

TECHNOLOGIES FOR CAPTURE OF CARBON DIOXIDE

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ABSTRACT

This paper reviews the technologies that could be used to capture CO₂ from use of fossil fuels. It identifies the main opportunities for capturing CO₂ which are power generation, other large energy consuming industries and production of carbon-free energy carriers. The three main overall methods of capturing CO₂ in power plants: post-combustion capture, oxyfuel combustion and pre-combustion capture are described. The paper also describes the various CO₂ separation techniques that could be used and their current development status.

The impacts of different CO₂ capture technologies on the thermal efficiencies and costs of power plants are summarized, based on recent studies carried out by process technology developers and plant engineering contractors.

INTRODUCTION

About 85% of the world's commercial energy needs are currently supplied by fossil fuels. A rapid change to non-fossil energy sources would result in large disruption to the energy supply infrastructure, with substantial consequences for the global economy. The technology of CO₂ capture and storage would enable the world to continue to use fossil fuels but with much reduced emissions of CO₂, while other low-CO₂ energy sources are being developed and introduced on a large scale. In view of the many uncertainties about the course of climate change, further development and demonstration of CO₂ capture and storage technologies is a prudent precautionary action. This paper provides an overview of technologies for capture of CO₂. It deals not only with application of existing technology but describes many new processes under development which should result in lower CO₂ capture costs in future.

Global emissions of CO₂ from fossil fuel use were 23,684 million tonnes/year in 2001 [1]. These emissions are concentrated in four main sectors: power generation, industrial processes, the transportation sector and residential and commercial buildings, as shown in figure 1.

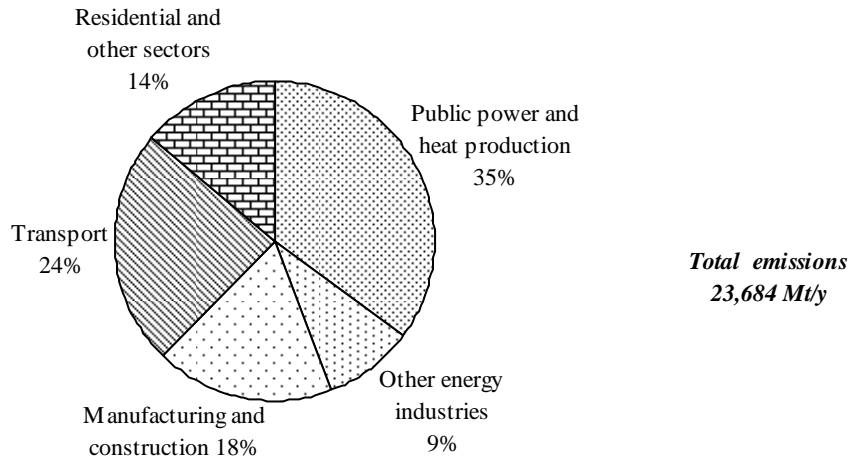


Figure 1: Emissions of CO₂ from fossil fuel use (2001) [1]

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The main application of CO₂ capture is likely to be in power generation and large energy consuming industries, particularly cement, iron and steel and chemicals production and oil refining. This paper focuses on power generation. Capturing CO₂ directly from small and mobile sources in the transportation and domestic and commercial buildings sectors is expected to be significantly more difficult and expensive. However, some of the CO₂ emissions from these sectors could be avoided by use of energy carriers such as hydrogen or electricity produced in large plants with CO₂ capture.

Most of the emissions of CO₂ to the atmosphere from the electricity generation and industrial sectors are currently in the form of flue gas from combustion, in which the CO₂ concentration is typically 4-14% by volume, although CO₂ is produced at high concentrations by a few industrial processes. In principle, flue gas could be stored, to avoid emissions of CO₂ to the atmosphere it they would have to be compressed to a pressure of typically more than 10 MPa and this would consume an excessive amount of energy. Also, the high volume of flue gas would mean that storage reservoirs would be filled quickly. For these reasons it is preferable to produce a relatively high purity stream of CO₂ for transport and storage; this process is called CO₂ capture.

HOW CAN CO₂ BE CAPTURED?

There are three main techniques for capture of CO₂ in power plants:

- Post-combustion capture
- Pre-combustion capture
- Oxy-fuel combustion

Similar techniques could be used in other large industries.

Post combustion capture

Post-combustion capture involves separating CO₂ from the flue gas produced by fuel combustion. A variety of techniques, described later, can be used for this separation. The most proven technique at present is to scrub the flue gas with an amine solution. Post-combustion capture is a downstream process and in many respects is analogous to flue gas desulphurization (FGD), which is widely used to capture SO₂ from flue gas in coal and oil fired power plants.

The low concentration of CO₂ in power plant flue gas (typically 4-14%) means that a large volume of gas has to be handled, which results in large equipment sizes and high capital costs. A further disadvantage of the low CO₂ concentration is that powerful chemical solvents have to be used and regeneration of the solvents to release the CO₂ requires a large amount of energy.

Pre-combustion capture

In pre-combustion capture, fuel is reacted with oxygen or air, and in some cases steam, to give mainly carbon monoxide and hydrogen. This process is known as gasification, partial oxidation or reforming. The mixture of mainly CO and H₂ is passed through a catalytic reactor, called a shift converter, where the CO reacts with steam to give CO₂ and more H₂. The CO₂ is separated and the H₂ is used as fuel in a gas turbine combined cycle plant. The process is, in principle, the same for coal, oil or natural gas, but when coal or oil are used there are more stages of gas purification, to remove particles of ash, sulphur and nitrogen compounds and other minor impurities. The CO₂ concentration and pressure are both higher in pre-combustion capture than in post-combustion capture, so the CO₂ capture equipment is much smaller and different solvents can be used, with lower energy penalties for regeneration.

Although pre-combustion capture involves a more radical change to power plant design, most of the technology is already proven in ammonia production and other industrial processes. This type of process, without CO₂ capture, is already used in several commercial scale power plants fuelled by coal, residual oil and petroleum coke, known as IGCC (integrated gasification combined cycle) plants [2].

The hydrogen produced in pre-combustion capture processes could alternatively be used to generate electricity in fuel cells. Fuel cells are currently not economically competitive with gas turbines, but they may become more competitive in future, particularly for small-scale distributed power generation. The technology of capture and storage is therefore expected to be suitable for future as well as current power generation technologies. Hydrogen fuel cells could also be used by cars and other mobile energy consumers.

Oxyfuel combustion

The concentration of CO₂ in flue gas can be increased greatly by using concentrated oxygen instead of air for combustion, either in a boiler or gas turbine. The oxygen would be produced by cryogenic air separation, which is already used on a large scale, for example in the steel industry. If fuel is burnt in pure oxygen, the flame temperature is excessively high, so some CO₂-rich flue gas would be recycled to the combustor to make the flame temperature similar to that in a normal air-blown combustor. The advantage of oxygen-blown combustion is that the flue gas has a CO₂ concentration of over 80%, so only simple CO₂ purification is required. Another advantage is that NO_x

formation is suppressed, with attendant benefits in the post combustion removal of NO_x , and the volume of gas to be treated in the flue gas desulphurization plant is greatly reduced. Additionally, other than a need for flue gas desulphurization, oxyfuel combustion relies mainly on physical separation processes for O_2 production and CO_2 capture thereby avoiding the use of any reagents and/or solvents that contribute to operating costs and the environmental disposal of any related solid or liquid wastes. The main disadvantage of oxyfuel combustion is that a large quantity of oxygen is required, which is expensive, both in terms of capital cost and energy consumption. Advances in oxygen production processes, such as new and improved membranes that can operate at high temperatures could improve overall plant efficiency and economics [3]. Oxyfuel combustion has so far only been demonstrated in small scale test rigs [4].

Oxyfuel combustion could also be applied to boilers, fired heaters or gas turbines. However, gas turbines that use CO_2 as the working fluid would be substantially different to conventional gas turbines that use air, and retrofit of existing gas turbines would not be feasible. Substantial investment would be needed to develop an oxygen fired gas turbine and there would need to be the prospect of a large market to persuade manufacturers to make such an investment. Novel gas turbine and fuel cell based cycles involving oxyfuel combustion and condensation of CO_2 have been proposed. Such cycles could be attractive, but they would involve even more development work.

TYPES OF CO_2 SEPARATION TECHNOLOGY

Chemical solvent scrubbing

Currently the favoured method for post-combustion removal of CO_2 from flue gases uses chemical solvents. The most common solvent is monoethanolamine (MEA). Prior to CO_2 removal the flue gas is cooled and particulates and other impurities are removed as far as possible. It is then passed into an absorption vessel where it comes into contact with the chemical solvent, which absorbs much of the CO_2 by chemical reactions to form a loosely bound compound. The CO_2 -rich solvent taken from the bottom of the absorber is passed into another vessel (stripper column) where it is heated with steam to reverse the CO_2 absorption reactions. CO_2 released in the stripper is compressed for transport and storage and the CO_2 -free solvent is recycled to the absorption vessel.

Amine scrubbing technology has been established for over 60 years in the chemical and oil industries, for removal of hydrogen sulphide and CO_2 from gas streams [5]. This experience is largely on natural gas streams and/or with chemically reducing (primarily oxygen deficient) gases but there are several facilities in which amines are used to capture CO_2 from flue gas streams today, the largest of which has a capacity of 800 tonnes/day of CO_2 using two parallel trains [6]. CO_2 recovery rates of around 85-95% capture are normally proposed and product purity can be in excess of 99% [7].

The main concerns with MEA and other amine solvents are corrosion in the presence of O_2 and other impurities, high solvent degradation rates from reaction with SO_x and NO_2 and the large amounts of energy required for regeneration. Inhibitors are used to reduce corrosion, enabling use of conventional materials of construction, mostly carbon steel. The SO_x concentration in the feed to an MEA scrubber needs to be reduced to typically 10ppm or lower, significantly lower than the levels normally achieved by most current FGD plants. However, the conventional wet limestone gypsum FGD technology can achieve this lower SO_x level without significantly increasing the cost of a new FGD plant [8]. Selective Catalytic Reduction (SCR) is needed to achieve the required low levels of NO_2 in the flue gas.

New or improved solvents with higher CO_2 absorption capacities, faster CO_2 absorption rates, high degradation resistance and low corrosiveness and energy use for regeneration are needed to reduce equipment sizes and capital and operating costs. The hindered amine solvents developed by MHI and partners have lower heats of regeneration than MEA [9]. They are also reported to have lower rates of degradation and corrosion than MEA but they are more expensive.

Post combustion amine scrubbing requires very large equipment because of the large flue gas volumes. Scale-up issues have been addressed in the oil and gas industry where amine scrubbing technology was developed and are not expected to be a problem. With absorber diameters of 12-15m considered feasible, CO_2 recovery plant capacities of up to 8000 t/d are achievable, depending on the inlet flue gas CO_2 concentration [6]. This corresponds to a coal fired power plant with CO_2 capture with a net power output of about 400 MW. Even larger single stream plants are under study for application to large power plants.

Physical solvent scrubbing

The conditions for CO_2 separation in pre-combustion capture processes will be different from those in post-combustion capture processes. The feed to the CO_2 capture unit in a coal-based IGCC process, located upstream of the gas turbine, would have a CO_2 concentration in the range of 15-60% and a total pressure of 2-7 MPa. The CO_2 partial pressure is therefore up to 1000 times higher than in post-combustion capture. In pre-combustion capture it may be preferable to use different solvents, known as physical solvents, which combine less strongly with CO_2 . The

advantage of such solvents is that CO₂ can be separated from them in the stripper mainly by reducing the pressure, resulting in much lower energy consumption. The main physical solvents that could be used for CO₂ capture are cold methanol (Rectisol process), dimethylether of polyethylene glycol (Selexol process), propylene carbonate (Fluor process) and sulpholane. Physical solvent scrubbing for separation of sulphur compounds is already used in large scale commercial IGCC plants [10]. Physical solvent scrubbing of CO₂ is well established at a large scale, e.g. in ammonia production plants but needs to be demonstrated in full scale power plants.

Adsorption

Some solid materials with high surface areas, such as zeolites and activated carbon, can be used to separate CO₂ from gas mixtures by adsorption. Gas is fed to a bed of solids that adsorbs CO₂ and allows the other gases to pass through. When a bed becomes fully loaded with CO₂, the feed gas is switched to another clean adsorption bed and the fully loaded bed is regenerated to remove the CO₂. In pressure swing adsorption (PSA), the adsorbent is regenerated by reducing the pressure. In temperature swing adsorption (TSA), the adsorbent is regenerated by raising its temperature and in electric swing adsorption (ESA) regeneration takes place by passing a low-voltage electric current through the adsorbent.

PSA and TSA are used commercially for gas separation and are used to some extent in hydrogen production and in removal of CO₂ from natural gas [10] but ESA is poorly explored and tested at present. Most attention has focused on PSA for CO₂ separation in pre-combustion capture processes since TSA absorption systems involve more cumbersome heating of the adsorbent during regeneration, usually with a secondary gas flow, and the physical size of a TSA plant is much larger. Adsorption is not yet considered attractive for large-scale separation of CO₂ from flue gas because the capacity and CO₂ selectivity of available adsorbents is low [11]. However, it may be successful in combination with another capture technology. Adsorbents that can operate at higher temperatures in the presence of steam with increased capacity and improved selectivity are needed.

A concept called Sorption Enhanced Reaction uses a packed bed containing a mixture of a steam methane reforming or water gas shift conversion catalyst and a selective adsorbent such as lithium silicate or hydrotalcites which removes CO₂ from the high temperature reaction zone, thus driving the reaction to completion [12]. The adsorbent is periodically regenerated using PSA or TSA. This technology is in the very early stages of development.

Membranes

Gas separation membranes rely on differences in physical or chemical interactions between gases and a membrane material, causing one component to pass through the membrane faster than another. Various types of membrane are currently available, including porous inorganic membranes, palladium membranes, polymeric membranes and zeolites. These membranes cannot usually achieve high degrees of separation, so multiple stages and/or recycle of one of the streams is necessary. This leads to increased complexity, energy consumption and costs. Several membranes with different characteristics may be required to separate high-purity CO₂. A possible future improvement would be to combine inorganic membranes, with operating temperatures up to 1000°C, with reforming or shift conversion reactions [13]. This would overcome the chemical equilibrium limitations experienced in conventional reactors for production of hydrogen, in a similar way to the Sorption Enhanced Reactor described in the previous paragraph.

Gas absorption membranes are hybrid systems that involve gas-liquid contacting [14]. The CO₂ diffuses through the membrane and is removed by an absorption liquid such as amine, which selectively removes certain components. In contrast to gas separation membranes, it is the absorption liquid, not the membrane that gives the process its selectivity. The advantages of these membranes would be avoidance of operational problems such as foaming, flooding, entrainment and channeling that can occur in conventional systems where gas and liquid are in direct contact. Compact membranes also result in smaller equipment sizes and offer the possibility of cost reductions.

Membranes are used commercially for CO₂ removal from natural gas at high pressure and at high CO₂ concentration. Much development is required before membranes could be used on a large scale for capture of CO₂ in power plants.

Cryogenics

CO₂ can be separated from other gases by cooling and condensation. Cryogenic separation is widely used commercially for purification of CO₂ from streams that already have high CO₂ concentrations (typically >90%) but it is not normally used for more dilute CO₂ streams. A major disadvantage of cryogenic separation of CO₂ is the amount of energy required to provide the refrigeration necessary for the process, particularly for dilute gas streams. Another disadvantage is that some components, such as water, have to be removed before the gas stream is cooled, to avoid blockages. Cryogenic separation has the advantage that it enables direct production of liquid CO₂, which is needed for ship transport. The most promising applications for cryogenics are expected to be for separation of CO₂ from high pressure gases, such as in pre-combustion capture processes, or oxyfuel combustion in which the input gas contains a high concentration of CO₂.

Solid sorbents

Post-combustion capture systems have been proposed that make use of regenerable solid sorbents to remove CO₂ at relatively high temperatures. Sorbents such as calcium or lithium based oxides can react with CO₂ to form carbonates and the carbonates can be regenerated to oxides by heating to a higher temperature [15]. Sodium and potassium oxides and carbonates usually supported on a solid substrate are also being investigated [16]. These processes have the potential to reduce efficiency penalties compared to wet absorption processes. A weak point of processes that use natural solid sorbents (limestone and dolomite) is that they deactivate rapidly and a large make-up flow of sorbent is needed, although the deactivated sorbent may find application in the cement industry. Lithium based sorbents are much more durable but they are intrinsically expensive materials.

Various pre-combustion capture systems that involve reaction of calcium oxide, carbon and steam to produce calcium carbonate and hydrogen have been proposed but are at an early stage of development.

Chemical looping combustion

The need to capture CO₂ may make some radically different power generation technologies attractive. One such technology is chemical looping combustion, in which direct contact between the fuel and the combustion air is avoided by using a metal oxide to transfer oxygen to the fuel in a two-stage process [17]. In the reduction reactor, the fuel is oxidised by reacting with a metal oxide, which it converted to a lower oxidation state. It is then transported to a second reactor, the oxidation reactor, where it is re-oxidised by reacting with O₂ in air. The major development issue associated with chemical looping combustion is development of a metal oxide material that is able to withstand long term chemical cycling and is resistant to physical and chemical degradation from impurities generated from fuel combustion. Possible oxides include iron, nickel, copper and manganese. Chemical looping combustion could be applied at atmospheric pressure or at elevated pressure as part of a gas turbine. Systems evaluated to date have only looked at natural gas combustion in small laboratory or pilot scale equipment.

THERMAL EFFICIENCIES

Capture of CO₂ results in a significant reduction in the efficiency of a power plant, so it is important that it is applied to the most modern efficient power plants. Retrofitting CO₂ capture to old inefficient plants is unlikely to be attractive unless the power plant itself is substantially upgraded to increase its efficiency at the same time that CO₂ capture is retrofitted.

Thermal efficiencies of new coal and natural gas fired power plants with and without CO₂ capture and compression are summarized in Figure 2.

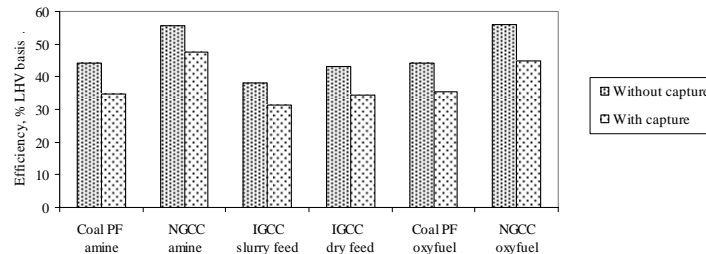


Figure 2: Thermal efficiencies of electricity generation with and without capture of CO₂

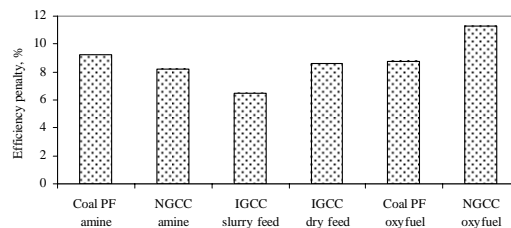


Figure 3: Thermal efficiency penalties for CO₂ capture

The data in figure 2 are from recent studies carried out by major process technology manufacturers and licensors [8,18,19]. The plants are based on the current state of the art of each technology. The pulverized coal plants are based on 290 bar, 600/620°C steam conditions and the combined cycle plants are based on General Electric 9FA gas turbines, except the oxyfuel fired combined cycle which is based on a substantially modified turbine. Gas turbines

that are similar to the 9FA are available from other manufacturers. The slurry feed gasifier is the ChevronTexaco gasifier with water quench of the product gas and the dry feed gasifier is the Shell gasifier with a product gas heat recovery boiler. The IGCC plants are based on the Selexol physical solvent scrubbing process for CO₂ separation and the post-combustion capture plants are based on the Econamine FG+SM amine scrubbing process.

The thermal efficiency losses due to CO₂ capture are shown in Figure 3.

The overall losses are lower for IGCC than for pulverized coal firing with post-combustion amine scrubbing. The energy losses in the CO₂ separation stage are higher for post-combustion amine scrubbing than for pre-combustion capture because of the high heat requirement for amine regeneration and the power consumption for CO₂ compression is also higher because the CO₂ is recovered at a lower average pressure. However, in IGCC processes there are additional energy penalties due to shift conversion and the loss of high pressure CO₂ which would otherwise be expanded in the gas turbine. The efficiency loss shown in Figure 3 for post combustion capture is lower than in many earlier studies due to the development of an improved split-flow amine scrubbing process [7,8] and better heat integration between the amine scrubbing unit and the power plant steam cycle. New hindered amine solvents such as those being developed by MHI and partners with lower heats of regeneration would provide further efficiency improvements [9].

The efficiency loss for CO₂ capture in IGCC depends on the type of gasifier that is used. Dry feed Shell gasifier plants have higher overall efficiencies than the slurry feed ChevronTexaco plants but the penalty for CO₂ capture is higher in Shell gasifier plants. This is because the slurry-feed water-quench gasifier produces a raw fuel gas containing the steam required for the subsequent shift conversion of CO to H₂ and CO₂. With the dry-feed gasifier and heat recovery boiler, additional steam has to be added for the shift conversion. This steam would otherwise be used for power generation.

The efficiency penalty for coal fired oxyfuel combustion is very similar to that for post-combustion capture. The main penalty is electricity used for cryogenic oxygen production. In a pulverised coal fired power plant, improved heat recovery in the boiler and from condensed cooling of the flue gas reduces the overall energy penalty incurred from oxygen production, CO₂ purification and compression.

The percentage point efficiency penalty for post combustion CO₂ capture in a natural gas combined cycle power plant is slightly lower than in a pulverised coal plant. The quantity of CO₂ captured per unit of power output is lower in a natural gas combined cycle plant but the quantity of flue gas that has to be processed is higher and the CO₂ concentrations are lower. The efficiency loss for CO₂ capture from natural gas by oxyfuel combustion is higher, because about half of the oxygen has to be used for combustion of hydrogen rather than carbon. However, this technology is only at a conceptual stage of development so the performance predictions are less certain.

The efficiencies of power plants with CO₂ capture depend on the efficiency of the basic power plant technology. Pulverised coal power plants with higher steam conditions and gas turbines with higher inlet temperatures and improved blade cooling are being developed, so the efficiencies of all power generation technologies will increase substantially in future. It is possible that the efficiencies of power plants with CO₂ capture in 20 years will be similar to the efficiencies of current plants without CO₂ capture [8,18].

COSTS

CO₂ capture also has a significant impact on costs. The percentage increases in fuel, capital and overall costs of electricity generation due to CO₂ capture are shown in Figure 4 [8,18,19]. The percentage increases are calculated by comparing power plants with capture against the same type of plants without capture.

In most cases CO₂ capture increases the fuel consumption, and hence the cost of fuel, by about 25%. The increase is slightly lower (21%) for the slurry feed IGCC process and is lowest (17%) for the natural gas fired combined cycle plant with post-combustion capture. The increase in specific capital cost (\$/kW) due to capture is 25-50% for coal fired plants. The lowest increase is for IGCC. The percentage increase is higher, 70-85%, for natural gas fired plants. The increase in specific capital cost is due partly to the reduction in efficiency and partly to the cost of the extra process units required for CO₂ capture and compression.

The costs of CO₂ capture consist mainly of additional fuel costs and capital related costs, although the cost of solvent is also significant for the amine scrubbing cases. The percentage increase in the overall cost of electricity due to capture therefore lies in between the percentage increases in the capital and fuel costs for each plant. The costs in Figure 4 are based on coal and natural gas prices of 1.5 and 3 US\$/GJ (LHV) respectively (1.57 and 3.32 \$/GJ HHV), a 10% annual discount rate in constant money values and a 25 year plant life. Fuel prices and discount rates depend highly on local conditions. If capital is cheaper and fuel is more expensive, the fuel cost element will be more significant and vice versa.



Figure 4: Percentage cost increase due to CO₂ capture compared to the same base plant without capture

Costs of electricity generation with and without post-combustion capture of CO₂ for a range of fuel prices are shown in Figure 5. If the coal price is \$1.5/GJ then the gas price has to be about \$5/GJ for coal and gas fired plants without capture to generate electricity at the same cost. Adding CO₂ capture increases the breakeven gas price to about \$5.5/GJ. Including the cost of CO₂ transport and storage would result in a further increase in the breakeven gas price, to about \$6/GJ, if the transport and storage cost is \$10/tonne of CO₂ stored. CO₂ transport and storage costs have a greater impact on the cost of generating electricity from coal because about twice as much CO₂ has to be transported and stored per kWh of electricity from a coal fired plant compared to a natural gas combined cycle plant. The costs presented in Figure 5 are indicative only and should be used with caution because costs depend on a great many local factors apart from the fuel price.

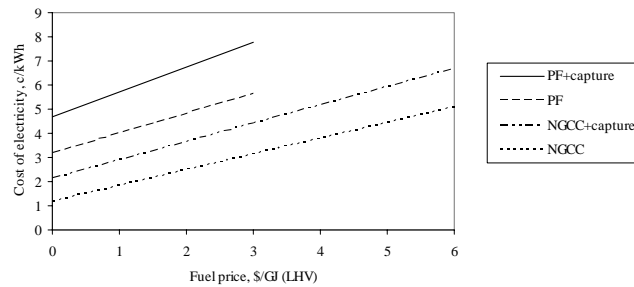


Figure 5: Cost of electricity generation with and without post-combustion capture of CO₂

Pulverized coal combustion is currently in general the preferred technology for coal fired power plants worldwide. The only major coal fired IGCC plants built so far have been government sponsored demonstration plants. Addition of CO₂ capture should make IGCC more cost competitive with pulverized coal combustion because the additional costs of capture are predicted to be lower, as shown in Figure 4. However, it is not clear at this stage which technology would be preferred for coal fired power generation with CO₂ capture. Various other factors such as plant availability, ease and flexibility of operation and “bankability” would also have to be taken into account. Improvements are being made in all technologies so the long term future situation is also not clear. However, a variety of options will be offered by plant manufacturers, so the availability of capture technology should not be a significant barrier to adoption of CO₂ capture and storage.

Whether or not power generation with CO₂ capture and storage will be used widely in future will depend on its relative costs compared to alternative methods of generating power with low CO₂ emissions, such as renewables and nuclear, as well as other issues such as safety, security, environmental impact and public acceptability. These other issues relate mainly for CO₂ transport and storage rather than capture so are beyond the scope of this paper.

CO₂ CAPTURE FROM OTHER LARGE POINT SOURCES

Power generation is the largest source of CO₂ which could be captured and stored. However, substantial quantities of CO₂ could also be captured in some large energy consuming industries, in particular iron and steel, cement and chemicals production and oil refining.

Cement production

The largest industrial source of CO₂ is cement production, which accounts for about 5% of global CO₂ emissions [20]. The quantity of CO₂ produced by a new large cement kiln can be similar to that produced by a power plant boiler. About half of the CO₂ from cement production is from fuel use and the other half is from calcination of CaCO₃ to CaO and CO₂. The concentration of CO₂ in the flue gas from cement kilns is between 14 and 33 vol%,

depending on the production process and type of cement [20]. This is higher than in power plant flue gas, so cement kilns could be good candidates for post-combustion CO₂ capture. It may be advantageous to use oxyfuel combustion in cement kilns because only about half as much oxygen would have to be provided per tonne of CO₂ captured. However, the effects on the process chemistry of the higher CO₂ concentration in the flue gas would have to be assessed.

Iron and steel production

Large integrated steel mills are some of the world's largest point sources of CO₂. About 70% of the CO₂ from integrated steel mills could be recovered by capture of the CO₂ contained in blast furnace gas [21]. Blast furnace gas typically contains 20% by volume CO₂ and 21% CO, with the rest being mainly N₂. An important and growing trend is the use of new processes for direct reduction of iron ore. Such processes are well suited to CO₂ capture.

Oil refining

About 65% of the CO₂ emissions from oil refineries are from fired heaters and boilers [21]. The flue gases from these heaters and boilers are similar to those from power plants, so CO₂ could be captured using the same techniques and at broadly similar costs. The same would be true for major fired heaters in the petrochemical industry, such as ethylene cracking furnaces.

Hydrogen and ammonia production

Large quantities of hydrogen are produced by reforming of natural gas, mainly for production of ammonia-based fertilizers. CO₂ separated in hydrogen plant is normally vented to the atmosphere but it could instead be compressed for storage. This would be a relatively low cost method of avoiding release of CO₂ to the atmosphere. It could also provide useful opportunities for the early demonstration of CO₂ transport and storage techniques.

Natural gas purification

Some natural gas fields contain substantial amounts of CO₂. The CO₂ concentration has to be reduced to ~2.5% for the market, so any excess CO₂ has to be separated. The captured CO₂ is usually vented to the atmosphere but, instead, it could be stored in underground reservoirs. The first example of this being done on a commercial scale is the Sleipner Vest gas field in the Norwegian sector of the North Sea [22].

Energy carriers for distributed energy users

A large amount of fossil fuel is used in transport and small-scale heat and power production. It is not practicable using current technologies to capture, collect, and store CO₂ from such small scale dispersed users. Nevertheless, large reductions could be made in CO₂ emissions through use of a carbon-free energy carrier, such as hydrogen or electricity. Both hydrogen and electricity are often considered as a carrier for energy from renewable sources. However, they can also be produced from fossil fuels in large centralized plants, using capture and storage technology to minimize release of CO₂. Production of hydrogen or electricity from fossil fuels with CO₂ storage could be an attractive transitional strategy to aid the introduction of future carbon free energy carriers [23].

CONCLUSIONS

- CO₂ could be captured at large point sources in the power generation and other large energy using industries, which currently account for over half of CO₂ emissions from fossil fuel use.
- CO₂ emissions in other sectors could be reduced by use of energy carriers such as hydrogen or electricity produced in plants with CO₂ capture. This could be an attractive transitional strategy to aid the introduction of carbon-free energy carriers.
- The main technologies required for CO₂ capture are available but integrated operation at a large scale needs to be demonstrated.
- Based on current technology, CO₂ capture would increase the fuel consumptions of power plants by typically about 25% and increase the costs of electricity generation by about 25-50%.
- There are prospects for reducing the energy consumptions and costs of CO₂ capture in future by improvements in technology and wide-scale application.

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