University of Stavanger

VEGARD MOEN (9132)
SUPERVISOR: BERNT ARNE ØDEGAARD

The Economics of Carbon Capture and Storage

An assessment of the economic viability of CCS in Europe.

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Master of Science in Business Administration

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Preface

This master's thesis completes a two-year degree in Business Administration and marks the end of the master's program in Applied Finance at the University of Stavanger Business School.

The thesis explores the economics of carbon capture and storage (CCS), a technology that is thought necessary for economies to reach net-zero CO_2 emissions. Cost studies on CCS exists in the literature, but the lack of sufficient real experience with the technology makes cost estimates uncertain. This in turn makes it difficult to assess the economics of prospective CCS opportunities. The thesis seeks to assess the economics of CCS and its economic viability across sectors with the highest point source emissions in Europe. The technology has recently experienced newfound momentum and seems set for commercial deployment at scale. CCS is both an interesting and potentially vital technology, that can play an integral role in the transition to net-zero emissions economies.

I would like to express gratitude to people that aided me throughout the writing of this thesis. My academic supervisor at the University of Stavanger, Bernt Arne Ødegaard, for constructive feedback and guidance. My industry supervisor, Rasmus Osaland, for helpful discussions along the way. Other colleagues at Neptune Energy for assisting on the technical details of CCS. And last, but not least, friends and family for all their support.

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Abstract

Carbon capture and storage (CCS) is a key technology in the transition to net-zero emissions economies. By 2030, the European Union aims to capture and store at least 50 million tonnes of CO_2 per year (Mtpa), and demand for CO_2 storage is forecasted to be 80 Mtpa. Current all-time high cost of emitting CO_2 in Europe can incentivise the commercial deployment of CCS. However, great variation and uncertainty in the cost of CCS makes its economic evaluation for industry practitioners challenging. This thesis seeks to assess the economics of CCS in Europe by quantifying its cost structure and evaluate it against policy rates for emitting CO_2. The economic assessment is done through a survey of the literature on CCS and the development of a financial model for calculating CO_2 transportation and storage costs. The thesis finds that the total cost of CCS across Europe's largest emitting sectors is in the range of €91-€193 per tonne CO_2 (€/tCO_2) captured, transported and stored. Current carbon prices of 90 €/tCO_2 enable commercial CCS, albeit on a small scale. Beyond 2030, the results suggests that CCS is viable for more than 150 million tonnes of stationary emissions. However, challenges to large-scale deployment exist and clarity in regulation and further supportive policy is necessary to realise the scale of CCS for deep decarbonisation of European economies.

1. Introduction

The world needs to reduce greenhouse gas emissions (GHGs) to limit global warming as much as possible. CO_2 is the most significant GHG, and 90% of all CO_2 emissions come from the burning of fossil fuels (Ritchie et al., 2020; Friedlingstein et al., 2022). In 2021, global CO_2 emissions from fossil fuel combustion exceeded 37 billion tonnes, while emissions in the European Union (EU) and Great Britain exceeded three billion tonnes. The IEA estimates that most emissions reductions will come through energy efficiency measures and fuel-switching, i.e. electrification and renewable energy replacing fossil fuels (IEA, 2021). Some CO_2 emissions will exist even in net-zero emissions economies. Fossil fuel use will remain, and some industrial process emissions from chemical reactions cannot be abated through main pathways, often referred to as the "hard-to-abate" sectors. The remaining CO_2 emissions are proposed abated through carbon capture, use and storage (CCUS).

CCUS is a collective term for technologies to capture, transport and store or use CO_2. Capture of CO_2 can be from stationary sources such as power and industrial plants, or directly from the air. Following capture, the CO_2 is prepared for transport. Large-scale, multi-million tonne transport of CO_2 will be performed by a combination of shipping and pipeline (IEA, 2022a). The captured CO_2 can either be used as input in various processes and products or permanently stored. Dedicated storage can be both onshore and offshore. When stored, the CO_2 is injected via wells to deep geological reservoirs, where different trapping mechanisms ensures permanent storage.

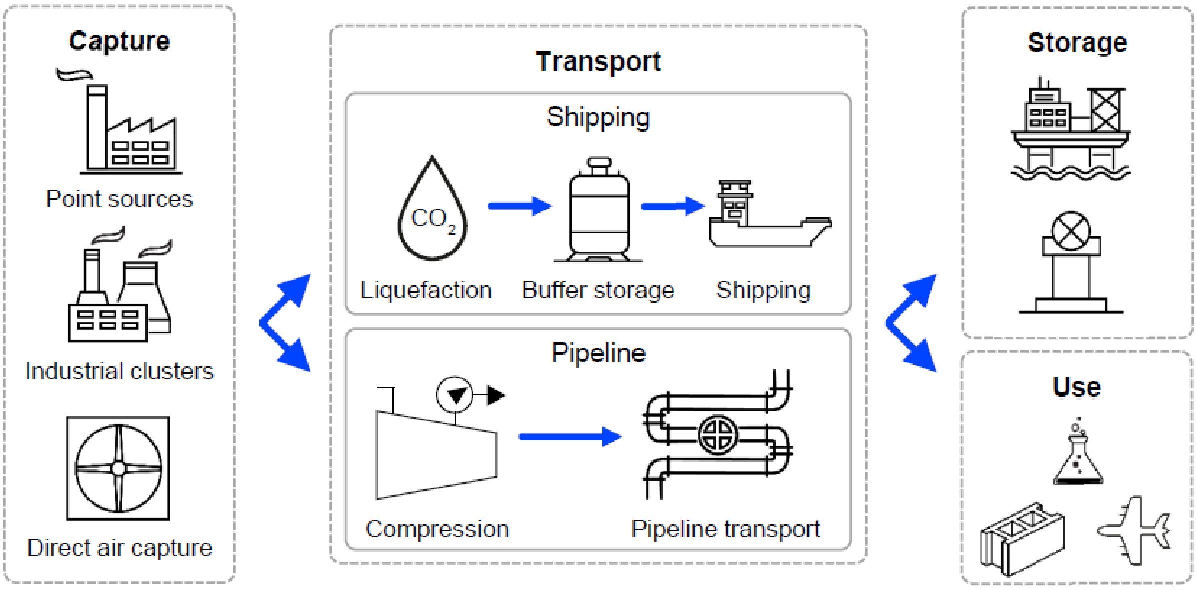

Figure 1. Schematic of the CO_2 management value chain.

Blue arrows indicate the flow of CO_2 through the chain. CO_2 can be permanently stored in geological formations both onshore and offshore, or it can be used as input factor in production (IEA, 2023a, p. 336).

What is the outlook for CCUS in Europe? CCUS is projected to play a minor role in overall emissions reductions up until 2030. Towards 2050, large-scale CCUS deployment is forecasted, with 7-8 billion tonnes of CO_2 captured and stored globally in 2050 (IEA, 2021; Lyons et al., 2021). In Europe, ambitious climate action and policy support have recently brought momentum to CCUS projects, with forecasts of 70 Mtpa CO_2 captured by 2030 (IEA, 2022a).[1] The European Commission (EC) has set a target of injecting at least 50 Mtpa for permanent storage by 2030, which increases to 300 Mtpa by 2040 (EC, 2023). European industry stakeholders forecast demand for storage services at 80 Mtpa in 2030. Energy sector emissions from stationary sources in Europe – suitable for capture – totalled around 1,9 billion tonnes in 2019 (IEA, 2020). However, this represents a significant scale-up of European CCUS from current operating capacity of less than 3 Mtpa captured, and around 1,5 Mtpa permanently stored (IEA, 2022a; GCCSI, n.d.). There is ample storage capacity in Europe, estimated at 300 billion tonnes of CO_2, in which about half of the capacity is offshore, mostly in the North Sea (IEA, 2020).[2] Given the EU's ambitions, deployment of commercial CCUS appears imminent, and the location of suitable assets for storage indicate that early development will be centralised around the North Sea area.

[1] Distributed on 50 different projects.
[2] Offshore storage capacity of 150 billion tonnes could store 300 Mtpa for 500 years.

Besides permanently stored, the CO_2 can be used as input factor in production. In IEA's sustainable development scenario, more than 90% of captured CO_2 is to be permanently stored in geological reservoirs (IEA, 2020). The remaining CO_2 is mostly planned to be used as input factor for synthetic fuels and in chemical production. CO_2 use is today largely within enhanced hydrocarbon recovery (EOR)[3] – where most of the CO_2 is permanently stored – and in fertiliser production. While CO_2 use creates a revenue stream, incentivising investment in CO_2 capture, its climate benefit is less clear. This because CO_2 is rereleased into the atmosphere as the product is expended, and CO_2 for EOR does not remove emissions (Lyons et al., 2021). Using CO_2 for EOR is not widespread in Europe (GCCSI, n.d.), and it does not receive the same policy support as injecting CO_2 in dedicated storage (EC, 2023a). While other CO_2 use is supported, limited demand and immature technologies favour CO_2 in permanent storage rather than use. This thesis will primarily focus on the economics of CO_2 in dedicated storage, CCS.

For CCS to be the preferred emissions abatement option for emitters, the cost of emitting, or carbon price, must be at a level sufficient to offset total CCS costs. This is referred to as the carbon price breakpoint, the level of carbon prices that enable commercial CCS. As the commercial deployment of CCS appears near, a deeper understanding of its economics is warranted. This thesis seeks to assess the economics of CCS in Europe by quantifying its cost structure and evaluate it against policy rates/carbon prices for emitting CO_2. This is done through surveying the literature on CCS and developing a financial model for calculating the cost of CO_2 transportation and storage. This results in calculations of carbon price breakpoints across the sectors with highest point source emissions in Europe. This is important in order to gain a deeper understanding of the economics of CCS and its economic viability across sectors. First however, the reader is presented with current and historical challenges faced by commercial CCS deployment in Europe.

Historically, the deployment of CCS has struggled with "The chicken or the egg" dilemma. No transport and storage infrastructure will be developed if no CO_2 is captured, no CO_2 can be captured without the necessary infrastructure. Therefore, demonstration phase projects have been structured as a full chain solution, i.e. only one investor/developer. This is infeasible for CCS at scale, as few companies – except oil majors – have the diverse in-house knowledge required to operate an entire CCS value chain. For part chains, i.e. different operators in each element of the value chain, there is a special need to coordinate project assessment,

[3] Where CO_2 is injected as pressure support, increasing the production of oil and gas.

development and operations for CCS, particularly in early deployment, with a high risk of cross-chain default.[4] This points to the need for specialisation across the value chain for CCS to become economically viable, a development that appears to be underway (IEA, 2023b).

Other risks in relation to CCS pose barriers to commercial deployment. As CO_2 is permanently stored in geological reservoirs, the risk of leakage and potential release into oceans and/or the atmosphere, could represent a substantial financial liability (ZEP, 2019). [5] This leakage liability is not easily insured for two reasons. First, pricing of leakage is difficult as the future policy rate for emitting is unknown, making the size of the liability uncertain. Second, the longevity of CO_2 storage makes the liability difficult for private corporations to bear (IEA, 2020). The "Directive on the geological storage of carbon dioxide" is the main legal framework for CO_2 storage in Europe (ZEP, 2022) and includes provisions on the need for a financial security to cover leakage risk and on the handover of storage liability, which to an extent addresses the risks mentioned above. However, regulatory uncertainty around CCS – how European governments interprets the directive – remains. There are also risks associated with the assessment of potential storage sites, that if not properly regulated, could lead to market failure. Like the exploration for oil and gas, CO_2 storage sites will have to be explored and assessed through costly data acquisition. Unlike oil and gas, there is not yet a large financial upside if suitable storage is discovered as the industry is immature. Absent regulations that incentivise exploration activities, like the special tax for the oil and gas sector in Norway, pose a risk of too low supply of storage assets and can ultimately slow down European CCS deployment.

The lack of a sufficiently strong financial incentive to capture rather than emit CO_2 is another barrier to commercial deployment of CCS (GCCSI, 2020b; IEA, 2020). However, several pathways for incentivising investment in capture exist. Carbon prices and subsidies – like tax credits – are common. In Europe, the EU's Emissions Trading System (EU ETS) – a compliance-based carbon market – puts a price on GHG emissions by requiring emitters to hold allowances for each tonne of CO_2 emitted.[6] The adverse effects of stringent climate policy on the competitiveness of European manufacturing industry, means that most industrial emitters have historically received most of their allowances for free, undermining investment in CCS. Additionally, the price of allowances has been too low to enable CCS, even from lowest cost sources. However, recent developments in European climate policy, resulting in stronger carbon

[4] The risk of the development or operation of one or more elements in the chain being delayed or stopped.
[5] By one estimate, the financial liability of leakage could be in the order of 500 M€ (ZEP, 2019).
[6] For other GHGs, emissions are converted to CO_2-equivalents, which is based on the global warming potential of one tonne of CO_2.

price signal, have significantly improved the outlook for investment in CCS. Still, there is need for financial support in the form of grants and/or subsidies to help alleviate the high capital and operational costs for CCS, especially in an early phase where the risk of stranded assets are greatest (IEA, 2020). In a long-term perspective, favourable market-based climate financing could be available for CCS projects, but proof of profitability is necessary first.

In the following paragraphs, a brief summary of the main findings in the thesis is presented. The survey of the literature on CCS has yielded insights that are relevant for the economic assessment of CCS in Europe and the evaluation of economic viability across sectors with the highest point source emissions. These insights are reiterated below.

The outlook for carbon prices in Europe appears positive. The price of emissions allowances[7] in the EU reached an all-time high of 105 €/tCO_2 earlier this year, with an average of around 90 €/tCO_2 so far in 2023. More ambitious climate strategies in the EU and in European countries have resulted in reforms of tax systems and the EU Emissions Trading System (EU ETS). The most important development is the introduction of a carbon border adjustment mechanism – a tax on the CO_2 emissions from production of certain imported products – which lowers the risk of European industry offshoring production as carbon prices increase. Consequently, the free allocation of emissions allowances will be phased out, expanding the potential market for CCS.

Cost estimates on CCS in the literature are uncertain as real experience is limited. Many studies on the cost of capture across sectors are available. Cost estimates exhibit significant variation between and within sectors. The CO_2 concentration in the emissions processed for capture is inversely related to the energy required to capture CO_2, and therefore a prime driver of cost differences. Use of different capture technologies and approaches is another factor contributing to the observed variation. Steam provides the energy for capture, and for mature capture technologies, steam is the dominating cost item. As such, how the steam is generated, and whether low-cost waste heat is available, is an important variable which further explains differences in cost estimates. Average capture costs of 65-133 €/tCO_2 is found in the literature[8], reflecting capture costs of the largest point source emitters in Europe. An important characteristic of capture development in Europe is that most capture facilities will be retrofits as existing power and industrial plants are midway through their economic lifetimes of 50 years.

[7] Covering "the cost" of emitting one tonne of CO_2.
[8] Based on: Diaz-Herrera et al. (2022); Eliasson et al. (2022); Garcia et al. (2022); Santos & Hanak (2022); Gardarsdottir et al. (2019); Onarheim et al. (2017); IEAGHG (2017e; 2016; 2013a; 2013b); Porter et al. (2017); Rubin et al. (2015); Kuramochi et al. (2012); GCCSI (2011).

This limits the suite of available, potentially cost-reducing, capture technologies that are feasible, and may pose a barrier to large-scale capture capacity and development of CCS in Europe.

Fewer studies on CO_2 transportation costs compared to capture exists. Large-scale CO_2 transportation will be performed by a combination of pipelines and shipping. While pipelines are generally cost-effective over shorter distances, shipping's value proposition to early investors in CCS – when volumes may be uncertain – is the comparably lower investment cost and higher flexibility to scale capacity, mobility in shipping routes and opportunity for co-utilisation. Pipelines are the most mature transportation option. Shipping faces barriers for cost-optimal ship designs and is not yet recognised by the EU as a credible transportation option. Still, the lower sensitivity of shipping costs to distance and volume, makes the option valuable both for early CCS deployment and in the longer-term enabling storage for more distant emissions sources needed for deep decarbonisation. Cost estimates from the literature suggests unit pipeline costs between 10-30 €/tCO_2 over shorter distances (100-400 km), transporting more than 5 Mtpa (Roussanaly et al., 2021b; Knoope et al., 2014). Estimated shipping costs are 20-30 €/tCO_2 regardless of distance, for volumes above 5 Mtpa (Roussanaly et al., 2021b). Transportation cost estimates from the financial model developed for this study generally fall in the same range.

Even fewer cost studies on CO_2 storage exists. Again, the lack of sufficient real experience limits understanding of the true costs of storage. Early storage development in Europe will have to be mostly offshore. Onshore storage is prohibited in many European countries and generally lacks public support. These barriers do not exist for offshore storage. Storage capacity, annual injection rates and safety of storage sites are all uncertain, but they drive economic performance. Costly exploration activities can mitigate some of this uncertainty, but poses exploration risk, all of which are pre-FID costs.[9] The large capital investments necessary to develop storage sites, coupled with the uncertainty in cost of operations, are challenging for developers and should be addressed through special business models. The CO_2 in reservoir is periodically monitored to verify containment. After closure of storage site, the CO_2 is monitored for a further 20 years before handover of storage liability and ownership to competent authority. Regulatory uncertainty on CO_2 storage remains, particularly on necessary exploration and monitoring activities, in addition to the size of a financial security meant to cover the cost of potential

[9] Pre final investment decision.

leakage and handover. Another barrier is the lack of supportive policy incentivising the assessment and development of CO_2 storage. Both factors can lead to storage assets being undersupplied. Literature estimates on the cost of storage offshore suggests a range of 10-45 €/tCO_2 (Pale Blue Dot, 2016; ZEP, 2011b). The financial model developed for this thesis estimates a unit storage cost of about 10 €/tCO_2.

Combining average capture cost estimates from the literature, with the transportation and storage costs estimated using the financial model, including profit margins, results in the carbon price breakpoints across sectors. At current carbon prices, CCS is uneconomical for the largest point source emitters in Europe.[10] Estimated carbon price breakpoints are in the range of 128-230 €/tCO_2 when considering storage on the Norwegian continental shelf and transportation by ship for direct injection offshore. Considering suitable storage within 100 km of CO_2 source, then transported by pipeline, results in a carbon price breakpoint of about 93 €/tCO_2. Opportunity for early CCS lies in capture from near-pure CO_2 emissions sources. While emissions from these sources are insufficient for large-scale CCS, it can be realised at lows of 50 €/tCO_2 and can assist in the development of necessary CCS infrastructure, lowering the cost of transportation and storage for future capture volumes.

This thesis progresses as follows. First, a theory and methodology section. Here, I give a detailed presentation of the typical CCS process flow and explain important terminology. A presentation of the financial model for analysing CO_2 transportation and storage costs is necessary for the reader to understand the underlying calculations of the economic assessment. The thesis' cost methodology is briefly discussed at the end. Second, a close look at carbon prices in Europe and presentation of recent and future developments with implications for CCS. Third, an economic assessment of CCS is performed based on the literature survey and calculations from the financial model. Each element in the CCS value chain, i.e. capture, transport and storage, is assessed separately. Fourth, presentation of the results from the case study using the financial model to evaluate five different potential CCS projects. The results are discussed in context of the topics explored in the thesis. Fifth and final, concluding remarks on thesis results and their limitations, implications for practitioners, researchers and policy makers and suggestions for future research.

[10] According to the thesis results, subsidies are necessary to make CCS economical.

2. Theory and Methodology

In the following paragraphs, I give a description of the general process flow for CCS. Then, I will present the financial model which assists in assessing the economic viability of CCS. Finally, an explanation is given on how cost estimates from the literature have been handled in order to assess the current economic viability of CCS.

2.1. CCS Process Flow

To understand the processes and terminology of CCS, a general overview of the process flow in operations is helpful.

Emissions from power plants or industrial installations, referred to as off-gas, often contain CO_2. In the case where the emitter pays a price for emitting, a cost-saving – from foregone carbon price – can be obtained if CO_2 is captured rather than emitted. In capture, the CO_2 is separated from the off-gas using one of many possible techniques (Rackley, 2010) resulting in a near-pure CO_2 stream which will be processed/conditioned for further transport. Both transport and storage infrastructure are designed for a certain degree of CO_2 purity. Therefore, removal of impurities that exceed these threshold values are important. Removal of water, through dehydration, is especially important, as water can react with CO_2 and create corrosive acids that damage transport and storage infrastructure. Higher levels of impurity in the CO_2 stream will drive removal costs. Depending on the mode of transport, CO_2 undergoes either liquefaction[11] or compression[12] to achieve high-density CO_2, the most cost-effective state of transport. To put it simply, CO_2 can be either pre-pressurised or non-pressurised prior to transport. If pre-pressurised, CO_2 has undergone liquefaction or compression at the capture

[11] Liquefaction: a process of refrigerating CO_2 to temperatures of -20 to -50°C, and compressing/decompressing CO_2 to low/medium pressures. An energy-intensive process largely because of the refrigeration, that is most costly when CO_2 have low pressure, i.e. is non-pressurised before liquefaction.

[12] Compression: a process where the pressure of CO_2 is increased in stages. Construction and operation are complex, which results in high capital costs. An energy-intensive process, where energy cost scales linearly with amount of CO_2 processed and necessary pressure-increase.

facility. When non-pressurised, the CO_2 arrives for transport in a gaseous state, characterised by normal atmospheric pressure and at ambient temperatures.

If transported by ship, the CO_2 needs to be liquefied. Temporary storage tanks are used to bridge the gap between continuous delivery of captured CO_2 and batchwise loading onto ships. The unloading of CO_2 can be both onshore to a harbour facility or directly offshore to floating platform or vessel. A receiving harbour facility will have unloading equipment and temporary storage to accommodate operational downtime and maintenance at storage facilities. For further transport by pipeline or for storage, the CO_2 must undergo gasification[13].

If transported by pipeline, the CO_2 is compressed to high pressure. When in liquid state before pipeline transport, the CO_2 can be pumped rather than compressed, as pumping requires significantly less energy.

Arriving at the storage site/wellhead, CO_2 must be within certain temperature and pressure ranges for efficient injection, otherwise further conditioning is needed. When fit for injection, the CO_2 is injected into the geological reservoir, where it ideally spreads out and forms a plume. Over the injection period, the CO_2 plume is monitored to verify its containment in the reservoir. When storage capacity is reached, the storage site and other infrastructure that cannot be reused is decommissioned/abandoned, which includes the plugging of wells into the reservoir. A prolonged period of post-closure monitoring ensues, with the eventual handover of storage ownership and liability to competent authority.

[13] Gasification: a process of pumping and heating the CO_2 to high pressure and ambient temperatures from a liquified state. Necessary for cost-effective transport by pipeline, and for safe and efficient injection into storage.

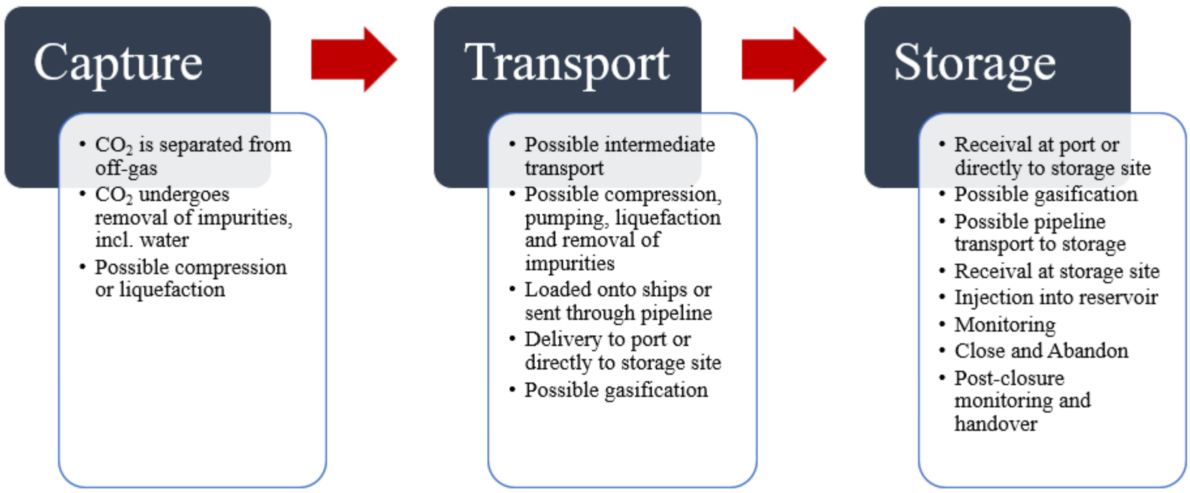

Figure 2. Overview of the process steps for a typical CCS project.

The processes of liquefaction, compression and gasification is collectively known as CO_2 conditioning, i.e. processes that alters CO_2 temperature and pressure.

2.2. CO_2 Transportation and Storage Financial Model

In order to quantify the cost structure of CCS, I develop a financial model to calculate the cost of CO_2 transportation and storage. The financial model has two key outputs. First, I calculate separately the unit cost of CO_2 transportation and storage. This is done to give an indication of what a typical, first-of-a-kind CCS-project can cost. Second, accounting for depreciation and corporate taxes, I calculate the free cash flow from both transportation and storage development and operations. A target internal rate of return for the projects is set, resulting in transportation and storage tariffs. The tariffs are added to the capture cost – sourced from the literature on CO_2 capture – to calculate carbon price breakpoints across the sectors with largest point source emissions.

The complete financial model is divided into storage, shipping and pipeline components. Storage is modelled as offshore storage in two different reservoirs and is created in collaboration with industry. The transportation options considered are shipping and pipeline. The CO_2 shipping section of the model is based on the framework in Durusut and Joos (2018) study, who conducted a survey on the literature of CO_2 shipping. The CO_2 pipeline model is based on the framework by Knoope et al. (2014), who developed a techno-economic model of CO_2 transport by pipeline, and in collaboration with industry.

I illustrate and evaluate five different project structures, or cases, in the financial model. These cases are all representative of project structures considered by industry practitioners for CCS. It is the transportation element that is the primary difference between cases. The Base and Tie-in cases (case 1 and 2) consider CO_2 shipping with onshore unloading (port-to-port), includes a CO_2 receiving onshore terminal and an offshore pipeline to final storage. The Direct Injection and Injection via FSIU cases (case 3 and 4) consider CO_2 shipping with direct offshore unloading to a stand-by floating unit which connects to the seabed infrastructure via a submerged loading system[14]. The Pipeline case (case 5) considers CO_2 transported by one long pipeline directly to storage. Figure 3 illustrates the major components of each case.

I consider a scenario where 7,2 Mtpa CO_2 is transported and stored over a 30-year period. Source of captured CO_2 is assumed to be emissions point sources in Northwest Europe, close to exporting harbours in the Rotterdam area. This simplifies the case study, as the need for intermediate transport from capture facility to exporting harbour can be neglected. The annual transported and stored volumes are representative of project scales considered by industry practitioners.

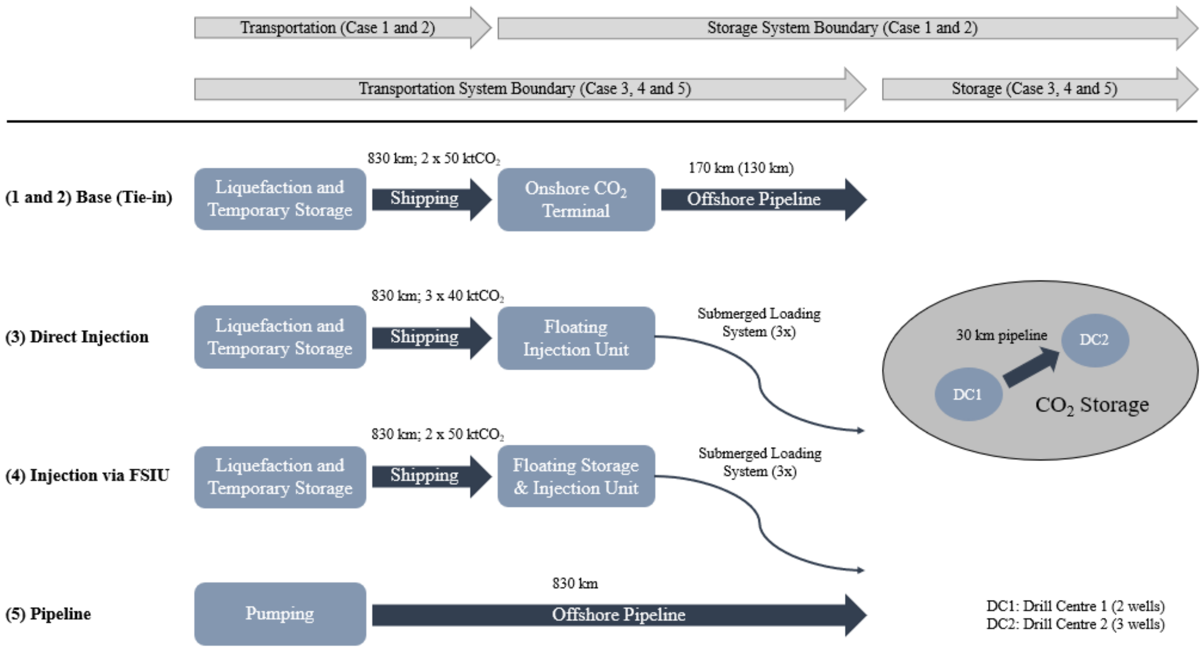

Figure 3. Summary of cases in the financial model.

Top section describes the system boundaries for transportation and storage operations, respectively. The bottom section gives an overview of the main components in each of the five cases. Storage site infrastructure is identical

[14] Picture a squid with tentacles connecting to the seabed infrastructure.

in all modelled cases. For shipping, fleet size and ship capacity in thousands of tonnes CO_2 ($ktCO_2$) is presented. Cases for a project transporting and storing 7,2 million tonnes of CO_2 per year for 30 years.

Figure 3 shows how all cases connect to the same offshore storage. Since storage is in two different reservoirs, separated by 30 km, two drill centres (DC) are necessary. The first drill centre contains two injection wells and the second drill centre contains three injection wells. System boundaries of transportation and storage development and operation differ between cases. For the Base and Tie-in cases, onshore CO_2 terminal and offshore pipeline is included in storage development and operation scope. For the remaining cases, storage scope is limited to the subsurface infrastructure. The system boundaries of the Base and Tie-in cases is like that of the first-of-a-kind transportation and storage project of Northern Lights (Northern Lights, n.d.).

For the reader to gain a better understanding of the thesis' financial model, I present a high-level summary of the shipping, pipeline and storage component. This summary includes the inputs, data, calculations and key outputs for each of the components of the financial model. Inputs are defined as variables that can be changed by the model user. Data represents the information sourced from the CCS literature and from industry consultations that feed into the model calculations. Key model outputs summarise the main production of the financial model.

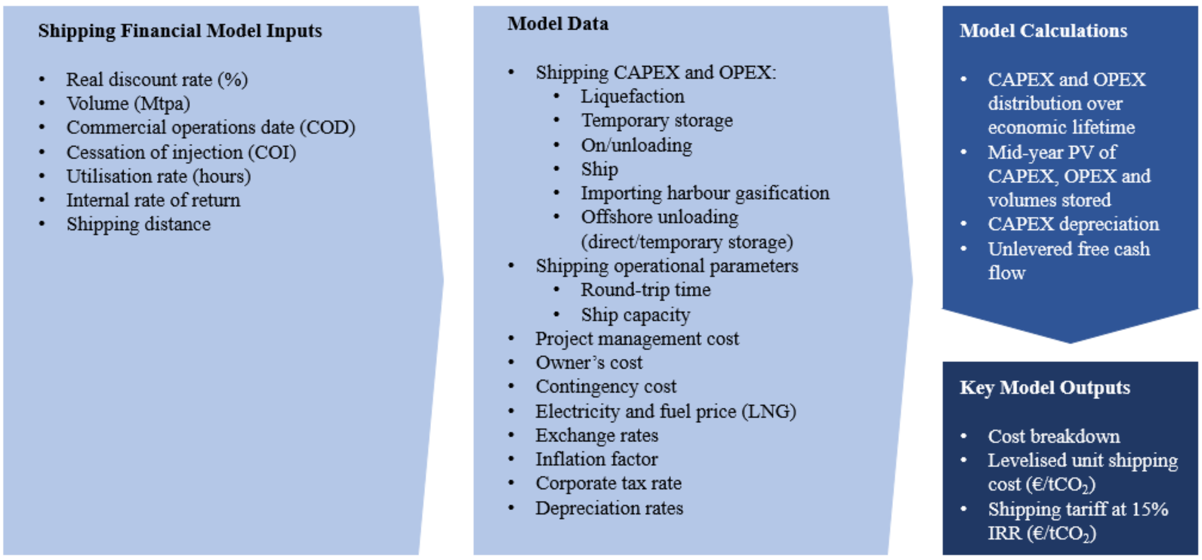

Figure 4. Summary of shipping component in the financial model.

Shipping CAPEX, OPEX and operational parameters are based on Durusut and Joos (2018) and on industry consultations. Levelised unit shipping cost is the sum of discounted annual CAPEX and OPEX divided by the sum of discounted annual volumes transported.

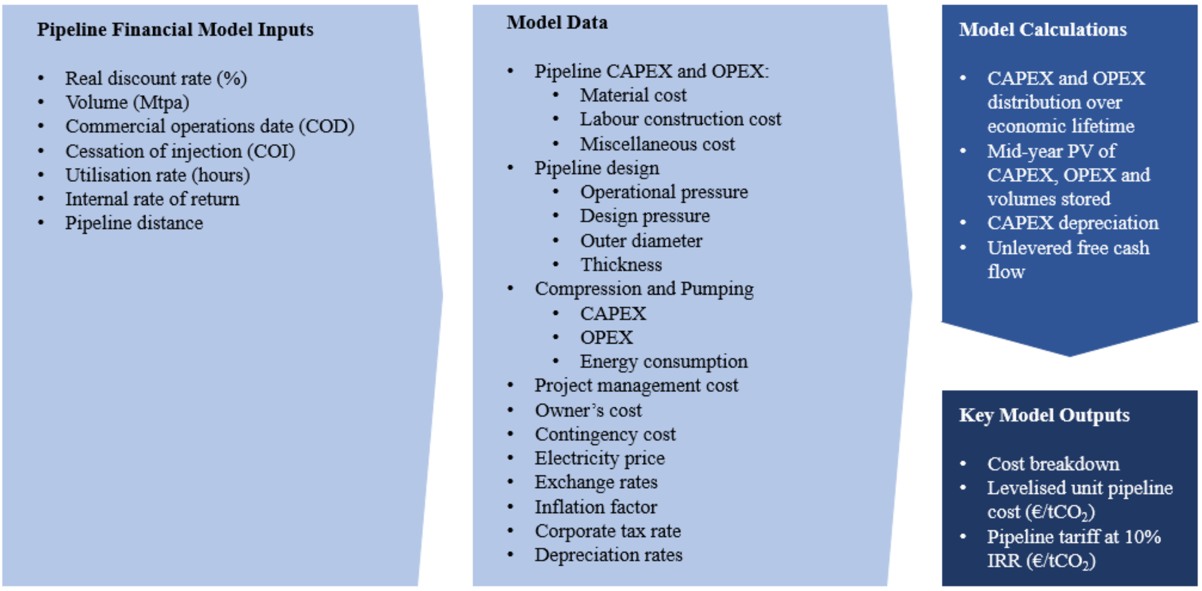

Figure 5. Summary of pipeline component in the financial model.

Pipeline, compression and pumping CAPEX and OPEX and pipeline design is based on Knoope et al. (2014) and on industry consultations. Levelised unit pipeline cost is the sum of discounted annual CAPEX and OPEX divided by the sum of discounted annual volumes transported.

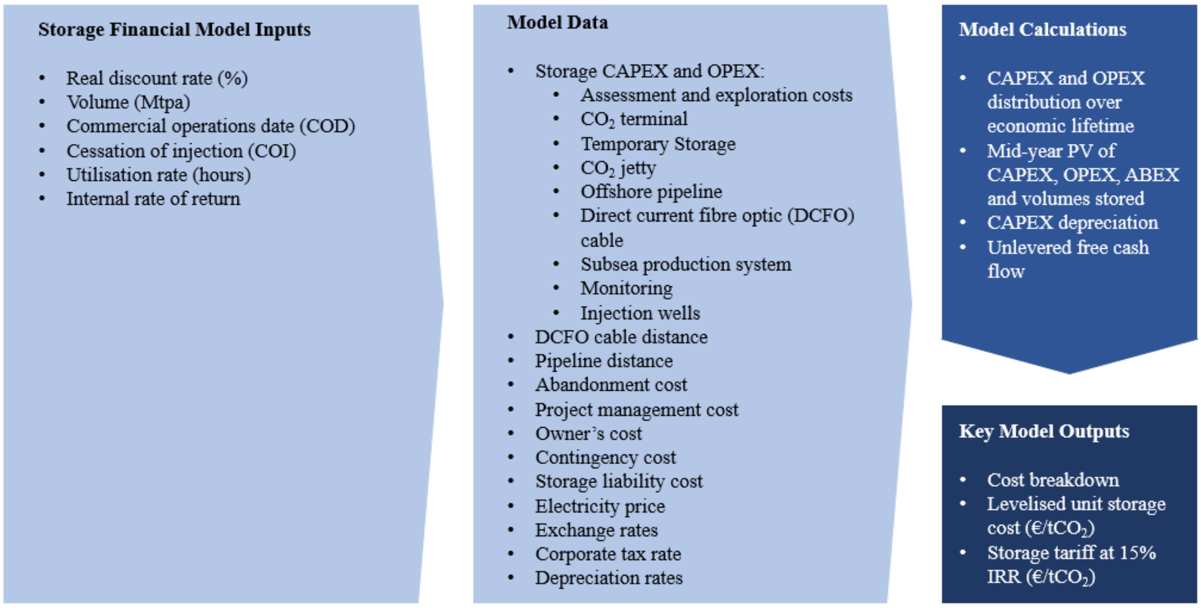

Figure 6. Summary of storage component in the financial model.

Storage CAPEX and OPEX, abandonment cost, project management cost, owner's cost[15] and contingency cost is based on industry consultation. Storage liability cost is based on ZEP (2011b). Levelised unit storage cost is the

[15] Owner's cost covers the cost of necessary engineering work, insurance, financing, generally non-construction development costs.

sum of discounted annual CAPEX, OPEX and ABEX[16] divided by the sum of discounted annual volumes transported.

Figures 4-6 summarise the components of the financial model. Detailed tables containing the cost estimates used can be found in appendix 1.

Choice of internal rates of return for shipping, pipeline and storage warrants an explanation. As explained above, a target internal rate of return is chosen. Using Solver in Microsoft Excel results in a tariff corresponding to the target IRR. The project is assumed financed exclusively by equity. Therefore, the cost of equity is used as a hurdle rate for the choice of IRR. Estimates on the cost of equity is for the sectors shipbuilding and marine (11,8%), oil and gas exploration and production[17] (10,6%) and water utilities[18] (8,3%) (Damodaran, 2023). All estimates are for Western Europe. The target IRR of 15% for shipping and storage projects are somewhat arbitrarily chosen. However, it falls within a range of target IRRs for prospective CCS opportunities assessed by industry practitioners. Additionally, while 15% IRR is lower than the estimated return to equity in the shipping and oil and gas sector, it can be argued that this lower return represents the immaturity of the industry, and will improve if CCS deploys at scale. The lower return of pipelines reflects the typical lower cost of capital faced by pipeline developers and operators (Roussanaly et al., 2014). As the projects are discounted at a real discount rate, the IRRs are real rates of return for consistency. However, the estimates for cost of equity above are nominal values.

Each of the components in the financial model share common economic parameters that have different sources. Table 1 presents the financial model's economic parameters that are shared across the model's components.

[16] Refers to abandonment expenditure, i.e. the cost of decommissioning infrastructure at the end of a project's economic life.
[17] Oil and gas exploration and production firms are similar to storage developers and operators.
[18] Water utilities are assumed to represent the economic return of pipeline developers and operators.

Economic Parameters	Unit	Value
Storage Assessment Period	years	2023-2026
Storage Development Period	years	2027-2029
Shipping Chain Development Period	years	2025-2029
Pipeline Development Period	years	2024-2029
Commercial Operation/Start Date	date	01/01/2030
Cessation of Injection/End Date	date	01/01/2060
Post-injection Monitoring Period	years	2060-2079
Project Economic Lifetime	years	30
Utilisation Rate (average year)	hours/year	8327.7
Discount Rate (real)	%	8
Corporate Tax Rate	%	22
On/offshore Infrastructure DR	%	4
Liquefaction, Loading and DCFO equip. DR	%	10
Ship, Floating Unit and Loading System DR	%	14
Compression and Pumping DR	%	20
Electricity Price (Netherlands)	€/MWh	137.3
Electricity Price (South Norway)	€/MWh	119.2
LNG Price	€/tonne	862.8
NOK/EUR		0.096
GBP/EUR		1.154
USD/EUR		0.957
Cost Year	quarter, year	Q2, 2022

Table 1. Economic parameters in the financial model.

Development refers to the project's construction period. Cost year is Q2, 2022. The corporate tax rate is the statutory rate in Norway (The Norwegian Tax Administration, 2023a) and depreciation rates (DR) are rates for Norway in 2023 (*ibid.*, 2023b). Electricity prices are the daily day-ahead price for the Netherlands and south of Norway on March 1, 2023 (Nord Pool, 2023). LNG price is the Rotterdam bunker price as of March 1, 2023 (Ship and Bunker, 2023). All exchange rates are of July 1, 2023 (European Central Bank, 2023).

I consider three scenarios, each with different total and annual volume of CO_2 transported and stored. This illustrates how the cost of transportation and storage changes as volumes change. The scenarios are called *Phased*, *Normal* and *Accelerated*, transporting and storing 6, 7,2 and 7,5 Mtpa, in 4, 5 and 6 wells respectively.

Even though cost estimates on CO_2 transportation and storage exists in the literature, deeper analysis is not possible on these estimates alone. Therefore, I develop a financial model calculating the cost and tariff of CO_2 transportation and storage, with the possibility of changing transportation distances and volumes. Additionally, this enables the calculation of carbon price breakpoints for assessing the economic viability of CCS across sectors with highest emissions from point sources in Europe.

2.3. Cost Methodology

When presenting the economics of CCS and when developing the financial model, I will use cost estimates from the literature on different parts of the CCS chain. The literature report estimates in several currencies and cost year. In order to assess the current economic viability of CCS, these cost estimates are first inflated to 2022 costs using either the EU27 producer price index, EU 27 PPI (Eurostat, 2023), or the US producer price index for total manufacturing industries, US PPI[19] (U.S. Bureau of Labor Statistics, 2023), for euro and pound-sterling and dollar estimates respectively. Following this, the estimates are all converted to a common currency, euro, using the exchange rate on July 1, 2022. While these inflation indices are broad[20], they closely track an index more relevant for CCS, the Chemical Engineering Plant Cost Index[21] (The University of Manchester, 2023). This approach to handling cost inflation is common in techno-economic analysis from the literature (Leeson et al., 2017; Rubin et al., 2015; Kuramochi et al., 2012).

[19] The resulting monthly index values are averaged to yearly index values used in the thesis.
[20] That they track inflation in sectors not relevant for CCS.
[21] Figure A1.2. in the appendix shows the development in these three indices over a 20-year period, while table A1.2. shows index values for EU27 PPI and US PPI.

3. Carbon Pricing

The following chapter presents the status of carbon prices in Europe. Special emphasis is given to the EU's Emissions Trading System, how it works and recent developments. The outlook for European carbon prices and its implications for CCS is discussed.

Carbon pricing is central for enabling commercial CCS in Europe (GCCSI, 2020b). Carbon prices[22] puts a price on the emissions of greenhouse gases (GHGs), thereby incentivising abatement. The total cost of CCS must be offset by carbon prices for it to be an economically viable abatement option for emitters in "hard-to-abate" sectors. European carbon prices will consist of local carbon taxes and/or the price of emissions allowances in the EU Emissions Trading System (EU ETS). According to the World Bank (2022), most European countries have implemented local carbon taxes for sectors that are not covered by the EU ETS.

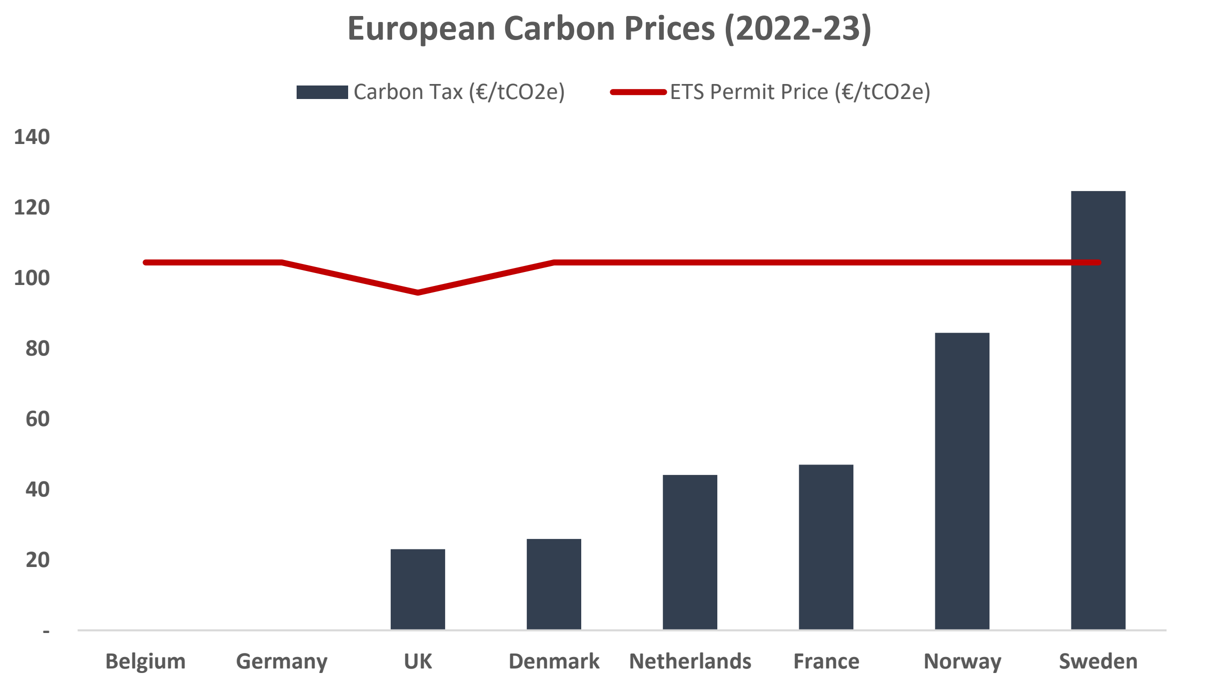

Figure 7. Carbon tax and ETS permit price in countries near the North Sea.

Both carbon taxes and ETS permit prices are levied on a per tonne CO_2-equivalent basis. Converted into euro using the exchange rates specified above. UK ETS price on January 1, 2023: £83.03 (BEIS, 2022), EU ETS price on March 1, 2023: €104,41 (Trading Economics, 2023), carbon taxes from World Bank (2022).

[22] A collective term for any tax, charge or emissions permit levied on carbon-based emissions. Is generally levied on the equivalent global warming potential of one tonne of CO_2, i.e. a CO_2-equivalent (CO_2e) (World Bank, 2022).

Today, the price of emissions allowances is higher than carbon taxes. Generally, carbon taxes cover emissions in non-ETS sectors, and is not added to the emissions allowance price. For CCS, it is the price of emissions allowances that count, as this is the cost incurred by emitters in power and energy-intensive industry, sectors that are included in the EU/UK ETS. Several European countries are planning to gradually increase carbon prices, given ambitious climate action. In the Netherlands, the minimum carbon price in 2030 – for all sectors – will be 125 €/tCO_2e (EC, 2021, p. 39). Denmark plans to implement a green tax reform that will increase the carbon tax for all sectors of the economy (Ministry of Finance, 2021). Norway will increase their carbon tax for some ETS[23] and all non-ETS GHG emissions to a total carbon price of about 193 €/tCO_2e[24] by 2030 (Meld. St. 13 (2020-2021)). Henceforth, carbon price will refer to the emissions allowance price, plus, any carbon tax incurred by the same emitter, unless otherwise stated.

The price of EU ETS emissions allowances (EUAs) is central for a minimum, European carbon price. Prior to the COVID-19 pandemic, EUAs traded around 25 €/tCO_2e (Trading Economics, 2023). So far in 2023, EUAs has not traded below 80 €/tCO_2e and has generally been between 90-100 €/tCO_2e. Forecasts indicate that the EUA price will continue its upward trajectory in the years to come, which further improves the economic outlooks for CCS.

Given the centrality of the EU ETS for European CCS, understanding how the system functions and its likely development is important. The EU ETS is a compulsory carbon market, where emitters are required to hold and surrender emissions allowances for each tonne of verified CO_2e emissions (EC, 2015). Allowances are either auctioned, sold over the counter or provided for free.[25] Overall, roughly 40% of total verified emissions from stationary installations were covered through free allowances in 2021, mostly for industrial installations due to the risk of carbon leakage (EC, 2022, p. 33). Total allowances in circulation each year is reduced over time, capped by the EU's emissions targets.

There are two mechanisms important for the future development in the EUA price, the linear reduction factor (LRF) and the market stability reserve (MSR). The LRF determines the annual

[23] The carbon tax is limited to domestic aviation and oil and gas extraction. The combination of the tax and the EU ETS price will not exceed NOK 2 000 by 2030, unless the EU ETS price alone is higher than this.
[24] Corresponding to NOK 2 000 using the exchange rate specified above. The target carbon tax is measured in fixed 2020 NOK, therefore the nominal carbon tax in 2030 will be higher than this.
[25] Sectors at risk of carbon leakage, i.e. offshore production to countries with less stringent climate policies, have traditionally received allowances for free. Those installations with best-in-class/lowest emissions are also eligible for free allowances (EC, 2022). According to data from the EU transaction log, free allowances amount to between half and three-quarters of total allowances allocated, and covers most industrial process emissions (EEA, 2022).

amounts of allowances in circulation that are fully retired from the system. For the fourth trading period (2021-2030), the LRF is at 2,2% of allowances in circulation (EC, 2022).[26] The MSR is designed to ensure stability of the carbon price signal through increasing or reducing the number of allowances in circulation[27,28]. In the period 2019-2023, 24% of last year's allowances in circulation is placed in the reserve[29] and made unavailable (EC, n.d.[a]). From 2023 onwards, the size of the MSR is capped at last year's total allowances auctioned, the overshooting allowances are fully retired, representing a significant decrease in the size of the MSR. Both mechanisms are designed to fulfil the EU's ambition for the EUA price, i.e. a high and stable carbon price. Naturally, the increased retiring of allowances will – all else equal – result in higher carbon prices, underpinning the more ambitious climate strategy of the EU.

The outlook for carbon prices in Europe appears positive given recent developments. In October 2023, the first phase of the European carbon border adjustment mechanism (CBAM) enters into force (EC, n.d.[b]). This is a tax on the CO_2 emissions from the production of selected imported goods, which makes European producers less sensitive to increases in the carbon price, addressing the issue of carbon leakage.[30] With the lower risk of carbon leakage, free allocation of allowances is planned phased out in the period 2026-2034, which increases the potential market for CCS. The initial phase of the CBAM includes iron and steel, cement and fertiliser production. Further, the maritime sector is planned fully included in the EU ETS by 2027, all of which increase the demand for EUAs (EC, n.d.[a]).

[26] Given more ambitious climate action, the EC have proposed that the LRF be increased to 4,2% (EC, n.d.[a]).
[27] Excess EUAs are removed from the system to prevent steep declines in EUA price, while injection into the system occurs at significantly higher-than-normal EUA prices (EC, 2015).
[28] The MSR was originally created as a long-term measure to address the oversupply of allowances in the market, and became operational in 2019 (EU, 2022, p. 21).
[29] For 2024 and onwards, the regular feeding rate of 12% will be restored.
[30] Among the goods included in the initial phase of the CBAM is cement, iron and steel and fertiliser (EC, n.d.[b]).

4. Economics of CCS

The following sections presents the economics of CCS based on the survey of the topic's literature. Each element of the CCS value chain, i.e. capture, transport and storage, is separately presented. The chapter provides the reader with a deeper understanding of CCS, the industry's economics and existing challenges to commercial deployment. This aids the reader during the later discussion on carbon price breakpoints.

4.1. Economics of CO_2 Capture

CCS offers a viable option for emissions abatement in sectors that have no other abatement pathway currently. This is the case for fossil fuel-based power plants and energy-intensive industry. These sectors emitted more than 40% of Europe's total energy sector emissions in 2019 (IEA, 2020)[31]. While the transition to economies based on renewable energy has begun, fossil fuels could still be the major energy source for decades to come. Additionally, CO_2 emissions from chemical processes in industry, such as the production of clinker for cement, cannot be abated through fuel-switching. Generally, the high heat demand in industry can only viably be supplied by fossil fuels. As carbon prices increase, emitters in the power and industry sectors are considering the cost-saving potential of CO_2 capture for dedicated storage.

The decision to invest in a capture facility for an emitter is based on the cost of avoided CO_2 captured (CAC). This metric warrants an explanation. As capturing CO_2 requires energy, there are often CO_2 emissions from capturing. This energy penalty must be accounted for. CAC is defined as the difference in cost – both capital and operational costs – between a plant with capture and a reference plant without capture (Roussanaly et al., 2021a). The reference plant must be like the plant with capture, both in terms of size and output. This cost difference is further divided by the difference in CO_2 emissions of the reference plant with that of the plant with capture.

[31] European energy sector emissions were 3,9 billion tonnes in 2019, according to the IEA (2020).

$$Cost\ of\ avoided\ CO_2\ captured\ (€/tCO_2)\ =\ \frac{Plant_{capture} - Plant_{ref}}{CO_2\ emissions_{ref} - CO_2\ emissions_{capture}}$$

Where $Plant_{capture}$ and $Plant_{ref}$ refer to the annualised capital and annual operational costs of industrial or power plants with and without capture facility respectively. CO_2 $emissions_{ref}$ and CO_2 $emissions_{capture}$ refer to the annual CO_2 emissions of the reference plant and the plant with capture respectively. Framework for the above function from Roussanaly et al. (2021a). CAC is the per tonne cost of investing and operating a capture facility. As such, it is the metric measured against a carbon price incurred for emitting a tonne of CO_2 rather than capturing it. Current European carbon prices of around 100 €/tCO_2 marks an upper limit for the size of CAC, beyond this threshold, unsubsidised capture is uneconomical. Henceforth, CAC is referred to as the capture cost.

While there exists many different techniques for capturing CO_2, it is beyond the scope of this thesis to cover them all. Instead, the study focuses on explaining the economics surrounding the most common way of capturing CO_2, namely through absorption (Gardarsdottir et al., 2018). Like a sponge, the CO_2 is absorbed into the capture media[32], or solvent. Heat separates/strips the CO_2 from the solvent, which is then recycled. The solvent needs to be cooled and washed in-between use. The captured CO_2 is cooled, and often undergoes compression and pumping to an outlet pressure suitable for pipeline transport. Capture facilities can also have liquefaction plants, which would process the CO_2 fit for shipping rather than pipeline transport (Mirza and Kearns, 2022).

Capturing CO_2 requires special equipment. Total investment cost for capture facilities is estimated to 190-300 M€, when capturing between 0,6-1,6 Mtpa from sources with 13-30% CO_2 concentration – typical concentration for emissions at many industrial plants. The highest cost CAPEX item for a capture facility is generally auxiliary power units and heat exchangers, providing steam which changes temperature, activating and reactivating the solvent that captures the CO_2 (Gardarsdottir et al., 2018). Estimates on heat exchanger capital cost is 80-130 M€. Other large capital cost items are compressors (40-60 M€) as well as absorber, stripper and washer columns (40-60 M€) which are necessary for capturing and separating the CO_2 and for reusing the solvent. These estimates are indicative only for plants with similar output. Larger plants will naturally need larger equipment to process more off-gas for CO_2 capture, resulting

[32] Many different capture media exists, for absorption, chemical solvents are typically used.

in higher capital cost. More CO_2 is captured when capturing from CO_2-rich sources compared to lean sources. This scales capital investment, as larger equipment is necessary, and operational expenditure, as more CO_2 is captured and processed. However, it requires less energy to capture from CO_2-rich emissions, which is reflected in unit cost estimates. Additionally, factors like location, capture rate[33] and underlying technical and economic assumptions of the assessment affect the estimates.

While capital costs are high for capture of CO_2, total capture costs are OPEX-driven and scales with CO_2 concentration. Energy/heat is needed to capture CO_2, which is supplied through steam. The cost of steam generation is typically the dominating cost item in total capture cost (Roussanaly et al., 2021a; Johnsson et al., 2020; Gardarsdottir et al., 2019). Therefore, the way in which steam is generated can have a significant impact on the capture cost. Estimates of steam generation costs from the literature are in the range of 4-125 €/tCO_2, where the use of excess or waste heat is in the lower range of estimates while a dedicated on-site energy plant has the highest costs (Kearns et al., 2021; Gardarsdottir et al., 2018). The energy-intensiveness of CO_2 capture means that costs are sensitive to local energy-market conditions and volatility in energy prices will affect economically optimal output for capture facilities. Both from a climate point-of-view and for the CCS value chain, high and stable capture activity is necessary. The latest period of high energy prices in Europe reflects the need for capture business models to address this sensitivity and to ensure overall economic efficiency. Excess steam could generate electricity for sale to the grid, offsetting the high energy cost. Other large operational cost items include electricity for pumps and compressors, maintenance work (as capture facilities are technically complex) and cooling water (which is vital for the reuse of the capture solvent).

[33] Share of total CO_2 emissions captured.

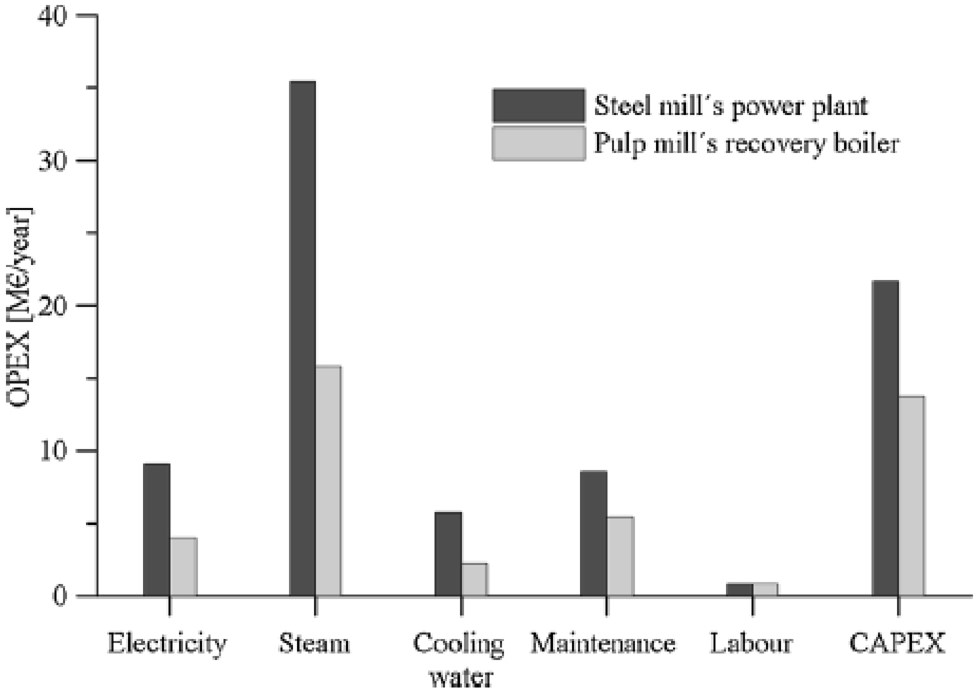

Figure 8. Overview of OPEX items per year and annualised CAPEX of CO_2 capture.

For capture at a steel mill's power plant, with 30% CO_2 concentration, capturing 1,6 Mtpa, and a pulp mill's recovery boiler, with 13% CO_2 concentration, capturing about 0,6 Mtpa. CAPEX annualised at 7,5% discount rate and 25-year economic lifetime. Cost year is 2015 (Gardarsdottir et al., 2018, p. 118).

Figure 8 shows the relative OPEX-intensity of CO_2 capture. Capture from the CO_2-rich source, the steel mill's power plant, has higher OPEX relative to the CO_2-lean source. In sum, total OPEX far exceeds the annualised CAPEX. Unit capture CAPEX, maintenance and labour costs are all reduced with scale, while electricity, steam and cooling water increase with higher activity level. The OPEX-intensity of capture results in a high sensitivity to changing operational conditions, affecting economically optimal output. From both a climate and commercial perspective, high and stable capture rates are preferred. A challenge lies in the construction of business models for capture that provides cost certainty without limiting the upside from favourable operating conditions.

The above example illustrates capture and its costs for a mature technology. It should be noted that no one technology has yet been chosen as the optimal, cost-effective option for CO_2 capture in any application (Kearns et al., 2021). The above example is for a post-combustion capture approach, where the CO_2 is captured after fossil-fuel combustion (Lyons et al., 2021). This process is placed at the end of an industrial or power generation process. As such, the approach is easy to retrofit on existing plants and will generally not have an adverse effect on the manufactured product. Other technologies that are near commercialisation have the potential to significantly reduce capture costs.

Other capture technologies exist, mainly pre-combustion and oxyfuel combustion (*ibid.*). Pre-combustion is the capture of CO_2 before the combustion of fossil fuels. It is harder to retrofit, as it is placed in the beginning of the industrial or power generation process, and the risk of adverse effects on produce is greater. Oxyfuel combustion is the process of burning the fossil fuel in pure oxygen, which creates a synthetic gas of hydrogen and carbon monoxide. After exposure to water, the gas is rich in CO_2, which is then captured. The hydrogen is used to fuel the industrial process. As oxyfuel combustion is at the beginning of the industrial process, it is harder to retrofit. Additionally, specialised equipment designed for burning hydrogen as fuel is necessary, which further makes retrofitting cost-prohibitive. Different capture techniques, i.e. the media used to capture CO_2, also affect the economic performance of capture facilities, contributing to the great variation in capture cost estimates seen in the literature.

Estimates on the capture cost from the literature are summarised in Figure 9. The great variation in capture cost between and within each sector is due to the many technologies and techniques available for capturing CO_2, as well as the differing CO_2 concentration in the emissions from these sources.

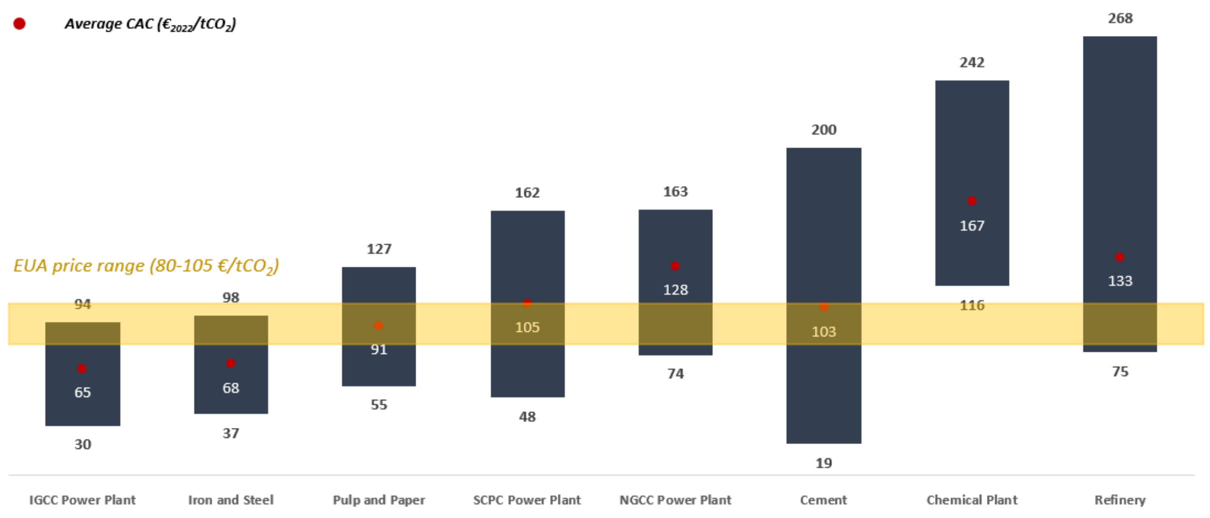

Figure 9. Estimates on cost of avoided CO_2 (CAC) from the literature.

Estimates excludes transport and storage costs. EU emissions allowance (EUA) price range (€/tCO_2) is based on the lowest and highest EUA price so far in 2023[34]. All estimates have first been inflated from reported cost year to 2022, then converted to Euro.[35,36]

Estimates on the cost of capture from the literature vary significantly, both between and within sectors. Additionally, uncertainty in estimates is high because real-life experience of capture facilities is limited. Bearing this in mind, Figure 9 shows that current carbon prices – a simple average of about 90 €/tCO_2 – is too low to incentivise investment in CCS in many sectors. Opportunities can exist in capture from near-pure CO_2, such as natural gas processing and fertiliser production. By one estimate, capture costs from these sources are around 22 €/tCO_2 (GCCSI, 2011). The highest cost estimates for each sector will generally represent capture from CO_2-lean emissions sources and/or using non-optimal capture technologies. Low end estimates represent longer term costs based on still immature technologies, often including the learning cost effect that comes with experience, in addition to capture from CO_2-rich emissions sources. Mean values can be considered to represent use of optimal available technology, capturing from CO_2 emissions sources with higher CO_2 concentrations. There are different kinds of power plants represented in the above figure. An integrated combined cycle (IGCC) power plant can use both coal and natural gas as feedstock. It is generally more expensive than the supercritical pulverised coal (SCPC) and natural gas combined cycle (NGCC) power plants, but have higher purity CO_2 and can easier be retrofitted with CO_2 capture (IEAGHG, 2019).

According to the literature, at least three additional factors influence the CAC estimates. First, the generation of steam is generally the dominating cost item for CO_2 capture (Johnsson et al., 2020; Roussanaly et al., 2021a). How it is generated and at what cost affect economic performance. By one estimate, if using only zero cost waste heat, CO_2 can be captured at one-third the cost, mostly due to the foregone capital cost of new steam generation capacity and the lower steam generation/energy cost. While unrealistic for high capture rates, only using waste heat is achievable for partial CO_2 capture. Second, costs for conditioning and treatment of CO_2 can add more than 20€/tCO_2 to the cost of capture. High-purity, high pressure CO_2 streams fit for transport and storage represent the lower range of this estimate (Kearns et al., 2021; Roussanaly et al., 2021a; Gardarsdottir et al., 2019; IEAGHG, 2017e). Third, the cost of

[34] Trading Economics (2023).

[35] Based on: Diaz-Herrera et al. (2022); Eliasson et al. (2022); Garcia et al. (2022); Santos & Hanak (2022); Gardarsdottir et al. (2019); Onarheim et al. (2017); IEAGHG (2017e; 2016; 2013a; 2013b); Porter et al. (2017); Rubin et al. (2015); Kuramochi et al. (2012); GCCSI (2011).

[36] See Table A1.3. in appendix for all the CAC estimates, capture rates, cost year, inflation factors used and source of estimate.

retrofitting capture facilities is important, especially in a European context. The average age of fossil fuelled power plants and industrial plants in Europe is about 28 and 25 years respectively, with a technical lifetime of 50 years (IEA, 2020, p. 135). In the process of retrofitting, production might seize and cause loss of revenue, adverse effects on product quality and plant operation might occur, spatial constraints – especially in industrial clusters – will further increase installation costs (Rubin et al., 2015; IEAGHG, 2019). Retrofitting also limits the suite of feasible capture technologies, discarding potentially cost-reducing options.

Several developmental aspects could see reduced cost of capture. As mentioned above, optimal steam generation strategies have the potential to drastically reduce costs. Exporting electricity from excess heat generation can improve capture economics (Johnsson et al., 2020; Gardarsdottir et al., 2018), especially when electricity prices are high. Since CO_2 capture is not yet deployed at scale, benefits from standardisation and modularisation of capture facilities have not yet crystallised. Modularisation could lead to shorter construction times, meaning shorter production stops, lower labour costs, lower insurance costs and lower facility costs as original equipment manufacturers can scale production (Kearns et al., 2021). However, standardisation and modularisation of capture facilities can be difficult, because both size and output of industrial/power plants vary.

What does the economics of CO_2 capture imply for the overall economic viability of European CCS? Current carbon prices can enable CO_2 capture from some of the sectors with high point source emissions. Some power plants and steel mills have average capture cost below carbon prices seen in 2023. However, the remaining cost difference after accounting for capture cost leaves little room for transportation and storage costs. Low-cost capture from near-pure CO_2 sources – while not the largest emitting sectors – can help enable the early development of shared CCS infrastructure. This would lower the cost of transport and storage overall. Additionally, the cost structure of CO_2 capture makes it sensitive to changing operational conditions. This can either be addressed through higher carbon prices, ensuring that the higher cost from adverse operational conditions is still offset by the carbon price, or, through tailored business models that manages the potential downsides of capture operations. In the following sections, the economics of CO_2 transport and storage will be analysed, culminating in a more complete view of the economic viability of CCS.

4.2. Economics of CO_2 Transportation

As suitable dedicated storage of CO_2 is generally located at some distance from point of capture, transportation of the CO_2 is necessary. CO_2 can be transported in several ways such as by pipeline, ship, barge, train or truck (IEA, 2022a). Intermediate transport by barge, train or truck to larger CCS infrastructure[37] can be feasible if the alternative is an onshore pipeline through populated areas which lack public support. This thesis focuses on CO_2 transport by pipeline and ship, as these are the main transportation options for large-scale CCS deployment (IEA, 2020).

Commercial transportation of CO_2 exists today. Most of the transport by pipeline takes place in the US for CO_2 used in enhanced hydrocarbon recovery. Pipelines are considered a mature technology (Knoope et al., 2014; Kearns et al., 2021) both because of the extensive network of CO_2 pipelines for EOR in the US and because of the network of high-pressure pipelines for natural gas in the North Sea.[38] As such, development of CO_2 pipeline infrastructure does not face technical barriers. CO_2 shipping is a less mature technology. 3 Mtpa of CO_2 is shipped globally, mostly in relation to the food and beverage industries, with ship capacities of around 2 000 tonnes of CO_2. Shipping of CO_2 at scale, i.e. 10 000 tonnes or more, remains to be demonstrated. Shipping of liquefied petroleum gas (LPG) is closest to the conditions required for shipping CO_2, and re-use is possible with modifications, even though it is not the optimal solution (Orchard et al., 2021; Durusut and Joos, 2018). Strict operating conditions for CO_2 shipping means special ship designs which limits the feasibility of back-hauling[39] a different cargo than CO_2. While some elements of CO_2 shipping are mature[40], large-scale operations and direct unloading offshore are not (Kearns et al., 2021; Orchard et al., 2021; Durusut and Joos, 2018). However, such technology for CO_2 shipping is near commercialisation (Altera Infrastructure, n.d.).

[37] From industrial hubs in Germany to CCS cluster in the Netherlands, using the Rhine-river as transportation pathway (Bellona, 2016).
[38] High-pressure pipelines for natural gas are much like the pipelines required to transport CO_2 (IEA, 2020).
[39] Carrying a cargo on the way back from unloading, as the ship is empty, improving shipping economics.
[40] Due to the activity in the food and beverage industries.

4.2.1. Pipeline Economics

Figure 10. Process steps for CO_2 transportation by pipeline.

As CO_2 arrives at the onshore-offshore transition point, pumping of CO_2 is required for increased pressure suitable for transportation by offshore pipeline. Source: Ansaloni et al. (2020, p. 2).

Many industrial hubs in Northwest Europe are located close to ports with access to the North Sea (IEA, 2020). Le Havre in France, Antwerp in Belgium and Rotterdam in the Netherlands, have combined CO_2 emissions from point sources exceeding 70 Mtpa. Some intermediate transport from point of capture to larger CCS infrastructure connecting to use or dedicated storage will be necessary. One option is onshore pipelines as seen in figure 5. This option can be cheaper than shipping routes (Roussanaly et al., 2013), but may face significant public opposition and high permitting and rights-of-way costs (Roussanaly et al., 2021b; Onyebuchi et al., 2018; Knoope et al., 2014), especially in Europe, making the option infeasible. Generally, onshore pipelines are cheaper than offshore[41], and onshore pipelines through sparsely populated areas are considered the cheapest (Onyebuchi et al., 2018).

[41] Higher labour costs from more complicated construction and larger pipelines contribute to this cost difference.

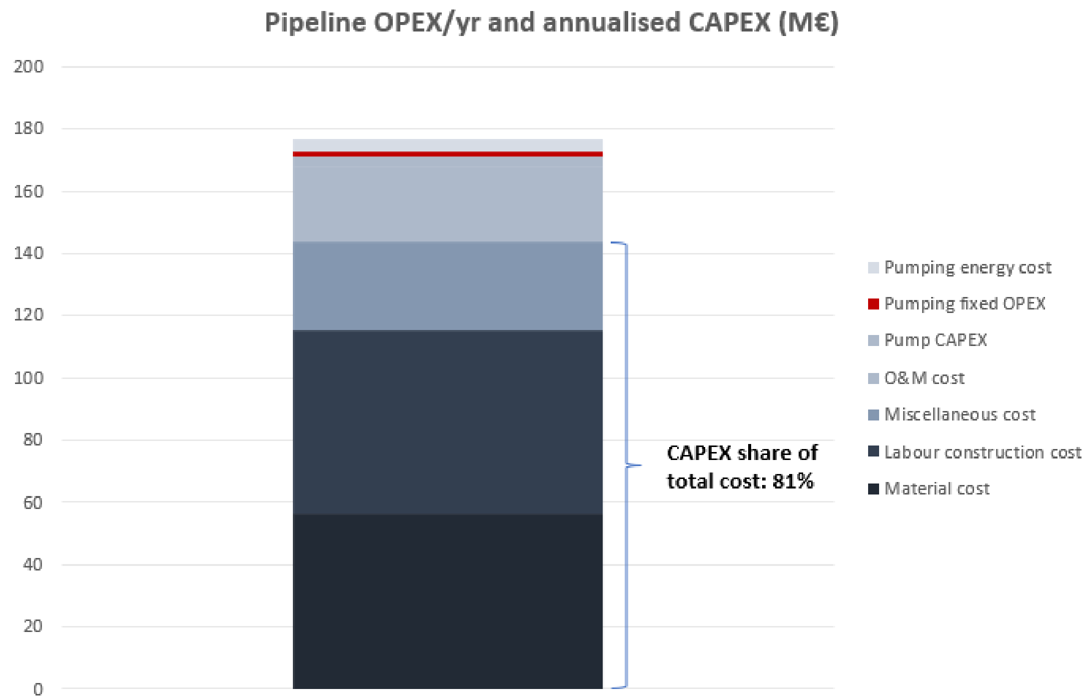

Figure 11. Cost breakdown of an offshore pipeline from the financial model.

The pipeline is 830 km long and transports 7,2 Mtpa. OPEX/yr and annualised CAPEX (8% real discount rate, 30-year pipeline project lifetime), in million euros. Miscellaneous cost is assumed 25% of material and construction cost and covers all non-construction pipeline development costs. CO_2 is assumed pre-pressurised, which means that no compression is needed. Based on Knoope et al. (2014).

The cost breakdown in the above figure, illustrates the capital-intensiveness of pipelines. Total pipeline costs can consist of 90% CAPEX (ZEP, 2011a), with pipeline construction work often the largest share of pipeline CAPEX.[42] Naturally, pipeline capital cost increases with distance. Halving the distance of the pipeline as illustrated above reduces total lifetime costs[43] from less than €3,7 billion to just below €1,7 billion. The large share of capital costs in total pipeline costs means that pipeline economics exhibit considerable economies of scale as volumes transported increase (see Figure 12 below). The high investment cost and inflexibility of pipelines make them an unattractive option for early investors in CCS, as volumes are uncertain.

An important assumption in transportation costs is the condition of CO_2 ex ante transport. Cost-effective pipeline transport happens at high CO_2 pressures. To put it simply, CO_2 can either be

[42] Labour construction cost for offshore pipelines is estimated at 845 €/m^2, with a standard deviation of about 50%, i.e. significant uncertainty in estimate (Knoope et al., 2014). Through industry consultation, a labour construction cost one-third the size has been determined as reasonable. Once applied, results of the pipeline model match better the cost estimates found in the literature after accounting for inflation.
[43] Total CAPEX and OPEX.

pre-pressurised or non-pressurised. If pre-pressurised, the CO_2 can be pumped rather than compressed to a pressure necessary for offshore transport.[44] As the required energy for pumping is about 5% that of compression and capital costs are far lower, pre-pressurised CO_2 lowers transportation costs significantly (Knoope et al., 2014; McCollum and Ogden, 2006). When non-pressurised, the CO_2 must first be compressed to high pressure, and then pumped to offshore pipeline pressure. Estimates suggests that compression can add an additional 16 €/tCO_2[45] to unit transportation costs (Knoope et al., 2014). When CO_2 is non-pressurised, the annual cost in Figure 11 increases to around 300 M€. Also, impurities in the CO_2 can add an additional 9 €/tCO_2 from impurity removal[46] to unit transportation costs (Roussanaly et al., 2021b; Deng et al., 2019). The assumption of pre-pressurised CO_2 for transport is a realistic one, as compressors are typically included in capture facilities (Mirza and Kearns, 2022; Knoope et al., 2013).

[44] Pumping requires about ~5% the energy input of compressors (Knoope et al., 2014; McCollum and Ogden, 2006).

[45] This estimate includes the annualised capital cost, O&M, and energy cost of compression.

[46] A necessary step in order to prevent corrosive acids forming that damage transport and storage infrastructure (Rackley, 2010).

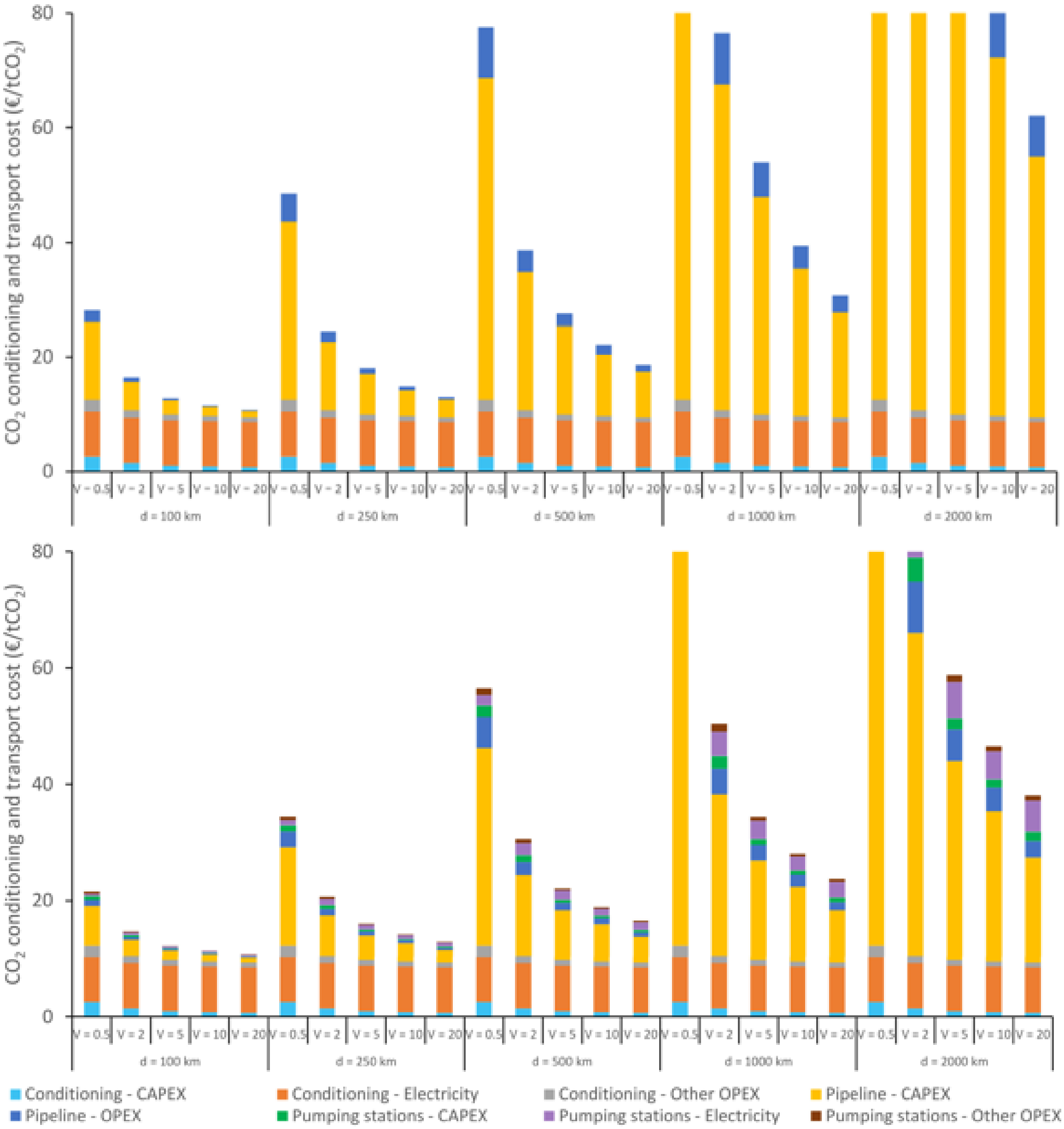

Figure 12. Cost breakdown of pure CO_2 conditioning and transport cost (€$_{2017}$/tCO_2).

Mass flow rate (V) in million tonnes per annum and distance (d) for offshore pipelines (top) and onshore pipelines (bottom). Y-axis is capped at 80 €/tCO_2, not fully displaying all the cost breakdowns. CO_2 is assumed non-pressurised. Source: Roussanaly et al. (2021b, p. 24-25).

Figure 12 shows a cost breakdown of onshore and offshore conditioning and transportation of pure CO_2 for different volumes[47] and distances. Pipelines over distances exceeding 1 000 km will need larger volumes than 20 Mtpa if unit economics are to be cost-competitive with

[47] Volume refers to mass flow rate, i.e. the amount of CO_2 transported, in this thesis. Volume is a misnomer, but chosen to avoid too technical speech.

shipping. For onshore pipelines, pumping stations for each 100-200 km keeps the CO_2 at high pressures throughout pipeline transport.[48] The high CAPEX share of pipeline costs results in a sensitivity to changes in the availability of the pipeline. Halving the availability is estimated to double the unit cost, while a gradual ramp-up of availability/volume transported over a 10-year period can increase unit costs by 35-50% (ZEP, 2011a). This underlines the importance of certainty in volumes when pipeline is the chosen transportation option, which makes pipelines a challenging option for early CCS deployment.

Repurposing existing pipeline infrastructure for CO_2 transport can offer a substantial cost reduction. By one estimate, repurposing can be as low as 1-10% the cost of constructing new CO_2 pipelines (IEA, 2020). There are 850 pipelines, with a combined 7 500 km in the North Sea that are scheduled for decommissioning over the next decade and repurposing could defer decommissioning costs of 1 billion GBP. However, not all natural gas pipelines are fit for repurposing. Pipelines transporting CO_2 must be built for handling the higher operating pressure and be within range of suitable storage (Knoope et al., 2014).

The transportation distance required to reach suitable offshore storage is a central factor for the economic viability of CCS. The CO_2 can be captured in Northwest Europe, around the Netherlands, Belgium and West-Germany, an area with more than 80 Mtpa of stationary CO_2 emissions from industrial hubs (IEA, 2020). If captured from industrial hubs in West-Germany, a transportation distance of up to 400 km by river or onshore is necessary to reach Rotterdam, the assumed onshore-offshore connection point, as seen in Figure 13 below. Figure 12 indicates a unit transportation cost of around 15-25 €/tCO_2 for onshore pipelines at this distance, transporting more than 5 Mtpa. The grey lines in Figure 13, extending from shore outwards to the North Sea indicate the boundaries for each country's continental shelf. With an average shipping distance of 400 km from Rotterdam, storage sites on the UK continental shelf can be accessed. Beyond 400 km transportation distance, the Danish and Norwegian continental shelfs can be reached. Projects with storage sites closer to the CO_2 source will usually have lower transportation costs and can be a determining factor for storage asset development in the North Sea. However, the proposed scale of CCS in Europe suggests that storage development on all continental shelfs will be necessary (EC, 2023).

[48] Pumping stations offshore are considered cost prohibitive as power from shore or offshore installation is necessary, rather designing larger pipelines (Knoope et al., 2014; Roussanaly et al., 2021b).

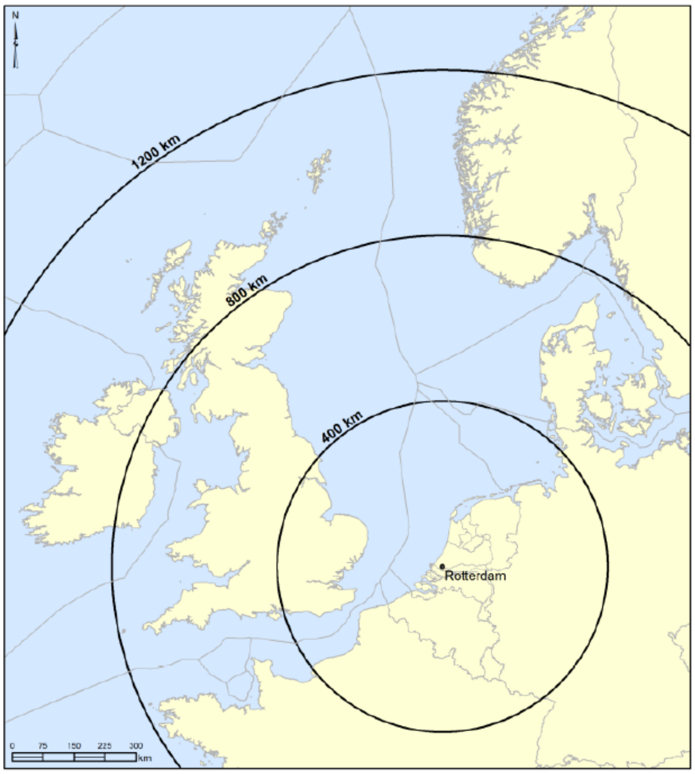

Figure 13. Transportation distance from Rotterdam.

Source: industry consultations.

The early commercial deployment of CCS is influenced by the uncertainty in volumes for transport and storage. While the EU has a goal of 50 Mtpa CO_2 injected for dedicated storage by 2030 (EC, 2023), this is likely insufficient to incentivise investments in pipeline infrastructure. Proof of volumes are likely needed given the high investment cost and financial risk of pipelines. Therefore, early phase CCS projects will feature CO_2 shipping more often than pipelines, even though there are commercial examples of both (Porthos, 2023; Northern Lights, n.d.). For projects with high (more than 5 Mtpa) and certain volumes, and with shorter distance to storage, pipelines are generally the cost-effective transportation option.

4.2.2. Shipping Economics

Even though shipping is less mature than pipeline transport of CO_2, it can be an economically viable transportation option. As seen above, over longer distances, pipelines become cost-prohibitive. Shipping is less sensitive to both distance and volume and offers greater flexibility than pipelines. Overall, shipping has higher value proposition for CO_2 transportation, especially during early commercial deployment.

Figure 14. Process steps for CO_2 shipping, for the option of unloading directly offshore.

Source: Ansaloni et al. (2020, p. 2).

As seen in the above figure, shipping of CO_2 involves several steps. Upon arrival to the harbour, the CO_2 is first liquified through refrigeration and compression for cost-efficient further transport. It is then temporarily stored, bridging the gap between continuous CO_2 capture and batchwise loading to ship. Loaded onto ships, the CO_2 is then transported for unloading either onshore, for further transport by pipeline or directly offshore to a storage site. The literature considers unloading offshore options to be via a floating unit, both with and without temporary storage (Orchard et al., 2021; Durusut and Joos, 2018). This floating unit is connected to the wellhead on the seabed via a loading system[49]. Heating and pumping of CO_2 is necessary prior to CO_2 injection into storage site. The shipping of CO_2 requires dedicated facilities and equipment, a shipping chain. Early deployment of commercial CCS, includes the cost of developing this shipping chain.

Two options for ship design of CO_2 transport at scale is considered today, low transport pressure and medium transport pressure. Medium pressure ships are limited to a capacity of about 10 $ktCO_2$[50] (Roussanaly et al., 2021b; Durusut and Joos, 2018; de Kler et al., 2016), while low pressure ships do not face the same limitation and have been technically proven for capacities of 50 $ktCO_2$ (Roussanaly et al., 2021b). Low pressure ship designs have the potential to reduce transport costs by more than 30% compared to medium pressure, but designs are immature and its reliability and safety remains to be demonstrated. As such, medium pressure ships are used in early deployment of CCS (Northern Lights, 2022), but low transport pressure designs are forthcoming (Altera Infrastructure, n.d.). For CCS projects transporting and storing several

[49] Picture a squid with tentacles reaching down to the wellhead.
[50] 10 000 tonnes of CO_2, actual limitation is about 10 000 m^3, then capacity in tonnes depends on CO_2 density.

million tonnes per year, medium pressure shipping is generally uneconomical at greater distances given the large fleet size necessary to move the same volume.

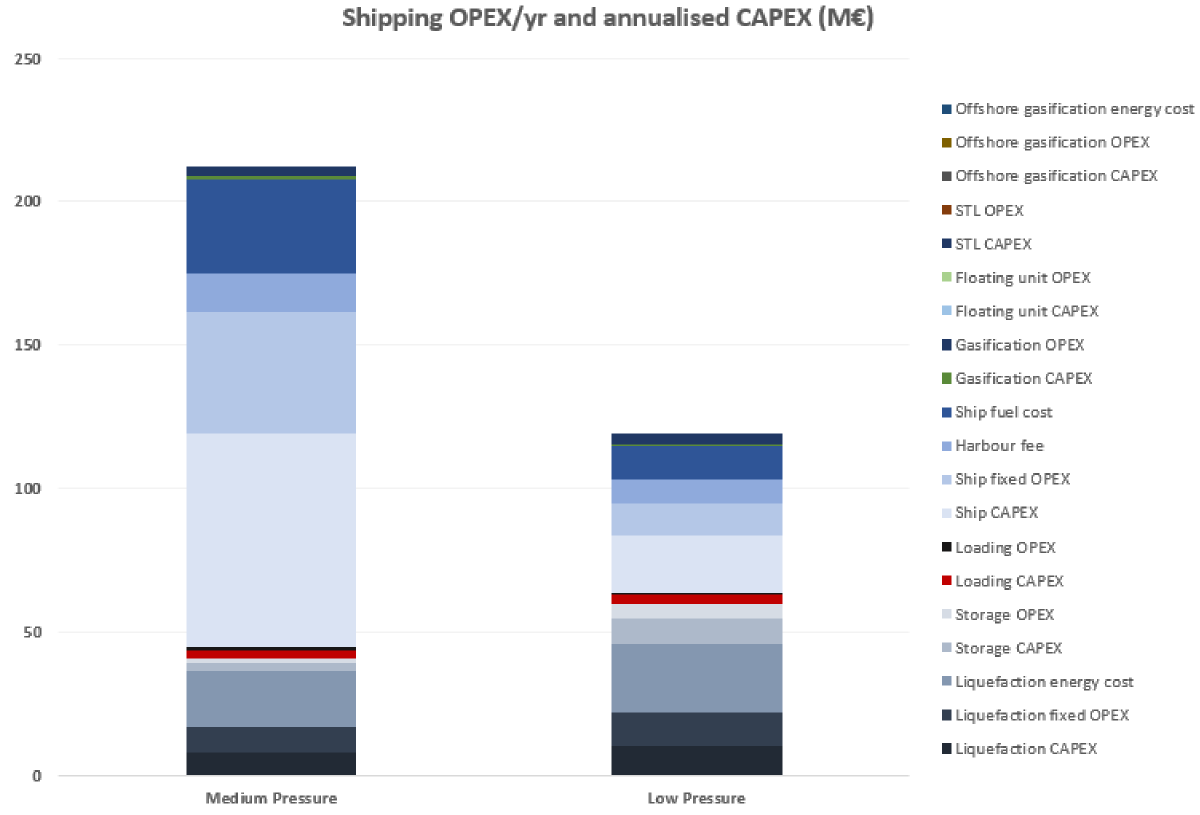

Figure 15. Cost breakdowns of CO_2 shipping chains at different transport pressures (M€).

Annual OPEX and annualised CAPEX (8% real discount rate and 30-year project lifetime) for CO_2 shipping of 7,2 Mtpa over 830 km distance, with onshore unloading, assuming pre-pressurised CO_2. Based on Durusut and Joos (2018).

The above figure illustrates the benefit of low transport pressure shipping on costs. The fleet size for medium pressure shipping is nine vessels at 10 ktCO_2 each. Low pressure shipping transports the same amount with two vessels at 50 ktCO_2 each, leading to significantly lower ship CAPEX, fixed OPEX and fuel cost. Liquefaction CAPEX and energy cost are higher for low pressure shipping[51], as is temporary storage costs, as this is based on ship capacity. Overall, low transport pressure shipping of CO_2 lowers the annual cost of the shipping chain by more than 40% compared to medium pressure shipping. The cost breakdown above would be dominated by liquefaction energy cost if CO_2 where non-pressurised prior to liquefaction[52], as

[51] This is because of lower temperatures, -50°C compared to -20°C for medium pressure (Roussanaly et al., 2021b).
[52] When arriving for liquefaction by onshore pipeline, CO_2 is usually pre-pressurised (Durusut and Joos, 2018).

can be seen in Figure 15, with a fourfold increase in necessary energy input (Durusut and Joos, 2018).

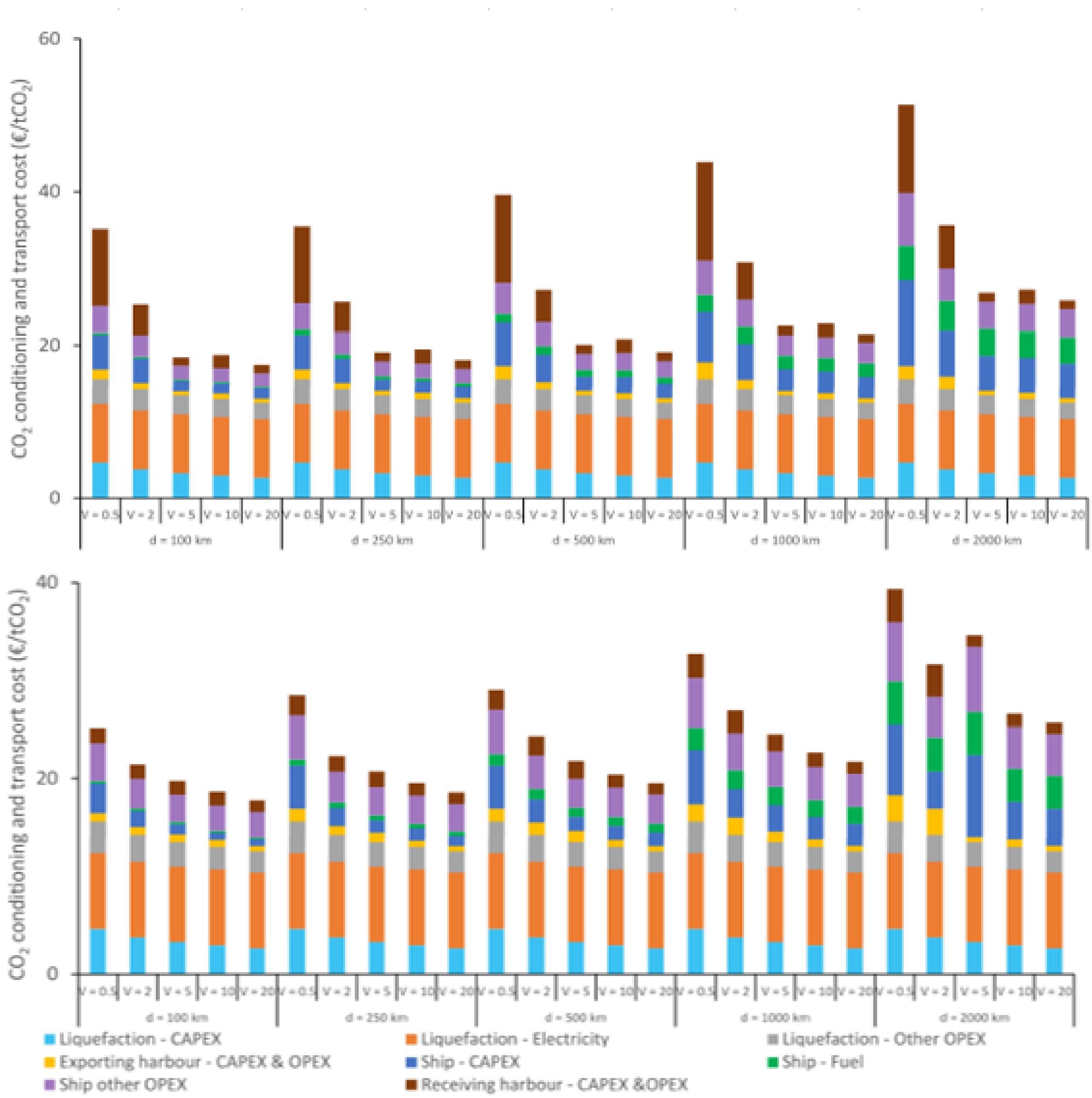

Figure 16. Cost breakdown of pure CO_2 conditioning and transport cost (€$_{2017}$/tCO_2).

Mass flow rate (V) in Mtpa and distance (d), for low transport pressure shipping with onshore unloading (top) and unloading to an offshore site (bottom). Unit cost is calculated as annualised CAPEX with real discount rate of 8% and 25-year project lifetime, plus, annual OPEX, divided by annual CO_2 volume transported. CO_2 is non-pressurised. Source: Roussanaly et al. (2021b, pp. 23 and 25).

Figure 16 above shows the comparatively lower sensitivity to both distance and volume for CO_2 shipping versus that of pipelines. Unit shipping costs at scale – 5 Mtpa and higher – are in the range of 20-30 €$_{2017}$/tCO_2 for both onshore and offshore unloading, regardless of distance.

Sensitivity estimates from the literature are ambiguous in their results. One study finds that shipping costs are most sensitive to changes in OPEX, with a 50% change resulting in +/-35% change in costs (ZEP, 2011a), while others find that changes in distance is the most important (Durusut and Joos, 2018). Generally, CO_2 shipping is a cost-effective transportation option for longer distances and smaller volumes (Orchard et al., 2021; Roussanaly et al., 2021a; Durusut and Joos, 2018; ZEP, 2011a), ideal for transporting demonstration scale capture volumes to more distant storage sites, as well as being cost-competitive when transporting larger volumes, given low transport pressure ship designs.

4.2.3. Pipeline versus Shipping

As shown above, large volumes over short distances favour pipelines as the cost-effective transportation option. Shipping of CO_2 is less sensitive to both volume and distance, and at a certain distance, the unit cost of shipping and pipeline breaks even. Being capital-intensive, pipelines are naturally sensitive to cost-overruns in CAPEX and changes in the discount rate, as pipeline construction can stretch over the better-half of a decade (Roussanaly et al., 2014). Increases in these factors will decrease the breakeven distance in which shipping is the cost-effective transportation option. Factors affecting OPEX items, like the utilisation rate, project duration and energy prices, are more important for shipping economics, and adverse change will naturally expand the distances at which pipelines are cost-effective.

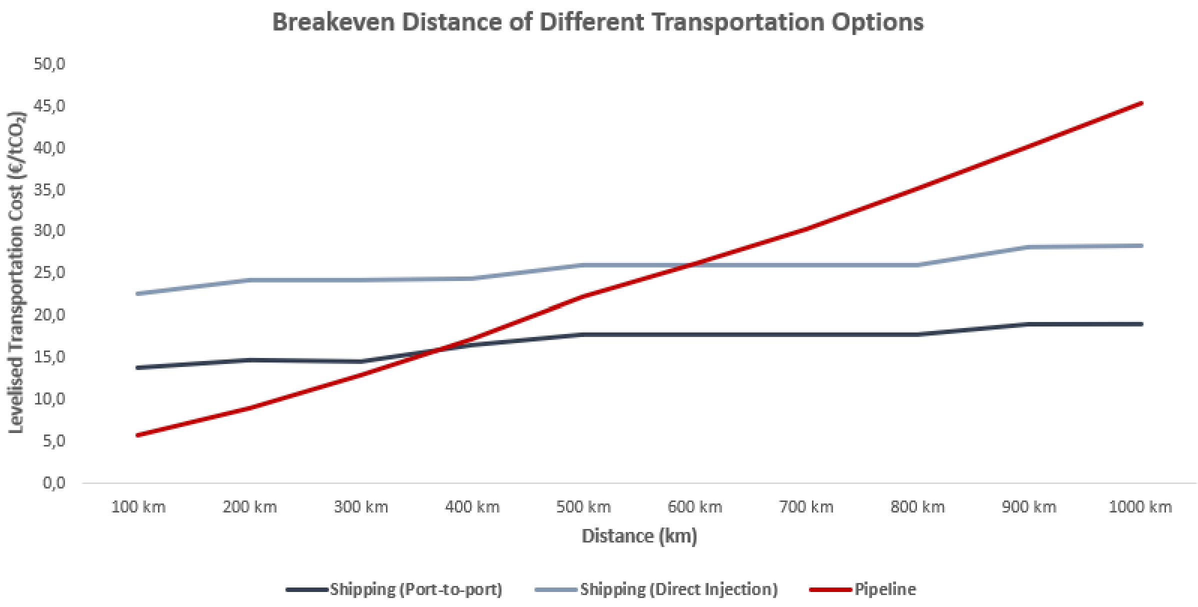

Figure 17. Breakeven distance of pipeline versus shipping.

Comparing unit costs of shipping with onshore unloading, with offshore unloading and pipeline. Transporting 7,2 Mtpa, assuming pre-pressurised CO_2 and low transport pressure. Levelised transportation cost (€/tCO_2), PV of CAPEX and OPEX, divided by the PV of total transported volume, at 8% real discount rate over 30-year project lifetime.[53]

The above figure shows the estimated breakeven distance for shipping versus pipeline and is based on the CO_2 transportation and storage financial model built for this study. According to Figure 17, shipping with onshore unloading (port-to-port) is the cost-effective transportation option at distances greater than 400 km, when transporting 7,2 Mtpa. In the case of offshore unloading (direct injection), pipelines remain the cost-effective transportation option up to 600 km. Assuming Rotterdam as the CO_2 source, a breakeven distance of about 400 km would make shipping the cost-effective transportation option for storage sites on the Danish (400-600 km) and Norwegian (600 km and longer) continental shelves. In early commercial deployment of CCS, shipping can still represent higher value proposition for investors at distances shorter than the breakeven. Compared to pipelines, shipping has lower upfront investments, shorter construction time, increased flexibility (both in scaling capacity and choice of route) and opportunities for co-utilisation (Roussanaly et al., 2021a). These factors contribute to lowering the risks of stranded assets and makes shipping a more attractive option for early investors in CCS. While most of European CO_2 emissions from point sources are centralised around industrial hubs – where large CO_2 volumes improves the investment case for pipelines – a non-negligible share of point source emissions are small and dispersed (IEA, 2020). Such CO_2 sources are generally unsuited for pipeline transport, but shipping can connect these sources to storage cost-effectively.

Despite the apparent benefits of CO_2 shipping, from a regulatory perspective, only pipelines have been considered as CO_2 transportation option in Europe, and been eligible for funding from the EU (ZEP, 2020). However, this should change in order to achieve successful early deployment of commercial CCS. With the inclusion of the maritime sector in the EU ETS, both shipping and pipelines will likely be considered equally important for enabling European CCS (ZEP/CCSA, 2022). CCS projects are likely to feature a combination of both shipping and pipeline transport, based on the experience of early project assessments and proposed future

[53] Based on Durusut and Joos (2018), Knoope et al. (2014), McCollum and Ogden (2006) and industry consultations.

infrastructure solutions (Equinor, 2022). Longer term CCS transport infrastructure development in Europe, will likely be based on a hubs and clusters approach (IEA, 2020). This realises economies of scale in shared infrastructure elements, such as harbour areas with open-source liquefaction and compression equipment, as well as large-scale pipelines/trunklines that can connect large CO_2 volumes with multiple storage sites in the North Sea, which will lower unit transportation costs.

What does the economics of CO_2 transportation imply for the economic viability of European CCS? The necessary transportation distance to reach suitable storage is a key determinant for the size of transportation costs. However, distance is less important for CO_2 shipping. The flexibility provided by shipping versus pipeline suggests that the former be the preferred mode of transport in early commercial CCS development, especially considering the uncertainty in early volumes. This has implications for storage site development in the North Sea as well. With distance being less of a cost driver, storage sites can be developed on all continental shelves and still offer cost-competitive transport and storage services. Cost estimates from the literature and the financial model suggests unit shipping costs at scale between 20-30 €/tCO_2 regardless of distance. In the following section, the economics of CO_2 storage is explored, which will provide a more complete view of the economics of CCS.

4.3. Economics of CO_2 Storage

Storage sites are an integral part of CCS infrastructure, and crucial for the role of CCS as a climate change mitigation strategy. There is ample geological storage capacity in Europe with capacity estimates of around 300 billion tonnes, in which half is offshore, most in the North Sea (IEA, 2020). The IEA estimates that around 19% of all CO_2 emissions from industrial point sources in Europe are within 100 km of suitable offshore storage (IEA, 2020). This corresponds to roughly 150 Mtpa, distributed on oil refineries (25%), chemical plants (20%), power plants (19%), iron and steel (17%) and cement plants (10%). In comparison, the share of CO_2 emissions within 100 km of suitable onshore storage is estimated to be 68%. However, the prohibition of onshore CO_2 storage in many European countries – coupled with the lack of public support – means that early phase storage will mostly be offshore (Roussanaly et al., 2021a; Rubin et al., 2015; Shogenova et al., 2014). This thesis focuses primarily on offshore storage. Currently, about 1,5 Mtpa of CO_2 is injected for dedicated storage in the North Sea and the Barents Sea[54], and operations stretch back nearly three decades (GCCSI, n.d.). For this reason, storage of CO_2 – in certain types of reservoirs – are considered mature. While projects for dedicated storage of CO_2 in Europe is gaining momentum (Reuters, 2023), regulatory uncertainty regarding development and operations of storage sites prevail (ZEP, 2022).

Most of the estimated 140 billion tonnes of offshore storage capacity in Europe is in the North Sea (IEA, 2020). The largest potential storage formation in Europe is the Utsira formation on the Norwegian continental shelf (NCS) with an estimated capacity of 16 billion tonnes. An additional 40 billion tonnes of potential storage capacity exist on the NCS. The UK's estimated storage capacity of 78 billion tonnes is also mostly offshore. Germany and the Netherlands have estimated storage capacities of 20 and 3 billion tonnes respectively. Most of Germany's storage capacity is offshore in the North Sea, while the Netherlands has 1,2 billion tonnes of estimated offshore storage, primarily in depleted oil and gas fields.

After CO_2 has been transported to offshore storage site, it is injected into a geological reservoir for long-term/permanent storage. Different storage types exist but the most mature forms of storage are in saline aquifer systems and depleted oil and gas fields (IEA, 2022b). Saline aquifer systems, or SAs, are geological reservoirs that have never held hydrocarbons, but are usually

[54] 0,85 Mtpa at the Sleipner Field since 1996 and 0,7 Mtpa at the Snøhvit area in the Barents Sea since 2008 (GCCSI, n.d.).

filled with salty water, or brine. Depleted oil and gas fields, or DOGFs, on the other hand, contains unrecoverable amounts of hydrocarbons, but can have ample CO_2 storage capacity. As DOGFs contain hydrocarbons, the existence of a necessary trapping mechanism for CO_2 storage is verified[55]. According to the literature, this information advantage is a key benefit of storage development in DOGFs versus SAs, as expensive data acquisition on reservoir properties can be avoided. Reuse of existing infrastructure in DOGFs can represent cost-saving opportunities, but experience so far has mixed results. Issues around the integrity of storage in DOGFs, e.g., whether abandoned wells are properly sealed, can make pre-existing infrastructure a mixed blessing.

Over time, the risk of leakage from storage will generally reduce (Pale Blue Dot, 2016; IEA, 2022b). Multiple mechanisms in the reservoir prevent the CO_2 from escaping storage. After injection, the CO_2 will move upwards, because it is buoyant, until it reaches the caprock which provides horizontal containment. If the storage reservoir is laterally contained, the CO_2 is trapped permanently.[56] As the CO_2 plume moves through the reservoir, with a speed of about 10 meters per year, the plume itself becomes ever smaller, as chunks of CO_2 are left behind, and will eventually dissolve. Reacting with the brine, the heavier combination sinks to the bottom of the reservoir. In geological timeframes, i.e. thousands to millions of years, the CO_2 will react with minerals in the reservoir, eventually becoming part of the rock itself.

Good and economically valuable storage sites are determined by reservoir properties. Storage capacity and at what rate CO_2 can be injected naturally contribute to economic value. Both are affected by central factors such as the ease in which CO_2 flows through the reservoir and away from injection point, i.e. reservoir permeability, and how much of the reservoir that can be used for storage, i.e. reservoir porosity (IEA, 2022b). As CO_2 is injected, the pressure in the reservoir increases. This increase must be within the pressure difference between the pre-injection reservoir pressure and the fracture pressure, i.e. the pressure at which the seal/cap rock of the reservoir fractures, resulting in increased risk of vertical leakage. These three factors, permeability, porosity and pressure difference, are central to a storage sites economic value and will vary both between and within storage sites. Additionally, the containment of the reservoir can be lateral as well as horizontal. Such a closed system will experience a decreasing injection rate over time as pressures increase markedly over the injection period. If open, the reservoir will not experience this same pressure increase and injection rates can be high and stable over

[55] Since the reservoir has trapped hydrocarbons for millions of years.
[56] If the storage reservoir is both horizontally and laterally contained, the CO_2 is fully trapped like in a closed box.

a prolonged time. The drawback from open systems is that the area of monitoring of the CO_2 plume can be much larger compared to closed systems, driving operational expenditure. Experience from CO_2 injection in the North Sea also suggests the necessity of water producing/extracting wells and other reservoir interventions to maintain injection rates over time, further increases storage costs (IEA, 2022b; Anderson, 2017).

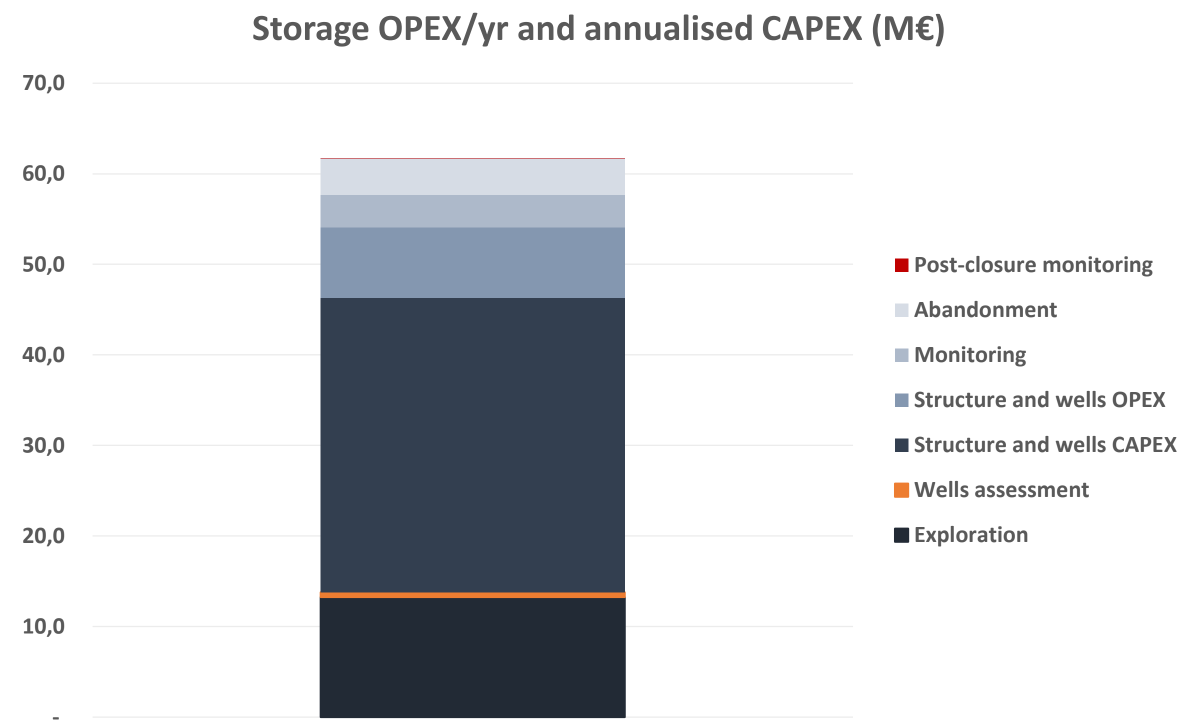

Figure 18. Cost breakdown of CO_2 storage (M€).

Cost breakdown for annual costs of CO_2 storage in a saline aquifer system (M€). With 7,2 Mtpa injection rate over 30-year injection period, storing 216 $MtCO_2$. Annual OPEX and annualised CAPEX (8% real discount rate, 56-year project lifetime).[57]

Figure 18 shows the cost breakdown of annual OPEX and annualised CAPEX of CO_2 storage development and operations, as estimated in the storage financial model developed for this study. Storage site is in an area of the North Sea that is well developed for oil and gas production, and data on the storage site reservoir properties is pre-existing, which explains why exploration costs are lower than found in the literature for storage in saline aquifer systems. Still, some exploration is assumed necessary, both for determining storage safety and for increasing certainty in economic value. Storage CAPEX is the dominating cost item, which is

[57] Cost breakdown from the storage component of the thesis' financial model, based on industry consultations.

expected given that the numbers represent an early assessment of storage economics.[58] The size and certainty of OPEX items will change as more data on reservoir properties are gathered.

The literature on CCS have mostly focused on CO_2 capture, and in later years, on CO_2 transport.[59] Cost estimates and economic assessments of CO_2 storage are scarce due to limited real experience and results exhibit high uncertainty. ZEP (2011b) did a bottom-up study of the economics of CO_2 storage in a European context and Pale Blue Dot, in collaboration with other organisations, did a detailed assessment of CO_2 storage potential in different reservoirs on the UK continental shelf (UKCS), including cost estimates (Pale Blue Dot, 2016).

Storage Type	5 Mtpa, 200 Mt	2 Mtpa, 66 Mt	1 Mtpa, 40 Mt
Onshore - DOGF - legacy	1,5	4,6	10,6
Onshore - DOGF - no legacy	1,5	6,1	15,2
Onshore - SA - no legacy	3,0	7,6	18,2
Offshore - DOGF - legacy	3,0	9,1	13,7
Offshore - DOGF - no legacy	4,6	15,2	21,3
Offshore - SA - no legacy	9,1	21,3	30,4

Table 2. Cost estimates for CO_2 storage in different storage types (€$_{2022}$/tCO_2).

Cost estimates for CO_2 storage in different storage types (€$_{2022}$/tCO_2). Calculated as annualised CAPEX and annual OPEX, divided by annual stored volume. Storage over 40 years at 8% discount rate. For a nth-of-a-kind commercial storage project. DOGF refers to depleted oil and gas field, while SA is saline aquifer. Legacy refers to pre-existing infrastructure. Results from ZEP (2011b).

The above table presents the results of the cost analysis of CO_2 storage from ZEP (2011b). It is evident that onshore storage is cheaper than offshore, and storage in DOGFs are cheaper than storage in SAs. The unit costs exhibit economies of scale as storage capacity and injectivity increases. While the results do not capture the variability in storage costs caused by the heterogeneity in storage sites, the general characteristics mentioned above will typically be true for storage costs. Compared to other storage cost estimates in the literature, the results from ZEP (2011b) appears underestimated. However, as both the development and operational characteristics of storage sites vary on a project-by-project basis, the results cannot be fully discarded. Additionally, estimates in the above table represent mature storage projects.

[58] Much of storage infrastructure is identical to that needed for oil and gas production. CAPEX estimates are therefore more certain.
[59] Much of the earlier literature on CCS treated transport and storage costs as a lump sum, often of \$10/tCO_2 transported and stored (Smith et al., 2021).

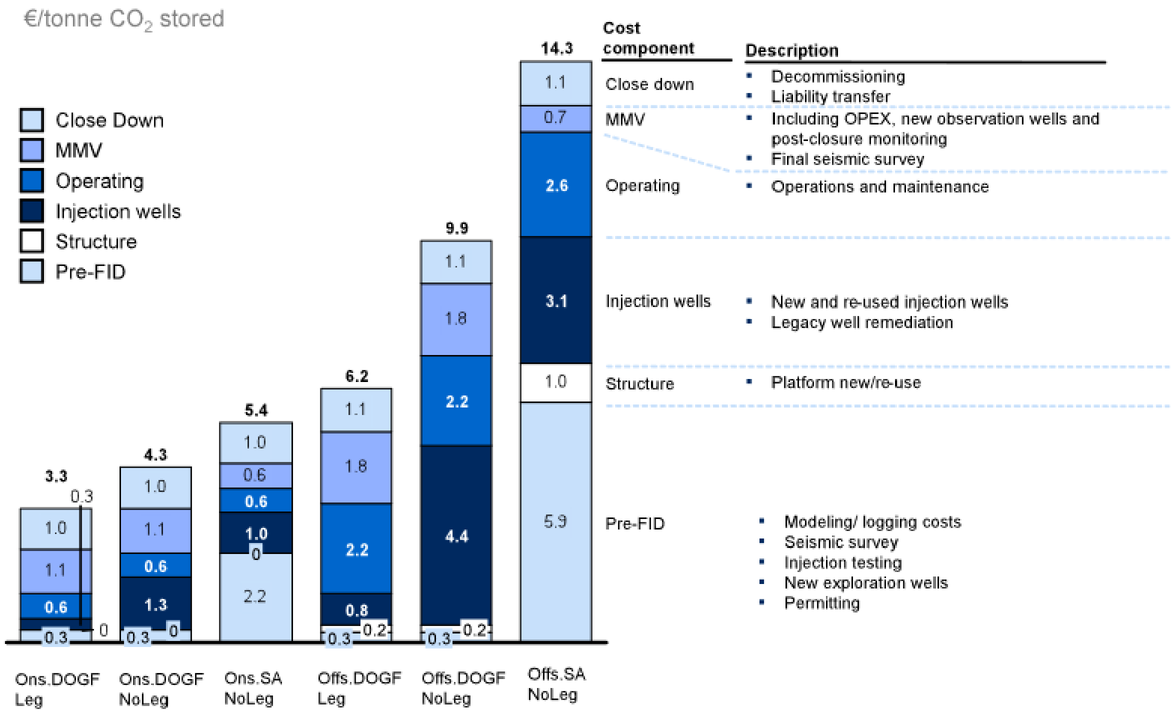

Figure 19. Cost breakdown and categorisation of CO_2 storage (€$_{2009}$/tCO_2).

For storage over 40 years, storing 2 Mtpa. "Ons. DOGF Leg": onshore storage in depleted oil and gas field with reuse of legacy infrastructure; "Offs. SA NoLeg": offshore storage in saline aquifer with no reusable legacy infrastructure. "MMV": measuring, monitoring, verification. Source: ZEP (2011b, p. 27).

The cost breakdown above illustrates the different cost-drivers in CO_2 storage projects and how they vary based on storage type. The costs in an assessment phase can be significant. If no prior data on the reservoir exists, the developer must ensure viability and safety of storage through seismic surveys and drilling of exploration/appraisal wells, gaining insight into the reservoirs geological and geophysical properties. Any legacy wells must be assessed for containment risk. Assuming positive outcomes from this stage, a final investment decision is taken and construction can begin. Storage development includes large capital investment. Operational expenditure will vary by the extent of both monitoring and intervention[60] activities necessary, which are uncertain prior to injection at scale.[61] Decommissioning of the site is costly, and is followed by 20 years of monitoring. An eventual handover of storage liability and ownership to the government will require payment for continued monitoring and any other costs necessary to ensure CO_2 confinement in storage.

[60] To maintain or improve injection rates.
[61] Reservoir properties can change as CO_2 is injected into storage reservoir at scale.

To illustrate the characteristics of storage site development, I will present one of the proposed developments in the storage appraisal project on the UKCS. The *Forties 5, site 1*, is a saline aquifer system off the coast of East-Scotland (Pale Blue Dot, 2016). The site has an estimated storage capacity of 300 MtCO_2 and an average annual injection rate of 7,5 Mtpa. Both 3D seismic and an appraisal well is considered necessary for further reservoir data on possible lateral containment and to determine optimal development well placement, all before final investment decision is made. Additionally, the existence of legacy wells from earlier oil and gas exploration poses containment risk, and will need to be assessed. The proposed development is phased in two stages. The first stage features the construction of an unmanned platform topside, i.e. above sea, with 4 injection wells and an additional well as back-up for operational robustness. The first stage is for 10 years, injecting 6 Mtpa. The second stage of development features a subsea template – on the seabed – tied back via 25 km pipeline to the unmanned platform, with an additional 4 injection wells, now injecting 8 Mtpa. After 20 years of operations, it has been conservatively estimated that the initial injection wells must be fully replaced. Saline aquifers typically have low storage efficiency[62]. For the *Forties 5, site 1*, storage efficiency is low at 6% and further development of the site, realising higher storage efficiency, presents potential upside. Further upside potential exists in developing nearby sites for storage, or storage in deeper reservoirs, reusing existing infrastructure. The storage site is connected to shore via a 217 km pipeline. Total undiscounted lifecycle costs are estimated to be 4,8 billion $€_{2022}$ and the levelised unit cost of transport and storage[63] is 29,4 $€_{2022}$/tCO_2, while levelised unit storage cost is 22,7 $€_{2022}$/tCO_2. Only 3,5% of total lifecycle costs are pre-FID given the amount of pre-existing data available. The *Forties 5, site 1* is one of the most expensive proposed storage developments in the assessment, but also has one of the largest potential storage capacities.

[62] Storage efficiency refers to the share of the reservoir rock that can store CO_2. Interventions, like the production of water/brine, can improve storage efficiency and represents some of the upside for storage development in saline aquifers.
[63] Calculated as the discounted CAPEX, OPEX and ABEX, over discounted total volume transported and stored, at 10% real discount rate.

Storage site	*Viking A*	*Captain X*	*Forties 5, site 1*	*Bunter CL36*	*Hamilton*
Levelised Unit Cost (€/t)	27.2	29.0	29.9	20.2	17.9
Transport Cost Share (€/t)	7.6	2.0	7.2	5.2	2.0
Storage Cost Share (€/t)	**19.6**	**27.0**	**22.7**	**14.9**	**15.9**
Injection Rate (Mtpa)	5	3	7.5	7	5
Capacity (MtCO2)	130	60	300	280	125
Storage Efficieny %	78%	3%	6%	19%	70%
Potential Commencement of Injection	2031	2022	2030	2027	2026

Table 3. Results of the storage appraisal project on the UKCS.

Levelised costs are in €$_{2022}$/tCO_2 and is calculated as the sum of discounted CAPEX, OPEX and ABEX, divided by the discounted total volume stored. Discounted at 10% real rate back to 2015. Based on Pale Blue Dot (2016).

The storage appraisal project on the UKCS, captures the variation in transport and storage costs that arise from qualitatively different storage projects. The assessment finds a range of levelised transport and storage cost across the sites evaluated of about 15-53 €/tCO_2, with an average cost of 28 €/tCO_2. For storage, the assessment results in a range of 13-44 €/tCO_2, with an average storage cost of 22 €/tCO_2. The storage appraisal project finds that storage OPEX is the dominating cost item for storage development and operations – more than half of total costs – contrary to the findings in ZEP (2011b), where exploration or CAPEX are the highest cost items when no reusable infrastructure exists. These results are affected by multiple factors that are different for each storage type.

The "Directive on the geological storage of CO_2" is the main legal framework for CO_2 storage in the EU (ZEP, 2022). It is meant to guide legislation on CO_2 storage in member states. Provided in the directive is the requirement of measuring, monitoring and verification activities when storing CO_2. Additionally, the eventual handover of storage liability to competent authority also comes from the directive. A financial security to cover both the MMV activities and the costs of handover, are necessary to safeguard member states against storage operators not being willing or able to cover these costs.[64] It is in these aspects of regulations on storage that regulatory uncertainty prevails, more specifically, how governments interpret the directive, particularly the size of the financial security is contentious. By one conservative estimate, such a security could be in the order of 500 M€, but a risked value estimate suggest a much lower liability of about 0,8 M€, showing the effects of wrongful interpretation of the directive on storage costs (ZEP, 2019). The owner of the storage permit is required to verify the safety of storage throughout the permit's validity period. This is partly done through exploration and monitoring activities. Conservative interpretations of storage safety in member states can drive the cost of exploration and monitoring through requirements of excessive verification, making storage more costly than is necessary. Additionally, if financial securities required are too large, smaller actors – with limited financing opportunities – can be prevented from developing storage, leading to an undersupply of storage assets. Uncertainty in carbon prices, coupled with the longevity of storage liability, makes leakage risk hard to ascertain financially. Some possible solutions to the issue of required financial security exists. Public-private partnerships, i.e. risk-sharing, could be necessary in the initial phase of market development, while private insurance could cover the risk once CCS matures.

Some additional challenges for the development of CO_2 storage exist. First, uncertainty in reservoir quality – in addition to affecting the cost of storage – can affect both the design and cost of the entire CCS chain (Middleton et al., 2012; Anderson, 2017). Capture and transport of CO_2 are, combined, more expensive than storage, but also more predictable, especially for CO_2 volumes. Coordination between storage developers and emitters when designing the CCS project structure, ensuring that annual injection capacities match annual capture rates, will mitigate much of the uncertainty. Measures to increase operational robustness, such as back-up injection wells could also be necessary. Middleton et al. (2012) highlight the potential premium in offering certainty in storage. An emitter could be willing to pay a higher price for certainty in volumes stored as this directly affects emitter's investment in capacity of capture facility. This premium can offset some of the increased development costs associated with increased certainty in storage reservoir properties. Second, conflicting interests in the North Sea – for instance, offshore wind, fishing, CCS and oil and gas, all compete for the licence to operate – can be a barrier to the scale-up of CCS. Third, differences in project lead times also pose challenges. While a construction time of around 3 years is common for both capture and storage developments, total project lead times differ (IEA, 2022b). Storage developments have historically lasted 5-10 years, while capture projects could be realised in 4-5 years. This too, suggests that CCS projects should be developed through close collaboration and coordination with all elements in the value chain to ensure the timely delivery of the project. These factors complicate the source-sink matching necessary for CCS to scale-up and are related to the cross-default risk which is especially pertinent at this phase of industry development.

According to the IEA, more than 60 Mtpa of CO_2 storage in Europe is in various stages of development (IEA, 2022c). Capture facilities planned for 2030 is estimated to capture more than 80 Mtpa (IEA, 2022a). This capture-storage gap can pose a barrier to CCS deployment. As explained, emitters require a suitable storage site that match annual capture rates and total capacity.[65] This matching effectively reduces the menu of storage sites. As such, for rapid scale-up of CCS, storage capacity should exceed capture. Providing clear regulation and supportive policies can incentivise increased development of CO_2 storage.

What does the economics of CO_2 storage imply for the economic viability of European CCS? The large upfront investment associated with storage site development, which imply high financial risk for developers, cannot go unaddressed. Both the lack of supportive policies and regulatory uncertainty disincentivise investments in storage site development. The uncertainty in storage operational costs prior to large-scale injection of CO_2 also poses a challenge. Tailored business models, like that proposed for capture, can address some of this uncertainty. To maintain the momentum for capture projects in Europe, development of storage capacity in excess of capture capacity can be necessary to ensure matching storage and capture characteristics. These findings suggest storage site development all over Europe, where storage is feasible. This has implications for the chosen mode of transport, with CO_2 shipping unlocking more distant CO_2 storage sites.

[65] A typical emitter requires a storage site with total capacity of 200 million tonnes of CO_2 or more, to cover emissions over the economic lifetime of capture facility (ZEP, 2011b).

5. Results

In the following sections, the main findings in the literature on the economics of CCS is presented along with the results of the CCS case study. This concludes with the presentation of carbon price breakpoints across sectors with the highest point source emissions in Europe.

5.1. Economics of CCS

The outlook for carbon prices in Europe is positive following recent developments. The price of emissions allowances in the EU reached an all-time high of 105 €/tCO_2 earlier this year, with an average of around 90 €/tCO_2 so far in 2023. More ambitious climate strategies in the EU and in European countries have resulted in reforms of tax systems and the EU Emissions Trading System (EU ETS). The most important development is the introduction of a carbon border adjustment mechanism – a tax on the CO_2 emissions from production of certain imported products – which lowers the risk of European industry moving production abroad as carbon prices increase. Consequently, the free allocation of emissions allowances will be phased out, expanding the potential market for CCS.

Because real experience is limited, cost estimates on CCS in the literature are uncertain. Many studies on the cost of capture across sectors are available, and cost estimates exhibit significant variation between and within sectors. CO_2 concentration in the emissions processed for capture is inversely proportional to the energy required to capture CO_2, and therefore a prime driver of cost differences. Use of different capture technologies and approaches is another factor contributing to the observed variation. Steam provides the energy for capture, and for mature capture technologies, steam is the dominating cost item. As such, how the steam is generated, and whether low-cost waste heat is available, is an important variable further explaining differences in cost estimates. Average capture costs of 65-133 €/tCO_2 is found in the literature, reflecting capture at the largest point source emitters in Europe. An important characteristic of capture development in Europe is that most capture facilities will be retrofits as power and industrial plants are midway through their economic lifetimes of 50 years. This limits the suite of available, potentially cost-reducing, capture technologies that are feasible and may pose a barrier to large-scale capture capacity and realisation of cost-reductions.

There exist fewer cost studies on CO_2 transportation costs compared to capture. Cost estimates are uncertain because of limited real experience, especially for CO_2 transportation at scale. Large-scale CO_2 transportation will happen by a combination of pipelines and shipping. While pipelines are generally cost-effective over shorter distances, shipping offer comparably lower investment cost, higher flexibility to scale capacity, mobility in shipping routes and opportunity for co-utilisation. Pipelines are the most mature transportation option, while shipping faces barriers for cost-optimal ship designs and has historically not been recognised by the EU as a credible transportation option. Still, the lower sensitivity of shipping costs to distance and volume, makes the option valuable both for early CCS deployment and in the longer-term enabling storage for more distant emissions sources needed for deep decarbonisation. Cost estimates from the literature suggests unit pipeline costs between 10-30 €/tCO_2 over shorter distances (100-400 km), transporting more than 5 Mtpa. Estimated shipping costs are 20-30 €/tCO2 regardless of distance, for volumes above 5 Mtpa. Transportation cost estimates from the financial model developed for this study generally fall in the same range.

Even fewer cost studies on CO_2 storage exist. Again, the lack of sufficient real experience limits the certainty on the true costs of storage. Early storage development in Europe will be mostly offshore. Onshore storage is prohibited in many European countries, in addition to lacking public support, which is not experienced for offshore storage. Uncertainty exists on the storage capacity, annual injection rates, and safety of storage sites – all of which drive economic performance. Costly exploration activities can mitigate some of this uncertainty, but poses exploration risk, and costs are incurred before final investment decision. Development of storage sites involves large capital investments, and the cost of operations is uncertain, because of potentially changing reservoir properties as CO_2 is injected can entail costly interventions to maintain injection rates. The CO_2 in reservoir is periodically monitored to verify containment. After closure of storage site, the CO_2 is monitored for a further 20 years before handover of storage liability and ownership to competent authority. Regulatory uncertainty on CO_2 remains, particularly on necessary exploration and monitoring activities, in addition to the size of a financial security meant to cover the cost of potential leakage and handover. Another barrier is the lack of supportive policy incentivising the assessment and development of CO_2 storage. Both factors can lead to storage assets being undersupplied. Literature estimates on the cost of storage offshore suggests a range of 10-45 €/tCO_2. The storage financial model developed for this study, estimates a unit storage cost of about 10 €/tCO_2.

5.2. Case Study and Carbon Price Breakpoints

In the following section, results of the case study and calculation of carbon price breakpoints across sectors are presented. The results are discussed in a wider European CCS context, covered through the thesis.

	Phased - 6,0 Mtpa	Normal - 7,2 Mtpa	Accelerated - 7,5 Mtpa
Base	43,4	41,8	42,1
Tie-in	39,0	37,6	37,9
Direct Injection	38,9	37,8	38,0
Injection via FSIU	39,8	38,5	38,7
Pipeline	50,4	46,0	47,7

Table 4. Levelised unit costs of CO_2 transport and storage (€/tCO_2).

Results from the financial model for each case and scenario considered. Transporting and storing 7,2 Mtpa over 830 km. Levelised unit cost is discounted CAPEX, OPEX and ABEX[66], divided by discounted transported and stored volumes, at 8% real discount rate, valuation year is 2023. 30-year operations, followed by 20-year post-closure monitoring.[67]

Combining the levelised unit cost of transport and storage results in the table above. The lowest unit costs are achieved for the tie-in case under a normal development scenario, at 37,6 €/tCO_2. Transportation and storage costs make up about half of the levelised unit cost each, around. The tie-in case represents the value of shared infrastructure; thus, it is generally unavailable for first-of-a-kind transport and storage projects. It is identical in structure to the base case, but has significantly lower costs associated with the onshore CO_2 terminal, as this is shared with other projects. Marginally more expensive is the direct injection case, at 37,8 €/tCO_2. Shipping makes up about 75% of total costs in this case, or 28,1 €/tCO_2, with storage costs making up the remaining quarter, at 9,7 €/tCO_2, the overall cheapest storage case. Despite the longer unloading time of direct injection versus injection via FSIU, resulting in an additional ship being necessary, the former is the marginally cheaper option. The combined costs of temporary storage offshore, resulting in higher floating unit CAPEX, and the higher gasification CAPEX and OPEX, makes injection via FSIU marginally more expensive. At the transportation distance and volumes considered, pipelines are too expensive to consider. As part chain commercial CCS projects are not yet operational, only the cases corresponding to a first-of-a-kind transport

[66] Refers to abandonment expenditure, which is only included for storage cost calculations.
[67] Based on Durusut and Joos (2018), Knoope et al. (2014) and industry consultations.

and storage project should be considered. The base case is mature[68], and cost-effective versus pipelines, and the offshore unloading options for shipping are forthcoming, with estimated commercial deployment in 2027 (Altera Infrastructure, n.d.).

The implication on transportation and storage costs from profit margins of the operators have generally not been analysed in the literature that I have surveyed. It is an important and realistic component of total transportation and storage costs for the emitter. As explained in the presentation of the financial model, IRRs for shipping, pipeline and storage projects are chosen based on each sectors estimated cost of equity and reflect the range of target IRRs currently used to evaluate CCS projects in the industry. Shipping and storage have been assigned a target IRR of 15%, while offshore pipeline development and operation has a target IRR of 10%.

Accounting for the economic return to transport and storage operators is essential for assessing the economic viability of CCS. The direct injection case is the chosen transportation option for the project, resulting in a transport and storage (T&S) tariff of 63,2 €/tCO_2. Shipping tariff accounts for the highest share of the total tariff, at around 72%, or 45,3 €/tCO_2, while storage is 17,9 €/tCO_2. For reference, the Northern Lights project quotes a tariff-range of 35-55 €/tCO_2 for their operations (Smith et al., 2021), with 55 €/tCO_2 thought to be the more realistic estimate, having received substantial government funding for the project's first phase (Northern Lights, 2023, p. 51). A profit margin for CO_2 capture has not been considered, assuming emitters invest in CCS if economically indifferent between capturing and emitting. No excess return to capture projects is a simplified and not fully realistic assumption. For example, electrification of oil and gas installations are comparable projects to CO_2 capture and firms have return requirements for these projects. Deprecation and tax calculations for capture projects – which is necessary for the calculation of a target return – is out of scope for the thesis.

[68] The case is identical to how the Northern Lights will transport and store CO_2 in the north end of the North Sea (Northern Lights, n.d.).

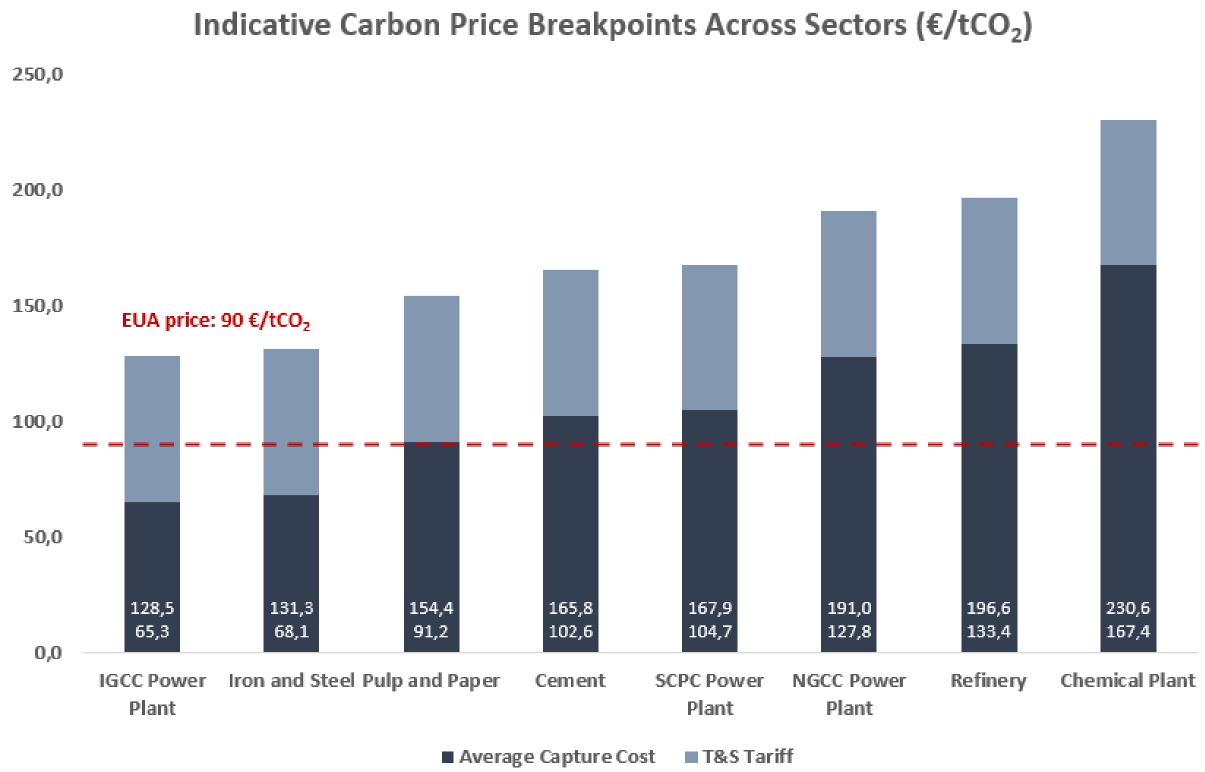

Figure 20. Indicative carbon price breakpoints across sectors (€/tCO$_2$).

Carbon price breakpoints (top value) are based on average capture cost (bottom value) and a transport and storage tariff (T&S Tariff) of 63,2 €/tCO$_2$. An EU emissions allowance price of 90 €/tCO$_2$ is chosen as representative for 2023.

Figure 20 presents carbon price breakpoints across sectors. This is calculated as the average capture cost from Figure 9, combined with the calculated transport and storage tariff of 63,2 €/tCO$_2$. Compared to the chosen EUA price of 90 €/tCO$_2$, carbon price breakpoints for the sectors analysed are too high to enable a storage project in the north end of the North Sea. Figure 20 suggests a transport and storage tariff of at most 25 €/tCO$_2$ to enable CCS for some power plants. Low-cost capture from near-pure CO$_2$ sources can be achieved at around 22 €/tCO$_2$, leaving 68 €/tCO$_2$ for transport and storage services, enabling storage further away from the source.

6. Discussion

In this section the results just presented and implications for European CCS are discussed. Opportunities and future developments are also discussed.

For most sectors analysed in Figure 20, CCS is not economically viable at current carbon prices – even when suitable storage is close. Supportive policies – like subsidies and funding – are required to bridge the gap between carbon prices and breakpoints. However, opportunities exist for commercial CCS deployment from capture in applications with emissions that are near-pure CO_2. Both natural gas processing and fertiliser production can capture CO_2 at around 20 €/tCO_2, leaving about 70 €/tCO_2 for transport and storage at current carbon prices. This could enable suitable storage more than 1000 km away. While CO_2 emissions from these sources are insufficient to incentivise large-scale deployment of commercial CCS on their own, these low-cost capture projects could enable the development of necessary CCS infrastructure, lowering the cost of transport and storage for future captured CO_2 volumes.

Large point source emitters close to exporting harbours represent the emitters that can scale up CCS. The IEA estimates that around 19% of all CO_2 emissions from industrial point sources in Europe are within 100 km of suitable offshore storage (IEA, 2020). This corresponds to roughly 150 Mtpa distributed on oil refineries (25%), chemical plants (20%), power plants (19%), iron and steel (17%) and cement plants (10%). From Figure 20, CCS is currently uneconomical for most of these large emitters when considering storage in the north end of the North Sea. Suitable storage located closer to the CO_2 source can result in sufficiently low transportation costs to enable CCS for some of these larger emitters. However, development of storage sites further away from Europe's largest emitters is necessary for large-scale CCS. The large estimated storage capacity on the NCS and the UKCS are the reason for developing storage sites further away from the largest emissions sources in Europe. At an estimated offshore storage capacity of 1,2 billion tonnes, mostly in depleted oil and gas fields with limited upside potential, it would take 24 years to use up the storage capacity on the Dutch continental shelf when storing 50 Mtpa. The ambitions of the EU for CCS by 2040, is to store 300 Mtpa of CO_2, making storage development on all continental shelves in the North Sea – and elsewhere – inevitable.

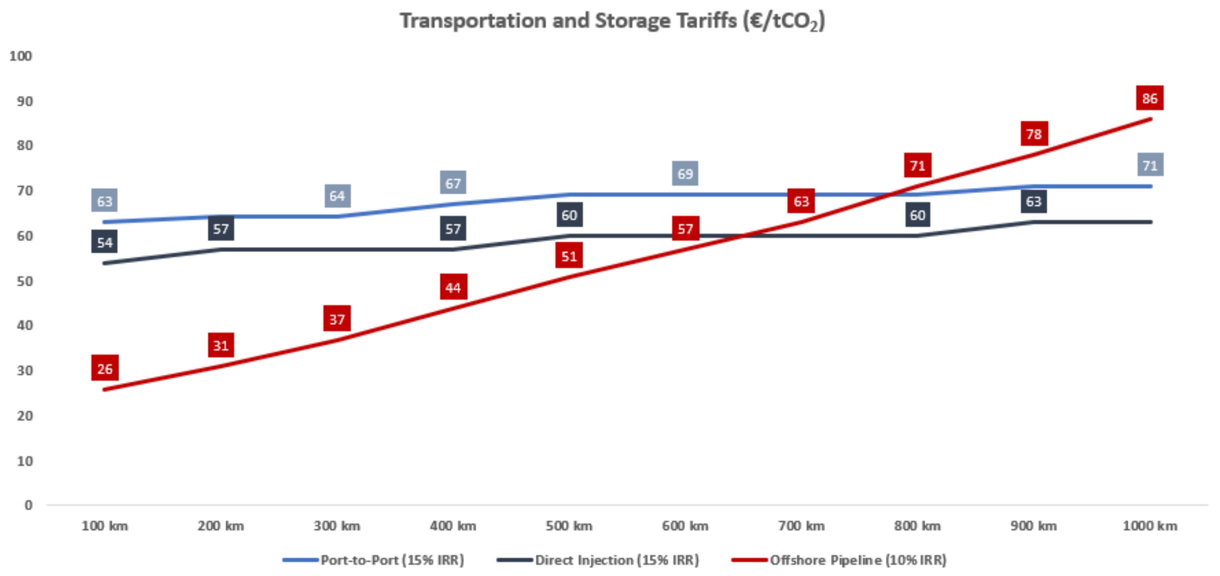

Figure 21. Transportation and storage tariffs (€/tCO_2) evaluated at different distances.

Transportation and storage tariffs (€/tCO_2) for different transportation options at different distances. Offshore storage is identical in all cases considered. Tariff at 15% IRR for shipping and storage, while 10% IRR is chosen for offshore pipeline. Transporting 7,2 Mtpa.[69]

Figure 21 above presents T&S tariffs for different transportation options, over increasing distances. The storage share of tariffs is identical for all distances, and is 43,1 €/tCO_2 for onshore unloading and 17,9 €/tCO_2 for direct injection and offshore pipeline. CO_2 capture from a steel mill, for transport and permanent storage, would at current carbon prices be economically viable at transport and storage tariffs of around 22 €/tCO_2. About 25 Mtpa of CO_2 emissions from iron and steel production is located at or closer than 100 km away from suitable offshore storage (IEA, 2020). Figure 21 presents T&S tariffs at different distances to storage, assuming identical storage at all distances. The tariff at 100 km, 26 €/tCO_2, is higher than the 22 €/tCO_2 that would enable CCS for steel mills today. Carbon price breakpoints for the lowest cost T&S project in Figure 21, would be in the range of 91-193 €/tCO_2, indicating a low level of carbon prices necessary to enable CCS for Europe's largest emitters. Considering the level of carbon prices in 2030, a minimum of 125 €/tCO_2, about 57 €/tCO_2 as T&S tariff would be sufficient to make CCS economically viable for iron and steel producers with average capture costs today. This can also enable the storage project on the Norwegian continental shelf.

As shown in Figure 21 it is evident that at storage closer than 650 km away, pipelines are the cost-effective transportation option. However, given the high capital investment and

[69] Based on Durusut and Joos (2018), Knoope et al. (2014) and industry consultations.

inflexibility of pipelines, the option can be infeasible for early investors in CCS. It will depend on the certainty in volumes. However, pipelines have been the preferred CO_2 transportation option of the EU, discarding CO_2 shipping. This is about to change as industry actors are pushing the EU to recognise the need for CO_2 shipping, which is made easier by the forthcoming inclusion of the maritime sector in the EU ETS. The lower sensitivity to distance of CO_2 shipping costs versus pipelines is also clear from Figure 21. Assuming Rotterdam as the source of CO_2, storage sites on the Norwegian continental shelf (NCS) requires transportation over about 600 km. The NCS contains Europe's largest storage formation, i.e. the Utsira formation with an estimated 16 billion tonnes of storage capacity, which makes this distance important to CCS development in Europe. Another important aspect to storage in this area is that CO_2 has been injected into this formation for nearly three decades at the Sleipner field, providing evidence of suitable storage, limiting necessary exploration activities. This can open for lower cost storage developments, and given the size of the formation, it is possible to create storage hubs sharing topside infrastructure, where new storage sites – as subsea templates/satellites – are tied back to this hub, much like modern day oil and gas field developments in the North Sea, providing further cost reductions.

For transport to the NCS, shipping will likely be the preferred transportation option, especially for volumes up to 20-30 Mtpa, as shipping would still be cost-effective versus pipelines, when comparing figures 12 and 16.[70] However, Equinor has proposed the construction of a 1 000 km long pipeline connecting CO_2 emissions from Northwest Europe to storage on the NCS (Equinor, 2022). This trunkline would have an estimated capacity of between 20-40 Mtpa. Using the pipeline financial model to calculate a high-level estimate on the unit cost of such a pipeline, suggests levelised costs between 34-39 €/tCO_2, depending on the volume transported, and a tariff of around 60 €/tCO_2.[71] Shipping tariffs for the same distance and volumes are estimated to be lower, at 28-32 €/tCO_2.[72] It is important to note that the economic lifetime of CO_2 pipelines is twice that of ships, 50 years versus 25-30 years, which – if considered – would reduce the cost gap between the two options (Roussanaly et al., 2021a; Knoope et al., 2014). Another consideration is the economic return of pipelines. Owners of pipelines are often state-entities or pension funds with access to low-cost capital that will accept a lower rate of return compared to most private companies (Roussanaly et al., 2014).

[70] The cost breakdowns of offshore pipelines and shipping, respectively, for different volumes and distances.
[71] Assuming 10% IRR.
[72] Assuming 15% IRR.

One possible future scenario for European CCS can be realised through low-cost capture from near-pure CO_2 sources. Capture from these sources can help enable shared infrastructure through CCS hubs which reduce transport and storage tariffs. Estimates on the tariffs for transportation and storage when existing infrastructure is available, is 52,6 €/tCO_2 and 42,6 €/tCO_2 for onshore unloading and direct injection, representing cost reductions of around 22% and 26%, respectively.[73] Combining the T&S tariffs for a future CCS scenario with capture costs realised from the potential commercialisation of optimal capture technologies, presents a view of what CCS beyond 2030 could look like.

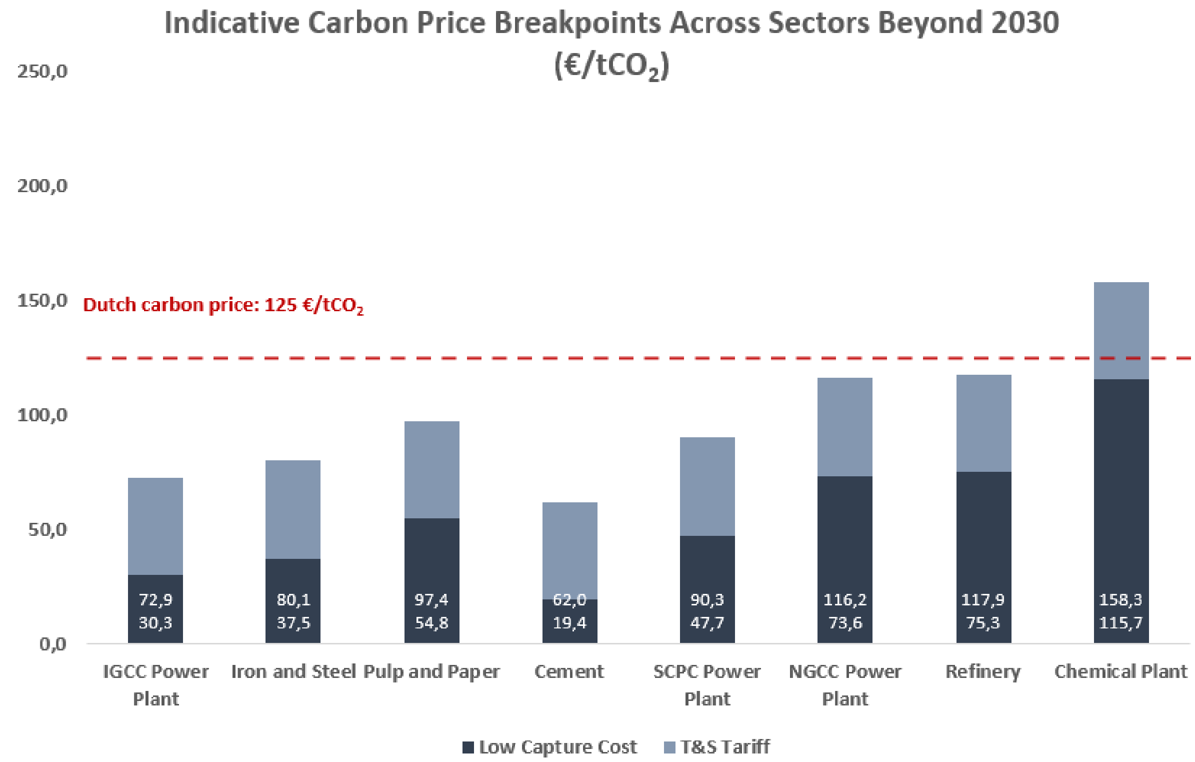

Figure 22. Indicative carbon price breakpoints (€/tCO_2) beyond 2030.

Carbon price breakpoints (top value) are based on low capture cost estimates (bottom value) from the literature and the transport and storage tariff for direct injection in a mature industry, of 42,6 €/tCO_2. Transporting and storing 7,2 Mtpa, over 830 km. The certain Dutch carbon price in 2030, of 125 €/tCO_2, has been chosen as representative of future carbon prices.[74]

Figure 22 summarises a scenario for European CCS beyond 2030. The Dutch carbon price in 2030, of 125 €/tCO_2, has been chosen as representative of carbon price development in the near-

[73] Using the tie-in case for storage when analysing onshore unloading, representing tie-in to existing onshore terminal. For direct injection, shipping costs without shipping chain CAPEX, i.e. liquefaction plant and temporary storage facility, is assumed.
[74] Based on the same literature as in Figure 9 including Durusut and Joos (2018), Knoope et al. (2014) and industry consultations.

term, underpinned by recent reforms to the EU ETS and more ambitious climate policies in several European countries. Indicative carbon price breakpoints are lower than carbon prices for all sectors except for average chemical plants. By one estimate, this could enable CCS for 150 Mtpa of stationary emissions in Europe within close range of an exporting harbour (IEA, 2020). Not fully considered here is the necessary intermediate transport for landlocked emissions that could add significant costs to CCS. The scenario beyond 2030 highlights the combined longer-term effects of increased carbon prices and lower costs throughout the CCS value chain from optimal capture technologies, the standardisation and modularisation of equipment and facilities necessary in the supply chain and the construction of CCS infrastructure hubs. The realisation of these effects depends on large-scale deployment of European CCS, which could be limited by existing barriers today that will need to be overcome.

Some key challenges for the scale-up of commercial CCS in Europe needs to be considered. First, many capture facilities in Europe will be retrofitted due to power and industrial plants being midway through their economic lifetime. Spatial constraints – particularly pertinent for industrial hubs where most of Europe's stationary emissions originates – may prove to be a real barrier for scaling capture capacity. Another consequence of retrofitting is that it could limit the suite of potentially cost-reducing capture technologies, because both pre-combustion and oxyfuel-combustion capture is infeasible to retrofit. This could prolong the time it takes to realise lower cost capture in Europe. Second, there is a need for clarity in storage regulation and supportive policies incentivising exploration and assessment activities for CO_2 storage in order to ensure sufficient supply of storage assets. Currently, forecasted demand for storage exceeds planned supply in Europe. While some CO_2 is captured for use, most is permanently stored and require a matched, suitable storage site. Availability of storage sites of varying characteristics are necessary to keep momentum in the planned capture capacity. Finally, shipping must be acknowledged as suitable CO_2 transportation option, just as pipelines. This could enable CO_2 shipping to become a project of common interest in Europe, unlocking faster permitting processes and increased funding. The results in this thesis suggest that CO_2 shipping is an important enabler of early CCS and, in the long-term, plays a vital part in supplying storage services for distant emitters. The development of shipping chains is therefore essential to enable large-scale CCS and deep decarbonisation.

The results of the economic assessment are indicative at best. The lack of real experience in CCS lowers certainty in cost estimates throughout the value chain. Additionally, when constructing the financial model to calculate shipping and pipeline costs, simplified assumptions have been necessary to avoid too technical calculations, which is at the expense of cost estimate accuracy. However, focus has been on capturing the major drivers determining the cost of CO_2 transportation. When correcting for inflation, cost estimates produced by the financial model generally fall within cost intervals from the literature.

7. Conclusions

In this study, the economics of CCS in Europe have been assessed. This was done through a survey of the literature on CCS and carbon prices in Europe. Additionally, a CO_2 transportation and storage financial model was developed to assist in the calculation of carbon price breakpoints across sectors, indicating the level of carbon prices necessary to make CCS economically viable.

Some key take-aways from the economic assessment of CCS is presented below. First, the recent reforms to the EU ETS, including the introduction of a carbon border adjustment mechanism. Second, that current carbon prices – on its own – appear insufficient to enable CCS for most large point source emitters, but that opportunities exist for enabling early CCS. Third, provided initial large-scale deployment of CCS, the positive outlook for carbon prices in Europe is estimated to enable CCS for most large point source emitters close to exporting harbours in the medium term, beyond 2030. However, current barriers to CCS adoption at scale must be overcome first.

The outlook for European carbon prices is positive. More ambitious climate policies in the EU and in European countries, have resulted in reforms that strengthen the carbon price signal. Recent reforms to the EU ETS, like the increased retirement of emissions allowances in circulation, and the forthcoming inclusion of the maritime sector in the system, provide an upward trajectory for EU allowance prices. However, the most important development is the introduction of a carbon border adjustment mechanism – a tax on the emissions from production of selected imported products – and the resulting phasing out of free allowances for manufacturing industry.

The results of the study show that despite the recent increase of carbon prices – to all-time highs – carbon price breakpoints for most sectors are insufficient to make CCS an economically viable emissions abatement option. Sectors contributing to the largest point source emissions in Europe have estimated carbon price breakpoints between 91-193 €/tCO_2, where capture from certain types of power plants are in the low-end of estimates, and capture from chemical plants represent the high-end estimates. This range includes the cost of pipeline transport over 100 km to suitable storage, transporting and storing 7,2 Mtpa. For a typical storage project on the Norwegian continental shelf, carbon price breakpoints for the same sectors increase to 128-231

€/tCO_2. Capture from near-pure CO_2 sources for transport and storage, like natural gas processing and fertiliser production, represent low-hanging fruit for scaling CCS. Capture costs for these sources are sufficiently low to enable even distant suitable storage operations and can contribute to the early development of necessary CCS infrastructure which lowers costs for future capture volumes.

Estimates on carbon price breakpoints across sectors beyond 2030 indicate that CCS can be viable for more than 150 Mtpa of CO_2 emissions from stationary sources located close to exporting harbours. The results of shared infrastructure through CO_2 transportation hubs, coupled with cost reductions from the commercialisation of optimal capture technologies, could lower carbon price breakpoints to 73-158 €/tCO_2. However, this depends on large-scale deployment of CCS in Europe, to realise cost-reductions in technologies throughout the value chain and the development of shared infrastructure through CCS hubs. Achieving this entails first overcoming key barriers. First, clarity in storage regulation and supportive policies can ensure rapid storage asset development, underpinning the development of capture capacity as well. Second, recognising the role that CO_2 shipping has for enabling early CCS, and for achieving deep decarbonisation in the longer-term. Third, dealing with the challenge of most capture facilities being retrofitted, limiting both cost-reductions through technology in the shorter term and the scale of capture capacity.

While many studies on the cost of capture can be found in the literature, there is a lack of real experience, which increases the uncertainty in true costs. No one capture technology has yet surfaced as the optimal for any sector. This contributes to the significant variation in capture cost both between and within sectors. The lack of real experience in CCS influences cost estimates and their certainty throughout the value chain. An added challenge is the limited number of studies for these costs. Compiled, the estimates calculated in this study are uncertain. However, results reflect both what the research and industry practitioners currently estimate the cost of CCS to be.

An additional shortcoming of the results is the limited scope of the study that is necessary to complete the thesis. CCS, while conceptually easy to understand, is complex and technical, which is not fully reflected here. As such, simplified assumptions have been made, which affects the true costs of CCS. However, care has been taken to represent the main driving forces on the functioning and economics of CCS.

The thesis shows that an apparent shift in the attractiveness of CCS has occurred, mostly due to the developments in carbon prices, the EU ETS and climate policies. Carbon prices are close to the levels necessary to make CCS economically viable for large point sources. This has implications for practitioners, which is evident from the large increase in planned projects for both capture and storage that has occurred over the last six months. The barriers that still need to be overcome is of importance to policy makers, as all of them can be resolved through supportive policy. Lastly, the literature on CCS focuses primarily on the component parts of the chain, only rarely doing deep analysis overall. The approach of calculating carbon price breakpoints and assessing the economic viability of CCS – which is done in this thesis – could be incorporated into more technical analysis, providing a deeper understanding on the status of CCS. A deeper technical analysis has been beyond the scope of this thesis.

CCS is developing fast, and multiple avenues of future research exist. Research on tailored business models for CO_2 capture and for storage, ensuring high and stable capture/storage rates despite changing operational conditions that alter the economically optimal activity level, would be useful. Especially since this has consequences across the value chain and the climate benefit of CCS. Research on the CCS value chain's sensitivity to changes in both interest rates and energy prices, as many parts of CCS is energy-intensive and involves high capital investments, would also be useful. Lastly, a more detailed approach to calculations of carbon price breakpoints would be fruitful, coupled with area-specific demand analysis. This can provide information on the optimal placements of CCS hubs, providing practitioners with inputs on how to structure projects and policy makers can get a clear view of any regulatory or political hurdles necessary to overcome.

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9. Appendix

9.1. Appendix 1. Financial Model Cost Estimates and Operational Parameters.

Storage

Onshore Facility	Unit	Base Case	Tie-in Case
Facility FEED	mGBP	1.5	-
CO2 jetty (specific CAPEX)	mNOK/Mtpa	131.9	31.3
Buffer storage (specific CAPEX)	mNOK/Mtpa	68.4	-
CO2 terminal (specific CAPEX)	mNOK/Mtpa	243.3	200.0
Energy requirement	MW/Mtpa	1.6	1.6
Labour	FTE	9.0	9.0
Labour cost	mNOK/FTE/y	1.3	1.3
Facility maintenance (% of facility CAPEX/	%	1.50%	1.50%
Maximum annual injection rate	Mtpa	7.2	7.2
Average annual injection rate	Mtpa	7.2	7.2
Utilisation rate [UR]	hours	8,327.7	8,327.7

Table A1.1. Cost estimates for the onshore CO_2 terminal. Based on industry consultations. FEED refers to front-end engineering and design, a part of the initial project assessment.

Pipelines		Base Case	Tie-in Case
Pipeline studies	mGBP	1.4	1.4
Pipeline FEED, development and route surve	mGBP	3.5	3.5
Pipeline length	km	170.0	130.0
Pipeline cost	mNOK/km	14.0	14.0
Pipeline OPEX	mNOK/yr	10.0	10.0

Table A2.1. Cost estimates for the offshore pipeline connecting onshore CO_2 terminal to offshore storage. Based on industry consultations.

Offshore Facility	Unit	Base Case	All other cases
Pipeline Length	km	30.0	30.0
Pipeline cost	mNOK/km	14.0	14.0
Additional pipeline construction work	mNOK	70.0	70.0
Pipeline OPEX (% of pipeline CAPEX/yr)	%	0.40%	0.40%
Direct current fibre optic cable length	km	200.0	160.0
DCFO cable cost	mNOK/km	2.3	2.3
DCFO cable OPEX	mNOK/yr	5.0	5.0

Table A3.1. Cost estimates for the offshore facility – two drill centres – and the necessary infrastructure. Based on industry consultations.

Subsea Production System [SPS]		
Subsea FEED	mGBP	1.5
Site surveys (deep borings)	mGBP	2.0
Pre-operations Seismic	mGBP	8.0
SPS CAPEX	mNOK/well	125.0
SPS OPEX	mNOK/well/yr	5.5
Ongoing MMV	mGBP/yr	0.4
Time-lapsed seismic (every 5 years)	mGBP/yr	2.7

Table A4.1. Cost estimates for subsea production system. Based on industry consultations.

Wells		
Injection well engineering study	mNOK	1.5
Wells FEED	mNOK	3.8
Mobilisation & demobilisation	mGBP/well	2.0
Drilling and Completion 1st formation wells	mNOK/well	375.0
Drilling and Completion 2nd formation wells	mNOK/well	450.0
Well maintenance and workover activities	mNOK/well/yr	9.2

Table A5.1. Cost estimates for well infrastructure. Based on industry consultations.

Abandonment		
Wells	mNOK/well	75.0
SPS (% of SPS CAPEX)	%	5%
Pipeline & DCFO (% of pipeline & DCFO C.	%	2%
Onshore facility (% of facility CAPEX)	%	5%
Post-closure monitoring cost	mNOK/yr	4.0

Table A6.1. Cost estimates for abandonment/decommissioning. SPS refers to the subsea production system. Based on industry consultations.

Project Management, Owner's Cost and Contingency		
Project management [PM] (% of total CAPE	%	10%
Owner's cost (% of total CAPEX)	%	8%
CAPEX contingency (% of total CAPEX inc	%	20%
OPEX contingency (% of total OPEX)	%	20%
Liability cost (per tonne stored)	EUR/tCO2	1.0

Table A7.1. Project management, owner's cost and contingency percentages. Identical for storage and transport, except for the liability cost of storage. Based on industry consultations and (ZEP, 2011b).

Shipping

Parameter	Unit	Onshore Unloading	Injection via FSIU	Direct Injection
Loading time	hours	15	15	15
Unloading time	hours	15	15	36
Port entry and exit	hours	4	2	2
Offshore connection	hours	0	4	4
Total round-trip sailing distance	km	1660	1660	1660
Ship speed	km/hours	27.8	27.8	27.8
Total round-trip sailing time	hours	60	60	60
Total round-trip time	hours	94	96	119
Utilisation rate (average year)	hours/year	8327.7	8327.7	8327.7
Round-trips per year at utilisation loss	#	88	86	71
Days sailing and in connection	#	234	236	195
Annual transported volume	Mtpa	7.2	7.2	7.2
Ship capacity	tonnes CO2	50000	50000	40000
Ship annual capacity	Mtpa	4.4	4.3	2.84
Fleet size	#	2	2	3

Table A8.1. Shipping operational parameters for each unloading option in the normal scenario, transporting 7,2 Mtpa. Based on Durusut and Joos (2018).

Liquefaction				
CO2 Condition	Pre-pressurised		Non-pressurised	
Transport pressure	Low	Medium	Low	Medium
Energy (MW/Mtpa)	3.0	2.4	12.5	10.0
Specific CAPEX (m£/Mtpa)	9.8	7.6	19.5	15.1
Fixed OPEX (% of CAPEX)	10%	10%	10%	10%

Table A9.1. Cost estimates and energy requirement for liquefaction, in £$_{2017}$. Based on Durusut and Joos (2018).

Temporary Storage (120% of ship capacity)		
Transport Pressure	Low	Med
CAPEX per tCO2 of storage capacity (£/tCO2)	516.0	795.0
OPEX (% of CAPEX)	5%	5%

Table A10.1. Cost estimates for temporary storage facility and operations, in £$_{2017}$. Based on Durusut and Joos (2018).

On-/unloading Costs		
Specific CAPEX (M£/Mtpa)	1.4	1.4
OPEX (% of CAPEX)	3%	3%

Table A11.1. Cost estimates for on/unloading equipment and operations, in £$_{2017}$. Base on Durusut and Joos (2018).

Ship Costs				
Capacity (tCO2)	10,000.0	30,000.0	40,000.0	50,000.0
CAPEX (£m)	58.0	53.0	61.0	69.0
Ship Fixed OPEX and Harbour Fee				
Fixed OPEX (% of CAPEX)	5%	5%	5%	5%
Harbour fee (£/round-trip)	10,194.0	19,464.0	24,099.0	28,734.0
Ship Fuel Cost				
Fuel	LNG	LNG	LNG	LNG
LNG price (€/t)	862.8	862.8	862.8	862.8
Fuel content (MWh/t)	14.5	14.5	14.5	14.5
Fuel price (€/MWh)	59.7	59.7	59.7	59.7
Fuel consumption (MWh/d)	263.0	339	377	415

Table A12.1. Cost estimates for ship CAPEX and OPEX. In £$_{2017}$ and €$_{2023}$. All except LNG price is based on Durusut and Joos (2018).

Receiving Harbour Gasification		
Transport Pressure	Low	Med
CAPEX (m£/Mtpa)	0.8	0.8
OPEX (£/tCO2)	0.3	0.3

Table A13.1. Cost estimates for receiving harbour gasification, in £$_{2017}$. Based on Durusut and Joos (2018).

Offshore Unloading				
Transport Pressure	Low	Medium		
Injection and/or storage ship CAPEX (m£)	69.0	58.0		
Ship OPEX (% of CAPEX)	5%	5%		
Submerged turret loading system [STL] units	3.0			
STL system CAPEX (2022 m€/unit)	45.0			
STL system OPEX (2022 m€/yr)	1.6			
Unloading option	Direct injection		FSIU	
Gasification CAPEX (m£/Mtpa)	4.3		6.7	
Gasification Fixed OPEX (% of CAPEX)	5%		5%	
Transport Pressure	Low	Medium	Low	Medium
Gasification Energy (MW/Mtpa)	0.82	0.78	1.24	1.20

Table A14.1. Cost estimates and energy requirement for offshore unloading, in £$_{2017}$ (Durusut and Joos, 2018) and €$_{2022}$ (industry consultations).

Pipeline

Pipeline	Unit	Value
Material		
Distance	km	830
Thickness	m	0.03
Outer diameter	m	0.6
Steel density	kg/m3	7900
Steel cost	€/kg	2.2
Material cost	M€/km	0.8
Construction		
Labour cost	M€/km	0.5
Onshore/offshore difference	M€	35
Rights-of-way costs	M€	0
Miscellaneous cost (% of material and const.)	%	25%
Operations		
O&M cost (% of pipeline CAPEX/yr)	%	1.5 %

Table A15.1. Cost estimates for pipeline construction and operations in $€_{2010}$. Based on Knoope et al. (2014) and industry consultations.

Compression (1 bar to 100 bar)	Unit	Value
Units	#	3
Per unit capital cost	M€/unit	66.8
Energy input	MW/Mtpa	11.2
O&M (% of compressor CAPEX/yr)	%	4%

Table A16.1. Compression cost estimates and energy requirement in $€_{2010}$ (Knoope et al., 2014; McCollum and Ogden, 2006).

Pumping (100 bar to 200 bar)	Unit	Value
Units	#	2
Per unit capital cost	M€/unit	12.7
Energy input	MW/Mtpa	0.5
O&M (% of pumping CAPEX/yr)	%	4%

Table A17.1. Pumping cost estimates in $€_{2010}$ (Knoope et al., 2014).

Pipeline technical calculations

Pipeline design factors		
Inlet Pressure	bar	200
Outlet Pressure	bar	80
Design Pressure	bar	250
Construction time (40", 1000 km)	years	6

Table A18.1. Overview of pipeline design factors.

Pipeline Cost Calculations	Unit	Value	
Thickness (t)			
Outer diameter (OD_{NPS})	m	0.6	
Design pressure (MAOP)	MPa	25	
Minimum yield stress (S)	MPa	450	
Terrain design factor (F)		1.2	
Longitudinal joint factor (E)		1	
Corrosion allowance (CA)	m	0.001	
Thickness (m)	m	0.0258	$t_{min} = OD_{NPS}/((F*E*S)/MAOP + 1)$
Material Cost ($C_{material}$)			
Length (L)	m	830000	
Steel density (ρ_{steel})	kg/m3	7900	
Steel cost (C_{steel})	€/kg	2.2	
Material pipeline costs	M€	635.0	$C_{material} = t\pi * (OD_{NPS} - t) * L * \rho_{steel} * C_{steel}$
Construction Cost			
Labour cost	€/m^2	281.7	
Total surface area of pipe	m^2	1463382.6	
Onshore/offshore difference	M€	35	
ROW costs	€/m	0	
Labour construction cost	M€	412.2	Labour construction cost = L x OD_{NPS} x pi x Labour cost

Table A19.1. Pipeline thickness, material cost and construction cost calculation, formulas used to the right, in €$_{2010}$ (Knoope et al., 2014).

Compressor cost calculations	Unit	Value	
Compressor energy consumption			
Mass flow rate (m)	Mtpa	7.2	
Mass flow rate	tonnes/day	19726.0	
Utilisation rate	h/yr	8327.7	
Power Input	kW x t/d	4.1	
Energy Consumption (E_{comp})	MW/Mtpa	11.2	
Compressor Capacity (W_{comp})	MWe	80.9	$W_{comp} = E_{comp} * m$
Compressor investment cost			
Base cost (I_0)	M€	21.9	
Compressor Capacity	MWe	80.9	
Base compressor scale ($W_{comp,0}$)	MWe	13	
Scaling factor (y)	exp	0.67	
Train capacity	MWe	40	
Compressor trains (n)	#	3	
Multiplication exponent (me)		0.9	
Capital Cost (I_{comp})	M€	200.3	$I_{comp} = I_0 * \left(\frac{W_{comp}}{W_{comp,0}}\right)^y * n^{me}$

Table A20.1. Compressor capital cost and energy requirement calculations in €$_{2010}$, formulas used to the right (Knoope et al., 2014). Power input is sourced from McCollum and Ogden (2006).

Pumping Station	Unit	Value	
Pumping energy consumption			
Mass flow rate (m)	Mtpa	7.2	
Mass flow rate	kg/s	228.3	
Outlet pressure (P2)	MPa	20	
Inlet pressure (P1)	MPa	10	
Pumping station efficiency (η_{pump})		75%	
CO2 density (ρ)	kg/m3	914	
Pump energy consumption (E_{pump})	MJ/kg	0.0146	$E_{pump} = \frac{P_2 - P_1}{\eta_{pump} * \rho}$
Pumping station capacity (W_{pump})	MWe	3.3	$W_{pump} = E_{pump} * m$
Pump energy input	MW/Mtpa	0.5	
Pump capital cost			
Base cost	k€	74.3	
Max. pumping station capacity	MWe	2.0	
Advantage multiplication factor		0.58	
Pumping station trains (n)		2	
Multiplication exponent (me)		0.9	
Capital Cost (I_{pump})	M€	25.4	$I_{pump} = 74.3 * W_{pump}^{0.58} * n^{me}$

Table A21.1. Pumping station capital cost and energy requirement calculations in €$_{2010}$, formulas used to the right (Knoope et al., 2014).

	2023	2024	2025	2026	2027	2028	2029
Storage							
Assessment	2.40%	5.70%	46%	46%	0%	0%	0%
Construction	0%	0%	0%	0%	10%	40%	50%
Shipping							
Construction	0%	0%	10%	10%	20%	30%	30%
Pipeline							
Construction	0%	5%	5%	20%	20%	25%	25%
Compression and pumping							
Construction	0%	0%	0%	0%	10%	40%	50%

Table A22.1. Overview of investment cost phasing during assessment and construction of the project. Shipping refers to the construction of the entire shipping chain.

9.2. Appendix 2. Price Indices and Inflation Factors.

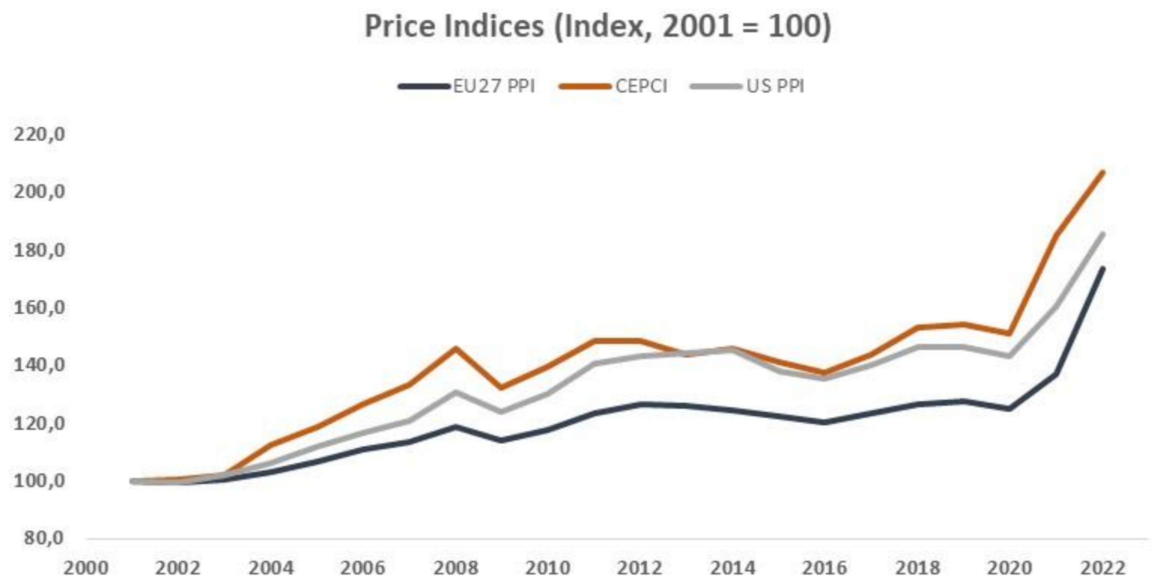

Figure A1.2. Development in the EU and US producer price indices compared to developments in the Chemical Engineering Cost Index (CEPCI) over the period 2001-2022. Index values are normalised to base year 2001.

Year	EU27 PPI Inflation factor	US PPI Inflation factor
2001	1,737	1,855
2002	1,747	1,867
2003	1,726	1,821
2004	1,687	1,746
2005	1,629	1,655
2006	1,564	1,590
2007	1,530	1,532
2008	1,461	1,419
2009	1,519	1,493
2010	1,476	1,422
2011	1,404	1,320
2012	1,372	1,292
2013	1,378	1,287
2014	1,393	1,277
2015	1,417	1,345
2016	1,443	1,372
2017	1,404	1,326
2018	1,369	1,268
2019	1,360	1,268
2020	1,391	1,295
2021	1,266	1,154
2022	1,000	1,000

Table A1.2. Overview of inflation factors for the EU27 and US producer price index. The inflation factor for 2010 reflects the price increase in the period 2010 to 2022, with an inflation factor of 1,476, or 47,6%.

9.3. Appendix 3: Literature Estimates on Cost of Avoided CO_2 Captured.

Sector	Low CAC	High CAC	Capture rate	Cost year	Inflation factor	Low (EUR_{2022})	High (EUR_{2022})	Source
Ammonia/urea	78,0	83,9	90 %	2014 EUR	1,39	108,7	116,9	IEAGHG (2017c)
Cement	42,4	80,2	90 %	2014 EUR	1,39	59,1	111,7	Gardarsdottir et al. (2019)
Cement	50,0	56,2		2010 USD	1,42	68,0	76,5	GCCSI (2011)
Cement	52,4	102,9		2014 EUR	1,42	74,3	145,8	IEAGHG (2013a)
Cement		131,0	60 %	2007 EUR	1,53		200,5	Kuramochi et al. (2012)
Cement		66,0	70 %	2007 EUR	1,53		101,0	Kuramochi et al. (2012)
Cement		91,0	62 %	2007 EUR	1,53		139,3	Kuramochi et al. (2012)
Cement		92,0	84 %	2007 EUR	1,53		140,8	Kuramochi et al. (2012)
Cement	59,7	72,4	60 %	2017 EUR	1,40	83,8	101,7	Santos & Hanak (2022)
Cement	68,3	128,4	85 %	2017 EUR	1,40	95,9	180,3	Santos & Hanak (2022)
Cement	13,8		53 %	2017 EUR	1,40	19,4	0,0	Santos & Hanak (2022)
Cement	38,7	62,2	62 %	2017 EUR	1,40	54,3	87,4	Santos & Hanak (2022)
Chemical plants	94,8	120,5	82 %	2017 EUR	1,40	133,1	169,2	Santos & Hanak (2022)
Chemical plants	117,5	172,1	100 %	2017 EUR	1,40	165,0	241,7	Santos & Hanak (2022)
Chemical plants	82,4	127,8	98 %	2017 EUR	1,40	115,7	179,5	Santos & Hanak (2022)
Fertiliser	15,3	16,3		2010 USD	1,42	20,8	22,2	GCCSI (2011)
Hydrogen	36,7	58,7	75 %	2014 EUR	1,39	51,1	81,8	IEAGHG (2017d)
Hydrogen		37,8	90 %	2016 EUR	1,44		54,5	Roussanaly et al. (2020)
Hydrogen		117,5	80 %	2017 EUR	1,40		165,0	Santos & Hanak (2022)
Hydrogen		62,8	56 %	2017 EUR	1,40		88,2	Santos & Hanak (2022)
IGCC Power Plant		36,0	86 %	2017 EUR	1,40		50,6	Garcia et al. (2022)
IGCC Power Plant	56,0	60,0		2010 USD	1,42	76,2	81,6	GCCSI (2011)
IGCC Power Plant		46,5	95 %	2014 EUR	1,39		64,8	Porter et al. (2017)
IGCC Power Plant		21,7	95 %	2014 EUR	1,39		30,3	Porter et al. (2017)
IGCC Power Plant		67,2	95 %	2014 EUR	1,39		93,7	Porter et al. (2017)
IGCC Power Plant	37,0	58,0	86 %	2013 USD	1,29	45,5	71,4	Rubin et al. (2015)
Iron and Steel	40,0	44,0	13 %	2016 EUR	1,44	57,7	63,5	Eliasson et al. (2022)
Iron and Steel	29,0	40,0	36 %	2016 EUR	1,44	41,8	57,7	Eliasson et al. (2022)
Iron and Steel	50,0	56,2		2010 USD	1,42	68,0	76,5	GCCSI (2011)
Iron and Steel	55,0	60,6	55 %	2010 EUR	1,48	81,2	89,4	IEAGHG (2013b)
Iron and Steel		64,0	33 %	2007 EUR	1,53		97,9	Kuramochi et al. (2012)
Iron and Steel		53,0	34 %	2007 EUR	1,53		81,1	Kuramochi et al. (2012)
Iron and Steel		41,0	35 %	2007 EUR	1,53		62,7	Kuramochi et al. (2012)
Iron and Steel		45,0	36 %	2007 EUR	1,53		68,9	Kuramochi et al. (2012)
Iron and Steel		57,0	69 %	2007 EUR	1,53		87,2	Kuramochi et al. (2012)
Iron and Steel		64,0	78 %	2007 EUR	1,53		97,9	Kuramochi et al. (2012)
Iron and Steel		43,0	82 %	2007 EUR	1,53		65,8	Kuramochi et al. (2012)
Iron and Steel		54,0	74 %	2007 EUR	1,53		82,6	Kuramochi et al. (2012)
Iron and Steel		26,0	79 %	2007 EUR	1,53		39,8	Kuramochi et al. (2012)
Iron and Steel		41,0	79 %	2007 EUR	1,53		62,7	Kuramochi et al. (2012)
Iron and Steel	35,1	59,7	70 %	2017 EUR	1,40	49,3	83,8	Santos & Hanak (2022)
Iron and Steel	28,1	52,7	70 %	2017 EUR	1,40	39,5	74,0	Santos & Hanak (2022)
Iron and Steel	26,7	35,1	70 %	2017 EUR	1,40	37,5	49,3	Santos & Hanak (2022)
Iron and Steel		68,9	70 %	2017 EUR	1,40		96,8	Santos & Hanak (2022)
Methanol	70,6	78,9	90 %	2014 EUR	1,39	98,4	109,9	IEAGHG (2017c)
NG Processing	14,7	15,6		2010 USD	1,42	20,0	21,2	GCCSI (2011)
NGCC Power Plant	125,0	165,0		2022 USD	1,00	119,6	157,8	Diaz-Herrera et al. (2022)
NGCC Power Plant		76,0	86 %	2017 EUR	1,40		106,7	Garcia et al. (2022)
NGCC Power Plant	96,0	100,0		2010 USD	1,42	130,6	136,0	GCCSI (2011)
NGCC Power Plant	58,0	121,0	88 %	2013 USD	1,29	71,4	149,0	Rubin et al. (2015)
Pulp and Paper	52,0	82,0		2015 EUR	1,42	73,7	116,2	IEAGHG (2016)
Pulp and Paper	72,4	90,7	75 %	2017 EUR	1,40	101,7	127,4	Onarheim et al. (2017)
Pulp and Paper		52,5	62 %	2017 EUR	1,40		73,7	Santos & Hanak (2022)
Pulp and Paper		39,0	90 %	2017 EUR	1,40		54,8	Santos & Hanak (2022)
Refineries	145,5	189,4		2015 EUR	1,42	206,2	268,4	IEAGHG (2017e)
Refineries		118,0	59 %	2007 EUR	1,53		180,6	Kuramochi et al. (2012)
Refineries		54,0	84 %	2007 EUR	1,53		82,6	Kuramochi et al. (2012)
Refineries		55,0	77 %	2007 EUR	1,53		84,2	Kuramochi et al. (2012)
Refineries		106,0	67 %	2007 EUR	1,53		162,2	Kuramochi et al. (2012)
Refineries		72,0	77 %	2007 EUR	1,53		110,2	Kuramochi et al. (2012)
Refineries	78,3	82,4	85 %	2017 EUR	1,40	110,0	115,7	Santos & Hanak (2022)
Refineries	53,6	58,7	69 %	2017 EUR	1,40	75,3	82,4	Santos & Hanak (2022)
Refineries	89,6	92,7	77 %	2017 EUR	1,40	125,8	130,2	Santos & Hanak (2022)
SCPC Power Plant		62,0	88 %	2017 EUR	1,40		87,1	Garcia et al. (2022)
SCPC Power Plant		57,0	92 %	2017 EUR	1,40		80,0	Garcia et al. (2022)
SCPC Power Plant	34,0	74,0		2010 USD	1,42	46,3	100,7	GCCSI (2011)
SCPC Power Plant		116,1	90 %	2014 EUR	1,39		161,8	Porter et al. (2017)
SCPC Power Plant		103,5	92 %	2014 EUR	1,39		144,2	Porter et al. (2017)
SCPC Power Plant		71,0	100 %	2014 EUR	1,39		98,9	Porter et al. (2017)
SCPC Power Plant	100,2	102,1	90 %	2014 EUR	1,39	139,6	142,3	Porter et al. (2017)
SCPC Power Plant	45,0	70,0	87 %	2013 USD	1,29	55,4	86,2	Rubin et al. (2015)
Waste-to-energy	35,0	50,0	90 %	2019 USD	1,27	42,4	60,6	Kearns (2019)

Table A1.3. Estimates on cost of avoided CO_2 captured ($€_{2022}/tCO_2$) from the literature. Cost estimates are first inflated using the EU27 PPI or the US PPI (IF), depending on the source currency, then converted to EUR using the USD/EUR exchange rate on July 1, 2022. Capture rates, when available, represent total plant emissions share. IGCC = Integrated gasification combined cycle (coal or NG); NGCC = Natural gas combined cycle (NG); SCPC = Supercritical pulverised coal (coal).