CONTROLLING CARBON EMISSIONS: THE OPTION OF CARBON SEQUESTRATION

E. TZIMAS and S. PETEVES
INSTITUTE FOR ENERGY
Petten, The Netherlands

EUROPEAN COMMISSION
JOINT RESEARCH CENTRE

Report EUR 20752 EN

Mission of the Institute for Energy

The Institute for Energy provides scientific and technical support for the conception, development, implementation and monitoring of community policies related to energy.
Special emphasis is given to the security of energy supply and to sustainable and safe energy production.

European Commission
Joint Research Centre (DG JRC)
Institute for Energy
Petten
The Netherlands

Contact:

E. Tzimas	+31-224-565149
S. Peteves	+31-224-565245

http://ie.jrc.cec.eu.int/

http://www.jrc.cec.eu.int

Luxembourg: Office for Official Publications of the European Communities, 2003

ISBN 92-894-5751-1

Printed in The Netherlands, Institute for Energy – JRC IE, PR&Communication

COVER: Picture adopted from the photo library of Public Power Corporation’s website
http://www.dei.gr/en/ppc/business/environment/gallery.htm

Sustainable Energy Technologies
Reference and Information System
(SETRIS)

The objective of SETRIS is to collect, harmonise and validate information on sustainable energy technologies and perform related techno-economic assessments to establish, in collaboration with all relevant national partners, scientific and technical reference information required for the debate on a sustainable energy strategy in an enlarged EU, and in the context of global sustainable development.

Table of Contents

List of Figures

List of Tables

Executive Summary

Carbon sequestration is a distinct technological option for controlling carbon emissions, complementing efficiency improvements, cogeneration of heat and power and the evolution towards zero- and low-carbon fuels. It is an integrated process that includes (i) the capture of carbon dioxide (CO_2) from emission sources and the atmosphere, (ii) the transportation of CO_2, and, (iii) its permanent storage or reuse. The technology of carbon sequestration is most applicable to large combustion plants and specifically to thermal power stations, where it could contribute stopping the release of about 90% of generated CO_2 in the atmosphere. Furthermore, carbon sequestration technologies may play a catalytic role in the deployment of a hydrogen economy: It is strongly argued that during the early stages of deployment of the hydrogen economy, hydrogen will be produced in Europe from fossil fuels, mainly via natural gas steam reforming; a process that also generates CO_2. Thus, carbon sequestration may be required to justify this hydrogen production pathway as sustainable.

Foremost, carbon sequestration is a natural process. Significant amounts of carbon are being exchanged continuously (mainly in the form of CO_2) via natural processes, between the atmosphere and the terrestrial biota and the ocean. It has been estimated that the amount of CO_2 exchanged between the atmosphere and the land biota is 10 times larger than the amount of CO_2 emitted to the atmosphere by fossil fuel combustion on a yearly basis. The amount of CO_2 exchanged between the atmosphere and the ocean is even larger. However, most of CO_2 uptaken by these natural carbon sinks is re-emitted in the atmosphere. Although the results are not yet conclusive, it has been estimated, that 27% of the anthropogenic emissions are stored in the ocean, 22% in terrestrial ecosystems, while 51% accumulate in the atmosphere increasing its concentration.

There are different approaches to carbon sequestration, which can be grouped into 2 main categories: the enhancement of the natural processes described above and the capture of CO_2 directly from the emission sources and its permanent storage.

In terrestrial sequestration, CO_2 is removed from the atmosphere via natural processes, such as photosynthesis, and is converted into biomass. It has been estimated that 5 billion tonnes of CO_2 are uptaken by forests and agricultural land each year worldwide, while the global potential has been estimated as 220-320 billion tonnes of CO_2 in forests by 2050 and another 84-160 billion tonnes in agricultural soils. The European potential is small: The European Climate Change Programme has estimated that 60-70 million tonnes of CO_2 could be stored in EU15 by 2010, which is roughly 10% of the corresponding EU reduction target. Among the main limitations for the application of terrestrial sequestration are the non-permanent storage and the availability of land. Furthermore, basic and applied research is needed to estimate more accurately the storage capacity and the storage rates and to devise verification mechanisms.

Ocean is the largest natural carbon sink. The main mechanism of CO_2 capture by the ocean is the so-called ‘biological pump’. Phytoplankton in the oceans absorb CO_2 from the atmosphere, thus carbon enters the food chain. While, ultimately, most of the absorbed carbon returns back to the atmosphere, a fraction is trapped practically permanently in deep water or ends up as sediment at the ocean’s floor. This natural mechanism can be enhanced by fertilizing the ocean with macronutrients (e.g. nitrates and phosphates) or iron (iron fertilization). Experiments in the Southern Pacific have shown that, iron fertilization enhances plankton growth and decreases the local CO_2 concentration. However, it is not clear if iron enrichment accelerates the downward transport of carbon from surface waters to the deep sea, and if so how can this amount of carbon be verified. Most importantly, the environmental impact as a result of affecting the food chain is likely to be substantial. A lack of fundamental understanding of the processes involved as well as the potential impact to the ecosystem makes it unlikely that any large-scale ocean fertilisation schemes will be implemented in the short term. Overall, the European potential for ocean fertilisation is very small.

In contrast to natural carbon sequestration, the capture of CO_2 directly from the emission sources and its permanent storage has the potential to remove larger quantities of CO_2 and in a shorter time period. Since emission sources in transport, industry and manufacturing are small and disperse, while power generation plants (for electricity and potentially for hydrogen) are comparatively few and large but are currently responsible for one third of the total CO_2 emissions, it is evident that significant steps towards reducing CO_2 emissions can be made faster and more cost-effectively by applying the carbon sequestration technologies to power plants.

Several commercial technologies are available today that are able to separate CO_2 from a stream of gases. However, none of these technologies has been developed for large-scale carbon sequestration operations. Rather, they have been developed to produce a stream of high purity CO_2 for commercial markets, such as chemical manufacturing and food processing, to remove CO_2 from natural gas or to produce hydrogen for the petrochemical industry. These technologies are grouped into three main categories: (i) *post-combustion decarbonisation*, (ii) *syngas decarbonisation*, and (iii) *oxyfuel combustion*. The former two categories are based on chemical and physical absorption, gas adsorption, membrane separation, and low temperature distillation. Oxyfuel combustion is a not-yet-demonstrated approach that is based on the combustion of the fuel with pure oxygen and the recirculation of flue gases into the combustor to control the temperature, aiming to produce exhaust gases that contain at least 90% CO_2. The applicability of each capture technology depends on the conditions of the gas that contain the CO_2, namely its composition, temperature and pressure, the concentration of CO_2 and the degree of required CO_2 removal.

Chemical absorption is considered as the state-of-the-art for the separation of CO_2 when present at low partial pressures, having demonstrated at least 90% removal efficiency, hence, making this process ideal for removing CO_2 from the flue gases of gas turbine combined cycle (GTCC) plants and pulverised coal (PC) plants. Physical absorption is suitable for removing CO_2 from shifted syngas, making this separation technology appropriate for hydrogen production plants and integrated gasification combined cycle (IGCC) plants for electricity generation. The main disadvantages of absorption are the high energy requirements (with concomitant penalty on power plant efficiency and thus in fuel consumption) and the increased capital costs (up to 85% for PC and GTCC plants). Effort is currently made to develop improved solvents with lower energy requirements and retrofitable processes. Pressure swing adsorption is another approach to remove CO_2 from syngas but, currently, cannot be considered competitive to physical absorption, rather complementary to achieve a higher CO_2 removal efficiency. Low temperature distillation is also not considered as a viable CO_2 capture option. On the contrary, membranes, and specifically gas absorption membranes, although still in development, offer a significant future potential for CO_2 capture.

The transport of CO_2 does not impose any technological obstacles. Nowadays, CO_2 is transported via high-pressure steel pipelines (100-200 bar). There is CO_2 pipeline experience since the early 80's and 3000 km of such pipelines exist worldwide with a very good safety record. As an alternative, the use of tankers has been proposed as a future solution to transport CO_2 to offshore storage sites or to locations far away from the CO_2 generation sources. These tankers will be based on existing LPG vessels.

An option to improve the economics of carbon sequestration is CO_2 utilisation. However, it should be born in mind that the amount of CO_2 that can be utilised is extremely small when compared to the amount being generated. The largest potential for CO_2 utilisation is offered by the petrochemical industry for enhanced oil recovery (EOR). The injection of CO_2 into oil wells may increase oil production and store simultaneously CO_2 underground. However, this process is marginally competitive for the given range of today's oil prices. As such, EOR is utilised nowadays only in few locations, mainly in USA. The potential for EOR in North Sea appears to be small, given that EOR is far more difficult to be deployed in offshore oil fields than inland. It is noted that once North Sea oil platforms are decommissioned and removed, it is unlikely that an EOR project could justify the costs of new platforms and wells. As such, any CO_2-based EOR projects in North Sea should be initiated within the next 20 years. An alternative use of CO_2 is for enhanced coalbed methane (ECBM) recovery that can be achieved by injecting CO_2 into coal strata that cannot be mined. There is only one demonstration plant and one pilot plant worldwide, both situated in N. America. The EU is currently funding the first project of its kind in Europe, located in Poland (RECOPOL). The European potential for ECBM recovery appears to be modest, in the areas of the upper Silesian basin in Poland and the Czech Republic, and the Saar/Lorraine basin in Germany and France.

The amount of CO_2 that cannot be utilised after capture needs to be stored safely and permanently, at a low cost and in a way that is environmentally compatible and in accordance with international treaties and national legislation. The main options for storing CO_2 are: (i) *underground in suitable geological formations, such as active and depleted oil and gas reservoirs and deep saline aquifers (geological storage)* and (ii) *in the ocean (ocean storage)*. In addition, *novel approaches* are been explored, that consist of a basket of technologies under development, not yet proven, that promise to offer potential solutions, such as mineral storage, formation of clathrates, enhanced fixation to algae, etc.

Disposal of chemicals and periodic storage of natural gas in geological formations is a widely accepted industrial practice with a long accumulated experience. Furthermore, potential storage sites are widely dispersed and plentiful in number, characteristics that make geological storage the most favourable CO_2 storage option today. The issues associated with geological storage are the assessment of storage capacity and retention times; monitoring and verification; legal complications (including conflicts with international Conventions such as the London convention for the storage of waste in the ocean); and safety and assessment of risks associated with leakage of CO_2 from storage sites. Although CO_2 is not toxic, may cause asphyxiation, contaminate drinking water supplies and, on a global scale, may make carbon sequestration an ineffective strategy to control CO_2 emissions if leaks are large enough. Therefore, given the lack of understanding of the behaviour of CO_2 when stored underground, the public may mistrust carbon sequestration as a safe option and thus reject it as an acceptable solution. Currently, there is only one commercial application of geological CO_2 storage, in a saline aquifer in North Sea, the Sleipner Project, where one million tonnes of CO_2 are injected and stored annually (equivalent to the emissions of a 140 MW power plant). A monitoring project funded by the EU (SACS) studies the behaviour of injected CO_2.

Ocean has been proposed as an alternative storage option. The introduction of CO_2 in the ocean can be achieved by dispersion at intermediate depths (~1500 m) using pipelines from the coast or moving ships, or by injection at depths greater than 3000 m where CO_2 remains as a distinctive phase, probably forming a pool of liquid CO_2 at the bottom of the ocean. However, the major barrier to this approach is the lack of fundamental understanding of the potential impact to the marine ecosystem and environment, given that, the injection of CO_2 increases the acidity of water, at least in the vicinity of the injection site. Furthermore, ocean models need to be developed so that the storage capacity can be determined, as well as the retention times and the optimal injection sites. Additional problems relate with the fact that the legal framework is unclear (possible conflict with the Paris Convention), injection to great depths has not been demonstrated and finally, a strong opposition from the public is to be expected.

Studies have attempted to estimate the global storage capacity of the various options. All recent reports converge to the conclusion that, on a global scale, there is sufficient capacity to store all CO_2 expected to be generated during the next 50 years. On a European scale, we believe that the optimal option is the storage in deep saline aquifers, followed by storage in depleted oil and gas reservoirs. The storage potential offered by other options appears to be limited.

The cost of carbon sequestration is highly variable and depends on a range of factors such as the chosen capture technology, power plant operating conditions and sitting, distance from storage sites, local legislation etc. Costs reported in the literature may vary between €15-80 per tonne CO_2 avoided for capture, €1-4/tonne CO_2 for transport (depending on the throughput and pipeline length) and €1-3/tonne CO_2 for storage depending on the option. On average, the cost of carbon sequestration is €50/tonne CO_2 avoided; this cost is dominated by the cost of capture.

Our economic assessment of the effects of deployment of carbon sequestration on electricity generation in Europe in 2020, has shown that (i) the cost of electricity will be increased by 35% to 57% depending on the electricity generation option; (ii) GTCC will remain the most competitive option for electricity generation; (iii) IGCC will become equally competitive to PC technology, and (iv) unless coal prices drop dramatically (or natural gas prices increase significantly) natural gas will remain the fuel of choice for electricity production. Similarly, our analysis of the effects of deployment of carbon sequestration on hydrogen production in Europe in 2020, has indicated that (i) the cost of produced hydrogen by natural gas steam reforming or coal gasification will increase by 14 and 16% respectively; (ii) hydrogen production via steam reforming is significantly more economical than production by coal gasification; (iii) the cost of hydrogen produced by steam reforming is dominated by the cost of fuel; and; (iv) unless coal prices drop dramatically (or natural gas prices increase significantly) natural gas will be the main fuel to produce hydrogen. Finally, our assessment on the introduction of hydrogen as an alternative transport fuel in 2020 according to the Communication of the Commission on alternative fuels (COM(2001)547) targets, based on the assumption that all required hydrogen will be produced by natural gas steam reforming, equipped with carbon sequestration with 90% capture efficiency, indicates that the CO_2 mitigation cost will be relatively small (€11/tonne CO_2 avoided).

1. The Case for Carbon Sequestration

1.1 Energy and the Environment

Affordable and plentiful energy is an absolute prerequisite for the high quality of life Europeans enjoy and an essential ingredient to economic prosperity. Yet, with the turn of the century, the European Union (EU), as the rest of the world, is confronted with a major challenge: how to meet the continuously increasing energy demand, a result of the economic growth in EU member states, while minimising the adverse effects of energy production and use to the environment, the ecosystem and the human welfare. As a response, the EU has recently intensified a European energy-strategy debate launching a number of important policy initiatives aiming to environmental protection, along with fuelling sustainable growth via improving European competitiveness and securing the energy supply.

Indeed, the energy industry is among the worst polluters, the reason being the strong dependence of energy production on fossil fuels. The environmental impact of energy production and use includes damage to the natural ecosystems, deterioration of the built environment, cause of adverse effects to human health and contribution to climate change. On a regional/local level, the fossil fuel-based energy industry is responsible for pollution, manifested as: (i) water pollution, i.e. the contamination of aqueous masses such as rivers and the sea from rejected residue; (ii) soil pollution from hazardous and inert solid and liquid waste disposal, and, (iii) air pollution (emissions of acid gases such as nitrogen oxides –NO_X- and sulphur dioxide –SO_2-, particulates, etc.). However, the level of pollution and thus, the impact of energy production and use at a regional level can be effectively reduced with the establishment of proper legislative measures. Such measures include the *National Emission Ceiling* Directive [1] that sets targets for reducing air emissions for the EU and each Member State; the Directive *on the Sulphur Content of Liquid Transport Fuels* [2], aiming to reduce SO_2 emissions from the transport sector; the *Large Combustion Plant* Directive [3], that sets limits to the emissions of pollutants from combustion installations, including thermal power plants; the *Waste Incineration* Directive [4] that limits emissions from waste incineration plants; and the *Integrated Pollution Prevention and Control* (IPPC) Directive [5] that dictates the use of best available techniques (BAT) to combat pollution. Similar programs exist in other developed regions of the world. For example, the Clean Air Act [6] is enforced in the USA, to combat air pollution from industrial sources including thermal power stations.

The effectiveness of such measures lays to a large extent on the successful development and deployment of technologies capable to minimise and control pollution, thus supporting successfully the enforced legislative actions. The European IPPC Bureau (EIPPCB) has been formed to catalyse an exchange of technical information on BATs under the IPPC Directive and to create reference documents (BREFs) that inform about what may be technically and economically available to industry in order to improve their environmental performance[1]. These BREFs must be taken into account before a permit is granted to an installation. The American approach is similar: The US Environmental Protection Agency (EPA) offers a database of Maximum Available

---

[1] More information on the EIPPC Bureau can be found on the internet at: http://eippcb.jrc.es/

Control Technologies (MACT) to help industry reduce pollutant releases[2]; their implementation is also required before an operating licence is granted. The BREF and MACT initiatives are examples that demonstrate how technology and policy can go hand in hand to successfully achieve a common goal, the environmental protection.

Yet, the impact of the energy sector to the environment has another dimension on a global scale, the climate change. Since the early 90's it has been widely accepted by the scientific community that the global climate changes as a result of an enhanced greenhouse gas phenomenon that causes global warming [7, 8]. Global warming is the result of an increased concentration of a family of specific gases to the atmosphere. These gases have the property to trap solar heat and energy radiating from earth, that otherwise would have been reflected from the Earth's surface back to space. These gases are mainly generated by anthropogenic sources and include carbon dioxide (CO_2), methane (CH_4), fluorinated gases (PFCs, HFCs and SF_6) and nitrous oxide (N_2O), collectively termed as greenhouse gases (GHGs). Among these gases, CO_2 is the dominant human-influenced GHG, being responsible for over 60% of the enhanced greenhouse effect that leads to climate change [7]. Furthermore, the energy production and use sector is responsible for more than 85% of the total CO_2 emissions, as will be discussed in a following section, highlighting the contribution of the energy sector to climate change.

Due to the global scale of the climate change issue and the potential devastating effects of global warming to sustainable development[3], political discussions have taken place for the last decade under the auspices of the United Nations Framework Convention on Climate Change (UNFCCC)[4]. In 1997, UNFCCC produced the Kyoto Protocol[5], a legal agreement among the developed countries to limit their GHG emissions by at least 5% below the 1990 levels, by the period 2008-2012. The EU, Switzerland and most of the central and east European countries have committed to cut emissions by 8% [6]; the USA by 7%; Canada, Hungary, Japan and Poland by 6%. Russia and Ukraine are to stabilise their emissions, while Norway, Iceland and Australia are permitted to increase their level. Although the Kyoto protocol has been ratified by the EU (on May 31, 2002), its implementation is currently questionable given the resistance of a few countries, including USA to ratify it[7]. However, the EU, being at the forefront of the international Community's efforts to combat climate change, has *"…committed under the Kyoto Protocol to reduce greenhouse gas emissions…"* [9], being convinced that the Kyoto Protocol is *"… without a doubt, one of the most effective instruments in advancing toward the new model of development, … a model of sustainable development.* [10]*"*

---

[2] The technology and regulation databases of the EPA are available on the internet: http://www.epa.gov/ttn/catc/

[3] Consequences of climate change include rising sea levels, depleted agriculture, reduced water flows, increased health hazards, turbulent weather and social strains.

[4] More information on the UNFCCC can be found in the internet: www.unfccc.de

[5] For the full text of the Protocol see: http://unfccc.int/resource/docs/convkp/kpeng.html

[6] Under a "Burden Sharing" Agreement, agreed in June 1998, and legalised in March 2002, each member state has a different emissions reduction target, varying from -26% for Luxembourg and –21% for Germany, to +25% for Greece and +27% for Portugal.

[7] The rules for entry into force of the Kyoto Protocol require 55 Parties to the Convention that led to the Kyoto Protocol to ratify (or approve, accept, or accede to) it, including developed countries accounting for 55% of that group's CO_2 emissions in 1990. As of April 14, 2003, 106 countries have ratified the Protocol, accounting for 43.9% of the CO_2 emissions in 1990.

1.2 The introduction of hydrogen as the energy carrier for the future

The environmental issues highlighted in the previous section, together with concerns about the security of energy supply[8], have led many energy-sceptics to propose hydrogen as the energy carrier for the future, creating the so-called *hydrogen-economy*. Advocates of hydrogen support its advantages as a versatile, clean and efficient energy vector. Utilisation of hydrogen can reduce significantly the level of environmental pollution, the emissions of GHGs, the dependence on fossil fuel, and can open the path for distributed power generation. However, the hydrogen economy is hampered by technological hurdles, the most important being the production of hydrogen. Other issues that follow include the transport, distribution, storage and utilisation (vis-à-vis fuel cells).

Hydrogen is not a naturally occurring fuel. It is combined with other elements forming compounds such as water and hydrocarbons; the latter including fossil fuels. A necessary step for the utilisation of hydrogen as a fuel is its separation from these compounds. Currently, three major pathways have been identified that can lead to hydrogen production:

- Electrolysis to split the water molecule into hydrogen and oxygen, using electricity produced by *renewable energy sources* (RES) or other zero or low-carbon energy sources such as *nuclear energy*.
- Complex thermochemical reactions using heat from high temperature gas-cooled *nuclear reactors* or *solar-based RES*.
- *Chemical processes* to disassociate hydrogen from fossil fuels (coal, natural gas or heavy oil).

The discussion of the advantages and disadvantages of each of these approaches is out of the scope of this report[9]. However, it is important to mention that the option of electrolysis is hindered by the availability of RES (the use of electricity produced by fossil-fuelled power plants does not solve the problems of climate change and the security of supply), while the use of nuclear power is a highly controversial political issue. Nevertheless, both these options have the capability to produce hydrogen without emitting CO_2. The third option, the production of hydrogen from fossil fuels, although it has the drawback of producing CO_2, needs to be considered since it is easier to implement given that the technology is proven and the resources are significant and diverse.

Hydrogen can be produced by coal via the gasification process; by natural gas via steam reforming, and by heavy oils and biomass via partial oxidation. These processes convert fossil fuel, typically at elevated temperature and pressure, into a mixture of carbon monoxide (CO) and hydrogen, called synthesis gas or syngas. Subsequently, the CO reacts with steam to produce CO_2 and additional hydrogen by a water-gas shift reaction. Finally, CO_2 is separated resulting in a stream of hydrogen with high purity. The corresponding reactions that lead to the production of hydrogen from natural gas (essentially methane) are:

$$CH_4 + H_2O \leftrightarrow CO + 3H_2 \qquad \text{(methane reforming)}$$

---

[8] More information can be found in the European Commission's Green Paper "Towards a European Security for the Security of Energy Supply", COM(2000) 769 final, November 2000.

[9] SETRIS is considering launching within 2003 a study to assess the benefits and drawbacks of the various paths that can lead to large-scale hydrogen production in the medium term.

$CO + H_2O \leftrightarrow CO_2 + H_2$ (Water-gas shift reaction)

The overall reaction is:

$CH_4 + 2H_2O \leftrightarrow CO_2 + 4H_2$

In essence, in order to produce 1 tonne of hydrogen, 2 tonnes of methane are needed and 5.5 tonnes of CO_2 are produced. The amount of CO_2 emitted following the coal gasification route is even higher. Although it depends on the composition of coal, in general terms, the production of 1 tonne of hydrogen requires 3 tonnes of coal and produces 11 tonnes of CO_2.

Whether the idea of hydrogen economy materialises or not, will depend on technological and more importantly on economic and political factors. Foremost, the question of hydrogen production needs to be answered, and in this framework, the fossil fuel option should be considered. However, this option can be justifiable only when the issue of avoiding CO_2 emissions is resolved.

1.3 Setting the issue of CO_2 emissions in perspective

1.3.1 Carbon dioxide: Properties, formation, safety and risks

Carbon dioxide is a colourless, non-flammable gas. It is heavier than air with a density of 1.977 grams per litre (g/l). Its triple point is at a temperature of –56.6°C and at a pressure of 5.1 atm. Its critical point is at a temperature of 31.1°C and pressure of 72 atm; at higher temperatures and pressures CO_2 is in a supercritical state, characterised by liquid-like densities and gas-like mobility[10]. These advantageous physical properties of CO_2 in the supercritical state are fully exploited for the transport, utilisation and storage of CO_2. Carbon dioxide dissolves easily in organic solvents (such as acetone and ethanol) and in water, a property exploited by the carbonated drinks industry; its solubility declines as the water temperature rises. Carbon dioxide is one of the products of animal metabolism and is important in the life cycles of both animals and plants. It is present in the atmosphere in small quantities (0.03%, by volume). Carbon dioxide has several commercial applications (see page 64) and is treated as a commodity.

Carbon dioxide is mainly produced by the combustion of carbon-containing fuels such as natural gas, oil, coal and biomass. The chemical reaction of carbon, bound in the fuel, with oxygen generates CO_2 and releases energy:

$$C + O_2 \leftrightarrow CO_2,\ \Delta H° = -393.8\ \text{KJ/mol}$$

The production of CO_2 is therefore an intrinsic product of the combustion process, is proportional to the amount of energy released and, unlike many other pollutants such as sulphur and nitrogen oxides, no combustion technique can reduce its formation.

Given that, in general, the fuel is not combusted with pure oxygen but with excess air, the exhaust gases leaving a combustor also contain nitrogen, water vapour, oxygen, and other compounds. The relative proportion of these products in the exhaust gases varies with the fuel used and the parameters of the combustion process. As a rule of thumb the concentration of CO_2 in the flue gas of power plants ranges from 15% for pulverised coal (PC) combustion to 4% for natural gas combustion in combined cycle (NGCC)

---

[10] In practical terms, a material in supercritical state could be considered as a dense but extremely fluid liquid.

[14]; thus the concentration of CO_2 in the exhaust gas of combustion plants is relatively low. On the other hand, during the production of hydrogen from fossil fuels (from coal via gasification and from natural gas via steam reforming), a stream of almost pure CO_2 is produced as a result of chemical conversion processes, the amount of CO_2 formed being proportional to the hydrogen produced and depending on the chemical composition of the feedstock fossil fuel.

Carbon dioxide is not toxic and does not impose a hazard to humans unless it is found at high enough concentrations. At air concentrations within the range of 2-5% it causes discomfort and nasal irritation, while at concentrations of about 10% it can be lethal. Its introduction to ground waters can cause loss of wells, pumps and pipes due to corrosion[11], failure of the pumps due to gas lift, salt precipitation, breakage of infrastructure due to cavitation and loss of pumping volume. Presence of CO_2 in surface waters can be damaging to crops and kill trees, and have significant effects in fish physiology. The consequences of CO_2 are summarised Table 1 [13]. It has to be noted that the release of CO_2 in high e concentrations is a rare natural phenomenon that can be devastating. Release of CO_2 in Lake Nyos in Cameroon in 1986 has been responsible for the death of at least 1700 people and many animals. More recently, a slow release of CO_2 in Mammoth Mountain in California has resulted the death of trees in a 30 hectare zone.

Table 1: Consequences of the presence of CO_2 at concentrations higher than normal (shown in parenthesis in the left column) [13].

Media	*Consequences*		
	Low	**Moderate**	**Severe**
Air (280 ppm)	Discomfort (>1%)	Injuries (>5%)	Lethal, habitat loss (10%)
Buildings (280 ppm)	Noticable, no harm (>1%)	Irritation, discomfort (>2%)	Injury, evacuation (>5%)
Ground water (0.2%)	Elevated, low acidity without impacts (>0.2%)	Mild acidity and corrosion (>2%)	Acidity, well corrosion, irrigation loss (>6%)
Surface water (0.022%)	Elevated, low acidity without impacts (>0.022%)	Higher acidity, mild toxicity effect on irrigation (>1%)	Acidity, CO_2 explosion, fish kills (>2%)
Soils (1-2%)	Mild suppression of pH with no significant impacts (>2%)	Moderate acidity, tree/crop/soil cover loss (>3%)	Low pH, tree kills, animal deaths (>8%)
Biota (10^{-5} M)	Mild toxicity (>0.5%)	Injury to life functions (>2%)	Oxygen depletion, lethal (>4%)

---

[11] When CO_2 dissolves in water, it forms carbonic acid.

1.3.2 Reduction of greenhouse gas emissions in the EU during the period 1990-2000

Direct atmospheric measurements of CO_2 and of oxygen concentrations indicate that, 23.1±1.5 billion tonnes (Gt) of CO_2 had been emitted in average annually to the atmosphere by anthropogenic sources during the period 1990-99 (Ref. [7], p. 39, Table 2). Furthermore, in 1990, the reference year for the Kyoto protocol, the most developed countries, referred to as the Annex I countries,[12] emitted in total, 14.3 Gt of CO_2 [15]. The same year, the EU member states emitted 3.342 Gt, or approximately 23% of the emissions from the developed world [16]. That year, the USA produced 36% of the emissions from the developed world, the Russian Federation 17%, and Japan 8%[13].

The most updated data for the EU GHG emissions refer to the year 2000 [16] and show that, while the total GHG emissions fell between 1990 and 2000 by 3.5%, CO_2 emissions fell considerably less, by 0.5% to 3.325 Gt, see Figure 1 and Figure 2.

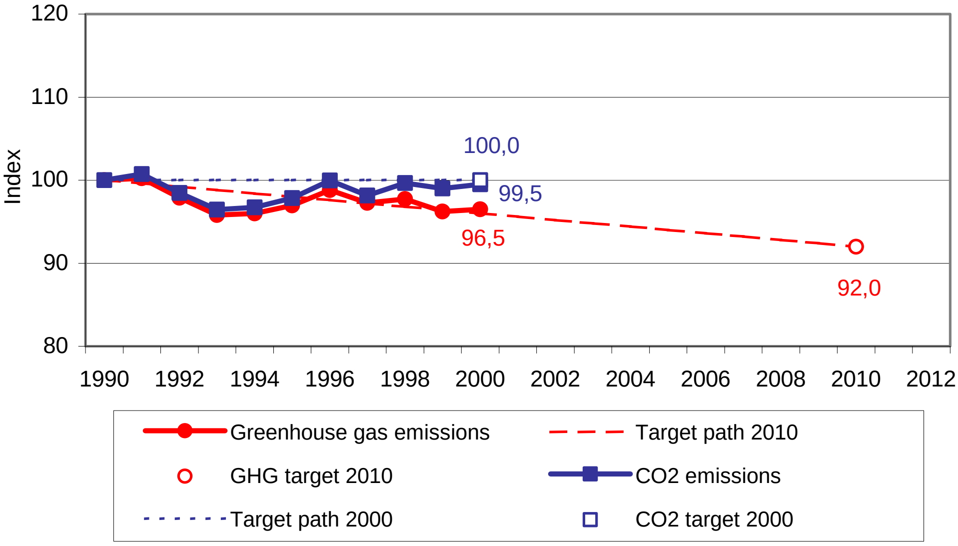


Figure 1: European Union greenhouse gas emissions during the period 1990-2000 compared with targets for 2000 and 2008-2012 (excluding land use change and forestry). The unit is index points with 1990 emissions being 100, providing a measure to evaluate overall EU greenhouse gas emissions. While GHG emissions in 2000 were 3.5% lower than the 1990 levels, CO_2 emissions were decreased by just 0.5% (Source: EEA [17]).

According to the European Environmental Agency (EEA) [17], despite the decrease in GHG emissions and the stabilisation of CO_2 emissions, the EU may not be able to achieve more ambitious emission reductions in the longer term. The observed reduction of GHG emissions came from non-energy production related sectors, where emissions decreased by 13.9%. However, non–energy production related sources account for less than 20% of the total emissions, indicating that, in order to achieve lower emission

---

[12] The Annex I countries are the EU15, Bulgaria, the Czech Republic, Australia, Estonia, Hungary, Iceland, Japan, Latvia, Liechtenstein, Monaco, New Zealand, Norway, Poland, Romania, the Russian Federation, Slovakia, Switzerland and USA.

[13] Calculations based on data for year 1990, collected by the IPCC secretariat by the end of 1997.

levels, these reductions should come from the energy industries (including public electricity generation, public combined heat and power generation, public heat plants, petroleum refining and manufacture of secondary and tertiary solid fuels) which is not likely for a number of reasons: About half of the stabilisation of CO_2 emissions at 1990 levels by 2000 resulted by one-off reductions in Germany and the UK, as a result of pre-decided restructuring plans of the energy industry, mainly the switch from coal to natural gas, and the closure of inefficient coal plants in former Eastern Germany. Furthermore, projections based on various business-as-usual (BAU) scenarios suggest that GHG emissions in 2010 will be at the same level as in 1990 (see next section).

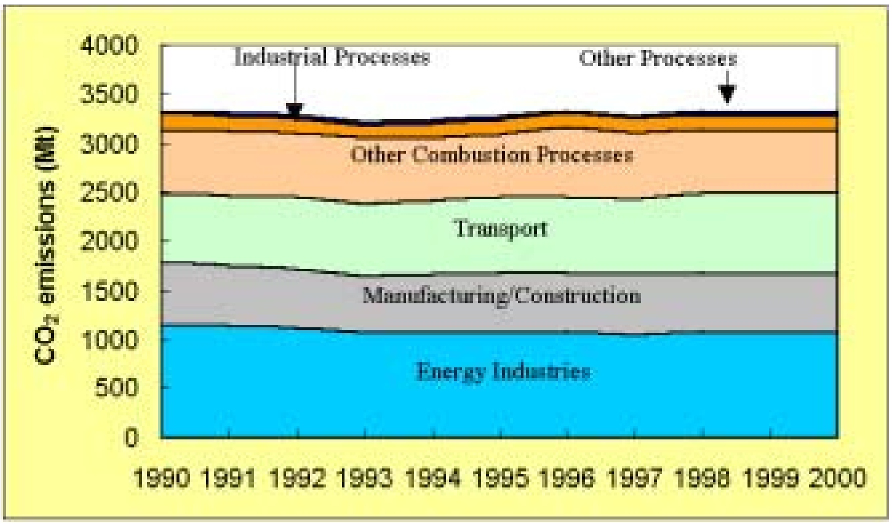


Figure 2: Carbon dioxide emissions in the EU during the period 1990-2000. The term ‘Energy Industries’ refers to emissions from fuels combusted by the fuel extraction or fuel processing industries. These emissions sources include public electricity generation, public combined heat and power generation, public heat plants, petroleum refining, manufacture of secondary and tertiary solid fuels (e.g. charcoal, coke, etc.), coal mining and gas extraction. Emissions from ‘Energy Industries’, ‘Manufacturing/Construction’, ‘Transport’ and ‘Other Combustion Processes’ originate from combustion of fossil fuel. ‘Other Processes’ include fugitive gases, solvent and other product use, agriculture and waste management. (Source: EEA [16]).

1.3.3 Carbon dioxide emissions and the energy sector

In 2000, almost one third of the total CO_2 emissions were generated from power plants that combust fossil fuel (coal, natural gas and oil) to produce electricity, and to a less extent heat. The second most important polluting sector is transportation that relies practically exclusively on oil. The remaining sources of CO_2 emissions are industrial and manufacturing sites that combust fossil fuel to meet their power needs, while non-combustion sources (industrial processes and others) account for less than 6% of the total CO_2 emissions [16], see Figure 2 and Figure 3.

In the future, it is anticipated that CO_2 emissions will continue to rise for two reasons. Firstly, the demand for power generation and especially for electricity is predicted to increase continuously and more rapidly than the anticipated improvements in the efficiency of the energy conversion sector, and secondly, it is widely accepted that fossil fuels will remain the main source for energy, at least during the first quarter of the 21st century, despite efforts and initiatives to reduce the reliance of our energy system on fossil fuels for reasons of energy security and environmental protection. In addition, the possibility of emitting CO_2 from hydrogen production plants (gasifiers and reformers) in the longer term, should also be considered. These statements, that are rationalised next, lead to the conclusion that energy related emissions will increase offsetting the reductions coming from the non-energy sectors.

The aforementioned statements that (i) energy demand in the EU will be increased, and, (ii) fossil fuels will remain the main source for energy, are reflected in a number of outlook reports that converge to similar conclusions irrespective of the institutions that developed them, indicating a consensus of the scientific community. The results of these outlooks are briefly presented next.

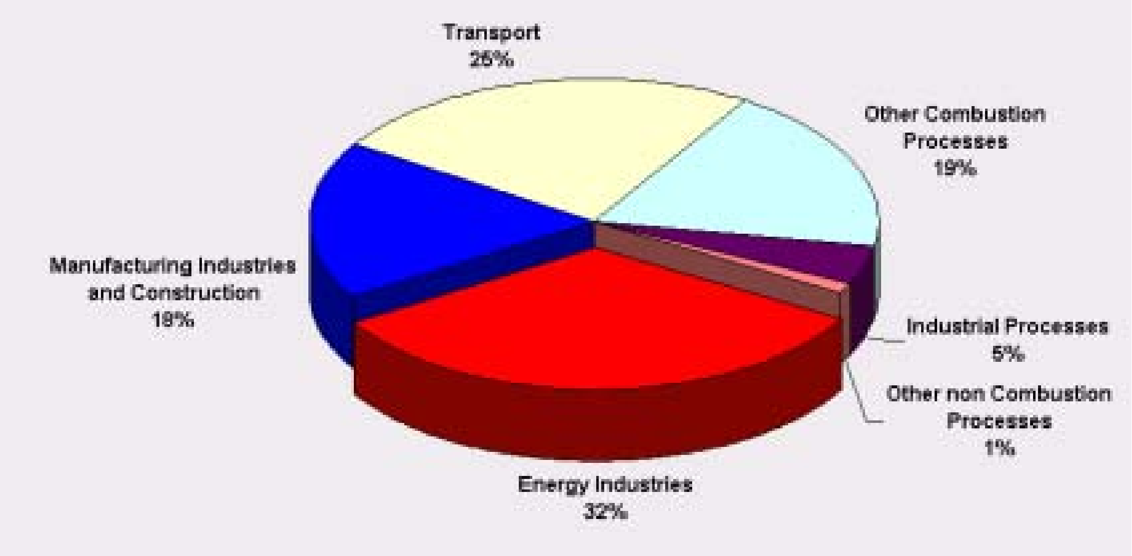


Figure 3: Carbon dioxide emissions in EU during 2000 by sector (Source: EEA [16])

A. *European Union Energy Outlook to 2020, European Commission*

In the 90's the European Commission funded an energy systems analysis aiming to identify a consistent energy and emissions outlook for the EU for the period to 2020. A key assumption for the baseline scenario developed is that, EU policies currently in place will be continued (liberalisation of the energy market, improvement of energy technologies, support to RES and to cogeneration, further penetration of natural gas, extension of lifetimes of nuclear plants and stringent regulation of air pollutants). However, the baseline scenario does not include any policies that specifically address the climate change issue. The results were published in 1996 and updated in 1999 [18]. Based on the baseline scenario presented in the updated study, final energy demand is expected to grow annually by 1.2% until 2010 and by 0.5% in the period 2010-2020, continuously relying heavily on fossil fuels (Figure 4). During the same period, the use of electricity is expected to expand by 1.7% per annum (Figure 5). Total CO_2 emissions are projected to increase annually by 0.6% in the period 1995-2020 despite the decline in the carbon intensity of the EU energy system (Figure 6). It is predicted that, by 2010, EU emissions will be 7.1% higher than they were in 1990; and by 2020 they are expected to be 14% higher than their 1990 level (Ref. [18], Table 3-26). The report explicitly states[14] *"Under the assumptions of the baseline scenario presented (…in this analysis…), the EU will not achieve stabilization of CO_2 emissions, let alone the decline commensurate with the commitment undertaken at the Kyoto conference."* It is interesting to note that, for the period until 2010, the transport sector will be responsible for 2/3 of the increase in CO_2 emissions, while, for the period 2010 to 2020, electricity and steam generation will be almost solely responsible for the increase in CO_2 emissions. Subsequently, in 2001, the results were updated indicating that CO_2 emissions in 2010 will be only 1% higher than the 1990 levels (see Ref. [19], Table 1) if an agreement with the European, Japanese and Korean car manufacturers would materialise aiming to reduce CO_2 emissions from the road transport sector by 25% until 2008 (the ACEA/JAMA/KAMA agreement).

B. World Energy Outlook, International Energy Agency

The World Energy Outlook is a regular (biannual) publication of the International Energy Agency (IEA)[15] that provides the Agency's views on the latest world energy projections. The 2000 edition [20] examines energy demand and supply to 2020 and draws the implications of these projections for energy related CO_2 emissions. In OECD-Europe, that includes EU-15 and Poland, Hungary, Turkey, the Czech Republic, Iceland, Switzerland and Norway, total final consumption is projected to advance by 1% annually (Figure 7) and electricity generation to grow by 2% annually (Figure 8). CO_2 emissions are expected to rise significantly, in contrast to their stability since 1990, due to rising demand for fossil fuel, despite established programmes and targets for the deployment of RES, including direct and indirect subsidies and renewable energy purchase obligations. The projected annual increase is 0.9% (Figure 9). The energy sector will account for an increasingly higher share of total CO_2 emissions, reflecting the higher growth in electricity demand relative to most other types of energy and increased reliance on fossil fuels for power generation. The share of electricity generation to CO_2 emissions will increase from 31% in 1997, to 33% in 2010 and 34% in 2020. The total CO_2 emissions from the energy sector will reach 24% above 1997 levels in 2010 and 36% in 2020. The report concludes by stating: " *… without major new initiatives (…) the EU as a whole will fall considerably short of achieving its greenhouse-gas emission target, unless exceptionally big savings are made in non-energy related emissions. …(It is reminded that) energy related CO_2 emissions account for the bulk of greenhouse gases"* [16].

C. Statistics and Prospects for the European electricity sector, EURELECTRIC

Eurelectric, the association of the European Union electricity supply industry, publishes an annual report, the *Eurprog* report, which contains statistics for the European electricity sector and medium and long-term forecasts. According to *Eurprog* 2001, electricity consumption in EU15 will raise by 16% during the period 2000-2010 (see Ref. [21], p. 168, Table 6.1). During the same period, electricity consumption in

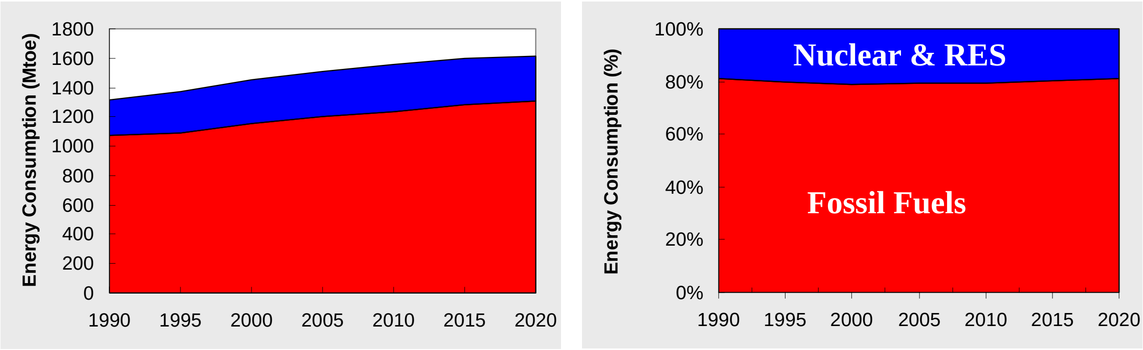
---

[14] Ref. [18], pages 60-61.

[15] IEA is an autonomous body established within the framework of the Organization for Economic Co-operation and Development (OECD).

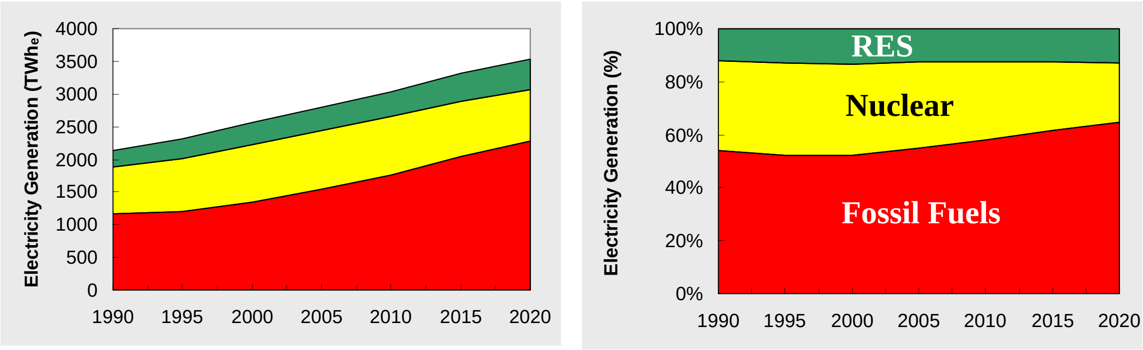
[16] Ref. [20], page 142.

candidate countries[17] will be increased by 26% (Figure 10a). The corresponding CO_2 emissions from thermal power stations are also expected to rise in the period 2000-2010, despite the reduction in emissions in the 90's (Figure 10b). More specifically, it is estimated that CO_2 emissions from electricity production for EU15 and the candidate countries will be at the same level as in 1990 (based on Ref. [21], p. 214, Table 7.3)[18].



(a) Absolute values (b) Fuel Shares

Figure 4: Outlook of the EU gross energy consumption, according to the European Union Energy Outlook to 2020 (Ref. [18], p. 186). Fossil fuels will remain the main source for energy. RES refers to renewable energy sources.



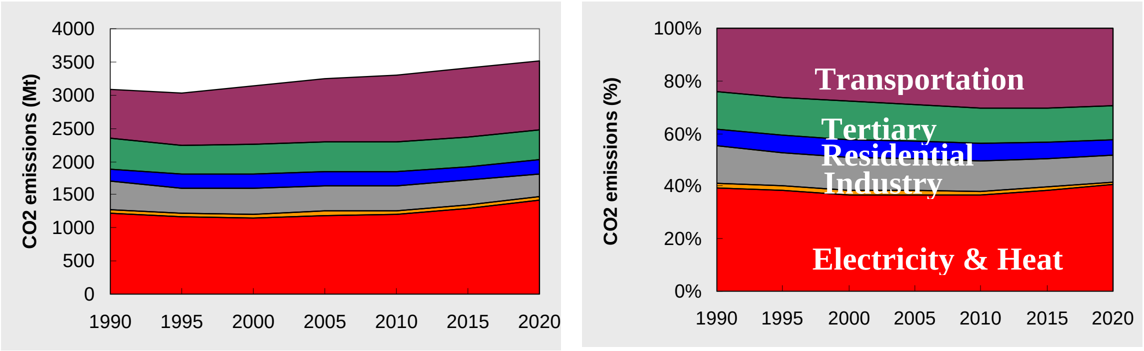
(a) Absolute values (b) Fuel Shares

Figure 5: Outlook of the EU electricity generation, according to the European Union Energy Outlook to 2020 (Ref. [18], p. 186). Electricity generation will increase and its production will rely more heavily on fossil fuels.

---

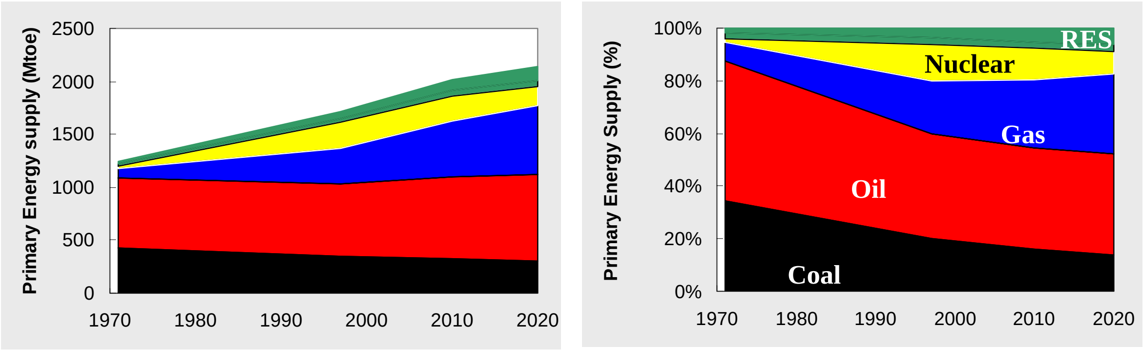
[17] In the context of that report candidate countries are Cyprus, the Czech republic, Hungary, Latvia, Lithuania, Poland, Romania, Slovakia and Slovenia.

[18] Data were not available for Belgium, Luxemburg, Hungary and Lithuania.



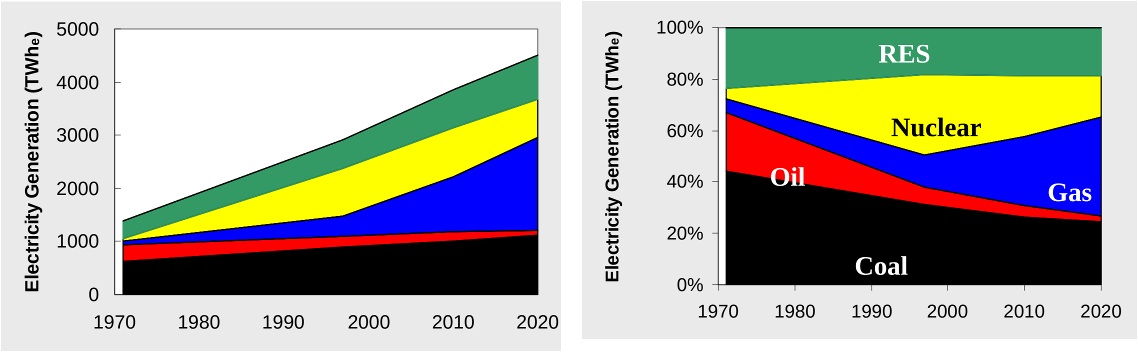
(a) Absolute values (b) Sector Shares

Figure 6: Outlook of CO_2 emissions in the EU by sector, according to the European Union Energy Outlook to 2020 (Ref. [18], p. 186). Electricity production will continue to be the main source of CO_2 emissions.



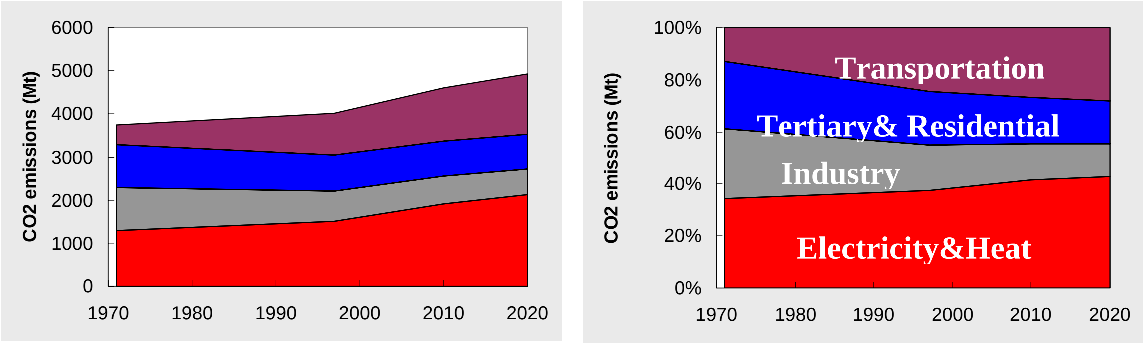
(a) Absolute values (b) Fuel Shares

Figure 7: Outlook of primary energy supply by fuel, in OECD-Europe, according to the World Energy Outlook (Ref. [20], p. 366).



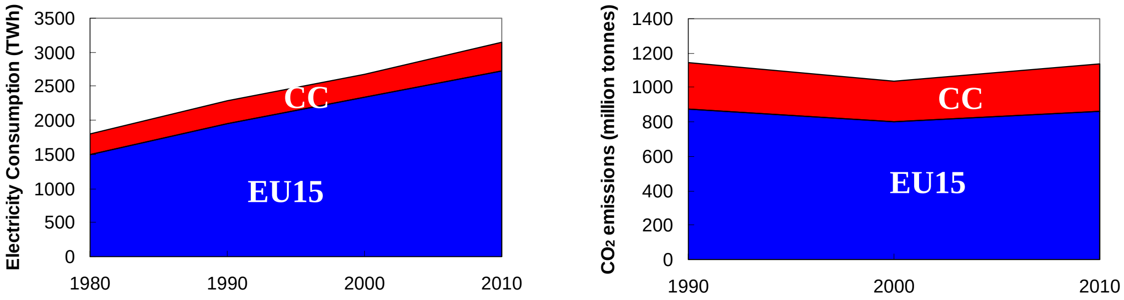
(a) Absolute values (b) Fuel Shares

Figure 8: Outlook of electricity generation in OECD-Europe, according to the World Energy Outlook (Ref. [20], p. 368).



(a) Absolute values (b) Sector Shares

Figure 9: Outlook of CO_2 emissions in the OECD-Europe by sector, according to the World Energy Outlook (Ref. [20], p. 369).



(a) (b)

Figure 10: (a) Electricity consumption and (b) CO_2 emissions from thermal power plants in EU15 and candidate countries (CC) [21].

C. International Energy Outlook 2002, US Department of Energy

The International Energy Outlook [22] presents international energy projections through 2020, prepared by the Energy Information Administration of the US Department of Energy (DoE), including outlooks for major energy fuels and issues related with, among others, electricity and the environment. According to the Reference Case Projections, the energy consumption in Western Europe (that includes the EU15, Norway, Switzerland and Iceland) will rise by 1% in average during the period until 2020[19] and the net electricity consumption by 1.7%[20]. The average annual percent change anticipated for oil, natural gas and coal is 0.6%, 3.0% and –1.2% respectively[21] and the corresponding CO_2 emissions from the energy sector will rise by 0.9% annually during the same period due to an increased energy demand that will be covered mainly by

---

[19] Ref. [22], page 179.

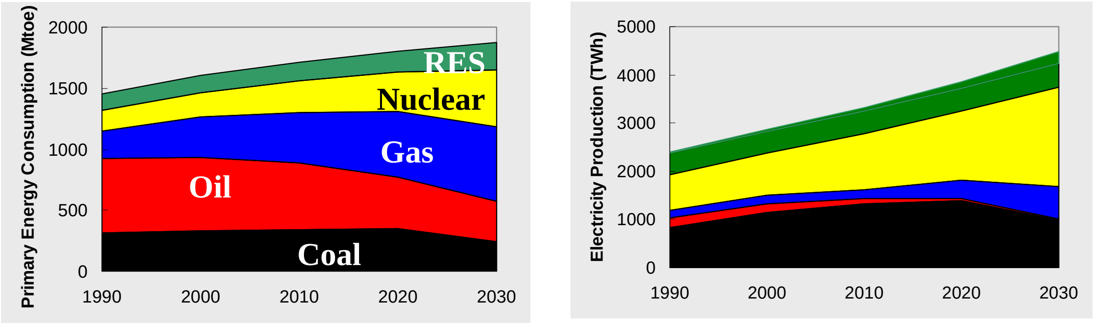
[20] Ref. [22], page 188.

[21] Ref. [22], page 180.

fossil fuels[22]. More specifically, it is anticipated that emissions due to combustion of oil and natural gas will rise by 0.8% and 3.0% annually, while emissions due to coal utilisation will fall by 1.3% annually[23]. Based on an alternative High Economic Growth Case, emissions will rise in average by 1.3% annually[24], while on a Low Economic Growth Case, emissions from the energy sector will rise by 0.5% annually[25].

D. Global Energy Perspectives, IIASA/World Energy Council

This publication [23] summarises the results of a five-year study conducted jointly by the International Institute for Applied Systems Analysis (IIASA) and the World Energy Council (WEC). The principal analysis covers the period through 2020 with some extensions to 2100. The projections of the 'middle course' scenario for Western Europe (EU and Norway, Switzerland and Iceland) for the period 2000-2020 indicate that: (i) primary energy consumption will increase by 0.6% annually, (ii) electricity generation will increase by 1.7% annually, and (iii) energy related CO_2 emissions in 2010 and 2020 will be 6% and 5% higher than in 1990 respectively. This is due to the continuous reliance to fossil fuels as the main source for energy, see Figure 11.



(a) (b)

Figure 11: (a) Primary energy consumption and (b) Electricity generation by fuel in W. Europe, according to IIASA projections [26].

1.4 Paths towards reductions in CO_2 emissions

During the last two years, the EU has adopted a number of instruments covering a range of issues directly related with CO_2 emissions reduction. These instruments include the Directive *on the promotion of electricity produced from renewable energy sources* [24]; a proposal for a Directive *on further liberalisation of the energy market* [25]; a Directive *on the energy performance in buildings* [26]; an Action Plan *to improve energy efficiency* [27]; a Green Paper *on the security of energy supply* [29]; a revision of

---

[22] Ref. [22], page 189.

[23] Ref. [22], page 190-2.

[24] Ref. [22], page 209.

[25] Ref. [22], page 229.

[26] Source: IIASA Website at: http://www.iiasa.ac.at/cgi-bin/ecs/book_dyn/bookcnt.py

guidelines on state aid for environmental protection [28]; a proposal for a Directive *for the promotion of cogeneration* [30]; and a proposal *for a common transport policy* [31] *and the introduction of alternative fuel for transport* [32]. However, the European Commission has recognised that these measures will not be sufficient to lead to the meeting of the targets set by the Kyoto protocol[27]. Consequently, the European Commission established the European Climate Change Programme (ECCP) in June 2000 with a mission to help identify the most environmentally and cost effective additional measures required to meet the targets set by the Kyoto protocol. The outcome of the ECCP initiative has been a report that includes both the development of existing policies and new proposals to contribute to the formulation of the EU's strategy to combat climate change [33].

The ECCP evaluated several measures based on their contribution to the reduction of GHG emissions, their cost effectiveness and the time frame within which the emissions reductions could materialise. These measures can be grouped into five areas, two of which refer to reductions of CO_2 emissions[28]:

- Improvement of energy efficiency, particularly in the transport sector, the industry and the tertiary sector (households and services).
- The decarbonisation of the energy supply.

Indeed, the ECCP Working Group (WG) 3 'Energy Consumption' has concluded that there is a CO_2 reduction potential between 220 million tonnes (Mt) and 247 Mt of CO_2 per year up to the year 2010, which can be achieved by applying measures to improve efficiency in buildings and services; furthermore, the ECCP Joint Sub Group on Energy Efficiency in End-Use Equipment and Industrial Processes estimates that the CO_2 reduction potential by improving energy efficiency in commercial equipment and the industrial sector can be 270 Mt; WG 4 'Transport' estimates that measures such as improvements in vehicle technology and fuel, transport infrastructure and fiscal measures, can reduce CO_2 emissions by 75 to 100 Mt annually. Finally, significant reductions in CO_2 emissions can be achieved by improving the efficiency of energy production and conversion sector. The ECCP WG 2 'Energy Supply' has identified that the following quantities of CO_2 can be avoided if the proper measures are applied: the introduction of combined heat and power (CHP) can result in reductions of 18 Mt of CO_2 annually, at a cost of 50€/tonne CO_2 avoided or less, or 65 Mt at a cost up to 100€ per tonne. An additional 100 Mt at a cost of 50€/tonne CO_2 or less can be achieved by increasing efficiency in fuel conversion. An improvement in energy efficiency offers an additional advantage as at the same time improves energy security, minimising the risks of dependence from fossil fuel imports, making these measures very attractive options. Indeed, by improving energy efficiency in EU significant gains can be made. An estimated economic potential for energy efficiency improvement of more than 18% of present energy consumption still exists today in the EU as a result of market barriers, which prevent the satisfactory diffusion of energy-efficient technologies and the efficient use of energy. This potential is equivalent to roughly the total final energy demand of Austria, Belgium, Denmark, Finland, Greece and the Netherlands combined. Realising the significance of improving energy efficiency the EU has set an indicative target to improve energy intensity by 1% per year above the estimated yearly baseline change, thus realising 2/3 of the available savings potential by 2010 [27].

---

[27] As mentioned in the previous section, it has been estimated that, with existing measures the level of GHG emissions for 2010 will be 1% higher than in 1990, based on the most optimistic scenario.

[28] The other three areas refer to reductions of nitrous oxide, methane and fluorinated gases.

Equally significant reductions in CO_2 emissions can be achieved by applying measures for the decarbonisation of energy supply (see Table 2). Two main approaches are currently explored: fuel switching in electricity generation and the use of renewable energy sources (RES). According to ECCP WG 2, by shifting existing power plants from coal to natural gas and by introducing natural gas plants in combined cycle mode instead of new coal plants, reductions of up to 90 Mt of CO_2 until 2010 can be achieved at a cost of 20€/t or less, and a further 25 Mt at a cost up to 50€/t. However, the majority of CO_2 emission reductions may arise from the potential use of RES. Recognising the positive contribution of RES to both energy security and environmental protection, the EU promotes their development and utilisation. The targets set by the Union are to increase the share of renewables to 12% of gross inland energy consumption and to increase the share of electricity from renewables to 22% of gross electricity consumption by 2010. If these targets are met, 126 Mt of CO_2 can be avoided at a cost of 20€/t or less until 2010, mainly by exploring the potential offered by onshore wind farms and biomass; an additional 18 Mt can be avoided (with a cost ranging 20-50€/t) mainly from onshore wind farms and CHP using biomass. The ultimate potential of RES in terms of avoided CO_2 emissions can be up to 200 Mt, but at a significant cost that may exceed 200 €/t depending on the technology, as in the case of photovoltaics and biofuel (ethanol or biodiesel) (see Table 2 and Figure 12).

Nowadays, technology offers an additional option with a significant potential to reduce even further the level of CO_2 emissions without decoupling immediately energy production from its main source, the fossil fuels: the carbon sequestration option; the capture of CO_2 from its emission sources and its permanent storage. The ECCP WG2 has identified that 50 Mt of CO_2 per annum can be avoided until 2010 with the implementation of carbon sequestration at a cost of up to 50€/tonne of CO_2, i.e., at a cost compatible with some of the RES. The volume of CO_2 emissions that can be avoided by carbon sequestration corresponds to 12% of the maximum emissions reduction that can be achieved at a cost of 50€/t of CO_2 or less (see Table 2).

In conclusion, the EU must drastically reduce GHG emissions, and thus CO_2 emissions within the next decade, to meet the targets set by the Kyoto Protocol. These reductions in CO_2 emissions should mainly come from the energy sector. Technology can play a significant role in realising these reductions, as this potential has already been realised in the past, with the successful control of pollution from the energy industry. However, studies indicate that CO_2 emissions will rise, unless appropriate measures are taken. This rise in emission levels is the result of a continuously increasing demand for energy, and especially for electricity. Furthermore, despite all measures to promote the penetration of renewable energy sources, fossil fuels will remain the main source for energy, at least for the next 20 years. One of the choices considered to reduce further the level of CO_2 emissions is carbon sequestration; an option that permits the continual use of fossil fuel as the main energy source for the near-term, thus smoothly reducing the impact of the forthcoming decoupling of energy production from fossil fuel sources.

Table 2: Potential for CO_2 reductions in Mt of CO_2 from the energy supply sector (based on ECCP Long Report [33], Table 4, p. 30).

Specific abatement costs (€/tonne CO_2 avoided)	**<0**	**0-20**	**20-50**	**50-100**	**100-200**	**>200**	**Maximum Potential (Mt)**
CHP		1	17	47			**65**
Fuel Switching							**113**
Shift from coal to gas		25	25				
New gas instead of new coal		63					
Increasing Efficiency of Fuels Conversion			100				**100**
RES							**200**
Wind onshore		20	10				
Wind offshore				18			
Biomass	25	64	8				
Hydro		17					
Tidal/Geothermal/Solar photovoltaic				2	2	1	
Biofuels						33	
Sequestration			50				**50**
TOTAL per cost range (Mt)	**25**	**190**	**210**	**67**	**2**	**34**	**528**

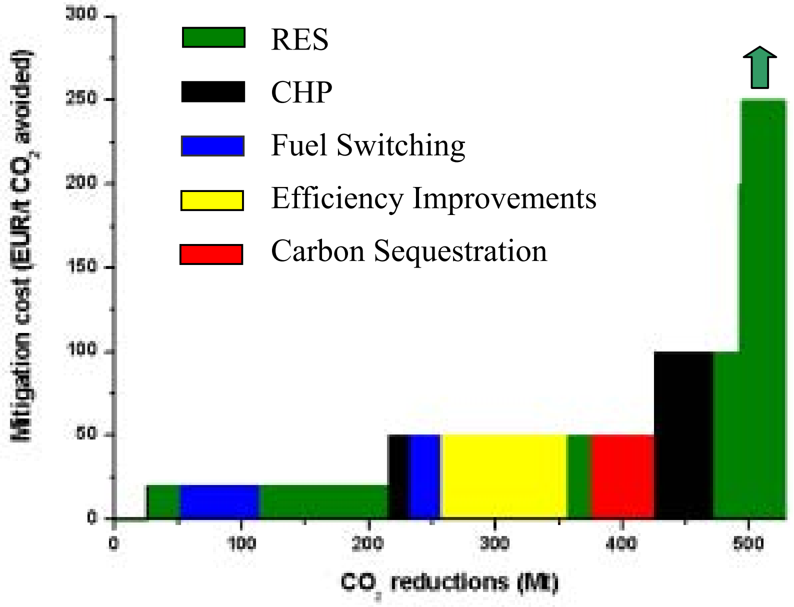


Figure 12: Potential and cost of avoidance of CO_2 in EU according to ECCP

2. Methods of Carbon Sequestration

2.1 Carbon Sequestration as a Natural Process

Carbon is an element abundant on Earth and essential for maintaining life, as it is the key constituent of organic matter. It is present underground in many forms such as carbonated minerals and fossil fuel; it is abundant on the surface of the earth in soil and as a key component to fauna and flora; it is present in water masses, as organic matter or in diluted inorganic compounds; and it is found in the atmosphere, mainly as CO_2. Carbon dioxide is the main form through which carbon is exchanged between the aforementioned natural carbon reservoirs, i.e. the ocean, the atmosphere, the terrestrial biosphere, sediments and sedimentary rocks. This carbon exchange process is known as the carbon cycle (Figure 13). The amounts of carbon exchanged via natural processes is far more larger when compared with the amount of carbon emitted due to anthropogenic sources (7 billion tonnes of carbon annually). For example, it is estimated that 62 billion tonnes of carbon are absorbed by terrestrial ecosystems (forests, soil and other vegetation) via photosynthesis, although 60 billion tonnes are re-emitted as a result of respiration and decomposition of organic matter every year. Similarly, the ocean absorbs roughly 92 billion tonnes of carbon annually via physical and chemical processes, and releases 90 billion tonnes back to the atmosphere while it is estimated that 3 billion tonnes are transformed into ocean sediment.

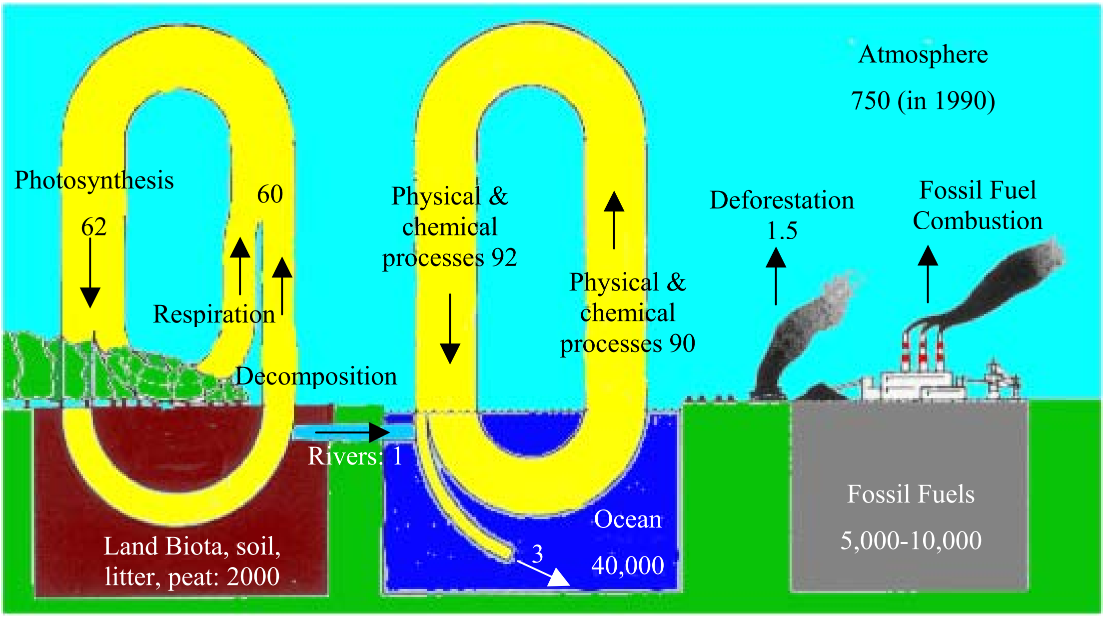


Figure 13: Carbon cycle in the Earth. The units are billion tonnes of carbon. (Adopted from Ref. [34], p. 23).

Recent measurements have shown that such natural processes have the capability to capture and store a part of the carbon emitted in the atmosphere due to human intervention; thus, from this perspective, carbon sequestration can be considered as a natural process. Although, the results are not yet conclusive, it is estimated that, out of the 6.3 billion tonnes of carbon emitted in the atmosphere annually due to fossil fuel combustion in average during the period 1990-99, only half of it is accumulated in the atmosphere (3.2 billion tonnes, or 51%) [7]. The ocean absorbs 1.7 billion tonnes or 27% of carbon emissions and the remaining 1.4 billion tonnes (22%) is absorbed by the terrestrial ecosystems (see Figure 14). The annual average anthropogenic carbon budget for the period 1990-99 is summarised in Table 3.

Table 3: Annual average anthropogenic carbon budget for the period 1990-99, in billion tonnes (Gt) of carbon per year[29]. For comparison, emissions from fossil fuel combustion during the period 1980-89 were 5.5 billion tonnes [7].

Sources (billion tonnes of carbon, Gt C)	
Emissions from fossil fuel combustion and cement production	6.3 ± 0.4
Sinks (billion tonnes of carbon, Gt C)	
Storage in the atmosphere	3.2 ± 0.1
Ocean uptake	1.7 ± 0.5
Land use change and residual terrestrial sink	1.4 ± 0.7

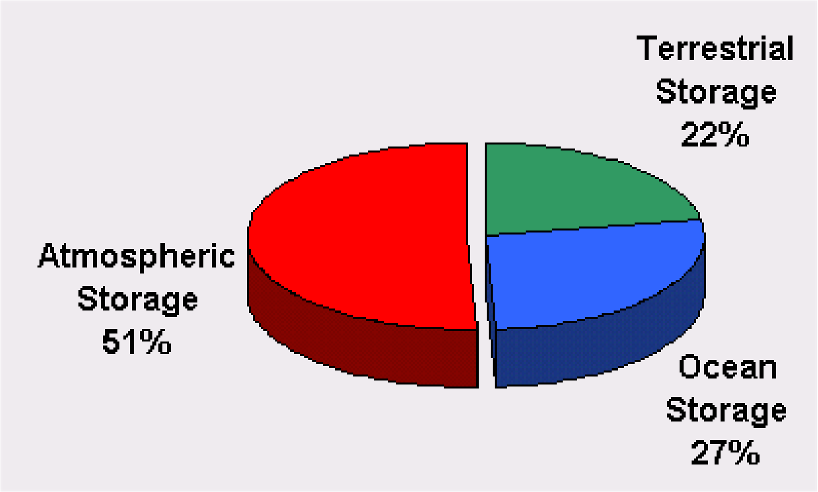


Figure 14: Partitioning of anthropogenic emissions related with fossil fuel combustion to natural carbon reservoirs (Data after [7]).

---

[29] To convert tonnes of carbon to tonnes of carbon dioxide multiply by 3.67.

2.2 Types of Sequestration

Natural processes that capture CO_2 from the atmosphere occur at very slow rates, making them practically inefficient tools in our efforts to control the level of CO_2 concentration in the atmosphere. For example, it has been estimated that of 100 molecules of CO_2 injected into the atmosphere 6 molecules will dissolve in the ocean in 1 year, 29 molecules will dissolve in 10 years, 59 molecules in 60 years and 84 molecules in 360 years. More than 1000 years will be needed to dissolve them all [35]. Similarly, it takes up to 100 years for trees to grow and thus, store carbon in their trunks. Eventually, the carbon stored in trees and other vegetation will return back to the atmosphere, via fires, decomposition, etc.

However, there are two distinctive paths that can be followed in order to sequester carbon from the atmosphere more efficiently. The first approach is to enhance the natural processes discussed in the previous section. The second approach is to capture CO_2 directly from the emission sources by technological means, transport it and store it permanently.

2.2.1 Enhancement of natural processes: Terrestrial sequestration

Carbon dioxide is removed from the atmosphere by photosynthesis in plants and stored in organic matter (biomass). Our current knowledge about sequestration of carbon in terrestrial ecosystems is hampered by uncertainties about the estimation of the amount of carbon that can be removed from forests and soil. However, the most important drawback of terrestrial sequestration is the low removal efficiency. For example, the British Government Panel on Sustainable Development has estimated that in order to capture and store the carbon emitted from fossil fuels in UK solely by terrestrial sequestration, the area that needs to be planted is twice the land area of UK; the annual emission from an average car (about 4 tonnes of CO_2) is absorbed by about 0.4 hectares of conifer forest or about 40 widely-spaced broadleaved trees. However, in countries like Finland and Sweden, the forest sink may be equivalent to 40-50% of the national fossil fuel emissions whereas in most of the smaller nations with high population densities the sink is 1-15% of national fossil fuel emissions. The European average forest sink is about 9.5% of European emissions [36].

While the annual average uptake of CO_2 from the terrestrial ecosystems worldwide during the period 1990-99 is estimated as 5 billion tonnes, the maximum potential for terrestrial ecosystems to capture CO_2 between 1995 and 2050 is estimated as 220-320 billion tonnes in forests and another 84 to 160 billion tonnes in agricultural soils, or 16-26% of the total fossil fuel emissions over the same period, according to the IS92a emissions scenario from IPCC[30] [37]. Furthermore, the second ECCP Progress Report has identified that the emission reduction potential of EU15 by 2010 in forests and agricultural soil is 60-70 million tonnes of CO_2-equivalent, or roughly 10% of the corresponding EU emission reduction target [38].

Afforestation is accompanied by environmental side effects: biodiversity is likely to increase when converting agricultural land to forest but water use is expected to

---

[30] The Intergovernmental Panel on climate change (IPCC) is a body that provides scientific, technical and socio- economic advice to the world community, and in particular to the 170 plus Parties to the United Nations Framework Convention on Climate Change (UNFCCC). More information is available of the Internet: www.ipcc.ch

increase; humidity is likely to increase, temperature to lower and rainfall to increase locally, in the vicinity of large forests; and in areas with air pollution, afforestation will result in the transfer of pollutants to soil.

The developing countries have greater potential for long-term forestry compared with industrialised countries. An analysis by the IEA Greenhouse gas programme [39] estimates that there is the potential to remove an additional 0.94 Gt of carbon every year from the atmosphere by implementing aforestation in developing countries (mainly in the tropics) and make use of excess pasture and low-producing arable land in the industrialised countries; more than 60% of this potential is in Africa and South America. The minimum cost per tonne of CO_2 removed from the atmosphere is estimated as 3.3€/tonne of CO_2 in the tropical countries that benefit from low plantation costs and high carbon fixation rates. The average cost in the developing countries is estimated as 4.4€/tonne, while costs are significantly higher in the industrialised countries (~21€/tonne). Costs and global potential are summarised in Table 4.

Table 4: Cost of terrestrial sequestration and estimated potential [39]

	Developing Countries	*Industrialised Countries*
Land purchase, plantation, maintenance costs (€/ha/y)	61	170
Minimum cost of CO_2-avoidance (€/t CO_2)	3.3	17
Average cost of CO_2-avoidance (€/t CO_2)	4.4	21
Minimum increase in electricity costs (c/kWh)	0.3	1.4
Average increase in electricity costs (c/kWh)	0.4	1.7
Global reforestation potential (Mha)	210	78
Global CO_2 sequestering potential (Gt CO_2/y)	2.86	0.59

However, plant respiration, deforestation, fires, plant decomposition and other natural events eventually return CO_2 back to the atmosphere. Thus, it should be stressed that terrestrial biota are temporary carbon sinks with a life span of 15-100 years that is a typical life span of the fauna. Therefore, the benefit gained during the period that plants and tress grow will eventually be reversed by a change in land use, or by fire, thus imposing a burden to future generations to maintain the land use, which originally created the enlarged carbon reservoirs. However, growing biomass for energy offers an advantage over traditional afforestation by maintaining the level of carbon sink constant and in parallel providing an alternative energy source. The growing of biomass involves the short rotation cropping of a plantation of fast growing trees which are harvested every 3-10 years and which retain the same root system for several generations. The average cost of biofuel varies from 20€/tonne (or 1.2€/GJ) in the tropical countries, to

47€/tonne in the developing countries to 84€/tonne in the industrialised countries[31] [39]. The idea of introducing biofuel on a large scale has gained a momentum recently and plethora of information is available; as such this topic will not be discussed further herein.

2.2.2 Enhancement of natural processes: Ocean fertilisation

Like the terrestrial biota and the atmosphere, the ocean is a natural sink for CO_2. It is estimated that currently the world's oceans contain 40,000 billion tonnes of carbon (compared with 750 billion tonnes of carbon stored in the atmosphere) being the largest natural carbon reservoir. Furthermore, oceans are not saturated with CO_2 thus they can store additional significant amounts, an idea that can be exploited as a storage option (see page 79). It is claimed that by adding to the ocean an amount of CO_2 equivalent to doubling the pre-industrial atmospheric concentration of the gas, it would change the carbon content of the sea by less than 2% [40].

Transfer of CO_2 from the air to the sea is rapid, facilitated mainly by entrapment of air in breaking waves. Upon entering the seawater, CO_2 is partitioned between three main chemical species in the oceans: dissolved CO_2, bicarbonate ions (HCO_3^-) and carbonate ions (CO_3^{2-}). For every 100 units of inorganic carbon, approximately 98 are present as HCO_3^-, one as CO_3^{2-} and one as CO_2 [41]. Subsequently, some of this carbon is trapped for long times either in the deep ocean or transformed into organic carbon.

CO_2 can be absorbed in the ocean by two distinctive mechanisms.

- The solubility pump: CO_2 is soluble in cold seawater in high latitudes of North Atlantic. The CO_2-rich water subsequently sinks to the bottom of the ocean and is 'conveyed' southwards nearly to Antarctica before eventually surfacing in the Indian Ocean and in the Equatorial Pacific. There, CO_2 escapes to the atmosphere again. The time interval, between water sinking at high latitudes and resurfacing in the tropics, is estimated to be around 1000 years, practically trapping permanently the CO_2; a phenomenon called the *thermohaline circulation*, see Figure 15.

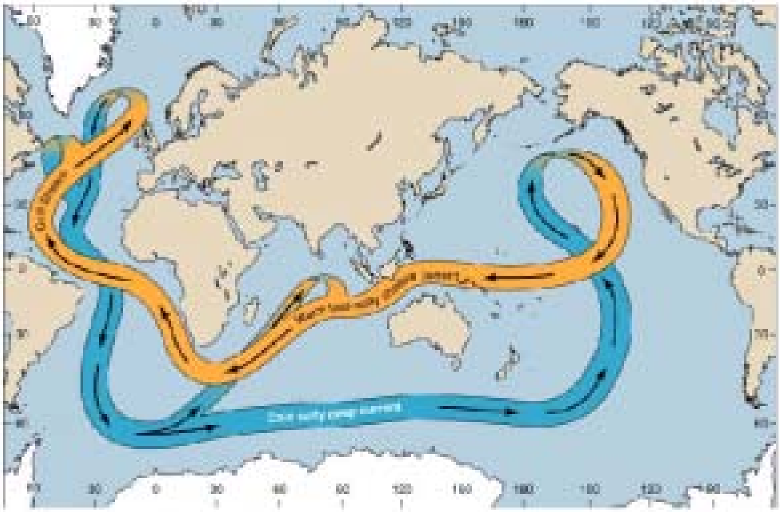


Figure 15: The thermohaline circulation (Source: Ref. [42])

---

[31] Costs include land purchase, plantation and maintenance, harvesting and transport.

- The biological pump: carbon from the atmosphere is absorbed by phytoplankton on the surface of the ocean and CO_2 is transformed into organic carbon entering the ocean food chain. While the majority of organic carbon ultimately returns to the atmosphere, a fraction of it (approx. 30%) becomes trapped in the deep ocean for long times (practically permanently) and a part of it sinks into the bottom of the ocean and transforms into rock by bacteria (See Figure 16).

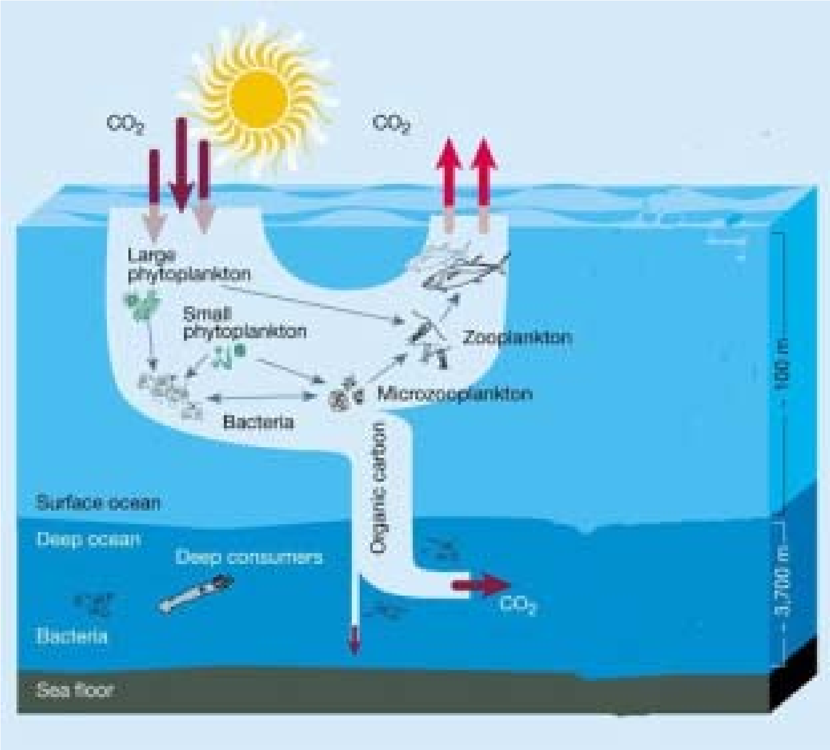


Figure 16: The ocean biological pump (Source: Ref. [43])

Approaches have been considered to enhance the natural uptake of CO_2 by the ocean. Two different methods have been proposed: To inject CO_2 directly into the ocean (a subject to be dealt in Chapter 5, page 79) and to enhance the superficial uptake by fertilising the ocean in order to stimulate the growth of phytoplankton. It has been demonstrated that the addition of either macronutrients[32] or iron, an essential micronutrient, can increase the amount of CO_2 that is absorbed from the ocean's superficial waters. The addition of macronutrients for the purpose of creating massive floating seaweed farms has been considered as an extremely expensive and ineffective sequestration approach [71]; however the introduction of nitrates finds few supporters in the scientific community who claim that this process can enhance significantly the fish catch and sequester up to 3.5 billion tonnes of CO_2 annually at a cost of 5-15€ per tonne of CO_2 [72]. On the other hand, several large-scale experiments[33] in the South Pacific

---

[32] Macronutrients include nitrates and ammonia, phosphates and silicates.

[33] As an example, the Southern Ocean Iron Experiment (SOFeX) was launched recently that involves 76 scientists from 17 institutions.

have proven that the addition of iron enhances the growth of phytoplankton and reduces the levels of CO_2 concentration in the atmosphere in the area of the experiments. For example, the IRONEX2 experiment demonstrated that the addition of 0.1 mg of diluted iron per litre of seawater, equivalent to 10-20 fold increase in iron concentration, increased the production of biomass 30 times and reduced the surface concentration of CO_2 by 60% [71]. However, the success of such an approach depends strongly on local circulation and hydrography. Furthermore, the area of Southern Pacific has been identified as the most promising location for iron fertilisation and modelling work indicates that potentially, atmospheric CO_2 concentration could be lowered by 6-21% with the deployment of such an approach. The amount of iron required to achieve this goal is 100-500 thousand tonnes annually at a cost varying from 1.2-11 €/tonne of CO_2 removed.

Nevertheless, there are many questions and unknowns at this stage to determine whether iron fertilisation represents a feasible and practical approach to enhance ocean sequestration: It is not clear if iron enrichment accelerates the downward transport of carbon from surface waters to the deep sea, and if so how can this amount of carbon be verified. Most importantly, the environmental impact is likely to be substantial. Ocean fertilisation may lead to a decline in oxygen levels, with negative effects to biodiversity and food chain, biology and biogeochemistry; can be responsible for the formation of other GHGs such as nitrous oxide and methane, due to enhanced bacterial processes; and result in the production of harmful chemical compounds (e.g., chloroform) from the macro-algal action. Furthermore, public perception can be an additional difficulty to overcome. A lack of fundamental understanding of the processes involved as well as the potential impact to the ecosystem makes it unlikely that any large-scale ocean fertilisation schemes will be implemented at present, but pilot schemes are planned, primarily to investigate the potential for increasing fish catches. Increased levels of marine research are needed to improve our understanding of the oceans and confirm the merits and net benefits offered by these proposed strategies.

2.2.3 Direct Carbon Sequestration

The term direct carbon sequestration refers to the removal of CO_2 directly from anthropogenic emission sources such as large combustion installations (power plants and industrial and manufacturing sites) and potentially large hydrogen production facilities, by technological means. As has already been mentioned, CO_2 is contained either at high concentrations in syngas or shifted syngas (in hydrogen production applications and nowadays in electricity generation using the integrated gasification combined cycle –IGCC- technology) or at a small fraction in the flue gas of combustion systems (4-14% depending on the fuel used and the combustion process). In both cases, it would be more practicable, economical and less energy consuming to separate and store CO_2 from the feed gas[34], rather than to capture and store the whole volume of feed gas[35]. Therefore, the gases that contain CO_2 need to be processed so that CO_2 is separated and captured. Subsequently, CO_2 has to be transported to a location where it

---

[34] Feed gas refers to the gas that contains the CO_2. For example, in PC and GTCC plants, feed gas refers to the exhaust gas, while in hydrogen production and IGCC, to the shifted syngas.

[35] An analysis has shown that the energy required to compress the total volume of flue gas generated by a thermal power plant to 100 bar, is approx. 65% of its power output. This power requirement drops below 8% when only the contained CO_2 is compressed [62].

can be stored for as long as possible, effectively for hundreds or thousands of years. Broadly speaking, the direct carbon sequestration process (referred to simply as *carbon sequestration* from now on) involves three stages, shown schematically in Figure 17:

1. The separation and capture of CO_2 from the sources of emission
2. The transportation of the captured CO_2 to the storage/disposal site, and,
3. The storage of captured CO_2, or its utilization in other applications offering an added value to the whole process.

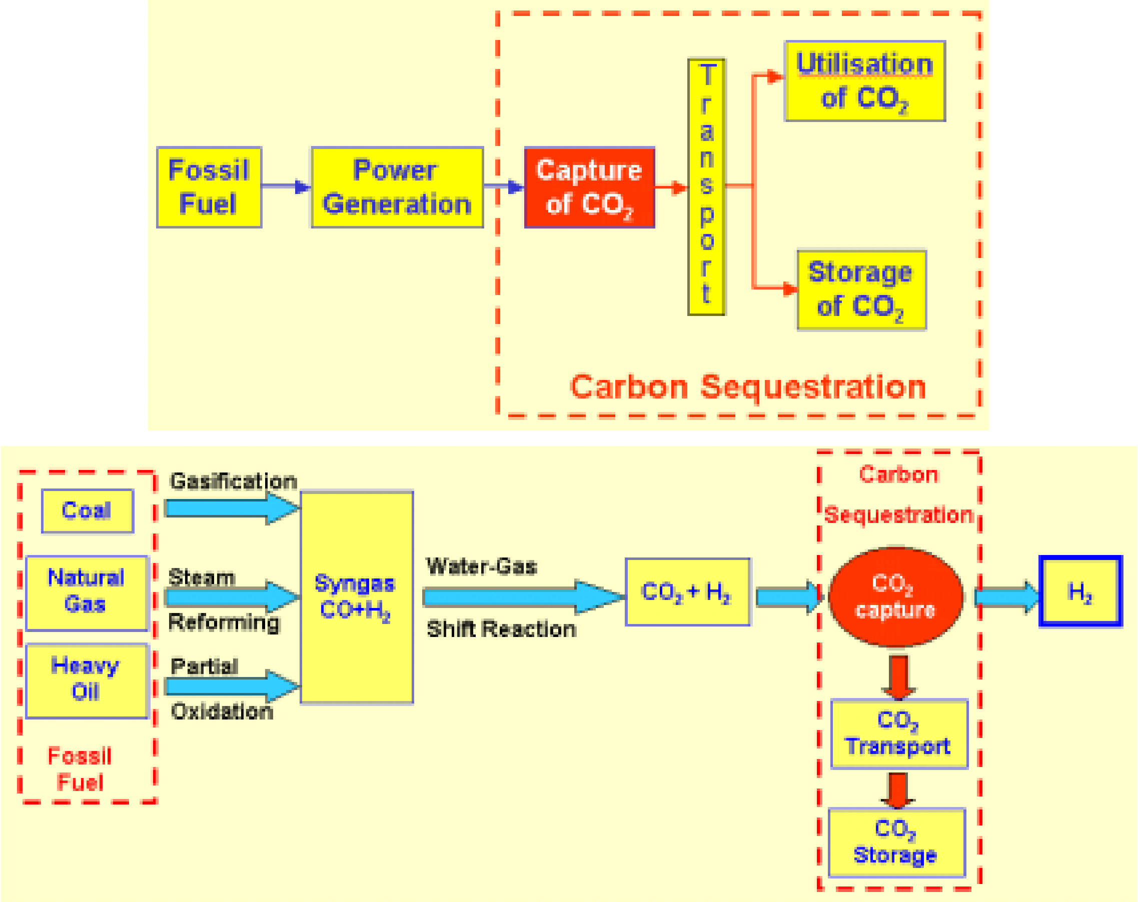


Figure 17: Carbon sequestration in fossil fuelled power plants (top) and hydrogen production plants (bottom)

In contrast to natural sequestration, direct sequestration has the potential to remove larger quantities of CO_2 and in a shorter time period. Moreover, since emission sources in transport, industry and manufacturing are small and disperse, while power generation plants (for electricity and potentially for hydrogen) are comparatively few and large, it is evident that significant steps towards reducing CO_2 emissions can be made faster and more inexpensively by reducing emissions from power plants that are few in number but are currently responsible for one third of the total CO_2 emissions.

The issues involved with carbon sequestration present major technological challenges that have to be met in order for the process to be deployed successfully. Most pressing issues are reducing capital and operating costs of CO_2 capture and developing storage options. In view of the potential to reduce the emissions of CO_2 emitted in the atmosphere without having to make significant sacrifices in terms of infrastructure, carbon sequestration has gained a momentum and is considered as a valid option for carbon dioxide emissions abatement.

3. Separation and Capture of Carbon Dioxide

3.1 Introduction

Several commercial technologies are available today that are able to separate CO_2 from a stream of gases. However, none of these technologies has been developed for large-scale carbon sequestration operations. Rather, they have been developed to produce a stream of high purity CO_2 for commercial markets, such as chemical manufacturing and food processing, as will be discussed next, to remove CO_2 from natural gas or to produce hydrogen for the petrochemical industry. Traditionally, the technologies available for the separation and capture of CO_2 can be grouped into three main categories:

- **Post-combustion decarbonisation:** A typical approach to decarbonisation is to clean the flue gas that exits the combustor of fossil-fuelled power generation plants (that contain 4-14%vol. of CO_2). This is a standard 'end-of-pipe' approach also used to remove other pollutants such as oxides and nitrogen and sulphur (by FGD[36] and SCR or SNCR technologies respectively), dioxins and furans from waste incineration plants (using SCR or active carbon), etc.
- **The syngas approach/pre-combustion decarbonisation:** As was briefly discussed in page 15, fossil fuel can be treated to produce syngas, a hydrogen-rich fuel that can either be combusted to produce electricity (e.g. in integrated gasification combined cycle plants-IGCC), or can be further treated (in a water-gas shift reactor) to produce pure hydrogen, that can either be combusted in gas turbines or used in fuel cells. In the latter case, which has the potential to play a significant role in a future hydrogen economy, CO_2 formed during the process is separated from hydrogen before the latter can be utilised (pre-combustion decarbonisation).
- **Oxyfuel combustion:** This approach to decarbonisation is quite distinct from the other approaches described above. In this case, separation is achieved by intervening to the combustion process itself, aiming to increase significantly the amount of CO_2 in the exhaust gas (to a level of at least 90%) thus facilitating a more efficient and simple removal of CO_2. This is achieved by combusting the fuel with pure oxygen and re-circulating part of the flue gas into the combustor.

There are a number of technologies that have the potential to separate CO_2 from the flue gas (in post-combustion decarbonisation), or the syngas (in pre-combustion decarbonisation). These technologies are based on gas absorption, gas adsorption, membrane separation, cryogenics (low temperature distillation) and other novel techniques. The applicability of each capture technology depends on the feed gas conditions, namely its composition, the concentration of CO_2, the degree of required CO_2 removal from the feed gas, and the gas temperature and pressure. It should be noted that flue gas is quite different from syngas. Syngas is available at a higher pressure and temperature than flue gas and has a higher CO_2 concentration. Furthermore, it has been estimated that the exhaust gas from oxyfuel combustion is produced at even higher pressures at ambient temperature. The exact temperature, pressure and composition of each feed gas depend on the plant type, operating conditions and application. Indicative values are presented in Table 5.

---

[36] FGD stands for flue gas desulphurisation and S(N)CR for selective (non)catalytic reduction.

Table 5: Indicative values of the pressure, temperature and CO_2 concentration of the various types of feed gas. Carbon dioxide capture and separation processes should be compatible with these gas conditions.

	Flue gas	***Syngas***	***Oxyfuel exhaust gas***
Pressure (atm)	1	>5	>50
Temperature (°C)	<100	>100	<50
CO_2 concentration	4-14%	~35%	>90%

3.2 Absorption technologies

Gas separation by absorption relies on the principle that a gas species (in this case CO_2) is transferred between the feed gas (e.g. syngas or flue gas) and a liquid phase, the absorbent or solvent. The liquid and the gas phases are brought in contact, and, based on the solubility of the components of the feed gas, gas species can be selectively absorbed into the liquid solvent, while the remaining components of the feed gas pass through the absorber and are released in the atmosphere. As a last step, after absorption, the solvent, rich in CO_2, is regenerated by the application of heat or pressure (depending on the type of solvent): The captured CO_2 is separated from the absorbent and collected, while the lean absorbent is recycled.

Carbon dioxide separation by absorption can be achieved by physical, chemical and hybrid methods, the difference being the type of bonding between the absorbent and CO_2. In physical absorption, CO_2 is absorbed in a solvent according to Henry's law[37]. In chemical absorption, CO_2 reacts with the absorbent, creating weakly bonded compounds, called carbamates. Hybrid systems combine the attributes of physical and chemical absorption. A major difference between chemical and physical absorption is that the solubility of a target gas[38] in physical solvents increases linearly with the target gas partial pressure, while chemical solvents have a high absorption capacity at relatively low partial pressures but reach a plateau at higher partial pressures (see Figure 18). Therefore chemical absorption is preferred for the separation of CO_2 at low partial pressures (e.g. in flue gas treatment), while physical absorption is favoured at high partial pressures, for example for syngas treatment in pre-combustion decarbonisation and in hydrogen production. Because typical flue gases from power stations have low CO_2 partial pressures (less than 10 kPa), chemical absorption is the separation technology of choice, since the driving force for other separation methods such as physical absorption, adsorption, membrane separation and cryogenic separation is diminished.

---

[37] According to Henry's law, the mass of a gas dissolved by a given volume of solvent at constant temperature (m_{solute}) is proportional to the pressure of the gas in equilibrium with the solution (P_{solute}). Mathematically stated: $m_{solute} = k\, P_{solute}$, where k is the Henry's law constant.

[38] Target gas refers to the gas species to be separated, in this case CO_2.

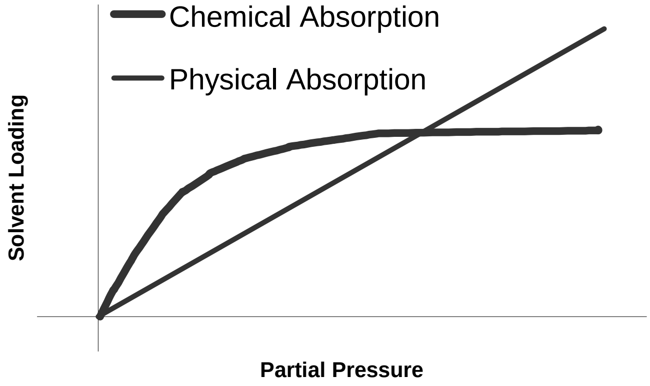


Figure 18: Comparison between chemical and physical solvents

3.2.1 Chemical absorption

Chemical absorption is a mature, demonstrated commercial technology, used to purify natural gas and produce CO_2 from flue gas for commercial applications. The process can be used effectively at low CO_2 partial pressures, making the process the best available technology to clean the flue gas from gas turbines. Chemical absorption has capture efficiency higher than 90% and produces CO_2 with a purity of 99%.

Chemical absorption is a continuous process. The separation takes place in a unit, called scrubber that typically consists of large towers filled with the absorbent, see Figure 19. These systems have been used extensively for scrubbing gas streams of components such as sulphur dioxide (SO_2), CO_2 and ammonia in the chemical and petrochemical industry. The gas stream is initially cooled at temperatures around 50°C, treated for reduction of particulates and acid gases (see below) and pumped upwards through the separator (scrubber), while the liquid absorbent flows downwards in the tower by gravity. Generally, the absorbent is not transferred to the gas stream, while only specific soluble components of the feed gas are transferred into the liquid absorbent. Thus, in carbon sequestration applications, only CO_2 is separated from the feed gas while the remaining gases are released in the air. After capture, the CO_2-rich absorbent is heated at 100-120°C depending on the solvent, to release the captured CO_2 and result in a lean solvent solution that is re-circulated into the separator, see Figure 20.

The most common absorbers are alkaloamine systems in aqueous solution, with monoethanolamine[39] (MEA) being the most widely used solvent. Other solvents include diethanolamine (DEA), triethanolamine (TEA) and methyldiethanolamine (MDEA). These amines are commonly referred to as primary, secondary and tertiary amines respectively, according to the number of carbon-containing groups attached to the nitrogen atom of the amine molecule. Other amines used include mindly hindered primary amines such as alanine, moderately hindered amines such as methylaminopropanol and cycled diamines such as piperazine [50]. Commercially, there are available generic forms of these compounds and trademarks including Econamine FG by Fluor Daniel (an inhibited 20-30wt.% MEA solution), the Kerr-

---

[39] Monoethanolamine is a corrosive, combustible chemical that may be absorbed through the skin and may cause central nervous system depression, liver and kidney damage, severe eye and skin irritation (information from MSDS datasheet).

McGee/ABB Lummus Global's MEA-based technology, Exxon Flexsorb, BASF-Piperazine (used combined with other solvents) and their mixtures[40] (e.g. [50, 54, 65]). Experimental results have demonstrated that for a given size of scrubber, CO_2 capture efficiency is higher with MEA than with secondary and tertiary amines, because the absorption kinetics is significantly faster than with other amine-based solvents. Thus, the use of MEA requires smaller installations to capture a desired amount of CO_2 [46]. A typical solvent loading of CO_2 is 0.4 moles CO_2 per mole MEA [67]. Table 6 shows some important physical properties of the various amine solutions.

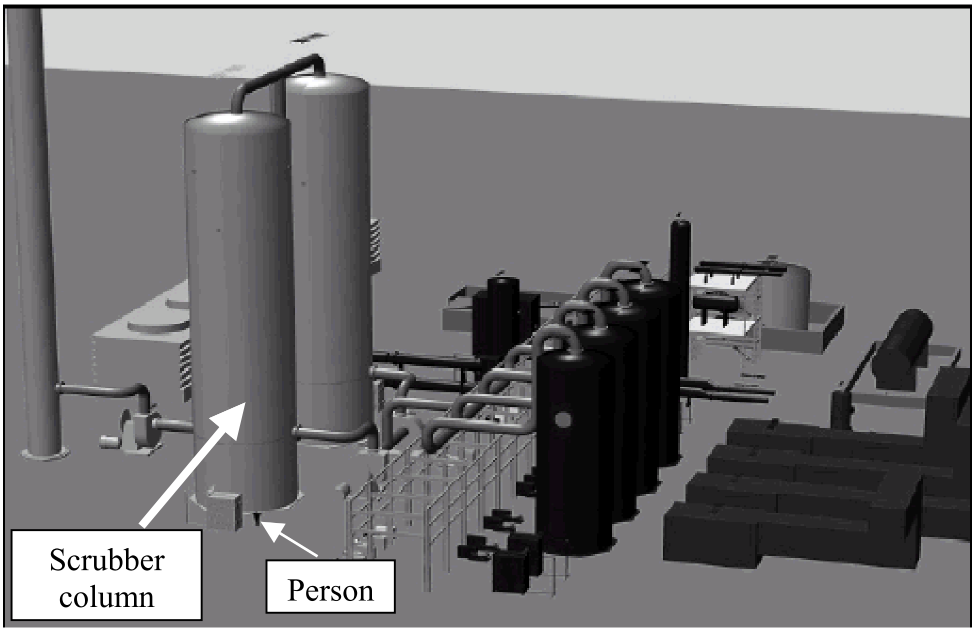


Figure 19: A design of a CO_2 scrubber, with a capacity to separate 2 million tonnes of CO_2 annually. The diameter of the scrubber column is 10.4 m. As an indication of tits size, a person is drawn in front of the scrubber column [44].

Table 6: Important physical properties of various amines [59]

Solvent	***MEA***	***DEA***	***TEA***	***MDEA***
Molar concentration	5	3.5	3.35	4.28
Weight concentration	30%	36%	50%	50%
CO_2 loading, mole CO_2/mole amine	0.4	0.4	0.5	0.5
Latent heat of vapourisation(kJ/kg)	826	670	535	550
Heat of reaction (kJ/mole CO_2)	72	65	62	53.2
Reaction rate constant (mol/L.s)	7600	1500	16.8	9.2

---

[40] Mixtures of primary amines with a small quantity of a tertiary amine exhibit improved absorption capacity and reduced degeneration; however at the expense of regeneration.

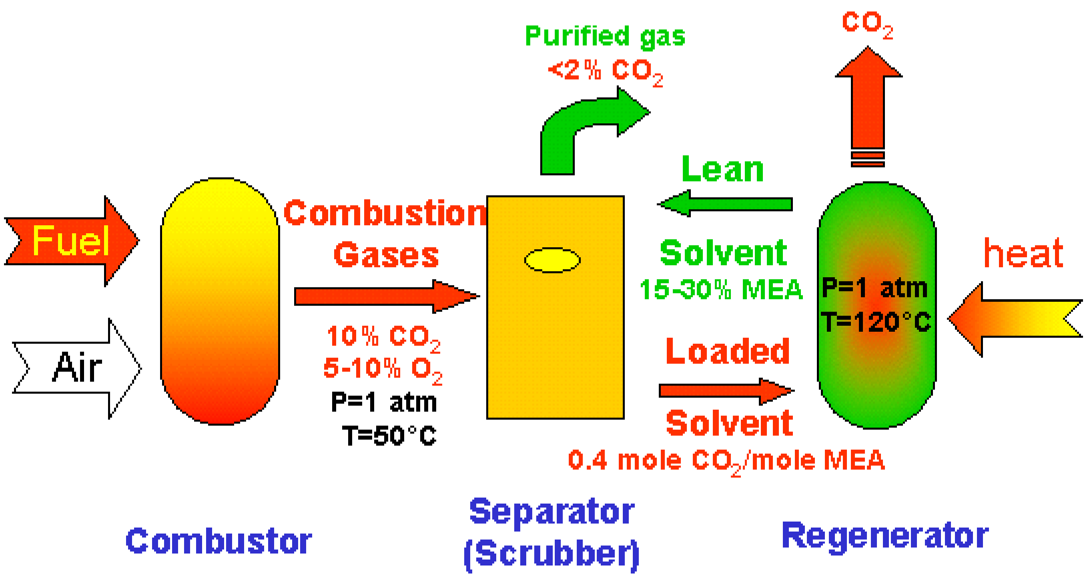


Figure 20: Schematic of chemical absorption system, using MEA as solvent. Process parameters according to [50].

An important implication of the use of chemical solvents is the requirement for the pre-treatment of the feed gas in order for deleterious components to be removed. This pretreatment depends on the type of absorbent. In general, the feed gas must be free of SO_2, oxygen, and particulates, since these components react with the amine leading to its oxidation, degradation (dimerisation), and formation of heat-stable salts that ultimately result in absorbent loss and deterioration of capture efficiency. It has been reported that 1- 4 kg of MEA need to be replaced for each tonne of CO_2 captured, depending on the feed gas composition and the amine concentration [51, 52]. In existing CO_2 capture facilities, the degradation products are separated by evaporation and are disposed of as hazardous chemical waste [52]. Solvent degradation and oxidation can be overcome by: minimizing contact time with dissolved oxygen, dissolved metals and acid gases; utilizing corrosion inhibitors to protect the carbon-steel piping; using low amine concentrations; and optimizing the temperature and pressure in the scrubber. For example, it has been proposed that for MEA-based processes, it is less expensive to install a SO_X scrubber than to accept the solvent losses when the flue gas contains more than 10 ppmv SO_2 [56]. However, the option of using lower concentrations of the absorbents leads to larger overall equipment size, higher solvent circulation rates and thus increased energy consumption.

Besides amines, hot potassium carbonate (K_2CO_3) can be used [57] as a chemical absorbent. Carbon dioxide capture is achieved based on the chemical reaction:

$$K_2CO_3 + CO_2 + H_2O \leftrightarrow 2\ KHCO_3$$

Hot potassium carbonate is effectively used in many ammonia, hydrogen and natural gas plants. Usually, the compound is mixed with proprietary activators to improve CO_2 removal and inhibit corrosion; the resulting absorbent being called *activated hot potassium carbonate*. The most widely licensed system is the Benfield process, with over 675 units licensed worldwide by UOP. However, the minimum feed gas pressure should be more than 10 atm [58], possibly requiring the compression of the feed gas before treatment. Other commercial processes include the Catacarb process, the Exxon Flexsorb HP process and the Giammarco-Vetroke process. The Benfield and Catacarb processes are suitable for CO_2 capture when its partial pressure is at least 200-350 kPa [56]. Finally, current research effort is focused on the use of calcium oxide [e.g. 63, 64], an option that relies on the same capture mechanism as the hot potassium carbonate.

As has already been mentioned, chemical absorption has been proven to be the most effective option for CO_2 separation from gas mixtures in industrial applications, when the partial pressure of the target gas is low, making the process suitable for post combustion capture. Although the process has not been designed for large scale CO_2 capture for sequestration purposes, significant knowledge has been accumulated from the natural gas and chemical industry. A non-exhaustive list of commercial CO_2 capture plants is presented in Table 7. In addition, pilot and small-scale plants that capture CO_2 from power stations are operational, for example at Boundary Dam coal-fired power station in Canada treating 14000 m^3/day of flue gas capturing 4 tonnes of CO_2 daily [45]. However, the size of that plant is at maximum about one tenth of that needed for a commercial-scale power station [50].

Table 7: A non-exhaustive list of commercial CO_2 recovery plants [55]

Site	***Capacity (t/d CO_2)***	***Feed gas origin***	***Technology***	***Status***
CDT. USA	1200	Gas boiler	Econamine FG	Closed
NAC Co, USA	800	Coal boiler	Kerr-McGee MEA	Operational since 1978
ME, USA	493	Gas heaters, engines, turbine	Inhibited MEA	Closed
NEA, USA	320	Gas turbines	Econamine FG	Operational since 1991
SA, Botswana	300	Coal boiler	Kerr-McGee MEA	Operational since 1991
AES, USA	200	Coal boiler	Kerr-McGee MEA	Operational since 1991
SC, Japan	165	Gas boiler	Econamine FG	Operational since 1994
LNG, China	160	NH_3 plant	Econamine FG	No information
IGF, India	150	NH_3 plant	Econamine FG	Operational since 1988
NRS, USA	104	NH_3 plant	Econamine FG	Closed
Prosint, Brazil	90	Gas boiler	Econamine FG	Operational since 1997
LAA, Australia	2 x 60	Gas boiler	Econamine FG	Operational since 1985

The main disadvantage of the technology is the high use of energy, mainly to regenerate the absorbent after capturing. Experimental results have demonstrated that MEA requires the highest energy for regeneration among the amines, followed by DEA and MDEA [46]. The reason for the high-energy requirements for MEA regeneration is that MEA itself has a higher reactivity with CO_2 and thus a higher heat for reaction (see Table 6). Thus, MEA is more difficult to regenerate and results in higher CO_2 loading of lean solution. In general, the higher the water content, and thus the lower the amine concentration, the higher is the energy requirement. On the basis of heats of reaction and the latent heats of vapourisation (see Table 6) MDEA would appear the ideal candidate for absorbent. However, considering the kinetics of reaction, the rate constant of MDEA is 900 times lower than that of MEA. Given that the higher the rate of reaction the greater the mass transfer is, less solvent is required and the absorption system becomes smaller in size. Many investigators consider that 30wt.% MEA as the optimum absorbent [59]. As a comparison, in natural gas treating, the use of MDEA solvents is considered the state-of-the-art. However, this choice could not be effective in CO_2 removal in post-combustion decarbonisation, due to low partial pressures of CO_2 and the slow reactions that require tall and expensive absorption columns [65]. In essence, an optimisation is needed between absorption performance and energy requirement for absorbent regeneration. A second major problem is associated with corrosion of the infrastructure due to the reactivity of the amines. Finally, as stated above, the amines have limited lifetime due to degradation and loss.

The energy of regeneration comes from steam extracted at the end of the steam cycle of the power plant that leads to the loss of electricity. Various investigators have calculated that for a 500 MW_e-rated power plant where 90% of CO_2 is captured from flue gas using 30wt% MEA solution, 2 kg of steam are needed for the capture of 1 kg of CO_2. This corresponds to a heat consumption of about 4.5 MJ per kg CO_2 [59]. This energy is required for, (i) desorption of CO_2 (~1.8 MJ/kg CO_2), (ii) the evaporation of water to carry out the stripping process (~1.8 MJ/kg), and (iii) the reheating of the solvent (0.9 MJ/kg) [66]. A second major source for energy consumption during capture comes from the amine plant fan. It has been estimated that the corresponding energy consumption is about 15 MW in a 500 MW_e plant. On top of these, the cost for compression and drying of captured CO_2, necessary for its transport, should be considered. An IEA study [59] has calculated these energy requirements, based on 835 MW_{th} / 490 MW_e natural gas combined cycle power plant. The reported energy losses of the power plant are shown in Table 8. The consumed energy is provided by the power plant itself, and in this case, the efficiency losses are almost 10%. Other values reported in the literature for natural gas combined cycle plants lie within the range of 9% (e.g. [60, 61]) to 13% [62]. The energy losses for pulverised fuel coal plants are reported to be in the range of 13% [60] to 25% [62], while the energy loss in a IGCC plant, that uses chemical absorption as a means of post combustion decarbonisation has been estimated to be 14% [57]. These losses should be subtracted from the power plant efficiency without capture to calculate the efficiency of the power plant that is equipped with carbon capture technology.

Table 8: Efficiency losses introduced in a natural gas combined cycle plant by CO_2 capture [59]

Source of efficiency loss	*MW_{th}*	*% of input energy (based on 835 MW_{th})*
Reduced electricity due to steam extracted from low pressure turbine for amine regeneration	48.2	5.8
Additional load on cooling water pump, plus others and parasitics	15.9	1.9
CO_2 compression and drying	17.3	2.1
Efficiency loses due to CO_2 capture	**81.4**	**9.8**

The capital costs of CO_2 capture depend on the quantity and concentration of the solvent, the design of the scrubber (e.g. the type of packing used), and the materials used for the construction/corrosion prevention. According to IEA [59], the cost of a chemical absorption unit capable of removing 90% of CO_2 from a 490 MW_e natural gas combined cycle plant is about $131 million. Capital costs are dominated by the size of the absorber, due to the large volume of the flue gas that needs to be treated. The capital cost estimate is shown in Table 9. In this example, half of the costs correspond to the absorber and regenerator.

Table 9: Capital cost estimates for a MEA-based CO_2 capture installation [59]

Equipment	*Million $*
Gas Supply	
Amine Fan	4.5
Gas Cooling	
Direct Contact Cooling System	11.6
CO_2 Removal	
Absorption Section, Heat exchangers, Pumps	27.6
CO_2 Regeneration	
Regeneration Section, Heat exchangers, Pumps	24.8
Amine Cleaning & Reclamation	15.0
Others (Materials, Support systems, Supplies)	23.0
Bare Costs (BC)	**106.5**
Engineering, Construction Management	5.3
Capital Investment	**111.8**
Fees	2.2
Land purchase	5.6
Contigencies	11.2
Total Plant Costs	**130.8**

The operating costs of the aforementioned plant examined by IEA include the cost of labour and the cost of consumables, mainly amine and activated carbon. IEA estimates that 22 people would be employed on a basis of 1960 person-hours per year basis. Given that the cost of amine is about $19/kg and the cost for the activated carbon $38/kg, then the annual cost of consumables would be about $2,700,000. The same report mentions that other studies have reported that the capital cost of a capture plant with a capacity of 1000 tonnes/day, that is one third of the capacity of the previously analysed plant is $20 million (1984 prices) when the CO_2 concentration in the flue gas is 8% (excluding the cost for drying and compressing the CO_2). The cost increases to $26 million when the CO_2 content in the flue gas is only 4%. Overall, IEA estimates that the specific capital investment[41] for a power plant increases by 75% for a coal plant, 95% for a gas plant in combined cycle mode, and 100% for IGCC when the plant is equipped by a chemical absorption unit.

There are underway research and development efforts to develop advanced chemical absorbents with increased capture efficiency and higher capture rates that can be more tolerant to delirious agents, thus reducing the negative impact of their presence to the amines (e.g. [53]). It is estimated that the introduction of advanced absorbents may lead to reductions of energy associated with carbon capture by 40%. Currently, the Mitsubishi process uses a promoted hindered amine that consumes 20% less energy in regeneration. The introduction of such advanced absorbents will also lead to the reduction of equipment size that is currently comparable to the size of the power plant itself. Furthermore, energy savings may arise from integrating heat and mass transfer in the stripper; it is claimed that 50% energy savings can be achieved via this approach [66]. In addition, there is need for fundamental data including solubility studies of CO_2 in absorbents, comprehensive data for alternative solvents, degradation kinetics studies, development of new solvent systems, advanced auxiliary devices such as packing, spraying, energy optimization, methods to minimize degradation and corrosion. There is also a need to develop alternative processes that can be immediately applicable to existing power plants.

3.2.2 Physical absorption

The process of physical absorption is similar to the chemical absorption described above. However, in contrast to the chemical absorption where the process is more efficient at low partial pressures of CO_2, physical absorption is more suitable for higher partial pressures, making this approach suitable for syngas/pre-combustion decarbonisation. Typical feed gas pressures could be in the range of 20-130 atm with CO_2 gas composition from 5% to 35 - 60 vol.%, depending on the solvent. The removal efficiency of CO_2 is around 90% [68].

The most widely used absorbers are Selexol[42], owned by Union Carbide and licensed by UOP, and Rectisol[43], licenced by Linde AG. The Selexol process was introduced in the 70's and according to UOP, there are currently more than 50 units in service. The process has been traditionally used for treating natural gas and syngas streams, for the selective removal of H_2S in IGCC plants and of CO_2 in gasification plants used for the production of high purity hydrogen, for refinery and fertiliser use, and for natural gas treatment. The process uses a solvent that is a mixture of dimethyl ethers of polyethylene glycol, is chemically stable, non-toxic and biodegradable. It is regenerated by application of heat, by flashing or by stripping gas. Rectisol uses an organic solvent,

---

[41] Specific capital investment is a measure of a capital cost of a power plant for each unit of electricity produced. It is expressed in €/kW.

[42] For more information, see: http://www.uop.com/gasprocessing/Techsheets/Selexol.pdf

[43] More information at: http://www.linde-process-engineering.com/en/p0001/p0023/p0121/p0121.jsp

typically methanol at subzero temperatures. However, methanol is a volatile compound that leads to solvent losses. It is traditionally used to purify syngas from CO_2 in two stages. Initially, shifted syngas enters the Rectisol unit and the CO_2 concentration is reduced to 3% using flash-regenerated methanol. The remaining 3% is removed using hot-regenerated cold methanol (up to 3%vol.) or pressure swing adsorption (see below). Regeneration of the absorbent is done by reducing the pressure. Rectisol units are operational worldwide for the purification of hydrogen, ammonia and methanol syngas. Due to the low operation temperature Rectisol is also favourable for cryogenic downstream processes. It is important to note that, since the physical solvents do not react chemically with CO_2, thus they are not subject to degeneration. In addition, they do not create corrosion problems to the infrastructure.

The above described solvents are proprietary, so detailed information about their cost and performance is not widely available. Both solvents are considered inexpensive. The price of methanol (Rectisol) was between €0.15-0.25/kg in 2001, while the price of Selexol was €8.5-10/kg [69]. An IEA report mentions that the energy penalty for an IGCC plant rated as 500 MW_e with a CO_2 removal efficiency of 82% is about 6-8% [57, 60]. The specific cost investment for the whole plant (power plant and capture equipment) was estimated being 2400 $/kW, compared with 1560$/kW for an IGCC plant without CO_2 capture [57]. However, the efficiency penalty is only 6%, indicating that physical absorption is less energy intensive than chemical absorption.

3.2.3 Hybrid Absorption

Hybrid solvents combine the best characteristics of both the chemical and physical solvents and they are usually composed of a mixture of components. According to an IEA report, hybrid solvents have out-performed existing solvents and those developed for one application have easily been adopted for others [57]. However, the same report claims that this is not always desirable and the tendency has been to develop tailor-made solvents where proportions of the constituents are varied to suit each individual application.

Typical solvents are BASF's aMDEA process[44], Shell's Sulfinol[45] and Dow's UCARSOL[46]. The aMDEA process is an aqueous solution of methyldiethanolamine that contains an activator for enhancing the CO_2 absorption rate; it is used in natural gas processing and syngas treating. According to the manufacturer, the use of the process can reduce significantly the CO_2 concentration, down to 5 ppmv. The operating pressure is within the range of 1 to 120 atm and the capacity for a single train may vary between 3,000 and 810,000 Nm^3/h of feed gas. Currently, the aMDEA process is operational in more than 130 plants worldwide. Sulfinol is a mixed solvent process combining a chemical solvent (a secondary or tertiary amine, depending on the application) and a physical solvent (sulfolane). According to the manufacturer, it can reduce the CO_2 concentration in syngas down to 0.5%. To date 200 units have been licensed worldwide.

---

[44] For more information, see: http://www.lurgi-oel.de/english/nbsp/main/info/amdea.pdf

[45] For more information, see: http://www.sulfinol.com/

[46] For more information, see; http://www.dow.com/alkanolamines/dg_alk.htm

3.3 Adsorption technologies

Adsorption is the process where a molecule becomes selectively attached (adsorbed) onto a surface of another phase (Figure 21). Thus, by using special solids (called adsorbents), substances from gaseous (or liquid) mixtures can be selectively removed. The separation of a substance, the adsorbate, is achieved by its accumulation at the surface of the adsorbent. This process is different from absorption, described in the previous section, the latter term being used when describing the uptake of a substance into the bulk of a solid or liquid phase and not on the surface of a solid.

Adsorption phenomena are operative in most natural physical, biological, and chemical systems, and adsorption operations employing solids are used widely in industrial applications. Adsorption is effective in purification of gas streams (i.e. removal of a gas component with concentrations ranging from 1 ppb to 0.1 vol.%) and for bulk separations (removing 1 to 50% from a gas stream). A prominent application example is in refineries and petrochemical plants where pressure swing adsorption (see below) has replaced cryogenic distillation as the most economical method for separating hydrogen from other chemical compounds. Adsorption is also used for recovery of certain constituents (e.g. solvents from air) preventing pollution, purifying materials etc. Examples of adsorption applications include: removal of SO_X and water vapour from flue gases, solvents and odour from air, and separation of CO_2 from natural gas.

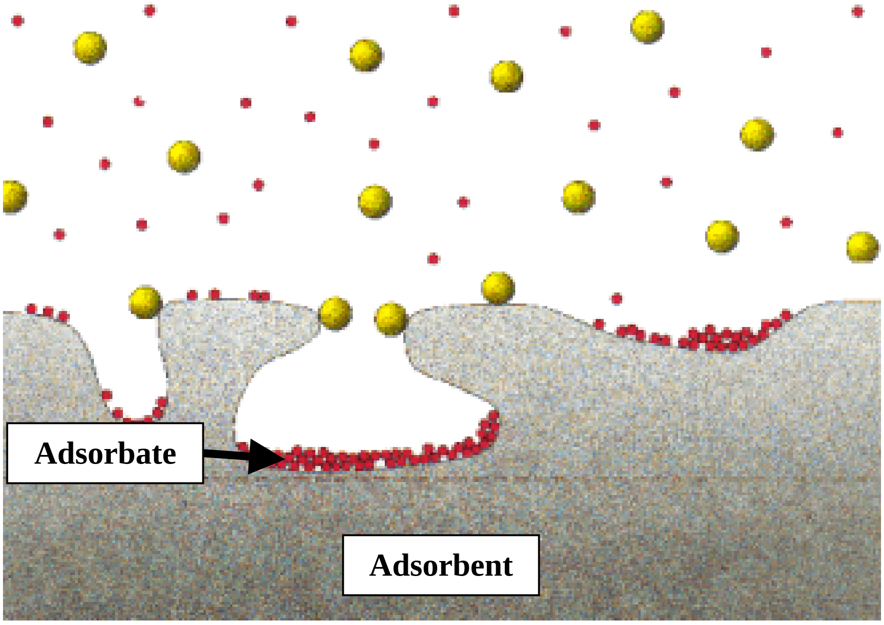


Figure 21: A schematic of the adsorption process (Source: Ref. [70])

There are two principal mechanisms of adsorption of molecules on surfaces: physical adsorption (physisorpion) and chemical adsorption (chemisorption). The difference lies in the nature of the bonding between the captured molecule and the surface. In physical adsorption bonding is by weak Van der Waals - type forces. In chemisorption bonding is chemical, involving substantial rearrangement of electron density; the nature of this bond may lie anywhere between the extremes of virtually complete ionic or complete covalent character[47]. From a practical point of view, chemisorption from a gas generally takes place only at temperatures above 200°C and may be slow and irreversible. For this reason, most commercial applications rely on physical adsorption.

The major types of adsorbents used are activated alumina, silica gel, activated carbons, zeolites and polymeric adsorbers. In selecting the appropriate adsorber for a specific application the following criteria should be met: The adsorber should demonstrate high selectivity to the gas species to be separated (CO_2 in this case), high capacity to minimise the amount of adsorbent needed, fast adsorption kinetics, chemical and thermal stability, capacity of being easily regenerable and being of relatively low cost.

Research has demonstrated that only activated carbon and zeolites can find applications in CO_2 separation. *Activated carbons* comprise elementary micro-crystals stacked in random orientation. They can be produced from wood, refinery residuals, coal, carbon black and other carbon-containing materials via gas or chemical activation, at a temperature range between 400 – 1000°C depending on the process. They are very porous (the porosity may vary between 40-60%) and have a high surface area, ranging from 0.5 m^2/g to 1000 m^2/g depending on the pore size that may vary from more than 50 μm to less than 2 μm. *Zeolites* are microporous crystalline solid aluminosilicates that consist of assemblies of SiO_4 and AlO_4 tetrahedra joined together by sharing oxygen atoms. The atomic structure of zeolites is such that cavities and channels (cages) are formed between the atoms (see Figure 22). Their size can be altered under control by changing the chemical composition of the zeolite. There are currently available more than 150 synthetic zeolite types. Zeolites are distinct from other adsorbents in that each zeolite type is characterised by a single pore size. For this reason, zeolites are capable of separating effectively on the basis of channel size, and they have become known are molecular sieves. This shape-selective property of zeolites is the basis for their use in molecular adsorption. The ionic nature of most zeolites makes them also potential adsorbents for polar molecules such as CO_2. Zeolites can thus separate molecules based on differences of size, shape and polarity. In industrial applications, combinations of adsorbent beds are used on top of one another, so the adsorber column is divided into distinct zones, each containing a different adsorber. In general, molecular sieves have the higher capacity to adsorb CO_2 in terms of per unit weight compared with active carbons.

As with absorption, a critical step in the adsorption process is the removal of the captured gas species from the adsorbent, a process called desorption. There are a variety of methods to force an adsorbent to release the adsorbed components; these methods can be grouped into three main categories[48]: (i) temperature swing adsorption, (ii) pressure swing adsorption, and, (iii) displacement purge adsorption.

---

[47] However, although the difference between physical and chemical adsorption is obvious in theory, the practical distinction is not that simple.

[48] Electrical Swing Adsorption is another emerging technology that is not discussed herein, since the process is still in experimental stage. In this process, desorption is achieved by passing an electric current through a monolithic ceramic adsorbent [47].

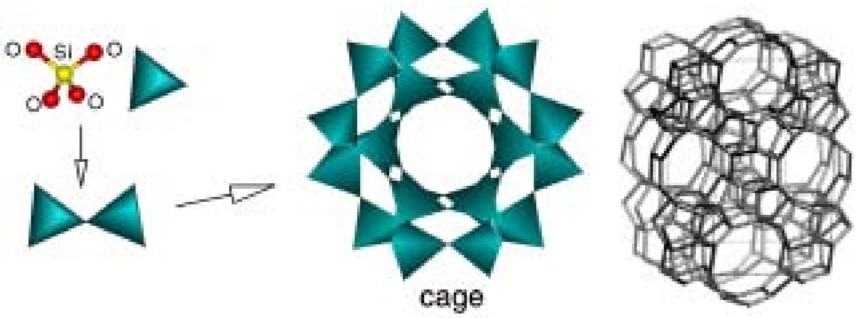


Figure 22: (Left) A schematic of a typical zeolite structure, showing the formation of cages [48]; (right) a typical structure of an MFI-type zeolite, a candidate zeolite for large scale CO_2 separation [49].

3.3.1 Temperature Swing Adsorption (TSA)

TSA is a traditional method where gas separation occurs by cycling temperature and is used virtually exclusively for treating feed gas with low concentrations of target gas. It usually involves the use of at least two adsorbent towers. The feed gas is led into the first tower that contains the lean adsorbent, where separation takes place under constant temperature. As soon as the adsorbent cannot adsorb additional target gas it is taken off-line and the feed gas is led to the second tower while the temperature in the first tower is reduced, releasing the captured gas. By purging with hot inert gas, the released gas is forced to exit the adsorption bed. The regenerated bed is then cooled to the ambient temperature and is ready for adsorption again. Typically, this process is done at ambient pressure. Since adsorbent beds cannot normally be heated and cooled quickly, the cyclic time of a PSA system may range to several hours for bulk gas separation. Furthermore, large adsorption equipment is required to contain the large volume of adsorbents needed to carry out the process in a comparatively short time. It is important to note that for the process to be continuous, the time required for desorption of the loaded bed should match the time that adsorption takes place in the other bed. An issue associated with TSA is the degradation of the adsorbent as a result of the continuous thermal cycling.

3.3.2 Pressure Swing Adsorption (PSA)

More recently, PSA has become the technique of choice in the petrochemical and gas industry. The PSA processes rely on the fact that under pressure gases tend to be attracted (adsorbed) to solid surfaces. The higher the pressure, the more gas is adsorbed; when the pressure is reduced, the gas is released. PSA processes can be used to separate gases in a mixture because different gases tend to be attracted to different solid surfaces more or less strongly. In typical PSA applications the gas is preferentially adsorbed at a high pressure, within the range of 5 to 50 atm depending on the application and the specific process characteristics. Regeneration of the adsorbent is accomplished by counter current depressurisation and by purging at low pressure with previously recovered near product quality gas. In a variation of the process, vacuum may be needed for regeneration (vacuum swing adsorption – VSA). To obtain a continuous flow of product, a minimum of two adsorbers is needed, as in TSA, so at least one adsorber is receiving feed gas while the other adsorber produces a product of desired purity, see Figure 23. After adsorbent regeneration and repressurization, the adsorber is switched onto adsorption duty, whereupon another adsorber is regenerated. Cycling time is within minutes and depends on the required purity of the target gas. A PSA plant may consist of 12 adsorbers each one being at a different stage of the adsorption/desorption cycle.

3.3.3 Displacement Purge Adsorption (DPA)

Adsorbed gas can be removed from the adsorbent bed by replacing it with a more preferentially adsorbed species, called displacement gas. The mechanism of desorption involves initially the reduction of the partial pressure of the adsorbate in the gas phase surrounding the bed and subsequently, the competitive adsorption for the displacement gas.

Although both PSA and TSA have the potential to be used for the removal of CO_2 from high-pressure gas streams, such as those encountered in IGCC power plants or in hydrogen production, they are hampered by low removal efficiencies, especially the TSA, when reasonable efficiency penalties are considered. PSA could only be considered and only as a complementary method to absorption. Such installations are manufactured by most of the major gas treating companies such as Praxair, UOP and Air Liquide.

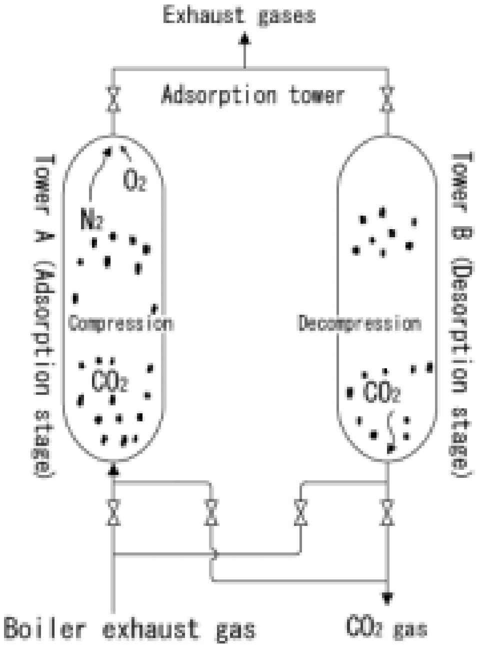


Figure 23: A schematic of the pressure swing adsorption Process (Source: Ref. [70])

3.4 Cryogenic Separation

Cryogenic separation is a commercial process, widely used for the liquefaction and purification of CO_2, especially where its concentration in the feed gas is very high, typically higher than 90%. It is a distillation process that takes place at very low temperatures where the components of the feed gas start to liquefy. The process relies on the principle that, a liquefied gas is purified in a cycle of evaporation-condensation steps. The process temperature is thus dictated by the condensation temperature of the components of the feed gas that need to be separated. The process requires the compression and cooling for the feed gas. If CO_2 is the only condensable gas in the feed gas, its partial pressure in the gas phase is reduced to its vapour pressure at the process temperature and the mole fraction in the gas phase is its partial pressure divided by the total pressure[49]. The minimum CO_2 mole fraction in the gas phase (and thus its separation from the feed gas as liquid) is achieved by lowering the temperature and raising the total pressure as much as practical [57]. Generally, the feed gas is compressed to a pressure of about 10 atm and dried using molecular sieves to remove water and other compounds such as acid gases (NO_X and SO_X) that would otherwise freeze during the process. Subsequently the feed gas is cooled using a series of heat exchangers until CO_2 is condensed. In industrial practice the temperature is not lowered below –56.6°C, the freezing point of CO_2. A schematic of the process is shown in Figure 24.

Cryogenic distillation is most effective when the feed gas contains components with widely separated condensation temperatures, when the feed gas is available at high pressures and when the separated gases are also needed at high pressures. Therefore, this option may appear attractive for CO_2 capture operations from IGCC plants where the feed gas contains CO_2 at high concentrations and is available at high pressures. Furthermore, as it will be presented in the next Chapter, there is a need for the separated CO_2 to be available at high pressures for a more efficient transport.

However, the cryogenic separation approach is prohibitive for post-combustion decarbonisation, where the feed gas is available at near ambient pressure and CO_2 concentration is low. The major disadvantage of the process is the high capital cost (due to the need for compressors and expanders, heat exchangers, insulation and the distillation column), high-energy requirements for the cooling process, and the demand for removing compounds from the feed gas that are expected to freeze before the CO_2 during cooling such as water vapour and other acid gases. IEA has estimated that the efficiency penalty of an IGCC plant equipped with cryogenic separation is 6% and the increase in capital costs is 77% [57]. The specific cost investment for the cryogenic separation equipment is about €1200/kW. These disadvantages tend to make cryogenic distillation a less economical route compared with other pathways to decarbonisation.

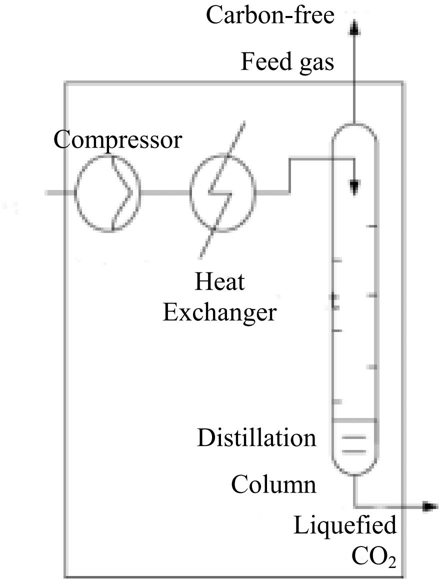


Figure 24: A schematic of the cryogenic distillation process [76]

---

[49] Based on the assumption that gases behave as ideal.

3.5 Membranes

Gas separation using membranes is emerging into an important pathway for capturing CO_2 from a stream of gases since it is claimed that this approach offers significant advantages over the conventional separation processes discussed above. Although there are currently no commercial applications to separate CO_2 from flue gases, membranes are used in enhanced oil recovery (EOR) operations to recycle CO_2 from the associated gas, see p. 57, and to remove CO_2 from natural gas and biogas/landfill gas. The membranes that have the potential to be used in carbon capture operations can be grouped into two main categories: the gas separation membranes and the gas absorption membranes.

3.5.1 Gas separation membranes

Gas separation membranes rely on the difference in physical or chemical interaction between each of the components of the feed gas and the membrane material, causing one of the components of the feed gas to permeate faster through the membrane than the other components [57]. Permeation is achieved via a solution-diffusion mechanism: the target gas is dissolved in the membrane and is transported through the membrane by diffusion, driven by the difference in partial pressure of gas components at the opposite sides of the membrane, see Figure 25. The quality of separation depends on the selectivity of the membrane to the components of the feed gas and the process parameters, notably the ratio of the permeate flow to the feed gas flow and the differential pressure across the membrane. The higher the selectivity, the more efficient the process, reducing the requirement for increased pressure difference and thus decreasing operating costs. Large separation factors are essential to achieve the desired results in a single stage. For multiple gas mixtures, several membranes with different characteristics may be required to separate and capture CO_2. Furthermore, a high flux of target gas through the membrane reduces the requirements for a high membrane area and therefore, the required capital cost of the membrane system is lowered.

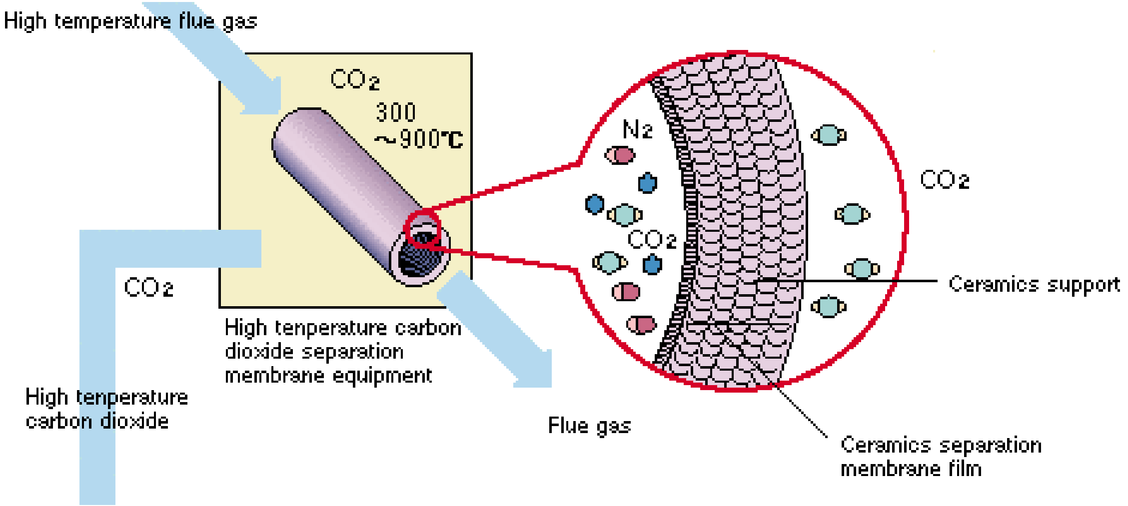


Figure 25: A schematic of a high temperature separation of CO_2 from flue gases using a ceramic gas separation membrane [75]

There are a number of different types of gas separation membranes that have been proven capable of separating CO_2 from a gas mixture; however only few of them have seen industrial applications. These membranes are metallic membranes, ceramic membranes, zeolitic molecular sieves and polymeric membranes. The first three families of membranes can be effectively used at high pressures (25-100 atm) and at temperatures up to 600°C, for gases with wide CO_2 concentration levels (from 3 to 70%); they are moderately tolerant in corrosive environments. However, the presence of fly-ash and acid gases may contaminate the membrane. Metal membranes are mainly palladium or palladium-alloy membranes supported by low-cost strong materials, such as porous metallic tubes. They have a thickness within the range of 1-10 μm and are produced by electroless plating, sputtering and chemical vapour deposition. Metallic membranes have a high selectivity and low permeance[50], the latter being negatively affected by the presence of water, CO and sulphur compounds in the feed gas. Such membranes have been tested at temperatures 300-600°C, pressures up to 35 bar, and H_2S concentrations as high as 10% in hydrogen separation applications [78]. Ceramic membranes can either be microporous (such as silica with a pore size less than 2 nm) or dense mixed conducting ceramic materials (e.g. pervoskites). The thickness of ceramic membranes varies between 20 and 100 nm, however, the production of defect-free membranes currently has become a manufacturing challenge, given that defects affect negatively the selectivity of the membrane. Silica-based ceramic membranes can be used at temperatures up to 400°C. They degrade at higher temperatures and in the presence of water. A major advantage of inorganic membranes is that they offer the flexibility to keep the desired gas either at high or low-pressure side of the membrane [79]. Typical zeolite membranes have lower permeance and selectivity than silica membranes, mainly because they have a greater thickness and are characterized by enhanced diffusion and strong adsorption effects. In addition, their cost is higher than that of porous ceramic membranes [79]. These membranes are unstable at temperatures higher than 400°C [80]. Polymeric membranes are characterized by low permeance and by the need for a trade-off between permeability and selectivity. Polymer membranes can be up to 100 to 10000 times less permeable than ceramic membranes. However, they can be densely packed into the separation equipment, achieving large ratios of membrane area to equipment volume. This ratio is 100 to 1000 times higher than in ceramic membranes. These factors tend to equilise the cost per membrane module to the cost of inorganic membranes and they come with a cost of the order of €150/m^2 [57]. However, their service life is inferior to ceramic membranes, they are difficult to process and fragile. Thus, they are currently used only in niche applications [77]. Typical polymeric membranes are made of polypropylene and polyimides [81]. A major operation cost associated with gas separation membranes is the cost of compression of the feed gas and the cost of heat exchange.

3.5.2 Gas absorption membranes

Gas absorption membranes rely on the chemical absorption principle described above, however the membranes are used to increase the mass transfer area in a given volume and to avoid some of the problems associated with vapour/liquid contacting. The process utilizes a porous membrane for the transfer of selective components between the

---

[50] Permeance is the volume of gas transported through a membrtane per unit of surface area per unit of time per unit of differential pressure.

feed gas and an absorption liquid, typically a primary amine. The membrane itself does not contribute to the separation but serves only the role of a gas-permeable barrier between the absorbent and the feed gas (Figure 26). As with traditional chemical absorption, the CO_2 is chemically absorbed in the absorber, which is regenerated thermally and is recirculated. With this approach a large contact area between the feed gas and the absorbant per unit volume of equipment can be achieved (up to 300 to 1500 m^{-1}) [81, 82]. It is claimed that typical problems associated with conventional absorption (e.g. foaming and flooding) and significantly reduced. Furthermore, it has been suggested that the process has a high removal efficiency and flexibility in applications by varying the absorbent, low energy consumption and easy scale-up capability [81]. It has also been suggested that the efficiency of separation is not influenced by the ratio of feed gas to absorption liquid, since high specific surface area through the use of small size hollow fibre membranes is available to facilitate the absorption, leading to the use of compact equipment with a modular design.

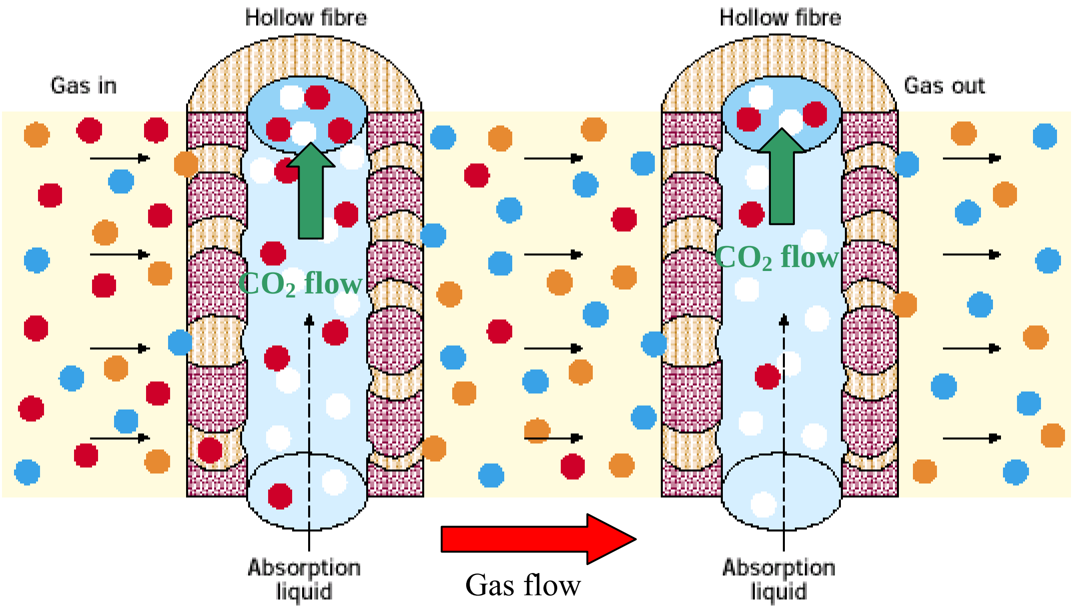


Figure 26: The operational principle of gas absorption membranes. The target gas is represented by the red spheres [83].

Gas absorption membranes are being developed by TNO and Kvaerner Process Systems in collaboration with W.L. Gore. The later are made of PTFE (Pdytetrafluoroethylene) and can be used with a range of solvents [82]. Initial efforts in developing such membranes were unsuccessful because the absorbent destroyed or wetted the membrane. Nowadays, a demonstration program of the use of membranes for natural gas treatment by Kvaerner has resulted in 70-75% weight reduction and 65% space reduction for the absorber and the stripper, reduced stripper duty and reduced solvent loss compared with the traditional chemical absorption process [84]. The cost of these membranes is in the range of €300/m^2 [57]. Finally, there are composite membranes available that combine the results of different membranes. They contain hollow fibre or spiral wound membrane elements and can be used for CO_2 removal from natural gas, see Figure 27.

The main differences between the two different types of membranes (separation vs. absorption membranes) are summarized in Table 10.

According to an IEA study [57], the efficiency penalty associated with the use of gas separation membranes in coal plants, GTCC plants and IGCC plants is 9%, 21% and 16% respectively. The corresponding efficiency losses resulting from the use of gas absorption membranes is 10%, 3% and 10%. In all cases, the aim of the study was to reduce by 80% the CO_2 emissions from a 500 MW_e power plant. The results of this analysis indicate that absorption membranes have the potential to improve significantly the economics of the CO_2 capture process. The specific capital investment for a coal plant with gas absorption membranes was found increased by 55% ($1644/kW vs. $1058/kW for a coal plant without CO_2 capture equipment) while the increase in specific capital investment in order to add gas absorption membranes in an IGCC plant was estimated to be 75% ($2736/kW compared with $1561/kW for the reference IGCC plant without capture).

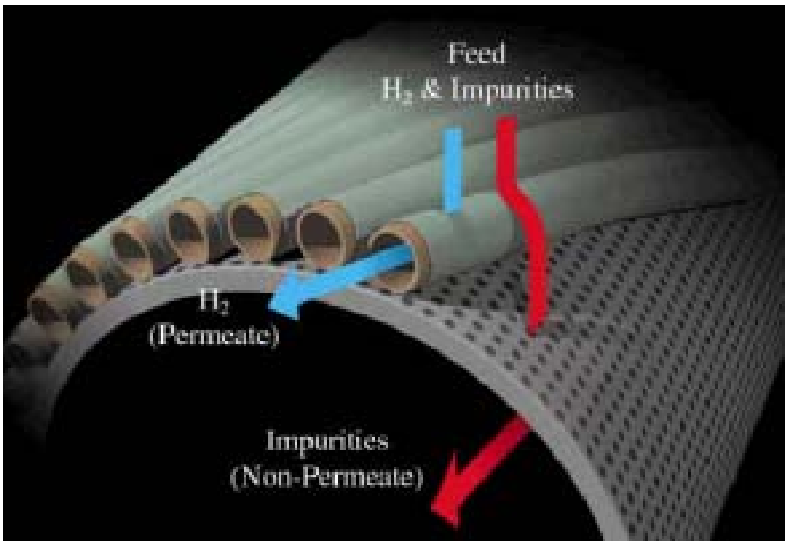


Figure 27: An illustration of a composite hollow fibre membrane that is used for the production of high-purity hydrogen. Such membranes can be used also for the CO_2 removal from natural gas [85].

Table 10: Main differences between gas separation and gas absorption membranes [81]

	Separation membrane	***Absorption membrane***
Separation mechanism	Solution and diffusion	Selective reaction
Drive force	High pressure	Low pressure
Gas flux	1	4000
Mass transfer coefficient	$>10^{-5}$	10^{-3}
Flexible applicability	Depends on membrane structure	Depends on absorbent

3.6 Oxyfuel combustion

Oxyfuel combustion is a proposed approach to achieve high CO_2 removal efficiencies by altering the characteristics of the combustion process. The aim of oxyfuel combustion is to increase significantly the concentration of CO_2 in the flue gases, to at least 90%, thus avoiding the need for CO_2 separation, of if a stream of high purity CO_2 is needed, to take advantage of the more efficient CO_2 capture at high concentrations using a post-combustion decarbonisation technique. The increased CO_2 concentration in the flue gas is achieved by combusting the fuel with pure oxygen instead of air, thus reducing significantly or even eliminating nitrogen from the gas that enters the combustor and thus producing a flue gas with a high CO_2 concentration. This decarbonisation option is still in an experimental stage.

A major issue associated with this approach is the temperature control of the combustion process itself. During fuel combustion with pure oxygen, very high temperatures are generated due to the absence of a diluting medium in the combustor atmosphere. To moderate combustion temperatures, a part of the flue gas is re-circulated into the combustion chamber to dilute the combustion atmosphere. The flue gas leaving the combustor is divided after the economiser into two streams. Roughly two thirds of the flue gas is re-circulated into the combustor where they are mixed with fresh oxygen and are combusted as in a normal power plant [86]. The remaining flue gas is treated, compressed and transported to storage or any other application.

The concentration of CO_2 in the flue gas depends strongly on the oxygen purity and on the infiltration of air into the combustor. For example, using oxygen with 95% purity and assuming that air penetration in the combustor is of the order of 3%, the flue gas may contain at least 80% CO_2 by volume on dry basis [87]. A main issue associated with the process is the production of oxygen. Oxygen needs to be produced using a cryogenic air separation unit (ASU), since the volumetric flow required for the combustion process is high. Although in theory, oxygen does not need be very pure, there is an inverse relationship between oxygen purity and capture cost, with the cost of CO_2 removal increasing sharply at lower oxygen purities. It has been estimated that, above 95% oxygen purity the capture cost is quite small with a minimum at 97% oxygen purity [86].

It is claimed that this approach can be easily applicable to existing power plants, either as stand-alone or combined with other CO_2 capture techniques, and pilot and laboratory scale studies have indicated that this method is feasible [86]. Other advantages that may be associated with this method are lower NO_X emissions than in normal air combustion and the potential to increase combustion efficiency [89]. The major disadvantage of oxyfuel combustion is the decreased efficiency of the power plant, due to the high energy consumption for the production of oxygen in the ASU and the associated high costs. Thus, the method would be benefited from any developments in oxygen production. Furthermore, oxyfuel combustion requires complex machinery and has not been demonstrated yet. Remaining uncertainties lie in the performance of large-scale gas and oil burners using oxygen and recycled flue gas and in the prediction of flame properties.

The capital cost investment required for an oxyfuel combustion plant has been calculated in a study prepared by Chalmers University of Technology [89]. As a reference plant a lignite-fired power station was considered with a 2x865 MW net electrical power output. The investment cost required to convert the plant into oxyfuel was estimated to be €28 million. On top of that, the cost of the ASU should be added

(~€100 million) raising the total required additional capital cost to €128 million. However, the author claims that the oxyfuel plant does not require a desulphurisation unit, claiming that SO_X could be sequestered together with the CO_2[51]. The cost of a desulphurisation unit is €160 million. The total energy consumption of the auxiliary units that have to be added (compressors, separators, etc) was calculated as 60 MW that have to be added to the energy consumption of the ASU (165 MW). The total energy penalty is about 10%. This is within the range of most values reported elsewhere (e.g. [57], [61]). Nevertheless, there are reports that calculate a higher associated energy penalty of about 22% because they assume a higher energy consumption from the ASU [88].

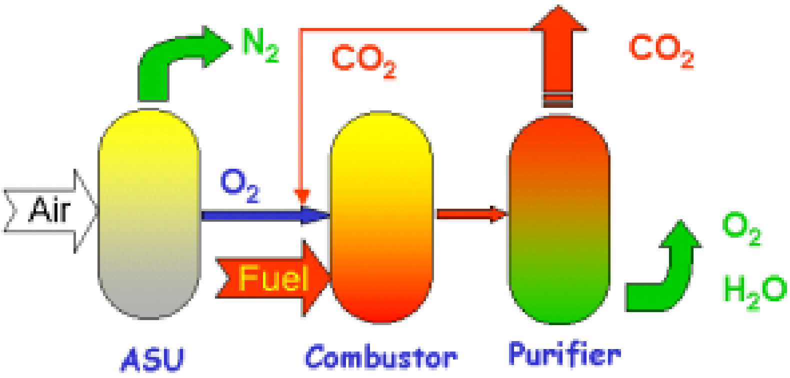


Figure 28: A schematic of the oxyfuel combustion process. ASU stands for air separation unit.

3.7 Novel Concepts

A number of other concepts are currently considered for the capture of CO_2, however they are still in a conceptual stage, so they are mentioned only briefly next.

3.7.1 Chemical Looping Combustion

Chemical looping combustion is a combustion process, at an early experimental stage, where direct contact between the fuel and the combustion air is avoided, thus a stream of pure CO_2 can be produced. This approach uses a metal oxide as the oxygen carrier that transfers oxygen from air to the fuel. The process consists of two reactors: in the first reactor the metal oxide is reduced by reacting with the fuel and in the second reactor the reduced metal oxide is oxidised with air. The flue gas from the first reactor consists of CO_2 and water while the flue gas from the second reactor consists of nitrogen and unused oxygen, see Figure 29 [90, 91].

---

[51] Nevertheless, other investigators claim that presence of SO_X in the stream of CO_2 is prohibitive as it may create corrosion problems during transport and storage.

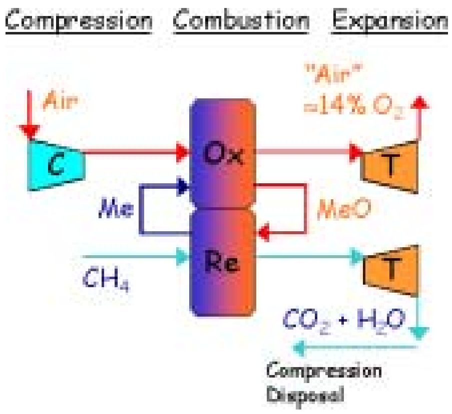


Figure 29: A schematic of the chemical looping combustion process [92]

3.7.2 Advanced Zero Emissions Power plant (AZEP)

AZEP involves a gas turbine that uses CO_2 and steam as a working fluid (as in oxyfuel combustion). However, in contrast to the traditional oxyfuel combustion described above, where oxygen is produced by cryogenic separation, AZEP utilises advanced metal oxide membranes to separate oxygen from air. Main partners in the development of this technology are Norsk Hydro and ALSTOM. It is claimed that this approach can achieve very high CO_2 removal efficiencies (up to 100%) with a small energy efficiency penalty (less than 10%) [93, 94]. A schematic of the process is shown in Figure 30.

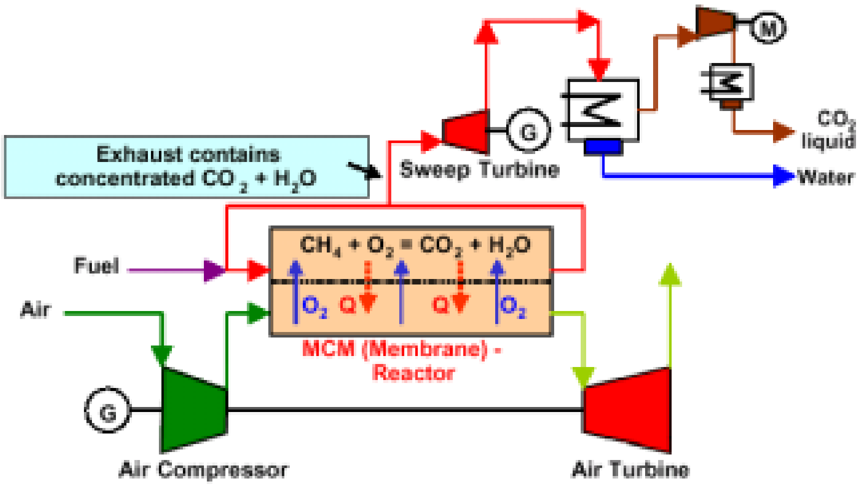


Figure 30: A schematic of the AZEP process. The process comprises a gas turbine that uses recirculated CO_2 as a working fluid and a membrane for the production of oxygen from air [93].

3.7.3 Biological Fixation with Algae

Biological fixation utilises algae that are fed with CO_2 to produce high-value products such as food supplements. In principle, CO_2 from power plants are bubbled into ponds where algae grow. The grown algae can be used to produce biogas and bio-diesel or other biofuels. However, it has been estimated that a pond area of 50-100 km^2 would be needed to capture the CO_2 emitted from a 500 MW power plant [99], making the process unsuitable as an instrument for CO_2 sequestration. Despite its far-fetched principle, this approach has seen a commercial application: there is one commercial production plant in Hawaii that uses flue gas from a power station to grow algae, see Figure 31.

Figure 31: A 90 acre microalgae production facility in Hawaii. The algae grow consuming CO_2 captured from a nearby power plant [95].

3.8 Comparison of the capture options

With the exception of membranes, all other options described in the previous section have reached a technological maturity to have the potential to be utilised in a future deployment of carbon sequestration on a large-scale in the mid-term. However, economic assessments demonstrate that only a few of these pathways may see large-scale deployment.

- Chemical absorption is a well-demonstrated technology. It is considered as the state-of-the-art for the decorbonisation of a feed gas with low CO_2 partial pressures. As such it is considered as the best option for capturing CO_2 from the flue gas of electricity generation coal and natural gas power plants.
- Physical absorption is also a widely used technology. It is best utilised at higher CO_2 partial pressures. As such it may be considered as a good solution for capturing CO_2 from shifted syngas in hydrogen production installations, as well as in IGCC power plants.
- Pressure swing adsorption offers significant advantages over temperature swing adsorption. However, overall, adsorption under the current state of technology cannot be competitive to physical absorption for syngas decarbonisation. Nevertheless, it is widely used for the purification of hydrogen, and as such can be a part of a hydrogen production plant, where CO_2 is captured in two stages: in the first stage, most of the CO_2 is removed by physical absorption, while in the second stage, the remaining CO_2 is separated from hydrogen, by PSA.
- Cryogenic separation is unlikely to be utilised for carbon sequestration, except in niche applications.
- In the long term, membranes (and more likely chemical absorption membranes) are excepted to play a very important role, replacing chemical absorption.

4. Transport of Carbon Dioxide

Transport of CO_2 in a gaseous state is prohibitive as it causes cavitation with detrimental effects in fluid flow and to the integrity of the transport pipes due to corrosion, and results in a significant increase in volume. Thus, after capture, CO_2 needs to be compressed at high pressures, higher than 80 bar, so to be at a supercritical state within the temperature range of 10 to 20°C and thus to have a high density. This can be achieved using multi stage compressors. An important aspect of the preparation of CO_2 for transport is dehydration: it is essential that the content of water in the compressed CO_2 be below 10 ppm, since the combination of water with CO_2 forms a corrosive atmosphere and hydrate precipitates with deleterious effects in the life of the transportation system. Most of the water can be removed during compression, and drying can be completed by forcing the CO_2 pass through a solid desiccant [97]. Finally, the CO_2 has to be pure, at least 95%, because contamination with other elements can also lead to corrosion of the transport system, an issue that still needs further research.

In general, CO_2 transport does not pose problems in carbon sequestration. Pipelines dedicated for the transport of CO_2 are in place since the 80's and a 3,100 km long network is operational in North America (USA and Canada) transporting about 45 million tonnes of CO_2 annually [14, 73]. To put these numbers in perspective, in 2000 the length of natural gas and of hazardous liquid pipelines in the USA was 514,000 km and 248,000 km respectively [73]. The CO_2 transport network consists of high-pressure pipelines (100-200 bars), made of steel. Most pipeline systems are designed so that pressure drop is minimal (around 10 bars along the total length of the network [97]) so that recompression is not required beyond the entry point. Furthermore, in N. America there are standards in place for the construction, design and monitoring of these pipelines and largely represent an extension of industry best practises for natural gas and other hazardous gas pipelines [99].

Carbon dioxide pipelines are considered as high volatile/low hazard and low risk. Safety studies have shown that CO_2 pipelines are no less prone to incidents than natural gas pipelines. More specifically, statistics in the USA have demonstrated that the impacts of CO_2 incidents are lower than that of natural gas and hazardous liquid pipelines, see Table 11. Principal causes of CO_2 pipeline accidents in the USA were outside causes (35%, mainly human error accidents such as third party damage by contractors, farmers and utility workers), corrosion (32%) and others (17%, including vandalism, improper operation of valves, etc) [73]. A European study based on natural gas pipeline failures during the period 1970-87 showed similar results i.e. 50% of 664 reported incidents were the result of human error (contractors and farmers), 18% due to construction defects (mainly weld failures), 16% due to corrosion, 3% by utility workers and 13% due to undefined reasons. However, to reduce potential risks, pipelines could be placed far from population concentration areas.

Table 11: Statistics of pipeline incidents in the USA [73]

Pipelines	*Natural Gas (1986-2001)*	*Hazardous Liquids (1986-2001)*	*CO_2 (1990-2001)*
No. of incidents	1287	3035	10
No. of fatalities	58	36	0
No. of injuries	217	249	0
Property damage	$285.3 million	$764.2 million	$469,000
No. of incidents per 1,000 km pipeline per year	0.17	0.82	0.32
Property damage per 1,000 km pipeline per year	$ 37,000	$ 205,400	$15,200

An alternative option considered for the transport of CO_2 is the use of tankers. This option can become increasingly attractive if large scale sequestration were deployed so there would be a demand for transporting large quantities of CO_2 to overseas underground storage sites (see page 73), or if ocean storage (see page 79) were accepted as a viable option. Although the transport of CO_2 with tankers has not been demonstrated, it is believed that such an option will not pose any obstacles, as ship designs will be based upon current tankers used to carry liquefied petroleum gas (LPG) [52]. Furthermore, there are plans to expand the capacity of such ships from the current level of capacities (300,000 tonnes in average) to 1 million tonnes. Already, the shipping division of the Norwegian state oil company Statoil, Navion, has designed such a vessel and distributed the drawings to major shipbuilders for comments. According to Statoil, tankers would be "*… more flexible and less costly …*" than a dedicated pipeline. Nevertheless, the capability to produce vessels with such a large capacity has not been demonstrated yet and it is questionable whether such ships can be built. It was estimated that two ships would be needed to transport the CO_2 captured from a standard-sized European gas-fired power plant [74]. Nevertheless, there will be a need to develop intermediate storage and loading sites to cope with variability in supply, transport and storage.

The costs of CO_2 transport depend on the distance between the CO_2 source and the utilisation/storage site, the volume of CO_2 transferred and the presence of existing infrastructure. Compression, if needed, costs about 9-10€/tonne CO_2 [97, 120]. Transport costs via pipeline can be estimated with a good accuracy given the long experience gained by constructing and operating natural gas pipelines. Land

---

[52] The Swedish gas manufacturer AGA AB owns a ship that is used to carry CO_2. The ship can carry 1250 tonnes. Losses are insignificant in a 5-day trip. The ship radius is 2600 km [89].

construction costs (that include the value of land, material and labour) depend on the pipe diameter and may range between 170,000€/km for an 8” pipe to 850,000€/km for a 35” pipeline, see Figure 32 [62]. Calculations indicate that costs decrease exponentially with the increase in mass flow rate and vary between 0.4€ for every tonne of CO_2 transported with a mass flow rate of 50 million tonnes annually in a 100 km long pipeline (0.4€/100 km/tonne CO_2), to 1.1-1.8€/100 km/tonne CO_2 when the mass flow rate is 5 million tonnes annually.

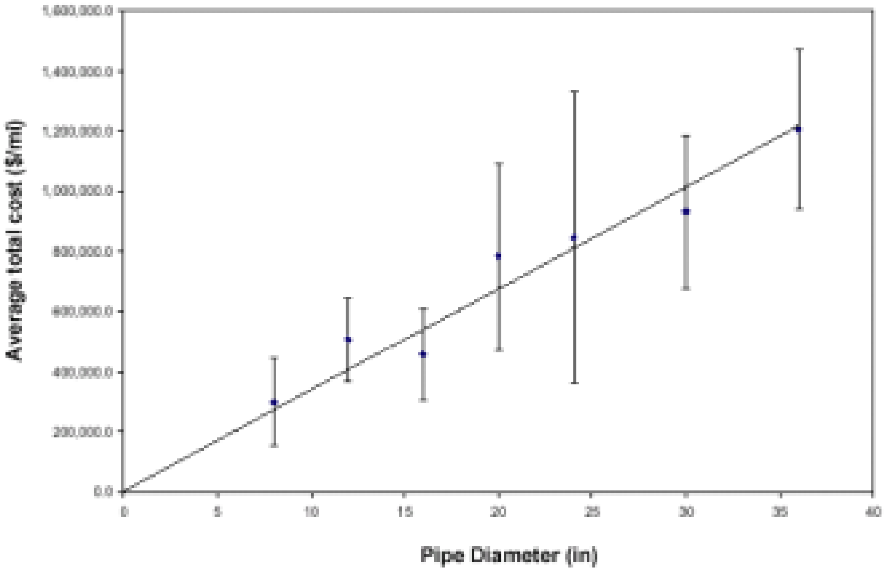


Figure 32: Land construction costs of natural gas pipeline (1989-1998) as a function of pipe diameter [62]

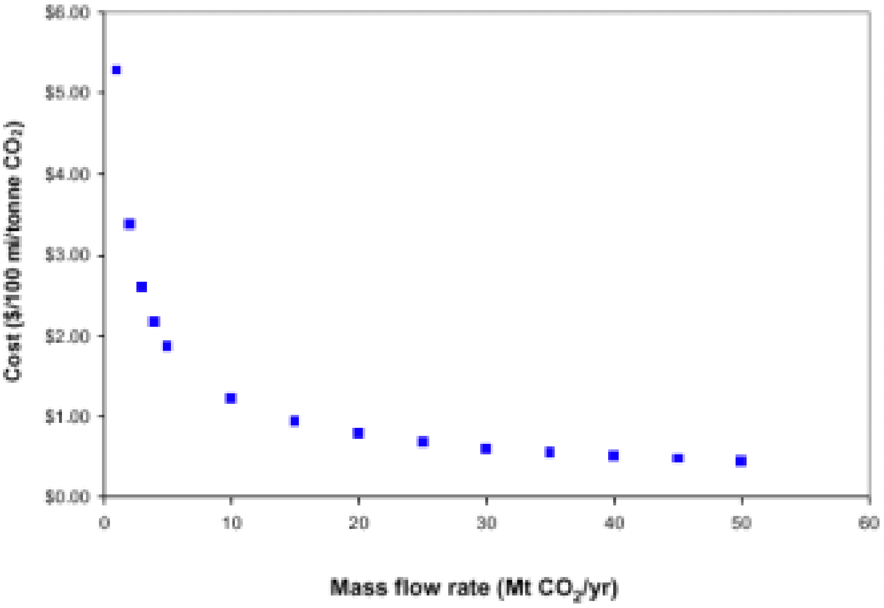


Figure 33: Cost of CO_2 transport via pipeline as a function of the mass flow rate [62]

A recent study contracted by IEA [98] has calculated the cost of CO_2 transport via pipelines as a function of mass of CO_2 transported and the transport distance. The results are summarised in Table 12. The specific cost of CO_2 transport (per tonne CO_2

per 100 km) varies from \$13 when the throughput is 0.1 million t/y to \$1.1 when the throughput is 5 million t/y to \$0.4-0.5 when the throughput is 50 million t/y. As such, there is a strong dependence of transport cost on the scale of operation. Given that a typical coal-fired power station with 500 MW_e electrical output generates 3.4 million tonnes of CO_2 annually, then the average transport cost could be in the range of \$1.2-1.5 per tonne per 100 km. Obviously, the transport cost increases significantly when lesser amount of CO_2 needs to be transported, e.g. from distributed hydrogen generation plants.

Table 12: Cost of CO_2 transport by pipeline [98]

Throughput	***Length of pipeline***	
	100 km	***400 km***
	Capital Cost (\$million)	
0.1 million t/y	9	33
5 million t/y	31	135
50 million t/y	137	753
	Operating Cost (\$million/y)	
0.1 million t/y	1.3	5.1
5 million t/y	5.3	21
50 million t/y	21	110
	Total Cost (\$/tonne CO_2)	
0.1 million t/y	13	51
5 million t/y	1.1	4.2
50 million t/y	0.4	2.2

The costs associated with the use of tanker have been quantified in another report by the IEA Greenhouse Gas Programme [41]. A large tanker designed to carry 22,000 m^3 of LPG costs \$50 million. By considering that two such ships will be used to carry CO_2 in an offshore platform 500 km away from the terminal, the transport cost would be around 2€/tonne CO_2 which is lower than the cost of a pipeline. However, additional costs related with port fees and operating expenses may bring overall costs at the same level as the cost of a pipeline.

Overall, it is cheaper to transport CO_2 than to transmit an equivalent amount of electricity. Therefore, it would be more economical to site power plants close to the electricity demand and transport the CO_2 to the storage site.

5. Utilisation of Carbon Dioxide

5.1 Introduction

Carbon dioxide is a chemical compound with commercial applications, so utilisation of captured CO_2 may provide a possible way to reduce the cost of the carbon sequestration process. However, the amount of CO_2 that can be utilised is significantly lower than the amount of CO_2 that has to be captured. For example, the US market of CO_2 is currently 4.2 million tonnes per year, or 2% of the US power plant emissions [100]. Furthermore the use of CO_2 does not necessarily constitute a way of its permanent removal from the atmosphere, since, utilised CO_2 eventually escapes back to the atmosphere.

The major applications for CO_2 and their potential are thoroughly presented in a report prepared by IEA Greenhouse Gas Programme [39]. The current major industrial uses for CO_2 include:

- The petroleum industry
- The chemical industry, for the production of chemical compounds and fertilisers
- The food industry, to provide an inert atmosphere to inhibit bacterial growth; and the beverage industry, for the production of carbonated soft drinks. The latter market segment consumes 1 million tonnes of CO_2 annually.
- The materials industry, for the production of carbonated polymers and for the generation of shielding atmospheres for metal welding.
- The pharmaceutical and medical industry, and,
- Other applications such as dry cleaning and production of fire extinguishers

Among these markets, the petroleum industry uses most of the utilised CO_2 to enhance oil extraction, a method called Enhanced Oil Recovery (EOR) that is discussed in detail in the next section (see Figure 34). The second most important market is the chemical industry.

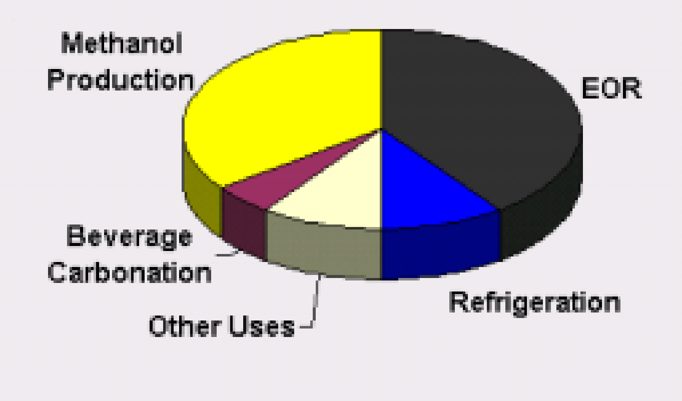


Figure 34: Main uses of CO_2 (Adopted from [39])

The amount of CO_2 utilised by the chemical industry at present, is estimated as 89 million tonnes annually, only a small fraction of CO_2 emitted in the atmosphere. There are efforts for further utilisation of CO_2; however, these efforts are hindered by the significant amount of energy required to process CO_2, since it is a very stable molecule. Carbon dioxide is mainly used in the chemical industry for the production of: (i) aromatic organic compounds, such as benzene, toluene and xylene; (ii) methanol; (iii) polycarbonate-based polymers; and (iv) dimethyl carbonate (DMC), a potential additive to gasoline, used as octane booster. There is also scope for CO_2 to replace other chemicals and solvents used today in commercial operations. Among these applications, the highest potential for further utilisation of CO_2 is offered by the production of DMC. If accepted as a gasoline additive, the potential for CO_2 utilisation could increase sharply. It is expected that the fuel economy achieved by the engine might be improved, which could lead to a saving in CO_2 emissions from transport. This would be partially offset by the extra CO_2 produced by combustion of DMC. Globally one million tonnes of CO_2 per year could be used in DMC production. In practice, methyl tertiarybutyl ether (MTBE) is already established as a vehicle fuel additive, with a large capacity installed worldwide, so DMC would have problems becoming competitive with MTBE in a very large market. In addition, detailed projections of cost and energy balance indicate that DMC can be produced from CO_2 below current market costs only if the CO_2 is subsidised. Current estimated costs of CO_2 avoided are high ($1000/t CO_2) [39].

The CO_2 needed for all the aforementioned applications is not normally derived from flue gases. Although some process plants in the United States have been set up to extract CO_2 from flue gas for use in the petroleum industry, in most cases CO_2 is produced for the particular process involved, or in the case of the majority of oil industry applications, CO_2 is extracted from natural sources. These natural wells can contain up to 97% by volume carbon dioxide and may be piped hundreds of kilometres to the oil fields. In addition, CO_2 is a by-product gas of many chemical processes including the production of ammonia, hydrogen, substitute natural gas, removal from natural gas reservoirs, etc., which are often exploited as an economic source of CO_2.

5.2 Enhanced Oil Recovery[53]

The most important industrial consumer for CO_2 is the petroleum extraction industry, a sector with significant potential for further CO_2 utilisation. In most oil fields, only a small proportion of original oil in place (OOIP) is recovered via traditional production methods, primary and secondary[54], leaving in average two thirds of oil un-recovered [101]. This is simply because there is a point at which the cost of production of an additional barrel of oil is higher than the price the market is willing to pay for it. However, during the oil crises in the 70’s when oil prices soared, oil extraction went one step beyond traditional approaches applying methods to enhance oil recovery (EOR). One of these methods was to inject CO_2 into the oil reservoir. However, with the drop in oil prices in the 80’s EOR methods were abandoned, as they were not economically viable. Nevertheless, in limited cases EOR has been proven competitive due to reductions in development and operating costs, a local abundant supply of cheap CO_2 and a higher operational efficiency for oil producers.

---

[53] Herein, EOR is approached from a CO_2 utilisation point of view. The issues associated with EOR as a storage option are discussed in Chapter 6.

[54] Primary recovery is defined as production by natural reservoir pressure or pumping until depletion. Secondary recovery refers to methods used to further increase the pressure of the oil in the reservoir and extract additional oil; the most common method used being water flooding.

The three main methods for EOR include thermal, miscible and chemical[55]. In miscible EOR, a solvent such as CO_2 is injected in the oil well with appropriate characteristics, achieving the recovery of additional oil. Oil can be recovered through two processes, miscible or immiscible displacement. The term miscible refers to the mixing of oil and CO_2 into a single-phase fluid, since CO_2 in highly soluble in crude oil under high pressure. The oil then swells and its viscosity decreases. Miscible CO_2 displacement is suitable for reservoirs deeper than 1200 m (to provide with the necessary pressure) with oil lighter than 25° API (density 904 kg/m^3) [102]. However, when the pressure of the reservoir is too low and/or the density of oil is higher, the injected CO_2 does not dissolve in oil but remains in a gaseous phase, also causing oil to swell, thus improving its fluidity (Figure 35).

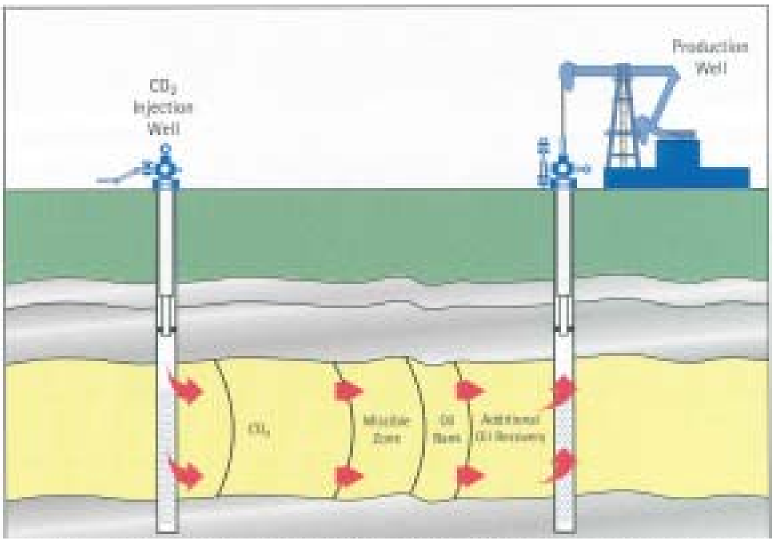


Figure 35: A schematic of the EOR process [95]

The worldwide production of oil using CO_2 assisted-EOR during 1998 reached 210,500 barrels of oil per day (BOPD), from 79 individual projects, accounting for 0.3% of total worldwide crude oil production. The USA, where the technology for CO_2-EOR was first demonstrated on a large scale, is by far the most active area for CO_2-EOR development and production, hosting the vast majority of operations (93% in terms of volume of oil recovered). Another major operation is situated in Turkey, while smaller operations are in Canada and Trinidad. Furthermore, a large project in Canada has become operational since late 1999 (the Weyburn Project, see below), that is expected to boost the Canadian oil recovery using CO_2.

Generally, data concerning the specific volumes of CO_2 used for EOR are not publicly available. It is estimated that, currently, the amount of CO_2 used for EOR is approximately 40 million tonnes per year. However, most of the injected CO_2 comes from natural underground reservoirs, rather than being captured from combustion sources, the former being an abundant and cheap source that contributes the most to the financial viability of the process. It is estimated that the amount of CO_2 captured from

---

[55] In thermal EOR the oil temperature is increased, by injecting a heated fluid or burning some of the oil in place, thus reducing significantly its viscosity. In chemical EOR the reservoir is flooded with surfactants to improve fluidity.

anthropogenic emission sources and used for EOR applications is up to 6 million tonnes per year. Captured CO_2 comes from 5 individual projects in N. America, the most visible being the Weyburn oil field project in Saskatchewan, Canada[56], an international project, co-funded by the European Commission and other European Institutions. In this project, CO_2 is captured from a coal gasification plant in N. Dakota, USA, compressed to 152 bar and transported via pipeline 330 km away in Weyburn field, delivered in a supercritical condition at 150 bar and injected underground at a rate of 5,000 tonnes of CO_2 daily. It is estimated that ultimately 18 million tonnes of CO_2 will be injected producing 120 to 140 million barrels of oil [105-107][57].

The barrier preventing the extensive use of EOR is economics; current oil prices do not justify EOR unless CO_2 is available at a very low cost. Even under conditions of abundant and cheap CO_2 supply from natural sources, EOR is marginally competitive under the current market situation. Infrastructure cost is a major barrier, while the purchase of CO_2 is the largest operating cost. Therefore, all commercial EOR operations are designed to minimise injection of CO_2 into the reservoir[58]. Currently, as a rule of thumb, half a tonne of CO_2 is used of each barrel of extracted oil in the USA; however this value is very reservoir-specific [108]. A major commercial stakeholder (Kinder Morgan) showed in a recent study that the capital cost for EOR applications is of the order of $0.80 per barrel of oil extracted while operating and maintenance costs are about $2.70 per barrel [104]. Furthermore, transport of CO_2 to oilfields remote from industrialised countries, e.g. to the Middle East, would pose problems, increase the cost of the process and limit potential. With oil prices of $14/barrel, CO_2 would have to be available for less than $25/t CO_2 for even the most efficient EOR applications to be economic[59]. However if oil prices doubled, CO_2 prices of $40/tonne could be tolerated. A report from IEA [39] suggests that CO_2 use in EOR could be applied more extensively than previous studies had envisaged; the global potential use of CO_2 for EOR, applied to the proven reserves of oil, is estimated at 45-85 Gt CO_2 based on a detailed field-by-field examination. These estimates do not take into account undiscovered petroleum reserves, so they may be considered conservative. On the other hand an unrestricted supply of CO_2 was assumed which is overly optimistic. If applied to current oil production rates, EOR would utilise CO_2 at the rate of 1.4 Gt CO_2 per year (0.4 Gt C/y).

Finally, there are a number of technological issues that need to be addressed by the scientific community in order to increase the performance characteristics and reduce the costs of EOR operations: (i) minimise gas losses during injection, (ii) monitor reservoir performance, (iii) optimise immiscible and heavier oil applications, (iv) study the effects of impurities in the injected gas, (v) simulate reservoirs to include CO_2 migration into unrecoverable pore spaces and brines.

---

[56] Among the remaining 4 projects, in 3 of them CO_2 is captured from gas processing plants (total daily supply approx. 9,000 tonnes) and in the fourth, CO_2 is captured from a fertiliser plant (daily supply is approx. 2,000 tonnes). All 4 plants are located n the USA [104].

[57] For more information on the Weyburn project, see Chapter 8.

[58] This is in contrast to the carbon sequestration principle and will be dealt in the next section.

[59] Costs are based on a 10% rate of return on capital.

5.2.1 The Potential for EOR in North Sea

The fact that EOR is far more difficult to be deployed in offshore oil fields than inland poses a major barrier for the deployment of EOR projects in Europe, given that the European oil fields are in the North Sea. The main reason for this difficulty is that offshore wells are more distant from each other, extending the time between EOR initiation and results. This increased spacing of wells also increases the likelihood of undetectable heterogeneities between wells, impairing simulations of well behaviour.

To date, no CO_2-EOR projects have been developed in the North Sea. However, a consortium of European companies, has studied the feasibility to develop a CO_2 pipeline infrastructure in the North Sea, capable of transporting more than 30 million tonnes annually. According to the proposed plan, CO_2 will initially be captured from on-shore coal-fired power plants in the UK and Denmark and used for EOR in oil reservoirs in the North Sea. The analysis made by the consortium indicates that during a 25-year lifetime, 2.1 billion barrels of oil could be produced via EOR, while storing underground 680 million tonnes of CO_2. By assuming an oil price at \$20/barrel, the net cost for capture, transport and injection of CO_2 could be less than \$1.5 per tonne CO_2 avoided. The project comprises onshore pipeline networks in Denmark and UK (900 km in length), underwater feeder lines and the main pipe transporting the CO_2 northwards (1500 km long), off the west coast of Norway. There is also the option to connect this network with another feeder line from Scotland (see Figure 36). The investment for CO_2 transport is estimated in the range of \$1.70 billion. With an estimated cost for CO_2 capture of \$35 per tonne CO_2, oil prices need to be in the order of \$30 per barrel for the investment to be considered as economic. Alternatively, with an oil price of \$20/barrel, the cost of CO_2 should not exceed \$12 per tonne, which is not realistic under the given nowadays cost of carbon sequestration technologies [109, 110].

Another proposed project that involves EOR operations in the North Sea is the 'HydroKraft' initiative by the Norwegian company Hydro. The project comprises the construction of 2 gasification plants with a combined production capacity of 11 TWh, to produce hydrogen from natural gas. Carbon dioxide, a by-product of the process, will be injected to undersea oil reservoirs to enhance oil recovery [111].

A more pessimistic view on deploying CO_2-EOR projects in the North Sea is shared by a major oil exploration company, BP. BP claims that despite the significant benefits of EOR (injection of 2-4 million tonnes of CO_2 annually could produce an additional 100-200 million barrels of oil and store 40-80 million tonnes of CO_2 over a 20 year period), the large capital expenditure required to radically modify the wells, pipelines and surface facilities to make them compatible with CO_2-EOR operations make such a project not economically attractive. Two barriers prevail, the high cost for modifying existing facilities, and the lack of high volume low cost source for CO_2. It is claimed that, based on engineering studies, it would be a cheaper option to build new platforms than to modify existing facilities [112]. Furthermore, a study that assessed the EOR potential of 15 major Norwegian fields concluded that CO2-EOR is the least viable option for tertiary oil recovery [113].

One must bear in mind that once North Sea oil platforms are decommissioned and removed, it is highly unlikely that a CO_2-EOR project could justify the costs of new platform and wells. This means that any CO_2-EOR project in the North Sea should start within the next 10 years.

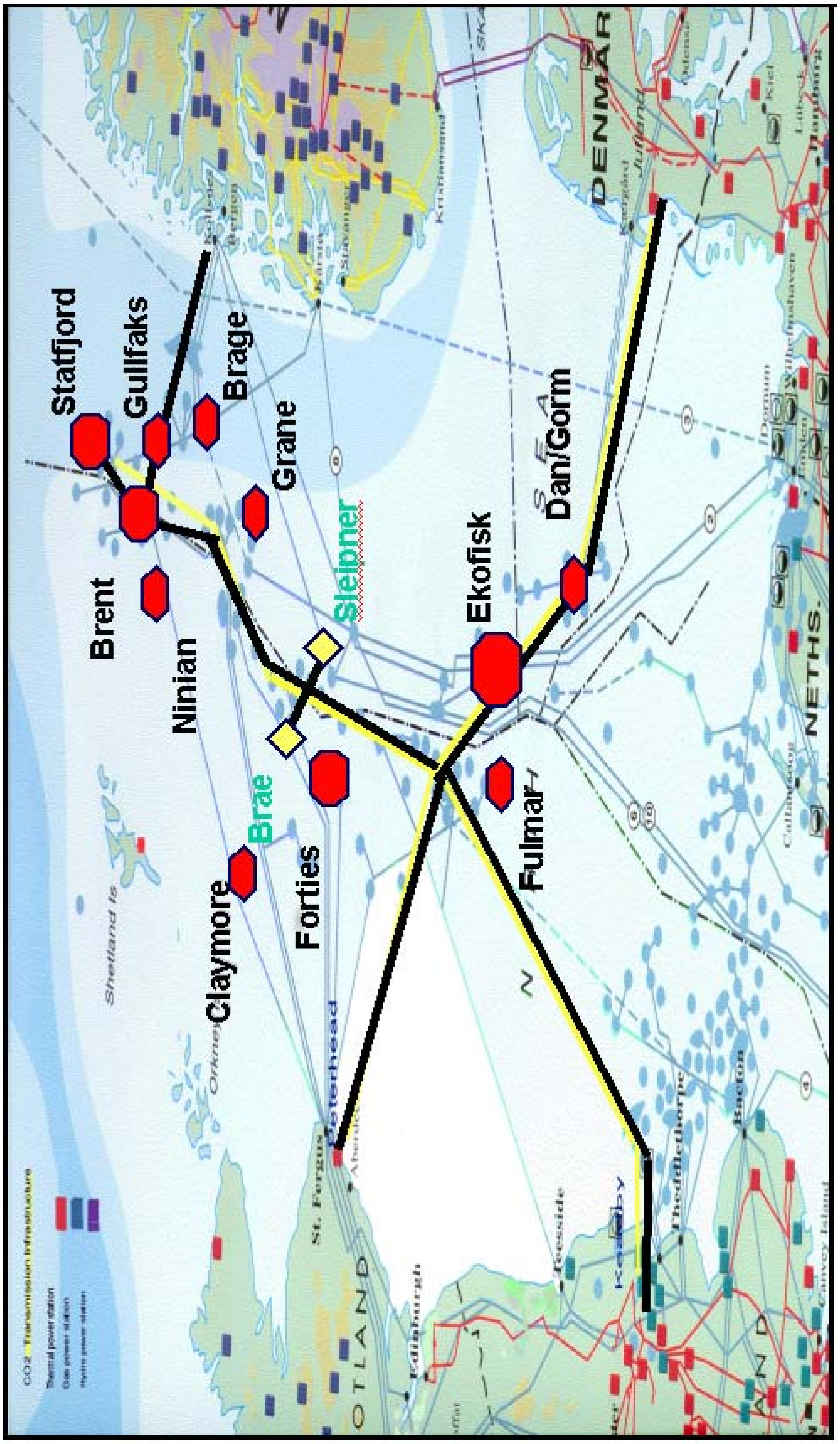


Figure 36: Planned EOR project in North Sea (in yellow). Black lines indicate existing oil pipelines, blue lines show existing natural gas pipelines and red areas the oil fields. Source: Ref [114].

5.3 Enhanced Coal Bed Methane (ECBM) Recovery

A process related with CO_2-EOR but operationally different is to improve recovery of coalbed methane (CBM) from deep un-minable coal seams. Coalbed methane can be used as a fuel, like natural gas. It is among the gases created during the process of coal formation and it is either adsorbed on the coal surface or dispersed into the coal pores. Coalbed methane extraction has its origins in the 40's when it was used for degassing coal seams to improve the safety of coal mining operations. This was then achieved by pumping out groundwater, thus lowering the reservoir pressure, forcing methane to desorb and flow out. Coalbed methane development has grown rapidly in the US during the past decade, emerging as an important component of natural gas supply [102]: in 1998, approximately 37 million cubic meters of CBM were produced in USA, or 6% of the total US natural gas production. Nowadays, the extraction of CBM can be enhanced by injecting CO_2 or nitrogen. Carbon dioxide absorbs more easily to the coal than methane, so methane is replaced by the injected CO_2 and flows out while the pressure of the reservoir is maintained. As a rule of thumb, 2 unit volumes of CO_2 replace 1 unit volume of methane. In theory, 90% of the original gas in place (OGIP) can be recovered using enhanced CBM (ECBM) recovery, compared with only 30% to 70% using traditional approaches. In principle, ECBM recovery is similar to CO_2-EOR: CO_2 is transported to the field and injected through dedicated wells (Figure 37). However, ECBM recovery cannot be applied to all coalseams. Many requirements need to be met such as suitable geological characteristics (continuous and isolated coal strata, without faults and with moderate permeability (1-5 mDarcy), appropriate depth (300-1500 m) and minimum saturation levels).

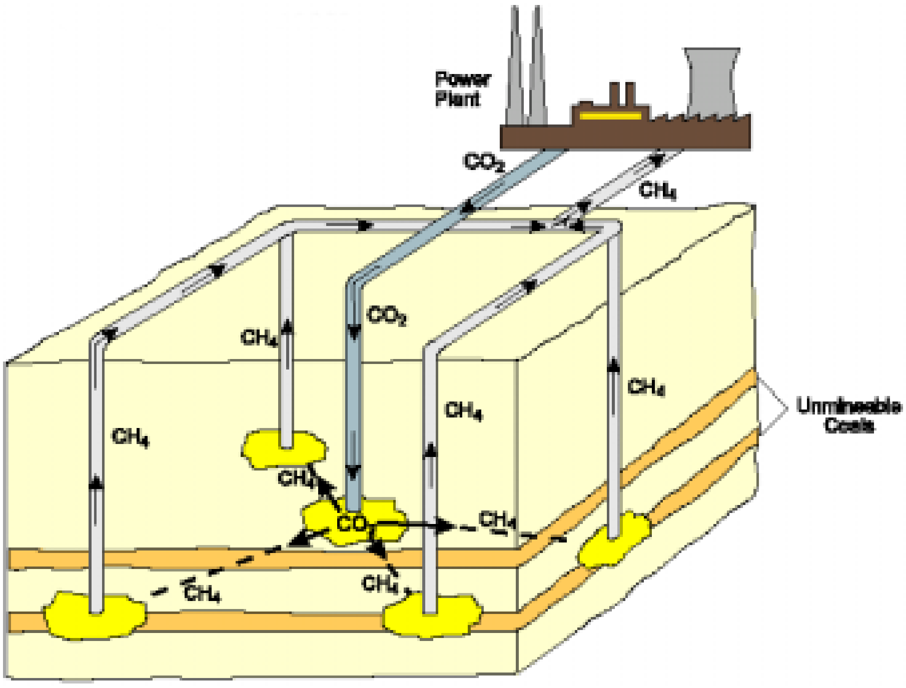


Figure 37: ECBM recovery concept. Source: Ref. [103]

In recent years, ECBM recovery has attracted attention given the presence of vast coal deposits worldwide, and effort is made to develop economically viable techniques to exploit this energy source. Nevertheless, it is a very young process, thus our current understanding about the related science and technology is very limited. Besides laboratory experiments, ECBM recovery utilising CO_2 has not yet see the deployment of large demonstration projects that could help improve our knowledge. Currently, there is only one major field pilot study in the USA, in the San Juan Basin, and a pilot test in Alberta, Canada. The former project injects 70,000 tonnes of CO_2 annually [105] with promising results, to the extent that a second 3-year project was launched in 2000 in the same area by a US government-industry partnership (called Coal-Seq) [115]. First results indicate that the low permeability of most of the coalbeds, a result of the swelling of the coal from the injection of CO_2, appears to be one of the main problems associated with the technique [116, 117]. In 2001, a European project was also launched, co-funded by the European Union, called RECOPOL, being the first European field demonstration of its kind. The project will take place in Poland. Drilling will start in 2003 and it is estimated that up to 10,000 m^3 of CO_2 will be injected daily for a period of at least 1.5 years [118]. More information on this project can be found in page 105.

5.3.1 European Potential for ECBM Recovery

It is uncertain what is the potential for implementation of ECBM recovery in Europe. A Dutch research group claims that on a worldwide scale, the European coal occurrences are less promising considering the technical features of the coal seams [119, 120]. Another study by IEA also concludes that the European coal basins are poorly suited to coalbed methane development [96]. Two sites with modest potential have been identified: the upper Silesian basin in Poland and the Czech republic, and the Saar/Lorraine basin in Germany and France. The total amount of CO_2 that could be stored has been estimated as 7.4 and 9.3 Mt respectively. However, a report by the Netherlands Agency for Energy and the Environment (NOVEM) [97] claims that the technical potential of CBM in the Dutch underground is significant: Coalbed methane stored in coal layers up to a depth of 2000 m may account for 20 times the annual energy consumption of the country and be equal to the natural gas reserves. The CO_2 storage potential could be about 8 billion tonnes or 40 years of Dutch accumulated emissions. However, it is still uncertain to what extent these reserves can be accessed. With conservative assumptions regarding the potential completion and recovery rate of CBM from coal layers by means of drilling and CO_2 injection, as well as by limiting the ECBM recovery to a depth range of 500 - 1500 metres, the possible reserves could be up to about 3.9 EJ, or one-year of the Dutch energy consumption. Similarly significant could be the drop in CO_2 utilisation potential, highlighting the uncertainties of the potential of ECBM in the Netherlands and in Europe in general; uncertainties that result from incomplete knowledge. The same report estimates that, the cost of ECBM recovery ranges from 3.5 to 6.5 €/GJ of methane produced, that is comparable with the price of natural gas. In conclusion, this study claims that ECBM is likely to become an economically feasible option for the Netherlands on relatively short term and stresses the need for more detailed geological surveys combined with getting good quality samples, laboratory experiments, system studies on implementation scenarios and a pilot project (with a special focus on drilling techniques).

It has been estimated that, for an ECBM recovery operation to be economically viable the maximum acceptable price for CO_2 is 5-6€/tonne, given that the significant amount of CO_2 needed to extract methane. However, transport costs could be very low given the abundance of suitable coal strata [121].

6. Storage of Carbon Dioxide

The amount of CO_2 that cannot be utilised after capture needs to be stored safely and permanently, at a low cost and in a way that is environmentally compatible and in accordance with international treaties and national legislation. The main options for storing CO_2 are: (i) underground in suitable geological formations (geological storage) and (ii) in the ocean (ocean storage). In addition, *novel approaches* are been explored, that consist of a basket of technologies under development, not yet proven, that promise to offer potential solutions.

6.1 Geological Storage

Storage of CO_2 in geological formations is the most favourable option nowadays. In principle, CO_2 is injected and stored into suitable geological formations underground such as depleted oil and gas reservoirs, saline aquifers and unminable coal beds (Figure 38). This process is very similar to the EOR and ECBM recovery discussed in the previous section, the difference being that in the utilisation processes the amount of CO_2 used is not the maximum that can be stored but is minimised so to yield the maximum amount of oil or methane at the lowest possible cost. In storage processes, the aim is to store as much CO_2 as possible ignoring the effects to the contents of the reservoir. However, efforts are made to bridge this gap and increase the amount of CO_2 stored while recovering maximum oil. Proposed approaches include adjustment of injected gas composition, new well designs and optimisation of water injection.

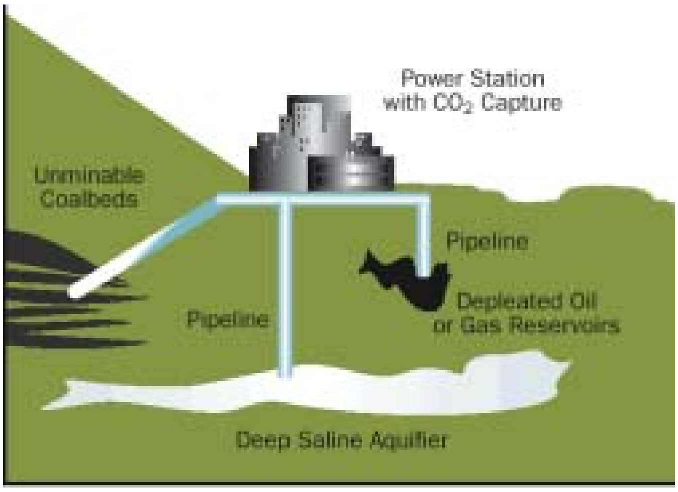


Figure 38: Potential options for the geological storage of CO_2 [99]

Carbon dioxide can be stored in geological formations via three different mechanisms: (i) hydrodynamic trapping[60] as a supercritical fluid under a low-permeability caprock,

---

[60] It should be noted that all potential geologic formations suitable for CO_2 storage consist entirely of rocks and fluids, thus storage capacity comes from the compressibility of both the rock and the fluids due to increased pressure.

see Figure 39; (ii) aqueous solubility into underground fluids; and (iii) mineralisation, i.e. the reaction with minerals and bacteria and its transformation into minerals. It is still not clear which is the dominant storage mechanism when CO_2 is injected underground. While most scientists agree that hydrodynamic trapping may dominate at early stages of injection, and subsequently CO_2 should be dissolved slowly into the fluid medium, there is no consensus on the amount of CO_2 that would ultimately transform into minerals, which constitute the only permanent storage option (e.g. Ref. [107] vs. Ref. [117]). Possibly, the contribution of each mechanism is storage-site specific, dictated by the type of minerals present in the vicinity of the storage site.

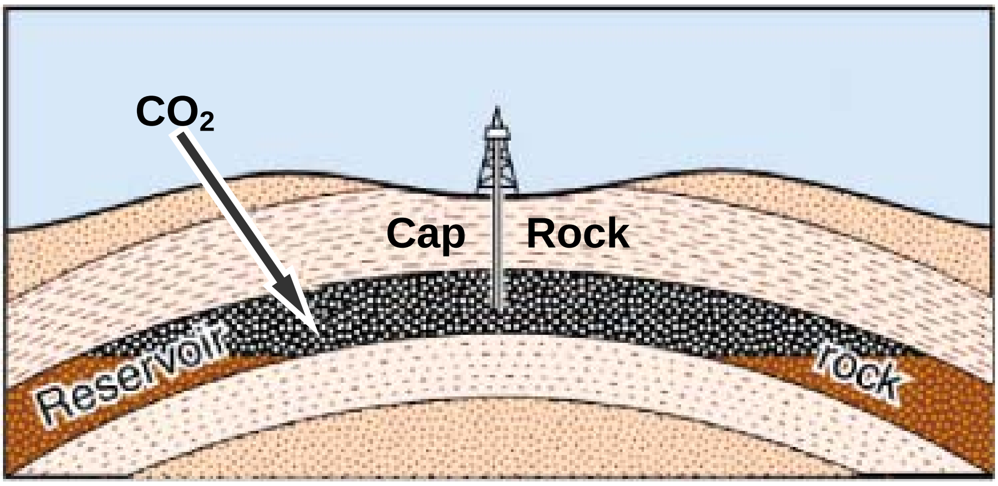


Figure 39: Hydrodynamic trapping of CO_2 under a low-permeability cap-rock (Adopted from Ref. [122]).

The technology for injecting CO_2 and other compounds underground is well established. Since the early 30's the petroleum industry has been injecting oilfield-produced brine wastes in underground reservoirs to avoid surface contamination; in the USA, oil producers have been injecting CO_2 into oil fields to enhance oil recovery for more than 25 years. Furthermore, underground reservoirs have been used for more than 50 years as underground storage sites for natural gas with annual cycles of injection and recovery. Therefore there is significant experience that has been accumulated and could be exploited for CO_2 storage.

Depleted and disused oil and gas reservoirs can be very effective storage sites: they are dispersed geographically, they have large capacities and they can offer an added-value from the additional extraction of oil and possibly natural gas[61], thus improving the economics of the carbon sequestration process. In addition, the existing surface and down-hole infrastructure for oil and gas extraction can be modified only slightly to become compatible with CO_2 storage, while significant volume of information related with the characterisation of such sites has already been accumulated during the

---

[61] Enhanced gas recovery (EGR), the exploitation of gas fields by injecting CO_2, has been considered as a non-efficient method, for two reasons: primary gas recovery could be as high as 95% and secondly, CO_2 is more mobile and can by-pass natural gas. However, there are some reservoirs in California, USA that implement EGR by CO_2 flooding [116].

exploration process. Moreover, significant experience has been gained by the oil and gas industry in issues such as drilling and injection, gas storage, evaluation and understanding of geological formations. Furthermore, such reservoirs have been natural storage sites for fluids (oil and natural gas) for millions of years, so supporters of this option claim that the storage of another gas could not be a problem, as long as the original pressure of the reservoir is maintained.

However, there are no specific demonstration projects *per se* on the injection of CO_2 into oil and gas reservoirs for the purpose of CO_2 storage with the exception of the Wyburn project (briefly described in page 66).

As expected, the cost of a project involving the injection of CO_2 in an oil reservoir for the double purpose of storage *and* EOR is higher than in a purely EOR project, because: (i) higher volumes of CO_2 have to be transported and injected, and probably purchased, (ii) less CO_2 can be recycled, (iii) well costs are higher, associated with long-term site integrity (see next), and, (iv) operational and maintenance costs are also higher for monitoring and verification. An analysis from Advanced Resources Int'l [104] indicates that, EOR projects with an additional storage target, will cost \$25-\$33 per barrel of oil. However, a credit of \$10/tonne CO_2 stored could bring down the cost of the process to \$20-\$25 per barrel of oil.

The most potent in terms of capacity but least studied geological storage sites are **deep saline aquifers**. Suitable aquifers should not be suitable for exploitation as drinking-water resources, be isolated from the surrounding aquifer network to avoid the spreading of the stored CO_2, and be located at significant depths, typically deeper than 800 m. At these depths, temperature and pressure are high enough for the CO_2 to remain in a supercritical state ensuring the efficiency of storage. Although these storage sites do not offer an added value, they have the advantage for being spread worldwide, thus they can be close to emission sources. Deep saline aquifers have been poorly studied and mapped, thus, significant effort is being made towards mapping the sub-terrain for aquifers and identifying suitable injection locations.

The storage of CO_2 into **unminable coal seams** can be achieved by the sorption of CO_2 on coal surface, displacing methane and by physical trapping into the pores of coal. The technology has alredy been described in page 70. Provided that coal will never be mined, stored CO_2 can remain within the deposit indefinitely, becoming the most preferable CO_2 storage medium when compared to (saline) aquifers, depleted oil and gas fields and other storage options. However, the technical potential has not been demonstrated, even though it can offer an added value to the storage process by extracting methane. Major obstacles associated with the development of this storage option is the low permeability of most of unminable coal strata and the estimated limited capacity, as will be discussed in page 82.

Among these approaches, only the storage in deep saline aquifers has become an industrial application: the capture and geological storage of industrial quantities of CO_2 is currently being demonstrated at the Sleipner West gas field in the Norwegian sector of the North Sea. The project was initiated in 1996 by the Norwegian state oil company Statoil, which extracts natural gas from the Sleipner strata. The extracted natural gas contains 9% of CO_2, while the upper limit for its commercial use is 2.5%. As such, Statoil used to separate CO_2 from the natural gas on the extraction platform, using chemical absorption, and the vent it to the atmosphere. However, in 1996, the Norwegian state imposed an offshore carbon dioxide tax of \$50 for every tonne of CO_2 emitted (as of 2000, the tax was lowered to \$32 per tonne). This tax was the main motivation for the first geological storage project. The investment cost about $80 million, while the consortium of companies that own the Sleipner field would have to pay about $50 million annually in taxes if they had decided not to store CO_2. In essence, the tax savings paid off the investment in 1.5 years [40]. The separated CO_2 is stored in the Utsira formation, a porous sandy stratum, saturated with saline water, 800 m below the sea's bottom, see Figure 40. One million tonnes of CO_2 are stored annually in the Utsira formation, this is roughly the amount of CO_2 emitted by a conventional 140 MW power plant. The project has been a success and a number of other projects have been evolved around it. Notable are the EU-funded SACS and SACS2 projects with aim to monitor the storage of CO_2 underground. Currently, Statoil intends to store CO_2 in additional sites in the North Sea, such as in the Snøhvit gas field [133]. A similar large-scale project is planned in the Natuna field, in South China Sea, and a smaller project is planned in the USA (the Frio Brine Sequestration Pilot) [134].

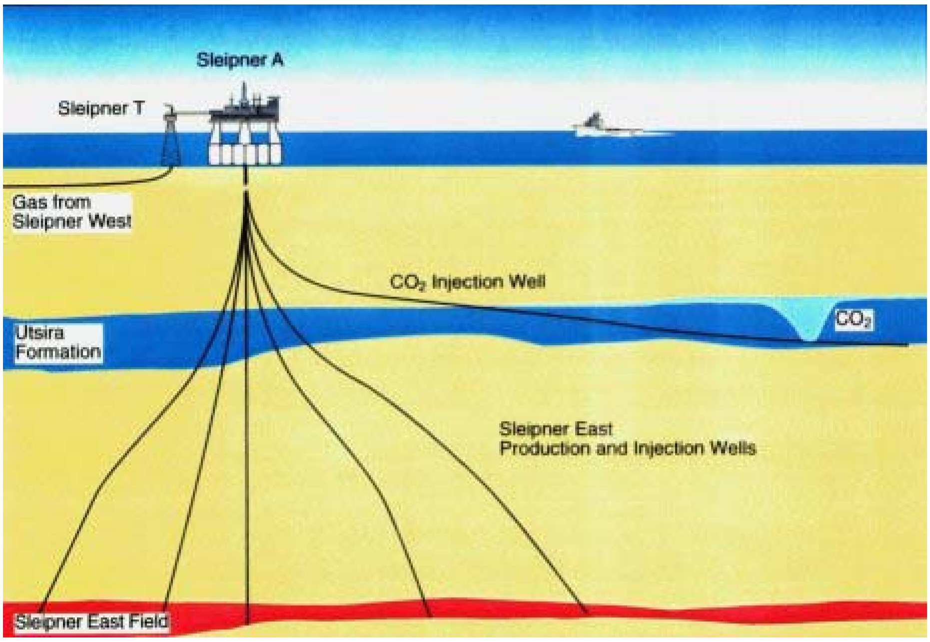


Figure 40: The Sleipner CO_2 storage operation (Source: Ref. [135])

Although geological storage of CO_2 does not involve new technologies, many fundamental and technical issues have not been fully understood and resolved. Major challenges associated with geological storage are to:

- Identify the most suitable sites for long-term and safe storage and evaluate their capacity.
- Understand the requirements and costs to make these underground formations suitable for long-term storage and estimate retention times.
- Ensure the safety of storage and avoid/minimise leakage with potentially devastating effects to local communities and on a global scale.
- Establish appropriate monitoring systems for the movement of CO_2 underground and for potential leaks; and verification schemes, especially needed to verify national commitments and participate in emissions trading programmes.
- Convince the public that geological storage is a safe and environmentally compatible option and overcome political and legislative barriers.

These challenges are discussed next.

Although criteria have not yet been established to characterise potential reservoirs, a good candidate should have the following characteristics:

- Sufficient volume to allow for storage for long times, without exceeding the original pressure of the reservoir (with potentially negative effects to the integrity of the reservoir) and without requiring a non-economic compression of the injected gas. This in turn requires the optimisation of geological characterisation techniques for potential sites, improved sensing and development of advanced reservoir models to account for interactions with coal, brine and minerals. This issue is of major importance for saline aquifers, since, as was mentioned above, they have been poorly surveyed.
- Adequate permeability to allow an efficient injection and limited sensitivity to reductions in permeability due to plugging in the near-injection region and due to reservoir stress fluctuations [123].
- Satisfactory containment of the reservoir to avoid leakage. Techniques are needed, based on seismic and electrical geophysics and pressure testing to evaluate the geological structure

Among the issues surrounding geological storage, mentioned above, reliability and security are of paramount importance. A better understanding of the long-term geochemical behaviour and safety of underground storage sites can be gained with the study of the behaviour of natural CO_2 accumulations underground, containing up to 99% CO_2[62], called natural analogues. Such sites exist in many locations in Europe and worldwide. These geological formations have demonstrated that CO_2 can remain trapped underground for millions of years. By studying them, important conclusions can be drawn on the effects of CO_2 on rock properties, including permeability and rock strength providing information for: the development and optimisation of models necessary for the understanding of CO_2 behaviour underground upon injection; for the prediction of the response of the reservoirs and caprock in the event of leaking; the effects of CO_2 on groundwaters and ecosystems; and the identification of mechanisms for the migration of injected CO_2. Due to the importance of the studying these natural analogues, a number of projects have been launched worldwide including the EU-funded *Natural Analogues for the Storage of CO_2 in the Geological Environment (NASCENT)* project and the American project, *Natural Analogs for Carbon Sequestration (NACS)*[63].

A major concern for geological storage is the possibility of leakage of CO_2 out of the reservoir. Natural analogues have shown that CO_2 can leak out of their storage sites back to the atmosphere (e.g., Lake Nyos-Cameroon, Mammoth Mountain-USA and the French peri-Alpine Province [124]), potentially with fatal effects (e.g. Lake Nyos). Furthermore, a sudden release of stored CO_2 as a result of rock-cap failure could have even more devastating effects. At a regional scale, leaks might endanger drinking water supplies and public health. On a global scale, leaks can be large enough to make geological storage ineffective. It is understood that retention times depend strongly on the quality of the geological seal, i.e. the integrity of the caprock and the technical solution for injection. It is expected that the option of geological storage would be valid

---

[62] Carbon dioxide could have been formed by the transformation of hydrocarbons due to high temperatures, or has migrated from deeper sources.

[63] More details on these projects can be found in page 129.

if retention times are at least of the order of several hundreds of years, otherwise it could be considered as just postponing the climate problem to future generations.

It is generally accepted that depleted oil and gas reservoirs are acceptably safe options. The fact that they are currently used for the temporary storage of natural gas as was mentioned earlier provides evidence for the safety of these storage sites. However, leakages may occur due to over-pressurisation associated with the injection, or through existing old wells (see Figure 41). The latter is of significant importance given that abandoned oil and gas fields may have been explored intensively in the past and may contain a large number of abandoned wells. Thus, a number of scientists claim that leakage is unavoidable [125]. The most important cause for a potential leakage could be a cap-rock with compromised integrity. Exploitation processes expose the reservoir to physical and chemical changes such as changes in local stresses, consolidation, depressurisation, repressurisation and temperature [126]. These effects can have a significant impact on the integrity of the reservoir, which if had been left undisturbed, could have been a safe storage site. In other words the integrity of the sealing cap-rock can be reduced due to drilling for exploitation or injection, and the reservoir may not be able to withstand the original pressure. However, according to most scientists, the presence of leakage does not make geological storage an unsafe option, though release rates need to be evaluated and the environmental consequences be assessed. Some scientists claim that leakage at rates of 1% annually could be tolerated, as they may not affect the targets for stabilising CO_2 atmospheric concentrations [127]. Other scientists bring this threshold to 0.01% [128]; they claim that a leakage of 1% is intolerable as it presents an unacceptably costly financial burden to future generations [129]. The issue of leakage is equally important whether the storage reservoir is an oil field or a saline aquifer. In the latter case, because aquifers are dynamic systems, much of the stored CO_2 will eventually escape over a time period of few thousand years [102]. A number of research programs is underway to estimate risks associated with CO_2 storage (CO_2 Capture Project/NGCAS, GEODISC, U.S. DoE Carbon Sequestration Program, Weyburn Project and the Japan CO_2 Sequestration Programme, see page 129).

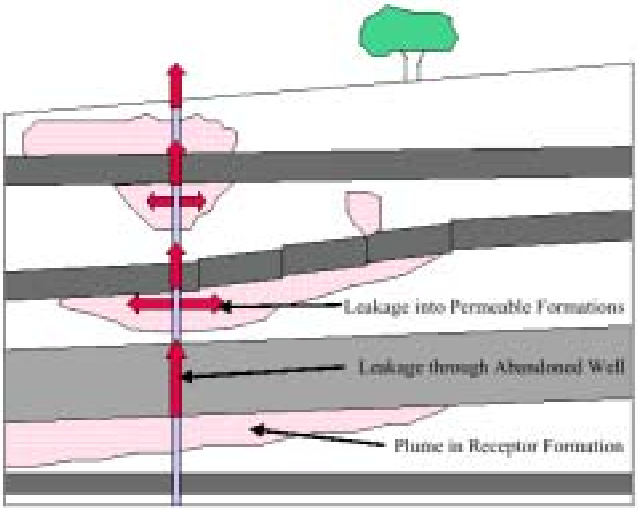


Figure 41: Leakage pathways through existing wells [125]

The issue of safety and leakage raises the need for development of CO_2 monitoring technologies with a very high sensitivity. More specifically, monitoring techniques such as seismic methods and electrical resistance tomography need improvements to offer higher spatial resolutions, lower cost and improved quantification. Without such technologies regulatory obstacles could hinder the storage operation. Monitoring will also be needed to manage the process of filling the reservoir and verify the amount stored. Seismic methods [e.g. 130, 131] and electrical resistance tomography [131] could provide accurate results. The cost of seismic methods for monitoring the sequestration of CO_2 produced by a 1,000 MW power plant is estimated at €0.03 per tonne of CO_2 stored [131].

The cost of geological storage is still not well khown. The main barrier to cost evaluations is the lack of demonstration programs. This topic is tackled in detail in page 83. Nevertheless, one of the foremost factors that will dictate whether or not geological storage will be successfully deployed is public perception. As such, monitoring and verification methodologies will become critical parts of gaining public acceptance and thorough risk analyses will be needed to prove the safety of storage sites[64].

6.2 Ocean Storage

Ocean is the largest sink for CO_2 with the potential to store vast additional amounts; in addition, scientists agree that ultimately about 80% of present-day emissions will end up in the ocean, via natural processes, as described in page 33. Thus, it has been proposed since the late 70's that the direct injection of captured CO_2 into the ocean is a valid storage option, as it will just accelerate the natural processes involved.

The options considered today for the introduction of CO_2 into the ocean for the purpose of storage are (see Figure 42):

- Dissolution and/or dispersion of CO_2 at intermediate depths (approx. 1500 m) using either a land-based pipe or a moving ship. Dispersion and dissolution can be effectively achieved since at these depths, CO_2 is in a buoyant liquid state.
- Injection of CO_2 using vertical pipes at large depths, more than 3000 m, where CO_2 does not dissolve in the water but sinks to the ocean floor, being denser than seawater, forming a pool of liquid CO_2. The formation of such a liquid lake could also be facilitated with the release of solid CO_2 from moving ships. This could be achieved because of the high density of solid CO_2 and its heat transfer properties that minimise dissolution at low depths during sinking. However, the latter approach could not be considered as a realistic option due to associated costs.

Despite its significant theoretical potential, this storage option is currently hampered by uncertainties related with (i) the technical feasibility of injection and dispersion options, (ii) the long-term effectiveness, and, (iii) most importantly, the impact to marine life. In addition, the legal framework is unclear. These barriers are analysed next.

---

[64] The issue of public perception to carbon sequestration is discussed in page 86.

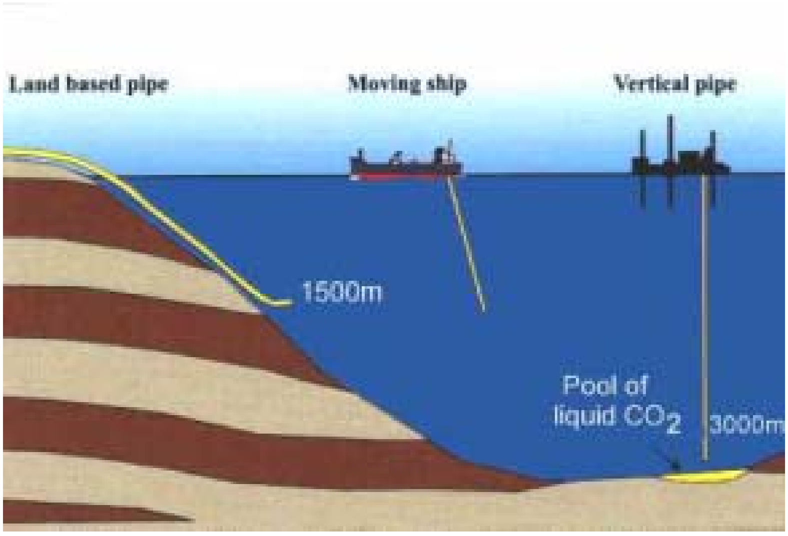


Figure 42: Ocean storage via direct injection options (Source: Ref. [135])

To date, most research has been theoretical (modelling) or limited to laboratory-scale or small-scale field experiments in order to study the dissolution and dispersion mechanisms of injected CO_2 and the transformation of a liquid CO_2 ‘lake’ into solid hydrates, in order to optimise injection systems. To this respect, the Monterey Bay Aquarium Research Institute (MBARI) is a pioneer in field experiments. From a technical point of view, high depths posse challenges of cost and technical difficulty. It is claimed that while the technology to disperse CO_2 from a land-based pipeline to a depth up to 2,000 m is currently available, the development of a vertical pipeline with lengths up to 5,000 m hanging from an offshore platform has yet to be demonstrated [41]. Attempts have been made to perform an international field experiment of direct injection at mid ocean depths by a consortium of American, Japanese, Norwegian and Australian institutes. However, initial efforts to perform this experiment in Hawaii (1999-2001) and later in Norway (2002) have met strong resistance from the public resulting in the refusal of granting a permit by the responsible authorities[65]. While American efforts have been focused on injection using land-based pipelines and offshore platforms, intensive Japanese efforts via their National Ocean Sequestration programme initiated in 1977, have concentrated on the ‘moving ship’ dispersion option. According to Japanese scientists, such an approach offers the maximum dilution of injected liquid CO_2: carbon dioxide is captured and liquefied in CO_2 recovery plants and is delivered by ship in liquid form (at –55°C) to several hundred kilometers offshore and injected into the ocean depth of 1,000 to 2,500m. The droplets of liquid CO_2 (about 5 to 10 mm in diameter) are dispersed from a towed pipe and are dissolved into the seawater. Typical discharge rates could be up 100 kg per second. This concept will be demonstrated during the period 2002-2007 [136].

There is little consensus at present about the overall viability of direct ocean injection mainly due to uncertainties as to how effective the process will be at keeping CO_2 stored away from the atmosphere. Since, no field experiments have been performed, the long-term effectiveness must be predicted based on observations of other ocean tracers[66]

---

[65] Due to its importance, this case is analysed in page 86.

[66] Researchers from Lawrence Livermore National Laboratory have recently dismissed the idea of using tracers as a means to estimate retention times [138].

and on computer models of ocean circulation and chemistry, given that, to a large extent, ocean transport processes control efficiency. Different scenarios of CO_2 disposal in the ocean have been proposed at various depths and in different forms in relation with the phase properties of CO_2. However, modelling studies do not yield consistent efficiency[67] estimates: Simulations show that, in average, in a 800 m-deep injection, 25% of CO_2 still remains dissolved in the ocean at least 500 years [137]; at 1500 m, 50% of injected CO_2 remains in the ocean at least 500 years and, if the injection is at 3000 m, the efficiency increases significantly to about 80% after 500 years. However, there is modeling work that indicates that retention times after injection at 3,000 m are significantly less than mentioned above and thus not sufficient to lead to stabilization of emissions [141]. Furthermore, leakage can be significant if costs and technology push for injection at shallower waters. In addition, present day models disagree as to the leakage time-scales at particular locations due to the presence of currents, highlighting the need for identifying the real retention times and the most promising injection sites. Overall, long retention times have yet to be proven.

Environmental impacts may be the most significant factor determining the acceptability of ocean storage, since this approach would be adopted only if the impacts of injecting CO_2 in the ocean are significantly less than the avoided impacts of continued emissions to the atmosphere. It is widely accepted that dissolving CO_2 in the ocean will decrease the pH of the water due to the formation of carbonate and bicarbonate ions. Scientists also warn that sea animals are highly sensitive to environmental changes in CO_2 concentrations and pH. More specifically, a recent study has demonstrated that decreased pH can result in metabolic suppression in marine life, which can inhibit growth and reproduction [142]. Several other reviews have identified potential impacts to non-swimming marine organisms, such as plankton and benthos and to high metabolism rate animals that live in deep waters, such as squid. Obviously, for the acceptance of CO_2 ocean injection, minimum requirements should be put in place so that, no species should be driven to extinction; no significant disruption of ecological processes should occur; and, there should be no impact to ocean living resources. Some scientists claim that the impact of CO_2 injection into the ocean would be minimal, since calculations indicate that the injection of 1,300 billion tonnes of carbon (equivalent to 200 years of current emissions) would decrease the average ocean pH by about 0.3 [137]. However, such calculations assume that the distribution of dissolved CO_2 would be uniform worldwide. Nevertheless, significant pH changes are expected in the vicinity of the injection sites. It has been estimated that pH reductions of about one unit could take place in an area several kilometers away from the injection point [41]. Thus, significant engineering designs have to evolve to disperse as much as possible the injected CO_2, minimizing local concentrations. To this end, Japanese scientists claim that the option of the 'moving ship' may be of minimal environmental impact: the additional concentration of CO_2 when 1 billion tonnes of CO_2 is injected and diluted homogeneously into the seawater at 1,000 m depth in an area of 100 Km X 100 Km is estimated to be 1 ppm (compared with the background concentration of 2,000 to 2,500 ppm). Nevertheless, all studies are incomplete and as such, a better understanding of the biological consequences on direct ocean sequestration is essential before this option is adopted.

---

[67] Efficiency is the fraction of injected CO_2 at a particular site that remains in the ocean after a given length of time.

It is therefore clear that many scientific and technical issues need to be tackled and answers be given by the scientific community before any scheme to enhance the storage of CO_2 in the ocean could be implemented:

- It is imperative that a better understanding is gained about the impact on marine ecology. This will necessitate research work at all levels: from fundamental laboratory work on the physiological responses of marine animals to elevated CO_2 concentrations, to field experiments to study the impact on community structure.
- Scientific and technological gaps should be narrowed, mainly related with optimisation of injection procedures, prediction of storage effectiveness, determination of storage capacity and identification of favourable injection sites. To this extent, ocean models, with resolutions of hundreds of meters to hundreds of kilometres, need to be developed and validated, so confidence on model predictions is increased.
- Ultimately, large-scale experiments will be needed to demonstrate the effectiveness of this storage option.

Nevertheless, given that the oceans are considered to be an important part of the common good for mankind it has been suggested that they should not be part of a carbon sequestration strategy, even for ethical reasons. Such positions have delayed experiments and have made it a less attractive topic for scientists to pursue related activities [143].

In addition to the scientific and technical issues involved, equally important are the public perception and the legal aspects. Due to their peculiar character, they are discussed separately in page 86.

6.3 Novel Approaches

Novel approaches are a basket of innovative yet unproven technologies, still in experimental stage, aiming to store CO_2 by conversion into inert materials via chemical and/or biological processes. Some of these approaches are: (i) mineral storage (the reaction of CO_2 with silicate minerals to form calcium or magnesium carbonate minerals), (ii) the formation of stable hydrate clathrates, and, (iii) advanced biological options (e.g. genetically modified plants to absorb increased amounts of carbon). However, all these options are still in the drawing table, with undetermined effectiveness, and thus, are beyond the scope of this report.

6.4 Estimates of Storage Capacity

A number of studies have been performed during the last decade aiming at identifying the storage potential of the various options described earlier. The results of these analyses deviate significantly from each other, although the trend is that the more recent analyses identify a higher potential.

The latest and most complete analysis of storage capacity in geological formation was performed by Advanced Resources International for the IEA Greenhouse Gas Programme and the U.S. Department of Energy [104]. The analysis assessed 155 oil and gas areas worldwide, using actual reservoir properties and concluded that:

- ➢ 126 billion tonnes of CO_2 can be stored in abandoned oil reservoirs and in active oil reservoirs via EOR

- 797 billion tonnes of CO_2 can be stored in gas fields.

Furthermore, according to IEA Greenhouse Gas Programme, the storage capacity in deep saline aquifers varies between 400-10,000 billion tonnes of CO_2; the storage potential in unminable coal strata is about 15-20 billion tonnes [14]. To put these numbers in perspective, it is reminded that annual CO_2 emissions in the late 90's were about 24 billion tonnes, and the IPCC has estimated that the accumulated CO_2 emissions worldwide for the period until 2050 to be 2,045 billion tonnes.

However, these values, especially for deep saline aquifers and for coalbed strata, should be treated as 'best guesses' rather than calculated estimates. IEA Greenhouse Gas Programme warns that the above-mentioned estimates for the deep saline aquifers were made in early 90's. More recent estimates indicate that the storage potential in North West Europe could be as much as 800 billion tonnes, mostly as saline aquifers. In another example, the U.S. DoE estimates that the potential for coalbed storage worldwide exceeds 220 billion tonnes [105], i.e. 11 times higher than IEA's estimate. These variations in estimates of capacity highlight the level of uncertainty and the need for additional data and research in order to assess the potential storage capacity, especially for deep saline reservoirs. More specifically, there is a need to map, characterise and model underground reservoirs to gain a better estimate of capacity. Towards this direction, the EU has funded the GESTCO project (*European Potential for Geological Storage of Carbon Dioxide from Fossil Fuel Combustion*) that aims to investigate the viability of geological CO_2 storage through reservoir engineering studies and an extensive inventory of storage sites, as well as emission sources and optimal transport routes.

The storage capacity of the ocean is very difficult to estimate. Calculations based on physical chemistry only, demonstrate that the ocean is capable to dissolve more carbon than that contained in the total global fossil fuel reserves, in excess of 5,000 to 10,000 billion tonnes of carbon. However, the storage potential of the oceans is limited by uncertain biogeochemical factors. For example, by storing 5,000 billion tonnes of CO_2, the pH of the oceans will decrease by 0.3 [137] with unpredictable consequences to marine life. Clearly, significant effort should be made to understand the consequences of CO_2 storage in the ocean and identify its storage potential.

There are some studies to estimate the storage potential in specific countries: A Danish study showed that half of the CO_2 that needs to be avoided in Denmark until 2010 as a fulfilment to the Kyoto protocol can be stored in a single aquifer in a single location [139]; while a study for Finland showed that there are no suitable storage sites in the country and as such, CO_2 should be stored in depleted oil and gas reservoirs at distances away from the emission sources with a significant negative impact on costs [140].

6.5 The Cost of CO_2 Storage

There are significant uncertainties involved in estimating the costs of CO_2 storage, given that the conditions of underground reservoirs are unknown and the volume of CO_2 stored as well as oil prices (relevant for EOR operations) may fluctuate annually. Over the years, several cost estimates have been reported for the different storage options. Most of the publications report the cost of storage combined with the cost of transport. In the publications where the cost of storage is separately mentioned, only rough estimates are mentioned without a justification. The range of costs reported is €1-€5 per tonne of CO_2 stored.

A notable exception is a report from IEA Greenhouse Gas Programme [144] that provides with the analytical cost estimates for geological storage options. In this IEA Greenhouse Gas Programme report, costs have been estimated including transport costs and are reported in US$93. These results are presented in Table 13 and Table 14, after having been adjusted to current values, and excluding the cost of transport.

The main differences in the above cost estimates lay on the drilling costs and the operational costs, which appear to be location specific. Nevertheless, storage costs are less than 3€/tonne CO_2 stored.

In the same analysis the costs of direct injection in the ocean was estimated. For the sake of the analysis it was assumed that CO_2 is injected at a depth of 500 m using a 100 km long underwater pipeline, the cost of which is included in the reported results, see Table 15. Pumping costs refer to the additional pressure required to overcome pressure losses in the underwater pipeline and injection system. The cost of the 'moving ship' option has not been estimated, however it should be similar to the costs of CO_2 transport using tankers increased by the cost of the injection system. The total cost should be of the order of 2.5€/tonne CO_2 injected.

Table 13: Estimate of CO_2 storage costs in an aquifer (Based on [144])

Storage in an Aquifer	
Annual Disposal Rate	3.9 million tonnes CO_2
Capital Costs (million €)	
Well Systems (6 wells included)	8.7
Field Costs	2.2
Project Development and Land Acquisition	12.7
Annual Operating Costs (million €)	
Field Facilities	3.0
Storage Costs (10% Discount Rate)	
Cost per tonne CO_2 stored	€ 1.3

Table 14: Estimate of CO_2 storage costs in a depleted oil or gas reservoir (Based on [144])

Storage in exhausted oil and gas reservoirs		
Annual Storage Rate	3.7 million tonnes CO_2	
	Capital Cost (million €)	**Annual Cost (million €)**
Compressor (3.5 MW)	13.3	1.57
Metering and Control Station	0.49	0.06
Well drilling (4 wells)	18.50	2.18
Operation and maintenance		0.49
Power Consumption costs (at 7.5 c/kWh)		2.22
Total Costs	32.29	6.52
Cost per tonne CO_2 stored (10% discount rate)	€ 2.6	

Table 15: Estimate of CO_2 ocean storage costs via direct injection (Based on [144])

Ocean Storage via Direct Injection	
Annual Disposal Rate	19 million tonnes CO_2
Capital Costs (million €)	
Pipeline (100 km)	190 million €
Injection Unit	21.5 million €
Annualised capital cost (10% interest rate)	21.1 million €
Annual Operating Costs (million €)	
Maintenance	5.6 million €
Pumping	4.9 million €
TOTAL ANNUAL COSTS	31.6 million €
Storage Costs (10% Discount Rate)	
Cost per tonne CO_2 stored	€ 1.7

6.6 Non Techno-economic Barriers to Carbon Sequestration

To date, most studies have been focused on the technological, scientific and economic aspects of carbon sequestration, aiming to meet the challenge of making this process a useful tool in our efforts to control carbon emissions. However, the success of carbon sequestration does not solely depend on solving engineering problems and clarifying related scientific aspects. Regulatory implications and public perception could play a very important role, to the extent that they could be the deciding factors for the deployment of this option. These non techno-economic barriers are discussed next.

6.6.1 Legal Implications

Legislation regulating carbon sequestration will be necessary to provide a robust framework for the operation of the process, when and if, this option will be deployed on a large scale. Foremost, regulation will have to manage associated risks and ensure that the impact of related activities (especially transport and storage) is minimised. Definitely, legislation will be called in to consider health, environmental and safety risks on a local/regional level (e.g. contamination of drinking water due to CO_2 storage in aquifers, catastrophic events due to sudden leakage of CO_2 from underground reservoirs, reductions to fish stock due to uncontrolled ocean storage). Thus, legislation will have to (i) dictate rules and standards that ensure safety and the minimisation of other adverse impacts of carbon sequestration, and (ii) define performance standards for monitoring and verification to ensure that acceptable risk levels are not exceeded. In addition, legislation may be invited to go one step further, to reduce the global risk of re-accumulation of CO_2 in the atmosphere related with the (in-)effectiveness of carbon sequestration.

Currently, there is no legislation in force in Europe prepared specifically to tackle the issues related with carbon storage in geological formations inland. However, international law, applicable to European countries, could have a major impact to the deployment of carbon sequestration in European waters.

Ocean sequestration is controlled to a large extent, both by national legislation and international treaties. While storage in oceans seems to be encouraged by the UNFCCC (see page 13)[68], it is hindered by the London Convention on the prevention of marine pollution by dumping waste and other matter, signed in 1972[69]. The London Convention essentially prohibits all dumping of industrial waste[70] in the oceans without authorisation by national authorities, with the exception of an approved list of substances. The issue of CO_2 disposal in the context of the London Convention was brought up for discussion in 1991, however not having yet reached a consensus whether it should be classified as an industrial waste [147]. It should be noted that the London

---

[68] Article 4.1.d states: *"All Parties, taking into account their common but differentiated responsibilities and their specific national and regional development priorities, objectives and circumstances, shall (…) promote sustainable management, and promote and cooperate in the conservation and enhancement, as appropriate, of sinks and reservoirs of all greenhouse gases not controlled by the Montreal Protocol, including biomass, forests and* ***oceans*** *as well as other terrestrial, coastal and marine ecosystems"* . For the full text of the Convention see: http://unfccc.int/resource/conv/index.html

[69] For the full text and the convention and more details see www.londonconvention.org

[70] Industrial waste is defined as generated by manufacturing or processing applications.

Convention applies only to ships, aircraft and offshore platforms, the latter with the exception of the disposal of wastes or other matter directly arising from, or related to the exploration, exploitation and associated off-shore processing of sea-bed mineral resources, which are not be covered by the provisions of this Convention[71]. The Sleipner project falls into this exemption[72].

Beyond the above-mentioned exemption of activities related with the exploration of offshore natural resources, the Convention generally prohibits the storage of CO_2 generated from other sources using ships and offshore platforms. In 1997, the Joint Group of Experts on the Scientific Aspects of Marine Environmental Protection (GESAMP) reported that CO_2 dumping from ships violates the London Convention [148][73]. In essence, the London Convention makes ocean storage via the 'moving ship' option and via direct injection from an offshore platform at any depths illegal. Furthermore, a Protocol to the London Convention has been prepared in 1996, which is not yet in force, that includes a list of allowed substances to be discarded at sea, the bed and the subsoil; however, it does not include CO_2. The same Protocol also clarifies that the term *ocean* includes water masses, the seabed and the subsurface.

It should be stressed that the London Protocol imposes minimum limits that can become more stringent by national legislation. For example, it is claimed [147] that if a similar project were to be attempted in US waters, the Ocean Dumping Act would make storage in or under the ocean "from anywhere" illegal; especially since, for the American case law, CO_2 is considered as hazardous industrial waste[74].

Storage of CO_2 originating from a European source and transported via a pipeline either to the ocean or below the seabed, does not fall under the auspices of the London convention. However, this storage option may be within the jurisdiction of the Paris Convention of 1992 for the protection of the marine environment of the northeast Atlantic[75]. Specifically, this Convention prohibits *"… the introduction by man, directly or indirectly, of substances or energy into the maritime area[76] which results, or is likely to result, in hazards to human health, harm to living resources and marine ecosystems, …"[77]* including from inland sources and explicitly mentioning the use of pipelines. Any discharges and releases are subject to authorisation by competent national authorities. Annex II of the Convention includes a list of waste that are allowed to be disposed of;

---

[71] Article 3.1.c. of the Convention.

[72] Objections have been raised about the legality of the Sleipner Project by environmental groups, claiming that the project is in violation of the London Convention because the platform used to produce natural gas is not the same platform that injects the CO_2 into the ocean floor, thus CO_2 storage is not an integral part of natural gas recovery.

[73] The report states that, *"It (…) seems unlikely unless the Convention can be amended to permit the dumping of CO_2, from ships, that any of the current Parties to the Convention which include all the OECD countries except Austria and Turkey, could give approval to such a practice. It should be further noted that the same conclusion would apply to liquid CO_2 disposal from vessels and platforms which would also fall within the purview of the London Convention 1972".*

[74] *Arco Oil and Gas Company versus EPA* (1993).

[75] For the full text see the Official Journal, L 104,03/04/1998, p.2-21.

[76] "Maritime area" means the internal waters and the territorial seas of the Contracting Parties, the sea beyond and adjacent to the territorial sea under the jurisdiction of the coastal State to the extent recognised by international law, and the high seas, including the bed of all those waters and its subsoil, situated within well-specified limits in North-eastern Atlantic.

[77] Article 1.d. of the Convention.

however, CO_2 is not included in this list. It is not clear, whether or not the Paris Convention has jurisdiction on CO_2 storage either for the purpose of ocean storage (dissolution via pipeline), geological storage (injection into sub sea aquifers using a pipeline) or for EOR applications. Even in the case that one or more of the aforementioned options is exempt from the Paris Protocol, national laws have jurisdiction and require an ecological impact study before they grant a permit in order to allow this activity. However, the current state of scientific certainty regarding carbon sequestration may not be sufficient to meet this burden of proof, hence there is a need for continued research and experiments.

The HydroKraft project (see page 70) may be a case that the Paris Convention is applicable. From a legal perspective, the HydroKraft project is substantially different from the Statoil project since in the former case, the sources of emissions are inland (a power plant). However, in this case it has to be clarified from a legal point of view whether EOR is '*dumping*' and '*pollution*', or '*utilisation*'.

In conclusion, unless international law is amended ocean storage and geological storage under the sea of CO_2 capture inland would encounter major legal obstacles in Europe.

The legal terrain of geological storage inshore in Europe is unmapped. Possibly, national legislation applies to disposal of waste in underground aquifers and salt mines and to storage of natural gas in geological formations in some countries, such as Germany. However, the legal framework in the US has been published in several scientific publications, so it would be informative to briefly describe this regulatory analogue. US regulation of underground injection of industrial waste (mainly of brine and industrial residue) into depleted oil reservoirs began in the 70's due to disposal well failures that caused water contamination and seismic events [145]. Concerns about waste storage via deep injections led the US authorities to state that they oppose to disposal via deep injection without strict control and the preparation of thorough environmental impact assessments. In 1974 the Environmental Protection Agency (EPA) was given the mandate to regulate underground injection (via the Safe Drinking Water Act) and ask for minimum requirements, which would prevent endangerment of underground sources of drinking water, by contamination; however, natural gas storage was exempted in 1980. These regulations have been specifically designed to prohibit the movement of the injected material into any aquifer that could potentially be used as a resource for drinking water. For injections suitable for CO_2 storage in deep (more than 1,000 m) saline aquifers, regulations require: submission of detailed geological data to prove the continuity and homogeneity of the aquifer; the demonstration that all unused abandoned wells in the vicinity of the proposed injection well are properly completed and plugged; minimum construction standards; and monitoring requirements. In addition, injection of CO_2 for the purposes of EOR has been encouraged by the US internal revenue legislation and tax credit is given for ECBM recovery, amounting to almost half the price of the injected gas [146].

In conclusion, a legal framework to regulate carbon sequestration is not in place to minimise risks and set the procedures for deploying related technologies. International Conventions, agreed even before carbon sequestration was considered as a carbon management option, could pose significant obstacles not only in the deployment of carbon sequestration technologies, but for large demonstration projects as well. However, such projects are deemed necessary to provide with answers to fundamental questions, in order for risks and impacts to be assessed so the proper legislation is defined. The breaking of this vicious cycle is a prerequisite for further promotion on research, development and demonstration related with carbon sequestration.

6.6.2 Public Perception

History has shown that the public can become fearful when a new technology is deployed without the associated risks and impact been thoroughly explained, and sceptical when they feel excluded from the decision making process. It is not rare to see cases where obstacles set by the public are more difficult to overcome than technological and economic barriers, which may ultimately stop the deployment of an otherwise economically and technologically viable technology. To this extent, and given the increased sensitivity of the public over issues related with the environment and climate change during the recent years, it is expected that carbon sequestration will be severely scrutinised by environmental groups and the public at large.

It is questionable whether the public will receive carbon sequestration positively as a useful instrument to combat climate change, or rather consider it as a controversial option with high associated risks, negative impact to the environment and doubtful effectiveness. A negative opinion may be fuelled by the little or no awareness among the environmental groups and the general public, the lack of consensus among the scientific community about the benefits and implications of the option, and the existence of major knowledge gaps that currently hamper carbon sequestration.

Given that, environmental groups strongly support other carbon management options, such as the promotion of renewables and the improvement of energy efficiency, carbon sequestration may be perceived as a political tool to continue using and investing in fossil fuels, thus deviating attention and funds from other carbon management options and causing delays in real reductions of emissions. Furthermore, the '*disposal of*' emissions may be negatively perceived in principle, and may be used to tag carbon sequestration as a non-clean and non-sustainable technological option. Unless there is a robust proof that CO_2 leakage from geological storage sites is negligible and safe and does not create a burden to future generations, public will demand assurances about the safety of carbon sequestration and may not allow for storage operations to function (the Not-In-My-Backyard-Syndrome). Similarly, the unknown impact of ocean storage to biodiversity and the ecosystem will stimulate long debates between scientists and the public, even for the approval on experimental and demonstration projects.

The fate of the Direct Ocean Injection Experiment is an example that highlights clearly the issues involved [149]: In 1997, US, Japanese and Norwegian research centres, later joined by Australian and Canadian centres and the firm ABB, signed an international project agreement for a collaborative study of the direct injection of CO_2 into the deep ocean. In March 1998, the island of Hawaii was identified as the best location to host the experiment. In March 1999, the project went public via the local press, before the public outreach programme of the project was developed, and a strong opposition was built quickly, creating the "Coalition Against CO_2 Dumping". According to Ref. [149], the opposition fell into three categories: (i) those opposed to the experiment itself, mainly fishermen and native Hawaiians (the latter claimed decreased tourism); (ii) those opposed to ocean carbon sequestration, considering that the possible risks to ocean fauna could be significant; and (iii) those opposed to any form of carbon sequestration, feeling that carbon sequestration diverted attention and resources away from other carbon management options. Major legal and administrative battles took place until 2001 at local, state and federal level, in order to get a permit for the experiment, resulting in long and "*…excessive…*" delays forcing the project team to withdraw the permit application and apply for a permit in Norway in Spring 2002. However, a campaign against the experiment started, led by Greenpeace, and in August 2002, the Norwegian government denied permission on grounds that the experiment violates international conventions on dumping industrial waste at sea. According to the Environment Minister, Børge Brende "*The possible future use of the sea as storage for* CO_2 *is controversial … Such a deposit could be in defiance of international marine laws and the ministry therefore had to reject the application*" [150].

Environmental groups suggest [151, 152] that carbon sequestration would be welcome only if it is a part of a sound strategy that accelerates the penetration of renewable energy sources and improves energy efficiency. The role of carbon sequestration in this strategy would be complementary to other carbon management options, aiming to offer deeper emissions reductions in the short to medium term, until the other carbon management options start producing results. However, the development of a rigorous research, development and demonstration program that would be capable of providing robust answers to questions regarding safety, effectiveness and impact to the environment and the ecosystem would be a prerequisite. Finally, the development of a public outreach program would be imperative to inform and have the public involved.

6.7 Comparison of CO_2 Storage Options

The tables in this section summarise the carbon storage options discussed above, including the enhanced natural processes, EOR and ECBM recovery. Novel approaches and other utilisation paths are not included in the comparison due to their very low level of technical maturity. For each storage option considered, two tables are presented. The first summarises the major advantages and disadvantages, the European potential and the current level of deployment. The second table includes suggestions for needed R&D work. The latter list is not detailed nor exhaustive, rather it serves the purpose of highlighting the most important items that require further research effort. Finally, the readiness of these storage options to be effectively implemented in a European carbon sequestration strategy is shown in Figure 43.

Table 16: Storage in deep saline aquifers: Main process characteristics

Sequestration Option	***Advantages***	***Disadvantages***	***European Potential***	***Level of Experience***
Storage in Deep Saline Aquifers	• Available technology • Very large storage potential and widespread availability of sites • Long retention times • Reduced safety risks when aquifer is offshore • Inexpensive	• Possible contamination of potable water • Risk of leakage back to the atmosphere • Negative public perception • Legal conflicts for offshore storage (with exceptions)	• Estimated very large storage potential and widespread availability, although not thoroughly documented and characterised.	• One industrial project in Europe (Norway) that injects 1 million tonnes of CO_2 annually in a deep saline aquifer offshore since 1996. • Injection of industrial waste into saline aquifers since the 60's.

Table 17: Storage in deep saline aquifers: R&D needs

Sequestration Option	*R&D needs*
Storage in Deep Saline Aquifers	**Fundamental understanding of storage** o Identification of the significance, kinetics and interactions of the various geophysical / geochemical storage mechanisms (hydrodynamic trapping, dissolution, mineralisation) assisted by the study of natural analogues o Understanding and monitoring of CO_2 flow underground **Safety** o Evaluation of caprock integrity and assessment of integrity compromise due to drilling, injection and pressure build-up o Assessment of acceptable leaking rates and risk to public and global climate o Development of monitoring tools for the migration of CO_2 underground and the detection of leaks **Capacity** o Compilation of selection criteria for potential storage sites o Mapping and characterizing of European aquifers

Table 18: Storage in depleted oil and gas reservoirs: Main process characteristics

Sequestration Option	***Advantages***	***Disadvantages***	***European Potential***	***Level of Experience***
Storage in Depleted Oil and Gas Reservoirs	• Mature technology, long experience and thorough characterisation of reservoirs • Significant storage capacity in the long term. • Potentially reduced risks of leakage, based on the study of natural analogues • Inexpensive • Relatively simple monitoring and verification procedures	• Limited readily available capacity due to a small number of depleted wells • Undetermined storage risks of leakage back to the atmosphere due to the potentially large number of abandoned wells • Negative public perception (Not-in-my-backyard syndrome) • Legal conflicts for offshore storage (with exceptions)	• Suitable for areas with depleted oil and gas reservoirs (e.g. North Sea basin) • Limited number of depleted oil and gas reservoirs in Europe. However, it is expected that within 25 years, oil and gas fields could become suitable for CO_2 storage.	• Injection of CO_2 in depleted oil and gas reservoirs exclusively for the purpose of carbon sequestration has not been performed. Nevertheless, the process is very similar to EOR, a matured industrial operation (see below). In addition, demonstration projects are in progress aiming to maximise CO_2 storage (e.g. Weyburn). Storage of natural gas in geological formations is a standard industrial practice for 50 years.

Table 19: Storage in depleted oil and gas reservoirs: R&D needs

Sequestration Option	*R&D needs*
Storage in Depleted Oil and Gas Reservoirs	**Fundamental understanding of storage** o Identification of the significance, kinetics and impact of geochemical reactions between CO_2 and remaining oil and gas within the reservoir, in relation to reservoir integrity and long-term oil and gas recovery o Understanding and monitoring of CO_2 migration underground **Safety** o Evaluation of caprock integrity and assessment of integrity compromise due to drilling, injection and pressure build-up o Assessment of acceptable leaking rates and risk to public and global climate o Development of monitoring tools for the migration of CO_2 underground and the detection of leaks **Capacity** ➢ Compilation of selection criteria for potential storage sites ➢ Mapping and characterising of European oil and gas fields with storage potential

Table 20: Enhanced oil recovery: Main process charracteristics

Sequestration Option	*Advantages*	*Disadvantages*	*European Potential*	*Level of Experience*
Enhanced Oil Recovery (EOR)	• Mature technology; a commercial process with significant accumulated experience • An added-value process; the production of oil improves the economics of carbon sequestration • Established monitoring and verification procedures at a low to medium cost	‣ Not a real storage option. CO_2 injection is minimized to maximise oil yield and is frequently recycled. ‣ Not an unconditionally economically viable option under current oil prices due to the high cost of CO_2. ‣ Limited storage capacity due to relatively small amounts of CO_2 that could be utilised. ‣ Need for a change in operational procedures to compromise maximum oil recovery with maximum CO_2 storage potential at competitive prices	• Limited to areas with operational oil fields and abundance of nearby emission sources (North Sea).	• EOR is an industrial process since the 70's. At least 70 projects are operational worldwide (none in Europe).

Table 21: Enhanced oil recovery: R&D needs

Sequestration Option	***R&D needs***
Enhanced Oil Recovery (EOR)	Same as for storage in depleted oil and gas reservoirs (Table 19). In addition: o Minimisation of injection losses o Optimisation of immiscible and heavy oil applications o Relaxation of CO_2 purity implications o Development of advanced reservoir simulators o Identification of approaches to balance oil production and CO_2 storage

Table 22: Enhanced coalbed methane recovery: main process characteristics

Sequestration Option	*Advantages*	*Disadvantages*	*European Potential*	*Level of Experience*
Enhanced Coalbed Methane Recovery (ECBM)	• An added-value process; the production of methane could improve the economics of sequestration • Potentially large storage potential • Very low risk for leakage. Unless coalbeds are mined, storage is permanent. • Established monitoring and verification procedures at low to medium cost	• Technology is immature • Lack of identification and characterisation of potential storage sites	• Undetermined but not expected to be significant.	• One commercial application in USA. Two demonstration applications in N. America. One demonstration project to start in 2003 in Poland.

Table 23: Enhanced coalbed methane recovery: R&D needs

Sequestration Option	*R&D needs*
Enhanced Coalbed Methane Recovery (ECBM)	**Fundamental understanding of storage** o Understanding of the adsorption/desorption mechanisms of CO_2 on coal o Understanding the swelling behaviour of coal due to CO_2 adsorption and the subsequent reductions in permeability o Development of drilling techniques and optimisation of drilling/injection schemes **Safety** o Development of monitoring tools for the migration of CO_2 underground and the detection of leaks **Capacity** o Compilation of selection criteria for potential storage sites o Mapping and characterizing of European coalbeds with storage potential

Table 24: Ocean storage via direct injection: Main process characteristics

Sequestration Option	***Advantages***	***Disadvantages***	***European Potential***	***Level of Experience***
Ocean Storage via Direct Injection (all depths)	• Enormous storage potential • Limited local safety hazards	• Not demonstrated technology; significant S&T gaps • Possible major negative impacts to ecosystems • Major legal obstacles • Negatively perceived by public • Retention times depend on injection depth (from a few hundred years to possibly practically indefinitely) • Cost is undetermined	• Currently, possibly unlawful in Europe (violation of London and Paris Conventions). • Ignoring legal barriers, suitable only for sources with access to deep sea.	• Laboratory level experiments only. Planned field experiments in USA and Norway have been banned.

Table 25: Ocean storage via direct injection: R&D needs

Sequestration Option	*S&T knowledge gaps - R&D needs*
Ocean Storage via Direct Injection (all depths)	**Impact to marine ecosystem** o Understanding the effects of pH change to marine life, the ecosystem and to ocean biochemical processes o Optimisation of technologies to inject CO_2 in deep ocean minimising environmental impact **Fundamental understanding of storage** o Characterisation of the mechanisms of carbon dissolution and hydrate formation o Development of injection techniques **Safety** o Development of monitoring tools for the migration of carbon-rich ocean waters o Optimisation of ocean models to predict optimal injection sites, storage capacity and regional impact.

Table 26: Ocean fertilisation: Main process characteristics

Sequestration Option	***Advantages***	***Disadvantages***	***European Potential***	***Level of Experience***
Ocean Fertilisation	• A simple process • May improve fish yield • Inexpensive	• Effectiveness not proven • Possible major negative impacts to ecosystems • Limited storage capacity • Extremely difficult to monitor and verify storage	• Very limited to European waters due to very low expected storage efficiency	• Field experiments with iron fertilisation performed in Southern Pacific for the last 10 years

Table 27: Ocean fertilisation: R&D needs

Sequestration Option	***S&T knowledge gaps - R&D needs***
Ocean Fertilisation	o Understanding the effects of fertilisation to marine life, the ecosystem and to biochemical processes o Development of models to predict the effectiveness of ocean fertilisation o Understanding the fate of carbon reserved by phytoplankton in superficial waters o Optimisation of technologies to disperse micro/macronutrients o Development of technologies for measuring carbon at sea o Development of monitoring tools to follow the effects of ocean fertilisation to the ecosystem

Table 28: Terrestrial sequestration: Main process characteristics

Sequestration Option	*Advantages*	*Disadvantages*	*European Potential*	*Level of Experience*
Terrestrial Sequestration	• Low cost • Improves employment in rural areas • Preservation of biodiversity • Production of biofuels • Acceptable from the public	• A short-term option; CO_2 retention times are limited by the life of biota. • Monitoring and verification procedures are not well defined and expensive. • Limited global capacity.	• Applicable in areas with low population density and favourable conditions to grow and maintain forests (mainly N. Europe) • Limited additional capacity for aforestation.	• Forestry is a mature science.

Table 29: Terrestrial sequestration: R&D needs

Sequestration Option	*S&T knowledge gaps - R&D needs*
Terrestrial Sequestration	o Understanding the carbon cycle in terrestrial ecosystems o Identification of storage rates and capacity o Development of methods to monitor and verify carbon storage o Identification of optimal aforestation sites and optimization of land area

Table 30: Utilisation of CO_2 (other than EOR and ECBM): Main characteristics

Sequestration Option	*Advantages*	*Disadvantages*	*European Potential*	*Level of Experience*
Direct Utilisation (other than EOR and ECBM)	• A set of value-added processes that could improve the economics of sequestration.	• Not a real sequestration option; utilised carbon is re-emitted to the atmosphere. • Difficult to expand the CO_2 market and develop other products due to the high associated production costs and the presence cheaper alternatives.	• Very limited due to the small need for CO_2 based products	• Novel products can be manufactured that could have a significant impact to the degree of utilisation of CO_2; however, they come at a prohibited high cost compared with already established products

Storage Option	***Level of readiness to effectively contribute to European emission reductions***
Aquifers	🙂
Depleted Oil and Gas Reservoirs	😐
Enhanced Oil Recovery	🙁
Enhanced Coalbed Methane Recovery	🙁
Ocean Storage-Direct injection	🙁
Ocean Fertilisation	🙁
Terrestrial Sequestration	🙁
Direct Utilisation	🙁

Figure 43: Characterisation of the level of readiness of the discussed CO_2 storage options to contribute in the near to medium term to an effective deployment of carbon sequestration.

🙂 = Favourable, 😐=Medium, 🙁=unfavourable

7. The Economics of Carbon Sequestration

7.1 Introduction

The technological assessment, presented in the previous chapters, has shown that the deployment of carbon sequestration technologies in power plants will require additional investments for the development of infrastructure (e.g. CO_2 capture facilities, pipelines, injection wells, etc.) and will increase operating costs (e.g. increased maintenance requirements, consumables, labour). Furthermore, additional energy will be required for the capture of CO_2 (e.g. for the regeneration of a loaded amine in chemical absorption), and the compression of the captured CO_2 at pressures of about 100 bar to facilitate its transport. This demand for energy will be met by the power plant itself, thus decreasing its net power output. As was described in Chapter 3, this additional energy consumption, compared with a plant without CO_2 capture, results in the drop of the power plant efficiency by 13% to 25%, depending on the power plant type (PC, GTCC, or IGCC) and the capture method. Maintaining a designated plant capacity requires the generation of additional electricity that has to come either from expanding the plant or by building another plant. In turn, both options require additional capital and result in an increase in fuel consumption so that the same amount of power is generated. In addition, energy is needed for the storage of the captured CO_2, which, although may not be provided directly from the same power plant that generates the emissions, it has an impact on the total efficiency of the power system. Overall, the introduction of carbon sequestration technologies will result in an increase in a number of costs:

- Increased capital costs for each plant to be equipped with carbon separation and capture technology.
- Additional capital costs for CO_2 transport and storage.
- Increased fixed operational costs (such as insurance and scheduled maintenance, typically calculated as a fraction of the total capital costs, and labour) and increased variable costs (mainly use of consumables such as absorbers, adsorbers, water, additional electricity consumption and non-scheduled maintenance).
- Additional operating costs for CO_2 transport and storage.

Furthermore, additional capital and fuel are required so that the energy system maintains its overall capacity as explained above. All these costs are translated into increases in the cost of electricity (COE). Similar conclusions can be drawn for the production of hydrogen; however, this issue is dealt separately in detail later in this chapter.

7.2 A review of costs

The cost of carbon sequestration comprises the cost of capture (including the cost of compression), the cost of transport and the cost of storage. These costs have been described in detail in the previous chapters, however, for the sake of continuity they are summarised herein:

7.2.1 Capture costs

The cost of capture depends on the power plant type, the utilised capture technology and the degree of CO_2 capture. However, the first two factors are not independent. As was explained in Chapter 3, the power plant type determines the concentration and the partial pressure of CO_2 in the feed gas, which in turn dictates the most suitable capture technology.

With the current available technology, the optimal way to capture CO_2 from coal and natural gas power plants is post-combustion decarbonisation using chemical absorption. Since the technology has not yet been deployed commercially in power plants, the cost of technology can only be estimated based on basic engineering principles. Such estimations have been published by a number of institutions (typically, subcontracting this work to cost estimating departments of engineering contractors). According to IEA Greenhouse Gas Programme [98], such calculations can provide results of relatively high confidence (±25%). Further refinement in the accuracy of the results has not been deemed necessary for the purposes of assessing the cost of carbon sequestration. According to the open literature [153 - 158], the specific capital investment (SCI)[78] for a supercritical pulverised coal (SC) power plant without CO_2 capture is about1150/kW_e (see Table 31). The variability in the reported values is attributed mainly to different assumptions, such as plant efficiency and type and capacity of required equipment. This variability is discussed later in the chapter. The utilisation of capture technologies raises the SCI to $1975/kW, i.e. by 72%. Similarly, the SCI for GTCC plant is about $535/kW. The introduction of carbon capture increases the SCI to $1000/kW, i.e. by 88%. These sharp increases in capital cost reflect the high cost of the scrubber and its peripheral equipment, and also the reduction of the power output due to energy losses in capture and compression of CO_2. It has been reported that in coal plants, about half of the increase in SCI is due to the cost of CO_2 capture equipment and half is a result of reductions in the power output [98]. Furthermore, the higher increase in SCI in GTCC compared with coal plants is due to the lower concentration of CO_2 in the flue gas of GTCC plants, that makes CO_2 capture more demanding in terms of equipment and energy consumption.

The plant efficiency losses are also summarised in Table 31. About a third of the efficiency penalty for CO_2 capture in a coal plant is due to auxiliary power consumption, such as the flue gas fan and the CO_2 compressor, while the rest is due to steam consumed for the regeneration of the amine. The average coal power plant considered in these studies has an efficiency of 41.8% without CO_2 capture. However, the efficiency drops to 31.4% with CO_2 capture. Similarly, an average GTCC plant is considered to have an efficiency of 55.4% without capture and 48.2% with capture.

In contrast to the relatively high availability of information on capital costs, operating and maintenance costs are not typically reported. The operating cost is usually dominated by fuel costs, highlighting the importance of plant efficiency. Other major contributors to operating costs are labour, maintenance, chemical and other consumables, etc. An IEA report [98] summarises these costs (obtained from 2 independent studies); they are presented in Table 32.

---

[78] Specific capital investment (SCI) is a measure of the capital cost of a facility for each power unit of electricity produced, given in €/kW.

Table 31: A review of the capital cost, efficiency and specific CO_2 emissions of different power plant types as reported by various sources

STUDY	SCI ($/kW)	SCI w/capture ($/kW)	Change (%)	η[79] %)	η w/capture (%)	Change (%)	Specific CO_2 Emissions (kg/MWh)	Sp. Emissions w/ capture (kg/MWh)	Reduction (%)
SUPERCRITICAL COAL (SC)									
[154]	1150	2073	80.3	41.0	31.5	23.2	800	100	87.5
[155]	1129	1980	75.4	36.1	23.8	34.1	909	138	84.8
[156]	1300	2022	55.5	44.4	37.4	15.8	717	128	82.1
[157]	1022	1856	81.6	45.6	33.0	27.6	722	148	79.5
[158]	1143	1981	73.3	N/R[80]	N/R	-	774	108	86.0
[158] USC[81]	1161	1943	67.4	N/R	N/R	-	734	101	86.2
AVERAGE	**1151**	**1976**	**71.7**	**41.8**	**31.4**	**24.8**	**776**	**121**	**84.5**
NATURAL GAS COMBINED CYCLE PLANTS (GTCC)									
[154]	485	1135	134.0	60.0	53.0	11.7	330	56	83.0
[155]	754	1317	74.7	52.2	44.5	14.6	400	46	88.5
[156]	414	786	89.9	56.2	47.2	16.0	370	61	83.5
[157]	531	807	52.0	53.3	48.1	9.8	374	37	90.1
[158]	496	943	90.1	N/R	N/R	-	338	40	88.1
AVERAGE	**536**	**998**	**86.1**	**55.4**	**48.2**	**13.0**	**369**	**50**	**86.3**
INTEGRATED GASIFICATION COMBINED CYCLE PLANTS (IGCC)									
[159]	1332	1687	26.7	38.2	34.8	8.9	790	176	77.8
[160]	1536	1913	24.5	43.7	37.3	14.6	709	71	90.0
[154]	1265	1799	42.2	43.6	36.3	16.7	674	88	86.9
[155]	1600	2152	34.5	36.8	29.6	19.6	760	40	94.7
[156]	1300	1767	35.9	47.3	37.2	21.4	868	105	87.9
[157]	1471	2204	49.8	46.3	38.2	17.5	710	134	81.1
[158]	1263	1642	30.0	N/R	N/R	-	718	73	89.8
AVERAGE	**1395**	**1881**	**34.8**	**42.7**	**35.6**	**16.6**	**753**	**91.8**	**87.8**

---

[79] η denotes thermal efficiency.

[80] N/R : Not Reported values

[81] USC denotes an ultra supercritical power plant.

Besides the ‘traditional’ pathways to produce electricity (pulverised coal and natural gas), IGCC plants have recently been designed to produce electricity with high efficiencies and a reduced impact to the environment. Electricity can be produced by combusting syngas or pure hydrogen in a gas turbine. However, the second option (combustion of hydrogen) is best suited for carbon sequestration, based on the cost of electricity [57]. These plants only now are becoming commercial, and as such there is variability in design and performance. The optimal approach for the decarbonisation of such plants is the syngas/precombustion decarbonisation approach, where coal is gasified to produce syngas that is subsequently converted into a mixture of hydrogen and CO_2. Carbon dioxide is then separated using a physical absorbent while the stream of hydrogen is purified by pressure swing absorption. Ultimately, hydrogen is combusted in a gas turbine while the captured CO_2 is compressed and stored. The economics of IGCC is summarised in Table 31 and Table 32. The results have a high variability since that the technology is still immature, so that performance and costs are not yet well established. The SCI of an IGCC plant without CO_2 capture is estimated as \$1395/kW, while with CO_2 capture \$1880/kW, i.e. increased by 35%. This increase in capital cost is significantly lower than the corresponding increases in coal and natural gas plants. This is attributed to the higher concentration of CO_2 in the feed gas and the higher pressure of the feed gas in the IGCC plants that reduces compression needs and facilitates its easier removal. The efficiency of the IGCC power plant drops from 42.7% to 35.6%. The efficiency penalty for IGCC plants is smaller compared with coal and natural gas plants; one reason for this is that physical solvents used in IGCC decarbonisation are less energy intensive than chemical solvents used in coal and natural gas plants.

Additional economic evaluations of other combinations of power plants and capture technologies can be found in an IEA Greenhouse Gas R&D Programme Report [57].

Table 32: Operating and maintenance costs in power plants. Values are the arithmetic average of figures from 2 independent studies as reported in [98]

Operating Costs (c/kWh)	*Coal*	*IGCC*	*IGCC*
Maintenance	0.20	0.14	0.11
Labour	0.08	0.04	0.04
Consumables/ chemicals	0.24	0.10	0.20
Waste disposal	0.03	0.01	0
Insurance	0.10	0.06	0.05
Total other costs	0.63	0.33	0.39

7.2.2 Transport costs

The costs of CO_2 transport depend on the distance between the CO_2 source and the utilisation/storage site, the volume of CO_2 transferred, the terrain, the existing regulations, the inlet pressure and the presence of existing infrastructure. The economics of CO_2 transport have been discussed in detail in Chapter 4 and are summarised herein in Table 33.

Table 33: Review of CO_2 transport costs (Information based on [98])

Pipeline	
Throughput (million t/y)	Specific cost ($/t/100 km)
0.1	13
5	1.1
50	0.4-0.5
Ship	
$1-2 /tonne	

7.2.3 Storage

The cost of storage depends on the type of reservoir (aquifer, oil or gas reservoir, coal bed, ocean), the amount of work necessary to access the reservoir and the injection method. The cost of storage was discussed in Chapter 5; these results are summarised in Table 34.

Table 34: CO_2 storage costs (see Chapter 5 for details)

Storage Option	***Storage Cost (€/tonne CO_2)***
Aquifer	1-2
Depleted oil and gas reservoir	2-3
Ocean	~2

Based on the above-presented cost estimates, it is evident that carbon sequestration costs are dominated by the cost of separation and capture.

7.3 Economic assessment methodology and review of published results

The most common method to estimate the cost of carbon sequestration in power plants is the so-called *plant-level approach*, where the cost of electricity for a plant without carbon sequestration (called *reference plant*) is compared with the cost of electricity for a plant with carbon capture, referred to as the *capture plant*. This approach has several shortcomings that are described in detail in [161]. In brief, the plant-level approach ignores fuel switching and assumes that a given technology will be replaced with the same technology incorporating capture. Furthermore, this methodology assumes that the plants are new, ignoring their competition with existing facilities that have been 'paid-off' but remain competitive due to low generating costs. Finally, it is assumed that plant utilisation is constant, ignoring the reduction of capacity factor of plants designed to meet peak demand, such as GTCC plants, or plants being displaced due to the potential introduction of a carbon tax that will make the production of electricity from plants without carbon capture technologies uneconomical. These disadvantages of the plant-level approach have triggered the development of complex dynamic energy system models. However, the complexity of these models and the large number of parameters involved make the use of these models unattractive and as such they will not be discussed herein. Despite its shortcomings, the plant-level approach is widely used by most of the research organisations involved with the estimation of the costs of carbon sequestration as it can provide with an indication of the increase in costs associated with the deployment of carbon sequestration technologies.

The COE (in €/kWh) can be calculated as[82]:

$$COE = \frac{SCI * NPO * DR + FOC}{LF * 8760 * NPO} + VOC + HR * FC$$

where:

SCI	is the specific capital investment, see footnote 78.
NPO	is the net power output (in kW). Notice that SCI*NPO gives the total capital requirement for the plant.
DR	is the discount rate of the capital investment
LF	is the load factor of the plant. Notice that LF*8760 gives the total hours that the plant is operational annually
FOC	is the fixed annual operating costs (€/yr)
VOC	is the variable operating costs (€/kWh)
HR	is the plant heat rate, i.e. the energy input (coming from the fuel) that is required for the production of a unit of electrical energy (kJ/kWh), and,
FC	is the fuel cost (in €/GJ)

A range of values for the COE has been reported in the literature. The observed variability is a result of the use of different values for variables like load factor, fuel cost, discount rate, etc. In an effort to clarify the outcome of all these studies, several investigators have re-calculated the original results into a comparable set so that they can be more easily evaluated. One such work is Ref. [153]. The author, re-worked the results of a number of assessments having fixed the following variables: LF=77%, DR=15%, coal price (LHV)=$1.18/GJ, natural gas price (LHV)=$2.78/GJ. The results are summarised in Table 35.

However, the assumptions of the analysis, and more specifically the cost of natural gas, are considered unrealistic, under the current European situation[83]. In order to draw more useful conclusions about the increase of COE in Europe, additional calculations are presented at the end of this chapter.

---

[82] The cost of hydrogen (in €/GJ) can be calculated in an analogous way.

[83] The natural gas price in Europe during the second half of 2002 was about €5.4/GJ.

Table 35: COE as calculated in [153]. The reported values are the average of a number of studies whose results have been normalised to a common economic basis.

	IGCC	*PC*	*GTCC*
COE in Reference Plant (c/kWh)	4.99	4.39	3.30
COE in Capture Plant (c/kWh)	6.69	7.71	4.91
Absolute increase in COE (c/kWh)	1.70	3.32	1.61
Relative increase in COE (%)	34.1	75.6	48.8
Mitigation Cost (\$/ton CO_2 avoided)	26	49	49

Another way of presenting the economics of carbon sequestration is to calculate the cost per tonne of CO_2 avoided. This is also referred to as the mitigation cost, MC. It must be stressed that there is a significant difference between the amount of CO_2 captured and the amount of CO_2 avoided. This difference is explained with the following example. A 500 MW_e GTCC reference power plant is considered that emits 450 kg/MWh of CO_2 and has a thermal efficiency of 55%. When this plant operates at its maximum rated power output (i.e. 500 MW_e) it consumes 24.5 billion GJ of fuel and emits 1.69 million tonnes of CO_2 annually. When the same plant is equipped with a CO_2 capture technology an efficiency penalty of 12% is assumed for the sake of the example, i.e. the total efficiency of the capture plant drops to 43%. The capture power plant consumes the same amount of fuel and generates the same amount of CO_2 as the reference plant. Due to the reduction in thermal efficiency, the plant produces 21.8% less power (390.9 MW_e), and emits 576 kg/MWh. If it is assumed that 90% of the generated CO_2 is captured, the amount of CO_2 emitted in the atmosphere is 0.17 million tonnes, or 57.6 kg/MWh. Therefore, the amount CO_2 captured is 576-57.6=518.4 kg/MWh, while the amount of CO_2 avoided is the difference between the specific emissions of the reference plants (E_{ref}) and the specific emissions of the capture plant (E_{seq}), i.e. 450-57.6=392.4 kg/MWh, see Figure 44.

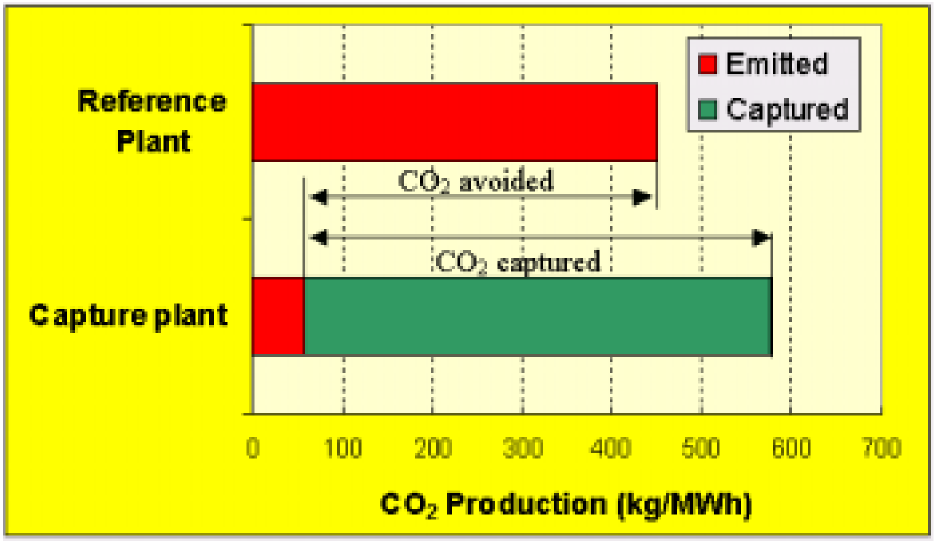


Figure 44: Calculation of CO_2 avoided and CO_2 captured in a GTCC plant (see worked example)

The mitigation cost, in €/tonne CO_2 avoided, is calculated by diving the difference of the COE between a reference (COE_{ref}) and a capture plant (COE_{seq}) to the specific CO_2 emissions avoided and reflects the average cost of reducing atmospheric CO_2 emissions by one unit of mass while still providing one unit of electricity to consumers [163].

$$MC = \frac{COE_{seq} - COE_{ref}}{E_{ref} - E_{seq}}$$

The mitigation cost of the comparison analysis presented earlier (Ref. [153]) is shown in Table 35. The mitigation cost for IGCC power plants is about half of the mitigation cost for the traditional power plants, highlighting the significant role that IGCC plants may play in the future. The mitigation costs reported by other investigators may vary; however this variability results from the use of different assumptions. As an example, Table 36 presents the values reported by another investigator [162].

Table 36: Characteristics of low emission power plants, according to [162]

Plant Type	*Net Plant Efficiency (%)*	*Capture technology*	*Mitigation Cost (€/ton CO_2)*	*Increase in COE (%)*
Supercritical Coal	40	Chemical absorption	37-43	60
Coal	40	Membrane separation	71-88	120
Coal	40	Cryogenic separation	33-50	60
Pulverised Coal	33	Chemical absorption	66-77	120
IGCC	43	Physical absorption	20-35	30
NGCC	55	Chemical absorption	36-66	50

7.4 Uncertainty in costs

As was shown in the previous section, the costs of electricity and mitigation depend on a number of factors and assumptions. Since there is not an established framework for such economic assessments, the uncertainty and variability of the factors used in the analyses result in the observed differences in the reported prices, introducing a level of uncertainty on what is the ‘actual’ value of cost quantities. To list a few of these factors that can alter significantly the calculated costs:

- Assumptions of different system boundaries: There is not a widely accepted system boundary where costs are calculated. Actually, the limited availability of data dictates to a large extent which processes are considered for cost evaluation.

For example, not all reports account for the cost of transport and storage of CO_2, while on the other extreme, few reports include emissions from the full life cycle of the fuel.

- Assumptions of capital and operating costs and operating conditions of established technologies: Even with established power plant technologies (PC and GTCC) certain factors that affect cost are not widely known and as such are not considered by investigators in their analyses. Such costs include elements of operating and maintenance costs. Other investigators omit specific indirect costs such as insurance, fees and land cost that may have a considerable contribution to costs. The omission of such costs results either from a lack of information or from an attempt to simplify the analysis, which can become rather cumbersome if all actual costs are included. Another factor that has a direct effect on cost assessment is the discount rate. A range of rates is being used; however all these values could be applicable depending on the spatial financial framework. Furthermore, all analyses assume constant (and high) load factors and relatively high thermal efficiencies.
- Assumptions of capital and operating costs and operating conditions of new technologies: With the exception of chemical absorption, none of the other capture technologies has been deployed commercially in large capacities, therefore cost estimates presented in the various reports should be treated as best-guesses. There is some experience with small scale applications in physical absorption, adsorption and cryogenics, mainly in the hydrogen, petrochemical and natural gas industry so cost estimates about these technologies could be realistic. However, a number of other technologies considered in the economic assessments have not yet materialised. The credibility of such cost estimates is questionable.
- Plant individuality and power systems: The used cost values and operating conditions correspond to an 'ideal' plant and a fixed financial framework. However, in reality each plant has its own characteristics and costs, dictated by a range of conditions, such as regional regulations, financial framework, location, politics, etc. and therefore, ideally, economical assessments should be made on plant-to-plant basis. On the other hand, on plant-level analyses, economies of scale are ignored, that have a major impact to economic assessments.
- Fuel costs: The fuel market, especially for natural gas, is rather volatile with prices changing with time and location. Most of the reported economic analyses have been performed in the USA, where coal and natural gas prices can be quite different than the European prices. As an example, most of the assessments examined assume a natural gas price of about €2/GJ, while the current European price is in excess of €5/GJ. Furthermore, other subtle differences may result in differences in fuel costs such as fuel properties.

The issue of cost uncertainties has been tackled by investigators by performing simple parametric analyses; however one research group has gone a step further quantifying the uncertainty using a probabilistic analysis [163]. In a case study for a new coal power plant they calculated not only the cost of electricity and the mitigation cost, but also the overall variability. While the mean and the median values of the mitigation cost lie in the range of \$45 to 53/tonne CO_2, the 95% probability interval varies by approximately a factor of 3, from \$28 to 74/tonne CO_2.

Finally, it should be noted that, when comparisons between the reported values are made, special attention should be paid to the units of costs. The most commonly overlooked figure is the mitigation cost, that in US is most commonly reported in short tonnes (i.e. in $/ton), see Table 35 and Table 36, while in Europe the mitigation cost is reported in metric tonnes (€/tonnes). The use of short tonnes results in lower values for the mitigation cost by 10%.

7.5 Estimating future costs and the role of technology learning

As was explained in the previous section, the uncertainty of the current costs associated with carbon sequestration technologies impedes our efforts to calculate what would be the today's cost of introducing carbon sequestration technologies in the power system. Unquestionably it is of greater value to know the cost of carbon sequestration in the future, in a time horizon when (and if) carbon sequestration technologies will be deployed. To be able to perform such calculations, not only the anticipated changes in costs and technology performance for power plants should be known but also for the sequestration technologies, information that is not available even for the present time. However, some predictions can be made by taking advantage of our experience in similar technologies. Yet, projections of costs will always be speculative and cost reduction will depend on the extent to which these technologies will be utilised. Last but not least, future cost assessment requires knowledge of the development of fuel costs with time.

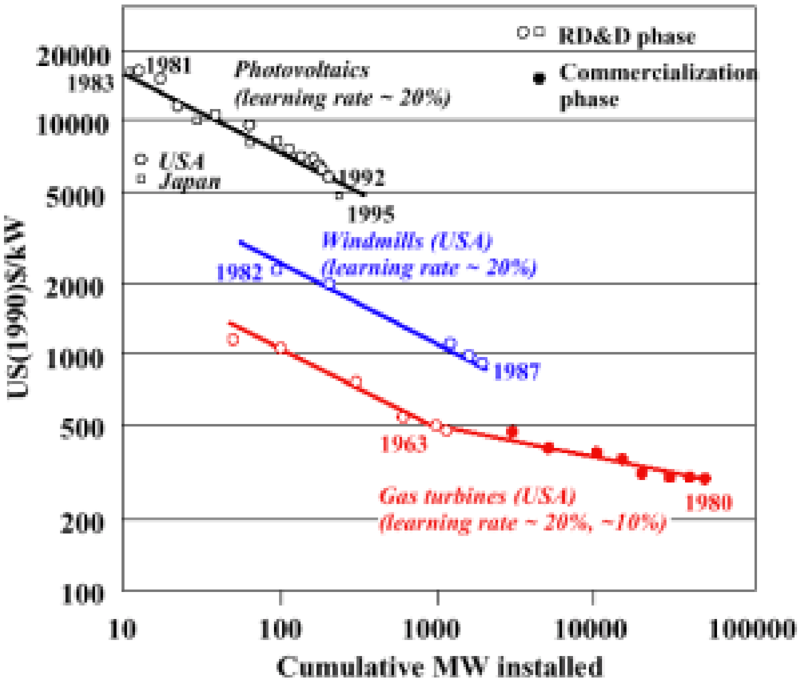


Figure 45: Decrease of specific capital costs with the increase in the cumulative installed capacity for a number of energy technologies. Such graph is called a 'learning curve' and can be used to predict future costs [165]

Without doubt, the cost of technologies is expected to decrease in the future because of technological improvements and innovation and the creation of larger markets. Costs will improve as experience is gained by both producers (learning-by-doing) and consumers (learning-by-using). For instance, capital requirements will be lowered, both for power plants and for carbon sequestration technologies. A notable example has been that significant drop of the capital cost for gas turbines over the past few decades, see Figure 45. It is likely that improved solvents, membranes and adsorbers, equipment and processes can reduce both the operating cost and the capital investment required for more economic carbon sequestration technologies. Efficiencies of plants with CO_2 capture will improve as a result of technology innovation and overall improvements in power plant efficiency.

It is difficult to quantify the reduction in the cost of capture technologies with time; however, useful conclusions can be extracted by studying analogous past cases. Such an example is the flue gas desulphurisation (FGD), a flue gas treatment technology similar to the chemical absorption. According to IEA Coal Research, the specific capital cost for FGD dropped from \$400/kW in 1970 to \$100/kW in 2000 [50], see Figure 46. Along the capital costs, the operational and maintenance costs dropped by 40% [165]. Similar conclusions can be drawn by studying the historical data for another gas treating technology, namely the selective catalytic reduction (SCR). Within the last 20 years, capital costs fell by 50% and operational and maintenance costs by 90% [165].

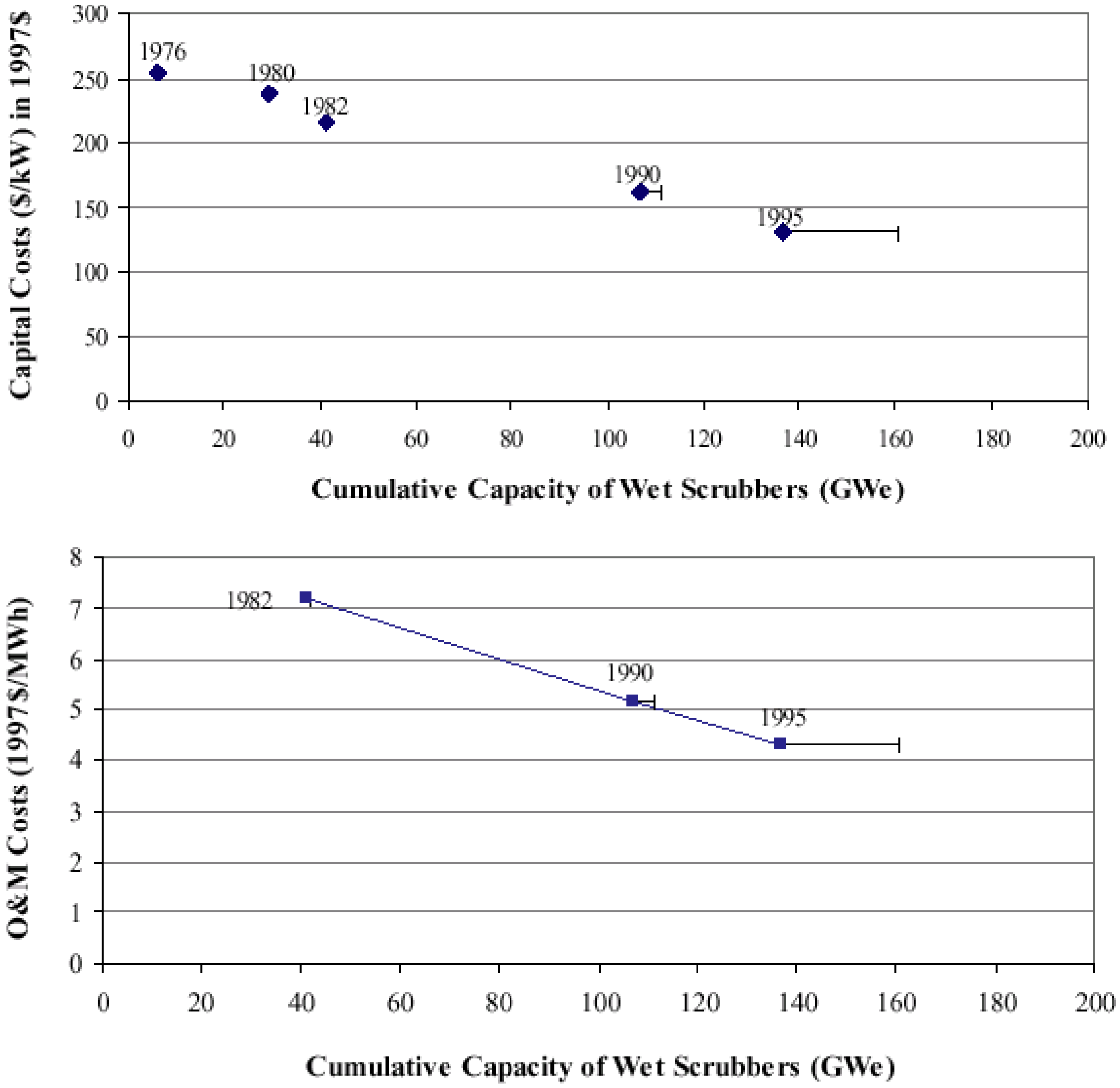


Figure 46: Decrease in capital costs (top) and operational and maintenance costs (bottom) of FGD technology with accumulated installed capacity [165]

Based on the experience gained by such analogous cases, IIASA has estimated that the cost of carbon sequestration technologies can be expected to decrease by 15% per doubling of installed capacity [165]. Furthermore, under a scenario where CO_2 concentration in the atmosphere is stabilised at 550 ppm by 2100, partly due to the contribution of carbon sequestration, it has been calculated that the mitigation cost for natural gas technologies can be as low as \$10/tonne CO_2 and for coal technologies to \$14/tonne CO_2 [164].

What is important to emphasise is that cost reductions should not be calculated as a function of time but on accumulated installed capacity, i.e. cost reductions will not come ‘automatically’ with time but require a driver that will trigger their deployment. These drivers can be political decisions and significant R&D developments. However, these two issues go hand in hand. As shown in Figure 47, the installed capacity of FGD equipment has increased with time, driven by national legislation. In USA, the number of filed patents on FGD technology showed a dramatic increase immediately after the Clean Air Act (CAA) was brought into effect.

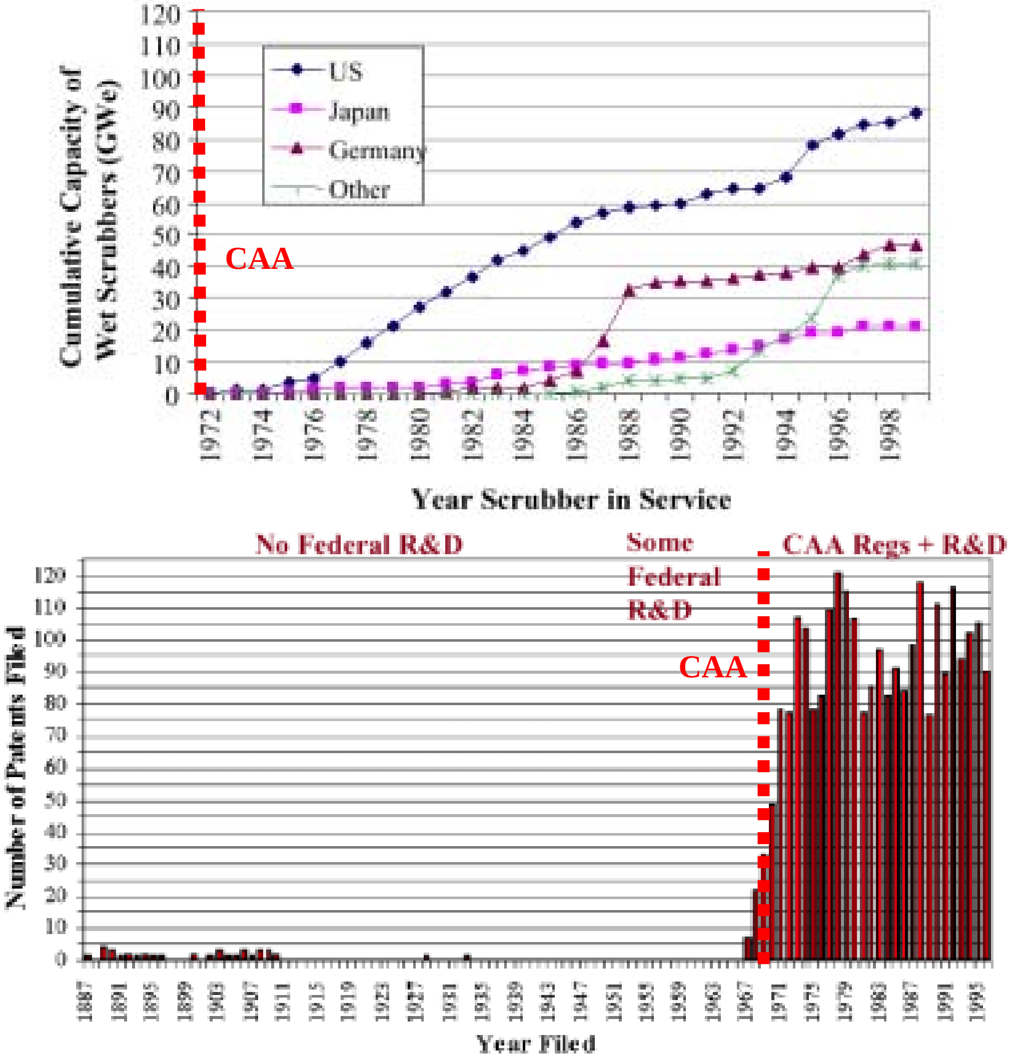


Figure 47: Deployment of technology (top) and number of patents filed in USA on FDG with time [165]. Clearly, the Clean Air Act (CAA) has triggered R&D on FGD resulting in a dramatic increase in patents.

7.6 Estimation of the effects of deployment of carbon sequestration in electricity generation and hydrogen production in Europe in 2020

In this section an attempt is made to calculate the cost of electricity and the cost of hydrogen produced by fossil fuels in the future and to recognise the impact that the introduction of carbon sequestration technologies might have to the related production costs. The time horizon for the analysis is set to 2020. It is noted that in the context of this publication, the terms 'cost of electricity' and 'cost of hydrogen' refer to the production costs only. The consumer also pays distribution, marketing, research and development and other costs.

7.6.1 Electricity generation

Plant-level analysis, as described earlier, can provide an indication of the increase in the cost of electricity that will occur by the deployment of carbon sequestration technologies. Three types of plants are studied in this analysis: supercritical coal plants (SC), natural gas combined cycle plants (GTCC) and integrated gasification combined cycle plants (IGCC).

In line with the IEA Greenhouse Gas R&D Programme methodology, it has been assumed that both the reference and the capture plant have the same net power output. As such, additional capital, operating and maintenance (O&M), and fuel costs are incorporated in the results so that the power output is maintained. Furthermore, the values for the parameters that are used in the IEA methodology are also used in this analysis to the largest possible extent. These assumptions are presented in Table 37.

The assumptions for the costs and performance of the reference power plants are based on the results of the share analysis project (Ref. [18], Table 9-11). These values are shown in Table 38[84]. However, the corresponding parameters for the capture plants can be estimated only by using engineering judgement. Due to technological learning, the capital cost of both reference and capture plants will decrease. The scenario that this analysis is based on, assumes that the capital cost decrease rate for reference plants is lower for GTCC plants (since they are a mature technology) and higher for the IGCC plants (which is a technology at its infancy). The difference between the capital costs of reference and capture plants is shown in Table 31: 72% for SC plants, 86% for GTCC and 35% for IGCC. It is herein assumed that this difference in capital costs between reference and capture plants will become narrower with time due to faster improvements in capture plants, despite the fact that no significant deployment of capture technologies is expected to happen before 2020 to trigger a major learning effect. This assumed cost reduction would come from R&D improvements. Furthermore, it is assumed that the narrowing of such a cost gap will be minimal for IGCC plants, since both reference and capture plants are new technologies so improvements will happen at a similar pace. The difference of SCI between captured and reference plants in 2020 is ultimately assumed to be 10% narrower than the values reported in Table 31 for SC and GTCC plants (calculated as 65% and 77% respectively) and 5% narrower for IGCC plants (33%). Ultimately, the SCI for the capture plants in absolute terms is assumed to be €1894/kW, €951/kW and €1856/kW for SC, GTCC and IGCC plants respectively. In an analogous approach the efficiencies of the capture plants can be estimated as: 39.6% for DC, 53.9% for GTCC and 41.7% for IGCC.

---

[84] It is noted that these values may differ from values reported in other studies. For example, the US DoE predicts that by 2015 the SCI of IGCC will be about $850/kW and its efficiency ~54% [166].

Table 37: Economic basis for the plant-level economic analysis for the calculation of the cost of electricity

Parameter	***Value***
Plant size (NPO)	500 MW_e
Load factor (LF)	90% for GTCC – 85% for SC and IGCC
Discount rate (DR)	10%
O&M costs	6% of capital investment for GTCC reference plants 9% of capital investment for SC and IGCC reference plants 6% of additional capital investment required for all capture plants
CO_2 transport and storage costs	Transport cost: €1/tonne CO_2 transported Storage cost: €2/ tonne CO_2 stored

Table 38: Techno-economic characteristics of power plants

Plant type	***SCI (€/kW)***	***Efficiency (%)***	***Specific CO_2 Emissions (kg/MWh)***
Reference GTCC	528	62.0	350
Capture GTCC	951	53.9	Calculated, see Table 39
Reference IGCC	1333	50.0	750
Capture IGCC	1856	41.7	Calculated, see Table 39
Reference SC	1114	51.0	750
Capture SC	1894	39.6	Calculated, see Table 39

The contribution of CO_2 transport and storage costs to the total cost of electricity was calculated based on the scenario that CO_2 is transported 100 km and injected to an aquifer. Based on the assumption that the CO_2 removal efficiency in the capture plant is 90%, the typical amount of CO_2 that is transported from a 500 MW_e coal plant is about 3.5 million tonnes annually. Based on Table 33 and Table 34, the transport and storage costs were set as €1/tonne and €2/tonne CO_2 respectively. Finally, fuel prices were set at €1.55/GJ for coal and €3.35/GJ for natural gas, according to Ref. [18], page 27.

The approach used in this analysis to calculate the COE is simpler than the one presented in page 111. Herein COE is partitioned into 4 components: COE due to capital investment (COE_{ci}), COE due to fuel costs (COE_{fc}), COE due to O&M costs (COE_{OM}), and COE due to CO_2 transport and storage (COE_{seq}). The latter cost component is applicable only to capture plants. These cost components are calculated as follows[85]:

---

[85] For definitions of terms, see page 111.

$$COE_{ci} = \frac{DR * SCI}{LF * 8760}$$

$$COE_{fc} = HR * FC$$

$$COE_{OM} = \frac{\text{Annual O \& M costs}}{NPO} = f(SCI)$$

$$COE_{seq} = \frac{\text{Annual costs for } CO_2 \text{ transport and storage}}{NPO}$$

and,

$$COE = COE_{ci} + COE_{fc} + COE_{OM} + COE_{seq}$$

The results of the analysis are summarised in Table 39 and in Figure 48.

Table 39: Calculated cost of electricity and CO_2 mitigation costs in 2020

	GTCC$_{ref}$	$GTCC_{cap}$	$IGCC_{ref}$	$IGCC_{cap}$	SC_{ref}	SC_{cap}
COE_{ci} (c/kWh)	0.67	1.21	1.79	2.49	1.50	2.54
COE_{fc} (c/kWh)	1.95	2.24	1.12	1.34	1.09	1.41
COE_{OM} (c/kWh)	0.40	0.72	1.61	2.03	1.35	1.98
COE_{seq} (c/kWh)	-	0.11	-	0.24	-	0.26
COE (c/kWh)	**3.02**	**4.28**	**4.52**	**6.11**	**3.94**	**6.19**
ΔCOE (%)	41.75		35.17		57.20	
MC (€/t)	**40.66**		**24.07**		**34.46**	
Δf[86] (%)	15.0		19.9		28.8	
CO_2 Emissions (kg/MWh)	350	40.3	750	89.9	750	96.6

The results show that:

- The deployment of carbon sequestration technologies will increase the cost of electricity by 35-57% depending on the electricity generation power plant type.
- GTCC technology will continue to be the most economic pathway to produce electricity, even with the deployment of carbon sequestration technologies.
- IGCC technology cannot be competitive with other electricity generation technologies when carbon sequestration is not considered. However, the deployment of carbon sequestration makes IGCC an attractive pathway, bringing the technology at the same level of competitiveness with supercritical pulverised coal plants.
- The cost of CO_2 transport and storage is unlikely to have a significant contribution to the total cost of electricity

---

[86] *Δf* denotes the increase in fuel consumption.

- The main component in the cost of electricity in SC and IGCC plants is the capital cost, and in GTCC plants the cost of fuel. As such, technological developments that can reduce capital costs offer a higher potential to lower the COE in coal plants than in natural gas plants. On the other hand, improvements in process efficiency will reduce the COE more in natural gas-fuelled plants than in coal plants.

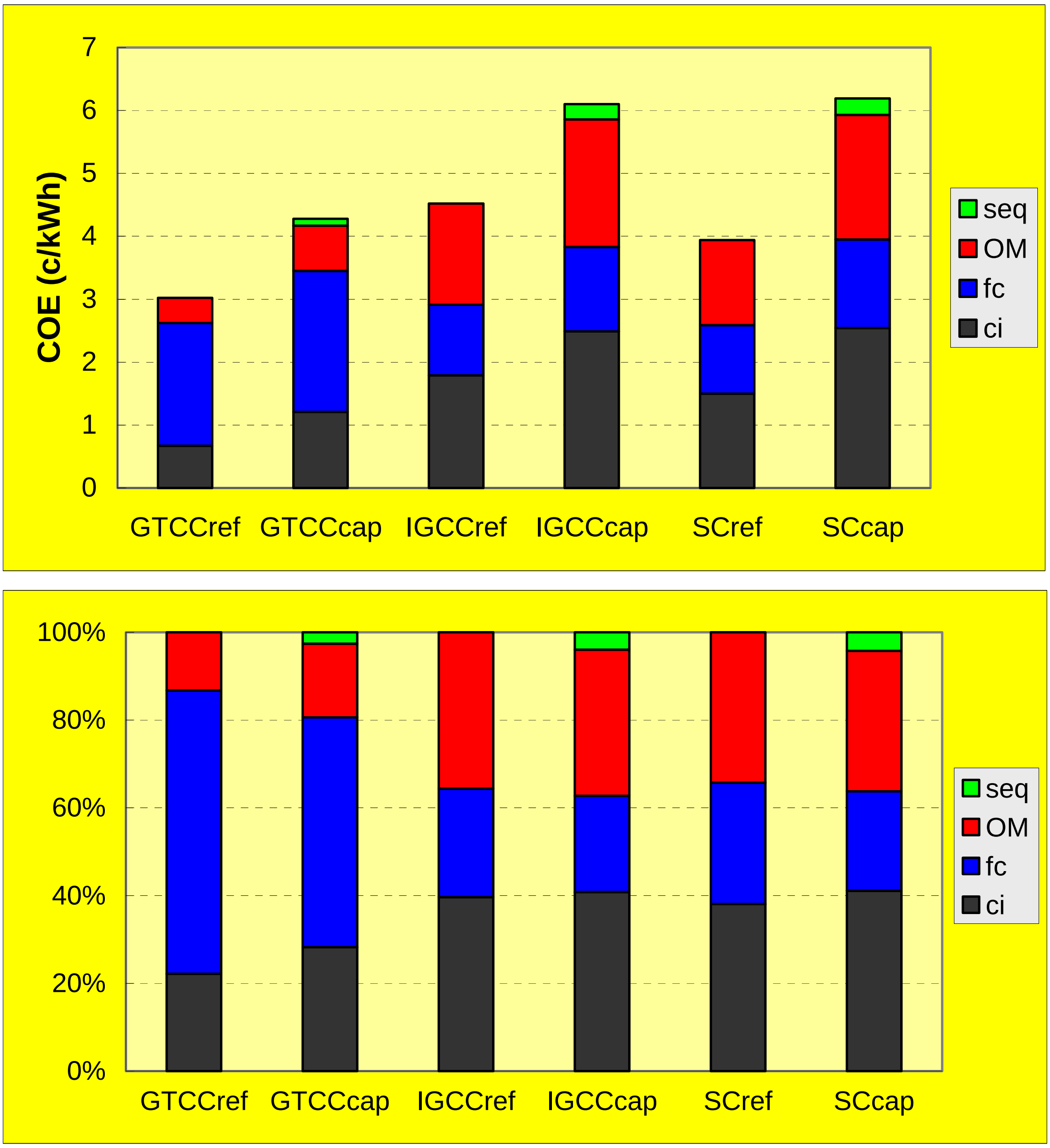


Figure 48: Calculated cost of electricity with and without carbon sequestration in 2020: (top) absolute values; (bottom) contribution (in %) of capital investment costs (ci), fuel costs (fc), operation and maintenance costs (OM) and CO_2 transport and storage costs (seq) to the cost of electricity.

The last conclusion highlights the strong dependence of electricity costs on natural gas price, given the volatility of the natural gas market. In order to identify the threshold price of natural gas, above which GTCC technology becomes equally competitive with coal-based technologies (IGCC and SC) after the deployment of carbon sequestration, two alternative scenarios were considered: It was assumed that the cost of coal varies within 15% of the set coal price of €1.55/GJ, i.e. between €1.32 (low coal price scenario) to 1.78/GJ (high coal price scenario). The COE for IGCC varies between 5.91 (for the low coal price) and 6.30c/kWh (for the high coal price) and for SC between 5.98 and 6.40c/kWh. Therefore, overall, the COE produced from coal varies between 5.90-6.40c/kWh. The calculated threshold price of natural gas is in the range of €5.78 (low coal price) and 6.53/GJ (high coal price), see Figure 49. This threshold price of natural gas, in the case where carbon sequestration is not considered, i.e. based on reference plants calculations, is significantly lower, within the range of €4.64-5.20/GJ. Therefore, it is unlikely that coal-based power plants can be competitive to GTCC plants after the deployment of carbon sequestration as long as natural gas price does not exceed €5.7/GJ (provided that natural gas is locally available).

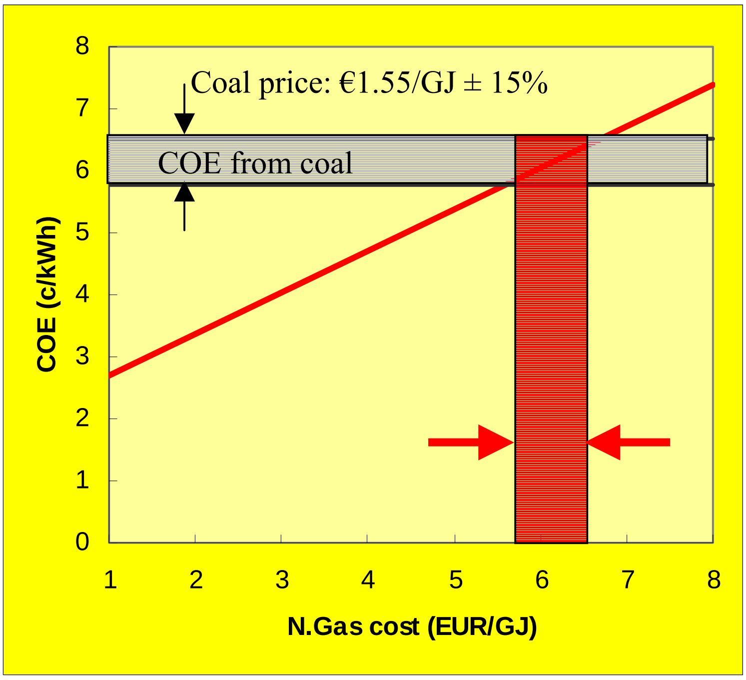


Figure 49: COE from GTCC plants with carbon capture technologies as a function of the cost of natural gas (red line). The threshold price of natural gas that makes COE from coal plants equally costly with COE from GTCC plants is shown with the red arrows.

Obviously, the accuracy of these results depends strongly on the assumptions of the economics and performance of both the reference and the capture plants used in the baseline scenario (Table 37 and Table 38). Furthermore, our confidence in the assumptions regarding the reference plants is higher than that of the capture plants given that the former are matured technologies. To estimate the sensitivity of the results of our calculations, two alternative scenarios were considered: In a 'high technological development' scenario both SCI and efficiency of the capture plant are improved compared with the reference scenario: the difference of SCI and plant efficiency between the reference plant and the capture plant are narrowed by 10%, compared with the reference scenario. In a 'low technological development' scenario the difference of SCI and plant efficiency between the reference plant and the capture plant are increased by 10%. All assumptions are summarised in Table 40. The results for the cost of electricity and mitigation cost are shown in Table 41. The COE changes only slightly by 2.8% for GTCC, 2.6% for IGCC and 3.4% for SC. It is interesting to note that if the slow technological development is assumed for GTCC, while a fast technological development is assumed for coal technologies, GTCC remains the most competitive source for electricity as long as natural gas prices remain below €5.38-5.98/GJ depending on the coal price. In conclusion, GTCC technology, even with the additional costs incurred by the deployment of carbon sequestration technologies, remains the most competitive technology for electricity generation, as long as the price of natural gas remains below approximately €5.5/GJ, depending on the coal price and the developments in power plant costs and performance.

Table 40: Assumptions on power plant economics and performance for alternative scenarios

		Reference Scenario	***High development***	***Low development***
GTCC	***SCI (€/kW)***	951	909	993
	Efficiency (%)	53.9	54.7	53.1
IGCC	***SCI (€/kW)***	1856	1804	1908
	Efficiency (%)	41.7	42.5	40.9
SC	***SCI (€/kW)***	1894	1816	1972
	Efficiency (%)	39.6	40.7	38.5

Table 41: Results of the analysis based on the alternative scenarios

	GTCC		***IGCC***		***SC***	
	COE (c/kWh)	***MC (€/t CO_2)***	***COE (c/kWh)***	***MC (€/t CO_2)***	***COE (c/kWh)***	***MC (€/t CO_2)***
Reference	4.28	40.66	6.11	24.07	6.19	34.46
High	4.16	36.73	5.96	21.87	5.98	31.08
Low	4.40	44.64	6.25	26.30	6.40	37.92

7.6.2 Hydrogen production

The cost of hydrogen produced from fossil fuels in the mid-term (2020) can be calculated using a plant-level approach, similar to the methodology described in the previous section. The following analysis attempts to calculate the cost of hydrogen focusing on two main pathways, namely natural gas steam reforming and coal gasification.

In contrast with electricity generation technologies, steam reforming and coal gasification although mature technologies, they have not been widely deployed due to the limited demand for hydrogen. Reformers and gasifiers are utilised mainly in the petrochemical and chemical industry (e.g. for the production of ammonia and fertilisers). Due to their limited deployment, cost and performance information about gasification and reforming plants is scarce in the open literature, hindering any attempt to calculate precisely the cost of hydrogen. Although the following analysis is based on the latest available information, it is understood that the degree of confidence of the results cannot be determined.

Effort was made to keep the methodology for calculating the cost the hydrogen, similar to the previously described methodology for the calculation of the cost of electricity. It was assumed that the hydrogen production plant has a capacity of 5 million Nm^3/d, which is more than 2 times larger than the largest single stream steam reformer built to date [167]. Reference plant characteristics were obtained from [168]. The characteristics of the capture plants were estimated based on the following rationale:

- Given that CO_2 is already separated during the production of hydrogen in the reference plant, carbon sequestration requires only the compression of the separated CO_2. The cost for such a compressor may vary between €10-30 million [89, 169]. The higher value is considered in this analysis. The SCI for the capture plant considered in this analysis is €12/GJ and €32/GJ for steam reforming and coal gasification respectively.
- A techno-economic report from IEA Greenhouse gas R&D Programme has calculated that the energy penalty associated with carbon sequestration in the gasification of orimulsion for hydrogen production is approx. 4% in relative terms, compared with the overall efficiency of the reference plants. Furthermore, Herzog from MIT has estimated that the efficiency penalty associated with CO_2 compression is approx. 8% [62]. In this analysis, it is assumed that the energy penalty associated with CO_2 sequestration in hydrogen production plants is 6%.

As with the previous analysis on the cost of electricity, the contribution of CO_2 transport and storage costs to the total cost of hydrogen was calculated based on the scenario that CO_2 is transported 100 km and injected to an aquifer. All assumptions are listed in Table 42 and Table 43.

Table 42: Assumptions of economic parameters used in the plant-analysis for the production of hydrogen

Parameter	***Value***
Plant size (NPO)	5 million Nm^3/d
Load factor (LF)	90%
Discount rate (DR)	10%
O&M costs	6% of capital investment
Fuel costs	€3.35/GJ for natural gas €1.55/GJ for coal
CO_2 transport and storage costs	Transport cost: €1/tonne CO_2 transported Storage cost: €2/ tonne CO_2 stored

Table 43: Hydrogen plant characteristics

Plant type	*SCI (€/GJ)*[87]	*Efficiency (%)*
Reference steam reformer	10	75.0
Capture steam reformer	12	70.5
Reference coal gasifier	30	50.0
Capture coal gasifier	32	47.0

As in the previous analysis, the cost of hydrogen (COH) is partitioned into 4 components: COH due to capital investment (COH_{ci}), COH due to fuel costs (COH_{fc}), COH due to O&M costs (COE_{OM}), and COH due to CO_2 transport and storage (COH_{seq}).

Emissions have been estimated based on mass balance calculations: It was assumed that the following reactions take place:

$CH_4 + 2H_2O \leftrightarrow CO_2 + 4H_2$ (steam reforming)

$C + 2H_2O \leftrightarrow CO_2 + 2H_2$ (coal gasification)

Furthermore, it was assumed that natural gas consists of pure methane and coal contains 86% carbon. Energy content (for natural gas and coal) was converted into mass using the low heat values of the fuels (43.2 MJ/kg and 25.5 MJ/kg respectively).

The results are shown in Table 44 and in Figure 50.

Table 44: Calculated cost of hydrogen and mitigation cost

	Steam reforming		*Gasification*	
	Reference	*Capture*	*Reference*	*Capture*
COH_{ci} (€/GJ)	1.00	1.20	3.00	3.20
COH_{fc} (€/GJ)	4.47	4.75	3.10	3.30
COH_{OM} (€/GJ)	0.60	0.72	1.80	1.92
COH_{seq} (€/GJ)	-	0.24	-	0.71
COH (€/GJ)	**6.07**	**6.92**	**7.90**	**9.13**
ΔCOH (%)	13.99		15.56	
MC (€/t)	**11.19**		**5.55**	
Δf (%)	6.4		6.4	
Emissions (kg/GJ)	84.9	9.0	247.8	26.4

---

[87] For hydrogen production technologies, SCI is the total capital investment divided by the annual hydrogen production.

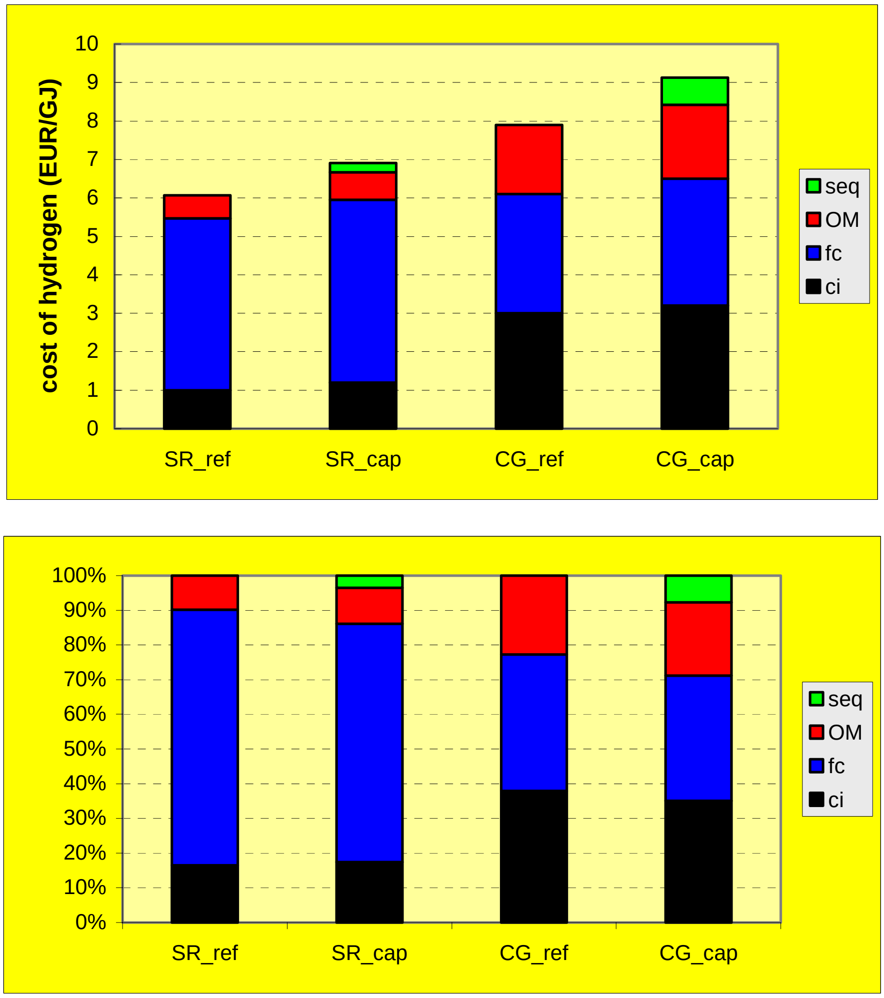


Figure 50: Calculated cost of hydrogen as produced by steam reforming (SR) and coal gasification (CG): (top) absolute values; (bottom) contribution (in %) of capital investment costs (ci), fuel costs (fc), operation and maintenance costs (OM) and CO_2 transport and storage costs (seq) to the cost of hydrogen.

The results show that:

- The deployment of carbon sequestration on natural gas steam reforming and coal gasification plants will increase the cost of hydrogen by 14 and 16% respectively.
- Hydrogen production via steam reforming is significantly more economical than production using coal gasification.
- The cost of CO_2 transport and storage is unlikely to have a significant contribution to the cost of hydrogen
- The cost of hydrogen as produced by steam reforming is dominated by the cost of fuel. In coal gasification, capital costs play a role equally important to the cost of fuel.

With a natural gas price of €3.35/GJ, coal gasification can be competitive only when coal is available at a price of €0.51/GJ. Vice versa, with a coal price of €1.55/GJ, coal gasification is competitive to steam reforming when the price of natural gas exceeds €4.90/GJ. Even, if coal price drops by 35% to €1/GJ, then hydrogen production by steam reforming is more economical as long as the price of natural gas remains below

€4.01/GJ. Therefore, under the current trends of the energy market, hydrogen production via steam reforming will be more competitive than hydrogen produced by coal gasification (Figure 51). However, coal gasification may offer an economic advantage over steam reforming only under specific local conditions, e.g. local abundant coal reserves and lack of natural gas delivery infrastructure.

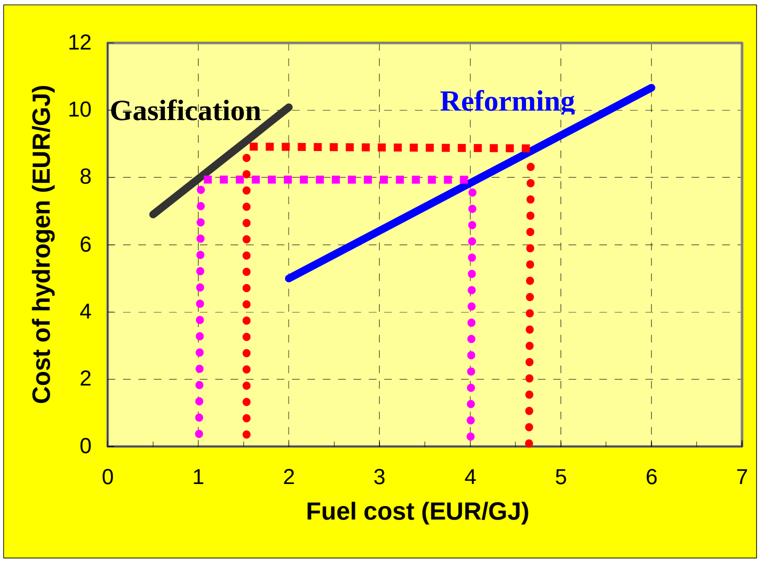


Figure 51: Cost of hydrogen as a function of fuel cost, produced by coal gasification (in black) and by steam reforming (in blue).

7.6.3 The additional cost introduced by the deployment of carbon sequestration to the production of hydrogen for alternative transport fuel in Europe in 2020

Driven by concerns about security of energy supply and emissions of GHGs, the European Commission took the initiative to propose the introduction of alternative fuels in the transportation sector and set an indicative target of substituting 20% of traditional fuel by alternative fuel by 2020. Among the alternative fuels considered in the Communication of the Commission[88] is hydrogen. The vision of the Commission is that hydrogen substitutes 5% of the energy demand of the road transport sector by 2020.

According to the European Union Energy Outlook to 2020, the total transportation energy demand in 2020 will be 358.8 Mtoe (Ref. [18], Table 6-12). As such, the demand for hydrogen will be 17.9 Mtoe or 751 million GJ. Based on the previous section, it may be assumed that the required amount of hydrogen will be produced by natural gas steam reforming. Based on an average plant load factor of 90%, the daily production of hydrogen should be 2.29 million GJ or 212 million Nm^3. Assuming that the daily production rate of a steam reforming plant is 5 million Nm^3, then the number of natural gas steam reforming plants required is 43, in order to meet the demand for hydrogen.

---

[88] COM(2001) 547 final

In a scenario where there are no constraints in CO_2 emissions, the total capital cost for these plants is estimated at €7.63 billion (at a SCI of €10/GJ). Assuming an overall process efficiency of 75%, the amount of natural gas consumed annually is 1.0 billion GJ at a cost of €3.35 billion (at a natural gas price of €3.35/GJ). The total annual cost of hydrogen production is €4.56 billion. In the process of hydrogen production, 63.7 million tonnes of CO_2 are emitted in the atmosphere, which is equal to 8.6% of the CO_2 emissions from the road transport sector in EU15 in 1999[89] or 6.1% of the total CO_2 emissions of the transport sector in 2020 [18].

In a 'carbon sequestration' scenario where 90% of the generated CO_2 during hydrogen production is captured and stored, the capital cost of the required hydrogen production plants rises to €9.15 billion (at a SCI of €12/GJ). Due to the reduction of the process efficiency (to 70.5%), 6.4% additional fuel is required, i.e. 1.07 billion GJ that costs €3.57 billion. The total annual cost of hydrogen production is €5.20 billion. During production, 68 million tonnes of CO_2 are generated, however, only 6.8 million tonnes are emitted in the atmosphere (which corresponds to 0.9% of the CO_2 emissions from the road transport sector in EU15 in 1999 or 0.7% of the total CO_2 emissions of the transport sector in 2020), while 61.2 million tonnes are stored annually. Assuming that each hydrogen production plant is associated with a single storage site, then 1.4 million tonnes of CO_2 will be stored annually in each of the 43 geological storage sites. It is noted that the annual storage rate at Sleipner is 1 million tonnes, while the annual use of CO_2 for EOR worldwide is 40 million tonnes.

Overall, under a 'carbon sequestration' scenario annual costs are increased by €640 million compared with a 'unrestricted emissions' scenario for the production of 751 million GJ of hydrogen annually, while 56.9 million tonnes of CO_2 are avoided, at a cost of €10.95/tonne CO_2. The results are summarised in Table 45.

Table 45: Economics of hydrogen production (with and without carbon sequestration) to meet the demand for hydrogen by the transport sector in 2020.

	No CO_2 constraints	***Carbon sequestration***	***Difference***
Capital cost	€7.63 billion	€9.15 billion	€1.52 billion
Natural Gas consumption	1.00 billion GJ	1.07 billion GJ	~ 70 million GJ
Annual cost of hydrogen production	€4.56 billion	€5.20 billion	~ €640 million
CO_2 emissions	63.7 million tonnes	6.8 million tonnes	56.9 million tonnes

---

[89] The emissions from road transport in EU15 in 1999 were 743.3 million tonnes. (Source: EU Energy and Transport Figures: Statistical Pocketbook 2001, European Commission, DG TREN).

8. Research, Development and Demonstration Projects on Carbon Sequestration

8.1 European Programmes

The European Commission started funding projects related with carbon sequestration during the mid-90's, utilizing the instruments offered by the Third Framework Programme for research and technological development (1990-1994). At that time a number of cycles with CO_2 capture were studied. The level of funding for carbon sequestration programs has been increased continuously since these early days. In the Fourth Framework Programme (1994-1998) the SACS project was funded (see below), while in the Fifth Framework Programme (1998-2002), the European Commission spent more than €33 million in activities related with carbon capture and storage. Among the most important projects that have received funding from the European Commission are[90]:

- **SACS 1&2/Saline Aquifer CO_2 Storage - Demonstration in the Sleipner Field**: The project started in 1998, funded initially by the Thermie Programme, aiming to collect data, monitor and verify the distribution of CO_2 injected in the Sleipner Field, see page 76. Through monitoring and verification of integrated use of existing models, the project provides a scientifically based 'best-practice manual' to assist other organizations planning CO_2 injection projects to take advantage of the learning processes undertaken and to assist in facilitating new projects of this type [170]. The major success of the SACS/SACS2 projects has been the demonstration that conventional time-lapse seismic data can be a useful monitoring tool for CO_2 injected into a saline aquifer. Furthermore, it has been shown that CO_2 accumulations with a thickness as low as 1 m can be detected. The repeat seismic surveys have clearly shown that the injected CO_2 migrates due to buoyancy effects from the injection point and accumulates under the cap-rock (see Figure 52). The project ran through 2002 with a budget of €3.03 million, €1.2 million being funded by the European Commission. The participants of the project include petrochemical companies, research organizations and national geological surveys.
- **CO2STORE:** To an extent, this project may be considered as a continuation of the successful SACS projects. The project started in 2003 and has two main goals: i) to extend the work on Sleipner to investigate the long-term fate of the injected CO_2 and evaluate other monitoring techniques that could be more cost-effective than seismic surveys, (ii) apply the knowledge gained in SACS 1&2 projects to develop site-specific plans for CO_2 storage operations elsewhere in Europe, both on and off-shore.
- **NASCENT/Natural Analogues to the Storage of CO_2 in the Geological Environment:** NASCENT addresses the key issues of geological carbon storage by using natural CO_2 occurrences as analogues for geological repositories of anthropogenic CO_2. The issues studied include the long-term safety and stability

---

[90] Details about the European Commission funded projects can be found in the Cordis database: http://www.cordis.lu

of storage underground and the potential environmental effects of leakage from an underground reservoir[91]. Among the contractors are geological research organizations from UK, France, Germany, the Netherlands, Greece, Hungary and universities. The project started in 2001, with duration of 3 years. The total budget is €3.29 million, €1.86 million being funded by the Commission.

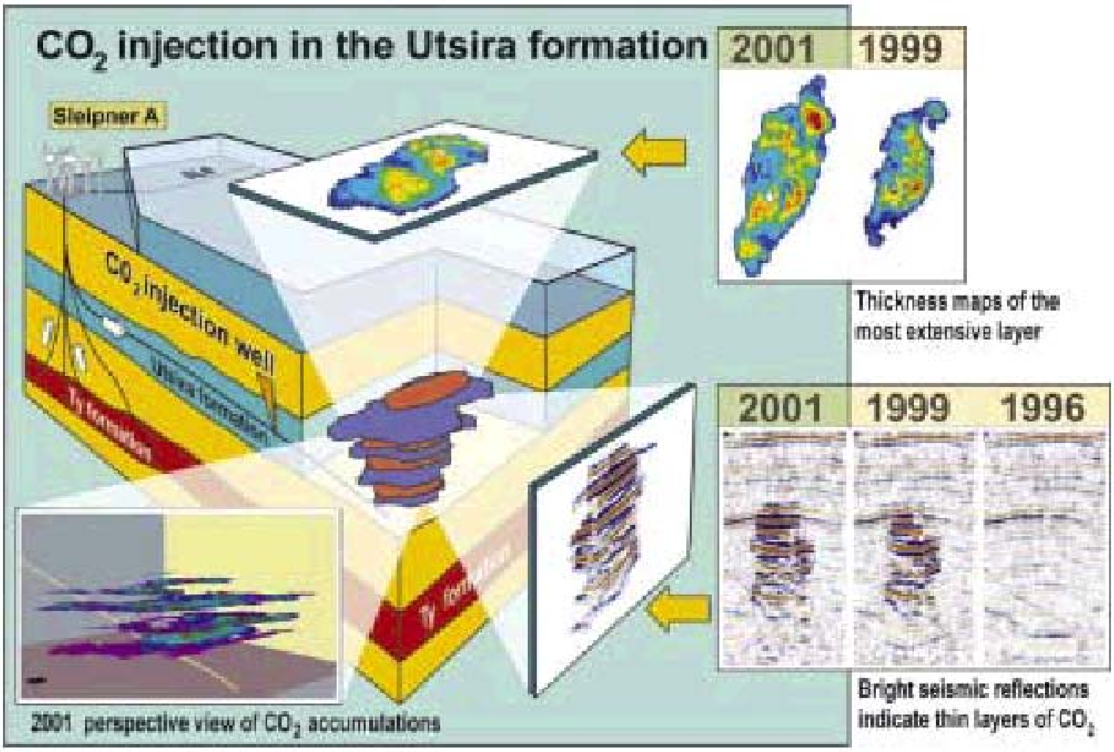


Figure 52: Diagrammatic representation of repeat seismic surveys and position of injected CO_2 [170]

- **GESTCO/The European Potential for Geological storage of CO_2 from Fossil Fuel Combustion:** The principal objective of GESTCO is to identify the CO_2 geological storage capacity in Europe. The project intends to provide the first documentation that, for emission sources within selected key areas, sufficient geological storage capacity is available. The project studies the distribution and coincidence of thermal CO_2 emission sources and location/quality of geological storage capacity. The study will be thematic in nature and will investigate the storage potential of four main storage types in selected areas, using these as representative settings which, at a future time, could provide the backbone of an atlas of European geological storage capacity: i. Onshore/offshore saline aquifers with or without lateral seal; ii. Low enthalpy geothermal reservoirs; iii. Deep methane-bearing coal beds, and abandoned coal and salt mines; iv. Exhausted or near exhausted hydrocarbon structures. The results of the project will encompass evaluation of the underground storage potential in the representative areas combined with inventories of power plant

---

[91] A similar project is run under the auspices of the US DoE, called Natural Analogs for Carbon Sequestration, NACS.

(and major industrial) point sources of CO_2 emission. Through a number of realistic scenarios, cost of CO_2 storage will be calculated (per tonne of CO_2 and as electricity cost increase). The project started in 2000 with duration of 3 years. Participants include national geologic surveys and research organizations. The project budget is €3.8 million, 50% is funded by the European Commission.

- **RECOPOL/Reduction of CO_2 Emission By Means Of CO_2 Storage In Coal Seams In The Silesian Coal Basin Of Poland:** In this project the feasibility of GHG emission reduction by CO_2 storage in subsurface coal seams is studied. This is the first project of its kind outside N. America. Locally produced CO_2 or flue gas from a power plant will be injected in the coal at a selected test site in the Silesian Coal Basin (Poland) with a rate of 20 tonnes per day, while methane (CH_4) will be produced simultaneously. This research involves laboratory work, model simulations, and investigation of time-lapse monitoring. Existing wells at the test site and a newly drilled well will be used for the test. The project started in 2001 and will be concluded in 2004. The total budget is €3.44 million, half of it will be funded by the European Commission. Additional information can be found in [171].

- **CO2NET/European Thematic Network:** CO2NET is the European Network of researchers, developers and users of CO_2 technology, facilitating co-operation between these organisations and the European projects on CO_2 geological storage, CO_2 capture and zero emissions technologies. The aim of the network is to: facilitate research collaboration and map European centres of excellence; assess and define R&D strategy; provide information to assist policy making at European and national level; develop training materials and educational activities/material; increase public awareness towards acceptance; assess best practice; lay foundations for benchmarking and standardization; facilitate exploitation and dissemination of CO_2 projects and results; establish real-time online communication facility; and, develop an interactive relational database for collation of all information and network outputs.

- **WEYBURN/The Weyburn CO_2 Monitoring Project:** This project will enhance the knowledge and understanding of the underground sequestration of CO_2, especially where associated with EOR, and develop and enhance monitoring techniques to ensure safe and stable underground storage. It is anticipated that approximately 20 million tonnes of anthropogenic CO_2 will be permanently sequestered underground during the project. The project takes place at the Weyburn oil field (Saskatchewan, Canada) being an integral part of a long-term IEA-facilitated project with a total budget of Can$1.5 billion. The European Commission provides €1.19 million to fund the project. Injection of anthropogenic CO_2, generated during coal gasification, has started in late in 2000. More information can be found in [172]

Currently, with the launch of the 6th Framework Programme for Research, Technological Development and Demonstration (2002-2006), carbon sequestration has become a focal point for European research, in the context of sustainable energy systems. The aim of promoting research on carbon sequestration is to reduce the cost of carbon sequestration and make it a viable option for the future.

More specifically, the Programme states explicitly the targets to be met in carbon sequestration research activities[92]:

> *Capture and sequestration of CO_2, associated with cleaner fossil fuel plants: Cost effective capture and sequestration of CO_2 is essential to include the use of fossil fuels in a sustainable energy supply scenario, reducing costs to the order of €30 in the medium term and €20 or less in the longer term per tonne of CO_2 for capture rates above 90%. Research will focus on: developing holistic approaches to near zero emission fossil fuel based energy conversion systems, low cost CO_2 separation systems, both pre-combustion and post-combustion as well as oxyfuel and novel concepts; development of safe, cost efficient and environmentally compatible CO_2 disposal options, in particular geological storage, and exploratory actions for assessing the potential of chemical storage and innovative uses of CO_2 as a resource.*

The strategically important areas in which research will be concentrated are: post-combustion CO_2 capture (RTD on new and retrofit options and suitability for subsequent sequestration options), pre-combustion CO_2 capture (RTD on de-carbonisation and oxy-fuel techniques and on suitability of captured gases for subsequent sequestration options), geological storage of CO_2 (RTD aiming at safe, reliable and stable cost-effective storage options such as saline aquifers, enhanced coal bed methane and enhanced oil recovery, identification of sequestration potential, long term geological stability and geochemical interactions, public acceptance and costs), and chemical/mineral sequestration of CO_2 (comparison of the available options, as well as other innovative solutions and uses of the products). Already, in December 2002, the European Commission invited proposals for projects on pre-combustion and post-combustion capture technologies, geological and chemical/mineral storage, CO_2 transport and CO/H_2 and/or CO_2/H_2 separation in pre-combustion capture.

In addition to projects being funded by the European Commision, additional research is done at a European national level. The following bodies are examples of organizations that are active in carbon sequestration:

- NOVEM-Netherlands Agency for Energy and the Environment (The Netherlands)[93]: Research on enhanced coal bed methane recovery, carbon capture, geological storage, etc. Participants to EU-funded and other international projects.
- VITO-The Flemish Institute for Technological research (Belgium)[94]: Research on geological storage.
- Danish Geological Survey (Denmark): Active in assessing geological storage capacity.
- KLIMATEK-Norwegian National Climate Technology Programme (Norway)[95]: Reseach on capture and storage including absorption membranes, the Hydroraft project (see p. 68), CO_2 capture from gas power plants, geological storage in aquifers, etc. Participants to EU-funded and other international projects.

---

[92] Council decision of 30 September 2002 adopting a specific programme for research, technological development and demonstration :'Integrating and strengthening the European Research Area' (2002-2006) 2002/834/EC.

[93] For more information see: http://www.novem.nl/

[94] For more information see: http://www.vito.be/english/index.htm

[95] For more information see: http://www.cmr.no/klimatek/

- DTI Cleaner Coal Technology Transfer Programme (UK): DTI funds national projects on improved coalbed methane recovery and the Gas-Zero Emissions plant (ZEP) that involves CO_2 capture for gas power plants.

8.2 American programmes

The USA has been engaged in a very large and ambitious programme of carbon sequestration since the late 90's. The US Carbon Sequestration Program was established by the US Department of Energy in 1997 and is currently administered by the Office of Fossil Energy[96] and by the National Energy Technology Laboratory (NETL)[97]. The program encompasses all aspects of carbon sequestration (capture, terrestrial sequestration, geological and ocean storage, advanced biological and chemical processes) however the focal point is on capture of CO_2 emissions from large combustion sources and the subsequent geological storage. The goals of the Program are[98] [173]:

- *By 2006 develop instrumentation and measurement protocols for direct sequestration in geologic formations and for in-direct sequestration in forests and soils that enable the implementation of wide-scale carbon accounting and trading schemes*
- *By 2008, begin demonstration of large-scale carbon storage options (> 1 million tonne CO_2/year) for value-added (enhanced oil recovery, enhanced coalbed methane recovery, enhanced gas recovery) and non-value added (depleted oil/gas reservoirs and saline aquifers)*
- *By 2008, develop to the point of commercial deployment systems for advanced indirect sequestration of GHGs that protect human and ecosystem health and cost no more than $10 per metric ton of carbon sequestered, net of any value-added benefits.*
- *By 2010 develop instrumentation and protocols to accurately measure, monitor, and verify both carbon storage and the protection of human and ecosystem health for carbon sequestration in terrestrial ecosystems and geologic reservoirs. Measurement, monitoring and verification systems should represent no more that 10% of the total sequestration system cost.*
- *By 2012, develop to the point of commercial deployment systems for direct capture and sequestration of GHG emissions from fossil fuel conversion processes that protect human and ecosystem health and result in less than a 10% increase in the cost of energy services, net of any value-added benefits.*
- *By 2015, develop to the point of commercial deployment systems for direct capture and sequestration of GHG and criteria pollutant emissions from fossil fuel conversion processes that result in near-zero emissions and approach a no net cost increase for energy services, net of any value-added benefits.*
- *Enable sequestration deployments to contribute to the President's Global Climate Change Initiative goal of an 18% reduction in the GHG intensity of the United States economy by 2012.*

---

[96] For more information see: http://www.fe.doe.gov/

[97] For more information see: http://www.netl.doe.gov/

[98] Text copied from the referenced document.

- *Provide a portfolio of commercial ready sequestration systems and also one to three breakthrough technologies that have progressed to the pilot test stage for the 2012 assessment under the Global Climate Change Initiative.*

While before 1997, the program funding was about $1-2 million annually, in 2001, the programme budget exceeded $30 million, and in 2002 it was more than $40 million (Figure 53). The future program funding is estimated at roughly $50 million annually and is planned to last until 2020. Until now, about 60 external projects have been funded with $100 million (see Figure 53), in many cases with a strong industrial support (~40% cost share).

In addition, the US program seeks to engage local government agencies and NGOs along with the research community and private sector participants in ‘Regional Sequestration Partnerships’ in order to promote the development of a framework and infrastructure necessary for the validation and the deployment of carbon sequestration technologies. Furthermore, in 2003, the Program plans an ‘Integrated Sequestration and Hydrogen Research Initiative’ called FutureGen. The aim is to design, construct and operate a 275 MW plant that produces electricity and hydrogen, while at least 90% of the CO_2 emissions are captured and stored in geologic formations. The total funding requirements of the US carbon sequestration program in the short to medium term is shown in Figure 54.

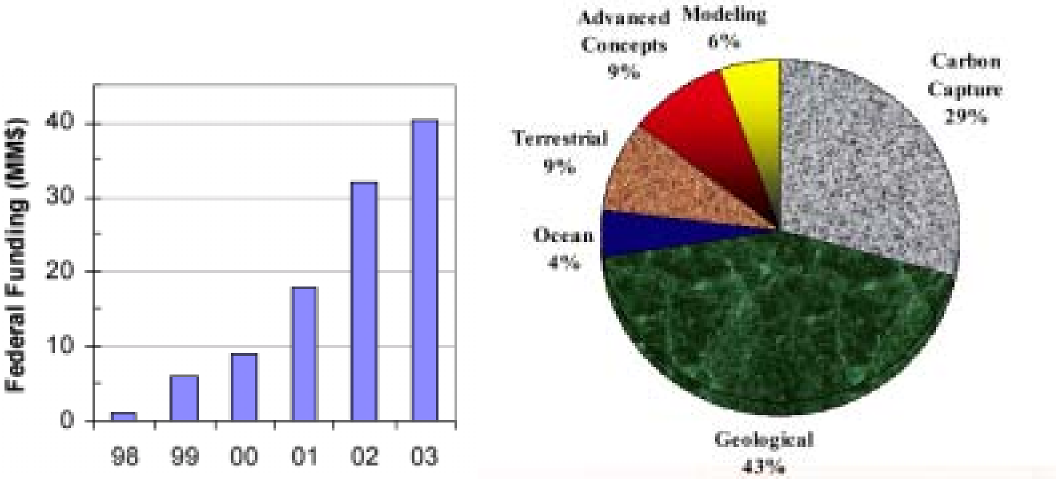


Figure 53: (Left) Annual budget of the US carbon sequestration program [173]; (right) partitioning of the funding to the various research activities [174]. Clearly, the emphasis is on capture and geological storage.

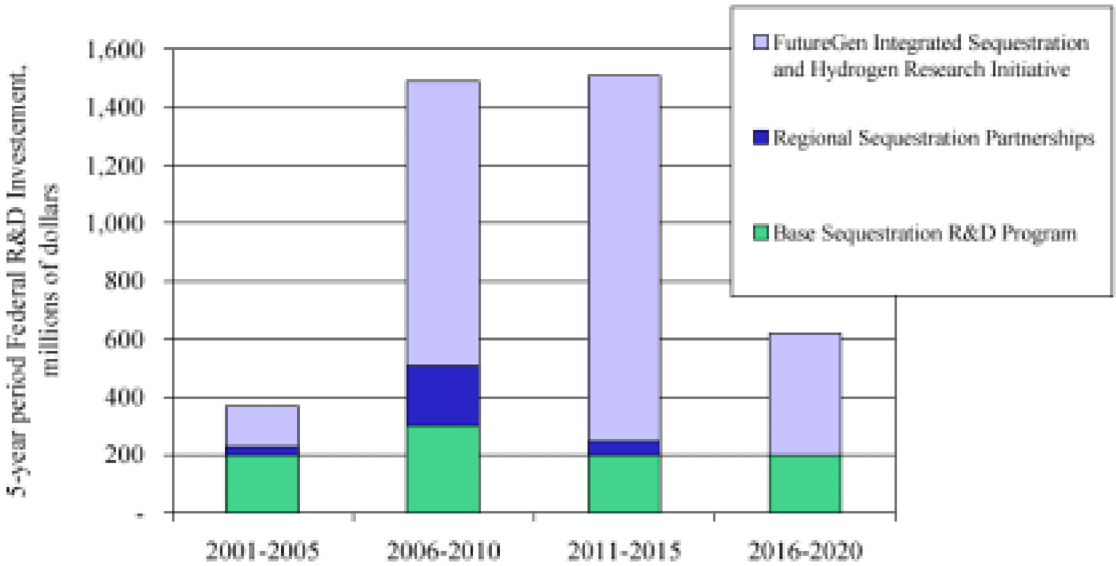


Figure 54: Proposed investments for the US carbon sequestration program in the short to medium term [173]

Besides DoE, other US organizations are active in the area of carbon sequestration. Examples are:

- MBARI-Monterey Bay Aquarium Research Institute[99]: Research in the area of ocean storage performing unique small-scale field experiments to observe the reaction of CO_2 with seawater at various depths.
- EPRI-Electric Power Research Institute[100]: A non-profit energy research consortium that among others, performs techno-economic assessments on carbon sequestration.
- MIT-Massachusetts Institute for Technology Carbon sequestration Initiative[101]: Extensive research on Carbon Sequestration, with the support of ChrvronTexaco, EdF, ExxonMobil, Ford Motor Company, General Motors, TotalFinaElf, EPRI, Americal Electric Power and Paebody Energy.
- Princeton University Carbon Mitigation initiative[102]: Research on carbon sequestration, with the support of BP and Ford Motor Company,

Canada is also active in research on carbon sequestration. Besides the Weyburn project that takes place in its territory, Canada hosts the International Centre for CO_2 Capture that has two main components: a pre-commercial scale chemical absorption technology demonstration pilot plant at the Boundary Dam power plant and a technology development pilot plant at the Univerity of Regina. Research is focused on geological storage in aquifers, depleted oil and gas reservoirs and deep coal seams, oxyfuel combustion, advanced turbine cycles, etc. In a position paper prepared by Natural

---

[99] For more information see: http://www.mbari.org/default.htm

[100] For more information see: http://www.epri.com/

[101] For more information see: http://sequestration.mit.edu/

[102] For more information see: http://www.princeton.edu/~cmi/

Resources Canada [175], it has been estimated that the financial needs for the further development, demonstration and deployment of CO_2 sequestration technologies for the short to medium term (until 2020) lie within the range of Can$700-1,100 million.

8.3 Japanese and Australian Programmes

Japan has the longest running research programme on carbon sequestration and the largest so far, covering all technological aspects: capture (including the funding of many demonstration plants [176]), geological storage [177], ocean storage [136], biological/chemical fixation, etc. However, a major focal point for storage research is ocean storage given the lack of significant potential for geological storage. It has been estimated that during the last decade the Japanese government has spent more than $50 million annually in direct expenses on R&D about carbon sequestration, i.e. not counting for researcher salaries [178]. Only the ocean sequestration research program that started in 1997 has an annual funding in excess of $10 million [179]. The central point for research activities is the Research Organisation of Innovative Technology for the Earth (RITE)[103].

Research on carbon sequestration in Australia is performed by the Commonwealth Scientific and Industrial Research Organisation (CSIRO)[104]. GEODISC is a successful Australian project on geological storage. It started in 1999 with a budget of $10 million for 4 years.

8.4 International Programmes

The **IEA Greenhouse Gas R&D Programme (IEA GHG)[105]** is an international collaboration programme on technologies for reducing GHG emissions. It aims to evaluate technologies for reducing emissions of greenhouse gases in the form of expert reports; disseminate the results of these studies; and, identify targets for research, development and demonstration and promote the appropriate work. The IEA Greenhouse Gas R&D Programme operates under an Implementing Agreement provided by the International Energy Agency (IEA). The IEA GHG Programme started in November 1991. Currently 16 countries and the European Commission support the Programme which has also attracted an increasing number of major industrial companies as sponsors. IEA GHG has participated to the SACS project and is currently participating to oxyfuel and enhanced coalbed methane recovery research activities as well as to the Weyburn project. The Programme issues a bi-monthly newsletter, produces publications and organizes conferences.

The **CO2 Capture Project (CCP)[106]** is an international effort by eight large energy companies (BP, Chevron Texaco, ENI, Norsk Hydro, EnCana, Shell, Statoil and SunCor Energy). The project is also co-funded by the European Commission, the US DoE and the Norwegian KLIMATEK programme. The primary objective of CCP is to develop new technologies to reduce the cost of CO_2 separation, capture, and geological

---

[103] For more information see: http://www.rite.or.jp/

[104] For more information see: http://www.csiro.au/

[105] A wealth of information can be found at the Programme's website: http://www.ieagreen.org.uk/

[106] More information can be found at: http://www.co2captureproject.org/

storage from combustion sources such as turbines, heaters, and boilers. The project involves research and development (engineering studies, computer modelling, laboratory experiments) to prove the feasibility of advanced CO_2 separation and capture technologies, specifically targeting post-combustion methods, pre-combustion decarbonisation, and oxyfuel and to develop guidelines for maximizing safe geological storage, for measuring and verifying stored volumes, and for assessing and mitigating storage risks.

9. Conclusions

- A number of technologies currently exist that can be used for carbon sequestration.
- Significant RD&D effort is needed to gain a fundamental understanding and overcome technological barriers to achieve the desired technological capacity. Main targets should be to:
  - Reduce energy penalty and cost of capture
  - Provide storage options that are:
    - Environmentally acceptable
    - Safe
    - Verifiable
    - Economically viable
    - Acceptable to the public

CAPTURE:

- Chemical absorption, a demonstrated technology, is the current state-of-the-art for post-combustion decarbonisation of PC and GTCC plants.
- Physical absorption combined with pressure swing adsorption is the current optimal decarbonisation technology for hydrogen production and IGCC (syngas approach).
- Membranes are likely to play a dominant role in CO_2 capture in the future.

TRANSPORT:

- No major technological obstacles.

STORAGE:

- With our current level of knowledge, aquifers appear to be the best option for CO_2 storage in Europe.
- Ocean storage is hampered by uncertainty over environmental impacts. Significant effort is required to enhance our understanding about the impact of CO_2 injection in the ocean to marine life.

ECONOMICS:

- Carbon sequestration costs are dominated by carbon capture costs.
- With the deployment of carbon sequestration technologies in thermal power plants the production cost of electricity may increase by 35-57%, depending on the electricity generation technological option.
- GTCC will remain the most competitive pathway to produce electricity, while IGCC will become equally competitive with PC.

- Although economics may improve with EOR and ECBM recovery, the European potential is limited.
- It appears that the deployment of carbon sequestration technologies has a relatively small impact to the economics of hydrogen production.
- Based on our calculations, coal cannot be competitive to natural gas for electricity generation and hydrogen production, even with the deployment of carbon sequestration. Coal gasification may offer an economic advantage over steam reforming only under specific local conditions.

References

1. Directive 2001/81/EC of the European Parliament and of the Council of 23 October 2001 on national emission ceilings for certain atmospheric pollutants, Official Journal L 309, 27/11/2001, pp. 0022 – 0030.
2. Council Directive 93/12/EEC of 23 March 1993 relating to the sulphur content of certain liquid fuels, Official Journal L 074, 27/03/1993, pp. 0081 – 0083.
3. Directive 2001/80/EC of the European Parliament and of the Council of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants, Official Journal L 309, 27/11/2001 pp. 0001 – 0021.
4. Directive 2000/76/EC of the European Parliament and of the Council of 4 December 2000 on the incineration of waste, Official Journal L 332, 28/12/2000 pp. 0091 – 0111.
5. Council Directive 96/61/EC of 24 September 1996 concerning integrated pollution prevention and control, Official Journal L 257, 10/10/1996 pp. 0026 – 0040.
6. United States Code, Title 42, Chapter 85, "Air Pollution Prevention Control".
7. IPCC, Climate Change 2001: The Scientific Basis - Contribution of Working Group I to the Third Assessment Report of the Intergovernmental Panel on Climate Change (IPCC) – Technical Summary –, J.T. Houghton, *et. al.* (Eds), Cambridge University Press, UK, 2001.
8. National Research Council, Climate Change Science, R.J. Cicerone *et. al.*, National Academy Press, USA, 2001.
9. EU Institution Press Releases, MEMO/02/46, The Kyoto Protocol and Climate Change, Brussels, 4 March, 2002.
10. EU Institution Press Releases, IP/02/794, European Union Ratifies the Kyoto Protocol, Brussels, 31 May, 2002.
11. Proceedings of the 1st National Conference on Carbon Sequestration, Washington D.C., USA, 2001.
12. Proceedings of the 6th International Conference on Greenhouse Gas Control Technologies, Kyoto, Japan, October 2002.
13. K.P. Saripalli *et. al.*, Risk and Hazard Assessment for Projects Involving the Geological Sequestration of CO_2, *ibid.* [12].
14. IEA Greenhouse Gas R&D Programme, Putting Carbon Back into the Ground, February 2001, Cheltenham, UK.
15. United Nations, Framework Convention on Climate Change, Summary compilation of annual greenhouse gas emissions inventory data from Annex I Parties, Note by the Secretariat, FCCC/CP/1998/INF.9, October 1998.
16. European Environmental Agency, Annual European Community Greenhouse Gas Inventory 1990-2000 and Inventory Report 2002, Technical report No 75, Copenhagen, 2002.

17. European Environmental Agency**,** Energy and Environment in the European Union, Environmental Issue Report No 31, Copenhagen, 2002.
18. European Commission, Directorate General for Energy, European Union Energy Outlook to 2020, Special Issue, Luxembourg, 1999.
19. ECOFYS Energy and Environment & AEA Technology Environment: Economic Evaluation of Sectoral Emission Reduction Objectives for Climate Change, Summary Report for Policy Makers/Updated, March 2001. http://www.europa.eu.int/comm/environment/enveco/climate_change/summary_report_policy_makers.pdf
20. International Energy Agency, World Energy Outlook 2000, Paris, 2000.
21. Eurelectric, Statistics and Prospects for the European electricity sector (1980-1999, 2000-2020), Eurprog 2001, Ref:2001-2745-0002, November 2001.
22. US Department of Energy, International Energy Outlook 2002, Washington DC, 2002.
23. IIASA, Global Energy Perspectives, Cambridge University Press, UK, 1998.
24. Directive 2001/77/EC of the European Parliament and of the Council of 27 September 2001 on the promotion of electricity from renewable energy sources in the internal energy market, Official Journal L 283, 27/10/2001, pp. 0033 - 0040
25. Communication from the Commission to the Council and the European Parliament: Completing the internal energy market, COM(2001)125 final, Brussels, March 2001.
26. Proposal for a Directive of the European Parliament and of the Council on the energy performance of buildings, COM(2001)226 final, Brussels, May 11, 2001.
27. Communication from the Commission to the Council, the European Parliament, the Economic and Social Committee and the Committee of the Regions: Action plan to improve energy efficiency in the European Community, COM(2000)247 final, Brussels, April 26, 2000.
28. Community guidelines on State aid for environmental protection, Official Journal C 37, 3/2/2001, pp. 0003 – 0015.
29. Green Paper: Towards a European strategy for the security of energy supply, COM(2000)769 final, Brussels, November 29, 2000.
30. Proposal for a Directive of the European Parliament and of the Council on the promotion of cogeneration based on a useful heat demand in the internal energy market, COM(2002)415 final, Brussels, July 22, 2002.
31. White Paper: European transport policy for 2010: time to decide, COM(2001)370 final, Brussels, September 12, 2001.
32. Communication from the Commission to the Council, the European Parliament, the Economic and Social Committee and the Committee of the Regions: On alternative fuels for road transport and on a set of measures to promote the use of biofuels, COM(2001)547 final, Brussels, November 7, 2001.
33. European Climate Change Programme, Long Report, June 2001. http://www.europa.eu.int/comm/environment/climat/eccpreport.htm

34. John Houghton, Global Warming: The Complete Briefing, Cambridge University Press, Cambridge, UK, 1997.

35. J. Seinfeld and S. Pandis, Atmospheric Chemistry and Physics, J. Wiley and Sons, N.Y., USA, 1997.

36. Global Atmosphere Division - Department of the Environment, Transport and the Regions, Paper to the British Government Panel on Sustainable Development Sequestration of Carbon Dioxide, July 1999. http://www.sd-commission.gov.uk/panel-sd/position/co2/index.htm

37. IPCC, Climate Change 2001, Mitigation, Contribution of Working Group III to the Third Assessment Report of the IPCC, B. Metz *et .al.* (Eds.) Cambridge University Press, UK, 2001.

38. Second ECCP Progress Report, April 2003. http://www.europa.eu.int/comm/environment/climat/second_eccp_report.pdf

39. IEA Greenhouse Gas R&D Programme, Carbon Dioxide Utilisation, Technical Report, 1995. http://www.ieagreen.org.uk/sr4p.htm

40. H. Herzog *et. al.,* Capturing Greenhouse Gases, Scientific American, February 2000, p.54.

41. IEA Greenhouse Gas R&D Programme, Ocean Storage of CO_2, Technical Report, 2002. http://www.ieagreen.org.uk/ocean.htm

42. Utah State University Website: http://usu.edu/planetearth/

43. S.W. Chrisholm, Oceanography: Stirring times in the Southern Ocean, Nature, **407**, 2000, p. 685.

44. M. Simmonds *et. al.*, A Study of a Very Large Scale Post Combustion CO2Capture at a Refining & Petrochemical Complex, *ibid.* [12].

45. M. Wislon *et. al.*, Test Results from a CO_2 Extraction Pilot Plant at Boundary Dam Coal-Fired Power Station, *ibid.* [12].

46. A. Veawab *et. al.*, Performance and Cost Analysis for CO_2 Capture from Flue Gas Steams: Absorption and Regeneration Aspects, *ibid.* [12].

47. R.R. Judkins and T.D. Burchell, CO_2 Removal From Gas Streams Using a Carbon Fiber Composite Molecular Sieve, *ibid.* [11].

48. British Zeolite Association Website: http://www.bza.org/

49. Ch. Baerlocher *et. al., A*tlas of Zeolite Framework Types, 5th ed., Elsevier: Amsterdam, 2001.

50. IEA Greenhouse Gas R&D Programme, International Test Network for CO_2 Capture: Report on a Workshop, Report No. PH3/33, December 2000.

51. S. Chi and G.T. Rochelle, Oxidative Degradation of Monoethanolamine, *ibid.* [11].

52. B.R. Strazisar *et. al.,* Degradation of Monoethanolamine Used in CO2 Capture from Flue Gas of a Coal-Fired, Electric Power Generation Station, *ibid.* [11].

53. Y. Soong *et. al.*, Novel Amine Enriched Solid Sorbents for Carbon Dioxide Capture, *ibid.* [11].

54. H. Dang *et. al.* , CO_2 Absorption Rate and Solubility in Monoethanolamine / Pipoerazine / Water, *ibid.* [11].

55. H. Herzog, An Introduction to CO_2 Separation and Capture Technologies, MIT Energy Laboratory, MA, USA, August 1999. http://sequestration.mit.edu/pdf/introduction_to_capture.pdf

56. D.G. Chapel *et. al.*, Recovery of CO_2 from Flue Gases: Commercial Trends, the Canadian Society of Chemical Engineers Annual Meeting, October 4-6 1999, Saskatoon, Saskatchewan, Canada.

57. IEA Greenhouse Gas R&D Programme, Carbon Dioxide Capture from Power Stations, Technical Report. http://www.ieagreen.org.uk/sr2p.htm

58. Benfield™ Process, Information Pamphlet UOP 3205-3 899GP1C, UOP LLC, 2000.

59. IEA Greenhouse Gas R&D Programme, Multiple Products with CO_2 Capture: Power and Thermal Energy, Report PH3/6, June 1999.

60. H. Audus, Leading Options for the Capture of CO_2 at Power Stations, paper presented at the 5th International Conference on Greenhouse Gas Control Technologies, Australia, 13-16 August 2000.

61. E. Lindeberg, Future Large-Scale Use of Fossil Energy Will Require CO_2 Sequestering and Disposal, Minisymposium on Carbon Dioxide Capture and Storage, Goteborg, Sweden, October 1999.

62. H. Herzog, Economics, Workshop on Carbon Sequestration Science, May 2001, USA. http://www.netl.doe.gov/publications/proceedings/01/carbon_seq_wksp/herzog_eco.pdf

63. H.-J. Ziock and D.P. Harrison, Zero Emission Coal Power, a New Concept, *ibid.* [11].

64. J.C. Abanades *et. al.*, Novel Combustion Cycles Incorporating Capture of CO_2 with CaO, *ibid.* [12].

65. S. Chakravarti *et. al.,* Advanced Technology for the Capture of Carbon Dioxide from Flue Gases, *ibid.* [11].

66. P.H.M. Feron, Advanced Separation Processes for CO_2 Capture from Power Stations, Proceedings of the International Conference on Future Energy Systems and Technology for CO_2 Abatement, November 18-19, 2002, Antwerpen, Belgium, pp. 107.

67. G.S. Foff and G.T. Rochelle, Oxidative Degradation of Aqueous Monoethanolamine in CO_2 Capture Systems under Absorber Conditions, *ibid.* [12].

68. C.R. Sharp *et. al.*, Recent Selexol™ Operating Experience with Gasification including CO2 Capture, Presentation at the 5th European Gasification Conference, 8-10 April 2002, Noordwijk, the Netherlands.

69. C. Descamps *et. al.*, CO_2 Removal from an IGCC Power Plant: Comparison of the Capture Options, *ibid.* [66].

70. University of Siegen website:
www.mb.uni-siegen.de/d/ifft3/ GASADSORPTION.HTM

71. I*bid.* [36], Annex B, Sequestration of carbon dioxide by ocean fertilisation.

72. The Global Impact of Ocean Nurishment, *ibid.* [12].

73. J. Gale and J. Davison, Transmission of CO_2 – Safety and Economic Considerations, *ibid*. [12].

74. Reuters News Service, Shipping CO_2 Could Help Norway Hit Kyoto Targets, April 24, 2002.

75. New Energy Industrial Technology website:
http://www.nedo.go.jp/itd/fellow/english/project-e/21-3e.html

76. The Federation of Electric Power Companies of Japan website:
http://fepc.or/jp/english/energy-env/036.html

77. W.J. Koros and R. Mahajan, Pushing the Limits on Possibilities for Large Scale Gas Separation: Which Strategies? J. Membrane Sci., 175, 2000, 181.

78. T.G. Kreutz *et. al.,* Production of Hydrogen and Electricity from Coal with CO_2 Capture, *ibid*. [12].

79. U.S. Department of Energy, Carbon Sequestration Research and Development, December 1999.

80. K. Jordal *et. al*., Integration of H_2-Separating Membrane Technology in gas Turbine Processes for CO_2 Sequestration, *ibid*. [12].

81. Z. Xu *et. al.*, Separation and Fixation of Carbon Dioxide Using Polymeric Membrane Contractor, *ibid.* [11].

82. H.F. Svendsen *et. al.*, Absorption as a Method for CO_2 Capture, 2nd Nordic Minisymposium on Carbon Dioxide Capture and Storage, Goteborg, Oct. 26, 2001, Sweden.

83. TNO Environment, Energy and Process Innovation, CO_2-Recovery Using Membrane Gas Absorption, Information Pamphlet 2001/03/05/104e.

84. H. Herzog and O.F-Pedersen, The Kvaerner Membrane Contractor: Lessons Learned from a Case Study in How to Reduce Capture Costs, 5th International Conference on Greenhouse Gas Control Technologies, Cairns, Australia, August 13 - August 16 (2000).

85. UOP LLC, Polysep™ Membrane Systems for Gas Extraction and Purification, Information Pamphlet UOP 3150-7 899PPS5C.

86. M.B. Wilkinson *et. al.*, CO_2 Capture via Oxyfuel Firing: Optimisation of a Retrofit Design Concept for a Refinery Power Station Boiler, *ibid.* [11].

87. D.J. Singh *et. al.*, CO_2 Capture Options for an Existing Coal Fired Power Plant: O_2/CO_2 Recycle Combustion vs. Amine Scrubbing, *ibid.* [11].

88. N. Nsakala *et. al.*, Engineering Feasibility of CO_2 Capture on an Existing US Coal-Fired Poer Plant, *ibid.* [11].

89. H. Birkestad, Separation and Compression of CO_2 in an O_2/CO_2-firted Power Plant, Chalmers University of technology, Thesis for a Degree of Master of Science, Sweden, 2002.

90. T. Mattison and A. Lyngfelt, Capture of CO_2 using Chemical-Looping Combustion, 1st Biennial Meeting of the Scandinavian-Nordic Section of the Combustion institute, April 18-20, 2001, Goteborg, Sweden.

91. H.J. Ryu *et. al.*, Carbon deposition Characteristics of NiO Based Carrier particles for Chemical-Looping Combustor, *ibid.* [12].

92. NTNU Website: http://www.tev.ntnu.no/sommerjobber/chemical_looping_combustion_2002.htm

93. S.G. Sundkvist *et. al.*, AZEP-Development of an Integrated Air Separation Membrane – Gas Turbine, Minisymposium on Carbon Dioxide Capture and Storage, Goteborg, Sweden, October 1999.

94. T. Griffin *et. al.*, CO_2 Control technologies: ALSTOM Power Approach, *ibid.* [12].

95. IEA Greenhouse Gas R&D Programme, 10th Anniversary Report, 10991-2001, 2001.

96. IEA Greenhouse Gas R&D Programme, Enhanced Coal Bed Methane Recovery with CO_2 Sequestration, Report PH3/3, August 1998.

97. C.N. Hamelinck *et. al.*, Potential for CO_2 Sequestration and Enhanced Coalbed Methane Production in the Netherlands, NOVEM, Utrecht, 2001.

98. P. Freund and J. Davison, General Overview of Costs, Proceedings of Workshop on Carbon Dioxide Capture and Storage, Regina, Canada, 18-21 November 2002, pp. 79.

99. IEA, Solutions for the 21st century, Zero Emissions Technologies for Fossil Fuels, Technology Status Report, Committee on Energy Research and Technology, Working Party on Fossil Fuels, May 2002.

100. H. Herzog *et. al.,* CO_2 Capture, Reuse and Storage Technologies for Mitigating Global Climate Change, White Paper-Final report, MIT, MA, USA, 1997.

101. L.W. Lake *et. al.,* A Niche for Enhanced Oil Recovery in the 1990s, Oilfield Review, **4**(1), 1992, p. 55.

102. EPRI, Enhanced Oil Recovery Scoping Study, TR-113836, Palo Alto, CA, USA, 1999.

103. US Department of Energy, Carbon Sequestration R&D program Plan: FY 1999-FY2000.

104. V. Kuustra, Geologic Sequestration of Carbon in Oil and Natural Gas Resources, presentation at the workshop on Carbon Sequestration Science, 2001.

105. D.A Beecy *et. al.,* A Perspective on the Potential Role of Geologic Options in a National Carbon Management Strategy, *ibid.* [11].

106. K. Brown *et. al.*, Role of Enhanced Oil Recovery in Carbon Sequestration, The Weyburn Monitoring Project, a Case Study, *ibid.* [11].

107. S. Emberley *et. al.*, Geochemical Monitoring of Fluid-Rock Interaction and CO_2 Storage at the Weyburn CO_2-Injection Enhanced Oil Recovery Site, Saskatchewan, Canada, *ibid.* [12].

108. National resources Canada, IEA Implementing Agreement on Enhanced Oil Recovery, presentation at 2nd Planning Workshop of the Task Force "Zero Emissions Technologies Strategy", IEA working party on fossil fuels, Washington DC, USA, March 2002.

109. Elsam A/S, New technology increases oil production and improves environment, Press Release, February 6, 2002, Fredericia, Denmark.

110. P. Markussen *et. al.,* A CO_2-Infrastructure for EOR in the North Sea (CENS): Macroeconomic Implications for Host Countries, *ibid.* [12].

111. Hydro Norsk, Press release, 23 April 1998, http://www2.hydro.com/konsern/news/eng/1998/980423e.html

112. A.A. Espie *et. al.*, Obstacles to the Storage of CO_2 through EOR operations in the North Sea, *ibid.* [12].

113. IEA Greenhouse Gas R&D Programme, Barriers to Overcome in Implementation of CO_2 Capture and Storage (1) Storage in Disused Oil and Gas Fields, Report PH3/22, February 2000.

114. Kinder Morgan CO_2 Company, Geological Sequestration and EOR, presentation at IOGCC, 18 July 2002.

115. S. Reeves, Coal-Seq Project Update: Field Studies of ECBM Recovery/CO_2 Sequestration in Coal Seams, *ibid.* [12].

116. L.G.H. v.d. Meer, CO_2 Storage in the Subsurface, *ibid.* [12].

117. J. Gale, Geological Storage of CO_2: What's Known, Where are the Gaps and What More Needs to Be Done, *ibid.* [12].

118. F.v. Bergen *et. al.,* Development of a Field Experiment of CO_2 Storage in Coal Seams in the Upper Silesian Basin of Poland (REPOCOL), *ibid.* [12].

119. F.v. Bergen *et. al.,* Worldwide Selection of Early Opportunities for CO_2-EOR and CO_2-ECBM (1), *ibid.* [12].

120. K. Damen *et. al.,* Worldwide Selection of Early Opportunities for CO_2-EOR and CO_2-ECBM (2), *ibid.* [12].

121. V.A. Kuuskraa *et. al.,* Defining Optimum CO_2 Sequestration Sites for Power and Industrial Plants, *ibid.* [12].

122. W.D. Gunter, Role of Hydrodynamic and Geochemical Trapping in Secure Geological Storage of Carbon Dioxide, Workshop on Carbon Sequestration Science, 2001.

123. D. Bossie-Cordreanu *et. al.*, CO_2 Sequestration in Depleted Oil Reservoirs, *ibid.* [12].

124. I. Czernichowski-Lauriol *et. al.*, The French Carbogaseous Province: An Illustration of Natural Gas Processes of CO_2 Generation, Migration, Accumulation and Leakage, *ibid.* [12].

125. M.A. Celi *et. al.,* Geological Sequestration of CO_2: Is Leakage Unavoidable and Acceptable?, *ibid.* [12].

126. J.A. Jimenez *et. al.,* Are Disused Hydrocarbon Reservoirs Safe for Geological Storage of CO_2? , *ibid.* [12].

127. S.W. Pacala, Global Constraints on Reservoir Leakage , *ibid.* [12].

128. R.D. Hepple *et. al.,* Implications of Surface Seepage on the Effectiveness of Geologic Storage of Carbon Dioxide as a Climate Change Mitigation Strategy, *ibid.* [12].

129. J.J. Dooley *et. al.,* Why Injecting CO_2 into Various Geologic Formations is not the Same as Climate Change Mitigation: The Issue of Leakage, *ibid.* [12].

130. B. Arts *et. al.,* Monitoring of CO_2 Injected at Sleipner Using Time Lapse Seismic Data, *ibid.* [12].

131. L.R. Myer *et. al.,* Sensitivity and Cost of Monitoring Geologic Sequestration Using Geophysics , *ibid.* [12].

132. R.L. Newmark *et. al.,* Monitoring Carbon Dioxide Sequestration Using Electrical Resistance Tomography (ERT): A Minimally Invasive Method , *ibid.* [12].

133. T. Maldal *et. al.,* CO_2 Underground Storage for Snøhvit Gas Field Development, *ibid.* [12].

134. S.D. Hovorka *et. al.,* Frio Brine Sequestration Pilot in the Texas Gulf Coast , *ibid.* [12].

135. IEA Greenhouse Gas Programme Website: www.ieagreen.org.uk

136. S. Murai *et. al.,* The Second Phase of Japanese R&D Program for CO_2 Ocean Sequestration , *ibid.* [12].

137. K. Caldeira *et. al.*, Predicting and Evaluating the Effectiveness of Ocean Carbon Sequestration by Direct Injection, *ibid.* [11].

138. K. Caldeira *et. al.*, Depth, Radiocarbon and the effectiveness of Direct CO_2 Injection as an Ocean Carbon Sequestration Strategy, Geophysical Research Letters, **29** (16), August 2002.

139. M. Larsen *et. al.*, Saline Aquifer Storage of CO_2 from Major Point Sources – A Danish Case Study, *ibid.* [12].

140. T. Koljonen *et. al.*, CO_2 Capture, Storage and Reuse Potential in Finland, *ibid.* [12].

141. H.S. Kheshgi, Evasion of CO_2 Injected into the Ocean in the Context of CO_2 Stabilisation , *ibid.* [12].

142. B.A. Seibel *et. al.*, Potential Impacts of CO_2 Injection on Deep-Sea Biota, Science, **294**, October 2001, p. 319.

143. P.M. Haugan, On the Production and Use of Scientific Knowledge about Direct Ocean Storage, *ibid.* [12].

144. IEA Greenhouse Green Programme, Carbon Dioxide Disposal From Power Stations, Technical Report. http://www.ieagreen.org.uk/sr3p.htm

145. C.F. Tsang *et. al.*, Scientific Considerations Related to Regulation Development for CO_2 Sequestration in Brine Formations, Environmental Geology, **42**, 2002, 275.

146. D.M. Reiner *et.al.,* A Search for Regulatory Analogs to Carbon Sequestration, *ibid.* [12].

147. J. Heinrich, Legal Implications of CO_2 Ocean Storage, Working Paper, M.I.T., MA, USA, July 2002.

148. United Nations Environmental Programme (UNEP), Report of the 27th Session, Nairobi, 14-18 April 1997, 1997, Rep.Stud.GESAMP, (63), 45 p.

149. M.A. de Figueiredo *et. al.*, Ocean Carbon Sequestration: A Case Study in Public and Institutional Perceptions, *ibid.* [12].

150. Reuters News Service, Norway scraps experiment to dump CO_2 at sea, August 23, 2002.

151. D. Hawkins, Stick it Where??—Public Attitudes toward Carbon Storage, *ibid.* [11].

152. D.G. Hawkins, Passing Gas: Implications of Leakage from Geologic Carbon Storage Sites, *ibid.* [12].

153. J. David, Economic Evaluation of Leading Technology Options for Sequestration of Carbon Dioxide, Master of Science in Technology and Policy, MIT, May 2000.

154. C.A. Hendriks, Carbon Dioxide Removal from Coal-Fired Power Plants, Dordrecht, the Netherlands, Kluwer Academic Publishers, 1994.

155. P. Cordonelli *et. al.*, Engineering and Economic Evaluation of CO_2 Removal from Fossil Fuel Fired Power Plants, Vol. 2, EPRI, Report IE-7365, 1991.

156. D. Simbeck, A Portfolio Selection Approach for Power Plant CO_2 Capture, Separation and R&D Options, 4th International Conference on Greenhouse Gas Control Technologies, Interlaken, Switzerland, 1998.

157. IEA Greenhouse Gas R&D Programme, Leading Options for the Capture of CO2 Emissions at Power Stations, Report Number PH3/14, February 2000.

158. B.R. Bock *et. al.*, CO_2 Storage and Sink Enhancements: Developing Comparable Economics, *ibid.* [12].

159. R.D. Doctor *et. al.*, Oxygen-Blown Gasification Combined Cycle: Carbon Dioxide Recovery, Transport, and Disposal, Energy Convers. Mgmt., **38**, Suppl., p. S575, 1997.

160. P. Chiesa *et. al.*, A Comparative Analysis of IGCCs with CO_2 Sequestration, 4th International Conference on Greenhouse Gas Control Technologies, Interlaken, Switzerland, 1998.

161. T.L. Johnson and D.W. Keith, Electricity from Fossil Fuels without CO_2 Emissions: Assessing the Cost of Carbon Dioxide Capture and Sequestration in US Electricity Markets, *ibid.* [11].

162. B. Geeraert, Comparison of CO_2 Emissions from Various Power Generation Technologies, Proceedings of the International Conference on Future Energy Systems and Technology for CO_2 Abatement, November 18-19, 2002, Antwerpen, Belgium, pp. 49.

163. E.S. Rubin and A.B. Rao, Uncertainties in CO_2 Capture and Sequestration Costs, *ibid.* [12].

164. K. Riahi *et. al.*, Prospects for Carbon Capture and Sequestration technologies Assuming their Technological Learning, *ibid.* [12].

165. E.S. Rubin, Learning our Way to Zero Emissions Technologies, Presentation at IEA Zero Emissions Technologies Strategies Workshop, Washington DC, March 19, 2002, USA.

166. US Department of Energy, Office of Fossil energy, FETC, Integrated Gasification Combined Cycle: Clean, Affordable Energy for Tomorrow's World. http://www.netl.doe.gov/publications/brochures/pdfs/igccbro.pdf

167. IEA Greenhouse Gas R&D Programme, Orimulsion: CO_2 Capture in Power Generation; Power Production; and Methanol Production, Report PH2/11, May 1997.

168. C.E.G. Padro and V. Putsche, Survey of the Economics of Hydrogen Technologies, National Renewable Energy Laboratory (NREL), Report No. NREL/TP-570-27079, September 1999.

169. K. Blok *et. al.*, Hydrogen Production from Natural Gas, sequestration of Recovered CO_2 in Depleted Gas Wells and Enhanced Natural Gas Recovery, Energy, 22, 2/3, 1997, p. 161.

170. T.A. Torp and J. Gale, Demonstrating Storage of CO_2 in Geological Reservoirs: The Sleipner and SACS Projects, *ibid.* [12].

171. F. van Bergen *et. al.,* Development of a Field Experiment of CO_2 Storage in Coal Seams in the Upper Silesian Basin of Poland (RECOPOL), *ibid.* [12].

172. K. Brown *et. al.,* Role of Enhanced Oil Recovery in Carbon Sequestration: The Weyburn Monitoring Project, a case study, *ibid.* [11].

173. US Department of Energy, Carbon Sequestration Technology Roadmap and Program Plan, US DoE Office of Fossil energy and National Energy Technology Laboratory, March 12, 2003.

174. S.M. Forbes, US DoE Sequestration Program, Presentation to the IBC's Carbon Sequestration Conference, October 24-25, 2002, Houston, TX, USA.

175. Natural Resources Canada, The Capture and Storage of Carbon Dioxide Emissions: A Significant Opportunity to help Canada meet its Kyoto Targets, Ontario, Canada, 2001.

176. T. Yokoyama, Japanese R&D on CO_2 Capture, *ibid.* [12].

177. H. Koide *et. al.*, Japanese R&D Project for CO_2 Geological Sequestration, *ibid.* [12].

178. H.J. Herzog, What Future for Carbon Capture and Sequestration? Environmental Science and Technology, 55, 7, p.1 48, 2001

179. H.J. Herzog *et al.*, Carbon Sequestration via Direct Injection, in *Encyclopedia of Ocean Sciences*, eds. J.H. Steele, S.A. Thorpe, and K.K. Turekian, **Vol. 1**, pp. 408 - 414, Academic Press, London, UK, September (2001).

European Commission

EUR 20752EN – Controlling Carbon Emissions: The Option of Carbon Sequestration

Evangelos Tzimas and Stathis Peteves

Luxembourg: Office for Official Publications of the European Communities

2003 – 150 pp. – 21 x 29.7 cm

Scientific and Technical Research series

ISBN 92-894-5751-1

Abstract

Carbon sequestration is a distinct technological option to control carbon emissions, complementing other measures such as improvements in energy efficiency and utilization of renewable energy sources. Carbon sequestration is most applicable to large combustion plants and specifically to thermal power stations, where it could contribute stopping the release of about 90% of generated CO_2 in the atmosphere. Furthermore, carbon sequestration technologies may play a catalytic role in the deployment of a hydrogen economy complementing the production of hydrogen from fossil fuels in a sustainable manner.

This publication reviews the state-of-the-art on carbon dioxide capture, transportation, utilisation and storage technologies and the economical implications of their deployment to power plants for electricity generation and hydrogen production in the EU. The report focuses on capture technologies and costs and highlights the present-day understanding of storage options (environmental impact, storage capacity, legal implications and public perception).

15

LD-NA-20752-EN-C

The mission of the Joint Research Centre is to provide customer-driven scientific and technical support for the conception, development, implementation and monitoring of European Union policies. As a service of the European Commission, the JRC functions as a reference centre of science and technology for the Community. Close to the policy-making process, it serves the common interest of the Member States, while being independent of commercial or national interests.

EUROPEAN COMMISSION
JOINT RESEARCH CENTRE

ISBN 92-894-5751-1

9 789289 457514

Publications Office
Publications.eu.int