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Performance and costs of power plants with capture and storage of CO_2

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Abstract

This paper assesses the three leading technologies for capture of CO_2 in power generation plants, i.e., post-combustion capture, pre-combustion capture and oxy-fuel combustion. Performance, cost and emissions data for coal and natural gas-fired power plants are presented, based on information from studies carried out recently for the IEA Greenhouse Gas R&D Programme by major engineering contractors and process licensors. Sensitivities to various potentially significant parameters are assessed.

Keywords: CO_2; Capture; Electricity; CCS; Costs

1. Introduction

Anthropogenic emissions of greenhouse gases to the atmosphere are expected to cause significant global climate change [1]. The most significant anthropogenic greenhouse gas is CO_2, which arises mainly from use of fossil fuels. Fossil fuels currently provide about 85% of the world's commercial energy needs. Measures, such as improved energy efficiency and use of alternative energy sources, will help to reduce emissions but a rapid move away from fossil fuels may cause serious disruption to the global economy, as energy supply infrastructure has a long lifetime. A technique that could make it possible to more rapidly achieve large reductions in greenhouse gas emissions is capture of CO_2 for storage in deep geological formations.

The main sources of CO_2 emissions are power generation, industrial processes, transportation and residential and commercial buildings, as shown in Fig. 1 [2]. The main application of CO_2 capture is currently expected to be in power generation and large energy-consuming industries, particularly oil and gas processing and cement, iron and steel and chemicals production. This paper focuses on power generation, which accounts for about a third of CO_2 emissions from fossil fuel use, mainly from use of coal and natural gas. The costs, performance and emissions of coal and natural gas-based power plants with and without CO_2 capture are assessed on a consistent basis.

The leading technologies for power generation in the current market are pulverised fuel (PF) combustion steam cycles and natural gas combined cycles (NGCC). CO_2 can be captured from the flue gas of both of these types of plants by scrubbing with a regenerable amine solvent. This is known as post combustion capture. Alternatively, oxygen can be used for combustion instead of air, which results in a flue gas consisting mainly of CO_2 and H_2O. This is known as oxy combustion. A third capture method which is applicable to gas turbine combined cycles is pre-combustion capture. In this process a fuel is reacted with air or oxygen to produce a fuel gas containing CO and H_2, which is then reacted with steam in a catalytic reactor called a shift converter to produce a mixture of CO_2 and H_2. The CO_2 is separated and the H_2 is used as the fuel in a gas turbine combined cycle. Pre-combustion capture can be applied to natural gas or coal-based plants. When the primary fuel is coal, this process is usually known as an integrated gasification combined cycle (IGCC). It should be noted that none of the existing coal-based IGCC plants includes shift conversion and CO_2 capture.

The IEA Greenhouse Gas R&D Programme (IEA GHG) has assessed the performance and costs of new power plants with and without CO_2 capture. Studies were carried out for IEA GHG by the following leading engineering contractors and process developers:

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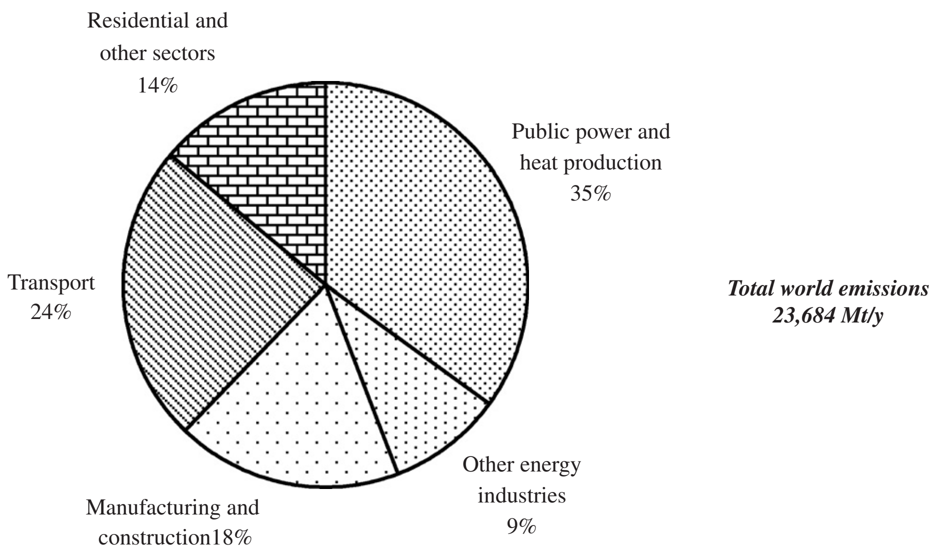

Fig. 1. Emissions of CO_2 from fossil fuel use (2001).

- *Post combustion capture*: Fluor, in collaboration with Mitsui Babcock and Alstom, and MHI [3].
- *Pre-combustion capture* (*IGCC*): Foster Wheeler, with data from gasification and gas treating vendors [4].
- *Oxy-combustion*: Mitsui Babcock, in collaboration with Air Products and Alstom [5].

IEA GHG's recent studies on new power plants do not include natural gas-based pre-combustion capture but IEA GHG has carried out a study on retrofit of capture to existing natural gas combined cycle plants [6]. That study showed pre-combustion capture to be significantly more expensive than post-combustion capture. IEA GHG carried out a later study which put some of the results from the earlier studies [3–5] on a consistent basis with updated fuel prices and currency exchange rates [7]. This paper presents results from that later report [7] and also includes more of the cases from the IGCC study [4] on the same updated basis.

2. Basis of plant assessments

The reference power plants without CO_2 capture in this paper use high-efficiency commercially demonstrated technologies. The CO_2 capture units are based on current designs but it is recognised that CO_2 capture has not yet been demonstrated in large commercial power plants. The efficiencies of all of the power-generation technologies considered in this study will improve in future due mainly to development of more advanced gas and steam turbines. The performance and costs of CO_2 capture technologies are also expected to improve in future due to technology developments and 'learning by doing'. This is discussed further in Section 6.

The main criteria used in the assessments in this paper are summarised below and in the following plant descriptions.

2.1. Technical criteria

Coal feed	Australian bituminous coal	
	Ash	12.2% as-received
	Moisture	9.5% as-received
	Carbon	82.5% dry-ash-free
	Hydrogen	5.6% dry-ash-free
	Oxygen	9.0% dry-ash-free
	Nitrogen	1.8% dry-ash-free
	Sulphur	1.1% dry-ash-free
	Chlorine	0.03% dry-as-free
	LHV	25.87 MJ/kg as-received
Natural gas	Southern Norwegian North Sea	
	Methane	83.9 vol%
	Ethane	9.2 vol%
	Propane	3.3 vol%
	Butane +	1.4 vol%
	CO_2	1.8 vol%
	N_2	0.4 vol%
Plant location	Greenfield plant site, Netherlands coastal location with no special civil works	
	Ambient pressure	101.3 kPa
	Average air temperature	9 °C
	Average sea water temperature	12 °C
Cooling water system	Once-through sea water cooling	
CO_2 output pressure	11 MPa	
Maximum emissions	Particulates	25 mg/Nm^3 (6% O_2)
	NO_X	200 mg/Nm^3 (6% O_2)
	SO_2	200 mg/Nm^3 (6% O_2)

The pressure to which CO_2 is compressed will depend on how it is transported and the nature of the storage reservoir. The data in this paper include compression of CO_2 to 11 MPa, at which pressure it is a dense phase fluid with a density of about 0.75t/m^3 at 35 °C. Because of its high density, the CO_2 could if required be pumped to a higher pressure with very little impact on the plant performance and cost.

2.2. Economic criteria

DCF rate	10% per year, excluding inflation
Plant operating life	25 years
Plant construction time	3 years
Expenditure schedule	20%/45%/35%
Load factor	85%
Coal price	US$2.2/GJ (LHV basis), with sensitivity to $1.1/GJ [1]
Natural gas price	US$7.8/GJ (LHV basis), with sensitivity to $3.9/GJ
Contingencies:	10% of installed plant cost
Fees and owners cost	7% of installed plant cost (excludes interest during construction)
Interest during construction	Calculated from the expenditure schedule and discount rate
Decommissioning cost	Zero net cost (assumed to be equal to scrap value)
Working capital	30 days of raw materials and consumables, excluding natural gas
Start up costs	3 month commissioning period Reduced load factor (60%) for remainder of year 1 for coal plants
Operating labour	€50k/year (excludes maintenance labour), 5 shift operation
Maintenance costs	2–4% of installed cost per year, depending on type of process unit
Local taxation and insurance	2% of installed cost per year
By-product/waste values	Zero net values for sulphur, slag/ash and gypsum
Exchange rate	1.23 US$/€

[1]These fuel prices are on an LHV basis, for consistency with the plant performance data. However, it should be noted that fuel is often traded on an HHV basis. Bituminous coal prices on an LHV basis are about 5% higher than on an HHV basis and natural gas prices are about 10% higher.

The base case fuel prices are the average of Mott MacDonald's long-run forecast prices up to 2025 for the Netherlands coastal location [7]. The sensitivity to lower prices (half those of the base case) is assessed because of the high uncertainty in prediction of long-term energy prices and because prices vary between different locations.

The capital costs shown in Table 4 include miscellaneous owner's costs but exclude interest during construction and start-up costs, although these are taken into account in the calculation of costs of electricity generation. Costs of electricity (380 kV) and CO_2 (11 MPa) transmission beyond the plant boundary are excluded. Coal is delivered to the plant boundary by conveyor and 30 days of outdoor storage is included on-site. The inlet and discharge ducts for the seawater cooling system are included.

The capital costs in IEA GHG's original studies [3–5] were estimated using source data denominated mainly in US$ and €. The $/€ exchange rate has varied between about 0.85 and 1.35:1 between 2001 and 2006, which introduces a degree of uncertainty into cost estimates. In IEA GHG's latest study [7], costs for selected cases from the earlier studies [3–5] were updated using the 2005 average exchange rate of 1.23$/€. For this paper further cases were updated using this same exchange rate.

The plant costs are based on equipment costs provided by process licensors and equipment manufacturers and information from the in-house cost databases of the engineering contractors who carried out the detailed studies [3–5]. The costs do not include development costs or costs which are specific to first-of-a-kind plants. The plant cost estimates are subject to uncertainties due to the state of development of some of the technologies which have not yet been operated in full-scale commercial plants. Another source of uncertainty is the general state of the market for plants and materials. The costs in this study are unlikely to fully reflect the recent large increases in steel and other material prices and cost increases due to shortages of skilled labour but these may be a short-term phenomenon. Such cost increases will also apply to alternative power-generation technologies. Fuel price is another major source of uncertainty and this is discussed later in this paper. The results presented in this paper should not be taken to be an endorsement or otherwise of any particular proprietary technology.

3. Plant descriptions

3.1. Post-combustion capture plants

The pulverised coal-fired plants are based on an ultra-supercritical steam cycle, with main steam conditions of 29 MPa, 600 °C and a reheat temperature of 620 °C. Plants with these steam conditions are commercially available [3] and plants with similar conditions are being built and operated in Europe and Japan. Limestone-gypsum flue gas desulphurisation (FGD) and low-NO_X burners and selective catalytic reduction (SCR) are used to reduce the SO_X

and NO_X concentrations in the flue gas. Two chemical solvent scrubbing processes for CO_2 capture are assessed; Fluor's Econamine FG+^{SM} process, which uses mono-ethanolamine (MEA) solvent [8] and MHI's KS-1 process, which uses a proprietary sterically hindered amine solvent [9]. In these processes flue gas is contacted with CO_2-lean amine solvent, which removes 85–90% of the CO_2 (higher CO_2 removal rates can be achieved, if required). The CO_2-rich amine is passed to a stripper vessel, where it is regenerated to release CO_2. Heat for the regeneration is provided by low-pressure steam extracted from the steam turbine. Further details of post-combustion capture plants have been published [3,8,9].

The Econamine FG+^{SM} process is a modification of the Econamine FG^{SM} process, which is in operation at commercial plants that produce CO_2 mainly for enhanced oil recovery, chemicals production and the food industry. The Econamine FG+^{SM} process includes a split flow configuration, an improved solvent formulation and other features which reduce the energy consumption. No commercial scale Econamine FG+^{SM} plants are currently operating but the process is being offered commercially by Fluor. A KS-1 plant in Malaysia which captures about 200 t/d of CO_2 from reformer flue gas has been operating since 1999 and plants capturing up to 450 t/d are being built. Fluor and MHI's existing capture units are at gas fired plants but 150–200 t/d capture units based on the ABB Lummus Global/Kerr McGee MEA scrubbing process are operating at two coal-fired power plants in the USA.

The flue gas input to a CO_2 solvent scrubbing unit has to have low concentrations of SO_X and NO_2, as these substances result in loss of solvent. The SO_X specification is set at 10 ppm(v) (6% O_2) by Fluor and 1 ppm(v) by MHI [3]. These concentrations are lower than from typical plants without capture but they can be achieved by some current FGD technologies. The SCR unit included in the coal-fired plants in this assessment produces a flue gas with a NO_2 concentration to 5 ppm(v) (6% O_2), well within the limits set by the amine scrubbing unit suppliers.

The plants are based on a single train of boiler, steam turbine and FGD unit, although multiple equipments are used for some items such as the air fans. Several single-train-pulverised coal power plants of the size specified in this study, or larger, are in commercial operation. The CO_2 capture unit consists of two trains. In the long-term it may be feasible to build single-train capture units.

The NGCC plants in this paper are based on two GE 9FA gas turbines, which are typical of large commercially available 50 Hz gas turbines from the major turbine manufacturers. More advanced 'H class' gas turbines for natural gas are now being developed and a demonstration and test plant is being operated but there are currently no fully commercial plants. The efficiencies of H turbine combined cycle plants will be about 4 percentage points higher than the FA turbines used in this study. There are not expected to be any constraints on use of post-combustion capture with more advanced gas turbines or turbines from other manufacturers.

CO_2 is captured in the NGCC plants using the Econamine FG+^{SM} and MHI KS-1 processes. The Econamine plants include 3 parallel absorbers and the MHI plants use 2 absorbers, as specified by the process licensors.

3.2. Pre-combustion capture plants

Pre-combustion capture can be applied to coal-based IGCC plants. Plants based on two types of oxygen-blown entrained flow gasifier are assessed:

- GE (formerly Texaco) slurry feed gasifier, with product gas cooling by water quench.
- Shell dry feed gasifier, with product gas cooling in a heat recovery boiler.

Other types of oxygen-blown gasifier suitable for use in power plants with CO_2 capture are available, for example the Conoco-Phillips E-Gas slurry feed two-stage gasifier and the GSP (Future Energy/Sustec) dry feed gasifier with water quench, which is now owned by Siemens.

In the GE gasifier plant without CO_2 capture, the coal is ground and slurried with water and then pumped to the gasifier vessels where it reacts with oxygen. The gasifiers operate at a pressure of 6.5 MPa. The products from gasification are quenched with water, the saturated gas is cooled and condensed water and minor impurities are removed. The gas is then passed through a COS hydrolysis reactor and fed to a Selexol acid gas removal plant for removal of sulphur compounds. The sulphur compounds are converted to elemental sulphur in a Claus plant with tail gas treating. The clean fuel gas is passed through a turbo-expander and fed to the gas turbine combined cycle plant. The flow sheet for the case with CO_2 capture is the same except that the quenched gas from the gasifier is fed to a single-stage CO-shift converter prior to cooling and the Selexol unit removes CO_2 as well as sulphur compounds. The Selexol is selectively regenerated to produce separate CO_2 and sulphur compound streams. The CO_2 is compressed and dried for pipeline transportation. Four 33% capacity gasifiers are used as recommended by the technology provider to enable the plant to achieve the required availability. The plants include two 50% capacity trains of ASU, syngas treating, gas turbines and HRSGs and a single-train Selexol plant and steam turbine.

In the Shell gasifier plant without capture, the coal is dried and ground and fed to the gasifier vessels via lock hoppers. The gasifier product gas is quenched with recycle fuel gas and cooled in a heat recovery boiler before being fed to a dry particulate removal unit. Some of the gas is recycled as quench gas and the remainder is scrubbed with water, reheated, passed through a COS hydrolysis reactor and fed to an acid removal plant which uses MDEA solvent. The clean fuel gas is fed to the gas turbine combined cycle plant. The configuration of the plant with CO_2 capture is the same except that the COS hydrolysis unit is replaced by a two-stage shift converter and H_2S and CO_2 are separated in a Selexol acid gas removal unit. The gasifier operating pressure is 3.6–3.9 MPa. Two 50% capacity gasifiers are used as recommended by the technology provider. The plants include two 50% trains of ASU, syngas treating, gas turbines and HRSGs and a single-train Selexol plant and steam turbine. The combined cycle units in the IGCC plants are based on two GE 9FA gas turbines, as used in the NGCC plants considered in this paper. The more advanced H class turbines are not currently commercially available for IGCC but they may be modified in future to enable them to be used in IGCC. Oxygen for the gasifiers is produced by cryogenic air separation. In the GE gasifier plants and the Shell gasifier plant without capture, 50% of the compressed air for the air separation unit (ASU) is extracted from the gas turbine during normal full load operation and the remaining 50% is provided by a separate electrically driven compressor. In the Shell plant with capture, 30% of the air for the ASU is extracted from the gas turbine. Pressurised nitrogen from the ASU is fed through booster compressors to the gas turbines, to maximise the loading on the turbine, modify combustion properties and reduce NO_X emissions. Selection of the optimum degree of ASU integration is important to improve plant performance and reduce costs while maintaining a high operating flexibility and plant availability. The study which is the source of the IGCC plant data in this paper [4] included an assessment of the optimum degree of integration. However it should be noted that the optimum degree of integration may be different for different types of gas turbine, site conditions and operability considerations.

In the detailed reference study [4] a variety of plants were assessed, including different gasifier pressures, shift and acid gas removal plant configurations and production of a combined stream of CO_2 and sulphur compounds. The plants described in this paper are the ones which have the lowest costs for each of the two gasifiers for production of high purity CO_2. Production of a combined stream of CO_2 and sulphur compounds resulted in a 20% lower cost of capture. Further details of the different plants are available [10].

3.3. Oxy-combustion

The pulverised coal oxy-combustion plant uses the same steam conditions as the post-combustion capture plant. 95 mol% oxygen from a cryogenic ASU is used for combustion. Based on earlier studies this was considered to be the optimum purity, taking into account the trade off between the cost of producing higher-purity oxygen and the cost of removing oxygen from the CO_2. About two-thirds of the cooled flue gas is recycled to the boiler to avoid excessively high temperatures. The plant includes a 2 train ASU plant which produces gaseous oxygen at atmospheric pressure.

After the flue gas is de-dusted and cooled, it is compressed to 3 MPa and fed to a cryogenic separation unit where sufficient impurities, mainly N_2, Ar and O_2, are removed to increase the CO_2 concentration from 75.7 mol% (dry basis) to 95.8 mol%. The main sources of the impurities in the raw CO_2 are air in-leakage, the 'excess' oxygen required for combustion and the impurities in the oxygen feed. Unlike the reference PF plant without capture and the plant with post-combustion capture there are no SCR and FGD units. At the time that this study was carried out it was expected that some of the SO_X and NO_X that are produced would be removed in the cryogenic separation unit and the remainder would be contained in the CO_2 which is fed to storage. Storage of CO_2 containing SO_X and NO_X has not yet been demonstrated, although CO_2 containing H_2S and some other sulphur compounds is being stored underground [11,12]. However, recent work indicates that essentially all of the SO_X and 90% of the NO_X may be converted to nitric and sulphuric acid during compression, which would make them easy to separate, although there would be implications for the plant design and materials [13].

The oxy-combustion NGCC plant requires a gas turbine that is specifically designed for the different working fluid, which is mainly CO_2. The gas turbine inlet pressure is 3 MPa, about twice as high as the reference turbine, and the operating temperatures are adjusted to give the same blade mechanical creep rupture life as conventional large industrial gas turbines. The gas turbine exhaust gas is fed to a heat recovery steam generator and 94% of the cooled gas is recycled to the turbine. The remaining flue gas, with a CO_2 concentration of 88.3 mol% dry basis, is compressed and the CO_2 concentration is increased to 95.9 mol% by a cryogenic inerts removal unit that is integrated with the compression unit. The oxyfuel NGCC plant includes two gas turbines and ASUs and a single steam turbine. The ASU produces high-pressure gaseous oxygen by pumping liquid oxygen to the required pressure and vaporising it against condensing high-pressure air.

4. Plant performance

4.1. Efficiency and power output

The thermal efficiencies, on a lower heating value (LHV) basis, and the auxiliary power consumptions of power plants with and without CO_2 capture are shown in Table 1.

The pulverised coal plant without CO_2 capture has a net efficiency of 44.0%[2], which is similar to the 43.1% efficiency of the Shell gasifier IGCC plant. The Shell IGCC plant has a significantly higher efficiency than the GE gasifier IGCC plant (38.0%), mainly because of a

[2]This paper uses data for reference-pulverised coal and natural gas combined cycle plants from [3]. These data are similar to data from [5].

Table 1
Power plant thermal efficiencies

Fuel	Power generation technology	CO_2 capture technology	Gross efficiency (%, LHV)	Auxiliary consumption (% fuel feed)	Net efficiency[a] (%, LHV)
Coal	Pulverised fuel	None	48.2	4.2	44.0
		Post-combustion, Fluor	43.2	8.4	34.8
		Post-combustion, MHI	43.8	8.5	35.3
		Oxy-combustion	49.1	13.7	35.4
	IGCC, Shell	None	50.5	7.4	43.1
		Pre-combustion, Selexol	45.7	11.2	34.5
	IGCC, GE	None	45.4	7.4	38.0
		Pre-combustion,Selexol	41.9	10.4	31.5
Gas	Gas turbine combined cycle	None	57.3	1.7	55.6
		Post-combustion, Fluor	53.0	5.6	47.4
		Post-combustion, MHI	54.3	4.7	49.6
		Oxy-combustion	58.4	13.7	44.7

[a]HHV efficiencies of the coal-fired plants are 0.956 times the LHV efficiencies. HHV efficiencies of the gas-fired plants are 0.904 times the LHV efficiencies.

higher efficiency of conversion of coal to fuel gas in the gasifier and the use of a heat recovery boiler instead of water quench to cool the output from the gasifier. As expected, the natural gas-fired plant without capture has a substantially higher thermal efficiency, 55.6%.

The efficiencies of the post-combustion capture, Shell IGCC and oxy-combustion coal fired plants with capture are similar, 34.5–35.4%. The efficiency reductions for CO_2 capture compared to the same type of plant without capture are 8.6–9.2 percentage points. The GE gasifier IGCC plant with capture has a lower efficiency, 31.5% but it also has a lower-efficiency reduction compared to the same type of plant without capture; 6.5 percentage points. The efficiency of the GE IGCC plant with capture is 12.5 percentage points lower than that of the reference pulverised coal plant without capture. At a late stage in the reference IGCC study [4] Texaco proposed an alternative version of their gasifier with a radiant cooler followed by a water quench, which increased the efficiency of power generation with capture by 1.2 percentage points. The efficiencies of the NGCC plants with post-combustion capture are 47.4–49.6% and the efficiency reduction for CO_2 capture is 6.0–8.2 percentage points. The oxy-combustion NGCC plant has a lower efficiency, 44.7%.

The factors which contribute to the efficiency reductions for CO_2 capture for each fuel and technology are summarised in Fig. 2. For post-combustion capture, more than half of the efficiency reduction is due to the use of low-pressure steam for CO_2 capture solvent regeneration. The energy losses are lower for MHI's process because the heat consumption for regeneration of the KS-1 solvent is lower than for MEA [3,9] and the flue gas fan power consumptions are lower, partly due to the use of structured instead of random packing in the absorber. The efficiency reduction for post-combustion capture is lower for the

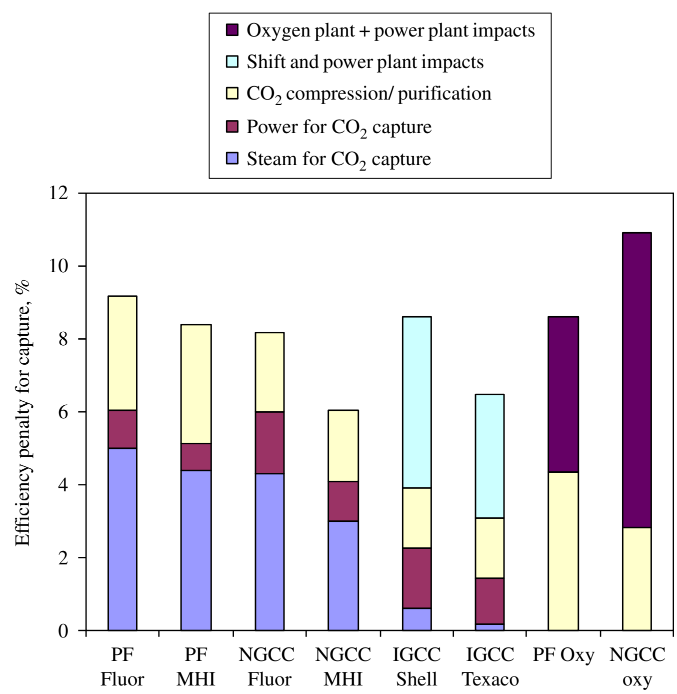

Fig. 2. Breakdown of efficiency penalty for CO_2 capture.

natural gas-fired plants than for the coal-fired plants. The fan power consumptions are higher in the gas-fired plants, because a greater volume of flue gas has to be processed per unit of fuel but the solvent-regeneration heat consumption is lower because less CO_2 has to be captured, because natural gas has a lower carbon content per unit of energy than coal.

The energy losses due to the CO_2 separation units in the IGCC plants are lower than those in the pulverised coal post combustion capture plants because a less energy intensive physical solvent scrubbing process can be used in IGCC because the CO_2 partial pressure is higher (5.7 MPa total pressure and 40% CO_2 concentration in the GE gasifier case and 2.8 MPa and 37% CO_2 in the Shell gasifier case). In the post combustion capture plants the feed gas is close to atmospheric pressure and the CO_2 concentration is lower (14% dry basis in the coal cases and 4.3% in the gas combined cycle cases), which requires use of a more energy-intensive chemical solvent. Most of the solvent regeneration in the IGCC plants is carried out by solvent depressurisation. The energy consumption for CO_2 compression is also lower in the IGCC plants because some of the CO_2 is recovered at elevated pressures. However, the IGCC plants have additional energy losses which do not occur in the post combustion capture plants. The fuel gas has to be passed through shift reactors prior to CO_2 removal and the shift reactions are highly exothermic (about 85% of the heat of combustion of CO is converted to heat of combustion of H_2). Even though most of the exothermic heat is recovered in steam generators, this means that energy bypasses the gas turbine and is fed directly into the lower efficiency steam cycle. In the Shell gasifier plant, medium pressure steam has to be added to the fuel gas feed to the shift converter, resulting in further energy loss, but in the GE plant sufficient steam is already present in the fuel gas because the hot gasifier output gas is quenched with water. The overall energy losses due to the shift converter are higher in the Shell IGCC plant than in the GE plant because the raw fuel gas has a higher CO concentration and hence more shift conversion is needed and because of the need to add steam to the shift converter feed. A further energy loss in IGCC plants with capture is due to the impacts of shift conversion and CO_2 separation on the performance of the gas turbine combined cycle. In plants without capture, CO_2 produced by combustion of the fuel gas is expanded in the gas turbine. In plants with capture the CO_2 is separated and is not available for expansion. The use of a hydrogen-rich fuel gas in the plants with CO_2 capture also has other impacts on the combined cycle performance, in particular the expansion gas has a higher steam concentration, which increases the rate of heat transfer to the turbine blades. In order to maintain the same blade temperature, the turbine inlet temperature has to be reduced, which reduces the turbine efficiency. These effects are included in the "shift and power plant impacts" category in Fig. 2, which accounts for over half of the total efficiency reduction due to CO_2 capture in the IGCC plants.

The main efficiency reduction for coal-fired oxy-combustion is due to the electricity consumed by the cryogenic oxygen production unit. This is offset slightly by a small overall reduction in losses in the main power generation units, for example due to deletion of the FGD plant. The energy consumption for CO_2 compression is higher than in the post combustion capture plant because the volume of gas fed to the CO_2 compressors is higher, due to the presence of impurities, and because some additional compression is required to drive the cryogenic separation unit which removes impurities part way through the CO_2 compression. The energy consumption for CO_2 compression is lower in the oxy-combustion NGCC plant than in the oxy-combustion coal plant because less CO_2 is produced, but the efficiency reduction due to the power generation and oxygen plant is substantially greater, resulting in a greater overall efficiency reduction for capture. The quantity of oxygen required per MW of fuel is about 15% lower in the NGCC plant but the oxygen is produced at high pressure for feeding to the gas turbine, resulting in a higher overall energy consumption.

The efficiency reductions for CO_2 capture in IGCC quoted in this paper are similar to those reported in a detailed study carried out for EPRI [14] and a compilation of earlier studies [15] but the efficiency penalties for post-combustion capture in this paper are lower because of recent significant improvements in the capture processes and because of more detailed heat integration between the CO_2 capture unit and the power plant. The reduction in the energy penalty for post combustion capture has been confirmed by recent work by EPRI [16] and others.

4.2. CO_2 emissions

The quantities of CO_2 emitted, captured and avoided are shown in Table 2. The quantities of CO_2 avoided are the emissions of a plant with CO_2 capture compared to the emissions of a baseline plant without CO_2 emissions. The baseline plant should be type of plant that would be displaced by a plant with CO_2 capture. This could either be a plant based on the same type of power generation technology as the plant with CO_2 capture or an alternative type of plant. Table 2 shows the quantities of emissions avoided for three baselines: the same type of power generation technology, a PF plant and an NGCC plant. When compared to plants using the same type of power generation technology, the quantities of emissions avoided are lower than the quantities captured because of the reduction in thermal efficiency, which results in greater production of CO_2. In some circumstances plants with CO_2 capture may displace old inefficient power plants, in which case the quantities of CO_2 emissions avoided would be significantly higher than those shown in Table 2.

The percentages of CO_2 captured which are shown in Table 2 are in the range of 85–90% for the post-combustion and pre-combustion capture plants and 90–97% for the oxy-combustion plants. These are not necessarily the technical limits or economic optima for each of the technologies. For example, increasing the percentage CO_2 capture in coal-based post combustion capture from 85–95% is reported to reduce the cost per tonne of CO_2 captured by 2% [3]. Further work is needed to determine the effects of percentage CO_2 capture on costs and efficiency for all technologies.

Table 2
CO_2 emissions

Fuel	Power generation technology	CO_2 capture technology	CO_2 emissions (g/kWh)	CO_2 captured (g/kWh)	CO_2 captured (%)	CO_2 avoided (g/kWh)		
						Same technology baseline	PF baseline	NGCC baseline
Coal	PF	None	743	—	—	—	—	—
		Fluor	117	822	87.5	626	626	262
		MHI	92	832	90	651	651	287
		Oxy	84	831	90.8	659	659	295
	IGCC (Shell)	None	763	—	—	—	—	—
		Selexol	142	809	85	621	601	237
	IGCC (GE)	None	833	—	—	—	—	—
		Selexol	152	851	85	681	591	227
Gas	IGCC	None	379	—	—	—	—	—
		Fluor	66	378	85	313	677	313
		MHI	63	362	85	316	680	316
		Oxy	12	403	97.2	367	731	367

The plants do not all produce the same purity of CO_2. Some technologies inherently produce high-purity CO_2 but others inherently produce lower purity CO_2 which has to be refined if a higher purity is required. The relative merits of the technologies therefore depend on the CO_2 purity requirements.

5. Resource consumptions and emissions

The main resource consumptions, solid waste and by-product outputs and atmospheric emissions are shown in Table 3. Natural gas-fired plants have the lowest resource consumptions and emissions. Emissions to the atmosphere from plants without capture depend on environmental legislation and the emissions shown in Table 3 do not represent the practical limits for each technology. For each type of fuel and power generation technology, CO_2 capture results in increases in the fuel consumption and outputs of wastes and by-products per unit of net electricity output, except for SO_X emissions to the atmosphere which are reduced.

Post-combustion capture plants consume substantially more solvent than IGCC plants and produce more solvent residue, which needs to be incinerated or disposed of by other means. Use of advanced solvents such as KS-1 instead of MEA greatly reduces the solvent consumption and waste production. Post-combustion capture will also emit trace quantities of solvent and decomposition products such as ammonia to the atmosphere.

Limestone is used as the reagent in FGD and in some cases as a flux for the slag in coal gasifiers. The quantities of limestone that are consumed depend on the sulphur content of the coal and quantity and composition of the ash. The quantities of ash, sulphur and gypsum that are produced also depend on the coal analysis. In some cases these outputs will be valuable by-products and in other cases they will be regarded as wastes. The optimum technology for coal-based power generation, from an environmental perspective, will depend on the relative importance given to consumptions of different resources and the environmental impacts of different types of wastes and emissions.

6. Costs

6.1. Costs of power generation

Capital costs and costs of electricity generation are shown in Tables 4 and 5 and Fig. 3. The capital costs and costs of electricity generation of the coal-fired plants are similar, and are within the limits of precision of the cost estimates. The lowest cost plant with capture is the GE IGCC plant; for the base case coal price the cost of electricity generation is 6% lower than that of the lowest-cost post-combustion capture plant and 11% lower than the oxy-combustion plant. However, it should be recognised that these studies are based on standardised assumptions about plant performance and availability which have yet to be demonstrated in practise. Costs can also vary significantly for different coals and plant locations and there is significant scope for improvement in all of the technologies considered in this paper, so the cost relativities could change in future.

The cost of electricity generation with CO_2 capture is marginally higher for the natural gas combined cycle plants with post combustion capture than for the coal-based IGCC and post-combustion plants. The cost difference is greater between natural gas and coal based oxy-combustion plants. The natural gas fired oxy-combustion plant has a cost of electricity that is about 25% higher than that of

Table 3
Resource consumptions and emissions [g/kwh]

Fuel	Power generation technology	Capture technology	Resource consumptions			Wastes and by-products (dry basis)				Atmospheric emissions		
			Fuel	Limestone /flux	Chemicalsorbent	Ash /slag	Gypsum	Sulphur	Spent sorbent	CO_2	SO_x	NO_x
Coal	PF	None	316	8.4	—	39.3	13.8	—	—	743	0.61	0.61
		Fluor	400	11.6	1.31	48.9	19.1	—	2.63	117	<0.01	0.69
		MHI	394	11.4	0.13	48.3	18.8	—	0.26	92	<0.01	0.68
		Oxy-fuel	393	—	—	48.0	—	—	—	84	—	0.26
	IGCC (Shell)	None	323	10.0	0.01	44.7	—	2.78	0.01	763	0.04	0.58
		Selexol	404	12.5	0.02	55.8	—	3.48	0.02	142	0.01	0.55
	IGCC (GE)	None	367	—	0.01	54.1	—	3.16	0.01	833	0.07	0.39
		Selexol	442	—	0.02	65.3	—	3.81	0.02	152	0.01	0.40
Gas	NGCC	None	120	—	—	—	—	—	—	379	—	0.16
		Fluor	141	—	0.61	—	—	—	1.19	66	—	0.19
		MHI	135	—	0.10	—	—	—	0.20	63	—	0.18
		Oxy-fuel	150	—	—	—	—	—	—	12	—	—

the natural gas post-combustion capture plant. A 40% increase in the cost of the combined cycle unit (excluding the oxygen plant and CO_2 compression), per MW of gross output, contributes to the relatively high cost of the natural gas fired oxy-combustion plant.

In Fig. 3 the costs of electricity generation are broken down into capital charges, operation and maintenance (O + M) and fuel costs. It can be seen that the main cost for the gas-fired plants is fuel but for the coal-fired plants, the capital charges are most significant.

The net outputs of the plants with and without capture [3–5] differ somewhat, as shown in Table 4 because some items of equipment, e.g., gas turbines have fixed sizes. The only way to force the plant outputs to be the same would be to operate some of them at non-optimum conditions, which would not be realistic. The differences in plant size affect the economic comparisons, because plants normally have economies in scale, i.e. the cost per unit output usually decreases with increasing plant size. If all of the plants were converted to a hypothetical standard power out of 750 MWe using a scale exponent of 0.8, the cost of electricity would decrease by 0.3 c/kWh for the oxyfuel plant, by 0.1 c/kWh for the coal post-combustion capture plants and the Shell IGCC with capture and by less than 0.05 c/kWh for the GE IGCC with capture and the gas-fired plants with post-combustion capture. This would not alter the main conclusions of this paper.

6.2. Costs of CO_2 emissions avoidance

Costs of avoiding CO_2 emissions are shown in Table 5, for the base case fuel prices and the low fuel prices sensitivity case. The cost of emission avoidance is calculated by comparing the cost and emissions of a plant with capture and those of a baseline plant without capture. A pulverised coal plant without capture was chosen as the baseline coal-fired plant because it has the lowest cost of electricity and is the most proven technology, and hence is likely to be the technology that would be chosen by utilities in the absence of a need to capture CO_2. The baseline gas-fired plant is a combined cycle plant without capture. The cost of avoiding CO_2 emissions is 27–39 \$/t CO_2 for the coal fired plants. The lowest cost is for the GE gasifier IGCC plant and the highest cost is for the Shell gasifier IGCC plant. Post combustion capture and oxy-combustion have intermediate costs. Costs per tonne of CO_2 are higher for the gas fired plants, 48–102 \$/t CO_2, because less CO_2 emission is avoided per kWh of electricity generated.

6.3. Costs of CO_2 transport and storage

The power plants described above include compression of CO_2 to 11.0 MPa, for pipeline transport and underground storage. Costs of transporting CO_2 from a power plant to a storage site and the costs of storage depend on local circumstances. If the CO_2 is used for enhanced oil recovery the revenue from additional oil production could

Table 4
Power outputs and capital costs

Fuel	Power generation technology	CO_2 capture technology	Net power output MW	Capital cost $/kW
Coal	Pulverised fuel	None	758	1408
		Post-combustion (Fluor)	666	1979
		Post combustion (MHI)	676	2043
		Oxy-combustion	532	2205
	IGCC (Shell)	None	776	1613
		Pre-combustion, Selexol	676	2204
	IGCC (GE)	None	826	1439
		Pre-combustion, Selexol	730	1815
Gas	Gas turbine combined cycle	None	776	499
		Post-combustion (Fluor)	662	869
		Post-combustion, MHI	692	887
		Oxy-combustion	440	1532

Table 5
Cost of electricity and CO_2 avoidance

Fuel	Power generation technology	CO_2 capture technology	$1.1/GJ coal, $3.9/GJ gas		$2.2/GJ coal, $7.8/GJ gas	
			c/kWh	$/t CO_2 avoided	c/kWh	$/t CO_2 avoided
Coal	Pulverised fuel	None	4.46		5.36	
		Post-combustion, Fluor	6.34	30	7.49	34
		Post combustion, MHI	6.27	28	7.40	31
		Oxy-combustion	6.63	33	7.76	36
	IGCC (Shell)	None	4.88		5.81	
		Pre-combustion, Selexol	6.52	33	7.68	39
	IGCC (GE)	None	4.55		5.60	
		Pre-combustion, Selexol	5.66	20	6.94	27
Gas	Combined cycle	None	3.70		6.23	
		Post-combustion, Fluor	5.07	44	8.03	58
		Post-combustion, MHI	4.93	39	7.76	48
		Oxy-combustion	6.84	85	9.98	102

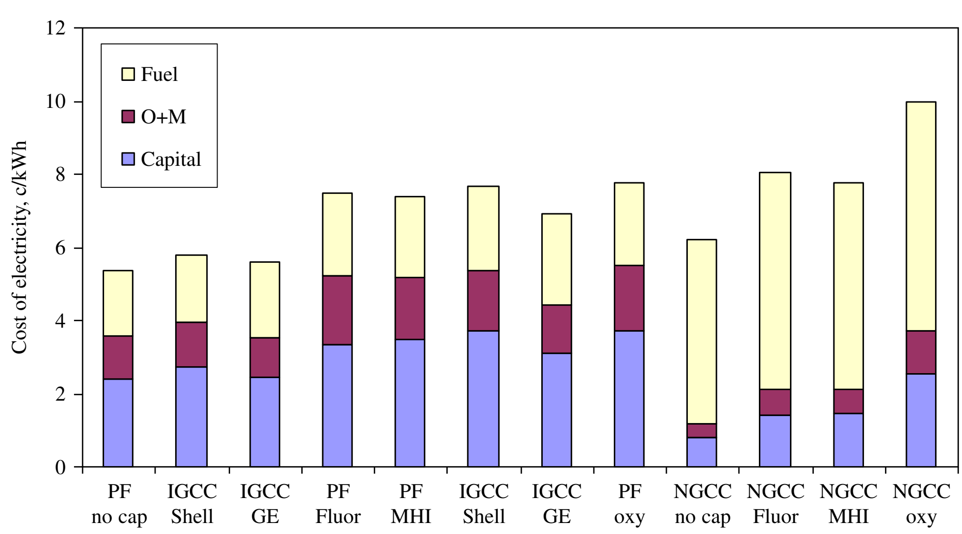

Fig. 3. Breakdown of costs of electricity.

in some cases be greater than the total costs of CO_2 capture, transport and storage. For example, at a crude oil price of \$50/barrel (less than the \$70/barrel price at the time of writing this paper), and a typical CO_2 storage of 0.33 t/barrel of incremental oil production by miscible injection [17], the gross oil revenue would be equivalent to \$150/t CO_2, although the net revenues would be lower after subtracting oil field costs, taxes and royalties. However, if CO_2 capture and storage was applied widely most CO_2 would have to be stored in disused hydrocarbon fields or deep saline aquifers, which would generate no revenue. Recent studies [18,19] indicate that the average costs of CO_2 transport and storage, excluding oil revenues, may be about \$4–5/t CO_2 stored in Europe and \$12.5/t CO_2 stored in North America. The main reason for the difference in costs is assumptions made about the injectivity of the storage reservoirs, which affects the well spacing required to inject a given quantity of CO_2. Further work is needed to characterise potential CO_2 storage formations, particularly in Europe, to increase confidence in CO_2 storage costs. An illustrative cost of \$10/t of CO_2 stored would increase the cost of electricity by about 0.8 c/kWh for the coal fired plants and about 0.4 c/kWh for the gas-fired plants. The impact is lower for the gas-fired plants because less than half as much CO_2 is stored per kWh of net electricity, as shown in Table 2. A transport and storage cost of \$10/t CO_2 would increase the cost of CO_2 avoided by about \$13/t CO_2 for the coal-fired plants and 12 \$/t CO_2 for the gas-fired plants. The cost per tonne of CO_2 avoided is greater than the cost per tonne of CO_2 stored, because the quantity of CO_2 stored is greater than the quantity of emissions avoided as a result of the reduction in thermal efficiency caused by CO_2 capture.

6.4. *Sensitivity to fuel cost*

The prices of fuels are different at different locations and prices vary over time. Prices can be lower than internationally traded prices in low-cost fuel-producing regions which do not have easy access to international markets and similarly they can be higher than international prices in fuel importing regions which do not have easy access to international markets. Table 5 shows costs of power generation for the base case coal and gas prices (\$2.2/GJ and \$7.8/GJ, respectively, LHV basis) and a sensitivity case of a 50% reduction in fuel prices, to \$1.1/GJ and \$3.9/GJ. There is a linear relationship between fuel price and electricity generation and CO_2 capture costs, so other fuel prices can be simply assessed by interpolation or extrapolation. In the lower fuel price scenario, a gas fired combined cycle plant becomes the least cost generation option without capture and a gas-fired plant with post-combustion capture becomes the least cost option with capture. The low fuel price scenario reduces the cost of capture by 3–7\$/t CO_2 for the coal-fired plants and 9–17\$/t CO_2 for the gas-fired plants.

6.5. *Sensitivity to discount rate*

A 10% discount rate, in constant money values, is used in this paper. This is substantially higher than the rates of return on typical government and corporate bonds, to allow for the effects of taxation and the higher rates of return which are necessary to compensate for investment risks. The discount rate has a significant impact on the cost of electricity generation. If the discount rate is reduced from 10% to 7%, the cost of electricity from the coal fired plant with Fluor post combustion capture decreases from 7.49 to 6.64 c/kWh and the cost of CO_2 emission avoidance decreases from 34 to 30 \$/t. For the corresponding gas-fired plant the costs decrease from 8.03 to 7.69 c/kWh and 58 to 53 \$/t CO_2. Coal-fired plants are more sensitive to discount rate than gas-fired plants because they are more capital intensive.

6.6. *Sensitivity to load factor*

The cost data in Table 5 and Fig. 3 are for base load plants, operating at a load factor of 85%. In the short to medium term, power plants with CO_2 capture and storage are expected to operate at base load, to maximise the utilisation of the investment in CO_2 capture equipment but the situation may be different in the longer term. The requirement for large reductions in CO_2 emissions is expected to result in a large increase in the use of variable renewable energy sources for electricity generation, such as wind and solar energy. Such renewable generators should operate whenever they are able to do so because of their low-marginal operating costs and consequently other plants on the grid will have to operate at lower annual load factors [20] to satisfy the varying demand for electricity. To illustrate the effects of operation at lower load factors, Table 6 shows the costs for pulverised coal and NGCC plants with and without Fluor post-combustion capture at 60% and 35% load factors. It should be recognised that intermediate load electricity has a higher value than base load electricity, so operation at intermediate load would not necessarily be less profitable than base load operation. Operation at low load factors increases the costs of electricity generation more for coal-fired plants than for gas-fired plants, because more of the costs are fixed, regardless of output. At these low load factors, gas-fired generation becomes the least cost option. Plants with CO_2 capture, particularly gas-fired plants, should be suited to operation in combination with variable renewable electricity generators better than alternative more capital intensive and less flexible generation technologies, such as nuclear power.

Further work is needed to assess the ability of power plants with CO_2 capture to operate with frequent and rapid variations in output. For the purposes of this paper, operating and maintenance costs, excluding chemicals and consumables, are assumed to be fixed but no further costs for extra start-ups and shut-downs are included. There may

Table 6
Sensitivity of costs to load factor

Fuel	Power generation technology	CO_2 capture technology	60% load factor		35% load factor	
			c/kWh	\$/t CO_2 avoided	c/kWh	\$/t CO_2 avoided
Coal	Pulverised fuel	None	6.69		10.11	
		Post-combustion, Fluor	9.33	42	14.08	63
Gas	Combined cycle	None	6.70		7.80	
		Post-combustion, Fluor	8.83	68	10.71	93

be opportunities to increase the load following capabilities and profitability of power plants with CO_2 capture by varying the operation of the CO_2 capture unit, for example by reducing CO_2 capture at times of peak electricity demand and by storing CO_2-rich solvent [21]. Such operating techniques may reduce the net cost of CO_2 capture.

Although the costs of avoiding CO_2 emissions by CO_2 capture in intermediate load power plants are higher than in base load plants, they may be lower than costs of deep CO_2 emission reductions in the transportation sector, where costs are indicated to be in excess of \$100/t CO_2 [22].

6.7. Sensitivity to coal type

This paper focuses on bituminous coal-fired power plants at greenfield sites. For such plants this paper shows that the least-cost of the IGCC technologies has the lowest costs of electricity generation and CO_2 capture. For sub-bituminous coal the cost advantage of IGCC over post-combustion capture is substantially reduced [16,23] and for lignite, post-combustion capture is the lowest cost technology [23,24].

7. Potential for future improvement

Reductions in the cost of technologies as a result of learning-by-doing, R&D investment and other factors have been observed over many decades. Historical trends in costs of various technologies were used to predict future costs of power generation with CO_2 capture [25]. Cost improvements for individual process units within power plants with CO_2 capture were predicted taking into account their existing installed capacities and historical cost reductions for analogous technologies. After installation of 100 GW of capacity worldwide, the cost of electricity from an IGCC plant with CO_2 capture was predicted to reduce by 18%. The cost reductions were lower for power plants with post-combustion capture (14–16%) and coal-based oxy-combustion (10%). The reduction in the incremental cost of CO_2 capture was lower for IGCC than for post-combustion capture, because the main capture units in IGCC (shift conversion, high pressure acid gas removal etc.) are already well developed and widely used, whereas post-combustion capture has only been applied on a small scale. However, the costs of the core power generation units in an IGCC are expected to decrease more than the costs of pulverised coal boilers, because they are less widely used and developed. This is the reason for the greater overall reduction in the cost of IGCC power generation with CO_2 capture.

Development of radically new CO_2 capture processes may result in cost reductions that are greater than those resulting from incremental improvement to existing processes, as described above. Detailed discussion of such processes is beyond the scope of this paper but some examples are highlighted below. Post-combustion ammonia scrubbing and flue recycle for a gas turbine combined cycle plant is predicted to reduce the energy consumption for post-combustion CO_2 capture and compression by 50% and reduce the cost per tonne of CO_2 avoided by 40% [26]. Integration of post-combustion capture of CO_2 and control of other emissions (SO_X, NO_X, particulates and mercury) may also provide significant benefits. Successful development of novel oxygen production technologies such as Ion Transport Membranes could significantly improve the competitiveness of oxy-combustion and, to a lesser extent, IGCC. ITM's could reduce the cost of oxygen production by more than 35% and in an IGCC this would result in a 1 percentage point increase in the overall plant efficiency and a 7% reduction in capital cost [27]. For pre-combustion capture, high-temperature membrane separation of hydrogen could be combined with shift conversion and methane reforming reactors [28]. Chemical looping combustion may be an attractive long-term technology for ox-combustion. A preliminary evaluation resulted in a $>40\%$ saving compared to a post-combustion capture baseline [28]. However, it should be recognised that novel processes have significant development risks and the expected improvements may not be achieved.

8. Other criteria affecting technology choice

This paper assesses some of the main criteria which would affect a utility's choice of power generation and CO_2 capture technology. However, there are other important criteria, such as:

- Health and safety
- Operating flexibility and compatibility with future grid requirements
- Risks of underperformance
- Diversity of equipment and technology suppliers
- Compatibility with utilities' operating experience
- Potential for future improvements
- The ability to co-produce hydrogen and liquid fuels (in-pre-combustion capture processes)

These criteria are beyond the scope of this paper but the criteria and the weightings assigned to them by utilities are assessed in a recent study [7]. Further work is needed to assess in detail some of these issues, including health and safety issues and operating flexibility.

9. Conclusions

The thermal efficiencies of power plants with CO_2 capture based on the current leading technologies are 32–35%, LHV basis, for bituminous coal fired plants and 45–50% for natural gas combined cycle plants.

The cost of electricity generation with CO_2 capture depends on various technical and economic factors including the fuel cost, which is highly variable at present. Based on predicted fuel prices for North West Europe for the next 25 years, the cost of electricity generation with CO_2 capture is estimated to be 6.9 c/kWh for the least cost coal technology (water quench IGCC) and 7.8 c/kWh for the least cost natural gas technology (combined cycle with post-combustion capture).

The estimated cost of CO_2 capture and compression (excluding CO_2 transport and storage) is 27–39 $/t of CO_2 emissions avoided for coal-fired plants and 48–102 $/t for natural gas combined cycle plants. The costs are 1.6–2.4 c/kWh for coal-fired plants and 1.5–3.7 c/kWh for gas-fired plants. An indicative cost of CO_2 transport and storage of $10/t CO_2 stored would increase the cost of CO_2 avoided by 12–13 $/t and increase the cost of electricity by about 0.8 c/kWh for coal fired plants and 0.4 c/kWh for gas-fired plants.

The optimum power generation and CO_2 capture technologies will depend on various criteria which will depend on local circumstances and utilities' preferences. Further work is needed to assess power generation with CO_2 capture at a range of different locations worldwide and to assess the abilities of capture processes to accommodate the present and future operational requirements of power utilities.

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