



Global Energy Perspectives

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Global Energy Solutions e.V.

**Part 1: Basic elements for avoiding greenhouse gases and
generating climate-neutral energy
(technical toolbox)**

Chapter 2-8

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2.8 Technical capture and storage of CO₂ (CCS)

Glossary for 2.8

ATR	Autothermal Reforming
eFuels:	Fuels produced with the help of electrical energy, such as CH ₄ (methane), CH ₃ OH (methanol) or petrol and diesel.
CCE	Carbon Capture Efficiency
CCS ³⁷⁸	Carbon Capture and Storage: Processes in which the CO ₂ is captured at the point of origin, transported to a geological storage facility and permanently stored there (e.g. mineralisation in basaltic rocks).
CCU ³⁷⁸	Carbon Capture and Usage: Processes in which the CO ₂ is captured at the point of origin and transported to plants where it is used as a feedstock or raw material. A further distinction must be made between CCU products in which the captured CO ₂ is permanently bound (e.g. mineralisation) and those in which the bound CO ₂ is released again (e.g. in synthetic fuels).
CCGT	Combined Cycle Gas Turbine
CFB	Circulating Fluidized Bed
CO ₂	Carbon Dioxide
CO _{2e}	Used for a common statement of quantities of carbon dioxide and its equivalent climate-damaging substances such as e.g. CH ₄ , N ₂ O, hydrofluorocarbons, sulphur hexafluoride, taking into account their specific GWP Global Warming Potentials
DAC	Direct Air Capture
EOR	Enhanced Oil Recovery: Injection into active oil fields to increase production pressure and recovery from the field.
EGR	Enhanced Gas Recovery: as with EOR only in gas reservoirs
GHG	Greenhouse Gas, climate-damaging gases such as CH ₄ and CO ₂
IGCC	Integrated Gasification Combined Cycle
ILCD	International Life Cycle Data System, ISO 14040, 14044 <i>Environmental management - Life cycle assessment - Requirements and guidelines</i>

³⁷⁸ Definition according to Bellona (2022b)

LCA	Life Cycle Analysis: Compilation and assessment of the inputs, outputs and potential environmental impacts of a product system throughout its life cycle.
LCI	Life Cycle Inventory: Phase of life cycle assessment that involves the compilation and quantification of inputs and outputs for a product throughout its life cycle.
LCIA	Life Cycle Impact Assessment: phase of life cycle assessment that aims to understand and evaluate the extent and significance of the potential environmental impacts of a product system throughout the life cycle of the product.
LCIPP	Local Communities and Indigenous People Platform, part of UNFCCC
LNG	Liquid Natural Gas, liquefied natural gas (methane)
LOHC	Liquid Organic Hydrogen Carrier: organic substances that bind and transport H ₂ and can release it again at its destination when dehydrated.
Purisol:	Process for the removal of acidic components (CO ₂ , H ₂ S, COS) from gases with the aid of methylpyrrolidone.
PtL	Power to Liquid: Generation of liquid fuels by means of electrical energy
Rectisol:	Washing medium methanol for the removal of CO ₂ , H ₂ S, COS, NH ₃ at 30 – 60 bar and –40°C
SCPC	Supercritical Pulverized Coal
Selexol:	Process for the removal of CO ₂ and H ₂ S (20 – 200 bar), physical process without chemical reactions. Reactions
TRL:	Technology Readiness Level: e.g. with values 1: Basic Technology Research, 6: Technology Demonstration, 9: System Test, Launch & Operations
UNFCCC	United Nations Framework Convention on Climate Change

2.8.1 Introduction

This document deals with processes to reduce CO₂ production and CO₂ emissions, which can be classified into four process groups:

- *Direct Air Capture (DAC)*: the capture of CO₂ directly from the air, i.e. at low concentrations of approx. 400 ppm.

- *Oxy-fuel*: Use of oxygen instead of air during combustion to achieve higher CO₂ concentrations in the exhaust gas (80 % – 98 %), i.e. easier capture of CO₂
- *Pre-combustion*: Reduction of the carbon content in the fuel, e.g. by gasification of the fuel, water gas shift reaction, CO₂ sequestration and then combustion of the H₂-enriched gas.
- *Post-combustion*: capture of CO₂ from the exhaust gas in different concentration ranges and different industrial processes.

It can be seen that the costs of capture processes depend on the industry in which they are used, i.e. on the depth of integration into the process technology at the point of use, and that the costs are below 100 €/t CO₂ (OPEX and CAPEX) at high CO₂ concentrations in the flue gas. In general, it can be said that the transfer of CO₂ to an absorber or into a solution is faster when the partial pressure is higher. If the total pressure in the gas is higher, this means higher gas density and smaller equipment, i.e. reduced investment costs.

According to the IEA classification, only very few components in the overall process from capture to injection are in a mature state.³⁷⁹ According to this classification, the majority of the components are in the state of 'early adoption' or 'demonstration'. This is to be interpreted as meaning that the capture processes function technically and are partly already operational on a large scale, but their application and realisation is not yet far advanced on a broad scale due to the high costs, especially for DAC (currently still > 600 €/t CO₂).

As a special case of CO₂ capture from gases, DAC is also considered in this document. Even though the processes for this are identical to the processes in the post-combustion group and also have a high degree of technical maturity, they cannot be considered ready for the market because the costs per quantity of CO₂ captured are about a factor of 10 higher than for the post-combustion processes. Some authors express the hope that CAPEX and OPEX can be reduced in a targeted manner, but this will be difficult to achieve due to the lack of scaling options.

When capturing CO₂ from the flue gases of power generation plants, it becomes apparent that CCS is associated with a loss of efficiency of the plants of 10 – 20 %, depending on the technology used and at a capture efficiency of 90 %. The electricity generation costs are also increased by 10 – 20 % as a result of this and the increased investment costs.

In order to obtain more precise information on the benefits, costs and environmental impact of a planned CO₂ capture plant, it is essential to carry out plant simulations and life cycle assessments. Also with regard to the EU Commission's planned system of sustainable carbon cycles

³⁷⁹ Cf. IEA, 2020; Massey, (2021).

and the associated guarantee of origin system, which is to be implemented by 2028, it is important that companies comprehensively prepare their CO₂ balance sheet.

In order to sustainably remove the captured CO₂ from the atmosphere, it should either be used for the production of products (CCU) or deposited underground or under the sea (CCS). A look at the worldwide projects with CCS shows that most of the projects are in the oil and gas industry (EOR and EGR) and increasingly also in the cement industry to capture CO₂ and subsequently store it.

This document deals with CCS and the logistical transport options necessary between capture of CO₂, conditioning of the gas and safe underground or submarine storage. Based on the estimated storage capacities of 8,000 to 55,000 Gt and a current CO₂ production of 36 Gt/a, there would be sufficient storage capacity for CO₂ for 222 to 1,527 years in purely mathematical terms. Other researchers put the storage capacity for safe injection with mineralisation of the rock higher (up to 250,000 Gt) than is needed for the combustion of all fossil sources.

After studying various international publications, we can see that CCS is internationally considered a safe method to store the captured CO₂ in an environmentally sound and permanent way. In particular, injecting CO₂ dissolved in water into basalt is considered safe because the CO₂ reacts to form carbonates within a few years.

Industry clusters are now forming in various countries with the aim of capturing and transporting CO₂ and storing it underground or under the sea. The reluctance and indecisiveness of the German government so far to promote the market in Germany for CCS by releasing storage sites and a clear regulation regarding CO₂ levies means that German industrial companies are not shown any perspective on how to avoid the threatening and in some cases existence-threatening CO₂ levies. We would also like to point out that in the declaration of the G20 heads of state and government in Rome, CCS is seen as a means of reducing CO₂ emissions from power plants.

At least in constitutional states, CO₂ storage requires acceptance by the population living in the vicinity of storage sites, which would certainly be easier to achieve by developing reliable safety standards and currently still lacking monitoring possibilities for the storage sites.

2.8.1.1 Relevance to the overall context

Controlling and managing global CO₂ emissions are crucial to our project's goal of ensuring a prosperous supply of the world's population with energy, heat, fuels and products such as steel and cement that are necessary for their development. Since, on the one hand, it will not be possible for reasons of cost and time to redesign all industrial processes in such a way that

they become CO₂-free in the short term, and for some CO₂ sources CO₂-avoidance will not be possible even in the long term, it is essential to have processes and techniques for removing CO₂ from waste gas streams and also directly from the air available and to know their areas of application and the costs to be expected. As the EU Commission is pushing to introduce a carbon cycle implementation and monitoring system, CO₂ capture will play a central role in the European climate strategy.

According to recent publications, industry clusters are already forming in which companies from different sectors, ranging from the production of green energy sources, the production of goods with simultaneous capture of climate-damaging CO₂ to service providers who collect CO₂ and carry out the injection into underground or submarine storage facilities, are merging into one organisation. This suggests that CCS will initiate new business models and that the necessary construction of CCS plants will create a large number of new jobs for several decades to come, thereby having a wealth-sustaining effect.

In addition, the chemical compound carbon dioxide is of great importance in industry and in our daily lives, as the figure below shows.

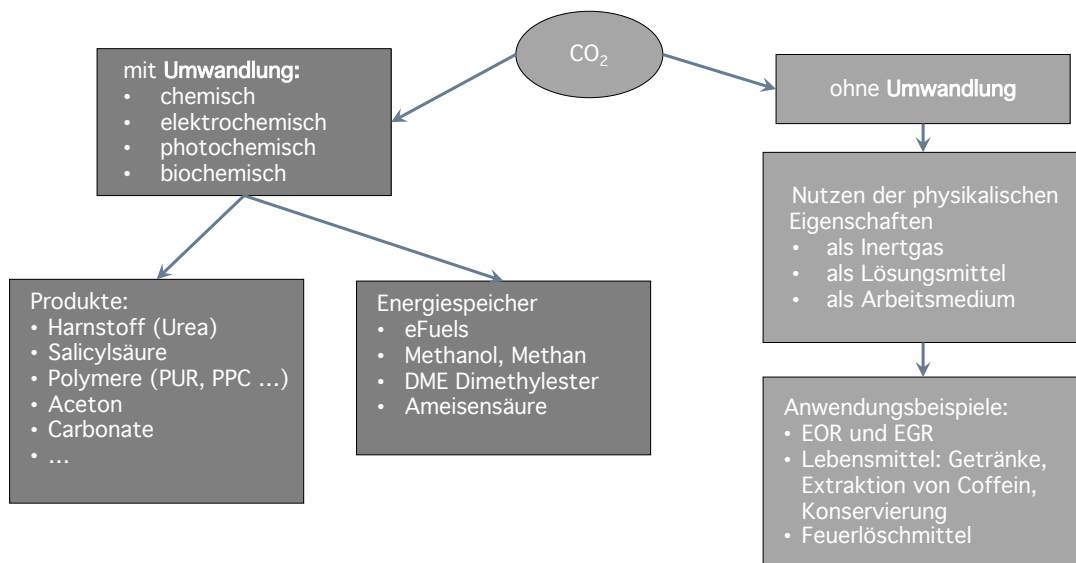


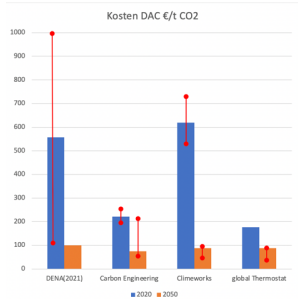
Figure 131: Possible paths for the use of CO₂

Source: based on Otto, 2015.

Some of the pathways described in Figure 131: Possible paths for the use of CO₂ "with conversion" have already been described in chapters 2.6. and 2.7.

2.8.1.2 Overview of figures

Table 30: Overview of figures from the carbon capture environment

Description	Energy consumption	Costs (CAPEX+OPEX incl. costs for transport and injection of CO ₂) per t CO ₂																	
DAC: Current costs for intercepting CO ₂ from the air	5 – 8 GJ/kg CO ₂ 500 kWh _{el} /t CO ₂ 5.4 GJ _{th} /t CO ₂	600 – 800 US\$ Climeworks 113 – 1,000 € ³⁸⁰ 540 €/t CO ₂ ³⁸¹																	
Target value for DAC		< 100 € or very optimistic 50 \$ (Global Thermostat)																	
CCUS: Current costs for intercepting CO ₂ from point sources	Capture: 10 kWh/t CO ₂ Compressor: 100 kWh/t CO ₂ Thermal: 2 GJ/t CO ₂ = <u>555 kWh</u> 665 kWh/t CO ₂	75 - 200 € 																	
Global capacity to capture CO ₂ worldwide production of CO ₂	Productive: ~ 44 Mt/a ~ 36 Gt/a	In projects: ~ 472 Mt/a																	
Costs by sector: <table border="1" data-bbox="242 1097 552 1305"><tr><td>Steel</td></tr><tr><td>Paper</td></tr><tr><td>Cement</td></tr><tr><td>Silicon (for wafers)</td></tr><tr><td>Power plants with oxyfuel</td></tr></table>	Steel	Paper	Cement	Silicon (for wafers)	Power plants with oxyfuel		<table border="1" data-bbox="1000 1064 1348 1395"><tr><th>Skagestad</th><th>Dena</th></tr><tr><td>28 – 45 €</td><td>50 – 90 €</td></tr><tr><td>41 – 54 €</td><td></td></tr><tr><td>50 – 80 €</td><td>50 – 148 €</td></tr><tr><td>125 €</td><td></td></tr><tr><td></td><td>45 – 90 € 32 – 60 €</td></tr></table> For details, see chapter 2.8.6.	Skagestad	Dena	28 – 45 €	50 – 90 €	41 – 54 €		50 – 80 €	50 – 148 €	125 €			45 – 90 € 32 – 60 €
Steel																			
Paper																			
Cement																			
Silicon (for wafers)																			
Power plants with oxyfuel																			
Skagestad	Dena																		
28 – 45 €	50 – 90 €																		
41 – 54 €																			
50 – 80 €	50 – 148 €																		
125 €																			
	45 – 90 € 32 – 60 €																		
Transport of CO ₂ in pipelines		~ 3.6 10 ⁻⁵ €/m ³ CO ₂ /km																	
Compression of CO ₂	7 kWh/t CO ₂	2 – 20 US\$/t CO ₂ depending on on-shore or offshore																	
Storage capacity for injected CO ₂	Capacity storage with mineralisation	100 – 250 Tt CO ₂ worldwide 5 – 8 Gt/a Europe																	

The costs depend very much on

- the type of point source and the partial pressure of the CO₂ in the flue gas stream
- the integration of the interception processes into the local production processes
- and of course, from the local energy costs

³⁸⁰ Cf. Dena, (2021).

³⁸¹ Cf. Block, (2022).

Table 31: Compilation of annual CO₂ quantities used in 2018.

Source: VDI Status Report, (2021).

	Amount of CO ₂ in Mt/year
Use of CO ₂ worldwide, of which:	230
Fertiliser: 146 Mt urea, use of CO ₂ :	107
Methanol: 80 Mt worldwide (1.13 Mt in GER)	2
Cyclic carbonates (0.08 Mt)	0,04
Salicylic acid (0.07 Mt)	0,025
EOR, EGR	70 – 80

Table 32: Compilation of CO₂ emissions in Germany and Europe.

Source: Statista for the years 2019 and 2021.

CO ₂ emissions in Germany and the EU ³⁸²	Amount of CO ₂ in Mt/year
CO ₂ emissions in Germany	854
CO ₂ emissions from point sources in Germany	274
that appear suitable for capture:	
without coal-fired power plants	110
only lignite-fired power plants	163
only waste incineration	16,5
Biogas plants	75,55
Cement production	18,84
Energy-related CO ₂ emissions in the EU:	2.550
Theoretically usable for synthesis: ³⁸³	1.930
- Coal-fired power plants	9.031
- Natural gas power plants -	2.288
Cement production -	2.000
Iron and steel production	1.000
- Refineries -	850
Petroleum power plants	765
- Ethylene production -	260
Bioenergy	73

2.8.1.3 Terminology

There are several reasons for capturing CO₂ from process and waste gases from industrial and power generation plants (so-called CO₂ point sources) or from atmospheric air (Direct Air Capture, DAC). On the one hand, the increase of climate-active gases (GHG) such as CO₂ in

³⁸² Cf. Statista, 2019; Statista, (2021). The figure given by Statista for 2020 clearly contradicts the figures given in the VDI report for the EU, which are based on published values from the European Commission.

³⁸³ For details, see VDI Status Report, 2021, p. 13.

the atmosphere must be reduced in order to stop or at least slow down global warming. On the other hand, the capture of CO₂ is also interesting because CO₂ is increasingly seen as a potential recyclable material with an interesting "application profile and value creation potential".³⁸⁴ In addition to the long-standing use of CO₂ in the production of e.g. urea, methanol or cyclic carbonates, the production of synthetic fuels (eFuels) together with the production of hydrogen is increasingly coming into focus.

Different degrees of purity of the captured CO₂ are required for the different application purposes (sequencing, i.e. injection into caverns or storage in rock formations and thereby conversion of silicate rock into carbonates) or feedstock for different products (e.g. polymer-based materials for construction). However, requirements for the degree of purity as well as the transport of CO₂ influence the process costs.

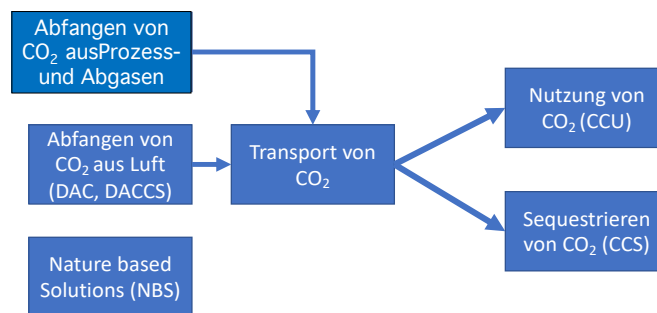


Figure 132: From the capture of CO₂ to its use or deposition. Source: Author

Figure 132 shows the main topics of this summary: the technical capture of CO₂ from gases, especially exhaust gases and air, the transport of the captured CO₂ until it is used or deposited (sequestration). Experience with the transport of CO₂ has been available for many years, especially in the USA and Canada,³⁸⁵ so that the transport of CO₂ can be regarded as state of the art.

In the figure above, the area of nature-based solutions (NBS) is also listed as a non-technical process, i.e. measures such as reactivating peatlands, reforesting forests, storing CO₂ in water, etc.³⁸⁶ NBS will not be discussed further in this chapter, as NBS is not a technical process. This is not to detract from the necessity of using NBS.

Basically, three process families can be distinguished in the reduction of CO₂ from exhaust gases:

³⁸⁴ Cf. Markewitz et al., 2010.

³⁸⁵ Cf. Markewitz et al., 2010.

³⁸⁶ Cf. Markewitz et al., (2017).

- *Oxy-fuel*: the process in which pure oxygen is added to the combustion instead of air, serves as the basis for production processes that aim to capture CO₂.
- *Pre-combustion*: Separation of carbon components from the fuel or synthesis gas, use of hydrogen-rich fuel gases. In a compilation of CCS plants in planning or operation,⁷ pre-combustion is used at $\frac{1}{5}$ of the total of over 300 plants.
- *Post-combustion*: after combustion, CO₂ is removed from the flue gas. In a compilation of CCS plants in planning or operation by the National Energy Technology Laboratory, post-combustion is used at more than $\frac{1}{3}$ of the plants mentioned.³⁸⁷

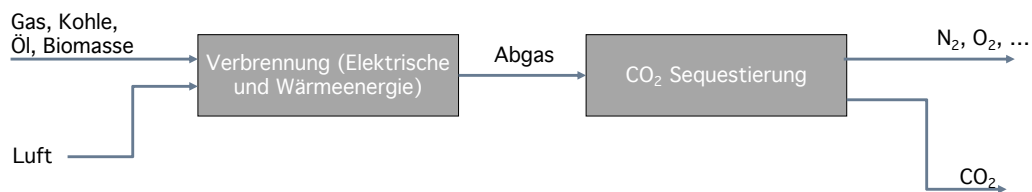


Figure 133: Principle of post-combustion. Source: Author

Various terms are used for the reduction of CO₂ from air or gases.

1. **DAC**: If the CO₂ content in air is reduced, this is referred to as Direct Air Capture (DAC), DACC Direct Air Carbon Capture or, in English literature, CO₂ -Removal, without referring to a specific technical process. The recently commissioned Climeworks plant in Iceland (ORCA project) with sequencing of the captured CO₂ could then be called **DACCS** Direct Air Carbon Dioxide Capture and Storage.

In principle, the task of further reducing the concentration of a chemical compound with a low partial pressure (in this case 400 ppm \cong 0.04 vol%) or even bringing it close to zero is much more demanding than, for example, in exhaust gases with CO₂ concentrations \geq 15 vol%, reducing these noticeably (i.e. capture efficiency 80 – 95 %). In the case of the latter, the term CO₂ reduction is used in English literature.

In general, it can be said that the transfer of CO₂ to an absorber or into a solution takes place more quickly when the partial pressure is higher (see Figure 148, S. **Fehler! Textmarke nicht definiert.**). If the total pressure in the gas is higher, this means higher density and smaller equipment. Accordingly, the investment and operating costs per quantity of CO₂ captured are significantly higher for DAC than for CCS.

On the other hand, apart from point sources at locations with high CO₂ production, e.g. combustion processes, there are also applications where capturing CO₂ is difficult or

³⁸⁷ Own analysis of data from NETL, (2021).

impossible (e.g. old plants, vehicles with combustion engines, aircrafts), so that CO₂ reduction in air is sometimes the only technical option for removing climate-damaging substances.

2. **CCU:** If CO₂ is extracted from a point source such as the flue gas of a cement plant in order to feed the captured CO₂ to a use such as the production of eFuels, this is referred to as "carbon capture and utilisation" (CCU). Since CO₂ is produced again at the end of life of the manufactured products or during the combustion of the eFuels, CCU is only conducive to the goal of greenhouse neutrality if the CO₂ used comes from sustainable bioenergy, from a cycle of CO₂ or was captured from the air with the help of DAC.

Even if a circular economy does not reduce the CO₂ that is already in the atmosphere, CCU at least does not further increase the CO₂ in the air.

CO₂ is used today as a coolant or refrigerant or in fire extinguishers or in oil and gas production (EOR and EGR). A number of new fields of application for CO₂ are, for example, its use in the recycling of plastic and rubber products. The stimulation of growth in greenhouses and in algae farms through increased CO₂ concentrations is gaining in importance.

The use of CO₂ as a synthesis component contributes to the production of urea (107 Mt/a), methanol (2 Mt/a), cyclic carbonates (0.04 Mt/a) or salicylic acid (0.025 Mt/a) (see

- 3.
4. Table 31), which, however, is negligible in view of the production of CO₂ in Germany of 644 Mt/a.³⁸⁸
5. **CCS:** In the case of carbon capture and storage, the CO₂ is not used for further production, but is stored (also called "sequestered"). A distinction is made here essentially between
 - Storage in caverns: with Enhanced Oil Recovery EOR (increase in oil yield through storage of CO₂ or H₂ O) CO₂ is injected into caverns
 - solution into underground aquifers, i.e. water-bearing strata, and
 - Carbonisation of siliceous rock at depths of about 800 m (see chapter 2.8.5).

The acronym BECCS (Bioenergy with Carbon Capture and Sequestration) is in use for the sequestration of CO₂, which is produced during the generation of energy (biogas)

³⁸⁸ Cf. Statista, (2021).

from biological sources that have captured CO₂ during their growth. Sequestration is indispensable in biogas production in order not to cancel out the negative emissions caused by plant growth. For more information, see also chapter 2.10.

Scientific studies have meanwhile shown that there is a clear rejection of CO₂ storage among the population and a great need for information, even if, for example, stable carbonates are formed when injected CO₂ is deposited in rock, making it seem impossible for the CO₂ to escape. Defects in underground and sub-sea storage are discussed in Chap. 2.8.5.2 is dealt with.

In addition, the KSpG (Carbon Dioxide Storage Act) also legally limited the storage of CO₂ in 2012. After decades of wrangling over "safe final storage sites" for radioactive waste, the German population's trust in final storage procedures has been severely strained).

In the context of CCS, the term "abatement costs" is often used to quantify the costs of avoiding CO₂ emissions at plants by installing CCS technology.³⁸⁹ The abatement costs are higher than the CO₂ capture costs because, for example, a reduction in power plant efficiency must be compensated for by higher fuel input (see Chapter 2.8.3.6).

***CCUS:** If CO₂ is used for both production and sequestration, the acronym CCUS is commonly used. If, during the production of "grey hydrogen", the resulting CO₂ is fed into final storage or use by thermally splitting methane with steam, the "colour" of the hydrogen would have to change, as it becomes "blue hydrogen". For political reasons, this line of argument is not yet generally followed.*

In

6. Table 31 gives some exemplary figures for the use of CO₂ as a feedstock for production. In the EU, 1,930 Mt CO₂/a could theoretically be chemically bound.³⁹⁰ In 2020, about 110 Mt CO₂ /a were used as feedstock in chemical syntheses. According to a survey in 2019, the potential is estimated at 600 Mt CO₂ /a by 2030.³⁹¹
7. **NBS:** Since it will not be possible to completely capture CO₂ produced by industrial processes in the future, the so-called "nature-based solutions", i.e. the storage of CO₂ in long-lived trees, in peatlands, in the soil or in the sea, must be intensified as much as possible in order to achieve the goal of "zero CO₂ emissions".

These methods will be reported on in chapter 2.10.

³⁸⁹ "The effective costs of a climate protection measure per tonne of avoided CO₂ emissions" (Energie-Lexikon, n.d.).

³⁹⁰ Cf. VDI Status Report, (2021).

³⁹¹ Cf. VDI Status Report, (2021).

2.8.2 Removal: Direct Air Capture (DAC)

2.8.2.1 Overview and costs

In Direct Air Capture (DAC), there are essentially two types of process: solid adsorption with low temperatures for regeneration at 100 °C (LT-DAC) and liquid absorption with regeneration of the absorber at high temperatures of about 900 °C (HT-DAC).³⁹² There are three main players in the market for this, which are listed in Table 33.

Table 33: Overview of suppliers and costs of DAC systems.

Source: Hess et al, 2021; Sutherland, (2019).

Company	Attachments	Energy demand in kWh/t CO ₂	Current and perspective costs in US\$/t CO ₂
Carbon Engineering (Canada)	1 Mt CO ₂ /a for oil production via EOR in Texas	Electr.: 366 Therm.: 1,458	currently < 250 perspective: 64 – 232
Climeworks (Switzerland)	- 4,000 t CO ₂ /a ORCA in Iceland - Norsk e-Fuel in Norway with PtL capacity of 8,000 tPtL/a in 2023 and 80,000 tPtL/a in 2026	Electr.: 200 – 300 Thermal: 1,500 – 2,000	current: 600 – 800 Perspective: < 100
Global Thermostat (USA)	Haru-Oni (Chile) SynFuels will be produced together with Porsche and Siemens: 2,000 t CO ₂ /a in 2022 and up to 10 t CO ₂ /a in 2026	Electric 200 Thermal 1.170	current < 200 Perspective: 50

The data shown in Table 33 are all discontinuous processes, i.e. separate plant sections are available for the working and regeneration phases. The changeover time is specified by Global Thermostat as 15 minutes.

From the comparison of the data Table 33 shows that

- the cost per tonne CO₂ for DAC varies widely; it is currently in the range of 200 – 800 US\$/t CO₂, according to DENA the current capture cost is 540 €/t CO₂ and for HT plants with an electricity demand of 366 kWh/t CO₂ and a thermal demand of 5.25 GJ/t CO₂ and considerable research and development is still needed to achieve a cost reduction,³⁹³

³⁹² Cf. Hess et al., 2021; Sutherland, (2019).

³⁹³ Cf. Dena, 2021, p. 8; Block, (2022).

- the perspective costs of 50 US\$/t CO₂, e.g. at Global Thermostat, are probably too optimistic,
- the costs below \$100/t CO₂ forecast by various companies will certainly only be reached in probably 20 years, provided that electric power remains cheap and cost reductions through economies of scale and integration into a plant's thermal processes succeed.³⁹⁴

This cost development was estimated by Dr. H. J. Wernicke in 2021 and is shown in Figure 134.

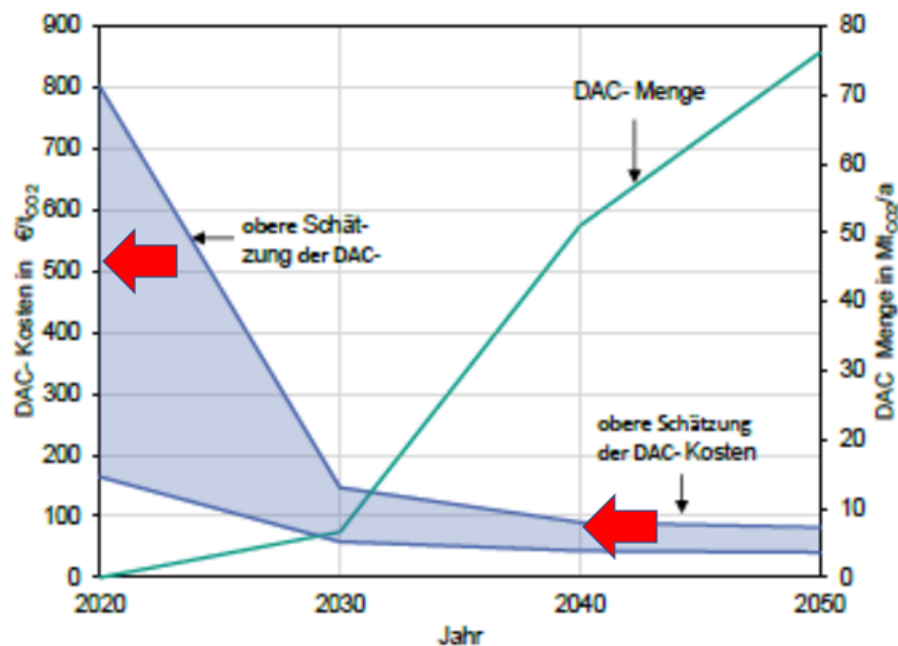


Figure 134: Development of DAC costs over the next decades.

Source: GES internal communication H.J. Wernicke (2021b), F.J. Radermacher.

For DAC plants, DENA (2021) quotes costs and forecasts their development as shown in Figure 135. In order to achieve a value of approx. 100 €/t CO₂ in 2040, considerable cost reductions are still to be achieved.

³⁹⁴ Cf. GES internal communication Dr Wernicke , 2021a , Prof. Radermacher.

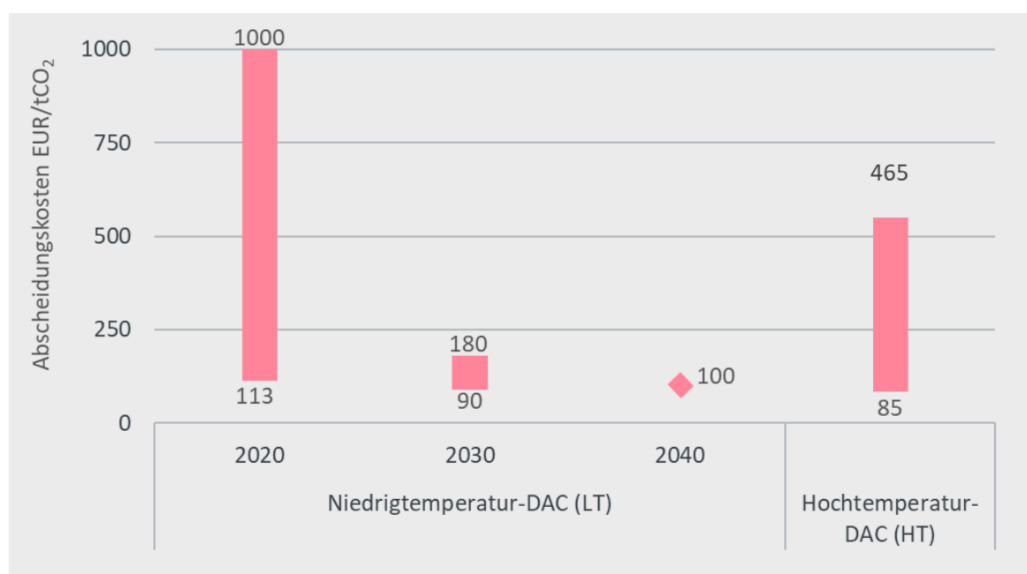


Figure 135: Deposition cost DAC using different sources.

Source: DENA, (2021).

As the investment costs for DAC account for approx. $\frac{2}{3}$ of the capture costs, the reduction of the investment contributes significantly to achieving the target of 100 €/t CO₂. In the area of operating costs, it is the operating time whose increase reduces the capture costs. Of course, the price of electricity has a significant impact on capture costs. DENA (2021) cites a model calculation by Prognos, which shows the contributions to reducing capture costs by way of example in Figure 136.

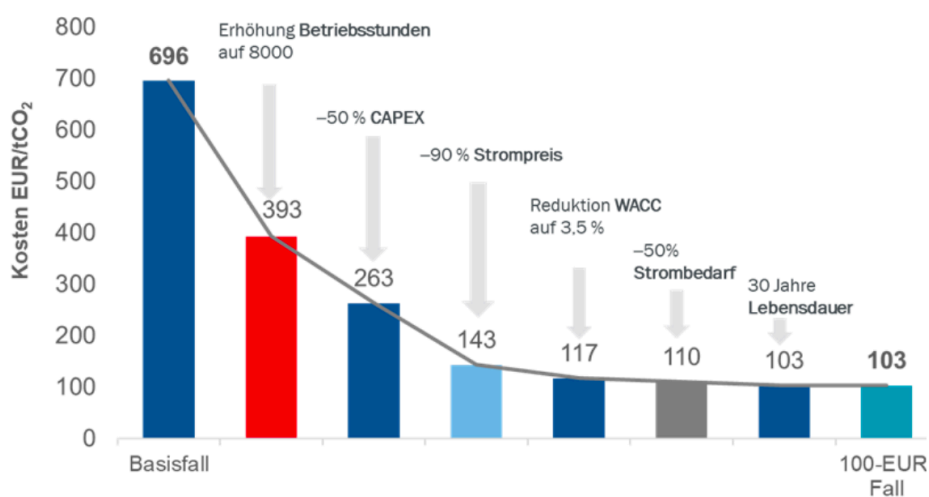


Figure 136: Prerequisites for reducing capture costs to 100 €/t CO₂.

Source: DENA, 2021, p. 34.

For DAC plants with liquid and solid sorbents, OPEX and CAPEX were calculated by McQueen et al. (2020) and also special cases that geothermal energy and nuclear energy can be used were taken into account.³⁹⁵ The result for plants with 100 kt CO₂/a is shown in Figure 136.

- CAPEX: Plants using geothermal energy are (only) 6 % more expensive to build than a reference plant with conventional energy supply; plants using energy from nuclear power plants are only 1 % more expensive than this reference plant.
- OPEX: it is not surprising that the operation of DAC plants using geothermal energy is 10 % cheaper; the use of nuclear energy is 8 % more expensive than in the reference plant, as obviously the steam generation is more costly here.

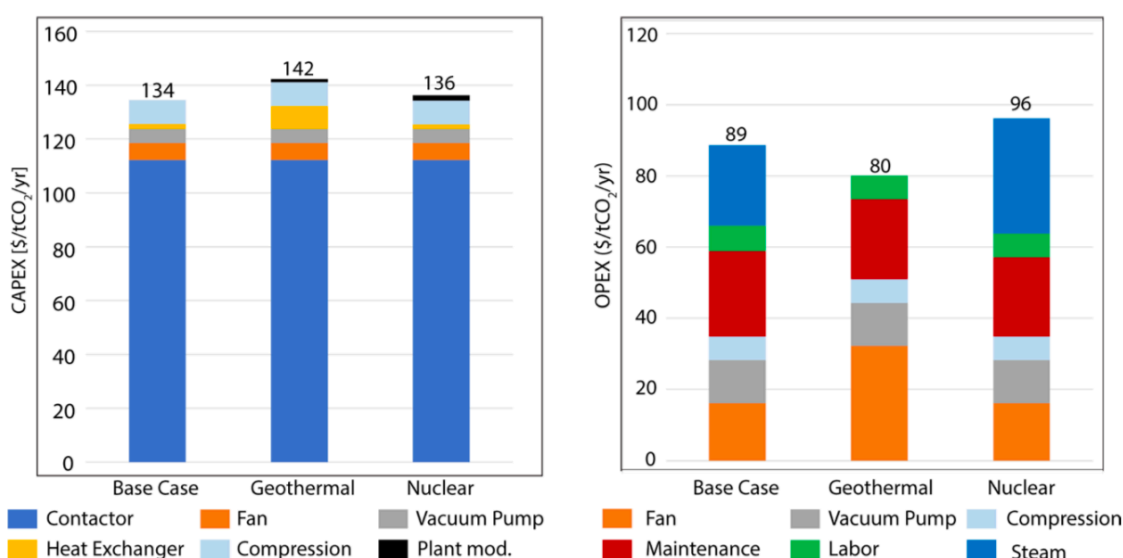


Figure 137: OPEX and CAPEX for DAC plants with a capacity > 0.1 Mt CO₂/a, taking into account the use of different energy sources, without sequestration. Source: McQueen et al., (2020).

The numerical values from Table 33 and Figure 135 have been summarised in the Figure 138 below. On the one hand, it illustrates the ambitious goal of reducing process costs by 2050 and, on the other hand, the relatively large scatter in the indication of process costs.

³⁹⁵ Cf. McQueen et al., 2020, with available supplements.

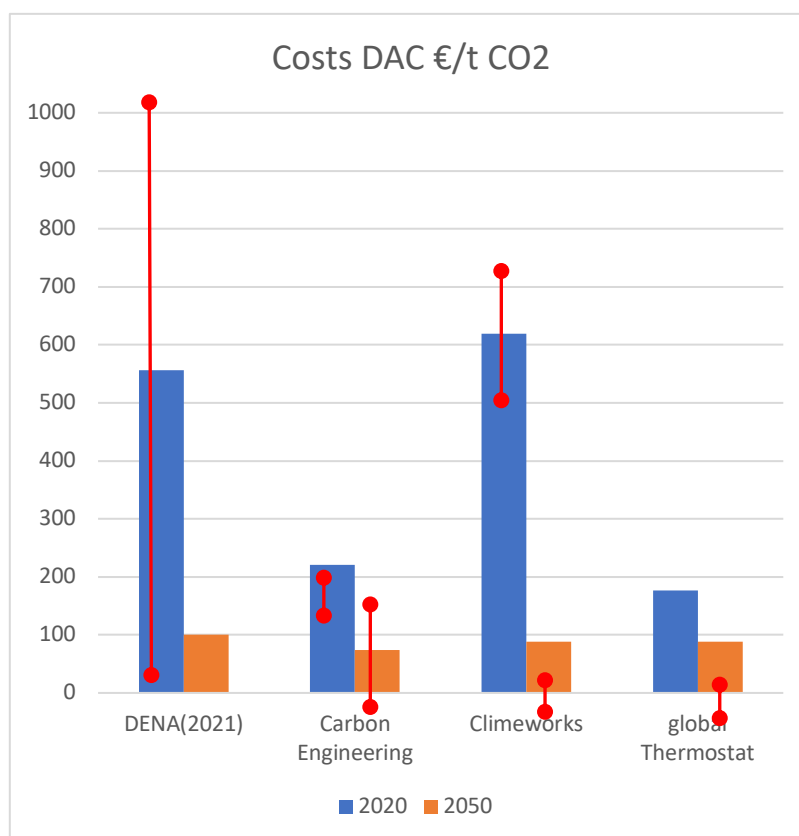


Figure 138: Current and perspective DAC costs from various sources (see Table 33 and Figure 135) with scatter ranges.

2.8.2.2 Comparison of two DAC methods with the help of LCA

As an example, the comparison of two methods for DAC using Life Cycle Assessment (LCA) is presented below. According to Madhu et al. (2021), only these two process groups are currently sufficiently operational and documented: the "High Temperature aqueous solution" (HT-Aq) and the "Low temperature solid sorbent" or Temperature Swing Adsorber (TSA) process.

When comparing processes, attention should not only be paid to a few, certainly very interesting parameters such as energy consumption per quantity of CO₂ captured, but the entire spectrum of the environmental impact should be considered, as is done in a LCAs. In the comparison of the methods described below, the following criteria are examined:

- Climate change
- Use of fossil fuels
- Metal use
- Formation of respirable particles
- Water consumption
- Land consumption

In the LCA, not only a 'worst case' and a 'best case' are considered for the numerous variable parameters, but with the help of a Monte Carlo simulation the most probable results are considered in a sensitivity analysis. For example, the Carbon Capture Efficiency (CCE) is varied, which assumes values between 25 % – 47 % for HT-Aq, and the service life of the plants is between 15 – 22 years.

High Temperature Aqueous solution DAC

A plant that has been built according to the procedure in Figure 145 on p. **Fehler! Textmarke nicht definiert.** consists of four parts:

- 1) *Air Contactor*: here the CO₂ contained in the air reacts with a strong hydroxide (KOH or NaOH) and forms a carbonate.
- 2) *Causticiser*: In the causticiser, the carbonate formed from the hydroxide releases the CO₂ group to calcium hydroxide and forms calcium carbonate CaCO₃.
- 3) In the *calciner*, the CO₂ is expelled from the calcium carbonate under the influence of heat and lime (CaO) is formed.
- 4) In the *slaker* (lime slaker), the lime is converted back into Ca(OH)₂ and can be circulated.

TSA DAC Temperature Swing Adsorber DAC

For the absorption of CO₂ a polyamine (polyethyleneimine) is used,³⁹⁶ which on contact with CO₂ converts the R-NH₂ groups of the amine into NCOOH groups and also releases them again on moderate temperature increase and pressure reduction (see Figure 139). Since temperatures of only about 120 °C are required for this, the recovery of heat can be increased to up to 90 % if existing residual process heat can be used. With TSA, locally available heat sources can be used flexibly for the heat demand or replaced by electrical energy with the use of heat pumps.³⁹⁷

Both processes are subjected to a life cycle analysis and a scale-up to plant sizes of 1 Gt CO₂/a was carried out. The results are shown in excerpts in Table 34. It is noteworthy that with "HT-

³⁹⁶ Polyethyleneimine, Mw 600 (bPEI 600) is a highly branched, liquid, water-soluble polyamine with a high cationic charge density (cf. Wikipedia, n.d.).

Cost: approx. 500 US\$/kg (Source: <https://www.polysciences.com/default/polyethylenimine-branched-bpei-600>)

³⁹⁷ Cf. DENA, 2021, p. 31.

Aq" about 0.58 t CO₂e are emitted for every tonne CO₂ captured, and with TSA this is only 0.3 t CO₂e

The result of the comparison between HT-Aq and TSA in the above six areas is shown in Figure 140. The abscissa is used for different values and only has the purpose of showing how large the variation of the values can be when the parameters of the models are changed between best and worst case. Within the six groups, however, it can be seen that TSA has clear advantages over HT-Aq in all areas. The authors of the LCA summarise:

"TSA-DAC outperforms HT-Aq-DAC by a factor of 1.3 – 10 in all environmental impact categories studied."³⁹⁸

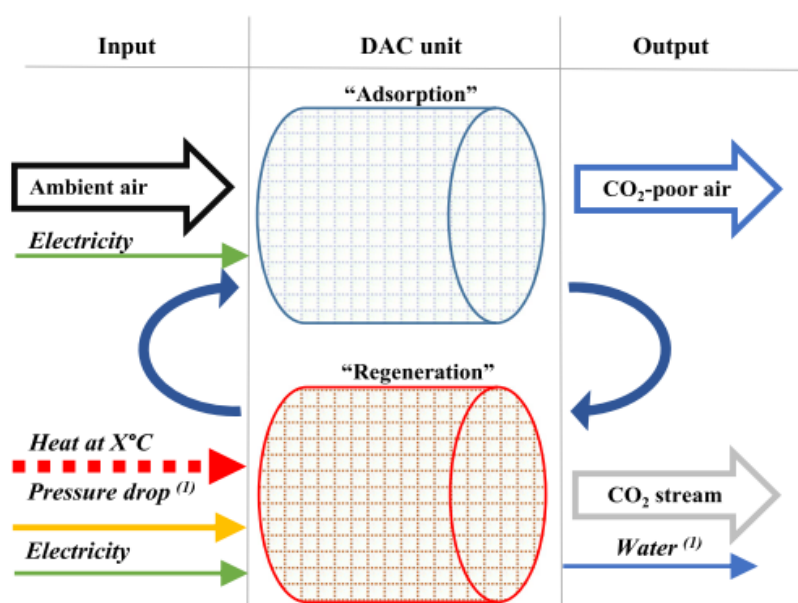


Figure 139: How a Temperature Swing Adsorber (TSA) works.

Source: Madhu et al., (2021).

³⁹⁸ Cf. Madhu et al., 2021, supplementary databases of LCA.

Table 34: Comparison of some parameters for HT-Aq and TSA.

Source: Madhu et al., 2021 [publication and Supplementary Information and further data sheets]; Block & Viebahn, (2022).

	HT-Aq	TSA
Temperature range	850 – 900 °C	20 – 120 °C
Energy consumption GJ/kg CO ₂	5,1 – 8,1	5 – 7,5
Water consumption t/t CO _{H2O2} according to Block & Viebahn (2022)	4,7	-0.2 to -2 (production)
CCE carbon capture efficiency	10 % – 90 %, according to de Jonge ³⁹⁹ 50 % – 90 % according to Liu ⁴⁰⁰	85.4 % – 93.1 % according to Climeworks ⁴⁰¹ 88 % – 95 % ⁴⁰²
Emission of t CO _{2e} /t CO ₂ captured	0,58 (+0,2/-0,03)	0,3 (+0,02/-0,009)
Land consumption: (/10 ⁻³ m ² a) or in m ² /tCO ₂ according to Block & Viebahn (2022)	435,7 0,04	112,1 0,26
Metal consumption in kg Fe	194,7	18,4
Carbon efficiency GHG emissions/t CO ₂	73 %	86 %
Total electrical energy (kWh/t CO ₂)	337 – 449	130 – 350,
Total heat (GJ/t CO ₂) ⁴⁰³	4.05 – 4.47 [1125 – 1241 kWh]	2.3 – 6.2 [639 – 1722 kWh]
Heat/electric energy ratio	3,3 – 2,8	4,9
Heat recovery rate		90 % – 10 %

In the KNDE2045 study, the capture of 20 Mt CO₂/a from the air with subsequent injection (DACCS) is modelled with a low-temperature process for different locations, i.e. different energy supply by, e.g. wind turbines and/or PV plants, and use of waste heat from electrolyzers.⁴⁰⁴ The goal is to reduce CO₂ emissions by 95 % in 2045. The water produced in this way can be used in the electrolyzers to produce hydrogen.

³⁹⁹ Cf. de Jonge et al., (2019).

⁴⁰⁰ Cf. Liu et al., (2020).

⁴⁰¹ Cf. Climeworks for the demonstration plant with 4 kt CO₂/a.

⁴⁰² Cf. Climeworks for 1 Mt CO₂ /a.

⁴⁰³ 80 % of the thermal heat is required for the absorption process, 20 % of the electrical energy is used to operate the fans, cf. McQueen et al., (2020).

⁴⁰⁴ Cf. KNDE2045, (2021).

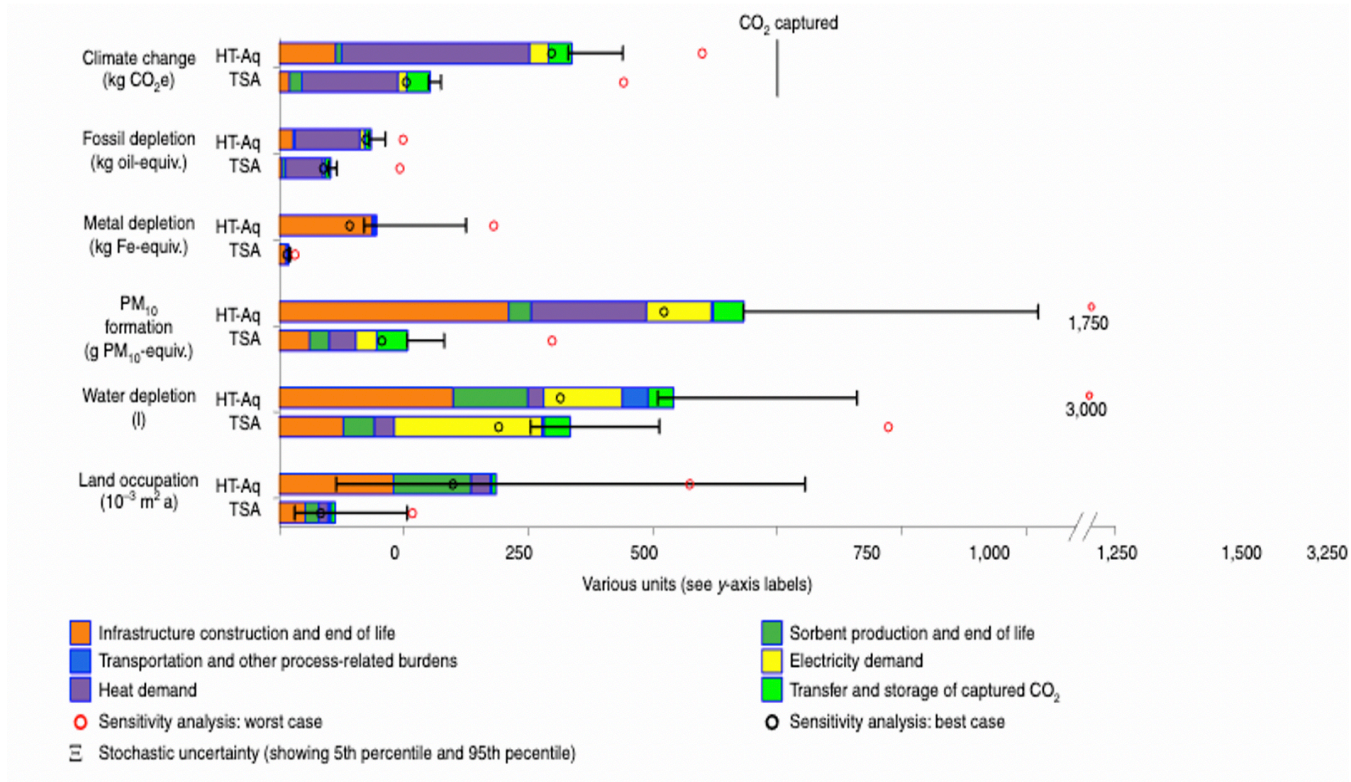


Figure 140: Results of the life cycle analysis (LCA) for HT-Aq and TSA.

Source: Madhu et al., (2021).

2.8.3 Reduction: Oxy-fuel process, pre- and post-combustion

2.8.3.1 Oxy-fuel process

In the oxy-fuel process, the fuels are not burnt with ambient air, but with pure oxygen. On the one hand, this leads to an increase in combustion temperature, but in particular also to an increase in the CO₂ partial pressure in the exhaust gas. A rule of thumb for CO₂ capture states that the investment costs decrease when the CO₂ partial pressure increases.

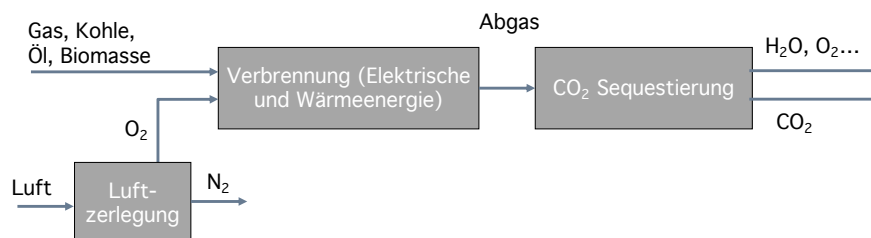


Figure 141: Schematic representation of oxy-fuel combustion. Source: Author

Since with oxy-fuel there is essentially only CO₂ and H₂O vapour in the exhaust gas – if methane were burnt, the partial pressure in the exhaust gas would increase from about 9 % to

33 % – obtaining a pure CO₂ stream is technically easier than with combustion with air. The disadvantage is that a cryogenic air separation plant, for example, must be available to produce pure oxygen.

In Chemical Looping Combustion (CLC), nitrogen is also avoided by passing it through the combustion process by oxidising the metal in the oxidiser in a stream of air and steam in a double fluidised bed with metal oxides on the one hand and releasing the oxygen in the reducer to the fuel gas mixture on the other. This process is used in only 4 % of the CCS plants⁷ listed above.

The energy required for the cryogenic extraction of oxygen reduces the power plant efficiency by about 7 %.³

2.8.3.2 Cost development of the oxy-fuel process

Expectations for the cost development of the oxy-fuel process from a Chinese perspective are shown in Figure 142. It is expected that in China the current costs of about 37 ± 5 €/t CO₂ will fall to 23 ± 2 €/t CO₂ in the next 20 years.

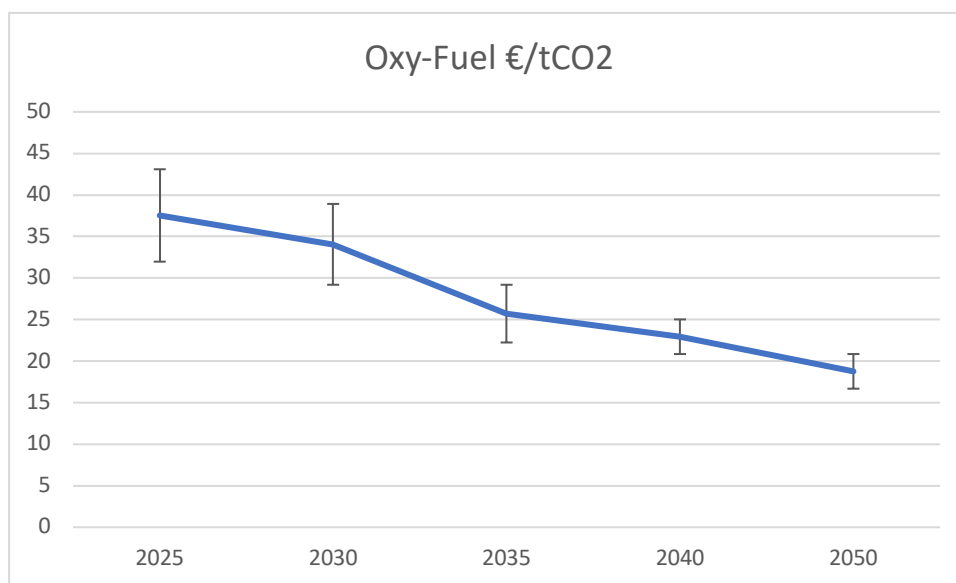


Figure 142: Chinese view of the cost development of oxy-fuel processes.

Source: revised values from Qi, (2021).

A discussion of the cost impact of using oxy-fuel in power generation in power plants is provided in section 2.8.3.6.

2.8.3.3 CO₂ reduction through pre-combustion

The principle of pre-combustion is illustrated in the figure below.

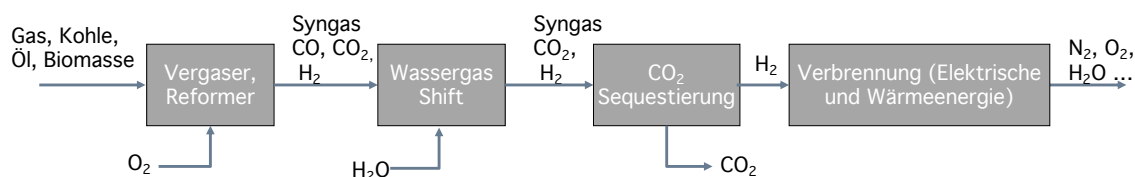


Figure 143: Principle of pre-combustion with the process steps gasification to produce syngas and conditioning of syngas; Source: Author

If the fuel is not already present as a gas, then it is converted into the gas phase in the gasifier. In the syngas produced, which certainly contains the species CO, CO₂ and H₂, the CO₂ partial pressure is increased by the water gas shift reaction. After purification of the syngas (separation of dust, NO_x and sulphur), the separation of CO₂ can be carried out in a technically simpler and more cost-effective manner than in post-combustion.

The fuel gas is treated by separating CO₂ from the gas and, if necessary, converting the CO to CO₂ (water gas shift reaction) before combustion, so that the subsequent hydrogen-fired combustion process in a combined cycle gas turbine process (CCGT) for the generation of electrical energy can take place almost free of CO₂. CO₂ capture takes place with the help of physical solvents.

Since the partial pressure of CO₂ in the syngas is higher after the water gas shift reaction than after combustion, the costs of sequestration are reduced. The exhaust gas after combustion is free of climate-damaging components such as CO₂.

The question of whether the costs of building and operating the necessary process engineering facilities for pre-combustion "pay off" must remain unanswered at this point, as the author of the figures does not provide separate information on CAPEX and OPEX.

Figure 144 shows current and projected costs for pre-combustion in China. The plan is to more than halve current costs by 2050.

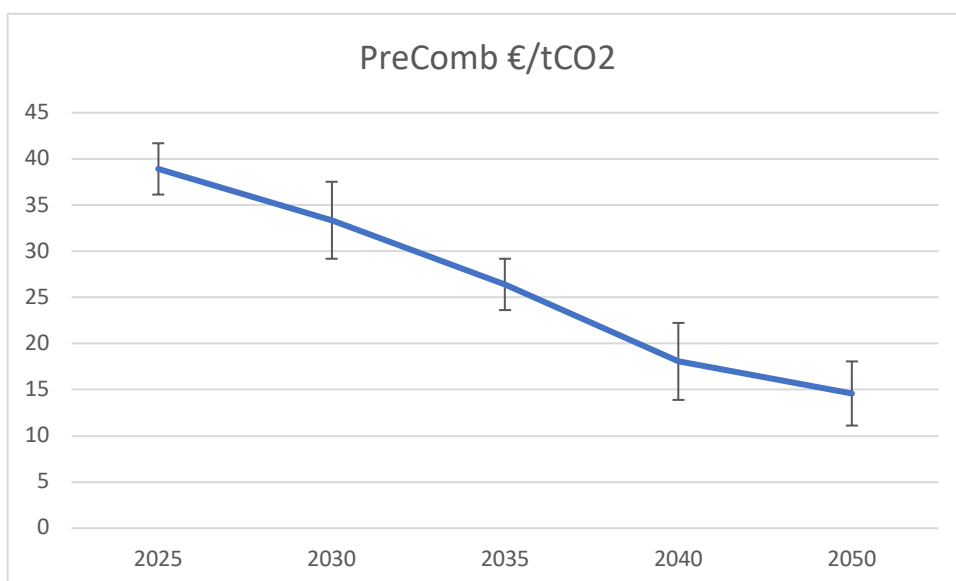


Figure 144: Chinese view of the cost development of pre-combustion processes.

Source: revised data from Qi, (2021).

2.8.3.4 CO₂ reduction through post-combustion

Process overview and its TRL

The following is a brief description of the technical processes used to capture CO₂ from gas streams. An overview of the processes is given.

In general, it can be noted in advance that the use of absorption processes, e.g. in power plant technology, can result in a loss of efficiency of 10 % – 20 %. In the case of carbonate looping (see below), the efficiency losses appear to amount to 6 % – 8 %.⁴⁰⁵ This has an impact on the LCOE.

According to McKinsey, in 2008 the processes for capturing CO₂ were in some cases still in very early stages of development⁴⁰⁶ – and according to J. Massey (2021) they still are⁴⁰⁷. Only processes for injecting and transporting CO₂ are classified as commercially available (see Figure 175 in the appendix p. 287). The setting is not necessarily supported by the TRL classification of the processes by NASA (2019) (cf. also

⁴⁰⁵ Cf. VDI Status Report, (2021).

⁴⁰⁶ Cf. McKinsey, 2008.

⁴⁰⁷ Cf. Massey, (2021).

Table 35 on page 253).

The assessment is quite controversial, since on the one hand, from a technical point of view, the processes work satisfactorily, but on the other hand, from an economic point of view, the costs for their use are still clearly too high and therefore their numerous realisations are inhibited.

In the following list of extraction methods, it must be taken into account that their use places conditions on the conditioning of the waste gases, because otherwise, for example, the adsorbing gap volumes become clogged, as in the case of zeolite, or the chemical substances for absorption are poisoned. This means that in some cases additional costs are incurred for dust removal or scrubbing, which are not included in the individual cost figures.

1. **TSA Temperature Swing Adsorbers:** In the ORCA project already mentioned above, the company Climeworks uses amines on a contact surface to adsorb CO₂. In the regeneration cycle, CO₂ is released and captured by heating the adsorber.

Climeworks has already built a pilot plant for the production of eFuels (1,000 l kerosene/day) in Dresden in 2014 in partnership with Audi and Sunfire.

For large plants, the company expects costs in the range of 70 €/t CO₂ (LT system Climeworks) and 90 €/t CO₂ (HT system Carbon Engineering) for a site in Morocco (see also GES internal communication Wernicke, HW (2021b)).

Another company (Global Thermostat, NY USA), which builds plants in the LT DAC category, has announced that costs of 11 - 38 €/t CO₂ are feasible in the future. Considering that the costs are far from those of other suppliers, Global Thermostat's announcement seems rather unrealistic.

Low-temperature processes have the advantage that the heat portion of the required energy can be reused from process heat that is available in the company and may be surplus.

2. **Carbonate looping** (or calcium looping, see Figure 145): Utilising the reversible, exothermic carbonation of CaO at high temperatures together with the endothermic calcination of the carbonate CaCO₃. Even though the process has disadvantages in terms of efficiency compared to the process used by Carbon Engineering, the advantages of carbonate looping lie in its simplicity and the fact that the absorption heat of carbonation can be used in a power plant. The process used in cement and lime production, in

which a partial stream of the burnt lime is used for CO₂ binding, has the advantage of being easily retrofitted in existing plants.⁴⁰⁸

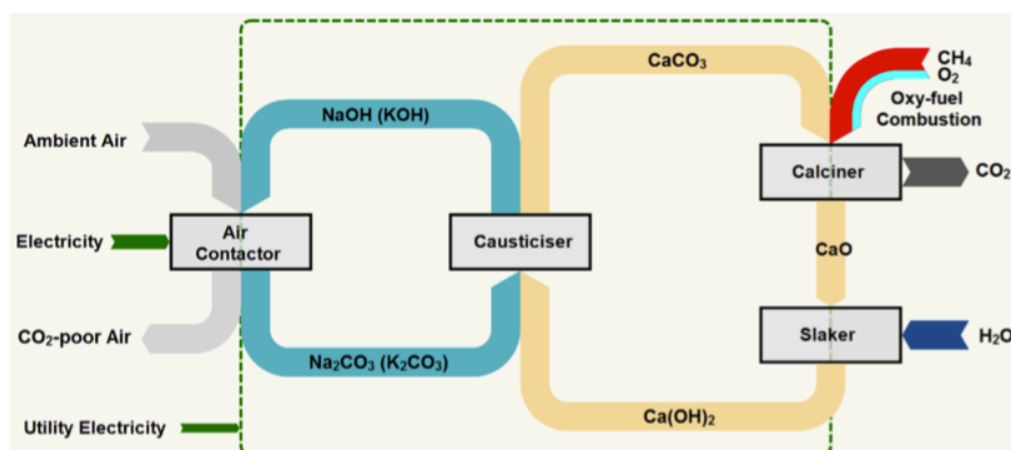


Figure 145: Carbonate looping" process according to Carbon Engineering to capture CO₂ in an aqueous solution of NaOH and KOH.

Source: Fasihi et al., (2019).

3. **Washing in aqueous solutions:** Various solutions in different processes are suitable for scrubbing, which are already known for the treatment of gas, e.g. in the petroleum and steel industries.

Carbon Engineering, a Canadian company supported by the Bill Gates Foundation, uses a multi-stage high-temperature process with potash or caustic soda to capture CO₂ (see Figure 145), which in the final stage of development requires only electrical energy and no additional energy from the combustion of methane.

The Benfield process uses potash (K₂ CO₃) to reduce CO₂.

One of the world's largest CO₂ scrubbing plants in connection with a power plant is operated in Shady Point (Oklahoma, USA). The CO₂ washed out (approx. 800 t/day = 15 % of the total amount) is made available to the food industry for use in greenhouses only.

Either monoethanolamine (MEA) or also diethanolamine (DEA) or also ammonia ("chilled ammonia" process) are used for washing. The solvent MEA decomposes with oxygen and other foreign substances such as SO_x and NO_x, which increases operating costs because the substance has to be replaced continuously.

A further disadvantage is that the energy required to regenerate the solvent is very high and the space required for post-combustion processes is significantly greater than that for the boiler house, which can make it difficult to retrofit existing plants.

A comparison of the process with Temperature Swing Adsorber using LCA is carried

⁴⁰⁸ Cf. GES internal communication with H. J. Wernicke, 2021a.

out in section 2.8.2.2.

The hope is that further research activities can reduce energy use and solvent degradation. In particular, the use of so-called sterically hindered or tertiary amines and the use of activators gives hope to achieve these goals.

4. **PSA** Pressure Swing Adsorber

In the case of extremely dry and pure gases, CO₂ is accumulated under pressure in the structures of a crystal such as zeolite 13X (consisting of Al O₂₃ and SiO₂) and released again when the pressure is reduced. An important parameter in this method is the CO₂/N₂ selectivity, which according to Minh et al. (2008) is currently 54 and could be increased to 150 by further development of the adsorber in order to provide the highest possible concentration of CO₂ in the captured gas. The costs of the process could be reduced to 30\$/t CO₂ with such an adsorber.

5. **CCC** Cryogenic Carbon Capture: By cooling the exhaust gas to a temperature just above the freezing temperature of CO₂ (-78.5 °C, normal pressure), CO₂ then freezes out in liquid phase with slight expansion. Depending on the process temperature, very high reduction efficiencies (99 % at -135 °C) can be achieved with very high purity of the captured CO₂ compared to other processes. Due to the freezing out of the CO₂, a CCC plant tends to freeze and is therefore not easy to operate and keep in operation. The calculations of process costs by Baxter et al. (2009) (see Figure 146) indicate that under certain conditions CCC is a significantly more cost-effective method for CO₂ reduction than the other processes. On the other hand, the high energy input and the fact that the process should only be applied to concentrated and dry gas streams is reason enough for the VDI to classify CCC as non-competitive.⁴⁰⁹

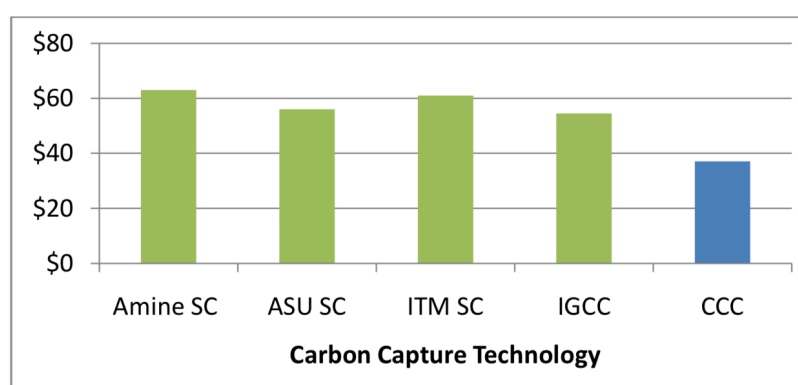


Figure 146: Estimated costs in US\$ per t CO₂ for various CO₂ reduction processes, legend: Amine SC: scrubbing with amine solutions; ASU SC: air separation unit SC; ITM: ion transport membranes; IGCC: integrated gasification combined cycle; CCC: cryogenic carbon capture.

Source: Baxter et al., (2009).

⁴⁰⁹ Cf. VDI Status Report, (2021).

6. **Membrane process:** Suitable for CO₂ concentrations >40 %. Amine-based cellulose membranes provide good removal efficiencies and high purity of CO₂ from air.⁴¹⁰ Membrane-based processes are generally not suitable for flue gases, as temperature-stable membranes that are resistant to the SO_x and NO_x components in the gas are still under development.
7. **Direct separation:** The cement industry is testing LEILAC (Low Emissions Intensity Lime and Cement) in a demonstration plant in Lixhe, Belgium. The new feature of the process is that the limestone is heated together with a calciner, so that CO₂ is directly bound and does not enter the flue gas.
8. **Chilled ammonia process**
This process, in which the exhaust gas is introduced into a chilled ammonia solution or ammonium carbonate solution with excess ammonia, is currently being tested in the cement industry. In the regenerator (8 - 25 bar, 130°-160°C), the CO₂ is released again. The released CO₂ has purity levels >99.7 %.
9. **Allam-Fetvedt cycle**
The process uses supercritical CO₂ (~1,000°C, 200 - 300 bar) as the working fluid, to which the hot exhaust gases are fed by burning natural gas with oxygen, which then drives a gas turbine. Clean water vapour and CO₂, which can be fed directly into a pipeline, are continuously extracted from the circulating gas stream.

Unfortunately, there is no further information on the consumption of electrical and thermal energies for the individual processes in the literature, in order to be able to compare them better and to better assess the procedural conditions for their optimal use.

Year	1995	2005	2015
Thermal energy	4.2 GJ/t CO ₂	3.2 GJ/t CO ₂	2.0 GJ/t CO ₂
Power equivalent factor used	0.292 kWh/kg CO ₂ (0.25)	0.178 kWh/kg CO ₂ (0.20)	0.083 kWh/kg CO ₂ (0.15)
Power for capture	0.040 kWh/kg CO ₂	0.020 kWh/kg CO ₂	0.010 kWh/kg CO ₂
CO ₂ compressor	0.114 kWh/kg CO ₂	0.108 kWh/kg CO ₂	0.103 kWh/kg CO ₂
Total	0.446 kWh/kg CO₂	0.306 kWh/kg CO₂	0.196 kWh/kg CO₂

Note: The Power equivalent factor used refers to the electric efficiency at which the thermal energy needed for capturing CO₂ could be used for power generation. There is considerable debate about these trends in the scientific community, and the trends shown here depend on some step-changes in the technology.

Source: Feron, 2006.

Figure 147: Expected performance trend of the energy required for carbon capture.

Source: IEA, 2008a, p. 50.

⁴¹⁰ Cf. VDI Status Report, (2021).

Table 35: Technical readiness level of selected procedures.

Source: Nasa, (2019).

Technology	2014 TRL	2017 TRL
Post-Combustion Processes		
Conventional Solvents	9	9
Improved Conventional Solvents	6-8	6-8
Encapsulated Solvents	1	2-3
Precipitating Solvents	4-5	4-5
Biphasic Solvents	4	4
Ionic Liquids	1	1
Algae Based Capture	1	3
Polymeric Membranes	6	6
Polymeric Membranes / Cryogenic Separation Hybrid	6	6
Room Temperature Ionic Liquid (RTIL) Membranes	2	2
Vacuum Pressure Swing Adsorption (VPSA)	3	3
Temperature Swing Adsorption (TSA)	1	7
Molecularly Imprinted Polymer Particle CO ₂ Sorbents *	-	1-2
Enzyme Catalysed Adsorption	1	6
Amine Catalysed Adsorption *	-	6
Electrochemically Mediated Adsorption	1	1
Mineral Carbonation *	-	5
Cryogenic Capture	3	4
Supersonic Inertia Capture	1	3
Pre-Combustion Processes		
Conventional Solvents for Natural Gas Treating	9	9
Conventional Solvents for Hydrogen Purification *	-	9
Gas Separation Membranes for Natural Gas Treating *	-	8
Gas Separation Membranes	5	5
Physical Separation	2	7

Technology	2014 TRL	2017 TRL
Pressure Swing Adsorption *	-	9
Vacuum Swing Adsorption *	-	8
Low Temperature Separation of CO ₂ from Natural Gas *	-	7
Low Temperature Separation of syngas	2	2
Oxy-combustion Processes		
Oxy-fired Circulating Fluid Bed Boiler (coal)	7	7
Oxy-fired Pulverised Coal Boiler	7	7
Oxy-combustion Flue Gas Purification Units	5-6	5-6
Oxy-fired Gas Turbine Cycles (Allam Cycle)	2	7
Oxy-fired Gas Turbine Cycles (CES Cycle)	5	5
Oxy-fired Gas Turbine Cycles (Others)	2	2
Chemical Looping Processes		
Post-Combustion Calcium Looping	6	6-7
Sorbent-Enhanced Water Gas Shift (SEWGS)	5	5
Chemical Looping Combustion	2	6-7
Chemical Looping Combustion with Oxygen Uncoupling	1	2-3
Chemical Looping Steam Reforming	3	3
Fuel Cell Processes		
Solid Oxide Fuel Cells (SOFC)	6	6
IGFC/IRFC and SOFC based power plant with CCS	4	5
Molten Carbonate Fuel Cells (MCFC) *	-	7
CCGT and MCFC based power plant with CCS *	-	5

Table 35 shows the TRLs of some of the processes in the carbon capture field. The table shows that, in NASA's estimation, most of the processes mentioned are already at an advanced stage of development.

2.8.3.5 Costs of CO₂ removal processes

The costs for the removal of CO₂ vary not only depending on the selected process, but also due to the assumption of special conditions for the conditioning of the gases and, of course, also depending on the CO₂ concentration in the exhaust gas. In general, it is true in any case that the costs of the processes increase when the partial pressure of the CO₂ to be captured decreases. This relationship is clearly shown in Figure 148 can be seen.

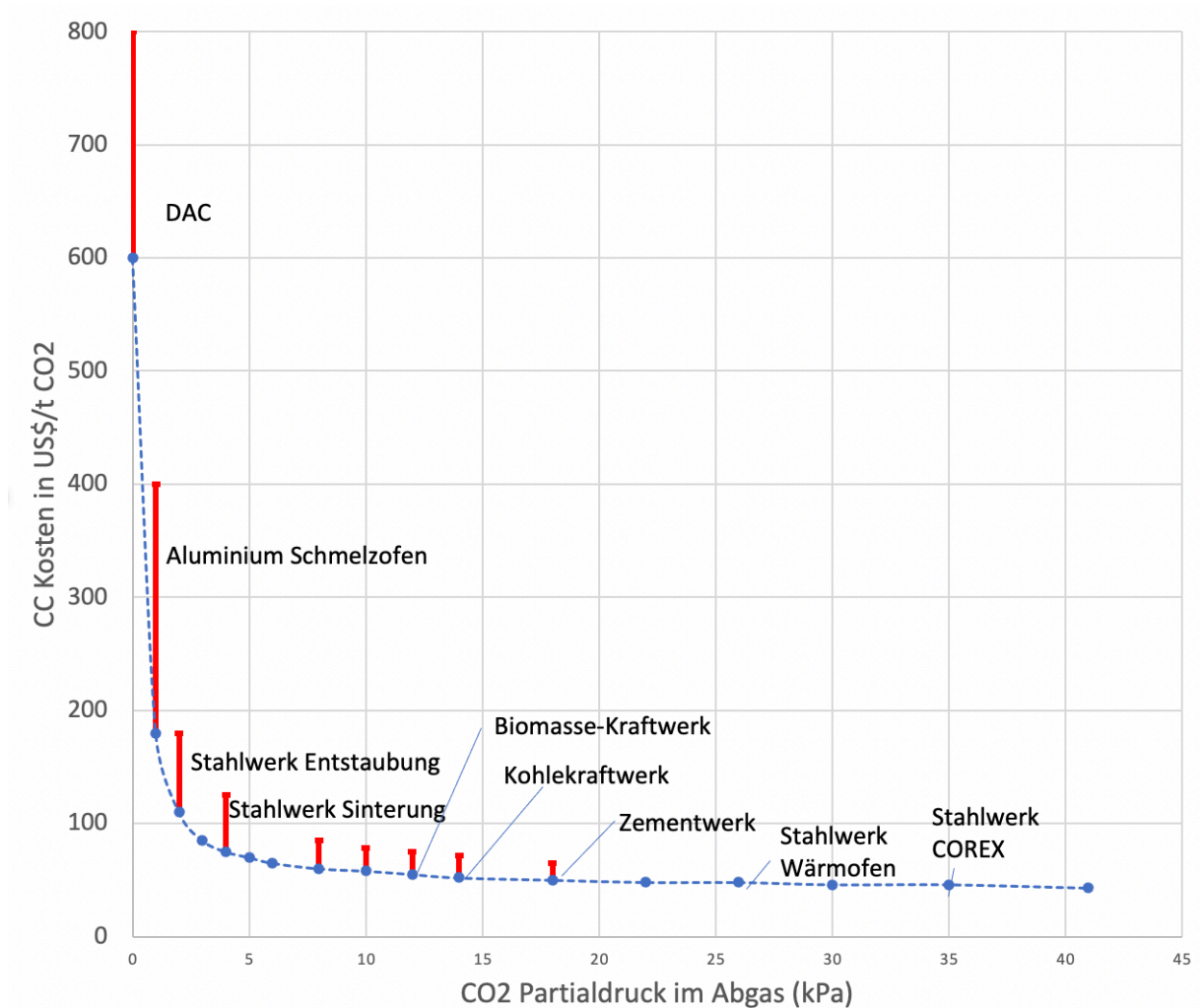


Figure 148: CO₂ partial pressure and cost per tonne of CO₂ captured in industrial flue gas.

Source: adapted from Massey, 2021

In particular, capturing CO₂ from the air is significantly more cost-intensive, currently by a factor of up to 10, in relation to the amount of CO₂ captured than capturing it at CO₂ point sources such as power, steel or cement plants. The figures shown in Figure 148 do NOT apply to DAC, as the costs for capturing CO₂ at low partial pressures are significantly higher.

Table 36: Overview of different processes for CO₂ capture and their costs.

Sources: as indicated in the table.

Procedure	Manufacturer	Cost in € or \$ per t of CO ₂ captured	Source
Amine wash (chemical absorption)	Climeworks	Operation: 75 - 113 €/t 49 \$/t	Fasihi et al. (2019) Minh et al. (2008)
HT aqueous solution	Carbon Engineering	Operation: 90-200 €/t	Fasihi et al. (2019) Keith et al. (2018)
Physical separation - PSA Pressure Swing Adsorber with 13X Zeolite		57 - 82 US\$/t 51 US\$/t	Rahman (2016), p.40 Minh et al. (2008)
- Cryogenic Carbon Capture		< 40 €/t	Baxter et al. (2009)
Membrane separation		30 - 50 €/t	
CCS (see chapter 9)	SSAB Lulea Paper Cement Silicone	Skagestad et al. (2019) 28 - 45 €/t ebd p.16 41 - 54 €/t ebd p.18 50 - 80 €/t ebd p.20 125 €/t ebd p.21	Skagestad et al. (2019) ⁴¹¹

The data shown in the above Table 36 above are difficult to compare with each other, as some of the figures represent current costs, e.g. for pilot plants, while others were determined by extrapolation to plants with larger capacities or with expected development progress in the future. That cost reductions are possible in principle is shown by the depiction of separation costs over time in the figure below.

The costs calculated by Skagestad et al. (2019) for plants in various sectors by simulation also include transport and injection costs.

⁴¹¹ The calculations are based on simulations of MEA amine washing with Aspen Hysys. The investment costs for a high degree of development were calculated with Aspen In-Plant Cost Estimator. Furthermore, a "partial capture rate" of, for example, 85 %-96 % is calculated for coal firing, as this minimises the specific costs and reduces the emission penalties.

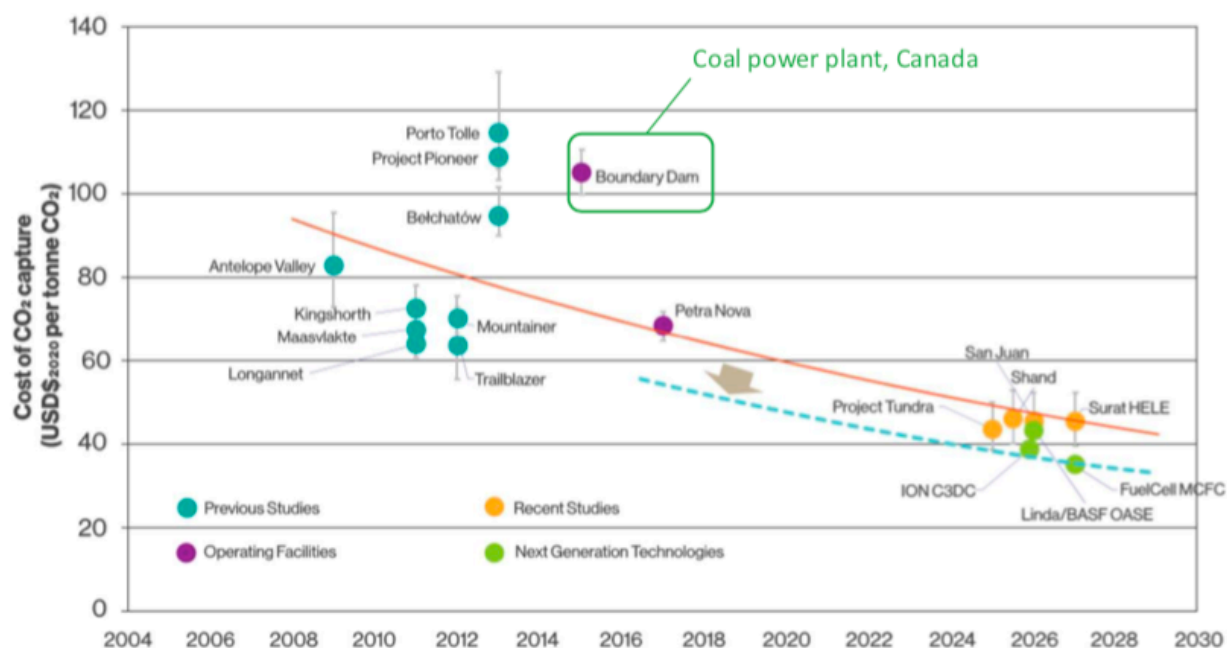


Figure 149: Development of CO₂ capture costs over time.

Source: Massey, (2021).

The Chinese Academy of Sciences forecasts a similar degradation in separation costs. This development is shown in Figure 150 is shown. Under which conditions the absolute values are to be understood was not stated by the author of the figures.

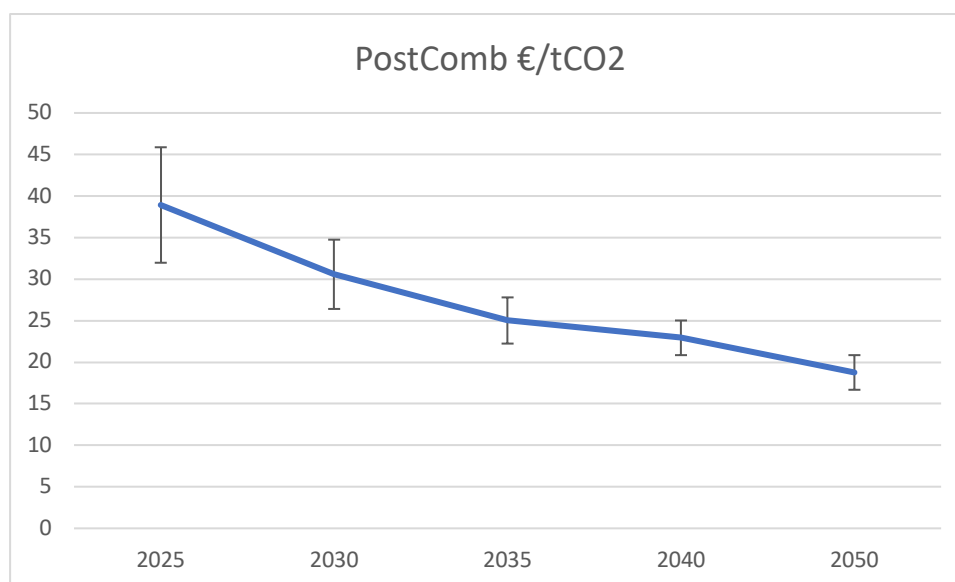


Figure 150: Chinese view of the cost development for post-combustion processes.

Source: revised values from Qi, (2021).

2.8.3.6 Costs of CO₂ reduction at power plants

The use of all CCS plants requires additional energy and, especially in the case of power plants, this reduces the efficiency of the plant.⁴¹² This creates a situation as shown in Figure 151 with CCS capturing 80-90% of increased CO₂ emissions. Since a power plant with CCS requires more energy, i.e. burns more coal or gas, the amount of CO₂ captured is not identical to the amount of CO₂ avoided. Of the exhaust gases, 80-90 % are captured, so that only the amount "CO₂ avoided" remains in comparison to the reference power plant; the production costs for electrical energy are therefore increased not only by the investment costs of a CCS plant, but also by the reduced efficiency of the power plant.

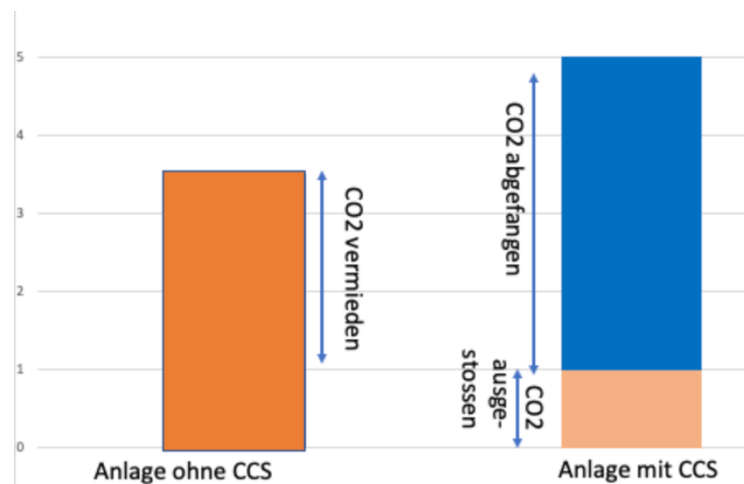


Figure 151: Difference between captured CO₂ and avoided CO₂ for power plants with CCS.

Source: Author

Figure 152 shows the calculated electricity production costs for the use of different fuels such as lignite (BK), hard coal (SK) and natural gas for different concepts from the post-combustion, pre-combustion and oxy-fuel sectors. Although the costs in Figure 152 are no longer up to date, the Figure nevertheless shows the influence of the use of oxy-fuel and carbon capture on the LCOE for the use of different fuels.⁴¹³

⁴¹² Cf. Markewitz et al., 2010, p. 23.

⁴¹³ Cf. Fraunhofer ISE, (2021).

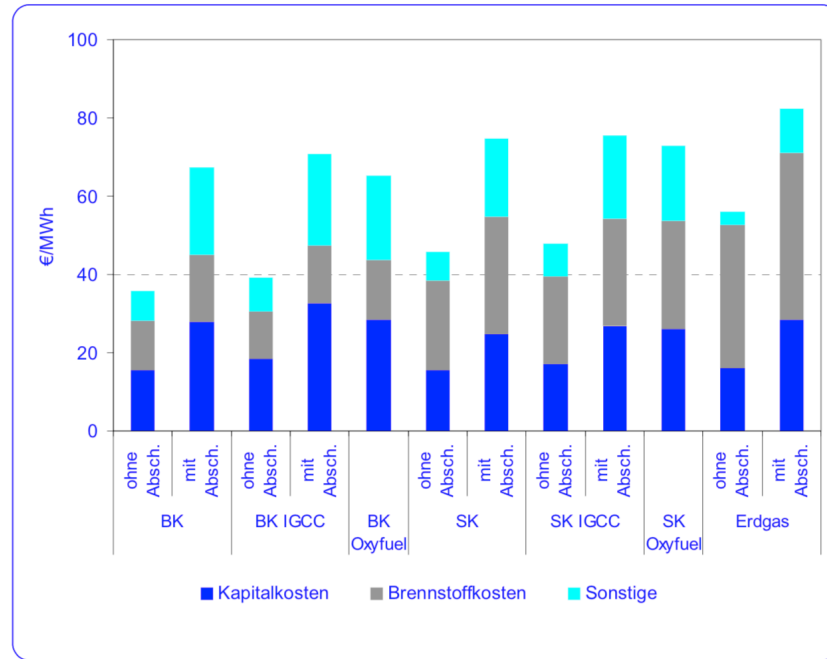


Figure 152: LCOE of fossil-fired power plants for 2010 and cost structures with and without CO₂ capture or the use of oxy-fuel processes, broken down by capex, fuel costs and other (OPEX).

Source: Markewitz et al., 2010, p. 53.

For natural gas-fired power plants, only the costs for post-combustion plants are considered. The costs were researched and include depreciation of the plant over 20 years, costs for treating the CO₂ (compression, liquefaction), the costs for a 350 km pipeline and storage in a saline aquifer at a depth of 1,000 m, including monitoring costs. Costs for certificates are not included.

In Figure 152 it can be seen that

- the production costs for electricity are significantly increased by the use of CCS (see BK (lignite) and SK (hard coal) without and with capture).
- CCS increases costs relatively less (47 %) for natural gas power plants than for hard coal (approx. 60 %) or lignite (80 - 87 %). For the latter, however, the costs for the fuel are lower.
- The CO₂ abatement costs are 35 - 40 €/t for lignite and 42 - 44 €/t CO₂ for hard coal. For gas-fired power plants or RWE's IGCC power plant, the costs for CO₂ avoidance increase - as shown in Figure 152 to 85 €/t CO₂. It should be taken into account that the combustion of methane produces relatively less CO₂ than coal-fired power plants and therefore the costs of procuring a capture device are specifically higher for the former.

These high costs are intensively discussed in the literature. In Renzenbrink et al. (2009), additional costs of 46 €/t CO₂ are given, which fits a range of costs of 30 - 45

€/t CO₂ calculated by McKinsey (2008).

Renzenbrink expresses the hope that the generation price of € 125/MWh given there can be reduced to € 81 in large CCS plants, which is much closer to the market prices of €70-80/MWh.

Even if with CCS the electricity production costs with lignite and hard coal according to the calculation in Figure 152 still offer minor advantages, no preference for these can be derived from this for energy sources, especially since there are some uncertainties regarding the data situation.

A study by the UK Department of Business, Energy & Industrial Strategy further details the cost impact of the processes used when calculating the cost of carbon capture at power plants. As shown in Table 37 10 processes were investigated with regard to the cost of electricity generation based on the reference costs. The results are shown in Figure 153.

- Case 0 – Reference Case – Unabated natural gas CCGT
- Case 1 – Natural gas CCGT with post-combustion carbon capture
- Case 2 – Natural gas reformation with pre-combustion carbon capture
- Case 3 – Coal SCPC with post-combustion carbon capture
- Case 4 – Coal SCPC with oxy-combustion carbon capture
- Case 5 – Coal IGCC with pre-combustion carbon capture
- Case 6 – Oxy-fired supercritical gas power generation with carbon capture
- Case 7 – Natural Gas CCGT with Molten Carbonate Fuel Cell carbon capture
- Case 8 – Biomass CFB boiler with post-combustion carbon capture
- Case 9 – Biomass CFB boiler with oxy-combustion carbon capture
- Case 10 – Biomass IGCC with pre-combustion carbon capture

Table 37: Different processes for electricity generation from fossil fuels and from biomass.

Source: GOV.UK, (2018).

Depending on the type of electricity generation, the cost price is increased by 10 % to 20 % by intercepting CO₂, as efficiency losses of the order of 10 % to 20 % occur as a result of intercepting CO₂ (see Table 38). The lowest cost premiums are for oxy-fuel processes.

In this calculation, biomass-based generation processes have the highest overall production costs, not because of higher carbon capture costs, but because of high capital and fuel costs.

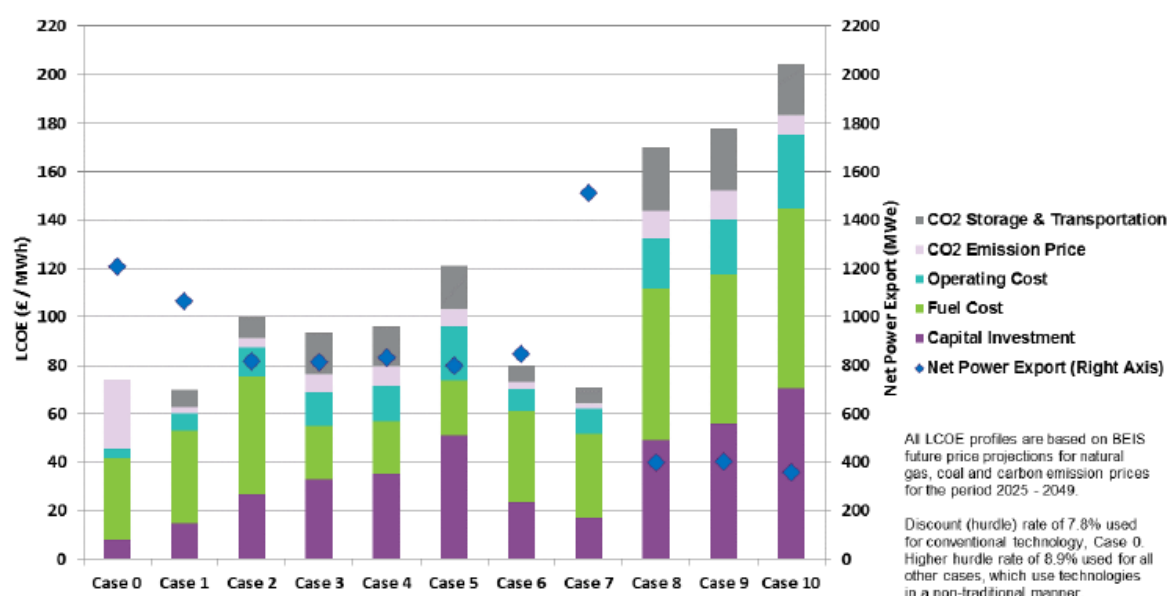


Figure 153: Comparison of LCoE in the UK.

Source: GOV.UK, (2018).

The results from Table 38 can be summarised with regard to the efficiency losses of the electricity generation processes as shown in Table 39. This table also notes the CO₂ abatement costs for capture, which are shown in detail in Table 40 are shown in detail.

Table 38: Technical parameters with efficiencies and interception rates for different power generation processes.

Source: GOV.UK, (2018).

	Units	Case 0	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9	Case 10
Total Gross Installed Capacity	MWe	1229	1144	919	953	1113	1063	1264	1645	498	598	493
Gas Turbine (s)	MWe	823	823	554	0	0	671	1264	823	0	0	303
Steam Turbine	MWe	406	321	365	953	1098	392	0	381	498	598	190
Others	MWe	0	0	0	0	15	0	0	440	0	0	0
Total Auxiliary Loads	MWe	21	80	101	139	280	263	416	136	102	196	137
Net Power Export	MWe	1208	1065	818	814	833	800	848	1509	396	402	356
Fuel Flow Rate	kg/h	150,296	150,296	147,539	325,000	325,000	314,899	118,940	195,722	635,178	635,178	225,417
Fuel Flow Rate (LHV)	MWth	1940	1940	1907	2335	2335	2263	1536	2527	1288	1288	1052
Net Efficiency (LHV) - As New	%	62.3	54.9	42.9	34.9	35.7	35.3	55.2	59.7	30.8	31.2	33.9
Net Efficiency (LHV) - Average	%	59.0	52.0	40.7	34.7	35.5	33.5	52.3	56.6	30.6	31.1	32.1
Plant Availability	%	93	90	85	90	90	85	90	90	90	90	85
Total Carbon in Feeds	kg/h	108,640	108,640	106,647	209,950	209,950	203,425	85,975	141,476	158,795	158,795	107,095
Total Carbon Captured	kg/h	0	98,661	96,418	188,926	187,176	183,697	77,378	130,333	142,954	142,748	97,194
Total CO ₂ Captured	kg/h	0	361,539	353,319	692,310	685,896	673,147	283,546	477,597	523,849	523,093	356,162
Total CO ₂ Emissions	kg/h	398,105	36,566	37,483	77,040	83,455	72,292	31,503	40,934	58,045	58,801	36,283
CO ₂ Capture Rate	%	0	90.8	90.4	90.0	89.2	90.3	90.0	92.1	90.0	89.9	90.8
Carbon Footprint	kg CO ₂ /MWh	329.4	34.3	45.8	94.6	100.2	90.4	37.1	27.1	146.5	146.2	101.9

Table 39: Efficiency losses at CO₂ capture rates of 90 % for different power generation processes from Table 8.

Source: GOV.UK, (2018).

Efficiency SCPC without CCS	Case 1 (Gas)	Case 2 (Gas)	Case 3 (coal)	Case 4 (coal)	Case 5 (coal)
40 %	-12 %	-31 %	-13 %	-11 %	-14 %
Abatement costs USD/t CO ₂	92	227	217	236	261

From Table 40 it can also be seen that the capital costs for plants with CCS are increased by 40 - 250 %.

Table 40: Economic data on CO₂ capture in power generation.

Source: GOV.UK, (2018).

	Units	Case 0	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9	Case 10
Total Project Cost	£M	672	968	1256	1732	1902	2396	1213	1570	1248	1450	1465
Pre-Licensing, Tech & Design	£M	6	8	11	15	17	22	11	14	11	13	13
Regulatory & Public Enquiry	£M	13	18	24	32	35	44	23	29	23	27	27
EPC Contract Cost	£M	584	845	1107	1547	1702	2151	1068	1392	1107	1290	1305
Infrastructure Connections	£M	29	37	37	29	29	29	37	37	29	29	29
Owner's Costs	£M	41	59	77	108	119	151	75	97	77	90	91
Overall CAPEX Impact (vs Ref Case)		-	44%	87%	158%	183%	256%	80%	134%	86%	116%	118%
Estimate Accuracy		± 30%	± 30%	± 30%	± 30%	± 35%	± 35%	± 45%	± 40%	± 40%	± 40%	± 40%
Total Fixed OPEX	£M pa	36	47	60	81	87	112	55	72	58	66	70
Total Variable OPEX (excl. Fuel & C)	£M pa	0	62	58	108	108	103	44	108	82	82	54
Average Fuel Cost ⁽¹⁾	£M pa	315	305	283	143	143	131	242	398	190	190	183
Typical CO ₂ Emission Cost ⁽¹⁾	£M pa	369	33	32	69	75	61	28	37	52	53	31
Discount Rate	% / year	7.8 ⁽²⁾	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9
Levelised Cost of Electricity	£/MWh	74.2	69.9	100.0	93.3	96.0	120.8	80.1	70.7	170.1	177.9	204.3
Capital Investment	£/MWh	8.0	14.9	26.2	32.9	35.3	51.1	23.2	17.1	49.0	55.9	70.6
Fuel Cost	£/MWh	33.5	37.9	48.5	22.2	21.7	22.8	37.7	34.7	62.6	61.8	74.1
Operating Cost	£/MWh	4.0	7.2	12.2	13.8	14.7	22.0	9.2	10.1	20.6	22.8	30.5
CO ₂ Emissions Price	£/MWh	28.7	2.9	3.8	7.5	8.0	7.5	3.1	2.3	11.7	11.6	8.4
CO ₂ Storage & Transportation	£/MWh	0	7.0	8.9	16.9	16.3	17.4	6.9	6.5	26.2	25.8	20.7
Cost of CO ₂ Avoided (incl. Carbon Price)	£/tCO ₂	-	-14.5	91.1	81.3	95.1	195.1	20.0	-11.7	524.1	566.1	571.7
Levelised Cost of Electricity (zero Carbon Price)	£/MWh	45.5	67.1	96.2	85.8	88.0	113.3	77.0	68.4	158.4	166.3	195.8
Cost of CO ₂ Avoided (zero Carbon Price)	£/tCO ₂	-	73.1	178.9	171.4	185.5	283.8	107.7	75.8	617.2	659.3	660.7

2.8.3.7 Costs of CO₂ reduction in steel production

In the CO₂ stCap project at Chalmers Technology University in Gothenburg, production processes in the steel, paper, cement and silicone manufacturing industries were studied in detail,⁴¹⁴ i.e. the use of pressure and heat energies already present in the industries' processes was taken into account in the operating costs during the simulation with the Aspen software. The investment costs were also estimated using Aspen tools.⁴¹⁵

⁴¹⁴ Cf. Skagestad et al., (2019).

⁴¹⁵ Aspen In-Plant Cost Estimator gives an inaccuracy of ±40 % for the estimation of investment costs

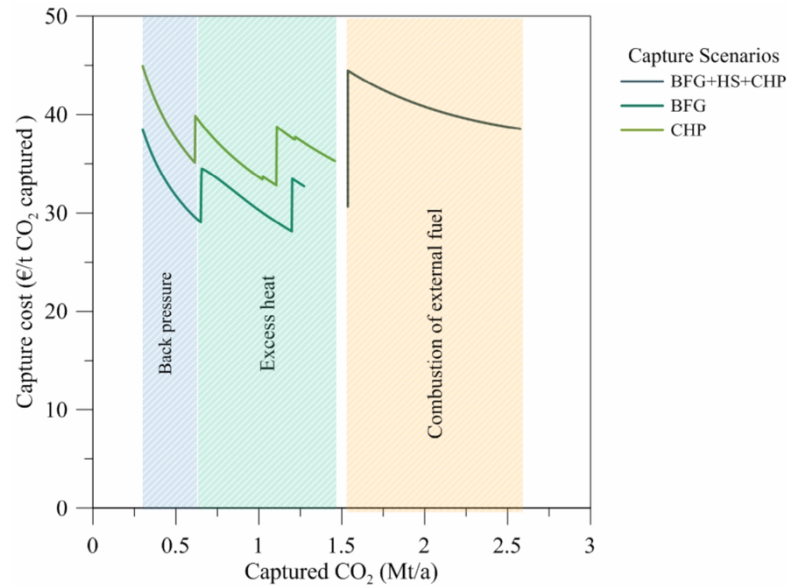


Figure 154: CO₂ reduction costs using the example of the SSAB steel plant in Lulea as a function of the amount of CO₂ captured. The coloured fields indicate the areas where different resources (pressure, heat) were used. In the scenarios, waste heat from Blast Furnace Gas (BFG), Combined Heat and Power (CHP) and Hot Stoves (HS) was included.

Source: Skagestad et al., (2019).

Only in the BFG+HS+CHP scenario is "full capture" achieved with 76.3 % CO₂ reduction (right part on yellow background in Figure 154).

The variation of costs by sector and as a function of the amount of CO₂ captured show that the costs for CCS vary between 28 €/t CO₂ and 120 €/t CO₂ depending on the integration into the processes of the sector. The costs include both investment (capex with "Nth of kind" approach, i.e. no development costs, optimised design) and operating costs (opex). The costs are shown in Figure 154 if the existing equipment can be used or if no additional energy is required. Fixed costs occur when these limits are exceeded.

2.8.3.8 Costs of CO₂ reduction in other sectors

A similar assessment is made by DENA's study,⁴¹⁶ which sees the capture costs per t CO₂ as strongly dependent on the technology and the point source (see Figure 155).

At the same time, the study expresses the hope that a price of about 50 €/t CO₂ is achievable in the medium term. Especially for cement plants and waste incineration plants, a CAPEX value for capture technology between 750 and 1,000 €/t CO₂ /a is considered realistic.

⁴¹⁶ Cf. Dena, 2021, p.17.

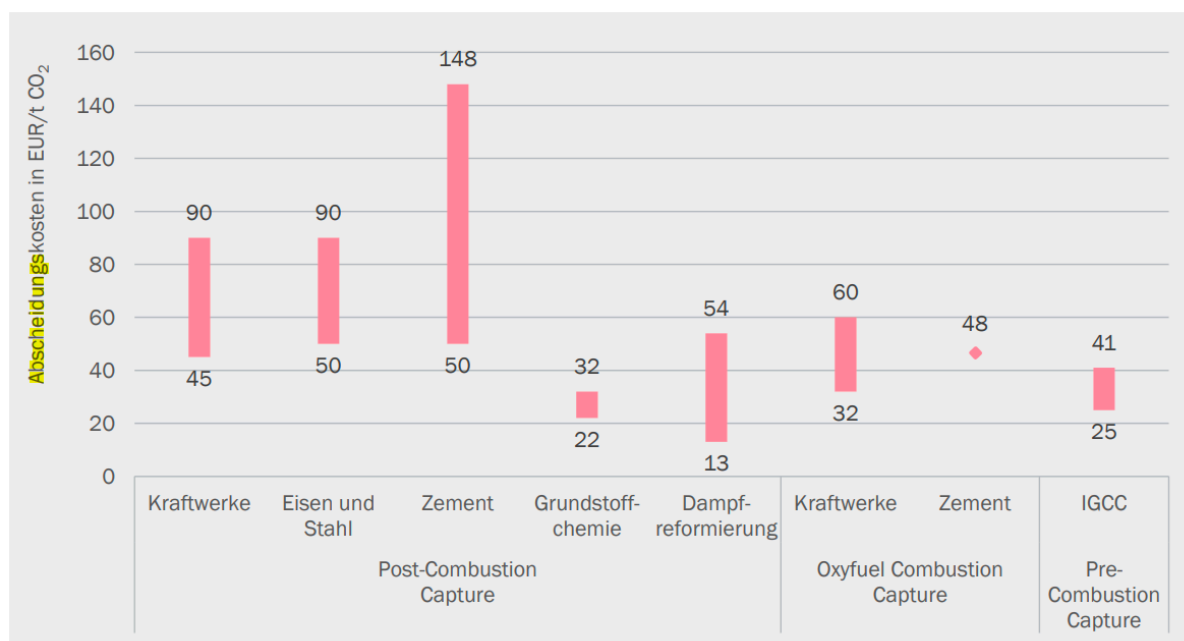


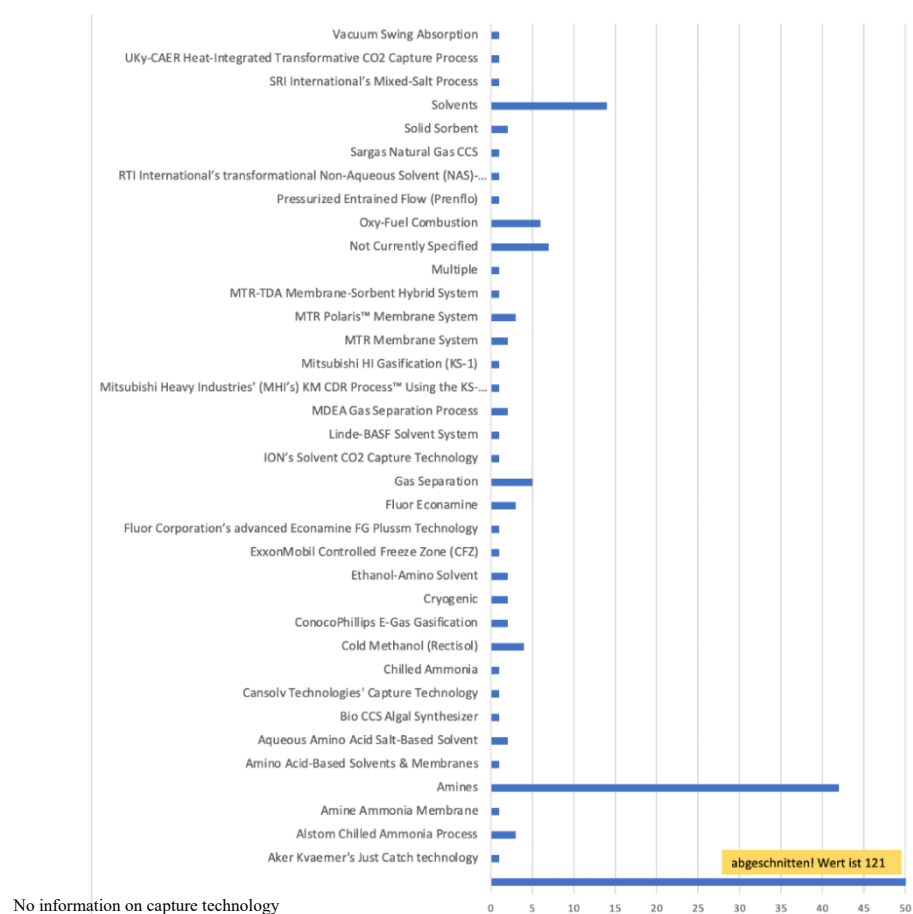
Figure 155: Separation costs from point sources for different industries.

Source: Dena, 2021, p. 17.

The netl.doe.gov "Carbon Capture and Storage Database" (2021) contains data on 307 CO₂ reduction plants worldwide, 242 of which are not in 'cancelled' or 'decommissioned' status.

Our own evaluation according to "capture technologies" used (n=121) shows a great variety of self-developed processes (see Figure 156). It is sometimes difficult to deduce the use of the basic technology from the process names. However, it is recognisable that processes using amines (approx. n=46) and unspecified solvents (n=14) dominate, as they have been tested for a long time.

Costs are known for n=99 projects, which have a total project budget of €155 billion converted to euros and give an idea of the extent of the worldwide development costs in capture processes. Since planned daily CO₂ capture rates are also given for these projects, a project value of approximately 281 k€/t CO₂/day can be determined from this without differentiating between capture processes.

2.8.3.9 Current projects for CO₂ reductionFigure 156: Evaluation of the NETL database according to the CO₂ separation processes used.

Source: NETL, (2021).

From the data on daily capacity (n=140), a total capacity of 1.3 Mt CO₂/day or 0.472 Gt CO₂ /year can be calculated with an average capacity of 9,244 t CO₂ /day (see Figure 157).

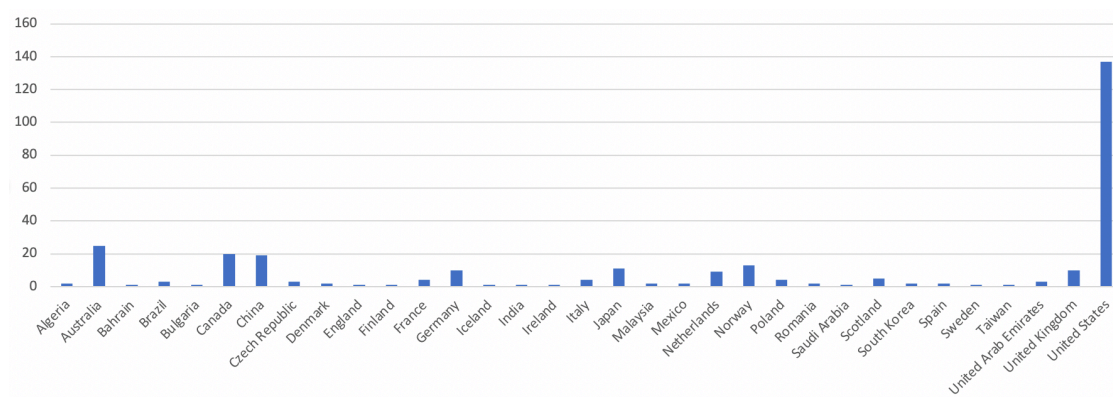


Figure 157: Analysis of the NETL database of active and planned CCS facilities: Number by country.

Source: Author, own analysis of data from NETL, 2021 .

In this data collection, the most CCS plant data was identified for plants in the USA (n=86), Australia (n=21), China (n=18), Canada (n=16), Norway (n=13) and Germany (n=10).

In Germany, a total of € 3.77 billion was invested in 10 projects for a daily production of 12,068 t CO₂ /day. These projects are shown with their status in Figure 158.

Anzahl	In Status	Capture/Storage	wer	Budget Mio €	t CO ₂
1	Aktiv	Capture	E.ON	10	
1	beendet	Storage	Leuna in Ketzin	30	67.271
3	Beendet	Capture	E.ON, RWE	29	
1	unterbrochen	Capture & Storage	RWE in Heurth	2.000	7,124/d
1	Abgebrochen	Capture & Storage	Vattenfall in Janschwalde	1.500	4,658/d
3	Unter-/abgebrochen	Capture & Storage	Vattenfall, Dong	120	100.000
Σ 10				3.773	

Post-Combustion, Anlage von Siemens mit >90% CO₂-Reduktion am Kraftwerk in Grosskrotzenburg mit 510 MW

Figure 158: CCS projects in Germany.

Source: NETL database, (2021).

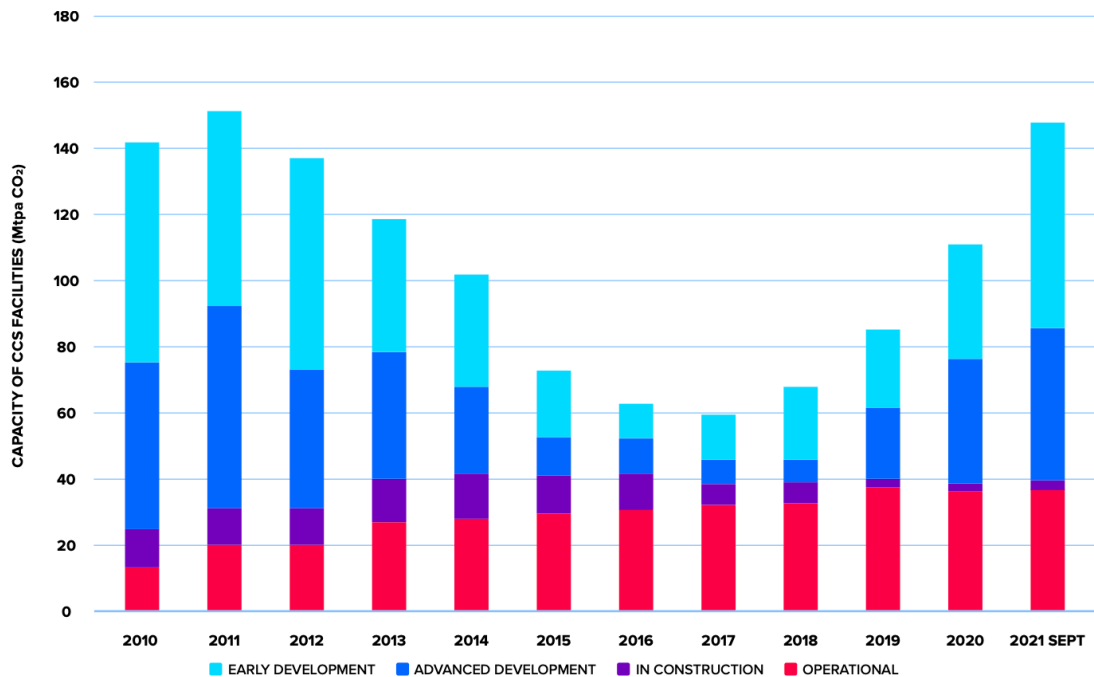


Figure 159: Project pipeline of CCS plants from 2010 to 2021.

Source: Global CCS Institute, (2021).

The Global CCS Institute's CO₂ RE database (2021) contains fewer projects than the NETL database with a total capacity of 0.14 Gt CO₂ /year, but due to their historical documentation

they are included in Figure 159 clearly show that the number of CCS projects has increased significantly since 2017.

Other graphs available from Global CCS also show,⁴¹⁷ that both the production capacity of projects has increased significantly from 2020 (size of blue circles) and at the same time the diversity, i.e. deployment beyond the previously common sectors, has increased (see Figure 160).

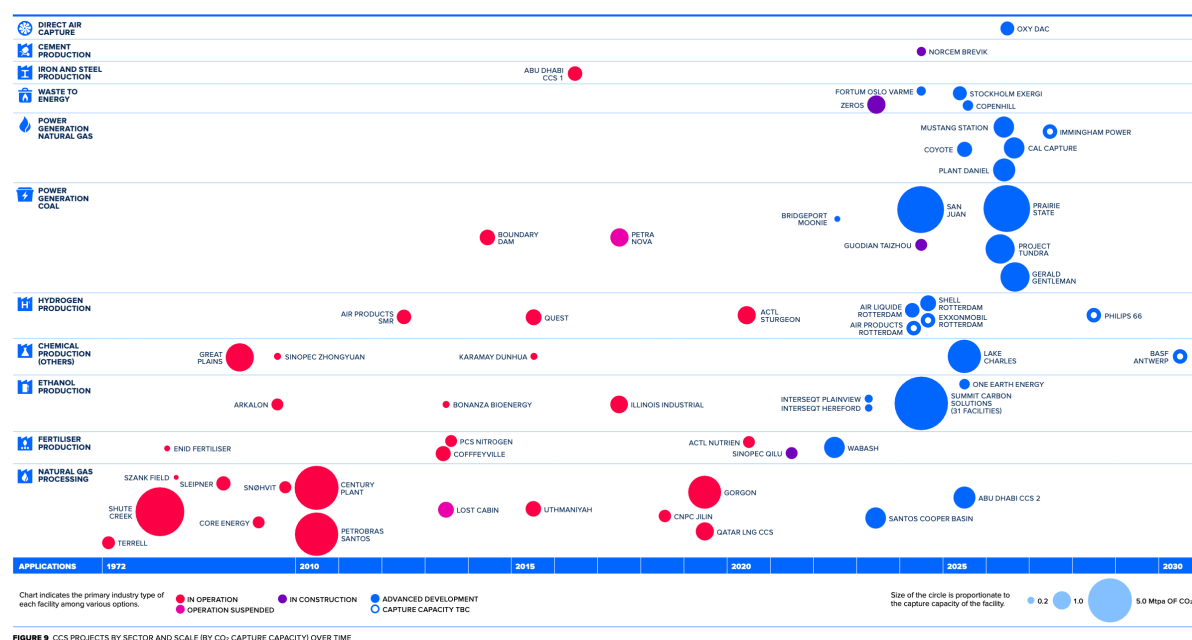


Figure 160: CCS projects by sector and size.

Source: Global CCS Institute, (2021).

It is also interesting to note that the Global CCS Institute uses a "CCS Readiness Index" for countries, which assesses indicators such as the inherent interest of the country, its policy and preparation for CCS through laws and regulations, and the provision of storage facilities.

According to this index, the USA, Canada, Australia, Norway and the UK are rated very highly, while other European countries including Germany, as well as Japan and China in the Asian region, are ranked in the middle.

The top position in this index is certainly also due to the fact that several companies in the USA and Canada have joined forces to jointly build pipelines and to inject the CO₂ produced in large quantities (100 Mt CO₂ /a in the USA and 40 Mt CO₂ /a in Canada), which is produced e.g. during the refining of oil or the processing of Canadian oil sands, into already exploited oil or gas fields. These activities are promoted by massive tax concessions or the assumption of investment and production costs by government bodies. In the case of the Langskip (Longship)

⁴¹⁷ See Global CCS Institute, n.d.

project in Norway, for example, in which CO₂ is collected by ship in Oslo and Brevik and injected by pipeline from a collection and liquefaction point into a depleted oil field in the North Sea, the Norwegian state assumes 75 % of the operational costs over 10 years. The ex-ship terminal costs for this service would be 30 - 55 €/t CO₂ from 2030.⁴¹⁸

The riparian states are invited by the Norwegian state to expand the network and also inject their CO₂ into this oil field via the same transport routes.

The increase in CCS projects should not obscure the fact that there is still a long way to go to realise the necessary amount of 5 - 10 Gt/CO₂ /a estimated by IPCC, which must be removed from the atmosphere in the second half of the century to prevent profound climate change (temperature increase < 1.5 °C). Indeed, CCS capacity must be increased by a factor of 100 by 2050, which means that 70 - 100 new CCS plants must be built per year and a budget of between US\$ 655 billion and US\$ 1280 billion must be made available for this purpose.⁴¹⁹

The CCS Institute estimates that this will create about 100,000 jobs for design and construction and about 30,000 jobs for operation and maintenance.

2.8.4 Transport of CO₂

2.8.4.1 Conditioning of the CO₂

In principle, CO₂ can be transported as a gas, liquid or solid. The phase diagram of pure CO₂ in Figure 161 shows the area in the P-T diagram above the vapour pressure curve in the supercritical range that is suitable for liquefying the CO₂. Usually, the transport of liquid CO₂ will take place at pressures >75 bar.

⁴¹⁸ Cf. TAZ, (2022).

⁴¹⁹ Cf. Global CCS Institute, (2021).

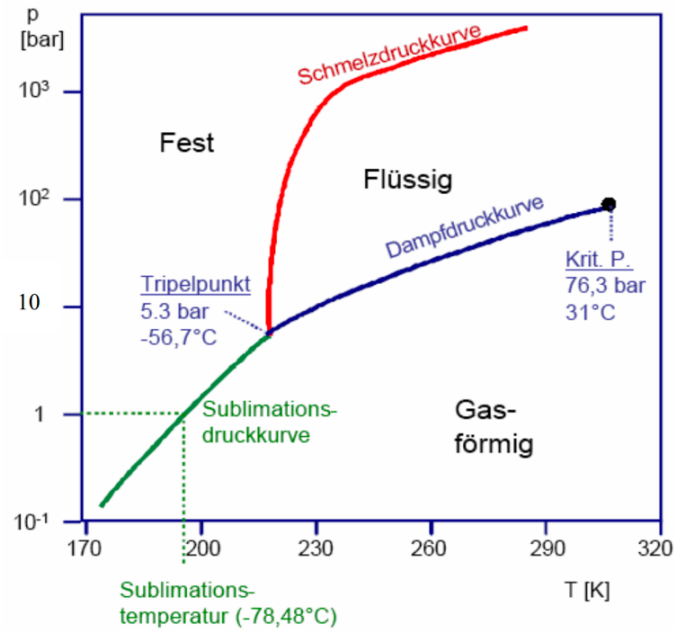


Figure 161: Phase diagram of pure CO₂.

Source: Markewitz et al., 2010, p. 25.

Dehydration of the gas is necessary to avoid carbonic acid. The cost of compression is significant, ranging from \$25 (at 0.1 Mt/a) to \$13 (at 5 Mt/a).⁴²⁰

Transporting gas has the disadvantage that large-volume transport containers are needed. Transporting compressed gas is more efficient, but places demands on the pressure resistance of the transport containers or a pipeline (10 MPa < pressure < 80 MPa) and requires additional energy.

Experiences from the transport of liquefied hydrocarbons (e.g. LNG, LPG) can also be transferred to the transport of liquefied CO₂. The conversion of CO₂ into a solid state for the purpose of transport is considered to be disadvantageous due to the high energy requirements.

In order to be able to transport the large quantities of CO₂ that are expected to be captured in the future, an expanded infrastructure and functioning logistics are needed.

2.8.4.2 Investment and transport costs for pipelines

Ships or trucks are used for the transport of smaller quantities of CO₂. There has been experience with the continuous transport of large quantities of CO₂ in pipelines since the 1970s. A

⁴²⁰ Cf. Massey, (2021).

pipeline network of 3,100 km has been built in the USA and CO₂ is transported in 6,500 km of pipelines worldwide, so these pipelines can be considered state of the art.⁴²¹

In Table 41 lists some long-distance pipelines with a CO₂ mass throughput of 5 to 19 Mt CO₂ /a mainly from the USA.

Pipeline	Location	Operator	Capacity (MtCO ₂ yr ⁻¹)	Length (km)	Year finished	Origin of CO ₂
Cortez	USA	Kinder Morgan	19.3	808	1984	McElmoDome
Sheep Mountain	USA	BP Amoco	9.5	660	-	Sheep Mountain
Bravo	USA	BP Amoco	7.3	350	1984	Bravo Dome
Canyon Reef Carriers	USA	Kinder Morgan	5.2	225	1972	Gasification plants
Val Verde	USA	Petrosource	2.5	130	1998	Val Verde Gas Plants
Bati Raman	Turkey	Turkish Petroleum	1.1	90	1983	Dodan Field
Weyburn	USA & Canada	North Dakota Gasification Co.	5	328	2000	Gasification Plant
Total			49.9	2591		

Table 41: Existing long-distance pipelines for the transport of CO₂

Source: IPCC, 2005, P. 183.⁴²²

The comparison of the total length of American and Canadian CO₂ pipelines with the total length in selected European countries in Table 42 clearly shows that in Europe only the UK has a good basis for expanding CCS activities.

Table 42: Comparison of the total length of national CO₂ pipelines.

Source: Global CCS Institute, 2014.

Anzahl	Land	Länge der Pipes in km	Kapazität in Mt/a
4	UK	931	42
3	NL	142	6,3
1	NO	153	0,7
1	DE	52	2
1	FR	27	0,06
5	CA	>720	
12	USA	3045	

The lack of international R&D budgets for pipelines is an expression of the fact that there is apparently no need for further research on pipelines. Damage statistics also show that CO₂ pipelines are significantly safer than natural gas or liquid pipelines.⁴²³

In principle, it is also possible to use LNG pipelines for the transport of appropriately conditioned CO₂. A look at the total throughput of active pipelines for LNG Figure 162 shows that

⁴²¹ Cf. Markewitz, (2017).

⁴²² More data on worldwide CCS projects is available at statista.

⁴²³ Cf. Markewitz, 2010, p. 27.

the LNG capacities in Germany (14.1 Mt/a) and Europe (294 Mt/a) are relatively low compared to those in the regions of East Asia and North America.

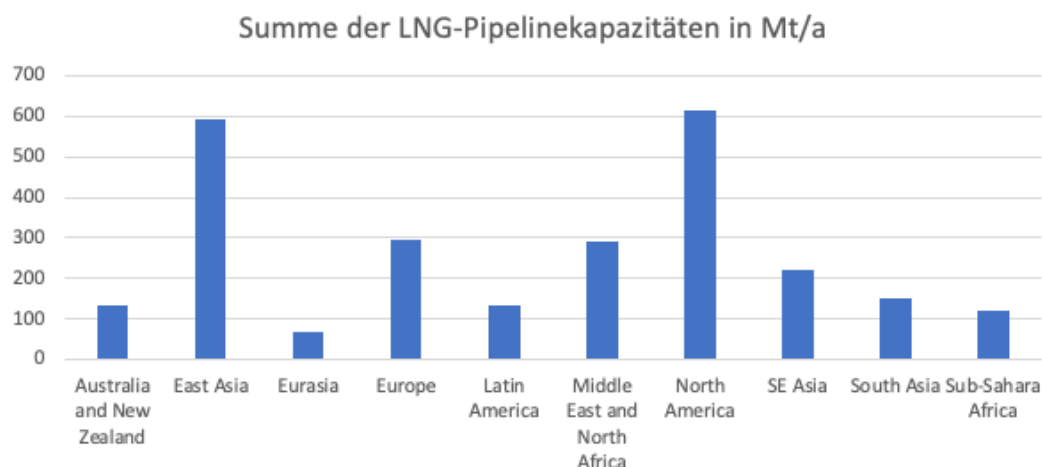


Figure 162: Globally active LNG pipelines with total throughput in Mt/a.

Source: Global Fossil Infrastructure Tracker, as of June 2021.⁴²⁴

Since some authors are considering transporting generated CO₂ in converted LNG pipelines to the point of injection, this means that there is little potential for this in Europe, so special CO₂ pipelines will essentially have to be newly built.

With regard to the investment costs for the construction of a pipeline, there are Figure 163 provides some information. Depending on the diameter of a pipeline and whether it is laid on land or in water, the costs range between 0.2 and 1.2 M€/km.

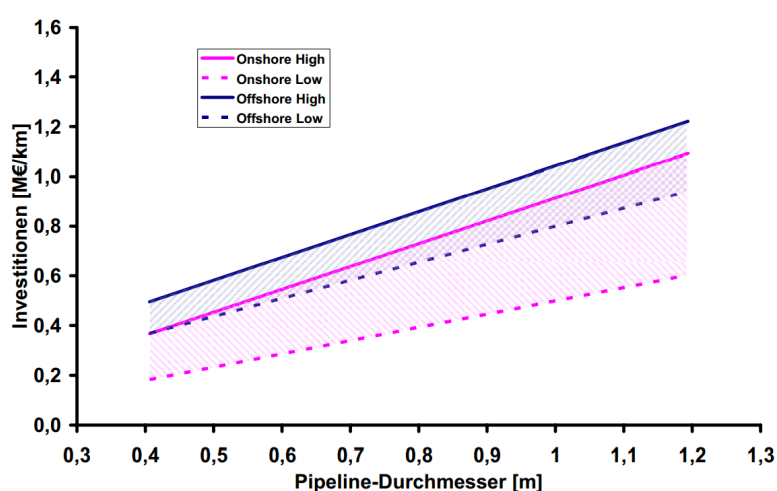


Figure 163: Range of investment costs for pipeline construction per km.

⁴²⁴ Global Energy Monitor, 2021: The source not only provides data on over 1,000 pipelines but also their location on a geographical map.

Source: IEA, 2008a; IEA, 2008b; IEF-STE, 2009 ; Markewitz et al., 2010, p. 27.

For the operation of a pipeline, the costs of the Figure 164 can be seen.⁴²⁵ For long pipelines of 400 km or more, the costs per km change only slightly.

The operating costs of a pipeline are mainly determined by the investment costs (CAPEX), which are proportional to the length of the pipeline. Changes in costs occur if the pipeline runs on land through difficult terrain, e.g. mountains or settlement. The transport costs per t CO₂ also depend on the degree of utilisation.

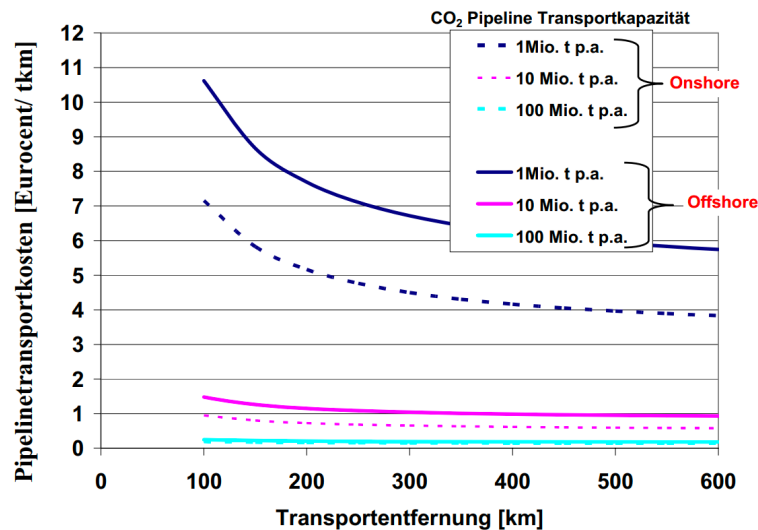


Figure 164: Range of transport costs for pipelines as a function of distance and with the parameter transport capacity onshore and offshore.

Source: Markewitz et al., 2010, p. 27.

Other authors assume a transport price of $6 \cdot 10^{-5}$ CAD/m³/km ($\equiv 3.6 \cdot 10^{-5}$ €/m³/km) based on the throughput quantity and length of the pipeline.⁴²⁶ If this is calculated on the basis of quantities and distances Figure 164 we arrive at the same order of magnitude for the transport costs, so that these figures can serve as a point of reference for cost calculations.

2.8.4.3 Quality requirements for CO₂ pipelines⁴²⁷

Corrosion tests on pipelines have shown that CO₂ with manganese alloy carbon steel pipes does not corrode as long as the relative humidity is less than 60 %.⁴²⁸ Otherwise, stainless

⁴²⁵ Cf. Markewitz, 2010.

⁴²⁶ Cf. Karangwa, 2008.

⁴²⁷ Details can be found in the European Commission SARCO report₂ : European Commission, (2017).

⁴²⁸ Cf. IPCC, 2005, p. 181.

steel pipes must be used. Further requirements for the quality of the transported gas are shown in the following table. Table 43 below.

The impurities of the gas to be transported also play a role in the compression of the gas for transport in the pipeline or in a tank. Since a two-phase region is passed through during compression (see Figure 161, S.269), a multi-stage compression is necessary, taking into account the shift in the dew line caused by impurities in the gas.⁴²⁹ The energy required for compressing pure CO₂ to e.g. 120 bar is 89 kWh/t CO₂. Depending on the size and type of the contaminating gas, the additional energy expenditure can be up to e.g. 28 % for 10% contamination by H₂.

Table 43: Quality requirements for the gas to be transported .

Substance in the transport gas	Quality requirement for the transport gas
CO ₂	> 95 mol%
H ₂ O	No free water, < 60 % relHumidity
H ₂ S	< 1,500 (wt)ppm
S _{tot}	< 1,450 (wt)ppm
Temperature	< 48,9 °C
N ₂	< 4 mol%
C _n H _m	< 5 mol%
O ₂	< 10 (wt)ppm
Glycol	< 4 · 10 ⁻⁵ l/m ³ = 0.04 (vol)ppm

It is hoped that existing pipelines for natural gas can be used to transport CO₂ with only minor conversion work.

2.8.4.4 Transport of CO₂ by ship

Experience with the transport of liquefied CO₂ is not yet as extensive as with the transport of LNG or LPG. Basically, there are three types of gas transport: Pressure tanks, which can prevent the liquid medium from evaporating under different ambient conditions; low-temperature transport, where the medium is cooled and kept liquid under atmospheric pressure; and semi-frozen transport, where the medium is cooled and kept under low pressure. In the operational tanker fleet, the rather small tankers have pressure tanks and large tankers designed for bulk transport are flexibly equipped for low temperatures and low pressure.

During transport by ship, conditions are usually set to keep CO₂ near the triple point in a semi-frozen state (see phase diagram in Figure 161).⁴³⁰ When transporting CO₂, a loss of

⁴²⁹ Cf. Markewitz, 2010, p. 34 f.

⁴³⁰ Cf. IPCC, 2005, p. 186 [1284].

3 – 4 %/1,000 km is to be expected,⁴³¹ which can be reduced by intercepting and reliquefying the CO₂.

The transport costs indicated by the IPCC in Figure 165 show that transport by ship is more cost-effective than a pipeline from a transport distance greater than about 1,800 km. The costs for transport by ship depend strongly on the size of the ships with the corresponding equipment and the existence of stations for loading and unloading the ships.

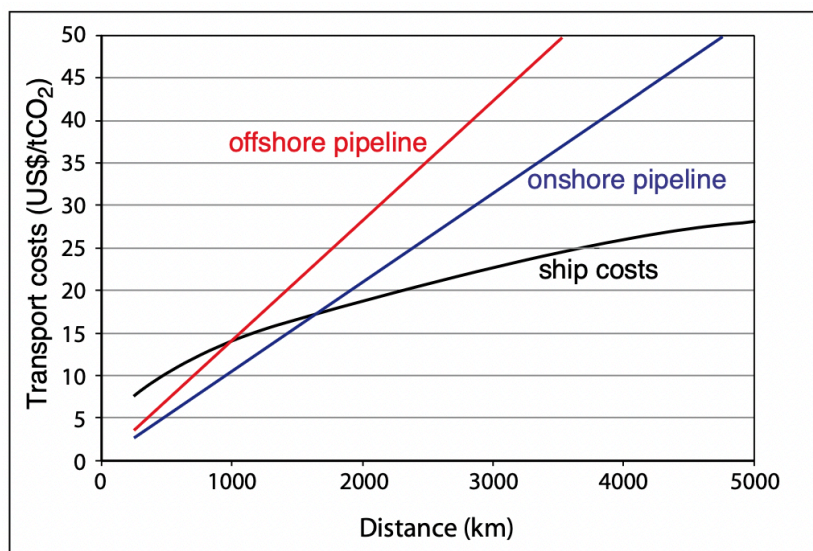


Figure 165: Comparison of transport costs per t CO₂ for a mass flow of 6 Mt CO₂/a as a function of distance.

Source: IPCC, 2005, P. 31.

2.8.4.5 Transport of CO₂ by truck or rail

CO₂ can also be transported in pressure vessels at about -20 °C and 2 MPa on trucks or railway wagons.

⁴³¹ Cf. Greenfacts, n.d.

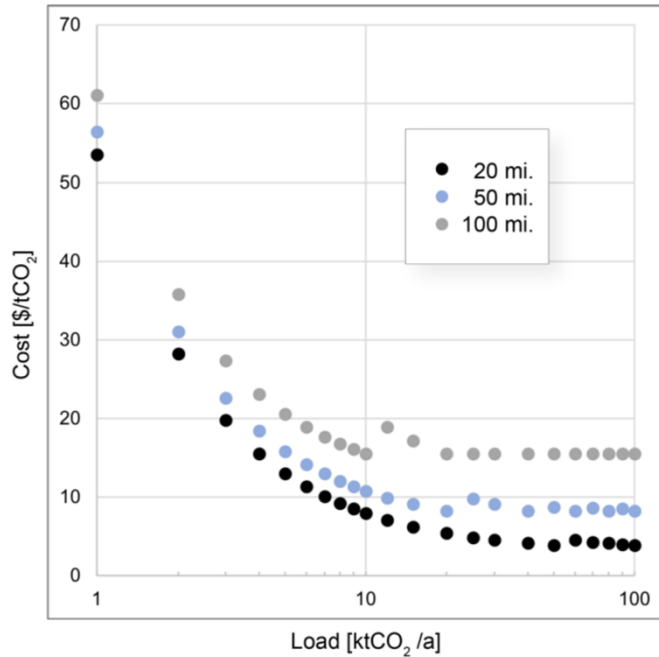


Figure 166: Costs for transporting CO₂ by truck as a function of the quantity captured and with the length of the transport route as a parameter.

Source: McQueen et al., (2020).

Costs for rail and boat transport are unfortunately not available on the internet.

Further information on the transport of hydrogen is available in chapter 2.5.

2.8.5 Storage of CO₂ (CCS)

2.8.5.1 Procedure

In principle, a distinction is made in the storage of CO₂ between storage in caverns, solution in underground, water-bearing strata (aquifers) and carbonisation of silicate-containing rock.

Since the early 2000s, the permanent storage of CO₂ in unused, water-bearing strata (aquifers at depths of more than 800 m) on land and under the seabed has been investigated or scientifically researched in pilot projects such as in Ketzin/near Berlin. Since 2005, large projects (e.g. Sleipner natural gas processing project in Norway, Weyburn EOR in Canada or Salah natural gas project in Algeria) have been injecting gas volumes of about 1 - 2 Mt CO₂ /a each.⁴³²

Land-based storage of CO₂ in gas or oil fields (EOR and EGR) and salterns is described as "economically viable" to "market-ready" under specific conditions, while subsea storage and also storage by mineralisation are still in the development phase.⁴³³

Injection of CO₂ into reservoirs of crude oil or natural gas to increase recovery (see EOR and EGR) can lead to permanent storage of CO₂ through various physical and geological mechanisms.

- High pressures (from 800 m depth) keep the CO₂ in a liquid-like state,

⁴³² Cf. IPCC, 2005.

⁴³³ Cf. ibid., p. 8, Table SPM2.

- Structural confinement by the seal, an impermeable overburden prevents re-emergence to the earth's surface
- Solubility inclusion, in which the CO₂ dissolves in the salt water,
- Residual trapping, where the CO₂ remains trapped in the pore spaces between the rocks, and
- Mineral inclusion in which the CO₂ reacts with the rocks of the deposit and forms carbonate minerals (mineralisation). Emplacement in basalt of volcanic origin enables emplacement at high concentrations and is currently under development. At the ORCA project in Iceland, 4,000 t CO₂ /a are currently injected and mineralised in the basalt.

This process is discussed separately below.

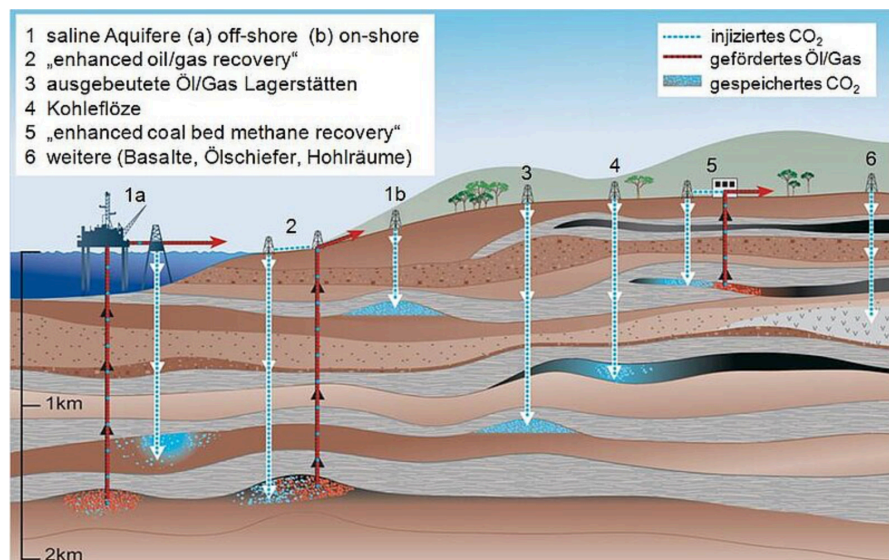


Figure 167: Schematic representation of CO₂ storage options.

Source IPCC, 2005, p. 6.

Large-scale underground storage of CO₂ is currently limited in Germany by the KSpG.⁴³⁴ 1.3 million t CO₂ /a in individual cases and 4 million t CO₂ /a in Germany are the upper limits within the scope of the law. The law leaves the federal states largely free to decide whether to allow or ban storage, so Schleswig-Holstein and Mecklenburg-Western Pomerania have already passed clear laws banning CO₂ storage.

The acceptance of CO₂ storage among the German population is relatively low and significantly reduces the probability of large-scale storage. Storage in European countries remains

⁴³⁴ KSpG: Carbon Dioxide Storage Act of 2012 with last amendment 2021

feasible. The world's largest test centre for CO₂ capture is located in Mongstad, Norway, 70 km north of Bergen.

The IEA states that there is a sufficient number of storage sites worldwide to store CO₂. Estimates of the geologically available capacity of storage sites range from 8,000 to 55,000 Gt CO₂ (for global storage).⁴³⁵ For Europe, capacities of 5 to 8 Gt/a were still estimated in 2015.⁴³⁶

Currently, only about 43 Mt CO₂ /a are captured worldwide (see Figure 168), which is negligible compared to the 35 Gt CO₂ /a produced in 2020.⁴³⁷ Figure 168 also shows that the addition of capacities to capture CO₂ in 2021 has increased by leaps and bounds compared to previous years. The largest share, about 29 Mt CO₂, comes from processing (production of "blue" hydrogen) from natural gas. Only about 3 Mt CO₂ are currently captured in the production of hydrogen. Should attitudes towards blue hydrogen change, the expansion of capacities to capture CO₂ generated during blue hydrogen production will have to be significantly increased.

CCUS facilities in operation by application, 1980-2021

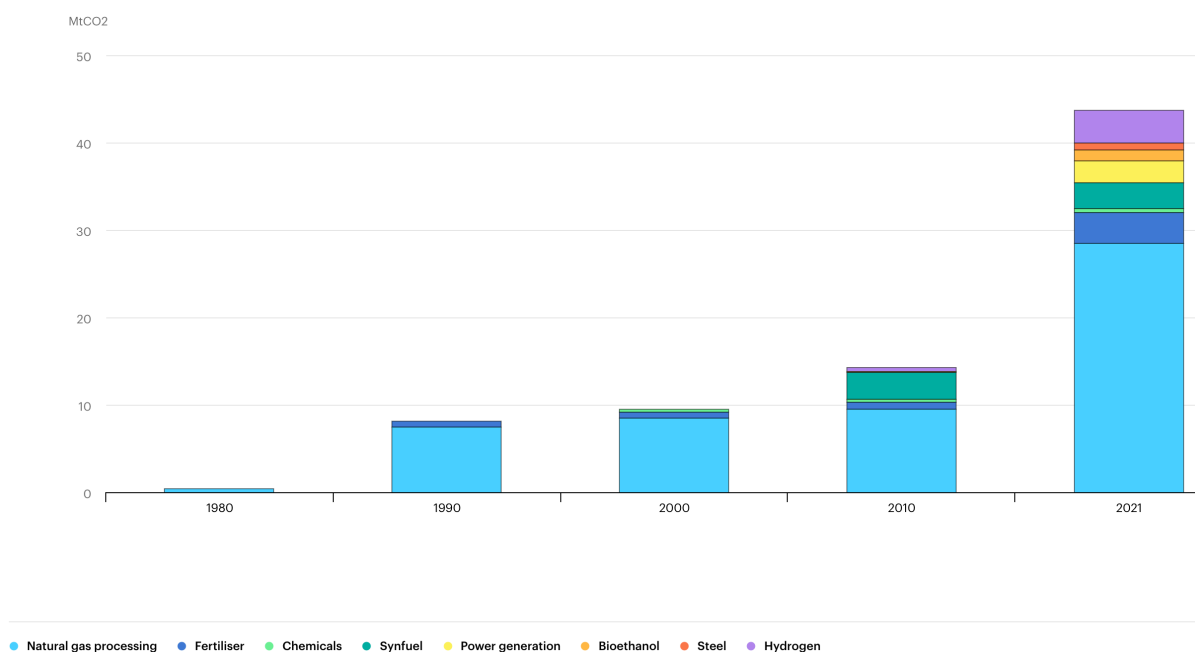


Figure 168: Global capacity to capture CO₂ at large plants from 1980 to 2021 in Mt/a.

Source: IEA, (2021).

⁴³⁵ Cf. Kearns et al., 2017, MIT and Exxon Mobile. With an emission rate of 35 Gt CO₂ /a (source: our-worldindata.org) from fossil fuel combustion, there is obviously sufficient storage capacity available for more than 100 years.

⁴³⁶ Cf. Mahnke, 2015.

⁴³⁷ Cf. Ritchie & Roser, n.d.

2.8.5.2 Perception of hazards in the injection of CO₂

The situation in places where CO₂ is injected underground or below the seabed is not always as ideal as in Figure 167 shown. The dangers associated with injection cannot be considered completely eliminated. In recent years, however, experience gained in various projects has led to the development of procedures for monitoring the storage sites, detecting leaks or repairing damage using procedures that have already been tried and tested.

CCS opponents often cite the case of Weyburne (Saskatchewan, Canada), where in 2010 on a farm above a field where CO₂ had been injected, animals on the pastures died in an unexplained manner and CO₂ concentrations of up to 11 % were measured at the earth's surface. The CO₂ could be attributed to the CO₂, which was injected, after an isotope analysis. Weyburne is still fuelling CCS opponents' fear of the consequences of leaking CO₂ storage facilities.

Figure 169 shows several ways in which the compressed CO₂ can return to the surface if there is no impermeable overburden above the reservoir to prevent CO₂ from rising to the surface.

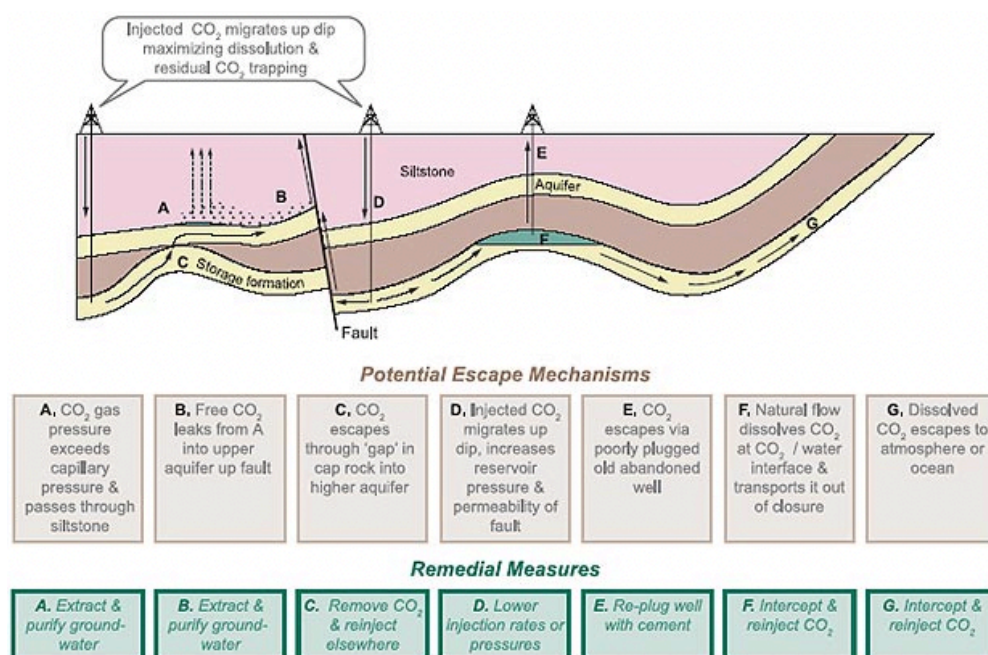


Figure 169: Faults in the injection of CO₂.

Source: Greenfacts, n.d.

- A: The gas pressure is greater than the capillary pressure and gas escapes e.g. through siltstone i.e. loose sedimentary rock in higher layers.
- B: Injected gas escapes at a fracture in the rock (tectonic fracture) into higher strata.⁴³⁸

⁴³⁸ Cf. Focus, 2015.

- C: Gas changes to a higher aquifer at a fracture. There is a possibility that saline aquifers are pushed to higher elevations and salinate the groundwater there, for example.
- D: The injected gas migrates to another aquifer, increases the reservoir pressure there and the permeability of the fault, causing gas to come to the surface.
- E: CO₂ escapes to the surface via an incorrectly sealed or older borehole.
- F: CO₂ dissolves in an aquifer and the water transports it out of the reservoir.
- G: CO₂ reaches the surface or the ocean with the water in which it is dissolved.

In the case of submarine storage, the escaping CO₂ could contribute to further acidification of the oceans. In addition to the risks listed above, there is also the risk of microquakes, such as those observed in the vicinity of exploited gas caverns.⁴³⁹ These quakes could in turn reduce the impermeability of the reservoirs.

The issue of CCS has already led to fierce demonstrations and the abandonment of some attempts to set up storage sites in the FRG.

This was preceded by the publication of an expert report on possible CO₂ storage sites in Germany, which had been commissioned by the BGR and was supposed to be kept secret but was published by Greenpeace with a map of the storage sites considered permissible (cf. Figure 176, Annex p. 288).⁴⁴⁰

Main arguments against CCS beyond those mentioned above and formulated by Greenpeace are:

- CCS comes much too late; the technology should have been in use as early as 2015,
- CCS wastes energy because, as already described in Chapter 2.8.3.6, the capture of CO₂ in power plants consumes up to 40 % of the energy generated and power plants with CCS consuming twice as much fresh water than power plants without CCS,
- CCS is too expensive, which would make the price of electricity more expensive,
- the question of who is liable for the damage in the case of a leaking bearing is open, as the insurance industry considers the risk incalculable.

The Federal Environment Agency also considers the many questions surrounding CCS to be still unresolved (publication dated May 2022).⁴⁴¹

⁴³⁹ Cf. Frankfurter Rundschau, (2022).

⁴⁴⁰ Cf. Greenpeace, 2011.

⁴⁴¹ Cf. Federal Environment Agency, (2022).

As long as the risk to the population living near or even on CO₂ storage sites cannot be controlled, there will certainly be little change to the restrictions of the KSpG in Germany. The Federal Environment Agency also complains that there is still too little know-how available for monitoring storage sites.

This means that in Germany the captured CO₂ has to be transported over longer distances until it is injected abroad and that an infrastructure has to be created for the transport of CO₂ to a storage site, e.g. in Norway (Sleipner since 1996, Snoevhit since 2011), Finland, Australia (Gorgon since 2019) the Netherlands (Porthos) or Scotland (Acron).

2.8.5.3 In situ mineralisation

The situation is different when CO₂ is injected into a geological layer made of basalt (volcanic rock with low silicate content), mafic or ultramafic (also of volcanic origin with high magnesium and iron oxide content). Important for in situ storage is the presence of double-positive charged ions such as Ca²⁺, Mg²⁺, Fe²⁺, which enable the complete setting of the CO₂ by carbonate formation in a rather short time of 1 – 2 years.

Figure 170 shows the locations in the world suitable for in-situ injection. According to Snoebjörndottir et al. (2020), the total storage capacity is about 250,000 Gt CO₂.

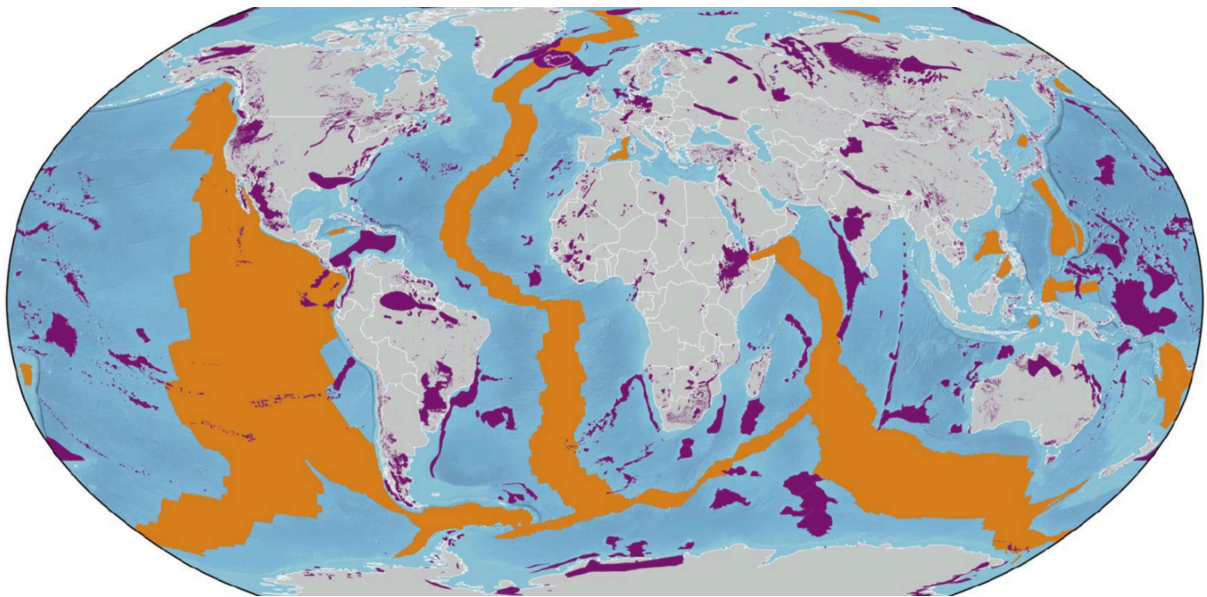


Figure 170: Basalt layers suitable for in situ mineralisation worldwide; orange: oceanic ridges younger than 30 Ma, purple: oceanic and continental suitable basalt layers.

Source: Snoebjörndottir et al., (2020).

While in other rocks CO₂ is only physically trapped in the gap volumes, in the types of rock mentioned a chemical bond (mineral trapping) can take place, which significantly limits the mobility of CO₂, so that the risks for the escape of CO₂ expressed in the previous section do not apply here.

The process of mineralisation, which occurs very slowly in nature (see Figure 171) can be accelerated by injecting CO₂ dissolved in water into reactive rock in such a way that 100 % of the CO₂ is converted into carbonates after only a few years,⁴⁴² i.e. the deposit can be secured against migration of the CO₂ to the surface. The reason for this is that CO₂ dissolved in water has an acidic character (pH 3 – 5) and dissolves calcium from the rock, which then combines very quickly with CO₂ to form CaCO₃. Likewise dissolved magnesium forms MgCO₃ or dolomite CaMg(CO₃)₂ at temperatures above 65°C and below that other, less stable compounds are formed.

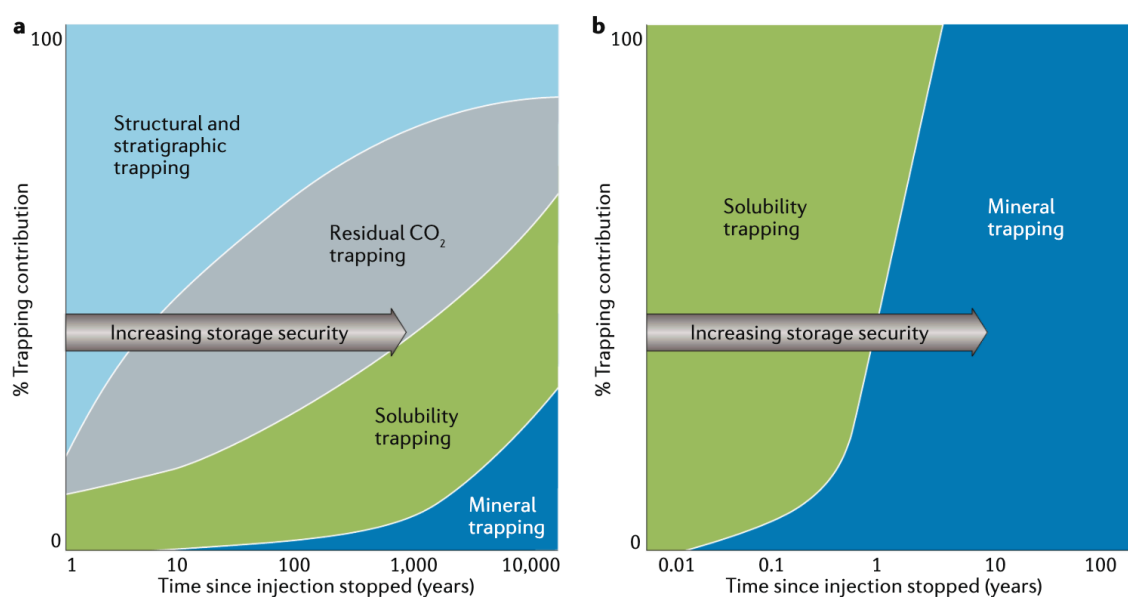


Figure 171: Comparison of capture mechanisms for CO₂ by compressing (a) supercritical CO₂, (b) of CO dissolved in water.

Source: Snoebjörnsdottir et al., (2020).

Fortunately, geological layers suitable for mineralisation are abundant worldwide, as about 70 % of the Earth's surface⁴⁴³ is basaltic. Mineralisation of the oceanic crust consisting of volcanic submarine basalt layers is also constantly taking place in the sea, which is estimated to chemically bind about 40 Mt CO₂/a from active submarine magma degassing. Measurements on the Icelandic coast give reason to believe that young basalts can naturally store more than 100 kg CO₂/m³.

This results in a globally distributed theoretical storage potential of 100,000 – 250,000 Gt CO₂, which is orders of magnitude larger than all CO₂ that can be produced by burning fossil sources.⁵⁰ This means that there is a sufficiently large storage potential to show CCS as a

⁴⁴² See also Carbfix, n.d.

⁴⁴³ Cf. Snoebjörnsdottir et al., 2020; Global Status of CCS, (2021).

fundamentally viable way to avoid climate change caused by the globally increasing production of CO₂.

2.8.5.4 Ex-situ mineralisation

The carbonisation of materials such as fly ash, iron industry waste, mining overburden by CO₂ streams has been intensively studied. In order to achieve sufficient carbonisation, the materials must be sufficiently crushed, which, together with the transport and storage of the carbonised products, drives the costs of this process to unattractive heights⁵⁰ and higher than those of in-situ mineralisation.

2.8.6 Interception, transport and grouting costs

The entire process from generation to securing the injected CO₂ can be broken down into the following steps (see Figure 172):

1. **Captureing** of CO₂: different processes are available for the gas streams depending on the CO₂ partial pressure, which differ significantly in cost. The costs are in the range of 30 – 80 US\$/t CO₂ (without DAC) and depend mainly on the partial pressure of CO₂ in the gas stream (see left cost groups in Figure 172).
2. **Drying and compression** of CO₂: depending on the throughput, the costs for this are 12 – 22 US\$/t CO₂
3. **Transport by pipeline**: depending on the transported quantity, the costs for onshore or offshore pipelines are in the range of 5 – 25 US\$/t CO₂ depending on the length of the pipeline.
4. **Transport by ship**: the costs depend, of course, on the transport route (see also Figure 165). A minimum value of 13 US\$/t CO₂ is used here.
5. **Injection** of CO₂: 3 – 19 US\$/t CO₂ (US\$ 0.5 – 8/t CO₂ according to IPCC)
6. **Monitoring and securing** CO₂ stock: about 1 US\$/t CO₂ (0.1 – 0.3 US\$/t CO₂ according to IPCC)

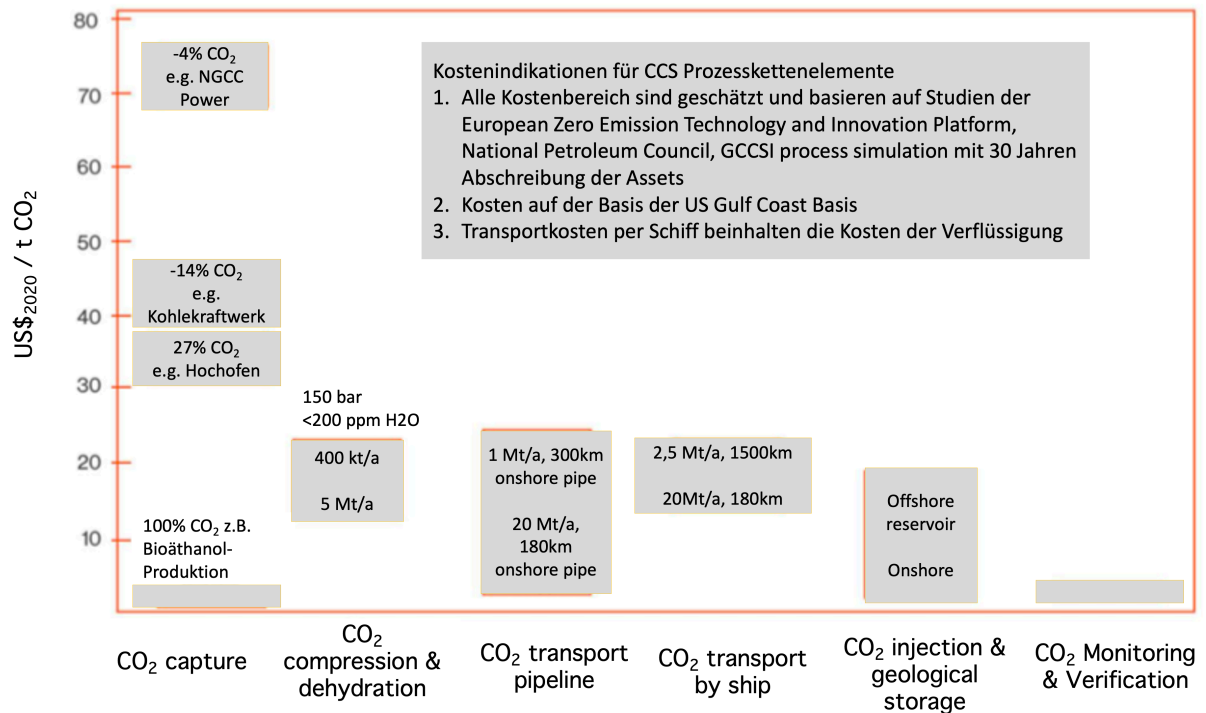


Figure 172: Cost blocks for the complete process from interception to monitoring of the injected CO₂

Source: adapted from Massey, (2021).

This means that in the best case, at least about 20 US\$/t CO₂ are added to the costs of capturing CO₂ for steps 2 to 6. In the worst case, this is even 80 US\$/t CO₂.

2.8.6.1 New business models with CCUS

Considering that local industries need to be able to reduce or avoid the levies on emitted CO₂ by capturing CO₂ and transferring it to sites for injection or use in CCU, they will leave the necessary activities and investments to service providers (e.g. Acorn Project in Scotland or Langskip (Longship) Project in Norway) if necessary. service providers (e.g. Acorn Project in Scotland or Langskip (Longship) Project in Norway),⁴⁴⁴ which receive the captured CO₂ at different production sites and process it further according to steps 2 – 6 in Section 2.8.6. New business models will develop in which, possibly through government start-up financing as with Langskip and through the (partial) assumption of operating costs, infrastructures will develop that will take over transport and final storage logistics as service providers (see Figure 173). In order to reduce costs, preferred locations for the injection of CO₂ are those close to the production of CO₂ or, if not that, then with a cost-effective connection to transport infrastructure such as pipelines or loading terminals for CO₂.

⁴⁴⁴ Cf. Massey, (2021).

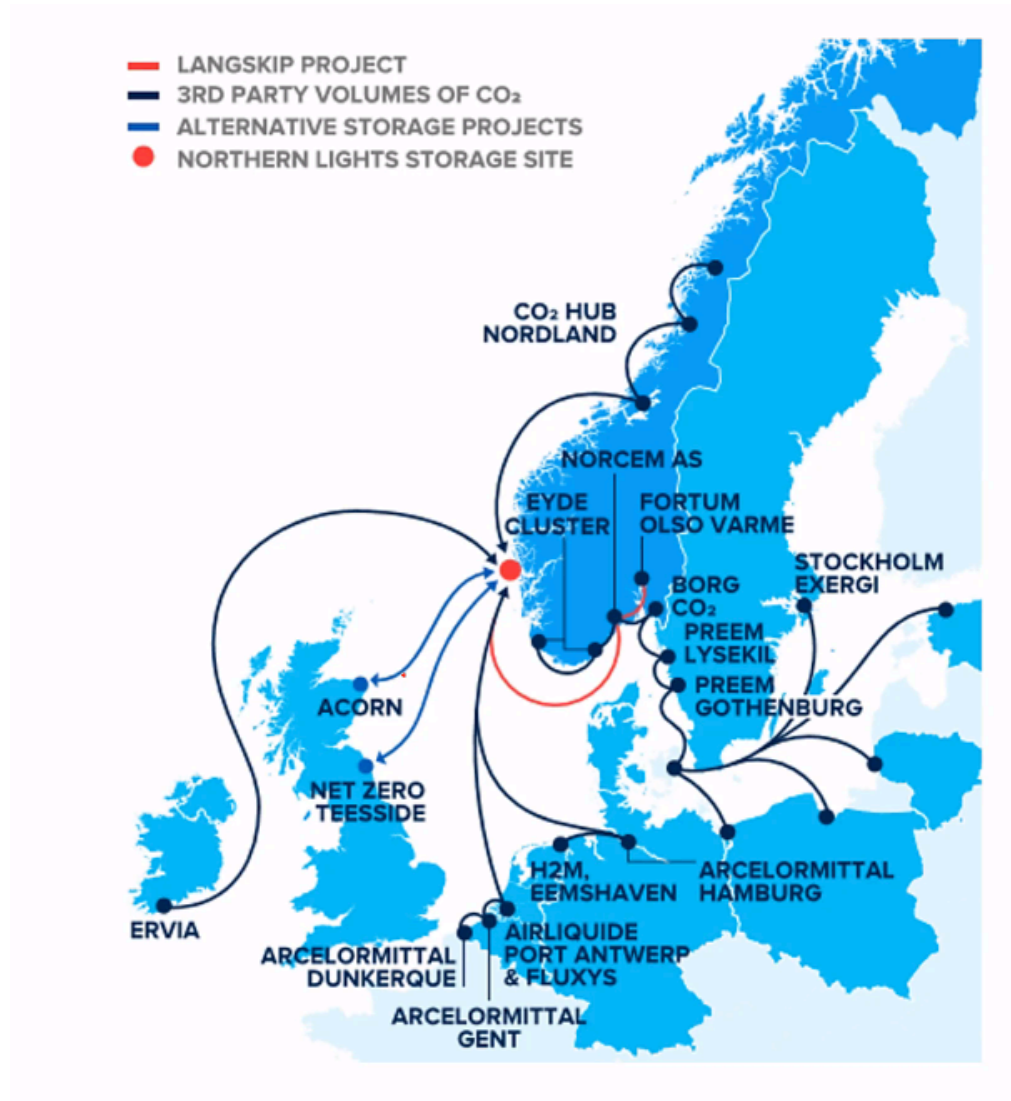


Figure 173: Project plan Langskip Project with Northern Lights Storage Site .

Other noteworthy projects in Europe are:

Porthos project: first commercial project in the EU, to be adopted in 2022 and operational in 2024, in which various companies in the region of the ports of Rotterdam and Antwerp will collect their CO₂ and inject it into an empty gas cavern in the North Sea about 20 km from the coast at a depth of 3 – 4 km.

Aramis project: Establishing a value chain and providing services for

- CO₂-Transport: liquid CO₂ (13 – 18 bar) by ship to the compressor station of Porthos
- CO₂ Collection point (hub): Port of Rotterdam
- Offshore pipeline from the hub to the offshore platforms
- CO₂ Storage

Dartagnan Project: Expansion of Porthos and Aramis through collection infrastructure near Dunkirk.

2.8.6.2 Legal basis for CCS

Large-scale underground storage of CO₂ is currently limited in Germany by the KSpG⁴⁴⁵: 1.3 Mt CO₂/a in individual cases and 4 Mt CO₂/a in Germany are the upper limits within the scope of the law. The law leaves the federal states largely free to decide whether to allow or ban storage, so Schleswig-Holstein and Mecklenburg-Western Pomerania have already passed clear laws banning CO₂ storage. The German Federal Government plans to revise the KSpG in the current legislative period.

CCS chain facilities remain subject to the Greenhouse Gas Emissions Trading Act (TEHG). The Federal Environment Agency (UBA) is responsible for the implementation of TEHG and KSpG and for monitoring the legal provisions. In 2009 it issued a guideline on the framework conditions for CCS. At that time, the UBA did not consider CCS to be sufficiently developed. In addition, there is a requirement that the captured CO₂ should be injected into storage sites in the immediate vicinity of the generating plant and that the storage sites should deposit the CO₂ generated throughout the life cycle of the CO₂ source there, which would rule out business models such as those mentioned above.

In summary, the Bellona report presents the legal situation for CCS in Germany.⁴⁴⁶ It assumes that the storage of CO₂ will not take place in Germany anyway, but in Norway or the Netherlands, so that the aspect of storage is not even considered further.

Germany is implementing the EU's requirement in Directive "2009/31 on the geological storage of carbon dioxide" for what is referred to as bridging technology. In paragraph (4), the EU emphasises that CCS must not be misused to increase the share of fossil-fuelled power plants. In 2009, the EU still planned moderate quantities of compressed CO₂: 7 Mt by 2020 and 160 Mt by 2030.

For submarine injection, the international legally binding treaty "Ospar" (Oslo and Paris) from 1992 is still taken into account. OSCOM (1972) and PARCOM (1974) regulated the dumping and discharge, respectively, of environmentally hazardous substances of continental origin into the North Sea and North Atlantic. OSPAR is responsible for everything that is discharged, dumped or otherwise introduced into the North Sea and North Atlantic. Signatories are the European Union and, as individual states, Belgium, Germany, Denmark, Finland, France, United Kingdom, Ireland, Luxembourg, Norway, the Netherlands, Portugal, Spain, Sweden and Switzerland.

⁴⁴⁵ KSpG: Carbon Dioxide Storage Act of 2012 with last amendment 2021; Federal Environment Agency, (2009).

⁴⁴⁶ See BBH, (2022).

The IMO (Intergovernmental Maritime Consultative Organization, founded in 1948) established procedures in 1969, which were primarily intended to enable the rapid and appropriate compensation of victims of oil spills. The "London Protocol" (LP) and the "London Convention" (LC) are considered the most advanced legal instruments dealing with CCS-SSGF (CCS in sub-sea geological formations) since 2006, but unfortunately they have not yet been ratified by all states – including Germany. The LP prescribes the steps to be taken before injection into marine areas under its own jurisdiction: Risk assessment and management, strict compliance with all protection standards, and is thus one of the most important pillars of environmental protection in the seas.

2.8.6.3 Life cycle of a CCS project

The lead time for a CCS project until the start of the work phase is 4 – 7 years as shown in Figure 174. In order to use the potential of CCS to relieve the environment of climate-damaging CO₂ as quickly as possible, action is needed as soon as possible.

When calculating the costs for a CCS project, it must also be taken into account that, similar to mining, so-called "perpetuity costs" are incurred even after the decommissioning of the plant due to the fact that the storage of CO₂ must be monitored, especially when it is stored in caverns and former storage sites of oil and gas.

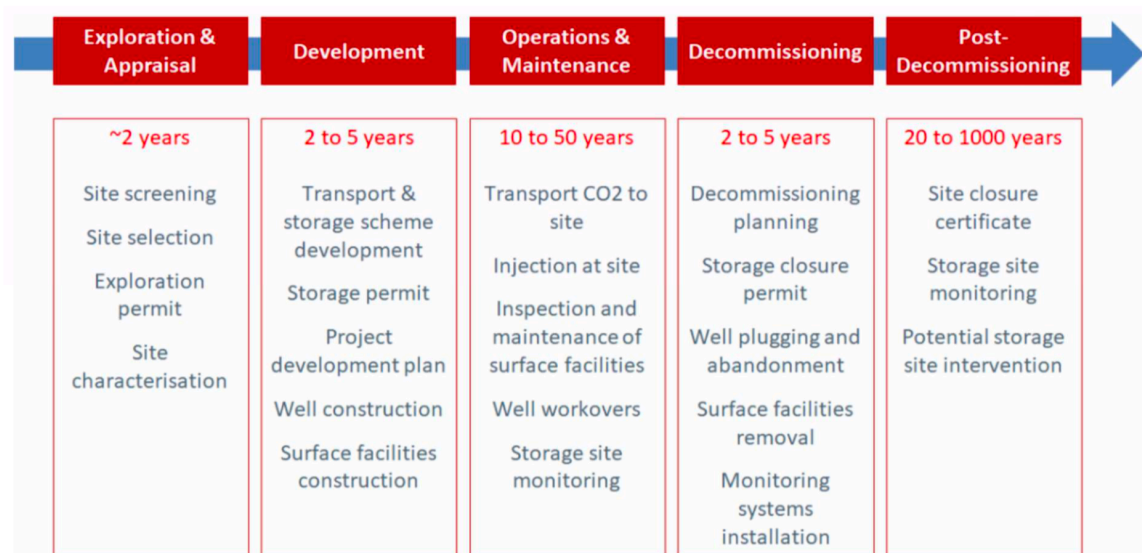


Figure 174: Life cycle of a CCS project.

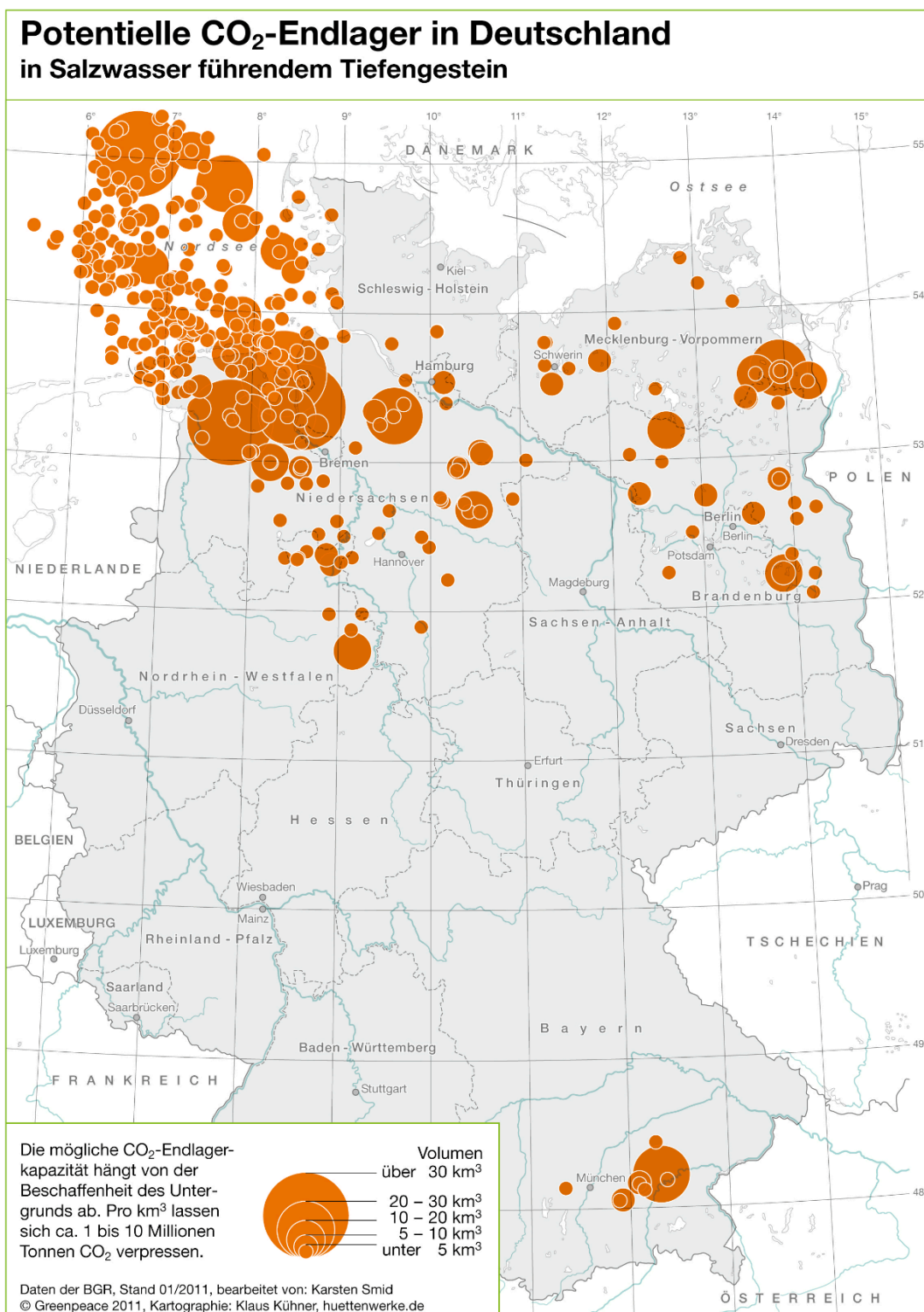
Source: Energy Transition Alliance, (2021).

Appendix to 2.8



Figure 175: Assessment of the maturity of CCS process parts.

Source: IEA, 2020 from Massey, (2021).



Die Bundesanstalt für Geowissenschaften und Rohstoffe (BGR) nennt in Deutschland 408 Standorte, die als CO₂-Endlager in „salinen Aquiferen“ in Frage kommen. Die meisten befinden sich in Norddeutschland und unter dem schleswig-holsteinischen Wattenmeer. In allen Regionen möglicher Endlager gibt es starke Proteste der Bevölkerung.

Figure 176: Locations for CO₂ repositories from an expert report by the BGR (2011) and the revision by Greenpeace.