CO_2 Capture and Storage

HIGHLIGHTS

■ **PROCESS AND TECHNOLOGY STATUS –** Carbon capture and storage (CCS) is a process that significantly reduces carbon dioxide (CO_2) emissions from fossil fuel combustion in power generation and in the industrial sector. CCS includes 3-steps, i.e. **CO_2 capture** by *decarbonisation* of fossil fuels or separation from flue gases and other gaseous mixtures; **CO_2 transportation** to the storage site - usually via pipelines; and **CO_2 storage** by injection of high-pressure supercritical CO_2 into geological formations, e.g. deep saline reservoirs, depleted oil and gas fields, and *unmineable* coal seams. In fossil fuel combustion processes, the CO_2 can be captured in pre-combustion mode (i.e. fossil fuel decarbonisation), in post-combustion mode (i.e. chemical separation from the flue gas), and by the oxy-fuel combustion (i.e. fuel combustion in oxygen-rich atmosphere). Apart from combustion, CO_2 can also be separated from gaseous mixtures, e.g. in natural gas fields with high CO_2 content or in chemical processes. The CCS process is based on well-known technologies, but has never been applied to large-scale power or industrial plants. The five large-scale, industrial demonstration projects that are currently in operation use CO_2 sources other than power plants (e.g. CO_2 from natural gas production or coal gasification). With a total storage capacity above 5 $MtCO_2$/y, these projects focus on CO_2 geological storage rather than on CO_2 capture. CO_2 underground injection and storage is also used in enhanced oil recovery (EOR) projects (mostly in North America) where the additional production of oil offsets the cost of CO_2 separation, transportation and injection. CCS applications in power generation are currently being demonstrated in relatively small (5-40 MW) pilot plants. A number of full-scale projects are currently underway or planned.

■ **PERFORMANCE AND COSTS –** CCS can reduce CO_2 emissions by more than 85% in power generation, and significant reductions are expected in other industrial sectors. In general, CO_2 separation from natural gas wells is a relatively easy and cheap process, but CO_2 capture from combustion processes is rather expensive and energy-consuming. CCS applications in power generation may involve reductions of the power plant efficiency between 8 and 12 percentage points, (typically, from 45% to 35% in coal power plants and from 60% to 50% in gas-turbine combined cycles). Today's costs of CCS in power generation is estimated between US \$50 to \$90/tCO_2 and may be even higher, depending on technologies and storage site location. This cost typically includes \$30-50/tCO_2 for capture, \$5-20/tCO_2 for on/offshore pipeline transport (100-200 km) and \$5-10/tCO_2 for injection, storage and monitoring in deep geological formations. Using CCS in power plants can increase the electricity generation cost to between \$20 and \$40/MWh. Assuming reasonable technology advances, the CCS cost is projected to fall to some \$30-35/tCO_2 by 2030, with a lower impact on the cost of electricity. While the cost of CCS in industrial applications (e.g. cement, iron and steel production) is significantly higher, the cost of CO_2 separation from natural gas fields with re-injection and storage in near geological formations is relatively low, ranging between \$5/tCO_2 (onshore) and 15/tCO_2 (offshore).

■ **POTENTIAL AND BARRIERS –** Assuming appropriate emission reduction policies and considering marginal costs of CO_2 abatement of up to \$180/tCO_2, the International Energy Agency projects that the CCS technology could make a contribution of up to 19% to the global greenhouse gas (GHG) emission reduction targets by 2050. This includes applications in power generation and industry. Prudent estimates suggest that the global geological storage potential amounts to at least to 2000 $GtCO_2$. At either the current (i.e. 28-29 $GtCO_2$/yr) or increased levels of CO_2 emissions, this would allow the storage of the global emissions for almost a century. However, the global storage potential in deep saline formations and in other sites could be well beyond this level (above 10,000 Gt). Today's main barriers to CCS deployment include: a) the need to demonstrate that geological storage is definitely safe and permanent; b) the need for international regulatory frameworks; c) possible social acceptance issues; d) the high investment and operation costs, and related increase in the electricity generation cost; e) the lack of specific policies (incentives) for emission reduction via CCS.

PROCESSES – Carbon capture and storage (CCS) technology could enable large (up to 90-95%) reductions of the CO_2 emissions in power generation and significant reductions in both fossil fuel transformations and energy-intensive industrial processes, e.g. cement, iron and steel production. These processes are prime candidates for CCS applications as they are large, concentrated sources of CO_2 and all together account for more than 65% of the global CO_2 emissions from energy use. The capture of CO_2 from dispersed and/or mobile sources such as the residential and transport technologies is more expensive and technically difficult. The CCS process is based on technologies that are widely used in the chemical and oil industry, but have never been integrated and applied in large-scale power and industrial plants. The process consists of three phases: **CO_2 capture** (via different processes in power generation and in industrial facilities); **CO_2 transportation** (usually via pipelines); and **CO_2 storage** in geological formations, i.e. deep (> 800 m) saline formations, depleted oil and gas reservoirs (possibly, with enhanced oil/gas recovery, EOR/EGR), unmineable coal seams, and sites with enhanced coal bed methane (ECBM) recovery. A number of CCS technologies and variants are being considered. All processes involve additional costs and efficiency reductions of the basic plant, and require further R&D.

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■ **CO_2 Capture in Power Generation -** Power generation is the most important source of CO_2. Modern coal-fired power plants with 43-44% LHV[1] efficiency emit 740-760 kg CO_2/MWh (up to 6MtCO_2 per year per 1000 MW), with 13-14% of CO_2 in the flue gas, by volume. Natural gas combined cycles with 55-56% LHV efficiency emit 370-380 kg CO_2/MWh, with 3-4% CO_2 in the flue gas. The average net efficiency of coal power plants is actually well below the level of modern plants and in 2007 CO_2 emissions from coal-fired power plants accounted for about 27% of the global CO_2 emissions in the energy sector. In power generation, the CO_2 emissions from fossil fuel combustion can be captured (Figure 1) either before combustion (pre-combustion capture or fossil fuel decarbonisation) or after combustion (post-combustion capture from flue gas), or by the oxyfuel process (fuel combustion in an oxygen-rich gaseous mix to produce a CO_2-rich flue gas that is ready for transportation and storage). The CO_2 capture from biomass combustion would enable a net removal of CO_2 from the atmosphere as the biomass combustion is CO_2 neutral. ● **Pre-combustion CO_2 capture** can be used in power plants using solid and gaseous fuels (coal, natural gas) and in industrial processes such as hydrogen and chemicals production from hydrocarbons. If the primary feedstock is a solid fuel (e.g. coal) it must first be gasified (partial oxidation) with the addition of oxygen (O_2) and steam to produce a synthetic gas (i.e. syngas, a mix of mainly H_2 and CO, with CO_2, CH_4 and impurities). If the primary fuel is natural gas the syngas can be obtained from natural gas reforming. A shift reaction is then used to convert further CO into CO_2 and produce a high-pressure (up to 70 bar) mix of H_2 and CO_2, with high CO_2 concentration (up to 40%). The CO_2 is finally captured by physical adsorption while H_2 can be used for electricity generation in a combined-cycle gas turbine. Using physical adsorption, the CO_2 is captured by weak bonds created at high pressure and released at low pressure: the higher the CO_2 concentration, the lower the energy needed for pressurization. Physical adsorption is therefore more efficient at high CO_2 concentration (>15%). Pre-combustion capture can be applied to both coal-fired integrated gasification combined cycles (**IGCC**) and natural gas combined cycles (**NGCC**). In the IGCC plants, the gasifier converts coal into syngas for electricity generation. If CCS is added to the process, the syngas is then passed to the shift reactor and to a deep-cleaning system to reduce pollutant emissions and protect the H_2-fired turbine. In principle, the IGCC technology could be one of the cheapest options for CCS in power generation as the CO_2 is made available as a by-product from coal gasification. However, current IGCC plants are more expensive and less reliable than conventional supercritical pulverised coal (SCPC) power plants, and the integration of the CCS

[1] Power plant efficiency can be based either on *low* or *high* heating value (LHV or HHV), the difference being the latent heat of evaporation of water in combustion products. This results in about 2-5 percentage points lower efficiency for bituminous coal- and gas-fired power plants, respectively, when HHV is used. (i.e. a coal power plant with 38% HHV efficiency would have a 40% LHV effciency). The difference between gross and net efficiencies accounts for the own energy consumption of the power plant and its auxiliary systems.

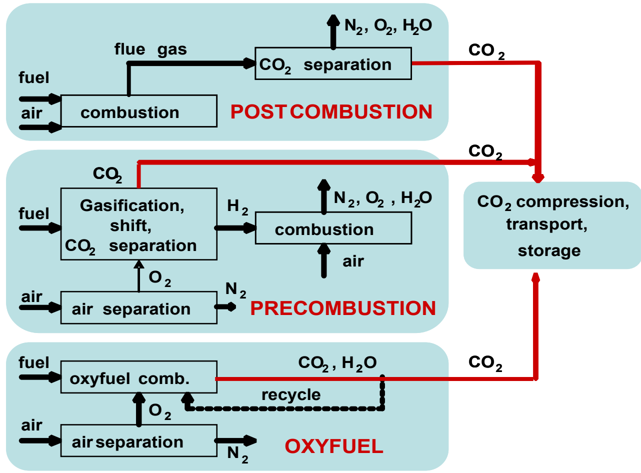

Figure.1 - CCS Technologies for Power Generation

technology needs commercial demonstration. Areas of process improvement include reliability and availability of the gasifier; efficiency of the shift conversion; performance of H_2 turbines (NOx emissions and temperature control to avoid blade damage); and novel methods for CO_2 separation, e.g. new separation membranes, pressure swing and electrical swing adsorption, cryogenics. ● **Post-combustion capture** is the most established CO_2 capture technology. It is the technology of choice for supercritical pulverised coal (**SCPC**) power plants, and has been used for decades in refining and gas processing. Post-combustion capture involves CO_2 scrubbing from the flue gas, which contains 4-8% of CO_2 by volume in gas-fired plants and 12-15% of CO_2 in coal-fired plants. The CO_2 is captured by chemical absorption using solvents (usually, mono-ethanol-amines, MEA) that must then be heated to regenerate and to release almost pure, storage-ready CO_2. Chemical solvents create strong chemical bonds with CO_2 and require significant thermal energy for CO_2 release. Unlike physical adsorption, the energy need for chemical absorption (i.e. 0.3 kWh/kg CO_2) is slightly sensitive to CO_2 concentration (10% energy reduction if the CO_2 concentration increases from 3% to 14% in volume). Therefore, chemical absorption is the option of choice for low CO_2 concentrations (e.g. NGCC flue gas). The overall energy need for post-combustion capture has been declining by one-third over the past decade and is expected to decline by another third over the next few years. As a consequence, the efficiency penalty - currently, 8-12 percentage points, which means, for instance, reducing the efficiency of a new coal power plant from 45% to 35% - is expected to decline to below 8 points by 2020. In spite of the higher CO_2 concentration, the efficiency penalty in coal-fired power plants tends to be higher (than in NGCC plants as the CO_2 emissions per kWh is twice as high. The challenge is to reduce the energy needed for solvent regeneration, and for CO_2 release and compression. Solvent degradation is also of concern and can be reduced by a low concentration of NO_x, SO_2 and O_2 in the flue gas. Alternative solvents with less regeneration energy, less degradation and corrosion risks (higher sulphur tolerance) are under investigation and include sterically hindered amines, potassium carbonates, and ionic acids. Some such alternative solvents could reduce capture costs by 50% in SCPC plants and by 40% in NGCC plants. Novel approaches also include separation membranes (polymeric gel, ceramic, contactors) being developed for both pre- and post-combustion capture applications, and combinations of membranes, solvents and solid adsorption processes. Research on post-combustion capture also focuses on retrofitting of existing SCPC and NGCC plants. ● **Oxyfuel capture** involves fossil fuel combustion in oxygen-rich (almost pure) O_2 atmosphere, with recycled flue gas to control the combustion temperature. This results in a flue gas with very high CO_2 concentrations (70% to 85%), which is almost ready for compression, transportation and storage, with no need for separation. The oxygen needed for the process is obtained from air separation units (ASU) or membrane-based separation. The oxyfuel capture has been demonstrated in the steel manufacturing industry at plant scales of up to 250 MW. A few pilot power plants with oxyfuel combustion (30-40 MW capacity) are in operation (Germany) or in advanced construction. If low-cost O_2 is available the process has the potential to be cheaper than pre-combustion and post-combustion capture. The typical net efficiency of a commercial SCPC plant equipped with oxyfuel capture or post-combustion capture is estimated at about 35% LHV. The oxyfuel combustion could also apply to IGCC and NGCC plants. Research efforts focus on energy saving in O_2 separation, materials for high-temperature combustion and applications to industrial cement kilns. A tight control of nitrogen in the combustion process and sulphur concentration in the off-gas is needed to avoid corrosion. **Chemical looping** is a process variant currently under development where calcium or metal compounds are used to produce O_2 and heat through a reaction loop. This could improve the efficiency in IGCC plants by 2-3 percentage points. The efficiency of both oxyfuel and pre-combustion capture depends significantly on the energy needed for oxygen production. A typical 250-MW IGCC plant needs some 2000 tonnes O_2 per day. At present, large-scale O_2 production (3000 t/day) based on cryogenic separation requires 0.28-0.30 kWh/Nm^3 of low-pressure oxygen (about 0.8 GJ/tO_2). High-pressure processes, pressure swing adsorption, and ceramic oxide ion transport membranes might reduce energy and capital cost for O_2 production by 30%, and increase the efficiency of IGCC plants by 1-2 percentage points. These technologies however, require further research. ● **CCS Retrofit and Capture-Ready Power Plants –** Retrofitting the existing power plants with CCS involves high cost and efficiency penalties. Estimates suggest efficiency losses of up to 14 percentage points and investment costs in the order of €700/kW. As a consequence, retrofit makes sense only for recent coal- and gas-fired power plants with net electric efficiency above 40% and 55%, respectively, which represent just a part of the existing capacity. Retrofit of SCPC power plants using the most suitable retrofitting option (oxyfuel combustion) would imply additional energy input for O_2 production (ASU) and CO_2 pressurization (150 bar), and the use of up to 35% of the electricity produced in the plant without CSS. The associated net CO_2 emission reduction is about 75%. Retrofitting technologies are not yet commercially viable, but it is crucial that new fossil fuel-based power plants under commission are designed to enable CCS retrofit (capture-ready plants) as soon as the technology becomes commercial and marketable. Some governments (e.g. UK) already require CCS on a proportion of the new capacity and envisage retrofitting for the remainder. Capture-ready plants involve space allocation for capture facilities (e.g. shift reactor, large ASU) to be installed later on as well as identification of CO_2 transportation facilities and storage sites. Available studies (e.g. IEA GHG, 2007) suggest capture ready plants may offer a significant reduction of retrofitting cost and time, with relatively inexpensive pre-investment.

■ **CO_2 Capture in Industrial Processes -** On a global scale, industry accounts for nearly one-third of the energy use and for approximately 10 Gt of CO_2 emissions per year including direct (67%) and indirect (33%) emissions. Iron and steel, and cement and (petro)chemicals are the most energy-intensive industrial sectors accounting for 30%, 26% and 16%, respectively. The manufacturing process such as ethylene, ammonia and direct reduced iron (DRI) production may offer early and cheap opportunities for industrial CCS demonstration projects as they are large and highly-concentrated sources of CO_2. However, they account for only 3-4% of the total. Blast furnaces and cement kilns are also important sources of CO_2, but they are usually smaller and thus imply higher capture costs ($\$/tCO_2$). ● **Iron and Steel -** With a global production of 800 Mt of iron per year, blast furnaces emit between 1 and 1.5 tCO_2 per tonne of iron. In this sector, potential, cost-affordable emission reduction cannot exceed 75% of the total as the CO_2 from auxiliary systems (coke ovens, sinter plants, etc.) can only be captured at prohibitive costs. CO_2 capture in blast furnaces is based on three approaches: oxyfuel combustion; chemical absorption; and substitution of coke and coal with hydrogen or electricity. The technology of choice is based on new-design blast furnaces with oxyfuel and CO_2 removal by physical adsorbents. The abatement potential is between 85% and 95%, but pilot and demonstration projects (mostly in advanced countries) aim for a 50% emission reduction in modern blast furnaces. If blast furnaces are re-designed to use oxygen-injection and recycled top gases, the CO_2 concentration would be high enough to enable capture by physical absorbents, but the process has not yet been proven. Also under evaluation is the use of biomass and new smelting reduction processes. If low cost oxygen is available, smelt reduction can offer CCS applications with almost no efficiency penalty compared to the same plant without CCS (demonstration by Siemens and Korean POSCO). Other processes being demonstrated include HiSmelt and gas-based direct reduced iron (DRI), which could enable low-cost CCS. However, DRI facilities are currently small and located in a few countries. Blast-furnace gas-reforming and chemical absorption using waste heat is an alternative CCS process under investigation. ● **Cement Industry -** In the cement production process (2.3 Gt per year, 46% in China), about 67% of the emissions originate from limestone decomposition into cement clinker (about 0.8 tCO_2 per tonne of clinker in modern coal-fired cement kilns) and 33% from fuel combustion. The CO_2 from limestone off-gas (25-35% CO_2) can be captured using three approaches: back-end chemical absorption; oxyfueling;

and chemical looping using calcium oxide. About 95% of these emissions could be captured by chemical absorption using 1.5 GJ heat and 0.2 GJ electricity (CO_2 compression) per tonne of clinker. This would result in a 50% increase of the energy need for clinker production. Using oxygen (oxyfuel) instead of air in new cement kilns with pure CO_2 off-gas might reduce the cost as the kilns productivity would be much higher than that of conventional methods. The process however requires more R&D. In a chemical looping variant, the CO_2 is captured using pure CaO to generate $CaCO_3$, from which the CO_2 is released by heating. This option is at an early stage as the CaO/$CaCO_3$ loop can withstand only a limited number of cycles. ● **Chemical and Petrochemical Industry -** In the chemical and petrochemical industry, processes such as ethylene, propylene, and aromatics production by steam cracking, methanol and olefins processing, chlorine, sodium-hydroxide, and ammonia production account for some 67% of the CO_2 emissions. Important sources of CO_2 are also steam boilers and combined heat and power (CHP) plants. In high-temperature steam cracking, the CO_2 capture is based on chemical absorption as the off-gas is a mix of CH_4 and H_2, with a low CO_2 concentration. Ammonia production (a large source of CO_2, i.e. 1.5-3.0 tCO_2/t of ammonia) and ethylene oxide production provide high-purity CO_2. In most ammonia production plants, a part of the CO_2 is used for producing urea-based fertilizers (0.9 tCO_2/t of urea) while the rest (some 180 $MtCO_2$/y on a global scale) offer a relatively low-cost CCS opportunity where the CO_2 is separated from H_2 using solvent absorption. ● **Pulp and Paper Industry -** The average amount of CO_2 emissions in paper production is about 0.5tCO_2 per tonne of final product, with a wide range or variability depending on the input fuels (biomass and hydropower are largely used in some countries). Cellulose production provides lignin as a by-product, which in combination with water and chemicals, provides so-called 'black liquor' that is used as a fuel in dedicated power plants. It is estimated that some 330 $MtCO_2$/yr could be captured globally using chemical absorption in black liquor boilers at a cost of \$30-50/tCO_2 (Hektor and Berntsson, 2007). Black liquor-based IGCC power plants with CCS offer an opportunity for net CO_2removal and to enable CCS projects with a moderate loss of efficiency and an incremental investment cost of about \$320/kW.

■ CO_2 Capture in Fuels Upstream and Transformation

On a global scale, fossil fuels (oil, gas, and coal) extraction accounts for almost 400 $MtCO_2$/yr and oil refinery and LNG production for 700 $MtCO_2$/yr. Emissions from conventional fossil fuel upstream (0.11 tCO_2/t oil, 0.2 tCO_2/t LNG) and refining (0.18 tCO_2/t product) are currently significantly lower than those from fossil fuel end-use, but this trend may change in the future because unconventional oil resources imply more energy and emissions for extraction (0.42 tCO_2/t) and upgrading (0.75 tCO_2/t). Similarly, fossil fuel transformations (e.g. synfuels production; Fischer-Tropsch coal to liquid, CTL; gas to liquid, GTL; hydrogen, methanol and dimethylether production) require much more energy than conventional refineries (e.g. 1.1 tCO_2/t for the GTL process). All these processes are being considered for CCS applications.

● **Sour Gas -** Natural gas quality varies from sweet gas (virtually CO_2-free gas) to sour gas (70-90% CO_2). For example, the large Natuna gas field in Indonesia (46 tcf) has a 70% CO_2 content. As commercial specifications for natural gas require a maximum CO_2 content of around 2% by volume, the CO_2 in excess has to be removed. Separation by chemical solvents (alkanoamines, MEA, DEA) has been used for decades for low CO_2 concentration while membranes can be used for high concentration. Today's major CCS demonstration projects (i.e. Sleipner and Snohvit, Norway, and In-Salah, Algeria) involve the separation of CO_2 during natural gas production, compression and re-injection into near geological formations. ● **Heavy Oil and Tar Sands -** Steam-assisted gravity drainage (SAGD) is the emerging technology for extra-heavy oil extraction and oil production from bituminous sand (unconventional oil resources). SAGD is an energy- and emission-intensive process (from 0.25 to 0.4 tCO_2/t of heavy oil). Before refining, the heavy oil must often be upgraded by adding hydrogen (usually produced from natural gas reforming). Producing heavy oil and sand oil thus requires 20-25% of the hydrocarbon energy content (to be compared with some 6% in conventional oil production). This results in 0.6 to 0.8 tCO_2 per tonne of oil. A cost-effective reduction of some CO_2 emissions is achievable by capturing almost pure CO_2 from upgrading plants and using it for enhanced oil recovery (EOR). ● **Refineries -** In the oil industry, between 5 and 10% of crude oil is used for the refining process and the CO_2 concentration in the refinery gas streams ranges from 3% to 13%. More than 600 refineries produce some 800 $MtCO_2$/yr globally. Some 45 refineries emit more than 3Mt CO_2/yr. Modern plants converting heavier crudes into light products produce even more emissions. Key processes are distillation, reforming, hydrogenation and cracking. While distillation requires low temperature heat, hydrogenation requires large amounts of hydrogen, and cracking produces heat and CO_2 from heavy oil residues. Reformers, catalytic crackers and vacuum distillation units account for 30-40% of the energy use, which could be supplied by CHP units with CCS. A study on the UK refinery plants suggests that the CO_2 capture would require 6.2 GJ of natural gas per tCO_2 captured. This is much more than the energy needed for CO_2 capture in power plants. The total cost would exceed \$200/tCO_2. ● **Hydrogen Production -** The increasing amount of hydrogen that is needed in the refinery industry to produce light products is obtained from hydro-cracking processes, carbon removal by coking, and gas reforming. The current global production of hydrogen is in the order of 60 Mt per year, that is 48% from natural gas reforming, 30% from refinery/chemical off-gases, 18% from coal, and the rest from electrolysis. Large, centralised hydrogen production is economically eligible for CCS, with capture processes that are similar to those used in coal gasification and natural gas reforming. ● **Gasification and Synfuels Production -** Liquid synfuels (methanol, DME, naphtha, gasoline and diesel) from coal gasification (coal to liquids, process CTL) and natural gas conversion (gas to liquids process, GTL) are gaining more importance in light of the increasing demand for transport fuels. CTL is an established technology developed in Germany (World War II) and more recently in South Africa

(Sasol). GTL is a more recent process. The efficiency of Fischer-Tropsch processes ranges from 40% for CTL to 70% for GTL, with CO_2 emissions ranging from 100-150 kg/GJ to 7-8kg/GJ, respectively. While CTL is likely to remain a niche activity up to the period 2030 (IEA CCC, 2008) GTL seems to be more attractive. The ongoing GTL production is about 1 million bbl/day (primarily diesel), with many plants in operation or being planned in regions with stranded gas resources (e.g. Qatar, Malaysia, Nigeria). The implementation of CCS in CTL and GTL is rather costly and energy consuming.

■ **CO_2 Transportation -** Carbon dioxide can be transported by pipelines, ships, and road tankers. Transportation via pipelines is cost-effective for large quantities (> 1-5 Mt/y) and distances (> 100-500 km). Globally, some 6200-km pipelines (0.6-0.8m diameter) currently handle about 50 Mt of dehydrated CO_2 per year. The largest pipeline ships several Mt of CO_2 over 800 km in the US. Because the CO_2 is transported in a supercritical state, with a density ten times higher than that of natural gas, CO_2 piping requires less energy than natural gas: the usual distance between CO_2 pumping stations is about 200 km in comparison with 120-160 km for natural gas. The energy needed for CO_2 transportation and compression depends on distance and pressure. A typical value is between 0.2 GJ and 0.5 GJ of electricity/tCO_2 (per 100-200 km). Operation records for CO_2 pipelines show low rates of CO_2 leakage and no major safety concern. The risk is associated to the CO_2 density that is higher than that of air. As a consequence, possible leakages can result in CO_2 accumulation and concentration at ground level. H_2S and SO_2 impurities can increase the risks associated to leakages. Design code, classification and regulations for CO_2 pipelines vary across countries. The designation of CO_2 as a commodity or as a pollutant may have an impact on regulations. International agreements on the legal aspects of CO_2 classification and transportation are needed. For a significant CCS deployment, the IEA projects that Europe, China, and the US may need a CO_2 transportation capacity in the order of some GtCO_2 per year by 2030. Pipeline deployment could be in the order of 10,000-12,000 km in the next 10 years (to transport 300 MtCO_2 from 100 CCS projects), 70,000-120,000 km by 2030, and 200,000-360,000 km by 2050, with investment in the order of $0.5-1 trillion. Tax benefits, incentives for CCS projects, and maps of potential storage sites may accelerate pipeline investments. The CO_2 can also be transported by ship either in semi-refrigerated tanks (-50°C, 7 bars) or in compressed natural gas (CNG) carriers. However, CO_2 transportation by ship is a viable option only for small CCS projects.

■ **CO_2 Geological Storage -** CO_2 can be stored in geological structures such as deep saline formations, depleted oil and gas reservoirs (with or without enhanced oil recovery), and deep, unmineable coal seams. The monitoring of data from ongoing storage demonstration projects shows no CO_2 leakage and CO_2 behaving as would be expected. However, more experience is needed to understand the underground behaviour of the injected CO_2 and to characterise the geological formations for large-scale, safe and long-term storage. Major CO_2 storage mechanisms include: a) Physical trapping, an immediate immobilization of CO_2 in a gaseous or supercritical phase in the geological formations (static trapping in porous structures); b) Chemical trapping, dissolution or ionic trapping in fluids, e.g. water/hydrocarbons. Once dissolved, the CO_2 can react with minerals (mineralization or adsorption on mineral surface). Dissolution and mineralization may occur over a geological time period; c) Hydrodynamic trapping**,** a slow upward migration of CO_2 to impermeable intermediate layers over millions of years. In any case, the CO_2 storage is intended to last for thousands of years with no significant leakage. Estimates of worldwide storage capacity vary considerably (two orders of magnitude in some cases) and need to be consolidated by further research and studies. The global potential ranges between 2000 and 20,000 GtCO_2. If compared to the current and projected global annual CO_2 emissions (25 and 50 GtCO_2/y, respectively), the lower bound of the global storage capacity would be enough to store global emissions for several decades, but the global storage potential could be well above this level. As significant uncertainties exist, most notably for the capacity of deep saline formations (the largest storage resource), the CSLF has classified the certainty of storage potential in terms of theoretical, effective, practical and matched capacity. Uncertainties also exist regarding environmental impact, costs and regulatory frameworks. ● **Storage in Oil & Gas Fields with Enhanced Recovery -** The CO_2 is the second most used fluid for EOR, following steam. The fluid choice depends on the hydrocarbon density. CO_2 is used with oil density < 910 kg/m^3 (>24° API), in deep fields (>600 m) with some 20-30% of the original oil still in place, once primary production (driven by reservoir pressure) and secondary production (by water flooding and pumping) have been applied. EOR can offer from 5% to 20% of the original oil in place. Estimates suggest CO_2-based EOR can increase the ultimate oil production by an average of 10%. Using CO_2 for EOR can produce an additional 0.1-0.5 ton of oil per ton of injected CO_2 (an average 2.5-3.0 tCO_2/t oil produced). Other estimates suggest 2 bbl oil/tCO_2, with a 60% CO_2 retention. Estimates of storage potential range from a few GtCO_2 to several hundreds GtCO_2 (Europe, North America, China, Qatar, Russia, Venezuela). In some 400 sites worldwide (with a total storage capacity of 0.5Gt/yr), CO_2 sources and depleted oil fields are within a distance of 100 km. Preliminary estimates suggest that some 30 Mt CO_2 per year could be used for EOR over a period of 15-25 years and that CO_2-based EOR could have a potential of 5-6 million bbl per day by 2030. Increasing oil prices and the availability of CO_2 transportation infrastructure are key incentives for CO_2-based EOR. The cost of EOR-based CO_2 storage is currently estimated at $20-30/t$CO_2$ and it is largely offset by the oil production revenue. Depleted gas fields can be re-pressurised by CO_2 injection to increase gas recovery and to reduce subsidence. The CO_2 is denser than natural gas and flows downwards displacing the natural gas. The CO_2-EGR is less profitable than CO_2-EOR. An initial screening of gas fields suggests a worldwide storage potential of 800 Gt CO_2 in depleted gas fields at $120/t$CO_2$ (about 6 times the EOR cost). At $50/t$CO_2$, the total CO_2 storage potential in depleted gas fields declines to 100 Gt. More analysis and demonstration projects are required to confirm these estimates. The K12B injection offshore in the Netherlands is the only ongoing CO_2-EGR project of a significant size where the CO_2 (30,000 m^3CO_2/d) contained in a natural gas field is separated and re-injected at 3500-4000 m - the deepest CO_2 injection to date. Apart from enhanced recovery, depleted oil and gas fields offer low-cost opportunities for CO_2 storage as facilities and wells are often in place, and the geological characterization of the site is already available. Worldwide estimates of the storage capacity range between 675 Gt and 1200 Gt. Prior to storing the gas, an accurate assessment of well integrity and chemical reaction of CO_2 with in-situ minerals and fluids is needed. ● **Storage in Unmineable Coal Seams -** Unmineable coal seams are too deep or too poor for commercial exploitation. CO_2 storage can help release methane that is absorbed into coal pores (i.e. Enhanced Coal Bed Methane recovery, ECBM). Coal can absorb two moles of CO_2 per mole of CH_4 released. ECBM resources are mostly located in North America, China, Russia, India, South Africa, and Central Europe. The global storage potential is estimated at between 100 and 200 Gt. A few small demonstration projects are currently in operation or planned. ● **Storage in Deep Saline Formations (Aquifers) -** Deep saline formations offer the largest storage potential, which is estimated at between 1000 and 10,000 Gt. Saline aquifers consist of water-saturated sedimentary rocks (e.g. sandstone or carbonate). In *open* aquifers, water circulates on a geological time-scale and rocks are permeable enough for fluids to be injected. In *closed* aquifers water is confined by *non permeable* layers for millions of years, usually with dissolved solids and are unsuitable for human use. Deep, stable, confined aquifers are being considered for CO_2 storage. CO_2 trapping mechanisms include a free phase at the top of the aquifer; CO_2 trapped in the pore space; water dissolved CO_2; and precipitated mineral carbonates. Available studies indicate that up to 30% of the injected CO_2 can dissolve during the injection period while the remainder flows in a plume below the cap rock and may dissolve later on or react in the rock aquifers. Dissolution is likely to be completed on a geological time-scale (a thousand years). In the absence of a structural trap, the CO_2 can spread over a large area (hundreds of km^2) below the aquifer cap rock over a period of a thousand years, depending on porosity and permeability. Other studies suggest that the plume may dissolve in the brine and that brine concentration could be one of the criteria for the aquifer selection. Anthropogenic damage of the cap rock (e.g. wells) may cause leakages, but it is unclear whether or not this leakage mechanism poses a serious problem. More research is needed to assess cap rock integrity and sealing; the CO_2 geochemical transport; the need for permanent monitoring; dynamic simulation models and seismic surveys. ● **Other storage options -** Among other storage options: salt caverns have limited capacity and shallow depth; abandoned mines are usually unsuitable because of leakages; oil and gas shales have shallow depth and low permeability; basalt formations have low permeability and porosity; ocean storage is considered environmentally unsafe (in 2007, the OSPAR marine protection treaty prohibited the storage of CO_2 in the sea water and on the sea bed); mineral carbonation (based on CO_2 reaction with Mg and Ca silicates to form carbonates) involves a huge amount of materials (1.6-3.7t of silicate per tCO_2 to form 2.6-4.7t of carbonate; this means e.g. 30,000 tMg/day for a 500 MW coal-fired power plant, with a cost of \$50-100/tCO_2); limestone ponds (based on CO_2 reaction with the limestone-water solution to form carbonates to be dissolved in the seawater) is a process yet to be demonstrated, which may require huge pond size, but moderate cost; algal bio-sequestration may offer efficient CO_2 conversion but needs further development; industrial use of CO_2 (in food industry, horticulture, welding, etc.) offer only temporary storage for limited quantities. A number of other options are being proposed and analyzed.

TECHNOLOGY STATUS –Technologies for CCS are rather well known, but a strong acceleration in system integration and large-scale commercial demonstration is needed for CCS to play a significant role in the coming decades. In particular, safe and permanent CO_2 underground storage needs to be proven. Major ongoing storage demonstration projects involve CO_2 sources other than power plants (mainly CO_2 from natural gas processing). The current total storage capacity exceeds 5 $MtCO_2$ per year. The underground behaviour of the injected CO_2 is confirming expectations. No leakage has been detected and natural chemical-physical phenomena such as CO_2 dissolution in saline water seem to minimise the risk of long-term leakage. In addition, enhanced oil recovery (EOR) projects at several oil fields (mostly in North America) offer storage demonstration opportunities and revenues that may offset the CCS cost. CCS in unmineable coal seams is being considered in small-scale pilot projects. As for CCS in power generation, only pilot projects are currently in operation or in a phase of advanced construction. They include[2] relatively small-size power plants (5-40 MW) with oxyfuel process, post- and pre-combustion capture (IGCC). Following a strong momentum, many governments and utilities are currently committed to large-scale CCS demonstration, with a number of large-size projects (power plants and other facilities) under consideration and construction worldwide, and an estimated total budget in the order of \$27bn. Major efforts are underway in Australia, Canada, the EU, Norway, Poland, South Korea, the UK, and the US. Australia is investing US\$2bn in CCS Gorgon demonstration project and in the Global CCS Institute (GCCSI). Canada is investing some \$3.5bn in CCS R&D and deployment in the Alberta State. The EU has already included the CCS among technologies eligible for the EU Emission Trading System and is currently planning to build 10-12 demonstration plants by 2020; the EU financial effort includes 300 million emissions permits (some €4.5bn) from the EU-ETS for CCS demonstration and innovative renewable energy technologies, plus €1bn from the EC energy recovery package. Norway is an early player in CCS technology with the first industrial

[2] e.g.: Schwarze Pumpe (Germany) 30-MW coal power plant with oxyfuel and post-combustion CO2 capture; Buggenum (NL) coal power plant with pre-combustion capture: Renfrew (UK) 40MW power plant with oxyfuel capture; Ferrybridge (UK) 5 MW power plant with post-combustion capture.

demonstration project which has been in operation since 1996 (Sleipner project). Poland is developing the Belchatow and Kedzierzyn large-scale projects that will start operation in 2015. The United Kingdom is investing between $11bn and $14.5bn to directly finance four CCS projects that were selected in a competition plus other projects through incentives or levy on utilities. The US Economic Recovery Act includes $ 3.4bn for clean coal and CCS, $1bn for new CCS approaches and $1.5bn for industrial CCS. In China, ongoing efforts include the GreenGen project (IGCC plant with CCS), the Near-Zero Emission Coal (NZEC) partnership with the EU and the UK, the Huaneng Group project on post-combustion capture, and ongoing CO_2 storage pilot projects. In Brazil, the Petrobras company is operating two pilot projects for CO_2 storage into saline formations. This global effort is expected to result in the construction of 20-40 large-scale integrated CCS projects by 2020. Moreover, mapping of suitable storage sites is underway in various countries. The IEA GHG R&D Programme maintains a comprehensive database[3] of CCS projects. In April 2010 a study commissioned by the GCCSI identified some 80 large-scale integrated projects at various stages of development[4] primarily in developed countries, but also in China (three IGCC plants), in the Middle East (two projects), and in Algeria (one project in operation). Some 65% of the 80 projects involve power generation plants while the rest consist mostly of projects involving natural gas upstream and a few projects in industrial sectors (e.g. cement, aluminium, iron and steel). More than 40% of the projects plan to use the CO_2 for enhanced oil recovery (EOR). The leadership in CCS deployment is expected to move (after 2020) from the industrialised countries to the emerging economies. However, for most projects, funding remains a challenge and additional investment effort is needed from private/public partnerships. Dedicated economic incentives are needed for CCS market uptake as the technology implies CO_2 abatement costs well beyond the current CO_2 price in the existing emission trading systems, and substantive additional costs of electricity generation. The five most important CCS projects in operation include: ● **Sleipner project** (Norway, North Sea, offshore), managed by StatoilHydro - Since 1996, the CO_2 contained in a natural gas field (9% in volume), is separated by amine scrubbing and injected (1MtCO_2/yr) through horizontal wells in a deep saline sandstone formation located 800-1000 m below the sea floor in the nearby Utsira formation, which offers a large storage capacity**.** Accurate geological characterization (cap rock and reservoir properties such as porosity and permeability) and monitoring (seismic, micro-seismic and gravity surveys, multi-component analysis and modeling) have been used to map and understand the CO_2 behaviour over time. The outcome shows that CO_2 mineral dissolution is limited because of the low carbonate content. The Sleipner project was the first commercial CCS demonstration project. It was started to avoid a carbon tax equivalent to $55/t$CO_2$. The operation costs, including CO_2 compression and monitoring, have been estimated at about $16/t$CO_2$ injected. ● **Weyburn-Midale project** (US/Canada, onshore) managed by EnCana oil company - Since 2001, the CO_2 (1.7 to 2.8 MtCO_2/y) from a coal gasification plant for syngas and chemicals production located in North Dakota is transported by a 320-km pipeline to Saskatchewan (Canada) and used for EOR. The project was the first CCS project with systematic scientific studies and monitoring of the CO_2 behaviour underground. The incremental oil production is estimated to be in the order of 155 million barrels. Further EOR operations in the Midale oil field started in 2005. The project currently injects 6500 tCO_2 per day, of which 3000 is recycled. The Saskachewan authorities provided an initial financial incentive of some $20/bbl. Some 30-40 million tCO_2 will be stored over the project lifetime. An international research consortium under the auspices of the IEA GHG R&D Programme monitors the CO_2 behaviour and assesses storage techniques and risks. Evidence exists that CO_2 storage in the oil reservoirs is viable and safe. The programme is coordinated by the Petroleum Technology Research Centre (Regina, Saskatchewan) and Natural Resources Canada. ● **In-Salah project** (Algeria, Sahara Desert, onshore), managed by Sonatrach, BP and StatoilHydro - Since August 2004, the CO_2 (10% in volume) from a natural gas field is separated by an amine-based process and injected (1Mt/yr) into a 2000-m deep saline aquifer in the Krechba geologic formation, close to the natural gas field. The total CCS cost including investment, operation and monitoring is about $6/t$CO_2$ injected, that is significantly lower than similar offshore operations. ● **Snøhvit project** (Norway, Barents Sea, off shore) managed by StatoilHydro – Since April 2008, the natural gas and CO_2 from the Snøhvit offshore field are piped to the 150-km far Hammerfest LNG plant where the CO_2 (0.7MtCO_2/yr) is separated and piped back to the offshore site to be injected in the 2600-m deep Tubasen saline formation below the gas field. ● **Rangely project** (US, Colorado, onshore) – Since 1986, the CO_2 from LaBarge (Wyoming) natural gas field is used for EOR operations and stored in the largest oilfield in the US. Approximately, 23-25 MtCO_2 have been stored so far. While a comprehensive monitoring of the CO_2 behaviour has been established only in the past few years, modeling analysis suggest that the injected CO_2 is mostly dissolved in the formation water.

CCS COSTS – A number of studies are available on current and projected costs of CCS, but estimates are affected by uncertainties and depend on a number of factors including the costs of energy. Available studies focus mostly on power generation. Therefore, even a larger uncertainty affects other industrial applications. The uncertainty also depends on the cost of the basic technologies. The investment costs for new power plants such as coal, nuclear and wind have more than doubled between 2000 and the first half of 2008 (IHS/CERA, 2008), with a 70% occurring in the period 2005-2008. Only a part of this increase can be attributed to the cost of the basic materials (a minor component of overall cost). More important cost drivers were the increasing demand for power plants and components (boilers, turbines,

[3] http://www.co2captureandstorage.info/co2db.php

[4] Nine projects in operation including 5 large-scale integrated projects and 4 EOR projects that are not fully integrated, 2 projects in execution, 21 under definition, and 48 under evaluation or identification.

piping) and supply bottlenecks. Since the end of 2008, the economic crisis has eased the market, and technology prices first rapidly declined and then slowly rebounded. It is not clear today how costs will develop in the future. This also applies to the cost of pipelines, wells, and the additional energy needed for CCS facilities and operation. Another source of uncertainty relates to advances in power plant technologies. While sub-critical steam cycles have been the dominant coal technology in the past and supercritical (SC) cycles are the current technology of choice, ultra-supercritical (USC) cycles, integrated gasification combined cycles (IGCC), and oxyfiring units are quickly improving their performance, reliability and costs[5]. CCS cost estimates and ranges from recent analysis (IEA, 2008a; IEA 2008b, IEA 2009a, IEA 2010a) are shown in Figure 2 where they are expressed in terms of $/t$CO_2$ avoided[6]). In general, apart from low-cost opportunities in a few industrial processes (e.g. ammonia production) and in natural gas processing, CCS in power generation is rather an expensive technology (i.e. $35-55/t$CO_2$ for coal-fired power and $53-73/t$CO_2$ for gas-fired power), and applications in industrial processes are even more expensive. Indicatively, the upper and lower bound of each cost range suggest respectively current and projected CCS costs.

■ **CCS cost in Power Generation -** The cost of CCS applications in power generation can be split into **capture** cost (including the additional capacity and fuel to compensate for the loss of efficiency, and equipment for CO_2 capture and compression), **transportation** and **storage** costs. The capture cost is the dominant CCS cost (about 70%) while transport (assuming a distance of 200 km) and storage (i.e. injection, storage and monitoring in deep saline formations) account for approximately 15% each. It is expected that the capture cost will decline over time due to technology learning while transportation and storage might increase because of transportation distance, cost of pipelines, regulatory- and safety-related costs (legal rights, liability, insurance, monitoring). Assuming a reasonable rate of technology learning, the overall CCS cost is expected to fall from the current range of $50-90/t$CO_2$ to the level of some

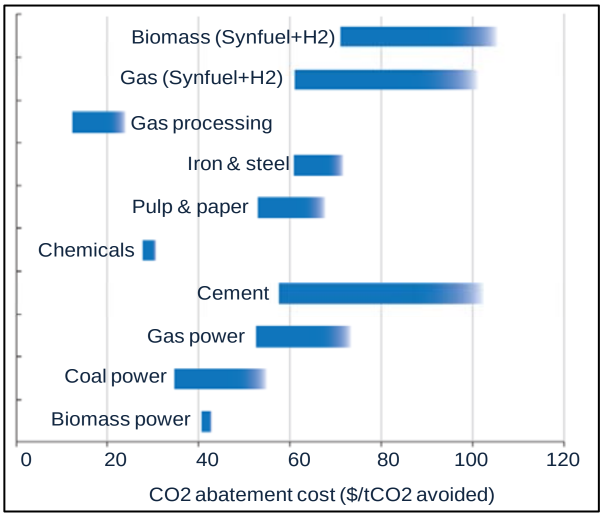

Figure 2 - CCS costs, $/t$CO_2$ avoided (IEA, 2009a)

$35/t$CO_2$ by 2030. Cost reduction could be more difficult for NGCC plants where the concentration of CO_2 is lower: In principle, the higher the CO_2 concentration in the flue gas, the lower the specific cost of the capture. However, the cost of the capture per unit of electricity will not be so different for coal- and gas-fired power as coal emits more than twice the amount of CO_2 per unit of electricity. The CCS costs translate into an additional cost of electricity generation. The comparison of power plants with and without CCS suggests current additional costs for CCS of between $30/MWh and $40/MWh for coal-fired plants (assuming $40-55/t$CO_2$ captured, $60-75/t$CO_2$ avoided), and $30/kWh for gas plants ($50-90/tCO_2 captured, $60-110/t$CO_2$ avoided). These costs are projected to drop to $30/MWh ($50-65/tCO_2 avoided) for coal and $ 20/MWh ($55-90/t$CO_2$ avoided) for gas by 2030. In this analysis, about 50% of the cost increase for coal plants is due to CO_2 transportation and storage and depends on local circumstances. Other assumptions include 12% annuity, O&M cost equal to 4% of the investment cost per year, declining transportation and storage cost from $20/t$CO_2$ in 2010 to $15/t$CO_2$ in 2030, coal prices between $1.5-2.5/GJ, and gas prices of $4-8/GJ). These estimates do not account for possible EOR, which could offset the CCS costs and provide a net profit. However, the global EOR-based storage potential is limited. The investment cost for different types of coal power plants with and without CCS is shown in Figure 3. The additional investment cost for CCS ranges from $600/kW to $ 1700/kW, an increase of between 50 and 100% compared to the plant with no CCS. Because of the high cost and loss of efficiency (8-12 percentage points in coal power plants), the CCS in power plants makes sense economically only for large, highly-efficient plants. The incremental investment cost for CCS demonstration in existing coal power plants is currently estimated between $0.5 and $1 billion, 50% of which is for the CCS equipment. The IEA, in its most ambitious CO_2 mitigation scenarios, (IEA, 2008b and 2010b) estimates that some 3400 plants with CCS will be needed by 2050 to meet the emission reduction targets. The associated incremental CCS cost is likely to be in the order of 40% of the cost without CCS and would be

[5] Typical parameters are:163 bar, 538°C for subcritical cycles; 245 bar and 550°C for SC cycles; 245 bar, 600°C for USC cycles with the potential to reach 375 bar and 700°C (e.g. AD700 and COMTES700 projects). Steam temperatures of 700°C and pressures of over 350 bar require new materials such as nickel-based super alloys, coating and cladding, with resistance to corrosion, fatigue and creep, but efficiency of new USC units is likely to reach 46% (HHV) and increase even more by 2020. While the cost of these new technologies is still high, their market uptake could result in a significant cost reduction via technology and industrial learning. For example, in the IGCC technology (a few plants in operation with a total 1.5 GW capacity) efficiency and reliability depend significantly on the gasification process and the deployment of more units could enable a rapid performance improvement and cost reduction.

[6] CO_2 capture and compression imply additional energy use and emissions, and reduced efficiency. This must be taken into account by referring to the cost of CO_2 avoidance instead of the cost of CO_2 capture, using the formula:

Cost CO_2av = (Cost CO_2capt x CE)/(Effccs/Effnoccs –1+CE)

If Effccs and Effnoccs are the power plant efficiencies with/out CCS (e.g. 31% and 43%) and CE is the fraction captured (e.g. 0.90), then the cost of CO_2avoided = 1.45 cost of CO_2captured.

between \$2.5 and \$3 trillion, of which \$1.3 tr for capture, \$0.5-1 tr for transport, and \$0.5 tr for storage.

■ **CCS Cost in Fossil Fuels Upstream, Industry, and Fuel Transformation -** CO_2 separation in natural gas production and reinjection in saline formations located nearby is perhaps the least cost CCS application; depending on CO_2 concentration, location of wells and storage site, its costs may be as low as \$5/tCO_2 for onshore installations and reach some \$15/tCO_2 for offshore sites. In the iron and steel industry, new-design furnaces have a significant impact on CCS cost; the capture cost in new-design, oxy-fuel blast furnaces with CO_2 removal by physical adsorbents and 85-95% CO_2 abatement, is estimated at \$25-35/tCO_2. Other estimates suggest CCS costs in blast furnaces around \$40-50/tCO_2 including transport and storage, without accounting for positive or negative changes in furnace productivity. CCS retrofitting would be, in any case, significantly more expensive than CCS in new plants. Affordable emission reduction in iron and steel making cannot exceed 75% of the total as the CO_2 from auxiliary systems such as coke ovens and sinter plants can only be captured at prohibitive cost. Apart from the oxygen cost, smelt reduction offers potential for CCS applications with low efficiency penalty compared to the same plant without CCS. Other processes under demonstration such as HiSmelt and gas-based direct reduced iron (DRI) could enable low CCS costs of \$25/tCO_2. In cement production, about 67% of the emissions originate from limestone decomposition into cement clinker and 33% from fuel combustion. Assuming a 95% CO_2 capture by chemical absorption from limestone off-gas, and taking into account the additional energy consumption (50%) for clinker production, the CCS cost is estimated at between \$75 and \$100/tCO_2 avoided (\$50 to \$75/t clinker). This includes about 40% capital cost, 30% heat cost, 30% transportation and storage, and would raise the production costs between 40% and 90%. CCS costs in other industrial plants and in synthetic fuel production processes are estimated to be higher and easily exceed the level of \$150-200/tCO_2 avoided.

■ **Cost of CO_2 Transportation -** The pipeline transportation cost (\$/km) depends on location (e.g. onshore, offshore), operating pressure. For example, pipeline costs in highly populated areas can be up to 15 times higher than costs in remote regions. Several cost analyses exist, mostly based on natural gas pipelines. Recently, steel piping and material prices have varied enormously as a consequence of the global economic crisis. For example, US prices for double-submerged arc-welded pipes more than doubled from 2003 to mid-2008 and dropped afterwards because of the declining demand resulting from the economic crisis. As a result, costs quoted in early studies need to be adjusted. Indicative figures are \$0.8-1.0 million/km for 0.7m-diameter onshore pipelines and \$1.0-1.2 million/km for offshore (O&GJ, 2007). In terms of cost per unit of weight, CO_2 transportation is cheaper than natural gas and hydrogen transportation because CO_2 is transmitted in supercritical state with a density 10-100 times higher than that of natural gas.

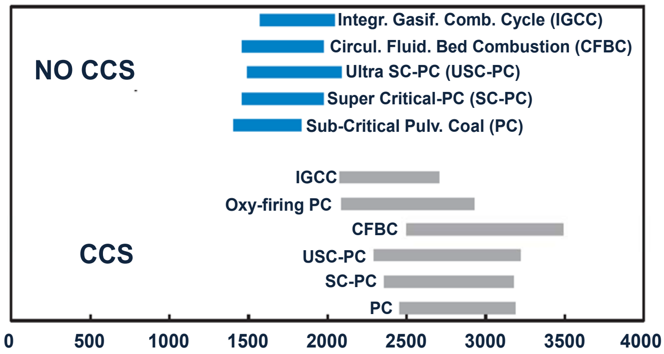

Figure 3 – 2010 Coal-fired Power Plants Investment Costs w/out CCS, US\$ 2006 - (IEA, 2008a)

Estimates range from \$2-6/tCO_2 (for 2 Mt/y) to \$1-3/tCO_2 (for 5-10Mt/y) over 100 km. For comparison, an 800-MW coal power station produces some 5 MtCO_2/y. The cost of ship transport, including storage facilities and harbour fees, is estimated between \$15-20/tCO_2 for 1000 km.

■ **Cost of CO_2 Storage -** Cost analyses of CO_2 storage is largely based on oil and gas experience and includes facilities for wells drilling, CO_2 compression and injection, operation and maintenance, and monitoring (seismic analysis and long-term monitoring). Offshore wells are significantly more expensive than onshore wells, depending on water depth. Costs of shallow-water wells can be more than four times higher and deep-water wells are even more costly. The cost of oil well drilling doubled between 2000 and 2007, following the general trend in technology equipment and services. Early IPCC estimates for CO_2 storage in deep saline aquifers in the OECD countries suggested costs from \$1 to \$5/tCO_2 onshore and from \$5 to \$12/t CO_2 offshore, (North Sea). Other estimates (IEA GHG, 2005) suggested \$10 and \$20/tCO_2 for onshore and offshore saline aquifers, respectively, and between \$10 and \$25/t CO_2 for storage in depleted oil and gas fields. Overall, between 3500 and 4000 GtCO_2 could be stored in saline formations, depleted oil and gas fields and coal bed methane at an average cost between \$15 and \$25/tCO_2 (with storage capacity in the order of 5 MtCO_2/y). The upper bound of this range includes penalties for extreme locations (North Sea, Arctic) and first-of-a-kind installations. More recent estimates for onshore storage based on the In-Salah project provide an average cost of \$6/tCO_2. In the case of onshore storage, the extension of the storage area over time should be taken into account.

CO_2-based enhanced oil recovery (EOR) offers an opportunity to make CCS a profitable activity. Associated costs and revenues must be assessed accurately based on size and location of the oil fields, resources in place, and existing facilities. Based on estimates of investment and operation costs, royalties, taxes and insurance, a CO_2 price of about \$30/tCO_2, a high level of oil recovery (1 tonne of oil per 2.5 tCO_2) and a wellhead oil price of \$60/bbl, a CO_2-based EOR investment may be cost-effective with more than a few million barrels of original oil in place and several producing wells. The enhanced gas recovery (EGR) is less economically attractive than EOR.

Average production has been estimated at approximately 0.03-0.05 tCH_4/tCO_2 injected and revenue between $1 and $8 per tCO_2 injected.

POTENTIAL AND BARRIERS – Analyses and studies (IPCC 2005, Stern 2006, IEA 2008b, 2009a and 2010b) indicate that CCS is an essential component of the strategies to reduce global GHG emissions. It has been estimated that, without CCS, the cost of climate stabilisation would increase by 70% (IEA, 2008b). According to the IEA's most ambitious mitigation scenario (IEA 2010b), assuming appropriate policies in place and CO_2 marginal abatement costs of up to $170-180/$tCO_2$, the CCS can make a 19% contribution to global CO_2 emission reductions by 2050. The largest part of this contribution (55%) is provided by CCS in power generation, followed by CCS applications in industry and in fuel transformation. The IEA projection involves about 1100 GW global power capacity equipped with CCS by 2050, of which 65% are coal-fired power plants and 17% retrofitted are power plants. In this analysis, the CCS emerges as the largest single contribution to the emission mitigation. This scenario can materialize only if there is a strong acceleration in CCS deployment, with timely investment in demonstration plants, capture-ready plants and retrofitting, and new CCS capacity. Major organizations involved in CCS R&D, development and deployment, e.g. the Carbon Sequestration Leadership Forum (CSLF), the IEA Greenhouse Gases R&D Programme (IEA GHG), and the Global CCS Institute (GCCSI), do recommend the launch of at least 20 full-scale CCS projects by 2010 for CCS. This recommendation was endorsed by the G8 Member States in 2008. While the ongoing economic crisis does not help achieve this target, several countries including emerging economies have programmes in place to support CCS demonstration. CCS could also provide a major contribution to the energy supply security by enabling the the huge coal reserves to be exploited with a low environmental impact.

The IEA Technology Roadmap for CCS deployment (IEA, 2009a) outlines the CCS deployment steps from now to 2050 and provides information on related investment. It calls for 20 industrial-scale,[7] demonstration plants to be launched by 2010, with an investment of between $30bn and $50bn, some 100 commercial full-scale projects by 2020 (40% in the power sector and 60% in the industry and upstream sectors), and over 3400 projects by 2050 (1700 in power generation, 1000 in industrial applications, 600 in fuel upstream). The global additional investment involved in the overall deployment programme would be in the order of $2.5-3.0 trillion. Assuming a successful demonstration and policies, CCS could make a significant contribution to emission reductions from 2030 onward.

Early opportunities for CCS projects involve CO_2 capture from high-purity, low-cost sources (e.g. natural gas processing and ammonia production plants), with short-distance transportation (50 km) and storage (and possibly CO_2 use in EOR projects. In 2005, the IPCC estimated that some 360 $MtCO_2$/year could be captured and stored from such early projects. A similar study by the IEA GHG R&D Programme concluded that some 420 EOR projects could store up to 500 $MtCO_2$ per year (with transportation for less than a 100km).

A widespread deployment of CCS requires reduced investment and operation costs; **policy measures** to stimulate private investment; a definitive demonstration of **safe and permanent storage**; a reliable assessment of the **storage capacity**, an internationally shared **regulatory framework**. Emission trading mechanisms alone are not enough to promote CCS as the current CO_2 price (€15/tCO_2) is too low to compensate for the high cost and financial risk in most CCS applications. As a consequence, the European Commission as well as financial institutions such as the World Bank (Carbon Partnership Facility, 2008), the European Investment Bank and the CCS Trust Funds offer financial support to CCS projects. A decision is also expected from the UN-FCCC to include the CCS as a mitigation option under the Clean Development Mechanism (CDM). The demonstration of safe and permanent geological storage is an ongoing process that needs several storage projects with different geological characterization operated for a significant time-period. Storage sites mapping and capacity databases are being assembled by several initiatives in many countries and regions. Germany, the Netherlands, Norway and the UK are evaluating their sub-seabed storage potential. Canada, Mexico and the US are producing a North American Atlas of major CO_2 sources and potential storage sites. The GCCSI is collaborating with the IEA GHG R&D Programme to develop a global storage resource analysis. Mapping efforts are also in place in developing regions. The harmonization of plans and methods is needed . As for CO_2 transportation, piping does not pose special technical problems, the main differences with respect to natural gas being the operating pressure, possible CO_2 stagnation at ground level in the case of leaks, possible corrosion (if CO_2 is mixed with water), with the advantage that CO_2 is not flammable. However, international regulations for CO_2 facilities, storage and transportation across countries and regions are needed. Over the past years, several initiatives aimed to amend legal and regulatory instruments for CCS development: In 2006, the IPCC released *Guidelines for National GHG Inventories*; in 2006, the London Protocol was amended to allow for offshore CO_2 storage; in 2007, the Convention for Protection of Marine Environment adopted regulations to prevent CO_2 storage or dispersion in the oceans; in 2009, the EU established a regulatory framework for CO_2 geological storage to be transposed into Member State legislation by 2011. In the US, a number of States are in the process of implementing CCS legislations. The IEA has created the International Regulators' Network that produces a bi-annual review of CCS Legal and Regulatory Models (July 2010).

[7] Typical commercial power plants with at least 100-200 MW capacity, CO_2 storage in the order of 1$MtCO_2$/y, full integration of capture, transport, storage and monitoring operations, identification of transport routes and storage sites with geological characterization (in operation from 2015-2020).

Table 1 – Summary Table - Key Data and Figures on CCS Technology

Technical Performance	Typical current international values and ranges
Energy input	Coal, Gas, Electricity
Output	CO_2 emission reduction

Typical basic CO_2 emissions in modern production plants

Power gen. ($kgCO_2/MWh$)		Industry (tCO_2/t)			Fossil fuels upstream and conversion (tCO_2/t)					
SCPC 43%LHV	NGCC 56%LHV	iron&steel	cement (clinker)	ammonia	nat. gas (% CO2)	conv. oil	unconv. oil	LNG	GTL	oil refinery
760	370	1.0-1.5	0.8	1.5-3.0	up to70%	0.11	0.25-0.4	0.20	1.1	0.18

CO_2 capture technologies and typical CO2 abatement		CO_2 abatement
Power generation	IGCC & NGCC: Pre-combustion with physical adsorption	85-90%
	SCPC & NGCC: Post-combustion with chemical absorption; Oxyfuel	85-90%
Industrial processes	Iron & Steel: Oxyfuel with physical adsorption; Chemical absorption	50-75%
	Cement: chemical absorption; Oxyfuel; Chemical looping	~ 65%
Nat. gas production	Chem. absorption for low concentration (membranes for high conc.)	80-90%

CO_2 Transportation	By pipelines (shipping for small quantity)		
CO2 Storage in:	Deep Saline formations	Depleted oil&gas fields (EOR)	Unmineable coal seams
Storage potential, $GtCO_2$	1000-10,000 (20,000)	675-1200	100-200
Existing CCS projects	3 in nat. gas processing; 1 in coal gasification with EOR; 5 EOR; small pilot CCS power plants		
Typical size (capacity)	from 0.7MtCO2/yr to 3 MtCO2/yr		
Total installed capacity	~ 12 MtCO2/yr, of which ~ 8 MtCO2/yr for EOR		
Estimated efficiency loss in power gen	8-12 percentage point reduction in coal- and gas-fired power plants to decline to below 8 percentage points by 2020-2030		
Construction time, yr	Same as the hosting facility for integrated power plants CCS; About 1 yr for retrofitting		
CCS equipm. lifetime, yr	Same as the hosting facility		
Land use	Same as the hosting facility plus 30-50% additional space for capture equipment, pipeline routes and storage site infrastructure		
Water & special materials	Amine-based solvents for post-combustion capture, Oxygen for pre-combustion and oxyfuel capture		

CCS Costs	Typical current international values and ranges (US$ 2008)							
Total Costs	Coal-fired power	Gas-fired power	Nat. gas fields	EOR	Iron&Steel production	Cement production	Ammonia production	Synfuels production
$/tCO2 avoid.	60-75	60-110	5-15	30-40	(25) 65-75	75-100	30-35	60-100(150)
$/tCO2 capt.	40-55	50-90						
Transport Cost	by 100-km pipeline: $2-6/tCO2 per 2Mt CO2/yr; $1-3/tCO2 per 5-10MtCO2/yr; by shipping $15-30/tCO2 per 1000 km							
Storage Cost	typical cost for storage in deep (> 800 m) saline formations $5-10/tCO2 onshore; $10-25/tCO2 off shore							

Investment cost coal-fired power	IGCC CCS	IGCC no CCS	SC-PC CCS	SC-PC no CCS	USC-PC CCS	USC-PC no CCS
US$2006/kW	2100-2700	1700-2200	2400-3200	1500-2000	2400-3200	1500-2100
O&M costs	4% (6%) of the investment cost per year					
CCS impact on electricity cost	Coal-fired power plants: + $30-40/MWh Gas-fired power plants: +$30/MWh					

Data Projections to 2030	
Power plant efficiency loss	< 8% for coal-fired power plants (tends to be higher for gas-fired power plants)
Incremental investment cost,	$600- 700/kW for coal fired power plants
Total CCS cost, $/tCO2 avoided	Coal-fired power $50-60/tCO2 (av.); Gas-fired power $50-90/tCO2 (av.)
Impact on electricity cost, $/MWh	Coal-fired power $30/MWh; Gas-fired power $20/MWh
Market share in power generation	1100 GW (~ 15%) power capacity with CCS by 2050
Contribution to CO2 reduction	19% of global CO2 emission reduction (55% from CCS in power gen)

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