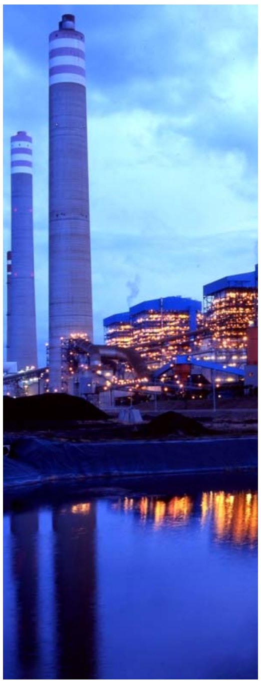

Potential cost reductions in CCS in the power sector

Discussion Paper

May 2012

Department of Energy and Climate Change

Mott MacDonald

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Executive Summary

This discussion paper, commissioned by DECC's Office of Carbon Capture and Storage presents a summary of the findings of Mott MacDonald's energy economics team on the potential for cost reduction in CCS in the power sector in the UK. The paper is intended to stimulate further thinking, particularly through the CCS Cost Reduction Task Force.

The paper is the result of three pieces of inter-related work: a literature review of work on CCS costs estimates and cost reduction focusing on the more recent or seminal work; a comparison of these studies with practical experience of real projects; and finally our own set of bottom-up projections developed in order to assess the key cost drivers.

Given the early stage of CCS development (there are no commercial scale full chain projects operating) there is great uncertainty in making cost projections. We do have more certainty regarding the host plant costs (for super critical coal and CCGT, at least), although even here there are uncertainties about future capital costs as engineering, procurement and construction (EPC) markets have become commoditised (and subject to demand and supply pressures) and fuel prices are even more uncertain. The projections in this report which are designed to reflect a moderate range need to be seen in this context.

Our review of the published literature shows that there is a general expectation that the costs of CCS will fall substantially as the technology matures. However there is a big differential between estimates of cost for the first commercial projects deployed by the market and the earlier pre-commercial projects necessary to establish the technology. The latest estimates of levelised costs of electricity (LCOE) for these earlier projects are some 30-40% above the estimates for the first commercial projects. Much of the difference is related to the much higher transport and storage costs (per MWh) incurred because early projects are not able to take advantage of economies of scale and have shorter operating lives.

The evidence from comparator energy technologies and other sectors is that costs tend to increase in the early stages of deployment with learning beginning only after a significant level of deployment (or third to fourth iteration) has occurred. Once learning does begin the evidence suggests that the capture component of CCS could see costs reduce by 8-14% per doubling of deployed capacity.

Transport and storage are more mature technologies and costs are unlikely to reduce much as a result of learning. However, there is greater scope for capturing economies of scale in these activities, through clustered developments.

Our bottom up approach reflects this difference between the CCS components. We have developed a disaggregated cost build-up tool that allows us to examine the impact of key drivers on capex, opex, levelised costs per tonne CO_2 and LCOE in £/MWh. A set of high and low cost paths have been developed for the four main capture options (post combustion coal and gas, oxy combustion coal and integrated gasification combined cycle (IGCC). In each case, the range covers our subjective 60% confidence band for a particular set of input assumptions, which includes underlying EPC prices, fuel prices, discount rates, etc.

In making the projections it has been necessary to make a number of assumptions:

- underlying power plant costs for CCGT and super critical coal are assumed to be constant - though costs for IGCC are projected to fall.
- fuel prices are based on DECC's 2011 central case projection; and
- carbon emission costs are excluded (in order to provide focus on the underlying costs).

In terms of deployment we have assumed a high level of CCS globally, which leads to significant learning on the capture side. Our low cost case assumes a significant level of deployment in the UK which allows the capturing of economies of scale in transport and storage. The higher cost path has a lower level of learning on capture and a much more modest reduction in transport and storage costs – reflecting lower levels of deployment in the UK.

Under the low cost path the LCOE from both coal and gas plant with CCS is projected to fall to £100/MWh in the 2020s. Under the high cost case costs are some 30-40% above this.

Our assessment shows reductions are projected to be split roughly 50:50 between capture and transport and storage by 2040, but with transport and storage providing most of the early gains and capture the later gains. In LCOE terms gas CCS appears to have the advantage over coal throughout the period – which reflects the lower capex and carbon intensity of gas, however this depends on DECC's central case fuel price assumptions. If gas markets were to tighten significantly, then gas would lose this advantage.

Of course, all these projections are extremely uncertain, with the range likely to be moved upward or downward and broadened with changes in assumptions regarding fuel prices, discount rates, deployment, etc. In time and with sufficient deployment the cost premium for CCS over reference plant costs should fall as both the internal CCS process costs fall and as the parasitic cost penalty falls.

Innovation areas

Our review has identified a number of areas where innovation could bring cost reductions in the near to medium term. The most likely areas, in an indicative hierarchy of significance are:

- Compressor advances – energy penalty reduction benefits for all options
- Air separation advances – leading to reductions in energy penalties for oxy combustion and to a lesser extent IGCC
- Improved solvents and sorbents – resulting in smaller absorbers, lower energy penalties for post combustion
- Gas recirculation for post combustion gas – reduced absorber size and lower energy penalties
- Economies of scale in absorbers – for post combustion
- Improvements in construction logistics from learning and advanced simulations – for all options
- Process optimisation for all technology routes
- Reduced design margins for all systems

As mentioned above, these innovations relate to the capture stage of CCS. Innovation in the transport and storage components of the chain is not expected to play as substantial a role in driving costs down. However, there are a few areas where advances could play a significant role especially in storage. Most notable of these improvements are in geological appraisal techniques and development of more sophisticated measurement, monitoring and verification (MMV) systems.

As noted throughout this report, there is huge uncertainty in any exercise projecting costs associated with a new technology significantly into the future. This uncertainty must be recognised when drawing conclusions or using the results of this study for further work. This paper is intended to be used as a discussion paper to prompt further work and discussion amongst interested stakeholders within the industry.

This paper does not form part of the assessment criteria for the CCS Commercialisation Programme, nor represent Government policy. While Bidders are welcome to draw on the paper in the preparation of their bids, they are also welcome to come forward with proposals that offer different ways of achieving cost reductions in CCS or which otherwise depart from the analysis set out here. All bids to the CCS Commercialisation Programme will be assessed by DECC and its advisors on their own merits, on a case-by-case basis.

1. Introduction

This report presents the initial findings of Mott MacDonald's review of the scope for cost reduction in carbon capture and storage in the UK. The work was commissioned by the Office of Carbon Capture and Storage within DECC to enable further discussion with industry through the CCS Cost Reduction Task Force.

The objective of the assignment is to identity the main activities that could potentially drive a reduction in the cost of commercial scale CCS and estimate the scale of any potential cost reduction, focusing on the near to medium term.

Our approach has been to first briefly comment on how CCS affects power generation costs, review how other studies have approached cost reduction and then develop our own bottom-up projections of the scope for cost reduction across the main technology routes.

There are a large number of uncertainties relating to this exercise as CCS is an early stage technology with no track record in commercial deployment: certainly less developed than offshore wind and probably also 3rd generation nuclear. This means that any cost projections must be treated as being extremely uncertain.

These projections have been developed from public studies and Mott MacDonald's own experience of the CCS and wider generation technologies with limited benchmarking, especially from technology developers and suppliers. This therefore represents an initial view which can be refined as more relevant data becomes available.

This paper has been led by MML's energy economics team though the technical assumptions have been informed by discussions with MML's CCS experts. It should be treated as a thought piece which is designed to raise questions and generate feedback from the wider community, particularly the equipment suppliers and contractors, which will feed into the work programme of the CCS Cost Reduction Task Force.

The report adopts the following structure:

Chapter 2 considers how CCS impacts on power generation costs and reviews the general findings on capex and levelised cost;

Chapter 3 examines the cost reduction process looking at how others have approached this task, explores the drivers of cost reduction by component and considers what lessons can be drawn from experience in comparator sectors. Also, the application of a top-down approach to cost reduction for carbon capture is set out;

Chapter 4 presents the analysis that has been carried out, outlining our initial cost reduction projections based on a bottom-up approach;

Chapter 5 outlines our key findings on cost reduction, confidence levels and recommendations for further work. It also briefly comments on potential interventions measures that would aid the process of cost reduction.

<u>Note on money terms:</u>

Unless otherwise stated money values are in 2012 GB Pounds.

2. Review of recent cost assessments

2.1 Introduction

This chapter briefly reviews recent findings on costs of CCS and sets the context for considering the dynamic process of cost reduction in the following chapters. First we consider how fitting and running CCS impacts power generation costs. Then we comment on the findings on capex and the levelised cost of electricity (LCOE), distinguishing between the three components of CCS; capture, transport and storage and between early stage, First of a kind (FOAK) and Nth of a kind (NOAK) projects.

2.2 Components of cost – How CCS impacts generation costs

The following sections consider how each of the three main parts of the CCS chain – capture, transport and storage - impact the costs of electricity generation.

2.2.1 Carbon Capture

There are three main types of capture, namely post-, pre- and oxy-combustion – these are summarised in Table 2.1. All involve adding chemical process plant to an underlying power plant which has substantial parasitic energy requirement which other things being equal reduces the net generation capability of the host power plant. Therefore all three processes will all impact the levelised cost of electricity (LCOE).

Table 2.1: Main features of three capture process

Post combustion capture applied to conventional combustion plant with air firing. This involves passing the combustion flue gases through an absorber where solvent capture the CO2 and then separating the carbon and recovering the solvents through a stripper/regenerator. This can be applied to most fuels as long as the flue gas stream is sufficiently clean, which may necessitate pre-treatment.
Oxy combustion capture is also applied to conventional combustion plant but in this case the fuel is fired with oxygen rich environment. The combustion flue gases are then re-circulated which increases the CO2 content to the point where CO2 can easily separated. To date this process is most advanced on coal combustion. A variant of this oxy firing approach is applicable to gas turbines but it is at a much earlier stage of development, with no significant pilots yet deployed.
Integrated gasification combined cycle (IGCC) with pre-combustion capture, contrasts with the conventional power plants above, in that it involves gasifying the coal (or other fuels) and using a water shift reaction to make a syngas which is then used to drive a CCGT. The CO2 is separated at the gas conditioning stage prior to firing, normally through a physical absorption process.
Compression of CO2 is a necessary and final step in all three of the above capture processes and involves compressing CO2 gas (often into a liquid phase) for efficient pumping into pipelines or potentially CO2 tankers.

Source: Mott MacDonald

Operating post combustion Carbon Capture (CC) requires steam (either tapped off from the host plant or from new steam capacity) and also increases the host plant's auxiliary electrical load. There are similar parasitic energy requirements on the other capture technologies. Carbon capture can be seen as equivalent to adding a new chemical processing plant fired by a dedicated combined heat and power (CHP) plant. This additional energy load or energy penalty is estimated to be equivalent to 15-26%[1] of the base plant's net electrical output, which compares with 3-4% for a modern flue gas desulphurisation (FGD) and selective catalytic reduction (SCR) plant combined[2].

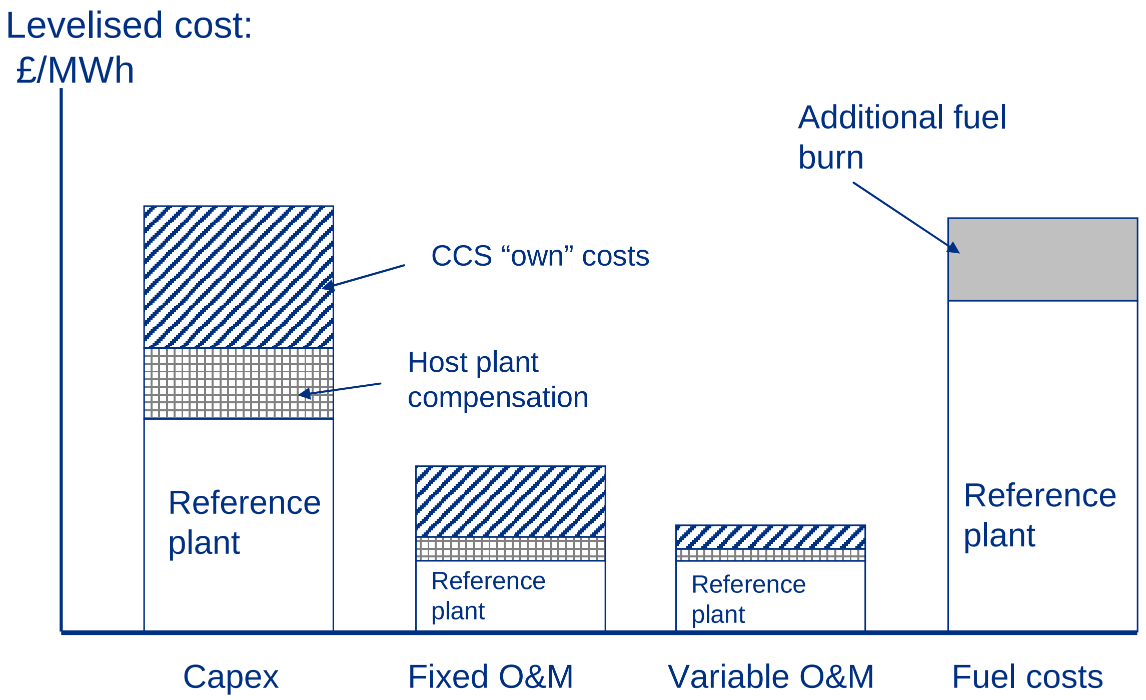
[2] There is in principle a further energy penalty which relates to the energy use in the transport and storage parts of the CCS chain, although these would typically be expected to be small in comparison to those of capture process (though Longannet Demo1 was an exception). These would be more significant for coal than for gas given the high carbon intensity of coal generation. These have not been included further in this study, although the energy costs will be a small component of operating costs for both transport

There are four main cost impacts:

- Capture unit capex and Fixed Operations and Maintenance (FOM) (adjusted to match the same net electrical output as the reference plant[3])
- Reduction in sent-out (net) electrical capacity of the host plant as a result of fitting capture unit requires that capex of host plant is increased to offset this reduction. We have called this the host plant compensation.
- Same applies to host plant FOM and Variable Operations and Maintenance (VOM) costs (as illustrated by the additional costs of a hypothetical standalone CHP built to drive CC process).
- Assuming the net electrical outputs are matched then the fuel costs of a CC equipped plant are increased by the ratio of thermal MW stolen (by applying an efficiency correction equal to the ratio of gross plant outputs)

These are illustrated in Figure 2.1.

Figure 2.1: How carbon capture affects the levelised cost of electricity generation



Source: Mott MacDonald

2.2.2 Transport

CO_2 can be transported via pipe, onshore and offshore, or via shipping. However, we consider only pipeline options in this report, given the emphasis on this mode and the poor economics of shipping[4] option

and storage.

[3] Reference plant here refers to the unabated host power generation plant for the technology in question, whether this is a super-critical coal for post combustion or oxy combustion, IGCC for pre-combustion coal and CCGT for post combustion gas.

[4] Shipping of CO2 is characterised by high per unit fixed costs which are less directly linked to route distance than pipelines so is less well suited to short distances. However, shipping does have the advantage of being flexible so can be phased to meet expansions and can be moved elsewhere when no longer needed. There is little active interest in shipping CO2 in the UK, so this is not

for short hauls. Transport of CO_2 has traditionally been considered a small component of the incremental costs of CCS on power generation. In the DECC generation costs analyses of 2010 and 2011, the cost of transport and storage for a coal plant was assumed to be £6-8/MWh. This reflects the fact that in principle, building and operating a CO_2 pipeline is often not technically demanding, and assuming the pipeline infrastructure is fully utilised the costs should be modest for reasonable transport lengths.

However, in practice, the costs of CO_2 transport may be higher especially in the early phases of CCS rollout, because the benefits of economies of scale are more difficult to capture. This is illustrated by the Longannet project (which even had the advantage of using legacy assets) where the transport capex came to over £220m (equivalent to over £700/kW scrubbed). There are also issues relating to the practical challenges of operating pipelines in multiphase conditions (i.e. with CO_2 both as a gas and liquid), and in ensuring appropriate quality specifications especially in offshore conditions and at the interface with injection wells. These factors suggest that the costs are likely to be higher than initial forecasts by developers. This has a larger impact on coal CCS costs versus gas CCS given the higher carbon intensity of generation since a coal CCS plant is likely to capture about 2.2 times as much CO_2 per MWh as a gas CCS plant.

2.2.3 Storage

Storage costs are the third component of overall CCS costs that increase capital and operating costs for any integrated CCS scheme. The recently published FEED cost data for Longannet and Kingsnorth indicate that storage comprise between 16-20% of the anticipated capex costs for these early stage projects.

Storage costs are very site specific and are highly dependent on the scale, geological characteristics such as reservoir depth, thickness and permeability and location factors including water depth. The cost of proving this viability will also vary according to the storage option involved.

There are two main types of offshore[5] storage; storage in depleted oil and gas fields (DOGF) and storage in saline aquifers. A third option is capturing CO_2 in a working oil or gas field and using the CO_2 as a fluid to increase hydrocarbon production, in what is called enhanced oil recovery (EOR). Where EOR is involved, there will be a revenue stream from incremental oil sales which may offset the additional development and operational costs[6] for this type of storage. EOR is not considered further in this report, because we consider this to be a special case. EOR's attractiveness will depend on whether the additional capex and opex in developing an EOR facility is offset by the revenues from selling CO_2.

The main components of storage costs are:

- Platforms, sub-sea infrastructure and facilities to host the offshore injection and storage scheme. These provide infrastructure to connect transport schemes that bring CO_2 to the storage site with the injection wells. There may be compression and other facilities at the site to clean-up CO_2 before injection (e.g. filtration) and heaters. In some cases existing platforms and facilities may be used although modifications are likely to be required prior to conversion for storage (e.g. Goldeneye). In other cases new platforms may be designed, even for existing depleted fields.

covered here.

[5] The alternative of onshore storage is not considered here since the UK has extensive options offshore and. the Government's view is that the priority for the present time is to develop an understanding of the benefits and costs of CCS with offshore storage.

[6] The application of EOR is likely to require additional development works to test the oil yields and increased operating costs to manage the process.

- Injection wells and all equipment associated with the well allowing safe CO_2 injection into the storage formation (plus any monitoring wells that may be required). These may include dedicated new wells, conversion of existing wells for injection (work-overs), and remediation of pre-existing wells to ensure long term integrity.
- Monitoring and metering equipment and technology to measure, monitor and verify (i.e. MMV) the injected CO_2. This may be either permanently installed or periodic surveys. Costs of different methods are highly variable; dedicated 3D/4D seismic and monitoring are among the highest cost techniques. Industry is making efforts to trial a range of techniques (e.g. Insar at In Salah (in Algeria) and 4D seismic surveys in Sleipner in Norwegian North Sea) with a view to reducing costs as experience develops.
- Operating costs covering ongoing maintenance, logistics, onsite energy use and other overheads.
- Pre-development investment costs may be significant for some sites, notably saline aquifers (pre-final investment decision on figure below). These costs relate to exploration and appraisal activities, including seismic and other surveying, drilling wells (with coring and extensive analytical data acquisition) and possible injection testing. This category also includes geological, engineering studies, FEED, permitting, etc.
- Costs associated with closedown of the site, including decommissioning, abandonment and financial requirements/obligations relating to long term liabilities.

The relative size of the above cost components varies considerably depending on the type of the storage, with pre-development costs and injection drilling being proportionately larger where there is no legacy infrastructure and saline aquifers are used for storage – see later in this chapter.

All of the main technology and equipment that is required for CO_2 storage is already in use in the oil and gas industry, although some degree of adaptation and modification will be required. Advances and developments in equipment and technology for storage will come from the oil and gas sector and it seems reasonable that some innovation within the storage sector may be anticipated in monitoring, modelling and well design/completions.

It is also important to recognise that overall unit costs depend on the performance efficiency and optimisation of the underground system. As experience with storage develops it is anticipated that there will be improvements in prediction, modelling and optimisation of the amount of CO_2 per unit of expenditure (i.e. through well design, well spacing, storage efficiency, etc). This may be considered partly analogous to reserves growth and improvement in recovery factors over time in the oil industry.

Some geologists caution that geological storage of CO_2 will always be exposed to a kind of “ground risk” comparable to tunnelling projects, which reflects the interplay between the geological conditions and the subsurface infrastructures and its impact on the sustainability of injection rates. In unfavourable conditions, injection rates could collapse and new drilling could be required, or at worst the site might need to be abandoned.

2.3 Findings on capex

This section provides a brief review of recent findings on capex costs, taking capture, transport and storage in turn. It provides a context for the initial capex estimates and the judgments of future capex as outlined in chapter 4.

2.3.1 Capture

2.3.1.1 Indicative breakdown by process type

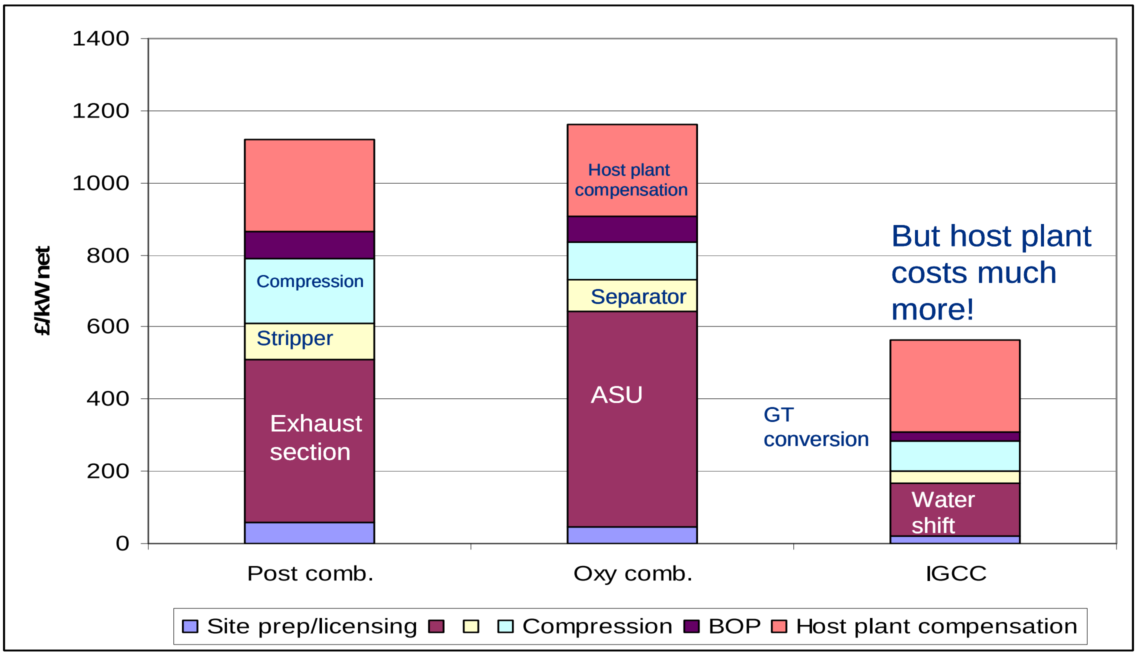
The three capture routes have different drivers in terms of the component costs, although all three have the common elements of host plant compensation and compressor requirements. In general the host plant compensation is greater for the coal options than for gas because of the higher capex of the host plant and the higher energy penalty when compared with gas. Compression requirements are also greater than for natural gas based CCS because of the higher carbon intensity of coal generation (reflecting higher fuel carbon content and lower conversion efficiency). However, integrated gasification combined cycle (IGCC), which operates at high pressure tends to have a lower compression need.

Of the core capture elements, for post combustion the exhaust cycle or absorption stage is the most significant component. This is proportionately greater for gas CCS than coal[7]. The stripper/regenerator stage, which recovers the solvent, is another significant component. For oxy combustion the dominant own process component is the air separation unit, with the gas conditioning being another large item. For IGCC, it is more difficult to split out the incremental process requirements, although it is generally considered that there are three main components; enhanced water shift, acid gas treatment and upgraded gas turbines to handle hydrogen.

Figure 2.2**Error! Reference source not found.** provides an indicative build up of specific capex by the main components for the three capture options for coal plants. There is no direct comparison with gas plants, largely since oxy-combustion of gas and pre-combustion options are considered at an early stage of development and as such specific capex estimates are even less reliable.

[7] This is because of the lower CO2 concentration in the flue gas for gas plant versus coal, makes absorption more challenging, however the lower CO2 intensity of gas generation reduces the amount of CO2 to stripped, conditioned and compressed.

Figure 2.2: Indicative breakdown of specific capex of capture plant by process type for early commercial projects



Source: Mott MacDonald estimates

2.3.1.2 Full scale early stage commercial projects

The only publicly available recent data on early stage projects for the UK are the two FEED[8] studies. Of these, we consider the Longannet costing to be the most reliable – as the design was most developed and component costs were tested through a tendering process. We have also seen other confidential project estimates across a range of generation and capture technologies which have helped inform our views.

Based on our interpretation of the FEED material and other studies we have assumed the following specific capex figures for capture only (including host plant compensation, but excluding the cost of the reference plant. These numbers provide the reference levels for the cost reduction assessment exercise described in Chapter 4. A high and a low estimate has been provided based on our judgement of a P20 and P80 assessment, which means were are capturing 60% of the outcomes. As discussed elsewhere, in this report, these figures are subject to a high degree of uncertainty and should be treated accordingly.

Table 2.2: Mott MacDonald estimates of initial CC early stage costs – assumed ordered in 2013 in £/kW

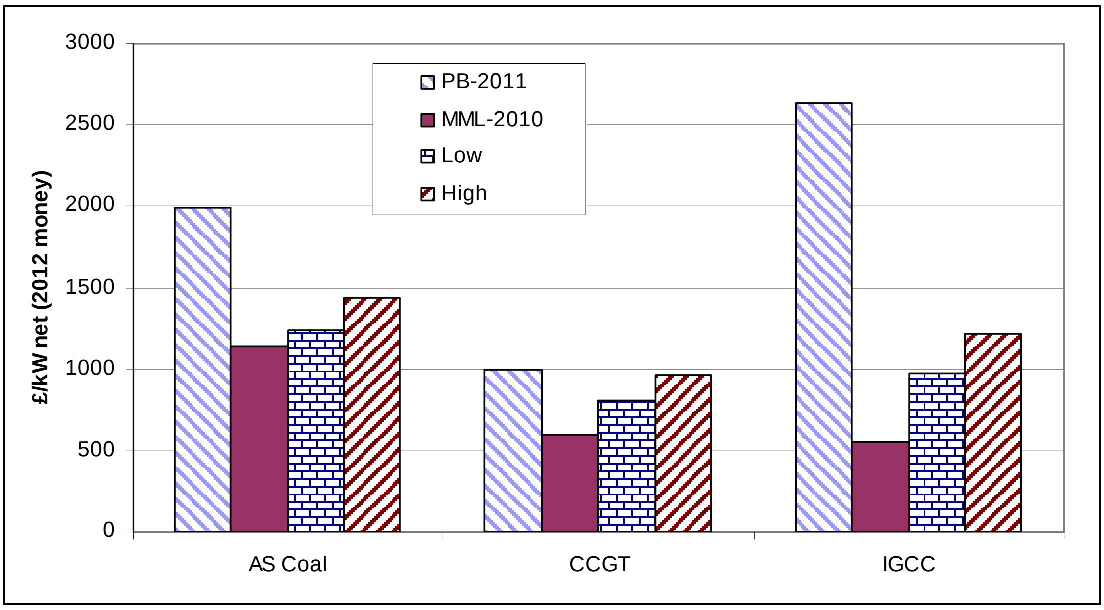
Capture technology and fuel	Low (P80)	High (P20)
Post comb. Coal	1241	1437
Post comb. Gas	813	964
Oxy comb. Coal	1245	1486
IGCC + CCS	974	1220
Note: these figures exclude the cost of the reference power plant, but do include host plant compensation		

[8] For Longannet and Kingsnorth, both based on full chain post combustion capture from existing sub-critical coal plants with pipeline transport of CO2 for storage in depleted oil and gas fields

Source: Mott MacDonald estimates

The above capex estimates fall between the FOAK estimates published by DECC in 2010 and 2011, from MML and PB Power respectively, see Figure 2.3. In both cases, the figures from the DECC reports are taken as the difference between the specific capex of the plant with and without CCS and they are adjusted for inflation. It is unclear why there is such a large difference between the PB and MML figures, but this possibly reflects a reassessment in the cost levels arising from a different interpretation of what should be categorised as incremental to the base plant, especially for IGCC.

Figure 2.3: Assumed early stage specific capex versus 2010-2011 estimates



Source: MML estimates and DECC's 2010 (Mott MacDonald) and 2011 (PB Power) generation cost update reports

2.3.2 Transport

Transport of CO_2 has generally had less attention than either capture or storage. The Zero Emission Platform (ZEP's) 2011 review of transport costs provides the most recent and in our opinion reliable general assessment – see Table 2.3. This reviews both pipelines and shipping options, with a focus on new build facilities operating in the period up to and beyond 2030.

Pipeline transport is capital intensive, with the capital cost comprising pipe works and installation. For any particular diameter of pipeline, these costs are directly related to distance, however there are substantial economies of scale from increasing pipeline diameter: a doubling in diameter brings a quadrupling of throughput capacity. Capacity can also be up-rated through increasing the working pressure and transporting CO_2 in liquid phase, rather than vapour.

Table 2.3: ZEP's estimates of CO_2 pipeline and shipping costs in £/tonne CO_2

Route length of spine (km) >	180	500	750
Demonstration[9] (@2.5 mt/yr)			

[9] Equivalent of early stage projects mentioned elsewhere in report.

Route length of spine (km) >	180	500	750
Offshore pipe	8.1	17.7	25.0
Ship	7.1	8.3	9.2
Liquefaction (for ship transport)	4.6	4.6	4.6
Ship+liquefaction	11.7	12.9	13.8
Early commercial (@ 20mt/yr)			
Offshore pipe	3.0	5.2	7.1
Ship+liquefaction	9.7	10.6	11.5

Source: ZEP Costs of CO_2 transport, 2011 (converted at €1.15 per GBP.

The clear message from the ZEP analysis is that transport of CO_2 could be comparatively expensive for small throughputs, such as would normally characterise early stage projects, at about £8/t for 2.5mt/yr rated system. The costs would be significantly higher for a 1mt/yr pipeline for new stand alone pipelines say matched to serve new gas CCS systems, However as capture projects scale up or are clustered together throughput will be increased and higher rated networks will be developed which should then drive unit costs down substantially.

2.3.3 Storage

Figure 2.4 shows the breakdown of cost components for different offshore storage options for ZEP's medium cost scenario. (Again, we are taking ZEP's estimates as a recent reliable source.) It shows Depleted Oil and Gas Field options (DOGF) with legacy infrastructure ("Leg") is the least cost option, below DOGF without legacy infrastructure, with Saline Aquifers being most expensive. In each case, an offshore location has a substantial premium over onshore sites. The premium for saline aquifers versus DOGFs reflects mainly the additional exploration and permitting costs and the higher operating costs. Figure 2.5 shows there is a considerable band of uncertainty and lots of scope for overlap once field conditions and liability transfer costs are varied. For practical purposes the three onshore options reported by ZEP and shown in the two charts are unlikely to be relevant in a UK context.

Figure 2.4: Breakdown of Cost Components for Offshore Storage Cases (Medium Cost Scenarios) in 2011 Euros

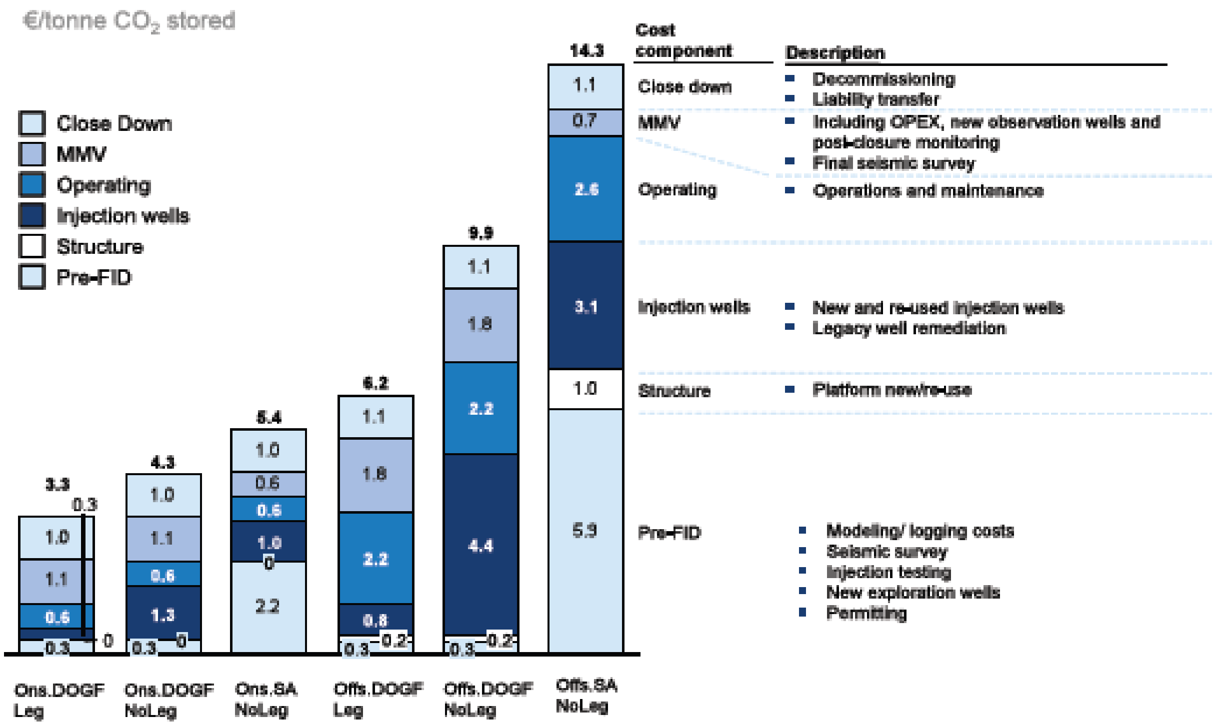
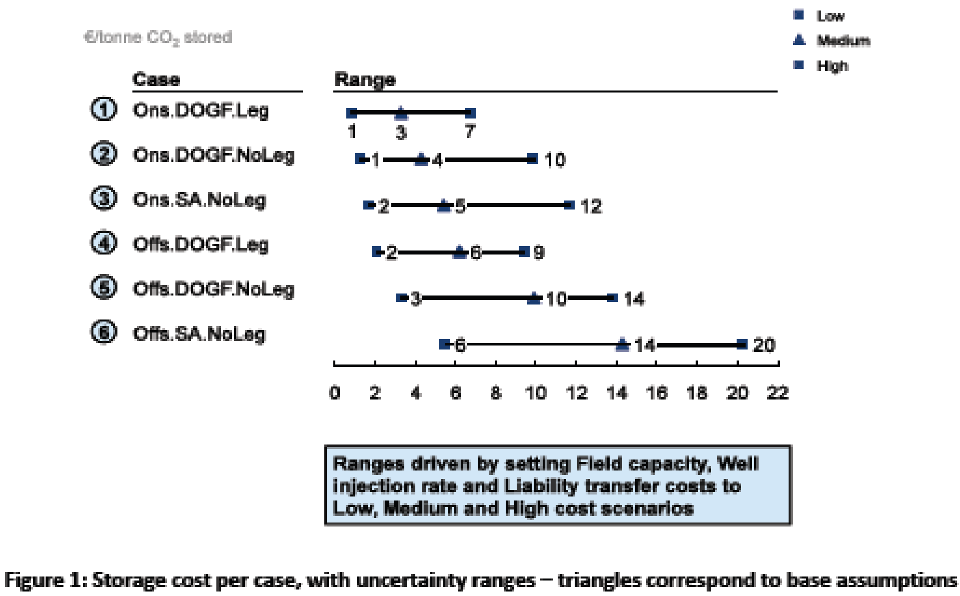


Figure 7: Breakdown of cost components – medium scenarios for all six cases

Source: ZEP Storage Costs Report (2011)

Figure 2.5: Storage cost ranges by storage option: (2011)€/tonne CO_2 stored



Source: ZEP Storage Costs Report (2011)

2.4 Findings on LCOE

The station gate[10] cost of electricity from a power station integrated with full chain CCS brings together the impact of the three (CCS) components on the reference generation plant in question. It is expressed as a discounted unit cost of clean energy which can be compared with levelised cost estimated of other low carbon options. This station gate definition excludes any wider system costs associated with handling generation of different types on the system.

There have been many assessments of the levelised costs of generation with CCS. The most recent published UK assessments are PB Power and Mott MacDonald's assessments for DECC and the Committee on Climate Change. The levelised cost estimates in these studies are for FOAK and NOAK CCS plants, rather than for early stage projects, which would have a premium over the FOAK. Nevertheless, the studies show the very different build up of levelised costs for the different technologies versus the reference plant. The 2011 PB Power estimates for coal and gas projects and the unabated reference plants both assumed to be started in 2011 are shown in Table 2.4. The cost estimates are in 2011 money.

These figures show that fitting CCS is mainly seen as a substantial uplift in capex costs, with more modest increases in fuel and opex. Clearly carbon costs are substantially offset. According to this analysis the overall station gate levelised costs of generation with CCS using post combustion and including the cost of unabated emissions is estimated to be £105-110/MWh for First of a Kind (FOAK), which assumes early

[10] Station gate definition is the same as bus-bar definition used by engineers and refers to all costs associated with getting the electricity onto to transmission network. While it will normally include back-end emission clean-up (including off site) it does not include any wider system impacts of handling the power.

CCS projects have been successfully undertaken. Costs of IGCC are estimated to be significantly higher, at about £130/MWh. The authors rightly point out that there is considerable uncertainty about these estimates. If carbon costs are excluded this takes off about £5/MWh from the coal CCS LCOE and about half this for gas CCS.

Table 2.4: PB Power's estimate of levelised costs for projects started in 2011 in £/MWh (2011 money)

Levelised Costs	CCGT NOAK	CCGT with CCS FOAK	Coal ASC NOAK	Coal ASC with CCS FOAK	Coal IGCC FOAK	Coal IGCC with CCS FOAK
	£/MWh					
Capital costs	9.0	35	22.2	59.6	39	85
Fixed operating costs	2.9	5.5	5.1	9.6	7.2	11
Variable Operating costs	0.1	0.6	1	2.5	1	2.9
Carbon costs	18.1	2.4	47.8	5.7	58.5	5.6
Fuel costs	46.5	57.5	19.3	23.1	20.5	22.5
Decommissioning and waste fund	0	0	0	0	0	0
CO_2 transport and storage	0	3.8	0	7.8	0	7.8
Total	76.6	104.8	95.4	108.3	126.2	134.8
Total excluding carbon costs	58.5	102.4	47.6	102.6	67.7	129.2

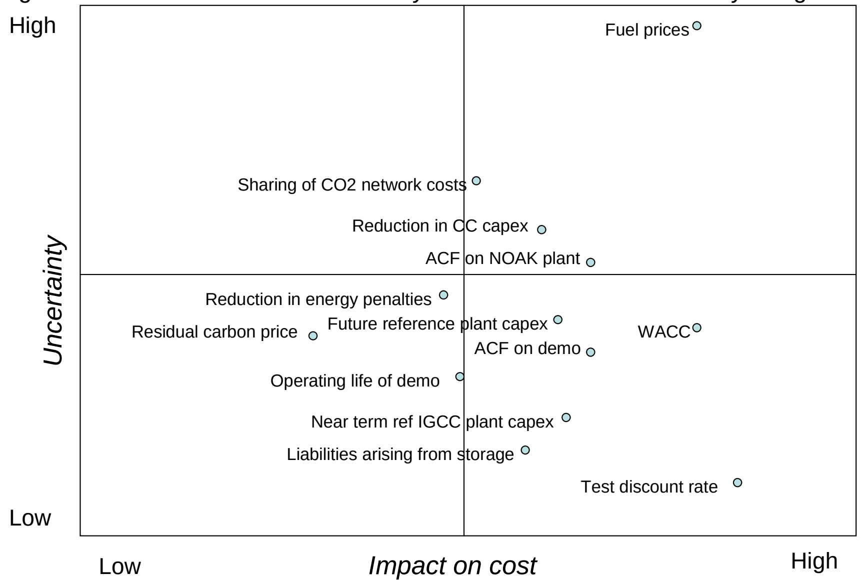
Source: PB Power, 2011

It is clear from the PB Power analysis that capex and fuel price will be the two key drivers of levelised costs. However, there are many indirect variables which influence this uncertainty. For instance, the levelised capacity cost is not only dependent on the specific capex value, but also the average annual capacity factor, the life of the plant and the discount rate applied.

The key drivers of levelised costs can be represented in a Boston 2x2 matrix with impact and uncertainty on the axes. This provides a context in which to consider how levelised costs might be impacted from technology and market developments. It shows the importance of fuel in influencing levelised generation costs, which is important to bear in mind, given this is largely uncontrollable and for fossil generation can only be hedged by providing a diversified portfolio of plant. WACC is another major driver of levelised costs, and although it is more predictable than fuel it is still uncertain as it depends on investors/lenders' perceptions of risk which in turn depends on a range of complex factors including the outturn of power plant's technical and commercial performance.

Both fuel and WACC are far more important variables in terms of impact on LCOE than most of the technical factors which often are considered important, such as the CO_2 percentage removal rate, energy performance ratios (MWh per tonne captured). This reflects the combination of potency and range of values for these variables. The test discount factor (the hurdle investment rate applied for national policy assessments) is another variable, though it tends to have less variability. Of the technical parameters, the average annual capacity factor (ACF) of the plant is probably the most important driver of LCOE.

Figure 2.6: Main drivers of uncertainty of Levelised cost of electricity using CCS



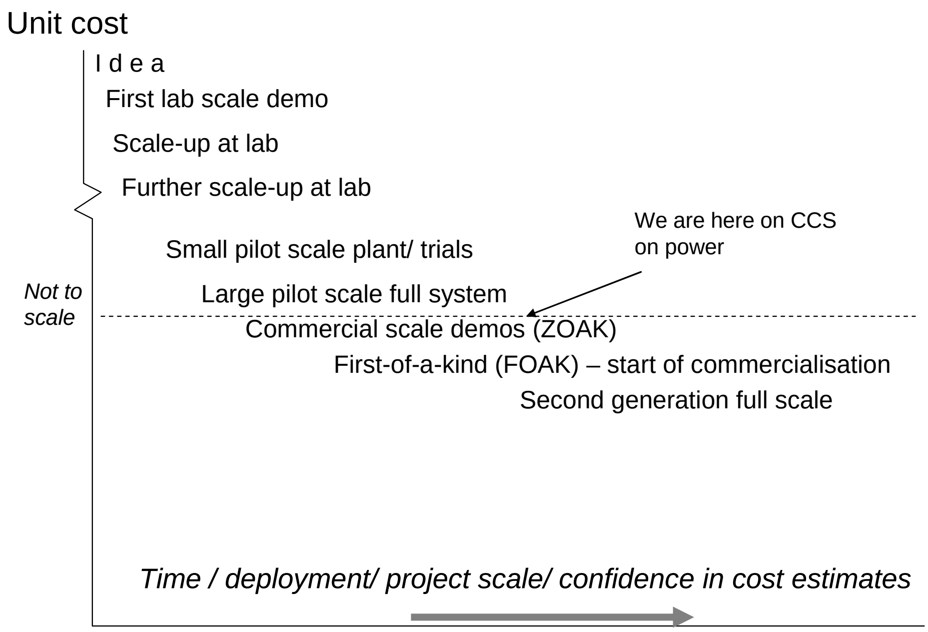
Source: Mott MacDonald

3. Cost drivers and the process of cost reduction

3.1 Introduction

This chapter examines the process of cost reduction. It first provides a brief review of how others have approached cost reduction and then considers what lessons can be drawn from looking at comparator technologies, both within and outside the power sector. Lastly it explores the drivers of cost reduction by component, which leads to the bottom-up projection of costs in the following chapter. As discussed elsewhere in this report, the numbers derived from our cost reduction analysis are subject to a very high degree of uncertainty and should be treated accordingly. The findings represent an initial thought piece designed to stimulate discussion on the subject and are the result of the use of some data but also significant amounts of subjective judgements based on our views at this time. To provide some context for this chapter we have provided a schematic of the general learning process for a successful power generation technology – see Figure 3.1.

Figure 3.1: Generalised learning process for a successful technology



Source: Mott MacDonald

3.2 Survey of approaches to cost reduction in CCS

We endeavoured to review a large amount of publicly available information, in particular academic literature and reports by various interest groups, on the projections for future costs of CCS to develop greater understanding of dominant approaches to cost forecasting.

Outside of academic articles published in peer-reviewed journals, detailed accounts of methodologies applied were often found missing or incomplete. It became apparent that expert judgement often plays a dominant role in this field. The approaches encountered broadly fell into four categories:

- top down learning curve analyses,
- top down learning curve analyses on cost components and performance variables,
- bottom up, engineering type studies,

- hybrid and/or judgemental.

Top-down learning curve type analyses principally rely on application of learning rates or progress ratios derived for related technologies in the context of CCS. The cost projections are derived through assumptions about future rates of deployment, which are necessarily highly judgemental.

The foremost challenge of this approach relates to the choice of comparator technology and the applicability of lessons learned to the context of CCS. The most closely related technologies are the Flue Gas Desulphurisation and Selective Catalytic Reduction plants, both of which find wide application in the power sector as flue gas treatment technologies. Their similarity to CCS, however, is only as large as two very complex systems with multiple physical processes can get.

Further difficulty lies in the need to ascertain whether technological learning is local or global. The need to establish the capacity from which the learning can begin from, marking the FOAK plant, is equally as judgemental. The lessons from other comparator technologies suggest that costs might increase in the early commercialisation period before they eventually start to decline. Matching the capacity growth with time is also very difficult. In general, those studies tend to appear very optimistic about achievable cost reductions as the assumptions about the pace of construction are usually unrealistic and the studies do not take into account real world engineering problems that often delay projects.

The more detailed studies apply the progress ratios to major component parts and also to performance variables. Arguably, they should be more accurate as the constituent components of CCS are well developed and deployed and as such the learning curves for them can be derived empirically. This approach, however, understates the issues related to the integration and up-scaling, which are particularly relevant to CCS. This was the lesson from liquefied natural gas (LNG) and also FGD. Other problems related to the learning curve analysis, discussed above, still apply. Consequently, some of the resulting cost estimates appear rather optimistic in our opinion.

Bottom up, engineering type studies that examine the CCS technology are very rare. This is undoubtedly related to the difficulty in ascertaining the cost reduction potential from technological advances. Their advantage lies in the detailed, scientific account of possible technological advancements relevant to a particular type of carbon capture technology. The field of solvent formulas is arguably the most vibrant one with a number of carbon capture processes promising significant cost savings stemming from lower energy requirements associated with sorbent regeneration and improved absorption performance, reducing absorber costs. However, the evidence from comparator technologies is that the early stage of developments moving from bench scale or pilots to full scale early stage projects is likely to prove more costly than anticipated as the product comes closer to commercialisation.

A further challenge, often omitted by authors, is associated with assigning a timeframe needed for those technologies to reach maturity and eventual commercial scale. For those reasons such studies are mostly relevant to projections with very long timescales. Another common misapprehension is related to a priori assumption that all innovation leads to reductions of the capital costs. Whilst true in many cases, the improvements in efficiency or increased reliability, which are equally as desirable, might come 'packaged' in more expensive equipment.

The dominant approach to CCS cost projections found in the literature appears to incorporate a mix of the methods discussed above coupled with expert judgement. This approach offers the best of all worlds. It is also the most subjective and arguably the most influenced by the industry rumours that prevail at the time of publication. The studies maintain transparency by including breakdown of assumptions used, although they are often not comprehensive.

Table 3.1summarises the four approaches and provides some examples of published studies. The assignment to the categories was based on our judgement as it was often difficult to draw unambiguous distinction between the papers.

Table 3.1: Approaches to cost reduction

Approach	Study
Mixed / Judgemental	"The Costs of CO_2 Capture", ZEP 2011 DECC Mott MacDonald: "UK Electricity Generation Costs Update", June 2010 "The future of Coal", MIT, 2007 "Economic assessment of carbon capture and storage technologies", Worley Parsons, GCCSI, 2011
Learning Curves / Top Down	"Generation Cost Update", PB 2011 "Use of experience curves to estimate the future costs of power plant with CO_2 capture", Rubin et al, 2007 "Realistic Costs of Carbon Capture", Harvard Kennedy School, 2009
Learning rates on components and/or performance variables	"Estimating the future trends in the cost of CO_2 capture technologies", IEA 2006 "Effects of technological learning on future performance of power plants with CO_2 capture", Van den Broek et al, 2009 "Carbon Capture & Storage: Assessing the Economics", McKinsey, 2008
Detailed Bottom Up / Engineering	"Techno-economic analysis of natural gas combined cycles with post-combustion CO_2 absorption, including detailed evaluation of the development potential", Peeters et al., 2007

3.3 Sectoral lessons

3.3.1 Lessons from power sector experience

As a part of this assignment we undertook a review of literature on technological learning in the power sector. This decision was informed on a premise that experience acquired with other relevant technologies might provide insight on the future trends in the cost of CCS.

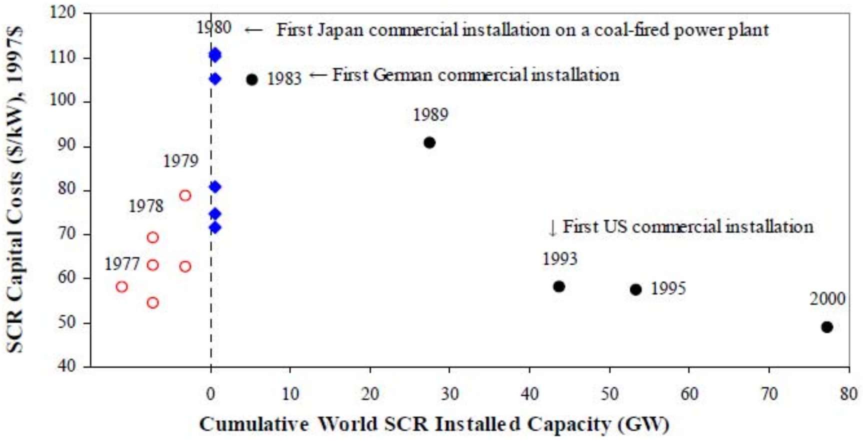
The most commonly adopted approach to learning (cost reduction) involves learning curve analysis. Learning (sometime called experience) curves show how costs (whether specific capex, levelised cost or operations costs) change with successive doublings in deployed capacity, where the rate of learning is represented by the progress ratio. A value below one indicates learning, while a value above one indicates cost escalation. The learning curve thus represents an aggregated representation of cost reductions through combined effects of improvements in the technology design, production process and standardisation, system integration, economies of scale, and changes in the input prices. It is a metric that captures a large amount of factors in a single number and as such conceals significant differences between projects. It is also worth noting that experience per se does not cause cost reductions, but rather provides opportunities for cost reductions. For instance, it is possible that in the early years the level of deployment of a technology could be so fast that a number of doublings occur but cost reductions may be constrained by supply chain bottlenecks.

In broad terms the empirical evidence from studies that apply the learning curve approach to the power sector suggests, unsurprisingly, that costs fall with cumulative deployment. The learning rates vary between technologies and usually fall in the range 1-20% (progress ratios are 0.80-0.99) per doubling. Meaningful results are only derived for established technologies and usually capture numerous doubling of installed capacity. The real difficulty with this approach, however, is related to the choice of initial capacity marking the 'start of learning' applicable to emerging technologies. This is associated with a widespread phenomenon whereby in the early stage of commercialisation, before 'learning-by-doing' gains momentum, a cost increase is often observed. This is due to 'learning-by-searching' or unforeseen escalation in capital and operations costs that arise from increased complexity and poor (and unexpected) reliability, which often requires product redesign and/or use of new advanced materials. For this reason it is considered that derived learning rates are only meaningful in the context of technologies with total installed capacity of a few GW or more.

Arguably, the most closely related technologies to CCS from which lessons might be drawn are the FGD and SCR systems, given that CCS also uses equipment that is already commercially available and involves an integration of chemical process with a power plant.

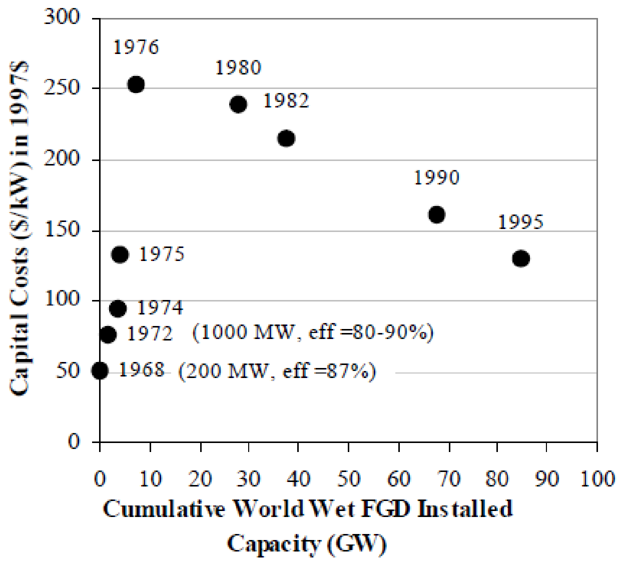
Empirically derived capital cost learning rates for FGD and SCR were estimated by the IEA at 13% and 14% per doubling of deployed capacity, respectively. However, both technologies exhibited cost increases during early commercialisation phase as shown in Figure 3.2 and Figure 3.3. These were not explained in the original studies, but were post facto attributed to shortfalls in performance and reliability. The corresponding reduction in operating and maintenance costs were 13% and 22%, respectively.

Figure 3.2: SCR Capital Cost reductions



Source: IEA GHG, 2006

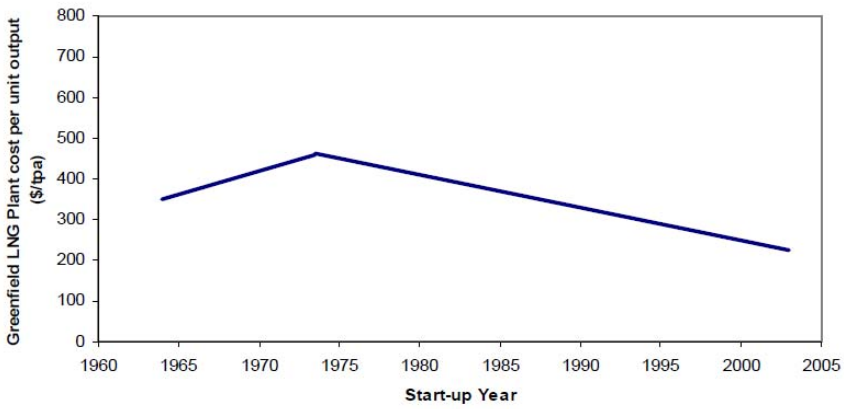
Figure 3.3: FGD Capital Cost reductions



Source: IEA GHG, 2006

Trends in LNG plant cost follow a similar trajectory whereby the early commercialisation period had witnessed some cost increases. Although, contrary to FGD and SCR, this has been largely attributed to lack of competitive forces and excessive redundancies built into the plants – see Figure 3.4.

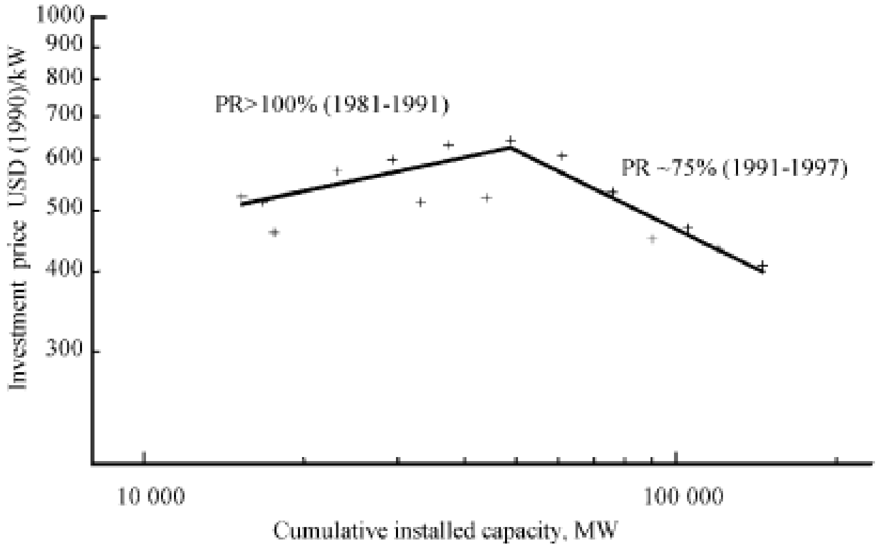
Figure 3.4: Development of LNG terminal costs



Source: IEA GHG 2008

Going beyond early commercialisation does not preclude progress ratios in excess of 100% (marking cost increases). The aforementioned technical problems coupled with uncompetitive markets and up-scaling may lead to cost rises even for relatively developed technologies. The experience of CCGT is probably a most telling example (- see Figure 3.5). For a 10 year period (1981-1991) associated with large increase in installed capacity the capital costs continually increased. The eventual price decline was attributed to improved performance and a shift towards more standardised machines.

Figure 3.5: CCGT cost for period 1981-1997



Source: Claeson Colpier and Cornland, Energy Policy (2002)

Considering the evidence it is difficult to overstate the apparent trend for cost increases for early commercial stages for technologies in the power sector. The learning rates derived for established technologies offer a more optimistic outlook conforming to common sense expectations. While the components of CCS are largely technologically proven as standalone equipment, there is still a major challenge in process integration and up-scaling of components. This fact makes it extremely challenging to apply the lessons gained from other technologies for the benefit of arriving at meaningful cost projections for CCS in the short term to medium. Paradoxically, the longer term projections are somewhat easier to make considering that eventually learning-by-doing will take place and then CCS cost reductions will probably be similar to those found for comparable technologies discussed in this section.

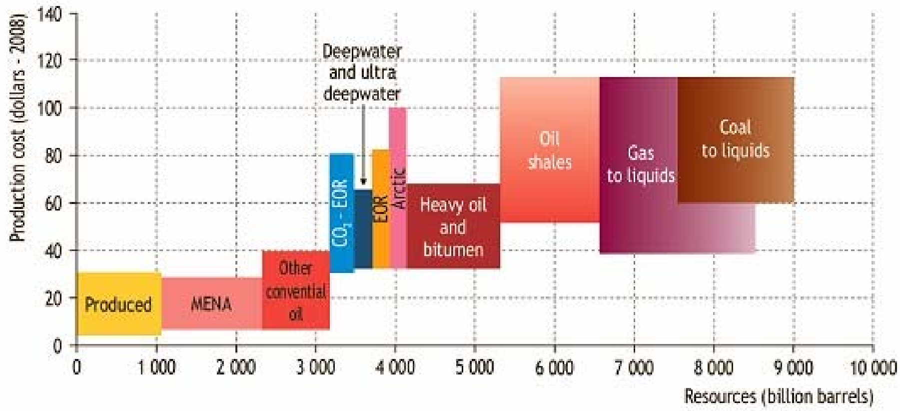
3.3.2 Oil & Gas

The upstream Oil and Gas sector is directly relevant to cost reduction for geological storage, but the understanding of cost reduction is complex for a number of reasons. The oil and gas industry might generally be considered as a mature sector, however that is an over-simplification. The upstream industry demonstrates an ongoing and continuing process of evolution and renewal, which continues even now.

Historically the industry has evolved from an onshore one that began over 100 years ago, then moving into offshore shallow water such as the North Sea (1960s onwards), then into deepwater (1990s onwards), with the offshore Arctic just beginning. Within any area there is a progression for conventional resources from primary recovery-secondary recovery and eventually opportunities for tertiary or Enhanced Oil recovery (including CO_2 EOR). This has been accompanied by increasing recovery factors.

Another major pattern of evolution is conventional oil and gas to unconventional oil and gas; oil sands and shale gas have only emerged as viable commercial sources within the last 10-20 years, but both have experienced extraordinary growth since then mainly in North America. Exploitation of oil shales along with coal and gas-to-liquids are potential future options. In each of these cases the unit cost of production are generally higher for the more challenging environments/resources.

Figure 3.6: Production cost curve for oil



Source: IEA (2008)

Note: The curve shows the availability of oil resources as a function of the estimated production cost. Cost associated with CO_2 emissions is not included. There is also a significant uncertainty on oil shales production cost as the technology is not yet commercial. MENA is the Middle East and North Africa. The shading and overlapping of the gas-to-liquids and coal-to-liquids segments indicates the range of uncertainty surrounding the size of these resources, with 2.4 trillion shown as a best estimate of the likely total potential for the two combined.

Source: IEA 2008

These evolutionary trends in the oil and gas industry have been driven by and accompanied by technological step changes and advances allowing exploration, drilling and development in progressively more challenging locations or resources. Some of the major technological advances over the last 25 years include:

- 3D seismic becoming routine, initial application of 4D seismic.
- Horizontal drilling; now progressing to multi-lateral wells
- Sub-sea systems replacing larger fixed platforms
- Deepwater drilling and production systems
- Fracking

The most relevant sector of upstream oil and gas to CO_2storage in the UK is conventional oil in offshore settings, but excluding deepwater. Within the North Sea, as in most basins, most of the largest oil and gas fields were discovered, developed and brought into production first, and have benefited from major economies of scale. Progressively smaller fields are discovered and developed as the basin matures, and ultimately production starts to decline for each field, contributing to rising development and operating costs in the latter stages.

Within this overarching trend of rising costs, technological advances, and industry cost reduction processes take place, such as the CRINE (Cost Reduction Initiative for the New Era) process in the UK in the 1990s. This led to major cost reductions through changes in contracting relationships between regulators, developers and suppliers, for example partnering, joint infrastructure/field developments, supply chain optimisation, procurement, risk sharing, standardisation and common data access. Subsequently development times were shortened, capital costs and operating costs reduced. This reportedly cut more than 30% from oil and gas project costs by improving competitiveness while not compromising safety or environmental standards[11].

3.4 Drivers for costs across the CCS chain

We now consider at a general level the key cost drivers for the three components of CCS. This review, along with the review of general drivers of costs in 3.5, together provide the context for the cost projection exercise reported in the next chapter.

3.4.1 Capture

The following are what we consider to be the main drivers for costs for the three main capture routes:

- Post Combustion – the biggest item is the exhaust stage or absorption stage of the capture process. This is the largest physical component requiring considerable on-site fabrication. The second largest element is normally compression stage, which requires a high capacity compressor much of which can be built off-site but which is demanding in terms of its materials and engineering tolerances. The stripper or regenerator is a third significant element. Post combustion has most to gain of the three capture routes from the application of new solvents and sorbents as it is essentially a bolt-on chemical scrubbing plant.
- Oxy-combustion of coal involves modest changes on conventional coal plant, but currently requires an expensive air separation unit (ASU). Reductions from advanced cryogenics and in the longer term membrane separation should bring major cost reductions, primarily through reducing energy penalties. Ultimately, oxy combustion offers probably involves the least complex route to capture and one that is most akin to traditional utility practice.
- IGGC involves modest Carbon capture spend on a more expensive base plant (IGCC) compared with the other two options. The host plant premium for which reflects the demanding gas treatment requirements in order to drive sensitive gas turbines without incurring unacceptable outages. The key issues for IGCCs are therefore reducing the cost of the base power plant while increasing its reliability.

3.4.1.1 Fluor's assessment of cost reduction in post combustion

We summarise below the results of a rare publicly available bottom-up assessment by a major carbon capture contractor and equipment vendor, Fluor, reported in 2004. Fluor's analysis suggested that the biggest reductions would come from absorber and compression improvements with pumps and blowers also being important. It did not explicitly mention host plant compensation. The results show a reduction in specific capex of about one third for gas and coal post combustion over a 16 year period - see Table 3.2. Our view is that Fluor's cost reduction assessment may be on the optimistic side, as it is unclear that improvements in performance will be matched by reductions in capex. Our assessment, later on in section 4.3 adopts more conservative reductions.

[11] http://www.dbd-data.co.uk/bb1998/chapter1.htm

Table 3.2: Fluor's 2004 assessment of post combustion cost reduction

	2004 costs: $m			2020 costs: $m		Reduction: $m	
	CCGT	Coal	Postulated reduction	CCGT	Coal	CCGT	Coal
Gas cooling	12	6	0%	12.0	6.0	0.0	0.0
Absorbers	39	39	25%	29.3	29.3	9.8	9.8
Stripper	6	6	25%	4.5	4.5	1.5	1.5
Reboiler	5	8	30%	3.5	5.6	1.5	2.4
Condenser	1	2	0%	1.0	2.0	0.0	0.0
Coolers	2	2	30%	1.4	1.4	0.6	0.6
Solvent HE	2	4	30%	1.4	2.8	0.6	1.2
Vessels	1	1	0%	1.0	1.0	0.0	0.0
Blowers	7	5	50%	3.5	2.5	3.5	2.5
Pumps	12	10	50%	6.0	5.0	6.0	5.0
Misc. equip	2	2	0%	2.0	2.0	0.0	0.0
Compression	25	40	50%	12.5	20.0	12.5	20.0
Direct field cost	114	125		78.1	82.1	36.0	43.0
% of 2004 cost				68%	66%		

Source: Fluor - 2004

3.4.2 Transport

The following outlines the main cost drivers for transport:

3.4.2.1 Length of the pipeline

In principle, the longer the pipeline and the elevation of the terrain crossed, the more compressor power is required to achieve the required delivery pressure at destination, increasing total cost. Under a fixed route and flow capacity, the number and size of booster stations depend on the circumstances and design.

3.4.2.2 Pipeline route (onshore versus offshore)

According to the IPCC Special Report on CCS pipeline costs may increase in congested and heavily populated areas by 50% to 100% compared to a pipeline in remote areas, or when crossing mountains, natural reserves, rivers, roads, etc.; and offshore pipelines are 40% to 70% more expensive than similar pipelines built on land.

The locations of the sources and storage points determine the pipeline route and the locations of facilities and control points. The pipeline construction in urban areas is very complex from a planning, legal, safety and technical perspective. In the planning of onshore pipelines it is better to follow existing pipeline trajectories as this will reduce costs and limit delays in planning procedures.

The identification of areas that are of special interest when planning a pipeline route is indispensable because of nature protection, biodiversity or other environmental constraints. Roads, railway tracks, streams, and rivers are considered as major obstacles in the course of a pipeline.

Water depth is a main factor for offshore pipeline trajectories. The costs increase with depth, due to higher costs for the laying of pipelines. Moreover the seabed profile (flat or not) is crucial for the type of laying method.

3.4.2.3 CO_2 specification

The composition of the captured CO_2stream depends on the source type, the implemented CO_2 capture technology and the type of fuel used. CO_2 captured from power plants and other sources is not pure. Captured CO_2 may contain impurities like water vapour, H_2S, N_2, CH_4, O_2, Hg, and hydrocarbons, which may require specific handling or treatment. The presence of impurities has a great impact on the physical properties of the transported CO_2 that consequently affects pipeline design, compressor power, recompression distance, and pipeline capacity, and could also have implications for the prevention of fracture propagation.

A CO_2 pipeline system must be able to accommodate varying flows and variations in the composition of the CO_2 fluid. The properties of the CO_2 stream will determine its corrosion behaviour and therefore will have implications on the pipeline design, such as on the material and coating selection as well as the selection of materials used for seals, gaskets, internal lining, and other safety or integrity-critical components, influencing as well the transport costs.

3.4.2.4 Existing on- and offshore pipeline infrastructure that can be reused

There is an extensive network of oil and gas pipelines in the UK, which presents a significant opportunity for re-use as part of CO_2 transport infrastructure. However there will be requirements to modify operation and maintenance processes to permit re-use with CO_2.

The main limitation of existing lines is design pressure, which for oil and gas transmission service typically varies between 60 and 80 bar. The effect of this limitation is to reduce transport capacity compared to a purpose-built new line, which would likely to be designed for a higher pressure. The second uncertainty regarding existing lines is remaining service life. Many existing pipelines have been in operation for 20 and 40 years. Remaining service life can only be assessed on a case-by-case basis, taking into account internal corrosion, and the remaining fatigue life. Timing will be a major limitation. The date at which pipelines become available is inherently uncertain and is commercially sensitive information. Even if information can be shared, it may be very difficult to match decommissioning timelines with those for CCS demand and sink availability – mothballing may be necessary.

3.4.2.5 Oversized infrastructure for the expected growth in CO_2 volumes

CCS network studies[12] and proposals often incorporate the concept of one or more common user storage sites. This usually involves a ‘backbone’ pipeline that initially transports CO_2 from just one or two sources to a particular storage area, but surplus capacity is built in to integrate additional sources in the future. The incentives for CCS projects being developed using a network approach include the economies of scale (lower per unit costs for constructing and operating CO_2 pipelines) that can be achieved compared to stand alone projects where each CO_2 point-source develops its own independent and smaller scale transportation or storage requirements.

[12] North Sea storage plan, TEES Valley, South Africa CCS roadmap

These economies of scale provide an incentive for the proponents of CCS projects clustered in the same region to coordinate their development according to an integrated network approach.

In principle, additional sources can be added in the future provided CO_2 pipeline capacity is sized and designed accordingly. A coordinated network approach can then lower the barriers of entry for all participating CCS projects, including for emitters who subsequently do not have to develop their own separate transportation and storage solutions.

For coal-fired power generation with CCS, the annual flow from the facilities is estimated to be in the order of 4 Mt/yr of CO_2, requiring a pipeline diameter of approximately 0.5 metres. Current pipeline construction allows for pipelines greater than one metre diameter to be constructed. Increasing the pipeline diameter by a factor of two allows for the pipeline flow to increase by a factor of four. Therefore, there is the potential for four stationary emitters using 0.5 metre pipelines to combine their captured CO_2 into a single one metre pipeline for delivery to the storage site. Through combining three or more plants, the CO_2 flow can be increased to greater than 10 Mt/yr, leading to a cost savings compared to four individual pipes.

An advantage of offshore pipelines for CO_2 transport is that higher design pressures can be used than onshore, potentially up to 300 bar. This is partly due to the reduced hazard to population compared to onshore routes, which allow higher design factors to be used; and partly due to the compensatory effects of external hydrostatic pressure, particularly in deep water.

These benefits arising from economies of scale need to be weighed against the risk of being left with an underutilised or stranded asset. This means that the development of transport and storage clusters needs to be carefully co-ordinated with capture.

3.4.3 Storage

As described in Chapter 2 the costs of storage vary according to the storage option type, location factors and geological characteristics specific to the site. The cost drivers for storage have been analysed in most detail by the ZEP Storage report. Based on that report and oil industry understanding the major cost drivers are considered to be as follows:

- Location: Onshore versus Offshore. In generic terms onshore storage will almost always be cheaper than offshore storage for a similar site because offshore platforms/infrastructure are not required, and well costs and general overheads are lower. Onshore storage is generally disregarded for UK due to policy consideration rather than geology.
- Water depth. Impacts new platform costs and drilling costs.
- Infrastructure Reuse. The ability to convert and re-use platforms, wells and offshore/infield pipelines in existing oil and gas fields offers potential for major cost savings in some cases in the UK North Sea. This is field specific and depends on the integrity of existing infrastructure and wells, which relates to their age of installation. The Longannet project had planned to re-use much of the infrastructure in place at the Goldeneye gas field, where the infrastructure is relatively young (7-8 years). However Eon considered it would be more viable to redevelop Hewett rather than to reuse existing platforms and wells some of which date back to 1960s. There is also an indirect benefit to the oil and gas sector through delayed decommissioning.
- Field capacity. Economies of scale reduce unit cost for larger fields. This was identified as the largest cost driver for a given any option type in the ZEP report, with a 30-40% reduction in unit costs between a medium (66Mt) and high capacity cases(200Mt)
- Field Injectivity. Higher injectivity and injection well rates reduces the number of wells required for a given storage. Low reservoir compartmentalisation and complexity is also favourable in this regard.

- Reservoir depth. Well costs increase with depth.
- Monitoring requirements. These are expected to be more stringent (and therefore higher unit cost) for early stage projects than during commercial deployment.
- Liability Transfer costs.
- Enhanced oil/gas production may provide supplementary revenues from Enhanced Oil/Gas production to offset storage/CCS cost.
- Exploration/Appraisal costs. These apply to saline aquifers and will depend on the availability and extent of pre-existing information

Another driver of overall storage costs based on economies of scale relates to the project or system scale and development. Economies of scale for storage are expected to be realised as CCS develops and expands from point to point projects into regional network and hubs. The benefits have been documented for network development for Scotland and NE England[13] and by ZEP as outlined earlier.

3.5 General drivers for cost reduction

There are lots of different ways of classifying cost drivers for energy technologies. We have chosen one based on that used by Edward Rubin et al in July 2010[14], which we consider provides a logical and reasonably transparent breakdown from a leading academic group in the study of cost reduction in energy technologies. Our assessment of future capital costs in Chapter 4 applies Rubin's breakdown in a judgemental bottom up analysis. Here we briefly outline the nine cost drivers used in the analysis.

3.5.1 Technology advancement – design:

Design improvements involve changing the way something works or the way it is put together. This can apply to particular components or the whole system or layout. In terms of a CCS plant examples could range from new designs for absorber systems for example based on feeding re-circulated (concentrated) flue gas streams, or more efficient compressors or novel pipeline couplings. Design changes tend to be only implemented after operational experience indicates problems or else new designs offer significant system cost or performance advantages.

3.5.2 Technology advancement – materials

Materials enhancements can bring benefits in several ways. Substituting lower cost materials with equivalent performance reduces input costs. Using better performing materials may allow design changes or easier assembly or reduced service requirements. The most obvious examples here are solvents and absorbents used in the different capture processes.

3.5.3 Optimised construction logistics

The easiest learning for large capital projects is improving construction oversight and revising the construction schedule so as to reduce poor workmanship (hence re-working) and reduce the risk of bottlenecks. By reducing the construction labour input (and associated materials and services) and shortening the construction period, the capital costs can be significantly reduced. Normally it is the EPC

13 Developing a CCS Network in the TEES Valley Region, Element Energy, 2010

14 Prospects for improved carbon capture technology – report to the Congressional Research Service, from Carnegie Mellon University, July 2010.

contractor and the main OEM who are the prime agents of learning, however most subcontractors will improve their assembly operations in successive applications.

3.5.4 Economies of scale

Using larger scale units typically results in reduced costs per unit of capacity (volumes expand faster than single dimensions). This is especially noticeable in pipeline and storage systems but it is also a factor in the capture process. Doubling the volume of an absorber as the MW rating of captured flue gas stream is doubled is likely to bring significant unit cost reduction. Such economies of scale benefits are an important contributor to the early stage cost reductions. Clearly, as the technology moves into full scale application the scope for further economies of scale in capture will be small, and the main scale benefit will derive from the transport and storage components.

3.5.5 Reduced design margins

Early stage plants tend to be built with high levels of redundancy in systems and with higher spec materials than is required. This tendency is likely to be reinforced where there exist complicated interfaces between parts of system, such that equipment suppliers/operators will tend to seek extra safeguards to mitigate claims against them.

At the other end of the spectrum are fully integrated systems using mature technology operating as part of a portfolio where developers will tend to seek little redundancy as they understand outage and performance risks and can hedge through their portfolio.

Designing with less redundancy in systems, generally reduces capex costs as one very good pump and associated piping can replace two average ones and lots more piping. In some cases, reducing design margins may lead to increased opex or reduced availability (due to increased outages and service requirements).

3.5.6 Product standardisation

As a technology begins to mature the technology developers and component suppliers will seek to standardise component design and fabrication methods as this allows them to reduce costs through modular production (and in some cases mass production of small components). Having a standardised design also allows developers to seek alternative suppliers which can improve the robustness of supply chains and/or lower costs through competitive tendering.

Once a design has been sufficiently debugged and is seen to be successful there is often considerable inertia to stay with this. Component suppliers are likely to warn of the dangers of experimenting with other approaches, but they clearly have in interest in defending their sales, ensuring recovery of their R&D costs and potentially some capturing of rent. In practice, standardised components that lack a strong patent protection will be subject to competition which should bring costs down.

3.5.7 Increased competition

The more suppliers offering a component or service the greater the prospect that costs will not include excessive rent. This clearly requires the development of sufficient supply chain capability and a degree of standardisation of components. This is easier where component and service suppliers can serve several markets. Where original equipment manufacturers (OEMs) face a small number of potential suppliers it is often difficult to get a competitive price, as most suppliers will be reluctant to risk not recovering their development and tooling up costs. However, where there is the prospect of securing a long term supply contracts with the OEM, then component suppliers will be able to offer cost reductions through series production. Generally, OEMs will only seek to put such long term arrangements in place once their own forward business is secured, which is unlikely to be in the early stages of technology deployment.

It is worth noting that there will be some component and service suppliers for the new technology which may already have established markets in other or related sectors and so may be prepared to offer prices more akin to mature technologies. Examples of this include, CO_2 pipelines, drilling rigs, geophysical surveys. Of course, the converse is also true, in that if there is scarcity of supply in the related sector then this will drive up prices for the CCS chain.

3.5.8 Input price reduction

The key inputs in most energy technologies are construction labour and services, materials and components. Land, licenses (including patent fees) and permits are other significant items.

These costs clearly vary by jurisdiction, most starkly illustrated by the approximate halving of coal plants capex in China versus Northern Europe. However, it is difficult to access low costs in other jurisdictions, since a large part of capex costs are associated with on-site labour and supervision which is for practical purposes not transportable. Component supplies, including some large components, could in principle be shipped from low cost jurisdictions. Of course, this still requires that they achieve the appropriate quality thresholds.

Input costs can move quite sharply even without accessing low labour costs overseas; most notably through volatile material and fuel prices and also through exchange rate movements, which affect also affect equipment and service costs (which are often priced in US dollars and Euros). On site labour and supervision costs, which makes up the largest item for many power generation technologies including carbon capture, tends to change only slowly in real terms.

3.5.9 System integration/ optimisation

There are two main aspects of system integration. One relates to thermodynamic efficiency, in terms of the mitigation of auxiliary power demand, process steam requirements and the recovery of waste heat. The second relates to broader design optimisation, in terms of the process layout which maximises sharing of infrastructures and mitigation of expensive connections. A well designed system should also have a degree of robustness in terms of its operation, such that outages in particular parts of its systems would not bring the whole plant to a halt (unless this was required for safety or environmental compliance).

Table 3.3 provides some of the key potential cost reductions arranged by the Rubin drivers.

Table 3.3: Cost drivers in capture

Cost drivers	Examples
Technology advancement – design	Advanced membrane based air separation units (for oxy combustion and IGCCs) and gas recirculation for post combustion gas
Technology advancement – materials	New materials for absorber vessels, advanced solvents
Optimised construction logistics	Mainly bespoke project in early phase of commercial deployment but some scope in common components.
Economies of scale	Larger absorbers, compressors and gasifiers

Cost drivers	Examples
Reduced design margins	Reduced number of pumps/ valves in low risk areas
Product standardisation	For common components such as compressors
Increased competition	As CCS business turnover increases competition should broaden across all fronts though OEMs with proprietary technology may protect margins
Input price reduction	In long term may be able to access low cost manufacturing capacity in China and elsewhere
System integration/ optimisation	Improved solvents, integration of energy flows should lower energy penalties

Source: Mott MacDonald

3.6 Storage cost reduction – early stage projects to FOAK

The ZEP Storage report has considered the likely costs when CCS moves from early stage projects to commercial deployment. They identified three factors which should lead to significantly higher unit cost of storage for early stage projects: namely diseconomies of scale, short injection period and demanding monitoring requirements. Accordingly, cost reduction is attributed to economies of scale related to larger field capacity, longer injection period and lower monitoring requirements for commercial projects, compared to early stage projects.

The ZEP report emphasises that the costs of storage are primarily dependant on the storage option and specific site characteristics. It notes that the cost sensitivities clearly show a major economy of scale benefit: large storage reservoirs lead to a much lower cost per tonne of CO_2 stored (up to 40%). It cautions that lowest cost sites may not always be available for storage (i.e. large depleted oil/gas fields), presumably due to continuing production. The report cites a learning rate in order of 3% for operating costs based on the oil and gas industry but concludes this will have insignificant impact on storage costs. It does not consider potential improvements in capital costs, technology advancements or system optimisation.

In other studies there has been less focus on cost reduction potential for storage. The IPCC CCS Special Report (2005) suggests that cost reduction will be achieved through application of learning from early projects, optimisation of new projects and application of advanced technologies such as horizontal and multilateral wells, which are widely used in the oil and gas industry. It is noted that many public domain storage cost assessments do not incorporate advanced well technologies (i.e. horizontal wells), even though these have been used by industry for storage at Sleipner and In Salah.

Table 3.4 presents the main areas where cost reduction may be anticipated in CO_2 storage.

Table 3.4: Cost drivers in storage

Cost drivers	Examples / Issues
Technology advancement – design	Application of advanced well types which are already in use in oil industry (horizontal, multilateral wells) Application of 4D seismic for storage monitoring (which is just emerging in oil sector) New monitoring technologies for CO_2 storage
Technology advancement – materials	New materials for well cements to reduce risk of leakage
Optimised construction logistics	Mainly bespoke project in early phase of commercial deployment.
Economies of scale	Economies of scale are clearly identified as a major cost driver for CO_2 storage. These may be realised through larger CCS projects with larger storage sites.

Cost drivers	Examples / Issues
	Longer term there may be additional economies of scale from and CCS network and storage grids/hubs.
Reduced design margins	Injection/storage design improvements likely Reduced monitoring requirements
Product standardisation	Limited impact in early stages
Increased competition	Limited impact until strong commercial drivers and market for CCS/storage develop
Input price reduction	Storage sector will benefit from input price reduction in oil and gas equipment and supplies (E.G. 4D seismic)
System integration/ optimisation	Improved well design, injection strategies and reservoir sweep/utilisation for CO_2 storage Gradual reduction in monitoring costs as a result of learning from early stage projects. Improvements in modelling, risk assessment and subsurface performance prediction.

Source: Mott MacDonald

3.7 Why costs may take a long time to fall?

There are a number of reasons why costs may not fall in the early years of developing a technology. We have identified the following from discussions with our own engineers and project managers and some external project engineers.

- Constructing and operating a processing plant at a significant scale-up is more difficult than developers often expect. The chances of deviations from expectation increase where components in process chain have limited testing at the scale of application.
- Early stage plant will often build in high level of redundancy in components and materials, which when designed out in follow-on projects may lead to further excursions.
- Early stage deployment involves lots of experimentation with various competing technology routes, which make learning between projects difficult. This is further complicated by the fact that technology developers/owners will not normally be willing to share the lessons from their experience.
- Early stage project developers normally face little choice of technology and service providers, who themselves will be looking to recoup development costs in their pricing. At such an early stage component suppliers are unlikely to invest in order to lower costs. This means that there may be supply chain bottlenecks as some component suppliers may have production problems.
- In some technologies, changes in regulations relating to managing safety and environmental impacts may lengthen permitting and construction times or require design changes.
- In the early stages of complex process engineering projects it is unlikely that an EPC contractor would take responsibility for the full chain, and so procurement is unavoidably in blocks. This necessitates that suppliers add contingencies for interfaces, which tend to be compounded, so inflating the overall procurement price.
- Given the reluctance sometimes for developers to be fully open regarding the lessons from experience and the limited number of personnel/ mangers with experience in the early days there is a risk that experience may lost, through natural attrition or through staff being poached by competitors.
- Long lead times tend to result in slower learning.

3.8 Projecting costs for Carbon Capture using learning curves

In order to provide a further benchmark for potential cost reductions we have developed our own high level top-down projection using learning curves. As noted previously, this analysis is highly subjective and represents our opinion based on reviews of previous approaches and existing data. The results should be treated accordingly.

As mentioned above, the application of learning curves requires making assumptions on three key variables:

1. The progress ratio (often called the learning rate) – percentage change in cost (or performance) variable per doubling in deployed (or installed) capacity;

2. The starting level of installed capacity;

3. The assumed level of deployment by a certain time period.

The last variable disappears if we are only concerned with the relationship between costs/performance and deployment level. This is the focus here.

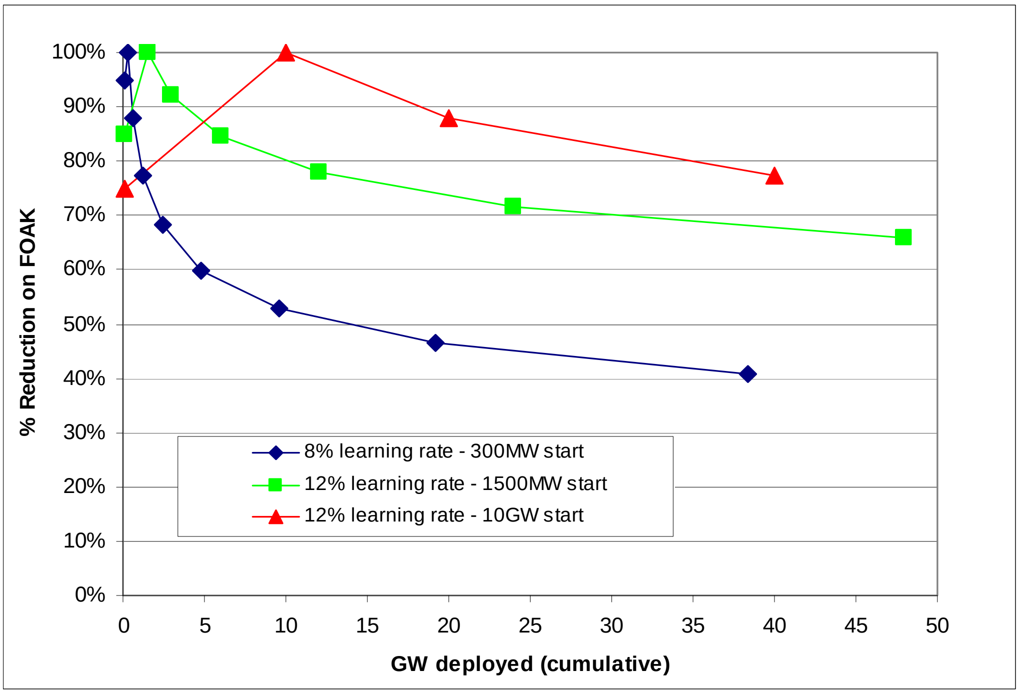
Taking the historical analogues outlined above (section 2.3.1), and given the significant uncertainties discussed elsewhere in this report, we would expect a learning rate of 8% to 12% per doubling of deployed capacity. The bigger challenge is determining what counts as the starting level. The most optimistic approach is to assume that learning starts from the first commercial early stage project, which could be just 300MW. A more conservative approach – given the evidence from other early stage roll-outs – would be to assume several GW (~10GW globally) of capacity would need to be installed before learning sets in.

There is of course a further issue of what happens to costs in the case that the starting point is deferred. The simplest assumption is that costs will be the same as the “current” assessment (this ignores the fact that costs often go up first before coming back down).

We have illustrated the impact of the different starting points and the learning rates in Figure 3.7. This shows that on two plausible scenarios of development we could see a divergence in carbon capture specific capex of around 1.9 times between 10GW and 40GW. The more modest reduction profile (which actually has a more favourable progress ratio) would achieve a 23% reduction after 40GW deployed versus a 60% reduction for the more aggressive case. The differentials here largely reflect the starting position and hence the number of doublings applied.

Our view is that a plausible central case projection would fall between the range above. Such an example is shown by the curve for a 12% learning rate applied to a 1500 MW starting point, which indicates as specific capex reduction of about a third after 40GW installed. This sets a benchmark for considering our bottom up analysis in Chapter 4.

Figure 3.7: Reduction in specific capex of carbon capture using learning curves



Source: Mott MacDonald Judgement

4. Cost reduction projections

4.1 Introduction

In this chapter we have developed quantitative bottom-up projections of potential cost reduction for the different CCS technologies. As previously discussed, the bottom-up approach allows us to identify the main areas which could potentially deliver cost reductions.

These projections must be considered extremely uncertain as there is no reliable data on the likely early stage project costs or consensus on the main forward trends. We are in effect projecting the outcome of the evolution of a set of complex systems without knowing the initial conditions. With this caveat in mind we have provided a range of estimates which reflect our subjective P80 and P20 estimates (ie defining a 60% confidence band).

We now outline the general approach to assessing cost reduction potential, before reporting the assumptions and results for carbon capture and then transport and storage. We complete the chapter by bringing the elements together and commenting on full chain costs and drawing some conclusions.

4.2 Approach

We have considered the cost reduction potential in terms of changes in specific capex (expressed in £/kW net) and the levelised cost of electricity generated based on the incremental costs of capture and the whole generation plant costs for the four main capture routes. We have also estimated a cost per tonne of annual capacity for transport and storage. An overall full chain estimate based on levelised cost of electricity generation is also provided based on representative coal and gas emission factors.

The main focus is on development of specific capex costs - by far the biggest driver of CCS costs - and this is split into capture and transport and storage. Our estimates of capture capex are built up from considering the nine (Rubin) drivers acting on six varying components for each capture option in a process which is outlined further in section 4.3. A different approach is used for pipeline costs, where transport distance and economies of scale are the key drivers, while for storage we have used a hybrid approach to adjust the costs from the Demo 1 FEED study estimates. Non-fuel opex for power and process plant is generally linked to capex[15]: typically annual fixed costs (for operations and maintenance) are 2.5-3.5% of the initial capex, with lower rates applied for pipelines.

The P20 and P80 ranges represent our judgement of what defines a moderate low and high case respectively. In capture these differential judgments reflect the extent of reduction in energy penalties and cost savings arising from economies of scale, materials, improved design, reduced redundancy, etc. In transport the range reflects different assumptions regarding accessing economies of scale, while for storage, the range is driven by a combination of specific capex and opex costs and economies of scale (lifetime storage capacities).

4.2.1 Complications

In conducting this assessment of the likely routes of cost reduction it is clear that there are many complications which make it difficult to provide projections with a high level of confidence. While it is

[15] At a particular application level there will however be cases where increasing the capex can reduce annual operations and service costs – for example by installing higher specification (more reliable) pumps.

possible to identify many potential and likely technological developments it is more difficult to translate these into cost trends. The reason for this is that there are many countervailing trends. Improved performance, in terms of reliability, energy penalty, amine use, etc will not necessarily be matched by a reduction in capex. In practical terms, innovations do not always work smoothly: so improved performance may be offset by reduced reliability and increased service costs elsewhere, which may require additional capex to mitigate. Designs which on paper improve system efficiency may in practice be more difficult to build and/or when built lead to a less reliable and operationally flexible plant. Furthermore the difference between the theoretical outcome and the actual could come down to how well-trained and managed contractors are.

The nature of commercial and contractual arrangements may also influence the project design and operating philosophy. For example, where owners are severely penalised for failing to achieve particular annual capacity factors and throughput requirements, then plants will be designed with a high degree of redundancy to ensure they achieve these targets. Also, if there are minimum requirements for percentage removal of CO_2 or high minimum plant efficiencies, these too may potentially increase capital costs in a way that increases overall levelised costs.

These factors have been taken into account in influencing our estimates of future capex, opex and performance parameters.

4.2.2 System integration

For all the capture options considered in this paper it is clear that improved system integration should bring significant cost reduction through thermodynamic and layout benefits. However, there is also an argument that a closely integrated plant requires more demanding construction standards and is more difficult to de-bug if things go wrong. One of the lessons learned from the early stage projects on IGCC plants is that high levels of integration often come at a price of low levels of average plant availability. Retrofitting post combustion capture plant to existing coal and gas plant in a way that maximises thermal integration (and mitigates the energy penalty) is also likely to be both tougher to construct and more challenging to operate reliably. The reality is that there is a trade-off between integration benefits and costs and potentially reliability. As above, these practical integration issues have been taken into account in influencing our estimates of future capex, opex and performance parameters.

4.2.3 General Assumptions

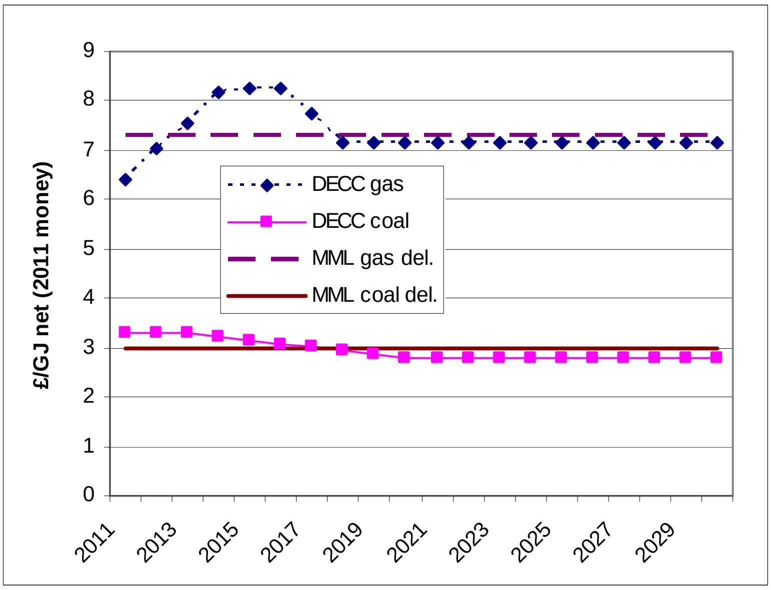
There are a number of common assumptions which apply to the analysis of capture, transport and storage.

- All costs are expressed in constant 2012 money (GB Pounds), unless otherwise stated.
- A real (pre-tax) discount rate of 10% has been applied for all annuity and levelised cost calculations irrespective of when the project starts. This is to simplify the analysis and allow a more straight forward comparison between technology options. (In practice, the discount rate would be expected to be differentiated by perceived risk and also it would be expected to decline over time as technologies matured). In 2011 Oxera concluded that CCS along with several exotic renewable options would initially face a high risk premium with real (pre-tax) discount rates at 12-17%, although this estimate was made before the Contract for Differences mechanism was announced.
- Fuel prices are based on DECC's latest projection (2011), using the central case which gives delivered station gate price of £3.0/GJ net for coal and £7.3/GJ net for gas, which gives coal a burner tip advantage of £4.3/GJ. Figure 4.1 shows these fuel price assumptions versus the DECC central

projections, expressed in real 2011 money[16]. At current (March 2012) prices, coal's advantage is about £2.5/GJ.

- Carbon emissions are priced at zero. No charge has been applied to unabated CO_2 emissions in order to focus on the underlying costs. Carbon costs will to a large extent be driven by the assumed social (regulated) cost of carbon as reflected in the carbon price floor.
- The projections for the high and low cost paths both assume a strong level of global deployment of CCS capacity spread across the technologies, though the low cost path assumes somewhat greater deployment. UK deployment is assumed to show reasonably strong deployment too, with annual deployment rates in the several hundreds of MWs range by the mid 2020s in the low case and some higher in the high case. It is the UK deployment rates that are critical in driving savings in transport and storage..
- Cost projections are made on a time of order basis with no distinction explicit distinction between FOAK and NOAK status, though one could assume prices in the early 2020s could be considered FOAK and those in 2040 as NOAK.

Figure 4.1: Assumed fuel price assumptions versus DECC 2011 central projection



Source: DECC 2011 and Mott MacDonald assumptions

4.3 Capture

The largest cost item for carbon capture is the up-front capital cost of the facility, or in the case of IGCC, the cost of major modifications to the host plant. This "own process" cost accounts for the largest part of the total capture capex. The capture capex also includes an element for host plant compensation which embodies an assumption about the evolution of the energy penalty and the reference (host) plant capex price.

[16] The exact DECC price projection was not used because the modelling approach used here applies a constant fuel price through the project life.

The energy penalty also determines the extent of uplift in energy cost. This is simply treated here by applying a percentage penalty to the fixed reference plant efficiency[17] and multiplying by the delivered fuel cost.

Table 4.1: Assumptions for calculating energy cost uplift

	Coal	Gas
Fuel cost: £/GJ net (delivered)	3.00	7.30
Reference plant net efficiency (HHV)	40%	54%

Source: DECC November, 2011 (for fuel price) and Mott MacDonald assumption for efficiency

The initial capex level and breakdown have come from a combination of sources. The total capex figures for carbon capture have been broadly aligned with the Demo 1 FEED/Post-FEED studies as well as a number of recent confidential project submissions. The breakdown by component is our own assessment based on these same studies.

There is considerable uncertainty here which reflects the design configuration, definition of costs and site specific issues and lack of track record in delivering full scale commercial projects.

For each technology option we have applied a six item breakdown, but this varies between technologies – see Table 4.2.

Table 4.2: Key components for each capture option

	Post combustion	Oxy combustion	IGCC
Pre-development costs	*	*	*
Absorber	*		
Stripper/regenerator	*		
Air separation		*	
Gas conditioning		*	
Water shift			*
Acid gas treatment			*
CO2 compression	*	*	*
Balance of plant	*	*	*
Host plant compensation	*	*	*

Source: Mott MacDonald estimates

All the main capture technologies have four common components – development costs, compression, balance-of-plant[18] and host plant compensation. Compression is highest for post combustion, especially for gas, slightly less for oxy combustion and much lower for IGCC. IGCC's lower requirement reflects the fact that gasification processes work at elevated pressures. Host plant compensation is a product of the energy penalty (in percentage terms) and the specific capex of the host plant. This item is therefore much

[17] This is the efficiency of the equivalent unabated power plant. The constant efficiency is a simplifying assumption (in practice efficiencies of unabated plant would probably increase slightly) however, the underestimate is offset by a slightly higher reduction in energy penalty.

[18] Balance of plant refers to the remaining items not covered by other categories, and typically would include supporting facilities and peripherals such as water treatment, fuel handling, storage and treatment, controls and instrumentation, transformers, switchgear and electrical connections.

less for gas post combustion, since both the efficiency penalty and the capex costs are low. The host plant compensation for post combustion coal and oxy coal are much greater, with IGCC having a still greater penalty given the high costs of the host plant (despite a slightly lower energy penalty).

We have considered how the nine different cost drivers identified in section 3.5 might affect each of the six component groups for each capture technology option. There is a degree of arbitrariness in how some measures might be categorised. A new design for a larger absorber using lower cost materials can be split between better design changes, material cost reduction and economies of scale. If it also reduces the energy penalty it contributes to a reduction in the host plant compensation. Also it is unclear whether advances in design will generally result in cost reductions rather than improvements in performance: new efficient compressors may or may not be cheaper than standard ones, but they should bring a reduction in the energy penalty (and host plant compensation).

The different cost drivers are likely to work over different time frames. Improvements in construction logistics and gains from economies of scale are likely to be come in the shorter term, while product standardisation and gains from competition are most likely to be captured in the longer term. Design changes may bring some medium term gains but the biggest benefit will probably come in the longer term, while reduced design margins and system optimisation are more important in the medium term. Table 4.3 summarises the timescales of influence for the cost drivers.

Table 4.3: Timescales of influence for cost drivers

	Time horizon		
	Near term	Medium term	Long term
Technology advancement – design		**	***
Technology advancement – materials	*	**	***
Optimised construction logistics	**	*	
Economies of scale	***		
Reduced design margins	*	***	
Product standardisation		**	***
Increased competition		*	***
Input price reduction		*	***
System integration/ optimisation	*	**	
Number of stars indicates weighting of importance			

Source: Mott MacDonald Judgement

Using this framework, we have populated a simple bottom up spreadsheet model with our best guesses as to cost changes based on our reading of other bottom-up studies (such as those from Fluor, Rubin, Peeters, etc) and our own experience in technology and project development and capital equipment markets. The overall rate of cost reduction has also been benchmarked versus the results of the top-down learning curve approach as outlined in section 3.8. This all assumes a supportive framework for the rollout of CCS and a fairly aggressive rate of deployment as outlined in section 4.2.3.

4.3.1 Assumptions by capture route

4.3.1.1 Post combustion:

The main reductions for post combustion capture are expected to come from gains in compression and absorbers. The former arising from new compressor designs while absorbers should benefit from economies of scale and design improvements. The absorber improvements are also likely to be linked to advances in absorbents which improve reaction efficiencies and reduce the required size of absorbers.

Coal should benefit more from compression improvements than gas given the higher share of compression in the capex cost. For gas, absorption is proportionately greater given the low concentration of CO_2 in the flue gas. However, there are expected to be big gains from gas recirculation (which concentrates the CO_2 in the flue gas stream) and reduces the required absorber size. This suggests bigger potential reductions for gas than for a coal in this area. There are however risks that the increased hydrogen content in the re-circulated flue gas may have a detrimental impact on the gas turbine performance[19].

The stripper/regenerator is expected to see smaller reductions as there is less scope for economies of scale however the capex requirements here will be more influenced by what happens in terms of the solvents and sorbents used.

There are complex trade-offs between the developments in chemical agents, reaction times, process vessel dimensions, energy requirements and compression needs and the capex and opex costs. As a result of this it is unclear where the cost reductions will fall. Improvements in compression design should reduce energy requirements and so reduce host plant compensation costs, but may or may not lead to significant reductions in compression capex. The same would apply for absorber and strippers.

4.3.1.2 Oxy combustion - coal

The main characteristic of oxy-combustion is the prominence of air separation and CO_2 conditioning costs, which the analysis suggests are also the main drivers of host plant compensation. While there may be some economies of scale benefits we consider the main cost reductions are expected to come from design improvements. These are likely to come from various options for of combining CO_2conditioning and compression - such as in Air Liquide's CPU technology. Looking at air separation alone, there is an expectation in the industry that continuing improvements in cryogenic process should reduce energy requirements. Current state of the art energy requirements are 160-180 kWh/t pure O_2, with the lower end being available through heat integration. Air Liquide is projecting 140kWh by 2015 and 120kWh by 2020. This is still some way from the theoretical limit for cryogenic ASU which is about 50kWh/t. Again, as with compressors and absorbers, it is unclear whether this improvement in performance will come with a significant reduction in capex.

In the longer run the application of new technologies promises to bring deep cost reductions. The two most notable technologies are membrane based air separation and chemical looping. Chemical looping is now deployed outside the UK at small pilot scale (bench scale in UK), while membranes are yet to be deployed at pilot scale[20].

4.3.1.3 IGCC

The special features of IGCC carbon capture in terms of incremental capex are the additional spend on the water shift reactor and acid gas treatment plant. Since this is incremental spend over the reference plant it

[19] Feed gas with high hydrogen content has to date presented a challenge to the major gas turbine manufacturers in terms of combustion temperatures.

[20] These developments have not be explicitly taken into account but their impact will only begin to be felt towards the end of the period covered here.

is quite difficult to determine the incremental cost. In general, it appears that these costs are less than for the comparable special components for post combustion and oxy combustion.

Both water shift and acid gas treatment are complex processes which have evolved over two decades with little indication of cost reduction so it is unclear how the costs for these processes might evolve. Our view is that cost reduction will be less marked than for the other capture routes. The main scope for cost reduction in this capture route is probably in the host plant compensation, where reductions in the host plant capex could play a significant role. If IGCC developers could find a workable hot gas clean technology then this could significantly improve the performance of IGCC and/or lower the capex cost of the host plant, however this has been goal which so far 25 years of R&DD has not yet cracked. In general, it's estimated that IGCC will have a lower energy penalty than other capture routes on coal, however the reference plant capex cost is much higher.

IGCC capture routes should also gain from advances in air separation, through improving the reference plant efficiency and potentially reducing capex, although the gains are likely to be much less than for oxy combustion. Similarly, improvements in gas compression technology will have a less marked impact for IGCC than for post combustion and oxy combustion, given the more modest compression requirements given that the IGCC process runs at high pressure.

4.3.2 Capture costs

The key results to focus on are the specific capex costs, the incremental levelised costs of the capture process and the whole plant generation costs with capture. These are summarised in the tables in Appendix C. Each set of results is addressed in turn below.

4.3.2.1 Specific capex of capture

The projected specific capex costs for capture plant expressed in £/kW net are summarised in Table 4.4 and Figure 4.2. The main points to note are:

- In the absence of any reliable data, these estimates are based on informed judgement and as such must be considered extremely uncertain. The assignment of probability limits should treated as an indication of our subjective level of confidence rather than estimates in a normal statistical practice.
- The low and high cost paths reflects our subjective P80 and P20 estimates, meaning that the two limits define a 60% confidence range, with 20% above the high value (P20) and 20% below the low (P80 – which means 80% above).
- In general there is expected to be a clear long run downward trend in specific capex for all the four capture options considered here.
- We have assumed a spread of initial capex in 2013, which reflects the uncertainty of costs out-turning near the early stage project cost estimates. The spread also represents a subjective 60% confidence level.
- Economies of scale impacts are expected to be moderate in capture on the assumption that the initial unit scale will be near full commercial scale. Later generation plants would probably see slightly larger units and multiple unit configurations, which should together bring some scope for cost saving.
- We expect that oxy combustion will see the deepest reduction, with post combustion gas and coal not far behind, while IGCC sees the least reduction. In the high case the reductions are in the range of 22% to 37% between 2013 and 2040. The corresponding low range is 5%-17% reduction. Note that these cost reduction percentages are calculated with reference to different initial (2013) cost levels.
- All the cost profiles here assume that costs fall period-on-period however, it is very possible that within this 60% confidence band we would see a rise in costs, especially in the initial phase.

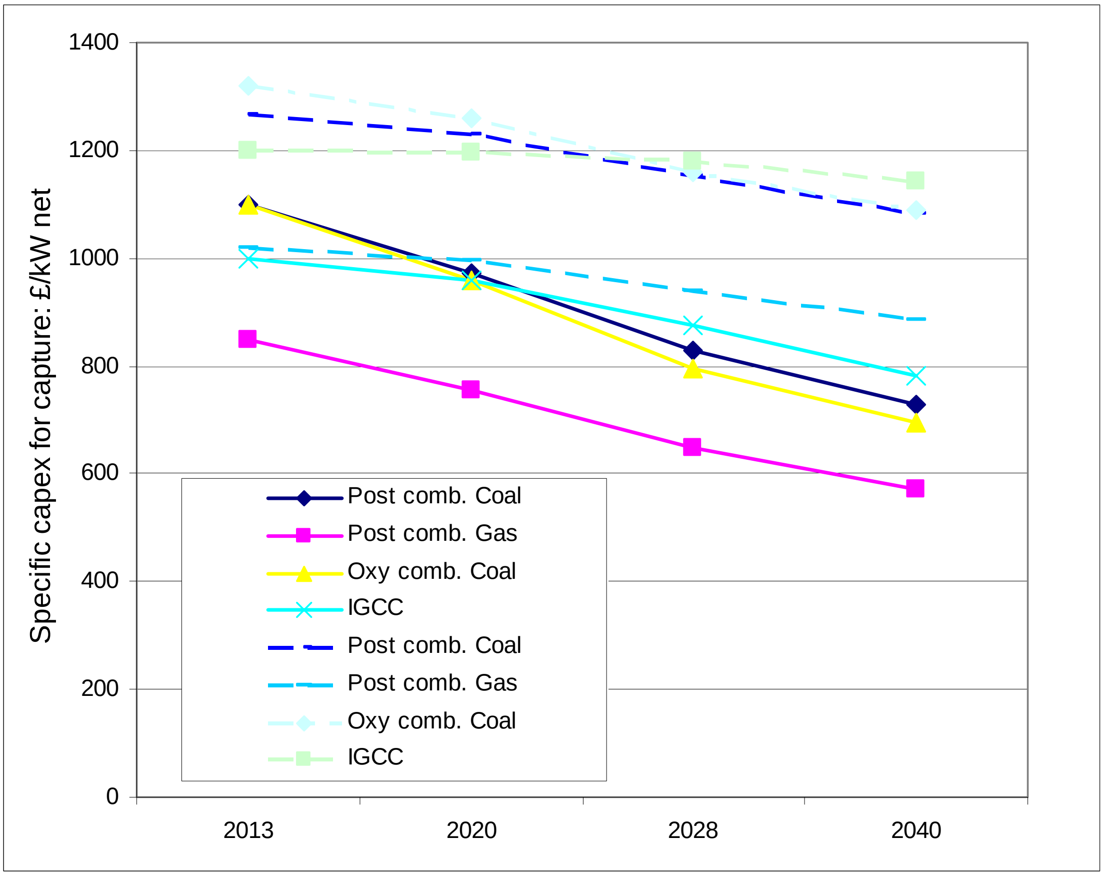
- In terms of components of cost reduction, we project that the deepest percentage reductions will come in host plant compensation as all processes see deep reductions in the energy penalty arising from compression, and other core parts of their process – air separation, gas conditioning, absorption and regeneration and acid gas treatment and H2 turbine designs. In absolute, £/kW terms, the greatest reductions are projected in absorbers, ASU and gas conditioning followed by compressors.

Table 4.4: Projected specific capex for capture in £/kW net

	Specific capex: £/kW				Period-on-period reductions in £/kW		
	2013	**2020**	**2028**	**2040**	**2020**	**2028**	**2040**
Low cost path (P80):							
Post comb. Coal	1241	1103	932	787	138	171	145
Post comb. Gas	813	727	626	543	86	101	83
Oxy comb. Coal	1245	1095	899	755	150	195	145
IGCC	974	906	771	681	68	135	91
High cost path (P20):							
Post comb. Coal	1437	1361	1281	1171	76	80	110
Post comb. Gas	964	943	889	832	21	54	57
Oxy comb. Coal	1486	1400	1286	1176	86	114	110
IGCC	1220	1178	1109	1039	42	68	70
Capture capex includes host plant compensation, but excludes transport and storage							

Source: Mott MacDonald estimates

Figure 4.2: Projected specific capex for capture by technology option



Source: Mott MacDonald estimates

Notes to figure:

Solid lines refer to P80 low cost path; broken lines refer to the P20 high cost path. Note initial 2013 values differ.

4.3.2.2 Uplift in levelised cost of electricity

The above specific capex projections have been used to build up an estimate of the uplift in levelised costs of generation from fitting carbon capture. The key input assumptions here relate to:

- The discount rate and operating life of the plant
- The average annual capacity factor
- The energy penalty (expressed as a percentage) and the capex and fixed operations and maintenance cost of the host plant
- The operating costs of the capture plant, both fixed and variable
- The base plant efficiency and delivered fuel cost which when combined with the energy penalty determine the uplift in energy costs.

The main points to note on these assumptions are:

- A very modest reduction in the base plants capex costs reflecting the fact that most technologies are mature. The host plant capex costs are Mott MacDonald's own estimates but they are close to PB Power's 2011 estimates for DECC for conventional coal and gas, though a little lower for IGCC.
- The strong reduction in energy penalty across all technologies, but with base plant efficiencies assumed constant at 43% for coal and 54% for gas.

- Annual capacity factors are set at constant 80% and 60% for low and high cost paths, respectively. (In practice annual capacity factors might be expected to fall over time)

The main differences between the low and high reduction paths are in the assumed capital cost reductions (and by correlation fixed opex), energy penalties, plant lives and annual capacity factors. Discount rates and fuel prices are kept the same in the two cases. Table 4.5 summarises the key assumptions regarding the capture aspects for the high and low cost paths. We have not conducted a sensitivity analysis here, however it is worth noting that the spread in the annual capacity factor has as a large an impact on costs as the range in specific capex costs.

Table 4.5: Summary of key assumptions regarding capture under low and high cost paths

	2013	2020	2028	2040
Common assumptions				
Delivered fuel price: £/GJ net				
- Coal	3.0	3.0	3.0	3.0
- Gas	7.3	7.3	7.3	7.3
Discount rate - real pre-tax	10%	10%	10%	10%
Main differential assumptions				
Annual capacity factor (ACF)				
- Low cost case	80%	80%	80%	80%
- High cost case	60%	60%	60%	60%
Plant life of capture process: years				
- Low cost path	15	30	30	30
- High cost case	15	20	25	30
Specific capex of capture: £/kW (derived from component build-up - Appendix C)				
Post combustion coal				
- Low cost path	1241	1103	932	787
- High cost case	1437	1361	1281	1171
Post combustion gas				
- Low cost path	813	727	626	545
- High cost case	964	943	889	832
Oxy combustion coal				
- Low cost path	1245	1095	899	755
- High cost case	1486	1400	1286	1176
IGCC coal				
- Low cost path	974	906	771	681
- High cost case	1220	1178	1109	1039
Energy penalty: %				
Post combustion coal				
- Low cost path	25%	23%	18%	13%
- High cost case	26%	24%	22%	18%
Post combustion gas				
- Low cost path	15%	14%	11%	7%
- High cost case	16%	15%	13%	10%
Oxy combustion coal				
- Low cost path	25%	22%	16%	11%

	2013	2020	2028	2040
- High cost case	26%	24%	21%	17%
IGCC coal				
- Low cost path	17%	16%	12%	10%
- High cost case	20%	19%	17%	15%
Source: Mott MacDonald estimates/assumptions				

On the basis of these assumptions the uplift of levelised cost has been estimated and is shown in Table 4.6.

Our analysis suggests that post and oxy combustion coal are seen as the most expensive options with capture levelised costs of £41-62/MWh in 2013, but technologies (especially oxy) are projected to see deep reductions in absolute and relative terms. Post combustion gas, starting from a lower level (£29-42/MWh) shows a less dramatic reduction, but still remains the least cost capture option. IGCC, which is expected to have a lower incremental cost in the near term than the other coal options (at £33-52/MWh), is projected to see a more modest decline than the other options, albeit some improvement on its trend over the last two decades. The post and oxy combustion coal options are projected to see a £16-19/MWh (30-48%) reduction in levelised costs between 2013 and 2040, versus £10-12/MWh (27-43%) for gas and £4-9/MWh (8-29%) for IGCC. Note that the values here cover only 60% of the outcomes. A wider confidence band would include some cases of no real cost reduction as well as some more marked reductions. The results presented here should therefore be treated and used accordingly.

4.3.2.3 Full LCOE of generation and capture

The levelised cost for the whole generation and capture plant (but still excluding transport and storage and any charge for unabated emissions) is shown in Table 4.7. The figures show similar absolute reductions in levelised costs as for the capture-only costs, except in the case of IGCC. The similar position for the pulverised coal and gas plant reflect our assumption that the base generation technologies are mature and therefore their costs should not move markedly, while for IGCC, there is still a reasonable chance of significant cost reduction.

The levelised cost estimates show that capture on gas has a cost advantage over coal expressed in terms of low carbon generation although the advantage is projected to be slim under our low cost path. The analysis here assumes constant prices for gas and coal: with coal priced at about 40% of the gas price. On current March 2012 forward prices gas would have a bigger advantage. However, fuel prices are extremely uncertain Note also highly significant uncertainty attached to these projections for a number of reasons outlined elsewhere in this report. The results should be treated and used accordingly.

Table 4.6: Projected levelised generation costs of the carbon capture component in £/MWh

	Levelised cost: £/MWh				Period-on-period reductions in £/MWh		
Low cost path:	2013	2020	2028	2040	2020	2028	2040
Post comb. Coal	42.3	33.5	28.3	23.7	8.8	5.2	4.6
Post comb. Gas	29.3	23.8	20.2	16.5	5.5	3.5	3.7
Oxy comb. Coal	41.4	32.0	26.0	21.3	9.4	6.0	4.6
IGCC	32.9	28.3	25.2	23.6	4.6	3.2	1.6
High cost path:							
Post comb. Coal	61.3	53.8	48.6	43.0	7.5	5.2	5.6

	Levelised cost: £/MWh				Period-on-period reductions in £/MWh		
Post comb. Gas	42.3	38.4	34.4	30.6	3.9	4.0	3.8
Oxy comb. Coal	61.9	53.9	47.4	41.8	8.0	6.6	5.6
IGCC	51.7	49.6	48.2	47.9	2.1	1.4	0.4
Note: Levelised costs are for capture only including host plant compensation (i.e. incremental costs of capture on generation.							

Source: Mott MacDonald estimates

Table 4.7: Projected levelised cost of generation from whole power plant with capture: £/MWh

	Levelised cost: £/MWh				Period-on-period reductions in £/MWh		
Low cost path:	2013	2020	2028	2040	2020	2028	2040
Post comb. Coal	103.7	92.9	87.7	83.0	10.9	5.2	4.6
Post comb. Gas	91.4	84.5	81.0	77.3	6.9	3.5	3.7
Oxy comb. Coal	102.8	91.4	85.4	80.7	11.5	6.0	4.6
IGCC	108.6	99.8	94.5	90.8	8.8	5.2	3.7
High cost path:							
Post comb. Coal	141.4	130.9	125.8	118.7	10.4	5.2	7.0
Post comb. Gas	110.1	106.2	101.4	97.0	3.9	4.8	4.3
Oxy comb. Coal	142.0	131.1	124.6	117.5	10.9	6.6	7.0
IGCC	157.8	152.7	144.6	139.4	5.1	8.1	4.7
Note: Excludes costs for transport and storage and excludes cost of unabated carbon.							

Source: Mott MacDonald estimates

These cost projections can be compared with three recent studies all published in 2011 by PB Power, ZEP and GCCI and summarised in Table 4.8. It is not possible to have direct comparisons, since the other studies focus on FOAK and NOAK definitions and in different or unspecified timescales. However, it appears that the UK study by PB Power projects a similar percentage reduction in LCOE for capture between FOAK and NOAK[21] as between our 2013 and 2040 projections, with coal achieving significantly deeper reduction than gas. However, the starting levels are less well aligned, as our estimate has a lower LCOE for gas. In contrast, GCCI estimates show virtually no reduction between FOAK and NOAK costs (~2%), however these figures are based on an assumption of existing technologies. The ZEP analysis does not specifically look at the cost reduction process, rather than drivers of costs.

Table 4.8: Levelised cost estimates from PB Power, GGCI and ZEP

LCOE estimates from PB Power, GCCI and ZEP in 2011				
PB Power				
	FOAK 2011 start	NOAK 2017 start	Reduction	%
LCOE excl carbon: £/MWh (2011)				
PC coal	102.6	85.5	17.1	17%
IGCC- coal	129.2	107.2	22	17%
PC gas	102.4	90.7	11.7	11%

[21] Between projected started in 2011 and 2017.

LCOE estimates from PB Power, GCCI and ZEP in 2011				
GCCI				
	FOAK	NOAK	Reduction	%
LCOE excl carbon: $/MWh (2011)				
PC coal	131	129	2	2%
IGCC	123	121	2	2%
PC gas	123	121	2	2%
ZEP				
	Low case	High case		
LCOE excl carbon: €/MWh (2011)				
PC coal	72	87		
PC gas	68	119		
Sources:				
Electricity generation cost model - 2011 update, PB Power, August 2011				
Economic assessment of carbon capture and storage technologies - 2011 update, Global CCS Institute.				
The Costs of CO_2 capture, transport and storage, Zero Emissions Platform, July 2011				

4.4 Transport and storage

4.4.1 Introduction

For transport and storage the costs are largely determined by the investment costs and the extent of fixed cost dilution, which is driven by annual throughput rates and operating lives of assets.

For CO_2 transport we are considering only pipelines in this analysis. It is assumed that successive projects will have higher ratings as sponsors build in spare capacity for further expansion. Also it is assumed that charges to generators are based on amortising pipelines over the economic lifetime of pipelines rather than station lifetimes. In practice, charges for the first user(s) of a pipeline may be considerably more than the levelised cost of asset over its full working life and to the extent this occurs our estimates will be slightly higher (though this is unlikely to be a material difference).

Storage costs mainly relate to the up-front exploration and development costs (of which offshore platforms can be a large component). For storage the relevant lifetime is the injection lifetime, which we have assumed for simplicity is the same as the power plant[22].

4.4.2 Transport

We have assumed a 300 km sub-sea pipeline and 30-80km onshore as our reference case. We have then calculated the total capex for pipeline of 10", 15", 18" and 36" diameter based on initial specific capex figures of £0.77m/km, £0.85m/km, £1.0m/km and £1.25m/km, respectively[23]. The specific capex is projected to fall by 5% between each of our snapshot years – 2013, 2020, 2028 and 2040 – which lead to a 16% real reduction between 2013 and 2040. We have then estimated an annual opex figure based on 2% of the initial capex which we consider is typical for this industry, on the basis that the primary compression

[22] Though there will some costs extending beyond the injection life, due to the need for post-injection monitoring.

[23] These are broadly consistent with ZEP estimates given UK's premium on capital projects versus the EU.

is carried out at the capture site. Onshore capex is assumed to be half of that for offshore on a per km basis (which allows for the additional consent costs and making good costs of onshore pipelines.

Cost reductions come from scale up, which is seen in increased throughputs and extended amortisation terms and operating lives. For our optimistic cost pathway we have assumed the following scale up:

- 2013 – 15" pipeline, rated at 2mt/yr
- 2020 – 18" pipeline, rated at 4mt/yr
- 2028 – 36" pipeline rated at 15mt/yr
- 2040 – 36" pipeline rated at 18mt/yr
- Lifetimes are assumed to be 25 years in 2013 and 40 years thereafter.

For the pessimistic pathway we have assumed a smaller starting scale and more moderate scale up thereafter:

- 2013 – 10" pipeline, rated at 1mt/yr
- 2020 – 15" pipeline, rated at 2mt/yr
- 2028 – 15" pipeline rated at 2mt/yr
- 2040 – 15" pipeline rated at 2.5mt/yr

The same assumptions are applied to the onshore pipeline costs, with the pipeline length assumed to increase from 30km for low throughput cases to 80km in high throughput cases in 2040. Table 4.9 summarises the assumptions on offshore capex.

Table 4.9: Key assumptions regarding offshore pipeline capex

	2013	2020	2028	2040
Specific capex: £m/km				
10"= 1mt/yr	0.77	0.69	0.66	0.63
15"= 2mt/yr	0.85	0.77	0.73	0.69
18" = 4mt/yr	1.00	0.90	0.86	0.81
36"= 16mt/yr	1.25	1.13	1.07	1.02
Total capex: £m (for 300km)				
10"= 1mt/yr	231	207.9	197.5	187.6
15"= 2mt/yr	255	229.5	218.0	207.1
18" = 4mt/yr	300	270	256.5	243.7
36"= 16mt/yr	375	337.5	320.6	304.6
Throughput: mt/yr				
10"= 1mt/yr	1.0	1.0	1.0	1.0
15"= 2mt/yr	2.0	2.0	2.0	2.5
18" = 4mt/yr	2.0	4.0	4.0	5.0
36"= 16mt/yr	2.0	10.0	15.0	18.0
Cost per tonne of capacity: £/t/yr				
10"= 1mt/yr	231.0	207.9	197.5	187.6
15"= 2mt/yr	127.5	114.8	109.0	82.8
18" = 4mt/yr	150.0	67.5	64.1	48.7
36"= 16mt/yr	187.5	33.8	21.4	16.9
Amortisation life: years	25	30	35	40

	2013	2020	2028	2040
Annuitised capex: £/t				
10"= 1mt/yr	25.4	22.1	20.5	19.2
15"= 2mt/yr	**14.1**	12.2	11.3	8.5
18" = 4mt/yr	16.5	**7.2**	6.7	5.0
36"= 16mt/yr	20.7	3.6	**2.2**	**1.7**

Note: Emboldened values are low cost path, underlined show high cost path. In a few cases throughputs in 2040 are assumed to exceed the nominal rated capacities, which reflected transport at slightly elevated pressures. .

Source: Mott MacDonald assumptions

4.4.3 Storage

We have considered two storage options – a depleted oil /gas field (or combination of fields) and a saline aquifer. Both are assumed to be offshore.

The initial costs are based on the estimates for the UK Demo 1 FEED studies and are adjusted for additional site characterisation work (surveying and drilling) for the aquifer. These costs include a substantial "early stage project" premium, which reflects a combination of scale diseconomies and learning premium. ZEP's analysis of storage costs indicated that early stage project costs would be broadly double early commercial level.

We have assumed that as total CO_2 throughput increases over the next decades then specific capex costs per tonne of CO_2 injected per year will fall reflecting this combination of economies of scale (and life extension) and learning. We have assumed that the first storage projects have an injection life of 15 years while by 2020 the life is extended to 25 years and by 2040 its 35 years.

Abandonment costs, which are only incurred at the end of injection period is treated as a discounted value in the same way as nuclear liabilities. This means that as injection lives are extended these abandonment costs decline. These abandonment costs do not include any set aside provision for unscheduled liabilities.

For the early stage projects operations and maintenance costs are assumed to be 6% of the up-front capex (excluding abandonment), which is consistent with the FEED study estimates, however this ratio is projected to lower for later projects with 4% assumed by 2040 (the rate as applied by ZEP).

All of these costs are based on storage in depleted oil and gas fields. For a comparable scale and assuming the same geology, the use of saline aquifers would add premium through increased pre-development and drilling costs.

Overall, our low cost path is broadly in line with the ZEP estimates for early commercial costs – see Table 4.10 and Figure 4.3.

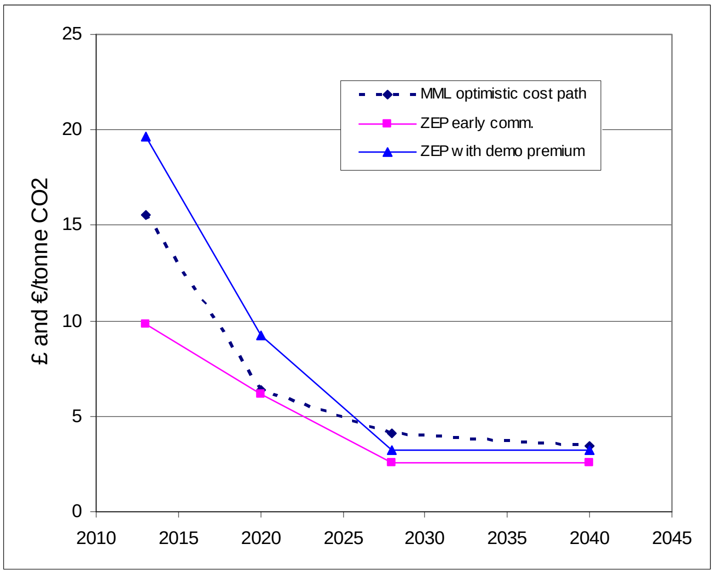
Table 4.10: MML assumptions for CO_2 storage in DOGF based on UK studies versus ZEP assessment

	2013	2020	2028	2040
MML estimates				
£m	265	231	195	166
Mt/yr	2	4	5	5
Life	20	25	30	35
Annuitised capex @10%	31.2	25.4	20.7	17.2

	2013	2020	2028	2040
Annuity £/t/pa	15.6	6.4	4.1	3.4
ZEP early commercial (not arranged in time sequence)				
€m	96	120	127	127
mt/yr	1	2	5	5
Life	40	40	40	40
Annuitised capex @10%	9.8	12.3	13.0	13.0
Annuity £/t/pa	9.8	6.1	2.6	2.6
Early stage project costs derived from ZEP				
Multiplier applied to ZEP early commercial estimate	2	1.5	1.25	1
€m	192	180	158.75	158.75
Mt/yr	1	2	5	5
Life	40	40	40	40
Annuitised capex @10%	19.6	18.4	16.2	16.2
Annuity £/t/pa	19.6	9.2	3.2	3.2

Source: Mott MacDonald assumptions and ZEP carbon storage report 2011

Figure 4.3: MML and ZEP estimates of annuitised capex on a DOGF storage reservoir



Source: Mott MacDonald and ZEP 2011

4.4.4 Levelised costs of transport and storage

4.4.4.1 Transport

The costs of CO_2 transport are clearly dominated by the offshore component, given the longer pipeline lengths and high per km costs. It is the scale in offshore pipelines and transition to network that promises substantial cost reduction. If there is sufficient throughput of CO_2 then it may be possible for a large part of the potential cost reductions to be captured well within a decade. If throughput volumes are constrained then the cost reductions will be small. Under our high cost path levelised costs are projected to fall from an estimated £25/t CO_2 in 2013 to £12/t in 2020, while in the low cost path costs also halve, falling from a lower starting point of £14/t to £7/t – see Table 4.11. The high starting cost for the high case is based on a new 1mt/yr pipeline on and offshore system. Note also highly significant uncertainty attached to these projections for a number of reasons outlined elsewhere in this report. The results should be treated and used accordingly.

Table 4.11: Indicative levelised cost of CO_2 pipeline transport in £/tonne CO_2

	£/t (with capex annuitised)				Period-on-period reductions in £/t		
	2013	**2020**	**2028**	**2040**	**2020**	**2028**	**2040**
Low cost path							
- Offshore Capex	14.0	7.2	2.2	1.7	6.9	4.9	0.5
- Offshore Opex	2.6	1.4	0.4	0.3	1.2	0.9	0.1
- Onshore Capex	0.7	0.6	0.3	0.2	0.1	0.3	0.1
- Onshore Opex	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Total	17.4	9.2	3.0	2.3	8.2	6.2	0.6
High cost path							
- Offshore Capex	25.4	12.2	11.3	8.5	13.3	0.9	2.8
- Offshore Opex	4.6	2.3	2.2	1.7	2.3	0.1	0.5
- Onshore Capex	1.3	0.6	0.6	0.4	0.7	0.0	0.1
- Onshore Opex	0.2	0.1	0.1	0.1	0.1	0.0	0.0
Total	31.5	15.2	14.1	10.6	16.4	1.0	3.5

Source: Mott MacDonald estimates

4.4.4.2 Storage

The projected movement to larger and longer life storage facilities promises to provide the deepest reduction in CCS component costs in the near to medium term. Our cost projects indicate a potential cost reduction of £14-17/t between 2013 and 2020 for DOGF, and a very similar amount for saline aquifers. Most of this reduction is due to economies of scale, although there should be a significant learning effect over this period also. Reductions continue beyond 2020, albeit at a decelerating pace. Note also highly significant uncertainty attached to these projections for a number of reasons outlined elsewhere in this report. The results should be treated and used accordingly.

Table 4.12 shows the projected levelised costs in £/t for both depleted oil and gas fields and saline aquifers.

Table 4.12: Projected indicative levelised costs of storage for DOGF and Saline Aquifer in £/tonne CO_2

	£/t (with capex annuitised)				Period-on-period reductions in £/t		
	2013	2020	2028	2040	2020	2028	2040
Low cost path							
DOGF							
- Capex	15.6	6.4	4.1	3.4	9.2	2.2	0.7
- Opex	8.0	2.9	1.8	1.3	5.1	1.1	0.4
Total	23.5	9.2	5.9	4.8	14.3	3.4	1.1
Saline Aquifer							
- Capex	18.5	7.5	4.8	3.9	11.0	2.8	0.9

	£/t (with capex annuitised)				Period-on-period reductions in £/t		
- Opex	9.5	3.4	2.0	1.5	6.0	1.4	0.5
Total	28.0	11.0	6.8	5.4	17.0	4.2	1.4
High cost path							
DOGF							
- Capex	20.0	10.6	6.9	6.3	9.4	3.8	0.6
- Opex	9.1	2.9	1.8	1.5	6.3	1.1	0.3
Total	29.2	13.5	8.6	7.8	15.7	4.9	0.8
Saline Aquifer							
- Capex	25.5	13.6	8.8	8.1	11.9	4.8	0.7
- Opex	11.6	6.2	3.9	3.2	5.5	2.3	0.7
Total	37.1	19.7	12.7	11.2	17.4	7.1	1.4

Source: Mott MacDonald estimates

4.4.4.3 Transport and storage combined

Table 4.13 shows the high and low path cost projections for transport and storage combined.

Table 4.13: Projected indicative levelised cost of transport and storage in £(2011) a tonne CO_2

	£/t (with capex annuitised)				Period-on-period reductions in £/t		
	2013	2020	2028	2040	2020	2028	2040
Low cost path							
DOGF	40.9	18.4	8.9	7.1	22.5	9.6	1.8
Saline Aquifer	42.0	18.1	9.0	7.1	23.9	9.1	1.9
High cost path							
DOGF	60.7	28.7	22.8	18.4	32.0	5.9	4.3
Saline Aquifer	68.6	34.9	26.8	21.8	33.7	8.1	4.9
Implied cost at coal and gas plant							
Coal plant @ 0.9t CO_2/MWh							
Low cost path							
DOGF	36.8	16.6	8.0	6.1	20.2	8.6	1.6
Saline Aquifer	37.8	16.3	8.1	6.4	21.5	8.2	1.7
High cost path							
DOGF	54.6	25.8	20.5	16.6	28.8	5.3	3.9
Saline Aquifer	61.7	31.4	24.1	19.7	30.4	7.3	4.4
Gas plant @ 0.38t CO_2/MWh							
Low cost path							
DOGF	15.6	7.0	3.4	2.7	8.5	3.6	0.7
Saline Aquifer	16.0	6.9	3.4	2.7	9.1	3.5	0.7
High cost path							
DOGF	23.1	10.9	8.7	7.0	12.2	2.3	1.7
Saline Aquifer	26.1	13.3	10.2	8.3	12.8	3.1	1.9

Source: Mott MacDonald estimates

4.5 Full chain costs

The analysis above suggests that there is a good prospect of a significant reduction in the full chain costs of CCS, with a significant part of the reduction potentially accessible in the early years if transport and storage economies of scale can be exploited. The coal technologies are projected to see a much bigger absolute reduction than gas – £29-£40/MWh versus £15-16/MWh in the 2013-2020 period (where the dates refer to orders not commissioning). The rate of reduction slows beyond 2020, however, a similar absolute reduction is projected between 2020 and 2040. Despite coal's deeper cost reduction potential, the levelised generation cost of gas is projected to remain significantly lower, although the differential becomes small by 2040. The differential versus oxy combustion and post combustion coal would be wiped out if DECC high fuel price assumptions were used, rather than the central case.

In terms of levels, under the low cost path almost all the technologies see their full chain costs fall below the £100/MWh level – see Figure 4.4. Under the more conservative high cost path only post combustion gas sees its costs approaching £100/MWh towards the end of the period (2040) in this analysis.

These costs exclude the cost of unabated carbon emission, which for a given capture rate would be expected to increase significantly over time, especially after 2020, under the proposed carbon price support.

The analysis indicates that transport and storage provides more than half of the reduction in costs for coal options, with slightly greater contribution in the early to medium term. For gas, transport and storage provides a little less than half of the reduction. By the end of the period, for both gas and coal, capture gains are projected to exceed those for transport and storage.

There is little difference between the three coal technology options in terms of absolute reductions. They all have the same in transport and storage gains, as it is unclear which of the three technologies will offer the best improvement in station efficiency. Our view is that on our central 60% confidence band oxy combustion has a slight edge over post combustion coal, while IGCC is slightly below post combustion.

It should be noted that these levelised cost estimates refer to the total electricity produced from the generation plant and is not adjusted for the proportion of emissions that are avoided through the application of CCS. The implication is that if the focus is on clean (carbon free) generation the costs need to be scaled up by around 10-15% to take account of the 85-90% capture rate for a true comparison with other low carbon generation options. Also, we need to be conscious that such unadjusted costing approach is appropriate as long as the capture rates are close between the technologies. The alternative would be to factor in a charge for residual carbon emissions.

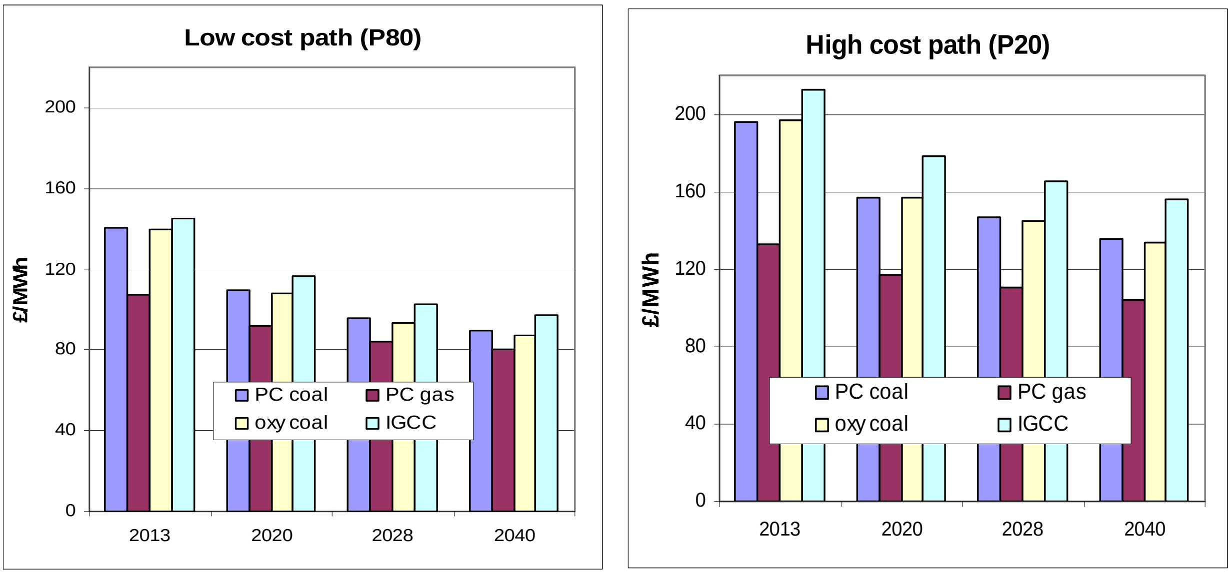
Table 4.14: Projected LCOE for full chain CCS (excluding carbon costs) in £//MWh

	2013	2020	2028	2040
Low cost path				
PC coal	140.6	109.4	95.7	89.4
PC gas	107.0	91.5	84.4	80.0
oxy coal	139.7	108.0	93.3	87.1
IGCC	145.4	116.4	102.5	97.2
High cost path				
PC coal	196.0	156.8	146.3	135.3

	2013	2020	2028	2040
PC gas	133.2	117.1	110.0	104.0
oxy coal	196.6	156.9	145.0	134.1
IGCC	212.5	178.5	165.1	156.0

Source: Mott MacDonald estimates

Figure 4.4: Development of full chain levelised costs estimates of electricity under low and high cost paths



Note: Estimates based on subjective P20 and P80 probability levels

Source: Mott MacDonald estimates

4.6 Conclusions of cost reduction exercise

Any cost reduction assessment is an exercise in judgements since there is no reliable and applicable data of previous deployment or obvious comparators. The assessment here has sought to provide a bottom up techno-economic assessment – still effectively judgemental based – on a central band of outcomes, which we have described as a subjective 60% confidence interval (defined by the P20 and P80 levels).

This is not a meta-analysis, so we have been selective in our references and where possible we have tried to benchmark against UK specific projects based on FEED studies and other confidential project studies, although there are very large discrepancies within the latter group.

Noting the caveats, about uncertainty, the main conclusion of the cost projection exercise at this stage in the development of CCS is that the biggest and most easily exploitable reductions are available from economies of scale benefits from a well designed integrated transport and storage network that allows sharing of pipelines and linking of multiple storage facilities. These scale benefits will only be realisable if there is sufficient throughput of CO_2. Even so an appropriately located transport hub could in principle transport 8-10mt/yr of CO_2 by the late 2020s. This is equivalent to 2GW of 85% abated coal plant or 5GW of CCGTs. The gains from improving capture systems are important and could contribute a broadly equal benefit, however, they are likely to be harder to achieve as this depends more on the successful application of learning by doing. All this requires a substantial rollout of CCS eventually of the order several GW a year of capacity. On this basis our central case potential reduction for LCOE is of the order of about one third. If one takes a broad confidence band the range of cost paths would be very wide, probably with cases of little or no real reduction by 2040, even based on reasonably high deployment levels. The extreme low cost paths are capped by the fact that the underlying base plant costs is unlikely to fall very significantly as the technologies are essentially mature.

5. Conclusions

This chapter summarises the key findings of the assessment of the scope for cost reduction and outlines the implications for government intervention in promoting commercialisation of CCS.

The first and most important conclusion is that until we have a working commercial scale full chain CCS project running in the UK or similar jurisdiction we have huge uncertainty regarding the performance and outturn costs of CCS. The most detailed FEED studies provide an indication but are often case specific and perhaps not the most likely to be replicated.

There is an important difference between the front and back end of the CCS chain. The capture part presents a major technical challenge as it has not been done at scale. Transport and storage of CO_2, though also not done at the necessary scale to date have the benefits of decades of applicable experience from the oil and gas sector. There is reasonably high confidence that an integrated transport and storage network could be deployed that would capture major economies of a scale. This promises the biggest contribution to cost reduction for CCS in due course.

For the capture side, it is difficult - if not impossible - to make cost projections on a bottom-up basis with a high level of confidence. The top down – ie learning curve approach - probably provides a better means of setting upper and lower bands, although determining the initial level of deployment from which to start the learning presents a major challenge.

The bottom-up engineering cost approach presents other challenges. Knowing where the key technology innovation areas are is useful, although it is not possible to confidently predict that performance improvements (such as reduced energy penalties) from various key components will be matched by capex cost reductions – equipment costs (or more importantly prices) could even increase, if there is not strong competition among equipment and service suppliers.

In the end we can recognise some areas where innovation in capture could bring cost reduction in the near to medium term. The most likely areas, in a indicative hierarchy of significance are:

- Compressor advances – energy penalty benefits for all options
- Air separation advances – energy penalty benefits for oxy combustion and to a lesser extent IGCC[24]
- Improved solvents and sorbents – resulting in smaller absorbers, lower energy penalties for post combustion
- Gas recirculation for post combustion gas – reduced absorber size and lower energy penalties
- Economies of scale in absorbers – for post combustion
- Improvements in construction logistics from learning and advanced simulations – for all options
- Process optimisation for all technology routes
- Reduced design margins for all systems

As mentioned above, these innovations relate to the capture stage of CCS. Innovation in the transport and storage components of the chain is not expected to play as substantial role in driving costs down. However, there are a few areas where advances could play a significant role most notably in storage, through application of novel oil and gas technology (eg advanced wells, geological characterisation to identify injection performance), optimisation of storage system design, wells and subsurface utilisation and novel MMV (measuring, monitoring and verification) technologies.

[24] IGCC would however also gain cost reductions in the reference plant.

This analysis is both highly subjective and as yet not tested on the developer and contractor community. This therefore very much represents an initial view which can be refined as more relevant data becomes available.

Appendices

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Appendix A. Abbreviations

ACF	annual capacity factor
ASU	Air separation unit
BOP	balance of plant
capex	capital expenditure
CC	Carbon capture
CCGT	Combined cycle gas turbine (gas power station)
CHP	combined heat and power
CO_2	Carbon Dioxide
comb.	combustion
CPF	Carbon price floor
DOGF	Depleted oil and gas reservoir
EOR	enhanced oil recovery
EPC	engineering procurement and construction
FEED	front end engineering design
FGD	Flue gas desulphurisation
FID	final investment decision
FOAK	first-of-a-kind (as in early commercial deployment)
FOM	fixed operations and maintenance (cost)
GT	gas turbine
HHV	high heating value
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle (usually using coal feedstock)
IPCC	Intergovernmental Panel on Climate Change
LCOE	levelised cost of electricity (generated)
MML	Mott MacDonald
MMV	monitoring, metering and verification
mt	million tonnes
NER-300	EU's own CCS competition to be funded from sale of 300m emission allowances from the New Entrant Reserve
NGO	non-governmental organisations
NOAK	Nth-of-a-kind (as in mature technology)
OEM	original equipment manufacturers
opex	operational expenditure
P80 and P20	Levels at which 80% and 20% of the distribution of values are exceeded
PB	Parsons Brinkhoff
PC	post combustion
R&D	research and development
SCR	Selective catalytic reduction
VOM	variable operations and maintenance (cost)
WACC	weighted cost of capital
yr	year
ZEP	Zero emission platform

Appendix B. Bibliography

Title	Date	Author/ Publisher
The Costs of CO_2 Storage	2011	ZEP
The Costs of CO_2 Transport	2011	ZEP
Cost and Performance of Carbon Dioxide Capture from Power Generation	2011	M. Finkenrath/ International Energy Agency
Economic Assessment of Carbon Capture and Storage Technologies	2011	WorleyParsons/ Global CCS Institute
Cost assessment of fossil power plants equipped with CCS under typical scenarios	2011	C. Bohtz/ Alstom
UK Carbon Capture and Storage Demonstration Competition	2011	Scottish Power CCS Consortium
Bridge to a Lower Cost of Clean Energy	2011	PB Power
The Impact of Clean Energy Innovation	2011	Google
First UK CCS Demonstration Competition Front End Engineering Design (Feed) Studies	2011	DECC
The Costs of CO_2 Capture	2011	European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP)
Electricity Generation Cost Model - 2011 Update	2011	PB Power/ DECC
Costs of low carbon technologies	2011	Mott MacDonald/ CCC
World Energy Outlook, 2011	2011	International Energy Agency
International Energy Outlook - 2011	2011	Energy Information Administration
Final Scientific/Technical Report	2010	K. Bower/ConocoPhillips Sweny IGCC/CCS Project
UK electricity Generation Costs Update, 2010	2010	Mott MacDonald/ DECC
Carbon dioxide capture and storage (CCS) technologies	2010	M. van der Broek
Potential application of CCS to UK industry and natural gas power sectors	2010	Element Energy
Carbon Capture: a technology assessment	2010	Peter Folgor/ Congressional Research Service
Prospect for improved carbon capture technology	2010	E Rubin et al/ Carnegie Mellon University
Developing a CCS network in the Tees Valley region	2010	Element Energy/ One North East & NEPIC
Realistic costs of carbon capture	2009	Al Juaied and A Whitmore/ Harvard Kennedy School
Factors affecting the cost of capture for Australian lignite coal fired power plants	2008	G.W. Allinson/ Elsevier
Costs and performance of fossil fuiel power plants with CO_2 capture and storage	2008	E Rubin et al
Carbon capture and storage: assessing the economics	2008	McKinsey / Vattenfal

Techno-economic analysis of natural gas combines circles with post-combustion CO_2absorption, including a detailed evaluation of the development potential	2007	A.N.M. Peeters et al
Use of experience curves to estimate the future costs of power plant with CO_2 capture	2007	E Rubin et al/ Carnegie Mellon University

Appendix C. CCS cost projections

This appendix provides selected tables showing key assumptions and summary results from MML's CCS cost projection model. The tables include:

1. Build-up of the specific capex of capture and incremental levelised cost of electricity for capture – for post-combustion coal, post-combustion gas, oxy combustion coal and IGCC coal (12 tables)
2. Summary of specific capex and levelised costs of capture by capture option
3. Breakdown of incremental levelised costs by capture option
4. Projected capex and opex for offshore and onshore pipelines
5. Summary of transport and storage costs
6. Full chain CCS levelised costs
7. Build-up of reference plant levelised costs for post-combustion coal, post-combustion gas, oxy-combustion coal and IGCC coal (4 tables).

As noted throughout this report, there is huge uncertainty in any exercise projecting costs associated with a new technology significantly into the future. This uncertainty must be recognised when drawing conclusions or using the results of this study for further work.

Table C.1: An extract of the build-up of the specific capex of capture – for post-combustion - coal

Low cost path - Build-up of capex of capture process for post combustion coal: £/kW							
	Near term		**Ordered 2013**				
	technology component						
Technology component	Dev.etc	Absorbers	Regen.	Compres.	Host plant	BoP	Total
First demo ordered	67	350	125	216	375	108	1241
	Medium term		**Ordered 2020**				
Technology component	Dev.etc	Absorbers	Regen.	Compres.	Host plant	BoP	
	63	304	113	203	322	98	1103
Technology advancement - design	3%	3%	3%	2%		3%	16%
Technology advancement - materials		1%	1%				3%
Optimised construction logistics		3%	2%	0%		2%	10%
Economies of scale		5%	2%	2%			16%
Reduced design margins		1%	1%	1%		3%	7%
Product standardisation	1%						0%
Increased competition							0%
Input price reduction							0%
System integration/ optimisation	1%	1%	1%	1%		2%	6%
Reduction on previous period: %	4.9%	13.3%	9.6%	5.9%	14.1%	9.6%	11.1%
Reduction on 2013 level	4.9%	13.3%	9.6%	5.9%	14.1%	9.6%	11.1%
	Long term		**Ordered 2028**				
Technology component	Dev.etc	Absorbers	Regen.	Compres.	Host plant	BoP	Total
	60	256	97	180	252	87	932
Technology advancement - design	3%	4%	4%	5%		3%	16%
Technology advancement - materials		3%	2%	1%		2%	8%
Optimised construction logistics		2%	2%	0%		2%	5%
Economies of scale		2%	2%	2%			6%
Reduced design margins		1%	1%			1%	3%
Product standardisation	1%						0%
Increased competition		2%	1%	2%		1%	6%
Input price reduction		1%	1%	1%			3%
System integration/ optimisation	1%	2%	2%	1%		2%	7%
Reduction on previous period: %	4.9%	15.8%	14.1%	11.5%	21.7%	10.5%	15.5%
Reduction on 2013 level	9.6%	27.0%	22.3%	16.7%	32.8%	19.1%	24.9%
	Very long term		**Ordered 2040**				
Technology component	Dev.etc	Absorbers	Regen.	Compres.	Host plant	BoP	Total
	57	226	88	158	182	77	787
Technology advancement - design	4%	4%	3%	4%		2%	15%
Technology advancement - materials		1%	1%	1%		2%	4%
Optimised construction logistics		1%	1%	0%		2%	3%
Economies of scale		0%	0%	0%		0%	0%
Reduced design margins		1%	1%	1%		1%	4%
Product standardisation	1%	1%	1%	2%		2%	6%
Increased competition		2%	2%	3%		1%	8%
Input price reduction		1%	1%	1%		1%	4%
System integration/ optimisation	1%	1%		1%		2%	4%
Reduction on previous period: %	5.9%	11.4%	9.6%	12.3%	27.8%	12.3%	15.6%
Reduction on 2013 level	15.0%	35.3%	29.8%	27.0%	51.5%	29.1%	36.6%

Source: Mott MacDonald estimates

High cost path - Build-up of capex of capture process for post combustion coal: £/kW							
	Near term		**Ordered 2013**				
	technology component						
Technology component	Dev.etc	Absorbers	Regen.	Compres.	Host plant	BoP	Total
First demo ordered	77	403	144	248	442	124	1437
	Medium term		order 2020				
Technology component	Dev.etc	Absorbers	Regen.	Compres.	Host plant	BoP	
	77	398	141	239	384	123	1361
Technology advancement - design	0%	0%	0%	0%		1%	1%
Technology advancement - materials		1%	1%				3%
Optimised construction logistics		-1%	-1%	0%		-1%	-4%
Economies of scale		2%	1%	2%			8%
Reduced design margins		-1%	0%	1%		0%	-1%
Product standardisation	0%	-1%					-2%
Increased competition							0%
Input price reduction							0%
System integration/ optimisation		1%	1%	1%		1%	5%
Reduction on previous period: %	0.0%	1.0%	2.0%	4.0%	13.1%	1.0%	5.3%
Reduction on 2013 level	0.0%	1.0%	2.0%	4.0%	13.1%	1.0%	5.3%
	Long term		**Ordered 2028**				
Technology component	Dev.etc	Absorbers	Regen.	Compres.	Host plant	BoP	Total
	74	375	133	229	352	118	1281
Technology advancement - design	3%	0%	0%	1%		1%	3%
Technology advancement - materials		1%	1%	1%		1%	4%
Optimised construction logistics		1%	1%	0%		1%	3%
Economies of scale		2%	2%	1%			5%
Reduced design margins		1%	1%			0%	2%
Product standardisation							0%
Increased competition		0%	0%	0%		0%	0%
Input price reduction		0%	0%	0%			0%
System integration/ optimisation		1%	1%	1%		1%	4%
Reduction on previous period: %	3.0%	5.9%	5.9%	3.9%	8.3%	3.9%	5.9%
Reduction on 2013 level	3.0%	6.8%	7.7%	7.7%	20.4%	4.9%	10.9%
	Very long term		**Ordered 2040**				
Technology component	Dev.etc	Absorbers	Regen.	Compres.	Host plant	BoP	Total
	71	353	127	220	288	111	1171
Technology advancement - design	4%	1%	1%	1%		1%	5%
Technology advancement - materials		1%	0%	0%		1%	2%
Optimised construction logistics		1%	1%	0%		2%	3%
Economies of scale		0%	0%	0%		0%	0%
Reduced design margins		1%	1%	1%		0%	3%
Product standardisation		1%	1%	1%		0%	3%
Increased competition		0%	0%	0%		0%	0%
Input price reduction		0%	0%	0%		1%	1%
System integration/ optimisation		1%		1%		1%	3%
Reduction on previous period: %	4.0%	5.9%	3.9%	3.9%	18.2%	5.9%	8.6%
Reduction on 2013 level	6.9%	12.3%	11.4%	11.4%	34.8%	10.5%	18.5%

Source: Mott MacDonald estimates

Table C.2: Build-up of incremental LCOE capture only – for capture only

Build-up of incremental LCOE capture only: £/MWh				
Specific capex build-up: £/kW				
Low cost path	**2013**	**2020**	**2028**	**2040**
Dev.etc	67	63	60	57
Absorbers	350	304	256	226
Regen.	125	113	97	88
Compres.	216	203	180	158
Host plant	375	322	252	182
BoP	108	98	87	77
High costpath	**2013**	**2020**	**2028**	**2040**
Dev.etc	77	77	74	71
Absorbers	403	398	375	353
Regen.	144	141	133	127
Compres.	248	239	229	220
Host plant	442	384	352	288
BoP	124	123	118	111
Specific capex: £/kW				
Low	1241	1103	932	787
High	1437	1361	1281	1171
ACF				
Low	80%	80%	80%	80%
High	60%	60%	60%	60%
WACC				
Low	10%	10%	10%	10%
High	10%	10%	10%	10%
Plant life				
Low	15	30	30	30
High	15	20	25	30
Levelised capex: £/MWh				
Low	27	19	16	14
High	41	35	31	27
FOM: £/kW/yr @2.5% of capex (includes share of FOM from host plant)				
Low	40	36	30	24
High	47	44	41	36
FOM: £/MWh				
Low	5.8	5.1	4.2	3.5
High	8.9	8.3	7.8	6.9
VOM: £/MWh				
Low	3.0	3.0	3.0	3.0
High	4.0	4.0	4.0	4.0
Total non fuel cost: £/MWh				
Low	36	27	23	20
High	54	47	43	38
Energy penalty: %				
Low	25%	23%	18%	13%
High	26%	24%	22%	18%
Energy cost: £/GJ net				
Low	3.0	3.0	3.0	3.0
High	3.0	3.0	3.0	3.0
Energy penalty: £/MWh (based 40% ref)				
Low	6.8	6.2	4.9	3.5
High	7.0	6.5	5.9	4.9
Total incremental CC cost: £/MWh				
Low	42	33	28	24
High	61	54	49	43
Component breakdown: £/MWh				
	2013	**2020**	**2028**	**2040**
Low cost path				
Capture own fixed costs	18.7	13.6	11.8	10.5
Capture FOM	3.1	2.8	2.4	2.2
Host plant comp	10.8	7.9	6.2	4.5
Variable cost	9.8	9.2	7.9	6.5
	42.3	33.5	28.3	23.7
High cost path				
Capture own fixed costs	28.6	25.1	22.4	20.5
Capture FOM	4.7	4.6	4.4	4.2
Host plant comp	16.9	13.5	11.8	9.4
Variable cost	11.0	10.5	9.9	8.9
	61.3	53.8	48.6	43.0

Source: : Mott MacDonald estimates

Table C.3: An extract of the build-up of the specific capex of capture – for gas post-combustion

Low cost path - Build-up of capex of capture process for post combustion gas: £/kW							
	Near term technology component		**Ordered 2013**				
Technology component	Dev.etc	Absorbers	Regen.	Compres.	Host plant	BoP	Total
First demo ordered	55	310	120	150	83	95	813
	Medium term		**Ordered 2020**				
Technology component	Dev.etc	Absorbers	Regen.	Compres.	Host plant	BoP	
	52	269	108	141	70	86	727
Technology advancement - design	3%	3%	3%	2%		3%	21%
Technology advancement - materials		1%	1%				4%
Optimised construction logistics		3%	2%	0%		2%	14%
Economies of scale		5%	2%	2%			21%
Reduced design margins		1%	1%	1%		3%	9%
Product standardisation	1%						1%
Increased competition							0%
Input price reduction							0%
System integration/ optimisation	1%	1%	1%	1%		2%	9%
Reduction on previous period: %	4.9%	13.3%	9.6%	5.9%	15.2%	9.6%	10.6%
Reduction on 2013 level	4.9%	13.3%	9.6%	5.9%	15.2%	9.6%	10.6%
	Long term		**Ordered 2028**				
Technology component	Dev.etc	Absorbers	Regen.	Compres.	Host plant	BoP	Total
	50	226	93	125	55	77	626
Technology advancement - design	3%	4%	4%	5%		3%	23%
Technology advancement - materials		3%	2%	1%		2%	11%
Optimised construction logistics		2%	2%	0%		2%	8%
Economies of scale		2%	2%	2%			9%
Reduced design margins		1%	1%			1%	4%
Product standardisation	1%						0%
Increased competition		2%	1%	2%		1%	9%
Input price reduction		1%	1%	1%			4%
System integration/ optimisation	1%	2%	2%	1%		2%	10%
Reduction on previous period: %	4.9%	15.8%	14.1%	11.5%	21.4%	10.5%	13.8%
Reduction on 2013 level	9.6%	27.0%	22.3%	16.7%	33.3%	19.1%	22.9%
	Very long term		**Ordered 2040**				
Technology component	Dev.etc	Absorbers	Regen.	Compres.	Host plant	BoP	Total
	47	200	84	110	35	67	543
Technology advancement - design	4%	4%	3%	4%		2%	22%
Technology advancement - materials		1%	1%	1%		2%	6%
Optimised construction logistics		1%	1%	0%		2%	5%
Economies of scale		0%	0%	0%		0%	0%
Reduced design margins		1%	1%	1%		1%	6%
Product standardisation	1%	1%	1%	2%		2%	8%
Increased competition		2%	2%	3%		1%	12%
Input price reduction		1%	1%	1%		1%	6%
System integration/ optimisation	1%	1%		1%		2%	6%
Reduction on previous period: %	5.9%	11.4%	9.6%	12.3%	36.4%	12.3%	13.2%
Reduction on 2013 level	15.0%	35.3%	29.8%	27.0%	57.6%	29.1%	33.1%

Mott MacDonald estimates

High cost path - Build-up of capex of capture process for post combustion gas: £/kW							
	Near term		**Ordered 2013**				
	technology component						
Technology component	Dev.etc	Absorbers	Regen.	Compres.	Host plant	BoP	Total
First demo ordered	66	372	144	180	88	114	964
	Medium term		Ordered 2020				
Technology component	Dev.etc	Absorbers	Regen.	Compres.	Host plant	BoP	
	66	368	141	173	83	113	943
Technology advancement - design	0%	0%	0%	0%		1%	1%
Technology advancement - materials		1%	1%				4%
Optimised construction logistics		-1%	-1%	0%		-1%	-5%
Economies of scale		2%	1%	2%			11%
Reduced design margins		-1%	0%	1%		0%	-1%
Product standardisation	0%	-1%					-3%
Increased competition							0%
Input price reduction							0%
System integration/ optimisation		1%	1%	1%		1%	7%
Reduction on previous period: %	0.0%	1.0%	2.0%	4.0%	6.3%	1.0%	2.1%
Reduction on 2013 level	0.0%	1.0%	2.0%	4.0%	6.3%	1.0%	2.1%
	Long term		**Ordered 2028**				
Technology component	Dev.etc	Absorbers	Regen.	Compres.	Host plant	BoP	Total
	64	347	133	166	72	108	889
Technology advancement - design	3%	0%	0%	1%		1%	3%
Technology advancement - materials		1%	1%	1%		1%	5%
Optimised construction logistics		1%	1%	0%		1%	4%
Economies of scale		2%	2%	1%			8%
Reduced design margins		1%	1%			0%	3%
Product standardisation							0%
Increased competition		0%	0%	0%		0%	0%
Input price reduction		0%	0%	0%			0%
System integration/ optimisation		1%	1%	1%		1%	5%
Reduction on previous period: %	3.0%	5.9%	5.9%	3.9%	13.3%	3.9%	5.7%
Reduction on 2013 level	3.0%	6.8%	7.7%	7.7%	18.8%	4.9%	7.7%
	Very long term		**Ordered 2040**				
Technology component	Dev.etc	Absorbers	Regen.	Compres.	Host plant	BoP	Total
	61	326	128	160	55	102	832
Technology advancement - design	4%	1%	1%	1%		1%	8%
Technology advancement - materials		1%	0%	0%		1%	3%
Optimised construction logistics		1%	1%	0%		2%	5%
Economies of scale		0%	0%	0%		0%	0%
Reduced design margins		1%	1%	1%		0%	5%
Product standardisation		1%	1%	1%		0%	5%
Increased competition		0%	0%	0%		0%	0%
Input price reduction		0%	0%	0%		1%	1%
System integration/ optimisation		1%		1%		1%	5%
Reduction on previous period: %	4.0%	5.9%	3.9%	3.9%	23.1%	5.9%	6.5%
Reduction on 2013 level	6.9%	12.3%	11.4%	11.4%	37.5%	10.5%	13.7%

Source: Mott MacDonald estimates

Table C.4: Build up of incremental LCOE capture only – Gas – post combustion

Build-up of incremental LCOE capture only: £/MWh				
Build-up of specific capture capex: £/kW				
Low cost path	**2013**	**2020**	**2028**	**2040**
Dev.etc	55	52	50	47
Absorbers	310	269	226	200
Regen.	120	108	93	84
Compres.	150	141	125	110
Host plant	83	70	55	35
BoP	95	86	77	67
High cost path	**2013**	**2020**	**2028**	**2040**
Dev.etc	66	66	64	61
Absorbers	372	368	347	326
Regen.	144	141	133	128
Compres.	180	173	166	160
Host plant	88	83	72	55
BoP	114	113	108	102
Specific capex: £/kW				
Low	813	727	626	543
High	964	943	889	832
ACF				
Low	80%	80%	80%	80%
High	60%	60%	60%	60%
WACC				
Low	10%	10%	10%	10%
High	10%	10%	10%	10%
Plant life				
Low	15	30	30	30
High	15	20	25	30
Levelised capex: £/MWh				
Low	17	12	10	9
High	27	23	21	18
FOM: £/kW/yr @2.5% of capex (includes share of FOM from host plant)				
Low	22	20	17	14
High	26	26	24	22
FOM: £/MWh				
Low	3	3	2	2
High	5	5	5	4
VOM: £/MWh				
Low	2	2	2	2
High	3	3	3	3
Total non fuel cost: £/MWh				
Low	22	17	15	13
High	35	31	28	26
Energy penalty: %				
Low	15%	14%	11%	7%
High	16%	15%	13%	10%
Energy cost: £/GJ net				
Low	7.3	7.3	7.3	7.3
High	7.3	7.3	7.3	7.3
Energy penalty: £/MWh (based 54% ref)				
Low	7.3	6.8	5.4	3.4
High	7.8	7.3	6.3	4.9
Total incremental CC cost: £/MWh				
Low	29	24	20	17
High	42	38	34	31
Component breakdown: £/MWh				
	2013	**2020**	**2028**	**2040**
Low cost path				
Capture own fixed costs	15.1	10.9	9.5	8.5
Capture FOM	2.6	2.3	2.0	1.8
Host plant comp	2.3	1.7	1.3	0.8
Variable cost	9.3	8.8	7.4	5.4
	29.3	23.8	20.2	16.5
High cost path				
Capture own fixed costs	24.1	21.2	18.9	17.2
Capture FOM	4.2	4.1	3.9	3.7
Host plant comp	3.3	2.8	2.3	1.7
Variable cost	10.8	10.3	9.3	7.9
	42.3	38.4	34.4	30.6

Source: Mott MacDonald estimates

Table C.5: An extract of the build-up of the specific capex of capture – for oxy – combustion - coal

Low cost path - Build-up of capex of capture process for oxy combustion coal: £/kW							
	Near term technology component		**order 2013**				
Technology component	Dev.etc	Air Sep.	Conditioning	Compres.	Host plant	BoP	Total
First demo ordered	67	280	200	216	375	107	1245
	Medium term		**order 2020**				
Technology component	Dev.etc	Air Sep.	Conditioning	compres.	host plant	BoP	
	63	243	181	203	308	97	1095
Technology advancement - design	3%	3%	3%	2%		3%	14%
Technology advancement - materials		1%	1%				3%
Optimised construction logistics		3%	2%	0%		2%	9%
Economies of scale		5%	2%	2%			13%
Reduced design margins		1%	1%	1%		3%	6%
Product standardisation	1%						0%
Increased competition							0%
Input price reduction							0%
System integration/ optimisation	1%	1%	1%	1%		2%	6%
Reduction on previous period: %	4.9%	13.3%	9.6%	5.9%	17.9%	9.6%	12.0%
Reduction on 2013 level	4.9%	13.3%	9.6%	5.9%	17.9%	9.6%	12.0%
	Long term		**order 2028**				
Technology component	Dev.etc	Air Sep.	Conditioning	Compres.	Host plant	BoP	Total
	60	200	152	176	224	87	899
Technology advancement - design	3%	4%	5%	5%		3%	15%
Technology advancement - materials		4%	2%	1%		2%	7%
Optimised construction logistics		2%	2%	1%		2%	5%
Economies of scale		2%	2%	2%			5%
Reduced design margins		1%	1%			1%	2%
Product standardisation	1%						0%
Increased competition		3%	2%	3%		1%	8%
Input price reduction		1%	1%	1%			3%
System integration/ optimisation	1%	2%	2%	1%		2%	6%
Reduction on previous period: %	4.9%	17.5%	15.8%	13.3%	27.3%	10.5%	17.9%
Reduction on 2013 level	9.6%	28.5%	23.9%	18.3%	40.3%	19.1%	27.7%
	Very long term		**order 2040**				
Technology component	Dev.etc	Air Sep.	Conditioning	Compres.	Host plant	BoP	Total
	57	177	136	155	154	76	755
Technology advancement - design	4%	4%	4%	4%		2%	16%
Technology advancement - materials		1%	1%	1%		2%	4%
Optimised construction logistics		1%	1%	0%		2%	3%
Economies of scale		0%	0%	0%		0%	0%
Reduced design margins		1%	1%	1%		1%	4%
Product standardisation	1%	1%	1%	2%		2%	6%
Increased competition		2%	2%	3%		1%	8%
Input price reduction		1%	1%	1%		1%	4%
System integration/ optimisation	1%	1%		1%		2%	4%
Reduction on previous period: %	5.9%	11.4%	10.5%	12.3%	31.3%	12.3%	16.1%
Reduction on 2013 level	15.0%	36.7%	31.9%	28.4%	58.9%	29.1%	39.4%

Source: Mott MacDonald estimates

High cost path - Build-up of capex of capture process for oxy combustion coal: £/kW

	Near term		**order 2013**				
	technology component						
Technology component	Dev.etc	Air Sep.	Conditioning	Compres.	Host plant	BoP	Total
First demo ordered	80	336	240	259	442	128	1486
	Medium term		order 2020				
Technology component	Dev.etc	Air Sep.	Conditioning	compres.	host plant	BoP	
	80	329	233	246	384	127	1400
Technology advancement - design	0%	1%	1%	1%		1%	5%
Technology advancement - materials		1%	1%				3%
Optimised construction logistics		-1%	-1%	0%		-1%	-3%
Economies of scale		2%	1%	2%			7%
Reduced design margins		-1%	0%	1%		0%	0%
Product standardisation	0%	-1%					-2%
Increased competition							0%
Input price reduction							0%
System integration/ optimisation		1%	1%	1%		1%	5%
Reduction on previous period: %	0.0%	2.0%	3.0%	4.9%	13.1%	1.0%	5.8%
Reduction on 2013 level	0.0%	2.0%	3.0%	4.9%	13.1%	1.0%	5.8%
	Long term		**order 2028**				
Technology component	Dev.etc	Air Sep.	Conditioning	Compres.	Host plant	BoP	Total
	78	301	213	237	336	122	1286
Technology advancement - design	3%	2%	2%	1%		1%	6%
Technology advancement - materials		1%	1%	1%		1%	3%
Optimised construction logistics		1%	1%	0%		1%	2%
Economies of scale		2%	2%	1%			5%
Reduced design margins		1%	1%			0%	2%
Product standardisation							0%
Increased competition		0%	0%	0%		0%	0%
Input price reduction		0%	0%	0%			0%
System integration/ optimisation		2%	2%	1%		1%	5%
Reduction on previous period: %	3.0%	8.7%	8.7%	3.9%	12.5%	3.9%	8.1%
Reduction on 2013 level	3.0%	10.5%	11.4%	8.7%	24.0%	4.9%	13.5%
	Very long term		**order 2040**				
Technology component	Dev.etc	Air Sep.	Conditioning	Compres.	Host plant	BoP	Total
	74	283	204	227	272	115	1176
Technology advancement - design	4%	1%	1%	1%		1%	5%
Technology advancement - materials		1%	0%	0%		1%	2%
Optimised construction logistics		1%	1%	0%		2%	3%
Economies of scale		0%	0%	0%		0%	0%
Reduced design margins		1%	1%	1%		0%	3%
Product standardisation		1%	1%	1%		0%	3%
Increased competition		0%	0%	0%		0%	0%
Input price reduction		0%	0%	0%		1%	1%
System integration/ optimisation		1%		1%		1%	3%
Reduction on previous period: %	4.0%	5.9%	3.9%	3.9%	19.0%	5.9%	8.5%
Reduction on 2013 level	6.9%	15.8%	14.9%	12.3%	38.5%	10.5%	20.8%

Source: Mott MacDonald estimates

Table C.6: Build up of incremental LCOE capture only – Oxy combustion - coal

Build-up of incremental LCOE capture only: £/MWh				
Specific capex build-up: £/kW				
Low cost path	**2013**	**2020**	**2028**	**2040**
Dev.etc	67	63	60	57
Air Sep.	280	243	200	177
Conditioning	200	181	152	136
Compres.	216	203	176	155
Host plant	375	308	224	154
BoP	107	97	87	76
High cost path	**2013**	**2020**	**2028**	**2040**
Dev.etc	80	80	78	74
Air Sep.	336	329	301	283
Conditioning	240	233	213	204
Compres.	259	246	237	227
Host plant	442	384	336	272
BoP	128	127	122	115
Specific capex: £/kW				
Low	1245	1095	899	755
High	1486	1400	1286	1176
ACF				
Low	80%	80%	80%	80%
High	60%	60%	60%	60%
WACC				
Low	10%	10%	10%	10%
High	10%	10%	10%	10%
Plant life				
Low	15	30	30	30
High	15	20	25	30
Levelised capex: £/MWh				
Low	£27	£19	£16	£13
High	£43	£36	£31	£27
FOM: £/kW/yr @2.5% of capex (includes share of FOM from host plant)				
Low	40	35	28	23
High	48	45	41	36
FOM: £/MWh				
Low	6	5	4	3
High	9	8	8	7
VOM: £/MWh				
Low	2	2	2	2
High	3	3	3	3
Total non fuel cost: £/MWh				
Low	35	26	22	18
High	55	47	42	37
Energy penalty: %				
Low	25%	22%	16%	11%
High	26%	24%	21%	17%
Energy cost: £/GJ net				
Low	3	3	3	3
High	3	3	3	3
Energy penalty: £/MWh (based 40% ref)				
Low	6.8	5.9	4.3	3.0
High	7.0	6.5	5.7	4.6
Total incremental CC cost: £/MWh				
Low	41	32	26	21
High	62	54	47	42
Component breakdown: £/MWh				
	2013	**2020**	**2028**	**2040**
Low cost path				
Capture own fixed costs	18.8	13.7	11.8	10.5
Capture FOM	3.1	2.8	2.4	2.1
Host plant comp	10.8	7.6	5.5	3.8
Variable cost	8.8	7.9	6.3	5.0
	41.4	32.0	26.0	21.3
High cost path				
Capture own fixed costs	30.0	26.1	22.9	21.0
Capture FOM	5.0	4.8	4.5	4.3
Host plant comp	16.9	13.5	11.3	8.9
Variable cost	10.0	9.5	8.7	7.6
	61.9	53.9	47.4	41.8

Source: Mott MacDonald estimates

Table C.7: An extract of the build-up of the specific capex of capture – for IGCC- coal

Low cost path - Build-up of capex of capture process for IGCC coal: £/kW							
	Near term		**Ordered 2013**				
	technology component						
Technology component	Dev.etc	Water shift	Conditioning	Compres.	Host plant	BoP	Total
First demo ordered	60	200	160	80	374	100	974
	Medium term		**Ordered 2020**				
Technology component	Dev.etc	Water shift	Conditioning	Compres.	Host plant	BoP	
	59	198	155	78	320	96	906
Technology advancement - design	1%	0%	1%	0%		1%	5%
Technology advancement - materials		0%	0%				0%
Optimised construction logistics		0%	0%	0%		1%	1%
Economies of scale		0%	1%	1%			3%
Reduced design margins		0%	0%	1%		1%	3%
Product standardisation	0%						0%
Increased competition							0%
Input price reduction							0%
System integration/ optimisation		1%	1%	1%		1%	8%
Reduction on previous period: %	1.0%	1.0%	3.0%	3.0%	14.4%	3.9%	6.9%
Reduction on 2013 level	1.0%	1.0%	3.0%	3.0%	14.4%	3.9%	6.9%
	Long term		**Ordered 2028**				
Technology component	Dev.etc	Water shift	Conditioning	Compres.	Host plant	BoP	Total
	58	183	140	72	228	90	771
Technology advancement - design	3%	1%	1%	1%		1%	5%
Technology advancement - materials		1%	1%	1%		1%	4%
Optimised construction logistics		1%	2%	0%		1%	4%
Economies of scale		1%	1%	2%			3%
Reduced design margins		1%	1%			1%	3%
Product standardisation							0%
Increased competition		1%	1%	1%		1%	4%
Input price reduction		1%	1%	1%			3%
System integration/ optimisation		1%	2%	1%		1%	5%
Reduction on previous period: %	3.0%	7.7%	9.6%	6.8%	28.8%	5.9%	14.9%
Reduction on 2013 level	4.0%	8.6%	12.3%	9.6%	39.0%	9.6%	20.8%
	Very long term		**Ordered 2040**				
Technology component	Dev.etc	Water shift	Conditioning	Compres.	Host plant	BoP	Total
	56	165	131	65	180	83	681
Technology advancement - design	2%	1%	1%	2%		1%	7%
Technology advancement - materials		2%	1%	1%		1%	7%
Optimised construction logistics		1%	1%	0%		2%	5%
Economies of scale		0%	0%	0%		0%	0%
Reduced design margins		2%	1%	1%		1%	7%
Product standardisation		1%	1%	2%		1%	6%
Increased competition		1%	1%	2%		1%	6%
Input price reduction		1%	1%	1%		1%	5%
System integration/ optimisation		1%		1%		1%	3%
Reduction on previous period: %	2.0%	9.6%	6.8%	9.6%	21.1%	8.7%	11.8%
Reduction on 2013 level	5.9%	17.4%	18.2%	18.2%	51.9%	17.4%	30.1%

Source: Mott MacDonald estimates

High cost path - Build-up of capex of capture process for IGCC coal: £/kW							
	Near term		**Ordered 2013**				
	technology component						
Technology component	Dev.etc	Water shift	Conditioning	Compres.	Host plant	BoP	Total
First demo ordered	72	240	192	96	500	120	1220
	Medium term		Ordered 2013				
Technology component	Dev.etc	Water shift	Conditioning	Compres.	Host plant	BoP	
	72	242	192	94	456	121	1178
Technology advancement - design	0%	0%	1%	0%		0%	2%
Technology advancement - materials		-1%	-1%				-5%
Optimised construction logistics		-1%	-1%	0%		-1%	-7%
Economies of scale		1%	1%	1%			6%
Reduced design margins		0%	0%	1%		0%	1%
Product standardisation	0%	0%					0%
Increased competition							0%
Input price reduction							0%
System integration/ optimisation		0%	0%	0%		0%	0%
Reduction on previous period: %	0.0%	-1.0%	0.0%	2.0%	8.8%	-1.0%	3.5%
Reduction on 2013 level	0.0%	-1.0%	0.0%	2.0%	8.8%	-1.0%	3.5%
	Long term		**Ordered 2028**				
Technology component	Dev.etc	Water shift	Conditioning	Compres.	Host plant	BoP	Total
	71	242	192	94	391	119	1109
Technology advancement - design	1%	0%	-1%	-1%		0%	-1%
Technology advancement - materials		-1%	-1%	0%		0%	-2%
Optimised construction logistics		0%	1%	0%		1%	2%
Economies of scale		1%	1%	1%			3%
Reduced design margins		0%	0%			1%	1%
Product standardisation							0%
Increased competition		0%	0%	0%		0%	0%
Input price reduction		0%	0%	0%			0%
System integration/ optimisation		0%	0%	0%		0%	0%
Reduction on previous period: %	1.0%	0.0%	0.0%	0.0%	14.3%	2.0%	5.8%
Reduction on 2013 level	1.0%	-1.0%	0.0%	2.0%	21.8%	1.0%	9.1%
	Very long term		**Ordered 2040**				
Technology component	Dev.etc	Water shift	Conditioning	Compres.	Host plant	BoP	Total
	71	238	188	94	330	119	1039
Technology advancement - design	1%	0%	0%	0%		0%	1%
Technology advancement - materials		1%	1%	0%		0%	3%
Optimised construction logistics		1%	1%	0%		0%	3%
Economies of scale		0%	0%	0%		0%	0%
Reduced design margins		0%	0%	0%		0%	0%
Product standardisation		0%	0%	0%		0%	0%
Increased competition		0%	0%	0%		0%	0%
Input price reduction		0%	0%	0%		0%	0%
System integration/ optimisation		0%		0%		0%	0%
Reduction on previous period: %	1.0%	2.0%	2.0%	0.0%	15.6%	0.0%	6.3%
Reduction on 2013 level	2.0%	1.0%	2.0%	2.0%	34.0%	1.0%	14.8%

Source: Mott MacDonald estimates

Table C.8: Build up of incremental LCOE capture only – IGCC -

Build-up of incremental LCOE capture only: £/MWh				
Specific capex build-up: £/kW				
Low cost path	**2013**	**2020**	**2028**	**2040**
Dev.etc	60	59	58	56
Water shift	200	198	183	165
Conditioning	160	155	140	131
Compres.	80	78	72	65
Host plant	374	320	228	180
BoP	100	96	90	83
High cost path	**2013**	**2020**	**2028**	**2040**
Dev.etc	72	72	71	71
Water shift	240	242	242	238
Conditioning	192	192	192	188
Compres.	96	94	94	94
Host plant	500	456	391	330
BoP	120	121	119	119
Specific capex: £/kW				
Low	974	906	771	681
High	1220	1178	1109	1039
ACF				
Low	80%	75%	70%	65%
High	60%	55%	50%	45%
WACC				
Low	10%	10%	10%	10%
High	10%	10%	10%	10%
Plant life				
Low	15	30	30	30
High	15	20	25	30
Levelised capex: £/MWh				
Low	21	17	15	15
High	35	33	32	32
FOM: £/kW/yr @2.5% of capex (includes share of FOM from host plant)				
Low	33.7	30.7	25.0	21.5
High	43.0	40.8	37.5	34.2
FOM: £/MWh				
Low	4.8	4.7	4.1	3.8
High	8.2	8.5	8.6	8.7
VOM: £/MWh				
Low	2.5	2.5	2.5	2.5
High	3	3	3	3
Total non fuel cost: £/MWh				
Low	28	24	22	21
High	46	44	44	44
Energy penalty: %				
Low	17%	16%	12%	10%
High	20%	19%	17%	15%
Energy cost: £/GJ net				
Low	3	3	3	3
High	3	3	3	3
Energy penalty: £/MWh (based 40% ref)				
Low	4.6	4.3	3.2	2.7
High	5.4	5.1	4.6	4.1
Total incremental CC cost: £/MWh				
Low	33	28	25	24
High	52	50	48	48
Component breakdown: £/MWh				
	2013	**2020**	**2028**	**2040**
Low cost path				
Capture own fixed costs	12.9	10.9	10.8	10.7
Capture FOM	2.1	2.2	2.2	2.2
Host plant comp	10.7	8.4	6.4	5.4
Variable cost	7.1	6.8	5.7	5.2
	32.9	28.3	25.2	23.6
High cost path				
Capture own fixed costs	20.7	20.2	20.8	21.9
Capture FOM	3.4	3.7	4.1	4.5
Host plant comp	19.1	17.5	15.8	14.4
Variable cost	8.4	8.1	7.6	7.1
	51.7	49.6	48.2	47.9

coal

Source: Mott MacDonald estimates

Table C.9: Summary of specific capex and levelised costs of capture by capture option

Specific capex: £/kW					**Period-on-period reductions in £/kW**				
Low cost path:	**2013**	**2020**	**2028**	**2040**	**2020**	**2028**	**2040**	Absolute reduction	% reduction 2040 on 2013
Post comb. Coal	1241	1103	932	787	138	171	145	453	37%
Post comb. Gas	813	727	626	543	86	101	83	269	33%
Oxy comb. Coal	1245	1095	899	755	150	195	145	490	39%
IGCC	974	906	771	681	68	135	91	293	30%
High cost path:	**2013**	**2020**	**2028**	**2040**					
Post comb. Coal	1437	1361	1281	1171	76	80	110	266	19%
Post comb. Gas	964	943	889	832	21	54	57	132	14%
Oxy comb. Coal	1486	1400	1286	1176	86	114	110	309	21%
IGCC	1220	1178	1109	1039	42	68	70	181	15%
Levelised cost of carbon capture component in £/MWh					**Period-on-period reductions in £/MWh**				
Low cost path:	**2013**	**2020**	**2028**	**2040**	**2020**	**2028**	**2040**	Absolute reduction	% reduction 2040 on 2013
Post comb. Coal	42.3	33.5	28.3	23.7	8.8	5.2	4.6	18.6	44%
Post comb. Gas	29.3	23.8	20.2	16.5	5.5	3.5	3.7	12.7	44%
Oxy comb. Coal	41.4	32.0	26.0	21.3	9.4	6.0	4.6	20.0	48%
IGCC	32.9	28.3	25.2	23.6	4.6	3.2	1.6	9.4	28%
High cost path:	**2013**	**2020**	**2028**	**2040**					
Post comb. Coal	61.3	53.8	48.6	43.0	7.5	5.2	5.6	18.3	30%
Post comb. Gas	42.3	38.4	34.4	30.6	3.9	4.0	3.8	11.8	28%
Oxy comb. Coal	61.9	53.9	47.4	41.8	8.0	6.6	5.6	20.1	33%
IGCC	51.7	49.6	48.2	47.9	2.1	1.4	0.4	3.8	7%
Levelised cost of whole power plant with carbon capture in £/MWh					**Period-on-period reductions in £/MWh**				
Low cost path:	**2013**	**2020**	**2028**	**2040**	**2020**	**2028**	**2040**	Absolute reduction	% reduction 2040 on 2013
Post comb. Coal	103.7	92.9	87.7	83.0	10.9	5.2	4.6	20.7	20%
Post comb. Gas	91.4	84.5	81.0	77.3	6.9	3.5	3.7	14.1	15%
Oxy comb. Coal	102.8	91.4	85.4	80.7	11.5	6.0	4.6	22.1	22%
IGCC	108.6	99.8	94.5	90.8	8.8	5.2	3.7	17.7	16%
High cost path:	**2013**	**2020**	**2028**	**2040**					
Post comb. Coal	141.4	130.9	125.8	118.7	10.4	5.2	7.0	22.6	16%
Post comb. Gas	110.1	106.2	101.4	97.0	3.9	4.8	4.3	13.1	12%
Oxy comb. Coal	142.0	131.1	124.6	117.5	10.9	6.6	7.0	24.5	17%
IGCC	157.8	152.7	144.6	139.4	5.1	8.1	5.2	18.4	12%

Note: Excludes cost of carbon emissions, assumes DECC's central fuel price projection, 10% discount rate

Source: Mott MacDonald estimates

Table C.10: Breakdown of incremental levelised costs by capture option

Breakdown of incremental levelised costs: £/MWh					Period-on-period reductions: £/MWh				
Low cost path	**2013**	**2020**	**2028**	**2040**	**2020**	**2028**	**2040**	Total reduction	% reduction 2040/ 2013
Post comb. Coal									
Capture own fixed costs	18.7	13.6	11.8	10.5	5.1	1.8	1.3	8.1	44%
Capture FOM	3.1	2.8	2.4	2.2	0.3	0.4	0.3	0.9	30%
Host plant comp	10.8	7.9	6.2	4.5	2.9	1.7	1.7	6.3	59%
Variable cost	9.8	9.2	7.9	6.5	0.5	1.4	1.4	3.2	33%
Total	**42.3**	**33.5**	**28.3**	**23.7**	**8.8**	**5.2**	**4.6**	**18.6**	**44%**
Post comb. Gas									
Capture own fixed costs	15.1	10.9	9.5	8.5	4.1	1.4	1.0	6.6	44%
Capture FOM	2.6	2.3	2.0	1.8	0.3	0.3	0.2	0.8	30%
Host plant comp	2.3	1.7	1.3	0.8	0.6	0.4	0.5	1.5	64%
Variable cost	9.3	8.8	7.4	5.4	0.5	1.5	1.9	3.9	42%
Total	**29.3**	**23.8**	**20.2**	**16.5**	**5.5**	**3.5**	**3.7**	**12.7**	**44%**
Oxy comb. Coal									
Capture own fixed costs	18.8	13.7	11.8	10.5	5.1	1.9	1.3	8.3	44%
Capture FOM	3.1	2.8	2.4	2.1	0.3	0.4	0.3	1.0	31%
Host plant comp	10.8	7.6	5.5	3.8	3.2	2.1	1.7	7.0	65%
Variable cost	8.8	7.9	6.3	5.0	0.8	1.6	1.4	3.8	43%
Total	**41.4**	**32.0**	**26.0**	**21.3**	**9.4**	**6.0**	**4.6**	**20.0**	**48%**
IGCC									
Capture own fixed costs	12.9	10.9	10.8	10.7	2.1	0.1	0.1	2.2	17%
Capture FOM	2.1	2.2	2.2	2.2	-0.1	0.0	0.0	-0.1	-3%
Host plant comp	10.7	8.4	6.4	5.4	2.4	2.0	1.0	5.3	49%
Variable cost	7.1	6.8	5.7	5.2	0.3	1.1	0.5	1.9	27%
Total	**32.9**	**28.3**	**25.2**	**23.6**	**4.6**	**3.2**	**1.6**	**9.4**	**28%**
High cost path									
Post comb. Coal									
Capture own fixed costs	28.6	25.1	22.4	20.5	3.5	2.7	1.9	8.1	28%
Capture FOM	4.7	4.6	4.4	4.2	0.1	0.2	0.2	0.5	11%
Host plant comp	16.9	13.5	11.8	9.4	3.4	1.7	2.4	7.5	44%
Variable cost	11.0	10.5	9.9	8.9	0.5	0.5	1.1	2.2	20%
Total	61.3	53.8	48.6	43.0	7.5	5.2	5.6	18.3	30%
Post comb. Gas									
Capture own fixed costs	24.1	21.2	18.9	17.2	2.9	2.3	1.6	6.9	28%
Capture FOM	4.2	4.1	3.9	3.7	0.1	0.2	0.2	0.5	11%
Host plant comp	3.3	2.8	2.3	1.7	0.4	0.5	0.6	1.5	46%
Variable cost	10.8	10.3	9.3	7.9	0.5	1.0	1.5	2.9	27%
Total	42.3	38.4	34.4	30.6	3.9	4.0	3.8	11.8	28%
Oxy comb. Coal									
Capture own fixed costs	30.0	26.1	22.9	21.0	3.9	3.2	1.9	9.0	30%
Capture FOM	5.0	4.8	4.5	4.3	0.1	0.3	0.2	0.7	13%
Host plant comp	16.9	13.5	11.3	8.9	3.4	2.2	2.4	8.0	47%
Variable cost	10.0	9.5	8.7	7.6	0.5	0.8	1.1	2.4	24%
Total	61.9	53.9	47.4	41.8	8.0	6.6	5.6	20.1	33%
IGCC									
Capture own fixed costs	20.7	20.2	20.8	21.9	0.5	-0.5	-1.2	-1.2	-6%
Capture FOM	3.4	3.7	4.1	4.5	-0.3	-0.4	-0.4	-1.1	-31%
Host plant comp	19.1	17.5	15.8	14.4	1.6	1.7	1.4	4.7	25%
Variable cost	8.4	8.1	7.6	7.1	0.3	0.5	0.5	1.4	16%
Total	51.7	49.6	48.2	47.9	2.1	1.4	0.4	3.8	7%

Note: Excludes cost of carbon emissions, assumes DECC's central fuel price projection, 10% discount rate

Source: Mott MacDonald estimates

Table C.11: Projected capex and opex for offshore and onshore pipelines

Capex cost in £m for a 300km sub-sea pipeline					
	2013	**2020**	**2028**	**2040**	
£m/km					
10"= 1mt/yr	0.77	0.69	0.66	0.63	10% reduction 2020 on 2013, 5% for each period thereafter
15"= 2mt/yr	0.85	0.77	0.73	0.69	ditto
18" = 4mt/yr	1	0.90	0.86	0.81	ditto
36"= 16mt/yr	1.25	1.13	1.07	1.02	ditto
£m for 300km					
10"= 1mt/yr	231	207.9	197.5	187.6	
15"= 2mt/yr	255	229.5	218.0	207.1	
18" = 4mt/yr	300	270	256.5	243.7	
36"= 16mt/yr	375	337.5	320.6	304.6	
Throughput: mt/yr					
10"= 1mt/yr	1.0	1.0	1.0	1.0	
15"= 2mt/yr	2.0	2.0	2.0	2.5	
18" = 4mt/yr	2.0	4.0	4.0	5.0	
36"= 16mt/yr	2.0	10.0	15.0	18.0	
£/t/yr					
10"= 1mt/yr	231.0	207.9	197.5	187.6	
15"= 2mt/yr	127.5	114.8	109.0	82.8	
18" = 4mt/yr	150.0	67.5	64.1	48.7	
36"= 16mt/yr	187.5	33.8	21.4	16.9	
Amortisation life: years	25	30	35	40	
Annuitised capex: £/t					
10"= 1mt/yr	**25.4**	22.1	20.5	19.2	
15"= 2mt/yr	**14.0**	12.2	11.3	8.5	orange shows pessimistic cost path
18" = 4mt/yr	16.5	**7.2**	6.6	5.0	
36"= 16mt/yr	20.7	3.6	**2.2**	**1.7**	green shows optimistic path

Capex cost in £m for an Onshore pipeline					
£/km *	**2013**	**2020**	**2028**	**2040**	
10"= 1mt/yr	0.39	0.35	0.33	0.31	assumes onshore is 50% of offshore costs
15"= 2mt/yr	0.43	0.38	0.36	0.35	No allowance for consenting costs
18" = 4mt/yr	0.50	0.45	0.43	0.41	
36"= 16mt/yr	0.63	0.56	0.53	0.51	
Av. pipeline length: km					
10"= 1mt/yr	30	30	30	30	
15"= 2mt/yr	30	30	30	30	
18" = 4mt/yr	40	50	50	50	
36"= 16mt/yr	50	80	80	80	
£m	**2013**	**2020**	**2028**	**2040**	
10"= 1mt/yr	11.6	10.4	9.9	9.4	
15"= 2mt/yr	12.8	11.5	10.9	10.4	
18" = 4mt/yr	20.0	22.5	21.4	20.3	
36"= 16mt/yr	31.3	45.0	42.8	40.6	
Throughput: mt/yr	**2013**	**2020**	**2028**	**2040**	
10"= 1mt/yr	1.0	1.0	1.0	1.0	
15"= 2mt/yr	2.0	2.0	2.0	2.5	
18" = 4mt/yr	2.0	4.0	4.0	5.0	
36"= 16mt/yr	2.0	10.0	15.0	18.0	
£/t/yr	**2013**	**2020**	**2028**	**2040**	
10"= 1mt/yr	11.6	10.4	9.9	9.4	

15"= 2mt/yr	6.4	5.7	5.5	4.1	
18" = 4mt/yr	10.0	5.6	5.3	4.1	
36"= 16mt/yr	15.6	4.5	2.9	2.3	
Annuitised capex: £/t	**2013**	**2020**	**2028**	**2040**	
10"= 1mt/yr	**1.27**	**1.10**	1.02	0.96	
15"= 2mt/yr	**0.70**	**0.61**	0.57	0.42	Pessimistic
18" = 4mt/yr	1.10	0.60	**0.55**	0.42	
36"= 16mt/yr	1.72	0.48	0.30	**0.23**	Optimistic path shown by green cells
Amortisation life: years	25	30	35	40	
Annual opex for pipelines					
Offshore @2% of initial capex					
10"= 1mt/yr	4.62	4.16	3.95	3.75	
15"= 2mt/yr	2.55	2.30	2.18	1.66	Pessimistic
18" = 4mt/yr	3.00	1.35	1.28	0.97	
36"= 16mt/yr	3.75	0.68	0.43	0.34	Optimistic path shown by green cells
Onshore @1.5% of initial capex					
10"= 1mt/yr	0.17	0.16	0.15	0.14	
15"= 2mt/yr	0.10	0.09	0.08	0.06	Pessimistic
18" = 4mt/yr	0.15	0.08	0.08	0.06	
36"= 16mt/yr	0.23	0.07	0.04	0.03	Optimistic path shown by green cells

Source: Mott MacDonald estimates

Mott MacDonald

Table C.12: Summary of transport and storage costs

	£/t (with capex annuitised)				Period-on-period reductions in £/t			Period-on-period reductions: %		
	2013	**2020**	**2028**	**2040**	**2020**	**2028**	**2040**	**2020**	**2028**	**2040**
STORAGE										
Optimistic										
DOGF										
- Capex	15.6	6.4	4.1	3.4	9.2	2.2	0.7	59%	35%	17%
- Opex	8.0	2.9	1.8	1.3	5.1	1.1	0.4	64%	39%	25%
Total	23.5	9.2	5.9	4.8	14.3	3.4	1.1	61%	36%	19%
Saline Aquifer										
- Capex	18.5	7.5	4.8	3.9	11.0	2.8	0.9	59%	37%	18%
- Opex	9.5	3.4	2.0	1.5	6.0	1.4	0.5	64%	41%	26%
Total	28.0	11.0	6.8	5.4	17.0	4.2	1.4	61%	38%	20%
Pessimistic										
DOGF										
- Capex	20.0	10.6	6.9	6.3	9.4	3.8	0.6	47%	35%	8%
- Opex	9.1	2.9	1.8	1.5	6.3	1.1	0.3	68%	39%	15%
Total	29.2	13.5	8.6	7.8	15.7	4.9	0.8	54%	36%	10%
Saline Aquifer										
- Capex	25.5	13.6	8.8	8.1	11.9	4.8	0.7	47%	35%	8%
- Opex	11.6	6.2	3.9	3.2	5.5	2.3	0.7	47%	37%	18%
Total	37.1	19.7	12.7	11.2	17.4	7.1	1.4	47%	36%	11%
	£/t (with capex annuitised)				**Period-on-period reductions in £/t**			**Period-on-period reductions: %**		
	2013	**2020**	**2028**	**2040**	**2020**	**2028**	**2040**	**2020**	**2028**	**2040**
TRANSPORT										
Optimistic										
- Offshore Capex	14.0	7.2	2.2	1.7	6.9	4.9	0.5	49%	69%	22%
- Offshore Opex	2.6	1.4	0.4	0.3	1.2	0.9	0.1	47%	68%	21%
- Onshore Capex	0.7	0.6	0.3	0.2	0.1	0.3	0.1	15%	50%	22%
- Onshore Opex	0.1	0.1	0.0	0.0	0.0	0.0	0.0	12%	49%	21%
Total	17.4	9.2	3.0	2.3	8.2	6.2	0.6	47%	68%	22%
Pessimistic										
- Offshore Capex	25.4	12.2	11.3	8.5	13.3	0.9	2.8	52%	7%	25%
- Offshore Opex	4.6	2.3	2.2	1.7	2.3	0.1	0.5	50%	5%	24%
- Onshore Capex	1.3	0.6	0.6	0.4	0.7	0.0	0.1	52%	7%	25%
- Onshore Opex	0.2	0.1	0.1	0.1	0.1	0.0	0.0	50%	5%	24%
Total	31.5	15.2	14.1	10.6	16.4	1.0	3.5	52%	7%	25%
TRANSPORT & STORAGE COMBINED										
	£/t (with capex annuitised)				**Period-on-period reductions in £/t**			**Period-on-period reductions: %**		
	2013	**2020**	**2028**	**2040**	**2020**	**2028**	**2040**	**2020**	**2028**	**2040**
Optimistic										
DOGF	40.9	18.4	8.9	7.1	22.5	9.6	1.8	55%	52%	20%
Saline Aquifer	42.0	18.1	9.0	7.1	23.9	9.1	1.9	57%	50%	21%
Pessimistic										
DOGF	54.6	25.7	19.9	16.3	28.9	5.8	3.7	53%	22%	18%
Saline Aquifer	68.6	34.9	26.8	21.8	33.7	8.1	4.9	49%	23%	18%
IMPLIED COST OF T&S AT COAL AND GAS PLANT: £/MWh										

Coal plant @ 0.9t CO2/MWh	£/MWh (with capex annuitised)				Period-on-period reductions in £/MWh			Period-on-period reductions: %		
	2013	2020	2028	2040	2020	2028	2040	2020	2028	2040
Optimistic										
DOGF	36.8	16.6	8.0	6.4	20.2	8.6	1.6	55%	52%	20%
Saline Aquifer	37.8	16.3	8.1	6.4	21.5	8.2	1.7	57%	50%	21%
Pessimistic										
DOGF	49.2	23.1	17.9	14.7	26.0	5.2	3.3	53%	22%	18%
Saline Aquifer	61.7	31.4	24.1	19.7	30.4	7.3	4.4	49%	23%	18%
Gas plant @ 0.38t CO2/MWh										
Optimistic										
DOGF	15.6	7.0	3.4	2.7	8.54	3.64	0.68	55%	52%	20%
Saline Aquifer	16.0	6.9	3.4	2.7	9.08	3.47	0.71	57%	50%	21%
Pessimistic										
DOGF	20.8	9.8	7.6	6.2	11.00	2.19	1.39	53%	22%	18%
Saline Aquifer	26.1	13.3	10.2	8.3	12.82	3.08	1.88	49%	23%	18%

Source: Mott MacDonald estimates

Table C.13: Full chain CCS levelised costs

Full chain CCS levelised cost of electricity									
			- - - - - - - - - - £/MWh - - - - - - - - -			Period-on-period reductions in £/MWh			
Low cost path:		2013	2020	2028	2040	2020	2028	2040	Total
Coal PC	Capture	103.7	92.9	87.7	83.0	10.9	5.2	4.6	20.7
	T&S	36.8	16.6	8.0	6.4	20.2	8.6	1.6	30.5
	Total	140.6	109.4	95.7	89.4	31.1	13.8	6.2	51.2
Gas PC	Capture	91.4	84.5	81.0	77.3	6.9	3.5	3.7	14.1
	T&S	15.6	7.0	3.4	2.7	8.5	3.6	0.7	12.9
	Total	107.0	91.5	84.4	80.0	15.4	7.2	4.4	27.0
Oxy comb.	Capture	102.8	91.4	85.4	80.7	11.5	6.0	4.6	22.1
	T&S	36.8	16.6	8.0	6.4	20.2	8.6	1.6	30.5
	Total	139.7	108.0	93.3	87.1	31.7	14.6	6.2	52.6
IGCC	Capture	108.6	99.8	94.5	90.8	8.8	5.2	3.7	17.7
	T&S	36.8	16.6	8.0	6.4	20.2	8.6	1.6	30.5
	Total	145.4	116.4	102.5	97.2	29.0	13.9	5.3	48.2
						Period-on-period reductions in £/MWh			
High cost path:		2013	2020	2028	2040	2020	2028	2040	Total
Coal PC	Capture	141.4	130.9	125.8	118.7	10.4	5.2	7.0	22.6
	T&S	54.6	25.8	20.5	16.6	28.8	5.3	3.9	38.1
	Total	196.0	156.8	146.3	135.3	39.2	10.5	11.0	60.7
Gas PC	Capture	110.1	106.2	101.4	97.0	3.9	4.8	4.3	13.1
	T&S	23.1	10.9	8.7	7.0	12.2	2.3	1.7	16.1
	Total	133.2	117.1	110.0	104.0	16.1	7.1	6.0	29.1
Oxy comb.	Capture	142.0	131.1	124.6	117.5	10.9	6.6	7.0	24.5
	T&S	54.6	25.8	20.5	16.6	28.8	5.3	3.9	38.1
	Total	196.6	156.9	145.0	134.1	39.7	11.9	10.9	62.5
IGCC	Capture	157.8	152.7	144.6	139.4	5.1	8.1	5.2	18.4
	T&S	54.6	25.8	20.5	16.6	28.8	5.3	3.9	38.1
	Total	212.5	178.5	165.1	156.0	33.9	13.4	9.1	56.5

Note: Excludes cost of carbon emissions, assumes DECC's central fuel price projection, 10% discount rate

Source: Mott MacDonald estimates

Table C.14: Build up of reference plant LCOE - for coal post-combustion

	2013	2020	2028	2040
Specific capex: £/kW				
Low	1500	1400	1400	1400
High	1700	1600	1600	1600
ACF				
Low	80%	80%	80%	80%
High	60%	60%	60%	60%
WACC				
Low	10%	10%	10%	10%
High	10%	10%	10%	10%
Plant life				
Low	30	30	30	30
High	25	25	25	30
Levelised capex: £/MWh				
Low	26	24	24	24
High	41	39	39	37
FOM: £/kW/yr @2.5% of capex				
Low	38	35	35	35
High	43	40	40	40
FOM: £/MWh				
Low	5	5	5	5
High	8	8	8	8
VOM: £/MWh				
Low	3	3	3	3
High	4	4	4	4
Total non fuel cost: £/MWh				
Low	34	32	32	32
High	53	50	50	49
Energy cost: £/GJ net				
Low	3.0	3.0	3.0	3.0
High	3.0	3.0	3.0	3.0
Energy cost: £/MWh (based 40% ref)				
Low	27.0	27.0	27.0	27.0
High	27.0	27.0	27.0	27.0
Total base plant cost: £/MWh				
Low	61.5	59.4	59.4	59.4
High	80.1	77.2	77.2	75.7
Total LCOE of CC £/MWh				
Low	103.7	92.9	87.7	83.0
High	141.4	130.9	125.8	118.7
Carbon cost /£/MWh				
CPF: £/t	16	30	62	110
% stored	0.85	0.85	0.85	0.85
CO_2 cost:	2.5	4.6	9.0	15.0
Amended LCOE of CC (including carbon) £/MWh				
Low	106.3	97.5	96.7	98.1
High	143.9	135.6	134.8	133.8

Source: Mott MacDonald estimate

Table C.15: Build up of reference plant LCOE - for gas post-combustion

Post combustion coal	2013	2020	2028	2040
Specific capex: £/kW				
Low	550	500	500	500
High	550	550	550	550
ACF				
Low	80%	80%	80%	80%
High	60%	60%	60%	60%
WACC				
Low	10%	10%	10%	10%
High	10%	10%	10%	10%
Plant life				
Low	25	30	30	30
High	20	20	25	30
Levelised capex: £/MWh				
Low	10	8	8	8
High	14	14	13	12
FOM: £/kW/yr @2.5% of capex				
Low	14	13	13	13
High	14	14	14	14
FOM: £/MWh				
Low	2	2	2	2
High	3	3	3	3
VOM: £/MWh				
Low	2	2	2	2
High	3	3	3	3
Total non fuel cost: £/MWh				
Low	13	12	12	12
High	19	19	18	18
Energy cost: £/GJ net				
Low	7.3	7.3	7.3	7.3
High	7.3	7.3	7.3	7.3
Energy cost: £/MWh (based 54% ref)				
Low	48.7	48.7	48.7	48.7
High	48.7	48.7	48.7	48.7
Total incremental CC cost: £/MWh				
Low	62.1	60.8	60.8	60.8
High	67.8	67.8	67.0	66.5
Total LCOE of CC £/MWh				
Low	91.4	84.5	81.0	77.3
High	110.1	106.2	101.4	97.0
Carbon cost /£/MWh				
CPF: £/t	16	30	62	110
% stored	0.85	0.85	0.85	0.85
CO2 cost:	1.1	2.0	4.0	6.8
Amended LCOE of CC				
Low	92.5	86.5	85.0	84.1
High	111.2	108.2	105.4	103.8

Source: Mott MacDonald estimates

Table C.16: Build up of reference plant LCOE - for oxy combustion - coal

Oxy combustion coal				
	2013	**2020**	**2028**	**2040**
Specific capex: £/kW				
Low	1500	1400	1400	1400
High	1700	1600	1600	1600
ACF				
Low	80%	80%	80%	80%
High	60%	60%	60%	60%
WACC				
Low	10%	10%	10%	10%
High	10%	10%	10%	10%
Plant life				
Low	30	30	30	30
High	25	25	25	30
Levelised capex: £/MWh				
Low	26	24	24	24
High	41	39	39	37
FOM: £/kW/yr @2.5% of capex				
Low	38	35	35	35
High	43	40	40	40
FOM: £/MWh				
Low	5	5	5	5
High	8	8	8	8
VOM: £/MWh				
Low	3	3	3	3
High	4	4	4	4
Total non fuel cost: £/MWh				
Low	34	32	32	32
High	53	50	50	49
Energy cost: £/GJ net				
Low	3	3	3	3
High	3	3	3	3
Energy cost: £/MWh (based 40% ref)				
Low	27.0	27.0	27.0	27.0
High	27.0	27.0	27.0	27.0
Total incremental CC cost: £/MWh				
Low	61.5	59.4	59.4	59.4
High	80.1	77.2	77.2	75.7
Total LCOE of CC : £/MWh				
Low	102.8	91.4	85.4	80.7
High	142.0	131.1	124.6	117.5
Carbon cost : /£/MWh				
CPF: £/t	16	30	62	110
% stored	0.85	0.85	0.85	0.85
CO2 cost:	2.5	4.6	8.8	14.7
Amended LCOE of CC				
Low	105.4	95.9	94.1	95.4
High	144.5	135.7	133.3	132.2

Source: Mott MacDonald estimates

Table C.17: Build up of reference plant LCOE – IGCC coal

IGCC coal	2013	2020	2028	2040
Specific capex: £/kW				
Low	2200	2000	1900	1800
High	2500	2400	2300	2200
ACF				
Low	80%	80%	80%	80%
High	60%	60%	60%	60%
WACC				
Low	10.0%	10.0%	10.0%	10.0%
High	10.0%	10.0%	10.0%	10.0%
Plant life				
Low	30	30	30	30
High	20	20	25	30
Levelised capex: £/MWh				
Low	38	35	33	31
High	64	62	55	51
FOM: £/kW/yr @2.5% of capex				
Low	55	50	48	45
High	63	60	58	55
FOM: £/MWh				
Low	8	7	7	6
High	12	11	11	10
VOM: £/MWh				
Low	2.5	2.5	2.5	2.5
High	3	3	3	3
Total non fuel cost: £/MWh				
Low	49	44	42	40
High	79	76	69	65
Energy cost: £/GJ net				
Low	3	3	3	3
High	3	3	3	3
Energy cost: £/MWh (based 40% ref)				
Low	27.0	27.0	27.0	27.0
High	27.0	27.0	27.0	27.0
Total incremental CC cost: £/MWh				
Low	75.6	71.4	69.4	67.3
High	106.1	103.1	96.4	91.5
Total LCOE of CC £/MWh				
Low	108.6	99.8	94.5	90.8
High	157.8	152.7	144.6	139.4
Carbon cost £/MWh				
CPF: £/t	16	30	62	110
% stored	0.85	0.85	0.85	0.85
CO2 cost:	2.3	4.2	8.4	14.5
Amended LCOE of CC				
Low	110.9	104.0	102.9	105.4
High	160.1	157.0	153.0	154.0

Source: Mott MacDonald estimates