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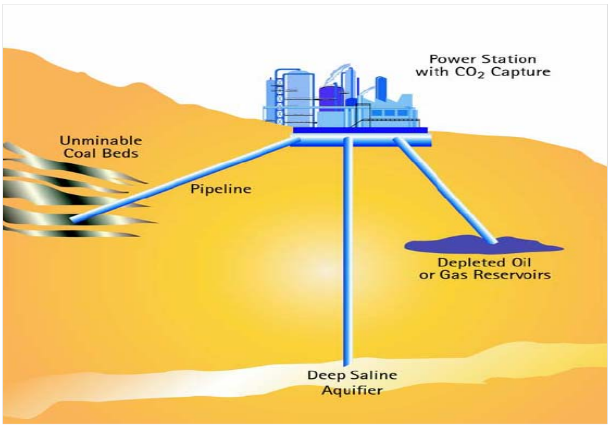
CO_2 Capture & Storage

- **PROCESS -** CO_2 capture & storage (CCS) is a 3-step process including CO_2 **capture** from power plants, industrial sources, and natural gas wells with high CO_2 content; **transportation** (usually via pipelines) to the storage site; and **geological storage** in deep saline formations, depleted oil/gas fields, unmineable coal seams, and enhanced oil or gas recovery (EOR or EGR) sites. In combustion processes, CO_2 can be captured either in pre-combustion mode (by fossil fuel treatment) or in post-combustion mode (from flue gas or by oxyfuel).
- **PERFORMANCE –** CCS can reduce CO_2 emissions from power plants (i.e., 40% of the emissions from the energy sector) by more than 85%, and power plant efficiency by about 8-12 percentage points.
- **COST –** CO_2 capture from combustion processes is rather expensive and energy-consuming, while CO_2 separation from natural gas wells is in general easier and cheaper. Today's typical cost of CCS in power plants ranges from US \$30 to 90/tCO_2 or even more, depending on technology, CO_2 purity and site. This cost includes capture \$20-80/t; transport \$1-10/t per 100 km; storage and monitoring \$ 2-5/t. The impact on electricity cost is 2-3 UScents/kWh. Assuming reasonable technology advances, projected CCS cost by 2030 is around \$25/tCO_2, with impact on electricity cost of 1-2 UScents/kWh. CO_2 separation cost from natural gas wells may be as low as \$5-15/t CO_2.
- **STATUS –** CCS is being demonstrated in 3 industrial storage facilities (storage capacity >3 MtCO_2/year) using CO_2 sources other than power plants. Several dozen oil fields use CO_2 for EOR (some 40 MtCO_2/year). Acid gas geological storage is a common practice in Canada. CCS in power plants is being demonstrated in a few, small-scale pilot plants. Full-scale projects are underway or planned.
- **POTENTIAL -** Global geological storage potential equals at least some 80 years current emissions (2000 GtCO_2). Saline formations 400-10 000 Gt; depleted oil/gas fields 900 Gt; unmineable coal seams 30 Gt.
- **BARRIERS –** Cost of large-scale demonstration projects (hundreds millions of dollars for a single power plant); operation cost; demonstration of permanent safe storage. Needs for regulatory framework; governmental policies and incentives for emission reduction; public acceptance.

PROCESS – Carbon Dioxide (CO_2) capture and storage (CCS) could enable large (> 85%) reduction of CO_2 emissions from fossil fuel combustion in power generation, industrial processes and synthetic fuel production. CCS involves three main steps: CO_2 **capture**; compression and **transport** by pipeline or tankers; and **storage** in deep (>800 m) saline formations, depleted oil and gas reservoirs or unmineable coal seams. Capture is possible either before combustion (decarbonisation of fossil fuels) or after combustion (capture from flue gas) using different processes.

■ **Pre-combustion capture** from coal and gas (by coal gasification and natural gas reforming followed by shift conversion) and CO_2 separation by physical absorption are currently promising options that could apply to integrated coal gasification combined cycle (IGCC) and natural gas combined cycle (NGCC) plants. ■ **Post-combustion capture** options include: CO_2 chemical absorption from flue gas in supercritical pulverised coal combustion (SC/PCC) plants and NGCC; and oxyfuel combustion (fossil fuel combustion with pure oxygen) producing almost pure CO_2 that can be easily separated. Other separation methods such as membranes are being considered as a potential longer-term option for both pre/post-combustion capture, alone or in combination with other absorption techniques. ■ **CO_2 separation from natural gas** - In both on/offshore natural gas wells, CO_2 can be separated from the gas stream and re-injected in geological formations. ■ **After capture or separation**, CO_2 must be compressed to be transported by pipeline or tankers. Compression is also needed for final geological storage. Several CCS technologies are likely to co-exist in the future, but all options require further R&D to improve efficiency and reduce cost.



CCS Concept - Courtesy IEA GHG R&D Programme

■ **SC/PCC Plants with CO_2 capture from flue gas -** CO_2 is captured from flue gases by chemical absorbents that are then heated to release the CO_2 and regenerated. The high CO_2 concentration in the coal plants' flue gas (about 13%) facilitates the capture process. Amines are the reference chemical absorbents but there are concerns about degradation of the solvent in an oxidising atmosphere and in the presence of SO_2 impurities. Improved solvents with high sulphur tolerance are being developed. A major issue is the energy required for solvent regeneration and CO_2 compression. Plant efficiency losses are in the range of 8-12 percentage points, with net efficiencies of about 35% (lower heating value, LHV). In new approaches, CO_2 can be separated through membranes or a combination of membranes with other absorption methods. Membranes technology is still under development. ■ **SC-PCC with CO_2 Capture by Oxyfuel Combustion –** Burning coal in a mixture of oxygen (O_2) and recycled flue gas produces a gas that is mainly a mixture of CO_2 and H_2O, from which CO_2 can easily be removed by cooling and water condensation, and the exhaust stream can be recycled. Oxyfuel avoids costly CO_2 gas separation but involves additional cost for O_2, which is commercially obtained by separation from air. Estimates (IEA GHG R&D Programme) suggest a net efficiency of 35% LHV for SC-PCC plants, similar to post-combustion capture from flue gas. Oxyfuel combustion holds potential for further development. Ion-transport membranes and new techniques for O_2 production are expected to be available in 5-10 years. Depending on combustion temperature, oxyfuel could also reduce NOx emissions. However, the fate of NOx, and SO_2 emissions in oxyfuel combustion is still matter of investigation. Tight control of sulphur concentration in the off-gas is needed to avoid corrosion. Oxyfuel has been demonstrated in lab-scale test units. A 30MW pilot plant is under construction. ■ **IGCC with CO_2 Capture -** In IGCC plants, coal is converted into a hydrogen-rich syngas that is cleaned and burned in a gas turbine. Gas exhaust from the gas turbine is then used to power a steam cycle. Deep gas cleaning is needed to protect the turbines and reduce pollutants emissions. If CCS is applied, the syngas is sent to a shift reactor to convert CO into CO_2 and further hydrogen (H_2). The process produces highly concentrated CO_2 that is readily removable by physical absorbents with relatively low efficiency penalties and cost. Hydrogen is then burned in a gas turbine (further R&D is required for H_2 turbines). An alternative process with post-combustion capture uses O_2 (oxyfuel) to burn the syngas in the turbine. The CO_2 can easily be separated from the resulting flue gas. This process is expected to be cheaper than using pre-combustion CO_2 removal and H_2 turbines. It could also be cheaper than post-combustion processes used in SC-PCC plants. In principle, the IGCC technology is the cheapest option for CCS. However, IGCC plants are more expensive than SC-PCC plants. There is no consensus on which option will cost least in the future. ■ **NGCC with CO_2 Capture -** In NGCC plants with pre-combustion CO_2 capture, natural gas is converted into H_2 and CO_2, the H_2 is used for power generation, and CO_2 is removed for storage. Post-combustion capture in NGCC plants is more difficult than in coal plants as the CO_2 concentration in the flue gas is lower (3-4%). CO_2 chemical absorption from NGCC flue gas is still done in a few isolated cases. The plant efficiency would be in the range 48-50%. Ongoing demonstration projects (Norway, UK) focus on better solvents and design optimisation. Alternative options such as oxyfuel and natural gas reforming are under investigation.

PERFORMANCE AND COST - CO_2 capture from combustion processes is rather expensive and energy-consuming while CO_2 separation from natural gas wells is in general easier and cheaper. CCS in power plants makes sense economically only for large, highly efficient plants. At present, the increased use of fossil fuels resulting from CCS could be as high as 35%-40%. It is expected to decline to 10%-30% in next-generation plants, and could be as low as 6% for more speculative designs. Efficiency losses, including CO_2 compression at 100 bar, are estimated to be 8-12 percentage points for existing coal plants and to decline significantly in next-generation plants. R&D is critical to reduce losses. In general, high design complexity results in high capital cost. It is estimated that the investment cost of a demonstration power plant with CCS ranges from US $0.5 to 1 billion, 50% of which covers the CCS equipment. Today's typical cost of CCS in power plants may range from US $30 to 90/t$CO_2$. Higher costs (up to $160/t) are reported, depending on technology, CO_2 purity and site. The cost includes capture $20-80/t; transport $1-10/t per 100 km; storage and monitoring $2-10/t. Using cost-effective technologies and favorable siting, best estimates for CCS from coal plant flue gas are at $50/t including capture $20-40/t; large-scale transportation by pipelines $1-5/t per 100 km; and storage $2-5/t. Short-distance transport and storage cost together can be estimated at less than $10/t if monitoring is of secondary importance. Assuming reasonable rates of technology learning, the total CCS cost is expected to fall down to below $25/t$CO_2$ by 2030, but reduction is more difficult in NGCC plants where CO_2 concentration is lower. The use of CO_2 in EOR can offset at least part of the CCS cost and allow storage demonstration projects at low or no cost. Using CO_2 in EOR can produce an additional 0.1-0.5 ton of oil per ton of CO_2. At $ 45/bbl oil price, EOR revenue could range from $30 to $150/t$CO_2$. EOR is currently used in Canada and US to improve production in several dozens of mature oil fields with several hundred wells. But, in general, its global potential in terms of CO_2 storage is limited. In addition, other fluids could be used instead of CO_2. The future of CCS in power plants largely depends on its impact on the electricity cost. In new power plants, CCS use would increase the electricity cost ($25-60/MWh) by some $20-30/MWh. This additional cost is expected to decrease to $10-20/MWh by 2030, and to be lower for coal plants than for gas plants. As the electricity price for large users is closer to the cost, and it is much higher for residential users, the CCS cost will impact more on large users. NGCC and advanced coal power plants (SC-PCC, IGCC) appear to be among the cheapest electricity supply options, even considering the incremental CCS cost. CO_2 separation cost from natural gas wells depends on the CO_2 concentration in the natural gas and on well locations. The cost may be as low as $5-15/t$CO_2$ for onshore and offshore sites, respectively.

STATUS - Technologies for CCS are rather well known, but system integration and commercial demonstration are needed. If CCS is to play a significant role in the coming decades, demonstration must be accelerated. In particular, safe and permanent CO_2 underground storage needs to be proven. Major ongoing demonstration projects include the offshore Sleipner project (Statoil, Norway - 1MtCO_2/year storage in a deep saline aquifer, since 1996); the Weyburn project (Canada - 1MtCO_2/year storage with EOR, since 2001); the In-Salah project (BP, Sonatrach, Algeria). They use CO_2 sources other than power plants. In these projects, the underground behaviour of the CO_2 corresponds to expectations. No leakage has been detected, and natural chemical-physical phenomena such as CO_2 dissolution in the aquifer water are expected to minimise the risks of long-term leakage. Pilot projects suggest that storage in unmineable coal seams may also be viable. Enhanced oil & gas recovery (EOR, EGR) at several sites offers demonstration opportunities and revenues that may offset the CCS cost. Several projects aim to demonstrate the CCS technology in IGCC plants (US-led FutureGen, European Zero Emission Technology Platform). Existing and planned demonstration projects (Gorgon in Australia, Miller in the UK) are likely to reach only 10 MtCO_2/year in the next decade. Given the range of technologies under development, CCS demonstration would require at least ten major power plants with CCS to be in operation by 2015. Substantially larger demonstration budgets as well as private/public partnerships and outreach to emerging economies are essential. As CCS implies an incremental cost, economic incentives are needed for CCS to be commercially demonstrated and deployed.

POTENTIAL – According to IEA *Energy Technology Perspectives* (ETP, IEA-2006), CCS in power generation, industry and synfuel production could contribute 20% to 28% of the effort to reduce global emissions by 2050. Important opportunities for CCS exist in coal-consuming countries, and it would be highly desirable to include CCS in the Kyoto mechanisms to reduce emissions. Commercial deployment of CCS could facilitate the use of huge world coal reserves with negligible impact on global emissions. Since power plants have long lifetimes, fast CCS expansion would imply retrofitting highly-efficient, existing plants, which is generally more expensive than building new power plants with CCS. While the technical and economic feasibility of CCS is being demonstrated, the construction of CO_2 *capture-ready* power plants for later retrofitting is a new concept under consideration to deal with the uncertainties of the future CCS market. Case studies suggest that an efficiency penalty of only 3% could be incurred for later retrofitting of new gas power plants conceived for CCS integration. Retrofit and capture-ready plants are under consideration by IEA in the G8 framework for 2007 and 2008. CCS in biomass-fuelled power plants may result in net CO_2 removal from the atmosphere. However, biomass plants are typically small (25-50 MW vs. 500-1000 MW coal power plants). Thus the CCS cost per kW is roughly twice as high as the cost in coal plants. Assuming successful R&D efforts and demonstration, and the adoption of emissions reduction incentives, CCS deployment could start from 2015 onward, and contribute to emissions reduction in the next decades. Prudent estimates suggest storage potential in geological formations of at least 2000 GtCO_2, equal to some 80 years of current global emissions.

BARRIERS – Major barriers to CCS deployment are cost, demonstration of commercial operation and safe permanent storage. CCS investment (hundreds of millions of dollars for a single power plant) poses a major financing challenge. A regulatory framework (liability, licensing, royalties, leakage cap) is needed for private investment and public acceptance. Governments should establish credible, long-term policies to stimulate private investment. Emission mitigation mechanisms such as emission trading should include CCS. A substantial increase in the global RD&D budget and outreach to emerging countries are essential.

Table 1 – Indicative characteristics of power plants with CCS

Fuel & Technology	Year	Invest. cost $/kW	Effic. %	Effic. loss, %	Capture effic., %	Capture cost, $/t	Electr. cost, $/MWh	Electr.cost no ccs, $/MWh
Coal steam cycle, CA	2010	1850	31	12	85	33	68	38
Coal steam cycle, CA	2020	1720	36	8	85	29	61	38
Coal steam cycle, CA	2030	1675	42	8	95	25	57	38
IGCC, selexol, PA	2010	2100	38	8	85	39	67	38
IGCC, selexol, PA	2020	1635	40	6	85	26	57	38
NGCC CA	2010	800	47	9	85	54	57	38
NGCC oxyfuel	2020	800	51	8	85	49	54	38
Black liquor, IGCC	2020	1620	25	3	85	15	34	24
Biomass IGCC	2025	3000	33	7	85	32	100	75

Note: 10% discount rate; 30-year lifetime; Overnight investment costs (no interest during construction, which may add 5-40%); Coal price $1.5/GJ; Nat. gas price $3/GJ; CO_2 produced at 100 bar; Transport & storage not included; CA, chemical absorption; PA, physical absorption; IGCC data for 2010 refer to highly-integrated plant (Shell gasifier), while 2020 data refer to US E-gas gasifier with high-efficiency gas turbines. Electricity cost = (Investment cost × (0.11+0.04)/31.54/availability factor + fuel price/efficiency)× 0.036, assuming 4% fixed O&M cost, 11% annuity. (IEA ETP 2006)

Table 2 - Major Storage Projects and Proposed Power Plant CCS Projects

Storage Project, Location	**CO_2 Source/CO_2 Storage**	**CO_2 Quantity**
Sleipner (offshore) Norway	nat. gas field /saline formation	1 Mt/year since 1996
In Salah, Algeria	nat. gas field /gas-saline formation	1.2 Mt/year since 2004
K12b (Netherlands)	nat. gas field /gas field -EGR	Over 0.1 Mt/year since 2004
Snohvit, (offshore) Norway	nat. gas field /gas-saline formation	0.75 Mt/year, from 2007
Gorgon (offshore), Australia	nat. gas field /saline formation	129 Mt total storage, from 2008
Weyburn , Canada-USA	coal gasific. /oil field –EOR	1 Mt/year since 2000
Permian Basin, USA	industrial & natural source/ EOR	500 Mt since 1972
Nagaoka, Japan	/ saline formation	10.4 Kt in 2004-2005
Ketzin, Germany	/ saline formation	60Kt, since 2006
PP Project, Location	**Power Plant/Project Cost**	**Technology/Storage/Starting Date**
BP/SSE Peterhead Miller, UK	NGCC 0.35 GW ($0.6bn)	Autoth. reformer, precomb, EOR, 2010
BP DF2, Carson, USA	IGCC petcoke 0.5 GW ($1bn)	shift, precomb, EOR, 2011
Huaneng, GreenGen, China	IGCC 0.1 GW	shift, precomb., 2015
E.ON, Killingholme, UK	IGCC 0.45 GW (£1bn)	shift, precomb. (capture ready), 2011
Ferrybridge, SSE, UK	SCPC 0.5 GW	retrofit, postcomb., 2011
FutureGen, USA	IGCC 0.27 GW ($1bn)	shift, precomb., 2012
GE/Polish utility, Poland	IGCC 1 GW	shift, precomb.
Karstø, Norway	NGCC 0.43 GW	postcomb. amine, EOR, 2009
Nuon, Eemshaven, NL	IGCC coal/biomass/gas 1.2 GW	option to capture, 2011
Powerfuel, Hatfield, UK	IGCC 0.9 GW	shift, precomb., 2010
Progressive Energy, UK	IGCC 0.8 GW ($1.5bn)	shift, precomb., H2 to grid, 2009
SaskPower, Canada	PC lignite 0.3 GW ($1.5bn)	postcomb. or oxyfuel, DSF/EOR, 2011
Siemens, Germany	IGCC 1 GW (€1.7bn)	shift, precomb., 2011
Statoil/Shell, Draugen, Norway	NGCC 0.86 GW	postcomb. amine, EOR, 2011
RWE, Germany	IGCC 0.45 GW (€1bn)	shift, precomb. saline formation, 2014
RWE, Tilbury, UK	SCPC 1 GW (£0.8bn)	retrofit, postcomb, capture ready, 2016

Table 3 - Typical Data and Figures for CCS Technology

Data Confidence – CCS is currently in demonstration phase with 3 industrial plants in operation using CO_2 sources other than power plants. Data below refer to estimates for power plant applications.	
Performance	
Efficiency	8-12 percentage points loss vs. power plants with no CCS (potential decline to 4%)
Lifetime, load factor	Same as the power plant but no O&M experience available
Installed Capacity	3 demonstration projects with 3-4MtCO_2/year storage capacity. Several new projects underway. Over 70 EOR sites using 40MtCO_2/year from natural and industrial sources, helping increase oil recovery from 5 to over 15%
Costs	
Investment ($/kW)	Some 50% of the power plant investment cost (demonstration plants with CCS)
O&M ($/kW)	Same as the power plant (2.5-4% of the investment cost per year)
Capture from p. plants	$ 20-80/tCO_2 ($20-40/t for cost-effective separation techniques)
Transport	$ 1-10/tCO_2 per 100 km for large-scale transportation by pipeline
Storage & monitoring	$ 2-5/tCO_2 site-sensitive
Total cost from p. plants	$ 30 to 90/tCO_2 (may be much higher depending on technology, site, CO_2 purity)
Impact on electricity cost	$ 20-30/MWh (incremental electricity cost due to CCS)
Separation from nat. gas	$ 5-15/tCO_2 (onshore-offshore)
Cost projections	Total CCS cost expected to fall below $ 25/tCO_2 by 2030, depending on technology learning/advances, with incremental electricity cost of $10-20/MWh
Environmental Impact	
CO_2 emissions reduction and storage potential	> 85 % in power plants; storage potential > 2000GtCO_2 ≈ 80 years today's emissions Saline formation 400-10,000 Gt, depleted oil/gas field 900 Gt, unmineable coal 30 Gt
CO_2 storage	0.32-0.34 kgCO_2/kWh from NGCC and 0.64-0.75 kgCO_2/kWh from coal plants (1 MtCO_2/y for 500 MW NGCC plant, 4.5 MtCO_2/y for 1000 MW coal plant)
Pollutants reduction	The oxyfuel process can also significantly reduce NOx, SOx, and PM
Land and water use	Same as the power plant plus CO_2 capture, transport and storage facilities
Special materials use	Post combustion capture: amines, other absorbents; IGCC and oxyfuel: oxygen
Further Information and References	www.iea.org; www.ieagreen.org.uk; www.cslforum.org; www.ipcc.ch; Prospects for CO_2 Capture & Storage (IEA, 2004); Energy Technology Perspectives (IEA, 2006); IEAGB(2006)35; Special Report on CO_2 Capture & Storage (IPCC, 2005)