the literature review concerns solvent volatility. Therefore there is a need to find out the local environmental impacts of the solvent.

4.4.2.4 Aqueous/ chilled ammonia

The removal of CO_2 through the use of aqueous ammonia is a promising removal technique that is relatively well advanced. Benefits of using ammonia are described in Ciferno (Ciferno et al., 2005), and Resnik (Resnik et al., 2004) and are summarised below:

- High CO_2 loading capacity;
- Low equipment corrosion risk;
- Low absorbent degradation;
- Low energy requirement for absorbent regeneration;
- Potential to sell ammonium sulphate and ammonium nitrate by-products to raise revenue (although the market may become over saturated i.e. supply>>demand);
- Reduction in steam requirements of up to 67% (Ciferno et al., 2005);
- Steam could be reduced by between 49-64% (Resnik et al., 2004).

The last two points above reduce the energy required for regeneration and hence a substantial cost saving can be made. In addition, solvent degradation would be of less importance because NH_3 is cheaper than MEA. This implies lower solvent makeup cost.

Problems with the technology include volatility– ammonia has a tendency to exit the absorber column with the flue gas. There are environmentally acceptable limits on NH_3 emissions (10ppm). Measures could be taken, but would add to complexity of process and cost. Therefore there is still the need to find a practical method to solve this problem. In addition, the rate of absorption could be much slower- thereby implying that a larger tower would be required (which would be more costly). Most current pollution control technologies have been associated with local pollution (particulates etc) therefore it is likely that local environmental conditions will not be compromised for CO_2 capture e.g. solvent escapes to atmosphere.

The following key questions arose as a result of the literature review:

1. How can the volatility problem be overcome?
2. Are CO_2 capacity improvements significant?
3. Are steam regeneration improvements significant?
4. Do the other advantages outweigh the disadvantages of the slow reaction rate?

One of the main benefits of the ammonia capture process is that all pollutant removal is done at once. Therefore, the additional complexity is minimal and capital costs are lower. Chilled ammonia, offered by Alstom Power, runs at between 2-16C and so the CO_2 rich gas requires significant cooling before entering the absorber. The process aims to minimise ammonia loss due to volatility and purports to consume 50% less energy than the MEA process.

Capture processes using Ammonia are fairly numerous and include the following:

- Alstom and EoN have signed a contract to build a 5MW chilled ammonia pilot plant at Karlshamn, Sweden.
- Alstom, We Energies and the EPRI operate a pilot plant removing 15,000 tonnes CO_2/year in the USA using chilled ammonia.
- Powerspan corp demonstrated their ECO_2 process at Basin Electric Power Antelope station.
- A mid-size "commercial scale" plant, in fact a demonstration (120MW), is expected to be operational by 2012, with the CO_2 being shipped and stored by Dakota Gasification Co, a wholly owned subsidiary of Basin Electric Power.

4.4.2.5 Piperazine promoted potassium carbonate solution

Potassium carbonate is used for carbon dioxide removal from natural gas reforming but in this process the high partial pressure of CO_2 provides a driving force for the reaction. Commercially available processes using a 30wt% potassium carbonate solution are from Benfield and Catacarb (Oexmann et al., 2008). However, the nature of the flue gas from a PC plant means that the rate of reaction with standard potassium carbonate solution is too low. Therefore the performance potassium carbonate can be enhanced through the addition of piperazine (Cullinane et al., 2004).

The process is the same process as MEA, but with a different solution- 5m K+/2.5m Pz (Oexmann et al., 2008). The benefits of this advanced solvent include:

- Lower heat of absorption than MEA;
- Faster rate of absorption than MEA (Oexmann et al., 2008);
- Roughly Equal to MEA in terms of carrying capacity. Potential for higher CO_2 capacity (Oexmann et al., 2008). Oexmann's result showed a similar CO_2 capture rate to Abu-Zahra (Abu-Zahra et al., 2007a);
- Lower heat of regeneration than MEA, therefore 25-49% less energy required for regeneration;
- Rate of absorption is 1-5 times faster than MEA; therefore a smaller absorption column is needed;
- The Piperazine/Potassium carbonate solution has a low volatility and in this respect is better than ammonia.

Oexmann (Oexmann et al., 2008) shows that due to the lower energy requirement for regeneration, a 2% increase in plant net efficiency is gained. This compares to results published regarding the optimisation of an MEA removal process (Abu-Zahra et al., 2007b). The paper also shows that the capital cost for the removal system is less, mainly due to reduced height of absorber and desorbers. A disadvantage is that the cost of piperazine/potassium carbonate solution is five times higher than the unit cost of MEA (Oexmann et al., 2008). According to the criteria put forward in Section 4.4.2.2, the following questions still remain regarding solvent performance: is solvent degradation significant? (addressed by (Oexmann et al., 2008)). If so, could solvent degradation more than compensate for decreases in capital costs for the absorber and desorber? What are the corrosive effects of the solvent?

In terms of commercial development, a small pilot plant has been operated at the University of Texas (Cullinane et al., 2004). In addition, full plant simulation in Aspen (chemical engineering simulation software) has been carried out at Hamburg University of Technology (Oexmann et al., 2008).

4.4.2.6 Amino acid salts

Amino acid salts are solvents that have applications with two CO_2 removal processes: chemical absorption and membrane contactors (see Section 4.4.2.11) (Feron and ten Asbroek, 2004).

The process relies on the formation of a precipitate when amino acid salts absorb CO_2. The formation of the precipitate means that CO_2 loading is higher than MEA, resulting in lower process energy consumption (Feron and ten Asbroek, 2004). Total plant efficiency penalty has been reported as 5%, less than MEA can achieve (Jockenhoevel et al., 2009). Other benefits include low volatility and smaller removal equipment sizes due to the higher CO_2 loading capacity. A lower heat of regeneration (80C) is also given, contributing to the lower performance penalty. One important advantage for amino acid salts is that they are environmentally benign i.e. the amino salts are biodegradable and non toxic (Jockenhoevel et al., 2009).

One of the cited disadvantages is that as a precipitate forms during absorption, equipment is required that can handle slurries. Additionally, the heat exchanger has to be integrated into the regenerator (Feron and ten Asbroek, 2004). Both of these points would increase complexity and could result in reliability and maintenance issues.

According to the criteria that were put forward in Section 4.4.2.2, some questions regarding the amino acid salts process still remain, including the ability of the solvent to resist degradation, although it appears in promotional material that degradation is very low (Jockenhoevel et al., 2009). It is also not entirely clear whether the high CO_2 loading capacity is matched by a low CO_2 desorber concentration and hence the overall amount of CO_2 captured.

A small lab scale process has been demonstrated (Feron and ten Asbroek, 2004). Siemens Energy have developed a form of amino acid salt technology and plan to use it in the Meri Pori demonstration CCS project in Finland (Jockenhoevel et al., 2009). At present the process is being validated in the slip-stream of an E.ON plant in Germany

4.4.2.7 Other solvents

Many other solvents are currently being researched that have not been included in this review, but have been covered by others and appear to be at such a stage of development that they are outside the scope of this Chapter. That is not to say that they are irrelevant or will not be better than MEA, but that research is at a relatively low technology stage. Other solvents include alkali-metal based sorbents, other amines and ionic liquids. More information can be found in Bailey (Bailey and Feron, 2005), Yang, (Yang et al., 2008), Aaron (Aaron and Tsouris, 2005), Eide (Eide et al., 2005), and Figueroa(Figueroa et al., 2008). Many of these processes are still at the lab or paper demonstration stage and there is insufficient public data to compare them with other solvents.

4.4.2.8 Discussion of advanced solvents

The alternative solvents discussed in the preceding Sections are presented in the table below in comparison to MEA according to the criteria that were made in Section 4.4.2.2.

Table 4-19: Comparison of alternative solvents to MEA

Criteria	Technology					
	Sterically hindered amines	Aqueous ammonia	Piperazine potassium carbonate	Amino acid salts	Alkali metal based	Other amines
Heat of absorption/regeneration	✓	✓	✓	✓	✗	-
CO2 absorption rate	✓	✗	✓	-	✓	-
CO2 absorption capacity	-	✓	-	✓	✓	-
Resistance to degradation/impurities	✓	-	✗	✓	✓	-
Corrosion	✓	✓	✗	-	✗	-
Volatility	-	✗	-	✓	✗	-

Key to table	✓	Better than MEA	-	Same as MEA	✗	Worse than MEA

Two points emerge from Table 4-19. Firstly, no solvent is unambiguously better than MEA over the whole range of criteria, partly because the literature lacks information concerning all performance parameters. The most promising technologies, based on information available in the literature appear to be sterically hindered amines, ammonia or amino acid salts, but performance could be lower than MEA in areas that have not been reported e.g. absorption capacity. It is clear that some compromise may be needed if an alternative solvent is to be successful. For example, does a better rate of absorption and absorption capacity more than compensate for a higher heat of regeneration?

Figure 4-19 gives an idea of how the attributes in the matrix might be ranked: the main factor that influences the heat required for CO_2 recovery is the heat of regeneration. Therefore potassium carbonate might be viable if it is deemed that the low heat requirement for regeneration more than compensates for the additional cost of the solvent. It is possible that this could be used to formulate individual criteria weightings so that alternative solvents could then be compared without bias. On the other hand there are difficulties with weighting the criteria; solvent degradation is important because it means that new solvent needs to be added and the cost of the solvent can then become important. Solvent volatility is important as most of the existing pollutant controls are to limit local pollution (particulates etc). Therefore it is highly desirable for the chemical solvent used in the removal process to be environmentally benign. In addition, it could be argued that a focus on reducing the heat required for solvent regeneration would be another area to focus on in order to reduce the performance penalty as much as possible. However, other factors that do not influence the energy penalty that much could be equally important.

In the course of reviewing the literature, it became clear that there is a lack of systematic comparison between processes. For example, it is not clear when alternative solvents are compared to amines, whether MEA characteristics are used or whether the best possible amine performance (e.g. KS-1) characteristics are used. For example, Ciferno et al (Ciferno et al., 2005) state that aqueous ammonia has a lower heat of regeneration than an amine system; which is ambiguous. Furthermore, there is no standard unit for reporting the impact of cost e.g. amines cost more than chilled ammonia: 30% more per pound. But the impact in terms of cost per unit of electricity produced is unclear. If such information was reported within a systematic framework, a comparison of a solvent that degrades rapidly but has a low temperature of regeneration with a solvent that is resistant to degradation but has a high temperature of regeneration could take place. The lack of a systematic framework is probably due to a lack of modelling experience at plant level compared to process level, where much of the research is being carried out, and the immaturity of the alternative processes.

The lack of a standard baseline makes it quite confusing when data is compared e.g. Resnik et al (Resnik et al., 2004) state that ammonia can remove 99% of CO_2, while MEA removes 94%. Meanwhile, Abu-Zahra (Abu-Zahra et al., 2007a) state that the optimum MEA removal rate is 90% CO_2. Such discrepancies are cause for concern, not least because of the economic impact of releasing an extra 4% of CO_2 could be significant. Moreover, there will be an optimal CO_2 removal % that is a balance between operational costs and capital costs for the capture process and carbon emissions costs.

The effect of lowering the capture rate (90% to 50%) and its effect on plant performance (i.e. efficiency of the plant) require further investigation. Once again, there will be a trade-off between the cost of CO_2 and the loss of electricity to capture a certain proportion of CO_2. Oexmann shows that capture energy per tonne of CO_2 captured reduces with reduced overall % capture of CO_2 i.e. 90% to 85% of all CO_2 captured (Oexmann et al.).

A significant benefit of chemical absorption is that the process equipment is broadly the same for all advanced solvents e.g. cooling, absorption, regeneration etc. The goal of using alternative solvents is to minimise the capital cost, operational cost and energy penalty associated with a chemical absorption process. In a sense, it is not necessary for the technology to be proven for each single solvent, but rather to match solvents to desirable characteristics. The next step would be to rank the characteristics in order of desirability and then to rate the solvents against this. Trade-offs may then be found between a cheap process and one that consumes the lowest amount of energy.

4.4.2.9 Process integration

The energy requirement for solvent regeneration and compression of CO_2 will inevitably incur some efficiency penalty. Process integration seeks to minimise the energy required from a process by changing the process network and acts in parallel to benefits gained from using alternative solvents.

Various studies and papers have reported the benefits of process integration. Leites et al report that process integration can reduce the heat consumption by between ½ and 1/3 of that required for a standard process (Leites et al., 2003).

As expected, most process integration studies seek to reduce the energy required for solvent regeneration. Fisher et al (Fisher et al., 2005) show that steam requirements can be reduced by 39% through process integration.

There is also a need to reduce energy for CO_2 compression. It has been reported that the stripping column could be operated at variable pressures with compressors between each step in the column (Fisher et al., 2005). In this way, partial CO_2 compression could take place in the regeneration column and can save 8.4% of capture costs (Fisher et al., 2005). In addition, the energy generated due to compression of CO_2 prior to transport can be used to augment the heat provided by steam from the low pressure cycle in the stripper reboiler (Fisher et al., 2005). This improvement saves up to 4.6% of CO_2 removal costs although it causes a slight increase in capital costs. The two improvements added to the regeneration system simultaneously could result in a total capture cost reduction between 4.3 to 9.8% and an 8-10% energy saving (Fisher et al., 2005).

Gibbins states six rules that post combustion processes should follow to maximise the effectiveness of the capture system. The rules cover design and operational plant parameters rather than the actual alternative process integration networks proposed in other studies. For example, rule number six "exploit the inherent flexibility of post combustion capture" is also an argument for deploying post combustion capture systems in preference to IGCC plants or oxyfuel plants due to the ability of a PC plant to switch its capture system on and off (Gibbins, 2004).

Finally, it should be noted that there is a trade-off between increase in capital cost and the increase in process performance. The two need to be balanced to see if the emergent parameter is acceptable. The major benefit of process integration is that it could be applied to all chemical absorption processes.

4.4.2.10 Cryogenic process

A cryogenic process involves taking advantage of the solidification of CO_2 at low temperatures to capture it on a surface. The temperature of sublimation is a function of the partial pressure of CO_2 which is function of the concentration of CO_2 in the flue gas (Eide et al., 2005). Therefore the frosting of CO_2 takes place over a temperature range of between -99.3°C and -155.8°C depending on the required percentage of CO_2 to be removed. To remove 90% of CO_2, the frosting temperature varies between -103.1°C and -121.9°C (Eide et al., 2005). The reduction of temperature is done in 4 stages (a cascade). During the stages, which operate at 0°C, -15°C, -40°C and <-100°C, water is removed during the first three stages which take place in one heat exchanger. The last stage involves another heat exchanger and cools the flue gas until at around -100°C, the flue gas is sent to the CO_2 low temperature frosting evaporators where CO_2 precipitates out of the flue gas (Eide et al., 2005). Two heat exchanger/ evaporators are used in a swing configuration, with one frosting and the other defrosting. Cold energy in the defrosting exchanger is recovered and used in the frosting exchanger hence improving the efficiency of the process. When the desired amount of CO_2 has been removed, the precipitate is heated to form a pure stream of CO_2 ready for compression. Compression is done in the liquid phase so that less energy consumption is required (Eide et al., 2005).

In terms of commercial development, the cryogenic capture system was developed in collaboration between ALSTOM and Ecole des Mines (Clodic et al., 2005). A test bench was built that demonstrated the effectiveness of the process at a range of CO_2 concentrations (Eide et al., 2005).

At 90% capture the anti sublimation process was found to have an energy penalty of 3.8-7.3 points, which is favourable to other developed processes. Other pollutants could also be captured in the system, which could eliminate the need for other pollutant control equipment. The process is particularly interesting as it is completely different to the chemical capture process and therefore involves different equipment.

The following key questions arose as a result of the literature review:

1. What is the cost of electricity generation associated with this concept?
2. Do the anti sublimation/sublimation and heat transfer processes happen fast enough such that equipment size is reasonable?
3. Can this technology scale up to handle the flue gas from a power plant?

4.4.2.11 Membranes

Membranes offer an alternative method of separating CO_2 from the flue gas. The idea behind the use of membranes is that they allow CO_2 to permeate the membrane layer, but not other gases. In general membrane technology is advancing relatively quickly due to the application of membranes in fuel cells and other separation processes. There are two classes of membrane: polymeric and metallic. Many types of membrane have been reported in the literature, including inorganic membranes, carbon membranes, alumina membranes, silica membranes and zeolite (Yang et al., 2008).

In terms of applicability to post combustion capture, membranes have a number of disadvantages when compared to chemical absorption. Firstly, the driving force for the separation is the pressure of the gas. This is low in PC plants therefore additional compression should be provided. This will increase the capital cost and energy requirement.

It has also been reported (Yang et al., 2008) that membranes have a relatively low selectivity and hence a low % of CO_2 can be captured. This indicates that at least multiple stages would be required. Finally, the exhaust gases need to be cooled otherwise the membrane is damaged or destroyed. The temperature should be below 100C. Moreover, membranes need to withstand the other impurities present in the flue gas. Therefore the application of membranes to post combustion capture seems limited. However one type of membrane removal process, membrane contactors, has been put forward for post combustion capture.

Membrane contactors have been used to remove CO_2 from natural gas at high pressures and concentrations (Eide et al., 2005). Contact membranes provide a barrier between two gas phases (one CO_2 rich, one CO_2 lean). The hollow membrane consists of two layers of hollow fibre membranes, with absorption liquid in the middle of the layers.

Membrane contactors allow CO_2 to permeate the outer wall of a hollow membrane which contains a chemical solvent. The solvent absorbs some CO_2 and the rest passes out of the other membrane wall. The CO_2 can then undergo another membrane filtering process which removes even more CO_2 until the desired level of CO_2 has been removed.

It is important to match the membrane and the absorption liquid otherwise leakage of the chemical absorbent can take place (Eide et al., 2005). This is the reason why MEA cannot be used in membrane contactors. Instead, amino acid salts are used as they have a surface tension similar to water and cannot permeate the membrane (Eide et al., 2005). The overall process is similar to the chemical absorption process, but allows for a large reduction in capital costs for the absorber and no solvent loss through evaporation (Eide et al., 2005).

In order to compare this process with MEA removal, it would be necessary to undertake a plant level analysis in order to find out the total energy requirement to pressurise the flue gas, the rate of absorption and the selectivity (i.e. resistance to impurities) as well as the ability of the membrane to resist corrosion. Finally, and perhaps most importantly, it would be necessary to find out the removal % of CO_2 and the number of stages required to remove the desired amount of gas. The latter (number of stages) implies that questions remain over the ability to scale up the membrane process to that required for a commercial plant.

4.4.2.12 Discussion

The goal of advanced processes for CO_2 removal from PC plant is to reduce the high additional capital and energy costs of the MEA system. For post combustion capture, most of the energy requirement is due to solvent regeneration (Figure 4-19). Other driving factors include solvent degradation, volatility, ease of operation etc. Removal technologies can be put into two groups: alternative processes and alternative solvents. The alternative solvents essentially use the same capture process with some modifications being necessary for individual cases, but the alternative solvents usually have some benefit over MEA in one of the key performance areas. New processes are alternatives to chemical absorption and use different process equipment to capture the CO_2 from the flue gas. Pollutants, particularly SO_2 affect the performance of chemical solvents.

As a result of using the same process equipment, chemical solvent capture process gives a certain degree of freedom: a generator could start operations with one type of solvent and then upgrade to a new solvent when the time is appropriate. If a degree of flexibility is brought into the process so that it can be upgraded, this could be a significant benefit. Therefore the generator should be wary of any irreversible features for processes that are available for advanced solvents as they could lead to a generator being trapped into using a certain solvent. For example, solvents that produce precipitates are likely to have specialised filters installed that may not be compatible with another solvent. However, it is likely that more generators would use the solvent capture process even though they might be using different solvents. This could have benefits on process efficiency development and process integration development.

Alternative processes, unless clearly superior, will lack the freedom and secondary benefits of improvements in process integration that capture by chemical absorption will gain. For example, the cryogenic capture process may not afford the same freedom to upgrade at a later date. Moreover, in a sense, it is wise to take advantage of the nature of the flue gas from a PC plant. The large volume of flue gas, the low pressure and CO_2 concentration appear to make the chemical solvent system the most preferable. If other processes are to be used e.g. membranes, the flue gas will have to be treated in order to make it viable e.g. compression. This will require additional energy and may not be worthwhile. One advantage of using chemical solvents and even membranes is that they use the same process i.e. the capture process is similar to that shown in Figure 4-13. Therefore it could be argued that process integration and development will be faster regardless of the type of solvent a generator takes up. In comparison, the cryogenic process is for one type of removal only and this could hinder its development if it is not taken up by a large number of generators.

As a result of the unsystematic method of reporting the results there is considerable uncertainty over which processes lead to clear benefits, and which are redundant: for example, a clearer comparison could be made if the total energy requirement for capture via membranes were given. Moreover there is a degree of author bias in the technology comparison including optimism, and ambiguous base case references, which make it difficult to analyse technologies objectively. A systematic method or framework is required for assessing capture technologies at the process and plant levels.

4.4.2.13 Conclusions

- No solvent is clearly better than MEA, although KS-1 appears closest to taking over as a preferred solvent. In addition, amino acid salts appear to have significant potential in the future, but need to be investigated further;
- It is even more difficult to rate advanced technologies and see past author biases etc;
- Process Integration appears an effective way to reduce the capture penalty.

4.4.3 Advanced technologies for oxyfuel capture

As shown in 4.3.3.1, the energy for air separation (oxygen production) for oxyfuel plants is the main source of performance loss. Therefore research into improving the performance of oxyfuel plants focuses on more efficient methods of separating the air into oxygen and other components. Figure 4-20 presents a breakdown of the sub processes that cause the plant performance to drop.

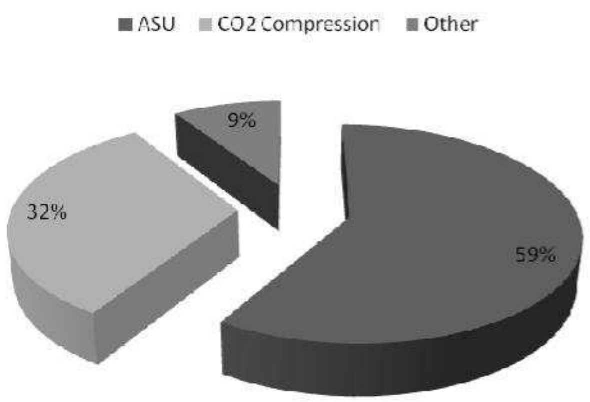


Figure 4-20: Proportional representation of energy penalty associated with installation of carbon capture on an oxyfuel plant (Data source: (Deutch and Moniz, 2007))

The bulk of efficiency is lost during CO_2 compression for transport and the operation of the ASU (91%). “Other” refers to the energy requirements of the CO_2 cleaning system. The first novel technology focuses on reducing the cost of an oxyfuel plant, while the next two technologies concentrate on removing the oxygen from air more efficiently.

4.4.3.1 Internal flue gas recirculation

There are a variety of methods for internal flue gas recycling. The main advantage of internal flue gas recycling is that it eliminates the need for external ductwork and reduces the flue gas volume. Therefore, internal flue gas recycling has the ability to reduce the cost of an oxyfuel plant.

4.4.3.2 Advanced O_2 separation- oxygen transport membranes (OTM)

A US DOE study was undertaken by Praxair to assess the feasibility of integrating oxygen transport membranes into advanced boilers (conceptual design by ALSTOM) for use in oxyfuel plants (Christie et al., 2007). Unless the OTM is integrated into the boiler it is generally thought to be too expensive as standalone air separation unit.

Ceramic membranes are particularly attractive due to their very high selectivity for oxygen at high temperatures (greater than 600^{o}C). This results in a very pure oxygen content of greater than 99% (Christie et al., 2007). As the gas is at low partial pressure, the process of separating oxygen from air via ceramic membranes can be driven by pressure or electricity.

When the process is electrically driven, the driving force is electric power, with only O_2 ions passing through the membrane. As a result O_2 ions pass through the membrane and combine to form oxygen molecules which then release an electron that passes back through the membrane. The separation is performed in a single step and there is no need for compression equipment. Pressure driven separation depends on the pressure differential between the O_2 rich and O_2 lean sides (across the membrane). The OTM has a number of applications apart from oxygen production and purification including syngas production.

The OTM process applied to oxygen production first requires air to be heated to a high temperature and pressure. As a result of the composition of air, (79% N_2) much of the energy transferred can be recovered through the use of an expansion step, therefore in a standard process, the energy is recovered in a gas turbine which makes the economics more complicated (Christie et al., 2007). Integrating the OTM tubes into a boiler reduces the partial pressure of O_2 on the permeate side and hence there is no need to compress air and the process is simplified.

Table 4-20: Performance data regarding OTM and cryogenic oxygen production (Data from (Christie et al., 2007).

	OTM	Cryogenic
Capacity	5-200t/day	20-3500t/day
Purity	99%+	95-99.9%

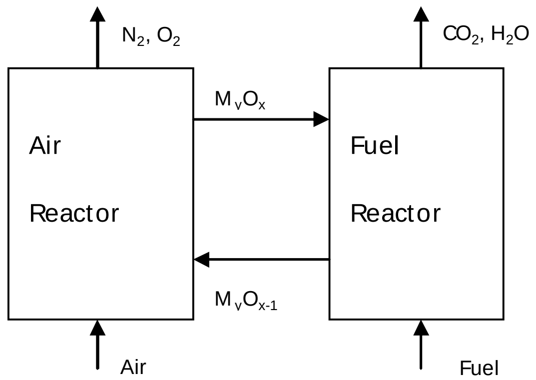
The following are the benefits associated with integrating OTM membranes into the boiler: as air compression is not required, the process is simplified and the capital cost and energy requirement will be less. In addition there is no need for flue gas recycling as the OTM tube integration controls the temperature which will also reduce capital costs and plant complexity.

Disadvantages of OTM membranes include scale of CO_2 removal (Table 4-20) and boiler material. The boiler requires a material that can handle the extreme environment, and problems have been reported with the reliability of the material (Christie et al., 2007). In addition, no integrated plant analysis has been performed: energy requirements for air compression etc. and a cost of electricity were not given for a coal fired power plant.

4.4.3.3 Chemical looping combustion (CLC)

Chemical looping combustion has inherent CO_2 separation as part of the process and therefore it avoids the need for an air separation unit and the energy penalty it incurs. The fundamental idea is to use an oxygen carrier to transfer oxygen between the air and fuel reactors. There is no contact between air and fuel, the only combustion products are CO_2 and water. The exhaust gas of the air reactor contains N_2 and some O_2. Therefore the energy required for carbon capture would be that needed for compression of the carbon dioxide and any requirements to drive the removal of the water content. Figure 4-21 illustrates the concept.

Figure 4-21: Diagram of chemical looping system (Adapted from (Eide et al., 2005))



The plant process consists of two interconnected fluidised bed reactors, one for air and one for fuel. Oxygen carriers circulate in between the two reactors. The oxygen carriers oxidise in the air reactor (remove oxygen) and reduce in the fuel reactor (release oxygen) where combustion takes place the oxygen carrier is then recycled to the air reactor to be enriched with oxygen and the process repeats over again. The reactions are given below where M represents the metal oxygen carrier:

Air Reactor

$$(2n+m)M_yO_{x-1} + \left(n+\frac{1}{2}m\right)O_2 \rightarrow 2(n+m)M_yO_x \quad (4.4)$$

Fuel Reactor:

$$(2n+m)M_yO_x + C_nH_{2m} \rightarrow (2n+m)M_yO_{x-1} + mH_2O + nCO_2 \quad (4.5)$$

Net reaction

$$C_nH_{2m} + \left(n+\frac{1}{2}m\right)O_2 \rightarrow mH_2O + nCO_2 \quad (4.6)$$

The net reaction is the same as for normal combustion. The reaction in the air reactor is highly exothermic, while the reaction in the fuel reactor is slightly endothermic, but can be exothermic depending on the type of metal carrier used (Johansson et al., 2006). As a result the majority of energy generation will take place in the air reactor. The oxygen carrier is a metal oxide particle, usually based on copper, iron or manganese or nickel (Mattisson et al., 2006). The fuel only comes into contact with oxygen from the carrier and never mixes with N_2, so the products in the reactor are CO_2 and H_20. These can easily be separated – no cryogenic ASU is required and no energy consuming separation process.

Chemical looping combustion has been tested in systems using natural gas as a fuel (Mattisson et al., 2006). A high fuel conversion can be attained, and a high purity CO_2 stream is also possible, with nearly 100% capture; carrier lifetime can reach 4000 hours with a cost of replacement of around $1/ton CO_2 captured (Eide et al., 2005). There is also a possibility to use chemical looping reforming to produce hydrogen (Johansson et al., 2006). In addition, the process is similar to circulating fluidised bed combustion and therefore may benefit from experience with that technology.

The reports that were examined show that chemical looping combustion has been applied to processes that use natural gas or syngas, the product of coal gasification, as a fuel. Therefore it is not immediately clear how well the process suits solid fuel i.e. that would normally be used in oxyfuel combustion. The rate of reaction between the oxygen carriers and the solid fuel could be lower and also the effect of solid fuel combustion by-products on the oxygen carriers could be problematic. Therefore, it could be simpler to combust coal gasification products in a CLC system (Eide et al., 2005).

Chemical looping combustion technology has advanced relatively quickly in a short time – in 2002 it was still a paper concept. Key research areas include carrier development, reactor design, improvements in system efficiency and prototype testing. Carrier development has probably been the most intensively studied area; over 300 different carriers have been investigated with key parameters being high rates of reaction under oxidation and reduction, good thermal properties and high mechanical and chemical availability (Mattisson et al., 2006).

There are two functioning test rigs for Chemical looping combustion; a 10kW test rig at Chalmers University of Technology, Sweden, has been in continuous operation for over 100 hours. There is also a 50kW Test rig in South Korea.

In summary, chemical looping combustion appears to be an attractive method of combusting fuel for energy generation and capturing CO_2. The removal of the need for any form of separation except the removal of water from the fuel reactor exhaust provides the motivation to seriously consider it as a candidate for advanced CO_2 separation. It should also be noted that chemical looping combustion was originally conceived as a more efficient method of generating power without considering CO_2 capture. It would therefore be expected that due to the lack of separation requirement that the system performance of process would be above that usually associated with oxyfuel capture. The other main benefit is the possibility of using CLC reforming to produce hydrogen in a CO_2 neutral manner. Operational benefits include the low cost of the metal carrier. However, the technology is still a long way from maturity. The technology is still at the lab test scale (10-50kW) and there appears to have been little work done on the application of CLC to solid fuel combustion. Although knowledge of circulating fluidised bed reactors could be useful, it should also be noted that this is an entirely new concept. Therefore a lot of unknown parameters exist at the plant level such as reliability, process integration, cost etc. Therefore it is anticipated that successful deployment of CLC plants will be a long-term prospect.

4.4.3.4 Discussion

The key parameter leading to energy loss in an oxyfuel plant is the air separation unit. Therefore proposed processes concentrate on reducing the energy penalty.

The OTM proposes integrating membranes into the boiler in order to separate oxygen from air. Although this design has been produced conceptually, and studies have shown that the cost of capture can be reduced, more integrated studies and scale tests are likely to be required.

The CLC concept proposes a different process, based on the use of oxygen carriers, to ensure that the fuel and air never come into contact. Although the process appears to have a high level of performance and potential, questions exist regarding the use of CLC with a solid fuel. In addition, no plant costs can be found in order to compare the process with other technologies.

Like advanced technologies for post combustion capture, it is not clear that any of the technologies is better than the state of the art. The problem is not necessarily that these technologies do not have the potential to be better, but rather that they are at such a low state of development it is difficult to make a definite judgement. For example, what is the impact on plant cost of constructing a boiler with integrated OTM's? What are the costs of a CLC plant likely to be and what is the impact of using a solid instead of a gaseous fuel? Are there any issues with scaling the technology up to pilot plant size?

4.4.3.5 Conclusion

In conclusion, significant uncertainty exists regarding the various processes analysed for advanced oxyfuel plants especially over which processes could lead to an improvement in the cost of capture. As commented on in 4.4.2.13, biases of authors are present as are the difficulties of conducting a review in the absence of a systematic framework. Although some processes do appear to offer much better performance than standard oxyfuel plants it is uncertain as to what are the timescales for implementation and the key hurdles that each alternative process faces.

4.4.4 Advanced technologies for pre-combustion capture

Although Integrated Gasification Combined Cycle (IGCC) plant has the lowest capture penalty of the alternative generation methods, it also has the highest capital cost and a poor reliability record. There are a number of alternative and advanced technologies that are being researched in order to compensate for the performance penalty.

4.4.4.1 Capture consequences

Figure 4-22 gives a breakdown of the sub processes that contribute to the performance penalty incurred when carbon capture takes place in an IGCC plant.

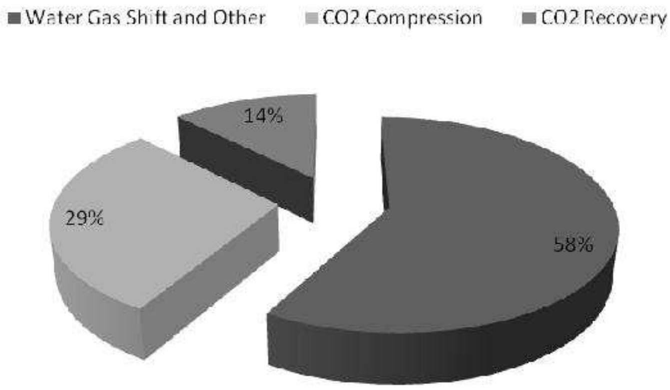


Figure 4-22: Proportional representation of energy penalty associated with installation of carbon capture on an IGCC plant (Data source: (Deutch and Moniz, 2007))

The reason for the low penalty in relation to CO_2 recovery in IGCC plant is that the gas stream is at high pressure and has a lower volume than exhaust gas from a PC plant. Therefore the rate of absorption is much greater and less energy intensive. In addition the CO_2 is desorbed via a reduction in pressure. Therefore steam is not required for solvent regeneration (but is required for water gas shift reaction). The IPCC report (IPCC, 2005) highlights the following areas for future pre-combustion capture process development:

- Loss of CO_2 pressure due to flash regeneration;
- Cooling/ Refrigeration of syngas to accommodate low operating temperatures- reheating prior to combustion;
- H_2 losses, particularly in membranes;
- Sulphur tolerant materials/membranes.

It is clear that improvements in the capture process will come about through either reducing the energy required for the water gas shift reaction and that for CO_2 recovery or both. The general goals for IGCC capture development are therefore to minimise temperature reduction for CO_2 removal and to maximise use of high pressure CO_2 rich gas (reduce the pressure loss associated with physical solvent regeneration), thereby reducing the energy penalty associated with CO_2 compression. The most important goal is to minimise the energy penalty associated with the Water Gas Shift Reaction (WGS); which is the topic of the next Section.

4.4.4.2 Sorption/membrane enhanced water gas shift (WGS) reaction

As the major energy consumer of the pre combustion capture process, improvements in the water gas shift reaction are being widely sought. Two processes are being investigated: membranes and sorption enhanced water gas shift reactions.

4.4.4.2.1 Sorption

The sorption enhanced WGS integrates the water gas shift reaction with the pressure swing absorption process used to regenerate the physical sorbent.

In order to do this, the shift reactor includes an adsorbent/catalyst bed. The first bed removes CO_2 and the adsorbent/catalyst bed catalyses the WGS reaction and simultaneously removes the CO_2 produced as the WGS reaction takes place. The reactors are operated in batch style where subsequent beds or trays remove more CO_2.

The reaction advances further to the products side, so more CO_2 is shifted to H_2 and a purified H_2 stream is produced. When the absorbent is near its CO_2 capacity, it is regenerated by releasing the pressure and purging the bed with steam, producing a pure CO_2 stream.

Advantages include:

1. WGS reaction is equilibrium limited; therefore the removal of CO_2 during the reaction drives it further to the products side, so a more pure stream of H_2 can be obtained with a small reactor;
2. The process can be conducted at high temperatures and pressures, minimising heat exchange equipment costs and reheat energy loss;
3. The H_2 fuel exits the reactors at high temperature and with excess steam which is ideal for a gas turbine as it promotes low NO_x formation and high process efficiency.

Disadvantages include a lack of demonstration at industrial scale. At present, a lab scale column built for a few thousand cycles followed by six column bench scale installation that can be operated continuously in Delft/ECN. A pilot scale installation is foreseen within 5 years.

4.4.4.2.2 Membranes

Using membranes for the integrated separation water gas shift reaction is similar to the sorption process described above, except for the use of membranes. Membranes are suited to use in IGCC plant due to the high partial pressure of CO_2, which provides a driving force for the separation reaction. The membrane is also smaller due to the favourable conditions. The membrane can either be CO_2 selective or H_2 selective. If the membrane is CO_2 selective, CO_2 permeates through and H_2 remains pressurised avoiding the need for compression prior to combustion. If the membrane is H_2 selective, the CO_2 is at a higher pressure. It has not been shown whether the energy required for H_2 compression is greater than the energy saved on CO_2 compression. In addition, the cost and maintenance of CO_2 compressors is much lower than H_2 compressors. It is also worth noting that as the driving force is the partial pressure difference, as more permeate is passed through the membrane, the lower the separation driving force and the purity of the permeate will also reduce (Grainger and Hägg, 2008). Therefore there is an optimum level of CO_2 removal for membranes- at present it appears to be 85%. If the CO_2 removal requirement exceeds this value, severe plant efficiency penalties are introduced. For example, the plant efficiency at 85% CO_2 removal was 40%, and roughly 32% at 90% CO_2 removal.

Grainger and Hagg (Grainger and Hägg, 2008), put forward two alternative plant configurations to separate CO_2 from the CO shifted gas stream. The difference between the processes is whether or not the high temperature shift reaction occurs before or after sulphur removal. It was reported that the plant efficiency loss was 9.6% for post sulphur removal and 10.5% for pre sulphur removal (Grainger and Hägg, 2008).

The following description is for a H_2 selective membrane. Syngas is fed into a fixed bed reactor that has a membrane wall and pressures are around 500psia. As H_2 is produced in the catalysed WGS reaction, it is passed selectively through the membrane and is swept by N_2 into the gas turbine or fuel cell. The removal of H_2 allows the WGS reaction to proceed further to the desired products side and a purified high-pressure stream of CO_2 and H_2O is produced on the other side of the membrane. Water is removed and CO_2 is then compressed for transport and storage.

Disadvantages of membranes include the pressure drop experienced by the working fluid, which needs further compression before entering the gas turbine, if using a H_2 selective membrane. If using a CO_2 selective membrane, the H_2 remains pressurised, but more energy would need to be used to compress the CO_2.

The palladium alloys that are commonly used for the membrane material are vulnerable to CO and H_2S poisoning. Both of these species are abundantly present after coal gasification. Therefore palladium membrane enhanced WGS has tended to be developed for natural gas applications. However alternative materials, such as PVAm (polyvinyl amine) that do not suffer from poisoning are being developed (Grainger and Hägg, 2008).

The main benefit of membrane separation is that it can be performed at high temperatures and pressures, therefore saving energy. In the case of a H_2 selective membrane, the CO_2 stream is at high pressure, therefore compression costs are lower than for post or oxy systems but there is a need to compress H_2 prior to mixing with CO_2 and water before it enters the combustion chamber.

Membrane enhanced WGS can also achieve >85% CO_2 removal and a pure H_2 stream and can decrease the amount and size of process equipment hence saving money on capital costs. Membrane technology appears to have the potential to lower the cost of CO_2 capture systems; however, membrane technology is still expensive and needs to advance with a commercial scale demonstration.

Some membranes are susceptible to H_2S poisoning and inhibition by CO, both of which are abundant after coal gasification. Therefore certain membrane materials e.g. palladium alloys are being targeted for natural gas reforming while PVAm membranes are reported to be suitable for use in IGCC plants. It should also be noted that the added complexity caused by the integration can sometimes decrease reliability and the ease of maintenance. Sorbents tend to be much less susceptible to H_2S compared to palladium membranes.

A techno-economic analysis of an IGCC plant using polyvinyl amine (PVAm) membrane has been conducted (Grainger and Hägg, 2008). The key performance parameters are given in the table below:

Table 4-21: Technical performance parameters of PVAm membranes (Source (Grainger and Hägg, 2008))

Parameter	Performance
CO_2 recovery	85%
CO_2 purity	95% vol
Efficiency penalty	10%
Capital cost	€ 2320/kW
Electricity cost	€ 7.6c/kWh
CO_2 avoidance cost	€ 40/tonne CO_2

It is reported that a lab scale demonstration of palladium membrane separation will take place in the next year or so (Grainger and Hägg, 2008).

Regardless of the process used, there is scope for system integration to improve the process performance i.e. reduce the steam taken from the heat recovery and steam generation Section of the IGCC plant (Carbo et al., 2007). In general, apart from the paper by Grainger and Hagg, it appears that membranes (palladium alloys) are being targeted towards enhanced WGS for natural gas; whereas sorption enhanced WGS is being developed for use in IGCC plants. This is primarily a result of the sensitivity of palladium membranes to CO and H_2S. Moreover, the separation enhanced reaction effect induced by hydrogen separation is much larger during steam reforming than during the water-gas shift reaction. During steam reforming one mole CH_4 is converted to three moles of H_2, which means that the hydrogen concentration is multiplied to the power of three in the reaction equilibrium constant (hence the large separation enhanced effect). In parallel to the steam reforming reaction the water-gas shift reaction also takes place.

$$\begin{aligned} &CH_4 + H_2O \rightleftharpoons CO + 3H_2 \qquad (a)\\ &CO + H_2O \rightleftharpoons CO_2 + H_2 \qquad (b) \end{aligned} \tag{4.7}$$

The separation enhanced reaction effect induced by CO_2 separation is quite small during steam reforming of natural gas, for the reason that only one mole CO_2 is formed during CH_4 reforming (not taken the other mole from the WGS reaction into account).

4.4.4.3 Physical absorption/ adsorption with alternative solvents

CO_2 and H_2S are removed after the water gas shift reaction. The solvent requires a low operating temperature so therefore the gas is cooled to between -5 and -10C. There is a lower temperature limit due to the trade-off between the viscosity of the absorbent and the rate of mass transfer. The absorption stage takes place in a packed or tray column. In order to regenerate the solvent, the pressure is lowered via expansion and the gaseous CO_2 is released from the liquid. Although the energy penalty for this process is a small proportion of the total required for the capture process (15%), there has been research into a number of alternative solvents that would allow the reaction to proceed at a higher temperature. Therefore the same process is used but a different solvent is deployed to minimise the energy loss and the capital cost incurred for the process components.

The use of pressure swing absorption is the process of choice for removing CO_2 from IGCC plant. The disadvantage is that the entire fuel gas stream needs to be cooled before entering Selexol unit and even further if Rectisol is used (-5C- -10C). The effect is compounded as the gas must first be cooled and then heated after the acid gas removal before combustion can take place. If the CO_2 removal step could be performed at a higher temperature, less energy would be required. Therefore there is research into alternative solvents that have the ability to remove CO_2 and H_2S at high temperatures and pressures.

Fluorinated solvents have the ability to separate CO_2 from gaseous streams at high temperatures, and pressure, removing the need for a cooling and reheat step. Laboratory scale experiments have been performed on fluorinated solvents that are able to capture CO_2 at up to 227 C and 30 bar pressure (Pennline et al.). In addition, the experiments report that the capacity of the solvent is comparable to Selexol. Other benefits include: high chemical stability, high gas solubility, low vapour losses, and low regeneration energy requirements. Therefore fluorinated compounds could serve as an attractive alternative to traditional solvents.

Ionic liquids were also investigated and found to have potential due to their thermal stability and perhaps more importantly, because certain ionic liquids can be regenerated via temperature swing absorption. This would mean that there would be a smaller CO_2 pressure loss and hence a smaller energy penalty due to CO_2 compression.

A list of desirable characteristics for alternative solvents include: thermal stability, yield high purity CO_2, tolerant to syngas contaminants, resistant to degradation, low vapour pressure, environmentally benign, a low viscosity and high regeneration efficiency, effective over a broad range of CO_2 concentrations, tolerant to cycling (no loss of carrying capacity).

In general, this area appears to be at a relatively low state of readiness. However, it may benefit from the use of Selexol and Rectisol if advanced sorbents can be used with the same process equipment. No data was found regarding system performance and costs associated with advanced sorbents, which makes comparison with Selexol difficult. In addition it should be noted that the CO_2 removal process accounts for relatively little of the energy penalty associated with CO_2 capture.

4.4.4.4 CO_2 separation from syngas via hydrate formation

This process separates CO_2 from a shifted syngas stream by taking advantage of the formation of gas hydrates rich in CO_2.

The underlying idea of this process is to take advantage of the formation of crystals in a gas mixture when that mixture is subject to certain temperatures and pressures. The crystals that are formed have different gas concentrations than the mixture they are formed from. In the case for CO_2 removal, the cleaned (de-SOx) gas stream (CO_2 and H_2) is pressurised and cooled before being fed into a reactor with saturated water where crystals are formed which trap CO_2 in hydrogen bonded water molecule “cages”(Linga et al., 2008). The crystals are then separated via a membrane to release the CO_2. Unless additives are added to the syngas mixture, the pressure required can reach 7.5MPa (Linga et al., 2008). The addition of 1mol% tetrahydrofuran or 3% propane causes the pressure requirement to drop dramatically (by at least 50%) (Linga et al., 2008). The hydrogen molecules are separated from the stream via a membrane process. Two stages of hydrate formation are reported to yield a CO_2 stream with 98% purity.

The process does not require the use of large absorber towers or steam heated regenerators, but it requires significant capital and energy use in refrigeration and pressurisation. It is also not clear how much compression the CO_2 stream requires after separation, if it is low then the process could be quite promising. However, there could be a trade-off against the energy required for refrigeration and pressurisation. Unfortunately, there are no system level parameters that are reported, so it is difficult for a comparison to be conducted. It appears that the process is moving from the experimental phase into the small scale pilot phase (Litynski and Deel, 2010).

4.4.4.5 Integrated gasification fuel cell combined cycle (IGFCC)

The IGFCC plant has the potential to be the most efficient coal plant for producing electricity. Figure 4-23 shows the layout of the plant.

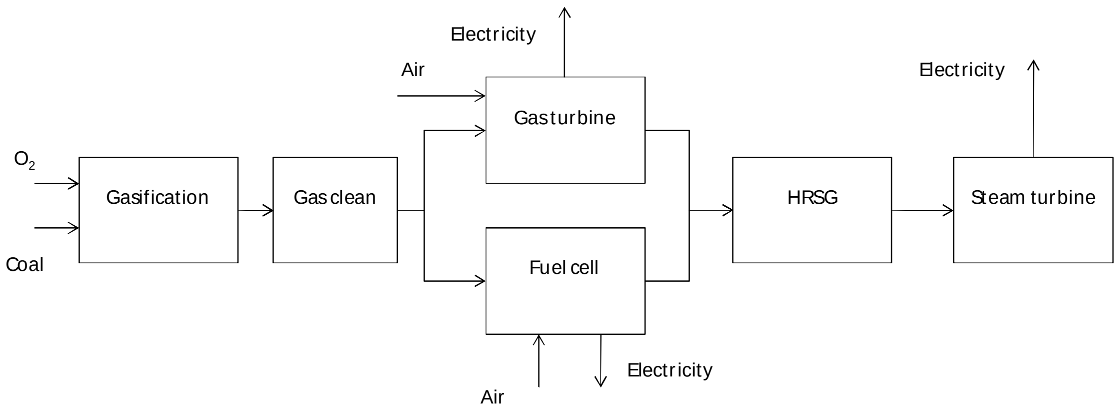


Figure 4-23: Schematic representation of integrated gasification fuel cell combined cycle plant

The fuel cell can process a variety of fuels including syngas, hydrocarbons or hydrogen. In a coal-fuelled system, gasifier and syngas cleaning steps would precede a SOFC. A water gas shift reactor could be used, but is not necessary because the high operating temperature of the fuel cells enables in situ fuel reforming to hydrogen (with the addition of steam). During the reforming, the CO_2 is formed and exits at the anode side along with H_2O and excess fuel (H_2 and CO). Because there is significant energy remaining in the stream, it is further processed in an afterburner step, which would typically be a catalysed combustion process, followed by expansion in a gas turbine and a steam bottoming cycle.

For a system in which the CO_2 is captured, the fuel cell is operated in the same fashion, but the excess fuel is fired with 95% pure oxygen, rather than air and the exhaust gases would not be expanded for energy recovery. The exhaust gases are almost entirely H_2O and CO_2 which can be easily separated and CO_2 can then be compressed.

Efficiencies for the IGFCCC have been reported of up to 50-55% (Wantanabe and Maeda, 2007). The plant has the same fuel flexibility as a standard IGCC plant in that it can burn lignite and bituminous coals. In addition, the in situ reforming capability of solid oxide and molten carbonate fuel cells reduces the energy requirement for the WGS reaction and the Selexol system can be removed. However, the energy required for CO_2 compression would still be needed. It has been reported that advanced IGFCCC plants (A-IGFCCC) using exergy recovery gasification technologies could reach 70% efficiency (NEDO, 2008). This process would rely on the coal gasification temperature being low (700-900C) in order to use the exhaust gas from the high temperature turbines and fuel cells as a heat source for gasification (NEDO, 2008).

Although the IGFCCC plant represents a new process, the fuel cell constitutes the main new part of the plant. In general, fuel cells can either be low or high temperature. High temperature fuel cells benefit from a fast rate of reaction at the anode between hydrogen and carbon and therefore normal coal gas (syngas) can be used as a feedstock. In addition, the high temperature exhaust gas from the fuel cell favours use in the CCGT cycle. In comparison, a low temperature fuel cell would require an expensive catalyst to be used and the rate of reaction would be slower. The catalyst could be poisoned by CO in which case a CO removal unit would be required, which would increase cost and complexity. As a result high temperature fuel cells are viewed as being applicable to the IGFCC plants.

High temperature fuel cells fall into two categories: solid oxide fuel cells, with an operating temperature of 750-1000C and molten carbonate fuel cells which operate at 600-670C. Both types of fuel cell have been applied to small-scale distributed generation in Japan, Europe and the USA.

4.4.4.5.1 Molten carbonate fuel cell

Molten carbonate fuel cells have been shown to produce electricity at 51% LHV (Wantanabe and Maeda, 2007). A distributed generation plant (300kW class) has been operational in Japan while American and German companies have also produced a 205kW version of the plant with an LHV of 47%. There are 50 units worldwide with individual units being operated for 25,000 hours. However, none of these plants used coal gas as a fuel. A project has been undertaken in Japan on a 10kW stack to examine the impact of the syngas on stability, resistance of the fuel cell to impurities and hence the allowable impurity concentration (NEDO, 2008).

The electrolyte material is a metal carbonate, either lithium or potassium. CO_2 and O_2 are formed at the cathode to create carbonate and 2 electrons which provide the current. The ions pass through the membrane by diffusion to the anode where the CO_3^{2+} reacts with H_2 to form CO_2 and H_2O, which can be easily separated.

4.4.4.5.2 Solid oxide fuel cell

A 10kW solid oxide fuel cell has been used in Japan for electricity generation since 2004 and a 200kW combined cycle plant using SOFC has been developed for distributed generation demonstration (NEDO, 2008). In Europe a 100kW system has demonstrated an efficiency of 46%, while a 200kW system has been operational from 2000 to 2003 and demonstrated efficiencies of 53% over 3300 operating hours (Wantanabe and Maeda, 2007). However, there has been little study on the use of coal gas for SOFC applications. Therefore key questions remain over sensitivity to impurities and allowable concentrations of CO and H_2S.

4.4.4.5.3 Discussion

It appears that the MCFC is closer to being applied in an IGFCCC plant as tests have been carried out using coal gas. It is also interesting to note that governments and companies appear to be opting for IGCC before IGFCCC plants.

In summary, IGFCCC plants offer a great potential for deployment for electricity production from coal. In comparison to a traditional IGCC plant, the IGFC plant reduces the energy requirement or removes the need for WGS shift. In addition, the Selexol process is not required. Both of these processes require energy and the WGS reaction accounts for 58% of the total energy penalty. Moreover, the advanced IGFCCC concept is reported to have a potential efficiency of 70%, far in excess of the standard IGCC plant. As a result it is likely that AIGFCCC plant will be developed in the future.

As the largest efficiency penalty encountered is due to the water gas shift reactor, most research concentrates on improving the efficiency of this area. Alternative methods to increase efficiency include: pressure swing absorption/adsorption (Alternative solvents), membrane enhanced water gas shift reaction, and fuel cell systems. Although the WGS offers the greatest rewards, it will be worth investing in another process e.g. alternative solvent if the cost is low.

If the carbon capture process were to go offline, the whole plant would need to shut down. There is no option to bypass the water gas shift reactor as all downstream plant is designed for CO_2 free operation. The sulphur cleanup system would face different operating conditions and the gas turbine could have flame stability problems

Questions remain regarding a variety of performance parameters and operational characteristics. These include: cost of generation, response to operating conditions (turn up and down), cost and durability of electrolytes, effect of syngas on material corrosion, manufacturing cost and the ability of the technology to scale up to compete with larger plants in the hundreds of MW range. Moreover, there is still an energy penalty due to CO_2 compression.

4.4.4.6 Conclusion

Pre combustion capture of CO_2 suffers from concerns regarding the underlying plant performance and the high capital cost. However, numerous reports state that the IGCC has the greatest potential in terms of reduction in capital costs and plant performance. Therefore it is likely that IGCC plant will be developed later than PC plant, but will come to be the dominant technology when the performance benefits are realised. In terms of CO_2 control, the pre combustion capture process benefits from the high pressure of the gas which can be used as a driving force in separation reactions. The major energy consumers for carbon capture are the water gas shift reaction and CO_2 compression. Although a variety of alternative sorbents have been put forward, the only clear advantage that they have is that they can operate at a higher temperature to the current solvent i.e. Rectisol or Selexol.

At present, it appears that sorption enhanced water gas shift reactions is favourable to palladium membranes which are sensitive to CO poisoning. Although separating CO_2 by hydrate formation has been discussed, it is unclear if it is advantageous to use compared to the standard processes because the syngas would need to be cooled. As found in other Sections, plant performance parameters are not reported in the literature, primarily as a result of the development stage of the technology.

4.4.5 Novel capture technology discussion

The objective of advanced capture technology is to reduce the performance penalty and additional cost incurred by the state of the art carbon capture process. For PC plant, this involves reducing the energy required for solvent regeneration. For oxyfuel, the production of oxygen is the main energy requirement and for IGCC the water gas shift reactor takes the most energy. Other processes under investigation do not target these main areas; one example is alternative sorbents for IGCC plants. This suggests that any process improvement is beneficial, if the cost of installation and operation is reduced.

The technologies investigated in this Section for advanced capture of CO_2 vary according to the plant process that the capture process must remove CO_2 from. The table below sets out the CO_2 capture processes or systems that are used for each type of plant.

Table 4-22: Carbon capture processes investigated as a function of plant type

	PC	Oxyfuel	IGCC
Chemical Absorption	X		
Physical Absorption			X
Physical Adsorption			X
Chemical Adsorption			X
Cryogenic Distillation	X	X	
Chemical Looping Combustion		X	X
Gas separation membranes	X		X
Fuel Cells			X

It can be seen from Table 4-22 that the IGCC plant has the most applicable alternative processes for carbon capture. This is primarily due to the nature of the CO_2 rich gas and the sequential nature of the

IGCC process. In general, altering the process may require extra energy: for example raising the pressure of exhaust gases if a membrane is to be used. The extra energy requirement must be more than compensated for by the new technique.

PC and oxyfuel plant have few applicable processes due to the exhaust gas conditions, but within the processes a wide variety of solvents is under investigation. Therefore, it is useful to distinguish which novel capture techniques are new and which use existing processes as this will impact the ability to upgrade technologies in the future. For example, some of the chemical absorption processes could be modified to accept alternative solvents as the process equipment is essentially the same. The question becomes: what value does this have?

Advanced capture processes appear to have some benefits in relation to the state of the arts technologies. In general there are two rules that a novel technology must fulfil:

- The benefits must more than compensate for any additional costs incurred by the technology;
- The novel technology must improve on processes which account for most of the energy penalty in the state-of-the-art process e.g. the water gas shift reactor for an IGCC plant.

It should be noted that if the technology is too expensive, it will not be implemented regardless of the benefits it brings. A lack of system performance data for most technologies makes it difficult to compare novel technologies with the current state of the art. In order to explain this, a clear distinction must be made between the technology provider (manufacturer) and the technology user (the generator). The data that is presented in this Section is either from research institutions, government bodies or industry (technology providers). It appears that neither of these is a completely reliable source of objective information, especially when it comes to reporting the impact of sub process performance on plant performance parameters: all of these bodies have a vested interest in their technology being adopted. Therefore, it is important to consider the technology from a generators perspective. Merchant generators are interested in the following questions concerning advanced technologies:

- When will the technology come to market?
- What operational/performance benefits will the technology bring?
- How much will this technology cost?
- What barriers are there to technology implementation?
- What other special characteristics does the technology have?

In order to answer these questions, the next Section evaluates the technology readiness of carbon capture and the key drivers that will define technology adoption.

4.5 Technology assessment

The fact that unites all of the prospective and “state of the art” technologies for carbon capture is a lack of proving at the commercial scale. This is a significant hurdle, and is one of the key technology evaluation criteria.

Section 4.5 presents a framework to evaluate the current status and expected time to system viability for certain capture processes. A modified form of technology readiness levels are used to categorise the various capture technologies on a common scale to show where they are at present and at discrete points in the future. The concept of system readiness levels is introduced to evaluate the readiness of the complete capture system. Key drivers and commercial backers of each plant technology are identified via a SWOT analysis. The classification of CCS technology by technology readiness and system readiness is novel and aids the comparison between the CCS technologies under investigation.

4.5.1 Technology readiness levels

Technology readiness levels are used by the US Department of Defense (DoD) and NASA to evaluate the maturity level of technologies that are to be integrated into technical systems (Mankins, 1995). The definition of technology readiness levels adopted in this thesis requires modification to the existing framework for two reasons: firstly, the traditional technology readiness level definition is from a technology developer's point of view. Secondly, the standard technology readiness level framework is not specific enough for assessment of power generation technologies.

The new framework borrows elements from the traditional definition of technology readiness levels in the early stage, but incorporates key technology parameters in the later stages that are specific for the deployment of power generation technology. Therefore modified form of technology readiness levels contains non-technical parameters that are deemed to be required for successful technology deployment.

4.5.1.1 Methodology

Technology performance and cost are just two components to be considered when analysing investment in new technology. It is also valuable to estimate the developmental stage of the technology which influences the expected time to commercialisation. Both plants and sub processes can be graded on this scale. This enables a comparison of the various sub processes and plants.

The NASA definition of technology readiness levels is unsuitable for use as they are from a technology developer's point of view. For the purposes of this report, the generators point of view is being considered. Therefore the definitions need to be modified to be applicable to the technologies under investigation (original definitions of technology readiness levels can be found in Appendix 4). A framework is established to identify and evaluate new technologies using a modified form of technology readiness levels.

New power generation technologies must go through four discrete stages before they are viable. The four main steps are research, advanced research and development, system demonstration and system deployment. The first two levels refer to the development and validation of processes at the sub system level. The key to third stage is to show that the sub-system can be integrated into the plant system. The final stage takes into account the requirements imposed by the wider generation system for the new plant to be successful, but only refers to the technology under investigation. It is important to note that in this context, system, relates to the next level up in the hierarchy i.e. if the assessment is of a capture process, the system will be the plant.

TRL 1: Research

- Basic scientific principles observed and reported;
- Technology concept/application formulated;
- Analytical and experimental critical function or proof of concept validation.

TRL 2: Advanced R&D

- Component and process validation at lab, full plant integrated computer simulation;
- Component/process validation at pilot scale.

TRL 3: System Demonstration

- Operation demonstrated at pilot plant scale (hundreds of hours);

TRL 4: System Deployment

- Actual system integrated into full-scale plant and successfully deployed, operation at full scale for thousands of hours;
- Actual system market proven for economic, reliable, successful industrial operations.

The data used for the classification of plants against the technology readiness levels is given in the appendix and in previous Sections. Tables in Appendix 4 (Commercial activities for CCS demos) give details of PC, oxyfuel and IGCC plants that have a capture process, the capacity of the process and the location and company involved.

4.5.1.2 Results and discussion of technology readiness assessment

Applying the modified technology readiness levels to evaluate the current status of the standard plants with state of the art carbon capture gives the results shown in Table 4-3:

Table 4-23: Tables showing the technology readiness levels of various plant processes

PC	TRL
Supercritical Boiler	4
Steam Cycle	4
Pollutant Controls	4
Carbon Capture	3

IGCC	TRL
ASU	4
Gasifier	3-4
Syngas Clean	3-4
Water Gas Shift Reactor	3
Separation Process	3
H_2 Turbine	3[14]
HRSG	4

Oxyfuel	TRL
ASU	4
Boiler	3-4
Steam Cycle	4
Pollutant	4
Carbon Capture	3

From the Table 4-23 it can be seen that PC plant with CCS appears to be the closest to commercialisation. Interestingly, it is also the plant with the least sub-processes; one of the reasons for the first generation of IGCC being unreliable is the complexity of plant.

PC with CCS is closest to deployment, due to the advanced nature of its component processes. The main barrier for PC with carbon capture at present is to scale up the relevant technologies and test them i.e. a question of integration and optimisation.

The IGCC process requires many more sub processes than the other plants. Therefore, questions arise over reliability and integration of these components. The IGCC process also requires the H_2 turbine to be developed (Eurelectric, 2008b), However, if pre-combustion capture for natural gas fired plants is to come to fruition, the H_2 turbine must also be developed for a CCS CCGT plant. The oxyfuel plant is above the IGCC plant in terms of process readiness. The oxyfuel process is being demonstrated at scale-30MW plant at Schwarze Pumpe and significant understanding of the oxyfuel combustion process exists from oxyfuel plants in other industrial processes. In general, advances in shared technologies e.g. more efficient CO_2 compression will benefit all competing technologies.

Error! Reference source not found. shows the current status of current and future potential capture technologies split by plant type on the y axis and TRL on the x axis. The first thing to note is the wide range of TRL's covered for all three plant technologies. The second point to note is that alternative capture processes for PC are higher up the TRL scale than for other plants e.g. aqueous ammonia and sterically hindered amines are both in TRL 3 or 4 while for IGCC plant there appears to be no alternative capture technologies in TRL 3. The reason for this could be the relatively small number of operational

[14] Source: (EURELECTRIC (2008b) Letter to Mr Chris Davies MEP Union of the Electricity Industry.Eurelectric, 2008)

IGCC plants compared to PC plants and also the ease of integrating a test capture process into the technology i.e. it is fairly simple to create a slipstream off the exhaust of a PC plant, but more complex (and uneconomical) to install the necessary equipment on an IGCC plant.

It is also useful to determine when these technologies might become commercially viable options for carbon capture. The US DOE and EPRI have produced documents estimating the time to commercialisation (system deployment) of new technologies. However, it appears that this data is subjective. For example; it is the opinion of Eurelectric that it will take until 2020 for CCS to overcome additional technical hurdles (Eurelectric, 2008b). Much of this will be due to process integration issues.

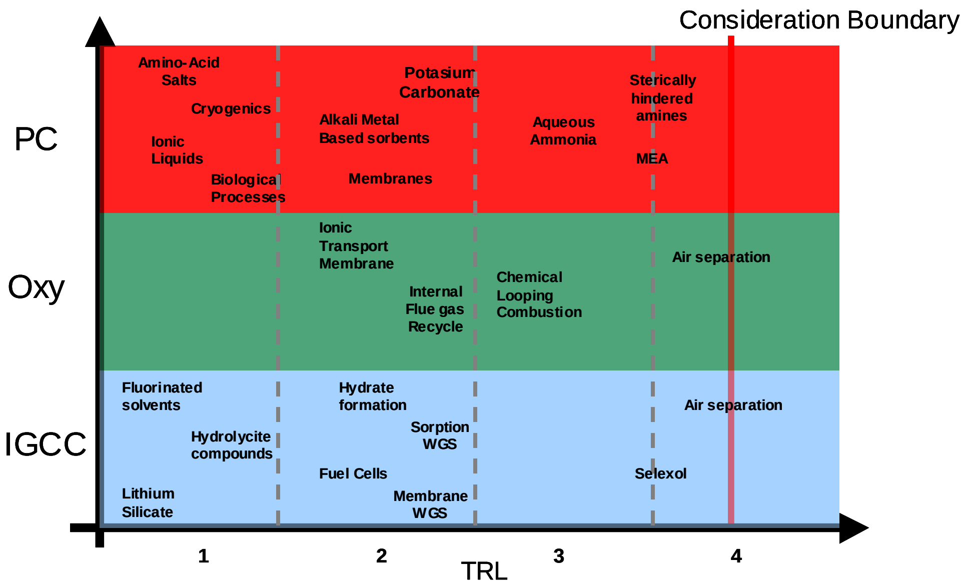


Figure 4-24: Graphical representation showing readiness of novel capture technologies (2008 as base year)

Table 4-24: Expected time to commercialisation for various capture processes (Figueroa et al., 2008).

PC	Oxyfuel	IGCC	Time to commercialisation
Amine Solvents	Cryogenic Oxygen	Physical Solvents Cryogenic Oxygen	Present
Advanced amine solvents		Advanced Physical Solvents	1-3 Years
Solid Sorbents Membrane Systems	ITM's	PBI Membranes Membrane Systems ITM's	2-6 Years
Ionic Liquids MOF's Enzymatic Membranes	CAR Process		4-8 Years
Biological Processes	OTM Boiler Chemical Looping	Chemical Looping	5-12 Years

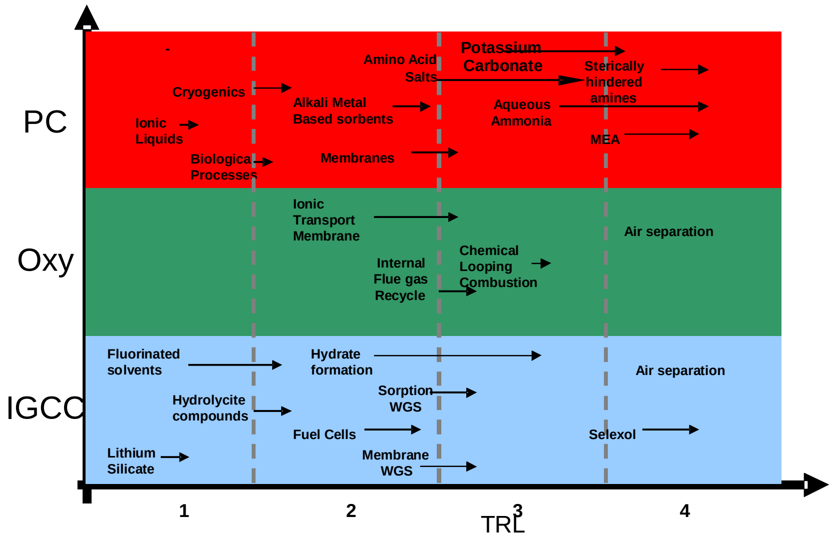


Figure 4-25: Possible position of novel CCS technologies in 5 years (with 2008 as base year)

Figure 4-25 shows the possible future position of capture technologies in 5 years based on the expected rate of development. The graph shows the various capture technologies rated according to the TRL scale and is based on the information in the academic reports in the literature survey and company information. As can be seen, there should be a number of PC capture technologies to choose from, sterically hindered amines, MEA, amino acid salts, potassium carbonate and chilled ammonia. This is because a number of proposed demonstration PC plants are using different processes i.e. the Meri Pori plant in Finland will use amino acid salts, the Pleasant Prairie plant in the USA uses chilled ammonia(see Appendix 4 for further details). Meanwhile most oxyfuel projects and IGCC projects are projected to use current technology. As a result, progress in IGCC and oxyfuel technology is expected to take place over a longer timescale.

It is unlikely that all potential capture technologies will reach maturity. Experience has shown that when multiple technologies compete for adoption, not all prospective technologies will reach full maturity (Wainwright and Clark, 1992). Figure 4-26 shows the result visually: the so called technology development funnel illustrates that the number of alternative technologies available to fulfil an objective decrease with increasing technology maturity levels.

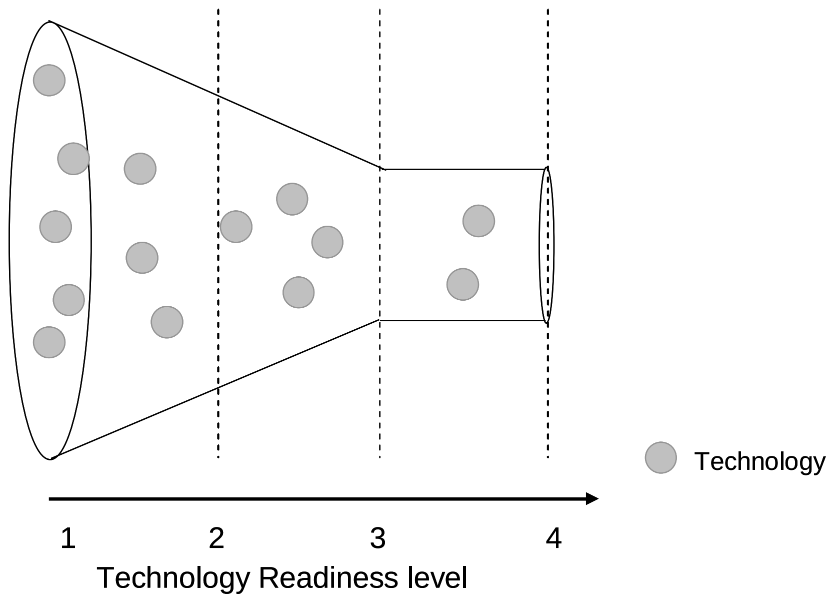


Figure 4-26: Technology development funnel concept

This is consistent with the refinement and evaluation that goes on as part of the development process. This is likely to be the case with the alternative capture processes, with a significant number of alternative technologies being lost along the way. At present it is difficult to state which technologies will drop out, but it appears that the technologies to be adopted will include sterically hindered amines, MEA, aqueous ammonia and amino acid salts for PC plant, while for IGCC plant, selexol is the only clear capture process that will be adopted in the near term. This judgement is based on the proposed capture process for demonstration plants worldwide and the characterisitics of the capture processes that were presented in the appendix.

Finally, it is important to note that there is a difference between technology readiness levels and system readiness levels. The next Section looks at the assessing the whole CCS system.

4.5.2 System readiness levels

System readiness levels sit above technology readiness levels and are used to assess the maturity of the whole system. The concept of system readiness levels has been used by the UK MOD (MOD, 2008) to evaluate system readiness. In this case the entire CCS system will be assessed in terms of system readiness.

Ranking the CCS system according to its system readiness level allows it to be compared to other generation technologies and enables an identification of the remaining barriers to commercial implementation in a formal framework. For the system to be viable, it must meet all wider system constraints (in this case the generation system). Therefore CCS system readiness is complex and depends on a variety of factors including economic, political, regulatory and technical constraints.

System readiness levels have been shown in the context of the systems V diagram which was developed to assess the state of systems in relation to commercial deployment (Sage and Rouse, 1999), as shown in Figure 4-27. System readiness levels are particularly relevant for CCS as most technology has been developed, but the whole system has yet to be demonstrated and deployed in a commercial environment.

The four stages of the CCS system are generation, capture and compression, transport and storage. It is important to note that the CCS concept will not work unless all aspects of the system are in place.

The three main phases for the CCS system to pass through are research, demonstration and commercialisation. However, experience has shown that the transition from research to commercialisation is where technologies fail; the so called valley of death (Grubb, 2002). Many technologies fail at this point as the system must meet constraints imposed by the wider system i.e. markets, reliability, political and regulatory. Although the 'valley of death' concept is usually attributed to TRL's, it is only when understood in the context of whole system performance and constraints that the concept can be fully understood.

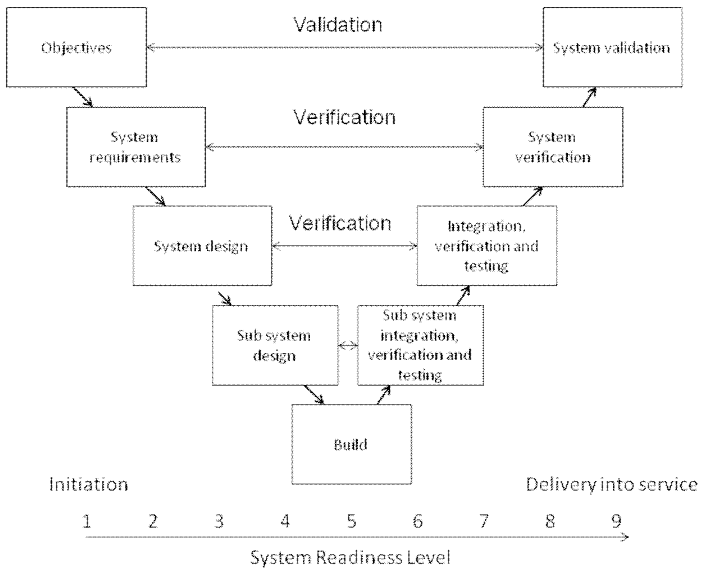


Figure 4-27: Systems V and system readiness level (after (Sage and Rouse, 1999))

Costs increase dramatically as a system approaches system readiness level 9. The integration of sub systems and testing of plant at a commercial scale require far more funding than that required to develop a novel capture process in a lab and therefore carry more risk. For example, the UK government will award around £1 billion to the winner of the CCS competition, while the EU has set aside 500 million emissions allowances and an additional EUR 1billion for six CCS projects as part of the EU recovery package.

The time between SRL's gets longer as the system comes closer to maturity. The time between the demonstration of CCS at a small scale (~30-50MW) and a demo scale (300MW) is forecast to be around 6 years. The first CO_2 capture plants were deployed in 2006 as part of the EU CASTOR project, a 1MW slipstream, and then 2008 (30MW Schwarze Pumpe and 5MW Pleasant Prarie[15]). The firm date for the UK competition winner to start operation is 2014. This is partly because of the construction time required to build a demo plant (3-4 years) and transport and storage facilities and the additional complexity involved in addition to the cost. To date, a number of proposed CCS projects have been mothballed or cancelled due to funding issues e.g. Futuregen and Peterhead.

In order to realise a fully integrated, functioning CCS system there will also need to be advances in other areas besides technology performance, demonstration and sub system integration. These areas include economic support, political support, development of a legal framework and public acceptance and development of a supply chain to deliver CCS infrastructure.

Economic support, in the form of government subsidies will be required if CCS is to become a viable generation technology. Compared to a standard coal plant, the increase in capital and operating cost of a CCS system is prohibitive and uncompetitive without some form of subsidy in place. Even if CCS were technically viable at present, long term economic support would be required in order for generators to even consider commissioning a CCS plant and associated transport and storage site.

For this reason, it is also clear that CCS requires political support; especially long term guarantees to support CCS plant economically e.g. a long term carbon price with a floor. Apart from the funding for EU and GB demonstration projects, governments are yet to provide this kind of support to generators.

There is a significant requirement for legal frameworks to be developed to allow an integrated CCS value chain to grow. The two main areas include classification of CO_2 as waste (allowing it to be disposed of) and the construction of a legal framework to allow liability for CO_2 to be passed from a generator to a transporter and onto a storage company. A framework is also needed to transfer long term liability of the stored CO_2 to a (trans) governmental body due to the long periods over which CO_2 will be stored. It is also unclear how CO_2 can be transported across national boundaries e.g. a plant in the UK sequesters CO_2 in Norwegian territorial waters- does the UK government have liability (as emissions are from the UK) or is the Norwegian government to take responsibility (for a fee) and to what extent does this account for UK emissions reductions- at present the CDM allows European countries to offset emissions by developing projects in the developing world. At present there are no legal frameworks in place to support CCS; in fact even the legal framework governing the UK demonstration plant has not yet been published.

Public acceptance is required in order for CCS to become widely adopted. Politicians will be able to pass legislation much more easily if people accept CCS. This also holds for planning issues for CO_2 transport across land and storage in aquifers at sea. At present, the public do not have a widespread understanding of the fundamental idea of CCS or how it fits into wider carbon mitigation strategy. This lack of understanding is applicable to several nations, not just the UK (Reiner et al., 2009), (de Coninck et al., 2009).

[15] See Appendix 4 for details

Finally, if CCS is to be adopted at a national level, there will need to be sufficient supply chain capacity to deliver the plants, transportation network and storage facilities. This has the potential to be a significant bottle neck- there is likely to be demand for new plant post 2016 (due to the closure of nuclear plant- see Section 2.4) and it will be important to ensure that sufficient skills and resources exist to develop the CCS option. If this does not happen, a similar situation to that seen by the wind developers prior to 2009 could be observed: construction prices will increase (due to excessive demand) so too will lead times for projects as resources are stretched.

4.5.2.1 Results and discussion of system readiness assessment

Table 4-25 presents the system readiness level of the CCS system. Base plant refers to the underlying generation plant type i.e. IGCC, Oxyfuel and PC plant. Both PC plant and IGCC plant have been commercially deployed, while oxyfuel plant has not. Capture and compression are between levels six and seven as they have not been demonstrated fully.

The transport system is at level six as it has been used in the USA for EOR but has not been deployed at the scale required for full implementation of CCS i.e. a full network solution capable of transporting CO_2 to storage sites.

Finally, the storage aspect is at level six because it too has not been deployed at the correct level. Projects such as Sleipner, Weyburn, and In-Salah only inject 1Mt of CO_2 per year. A full scale CCS plant will produce 5Mt of CO_2 per year. The Gorgon project which is projected to start in 2014, will use CO_2 in enhanced gas recovery will inject 3Mt CO_2 per year and is particularly noteworthy as the Australian government has accepted liability for the stored CO_2[16]. Therefore apart from economic barriers, other significant hurdles are:

- Demonstration of the CCS chain at scale i.e. that of whole power plant and large industrial plant;
- Managing the transition from single demonstration projects to the global deployment of CCS.

Table 4-25: System readiness levels for the CCS chain (authors own classification)

Process	SRL
Base plant	7-9
Capture and Compression	6-7
Transportation	6
Storage	6

This is a suitable point to discuss the role of technology demonstration and how it relates to system readiness. There are three categories of demonstration projects: small scale (1.5MW and above), medium scale (>200MW), and full scale (dependent on plant type). Each of the categories is used for different purposes: the smallest scale can test novel capture processes, medium demonstrates the entire CCS chain, while the full scale brings the system up to the commercial level. The demonstration process,

[16] http://.watoday.com.au/wa-news/gorgon-to-lead-nations-biggest-carbon-injection-effort-20090820-es1j.html, “Gorgon to lead nations biggest carbon injection effort”, WA Today. Accessed 10/10/2009.

theoretically, also provides the opportunity to begin the process of developing support for CCS in other areas e.g. regulation, liability framework etc.

Currently, the UK has a CCS demonstration competition, with a winner expected to develop a mid scale plant with transport and storage facilities by 2014. The EU currently has ambitions to finance 12-14 demonstration plants using a mixture of carbon credits and stimulus funding- these plants are likely to be at full commercial scale.

While the UK demo project is likely to be a post combustion plant, the EU demonstration programme will demonstrate all capture technologies, transport modes and storage methods. Appendix 4 (Proposed EU demonstration plants) presents details of proposed projects requiring EU funding by country and plant type. Most of the plants seeking funding are PC plants (9GW), followed by IGCC (4.5GW) and oxyfuel (1.4 GW) with one natural gas plant (0.4 GW) and two CHP plants (0.9GW). It is likely that the UK will be allocated more than one demonstration project from the EU, and there appears to be interest in developing IGCC plants (3 of the 5 plants in the UK are proposed as IGCC). At the time of writing, the EU funds are unallocated. Once published, the choice of demo plant along with the capture process should give a clearer indication of the most promising capture technologies. Other countries outside the EU, notably the USA, Australia and Japan are also pursuing CCS demonstration programmes, however, the level of funding is unclear—recently the USA chose to halt the development of Futuregen, an advanced IGCC plant with CCS.

4.5.3 SWOT analysis

The SWOT analysis provides a framework to systematically compare the three types of coal plant. This Section synthesises the research findings from the previous Sections of Chapter 4 to inform the strengths, weaknesses, opportunities and threats for each of the plant configurations under investigation.

Strengths are attributes that are considered to give the technology competitive advantage. Correspondingly, weaknesses are considered to be absent desirable attributes (missing strengths) that are considered to put the technology at a competitive disadvantage to its rivals. Opportunities cover changes in the wider environment that would create opportunities for the technology to grow in market share and profitability (e.g. regulatory and market conditions). Threats cover changes in the wider environment that would decrease opportunities for profit and growth and hence pose a threat to the technology (e.g. market conditions or performance of competing technologies).

Strengths	Weaknesses
• Ubiquitous underlying plant technology • Reliable • Large plant size (economies of scale) • Low capital cost (relative to other plants) • Retrofit possible • Switch capture process on and off	• Limited potential plant performance • Material limitations • Low concentration of CO_2 in flue gases at atmospheric pressure • Efficiency refinements rather than breakthroughs • High performance penalty for capture
Opportunities	**Threats**
• Market potential (India and China) • UK government backed • New capture processes (e.g. chilled ammonia) • High carbon price • Carbon capture law • Improved Capture Process Development	• Hydrogen Economy • Oxyfuel and IGCC show greater performance • Low-carbon price (not as bad as the other options) • Low natural gas price

Figure 4-28: SWOT analysis for PC plant with carbon capture

Strengths	**Weaknesses**
• Adaptable (produce hydrogen) • Simple to capture CO_2 (in relation to other processes) due to relatively pure stream of CO_2 • Low performance penalty for capture (4.2%) • Large power plants possible • Retrofit possible • Possibility for Hydrogen production • Experience of oxyfuel in glass	• No full scale oxyfuel power plants built • High capital cost compared to PCC • Energy Penalty of ASU • Lack of commercial deployment • Capture "lock-in" • Possibility of corrosion problems
Opportunities	**Threats**
• Hydrogen economy • CCS law • High Carbon Price • New O_2 production tech available	• Low CO_2 price • Efficient PC capture process • Low natual gas price

Figure 4-29: SWOT analysis for Oxyfuel plant with carbon capture

Strengths	Weaknesses
• Best **potential** performance (efficiency) • Low capture penalty- both cost and performance • Fuel flexibility • Low emissions(NO_x, SO_x, particulates)- easily meet future limits	• Capture "lock-in" • Immature- only 4 plants worldwide • Poor availability factor (reliability) • High capital cost • Small plant capacity (temporary)
Opportunities	**Threats**
• Improved capture processes • Low energy water-gas shift reaction • Hydrogen economy • Cheap lignite, expensive bituminous coal • High carbon Price • CCS enforced by law	1. No Hydrogen economy 2. Low natural gas price 3. Advanced Oxy and PC plant availability 4. Low-carbon price

Figure 4-30: SWOT analysis for IGCC plant with carbon capture

4.5.4 Discussion and conclusion of technology assessment

The ranking of the CCS system and sub-system processes in terms of system/technology readiness levels has shown that the CCS system is not yet technically viable. In particular, full scale demonstration and commercial operation of the CCS system has not been achieved. In order for CCS to become a part of the integrated electricity system, the entire CCS chain must be demonstrated, at full scale.

Full scale demonstration will reduce the ambiguity that currently surrounds the CCS system including uncertainty related to costs, legal barriers to CO_2 transport and storage and operational characteristics of a power plant that captures CO_2 e.g. data from the pilot oxyfuel plant in Schwarze Pumpe should help the case for oxyfuel plant.

Significant investment is required to demonstrate CCS at a commercial scale: merchant generators will not pay for the additional costs incurred for demonstration; this will need to be met by individual governments or inter-governmental organisations. The UK government has launched a competition to fund a CCS demonstration scale (300MW) plant and Eurelectric, the union of electricity producers has told the EU that a full scale European demonstration chain (i.e. 12 plants) could cost €9billion (Eurelectric, 2008a). Eurelectric has also suggested that the money for financing comes from the auction revenues from EU-ETS to fund the demonstration programme, but as member states appear unwilling to do this, Eurelectric supports the creation of €500 million fund from the new entrants' reserve. The EU demonstration programme will encompass all plant technologies together with transport and storage networks (Eurelectric, 2008a).

Successful demonstration does not guarantee commercial deployment of CCS; there are a number of risks associated with CCS technology demonstration and any failures will damage investor confidence. The very fact that such significant funds have been committed to the development of CCS indicates the political will behind developing the process. State of the art carbon capture technologies that have been demonstrated on a small scale have been found to function well, albeit with significant impact on plant performances.

CO_2 transportation has taken place for some time in the USA as part of enhanced oil recovery operations. Storage of CO_2 has been demonstrated in 4 projects around the world: Sleipner, Weyburn, and In-Salah. However, full scale demonstration of these processes has not occurred; for example, the complexity of a pipe network system for North West Europe would be a significant undertaking. In addition, large-scale storage would be required. The CO_2 output of one base load plant would be approximately 20,000 tonnes per day. The Sleipner project sequesters 1Mt/yr of CO_2, therefore an injection rate of around 5 times that of Sleipner would be required in order to sequester the carbon from just one coal plant. Operation at scale is the key barrier to CCS becoming commercially viable.

Even if the technical implementation of CCS were possible (i.e. fully functioning demonstration chains), the wider system must also be ready to support the introduction of CCS. At present this is not the case. Legal regulations governing categorisation and disposal of CO_2 need to be established. The only incentive to introduce CCS at a coal-fired power plant is the price of carbon, which is not yet at a sufficient level to promote CCS uptake. In addition, there is the critical issue of long-term liability for stored CO_2. For example: what are the sizes (and likelihood) of potential liabilities and who is responsible for the liability? It is difficult to see a way for CCS to become viable without national governments taking on some degree of responsibility for the storage of CO_2.

Flexibility is important as it allows a generator to wait and respond to emergent system requirements rather than trying to predict when they will occur. There are two types of flexibility associated with CCS: operational and retrofit. Operational flexibility is the ability of the plant to alter the amount of CO_2 that is captured per MWh of generation. Retrofit flexibility is related to the ability of a plant to be retrofitted at some point in the future, however, the time taken for retrofit and the cost associated with this is also important. Both of these types of flexibility allow plant operators to adapt to changing wider system constraints e.g. carbon price or legislation. However, the degree of flexibility associated with retrofit is not the same for all technologies: PC plants are generally considered to be much easier to retrofit than IGCC plants. Retrofit is a valuable option to have if a generator was expecting to build a coal-fired plant now, when a CCS plant would be uneconomic. Once the carbon capture sub processes are installed, operational flexibility becomes important; a process that captures less CO_2 will require less steam to regenerate the solvent and hence the cost of generation will decrease. This could be of value under low-carbon price scenarios or high electricity price scenarios where the revenue gained by generating additional electricity more than compensates for the expense incurred by emitting CO_2. Therefore, operational flexibility can be thought of as a permanent option that is exercised under suitable conditions. Retrofit flexibility is a one off irreversible investment that locks a generator into a capture regime.

System adaptability in a slightly different sense favours IGCC and oxyfuel plant (with Chemical looping combustion) due to their ability to be converted to produce hydrogen. Such plants would have the potential to be a significant source of CO_2 free hydrogen, and as a consequence, investment in the development of these technologies could dramatically increase. However, given timescales for the transition to a hydrogen economy, it is possible that the first generation of CCS plants will not benefit from this flexibility.

The only financial incentive for the CCS system to be deployed is the price of carbon. At present, the price of carbon is not at a sufficient level to enable CCS deployment. A flexible capture system could compensate for uncertainty in the price of carbon, as CO_2 could be vented to atmosphere under low-carbon price conditions. The flexible plant operation is essentially attributable to PC plant at present. IGCC plant would require a slipstream process to draw off gas prior to CO_2 capture, adding to plant complexity. The impact of putting syngas products through a hydrogen turbine is unknown, but is likely to be detrimental. If a separate turbine system were required, the complexity of the plant would further increase.

4.6 Chapter conclusions

This Chapter has made a technical assessment of the coal CCS chain using a systems approach. The over arching conclusion is that the CCS system is not yet ready for deployment in the power generation system. The main barriers to system deployment are technical, political, regulatory and economic. Key enablers have been identified as: financial incentives, technical progress, legal and regulatory framework, system demonstration at full scale and public acceptance of the CCS system. There are a number of conclusions at the base plant level, the CCS plant level and the CCS system level.

In terms of the base plant, PC plant is expected to be the dominant plant due to its reliability, availability, and performance. In the future IGCC could become the more efficient plant, although this will be dependent on RD&D spending. It is expected that IGCC plant will remain the most capital intensive plant although this should be partly offset by emissions performance and plant efficiency.

Producing electricity using CCS increases the cost of generation. This is a result of all stages of the CCS process, but predominantly the effect of the capture process, which lowers plant efficiency thus raising operational costs and capital costs. IGCC and Oxyfuel have the lowest performance penalty due to CCS operation, but this does not more than compensate for the extra costs incurred by the base plant compared to PC CCS.

The other elements of the CCS system are constrained in different ways. In terms of the transport network, the complexity and cost of the network, along with legal issues relating to carbon classification need to be addressed. In terms of the storage network, the appropriate regulatory framework, legal liability transfer and monitoring responsibility are key barriers to be overcome.

Given that demonstration were to occur, the uncertain nature of future CO_2 price means that system flexibility has value, as the owner can avoid lock-in to a capture regime. Two types of flexibility were identified: operational and retrofit. Operational flexibility is best suited to PC and oxyfuel plant. In addition, reliability is an essential part of the capture process, therefore it should be noted that in terms of breakdown of the CO_2 capture process, PC and oxyfuel have a definite advantage over IGCC, as the capture process is not integral to the plant process and could be bypassed in the event of emergency maintenance. Retrofit flexibility appears to suit PC plant and to a lesser extent IGCC plant.

Due to the additional costs incurred by the installation and operation of the CCS system, improvements in CCS system performance focus on research into making the capture process more efficient and cost effective. The specific target area differs according to the process under investigation, but due to the unsystematic nature of the reporting, probably due to technology immaturity, it is difficult to see clearly how these improvements will affect plant performance. However, it is inevitable that progress will be made although there will always be an additional penalty to operating the CCS system.

When performing a technology assessment, there is a need to be wary of published information. There area often missing metric so published sub system performance cannot be transposed to system performance. This makes objective evaluation difficult. The evolving nature of technologies means that although some technologies appear to be unfeasible, future developments could force a re-evaluation of the situation.

The development of a generic technology screening model could help evaluate the plethora of different technologies. The model could be used to determine the minimum plant performance for a technology to become viable. Such barriers may be: an availability of 85%, the ability to load follow, and the cost of generation to be less than £50/MWh. The constraints would dictate the subsystem performance parameters e.g. efficiency penalty of less than 4%, increase in capital of 15% etc. These performance parameters could then be disaggregated to the sub level to form performance parameters that must be met e.g. energy required for solvent generation etc. In order for this to happen, a program would need to be made that allows an input (cost of generation) to be disaggregated into optimal sub system technical performance measures.

In summary, PC with CCS appears to be closest capture system to deployment. PC has the greatest operational flexibility i.e. switch the capture process on and off and vary the capture load according to

demand, it is also the easiest to upgrade (retrofit). In addition, PC with CCS has been proven at a small scale. Although IGCC has the best potential performance in the future, it suffers from reliability and high capital costs while oxyfuel lies somewhere between the two.
Demonstration at full scale of the CCS chain is required. In terms of technology readiness, the PC system is closest to deployment; this is due to the robust nature of the underlying plant, the flexibility of operational CCS and the simplicity of integrating CCS into the existing plant layout. The entire CCS system must be in-place before CO_2 capture can operate; the phases are sequential and full system deployment is dependent on all aspects being operational. Demonstration projects should provide good data on system cost and performance as long as the results and costs are reported in a clear and transparent manner.

Policy support will be required to aid the transition between system demonstration and full system deployment. Although there are four steps associated with CCS system deployment, the steps are not evenly spaced. For example, although it might take 5 years to move from research to demonstration, it will take much longer to build a carbon transport infrastructure and suitable storage sites. Additional time will be required to amend laws and put in place a regulatory framework to cope with the unique risks of long term CO_2 storage. It has been estimated that the cost of full scale demonstration at 12 sites in Europe will be in the order of €9 billion (Eurelectric, 2008a). The status of PC plant with CCS as being the closest deployment can be seen in the proportion of applications for EU funding status that cover PC plant; more than double the capacity of IGCC plants.

The cost and performance penalty associated with CCS implies some form of government support could drive the early adoption of CCS in the UK. This intervention could take several forms: a CO_2 tax, CO_2 allowances or a feed in tariff. A long term fixed CO_2 tax would provide investors with certainty of returns over the lifetime of the project. The level of the tax could be set at the CO_2 price required to incentivise investment in coal CCS, but disincentivise investment in unabated coal and CCGT plants. Likewise a feed in tariff could be structured to compensate plant owners for the cost of generation and cover a pre-determined rate of return. Tradable allowances for CO_2 would be similar to the current EU-ETS setup. The important thing in this case would be for policy to ensure that the allowances were at a sufficient stable level to incentivise investment in coal CCS plant.

One question that has not been addressed in this Chapter regards competition from other methods of power generation, in particular natural gas fired CCGT plant, which is the dominant electricity generating technology at present. In addition, it is also possible for CCGT plant to be fitted with CCS. The next Chapter establishes a framework to examine the economic characteristics of coal and gas plants with and without CCS.

5 Investment appraisal

The objective of Chapter 5 is to analyse the economic characteristics and sensitivities of coal/gas with CCS compared to a standard coal/gas plant.

As shown in previous Chapters, but reiterated here for clarity, the retirement of nuclear plant and closure of coal plant due to the large combustion plant directive together with an expected increase in demand for electricity means that the UK will require an additional 34GW of power capacity by 2020. The choice of new plant is complicated by concerns over energy security and environmental impact; the UK has set a target of a 20% reduction in carbon emissions by 2020. These concerns force generators to consider a low-carbon electricity generation option, with gas CCGT plant currently the market choice. Coal with CCS has the potential to help the UK to achieve low-carbon growth while still using fossil fuels and thereby adding to fuel mix diversity. Research in clean coal technology appears to be proceeding well; however, in order to become a viable option for generation, coal with CCS needs to be robust economically. An alternative way to introduce coal CCS into the generation mix would be through government support. The question of the level of support that should be allocated also depends on understanding the economics of coal CCS plant.

This Chapter constructs a model that can be used to determine the cost to the generator of producing electricity from any of the power plants under investigation. In addition, the sensitivity of the cost of generation to input data for the plants under investigation is presented. As a result, implications for investment in CCS plants are brought forward. The results of the model are then fed into the next model stages i.e. first hitting time and options models. One of the key findings of the next Chapters is that the price of natural gas drives the economic case for coal with CCS.

5.1 Literature review

A plethora of papers has been written concerning investment in power plants. For the purposes of this thesis, the papers that will be reviewed are those that relate directly to the economic evaluation of CCS technology.

The literature can be classified into reports from industrial entities, those from academics and those from governmental organisations. In general the academic literature can be separated into those reports and papers that evaluate new technologies or processes or those that seek to provide an overview of potential capture technologies. As this Chapter is concerned with and economic comparison of the alternative coal plants with and without CCS and CCGT plants with and without CCS, the main source of interest lies in the approach used for economic comparison.

Reports concerning optimisation of capture process performance include Chalmers and Gibbins (Chalmers and Gibbins, 2007) which analyses the benefit of flexibility in plants with post combustion capture in order to grade the effectiveness of CCS plants as mid merit plants. They conclude that solvent storage (the ability to store CO_2 rich solvent and regenerate later, when the electricity price is lower) could have a positive impact if CCS plants are to play a role as mid merit plants; cost comparisons are based on short run marginal costs.

Abu-Zahra et al (Abu-Zahra et al., 2007a) optimised CO_2 loading according to economic constraints and found the minimum cost of CO_2 in terms of cost of electricity. Costs were based on levelised cost calculations supported by chemical kinetic modelling in Aspen plus.

Studies that have analysed potential costs of alternative capture methods of CO_2 often use chemical modelling software to aid cost derivations. Ciferno (Ciferno et al., 2005) wrote an economic scoping study on CO_2 capture using alternative solvents based on the levelised cost of electricity and cost of CO_2 avoided. Grainger reported the outcome of a techno-economic evaluation of a PVAm CO_2-selective membrane in an IGCC power plant with CO_2 capture (Grainger and Hägg, 2008). The motivation was to find out what the reduction in cost of generation for alternative membranes was in an IGCC plant. Costs were reported on a levelised basis. Fisher (Fisher et al., 2005) optimised process energy consumption to reduce the energy required for CCS with MEA solvent as part of a contract under the US Department of Energy. Costs were derived in terms of levelised cost and cost of CO_2 avoided. Peeters (Peeters et al., 2007) reports the results of a techno-economic analysis of natural gas combined cycles with post-combustion CO_2 capture. The cost is reported in terms of levelised cost and cost of CO_2 avoided (euro/kWh) and the effect of increases in plant performance and reductions in the cost and energy penalty installed by capture are given along with other sources of cost reduction e.g. lower capital costs. Improvements in the performance of the capture process were generated from chemical engineering models.

The next theme for papers from the academic environment is for papers to be written regarding a comparison between alternative capture technologies. Rubin has published many papers relating to the cost of CCS now and in the future (using learning curves), but those with particular relevance to this Chapter are (Rubin et al., 2007a), which presented a comprehensive analysis of the levelised cost of generation from coal and CCGT (natural-gas fired combined cycle) plants. The MIT study on the future of coal (Deutch and Moniz, 2007), provides a comprehensive assessment of the cost of generation from PC, oxyfuel, IGCC and pressurised fluidised bed combustion plants. Once again, levelised costs of generation are derived and set against a background of wider systems issues associated with CCS deployment e.g. public acceptance and security of supply issues. Damen (Damen et al., 2007), (Damen et al., 2006) provided a thorough review of normalised capital and operational costs for coal plants with CCS in order to derive suitable performance parameters for the production of hydrogen from CCS plants.

In general, reports commissioned by industry tend to focus on economics on a single process or a depending on the scope, a comparison of alternative processes that are relatively close to market. There appear to be far fewer studies that concentrate on alternative capture processes, however, studies tend to take into account revenue and the impact this has on the cost of CCS plants. Alstom have produced a

comprehensive study on the economics of CCS (Alstom, 2001), with levelised costs reported. Deutsche Bank have produced two reports (Lewis, 2008), (Lewis, 2007) detailing CCS cost performance figures, with data taken from industrial entities such as RWE. The cost of generation that is derived is low enough to allow for a 15% return on investment. The association of electricity producers (AEP) represent the utility industry in Europe. A consultation paper has been released that details costs associated with generation from CCS plants with and without CCS for IGCC, PC and oxyfuel plants.
A report for the London accord produced by Merrill Lynch (Levinson, 2007) analysed the economics of carbon capture and found that a cost of CO_2 around $45/tonne on a sustained basis was required. Data was based mainly on cost data from the Association of Electricity Producers (AEP). PB Power (PBPower, 2004) produced a report for the Royal Academy of Engineering analysing the cost of generation for standard PC and IGCC plants in levelised cost terms. No CCS plants were taken into account for the analysis. Pöyry (Poyry, 2007) conducted analysis to show how the cost of CCS is expected to change with deployment. Underlying model data was taken from a variety of sources including the IPCC and IEA. The report concluded that although significant potential for CCS deployment existed under a carbon price of £25/tonne, fuel price assumptions and the choice of reference plant were critical.

The final class of reports belongs to those from governmental and non-governmental organisations, usually made up of a combination of academics and industry representatives. These reports have produced some of the most thorough overviews of the costs of CCS. The IPCC produced the definitive study of the CCS chain and associated costs (IPCC, 2005). Metrics used include cost of generation and cost of CO_2 avoided and captured for plants and industrial processes with and without CCS. As part of the process of reporting the results of the IEA GHG program, Davison (Davison, 2007) presents an excellent overview of performance and cost data for CCGT and coal plants including a sensitivity analysis of input parameters. The levelised cost of generation is then calculated for the whole of the CCS chain.

As stated at the beginning of the Section, the objective of this Chapter is to develop a model that will facilitate an understanding of the cost profiles of CCS plants in relation to one another and standard plants. In addition, the model will provide the foundation for the more advanced modelling that will take place in Chapter 6. None of the studies above compare all methods of coal fired generation with natural gas with and without CCS and perform a sensitivity analysis on the results specifically for the UK market. Perhaps most importantly, this Chapter will provide an objective derivation and analysis of the cost of generation from the various coal plants under consideration. The most viable plant will then be used as the CCS benchmark plant in Chapter 6.

5.2 Methodology- global pricing model

The requirements of Chapter 5 are two-fold: to provide input data that will enable an answer to be produced for the first research question and to allow a comparison of the various coal plants under investigation as well as a comparison with a CCGT plant.

First, it is necessary to define the system of interest; the system under investigation in this Chapter is the power plant and associated CO_2 capture chain. Therefore the cost model in this Chapter calculates the cost of generation including the cost to transport and store CO_2.

The global pricing model allows the cost of generation to be calculated for any type of plant under investigation. Consequently, alternative fuel plants i.e. gas and coal can be compared, as well as alternative plants that use the same fuel source e.g. oxyfuel and PC plant. In addition, a sensitivity analysis of the cost of generation to input parameters can be performed. Therefore this Chapter provides the framework to answer the first research question. In addition, this Section will provide some of the input data for the more advanced models used in subsequent Chapters to answer the second two research questions.

The average cost of generating a unit of electricity over a plants' lifetime is given by:

$$C_g = \frac{C_c \cdot A(t,r) + C_{O\&M} + C_d \cdot B(t,r)}{hr_{yr} \cdot U_t \cdot P_c} + C_f + C_E \quad (5.1)$$

Where:

C_g : cost of generation (£/MWh)

$C_cA(t,r)$: annuity payable on the capital cost; r is the interest rate, t is the loan period (£/year)

C_{O+M} : fixed annual operation and maintenance costs (£/year)

$C_dB(t,r)$: annual payment to a decommissioning fund (£/year)

C_f : fuel cost (£/MWh)

Hr_{year} : 8760 (hours/year)

U_t : utilisation factor (%)

P_c : plant capacity (MW)

C_E : cost of emissions (£/MWh)

Equation (5.1) outputs the cost of generating one unit of electricity, where all costs are discounted into money of the day and C_g, the cost of generation, is equivalent to the minimum revenue (£/MWh) to break even. Under conventional investment appraisal methods, a generating company would consider investing in new power plant if the expected NPV was positive, given:

$$NPV = (R/\delta) - C_c \text{ and } R > \delta \cdot C_c \quad (5.2)$$

Where:

NPV : net present value (£)

δ : capital recovery factor (%)

R : revenue (£)

C_c : capital cost (£)

The capital recovery factor is defined by Dixit (Dixit, 1992) as:

$$\delta = \frac{e^{rt}\left(e^{r}-1\right)}{(e^{rt}-1)} \tag{5.3}$$

Where:

r : interest rate (applied to the debt) (%)

t : economic life of the facility (years)

Under NPV investment criteria, a generating company will invest in new facilities if the net present value (R/δ) of the annual revenue stream R is greater than the capital cost of the initial investment.

5.2.1 Decommissioning costs

Although the model allows the cost of decommissioning to be calculated as part of the cost of generation, costs of decommissioning coal and natural gas plant are treated as negligible and therefore are not included in this thesis. This is consistent with the literature, which states that decommissioning costs are a negligible component of total cost of generation (IPCC, 2005).

This is especially true if it is assumed that an operator sets asides funds for decommissioning from the beginning of the plants' lifetime. For example, calculations in the appendix show that decommissioning costs for nuclear plants account for less than £0.20/MWh if spread over the lifetime of a plant. Given that costs associated with decommissioning of coal or gas plant can be expected to be significantly less, this assumption appears to be justified. The cost of funds to cover monitoring and decommissioning costs at CO_2 storage sites is included in the costs for CO_2 transport and storage in Section 5.5.6.

5.2.2 Revenue uncertainty

In order to simplify this stage of the model, this Section assumes that the power output of alternative plants is the same. As a result revenue uncertainty does not affect the initial model, as to all intents and purposes it is the same for each plant as each plant has equal output capacity. Therefore the loss or profit made would be the difference between the alternative costs of generation per MWh of output. This method of problem formulation also means that tax does not need to be taken into account because we are only concerned with the break-even price. If the plants under investigation were to have different power outputs, these assumptions would be invalid.

5.3 Coal pricing model

Four costs need to be considered for to derive the minimum revenue required for a coal plant to break-even, $C_{coal(min)}$: construction costs (C_c), operational costs (C_o), decommissioning costs (C_d) and equity dividend (C_e). Project financing demands that a number a financial instruments be used, and in summary these will be senior debt, mezzanine debt, and equity. For the purposes of this thesis senior and mezzanine debt are combined to senior debt only (mezzanine debt will be at a higher rate of interest to adjust for risk) and equity. The debt/equity ratio is shown as d/(e+d) or e/(d+e) as appropriate; the cost of debt is $C_{cd} = C_c.(d/(d+e))$, and the cost of equity $C_{ce} = C_c.(e/(d+e))$. By strict definition, equity dividend is derived from net profit but will be included in this analysis as a derivative of 'expected' return on equity.

To derive an expression for $C_{coal\ (min)}$, first R_{min} (£) (revenue minimum) is derived;

$$R_{min} = (\delta_c \cdot C_{cd}) + (\delta_d \cdot C_d) + \left(C_{ce} \cdot \left(\frac{e^{\kappa t}(e^{\kappa} - 1)}{(e^{\kappa} - 1)} \right) \right) + C_o \tag{5.4}$$

Where

R_{min} : the minimum annual revenue to break even (£/year)

δ_c : capital recovery factor for construction financed by debt (year)$^{-1}$

C_{cd} : capital investment for construction financed by debt (£)

δ_d : annualisation factor for decommissioning fund (year)$^{-1}$

C_d : capital investment for decommissioning funds (£)

C_{ce} : capital investment for construction financed by equity (£)

κ : return required on equity in perpetuity (%)

C_o : annual operations costs (incl. O+M and fuel costs) (£/year)

The decommissioning factor, δ_d is given by:

$$\delta_d = \frac{\left(e^{\lambda} - 1\right)}{(e^{\lambda t} - 1)} \tag{5.5}$$

Where:

δ_d : annualisation factor for the decommissioning fund (year)$^{-1}$

λ : The rate of interest on decommissioning saving fund (%)

t : the period of time over which the fund accrues interest (years)

Also:

$$R_{min} = U_t \cdot P_c \cdot hr_{year} \cdot C_{coal\,(min)} \tag{5.6}$$

Where:

U_t : average annual load factor of the plant (%)

P_c : plant capacity (MW)

hr_{year} : hours per year (hr/year)

$C_{coal\ (min)}$: the minimum price to yield neutral pricing (£/MWh)

Equating equations (5.4) and (5.6) gives:

$$C_{coal\,(min)} = \frac{(\delta_c \cdot C_{cd}) + (\delta_d \cdot C_d) + \left(\delta_e . C_{ce}\right) + C_o}{U_t \cdot P_c \cdot hr_{year}} \tag{5.7}$$

Where

$$\delta_e = \frac{e^{\kappa t}\left(e^{\kappa} - 1\right)}{(e^{\kappa t} - 1)} \tag{5.8}$$

The return on equity is based on a fixed percentage of total equity provided as this reflects the way in which the investment contract is set up. In general equity providers require a return on capital as a fixed proportion of their investment which lasts for the economic life of the project. For the purposes of this model the decommissioning cost is considered as part of the construction cost. This assumption would need to be reviewed if the model were to compare plants for which decommissioning is an important component e.g. nuclear plant.

The minimum price/MWh ($C_{coal\,(min)}$) for coal is provided by equation (5.9):

$$C_{coal\,(min)} = \frac{\left(C_{cd} \cdot \delta_c\right) + \left(C_{ce} \cdot \delta_e\right) + C_{o\&m(coal)}}{hr_{yr} \times U_{t(coal)} \times P_{c(coal)}} + C_{f\,(coal)} + C_{E\,(coal)} \tag{5.9}$$

Coal will not be used when the plant is idle and therefore equation (5.9) is adjusted accordingly. The fuel cost is given by the expression:

$$C_{f\,(coal)} = \frac{C_{tc} \times 0.278}{Eff_{coalplant} \times cv_{coal}} \tag{5.10}$$

Where:

$C_{f\,(coal)}$	: the cost of coal to produce 1MWh of electricity (£/MWh)
C_{tc}	: the cost of coal on the market (£/t)
$Eff_{coalplant}$	: the thermal efficiency of the coal plant (%)
cv_{coal}	: the calorific value of the coal (GJ/t)
0.278	: constant conversion factor (GJ/MWh)

The cost of buying emissions credits for a unit output of electricity is given by the expression:

$$C_{E\,(coal)} = C_{carbon} \times (1 - \eta_{capture})\left(e.f. \times \dot{m}_{f\,(coal)}\right) \tag{5.11}$$

Where:

$C_{E(coal)}$	: the cost of buying emissions credits for a MWh of operation (£/MWh)
C_{carbon}	: the cost of carbon on the market (£/tonne)
$\eta_{capture}$	: the efficiency of the capture process
e.f:	: the emissions factor; 2.23 units of CO_2 per unit of coal combusted
$m_{f(coal)}$	: the rate at which fuel is burnt (t/MWh)

5.4 Coal with CCS pricing model

Additional sub processes must be added to a PC plant if it is to be able to capture carbon dioxide. The addition of carbon capture facilities means that the cost model must be modified to allow for additional costs due to transport and storage. Therefore, C_{TS} is the cost of transport and storage (£/MWh) of the captured CO_2, which the generator is expected to pay. C_E is not zero as the capture equipment is expected to be around 90% efficient (IEAGHG, 2004) so some CO_2 will be emitted, for which the generator is charged.

$$C_{coal(min)} = \frac{(\delta_c \cdot C_{cd}) + \left(C_{ce} . \delta_e\right) + C_{o\&m(c)}}{hr_{yr} \times U_{t(c)} \times P_{c(c)}} + C_{f(coal)} + C_{E(coal)} + C_{TS} \tag{5.12}$$

5.5 Coal model data

In order to produce the cost of generation, cost data needs to be inputted into equation(5.12). The following Section reports the results of a literature review to provide cost input data for standard and CCS enabled coal plants. The objective is to be as transparent as possible in using data sources to derive cost of generation.

5.5.1 Construction costs and financing

Construction costs or total construction requirements represent the total sum of money required to construct a power plant. In general, the construction cost comprises three components: the total plant cost (cost to build the plant), owners costs (which include start-up costs and land costs) and interest during construction. Owner's costs are typically represented as a percentage of the total capital cost, while interest accrued during construction is dependent on the interest rate and the timescale of the construction and commissioning process, which can be as little as two years for a CCGT or 4 years for a PC plant. The two processes together typically add on 10-20% to the capital cost of the plant (IPCC, 2005). However, sometimes these additional costs are incurred prior to the commencement of plant operation and are usually accounted for on balance sheets before plant operation begins and therefore do not appear in the cost of generation calculation (IPCC, 2005). In the literature that has been reviewed to derive values for capital costs, interest during construction has been taken into account- this is reflected by the phrase 'total capital requirement' rather than capital costs. For the purposes of this thesis, owner's costs are assumed to have been accounted for prior to commencement of plant operation and hence are disregarded.

The potential of CCS to act as a carbon abatement technology has led to a large number of reports from governmental bodies, non-governmental organisations, academia and private industry citing capital costs for coal plants with and without CCS. Much of the data for capital costs was distilled in Chapter 4; this Chapter uses that data to determine inputs to the cost model. For clarity, a modified form of the tables are presented below

Table 5-1: Capital cost ranges and values for coal plants (based on nameplate capacity)

Plant	Min (£/kW)	Max (£/kW)	Average (£/kW)
PC	719	965	825
IGCC	760	1080	904
Oxyfuel	644	975	819
PC_CCS	1125	1675	1294
IGCC_CCS	919	1475	1198
Oxyfuel_CCS	1090	1854	1386

The data includes that used in the source report followed by the amount when the currency has been converted into sterling 2009. This is to help avoid any uncertainties that can arise during calculations as a result of exchange rates. The methodology for converting the costs to current data was to use GDP deflators and average currency conversion factors to offset the volatile exchange rates between the dollar and pound since 2005, (Officer and Williamson, 2008).

All costs that are presented in Table 5-1 have been scaled accordingly to meet the 500MW plant output capacity that is used in this thesis. Although plants are assumed to be built on a 500MW capacity basis, it should be noted that some plants, particularly PC, benefit from economies of scale i.e. it is cheaper to build a larger capacity plant in terms of £/MW. A treatment of such parameters is outside the scope of this thesis.

A body of literature exists that cites capital costs of new coal plant with and without CCS. The most transparent studies appear to be from IEA GHG reports (IEAGHG, 2003), (IEAGHG, 2004), RAEng (RAEng, 2004), Deutch and Moniz (Deutch and Moniz, 2007), PB Power (PBPower, 2004) and the IPCC (IPCC, 2005). The cost data from these studies are taken as guides for the capital costs of the alternative coal plants with and without CCS.

Although the construction costs in the cost model are taken as fixed, real world construction costs depend on global market conditions, the price of raw commodities used and the cost of the labour that is hired, which is related to the amount of construction projects being undertaken. The cumulative effect of the variations is usually measured in the form of an index. For the case of large power plants, the PCI plant (plant cost index) can be used to provide an idea of the likely inflation or deflation of capital costs. Due to a lack of access to data sources, this study does not use any PCI data to inflate or deflate plant prices, but notes that in recent years a significant increase in PCI costs has taken place, the primary driver of which has been increased demand for raw materials by China.

It has been demonstrated that the capital cost of technology reduces as installed plant capacity (typically measured in GW) increases (IEAGHG, 2006a). The trend is probably applicable to CCS, and has been documented for other forms of pollution abatement technologies e.g. FGD; a study commissioned by the IEAGHG programme is reported in (Rao et al., 2006). However, while learning curves will reduce the costs of future generation units, the first CCS plants to be built will not benefit from the effect of learning by doing. Given that the research question of this thesis focuses on the deployment of the first CCS plants, the effect of learning curves is not taken into account in this model, although it is expected that the reduction in capital cost associated with learning by doing will enhance the deployment prospects of plants with CCS in second generation plants.

Financing the construction of a power plant is a significant undertaking. Given the substantial investment requirements, it is very difficult for the generator to fund the entire venture without resorting to borrowing some of the required capital. In summary, a 70/30 debt/equity ratio is assumed. A lower debt-equity

(50:50) split is unrealistic due to the high capital cost involved, while an 85:15 debt-equity split would represent an unrealistic level of offtake contracts (see Appendix E for more details). It is assumed that debt has an 8% interest rate. It is standard practice to assume that equity holders would expect a 15% return on investment throughout the operational life of the plant; hence equity is modelled as a fixed cost per annum based on a percentage return on equity provided (Yescombe, 2002).

5.5.2 Operations and management cost

Operations and management costs relate to the expenditure that is required to meet routine maintenance and operational tasks. This includes labour costs for operational staff and supervision, waste and chemicals, waste disposal and other items of expenditure incurred during normal operations (IPCC, 2005).

Costs for operations and management costs are sometimes expressed as a percentage of capital costs, and increase substantially when CCS is introduced. Operations and management costs used in this study are based on the IEAGHG programme reports (IEAGHG, 2004), the Royal Academy of Engineering (RAEng, 2004) and Sekar (Sekar, 2005).

5.5.3 Fuel cost

Fuel costs are defined as the price that a generator is expected to pay when purchasing fuel to run the plant. Coal prices are set by markets, but coal is not a global fuel as it sells for different prices in different markets. Coal is relatively difficult to transport in large quantities, but can be stored fairly easily at a plant site. The cost of transport can represent up to 20% of the market price of coal (IEA, 2008a). There are various sub-categories of coal, which vary in composition and calorific content. The table below lists the type of coal along with the average calorific value for OECD countries.

Table 5-2: Calorific values of various coal types (Data Source: (IEA, 2008a))

	Average Calorific Value MJ/kg (LHV/Net)	Use
Anthracite	27.5	Domestic
Bituminous (exl coking coal)	26.0	Electricity Generation
Sub-bituminous	19.7	Electricity Generation
Lignite/Brown	12.1	Electricity Generation

According to the IEA, the UK uses no lignite for power generation (IEA, 2008a). Therefore, for the purposes of this thesis, it is assumed that all coal used at power stations in the UK will be bituminous.

Figure 5-1: Average quarterly coal price paid by electricity generators (Data Source: (BERR, 2008b))

Figure 5-1 shows the price paid for coal by electricity generators in the UK for the last 19 years. The long downward turn in coal price throughout the nineties is due to the natural gas fired power plants replacing coal plants thereby reducing demand for coal and hence price. The price then appears to level off at around £30/tonne until 2007. The upward trend seen in 2007 and 2008 is due to the effect of increased demand from developing countries such as China and India. In the same period, many other commodities also rose significantly in price.

The UK imports most of its coal from overseas, due not to a lack of reserves, but because the price at which coal is sold by UK mines is higher than that of overseas companies, even when transport is taken into account. In addition, most UK coal, with the exception of some Scottish coal, has a high sulphur content (MottMcDonald, 2004); this makes it difficult for plants without FGD installed to meet sulphur emissions constraints of the LCPD when using coal from the UK. As a result, in recent years the UK has imported a substantial proportion (51%) of coal from Russia (IEA, 2008a)- this is sometimes held up as an example of the lack of energy security by diversifying into coal. There are two arguments to counter this: firstly coal can be stored fairly easily and secondly Russian coal is low in sulphur, therefore it helps plants meet sulphur emissions constraints; once plants without FGD are retired, low sulphur coal will not be needed although it might be of benefit to a CCS enabled coal plant as the low sulphur content will result in lower solvent losses during operations.

The price of coal can be broken down into two components: first, the cost of mining the resource and secondly, the cost of transportation to the customer. In general, transport costs make up less than 20% of the total cost. BERR (BERR, 2008a) gives the price of coal to be £36.6/tonne with a calorific value of 25MJ/Kg. The IEA Greenhouse Gas program uses bituminous coal with a gross calorific value of 27.06MJ/kg and a net calorific value of 25.87MJ/kg as a standard in all studies (IEAGHG, 2006a), (IEAGHG, 2006b). Therefore the central values used in this thesis are for bituminous coal at a price of £36.6/tonne and a net calorific value of 25.8MJ/kg.

5.5.4 Plant operating characteristics

The availability of a power plant is defined as the proportion of the year for which the plant is available to operate. At other times the plant will undergo routine maintenance. It should be noted that availability is different to the reliability of the plant, which can sometimes be very high (>99%); this is because reliability is a measure of the amount of time when unplanned maintenance is required and the plant is shut down (also known as unplanned outages). This study has used data from the NERC GADS database, which catalogues all availability factors of plants in North American and numerous other reports and studies (Deutch and Moniz, 2007), (IEAGHG, 2004), (RAEng, 2004}, all seem to indicate that 85% would be an appropriate value for all stations under investigation. For the purposes of this thesis, it is assumed that the plant is "base load" i.e. always generates electricity when it is available. This is not strictly true in the market, as plants tend to vary output depending on market conditions (price of electricity v cost of generation). However, it is likely that new CCS plant will operate base load, in part due to the high capital investment that needs to be serviced and because the plant produces low-carbon electricity. It would be an extraordinary event given current political conditions if, once built, a CCS plant was not run in favour of an unabated fossil fuel plant.

The lifetime of the plant defines the capital loan period and enables a calculation of the amount required to repay the loan. The MIT coal study (Deutch and Moniz, 2007) suggest a figure of 20 years, while the IEA GHG suggests a figure of 25 years. At present 60% of coal fired plants are over 20 years of age (Ambrosini, 2005), and a number of operators have decided to prolong the life of these plants, especially in Europe, until they need to retire in 2016. Therefore a total of 30 years lifetime will have been met by these plants. In the future, advances in preventive maintenance will probably increase the lifetime of plants further still. In addition, it is likely that once operational, CCS plants will be used for as long as is economically viable and given that the plants will produce low-carbon electricity, the likelihood is that this will happen. Therefore, for the purposes of this thesis 30 years is taken as the lifetime of the plants under investigation.

Chapter 4 detailed the thermal efficiencies of the standard PC plant, IGCC plant and oxyfuel plants. The same efficiencies are used in the financial model. Plant efficiency is reported on an LHV basis so as to be consistent with the calorific value of the fuel.

As shown in Chapter 4, for a plant equipped with CCS, the efficiency falls by around 9% for a PC plant, 7% for an IGCC plant and 4% for an oxyfuel plant. This is due to additional energy required to run the capture equipment and compress the CO_2 for transportation.

5.5.5 Price of carbon

The price of carbon is set by the European Union Emissions Trading Scheme (EU-ETS) market, a mechanism through which European governments incentivise the adoption of low carbon generation by setting carbon targets. Although in operation prior to 2005, 2005 signalled the first phase of the EU-ETS that tied in with the Kyoto Protocol. The objective of the EU-ETS is to facilitate the reduction of CO_2

emissions from European countries in market based manner to meet emissions targets set out in the Kyoto Protocol. At present, the EU-ETS is split into 3 phases. Phase 1 ran from 2005-2007, while phase 2 runs from 2008 -2012. The third phase of the EU-ETS will be from 2013 onwards; there is still consultation over the details (e.g. entities to be included) and timescale of the third phase.

At present, the EU-ETS covers all industrial installations with a thermal capacity of over 20MW in member states. The result is that power plants and large industrial plants (steel works) are covered by the scheme. The driving force behind the EU-ETS is that a price is assigned to carbon emissions, thereby forcing certain industrial sectors to buy and sell carbon emissions allowances (aka Emissions allocation unit (EAU)) based on their own emissions. The quota of emissions for individual countries is set by national allocation programmes (NAP), which ostensibly ensure that the total emissions of a country meet long term emissions goals (currently for the UK these are 60% reduction on 1990 levels by 2020). The idea is that efficient entities will sell emissions to inefficient entities for a certain price. The price is a function of supply (from the NAP) and demand (from the entities covered by the scheme). In theory as supply of emissions permits reduce (in accordance with reductions in NAP) the price of carbon should increase. At some point, the price of carbon will make it financially viable for companies to switch to forms of low-carbon generation. The decision to wait or to make an investment in low-carbon technology is an investment question that the individual entity must answer.

National allocations of permits are set by individual member states and cover the sectors that are to be involved in the emissions trading scheme. National allocation permits are set at the beginning of each phase. Emissions permits, that represent emissions of one tonne of CO_2 are then given or auctioned to individual entities at the start of trading periods covered by the scheme. The entities can then choose to buy more emissions permits or to sell the permits they hold in the market to another entity. Permits that are unused in one EU-ETS period can be rolled over into the next period, but allocations cannot be brought forward from future periods to the present. In addition, multinational companies can move emissions credits from operations in one EU country to operations in another EU country. As a result, the idea is that emissions will be reassigned to those most unable to improve emissions performance, while those that can improve emissions performance fairly easily will do so; the incentive being the revenue generated from selling emissions permits.

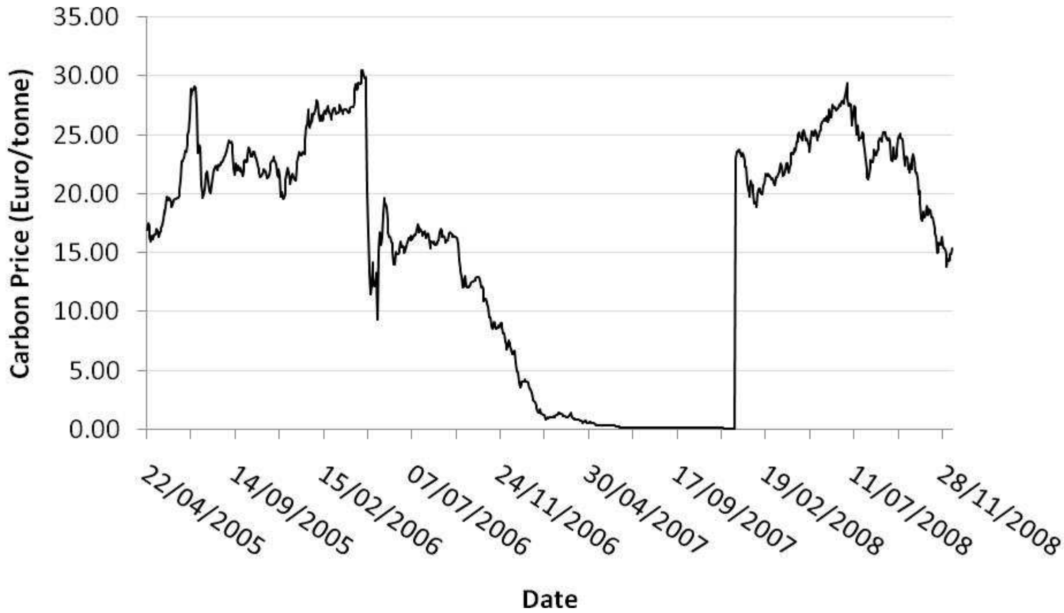


Figure 5-2: Historical year ahead carbon price (Data source: (ECX, 2008))

Figure 5-2 shows the historical year-ahead futures price for carbon dioxide from 2005 to present. The first point to note is that the price of carbon is not constant; it can be observed that the end of the first phase (2007) signalled a crash in the price of CO_2. This is because market participants realised that governments had over allocated emissions permits for the first phase of the programme, thereby creating excess supply and devaluing the price of EUAs. As the price of carbon is supposed to provide the incentive to switch to low-carbon generation, crashes in the carbon price cause investors to worry whether investment in low-carbon generation will generate sufficient returns. Therefore, with the beginning of the second phase, banking of EUA's is allowed between phases i.e. unused permits in phase two can be banked and used in phase three. This is in part to try and stop the sudden drop (or spike) in CO_2 price at the end of the phase. Some analysts have speculated that the price of CO_2 will therefore follow a long term upward trend, with the final price being that which will incentivise CCS (Lewis, 2008), however; as shown in the discussion, the price will not be sufficient to encourage a shift from gas to coal with CCS.

The price of carbon in the standard case is 16.5 £/tonne (equivalent to 22 euro/tonne) (FT, 2008). This assumption reflects in part the propensity of national governments to over allocate emissions to industry, although it is likely in the long term that restricted national allocations will be enforced by the European Commission.

5.5.6 CCS transport and storage cost

This Section applies to the CCS model only. As discussed in Chapter 4, once CO_2 has been captured and compressed, it must be transported to a suitable storage site and injected into the ground. Once in storage, the CO_2 must be monitored for leaks and other potential hazards.

The cost of transporting CO_2 depends on the mode of transport used and the distance to the storage site (IPCC, 2005), while the cost of storage represents the cost of monitoring and ensuring no leakages occur. In the event that CCS is deployed in the UK on a significant scale, there are likely to be significant engineering challenges in building the pipe network to transport the CO_2 from power station to injection point.

The IPCC report gives a range of \$0.6-\$8.3/tonne CO_2 stored (IPCC, 2005). Monitoring costs can be found in Benson et al (Benson et al., 2005) where it is shown that monitoring costs for 30 years varies between \$0.05/tCO_2 using a discount rate of 10%. In addition, increasing the monitoring period to 1000 years adds 10% onto the discounted cost using a discount rate of 1% for the additional years.

It is possible to offset part of the cost of CCS by using the CO_2 to displace oil or gas reserves in an existing field. Most of the projects operating commercial scale sequestration of CO_2 use the gas to get more oil or gas from a depleted field e.g. Sleipner and In Salah both use CO_2 for enhanced gas recovery. Revenue from the sale of gas or oil can then improve the project economics of CCS. However, in the longer term, and in order for CCS to become deployable on a national level, CCS will need to be viable without enhanced oil or gas recovery- there are simply not enough depleted fields to satisfy a large CCS infrastructure. Therefore this thesis does not take revenue from EOR or EGR into account. However, it is noted that EOR and EGR have the potential to provide CCS plants with the revenue needed to make the process viable under the correct circumstances (high fossil fuel price and carbon price).
For the purposes of this thesis, it is assumed that the CO_2 will be transported by ship/offshore pipe to a distance of 500km with the storage field located somewhere in the North Sea. Using data from the IPCC report (IPCC, 2005) gives a value of \$12/tonne CO_2 transported and stored, which includes the cost of monitoring and equates to approximately £7.01/tonne CO_2 transported and stored. This total equates to £5.73/MWh additional cost of generation for a PC plant with CCS installed, depending on the amount of CO_2 produced per MWh. A report produced for BERR derived an average cost of £6/tonne of CO_2 transported and stored for the UK (Element et al., 2007). This cost for transport and storage is slightly lower than the cost assumed in this thesis and is probably due to the additional cost of monitoring that has been assumed.

5.6 Gas pricing model

The minimum price of electricity generated from gas, $G_{t\ (min)}$ can be derived from the global cost model and is given by:

$$G_{t(min)} = \frac{(C_{c(g)} \cdot C_{cd} \cdot \delta_c) + (C_{c(g)} \cdot C_{ce} \cdot \delta_e) + C_{o\&m(g)}}{hr_{yr} \times U_{t(g)} \times P_{c(g)}} + C_{f(gas)} + C_{E(gas)} \tag{5.13}$$

Where:

$G_{t(min)}$: the minimum annual revenue to break even for a CCGT plant (£/year)

$C_{c(g)}$: total capital cost of CCGT plant (£)

C_{cd} : capital investment for construction financed by debt (£)

δ_c : capital recovery factor for construction financed by debt $(year)^{-1}$

C_{ce} : capital investment for construction financed by equity (£)

δ_e : equity recovery factor $(year)^{-1}$

$C_{o+m(g)}$: Annual operations costs for a CCGT (£/year)

hr_{year} : hours per year(hours/year)

$U_{t(g)}$: capacity factor of CCGT plant (%)

P_c : rated output capacity of plant(MW)

$C_{f(gas)}$: Fuel costs per unit of electricity generated (£/MWh)

$C_{E(gas)}$: Emissions costs per unit of electricity generated(£/MWh)

Fuel cost is given by the expression:

$$G_{f(g)} = \frac{C_{therm}}{0.02931 \times Eff_{plant}} \tag{5.14}$$

Where:

$C_{f(gas)}$: Fuel costs per unit of electricity generated (£/MWh)

C_{therm} : price of natural gas (£/therm)

0.02931 : conversion from therms to MWh (MWh/therm)

Eff_{plant} : thermal efficiency of CCGT plant

If annual fuel costs were to be calculated, it would be necessary to multiply equation (5.14) by the number of MWh produced by the plant in a year.

Many reports state emissions of CO_2 (kg/MWh) from CCGT plants on the basis of a single plant efficiency (e.g. 350g/kWh at 60% LHV). A more useful and versatile approach is to incorporate the emissions of CO_2 as a function of the plant efficiency, thereby allowing a comparison of the impact of different plant efficiencies on CO_2 emissions:

$$C_{E(gas)} = C_{carbon} \times (1-\eta_{capture})\left(e.f. \times \dot{m}_{f(gas)} \times 105.5(MJ\ /\ therm)\right) \tag{5.15}$$

Where:

$C_{E(gas)}$: the cost of buying emissions credits for a MWh of operation (£/MWh)

C_{carbon} : the cost of carbon on the market (£/tonne)

$\eta_{capture}$: the efficiency of the capture process

e.f. : the emissions factor; 0.05797kgCO_2/MJ natural gas

$m_{f(gas)}$: the rate at which fuel is burnt (therm/MWh)

The emissions factor in this thesis is derived from the emissions factor reported in the report estimating CO_2 emissions factors by Transco for the UK government (Transco, 2004). The adjustment reflects the use of LHV of natural gas (divide by 0.904) in this thesis. When considering a CCGT plant with an LHV of 55%, the methodology gives a CO_2 emissions rate of 379.3kg/MWh, which compares well to that given in the IPCC reports (IPCC, 2005) (for a plant efficiency of 55.1%, the emissions rate is 379kgCO_2/KWh).

As CCGT plants with CCS will also be included in the analysis, the cost of carbon transport and storage, C_{TS}, is also included to give:

$$G_{t(min)} = \frac{(C_{c(g)} \cdot C_{cd} \cdot \delta_c) + (C_{c(g)} \cdot C_{ce} \cdot \delta_e) + C_{o\&m(g)}}{hr_{yr} \times U_{t(g)} \times P_{c(g)}} + C_{f(gas)} + C_{E(gas)} + C_{TS} \tag{5.16}$$

5.7 Gas model data

The combined cycle gas turbine (CCGT) plant is widely considered to be the plant of choice for electricity generation from fossil fuels in the UK (Watson, 2004). Numerous factors have propelled CCGT plant into a position of market dominance. Firstly, the capital cost of a CCGT plant is much less (on a kW installed basis) than that for other fossil fuel plants. In addition, the construction time of a natural gas plant is around 2-3 years, compared to 4-6 for a coal fired station (Watson, 2004). Moreover, CCGT plants are modular in nature, allowing staged build to take place. Advantageous operational characteristics include plant flexibility; CCGT plants are able to increase and decrease output relatively easily, and can therefore act as peaking plants, although there are reports that older coal plant can also alter output relatively quickly (ATCO, 2008). Finally, CCGT plant has seen large increases in efficiency of its two cycle system (Brayton and Rankine) since being introduced into markets in the nineties, when the low price of gas helped it to break into the market. The first cycle, the Brayton cycle uses combustion products of gas to drive a turbine, while the exhaust gas is used in a second stage (Rankine cycle) to heat water to drive a steam turbine (the second stage is sometimes called heat recovery and steam generation (HRSG)). This also means that emissions are low for a fossil fuel plant, which means that CCGT plants are well placed to help reduce carbon emissions from the electricity generation sector.

If coal with CCS is to play a significant role in the UK energy market, it will need to compete against CCGT plant. The purpose of this Section is to construct a cost model to value the cost of generation from a CCGT (with and without CCS) and compare this to a coal plant with and without CCS. The following Section reports the results of a literature review to provide cost input data for standard and CCS enabled CCGT plants. The objective is to be as transparent as possible in using data sources to derive cost of generation.

The capture processes applicable to CCGT plants follow the same lines as those for coal plants and include: post combustion capture, pre-combustion decarbonisation and firing in oxygen (oxyfuel) also known as the Advanced Zero Emissions Plant (AZEP). A full treatment of all capture concepts applied to CCGT plant is outside the scope of this thesis; the objective of using a CCGT plant with CCS in this Chapter is to facilitate a comparison between CCGT plant with and without CCS in order to explain why gas plants will switch to CCS later than coal plants. Therefore, a single type of CCS plant will be considered. Of all of the concepts, the most advanced appears to be post combustion capture of CO_2 with amine solvents(IPCC, 2005), which also has the lowest performance penalty associated with capture (Bolland and Undrum, 2003) and as a result, CCGT plant with post combustion capture is used as the indicative CCGT CCS plant.

5.7.1 Construction costs and financing

The capital costs given in this Section are in line with the assumptions laid out in Section 5.5.1. In recent years, a significant number of reports and papers have been written covering capital costs of CCGT plants. Watson (Watson, 2004) identifies capital cost as £300 per kW, Morgan Stanley (Stanley, 2005) as £350 per kW and Platts (Platts, 2003) as £400 per kW. Latest capital costs based on a 1 GW plant would indicate that £400 per kW should be used.

CCGT plants with post combustion CCS have been widely reported in the literature. Data has been taken from the IEA GHG reports (IEAGHG, 2005), CCP (CCP, 2005) and the study undertaken by Rubin et al (Rubin et al., 2005). A summary of all capital cost data is presented in Table 5-3.

Table 5-3: Capital costs for CCGT plant with and without CCS

Plant	Min (£/kW)	Max (£/kW)	Average (£/kW)
CCGT	311	470	364
CCGT_CCS	590	819	660

The finance structure for the CCGT plant is identical to that for the coal model: a debt/equity ratio of 70% debt (senior only) and 30% equity is used.

5.7.2 Operations and management cost

The definition of operations and management costs follows that given in Section 5.5.2. The cost of operations and management are lower for a CCGT plant than for a coal fired plant. Marsh, (Marsh, 2003); Morgan Stanley (Stanley, 2005); OXERA, (OXERA, 2005); RAEng, (PBPower, 2004); Cousins and Hepburn (Cousins and Hepburn, 2005) all agree that the costs for O&M amounts to around 0.027£/kW.

The cost of operations and management increase significantly for plants with CCS, O&M costs roughly double to 0.052£/kW based on figures from the IPCC (IPCC, 2005), and IEAGHG program (IEAGHG, 2005), (Abadie and Chamorro, 2008a).

5.7.3 Fuel cost

In the UK, gas prices are determined at a regional (UK) level and are determined at the national balancing point (NBP hub). This is in contrast to other counties in Europe which rely on long term price agreements between suppliers and consumers (with contracts usually indexed to the price of oil, which is a global commodity). The result is that UK gas prices are fixed by supply and demand, but are also correlated to oil prices.

The graph below shows the spot price of natural gas over the past 10 years. As can be seen, the price of gas exhibits a general upward trend, but on a day to day basis is highly volatile; the underlying behavior of natural gas is a key part to the options model presented in Chapter 6, therefore, a more complete discussion of the trajectory of future gas prices can be found in that Chapter.

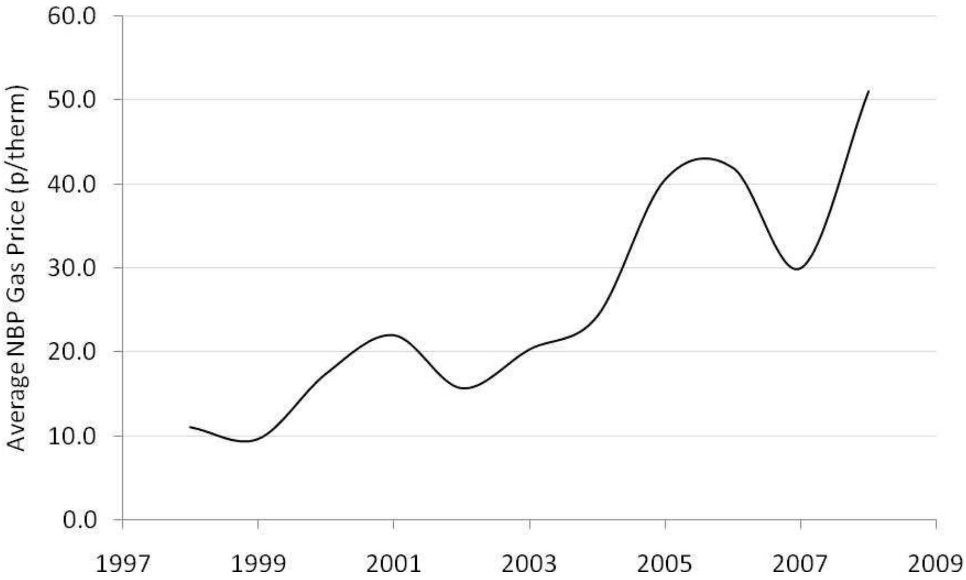


Figure 5-3: Average yearly NBP gas price in 2007 money (Data Source: (BERR, 2008b))

In order to protect themselves against gas price volatility, generators hedge gas supplies up to two years in advance, and in addition decrease their exposure to gas spot prices resulting in no (or very little) exposure to prices in the short term (ATCO, 2008).

BERR long range gas price estimates give a price between 21p/therm and 53 p/therm (BERR, 2008a), while the price of gas in May 2007 was £0.246/therm. Gas is sold on the UK market in p/therm, but the therm is measured on a higher heating value basis. As all of the plant efficiencies used in this thesis are in LHV, it is necessary to convert the price into an LHV basis- this is done by dividing the market price by 0.9 (ATCO, 2008).

5.7.4 Plant operating characteristics

The assumptions qualifying operating characteristics for CCGT plants are the same as those laid out in Section 5.5.4. In general, CCGT plants have high availability factors (Watson, 2004). Major maintenance takes place around every six years and involves the replacement of the gas turbine blades are replaced (ATCO, 2008). The IEAGHG report gives a capacity factor value of 85% (IEAGHG, 2005), as do the NETL (NETL, 2002), and PB Power (PBPower, 2004). Some studies, such as Rubin et al (Rubin et al., 2005), give two values of capacity factor, one high (>80%) and the other around 50% in order to illustrate that many CCGT plants do not operate as base load plants, but as mid-merit plants i.e. the plants come on and off line when market conditions are advantageous. The CCGT plant is particularly suited to this due to its relatively short start up time and its ability to ramp up (produce more) or ramp down (produce less) power with short notice (Watson, 2004). Such cyclic operations allow maximum value to be gained from a profit point of view, but can lead to more wear on turbine components and hence a shorter life expectancy than coal fired plants (ATCO, 2008); 25 years appears to be the accepted value (PBPower, 2004).

The combined cycle aspect of the CCGT plant leads to plants having the highest electrical output efficiencies of fossil fuel plants (Watson, 2004). Thermal efficiencies of CCGT plant are currently reported as being around 55% (IEAGHG, 2005), (Parsons, 2002), (Rubin et al., 2005), with some estimates up to 58% (PBPower, 2004). Future estimates of CCGT plant efficiency are in excess of 60%(PBPower, 2004). For the purposes of this thesis, 55% is used as the LHV efficiency of the plant; partly on advice received from ATCO Power cautioning against some of the higher plant efficiencies used in some studies (ATCO, 2008).

As shown in Chapter 4, the installation of post combustion on a coal plant causes efficiency to fall due to the extra energy required to drive the capture process, regenerate the solvent and compress the CO_2. Most studies quote a value of between 7.7% and 8.2% as a performance penalty (IEAGHG, 2005), (Rubin et al., 2005), (Parsons, 2002), (NETL, 2002), (CCP, 2005), all of which investigated CCGT plant with post combustion capture using MEA solvent. A good representative value therefore appears to be around 8%.

5.8 Cost model data

The numerical values of the terms in expressions (5.9), (5.12) and (5.13) for the minimum price of coal and gas generated power from various types of power plant with and without CCS are given in Table 5-4.

Table 5-4: Input data for cost model (costs derived by author from the literature)

	PC No CCS	IGCC	Oxyfuel	CCGT	PC CCS	IGCC CCS	Oxyfuel CCS	CCGT CCS
Construction cost $\mathbf{C_c}$ £/MW	900000	1000000	950000	400000	1350000	1530000	1400000	660000
Plant Efficiency	44%	44%	40%	55%	35%	37%	36%	47%
Debt financing discount rate **r**	8%	8%	8%	8%	8%	8%	8%	8%
Return on equity **ROE**	15%	15%	15%	15%	15%	15%	15%	15%
Debt ratio	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Equity ratio	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Operations and maintenance cost $\mathbf{C_{o\&m}}$ £/MW	24000	48000	35000	15000	40800	63360	40800	30000
Cost of fuel $\mathbf{C_f}$	£36.6/tonne	£36.6/tonne	£36.6/tonne	£0.29/therm	£36.6/tonne	£36.6/tonne	£36.6/tonne	£0.24/therm
Plant capacity **Pc** MW	500	500	500	500	500	500	500	500
Plant load factor **Ut**	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Plant life **t** years	30	30	30	25	30	30	30	25
Capture efficiency					90%	90%	90%	90%
Cost of carbon £/tonne	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5
Cost of transport and storage £/tonne					7.5	7.5	7.5	7.5

5.9 Cost of CO_2 avoided and captured

In addition to comparing the cost of generation, the specific avoidance cost or the cost of CO_2 avoided is defined as the difference between the cost of generation for a standard plant and the cost of generation from a CCS enabled plant divided by the difference in CO_2 emissions from the respective plants (Hendricks et al., 2004). As a result it is possible to compare the cost of the amount of CO_2 saved between a plant without CCS and a plant with CCS. The equation for the cost of CO_2 avoided, $C_{avoided}$:

$$C_{avoided} = \frac{\sum C_{coal\_CCS} - \sum C_{coal}}{E_{coal} - E_{coal\_CCS}} \tag{5.17}$$

Where:

$C_{avoided}$: cost of CO_2 avoided (£/tonne)

C_{coal_CCS} : cost of generation from coal with CCS (£/year)

C_{coal} : cost of generation from coal (£/year)

E_{coal} : emissions from coal plant (tonnes/year)

E_{coal_CCS} : emissions from CCS plant (tonnes/year)

An alternative approach to calculate the cost of CO_2 avoided is shown below, this proves to be useful if an analysis of marginal costs is required. The CO_2 emissions from a standard plant are a function of the amount of fuel that is required to meet the required electricity output and the emissions factor for the fuel in question. To find the CO_2 emissions from a plant on hourly basis, equation (5.10) is multiplied by an emissions factor, e.f.:

$$E_{CO_2} = \left(\frac{P_c \cdot 3600}{\eta_1 \cdot cv} \right) \cdot e.f. \tag{5.18}$$

Where:

E_{CO2} : Emissions of CO_2 (kg/hour)

P_c : Plant capacity (MW)

η_1 : The efficiency of the standard plant

cv : Calorific Value of the fuel (MJ/kg)

e.f. : Emissions factor of the fuel (kgCO_2/kgfuel)

3600 : number of seconds per hour

When CCS is installed, the CO_2 emissions are given by

$$E_{co_2}{}' = \eta_{capture} \cdot \left(e.f. \frac{P_c \cdot 3600}{\eta_2 \cdot cv} \right) \tag{5.19}$$

Where:

E_{CO2}' : emissions of CO_2 from a CCS enabled plant (kg/hour)

$\eta_{capture}$: efficiency of the capture process

P_c : plant capacity (MW)

η_2 : efficiency of the CCS enabled plant

cv : calorific value of the fuel (MJ/kg)

e.f. : emissions factor of the fuel ($kgCO_2/kgfuel$)

3600 : number of seconds per hour

If the electrical output of the plants is the same, the amount of CO_2 captured by the capture process is given by:

$$E_{CO_2\_cap} = E_{CO_2} \cdot \left(\frac{\eta_1}{\eta_2}\right) \cdot \eta_{capture} \tag{5.20}$$

Whilst the emissions to atmosphere from a CCS plant are given by the expression:

$$E_{CO_2\_CCS} = (1-\eta_{capture}) \cdot E_{CO_2} \cdot \left(\frac{\eta_1}{\eta_2}\right) \tag{5.21}$$

And therefore the amount of CO_2 avoided is:

$$E_{CO_2\_CCS\_avoided} = \left[1-(1-\eta_{capture})\left(\frac{\eta_1}{\eta_2}\right)\right] E_{CO_2} \tag{5.22}$$

This is because the amount of CO_2 avoided is the difference between the emissions from a normal plant and a CCS enabled plant, as shown in the diagram below, where the lightly shaded area corresponds to the CO_2 emissions captured and the red line indicates the CO_2 emissions that are avoided:

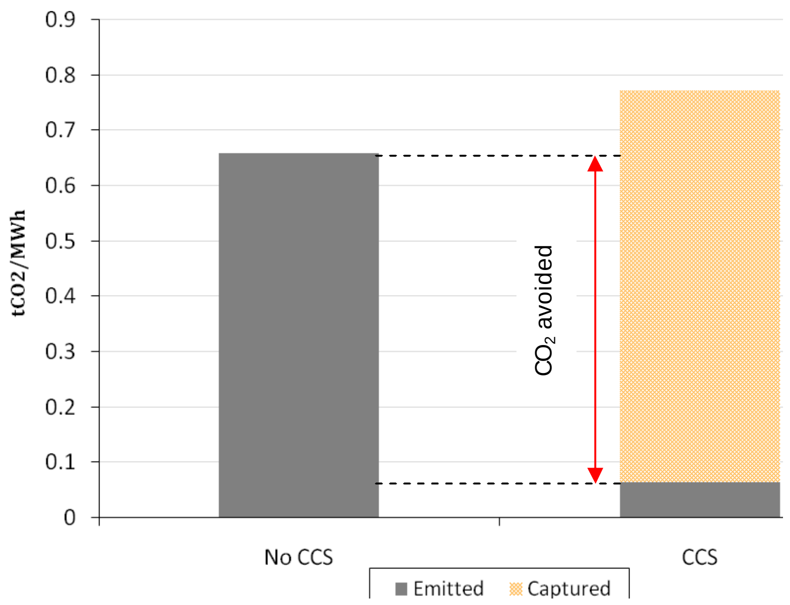


Figure 5-4: Illustration of CO_2 avoided

It is the difference shown by the red line in Figure 5-4 that needs to be compensated for by the price of carbon. Figure 5-4 clearly shows that care has to be taken when comparing the standard plant and CCS enabled plant as the amount of CO_2 emitted from a CCS plant is due to the performance penalty imposed by the operation of the capture process. As a result, the denominator in equation (5.17) reduces accordingly which implies a higher cost of CO_2 would be required than first anticipated to make the capture process viable. This process also serves as a check on the model presented in Section 5.4, as the cost of CO_2 avoided can be derived via either method.

Another measure of the cost of carbon abatement, in comparison to the cost of CO_2 avoided, is the cost of CO_2 captured. CO_2 captured is different to CO_2 avoided as it calculates the price of CO2 that must be set by the market to compensate for the installation of a capture process; in this sense, the cost of CO_2 captured is not a comparative measure, as opposed to the cost of CO_2 avoided.

$$C_{captured} = \frac{C_{coal\_CCS} - C_{coal}}{CO_2\ Captured} \tag{5.23}$$

As can be seen from equation (5.23) and Figure 5-5, the cost of CO2 captured is less than the cost of CO_2 avoided, as the denominator will always be greater.

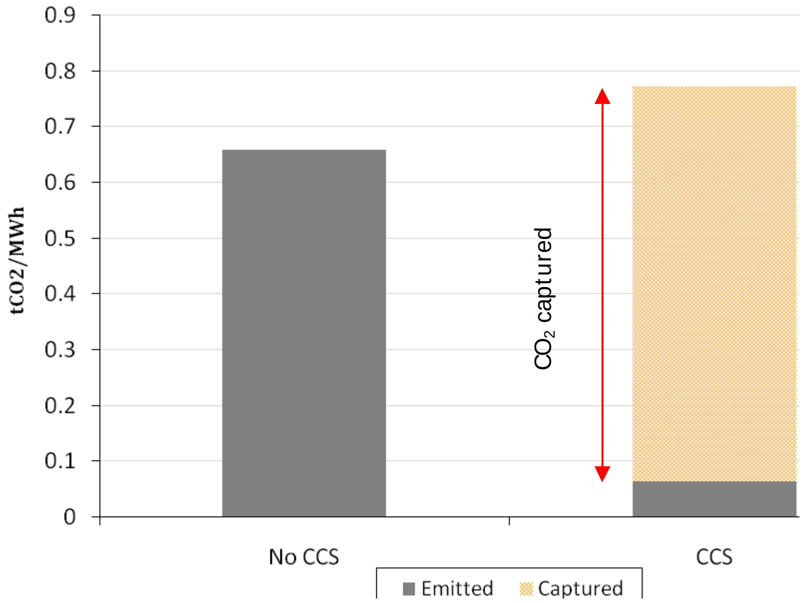


Figure 5-5: Illustration of CO_2 captured

The difference between the two methods presented above is that CO_2 avoided calculates the cost incurred for a CCS plant to produce the same electrical output as a standard plant. The CO_2 captured metric gives the amount that CO_2 must cost to compensate for the installation of CCS on a plant; the point being that the former method references the emissions of a non capture reference plant while the latter does not.

5.10 Results and discussion

Section 5.10 presents the results of the cost model along with a discussion of the implications for the power plants under investigation. Each of the plants is dealt with in turn; first coal and then gas, followed by a comparison of plants and a sensitivity analysis. Finally, a discussion of the methodology and limitations of the approach are given.

Putting the values in Table 5-4 into equations(5.9), (5.10) and (5.11) yields the results shown in Table 5-5.

Table 5-5: Results of cost model for power plants under investigation

	No Carbon Penalty	Carbon Penalty (16.5£/tonne)	Carbon Penalty (30£/tonne)
CCGT	24.22	30.00	34.72
PC	28.30	40.24	50.02
IGCC	32.01	43.96	53.73
Oxyfuel	30.96	44.10	54.85
CCGT_CCS	34.81	35.43	35.94
PC_CCS	44.71	46.21	47.44
IGCC_CCS	49.33	50.75	51.91
Oxyfuel_CCS	44.70	46.14	47.32

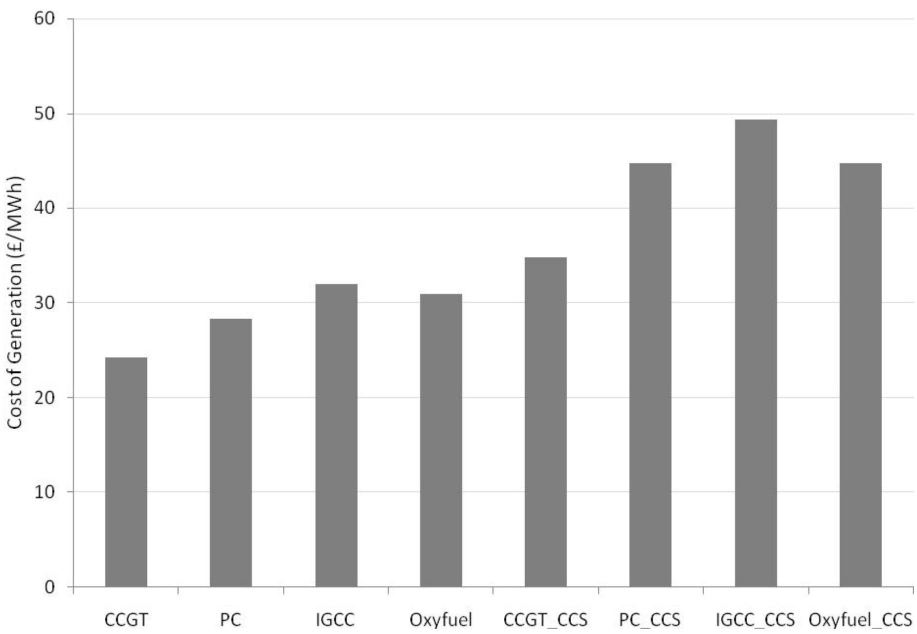


Figure 5-6: Cost of generation without a carbon penalty

Table 5-5 presents the cost of generation for the power plants under investigation for low (zero), medium and high carbon price. Figure 5-6 shows the cost of the power plants under the no carbon penalty scenario. As can be seen, the cost of generation from power plants with CCS is significantly greater than for those without CCS. In addition, the cost of generation for a normal plant is least for the CCGT plant, while for a CCS enabled plant, the CCGT with CCS once again offers the lowest cost of generation.

PC plant is the cheapest coal plant in the standard state, followed by IGCC and then oxyfuel plant. When CCS is added to the coal plant, PC plant and oxyfuel plant appear to be roughly equal. The reason for oxyfuel becoming more competitive when CCS is taken into account is due to the relatively minor adjustments that need to be made to the plant to enable capture of CO_2; more specifically, no extra chemical processes need to be installed so the additional cost is lower than for PC or IGCC plants.

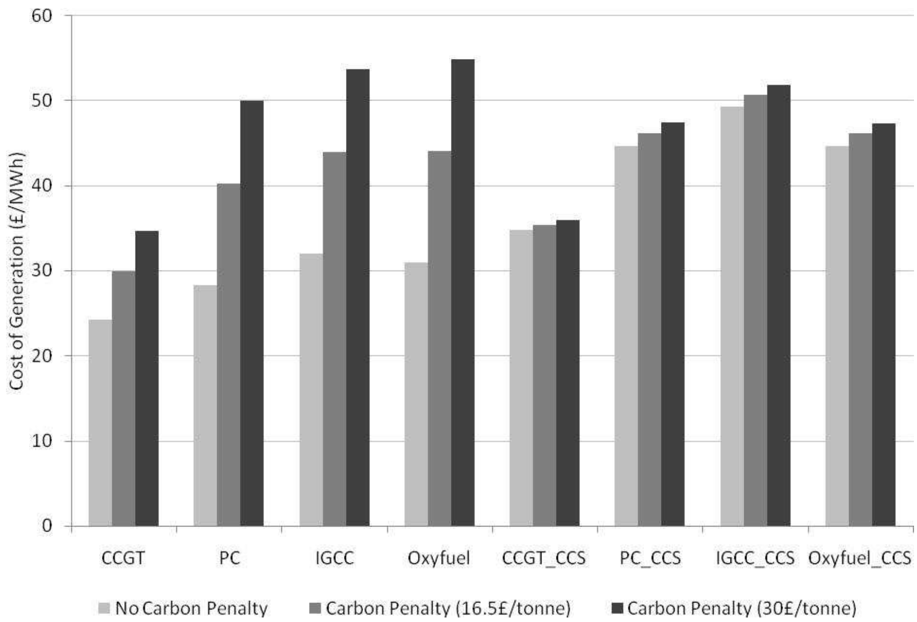


Figure 5-7: Cost of generation with varying carbon penalties

Figure 5-7 communicates a number of messages. Firstly, carbon price has a significant impact on coal fired plants and to a lesser extent, to the CCGT plant in the standard configuration. The reason for this is the emissions factor or the amount of CO_2 released per unit of coal combusted is roughly 2.5 times that of natural gas. The addition of CCS to a coal or natural gas fired power plant reduces the exposure of the plant to the price of carbon, as can be observed by comparing the left and right hand sides of Figure 5-7; the incremental cost of generation under the different carbon penalties for plants without CCS is far greater than the incremental cost for plants with CCS installed. Secondly, the only financial incentive for installing CCS is to reduce exposure to the price of carbon. Looked at the other way round, this implies that the price of carbon must compensate for all of the additional costs and performance penalties incurred by construction and operation of the CCS system. In addition, an oxyfuel plant in the standard configuration is the most exposed to increases in carbon price. This is due to the lower plant efficiency, which means that more coal must be burnt to produce the required output than for IGCC and PC plants and hence more CO_2 is released.

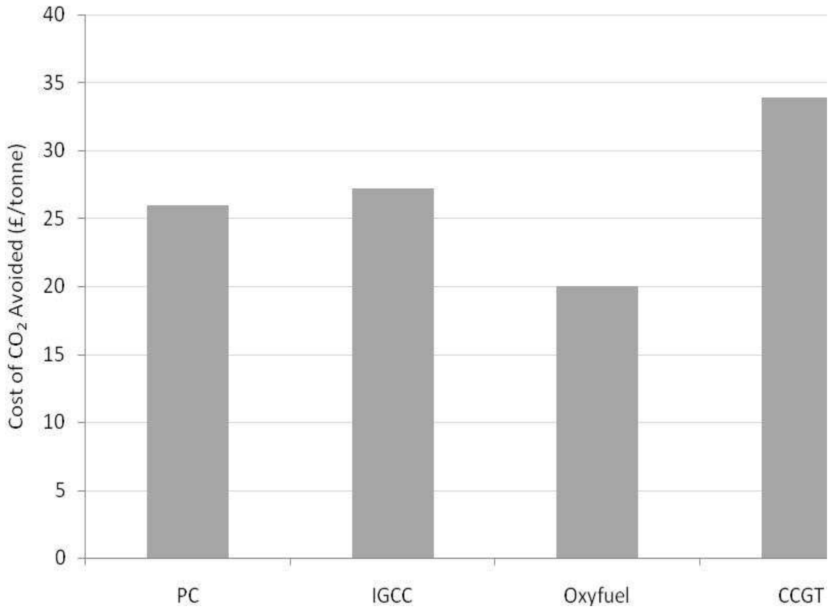


Figure 5-8: Cost of CO_2 avoided

The result of the cost of CO_2 avoided calculation is shown in Figure 5-8. CCGT plants have the greatest cost of CO_2 avoided, due to the low amount of CO_2 captured in relation to a coal plant, while the cost of CO_2 avoided is nearly the same for PC and IGCC plant, while oxyfuel exhibits a lower cost of capture. This is due to the relatively low additional cost incurred by building a CCS enabled oxyfuel plant rather than a standard plant.

Figure 5-8 also shows that the lower performance penalty associated with installing CCS on an IGCC plant does not more than compensate for the increase in capital cost associated with installing CCS on a PC plant. Therefore, reducing the performance penalty associated with installing CCS will not compensate for the difference in generation costs. Therefore, the efficiency of the plant will have to increase and the capital costs will have to decrease for an IGCC plant to become competitive with a PC pant, all other things being equal.

Figure 5-9 shows the cost of CO_2 captured. The values of the cost of CO_2 captured are lower than the cost of CO_2 avoided, primarily due to the larger denominator, as CO_2 emissions from a reference plant are not part of the equation. However, the denominator would alter if the plants under investigation were to have different values of $\eta_{capture}$. The reason why IGCC and the PC plants are further apart when using the CO_2 captured metric is because the performance penalty of installing PC plant is greater than that for IGCC plant, therefore proportionally, a PC plant with CCS needs to burn more fuel to meet output than an IGCC plant with CCS. More fuel burnt means more carbon emissions, and therefore a greater amount of carbon emissions are captured, hence the denominator is larger than that for an IGCC plant. In a way the metric discriminates in favour of the PC plant as the emissions from the previous capture free plant do not enter into the equation. As with the cost of CO_2 avoided, CCGT plants have the largest cost of CO_2 captured.

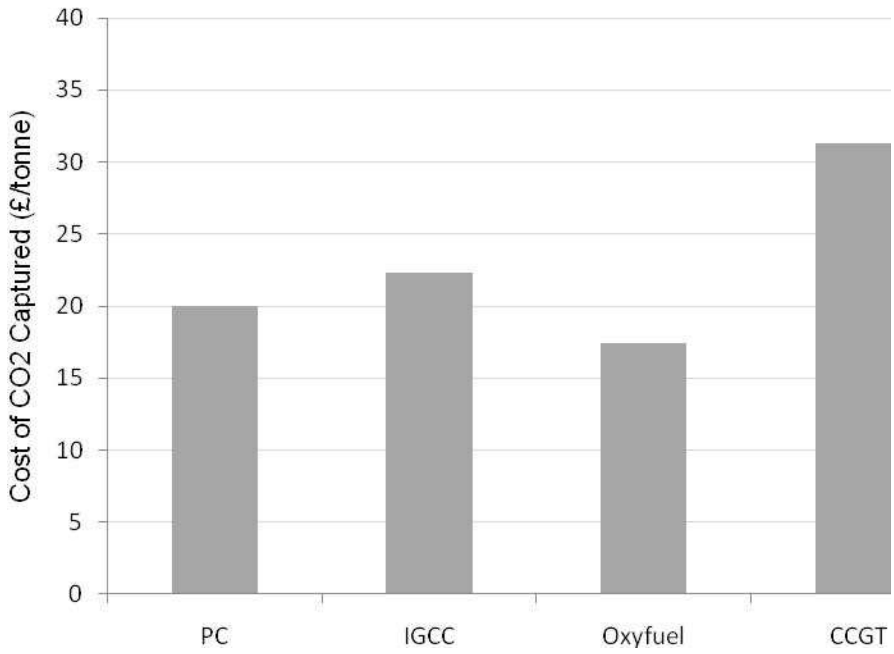


Figure 5-9: Cost of CO_2 captured

PC plant is one of the leading coal technologies in terms of cost of generation when both standard configurations and CCS enabled configurations are assessed. The reason lies with the base plant itself and the low capital cost coupled with relatively high plant efficiency that has come about as a result of the market penetration of PC technology. As a result, even though PC plant has the highest incremental capital cost when carbon capture is installed (Table 5-4), coupled with the largest performance penalty, the cost of generation from a PC plant is equal to or less than the cost of generation from IGCC and oxyfuel plants. In terms of cost of CO_2 captured and avoided, PC plant is a little cheaper than IGCC plant. This reflects the extra cost that the installation and operation of post combustion capture unit.

The cost of generation from an IGCC plant is greater than that of a PC plant in the standard configuration and has the greatest cost of generation with CCS installed. This occurs even though the performance penalty associated with installing CCS is less than that for a PC plant; 7.2% performance penalty for installing CCS on a IGCC plant compared to a 9% penalty for installing CCS on a PC plant. As a result, for IGCC plant to become competitive, capital costs will have to reduce, as even if IGCC plant had no efficiency penalty for CCS, the cost of generation would be £47.60/MWh, higher than the standard case for PC and oxyfuel plants with CCS.

Oxyfuel plant is the most expensive coal plant for generating electricity in terms of cost of generation in the standard configuration. This is because of the additional cost and performance penalty of the air separation unit (ASU) that needs to be installed and operated. As a result, it appears that oxyfuel plant is not a viable technology for electricity generation in the standard configuration. However, when an oxyfuel plant with CCS is considered, the cost of generation is roughly the same as that for a PC plant with CCS. This is because no extra chemical processes need to be installed and operated to allow a oxyfuel plant to capture CO_2, the only extra process equipment is that required for compression of the CO_2 itself. As a result, the cost of CO_2 avoided and CO_2 captured is lower for an oxyfuel plant than for all other plants (Figure 5-8, Figure 5-9). In conclusion, it is probably not viable to build a standard oxyfuel plant at all- the only time an oxyfuel plant becomes viable is when CCS plant must be built. As a result, the application of the cost of CO_2 avoided or CO_2 captured metric could be seen to be a little misleading as a reference plant without CCS is included in the calculation.

CCGT plant has the lowest cost of generation in the standard layout and also the lowest cost of generation in the CCS configuration. However, the cost of CO_2 avoided and CO_2 captured are significantly higher than for other plants (Figure 5-8and Figure 5-9). The cost of CO_2 avoided represents the cost of capture in relation to a standard plant and therefore the price of carbon that is required in order for the capture process to be installed. Although the cost of generation from CCGT with CCS is less than that of coal plant with CCS, the cost of CO_2 captured and cost of CO_2 avoided are higher. This implies two points:

1. Coal with CCS will become viable over a standard coal plant at a lower carbon price than a CCGT plant with CCS will become viable over a standard CCGT plant, all other input factors being constant.
2. Following on from the first point; the price of CO_2 will need to be higher in order to switch from a CCGT to a CCGT with CCS.

The implications of this are interesting as in the early stages, given constant fuel prices (coal v gas); there will be a switch from coal fired plant to natural gas fired plant, as CCGT plants offer some protection against carbon price. However, if this occurs, ultimately a higher CO_2 price will be required in order for generators to switch to CCGT CCS (due to the cost of CO_2 captured and CO_2 avoided).

Therefore it is the difference between the price of fuel as an input i.e. coal v gas that will determine the deployment of CCS; in the absence of clear long term climate goals i.e. enforcing a capture law by 2020, it could be concluded that in terms of CCS it is fuel price risk that is the main component of the investment decision, not carbon price risk: the differential between coal and gas prices will drive the uptake of CCS.

5.10.1 Sensitivity analysis

As with any system model, input data is determines model results. Therefore a sensitivity analysis has been conducted on the cost model in order to derive the critical input factors to the model for the various power plants under investigation. In addition, although taken as constant, many of the input parameters in this thesis fluctuate over time; indicative values have been used for fuel prices and carbon prices. Therefore, the sensitivity analysis gives an idea of the plants exposure to dynamic costs e.g. fuel and carbon.

The parameters that were chosen for sensitivity analysis were capital cost, fuel cost, carbon cost, interest rates, O&M costs and plant life. Although there were other inputs into the initial cost model e.g. return on equity, they were not investigated as they are assumed to be constant.

The figures below represent a 20% univariate sensitivity analysis. The program sub routine consists of holding all parameters constant except that under investigation and plotting the effect of the variation of the input parameter on the target value (the cost of generation). The results are then displayed in order of impact on the cost of generation, producing a tornado diagram. Implementing this procedure offers a way to judge the most important input parameters for the cost model, compare alternative plants, and observe how the cost sensitivity changes with the introduction of CCS. Tables of the raw data are presented in Appendix E.

Figure 5-10 shows the results for a PC plant in the standard configuration. It is clear that the cost of generation is equally sensitive to capital cost, carbon cost and fuel price.

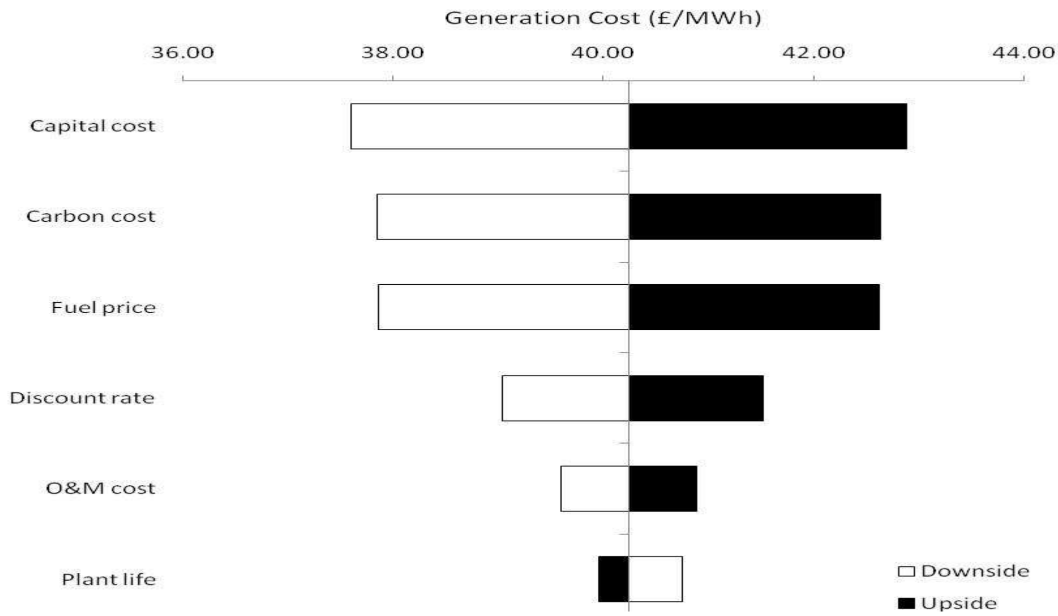


Figure 5-10: 20% sensitivity analysis for a PC plant

Figure 5-11 shows the results of the sensitivity analysis for a PC plant with CCS. As would be expected, sensitivity to carbon price is reduced, however; the capital cost becomes the dominant parameter- far more so than for a standard plant. In addition, sensitivity to fuel price increases due to a reduction in plant efficiency when operating CCS.

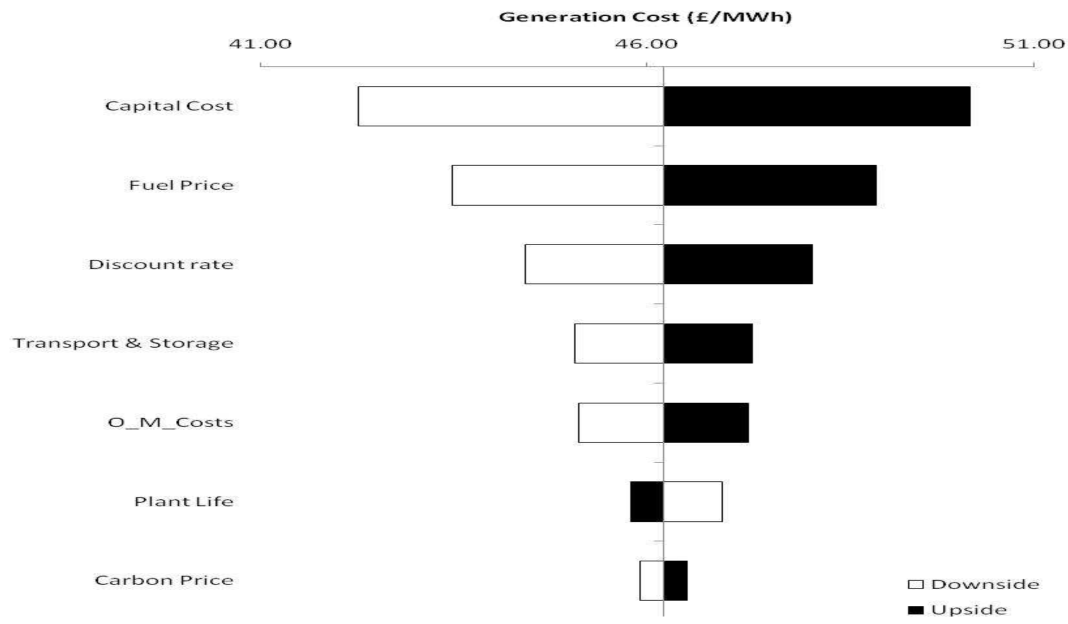


Figure 5-11: 20% Sensitivity analysis for a PC Plant with CCS

Figure 5-12presents the sensitivity analysis for a standard CCGT plant. In contrast to the PC plant (and other coal plants) the cost of generation is dominated by the cost of natural gas. CCGT plant is less sensitive to variations in carbon price due to the plants lower carbon intensity (kg CO2/MWh), while capital costs are also small relative to those of a coal fired plant.

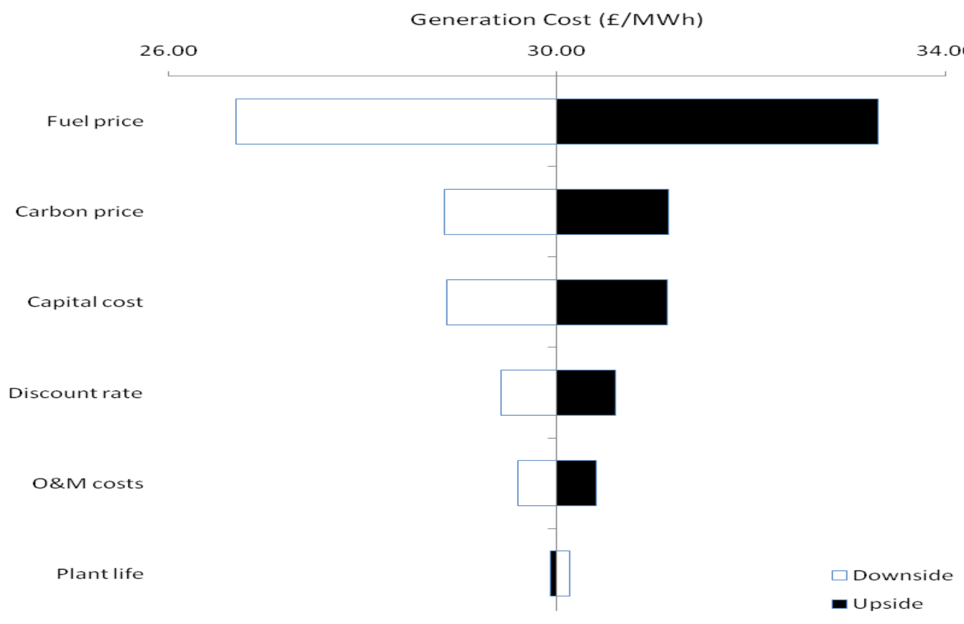


Figure 5-12: 20% Sensitivity analysis for a CCGT

Figure 5-13 shows the sensitivity of a CCGT plant with CCS to input parameters. In contrast to coal plants, fuel cost still dominates, promoted by the increase in fuel consumption to compensate for the CCS efficiency penalty. The capital cost also increases in importance, but not enough to stop the fuel cost dominating the cost of generation.

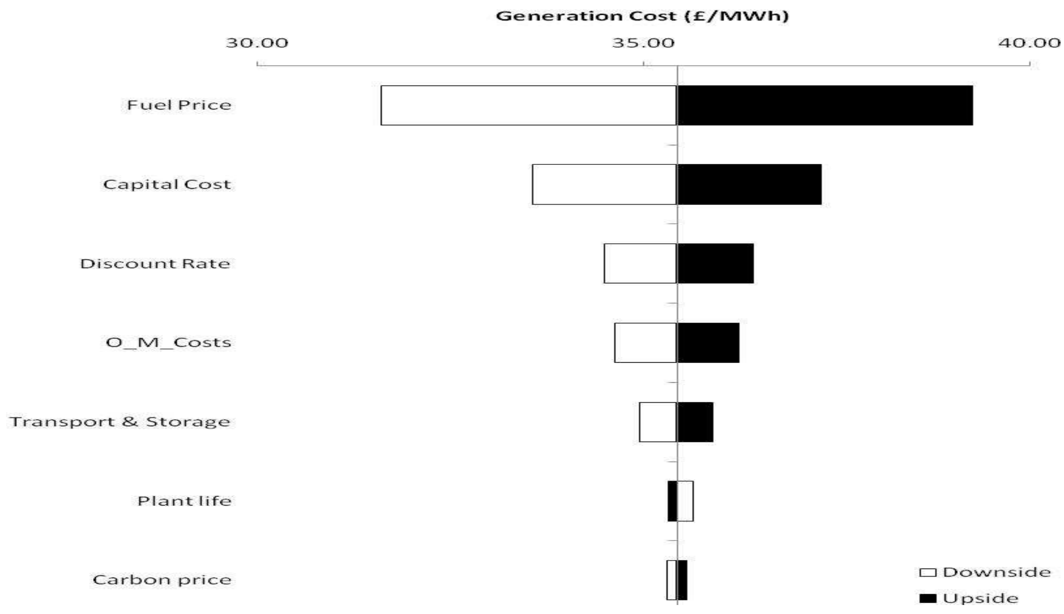


Figure 5-13: 20% Sensitivity analysis for a CCGT plant with CCS

Figure 5-14 presents the results of the analysis of a standard oxyfuel plant. Of all the plants investigated, the standard oxyfuel plant has the most even distribution of input parameters. This is possibly due to the low plant efficiency incurred by operation of the ASU.

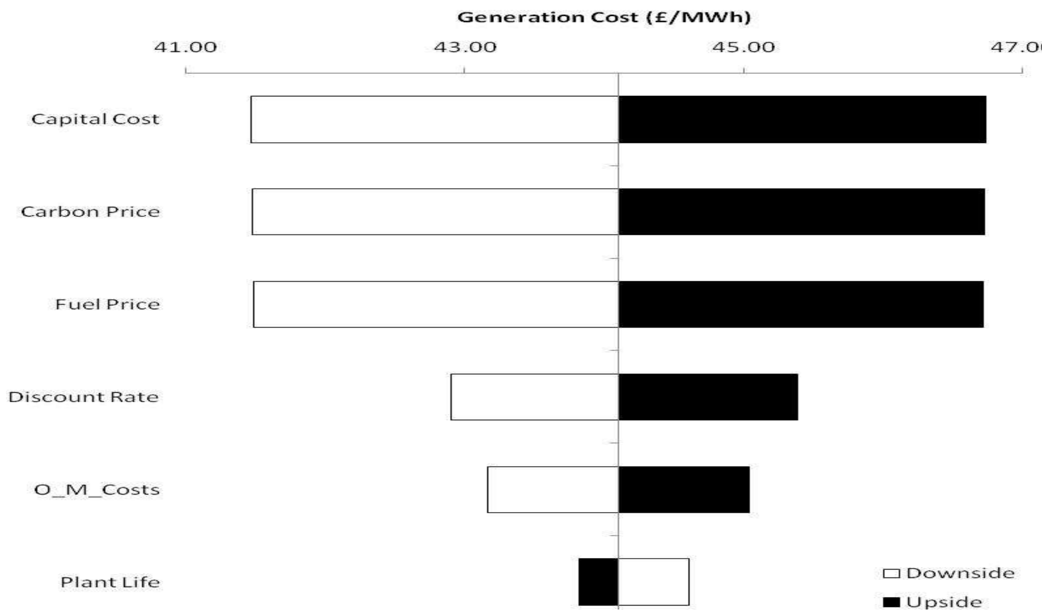


Figure 5-14: 20% sensitivity analysis for oxyfuel plant

By contrast, Figure 5-15 shows that when CCS is installed oxyfuel plant reverts to the profile exhibited by other coal plants: dependence on capital cost.

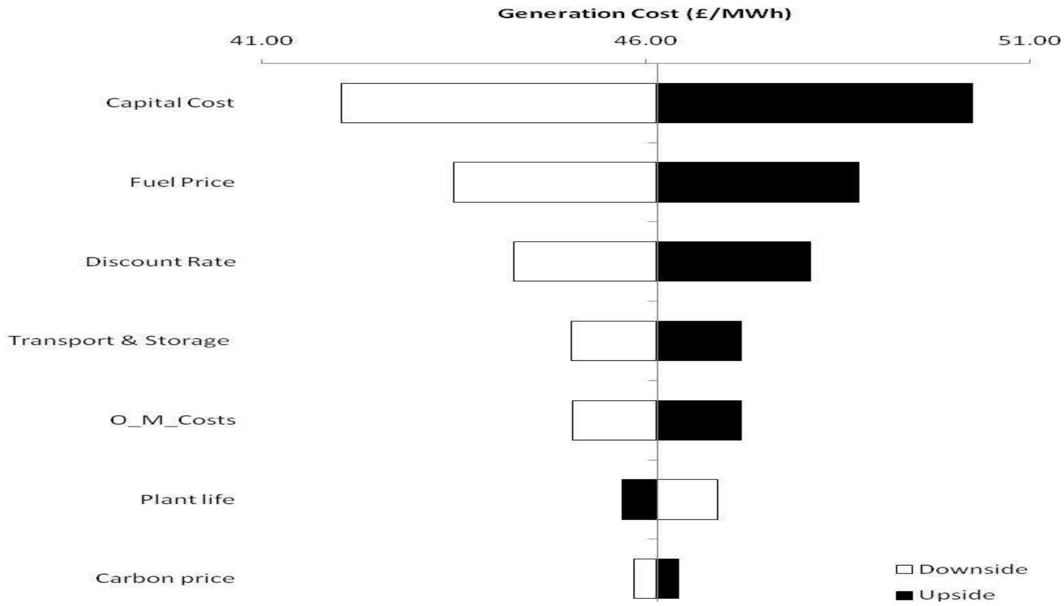


Figure 5-15: 20% Sensitivity analysis Oxyfuel with CCS

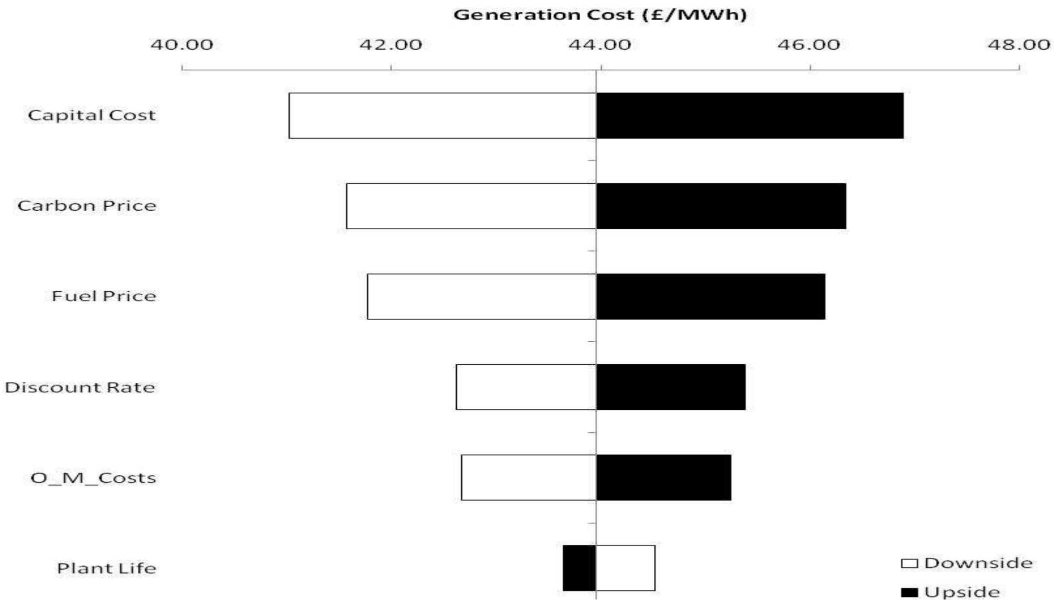


Figure 5-16: 20% Sensitivity Analysis for IGCC

Figure 5-16 and Figure 5-17 present the result of the sensitivity analysis for the IGCC plant with and without CCS. As with other coal plants, there is a tendency for the cost of generation to switch from being dependent on capital, fuel and carbon costs to become even more dependent on capital costs when CCS is installed.

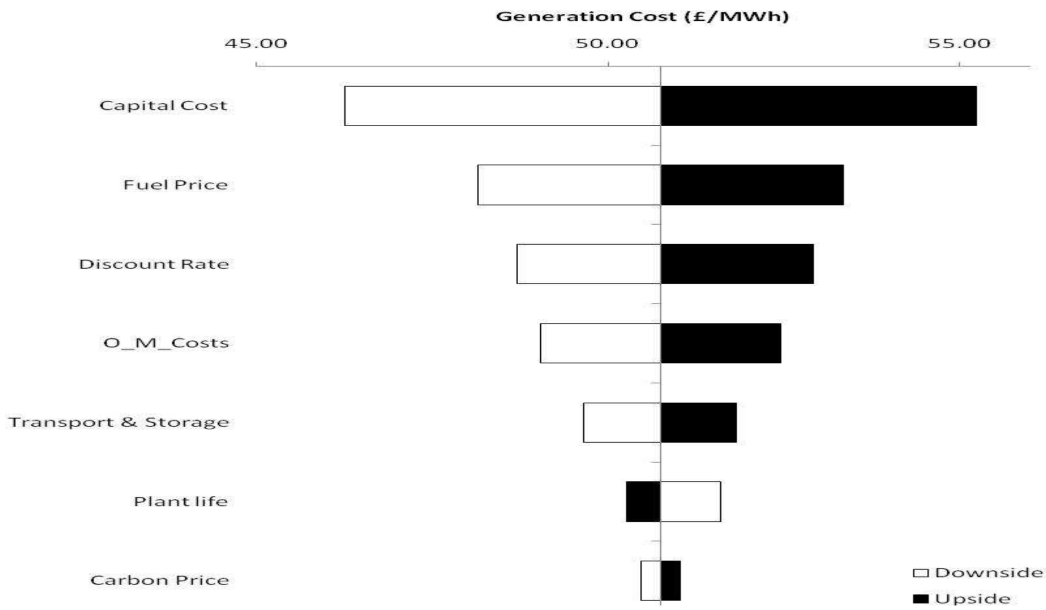


Figure 5-17: 20% Sensitivity Analysis IGCC with CCS

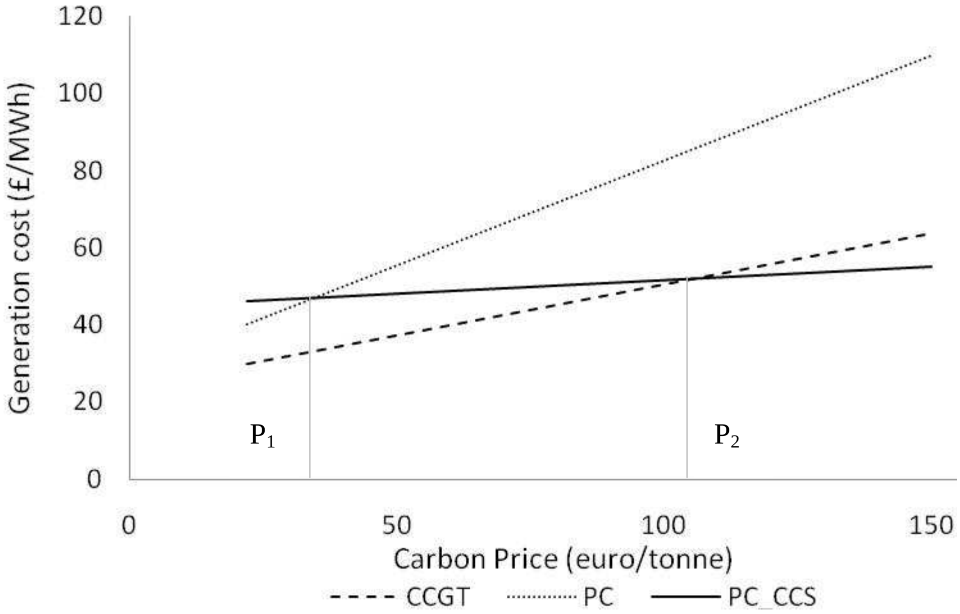


Figure 5-18: Effect of carbon price on CCGT and PC plant with and without CCS- central gas price

Figure 5-18 illustrates the effect of carbon price on the decision to switch from coal to gas fired plant rather than to switch to coal with CCS. Initially, PC plant is cheaper than PC with CCS (P_1). When the price of CO_2 reaches 40 euro/tonne, it becomes viable to switch from a PC plant to a PC plant with CCS. However, under the central assumptions given in the model, it is not until the price of carbon is in excess of 100 euro per tonne that it becomes viable to switch from a CCGT plant to a PC plant with CCS (P_2), implying that a much higher price of carbon will be required to switch from CCGT plant to coal with CCS plant under a central gas price.

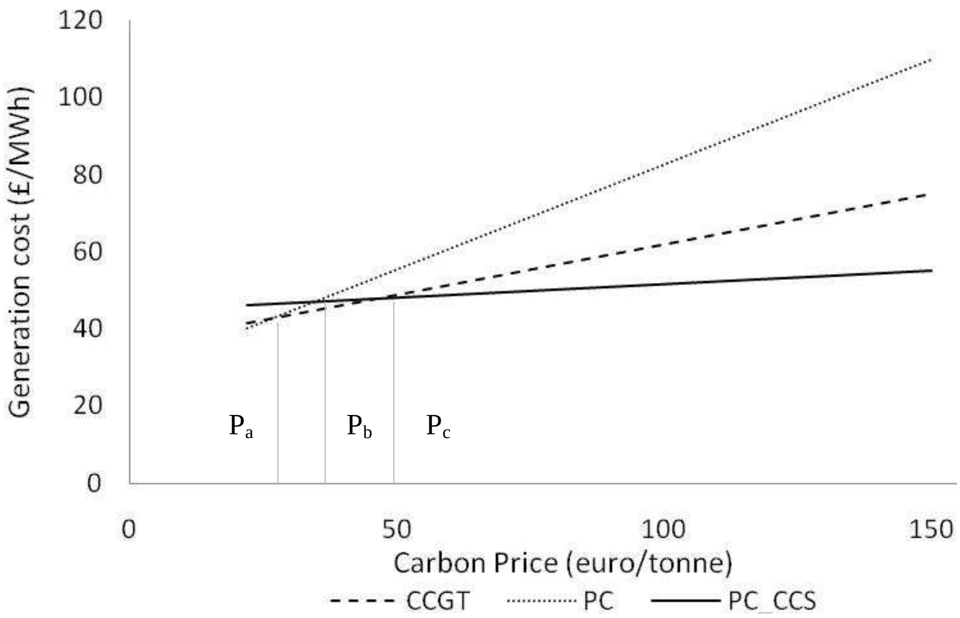


Figure 5-19: Effect of carbon price on CCGT and PC plant with and without CCS- high gas price

Figure 5-19 illustrates the effect of carbon price on the decision to switch from coal to gas fired plant rather than to switch to coal with CCS under a high gas price scenario of 45p/therm, in line with the BERR gas price estimates of 40-53p/therm (BERR, 2008a). Initially, PC plant is cheaper than both CCGT and PC with CCS, than PC with CCS. However, the increase in the price of carbon has a greater effect on PC plant than on CCGT plant due to the higher specific carbon emissions associated with coal. As a result of carbon price exposure, the cost of electricity from CCGT plant becomes less than that from PC plant at a carbon price, P_a, of around 28 euro/tonne. PC plant with CCS then becomes cheaper than PC plant at a carbon price, P_b, of 40 euro/tonne. Finally, PC plant with CCS becomes cheaper than CCGT plant at a carbon price, P_c, of 48 euro/tonne. Therefore the price of natural gas will be a key determinant of the competitiveness of CCS technology.

5.10.2 Comparison with published data

In order to add confidence to the cost of electricity derived in this thesis for coal with CCS, this Section presents the results of other studies reporting the cost of electricity from plants with CCS.

Table 5-6: Table of cost comparison data for PC plant with CCS

Source	Plant	Cost (£/MWh)	Cost derived in thesis (£/MWh)
Davison, 2007	PC_CCS	43.2	46.21
MIT, 2007	PC_CCS	44.39	46.21
Rubin, 2005	PC_CCS	50.63	46.21

Table 5-7: Table of cost comparison data for Oxyfuel plant with CCS

Source	Plant	Cost (£/MWh)	Cost derived in thesis (£/MWh)
Davison, 2007	Oxyfuel	44.8	46.14
MIT, 2007	Oxyfuel	40.29	46.14
Rubin, 2005		-	-

Table 5-8: Table of cost comparison data for IGCC plant with CCS[17]

Source	Plant	Cost (£/MWh)	Cost derived in thesis (£/MWh)
Davison, 2007	IGCC_CCS	44.30	50.75
MIT, 2007	IGCC_CCS	37.13	50.75
Rubin, 2005	IGCC_CCS	44.75/56.48	50.75

In general the prices derived in this thesis are higher than those reported in the literature. There are two reasons for this. Firstly, this study has taken into account project finance and the cost of transport and storage of CO_2. Most other studies have treated these costs separately and have not included them in their analysis. Secondly, input from ATCO Power has led us to increase some of the capital costs assumptions. Thirdly, the total cost of electricity that is derived is a function of input assumptions and these are not identical. Hence one would expect there to be a difference. Finally, a separate financial model using discrete time steps has also been built in excel and was used to validate the results from the approach presented in this Section. The model input sheet and cashflow results along with examples from the calculation engine have been placed in the appendix.

5.10.3 Model assumptions, scope and limitations

As part of the discussion, it is necessary to define and explain the effect of any assumptions regarding the data and modelling methodology and the implications of the assumptions in order to interpret the results of the cost model in the correct manner.

Most of the assumptions regarding data were made explicit in the data synthesis Section. This Section provides a brief re-cap and also presents the scope and limitations of the modelling approach and the impact of the data assumptions on the results of the cost model. The model was chosen in order to answer the first research question and to inform the model that will answer the second two research questions. Therefore, the model used in this Chapter is not an hourly plant simulation, but rather a general cost model applied over the life time of the plant. As a result, a number of factors have been kept constant,

[17] Exchange rate of 1.73$ to £1 which takes into account moving from 2005$ £2008. OFFICER, L. H. (2008) Five Ways to Compute the Relative Value of a UK Pound Amount, 1830 to Present. MeasuringWorth..

which would differ if an alternative approach were used. The following paragraphs detail the assumptions regarding plant performance.

Firstly, all capital and operational costs reported are based on literature reviews of detailed technical studies from academia, non governmental bodies and industry that include to some extent expert opinion and not on real plant construction cost data. Therefore, the figures are the best available estimate that can be used, especially with regard to data availability. Moreover, there are uncertainties in costs and operational performance of new technologies; it should be noted that no full scale operational CCS plant has yet been built that demonstrates the full chain of carbon capture and storage. As a result, data used for plants with CCS are based on models and industry judgement rather than actual costs.

The next area that necessitated assumptions was the price of fuel. As seen in Sections 5.5.3 and 5.7.3, the price of fuel fluctuates on a daily and annual (average) basis. The two Sections also mentioned that plants are not generally exposed to the daily fluctuations in fuel prices as a result of hedging and other strategic operations generators use to minimise exposure to high fuel prices. The inputs to traditional plant analysis are a series of forward curves, which usually settle to a long term price that reflects underlying market assumptions (ATCO, 2008). However, limited access to data meant that this study has used a gas and coal price based on the long term views of BERR and ATCO power. In addition, carbon price is also treated as constant in this Chapter, but in reality, the price of carbon fluctuates and is ultimately driven by CO_2 quotas from national allocation plans set by national government.

The results from this Chapter indicate the levels of government support (through a CO_2 price) that a coal CCS plant would require in order to be built instead of either:

1. A standard configuration PC coal plant,
2. A gas CCGT plant.

Under the long term coal price assumed in this thesis, a carbon price of 40€/tonne (£30/tonne) would be required to incentivise investment in a PC CCS plant. But under the assumed gas price (28p/therm), investment in an unabated CCGT plant would still be the best option. In fact, analysis shows a carbon price of more than 100€/tonne (£75/tonne) would be required for a PC plant with CCS to become viable over a CCGT plant (Figure 5-18). Such a high carbon price would arguably incentivise investment in CCGT plant with CCS (Figure 5-8), which would be a cheaper option. Therefore this suggests that either there is little room for coal CCS plant under low gas prices or policy would need to be designed in such a way to directly support coal CCS over gas CCGT plant or gas CCS plant.

In order to try and gauge the effect of the assumptions, a sensitivity analysis was performed on the cost model. Section 5.10.1 illustrated some of the potential cost characteristics regarding the various plants under investigation.

This paragraph explains the effect of parameters that were not included in the sensitivity analysis on the cost of generation. It has been assumed that all CCS plants will have an availability factor of 0.85. As the technology has not been demonstrated, this is an assumption that is based on the literature and also on the premise that in order to enter the market, CCS plants must be competitive in terms of reliability. This study has assumed that the availability or capacity factor is constant across all technologies under investigation. It is worth noting that a lower capacity factor leads to a higher cost of generation, and hence a greater cost of CO_2 avoided, whilst a higher capacity factor leads to a lower cost of generation and CO_2 avoided. In the current GB market, generators enter the market to sell electricity for a price set by the market. If the market price of electricity is too low, then the generator will not generate electricity, and vice versa if the price is high. As a consequence, annual capacity factors are often determined by the amount of hours an operator decides to run a plant, with the decision based on the variable (or short run marginal cost) cost of generation. This is unlikely to be the case for a CCS plant with significant capital burden as capital loans are likely to be significant at the MWh level (Figure 5-11, Figure 5-15, and Figure 5-17). In addition, the approach would require forecasting electricity prices with the plant operator deciding whether or not to dispatch the plant based on the cost of generation and the price of electricity, with correlations between electricity prices, gas prices, coal prices and carbon prices complicating matters. Moreover, in the current political climate, it is unlikely that any government would let operational CCS plants sit offline, while standard plants operate. This thesis has therefore made the assumption that a CCS plant will run as base load i.e. the plant will run for all hours that it is available. As a consequence, comparison with other plants (i.e. CCGT) must take into account that the competition will also run base load.

All CCS plants are assumed to capture 90% of emissions. In some cases, the literature has reported that there is an optimum % of CO_2 capture based on the price of carbon and the amount of CO_2 that is captured (which dictates the performance penalty) (Abu-Zahra et al., 2007b). This thesis is concerned with the overall characteristics of plants with and without CCS. Therefore, such calculations, based on hourly load conditions and electricity prices, are outside the scope of this thesis.

One value left out of the sensitivity analysis is that of efficiency. The efficiency of a plant influences the cost of generation dramatically. Plant efficiency is usually constant under full load, but changes under part load or at start up and shutdown (ATCO, 2008). Therefore, strictly speaking, plant efficiency is not constant over the whole range of plant operations. This would be important if the plant were to operate at the margin of capacity (as peaking plant); on the other hand, a base load plant would be expected to have a constant efficiency. There is no data publicly available regarding the performance of a coal fired plant with CCS at start up or shut down, nor are there associated costs. In addition, this study has assumed that CCS plants will operate as base load plants. Therefore, for the purposes of this study, plant efficiency is kept constant.

There has been research into strategies a generator can adopt to reduce its exposure to future carbon price uncertainty; capture ready plants and capture flexible plants have been investigated. Capture ready is hard to define accurately but at the minimum it is a set of pre-investments that enable plants to retrofitted with CCS at some point in the future (Chalmers and Gibbins, 2007), (Sekar et al., 2007), (Bohm et al., 2007) and (IEAGHG, 2007). Although the potential of "carbon lock-in" is avoided (Gibbins and Chalmers, 2008), plants will continue to emit carbon dioxide until a sufficient carbon price will provide the trigger to retrofit carbon capture processes.

Capture flexible plants have the ability to vary or to switch their capture facility on and off to meet external constraints (high electricity price or low-carbon price) or operational demands such as startup or shutdown (Chalmers and Gibbins, 2007). In deciding to switch off the capture facility, the plant gains efficiency, as it does not have to operate the carbon capture module. Due to a lack of data on the associated costs and operational impacts of such strategies, this has not been included in this model. However it is potentially a valuable attribute for a plant to have. Therefore, future work could include a calculation of the optimal cost of carbon required to trigger a capture ready plant to convert to CCS (this will also be greater than the "breakeven" carbon price if there is any uncertainty over the price of carbon in the future)

As the model has been constructed to answer the first research question, certain simplifications have been made e.g. redundancy of revenue risk. If single plants were being analysed for investment purposes, revenue risk would need to be taken into account and so too would the variation in the price of electricity.

Finally, although not a specific objective of the analysis of this thesis, it is worthwhile comparing the cost of generation from a PC plant with CCS to a nuclear plant. The main reason for doing this is that both technologies offer low carbon generation at a cost that is uncompetitive with natural gas plant. Appendix 5 derives the cost of nuclear generated electricity as being approximately £42.31/MWh. This is lower than the cost of generation from a PC plant with CCS plant, implying that nuclear plant may be the lower cost option. However, wider concerns such as public acceptance and issues concerning the disposal of nuclear waste means that CCGT plants are still the incumbent generation type of choice.

5.11 Chapter conclusions

Three different methods and a sensitivity analysis have been used to answer the first research question: What are the economic characteristics and sensitivities for coal/gas with CCS compared to a standard coal/gas plant? The viability of CCS varies according to the metric used. In terms of cost of generation, CCGT plants and CCGT plants with CCS have the lowest cost of generation under standard conditions. In comparison, when the cost of CO_2 avoided and CO_2 captured is used, CCGT with CCS become the most expensive plant in terms of cost per unit of emissions avoided (with reference to either the standard plant or not). The cheapest plant to switch to CCS in terms of CO_2 avoided is the oxyfuel plant. This is due to the comparatively low performance penalty and cost of oxyfuel with CCS in comparison to a standard oxyfuel plant. The implication of this is that CCGT plants will be the last plants to switch to CCS due to their lower exposure to carbon prices, except in a scenario that contains the combination of low gas prices and high carbon prices.

With regard to competition between coal plants with and without CCS, it appears that PC plant offers the best combination being the lowest cost standard plant and very nearly the lowest cost CCS plant. In comparison, oxyfuel plant has a more expensive standard plant and the lowest cost CCS plant. The conclusion of this is that PC plant could be built in either format and if built in the standard format could be retrofitted at some point in the future, while oxyfuel would only be viable if CCS were to be considered. In addition, most work centering on flexible capture plant focuses on PC plant. The main drawback of the standard oxyfuel plant is the increase in the cost of generation caused by the operation of the ASU, which causes a significant cost penalty to be incurred. However, when CCS is considered, a low additional performance penalty leads to an attractive cost of CO_2 captured/avoided. IGCC plant appears to be too expensive at present to be competitive with PC and oxyfuel plant with CCS.

In terms of comparison between standard plant and plant with CCS, a number of conclusions can be made. In general, making the decision to build a plant with CCS increases the cost of generation and consequently the economic case becomes more dependent on capital costs. Although not as dependent on capital costs as a nuclear plant, it can be expected that increases in construction labour costs or increases in the price of construction materials (steel, concrete) will have a significant impact on the cost of generation. Moreover, increasing capital costs for new plant are already being reported (Blankinship, 2007). This will influence the minimum cost of generation and hence the price at which the generator bids to provide electricity. In comparison, the impact of increased construction costs will be less pronounced for a CCGT plant with CCS. Although the CO_2 output is reduced by 90% per MWh when carbon capture is installed, a significant performance penalty is incurred owing to the operation of the capture facilities and the associated increase in capital cost. As a result, the current carbon price of 16.5£/tonne does not provide a sufficient incentive for generators to build CCS plant over standard coal fired power plant. Initial analysis indicates that an emissions price of 28£/tonne would make coal with CCS economically viable compared to a standard pulverized-coal plant. The price of electricity generated from natural gas at this point would be £34.72/MWh. Therefore, the price of carbon is the only incentive for a generator to switch from a non-capture plant to a capture plant. Therefore, any increase in capital costs or reduction in efficiency from CCS must be more than compensated for by an increase in the price of carbon e.g. a 20% increase in capital cost for CCS plant results in a carbon price of £30.15/tonne being required to promote the building of a CCS plant over a PC plant.

The sensitivity analysis took the input parameters to the cost model and varied them by ±20% while all other factors were kept constant. This allowed an analysis of the cost constituents of the various forms of power generation and provides the basis for modelling market uncertainties. The sensitivity analysis led to a number of conclusions:

- As the natural gas is less carbon intensive, CCGT plant is less exposed to carbon prices and once CCS is installed, to transport and storage costs than coal fired plant.

- Fuel price dominates the cost of generation from a CCGT plant. When CCS is installed, fuel cost continues to dominate the cost of generation from CCGT, although capital cost becomes more prominent. However, the main source of sensitivity is the price of natural gas.
- Installing CCS on a coal plant fundamentally alters its sensitivity characteristics; the profile becomes more top heavy like the investment profile of a nuclear plant or a wind farm i.e. the cost of generation is highly dependent on the capital cost. In addition, initial investigation implies that at present the cost of generation from coal with CCS is more expensive than that from nuclear plant
- When CCS is installed on a coal plant, fuel costs also increase as more fuel needs to be burnt to produce the same amount of energy. The effect is not as severe as that from the increase in capital costs.
- Standard coal plants are exposed to fluctuations in carbon price. This is a disadvantage when the price of carbon increases, but an advantage when the price of carbon decreases.
- The cost of generation from a CCGT plant with CCS is lower than that from a coal plant with CCS. Under present conditions of low gas price, gas CCS is the least cost option of any CCS plant. The low carbon content of natural gas means a higher cost of CO_2 is required to switch from a CCGT to a CCGT with CCS (CO_2 avoided cost).
- Coal plants are more sensitive to transport and storage costs as they produce more CO_2 per unit output and therefore must transport and store a greater volume of CO_2. This model assumes a linear scale factor for the amount of CO_2 shipped i.e. on a per tonne basis over a constant distance by ship/ offshore pipe.
- All standard coal plants move from being sensitive to capital cost, fuel cost and carbon cost to being predominantly capital cost dependent with some exposure to fuel costs. This characteristic suggests that coal plants enabled with CCS might be more suitable for base load generation as large debts will need to be serviced, and hence plants will be unable to afford to meet peak demands. However, the operational costs are still higher than those in other capital intensive plants, and hence in some respects coal with CCS has the worst of both worlds.

In order to choose coal with CCS over coal without CCS a carbon price of around 28£/tonne is required. However, given a natural gas price of 29p/therm, electricity generation from natural gas will be cheaper. Therefore the option to choose between natural gas and coal with CCS will be determined by the price of natural gas itself (in the absence of any mandatory CCS requirement) as shown in Figure 5-19. Therefore coal CCS plant will only become economically viable if the price of gas is very high relative to coal.

Figure 5-12 shows that the cost of fuel for a CCGT plant is the dominant parameter that determines the cost of generation. The price of natural gas that causes the cost of generation to increase to that of a CCS enabled plant is approximately 51p/therm. In comparison, the price of carbon has less effect on the option to switch to a CCS enabled coal-fired plant; a price in excess of £70/tonne would be required.

5.12 Further analysis

This Chapter answered the first answered the first research question:

- What are the economic characteristics and sensitivities for coal/gas with CCS compared to a standard coal/gas plant?

The two additional research questions are examined in the following Chapter:

- What is the effect of revenue uncertainty likely to be on CCS enabled coal fired plant deployment i.e. what extra compensation will the generator require in order to build a CCS plant?
- When will a coal with CCS plant replace a CCGT plant as the preferred method of generation?

6 Real options analysis

The objective of Chapter 6 is to evaluate the expected timeframe over which coal CCS plant could be become a viable generation choice in the UK market under revenue uncertainty.

Two questions have been formulated to meet the Chapter objective:

- What is the effect of revenue uncertainty likely to be on CCS enabled coal fired plant deployment i.e. what extra compensation will the generator require in order to build a CCS plant?
- When could a coal plant with CCS replace a CCGT plant as the preferred method of generation?

There are three characteristics of the problem which imply that a real options approach is required to address the research questions. These characteristics are: the irreversible nature of the investment decision, the uncertainty surrounding future revenue (or benefits) that investment in the project will bring and finally, the flexibility the investor has to wait before making the investment decision. It has been shown in the literature (Dixit and Pindyck, 1994), that traditional NPV analysis omits the (option) value associated with delaying investment (or deciding not to invest at all); a project with a high option value should be delayed.

The model built to answer the questions uses real options analysis to: i). evaluate the impact of revenue stream uncertainty on the optimal revenue required to invest in coal CCS. ii). Provide a prediction of the (stochastic) time at which this optimal revenue may be reached and hence the investment decision exercised (i.e. CCS becomes a viable investment proposition). The output of the cost model presented in Chapter 5 is used as an input into the real options analysis presented in this Chapter. A schematic of the research methodology framework is given in Figure 6.1.

This Chapter confines its investigation to PC plant with and without CCS and CCGT plant. The method described can be adapted to investigate IGCC plant or oxyfuel plant. This Chapter concentrates on pulverised coal (PC) plants with post combustion capture as this appears to be the technology the UK government is backing (GNN, 2007) and has been judged, in Chapters 4 and 5, to be best placed in terms of system readiness and cost.

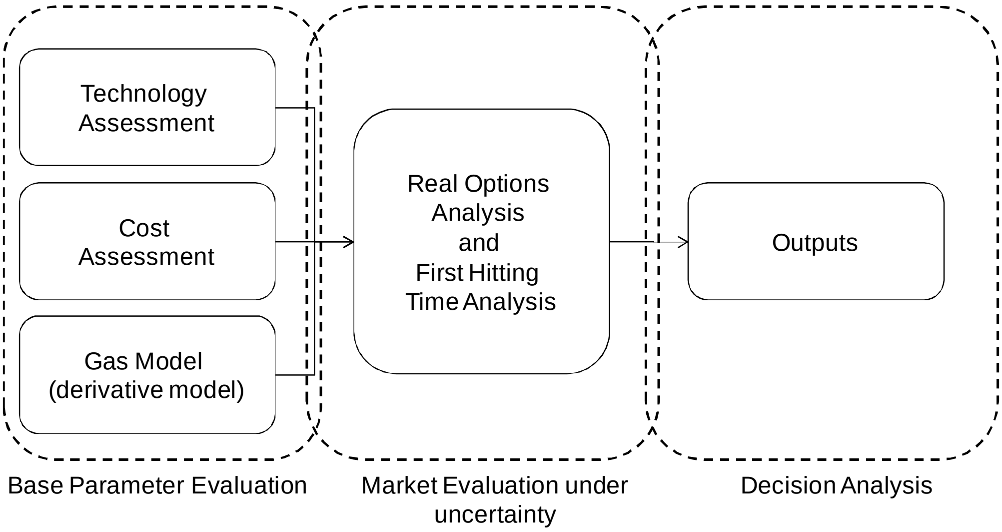


Figure 6-1: Chapter overview

The first Section of Chapter 6 presents the literature review, and gives an overview of the history and development of real options analysis. As this thesis is in the domain of engineering systems, the literature review then covers the application of real options analysis to engineering systems and outlines potential future applications for investigations into CCS from an engineering systems perspective. Finally, the literature review covers applications of real options modelling to valuing investment in power generation and specifically a review of RO applications to CCS.

The second part of this Chapter includes problem formulation and synthesis of the research questions. The methods of solving various options models are considered and matched to the research questions posed at the start of Chapter 6. The modelling approach is defined i.e. valuing CCS as an American call option and using the mean time to absorption calculus to derive the possible time scale over which investment could take place. The reasoning for the choice of natural gas as the underlying asset and the parameter estimation of the underlying gas model is also presented.

The third part of this Chapter details the method of parameter estimation for the underlying asset i.e. the drift and volatility of natural gas price. Parameter estimation drives the value of the option (volatility) and the mean time to absorption (drift and volatility).

The fourth part of Chapter six presents the results of the analysis from the options model and the mean time to absorption model. The results are accompanied by a discussion and sensitivity analysis for input parameters and underlying asset parameters.

The final part of Chapter 6 presents conclusions of the options model and directions for future work.

6.1 Real options analysis

Real options analysis (ROA) is considered to have been first used by Myers to refer to investment models using financial theory to value investment in real assets which exhibit or are susceptible to uncertainty over time (Myers, 1977). Additional papers were then published regarding the valuation of natural resource investment (Brennan and Schwartz, 1985), and the value of waiting to invest in a project (McDonald and Siegel, 1986). McDonald and Siegal also derived the analytical solution for the special case of the perpetual (non-expiring) option to invest (McDonald and Siegel, 1986).

In 1994, Dixit and Pindyck published their book "Investment Under Uncertainty" (Dixit and Pindyck, 1994) which emphasised the value of irreversible investments in uncertain environments and consequently, the value attached to waiting for some uncertainty to be resolved before making the investment decision. Trigeorgis (Trigeorgis, 1996) presented an overview of options and brought forward the idea of flexibility having value. The idea of flexibility is particularly important as it encompasses many decisions that a practising company faces e.g. expand, contract, shut down etc.

Real Options started to become adopted in mainstream business around the year 2000, reflected in a number of texts and journal papers that were aimed at the business community rather than the academic. In 1998, Luerhman published articles on the value of ROA and a heuristic approach to valuation (Luehrman, 1998). A typical example of a mainstream orientated text is the book by Mun (Mun, 2003), which provides an overview of real options analysis for managers. Meanwhile, texts also appeared that bridged the gap between the academic and business community approach: Howell et al (Howell et al., 2001) provide a more comprehensive (and if the reader chooses, theoretical) introduction to real options analysis but augments it with a series of applications in the real world from football players to real estate and power plant valuation.

Investment in power generation assets has many of the characteristics that real options analysis values. Key characteristics of investment in power generation include: uncertainty, irreversibility and flexibility which are not valued using traditional methods. Investment in new plants is partially to fully irreversible i.e. once a project has reached a certain stage, costs are sunk and cannot be recovered. Future revenue (electricity price) and fuel prices and carbon prices are unpredictable. Hence revenue is uncertain. Investors have flexible timing opportunities to invest i.e. they can choose to invest or not to invest or even to switch the plant on or off. Producers have the option of flexibility to abandon, expand, shorten or lengthen the lifetime of a plant.

6.1.1 Financial options

A brief explanation of financial options will show how real options analysis differs from that of financial options valuation. An option gives the holder the right, but not the obligation to buy or sell a traded financial asset (e.g. stock) for a fixed price (the exercise price) in the future up until a defined point (the expiration date). The option to buy an asset is known as a call while the option to sell an asset is known as a put.

In the broadest sense, options can be further classified into categories depending on when they can be exercised: a European option can only be exercised on the day the option expires, while an American option can be exercised at any point up until and including the day of expiration.

Figure 6-2 illustrates the payoff for a call option priced £1 as a function of the underlying asset price at the time which the option expires. Consider the option to buy a stock (a call option) and define the initial price of the stock by X_o, the strike price as S, and the price of the stock at any point in time as X_t, the following will occur:

•When X_t>S the option will be exercised,

•When X_t<S the option is left to expire.

Therefore, at the terminal point in time, a payoff function can be constructed:

$$\max\left(0, X_t - S\right) \tag{6.1}$$

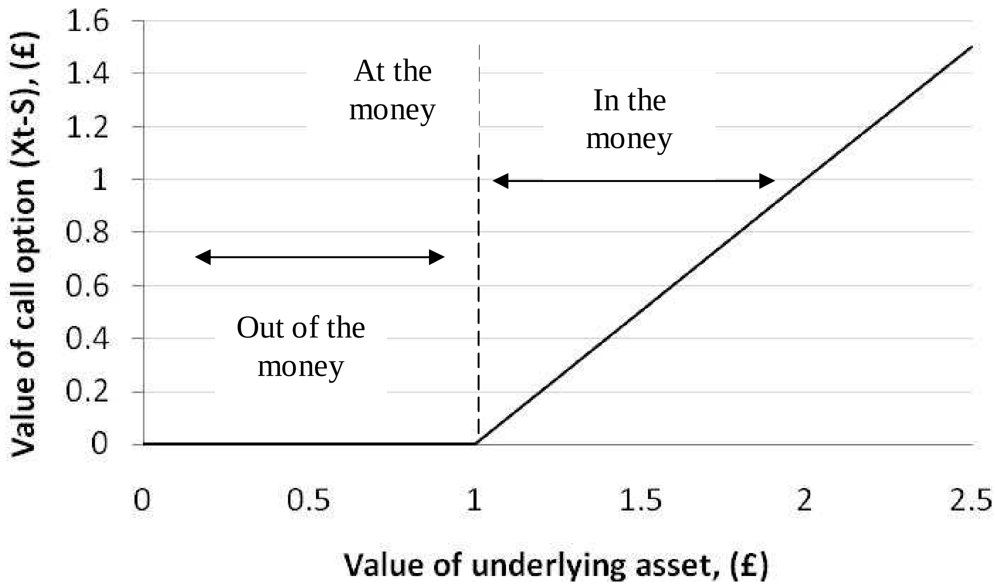


Figure 6-2: Payoff for a call option

The value of an option occurs because if the asset price is below £1, the option holder does not have to buy the underlying asset and therefore the most that is lost is the price of the option. The payoff function is also known as the intrinsic value. The option can never be worth less than zero (lower boundary), but has no upper limit therefore the payoff function is asymmetric; this gives the option value and the option holder leverage.

Of course, the natural question becomes how to value an option that is not at the time of expiry. Modern financial theory was founded by Black, Scholes and Merton in 1973.The Black-Scholes model determines the amount that should be paid for a call option on a tradable asset taking into account the time until the option expires, for which Merton and Scholes received the Nobel Prize for economics in 1997. The formula to value a call option that pays no dividends is given below:

$$C(t) = X_0\Phi(\omega) - Se^{-r(t)}\Phi\left(\omega - \sigma\sqrt{(t)}\right) \tag{6.2}$$

$$\omega = \frac{r(t) + \frac{1}{2}\sigma^2(t) + \ln\left(\frac{S}{X_0}\right)}{\sigma\sqrt{(t)}} \tag{6.3}$$

Where:

C(t)	: Price of the call option
X_0	: Initial value of the tradeable asset
S	: Exercise (strike) price
T	: Exercise time
r	: Risk-free interest rate
Φ	: Cumulative standard normal distribution

The first term on the right hand side of equation (6.2) is the expected share value and the second term is the expected cost if the option is exercised at maturity. The difference between the first term and the second term is the price of the call option. Time value is greatest when the option is at the money

There are two notes to make about the Black-Scholes formula. Firstly, because of constraints imposed in the derivation of the equation, the actual drift of the underlying stock is not included but instead a risk free rate is introduced. This is due to an assumption of no arbitrage and risk neutrality in the construction of the option (i.e. the stochastic components of the return on the asset being valued can be exactly replicated by the stochastic component of the return on some traded asset (or dynamic portfolio of traded assets) and secondly the underlying stock price follows a GBM.

Arbitrage entails profiting by taking advantage of different prices for the same good in different markets. Arbitrage opportunities will not last for long as traders will spot the opportunity for a risk free profit and buy the asset until the prices in the respective markets reach parity. If no arbitrage opportunities exist, a stock portfolio can be set up in a way such that the portfolio has no risk. It therefore grows at the risk free rate of interest.

In simple terms, a hedge of underlying/stock against the option would produce a risk free portfolio. Any gain or loss in the underlying will be compensated for by a corresponding loss of gain in the value of the the option .i.e. the price of a call option is perfectly positively correlated with the underlying while the price of a put option is perfectly negatively correlated with the underlying.

The price process of a stock over time has been shown to follow a Geometric Brownian Motion (GBM):

$$dX = \mu Xdt + \sigma Xdz \tag{6.4}$$

Where:

μ : drift

σ : volatility

dz : Weiner process having a drift of zero and variance of 1

The motion of the underlying asset is stochastic. As a stock cannot take negative prices, the returns are log normally distributed. There are many other types of options and many other types of stochastic processes to describe them; further discussion of these topics lies outside the scope of this thesis.

6.2 Real options

ROA uses terms and methodology from financial options and applies them to evaluating options on real assets. Typical examples include the option to invest in a copper mine given an uncertain price of copper or the option to invest in an offshore oilfield with an uncertain price of oil.

Trigeorgis (Trigeorgis, 1996) classifies real options into seven categories; options to defer, time to build option (delay investment), options to alter operating scale (expand or contract, shut down or restart), options to abandon, options to switch (outputs or inputs), growth options and multiple interacting options. The table below presents some of the literature in terms of the options that are represented for power generation.

Table 6-1: Examples of real options categories used for assessing investment in power generation assets

Type of Option	Example Reference
Option to defer investment	(Brennan and Schwartz, 1985)
Time to build option	(Rothwell, 2006)
Option to alter operating scale	(Gollier et al., 2005)
Option to abandon	(Yang et al., 2008)
Option to switch	(Abadie and Chamorro, 2008b)
Growth options	(Kalligeros et al., 2006)
Multiple interacting options	(Wang and de Neufville, 2006)

A typical example of a real option is as follows: a company has found deposits of gold and has the option to construct and operate a gold mine. If the price of gold is low, then the mine may not be economic to build and operate. However, the company can choose to wait until the price of gold rises and then start mining. In effect the company has a right but not an obligation, in other words an option, to delay the investment decision until the future when market uncertainty is clarified. The amount the company should pay for this option (in the case of further exploration etc) is the call value of the option while underlying asset would be price of gold.

The value of ROA is now clear: a traditional NPV analysis would return a negative result and the project would be abandoned. ROA values the right of a company to wait before making the investment decision. If the price of gold did not increase the company could walk away from the investment for a relatively small capital outlay. In simple terms, the holder of a real option that has not been exercised has access to upside potential but limited downside risk (i.e. the cost of holding the option), which NPV calculations fail to take into account.

In order to model the real option in the same way as a financial option, a number of parameters must hold true: the underlying price process must be stochastic, and a riskless portfolio of options must be constructed. The ability to delay an investment decision, coupled with the stochastic price process determines the value of a real option.

6.2.1 Comparison with financial options

Real Options Analysis (ROA) is the result of applying financial options theory to evaluate investment in or on technological systems. The following paragraphs cover the general points that must be met when applying real options theory.

The first point to note is that financial options are valued on underlying assets that are traded in the market. Real options are not often traded in the market, however, authors such as Trigeorgis (Trigeorgis, 1996) state that real options may be valued similarly to financial options if a riskless portfolio of traded options can be setup that mimics exactly (perfect correlation) the risk associated with the underlying asset, which is not simple for all options applications. If the assumption of spanning assets cannot be justified then a dynamic programming approach can be used to value the option. The main difference between dynamic programming and contingent claims analysis is that the discount rate for the former is arbitrary, while for the latter it is based on the risk free rate of return. When the discount rate used in the dynamic programming approach is the same as the risk free rate, both approaches yield the same option value (Dixit and Pindyck, 1994). The justification of using certain underlying assets for real options representing traded portfolios is tackled by Borrison (Borison, 2005).

The second point to note is that the underlying process must be stochastic and then parameters must be estimated. This is fairly straight forward in ROA for energy but can be difficult in other areas. It is also interesting to note that ROA uses both GBM and other stochastic process models to represent the underlying asset; the use of other stochastic models does not make the options assumptions invalid as long as an appropriate method is used to solve the problem.

There are many types of real options that can be evaluated through ROA and can be applied to a project. Some examples are: the option to defer, the option to follow a staged build process, the option to expand and the option to abandon (Munn (2002)). The most important process in ROA “on” projects is to find the uncertainties e.g. market risk and to investigate and represent these uncertainties in some way.

There is also an analogy to be made between the parameters of the financial options model and the parameters of the ROA model. The strike price is replaced by the price it will take to proceed with the project. The volatility is still the volatility associated with the underlying asset, but more accurately the volatility of the perfectly correlated asset that mimics the behaviour of the real asset.

Value drivers of both real options and financial options include: the date at which the option expires i.e. how long is it until the option needs to be relinquished, the risk free rate, the volatility, the start price and the strike price. It must be stated that each option does not represent an equal effect on the price of the call option. Out of all parameters, volatility has the greatest effect on option value.

6.2.2 Modelling and solving options

In general, four groups of solution method are available to model and solve options problems: closed form analytical, simulation, lattice methods and numerical solution of governing partial differential equations. Despite the examples given so far, the majority of real options problems have no closed form analytical solution i.e. the problems must be solved numerically.

Excluding closed form analytical solutions, each of the remaining three classes of options solutions has its own solution tools. Figure 6-3 illustrates this.

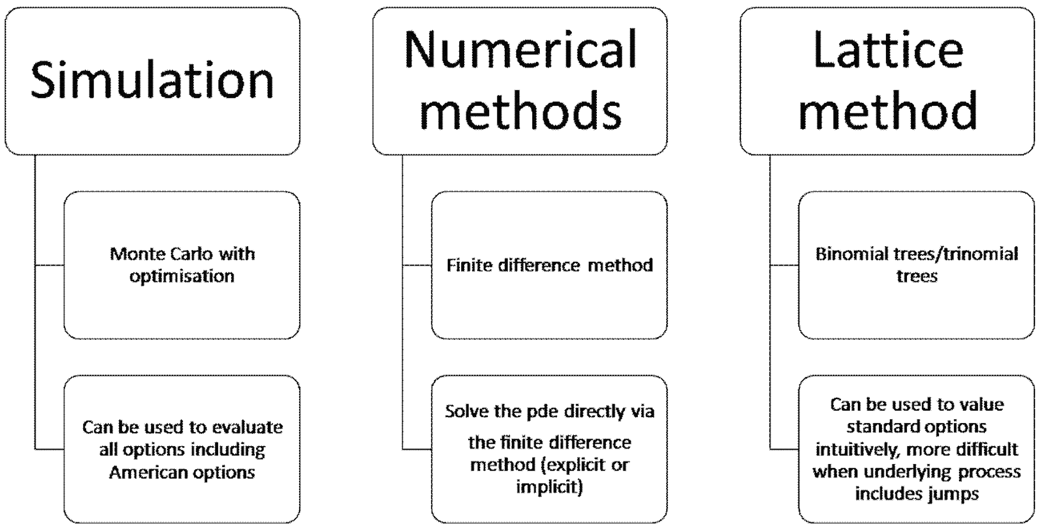


Figure 6-3: Numerical methods for solving ROA problems

Each of the three families of modelling tools has its own benefits and tradeoffs which are briefly explored in the following paragraphs.

In the case of simulation, Monte Carlo analysis is used to simulate thousands of price paths at discrete points in time until the option expires. The individual price paths are then analysed and the optimal decision is taken subject to heuristic criterion. Simulation evolved due to issues with binomial tree, and is a trade-off between computation intensity and the ability to model a wide range of uncertainties and stochastic processes. It is possible to value American and European options via simulation, although American options are more computationally demanding. Hence a trade-off occurs as it is more difficult to value path dependent options with simulation, but it is easier to value multiple uncertainties, correlations and stochastic processes.

Lattice methods were proposed by Cox Rubenstein and Ross and offer an intuitive method of treating real options as they model the option decision explicitly. The process uses a discrete time framework that models the underlying variable at discrete points in time. The value of the option is then calculated at the final node and the value of the option at previous points in time is calculated by backward induction. The method is widely used to value real options due to its flexibility and robustness in handling large complex simulations. There are some real options that are too complex to simulate using the binomial tree method (multiple correlations etc), and some stochastic processes that the lattice method is unable to evaluate such as regime switching.

The final class of model are numerical methods; these involve setting up the options problem as a series of partial differential equations and then solving the equations via the finite difference method. The solution of partial differential equations via the finite difference method has a rich background in other fields' e.g. computational fluid dynamics. In general, there are two sub-categories of the finite difference method; the implicit and explicit treatments. The implicit treatment solves the PDE indirectly via a series of linear differential equations, while the explicit treatment solves the PDE directly via boundary conditions and marching backwards through time (Anderson, 1995).

The choice of technique to solve an options problem is context dependent e.g. a simple option dependent on a single stochastic factor might be best solved via the binomial tree or numerical methods, while a problem with dependent on multiple factors may be better solved using Monte Carlo simulation with optimisation (Longstaff and Schwartz, 2001).

6.3 Real options and engineering systems

Despite its applicability, ROA has only recently been applied to the design of engineering systems. Two classes of ROA are applied to engineering systems- options "on" engineering systems and options "in" engineering systems (de Neufville, 2004). Real Options "on" systems generally treat the technology under investigation as a black box and evaluate the options value of management decisions associated with the system, while options in systems treats the system and specifically the system design explicitly. The following two Sections explain each and explain where this thesis sits in relation in options theory applied to engineering systems.

6.3.1 Real options on engineering systems

Most real options problems that are applied to an engineering system (e.g. a power station) treat the technology as a black box. Performance parameters are estimated based on technical assumptions and the economic case of whether to execute an operation or not are based on data gained from technical sources. In addition, the question that is asked is usually posed in response to an external event e.g. uncertain carbon emissions price. The plant has a number of options before it and the ROA helps to determine when to take that option and the price at which to take the option.

In essence, the technology appears to be passive in the face of external circumstances, it is management who can decide whether to close the plant, expand production or temporarily shut down operations. The vast majority of ROA treats engineering systems in this manner; however, recent research is beginning to show that there is a far greater role that options analysis can play in the design of engineering systems, essentially using ROA to act as a justification for active technology and hence more expensive design choices that allow future flexibility.

6.3.2 Real options in engineering systems

Engineering Systems has long valued flexibility as a desirable system parameter. The problem has always been how to value the flexibility and justify the extra cost to management. Intuitively, ROA can provide a basis for presenting this value in a logical framework. It will allow system designers to formally recognise that throughout their lifetimes, engineering systems will be upgraded or retrofitted or modified to a certain extent. The ease with which this can be done has a value associated with it. The ability to conceptualise and design engineering systems as being adaptive to an uncertain environment will alter the traditional focus of ROA on engineering systems and bring it round to focusing on design choices that can be made in order to maximise the right type of flexibility. Real Options “in” projects can be thought of design details that provide flexibility of an option. One reason the field has not been exploited by economists is that the requirements of building options in engineering systems require detailed knowledge of the systems in order to identify areas where options can be designed into the system.

Most of the work in this field is being conducted at MIT by Prof. de Neufville. The typical example given to illustrate the value of ROA applied to engineering systems design is a multi-story car park. At first there is only demand for 5 storeys, however, over time, it is expected that there will be demand for additional space. Therefore the designer of the car park faces a decision: to optimise the design and sink foundations that will support a five storey car park or to optimise the flexibility of the design and spend more funds on creating foundations that can hold an extra 4 storeys. The additional cost of the foundations and materials can be seen as equivalent to a call option, while demand for car park spaces can be seen as the underlying process. de Neufville shows that this design decision can be valued as a call option.

Real world examples of engineering system failure due the exclusion of flexibility in the design of systems are also presented in the literature. The case of two satellite networks, Iridium and Globestar, which were designed for optimal cost, is used as an example of inflexible system design. The network was incapable of upgrading to meet future demand and also of upgrading to use new transmission technology. As a result, in the space of 4 years, the network was rendered obsolete (de Weck et al., 2004). The B52 bomber is an example of a flexible platform design that has had its lifetime continually extended by its ability to alter its profile in order to meet new demands e.g. from a long range strategic bomber to a transport to a fuel tanker.

The obvious question arises of how to identify the system flexibility that will be most advantageous to design into the end product. de Neufville has published various papers and supervised thesis that are developing methodology to screen engineering systems for the key flexibility that can be designed into the system (Wang and de Neufville, 2006). There are many more potential options available for system design (“in”) than for real options “on” systems. Wang & de Neufville (Wang and de Neufville, 2006) describe a model to search for and assess various options “in” system design.

6.3.3 ROA “on” CCS systems and “in” CCS systems

This Section provides examples of areas of the CCS system that could have ROA applied to them and goes on to conclude with a statement on the position of this thesis in relation to ROA “on” and “in” engineering systems.

In terms of reference to the technical assessment conducted in the previous Chapter, it appears that once built with certain additional design features, a PC plant could be adapted to take advantage of improved solvent techniques that may become available in the future and thereby benefiting from the improved efficiency such solvents may bring. As with the examples presented above, the idea is that the cost incurred to design these options “in” to the system will be more than compensated for by the flexibility it gives to plant operation in the future. In essence, the operator has the right but not the obligation to switch the carbon capture process to a more efficient capture solvent in the future.

Other options also exist for a PC plant, which include the option to switch the capture process on or off at any time in the plant operations. PC plants also have the opportunity to switch off the capture process and vent CO_2 rich flue gas straight to atmosphere. This could be done at times of high demand or in a more sinister manner, to take advantage of low-carbon prices. This can be done because the PC capture process is a post combustion process and CO_2 free gas is not a requirement for any process operations. The type of technical modification proposed by Gibbins (Gibbins, 2004) is an example of a real option “in” a technical system (although not explicitly recognised as one by Gibbins).

The opposite is true in the IGCC case because the gas turbine will be designed for hydrogen, not syngas and therefore the plant will not be able to operate if the water shift reactor is taken offline. One characteristic of an IGCC plant that could be valued as an option would be the option value associated with the ability to switch outputs i.e. produce electricity or hydrogen (by not combusting the hydrogen in the turbine). In addition, multiple fuel input could also be used e.g. natural gas or coal. There is a report published under the auspices of the Laboratory for Energy and the Environment at MIT which evaluates the flexibility associated with retrofitting CCS to an IGCC plant as a real option (Sekar, 2005).

All of the options for the CCS plant described require a detailed knowledge of the process and associated costs in order to be able to value the option. It is envisaged that this type of analysis could be done in future research and at present the role of this thesis is to use ROA to answer the research questions posed at the start of the Chapter. Therefore this thesis lays the foundation for further research into flexible coal plants by addressing a number of areas and introducing ROA as a way of valuing coal plant with CCS. More specifically this thesis follows the real options "on" engineering systems approach, but sets up the foundation by collecting and analysing the technical performance characteristics of the capture processes to enable the work in this thesis to be extended to include real options "in" engineering systems approach.

6.3.4 Real Options on power generation systems

There are many examples of applications of real options to electricity production. Section 6.3.4 provides an overview and classification of real options approaches that have been used to aid decision making in the power industry and in particular to those in CCS.

The first part of the literature review covers relevant papers on real options for investment in power generation. As the field is wide, with many papers published on the subject, papers with a focus investment are concentrated on as this is the area of the research question.

Insley, (Insley, 2003) valued the option for a firm to invest in equipment to retrofit a plant with emission abatement technology (to reduce SO_x) in light of an uncertain emissions penalty, which varied stochastically as a GBM. The options valued included that of optimal investment price i.e. the trigger price of emissions permits required for the option to be exercised. In addition, the construction process was staged so that the owner had the option to abandon construction at discrete points in the build process. Once the facility had been built, the owners also had the option to cease production if the emissions price was too low. The problem was set up using partial differential equations that were solved using the Crank-Nicholson method. The option to halt construction was valued using contingent claims analysis. The authors find that increasing volatility increases the critical trigger price to retrofit pollution abatement and that including the time to build a facility and modelling the option to halt construction adds significant realism to the model. The authors do not consider the option to switch to low sulphur coal (as is happening in the UK at present due to the LCPD- interestingly, this is why the UK imports large quantities of Russian coal), which could be a more economic way of dealing with uncertainty in emissions prices as no large sunk costs in new structures would need to be made, rather an increased variable cost might be seen (as the fuel is more expensive).

Cavus, (Cavus, 2001) evaluates the investment in a new CCGT plant compared to running or retiring an existing OCGT plant. Plant dispatch is simulated on an hourly basis i.e. the option to run the plant or not is assessed at each hour, with the NPV being the discounted sum of net operating costs. The problem is first modelled as a series of European call options with one stochastic parameter before being extended to two correlated stochastic parameters (electricity price and fuel price). The method of solution for the first problem is the standard Black-Scholes for a European option. The second option is evaluated using the

Margrabe formula, allowing the 2D problem to be valued as a 1D spread option. The author finds that the NPV is sensitive to the correlation between electricity and gas prices. The influence of start up and no load costs is not included in the analysis, nor is the impact of fixed costs e.g. loan repayments, which make up a substantial proportion of CCS costs.

Yang et al (Yang et al., 2007) and Blyth et al (Blyth et al., 2007) present a framework to evaluate investment in generation assets under multiple input price uncertainties. The approach coupled IEA software for generating the levelised cost of electricity with commercial real options software (real option calculator). The stochastic parameters were fuel price and carbon price. Three plants were investigated- a nuclear plant, a coal plant and a CCGT plant. The decision to invest in one of the technologies under uncertain climate policy was set up as an American call option and evaluated using dynamic programming. Revenues are determined by the plant operating on the margin i.e. the plant with the highest cost of generation. To reflect uncertain climate policy, the price of carbon was modelled as a jump process. The authors found that the timing of the policy was important when there was a short time period between the decision to invest and the resolution of policy uncertainty- i.e. the authors showed that long term emissions frameworks that remove uncertainty result in more environmental technologies being adopted. The paper also showed that the effect of CO_2 price risk was higher when the marginal plant was coal due to the carbon intensive nature of emissions. The study assumed plant operated as base load and did not consider uncertain costs of generation. In addition, no CCS plants were included in the analysis.

Roques et al (Roques et al., 2006) use a Monte Carlo approach with stochastic optimisation to maximise NPV when a generator considers building 5 new plants over 20 years. The Monte Carlo approach allows stochastic electricity, carbon and gas prices to be modelled as well as correlations between the price processes and a sensitivity analysis on new build costs. The authors find that the correlation of gas and carbon prices leads to a decrease in the NPV of nuclear plant, suggesting that there is little incentive for generators to diversify away from natural gas plants to hedge fuel prices and therefore it is likely that new nuclear plants will require government support.

Laurikka (Laurikka, 2006) used real options analysis to evaluate the option value associated with operations of a new CHP plant or a modification to an existing plant using three stochastic variables; electricity, fuel and emissions to calculate the expected NPV. The stochastic model was compared to a normal discounted cash flow model- it was found that the DCF model could cause bias results where a number of uncertainties could make quantitative appraisal complex.

Gollier (Gollier et al., 2005) analyse the value associated with building a series of modular nuclear plants compared to one large capacity nuclear plant. In effect, the authors value a series of options to invest compared to a single option to invest, known as a sequential investment. The authors model revenue as being stochastic using geometric Brownian motion to evaluate the American option of the optimal investment rule. The authors find that significant value is attached to the flexibility associated if investment takes place as a series of sequential options.

The following paragraphs contain the second part of the literature review which examines papers assessing investment in CCS using options analysis.

Abadie (Abadie and Chamorro, 2008a) evaluated the option to retrofit a PC plant with CCS based on uncertain electricity prices and carbon prices. The process for electricity was mean reversion, while carbon prices were assumed to follow a GBM. The principal aim was to find the trigger price of carbon allowances that would cause a generator to install the capture facility. The option was evaluated using a 2D binomial lattice. It was found that the trigger price to justify immediate retrofit of CCS to a PC plant was 55€/tonne carbon. In addition, sensitivity analysis showed that increasing the price of electricity increased the trigger price as did increasing the cost of the capture technology. Meanwhile, plants with a remaining economic life of less than 8 years would not adopt the technology due to their inability to recoup the investment cost. In order to reduce the trigger price, the volatility of the emissions allowances must be reduced- reducing the volatility of emissions from 49% to 20% reduces the trigger price to 32€/tonne. The model does not evaluate new build CCS plants or “capture ready” plants i.e. plants that are designed to be easily retrofitted, therefore the analysis was applicable to existing PC plant, which in the case of the UK have relatively short remaining life times. In addition, it was assumed that the plant operated as base load and was not capable of flexible operations i.e. the ability to switch the capture process on and off depending on the external constraints (e.g. fuel price, electricity price or carbon price)

Abadie (Abadie and Chamorro, 2008b) also investigated the value of two technologies; a flexible IGCC plant and an inflexible CCGT plant. The value of the option of the IGCC plant was associated with the option to switch inputs i.e. the plant could switch from coal to gas or vice versa. In addition, the optimal investment rules were derived for CCGT plant and IGCC plant before a comparison of the two was made (on the basis of the maximum NPV). The modelling approach used involved a 1D binomial lattice for evaluation of the (inflexible) CCGT plant and a 2D binomial lattice to value the (flexible) IGCC plant. Electricity prices were considered to be deterministic and carbon prices were not included in the analysis. In addition flexibility in output (the decision whether to run or not) was not considered i.e. the model assumed the plants would run base load.

Reinelt, (Reinelt and Keith, 2007) investigated the decision of whether to replace an ageing PC plant with either; a PC plant, a CCGT plant, a (retrofitted) IGCC plant or an IGCC plant with CCS. The model uses two stochastic variables- the price of natural gas and carbon prices which are invoked with a probabilistic timing. However once a carbon tax is invoked, it persists at the same value throughout the simulation. The methodology used to solve the model is stochastic dynamic programming set to minimise the expected present value (cost) of generation over a finite time horizon. The authors examined the impact of policy on the optimal investment timing and (through the carbon price) on the value attached to retrofitting IGCC plant with CCS. It is found that a lack of retrofit flexibility results in delaying the retirement of the existing PC plant, as uncertainty regarding future regulations (in the form of a carbon tax). In terms of assumptions, base load operation was assumed and uncertainty regarding electricity prices was excluded from the analysis. In addition, PC plant with CCS was not considered in the analysis.

Reedman (Reedman et al., 2006) examines the impact of regulatory uncertainty in the form of uncertain carbon tax (magnitude and timing) on investments in a CCGT plant, standard PC and IGCC plants and PC and IGCC plants with CCS. Fuel and electricity prices are treated as exogenous as they are taken from the CSIRO partial equilibrium model; however, when a carbon tax is introduced it is seen as a jump in the electricity price. The analysis uses the expected NPV with dynamic programming to value the option associated with delaying the investment by comparing the NPV in the base case with perfect foresight to the expected NPV in the case involving imperfect foresight and a CO_2 tax of uncertain magnitude and timing. It was found that while the standard PC plant was the optimal choice in the no tax scenario (presumably due to gas-coal price relativity), the imposition of a certain carbon tax pushes investment towards CCGT and CCS plants. In comparison, the impact of an uncertain carbon price on an uncertain date neither of the CCS plants was adopted- instead PC plant was chosen to be invested in immediately while IGCC plant was put on hold. Limits to the model include the modelling of carbon taxes instead of permits (and the value associated with settling permits yearly), the exclusion of the option to retrofit plant and the possibility to introduce a different probability distribution regarding the implementation of a carbon tax. Flexible output (the option to curtail production) was not considered.

Laughton, (Laughton et al., 2003) uses real options analysis (decision trees and market based valuation (aka modern asset pricing)) to evaluate the several options faced by a company extracting natural gas from a field and compare this result to that obtained using probabilistic DCF. As CO_2 must be removed from the gas prior to selling, the company faces the option to vent or sequester the stripped CO_2, using the natural gas as the energy source. In addition, the authors derive the option value of investing in the sequestration facility now or never and finally the value of the investment to decrease the future cost of a sequestration plant. The authors compare two regimes: a tax regime and a cap and trade regime. A 2D lattice is used to model the future trajectories of prices. The authors also consider correlation between gas and carbon prices. The authors find that DCF undervalues the constructed sequestration project compared to ROA. They also find that DCF assigns less value to the investment to decrease future sequestration costs. The model does not consider the effect of delaying investment to obtain information on future CO_2 regulation.

Sekar (Sekar, 2005) reported the impact of uncertain CO_2 price on the option to retrofit an IGCC plant with CCS compared to a PC and IGCC plant where retrofit was not possible. The problem was approached so that CO_2 price was the only type of uncertainty involved. Market based valuation (modern asset pricing) was used to value cash flow uncertainty. The option to retrofit CCS to the flexible IGCC plant was modelled as an American call option and solved using dynamic programming (binomial tree method).The author found that under the fuel price assumptions made, PC plant has the most likelihood of being the optimal investment. In addition, the value of the option to retrofit increased with increasing uncertainty in carbon prices. Limitations to the study include the CCGT being excluded from the analysis and a static fuel price.

Liang et al (Liang et al., 2007) value the option to retrofit a PC plant in China with CCS as an American option. The authors use Monte Carlo analysis to derive the option value by subtracting the mean NPV of a capture ready plant from the mean NPV of a standard plant and find that the gross value of the capture ready option varies between \$0.1m (worst case) and \$107m (best case), when a range of different input parameters are used. Moreover, the range of gross values is highly dependent on the discount rate used. The Monte Carlo approach allows multiple parameters to be altered including stochastic carbon and electricity prices and correlations between coal, carbon and electricity to be taken into account. Although CCGT plant is excluded from the analysis, given the amount of coal plants expected to be constructed in China in the future, this assumption is reasonable, however the same does not hold for the UK.

In addition to the papers above Kemp (Kemp and Swierzbinski, 2007) finds the value associated with the UK government issuing long term capture options to finance CCS, in this way long term risk associated with emissions is reduced by guaranteeing investors a minimum price of carbon. The authors acknowledge possible difficulties associated with establishing a baseline for emissions and issues surrounding the transferability of the options.

While most of the studies derive findings related to the optimal decision conditions under which to invest in CCS, none are specific to investment in the full CCS chain in the UK and none have extended the ROA analysis to evaluate both the optimal decision conditions and characterise the (time-dependent) profile over which the optimal investment decision could take place. While the time to exercise an investment option using ROA is necessarily stochastic; the current status of the UK generation system (as presented in Chapter 2) suggests that such analysis would be useful for both government and industry. The following methodology will focus on the option value to wait before making an irreversible investment in coal fired plant investment and to characterise the time dependent probability profile of the investment decision being exercised.

6.3.5 Problem formulation

This Section formulates the problem posed by the research questions and matches it to an appropriate form of real options analysis. The objective is to provide a clear account of assumptions and reasoning in the choice of model process.

Firstly, the research questions answered in this Chapter are reiterated:

- When could a coal with CCS plant replace a CCGT plant as the preferred method of generation?
- What is the effect of revenue uncertainty likely to be on CCS enabled coal fired plant deployment i.e. what extra compensation will the generator require in order to build a CCS plant?

One of the conclusions of Chapter 5 was that in terms of CCS enabled plant, PC was closest to commercial deployment. Therefore PC plant is chosen as the CCS plant for the analysis. This does not mean that the plant is the best long-term technology option in terms of performance, but in the near-term is the most likely to be deployed at full scale. In addition, this appears to be the technology that the UK government is backing for the CCS competition.

Firstly, a few general points on the modelling approach are made, before an overview of the more specific areas relating to models answering the individual research questions.

In general, there are two approaches to modelling power generation assets using ROA. The first is to model from the top down, using parameters such as capital cost and fuel cost and, most importantly, an assumed availability factor (i.e. the percentage of time that the plant runs). The second approach is to model bottom up and to model the plant as it reacts to price signals from the market and hence decides whether to come on line or not and thereby derive the availability factor of the plant. The two approaches both have advantages and limitations.

The top down approach assumes a plant operational profile that exists for the whole of the economic lifetime of the power plant in question while the operating profile for a plant using bottom up modelling is derived from running the model itself i.e. the number of periods that the plant runs in response to favourable market conditions. As such the top down approach tends to assume that the plant operates as base load and therefore has a constant annual load profile. The load profile for the bottom up modelled plant is derived from the model. The latter approach has a number of more specific applications: it is more suitable for evaluating peaking plant i.e. plant that comes online for short periods of time to provide extra power, and also for evaluating plant that lies in the middle of the merit order (the order in which plants are dispatched i.e. provide electricity). As these plants react to the price of electricity set by the market, and choose whether to run or not, the bottom up approach suits them best.

For the purposes of this thesis, the top down approach is used for three reasons: lack of information regarding the operational costs and flexibility of CCS plant, lack of information regarding long term electricity prices (i.e. forward curves) and the likely environment that CCS will operate in. In order to make a realistic bottom up model, data detailing plant performance would be required that is not available for CCS plant. Papers that have published methodologies of bottom up approaches to plant evaluation typically require the following information: minimum on and off times, minimum start up (and ramp) times, minimum generation level, response rate constraints, non constant heat rate and variable start up costs (Gardner and Zhaung, 2000). The definition of these terms may be found in the appendix, but it is necessary to state that the author knows of no publicly available sources of such data for CCS plants. In addition, the interaction of these characteristics with the decision to run a plant is non-trivial i.e. the plant operational profile can mean that the plant stays online, even when faced with a low electricity price, and could lead to issues when considering the impact of cycling generation on the rest of the CCS chain. The operational environment was briefly touched on in Chapter 5: essentially, due to the complex technology, economics and politics involved in the deployment of CCS it is unlikely that the first generation of CCS plants will operate at anything other than base load. Although it is a moot point, CCS is assumed to operate as base load plant for this thesis and in order for the comparison to be fair, so is CCGT plant.

Therefore the choice of plant is between a base load CCS plant and a base load CCGT plant (which is currently the new entrant of choice in the UK power market).

Moving on to specific items relating to the research questions; the first research question asks for the effect of revenue uncertainty and hence the decision to wait before investing in a CCS plant. The call option can be taken at any point, from the present until expiry (it is assumed the option lasts forever) and is therefore a perpetual American call option. Investment is assumed to be instantaneous, which is a significant simplification of the model made for tractability- the option to invest in a power plant in a sequential nature has been valued using ROA (Rothwell, 2006). The volatility of the revenue is modelled as the natural gas price process. The reasons for this are the position of CCGT plant as a price setter in the market, and as a result of the analysis in Chapter 5; generating technologies were found to have different cost breakdown structures revealed by sensitivity analysis. In particular, the cost of generation from a natural gas plant has been found to be particularly sensitive to the price of natural gas (some 75% of the generation cost is as a result of natural gas). Therefore it is reasonable to state that any fluctuation in natural gas price will see a parallel fluctuation in the price of electricity generated from gas.

In terms of the second research question, a stochastic simulation is required to investigate the effect of the price of natural gas on the viability of coal with CCS as a generating option. The most suitable simulation method reviewed is the mean time to absorption, or first hitting time, method. The mean time to absorption has two advantages over the Black-Scholes model:

- The mean time to absorption method uses the actual drift of the underlying stock, not the risk free rate as the Black-Scholes does;
- The mean time to absorption method produces a probability distribution which will be useful in order to assess when the optimal investment decision may be applied.

Given that the mean time to absorption method will be used, the problem can be formulated as follows:

- Initial Price: The cost of electricity generated from natural gas;
- Strike price/Boundary value: the optimal price (breakeven plus margin) which must be reached before investment in a coal CCS plant will take place (derived from ROA);
- Volatility: The volatility of natural gas based on historical data;
- Drift: the drift of the natural gas price based on historical data.

The output of the model is the probability profile of the time over which investment in coal CCS plant could take place. As the objective of the research is to look at investment timing over a long scale it could be argued that models taking into account short term jumps and spikes are not necessary as a longer term view is required that will enable the long term trend to be modelled. Instances in the literature where this reasoning has occurred include Abadie (Abadie and Chamorro, 2008b).

The model is bounded by the parameters set by the start price; the cost of generation from a CCGT plant with no CCS, and the strike price; the optimal price (breakeven plus margin) required to trigger investment. The reason for this is that the research question asks when coal with CCS will become viable over a CCGT plant, currently the new entrant of choice. As an initial approach and in order to simplify the model, the price of coal and carbon is considered to be fixed for the life of the plant. Sensitivity analysis is used to gauge the impact of higher and lower carbon and fuel prices on the exercise boundary. The choice of parameters relates to the tornado diagrams seen in Chapter 5 which show that the cost of generation from CCGT plant depends on the price of fuel itself, while the cost of generation from a PC plant with CCS is dominated by capital costs. GBM is chosen to model natural gas prices due to the expectation that natural gas prices will rise in the future as supply weakens and demand grows. This argument relates back to that put forward in Chapter 2 regarding the relative abundance of coal compared to natural gas, implying that the fundamentally coal will be able to keep up with demand. This coupled with the storable nature of coal and the relatively low impact that coal prices will have on the cost of generation imply that the cost of natural gas will be the determining issue in the success or failure of the CCS system. Finally in terms of relationship to electricity prices, and therefore potential for profit, it has been shown that the price of natural gas and electricity have a correlation of 0.989 (Yang et al., 2007) in the UK market since 2003. As such, it would be logical to conclude that if electricity generated from a coal plant with CCS were to cost more than the cost of electricity from a CCGT plant, the plant would not make money and would therefore not be built. Therefore the price of natural gas will determine the success or failure of CCS plant.

Decommissioning is not explicitly evaluated due to a lack of data on the costs involved. All costs for transport and storage parts of the chain are expected to involve the full life costs of the storage process; however it is likely that these costs are underestimated as has been the case for nuclear waste. It is worth mentioning that one important difference is that the storage cost will commence at the same time as plant operation. As a result, the value of compound interest will not augment decommissioning funds, unlike the case in which all costs were incurred at the end of the operational lifetime. In terms of decommissioning it is also likely that costs of plant decommissioning are not negligible, but information on these costs are remarkably absent from any literature published on the subject including the IPCC report.

Specific methods employed for solving the options models are given in the relevant Sections, along with the justification for the choice of the underlying which is dealt with in the next Section.

6.4 The underlying gas model

The value of real options derives from the nature of the underlying asset, more specifically, the unpredictable future price of the underlying asset. Real options theory recognises the value of the option to buy or sell the asset at some point in the future value based on the price of the underlying. Section 6.4 presents the reason for choosing natural gas as the underlying process.

There are a number of stages to the characterisation and definition of the underlying process:

- The selection of the underlying itself;

- Identification of the stochastic process that the underlying follows;
- Parameter estimation of the stochastic process i.e. the volatility and drift.

Real options models have traditionally assumed commodity prices or portfolios of non traded assets with perfect correlation to traded assets, (Trigeorgis, 1996) (Luenberger, 1997) as the underlying. This thesis takes natural gas as the underlying process. The reasons for choosing natural gas as the underlying process are covered in Chapter 3 and 5 and with the research questions stated at the beginning of this Chapter. The following paragraph draws on the conclusions of the previous Chapters to set the selection of the underlying in context.

The research questions provide the justification for the selection of the underlying i.e. "when could a coal CCS plant replace a CCGT plant as the preferred method of generation?", and "what is the effect of revenue uncertainty likely to be on CCS enabled coal fired plant deployment?". The first question implicitly acknowledges that coal plants with CCS are not viable at present, but are expected to become viable within a less than infinite time, based on the price of natural gas. The second question relates to the value associated with the option to wait and its impact on the trigger price (the cost of generation from a CCS coal plant).

In the context of the second research question, revenue volatility will determine the additional value attached to waiting before making the investment decision. The key is to how the price of natural gas influences the viability of coal plant with CCS. The main reason for choosing natural gas as the underlying process to represent revenue uncertainty is that gas fired CCGT plants are currently the plant of choice for developers and the cost of electricity generation is dependent upon the price of natural gas; therefore it is likely that the price of natural gas gets passed through to electricity prices. Moreover, in the UK, the price of electricity has shown a strong correlation to the price of natural gas; 0.99 between 2003 and 2005 compared countries such as Finland where the correlation is 0.33 (Blyth et al., 2007). As a result natural gas prices also act as a reasonable proxy for electricity prices and hence revenue of the first wave of coal-fired CCS plants. As this thesis is only concerned with the time until CCS becomes viable, the effect of CCS plant penetration on the price of electricity i.e. a possible decoupling of gas and electricity prices, is outside the scope of this thesis and not investigated.

The second justification lies with arguments constructed in previous Chapters. Chapter 3 established that in order for coal with CCS to become competitive it would have to become a viable alternative to CCGT plant, but Chapter 5 showed that no economic incentive currently exists to build a coal plant with CCS over a CCGT plant, despite there being system benefits (e.g. security of supply). Chapter 5 also established that the price of carbon will drive coal to switch to CCS before natural gas due to the carbon emissions intensity of the fuel (the cost of CO_2 avoided). However, under such a carbon price (of around £28/tonne), generation from natural gas will be cheaper than a coal fired CCS plant. In comparison, due to the lesser carbon intensity of the fuel, CCGT plant will switch to CCS at a much higher carbon price (£35/tonne). Given the dominance of natural gas price in the cost of generation from CCGT plants, it is the price of natural gas that will be the driver for a switch to coal plants with CCS. Given that the price of natural gas is the key driver in determining when coal with CCS will become viable, provides the logic to pick it as the underlying.

The second stage of identifying the underlying involves identifying the stochastic process that best represents natural gas. The choice of stochastic process to act as being representative of the gas price will determine the output and behaviour of the model and determine the answer to the research questions posed at the start of the Chapter.

There have been many publications that study the most appropriate stochastic process for commodity prices and in particular for natural gas prices. The three main classifications of stochastic process are mean reversion, jump-diffusion and Brownian motion (either geometric or arithmetic) (Dixit, 1992). There are a variety of views as to the nature of the underlying dynamic that governs natural gas prices with publications using models based on all processes. A significant body of literature points to mean reversion being the most appropriate process for commodity prices. This includes Pindyck and Dixit who state that the price of a commodity should be modelled as a mean reverting process to allow for the price to revert to the marginal cost of producing the commodity in the long term (Dixit and Pindyck, 1994). However, this assumption is context specific- in daily markets, gas prices do show a strong mean reversion and jumps, however in the longer term, other authors have put forward that gas prices have shown properties of a random walk since 2001 (Geman, 2005b). The causes of mean reversion in short time periods can be supply and demand, temperature and a multitude of other factors. Over the longer time period (inter-year), it is believed that supply and demand determine the long run behaviour of commodity prices. Therefore the emergent question becomes what time scale are the thesis questions most suited to?

As this thesis is investigates the time until CCS becomes viable, long term trends are more important than short term price dynamics. As a result, the stochastic process that best represents the fundamentals of supply and demand rather than short term price dynamics is chosen. The contention is that the long term effects are most important due to the time scale over which investment takes place and the option to wait before investing in a CCS plant. Chapter 2 identified that at the global scale, natural gas reserves are limited (compared to coal) while gas demand faces strong growth in Europe and USA, especially due to the prospect of carbon penalties (which would encourage the use of gas over coal given a high enough carbon price). As a result it seems reasonable to conclude that the market for natural gas will remain tight thereby driving a long term upward trend in natural gas prices. It is expected that due to its abundant nature, coal will not exhibit such long term behaviour. This can be seen in Chapter 2 when the abundance of coal was cited as one of the reasons why it will remain part of the generation mix into the future. In recent years it the price process followed by natural gas has changed, perhaps in part due to the nature of natural gas reserves. Geman (Geman, 2005b) investigated the historical price process of natural gas and found that it switched from mean reversion to GBM in 2001, which would be expected in a resource constrained market. As a result it seems reasonable to assume that long term natural gas prices will also exhibit GBM, and given the lifetime of a power plant, that the macro behaviour of natural gas should be represented in the underlying process. An alternative approach could be made by modelling the mean reversion and price spikes observed in the natural gas data. A comparison of the effects of alternative processes on model outputs would be useful, but due to time constraints and for simplicity it is deemed outside the scope of this thesis.

The following Section derives the input parameters of drift and volatility that will be used in the mean time to absorption and the options model respectively.

6.4.1 Gas-price volatility and drift

Through the wide range of literature on Real Options, there is comprehensive information regarding techniques for estimating the volatility and drift of the underlying variable. This Section provides a review of the literature for methodology of estimating volatility and drift and then derives the two parameters of the underlying for use in the options model and the first hitting time model. The techniques described cover GBM; other types of processes require other techniques to estimate relevant parameters e.g. speed of mean reversion are not in the scope of this thesis, textbooks such as Geman's provide an overview (Geman, 2005a). The volatility of a process is a measure of the instantaneous deviation from the expected value. The drift is the underlying trend (the expected value)

6.4.1.1 Methodology

This Section presents the methodology used to estimate the drift and volatility parameters of the option model. As it is taken as given (for the purposes of this thesis) that price of gas on the UK market can be represented by GBM (Geman, 2005b), two parameters need to estimated: the volatility and drift of the gas price process. These parameters are key inputs for the options model and the first hitting time model investigated later in this Chapter. The parameters can be estimated in numerous ways: simulation (e.g. Monte Carlo), analysis of historical price processes, or some form of expert elicitation or judgemental analysis (Luehrman, 1998). In this thesis, historical prices will be used as data has been made available from ATCO Power and Heren Energy.

If the price of natural gas over time can be represented by GBM, the (continuous) path taken over time can be defined by the following stochastic differential equation (Wilmott et al., 1995):

$$\frac{dS}{S} = \mu dt + \sigma dX \tag{6.5}$$

Where:

S	: price of the asset
dS	: increment in asset price process (i.e. the infinitesimal change in price over time)
dX	: Wiener process
σ	: volatility
μ	: drift

It is also shown (Wilmott et al., 1995) that the Weiner process is the stochastic element, with :

$$dX = \phi\sqrt{dt} \tag{6.6)4}$$

 : random variable with mean zero and standard deviation of 1

dt : time increment

From equation (6.5), the returns, are log normally distributed, implying that the log of the price is normally distributed. If the price process is simulated using the log of the price instead of the price itself, Wilmott et al (Willmott, 1995) show that for the unlogged price to be GBM, the drift of the log of the price is:

$$d\ln S = \left(\mu - \frac{\sigma^2}{2}\right)dt + \sigma dX \tag{6.7}$$

Where:

dlnS : the difference in the log of the price

μ : drift

σ : volatility

dt : time increment

dX : Weiner process

The value of lnS in equation (6.7) is normally distributed and implies that S has a lognormal distribution. The drift term for the standard price process (equation(6.5)) is greater than the drift for the of the log-price process, where volatility has the effect of reducing the drift.

Given an historical time series, one approach to parameter estimation is to take the logarithm of the ratio of the price of natural gas on trading day t+1 compared to the price on the trading day in question, thereby giving the relative price change on a daily basis. The relative return of the price of natural gas is given by:

$$y_t = \ln\left(\frac{x_{t+1}}{x_t}\right) \tag{6.8}$$

Where:

y_t : relative return

x_t : price at time t

The logarithm of the ratio of the cost $G_{(price)}(t)$ of one therm of gas at time t in the future to that at the present time t_0 will follow a normal distribution with mean and variance that both increase with time: $\mu(t-t_0)$ and $\sigma^2(t-t_0)$, where σ is the volatility. This implies that the returns for the actual prices have a log normal distribution.

Volatility is the standard deviation of the expected returns on the underlying asset and is given by the following expression, and is based on the variance of the log return of inter daily prices, (Mun, 2002):

$$\sigma = \sqrt{\frac{1}{n-1}\sum_{t=1}^{n}\left(x_t - \overline{x}\right)^2} \tag{6.9}$$

Where:

x_t : the price of the stock at a point in time

$\overline{x}$: the mean of all x_t

n : number of data sets under consideration

The volatility figure is dependent on the frequency or spacing of the sample data points. For example, if the historical time series were in daily intervals, the volatility would be daily. In order to convert the daily volatility into an equivalent annual value, it is necessary to multiply the daily volatility figure by the number of trading days in a year. As there are 252 trading days per year, the average daily value should be multiplied by the root of 252. To derive monthly volatility, the factor is the number of trading days per month (typically 21) and for weekly volatility the factor is 5. Therefore the daily volatility is multiplied by the square root of the time period that is being used. Volatility varies with the square root of time to avoid trivial or meaningless solutions as dt→0 (Wilmott et al., 1995). As the price of natural gas follows a GBM, the square root of time scaling factor can be used.

$$\sigma_a = \sqrt{252}\sigma_d \tag{6.10}$$

Where:

σ_a : annualised volatility

σ_d : daily volatility

In this case, the drift of the log of the price is the average of the relative returns:

$$\mu = \frac{1}{n}\sum_{t=1}^{n} y_t \tag{6.11}$$

6.4.1.2 Data sets and parameter estimation

This Section presents estimates of the volatility and drift parameters that are used in the options model and first passage time calculation. Following the methodology presented Section 6.4.1.1, historical data is used to derive the drift and volatility.

The two sets of data are daily NBP (National Balance Point–mid point) prices for natural gas for the period March 1996 to March 2006, provided by Heren Energy (Heren, 2006), and monthly data for 1998-2008 from ATCO Power, (ATCO, 2008). The datasets are used to calculate gas price volatility and drift. Figure 6-4 presents a plot of the daily price data.

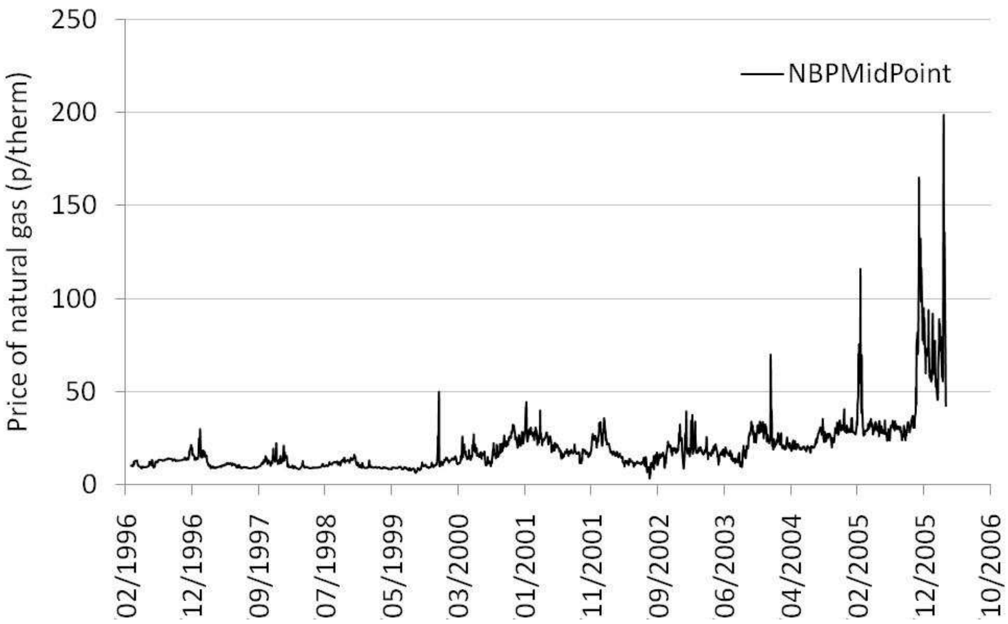


Figure 6-4: Spot price of natural gas price at national balancing point, 1996-2006 (Source: Heren Energy)

Figure 6-4 shows the daily price of natural gas at the national balancing point in the UK. It is clear from inspection of the graph that daily gas prices vary cyclically throughout the year and that there appear to be some periods when significant price spikes occur.

After applying the methodology in 6.4.1.1 to the raw time series, the volatility of natural gas based on one trading year of data was calculated- the results are given in Table 6-2.

Table 6-2 shows that the annual values for volatility are very high- in most cases in excess of 100%. This is reflected in the average value over all years of 168%. In addition, the volatility of the spot price increases between 2002 and 2005.

Table 6-2: Average daily and annual volatility of natural gas based on Heren data

Year	Daily volatility	Annual Volatility
1996	0.05	0.72
1997	0.08	1.29
1998	0.06	1.02
1999	0.12	1.95
2000	0.10	1.59
2001	0.09	1.40
2002	0.13	2.06
2003	0.12	1.85
2004	0.11	1.80
2005	0.15	2.34

In order to understand the level of volatility seen in natural gas spot prices, it is useful to make a comparison with another commodity. Figure 6-5 shows the logarithm of the ratio of inter-day prices according to equation (6.8) for WTI oil spot prices (left hand graph) and natural gas spot prices (right-hand graph) The average annual volatility of oil over the same period taken from the WTI (EIA, 2006) spot prices is 40%, compared to 168% for natural gas. Therefore gas prices exhibit high volatility.

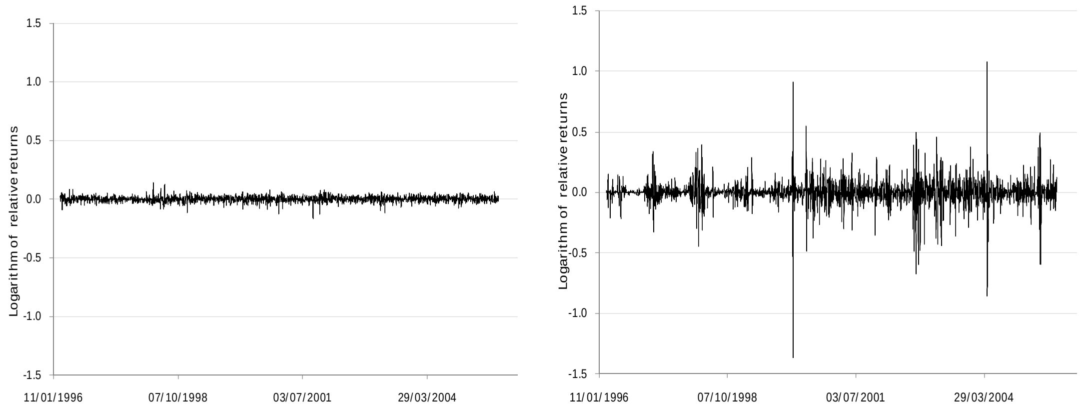


Figure 6-5: Comparison of variation in daily prices of oil (left) to natural gas (right)

Table 6-3 presents the average monthly volatility of natural gas prices. It is clear that there is some element of seasonality in the prices, with winter months having higher average volatility on average than summer months. This is partly due to supply and demand in winter as more gas is required in the UK. Other drivers of natural gas prices include crude oil prices, temperature, natural gas storage (LNG) levels (i.e. inventory levels), and weather (Brown and Yacel, 2008).

Table 6-3: Average monthly volatility

Month	Average Monthly Volatility
January	72.3%
February	44.9%
March	62.9%
April	37.9%
May	33.6%
June	28.0%
July	44.4%
August	38.7%
September	40.2%
October	34.3%
November	42.2%
December	77.8%

In addition to the data from Heren Energy, monthly gas price data for the period 1998-2008 was obtained from ATCO Power. Figure 6-6 shows the average monthly price based on historical data that has been discounted into 2007 money. The annual volatility based on monthly data is 66%. A similar monthly trend in volatility can be observed to that in Figure 6-6, with more volatile prices in winter months than in summer months.

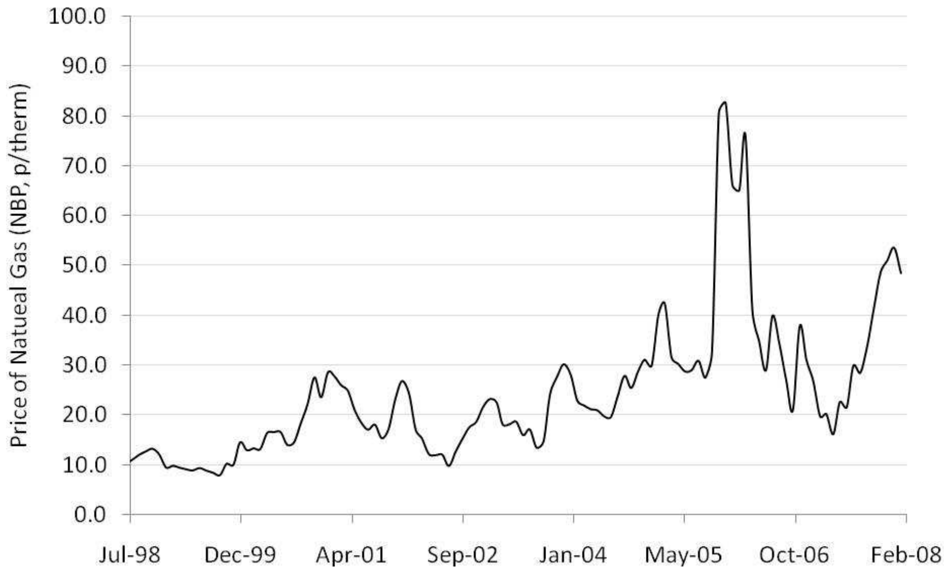


Figure 6-6: Average monthly price of natural gas (Data source: ATCO Power)

The seasonality effect and high volatility of natural gas prices found by the analysis of the spot price data is consistent with other sources; the US Energy Information Agency analysed spot prices between 1994 and 2007 and showed annual volatility fluctuated between 49% and 218% (Mastrangelo, 2007). In addition, the natural gas spot price was found to exhibit the same seasonality as described in this thesis. Although gas prices in the US cannot be used directly as a proxy for the UK market (due to different market structures and import facilities), the general comparison suggests that the high volatilities derived in this Section are valid.

The high annual volatility presents a problem for the options model as one of the key drivers of the option value is volatility; overestimating volatility overstates the option value of waiting and delays option exercise. Therefore the question arises of how to treat the volatility of natural gas so that it can be used in the options model.

Issues related to parameter estimation for options models are touched on in published reports. Abadie points out that price spikes are important for short term price modelling but the impact is dampened when longer time periods are considered (Abadie and Chamorro, 2008a). This implies that the application of the real options model dictates the volatility that is used. For example, if the objective of the options model were to value a plant on an hourly basis, price spikes would be important as they would indicate favourable or unfavourable operating conditions (Näsäkkälä and Fleten, 2005). Over longer periods of time the effect of price spikes is likely to be diluted. This can be seen when comparing annualised monthly volatility and annualised daily volatility.

Figure 6-7 shows the time and context dependent nature of volatility. The diagram could be said to hold for all options problems- electricity prices, which typically display mean reversion in the short term, exhibit higher volatility than natural gas. Gardner (Gardner and Zhaung, 2000) derives a volatility of

3023% and mean reversion of 2899 (equating to a half life of 2 hours) on an annual basis for electricity prices in New England for use in a short term model.

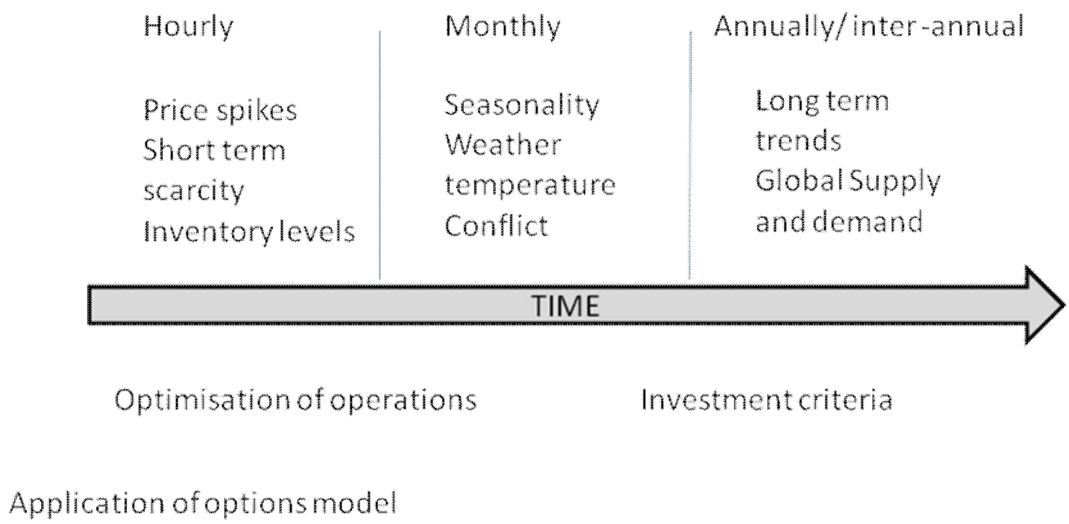


Figure 6-7: Illustration of volatility application for options analysis

If the data is averaged over a month, volatility falls to 33%. The problem of high volatility spot price data is also dealt with in the literature. Seppi (Seppi, 2002) states that given the strong mean reversion in energy prices, annualised volatility grossly overstates the actual volatility of annual price changes. This suggests that volatility derived from the daily spot price cannot be used directly in the options model of this thesis. Seppi (Seppi, 2002) states that although the standard convention is to quote annualised volatility, option pricing models account for the overestimation by de-annualising the annualised number. As a result, the following expression is used:

$$\sigma_{\mathrm{a(modified)}} = \sqrt{1} \times \sqrt{\frac{\sum_{i=1}^{n} (G_{(\mathrm{price})i} - \overline{G}_{(\mathrm{price})})^2}{n-1}} = 13.7\% \quad (6.12)$$

The drift parameter is calculated by taking the average of the increase in annual prices. Geman (Geman, 2005b) found the market switched from mean reversion to GBM in 2001. The reason for using the annual average is to capture the average annual increasing trend in prices, and therefore the period is one year to fully capture the effect of GBM drift (Campbell et al., 1997).

As a result of the analysis conducted in this Section, a volatility of 13.7% and a drift of 10% have been derived. Both are subject to sensitivity analysis later in the Chapter.

6.4.1.3 Comparison with other studies, projections and reality

Due to the uncertainty surrounding the values derived for the volatility and drift parameters, and the potential impact this may have on values calculated from the options model, Section 6.4.1.3 compares the derived volatility to other published options models that use the volatility and drift of natural gas prices as model inputs.

The format in which fuel prices are presented varies between studies. To facilitate a comparison of values, it is necessary to convert reported values into a common unit.

$$C_{gas} = \frac{C_{therm}}{0.02931} \tag{6.13}$$

Where

C_{gas} : the cost of gas (£/MWh)

C_{therm} the cost of natural gas (£/therm) (the unit used in the UK market)

0.02931 the conversion from therms to MWh: One therm = 29,308 watts and one Watt = 3.412 BTUs

The conversion enables the price of fuel to be expressed in £/MWh or £/GJ. This value should not be confused with the fuel cost of operating the plant, as plant efficiency would need to be taken into account. Table 6-4 presents an overview of values of the volatility and drift of natural gas used in options models and other technical reports and the basis on which values have been derived.

Table 6-4: Values for volatility and drift of natural gas

Study	Volatility	Drift	Technique used for parameter estimation
(Roques et al., 2006)	20%	-	Judgement
(EIA)			Historical data
(Reinelt and Keith, 2007)	\$0.2/GJ	\$0.1/GJ	EIA forecast
(Laurikka, 2005)	13%		
(Cavus, 2001)	48.5%		Historical data
(Abadie and Chamorro, 2008b)	20%		
(Laughton et al., 2003)	20%		Expert elicitation
(Yang et al., 2007)	7.75%		

The literature reports volatility that is significantly lower than that derived from market data. This suggests that, in terms of investment modelling, the spot price volatility of natural gas is inappropriate as a measure of underlying volatility.

In addition, energy companies are not exposed to the fluctuations in natural gas prices due to buying strategies (ATCO, 2008). Specifically, generating companies typically reduce exposure to gas prices so that in the near term, they are completely hedged against fluctuations in the price of natural gas, whereas for time scales in the order of years the proportion of hedged gas reduces.

In addition to a comparison with published data, the derived parameters can be tested by comparison with long term BERR forecasts for natural gas prices. The graph below shows the boundaries set by BERR in its projections (ATCO, 2008).

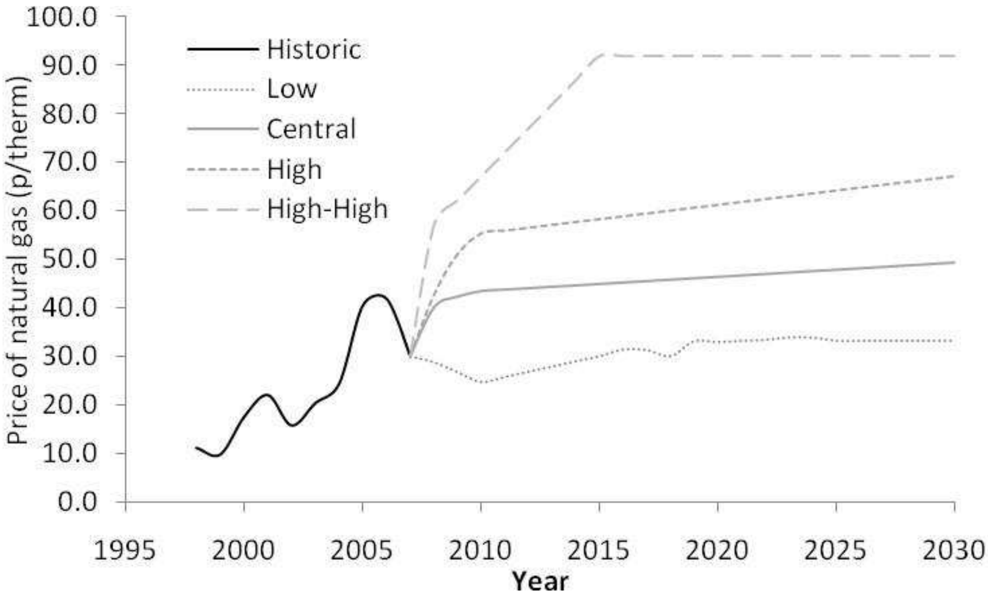


Figure 6-8: Forecast of UK natural gas prices (Data source: BERR, 2008)

The BERR central forecast shows gas prices staying relatively constant or slightly increasing between 2015 and 2030 after a steep increase in the near term. As a result of arguments presented in Section 6.4 (i.e. tightening of supply due to increasing in demand in the long run), this thesis will use the high and high-high scenarios to benchmark the GBM parameters that have been derived. More specifically, the expected value of the stochastic process after a certain amount of time should be no more than that given in the high or high-high scenarios. Using the values derived for drift and volatility it is possible to calculate the expected value of the GBM process representing natural gas at a future point in time according to the following equation (see the Section 6.8 for details):

$$\varepsilon\left[\mathrm{T}^*(\mathrm{S}_0 = \mathrm{S}_\mathrm{b})\right] = \frac{1}{\alpha - 0.5\sigma^2}\ln\left(\frac{\mathrm{S}_\mathrm{b}}{\mathrm{S}_0}\right) \text{ for } \alpha > 0.5\sigma^2 \tag{6.14}$$

Where

$\varepsilon[x(t)]$: expected time at which S will reach the boundary

S_0 : price of natural gas at start, 28p/therm

S_b : boundary price, 93p/therm

α : drift, 10%

σ : volatility, 13.7%

The expected time to cross the boundary is 15 years, suggesting that the value derived is high or σ is too low. From inspection of equation (6.14), it can be seen that all other things being equal, the effect of volatility is to reduce the value for the drift term. If the same volatility is used, a value for α of 8% would be required to stay within the BERR high-high projection. For the value of α to be 0.10, the volatility of natural gas would need to be between 25% and 30% to stay within the high-high bound.

If the boundary were to be decreased, for example to coincide with the high case projection, the boundary would move to 67p/therm. To allow $\alpha = 0.10$, a volatility of between 30% and 35% would now be required. It is noted that the volatility of 30% is beginning to move away from the average that is presented in other studies.

The interplay between volatility and drift shows how sensitive the expected price is to small changes in volatility. Therefore it is proposed that a central case be used with a volatility of 13.7% and α of 8%, with a sensitivity analysis to be run of higher and lower volatility and drift parameters.

6.4.1.4 Conclusion of parameter estimation

The price process of natural gas has been assumed to be represented by GBM. Historical data has been used to derive the GBM parameters i.e. volatility and drift from daily spot prices. In reality, the values for drift and volatility of natural gas are not constant but vary- short run gas prices based on the spot price show effects of seasonality, and price jumps.

The value of volatility associated with daily NBP prices was found to be too large to use directly in the modelling of this thesis. In addition, it was found that the values used for volatility in options investment models tend to be an order of magnitude lower than the annual volatility of the spot price. Moreover, a generator is not exposed to the high volatility of gas prices due to hedging strategies. Therefore it was concluded that that the spot price volatility is not representative of the long term volatility of natural gas for the purposes of the model used in this thesis which is to value investment.

As a result, the long term volatility and drift have been taken from the data available and benchmarked against long term government scenarios to give an acceptable range of drift (8%) and volatility (13.7%). The model will undergo sensitivity analysis to account for deviation in the volatility and drift parameters.

6.5 Options model

The objective of the options model is to quantify the trigger value of revenue (electricity price) that is required for a generator to build a CCS plant. Once identified, the revenue is then used to answer the research question regarding investment timing:

- What is the effect of revenue uncertainty likely to be on CCS enabled coal fired plant deployment i.e. what extra compensation will the generator require in order to build a CCS plant?

6.5.1 Problem formulation

Under traditional investment appraisal methods, investment in a project takes place when the net present value of the investment is positive i.e. the discounted revenue stream more than compensates for the cost of building a new plant. This can be expressed as:

$$\mathrm{NPV} = (\mathrm{R}/\delta) - \mathrm{C_c} \;>\; 0 \tag{6.15}$$

R : revenue

δ : capital recovery factor

C_c : cost of capital

However, there are a number of criteria present that imply that there is a value in a generator waiting before building a CCS enabled plant; these are given by Dixit (Dixit, 1992) together with Dixit and Pindyck (Dixit and Pindyck, 1994) and can be summarised as follows:

1. The investment in a new power station can be thought of as a sunk cost i.e. an irreversible investment;
2. The economic environment that the plant operates in exhibits uncertainty;
3. The investment opportunity does not disappear if not taken immediately.

The following paragraphs expand on the points above and provide arguments as to why the objective lends itself to such categorisation.
Firstly, once the decision to invest in a plant is made, the investment can be thought of as irreversible. Irreversible means that the investment is sunk and therefore is not recoverable. Dixit and Pindyck (Dixit and Pindyck, 1994) state that investments are sunk when the investment is industry or firm specific i.e. the output is non-transferrable. For the purposes of this thesis, a power plant is industry specific- it can only produce electricity, although it is noted that some plants, such as the IGCC CCS plant could be designed to switch output to hydrogen. Assuming that the industry is competitive, if the plant were not profitable, it would not be bought by other companies. Therefore costs would not be recoverable by selling a loss making plant.

The economic environment exhibits uncertainty i.e. the revenue stream is uncertain. This means that the revenue made by the plant is not deterministic. For the purposes of this thesis, revenue is the difference between the price of one unit of electricity and the cost required to produce one unit of electricity. It is assumed that the price of producing a unit of electricity stays constant which is a simplification, but in part reflects the expectation of relatively stable coal prices coupled with the top heavy nature of the investment (see the tornado diagram for a PC plant with CCS), while the price of electricity evolves over time according to a stochastic process. As a result, the revenue stream also evolves over time and is non deterministic.

The investment opportunity does not disappear if not taken immediately. This means that the investor has the option to build a plant at any point in time in the future. In fact the company could always decide to

defer investment and wait for the following period before making the decision to invest or wait again. In reality, this is also a simplification- a company faces pressure from competition to invest i.e. strategic decisions influence the investment decision, for which there are a myriad of reasons- an example could be to claim the subsidies for a demonstration plant. On the other hand, in reality, there is no specific time frame in which investment in CCS plant must be made. Of course, the situation would be different if the investment decision was whether to retrofit CCS technology to a coal plant with a certain number of operational years remaining, but for this thesis, the objective is to evaluate investment in a new PC plant with CCS. Therefore, for the purposes of this thesis, the investment opportunity is perpetual.
Given the situation described above, once a CCS plant has been built and commissioned, income is derived from the price paid for electricity. As the price of electricity is uncertain, the revenue stream is also uncertain. The question to answer is at what point is it optimal to make the irreversible investment in a new CCS plant, given that the revenue and hence value of the project evolves over time as stochastic process? The option of whether to invest in the project or not is equivalent to a perpetual call option- the right but not the obligation to buy stock at a predefined price. In this case, the predefined price is the cost of investing in a new plant, while the revenue is determined from the price of electricity, which evolves stochastically. Exercising the option exposes the owner to a stream of uncertain revenues, which can be modelled stochastically. In addition, as the coal plant is assumed to be running base load, it is exposed to the full range of price uncertainty i.e. it is assumed that the plant cannot switch production on or off. Therefore, this Section quantifies the effect of the uncertain revenue stream on the investment decision. As revenues are unknown i.e. stochastic, the time at which investment should take place cannot be derived. Therefore investment takes the form of a critical threshold at which electricity must be priced in order for investment in a CCS plant to take place.

For the purposes of this thesis, the volatility of the electricity price process is assumed to be the same as that for the natural gas price process. The two reasons for this are the correlation between electricity and gas prices historically and the expectation that gas fired plant will continue to act as the price setting plant for electricity. To reiterate, the correlation between gas prices and electricity prices has been 0.989 in the UK since 2003 (Blyth et al., 2007). The reason to expect this process to continue is the increase in deployment of CCGT plants coupled with increasing demand for natural gas as a fuel.

6.5.2 Perpetual American call option model

This Section presents the construction of the options model. As shown in equation (6.15) under traditional investment appraisal, investment in a CCS plant takes place when the NPV is greater than zero. The revenue produced by the plant is the difference between the price of electricity and the operational cost multiplied by the amount of MWh produced per year:

$$R = (P_e - C_o) \cdot \left(hr_{yr} \times U_{t(coal)} \times P_{c(coal)} \right) \tag{6.16}$$

R : annual revenue (£/year)

P_e : price of electricity (£/MWh)

C_o : variable operating cost of the plant (£/MWh)

hr_{yr} : number of hours per year (hr/year)

$U_{t(coal)}$: utilisation of coal plant (dimensionless)

$P_{c(coal)}$: capacity of plant (MW)

First, assume that revenue evolves as a GBM according to the following stochastic process and that the net revenues are perfectly correlated with a portfolio of traded assets (Dixit and Pindyck, 1994):

$$dR = \alpha R dt + \sigma R dz \tag{6.17}$$

μ : mean drift rate

σ : volatility

The expected value of the revenue is given by:

$$E[R(t)] = R e^{\mu t} \tag{6.18}$$

While the present value of the revenue stream is given by:

$$\int_0^\infty Re^{\mu t}\, e^{-\delta t} dt = R\int_0^\infty e^{-(\delta-\mu)} dt = \frac{R}{\delta-\mu} \tag{6.19}$$

Where:

δ : cost of capital

Dixit (Dixit, 1992) also shows that the value of the option to wait is given by the equation:

$$\Omega = BR^{\beta} \tag{6.20}$$

Where:

Ω : option value

B : positive constant

β : constant (function of δ and σ)

The investment opportunity will be exercised when the value of the option to wait is zero. This occurs when the option value is equal to the NPV value. This is known as the value matching condition and means that the investor is indifferent to waiting. Assuming that all parameters apart from P_e are constant, and that μ, the rate of increase in revenue is zero (Dixit, 1992), this occurs at R* and P_e*.

$$BR^{*\beta} = \frac{R^*}{\delta} \text{ -}C_c \tag{6.21}$$

Dixit (Dixit, 1992) shows that β is the solution to the differential equation that describes stochastic revenue process over time- the solution involves a quadratic term for β:

$$\beta^2 - \beta - \frac{2\delta}{\sigma^2} = 0 \tag{6.22}$$

Solving the quadratic equation for the positive root gives a value of β

$$\beta = \frac{1}{2}\left[1 + \sqrt{1 + \frac{8\delta}{\sigma^2}}\right] > 1 \tag{6.23}$$

Where:

σ : volatility associated with the revenue stream

δ : the capital recovery factor

The second condition, the smooth pasting condition, requires the derivative of the option value and the NPV to be equal at the point of optimal exercise. Therefore, the optimal revenue value occurs at the point at which the NPV and option curve are tangent. Hence, expression (6.21) is differentiated with respect to the optimal revenue:

$$\mathrm{B}\beta\mathrm{R}^{*(\beta-1)} = \frac{1}{\delta} \tag{6.24}$$

The optimal revenue value is given by eliminating B:

$$\mathrm{R}^* = \frac{\beta}{\beta - 1} \times \delta \times \mathrm{C_c} \tag{6.25}$$

The optimal trigger price of electricity is given by the equation below, where R* can be substituted with the identity in (6.25) :

$$\mathrm{P_e}^* = \left(\frac{\mathrm{R}^*}{3.72 \times 10^6 \,\frac{\mathrm{MWh}}{\mathrm{yr}}}\right) + \mathrm{C_o} \tag{6.26}$$

For the purposes of this investigation σ = 0.137 and δ = 0.0915 (for an interest rate, r, of 8% and a 30 year life). Appendix F contains a discussion on the impact on the critical option value if μ > 0 and the boundary conditions of this options model.

6.5.3 Results of options valuation

The results of the perpetual call option are presented in this Section. Figure 6-9 illustrates the underlying point; although the NPV (the dotted line) becomes positive at £46.21/MWh, the value of the option to wait (the solid curve) is greater and therefore the generator would delay investment until the NPV line is tangent to the option value curve. This occurs at a value of £47.17, the critical revenue.

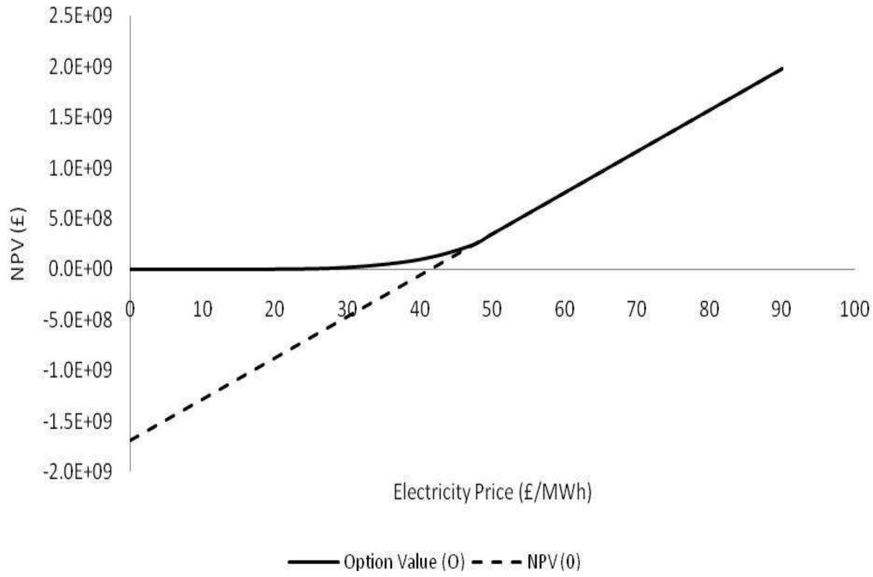


Figure 6-9: Option value and NPV showing the value associated with waiting to invest

Figure 6-10 shows how the optimal electricity price required to trigger investment in new plant varies according to volatility of the revenue stream i.e. the volatility of the price of electricity.

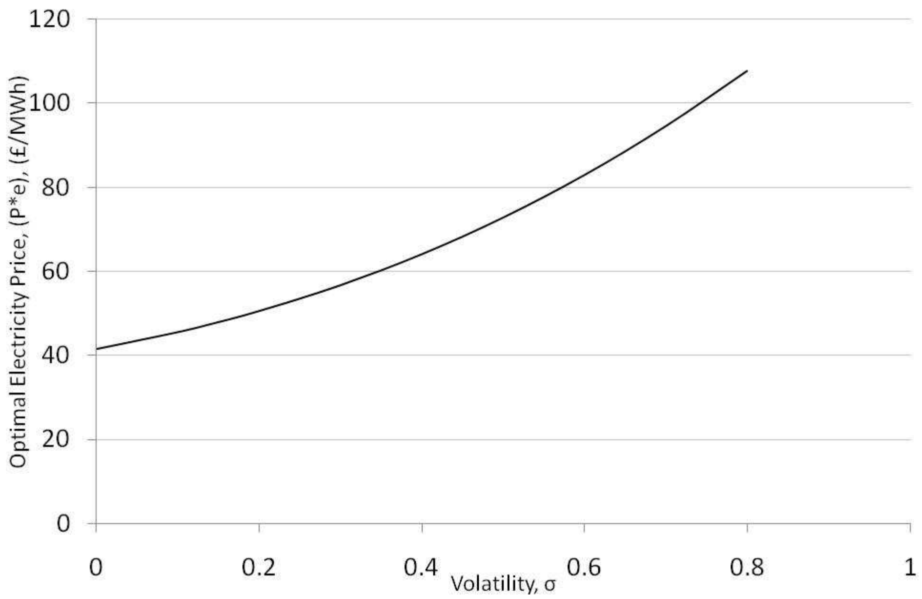


Figure 6-10: Optimal electricity trigger price as a function of price volatility

Figure 6-11 shows how the optimal trigger price for investment in CCS varies according to the discount rate. Table 6-5 shows the corresponding interest rates that give the levelised cost factors.

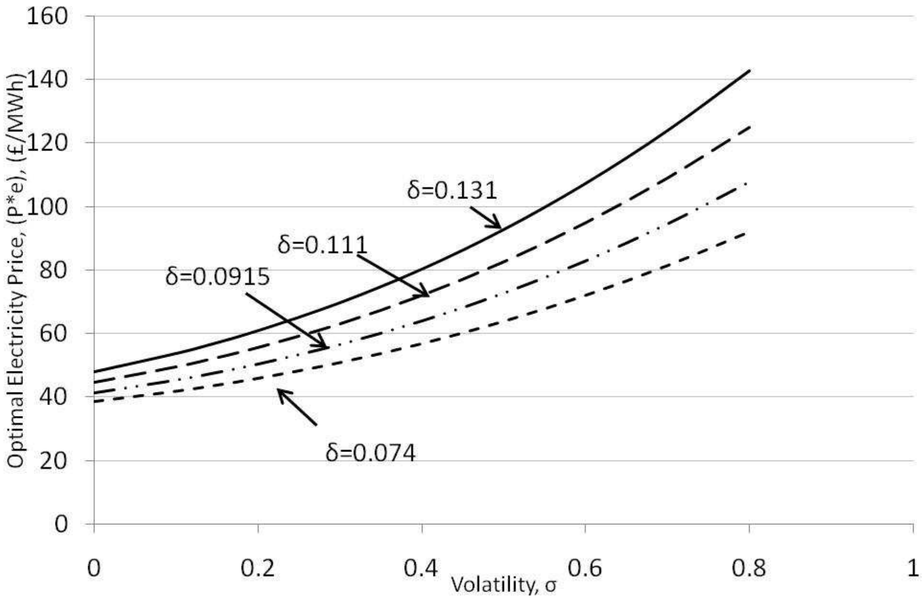


Figure 6-11: Optimal electricity trigger price as a function of volatility and interest rates

Table 6-5: Interest rate corresponding to levelised costs

Interest rate (%)	δ
6	0.074
8	0.0915
10	0.111
12	0.131

The other driver of option value is the cost of generation. Figure 6-12 shows the effect of high and low coal prices, resulting in high and low costs of generation for CCS on the value of the call option (high and low coal prices are defined in Section 6.10.1. Therefore the price of the input assumptions affect the value associated with the option.

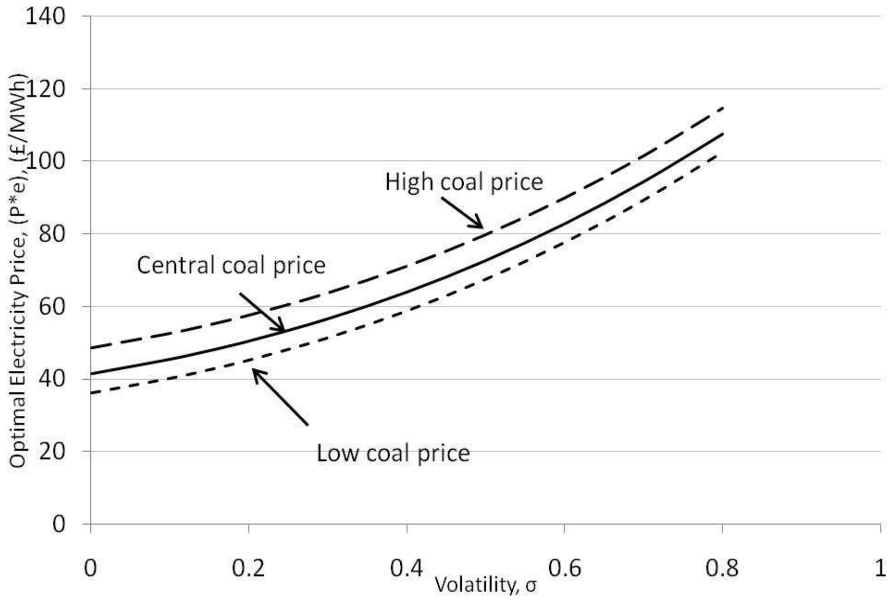


Figure 6-12: Optimal electricity price for coal price scenarios

Figure 6-13 shows the variation in the perpetual option value for a range of associated trigger price values and observed prices. The purpose of the chart is to show how the perpetual option value varies if the smooth pasting condition is not taken into account (i.e. an investor does not exercise the option at the point where the value of the call option is maximised – the critical investment threshold).

Figure 6-13 shows that significant value is lost by exercising the option early compared to late i.e. compare the rate of change in option value between the trigger price of 41.39£/MWh and the critical price of 47.17£/MWh to the rate of change in option value between the critical trigger price and a trigger price of 52£/MWh.

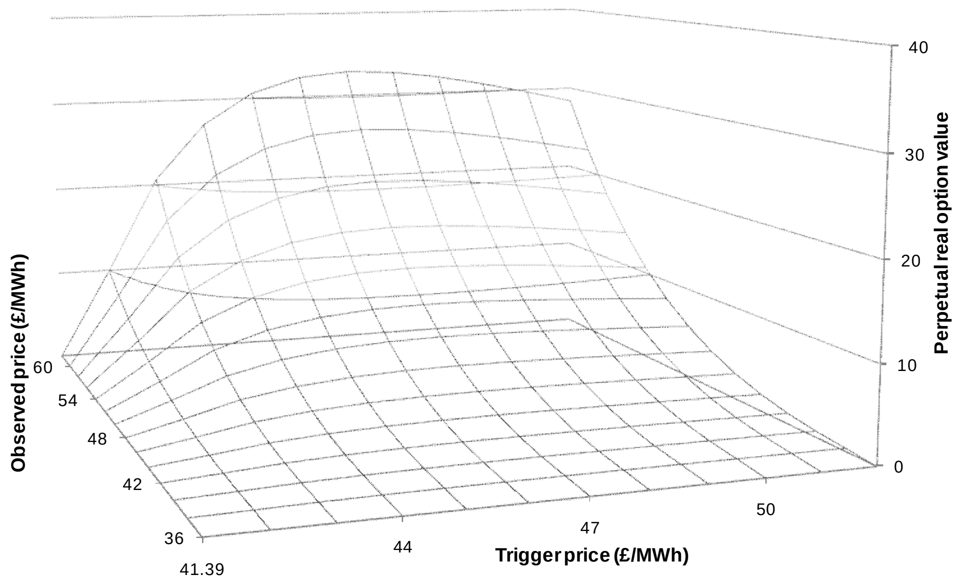


Figure 6-13: Surface plot of option value for various trigger values

This implies that even after the optimal trigger price has been reached, there could be relatively little lost in waiting for the observed price to increase beyond the critical value before taking the decision to invest. This general point (a consequence of the smooth pasting condition, which states that at the optimal trigger point, the option value touches the payoff function and the two lines are at a tangent) has also been made in the literature on real options (Sick and Gamba, 2005), but does not appear in the literature on investment in power generation. For the purposes of this thesis, it is relevant because it illustrates the possibility that an investor may wait even when the optimal investment threshold has been reached.

6.6 Mean time to absorption model

The objective of the mean time to absorption model is to aid the identification of an expected period over which investment in new coal plants with CCS will take place. Therefore this Section provides an answer to the research question:

- When could coal with CCS plant replace a CCGT plant as the preferred method of generation?

The question posed above can be broken down into two further objectives: given the dynamics of natural gas prices, the model will show whether the CCS option will become viable or not. Secondly, the model will aid the investment decision by identifying a window i.e. a time period over which investment in new CCS plant could be expected to take place.

6.7 Problem formulation

The problem may be set out as follows: given the price of natural gas and therefore the cost of generating electricity from natural gas evolves according to a GBM process with parameters derived in Section 6.4, will the cost of generating electricity from natural gas reach the level required to invest in new CCS plant, and if so, over what timescale is investment likely to take place?

Previous Sections showed that the cost of generation from natural gas plants is, to a large extent, dependent on the price of natural gas itself. The tornado diagram showing the sensitivity of the cost of generation to natural gas prices in Chapter 5 implies that changing natural gas prices will be reflected in the cost of generation. Section 6.4 showed that the price of natural gas can be considered to follow a GBM (which is expected to continue) due to supply and demand factors. Therefore, the cost of generation from a natural gas plant can be modelled as a GBM process with parameters that are derived from the process that describes the natural gas price.

The boundary that the cost of generation from a CCGT must cross in order to incentivise investment in a coal CCS plant was derived in the previous Section. The situation is analogous to the mean time to absorption problem or first passage time in probability theory and the analysis of stochastic calculus. A brief history of the mean time to absorption is given in Rhys (Rhys et al., 2002) who states that the situation can be traced back to problem of gamblers ruin (where two players with a finite wealth play a game based on the outcome of a toss of the coin- the ruin occurs when the reserves of a player reach zero). Schrodinger and Smoluchowski then derived the solution to the first passage time for a Brownian motion to meet a fixed boundary (Rhys et al., 2002). The application of mean time to absorption to GBM is used in a wide range of areas from maintenance to finance or cardiology (Chhikara and Folks, 1989).

Figure 6-14 illustrates the problem by showing one example stochastic price process, representing the cost of generation from natural gas, meet the boundary described by the cost of generation assumed for coal plant with CCS. The point of exercise i.e. the decision to build a CCS plant is a function of the time it takes for the cost of generation from natural gas to reach the level set by the CCS plant.

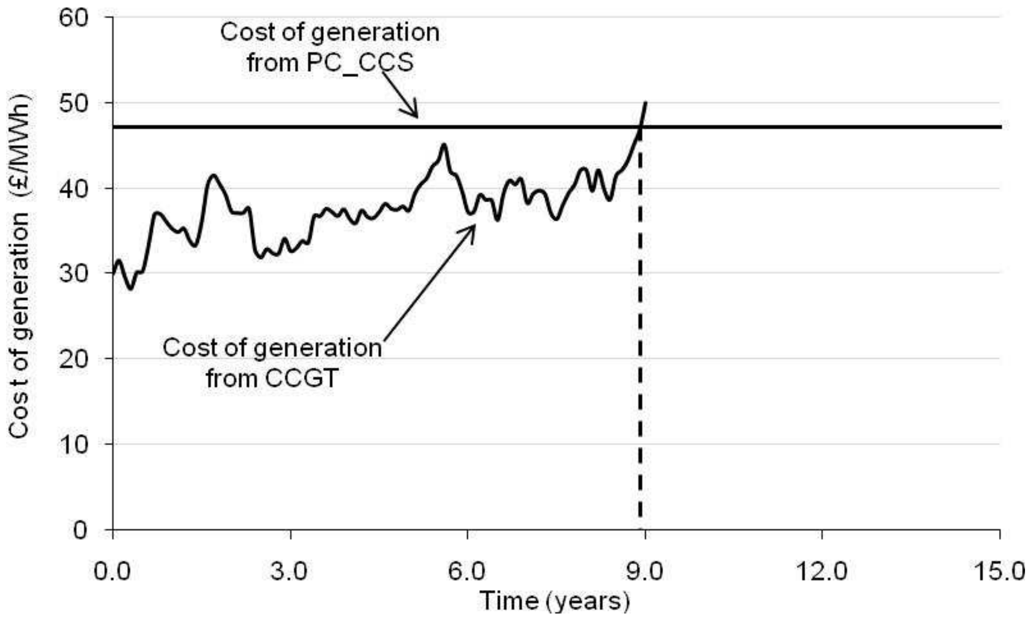


Figure 6-14: Illustration of the mean time to absorption for a single price process

Figure 6-14 is a simplification, as the actual time until the boundary is crossed is itself a stochastic variable and therefore is not known with certainty. The expected mean time to absorption is a stochastic parameter so it should be stressed that this model does not result in a point prediction. However, the identification of the expected time at which the cost electricity generated from natural gas reaches that of a coal with CCS plant is of interest. In addition, the probability of the process reaching the boundary value at some point is also of interest to the investor.

A further simplification seen on Figure 6-14 is that is also assumed that the cost of generation from a coal plant with CCS is constant. There has been much work published on the effect learning curves may have on the cost of generation (Riahi et al., 2004), (Rubin et al., 2007b). However, it could be argued that learning curves will not apply to the first generation of CCS plants as sufficient installed capacity will not have been deployed to fully benefit from learning by doing. Moreover, recent experiences with wind energy suggest that once demand for the technology begins to exceed supply, the benefit of learning curves may reduce as supply tightens and prices increase.

6.8 Mean time to absorption model

The mean time to absorption model is used to generate the time dependent probability profile that for the cost of generation from a CCGT plant to reach the cost of generation from a PC plant with CCS. The time taken for a Brownian motion with drift, ν, and volatility, σ, to transverse a distance, d, has an inverse Gaussian distribution with:

$$\begin{aligned} P\left[T \le t\right] &= F(t|\sigma,\nu,d) = \varphi\left(\frac{\nu t - d}{\sigma\sqrt{t}}\right) + e^{2\frac{\nu d}{\sigma^2}}\varphi\left(-\frac{\nu t + d}{\sigma\sqrt{t}}\right) \\ P\left[T > t\right] &= R(t|\sigma,\nu,d) = \varphi\left(-\frac{\nu t - d}{\sigma\sqrt{t}}\right) - e^{2\frac{\nu d}{\sigma^2}}\varphi\left(-\frac{\nu t + d}{\sigma\sqrt{t}}\right) \end{aligned} \tag{6.27}$$

Where:

φ : standard normal (cumulative) probability distribution

And

$$E\left[T|\sigma,\nu,d\right] = \frac{d}{\nu} \tag{6.28}$$

As it is assumed that the underlying process follows a geometric Brownian motion, the inverse Gaussian distribution can be used to examine the time to profitability. The distance the logarithm (the Brownian motion) of the process has to travel is thus $d = \ln\left(\frac{S}{G_0}\right)$ where the drift is $\nu = \alpha - \frac{1}{2}\sigma^2$, and α is the drift of natural gas price. The time to absorption thus has the law:

$$\begin{aligned} F\left(t|\sigma,\nu,\ln\left(\frac{S}{G_0}\right)\right) &= \varphi\left(\frac{\nu t - \ln\left(\frac{C_{coal(min)}}{G_0}\right)}{\sigma\sqrt{t}}\right)\ldots\ldots \\ &+ \exp\left(\frac{2\nu\ln\left(\frac{C_{coal(min)}}{G_0}\right)}{\sigma^2}\right)\varphi\left(-\frac{\ln\left(\frac{C_{coal(min)}}{G_0}\right)+\nu\Delta t}{\sigma\sqrt{t}}\right) \end{aligned} \tag{6.29}$$

The mean time to profitability is thus

$$\tau_{profit} = E\left[T|\sigma, G_t = C_{coal(min)}, G_0\right] = \frac{1}{\nu}\ln\left(\frac{C_{coal(min)}}{G_0}\right) \tag{6.30}$$

Since

$$E\left[\ln\left(\frac{P_{t+\Delta t}}{P_t}\right)\right] = \nu\Delta t, \tag{6.31}$$

Where P_t is the price of natural gas at time t, ν can be estimated. Because the data are evenly spaced one year apart set $y_t = \ln\left(\frac{P_{t+1}}{P_t}\right)$, then

$$\hat{\nu} = \frac{1}{n}\sum_{t=1}^{n} y_t \tag{6.32}$$

Giving:

$$\hat{\tau}_{profit} = \frac{1}{\hat{\nu}}\ln\left(\frac{C_{coal(min)}}{G_0}\right) \tag{6.33}$$

This is subject to the case of:

$$\begin{aligned} &\alpha - \frac{1}{2}\sigma^2 > 1 \\ &\alpha - \frac{1}{2}\sigma^2 = 0 \\ &\alpha - \frac{1}{2}\sigma^2 < 1 \end{aligned} \tag{6.34}$$

In the first case, the boundary will be reached in a finite time and expression (6.33) is valid. In the second case, the boundary will still be reached, but in an infinite time. The second condition is that the ratio of $C_{coal(min)}/G_o$ must be greater than one.

6.9 Results

Figure 6-15 plots the cumulative probability of profitability (the probability that the boundary has been crossed) against the time at which this occurs. Firstly, the mean time until CCS becomes viable to a CCGT plant is 6.4 years, with a cumulative probability of 64% (see equation (6.30)). As this simulation was run from 2008, this implies that there is a 64% probability that CCS becomes viable between 2008 and halfway through 2014, given the assumptions regarding the start price (£30/MWh), drift and volatility of natural gas. For the purposes of this thesis this is the very lower bound of the window of opportunity. The upper bound is defined as the time until it is 90% certain that the boundary will be crossed. This occurs 12.5 years after the simulation commences implying that the second half of 2020 give the upper limit to a 90% confidence interval that investment in CCS takes place between 2008 and 2021.

It should also be noted that one such cumulative distribution curve exists for every start price, so the results are therefore dependent on the choice of parameter values. This is investigated later using sensitivity analysis. All results in this section use a starting price of £30/MWh.

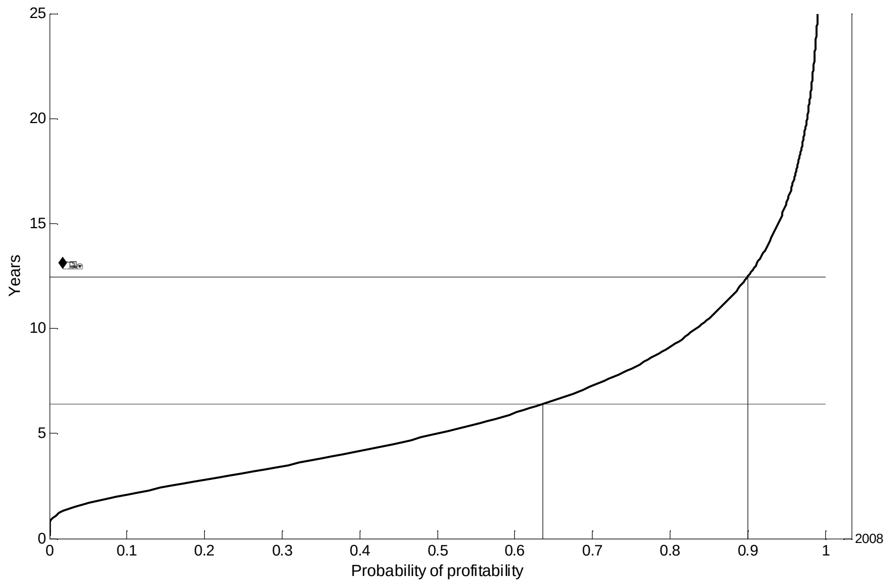


Figure 6-15: Probability of profitability over time

The effect of the option price model on the time of exercise is also interesting to report. Table 6-6 presents the difference between the boundary value that was derived under the standard investment assumption and the value that was derived using the option to wait. This is equivalent to a confidence interval of 40%. A confidence interval of 95% would be much wider – approximately 2-20 years from 2008.

Table 6-6: Mean time to absorption for levelised cost barrier and option barrier

Barrier value (£/MWh)	Expected mean time to absorption (years)	Time to absorption at prob = 90% (years)
46.21 (no option value)	6.1	12
47.17 (option value)	6.4	12.5

It is interesting, but unsurprising to see that increasing the boundary level shifts the window of opportunity to the right i.e. later in time. It is also worth noting that a relatively small absolute change in the price of electricity results in a delay of around 0.3 years for the expected time to absorption and 0.5 years for the 90% cumulative probability.

Figure 6-16 plots probability of profitability against time but also includes the boundary set by high and low volatility and high and low drift rates. It can also be seen from Figure 6-16 that the variance i.e. the distance between the bounds and the central line is not constant, but increases over time before decreasing as probability approaches 1. The reason for this is due to the curve being translated due to the effect of a different volatility or drift factor. The other point to note is that while the input variation might be symmetrical i.e. plus or minus 10%, the output is asymmetrical i.e. the lower bound is closer to the main value than the upper bound. This is because the probability of early absorption is extremely small and is conditional on a small set of rare upward gas price trajectories. Conversely, an equally rapid downward trajectory of gas prices can delay absorption. The probability of such a trend is uniform until absorption occurs.

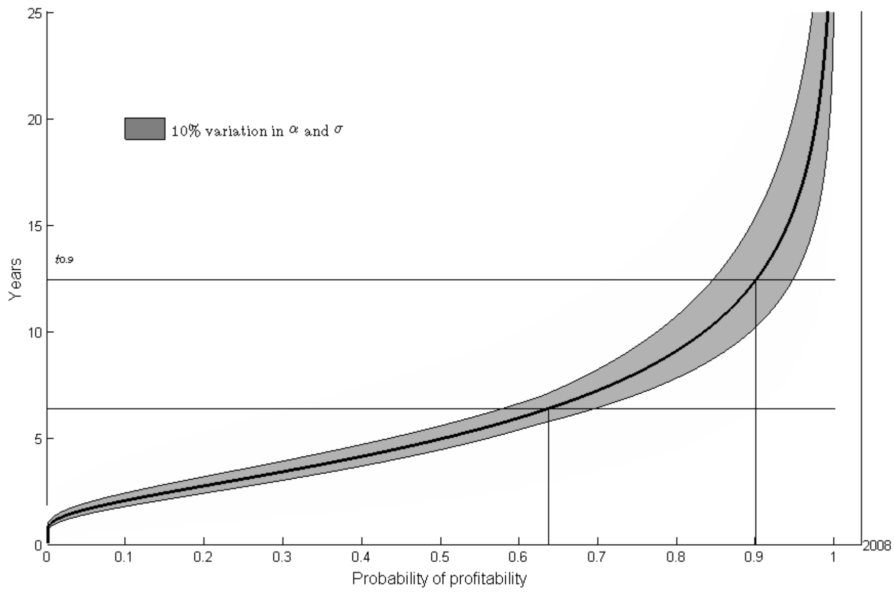


Figure 6-16: Probability of profitability with respect to volatility and drift of the underlying

Figure 6-17 shows the impact on the mean time to absorption of altering the drift parameter. Tables of the data can be found in the appendix. In general, for a given volatility value, increasing drift causes the expected time to profitability to decrease while decreasing the drift causes the expected time to profitability to increase considerably. Therefore model results are highly sensitive to the drift rate. The rate of drift can be thought of a proxy for the supply demand ratio for natural gas, which is dependent on global supply and demand. For example, a glut of gas on world markets caused by the discovery of new reserves will imply that the drift rate will decrease and the estimated time to profitability for CCS will increase.

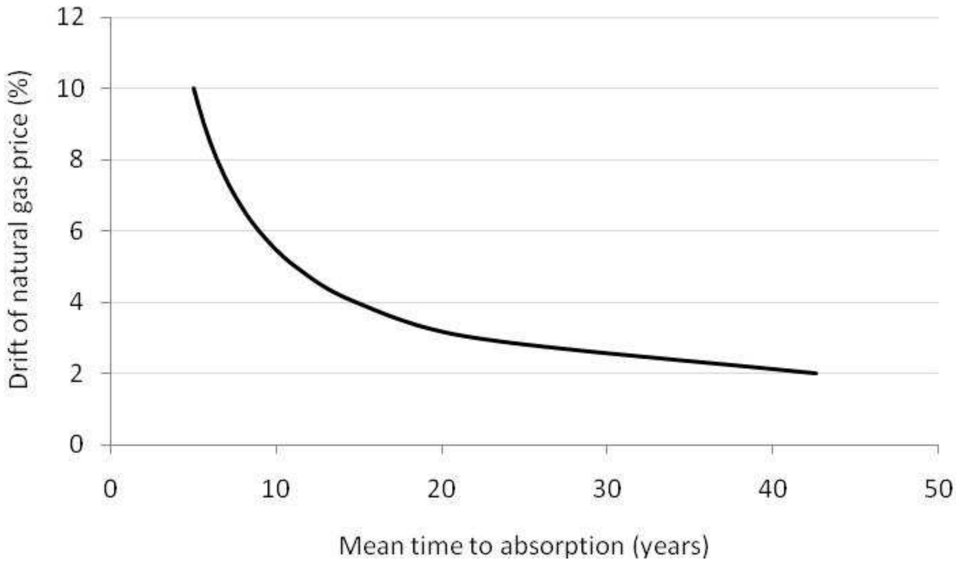


Figure 6-17: The relationship between the drift of the underlying and the mean time to absorption

Figure 6-18 presents the impact on the mean time to absorption altering the volatility parameter. Tables of the data can be found in the appendix. In general, for a given drift value, increasing volatility causes the expected time to profitability to increase; like drift, the model forecasts are also very sensitive to volatility.

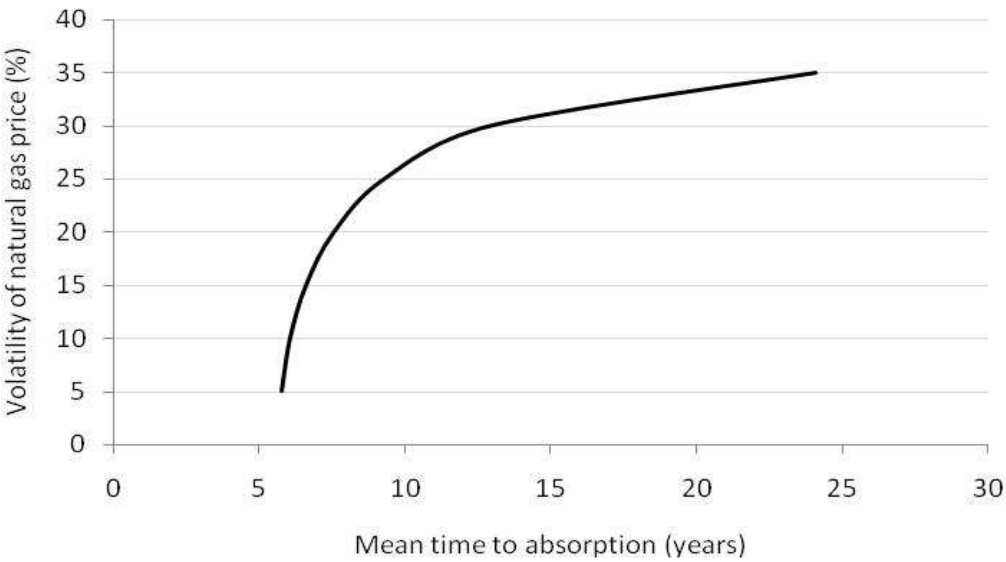


Figure 6-18: The relationship between the volatility of the underlying and the mean time to absorption

Figure 6-19 plots probability of profitability against time but also includes the boundary set by a 10% variance in drift and volatility rates and also a boundary that has a 10% variance on costs of generation i.e. $C_{coal(min)}$ and G_o as well as volatility and drift rates. The variation of values in Figure 6-19 is particularly wide in relation to the spread shown by variation in volatility and drift only. Altering the values of $C_{coal(min)}$ and G_o effectively alters the distance that the gas price process must transverse in order for CCS to be profitable. Therefore at one extreme this analysis shows the effect of an increase in the distance to travel by increasing the boundary price by 10%, reducing the start price by 10%, reducing the drift by 10% and increasing the volatility by 10%. At the other extreme, the distance the process must transverse is a minimum, as is the volatility, while the drift is a maximum. This explains why the boundary lines cover such a large area. In addition, Figure 6-19 exhibits the same characteristic of being non-symmetric around the central case as Figure 6-16. The reason for this is due to the curve being translated due to the effect of a different volatility or drift factor magnified by an alteration in the distance that the process must transverse.

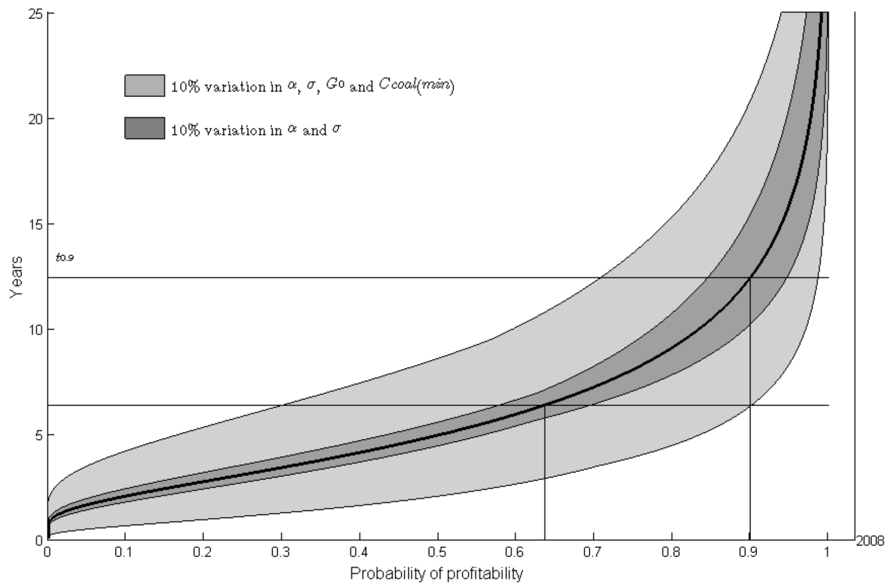


Figure 6-19: Probability of profitability as a function of volatility, drift and generation costs

6.10 Scenario investigation

While is worthwhile investigating the sensitivity of the models independently, an important issue is missed- when used to evaluate the investment decision, the models should be run in sequence. An example of this would be a scenario where the price of natural gas has a high volatility. The option value to wait will be larger, and this results in a longer mean time to absorption.

Therefore two alternative scenarios are constructed to give an indication of how the investment decision is affected. Broadly speaking, one of the scenarios leans towards favouring CCGT plants while the other leans towards favouring CCS plants, however the scenarios are still realistic and parameters coincide with those from other studies and government projections.

The scenario favouring gas has a high coal price coupled with a lower drift and volatility of natural gas. In addition, the carbon price is also low. The second scenario, favouring coal sees a high gas price volatility and drift coupled with a high carbon price and a low coal price. The next Section presents the input parameters for the two scenarios.

6.10.1 Evaluation of variance in input parameters

The first sensitivity parameter to derive is the high and low coal price. Figure 6-20 shows projected price projections for coal prices to 2030.

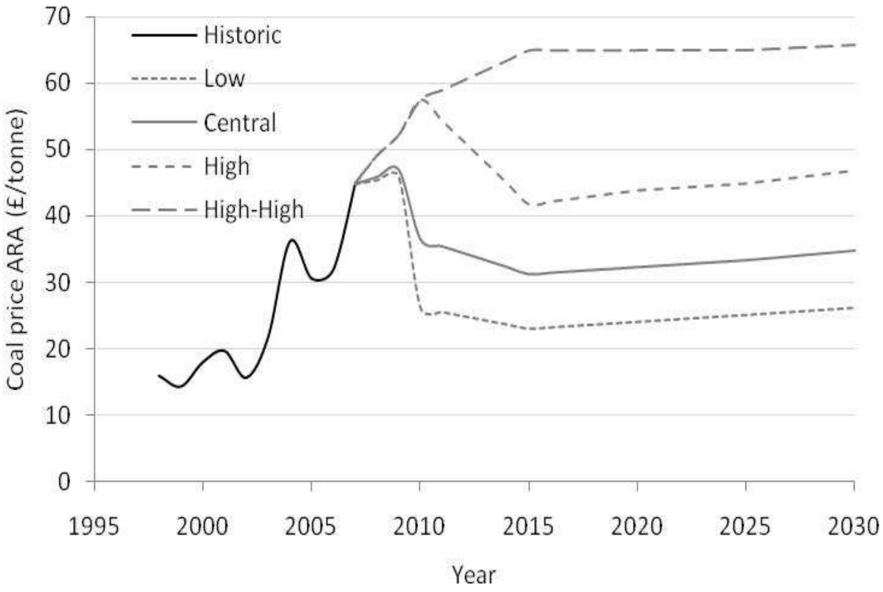


Figure 6-20: Projections of future coal prices (Source: ATCO Power)

A high coal price of £50/tonne will be used while a low coal price of £25/tonne will be used. Both of these assumptions fit in with the long term price projections for coal seen in Figure 6-20. The next parameter to be chosen is the high and low volatility. Based on the review of other papers, presented in Table 6-4, a high volatility of 25% is used and a low volatility of 10% is used. Meanwhile the low drift rate is 5% and the high is 10%. A high carbon price of £30/tonne coincides with the expected price that allowances are to reach by 2020 in a recent report from Deutsche Bank (approximately equal to 40€/tonne at an exchange rate of 0.75€/£) (Lewis, 2008)- however this would still be insufficient to incentivise investment in new build CCGT plants with CCS. The parameters and costs of generation are presented in the table below. In addition, construction costs of new CCS plants are 15% higher in the "favour gas" scenario but remain constant in the "favour CCS" scenario.

Table 6-7: Table of scenario parameters

Parameter	Favour gas scenario	Favour CCS scenario
Coal price	£50/tonne	£25/tonne
Gas price volatility	20%	10%
Gas price drift	6%	10%
Carbon price	16.5£/tonne	30£/tonne
CCS Capex	+15%	-

The high case sees the cost of coal plant with CCS rise to £55.87/MWh, while in the low case the cost is £42.70. The high carbon price causes the price of gas generation to rise to £34.72/MWh in the case favouring coal, and stay at £30/MWh in the favour gas scenario.

Table 6-8: Results of the time to absorption for the two scenarios

Scenario	Optimal Trigger Price (£/MWh)	Mean time to absorption (years)	Time to P=90% (years)
Favour Coal	42.70	2.18	4.2
Central	47.17	6.4	12.5
Favour Gas	55.87	25	>30years

Table 6-8 presents the result of the scenario analysis for the start price of gas (and hence electricity) as stated above. Unsurprisingly, there is a significant difference in the timing of the investment decision and the optimal electricity revenue as a result of the difference between the two scenarios that have been created. This is because the parameters that have been altered have a compounding effect: a high capital cost and fuel cost create a high optimal trigger price and therefore a larger distance for the stochastic process to transverse, which it does at a slower rate due to low drift rate.

6.11 Discussion

This Chapter set out to answer two research questions regarding the economic viability of the CCS system compared to CCGT plant. The objective was to answer two research questions that would help to aid the investment decision in CCS plant; what was the effect of revenue uncertainty on investment in CCS and when was CC likely to become a viable option compared to CCGT plant. In order to answer the research questions, two models were constructed. The results and implications of the models are discussed below.

6.11.1 Discussion of options model

The first question regarded the amount of extra revenue that was required to compensate for uncertainty in revenue when a CCS plant was built. This was solved as a perpetual American call option.

The real options model takes into account the uncertainty in future revenues and attaches a value to the decision to wait before investing. The model gives an optimal electricity trigger price of £47.17/MWh, under the central case. This is the optimal electricity price required for the option to construct a CCS enabled coal plant to be exercised. Exercising the option below or above this threshold is sub optimal. Therefore it should be noted that there is not always value in the option to wait. Waiting until the optimal trigger price is reached gives an expected NPV of £243 million over the project lifetime. Other studies which have published NPV data for plants include Rothwell, who derives a mean revenue of $740 million (Rothwell, 2006), which when discounted and adjusted gives a value of £430 million, which is in the same order of magnitude (the two might not be directly comparable as Rothwell evaluates investment in new nuclear plant).

The call option has been modelled as perpetual as the operator or investor always has the right but not the obligation to invest in a CCS plant. The value stemming from this option is captured in the value of the option to wait. This implies that given uncertainty in future revenue streams, a generator should wait until the NPV is greater than zero before investing- this is shown in Figure 6-9, where the option is not exercised when the NPV is zero, but when it is positive. It is also possible to formulate the problem so that the time until the option expires would be finite. This type of option can be evaluated using a binomial lattice and decision tree but is outside the scope of this thesis. However, it is worth noting (Siegel et al., 1987) that the critical investment value approaches the exercise price as time tends to zero. It has been shown by Dixit and Pindyck (Dixit and Pindyck, 1994) and Siegel, Smith and Paddock (Siegel et al., 1987), that the critical ratio for investment varies most between t_0 and 2 years ahead. After that the critical value is similar to that obtained using a perpetual options formula. Given that it is unlikely that investment in Coal CCS will be undertaken in the next 2 years the use of the perpetual options formula is acceptable (and within the bounds of other uncertainties e.g. capital cost, interest rate etc). Moreover, it is the effect of volatility more than time to expiration that drives the critical option value (as shown in the sensitivity analysis).

The value of the option is dependent on three parameters: the volatility of the revenue stream, the capital cost of the CCS plant and the variable cost of operations of the CCS plant.

Firstly volatility is important as it reflects the impact of future price uncertainty on the investment threshold and has a strong influence on the option to wait. For example, increasing volatility from 13.7% to 20% increases the optimal electricity price to £50.43/MWh and hence would push the expected time to profitability back. In addition, the capital recovery factor has two effects on R*; an increase in δ, by introducing either higher interest rates or reducing the economic lifetime of the plant, decreases β (see equation (6.23)) and hence R*, but δ more than compensates for this effect by increasing R* directly (see equation (6.25)). Finally, the cost of construction, the operational costs (fuel and maintenance) and the availability factor, which are taken as constant for the purposes of this paper, could alter the optimal trigger price. Figure 6-12 shows that the optimal trigger price to prompt new investment in CCS plants increases as the cost of coal increases.

Lowering the volatility of the revenue stream will reduce the optimal electricity price. On the other hand, as the revenue stream increases in volatility, the value of the option to wait also increases and therefore so does the optimal trigger price of electricity to build a new CCS plant. This has a number of implications. In a volatile market, it can be expected that the electricity price required to trigger investment in new plant will be high. Therefore any measures that could reduce the volatility in revenue will reduce the optimal price required for investment. Examples of this could include government subsidies for CCS which would guarantee a certain proportion of revenue and therefore reduce the volatility of revenues. Another option would be to introduce long term power purchase agreements, where the plant is financed on the basis of receiving a fixed price for electricity it produces- typically the buyers of such long term contracts are energy intensive industries that benefit from a lack of exposure to market electricity price fluctuations. It is noted that this approach has been used in Finland to finance a new generation of nuclear plants (Puikkonen, 2010).

The capital cost of the CCS plant also determines the value of the option to wait, as it determines the optimal revenue that is required. However, in reality the effect is more complex. In reality, the actual capital cost is only known once the plant has been built. Therefore in a sense the true value of the option to wait is only known once the project has been completed and the full cost of construction has been assigned. The variation would not matter if the construction cost difference were small; however, it is not uncommon for large capital projects to run over budget. This is especially true for complex first of a kind plant. Indeed it is likely that the first generation of CCS plants will fall into this category, as the technology, although relatively simple in some plants, such as PC, there is bound to be some over engineered aspect or faulty sub-system that needs redesigning and hence incurs extra cost. Therefore this thesis has included a certain degree of simplification compared to the real world. It is worth noting that other authors have used ROA to analyse the investment problem in more detail. Pindyck modelled the technical and market uncertainties associated with new build plants using ROA. Others have analysed the benefits of building modular plants to limit the downside risk i.e. a smaller plant is built that costs less and produces less energy, therefore it is less exposed in absolute terms to market uncertainty. Gollier valued a nuclear plant as a series of modular sub plants compared to one large plant using ROA. Other authors, such as Rothwell, have valued new investment in plant as a series of staged investments leading up to the final irreversible investment decision.

The options model also assumes that once the decision to build has been made, investment is instantaneous. In reality power plants take between 2 (CCGT) and 5 (nuclear) years to build. Coal plants typically take four years to construct. Therefore making the decision to build a plant at time t means that the plant will not be ready until $t+t_c$ where t_c is the time for construction. Construction costs for such large projects as power plants could be paid as a lump sum either at the beginning or the end of the construction period. In addition, payments may be spread over the construction period. Therefore any payment made after construction has started should be discounted according to the time of the construction cycle they are released. Due to a lack of available information on such payment, it has been assumed that construction is instantaneous in this thesis.

For the purposes of the options model, the variable cost of operations of the coal plant is treated as constant over the lifetime of the plant. The majority of the operations costs of CCS plant are taken up by fuel costs. The fact that these costs have not been varied over the life of the plant in the model has been compensated for by running sensitivity settings for the parameters as seen in Figure 6-12. Therefore the effect of increasing coal prices to a higher level increases the price of electricity required for investment to take place.

The options model does not assume that electricity and coal prices are correlated. Therefore high coal prices do not affect electricity prices. This is a simplification, but as we assume that natural gas sets the marginal price, this simplification can be justified. In reality, the effect of correlations between carbon, coal, gas and electricity prices has influence on the option value. If this were to be investigated, another approach would be applicable e.g. Monte Carlo analysis. In the model, the volatility of electricity prices and gas prices is assumed to be the same. Therefore in the sensitivity analysis, high gas price volatility extends mean time to absorption, but the high volatility also results in a higher option value of waiting. If the effect of non perfect correlation between gas prices and electricity prices on the option to develop CCS were to be investigated, a Monte Carlo or binomial tree approach could be used. However, as this thesis assumes that CCGT plants set the marginal price of electricity, it is reasonable to assume that the volatility of natural gas will be reflected by the spot price of electricity. Future work could examine the effects of correlations between the coal price, carbon price and electricity price. However, it should be noted that in order for the problem to remain tractable, another approach may be required to resolve the problem (for example Roques (Roques et al., 2006)).

6.11.2 Discussion of mean time to absorption model

The second model, using mean time to absorption calculus, gives a probability profile of the timescale over which investment in CCS plant could take place. In this respect, the mean time to absorption model augments the options model result by providing an estimation of the likely window of opportunity, defined as the time between the expected time to profitability and the probability of profitability of 90%, in which it would be feasible to produce electricity from CCS.

Expression (6.33) gives an expected mean time to absorption of 6.4 years. As the model is run forward from 2008, the expected crossing point will be in 2014. The fitted inverse Gaussian distribution $F\left(t \middle| \hat{\sigma}, \hat{\nu}, \ln\left(\frac{C_{coal(min)}}{G_0}\right)\right)$ using the estimated drift $\hat{\nu}$ =8% and volatility $\hat{\sigma}$ =13.7 is plotted in Figure 6-15. The mean time to attain $\mathbf{C_{coal\ (min)}}$ is 6.4 years and the cumulative probability of reaching this value in 6.4 years is 61%.

The time to profitability in itself is inconclusive as the actual mean time to absorption is a stochastic parameter. The trigger value for optimal investment provides a decision support tool so a generator knows when investment should be exercised. Using the mean time to absorption analysis has derived the time probability profile over which investment could take place. However, there is a wide time range associated with the probability profile.

The key parameters for the mean time to absorption model are the differences between the initial price (cost of generation from natural gas) and the strike price (cost of generation from a coal plant with CCS), and the volatility and drift of the underlying process (υ). Figure 6-16 reports the impact of volatility and drift input parameters on the estimated time to profitability. The dark grey band represents the results of a 10% variation in drift and volatility. Both of these parameters are important in determining the mean time to absorption and both were derived in Section 6.4 using market data for natural gas prices. Figure 6-19 represents the variation in expected time to profitability using a 10% variation in all parameters to generate upper and lower bounds. Both of these relationships are to be expected and are a consequence of the formula calculating the expected time to profitability:

$$\tau_{\text{profit}} = \mathrm{E}\left[\mathrm{T}\middle|\sigma, \mathrm{G}_{\mathrm{t}} = \mathrm{C}_{\mathrm{coal(min)}}, \mathrm{G}_0\right] = \frac{\ln\left(\frac{\mathrm{C}_{\mathrm{coal(min)}}}{\mathrm{G}_0}\right)}{\left(\alpha - \frac{1}{2}\sigma^2\right)} \tag{6.35}$$

Increasing the drift, α, increases the denominator and therefore decreases the expected time to profitability, while increasing the value of σ decreases the value of the denominator and so increases the expected time to profitability. Equation (6.35) also shows why the expected time to profitability varies as the cost of generation for CCS plant or CCGT plant changes. Increasing the cost of generation from a CCS plant increases the numerator and therefore the expected time to profitability, while increasing the cost of generation from a CCGT reduces the numerator and therefore the expected time to profit decrease.

The mean time to absorption model made a number of assumptions in terms of its formulation. Firstly, the exercise boundary is considered as fixed. As stated in the previous Section, this may not be the case as benefits of learning can be expected. However, the counter argument used is that learning benefits will not be seen in the first generation of CCS plant. Secondly, drift and volatility of gas prices are assumed to be constant over time. In reality it could be argued that volatility and drift change over time. While, this may be so for the spot market, the drift of natural gas was derived based on samples spaced a year apart, suggesting that the drift parameter depends more on long term trends. The purpose of the model is to help to define whether CCS will become viable and over what time frame investment is likely to occur.

6.11.3 Implications for investment in CCS

This Section analyses the implications of the model results on investment in CCS and how the model parameters can be used as a proxy for assessing the investment decision in alternative environments.

The results of the central scenario suggest that investment in CCS is viable and could become economically viable between 2008 and 2014 with a cumulative probability of 64%. To reach a cumulative probability of profitability of 90%, 12.5 years would have elapsed (i.e.2008-2020).

There is some speculation that (as shown in Figure 6-13) an investor could wait until after the optimal trigger price has been reached due to the relatively small amount of value lost, further delaying investment.

The scenario analysis was created to assess two different situations in which CCS could find itself. The first is favorable to the incumbent CCGT plant and involves a low gas price volatility and drift coupled with a high coal price and high capital cost of CCS. This results in theexpected mean time to absorption being pushed back to 25 years from when the model begins. At the other end of the spectrum, the model that is favorable to CCS has low volatility, high drift and a higher carbon price. As a result CCS is expected to become viable in 2.6 years. By means of contrast, the central case results in an expected time to profitability of 6.4 years. The large range seen as a result of the scenario analysis is a result of altering all of the input parameters that the models to which the models are sensitive in a manner to the detriment or advantage of CCS plant. In reality, it is quite unlikely, although not impossible, that either scenario will occur although individual elements (e.g. high construction costs) may occur.

Uncertainty over revenue has an effect on the potential profitability of CCS, as do the parameters describing the motion of natural gas prices. Parameters such as volatility drift can be altered to reflect future market expectations i.e. importing more natural gas and the long term dynamics of natural gas price (supply and demand) might cause the volatility and drift to increase. Moreover, given that deploying CCS is a policy goal it is logical to ask what could reduce future uncertainty regarding electricity prices and hence reduce the value associated with waiting. Firstly, the operators of CCS enabled plants could enter fixed contracts for delivery of electricity in the future and hence CCS plants will be guaranteed to be called on. This would guarantee a fixed price for a certain proportion of total plant output. Secondly, certainty over the long-term price of carbon would also allow a reduction in uncertainty over electricity prices (which could be inputted into the model as a reduction in the volatility of electricity).

The expected time to profitability and options model could be used to measure the likelihood of government deployment targets for CCS being met and in the case of a negative answer, as an argument for subsidies. For example, the models show that, in the case without direct subsidies, the cumulative probability of electricity prices reaching levels to incentive investment in new CCS plant is 64% to mid 2014, while it rises to 90% if 2020 is chosen as the boundary and 2028 if a 95% confidence interval is taken. The driver of this investment is the price of natural gas. Simply, if the government would like CCS to be adopted over a shortened time scale, it should introduce some form of incentive for new build.

Model input parameters have been validated against published data and against government price projections. However, it is still worth looking at the effects that misapplying the model might have. A drift rate for natural gas of 5% results in an expected time to profitability of 11.3 years, significantly more than the 6 years or so in the central case. Therefore, although the model can be used to inform the investment decision, it should be noted that it is sensitive to input parameters which should be taken into account in the decision of when to invest.

Looking at the underlying price of natural gas required to deliver investment in natural gas will allow the realism of the model to be gauged- if the price of gas were to be higher than the forecast range in the central case, it would suggest that the model parameters are too high.

Table 6-9: Natural gas prices required to deliver investment in CCS

Case	Optimal cost of electricity	Cost of natural gas
Favour coal	42.7	47p/therm
Central	46.21	52.7p/therm
Favour gas	55.87	68.5p/therm

Table 6-9 shows the prices of natural gas required to deliver investment in CCS. The values for the central and favour coal scenario compared well to the projections of gas prices shown in Figure 6-8, sitting near the central and high projections. The price of natural gas in the case favouring gas is between the high and high-high cases, but well below the upper boundary of 93p/therm. These results give a degree of confidence to the model results as they coincide with long term gas price projections.

6.12 Chapter conclusions

This Chapter presented a modeling approach to evaluate investment in CCS plant and specifically answered two research questions:

- What is the effect of revenue uncertainty likely to be on CCS enabled coal fired plant deployment i.e. what extra compensation will the generator require in order to build a CCS plant?
- When will a coal with CCS plant replace a CCGT plant as the preferred method of generation?

The methodology used to answer these questions employed options models to evaluate the investment decision under uncertainty. The questions were answered separately using different models, but were brought together to evaluate the economic case for CCS technology.

The first question was answered by evaluating the investment in a new CCS plant as a perpetual American call option i.e. the holder has the right but not the obligation to invest in the CCS plant at any time given an uncertain stream of future revenues from electricity. It was found that revenue uncertainty increases the value of waiting before investing and is a function of cost of generation and the volatility of the revenue stream. As a result it was shown that measures to reduce the volatility of the revenues from a CCS plant would reduce the minimum revenue required for investment to take place investment. In numerical terms, the option to wait increased the minimum revenue from £46.21/MWh, derived using a levelised cost model to £47.17/MWh using the options model.

The second question was answered using mean time to absorption analysis to evaluate the expected time at which CCS plant would be preferable economically to CCGT plant. The underlying model for the analysis was based on the price of natural gas and was modeled as a GBM. Given the parameters governing the dynamics of natural gas prices, CCS is expected to become profitable at some point in the future. The timing depends on a number of parameters including the drift and volatility of natural gas prices and the cost of generation from the respective plants. Under the central scenario, an expected mean time to absorption of 6.1 years was calculated. However, this increased due to the additional benefit associated with waiting before investing to an expected time of 6.4 years. As the price of the underlying is stochastic, there is also a probability distribution associated with the mean time to absorption. A level of 90% cumulative probability was chosen to represent an upper bound for investment. This criterion was reached in 12.5 years. More importantly, the commercial viability of the coal CCS system is dependent on the future behaviour of natural gas prices and the price of carbon (for both gas and coal CCS). Scenario

analysis showing a world favouring gas (expensive coal and low natural gas price) pushed the expected time to viability to 25 years.
The opportunity cost associated with the option to wait implies a higher minimum revenue requirement for a CCS plant to be deployed. This Chapter has shown that the optimal electricity price is £47.17/MWh. Exercising the option before or after this point is sub optimal. Therefore there is no value in waiting if the price of electricity exceeds £47.17/MWh. The result of the additional revenue requirement derived in the options model is that it pushes back the expected time to profitability by 0.3 years for the expected time to absorption and 0.5 years for the 90% cumulative probability.

Finally, the integration of the real options model with mean time to absorption calculus is particularly valuable as it allows the expected time to profitability to be recalculated using the results from the options model; usually real options models only report an optimal threshold. The time dependent probability profile over which the optimal investment trigger price could be reached is useful as it aids insight into the investment decision.

7 Conclusions

This thesis has assessed the case for CCS deployment in the UK at the national level, the system level and the plant level, using metrics that have been derived from technology system analysis. This has been augmented by an assessment of the investment required in the CCS system using real options analysis to compare investment timing in CCS to the current favoured method of generation: CCGT. It has been found that while CCS could provide a diversify electricity generation and meet low carbon policy goals, is not a viable system at present due to technical performance and economic competitiveness of the technology and regulatory issues surrounding the disposal of CO_2.

Technical issues surrounding CCS are expected to be resolved via a comprehensive demonstration process, while governments appear willing to accept some liability for stored CO_2. Given these developments, this thesis found that due to the advanced development state of the technology, PC plant is the most attractive plant for CCS in the near term. In the longer term, IGCC plant is projected to have greater potential for plant performance, but suffers from the relative immaturity of the IGCC plant for electricity generation.

Power plants that capture CO_2 will always have an additional capital cost and performance penalty associated with the capture process, which will raise the cost of generation. This means that the main hurdle to the adoption of CCS is the economic barrier. This thesis found that under a scenario of increasing gas prices (start price of 29p/therm, volatility of 13.7% and drift of 8%) CCS has a 40% probability of being commercially viable option between 2014 and 2020.

The commercial viability of the coal CCS system is dependent on the future behaviour of natural gas prices and the price of carbon (for both gas and coal CCS). Scenario analysis showing a world favouring gas (expensive coal and low natural gas price) pushed the expected time to viability to 25 years. Another significant barrier to the implementation of coal CCS is the price of natural gas. This thesis has assumed a long term increase in the price of natural gas that drives the viability of CCS plant. In the absence of this trend it is likely that coal CCS would not become viable and rather gas CCS could be the best option for deploying CCS. Overall it appears likely that CCS will need some additional form of government support if it is to become a viable generation technology in the near term (this could be through a guaranteed carbon price or a direct subsidy).

Chapters 1 and 2 evaluated the need for the deployment of coal with CCS at the UK level by identifying and assessing global and UK environmental, political and economic drivers.

Chapter 1 set the power generation challenge in the context of the global system and showed the inevitability of coal use on a global level, primarily by developing economies. The constraint of global warming was then introduced to show that emissions would continue to rise to unacceptable levels. The only way to reduce emissions and use coal is to deploy CCS technology. However, questions remained over the viability of the whole CCS system.

Chapter 2 introduced CCS as an option in the UK generation system. From a policy perspective CCS can help to meet low carbon goals while continuing to support the use of coal hereby delivering security of supply through fuel mix diversity. However, significant additional cost is required to deploy CCS with the only compensation being carbon mitigation. Therefore CCS is a purely climate driven option. Chapter 2 also showed the contribution that coal CCS could make to reducing UK CO_2 emissions in 2020 with CO_2 savings at the national level of the order of 11Mt CO_2 per annum and displace 4.7GW of new CCGT plant compared to an unabated CCGT baseline scenario.

Chapter 4 evaluated the entire CCS chain for technical feasibility and identified the leading carbon capture technology given current and future performance potential. The over-arching conclusion was that the CCS system is not yet ready for deployment into the power generation system. The main barriers to system deployment cover technical, political and economic aspects. Key enablers were identified as: financial incentives, technical progress, legal and regulatory framework, system demonstration at full scale at numerous sites for alternative technologies and public acceptance of the CCS system. It was noted that the entire CCS system must be in place in order for CCS to be viable. The Chapter also evaluated the potential performance of CCS plant. It was concluded that PC plant will continue to be the dominant plant due to its reliability, availability, and performance. In the future there is scope for other plants, such as IGCC, to become the more efficient plant, although this will be dependent on RD&D spending.

In addition, Chapter 4 investigated the technical parameters that cause the increase in cost of generation from the CCS system. This is a result of all stages of the CCS process, but predominantly the effect of the capture process, which lowers plant efficiency thus raising operational costs and capital costs. Out of all of the plants investigated, IGCC and Oxyfuel have the lowest performance penalty due to CCS operation, but this does not more than compensate for the extra costs incurred by the base plant. At present the only incentive for installing CCS is the price of carbon, which is not at a sufficiently high level. Given that demonstration were to occur, enabling the CCS process to be taken up, the uncertain nature of future CO_2 price means that system flexibility has value, as the owner can avoid lock-in to a capture regime. Two types of flexibility were identified: operational and retrofit. Operational flexibility appears to be best suited to PC plant and oxyfuel plant. In addition, reliability is an essential part of the capture process, therefore it should be noted that in terms of breakdown of the CO_2 capture process, PC and oxyfuel have a definite advantage over IGCC, as the capture process is not integral to the plant process and could be bypassed in the event of emergency maintenance. Retrofit flexibility appears to suit PC plant and to a lesser extent IGCC plant through the option to upgrade a CCGT.

The other elements of the CCS system are constrained in different ways. In terms of the transport network, the complexity and cost of the network, along with legal issues relating to carbon classification need to be addressed. In terms of the storage network, the appropriate regulatory framework, legal liability transfer and monitoring responsibility are key barriers to be overcome.

Chapter 5 compared and evaluated the economic characteristics of coal with carbon capture and storage technology between prospective technologies and CCGT plant using levelised cost analysis. Three different methods and a sensitivity analysis were used to assess the economics of CCS. The viability of CCS varies according to the metric used. In terms of cost of generation, CCGT plants and CCGT plants with CCS have the lowest cost of generation under standard conditions. In comparison, when the cost of CO_2 avoided and CO_2 captured is used, CCGT with CCS become the most expensive plant in terms of cost per unit of emissions avoided (with reference to either the standard plant or not). The cheapest plant to switch to CCS in terms of CO_2 avoided is the oxyfuel plant. This is due to the comparatively low performance penalty and cost of oxyfuel with CCS in comparison to a standard oxyfuel plant. The implication of this is that CCGT plants will be the last plants to switch to CCS due to their lower exposure to carbon prices.

With regard to competition between coal plants with and without CCS, it appears that PC plant offers the best combination being the lowest cost standard plant and very nearly the lowest cost CCS plant

The sensitivity analysis conducted in Chapter 5 took the input parameters to the cost model and varied them by ±20% while all other factors were kept constant. This allowed an analysis of the cost constituents of the various forms of power generation and provides the basis for modelling market uncertainties. The sensitivity analysis led to a number of conclusions:

- As natural gas is less carbon intensive, CCGT plant is less exposed to carbon prices and, once CCS is installed, also to transport and storage costs than coal fired plant;

- Fuel price dominates the cost of generation from a CCGT plant. When CCS is installed, fuel cost continues to dominate the cost of generation from CCGT, although capital cost becomes more prominent. However, the main source of sensitivity is the price of natural gas;

- Installing CCS on a coal plant fundamentally alters its sensitivity characteristics; the profile becomes more top heavy like a nuclear plant i.e. the cost of generation is highly dependent on the capital cost. Analysis also showed that nuclear plant has a lower cost of generation than coal CCS plant;

- When CCS is installed on a coal plant, fuel costs also increase as more fuel needs to be burnt to produce the same amount of energy. The effect is not as severe as that from the increase in capital costs;

- Compared to CCGT plant, coal plants with CCS are more sensitive to transport and storage costs as they produce more CO_2 per unit output and therefore must transport and store a greater volume of CO_2. This model assumes a linear scale factor for the amount of CO_2 shipped i.e. on a per tonne basis over a constant distance by ship/ offshore pipe;

- The cost of generation from a CCGT plant with CCS is lower than that from a coal plant with CCS;

- All standard coal plants move from being sensitive to capital cost, fuel cost and carbon cost to being predominantly capital cost dependent with some exposure to fuel costs. This characteristic suggests that coal plants enabled with CCS might be more suitable for base load generation as large debts will need to be serviced, and hence plants will be unable to afford to meet peak demands;

- The price of natural gas will determine if coal with CCS is a viable economic investment. The price of gas relative to coal will need to be high for coal CCS to be economic.

Chapter 6 evaluated investment in CCS as an option and answered two research questions:

- What is the effect of revenue uncertainty likely to be on CCS enabled coal fired plant deployment i.e. what extra compensation will the generator require in order to build a CCS plant?
- When will a coal with CCS plant replace a CCGT plant as the preferred method of generation?

The methodology used to answer these questions employed options models to evaluate the investment decision under uncertainty. The questions were answered separately using different models, but were brought together to evaluate the economic case for CCS technology.

The first question was answered by evaluating the investment in a new CCS plant as a perpetual American call option i.e. the holder has the right but not the obligation to invest in the CCS plant at any time given an uncertain stream of future revenues from electricity. It was found that revenue uncertainty increases the value of waiting before investing and is a function of cost of generation and the volatility of the revenue stream. As a result measures to reduce the volatility of the revenues from a CCS plant would incentivize investment. In numerical terms, the option to wait increased the minimum revenue from £46.21/MWh, derived using a levelised cost model to £47.15/MWh using the options model. The opportunity cost associated with the option to wait implies a higher minimum revenue requirement for a CCS plant to be deployed. Exercising the option before or after this point is sub optimal. However investors may not always invest at the optimal point, but wait due to the small change in option value after the optimal exercise price has been reached (Sick and Gamba, 2005).

The second question was answered using mean time to absorption analysis to evaluate the expected time at which CCS plant would be preferable economically to CCGT plant. The underlying model for the analysis was based on the price of natural gas and was modeled as a GBM. It was found that given the parameters governing the dynamics of natural gas prices, CCS is expected to become profitable at some point in the future. The timing depends on a number of parameters including the drift and volatility of natural gas prices and the cost of generation from the respective plants. Under the central scenario, an expected mean time to absorption of 6.1 years was calculated. However, this increased due to the additional benefit associated with waiting before investing to an expected time of 6.4 years. As the price of the underlying is stochastic, there is also a probability distribution associated with the mean time to absorption. Given the model input assumptions, there is a probability of 90% that it will be optimal to invest in coal with CCS within the next 12.5 years. The result of the additional revenue requirement derived in the options model is that it pushes back the expected time to profitability by 0.3 years for the expected time to absorption and 0.5 years for the 90% cumulative probability.

Finally, the integration of the real options model with mean time to absorption calculus is particularly valuable as it allows the expected time to profitability to be recalculated using the results from the options model; usually real options models only report an optimal threshold. In order to make investment decisions, it is also useful for a generator to have an idea of the time dependent probability profile over which the optimal investment trigger price could be reached and hence the investment decision made.

7.1 Recommendations for future work

There are a number of ways in which the work in this thesis could be expanded. In part due to the multidisciplinary scope of the thesis, constraints in time and resources have required a number of simplifications to be made. In addition, during this research, it has become clear that a number of further investigations are required.

There are four main categories for future work; a more detailed investigation into CCS and nuclear generation, further modelling and integration of CCS processes into a more comprehensive system analysis framework, an extension of the real options investigation into modelling the investment decision in CCS and finally, the integration of real options analysis with systems analysis to assess future potential areas of flexibility.

Both CCS and nuclear offer low carbon generation at a cost that is at present economically uncompetitive. However, it is not clear which would be the better investment choice in the market place in the longer term. In some ways the plants are similar but also different. Although both plants have high capital costs, the nuclear cost profile is even more top heavy than CCS, but nuclear plant has lower running costs compared to CCS. In addition, both processes produce a waste product that must be stored for substantial periods of time. However, nuclear waste differs from CO_2 in key ways e.g. radioactivity. Therefore although comparisons can be made between the two, the effect of these different characteristics on investor choice is yet to be fully investigated. In addition, the impact of the additional infrastructure and regulatory requirements on CCS has yet to be taken into account in the comparison.

A more detailed evaluation of decommissioning costs for CCS would also be valuable. This aspect was not modelled in this thesis due to a lack of information in public reports. There is also a clear need to be able to build a model that can rapidly assess the impact novel capture processes may have on the performance of CCS plant. This would most likely take the form of a piece of software that would use key parameters to calculate the performance of any coal plant with any capture process and would allow the quick derivation of reasonably accurate performance figures to be used in systems analysis where detailed models are not required. Given recent developments in gas prices, there is also value in a more detailed assessment of natural gas CCS.

This thesis made an assumption that the CCS plant runs as base load, and therefore the load factor is constant. Although the arguments used are sound, it would be interesting to see how well CCS plant performs if it were to operate as part of the mid merit order i.e. decide to run or not based on the current price of electricity. This type of approach would require hourly simulations of power prices and also data for CCS operational abilities to ramp and ramp down production in short timeframes. The decision to run or not could be valued as a call option. The result of this research would shed light on the type of subsidy needed for CCS i.e. will the UK government need to finance the construction cost and the operational costs? It is clear that a plant with a lower load factor would require a higher capture price (£/MWh) than a baseload plant. It would also be interesting to compare alternative CCS plants that have some flexibility in the CO_2 captured e.g. PC plants compared to others which have little flexibility e.g. oxyfuel plants. It should be noted that in this case flexibility refers to the option to capture different volumes of CO_2 as a trade-off against plant performance (and CO_2 emissions price).

The wide scope of the thesis placed certain limits on the depth of the options analysis. For example, different stochastic processes (such as mean reversion or jump diffusion) could be used to model the price process for natural gas and electricity prices. A model could also be developed to assess the impact of correlation between coal, gas and carbon prices on investment in CCS. In this case it is likely that a Monte Carlo approach would be used to allow tractability. In addition, learning curves could be introduced in the form of a non stationary boundary for the mean time to absorption calculation as well as an investigation of correlation between the price process and boundary itself. The impact of staged investment and modular build could also be an area of useful research. Modelling staged investment would entail the relaxation of the assumption in this thesis that investment is instantaneous. In addition, staged investment could look at, for example a CCS enabled plant with the option to retrofit capture technology at some point in the future depending on uncertain carbon prices, or the option value of a flexible plant which could capture different volumes of carbon dioxide depending on external conditions e.g. electricity price and CO_2 price. Part of the work on this topic could also investigate the case for retrofitting a CCGT plant with CCS, as at present CCGT plants are being built in the market. Moreover, results from Chapter 5 showed that at present low gas prices, fitting a CCGT with CCS is a lower cost option than a coal plant with CCS. In fact a CCGT plant has the potential to either be retrofitted with post combustion CCS or pre combustion CCS (as the power generation train from an IGCC plant is essentially a CCGT).

One potential extension of this work is to treat the option to invest as non-perpetual. A paper published on this topic after this thesis was submitted has been brought to the authors' attention and would provide a valuable reference for further analysis (Evatt et al., 2010). The paper uses the Feyman-Kac approach to derive PDE's, solved using semi Lagrangian numerical methods, to assess the probability that an extraction project stops as a function of the (stochastic) commodity price and the lifetime of the mine as a function of (stochastic) commodity price.

Table 7-1 presents an overview of the additional real options analysis that could be carried out for plant with CCS.

Table 7-1: Further real options topics applicable to coal plant with CCS

Category	Decision	CCS application
Option to operate plant	Option to switch plant on or off or stay at minimum stable generation	All
Option to alter CO2 vented	Option to alter CO_2 capture % in order to take advantage of market conditions (i.e. price spikes)	
Option to abandon	Halt construction, defer construction or abandon construction based on new information	All
Option to switch outputs	To produce electricity or hydrogen	IGCC plant with CCS
Option to retrofit CCS	Delayed investment decision in CCS	PC plant, IGCC plant
Option to switch plant fuel (input)	To use syngas or natural gas as an input fuel	IGCC
Option to modify plant with higher efficiency capture process	To upgrade capture process at a later date capture process with lower performance penalty	All, but especially PC, IGCC. Oxyfuel limited by ASU penalty

The final area of further research would be of use in Engineering Systems in general, could also be developed as an application for the assessment of CCS technology. The research would integrate the two pieces of further research given in the previous paragraphs to produce an engineering systems and real options hybrid model for the analysis of CCS systems. As stated in the main text, Engineering Systems has placed value in system flexibility and real options analysis appears to offer a methodology to evaluate this flexibility at the design stage. Therefore the integration of real options into systems analysis could allow systems designers to evaluate flexibility in power plant design. One example could be to use the software described in the first Section of this Chapter as one of the pieces of an integrated power system assessment tool, which could look at the benefits of advanced solvents and using options analysis calculate the value of investing in a (more expensive) flexible capture process that could be upgraded at some point in the future (i.e. the right but not the obligation). This analysis would also provide a means to further distinguish between power generation technologies.

A. Appendix for Chapter 1

i. Global coal reserves

Figure A-1 shows the estimated reserves of coal remaining for selected countries. The R/P ratio measures the amount of time proven reserves could last given current rates of consumption. Given that the rate of coal use in China and India is increasing this will cause reserves to decay significantly; however, it is clear that coal will continue to be used as a primary energy source due to its abundant nature.

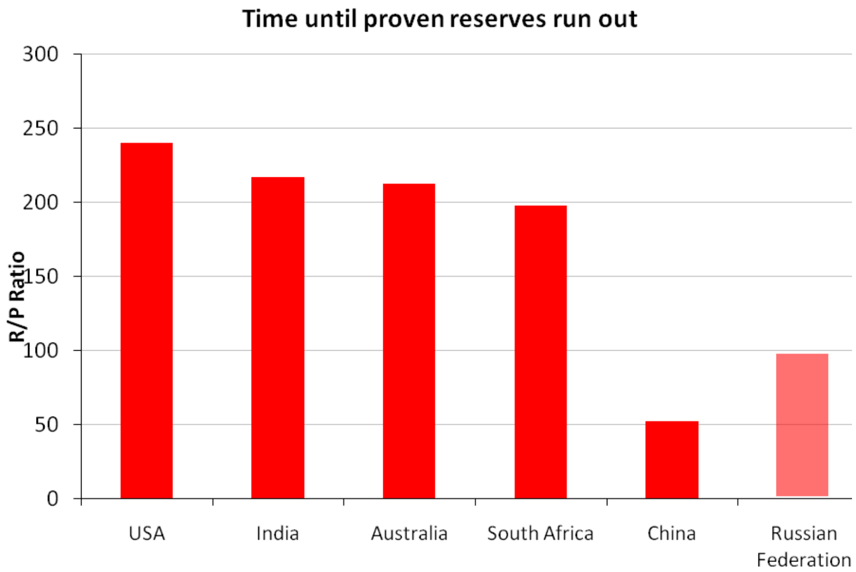


Figure A-1: Estimated time until coal reserves run out by country (Data source: (BP, 2007))

Based on DECC projections, the table shows the projected generation mix in 2020. The remaining 4% of energy required comes from imports and oil fired generation (DECC, 2008a).

ii. Indicative levelised cost of electricity

Indicative levelised costs of generation taken from the Royal Academy of Engineering report (PBPower, 2004). Nuclear costs are taken from Stupples et al (Stupples, 2007).

Table A-1: Generation costs for selected electricity production technologies

	Gas	Coal	Nuclear	Onshore wind	Offshore wind
£/MWh	22.2	23	42.31	37	55

B. Appendix for Chapter 2

i. LCPD

The LCPD is a piece of European legislation that limits the amount of running hours that coal plant without certain pollutant controls has. Plant that opted out of the legislation had 20,000 hours running time to 2016. Once the quota of hours has been used, the plant cannot run. However, the plant operator can choose when to run the plant. Therefore it is possible for plant to use 20,000 hours before 2016.

There are two stages of the LCPD:

- reduce sulphur emissions by 2016,
- for 2016 to 2020 install selective catalytic reduction to reduce emissions of NO_x.

In addition, a number of other challenges have presented themselves to the UK in the last few years, including: high volatility of fossil fuel prices, carbon prices from the EU-ETS and the prospect of higher future prices for both carbon and fossil fuels. Moreover, the renewables commitment in the EU dictates that 20% of demand is met through renewable energy by 2020.

ii. Stakeholder analysis

The stakeholders UK national level are:

- The population of the country;
- The government of the country;
- The industry of the country; especially energy intensive industry e.g. steel;
- The supply industry;
- The merchant generators;
- The network companies;
- NGO's.

It is necessary to define the value system of each party that plays a role in the system. Value system describes the attributes or characteristics of energy/electricity system that each party defined above holds. The reason for defining each stakeholder's value system is, ostensibly, to show that there exist different value systems for different stakeholders. Schelling (Schelling, 1960) states that individual stakeholders will have different value systems that appear rational to the individual holding them but may appear irrational to others. In order to find a solution to the problem it is necessary to recognise opposing value systems in order to formulate a strategy to deal with them.

Stakeholder value identification plays a key role in the Lean Aerospace Initiative (Murman et al., 2002). The book lays out a format for "doing the right project as well as doing the project right". The only way that value may be delivered is to identify stakeholders, identify stakeholder value and finally deliver the product.

The two paragraphs above are supposed to provide a framework in which value systems may be divided. Doing so will provide an unbiased statement of the situation faced by decision making organisations.

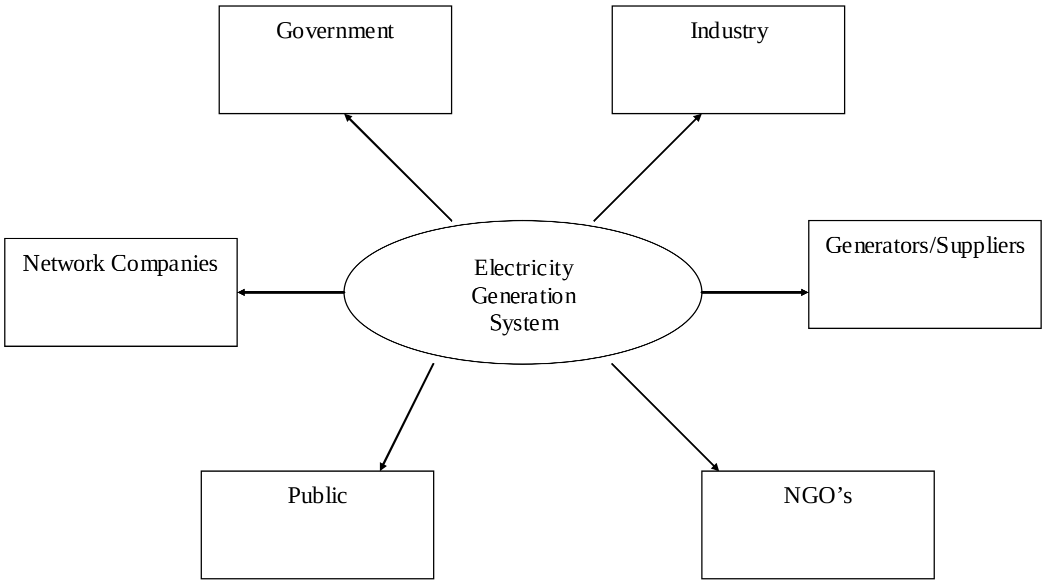


Figure B-1: Stakeholders in the generation system

Government

The Prime Minister states in the foreword to the Energy Review published in 2006 that: "a clean, secure and sufficient supply of energy is essential for the future of our country" and "ensuring we have a sustainable, secure and affordable energy supply is one of the principle duties of government".[18] This statement echoes previous statements, including the following from the UK Cabinet Office Performance and Innovation Unit (PIU): "…securing cheap, reliable and sustainable sources of energy supply".[19]

Other countries and organisations follow a similar route with the US Energy Plan of May 2001 stating "reliable, affordable and environmentally sound"[20], while the EU Parliament states "security of supply, competitiveness and protection of the environment"[21] as goals of its energy policy.

It can therefore be argued that the value system held by the government concerns what is known in Japan as the three E's: Energy Security, Environmental protection and Economic Efficiency.

Government should be considered the dominant player in the market (Helm, 2002). It intervenes in the market for social reasons- fuel poverty, for security of supply reasons, for industrial reasons, for environmental reasons and for monetary reasons- Gordon Brown pointed out in his pre-2002 budget speech that lowering fuel tax would lower government expenditure.

[18] The Energy Challenge Energy Review Report 2006, Department of Trade and Industry, http://www.dti.gov.uk/files/file31890.pdf
[19] PIU Energy Review, February 2002
[20] National Energy Policy, A Report by the National Energy Policy Development Group, May 2001
[21] Report of EP Committee A5-0363.2001, 2001, European Parliament

Public

A Eurobarometer survey[22] published in January 2006 presents an interesting public view towards energy policy. It appears that 45% of Britons questioned would not pay more for energy from renewable sources, and of the rest, 24% would pay up to 5% more and 10% would pay 6-10% more. In effect, a significant proportion of the UK population would be willing to pay more for low-carbon electricity. However, there is an appreciation of the global scale of the emissions problem with 55% of respondents replying that action must be taken at a European level.

There is also a strong interest in the areas where the government should research new energy options (respondents were asked to give two choices): 36% promote advanced research for new technologies e.g. hydrogen and clean coal, 17% think regulation should be introduced to limit emissions, 43% develop solar, 39% develop wind and 18% develop nuclear.

It should be noted that public opinion is influenced by media, NGO's, industry, government, and to a certain extent academic reports. Therefore it can be said that the value system held by the public is not static.

Industry

Recent news reports suggest that rising energy prices are a threat to profitability of companies[23]. Some sectors are particularly vulnerable, such as the manufacturing sector[24]. Although companies are making efforts to become more energy efficient, it is unlikely that the energy saved will offset the rise in energy costs. Therefore, although many companies now promote energy efficiency through their corporate policy and the government renewable obligation, it is likely that price and all matters affecting price, such as security, are the main components of the value system held by industry.

Generators

The role of the generator is substantially different than the other actors listed. The generators views can be divided into short and long term. In the short term the objective of the generator is to maximize profits by optimising the use of their generation assets given the price they can receive at any given time (price risk)

In the long-term view, generators must face a strategic decision- to invest in new plant and when to retire old plant or to prolong the life of plants already operating. Given the importance of these decisions it is not surprising that reports are coming in stating that generating companies are trying to extend the

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[22] Special Eurobarometer: Attitudes towards Energy, January 2006, European Commission
23 Steel maker Corus delivers warning on UK energy costs, Independent, 31 August 2006
[24]Rising Energy Prices, Energy Watch
http://www.energywatch.org.uk/uploads/Rising_Energy_Prices.pdf#search=%22industry%20energy%20prices%22

lifetime of power plants to see how the uncertainty unfolds e.g. future legislation, carbon prices, demand, fuel prices, and structure of the market.

It should be appreciated that the decision to wait for uncertainty to resolve will ensure that emissions still occur from fossil fuel plants. In fact, any demand is likely to be met in the most riskless way, meaning that future demand will be met by an expansion of CCGT's.

Finally, the Centrica report of 2004, states: "Creating shareholder value lies at the core of our strategy. Our increased investment in securing cost-effective energy supplies underpins our continual commitment to meeting customer needs", whilst the 2005 report states "As always, we will manage our business with shareholder value firmly at the top of our agenda."[25] This stance obviously has implications for the adoption of more costly low-carbon generation technologies.

Network companies

Network companies maintain and operate the distribution network in the UK. The network companies can be split into transmission network owners e.g. National Grid and distribution network operators, which are sometimes owned by merchant generators such as EDF. In addition to owning the transmission grid, National grid is also responsible for balancing electricity supply and demand. This balancing is done by calling on power plants or hydro plants to produce electricity during times of peak demand to ensure that demand is met. Network companies raise revenue by placing a charge on the use of their network for electricity distribution. As network operators are regulated monopolies, they will only invest in new infrastructure if they are incentivised to upgrade or build new networks.

NGO's

NGO's generally represent the views and political and social views of their members and as such try to influence governmental policy by commissioning studies or projects to show their path is the one that should be chosen or to discredit or reinforce government decisions. There are many different NGO's in the UK that have an interest in the future energy policy of the country, mainly because energy policy has an impact on their core political beliefs. Therefore, it is wise to view reports commissioned by such organisations objectively, for while the reports may contain useful or new information, the report will be compliant with the organisations political views. For example, a report commissioned by the WWF and conducted by Ilex Energy Consulting states "WWF has commissioned Ilex to provide a realistic assessment of the potential to achieve significant CO_2 reductions in the UK by 2010, 2016, 2020 and 2025 without new nuclear build" [26]. It is obvious that the report is already constrained in terms of power choice- this scenario has been chosen because the WWF organisation does not support new nuclear build.

[25] Centrica Report, Annual Report and Accounts 2005, Centrica Report, Annual Report and Accounts 2004, http://www.centrica.co.uk/files/reports/2005arep/files/pdf/2005_annual_report.pdf
[26] The Balance of Power, Reducing CO2 Emissions from the UK Power Sector, A report for WWF-UK by Ilex Energy Consulting, May 2006

In the final report, the lion's share of meeting increased demand is met by the deployment of gas fired CCGT plant. Other reports have suggested that there are significant consequences of allowing gas to dominate the market[27]. The failure of reports to consider the problem holistically means that solutions given can quite often be faulty when viewed in from a more holistic perspective. This is a case of knowledge by apriority as stated by Stafford Beer[28]: constraining the problem will generate a certain solution that answers the wrong question. This does not mean the methodology is wrong, or that nothing can be learned from the report, but the limitations of such an approach must be acknowledged.

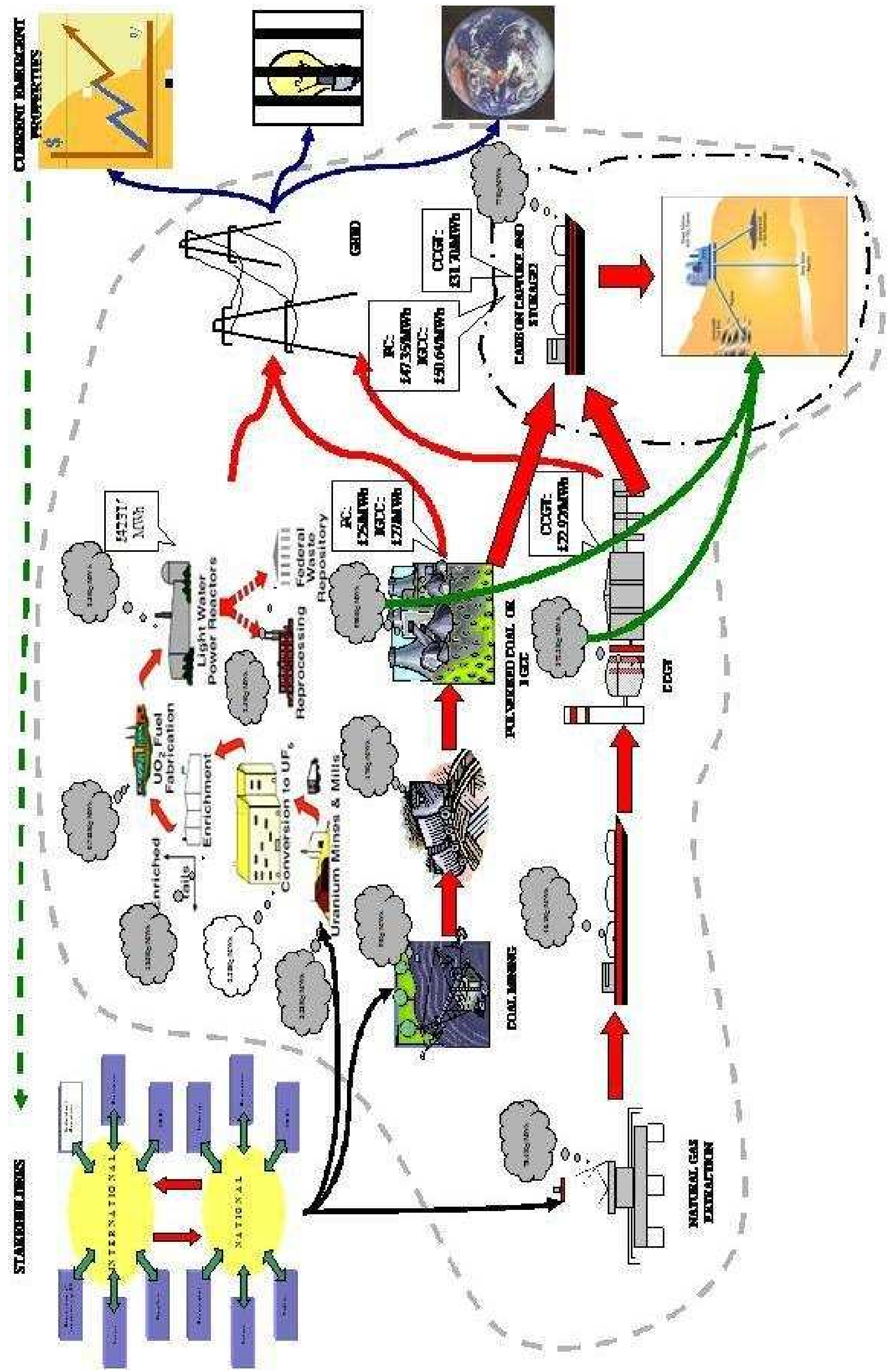
A further, international level (level 2) exists. The stakeholders at level two are: intergovernmental bodies such as the European Union, the UN, IEA/IAEA and individual/ groups of governments (as consumers), along with individual/ groups of governments (as suppliers e.g.OPEC, Russia).

The two stakeholder levels interact with each other to form a set of interactions that eventually determine the UK generation mix as shown below. The diagram shows how the stakeholders at the national and international level determine the mix of the UK generation system.

The emergent properties of the generation system are seen on the right hand side of the rich picture. These are the products of the generation system, which is in the middle. The three images symbolise energy security, economics and the environment, the three E's of energy policy. On the left, lie the stakeholders at both the national and international levels. The stakeholders observe the emergent properties of the generation system and try to alter the balance of the system in order to meet the goals of their value system. This is where the special role of government comes in as it blocks demands made by different parties e.g. no nuclear plants by certain NGO's or a number of new coal plants put forward by a generator. The government is also influenced by international governmental bodies such as the EU, who also try to enforce their view of how the generation system should be composed. The dynamics of stakeholder interaction are extremely complex and the eventual result is a product of tradeoffs and compromises, but in essence this is the mechanism via which stakeholders try to influence the composition of the generation system. The diagram also explains the generation system in terms of the feedback into it i.e. how it is regulated. This feedback mechanism is interesting, particularly because of the long life time of power generation systems; stakeholders only get the chance to influence system composition rarely and even when this happens it might be under a different set of emergent properties e.g. opposition to nuclear power in the 80's versus opposition to nuclear power with the background of climate change.

[27] Roques et al, Nuclear Power: A Hedge against Uncertain Gas and Carbon Prices" Cambridge University Working Paper, November 2005
[28] Decision and Control: The meaning of Operational Research and Cybernetics, Beer, S, 1956, Wiley

iii. Systems view of stakeholder interaction and emergent properties on the UK generation mix



Data for plant build times

Planning and construction times are notoriously difficult to estimate; even more so as each project has its own characteristics. The table below gives some expected times for planning and construction in the UK

Table B-1: Data for average plant build times (DECC, 2009)

Plant	Planning time	Construction time
Gas CCGT	2	2-3
Coal CCS	4	4
Nuclear	4	5
Wind	4	2

v. Supporting data for GB future generation mix

Table B-2: Emissions and generation mix from DECC projections (Data source (DECC, 2008b))

	Coal	Coal CCS	Natural Gas	Nuclear	Wind	Other renewables
Emissions (kg/MWh electricity produced)	0.9	0.15	0.4	0	0	0
Load factor (%)	0.85	0.85	0.85	0.85	0.27	0.65
% Split	25	0	45	9	13	4
Total energy required (TWh/annum)	348					
Generation (TWh/year)	87	0	156.6	31.3	45.2	13.9
Emissions (Mt Co2)/year	78	0	63	0	0	0
Installed capacity (GW)	11.7	0	21.0	4.2	19.1	2.5
Total Emissions (MtCO2/annum)	**141**					

An alternative scenario, showing the contribution CCS plant could make is shown in the table below. The proportion of gas generation in the mix remains at 35%, while the remaining 4% of energy required comes from imports and oil fired generation:

Table B-3: Emissions and generation mix with CCS (author calculations)

	Coal	Coal CCS	Natural Gas	Nuclear	Wind	Other renewables
Emissions (kg/MWh)	0.9	0.15	0.4	0	0	0
Load factor (%)	0.85	0.85	0.85	0.85	0.27	0.65
% Split	25	10	34	10	13	4
Total energy required (TWh/annum)	348					
Generation (TWh/year)	87	34.8	118.3	34.8	45.2	13.9
Emissions (Mt Co2)/year	78	5	47	0	0	0
Installed capacity (GW)	11.7	4.7	15.9	4.8	19.1	2.4
Total Emissions (MtCO2/annum)	**131**					

C. Appendix for Chapter 3

i. Fundamentals of engineering systems

Operational research (operations research, OR) refers to the application of mathematical models to solve industrial problems. Operations Research was developed in England before the Second World War to analyse military operations. During the war itself, operations research was used in the planning and analysis of military operations. A notable early example of the application of OR was to increase the proportion of enemy submarines sunk in British coastal waters (Beer, 1966). Since then, mathematical techniques used in OR have been applied to many industrial problems.

Systems engineering was developed at Bell laboratories, primarily to manage complex technical projects in telecommunications. Therefore it can be thought of as a tool to ensure that complex technical systems achieve key performance parameters through rigorous design methods (Sage and Rouse, 1999).

The field of systems dynamics is concerned with building models to predict and compare alternative outcomes of different management decisions or policies, see for example (Forrester, 1961), (Forrester, 1966), (Sterman and Sweeney, 2002). Systems dynamics is sometimes seen as being one of the tools used for systems analysis.

Systems Analysis compares systems that offer similar outcomes and was developed for military operations in the 50's by the RAND Corporation. In recent years, systems analysis has been used for social science research, for example the International Institute for Applied Systems Analysis (IIASA) in Austria has published work using systems analysis to solve long term energy planning problems (Messner and Strubegger, 1999). An excellent overview of systems analysis can be found in (Miser and Quade, 1985).

ii. Chaotic systems

Due to the complex nature of the climate system, there is still a lot of uncertainty over the effects a temperature rise will have on the planet and whether or not man can adapt to climate change. This is where traditional systems theory has a major challenge; as systems begin to develop chaotic behaviour. Chaotic behaviour is the attribute of a system that acts unpredictably. The foundations of chaos theory were introduced by Poincare in the late 19th century after studying the three body problem. This is an extension of the two body problem that can be solved using Newton's laws of motion. It was found that trying to extend the problem to include the dynamical relationships of three bodies resulted in an unsolvable problem. In particular, alteration of the initial system conditions by the smallest amount resulted in significantly different outcomes. This result had profound implications for belief in the deterministic nature of the sciences.

Apart from unpredictable behaviour, chaotic systems are very sensitive to initial conditions. Hence the famous quote that a butterfly flapping its wings causes a thunderstorm. Chaotic systems are typically non-linear and complex, but do not have to be- a simple two arm pendulum exhibits chaotic movement. The result is that it must be acknowledged that some systems cannot be reduced to the sum of the behaviour of individual parts i.e. predictability and this goes for seemingly simple i.e. simple pendulum and complex systems i.e. the earth's climate system.

As chaotic systems, such as the Earth's climate system are impossible to predict, there has been work that identifies system tipping points, that is points from which the system moves out of equilibrium and into chaos (Lenton et al., 2008). More importantly, these events are usually irreversible at the scale of a human lifetime. Once a tipping point is passed, the system finds equilibrium, but at a different equilibrium state than it started with. Such an example of a tipping point is the melting of the Antarctic ice sheet (Lenton et al., 2008). If the sheet melts, the heating load on the earth doubles, as the normally highly reflective ice is replaced by highly absorbing ocean; this is irreversible in terms of man's lifetime- such an event did happen hundreds of thousands of years ago but it took 12,000 years for the earth to return to from the higher equilibrium position (Pollard and DeConto, 2009).

A further example is the weak chaotic behaviour exhibited when sand in tipped onto a small pile, grain by grain. Sometimes the height of the cone exceeds the critical level before collapsing, and the slip of sand nudges the system towards stability. This is known as the principle of self organised criticality (Hitchins, 1992). The examples above are essentially holistic theories as the behaviour of the system cannot be predicted from its constituents be it grains of sand or molecules of carbon dioxide. Indeed, perhaps a better way to see such systems would be as systems that alternate chaotically about equilibrium.

iii. History of the generation system

The generation system was the result of Edison needing a means to power his light bulb (Mindell, 2002). Therefore, the inclusion of a generation plant and distribution network were backed up by system performance parameters; in order to replace the gas lights of the day, Edison's system needed to cost less than the incumbent system while maintaining reliability. As a result, it is likely that some basic form of systems engineering lay behind the success of the electricity network (Hughes, 1983). However, in the early days of power networks, individual towns had their own generating companies, which implied small independent systems that did not require knowledge of system interaction. It was not until the replacement of DC with AC and the centralisation of large power stations, distributing electricity via large grids that engineers began to model interaction between system elements and the result of these interactions on the generation and distribution system (Mindell, 2002). New networks could only be explained, and therefore designed, by looking at the whole, and not the individual parts (Mindell, 2002).

D. Appendix for Chapter 4

i. Comparison of CCS and other emission reduction technologies

The technological options for carbon emission reductions from PC plant are discussed in Section 4.3. Carbon emissions reductions are not to be reduced directly by legislation, but by a price being applied to carbon emissions from plants. The capture of carbon emissions from PC plant, although being a similar process to FGD (in the sense of it being a flue gas treatment that can be bolted on), has a far greater effect on plant performance than traditional emissions control measures. Due to the volume of gas that needs to be captured, the capture equipment will be much larger and will cost significantly more than standard emissions controls.

ii. Expected time to commercialisation for various capture processes

Table D-1: USDOE estimates for time until novel technologies come to market

PC	Oxyfuel	IGCC	Time to commercialisation
Amine Solvents	Cryogenic Oxygen	Physical Solvents Cryogenic Oxygen	Present
Advanced amine solvents		Advanced Physical Solvents	1-3 Years
Solid Sorbents Membrane Systems	ITM’s	PBI Membranes Membrane Systems ITM’s	2-6 Years
Ionic Liquids MOF’s Enzymatic Membranes	CAR Process		4-8 Years
Biological Processes	OTM Boiler Chemical Looping	Chemical Looping	5-12 Years

iii. Companies producing commercial CO_2 removal processes

Table D-2: Companies producing commercial CO2 removal processes

Company	Removal process	Country of test	Plant type
Aker Kvaerner	MEA	Norway	PC
Aker Kvaerner	Membrane contactors	Norway	PC
Sargas	Potassium Carbonate	Norway	IGCC/PFBC
Fluor	Econoamine, Econoamine + (MEA)	Global	PC
ABB	Lummus (MEA)	Global	PC
Mitsubishi Heavy Industries	KS range (Sterically hindered amine)	Japan	PC
Siemens	Amino acid salts	Germany	PC
Alstom	Chilled Ammonia	Global	PC
Cansolv	DSC-103 tertiary amine solvent		PC
Univeral Oil Products	Selexol	USA (global)	IGCC
Linde/Lurgi	Rectisol	Global	IGCC
Powerspan	Ammonia	USA	PC
Praxair	OTM	Oxyfuel	
ALSTOM	Advanced boiler design	Oxyfuel	

iv. Cost Data

PC performance data

A literature review has provided cost data for the PC plant and is shown in the tables below. The data was taken from a variety of sources, and as a consequence, capital costs are reported in a variety of currencies. This can introduce additional uncertainty into the calculations because exchange rate fluctuation can have a substantial effect on costs: the £/$ exchange rate has varied between 0.64 to 0.84 from 2001 and 2007 (Officer and Williamson, 2008).

Capital Cost

Table D-3: Capital cost data for various PC plants

Plant type	Efficiency (%)	Capacity(MW)	Capital cost(£/kW)	Source
Sub-critical	38	1600	885-928	(RAEng, 2004)
Sub-Critical	32.6	500	719	MIT, 2006
Super	36.6	500	747	MIT. 2006
			754-965	IPCC, 2007
Super	44	758	712	IEAghg, 2004 Fluor
Super	43.7	754	683	IEAghg, 2004 MHI
USC	41.2	500	764	MIT, 2006

Capital cost for a plant with CCS

Table D-4: Capital cost data for various PC plant with CCS

Plant type	Efficiency (%)	Capacity(MW)	Capital cost(£/kW)	Source
Sub-Critical	23.1	500	1253	MIT, 2006
Super	27.4	500	1202	MIT, 2006
Super			1231-1675	IPCC, 2007
Super	34.8	758	1022	IEAghg, 2004 Fluor
Super	35.3	754	1082	IEAghg, 2004 MHI
Super			1350	Lako, 2004
USC	32	500	1174	MIT, 2006

Operations and maintenance

Table D-5: Operations and maintenance costs for PC Plant

	CCS status	Capacity (MW)	O&M cost (£/kW)	Annual cost (£ million)
RAEng (2004)	No	1600	24	38.4
IEA (2004)a	No	758	38	28.8
	Yes	666	52.79	35.2
IEA (2004)b	No	-	-	-
	Yes	-	-	-
Sekar (2005)	No	513	25.14	12.90
	Yes	513	42.82	21.97

Fuel cost

There are various methods of calculating the cost of fuel for a power plant. The calorific value of the fuel, the electrical output of the plant and the efficiency of the plant are key input factors. The problem lies in the fact that coal is sold by the tonne. The DTI quotes the Antwerp Rotterdam Amsterdam (ARA) price in £/tonne, but assumes a gross calorific value of 25GJ/tonne (25MJ/kg).

Table D-6: Fuel cost for PC plant

Source	CCS status	Capacity (MW)	Fuel cost (£mn) per year
RAEng (2004)	No	-	-
IEA (2004)a	No	758	22.87-45.72
	Yes	666	45.72-91.45
IEA (2004)b	No	-	-
	Yes	-	-
Sekar (2005)	No	513	26.83-49.18
	Yes	513	37.69-58.13

The reason for the significant increase in fuel costs when installing CCS is because savings from avoidance of the CO_2 penalty are not taken into account. The figure is also determined by the efficiency penalty from CCS system operation – Sekar assumes a 10% performance penalty for installing CCS, and fuel price assumptions.

Table D-7: General plant attributes (various data sources) for PC

	CCS status	Utilisation factor	Lifetime (years)	Efficiency (%)
RAEng (2004)	No	-	30	38
IEA (2004)a	No	85	25	44
	Yes	85	25	34.8
IEA (2004)b	No	85	25	43.7
	Yes	85	25	35.3
MIT (2006)	No	85	25	32.6
	Yes	85	25	23.1
	No	85	25	36.6
	Yes	85	25	27.4
	No	85	25	41.2
	Yes	85	25	32
Sekar (2005)	No	90	25	34.19
	Yes	90	25	24.5

IGCC Performance data

For case studies, the following data is used to provide an estimate of the cost of generation. The methodology is presented in Chapter 5.

Table D-8: Capital cost of IGCC plant from various sources

	CCS status	Capacity (MW)	Capital cost (£/KW)	Plant cost (£bn)
RAEng (2004)	No	480	1028	0.493
	Yes	-	-	-
IEA a (2003)	No	776	821	0.637
	Yes	676	1114	0.753
IEA b (2003)	No	826	711	0.587
	Yes	730	896	0.654
MIT (2006)	No	500	786	0.393
	Yes	500	1038	0.519
Sekar (2005)	No	513	783	0.402
	Yes	513	1199	0.615

IEA a is for a Shell gasifier

IEA b is for a Texaco Gasifier

Table D-9: Operations and maintenance costs for IGCC plant

	CCS status	Capacity	O&M cost (£/kW)	Yearly cost (£mn)
RAEng (2004)	No	1000	48	38.4
IEA (2003)a	No	776	37.8	29.4
	Yes	676	48.2	32.6
IEA (2003)b	No	826	35.2	29.1
	Yes	730	35.6	26
MIT (2006)	No	500		
	Yes	500		
Sekar (2005)	No	513	33.5	17.18
	Yes	513	47.9	24.59

Table D-10: Fuel cost for IGCC plant (various sources)

	CCS status	Capacity	Fuel cost (£mn) per year
RAEng (2004)	No	-	-
IEA (2003)a	No	776	43.4
	Yes	676	47.0
IEA (2003)b	No	826	52.4
	Yes	730	55.9
Sekar (2005)	No	513	24.27-44.71
	Yes	513	31.94-58.13

Table D-11: General plant attributes (various data sources) for IGCC

	CCS status	Utilisation factor	Lifetime (years)	Efficiency (%)
RAEng (2004)	No	-	-	38
IEA (2004)a	No	85	25	44
	Yes	85	25	34.8
IEA (2004)b	No	85	25	43.7
	Yes	85	25	35.3

MIT (2006)	No	85	25	36.5
	Yes	85	25	29.7
Sekar	No	90	25	37.6
	Yes	90	25	29

In the projection of IGCC and PC costs below, PC plant will continue to have a lower capex than IGCC. To a certain extent this is to be expected because of the more complex and capital intensive nature of the IGCC plant. However, the chart does not tell the full story. This is because the better efficiency of the IGCC plant will more than compensate for the difference in capital cost between the IGCC and PC plant (Lako, 2004). It is also noteworthy that capex cost reduction is far greater for the IGCC (around 40%) plant than for the PC plant to 2050 (25%). Ultimately, future costs are also a function of the rate at which the technology matures, material costs and labour costs. Therefore it is difficult to draw any definite conclusion from Figure D-1; apart from that IGCC plant has greater potential for capital cost reduction than PC plant.

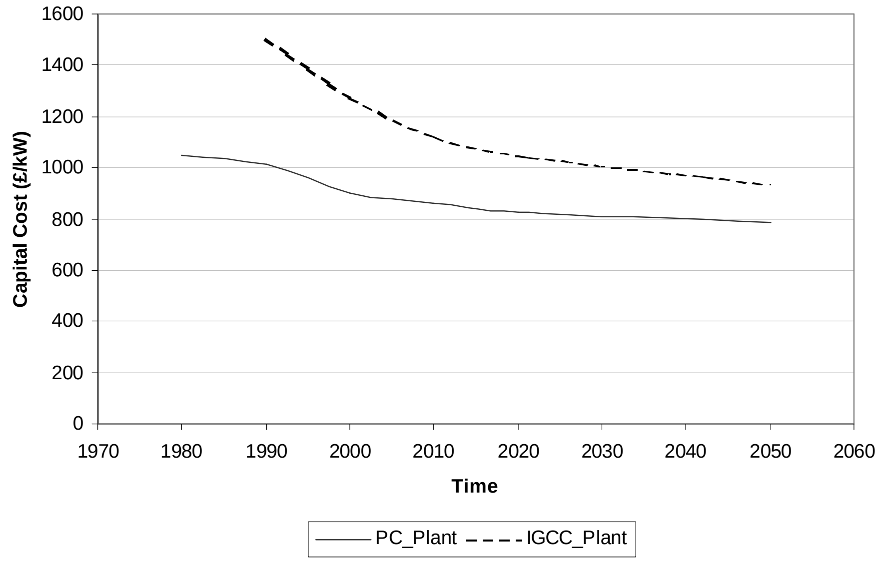


Figure D-1: Estimated future trends in PC and IGCC capital cost (Data source: (Lako, 2004))

v. Commercial Activities for CCS demonstration plants

The following pages list current CCS demo projects by plant type (PC, IGCC and Oxyfuel). The data has been taken from a variety of sources and represents an up to date view of current activity in the deployment of CCS technology. However, given the cost and uncertainty surrounding CCS, the projects on this list could change over time due to organisational decisions and funding issues.

Proposed and Active CCS Activities for PC Plant

	Manufacurer	Partner/Location	Date	Scale	Fuel
R&D Plant					
	Alstom	We Energies/Ohio, USA	Mar-08	1.7MW	Coal
	MHI	Matsushima/Japan		0.5MW	Coal
	Various	CASTOR Dong/ Denmark	2006	1MW	Coal
	ITC	Boundary Dam/ USA	2005	0.25MW	Coal
	BASF	RWE Niederaussem/ Germany	mid 2010	0.33MW	Coal
	?	RWE Aberthaw/ UK	2010	1MW	Coal
Small pilot Demo	Powerspan	Basin Electric Beulah/USA ND	2012	120MW	Coal
	MHI	Eon Germany	2010	6-25MW	Coal
	Flour	Eon Wilhelmshaven/ Germany	2010		Coal
	Cansolv	Eon Heyden/ Germany	end 2009	10MW	Coal
	Alstom	Karlshamn/ Sweden	2008	5MWe	Oil/gas
		Eon/ Electrabel/ HitachiEuro	2009		Coal
Industrial Scale	HTC	Searles Carley Minerals/ CA USA	2009	50MW	Coal
		CSIRO- Huaneng Beijing/ China	2009	175MW	Coal
	Alstom	AE oldahoma/ USA	2011	233MW	Coal
	Alstom	NRG WA Parish/ USA	2012	125MW	Coal
	HTC	Saskpower/ USA, Canada	2011		Coal
	HTC	EPCOR Genese/ Alberta Canada	2010		Coal
	HTC & EEST Tech	Loy Yang/ Australia		60MW	CBM
		Saskpower/ USA, Canada	2015	100MW	Coal
Commercial Demo					
	Winner of UK CCS Comp			2014	Coal

Data Source: Mike Farley, Doosan Babcock, Reuters and company websites

Appendix

Proposed and Active CCS Activities for IGCC Plant

	Manufacurer	Location	Date	Scale	Fuel
Industrial Scale	BP_Rio Tinto	California	2014	500MW	Petcoke
	BP_Rio Tinto	Australia	2014	500MW	Coal
	Centrica	UK	Postponed	800MW	
	EPCOR	Alberta, Canada	2015		
	GE/Polish Utility		-	1000MW	
	Huaneng	GreenGen China	2015	400MW	
	Nuon	Eemshaven, Germany	-	1200MW	various
	Powerfuel	UK	2010	900MW	Coal
	RWE	Germany	2014	450MW	Coal
	Siemans	Germany	2011	1000MW	Coal
	Stanwell	Australia	2012	100MW	Coal

Data Source: Reuters

Proposed and Active CCS Activities for Oxyfuel Plant

	Manufacurer	Partner/ Location	Date	Scale	Fuel
Test	Doosan		1996	160kW	
		EON	2007-08	1MW	
		RWE-npower	2008-2009	0.5MW	
Small Pilot Demo					
	Alstom	Vattenfall/ Germany	2008/9	30MWth	Lignite
	Alstom	Lacq/ France	2009	30MWth	Oil?
	IHI	Callide / Australia	2010	30MWe	
	B+W	B+W CEDF / USA	2008	30MWth	Coal
	Alstom	Alstom CE / USA	2010	15MWth	Coal
	Doosan Babcock	Doosan Babcock / UK	2009	40MWth	Coal
Industrial Scale					
	Vattenfall	Janschwalde/ Germany	2015	250MWe	Lignite

Data Source: Mike Farley, Doosan Babcock

vi. Proposed EU demonstration plants

Table D-12: Table of proposed CCS projects in Europe (Source: (Wilde, 2008))

Company	Country	Plant Type	Capacity (MW)
	Hungary	IGCC	650
Enel	Italy	PC	660
Fortum	Finland	Oxy	560
Statoil Hydro / Gassnova	Norway	CHP	300
Gassnova	Norway	NGCC	400
Vattenfall	Sweden	PC	900
DONG	Denmark	CHP	600
PGE	Poland	PC	858
PKE	Poland	IGCC	150
Vattenfall	Germany	Oxy	300
CEZ Group	Czech	PC	660
Endesa	Spain	Oxy	500
Union Fenosa	Spain	PC	500
Poweo	France	PC	800
Eon	Germany	PC	500
Nuon	Netherlands	IGCC	1200
Eon	NL/Ger	PC	1080
Electrabel	NL/Ger	PC	800
RWE	Germany	IGCC	450
Element Energy	UK	IGCC	800
Scottish and Southern	UK	PC	500
Power Fuel	UK	IGCC	900
EonUK	UK	IGCC	450
Npower	UK	PC	1600

No. of Plants	Type of Plant	Potential Installed Capacity (MW)
11	PC	8858
7	IGCC	4600
3	Oxy	1360
1	NGCC	400
2	CHP	900
24		16118

vii. Technology readiness levels definition (NASA)

Technology readiness level		Description
1	Basic principles observed and reported	Lowest level of technology readiness. Scientific research and development (paper studies)
2	Technology concept and/or application formulated	Invention begins, basic principles observed, practical applications invented. Application is speculative, and there is no proof or detailed analysis to support the assumption. Still paper studies
3	Analytical and experimental critical function and/or characteristic proof of concept	Active research and development initiated. This includes analytical studies and laboratory studies to physically validate analytical predictions of separate elements of the technology. Examples include components that are not yet integrated or representative
4	Component and/or breadboard validation in a laboratory environment	Basic technological components are integrated to establish that the pieces will work together. Examples include integration of ad hoc hardware in a lab
5	Component and/or breadboard validation in a relevant environment	Fidelity of breadboard technology increases significantly. The basic technological components are integrated with reasonably realistic supporting elements so that technology can be tested in a simulated environment. Examples include high fidelity laboratory integration of components.
6	System/subsystem model or prototype demonstration in a relevant environment	Representative model or prototype system, which is well beyond breadboard created for TRL 5, is tested in a relevant environment. Represents a major step up in technology readiness. Examples include developing a prototype in a high fidelity laboratory environment or in a simulated operational environment
7	System prototype demonstration in an operational environment	Prototype near or at planned operational system. Represents a major step up from TRL 6, requiring the demonstration of an actual system prototype in an operational environment e.g. aircraft. Examples include testing the prototype in a test bed aircraft
8	Actual system completed and flight qualified through test and demonstration	Technology has been proven to work in its final form and under expected conditions. In almost all cases this TRL represents the end of true system development/ Examples include developmental test and evaluation of the system to determine if it meets design specifications.
9	Actual system flight proven through successful mission operations	Actual application of the technology in its final form and under mission conditions, such as those encountered in operational test and evaluation. In almost all cases, this is the end of the last bug fixing aspects of system development. Examples include using the system under operational mission conditions

E. Appendix for Chapter 5

i. Generation costs for nuclear plant

Construction costs

Historical nuclear plant costs are shown below. The costs for 2nd generation nuclear plants cannot be used for planning new plant, as modular construction has significantly reduced costs. The historic UK cost is attributed to higher material costs and higher safety standard. Given that the Health and Safety Executive applies the same standards and that material cost differences still prevail, the UK can expect to spend £1.8bn some 50% higher than the equivalent US cost for 3rd generation nuclear plant. This figure assumes a five year construction period and additional financing costs accrued during construction.

Learning curve models predict a 5.8% reduction in the cost of building a "1st of class" plant based on a survey of new nuclear build in the OECD between 1975 and 1993 (McDonald and Schrattenholzer, 2001).

Table E-1: Nuclear plant capital costs

	Location	Capacity (MW)	Capital Cost (2006 £/kW)	Station Cost (£bn)
Morgan Stanley (2005)	N/A	1150	1139	1.31
Epaulard and Gallon (2000)	N/A	1150	1139	1.31
TVA (2004)	USA	1371	928	1.27
TVA (2004)	Japan		1080	
Hansard (1996)	UK	1188	2718	3.21

Decommissioning costs

Advanced reactor designs promise lower decommissioning costs[29]. In the Dominion report (Dominion, 2004) it is estimated that the capitalized cost of decommissioning an AP1000 is $416m (£234m) and for and ABWR $595m (£344m). These costs were calculated using the US based on the DECOM approach[30]. In France the estimated cost of waste disposal and decommissioning is estimated to be 10% of the construction cost (Epaulard and Gallon, 2000). Using the same uplift as described for construction costs to account for the UK's safety case regime and the additional costs for storing nuclear waste, it can be expected that present costs for decommissioning an AP1000 will be £234/0.55; i.e. £425m. The Morgan Stanley report (Stanley, 2005) identifies a mean figure of £323m. The higher figure of £425m will be used for this analysis.

[29] OECD (2003) and NEA (2002) reported US dollar (2001) decommissioning costs by 2nd generation reactor type. For Western PWRs the costs are $200-500/kW, for Russian VVERs $330/kW, for BWRs $300-550/kW, and for CANDU $270-430/kW. For gas-cooled reactors the costs were much higher due to the greater amount of radioactive materials involved,reaching $2600/kW for some UK Magnox reactors. The cost for decommissioning Sizewell A (Magnox) is estimated by theNuclear Decommissioning Authority (NDA) to be $1.2bn.

[30] DECOM refers to soon after the nuclear facility closes; the equipment, structures, and systems of the facility containingradioactive contaminants are removed or decontaminated to a level that would permit the release of the property and terminationof the NRC licence. The UK currently has a preference for SAFSTOR where the facility is maintained and monitored in amanner that allows the radioactivity to decay to safe limits before it is dismantled.

$$C_{d,hr} = \frac{C_d \left[\dfrac{e^r - 1}{e^{rt} - 1} \right]}{hr_{yr} \cdot U_t \cdot P_c}$$

$$\begin{aligned}
&C_{d,hr} : \text{Decommissioning cost } £ / \text{MWh}; \\
&C_d : \text{Total decommissioning fund}, £425\text{M}; \\
&r : \text{Interest rate}, 8\%; \\
&t : \text{economic lifetime}, 40 \text{ years}; \\
&hr_{yr} : \text{Hours per year}, 8760 \text{ hr / yr}; \\
&U_t : \text{Utilisation factor}, 0.85; \\
&P_c : \text{Plant capacity}, 1150 \text{ MW}.
\end{aligned} \tag{6.36}$$

Using the above equation results in a decommissioning cost of £0.19/MWh.

Financing

Myer (Myer, 2005) identifies the risk of cash flow as the most important element of financing. Government backed loan guarantees and power purchase agreements (PPAs) will address this risk. These measures will allow companies to structure projects with highly leveraged capital to obtain debt finance at preferential rates (Myer, 2005). Investment banks have indicated that providing loan guarantees and PPAs are agreed and that the scheme is fully licensed from the outset then debt financing with a discount rate of 8% could be arranged, but interest through the construction period could be higher in the order of 14% to 16% (UoC, 2004). In the UK it is likely that a 70/30 debt/equity deal could be struck with an 8% discount rate. Equity holders would also expect a 15% ROI.

Operations and management cost

Operational costs per annum have been calculated by Dominion (Dominion, 2004) at £58m/yr and by Morgan Stanley (Stanley, 2005) at £36m/yr. The World Nuclear Association (WNA, 2005) used current figures from Finland and Sweden to put the figure at £71m/yr. However, the most reliable cost is based on data from recent history in the UK and Europe (Thomas, 2005) being £73.6m/yr for a 1.2GW plant.

Fuel cost

Thomas (Thomas, 2005) puts the price of fuel at 0:5p/kWh installed but recognizes the need to include a wide error margin for the disposal of high-level waste. The analysis in this paper will assume a 50% margin thereby raising the fuel price to 0:75p/kWh installed (£78.8m/yr).

Plant operating characteristics Pc, Ut, Life(t)

Capacity of the AP1000 is 1150MW installed. The expected load factor of 80% is based on a review of world-wide installations of PWRs and ABGRs. Utilization factors of 90% have been reported (EIA, 2003) but this report will assume 80%.

ii. Results

The numerical values of the terms in the expression for the minimum price of nuclear generated power Nu(min), are

(a) construction costs Cc = £1.8bn;

(b) decommissioning costs Cd = £425m;

(c) debt financing discount rate r = 8%;

(d) return on equity ROE = 15%;

(e) debt ratio de = 0.7;

(f) equity ratio ed = 0.3;

(g) operations and management cost COM = £73.6m/yr;

(h) cost of fuel Cf = £78.8m/yr;

(i) plant capacity Pc = 1150MW installed;

(j) plant load factor Ut = 80%;

(k) plant life t = 50years.

Putting all these into equation (5) yields the price Nu(min) = £42.31/MWh. Generation cost (£/MWh) is sensitive to construction cost and to discount rate, but Nu(min) is much less sensitive to fuel costs[31].

iii. Debt-equity ratios

Typical debt equity ratios are (Yescombe, 2002):

- 90:10 for infrastructure projects with project agreement and no infrastructure risk (e.g. hospital);
- 85:15 for a power or process plant project with an offtake contract (i.e. a contract that states output will be bought at a given price);
- 80: 20 for an infrastructure project with usage risk (toll road or mass transportation project);
- 70:30 for a natural resources project or power generation project;
- 50:50 for a merchant power plant project with no offtake contract or price hedging

iv. Conversion data

Data for the table has been obtained from the Carbon Trust website[32]

From	To	Dividing factor
£/therm	£/MWh	0.02931
£/therm	£/mmBTU	0.10
£/therm	£/GJ	0.105
£/therm	£/m^3	2.713

The Digest of UK energy statistics has been used to provide the following[33]:

31 It should be noted that fuel cost includes all of the processes involved in the fuel preparation cycle (e.g. mining, milling, enrichment etc).

32 http://www.carbontrust.co.uk/resource/energy_units/default.htm

- Calorific value of natural gas: 10.9kWh/m^3

To convert from LHV to HHV

Gas: HHV = 0.965LHV

Coal: HHV = 0.904LHV

Source: (Davison, 2007)

v. Sensitivity analysis data tables

All units in tables are the following

Capital cost	£/MW
Carbon cost	£/tonne
Fuel price	£/tonne/£/therm
Discount rate	%
O&M cost	£/MW
Plant life	Years

PC plant

	Cost of Generation			Input		
Variable	Downside	Upside	Range	Downside	Upside	Base Case
Capital cost	37.60	42.88	5.28	720000	1080000	900000
Carbon cost	37.85	42.63	4.78	17.6	26.4	22
Fuel price	37.87	42.62	4.75	0.03	0.04	0.04
Discount rate	39.04	41.52	2.48	0.06	0.10	0.08
O&M cost	39.60	40.89	1.29	19200	28800	24000
Plant life	40.75	39.96	0.79	24	36	30

PC plant with CCS

	Cost of Generation (£/MWh)			Input		
Variable	Downside	Upside	Range	Downside	Upside	Base Case
Capital Cost	42.26	50.17	7.91	1080000	1620000	1350000
Fuel Price	43.47	48.96	5.49	0.03	0.04	0.03
Discount rate	44.42	48.14	3.72	0.06	0.10	0.08
Transport & Storage	45.07	47.36	2.29	5.6	8.4	7
O_M_Costs	45.12	47.31	2.19	32640	48960	40800
Plant Life	46.97	45.79	1.19	24	36	30
Carbon Price	45.91	46.51	0.60	17.6	26.4	22

Oxyfuel plant

Cost of Generation	Input

33 http://www.berr.gov.uk/energy/statistics/publications/dukes/page45537.html/statistics/publications/dukes/page45537.html

Variable	Downside	Upside	Range	Downside	Upside	Base Case
Capital Cost	41.46	46.74	5.28	720,000.00	1,080,000.00	900,000.00
Carbon Price	41.47	46.73	5.26	17.60	26.40	22.00
Fuel Price	41.49	46.72	5.23	0.03	0.04	0.04
Discount Rate	42.90	45.38	2.48	0.06	0.10	0.08
O_M_Costs	43.16	45.04	1.88	28,000.00	42,000.00	35,000.00
Plant Life	44.61	43.82	0.79	24.00	36.00	30.00

Oxyfuel plant with CCS

	Cost of Generation (£/MWh)			Input		
Variable	Downside	Upside	Range	Downside	Upside	Base Case
Capital Cost	42.04	50.24	8.21	1120000	1680000	1400000
Fuel Price	43.50	48.78	5.27	0.03	0.04	0.03
Discount Rate	44.28	48.14	3.86	0.06	0.10	0.08
Transport & Storage	45.04	47.24	2.21	5.6	8.4	7
O_M_Costs	45.04	47.24	2.19	32640	48960	40800
Plant life	46.93	45.70	1.23	24	36	30
Carbon price	45.85	46.43	0.58	17.6	26.4	22

IGCC

	Cost of generation (£/MWh)			Input		
Variable	Downside	Upside	Range	Downside	Upside	Base Case
Capital Cost	41.03	46.89	5.86	800000	1200000	1000000
Carbon Price	41.57	46.35	4.78	17.6	26.4	22
Fuel Price	41.77	46.14	4.36	0.03	0.04	0.03
Discount Rate	42.63	45.38	2.75	0.06	0.10	0.08
O_M_Costs	42.67	45.25	2.58	38400	57600	48000
Plant Life	44.52	43.64	0.88	24	36	30

IGCC with CCS

	Cost of Generation (£/MWh)			Input		
Variable	Downside	Upside	Range	Downside	Upside	Base Case
Capital Cost	46.26	55.23	8.97	1224000	1836000	1530000
Fuel Price	48.15	53.34	5.19	0.03	0.04	0.03
Discount Rate	48.71	52.93	4.22	0.06	0.10	0.08
O_M_Costs	49.05	52.45	3.40	50688	76032	63360
Transport & Storage	49.66	51.83	2.17	5.6	8.4	7
Plant life	51.61	50.27	1.35	24	36	30
Carbon Price	50.46	51.03	0.57	17.6	26.4	22

CCGT

Variable	Cost of Generation (£/MWh) Downside	Upside	Range	Input Downside	Upside	Base Case
Fuel price	26.69	33.30	6.61	0.21	0.32	0.27
Carbon price	28.84	31.15	2.31	17.6	26.4	22
Capital cost	28.86	31.13	2.27	320000	480000	400000
Discount rate	29.43	30.60	1.18	0.06	0.10	0.08
O&M costs	29.59	30.40	0.81	12000	18000	15000
Plant life	30.13	29.93	0.19	32	48	40

CCGT with CCS

Variable	Generation Cost (£/MWh) Downside	Upside	Range	Input Downside	Upside	Base Case
Fuel Price	31.61	39.25	7.64	0.21	0.32	0.27
Capital Cost	33.57	37.29	3.73	524800	787200	656000
Discount Rate	34.49	36.43	1.93	0.06	0.10	0.08
O_M_Costs	34.62	36.24	1.61	24000	36000	30000
Transport & Storage	34.96	35.90	0.95	5.6	8.4	7
Plant life	35.64	35.32	0.32	32	48	40
Carbon price	35.31	35.55	0.25	17.6	26.4	22

vi. Financial model

This Section of the appendix presents an overview of the financial model built to assess the economics of new build plant in Chapter 5.

Title	PC CCS Financial Model		
Version	1.1		
Date of last update	30/010/2009		
Results			
	Payback Period (SPB)	years	#NAME?
	Internal Rate of Return (IRR)	%	0%
	Net Present Value (NPV)	£	-£0.00
Summary Assumptions			
	Plant capacity	MW	500
	Average Cost of Electricity (£/MWh)	£/MWh	46.26
	Nominal Electricity Escalation Rate (%/year)	%/year	0%
	Capital cost	£/MW	1,350,000
	Total Installed Cost (£M)	£	675,000,000
	Debt	%	70%
	Equity	%	30%
	Return on equity	%	15%
	Debt Term (years)	years	30
	Debt Interest Rate (%/year)	%/annum	8%
	Marginal Effective Tax Rate (%/year)	%/annum	0%
	Hours per year		8,760
	Calorific Value (MJ/kg) or GJ/tonne	GJ/tonne	25.2
	Plant Efficiency	%	35%
	Variable Cost (£/MWh)	£/MWh	21.35
	Nominal Variable Cost Escalation Rate (%/year)	%/annum	0%
	CO2 content of fuel (input)	t/MWh	0.32
	Emissions factor		2.23
	Fixed O&M (£)	£/MW	40800
	Nominal Fixed Cost Escalation Rate	%/annum	0%
	Conversion from GJ to MWh		0.278
	Depreciation		No

Figure E-1: Input parameter list for financial model and output graph showing cash flow over time

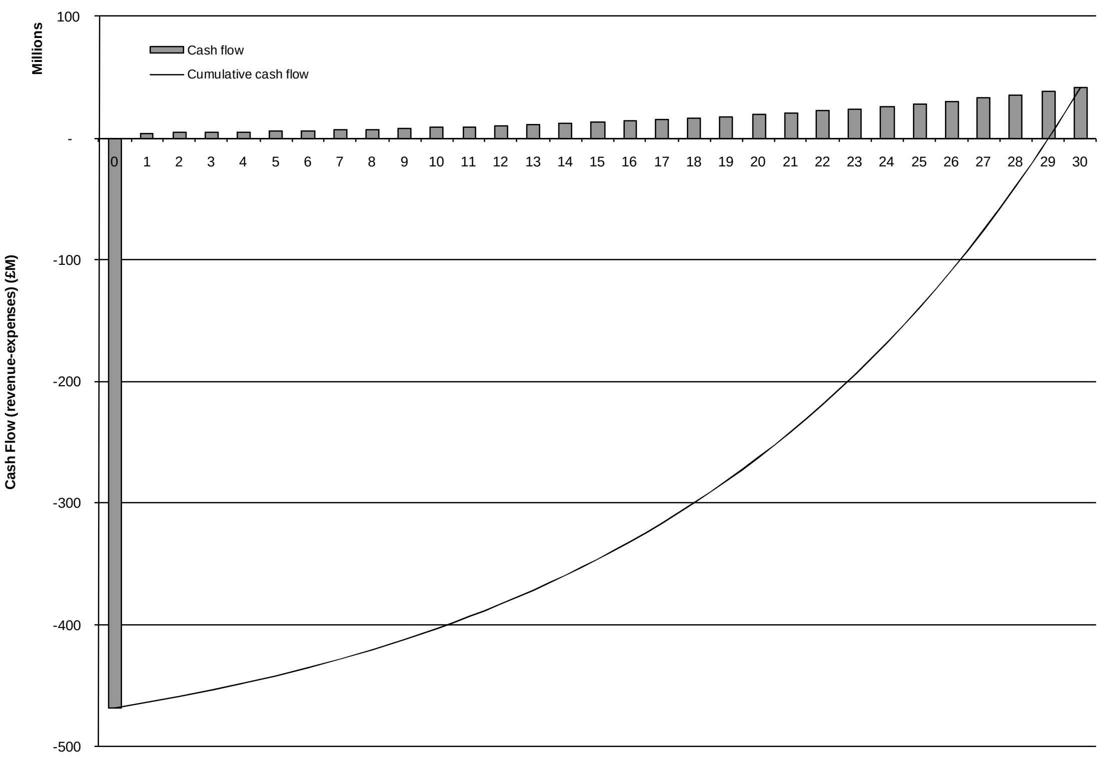


Figure E-2: Calculation steps for the financial model (full model runs for lifetime of plant e.g. 30 years)

Variable cost calculations																
Year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
Plant efficiency		35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Fuel price (£/tonne)		33.6	33.6	33.6	33.6	33.6	33.6	33.6	33.6	33.6	33.6	33.6	33.6	33.6	33.6	33.6
Fuel price (£/GJ)		1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33
Fuel input cost (£/MWh)		4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80
Fuel cost for 1MWh output (£/MWh)		13.703	13.703	13.703	13.703	13.703	13.703	13.703	13.703	13.703	13.703	13.703	13.703	13.703	13.703	13.703
CO2 content of fuel input (t/MWh)		0.3185	0.3185	0.3185	0.3185	0.3185	0.3185	0.3185	0.3185	0.3185	0.3185	0.3185	0.3185	0.3185	0.3185	0.3185
CO2 emissions t/MWh		0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91
Capture efficiency (%)		0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
CO2 captured (t/MWh)		0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82
CO2 emitted (t/MWh)		0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Carbon Price (£/tonne)		16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50
CO2 cost (£/MWh)		1.502	1.502	1.502	1.502	1.502	1.502	1.502	1.502	1.502	1.502	1.502	1.502	1.502	1.502	1.502
CO2 stored per year (tCO2/yr)		3,049,137	3,049,137	3,049,137	3,049,137	3,049,137	3,049,137	3,049,137	3,049,137	3,049,137	3,049,137	3,049,137	3,049,137	3,049,137	3,049,137	3,049,137
Transport and storage cost (£/tCO2)		7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50
Transport and storage cost (£/MWh)		6.14	6.14	6.14	6.14	6.14	6.14	6.14	6.14	6.14	6.14	6.14	6.14	6.14	6.14	6.14
Total Annual transport and storage costs (£/yr)		22,868,528	22,868,528	22,868,528	22,868,528	22,868,528	22,868,528	22,868,528	22,868,528	22,868,528	22,868,528	22,868,528	22,868,528	22,868,528	22,868,528	22,868,528
Total fuel cost per year		51,017,472	51,017,472	51,017,472	51,017,472	51,017,472	51,017,472	51,017,472	51,017,472	51,017,472	51,017,472	51,017,472	51,017,472	51,017,472	51,017,472	51,017,472
Total CO2 cost per year		5,590,085	5,590,085	5,590,085	5,590,085	5,590,085	5,590,085	5,590,085	5,590,085	5,590,085	5,590,085	5,590,085	5,590,085	5,590,085	5,590,085	5,590,085
Total variable costs (£/year)		79,476,084	79,476,084	79,476,084	79,476,084	79,476,084	79,476,084	79,476,084	79,476,084	79,476,084	79,476,084	79,476,084	79,476,084	79,476,084	79,476,084	79,476,084
Total variable costs (£/MWh)		21.35	21.35	21.35	21.35	21.35	21.35	21.35	21.35	21.35	21.35	21.35	21.35	21.35	21.35	21.35
30-Year Nominal Cash-Flow (All units are expressed as pounds unless otherwise noted)																
Year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
Load factor	0	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Revenue																
Power Output (MWh/year) (A)		3723000	3723000	3723000	3723000	3723000	3723000	3723000	3723000	3723000	3723000	3723000	3723000	3723000	3723000	3723000
Cost of Electricity (£/MWh) (B)		46.2595	46.2595	46.2595	46.2595	46.2595	46.2595	46.2595	46.2595	46.2595	46.2595	46.2595	46.2595	46.2595	46.2595	46.2595
Total Revenue (A*B)		172,224,118	172,224,118	172,224,118	172,224,118	172,224,118	172,224,118	172,224,118	172,224,118	172,224,118	172,224,118	172,224,118	172,224,118	172,224,118	172,224,118	172,224,118
Expenses																
Initial Capital Expenditure (Downpayment)																
Amount Financed by debt	472500000															
Amount financed by equity	202,500,000															
Total Debt Payment		41,970,962	41,970,962	41,970,962	41,970,962	41,970,962	41,970,962	41,970,962	41,970,962	41,970,962	41,970,962	41,970,962	41,970,962	41,970,962	41,970,962	41,970,962
Debt Interest repayment (C)	37,800,000	37,466,323	37,105,952	36,716,751	36,296,414	35,842,450	35,352,169	34,822,666	34,250,802	33,633,189	32,966,168	32,245,784	31,467,770	30,627,514	29,720,038	28,739,965
Annuity (D)	4,170,962	4,504,639	4,865,010	5,254,211	5,674,548	6,128,512	6,618,793	7,148,296	7,720,160	8,337,773	9,004,795	9,725,178	10,503,193	11,343,448	12,250,924	13,230,998
Remaining loan	472,500,000	468,329,038	463,824,398	458,959,388	453,705,177	448,030,629	441,902,117	435,283,324	428,135,027	420,414,867	412,077,094	403,072,300	393,347,121	382,843,929	371,500,481	359,249,557
Equity repayment (E)		30,375,000	30,375,000	30,375,000	30,375,000	30,375,000	30,375,000	30,375,000	30,375,000	30,375,000	30,375,000	30,375,000	30,375,000	30,375,000	30,375,000	30,375,000
Depreciation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EBITDA		72,348,035	72,348,035	72,348,035	72,348,035	72,348,035	72,348,035	72,348,035	72,348,035	72,348,035	72,348,035	72,348,035	72,348,035	72,348,035	72,348,035	72,348,035
EBIT		72,348,035	72,348,035	72,348,035	72,348,035	72,348,035	72,348,035	72,348,035	72,348,035	72,348,035	72,348,035	72,348,035	72,348,035	72,348,035	72,348,035	72,348,035
EBT		4,506,712	4,867,083	5,256,284	5,676,621	6,130,584	6,620,865	7,150,369	7,722,233	8,339,845	9,006,867	9,727,251	10,505,265	11,345,520	12,252,996	13,233,070
Taxes	0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Income		4,506,712	4,867,083	5,256,284	5,676,621	6,130,584	6,620,865	7,150,369	7,722,233	8,339,845	9,006,867	9,727,251	10,505,265	11,345,520	12,252,996	13,233,070
Cash flow income from operations		4,506,712	4,867,083	5,256,284	5,676,621	6,130,584	6,620,865	7,150,369	7,722,233	8,339,845	9,006,867	9,727,251	10,505,265	11,345,520	12,252,996	13,233,070
Variable Costs (F)		79,476,084	79,476,084	79,476,084	79,476,084	79,476,084	79,476,084	79,476,084	79,476,084	79,476,084	79,476,084	79,476,084	79,476,084	79,476,084	79,476,084	79,476,084
O&M costs (£/MW)		40800	40800	40800	40800	40800	40800	40800	40800	40800	40800	40800	40800	40800	40800	40800
O&M costs (£/MWh)		5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48
Total O&M costs per year		20,400,000	20,400,000	20,400,000	20,400,000	20,400,000	20,400,000	20,400,000	20,400,000	20,400,000	20,400,000	20,400,000	20,400,000	20,400,000	20,400,000	20,400,000
Fixed Costs (G)		20,400,000	20,400,000	20,400,000	20,400,000	20,400,000	20,400,000	20,400,000	20,400,000	20,400,000	20,400,000	20,400,000	20,400,000	20,400,000	20,400,000	20,400,000
Total Expenses (C+D+E+F+G)		172,222,046	172,222,046	172,222,046	172,222,046	172,222,046	172,222,046	172,222,046	172,222,046	172,222,046	172,222,046	172,222,046	172,222,046	172,222,046	172,222,046	172,222,046
Net Cash-Flow	- 468,329,038	4,506,712	4,867,083	5,256,284	5,676,621	6,130,584	6,620,865	7,150,369	7,722,233	8,339,845	9,006,867	9,727,251	10,505,265	11,345,520	12,252,996	13,233,070
Cumulative Net Cash-Flow	- 468,329,038	- 463,822,326	- 458,955,243	- 453,698,959	- 448,022,339	- 441,891,754	- 435,270,889	- 428,120,520	- 420,398,287	- 412,058,442	- 403,051,575	- 393,324,324	- 382,819,059	- 371,473,539	- 359,220,542	- 345,987,472

The model has also been used to validate the approach used in the main text i.e. discounting across continuous time.

F. Appendix for Chapter 6

Plant operational terminology

- **Minimum on and off time**: Imposed to limit fatigue to machinery
- **Minimum start time**: The time required to alter production output or to turn plant on and start to produce electricity e.g. raise steam
- **Minimum generation level**: Threshold below which units cannot operate
- **Response rate constraints**: Time required to raise output level
- **Non-Constant heat rate**: heat rate (efficiency) varies with generation level
- **Variable start up cost**: the cost of starting a unit can also depend on the time since the unit last ran, e.g. boiler temperature drops when plant is offline.

Table F-1: Historical fuel prices (monthly) 1998-2008 (Data source: ATCO Power)

HISTORICAL FOSSIL FUEL PRICES FROM 1998 (MONTHLY)

									6000 kcal/kg			
		Oil prices	**Gas prices**						**Coal prices**			**Carbon prices**
		Brent	**NPB**			**German border**			**ARA**		**Gas vs**	**EU ETS**
Month	**Year**	**$/bbl**	**p/therm**	**$/GJ**	**$/mmbtu**	**p/therm**	**$/GJ**	**$/mmbtu**	**$/tonne**	**$/GJ**	**coal ratio**	**E/tCO2**
Jan-98	1998	15.2	13.9	2.2	2.3	16.7	2.6	2.7	35.7	1.4	1.5	
Feb-98	1998	14.0	10.2	1.6	1.7	16.7	2.6	2.7	35.4	1.4	1.1	
Mar-98	1998	13.3	9.0	1.4	1.5	16.5	2.6	2.7	32.4	1.3	1.1	
Apr-98	1998	13.5	9.7	1.5	1.6	15.6	2.5	2.6	32.2	1.3	1.2	
May-98	1998	14.3	9.2	1.4	1.5	15.9	2.5	2.6	31.8	1.3	1.1	
Jun-98	1998	12.3	9.3	1.5	1.5	15.8	2.5	2.6	31.5	1.3	1.2	
Jul-98	1998	12.0	10.2	1.6	1.7	14.8	2.3	2.4	31.3	1.2	1.3	
Aug-98	1998	11.9	11.0	1.7	1.8	14.9	2.3	2.4	30.4	1.2	1.4	
Sep-98	1998	13.3	12.0	1.9	2.0	14.5	2.3	2.4	30.3	1.2	1.6	
Oct-98	1998	12.8	12.6	2.0	2.1	12.3	2.0	2.1	31.5	1.3	1.6	
Nov-98	1998	11.1	13.2	2.1	2.2	12.6	2.0	2.1	31.0	1.2	1.7	
Dec-98	1998	9.8	12.0	1.9	2.0	12.6	2.0	2.1	30.5	1.2	1.6	
Jan-99	1999	11.1	9.4	1.5	1.6	11.9	1.9	2.0	30.0	1.2	1.2	
Feb-99	1999	10.2	9.8	1.5	1.6	12.1	1.9	2.0	29.7	1.2	1.3	
Mar-99	1999	12.5	9.4	1.4	1.5	12.1	1.9	2.0	29.9	1.2	1.2	
Apr-99	1999	15.3	9.1	1.4	1.5	11.4	1.7	1.8	29.2	1.2	1.2	
May-99	1999	15.2	8.8	1.3	1.4	11.4	1.7	1.8	29.2	1.2	1.2	
Jun-99	1999	15.9	9.3	1.4	1.5	11.5	1.7	1.8	27.8	1.1	1.3	
Jul-99	1999	19.1	8.8	1.3	1.4	12.1	1.8	1.9	26.7	1.1	1.2	
Aug-99	1999	20.3	8.4	1.3	1.3	11.8	1.8	1.9	26.7	1.1	1.2	
Sep-99	1999	22.5	7.9	1.2	1.3	11.7	1.8	1.9	27.3	1.1	1.1	
Oct-99	1999	22.0	10.2	1.6	1.7	13.5	2.1	2.2	29.2	1.2	1.4	
Nov-99	1999	24.7	10.0	1.5	1.6	13.8	2.1	2.2	29.5	1.2	1.3	
Dec-99	1999	25.5	14.5	2.2	2.3	13.9	2.1	2.2	30.4	1.2	1.8	
Jan-00	2000	25.4	12.9	2.0	2.1	20.5	3.2	3.4	30.2	1.2	1.7	
Feb-00	2000	27.9	13.3	2.0	2.1	21.0	3.2	3.4	30.3	1.2	1.7	
Mar-00	2000	27.3	13.1	2.0	2.1	21.2	3.2	3.4	33.9	1.3	1.5	
Apr-00	2000	22.7	16.3	2.4	2.6	22.5	3.4	3.6	34.8	1.4	1.8	
May-00	2000	27.7	16.5	2.4	2.5	23.6	3.4	3.6	34.4	1.4	1.7	
Jun-00	2000	29.8	16.5	2.4	2.5	23.6	3.4	3.6	35.1	1.4	1.7	
Jul-00	2000	28.7	14.0	2.0	2.1	26.1	3.7	3.9	36.2	1.4	1.4	
Aug-00	2000	30.2	14.5	2.0	2.2	26.5	3.7	3.9	36.2	1.4	1.4	
Sep-00	2000	32.9	18.4	2.5	2.6	27.6	3.7	3.9	37.0	1.5	1.7	
Oct-00	2000	30.9	22.2	3.0	3.2	29.8	4.1	4.3	39.6	1.6	1.9	
Nov-00	2000	32.6	27.5	3.7	3.9	30.2	4.1	4.3	41.7	1.7	2.2	
Dec-00	2000	25.1	23.5	3.3	3.4	29.5	4.1	4.3	43.1	1.7	1.9	
Jan-01	2001	25.6	28.5	4.0	4.2	31.4	4.4	4.6	41.9	1.7	2.4	
Feb-01	2001	27.5	27.6	3.8	4.0	31.9	4.4	4.6	41.1	1.6	2.3	
Mar-01	2001	24.3	26.0	3.6	3.7	32.1	4.4	4.6	42.0	1.7	2.1	
Apr-01	2001	25.6	24.8	3.4	3.6	32.6	4.4	4.7	43.0	1.7	2.0	
May-01	2001	28.5	21.0	2.8	3.0	32.8	4.4	4.7	42.4	1.7	1.7	
Jun-01	2001	27.9	18.4	2.4	2.6	33.4	4.4	4.7	41.4	1.6	1.5	
Jul-01	2001	24.5	17.0	2.3	2.4	29.4	3.9	4.2	39.9	1.6	1.4	
Aug-01	2001	25.7	18.0	2.5	2.6	28.9	3.9	4.2	38.2	1.5	1.6	
Sep-01	2001	25.7	15.3	2.1	2.2	28.4	3.9	4.2	37.9	1.5	1.4	
Oct-01	2001	20.4	17.1	2.3	2.5	24.5	3.4	3.6	36.0	1.4	1.6	
Nov-01	2001	19.0	23.1	3.1	3.3	24.8	3.4	3.6	35.1	1.4	2.3	
Dec-01	2001	18.7	26.8	3.7	3.9	24.5	3.4	3.5	34.5	1.4	2.7	
Jan-02	2002	19.4	24.4	3.3	3.5	21.3	2.9	3.1	34.1	1.4	2.4	
Feb-02	2002	20.3	17.0	2.3	2.4	21.5	2.9	3.1	33.1	1.3	1.7	
Mar-02	2002	23.7	15.3	2.1	2.2	21.5	2.9	3.1	33.3	1.3	1.6	
Apr-02	2002	25.7	12.1	1.7	1.7	19.5	2.7	2.8	32.8	1.3	1.3	
May-02	2002	25.4	11.9	1.6	1.7	19.3	2.7	2.8	28.7	1.1	1.4	
Jun-02	2002	24.1	12.0	1.7	1.8	18.9	2.7	2.8	28.6	1.1	1.5	
Jul-02	2002	25.7	9.7	1.4	1.5	17.7	2.6	2.8	27.0	1.1	1.3	
Aug-02	2002	26.7	12.7	1.8	1.9	18.0	2.6	2.8	26.0	1.0	1.8	

Apr-02	2002	25.7	12.1	1.7	1.7	19.5	2.7	2.8	32.8	1.3	1.3	
May-02	2002	25.4	11.9	1.6	1.7	19.3	2.7	2.8	28.7	1.1	1.4	
Jun-02	2002	24.1	12.0	1.7	1.8	18.9	2.7	2.8	28.6	1.1	1.5	
Jul-02	2002	25.7	9.7	1.4	1.5	17.7	2.6	2.8	27.0	1.1	1.3	
Aug-02	2002	26.7	12.7	1.8	1.9	18.0	2.6	2.8	26.0	1.0	1.8	
Sep-02	2002	28.4	15.2	2.3	2.4	17.9	2.6	2.8	30.2	1.2	1.9	
Oct-02	2002	27.5	17.5	2.6	2.7	19.6	2.9	3.1	34.3	1.4	1.9	
Nov-02	2002	24.3	18.6	2.8	2.9	19.4	2.9	3.1	34.3	1.4	2.0	
Dec-02	2002	28.6	21.5	3.2	3.4	19.5	2.9	3.1	35.0	1.4	2.3	
Jan-03	2003	31.1	23.2	3.6	3.7	21.4	3.3	3.5	36.5	1.5	2.4	
Feb-03	2003	32.8	22.5	3.4	3.6	21.5	3.3	3.5	35.5	1.4	2.4	
Mar-03	2003	30.6	18.1	2.7	2.9	22.0	3.3	3.5	33.6	1.3	2.0	
Apr-03	2003	25.1	18.1	2.7	2.9	25.0	3.7	3.9	33.1	1.3	2.1	
May-03	2003	25.9	18.6	2.9	3.0	24.2	3.7	3.9	34.2	1.4	2.1	
Jun-03	2003	27.7	15.9	2.5	2.6	23.7	3.7	3.9	37.1	1.5	1.7	
Jul-03	2003	28.3	17.1	2.6	2.8	24.4	3.8	4.0	39.7	1.6	1.7	
Aug-03	2003	29.9	13.4	2.0	2.1	24.9	3.8	4.0	42.7	1.7	1.2	
Sep-03	2003	27.1	14.6	2.2	2.4	24.6	3.8	4.0	47.6	1.9	1.2	
Oct-03	2003	29.6	24.2	3.9	4.1	23.6	3.7	4.0	58.8	2.3	1.6	
Nov-03	2003	28.8	27.6	4.4	4.7	23.4	3.7	4.0	61.3	2.4	1.8	
Dec-03	2003	29.8	30.1	5.0	5.2	22.8	3.7	4.0	62.0	2.5	2.0	
Jan-04	2004	31.2	28.2	4.9	5.1	23.6	4.1	4.3	67.7	2.7	1.8	12.9
Feb-04	2004	30.9	22.8	4.0	4.3	23.1	4.1	4.3	69.9	2.8	1.5	13.0
Mar-04	2004	33.6	21.9	3.8	4.0	23.1	4.0	4.2	66.4	2.6	1.4	11.1
Apr-04	2004	33.5	21.1	3.6	3.8	23.7	4.1	4.3	66.2	2.6	1.4	7.4
May-04	2004	37.6	20.9	3.5	3.7	23.6	4.0	4.2	67.4	2.7	1.3	8.3
Jun-04	2004	35.2	19.7	3.4	3.6	23.5	4.1	4.3	73.9	2.9	1.2	9.7
Jul-04	2004	38.2	19.5	3.4	3.6	23.5	4.1	4.3	77.9	3.1	1.1	8.2
Aug-04	2004	42.7	23.7	4.1	4.3	23.9	4.1	4.3	76.5	3.0	1.3	8.8
Sep-04	2004	43.2	27.8	4.7	5.0	24.8	4.2	4.4	74.1	3.0	1.6	8.6
Oct-04	2004	49.8	25.4	4.3	4.6	25.6	4.4	4.6	72.1	2.9	1.5	8.9
Nov-04	2004	43.1	28.7	5.1	5.3	25.9	4.6	4.8	77.8	3.1	1.6	8.6
Dec-04	2004	39.6	31.1	5.7	6.0	27.7	5.1	5.3	77.1	3.1	1.9	8.5
Jan-05	2005	44.2	29.9	5.3	5.6	29.8	5.3	5.6	70.6	2.8	1.9	7.0
Feb-05	2005	45.4	40.2	7.2	7.6	29.5	5.3	5.6	64.4	2.6	2.8	8.0
Mar-05	2005	52.9	42.4	7.7	8.1	29.4	5.3	5.6	66.1	2.6	2.9	11.6
Apr-05	2005	51.8	31.5	5.7	6.0	29.5	5.3	5.6	67.0	2.7	2.1	15.7
May-05	2005	48.6	30.2	5.3	5.6	28.8	5.1	5.3	65.2	2.6	2.0	17.9
Jun-05	2005	54.4	28.7	4.9	5.2	28.6	4.9	5.2	60.9	2.4	2.0	20.7
Jul-05	2005	57.6	29.0	4.8	5.1	33.9	5.6	5.9	62.8	2.5	1.9	24.1
Aug-05	2005	63.9	30.9	5.2	5.5	33.4	5.7	6.0	59.2	2.4	2.2	22.0
Sep-05	2005	62.9	27.5	4.7	5.0	35.6	6.1	6.4	58.2	2.3	2.0	23.2
Oct-05	2005	58.3	32.7	5.5	5.8	38.1	6.4	6.7	54.9	2.2	2.5	22.5
Nov-05	2005	55.2	80.7	13.3	14.0	37.9	6.2	6.6	52.1	2.1	6.4	21.5
Dec-05	2005	56.9	82.8	13.7	14.4	37.8	6.3	6.6	52.2	2.1	6.6	21.1
Jan-06	2006	63.9	66.2	11.1	11.7	37.9	6.3	6.7	54.3	2.2	5.1	25.1
Feb-06	2006	61.1	65.1	10.8	11.4	38.6	6.4	6.7	60.6	2.4	4.5	27.0
Mar-06	2006	63.0	75.9	12.5	13.2	40.0	6.6	7.0	64.6	2.6	4.9	27.1
Apr-06	2006	70.5	41.0	6.9	7.2	46.1	7.7	8.1	63.8	2.5	2.7	25.3
May-06	2006	71.0	34.9	6.2	6.5	45.4	8.0	8.5	60.1	2.4	2.6	14.2
Jun-06	2006	69.8	28.9	5.1	5.3	45.5	8.0	8.4	62.6	2.5	2.0	15.3
Jul-06	2006	74.3	39.9	7.0	7.4	47.0	8.2	8.7	62.6	2.5	2.8	16.5
Aug-06	2006	73.9	34.3	6.2	6.5	46.4	8.3	8.8	71.0	2.8	2.2	15.9
Sep-06	2006	63.6	26.9	4.8	5.1	46.1	8.2	8.7	65.6	2.6	1.8	14.0
Oct-06	2006	59.8	20.9	3.7	3.9	45.0	8.0	8.4	66.2	2.6	1.4	12.2
Nov-06	2006	59.9	37.8	6.9	7.2	45.1	8.2	8.6	67.6	2.7	2.5	9.1
Dec-06	2006	62.3	31.1	5.8	6.1	44.9	8.4	8.8	68.1	2.7	2.1	6.9
Jan-07	2007	54.9	26.8	5.0	5.2	44.3	8.2	8.7	68.5	2.7	1.8	3.9
Feb-07	2007	58.8	19.7	3.6	3.8	44.5	8.3	8.7	68.9	2.7	1.3	1.3
Mar-07	2007	62.5	20.2	3.7	3.9	45.4	8.4	8.8	72.3	2.9	1.3	1.1
Apr-07	2007	67.6	16.1	3.0	3.2	47.7	9.0	9.5	71.7	2.9	1.1	0.7
May-07	2007	67.8	22.6	4.2	4.5	42.8	8.1	8.5	72.1	2.9	1.5	0.4
Jun-07	2007	70.5	21.5	4.1	4.3	42.4	8.0	8.4	77.1	3.1	1.3	0.2
Jul-07	2007	75.8	29.9	5.8	6.1	44.7	8.6	9.1	78.7	3.1	1.8	0.1
Aug-07	2007	72.7	28.5	5.4	5.7	45.0	8.6	9.0	86.6	3.4	1.6	0.1
Sep-07	2007	77.0	33.7	6.4	6.8	45.8	8.8	9.2	95.8	3.8	1.7	0.1
Oct-07	2007	82.5	41.2	8.0	8.4	43.5	8.4	8.9	116.3	4.6	1.7	0.1
Nov-07	2007	92.2	48.6	9.5	10.1	44.8	8.8	9.3	128.4	5.1	1.9	0.1
Dec-07	2007	91.4	51.0	9.8	10.3	44.3	8.5	8.9	129.6	5.2	1.9	0.0
Jan-08	2008	92.0	53.6	10.0	10.5	48.0	9.0	9.5				22.0
Feb-08	2008	94.7	48.5	9.0	9.5							20.7

vii. Check on natural gas drift rate

Based on the assumption that the input data is spaced a year a part

$$\log\left(\frac{G_{(price)}(t)}{G_{(price)}\left(t_0\right)}\right) \sim N\left(\alpha - 0.5\sigma^2\left(t - t_0\right), \sigma^2\left(t - t_0\right)\right) \tag{6.37}$$

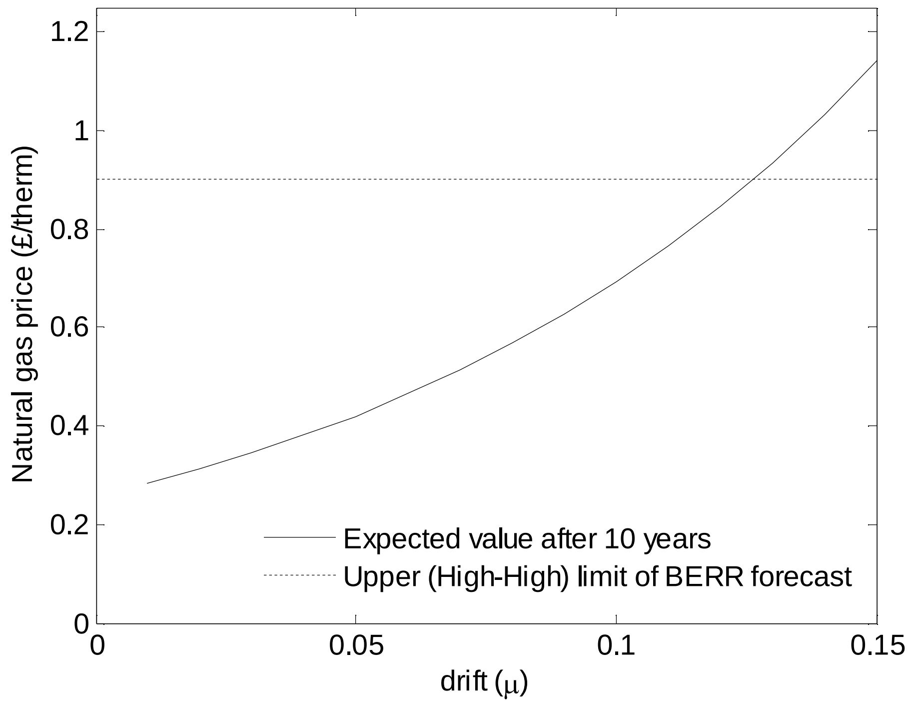


Figure F-1: Expected value of natural gas price over time with constant volatility and varying drift

Figure F-1 illustrates the expected value of the gas price process assuming it follows a GBM. In order to see if the drift range is viable, the expected price of natural gas has been calculated for 10 years in the future accounting for a GBM motion with varying drift. The maximum that it is not expected to cross is the long term BERR high-high scenario, which is shown as the dashed line in Figure F-1. In order to stay inside the limit, a drift of no more than 13% would be allowed given a constant volatility value.

viii. The effect of drift and volatility on the mean time to absorption

Table F-2: Effect of drift on mean time to absorption

Drift (%)	Mean absorption time (years)	Time to P=90% (years)
2	42.59	103.22
3	21.93	51.8
4	14.77	33.5
5	11.13	23.9
6	8.93	18.5
7	7.46	14.9
8	6.40	12.5
9	5.61	10.7
10	4.99	9.3

Table F-3: Effect of volatility on mean time to absorption

Volatility (%)	Mean absorption time (years)
5	5.74
10	6.03
15	6.58
20	7.54
25	9.27
30	12.92
35	24.11

ix. Analytic solution for real options problems

A real option with underlying asset P will have a value W (P,t), and a dividend D(P). The fundamental risk neutral PDE for the valuation of the option is given by (Sick and Gamba, 2005):

$$\mathrm{rW} = \mathrm{D} + \frac{\sigma^2(\mathrm{P})}{2}\frac{\partial^2 \mathrm{W}}{\partial \mathrm{P}^2} + \frac{\partial \mathrm{W}}{\partial \mathrm{P}}\hat{\alpha} + \frac{\partial \mathrm{W}}{\partial \mathrm{t}} \quad (1.38)$$

Where the lhs is the return a risk neutral investor requires for investment W and the rhs is the total return the investor expects to receive. D is the dividend, the second term is the Ito adjustment reflective of the drift the value W that the investor can expect from the interaction of the curvature of the function W with the variance of the underlying asset (Sick and Gamba, 2005). The third term is the growth in option value from risk neutral growth in the underlying and the fourth term represents the growth of the option value over time.

To determine the value of the real option, the payoff function is described at the time of option expiry (boundary condition). The boundary conditions for a call option are as follows: exercise the option when the underlying asset price, P less the cost of development, K is greater than zero:

$$W(P \mid \text{development}) = \max\{0, P - K\} \tag{1.39}$$

This is the value matching condition- option values for the unexercised and exercise states are equal at the point of transition. For a European option, this payoff occurs at maturity i.e. T:

$$W(P_T, T) = \max\{0, P_T - K\}$$

In addition,

$$W_P(0) = 0$$

As if W goes to zero, it will stay at zero (an implication of GBM) and hence the option value will be worthless.

American options require an additional condition to determine the boundary between the states where the options should be developed from where it should be delayed. This condition is an optimisation condition known as smooth pasting. The condition states that the option value as a function of the underlying asset value is tangent to the payoff function

Subject to the value matching condition and the management decision to develop the project as soon as the underlying asset rises to some hurdle or trigger value Pt. The best policy occurs where the option value function and the payoff function are tangent at the point of exercise. An option value function that is always above the payoff function is infeasible because the option value must be on the payoff boundary when the option is exercised.

The smooth pasting condition characterises the optimal exercise of trigger point P* for an arbitrary payoff function Π(P,t):

$$\begin{aligned} & W_p(P^*, t) = \Pi_p(P, t) \\ & \text{where} \\ & W_p(P, t) = \frac{\partial W}{\partial P} \\ & \text{and} \\ & \Pi_P(P, t) = \frac{\partial \Pi}{\partial P} \end{aligned} \tag{1.40}$$

For a development option ΠP, t =max(0,P-k) so in the region where there is a positive payoff (needed to justify early development), $\Pi_P = 1$

European call and put option on log-normally distributed asset

This Section presents a general solution for a dividend yield δ. Letting the call value be Wc(P,t) and the put value be Wp(P,t) for a European option expiring at time T>t with exercise price K:

$$
\begin{aligned}
& d_1 = \frac{\ln(P/K) + (r - \delta + \sigma_p^2/2)(T-t)}{\sigma_p\sqrt{T-t}} \\
& d_2 = d_1 - \sigma_p\sqrt{T-t} \\
& \text{Then} \\
& W^C(P,t) = Pe^{-\delta(T-t)}N(d_1) - Ke^{-r(T-t)}N(d_2) \\
& W^C(P,t) = Pe^{-\delta(T-t)}N(-d_2) - Ke^{-r(T-t)}N(-d_1)
\end{aligned}
\tag{1.41}
$$

Perpetual American call and perpetual American put on log-normally distributed asset

The general solution to the PDE (1.38) is given by lognormal parameters in equation

$$\alpha(P) = \alpha_P P \text{ and } \sigma(P) = \sigma_P P \tag{1.42}$$

is

$$W(P) = A_1 P^{\beta_1} + A_2 P^{\beta_2} \tag{1.43}$$

Where $\beta_1$is the positive root and β_2 is the negative root of

$$\beta = \frac{1}{2} - \frac{\hat{\alpha}}{\sigma_P^2} \pm \sqrt{\left(\frac{1}{2} - \frac{\hat{\alpha}}{\sigma_P^2}\right)^2 + \frac{2r}{\sigma_P^2}} \tag{1.44}$$

For a development option, β_2=0, and for an abandonment option β_1=0. Otherwise, βi is determined by the payoff at the time the option is exercised and a smooth pasting optimality condition. Ignoring the smooth pasting condition, assume the option is developed when the underlying price reaches a trigger price Pt.

For the development option, development occurs the first time that the underlying asset value P hits Pt from underneath and the value matching condition at exercise gives β_1=(Pt-K)(Pt)^-v1. Thus, using the trigger development price Pt, the perpetual American call option has the value:

$$W^C(P,t) = (P^\tau - K)\left(\frac{P}{P^\tau}\right)^{\beta_1} \tag{1.45}$$

The hurdle price Pt can be chosen to maximise A1, which maximises the value of the call option. This is equivalent to the smooth pasting condition and is Pt=Pc* where

$$P^{C*} = \frac{\beta_1 K}{\beta_1 - 1} \tag{1.46}$$

Similarly, for the abandonment (put) option, we have the optimal solution

$$W^{P}(P,t)=(K-P^{P*})\left(\frac{P}{P^{P*}}\right)^{\beta_2},$$

where (1.47)

$$P^{P*}=\frac{\beta_2 K}{\beta_2-1}$$

In the case where the expected rate of growth (drift) of the revenue stream is zero, α^ = 0; the solution to the PDE is:

$$\upsilon=\frac{1}{2}\pm\sqrt{\left(\frac{1}{2}\right)^{2}+\frac{2r}{\sigma_p^2}}$$

$$\upsilon=\frac{1}{2}\pm\sqrt{\frac{1}{4}+\frac{2r}{\sigma_p^2}} \tag{1.48}$$

$$\upsilon=\frac{1}{2}\pm\sqrt{1+\frac{8r}{\sigma_p^2}}$$

In the case where the expected rate of growth of the revenue stream is greater than zero, β is given by;

$$\beta=0.5-\frac{\hat{\alpha}}{\sigma^2}+\sqrt{(\frac{\hat{\alpha}}{\sigma_P^2}-0.5)^2+\frac{2\delta}{\sigma_P{}^2}} \tag{6.49}$$

While the optimal investment price is given by

$$R^{*}=\frac{\beta}{\beta-1}\times(\delta-\hat{\alpha})\times C_c \tag{6.50}$$

The implications of having an expected revenue growth rate of greater than zero are explained in the Figure F-2 and Figure F-3

A. If the future revenue stream is expected to grow, the expression $(\delta-\hat{\alpha})$ will be closer to zero, meaning that the critical value will decrease.

B. On the other side, $\hat{\alpha}$ affects the value of β. Increasing $\hat{\alpha}$ lowers the value of β, thereby increasing the value of β/(β-1) and increasing the value waiting.

C. The overall effect depends on the absolute difference between δ and $\hat{\alpha}$. If the difference is small, the waiting effect will become greater. However, if the difference is large, the effect of $(\delta-\hat{\alpha})$ will be greater, thereby reducing the critical investment value.

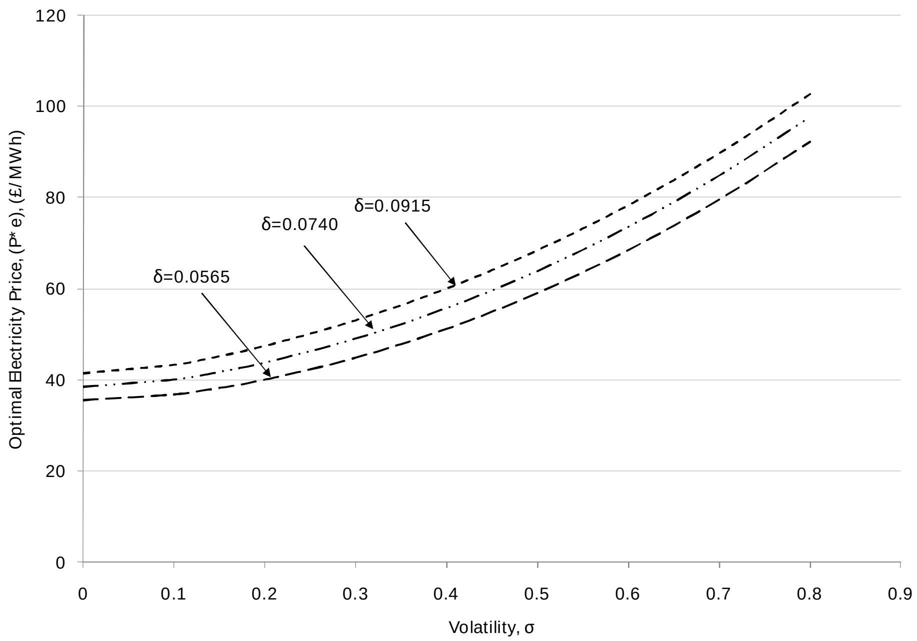


Figure F-2: Impact of varying δ on the optimal electricity trigger price when drift of revenue stream equals 3.5%

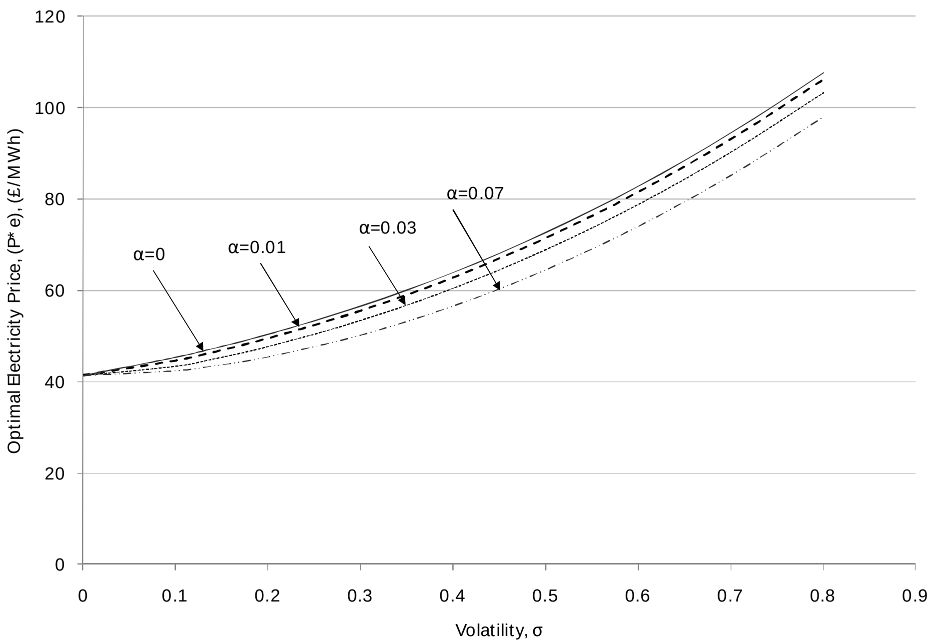


Figure F-3: Impact of varying drift of revenue stream on optimal electricity price when δ=0.0915

x. Derivation of mean time to absorption density function

The inverse Gaussian distribution is a first passage time distribution (Folks and Chhikara, 1978; Cox and Miller, 1965). The density is the probability density that for the time, T, taken by a particle beginning at the origin to cross a boundary at a fixed distance d from the origin when the particle is subject to Brownian motion with drift μ and variance σ^2. The density is:

$$f(t|\sigma,\mu,d)=\frac{d}{\sigma t^{\frac{3}{2}}\sqrt{2\pi}}\exp\left[-\frac{(d-\mu t)^2}{2\sigma^2 t}\right]$$

The cumulative distribution and survival function are

$$F(t|\sigma,\mu,d)=\phi\left(\frac{\mu t-d}{\sigma\sqrt{t}}\right)+e^{2\frac{\mu d}{\sigma^2}}\phi\left(-\frac{\mu t+d}{\sigma\sqrt{t}}\right)$$

$$R(t|\sigma,\mu,d)=\phi\left(-\frac{\mu t-d}{\sigma\sqrt{t}}\right)-e^{2\frac{\mu d}{\sigma^2}}\phi\left(-\frac{\mu t+d}{\sigma\sqrt{t}}\right)$$

The mean and variance are

$$E[T]=\frac{d}{\mu},\ V[T]=\frac{d\sigma^2}{\mu^3}=\frac{d}{\mu}\times\frac{\sigma^2}{\mu^2}=E[T]\times \text{coefficient of variantion}$$

and the mean residual life is:

$$E[T-t|T\geq t]=\mu t=\frac{d}{\mu}\frac{\phi\left(\frac{\mu t-d}{\sigma\sqrt{t}}\right)+e^{2\frac{\mu d}{\sigma^2}}\phi\left(-\frac{\mu t+d}{\sigma\sqrt{t}}\right)}{\phi\left(\frac{\mu t-d}{\sigma\sqrt{t}}\right)+e^{2\frac{\mu d}{\sigma^2}}\phi\left(-\frac{\mu t+d}{\sigma\sqrt{t}}\right)}-t$$

Wiener Process Degradation

The most difficult part of the calculations has been found to be computation of the joint density of the degradation process (or observed degradation process) and the maximum variable of the degradation process.

Joint Density of X_t and M_t

It is shown by Rogers and Williams (Rogers and Williams, 1994) that the joint density of a standard Brownian motion B_t and its maximum variable is of the form:

$$f_{S_t,B_t}(a,x)=\frac{2(2a-x)}{\sqrt{2\pi t^3}}\exp\left\{-\frac{(2a-x)^2}{2t}\right\},\quad a>0, x<a$$

with B_0 =0

The density as required is

$$f_T(m,x)=\frac{2(2m-x)}{\sqrt{2\pi\sigma^6\tau^3}}\exp\left\{-\frac{(x-\mu\tau)^2}{2\sigma^2\tau}\right\}\exp\left\{-\frac{2m(m-x)}{\sigma^2\tau}\right\}$$

This is conditional on X0=0. It is clear that starting from an initial stage X0=x0

$$E\ f_T(m, x|X_0 = x_0) = f_\tau(m - x_0, x_0 - x_0|X_0 = 0)$$

which implies that

$$f_T(m, x_0|x_0) = \frac{2(2m - x_0 - x_0)}{\sqrt{2\pi\sigma^6\tau^3}} \exp\left\{-\frac{(x_0 - x_0 - \mu\tau)^2}{2\sigma^2\tau}\right\} \exp\left\{-\frac{2(m - x_0)(m - x_0)}{\sigma^2\tau}\right\}$$

$$\text{for} -\alpha < x_0 < \infty, m \geq x_0 \text{ and } m \geq x_0$$

To look back from the current state to determine the distribution of the maximum conditional on the current state we need

$$f_{M_t|X_T}(m|x, x_0) = \frac{f_{M_t|X_T}(m, x|x_0)}{f_{X_t}(x|x_0)}$$

The marginal distribution of state is

$$f_{X_t}(x|x,) = \int_{x_0}^{\infty} f_\tau(m, x|x_0)dm$$

However, the marginal distribution of the state is clearly the distribution of X_t so without integration

$$f_{X_t}(x|x,) = \frac{1}{2\sqrt{2\pi\sigma^2 t}} \exp\left\{-\frac{1}{2}\left(\frac{x - x_0 - \mu t}{\sigma\sqrt{t}}\right)^2\right\}$$

The conditional distribution is:

$$f_{M_t|X_t}(m|x, x_0) = \frac{2(2m - x - x_{0)}}{\sigma^2 t} \exp\left\{-2\left(\frac{(m - x_0)(m - x)}{\sigma^2 t}\right)\right\}$$

The probability of crossing a threshold in [0,t] given the current state X_t=x is thus

$$R_{M_t|X_t} = \exp\left\{-2\frac{(c - x)(c - x_0)}{\sigma^2 t}\right\}$$

Distribution Function of X_T and M_t

We require

$$F_{X_\tau, M_\tau}(x, m|x_0) = P(X_\tau \leq x, M_\tau \leq m|X_0 = x_0) \text{ for } m \geq x_0, m \geq x.$$

After some heavy algebra

$$F_{X_\tau, M_\tau}(x, m|x_0) = \phi\left(\frac{x - x_0 - \mu\tau}{\sigma\sqrt{t}}\right) - \exp\left(\frac{2\mu(m - x_0)}{\sigma^2}\right)\phi\left(\frac{x + x_0 - 2m - \mu\tau}{\sigma\sqrt{\tau}}\right)$$

for x>-m it is clear that

$$P(X_\tau \leq x, M_\tau \leq m|X_0 = x_0) = P(X_\tau \leq m, M_\tau \leq m|X_0 = x_0) = P(M_\tau \leq m|X_0 = x_0)$$

Hence the distribution function of the maximum M_τ alone is given by

$$F_{X_\tau,M_\tau}(m|x_0)=\phi\left(\frac{m-x_0-\mu\tau}{\sigma\sqrt{t}}\right)-\exp\left(\frac{2\mu(m-x_0)}{\sigma^2}\right)\phi\left(\frac{-m+x_0-\mu\tau}{\sigma\sqrt{\tau}}\right)$$

Hitting Time Distribution

Clearly the maximum is increasing, so we have

$$\begin{aligned}P(M_\tau>m)=P[T_m\le t]&=1-F_{M_\tau}(m|x_0)\\&=1-\phi\left(\frac{m-x_0-\mu\tau}{\sigma\sqrt{t}}\right)-\exp\left(\frac{2\mu(m-x_0)}{\sigma^2}\right)\phi\left(\frac{-m+x_0-\mu\tau}{\sigma\sqrt{\tau}}\right)\\&=\phi\left(\frac{\mu\tau-m+x_0}{\sigma\sqrt{t}}\right)-\exp\left(\frac{2\mu(m-x_0)}{\sigma^2}\right)\phi\left(\frac{-m+x_0-\mu\tau}{\sigma\sqrt{\tau}}\right)\end{aligned}$$

lastly, putting d = m-x_0, the distance to traverse;

$$F_T(t)=P[T_m\le t]=\phi\left(\frac{\mu\tau d}{\sigma\sqrt{t}}\right)-\exp\left(\frac{2\mu d}{\sigma^2}\right)\phi\left(\frac{-d-\mu\tau}{\sigma\sqrt{\tau}}\right)$$

xi. Matlab code for mean time to absorption model

```
%Calculation of mean time to absorption
clear all;close all;clc

t=0.1:.1:25;
Nu=47.15;
G0=27.13;
a=10.6/100;
sigma=13.7/100;

% distance to travel
d=log(Nu/G0);

% inverse Gaussian parameter
mu = a-(1/2)*sigma^2;

% evaluation of inverse Gaussian CDF
A = (-d+mu*t)./sigma./sqrt(t);
B = -(d+mu*t)./sigma./sqrt(t);

F = norm_cum(A)+exp(2*mu*d/sigma^2)*norm_cum(B);
R = norm_cum(-A)-exp(2*mu*d/sigma^2)*norm_cum(B);

% mean time to absorption
ET = d/mu;

A = (-d+mu*ET)./sigma./sqrt(ET);
B = -(d+mu*ET)./sigma./sqrt(ET);
P0 = norm_cum(A)+exp(2*mu*d/sigma^2)*norm_cum(B);
Q0 = norm_cum(-A)-exp(2*mu*d/sigma^2)*norm_cum(B);

% look for 90th percentile
k = find(F<=0.9,1,'last');

F0=sum(F([k,k+1]))/2;
t9=sum(t([k,k+1]))/2;

ytick = [0 4:5:t(end)];    %yticklabel = ytick+2008;
```

```
ytick = sort([ytick,ET,t9]);
for i=1:length(ytick)
    yticklabel{i}=sprintf('%7.2f',ytick(i)+2008);
end

yticklabel = strrep(yticklabel,'.00','   ');


RightAxes = axes('YaxisLocation','right',...
                    'ytick',ytick,...
                    'yticklabel',yticklabel,...
                    'xtick',[],...
                    'xticklabel',[]);
ylabel('years')


% make a second set of axes
p = get(gca,'position');
LeftAxes = axes('position',p);



line(F,t,'color','black','linewidth',2);
xlabel('probability of profitability')


line([P0,P0],[0,ET],'color','black','linewidth',0.25)
line([0,1],[ET,ET],'color','black','linewidth',0.25)

line([F0,F0],[0,t9],'color','black','linewidth',0.25)
line([0,1],[t9,t9],'color','black','linewidth',0.25)


text(0.01,ET+3/4,'${\bf E}[T]$','interpreter','tex')
text(0.01,t9+3/4,'$t_{0.9}$','interpreter','tex')

Nu=47.15;
G0=27.13;

a=10.6/100;
sigma=13.7/100;

d=log(Nu/G0);
mu = a-(1/2)*sigma^2;

a = a*(1+[-1,1]/10);a=a([1,end]);

sigma = sigma*(1+[-1,1]/10);

FU = zeros(size(t));
FL = ones(size(t));
for i=1:length(a)
    for j=1:length(sigma)
            d=log(Nu/G0);
            mu = a(i)-(1/2)*sigma(j)^2;
            A = (-d+mu*t)./sigma(j)./sqrt(t);
            B = -(d+mu*t)./sigma(j)./sqrt(t);
            Fi = norm_cum(A)+exp(2*mu*d/sigma(j)^2)*norm_cum(B);
            FL = min(Fi,FL);
            FU = max(Fi,FU);
%               line(Fi,t)
    end
end


patch('xdata',[0,FL,1,fliplr(FU),0],'ydata',[0,t,t(end),fliplr(t),0],...
    'facecolor',0.5*[1,1,1],'facealpha',0.6)

Nu = sort(Nu*(1+[-1,1]/10));Nu=Nu([1,end]);
```

```
G0 = G0*(1+[-1,1]/10);G0=G0([1,end]);

FU = zeros(size(t));
FL = ones(size(t));
for i=1:length(a)
    for j=1:length(sigma)
        mu = a(i)-(1/2)*sigma(j)^2;
        for k=1:length(Nu)
            for ell = 1:length(G0)
                d=log(Nu(k)/G0(ell));
                A = (-d+mu*t)./sigma(j)./sqrt(t);
                B = -(d+mu*t)./sigma(j)./sqrt(t);
                Fi = norm_cum(A)+exp(2*mu*d/sigma(j)^2)*norm_cum(B);
                FL = min(Fi,FL);
                FU = max(Fi,FU);
%                line(Fi,t)
            end
        end
    end
end

patch('xdata',[0,FL,1,fliplr(FU),0],'ydata',[0,t,t(end),fliplr(t),0],...
    'facecolor',0.7*[1,1,1],'facealpha',0.6)


[hx,hy] = box1(0.05,0,0.05,1);

hy = hy+22;
patch(hx,hy,0.7*[1,1,1]);
text(hx(1)+0.06,hy(1)+1/2,...
    '$10\%$ variation in $\alpha$, $\sigma$, $G_0$ and $Nu$',...
    'interpreter','tex')

hy=hy-2;
patch(hx,hy,0.5*[1,1,1])
text(hx(1)+0.06,hy(1)+1/2,...
    '$10\%$ variation in $\alpha$ and $\sigma$',...
    'interpreter','tex')

hy = hy -1;
line(hx(1:2),hy(1:2),'linewidth',2,'color','k')
text(hx(1)+0.06,hy(1)+0.01,'estimated fit','interpreter','tex')

hy = hy - 1.5;
TextString = sprintf('${\\bf E}[T]=%5.2f$ years from now',ET);
text(hx(1),hy(1),TextString,'interpreter','tex');

hy = hy - 1.5;
TextString = sprintf('$$t_{0.9}=%5.2f$ years from now',t9);
text(hx(1),hy(1),TextString,'interpreter','tex');


set(LeftAxes,'ytick',ytick,'yticklabel',yticklabel,'box','on');
```

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