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Carbon capture and storage ☆

Jon Gibbins *, Hannah Chalmers

Energy Technology for Sustainable Development Group, Mechanical Engineering Department, Imperial College London, Exhibition Road, London SW7 2AZ, UK

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ABSTRACT

Carbon capture and storage (CCS) covers a broad range of technologies that are being developed to allow carbon dioxide (CO_2) emissions from fossil fuel use at large point sources to be transported to safe geological storage, rather than being emitted to the atmosphere. Some key enabling contributions from technology development that could help to facilitate the widespread commercial deployment of CCS are expected to include cost reductions for CO_2 capture technology and improved techniques for monitoring stored CO_2. It is important, however, to realise that CCS will always require additional energy compared to projects without CCS, so will not be used unless project operators see an appropriate value for reducing CO_2 emissions from their operations or legislation is introduced that requires CCS to be used. Possible key advances for CO_2 capture technology over the next 50 years, which are expected to arise from an eventual adoption of CCS as standard practice for all large stationary fossil fuel installations, are also identified. These include continued incremental improvements (e.g. many potential solvent developments) as well as possible step-changes, such as ion transfer membranes for oxygen production for integrated gasifier combined cycle and oxyfuel plants.

1. Introduction: current status and barriers to commercial deployment

Carbon capture and storage (CCS) is currently considered to be technically feasible at commercial scale using a range of technologies. In addition to existing carbon dioxide (CO_2) injection activities in the oil and gas industry,[1] around 20 technically feasible, but first-of-a-kind, electricity generation projects with CCS producing 275 MW or more have been proposed around the world. European deployment of CCS is envisaged to progress with up to 12 flagship demonstration projects operational by 2015. Although at the time of writing no firm projects exist,[2] a number of projects are under development. For example, a Government-run competition is taking place in the UK to identify a post-combustion 300–400 MW project that would capture CO_2 from a slipstream of gases produced by a supercritical pulverised coal (PC) plant. The captured CO_2 will then be transported to offshore geological storage.[3] The competition winner will receive government funding to cover the additional costs for CCS. In the USA, the flagship FutureGen project had government funding withdrawn in early 2008, but it was suggested that this resource would be redirected to cover the additional costs for CCS on a range of projects instead.[4]

None of these initial projects is considered to require any scientific breakthroughs. In fact, given the lead-times required for design and construction, they must be based on existing technology. But none of these projects has yet been confirmed either. The principal barriers to deployment are the lack of

(a) funding mechanisms that are sufficiently large and long-term enough to reward carbon abatement using CCS; and
(b) legal and regulatory frameworks for the transport and geological storage of CO_2, although significant progress has recently been made, including in amending the relevant international treaties to allow offshore storage, a necessary first stage.[5]

☆ While the Government Office for Science commissioned this review, the views are those of the author(s), are independent of Government, and do not constitute Government policy.

* Corresponding author. Tel.: +44 20 7594 7036; fax: +44 20 7594 1472.
E-mail address: j.gibbins@imperial.ac.uk (J. Gibbins).

[1] For example, Statoil's Sleipner and Snohvit projects; BP's In Salah project. These all involve aquifer injection of CO_2, which has to be separated from natural gas to allow export of that gas. Also, CO_2 injection for enhanced oil recovery (but not storage) has been standard practice in the Permian Basin in Texas for decades.

[2] The policy of 12 CCS projects in the EU by 2015 was announced by the European Commission in January 2007, although funding arrangements are yet to be agreed. See http://ec.europa.eu/environment/climat/ccs/work_en.htm for further details.

[3] As there will be continuous development in UK CCS Competition, see UK Government websites for the latest information. At the time of writing, all relevant information is summarised at http://www.berr.gov.uk/whatwedo/energy/sources/sustainable/ccs/ccs-demo/page40961.html.

[4] See US Department of Energy (2008) factsheet.

[5] Following successful negotiations on including sub-sea geological storage in the London and OSPAR regulatory regimes, the London Protocol was amended to allow CO_2 storage under the sea bed in late 2006 and the OSPAR convention in

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A number of R&D activities to develop technologies that would contribute to CCS implementation can be identified, including actions to reduce costs (particularly for CO_2 capture) and to assure the identification, performance and monitoring of appropriate storage sites. These barriers cannot be overcome solely by 'enabling' technological improvements. CCS, however advanced, will always incur additional costs beyond the unabated use of fossil fuels and will only be implemented if these costs can be justified for the lifetime of the project by the large CO_2 emission reductions that can be achieved. Similarly, irrespective of the scientific confidence associated with the injection of CO_2 into appropriate geological formations, the extent to which it is a financially viable emission reduction activity is governed by the legal and regulatory framework for emissions accounting and trading that is in place.[6]

Technological advances can complement policy developments to overcome these barriers, principally by reducing the costs and risks involved. Since the main element of CCS cost is the cost of capture, this will receive the most attention in this paper. But, since many advances can be realised only through 'learning by doing', some early deployment will have to take place while the barriers are still relatively high (Gibbins and Chalmers, 2008). Complying with likely regulations for CCS (e.g. European Commission, 2008) will also be easier with improved monitoring technology.

A comprehensive review of CCS was prepared in 2005 by the Intergovernmental Panel on Climate Change (2005). This is an extremely valuable and detailed reference document but, because it was based on a consensus of peer-reviewed literature, it reflects the understanding of perhaps an average of 5 years ago. Particularly in the field of CO_2 capture, however, technology concepts and their evaluation have been moving rapidly so some detailed conclusions have already been superseded (e.g. International Energy Agency Greenhouse Gas Programme, 2006a).

2. CO_2 capture technologies

Operating principles for the three main technologies currently proposed for CO_2 capture are shown in Fig. 1. In post-combustion capture, a new final processing stage is applied to remove most of the CO_2 from the combustion products just before they are vented to atmosphere. The most commercially advanced methods use wet scrubbing with aqueous amine solutions. CO_2 is removed from the waste gas by the amine solvent at relatively low temperatures (order 50 °C). The solvent is then regenerated for re-use by heating (to around 120 °C), before being cooled and recycled continuously. The CO_2 removed from the solvent in the regeneration process is dried, compressed and transported to safe geological storage.

Pre-combustion capture of CO_2, the second method, is in some ways an oxymoron because CO_2 is obviously not normally available for capture prior to combustion. All types of fossil fuels can, however, be gasified (partially combusted, or reformed) with sub-stoichiometric amounts of oxygen (and usually some steam) at elevated pressures (typically 30–70 atmospheres) to give a 'synthesis gas' mixture of predominantly CO and H_2. Additional water (steam) is then added and the mixture is passed through a series of catalyst beds for the 'water–gas shift' reaction to approach equilibrium: $CO+H_2O \Leftrightarrow CO_2+H_2$ (water–gas shift reaction—adding steam and reducing the temperature promotes CO conversion to CO_2).

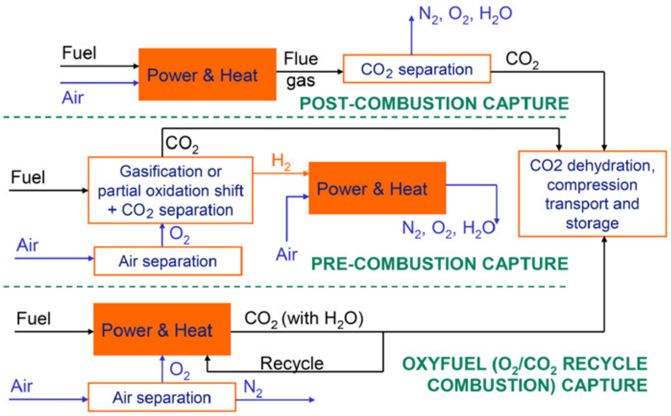

Fig. 1. Principles of three main CO_2 capture options (after Jordal et al., 2004).

The CO_2 can be separated to leave a hydrogen-rich fuel gas. The separation process typically uses a physical solvent; CO_2 is dissolved at higher pressure and then released as the pressure is reduced. Because no heat is required to regenerate the solvent and the CO_2 can be released at above-atmospheric pressure, the energy requirements for CO_2 capture and compression in pre-combustion capture systems may be of the order of half that required post-combustion capture. But pre-combustion capture systems have to pay an efficiency penalty for the shift reaction. Also, without capture, the CO (which is shifted to CO_2 for a plant with capture and removed) would be fired in the turbine so, compared to an equivalent plant without capture, there is a lost mass of CO_2 that does not pass through the turbine and generate power. In addition, the efficiency of hydrogen-burning gas turbines is lower than conventional natural gas or syngas units since heat transfer coefficients are higher for combustion products from hydrogen-rich fuels. This means that turbine inlet temperatures must therefore be reduced to achieve the same metal temperatures with an associated efficiency reduction. For solid and liquid fuels, additional efficiency losses are incurred during gasification, particularly for the most cost-effective gasifier designs in which the hot products are cooled by a simple water spray (which saves the cost of a very high-temperature heat exchanger and also adds additional water for the shift).

As a consequence, post-combustion capture on coal using best current commercial technologies (e.g. Fluor Econamine Plus or Mitsubishi Heavy Industries KS1 on advanced supercritical steam plants[7]) are currently predicted to have higher thermal efficiencies for conversion to electricity than pre-combustion integrated gasifier combined cycle (IGCC) designs (Table 1). Post-combustion capture also appears likely to give lower total electricity costs than pre-combustion capture for natural gas plants (Fig. 2). In contrast, pre-combustion capture from IGCC plants is currently predicted to produce low-carbon electricity slightly more cheaply from coal, due to the high capital costs for current atmospheric pressure post-combustion absorber designs and the cost of

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(*footnote continued*)
mid-2007. It is expected that OSPAR will shortly be ratified by the necessary seven countries to make geological CO_2 storage in the UK continental shelf legal.

[6] For example, under current laws, the Norwegian Sleipner project is legal and gains exemption from national carbon taxes and also reduces Norway's national inventory of CO_2 emissions, but it would not be eligible for consideration as a JI project under Kyoto since CCS is currently not recognised. Similarly, the proposed Peterhead/Miller project in the UK would have been legal, since the CO_2 would have been sent offshore for enhanced oil recovery and could reduce the UK inventory total for the UN Framework Convention on Climate Change process, but would not currently be eligible for inclusion in the EU Emission Trading Scheme, nor could any of the CO_2 have been sent offshore simply for storage under the then current rulings of the OSPAR and London Conventions.

[7] For more detail, see http://www.fluor.com/ias/gpr/markets.asp and http://www.mhi.co.jp/mcec/product/recov_co2/download/index.html.

Table 1
Comparison of power stations with and without CO_2 capture (International Energy Agency Greenhouse Gas Programme, 2006a)

Technology	Thermal efficiency (% LHV)	Capital cost ($/kW)	Electricity cost (c/kWh)	Cost of CO_2 avoided ($/t CO_2)
Gas-fired plants				
No capture	55.6	500	6.2	–
Post-combustion capture	47.4	870	8.0	58
Pre-combustion capture	41.5	1180	9.7	112
Oxy-combustion	44.7	1530	10.0	102
Coal-fired plants				
No capture	44.0	1410	5.4	–
Post-combustion capture	34.8	1980	7.5	34
Pre-combustion capture	31.5	1820	6.9	23
Oxy-combustion	35.4	2210	7.8	36

Costs for capture include CO_2 compression to 110 bar but not storage and transport costs. These are very site-specific, but indicative aquifer storage costs of $10/t CO_2 would increase electricity costs for natural gas plants by about 0.4 c/kWh and for coal plants by about 0.8 c/kWh. LHV = lower heating value.

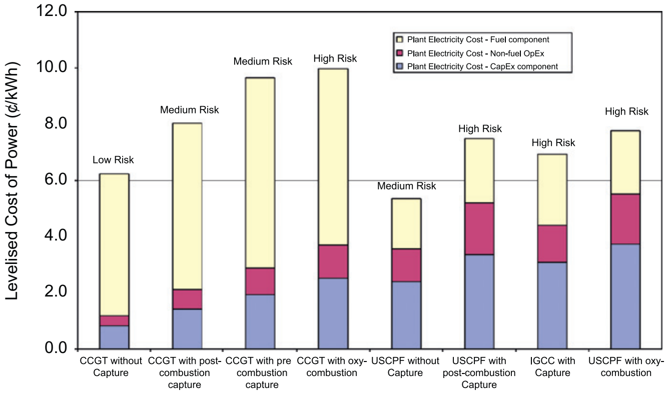

Fig. 2. Costs of electricity for gas- and coal-power plants with and without CCS (International Energy Agency Greenhouse Gas Programme, 2006a). Costs for capture include CO_2 compression to 110 bar but not storage and transport costs. These are very site-specific, but indicative aquifer storage costs of $10/t CO_2 would increase electricity costs for natural gas plants by about 0.4 c/kWh and for coal plants by about 0.8 c/kWh. (The perceived level of technical risk at the time of the International Energy Agency Greenhouse Gas Programme study is also indicated.)

replacing degraded solvent. It is important, however, to realise that all costs are estimates that can be expected to change as experience is gained with real plants (and that plant construction and fuel costs have also been changing rapidly, so absolute values need to be qualified by the date of the study). It is also likely that rates of learning, and hence cost reductions, will differ between technologies (International Energy Agency Greenhouse Gas Programme, 2006b).

Oxyfuel combustion options for gas and coal are also shown in Table 1 and Fig. 1. In these plants, the main separation step is oxygen from nitrogen. The fuel is then burnt in a mixture of oxygen and recycled flue gases (the latter to replace the nitrogen in air and thus moderate peak-flame temperatures to take account of materials and ash-slagging constraints in boiler design, etc.). This gives a flue gas mixture of mainly CO_2 and condensable water vapour, which can be separated and cleaned relatively easily during the compression process. For coal, oxides of nitrogen and sulphur (NO_x, SO_x) and other pollutants must be removed from the product gas before or during the CO_2 compression process. In addition, SO_x may also have to be removed from the recycle stream (to prevent high-temperature corrosion in the boiler furnace). Oxyfuel combustion options for natural gas combined cycles using current cryogenic distillation technology for oxygen production appear to be uncompetitive, even without allowing for the development costs for a completely new gas turbine design (see Table 1). New designs must also be developed for PC oxyfuel combustion boiler plants (although the steam turbine and alternator would be essentially unchanged). In contrast to gas-fired plant, these appear to have the potential to give efficiencies and costs that are competitive with amine-based post-combustion plant and a number of boiler manufacturers and utilities are already working in this area (e.g. Doosan Babcock-see Modern Power Systems, 2008; E.On UK, 2007; Vattenfall).

3. Geological storage of CO_2

Geological storage of CO_2 relies on injection at depths of more than 1 km. Temperatures will be above the critical value for CO_2 (31 °C) but pressures are high enough (order 100 atmospheres and above) to give densities of the order of 500 kg/m^3. CO_2 may be placed into oil reservoirs, where it can also give enhanced oil recovery, into abandoned gas fields or into deep saline aquifers. Total UK offshore storage capacity for regions assessed to date is at least 20 Gt CO_2 in depleted oil and gas fields and saline aquifers, representing approximately 40 years of total UK emissions at current rates (Gibbins et al., 2006). Storage capacity in all accessible saline aquifers is expected to be equivalent to several centuries of current total UK CO_2 emissions.

The critical factors in geological storage are the potential for CO_2 injection, the design of offshore enhanced oil recovery projects, the displacement of ambient porefluids, monitoring to appropriate standards and assurance on leakage. Rapid leakage paths, the most likely of which are failed wells, present an obvious re-emission problem but as such are likely to be identified and remediated relatively quickly. Lower rates of seepage, through unforeseen permeable faults for example, may cause local damage in the terrestrial or marine environment. Additionally, even at low rates (order 0.1% of stored volume per year) such seepage may ultimately lead to increases in atmospheric CO_2 concentrations compared to schemes where this does not occur. Key enabling technologies for geological storage are:

- directional and horizontal drilling to give cost-effective injection of CO_2, even into relatively impermeable strata, from a limited number of central facilities (particularly for offshore storage)
- modelling techniques to:
  - predict deep groundwater displacement
  - provide fundamental identification and quantification to predict CO_2 migration and dispersion
  - describe geochemical processes to predict CO_2 distribution and eventual immobilisation, in a wide range of geological rock formations and structural settings
- seismic and other imaging techniques to monitor CO_2 location underground and

- borehole logging and smart monitoring techniques to give early warning of seepage.

A comprehensive review, *Monitoring Technologies for the Geological Storage of CO_2*, was published by the UK Government Department of Trade and Industry (2005). Many techniques developed for the oil and gas industry can be applied to modelling and monitoring CO_2 storage, although it was concluded that 'a key requirement is to test these technologies in combination at a variety of storage sites so that their strengths and weaknesses can be evaluated in real situations, and optimal strategies developed,' another example of the need for 'learning by doing' to progress CCS. New developments for monitoring reflect a requirement for low-cost, long-term observations by instruments that can be left in place for a number of decades and will operate semi-autonomously, including borehole and sub-sea CO_2 sensors and pH sensors. There is also a need to develop passive seismic monitoring using multiple long-term sensors, such as resistivity or gravimetric monitoring. These may be able to give enhanced resolution of CO_2 dissolved in groundwater, which is difficult to resolve seismically. The response of sea-bed marine and terrestrial biological communities to slow leakage of CO_2 also needs to be assessed and this could aid the early detection of leaks.

Once further practical experience from CO_2 storage projects is available, it is likely that the basic additional requirements for modelling and monitoring will be developed into useable forms relatively quickly. In line with oil and gas industry experience, however, and helped by progress in other areas (e.g. electronics, materials, computing, oil and gas extraction) continuous improvements can be expected through to 2050 and beyond, reducing costs and giving more detailed information on CO_2 movements and interactions with the geological, and occasionally surface, environments. Different geological contexts will also require the development of specialised approaches through experience.

4. Future advances in CO_2 capture technology to 2050 and beyond

The key advances for CO_2 capture technology over the next 50 years are likely to arise from an adoption of CCS as standard practice for all large stationary fossil fuel installations, as is now the case for other pollutants. A parallel transition to the use of decarbonised energy vectors (electricity and hydrogen) in applications such as domestic heating (e.g. fuel cells, heat pumps) and ground transport (e.g. fuel-cell or plug-in hybrids or battery electric vehicles) that now use hydrocarbon gases and liquids will have to take place to achieve large reductions in CO_2 emissions. Decarbonised energy vectors can be produced by a variety of means but, for an extended transition period, fossil fuels and particularly coal, could be a relatively low-cost and environmentally sustainable source in locations with access to suitable CO_2 storage. CCS should also be applied, starting in the short to medium term, to minimise CO_2 from fossil fuel industries (e.g. LNG production, oil sand processing and coal-to-liquid plants), but these applications are at best only a transition, and perhaps a learning, measure since much of the carbon in the fuel will still be released to the atmosphere. Even with CCS to reduce emissions during production, long-term reliance on such carbon-based energy vectors for all but 'essential' uses (e.g. air travel, emergency and military vehicles) is clearly inconsistent with stabilising atmospheric CO_2 at safe levels.

Biomass may also be used increasingly in CCS plants, probably mostly in conjunction with fossil fuels where co-firing or co-gasification of biomass can give economies of scale and can even out natural supply fluctuations. This can both convert the energy content of the biomass into a more useable form (at an improved conversion efficiency vs most stand-alone utilisation, because of the scale) and removes most of the carbon in the biomass from the atmosphere. The latter benefit can, for example, be used to offset the use of liquid fuels in the premium applications noted above.

Hydrogen will tend to be made by gasifying lower-value fuels, probably coals and heavy (or residual) oils and bitumens (i.e. not natural gas and other clean, hydrogen-rich hydrocarbons), and biomass. Gasification and associated shift, gas cleaning and CO_2 capture technologies will be improved incrementally to give much greater reliability and reduced costs, but no major breakthroughs are expected. Hydrogen could be converted to electricity on the spot, or be transported for direct use elsewhere; this depends on developments in end-use applications (e.g. hydrogen storage vs batteries for road vehicles). It is likely, however, that hydrogen production would always most advantageously be combined with some electricity production (plants where this occurs are often called polygeneration plants, although examples that produce mainly environmentally benign decarbonised energy vectors should not be confused with polygeneration plants producing carbon-rich products such as synthetic liquids—these are better described as coal-to-liquid plants, etc.).

Where only electricity is required from a gasifier-based system, an IGCC would be used. The US National Energy Technology Laboratory commissioned a study of possible improvements in IGCC technology, with and without CO_2 capture (Gray et al., 2004). These changes were stated to be taking place up to 2020, but a longer period (e.g. to 2030) is possible. Beyond that, cost improvements could be expected but little further scope exists for efficiency or availability improvements. Absolute changes are shown in Table 2, relative changes in Fig. 3. The best cost reductions arise from incremental improvements: in gasifier load factor, instrumentation, materials and methods of construction. Historically well-understood changes, to two-stage gasification and dry coal feeding, also achieve some improvement, as does the use of the latest gas turbine technologies (through incremental combustor and cooling developments for the use of syngas). 'Breakthrough' ion transfer membrane technology for oxygen production could achieve fairly large cost reductions but, despite giving a large improvement in efficiency, the move to a solid oxide fuel-cell/gas turbine hybrid was predicted to give little improvement in electricity costs.

Equivalent performance with CO_2 capture at three stages in gasifier development is shown in Table 2 (Cases 12–14). In Case 12, a 'conventional' shift process is assumed with about 85% CO_2 capture. In Cases 13 and 14, a special oxyfuel combustion system for the syngas gives 100% CO_2 capture. Interestingly, although absolute costs of electricity with capture fall, the efficiency penalty stays constant at 6–7 percentage points and the relative increase in the cost of electricity with capture stays in the range 20–30%, highlighting that CCS will always result in additional cost, despite technical progress. Further cost reductions might, however, be achieved by using the very compact high-temperature 'rocket burner' oxyfuel 'steam' turbine system being developed by Clean Energy Systems[8] (which uses water recycle instead of flue gas recycle to moderate combustion temperatures) in place of the fuel-cell/turbine hybrid, although this could not so readily be integrated with an ion transfer membrane oxygen unit.

PC systems will be built in significant numbers for at least the next 10 years and these new plants are likely to remain in use until 2050 for electricity production from coal, because of their flexibility and general advantages of reliability, availability,

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[8] For an introduction to this system, see http://www.cleanenergysystems.com.

Table 2
Effect of technical developments on cost of electricity (COE), efficiency (lower heating value (LHV) basis) and specific capital cost for IGCC plants without (Cases 1–11) and with (Cases 12–13) CO_2 capture (Gray et al., 2004)

Case		COE ($/MWh)	Efficiency (% LHV)	Capital ($/kW)
1	Current technology	45.2	41.9	1294
2	75–85% load factor	41.2	41.9	1294
3	95–98% fuel conversion	40.6	43.1	1279
4	Two-stage gasification	39.4	44.8	1241
5	Wet to dry coal feeding	38.3	47.3	1217
6	FB class advanced gas turbine (vs F class)	36.4	49.0	1149
7	Advanced gas cleaning	34.6	50.2	1086
8	Ion transfer membrane vs cryogenic oxygen plant	32.7	50.6	1027
9	85–90% load factor	31.5	50.6	1027
10	H class ultra-advanced gas turbine (vs FB class)	29.6	52.9	953
11	Solid oxide fuel cell (SOFC+turbine hybrid cycle)	29.2	68.0	1002
12	Case 1 with pre-combustion capture	56.99	35.9	1656
13	Case 8 with oxyfuel turbine capture	43.04	43.7	1377
14	Case 11 with oxyfuel turbine capture	35.42	62.6	1242

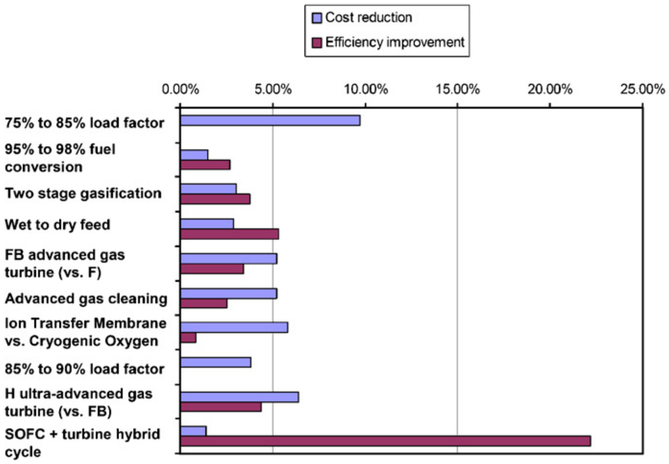

Fig. 3. Relative improvements in IGCC efficiency and cost of electricity from technical developments (Gray et al., 2004).

maintainability and operability. In the future, PC units (especially if built as 'capture-ready'[9]) may be retrofitted with capture equipment rather than being retired early or used only for peaking capacity, once appropriate developments in technology and market incentives for CCS have been established. For new build beyond 10 years, although the basic PC technology has been in use for nearly a century, an expected change from ferritic steel to nickel alloys for high-temperature components and consequent change in peak cycle temperatures from ~600 to 700–750 °C would allow significant further increases in power plant efficiencies (~45% to ~50% lower heating value) without capture. Thus, if capital costs for oxyfuel or post-combustion capture systems fall, these plants could be competitive for some time. Improved solvent systems for multi-component removal (SO_x, NO_x, Hg, CO_2) are also being considered (e.g. Alstom chilled ammonia, CANSOLV amine[10]) and these may have the potential to give significantly reduced capital costs as well as somewhat lower energy penalties. An important external factor determining the relative competitiveness of PC and gasification-based systems could be the emergence of a demand for hydrogen, which would clearly favour the latter.

A wider range of technologies, including chemical looping or high-temperature membranes, could be applied to CO_2 capture from natural gas, because of its clean-burning properties (Intergovernmental Panel on Climate Change, 2005), but it remains to be seen whether future gas prices are low enough to make capture from gas power plants attractive before 2050. A move to reduce CO_2 emissions from buildings, mostly originating from natural gas, through the use of decarbonised electricity could, however, see a natural transfer of gas consumption to plants with CCS from smaller-scale local units that cannot capture the CO_2 emissions.

5. Conclusions

CCS is currently considered to be technically feasible at a commercial scale using a range of technologies. A number of large-scale electricity generation projects have been proposed and, if implemented, should allow the 'learning by doing' that is required for technology to be developed so as to reduce the costs and risks currently associated with CCS schemes.

The three main technologies currently proposed for CO_2 capture are shown in Fig. 1. A wider range of other technologies, such as chemical looping or high-temperature membranes, could be applied to CO_2 capture from natural gas, but future gas prices may not be low enough to make capture from gas power plants attractive before 2050, unless venting CO_2 from natural gas use in buildings is displaced by natural gas use in central plants with CCS.

Critical aspects of CO_2 geological storage activities have also been identified and discussed. Many other aspects of CCS project development have not been considered in detail in this paper, but are vitally important in ensuring that the technology available to allow CCS can be implemented. Particular challenges include the development of an appropriate legal and regulatory framework and developing public understanding and acceptance. The infrastructure for CO_2 transport from the capture plant to storage site also needs to be considered.

It is expected that most of the improvements in CCS technology will be incremental, initially based on problem solving at first-of-kind plants and related R&D activity. A key research objective will be cost reduction, particularly for CO_2 capture processes. However, it should be noted that plants operating with CO_2 capture will always have a higher cost of electricity generation than equivalent plants without capture. Thus, CCS will only be a commercially viable option in situations where the CO_2 emission reductions associated with this process are given an appropriate value.

Acknowledgements

This work has drawn on knowledge and experience gained in a number of projects, including the Department of Trade and

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[9] Capture-ready plants are designed so that capture equipment can be retrofitted easily later, when justified by the rising cost of carbon emissions or required by regulation. Minimal expenditure is usually appropriate, for a feasibility study of how capture could be implemented later and for additional space and connection points to allow capture-related equipment to be accommodated. The plant should also be sited with viable access to storage (Gibbins et al., 2006; International Energy Agency Greenhouse Gas Programme, 2007).

[10] See ALSTOM (2006) and http://www.cansolv.com for introductions to these approaches.

Industry/Department for Business, Enterprise and Regulatory Reform Cleaner Coal Project 407 (Coal-Fired Advanced Supercritical Boiler/Turbine Retrofit with CO_2 Capture) and the UK Carbon Capture and Storage Consortium, part of the Towards a Sustainable Energy Economy programme (http://www.ukccsc.co.uk). Support for work at Imperial College in this area from the British Coal Utilisation Research Association and the International Energy Agency Greenhouse Gas Programme is also gratefully acknowledged. Parts of this paper have also benefited from conversations with colleagues, including Stuart Haszeldine at the University of Edinburgh. The opinions and interpretations expressed in this paper are, however, entirely the responsibility of the authors.

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