
Gas with CCS in the UK – *Waiting for Godot?*

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Waiting for Godot

“Let us do something, while we have the chance! It is not every day that we are needed. Not indeed that we personally are needed. Others would meet the case equally well, if not better.

It is true that when with folded arms we weigh the pros and cons we are no less a credit to our species. The tiger bounds to the help of his congeners without the least reflexion, or else he slinks away into the depths of the thickets. But that is not the question. What are we doing here, *that* is the question. And we are blessed in this, that we happen to know the answer. Yes, in the immense confusion one thing alone is clear. We are waiting for Godot to come – ”

– Samuel Beckett, *Waiting for Godot*

Preface

For those who have become increasingly frustrated by claims about, rather than demonstrations of, the contribution which natural gas can make to a low carbon economy, it has become important to understand more of the detail behind the headlines of carbon capture and sequestration (CCS). This paper shows that all aspects of the implementation of CCS projects are complex, albeit that the underlying technologies have been used individually in the petrochemical, refining and upstream industries for decades. Even for those of us who can make little claim to understanding the technical aspects of the different processes, the uncertainty of the economic assumptions, and the number of commercial interfaces required for transportation and storage (or enhanced oil recovery recycling and storage) of the carbon dioxide, represent daunting challenges. Costs, and technical and commercial complexity go a long way towards explaining why there is no gas-fired power plant with CO₂ capture and storage in operation or under construction anywhere in the world. The few gas-related CCS projects which exist mainly serve to process natural gas to grid specification and either store CO₂ close to gas production sites, or use it for enhanced oil recovery.

With slower than expected progress of other forms of power generation, UK policy makers have come to the realisation that gas-fired capacity will remain important for a considerable period of time. This in turn will mean that the question of whether CCS should be fitted (and retrofitted) to gas-fired power generation is likely to move higher up the UK's climate policy agenda. Howard Rogers' study demonstrates that, on paper, gas-fired generation with CCS can be more competitive than the low carbon generation options generally assumed to grow most significantly in the UK over the next decade, but the commercial complexities of CCS projects set out in this paper, do not give cause for optimism about its future development, absent a clear and sustained commitment from government.

Jonathan Stern

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Introduction

This paper is written at a time of renewed interest in Carbon Capture and Sequestration (CCS) as one means of achieving decarbonisation in the power sectors of Europe and other regions. CCS involves the removal of CO₂ from a mixed component gaseous stream (in the case of a power generation application this may be effected pre- or post-combustion), transportation of CO₂ via pipeline and injection into a permanent underground storage facility (usually a depleted oil or gas field or a brine-filled aquifer). The basic technical building blocks underpinning CCS have been understood and used at industrial scale in the upstream oil and gas, petrochemical and power generation industries at least as early as the 1980s¹, although technological advances in the CO₂ removal stage are still ongoing.

At one level the paper provides a means by which the reader may become better familiarised with the practicalities as well as the challenges relating to CCS. The main purpose of the paper however, is to address more pertinent questions regarding the lack of pace and tangible achievement to date in the widespread adoption of CCS; whether this is a consequence of the underlying economics of CCS relative to other low carbon generation technologies and what is needed to change this going forward, in a UK context. Prospective CCS projects in the power sector have generally been associated with coal. The paper briefly examines the reasons for this and why this situation could change, in the UK and more widely.

Given the apparent desire on the part of many policy makers to see CCS adopted on a commercial scale the key question the paper seeks to address is ‘what are the hurdles and barriers to achieving this aim?’ Is there a balance to be struck between investment in commercial-scale schemes using current technology now versus funding additional R&D to yield more effective, lower cost separation technologies? Given the emerging role of gas-fired generation in providing a flexible buffer/back-up for intermittent wind generation, the paper also explores whether power generation from gas with CCS is inherently less flexible than an unabated CCGT or whether such assumed lack of flexibility is based on ‘group think’. The final question addressed is ‘what is necessary from a commercial or contractual view to see CCS succeed?’

Chapter 1 examines the development of the role of CCS in climate abatement policy in a general and UK context and reviews the global status of power sector CCS projects. Chapter 2 describes the practicalities of the process itself and Chapter 3 focusses on the economics of power generation from gas using CCS compared to other fuels and technologies. In particular comparisons are drawn with other low carbon power generation sources.

Chapter 4 examines the potentially complex commercial arrangements required to launch full scale gas with CCS in a UK context and Chapter 5 presents the paper’s conclusions.

¹ In 1985, the Author worked on an acetic acid chemical complex in the UK which included a natural gas catalytic reformer (which produces hydrogen from methane), an ethanolamine CO₂ capture unit and a combined cycle gas turbine – all the components of the CCS power generation and capture process. CO₂ transportation and injection into oil reservoirs has been practised in North America for decades.

Chapter 1. CCS in the Context of Evolving Climate Change Policy

1.1 Historical Policy Context for CCS

In 2004 Pacala and Socolow², highlighted the role of CCS in three of fifteen CO₂ abatement options³, each of which would reduce carbon emissions by 1 Gigatonne per year by 2054 world-wide. Recognising that any option selected would grow in scale through time, the paper proposed that seven ‘wedges’ based on a subset of the fifteen options described, could stabilise atmospheric CO₂ concentration at 500 ppm compared with a ‘Business as Usual’ scenario of a 1.5% per year increase in CO₂ emissions. At the time this framework, often referred to as the ‘Princeton Wedges’, provided a bridge between the perplexing threat of CO₂-induced global warming and the practical steps which could be pursued, within appropriate policy frameworks, to reduce man-made CO₂ emissions.

In 2007 the US National Petroleum Council (NPC) published its report ‘Facing the Hard Truths about Energy’. Such periodic reports published by the NPC draw upon the findings of many specialist groups who are convened for the purpose of preparing input to the main report. The Carbon Capture and Sequestration Subgroup of the Technology Task Group of the NPC Committee on Global Oil and Gas acknowledged progress made to date internationally and the need to develop CCS as a means for mitigating anthropogenic CO₂ emissions, but the policy thrust of the paper was to support the development of large scale CCS as a means by which North America could continue to maintain a significant share of coal and gas in its energy mix⁴.

In 2010, the Global CCS Institute published a status report⁵ which, in its introduction, set out a refreshed context for CCS development and application. It referred to the United Nations Framework Convention on Climate Change (UNFCCC) Conference of Parties 16 (COP16), in which a non-legally binding aspiration to limit global temperature increases from pre-industrial levels to 2 °C was adopted. This is equivalent to stabilising greenhouse gas concentrations in the atmosphere to about 450 ppmv of CO₂ equivalent by 2050. From a cost perspective, the lower cost abatement options, such as energy efficiency and low-cost renewables were expected to be taken up more quickly in the near to medium term. During the medium to longer term (not specified in this source, but by inference beyond 2020), more expensive options such as nuclear, solar thermal and CCS were expected to play a more significant role in abatement strategies. In its 2010 World Energy Outlook and CCS Roadmap, the IEA estimated that in a ‘least cost emissions reduction pathway’ 100 industrial

² Pacala and Socolow 2004, pp 968-972

³ The three options were ‘Capture CO₂ at baseload power plant’, ‘Capture CO₂ at H₂ plant’ and ‘Capture CO₂ at coal-to-synfuels plant’, all with geological storage.

⁴ NPC 2007. The report contains some high quality summaries of the practical challenges of the CCS chain which are referred to in later chapters of this paper.

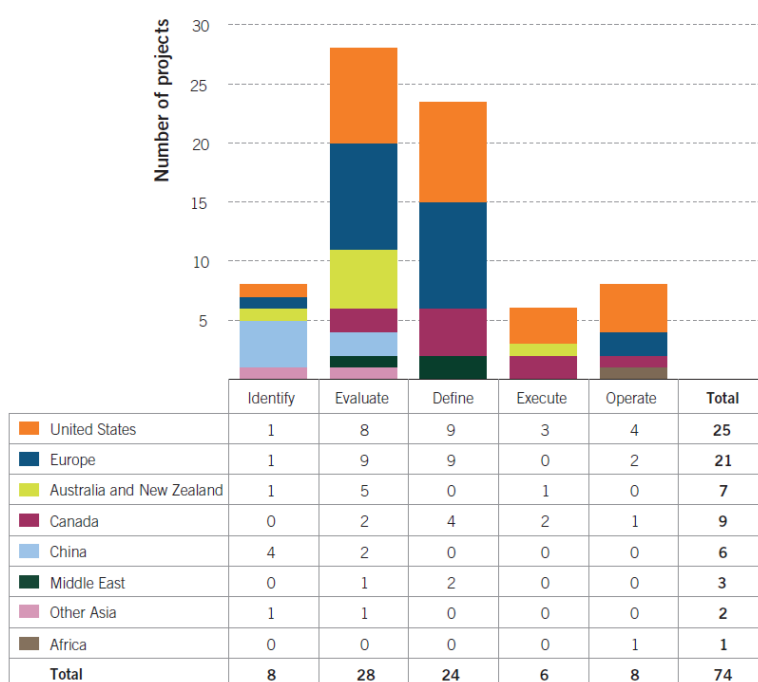
⁵ Global CCS 2010

scale CCS projects needed to be operational by 2020 and 3,400 projects by 2050⁶. At COP16, the UNFCCC’s main scientific advisory body agreed by consensus to the legitimacy of CCS as a long-term mitigation option and the Meeting of the Parties to the Kyoto Protocol agreed to include CCS as an eligible project under the Clean Development Mechanism (CDM)⁷.

1.2 Progress in the Implementation of CCS Projects

In light of such positive support for CCS, at least at the policy level, as a key weapon in the armoury of CO₂ abatement measures, it is pertinent to assess the progress, in tangible terms, of CCS projects.

Figure 1: Large Scale Integrated CCS Projects by Project Phase and Region, 2011



Source: *Global CCS 2011, P. 9*

The Global CCS Institute in its 2011 report⁸ tracks the progress of ‘Large Scale Integrated Projects’ (LSIPs) through five stages of development, namely ‘Identify’, ‘Evaluate’, ‘Define’, ‘Execute⁹’ and ‘Operate’. Figure 1 shows the demographics of identified LSIPs in 2011. Figure 2 provides an indication of the speed at which projects are moving through the project phases in the period 2009 to 2011.

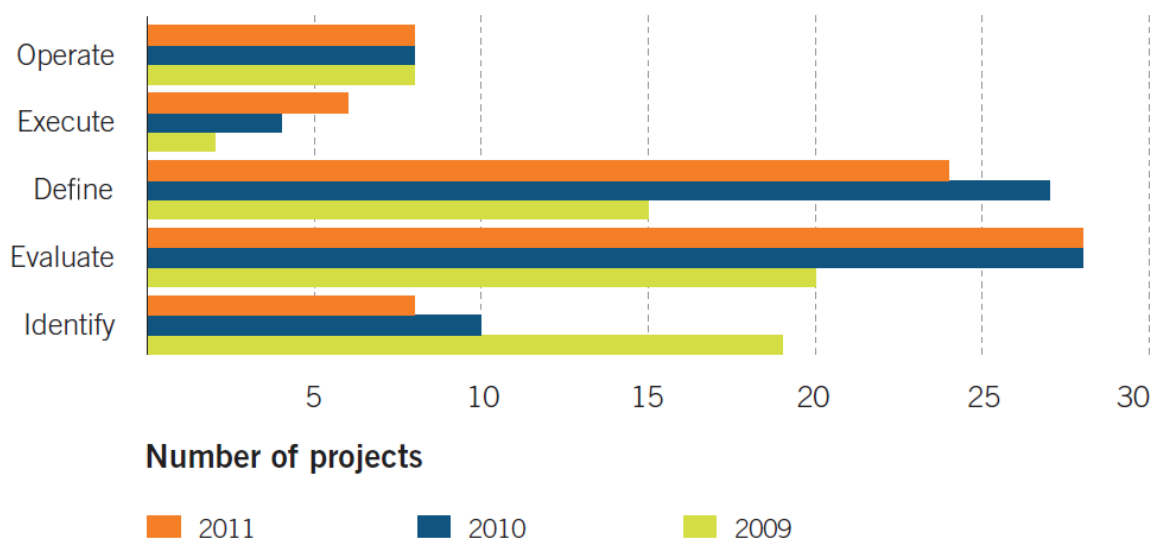
⁶ Ibid, pp. 16-17.

⁷ Ibid 18.

⁸ Global CCS 2011

⁹ Under Construction

Figure 2: CCS LSIPs – Progress through Project Phases 2009 - 2011



Source: *Global CCS 2011, P. 9*

The number of Operational projects has remained at eight through the period (although the scope of some existing projects has expanded), there has been an increase in the number of projects in the Execute phase (from 2 to 6), but the Define and Evaluate phases appear to contain a ‘backlog’ of many projects awaiting an investment decision. The number of projects in the Identify phase has reduced from 19 to 8 in this 3 year period.

Table 1 Shows the Large Scale Integrated Projects in the Operate and Execute Stages by location, sector and storage type as well as the date of operation and the annual CO₂ volume captured.

Of the eight operational projects the three in Norway and Algeria exist to remove high volumes of CO₂ from the production of natural gas fields which is then injected for storage in brine-filled aquifers. In the case of the two Norwegian projects CO₂ storage is offshore and for the Algerian project onshore. The Shute Creek Gas Processing Facility in the USA similarly removes CO₂ from a natural gas field’s production (from the la Barge field in Sublette County, Wyoming) with the CO₂ injected in producing onshore oil fields to enhance recovery. The Val Verde Natural Gas and the Century Plants, both located in Texas, remove CO₂ from the production streams of nearby natural gas fields and thus perform a similar role to that of the Shute Creek facility. Again the CO₂ streams are used in EOR in onshore fields¹⁰. The Great Plains Synfuels plant is a commercial scale coal gasification plant with the separated CO₂ removed and used for onshore enhanced oil recovery purposes. The Enid fertiliser plant produces CO₂ as a by-product which is separated and used for EOR. It is of note that none of these facilities, operational in 2011, are associated with power generation plant and that the North American facilities use the CO₂ produced for the value-adding

¹⁰ EOR is an acronym for Enhanced Oil Recovery; a process by which CO₂ is injected into partially depleted oil reservoirs to maintain pressure drive and thereby improve recovery rates.

purpose of enhancing oil recovery in third-party onshore oil fields. While the injection of CO₂ into oil fields for the purposes of EOR is technically ‘CO₂ storage’ (i.e. the CO₂ remains in the field), and such a practise has been used for decades in North America, this may have escaped the notice of those who object to the proposed storage of CO₂ in onshore structures in Europe.

Table 1: Large Scale Integrated Projects in the Operate and Execute Stages, 2011

Name	Location	Industry Sector	Volume CO ₂ (MTPA)	Storage Type	Date of Operation
Operate Stage					
Shute Creek Processing Facility	USA	Natural Gas Processing	7	EOR	1986
Sleipner CO ₂ Injection	Norway	Natural Gas Processing	1	Deep Saline Formation	1996
Val Verde Natural Gas Plants	USA	Natural Gas Processing	1.3	EOR	1972
Great Plains Synfuels Plants	USA/ Canada	Coal to Gas Synfuel Process	3	EOR with MMV	2000
Enid Fertilizer Plant	USA	Fertiliser Manufacture	0.7	EOR	1982
In Salah CO ₂ Storage	Algeria	Natural Gas Processing	1	Deep Saline Formation	2004
Snohvit CO ₂ Injection	Norway	Natural Gas Processing	0.7	Deep Saline Formation	2008
Century Plant	USA	Natural Gas Processing	5 (plus 3.5 in construction)	EOR	2010
Execute Stage					
Lost Cabin Gas Plant	USA	Natural Gas Processing	1	EOR	2012
Illinois Industrial Carbon Capture and Sequestration	USA	Bio-fuel (Ethanol) Manufacture	1	Deep Saline Formation	2013
Boundary Dam with CCS Demonstration	Canada	Power Generation	1	EOR	2014
Agrium CO ₂ Capture with ACTL	Canada	Fertiliser Manufacture	0.6	EOR	2014
Kemper County IGCC Project	USA	Power Generation	3.5	EOR	2014
Gorgon Carbon Dioxide Injection Project	Australia	Natural Gas Processing	3.4 - 4	Deep Saline Formation	2015

Source: Global CCS 2011, P. 11

At the Execute (under construction) stage two power facilities are identified. The Boundary Dam with CCS Demonstration project is a \$1.24 billion integrated ‘clean coal’ demonstration project in Saskatchewan, Canada. It aims to retrofit a carbon capture system at SaskPower’s coal-fired Boundary Dam Power Station, near Estevan, and integrate it with enhanced oil recovery operations¹¹. The Kemper County IGCC Project is a 582MW lignite-fired IGCC¹² plant in Mississippi which will use two integrated gasifier trains, and aims to capture 3.5 million tonnes of CO₂ per annum. The project began construction during 2011 and aims to reduce the facility’s CO₂ emissions by 65%. Captured CO₂ will then be transported by pipeline for use on EOR projects, and at least one CO₂ buyer has already been secured¹³. The Kemper County project is the only so far financially approved ‘commercial scale’ power generation facility employing CCS. It is coal-based and the target reduction of CO₂ emissions is 65% rather than the 90% level often assumed in future CCS utilisation projections.

1.3 Recent EC Policy Initiatives Impacting CCS

In December 2011, the EC published its Energy Roadmap 2050 communication to the European Parliament¹⁴. The report states that Carbon Capture and Storage has to play a pivotal role in system transformation. The Roadmap describes five decarbonisation scenarios in which CCS would represent up to 32% of power generation in the Low Nuclear scenario and shares of between 19% and 24% in other scenarios (with the exception of the High Renewable Energy Sources scenario). The report stresses a key role for gas in the transition of the energy system by substituting for coal in the power sector, and although gas consumption in the residential sector is expected to decrease by 25% by 2030 due to energy efficiency measures, its use in the power sector is expected to remain high over a longer period. However, the report also states that without CCS, the long term role of gas may be limited to a flexible back-up and balancing capacity for variable renewable supplies. The scenarios see the need for CCS to be applied from around 2030 onwards in the power sector in order to achieve the decarbonisation targets. This requires the successful investment in technology and large scale demonstration of CCS during the 2010s. Deployment in the 2020s would set the stage for widespread use by 2030¹⁵.

¹¹ <http://www.zeroco2.no/projects/saskpowers-boundary-dam-power-station-pilot-plant>

¹² IGCC – Integrated Gasification Combined Cycle

¹³ <http://www.zeroco2.no/projects/kemper-county-igcc>

¹⁴ EC 2011

¹⁵ Ibid, pp. 8., 11, 12

In 2011 the European Commission launched the "NER 300", the world's largest demonstration programme for low-carbon technologies, which will act as a catalyst for the demonstration of new low carbon technologies on a commercial scale. The NER 300¹⁶ aims to encourage the private sector and EU Member States to invest in commercial low-carbon demonstration projects. It focuses on environmentally safe capture and geological storage of CO₂ (CCS) and renewable energy technologies such as wind energy, concentrated solar power, and smart grids. NER300 will establish an EU-wide demonstration programme comprising the best possible projects using a wide range of technologies and involving all Member States. Since NER300 will be funded by the sale (or "monetisation") of 300 million emission allowances, the amount of money available for the demonstration projects will depend on the market price at the time the allowances are sold. At the market price at the call launch (early November 2011), the 300 million allowances would raise around € 4.5 billion, which will leverage matching funding of another €4.5 billion from Member States and industry¹⁷.

A total of 65 renewable and 13 CCS project proposals were submitted to the EC in May 2011 for assessment by the European Investment Bank (EIB). The EC intends to provide clarity on the outcomes of the first round of the funding programme in the second half of 2012. Funding from the total NER300 programme could probably support four to six large scale CCS projects, dependent on the quality of the applications and the value of the allowances auctioned. The 13 CCS submissions, 11 of which are power generation projects, are shown in Table 2. Of the projects listed in Table 2, four had already been cancelled by July 2012.¹⁸ While it is believed that economic and financial factors drove the decision to cancel Longannet and others, the Janschwade cancellation followed public protests against the use of onshore CO₂ storage¹⁹.

¹⁶ So-called because it will be funded from the sale of 300 million emission allowances held in the New Entrants Reserve (NER) of the EU Emissions Trading System (ETS)

¹⁷ EC Climate Action website: http://ec.europa.eu/clima/policies/lowcarbon/ner300/index_en.htm

¹⁸ Global CCS Institute website: www.globalccsinstitute.com/

¹⁹ UKERC 2012, P.7

Table 2: CCS Project Submissions for NER300 to the European Commission

CCS Project Categories	Projects Submitted by Name	Fuel
Power generation (pre-combustion)	C.GEN North Killinghome (UK)	Coal
	Don Valley (UK)	Coal
	Eston Grange CCS (UK)	Coal
Power generation (post-combustion)	Getica CCS Demonstration (Romania)	Lignite
	* Belchatow (Poland)	Coal/Lignite
	Porto Tolle (Italy)	Coal
	* Longannet (UK)	Coal
	* Peel Energy CCS (UK)	Coal/Biomass
	Peterhead Gas CCS (UK)	Gas
Power generation (oxyfuel)	UK Oxy CCS Demonstration (UK)	Coal
	* Vattenfall Janschwalde (Germany)	Coal/Lignite
Industrial applications	ULCOS - Blast Furnace (France) - steel production	
	Green Hydrogen (Netherlands) - hydrogen production	

*Cancelled

Source: *The Global Status of CCS: 2011*, Global CCS Institute

Here it is important to introduce the economic challenges for integrated CCS projects in a power generation context. While there exist commercial scale CCS plant in operation, as noted above, these are associated with gas processing, synthetic fuels and fertiliser production; applications that are of smaller scale (in terms of the volume of CO₂ removal) and which are more economically attractive than CCS in the power sector. The IEA estimates that ‘incorporating CCS into a power plant increases the levelised cost of the electricity produced by between 39% and 64%, depending on the fuel source’²⁰. This is an area we will return to in Chapter 3, however it is consistent with the general conclusion reached by the Global CCS Institute:

‘The most frequently cited reason for a project being put on hold or cancelled is that it was deemed uneconomic in its current form and policy environment. The lack of financial support to continue to the next stage of project development and uncertainty regarding carbon abatement policies were critical factors that led several project proponents to reprioritise their investments, either within their CCS portfolio or to alternative technologies’²¹

1.4 The UK’s Evolving Policy Position on Gas and CCS

The UK’s policy position on natural gas in the energy mix has undergone significant changes since the mid-2000s when it became clear that with domestic gas production in decline, the

²⁰ IEA 2011, P 378

²¹ Global CCS 2011, P. 13

UK had moved rapidly from an era of self-sufficiency and net gas exports, to one of increasing dependency on imports; either in the form of pipeline gas or LNG or both.

In the period 2005 to 2010 the focus was, not surprisingly, on security of gas supply which in turn generated a debate on the appropriate level of underground gas storage capacity and how to encourage the investment necessary to achieve this. In 2009 a report on energy security by the Prime Minister's Special Representative on International Energy, former Energy Minister Malcolm Wicks²², made recommendations to increase storage capacity from 4.5% to 10% of annual consumption based on a sound and practical understanding of the dynamics of the UK market and its interaction with that of the European continent²³. This report however was overshadowed by the publication of the UK Low Carbon Transition Plan in July 2009, which envisaged a 29% reduction in UK gas consumption by 2020, compared with 2008²⁴.

This and subsequent publications describing the anticipated rapid growth in renewables generation capacity served to reduce the urgency to resolve issues relating to gas supply security. Furthermore the issue of the role of gas in the UK's future energy mix appeared not to feature in any significant way. While policymakers continued to produce roadmaps with gas' share of the energy mix displaced by renewables and eroded by energy efficiency measures, the gas industry itself did little to establish and communicate a decarbonisation strategy for gas. Forest²⁵ found that gas industry stakeholders typically expressed views including:

- low carbon supply sources – renewables, nuclear power and coal with CCS - will fail to be implemented to the necessary extent within the required time frame;
- gas for coal substitution will be the lowest cost way of achieving the 2020 carbon reduction targets,
- and as a consequence gas will inevitably become the “default” choice for future power generation.

In contrast, NGOs favouring renewables have successfully played on the trauma of the UK's transition from gas self-sufficiency to import dependency to construct a narrative of a future in which the UK will need to compete internationally for scarce supplies of gas at oil-related prices²⁶. Renewable power generation sources are depicted as an ‘insurance policy’ against these hypothetical high price exposures, although the cost of such policies relative to the likelihood, and level of prices which would justify such investment are not made clear.

²² Wicks 2009

²³ See Stern 2010, P 150

²⁴ HMG 2009, P. 104

²⁵ Forest 2011, P. 34

²⁶ FOE 2012

In 2012 however, it appeared that the UK government was reappraising its view of gas. The March 2012 budget included a £3billion package of measures to support further UKCS oil and gas exploration and development²⁷ and followed a statement from Energy and Climate Change Secretary Ed Davey which relaxed the emissions performance standards for new power stations (which would enable new CCGTs to be built without CCS, but not unabated coal plant), and also promised the creation of a capacity market to improve the economics of load balancing plant. The Secretary was quoted as saying:

'I want a decarbonised grid in the long term, but we can't take our foot off the gas for some time yet'. 'A fifth of the UK's ageing fleet of power stations will close this decade and it's not possible to fill that gap entirely with low carbon alternatives in that timescale'. 'Gas will continue to play a vital role in a low-carbon economy. Modern gas-fired power stations are relatively quick to build and twice as clean as many of the coal plant they're replacing. Carbon capture and storage promises to give gas an even longer term future in the mix'.²⁸

The Secretary of State for Energy & Climate Change and the Chancellor also announced plans on 17 March 2012 to publish a Gas Generation Strategy in the Autumn of 2012, which will focus on the role of gas in the electricity market, with the aim of attracting investment in gas generation by overcoming any barriers, ensuring energy security, meeting the UK's carbon reduction targets, and making the best use of the nation's natural resources²⁹.

This new policy focus on gas has come as something of a surprise to the UK energy sector but clues as to the motivation for this are found in the Energy Secretary's quote:

- They reflect a recognition that the Large Combustion Plant Directive, which limits the number of hours which coal-fired power plant (without flue gas scrubbing equipment) can operate prior to closure, would result in 5.6 GW of coal-fired capacity closures by April 2013³⁰. The lower price of coal versus gas and higher utilisation of coal-fired plant since 2010 has brought forward many of these closures from the originally anticipated date of 2015.
- While governmental support for new nuclear power stations appears to have grown since 2010, there remain concerns over cost levels and lead-times: it is unlikely that new plant will be on-stream before the early 2020s.
- In the absence of a large-scale, cost effective means of storing electricity, gas-fired generation represents the most feasible back-up and balancing mechanism required to support increasing levels of intermittent wind generation. The levels of balancing

²⁷ HMG 12 a

²⁸ DECC 2012 b

²⁹ DECC 2012 a

³⁰ ICIS 2012

required at the anticipated future installed wind capacities are significant and may well have been underestimated until relatively recently³¹.

- The cost of offshore wind generation may have become a concern, especially with public opinion becoming more resistant to lower cost onshore wind projects. This is consistent with the reduction in financial support (Renewables Obligations Certificates – or ROCs) which will come into effect in 2015-2016³².
- The observed impact of US shale gas in reducing gas prices and CO₂ emissions (by displacing coal in the US power sector) may have been a factor, especially with the possibility (albeit bounded with uncertainties and caveats relating to scale, likelihood of success and timing) of the UK developing its own shale gas potential.

More recently, in July 2012, the Chancellor created an additional tax allowance for shallow water gas discoveries, which has been instrumental in progressing the Cygnus gas field (with reserves of 18 bcm) to development³³.

The extent to which the UK's 2012 Gas Strategy will set out a coherent policy framework for gas remains to be seen. Clearly a renewed commitment to gas in the energy mix, (or even perhaps a passive acceptance of gas playing a more significant role than was anticipated in earlier policy scenarios), is evident on the part of government. Gas with CCS was directly referred to by Secretary of Energy and Climate Change Ed Davey in the quote above and the Government in April 2012 launched a CCS 'competition' to encourage industry to bring forward projects which would constitute part or all of a CCS chain. The process is discussed in Chapter 4, but at this point it is worth reflecting on the chequered history of CCS project development in the UK.

In a previous incarnation, the Peterhead project in Table 2 was a joint project between Hydrogen Energy (a BP Joint Venture) and Scottish and Southern Energy, and was planned as a 475 MW natural gas pre-combustion CCS plant. The plant was estimated to cost \$1.9 billion and would have captured 1.8 million tonnes of CO₂ per year. The captured CO₂ would have been used (and stored) in an Enhanced Oil Recovery project at BP's Miller oil field in the North Sea, extending the life of the oil field for 15 to 20 years³⁴. The project was cancelled, but has seemingly re-emerged in a changed format. On 10th February 2011, SSE announced that it had submitted a proposal under the EU NER300 process to develop a gas-fired, post-combustion project at Peterhead. Shell and CO2DeepStore will provide offshore transport and storage elements as part of this proposal, with storage in an existing gas reservoir in the North Sea, operated by Shell, which will have ceased production.

³¹ See Rogers 2011

³² Offshore wind support will be reduced from 2 ROCs/MWh in 2014-2015 to 1.9 ROCs/MWh in 2015-2016 and to 1.8 ROCs/MWh in 2016-2017. Onshore wind support will be reduced from 1 ROC/MWh to 0.9 ROCs/MWh post 2013 and will be further reviewed for the period beyond March 2014 (see: HMG 2012 b).

³³ HMG 2012 c

³⁴ CCS Association website, <http://www.ccsassociation.org/why-ccs/ccs-projects/current-projects/>

The reason for the cancellation of the BP project in May 2007 is something of a mystery, especially as it immediately pre-dated the UK Government announcing a competition for integrated CCS projects to be launched in November 2007. One consequence of the cancellation was the loss of the incremental oil production from the Miller field. While BP's spokesperson was at the time suitably diplomatic, Stuart Haszeldine, a geoscientist from Edinburgh University pithily observed:

*'The government says it wants to lead a carbon capture and storage project. Well, it had a lead. Now it has a lead in hot air,'*³⁵

A clue to why the bilateral negotiations apparently broke down and why the CCS competition launched in 2007 failed to meet its goals is provided by the following quote from the National Audit Office after conducting its review of the failure:

"In the context of value for money, developing new technologies is an inherently risky undertaking. Taking calculated risks is perfectly acceptable if those risks are managed effectively; but in this case DECC, and its predecessor, took too long to get to grips with the significant technical, commercial and regulatory risks involved".

"Four years down the road, commercial scale carbon capture and storage technology has still to be developed. The Department must learn the lessons of the failure of this project if further time is not to be lost, and value for money achieved on future projects."

Amyas Morse, Head of the National Audit Office, 16 March 2012³⁶

Within DECC a 'lessons learned' exercise was undertaken. Key findings included³⁷:

- *'The need for speed, professionalism and thoroughness in managing the processes required to procure and negotiate a complex deal of this nature.*
- *A lack of clarity regarding DECC's commercial position, particularly in relation to the sharing of risk and the project's overall financial envelope, meant that potential 'showstoppers' had not been identified and addressed early enough.*
- *This led to unrealistic expectations on the part of the suppliers in relation to the nature of any final contractual arrangements'.*

The exercise also identified the need to:

- *'Adopt a collaborative approach with the market, using early engagement to shape procurement, prepare the market for [the] proposals stage and build confidence in the programme;*

³⁵ Chem World 2007

³⁶ NAO 2012

³⁷ DECC 2012 c, P. 27

- *Maintain procurement tempo, setting out a realistic and well defined timetable to avoid extensions which can increase procurement costs and make projects vulnerable to external events; and*
- *Allocate risk where it can be most effectively managed and give a clear early signal of Government's intended risk allocation following an assessment of market appetite'.*

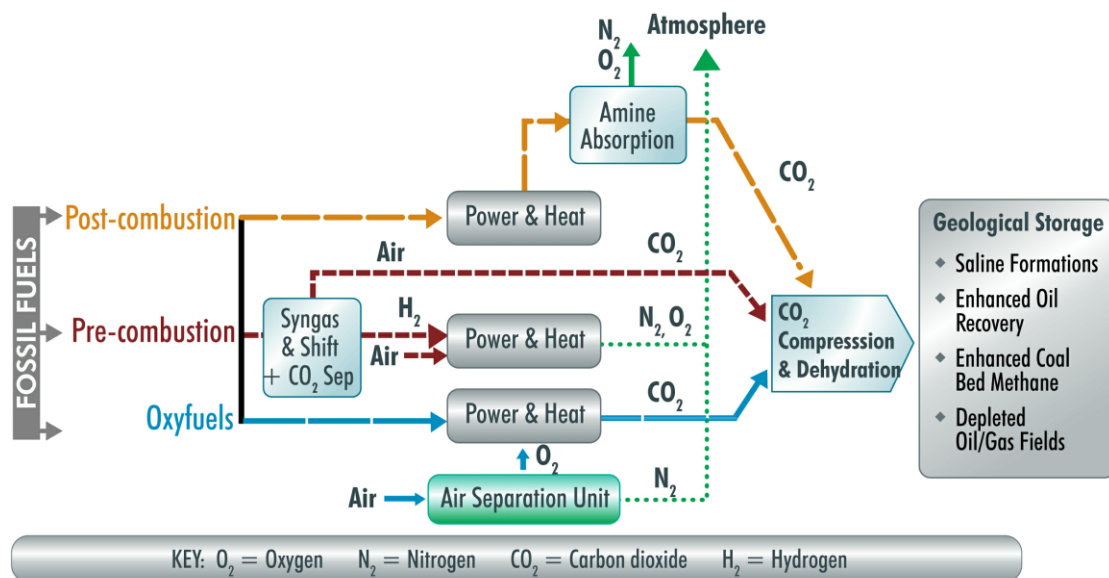
While the ability of DECC to objectively reflect on its past shortcomings is commendable, it remains to be seen whether it can address the issues outlined above and successfully progress any of the remaining UK projects to fruition. These issues will be addressed in Chapter 4 where the nature of the current UK CCS 'competition' is examined.

Chapter 2. CCS, the Practicalities of the Process

2.1 Introduction

The purpose of this chapter is to provide an overview of the physical and chemical processes which constitute an integrated CCS 'chain'. While such an overview may provide a useful summary and de-mystify aspects of CCS, it also provides a means by which the key challenges may be set out as they relate to specific parts of the chain. The CCS chain comprises four stages: Combustion and Power Generation, CO₂ Separation, CO₂ Transportation and lastly, CO₂ Injection and Storage. Figure 3 represents this chain with the three primary combustion and power generation stage variants shown to the left of the diagram.

Figure 3: Schematic Showing the Three Primary CCS Approaches in Power Generation



Source: CO₂CRC,

http://www.co2crc.com.au/images/imagelibrary/cap_diag/Captureapplications_IEA.jpg

2.2 The Combustion and Power Generation Stage

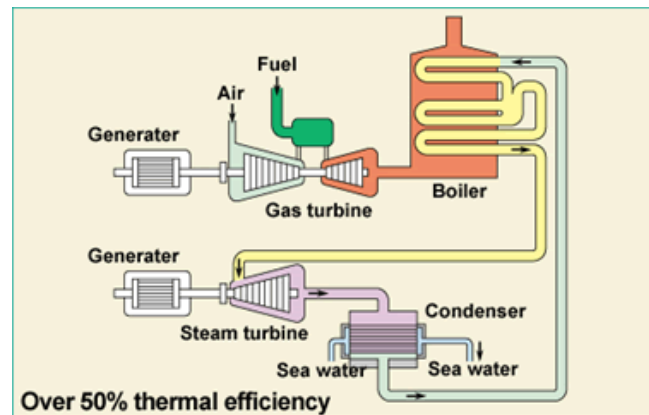
Before describing the three primary approaches to CCS in this stage of the chain (Oxyfuels, Pre-Combustion and Post-Combustion) for both natural gas and coal, it is useful to gain an appreciation of the existing (unabated) power generation processes as this conveys a crucial understanding of the size and complexity of the equipment involved.

2.2.1 Combined Cycle Gas Turbine

A CCGT power plant consists of one or more gas turbine generators equipped with heat recovery steam generators to capture heat from the gas turbine exhaust. Steam produced in the heat recovery steam generators powers a steam turbine generator to produce additional electric power. Use of the otherwise wasted heat in the turbine exhaust gas results in high thermal efficiency compared to other combustion based technologies. Combined-cycle plants

currently entering service can convert about 55 % of the combustion energy of natural gas into electricity (Lower Heating Value (LHV) basis)³⁸.

Figure 4: CCGT Process Schematic



Source: Mitsubishi website, http://www.mhi.co.jp/en/products/detail/ccpp_mechanism.html

An aerial photograph of an actual CCGT plant is shown in Figure 5. Using gas as a fuel leads to a relatively compact site footprint compared with coal-fired plant. The plant in Figure 5 is using air cooling units for recycled steam condensate instead of conventional cooling towers. The construction time for a CCGT plant is typically 2 to 3 years following a planning and approval period of typically 2 years.

Figure 5: 850 MW CCGT at Hamm Uentrop, Germany



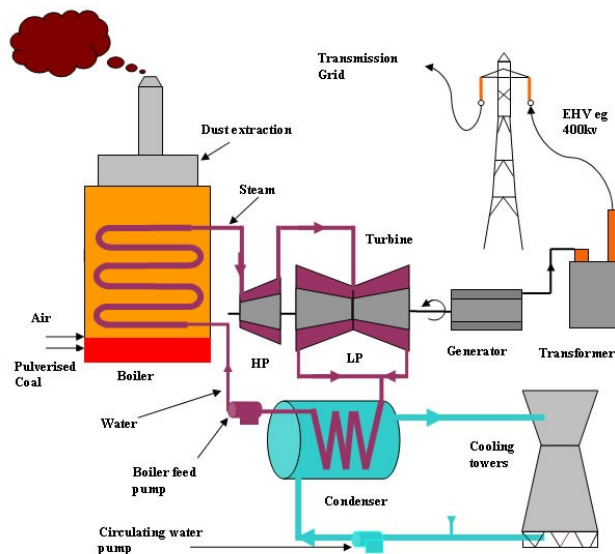
Source: Trianel website: <http://www.trianel-hamm.de/en/kraftwerk-hamm.html>

³⁸ Generation efficiency is the ratio of electricity produced per unit of fuel energy consumed. HHV (higher heating value) efficiency calculations include the total energy of combustion of the fuel. LHV (lower heating value) efficiency calculations exclude the latent heat of evaporation of the water vapour in the flue gas (as this is lost to the atmosphere).

2.2.2 Coal-Fired Generation Plant

In a coal-fired power plant, pumped water is heated in boilers to create superheated steam which is then passed through steam turbines to drive an electrical generator. Energy is lost in the conversion of heat to mechanical energy (and thus to electrical energy) in the water/steam 'cycle' in power stations limiting efficiency to 40% or less. Once the steam has passed through the turbine it is condensed and is sent around the cycle again. The condenser uses external water to cool the steam and this heat is lost to the environment via cooling towers. This cycle is illustrated in Figure 6.

Figure 6: Coal-Fired Plant Schematic



Source: climate and fuel website: <http://www.climateandfuel.com/pages/electrical.htm>

Figure 7: 1,000 MW Coal-Fired Plant, Rugeley, UK



Source: Rugeley Power Station website: <http://www.rugeleypower.com/finance/index.php>

The Rugeley coal-fired plant has a similar capacity to the Hamm Uentrop CCGT discussed above, but its footprint is considerably larger due to the extensive coal storage area, the

conventional cooling towers, the equipment needed for coal handling and processing and the size of the boilers. The construction time of such a facility would be 4 to 5 years, (following a planning and approval period of typically 3 years), as a consequence of the scale and range of the equipment and structures required. Capital costs are consequently higher than those of a CCGT for a similar generation capacity.

2.2.3 Carbon Capture at the Power Generation Stage

The following provides a brief overview of the three approaches envisaged for CO₂ capture at the power generation stage, including simplified schematics to illustrate the key points.

Oxyfuel

The distinctive feature of the Oxyfuel process is the use of oxygen, rather than air in the combustion stage. Whether the fuel is coal or natural gas, the products of combustion are water vapour and CO₂. After removal of the water, by condensation, the CO₂ stream is able to be transported as a pure stream for injection and storage (i.e. a CO₂ separation process is not required). This is shown schematically in Figure 8.

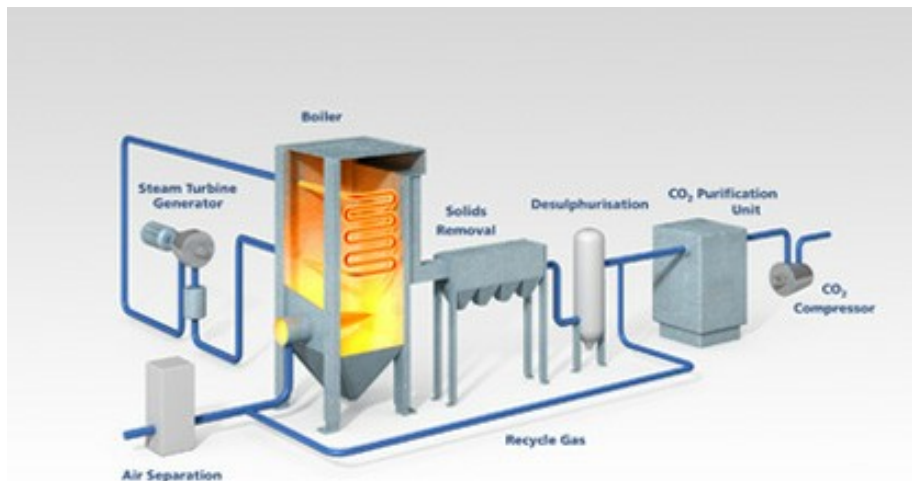
Figure 8: Oxyfuel Schematic



Source: Greentechmedia, <http://www.greentechmedia.com/articles/read/carbon-capture-according-to-stanford-university/>

Where the fuel is coal, the size of the generation plant and its associated services tends to be larger due to the need for handling pulverised coal and the separation and removal of residual ash. Power generation using coal as an oxyfuel is by use of a steam cycle, the steam being generated in a convection boiler. This limits the efficiency of the process to around 40%. In order to control the combustion chamber temperatures within operational limits, up to 2/3rds of the CO₂ and water vapour flue gas is recycled back to the combustion chamber. This is shown schematically in Figure 9.

Figure 9: Oxyfuel Process using Coal



Source: Capture Ready

<http://www.captureready.com/en/Channels/Research/showDetail2.asp?objID=298>

Where the fuel used is gas, it is possible to achieve higher generation efficiencies due to the ability to generate power using a combustion turbine and steam turbine cycle. However, because the temperatures experienced in the combustion turbine are up to 100°C higher³⁹ than for a conventional natural gas turbine, turbines must be specially designed for this duty.

The advantage of not needing a CO₂ separation process in this approach must be set against the capital cost and energy requirements of the cryogenic process for separating pure oxygen from air. Another challenge is to improve control of the combustion process in the boiler. Innovative solutions to meet these challenges will be important milestones towards rolling out the oxyfuel process on a utility scale⁴⁰.

2.2.4 Pre-Combustion

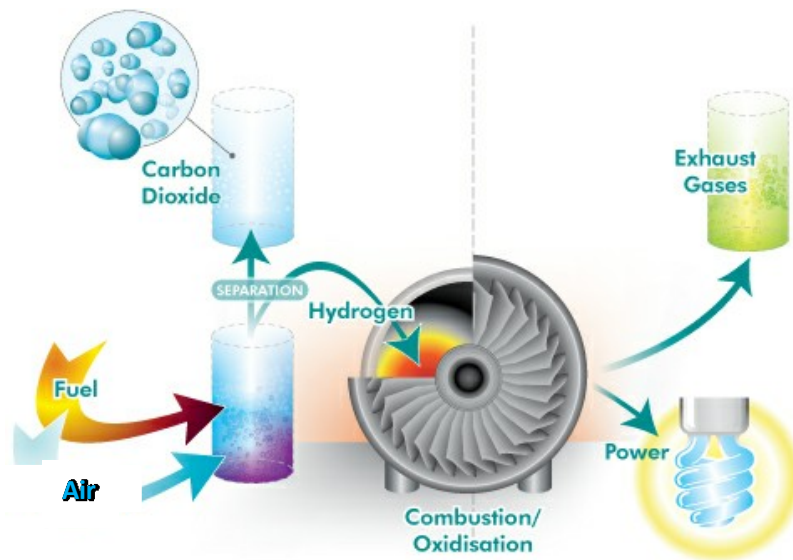
The essence of this approach is to subject the fuel, whether natural gas or coal, to a two-stage chemical process to produce a gaseous mixture of CO₂ and hydrogen. The CO₂ is removed from this mixture before the combustion and power generation step. The anticipated CO₂ removal level from the gaseous stream is 90%, which is generally cited as the operational target for CO₂ removal in the power sector⁴¹.

³⁹ ASME 2008

⁴⁰ <http://www.eon.com/en/business-areas/power-generation/coal/carbon-capture-and-storage/oxyfuel-combustion.html>

⁴¹ As the concentration of CO₂ in the mixed gaseous stream is reduced by the capture process, it becomes progressively more difficult in terms of energy input and the scale of the plant required to reduce the CO₂ to lower concentration levels. If technological breakthroughs in capture technologies are made in the future it may be possible to reduce CO₂ flue gas levels further at an acceptable cost.

Figure 10: Pre-Combustion Schematic



Source: CO2CRC, <http://www.co2crc.com.au/imagelibrary3/capture.php?screen=3>

Where the fuel is coal, this is reacted sequentially with steam and air to produce a mixed stream of carbon dioxide, hydrogen and nitrogen. (Note that some references to coal-based pre-combustion separation processes include air separation as an initial step which avoids the CO₂ and Hydrogen stream being diluted with nitrogen). The coal-fuelled generation plant envisaged for this approach are termed IGCC (Integrated Gasification Combined Cycle) Plants. Figure 11 shows an IGCC plant in Indiana, USA which was completed in June 2012. This plant does not at present have a CO₂ separation plant, but Figure 11 conveys the scale and complexity of the IGCC.

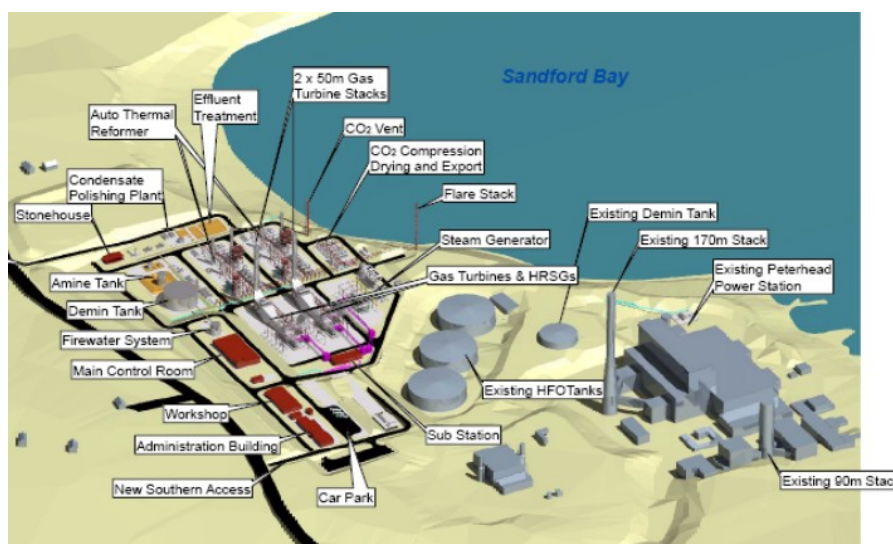
Figure 11: The 618 MW Edwardsport IGCC Plant, Indiana, USA



Source: Zeus Intelligence website:
http://member.zeusintel.com/gasification/project_news.aspx?plantid=141

Where the fuel is natural gas the first stage is steam reforming of the gas at high temperatures (700–1100 °C), such that steam reacts with methane to yield a mixture of carbon monoxide and hydrogen, referred to as syngas. In the second stage, further hydrogen is generated through the lower-temperature water gas shift reaction, performed at about 130 °C. The CO₂ is separated from the gaseous mixture before the power generation stage.

Figure 12: Artist's Impression of the Original 475 MW Peterhead Gas Pre-Combustion Separation Power Plant Project at Peterhead, UK



Source: BP Presentation: 'Hydrogen Power (with CCS) at Peterhead', 2007, at <http://www.ccsassociation.org.uk/docs/2007/Monday%201415%20-%20Jane%20Paxman.pdf>

Note: the structures in grey in the right half of this figure are existing facilities which are not part of the CCS project.

With both coal and natural gas pre-combustion approaches, the higher temperatures experienced in the combustion gas turbine (due to the fuel being hydrogen) are factors which require specific design considerations. Given the significantly higher flame speed of hydrogen compared with methane, special burner nozzle design features are necessary to ensure flame stability.⁴²

The key challenges for the pre-combustion approach relate to the relative complexity of the equipment necessary to transform the coal or gas fuel into a CO₂ and hydrogen mixture and to effect CO₂ separation prior to combustion and power generation. Figures 11 and 12 convey the impression of a petrochemical complex rather than a power generation plant.

Table 3 shows the status of world pre-combustion CCS projects in the power generation sector. Only one of these is gas based.

⁴² GE 2010, P. 4

Table 3: Pre- Combustion Project Status at July 2012

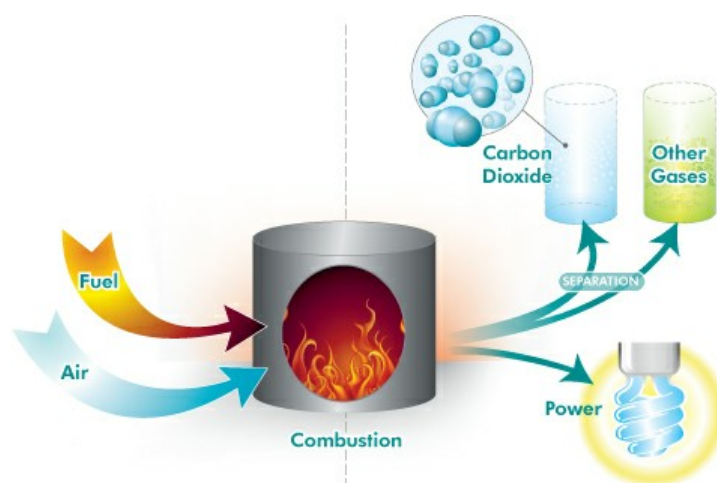
Name	Location	Stage	CO2 Storage	Fuel
Dongguan Taiyangzhou IGCC with CCS Project	China	Identify	Offshore Depleted Oil and Gas Reservoirs	Coal
Lianyungang IGCC with CCS Project	China	Identify	Enhanced Oil Recovery	Coal
C.GEN North Killingholme Power Project	Europe Area	Evaluate	Offshore Deep Saline Formations	Coal
Cash Creek Generation	United States	Evaluate	Enhanced Oil Recovery	Coal
GreenGen IGCC Project	China	Evaluate	Various	Coal
Quintana South Heart Project	United States	Evaluate	Enhanced Oil Recovery	Coal
Stuart Basin CCS Project	Australia	Evaluate	Onshore Deep Saline Formations	Coal
Teesside Low Carbon (formerly Eston Grange)	UK	Evaluate	Offshore Deep Saline Formations	Coal
Don Valley Power Project	UK	Define	Enhanced Oil Recovery	Coal
Hydrogen Energy California Project (HECA)	United States	Define	Enhanced Oil Recovery	Coal & Pet Coke
Hydrogen Power Abu Dhabi (HPAD)	Abu Dhabi	Define	Enhanced Oil Recovery	Gas
PurGen One	United States	Define	Offshore Deep Saline Formations	Coal
Taylorville Energy Center	United States	Define	Onshore Deep Saline Formations	Coal
Texas Clean Energy Project	United States	Define	Enhanced Oil Recovery	Coal
Kemper County IGCC Project	United States	Execute	Enhanced Oil Recovery	Coal

Source: Global CCS Institute Projects Portal, <http://www.globalccsinstitute.com/projects/browse>

2.2.5 Post Combustion

In the post combustion approach CO₂ is separated from the mixture of gases (CO₂, water vapour and nitrogen) after combustion has taken place. This is shown schematically in Figure 13.

Figure 13: Post Combustion Schematic



Source: CO2CRC, <http://www.co2crc.com.au/imagelibrary3/capture.php?screen=3>

The advantage of this approach is that complex plant to transform the fuel to hydrogen at the pre-combustion stage is not required. The drawback is that CO₂ must be removed at lower concentrations in the flue gas stream as it is diluted with nitrogen and water vapour. This approach does however allow plant to be built initially without CO₂ capture equipment but to be ‘capture ready’ for the future addition of CCS equipment.

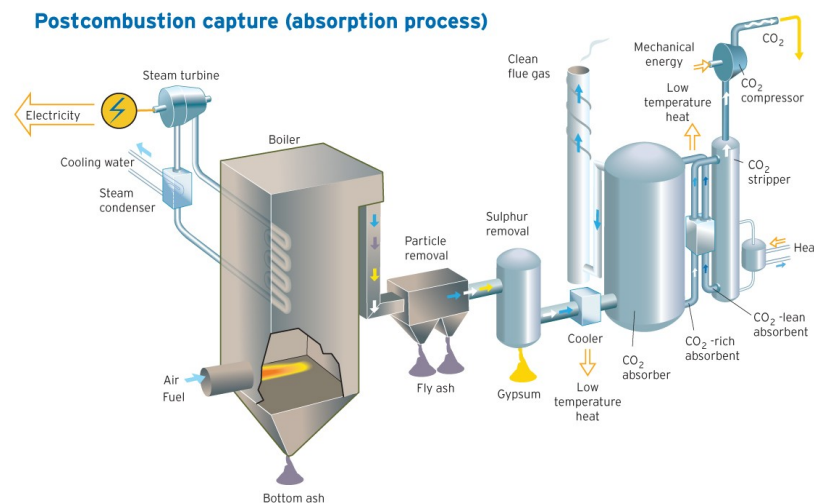
In 2009 the EU issued a ‘Directive on the Geological Storage of Carbon Dioxide’ of which Article 33 referred to ‘Carbon Capture Readiness’. In its Guidance Note summary DECC wrote:⁴³

‘Article 33 requires that the technical and economic feasibility of retrofitting carbon capture equipment and of the transport of CO₂, together with the availability of CO₂ storage sites, should be assessed by the applicant and consenting body during the process of deciding whether to grant an operating or construction licence for any new power station with electrical outputs at or over 300 MW and of type covered by the LCPD. If Member States’ consenting authorities consider that it is technically and economically feasible for a power station to be retrofitted with CCS technology, they must require suitable space to be set aside for the future retrofit of carbon capture equipment. This guidance implements both Article 33 of the Directive and the Government’s further requirement that if a proposed power station is subject to the Directive requirements, it will only be granted development consent if it is assessed positively against the Article 33 criteria’.

In addition it may be necessary to undertake design changes to some equipment items in the original plant. However, in the view of Mott MacDonald⁴⁴: ‘It is unlikely that these modifications, except possibly securing extra land, would significantly increase capital costs, if factored in at the initial design stage’

Unsurprisingly the ability to ‘add-on’ the separation plant at a later date enhances the appeal of post-combustion capture schemes. What should not be underestimated however is the physical size of the capture plant (and its cost).

Figure 14: A Coal-Fired Plant with Post-Combustion CO₂ Capture



Source: Vattenfall Website, <http://www.vattenfall.com/en/ccs/illustrations.htm> (illustrator: www.kjell-design.com)

⁴³ DECC 2009

⁴⁴ Mott MacDonald 2010, P 31

Figure 14 does not necessarily convey the size of the CO₂ separation plant relative to the power plant. RWE Power have built and are operating a pilot post-combustion capture plant on an existing coal-fired plant at Niederaussem, in Germany. In their literature they state:

‘The height of the pilot CO₂ scrubbing plant (40 m) corresponds to that of the future commercial plant. The plant also comprises all individual components of large plants, but on a smaller scale. The diameter of the absorber column was limited to the size required to obtain representative results. Depending on the set test parameters, up to 300 kg CO₂ per hour can be separated from a flue gas bypass (corresponds to a capture rate of 90 %).’⁴⁵

The status of the world’s post-combustion power sector CCS projects is shown in Table 4. The majority are associated with coal-fired generation. The three gas projects are at a relatively immature stage of definition with one located in the UK (Peterhead Power Station).

Table 4: Power Sector Post-Combustion Project Status at July 2012

Name	Location	Stage	CO2 Storage	Fuel
Maritsa Thermal Power Plant CCS Project	Bulgaria	Identify	Onshore Deep Saline Formations	Coal
Bow City Power Project	Canada	Evaluate	Enhanced Oil Recovery	Coal
Emirates Aluminium CCS Project	Middle East	Evaluate	Enhanced Oil Recovery	Gas
Full-scale CO2 Capture Mongstad (CCM)	Norway	Evaluate	Not specified	Gas
Getica CCS Demonstration Project	Romania	Evaluate	Onshore Deep Saline Formations	Coal
Korea-CCS 1	East Asia	Evaluate	Offshore Deep Saline Formations	Coal
Peterhead Gas CCS Project	UK	Evaluate	Offshore Depleted Oil and Gas Reservoirs	Gas
Sinopec Shengli Oil Field EOR Project	China	Evaluate	Enhanced Oil Recovery	Coal
Eemshaven CCS	Holland	Define	Enhanced Oil Recovery	Coal
NRG Energy Parish CCS Project	United States	Define	Enhanced Oil Recovery	Coal
Porto Tolle	Italy	Define	Offshore Deep Saline Formations	Coal
Rotterdam Opslag en Afvang Demonstratieproject (ROAD)	Holland	Define	Offshore Depleted Oil and Gas Reservoirs	Coal
Tenaska Trailblazer Energy Center	United States	Define	Enhanced Oil Recovery	Coal
Boundary Dam Integrated Carbon Capture and Sequestration Demonstration Project	Canada	Execute	Enhanced Oil Recovery	Coal

Source: Global CCS Institute Projects Portal, <http://www.globalccsinstitute.com/projects/browse>

Note: Mongstad involves the retrofit of carbon dioxide (CO₂) capture at an existing CCGT plant that produces 280 MW electricity and 350 MW heat. A final decision on the full-scale project is expected to occur in 2016. The full scale collection of CO₂ could begin in 2020 (Source Global CCS Institute Website, <http://cdn.globalccsinstitute.com/projects/12386>).

2.3 CO₂ Separation Stage

2.3.1 Currently Identified CO₂ Separation Processes

Clearly the Oxyfuel approach, after the removal of water vapour by condensation (through cooling the flue gas), produces essentially pure CO₂ and therefore a separation stage is not required. For the Pre- and Post-Combustion approaches the currently anticipated CO₂ separation technologies are:

- Absorption: the uptake of CO₂ into the bulk phase of another material, for example dissolving CO₂ molecules into a liquid solution. The solvent is regenerated by heating which releases the CO₂ which may then be transported to storage. The overwhelming

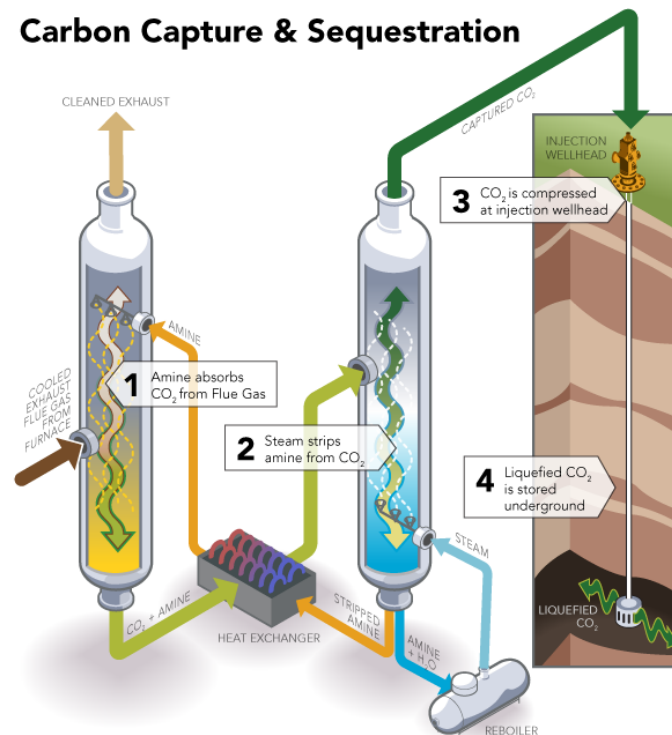
⁴⁵ RWE 2012 a

majority of near-term and mid-term Post-Combustion planned projects and all commercially available Pre-Combustion processes incorporate this technology.

- Adsorption: the selective uptake of CO₂ molecules onto a solid surface. The adsorbent selectively adsorbs CO₂ from the gaseous mixture and is then regenerated by lowering pressure and/or increasing temperature to liberate the adsorbed CO₂. A claimed advantage of the adsorption process is that the regeneration energy should be lower relative to the Absorption process.
- Membranes: the separation of CO₂ from a gaseous mixture by selectively permeating it through the membrane material. Like adsorbents, membranes are claimed to potentially offer low energy capture processes⁴⁶.

The schematic in Figure 15 represents an amine-solvent based absorption process. This process has been used for CO₂ removal in petrochemical processes for many years.

Figure 15: Amine-Based CO₂ Absorption Process



Source: http://www.captureready.com/userfiles/image/Carbon%20Capture/Carbon_Capture.png

⁴⁶ Global CCS 2011, pp. 38 – 39

It is important to stress at this stage, before consideration of the CO₂ transport and storage stages, that CCS in the power sector is characterised by:

- The requirement to add additional capital intensive process units to coal or natural gas generation plant, i.e. the additional plant required for oxygen separation, conversion of coal or gas to a CO₂ and hydrogen fuel mixture and of course the CO₂ removal units.
- The additional energy required to run such additional processes, whether a requirement for heating and cooling or additional pumping or compression power provided by a portion of the power generated by the plant.

Table 5 compares, for coal and gas power generation plant, a range of metrics which convey the impact on capital cost, conversion efficiency of adding CO₂ separation plant to coal and gas fired generation facilities.

Table 5: Average Cost and Performance Data by CO₂ Capture Route and Fuel

	Coal		Natural Gas
	Pre-Combustion (IGCC)	Post Combustion	Post Combustion
Net Efficiency Without Capture (LHV %)	41.7%	40.8%	54.7%
Net Efficiency With Capture (LHV %)	29.9%	29.3%	41.9%
% Loss of Efficiency compared to case without Capture	28.4%	28.2%	23.4%
Capital Cost Without Capture (£/Kw)	2669	1998	809
Capital Cost With Capture (£/Kw)	3187	3073	1372
Incremental Capital Cost for Capture (£/Kw)	518	1075	563
% of Capital Cost increase compared with case without Capture	19.4%	53.8%	69.6%

Note: Data cover only CO₂ capture and compression but not transportation and storage.

Source: ‘UK Electrical Generation Costs Update’ Mott MacDonald, 2010, <http://www.decc.gov.uk/assets/decc/statistics/projections/71-uk-electricity-generation-costs-update.pdf>

2.3.2 The Relative Merits of CCS for Coal and Gas Fuelled Power Sector Application

From the foregoing discussion, the pre-combustion CCS coal and gas applications involve radically different equipment design (to transform the raw fuel to a hydrogen and CO₂ mixture) compared to the ‘unabated’ power generation configuration for the same fuel. The relative merits of coal versus gas pre-combustion CCS can only therefore be judged by a comparison of their relative project economics. For ‘post-combustion’ CCS however, given the similarity of the CO₂ capture process and technology used for both, is it possible to generalise as to whether coal or gas based generation will generally be more attractive from a project economics perspective?

Table 6: Typical Compositions of Flue Gases from Coal- and Gas-Fired Plants

Gas Component	Coal	Natural Gas (CCGT)
Nitrogen	70-75%	73-76%
Carbon Dioxide	10-15%	4-5%
Water Vapour	8-15%	8-10%
Oxygen	3-4%	12-15%
Trace Gases (Sox, Nox, others)	<1%	<1%

Source: Global CCS Institute

The accompanying explanation on this issue from the Global CCS Institute is instructive⁴⁷:

‘Carbon is the predominant combustion species in coal, while both carbon and hydrogen are combusted in natural gas; thus, for each CO₂ molecule generated during combustion, coal has less energy release. This results in coal power plants typically generating twice as much CO₂ as gas power plants for the same power output, about 1 g CO₂/kWh vs. 0.5 g CO₂/kWh. However, flue gas from coal power plants has more concentrated CO₂ relative to natural gas. This results in CO₂ capture consuming less energy for coal power plants relative to gas power plants for the same mass of CO₂ captured. The net result in terms of parasitic load on the host power plant and cost of electricity increase due to the capture process therefore is not straight forward particularly with the range of coal and natural gas prices. Due to the predominance of coal in power production and the likelihood of CO₂ -control regulations impacting those most, the overwhelming emphasis of capture process developers has been on coal-fired power plants. Research and development for capture on natural gas-fired power plants is relatively scarce, though regulations may require natural gas-fired power plants to have CO₂ emission controls similar to that expected for coal fired power plants’.

This is consistent with the emphasis placed on coal-based CCS schemes in a power sector context in North America and European countries which historically have relied on coal as a major part of their power generation base.

2.3.3 The Potential for Technological Breakthrough in CO₂ Separation

Clearly Carbon Capture imposes a large additional energy load on a power plant, especially the energy required to regenerate the solvent in an absorption process. Energy is also required to compress the CO₂ prior to transportation to a storage site, however compression is a mature technology and there is less scope for increased energy efficiency. Consequently research and development efforts are focussed on the development of new chemistry, new process designs and novel power plant integration schemes, all aimed at reducing the separation stage energy requirements (often referred to as the ‘parasitic load’)⁴⁸

⁴⁷ Global CCS 2012 a

⁴⁸ Ibid, P. 8.

Table 7 sets out the current state of Post-Combustion CO₂ Capture Development.⁴⁹

Table 7: State of Post-Combustion CO₂ Capture Development

	Absorbent	Adsorbent	Membrane
Commercial Usage in Chemical Process Industries	High	Moderate	Low/Niche
Operational Confidence	High	High but Complex	Low to Moderate
Primary Source of Energy Penalty	Solvent Regeneration (thermal)	Sorbent Regeneration (thermal/vacuum)	Compression on feed and/or vacuum on permeate
Development Trends	New chemistry, thermal integration	New chemistry, process configuration	New membrane, process configuration

Source: *Global CCS 2012 a, P.13*

Near-term technologies are predominantly aqueous-based solvents and as such they are highly energy intensive. Longer term technologies may be less energy intensive but have greater uncertainty. There are certainly diverse lines of research in progress to improve the CO₂ separation stage, as demonstrated by the following examples:

Enzymes: Researchers at Codexis, California are experimenting with genetically engineered enzymes to improve capture efficiency. The enzyme, carbonic anhydrase, helps a solvent called methyl diethanolamine bind with the CO₂, thus potentially reducing the size and energy input required in the separation process. The challenge is to adapt the ability of the enzyme to survive the high temperatures existing in the CO₂ de-sorption stage⁵⁰.

Natural Molecular Sieves: Researchers at the University of Alberta are looking at the use of zeolites (naturally occurring minerals used in air separation and water purification) to separate CO₂ and hydrogen in a membrane separation process⁵¹. If successful this could find an application in the pre-combustion separation stage.

Algae: Research at the University of Kentucky is investigating the use of waste heat and CO₂ from power generation flue gases to cultivate algae. The demonstration project uses a closed culture system with vertical photo-bioreactor tubes. The intention is to process the harvested algae into bio-diesel, animal feed, fertiliser and chemicals⁵².

⁴⁹ Note: The challenges of improving efficiencies in Pre-Combustion schemes are analogous. While they are not specifically addressed here they are summarised in Global CCS 2012 b.

⁵⁰ MIT 2010

⁵¹ Chem Eng 2011, pp.42 – 44,

⁵² UOK 2011

CO₂ capture technology is an area which generates frequent comment in the energy media. An example is the recent article in Bloomberg: ‘U.K. Says Technology Advances May Cut Carbon Capture Cost By 29%’⁵³ The origin of this story is a report issued by the Low Carbon Innovation Co-ordination Group which assesses the process by which innovation could reduce costs between now and 2050⁵⁴, rather than an announcement of a specific technology ‘breakthrough’. While such breakthroughs would be welcomed, they are by nature difficult to predict. The less sensational scenario of progressive incremental gains in efficiency and cost reduction is equally plausible.

And while it is tempting to conclude that the wise course to follow would be to await further technology breakthroughs in the field of CO₂ separation, whilst ensuring such future lower-cost facilities could be added to new ‘capture ready’ gas and coal fired generation plant, this is not the view taken by the Global CCS Institute who state:

‘Although current technology needs further improvements, it is extremely important to demonstrate CCS on a commercial scale as soon as possible. This is needed for the demonstration of capture technology operating in an integrated mode in a real power plant and in a real power grid environment. It is also necessary to demonstrate sequestration/storage at sufficient scale that has credibility for further deployment. Unless progress is made at the commercial CCS demonstration scale to answer these two basic issues it will become increasingly difficult to justify continued R&D funding on potential improvements to capture and storage technologies.

If multiple CCS demonstrations with improved technologies are to be achieved at large-scale by 2020 to proceed with commercial deployment, then many technologies need to be approaching the pilot plant stage today. However, currently there are very few organizations funding demonstrations at one-tenth to full commercial-scale. Some pilot plant scale capture projects have been funded but advancing to sub-commercial scale demonstrations and larger will require an order of magnitude greater level of funding’⁵⁵.

At face value this seems a somewhat questionable approach which possibly speaks to the realpolitik of raising research and development funding rather than the optimal allocation of capital expenditure over time. However, this classic ‘chicken and egg’ issue needs to be set to one side until after the discussion in Chapter 3 of the relative economics of differing low carbon generation options.

2.4 CO₂ Transportation

In the USA there exist over 3,400 miles of CO₂ pipelines which transport CO₂ from naturally occurring CO₂ reservoirs to oil fields in West Texas and the US Gulf Coast for Enhanced Oil Recovery⁵⁶. Gaseous CO₂ is typically compressed to a pressure above 80 times atmospheric

⁵³ Bloomberg 2012

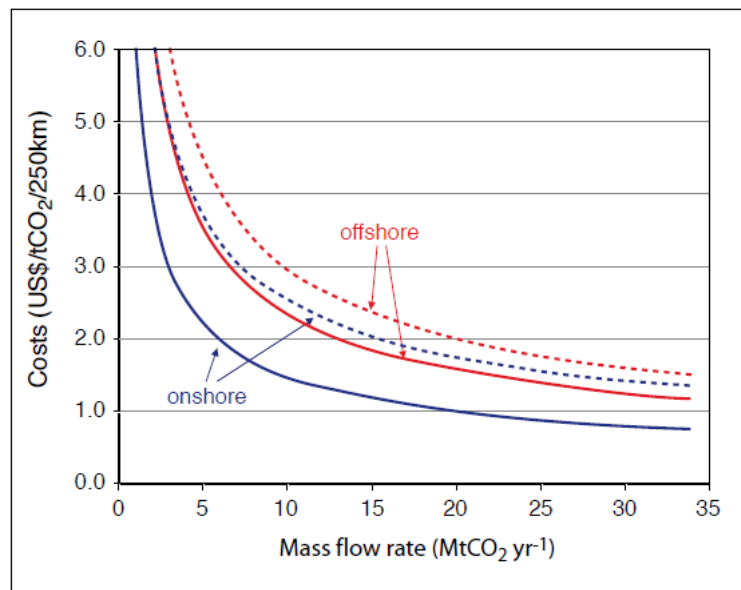
⁵⁴ TINA 2012

⁵⁵ Global CCS 2012 c, P. 6

⁵⁶ Herzog 2010, P.2

pressure in order to avoid two-phase flow⁵⁷ and increase the CO₂ density to improve transport economics. Dry CO₂ is not corrosive to the manganese steels usually used for pipelines even if it contains contaminants such as oxygen, hydrogen sulphide and sulphur or nitrogen oxides. Moisture-containing CO₂ is however highly corrosive and the pipeline in this case would need to be made from (more expensive) corrosion-resistant alloys or be internally coated⁵⁸. The economies of scale for CO₂ pipeline transportation are shown in Figure 16. This is extremely useful in demonstrating the need for ‘clusters’ of power plant to support the construction of CO₂ transportation systems.

Figure16: Transport Costs for Onshore and Offshore CO₂ Pipelines



Source: Rubin 2006: ‘Carbon Dioxide Capture and Storage, Technical Summary’.

Note: The graph shows high estimates (dotted lines) and low estimates (solid lines).

The annual CO₂ emissions from a 1,000 MW-sized CCGT and a Coal-Fired Power plant are calculated (at an 80% load factor) to be 2.2 and 5 million tonnes per year respectively. Figure 16 indicates the need to achieve a pipeline CO₂ flow-rate of at least 10 million tonnes per year to achieve economies of scale. This is a powerful argument in favour of the ‘cluster concept’, i.e. an optimally sized CO₂ transportation system linking multiple power generation plant with CCS with possibly several CO₂ storage sites.

⁵⁷ Two-phase flow is a situation where the substance being transported separates into (typically) liquid and gaseous phases. This results in the liquid phase accumulating in low points in the pipeline system until the point where it restricts the movement of the gaseous phase. At this point pressure build up causes a ‘slug’ of liquid to surge through the pipe which can destabilise the system operation and cause damage to downstream equipment.

⁵⁸ Rubin 2006, P.30

2.5 CO₂ Storage

The injection of CO₂ in deep geological formations involves many of the same technologies which have been developed in the oil and gas exploration and production industry. Natural gas storage and the deep injection of mixtures of CO₂ and H₂S have been conducted in North America since 1990 at industrial scale. CO₂ storage in oil or gas reservoirs or in saline aquifer formations is generally expected to take place at depths below 800m where prevailing pressures and temperatures will usually result in the CO₂ being in a liquid or supercritical state. In this state the CO₂ density will range from between 50% and 80% of the density of water, resulting in buoyancy forces tending to drive the CO₂ upwards. It is therefore essential to ensure that a sealing caprock of appropriately low permeability exists above the reservoir to ensure that the CO₂ remains trapped underground⁵⁹.

Deep saline aquifers probably have the largest potential in aggregate volume terms for CO₂ storage, nevertheless they will not have the pre-existing wells and facilities one might expect to be present at a depleted oil or gas field location, which represent a more economically attractive option. Studies on CO₂ storage in depleted oil and gas reservoirs have been extensive, whether dealing with underground migration, geochemical modelling or long-term integrity and risk-assessment. However, there have been more limited studies on what the suitable upper limit of storage site pressure should be. This has often been assumed to equate to the original reservoir pressure, prior to the start of field oil or gas production (which would be known from records). This is based on the assumption that the sealing capacity of the caprock which retained the oil or gas in the first place should be sufficient to prevent the injected CO₂ escaping. However a CO₂/water system has a lower interfacial tension than a hydrocarbon/water system and hence would result in a lower capillary sealing pressure for CO₂⁶⁰, i.e. it should be expected that CO₂ would escape through the caprock at a lower pressure than would natural gas.

The storage capacity of underground site types also differs depending on their nature. In a depleted natural gas reservoir which has not been invaded by formation water, storage capacity can be assessed as the volume of CO₂ which can be injected to take the reservoir up to the estimated caprock seal pressure limit. For water-flooded depleted oil reservoirs the volume available for CO₂ storage is limited to what can be injected as a gaseous phase in the top of the reservoir up to the estimate of the caprock sealing pressure, and the volume which dissolves in the formation water⁶¹. Clearly this is an area which requires detailed reservoir engineering study prior to the selection of a CO₂ storage site, and especially so where the CO₂ is being used in an oil reservoir EOR scheme where estimates of the quantity of CO₂ to be left in the reservoir at the end of field life require sophisticated reservoir engineering simulation.

⁵⁹ Ibid, P. 31

⁶⁰ Dong & Huang 2005, P. 2

⁶¹ Van der Meer 2005, P. 534

As was observed in Chapter 1 relating to the Janschwade project in Germany, it is likely that, in Europe, public (and therefore political) concerns regarding potential leakage of CO₂ from underground storage sites will lead to a preference for offshore depleted fields, at least until it can be demonstrated that risks are of an acceptable level⁶². In the Netherlands the use of three depleted onshore gas fields as potential CO₂ storage facilities was blocked by the Dutch government following local opposition⁶³. In the UK context the use of offshore depleted fields as storage sites is perhaps an obvious assumption given the relatively small number of onshore fields which, where they do exist, are of modest size. Offshore field storage does however have the added complication of requiring assurance that the offshore facilities (platform structures and required associated plant and equipment) have, or can be upgraded to have an extended useful life of an additional 20 to 40 years. This plus the installation of compression equipment and potentially additional wells or well recompletions will require additional investment which may be considerable.

2.6 Review of the Practicalities of CCS

This section may have left the reader with the impression that applying CCS to power generation adds a number of dimensions of complexity they were not expecting to encounter. This is an entirely reasonable response and one which highlights the challenges to be overcome in establishing CCS at a commercial scale in the power sector. In this respect, the following points stand out from our overview of the practicalities of CCS:

- A successful commercial scale CCS project requires a ‘chain’ of physical activities which, differing in nature, require differing skills sets for successful operation, from a technological and commercial perspective.
- In order to achieve economies of scale in transportation infrastructure and potentially to diversify operational risk at each end of the chain, the ‘cluster’ concept of power plant generating CO₂ and of CO₂ storage facilities is likely to be a requirement for success.
- Each segment of the chain needs an economic return commensurate with the perception of the risk undertaken and, where appropriate, shared with counterparties in the adjacent link in the chain.

The pressing question at this point is, inevitably: ‘Is the potential reward really worth the cost and complexity of CCS?’ This is addressed in the following Chapter.

⁶² Although this has not seemingly been a concern with regard to US CO₂ injection in oil fields for EOR purposes.

⁶³ Foreest 2011, P 18

3. The Economics of CCS Relative to Other Forms of Power Generation

3.1 Introduction

This Chapter examines the economics of CCS (for coal and gas) in a manner which enables us to explore the relative economics of different generation types based on assumptions regarding future gas and coal prices and also CO₂ allowance prices. The analysis is based upon data from two detailed reports prepared for DECC by consultants in 2010 and 2011^{64,65}.

Mott MacDonald's 2010 report provides a summary and supporting documentation for their assessment of current and future power generation costs. The report describes in some detail the cost and operating assumptions used and the basis on which they were derived. While the original brief from DECC is not disclosed in the report, it is evident that it is intended to provide a direct comparison between generation types, based on DECC's scenarios of future fuel, CO₂ prices and other economic assumptions. The comparison is based on the concept of 'levelised cost of generation'. This is explained further in Appendix 1, but in essence it is the electricity price which would remunerate the costs of generation and provide a return on investment at a specified discount rate. The main technologies covered in this report are: gas CCGT, gas CCGT with CCS (post-combustion), coal, coal with CCS (post-combustion), IGCC coal, IGCC coal with CCS (pre-combustion), onshore wind, offshore wind, offshore wind Round 3 and nuclear.

Parsons Brinckerhoff's report was produced in 2011. The Executive Summary states: *'This report provides the supporting information to the update of cost assumptions and technical inputs for the DECC Levelised Electricity Cost Model'*. The main technologies covered excluded the wind generation cases covered by Mott MacDonald.

Both reports focused on 'First of a Kind' (FOAK) cases (i.e. cases whose cost and efficiency level estimates were essentially those pertaining at the time of preparing the report) and 'Nth of a Kind' (NOAK) cases which reflect anticipated improvements in cost levels and efficiencies resulting from future technology improvements and more widespread deployment.

In this section we will use the results of a levelised model built by the author which incorporates the cost and efficiency assumptions provided by the two reports to compare the levelised costs of gas with CCS and coal with CCS with those of other power generation types over a range of price assumptions. By following the methodology in Mott MacDonald it was possible to effectively 're-create' the DECC model and achieve results close to those contained in the reports.

⁶⁴ Mott MacDonald 2010

⁶⁵ Parsons Brinckerhoff 2011

This chapter will also examine the impact on the UK power generation system of increasing levels of wind generation capacity and the role of gas-fired generation in meeting the challenge of providing balancing or buffering back-up for this variable and unpredictable power source. The chapter also investigates whether gas with CCS is also capable of providing this balancing role at an acceptable cost and with minimal CO₂ emissions.

3.2. Cost and Performance Assumptions

The cost and performance assumptions for the power technologies considered in this paper are shown in Table 8, for the First of a Kind case, as assessed in the Mott MacDonald paper.

The cost data have been normalised (scaled) in each instance to relate to a power generation facility rated at 1,000 MW capacity. Gas and coal plant are assumed initially to be operating in base-load mode (90% load factor) for purposes of comparison. The corresponding tables for the Mott MacDonald NOAK and the Parsons Brinckerhoff FOAK and NOAK gas and coal generation cases are shown in Appendix 2.

From Table 8 we note a wide variation in capital cost for a 1000 MW generating facility and the considerable increase in cost when adding CCS capability to both a CCGT (70% increase in capital cost) and coal (54% increase in capital cost). There is also a considerable range in net generation efficiencies for the fossil fuel examples here – ranging from 55% for unabated CCGT's down to 29.9% for a coal IGCC with CCS.

Included in the table are Mott MacDonald's estimate of CO₂ transport and storage cost. In their report they offer little in the way of detail other than:

'In all cases it is assumed that compressed CO₂ is fed into a pipeline network for transport to an underground storage site. Costs of transport and storage are factored in based on a user charge per tonne of CO₂ captured. No benefit is assumed from enhanced oil recovery (EOR)'.

While modelling results (see later) indicate that for gas with CCS this is not a major cost element⁶⁶ influencing economic viability, this may be an area which proves to be more significant if and when projects move to a higher level of definition, especially if storage sites are offshore.

⁶⁶ It is however more significant for coal with CCS schemes.

Table 8: Cost and Performance Data for a Range of FOAK Power Generation Types, (normalised to a 1,000 MW generation facility)

2010 Report FOAK	Units	Gas CCGT	Gas CCGT with CCS	Coal	Coal with CCS	Coal IGCC with CCS	Nuclear	Onshore Wind	Offshore Wind	Offshore Wind Round 3
Capital Cost	£million	809	1372	1998	3073	3187	3744	1701	3110	3625
Fixed Operating Costs	£million/year	17	32	50	77	75	78	16	80	98
Variable Operating Costs	£million/year	28	37	38	43	49	14	20	34	44
CO ₂ Transport & Storage Costs	£million/year	n/a	26	n/a	53	53	n/a	n/a	n/a	n/a
Planning time	years	2	2.4	3.3	4.4	4.4	4.4	6	6	6
Construction time	years	2.8	4.2	4.8	5.4	4.8	6	2	2	2
Availability	%	89.7%	88.0%	89.0%	84.5%	86.3%	86.3%	96.6%	94.6%	94.6%
Load Factor When Available	%	90%	90%	90%	90%	90%	90%	28%	39%	39%
Gross Efficiency (LHV)	%	56.0%	47.5%	43.9%	35%	35.1%	n/a	100%	100%	100%
Net Efficiency*	%	54.7%	41.9%	40.8%	29.3%	29.9%	n/a	98.0%	97.8%	97.8%
Operating Life	years	25	27	36	36	25	60	22	22	22

* After accounting for power used within plant.

Source: Mott MacDonald 2010, Own assumptions and analysis.

Note: All data is from Mott MacDonald scaled to a 1,000MW facility. For the non-Wind cases a 90% load factor was used for the purposed of comparison. For CCS options it is assumed that 90% of CO₂ is captured. Mott MacDonald simplified the treatment of Nuclear by incorporating expected fuel cost directly rather than apply a specific efficiency of generation.

In addition to capital and operating costs, for the fossil fuel options we also need to take into account fuel costs and also the impact of the price of CO₂ allowances, particularly on the unabated technologies. Using the ‘Levelised Cost of Generation’ methodology, we will examine the relative economics of this suite of power generation technologies under the following two assumption sets, defined by the Author:

Base Case Scenario:

Exchange Rates: \$/£ = 1.6, €/£= 1.1 (DECC assumptions in Mott MacDonald)

Gas Price: \$10/mmbtu (62.5 pence per therm)

Coal Price: \$90/tonne (\$3.78/mmbtu net calorific value basis)

CO₂ Allowance Price: £40/tonne

Levelised Cost Discount Rate: 10% (DECC assumptions in Mott MacDonald)

High Case Scenario:

Exchange Rates: \$/£ = 1.6, €/£= 1.1 (DECC assumptions in Mott MacDonald)

Gas Price: \$15/mmbtu (93.8 pence per therm)

Coal Price: \$120/tonne (\$5.04/mmbtu net calorific value basis)

CO₂ Allowance Price: £80/tonne

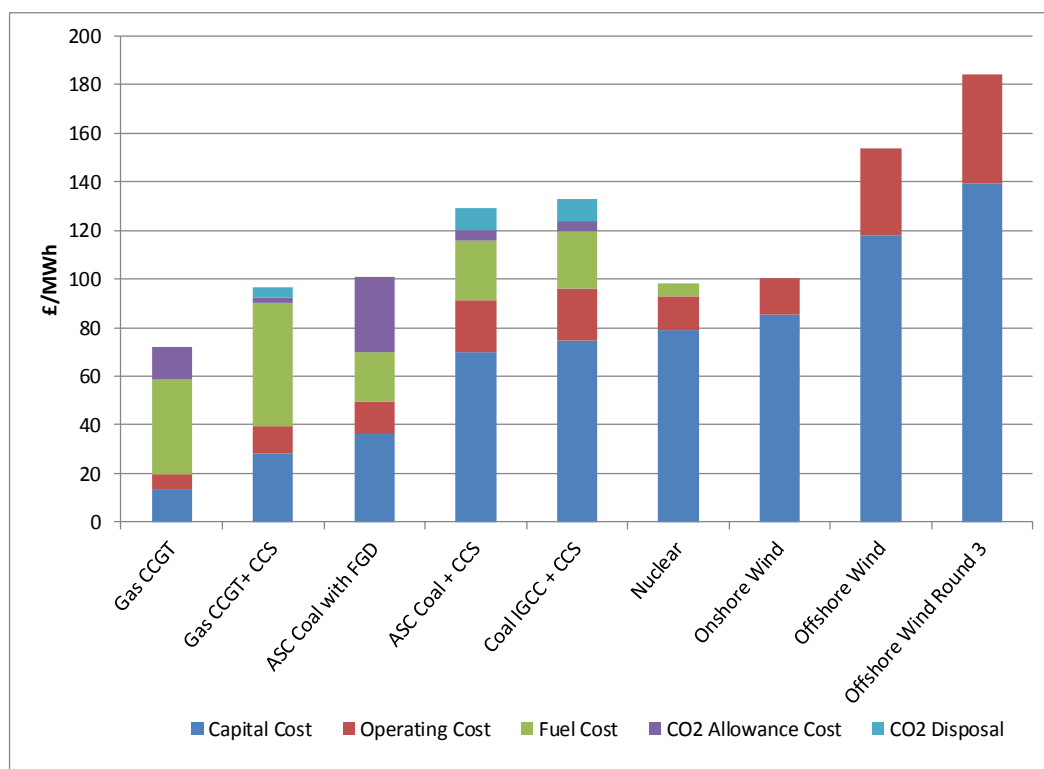
Levelised Cost Discount Rate: 10% (DECC assumptions in Mott MacDonald)

3.3 Levelised Cost Analysis

Mott MacDonald-Base Case: The levelised cost analysis looks at the four cost and performance assumption sets⁶⁷ for the Base Case Scenario.

⁶⁷ Mott MacDonald FOAK and NOAK, Parsons Brinckerhoff FOAK and NOAK

Figure 17: Levelised Cost of Generation, Mott MacDonald FOAK⁶⁸ Assumptions, Base Case Scenario



Source: Own Analysis

Figure 17 shows the levelised costs of generation under the base case scenario using the Mott MacDonald FOAK assumptions. The underlying data is shown in Table 9.

Table 9: Levelised Cost of Generation, Mott MacDonald FOAK Assumptions, Base Case Scenario

	Gas CCGT	Gas CCGT+ CCS	ASC Coal with FGD	ASC Coal + CCS	Coal IGCC + CCS	Nuclear	Onshore Wind	Offshore Wind	Offshore Wind Round 3
Capital Cost	13.4	28.2	36.0	70.1	74.9	79.0	85.2	117.8	139.2
Operating Cost	6.4	11.3	13.5	21.3	21.4	14.2	15.4	36.1	44.8
Fuel Cost	39.0	50.9	20.5	24.4	23.1	5.3			
CO2 Allowance Cost	13.0	1.7	30.9	4.3	4.2				
CO2 Disposal		4.3		9.3	9.2				
Total Levelised Cost	71.8	96.4	100.9	129.5	132.8	98.4	100.6	153.8	184.1

Source: Own Analysis

Note: The Nuclear fuel levelised cost was taken from MottMacDonald's results.

ASC = Advanced Supercritical Coal, FGD=Flue Gas Desulphurisation, IGCC Integrated Gasification Combined Cycle

⁶⁸ FOAK – First Of A Kind

The results of this analysis are:

- For the unabated fossil fuel options, the new-build investment economics⁶⁹ are more favourable for gas than for coal (levelised generation cost of £72/MWh vs £100.7/MWh), and this would be the case at zero CO₂ allowance prices. While CCGTs incur significantly higher fuel costs, they benefit from lower unit capital and operating costs and higher efficiencies, as shown in Table 9.
- CCGTs with CCS are significantly more viable than ASC coal with CCS or coal IGCC with CCS, by a significant margin. Although fitting CCGTs with CCS equipment represents a significant percentage increase in capital cost, the absolute cost increase associated with coal CCS plant outweighs this.
- CCGT's with CCS have a levelised cost broadly on a par with onshore wind and nuclear but are significantly more attractive than offshore wind and have around half the Levelised cost of Round 3 offshore wind.

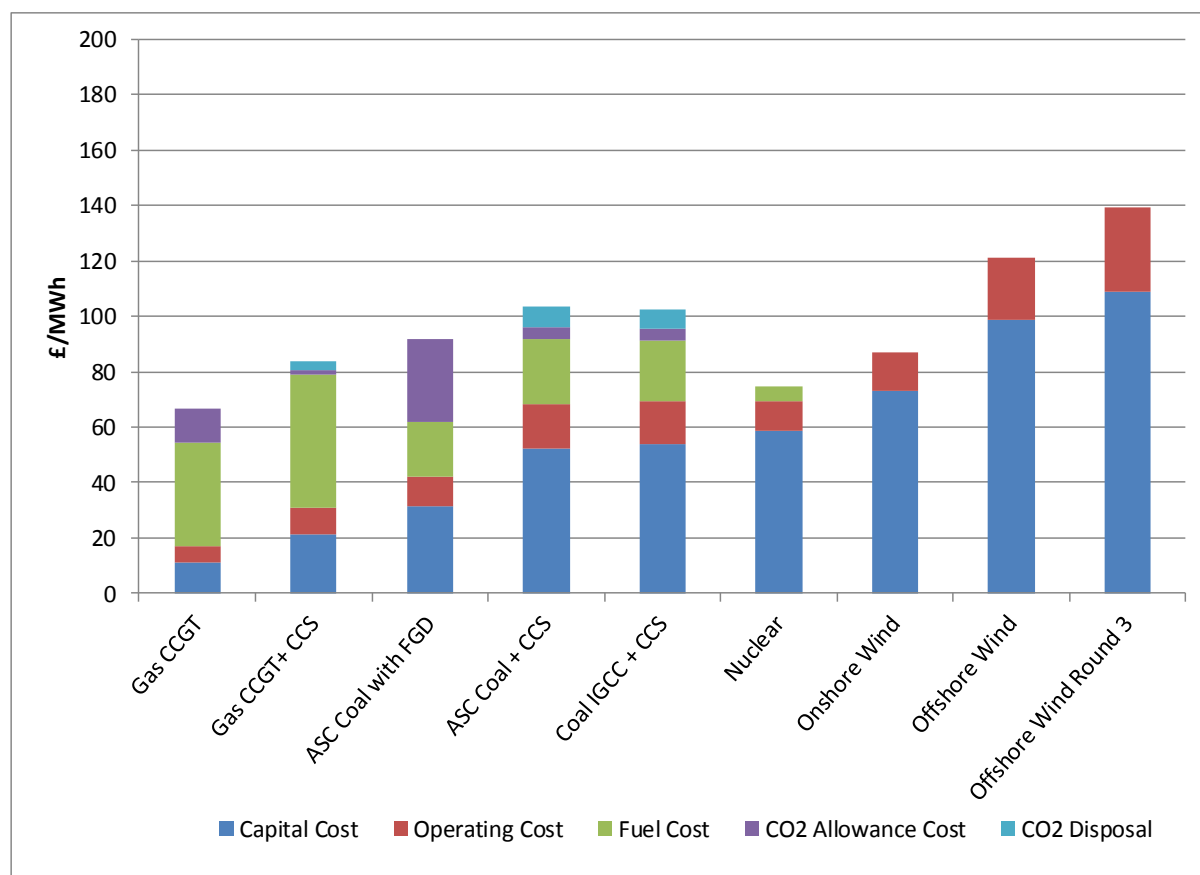
Although there has been significant recent discussion regarding uncertainty and upward cost pressures on new nuclear projects it is not the intention to explore this area in this paper⁷⁰.

The analysis was repeated for the Mott MacDonald NOAK data set, to explore whether assumed future reductions in the cost base of these power technologies led to different relative rankings between the generation technology types. It should be noted that Nuclear is included here for completeness.

⁶⁹ This is a different basis to comparing the operational economics of existing gas and coal plant, with sunk capital costs.

⁷⁰ See: 'EDF Sees UK New Nuclear Costs Rising By 40% - Report', May 2012, <http://www.4-traders.com/EDF-4998/news/EDF-Sees-UK-New-Nuclear-Costs-Rising-By-40-Report-14314952/>, and 'Soaring Costs Threaten To Blow Nuclear Plans Apart (UK)', May 2012, <http://www.democraticunderground.com/112714142>

Figure 18: Levelised Cost of Generation, Mott MacDonald NOAK Assumptions, Base Case Scenario



Source: Own Analysis

Note: NOAK – *Nth Of A Kind*

Table 10: Levelised Cost of Generation, Mott MacDonald NOAK Assumptions, Base Case Scenario

	Gas CCGT	Gas CCGT+ CCS	ASC Coal with FGD	ASC Coal + CCS	Coal IGCC + CCS	Nuclear	Onshore Wind	Offshore Wind	Offshore Wind Round 3
Capital Cost	11.3	21.4	31.3	52.4	53.7	58.6	73.2	98.6	108.7
Operating Cost	6.0	9.6	10.6	16.0	15.5	10.9	14.0	22.6	30.5
Fuel Cost	37.0	47.8	19.9	23.5	22.2	5.3			
CO2 Allowance Cost	12.4	1.6	30.0	4.2	4.1				
CO2 Disposal		3.5		7.5	7.3				
Total Levelised Cost	66.6	83.9	91.7	103.5	102.7	74.8	87.1	121.2	139.2

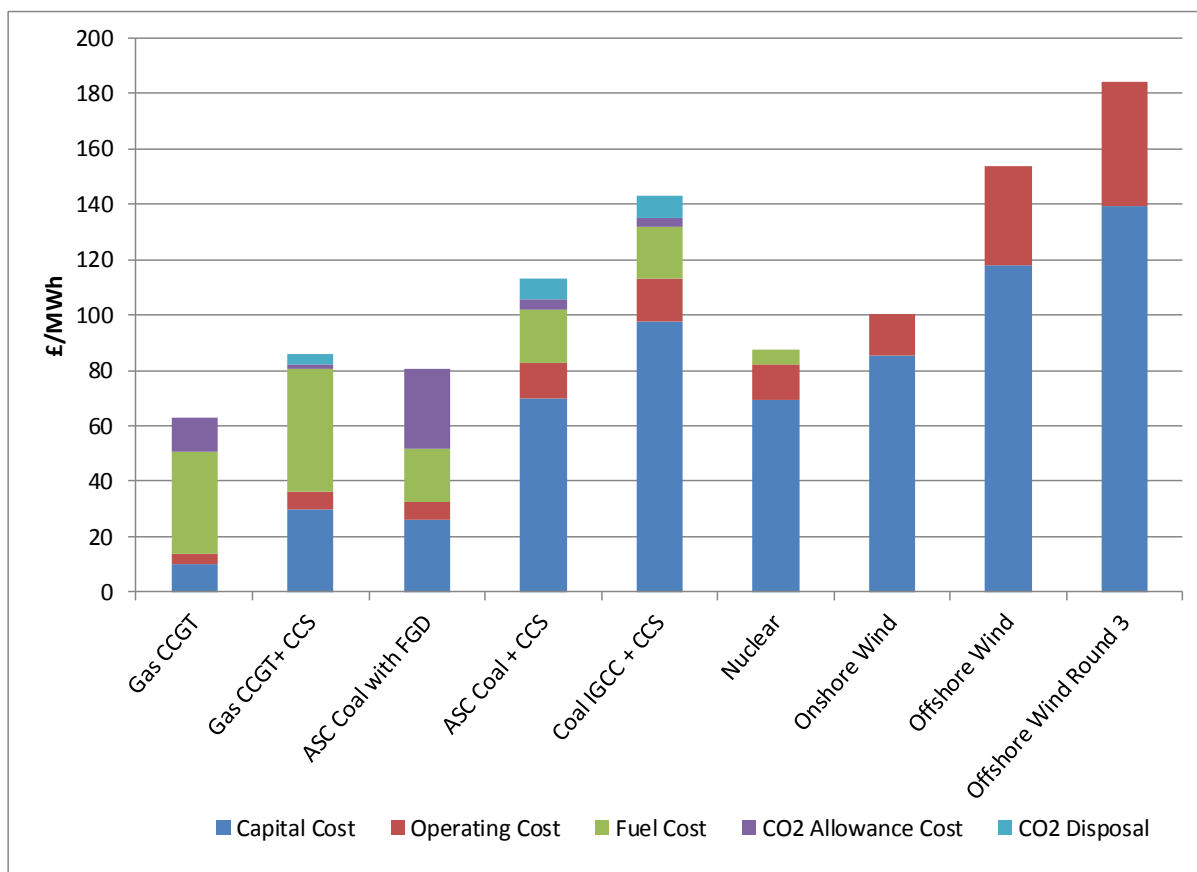
Source: Own Analysis

From Figure 18 and Table 10 it is evident that assumed future reductions in cost base and increased efficiencies have improved the economics of all the power generation technologies. In absolute terms the reduction in offshore wind levelised costs is most notable. This noted, the relative position of CCGTs with CCS versus coal with CCS, and CCGTs with CCS versus wind – onshore and offshore, is not significantly altered. On these assumptions,

CCGTs with CCS remain on a par with onshore wind but are still a much more attractive option than offshore wind on a levelised cost basis.

Parsons Brinckerhoff- Base Case: Turning to the cost and operational assumption set of Parsons Brinckerhoff, the analysis was repeated for the Base Case Scenario (Note the wind cases are unchanged from those based on the Mott MacDonald paper).

Figure 19: Levelised Cost of Generation, Parsons Brinckerhoff FOAK Assumptions, Base Case Scenario



Source: Own Analysis

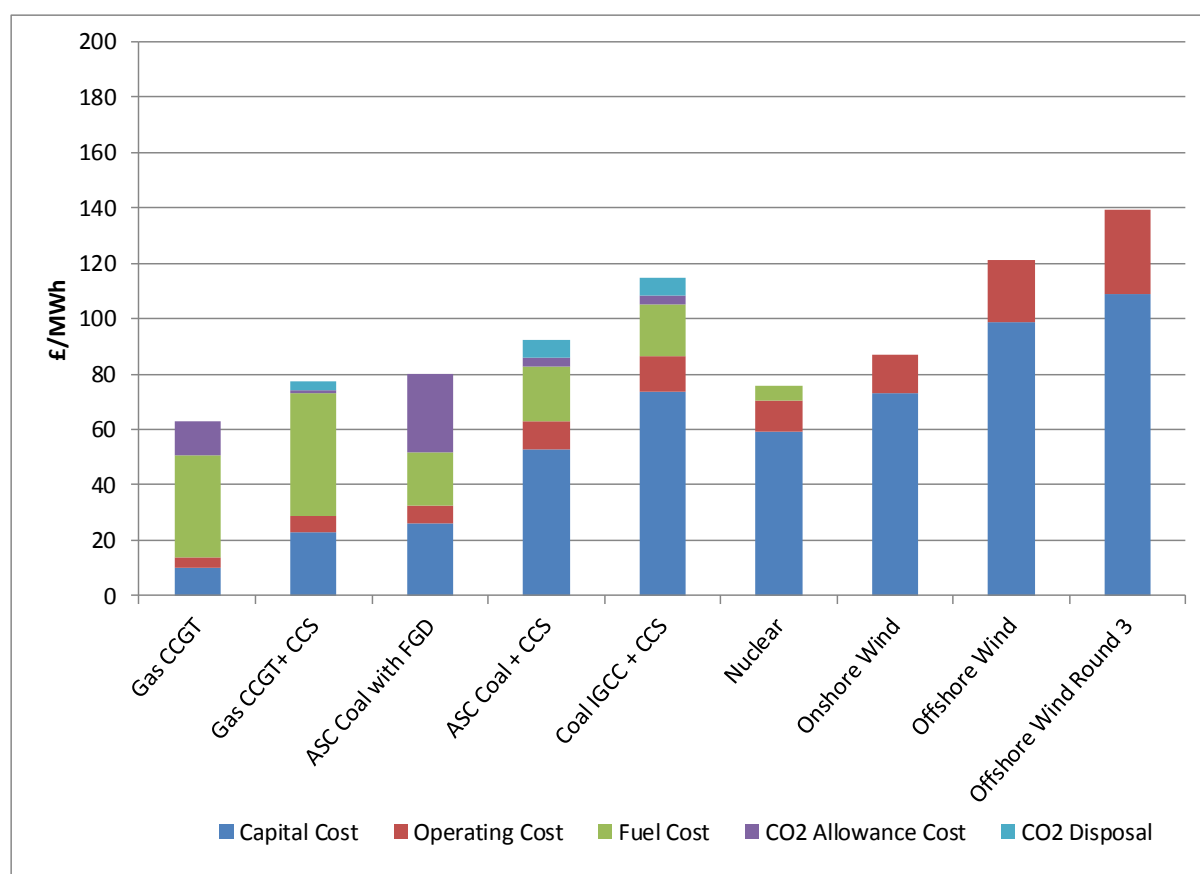
Table 11: Levelised Cost of Generation, Parsons Brinckerhoff FOAK Assumptions, Base Case Scenario

	Gas CCGT	Gas CCGT+ CCS	ASC Coal with FGD	ASC Coal + CCS	Coal IGCC + CCS	Nuclear	Onshore Wind	Offshore Wind	Offshore Wind Round 3
Capital Cost	10.1	29.6	26.0	69.8	97.8	69.4	85.2	117.8	139.2
Operating Cost	3.9	6.8	6.7	12.6	15.4	12.8	15.4	36.1	44.8
Fuel Cost	36.8	44.2	19.0	19.5	18.5	5.3			
CO2 Allowance Cost	12.3	1.5	28.7	3.4	3.4				
CO2 Disposal		3.8		7.8	7.8				
Total Levelised Cost	63.0	85.8	80.4	113.2	142.9	87.4	100.6	153.8	184.1

Source: Own Analysis

In this set of results the CCGT with CCS case is more advantageous relative to the coal with CCS cases. The gas and coal with CCS cases were viewed as having higher unit capital costs relative to the Mott MacDonald report, although this was more pronounced for coal. In general terms higher assumed conversion efficiencies more than offset the higher costs for gas with CCS but in coal the higher cost base led to a deterioration of economics overall. The Parsons Brinckerhoff nuclear case had a slightly lower capital cost but a shorter operating life assumption (40 years versus 60 years).

Figure 20: Levelised Cost of Generation, Parsons Brinckerhoff NOAK Assumptions, Base Case Scenario



Source: Own Analysis

Table 12: Levelised Cost of Generation, Parsons Brinckerhoff NOAK Assumptions, Base Case Scenario

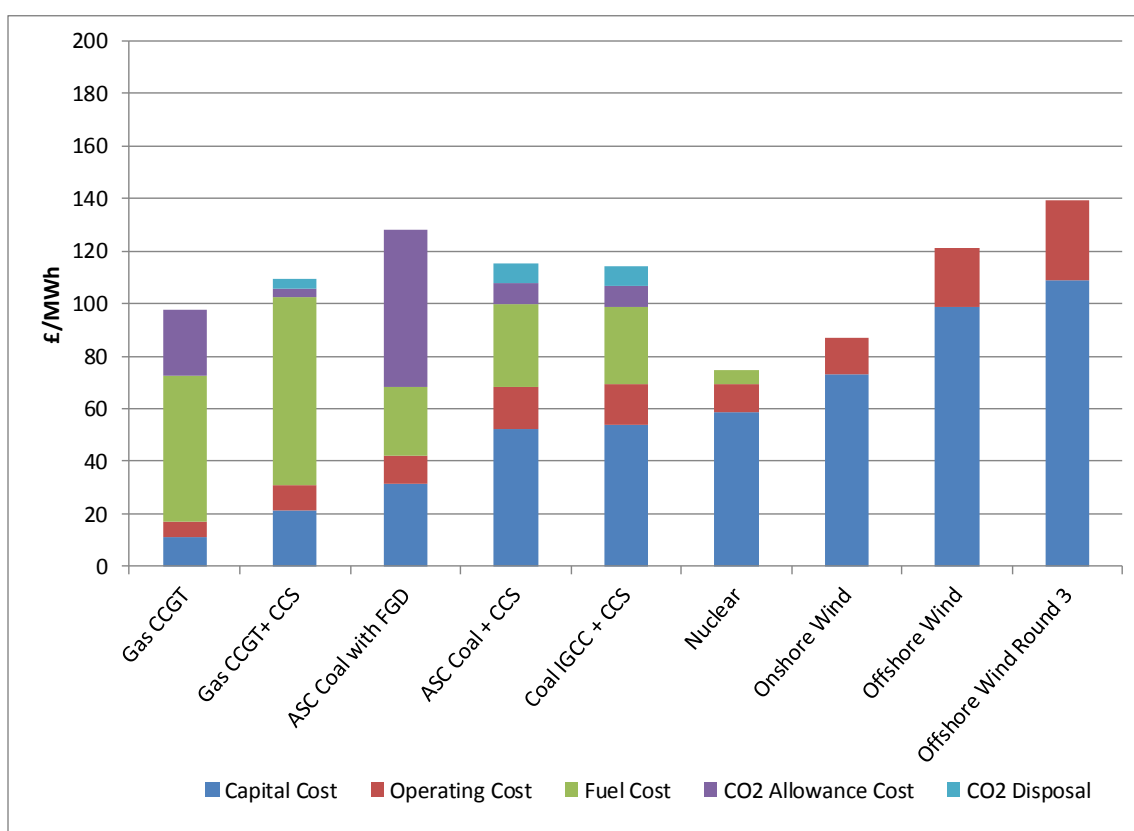
	Gas CCGT	Gas CCGT+ CCS	ASC Coal with FGD	ASC Coal + CCS	Coal IGCC + CCS	Nuclear	Onshore Wind	Offshore Wind	Offshore Wind Round 3
Capital Cost	10.1	23.0	25.9	52.6	73.6	59.3	73.2	98.6	108.7
Operating Cost	3.9	5.8	6.7	10.6	12.9	11.0	14.0	22.6	30.5
Fuel Cost	36.8	44.2	19.0	19.5	18.5	5.3			
CO2 Allowance Cost	12.3	1.5	28.7	3.4	3.4				
CO2 Disposal		3.1		6.3	6.3				
Total Levelised Cost	63.0	77.5	80.3	92.4	114.7	75.6	87.1	121.2	139.2

Source: Own Analysis

The main improvement in this set of results is in the economics of the coal with CCS cases which bring them to a lower level than the offshore wind cases. CCGTs with CCS are slightly more economic than onshore wind, and significantly more economic than offshore wind.

High Case Scenario: The High Case (Gas price \$15/mmbtu, Coal price \$120/tonne, CO₂ Allowance price £80/tonne), the Mott Macdonald NOAK Assumptions were modelled to see how the relative position of gas with CCS and wind power changes.

Figure 21: Levelised Cost of Generation, Mott MacDonald NOAK Assumptions, High Case Scenario



Source: Own Analysis

Table 13: Levelised Cost of Generation, Mott MacDonald NOAK Assumptions, High Case Scenario

	Gas CCGT	Gas CCGT+ CCS	ASC Coal with FGD	ASC Coal + CCS	Coal IGCC + CCS	Nuclear	Onshore Wind	Offshore Wind	Offshore Wind Round 3
Capital Cost	11.3	21.4	31.3	52.4	53.7	58.6	73.2	98.6	108.7
Operating Cost	6.0	9.6	10.6	16.0	15.5	10.9	14.0	22.6	30.5
Fuel Cost	55.5	71.7	26.5	31.4	29.6	5.3			
CO2 Allowance Cost	24.7	3.2	60.0	8.3	8.1				
CO2 Disposal		3.5		7.5	7.3				
Total Levelised Cost	97.5	109.4	128.4	115.5	114.2	74.8	87.1	121.2	139.2

Source: Own Analysis

From Figure 21 and Table 13 it can be seen that, even in this High Case Scenario with gas prices at \$15/mmbtu, the levelised cost of gas with CCS is 25% more expensive than onshore wind, but is still significantly lower than offshore wind. The coal with CCS cases also have lower levelised costs than offshore wind.

On the basis of the Mott MacDonald cost and operational NOAK assumptions, the gas price assumption, at which gas with CCS has the same levelised cost as Offshore Wind Round 3, is \$20.20/mmbtu or 133 pence per therm, a level which is almost three times the long run marginal cost of new European gas supplies⁷¹, and therefore unlikely to endure as a long-term price level.

3.4 Future UK Power Generation Dynamics

In ‘The Impact of Import Dependency and Wind Generation on UK Gas Demand and Security of Supply’⁷², I looked at the interaction of Wind Power in the UK generation system to 2025. The key findings from that paper were:

- As installed UK wind capacity (onshore and offshore) grows, the intermittency and variability of wind power will require to be balanced in order to maintain system stability. The UK has relatively little hydro and pumped storage and therefore flexible natural gas generation (CCGTs) will increasingly play a role in providing that balance.
- As coal-fired generation is retired in line with the Large Combustion Plant Directive, with as yet no firm plans in place to build new nuclear plant in the UK, the UK’s generation dynamic between 2015 and the early 2020s will be dominated by a growing contribution of unpredictable and variable wind generation and fast response gas-fired generation to provide a buffer or back-up.
- Interconnectors with continental Europe might provide some means of balancing in times of high wind variability, however these may be limited in scale and will not resolve the problem of low or high wind conditions extending over large areas of the North West European geography⁷³.
- Once wind capacity reaches around 28GW in the UK, the ability to rely on gas-fired generation to provide a stabilising buffer is exceeded. Unless or until a technology breakthrough provides a scalable, cost effective means of storing power, the UK may be limited to 28GW of installed wind capacity, unless it resorts to constraining wind power in order to balance the system. This would have the effect of increasing yet further the cost of wind power on a levelised cost basis, and as wind speed is difficult

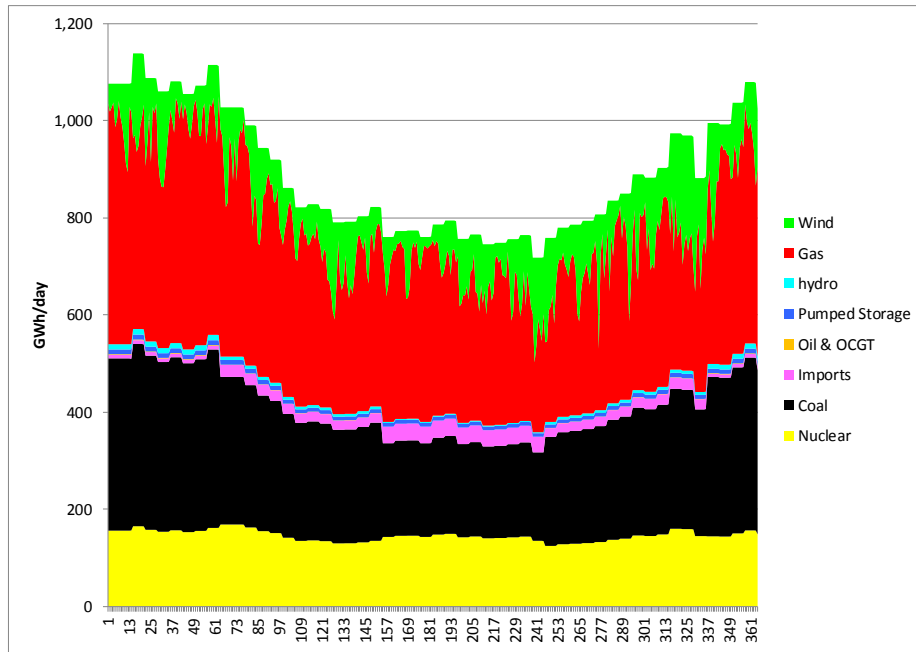
⁷¹ Henderson 2010, P. 35

⁷² Rogers 2011

⁷³ Poyry 2011, pp. 4, 8-11.

to predict accurately beyond 6 to 12 hours ahead, balancing by constraining wind generation may not be feasible in highly changeable conditions.

Figure 22: 2015 UK Modelled Daily Wind Power Generation in Generation Stack (15 GW of installed Wind Capacity).

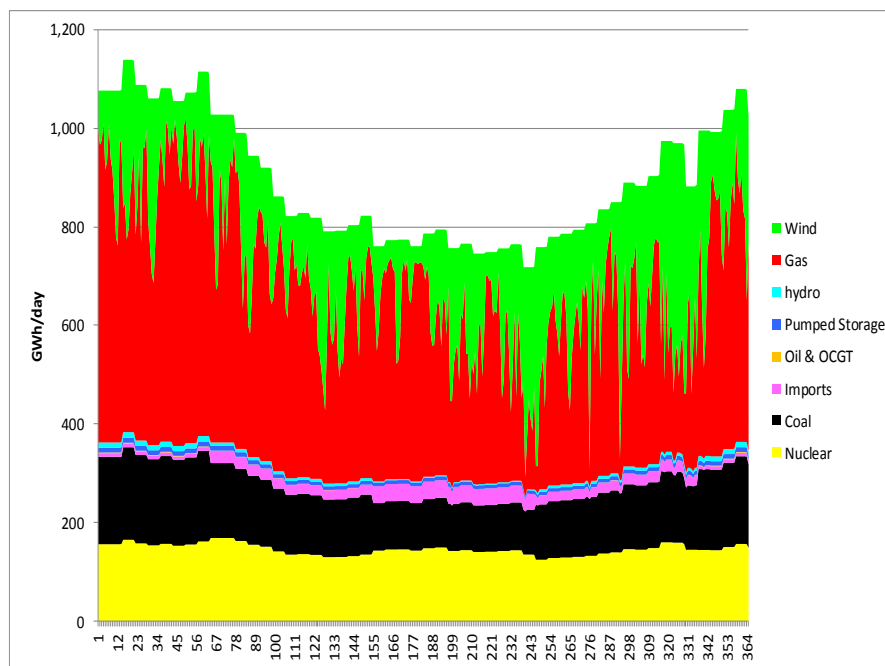


Source: Rogers 2011, P. 68

Figures 22 and 23 illustrate the dynamics of the UK generation system in 2015 and 2020 based on this analysis.

In 2015, the load factor of gas fired generation, (assuming a 10% reserve margin for gas-fired generation capacity above that required to balance low wind conditions), from the data underlying Figure 22 is 61%. This corresponds to a wind capacity of 15 GW. In 2020 (Figure 23) the gas-fired generation load factor is 52%, assuming an installed wind generation capacity of 28 GW.

Figure 23: 2020 UK Modelled Daily Wind Power Generation in Generation Stack (28 GW of Installed Wind Capacity)



Source: Rogers 2011, P. 69

The UK system modelled to 2020 appears from this analysis to represent a stable system provided that gas fired generation (CCGTs) is able to perform the crucial balancing load as wind generation increases. In Rogers 2011 it was noted that due to the assumed reduction in unabated coal-fired generation in the UK during the 2010s, and the need for gas to buffer wind generation, the demand for gas in the UK power sector in 2020 was only 5% lower than in 2009⁷⁴.

There are two key questions which arise from the analysis and its conclusions in this Chapter:

- If gas with CCS in base-load operation, on the basis of DECC's own commissioned studies, is so much more cost effective than offshore wind, why has it not received a higher policy priority? Clearly a re-direction of investment away from offshore wind towards commercial scale gas with CCS would result in lower power bills for UK consumers. While onshore wind is more attractive than gas with CCS at high gas prices, the question this raises is how many more onshore wind farms are acceptable given public opposition?
- Accepting that many offshore wind projects are already approved and are likely to proceed, the UK system will require a means of providing balancing or buffering the high variability of wind generation output. Unless or until a technological breakthrough delivers a means of storing electrical power at scale at an acceptable cost, the UK will rely on gas-fired generation to provide such a buffering role. But in

⁷⁴ Rogers 2011, P. 78

the interest of further reducing the UK's CO₂ emissions, could this role be provided by gas with CCS?

In Chapter 2 we noted the complexity of the gas and coal pre-combustion CCS approaches which in reality comprise a chemical process plant as a front end module to the combustion and power generation stage. Such plants are not ideally suited to rapid changes in output. It may be possible to turn down the power generation stage independently while continuing to run the pre-combustion CCS plant and store the surplus hydrogen for future use⁷⁵. This however introduces additional capital costs.

For post-combustion CCS physical limitations on flexibility will depend on the degree to which the CO₂ capture process can be 'turned-down' in synch with the power generation train. However similar processes described in Shell 2004⁷⁶ suggest that absorption systems can cope with gas phase flows reducing to 10% of maximum design throughput. Whilst efficiency penalties will prevail at very low utilisation rates it is likely that physical flexibility would be high in post-combustion processes.

It is widely assumed that the barrier to employing CCS schemes with low load factors is primarily an economic one. This certainly seems to be the case for coal with CCS, where the economics are primarily driven by its high unit capital costs.

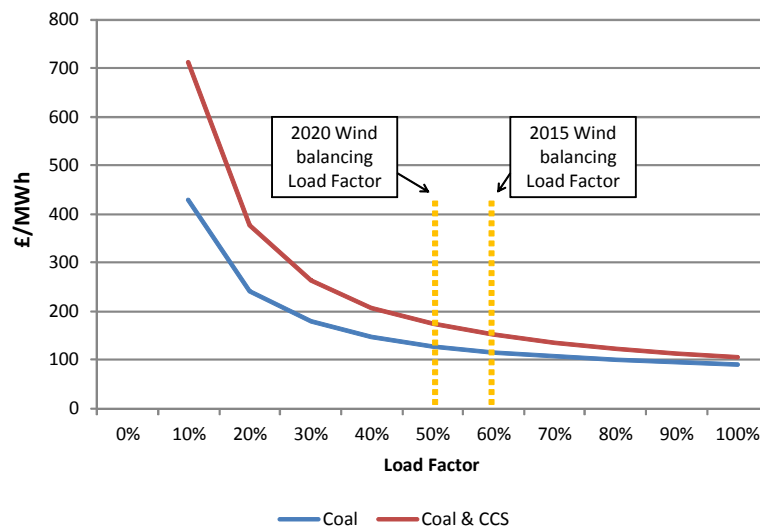
In Figure 24 the levelised cost for coal and coal with CCS at the load factors required for a generation source to balance wind generation in 2015 and 2020 (52% and 61% respectively) would be in excess of £150/MWh – in fact on a par with Round 3 offshore wind levels.

Figure 25 shows the comparable situation for gas and gas with CCS. Because gas generation economics are driven more by fuel costs and less by capital costs (compared with coal), the increase in levelised cost with decreasing load factor is much less severe. At the 2015 and 2020 load factors from Rogers 2011 the levelised costs of gas with CCS are 30% less than those of coal with CCS.

⁷⁵ See Gale 2010, Slide 8

⁷⁶ Rajani 2004

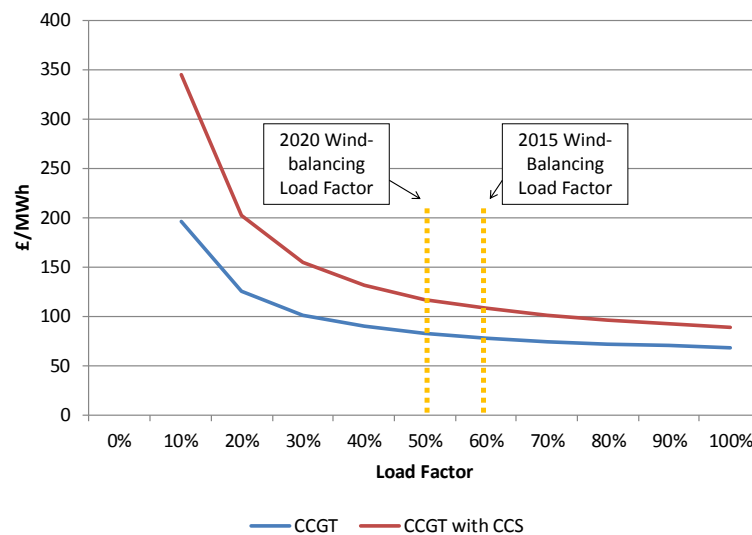
Figure 24: Coal and Coal with CCS Levelised Cost versus Generation Load Factor (based on Mott MacDonald FOAK modelled data, Base Case Assumptions)



Source: Own Analysis

Note: The vertical lines represent the load factor of the buffering generation source in 2015 and 2020 in the UK in Rogers 2011.

Figure 25: Gas and Gas with CCS Levelised Cost versus Generation Load Factor (based on Mott MacDonald FOAK modelled data, Base Case Assumptions)



Source: Own Analysis

Note: The vertical lines represent the load factor of the buffering generation source in 2015 and 2020 in the UK in Rogers 2011.

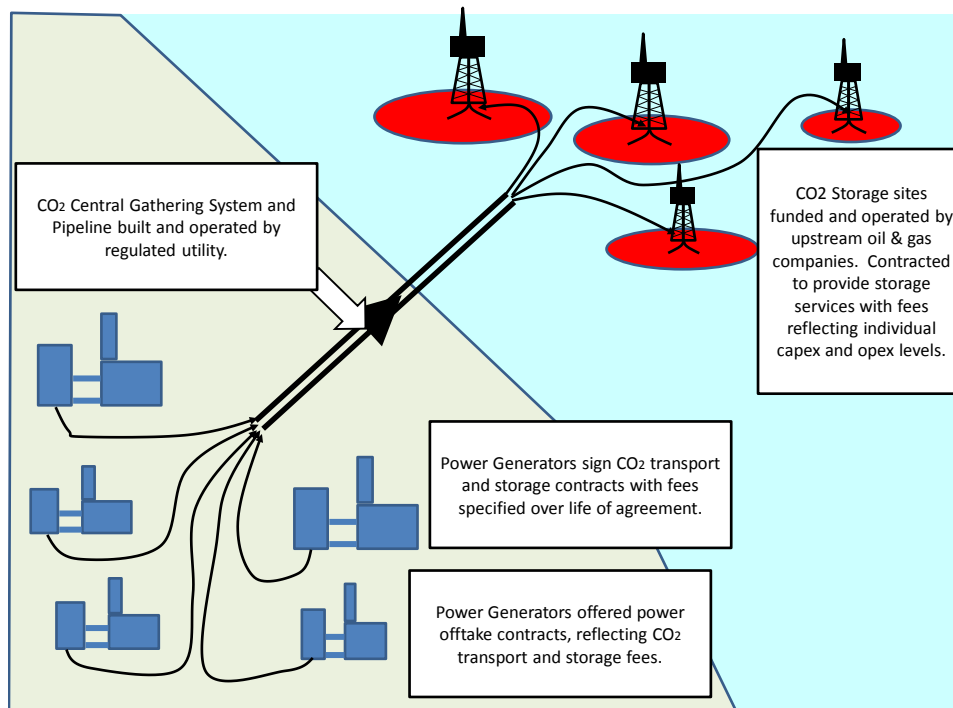
The case for accelerating gas with CCS, even on current (First of a Kind) cost assumptions appears to be compelling – either to provide a low carbon balancing and buffering generation source to stabilise variable wind generation or, as an evidently lower cost alternative to offshore wind.

So, if the case for gas with CCS is so compelling, why are we still ‘waiting for Godot?’

Chapter 4. Commercial Arrangements Necessary for CCS

In its quest to decarbonise the power generation sector the UK has made most progress in the installation of wind power. In the first quarter of 2012 DECC reported a total installed capacity of 4.7 GW of onshore and 2.2 GW of offshore wind farms⁷⁷. In commercial contractual terms, (excluding licensing, consultation and planning approvals) the process is fairly straightforward. The wind farm operator funds the capital cost of the wind turbines and the connection to the grid and National Grid, as part of its approved investment plan, upgrades or extends the national power transmission system to accommodate the new wind generation source. The wind farm operator (if offshore) receives 2 Renewables Obligation Certificates (which it sells to the power purchaser with a value of each equalling the wholesale electricity price). In addition it sells the power produced⁷⁸: at July 2012 UK power prices offshore wind generators receive $3 \times 45 = \text{£}135/\text{MWh}$. Of course the wind farm operator is exposed to the risk that capital costs will rise higher than those estimated at the point of Final Investment Decision, but otherwise the commercial arrangements are clear. Negotiation of commercial terms is not a feature of this process.

Figure 26: Schematic of a CCS Cluster Development



Source: Author

⁷⁷ DECC Website, http://www.decc.gov.uk/en/content/cms/statistics/energy_stats/source/renewables/renewables.aspx, Downloadable File ET 6.1

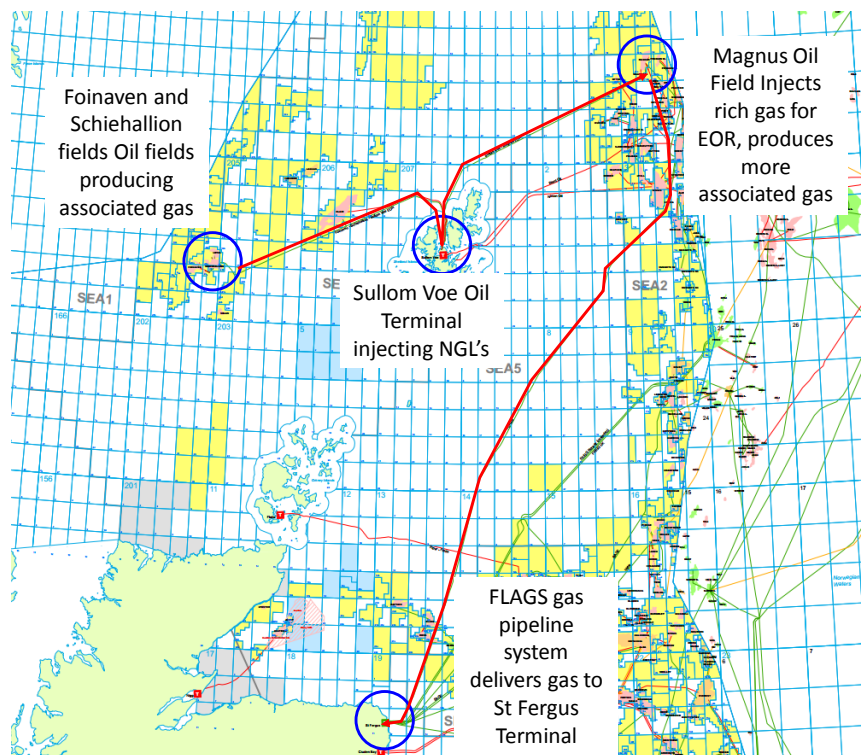
⁷⁸ Note ROC banding for offshore wind will be cut to 1.9 post 2015, and to 1.8 post 2016. (Bloomberg 2011)

Let us contrast this position with that of a potential ‘cluster’ development of CCS in the UK. Figure 26 shows schematically a cluster development of CCS power generation plant using a common CO₂ transportation system. At the downstream end of the CO₂ pipeline system are a number of CO₂ storage operators, using depleted oil or gas fields with topside facilities upgraded for the purpose. This is a chain of differing physical activities which requires a ‘chain’ of commercial agreements in which the fees to use a service are an important, but not the only key parameter to be negotiated. This word ‘negotiated’ here is paramount. Such fees cannot be dictated by a central body such as DECC or the Treasury because each power generator and each storage site operator will have a different cost base and possibly different technical or operating risk profiles.

When we look back at the statement from DECC after their internal ‘Lessons Learned’ exercise in Chapter 1 we see some recognition of these factors, but there also seems to be some confusion of DECC’s role, exemplified by the almost interchangeable use of the words ‘procure’ and ‘negotiate’, which are very different activities.

Constructing and concluding complex chains of commercial transactions is possible. A good example in a slightly different, yet possibly analogous context, is the Magnus EOR Project in the UK North Sea for which agreements were concluded in 2000. The Author worked on the strategic direction and negotiations relating to this project in 1999 – 2000.

Figure 27: Map Showing Components of the Magnus EOR ‘Chain’ Project



Source: DECC website, <http://og.decc.gov.uk/assets/og/data-maps/maps/infrast-off.pdf>, Author’s annotation.

The map conveys the physical scope of this project, in which the Magnus field built a gas pipeline from the Foinaven and Schiehallion fields⁷⁹ to the Sullom Voe oil terminal where NGLs⁸⁰ were injected into the gas stream. The pipeline continued on to the Magnus field where the rich gas was compressed and injected into the Magnus oil field to enable an Enhanced Oil Recovery Scheme to proceed. Over time this increased the production of associated gas, which necessitated the use of more capacity in the existing FLAGS pipeline which transported the gas to the St Fergus terminal and so into the UK gas transmission grid.

The key commercial interfaces in this physical ‘chain’ were:

- Foinaven and Schiehallion partners negotiated with the Magnus partners a sale and purchase contract for natural gas. (Foinaven and Schiehallion also negotiated arrangements between themselves on how to share their obligations under this contract).
- Magnus partners negotiated an agreement with the Sullom Voe partners to purchase NGLs.
- Magnus partners negotiated changes to an existing transportation agreement to export associated gas production through the FLAGS pipeline owned by Shell and ExxonMobil.

In addition to the key pricing terms the parameters at each negotiating interface included, duration, annual contract quantity, flow variability, unplanned shutdowns, quality variation, remedy for non-performance and a host of other parameters subject to uncertainty and remedies for possible future changes in gas quality, accidental contamination and production facility problems. The agreements were concluded in 6 months, which was viewed as unprecedented for a scheme of such complexity. The reasons behind the success of these negotiations were:

- The Magnus Field was the origin of the ‘prize’ in the form of additional oil recovery and gas sales. Located at the centre of the ‘chain’ it was in a position to negotiate how the prize was shared with other links of the chain. In other words, the Magnus field partners constituted a highly motivated ‘sponsor’.
- All negotiating participants had a common experience skillset which facilitated general engagement and informed judgement as to how far the opposing negotiating team were possibly exaggerating a negotiating position, allowing the key parameters to be traded as currencies and final negotiations, involving price and key commercial terms converged and closed.

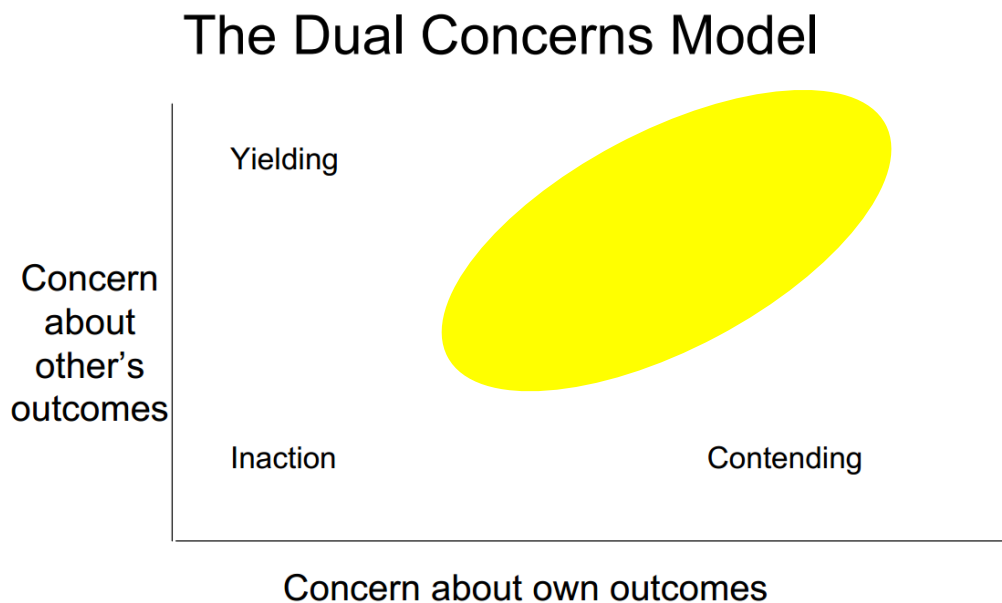
⁷⁹ Prior to the Magnus EOR project associated gas production from these fields was flared.

⁸⁰ NGLs: ethane, propane, butane and other higher alkanes.

- Momentum was maintained in negotiations through a common desire to close the deals to allow construction to begin within the North Sea weather window to allow all parties to secure their ‘slice of the prize’.

The dynamics of the negotiation process are illustrated in Figure 28 with the yellow shaded area defining where the majority of negotiating behaviours resided during this process, in the author’s opinion.

Figure 28: Negotiating Dynamics



Source: ‘Negotiation Theory and Practice’ presentation, M. Alvarez and J. Kennedy, Stanford, 2006, http://med.stanford.edu/careercenter/management/Negotiation_Skills_MA_JMK_2_16_06.pdf

Are there any lessons here for how a successful CCS cluster could be delivered in the UK?

Firstly let us examine the nature of the current ‘CCS Competition’ launched by DECC in April 2012. The elements of the process are taken from a press release⁸¹:

‘Energy and Climate Change Secretary Edward Davey today launched a new competition for Carbon Capture and Storage (CCS), a key technology in the Government’s drive to ensure our future energy security and reduce emissions. The Department of Energy and Climate Change also published today the first UK CCS Roadmap. This sets out the steps that the Government is taking to develop a new world-leading CCS industry in the 2020s, including:

- *the competition, the ‘CCS Commercialisation Programme’, to drive down costs by supporting practical experience in the design, construction and operation of*

⁸¹ DECC 2012 d

commercial scale CCS with £1bn funding, and additional support, subject to affordability, through low carbon Contracts for Difference;

- *£125m funding for Research and Development, including a new £13m UK CCS Research Centre;*
- *planned long term Contracts for Difference through Electricity Market Reforms to drive investment in commercial scale CCS in the 2020s and beyond;*
- *commitments to working with industry to address other important areas including developing skill and the supply chain, storage and assisting the development of CCS infrastructure; and*
- *a focus on international engagement, in particular on learning from other projects around the world to help accelerate cost reduction in the UK, and sharing the knowledge we have generated through our programme’.*

What is not made clear in this statement is what the actual ‘competition’ entails. The UK CCS Roadmap document⁸² contains some additional detail on eligibility to participate in the competition:

‘Eligibility criteria

In order to deliver our Outcome, we have set the following eligibility criteria for entry into the competition. The eligibility criteria include that projects:

- *May be full-chain or part-chain that can demonstrate the prospect of being part of a full chain project in the future;*
- *Comprise a power plant and capture facility located in Great Britain and a storage site offshore;*
- *Must be able to be operational by 2016 - 2020, though earlier is desirable;*
- *Must abate CO₂ at commercial scale (or be a substantive step towards that objective) whilst meeting all relevant environmental requirements; and*
- *May contain an electricity generator or an industrial emitter which is part of a cluster project.*

Further, in order to participate developers must have relevant expertise and experience of managing complex projects in this or a closely associated field, and the backing of at least one parent company with a significant balance sheet. Full details of the eligibility criteria are set out in the bid documentation, which registered bidders can access in the first month of the competition once signed Competition Process Agreements are returned.

⁸² DECC 2012 c

In evaluating projects, we will favour projects that:

- *Make the greatest contribution to reducing the future cost of CCS;*
- *Contribute to a sustainable future CCS industry, for example through the ability to link up multiple emitters (power and industrial) through shared infrastructure;*
- *Have strong and proactive knowledge transfer proposals;*
- *Provide wider benefits, such as facilitating new commercial opportunities like enhanced hydrocarbon recovery and contribute to the development of a CCS services sector and supply chain; and*
- *Contribute to wider government aims, such as strengthening the UK's energy resilience, and improving the option to effectively deploy CCS elsewhere in the world.'*

There is no explicit description of the 'process' or how the individual funding streams will be made available to fund a 'winning' project. This is a description of the 'materials and tools' rather than an 'architect's blueprint'. It is a competition to design the most attractive jigsaw piece, rather than solve the puzzle.

To make progress, what is necessary is clear description of:

- The financial 'prize' – i.e. revenue stream available to be negotiated in order to fund all stages of the CCS chain.
- The identity of the project 'sponsor', the negotiating parties and their scope of responsibilities and the timeline.
- The role of DECC/UK Government in terms of risks and responsibilities.

Perhaps this will be revealed in due course, however until then we are merely in the foothills of this undoubtedly protracted expedition. Defining the role of DECC is vitally important. It is difficult to envisage a successful outcome if DECC insists on performing a key negotiating role in this competition. Whilst the 'Lessons Learned' from the previous competition provide useful insights they will not compensate for DECC personnel lacking the 'hands on' knowledge or deep commercial experience of the power generation, pipeline transportation or offshore operations and reservoir management businesses. Possible solutions to this challenge include the outsourcing/delegation of negotiations to an agency staffed by experienced personnel within clear commercial mandates.

If DECC's commissioned analysis of levelised costs, as outlined in Chapter 3, is broadly accurate there is no reason to delay establishing genuine negotiations on a commercial scale for a CCS cluster and transportation and storage chain in the immediate future. Even without the benefit of further R&D-driven cost reductions a gas CCS scheme now would be on a par with onshore wind projects but significantly cheaper than future offshore wind projects.

To conclude on a more positive note however, statements made in June 2012 by the recently appointed chairman of the UK government's Carbon Capture and Storage Cost Reduction

Task Force⁸³ in an interview with Gas Matters brought more clarity as to the purpose of the competition as well as an intent to shape the commercial process in line with the approach recommended in this paper:

‘Q: What are the current challenges and next steps to realising the government’s vision of CCS in the UK?’

A; The current challenge is to make the projects coming forward under the competition financeable. We also need to make sure there is a workable feed-in tariff with Contracts for Difference (FiT-CfD) in place, in support of the project. We don’t call them demonstration projects any longer; the important thing is that this new phase of competition is now called the commercialisation phase, and that’s really a very important difference. We are talking about the first of the future, rather than ‘let’s demonstrate CCS, and if it works we’ll think about investing some more in it’.

The government has said it would like to see the electricity market de-carbonised by 2030, however realistic that is, but if you want to do that in reality you will need 20-30 GW from fossil fuels with CCS. What that means is that nuclear power and renewables will deliver their part of the equation as well, because we will need by that time an installed capacity of 70-80 GW altogether. For wind you need three or four times the effective capacity ... because the wind doesn’t blow all the time.

Q: Is that partly because too much time was spent on the Longannet CCS project?

There’s something in that. There’s also been a realisation that CCS is workable, but difficult to get off the ground because the projects are so big – and because it’s about innovation there are a lot of new issues to be addressed. We’re finding that a lot of projects are falling by the wayside because we are discovering lots of obstacles. We’ll overcome those, and once you get some projects laid down and in particular infrastructure, then other projects can join that at marginal cost.

Q: What are the main obstacles to developing CCS?

The main obstacle is always finance, and making sure contractually the money fits together. But included in all of that is the allocation of contractual risk, because basically you’re dealing with a situation where storage operators, pipeline operators and power generators depend upon one another for their business. So anyone along that chain that fails completely will break it.

Q: Is FiT-CfD the best way to address the finance issue?

Certainly in the first instance, and there’s £1 billion of capital grant available as well, to be shared among however many projects there are. That’s very useful, and will help to overcome the additional capital expenditure. There’s no difference in eligibility – if they win the competition they get a portion of the pot.

⁸³ GM 2012, pp. 25 - 27

With FiT-CfD you get a guaranteed amount of money from the electricity you sell. It takes the wholesale price of electricity, and it gives you a top-up to a guaranteed level called a strike price. That is the difference that you have a contract for. Feed-in tariff is just a name for a subsidy for clean electricity – you get the same thing with solar power. Then in the long run what we need to see is that CCS is very cost-effective, which it will be, there's no doubt about that. All the estimates we've got at the moment are that whatever comes on-stream from CCS will be a good deal cheaper than solar power and likely offshore wind too.

Q; Given DECC's recent call for evidence for a future gas generation strategy, it seems there is even more of a case for gas-fired power generation with CCS.

Absolutely, and it was disappointing to see that gas-fired power stations will be grandfathered at 450 g/kWh up until 2045. I understand why the government did that, because they're desperate for people to build combined-cycle gas turbines. There are even plants that have passed their planning permission but aren't being built, and I think that was the government trying to encourage them. But to give 30 years' guarantee that you don't need to install CCS is completely contradictory to the other policy that says we want to decarbonise the power sector by 2030. It's a scatter-gun approach.

What I'd say to that is fine, we understand that you want to get some plants installed now and as quickly as possible, but what you've got to make sure is that through the FiT-CfD system there will be the money available to incentivise retrofit later on but also to make sure that whatever plants are consented are truly capture-ready'.

This is a very positive development and one which increases the odds in favour of realising CCS for Gas in the UK, provided that the 'prize' is defined in reasonably bounded terms and is sufficient to elicit a positive response by would-be investors and operators.

Chapter 5. Summary and Conclusions

This paper has set the context for the long-standing support, expressed at the highest international climate change policy level, for the promotion and support of commercial scale carbon capture and sequestration schemes, with the intention of developing the sector to the scale necessary to contribute a ‘Princeton wedge’ of CO₂ abatement capacity. This commitment has been reflected in UK government policy since the early 2000s. Despite all this well-intentioned support, progress on the ground has been disappointing, as evidenced by the projects tracked by the Global CCS Institute.

Where CCS has been adopted at a commercial scale, this has been in sectors where it is either a necessary stage in the production of a high value product (natural gas processing, fertiliser manufacturing) and/or where the CO₂ is purchased for injection into oil reservoirs to enhance oil recovery. No commercial scale power sector CCS applications have yet achieved operational status. While 29 power sector CCS projects are identified worldwide, at various stages of definition and development, 25 of these are based on coal feedstock. The four gas-based schemes (located in UAE, Norway and the UK) are still in the pre-sanction phases of project development. Of the 11 power sector CCS projects (coal and gas based) submitted for the EU NER 300 process, four have already been cancelled. The Global CCS Institute suggests that the most frequently cited reason for projects being put ‘on hold’ or cancelled is that they were deemed uneconomic in their current form under the prevailing policy environment. This explanation begs the following questions: ‘Just how challenged are the economics of CCS in the power sector, and how do the economics of such projects compare to other low-carbon technologies?’; and, ‘Is the prevailing policy framework sufficiently supportive to allow such projects to proceed?’ These questions are given a further sense of urgency in the light of the UK Government’s renewed focus on developing a strategy for gas in the generation sector and in launching a competition to develop a CCS project in the UK.

Before addressing such questions, this paper examined the practicalities of the CCS process in a power sector context, the main objective here being to highlight: the sheer scale of the physical processes and equipment which constitute a CCS power sector project; the range of technology and operational skills required along the CCS activity chain; and the little appreciated fact that while technological breakthroughs would certainly lead to lower costs and higher efficiencies, all the building blocks of an operational power sector CCS chain have been used in the upstream hydrocarbon and petrochemical industries for decades. Building a commercial scale power sector CCS project is not ‘rocket science’, and while future breakthroughs in CO₂ separation or capture technology will undoubtedly improve project economics, at present it may be more prudent to assume a series of incremental improvements in CO₂ capture costs, rather than await a major technological breakthrough which is, by its very nature, difficult to predict in terms of timing and degree.

The paper then turned to the question of project cost and economics. Using detailed reports prepared for DECC, which set out in detail the cost and operating parameters for a range of power generation technologies, prepared by specialist consultants, it was possible to recreate a model similar to that used by DECC and compare the comparative economics of power

generation for a range of future fuel and CO₂ allowance costs. The results of this exercise show that while gas-fired generation with post combustion CCS has a levelised cost of electricity production on a par with onshore wind, it is a significantly less costly source of power than offshore wind. In fact at 2012 gas prices, gas with CCS could provide electricity at between 50% and 60% of the cost of Round 3 offshore wind projects. Gas with CCS is more attractive than Round 3 offshore wind, from a project economic viewpoint, at gas prices up to \$20/mmbtu (£1.33/therm), a gas price three times higher than the long run marginal cost of new European gas supplies and hence unlikely to represent a sustainable price level. This is important since the scope for investing in significantly more onshore wind may be constrained by public resistance; offshore wind representing the alternative to CCS projects in terms of low carbon generation capacity which could be onstream by 2020. (New nuclear stations, if sanctioned, are unlikely to come onstream much before 2025.)

In my 2011 report⁸⁴ the issues of wind power intermittency were explored in some detail and that paper concluded that unless or until a technological breakthrough allowed electrical power to be stored on a large scale at a reasonable cost, CCGTs would increasingly be required to provide a balancing and buffering role to offset the highly variable and unpredictable output of wind generation. The results of the analysis in Chapter 3 suggest not only that the UK's electricity consumers would benefit from less offshore wind and more gas with CCS investment, but that gas with CCS could also provide a low carbon source of balancing generation for the wind projects which do proceed, and furthermore at a lower cost than coal with CCS.

These seem compelling reasons for proceeding with gas with CCS, as a key contributor to the goal of decarbonising the UK's power sector. Here the paper turned its attention to the inevitable challenge of turning substantive and fundamentally attractive ideas into reality. Creating the commercial framework to incentivise the construction of what would be a 'chain' of physical processes each requiring substantial investment and with separate ownership structures is daunting, but it can be done. Using a UKCS upstream example as an analogue, it would be unwise to underestimate the levels of innovation and constructive competitive creativity unleashed in this context, providing that:

- The financial 'prize' is tangible and defined, and one of the investing participants assumes the role of a highly motivated 'sponsor'.
- All investing participants have a comparable experience and skillset to facilitate sufficient engagement for constructive negotiations on how the 'prize' is divided along the chain, and risks appropriately shared.
- Momentum is maintained through a common desire to close the deals within a defined timescale.

⁸⁴ Rogers 2011.

Examining the details of the current UK CCS ‘Competition’ however, one finds no explicit description of the ‘process’ or how the much-publicised individual funding streams will be made available to fund the ‘winner’s’ project. This is a description of the ‘materials and tools’ rather than an ‘architect’s plan’. In the view of the author, to make progress on this front, what is necessary is clear description of:

- The financial ‘prize’ – i.e. revenue stream available to be negotiated in order to fund all stages of the CCS chain;
- The identity of the project ‘sponsor’, the negotiating parties and their scope of responsibilities and the timeline;
- The role of DECC/UK Government in terms of role and responsibilities.

The review of the failure of DECC’s earlier CCS competition undertaken by the National Audit Office and DECC’s own internal Lessons Learned exercise raises the fundamental question of whether DECC has the internal skill, competencies and behaviours to engage as an active participant in the negotiation of a CCS chain project. If DECC aspires to play the role of ‘motivated sponsor’ it may consider outsourcing the negotiation activity to an agency which is able to assemble a multi-disciplinary team with the appropriate skills, operating under DECC with a clear negotiating mandate. However, to conclude on a more positive note, statements made in June 2012 by the recently appointed chairman of the UK government’s Carbon Capture and Storage Cost Reduction Task Force⁸⁵ brought more clarity as to the purpose of the competition as well as an intent to shape the commercial process in line with the approach recommended in this paper. If this is a true reflection of Government policy and is translated into a clear process through which investors from the upstream industry and midstream utilities may form integrated CCS chain projects and negotiate viable commercial agreements, the outlook for CCS in the UK can be viewed more positively.

This is a critical juncture for the European, and specifically the UK, gas industry which in the past few years have been largely unsuccessful (relative to pro-renewable NGOs) in influencing public opinion in favour of gas. The recent, somewhat unforeseen, UK government expression of support for gas provides an opportunity to shape a workable framework for CCS and to establish a long-term role for gas in the energy mix. If the gas industry fails to engage it risks a long-term demand erosion for their product as other low-carbon generation technologies and energy efficiency measures in the non-power sector reduce the role of gas. A strategy which ‘bets the farm’ on unabated gas-fired power generation as the ‘default option’, as low economic growth slows the pace of renewables investment, is a risky one which at best may delay the decline of the industry by just a few years.

The reference to ‘Waiting for Godot’ in the title of this paper evokes the less than optimistic expectations of its findings and conclusions at the time of the paper’s inception. Much that is

⁸⁵ In an interview with Gas Matters (GM 2012 pp 25 – 27).

positive in the policy sphere has developed during the course of its research and composition. At present the outcome of the current UK gas generation strategy and CCS competition process appears to rest on the actions, motivations and ‘enlightened self-interest’ of the players. Could this mark the point where the gas industry and UK policy makers move beyond the well-worn orbits of procrastination to make a difference? Or, will we sit back, rationalise our caution and inaction, and resume our wait for Godot’s arrival?

Appendix 1

Levelised Costs of Electricity Generation Methodology⁸⁶

The levelised cost of electricity generation (LCG) is defined as the ratio of the net present value of total capital and operating costs of a particular plant to the net present value of the net electricity generated over its operating life, i.e.

$$\text{LCG} = \text{TOTC} / \text{NPVG}$$

Where:

LCG = Levelised Cost of Generation (£/MWh)

TOTC = Net Present Value (NPV) of total costs (capital and operating) (£)

NPVG = NPV of net electricity generation (MWh)

$$\text{TOTC} = \sum (\text{TC}_n / (1+r)^n)$$

TOTC = Net Present Value (NPV) of total costs (capital and operating) (£)

TC_n = Total costs for Power in year n (capital and operating costs) (£)

$$\text{NPVG} = \sum (\text{G}_n / (1+r)^n)$$

G_n = Net generation in year n.

n = year

r = Annual discount rate (10%)

The LCG therefore represents the minimum breakeven power price expressed in £/MWh for each plant, based on the assumptions in the model and the discount rate chosen. The LCG is broken down in the model into the contribution from capital costs, operating costs, fuel costs, CO₂ allowance costs and carbon disposal costs.

⁸⁶ This definition is from Mott MacDonald 2010, P. 18

Appendix 2

Detailed cost assumptions for Power Generation cases

Table 14: Cost and Performance Data for a Range of Power Generation Types – First of a Kind (Mott MacDonald)

2010 Report FOAK

	Units	Gas CCGT	Gas CCGT with CCS	Coal	Coal with CCS	Coal IGCC with CCS	Nuclear	Onshore Wind	Offshore Wind	Offshore Wind Round 3
Capital Cost	£million	809	1372	1998	3073	3187	3744	1701	3110	3625
Fixed Operating Costs	£million/year	17	32	50	77	75	78	16	80	98
Variable Operating Costs	£million/year	28	37	38	43	49	14	20	34	44
CO2 Transport & Storage Costs	£million/year	n/a	26	n/a	53	53	n/a	n/a	n/a	n/a
Planning time	years	2	2.4	3.3	4.4	4.4	4.4	6	6	6
Construction time	years	2.8	4.2	4.8	5.4	4.8	6	2	2	2
Availability	%	89.7%	88.0%	89.0%	84.5%	86.3%	86.3%	96.6%	94.6%	94.6%
Load Factor When Available	%	90%	90%	90%	90%	90%	90%	28%	39%	39%
Gross Efficiency (LHV)	%	56.0%	47.5%	43.9%	35%	35.1%	n/a	100%	100%	100%
Net Efficiency*	%	54.7%	41.9%	40.8%	29.3%	29.9%	n/a	98.0%	97.8%	97.8%
Operating Life	years	25	27	36	36	25	60	22	22	22

* After accounting for power used within plant.

Source: Mott MacDonald 2010, Own assumptions and analysis.

Table 15: Cost and Performance Data for a Range of Power Generation Types – Nth of a Kind (Mott MacDonald)

2010 Report NOAK

	Units	Gas CCGT	Gas CCGT with CCS	Coal	Coal with CCS	Coal IGCC with CCS	Nuclear	Onshore Wind	Offshore Wind	Offshore Wind Round 3
Capital Cost	£million	718	1092	1789	2434	2443	2913	1520	2840	3087
Fixed Operating Costs	£million/year	15	25	38	58	50	62	14	50	69
Variable Operating Costs	£million/year	27	36	32	37	42	13	19	26	34
CO2 Transport & Storage Costs	£million/year	n/a	22	n/a	44	43	n/a	n/a	n/a	n/a
Planning time	years	2	2	3	4	4	4	5	5	5
Construction time	years	2.5	3.5	4	4.5	5	5	2	2	2
Availability	%	91.2%	89.5%	90.2%	89.0%	87.4%	90.8%	97.9%	95.9%	95.9%
Load Factor When Available	%	90%	90%	90%	90%	90%	90%	28%	41%	41%
Gross Efficiency (LHV)	%	59.0%	50%	45%	36%	36%	n/a	100%	100%	100%
Net Efficiency*	%	57.6%	44.6%	42.1%	30.4%	31.1%	n/a	98.2%	98.0%	98.0%
Operating Life	years	30	30	40	38	30	60	24	24	24

* After accounting for power used within plant.

Source: Mott MacDonald 2010, Own assumptions and analysis.

Table 16: Cost and Performance Data for a Range of Power Generation Types – First of a Kind (Parsons Brinckerhoff)

2011 Report FOAK

	Units	Gas CCGT	Gas CCGT with CCS	Coal	Coal with CCS	Coal IGCC with CCS	Nuclear
Capital Cost	£million	669	1634	1648	3584	4927	3561
Fixed Operating Costs	£million/year	23	40	35	72	81	87
Variable Operating Costs	£million/year	5	10	15	23	31	4
CO2 Transport & Storage Costs	£million/year	n/a	28	n/a	58	57	n/a
Planning time	years	2.3	5	3.5	5	5	5
Construction time	years	2	5	4	5	5	6
Availability	%	92.7%	92.7%	94.9%	94.9%	92.7%	90.8%
Load Factor When Available	%	90%	90%	90%	90%	90%	90%
Net Efficiency*	%	58.0%	48.3%	44%	36.7%	37.3%	100.0%
Operating Life	years	30	22**	35	20	20	40

* After accounting for power used within plant.

** The table in the Parsons Brinckerhoff Report has a figure of 12 years. This seemed abnormally short and contradicted their written assumptions on page 38 of their report.

Source: Parsons Brinckerhoff 2011, Own assumptions and analysis.

Table 17: Cost and Performance Data for a Range of Power Generation Types – Nth of a Kind (Parsons Brinckerhoff)

2011 Report NOAK

	Units	Gas CCGT	Gas CCGT with CCS	Coal	Coal with CCS	Coal IGCC with CCS	Nuclear
Capital Cost	£million	669	1314	1643	2876	3953	3030
Fixed Operating Costs	£million/year	23	33	35	60	67	75
Variable Operating Costs	£million/year	5	9	15	20	27	4
CO2 Transport & Storage Costs	£million/year	n/a	23	n/a	47	46	n/a
Planning time	years	2.3	4	3.5	5	5	5
Construction time	years	2	4	4	4	5	5
Availability	%	92.7%	92.7%	94.9%	94.9%	92.7%	90.8%
Load Factor When Available	%	90%	90%	90%	90%	90%	90%
Net Efficiency*	%	58.0%	48.3%	44%	36.7%	37.3%	100.0%
Operating Life	years	30	25	35	25	25	40

* After accounting for power used within plant.

Source: Parsons Brinckerhoff 2011, Own assumptions and analysis.

Glossary

Absorption: A physical or chemical phenomenon or process in which atoms, molecules, or ions enter a bulk phase - gas, liquid, or solid material.

Adsorption: The adhesion of atoms, ions, or molecules from a gas, liquid, or dissolved solid to a surface. This process creates a film of the *adsorbate* on the surface of the *adsorbent*

Algae: A large and diverse group of simple, typically autotrophic organisms, ranging from unicellular to multicellular forms. Most are photosynthetic and "simple" because their tissues are not organized into the many distinct organs found in land plants.

Anthropogenic: An effect or object resulting from human activity. The term is sometimes used in the context of pollution emissions that are produced as a result of human activities but applies broadly to all major human impacts on the environment.

Aqueous: A solution in which the solvent is water. The word *aqueous* means pertaining to, related to, similar to, or dissolved in water.

Aquifer, Brine-filled aquifer, Saline Aquifer: An underground layer of water-bearing permeable rock or unconsolidated materials (gravel, sand, or silt) from which groundwater can be usefully extracted using a water well. Where the water in the aquifer contains dissolved salts it is termed saline or brine-filled and unsuitable as a source of drinking water.

ASC: Advanced Supercritical Coal-fired generation.

Bcm: One billion cubic metres.

Caprock: The stratum or layer of impermeable rock overlying a hydrocarbon reservoir or aquifer which presents a physical barrier to the upward movement of liquid or gaseous fluids.

Capture Ready: A 'capture ready' facility is a large scale industrial or power source of CO₂ which could and is intended to be retrofitted with CCS technology when the necessary regulatory and economic drivers are in place.

CO₂DeepStore: An Aberdeen, UK company specifically focussed on the commercialisation of geological storage of CO₂.

Clean Development Mechanism (CDM): The Clean Development Mechanism (CDM), defined in Article 12 of the Kyoto Protocol, allows a country with an emission-reduction or emission-limitation commitment under the Kyoto Protocol to implement an emission-reduction project in developing countries. Such projects can earn saleable certified emission reduction (CER) credits, each equivalent to one tonne of CO₂, which can be counted towards meeting Kyoto targets.

DECC: The UK Government Department of Energy and Climate Change. Home page: <http://www.decc.gov.uk/>

Depleted oil or gas reservoir: An oil or gas reservoir (or termed a field) which is at or is approaching the end of its economic life as a consequence of the value of its daily oil or gas production converging on the associated operating costs.

Enhanced Oil Recovery, EOR: The process of increasing the recovery of oil from a reservoir in excess of that obtained as a result of the reservoir's inherent pressure drive. EOR uses methods including thermal recovery, gas (including CO₂) injection, chemical injection and water flooding.

Enzymes: Biological molecules that catalyze (i.e., increase the rates of) chemical reactions. Like all catalysts, enzymes work by lowering the activation energy for a reaction, thus dramatically increasing the rate of the reaction. As a result, products are formed faster and reactions reach their equilibrium state more rapidly.

EUA, European Emission Allowance: The European Union Emissions Trading Scheme was launched in 2005 and is a major pillar of EU Climate Policy. Installations must monitor and report their CO₂ emissions. Installations currently receive EUAs from their national allowance plans (NAPs), administered by the governments of participating countries. If carbon emissions exceed what is permitted by its EUAs, a factory can purchase EUAs from other installations or countries. Conversely, if an installation has performed well at reducing its carbon emissions, it can sell its leftover EUAs for money.

FGD: Flue Gas Desulphurisation – equipment to remove SO₂ from coal-fired power plant flue gas.

Final Investment Decision: The joint decision on the part of the investing companies and any state entities to proceed with the full development of a project through to commercial operation.

Flue Gas: Gas exiting to the atmosphere via a flue, which is a pipe or channel for conveying combustion exhaust gas produced at power plants. Its composition depends on the specific fuel, but it will usually consist of mostly nitrogen (typically more than two-thirds) derived from the combustion air, carbon dioxide (CO₂), and water vapour as well as excess oxygen (also derived from the combustion air). It further contains a small percentage of a number of pollutants, such as particulate matter, carbon monoxide, nitrogen oxides, and sulphur oxides.

Gigaton: 1 billion tons

Group-Think: Groupthink is a psychological phenomenon that occurs when the desire for harmony in a decision-making group overrides a realistic appraisal of alternatives. Group members try to minimize conflict and reach a consensus decision without critical evaluation of alternative ideas or viewpoints. The primary socially negative cost of group-think is the loss of individual creativity, uniqueness, and independent thinking.

GW: Gigawatt, i.e. 1 billion watts

HHV: The higher heating value (HHV: also known as the gross calorific value or gross energy) of a fuel is defined as the amount of heat released by a specified quantity (initially at 25 °C) once it is combusted and the products have returned to a temperature of 25 °C. It thus includes the latent heat of condensation of water in the combustion products.

IGCC: An integrated gasification combined cycle (IGCC) is a technology that uses a gasifier to turn coal and other carbon based fuels into synthesis gas (syngas). It then removes impurities from the syngas before it is combusted. Some of these pollutants, such as sulphur, can be turned into re-usable by-products. This results in lower emissions of sulphur dioxide, particulates, and mercury. Excess heat from the primary combustion and syngas-fired generation is then passed to a steam cycle, similar to a combined cycle gas turbine. This results in improved efficiency compared to conventional pulverized coal.

Interconnector: An interconnector may be either a bi-directional gas pipeline or high-voltage electricity cable effecting a connection between otherwise physically separate national gas or power transmission systems.

Interfacial Tension: is a contractive tendency of the surface of a liquid that allows it to resist an external force. This property is caused by cohesion of similar molecules, and is responsible for many of the behaviours of liquids. In some circumstances it serves to prevent the movement of fluids responding to buoyancy forces.

Kyoto Protocol: The Kyoto Protocol is a protocol to the United Nations Framework Convention on Climate Change (UNFCCC or FCCC), aimed at fighting global warming. The Protocol was initially adopted on 11 December 1997 in Kyoto, Japan, and entered into force on 16 February 2005.

Large Combustion Plant Directive (LPCD): the LPCD aims to reduce acidification, ground level ozone and particulate pollution throughout Europe by controlling emissions of sulphur dioxide and nitrogen oxides and dust from large combustion plant. Member States can choose to meet the obligations by either complying with emissions limits or limiting the remaining operating life of plant whose emissions exceed these limits.

Levelised Cost: See Appendix 1

LHV: The lower heating value (LHV) (*net calorific value* (NCV) or *lower calorific value* (LCV)) is determined by subtracting the heat of vaporization of the water vapour from the higher heating value (see HHV). The LHV assumes that the latent heat of vaporization of water in the fuel and the reaction products is not recovered. It is useful in comparing fuels where condensation of the combustion products is impractical, or heat at a temperature below 150°C cannot be put to use.

Mmbtu: Million British Thermal Units

Molecular Sieve: A molecular sieve is a material containing tiny pores of a precise and uniform size that is used as an adsorbent for gases and liquids. Molecules small enough to pass through the pores are adsorbed while larger molecules are not. It is different from a common filter in that it operates on a molecular level and traps the adsorbed substance.

MW: 1 million watts

MWh: A unit of energy equivalent to a Megawatt of power over the duration of one hour.

National Grid: National Grid is an international electricity and gas company which operates the UK's natural gas and electricity distribution systems.

Ppm, ppmv: Parts per million (parts per million; volume basis) – a measurement of concentration.

Renewables Obligation Certificate (ROC): The Renewables Obligation (RO) is designed to encourage generation of electricity from eligible renewable sources in the United Kingdom. The RO places an obligation on licensed electricity suppliers in the United Kingdom to source an increasing proportion of electricity from renewable sources, similar to a renewable portfolio standard. Suppliers meet their obligations by presenting *Renewables Obligation Certificates* (ROCs).

R&D: Research and Development

UAE: United Arab Emirates

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Table 11. Levelised Cost of Generation, Parsons Brincherhoff FOAK Assumptions, Base Case Scenario

Table 12. Levelised Cost of Generation, Parsons Brincherhoff NOAK Assumptions, Base Case Scenario

Table 13. Levelised Cost of Generation, Mott MacDonald NOAK Assumptions, High Case Scenario

Table 14. Cost and Performance Data for a Range of Power Generation Types – First of a Kind (Mott MacDonald)

Table 15. Cost and Performance Data for a Range of Power Generation Types – Nth of a Kind (Mott MacDonald)

Table 16. Cost and Performance Data for a Range of Power Generation Types – First of a Kind (Parsons Brinckerhoff)

Table 17. Cost and Performance Data for a Range of Power Generation Types – Nth of a Kind (Parsons Brinckerhoff)