Technology Data

Carbon capture, transport and storage

Energistyrelsen
Danish Energy Agency

Technology descriptions and projections for long-term energy system planning

Technology Data – Carbon Capture, Transport and Storage
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Amendment sheet

Publication date

Publication date for this catalogue is November 2021 and merges existing chapters around Carbon Capture, Transport and Storage of some of the other published Technology Catalogues. The catalogue will be updated continuously as technologies evolve if the data changes significantly, errors are found or the need for descriptions of new technologies arise.

The newest version of the catalogue will always be available from the Danish Energy Agency's web site.

Amendments after publication date

All updates made after the publication date will be listed in the amendment sheet below.

Version	Date	Ref.	Description
0001	November 2021		First published

Preface

The *Danish Energy Agency* publishes catalogues containing data on technologies for Energy Plants. All updates will be listed in the amendment sheet and in connection with the relevant chapters, and it will always be possible to find the most recently updated version on the Danish Energy Agency's website.

The primary objective of publishing technology catalogues is to establish a uniform, commonly accepted and up-to-date basis for energy planning activities, such as future outlooks, evaluations of security of supply and environmental impacts, climate change evaluations, as well as technical and economic analyses, e.g. on the framework conditions for the development and deployment of certain classes of technologies.

With this scope in mind, it is not the target of the technology data catalogues to provide an exhaustive collection of specifications on all available incarnations of energy technologies. Only selected, representative technologies are included to enable generic comparisons of technologies with similar functions in the energy system, e.g. thermal gasification versus combustion of biomass or electricity storage in batteries versus flywheels.

Finally, the catalogue is meant for international as well as Danish audiences in an attempt to support and contribute to similar initiatives aimed at forming a public and concerted knowledge base for international analyses and negotiations.

Data sources and results

A guiding principle for developing the catalogue has been to rely primarily on well-documented and public information, secondarily on invited expert advice. Where unambiguous data could not be obtained, educated guesses or projections from experts are used. This is done to ensure consistency in estimates that would otherwise vary between users of the catalogue.

Cross-cutting comparisons between technologies will reveal inconsistencies which may have several causes:

- Technologies may be established under different conditions. As an example, the costs of offshore wind farms might be established on the basis of data from ten projects. One of these might be an R&D project with floating turbines, some might be demonstration projects, and the cheapest may not include grid connections, etc. Such a situation will result in inconsistent cost estimates in cases where these differences might not be clear.
- Investors may have different views on economic attractiveness and different preferences. Some decisions may not be based on mere cost-benefit analyses, as some might tender for a good architect to design their building, while others will buy the cheapest building.
- Environmental regulations vary from between countries, and the environment-related parts of the investment costs, are often not reported separately.
- Expectations for the future economic trends, penetration of certain technologies, prices on energy and raw materials vary, which may cause differences in estimates.

- Reference documents are from different years. The ambition of the present publication has been to reduce the level of inconsistency to a minimum without compromising the fact that the real world is ambiguous. So, when different publications have presented different data, the publication which appears most in compliance with other publications has been selected as reference.

In order to handle the above mentioned uncertainties, each catalogue contains an introductory chapter, stating the guidelines for how data have been collected, estimated and presented. These guidelines are not perfect, but they represent the best balance between various considerations of data quality, availability and usability.

Danish preface

Energistyrelsen udarbejder teknologibeskrivelser for en række el- og varmeproduktionsteknologier. Alle opdateringer vil registreres i rettelsesbladet først i kataloget, og det vil altid være muligt at finde den seneste opdaterede version på Energistyrelsens hjemmeside.

Hovedformålet med teknologikataloget er at sikre et ensartet, alment accepteret og aktuelt grundlag for planlægningsarbejde og vurderinger af forsyningssikkerhed, beredskab, miljø og markedsudvikling hos bl.a. de systemansvarlige selskaber, universiteterne, rådgivere og Energistyrelsen. Dette omfatter for eksempel fremskrivninger, scenarieanalyser og teknisk-økonomiske analyser.

Desuden er teknologikataloget et nyttigt redskab til at vurdere udviklingsmulighederne for energisektorens mange teknologier til brug for tilrettelæggelsen af støtteprogrammer for energiforskning og -udvikling. Tilsvarende afspejler kataloget resultaterne af den energirelaterede forskning og udvikling. Også behovet for planlægning og vurdering af klimaprojekter har aktualiseret nødvendigheden af et opdateret databeredskab.

Endeligt kan teknologikataloget anvendes i såvel nordisk som internationalt perspektiv. Det kan derudover bruges som et led i en systematisk international vidensopbygning og -udveksling, ligesom kataloget kan benyttes som dansk udspil til teknologiske forudsætninger for internationale analyser og forhandlinger. Af disse grunde er kataloget udarbejdet på engelsk.

Table of Contents

Guideline/Introduction

This section aims at describing how the technology catalogue for carbon capture, transport and storage is elaborated.

The document is based on the guidelines for energy technology data for industrial process heat, version April 2020 (Energinet and the Danish Energy Agency), which in itself is based on the guideline for energy technology data for generation of electricity and district heating, version August 2016 (Energinet and the Danish Energy Agency).

As such, the preparation of a technology catalogue for carbon capture, transport and storage is to a wide extent similar to other technology catalogues prepared by the Danish Energy Agency – however certain principles and aspects of technology usage has to be described in more and slightly different details.

Therefore, the guideline for carbon capture, transport and storage comprises most of the sections that are in the guideline for the catalogue for generation of electricity and district heating, but some of the descriptions differ slightly to make them applicable for describing technology for carbon capture, transport and storage.

The main purpose of the catalogue is to provide generalized data for analysis of energy systems related to carbon capture, transport and storage including economic scenario models and inputs for high-level energy planning.

This catalogue covers data regarding energy technologies designed for carbon capture, transport and storage, mainly for technologies that are relevant for the Danish industry.

The technology catalogue for carbon capture, transport and storage is intended as a separate catalogue in the series of the catalogues *Technology Data for Energy Plants* which are developed and maintained in cooperation between the Danish Energy Agency and Energinet, thus in general it follows the same structure and data format as the catalogue for generation of electricity and district heating.

This catalogue covers data regarding plants/technologies designed for carbon capture related to heat and power plants, as well as transport and storage of carbon. In terms of carbon capture, the focus in this first edition is on post-combustion, pre-combustion and oxy-fuel combustion. Other carbon capture technologies and processes are relevant for capturing CO_2 and/or reducing the CO_2 content in the atmosphere and could be included in this catalogue. In terms of carbon transport, the focus is on CO_2 transport via pipeline, ship and road. Finally, in terms of carbon storage, the focus is on onshore and nearshore CO_2 storage in saline aquifers and offshore CO_2 storage in depleted oil and gas fields.

The technology chapters for carbon capture were previously a part of the *Technology data for industrial process heat* technologies, accompanied by a supplemental guideline that only featured the sections and assumptions that differed from the *Technology Catalogue for industrial process heat technologies*. The guideline can now be found in its entirety below with a description of all relevant sections. The technology chapters for CO_2 transport were previously a part of the *Technology data for energy transport* with a separate introductory chapter to that part of the catalogue. This introductory chapter is found directly above the chapters regarding CO_2 transport. The technology chapter on CO_2 storage was not published within the *Technology data* domain before and was finalized during the restructuring of the present carbon capture technology chapters.

First services and boundaries are defined, then guidelines for the sections corresponding to the sections in the main guidelines of the *Technology Data Catalogues* are given. These sections are both general assumptions and qualitative parts and quantitative parts of the catalogue. Templates for the data sheets are included in annexes.

Definition of the service

Carbon capture technologies (CC) are technologies that e.g. capture CO_2 from processes related to combustion or upgrading of fossil fuels and bio-fuels or from chemical processes in the industry (e.g. cement production) or that absorbs CO_2 directly from the air. Even as of today, CC is commercial and used around the world, although it has yet to become economically feasible in the power and heat sector and in the industry. The most common utilisation of the CC technologies today consists of a capture part, where CO_2, methane and hydrogen are separated from pure natural gas.[1] In Denmark today, the most common use of CC is for upgrading of biogas. Upgrading of biogas is described in chapter 82 of the *Technology Data for renewable fuels.*

This catalogue includes descriptions of technologies that provides the CC service, transport and storage of carbon.

The CC technologies can however be carried out using multiple types of systems. See examples of types and further descriptions in Table 1.

CC technology	Plant description	Advantages	Limitations
Post-Combustion (Tsiropoulos I, 2017)	CO_2 is removed from the flue gas through absorption by selective solvents, the most promising as of today is mono ethanolamine (Used at the Boundary dam project)	Can be applied on existing technologies with a flue gas	Energy intensive and costly post separation methodology, requires direct connection to stationary plant
Pre-Combustion (Tsiropoulos I, 2017)	The fuel is pre-treated and converted into a mix of CO_2 and hydrogen, from which CO_2 is separated. The hydrogen is then burned to produce power.	As the technology is not necessarily linked to a power plant, the hydrogen produced can be utilised in multiple sectors e.g. transport	High investment costs, energy intensive in both electricity usage and fuel conversion loss.
Oxy-fuel combustion (Tsiropoulos I, 2017)	The fuel is burned with oxygen instead of air, producing a flue stream of CO_2 and water vapour without nitrogen. From this stream water is condensed and a stream of CO_2 is obtained. The oxygen required for the combustion is extracted in situ from air.	The flue gas would primarily consist of CO_2 and H_2O, which are easier and cheaper to separate.	Energy intensive and costly oxygen production, requires direct connection to stationary plant
Chemical Looping Combustion (Schnellmann, 2018)	A new combustion technology with inherent separation of CO_2, by transferring oxygen from the combustion air to the fuel using metal oxides. The flue gas from the combustion chamber only consists of CO_2 and H_2O.	Potentially low costs and high efficiencies in both electricity and carbon capture, as the separation process happen internal during combustion	Low on the development stage and has, for now, only been proven with gas as an input fuel. Requires direct connection to stationary plant
Direct Air Capture (Keith, Holmes, Angelo, & Heidel, 2018)	CO_2 is captured directly from the air through absorption by selective solvents and large air conductors. Pure CO_2 is afterwards released for future processing The most used solvent today is $CaCO_3$.	Does not require a CO_2 heavy flue gas and can therefore be located close to storage or electro fuel production.	Very energy intensive

Table 1: Description of carbon capture technologies strength and weakness [1]

Except from the chemical looping combustion technology, all CC technologies do to a great extend rely on existing technologies put together in an innovative way. In Figure 1, the processes are illustrated.

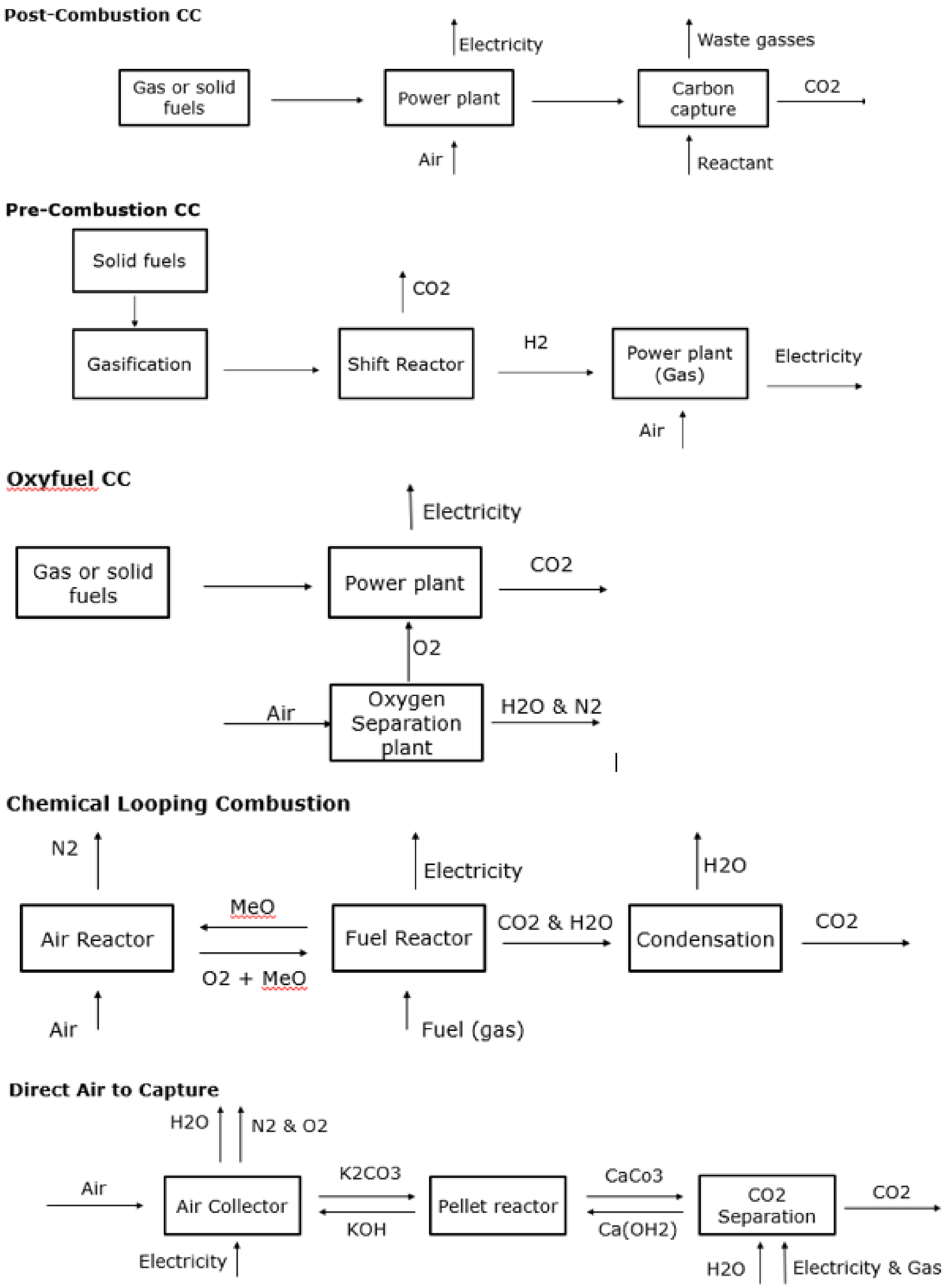

Figure 1: Diagrams of the differnet type of carbon capture systems [1]

The first three system types resemble the more traditional power plant solutions and has been proven at a larger scale, while Chemical looping combustion is only at demonstration scale and could be seen as a special case of oxy-fuel combustion. Direct Air Capture (DAC), however distinguish itself significantly from the other four technologies, as its sole purpose is to capture CO_2 and not limit the emissions from power and heat production.[1]

This guideline will focus on how to describe the carbon capture part of the first three technologies in a way that is useful when the purpose is to deliver technology data for technical energy system modelling.

A challenge is where to put the boundaries for the CC systems, it is desirable that it is done in the same way for all the three carbon capture systems categories. Therefore, the CC technology is described as a module. The module features the CC technology and specifies input and output. Thus, the power plant technologies or other technologies related to the CC technology is not described in this context.

Using this approach, the modeler has to provide technology data for technologies not included in the descriptions e.g. power plants using hydrogen as fuel, power plants using pure oxygen instead of air, thermal gasification plants, plants producing oxygen or prices for inputs (e.g. for O_2 or syngas).

In Figure 2, Figure 3 and Figure 4, the suggested boundaries for the carbon capture processes are illustrated by the red dotted lines.

For post combustion carbon capture technologies (shown in Figure 2), a carbon capture[1] technology is described. The inputs are flue gas, energy and other auxiliary inputs. The reduced energy efficiency of the power plant with post combustion CC is accounted for by an energy input to the CC. The output is CO_2, flue gas with lower CO_2 content and heat.

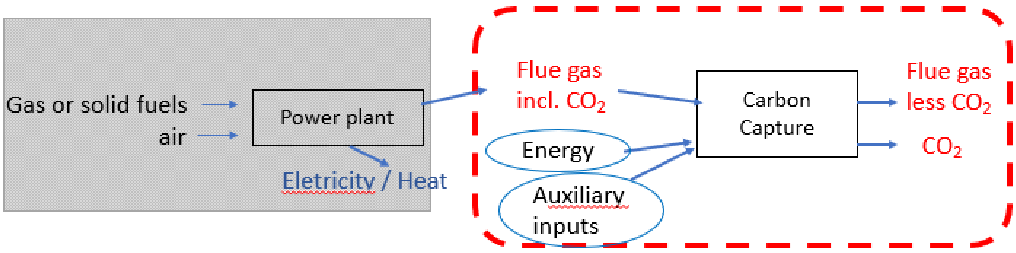

Figure 2: Post combustion

For pre-combustion carbon capture technology (shown in Figure 3), the shift reactor is described as the CC-technology. The inputs are syngas (from gasification of biomass), energy and other auxiliary inputs. The outputs, are CO_2, H_2 and heat.

There will be no descriptions of the gasification plants nor of the power plant burning H_2.

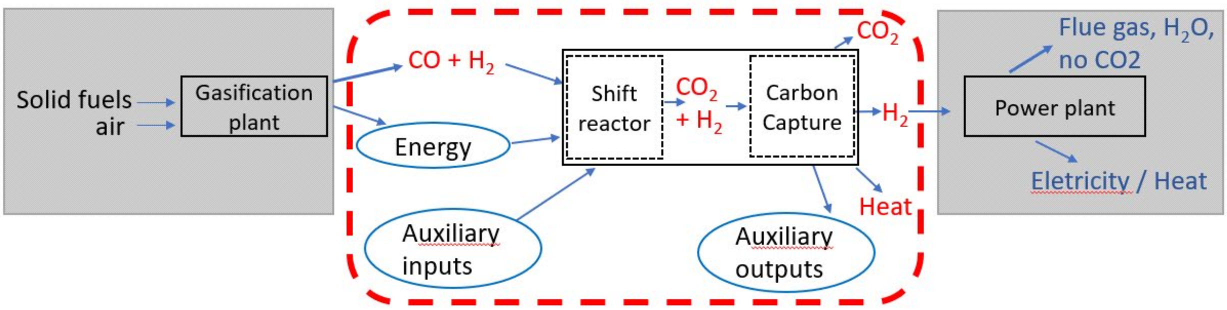

Figure 3: Pre-combustion

[1] There are different CC post combustion processes separating parts of the CO_2 from the fluegas e.g. absorption, adsorption, membrane and metal oxides [2].

For oxy-fuel combustion carbon capture technology (shown in Figure 4) the CC process can be regarded as an addon module that includes all the required modifications. Inputs are flue gas from oxy-fuel combustion (consisting of CO_2 and H_2O), energy and other auxiliary inputs. The outputs are CO_2, H_2O and heat.

Oxy-fuel combustion processes can only produce modest purity CO_2 (~70-90%), hence a CO_2 post processing unit is required to upgrade the CO_2 to meet transportation or utilisation conditions as shown in Figure 4. Because of the relatively low quality of the raw CO_2, the CO_2 processing unit will be more comprehensive compared to other CC technologies.

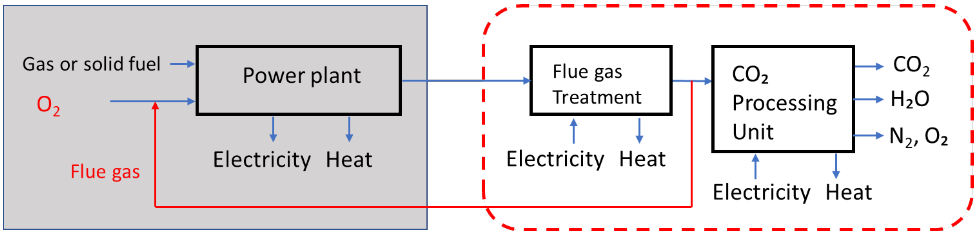

Figure 4: Oxy-fuel combustion

For direct air capture (DAC, shown in Figure 5) the CO_2 is captured directly from the air, hence the DAC module will have no interfaces to existing plants. The module comprises the entire capture plant and all auxiliary systems needed by the specific technology. Inputs to the module is air, energy and possibly (dependent on the specific technology) various auxiliaries.

As for the other CC technologies the DAC module will provide a concentrated low-pressure CO_2 stream which requires a CO_2 post treatment unit to upgrade the CO_2 to meet the quality requirements for transportation or utilisation processes.

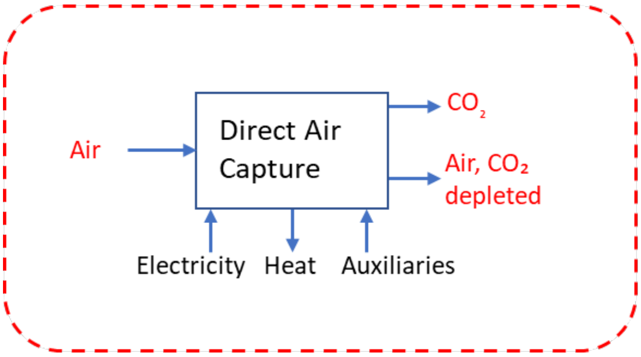

Figure 5. Illustration of Direct Air Capture (DAC).

All carbon capture processes need to deliver the captured CO_2 at a certain quality and at certain physical conditions (e.g. compressed CO_2), regardless whether the use is for geological storage or further utilisation. A CO_2 post processing unit (shown in Figure 6) will upgrade the CO_2 to required specification. Inputs to the post processing unit are raw CO_2 and electricity. Outputs are CO_2 (at required purity, pressure and temperature), water, heat and possibly O_2, N2 and Ar.

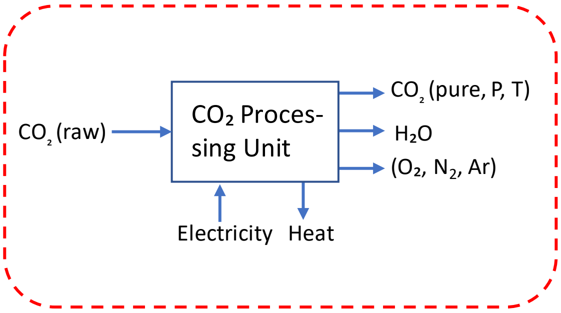

Figure 6. Illustration of CO_2 processing (conditioning) unit.

General Assumptions

The data presented in this catalogue is based on some general assumptions, mainly with regards to the utilisation time, load and start-ups of plants and technologies.

On the one hand, carbon capture technologies are assumed to be designed for continuous operation along the year, except for maintenance and outages. But their actual annual operation pattern will in general depend on the operation pattern of the technologies with which they are combined. Therefore, for the figures in this catalogue as default assumed load pattern is as assumed for the technologies generating electricity and district heating. The assumed number of annual operation hours is shown in Table 2. And the assumed number of start-ups for CC technologies are as shown in Table 3, unless otherwise stated.

Any exception to these general assumptions is documented in the relative technology chapter with a specific note. 3

	Full load hours (electricity)	**Full load hours** (heat)
CHP back pressure units	4,000	4,000
CHP extraction units	5,000	4,000
Municipal solid waste / biogas stand alone	8,000	8,000

Table 2: Assumed number of full load hours for technologies producing electricity and heating, 75 % of generation is expected to take place in full load and the remaining 25 % in part load.

	Assumed number of start-ups per year
Coal CHP	15
Natural gas CHP (except gas engines)	30
Gas Engines	100
Wood pellet CHP	15
Heat only boilers	50
Municipal solid-waste / biogas stand alone	5

Table 3: Number of start-ups for CC-technologies are assumed to be the same as for the power plant they are combined with.

Qualitative description

The qualitative description describes the key characteristics of the technology as concise as possible. The following paragraphs are included where relevant for the technology.

Contact information

Containing the following information:

- Contact information: Contact details in case the reader has clarifying questions to the technology chapters. This could be the Danish Energy Agency, Energinet or the author of the technology chapters.
- Author: Entity/person responsible for preparing the technology chapter

Brief technology description

Brief description for non-engineers of how the technology works and for which purpose.

An illustration of the technology is included, showing the main components and working principles.

Input

The flue/process gas and other main materials (e.g. amines in scrubber systems) and gasses (e.g. O_2 in oxy-fuel combustion) and energy consumed (e.g. electricity and/or heat) by the technology or facility. Moisture and CO_2 content of the flue gas and required temperature of the input heat is specified.

Auxiliary inputs, such as chemicals or enzymes assisting the process are mentioned and their contribution described, if considered relevant.

Output

The outputs are the CO_2 capture percentage (i.e. CO_2 reduction in the exhaust gas), the CO2 purity, as well as co-product or by-products, for example process heat. Pressure of the output gasses and temperature of the output heat is specified as well. Other non-energy outputs may be stated such as condensate from flue gas, if relevant.

Energy balance

The energy balance shows the energy inputs and outputs for the technology. Here, an illustrative diagram is shown based on data for the currently available technology.

For process heat losses and produced energy carrier, it is important to specify information about temperature and pressure.

The first important assumption is that the energy content of all the fuels, both produced and consumed, is always expressed in terms of Lower Heating Value (LHV). As a consequence, because of the presence of som latent heat of vaporization, the energy balance may result in a difference between the total energy input and total energy output.

Application potential

The application potential describes for which cases the technology can be used, e.g. how a retrofit case of carbon capture to existing heat and power plants is designed, or how carbon capture is integrated into cement production plants.

Typical capacities

The stated capacities are for a single unit capable of capturing carbon. If the range of capacities vary significant the typical range is stated (also in the notes), and it is mentioned if the different sizes of capacity is characteristic for e.g. a specific sector.

Space requirement
Space requirement is primarily expressed in m²/t CO_2 output/h. The value refers to the area occupied by the facilities needed to capture carbon, including chemical storage tanks and substation. If additional area is required for further required facilities it is stated separately.

Regulation ability
Regulation abilities includes the part-load characteristics, start-up time and how quickly it is able to change its production when already online. The technologies will most often have the necessary regulation abilities

Advantages/ disadvantages
A description of specific advantages and disadvantages relative to equivalent technologies and delivering the same energy service. Generic advantages are ignored; e.g. renewable energy technologies mitigating climate risks and enhance security of supply.

Environment
Particular environmental and resource depletion impacts are mentioned, for example harmful emissions to air, soil or water; consumption of rare or toxic materials; consumption of large amount of water (in general and relative to other technologies delivering same service); issues with handling of waste and decommissioning etc.

Research and development perspectives
This section lists the most important challenges to further development of the technology. Also, the potential for technological development in terms of costs and efficiency is mentioned and quantified if possible. Danish research and development perspectives are highlighted, where relevant.

Examples of market standard technology
Recent full-scale commercial projects, which can be considered market standard, are mentioned, preferably with links. A description of what is meant by "market standard" is given in the introduction to the quantitative description section. For technologies where no market standard has yet been established, reference is made to best available technology in R&D projects.

Prediction of performance and costs
Cost reductions and improvements of performance can be expected for most technologies in the future. This section accounts for the assumptions underlying the cost and performance in 2020 as well as the improvements assumed for the years 2030, 2040 and 2050.

The specific technology is identified and classified in one of four categories of technological maturity, indicating the commercial and technological progress, and the assumptions for the projections are described in detail (see section **Error! Reference source not found.**).

In formulating the section, the following background information is considered:

(i) Data for 2020
In case of technologies where market standards have been established, performance and cost data of recent installed versions of the technology in Denmark or the most similar countries in relation to the specific technology in Northern Europe are projected to 2020 (FID) and used for the 2020 estimates.

If consistent data are not available, or if no suitable market standard has yet emerged for new technologies, the 2020 costs may be estimated using an engineering-based approach applying a decomposition of manufacturing and installation costs into raw materials, labor costs, financial costs, etc. International references such as the IEA, NREL etc. are preferred for such estimates.

(ii) Assumptions for the period 2020 to 2050
According to the IEA:

"*Innovation theory describes technological innovation through two approaches: the technology-push model, in which new technologies evolve and push themselves into the marketplace; and the market-pull model, in which a market opportunity leads to investment in R&D and, eventually, to an innovation*" (ref. 6).

The level of "market-pull" is to a high degree dependent on the global climate and energy policies. Hence, in a future with strong climate policies, demand for e.g. renewable energy technologies will be higher, whereby innovation is expected to take place faster than in a situation with less ambitious policies. This is expected to lead to both more efficient technologies, as well as cost reductions due to economy of scale effects. Therefore, for technologies where large cost reductions are expected, it is important to account for assumptions about global future demand.

The IEA's New Policies Scenario provides the framework for the Danish Energy Agency's projection of international fuel prices and CO_2-prices and is also used in the preparation of this catalogue. Thus, the projections of the demand for technologies are defined in accordance with the thinking in the New Policies Scenario, described as follows:

"New Policies Scenario: A scenario in the World Energy Outlook that takes account of broad policy commitments and plans that have been announced by countries, including national pledges to reduce greenhouse gas emissions and plans to phase out fossil energy subsidies, even if the measures to implement these commitments have yet to be identified or announced. This broadly serves as the IEA baseline scenario." (ref. 7).

Alternative projections may be presented as well relying for example on the IEA's 450 Scenario (strong climate policies) or the IEA's Current Policies Scenario (weaker climate policies), or more recent equivalent IEA scenarios.

Learning curves and technological maturity

Predicting the future costs of technologies may be done by applying a cost decomposition strategy, as mentioned above, decomposing the costs of the technology into categories such as labor, materials, etc. for which predictions already exist. Alternatively, the development could be predicted using learning curves. Learning curves express the idea that each time a unit of a particular technology is produced, learning accumulates, which leads to cheaper production of the next unit of that technology. The learning rates also take into account benefits from economy of scale and benefits related to using automated production processes at high production volumes. The cost projections are based on the future generation capacity in IEA's 2 DS and 4 DS scenarios (2017 values are assumed to be a good approximation for 2015) [3], or more recent equivalent IEA scenarios.

Learning rates typically vary between 5 and 25%. In 2015, Rubin et al published "A review of learning rates for electricity supply technologies" [4], which provides a comprehensive and up to date overview of learning rates for a range of relevant technologies, among which:

The potential for improving technologies is linked to the level of technological maturity. The technologies are categorized within one of the following four levels of technological maturity.

<u>Category 1</u>. Technologies that are still in the *research and development phase*. The uncertainty related to price and performance today and in the future is highly significant (e.g. wave energy converters, solid oxide fuel cells).

<u>Category 2</u>. Technologies in the *pioneer phase*. The technology has been proven to work through demonstration facilities or semi-commercial plants. Due to the limited application, the price and performance is still attached with high uncertainty since development and customization is still needed. The technology still has a significant development potential (e.g. gasification of biomass).

<u>Category 3</u>. *Commercial technologies with moderate deployment*. The price and performance of the technology today is well known. These technologies are deemed to have a certain development potential and therefore there is a considerable level of uncertainty related to future price and performance (e.g. offshore wind turbines).

Category 4. *Commercial technologies, with large deployment*. The price and performance of the technology today is well known, and normally only incremental improvements would be expected. Therefore, the future price and performance may also be projected with a relatively high level of certainty (e.g. coal power, gas turbine).

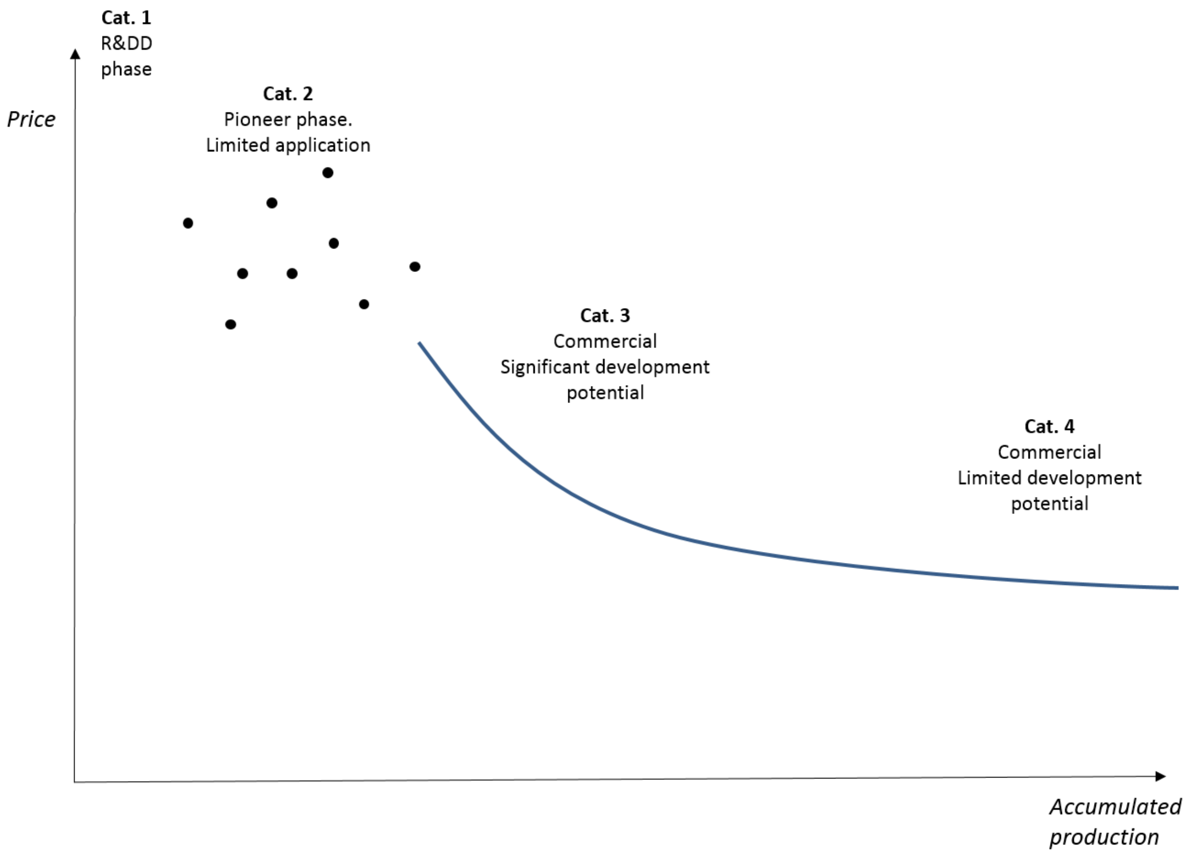

Figure 7: Technological development phases. Correlation between accumulated production volume (MW) and price.

Uncertainty

The catalogue covers both mature technologies and technologies under development. This implies that the price and performance of some technologies may be estimated with a relatively high level of certainty whereas in the case of others, both cost and performance today as well as in the future are associated with high levels of uncertainty.

This section of the technology chapters explains the main challenges to precision of the data and identifies the areas on which the uncertainty ranges in the quantitative description are based. This includes technological or market related issues of the specific technology as well as the level of experience and knowledge in the sector and possible limitations on raw materials. The issues should also relate to the technological development maturity as discussed above.

The level of uncertainty is illustrated by providing a lower and higher bound beside the central estimate, which shall be interpreted as representing probabilities corresponding to a 90% confidence interval. It should be noted, that projecting costs of technologies far into the future is a task associated with very large uncertainties. Thus, depending on the technological maturity expressed and the period considered, the confidence interval may be very large. It is the case, for example, of less developed technologies (category 1 and 2) and longtime horizons (2050).

Additional remarks

This section includes other information, for example links to web sites that describe the technology further or give key figures on it.

References

References are numbered in the text in squared brackets and bibliographical details are listed in the end of the technology chapter prior to the data sheets, references for data in the data sheet are listed below the data sheet for each sheet also in the Excel version. The format of biographical details of references should be; name of author, title of report, year of publication.

Quantitative description

For data sheets see the Excel file in the appendix

To enable comparative analyses between different technologies it is imperative that data are actually comparable. All cost data are stated in fixed 2020 prices excluding value added taxes (VAT) and other taxes. The information given in the tables relate to the development status of the technology at the point of final investment decision (FID) in the given year (2020, 2030, 2040 and 2050). FID is assumed to be taken when financing of a project is secured, and all permits are at hand. The year of commissioning will depend on the construction time of the individual technologies.

A typical table of quantitative data is shown below, containing all parameters used to describe the specific technologies. The table consists of a generic part, which is identical for groups of similar technologies and a technology specific part, containing information, which is only relevant for the specific technology. The generic part is made to allow for easy comparison of technologies.

Each cell in the table contains only one number, which is the central estimate for the market standard technology, i.e. no range indications.
Uncertainties related to the figures are stated in the columns named *uncertainty*. To keep the table simple, the level of uncertainty is only specified for years 2025 and 2050.

The level of uncertainty is illustrated by providing a lower and higher bound. These are chosen to reflect the uncertainties of the best projections by the authors. The section on uncertainty in the qualitative description for each technology indicates the main issues influencing the uncertainty related to the specific technology. For technologies in the early stages of technological development or technologies especially prone to variations of cost and performance data, the bounds expressing the confidence interval could result in large intervals. The uncertainty only applies to the market standard technology; in other words, the uncertainty interval does not represent the product range (for example a product with lower efficiency at a lower price or vice versa).

The level of uncertainty is only stated for the most critical figures such as investment cost and efficiencies. Other figures are considered if relevant.

All data in the tables are referenced by a number in the utmost right column (Ref), referring to the source specified below the table. The following seperators are used:

; (semicolon)	separation between the five time horizons (2020, 2025, 2030, 2040, 2050)
/ (forward slash)	separation between sources with different data
+ (plus)	agreement between sources on same data

Notes include additional information on how the data are obtained, as well as assumptions and potential calculations behind the figures presented are listed below the data sheet. References between notes and data are made by letters in the second utmost column in the data sheet Before using the data, please be aware that essential information may be found in the notes below the table.

It is crucial that the data for the technology is not based on one special version of the technology of which there is only one plant in operation or only on supplier of the technology.

Energy/technical data

Typical total plant size

The total CO_2 output per hour is used for describing the capacity, preferably a typical capacity. It is stated for a single plant or facility. In the case of substantial difference in performance or costs for different sizes of the technology, the technology may be specified in two or more separated data sheets. It should be stressed that data in the table is based on the typical capacity. When deviations from the typical capacity are made, economy of scale effects need to be considered inside the range of typical sizes (see the section about investment cost in the main catalogue). The capacity range should be stated in the notes.

Input

All inputs that contribute to the mass and energy balance are included as main input and are expressed mass per t CO_2 output and as molar/volume percentage in relation to the (flue or syn) gas input, or equivalently gas.

The energy inputs (and outputs) are always expressed in lower heating value (LHV) and moisture content considered is specified if relevant.

Auxiliary inputs, such as **chemicals** or **enzymes** that are assisting the process but do not contribute to the energy balance are included as *auxiliary products* (under *input*) and are expressed in kg/t CO_2 output.

Output

Similar to the mass and energy inputs, energy outputs are expressed as mass or energy per t CO2 output. Pressure of the output gasses and temperature of the output heat are specified as well.

Any energy co-product or by-product of the reaction has to be specified within the outputs, including process heat loss. Since fuel inputs are measured at lower heating value, in some cases the total efficiency may exceed or be lower than 100%.

The process heat (output) is, if possible, separated in recoverable (for example for district heating purposes) and unrecoverable heat and the temperatures are specified.

Forced and planned outage

Forced outage is reduced production caused by unplanned outages. The weighted forced outage hours are the sum of hours of forced outage, weighted according to how much of full capacity was out. Forced outage is defined as the number of weighted forced outage hours divided by the sum of forced outage hours and operation hours. The weighted forced outage hours are the sum of hours of reduced production caused by unplanned outages, weighted according to how much capacity was out. Forced outage is given in percent, while planned outage (for example due to renovations) is given in weeks per year.

Technical lifetime

The technical lifetime is the expected time for which a carbon capture plant can be operated within, or acceptably close to its original performance specifications, provided that normal operation and maintenance takes place. During this lifetime, some performance parameters may degrade gradually but still stay within acceptable limits. For instance, efficiencies often decrease slightly (few percent) over the years, and O&M costs increase due to wear and degradation of components and systems. At the end of the technical lifetime, the frequency of unforeseen operational problems and risk of breakdowns is expected to lead to unacceptably low availability and/or high O&M costs. At this time, the plant is decommissioned or undergoes a lifetime extension, which implies a major renovation of components and systems as required to make the plant suitable for a new period of continued operation.

The technical lifetime stated in this catalogue is a theoretical value inherent to each technology, based on experience. As stated earlier, typical annual operation hours and the load profile is specific for each carbon capture technology. The expected technical lifetime takes into account a typical number of start-ups and shut-downs (an indication of the number of annual operation hours, start-ups and shut-downs is given in the Financial data description, under Start-up costs).

In real life, specific plants of similar technology may operate for shorter or longer times. The strategy for operation and maintenance, e.g. the number of operation hours, start-ups, and the reinvestments made over the years, will largely influence the actual lifetime

Construction time

Time from final investment decision (FID) until commissioning completed (start of commercial operation), expressed in years.

Financial data

Financial data are all in Euro (€), fixed prices, at the 2020-level and exclude value added taxes (VAT) and other taxes, unless specified otherwise.

Several data originate in Danish references. For those data a fixed exchange ratio of 7.45 DKK per € has been used.

When data about costs is found in sources is shown in other price years, the Danish net price index shall be used when stating the costs at 2020 price level.

European data, with a particular focus on Danish sources, have been emphasized in developing this catalogue.

Investment cost

The investment costs are also called the engineering, procurement and construction (EPC) price or the overnight cost. Infrastructure and connection costs, i.e. electricity, fuel and water connections inside the premises of a plant, are also included.

The investment cost is reported on a normalized basis, i.e. cost per capacity (t CO_2 output / hour). The specific investment cost is the total investment cost divided by the Typical total plant size described in the quantitative section.

Where possible, the investment cost is divided on equipment cost and installation cost. Equipment cost covers the components and machinery including environmental facilities, whereas installation cost covers engineering, civil works, buildings, grid connection, installation and commissioning of equipment.

The rent of land is not included but may be assessed based on the space requirements, if specified in the qualitative description.

The owners' predevelopment costs (administration, consultancy, project management, site preparation, approvals by authorities) and interest during construction are not included. The costs to dismantle decommissioned plants are also not included. Decommissioning costs may be offset by the residual value of the assets.

Economy of scale

The main idea of the catalogue is to provide technical and economic figures for particular sizes of certain technologies. Where technology sizes vary in a large range, different sizes are defined and separate technology chapters (or just datasheets) are developed.

For assessment of data for technology sizes not included in the catalogue, some general rules should be applied with caution to the scaling of industrial technologies.

Example below is for the energy plants but is assumed that the same principle can be applied for the CC technologies.

The cost of one unit for larger technologies is usually less than that for smaller technologies. This is called the 'economy of scale'. The basic equation (ref. 2) is:

$$\frac{C_1}{C_2} = \left(\frac{P_1}{P_2}\right)^a$$

Where: C_1 = Investment cost of technology 1 (e.g. in M€)

C_2 = Investment cost of technology 2

P_1 = Power generation capacity of technology 1 (e.g. in MW)

P_2 = Power generation capacity of technology 2

a = Proportionality factor

Usually, the proportionality factor is about 0.6 – 0.7 for power plants, but extended project schedules may cause the factor to increase. It is important, however, that the technologies are essentially identical in construction technique, design, and construction time frame and that the only significant difference is in size.

The relevant ranges where the economy of scale correction applies are stated in the notes for the capacity field of each technology table. The stated range shall at the same time represents typical capacity ranges.

Operation and maintenance (O&M) costs.

The fixed share of O&M is calculated as cost per plant size (€ per t (CO_2 output/hour) per year), where the typical total plant size is the one defined at the beginning of this chapter and stated in the tables. It includes all costs, which are independent of how the plant is operated, e.g. administration, operational staff, payments for O&M service agreements, network use of system charges, property tax, and insurance. Any necessary reinvestments to keep the plant operating within the scheduled lifetime are also included, whereas reinvestments to extend the life beyond the lifetime are excluded. Reinvestments are discounted at 4 % annual discount rate in real terms. The cost of reinvestments to extend the lifetime of the plants may be mentioned in a note if the data has been readily available.

The variable O&M costs (€/t CO_2 output) include consumption of auxiliary materials (water, lubricants, fuel additives), treatment and disposal of residuals, spare parts and output related repair and maintenance (however not costs covered by guarantees and insurances).

Planned and unplanned maintenance costs may fall under fixed costs (e.g. scheduled yearly maintenance works) or variable costs (e.g. works depending on actual operating time) and are split accordingly.

All costs related to the process inputs (electricity, heat, fuel) are not included.

It should be noticed that O&M costs often develop over time. The stated O&M costs are therefore average costs during the entire lifetime.

Start-up costs

The O&M costs stated in this catalogue includes start-up costs and takes into account a typical number of start-ups and shut-downs. Therefore, the start-up costs should not be specifically included in more general analyses. They should only be used in detailed dynamic analyses of the hour-by-hour load of the technology.

Start-up costs are stated in costs per t_{CO2}/h per start up (€ per startup/[t CO_2/hour]), if relevant. They reflect the direct and indirect costs during a start-up and the subsequent shut down.

Technology specific data

Additional data is specified in this section, depending on the technology.

References

Reference documents are mentioned in each of the technology sheets and technology chapters. References used in the guideline supplement are below:

[1] Screening of (B)CCS and (B)CCR, An overview of Carbon Capture technologies for energy modelling, Mikkel Bosack Simonsen & Kenneth Karlsson DTU, December 2018

[2] CO2 Extraction from Flue Gases for Carbon, Capture and Sequestration: Technical and Economical Aspects;

Leonie Ebner, Mining University of Leoben 2008

[3] CO2-mitigation options for the offshore oil and gas sector, SINTEF 2017.

Appendixes

The datasheets in the appendix are in a separate Excel file.

Introduction to Carbon Capture Technologies

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i.1 Abbreviations

Abbreviation	Definition
ASU	Air Separation Unit
ATEX	ATmospheres EXplosives
CC	Carbon capture
CHP	Combined Heat and Power
CPU	CO_2 purification Unit
CFB	Circulating Fluidized Bed
DAC	Direct Air Capture
DH	District Heating
ECRA	European Cement Research Academy
FGR	Flue Gas Recirculation
MWh_e	Mega Watt hour electric
ORC	Organic Rankine Cycle
PC	Pulverized Coal
P2X	Power to X

i.2 Carbon Capture technologies

Carbon capture (CC) is a process that recovers CO_2 from a source (e.g. flue gas) and turns it into a concentrated CO_2 stream. Following the CC process, the concentrated CO_2 stream can be used as input to CO_2 utilisation processes e.g. P2X, urea production, etc. or compressed/liquefied and transported to geological underground formation with the purpose of permanent storage. In the context of CC from energy plants or other combustion plants, the CO_2 source is nearly always flue gas, hence the CC technology will be a gas separation technology.

A vast number of different carbon capture technologies have been proposed and investigated in the scientific community since the early nineties. Many of the technologies have not made it past the research stage and have failed to gain commercial attractiveness. A few technologies such as amine based CC and oxy-fuel technology have been demonstrated in large scale. The following section will provide a brief overview of the more significant CC technologies and explain the pros and cons in a Danish context.

i.2.1 Post combustion capture

Amine based

Amine based CC technology is the more mature and more widely demonstrated CO_2 capture technology available today. The technology works by scrubbing CO_2 out of the flue gas with an amine solvent and subsequent thermal regeneration of the amine solvent to yield a pure CO_2 stream. The technology is flexible with respect to CO_2 source and capacity. Amine CC may capture 90% or more of the CO_2 from the source.

Amine scrubbing has been used in smaller scale in the food and beverage industry for several decades to recover CO_2 from a flue gas/process gas stream and turn it into a high purity concentrated CO_2 stream. Amine scrubbing processes are also known within gas treatment (gas sweetening) and various chemical industries to remove CO_2 from process gasses e.g. natural gas, biogas, hydrogen, etc. The amine scrubbing process for upgrading biogas is described further in the chapter Biogas Upgrading in Technology Catalogue for Renewable Fuels.

For capture of CO_2 from flue gas streams, the capture plant is installed in the tail end of the combustion plant with minimal impact and interfaces to the combustion plant/point source. For these reasons the amine based CC process is very suitable for retrofitting to existing heat and power plants as well as to other industrial combustion processes. Amine CC technology may also be heat integrated with the steam cycle of boilers and the district heating network to obtain improved overall energy efficiency. Drawbacks with the amine technology is the use of substantial amount of heat, which may reduce heat output from a Combined Heat and Power (CHP) plant and/or result in large penalty in electrical efficiency. The capital cost today of the amine process is also significant.

The more recent years development of amine technology in a CO_2 capture context has focused on scale-up and optimization of the process with respect to energy requirement, capital investment and harmful emissions. There are several vendors offering amine based CC on commercial basis. The technology is further elaborated in section 0.

There is also research and development work ongoing regarding use of the classic amine CC process with alternative solvents such as amino acid salts, ionic liquids, non-aqueous solvents etc. This may lead to future improvements in energy requirements and investment costs of solvent CC processes, but these alternative solvents are still at low Technology Readiness Level (TRL).

Chilled ammonia/carbonate process

Chilled ammonia (or ammonium carbonate process) technology is relatively similar to amine CC process except that a solution of ammonium carbonate is used instead of amine. Due to the volatile nature of ammonia the process must be chilled to below ambient temperature to limit ammonia slip. The chilled ammonia process is proprietary process of Baker Hughes (former part of Alstom).

The advantage of the chilled ammonia process is supposed to be reduced heat consumption, CO_2 recovery at relatively high pressure (5-25 bar) and no emission of amine and degradation products. However, slow absorption kinetics, increased process complexity as well as challenges with handling of solid precipitation of carbonates have proven to be significant disadvantages. In addition, the heat requirement has proven higher than initially anticipated. The process has been demonstrated at relatively large scale (100,000 tpa). The process will be more relevant for more concentrated CO_2 sources.

Another carbonate process (Benfield process) has been applied for CO_2 removal in the process industry for decades. This process applies a solution of potassium carbonate instead of ammonium carbonate. As potassium carbonate is non-volatile the process does not require chilling. However, the very slow reaction kinetics and unfavourable equilibrium conditions will limit the application of this process to high pressure gas streams hence it is not suitable for CO_2 capture from flue gas.

Other solvent systems

Post combustion processes with alternative solvents such as non-aqueous solvents, ionic liquids, amino acid salts, enzymatically enhanced solvents, phase change solvents, etc. are also under development [1-4]. The aim with these alternative solvents is to achieve lower energy consumption and reduce the cost of CC technology. Most of the processes involving more novel solvents have not been demonstrated at large scale and are thus at relatively low TRL. Therefore, what energy and cost reductions these alternative solvents may bring relative to amine solvents remain uncertain.

Solid sorbents

Post combustion processes with use of solid sorbents instead of liquid solvents are under early stage development. Both solid adsorption processes working at low temperature suitable for tail-end retrofitting (similar as for amine technology) as well as high temperature processes working at the calcination temperatures of inorganic carbonates (600-900°C) exists.

For the low temperature process research focuses on developing solid sorbents with good properties for CO_2 capture and high process durability. Examples of sorbents are support materials of carbon, zeolite, metal organic framework (MOF), etc. loaded with amine functional groups [7]. Challenges relate to low cyclic loading of the solid i.e. need to circulate large amounts of solid, relatively rapid deactivation of solid sorbent, and difficulty in developing a robust industrial scale process.

The high temperature sorbent process also referred to as calcium looping applies lime (CaO) or modified lime with other metal oxides to capture CO_2 at high temperature (500-650°C) [1]. The formed solid carbonates are then calcined/regenerated to yield a pure CO_2 stream around 900°C [1]. Thus, the process requires heat input at high temperature, which may be delivered by direct oxy-firing in the regenerator (hence it may be regarded as oxy-fuel technology) or indirect heating. The main advantage of the process is the potential of high energy efficiency as the heat of absorption is released at high temperature (500-650°C) where it can be turned into power or used for process/district heating. If used as post combustion technology, calcium looping needs to be significantly integrated with the boiler, which in turn makes it non-suitable for retrofit. Challenges are also related to relatively low lifetime of the sorbent which implies relatively large mass streams of fresh and spent limestone will have to be handled [7]. In the case of a cement kiln where limestone is a major raw material, the short lifetime of the CaO sorbent is not an obstacle as spent CaO sorbent can be used as raw material. Calcium looping can also be applied in gasification plants to remove CO_2 from the gas prior to combustion. This makes the process a pre-combustion capture technology.

Solid sorbent technology is at low TRL and not relevant for near or midterm retrofit projects.

Membrane technology

Membrane technology is used in the industry today for gas separation. As a CO_2 capture technology, CO_2 selective membranes are under development and have been tested in pilot scale with some success [8]. The main challenge with membrane CC technology is the low partial pressure of CO_2 in flue gas, which make it difficult to obtain adequate driving force (i.e. CO_2 pressure gradient) for transport of CO_2 through the membrane. This is solved by compressing the flue gas and/or maintain high vacuum on the permeate side (CO_2 side) of the membrane. Both methods result in substantial electricity consumption [9]. Moreover, as the membrane area required for separation is inversely proportional to the driving force, there will always be trade-off between membrane area and driving force. In addition, membrane technology will be sensitive to dust and pollutants in the flue gas. Membrane CO_2 capture is at low TRL for flue gas and is more ideal for high pressure gas separation.

Cryogenic separation

Processes for CO_2 capture by freezing out CO_2 from the flue gas i.e. cryogenic separation, are also under development. The low CO_2 partial pressure in flue gas implies that the flue gas will have to be chilled to very low temperature (<-100°C) for the CO_2 to separate (freeze) from the gas. Therefore, the flue gas may also have to be compressed to avoid too low temperature. Handling of pollutants in the flue gas and use of expensive compression and chilling machinery are challenges to this technology. A process is being developed by Sustainable Energy Solutions. The technology may have some potential but is regarded as low TRL with only relatively small-scale pilot plant trials conducted. [10]

i.2.2 Oxy-fuel combustion

In oxy-fuel carbon capture, the oxygen required for combustion is separated from air prior to combustion, and the fuel is combusted in oxygen diluted with recycled flue-gas rather than by air.

This oxygen-rich, nitrogen-free atmosphere results in a flue-gas consisting mainly of CO_2 and H_2O (water), so producing a more concentrated CO_2 stream for easier purification.

In order to keep the temperature down and ensure the flue gas flow in the boiler, 60-70% of the cooled flue gas, which primarily consists of CO_2 and water vapor, is recirculated.

After the boiler, water vapor is removed from the flue gas which then typically consists of 70-85 vol% CO_2. CO_2 can then be further purified and compressed, ready for reuse or disposal.

The oxy-fuel technology is further elaborated in section 0.

i.2.3 Chemical looping combustion

Chemical looping combustion is a novel combustion concept with integrated carbon capture. Oxygen is carried to the combustion process in the form of a solid carrier e.g. metal oxide. The oxygen carrier will be reduced through reaction with the fuel and is hereafter regenerated in a separate oxidizing reactor with air. In principle, the technology is a kind of oxy-fuel process as nitrogen is eliminated from the combustion atmosphere. The concept will eliminate the costly air separation unit of oxy-fuel processes, hence offers a cost saving potential. The working principle of the technology has been demonstrated in pilot plant scale however, the concept has received little commercial attention and is therefore at low TRL level. The technology is not relevant for retrofit to existing emission sources.

i.2.4 Pre-combustion capture

Pre-combustion capture covers many different technology concepts. Common for all concepts is that the carbon from the fuel is separated from the combustible gases prior to combustion or use. The concept is only relevant for gasification/reforming plants where fuel is converted to CO_2 and H_2 prior to combustion. The concept is used today for hydrogen plants in the fertilizer industry to remove CO_2 from the feed stream to ammonia plants. Typically, the feed stream is at high pressure hence capture technology with physical solvents (pressure swing absorption) or less reactive amine (chemical) solvents can be applied. The concept is not relevant for flue gas from existing boilers but may be relevant for new-built energy plants based on gasification. Likewise, it will be relevant for production of emission free hydrogen from natural gas.

i.2.5 Direct air capture

The Direct Air Capture (DAC) technology captures CO_2 from ambient air and recovers a concentrated CO_2 stream like other CC technologies. Because of the low content of CO_2 in the atmosphere (~400 ppm) compared to that of typical flue gas, DAC processes have substantially higher energy requirements compared to CC from flue gas. Likewise, the capital expenditure per tonne captured CO_2 will be higher.

The DAC technology is still in its infancy and there are many different concepts under development. Most of the technologies and methods for DAC are still being developed in the laboratory and are thus at low TRL. A few technologies have been demonstrated in pilot- and/or commercial plants, but at relatively small scale (up to a few tonnes per day).

As DAC in the combination with renewable energy can be used to generate emission free CO_2 for use in CO_2 utilisation processes e.g. Power to Fuel, or carbon negative solutions in combination with geological CO_2 storage it may be a relevant technology despite the obvious obstacles. Another advantage with the DAC technology is it will be able to recover CO_2 at any location independently on an emission point source. The two most mature and relevant types of DAC technology for near to mid-term deployment are described further in section 0.

i.3 CO_2 post treatment

The CO_2 stream, i.e. raw CO_2, recovered by the different capture technologies typically requires further treatment/conditioning before it can be transported or used by other utilisation technologies.

Most CC technologies (including amine CC and oxy-fuel) will recover a concentrated CO_2 stream at fairly low pressure and saturated with water vapour. For oxy-fuel, the CO_2 purity is low and more extensive treatment is required. This will be further explained in the oxy-fuel technology section.

i.3.1 CO_2 compression and dehydration

If CO_2 is to be transported in pipeline from capture site to a geological storage or a utilisation site it will have to be compressed and dried to meet suitable conditions for pipeline transport.

Typical CO_2 pipeline pressures will be 80-180 bar to avoid two-phase region and obtain acceptable densities.

The moisture content of the CO_2 will be required to below 50-400 ppmv (depending on specifications) to avoid carbonic acid corrosion and/or hydrate formation. Dehydration processes such as mole sieve adsorption drying or glycol absorption drying is applied for drying of CO_2 gas. Table 0-1 summaries expected cost and performance of CO_2 compression from 1 to 150 bara.

Table 0-1. Energy consumption and cooling for CO_2 compression from 1 to 150 bara and dehydration to <50 ppmv moisture. Values estimated based on 8 stage internally geared compressor with inter-cooling to 30°C.

	Estimated value	**comment**
Compression electricity	~0.10 MWh_e/ton CO_2	0.09-0.12 depending on compressor design
Cooling requirement	~0.16 MWh/ton CO_2	30-100°C, possible to recover part of the heat
Dehydration electricity	~0.005 MWh_e/ton CO_2	
CAPEX CO_2 compression & dehydration	0.2 - 0.5 mill €/(t CO_2/h)	Depending on capacity

i.3.2 CO_2 liquefaction

CO_2 may be liquefied at various temperature and pressure conditions (-56 to 31°C and pressure of 5.2 to 74 bara). Typical conditions for transport, interim storage and trading of industrial CO_2 is in the order of -28°C and 15 bara.

In a standard industrial CO_2 liquefaction solution, concentrated CO_2 is compressed to 15-20 bara and liquefied by chilling at -25 to -30°C. The CO_2 is dehydrated prior to chilling. The requirements for CO_2 dryness for liquid CO_2 will be even more stringent due to greater risk of ice or hydrate formation at the lower temperatures (<30 ppm). Non-condensable gases will also have to be removed to low level as these will change the physical properties of the liquid CO_2. A standard liquefaction plant will include a stripping unit to remove non-condensable gasses, CO_2 dryer and activated carbon (or similar) filter to remove traces of organic compounds from the CC plant. A small loss of CO_2 in the liquefaction process through purging about 1% should be expected.

Typical energy requirement and CAPEX values of industrial CO_2 liquefaction plants are provided in Table 0-2.

Table 0-2. Energy consumption and cooling requirement for CO_2 liquefaction to -28°C and 15 bara. Values based on today's standard industrial solution for CO_2 liquefaction.'

	Estimated value	**comment**
Liquefaction electricity	~0.16 MWh_e/ton CO_2	Includes chillers, CO_2 dehydration and compression
Cooling requirement	~0.26 MWh/ton CO_2	~50% of cooling is through chiller air cooler, rest cooling water/cooling tower
CAPEX CO_2 liquefaction	0.4 - 0.8 mill €/(t CO_2/h)	Depending on capacity.

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Brief technology description

The amine carbon capture technology is based on cyclic absorption and desorption (stripping) processes. The CO_2 (which is an acidic gas) is absorbed from the flue gas by a circulating aqueous amine solution (alkaline solution) and released as a concentrated CO_2 stream through thermal regeneration of the amine solution i.e. applying heat to the solution, in a desorber. The CO_2 capture process is thus driven by thermal energy. The working principle of the process and its basic units are illustrated in Figure 1.

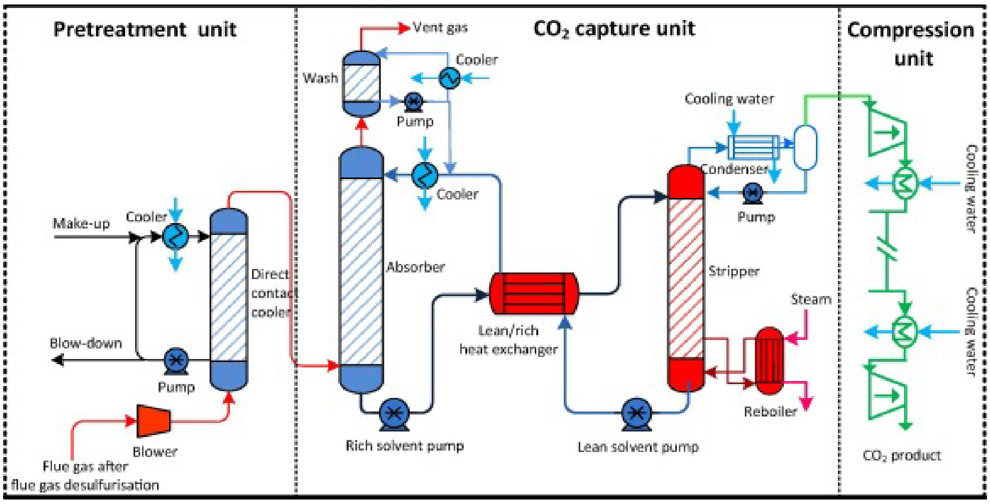

Figure 1. Schematic illustration of amine based CO_2 capture process as reported in [11]. Flue gas is cooled in a pre-treatment unit prior to entering the CO_2 capture unit where CO_2 is washed out by an amine solution. The CO_2 gas is stripped of the amine solution whereby it is regenerated by applying heat in a stripper (desorber). The recovered CO_2 may be compressed and dehydrated for transportation.

As outlined in Figure 1, a typical amine based CC plant will be composed of the following units:

Flue gas pre-treatment

Amine based CO_2 processes requires that the flue gas is relatively cool and clean i.e. low dust and acidic pollutants, before contacted with the amine solution. A too warm flue gas stream will disfavour the CO_2 absorption equilibria resulting in increased energy demand of the capture process. The presence of flue gas pollutants such as SO_2, HCl and NO_2 will inactivate the amine by irreversible absorption or degradation. This may in turn lead to excessive amine consumption, emission of amine degradation products, corrosion in the amine process as well as create more chemical waste. Furthermore, the presence of significant mass loadings of submicron particles in the flue gas e.g. acid mist, may lead to formation of amine aerosol emission.

Typically, the flue gas is preconditioned in a pre-scrubber or direct contact cooler. The pre-scrubber will quench the flue gas to typically 30-40°C and scrub out most remaining acidic pollutants and fly ash. Caustic solution is typically applied to remove the acid pollutants and keep the scrubbing water close to neutral pH. Because the flue gas is cooled below its dewpoint a bleed stream of condensate containing the absorbed pollutants is produced. Depending on the purity of the flue gas the condensate requires some level of treatment before discharged to public sewer. The cooling of the flue gas below its dew point requires also significant heat removal. This heat may also be upgraded with heat pump technology to be useful for district heating.

In case of a thermal power plant or other industrial emission source that is equipped with flue gas condensation it is likely that the described preconditioning unit may be omitted as the flue gas is already cooled to 30-40°C and polished for pollutants of dust, SO_2 and HCl. This will give small cost reduction for CC retrofitting.

Amine absorption loop

Following pre-treatment, the flue gas is led to a packed bed absorption column, where the CO_2 is scrubbed out through contact with the amine solution (solvent). The absorber will be the largest structure of the CC plant and may be 25-50 m tall. The absorber tower will be fitted with emission control sections in top (water wash and demisters) to minimize emissions of amine and degradation products with the treated flue gas. Significant heat will be released in the absorber due to the heat of absorption of CO_2. This will increase flue gas temperatures with 25-35°C. Cooling is therefore applied to maintain efficient absorption equilibrium and limit the evaporative loss of amine with the treated flue gas.

The CO_2 loaded amine solution (rich amine) is pumped to a regeneration tower (desorber) after pre-heating with hot regenerated amine solution. A reboiler – the device that heats the solvent - driven by low pressure steam (typically at 3-5 bara and 130-150°C) is installed in the bottom of the regeneration tower to supply the heat for releasing the CO_2 and regenerating the amine solution. The hot CO_2 and water vapours from the top of the desorber will be cooled in a condenser and the condensate will be refluxed. The concentrated CO_2 stream leaving the condenser is the product from the CC process. Typical operating conditions of the desorber is around 120°C and 2 bara in the bottom/reboiler and 100°C and 2 bara in the top. The condenser will cool the CO_2 to normally 30-40°C. The conditions will vary somewhat with the specific technology and there is also some flexibility in the design to adjust parameters.

The heat that must be removed from the desorber and absorber may be used for district heating.

Amine reclamation unit

Over time amine degradation products and traces of flue gas pollutants will build-up in the amine solution. To maintain the performance of the solvent, a reclamation process is applied where the active amine is recovered, and degradation products and pollutants are rejected as chemical waste. The reclamation process can be a thermal process that requires steam (6-10 bar) and caustic solutions. Alternatively, ion-exchange processes can be used which consumes more chemicals and water. [12] Some processes will also have continuous activated carbon filtration of the amine solution to remove some degradation products.

Input

The energy consumption for amine CC processes is significant and typically the largest element in the OPEX for the technology. The main energy consumption for the process is in the form of thermal energy, typically low-pressure (LP) steam (3-5 bara and 130-150°C) for regeneration of the solvent in the reboiler/desorber system. Depending on the specific technology (vendor), the CO_2 concentration in the flue gas and the flue gas temperature the thermal energy demand is typically reported to be within the interval listed in Table 1. For flue gases with CO_2 concentration above 6-8 % the specific energy requirement will only decrease marginal with increasing CO_2 concentration. At lower concentrations e.g. gas turbine exhaust (3-4% CO_2) there could be an energy penalty about 10-15%. Different options exist for reducing the thermal energy consumption of the CC process such as mechanical vapour compression, inter-cooling in absorber, internal heat integration, etc. [14] All these options will however increase the investment cost and may not necessarily be economically attractive.

The electricity demand for the amine based CC process is relatively modest as shown in Table 1. Electricity is mainly required for various recirculation pumps and the flue gas fan (increased pressure drop). Electricity for cooling water circulation is included. If a CO_2 post treatment process is included, where CO_2 is compressed to pipeline transport pressure or liquefied, the electricity consumption will be substantially higher as further described in section i.3.

Amine make-up needs to be added to the process to compensate for degradation and losses. This number is highly amine specific hence, it depends on the specific vendor technology. Typically, the variation range is as listed in Table 1. The classic amine process based on monoethanolamine (MEA) will see an amine consumption in the higher end whereas processes with more advanced amine solvents such as MHI's KS-1 or Aker Solutions S26 [13] solvents will be in the lower end.

Typical range for caustic soda consumption for flue gas pre-cooling and reclaiming is shown in Table 1. Other consumables such as activated carbon, lube oil, etc. are required in minor quantities. Caustic soda and the other minor consumables will typically constitute less than 1% of OPEX and can be ignored for initial evaluations.

Table 1. Typical main inputs for amine based CC processes. *Estimated from pumping works. ** Estimated based on 0-20 ppm SO_2 in flue gas + 0.1-0.3 kg/ton CO_2 for reclaiming use.

Parameter	Typical variation	Ref.	Comment
Reboiler LP steam demand	2.5-3.5 GJ/t CO_2 or 0.7 – 1.0 MWh/t CO_2 output (3-5 bara and 130-150°C)	[13, 16, 17, 18]	Depending on vendor technology
Electricity demand	25-35 kWh/t CO_2 output	*	Excluding CO_2 compression/liquefaction
Amine consumption	0.2 – 1.6 kg/t CO_2 output	[13]	Depending on vendor technology
Caustic soda consumption	0.1-0.5 kg/t CO_2 output	**	Depending on flue gas quality e.g. SO_2, HCl, and specific amine

Output

Main output of the process is the concentrated CO_2 stream i.e. the captured CO_2. Typically, 90% of the CO_2 content in the flue gas is captured, the remaining CO_2 is led to the stack through the flue gas stream. The capture rate can be increased to 95% or higher on the account of increased specific steam demand for regeneration and/or increased CC plant investment cost.

The CO_2 recovered from amine CC plants is highly pure. The CO_2 will normally be saturated with water vapour at the conditions it leaves the process (30-40°C and 1-3 bara), which corresponds to 2-3 %-vol. On dry basis the CO_2 purity will typically be 99.95 %-vol or higher. Main pollutants will be O_2 and N_2 as well as traces of volatile degradation products from the amine solvent.

For CO_2 storage and most technical applications the CO_2 from amine CC plants will have adequate quality. The requirement for post treatment of CO_2 is therefore mainly limited to conditioning of the CO_2 to meet conditions (pressure, temperature and dryness) for pipeline transport or ship/truck transport. In this context the water content will be an issue as CO_2 is very corrosive in the presence of water (forms carbonic acid).

As the captured CO_2 will normally have to be transported to storage/utilisation site, the amine CC plant will typically include a CO_2 compression plant (for pipeline transport) or liquefaction plant (for road or boat transport) with integrated dehydration plant. This is further described in section i.3.

Other main output from the amine process is low grade heat as listed in Table 2. Approximately the same amount of heat that is supplied to the CC process in the reboiler needs to be removed by cooling or used for district heating. This will be available at two or more distinct temperature levels, typically around 80°C in the desorber and around 50°C in the absorber. If flue gas pre-cooling is required, significant additional cooling is needed. This can be estimated from flue gas inlet conditions. As an example, if flue gas at 90°C with 20%-vol moisture and 13%-vol CO_2 is cooled to 35°C, approx. 0.5 MWh/t CO_2 output additional cooling is required and 0.5 m^3/t CO_2 output flue gas condensate needs to be discharged.

Minor outputs from the process are chemical waste from reclaimer, spent activated carbon, etc. which may be ignored in the initial OPEX estimate.

Table 2. Typical main outputs from amine based CC processes. * Estimated values based on typical inlet conditions for CHP flue gas.

Parameter	Typical variation	Ref.	Comment
CO_2 capture	85-95% (of flue gas CO_2 content)	[13, 16]	most studies are based on 90%
Heat output excl. flue gas pre-cooling	0.7–1.0 MWh/t CO_2 output 20% available at ~80°C 80% available at ~50°C	*	Cooling duty approximately similar to reboiler heat input
Heat output (cooling) flue gas pre-cooling	0-0.5 MWh/t CO_2 output Heat available at ~40°C	*	Depending on flue gas composition and inlet temperature
Flue gas condensate from pre-cooling	0-0.6 m^3 H_2O/t CO_2 output	*	Depending on flue gas composition and inlet temperature

Energy balance

An energy balance for a CO_2 capture facility with CO_2 compression and dehydration, which is treating a flue gas stream from a 100 MW_{th} biomass-fired energy plant, is illustrated in Figure 2. The biomass fired energy plant is assumed to be equipped with flue gas condensation (as in the data sheet), hence no additional pre-cooling of flue gas included. Electricity to pump cooling water/heat output stream from CC and compression plant is included.

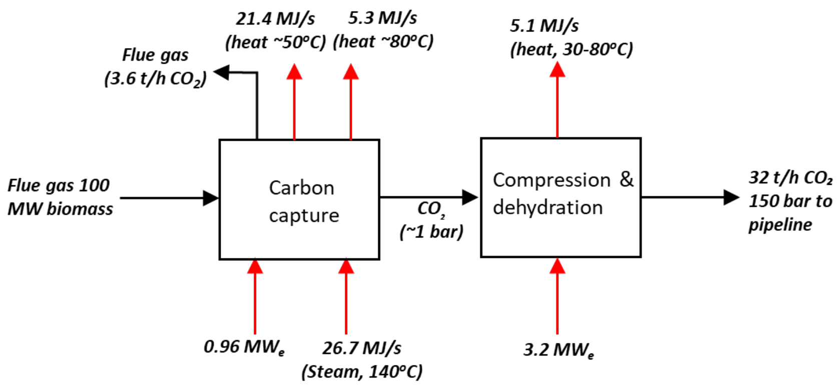

Figure 2. Illustration of energy balance for a CO_2 capture and compression plant treating all flue gas from a 100 MW_{th} biomass boiler that is equipped with flue gas condensation. 90% of the CO_2 in the flue gas is captured corresponding to 32 t CO_2 output per hour. Black arrows: Mass streams. Red arrows: Energy streams.

Application potential

The amine based CC process is very suitable for retrofit to existing heat and power plants as well as to other industrial combustion processes. Clearly installing a large process unit to an existing site in operation is always complicated. Typically, there may be challenges with space availability, tie-ins to existing plants, adequacy of existing utilities, etc.

For retrofitting an amine CC to power generation boilers, the LP steam for the amine plant can in many cases be extracted from the steam turbine of the power plant on account of an increased parasitic load. Thereby also investment in additional utility boiler for supply of steam to the CC plant is avoided.

Combined heat and power plants

A retrofit case of amine CC to an existing CHP plant is illustrated in Figure 3. The CC plant will typically have tie-in to the CHP plant in the tail-end just before the flue gas stack. Amine CC may therefore be applied to nearly all kinds of combustion technologies and fuels such as biomass CHP, Waste to Energy or fossil fuel fired plants. A CO_2 flue booster fan is typically included in the scope of the amine plant to overcome the increased pressure drop. The treated CO_2 lean flue gas (wet conditions) may be vented directly from the top of the absorber in a dedicated stack or alternatively routed back to the power plant's stack (more costly). Depending on local legislation, reheat of flue gas may be required.

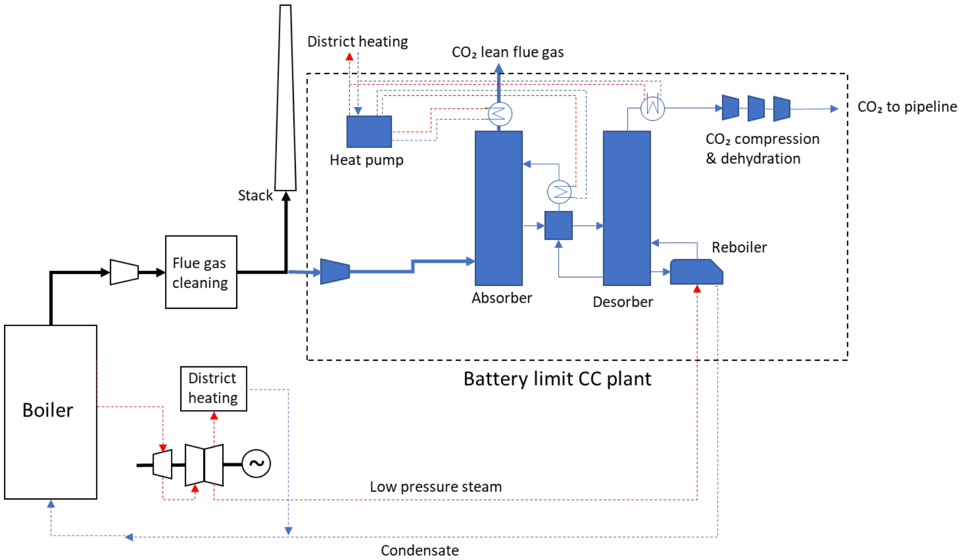

Figure 3. Illustration of amine CC retrofit to CHP plant. The CC plant includes a booster fan and CO_2 compression plant. The pre-scrubber has been omitted as the CHP has flue gas condensation and excellent flue gas cleaning. As an option heat pumps may be used to upgrade low value heat from CC plant to district heating.

In the CHP case it will typically be attractive to extract steam at low pressure from the turbine to drive the reboiler in the CC process as shown in Figure 3. This of cause depends on the specific steam turbine design as some turbines will not allow for steam extraction or not at correct pressure level. A major turbine modification may be required or even turbine replacement. To compensate for the reduced LP steam availability for district heating (DH), waste heat from the amine process and/or CO_2 compression may be integrated with the district heating network. However, about 80% of the waste heat will be available at relatively low temperature (about 50°C in average) that requires upgrade with heat pumps if to be used in the DH network. Heat pumps for upgrade of low temperature heat is not included in the energy numbers and CAPEX estimate in the data sheet (can be estimated from Technology Catalogue chapter regarding Technology Data for DH heat pumps), 20% of waste heat is available around 80°C, hence may be exchanged directly against DH water.

Depending on the possibility for heat integration with DH network and the available cooling capacity at the CHP, new cooling water capacity may need to be erected as part of the CC project.

As mentioned in Brief technology description, if the CHP is equipped with flue gas condensation, the pre-scrubber may be omitted from retrofit scope.

Other industrial emission sources

Amine CC will also be relevant for decarbonising emissions from other industries such as refinery emission sources, cement kilns, reforming plants, steel industry, large industrial utility boilers and more. In a Danish context, the largest industrial emission sources besides energy plants are cement kilns and refineries.

For cement kiln the tie-in will again be close to the existing stack downstream flue gas cleaning equipment. The CO_2 content of cement flue gas is typically higher (20-30%-vol) than for power plants (10-15%-vol), implying that the absorber part will be more compact. At cement kilns there is normally not steam available, hence a steam boiler or other heating plant will have to be included in the scope for an amine CC retrofit, which will increase costs and emissions to be captured. On the other hand, some cement kilns may have waste heat available after the preheating tower or in the clinker cooler excess air vent. Part of the heat demand of the amine CC process may therefore be covered by installation of Waste Heat Recovery Units (WHRUs) in the cement processing lines. Some cement kilns have already exploited this heat in a steam cycle for cogeneration of power. In this case it will presumably be cost efficient to use the produced steam for the CC plant instead of power generation.

The required cooling water capacity for a CC plant (Table 2) is unlikely to be present at the cement plant, hence this must typically be established as part of the CC project.

Refinery emission sources typically consist of several smaller point sources from fired heaters, crackers, auxiliary boilers, etc. The point sources may be combined and fed to a common capture plant for cost saving. At refineries several heat integration options would typically be available. It is however likely that an additional steam boiler will be required if a high share of the CO_2 emission should be captured.

Typical capacities

Amine based CC plants are today available from small scale 0.1 t CO_2 output/h in the food and beverage industry to large scale in the energy sector 200 t CO_2 output/h. This as single train units although plants at the higher end of the capacity interval will consist of multiple equipment units for heat exchangers and reboilers.

The biggest equipment in the amine CC plant are the absorber, desorber, pre-scrubber and reboiler. These will be tailormade equipment. Pumps, heat exchangers will be standard sizes.

The data sheet for "Post combustion - small biomass " is based on a 32-34 t CO_2 output/h capacity, whereas "Post combustion - large biomass" and "Post combustion - cement kiln" are based on 150-170 t CO_2 output/h.

CO_2 compressors are tailormade equipment and are available as single train units for the highest CC capacities.

Space requirement

An amine CC plant in the size range from 25 to 200 t CO_2 output/h is estimated to occupy an area of 40 m^2/[t CO_2 output/h], i.e. a 100 t CO_2 output/h CC plant will occupy 4000 m^2. This will include the basic CC process including chemical storage tanks and substation.

Additional area will be required for cooling towers or air coolers if no cooling water is available. For CO_2 compression and dehydration approximately 12 m^2/[t CO_2 output/h] additional is required. If liquefied CO_2 is produced, additional space should be allocated for CO_2 storage tanks and CO_2 export facilities.

Regulation ability

Amine based CC plants have good regulation ability. Turn-down to 20-30% of nominal capacity is possible.

In most retrofit projects, the CC plant will be integrated hence it is possible to bypass or partially bypass on the flue gas side. This will allow the energy plant or industrial emission source to operate without the CC plant in operation or with the CC plant at limited capacity.

Starting-up the process from cold conditions may involve slowly heating the system over 2-4 hours. If the CC plant is kept in hot standby conditions i.e. maintained at operating temperature, the CC plant will be able to start-up to full load in less than 0.5 hour.

It is also possible to regulate load up and down relatively fast by adjusting steam flow to the reboiler. In practice it may be the downstream transport and utilisation processes of CO_2 i.e. compressor, pipeline, injection well, that will be the limiting factor as these processes do not cope well with fast load changes.

Advantages/disadvantages

The main advantages and disadvantages by amine based CC can be summarised as follows:

Advantages:

- Can facilitate deep CO_2 emission reductions (+90%) from an emission point source
- Proven technology used in the industry for many decades
- Technology offered commercially by multiple vendors in a large capacity range
- Flexible with respect to flue gas source (biomass, waste, coal, oil, NG, etc.) and composition (CO_2 content typically 3 to 30 %)
- Very suitable for retrofit because of low impact on upstream combustion process and few tie-ins. An amine CC plant can be erected while the host plant remains in operation. In principle, only a few short stops are required to establish tie-ins. This will however be site specific.
- Possibility to heat integrate with steam cycle and district heating network (reduce OPEX and production loss). Both concerning heating and cooling requirement of the CC process.
- Possible to implement for partial capture (slip stream) from a CHP/emission source to meet demand for CO_2.
- Bypass mode is possible (i.e. low risk for primary plant). Flexible with respect to load changes.

Disadvantages:

- Requires high standards for upstream flue gas cleaning (low concentration of SOx, NOx, HCl, particulates (in particular submicron). Typically, a pre-scrubber is required.
- Amine degradation and emission of degradation products with flue gas may be an issue with large-scale plants. This can normally be solved with good design of emission control systems.
- High energy demand for thermal regeneration of amine solution

Environmental

Some of the amines applied in CC processes may be harmful to the environment due to high pH, low biodegradability, toxicity, secondary reactions such as reactions with NO_X to form harmful nitrosamines. [19]

Emissions of amine and amine degradation products to air with the treated flue gas is the largest environmental concern with amine CC technology. Reducing emissions has been a focus point in recent years R&D work. This has resulted in improved emission control technology and today several vendors claim low emissions of harmful components. [13, 16]

Most amine CC processes will not have emissions to water (only from pre-cooling of flue gas) from the amine loop. Risk of spillage and leakage of amine solution from the rather large hold-up in the process needs to be mitigated in the design as many of the used amine chemicals may have low biodegradability.

The consumption of amine due to degradation may also be significant for some amines, in particular monoethanolamine (MEA), Table 1. This will in turn generate substantial amounts of chemical waste for disposal/incineration (0.2-1 kg/ton CO_2).

Finally, the significant energy consumption of the CC technology has an indirect environmental impact.

Research and development perspectives

Over the past couple of decades, a lot of research has been conducted concerning development of new improved amine solvents which require less energy for regeneration, have higher cyclic capacity (smaller equipment), are more resistant to degradation, have better environmental properties, etc. The energy consumption and chemical consumption of the amine CC process have also decreased substantially with nowadays advanced solvents and amine processes. Development of amine processes and solvents which can provide a CO_2 stream at higher pressure i.e. saving expensive compression work/cost, is also underway [58]. It is likely that amine solvents with even better performance and properties may be identified, however further refinements are unlikely to provide a step change in terms of the energy consumption. Research is also being conducted into radically other kinds of solvents e.g. non-aqueous solvents, special engineered compounds, etc. which may provide a breakthrough in the future in terms of reducing energy consumption. However, this is very uncertain at present.

Also, more advanced process flowsheets with higher extent of heat integration have been developed, which reduces the energy requirement of CO_2 capture. Some suppliers are starting to implement these solutions in their design e.g. the Petra Nova plant by MHI.

On the integration side between the CC plant and the energy plant research is also ongoing. The availability of increasingly sophisticated heat pump technology may improve total energy efficiency of an integrated CC solution, where waste heat can be exploited to a greater extent.

Process equipment suppliers are also starting to develop optimised solutions for carbon capture e.g. Sulzer Chemtech has developed optimized absorber packing for CC. The potential here for CAPEX reductions is likely to be significant in the mid- to long-term as the suppliers are still reluctant to invest in improvements because the large-scale CC market is yet to take off.

Examples of market standard technology

Work on scale-up and improvement of amine based CC technology gained momentum during mid 2000s due to the growing commercial interest for CC. Several technology vendors (GE, Cansolv/Shell, Aker Solutions, MHI, Hitachi, Fluor, Linde/BASF, etc.) have erected large scale pilot plants in conjunction with power plants and demonstrated their technology. A few vendors have also delivered commercial plants for CO_2 utilisation in the chemical industry.

Below is listed some of the main amine based CC demo plants that has been erected. The Global Carbon Capture Institute also publishes an annual status reports on CCS projects which provides an overview of projects (not limited to amine CC technology) [22].

- Boundary Dam 1 Mtpa CO_2 capture demonstration plant, Canada (operational 2014 - present). First full-scale post combustion amine plant retrofitted to a commercial operating boiler. About 90% of CO_2 is captured from a refurbished 150 MWe coal-fired unit at Saskpower's Boundary Dam power station. The CO_2 is compressed and transported in pipeline to a nearby oil field where it is sold for EOR. The amine carbon capture technology is provided by Shell Cansolv. The project also included a SO_2 removal process with amine, which is heat integrated with the CO_2 removal process. The net power output of the unit declined by 13.6 % with the CC (and SO_2 removal) retrofit, however this number includes the gains by turbine and boiler refurbishments. The project claimed negative media coverage from cost overruns and delays [23]. Following start-up, the plant suffered some issues with fly ash deposition and plugging of equipment as well as excessive amine degradation. This resulted in low availability in the first years and short deliveries of CO_2 to the oil companies, which triggered large penalties. Most of these issues have now been rectified and the plant performs stable although the captured amount is somewhat below design (May 2020, CO_2 capture past 12 months was 732.000 tons [24]).

Figure 4. Photo [59] of Saskpower 800 MW$_e$ Boundary Dam coal-fired power station where one of the four units was retrofitted with amine CC in 2013.

- Petra Nova, 1.6 Mtpa CO_2 capture demonstration plant, USA (operational 2016-2020). The amine plant captures 90% of CO_2 from a 240 MW slipstream of flue gas from the coal-fired WA. Parish Unit 8. This is the world's largest amine based capture plant in operation. The CO_2 is compressed and transported in pipeline to a nearby oil field where it is sold for EOR. The CC technology is provided by MHI. Separate heat recovery boilers fitted to a gas turbine supplies the heat to the capture plant. MHI have implemented novel heat integration in the CC process to obtain low energy numbers. The plant was delivered on budget and schedule [28]. The published results indicate the facility performs as designed. The first million-ton CO_2 was captured 10 months after commencement of commercial operation and in Dec. 2019 (3 years anniversary) 3.5 million metric tons CO_2 had been captured. This is somewhat below target capacity (17%). The reasons for being below target are mainly related to outages of steam plant and other balance of plant systems as well as the load factor of the coal power station. It has recently been announced [29] that the plant has been mothballed due to low offtake price/volume of CO_2 following the collapse in crude oil price.

Figure 5. Petra Nova amine CC plant retrofitted to a slip stream of flue gas (equivalent to 240 MWe) from the WA Pariash unit 8 coal-fired power plant. Source: https://www.nrg.com/case-studies/petra-nova.html

- Technology Centre Mongstad (TCM), Norway (operational 2012-present). Large pilot facility established next to the Equinor's Mongstad refinery. The test facility operates a 80.000 tpa amine CC plant delivered by Aker Solutions and a 40.000 tpa sized Chilled Ammonia Plant delivered by ALSTOM (now Baker Hughes). The captured CO_2 is not used but released back to the atmosphere. Originally CO_2 could be captured from two different sources a) natural gas combined cycle CHP and b) a fluidized catalytic cracker (FCC). The amine plant has been used by several vendors (Aker Solutions [13], Shell, Carbon Clean Solutions, ION Engineering and Fluor corp.) to test and qualify their technology in semi-commercial scale. The chilled ammonia plant was only operated for test campaigns during 2012-2014 and has since been out of operation.

- Danish Experience. Esbjergværket 1 t/h CO_2 capture plant (operational 2005-2011), Ørsted (DONG Energy). World's first large pilot plant installed on a coal fired power station. The plant was used to demonstrate the feasibility of CC on coal derived flue gas and to test optimised solvent and process configurations. [30]

Several amine CC plants are also in the planning in Europe. The Norwegian national CCS demonstration project is currently moving towards final investment decision (expected autumn 2020) to realise a full carbon capture, transport and storage value chain. FEED studies have been conducted for two CO_2 capture projects both based on retrofit of amine CC plants:

- 400,000 tpa CO_2 capture from Norcem's cement plant in Brevik, Norway. The project includes waste heat recovery and heat integration with the cement plant as well as CO_2 liquefaction plant and liquid CO_2 export terminal. The 400.000 tpa constitutes approximately half of the total CO_2 emission from the cement kiln. This is evaluated to be the maximum feasible CO_2 capture capacity as the plant is solely to be driven by waste heat from the cement kiln and the CO_2 compressor. The technology provider for the amine capture plant is Aker Solutions. [33]

- Approx. 400,000 tpa CO_2 capture from Waste to Energy plant at Klemetsrud, Oslo. The project includes heat integration with WtE plant and upgrade of low-grade heat to district heating (compensate for heat loss with CC). The project also includes CO_2 liquefaction plant as well as 10 km truck/pipeline transport of CO_2 to CO_2 export terminal at harbour. The technology provider for the amine capture plant is Shell Cansolv. [32]

In the Netherlands two medium scale carbon capture and utilisation projects are in construction/planning based on amine CC from WtE plants and CO_2 use for greenhouse fertilization. Dutch WtE company AVR has completed construction of 60,000 tpa amine based capture and liquefaction plant [20] at their Duden site. Dutch WtE company Twence has announced installation of a 100,000 tpa capture amine plant at their Hengelo facility [21]. Furthermore, the project Porthos aims to establish a large CCUS hub around the Rotterdam harbour area with intended investment decision in 2021 [25]. In the first phases 2-2.5 MTPA CO_2 shall be captured from several industrial sites in the area and stored off the coast in abandoned oil and gas reservoirs as well as used for CO_2 utilisation.

In the UK several large-scale CCS demonstration projects have been far in the planning but they have all been cancelled for financial reasons. More recently Drax Power Station has installed a pilot plant to capture CO_2 from a biomass fired unit (BECCS) and plans exist to build full-scale at one of the units at Drax by 2027 [26]. Tata Chemicals is working on a CCU project and is about to install an amine based CC plant to recover 40,000 tpa CO_2 from a natural gas fired CHP plant. The captured CO_2 will be used for manufacturing of food and medical grade sodium bicarbonate [27].

Considering that a number of large-scale amine CC plants are in operation and that the technology is supplied by different vendors, the amine CC technology can be regarded as commercially available.

Prediction of performance and costs

CAPEX

The total capital cost of retrofitting an amine unit to an existing emission source will in addition to the cost of the CC plant itself consist of various integration costs. The integration costs are substantial and may vary significantly from case to case depending on the scope included. The following typical cost elements may be included in retrofit projects in addition to the CC plant costs:

- Boiler for generating low pressure steam to CC plant or modification of steam turbine/new steam turbine to allow for steam extraction to CC plant
- CO_2 compression and dehydration or CO_2 liquefaction plant
- Liquid CO_2 tank farm and export facilities
- Extensive heat integration
- Additional flue gas cleaning e.g. desulfurization plant
- Utilities such as cooling tower, water treatment plant, etc.
- Owners cost, contingency

Because of the different scope included and the general uncertainty on cost estimation significant scatter is seen in CAPEX estimates reported in the literature for retrofit cases. Moreover, because only few CC projects have been realised there is a general lack of as built capital cost data.

Table 2Table 3 lists the public available cost data for the two existing large-scale post combustion retrofit projects Boundary Dam and Petra Nova. To supplement also recent cost estimates for a retrofit case study for

Saskpower's Shand power plant and the Norwegian National CCS Demonstration project. For these projects, the cost data is based on significant level of engineering and therefore of higher credibility than miscellaneous high-level studies in the literature.

Table 3. Cost of specific amine CC retrofit projects based on engineering estimates or actual costs. * Realised cost for total project is 1.5 bill USD but the total project also included other works e.g. power plant refurbishment. ** although realised, the reported cost is an engineering estimate, total project cost is reported to 1 bill. USD, but includes pipeline cost. ***costs adjusted to 2018 level using 2% escalation rate similar as in study.

Project	Boundary Dam	Petra Nova	Shand feasibility study	Klemets-rud CCS	Norcem CCS
Project type	Commercial plant in operation	Commercial plant in operation	Feasibility study	Concept study	Concept study
Emission source	Coal-fired power plant	Coal-fired power plant	Coal-fired power plant	Waste to Energy	Cement kiln
Capacity (t CO_2 output/h)	135	200	272	52	55
CAPEX reported	800 mill USD*	635 mill USD**	876 mill USD***	3500 mill NOK	3100 mill NOK
Scope included in CAPEX besides capture plant	CO_2 Compression, stretch of pipeline	CO_2 Compression, steam plant, cooling tower	CO_2 Compression plant,	Liquefaction, 4 days storage, export of CO_2, transport, heat pumps	Liquefaction, 4 days storage, export of CO_2, WHRUs, host modifications
Year of cost data	2015	2016	2018	2018	2018
Reference	[23]	[28]	[31]	[32,34]	[34, 33]

As shown in Table 3, the scope included in the capital cost is not identical. All cases however include costs for integration and CO_2 compression/liquefaction, which are major addons. Total actual cost of the Boundary Dam project has been reported to 1.5 billion USD, but about half of this was related to refurbishing of old coal-fired boiler including new turbine and generator as well as an amine based desulphurisation plant. The Petra Nova total actual project cost has been reported to about 1 billion USD, which is more than the predicted engineering cost. The cost also included utilities and a steam plant. The Norwegian projects include CO_2 liquefaction and liquid CO_2 storage tanks for 4 days production as well as CO_2 export pier, which is more costly than CO_2 compression for pipeline transport. Also, the Norwegian projects included extensive heat integration with heat pumps, steam compression and waste heat recovery units.

To obtain a more equal basis for the CAPEX the scope and cost adjustments to the Norwegian projects as shown in Table 4 have been applied. The CAPEX reported for CC retrofit will then include CO_2 capture plant, CO_2 compression to pipeline pressure, utility systems (cooling water, electricity, steam, etc.), integration costs (hook-up to main plant) and owners cost.

Table 4. Specific CAPEX of CC retrofits with estimated scope adjustments.

Project	Boundary Dam	Petra Nova	Shand study	Klemetsrud CCS	Norcem CCS
Scope adjustment	-	-	-	Site preparation, CO_2 storage & export, truck transport, heat pumps	CO_2 storage and export, heat integration, Site preparation & relocation of equipment
CAPEX adjustment	0	0	0	-500 MNOK	-400 MNOK
Specific CAPEX (mill EUR/[t CO_2 output/h]	5.3 mill	2.9 mill	2.9 mill	6.0 mill	5.0 mill
Exchange rate applied	0.90 EUR/USD	0.90 EUR/USD	0.90 EUR/USD	0.10 EUR/NOK	0.10 EUR/NOK

Rubin et al. [35] compared cost estimates of 6 different case studies for new built coal fired power plants (capacity 3-4 MTPA, generic cases) with amine CC and found that the specific CAPEX varied from 1600 to 2300 USD/kWe generating capacity, which translates to approximately 2.1-2.9 mill EUR/(t CO_2 output/h). This is lower than any of the cases reported in Table 3, but the capture capacity is significantly higher, and the case covers newbuilt.

The Global CCS Institute has released an update on its predicted global cost of carbon capture in 2017 [36]. This shows estimates on cost of carbon capture implemented in different industries. For coal fired boilers specific capital costs of 1.6 mill EUR/(t CO_2 output/h) for CC installation can be deduced. This includes compression and transport of CO_2 and is related to newbuilt power station in USA with capacity of 480-550 t CO_2 output/h.

It is clear from the studies referenced above that many desktop studies of generic plants provide substantially lower CAPEX estimates compared to specific projects where the costs are based on some level of engineering. Also, the fact that most desktop studies concern newbuilt facilities will contribute to significantly reduced integration costs.

Figure 6 shows a comparison of the different CAPEX estimates in Table 4 and in the referenced studies vs. the CC plant installed capacity. It is apparent that the effect of scale on specific CAPEX shown in Figure 6 is quite pronounced even if the two data points from generic studies are omitted. However, it is also clear from the scatter in Figure 6 that the CAPEX of CC retrofit project is difficult to generalise and there will be considerable uncertainty on such generalised cost estimates. The CAPEX estimates for 2020 in the Data Sheets are based on the cost level indicated in Figure 6.

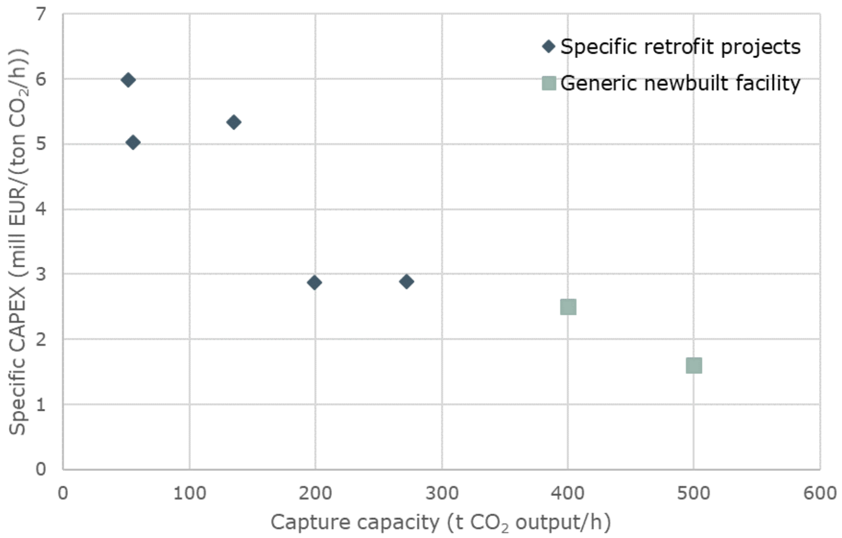

Figure 6. Specific CAPEX cost of complete CC plant installations including CO_2 compression, integration and utility costs vs. CC plant capacity (data from Table 4).

Figure 7 shows a rough estimate of the share of total CAPEX for a retrofit CC project that is related to respectively the capture plant, utilities incl. flue gas supply, CO_2 compression, Owner's cost and heat integration e.g. turbine refurbishment, steam plant and waste heat recovery. The estimate is amongst other based on data from [28]. Figure 7 can be used to correct the CAPEX estimate if not all scope is relevant to the investigated CC project.

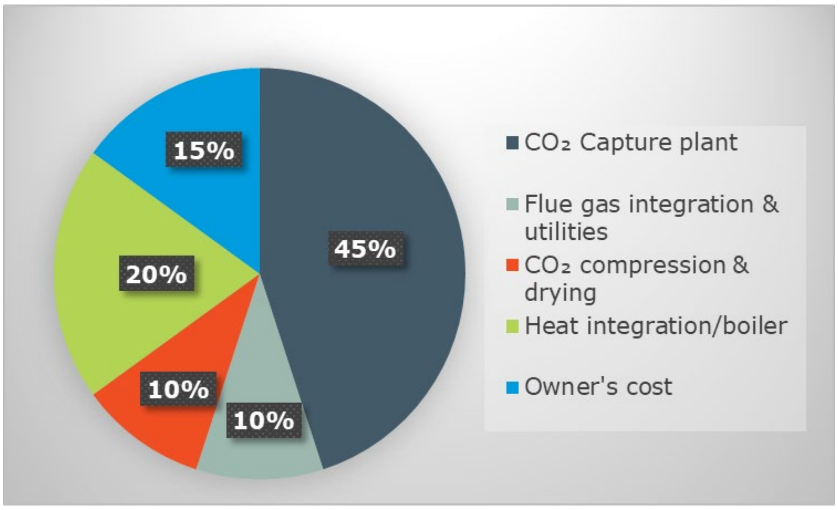

Figure 7. Estimated CAPEX distribution of a complete CC plant retrofit installation based on data from [28].

OPEX

Fixed O&M for amine CC includes staffing, maintenance, service agreements. As the amine CC plant will be an addon to an existing facility, the need for additional operating staff is reduced. 7 to 15 additional staff (depending on size and the site's existing organisation) for O&M is expected for a commercial plant including CO_2 compression and drying. Other fixed O&M such as service agreements and maintenance. Annual fixed O&M is calculated as 3% of CAPEX.

Variable OPEX for amine CC plants are dominated by cost of heat and electricity. Many reported variable OPEX in the literature includes cost of energy. Excluding heat and electricity (listed separately) the variable OPEX is mainly related to costs of make-up of amine, caustic soda for flue gas pre-treatment, waste disposal costs and the variable part of maintenance costs.

The cost of make-up amine may range from 1.5-12 EUR/kg depending on the specific amines applied. The consumption rate is as provided in Table 1. Based on this, a cost of 2 EUR/(t CO_2) is included in variable O&M.

Other consumables such as caustic soda, activated carbon, etc. are required in minor quantities. These consumables will typically constitute less than 1% of OPEX. Disposal cost of chemical waste from reclaimer is typically also comparatively small. A cost of 0.5 EUR/(t CO_2) is included in variable O&M to cover all these small consumables.

Uncertainty

The uncertainty on cost data for larger scale plants i.e. > 20 t CO_2 output/h, is relatively significant today as few of these plants have been erected. Although several large-scale projects have been in the planning, no large CC installations have been erected in Denmark or EU hence there will also be uncertainty related to the permitting process.

In a 2050 perspective there will be significant uncertainty predicting the performance and cost of technology as it will depend on how and when the market will develop. As the cost data at 2020 level is based on first-of-a-kind plants, it is however likely that costs will decrease substantially in the future.

Quantitative description

Three data sheets have been provided for amine based CC technology (separate Excel file). The sheets cover the following emission sources and capacities:

- CC plant (32 t CO_2/h) retrofit to 100 MW_{th} waste or biomass fired CHP
- CC plant (164 t CO_2/h) retrofit to 500 MW_{th} biomass fired CHP
- CC plant (152 t CO_2/h) retrofit to 4500 tpd clinker cement kiln

402 Oxy-fuel combustion technology

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Brief technology description

1.1 Oxy fuel combustion at Pulverized coal (PC) and Circulating Fluid Bed (CFB) fired units

Oxy-fuel combustion is a relatively new technology. The first proposals for commercial use of the technology originated in 1982 when oxy-fuel combustion was proposed as a technology to provide CO_2 for EOR. This chapter will be based on oxy-fuel retrofit to existing energy plants and emission sources.

Conventional boilers use atmospheric air for combustion, where the 79% nitrogen in air dilute the CO_2 in the flue gas. To avoid post-combustion capture, nitrogen is removed before combustion, resulting in a flue gas consisting primarily of water vapor and carbon dioxide.

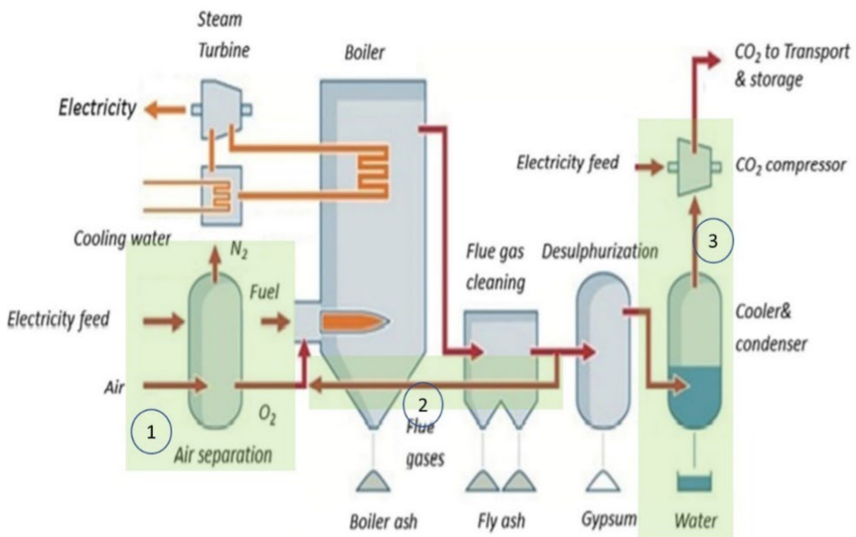


Figure 1 Schematic illustration of oxy-fuel combustion (25).

In principle, there are only three differences between a conventional power plant and an oxy-fuel power plant

1. A oxygen source typically an air separation unit (ASU)
2. Flue gas recirculation (FGR)
3. CO_2 purification (and compression) (CPU)

Theoretically the difference between the two combustion concepts seems limited, however, as gas properties and the thermodynamic framework conditions changes, the combustion zone, heat-transfer, etc. must be adapted.

The major differences are: The heat capacity of H_2O and CO_2 is higher than for N_2. The oxygen concentration must therefore be kept at 27-30%, instead of the atmospheric 21%, in order to maintain the same adiabatic flame temperature. This also means that approx. 60% of the flue gas must be recycled as the oxidant is pure oxygen.

Due to the higher heat capacity of H_2O and CO_2, the flow through the boiler after recirculation of flue gas is slightly reduced, while the flue gas flow out of the plant is reduced by approximately 80% as it primarily consists of H_2O and CO_2.

Both CO_2 and H_2O have a higher thermal radiation than N_2. If O_2 is kept below 30% in the burners, unchanged heat transfer in the radiation part of the boiler can be maintained. In the convection part of the boiler, (approximately after the first superheater) thermal transmission is lower, therefore additional (retrofitted) surfaces may be necessary.

The flue-gas outlet from an oxy-fuel boiler consists primarily of CO_2 and H_2O. However, due to air ingress, necessary O_2 surplus, argon in the O_2-input stream, nitrogen in the fuel etc. the final dry CO_2 concentration at full load lies between 70 - 90% where 70% can be reached at PC and CFB retrofit units and 80-90% at new plants.

1.2 Oxy-fuel at grate-fired units

At grate-fired units, air leakages are crippling for use of the oxy-fuel technology. As grate-fired boilers are small, notoriously leaking air at fuel-feeding and ash outlets etc., it will be very challenging to retrofit an existing grate boiler to oxy-fuel conditions. No demo plants for oxy-fuel firing of grate boilers have been erected. No relevant literature or reports on experimental work for oxy-fuel combustion in grate-fired units exists.

1.3 Oxy-fuel firing at cement plants

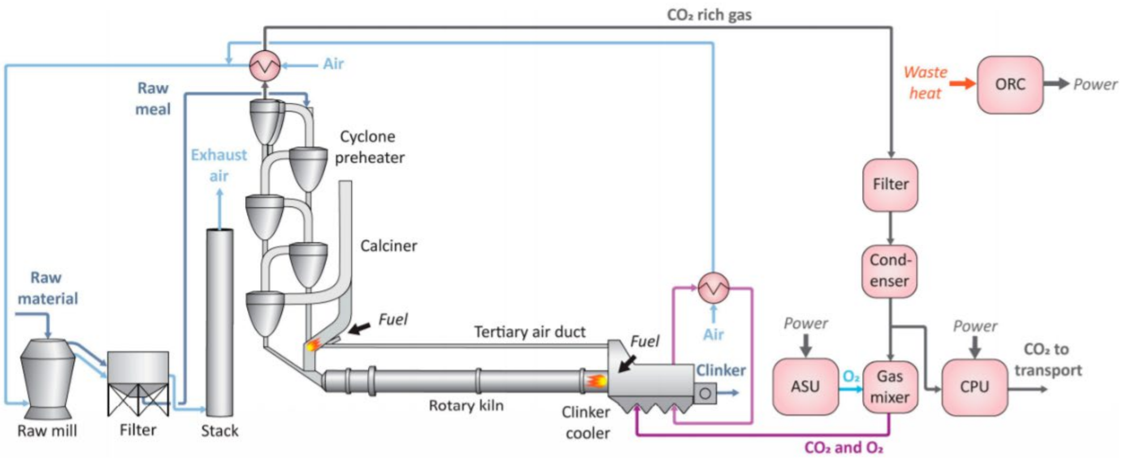
In cement plants it is possible to obtain a concentrated CO_2 flue gas by oxy-fuel firing like in power plants, however due to the much more integrated process (calcination, clinker burning, clinker cooling etc.) retrofitting a cement plant is substantially different from retrofitting a power plant.

Around two-thirds of the CO_2 emissions from the cement industry are process related, originating from the calcination of limestone where $CaCO_3$ is converted to CaO and CO_2, while one-third of the emissions come from combustion of fuels in the cement plant's calciner and rotary kiln. A measure such as fuel switch can therefore only remove one-third of the CO_2 emissions, which make CC a necessity to become close to CO_2 emission free. The CO_2 contribution from calcination results in higher CO_2 content of cement kiln exhaust gas, which is typically 20-30%-vol.

In the oxy-fuel process, combustion is performed with an oxidizer consisting mainly of oxygen mixed with recycled CO_2, to produce a CO_2 rich flue gas which allows a relatively easy purification with a CPU.

Additional power is required for the oxy-fuel process compared to a plant without capture, mainly by an ASU providing oxygen and the CPU. Some of this power demand can be covered by a waste heat recovery system. As an example, an organic Rankine cycle (ORC) can be installed, or surplus heat can be reused for district heating.

Figure 2: Cement kiln system converted to oxy-fuel firing. The reddish coloured blocks are new process units [49].



Conversion to oxy-fuel firing might seem uncomplicated, however the cement kiln process itself must be modified. The gas atmosphere in the clinker cooler, the rotary kiln, the calciner and the preheater is changed, and some of the flue gas is recycled.

Air that is heated by hot gases from the preheater and the clinker cooler is sent to the raw mill to dry the raw material, instead of the flue gas. The direct advantage is that the kiln throughput will be increased, but due to the higher CO_2 partial pressure the calciner shall operate at 60 °C higher temperature, which will increase energy consumption and the choice of construction material shall be re-evaluated, likewise fouling when firing alternative fuels might be an issue.

A list of necessary changes can be seen in the following Figure 3.

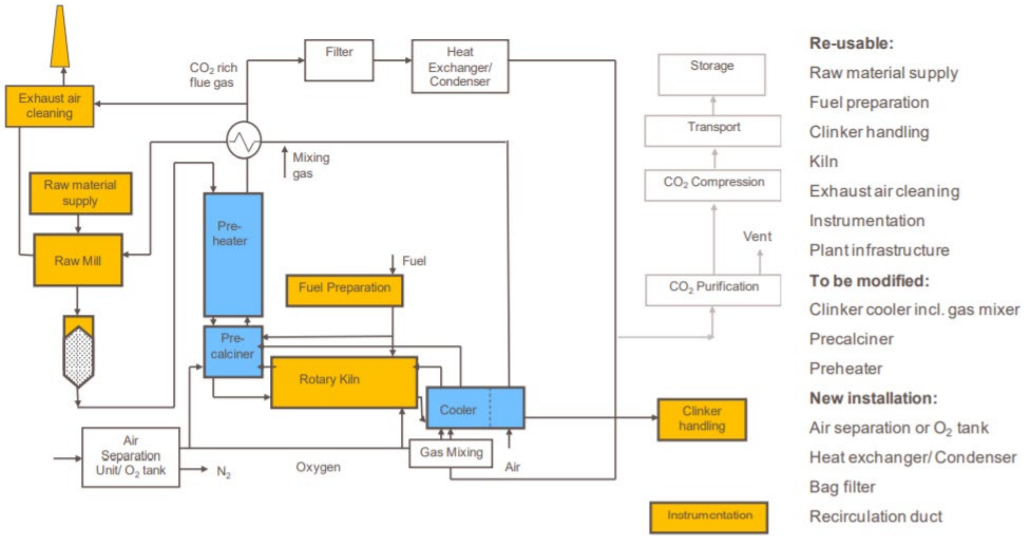


Figure 3 General Scheme for an oxy-fuel retrofit concept: White: To be installed new, Blue: To be utilized from existing plant, Yellow: To be modified, Grey: Not needed for proof of concept. [48]

A major drawback for the retrofit process is that the outage period for converting a cement plant to oxy-fuel will last 6 months with resulting lost production revenue.

Another main drawback is that even modern cement plants are leaky. A typical flue gas leaving the preheater chain will contain 15% gases that have entered the plant via leaks. An overview of sources of air-leakages at typical Portland cement plant is shown in Figure 4. A study by the European Cement Research Academy (ECRA) reveals that it might be possible to reduce this number to 1% at new plants/totally refurbished plants, but at considerable costs.

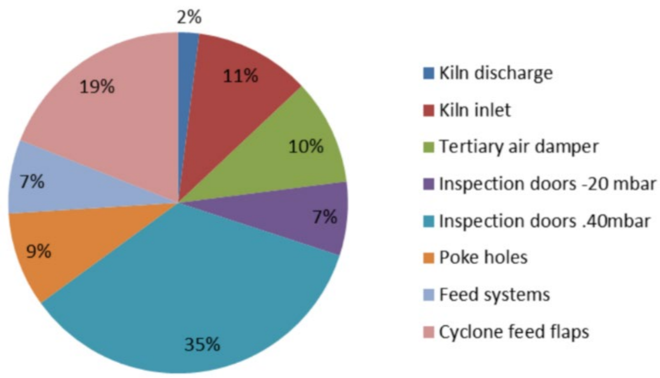


Figure 4 Overview of air-leakages at a typical Portland cement plant. [38]

Early phase design studies for an oxy-fuel cement plant have been conducted [60, 55], but demonstration units have not been built.

1.4 Partial oxy-fuel combustion

To reduce the complexity of the oxy-fuel system another option is to perform oxy-fuel combustion on the pre-calciner, as 80% of the CO_2 is generated here.

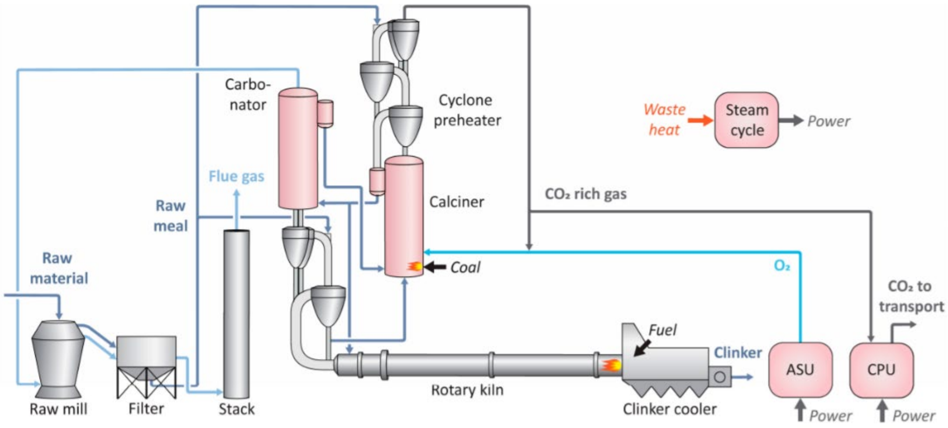


Figure 5. Partial oxy-fuel combustion with integrated Calcium looping (49)

The benefit of this system is that the kiln and cooler do not require retrofitting, this reduces the cost of installing CC and the size of the ASU can be reduced by 40%. On the other hand, two cyclone preheater towers are required and the utilisation of heat from hot kiln and calciner flue gases will be reduced increasing net fuel consumption. Feasibility studies of the concept has been conducted but no pilot facility has been constructed. A further simplification is to omit the calcium looping part of the process, thereby reducing CO_2 capture to < 80% as the flue gas from the rotary kiln is still emitted. Despite the simplification, ECRA indicates that the cost of CO_2 capture for the partial oxy-fuel case is higher than for the full oxy-fuel case [60]. This is both related to the increased fuel consumption and that the more expensive units (ASU and CPU) are still required.

Input

Compared to conventional combustion, the only differences is that pure O_2 is required as input i.e. from ASU or electrolysis unit. The energy penalty for producing pure O_2 by a standard ASU is around 200-220 kWh/ton O_2.

Instead of installing an ASU unit, it is in principle possible to deliver O_2 from an electrolysis unit producing H_2 and O_2 from e.g. wind power. However, there are technical and commercial challenges in balancing the O_2 production from electrolysis based on volatile renewable energy and the base load operating profile of a cement kiln. Decoupling of O_2 production by electrolysis and the operation of an oxy-fuel cement plant will require storage of large volumes of cryogenic O_2. An O_2 liquefaction plant + regasifying plant including cryogenic O_2 storage tanks for just few days of operation will be an equal sized investment as an ASU.

Output

The flue-gas outlet from an oxy-fuel boiler consists primarily of CO_2 and H_2O. The heat produced by the boiler will be the same as in air firing mode with flue gas condensation (and is not included here as an output).

However, due to air ingress, necessary O_2 surplus, Argon in the O_2-input stream, nitrogen in the fuel etc. the final dry CO_2 concentration at full load lies between 70 - 90% where only 70% has been demonstrated for retrofit units and 80-90% at new plants.

Figure 6 shows the CO_2 concentration reached on dry basis at the oxy-fuel retrofit plant Callide unit 4 as function of unit load. The overall air ingress was within the design limit of 7 % (mass), the maximum achieved CO_2 concentration reached was 71 vol-%, dry at full load, but at 50% load, only 45% CO_2 Vol-%, dry was achieved due to air ingress which is independent of load.

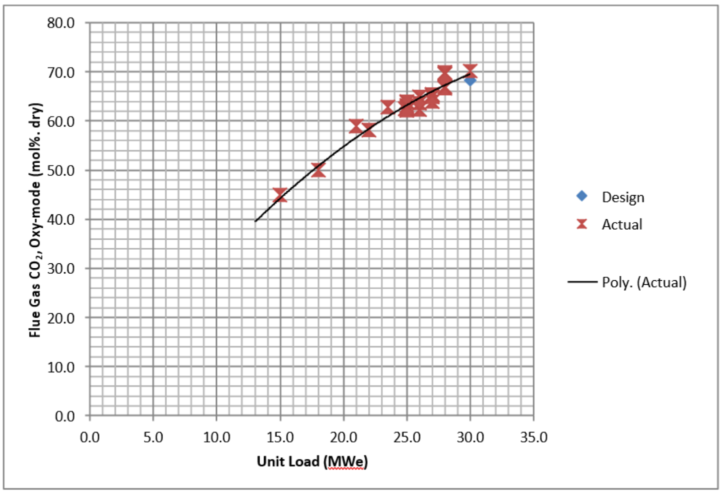


Figure 6 CO_2 concentration dependent on load at Callide oxy-fuel plant from [52].

Application potential

Technical viable oxy-fuel combustion can be implemented at both power plants and at cement plants if the air ingress can be kept low.

Compared to post combustion amine technology where the resulting CO_2 has a purity above 99%, oxy-fuel carbon capture requires extensive upgrading of the CO_2. System for upgrading CO_2 is shown in Figure 7.

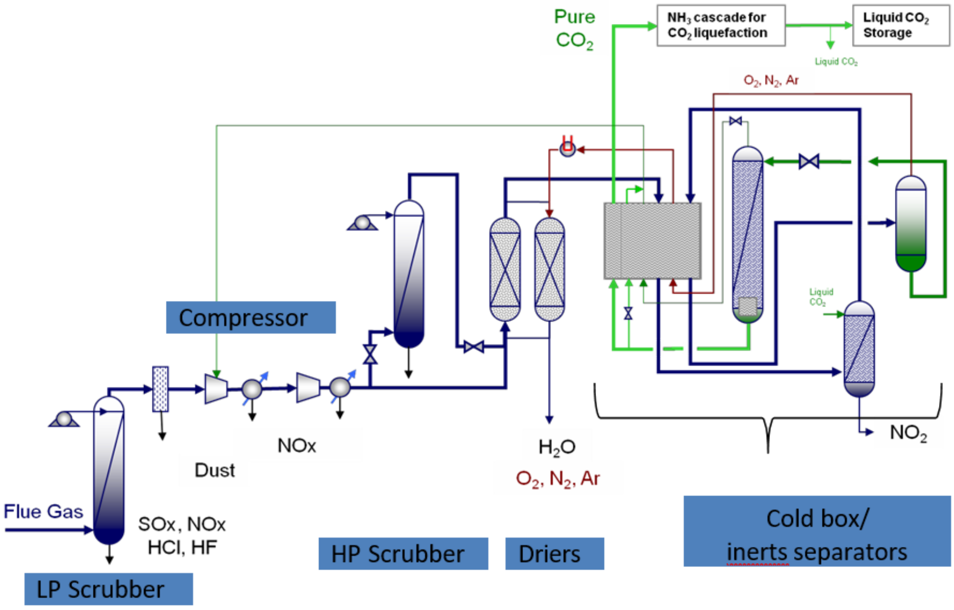


Figure 7 Upgrading of raw CO_2 at Callide oxy-fuel CCS. [44]

Due to the lower purity of the CO_2 it is necessary to remove inerts (O_2, N_2 etc. by cryogenic distillation. To reduce CAPEX, OPEX and recovery rate for the CPU part of the plant, it is therefore essential to keep CO_2 content above 60-70%. Also the lower the content of CO_2, the lower CO_2 capture will be obtained as the venting loss increases in the CPU. The CO_2 purification is further described in section i.13. At lower purities post treatment with an amine scrubber becomes more economical, in which case the oxy-fuel combustion makes no sense.

Typical capacities

1 PC oxy-fuel fired plants

At present no commercial PC fired oxy-fuel plants have been built, but two Demo size projects have been conducted, a retrofit project in Australia and a new built oxy-fuel boiler at Schwarze Pumpe in Germany. As shown in Table 1, oxy-fuel has only been demonstrated in relatively small scale e.g. 30-120 MWth.

In Denmark a design study at Studstrupværket has been carried out, but it was concluded that due to the chosen boiler steel, boiler configuration, load change ability etc. it would be more beneficial to build a new power plant.

Table 1. Overview of main PC oxy-fuel fired demonstration projects and the Danish experience (design study).

Unit scale, Location	Demo scale, Retrofit Callide Australia	Demo scale Brown-field Schwarze Pumpe Germany	Full scale retrofit Design study Studstrup Denmark [62]
Unit thermal power	120 MWth	30 MWth	900 MWth
Years of operation	2008-2012	2006-2014	
Aim of research	Process integration Proof of concept	Process integration Proof of concept	Design study Efficiency Proof of concept
Type of fuel	Bituminous coal	Sub bituminous coal	Biomass
Operators **Main conclusion**	Doable, but project terminated	To expensive	New plant is preferable

2 Oxy fuel fired CFB boilers

To date, no commercial-scale (>300 MW_{th}) oxy-fuel CFB boiler has been built despite the technology currently having a TRL of 7–8 [63], however several experimental Oxy CFB units have been built and operated as shown in Table 2.

Unit scale, Location	Industrial-scale, CIUDEN, Spain	Industrial-scale, Valmet, Finland	Pilot-scale, CanmetENERGY, Canada	Pilot-scale, University of Utah, USA	Pilot-scale, University of Stuttgart, Germany
Unit thermal power	30 MWth	4 MWth	0.8 MWth	0.33 MWth	0.15 MWth
Years of operation	2011–2014	2013-present	2011–2017	2011- present	2014- present
Aim of research	sulphur capture potential	combustion, heat transfer safety	combustion and pollutant formation	SO3 formation under oxy-fuel conditions	Solid burnout and emission of CO and NOx
Type of fuel	petcoke, coal and biomass	Bituminous coal	Coal, petcoke and lignite	bituminous coal	Bituminous coal
Ref	44	37	40	37	42

Table 2 Oxy-fuel CFB experimental units.

3 Cement plants

No integrated oxy-fuel cement plants have been erected at any scale. Some of the single unit operations have been proven in lab scale.

Space requirements

Limited additional space is required for the modifications at the energy plant or cement kiln. However, the ASU and CPU require relatively extensive area.

CPU: 15 m^2/[t CO_2 output/h]
ASU: 30 m^2/[t CO_2 output/h] for biomass plant and 10 m^2/[t CO_2 output/h] for cement kiln

Regulation ability

The main challenges with operation of oxy-fuel combustion systems are:

- Air leakages
- Start-up time for the ASU from ambient temperature
- Load ranges and load changes
- Complexity of operation of ASU, combustion and CPU as one integrated unit

The start-up time for the cryogenic ASU dictates the start-up for the complete plant in CC mode. The start-up time for a cryogenic ASU after long shut-down is around 60-70 hours, but if the stop is less than 24 hours it can be reduced to 2-3 hours due to a very efficient insulation of the cold box. The minimum load range for the ASU is around 30%,

The robustness of operation of the complete oxy-fuel combustion and CPU depends on how intimate the heat integration is and on whether adequate buffer storages has been applied. However, optimised heat-integration will reduce the load change ability. Because of the volatile power production from wind and solar plants, thermal power plants operating in the same market are typically required to balance production. It will be challenging to operate oxy-fuel power plants under such fluctuating conditions.

On the contrary, a Portland cement plant normally operates at full capacity with only minor fluctuations, hence an oxy-fuel cement plant will be easier to operate.

At power plants, the purity of CO_2 in the flue gas diminishes at low load. As a rule of thumb, the purity of the CO_2 should be > 60-70% to operate a CPU unit based on standard compression and dehydration, if the purity gets lower it is necessary to go through another purification step such as amine scrubbing, in which case oxy-fuel combustion makes no sense. At Cement plants air leakages are significant at all loads, requiring refurbishment before oxy-fuel combustion is a realistic option.

Basically, CFB boilers are more suitable for oxy-fuel retrofitting than grate and PC boilers as CFB boilers in principle are airtight, however, fans, ash outlets etc. are not completely airtight even if CO_2 is used as sealing air.

For a retrofit boiler, depending on design, it will probably be possible to reach 70-75% CO_2 at full load, but only 50-60% at half load, however an individual design study is needed for each unit to verify the achievable performance.

Advantages/disadvantages

1 PC and CFB fired boilers

The primary advantage with the retrofit oxy-fuel process are the potential saving on investment cost compared to post combustion capture as the existing boiler can be modified to oxy-combustion.

Nevertheless, both the air separation unit (ASU) for O_2 generation and the CO_2 purification unit (CPU) are expensive and energy intensive units, hence the cost saving potential will be rather limited. However, access to alternative O_2 source e.g. surplus production from electrolysis, will increase the attractiveness of oxy-fuel conversion.

Many of the advantages with the oxy-fuel process that can be achieved with newbuilt oxy-fuel boilers will however disappear with retrofitted boilers. This particularly concerns the issue with excessive air ingress which results in increased CAPEX and OPEX to the CPU. The percentages of air-ingress depend on boiler type in the following order: Grate fired > PC-fired > CFB. CFB boilers therefore have the best potential.

As the recently commissioned 500 MW_{th} BIO4 at Amagerværket is a CFB boiler conversion to oxy firing might be an option and should be considered in line with post amine technology.

2 Cement plants

As both the CAPEX and OPEX for the ASU or alternative oxygen generation are high, the mass of recovered CO_2 per ton O_2 produced should be as high as possible. This favour the (partial) oxy-fuel combustion applied at cement plants, as 3-4 times as much CO_2 is captured per unit O_2 consumed compared to that of energy plants. This is due to the calcination process $CaCO_3 \rightarrow CaO + CO_2$ which releases additional CO_2 without consumption of O_2. Another advantage is that cement plants are operated continuously at full load, hence reducing issues with long start-up times of oxy-fuel process and ASU.

A disadvantage is the rather comprehensive modifications required to the cement plant for oxyfuel retrofit (both full and partial conversion), which will require long downtime for the facility.

Environmental

In oxy-fuel combustion no new chemicals are introduced but handling of O_2 requires ATEX zones (from the French: ATmospheres EXplosives) and ATEX equipment, as most organic material ignites spontaneously in pure O_2.

Concerning the flue gas, the high content of CO_2 is a risk factor too. as the density of CO_2 is 60% higher than dry air, CO_2 could be concentrated in basements and other low lying pockets in the plant building

Research and development perspectives

At PC fired boilers no major R&D projects are ongoing as the potential is regarded as limited.

At Oxy-CFB the main driver for future plants is the option to reduce the size of the boiler by up to 80% by increasing the oxygen concentration (in the bottom) of the CFB from 21% to 50-80% as shown in Figure 8. This requires however, increasing the mass of circulating fluid bed material (sand used for heat transfer etc.) considerably to keep the bed temperature down. I.e. instead of recirculation of flue gas, a larger amount of bed material is recirculated.

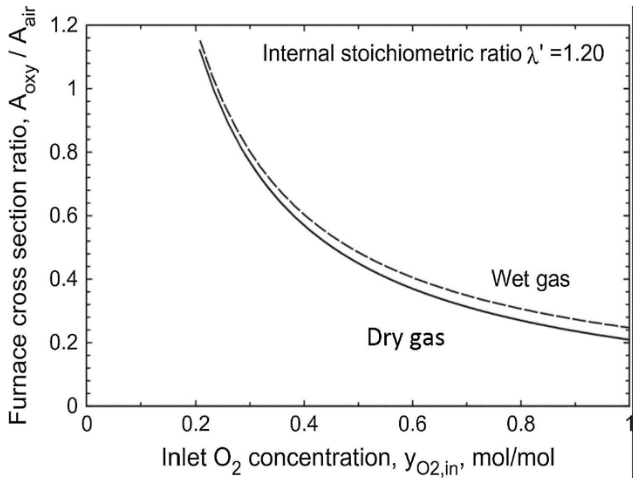


Figure 8 Potential to reduce boiler size by increasing O_2 concentration. [45]

With reduced boiler size the capital cost for the boiler is reduced considerably, which might totally offset the cost of the ASU unit making new Oxy-CFB viable.

These 2[nd] generation oxy CFB´s are still at a very early stage, demonstration units have not been built and commercial plants will not be erected within the next decade.

For retrofit Oxy-CFB, increasing O_2 to 50-80% is not an option, as the furnace size is fixed. The cost of retrofitting a CFB boiler to oxy fuel combustion is therefore more or less comparable to retrofitting a PC boiler. As the three major changes, the ASU, the CPU and the flue gas recirculation are in principle the same.

Examples of market standard technology

At present standard market technology does not exist, but several demonstration plants have been built.

1 Retrofit of Callide a unit 4

In reality, retrofit of a power plant is more complicated than illustrated in the introduction. As an example, the retrofit of the power plant Callide A, unit 4 is described in the following.

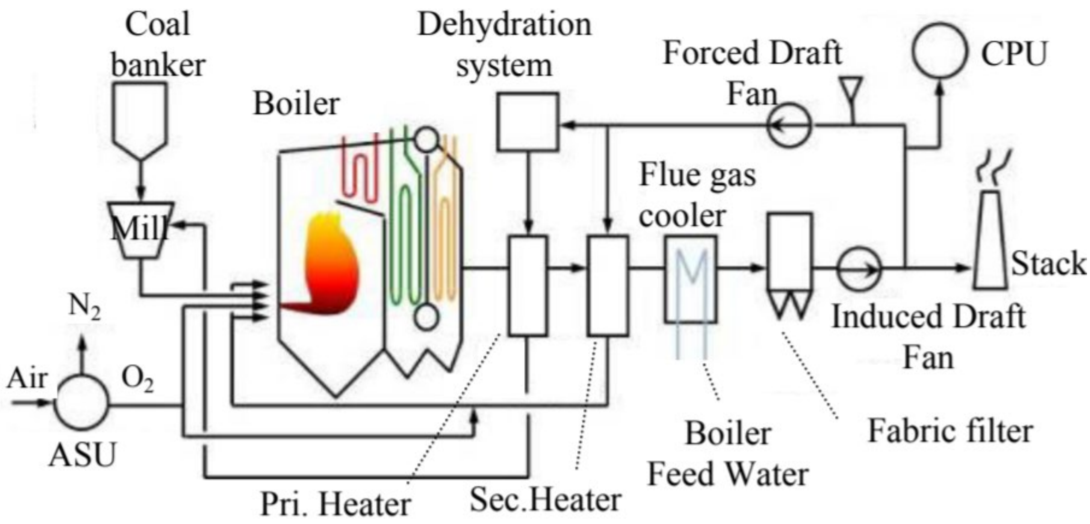


Figure 9 Illustration of the rebuilds needed to retrofit Callide A unit 4.[52]

The first step was operation of the boiler in air-fired mode for several months to ensure that the total plant (especially turbine, boiler, and SCADA system) had a residual life of at least 5 years, based on this, the retrofit was designed

Major new equipment included:

- Installation of two x 330 t/day air separation units (ASUs)
- Installation of a 75 t / day CO_2 purification plant (CPU) for the treatment of a side stream (~10%) of flue gas from the Oxy-fuel boiler.

Simultaneously, the retrofit of the boiler system was carried out over a period of 2 years. New boiler components included:

- Replacing the middle burner row with Low NOx burners with two O_2 injection lances per burner
- New flue gas low pressure preheater
- New induced draft fan
- Gas recirculation fan
- Flue gas condensation (dehydration system)

Above are listed the rebuilds that were needed to complete the trial program. If it had been a commercial plant, the plant owners would have considered further improvements which included:

- Improved integration of the ASUs with the oxy-fuel boiler by establishing buffer storage for cryogenic O_2

- Further development of the SCADA concept, including improved transition from air to oxy mode, as well as interaction between ASU, oxy-fuel boiler and CO_2 purification.

- Finally, an improved process and heat integration between ASU, Oxy-fuel boiler and CO_2 purification must be made and the unit operations: ASU, Oxy-fuel boiler and CO_2 purification must each be optimized.

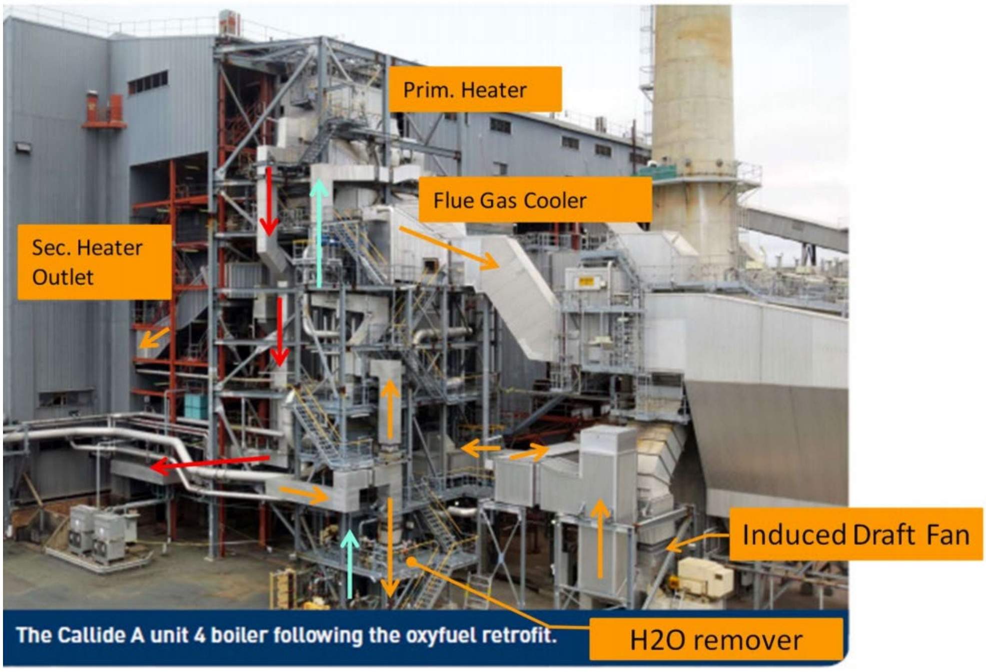


Figure 0-10 Photo of Callide Oxy-fuel boiler from [52] showing retrofit paths (red) and flue gas flue directions (yellow).

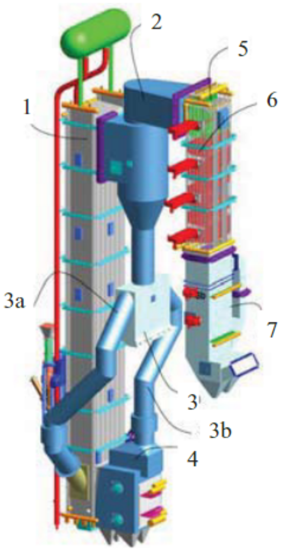
2 Oxy-CFB experimental units

The best documented Oxy-CFB boiler is Ciuden's 30 MWth experimental plant at Central térmica Compostilla II in northwestern Spain.

The demonstration unit was established around 2008 and was in operation until 2014. The plant was equipped with flue-gas purification and compression of CO_2. The focus was to prepare for a 330 MWe coal-fired ultra-supercritical Oxy-CFB plant at the nearby power plant.

The test plant was a Foster Wheeler Flexi-Burn® concept that enabled either conventional or oxy combustion operation. Interestingly, the maximum boiler capacity for air combustion was 15 MWth, while the capacity under oxy-fuel conditions was 30 MWth.

The reason for the substantially increased capacity is the high heat capacity in the solid bed material, which allows for additional firing. The fluid bed temperature either can be reduced by flue gas recirculation or alternatively by increased recirculation of bed material.



(1) combustion chamber
(2) solid separator
(3) ash sealing-direction device
(3a) ash duct to the furnace
(3b) ash duct to the cooler
(4) furnace cooler - INTREX™
(5) heat recovery zone
(6) steam cooled walls
(7) economizer

Furnace dimensions (m)	20x2.8x1.65
Thermal power (MW_{th})	15 (air mode) 30 (oxy mode)
Max steam flow (t/h)	47.5
Superheated steam T (ºC)	250
Superheated steam p (bar)	30
Feed water T(ºC)	170
Outlet flue gases T (ºC)	350-425

Figure 11 Ciuden's 30 MWth experimental plant at Central térmica Compostilla II in northwestern Spain [46].

It was anticipated that a full-scale Oxy-CFB plant should be operational in 2015, however the Ciuden project group have instead focused on further cost reduction to make the project viable. The focus in a newer EU project "Optimization of oxygen-based CFBC technology with CO_2 capture" have been.

1. Reduction of ASU energy consumption to 150 kWh/ton O_2
2. Reduction of Capex by increasing O_2 to 40-50% in the CFB
3. Improved integration of ASU, CFB and CPU

Except for the ASU, these improvements are only relevant for new plants due to the major increase in thermal output if a retrofit is carried out requiring a new turbine and new heat exchangers, and it would also be challenging to implement on a biomass fired unit due to lower ash melting points.

At Ciuden transition from air to oxy mode could be automated and carried out within 30-40 minutes in both directions. The unit was able to achieve 80 vol-% $CO_{2,}$ dry, corresponding to 3% air ingress. Actions are in progress to reduce this number to reduce the CAPEX and OPEX for the CPU.

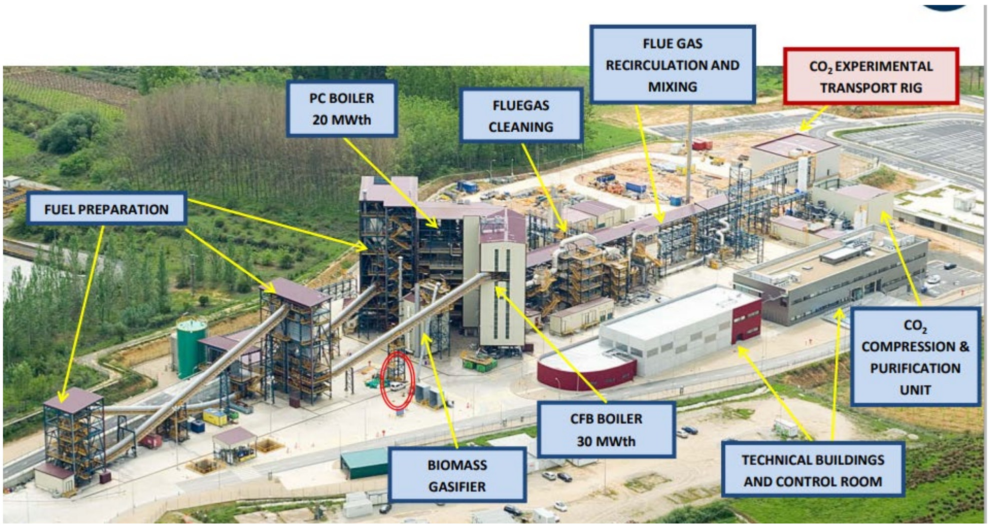


Figure 12 Ciuden's Demonstration site. [46]

Prediction of performance and cost

1 PC and CFB fired units

Retrofit of power plants to oxy-fuel combustion will never be a standard product. Due to the integration with the existing process, individual design studies for each project is needed covering:

- Options to minimize air ingress
- Recalculation of the energy transfer in the boiler and design of new heat-exchangers, O_2 and flue gas mixers, flue gas dehydrators, flue gas recirculation ducts, new fans and blowers etc.
- Based on the above the CPU can be designed

The only completed retrofit conversion of a power plant to oxy fuel firing was the Callide PC power plant and economic data are extrapolation from the number given in the public report. Although the retrofit costs will not be one to one comparable to CFB units, retrofit of either PC or CFB involves many of the same modifications and new installations, hence the cost estimate may be applied as a first estimate for both cases.

The Callide Oxy-fuel Project Capital Costs are summarised below. These data include an escalation to 2017 AUD assuming a CPI of 1.5% per year.

CAPEX	Boiler – Air-firing refurbishment	Boiler – Oxy-fuel retrofit (120 MW_{th})
2017 mill AUD	10	50.8

Figure 0-13 *Summary of Callide Oxy-fuel Capital Costs (rounded) [52].*

The capacity of Callide A from 1965 was 120 MW_{th} (30MW_e), with dry cooling towers etc. this corresponds to a thermal capacity of around 25% of the size of e.g. BIO4 at Amager.

A cost extrapolation for large scale plant was in the project estimated using the “Rule of Six Tenths”.” ($[size_1/size_2]^{0.6}$). For a 500 MW_{th} unit it gives a cost factor of 2.35

At present with the huge uncertainties given, it is anticipated that cost for retrofitting a PC and a CFB boiler are at the same level.

Below is presented the extrapolated costs for a 500 MW_{th} boiler oxy-fuel conversion (excluding CPU and ASU), currency conversion rate 0.67€/AUD, primo 2017, 1,5% CPI.

CAPEX, 2020	Refurbishment	Oxy fuel retrofit (boiler)
Total costs 500 MWth	16 mill. €	83 mill €
Specific investment (mill € /[t CO_2 output/hour])	0.1 mill. €	0.47 mill. €

The uncertainty on the numbers above are quite substantial. The cost of the oxy-fuel retrofit depends on the boiler design.

2 Cement plants

Oxy-fuel retrofit to an existing cement kiln will require substantial modifications to the kiln system, clinker cooler and entire flue gas path. As it will impact the gas flow through the preheating tower and downstream process, the heat balance will also be affected. In addition, ASU and CPU units are required.

There are no demonstration plants in operation, no as built data nor any detailed design studies available for oxy-fuel retrofit, hence the CAPEX estimates identified are based on high level studies. The most comprehensive work on oxy-fuel retrofit has been conducted by ECRA.

Table 3 shows cost estimates for full oxy-fuel retrofit to respectively a medium and a large cement kiln. The specific investment cost appears to be nearly identical for the two studies. It shall be emphasized that the cost estimates are based on high level studies and thus prone to substantial uncertainty.

Table 3. Cost studies for full oxy-fuel retrofit to cement kilns. *Value estimated from ASU cost in section 4.

Study	ECRA CCS project [60]	Gerbelová et al. [61]
Cement kiln size (t clinker/day)	3,000	5,000
CO_2 captured (t CO_2 output/h)	94.5	162
CAPEX (mill €)	110 - 125	217
CAPEX Excl. ASU (mill €)	92*	162
Specific investment (mill €/[t CO_2 output/h])	0.97	1.0

3 CO_2 purification oxy-fuel plant (CPU)

The oxy-fuel process will recover CO_2 at relatively low purity due to the presence of nitrogen and oxygen. The industrial method for purifying the CO_2 is through liquefaction and stripping (distillation) of liquid CO_2 to remove non-condensable gases (O_2, N_2, Ar). This is in principle a similar approach as described under CO_2 liquefaction. If the CO_2 has low purity from the oxy-fuel plant say below 80-85% it may be difficult to liquefy CO_2 in a standard liquefaction process (requires higher pressure and lower temperature). This will increase cost as more advanced chiller or compression process is used. In addition, flue gas pollutants such as NO_X and SO_2 carried with the CO_2 from the oxy combustion may require further purification steps such as activated carbon filtration, NOx Trap and water wash, etc. This will also create minor waste streams depending on the contents of acid contaminants in the flue gas reaching the CPU.

The high share of non-condensable gases (15-20 %-vol) will increase CO_2 liquefaction costs and will imply purging loss or recycle of some of the captured and liquefied CO_2. In the ECRA cement oxy-fuel retrofit study, the CPU is estimated to have 90% CO_2 capture rate i.e. 10% purging loss, at a CO_2 purity about 75 vol-% [60]. The energy consumption for liquefaction of oxy-fuel CO_2 gas will therefore increase substantially.

The CAPEX estimate for CPU is uncertain as no large-scale units have been built. However, one can assume it will be significantly more expensive than a standard CO_2 liquefaction unit which receives >99% pure CO_2 as input. In the Callide oxy-fuel project a CPU with 3.1 t CO_2 output/h was reported to 31.7 mill AUD [52], which corresponds to 6.8 mill EUR/(t CO_2 output/h). In the ECRA cement retrofit study [60] a 94.5 t CO_2 output/h CPU was reported to 0.7 mill EUR/(t CO_2 output/h). Savings due to scale cannot explain the entire cost gap, hence the ECRA estimate seems too optimistic.

Table 4. CO_2 purification (99.9%) and liquefaction/compression (to ~150 bar) after an oxy-fuel process.

	Estimated value	Comment
Purification electricity use	~0.16-0.2 MWh_e/ton CO_2	Includes chillers, CO_2 dehydration and compression. depending on CO_2 purity
CO_2 capture	90-95%	Some CO_2 is vented in the purification process
Cooling requirement	~0.3 MWh/ton CO_2	~50% of cooling is through chiller air cooler

CAPEX CO_2 liquefaction/purification	0.7 – 1.8 mill €/(t CO_2/h)	Depending on capacity and CO_2 purity. This is uncertain no large-sale units have been built

4 Air separation unit (ASU)

The air separation unit is a very significant part of the cost of an oxy-fuel installation. The CAPEX of large-scale standard ASU plants per unit O_2 produced is given in Table 0-5. This is converted to cost per t CO_2 output both for a biomass-fired unit and a cement plant. The O_2 cost is lower per unit of CO_2 for cement kiln due to the CO_2 released from calcination as explained in section 2.

Table 0-5. Estimated CAPEX of large-scale Air Separation Unit (100-250 t O_2/h). The cost per unit CO2 output is higher for biomass than cement because more CO2 is released per unit O2 in a cement plant as explained in section Advantages/disadvantages about Cement plants.

	CAPEX	Comment
ASU CAPEX	0.9 mill EUR/(t O_2/h)	Based on ref. [57]
Cost per unit CO_2 capture for biomass CHP	0.8 mill EUR/(t CO_2 output/h)	Assuming 96% CO_2 is captured
Cost per unit CO_2 capture for cement	0.3 mill EUR/(t CO_2 output/h)	Assuming 96% CO_2 is captured

Quantitative description

For oxy-fuel combustion the following two data sheets have been prepared:

- Oxy-fuel CC – Retrofit 500 MW biomass boiler
- Oxy-fuel CC – Retrofit 3,000 t clinker per day cement kiln

The data sheets are shown in separate Excel file.

The cost reported in the datasheet is without ASU, however cost of ASU is specified as an option.

403 Direct Air Capture (DAC)

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Brief technology description

The Direct Air Capture technology captures CO_2 form ambient air and recovers a concentrated CO_2 stream like other CC technologies. Because the CO_2 content of the atmosphere is only ~400 ppm or 200-300 times lower than that of typical flue gas, huge volumes of air need to be processed per unit of CO_2 captured (Approximately 2.5 mill m³ air/ton CO_2). Because of the large volumes to be treated and the low concentration of CO_2 DAC processes have substantially higher CAPEX and energy requirements compared to carbon capture form concentrated sources such as flue gas.

The DAC technology is still in its infancy and there are many different concepts under development. Most of the technologies and methods for DAC are still being developed in the laboratory and are thus at low TRL. A few technologies have been demonstrated in pilot- and/or commercial plants, but at relatively low scale (up to a few tonnes per day) compared to CO_2 capture from point sources.

The two most mature and relevant types of DAC technology for near to mid-term deployment are:

- Solid adsorption and low temperature regeneration (temperature swing adsorption or moisture swing adsorption)

- Liquid absorption and high temperature calcination

These are the only technologies that will be described in this catalogue. Other technologies at low TRL level work among others with liquid absorption combined with electrodialysis, ion-exchange or advanced carbon nano materials [40].

The DAC low temperature adsorption process works by adsorbing CO_2 from the air in a contactor device with an activated filter material. The filter material is typically made of polymeric material with amine functional groups that will chemically bind CO_2 to the surface [40]. A forced draft fan will ensure flow of air through the filter. After some hours on stream the filter is saturated with CO_2 and the desorption or regeneration phase is started. Typically, vacuum is applied to assist desorption (vacuum assisted temperature swing adsorption) and the filter is heated to 85-100 °C with a low temperature heat source e.g. hot water. The desorbed CO_2 is collected as a concentrated CO_2 stream with purities of 98-99.9% being reported [40]. Moisture is also adsorbed from air and released during regeneration of the filter hence a stream of pure water is co-produced. After regeneration the filter is cooled to ambient temperature and it is ready for a new cycle. See illustration of working principle in Figure 1. A commercial scale DAC plant will consist of multiple independent DAC modules [43].

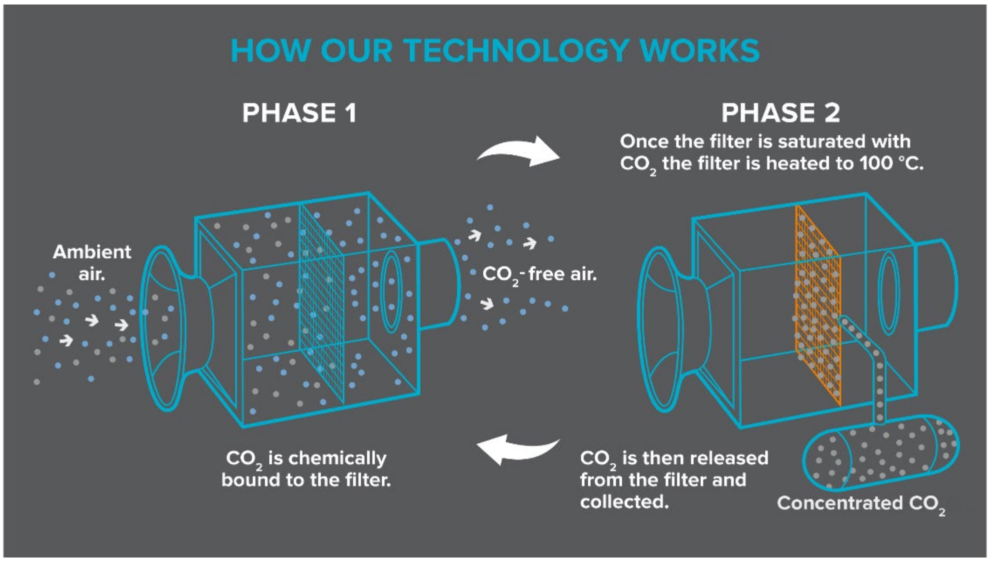

Figure 1. Illustration of working principle of Climeworks low temperature adsorption DAC process. Source: www.climeworks.com

The DAC process based on liquid absorption and high temperature calcination is mainly being developed by the company Carbon Engineering. The process involves an air contactor of the scrubber type where CO_2 from the air is absorbed by a circulating caustic solution (potassium hydroxide). Hydrated lime is added to the solution in a causticiser to precipitate captured CO_2 as limestone (CaCO3) and regenerate the caustic solution. Finally, a concentrated CO_2 stream is released by calcination of the solid limestone. The calcination process requires heat at 850-900°C, which in the process of Carbon Engineering is produced by burning natural gas. The burning of natural gas will result in 0.44 ton of CO_2 emission per ton CO_2 captured from the air. Therefore, other CC technology such as amine scrubbing or oxy-fuel combustion is required to make this DAC technology emission free. [40,41,44]. The technology will produce substantial amounts of high-temperature waste heat from the calcination process [44]. This heat will have to be integrated with a power cycle or other industry to obtain acceptable energy efficiency. The heat integration proposed by Carbon Engineering [44] is complex. Furthermore, a waste stream of calcium carbonate will be produced.

In addition to natural gas, the liquid absorption and high temperature calcination process use substantial amounts of electrical energy for air fans, solvent pumps, CO_2 capture/oxy-fuel plant, CO_2 compressor, etc. Make-up of limestone and potassium hydroxide will also be required as well as substantial amounts of water.

As the high temperature absorption process of Carbon Engineering in its current form requires natural gas as input and thereby dependent on fossil energy as well as other CC technologies to become emission free, it is not considered further in this catalogue.

Input

The low temperature adsorption process requires air, electrical energy for the air fans, vacuum pumps/compressors, cooling water pumps and possible cooling tower. In addition, heat is required at relatively low temperature (approx. 100°C) to heat the filter module and desorb the CO_2. Values in the literature [40,41,42] for energy requirement vary quite substantially, which may have to do with the level of CO_2 post treatment included in the figure or just a lack of data from pilot plants.

Output

The main output of the DAC process is a concentrated CO_2 stream with relatively high purity. The CO_2 is typically available at low pressure and contains moisture. The CO_2 will need to undergo further compression and dehydration to meet specifications for CO_2 transport or utilisation as most other CC technologies.

The low temperature process will also produce pure water recovered from the air. Low quality heat from cooling of the filter modules will be available. However, as this is a batch process the quality of heat will vary over time.

Examples of market standard technology

The DAC technology is currently under rapid development. The plants that are in operation today are mainly small-scale demonstration and pilot plants. It is mainly the high temperature absorption and calcination process developed by Carbon Engineering as well as the low temperature adsorption technologies developed by primarily Climeworks [43] and Global Thermostat that are under commercial development.

Table 1 provides an overview of some of the key DAC plants in operation.

Table 1. Overview of selected existing DAC demonstration and pilot plants. [41].
tpd = tonne per day, Power to Gas: the use of electricity to convert CO_2 and water to methane, Air to fuels: capture of CO_2 and moisture from air for fuel production with electricity i.e. P2X.

Plant	Hinwil (Switzerland)	Troia (Italy)	SRI international (Ca, USA)	Squamish (Canada)
Technology provider	Climeworks	Climeworks	Global Thermostat	Carbon Engineering
Type	Commercial	Pilot	Pilot	Demonstration
Capacity	2.46 tpd	0.419 tpd	2.0 tpd	0.6 tpd
CO_2 use	Greenhouse	Power to Gas	Not known	Air to fuels

Prediction of performance and cost

The performance and cost data for DAC is based on the low temperature adsorption technology. Mainly data on the technology from Climeworks will be used because performance and investment cost data from Global Thermostat or other companies is not available (only levelized cost of carbon capture).

It shall be stressed that the data reported in the literature for DAC is often from the technology vendors and has not been reviewed by independent party. In particular, the outlook on upscaling and levelized cost of CO_2 capture for future DAC plants appear to be too optimistic in many cases. Furthermore, the assumptions and conditions behind the levelized cost of carbon capture in $/ton CO_2 captured, reported by some vendors are unclear and not fully published.

Only CAPEX estimate available from a supplier of low-temperature adsorption DAC technology is from Antecy (now part of Climeworks) of 730 EUR/(t CO_2 output/year) or 6.5 mill EUR/(t CO_2 output/h) based on a 360,000 tpa DAC facility [40]. The estimate cannot be verified as no DAC unit of this scale has been erected yet.

O&M is estimated as 3.7% of CAPEX similarly as in [40]. In [42] it is indicated that the individual DAC modules only have a life expectancy of 4 years. Climeworks has clarified that only the sorbent filter part needs replacement. To include this in the O&M cost it is assumed that the DAC sorbent filter makes up 5% of total CAPEX. This is split in 4 years, hence 1.25% of CAPEX is added to the fixed annual O&M cost.

The land use for DAC is also very significant as huge air volumes are required. Viebahn et al. [41] report of 100 x 1000 m^2 for a 1 million t CO_2 output/year plant. It shall be remembered that there is not any experience with large DAC facilities. One may expect a significant lee-effect when many modules are located in the same area, hence depend

Uncertainty

The DAC technology is still in the early development phase hence the uncertainty on both performance and cost numbers are high.

The current energy consumption of DAC is much higher than CC from a concentrated source. It is expected that the energy consumption of DAC will continue to be substantially higher compared to CC from a concentrated source. Very optimistic outlooks for the technology's improvement potential are reported by some vendors e.g. indicating energy performance numbers that is approaching that of CC from concentrated sources. Also the estimated capital cost of a very large DAC plant of 6.5 mill EUR/(t CO_2 output/h) from Antecy as mentioned above is very uncertain as the scale-up is nearly 3 orders of magnitude.

It is difficult to make robust predictions of the future cost of DAC as little information is published on how the technology should improve. DAC modules offer great opportunity for standardisation and mass production, hence it is fair to assume that costs will decrease. Nevertheless, the level of cost reductions will be highly dependent on how the market for DAC develops. A 30% cost reduction to 2050 is assumed in this work well knowing that the starting point (2020 value) is also highly uncertain.

Quantitative description

A data sheet for the DAC based on the solid sorbent technology has been produced. See separate Excel file for Data sheet.

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Introduction to CO_2 transport

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i.1 General

The realisation of a complete carbon capture storage (CCS) and/or utilisation (CCU) value chain will nearly always involve transportation and or interim storage of CO_2. This because the CO_2 emission sources and suitable geological storage and/or CO_2 utilisation sites are likely to be geographically separated. Moreover, it may be anticipated that the CO_2 supply from CO_2 capture facilities and the use at CO_2 utilisation facilities may not always be balanced hence interim CO_2 storage capacity will be required. Likewise, CO_2 buffering capacity may be required when changing from one mode of transportation to another.

This chapter of the technology catalogue will describe the different technologies available for transportation of CO_2 i.e. the link between CO_2 capture and CO_2 storage/utilisation. The main transport technologies described are:

- Pipeline transport
- Ship transport
- Road transport

The carbon capture technology catalogue describes the capture of CO_2 from an emission source or ambient air including CO_2 compression and liquefaction technology which will condition CO_2 into a suitable state for transportation.

This chapter only describes the transportation of CO_2 from capture to storage/utilisation site. The technology required for geological storage of CO_2 e.g. CO_2 injection equipment, injection well, etc. or CO_2 utilisation is not covered.

i.2 CO_2 properties in relation to transport

The physical properties and phase behaviour of CO_2 are important to consider when selecting the design conditions for CO_2 transportation.

To facilitate cost optimal transportation of CO_2, conditions that enable high CO_2 density is required. High density is obtained by compressing CO_2 to a high-pressure gas/fluid or through liquefaction to liquid state. Solid CO_2 (dry ice) has also high density but solid CO_2 is impractical to handle and store, hence solid-state transportation is not normally considered a viable option.

Figure 1 shows a pressure-temperature phase diagram of pure CO_2. The critical point for CO_2 is at 31°C and 74 bar(a), which represents the highest temperature and pressure where a liquid phase can be present. On the lower temperature end of the phase diagram is the triple point of CO_2 -56.6°C and 5.2 bar(a), which represents the lower temperature and pressure where a liquid phase can be present.

For transport of CO_2 in liquid state e.g. by tanker truck or ship, it thus follows that the temperature must be in the range of -56 to +31°C and the pressure 5.2 to 74 bar(a). In practice some operating margin to the phase change curve will be required, which will reduce the operating window.

For CO_2 pipeline transport it is normally not desirable to operate at conditions where phase change may occur (gas-liquid). Therefore, pipelines are often operated above the critical pressure of CO_2 (74 bar) to avoid two phase formation. Another important factor is to achieve high density.

Figure 2 shows a relationship between pressure and CO_2 density. It appears that a CO_2 pipeline operating above the critical pressure (dense phase) may achieve CO_2 transport densities around 800-1000 kg/m^3 at typical temperatures for buried pipelines in Denmark. This is more than an order of magnitude higher density compared to what is known from the natural gas transmission net, which implies that relatively small pipeline diameters will be required for transport of CO_2.

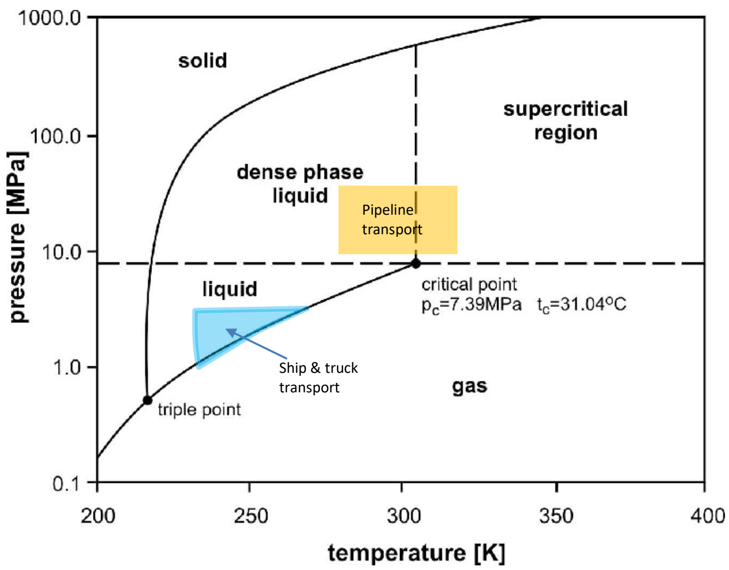

Figure 1. Pressure-temperature CO_2 phase diagram. Typical operating conditions for CO_2 pipeline as well as ship and truck transport indicated as coloured areas.

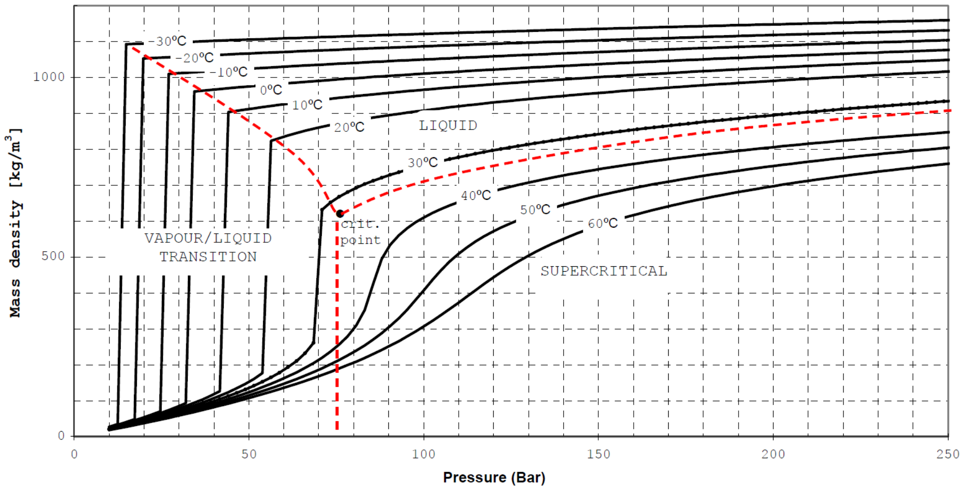

Figure 2. Mass density of pure CO_2 as function of pressure based on Peng-Robinson EQS. Source: DNV-GL RP-J202.

The above diagrams are representative for pure CO_2 only. The presence of other gases or contaminants (O_2, N_2, Ar, SO_2, NO_X, etc.) will alter the phase behaviour of CO_2 significantly. In general, the presence of contaminants tends to increase the critical pressure and temperature of CO_2, hence higher pipeline pressures will be required to stay out of the two-phase region.

For liquefied CO_2 the presence of even trace amounts of non-condensable gases e.g. O_2, Ar, N_2, etc. will change the physical properties substantially as illustrated in Table 1.

Table 1. Impact of non-condensable gases on vapour pressure of CO_2. [1]

Mixture	Vapour pressure at -50°C
CO_2 (100%)	6.7 bara
CO_2 mixture with 0.05 mol% N_2	7.0 bara
CO_2 mixture with 0.1 mol% N_2	7.3 bara
CO2 mixture with 0.5 mol% N_2	9.7 bara
CO2 mixture with 0.05 mol% O_2	6.9 bara
CO2 mixture with 0.05 mol% H_2	10.3 bara

Furthermore, with liquid CO_2 at low temperatures (cryogenic), the presence of even 100 ppm of water may lead to CO_2 hydrate or ice formation. This can cause severe operational problems such as plugging of valves, heat exchangers, etc. To circumvent such operational issues, CO_2 will be dehydrated to very low water content (<30 ppm) prior to liquefaction. Another issue with moisture is that CO_2 will be very corrosive for carbon steel in the presence of small amounts of H_2O due to the formation of carbonic acid. This is why CO_2 is also dehydrated to low value (low dew point) prior to pipeline transport.

i.3 Selection of transport form - influence of distance and capacity

Several studies have been conducted with relation to optimisation of transport of large volumes of CO_2 [1-6] in a CCS context. For transport of large volumes (>1 million tonne per annum (MTPA)) only pipeline and ship transport are viable transport options. Road transport is typically only considered for smaller volumes and for short distances when establishing a pipeline is not feasible.

Transport of CO_2 by ship and pipeline have different advantages and disadvantages.

In general, CO_2 transport by ship is a more flexible option than pipeline. For ships, the transportation route can easily be changed if another CO_2 source or storage site emerge, likewise the capacity of the transportation chain can be gradually upgraded by adding more ships if demands grow. Also ships (if a standard carrier type is selected), can be reused for transportation of other goods e.g. LPG, NH_3, etc. in case the CO_2 source should cease production. CO_2 transport by ship is on the other hand more costly than pipeline transport for short to medium distances and it requires costly CO_2 terminals with intermediate storage facilities.

For transport of large volumes of CO_2 (and obviously for CO_2 point sources located inland away from waterways) CO_2 pipelines will be the more cost-efficient solution. In a study by ZEP [2] the cost of CO_2 transport for 10 MTPA has been compared between ship and pipeline as shown in Figure 3. With the chosen assumptions e.g. pipeline utilisation factor of 50%, it appears from Figure 3 that pipeline transport is economically favoured for transport distances up to 500-700 km, where after ship transport is the favoured option. It also appears that at very short distances the ship option becomes much more costly. This is related to the fact that the full CAPEX investment for the ship case (ship + terminals) is present even for short distances and that the ship will spend most time in harbour loading and unloading. Different assumptions such as smaller CO_2 transport volumes will however change the turnover point where ship transport becomes more favourable.

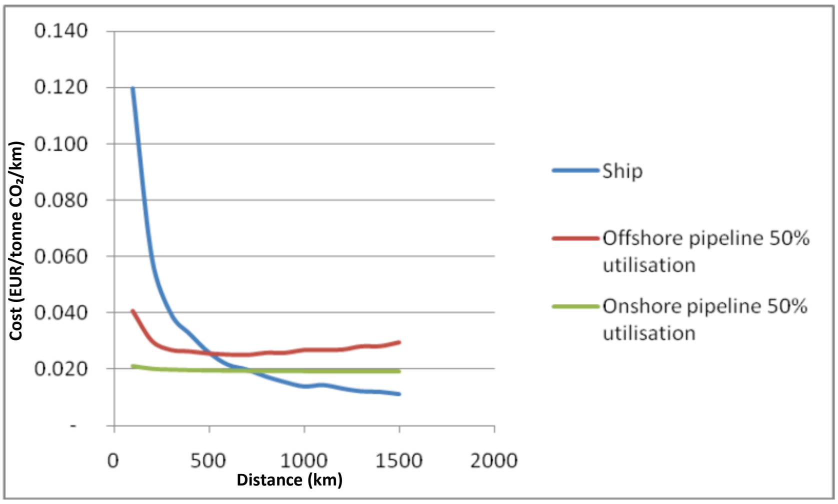

Figure 3. Cost of CO_2 transport (EUR/tonne/km, 2010 cost level) by pipeline at 50% capacity and by ship at 100% capacity (including terminal) for 10 MTPA. Source: ZEP [2]

The amount of energy and the associated CO_2 emission required for transporting CO_2 will clearly be dependent on the transport distance but also of the transport form. Pipeline transport will typically be the most energy efficient (less emission intense) mode of transportation and road truck the more emission intense.

In Table 2 an example is shown of the estimated CO_2 emission for 200 km transport of CO_2 by respectively pipeline, ship and truck using energy data from this catalogue. An important message from Table 2 is that although the CO_2 emission related to transportation varies significantly between the transport forms it constitutes only a small fraction of the transported amount of CO_2 even for a distance of 200 km.

Table 2. Example of estimated CO_2 emission associated with transport of CO_2 for 200 km by different transport forms. Only CO_2 related to the energy (fuel and electricity) requirement for operation is considered. *estimated as emission related to electricity consumption for pumping using 135 g CO_2/kWhe.

	Pipeline	*Ship*	*Truck*
CO_2 emission in % of transported volume	0.05 %*	0.4 %	1.6%

In addition to cost, other factors such as regulation, safety, timeframe, and availability, public perception, etc. could influence the choice of CO_2 transport technology. For instances it may be difficult to establish a CO_2 pipeline through densely populated areas hence road tanker transport may be the preferred solution even though it will lead to increased transportation costs.

i.4 CO_2 transport by pipeline

Transport of large volumes of CO_2 by onshore pipelines is today primarily known from USA and Canada although few CO_2 pipelines exist in Europe. Offshore CO_2 pipelines are few and the Norwegian Snøhvit CCS project is the best-known example.

The existing large CO_2 (transmission) pipelines all transport CO_2 in the dense phase region typically in the pressure region of 80-160 bar. Examples exist of CO_2 pipelines operating in the gaseous state at low pressure (<40 bar) or with liquid refrigerated CO_2. However, these conditions are mainly used for short distance transport within processing plants or locally between different industries.

In USA several regional networks with CO_2 pipelines exists predominantly in the southern and southwestern states as well as north on the border to Canada. Main CO_2 pipeline infrastructure in USA is shown in Figure 4.

There are more than 50 individual CO_2 pipelines with a combined length of about 7000 km. The pipelines transport CO_2 from point sources to oil fields where it is injected and used for enhanced oil recovery (EOR). The installed CO_2 pipelines cover a broad range of diameters and lengths.

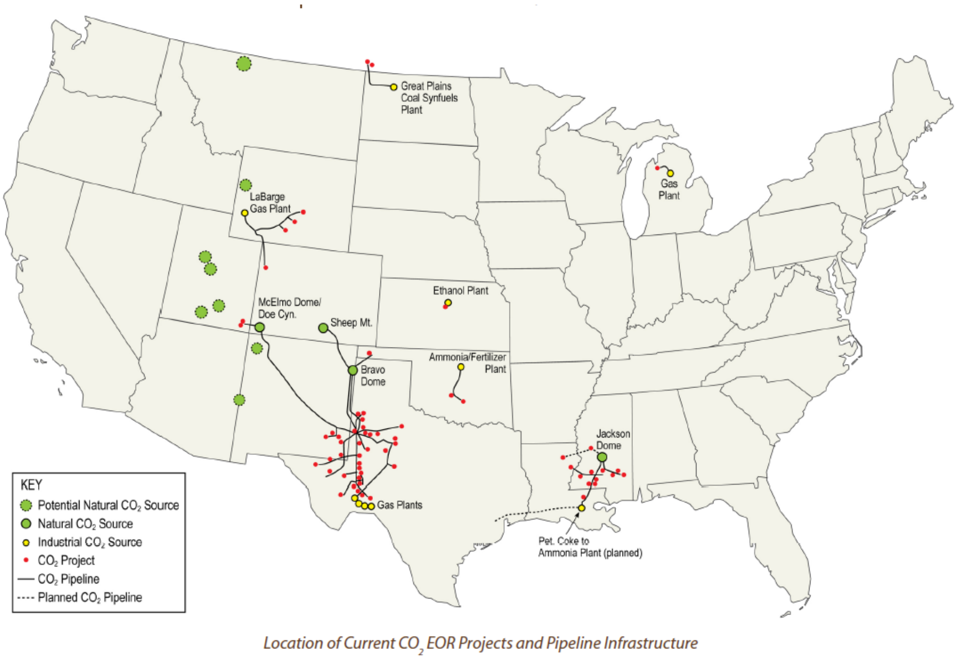

Figure 4. Location of existing CO_2 pipeline infrastructure in USA [3]

In the Netherlands a smaller CO_2 pipeline network exists to supply CO_2 from gas processing plants to large greenhouses for boosting the growth rates and yields of crops.

Table 3 lists examples of operational CO_2 pipelines with main data in America and Europe.

Table 3. Examples of operational CO_2 pipelines [5].

Name	*Country*	*CO_2 capacity (MTPA)*	*Length (km)*	*Diameter (mm)*
Weyburn	Canada	2.0	330	305-356
Saskpower Boundary Dam	Canada	1.2	66	
OCAP	The Netherlands	0.4	97	
Snøhvit (offshore)	Norway	0.7	153	
Bati Raman	Turkey	1.1	90	
Cortez	USA	24	808	762
Central Basin	USA	27	232	406
Monell	USA	1.6	52	203
Sheep Mountain Operational	USA	11	656	656
Slaughter	USA	2.6	56	305
West Texas	USA	1.9	204	203-305

i.4.1 Possibility of reusing the existing natural gas network for CO_2 transport

In Denmark there is an existing natural gas (NG) transmission and distribution network as described in chapter 112 Natural Gas Distribution Net of the Technology Catalogue.

In a future fossil free Denmark one can speculate in reusing the NG network or parts of it for CO_2 transport.

The NG network is designed for 80 bar operating pressure at the gas transmission lines and 40 bar at the main distribution lines. Secondary distribution lines have design pressure of below 20 bar. MR (Metering and Reduction) stations maintain the various pressure levels at the distribution net whereas the underground gas storage and interconnections maintain the pressure in the main transmission lines. A map of the NG network is shown in Figure 5.

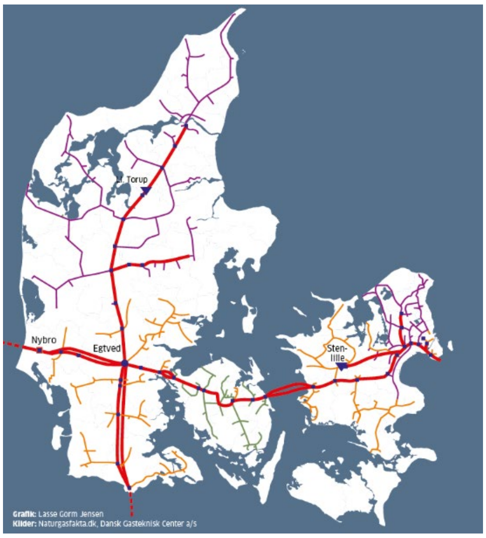

Figure 5. Natural gas pipeline network (steel piping) in Denmark. Source: Naturagasfakta.dk, DGC.

Considering dense phase pipeline transportation of CO_2 as described in previous section where operational pressures are typically in the range of 80-160 bar (above critical pressure) the max operating pressure of the NG system is too low when considering operational margins and pressure drop. The existing NG network is therefore not suitable for dense phase CO_2 transport.

Another possibility is to operate the pipeline network at relatively low CO_2 pressure in the gaseous state. For expected operating temperatures of buried pipeline i.e. down to 5°C, liquid phase may form at 40 bar. Hence to stay out of the two-phase region, pressures up to say 30 bar could be acceptable. At 30 bar the CO_2 density is reduced to approx. 80 kg/m³, greatly decreasing the transportation capacity compared to dense phase 800-1000 kg/m³ operation. Considering that the pipelines of the NG network is designed for gas transport, the capacity of the main transmission lines are still capable of transporting several MTPA CO_2 even at 30 bar, which may be sufficient in most scenarios.

The NG pipe network is constructed of carbon steel with small distribution lines of polymer. Carbon steel will be compatible with CO_2 as long as the CO_2 is maintained dry. Any compression and MR station will have to be upgraded to deal with the different physical properties of CO_2. Thus, from an overall technical point-of-view reuse of NG pipelines for CO_2 transport at low pressure conditions (<40 bar) seems feasible although this will need to be evaluated in greater details.

Other specific stretches of oil and gas pipelines may also become redundant when production from the Danish oil and gas fields in the North Sea is phased out or the general use of oil and gas diminishes. The possible reuse of these for CO_2 transport will have to be evaluated on a case by case basis considering remaining lifetime, design pressure and required modifications. Reuse of oil and gas pipelines for CO_2 transport has also been considered in other projects e.g. OCAP project in the Netherlands [6].

i.5 CO_2 transport by ship

Transport of CO_2 by ship is as previously mentioned feasible for medium to long transport distances of medium to large amounts of CO_2. CO_2 will be transported in liquid state and to some extent refrigerated in order to obtain high transport density and modest pressure level. Transport of CO_2 at high pressure and closer to ambient temperature is also possible but will require a special ship design and is likely to increase the weight of the ship's pressure tanks relative to cargo. Typically, a CO_2 terminal with interim storage tanks will be required at one or both ends. The required storage capacity will be dependent on the actual operating philosophy and specific design conditions of the transportation chain. The terminals will typically be designed with loading pumps, transfer lines, marine loading arms, metering and re-liquefaction plant for handling of boil-off gases from storage tanks, etc.

Today no large-scale CCS/CCU project employing ship transport of CO_2 is operational. However, experience exists with ship transport of smaller volumes of liquid CO_2 for industrial consumers around Europe.

- **Experience with CO_2 transport by ship in smaller scale:** The Norwegian fertilizer producer Yara has for more than 20 years operated a small fleet of CO_2 carriers (Yara has today sold-off its CO_2 business, now Nippon gases) between CO_2 recovery facilities (at ammonia plants) and CO_2 terminals around Europe. The ships have been relatively small units as shown in Figure 6 of 1000-1800 t CO_2 cargo capacity. Some of the CO_2 carriers have been converted dry cargo ships. The CO_2 transport conditions have been liquid CO_2 at 15-18 bara and -25 to -30°C. Today, these conditions are sort of a "standard" for transport and supply of industrial grade liquid CO_2.

Figure 6. M/T Yara Gas III liquid CO_2 carrier. [7]

- **CCS studies involving ship transport of large volumes of CO_2:** Several studies of CCS projects have considered transport of liquid CO_2 by ship. Ship sizes in the range of 2,000 to 100,000 m³ CO_2 cargo have been considered [1, 4, 8, 9, 11, 12, 13]. The studies consider different CO_2 transport conditions and ship designs. In many studies custom built CO_2 ships are considered, however it is also widely considered to use a standard gas carrier ship for CO_2 transport. Semi-refrigerated gas carriers used for LPG, ammonia, propylene and other chemicals have typically operating pressures up to 6-8 bar and operating temperatures down to -50°C. Such vessels may transport liquid CO_2 at 7 bar and -50°C. Standard semi-refrigerated gas carriers are normally not equipped with refrigeration machinery, hence the pressure and temperature of the liquid CO_2 will rise slightly during transport. The former shipping company IM Skaugan (now bankrupt) operated a fleet of semi refrigerated gas carriers in the capacity range of 8-10,000 m³, which had been approved for transport of CO_2 [4]. LPG ships may however not be the optimal ship for CO_2 transport because liquid CO_2 has twice the density of LPG implying that the volume capacity may be reduced if transporting CO_2 [9].

- **CCS demonstration project with CO_2 ship transportation:** The CO_2 storage and transportation part of the Norwegian full-scale CCS demonstration project named "Langskip" have studied ship transport of CO_2 from capture plant sites at Oslo and Brevik to a receiving terminal at the

Norwegian west coast. Several different ship sizes and classes have been studied [10, 12]. Liquid CO_2 at 15-18 bar and -25-30° has been selected as the transport conditions in the project i.e. similar to the standard industrial grade. The project has concluded to base the ship design (newbuilt ship) on a concept that closely resembles that of fully pressurised LPG vessels instead of a special design. The 15-18 bar operating pressure is above typical specification of a semi-refrigerated vessels hence the fully pressurized carrier with design pressure of 20 bar is selected. Fully pressurised LPG vessels do normally operate with the cargo at ambient temperature hence does not necessarily have insulted tanks suitable for refrigerated liquid CO_2. The project reports of about 18 months construction time for such vessels.

i.6 CO_2 transport by road

Today road transport of liquid CO_2 by tanker truck is common from distribution hubs to industrial consumers. Standard sizes for CO_2 semi-trailers are available from different vendors e.g. ASCO [14]. Trailers with capacities up to 25-30 m³ liquid CO_2 is typical. CO_2 semi-trailers are pulled by standard trucks as shown in Figure 7.

With tanker truck, liquid CO_2 is transported at 15-18 bar and -25 to -30°C i.e. the industry standard conditions. The density of liquid CO_2 at these conditions is around 1070 kg/m³. CO_2 trailer tanks are typically insulated by PUR foam or vacuum insulated to keep the CO_2 cool during transport. Trucks are typically not equipped with a re-refrigeration unit, hence temperature and pressure of the CO_2 may rise slightly during transport. Truck loading/unloading bays for liquid CO_2 and CO_2 transferring equipment is required at terminals receiving tanker trucks. Standard terminals for truck loading/unloading are commercially available.

Transportable ISO-tank-containers for liquid CO_2 are also available [14].

Considering the above road transport of CO_2 are relatively similar to that of liquid fuels or other pressurised gases.

Figure 7. CO_2 semi-trailer from ASCO. Source; www.ascoco2.com

i.7 CO_2 transport by rail

CO_2 transport by rail is technically possible and cryogenic rail cars (see Figure 8) are in use some places in the world today for distribution of liquid CO_2 to industrial users. However, there are no examples where rail cars are used for transportation of large amounts of CO_2 in a CCS value chain. In a Danish context where very few emission sources are linked to the railroad network it is difficult to imagine that rail transportation of CO_2 will ever play a significant role. This option is therefore not described any further in this catalogue.

Figure 8. Railroad car for liquid CO_2 transport. Source: www.VTG.com

i.8 CO_2 interim storage

Interim storage of CO_2 may be required in connection with CO_2 transportation from source to end destination. This will mainly be relevant when CO_2 is transported in liquid form by truck or ship. The interim storage is needed to buffer the continuous recovery/offtake of CO_2 from capture or utilisation plants between individual truck and ship loads.

As a result, the required capacity for interim storage will largely be governed by the cycle time of the tanker trucks or ships and the desired buffer capacity.

For pipeline transport alone from capture plant to end destination e.g. underground storage, interim storage of CO_2 will typically not be required.

Today liquid CO_2 is most commonly stored in bullet tanks or clusters of tanks of varying height and diameter. Tanks can both be vertically and horizontally oriented depending on local constraints. Bullet tanks are typically fabricated at workshops/shipyards and transported fully insulated and dressed to installation site. The maximum size of storage tanks will hence be limited by what is practical to transport. For smaller capacities (below 100 m³) standard liquid CO_2 tanks are available from vendors of industrial gases. These tanks are typically vacuum insulation and have double shell. Bullet tanks can be fabricated with unit size of 1000 m³ or more, however these are too big for road transport and will require that the installation site has good access to a harbour. For CO_2 terminals with storage capacities of several 1000 m³ the interim storage will consist of multiple tanks. Site assembly of large tanks is very expensive and rarely the preferred option.

Figure 9 and Figure 10 show examples of tank farms for interim storage of liquid CO_2 at medium pressure typical storage conditions.

Figure 9. Storage for 3300 tons liquid CO_2 at Yara's ammonia plant in Porsgrunn, Norway in conjunction with CO_2 export terminal (now operated by Nippon Gases Norway) [7]

Figure 10. Liquid CO_2 import terminal with truck filling bays operated by Yara (now Nippon Gases Norway). [7]

i.9 Examples of CO_2 transportation chains

To illustrate the different elements of CO_2 transportation and how these can be assembled to create the desired transportation chain a set of examples have been compiled as shown in the following.

Example 1 - Transport of CO_2 by road tanker and ship

This example illustrates how CO_2 can be transported from CO_2 source to offshore storage site. For a small to medium size CO_2 emission source located inland, the best CO_2 transport option may be truck transport to a nearby harbour and ship transport to offshore storage or receiving terminal. As an example, this could be a Waste-to-Energy (WtE) plant with 25 t CO_2/h CO_2 capture or 200,000 tpa. A liquefaction plant is included in the carbon capture facility.

The different elements required for the CO_2 transport chain is as listed below and shown in Figure 11:

- CO_2 interim storage at capture site e.g. 1000 t CO_2
- CO_2 transport by tanker truck. Capacity 30 t CO_2/truck indicating 20 truckloads per day

- CO_2 export terminal with interim storage, e.g. 4000 t CO_2 storage

- CO_2 carrier (ship) of 4000 t CO_2 capacity indicating one ship departure every 6 days (cycle time).

- Transfer of CO_2 from ship to injection vessel/platform for underground storage (CO_2 storage is not included in this chapter of the catalogue. The CO_2 carrier may be equipped with facilities for conditioning and injection of CO_2 into a reservoir, but this is not considered here)

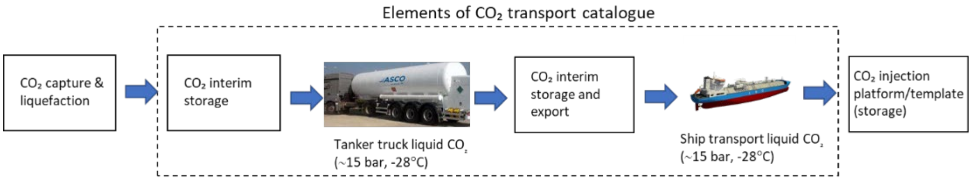

Figure 11. CO_2 transport by road tanker and ship to storage site/import terminal.

Example 2 - Transport of CO_2 by pipeline to offshore storage

This example illustrates how CO_2 from a large point source can be transported in pipeline to an offshore storage site. For a large point source say 1 MTPA of CO_2 capture, pipeline transport may be the more attractive solution. In this example it is assumed that CO_2 will have to be transported 50 km in a pipeline onshore before the pipeline goes offshore and proceeds further 30 km to the storage reservoir offshore. The compression plant is included in the carbon capture facility and will deliver CO_2 at the pipeline interface at 150 bar. However, because of the pressure drop in the pipeline say 1 bar/km, and the requirement for high injection pressure, a pumping station for boosting of pressure is included just before the pipeline goes offshore.

In this case, the different elements required for the CO_2 transport chain is as listed below and shown in Figure 12:

- 50 km onshore CO_2 pipeline from capture site to coast. Capacity of 1 MTPA or 120 t CO_2/h requires an 8” pipeline

- CO_2 pumping station to increase pressure to 150 bar

- 30 km offshore CO_2 pipeline to CO_2 injection template (wellhead)

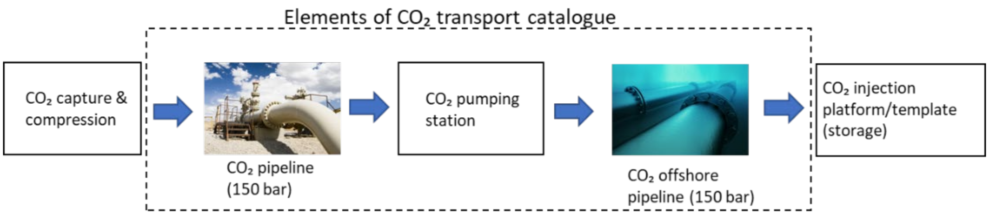

Figure 12. CO_2 transport by onshore and offshore pipeline to storage location.

Example 3 – Transport of CO_2 by pipeline and ship

In this example CO_2 is transported 20 km from a relatively big capture facility (50 t/h or 400,000 tpa) by pipeline to a CO_2 export terminal where it is liquefied and temporarily stored before transported by ship to end destination. This is relevant in the case the CO_2 source is located at distance from the sea and the conditions are in favour of pipeline transport instead of truck i.e. relatively big CO_2 source. The compression plant included in the carbon capture facility will deliver CO_2 at pipeline interface at 150 bar. The distance to the CO_2 export terminal will not be great enough to require a pumping station on the route.

The different elements required for the CO_2 transport chain is as listed below and shown in Figure 13:

- 50 t CO_2/h is transported by 30 km onshore pipeline (6 or 8" pipeline)
- CO_2 export terminal with liquefaction plant and interim storage for 5000 t CO_2.
- CO_2 carrier (ship) of 4000 t CO_2 capacity

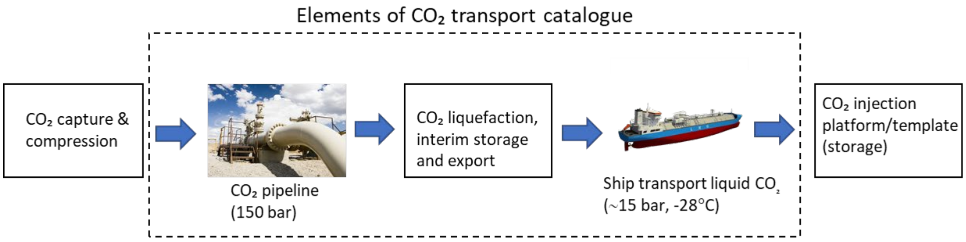

Figure 13. CO_2 transport by pipeline followed by liquefaction interim storage and ship transport.

i.10 References

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Date	Ref.	Description
-	-	-

Qualitative description

Brief technology description

CO_2 pipelines are relevant for transport of large volumes of CO_2 such as from large point source emitters to storage sites, export terminals or CO_2 utilisation facilities.

As explained in the introduction the standard concept for long distance (say above 10-30 km) CO_2 pipeline transport today is dense phase CO_2 transport at the conditions shown in Figure 1. Therefore, only this transport form is considered in the catalogue.

Dense phase operation is regarded as operating pressures above the critical pressure of CO_2 (73 bar). With operational and safety margins, the minimum operating pressure is selected as 80 bar. The maximum operating pressure of CO_2 pipelines is selected as 150 bar. This is a compromise between securing adequate operating range (allowance for pressure drop) and keeping the pipe wall thickness (piping cost) at reasonable level. The density of dense phase CO_2 will only increase weakly with pressure above 150 bar at relevant temperatures (5-20°C) as shown in Figure 2, hence there is limited process benefits of operating with higher pressures except from potential longer distances between compression/pumping stations. In addition, it is expected that the permitting process may become increasingly complicated at higher pressures (increased consequence if ruptured), which is also a factor that must be considered.

Several design standards exist for CO_2 pipelines. In Europe DNV-RP-J202 and ISO 27913:2016 are relevant.

The initial compression of CO_2 up to 150 bar and drying to pipeline specifications are included in the scope of the CO_2 capture plant and explained in the Carbon Capture Catalogue. The CO_2 compressor will hence control the pressure at the inlet side of the pipeline. During outages of the compressor isolation valves will isolate the pipeline hence it is maintained pressurised. Isolation valves are also expected along the pipeline (onshore) in order to seal off segments in case of leakages. The allowable distance between isolation valves will depend on a risk assessment of each segment. In populated areas isolation valves is expected to be required more frequently than in rural areas. Typical distances between isolation valves onshore are 10-20 km [36]. Offshore pipelines will typically not have isolation valves between the beach and the wellhead.

For CO_2 pipelines it is not expected that metering stations will be relevant along the route but will be located together with the compression plant at the inlet or at the end of the pipe. This is of course dependent on the pipeline configuration, i.e. whether it is a pipeline network or point to point pipeline.

Compression/pumping stations may be relevant along the route to overcome frictional loss. As CO_2 is in dense phase the pressure can be increased by centrifugal or reciprocating pumps which are significantly cheaper than compressors and consume much less energy. A compression/pumping station will be required if the pressure drops below the minimum pipeline operating pressure (80 bar). Typically, this may be every 70-140 km. It is expected that the pumps will be located in dedicated stations/houses along the route.

For offshore pipelines, compression/pumping stations are not applicable. Therefore, the dimension of the pipeline will have to be selected hence the pressure drop is acceptable without pressure boosting. In general, this implies that the pipeline diameter increases with length of the pipeline for the same transportation capacity [2].

Input

Input is dense phase CO_2 at the specified inlet conditions.

Energy is required in the form of pumping/compression work to overcome the frictional loss in the pipeline (pressure drop).

Output

This is same as the input as no CO_2 is vented or consumed along the pipeline. The CO_2 will exit at lower pressure due to the pressure drop in the line.

Efficiency and losses

Energy loss from CO_2 pipeline transportation occurs as a result of fluid frictional loss (pressure drop) in the pipelines. The energy loss for CO_2 pipeline transport is a strong function of fluid velocity (approximately third power), therefore the extent of energy loss will be determined by the design velocity of the pipeline. This is ultimately a trade-off between capital cost (pipeline diameter) and operating cost (pumping energy).

For the technology catalogue CO_2 fluid velocities of 1-2 m/s has been applied for the pipelines resulting in pressure drop of approx. 0.5-1.5 bar/km. Highest pressure drop (1.5 bar/km) is tolerated for the smaller pipeline diameters (10-30 t CO_2/h) because it is anticipated that the small bore pipeline is used for relative short distances.

In addition, energy is required at terminals if CO_2 has to be transformed from dense phase fluid to liquid CO_2 at intermediate storage/ship transport conditions. However, the energy requirement (loss) at terminals is included as a separate post.

Application potential

Pipelines will be applicable for point to point transport of CO_2 e.g. from one capture site to one storage or utilisation site, or as part of a larger pipeline network or CO_2 hub.

Typical capacities

The existing CO_2 pipelines in operation covers a large capacity range from 0.06 to 27 MTPA. Pipeline diameters from 4” to 30” have been deployed.

In a Danish context, CO_2 pipeline transport is not likely to exceed around 5-10 million tonnes per annum (MTPA) as this will cover many of the largest point sources of CO_2. The smallest capacity that will be relevant for pipeline transport will of cause depend on a lot of factors such as the distance and location. However as the engineering and installation costs do not scale down proportionally for small bore pipelines it is expected that truck transport will be favoured over pipeline transport at low capacities (e.g. below about 50-100 kton CO_2 per year). For very shorts distances e.g. few km's, over open (rural) terrain pipeline transport could still be an attractive solution even for small volumes.

Advantages/disadvantages

The main advantages with pipelines are that large volumes can be transported at low operating costs, with low energy consumption (and CO_2 emission), no occupation of existing infrastructure (roads, harbours, etc.) as well as continuous operation independent on weather conditions and other external disruptions.

Disadvantages with pipeline transport are high investment cost, long planning and construction time, extensive approval procedures i.e. construction within city limits is difficult, land purchase issue, public perception and low flexibility (end-use value) if CO_2 source disappears or is relocated.

Environmental and safety

Environment

The construction phase of a pipeline may have substantial environmental impact depending on the chosen route. An environmental impact assessment (VVM) will be required. It is likely that future CO_2 pipelines will be constructed as part of an integrated CCS or CCU project, hence the environmental impact assessment will cover the entire project.

Once the pipeline is constructed it will only have marginal environmental impact. CO_2 losses from pipeline will not occur during ordinary operation. Blow down of pipeline sections for maintenance or repair work is likely in the operational phase, however as long as the blow down rate is slow and controlled it will have insignificant environmental impact.

Safety

As CO_2 is a non-flammable but asphyxiant gas which becomes harmful at higher concentrations. Safety must be an integral part of a pipeline project from design to operational phase. Risk assessment of exposure of people to CO_2 from accidental leakages has to be performed and suitable risk mitigating measures need to be implemented. This may include proper leak detection systems (monitoring for sudden pressure drop), CO_2 sensors at relevant locations and low points, sectionalisation (isolation valves) or ESD valves to limit accidental releases, automatic monitoring and shutdown functions.

If a high-pressure CO_2 pipeline is rapidly depressurised to atmospheric pressure CO_2 will form a mixture of solid and gaseous CO_2 at -78°C. This may create a cloud of heavy CO_2 gas which will flow to low points in the terrain. Depending on weather conditions and local turbulence a CO_2 cloud may disperse quickly or be present for several minutes. A risk assessment concerning exposure of third party in the event of rupture will have to be performed as part of the engineering phase. For a CO_2 pipeline there will be operational risks related to CO_2's phase behaviour and load fluctuations e.g. liquid phase or dry ice formation during sudden drops in pressure, freezing of safety valves, etc. Maintenance stops with full depressurization will have to be conducted at a slow pace in order to prevent freezing.

The safety of natural gas pipelines and related installations will be evaluated by the Working Environment Authority in Denmark. It is not precisely known which authority that will evaluate future CO_2 pipelines and what the safety requirements will be.

Monitoring

In daily operation flow, pressure and temperature of CO_2 pipelines must be continuously monitored. The readings from field instruments shall be transferred to a manned control room.

Buried pipelines are also normally equipped with cathodic protection system for monitoring of external corrosion. The pipeline will also be equipped with provisions for pig launchers and receivers (cleaning and inspection device) hence intelligent pigging can be performed for inspection and assessment of internal corrosion and fouling. Because only clean, dry CO_2 gas will be transported in the pipelines, fouling and internal cleaning will probably be less significant compared to the natural gas pipelines.

CO_2 compression/pumping houses, metering house, valve pits or other places where leaking CO_2 can accumulate to dangerous concentrations will be equipped with CO_2 detectors and alarms.

Flow in and out of the pipelines are to be determined by fiscal metering hence adequate control exist on volumes transferred between different parties (e.g. emission source owner and transport/storage provider). Monitoring of the CO_2 quality e.g. moisture content, O_2 content and other trace impurities will probably be a requirement at the inlet, hence it is ensured that the CO_2 quality is compatible with pipeline design materials and downstream specifications.

Research and development perspectives

Pipeline transport of CO_2 and other pressurized fluids is a mature and commercially available technology (TRL 9). Little technical development potential for pipeline transport is expected.

Prediction of performance and costs

CAPEX

For onshore pipelines COWI has made its own estimate of the investment cost based on inhouse experience obtained from engineering, procurement and installation of natural gas transmission lines in Denmark taking into account expected cost differences related to CO_2 specific design conditions e.g. higher pressure, safety factor, etc. The own estimate is benchmarked against references from the literature.

The following assumptions are applied for estimate of CO_2 pipeline investment cost:

- Point to point pipeline (no compressors or conditioning equipment included)
- Pipe dimensioned for 150 bar using a safety factor of 0.2 (conservative). Pipeline construction material is carbon steel (extra strong) with polymer coating. Cathodic protection is included.
- Unit cost based on pipeline distance of 50-100 km in rural area. For very short pipelines the unit cost will increase. This effect is not captured in the estimates.
- Pipeline dimensioned for pressure drop of 0.5 to 1.5 bar/km where the highest pressure drop is accepted for the smallest diameter. The corresponding pipeline flow velocities are in the range of 1.2-2 m/s.
- 3 different pipeline dimensions namely 4, 8 and 12” are priced and used as cost basis for the 3 capacity intervals provided in the data sheet:
  - The 4” pipeline will represent CO_2 flow capacity of 10-30 t CO_2/h and the specified unit cost in the data sheet (15 EUR/[t CO_2/h]/m) is related to a flow rate of 20 t CO_2/h.
  - For pipeline capacity of 30-120 t CO_2/h the cost is based on unit costs for the 4 and 8” pipelines where the 4” has weight of 1/3 and 8” of 2/3. The unit cost of the 8” pipeline is related to a flow rate of 120 t CO_2/h.
  - For pipeline capacity of 120-500 t CO_2/h the cost of the 12” pipeline is applied. The unit cost in the data sheet (2.3 EUR/[t CO_2/h]/m) is related to 300 t CO_2/h flow rate.
- Sectionalisation vales (ESD) with ancillaries every 15 km is assumed. This is uncertain as regulative requirements for CO_2 pipelines in DK is unclear.
- Installation cost includes trenching and 8 % for controlled drilling, permitting and environmental investigations
- Cost factor for engineering and follow-up added (6 to 10% depending on size).

Table 1 shows the estimated pipeline cost for a 12” pipeline per unit of distance (km) and capacity (t CO_2/h). Also shown are estimates for onshore pipeline of similar dimension from the ZEP CO_2 transportation study [2]. It appears that the estimated pipeline cost is a bit lower, but in relatively good agreement with estimates from ZEP. It shall be remarked that the ZEP estimate is not specific for Danish conditions, but also based on rural area and non-challenging ground conditions [2].

Table 1. Investment cost estimates for onshore CO_2 pipeline in rural area and compared to ZEP estimate. Both estimates do not include upstream CO_2 compression or pressure booster stations. ZEP estimate is not specific for Danish conditions.

	COWI estimate	ZEP study [2]
OD Pipe size	12”	12”
CO_2 capacity (MTPA)	2.5	2.5

Pipeline length (km)	50-100	10 and 180
Total installed cost (EUR/km/[t CO_2/h])	2.3	2.8 (180 km) 3.9 (10 km)

For offshore pipeline, the CAPEX is based on ZEP-s estimate [2] for 180 km 12" pipeline transporting 2.5 MTPA CO_2 (approx. 300 t CO_2/h) but reduced from 4.7 to 4.0 EUR/[t CO_2]/m to be more in line with expectations for Danish conditions and the estimate for onshore pipeline.

OPEX

The O&M value is based on ZEP value of 6000 EUR/km for 12" onshore pipeline transporting 2.5 MTPA CO_2 [2]. This corresponds to approx. 20 EUR/km/[t CO_2/h]. The estimate excludes maintenance and energy cost for the initial CO_2 compression as this is included with the capture plant. The cost is assumed to be fixed O&M cost independent on capacity factor. The variable O&M cost is assumed to be negligible.

Levelized cost of CO_2 pipeline transport

For benchmarking of inhouse pipeline CO_2 transport cost to literature values an example with transport of 2.5 MTPA for 250 km is calculated as shown in Table 2.

Table 2. Example of cost of CO_2 transport. Cost is based on 250 km 12" pipeline operating at full capacity (8400 hrs/year).

Parameter	Cost	Comment
CAPEX 250 km 12" pipeline	173 mill EUR	Unit cost of 2.3 from catalogue
1 x pumping station	4.0 mill EUR	ΔP is 0.5 bar/km, total ΔP is therefore 125 bar => 1 pumping station
Annual. CAPEX (6%, 50 year)	11.2 mill EUR/year	50 years lifetime
Fixed O&M	1.5 mill EUR /year	
Power cost	0.50 mil EUR/year	0.02 kW/km/[t CO_2/h] and 40 EUR/MWh
Total annual cost	13.2 mil EUR/year	
Annual CO_2 transport	2.52 mill t CO_2/year	8400 hrs at 300 t CO_2/h (full capacity assumed)
Specific transport cost	**5.3 EUR/t CO_2**	

In IPCC's carbon capture and storage report from 2005 [4] CO_2 transportation costs have been assessed for onshore and offshore pipelines (and ship) as shown in Figure 1.

From Figure 1 (left) the cost of transport of 2.5 MTPA for 250 km can be read to about 4 USD/t CO_2 (2005 cost level), which is close to 4 EUR/t CO_2 in 2020 level (20% escalation and 1.24 USD/EUR). The estimated value for Danish conditions is shown in Table 2 to be 5.3 EUR/t CO_2, which is higher but in the same order of magnitude as the ICCP value.

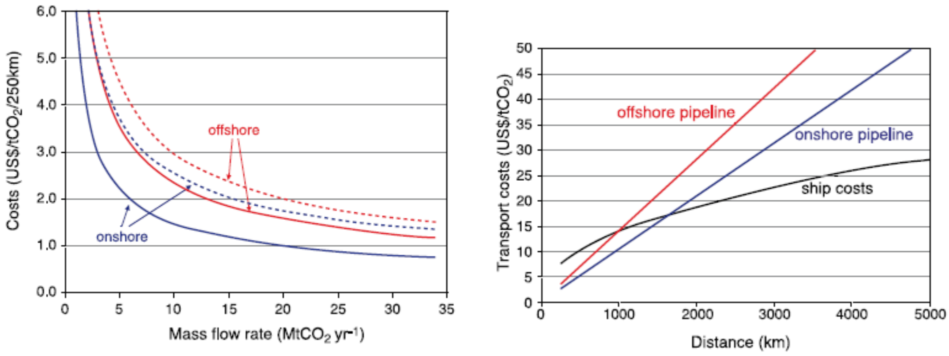

Figure 1. Cost of pipeline transport from ICCP study from 2005 [4]. Figure to the left assume fixed pipeline length of 250 km. Figure to the right is for transport of 6 MTPA CO_2.

In the ZEP report [2], the levelized cost of CO_2 transport for 180 km onshore pipeline is estimated to 5.38 EUR/t CO_2 using different CAPEX annualization parameters (8%, 40 years). With similar CAPEX parameters the estimated cost for Danish conditions will increase to 6.7 EUR/t CO_2.

Uncertainty

No CO_2 pipelines have been constructed in Denmark hence there will be uncertainty related to the permitting process and safety requirements. It is however likely that the procedures and rules will be relatively similar to what is known from NG pipelines. The uncertainty on specific safety requirements will add some uncertainty to the cost estimates.

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9 Shipping CO_2 - UK cost estimation study. Elementenergy. Final report for Business, Energy & Industrial Strategy Department, Nov 2018.

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13 Knutsen Shipping. The Pressurised CO_2 Transport Solution PCO_2. Presentation Dansk Industri seminar. Fangst og lagring af CO2 som klimavirkemidde. 22 Septemper 2020.

14 CO_2 tanker Asco: https://www.ascoco2.com/

15 CO_2 pipeline infrastructure. IEAGHG / Global CCS Institute. Report: 2013/18, January 2014.

Quantitative description

See separate Excel file for Data sheet

422 CO_2 transport by ship

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Brief technology description

Ship transport of CO_2 is most relevant for transport of medium to large volumes of CO_2 over medium to long distances e.g. from large point source emitters to offshore storage destination or land-based terminals. Ships do however also have the flexibility to operate in a route network picking up CO_2 from multiple locations. In this case ship may be relevant for relatively short transport distances.

As described in the introduction, only limited volumes of CO_2 is transported by ship today and in relatively small ships 1000 – 2000 m^3.

For ship transport only liquid CO_2 is considered. Most studies in the literature considers modest pressure levels (<20 bar) as this will ensure high CO_2 density without requiring too heavy pressure tanks. However, examples of higher pressure alternatives have also been considered [12, 13]. Thus, the transportation conditions can be grouped in the following three alternatives:

- Low pressure conditions: Around a few bar above the triple point (5.2 bara, -56°C) say 6-8 bara and approx. -50°C. These conditions will result in the highest CO_2 density 1150 kg/m^3 and lowest thickness of pressure tanks. The low temperature will however require more comprehensive (expensive) insulation and use of low-temperature steel types.

- Medium pressure conditions: 15-18 bara and -25 to -30°C (The most common conditions for transport of liquid CO_2 today). This is a CO_2 density around 1070 kg/m^3.

- High pressure conditions: 40-50 bara and +5 to +15°C. CO_2 density of 800-900 kg/m^3. This alternative will require pressure vessels with higher design pressure (heavier per volume CO_2) but less insulation is needed.

The ship design will be different for the different transport conditions. The selection of CO_2 transport conditions will also affect the export terminal design and the CO_2 liquefaction plant to some extent. Examples of design and pressure tank layout of CO_2 carrier ships are shown in Figure 1.

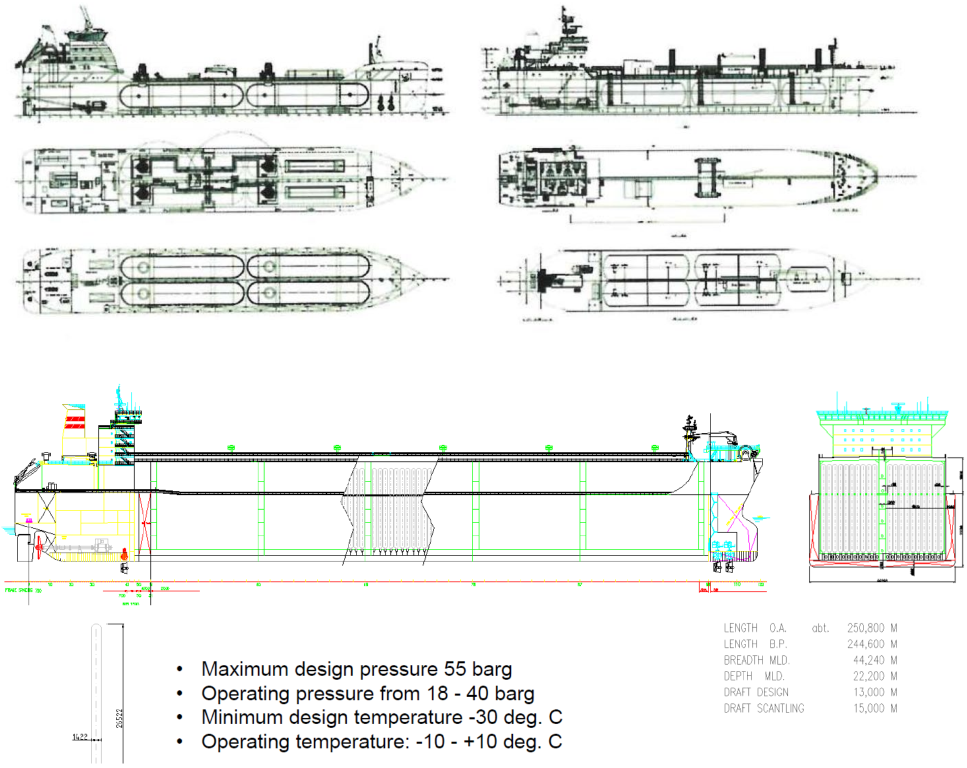

Figure 1. Top) Sketch of refrigerated CO_2 ship designs for Gassco Concept study [12]. Bottom) sketch of Knutsen Shipping's design of a pressurised CO_2 carrier (PCO2) [13].

For ship transport the logistics is important to consider as the cost of additional ships is significant. An optimisation exercise should be conducted where transport distance, ship size, unloading/loading time, cruising speed and number of ships are considered. An example of typical values applied to estimate cycle time is shown in Table 1.

Table 1. Example of estimating ship cycle time and number of cycles/year for 700 km (each way) CO_2 transport.

Activity	***Duration***	***Comment***
Time for ship loading and unloading	2 x 12 hours	If offshore direct injection to storage,
Time spent cruising:	2 x 700 km/(28 km/h) = 50 hours	28 km/h speed is used
Cycle time	74 hours	
Availability	90%	Impact of weather, repair, maintenance
Total cycles / year	106	

Table 2 provides an example on how much CO_2 that can be transported with one ship per year under the specified assumptions.

Table 2. Example on annually transported CO_2 amount by one ship. Assumptions Cycle time is 4 days (~700 km each way) and availability is 90%.

Ship capacity	2,000 tons	4,000 tons	10,000 tons
CO_2 transported annually	160.000 TPA	330.000 TPA	820.000 TPA

CO_2 Liquefaction and terminal

To condition CO_2 for ship transport it will have to be liquefied. Liquefaction of CO_2 directly from a CO_2 capture plant (at low CO_2 feed pressure) is described in the Technology Catalogue on carbon capture.

Alternatively, if the CO_2 liquefaction plant is fed by dry high-pressure CO_2 from a pipeline the liquefaction process will be less complicated and consume significantly (approx. 1/3) less energy compared to directly from a capture plant. This can be relevant in the case CO_2 is transported in onshore pipeline to a CO_2 export terminal. In this case one can assume the liquefaction plant investment cost is only 0.2 M€/[ton CO_2/h] and power use is 50 kWh/ton CO_2.

The CO_2 terminal will consists of well-insulated storage tanks for liquid CO_2. The capacity can as a first estimate be selected as 100% of the ship's capacity. The storage tanks will as a minimum need to hold a volume equivalent to the amount of CO_2 recovered between each ship arrival (cycle time). The requirement of buffer e.g. for delays in ship arrival frequency, will normally be desirable. The buffer requirement will have to be evaluated from project to project.

In addition, a terminal will be equipped with transfer lines (liquid CO_2 and vapor return) and pumps that can load/unload the ship in typically around 10 hours will be present. Also, marine loading arms or flexible hoses to connect to the ship and other utilities are required. Vapour equalisation between onshore tank and ship tanks is required during ship loading/unloading. Because of heat ingress into the refrigerated liquid CO_2 storage there will be continuous evaporation of CO_2. This needs to be re-liquefied at the terminal. In case the terminal is located together with the capture plant, the CO_2 vapours can be routed back to the main liquefaction plant and re-liquefied. If it is a satellite terminal it will need to be equipped with own refrigeration plant unless the ship arrival frequency is high.

Input

Input to CO_2 ship transport is except for the liquid CO_2 cargo, fuel for propulsion. The fuel consumption is provided in units of MWh/day referring to energy content in the applied fuel (LHV, lower heating value). The fuel consumption applies only when the ship is operating at cruising speed and is an average of loaded and unloaded cruising. The energy consumption during unloading/loading at pier is significantly lower (around 10%) and may in some cases be covered by electric power from land. The consumption during unloading/loading is neglected here.

The fuel consumption applied in the datasheet for the 4,000 and 10,000 ton CO_2 ship of 90 and 180 kWh/day is based on input from Knutsen Shipping.

Output

Output is liquid CO_2 cargo.

When a CO_2 tanker ship is loaded with CO_2 from an onshore storage tank, the CO_2 vapours in the ship's tank will be returned to the onshore storage tank. This will reduce the effective transport volume (or mass) of the ship. Because of the difference in vapour and liquid density this will only result in 3-4% reduction.

Efficiency and losses

Significant energy consumption is involved with ship transport. IEA has estimated that 2.5% of the transported CO_2 is emitted from transporting CO_2 by ship for 200 km. For 12,000 km 18% CO_2 of transported CO_2 is released [4]. In a more recent study emissions from ship inclusive liquefaction (indirect emission from power generation) was reported to be unlikely to result in more than 2% of transported CO_2 volume [9]. Using the energy data of this catalogue a CO_2 emission of 0.4% of the transported volume is obtained for 200 km as shown in Table 2.

The CO_2 emission from ship transport will in addition to the transport distance depend on factors such as ship cruising speed and the type of fuel burned (HFO, MDO, LNG, etc.).

Application potential

Ships will be applicable for point to point transport of CO_2 from CO_2 terminal at a capture plant location to offshore storage site (e.g. to an injection vessel) or another ship terminal e.g. at CO_2 utilisation site. A CO_2 ship may also operate in a route network where it collects CO_2 from several capture plant sites and deliver the CO_2 at a common destination.

Ship transportation requires a certain minimum volume and distance to be economically favourable compared to the alternatives (pipeline and road transport).

Typical capacities

The capacity range considered for ships in a CCS value chain are from 2,000 to 100,000 t CO_2 capacity. For as specific project the ship size is selected based on cost optimisation and redundancy requirements.

Only CO_2 carriers up to approx. 2000 t CO_2 is in operation today.

Environmental and safety

The environmental impact of ship transport is mainly during the operation phase of the project. This is linked to the energy requirement and emissions from the ship.

Safety

Pressure tanks on ships are normally designed according to the international maritime organisation's (IMO) IGC code. The code specifies higher safety factors and margins compared to land-based pressure tanks. [12]

Because of the large volumes of CO_2 onboard ships or at land-based terminals, accidental release of large volumes of CO_2 (loss of containment scenario) is the main safety concern with ship transportation of CO_2. If liquid CO_2 is depressurised to ambient pressure it will form a mixture of solid and gaseous CO_2 (approx. 50/50) at -78°C. A large sustained release of liquid CO_2 will form a cold CO_2 gas cloud of high CO_2 concentration. The cloud will flow to low-points in terrain and gradually disperse in air depending on wind speed.

Sectionalisation of storage and transfer equipment, leak detection and ESD are means of risk mitigating. A risk assessment will have to be conducted for the CO_2 interim storage and loading operations to see if the location meets risk acceptance criteria.

Research and development perspectives

If CO_2 transportation market will take off, there is a potential for development of new ship classes dedicated for CO_2 transport, which may reduce cost. In addition, development of new propulsion types and green shipping fuels may significantly decrease CO_2 emissions form ship transportation of CO_2. If specialised CO_2 carriers are developed it is plausible that the energy consumption can be somewhat reduced due to a more optimised design.

The fixed O&M cost is to a large extent made up of personnel costs. Development of more autonomous ships may also reduce operating cost of ship transportation.

Examples of market standard technology

It is possible to use standard semi-refrigerated or fully pressurised gas carriers for transport of liquid CO_2.

Prediction of performance and costs

CAPEX

Several studies on the cost of ships for CO_2 transport have been reported in the literature. The energy consultancy company ElementEnergy have estimated CO_2 shipping cost for a UK scenario based on cost fitting to many of the available literature cost studies as shown in Figure 2. The figure distinguishes between low pressure CO_2 transport (6-8 bara), medium pressure (15-18 bara) and high pressure (40-50 bar). According to Figure 2, a ship equipped for the low-pressure CO_2 transport conditions is less than half of the cost of a ship for medium pressure. This is a remarkable cost gap which cannot be justified by cost differences between the pressure tanks alone. This may amongst others be related to poorer utilisation of ship's cargo volume as smaller pressure tanks will be used when design pressure is increased. As there is no data for the medium pressure alternative above about 12,000 t, the shown shape of the cost cure is uncertain for higher capacities. For the high-pressure conditions only a single data point is present, hence the CAPEX is highly uncertain for this alternative.

As the industrial standard today is based on CO_2 transport at medium pressure (15-18 bara) conditions the ship cost data for this alternative is selected for the data sheet.

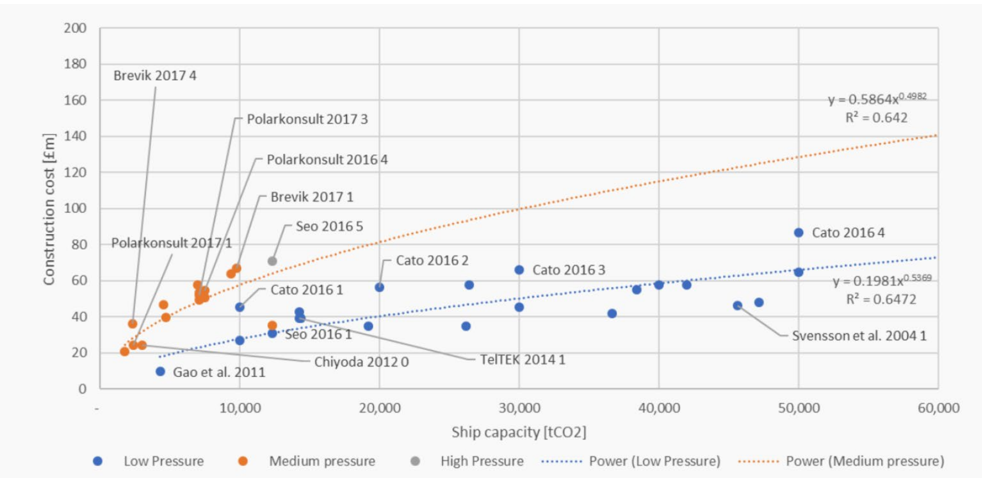

Figure 2. Investment cost for CO_2 carriers as a function of capacity from [9]. Low pressure 5-8 bar, Medium pressure: 15-20 bar.

Different opinions in the literature exist on the advantage of refurbishing old gas carriers for CO_2 transport compared to newbuilt. According to Gassco study [12] refurbishment of old carriers may result in cost reduction of 60% or more compared to newbuilt vessel. On the other hand, ElementEnergy [9] argues that the investment cost of the ship will only constitutes 14% of the total transport cost of CO_2 (when liquefaction is included) hence CAPEX saving by refurbishing old vessels has low impact on the overall cost of CO_2 transport.

To obtain the full CAPEX of a full CO_2 ship transport chain, also CO_2 terminals for exporting and receiving the CO_2 with intermediate storage facilities must be included.

CO_2 export terminals of two capacities (4,000 and 14,000 ton CO_2) have been estimated. Facilities included in the terminals include insulated bullet tanks, CO_2 transfer piping, marine loading arm, loading pumps, CO_2 metering equipment and utilities. The terminals are estimated for CO_2 at 15 bara and -27°C.

OPEX

Main OPEX elements of ship transport are ship fuel cost and O&M cost for the ship. Fixed O&M is typically estimated as 5% of CAPEX per year for ships [9]. An uncertainty on OPEX is the harbour fee e.g. for landing a tonne of cargo, which may potentially be a substantial OPEX element. Harbour fee is not estimated here. Cost of CO_2 liquefaction is also substantial, but this is included at the CO_2 capture plant.

Levelized cost of CO_2 ship transport

An example of the levelized cost of CO_2 transport by ship is shown in Table 3. The cost is estimated to 11.2 EUR/t CO_2 for transport of 560,000 tpa at a distance of 500 km with a vessel size of 4000 t CO_2. Also included an onshore export terminal of 5000 t CO_2 capacity (25% buffer capacity).

Table 3. Example of levelized cost of CO_2 ship transport. Ship size is 4000 t CO_2. Export terminal of 5000 t CO_2 is included. CO_2 conditions 16 bara and -26°C, transport distance 500 km each way, loading/unloading time per cycle is 24 hours.

Parameter	Cost	Comment
CAPEX 4000 t CO_2 ship	40 mill EUR	Unit cost of 10,000 EUR/t CO_2 from data sheet
CAPEX 5000 t CO_2 export terminal	12.5 mill EUR	Unit cost of 2500 EUR/t CO_2 from data sheet.
Annual. CAPEX (6%, 40 year)	3.5 mill EUR/year	40 years lifetime ship (only 25 years of terminal)
Fixed O&M	2.4 mill EUR /year	5% of CAPEX ship + 75 EUR/t CO_2 terminal capacity
Fuel cost	0.45 mil EUR/year	90 MWh/day from data sheet, 270 EUR/ton HFO,
Total annual cost	6.3 mil EUR/year	
Annual CO_2 transport	0.56 mill t CO_2/year	8400 hrs and 140 cycles per year, 60 hour cycle time
Specific transport cost	**11.2 EUR/t CO_2**	Ex. harbour fee and taxes

The ZEP CO_2 transportation study [2] estimates cost of ship transport of CO_2 for 500 km distance at a yearly volume of 2.5 MTPA (smallest scenario) to 9.5 EUR/t CO_2. This is relatively close to the estimate in Table 3. The ZEP estimate covers the low pressure transport conditions and larger vessels (30,000 t CO_2) which leads to significantly lower CAPEX of the ship (Figure 2). On the other hand, the ZEP study applies higher value of capital (8%, 30 years).

Uncertainty

As there is no commercial market for CO_2 transport by ship today the cost numbers are relatively uncertain. Most cost studies are based on LPG and other gas carriers, which are of relatively similar design and capacity.

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15 CO_2 pipeline infrastructure. IEAGHG / Global CCS Institute. Report: 2013/18, January 2014.

Quantitative description

See separate Excel file for Data sheet

423 CO_2 transport by road

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Brief technology description

Transport of CO_2 on road tankers is widely applied today. For transport of large amounts of CO_2 it is transported in liquid form similar to ship transport conditions. The conditions used for road transport of liquid CO_2 is 15-18 bara and -25 to -30°C. Road transport of CO_2 is relevant of small to medium volumes of CO_2 e.g. from small point source emitters to CO_2 utilisation facilities or export terminals.

CO_2 trucks may be loaded from interim storage tanks. Normally dedicated loading bays with transfer equipment and gas return lines are present. A truck of 30 t CO_2 capacity can be loaded with Liquid CO_2 in around 45 min. It can be assumed that 45min unloading time at the destination.

Input

Except from the liquid CO_2 cargo, input is fuel for the truck. In the data sheet the fuel cost has been included in the estimated km price for road transport of CO_2. The energy demand (fuel use) applied in the cost calculation is stated in the data sheet.

Output

Output of liquid CO_2 is same as input.

Efficiency and losses

Significant energy consumption is involved with road transport of CO_2. However, for short distances the emission is not that significant compared to the amount of CO_2 transported. As an example, transporting 30 t CO_2 25 km will result in emission of less than 1% of the CO_2 for a round trip.

Application potential

Road truck transport of CO_2 will mainly be relevant for small to medium volumes of CO_2 over limited distances. This may for instances by from a CO_2 capture plant at a relatively small emission source and to a nearby export terminal or CO_2 utilisation facility. Max CO_2 tanker truck capacity is around 25-30 t CO_2 hence a large CO_2 point source e.g. 100 t CO_2/h will imply many truckloads per hour around the clock which is often not desirable and more expensive than a pipeline.

Typical capacities

The typical capacities of CO_2 road tankers are 25 to 30 ton. The annual transport capacity of a single truck will clearly decrease as the transport distance increases.

Environmental and safety

The environmental impact of truck transport is mainly during the operation phase of the project. This is linked to high energy requirement and emissions from the truck.

Safety

CO_2 semi-trailers are accepted for road transport of CO_2 today. As the amount of CO_2 carried is relatively limited an accident involving leaking CO_2 will have relatively local effect. In congested areas such as in tunnels or in narrow streets dangerous levels of CO_2 is more likely to form in case of a large leakage.

Examples of market standard technology

Semi-trailers with transport of liquid CO_2 at 15-18 bara and at -25 to -30°C is the standard technology for road transport.

Prediction of performance and costs

Transport of CO_2 by truck is a standard service today, which is offered by several large transport companies. COWI has learned from commercial offers that road transport of CO_2 with diesel trucks with capacity of about 30 t CO_2 will cost around 6-8 EUR/t CO_2 for about 15 km and 13-18 EUR/ton CO_2 for 100 km distance. The cost includes loading and unloading to storage tanks and is based on transport of 400.000 tpa.

An estimate for CO_2 transportation cost by truck as function of capacity and distance has been derived where all cost elements (CAPEX and OPEX) have been lumped into a “fixed cost factor” (covering the time spent loading/unloading+ time share of CAPEX + O&M) as well as a variable cost factor (covering fuel consumption, time share of CAPEX + O&M, hours on road).

In the calculation of a cost factors for CO_2 road transport the following is assumed:

- CAPEX of semi-trailer truck with 30 t CO_2 load capacity (50 t gross weight) is estimated to 660,000 EUR.
- Annual maintenance is set to 4% of CAPEX and results in 1000 h unavailability per year
- Driver cost is 47 EUR/h (operation 24/7).
- Fuel consumption is 18 MJ/km (average of loaded and unloaded consumption) and fuel cost is 0.028 EUR/MJ.
- Loading and unloading time is set to 45 min each
- Average speed is 50 km/h.
- Truck CAPEX is annualized with 8% over 4 years.

With the above assumptions the cost of CO_2 transport is modelled at 3.8 EUR/t CO_2 + distance x 0.14 EUR/t CO_2/km.

Example of cost of CO_2 transport

In the table below the cost of truck transport of CO_2 is calculated for 15 and 100 km with the cost numbers given above. This is in good agreement with experienced commercial rates.

	15 km transport	100 km transport
Fixed cost	3.8 EUR/t CO_2	3.8 EUR/t CO_2
Variable cost	15 x 0.14 EUR/t CO_2	100 x 0.14 EUR/t CO_2
Total cost	**5.9 EUR/t CO_2**	**17.8 EUR/t CO_2**
CO_2 volume transported (24/7 operation)	110,000 tpa	42,000 tpa

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Quantitative description

See separate Excel file for Data sheet

Introduction to CO_2 storage

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November 2021

Amendments after publication date

Date	Ref.	Description
-	-	-

i.1 This report

This report with the below chapter addresses a number of generic geological CO_2 storage options relevant for Denmark. The purpose is to create input to different activities in the Danish Energy Agency under the Ministry of Climate, Energy and Utilities on the possibilities for CCUS (Carbon Capture, Utilisation and Storage) in Denmark. The main objective is to collect and establish basic knowledge about investment requirements and operational costs for CO_2 storage in Denmark.

The report describes three different generic scenarios with respect to suitable geological storage sites and based on these descriptions, assessments are made regarding the investment and operational costs for three different annual storage volumes. Furthermore, some general issues related to regulatory and other requirements for CO_2 storage are discussed.

The three storage types, which have been analysed, are:

- Onshore saline aquifers
- Nearshore saline aquifers
- Offshore depleted oil/gas fields

The cost estimates may, when combined with cost estimates for CO_2 capture and transportation, be used to establish an early shadow price for Carbon Capture and Storage (CCS).

As part of the preparation of the present report, contacts have been made with different stakeholders working on developing CO_2 storages in Denmark and abroad. Input from stakeholders has been used as verification of project estimates during the preparation of the present report and upon finishing the draft report.

The report was made under a contract with the Danish Energy Agency within a budget corresponding to 3000 man-hours, which has restricted the level of detailing. The final version has been incorporated into the Technology Catalogue for Carbon Capture, Transport and Storage.

i.2 Delimitation of this report – CO_2 storage

The present report concerns CO_2 storage only, while capture and transportation of CO_2 are described in parallel studies. In some cases, however, local infrastructure has been defined, e.g. buffer storage facilities aimed to receive CO_2 from the transportation option. On land, this may also include local pipelines, while for the offshore cases offloading and injection vessels have been included.

All geologic storage scenarios analysed in this study are found to be feasible and realistic.

However, the present report should not be used for decision-making for development of concrete storage projects.

i.3 Uncertainty of cost estimation

Cost estimation is uncertain as costs, capacity etc. can only be clearly defined after design and data collection. This is the case for geological parameters where the number, location and type of wells, including material selection, will depend on detailed knowledge about the CO_2 stream and the reservoirs.

For the process industry, it is normal to use different categories for cost estimation. The following table is copied from AACE International Recommended Practice No. 18R-97 [1].

	Primary Characteristic	*Secondary Characteristic*			
ESTIMATE CLASS	**LEVEL OF PROJECT DEFINITION** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]	**PREPARATION EFFORT** Typical degree of effort relative to least cost index of 1 [b]
Class 5	0% to 2%	Concept Screening	Capacity Factored, Parametric Models, Judgment, or Analogy	L: -20% to -50% H: +30% to +100%	1
Class 4	1% to 15%	Study or Feasibility	Equipment Factored or Parametric Models	L: -15% to -30% H: +20% to +50%	2 to 4
Class 3	10% to 40%	Budget, Authorization, or Control	Semi-Detailed Unit Costs with Assembly Level Line Items	L: -10% to -20% H: +10% to +30%	3 to 10
Class 2	30% to 70%	Control or Bid/ Tender	Detailed Unit Cost with Forced Detailed Take-Off	L: -5% to -15% H: +5% to +20%	4 to 20
Class 1	50% to 100%	Check Estimate or Bid/Tender	Detailed Unit Cost with Detailed Take-Off	L: -3% to -10% H: +3% to +15%	5 to 100

Table 0-1: Cost estimation categories from AACE International Recommended Practice No. 18R-97 [1]

The estimates of the present report are in class 5 and costs are to a large degree taken from analogies from the oil and gas industry. This may result in too high costs as CO_2 storage may be less risky, since CO_2 is not flammable, and because the requirements for robustness and a high degree of availability may be less important in a carbon abatement industry. However, a fully integrated CCS value chain as an industry is not yet fully developed, and only few examples exist, and issues such as the choice of materials for wells and pipelines may require more development. Also, regulatory requirements are more stringent and thus more costly for CO_2 storage.

i.4 CO_2 Footprint

While the purpose of CCS is to reduce CO_2 emissions, the activities related to storage of CO_2 could potentially introduce additional emissions. However, the basis for all the described concepts is that all energy required for the operation is based on green energy, e.g. power from wind turbines or green e-fuels such as ammonia.

Consequently, it should be noted that there will be some emissions from the construction of the required facilities and the operation of the facility. These have not been quantified at part of this report.

451 CO_2 storage

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1.1 Brief technology description

The full carbon capture chain consists of several elements, which all need to be in place to ensure storage of CO_2:

- Capture
- Compression/liquefaction
- Intermediate storages – option at capture site and/or at storage site
- Pipeline transportation – option
- Ship transportation – option
- Geological storage

The storage part is to a certain degree linked to either ship transport, combined with intermediate storage, or pipeline transport and compression. Other kinds of transportation by truck or rail will be related to smaller scale storage than what is presented in the following section.

The simplest system will be a system consisting of capture, compression, pipeline transport and storage. Depending on the reservoir pressure in the storage, there may in addition be a need for compression or pumping at the storage facility. Such systems would benefit from a cluster of CO_2 sources to ensure the robustness of the system and, in case a CO_2 supplier ceases to deliver, to safeguard the investment in the storage and transportation components.

In cases involving several different sources, which cannot be linked to a pipeline, the system will consist of an intermediate above-ground storage (i.e. a number of storage tanks) connected to the geological storage facility by either pipeline for onshore or nearshore solutions or ship transportation for offshore solutions. These are the scenarios used in the present analysis.

For larger volumes, it may also be possible to connect the offshore storage by a pipeline from shore. This can be a new pipeline or re-use of existing pipelines which are no longer needed and can be converted to CO_2 transportation.

1.2 Maturity of storage technology and potential storage sites

Storage of CO_2 is a mature technology, which has been used for decades. There are many CCS projects globally, both operational and in the making. For a more detailed review, reference is made to:

- Global CCS Institute Report 2020 [2]

- ISO TC/265 TR 27923:2020 Geological storage of carbon dioxide injection operations and infrastructure (in press) [3]

Some of the **currently operating projects, of relevance to the potential Danish cases,** are briefly reviewed below.

Sleipner, North Sea Norway

Began injection in 1996, offshore storage of CO_2 captured from natural gas. The natural gas has an original CO_2 content of about 9%, which is to be reduced to less than 2% for sales to Germany. Initially, about 1 Mt pa (Million ton per annum) CO_2 stored, decreasing with time. Now also CO_2 from satellite fields. Storage in high permeability Utsira sand through one extended reach well drilled from the Sleipner platform. Storage takes place in thick, high-quality sand with little lateral closure. Sleipner has led the development of monitoring methodology on offshore storage.

Snøhvit, Barents Sea Norway

5-7.5% CO_2 is captured from natural gas aimed for LNG (Liquefied Natural Gas) production, which will be transported by ship to the market. The field is developed with subsea installations and a multiphase pipeline to shore and a CO_2 return pipeline. Operations began in 2016 with storage in a saline aquifer below the gas reservoir. Due to pressure build-up, the injection zone was shifted to the flank of the gas reservoir. The combination of pressure monitoring and 3D seismic was instrumental in addressing the issues.

Both the Sleipner and Snøhvit CO_2 storage projects were originally permitted under petroleum regulations but are now regulated under the relevant EU/EEA directives.

Gorgon, Western Australia

Began injection in 2018. Storage of CO_2 from gas processing. Gas fields are located offshore, while storage takes place from a small island. Expected to reach about 4 Mt pa. Storage takes place in a monoclinal saline aquifer using water production wells for CO_2 plume control.

Weyburn, Saskatchewan Canada

Oil field using CO_2 for improved recovery of oil from carbonates. One of the first Canadian fields with extensive R&D into CO_2 EOR (Enhanced Oil Recovery) and CCS. Baseline survey data used in surface liability case.

Boundary Dam, Saskatchewan Canada

Began operations in 2014 at a coal-fired power plant block. Aim to capture about 1 Mt pa, which is sold for CO_2 EOR at Weyburn and any excess stored in a nearby saline aquifer. Provides a documented overview of uptime for the capture system, generally running at less than 80%

Sacroc, Texas USA

An old, giant oil field and one of the early CO_2 EOR fields, going back to the 1970s proving the effectiveness of CO_2 as a tertiary oil production method. The use of CO_2 in oil fields was linked to a tax credit in the US. CO_2 was used to build pressure back up to the initial reservoir pressure level, after which additional oil production occurred some ten years later. Subsequently, another nearby giant oil field, the Yates field, was also subjected to CO_2 EOR flood.

Relevant demonstration projects

Ketzin, Brandenburg Germany

Storage of CO_2 in a saline aquifer in a sandstone reservoir below a former DDR natural gas storage facility. More than 70,000 tons stored, mainly commercial, food-grade CO_2 as well as some CO_2 from a power plant capture pilot. Very well-documented onshore storage activity close to Potsdam and Berlin. Excellent relations with the local population. Site now abandoned.

Tomakomai, Hokkaido Japan

CO_2 captured from a hydrogen plant. Storage well drilled from land and under the sea to an offshore storage structure. About 300,000 tons stored in all, and the site is now being monitored.

CCS projects in the making

Ministry of Environment Sustainable CCS project, Japan

Began capture on 50 MW biomass power plant in Mikawa, southern Japan, in June 2020. Capture of CO_2 from waste incineration in Saga City is under development. Work ongoing to develop ship transportation options for offshore mid-Japan storage site. Both shuttle tankers and stationary tankers are being considered.

ECO2S CarbonSAFE project, Alabama-Mississippi USA

Initially aiming at capture of CO_2 from the Southern Company's Kemper power plant in Alabama, this project is developing saline aquifer storage capacity for up to 35-50 Mt pa from regional industries. The project is currently in Phase III drilling observation and injector wells. While US legislation for CO_2 EOR, where CO_2 is considered an oil field additive, is very different from European legislation, US requirements for CO_2 storage-only are as demanding as national and EU requirements in Europe.

Several European projects for CO_2 storage are being developed including

Project Greensand, North Sea Denmark

Located in the western part of the Danish North Sea, this project aims to mature storage of ½-1½ Mt pa from 2025 in the Nini Field and up to 8 Mt pa in all the Siri Area Fields by 2030. CO_2 will be transported by ship directly to the offshore installation and will avoid the construction and installation of pipelines and new drill centres. The storage cost will therefore be lower than for those requiring new-build facilities. The flexible operational setup allows for CO_2 emitters in the Baltic Sea Region and North Sea Region to use the Greensand storage site. Greensand has, as the only Danish storage site, a certified Statement of Feasibility.

Project Bifrost, North Sea Denmark

The project aims to evaluate and mature CO_2 transport and storage in the Harald Field located in the Danish part of the North Sea. The project has an expected start-up storage capacity of 3 million tons of CO_2 per year (m/t pa). The related studies intend to develop and select the transport and storage concept for Project Bifrost. The project aims to reuse existing North Sea infrastructure while demonstrating CO_2 storage in a depleted offshore gas field and utilising additional North Sea reservoirs as well as the possibility to use the existing pipeline infrastructure connected to the Danish shore as a step to connect to a future European cost- and climate-efficient CO_2 transportation system.

Northern Lights, North Sea Norway

This project aims to store CO_2 in an offshore saline aquifer some 100 km off the coast of Norway. An intermediate CO_2 storage hub and associated harbour facilities are being built on the coast. CO_2 will arrive on ships and be sent via a pipeline for injection at the storage site. Wells will be developed as subsea installations and injection will be controlled from shore. Initial storage from one capture source is expected to be about 0.6 Mt pa with an upside capacity of about 1.5 Mt pa. The pipeline is designed for 4-5 Mt pa allowing for later stepwise expansion with domestic and international CO_2 supplies. An appraisal well has been completed and additional CCS relevant information has also been obtained in a nearby oil exploration well. The operator is making much of this information available at request.

Acorn and Sapling, Scotland

This project, which is strongly supported by the Scottish government, is the successor of the now moth-bagged Peterhead project. The storage is to take place in an offshore, depleted sandstone oil reservoir, re-using the pipeline from St. Fergus as well as the four-well platform. The wells will be recompleted. Once the project is initiated, it is the intention to stepwise link up CO_2 supplies along the east coast all the way down to Grangemouth and Edinburgh, re-using existing pipeline facilities.

Zero Carbon Humber, UK

A project to transport CO_2 from several industrial plants in the industrial cluster of Humber, including a hydrogen production plant with CCS at Equinor's H2H Saltend project, a carbon negative power station at Drax, decarbonised gas power station at SSE's Keadby site, additional hydrogen production capability at Uniper's Killingholme site and Scunthorpe steelworks. The industrial clusters plants will be connected by a CO_2 and hydrogen pipeline, and CO_2 will be injected into the offshore saline aquifer in the UK Southern Gas Province.

Porthos, The Netherlands

A project to transport CO_2 from industry in the Port of Rotterdam and store this in depleted gas fields beneath the North Sea. Porthos stands for Port of Rotterdam CO_2 Transport Hub and Offshore Storage. The project aims to re-use a depleted, low-pressure gas field for storage. These fault-bounded, depleted gas fields behave as 'pressure tanks', very differently from open aquifers elsewhere in the North Sea. An existing platform, and possibly also an existing pipeline, may be considered for re-use. An earlier CCS project, the ROAD project, used the same storage concept for storage of CO_2 from a coal-fired power plant. A number of studies have worked on solutions to take German CO_2 from the Ruhrgebiet out for storage on barges on the Rhine river through Rotterdam.

Storage potential of the Baltic region

The main work on the geological storage potential of the Baltic region was carried out in the EU GeoCapacity project [4], covering all Baltic states except Sweden and Finland.

Only in the far southern part of Sweden, the subsurface is comprised of sedimentary rocks suitable for storage. Oil and gas exploration data from the 1970s indicated no or little storage potential. Minor offshore storage potential may be present. For further information see https://data.geus.dk/nordiccs/map.xhtml. With abundant hydropower and nuclear power, Sweden has very little CO_2 from fossil fuel use. A number of studies are currently under way to hook up local fossil fuel power generation and industry in the Gothenburg area to the Norwegian storage project.

Finland has no deep sedimentary deposits of any size and thus no storage potential. Through partly state-owned FORTUM, Finland is engaged in CCS as the owners of the waste incineration plant in Oslo, the likely second supplier of CO_2 for the Northern Light storage facility.

The map below (Figure 0-1) shows the outlined sedimentary basins in Europe.

In Estonia, the crystalline bedrock is fairly shallow, with less than the 700-800 metres depth required for CO_2 to be in a dense phase; thus the geology is not suitable for storage.

Latvia has maybe one or two deep sandstone structures, one being used for natural gas storage.

Lithuania (and Kaliningrad) has a number of small geological structures suitable for storage, partly in active and depleted oil fields.

Poland has considerable potential storage capacity in the giga-tonne range.

Germany has very ample storage potential in the northern parts of the country as well as in the southern alpine forelands. Limited storage potential in the offshore Baltic Sea area and virtually no capacity in the North Sea. The geology is well-mapped and documented, but German legislation makes domestic storage difficult. Germany is the largest emitter of CO_2 in Europe and could become a future supplier of CO_2 for geological storage in the Northern Light project or one of the other North Sea storage project.

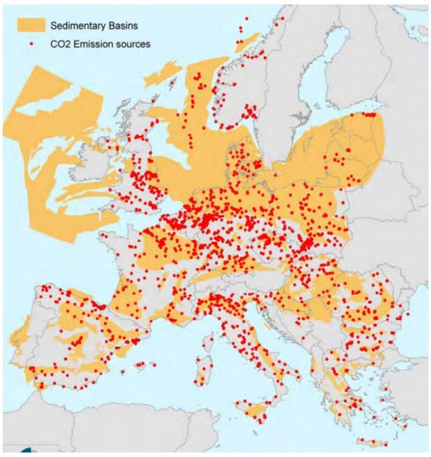


Figure 0-1: Map outlining sedimentary basins and CO_2 emission points in Europe [4]

Storage potential outside the Baltic region has not been described as CCS projects are already under implementation in UK, Norway and the Netherlands.

1.3 Maturing a CO_2 geological storage site

The maturity of potential CO_2 storage structures and reservoirs is a function of the integrated understanding of geological and other factors based on numerical models, seismic surveys, and dynamic and static well information. A methodology for assessing the maturity of potential storage sites has been developed by a working group within CSLF (Carbon Sequestration Leadership Forum). With some modification, this methodology was adapted by the Norwegian Petroleum Directorate when generating a very comprehensive atlas of the storage potential of the Norwegian continental shelf [5].

The atlas was later applied as part of the information used in screening potential storage sites in the early stages of the Northern Lights project.

Based on this methodology, an informal ranking would place the existing Danish oil and gas fields and the Stenlille gas storage structure in the upper part of the pyramid as detailed knowledge is available. The saline aquifer structures mapped from seismic coverage and the use of analogue wells (i.e. structure not drilled) by GEUS such as the Hanstholm, Havnsø, Røsnæs and Voldum structures would place in the lower part of the “realistic capacity”. The Gassum and Voldum structures would rank somewhat below Vedsted, having been mapped on older seimic data and with the structure explored by wells.

While known oil and gas structures would classify towards the top of the pyramid, a number of issues must be considered:

Legacy wells within the storage complex (location, abandonment, risk of leakage)

Storage reservoir quality (seal, porosity and permeability, geochemical issues)

- Presence of suitable cap rocks above the storage reservoir
- Porosity is very high in many chalks and high in many sandstones
- Permeability is low in chalks, reducing injectivity
- Geochemical reactions will tend to neutralise CO_2 in chalk, while it may produce adverse effects in some sandstones

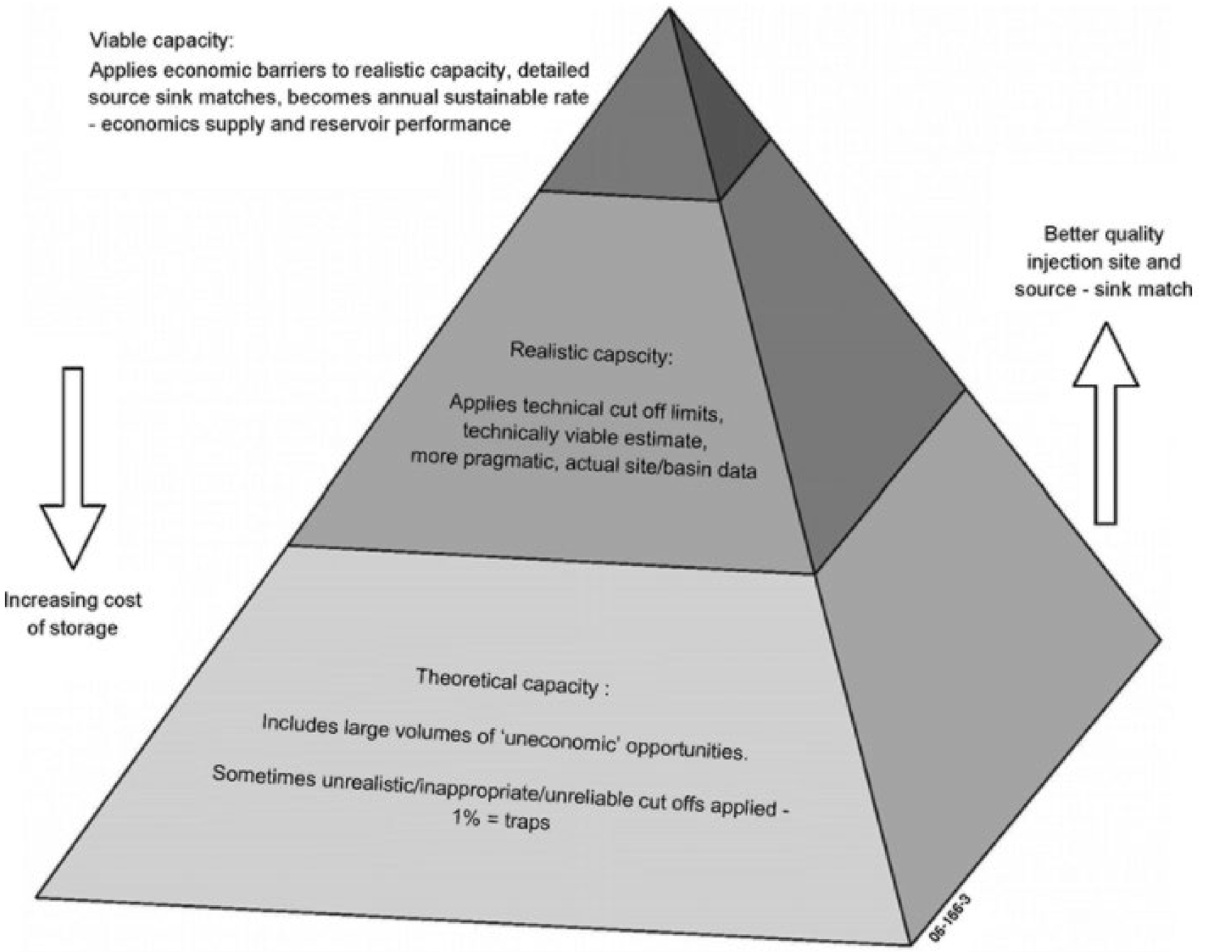
Potential for re-use of wells, particularly long horizontal wells for chalk

Potential for re-use of infrastructure, particularly wellhead platforms

In order to further mature and move saline aquifer storage structures upwards in the pyramid, more data and more recent data is usually required, including:

- Modern seismic surveys, 2D or 3D as appropriate
- Well data, including flow testing, if feasible
- Mathematical models and predictions

With additional and more detailed information of the subsurface geology, experience shows that the geology becomes more complex and heterogeneous and simple structures often become faulted.



Techno-economic resource pyramid for capacity for CO 2 geological storage, showing the three levels of theoretical, realistic and viable estimates. Theoretical includes the entire pyramid, realistic the top two portions and viable only the top portion.

From: Bradshaw, Bachu, Binijoly, Burruss, Holloway, Christensen & Mathiassen, Int. Journal of Greenhouse Gas Control, 2007

Figure 0-2: Techno-economic resource pyramid [6]

A more recent approach to CO_2 geological storage maturation and classification has been presented by OGCI (Oil and Gas Climate Initiative) and Pale Blue Dot, and this methodology is more in line with the approach used for oil and gas resources. This methodology has not been applied to the Danish CO_2 storage potential.

Classification of CO_2 storage capacity has until recently been dominated by work carried out predominantly by academia. With the current focus on turning CCS operational, the industry is now increasingly engaged in turning the R&D-based work into practical use. This includes work within the Society of Petroleum Engineers (SPE).

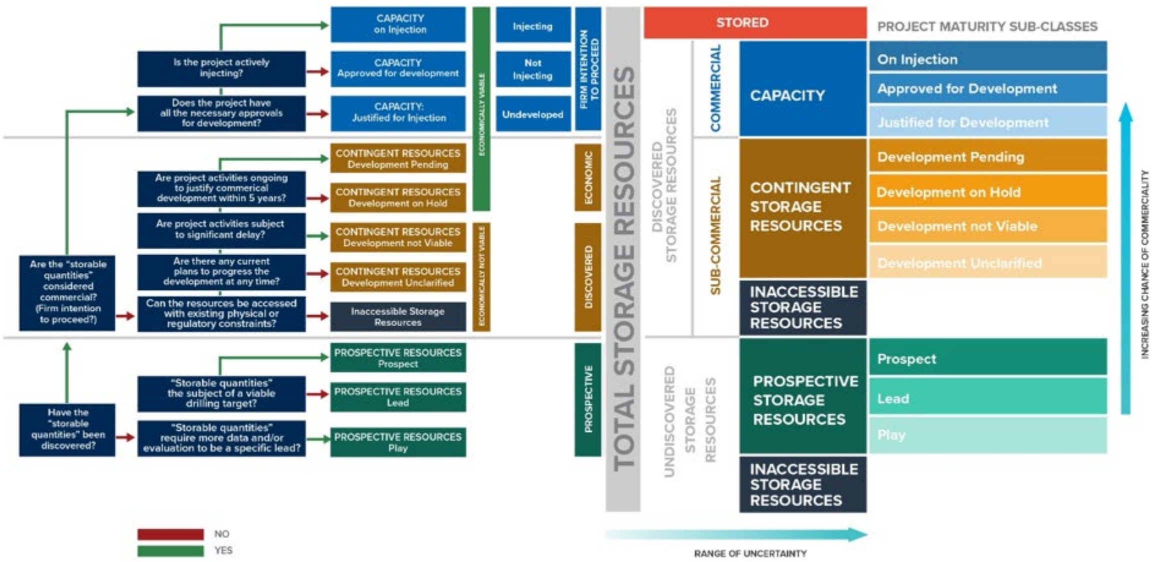


Figure 0-3: CO_2 geological storage maturation and classification [7]

In order to lift new storage fields to a higher level of readiness, it is necessary to carry out seismic surveys as well as appraisal drilling. This aspect is taken into account in our description of the timeline for establishing new CO_2 storages for saline aquifers.

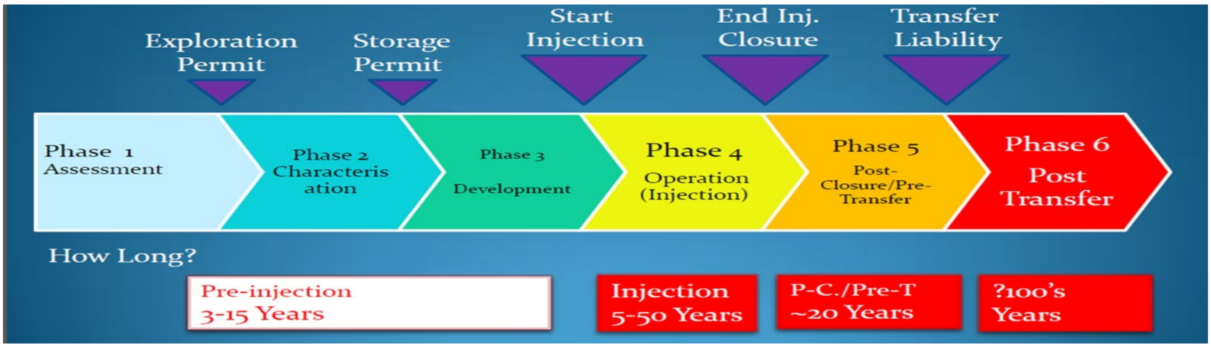


Figure 0-4: Typical phases in the development of a geological storage site [8]

1.4 Prediction of performance and costs

As only a few carbon storage projects have been implemented in Europe – and mostly in association with oil and gas production – there is still a lot of uncertainty about performance and cost. Implementation of projects according to the EU Directive creates some uncertainty with respect to delimitation of the operator's responsibility after closing of the storage.

With respect to the technical development, there is uncertainty in terms of injection rates in different types of reservoirs as well as the choice of steel material for wells and pipes. Initially, we assume that a conservative approach will be used, which may tend to increase cost for the first large-scale projects. In line with operational experience, there may be a decline in cost due to more optimised design but also because the actual capacity may prove to be larger than the nameplate capacity. In addition, the cost-level seen in petroleum projects may in the longer term prove to be on the high side when dealing with non-flammable CO_2.

Initially, it is assumed that the physical gap between the CO_2 capture location and the storage location will be bridged via ship transportation, which, in some cases, is an expensive solution compared to pipeline transportation. In high-volume cases, there may be a decline in unit cost due to economics of scale and use of pipelines, whereby the use of intermediate storage could become unnecessary. The use of pipeline for offshore solution is included as a sensitivity.

The cost of post-injection monitoring and the regulatory requirements of operator's financial guarantee are parameters that are not well-defined at present. In line with development of more carbon storage according to the EU Directive, it is expected that such costs will be better known.

The general investment costs for CO_2 storage are, for the early projects, expected to follow the upstream cost for the oil and gas industry as drilling, wells, materials etc. are very much the same. The upstream capital cost index (IHS and used by IEA) in general follows oil prices, as some of the surplus income to oil and gas companies is allocated to service providers such as drilling rig operators. The upstream capital cost index is based on costs for material and personnel costs.

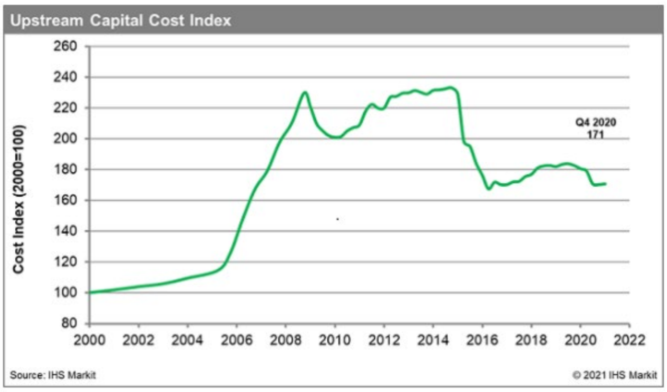


Figure 0-5: Upstream capital cost index

Apart from the general cost index, there is a general development in technology of more advanced solutions. Here the IHS upstream innovation index (UII) is a relevant measure. During the last decade there has been a gradual decline in total costs due to innovations.

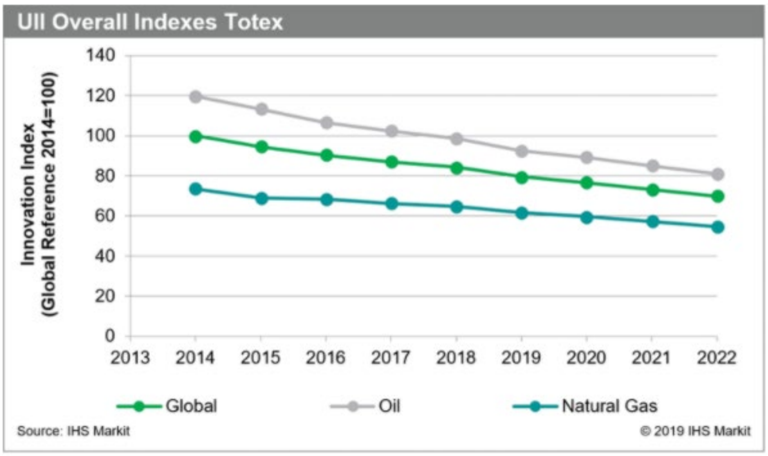


Figure 0-6: UII overall indexes Totex

For IEA stated policies scenario, it is forecasted by IEA that oil and gas production will experience a small increase and that there will be a small increase in oil and gas prices. In the sustainable development scenario, there will be a sharp decline in oil and gas production and a decline in oil and gas prices. Consequently, there is nothing in the two scenarios which indicates an increase in the investment cost index as seen before. Instead, we foresee a decline in capital cost as follows:

- Medium development: annual decrease in fixed price of 1% per year
- High: constant fixed prices
- Low: annual decrease in fixed price of 2 % per year

The medium development is assumed to reflect the stated policy scenario and the low development reflects the sustainable development scenario.

There is some uncertainty connected to the medium development, as other sources expect offshore solutions to be more expensive than what is presented here. As some of the estimations are based on industry practice from oil and gas, there might be a bias to exclude the practice of other (established or not established) sectors from the estimation for CCS projects. Finally, the project-specific split of cost before and after Final Investment Decision, with different commercial companies having different decision gates (due to different risk willingness among others), can have an effect on the costs represented here.

1.5 Geological structures suitable for CO_2 storage

The Geological Survey of Denmark and Greenland (GEUS) has mapped a number of potential storage structures as shown on the map below, and some offshore oil and gas operators have assessed the possibility of using depleted oil and gas fields or offshore aquifers for CO_2 storage. The geology of Denmark is found to be well-suited for CO_2 storage. For further information, please refer to the excellent GEUS publication GeoViden, March 2020 (https://issuu.com/geoviden/docs/geoviden_1_2020_book?fr=sYTM3YjIzODE0OTA).

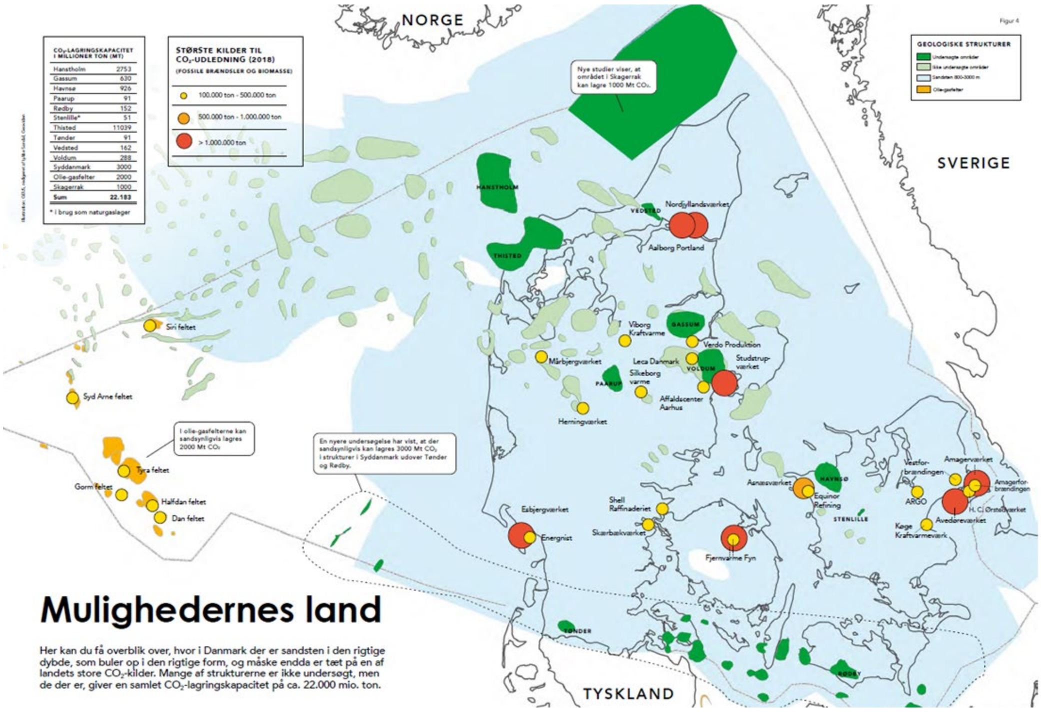


Figure 0-7: Potential CO_2 storage structures published by GEUS (GeoViden, March 2020)

The most suitable reservoirs for CO_2 storage are deep saline aquifers in sandstone or oil and gas fields in sandstone. Other reservoirs like the chalk fields, which constitute most of the Danish oil and gas fields, may also be used for CO_2 storage but with lower specific injection rates than for sandstone reservoirs. Both kinds of reservoirs are being assessed by commercial players.

1.6 Capacity calculations and variation in storage

The storage capacity is a function of, among others, the area and thickness of the reservoir, pressure and porosity. Therefore, there is a need to have good seismic surveys and proper well data from the potential reservoirs.

A regional or unconfined aquifer usually has a large area of hundreds or thousands of square kilometres. The storage capacity is a function of the hydraulic ability of the injected CO_2 to saturate the porosity of the reservoir. This is expressed by the storage efficiency.

Storage capacity in a regional aquifer:

$$Q = A \cdot D \cdot \varphi \cdot \rho CO_2 \cdot h_{st}$$

where Q is the storage capacity in kg, A is the areal distribution of the aquifer (m^2), D is the cumulative thickness of good reservoir rocks (m), φ is the effective porosity (<1), h_{st} is the storage efficiency (<1), and ρCO_2 is the density (kgm^{-3}) of CO_2 at reservoir conditions.

A confined reservoir is of more limited extent, for instance bounded by faults. When enclosed totally by barriers such as fault (or non-porous rocks), the storage will behave like a pressure tank and the storage capacity is a function of how much pressure the system can, or is allowed, to take. This approach is particularly useful in depleted oil and gas fields.

In a confined reservoir the storage capacity principally depends on constraining the pressure increase with respect to caprock stability, and can be written:

$$Q = A \cdot D \cdot \varphi \cdot (C_R + C_W) \cdot \Delta p \cdot \rho CO_2$$

Where:

C_R = Compressibility of the rock (grain)

C_W = Compressibility of water

Δp = Permissible pressure increase

Source: Best Practice for the storage of CO2 in saline aquifers, BGS 2008

The injection capacity per well is one of the most important parameters for assessing costs of CO_2 storage as the number of wells is the main cost driver. The injection capacity will depend on cap rock strength, reservoir characteristics, as well as geometry of the storage structure and the well design. Applying highly deviated or horizontal well sections in the storage reservoir increases injectivity and CO_2 dispersion within the reservoir, which is favourable in particular for offshore developments where well costs are higher.

In the present study, it is estimated that injectivity per well will be in the range of about 0.5 million tonnes of CO_2 per year in the Gassum Formation sandstone reservoirs, which comprise the majority of the potential storage sites mapped by GEUS. This assumption is assumed also to be valid for the depleted offshore sandstone oil and gas fields in question. The use of a well injection capacity is based on a general comparison with other, high-quality reservoirs. The Sleipner Utsira Formation comprises very permeable, shallow and unconsolidated sands with an average permeability of 2 Darcy, and the injector well could presumably take several million tonnes per year with ease. The Northern Light Johanssen Formation would fall in the range of 0.5-0.6 Darcy to locally beyond 1 Darcy, and the facility is designed to take 0.6 to 1.5 Mt pa presumably from one well. The most prevalent Danish sandstone formation in question, the Gassum Formation, is of good quality with permeabilities of up to about ½ a Darcy; thus we assume an injectivity rate of about 0.5 Mt pa, occasionally – in the case of the offshore oil field storage – up to 1 Mt pa during periods when CO_2 is shipped in on a weekly basis. It should be noticed that the estimated 0.5 Mt pa per well is for the entire duration of the storage facility lifetime, i.e. 30 years. Experience from Canada where thousands of wells have been used for (acid) gas injection shows that the most common cause of well failure is loss of injectivity.

Use of CO2 for EOR, and incidental storage, is documented to be very efficient not only in sandstone reservoirs but also in carbonate reservoirs such as in the Sacroc and Weyburn oil fields. North Sea chalk reservoirs are generally of low permeability and high porosity, thus possessing a high theoretical storage capacity but with a low injectivity rate, requiring a high transmissivity in order to be suitable for CO_2 injection. The transmissivity is the permeability multiplied by the length of the well in contact with the reservoir. Consequently, storage in chalk reservoirs would be of potential interest where existing long horizontal wells and other infrastructure such as wellhead platforms could be re-used. Studies on the potential for use of CO_2 for EOR in chalk fields in the Norwegian and Danish sectors have indicated considerable potential, which could also be interpreted to indicate suitability for geological storage of CO_2.

As there will be a need for continuous maintenance and intervention into the injector wells, it is assumed that it would be prudent to have an extra well per storage site or storage complex. Additionally, in order to avoid excessive, local pressure build-up there is a need to distribute the CO_2 within the storage structure, otherwise it may not be possible to utilise the entire storage volume. Exceeding the allowed reservoir pressure could lead to problems with the Competent Authority and thus with the storage permit. Typically, an offshore development for 1 Mt/year would hence require 3 wells while a development for 3 Mt/year would require 7 wells. However, these estimates are very site-specific, and after some years of operation of a storage facility it will be possible to reduce this uncertainty.

For onshore aquifers, there may be a further requirement for observation wells to ensure the integrity and compliance of the storage complex. The number of observation wells will depend on the size of the storage. There may be a need for 2 to 6 observation wells at the spill points of the storage structure depending on the results of the seismic survey and the regulatory requirements. In the quantitative assessment, 2 wells have been assumed for a 1 Mt/y development, 4 wells for a 3 Mt/y development and 6 wells for a 5 Mt/y development.

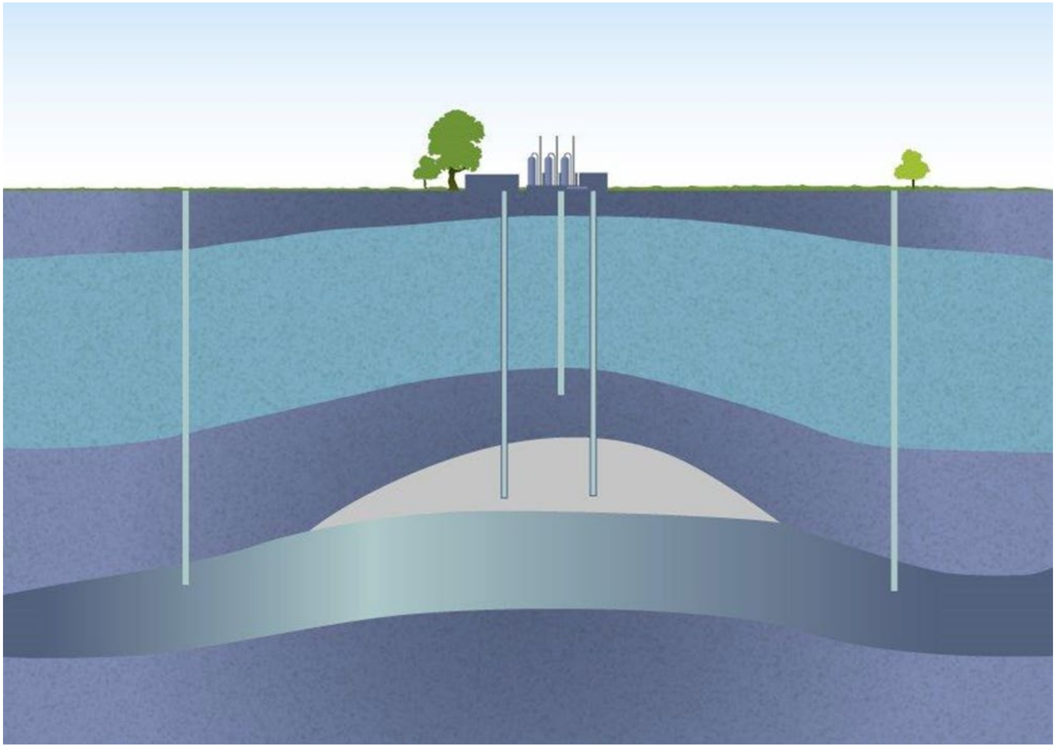


Figure 0-8: Schematic illustration of a storage site with central injection wells and observation wells placed to monitor the flanks and the spill-point of the structure [9]

For offshore saline aquifers and depleted oil and gas fields, there may not be the same need for spill point observation wells as marine seismic will be readily available at more frequent intervals. In oil and gas fields, containment and cap rock integrity have been assured by geologic history, and in these cases it is assumed that observation well(s) would be converted, existing wells equipped with down-hole pressure sensors.

1.7 Space requirements and competition with other activities

The space requirements for surface facilities for CO_2 storage depend on the size of the storage and type of wells to be used – horizontal or vertical. For the Stenlille gas storage, where vertical and deviated wells were drilled, there was a need for a central compression site of 100,000 m^2 and well sites at a distance of up to 3 km each with a size of approx. 25,000 m^2 and connected to the compression site with high pressure pipelines. A modern storage facility is more likely to have a central site only and to use extended reach or even horizontal wells, which will also increase the injection capacity per well. For CO_2 injection, the requirement for space will be less than for Stenlille as there is no need for flare and withdrawal trains, so an estimate will be less than 50,000 m_2.

Figure 0-9: Stenlille gas storage [9]

Figure 0-10: Drilling rig on gas storage facility [9]

For nearshore storage facilities, it is possible to have the compression site onshore, depending on the distance from shore. Also, one particular storage site option provides the opportunity to drill wells from shore into an offshore storage reservoir. For longer distance offshore, it will be necessary to have a small wellhead platform or a subsea connection. The size of the compression site is again found to be 50,000 m^2.

It is not clear if landowners that live close to a CO_2 storage will be eligible for compensation due to possible reduction of property value. This can among others be the case in connection with seismic surveys and installation of pipelines.

The actual value of land and expropriation needs to be based on a concrete assessment. In the following section, a unit cost of 10 m DKK is used. This number is only an indication based on assumptions that land cost is approx. 0.2 MDKK/ha for agriculture land while compensation for pipelines is approx. 500 DKK/m. If there is a need to expropriate buildings etc., the number may be different.

1.8 Operation of CO_2 storage

1.8.1 Handling of CO_2

The properties of CO_2 give some challenges in terms of transportation and injection.

In order to transport large quantities of gas by ship, truck or rail, it is necessary to liquefy the gas; this can either be done by cooling, compression or a combination hereof.

In order to avoid thick wall pressure vessels, the current concept for the large LNG tankers is to liquify gas by cooling only, i.e. down to -163˚C, which is the boiling temperature for liquid methane at atmospheric pressure.

The same approach is not possible for CO_2, as at atmospheric pressure it would go directly from the gas phase to the solid phase if cooled below -78˚C. On the other hand, the pressure vessel would be designed for 60-80 bar if no cooling was applied, which is not considered feasible due to the weight of the pressure vessels. A practical approach is operation between -50˚C at 6 barg and -30˚C at 14 barg. For large carriers, the pressure should be as low as practically possible.

Before the CO_2 is injected into the reservoir, it needs to be heated to above 0˚C in order to avoid ice formation when it is in contact with formation water. This is also the case if transferred in offshore loading hoses and subsea pipelines.

In pipeline systems for transport in dense phase, the typical operating pressure is 80-125 barg and can also be higher; therefore there is no cooling requirements for CO_2.

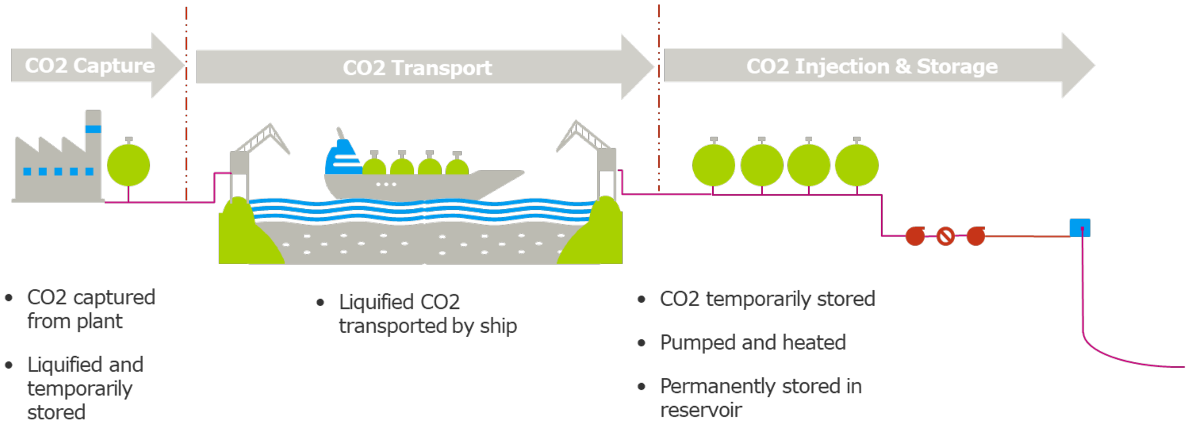


Figure 0-11: Interface between the different elements of CCS

For the present study, we have defined three cases for CO_2 storage:

	Reservoir and wells	Compression/ pumping	Manning	Alternatives, not assessed by cost
Onshore	Onshore reservoir and well sites, new wells, intermediate storage at port and pipeline from port to site.	On site or alternatively at port facility	Normally unmanned operation	Pipeline from cluster of CO_2 sources directly to storage
Nearshore	Offshore reservoir, new wells, small platform, intermediate storage at port and pipeline from port to platform.	Onshore at port facility	Normally unmanned operation	Pipeline from CO_2 sources
Depleted oil/gas field	Reuse of existing platform and reuse of existing wells to the extent possible, SAL (single anchor loading) loading system	On vessel	Normally unmanned operation of platform, Operation from vessel	Pipeline from shore to fields. [1)] Port facility to feed pipeline or onshore pipeline system to offshore pipeline.

Table 0-1: Cases for CO_2 storage

1) Sensitivity case described in section 1.3.5

The main difference in operation is that the offshore use of existing oil and gas platforms includes the use of a vessel with pumping facilities onboard. For both the nearshore and onshore solution, there is intermediate storage included in a port nearby. The operation of the on- and nearshore solutions does therefore not include vessel operation.

If the CO_2 was routed in pipelines directly from the capture site to the injection site, there would not be any requirement for an intermediate storage. However, the assumption for this study is that the bulk part of the CO_2 is transported by ship.

1.8.2 Intermediate storage onshore and near shore

Regardless of which concept is chosen, the assumption for this study is that although local CO_2 sources might be available, the bulk of the CO_2 is collected from various point sources by shuttle tanker(s) and shipped to intermediate storage close to the injection site. There may be cost savings by direct pipeline from source to storage, but the analysed concepts have been chosen to allow for flexibility and avoid storage dependency on one or a few sources.

The shuttle tankers commercially available today are relatively small, a few thousand tonnes net load, whereas the CCS volumes used as the basis for this report will require significantly larger vessels to support the economy of scale. Whether these can be 2,000, 4,000, 10,000, 20,000 tonnes or even larger net loads will depend on capture sites and the collection ports. For this study, it is assumed that vessels up to at least 20,000 tonnes will become available in the future.

For the 1 Mt/year case, a 20,000 tonnes intermediate storage will be suitable for 20,000 tonnes shuttle tanker with a weekly cycle collecting CO_2 from various sources and offloading close to the injection site. An intermediate storage of this size would also support two 10,000 tonnes shuttle tankers, which are not completely synchronised.

For the 3 Mt/year case, a 30,000 tonnes intermediate storage will be suitable to receive three weekly 20,000 tonnes shipments with a minimum of two days between shipments. For the 5 Mt/year case, a 50,000 tonnes intermediate storage will be suitable to receive five weekly 20,000 tonnes shipments and up to two shipments a day.

The liquid CO_2 is pressurised and cooled at the capture site. Although the storage tanks are well insulated, there will be continuous release from evaporation due to the heat input from the surroundings; to capture this a small CO_2 recovery unit is required. In the quantitative assessment, the investment and operational cost have been included for recovery units which potentially can recover up to 1% of the nominal throughput.

1.8.3 Intermediate storage offshore

For the 1 Mt/year case, the same vessel can be a shuttle tanker and an intermediate storage onsite and at the same time be the host for the injection facilities. Based on one weekly cycle, a vessel with 20,000 tonnes net load will be required.

The use of significantly larger shuttle tankers is not considered feasible and instead of having multiple shuttle tankers equipped with injection facilities, the 3 Mt/year and 5 Mt/year cases will require a permanently moored vessel, a so-called floating storage unit (FSU) equipped with the injection facilities.

For the 3 Mt/year case, a 30,000 tonFSU will be suitable to receive three weekly 20,000 tonnes shipments with a minimum of two days between shipments and for the 5 Mt/year case, a 50,000 tonnes FSU will be suitable to receive five weekly 20,000 tonnes shipments.

The reason for having the injection facilities on the FSU is that most of the potential offshore platforms do not have sufficient size and capacity to hold the additional installations, and those which might would no longer have any fuel gas to operate their power generation.

1.8.4 CO_2 injection

Liquid CO_2 from the intermediate storage (onshore or floating) is pressurised to approx. 40 barg and heated to approx. 5˚C before the pressure is increased to the required injection pressure and the CO_2 is injected into the reservoir. The heat will be provided either from seawater or air, and during wintertime an electrical or a fired booster heater might be required to achieve the last few degrees of heating.

Once the CO_2 is injected into the reservoir, the CO_2 might come into contact with formation water and can potentially form a highly corrosive environment, for which reason it is assumed that the well tubing will have to be made out of corrosion-resistant alloys.

1.9 Regulation of CO_2 storage, liability and monitoring

1.9.1 EU Directive and international standards

CO_2 storage is regulated on EU level by the following directive:

DIRECTIVE 2009/31/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL

of 23 April 2009 on the geological storage of carbon dioxide [10]

The directive refers to other legal regulations such as the London convention and the OSPAR convention as well as other EU directives and regulations.

The directive has been transposed into the Danish sub-soil act [11].

An international standard has been published for the storage of CO_2 in geological formations including depleted oil and gas fields. This standard, known as ISO 27914:2017 Geological Storage [12], has been adopted by the Norwegian authorities and thus by the Northern Light Project. The permit to store CO_2 is granted by the Norwegian Environment Agency, who is also the recipient of the financial guarantee. The license to a specific offshore area intended for CO_2 storage is granted by the Norwegian Petroleum Directorate.

The requirements of the directive and need for reporting will add costs to the development of new CO_2 storage facilities. The cost of obtaining permits and reporting is estimated at 20 MDKK per storage location.

The EU Directive and the ISO standard work with the concept of 'storage complex' as illustrated in the figure below. The operator of the storage facility defines the boundaries of the storage complex, which after approval by the Competent Authority becomes the volume inside which CO_2 is considered to be stored while CO_2 outside these boundaries constitutes leakages.

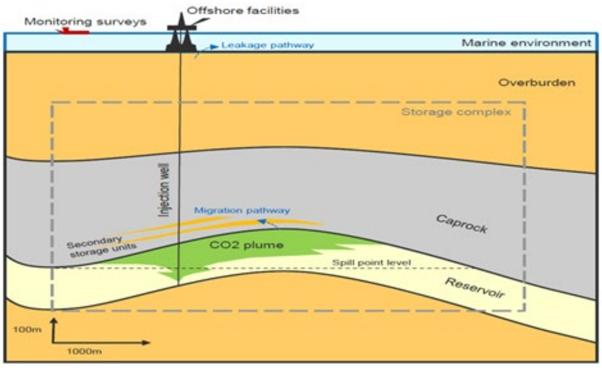


Figure 0-12: CO_2 storage complex [13]

1.9.2 Liability and insurance

In case of leakage from the storage during operation or after closing the storage, there will be a financial liability. The operator is required to post a financial guarantee, based on the risk of CO_2 being present outside the defined storage complex.

The financial liability will be the value of CO_2 on the European ETS-market at the time of leakage, according to the EU Directive 2009/31/EC on CO_2 storage [14]. The liability will hence be the number of tonnes of CO_2 leaked multiplied by the unit prices, which at present is 40 EUR/tonne. The operator will hence have double uncertainty: the future lost volumes and the future unit price.

To fully understand the cost of liability for the operators, there will be a need to apply jointly agreed risk assessment methodologies and, in the longer term, to develop an insurance market. A starting point may be for the Competent Authority to put a cap on liability.

1.9.3 Baseline surveys and monitoring of storage sites

Baseline monitoring programme

The monitoring programme, which shall be in effect before injection begins and until transfer of responsibility, shall be based on a baseline survey comprising all relevant pre-injection data pertaining to the storage complex itself supplemented by data covering the near-surface (e.g. ground water) and surface conditions (e.g. onshore and offshore biota, natural CO_2 flux, natural CO_2 compositions, etc.).

Baseline survey onshore – typical components:

- 2D or 3D seismic survey
- At least one well with ample data from reservoir, cap rock, and top hole
- Laboratory analysis of samples, especially cap rock integrity
- Storage complex numerical maps, models and predictions
- Legacy wells (location, abandonment, leakage risk)
- Well integrity monitoring
- Groundwater survey: mapping and representative sampling of water
- Natural CO_2 flux in representative locations above storage complex taking into account soil types, vegetation, seasonal variations, etc.

The cost of establishing the onshore baseline is estimated at 20 MDKK, and some 5 MDKK in annual follow-up cost. In addition, there is the cost of less frequent onshore seismic surveys (estimated at about 90 MDKK per survey) combined with the use of monitoring wells at spill points.

Baseline survey offshore – typical components:

- 3D seismic survey
- Storage complex model based on at least one well, or in the case of a depleted oil and gas field numerical models based on production data and operational experience, possibly supplemented by specific additional data on cap rock and reservoir susceptibility to CO_2
- Legacy wells; exploration, appraisal and production wells (location, abandonment, leakage risk)
- Well integrity monitoring
- Marine pelagic and benthonic biota survey
- Seabed and survey of shallow geographical and geological features including possible natural flux of CO_2 or other gasses

Cost of establishing the offshore baseline is estimated at around 10 MDKK. To be repeated every 4-5 years combined with a 3D seismic survey (estimated at about 70 MDKK per survey) and model updates.

Monitoring while injection is ongoing

Monitoring of CO_2 storage is very important as the purpose of the storage is to ensure the permanent removal of CO_2 from the atmosphere. The focus of the monitoring and reporting programme will be to document to the Competent Authority that stored CO_2 remains within the storage complex. Monitoring shall be carried out according to a plan which takes into account the specific geological conditions, according to Appendix II of the Directive. Monitoring is to be carried out from day one as part of the storage permit.

Post-injection monitoring

According to the EU directive there is a need to continue monitoring for a duration of a minimum of twenty years after ending the injection, unless the operator is able to convince the competent authorities of complete and permanent storage at an earlier stage (see Figure 2-14). This monitoring is to be carried out by the operator.

Once injection ceases, the reservoir pressure will tend to dissipate and gravitational forces take over (Figure 2-13). In open saline aquifers, and in many other cases, this pressure stabilisation process is fairly quick, often being a logarithmic function. This means that a closed-in storage site tends to become stable with the CO_2 plume slowly migrating towards the apex of the reservoir, only driven by gravity. The dense CO_2 fluid plume in a storage will often have a density of approx. 0.85 g/cm^3 while the salty formation water would be 1.1 to 1.3 g/cm^3. With time, the CO_2 plume, i.e. the amount of free CO_2, will shrink; some of the CO_2 will be trapped in small pores in the reservoir, other CO_2 will be dissolved in the formation water while some CO_2 will slowly form new minerals.

Cost of monitoring during injection and in the post-injection period

Full monitoring is to be carried out while injecting CO_2. Formally, the monitoring of the post-injection period, in addition, comprises a minimum of 20 years and this is the number used in this study. We use an annual cost of 10 MDKK for onshore storage and 20 MDKK for offshore storage to cover monitoring, not including the repeated 3D seismic surveys, which are to be performed every 4 or 5 years as agreed with the Competent Authority.

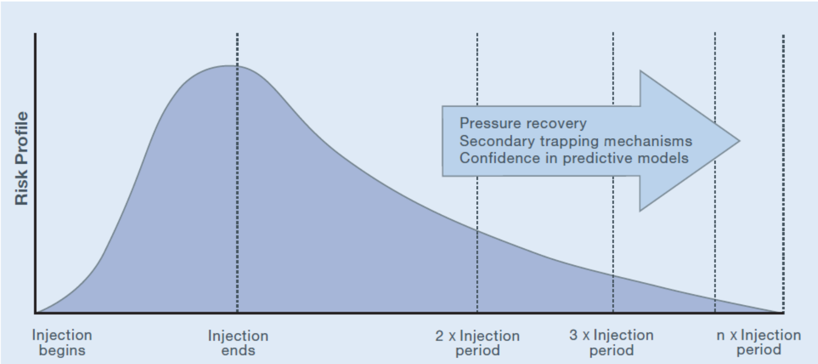


Figure 0-13: Post-injection monitoring [15]

Transfer of responsibility

The three criteria for transfer of responsibility are listed in the figure below.

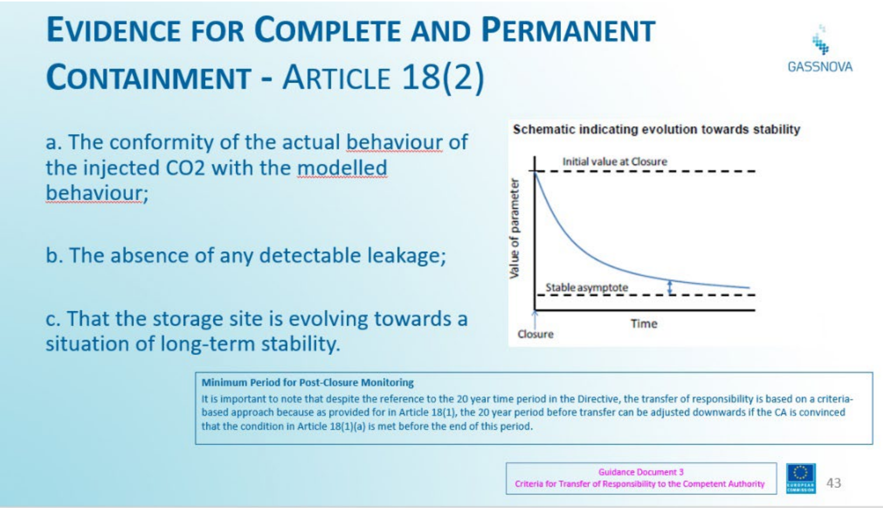


Figure 0-14: Criteria for transfer of responsibility [16]

Post transfer financial mechanism

Once the storage licence, and thus the future responsibility for the storage site, is handed back to the Competent Authority, the operator shall provide a financial contribution, which shall at least cover the anticipated cost for the future monitoring for thirty years. As illustrated in the figures above, a storage site will stabilise with time and during the post transfer period, being up to 20 years after injection ceased, the monitoring requirements are expected to be light and thus cost-efficient. The cost of this period will be site- and project-specific, and for the current study we have not included this cost element.

1.10 Environmental impact and risk assessment

The storage shall be established in an environmentally safe way and fulfil relevant directives including the EU Directive for Environmental impact assessment (EIA).

As part of the EIA, there is a need to comply with the Natura 2000 areas, as some of the potential storage sites may be located within designated Natura 2000 areas.

If the storage facilities are selected as a project of common interest (PCI), there are special time restrictions on maximum duration on the handling of the authority process.

The EIA will also address risks associated with CO_2 storage. Experience from other similar projects, like underground gas storage and pipelines, shows that risk is an important issue which needs to be addressed in detail. It has been outside the present report to do such risk assessment, but it is recommended to carry out early studies and secure political and public acceptance at an early stage.

The cost of EIA preparation and handling of permit will be part of the CAPEX with the risk that the permits will not be obtained. Estimated cost to carry out EIA and obtaining permit is 50 MDKK per site onshore and nearshore and 20 MDKK for use of depleted oil and gas fields.

1.11 Use of depleted oil and gas fields

Depleted oil and gas fields can be used for CO_2 storage and have the advantage that the tightness of the geological system has been demonstrated. Initially, CO_2 injection was used for EOR (Enhanced Oil Recovery), particularly in North America, where it initially was linked to a tax credit. There are more than a hundred current and depleted onshore US oil fields using CO_2 to enhance the production of oil. In the process, between 1/3 or ½ of the CO_2 is 'lost', i.e. incidentally stored in the reservoir. This is a very efficient storage mechanism and, thus far, more than one billion tonnes of CO_2 have been stored in this fashion in the US. This proves the technical validity of the concept, but in Europe, and perhaps increasingly in the US, CO_2 EOR is no longer considered relevant.

A number of hydrocarbon fields in the Danish North Sea are now at tail-end production and moving towards the end of commercial life within the next decade. Such fields are therefore seen as relevant for CO_2 storage. At this point in time, depleted oil and gas fields with sandstone reservoirs are considered most suitable for CO_2 storage; however, chalk fields may also be used but with a lower transmissivity, thus requiring the option to re-use existing horizontal wells.

In all cases, we expect that the initial storage of CO_2 will take place by use of existing platforms, which are then foreseen to be able to have the design life extended. It will be possible to reuse parts of the topside facilities such as manifolds and support systems. The possibility of using existing wells may be different from field to field depending on the materials used initially for oil and gas production, and the overall well integrity considerations. In some cases, it will be necessary with new wells or well completions and replacement of down-hole equipment. This may also include installation of pressure monitoring equipment. For the 1 and 3 Mt/y case, it is assumed that existing wells can be partly reused with new corrosion resistant tubing, whereas the 5 Mt/y case will also require drilling of new wells – for details see section 0.

Operation of the CO_2 injection is assumed to be based on the ship transportation of CO_2 to the fields with pumping of CO_2 from the vessel. The platform will hence not be manned during normal operation. For smaller volumes, such as 1 Mt/year, we assume that CO_2 will be injected in batch mode with one ship load being injected before the vessel takes another round trip. For larger volumes, we expect that it will be more optimal to have a permanently moored vessel as intermediate storage.

1.12 Use of existing pipelines

For large-scale injection of CO_2, pipelines will be more economical than ship transport due to lower operational cost and due to continuous injection into the storage.

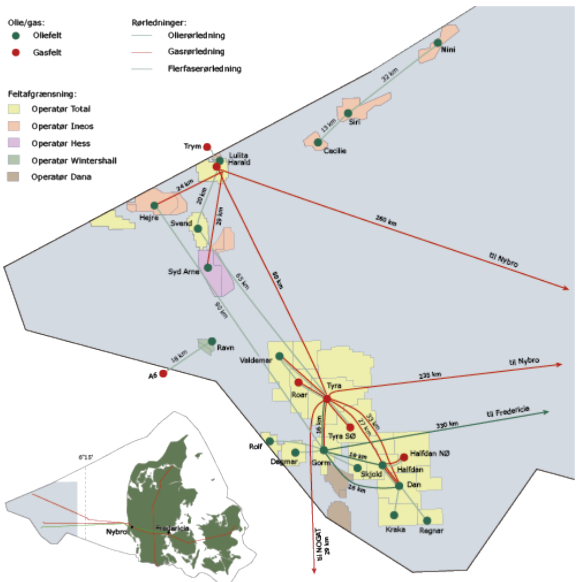


Figure 0-15: Existing pipelines

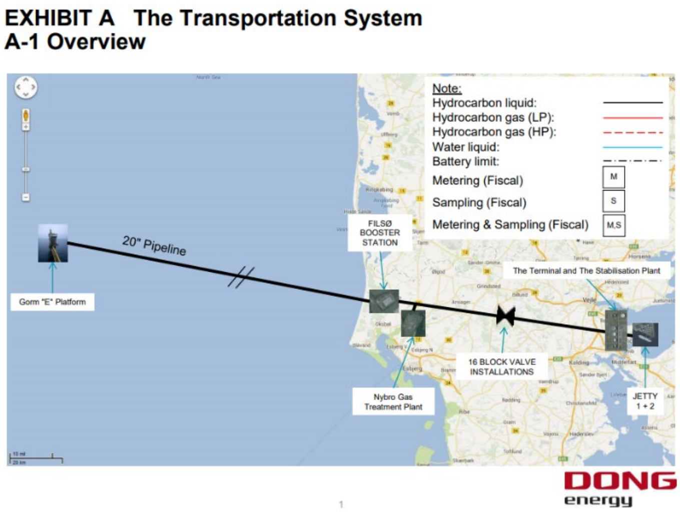


Figure 0-16: Oil transportation system [17]

The South Arne gas pipeline was originally constructed as back-up for the Tyra pipeline to ensure capacity and security of gas supply to Denmark. As the gas production is declining and Baltic Pipe connected to the Norwegian Europipe II will be established in 2022, there is no longer a need for this pipeline as part of the gas transmission system. It will hence be possible to use the pipeline for other purposes such as CO_2 transportation or hydrogen from energy islands.

The oil pipeline system may also become redundant as domestic oil production declines. As operational cost becomes too high at low production, it will be an option to establish offshore oil loading and to use the oil pipeline for CO_2 transportation.

Use of the existing offshore pipelines could be connected to an intermediate storage in e.g. Esbjerg or Fredericia, or a complete onshore pipeline from the main sources to the offshore pipelines could be developed. It may also be possible to use other existing onshore pipelines for CO_2 transportation as part of such a system.

Three concepts for CO_2 storage in Denmark

1.1 Onshore CO_2 storage – description

The geological structures below are considered to be realistic options for onshore CO_2 storage. See also section 1.3 for some informal comments on the maturity of the various potential storage sites.

<u>Vedsted structure (storage capacity as published by GEUS: 162 Mt)</u>

The structure is mature for further development, newer dense 2D seismic (2008) and an older exploration well on the structure itself, and another well off-structure is available.

Potential CO_2 sources are located in the Aalborg area, requiring a 30 km pipeline comprising: Aalborg Portland (2.2 Mt/y), the city waste incineration plant and Nordjyllandsværket power plant for a total of maybe 3 Mt/y. Other CO_2 sources could be captured in other urban areas such as the Aarhus area requiring an approx. 100 km pipeline or could be imported by ship to a nearby port.

<u>Gassum structure (630 Mt), Voldum structure (288 Mt) and Paarup structure (91 Mt)</u>

The three structures could be developed as storage options for central eastern Jutland. These structures were a part of an extensive mapping exercise published by Japsen and Langtofte (1991). The Gassum and Voldum structures were evaluated by oil exploration wells. Transport from CO_2 capture sites (power plants, CHP plants, waste-to-energy plants) to the storage site (1 Mt/y) in pipelines up to 1 Mt /y. Other CO_2 sources could be imported by ship to a nearby port.

<u>Havnsø structure (926 Mt)</u>

A very large and promising structure mapped from old 2D seismic of low quality. The structure has not been drilled, and the geological interpretation is based on analogy from Stenlille natural gas storage structure.

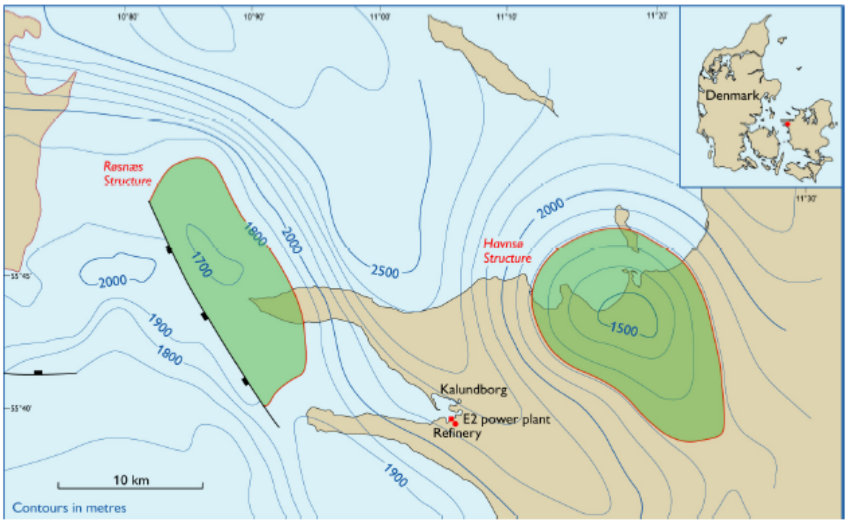


Figure 3.14 Depth structure map of the Havnsø and Røsnæs closures. Both structures are defined in the Upper Triassic to Lower Jurassic Gassum Formation.

Figure 0-17: Geological maps of the Havnsø and Røsnæs structures [18]

Potential CO_2 sources are located in the Kalundborg area (0.5 Mt/Y) requiring a 20 km pipeline from port to the injection site. Other CO_2 sources could be other urban areas such as the Copenhagen area, i.e. capture of CO_2 from e.g. Amager Resource Centre, Amager power plant, HC Ørsted power plant, Avedøre power plant, Roskilde waste incineration plant and others along the route for a total of 3 to 5 Mt/y or maybe up to 7-8 Mt/y. This would either require a pipeline across Zealand or import by ship to gathering hub in the nearby Kalundborg port.

Generic onshore case

The generic case assumes some local CO_2 capture in a port area, which can also be used for import of CO_2 by ship. The port facilities will include an intermediate storage from where the CO_2 is transferred to the injection plant through a 40 km pipeline.

1.1.1 1 Mt/year onshore CO_2 storage

CO_2 is expected to be supplied to the port by shuttle tanker and stored in a 20,000 tonnes intermediate storage close to the port. The storage will consist of a number of well-insulated pressurised tanks where the CO_2 is stored under the same conditions as in shuttle tankers (between -50˚C @ 6 barg and -30˚C @ 14 barg). A recovery unit will capture and liquify the CO_2, which evaporates from the tank storage.

The CO_2 is pumped from the storage tanks and heated with sea water and then transferred in a pipeline to the injection site where a high-pressure pump will increase the pressure to the required injection pressure to allow injection into the reservoir.

It is expected that the 1 Mt/y CO_2 can be injected from one well pad with five wells, two for injection, one spare and two for observation.

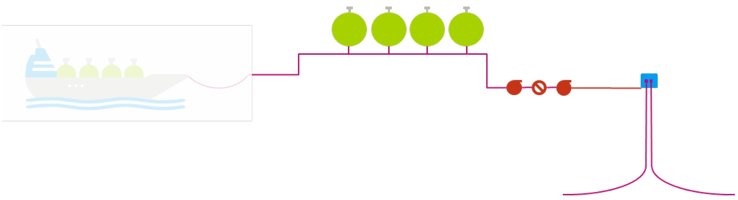


Figure 0-18: 1 Mt/year Onshore storage facility

1.1.2 3 Mt/year onshore CO_2 storage

CO_2 is expected to be supplied to the port by shuttle tankers and stored in a 30,000 tonnes intermediate storage. The CO_2 is heated and pumped to the injection plant.

It is expected that the 3 Mt/y CO_2 can be injected from three well pads with four wells each, six for injection, 2 spares and 4 for observation.

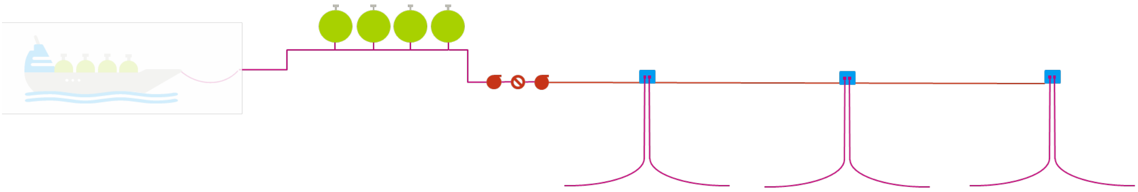


Figure 0-19: 3 Mt/year Onshore storage facility

1.1.3 5 Mt/year onshore CO_2 storage

CO_2 is expected to be supplied to the port by shuttle tankers and stored in a 50,000 tonnes intermediate storage. The CO_2 is heated and pumped to the injection plant.

It is expected that the 5 Mt/y CO_2 can be injected from five well pads with four wells each, 10 injection, 4 spare and 6 for observation.

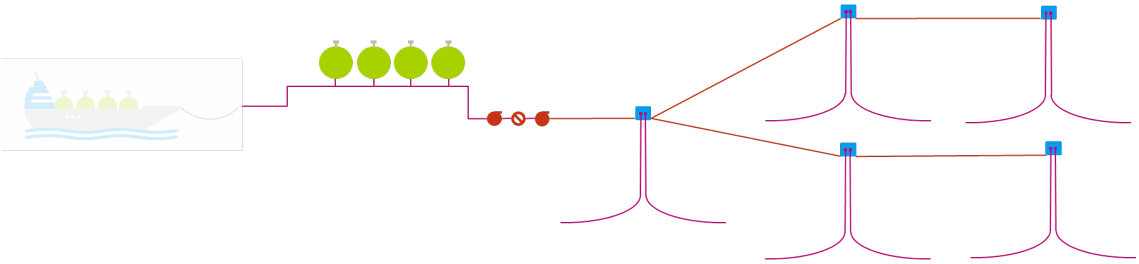


Figure 0-20: 5 Mt/year Onshore storage facility

1.1.4 Typical timeline for an onshore CO_2 storage

Year	Activity
1-2	Additional seismic surveys
	Appraisal well
	Conceptual studies for facilities
3	Environmental impact assessment, public hearings and approvals
	FEED studies
	Baseline studies
	Final Investment Decision
	Land acquisitions
4-5	Establish CO_2 terminal
	Construction of pipeline
	Establish injection plant and well pads
	Drilling of first injection and observation wells
6-7	Commence Injection CO_2
	Evaluation of reservoir behaviour
	Investment decision for additional injection wells
8-9	Establish additional well pads
	Drilling of additional injection and observation wells
10-35	Injection at nominal capacity
	Continuous observation and seismic surveys , say every 5 years
36	Decommissioning of surface facilities, plug and abandonment of wells
Up to next 20 years	Continuous observation and seismic surveys
	Transfer of responsibility
	Release of financial security

Table 0-2: Typical timeline for onshore CO_2 storage

It may be possible to accelerate the timeline shown above depending on the priority. Based on experience from other projects in terms of the permitting process, involvement of stakeholders and internal company approval to pass Final Investment Decision, the timeline presented here may seem shorter than what is realistic. But in view of the urgency of solving the climate problem and the need for reduction of CO_2 content in the atmosphere, the timeline presented here is an estimation based on the assumption that the required political support will be available to realise it.

1.2 Nearshore CO_2 storage – description

Relevant geological structures have been mapped with, often older, 2D seismic and the use of analogue wells. Further maturation of the nearshore storage potential will therefore involve 3D seismic and drilling of one or several appraisal wells, some of which potentially can be reused for injection or observation. See also discussion about maturation in section 1.3.

<u>Hanstholm structure (2753 Mt):</u>

This very large structure was mapped by Japsen and Langtofte (1991) and has not been evaluated by a well inside the closure. However, the Felicia-1 oil exploration well tested the Gassum Formation sandstone in a fault block adjacent to the Hanstholm structure. Detailed geological and numerical modelling was carried out by Frykman in Lothe et al., 2015: Updated estimate of storage capacity and evaluation of Seal for selected Aquifers, NORDICCS Technical Report. These studies indicate good permeability ranging between 200 and 650 mD and a theoretical storage capacity of at least 250 Mt. (see Figure 3-5 below). The expected injection site is located some 30-50 km offshore from the Port of Hanstholm. Water depth at the injection site is 30-40 m.

Import of CO_2 is expected to take place by ship to an intermediate storage located at an existing seaport.

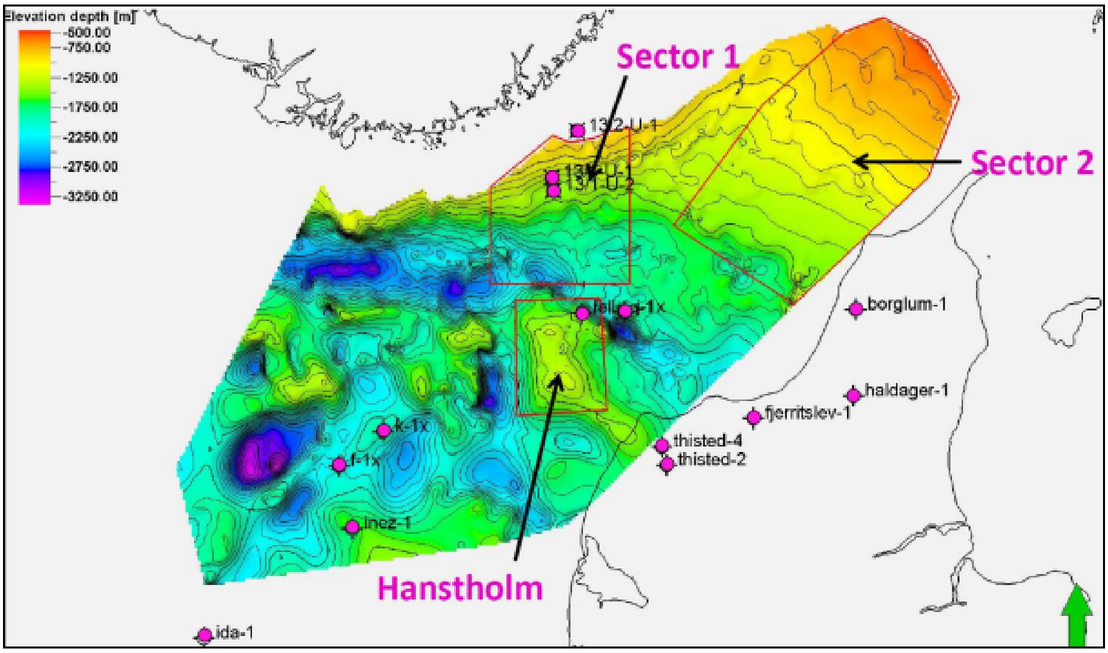


Figure 3-1 Overview map for the top Gassum Formation surface in the Skagerrak area. The modelled areas are marked as Model 1, Model 2 and the southern Hanstholm area. Colour scale in meters.

Figure 0-21: Geological map of the Hanstholm Structure [19]

A similar type of near-shore storage option may exist in the southern part of the North Sea, off the coast of Esbjerg, with the geological structure located some 100 km offshore. This immature option has not been specified in any detail and is considered to be included in the generic case. See the map in Figure 2.7.

Røsnæs structure (227 Mt):

This structure is located under the Great Belt with a smaller part below the tip of Røsnæs. This means that wells could potentially be drilled from land whereas marine 3D seismic surveys could still be acquired by ship. See the map in Figure 0-17.

Due to the nature of the structure with a large fault, at least two additional appraisal wells will be required.

Potential CO_2 sources are located in the Kalundborg area (0.5 Mt/Y) requiring a 10-15 km pipeline. Other CO_2 sources could be urban areas such as the Copenhagen area, i.e. capture of CO_2 from e.g. Amager Bakke, Amager Værket, HC Ørsted power plant, Avedøre power plant, Roskilde waste incineration and others, a total of 3 to 5 Mt/y or maybe up to 7-8 Mt/y. This would either require a pipeline across Zealand or import to the nearby Kalundborg port.

Generic nearshore case

The generic case assumes some local CO_2 capture in a port area, which can also be used for import of CO_2 by ship. The port facilities will include an intermediate storage and CO_2 injection plant from where the CO_2 is transferred to the injection plant through a 40 km pipeline to the nearshore injection site.

Wells will be drilled from a minimum facilities wellhead platform. Initial studies have shown that the costs of a minimum facilities wellhead platform and subsea injection development are comparable even for a few wells, and if additional wells are required, the wellhead platform option is the optimal solution.

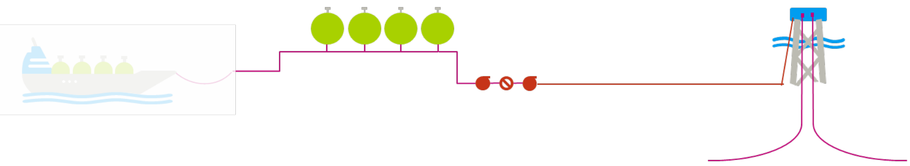


Figure 0-22: Nearshore storage facility

1.2.1 1 Mt/year nearshore CO_2 storage

CO_2 is expected to be supplied to the port by shuttle tanker and stored in a 20,000 tonnes intermediate storage close to the port. The storage will consist of a number of well-insulated pressurised tanks where the CO_2 is stored under the same conditions as in shuttle tankers (between -50˚C at 6 barg and -30˚C at 14 barg). A recovery unit will capture and liquefy the CO_2, which evaporates in the storage.

The CO_2 is pumped from the storage tanks and heated with sea water before high-pressure pumps increase the pressure to the required injection pressure to allow injection into the reservoir. The CO_2 is transferred in a high-pressure pipeline to the wellhead platform where the CO_2 can be injected directly into the reservoir.

It is expected that the 1 Mt/y CO_2 will require a minimum of two injection wells: one to provide redundancy and one for observation.

1.2.2 3 Mt/year nearshore CO_2 storage

CO_2 is expected to be supplied to the port by shuttle tankers and stored in a 30,000 tonnes intermediate storage. The CO_2 is heated and then pumped to the minimum facilities wellhead platform for injection.

It is expected that the 3 Mt/y CO_2 will require a minimum of six injection wells, one to provide redundancy and one for observation.

1.2.3 5 Mt/year nearshore CO_2 storage

CO_2 is expected to be supplied to the port by shuttle tankers and stored in a 50,000 tonnes intermediate storage. The CO_2 is heated and then pumped to the minimum facilities wellhead platform for injection.

It is expected that the 5 Mt/y CO_2 will require a minimum of ten injection wells, two additional wells to provide redundancy and one for observation.

1.2.4 Typical timeline for a nearshore CO_2 storage

Year	Activity
1-2	Additional 3D seismic surveys
	Appraisal well
	Conceptual studies for facilities
3	Environmental impact assessment, public hearings and approvals
	FEED studies
	Baseline studies
	Final Investment Decision
	Land acquisitions
4-5	Establish CO_2 terminal
	Construction of pipeline
	Construction and installation of wellhead platform
	Drilling of first injection wells
6-7	Commence Injection CO_2
	Evaluation of reservoir behaviour
	Investment decision for additional injection wells
8-9	Drilling of additional injection wells
10-35	Injection at nominal capacity
	Continuous observation and seismic surveys , say every 5 years
36	Decommissioning of surface facilities, plug and abandonment of wells
Up to next 20 years	Continuous observation of seabed and seismic surveys
	Transfer of responsibility
	Release of financial security

Table 0-3: Typical timeline for a nearshore CO_2 storage

It may be possible to accelerate the timeline shown above depending on priority. Based on experience from other projects in terms of the permitting process, involvement of stakeholders and internal company approval to pass Final Investment Decision, the timeline presented here may seem shorter than what is realistic. But in view of the urgency of solving the climate problem and the need for reduction of CO_2 content in the atmosphere, the timeline presented here is an estimation based on the assumption that the required political support will be available to realise it.

1.2.5 Sensitivity case – Subsea wells

Instead of drilling the wells from a minimum facilities wellhead platform, the wells can be drilled from a subsea template, which is a heavy steel structure that protects the valve assemblies on top of the wells, the manifold and the controls.

An umbilical with control signals and hydraulic fluid is routed from the subsea template to the host platform, which in this case will be onshore and 40 km away.

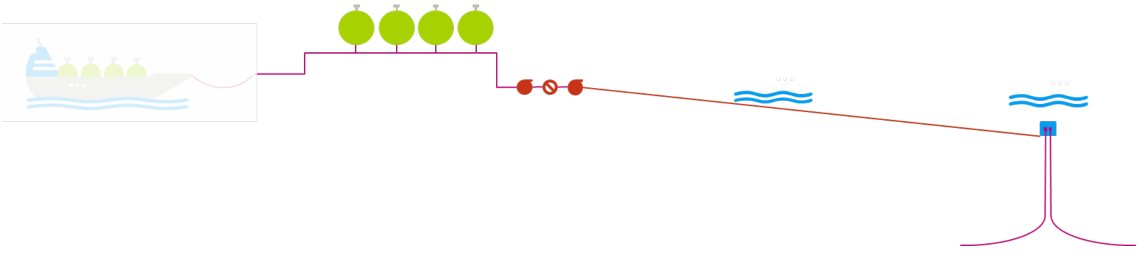


Figure 0-23: Nearshore storage facility with subsea wells

1.3 Offshore CO_2 storage – description

Oil & gas have been produced from the Danish North Sea since the early 70s, and some of the fields are approaching end of field life while others are expected to continue production until the end of the current concession.

The largest theoretical storage capacity would probably be in some of the very large chalk structures, which have been producing since the early 80s. Several of these fields are still operating or, in the case of the Tyra gas field, are currently being redeveloped. Repurposing some of the smaller, non-commercial chalk fields or suitable parts (e.g. long horizontal wells and wellhead platforms) of some of the larger chalk fields may well provide an attractive option for the utilisation of the storage capacity of the North Sea chalk reservoirs.

The focus in this report will be on the depleted northern sandstone fields, which at this point in time are considered more readily available for timely development of geological CO_2 storage.

The northern fields are either developed as standalone wellhead platforms or as integrated facilities with wells, process plant and accommodation; however, for this exercise these are assumed to be converted to unmanned installations.

Both the storage capacity, well tubing material and remaining lifetime vary from field to field, a factor which needs to be taken into consideration when developing a generic case. The cases below are not tailored towards one solution or operator, but known limitations are considered in order to be realistic.

Typical design lifetime of offshore production facilities are around 25 years; however, it is realistic to assume that the lifetime can be significantly increased. The first platforms in the Danish North Sea were installed in the early 70s and are after 50 years still in service and considered safe to operate. The actual lifetime of an offshore CO_2 storage facility may to a higher degree also be dictated by the available storage capacity.

Base case for the well conversion is that well tubing in contact with reservoir fluids must be converted to corrosion resistant material due to the risk of corrosion when CO_2 is mixed with saline formation water.

1.3.1 1 Mt/year offshore CO_2 storage

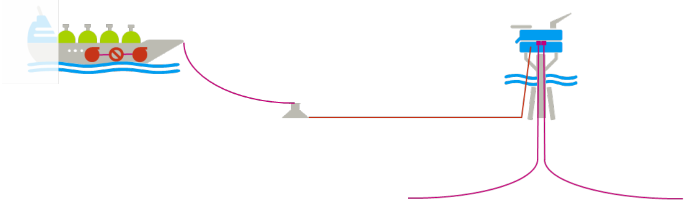


Figure 0-24: 1 Mt/year offshore storage facility

It is expected that 1 Mt of CO_2 per year can be injected into one depleted oil or gas field or a sector in a larger field. This will require conversion of a minimum of two wells and a third will be converted for redundancy. An additional well will be converted for use as an observation well equipped with down-hole pressure gauges.

It is expected that existing manifold and flowlines are reused to the extent possible limiting the platform modifications mainly to installation of a new riser for import of CO_2 from the loading boy.

CO_2 is expected to be supplied to the field in a CO_2 shuttle tanker with 20,000 tonnes capacity. In addition to operating as shuttle tanker, the vessel will also accommodate the CO_2 injection facilities where the CO_2 is heated and pressurised to the required injection pressure in order to allow direct injection of CO_2 on the wellhead platform.

CO_2 will be offloaded through a loading boy system (SAL/SBM) located approx. 3 km from the wellhead platform and transferred to the wellhead platform through a pipeline.

1.3.2 3 Mt/year offshore CO_2 storage

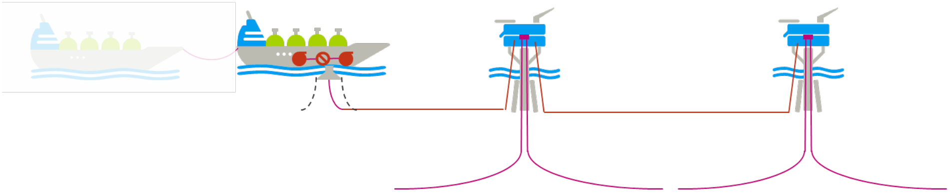


Figure 0-25: 3 Mt/year offshore storage facility

It is expected that 3 Mt of CO_2 per year can be injected into one larger or two smaller depleted oil or gas reservoirs or sectors. For this generic case, two depleted reservoirs or sectors are assumed, but that an existing interfield pipeline can be used to transfer the CO_2.

This will require conversion of a minimum of six wells and a seventh will be converted for redundancy. An additional well will be converted for use as an observation well equipped with down-hole pressure gauges.

It is expected that the existing manifold and flowlines are reused to the extent possible limiting the platform modifications mainly to the installation of a new riser for import of CO_2.

CO_2 is expected to be supplied to the field in shuttle tanker(s) and via a bow loading system loaded to a permanently moored vessel with up to 30.000 tonnes capacity, operating as a floating storage unit (FSU) and also accommodating the CO_2 injection facilities. Using a permanently moored FSU injection facilities is considered more cost-effective and operational than having multiple shuttle tankers each with dedicated injection facilities.

The FSU will have a turret mooring system, which will allow transfer of CO_2 to the wellhead platform through an approx. 3 km long pipeline.

1.3.3 5 Mt/year offshore CO_2 storage

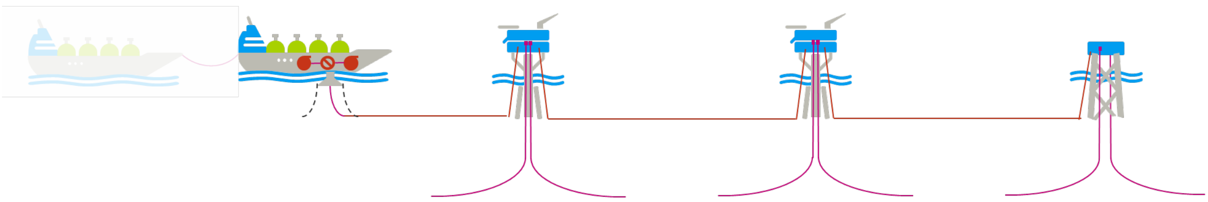


Figure 0-26: 5 Mt/year offshore storage facility

It is expected that 5 Mt of CO_2 per year can be injected into one larger or several smaller depleted oil or gas reservoirs or sectors. For this generic case, three depleted reservoirs or sectors are assumed. Two existing wellhead platforms are assumed to be reused, and for the third field a new wellhead platform will be installed to provide sufficient lifetime. It is assumed that existing interfield pipelines can be used for the transfer of CO_2.

In total, 11 wells are assumed to be required, six conversions and five new. An additional well will be converted for use as an observation well equipped with down-hole pressure gauges.

For the existing wellhead platforms, it is expected that existing manifold and flowlines are reused to the extent possible limiting the platform modifications mainly to the installation of a new riser for the import of CO_2.

CO_2 is expected to be supplied to the field in shuttle tanker(s) and via a bow loading system loaded to a permanently moored vessel with up to 50,000 tonnes capacity, operating as a floating storage unit (FSU) and also accommodating the CO_2 injection facilities.

The FSU will have a turret mooring system, which will allow transfer of CO_2 to the wellhead platform through an approx. 3 km long pipeline.

1.3.4 Typical timeline for an offshore CO_2 storage

Year	Activity
1	Evaluation of exiting production and seismic data
	Conceptual studies for facilities and purpose-built CO_2 Carrier/Storage Unit
2	Environmental impact assessment, public hearings and approvals
	FEED studies, including life-time extension studies
	Baseline studies
	Final Investment Decision
3-4	Construction of purpose-built CO_2 Carrier/Storage Unit
	Installation of mooring and loading system
	Modification of existing well platform
	Conversion of first injection wells
5-6	Commence Injection CO_2
	Evaluation of reservoir behaviour
	Investment decision for conversion of additional wells to injection wells
7	Conversion of additional injection wells
8-9	Evaluation of reservoir behaviour and requirement for additional wells
	Conduct Concept and FEED studies for new facilities (if required)
	Environmental impact assessment, public hearings and approvals
10-11	Construction of pipeline
	Construction and installation of wellhead platform
	Drilling of injection wells
12-35	Injection at nominal capacity
	Continuous observation and seismic surveys every, say every 5 years
36	Decommissioning of surface facilities, plug and abandonment of wells
Up to next 20 years	Continuous observation of seabed and seismic surveys
	Transfer of responsibility
	Release of financial security

Table 0-4: Typical timeline for an offshore CO_2 storage

Based on experience from other projects in terms of the permitting process, involvement of stakeholders and internal company approval to pass Final Investment Decision, the timeline presented here may seem shorter than what is realistic. But in view of the urgency of solving the climate problem and the need for reduction of CO_2 content in the atmosphere, the timeline presented here is an estimation based on the assumption that the required political support will be available to realise it.

1.3.5 Sensitivity case – Reuse of existing offshore pipeline

According to the latest parliamentary agreement of 3 December 2020, the production of Danish oil & natural gas shall cease no later than 2050, and there may be an opportunity to utilise the Danish oil & gas pipeline grid or parts hereof for the transport of CO_2 for underground storage. Assessing when which parts of the grid become available is outside the scope for this report, but at least one of the gas pipelines from the offshore fields to the Nybro gas terminal may become available earlier than 2050.

Unless CO_2 is collected in a pipeline grid and sent to Nybro, this option will require that the CO_2 is shipped to a nearby port where there should be an intermediate storage from which the CO_2 is pumped through a new pipeline to Nybro and into e.g. the South Arne/Harald gas pipeline for injection into the Harald reservoir or other nearby reservoirs.

The maximum operating pressure in the South Arne/Harald gas pipeline is limited to approx. 135 barg, which after pipeline losses most likely is insufficient injection pressure, for which reason a high-pressure injection pump must be installed offshore. But after the cease of gas production, there will be no fuel gas available for power generation, and therefore an alternative power supply must be installed. The cost of a power cable cannot be justified and installation of a new power module/platform with liquid-fired generator driver and associated fuel storage will both result in high investments and also a high operating cost.

As power source, it is therefore suggested to install two 100% rated wind turbines providing "free" electricity. Fluctuation in the power available can be partly compensated for by controlling the export pressure from shore. However, up to 5% of the time, there will be insufficient wind to operate the wind turbines. To compensate for this, additional intermediate storage capacity is required onshore. A conservative assumption is that a total intermediate storage capacity sufficient for one week of injection is required.

A generic 5 Mt/y case could be a 100,000 tonnes intermediate storage at a port in Jutland from where is pumped to Nybro through a 40 km pipeline and transferred to one of the offshore platforms. Here CO_2 injection pumps are installed to inject the CO_2 into the reservoir. In order to provide sufficient storage capacity, it is assumed that a new wellhead platform must be installed and connected by a new pipeline, say 30 km long. Power is provided from two new 4-6 MW offshore wind turbines – the smallest commercially available today.

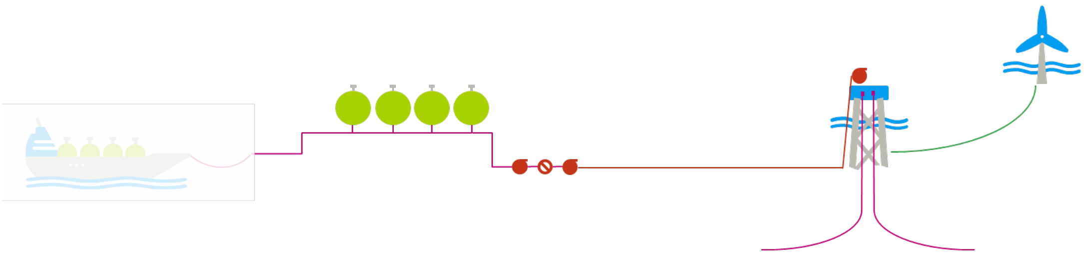


Figure 0-27: 5 Mt/year offshore storage facility

Quantitative description

See separate Excel file for Data sheets of all cases. Input to the data sheets found below.

1.1 Onshore CO_2 storage

Case		1 Mt/year	3 Mt/year	5 Mt/year	Notes
Pre-FID Cost	Mill DKK				
- 2D Seismic		90	90	90	
- Baseline studies		20	20	20	
- Appraisal well		55	55	55	
- FEED Studies		10	10	10	
- Approvals		20	20	20	
CAPEX	Mill DKK				
- Intermediate storage		70	110	180	1
- Injection plant		105	255	420	2
- Pipeline		100	115	130	3
- Injection wells		390	945	1575	4
Abandonment cost (ABEX)	Mill DKK	114	255	418	
Accumulated OPEX	Mill DKK				6
- Base organisation		175	175	175	
- Intermediate storage		87	136	223	1
- Injection plant		130	316	521	2
- Pipeline		31	36	40	3
- Injection wells		121	275	427	4
- Monitoring		670	670	670	
- Power		204	572	884	5
Post-closure Cost	Mill DKK	400	400	400	
- Post-closure monitoring					
CO_2 Injected	Mill tonnes	30	84	130	
Energy Consumption	MJ/t CO_2	49	49	49	

Table 0-5: Onshore CO_2 storage

Notes

1. Intermediate storage includes storage tanks and CO_2 recovery unit
2. Injection plant includes booster pumps, injection pumps, heater exchanges, boiler system
3. Pipeline between storage and injection site
4. Injection wells includes wells, manifolds and well pad
5. Energy cost is based on electrical power at 0.5 DKK/kWh
6. Accumulated OPEX is over a period of 30 years

1.2 Nearshore CO_2 storage

Case		1 Mt/year	3 Mt/year	5 Mt/year	Notes
Pre-FID Cost	Mill DKK				
- 3D Seismic		90	90	90	
- Baseline studies		20	20	20	
- Appraisal wells		230	230	230	
- FEED Studies		10	10	10	
- Approvals		20	20	20	
CAPEX	Mill DKK				
- Intermediate storage		70	110	180	1
- Injection plant		105	255	420	2
- Pipeline and power cable		305	325	340	3
- Wellhead platform		280	280	280	
- Injection wells		945	1890	2835	
Abandonment cost (ABEX)	Mill DKK	301	521	747	
Accumulated OPEX	Mill DKK				6
- Base organisation		350	350	350	
- Intermediate storage		87	136	223	1
- Injection plant		130	316	521	2
- Pipeline and power cable		95	101	105	3
- Wellhead platform		694	694	694	
- Injection wells		292	668	825	
- Monitoring		920	920	920	
- Power		204	585	884	4
Post-closure Cost	Mill DKK	600	600	600	
- Post-closure monitoring					
CO_2 Injected	Mill tonnes	30	86	138	
Energy Consumption	MJ/t CO_2	49	49	49	

Table 0-6: Nearshore CO_2 storage

Notes

1. Intermediate storage includes storage tanks and CO_2 recovery unit
2. Injection plant includes booster pumps, injection pumps, heater exchanges, boiler system
3. Pipeline and power cable between storage and near shore injection platform
4. Energy cost is based on electrical power at 0.5 DKK/kWh
5. Accumulated OPEX is over a period of 30 years

The CAPEX for a 1 Mt/year nearshore subsea development is about 75 Mill DKK higher as the cost difference of 100 mill between a minimum facilities wellhead platform and a subsea templet is more than outweighed by the additional cost of a control umbilical and the subsea well assemblies. Depending on requirements for well intervention operations, OPEX could both be higher or lower for the platform scenario. Overall, the assessment is that, based on the details available at this stage, it can be assumed that the costs for both concepts are almost identical.

1.3 Offshore CO_2 storage

Case		1 Mt/year	3 Mt/year	5 Mt/year	5 Mt/year Reuse ex. pipeline	Notes
Pre-FID Cost	Mill DKK					
- 3D Seismic		50	60	70	70	
- Baseline studies		20	20	20	20	
- FEED Studies		10	10	10	10	
- Approvals		20	20	20	20	
CAPEX	Mill DKK					
- Wellhead platform (incl. brownfield work)		55	80	525	545	1
- Mooring and loading system/ pipelines		135	355	375	540	2
- Purpose built CO_2 carrier/FSU		475	545	640		3
- Injection plant		85	240	390	415	4, 5
- Injection wells		490	980	1925	1645	
- Onshore Storage					365	6
- Wind turbines					375	7
Abandonment cost (ABEX)	Mill DKK	203	475	731	731	
Accumulated OPEX	Mill DKK					12
- Base organisation		525	525	525	525	
- Wellhead platform		930	1740	2430	1760	8
- Mooring and loading system / pipeline		335	831	831	1224	
- Purpose-built CO_2 carrier/FSU			1352	1587		13
- Injection plant		211	595	967		
- Standby vessel		620	620	620		9
- Injection wells		152	290	527	765	
- Monitoring		920	920	920	920	
- Fuel/power		690	1932	3036	605	10
- Onshore plant					967	
- Wind turbines					620	
Post-closure Cost	Mill DKK	600	600	600	600	
- Post-closure monitoring						
CO_2 Injected	Mill tonnes	30	84	132	129	
Energy Consumption	MJ/t CO_2	49	49	49	34 15	 11

Table 0-7: Offshore CO_2 storage

Notes

1. For the 1 and 3 Mt/y cases, "Wellhead platform" only includes modifications to existing platform; for the 5 Mt/y cases an additional new wellhead platform at a nearby reservoir has been included
2. Mooring and loading system/pipeline includes the loading/mooring buoys and the pipelines from here to the wellhead platform. For the 5 Mt/y cases an interfield pipeline is also included

3. Purpose-built CO_2 carrier/FSU for the 1 Mt/y includes the shuttle tanker, and for the 3 and 5 Mt/y cases a permanently moored floating storage unit
4. Injection plant includes booster pumps, injection pumps, heater exchanges, boiler system located on the purpose-built CO_2 carrier/FSU, except for the 5 Mt/y pipeline reuse case.
5. For 5 Mt/y pipeline reuse case booster pumps, transfer pumps, heater exchanges and boiler system are located onshore; only high-pressure injection pumps are located offshore
6. Intermediate storage includes storage tanks and CO_2 recovery unit
7. Wind turbines include two offshore wind turbines to provide poser for the high-pressure injection pumps
8. Wellhead platform OPEX includes all OPEX for the platform(s)
9. Standby vessel covers the cost for a safety standby vessel expected to be present due to the marine operations
10. Energy cost for the operation of the injection facilities located offshore is based on a cost of 450 €/t for green ammonia, and for the onshore transfer facilities the cost is based on electrical power at 0.5 DKK/kWh
11. Energy for the offshore high-pressure injection pumps is provided by offshore wind turbines
12. Accumulated OPEX is over a period of 30 years
13. The proposed purpose-built CO_2 carrier proposed for the 1 Mt/y offshore CO_2 storage case will also be used as shuttle tanker and therefore the OPEX costs for the vessel are not being included as they are assumed to be part of “transport cost”. OPEX for the injection facilities are stated as a separate line item.

1.4 Assumptions

The following assumptions have been used as basis for the quantitative assessments:

All cases

- Cost of post-injection monitoring and reporting has been included for a 20-year period
- No cost has been assessed for monitoring after hand-over to the Competent Authority
- The mandatory financial guarantee has not been evaluated at this stage, being very case-specific
- The technical lifetime of the CO_2 injection is for all cases set to 30 years to be comparable; however, especially for the injection into depleted oil fields, this may for some fields be significantly less, maybe as low as 15 years.

Onshore and nearshore

- Intermediate storage at the CO_2 receiving port is part of the quantitative assessments
- Pipeline from port to the injection site is part of the quantitative assessments
- Costs related to upgrade of port facilities (jetty, quayside, etc.) are not included as they are assumed to be part of “transport cost”
- Compensation to local community due to any value loss of property in the vicinity of the CO_2 storage or facilities is not included in the quantitative assessments

Offshore

- Value of existing offshore facilities at the time of transfer from production to injection is set to zero, which is considered to be realistic as the net present value of the postponement of the abandonment cost is most likely higher than any remaining value of the facilities
- All abandonment costs of existing facilities and wells are expected to be covered by the oil & gas license
- Any upside due to deferral of abandonment costs of existing facilities and wells is not taken into account
- The proposed purpose-built CO_2 carrier proposed for the 1 Mt/y Offshore CO_2 storage case will also be used as shuttle tanker, and therefore the OPEX costs for the vessel are not being included as they are assumed to be part of “transport cost”

Energy

- Energy for the offshore CO_2 storage cases is assumed to be provided through CO_2 neutral E-fuels such as ammonia

1.5 Basis for cost assessment

1.5.1 CAPEX (capital expenditure)

The size and weight of the main components of the facilities are established based on the design capacities, whereas the size and weight of support systems and bulk items are established as typical percentages hereof. This has been used as a basis for the cost estimate, which is based on industry unit cost, mainly from the oil & gas industry.

Ships suitable to be used as CO_2 floating storage and host for the injection facilities have not yet been built, for which reason the costs have been extrapolated from the cost of smaller vessels such as the CO_2 tankers from the Northern Light project. These extrapolated costs have then been benched-marked against the cost of similarly sized LNG tankers.

Pipeline costs are mainly based on typical costs per metre onshore and offshore.

Cost of wells include cost of the well itself, surface valve assembly and tubing and the drilling costs, which include the drilling rig and associated spread cost. The day rate of an offshore drilling, especially, can vary based on the activities in the industry; for this study a cost close to the average for the past 10 years has been assumed.

1.5.2 OPEX (operational expenditure)

The operational expenditure for facilities, wells, pipelines and vessels is estimated based on industry norms (percentages of CAPEX) mainly from the oil and gas industry. In addition, the operational expenditure includes costs for monitoring, energy, standby vessel (where required) and support organisation.

Again, it shall be highlighted that all costs related to transportation of CO_2 from the capture site to an onshore intermediate storage or the offshore fields are excluded.

1.6 Employment in connection with CO_2 storage

Establishment and operation of CO_2 storage will create employment directly in relation with the preparation work, design and construction, operation, monitoring and abandonment. In addition, CO_2 storage facilities may create additional employment in relation to industries with CO_2 emissions as industrial plants. In the following section, only direct employment is assessed.

A typical natural gas storage uses approx. 20 full-time employees, and it has been assessed that the same number will be relevant for an onshore CO_2 storage as fewer people may be necessary for the plant operation, while the need for monitoring and reporting may be higher. For an onshore CO_2 storage, we assume 20-30 persons for operation, for nearshore 30-40 persons and for offshore solutions 60-90 persons. These differences are included in the cost estimates for operation.

Based on the estimates for operational costs, our estimate is one man-year for operation per 2.5 MDKK in OPEX for onshore plants. For offshore storage, a major part of the OPEX will be fuels and rental of vessels and by subtracting this from the OPEX, the ratio becomes approximately one man-year for 5 MDKK OPEX. Employments in relation to fuels and construction of vessels are not included.

Direct employment for investment will be lower as some part of the investment will be materials such as steel and equipment such as drilling rigs. Our estimate is that one person will be employed per 5 MDKK CAPEX. For the investment cost, the employment may be different for on- and offshore solutions as a higher share of off-shore solutions may be carried out outside Denmark. For ABEX, the same ratio is used as for CAPEX.

The total number of man-years in the different cases is consequently estimated to 1000 man-years for the 1 Mt/year onshore solution and 4000 man-years for the offshore case with 5 Mt/year.

For comparison, the Norwegian study "Industrial opportunities and employment prospects in large-scale CO_2 management in Norway", published by SINTEF in 2018, assessed that the Norwegian full-scale CO_2 storage project, with a yearly capacity of 1.4 million tonnes CO_2, would create employment of 5000 man-years for the entire CO_2 chain. It is estimated that 30 percent of these jobs will be for storage, corresponding to 1500 man-years.

1.7 Unit cost for CO_2 storage

1.7.1 Unit storage cost - NPV calculations of direct cost, CAPEX, OPEX, ABEX and monitoring

The direct unit cost for CO_2 storage has been calculated considering different costs of capital of 3.5%, 8% and 10% respectively to reflect the viewpoints of different stakeholders and potential investors in CO_2 storage. The direct cost does not include contingencies and additional risks outside the individual projects. All costs do not include taxes.

NPV per ton CO2 @ WACC =	3.5%	1 MTA Onshore	3 MTA Onshore	5 MTA Onshore
CAPEX (Incl Pre FID)	DKK/t	45.9	30.3	29.7
OPEX	DKK/t	46.5	26.2	23.3
ABEX	DKK/t	2.1	1.8	1.9
Post Monitoring	DKK/t	5.3	2.0	1.3
Total	DKK/t	99.9	60.3	56.3

NPV per ton CO2 @ WACC =	8.0%	1 MTA Onshore	3 MTA Onshore	5 MTA Onshore
CAPEX (Incl Pre FID)	DKK/t	73.9	48.3	47.3
OPEX	DKK/t	46.1	27.0	24.6
ABEX	DKK/t	0.9	0.8	0.9
Post Monitoring	DKK/t	1.6	0.6	0.4
Total	DKK/t	122.6	76.7	73.2

NPV per ton CO2 @ WACC =	10.0%	1 MTA Onshore	3 MTA Onshore	5 MTA Onshore
CAPEX (Incl Pre FID)	DKK/t	87.9	57.4	56.3
OPEX	DKK/t	46.1	27.4	25.3
ABEX	DKK/t	0.6	0.6	0.7
Post Monitoring	DKK/t	0.9	0.4	0.3
Total	DKK/t	135.6	85.8	82.6

Table 4-3: Onshore CO_2 storage - NPV calculation of direct cost

NPV per ton CO2 @ WACC =	3.5%	1 MTA Near shore	3 MTA Near shore	5 MTA Near shore
CAPEX (Incl Pre FID)	DKK/t	109.8	59.3	50.2
OPEX	DKK/t	91.7	43.1	33.9
ABEX	DKK/t	5.6	3.5	3.2
Post Monitoring	DKK/t	8.0	2.9	1.8
Total	DKK/t	215.1	108.8	89.1

NPV per ton CO2 @ WACC =	8.0%	1 MTA Near shore	3 MTA Near shore	5 MTA Near shore
CAPEX (Incl Pre FID)	DKK/t	174.5	94.5	79.8
OPEX	DKK/t	91.8	44.4	35.5
ABEX	DKK/t	2.5	1.6	1.5
Post Monitoring	DKK/t	2.4	0.9	0.6
Total	DKK/t	271.2	141.4	117.4

NPV per ton CO2 @ WACC =	10.0%	1 MTA Near shore	3 MTA Near shore	5 MTA Near shore
CAPEX (Incl Pre FID)	DKK/t	206.4	112.1	94.9
OPEX	DKK/t	92.2	45.2	36.4
ABEX	DKK/t	1.7	1.1	1.0
Post Monitoring	DKK/t	1.4	0.5	0.4
Total	DKK/t	301.7	159.0	132.7

Table 4-4: Nearshore CO_2 storage - NPV calculation of direct cost

NPV per ton CO2 @ WACC =	3.5%	1 MTA Offshore	3 MTA Offshore	5 MTA Offshore	5 MTA Offshore with SA pipeline
CAPEX (Incl Pre FID)	DKK/t	69.7	43.0	45.8	45.7
OPEX	DKK/t	145.3	106.3	89.3	59.5
ABEX	DKK/t	3.8	3.3	3.8	3.2
Post Monitoring	DKK/t	8.0	3.0	1.9	2.0
Total	DKK/t	226.8	155.5	140.9	110.4

NPV per ton CO2 @ WACC =	8.0%	1 MTA Offshore	3 MTA Offshore	5 MTA Offshore	5 MTA Offshore with SA pipeline
CAPEX (Incl Pre FID)	DKK/t	108.2	68.5	71.0	68.5
OPEX	DKK/t	145.9	109.8	93.7	64.1
ABEX	DKK/t	1.7	1.5	1.8	1.6
Post Monitoring	DKK/t	2.4	0.9	0.6	0.7
Total	DKK/t	258.1	180.9	167.2	134.8

NPV per ton CO2 @ WACC =	10.0%	1 MTA Offshore	3 MTA Offshore	5 MTA Offshore	5 MTA Offshore with SA pipeline
CAPEX (Incl Pre FID)	DKK/t	126.5	81.4	83.7	79.7
OPEX	DKK/t	146.7	111.9	96.2	66.6
ABEX	DKK/t	1.1	1.1	1.3	1.1
Post Monitoring	DKK/t	1.4	0.6	0.4	0.4
Total	DKK/t	275.7	194.9	181.6	147.9

Table 4-5 Offshore CO_2 storage in depleted oil/gas fields - NPV calculation of direct cost

The offshore CO_2 cost does not include the potential value of existing infrastructure such as platforms, wells and pipelines. The re-use of an existing pipeline from shore to the storage site is considered here as an option, but the cost of the acquisition of the pipeline and its eventual abandonment is not included.

1.7.2 Uncertainties and contingencies

The cost estimates made in the present project are associated with some uncertainty as described in chapter i.3. In order to limit the uncertainty, it will be necessary to mature the different projects, typically with more advanced design to a so-called FEED level, and potentially with additional geophysical surveys and drilling.

There are also uncertainties concerning the injection rate for the wells and the total volume, which can be stored in different geological structures or depleted hydrocarbon fields.

There are different philosophies as to how to accommodate uncertainties regarding cost and performance. For some investment projects, the uncertainties are covered by adding contingencies as the basis for the investment decision. Such contingencies have not been used in the present report.

There is some uncertainty connected to the cost estimates, as some industry players expect offshore solutions to be by up to 30% more expensive than what is presented here as a central estimate. As some of the estimations for CCS projects in this report are based on industry practice from oil and gas, other approaches might result in a variation of the cost levels, which however was out of scope for this analysis. Finally, the project-specific split of cost before and after Final Investment Decision of a specific project can have an effect on the generalized costs represented in this report, as different commercial companies may have different decision gates (among others due to different risk willingness across those companies).

1.7.3 Development cost – including prospects which are not developed

General overhead costs for development of a portfolio of prospects, general company costs, legal costs etc. will have to be added to the cost of individual storage development. This will also include any pre-FID costs of the initial development of storage facilities for which no investment decision will be taken.

The overall cost will naturally also depend on the chosen business model, degree of competition, tender cost, etc.

Abbreviations and Glossary

Abbreviation

ABEX	Abandonment Expenditure
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilisation and Storage
CHP	Combined heat and power
CSLF	Carbon Sequestration Leadership Forum
EC	European Commission

EIA	Environmental Impact Assessment
EOR	Enhanced Oil Recovery
EU	European Union
EU ETS	EU Emissions Trading System
FEED	Front End Engineering Design
FID	Final Investment Discission
FSU	Floating Storage Unit
GEUS	Nationale Geologiske Undersøgelser for Danmark og Grønland
IEA	International Energy Agency
IHS	IHS Markit Economics & Country Risk, Inc.
ISO	International Organization for Standardization
LNG	Liquefied Natural Gas
NOV	National Oilwell Varco
OGCI	Oil and Gas Climate Initiative
OPEX	Operational Expenditures
OSPAR	Oslo-Paris Convention
PCI	Project of Common Interest
PLEM	Pipeline end manifold
ROAD	Rotterdam Capture and Storage Demonstration Project
SAL	Single Anchor Loading (offloading system)
SBM	Single buoying moorings
UK	United Kingdom
US	United States
AACE	Association for the Advancement of Cost Engineers

Glossary

Injection well	A well for injection of CO_2 into a subsurface reservoir, see an example in Figure 0-33
Observation well	A well for observation of leakages from a storge reservoir
Well pad	An area that is cleared or prepared for the drilling of wells, the area is a fenced off area with drainage and other facilities to allow safe and environmentally friendly drilling of wells, see also Figure 0-32.

Wellhead platform	A steel offshore structure for the support of production and/or injection wells and associated support systems. See also Figure 0-29
Turret	The turret mooring system consists of a turret assembly that is integrated into a vessel and permanently fixed to the seabed by means of a mooring system. The turret system contains a bearing system that allows the vessel to rotate around the fixed geostatic part of the turret, which is attached to the mooring system. See also Figure 0-31
SAL	A SAL base anchored into the seabed integrates the PLEM (Pipeline End Manifold), a mooring turret and in-line swivel. The vessel can freely weathervane around the SAL subsea turret via a mooring polyester rope. Fluid is transferred through an in-line swivel and a hose string assembly up to the vessel piping at the bow. See also Figure 0-30
SBM	Single buoy mooring or single point mooring buoy consists of a buoy that is permanently moored to the seabed by means of multiple mooring lines. The buoy contains a bearing system that allows a part of it to rotate around the moored geostatic part. When moored to this rotating part of the buoy with a mooring connection, the vessel is able to freely weathervane around the geostatic part of the buoy
Bow loading system	The system to allow offloading from the aft of the Floating Storage Unit to the bow of shuttle tanker.
Intermediate CO_2 storage	A site with pressurised and cooled tanks for storage of liquified CO_2. See also Figure 0-29
Manifold	A pipe section for distribution into several pipe segments
Flowline	Pipe connection between manifold and the individual wells
Riser	Vertical pipe section between a subsea pipeline the topside of an offshore platform
Standby vessel	A Safety Standby Vessel is a vessel designed rapid assistance or evacuation in the event of an emergency.

Figure 0-28: Unmanned wellhead platform [20]

Figure 0-29: Typical gas storage tanks [21]

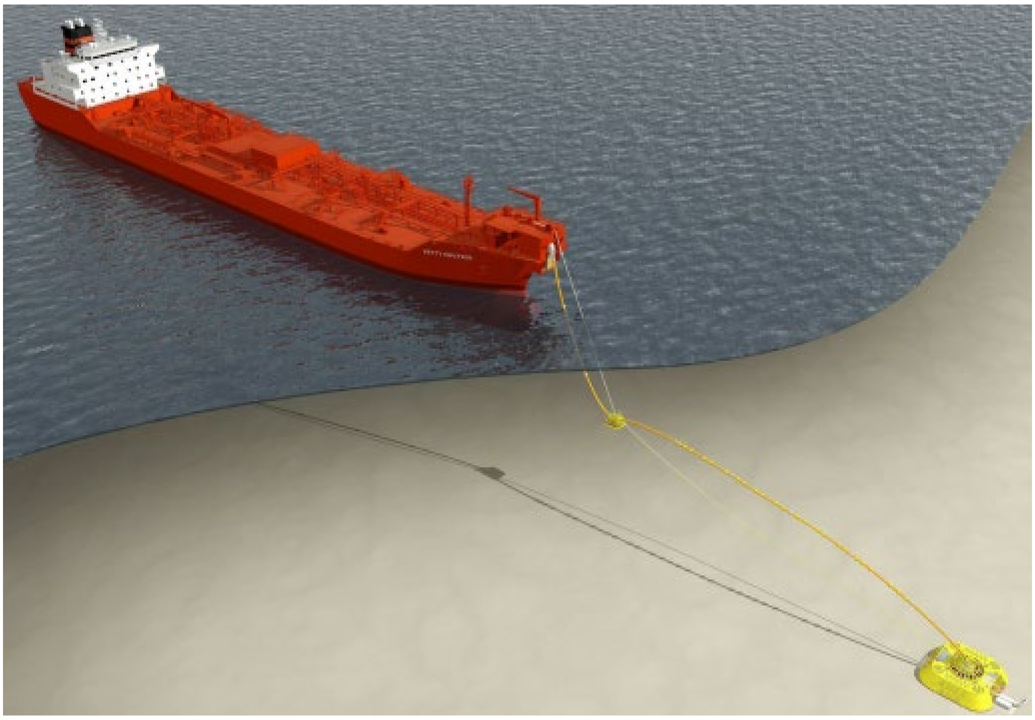


Figure 0-30: Single Anchor Loading system (NOV) [22]

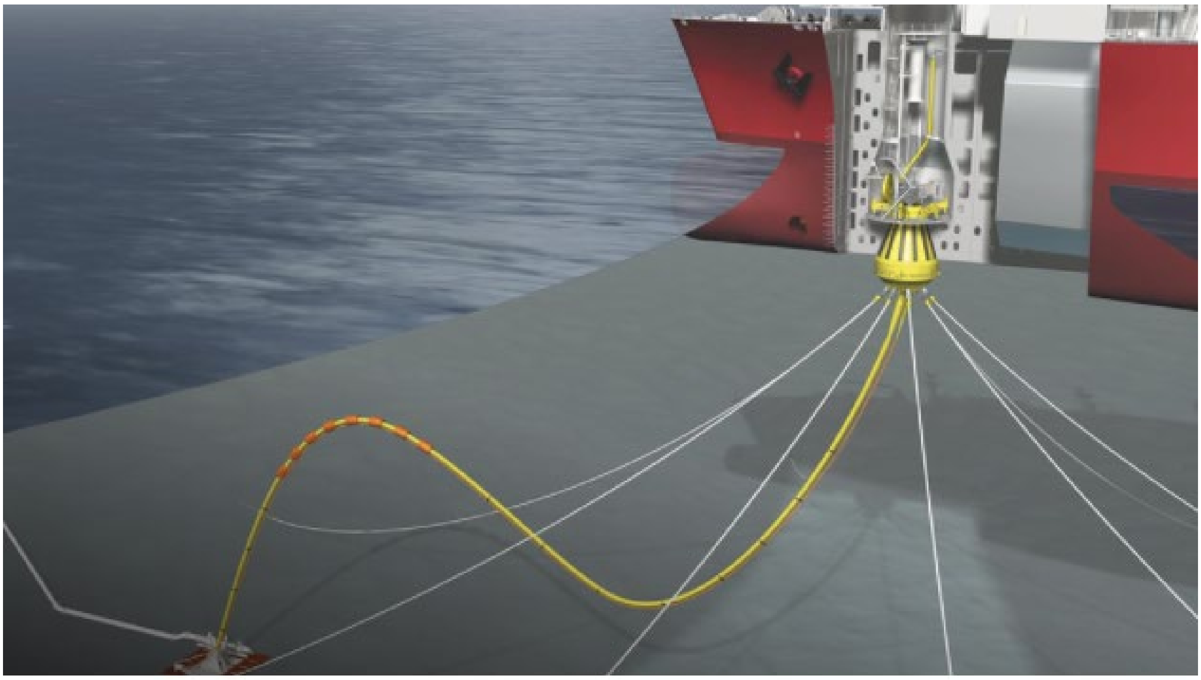


Figure 0-31: Turret mooring system [22]

Figure 0-32: Drilling operation at injection well pad [9]

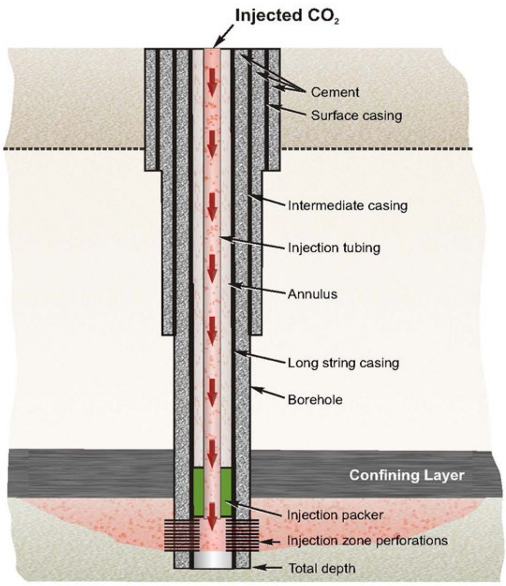


Figure 0-33: High level diagram of injection well [23]

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