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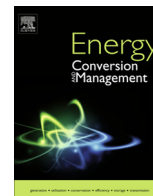Link to publication

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The prospects for coal-fired power plants with carbon capture and storage: A UK perspective

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A B S T R A C T

Carbon capture and storage (CCS) facilities coupled to coal-fired power plants provide a climate change mitigation strategy that potentially permits the continued use of fossil fuels whilst reducing the carbon dioxide (CO_2) emissions. Potential design routes for the capture, transport and storage of CO_2 from United Kingdom (UK) power plants are examined. Energy and carbon analyses were performed on coal-fired power stations with and without CCS. Both currently available and novel CCS technologies are evaluated. Due to lower operating efficiencies, the CCS plants showed a longer energy payback period and a lower energy gain ratio than conventional plant. Cost estimates are reported in the context of recent UK industry-led attempts to determine opportunities for cost reductions across the whole CCS chain, alongside international endeavours to devise common CCS cost estimation methods. These cost figures should be viewed as 'indicative' or suggestive. They are nevertheless helpful to various CCS stakeholder groups [such as those in industry, policy makers (civil servants and the staff of various government agencies), and civil society and environmental 'non-governmental organisations' (NGOs)] in order to enable them to assess the role of this technology in national energy strategies and its impact on local communities.
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1. Introduction

1.1. Background

Energy systems pervade industrial societies and weave a complex web of interactions that affect the daily lives of their citizens. Human development is therefore heated and powered by energy sources of various kinds, but these put at risk the quality and longer-term viability of the biosphere as a result of unwanted, 'second order' effects [1]. Many of such adverse consequences of energy production and consumption give rise to resource uncertainties and potential environmental hazards on a local, regional and global scale. Global warming, predominately caused by the enhanced 'greenhouse effect' from combustion-generated pollutants, is viewed by many as the most serious of the planetary-scale environmental impacts. Carbon dioxide (CO_2) – the main greenhouse gas (GHG) – is thought to have a 'residence time' in the atmosphere of around one hundred years. CO_2 accounts for some 80% of the total GHG emissions, for example, in the United Kingdom (UK) and the energy sector is responsible for around 95% of these [1–3]. The emphasis of energy strategies around the world has consequently been on so-called 'low or zero carbon' (LZC) energy options: energy efficiency improvements and demand reduction measures, fossil fuelled power stations with carbon capture and storage (CCS), combined heat and power (CHP) plants, nuclear power, and renewable energy systems. The British Government has therefore set a challenging, legally binding target of reducing the nation's CO_2 emissions overall by 80% by 2050 (in comparison to a 1990 baseline) in their 2008 *Climate Change Act*. This provides the basis for the adoption of LZC energy options in the UK.

Coal, one of the world's most abundant fossil fuel sources, currently meets about 23% of the total world primary energy demand, some 38% of global electricity generation [4]. It is an important input, for example, in steel production via the basic oxygen furnace process that produces approximately 70% of world steel output [5,6]. But tougher environmental/climate change regulations mean that coal will have to reduce its environmental impact if it is to remain a significant energy source. CO_2 capture and storage facilities coupled to coal-fired power plants therefore provide a climate change mitigation strategy that potentially permits the continued use of coal resources, whilst reducing the CO_2 emissions. The CCS process involves three basic stages [4,8]: capture and compression of CO_2 from power stations, transport of CO_2, and storage away from the atmosphere for hundreds to thousands of years. The

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principle of the various capture methods [7] is that the CO_2 is removed from other waste products so it can be compressed and transported for storage. Transport of the CO_2 can be by ship or by pipeline [4,8].

1.2. The issues considered

Electricity generation accounts for around two fifths of CO_2 emissions in the UK, and CCS is one of several so-called *Carbon Abatement Technologies* (CATs) that could be employed to mitigate these emissions. Potential routes for the capture, transport and storage of CO_2 from UK power plants, such as the Kingsnorth and Longannet sites, are examined here. Storage for the UK is likely to be in geological formations, such as depleted oil and gas fields under the North Sea or saline aquifers. The present contribution is part of an ongoing research effort aimed at evaluating and optimising the performance of energy systems, together with transition pathways towards a low carbon future. It builds on earlier studies of the thermodynamic (including 'exergoeconomic') and techno-economic analysis of power plants with and without carbon capture by Hammond and Ondo Akwe [9] and Hammond et al. [4] respectively. Although the focus in the present work has been on the UK context, the findings have much broader implications for the adoption of clean power technologies in an international perspective.

In the present study, both currently available and novel CCS technologies are evaluated in order to provide an illustrative 'technology assessment'. The findings of energy and carbon analyses are reported for UK coal-fired power stations with and without CCS, together with a review of recent cost estimates. A discussion is included about the important distinction between operational (or 'stack') and upstream CO_2 emissions from electricity generators with coupled CCS facilities. The cost estimates are reported in the context of recent UK industry-led attempts to determine opportunities for cost reductions across the whole CCS chain, alongside international attempts to devise common CCS cost estimation methods. However, at the time of writing, no full-scale carbon capture plant has been built for an operating fossil-fuelled power station (i.e., of a size >500 MW_e) anywhere in the world. Performance parameters are therefore typically estimated on the basis of computational modelling or simulation, detailed '*Front End Engineering Design*' (FEED) studies, expert views, the scaling-up of relatively small-scale capture equipment, and the like. Consequently, the parameters published here should be viewed as 'indicative' or suggestive. They are nevertheless required by various CCS stakeholder groups [such as those in industry, policy makers (civil servants and the staff of various government agencies), and civil society and environmental 'non-governmental organisations' (NGOs)] in order to enable them to assess the role of this technology in national energy strategies and its impact on local communities. The current findings are placed within the wider landscape of CCS opportunities and challenges identified in the interdisciplinary literature.

2. Current carbon capture and storage (CCS) technologies

2.1. CO_2 capture

There are three main methods for capturing the carbon dioxide from coal-fired power stations that are currently in development: post-combustion capture, pre-combustion capture, and oxy-fuel combustion capture [4,7]. These three generic 'routes' all involve the process of removing CO_2 from point-source gas streams, and this can be done in a number of ways. Technical and cost data associated with these routes have been described in the *Intergovernmental Panel on Climate Change* (IPCC) Special Report on CCS (SRCC) [8]. The drivers for and barriers to the deployment of currently available CCS technologies in the UK were recently

discussed by Hammond et al. [4]. They suggested that around 90% of operational carbon emissions can be captured; albeit with an energy penalty of about 16% and rises by some 140% in 'cost of electricity' (COE) compared with a Pulverised Coal reference plant [4]. Kleijn et al. [10] have also recently found that power plant CCS are substantially more metal intensive than existing electricity generators. There are five main technologies to remove CO_2 from a gas stream that are available for use in CCS, and the pressure, temperature and concentration of CO_2 in the flue gas stream will determine which is best suited to a given process [7,11]. The five technologies are: (i) Chemical Solvents; (ii) Physical Solvents; (iii) Adsorption/Desorption; (iv) Membrane Separation; and (v) Cryogenic Separation.

The method of *post-combustion capture* (or 'flue gas scrubbing') is currently the most developed and popular technique employed in industry for capturing CO_2 from the exhaust gases of fossil fuel combustion [4,7,8]. It can be retrofitted at relatively low cost to existing power stations [7] and allows the combustion process to be kept relatively unchanged. The coal is burnt in a conventional combustion chamber, and then the exhaust gases are passed through a particle removal chamber that separates out ash and smoke particles. After a sulphur removal stage, the flue gas is transferred into a CO_2 absorption unit where a solvent absorbs the CO_2. The solvent would react adversely (or be consumed at a fast rate) if the ash, sulphur and other major impurities had not previously been filtered [11]. A CO_2 rich, (typically) amine-based solvent, like mono-ethanol amine (MEA) [4,7], is subsequently heated in a CO_2 stripper, where it releases the pure CO_2 that can be recycled to absorb more CO_2 [12]. The CO_2 that is collected by the stripper is then compressed and stored locally before being piped or shipped directly to its final storage location. Amine-scrubbing is a proven process that is currently used in CO_2 removal for industrial applications [7]. It does however carry an added energy penalty because of gas compression and solvent cooling and heating requirements. This is typically amounts to around 16% [4,7,12,13], and therefore more coal needs to be burnt to achieve the same level of electrical output.

Pre-combustion capture uses a process whereby the coal fuel is converted into a relatively clean gas, often called 'syngas', which comprises mainly of hydrogen (H_2) and carbon monoxide (CO) [7,8,13,14]. Coal comprises mainly carbon with some hydrogen, sulphur, and various impurities. An air separation unit (ASU) is used to extract oxygen from the air, which is then added to the heated Pulverised Coal (PC) – coal pulverised to the consistency of a powder – to produce syngas. Filters and scrubbing units are then used to remove the sulphur and particulates of the gas (in a similar manner as employed with the post-combustion technique), before being passed through a shift reactor. The latter is a catalyst that induces a reaction between the carbon monoxide and the high temperature steam to produce more hydrogen and carbon dioxide. This gas is then scrubbed using a solvent (such as 'Selexol' [4,7] used for natural gas 'sweetening' – the removal of organo-sulphur compounds and hydrogen sulphide – since the 1960s) in much the same way as for post-combustion gases. The CO_2-free gas, which is now composed almost entirely of hydrogen, is used in a gas turbine generator to produce electricity. However, the pre-combustion process requires a significant quantity of additional energy to power the ASU, and to generate the heat required for coal gasification. The energy penalty is typically between 8% and 12% [8,12,13], which is primarily due to the operation of the ASU and losses during coal gasification.

Oxy-fuel combustion is similar to the post-combustion technique in that the combustion exhaust gases are processed after combustion takes place. Pulverised Coal is only pre-treated and then the resulting fuel in the combustion chamber is passed through an ASU [4,7,8,13,14]. Subsequently it is mixed with CO_2 from the flue gas to give a variable CO_2/O_2 mix. The CO_2 is required solely to regulate the temperature of the combustion, and it needs fine-tuning

to achieve an optimum combustion temperature. The purity of the combustion gas leads to a reduction in exhaust impurities, and thus less filtering is required before the CO_2 is scrubbed. After scrubbing, a small fraction of the produced CO_2 is fed back into the combustion unit to be mixed with the oxygen to yield the oxy-fuel. As with pre-combustion capture methods, the major energy penalty comes from the requirement to have an ASU to provide pure oxygen. This leads to an energy penalty of about 8–9% [13], when compared with conventional PC combustion. The oxy-fuel combustion method can be retrofitted to existing power stations, although an ASU, CO_2 scrubbing, and compression apparatus must be added to the conventional plant.

2.2. CO_2 transport

The *International Energy Agency* (IEA) in their CCS 'Technology Roadmap' [12] suggest that pipelines will be the main method for CO_2 transportation with ships and trains being used in the short-term in some demonstration projects worldwide (see also Anderson and Newell [14]; Hammond et al. [4]; Svensson et al. [15]). Shipping becomes more economical than piping for the transport of CO_2 over long distances (>1000 km). Liquefied CO_2, which has similar properties to LPG [8], can be shipped overseas at a pressure of around 0.7 MPa on a commercially attractive basis. The transportation of natural gas and other liquids and gases in the UK is well established, where natural gas and oil have been piped from the North Sea reservoirs since the early 1970s. Consequently, it may be possible to use the existing pipeline infrastructure in the UK operated by *National Grid* [4,13] to reduce the investment required to set up a CO_2 new network. However, existing oil and natural gas pipelines out into the North Sea are reaching the end of their engineering life, and were designed for rather different operating conditions. CO_2 pipelines would therefore need to be designed to withstand high pressure, and the resultant risk of leaks that could arise. The CO_2 behaves differently in various phases, and these can influence the development of corrosion in pipes. Thus, the pipe material would have to be carefully chosen and engineered to minimise the risk of pipeline failure, especially if the pipe is located on the ocean floor. In addition, it will be necessary to devise new metering devices to monitor the quality of the dense phase CO_2 [4,13]. There may also be the requirement to insert recompression stages into the pipeline. In the medium-term, it is believed that the CO_2 pipeline network would work most effectively with a number of onshore 'hubs' that would compress and clean the CO_2 transported in smaller pipes from several power stations and industrial capture plants. At these hubs, the more highly compressed and cleaned CO_2 would be transported through one or two larger, stronger pipes to its offshore storage reservoir [11]. This would not only reduce costs in installation and the length of pipeline required, but would also allow for an interconnected system that could be shared. Such a network would have the potential to evolve into a network of pipes with redundancy and security should a leak or failure occur [11,12]. A hub-network system also allows better managing of the CO_2 transport with third parties leasing pipe use to the power generators to spread the costs and reduce the maintenance and operation strain on single electricity generator and industry users. The CO_2 transportation needs of the UK will benefit from the fact that its storage reservoirs in the North Sea are typically located only 200 or 300 km away from the power stations. Stakeholders feel that there are no long-term technical barriers to the development of a CO_2 pipeline network in the UK [16]. But a CO_2 pipeline operator runs a significant financial risk [16], because of the high cost of the assets and low returns. Indeed, Gough et al. [16] suggest that the cost increase between a network and alternative transmission means could be as high as £3 per tonne ($4.5 or €4.0/tCO_2).

2.3. CO_2 storage

Naturally occurring geological formations provide potential locations for the storage of the captured CO_2: oil or gas recovery, unmineable coal beds, saline aquifers, and depleted oil or gas fields [4,8,11]. These are favoured because of the maturity of the technology involved. CO_2 has been sequestered in geological formations, for example, for over 35 years in both Norway and the United States of America (USA) [11]. Such permeable layers are typically found at least 800 m below the ocean floor. Other potential storage options include ocean storage and CO_2 mineralisation. *Enhanced Oil Recovery* (EOR) and *Enhanced Gas Recovery* (EGR), whereby CO_2 is employed to extract oil and gas from geological formations, have been widely used in Canada and the USA since the early 1970s [4,8,11,14]. The injection of CO_2 into an oil reservoir mixes the gas with the crude oil and thins the resulting mixture. It is then easier to extract from the reservoir. These techniques are presently only employed in inshore applications, and therefore they appear to have very limited application on the UK continental shelf. The *Advanced Power Generation Technology Forum* (APGTF) in the UK has argued that EOR and EGR are not currently economical for 'offshore' applications [11]. *Enhanced Coal Bed Methane* (ECBM) makes use of unmineable coal beds by injecting the CO_2 into parts of a coal seam that are not reachable or economical [4,8,14]. The main benefit of using this method is that a large number of coal beds in the UK that are not economical to mine. In addition, most coal beds contain vast trapped pockets of methane gas that can be displaced by the CO_2 and captured, much like with the EGR method [11]. Several small-scale trials using ECBM have been undertaken in the USA. A saline aquifer is an underground geological formation in which a large quantity of salt water has become trapped during the formation of the rock layers that surround it. The CO_2 can be pumped down into the deep saline aquifers, where the CO_2 will be stored in the natural gas pockets, where it will dissolve in the water to an extent. Saline aquifers are the most promising long-term CO_2 storage globally according to the SRCC [8]. There has been one major storage project undertaken in a saline formation in the Norwegian sector of the North Sea: the Sleipner field [4,8,17]. Monitoring suggests that no CO_2 has currently escaped. However, the monitoring of saline formations is a lot less well-developed than in the case of oil and gas wells [4]. The confidence in the permanence of storage is consequently lower, especially because the majority of the potential storage is in 'open saline formations' that provide an eventual escape path for CO_2. More development is required in these cases to simulate options and determine whether the CO_2 will be held over hundreds to thousands of years in order to mitigate climate change [4]. The final option for CO_2 storage, and the one that is most attractive for UK, is to store it in geological formations that naturally occur under the seabed of the North Sea. The CO_2 storage capacity in North Sea depleted oil and gas reservoirs is estimated to be around 10,190 MtCO_2 [18]. This is equivalent to roughly 59 years of storage, based on 2008 CO_2 emission data. This is complimented by a further 14,466 MtCO_2 [18] of storage capacity is available in UK saline aquifers. In contrast, the *Scottish Centre for Carbon Storage* [19] estimated that total of up to 46,000 MtCO_2 of storage capacity could be available in ten saline aquifers in and around Scotland. This would represent 266 years of UK storage requirements, based on UK CO_2 emissions from power generation in 2008.

3. Novel carbon capture and storage (CCS) technologies

Many of the issues concerned with innovation and the deployment of CCS technologies in the UK context have recently been discussed by Hammond et al. [4]. Likewise, the maturity of the various

CCS processes have been characterised in the SRCC [8]; see also Hammond et al. [4] and Spigarelli and Kawatra [7]. The market penetration of a (successful) new technology typically varies in the manner of the hypothetical S-shape, or 'logistic', curve shown in Fig. 1 [4]. Take-up of the technology begins slowly, then as commercial viability is reached production 'takes off', and finally the technology rapidly diffuses before gradually slowing down as the market saturates. A 'roadmap' for the deployment of CCS in the UK has recently been devised by Gough et al. [16] on the basis of a two-stage process involving a CCS landscape review and a 'high-level' (i.e., 'expert') stakeholder workshop. They envisage that the development phase would extend over the period to 2015, followed by commercialisation out to 2050. The cost of production of a technology tends to reduce as production volumes increase; a phenomenon reflected by so-called technology *'learning curves'* or *'experience curves'* [4]. The causes of cost reduction vary, but can include 'learning by doing' improvements and economies of scale. It is therefore clear that higher costs for new technologies present a barrier to entry when competing with established technologies. This contributes to the 'lock-in' of incumbent technologies, and highlights the path dependence of development; both of which can discourage innovation [4]. In order to promote innovation and create a market for diverse technology options, these processes must be considered in the context of policy-making.

Some of the more advanced or novel CCS options are outlined here. The first of these is known as *Chemical Looping Combustion* (CLC), and it involves using an oxidiser to enhance fuel combustion rather than just the oxygen in the air [7]. The oxidiser used is a metal oxide, such as iron oxide or calcium oxide. It is a relatively well-researched method for natural gas CCS. In contrast, for coal CCS this is more challenging, although it can be achieved by using coal gasification or more complex mixing and combustion techniques. The oxidiser burns in the combustion chamber (or 'fuel reactor' [7]) with the Pulverised Coal, and then burns to produce CO_2 and H_2O. The metal is then removed from the system and re-oxidised using oxygen from the air and can be completely recycled with minimal matter lost. The US *Department of Energy* (DOE) claimed that in their chemical looping CCS demonstrator plant they could achieve 90% CO_2 capture rate for less than a 35% increase in cost when compared to a reference (non-CCS) plant [20].

Several innovative methods are being researched to reduce the losses associated with *post-combustion capture*, and thereby reduce the energy and work input required for traditional, reactive amine-based solvents. *Carbonate Looping* [14] works in a similar way to chemical looping only. Instead of metal oxides, it uses alkali hydroxides or carbonates that are converted to bicarbonates. Limestone can be used to extract the CO_2 from the combustion system in a 'Calciner' in which it can be removed and compressed in an incredibly pure state. Although this method will only remove around 83% of the CO_2 from the flue gas, it could represent a very cost effective solution with limestone being an abundant, affordable material and much of the equipment is already available. In contrast, the process of *mineralisation* uses a solid sorbent to absorb the CO_2 from the flue gases where it can then be removed and sequestered. In general this process does not regenerate the sorbent; the CO_2 rich mineral is then transported away for storage or, in some cases, use in industrial processes [8,14]. An example of mineralisation uses sodium chloride extracted from seawater to manufacture sodium hydroxide [7]. It is being utilised in cement manufacturing plants in Texas, albeit with substantial increase in energy requirements. However, seawater is abundant and cheap, and the by-products (sodium bicarbonate and chlorine gas) have some commercial value. A similar process can be performed using calcium compounds to store CO_2 in the form of calcium carbonate. In Canada, a 'biomimetic' approach is being employed to convert CO_2 to bicarbonate using an enzyme (carbonic anhydrase) that is normally found in red blood cells. This enzyme is stored in large capture units filled with bio-engineered *Escherichia coli* bacteria through which the flue gas passes. The enzymes within the bacteria convert the CO_2 into bicarbonate ions, which are then removed with the water. When the water is purified and passed back
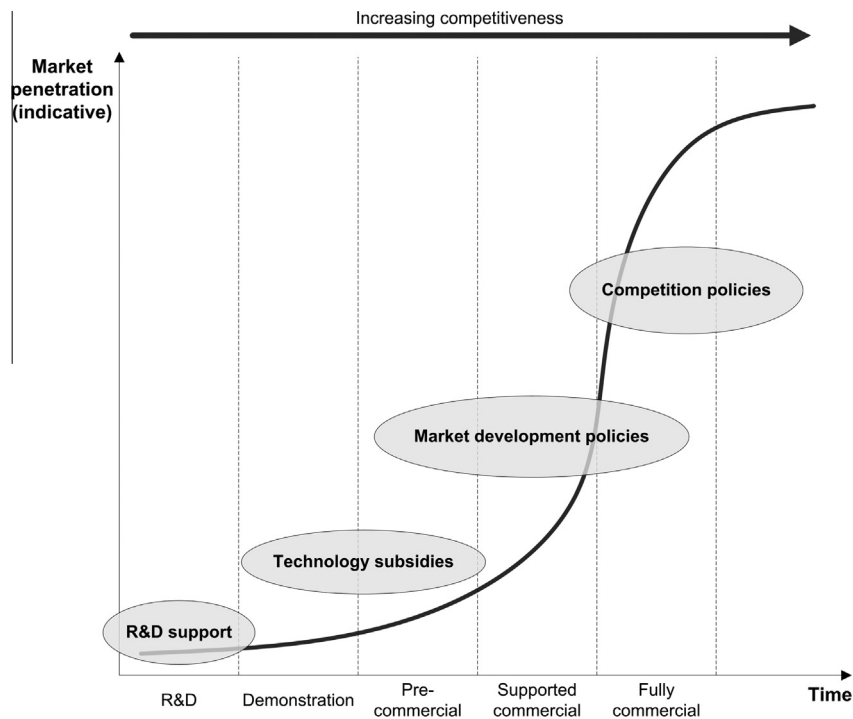

Fig. 1. S-curve of technology development and policy categories. *Source:* Hammond et al. [4].

through the system, the bicarbonate ions are either stripped of their CO_2 (which can then be compressed and stored in a very pure form) or can be stabilised as a solid and sold as a commodity or stored. A significant advantage of these enzymes is that they can be used in conjunction with traditional amine-based solvents, and the enzyme reaction with CO_2 is approximately 6 times faster.

Integrated (coal) Gasification Combined Cycle (IGCC) plants have recently started to receive more interest from power generators and generation equipment manufacturers in the UK [4]. This system uses a *pre-combustion technique* to gasify coal by heating the PC in a 100% oxygen environment to produce a 'syngas' fuel. This syngas is cooled and then cleaned before being burnt in the gas turbine to generate electricity. The exhaust from this, which consists of H_2O and other inert gases, is then emitted to the atmosphere having been passed through a heat exchanger to extract as much heat as possible from the exhaust gases; thereby maximising the cycle efficiency. The gasification process is regulated by water-cooling via (a water-side) heat exchanger. This water then evaporates to form steam, which is used to drive a second, steam driven turbine that generates additional electricity. When this steam leaves the turbine it is condensed before being reheated from the exhaust heat exchanger. This method is believed to be able to provide efficiencies of over 46%; some 14% higher than many of the currently operating non-CCS coal power stations in the UK (Dr. Mike Farley, formerly of *Doosan Babcock Energy*, private communication, 2008). This technology is quite attractive, because of its relatively high efficiency and versatility in terms of fuel use - it could burn either natural gas or hydrogen should the situation arise, or technology advances to enable a partial refit of the IGCC system. The main disadvantage of this technology presently is the high capital cost of the hardware, as well as operational costs [7].

A number of novel improvements could be made to improve the efficiency of the capture and combustion steps employed with *oxy-fuel combustion*. One of the areas that yield high losses in efficiency is the use of an ASU. These ASUs are typically high temperature, high-pressure chambers that use a three stage cryogenic process to remove the oxygen from air for injection to the combustion chamber. Through basic engineering improvements and the increased capacity of ASUs, it is likely that process efficiencies will rise in the future. Another method for separating oxygen from air is through the use of *Ion Transport Membranes* (ITM). ITMs are a type of ceramic membrane that is permeable only to oxygen [7]. Although the membrane needs to be heated for oxygen to be able to pass through it, typically to over 700 °C, it offers much greater efficiency than methods such as using an ASU [21], which can account for up to 80% of the internal power consumption of the process [22]. Membrane technology is not limited in its use to oxygen separation; gas separation membranes are also being developed for CO_2 adsorption. These work in a similar way to the ITMs described above only they are utilised in *post-combustion capture* to remove CO_2 from the flue gas. The principle of a CO_2 removal membrane is based on flue gas being passed through a set of tubes, which under high temperature and pressure will transfer the CO_2 content from the flue gas through the tubular membranes into the surrounding cavity. This gas is then compressed and transported for storage and the flue gas is emitted to the atmosphere having had the CO_2 removed. Some estimates predict that the operating costs of a membrane CO_2 removal system would be 60% lower than that of current post combustion capture methods and a 70% reduction in capital costs [22].

The advanced CCS methods outlined above are the type principally evaluated here, but there are obviously a number of other potential innovations under development worldwide. Many efficiency improvements can be expected to arise, for example, from the use of advanced materials. Boiler plant and corresponding pipework materials are currently being developed that can operate at temperatures in excess of 700 °C. This would not only yield improvements in efficiency for all steam cycles involved in any CCS combustion process, but would also provide the biggest improvement in the *oxy-fuel combustion method* [11]. Currently CO_2 is removed from the flue gases and used in the combustion chamber as a regulator of the temperature. If the combustion chamber was able to function at higher temperatures using novel cooling technologies, advanced metal alloys and ceramics, then less CO_2 would be required to regulate the combustion making the system simpler and therefore less energy intensive. In addition, biotechnology can potentially be employed to harness the natural process of photosynthesis in which CO_2 is extracted from the atmosphere, and then combined with water and energy from the sun to produce oxygen and sugars [14]. Algae in large tanks, for example, when exposed to natural light, separates the CO_2 from the flue gas as it is passed through the tanks. This technology is being trialled in the USA, and used in Spain at a cement factory. This biotechnology does have the disadvantage of a large area being required to capture a relatively small amount of CO_2. However, algae, or micro-algae, also yield by-products that have value both financially and as an energy source. When the algae are harvested at the end of their useful life, they can provide fuel both as dried out cellulose-based biomass or, in some cases, an oil product. In addition, they have useful nutrient products that are often refined and sold as dietary supplements or as a fertilizer or feedstock.

4. Potential UK CCS developments

4.1. The wider context

The 2009 IEA roadmap for the implementation of CCS [12] suggested a need for increased funding for demonstration projects of $3.5–4.0 billion (€2.6–3.0 bn) from 2010–2020. This would lead to the construction of around 100 large-scale demonstrators by 2020, which they believe should be increased to over 3000 projects. IEA analysis [12] indicates that without CCS the overall costs of GHG mitigation over the period 2005–2050 would increase by 70%. This thinking was then fed into the considerations of the G8 group of industrialised countries at its 2010 Muskoka (Japan) Summit [23]. Here the IEA worked jointly with the 'Carbon Sequestration Leadership Forum' and the 'Global CCS Institute'. They noted that the deployment of large-scale CCS demonstration projects is critical to the deployment of the technology. Their progress review [23] suggests that government and regional groups had made commitments to launch 19–43 such demonstrators by 2020. These developments were identified in the USA, the European Union (EU), "particularly the United Kingdom", Canada and Australia. But the partners noted that implementation of such a programme would be challenging. The 2008 economic turndown, and the more recent *Eurozone* financial crisis, have both made the economic situation far more difficult in terms of potential public investments in large-scale energy projects of all kinds. Indeed, the APGTF [11] believe that there is a global funding gap associated with the construction of CCS demonstrators by governments and industries of around €7–12 bn ($9.3–16 bn).

The individual technological components of CCS have reached maturity within many industrialised countries [4,8,14,24] (see also Section 2 above), but there is currently no end-to-end commercial-scale demonstrators operating in the Britain. The UK *Climate Change Act* of 2008 set the pace for implementing low carbon technologies generally, and the potential commercial development of CCS specifically [4,13]. It was preceded a year earlier by the announcement of a UK Government competition to build a full-scale CCS demonstrator: so-called 'Competition One'. This was aimed at tackling the shortcomings to CCS acceleration in Britain

in order to eventually deliver four commercial-scale demonstrators. The competition consisted of nine proposals, and went through several stages of assessment. In March 2010 the UK *Department of Energy and Climate Change* (DECC) announced that funding would be awarded to *E.On* and a consortium led by *ScottishPower* (with *National Grid* and *Shell*) to develop two end-to-end CCS power plants at Kingsnorth in Kent (south east England) and at Longannet near Kincardine, Fife (Scotland) respectively. Both were sites of existing large-scale coal-fired power stations. The initial phase of the CCS demonstrator competition involved various FEED studies. Both potential CCS projects were studied within a collaborative, interdisciplinary, social-technical framework co-ordinated by Markusson et al. [25] in order shed new light on the social and policy challenges for the adoption of this crucial technology.

4.2. The Kingsnorth power station

E.On, the German-owned electricity utility company, originally aimed to implement a 300–400 MW-sized post-combustion capture demonstrator facility linked to a new 1600 MW$_e$ coal-fired generation unit on a site at Kingsnorth in Kent (in the South East region of England) as part of the DECC CCS competition. This would have been coupled to pipeline transport of CO_2 to the North Sea for storage. The idea behind the pipeline was to ultimately provide a method of CO_2 transport from the 'Thames Cluster': a group of ten fossil-fuelled power stations. Kingsnorth power station would have captured 8.0 MtCO$_2$/year and the pipeline could, by 2016, have been transporting 27.9 MtCO$_2$/year from the Thames Cluster. But the project ran into strong opposition from environmental campaigners, including those at the nearby 'Camp of Climate Action' [25]. *E.On* consequently announced in October 2009 its decision to postpone the construction of new power station at the Kingsnorth site on the grounds that electricity demand had fallen as a consequence of the recession following the 2008 economic downturn. Nevertheless, it won a share of £90 M for a FEED study as part of the DECC CCS competition in March 2010, although it ultimately announced in October of that year that it would pull out of the Competition One. It stated that the market conditions were not conducive in the UK, and that it would concentrate on a CCS project in Holland. It is argued in Markusson et al. [25] that the "very vocal and media-savy" Climate Camp caught public attention in making the case for low carbon power generation; claiming that a new coal-fired power plant at Kingsnorth with only 20–25% of initial capture capacity did not meet environmental sustainability requirements.

4.3. The Longannet power station

Longannet power station at Fife (Scotland) is owned and operated by *ScottishPower*, and is the third largest coal-fired power station in Europe with a generation capacity of 2400 MW$_e$ [25]. The intention would have been to retrofit amine-based CO_2 strippers to remove the CO_2 from the exhaust gases after coal combustion. This CO_2 would then be transported via a reused natural gas pipeline to depleted oil and gas fields in the North Sea. *ScottishPower* would be responsible for retrofitting post-combustion CCS for a 300 MW demonstrator facility. *National Grid Carbon* would then develop onshore transport and compression at the St Fergus existing natural gas terminal on the Scottish coast with a new Above Ground Installation (AGI) near Longannet, Dunipace and Kintore, as well as a coastal CCS compressor station. *Shell* would be responsible for offshore transport of CO_2 to the North Sea geological storage site. A prototype Mobile Test Unit (MTU) commenced operation in 2009 in order to capture a small percentage of the power station's flue gas CO_2 emissions to test the complex chemistry

involved in carbon capture. In October 2011, DECC announced that negotiations with the *ScottishPower CCS Consortium* had concluded, but that the Longannet CCS project would not proceed to full-scale. DECC stated that there were specific technical difficulties associated with Longannet, including the length of pipeline from the Fife coast to the North Sea oil fields. However, *ScottishPower* claimed that the main problem appeared to be the estimated £1.5 bn UK Government subsidy required for the CCS trial at a time of economic recession.

The study co-ordinated by Markusson et al. [25] examined the Longannet CCS project with a view to learning the social and political lessons from potential demonstrators. They suggest that the UK Government's CCS Competition One was aimed at addressing, in part, the element of 'picking winners' identified by Scrase and Watson [26]. However, the initial CCS demonstrator competition was based only on the use of post-combustion capture technologies, and this influenced the design of the project [25]. It had the support of the Scottish Government and the authority, and induced little public opposition on environmental or other grounds [25]. Nevertheless, the carbon capture project at Longannet was ultimately scrapped by DECC. According to the consortium, led by ScottishPower (in collaboration with Shell and the National Grid), the failure of financial negotiations with the UK Government were partly 'scuppered' [25] by the Treasury's introduction of a carbon floor pricethe carbon price floor tax that became government policy after the Coalition came to power in May 2010 at £16 per tonne from 2013. [This was originally planned to rise to £30 per tonne by the end of the decade, and £70 per tonne in 2030.] Nevertheless, both technical and social learning will have been gained from these design projects. For example, FEED studies from the Longannet proposal have yielded in-depth technical reports that have been made quite broadly available. Consequently, project developers and the key stakeholders engaged in this CCS proposal will have benefited and learned from the practical experience and generated knowledge [25].

4.4. The UK government's view of the next steps for CCS developments

Despite the failure of negotiations between the *ScottishPower*-led consortium over the development of the demonstration project at the Longannet power station, the UK Government reaffirmed their commitment to CCS and thus potentially to Competitions Two, Three and Four. It has made available £1bn for a new process for the selection of further CCS demonstrator projects. The UK Government published its CCS 'roadmap' in the spring of 2012 [27,28], and announced its latest competition (known as the 'CCS Commercialisation Programme') for £1bn capital funding to build a commercial scale, coal or natural gas fuelled, power plant and capture facility in Great Britain to be operational by 2016–2020 with an appropriate storage site offshore. It is anticipated that energy penalties for first generation, post-combustion and oxy-fuel power plants with a range of fuels could be reduced to around 8% [4,9]. Pre-combustion plant might similarly see their energy penalties fall to 7% with reductions in steam requirements on the same timescale [13,29].

In March 2013, DECC announced two preferred bidders under the CCS Commercialisation Programme (Competition Two). These were a natural gas retrofit scheme (the Peterhead Project in Aberdeenshire, Scotland) led by Shell with SSE and an oxy-fuel combustion project at a new 'super-efficient' coal-fired power station (the White Rose Project [28] at the Drax site in North Yorkshire) from an industry consortium (Alstom, Drax Power, BOC and National Grid). The UK Government agreed terms for the White Rose CCS Project in December 2013 for FEED studies, which will last approximately 24 months. A similar agreement for FEED studies associated with the Peterhead CCS Project were signed in February 2014.

Two of the remaining schemes (from Captain Clean Energy and Teesside Low Carbon) were assigned as 'reserve projects'; should one or both of the preferred bidders fails to enter into FEED contracts. A final investment decision will be taken by the British Government in early 2015 on the construction of up to two projects.

5. Energy and carbon analyses

5.1. Methods statement

In order to determine the primary energy inputs needed to produce a given amount of product or service, it is necessary to trace the flow of energy through the relevant industrial system [6,30–34]. This idea is based on the *First Law of Thermodynamics*, that is, the principle of conservation of energy, or the notion of an energy balance applied to the system. Thus, First Law or 'energy' analysis [6,32,33], sometimes termed 'fossil fuel accounting' [30], can be employed to estimate the energy requirements of building new electricity generation plant. Analysis is performed over the entire life-cycle of the power cycle: from 'birth to death' [34] or 'from cradle to grave' [6,32,33]. Energy analysis (EA) implies the identification of feedback loops [6,32,33], such as the indirect or 'embodied', energy requirements for materials and capital inputs. This procedure is indicated schematically in Fig. 2. Several differing methods of EA have been developed, the most significant being statistical analysis, Input–Output (I–O) analysis, process analysis (or energy 'flow charting'), and hybrid analysis [6,30–32]. It yields the following metrics, amongst others:

- *Energy Payback Period* (EPP) and *Energy Gain Ratio* (EGR) - The EPP is the time taken for a power system to 'repay' the energy that has been used in its construction. It is defined [32] via:

$$EPP = E_{construction}/E_{output/year}$$

In contrast, the EGR is a ratio of the total energy output over the life of a power system divided by the energy input to the system during construction. In order to calculate the corresponding EGR [32,34], the following formula is employed:

$$EGR = E_{output}/E_{input}$$

This equation represents the total energy produced over the lifetime of the power system divided by the sum of the energy input in terms of materials production, construction, operation,

and decommissioning [34]. The boundaries of the system studied coincided with inputs of raw materials, such as coal and the steel and concrete used in construction of the power stations. Energy is required for the processing and manufacturing of raw materials, and that used during construction (predominantly through the burning of fossil fuels during the transport of materials and the operation of construction machinery). Obviously, the major energy requirement is associated with power plant operation. An allowance has also to be made for the energy needed to decommission and demolish the power station at the end of its life. The outputs from this system are electrical power, emissions that are released to the atmosphere or, in the case of CCS stored in its final location, and materials that can be recycled or reused.

- *CO$_2$ Emissions per kWh* – these emission factors reflect the amount of carbon that is released as a result of using one unit of energy, and have units of kgCO$_2$/kWh.

Carbon emissions are the 'currency' of debate in a climate-constrained world. In order to estimate the embodied energy and embodied carbon of a product or service, the technique of environmental life-cycle assessment (LCA) is required [6,32,33]. This involves identifying all of the processes that are needed to create the product or service, whilst assigning energy requirements and carbon emissions to upstream processes. All of these individual processes are summated, and the embodied energy and carbon [6] within the prescribed system boundary can be calculated. A full LCA requires a detailed investigation that is often time consuming. Therefore, wherever possible, the embodied energy and carbon data are taken from pre-existing studies, such as the ICE database developed at the University of Bath [6,35].

5.2. Energy requirements of current technology

In order to estimate performance metrics (such as EGR, EPP, and CO$_2$ emissions per kWh) it was first necessary to select a reference plant against which to normalize data. The reference that was chosen is a coal-fired power station of a capacity of 1 GW$_e$ without CCS. This is similar to that of a small coal power station in operation in the UK, and has a nominal life of some 40 years. The reason a larger size has not been chosen, for example the Didcot power station (that has a capacity of 2 GW$_e$) or Drax (with a capacity of 4 GW$_e$), is because the majority of CCS demonstrators are likely to be between 250 MW$_e$ and 1 GW$_e$ (being at the higher end of that
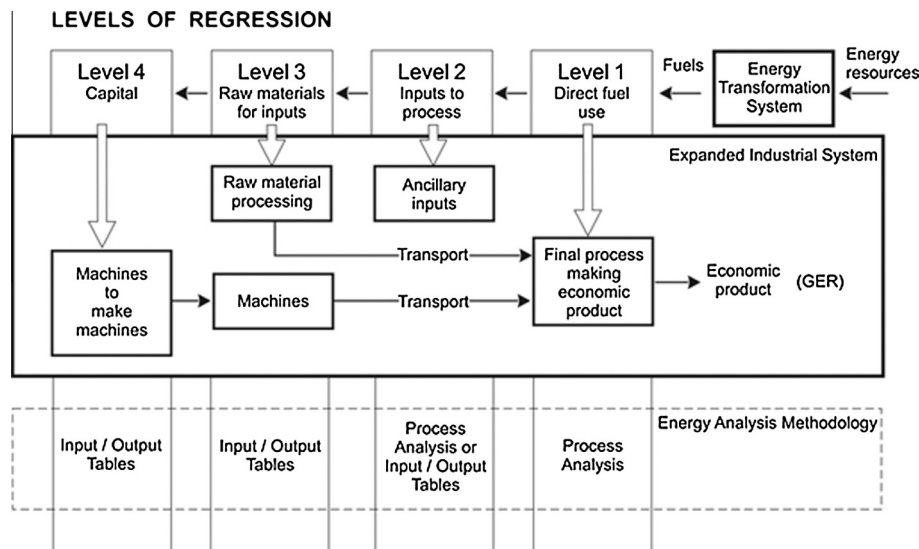

Fig. 2. Schematic representation of the energy analysis process. *Source:* Allen et al. [31]; adapted from Slesser [30].

scale as development and deployment advances). Capacities of the reference and hypothetical CCS plant were assumed to be identical for the purposes of comparing parameters like energy output and emissions efficiencies. Data used to estimate the construction energy investment for the reference coal-fired power station was extracted from a *Fusion Technology Institute* (FTI) report [34]. This data was then scaled to provide the equivalent materials quantities required for a nominal 1 GW_e power station. Embodied energy and carbon data for each of the materials was then extracted from the *Inventory of Carbon and Energy* (ICE) [6,35]. It was then necessary to establish the additional materials and refining processes that would be required for a CCS plant. The precise data is not publicly available, due to intellectual property (IP) concerns. Manufacturers are therefore reluctant to release exact specifications for their actual or potential CCS hardware. Instead a range of assumptions was employed to facilitate the estimation of the additional equipment and costs associated with the 1 GW_e non-CCS reference plant. For example, it was assumed that the quantity of concrete, which is by far the largest single material component of most power stations, should be assigned an uncertainty of ±10%. Stainless steel and copper, which make up the majority of the CCS specific equipment, were likewise assigned an uncertainty of ±20%. All other construction materials had an uncertainty factor of ±15% applied.

Data was then gathered for the other stages of the whole life CCS power plant chain. This was again obtained from the FTI report [34], together with a *World Energy Council* LCA study of a variety of energy systems [36]. Table 1 provides a breakdown of these energy investments and the factors that were applied to non-CCS coal power station data for each section. A key point is that although there would be negligible additional construction energy expenditure, an additional 8% increase in mining and fuel transport energy was applied to compensate for the extra coal that would be needed to achieve 1 GW_e output. This results from a loss of efficiency of ~8% when capturing and compressing the CO_2 [36]. Another key adjustment that was made related to the energy expenditure for waste disposal. This was doubled in order to compensate for the pipeline operation and maintenance. Although this could potentially be higher than +200% in the early stages of commercialisation, the energy and financial costs would fall as a shared pipeline infrastructure was developed. The EPP and EGR could then be calculated based on the sum of energy investments for the power production of a nominal 1 GW_e output over 40 years – 1.261 EJ (1.261×10^{18} J).

The EGR shows (see again Table 1) that, over its lifetime, the 'reference' or non-CCS power plant 'repays' its energy investment in construction, operation and decommission by nearly 11 times, whereas for a contemporary CCS plant this is 9.9. Similarly, the EPP for the non-CCS power plant was found to 3 years and 8 months, which indicates that (following its entry into service) the reference plant will have produced more energy than required

for its construction in less than 4 years. The corresponding figure for a CCS plant is 4 years, and the 4-month difference between the results is the energy that is required to produce the additional CCS hardware, along with associated transportation (e.g., pipeline) and storage. It should be noted that due to the assumptions that have been made regarding material quantities and additional energy used over the life-cycle, there is a certain level of uncertainty in the EGR and EPP values. For the information on current CCS values it is believed that this is in the range ±10%, which would lead to EGR values of between 9.10 and 10.69 and those for the EPP of between 4 years and 4 months, and 3 years and 9 months. This shows that even a ±20% range of input values yields only a small change in EGR and EPP; having a variation significantly less than ±20%.

5.3. Energy requirements of novel technology

The analysis of contemporary, 'First-of-a-Kind' (FOAK) CCS developments are clearly inhibited by lack of accurate data. This is even more the case with innovative or novel CCS technologies, and this needs to be borne in mind when considering the results of the appraisal of a prototypical advanced CCS power plant reported here. An advanced oxy-fuel combustion coal-fired power station that incorporated *Ion Transport Membranes* (ITM) was selected for this purpose. In terms of the energy investment, the materials used in construction of an oxy-fuel CCS plant with ITM CO_2 capture were assumed to be the same as for a contemporary CCS plant. This would result in increased CO_2 capture efficiency of the ITM method and the improved fuel efficiency of the oxy-fuel combustion. But the energy investment into fuel mining and transporting was nevertheless increased by 4% compared to a power plant without CCS. The operating input energy of traditional oxy-fuel plants would be higher than that for contemporary CCS technologies described earlier. Likewise, an ITM unit uses less energy than in a traditional ASU. Therefore, the total energy investment in process has been assumed to be 15% higher than that of a contemporary CCS plant. Other than these factors, the energy input data for this novel CCS plant remains unchanged from that of a modern post-combustion CCS power plant. Table 2 displays the breakdown of this energy investment. It can be seen that the resulting EGR values for the oxy-fuel CCS power plant are lower than those for current post-combustion CCS plant previously assessed. These values imply that the novel technologies will give rise to a longer energy payback period (EPP) than for the traditional CCS plants.

There are again uncertainties associated with the energy and material requirements of the plants that have been analysed here. The novel CCS technology involves an immature development, and is less well documented than contemporary technology. Thus, its

Table 1
Energy analysis of contemporary CCS technologies. (Non-CCS figures based on values from FTI report [33]. All values except EGR and EPP have the units of TJ_{th}).

Energy investment (TJ_{th} – for a 1 GW_e plant over 40 years)		Coal reference (non-CCS)	Coal CCS plant (with CCS)
Materials	Manufacture & refining	1219	1400
Construction	Construction	3680	3680
Operation	Fuel mining	50,320	54,346
	Fuel transportation	42,360	45,749
	Operation	17,600	21,120
	Waste disposal	240	480
Decommissioning	Plant deconstruction	400	480
	Land reclamation	160	160
Total		116,000	127,400
Energy Gain Ratio (EGR)		10.88:1	9.90:1
Energy Payback Period (EPP) – Years		3.67	4.00

NB: The data sources employed here would suggest that these estimates are only valid up to an accuracy of not more than three significant figures.

Table 2
Energy analysis of novel CCS technologies. (Non-CCS figures based on values from FTI report [33]. All values except EGR and EPP have the units of TJ_{th}).

Energy investment (TJ_{th} – for a 1 GW_e plant over 40 years)		Coal reference (non-CCS)	Advanced CCS (oxy-fuel & ITM)
Materials	Manufacture & refining	1219	1400
Construction	Construction	3680	3680
Operation	Fuel mining	50,320	52,333
	Fuel transportation	42,360	44,054
	Operation	17,600	20,240
	Waste disposal	240	480
Decommissioning	Plant deconstruction	400	460
	Land reclamation	160	160
Total		116,000	122,800
Energy Gain Ratio (EGR)		10.88:1	10.27:1
Energy Payback Period (EPP) – Years		3.67	3.92

NB: The data sources employed here would suggest that these estimates are only valid up to an accuracy of not more than three significant figures.

uncertainty was taken to be ±20%. This gives a range of values for EGR of between 8.69 and 12.57, and that for EPP of between 3 years and 2 months and 4 years and 7 months.

5.4. Analysis of CO_2 emissions

CCS plants require larger energy input and higher energy to operate due to processes such as air separation and CO_2 compression. But without capture, this would result in a higher level of CO_2 emitted to the atmosphere. The more advanced novel technologies, such as pressurised oxy-fuel combustion, have the potential to capture over 98% of the operational CO_2 emissions emitted from a power station chimney or 'stack' that would otherwise be exhausted to the atmosphere. However, these plants and their CO_2 emissions must be assessed based on their entire life-cycle, as was done with the energy assessment above, not just the CO_2 emitted during operation. The ICE database (version 1.6a; see, for example, Hammond and Jones [6]) was employed in the present study to estimate the CO_2 emissions for the processing of the materials used in the construction of the reference coal-fired power plant (without CCS), the contemporary CCS plant, and the novel CCS plant (oxy-fuel combustion, plus ITM separation) respectively. This ICE-based data, and the data that was used in the energy analysis for the FTI report [34], enabled the CO_2 emissions for each LCA step to be estimated. Table 3 shows the breakdown of the life-cycle stages, and the amount of CO_2 emitted to the atmosphere as a direct result of each stage. The sum of these CO_2 emissions, including the operation of the CCS power station: the most significant component, which accounts for over 98% of the CO_2 emissions, because it includes the burning of coal. These totals can then be divided by the total number of energy units (kWh) generated by

the plant over its 40-year life span. This was found to yield 1.261 EJ, or 350,400 GWh.

The CO_2 generated per kWh [kg CO_2/kWh] is separated in Table 3 from the quantity of CO_2 emitted to the atmosphere. The CO_2 capture factor depends on the CCS technology employed: obviously zero carbon capture for power plants without CSS, 90% CO_2 capture for contemporary CCS technology, and 95% for novel CCS technology. The figure of 95% may be a pessimistic estimate for the selected novel CCS plant – *Sargas AS* (Norway), for example, achieved this capture factor in a demonstrator plant in 2008, although they predict an ultimate rate of 98%. In contrast, CanmetENERGY [37] state as a result of their technical and feasibility study of a pressurised oxy-fuel approach to CCS that 100% capture is achievable. The figure of 55 g of CO_2 per kWh represents a practical maximum figure for carbon emissions to the atmosphere that would be achieved by high-pressure oxy-fuel coal-fired power stations with ITM technology. The CO_2 produced from the three technology options analysed here are illustrated in Table 3, and reproduced graphically in Fig. 3, show that (although the two CCS methods produce more CO_2 than the non-CCS reference plant) a significant proportion of these emissions is removed and stored, as represented by the light grey area. In the SRCC report [8] emission rates are presented for new non-CCS PC power plants of 736–811 g CO_2/kWh, and 92–145 gCO_2/kWh with capture respectively. Spath and Mann [38] found that for their reference PC power plant emitted 847 g CO_{2e}/kWh, and that with modern CCS emitted 247 gCO_{2e}/kWh, i.e., giving a 71% reduction. In contrast, Viebahn et al. [39] found from an LCA study that their base case PC power plant gave rise to emissions of 792 gCO_{2e}/kWh, and 262 gCO_{2e}/kWh with CCS fitted.

Upstream environmental burdens arise from the need to expend energy resources in order to extract and deliver fuel to a

Table 3
CO_2 breakdown for coal-fired power plants with and without CCS at each life-cycle stage, including the quantity of CO_2 emitted to the atmosphere based on capture rates. (All value in Mt of CO_2 unless otherwise stated).

CO_2 emissions (Mt CO_2 – for a 1 GW_e plant over 40 years)		Coal reference (non-CCS)	Coal CCS Plant (with CCS)	Advanced CCS (oxy-fuel & ITM)
Materials	Manufacture & refining	96	109	109
Construction	Construction	245	245	245
Operation	Fuel mining	2943	3179	3061
	Fuel transportation	3154	3406	3280
	Operation	334,982	401,979	385,230
	Waste disposal	18	35	35
Decommissioning	Plant Deconstruction	35	42	40
	Land reclamation	11	11	11
Total		341,483	409,006	392,011
CO_2 generated per kWh (kgCO_2/kWh)		0.975	1.167	1.119
CO_2 emitted to atmosphere (kgCO_2/kWh)		0.956	0.115	0.055

NB: The data sources employed here would suggest that these estimates are only valid up to an accuracy of not more than three significant figures.

power station or other users. They include the energy requirements for extraction, processing/refining, transport, and fabrication, as well as methane leakages from coal mining activities – a major contribution – and natural gas pipelines. These were not fully taken into account in the above calculations that allowed for just operational and embodied emissions. The upstream carbon dioxide equivalent (CO_{2e}) emissions associated with various power generators and UK electricity transition pathways towards a low carbon future have recently been evaluated on a 'whole systems' basis [40,41]. The associated stages are shown by the bars in the chart presented as Fig. 3, with 'non-operational emissions' depicted by the black bars. The operational (direct or 'stack') emissions associated with the combustion of fuels are compared with GHG emissions from upstream coal mining and refining activities in Table 4. This data indicates the magnitude of the difference between direct combustion and upstream emissions. Such fugitive GHG emissions indicate (see Table 5) that coal CCS is about 2/3 lower in terms of GHG emissions in comparison with conventional coal-fired plant (without CCS), i.e., a fall from 1.09 to 0.31 kg CO_{2e} per kWh. Thus, CO_2 capture is likely to deliver only a 70% reduction in carbon emissions on a whole system basis (including both upstream and operational emissions), in contrast to the normal presumption of a 90% saving [40]. This brings into question the attractiveness of coal CCS as an environmental proposition. Nevertheless, it is a relatively cheap fuel, which is readily available (from the UK and elsewhere), and provides flexible generation in contrast to new nuclear power [41]. Consequently, there is a broader range of factors to consider when selecting new UK power generation capacity.

It is theoretically possible to create a CCS plant with 100% capture rate – a so-called Zero Emission Plant (ZEP) – this would not generate carbon-free electricity. This is due to 'upstream' emissions. Here the 'non-operational emissions' (see Fig. 3) reflect the CO_2 emission per kWh that are attributed to the construction, mining, refining, and decommissioning of the generating power station. However, it would be possible to reduce or even nullify these CO_2 emissions through the implementation of a decarbonised energy sector, including industrial emissions [5,13]. It should be noted that the values for CO_2 per kWh depicted in Fig. 3 were calculated using a power cycle efficiency of approximately 35%; typical of current UK coal-fired power stations. This is the efficiency that is likely to apply for CCS demonstrators currently planned for around 2020 [39]. Some more advanced coal power stations that exploit super-critical and ultra super-critical cycles can achieve cycle efficiencies of over 40% leading to an emissions level of 675 gCO_2/kWh – some 280 gCO_2/kWh less than that of the reference plant. The high pressure oxy-fuel and ITM novel technology is still under development. It might therefore be assumed that the cycle efficiency will operate with at least around 5% higher than contemporary plants, due to the benefits of a super-critical cycle.

Various assumptions were made during the CO_2 analysis, in line with those for the associated energy analysis. Thus, the range of
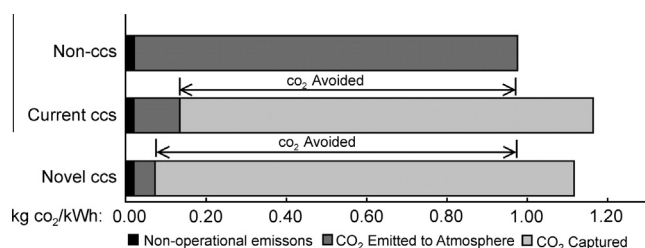
CO_2 emissions for current CCS technology was taken to be between 105 and 125 gCO_2/kWh. For the high pressure oxy-fuel and ITM novel technology CCS this range was taken as being between 45 and 65 gCO_2/kWh. It can be seen that these figures are well below the 735–850 gCO_2/kWh emitted by modern PC coal-fired power stations without CCS (see Fig. 3, or the data presented by Hammond et al. [4]; IPCC [8]; Spath and Mann [38]; and Viebahn et al. [39]).

6. Economic appraisal

6.1. Introduction

Coal-fired CCS power plants will be more expensive than an equivalent non-CCS plant, due to the increase in energy used to capture, compress and transport the CO_2, as well as the additional hardware that is required to carry out these operations. The most costly part of the CCS process is capture of the CO_2. It typically represents around 75% of the overall costs for the running and the building of a CCS system [42]. In order for CCS technology to be adopted and implemented it must clearly be economical in the liberalised energy market. UK electricity generators and their investors are looking to construct a new generation of power plants in the medium-term that will be environmentally friendly. CCS power plants are high up on the list of low carbon options, but the utilities will not invest unless they can be shown to be economical. Indeed, a UK CCS stakeholder workshop reported by Gough et al. [16] – and held in May 2007 – identified a potential to reduce CCS costs of 50–75% by 2040. But several of the industry representatives were also concerned that the UK Government was failing to provide sufficient enabling technology 'push' across the entire CCS chain. They argued that greater financial incentives for carbon abatement were required through a higher carbon price from the EU '*Emissions Trading Scheme*' (ETS). The UK Government in its March 2011 Budget Statement gave notice of their intention to introduce a 'floor price' for carbon under the EU-ETS in order to make low carbon power generators (for example, fossil-fuelled power plants with CCS, nuclear power, and renewable energy technologies) economically viable in the future. This would ensure a floor price for carbon of £16/tonne of CO_2 (tCO_2) in 2013, rising to £30/tCO_2 in 2020, and perhaps £70/tCO_2 in 2050 [43]. However, in the UK Budget of 2014 it was announced that the UK-only element of the Carbon Price Support (CPS) rate per tonne of carbon dioxide (tCO_2) will be capped at a maximum of £18 from 2016 to 2017 until 2019–2020. This will effectively freeze the CPS rates for each of the individual taxable commodities across this period at around 2015–2016 levels. It will ensure that the carbon price floor is kept at a rate that the UK Treasury feels will maintain British industrial competiveness.

Any power generation system that has higher operating and construction costs than non-CCS coal-fired power station will lead to an increase in electricity costs for the end-use consumer (unless the financing gap is met by the government concerned). This is believed to represent between 30% and 50% increase in the cost of electricity produced per kWh [11,42]. This would lead to higher electricity bills for UK households, although fossil fuelled CCS plants have lower operating costs per unit of output than renewable energy sources, such as wind turbines [4,11], and a much lower construction cost per unit of output when compared to nuclear power stations [11]. It has been suggested that offshore wind might give rise to an electricity price per kWh that could be 3 times that of a non-CCS coal-fired power station, or over twice that of a power plant with CCS [11]. The economics behind the 'full fuel cycle' of coal-fired PC power stations with and without CCS have therefore been assessed below in alternative ways. The results are presented in terms of US dollars {$}, arguably the

Fig. 3. CO_2 emissions avoided by adopting CCS technologies compared to conventional (non-CCS) power plants.

Table 4
Upstream GHG emissions from UK coal-fired generation. *Source:* adapted from Hammond et al. [40].

Fuel	Defra[†]GHG emissions factor from combustion of fuel (kg CO_{2e}-per kWh)	GHG emissions from upstream activities (kg CO_{2e}-per kWh)	Resulting ratio (increase)
Coal	0.330	0.060	6.5:1 (+18%)

[†] *Data Source:* The UK *Department for Environment, Food and Rural Affairs* (defra) – UK *National Atmospheric Emissions Inventory* (NAEI) maintained by Ricardo-AEA [see http://naei.defra.gov.uk/].

Table 5
UK power technologies in ranked order by 'whole systems' GHG (upstream plus operational or 'stack') emissions. *Source:* Hammond and O'Grady [41]; adapted from Hammond et al. [40].

Technology (mix)	GHG emissions (kg CO_{2e}-per kWh$_e$)
Coal	1.09
Grid average, 1990	0.90
Grid average, 2008	0.62
Natural gas	0.47
Coal CCS	0.31
Natural gas CCS	0.08
Nuclear	0.02

leading international reserve currency (converted into Euros {€} and Pounds Sterling {£} as appropriate for comparison purposes). Conversion rates were those applying in May 2010: $1 ≈ £0.655 and $1 ≈ €0.754.

6.2. Recent methodological developments in CCS economics

It has been recognised that significant differences and inconsistencies have been exhibited in various methods and metrics employed within international studies of CCS costs [44,45]. These included key technical, economic and financial assumptions, such as differences in plant size, fuel type, capacity factor, and cost of capital. But it was also recognised [44] that the underlying methods and cost components that are included (or excluded) from a given study can have a major impact on the results that are reported publicly or in the technical literature. For example, measures that have very different meanings (such as the costs of CO_2 avoided, CO_2 captured, and CO_2 abated [4]) are often reported in similar units, such as $/tCO_2$ (€/tCO_2$ or £/tCO_2$) . Likewise, there can be major differences between cost estimates associated with *First-of-a-Kind* (FOAK) plants and more mature [or *Nth-of-a-Kind* (NOAK)] technologies. As a consequence, there is likely to be some degree confusion, misunderstanding and possible mis-representation of CCS costs. Rubin [44] identified a hierarchy of ways to estimate CCS costs. These included expert elicitations, the use of published data, modified published values, new model results, and the findings of detailed engineering analysis (such as FEED studies).

Given the widespread interest in the cost of CCS and the potential for lower-cost CO_2 capture technologies (see Section 3 above), methods to improve the consistency and transparency of CCS cost estimates are obviously needed. In order to address these issues a *CCS Costing Methods Task Force* (CCSCMTF) was established with the support of EPRI in the USA [45]; bringing together an international group of experts from industry, government and academia. This set out a pathway towards a common methodology for CCS cost estimation and good practice in communicating findings. Their final report set out requirements in terms of the project goal or scope, assumptions and design parameters; financial and economic parameters; method of quantifying various cost components; and ways to calculate overall cost values, such as the increased levelised cost of electricity and the cost of CO_2 avoided. However, even with adherence to common guidelines, many of the details and assumptions required for CCS cost estimation vary from one project to another [44,45]. The CCSCMTF [45] therefore felt that they could not realistically be standardised. Nevertheless, they presented a range of 'checklists' that could be used to convey appropriate information in technical reports, journal-length papers, and conference presentations. The present study is presented in that spirit, and with an awareness of the limitations to the present state-of-the-art in CCS cost estimation.

6.3. Cost of CO_2 avoided – A life-cycle approach

In order to carry out an assessment of the economic viability of CCS it was necessary to gather data regarding the costs involved with each stage of the whole CCS chain. The *MIT Joint Program on the Science and Policy of Global Change* recently undertook a study [46] of current US investments in alternative coal-fired power plant designs. This sets out the major costs of a PC power station both with and without CCS. The values in the MIT report corresponded to a 500 MW$_e$ output, and have been normalised here for a typical 1 GW$_e$ plant. Table 6 shows the key data for the non-CCS reference plant in comparison to a CCS plant using current post-combustion amine scrubbing capture of equivalent capacity. It can be seen that both in terms of initial capital costs, as well as annual operating costs, the CCS plant is more expensive. *Levelised Cost of Electricity* (LCOEs) convert these costs into a cost per unit of electricity generated. The CO_2 emitted to the atmosphere for each unit of electricity generated by each of these power plants is given in Table 7. It is possible to calculate a figure for the cost per unit of CO_2 produced by dividing the total LCOE cost shown above by the values for CO_2 emitted per unit of electricity. On its own, this value has little significance but, if the LCOE is divided by the difference in CO_2 emissions per unit of electricity, then the cost of CO_2 avoided is determined. The latter parameter is the additional cost to the electricity generators to enable them to reduce the CO_2 emissions from the power plant by one tonne (see again Table 7). Here the value for the cost of CO_2 avoided was found to be $35.30 per tonne (€26.62 or £23.11/t CO_2). This can be compared to the range recently estimated by Hammond et al. [4] to be £16.00–28.50/tCO_2$, depending on whether EOR or depleted gas fields were employed for storage, and using a slightly different basis for calculating the power plant costs [47]. The recent study co-ordinated by Markusson et al. [25] suggested that the full-chain cost of CO_2 avoidance ranges between $45–70/tCO_2$ (€34.0–53.0.0/t CO_2 or £29.5–46.0/t CO_2) for coal-fired power plants according to different studies. However, uncertainties over full-scale power plant CCS technical performance and costs may only become clearer when the first demonstrators are operational in perhaps five years time.

7. Coal-fired power plant CCS prospects in the UK

7.1. Recent CCS developments in the UK

In the last decade, CCS has moved from being a technology largely employed on a relatively small industrial scale [8,14] to one that is now seen as one of the main carbon mitigation technologies

Table 6

Economic comparison of life-cycle components showing the Levelised Costs of Electricity (LCOE) for each element. *Source:* adapted from Sekar et al. [46].

Cost component	Coal reference (non-CCS)	Coal CCS power plant
Capital cost ($ millions)	1452	2516
Fuel costs ($ millions/year)	91.20	128.10
Operating & maintenance costs ($ millions/year)	52.60	124.20
Levelised costs of electricity		
Capital cost ($MWh)	19.5	33.8
Fuel costs ($/MWh)	13	18.2
Operating & maintenance costs ($/MWh)	7.5	17.7
Total ($/MWh):	40	69.7

Table 7

Calculation of the cost of CO_2 avoided.

	Coal reference (non-CCS)	Coal CCS power plant	*Difference*
Total LCOE ($/MWh):	40	69.7	*29.7*
kg CO_2 emitted per kWh	0.956	0.115	*0.841*
Cost of CO_2 avoided ($/tonne):			*35.30*

that will be supported by the UK Government [48] to meet their CO_2 reduction commitments. The CCS industry is thought to be worth $51 billion (€38.5 bn or £33.4 bn) in the UK alone [13], and also provides opportunities for jobs within British manufacturing and engineering companies. The more mature capture methods (i.e., pre-combustion, post-combustion and oxy-fuel combustion) are planned to be built as full-scale demonstrators in the UK [4,49], and commercially operational CCS power plants in other countries such as Norway and Germany. Pipeline technology for building a CO_2 transport network is ready to be rolled out and the UK already has plans for at least two large transport 'hubs' that will eventually be centrally located amongst a cluster of CCS power stations. These will compress the CO_2 further and pump it to storage locations predominantly in the North Sea depleted fossil fuel deposits or deep saline aquifers, such as the Sleipner field [4]. The UK has an advantage when it comes to CO_2 storage as it has access rights to a large proportion of the North Sea oil and gas fields. This will have both a logistical and an economical advantage for CO_2 storage. The CO_2 can therefore be used in EOR and EGR with these oil and gas fields to give greater yields of extraction and therefore reduce the cost of CO_2 avoided. Although all of these current technologies involve energy penalties, due to the additional energy required for operating them.

Participants in the UK CCS stakeholder workshop organised by Gough et al. [16] argued that greater financial incentives for carbon abatement were required through a higher carbon price from the EU-ETS, and the industry representatives expressed concern over the perceived failure of the UK Government to provide sufficient enabling technology 'push' across the entire CCS chain. Gough et al. [16] also identified a potential to reduce CCS costs of 50–75% by 2040.

7.2. UK Industrial Estimates of CCS Cost Reductions

The UK Government established a *CCS Cost Reduction Task Force* (CCRTF) as an industry-led joint venture to assist with the challenge of making CCS a commercially viable operation by the early 2020s. They estimated NOAK CCS levelised costs, in real 2012 money, as being £161/MWh in 2013, falling to £114/MWh in 2020 and £94/MWh in 2028 [50]. Here, the main cost reduction opportunities were seen as being: (i) transport and storage scale and utilisation, (ii) improved 'financeability' for the CCS chain, and finally (iii) improved engineering designs and performance. These figures can be contrasted with those for alternative power

generators [51] as follows: NGCC plant – £80/MWh; PC plant (without CCS) – £90/MWh; nuclear power – £85/MWh; onshore wind (>5 MW) – £107/MWh; and offshore wind (>5 MW) – £164/MWh. Thus, CCS currently exhibits a significant cost premium over its competitors, and will rely on cost reduction to become commercially viable. Greater financial incentives for carbon abatement could, in principal, be secured through a higher carbon price from the European Union *Emissions Trading Scheme* (EU ETS), although that has been a significant disappointment in terms of the carbon price (falling from €20 per tonne in 2011 to less than €5 per tonne presently). European Ministers, including the UK *Secretary of State for Energy and Climate Change*, called for decisive action in May 2013 to overcome the travails of the EU ETS. In order to bolster this mechanism, the UK Coalition Government alone introduced its so-called 'Carbon Floor Price' [52] from 1 April 2013 at £16 per tonne.

7.3. Investment challenges to the CCS take-up

CCS faces a number of critical challenges to its development [28]. A collaborative study between the *Energy Technologies Institute* [ETI], a public–private partnership key industrial companies and UK funders of energy RD&D, and the *Econfin Research Foundation* [ERF] has recently examined the conditions required for mobilising private sector financing of CCS in the UK [53]. They argue that this technology would be a "huge prize" that could cut the annual costs of meeting the 2050 carbon target by up to 1% of Gross Domestic Product (GDP). But they also note that the prevailing financial market conditions are demanding. In order to meet this challenge, they suggest that the UK needs to build confidence in long-term policy, develop attractive pricing for CCS contracts with suitable risk sharing, put in place an appropriate regulatory and market framework (see also Agus and Foy [54]), and devise new ways to offset North Sea storage liability risks.

8. Concluding remarks

The UK Government in their 2007 *Energy White Paper* (EWP [48]) accepted that Britain should put itself on a path to achieve a goal by adopting various low-carbon options, principally energy efficiency measures, renewable energy sources, and next generation nuclear power plants. Carbon capture and storage (CCS) facilities coupled to coal-fired power plants provide a climate change

mitigation strategy that potentially permits the continued use of fossil fuels whilst reducing the carbon dioxide (CO_2) emissions. The 2007 EWP [48] also identified CCS as an important element in any energy RD&D programme. Potential routes for the capture, transport and storage of CO_2 from UK power plants, such as the Kingsnorth and Longannet sites, were examined. Storage for the British Isles is likely to be in geological formations, such as depleted oil and gas fields under the North Sea or saline aquifers. Both currently available and novel CCS technologies were evaluated. Due to lower operating efficiencies, the CCS plants showed a longer energy payback period and a lower energy gain ratio than conventional plant. The CO_2 that was emitted per unit of electricity generated from the assessed CCS power station is found to be only 0.12 $kgCO_2$ per kWh [in contrast to 0.96 $kgCO_2$ per kWh for a non-CCS plant]. A complementary economic analysis of the CCS power plants found them to be relatively expensive. However, cycle improvements and the introduction of a 'floor price' for carbon under, for example, the EU '*Emissions Trading Scheme*' might make CCS economically viable in the future. The undiscounted cost of CO_2 avoided is shown to be $35.30/tonne (€26.62 or £23.11/tCO_2). That represented roughly a median value between the earlier techno-economic study of various CCS power plants by Hammond et al. [4] and those more recently reviewed by Markusson et al. [25]. They represent the lower and upper bounds of model studies respectively.

The 2007 EWP placed targets on new renewable electricity supply of 10% by 2010 and 20% by 2020. It is going to be difficult for renewables (principally wind) to fill the perceived 'electricity gap' [4,5]. The UK Government is supportive of building a new generation of nuclear reactors to replace those currently undergoing decommissioning [48]. This, together with carbon capture and storage technologies and renewables, are likely to be their preferred route to a decarbonised power generation system [4,5]. It has been argued here that CCS coupled to fossil-fuelled power plants is a climate change mitigation option that potentially permits the continued use of fossil fuels, whilst reducing the CO_2 emissions. The UK Government stated in their 2009 UK *Low Carbon Transition Plan* [49] that they intended to support the construction of up to four CCS demonstrators linked to coal-fired power stations by 2014–2015. In addition, it proposed to place a requirement on any new coal power stations to demonstrate this technology. Scrase and Watson [26] discussed the limitations to this strategy, which involve an element of 'picking winners' (via the UK Government's CCS demonstrator competition, based only on post-combustion capture technologies). They noted that the uncertainties over full-scale power plant CCS technical performance and costs may only become clearer when the first demonstrators are operational in perhaps five years time. The present study has attempted to reduce these uncertainties by way of indicative estimates of the techno-economic performance of both modern and advanced UK power plant/CCS chain options over their whole chain: from power stations to typical storage reservoir. In addition to carbon mitigation on the supply-side, it is clearly important to reduce energy demand in the UK and elsewhere. This could be achieved, in part, by the array of methods available to improve the efficiency with which energy is produced and consumed [4]. That would mitigate against climate change and enhance energy security.

Acknowledgements

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