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## **VLEEM 2**

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## **FINAL REPORT**

**ANNEX 3.4:  
CO<sub>2</sub> capture and sequestration**

# ANNEX 3.4 : CO<sub>2</sub> capture and sequestration

## 1. Introduction

CO<sub>2</sub> capture and sequestration has gained a lot of interest lately, not only in the context of climate change (emissions mitigation) but also from industry (extension of lifetime of coal power plants in the USA). It is a new technology when focusing on energy systems, in the chemical industry CO<sub>2</sub> separation already occurs but for process purposes. Industry and material flows fall outside the scope of this study and will not be treated. The focus will be on energy related CO<sub>2</sub> capture. Also the use of natural occurring CO<sub>2</sub> for enhanced oil recovery and the single example where it is used for enhanced coal bed methane recovery will not be considered.

## 2. Status

Although a lot of work is ongoing, realisations are few. So far only three sites are actually capturing and storing the captured CO<sub>2</sub>. It concerns the Sleipner oil platform off the coast of Norway and the Weyburn facility in the USA-Canada. Further projects with CO<sub>2</sub> capture from energy processes are announced but are only on the drawing board at this time (e.g. capture and storage at LNG facility in Australia).

## 3. Technologies

The IEA GHG R&D programme has collected a thorough number of technology describing reports with all possibilities and parameters. For detailed technology analysis and comparison these are very valuable, but for large energy system analysis tools, they prove to be too detailed.

For this study, two technology options for capture will be retained. They cover the bulk of the capture possibilities and have a wide area of application that is favourable for technology spill over effects.

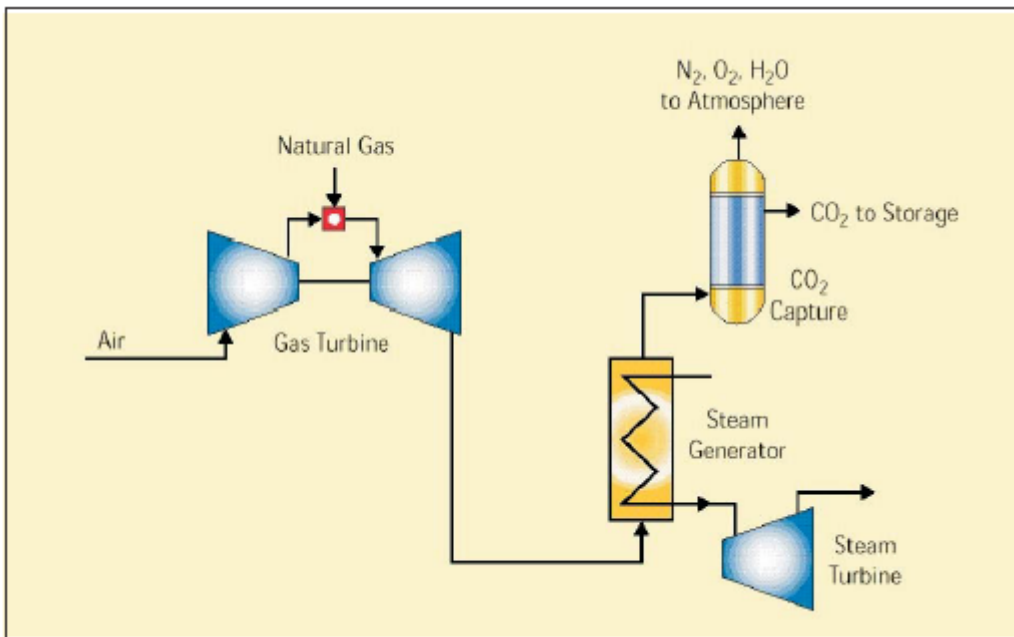
### ***3.1 The first options is a post combustion separation and capture of CO<sub>2</sub>***

A variety of techniques are available - the main one in use today for separating CO<sub>2</sub> from flue gases or other gas streams is scrubbing the gas stream using an amine solution. After leaving the scrubber, the amine is heated to release high purity CO<sub>2</sub> and the CO<sub>2</sub>-free amine is then reused.

In many respects, post-combustion capture of CO<sub>2</sub> is analogous to flue gas desulphurisation (FGD), which is widely used on coal- and oil-fired power stations to reduce emissions of SO<sub>2</sub>. The low concentration of CO<sub>2</sub> in flue gas ( PC 14%, IGCC 9%, NGCC 4%) means that a large volume of gas has to be handled, resulting in large and expensive equipment. A further disadvantage of the low CO<sub>2</sub> concentration is that powerful solvents have to be used to capture CO<sub>2</sub> - regeneration of these solvents, to release the CO<sub>2</sub>, requires a large amount of energy. The CO<sub>2</sub> capture rate is about 85 (now) to 90 % (2010), i.e. 85% of the carbon contained in the flue gases (and hence in the fuel) is separated and ready for storage, the remaining 15% is vented in the air.

The CO<sub>2</sub> concentration can be increased greatly by using concentrated oxygen instead of air for combustion, either in a boiler or gas turbine. If fuel is burnt in pure oxygen, the flame temperature is excessively high, so some CO<sub>2</sub>-rich flue gas would be recycled to the combustor to make the flame temperature similar to that in a normal combustor. The advantage of oxygen-blown combustion is

that the flue gas has a CO<sub>2</sub> concentration of typically >90%, so only simple CO<sub>2</sub> purification is required. The disadvantage is that production of oxygen is expensive, both in terms of capital cost and energy consumption. this option is actually not considered due to lack of information about dedicated oxygen technologies (turbines, combustion chambers) for power technologies.



Post combustion capture of CO<sub>2</sub> (example = gas turbine)

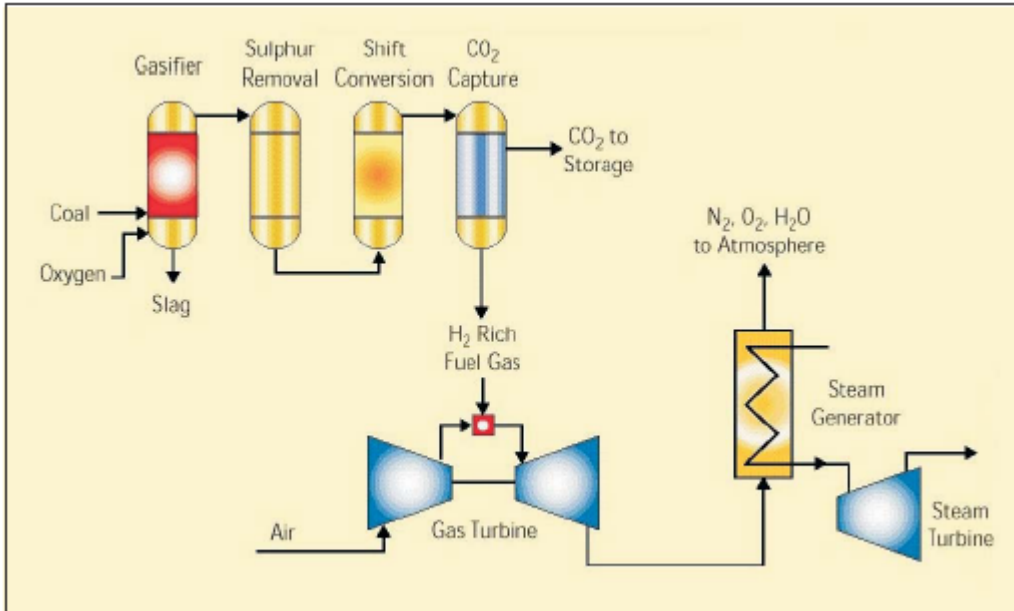
The post combustion option is considered to be suitable for CO<sub>2</sub> capture from all flue gas flows from power plants (and large industrial boilers). The Sleipner project uses the same technology (amine scrubbers) to remove excess CO<sub>2</sub> from the extracted natural gas.

### ***3.2 An alternative way to increase the CO<sub>2</sub> concentration and partial pressure is to use pre-combustion capture.***

This involves reacting the fuel with oxygen and/or steam to give mainly carbon monoxide and hydrogen. The carbon monoxide is reacted with steam in a catalytic reactor, called a shift converter, to give CO<sub>2</sub> and more hydrogen. The CO<sub>2</sub> is then separated, e.g. using Selexol as solvent and with depressurisation to release the CO<sub>2</sub>, and the hydrogen is used as fuel in a gas turbine combined cycle plant. The process is, in principle, the same for coal, oil or natural gas. The figure is a simplified diagram of a coal-fired power plant with pre-combustion capture of CO<sub>2</sub>.

Although pre-combustion capture involves a more radical change to the power station design, most of the technology is already well proven in ammonia production and other industrial processes. One of the novel aspects is that the fuel gas is essentially hydrogen. It is expected that it will be possible to burn hydrogen in an existing gas turbine with little modification but this is not commercially proven technology. At least two gas turbine manufacturers are known to have undertaken tests on combustion of hydrogen-rich fuels.

The hydrogen produced in pre-combustion capture processes could, alternatively, be used to generate electricity in a fuel cell. The technology of capture and storage is therefore expected to be suitable for future as well as current power generation technologies.



pre-combustion capture of CO<sub>2</sub> (example = IGCC)

Pre-combustion can be considered to be suitable for all fuel treatment processes in which hydrocarbons are shifted to H<sub>2</sub> and CO<sub>2</sub>, this includes fossil fuel gasification for electricity generation as well as H<sub>2</sub> production from the (partial) oxidation of natural gas, oil or solid fuels (coal and biomass). The capture rate lies now above 90%, and can reach 97% for H<sub>2</sub> production facilities. The Weyburn facility uses CO<sub>2</sub> from a synthetic fuel plant, so using a pre combustion separation and capture.

## 4. Characteristics

### 4.1 post combustion:

The additional costs for CO<sub>2</sub> capture are expected to go down from 890(coal)-370(gas) US\$2000/kW<sub>electric</sub> now (estimated to be around 920 US\$2000/kW<sub>electric</sub> for coal and 470 US\$2000/kW<sub>electric</sub> for gas in 2000) to 623(coal)-314(gas) US\$2000/kW<sub>electric</sub> by 2012. The assumed floor cost lies around 400-200 US\$/kW<sub>electric</sub>. These cost assumptions are based on new plants in which CO<sub>2</sub> capture is integrated from the beginning. Retrofitting existing coal fired plants would lead to a cost of 710 US\$/kW<sub>electric</sub>

The energy penalty, i.e. the difference in efficiency between a similar power plant without and with CO<sub>2</sub> capture, lies currently around 10.3% for coal based plants and 7.2% for natural gas based. These energy penalties are assumed to reduce to 6% by 2010 due to further optimization of the components in the CO<sub>2</sub> capture process.

## 4.2 pre-combustion

The costs for CO<sub>2</sub> capture combined with gasification or natural gas reforming are assumed to be 451-504 US\$2000/kW<sub>electric</sub> now and 314 US\$2000/kW<sub>electric</sub> by 2012. The energy penalty could drop from 6.1% now to 4.3% by 2012.

Additional cost for CO<sub>2</sub> capture from H<sub>2</sub> production from partial oxidation processes ranges around 2.2 and 2.9 US\$2000/GJ H<sub>2</sub>.

### 4.3 summarising cost table

The additional cost for power plants if equipped with a capture and separation unit (including compression to make the CO<sub>2</sub> ready for transportation) are as follows:

US\$2000/kWe	2000	2003	2012	floor cost
pre combustion capture		451-504	314	180
post combustion coal	920	890	623	400
post combustion gas	470	370	314	200

## 5. Storage options

Capturing of CO<sub>2</sub> is not sufficient to remove it from the atmosphere, a safe and permanent storage is also required. To store CO<sub>2</sub> different options are recognized. The most important ones are to be found in geological storage. Storage in mineral products or e.g. use in food products (gasified drinks) other more "exotic" forms of sequestration are not expected to contribute significantly to climate mitigation and not in the quantities related to CO<sub>2</sub> capture from energy technologies. Sequestration in biological sinks (forest and soils) is not considered here because these options capture the CO<sub>2</sub> directly from the atmosphere and do not need a separate capture technology or process.

The geological options considered for CO<sub>2</sub> storage are :

- depleted oil and gas fields
- enhanced oil and gas recuperation (EOR and EGR)
- unminable coal seams (enhanced coal bed methane ECBM)
- saline aquifers.

Ocean storage is expressly not included because of the dispute about its environmental character.

The global potential of storage is estimated as follows:

	Gton CO <sub>2</sub> 2050 (IEA GHG, 2001)	Gton CO <sub>2</sub> (Edmonds , 2000)
depleted oil and gas fields	126-400 oil 800 gas	150-700 oil 500-1100 gas
saline aquifers	400-10 000	320-10 000
unminable coal seams	>15	>73
enhanced oil recovery	61-65	..

Other studies give the following estimated regional distribution for a couple of options:

	Gton CO <sub>2</sub> depleted oil and gas fields	Gton CO <sub>2</sub> depleted oil and gas fields	Gton CO <sub>2</sub> ECBM
FSU	177		19
Middle east	197		
USA	47	13-98	35
Canada	17	0.283 oil 2.8 gas	12
WEurope	17	6 oil 30 gas	4
Australia			30
China			13
Other Asia			29
Africa			7
Global	455		148

Gton CO <sub>2</sub> storage potential	depleted oil and gas fields	EOR/EGR	ECBM	Aquifers
Africa	3-6	3-23	5	1000
Australia	0-1	0-9	50	550
Canada	1-6	6-35	50	1050
China	0-1	0-1	100	550
EEurope	1-2	1-2	20	250
FSU	15-30	35-244	100	1000
India	0	0	10	500
Japan	0	0	0	10
LAmerica	9-20	20-61	0	1255
Middle East	25-85	20-300	0	505
Other Asia	6-12	11-52	50	1040
USA	10-20	15-30	80	1050
WEurope	3-5	16-46	30	300
Global	72-187	125-801	495	9060
cost estimates				
Investment US\$/ton CO <sub>2</sub>	5-11	5-11	12.5-17.5	1-11
transport US\$/ton CO <sub>2</sub> /300km	2.5	2.5	2.5	2.5
Fixed O&M US\$/ton CO <sub>2</sub>	0.25-0.35	0.17	0.25-0.50	0.375
Variable O&M US\$/ton CO <sub>2</sub>	1.35	0.90	12.5	0.30

electricity requirement MWh/ton CO <sub>2</sub>	0.08-0.11	0.14	0.08-0.21	0.11
energy recovery GJ/ton CO <sub>2</sub>	-	1.80-2.22	5.5-9.0	-
currently in use	-	USA: 33Mton CO <sub>2</sub> /year from natural sources, since 1972; Weyburn 1 Mton CO <sub>2</sub> /year since 2000	USA: 30 kton CO <sub>2</sub> /year from natural sources since 1998	Sleipner: 1Mton CO <sub>2</sub> /year since 1996

As can be noticed the range of potential estimates varies considerably, also cost estimates are far from uniform. About the costs, quite often is the oil/gas price included in storage cost estimates, making it difficult to use, especially because of the uncertainty and range of these fuel prices. When the fuel costs are included, quite often negative storage costs per ton CO<sub>2</sub> are quoted, taking into account the benefits from the energy recovered (oil, gas or coal bed methane).

## 6. Modelling data

Cumulative capacity

Mton CO <sub>2</sub>	1995	1996	1997	1998	1999	2000	2001	2002	2003
captured		0.2	1.2	2.2	3.2	4.2	6.2	8.2	10.2
stored, excluding 33 Mton/year EOR in USA since 1972		0.2	1.2	2.23	3.26	4.29	6.32	8.35	10.38

These data are derived from:

Sleipner : 1 Mton CO<sub>2</sub>/year since 1996, capture is gas scrubbing, storage is aquifers

Weybrun : 1 Mton CO<sub>2</sub>/year since 2000, capture is shift reactor, storage is EOR

USA Allison unit : 30 kton/year since 1998 ECBM

Japan : 2.2 kton in aquifers in 2003